NGSI Methane Emissions Intensity Protocol

Version 3.0

Natural Gas Sustainability Initiative

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

SLR

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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 Version 2.0 and this Version 3.0 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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NGSI Protocol 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
January 2026	Issuance of NGSI Protocol Version 3.0, 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. This document, 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, using the accompanying NGSI reporting templates.

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 regularly request information on natural gas company performance based on methane intensity. While intensity has become 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** • **Gathering & Boosting** • **Processing** • **Transmission & Storage** • **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 1.0 of the NGSI Protocol was publicly released in February 2021. Version 2.0 of the Protocol was released in September 2024; it incorporated a number of updates to Version 1.0 to maintain consistency with

EPA methodologies and other industry standardized methodologies being used for other reporting programs. Version 2.0 was aligned with the version of EPA's Greenhouse Gas Reporting Program ("GHGRP") Subpart W regulations (40 CFR Part 98) that were in effect as of January 1, 2024. Version 2.0 did not incorporate the revisions to Subpart W that were finalized and published in the *Federal Register* on May 14, 2024, and effective on January 1, 2025 for reporting year ("RY") 2025 emissions.[1] Version 3.0 of the NGSI Protocol incorporates the May 2024 revisions to Subpart W, the most recently available emission factors from EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks ("GHG Inventory" or "GHGi"), and some additional updates as detailed in the following sections of this document.[2]

[1] Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, 89 Fed. Reg. 42,062 (May 14, 2024), https://www.govinfo.gov/content/pkg/FR-2024-05-14/pdf/2024-08988.pdf.

[2] In September 2025, EPA proposed to eliminate most of the GHGRP, remove the natural gas distribution segment from Subpart W and discontinue the segment's reporting obligations, and delay until RY2034 the reporting obligations of the remaining Subpart W segments. *See* Reconsideration of the Greenhouse Gas Reporting Program, 90 Fed. Reg. 44,591 (Sept. 16, 2025), https://www.govinfo.gov/content/pkg/FR-2025-09-16/pdf/2025-17923.pdf. However, as of the date of this Version 3.0 of the NGSI Protocol, the GHGRP reconsideration proposal has not yet been finalized and the GHGRP is still in effect. NGSI will address the impact of modifications to the GHGRP if and when EPA issues a final rule effectuating changes that are relevant to NGSI.

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 importance of environmental and social goals for customers, as well as the 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 NGSI 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 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 Versions 2.0 and 3.0 of the NGSI Protocol was similarly informed by feedback from natural gas 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 Versions 2.0 and 3.0 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 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 derived 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 E, 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 key dates associated with the substantive development and issuance of Versions 1.0 to 3.0 of the NGSI Protocol and the accompanying segment-specific reporting templates:

- **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 C for a list of key resources reviewed).
- **July 2019:** NGSI 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 revised version released in April 2021. In July 2021, NGSI issued updated reporting templates for gathering and boosting, processing, and production to correct an inconsistency identified by participating pilot companies. No changes were needed for the distribution or transmission and storage reporting templates.
- **May 2022, April 2023:** NGSI released updates to the distribution reporting 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 and released as Version 2.0. The new version incorporated 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 the Version 2.0 update process, there were opportunities for stakeholders to review and comment. The distribution template was also updated to reflect the most recent HDD data.
- **October 2024, February 2025, June 2025:** Version 2.0 of the distribution segment reporting template was updated to correct a formula error in one of the worksheet tabs. The processing template and the transmission and storage template were each updated to allow users to un-hide and use additional facility columns. The distribution template was updated to reflect the HDD data set that corresponds with RY2024.
- **February 2025 to January 2026:** Version 2.0 of the NGSI Protocol and the segment specific reporting templates were revised and released as Version 3.0. This updated version incorporates the May 2024 revisions to Subpart W of the GHGRP, the 2025 GHGi emission factors,[3] the distribution template HDD data corresponding with RY2025,[4] and several other template updates to improve the user experience.

[3] EPA did not formally publish the final version of the 2025 GHGi as it typically does each April; rather, it was made available to the public from May to August 2025 via a Freedom of Information Act ("FOIA") request. Version 3.0 of the NGSI Protocol and Reporting Templates incorporates the 2025 GHGi's natural gas and petroleum systems emission factors for each industry segment. The 2025 GHGi and accompanying data files are available via this Environmental Defense Fund website: https://www.edf.org/freedom-information-act-documents-epas-greenhouse-gas-inventory.

[4] The Version 3.0 distribution segment reporting template includes the HDD data released for the 12-month period from July 1, 2024 to June 30, 2025. This HDD data is used to normalize the distribution segment throughput for RY2025. As in past versions of NGSI, the distribution segment reporting template must be updated annually to reflect the correct HDD dataset corresponding for each reporting year.

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 among participating companies operating ***within the same natural gas industry segment***. Due to the operational differences and complexity of normalizing the throughput denominator across the various natural gas industry segments, this Protocol does not include guidance or methodology for summing 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, but have been identified by EPA through the 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.[5] 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.

Version 3.0 of the NGSI Protocol adopts updated emission factors from the GHG Inventory that was made public in 2025 and incorporates calendar year 2023 emissions (*i.e.*, the 2025 GHGi). As has been the case in several recent years, the 2025 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—

[5] EPA sunset the Methane Challenge Program at the end of 2024. *See* EPA, Methane Challenge Partnership (2016 – 2024) (last updated Jan. 14, 2025), https://www.epa.gov/natural-gas-star-program/methane-challenge-partnership-2016-2024.

as noted in the segment-specific tables below. Thus, except where noted otherwise, the GHG Inventory emission factors used in NGSI Protocol Version 3.0 are from the 2025 GHGi and are segment-specific factors.

- **Segment Definitions.** The NGSI Protocol uses segment definitions that are consistent with the definitions in Subpart W of the GHGRP.
- **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, and 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 each based on information reported to EPA 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 unintentional under-reporting methane intensity for companies within 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 potential double-counting of throughput, it aims to lessen it because the annual reporting of a company's pipeline-specific throughput to PHMSA reflects a 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 were updated in NGSI Version 2.0 primarily to make the templates more user friendly by making functional and formatting improvements, streamlining data entry, and correcting/updating emission calculation formulas and factors. The Version 3.0 updates to the reporting templates primarily incorporate the updated and new calculation methodologies, activity data, and measurement methods specified in the May 2024 revisions to GHGRP Subpart W, along with some additional updates to improve the user experience. The templates include data entry worksheets for a company's GHGRP facilities (*i.e.*, those that trigger reporting to the GHGRP) and a company's Non-GHGRP facilities (*i.e.*, those that do not trigger reporting to the 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 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, for 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 3.0 of the NGSI Protocol are available for download as Excel files from both 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 in Version 2.0 and refined in Version 3.0. 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 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 were 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 recommended that users also perform their own separate QA/validation on their data entered in these reporting templates.

- ***Company Information Worksheet:*** A company information worksheet was added to all segment reporting templates. Make sure to complete this worksheet first by entering the company name and name(s) 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 finished entering your data in the GHGRP and Non-GHGRP worksheets. The same results are also summarized in the Public Disclosure Data worksheet.

- ***GHGRP Emission Sources Itemized:*** All templates now include itemized GHGRP sources, regardless of whether source-level data input is required. For Production, Gathering & Boosting, and Transmission & Storage, this detail is optional. For Processing and Distribution, source-level data entry remains required. Note: this update was made for the first time in Version 3.0 to enhance comparability and consistency across templates.

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 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 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 and the methane emissions associated with the natural gas value chain from production to distribution. Since production, gathering & boosting, and processing segments can produce and handle natural gas and 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 products 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 separately allocate emissions by product. For these two segments, the methane emissions are 100 percent allocated to the natural gas that gets transported.**

3. Protocol for the Onshore Production Segment

For NGSI reporting purposes, the onshore production segment definitions are consistent with the definitions in the May 2024 revisions to GHGRP Subpart W, except that NGSI addresses natural gas only:

- **Onshore natural gas production**[6] 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. Onshore natural gas production also means all equipment on or associated with a single enhanced oil recovery ("EOR") well-pad using CO_2 or natural gas injection.
- **Production facility**[7] means all natural-gas equipment on a single well-pad or associated with a single well-pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore natural gas production owner or operator and that 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 Version 3.0 of the NGSI Protocol are from the 2025 GHGi. In addition to the individual emission sources listed in Table 2, a general emission source called "Other Large Release Events" ("OLRE") is also included in Table 2 as a new source consistent with the May 2024 Subpart W revisions. This emission source generally refers to non-routine, high-volume, unintentional releases of GHGs due to equipment failures, accidents, or emergency releases. The Version 3.0 updates are summarized below:

- OLRE is defined as any planned or unplanned uncontrolled release of gases or liquids from wells or other equipment not covered by other calculation methods in 40 CFR 98.233.[8] Examples include:
    - Well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire, or explosion
- OLRE is distinct from routine emission sources like flares, blowdown vents, pneumatic devices, and equipment leaks.

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[6] *See* 40 CFR 98.230(a)(2).

[7] *See* 40 CFR 98.238.

[8] *See* 40 CFR 98.238 for full definition.

- Not every release is required to be measured. However, compliance with super-emitter response protocols under 40 CFR 60.5371, 60.5371a, or 60.5371b is required. If EPA or facility-funded monitoring or measurement data demonstrates that a release meets, exceeds, or may be reasonably anticipated to meet or exceed the applicable emissions threshold criteria listed below for the event, then emissions must be calculated and reported.
- Emission thresholds that trigger reporting include either of the following:
  - **Unreported sources:** If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions)
  - **Reported sources:** If emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported under 40 CFR 98.233 (a) through (h), (j) through (s), (w), (x), (dd), or (ee).
- This protocol recognizes that there are some sources represented in the GHGi that also could meet the definition and threshold of OLRE. For Production, this includes Compressor Starts and Pressure Relief Valve ("PRV") Releases. **Important: To avoid potential double counting of these emissions, the following additional guidance is given for these two sources.**
  - For any Compressor Starts that equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology. To avoid double counting, the GHGi methodology should only be applied when a Compressor Start event is not reported under OLRE. If a Compressor Start event is included in OLRE, the GHGi calculation should assume zero Compressor Start emissions for that event.
  - For any PRV releases where the valve emissions equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology.

Table 2 includes the OLRE emission source, GHGRP regulatory references, and general applicability and reporting methodologies. For further details on qualification for OLRE and/or calculation methodology, please refer to 40 CFR 98.233(y). In addition, Appendix B includes additional detailed guidance regarding OLRE.

More generally, the purpose of Table 2 is to provide simplified, top-level regulatory references and general estimation methodology for user convenience ***only***. You should always review regulatory text directly in the Code of Federal Regulations ("CFR") when making any regulatory compliance decisions. ***Please do not rely solely on this Protocol to determine the applicable GHGRP emission estimation methodology(ies) and detailed reporting requirements for any emission source***.

Table 2. Onshore Production Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Acid Gas Removal Units (AGRU) and Nitrogen Removal Units (NRU)	40 CFR 98.233(d)(2)	Subpart W – Calculation Method 2 if a vent meter is installed, use the composition and annual volume of vent gas to calculate emissions of CH_4.
	40 CFR 98.233(d)(3)	Subpart W – Calculation Method 3 if a vent meter is not installed, use inlet and/or outlet gas flow rate and gas composition.
	40 CFR 98.233(d)(4)	Subpart W – Calculation Method 4 if a vent meter is not installed, use a standard simulation software package. If a vent meter is installed at an AGRU, you must determine the difference between the measured and simulated vent gas volume.
	40 CFR 98.233(d)(11)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(d)	If venting is routed to combustion, calculate and report under 40 CFR 98.233(z).
Associated Gas Venting	40 CFR 98.233(m)(1)	Subpart W – If you measure the associated gas flow to a vent using a continuous flow measurement device, you must use the measured flow volumes to calculate vented associated gas emissions.
	40 CFR 98.233(m)(2)	Subpart W – If you do not measure using a continuous flow measurement device, calculate using volume of oil produced, gas to oil ratio ("GOR"), and volume of associated gas sent to sales.
Associated Gas Flaring	40 CFR 98.233(m)	Subpart W – If associated gas venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Blowdown Vent Stacks (Equipment and Pipeline) with volume ≥ 50 ft^3	40 CFR 98.233(i)(1) 40 CFR 98.233(i)(2) 40 CFR 98.233(i)(3)	Subpart W – To determine applicability, calculate unique physical volumes between isolation valves using engineering estimates based on best available data. Subpart W – Calculation method using engineering calculation by unique physical volume. Subpart W – Calculation method using direct measurement of emissions using a flow meter. 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.[9]
Combustion Units (per 40 CFR 98.232(c)(22), stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, including: well drilling and completion equipment, workover equipment, dehydrators, compressors, electrical generators, steam boilers, and process heaters)	40 CFR 98.233(z)(6) and (7) 40 CFR 98.233(z)(1) and (2) 40 CFR 98.233(z)(4)	Subpart W – only external combustion units greater than 5 MMBtu/hr and internal combustion units greater than 130 hp are applicable. Subpart W, as applicable based on fuel type and specifications – for each unit calculate emissions for applicable Tier or higher heating value ("HHV") using methods in Subpart C. Use fuel usage records and measured or estimated composition for calculations. Subpart W – For natural gas internal combustion engine or turbine, use either a measurement-based emission factor, manufacturer-based emission factor, or default methane emission factors in Table W-7.

[9] Alternate method is adapted from the ONE Future program alternate method for Transmission Station Blowdowns. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 43 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Centrifugal (with wet seal oil degassing vents and dry seal vents)	40 CFR 98.233(o)(10) 40 CFR 98.233(o)(10)(i) 40 CFR 98.233(o)	Subpart W – Calculation using default population emission factor for compressors with wet seal oil degassing vents using Equation W-25B. Subpart W – Compressors that are subject to OOOOb standards or an applicable approved state plan or federal plan in 40 CFR Part 62 must conduct volumetric measurements as required by 40 CFR 60.5380b(a)(5) or the applicable plan, as well as conducting all additional volumetric measurements and calculating emissions as specified in 40 CFR 98.233(o). Subpart W – Compressors that are not subject to OOOOb standard or an applicable approved state plan or federal plan in 40 CFR Part 62 may elect to conduct volumetric measurements and calculate emissions as specified in 40 CFR 98.233(o). If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in 40 CFR 98.233(z). If routed to vapor recovery system, 40 CFR 98.233(o)(1) through (11) do not apply.
Compressors, Reciprocating	40 CFR 98.233(p)(10) 40 CFR 98.233(p)(10)(i) 40 CFR 98.233(p)	Subpart W – Calculation using default population emission factor for reciprocating compressors using Equation W-29E. Subpart W – Compressors that are subject to OOOOb standards or an applicable approved state plan or federal plan in 40 CFR Part 62 must conduct volumetric measurements as required by 40 CFR 60.5385b(b), as well as conducting any additional volumetric measurements and calculating emissions as specified in 40 CFR 98.233(p). Compressors not subject to the above may elect to conduct measurements and calculate emissions as specified in 40 CFR 98.233(p)(6) through (9) based on mode in which the compressor was found at time of measurement. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in 40 CFR 98.233(z). If routed to vapor recovery system, 40 CFR 98.233(p)(1) through (11) do not apply.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Crankcase Vents (for each reciprocating internal combustion engine ("RICE") crankcase vent with heat capacity > 1mmBtu/hr or equivalent of >130 hp)	40 CFR 98.233(ee)(1) 40 CFR 98.233(ee)(2) 40 CFR 98.233(ee)	Subpart W – Calculation Method 1 using direct measurement to determine annual RICE emissions. Subpart W – Calculation Method 2 using default emission factor applicable per hour per RICE. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
Dehydrator Vents, Glycol	40 CFR 98.233(e) 40 CFR 98.233(e)(1) 40 CFR 98.233(e)(2) 40 CFR 98.233(e)(4) 40 CFR 98.233(e)(5)	Subpart W – Glycol dehydrator methodology based on annual average daily natural gas throughput and/or emissions routing: • ≥ 0.4 mscf/day use Calculation Method 1. • > 0 mscf/day and < 0.4 mscf/day use either Calculation Method 1 or 2. • If vents are routed to vapor recovery system, use methods in 98.233(e)(4). • If vents routed to regenerator firebox/fire tubes or other non-flare combustion units, use methods in 98.233(e)(5). • If vents routed to flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). Subpart W – Calculation Method 1 using computer modeling for both still vent and, if applicable, flash tank vents. Required if software program is used for compliance with federal or state regulations, air permit requirements or annual emission inventory. Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators. Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n). Subpart W – Calculation for combustion emissions when routed to non-flare combustion unit using flow and composition. If CEMS is installed on a combustion device, use Tier 4 Calculation Method in Subpart C.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Dehydrator Vents, Desiccant	40 CFR 98.233(e)(3) 40 CFR 98.233(e)(5)	Subpart W – dehydrators of any size that use desiccant must use Calculation Method 3 to calculate amount of gas vented during depressurization for desiccant refilling. Desiccant dehydrator emissions calculated via Method 3 do not have to be calculated separately using the method specified in 40 CFR 98.233(i) for blowdown vent stacks. Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n). For any desiccant dehydrator emissions routed to a non-flare combustion unit, calculate the combusted emissions as specified in 40 CFR 98.233(e)(5)(i) through (iii).
Drilling Mud Degassing	40 CFR 98.233(dd)(1) 40 CFR 98.233(dd)(2) 40 CFR 98.233(dd)(3)	Subpart W – Calculation Method 1 using mudlogging measurements from the penetration of the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore to develop measurement-based emission factor. Subpart W – Calculation Method 2 using default emission factor for water-based drilling muds, oil-based drilling muds and synthetic drilling muds. Subpart W – Calculation Method 3 combines intermittent mudlogging and default methodology for intermittent measurements.
EOR Hydrocarbon Liquids Dissolved CO_2[10]	40 CFR 98.233(x)	Subpart W – Calculation using amount of CO_2 retained in hydrocarbons using annual samples downstream of storage tank and total volume produced.
EOR Injection Pump Blowdown[10]	40 CFR 98.233(w)	Subpart W – Calculation using the total injection pump system volume between isolation valves and events per calendar year.

[10] EOR Hydrocarbon Liquids Dissolved CO_2 and EOR Injection Pump Blowdown are listed in this table for completeness; however, they are excluded from the templates as they only emit CO_2 (no methane emissions) and therefore are outside the scope of this protocol.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Equipment Leaks (excluding thief hatches or other openings on storage vessels)	40 CFR 98.233(q)(2) 40 CFR 98.233(q)(3) 40 CFR 98.233(r)	Subpart W – Calculation Method 1, must use facility-specific leaker emission factor if available (calculated per 40 CFR 98.233(q)(4)) or use appropriate default whole gas emission factors consistent with well type and service (gas or crude) in Table W-2. Subpart W – Calculation Method 2 if leaks are detected during survey, may elect to measure volumetric flow or use default rate for component and site type, only using a default rate if leak cannot safely be measured. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor as specified in 40 CFR 98.233(q)(4). Subpart W – Calculation using component counts for each wellhead, separator, meter/piping, compressor, dehydrator, heater, and storage vessel, and the appropriate default population emission factors.
Flare Stacks	40 CFR 98.233(n)(5) 40 CFR 98.233(n)(6) 40 CFR 98.233(n)(9) 40 CFR 98.233(n)(10)	Subpart W – Calculation using applicable default destruction and combustion efficiencies, alternative test method, or directly measured destruction and combustion efficiencies for Tier 1, Tier 2, Tier 3, or alternative test method for the pilot, flow determination, gas composition. For CEMS with a CO_2 concentration monitor and volumetric flow monitor for combustion gases from the flare, must follow Tier 4 Calculation Method in Subpart C. Disaggregate total emissions from the flare as applicable to each source type that routed emissions to the flare.
(Well Venting for) Liquids Unloadings	40 CFR 98.233(f)(1) 40 CFR 98.233(f)(2) 40 CFR 98.233(f)(3) 40 CFR 98.233(f)	Subpart W – Calculation Method 1 using direct measurement for each unloading combination (automated or manual, with or without plunger lift) for each tubing diameter and pressure group. Subpart W – Calculation Method 2 using engineering calculations for wells without plunger lifts. Subpart W – Calculation Method 3 using engineering calculations for wells with plunger lifts. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Other Large Release Events ("OLRE")	40 CFR 98.233(y)(1)	You must report an OLRE if it meets either of these emission thresholds at any point during a release: • **Unreported Sources**: If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions). • **Reported Sources**: If methane emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported using methodologies found elsewhere in 40 CFR 98.233(a)–(h), (j)–(s), (w), (x), (dd), or (ee).
	40 CFR 98.233(y)(2)–(5)	Subpart W – Calculation based on measurement data, if available, and/or process knowledge and engineering estimates and composition of the gas released. If multiple release points have a common root cause (*e.g.*, system overpressure), treat them as one OLRE. For multi-year events, apportion emissions across years by event duration or variable rates.
	40 CFR 98.233(y)(6)	Include emissions upon receipt of EPA-provided notification under the super emitter program or an applicable approved state plan or federal plan.
	40 CFR 98.238	OLRE does not include blowdowns calculated pursuant to 40 CFR 98.233(i).
Pneumatic Device (Controller) Vents, Natural gas	40 CFR 98.233(a)(1)	Subpart W – Calculation Method 1 using continuous measurement via flow monitor of natural gas supply line dedicated to device(s).
	40 CFR 98.233(a)(2)	Subpart W – Calculation Method 2 using flow meter to measure volumetric flow of all devices in the same calendar year to develop site-specific measurement-based emission factors by device type.
	40 CFR 98.233(a)(3)	Subpart W – Calculation Method 3: o Continuous high bleed and continuous low bleed devices using count of devices and default emission factors. o Intermittent bleed devices using either malfunctioning or properly operating emission factors per site, determined from one complete monitoring survey of all devices at a site in a calendar year.
	40 CFR 98.233(a)(4)	Subpart W – Calculation Method 4 using default emission factors for low-bleed, high-bleed, and intermittent-bleed devices as specified in Table W-1.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Pneumatic (Chemical Injection) Pump Vents, Natural Gas Driven	40 CFR 98.233(c)(1)	Subpart W – Calculation Method 1 using continuous measurement of natural gas supplied to pumps.
	40 CFR 98.233(c)(2)	Subpart W – Calculation Method 2 using measurement-based emission factors from periodic measurements.
	40 CFR 98.233(c)(3)	Subpart W – Calculation Method 3 using actual count of devices and default emission factors.
	40 CFR 98.233(c)(4)	Subpart W – Calculation for periods when venting goes directly to atmosphere (but are normally routed to flare, combustion, or vapor recovery system): use the applicable method from 40 CFR 98.233(c)(1), (2), or (3) to calculate emissions for the portion of the year where venting occurred. When venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). When venting is routed to combustion, calculate and report emissions as specified in 40 CFR 98.233(z).

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)

Hydrocarbon Liquids and Produced Water Storage Tanks	40 CFR 98.233(j)	• For tanks receiving hydrocarbon liquids from wells, gas-liquid separators, or non-separator equipment with annual average daily throughput:
		  ○ ≥ 10 barrels per day use Calculation Method 1 or 2
		  ○ > 0 and < 10 barrels per day use Calculation Method 1, 2, or 3.
		• For tanks receiving produced water, use Calculation Method 1, 2, or 3.

	40 CFR 98.233(j)(1)	Subpart W – Calculation Method 1 using computer modeling for gas-liquid separators or non-separator equipment. Required if flash emissions modeling software is necessary for compliance with regulations, air permit requirements, or annual inventory reporting.
	40 CFR 98.233(j)(2)	Subpart W – Calculation Method 2 using mass balance approach assuming all methane in solution at the well is emitted from hydrocarbons or produced water sent to tanks.
	40 CFR 98.233(j)(3)	Subpart W – Calculation Method 3 using an emission factor and population counts for hydrocarbon liquids or produced water flowing to gas-liquid separators, non-separator equipment, or directly to atmospheric storage.
	40 CFR 98.233(j)(4)	For periods when tank is not routed to vapor recovery system or flare, estimate average hourly vented emissions using annual operating hours to calculate emissions for the total hours when vented directly to atmosphere.
	40 CFR 98.233(j)	When venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(j)(5)	Subpart W – Calculate emissions from gas-liquid separator liquid dump valves that did not close properly based on duration of failed valve closing, only if using Calculation Method 1 or 2.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Well Venting During Well Completions / Workovers with Hydraulic Fracturing	40 CFR 98.233(g)(1)(i) 40 CFR 98.233(g)(1)(ii) 40 CFR 98.233(g)	Subpart W, for gas or oil wells – Calculation Method 1 using measured flowback rate from example completions or workovers in a sub-basin and well type combination and engineering calculations in Equation W-10A. Subpart W, for gas wells only – Calculation Method 2 when gas flowback volume is measured for each completion or workover in a sub-basin and well type combination using measured vented volume from each well in Equation W-10B. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
Well Venting During Well Completions / Workovers without Hydraulic Fracturing	40 CFR 98.233(h)	Subpart W, for workovers – Calculation using a count of workovers and an emission factor in Equation W-13A. Subpart W, for completions – Calculation using measured production rate in Equation W-13B. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
Well Testing Venting & Flaring	40 CFR 98.233(l)(3) 40 CFR 98.233(l)	Subpart W, for oil wells – Calculation using gas-to-oil ratio ("GOR"), average annual flow rate, and testing duration in Equation W-17A. Subpart W, for gas wells – Calculation using average annual production rate and testing duration in Equation W-17B. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).

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

Emission Source	Description of Quantification Method	GHG Inventory CH_4 Emission Factor
Compressor Starts	GHG Inventory emission factor multiplied by number of compressors	172.03 kg/compressor
Pressure Relief Valve ("PRV") Releases	GHG Inventory emission factor multiplied by number of valves	0.69 kg/pressure relief valve
Note: GHG Inventory emission factors are available in Annex 3.6, Table 3.6-2 (Average CH_4 Emission Factors) of the 2025 GHGi.		

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}). 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.[11]
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 $\frac{E_{ng}}{E_{ng}+E_{liq}}$.
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.[12]

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

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

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 find it useful to also report certain elements at the facility level and/or allocate emissions at the basin level to provide more granular data.

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

Disclosure Element	Description
Total Methane Emissions (metric tons)	Total onshore production segment methane emissions from GHGRP and Non-GHGRP facilities; sum of emissions from the sources listed in Tables 1 and 2
Produced Natural Gas (thousand standard cubic feet)	Total volume of natural gas produced by GHGRP and Non-GHGRP facilities
Energy Content of Produced Natural Gas (MMBtu per thousand standard cubic feet)	Raw gas higher heating value (weighted average energy content of all gas production)
Methane Content of Produced Natural Gas (%)	Methane content of produced natural gas (weighted average methane content of all gas production)
Produced Crude Oil and Condensate (barrels)	Total crude oil and condensate produced for sales by GHGRP and Non-GHGRP facilities
Energy Content of Produced Crude Oil and Condensate (MMBtu per barrel)	Crude oil and condensate heating value (weighted average energy content from all oil production)
Gas Ratio (%)	Share of natural gas produced on an energy equivalent basis
NGSI Methane 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 in the May 2024 revisions to GHGRP Subpart W, except that NGSI addresses natural gas only:

- **Onshore natural gas gathering and boosting**[13] means gathering pipelines and other equipment used to collect natural gas from onshore production wells and used to compress, dehydrate, sweeten, or transport the natural gas to a downstream endpoint, typically 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 GHGRP Subpart W. Gathering and boosting equipment does not include equipment reported under any other industry segment. 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**[14] 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 Subpart W.[15] 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 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 3.0 are from the 2025 GHGi . In addition to the individual emission sources listed in Table 5, a general emission source called "Other Large Release Events" ("OLRE") is also included in Table 5 as a new source consistent with the May 2024 Subpart W revisions. This emission source generally

[13] *See* 40 CFR 98.230(a)(9).

[14] *See* 40 CFR 98.238.

[15] Subpart W defines "basin" as "geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see 40 CFR § 98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see 40 CFR § 98.7)." 40 CFR 98.238.

refers to non-routine, high-volume, unintentional releases of GHGs due to equipment failures, accidents, or emergency releases. The Version 3.0 updates are summarized below:

- OLRE is defined as any planned or unplanned uncontrolled release of gases or liquids from wells or other equipment not covered by other calculation methods in 40 CFR 98.233.[16] Examples include:
    - Well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire or explosion
- OLRE is distinct from routine emission sources like flares, blowdown vents, pneumatic devices, and equipment leaks.
- Not every release is required to be measured. However, compliance with super-emitter response protocols under 40 CFR 60.5371, 60.5371a, or 60.5371b is required. If EPA or facility-funded monitoring or measurement data demonstrates a release meets or exceeds, or may be reasonably anticipated to meet or exceed the applicable emissions threshold criteria listed below for the event, then emissions must be calculated and reported.
- Emission thresholds that trigger reporting include either of the following:
    - **Unreported sources:** If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions)
    - **Reported sources:** If emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported under 40 CFR 98.233 (a) through (h), (j) through (s), (w), (x), (dd), or (ee).
- This protocol recognizes that there are some sources represented in the GHGi that also could meet the definition and threshold of OLRE. For Gathering & Boosting, this includes Compressor Starts and Damages (Gathering & Boosting Upsets: Mishaps). **Important**: **To avoid potential double counting of these emissions, the following additional guidance is given for these two sources.**
    - For any Compressor Starts that equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology. To avoid double counting, the GHGi methodology should only be applied when a Compressor Start event is not reported under OLRE. If a Compressor Start event is included in OLRE, the GHGi calculation should assume zero Compressor Start emissions for that event.
    - For Damages (Gathering & Boosting Upsets: Mishaps), if emissions equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology. Zero gathering-pipeline miles should be entered into the calculation template for that facility.

Table 5 includes the OLRE emission source, GHGRP regulatory references, and general applicability and reporting methodologies. For further details on qualification for OLRE and/or calculation methodology, please refer to 40 CFR 98.233(y). In addition, Appendix B includes additional detailed guidance regarding OLRE.

More generally, the purpose of Table 5 is to provide simplified, top-level regulatory references and general estimation methodology for user convenience ***only***. You should always review regulatory text directly in the

[16] *See* 40 CFR 98.238 for full definition.

Code of Federal Regulations ("CFR") when making any regulatory compliance decisions. ***Please do not rely solely on this Protocol to determine the applicable GHGRP emission estimation methodology(ies) and detailed reporting requirements for any emission source***.

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

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Acid Gas Removal Units (AGRU) and Nitrogen Removal Units (NRU)	40 CFR 98.233(d)(2)	Subpart W – Calculation Method 2 if a vent meter is installed, use the composition and annual volume of vent gas to calculate emissions of CH_4.
	40 CFR 98.233(d)(3)	Subpart W – Calculation Method 3 if a vent meter is not installed, use inlet and/or outlet gas flow rate and gas composition.
	40 CFR 98.233(d)(4)	Subpart W – Calculation Method 4 if a vent meter is not installed, use a standard simulation software package. If a vent meter is installed at an AGRU, you must determine the difference between the measured and simulated vent gas volume.
	40 CFR 98.233(d)(11)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(d)	If venting is routed to combustion, calculate and report under 40 CFR 98.233(z).
Blowdown Vent Stacks (Equipment and Pipeline) with volume ≥ 50 ft^3	40 CFR 98.233(i)(1)	Subpart W – To determine applicability, calculate unique physical volumes between isolation valves using engineering estimates based on best available data.
	40 CFR 98.233(i)(2)	Subpart W – Calculation method using engineering calculation method by unique physical volume.
	40 CFR 98.233(i)(3)	Subpart W – Calculation method using direct measurement of emissions using a flow meter.
		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.[17]

[17] Alternate method is adapted from the ONE Future program alternate method for Transmission Station Blowdowns. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 43 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Combustion Units (per 40 CFR 98.232(j)(12), stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, includes dehydrators, compressors, electrical generators, steam boilers, and process heaters)	40 CFR 98.233(z)	Subpart W – only external combustion units greater than 5 MMBtu/hr and internal combustion units greater than 130 hp are applicable. Subpart W, as applicable based on fuel type and specifications – for each unit calculate emissions for applicable Tier or higher heating value ("HHV") using methods in Subpart C. Use fuel usage records and measured or estimated composition for calculations. For natural gas internal combustion engine or turbine, use either a measurement-based emission factor, manufacturer-based emission factor, or default methane emission factors in Table W-7.
Compressors, Centrifugal	40 CFR 98.233(o)(10)	Subpart W – Calculation using default population emission factor for compressors with wet seal oil degassing vents using Equation W-25B.
	40 CFR 98.233(o)(10)(i)	Subpart W – Compressors that are subject to OOOOb standards or an applicable approved state plan or federal plan in 40 CFR Part 62 must conduct volumetric measurements as required by 40 CFR 60.5380b(a)(5) or the applicable plan, as well as conducting all additional volumetric measurements and calculating emissions as specified in 40 CFR 98.233(o).
	40 CFR 98.233(o)	Subpart W – Compressors that are not subject to OOOOb standard or an applicable approved state plan or federal plan in 40 CFR Part 62 may elect to conduct volumetric measurements and calculate emissions as specified in 40 CFR 98.233(o). If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in 40 CFR 98.233(z). If routed to vapor recovery system, 40 CFR 98.233(o)(1) through (11) do not apply.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Reciprocating	40 CFR 98.233(p)(10) 40 CFR 98.233(p)(10)(i) 40 CFR 98.233(p)	Subpart W – Calculation using default population emission factor for reciprocating compressors using Equation W-29E. If subject to reciprocating compressor standards in OOOOb or an applicable approved state plan or federal plan in 40 CFR Part 62, must conduct volumetric measurements as required by 40 CFR 60.5385b(b), as well as conducting any additional volumetric measurements and calculating emissions as specified in 40 CFR 98.233(p). Compressors not subject to the above may elect to conduct measurements and calculate emissions as specified in 40 CFR 98.233(p)(6) through (9) based on mode in which the compressor was found at time of measurement. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in 40 CFR 98.233(z). If routed to vapor recovery system, 40 CFR 98.233(p)(1) through (11) do not apply.
Crankcase Vents (for each reciprocating internal combustion engine ("RICE") crankcase vent with heat capacity > 1mmBtu/hr or equivalent of >130 hp)	40 CFR 98.233(ee)(1) 40 CFR 98.233(ee)(2) 40 CFR 98.233(ee)	Subpart W – Calculation Method 1 using direct measurement to determine annual RICE emissions. Subpart W – Calculation Method 2 using default emission factor applicable per hour per RICE. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Dehydrator Vents, Glycol	40 CFR 98.233(e)	Subpart W – Glycol dehydrator methodology based on annual average daily natural gas throughput and/or emissions routing: • ≥ 0.4 mscf/day use Calculation Method 1. • > 0 mscf/day and < 0.4 mscf/day use either Calculation Method 1 or 2. • If vents are routed to vapor recovery system, use methods in 98.233(e)(4). • If vents routed to regenerator firebox/fire tubes or other non-flare combustion units, use methods in 98.233(e)(5). • If vents routed to flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(e)(1)	Subpart W – Calculation Method 1 using computer modeling for both still vent and, if applicable, flash tank vents. Required if software program is used for compliance with federal or state regulations, air permit requirements or annual emission inventory.
	40 CFR 98.233(e)(2)	Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators.
	40 CFR 98.233(e)(4)	Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(e)(5)	Subpart W – Calculation for combustion emissions when routed to non-flare combustion unit using flow and composition. If CEMS is installed on a combustion device, use Tier 4 Calculation Method in Subpart C.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Dehydrator Vents, Desiccant	40 CFR 98.233(e) 40 CFR 98.233(e)(5)	Subpart W dehydrators of any size that use desiccant must use Calculation Method 3 to calculate amount of gas vented during depressurization for desiccant refilling. Desiccant dehydrator emissions calculated via Method 3 do not have to be calculated separately using the method specified in 40 CFR 98.233(i) for blowdown vent stacks. Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n). For any desiccant dehydrator emissions routed to a non-flare combustion unit, calculate the combusted emissions as specified in 40 CFR 98.233(e)(5)(i) through (iii).
Equipment Leaks, from components and major equipment (excluding thief hatches or other openings on storage vessels)	40 CFR 98.233(q)(2) 40 CFR 98.233(q)(3) 40 CFR 98.233(r)	Subpart W – Calculation Method 1, must use facility-specific leaker emission factor if available (calculated per 40 CFR 98.233(q)(4)) or use appropriate default whole gas emission factors for components in gas service in Table W-2. Subpart W – Calculation Method 2 if leaks are detected during survey, may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor as specified in 40 CFR 98.233(q)(4). Subpart W – Calculation using component count for each wellhead, separator, meters/piping, compressor, dehydrator, heater, and storage vessel, and the appropriate default population emission factors.
Equipment Leaks, Gathering Pipelines	40 CFR 98.233(r)	Subpart W – Calculated using count of miles of pipeline by material type (protected steel, unprotected steel, plastic, or cast iron) and default emission factors.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Flare Stacks	40 CFR 98.233(n)(5) 40 CFR 98.233(n)(6)	Subpart W – Calculation using applicable default destruction and combustion efficiencies, alternative test method, or directly measured destruction and combustion efficiencies for Tier 1, Tier 2, Tier 3, or alternative test method for the pilot, flow determination, gas composition.
	40 CFR 98.233(n)(9)	For CEMS with a CO_2 concentration monitor and volumetric flow monitor for combustion gases from the flare, must follow Tier 4 Calculation Method in Subpart C.
	40 CFR 98.233(n)(10)	Disaggregate total emissions from the flare as applicable to each source type that routed emissions to the flare.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)

Hydrocarbon Liquids and Produced Water Storage Tanks	40 CFR 98.233(j)	• For tanks receiving hydrocarbon liquids from wells, gas-liquid separators, or non-separator equipment with annual average daily throughput:
		  o ≥ 10 barrels per day use Calculation Method 1 or 2
		  o > 0 and < 10 barrels per day use Calculation Method 1, 2, or 3.
		• For tanks receiving produced water, use Calculation Method 1, 2, or 3.

	40 CFR 98.233(j)(1)	Subpart W – Calculation Method 1 using computer modeling for gas-liquid separators or non-separator equipment. Required if flash emissions modeling software is necessary for compliance with regulations, air permit requirements, or annual inventory reporting.
	40 CFR 98.233(j)(2)	Subpart W – Calculation Method 2 using mass balance approach assuming all methane in solution at the well is emitted from hydrocarbons or produced water sent to tanks.
	40 CFR 98.233(j)(3)	Subpart W – Calculation Method 3 using an emission factor and population counts for hydrocarbon liquids or produced water flowing to gas-liquid separators, non-separator equipment, or directly to atmospheric storage.
	40 CFR 98.233(j)(4)	For periods when tank is not routed to vapor recovery system or flare, estimate average hourly vented emissions using annual operating hours to calculate emissions for the total hours when vented directly to atmosphere.
	40 CFR 98.233(j)	When venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(j)(5)	Subpart W – Calculate emissions from gas-liquid separator liquid dump valves that did not close properly based on duration of failed valve closing, only if using Calculation Method 1 or 2.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Pneumatic Device (Controller) Vents, Natural gas	40 CFR 98.233(a)(1) 40 CFR 98.233(a)(2) 40 CFR 98.233(a)(3) 40 CFR 98.233(a)(4)	Subpart W – Calculation Method 1 using continuous measurement via flow monitor of natural gas supply line dedicated to device(s). Subpart W – Calculation Method 2 using flow meter to measure volumetric flow of all devices in the same calendar year to develop site-specific measurement-based emission factors by device type. Subpart W – Calculation Method 3: ○ Continuous high bleed and continuous low bleed devices using count of devices and default emission factors. ○ Intermittent bleed devices using either malfunctioning or properly operating emission factors per site, determined from one complete monitoring survey in a calendar year. Subpart W – Calculation Method 4 using default emission factors for low-bleed, high-bleed and intermittent-bleed devices.
Pneumatic (Chemical Injection) Pump Vents, Natural Gas Driven	40 CFR 98.233(c)(1) 40 CFR 98.233(c)(2) 40 CFR 98.233(c)(3) 40 CFR 98.233(c)(4)	Subpart W – Calculation Method 1 using continuous measurement of natural gas supplied to pumps. Subpart W – Calculation Method 2 using measurement-based emission factors from periodic measurements. Subpart W – Calculation using actual count of devices and default emission factors. Subpart W – Calculation for periods when venting goes directly to atmosphere (but are normally routed to flare, combustion, or vapor recovery system): use the applicable method from 40 CFR 98.233(c)(1), (2), or (3) to calculate emissions for the portion of the year where venting occurred. When venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). When venting is routed to combustion, calculate and report emissions as specified in 40 CFR 98.233(z).

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Other Large Release Events ("OLRE")	40 CFR 98.233(y)(1)	You must report an OLRE if it meets either of these emission thresholds at any point during a release: • **Unreported Sources**: If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions). • **Reported Sources**: If methane emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported using methodologies found elsewhere in 40 CFR 98.233(a)–(h), (j)–(s), (w), (x), (dd), or (ee).
	40 CFR 98.233(y)(2)–(5)	Subpart W – Calculation based on measurement data, if available, and/or process knowledge and engineering estimates and composition of the gas released. If multiple release points have a common root cause (*e.g.*, system overpressure), treat them as one OLRE. For multi-year events, apportion emissions across years by event duration or variable rates.
	40 CFR 98.233(y)(6)	Include emissions upon receipt of EPA-provided notification under the super emitter program or an applicable approved state plan or federal plan.
	40 CFR 98.238	OLRE does not include blowdowns calculated pursuant to 40 CFR 98.233(i).

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

Emission Source	Description of Quantification Method	GHG Inventory CH_4 Emission Factor
Compressor Starts*	GHG Inventory emission factor multiplied by number of compressors	172.03 kg/compressor
Damages (Gathering & Boosting Upsets: Mishaps)†	GHG Inventory emission factor multiplied by miles of gathering pipeline	13.65 kg/mile
Note: GHG Inventory emission factors are published in Annex 3.6, Table 3.6-2 (Average CH_4 Emission Factors) of the 2025 GHGi. *** 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 2025 GHGi no longer has a gathering and boosting-segment factor.**		

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.[18]

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)).

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:

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[18] 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.

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

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 find it useful to also 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 definitions are consistent with the definitions in the May 2024 revisions to GHGRP Subpart W and the Methane Challenge Program:

- **Onshore natural gas processing**[19] means the forced extraction of natural gas liquids ("NGLs") from field gas, fractionation of mixed NGLs to natural gas products, or both. Natural gas processing does not include a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant.
- **Natural gas processing facility**[20] means 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 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. Table 8 lists sources that are estimated using the GHGRP quantification method. A general emission source called "Other Large Release Events" ("OLRE") is also included in Table 8 as a new source consistent with the May 2024 Subpart W revisions. This emission source generally refers to non-routine, high-volume, unintentional releases of GHGs due to equipment failures, accidents, or emergency releases. The Version 3.0 updates are summarized below:

- OLRE is defined as any planned or unplanned uncontrolled release of gases or liquids from wells or other equipment not covered by other calculation methods in 40 CFR 98.233.[21] Examples include:
  - Well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire or explosion
- OLRE is distinct from routine emission sources like flares, blowdown vents, pneumatic devices, and equipment leaks.
- Not every release is required to be measured. However, compliance with super-emitter response protocols under 40 CFR 60.5371, 60.5371a, or 60.5371b is required. If EPA or facility-funded monitoring or measurement data demonstrates that a release meets, exceeds, or may be reasonably

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[19] *See* 40 CFR 98.230(a)(3).

[20] Subpart W does not define "facility" with respect to the natural gas processing segment, therefore NGSI uses the facility definition from EPA's Methane Challenge Program. *See* U.S. Environmental Protection Agency, "Natural Gas STAR Methane Challenge Program: ONE Future Commitment Option Technical Document" at 52 (Mar. 15, 2019), https://www.epa.gov/sites/production/files/2016-08/documents/methanechallenge_one_future_supp_tech_info.pdf.

[21] *See* 40 CFR 98.238 for full definition.

anticipated to meet or exceed the applicable emissions threshold criteria listed below for the event, then emissions must be calculated and reported.

- Emission thresholds that trigger reporting include either of the following:
    - **Unreported sources:** If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions)
    - **Reported sources:** If emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported under 40 CFR 98.233 (a) through (h), (j) through (s), (w), (x), (dd), or (ee).

Table 8 includes the OLRE emission source, GHGRP regulatory references, and general applicability and reporting methodologies. For further details on qualification for OLRE and/or calculation methodology, please refer to 40 CFR 98.233(y). In addition, Appendix B includes additional detailed guidance regarding OLRE.

More generally, the purpose of Table 8 is to provide simplified, top-level regulatory references and general estimation methodology for user convenience ***only***. You should always review regulatory text directly in the Code of Federal Regulations ("CFR") when making any regulatory compliance decisions. ***Please do not rely solely on this Protocol to determine the applicable GHGRP emission estimation methodology(ies) and detailed reporting requirements for any emission source***.

Table 8. Processing Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Acid Gas Removal Units (AGRU) and Nitrogen Removal Units (NRU)	40 CFR 98.233(d)(2)	Subpart W – Calculation Method 2 if a vent meter is installed, use the composition and annual volume of vent gas to calculate emissions of CH_4.
	40 CFR 98.233(d)(3)	Subpart W – Calculation Method 3 if a vent meter is not installed, use inlet and/or outlet gas flow rate and gas composition.
	40 CFR 98.233(d)(4)	Subpart W – Calculation Method 4 if a vent meter is not installed, use a standard simulation software package. If a vent meter is installed at an AGRU, you must determine the difference between the measured and simulated vent gas volume.
	40 CFR 98.233(d)(11)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(d)	If venting is routed to combustion, calculate and report under 40 CFR 98.233(z).

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Blowdown Vent Stacks with volume ≥ 50 ft^3	40 CFR 98.233(i)(1) 40 CFR 98.233(i)(2) 40 CFR 98.233(i)(3)	Subpart W – To determine applicability, calculate unique physical volumes between isolation valves using engineering estimates based on best available data. Subpart W – Calculation method using engineering calculation method by unique physical volume. Subpart W – Calculation method using direct measurement of emissions using a flow meter. 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.[22]
Combustion Units	40 CFR 98.233(z) 40 CFR 98.33(c)	Subpart W – only external combustion units greater than 5 MMBtu/hr and internal combustion units greater than 130 hp are applicable. 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.

[22] Alternate method is adapted from the ONE Future program alternate method for Transmission Station Blowdowns. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 43 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Centrifugal	40 CFR 98.233(o)(1)(i)	Subpart W – Individual compressor source "as found" measurements taken at least once annually and based on compressor mode: • Operating mode or standby-pressurized-mode: blowdown valve leakage, methods specific to either wet seal oil degassing vent or dry seal vent • Not-operating-depressurized mode: isolation valve leakage (no measurement required if blind flanges and no operation)
	40 CFR 98.233(o)(6)	Calculate volumetric emissions from "as found" measurements for individual compressor source from each mode-source combination that was measured during the calendar year; use reporter-specific emission factor for mode-source combinations not measured in the reporting year.
	40 CFR 98.233(o)(1)(iii) 40 CFR 98.233(o)(8)	Manifolded "as found" measurements can be taken at the common vent stack and volumetric emissions calculated for the manifolded group.
	40 CFR 98.233(o)(1)(ii) 40 CFR 98.233(o)(1)(iv) 40 CFR 98.233(o)(7) 40 CFR 98.233(o)(9)	Subpart W – continuous source monitoring can be used to measure volumetric emissions and calculate annual emissions (individual or manifolded). If manifolded, emissions calculated for the manifolded group.
	40 CFR 98.233(o)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in Subpart C. If venting is routed to vapor recovery system, 40 CFR 98.233(o)(1) through (11) do not apply. 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.[23]

[23] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 39 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Reciprocating	40 CFR 98.233(p)(1)(i)	Subpart W – Individual reciprocating compressor source "as found" measurements taken at least once annually and based on compressor mode: • Operating mode or standby-pressurized mode: blowdown valve leakage and rod packing emissions • Not-operating-depressurized mode: isolation valve leakage (no measurement required if blind flanges and no operation).
	40 CFR 92.233(p)(6)	Calculate volumetric emissions from "as found" measurements for individual compressor source from each mode-source combination that was measured during the calendar year; use reporter-specific emission factor for mode-source combinations not measured in the reporting year.
	40 CFR 98.233(p)(1)(iii) 40 CFR 98.233(p)(8)	Manifolded "as found" measurements can be taken at the common vent stack and volumetric emissions calculated for the manifolded group.
	40 CFR 98.233(p)(1)(ii) 40 CFR 98.233(p)(1)(iv) 40 CFR 98.233(p)(7) 40 CFR 98.233(p)(9)	Subpart W – continuous source monitoring can be used to measure volumetric emissions and calculate annual emissions (individual and manifolded). If manifolded, emissions calculated for the manifolded group.
	40 CFR 98.233(p)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in Subpart C. If venting is routed to vapor recovery system 40 CFR 98.233(p)(1) through (11) do not apply. 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 reciprocating compressor measurements.[24]

[24] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 39 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Crankcase Vents (for each reciprocating internal combustion engine ("RICE") crankcase vent with heat capacity > 1mmBtu/hr or equivalent of >130 hp)	40 CFR 98.233(ee)(1)	Subpart W – Calculation Method 1 using direct measurement to determine annual RICE emissions.
	40 CFR 98.233(ee)(2)	Subpart W – Calculation Method 2 using default emission factor applicable per hour per RICE.
	40 CFR 98.233(ee)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
Dehydrator vents, glycol	40 CFR 98.233(e)	Subpart W – Glycol dehydrator methodology based on annual average daily natural gas throughput and/or emissions routing: • ≥ 0.4 mscf/day use Calculation Method 1. • > 0 mscf/day and < 0.4 mscf/day use either Calculation Method 1 or 2. • If vents are routed to vapor recovery system, use methods in 98.233(e)(4). • If vents routed to regenerator firebox/fire tubes or other non-flare combustion units, use methods in 98.233(e)(5). • If vents routed to flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(e)(1)	Subpart W – Calculation Method 1 using computer modeling for both still vent and, if applicable, flash tank vents. Required if software program is used for compliance with federal or state regulations, air permit requirements or annual emission inventory.
	40 CFR 98.233(e)(2)	Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators.
	40 CFR 98.233(e)(4)	Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(e)(5)	Subpart W – Calculation for combustion emissions when routed to non-flare combustion unit using flow and composition. If CEMS is installed on a combustion device, use Tier 4 Calculation Method in Subpart C.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Dehydrator vents, desiccant	40 CFR 98.233(e) 40 CFR 98.233(e)(5)	Subpart W – dehydrators of any size that use desiccant must use Calculation Method 3 to calculate amount of gas vented during depressurization for desiccant refilling. Desiccant dehydrator emissions calculated via Method 3 do not have to be calculated separately using the method specified in 40 CFR 98.233(i) for blowdown vent stacks. Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n). For any desiccant dehydrator emissions routed to a non-flare combustion unit, calculate the combusted emissions as specified in 40 CFR 98.233(e)(5)(i) through (iii).
Equipment Leaks from components in gas service (excluding thief hatches or other openings on storage vessels) subject to equipment leak standards for onshore natural gas processing plants	40 CFR 98.233(q)(2) 40 CFR 98.233(q)(3)	Subpart W – Calculation Method 1, must use facility-specific leaker emission factor if available (calculated per 40 CFR 98.233(q)(4)) or use appropriate default total hydrocarbon leaker emission factors for compressor components and non-compressor components in gas service. Subpart W – Calculation Method 2 if leaks are detected during survey, may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor per 40 CFR 98.233(q)(4). For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses an average company emission factor (as opposed to a facility-specific factor) based on all company-specific Subpart W leak surveys.[25]

[25] Alternate method is adapted from the ONE Future program alternate method for Distribution: Equipment Leaks (Storage). *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 46 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Flare Stacks	40 CFR 98.233(n)(5) 40 CFR 98.233(n)(6)	Subpart W – Calculation using applicable default destruction and combustion efficiencies, alternative test method, or directly measured destruction and combustion efficiencies for Tier 1, Tier 2, Tier 3, or alternative test method for the pilot, flow determination, gas composition.
	40 CFR 98.233(n)(9)	For CEMS with a CO_2 concentration monitor and volumetric flow monitor for combustion gases from the flare, must follow Tier 4 Calculation Method and associated calculation, quality assurance, reporting and recordkeeping requirements in Subpart C.
	40 CFR 98.233(n)(10)	Disaggregate total emissions from the flare as applicable to each source type that routed emissions to the flare.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)

Hydrocarbon Liquids and Produced Water Storage Tanks	40 CFR 98.233(j)	• For tanks receiving hydrocarbon liquids from wells, gas-liquid separators, or non-separator equipment with annual average daily throughput:
		  o ≥ 10 barrels per day use Calculation Method 1 or 2
		  o > 0 and < 10 barrels per day use Calculation Method 1, 2, or 3.
		• For tanks receiving produced water, use Calculation Method 1, 2, or 3.

	40 CFR 98.233(j)(1)	Subpart W – Calculation Method 1 using computer modeling for gas-liquid separators or non-separator equipment. Required if flash emissions modeling software is necessary for compliance with regulations, air permit requirements, or annual inventory reporting.
	40 CFR 98.233(j)(2)	Subpart W – Calculation Method 2 using mass balance approach assuming all methane in solution at the well is emitted from hydrocarbons or produced water sent to tanks.
	40 CFR 98.233(j)(3)	Subpart W – Calculation Method 3 using an emission factor and population counts for hydrocarbon liquids or produced water flowing to gas-liquid separators, non-separator equipment, or directly to atmospheric storage.
	40 CFR 98.233(j)(4)	For periods when tank is not routed to vapor recovery system or flare, estimate average hourly vented emissions using annual operating hours to calculate emissions for the total hours when vented directly to atmosphere.
	40 CFR 98.233(j)	When venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(j)(5)	Subpart W – Calculate emissions from gas-liquid separator liquid dump valves that did not close properly based on duration of failed valve closing, only if using Calculation Method 1 or 2.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Other Large Release Events (“OLRE”)	40 CFR 98.233(y)(1)	You must report an OLRE if it meets either of these emission thresholds: • **Unreported Sources**: If methane emissions ≥ 100 kg/hr from a source not already covered in § 98.233 (e.g., fires, blowouts, explosions). • **Reported Sources**: If methane emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported under § 98.233(a)–(h), (j)–(s), (w), (x), (dd), or (ee).
	40 CFR 98.233(y)(2)–(5)	Subpart W – Calculation based on measurement data, if available, and/or process knowledge and engineering estimates and composition of the gas released. If multiple release points have a common root cause (*e.g.*, system overpressure), treat them as one OLRE. For multi-year events, apportion emissions across years by event duration or variable rates.
	40 CFR 98.233(y)(6)	Include emissions upon receipt of EPA-provided notification under the super emitter program or an applicable approved state plan or Federal plan.
	40 CFR 98.238	OLRE does not include blowdowns calculated pursuant to 40 CFR 98.233(i).
Pneumatic Device Venting (Low-Bleed, Intermittent-Bleed, and Hi-Bleed)	40 CFR 98.233(a)(1)	Subpart W – Calculation Method 1 using continuous measurement via flow monitor of natural gas supply line dedicated to device(s).
	40 CFR 98.233(a)(2)	Subpart W – Calculation Method 2 using flow meter to measure volumetric flow of all devices each year (if < 26 devices at facility) to develop site-specific measurement-based emission factors by device type. Facilities with 26 or more devices can perform measurements over multiple years.
	40 CFR 98.233(a)(4)	Subpart W – Calculation Method 4 using default emission factors for low-bleed and high-bleed devices.

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 segment 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 9 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 9, 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 9.

Table 9. 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.[26]

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 10. Information should be reported at the company level; companies may find it useful to also report certain elements at the facility level.

[26] 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.

Table 10 . 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 Table 8
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

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 in the May 2024 revisions to GHGRP Subpart W and the Methane Challenge Program:

- **Onshore natural gas transmission compression**[27] means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. A transmission 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 the onshore natural gas transmission compression segment.
- **Underground natural gas storage**[28] means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration, and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.
- **Natural gas transmission compression facility** or **underground natural gas storage facility**[29] means any physical property, plant, building, structure, source, or stationary equipment in the natural gas transmission compression industry segment or underground natural gas storage industry segment located on one or more contiguous or adjacent properties in actual physical contact or 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.
- **Onshore natural gas transmission pipeline**[30] means all natural gas transmission pipelines that meet the following definition: 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).

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[27] *See* 40 CFR 98.230(a)(4).
[28] *See* 40 CFR 98.230(a)(5).
[29] Subpart W does not define "facility" with respect to the onshore natural gas transmission compression or underground natural gas storage segments, therefore NGSI uses the facility definition from EPA's Methane Challenge Program, which is a shared definition for both segments. *See* U.S. Environmental Protection Agency, "Natural Gas STAR Methane Challenge Program: ONE Future Commitment Option Technical Document" at 52 (Mar. 15, 2019), https://www.epa.gov/sites/production/files/2016-08/documents/methanechallenge_one_future_supp_tech_info.pdf.
[30] *See* 40 CFR 98.230(a)(10) and 98.238.

- **Onshore natural gas transmission pipeline facility**[31] means the total U.S. mileage of natural gas transmission pipelines owned or operated by an onshore natural gas transmission pipeline owner or operator. If an owner or operator has multiple pipelines in the United States, the "facility" is considered the aggregate of those pipelines, even if they are not interconnected. The facility does not include pipelines that are part of any other industry segment as defined in Subpart W.
- **LNG storage**[32] means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.
- **LNG storage facility**[33] means any physical property, plant, building, structure, source, or stationary equipment in the LNG storage industry segment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. 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.[34]

Transmission & Storage Segment Emissions

Under NGSI, companies 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 11. Table 11 lists sources that are estimated using the GHGRP quantification method. A general emission source called "Other Large Release Events" ("OLRE") is also included in Table 11 as a new source consistent with the May 2024 Subpart W revisions. This emission source generally refers to non-routine, high-volume, unintentional releases of GHGs due to equipment failures, accidents, or emergency releases. The Version 3.0 updates are summarized below:

- OLRE is defined as any planned or unplanned uncontrolled release of gases or liquids from wells or other equipment not covered by other calculation methods in 40 CFR 98.233.[35] Examples include:
    - Well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire or explosion

[31] Subpart W contains an applicable definition of "facility," which NGSI has blended with the Methane Challenge Program definition to provide added clarity. *See* 40 CFR 98.238 and U.S. Environmental Protection Agency, "Natural Gas STAR Methane Challenge Program: ONE Future Commitment Option Technical Document" at 53 (Mar. 15, 2019), https://www.epa.gov/sites/production/files/2016-08/documents/methanechallenge_one_future_supp_tech_info.pdf.
[32] *See* 40 CFR 98.230(a)(6).
[33] Subpart W does not define "facility" with respect to the LNG storage segment, therefore NGSI uses a facility definition that is consistent with EPA's Methane Challenge Program. *See* U.S. Environmental Protection Agency, "Natural Gas STAR Methane Challenge Program: ONE Future Commitment Option Technical Document" at 53 (Mar. 15, 2019), https://www.epa.gov/sites/production/files/2016-08/documents/methanechallenge_one_future_supp_tech_info.pdf.
[34] In practice, many LNG storage facilities are associated with distribution infrastructure and operations. However, to match the GHGRP reporting structure for LNG storage facilities, all LNG storage emissions should be reported under the NGSI transmission and storage segment.
[35] *See* 40 CFR 98.238 for full definition.

- OLRE is distinct from routine emission sources like flares, blowdown vents, pneumatic devices, and equipment leaks.
- Not every release is required to be measured. However, compliance with super-emitter response protocols under 40 CFR 60.5371, 60.5371a, or 60.5371b is required. If EPA or facility-funded monitoring or measurement data demonstrates that a release meets, exceeds, or may be reasonably anticipated to meet or exceed the applicable emissions threshold criteria listed below for the event, then emissions must be calculated and reported.
- Emission thresholds that trigger reporting include either of the following:
  - **Unreported sources:** If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions)
  - **Reported sources:** If emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported under 40 CFR 98.233 (a) through (h), (j) through (s), (w), (x), (dd), or (ee).

Table 11 includes the OLRE emission source, GHGRP regulatory references, and general applicability and reporting methodologies. For further details on qualification for OLRE and/or calculation methodology, please refer to 40 CFR 98.233(y). In addition, Appendix B includes additional detailed guidance regarding OLRE.

More generally, the purpose of Table 11 is to provide simplified, top-level regulatory references and general estimation methodology for user convenience ***only***. You should always review regulatory text directly in the Code of Federal Regulations ("CFR") when making any regulatory compliance decisions. ***Please do not rely solely on this Protocol to determine the applicable GHGRP emission estimation methodology(ies) and detailed reporting requirements for any emission source***.

Table 11. Transmission & Storage Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Acid Gas Removal Units (AGRU) and Nitrogen Removal Units (NRU), LNG Storage	40 CFR 98.233(d)(2)	Subpart W – Calculation Method 2 if a vent meter is installed, use the composition and annual volume of vent gas to calculate emissions of CH_4.
	40 CFR 98.233(d)(3)	Subpart W – Calculation Method 3 if a vent meter is not installed, use inlet and/or outlet gas flow rate and gas composition.
	40 CFR 98.233(d)(4)	Subpart W – Calculation Method 4 if a vent meter is not installed, use a standard simulation software package. If a vent meter is installed at an AGRU, you must determine the difference between the measured and simulated vent gas volume.
	40 CFR 98.233(d)(11)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).
	40 CFR 98.233(d)	If venting is routed to combustion, calculate and report under 40 CFR 98.233(z).

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Blowdowns Vent Stacks with volume ≥ 50 ft³ – Onshore Natural Gas Transmission Pipeline[37]	40 CFR 98.233(i)(1) 40 CFR 98.233(i)(2) 40 CFR 98.233(i)(3)	Subpart W – To determine applicability, calculate unique physical volumes between isolation valves using engineering estimates based on best available data. Subpart W – Calculation method using engineering calculation method by unique physical volume. Subpart W – Calculation method using direct measurement of emissions using a flow meter. 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.[36]
Blowdown Vent Stacks with volume ≥ 50 ft³ – Onshore Natural Gas Transmission Compressor Stations, Underground Natural Gas Storage, and LNG Storage[37]	40 CFR 98.233(i)(1) 40 CFR 98.233(i)(2) 40 CFR 98.233(i)(3)	Subpart W – To determine applicability, calculate unique physical volumes between isolation valves using engineering estimates based on best available data. Subpart W – Calculation method using engineering calculation method by unique physical volume. Subpart W – Calculation method using direct measurement of emissions using a flow meter. 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.[38]

[36] Alternate method is adapted from the ONE Future program alternate method for Transmission Station Blowdowns. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 43 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

[37] In earlier versions of the NGSI Protocol, underground natural gas storage and LNG storage blowdown vent stack emissions were calculated using an applicable GHGi emission factor. The May 2024 revisions to GHGRP Subpart W added blowdown vent stacks as a reportable source for these two industry segments. The GHGi emission factor is no longer used and has been removed from this version of the NGSI Protocol. Under the GHGRP, blowdown vent stack emissions must be grouped into the segment-specific categories specified in 40 CFR 98.233(i)(2)(iv)(A) and (B). Although this NGSI Protocol does not require further sub-categorization of blowdowns by equipment or event type, the NGSI Transmission & Storage template aligns with the GHGRP's high-level segment groupings in 98.233(i)(2)(iv) for ease of data aggregation and better comparability.

[38] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 43 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Combustion Units	40 CFR 98.233(z) 40 CFR 98.33(c)	Subpart W – only external combustion units greater than 5 MMBtu/hr and internal combustion units greater than 130 hp are applicable. 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.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Centrifugal (not applicable to Transmission Pipeline)	40 CFR 98.233(o)(1)(i)	Subpart W – Individual compressor source "as found" measurements taken at least once annually and based on compressor mode: • Operating mode <u>or</u> standby-pressurized-mode: blowdown valve leakage, methods specific to either wet seal oil degassing vent or dry seal vent • Not-operating-depressurized mode: isolation valve leakage (no measurement required if blind flanges and no operation)
	40 CFR 98.233(o)(6)	Calculate volumetric emissions from "as found" measurements for individual compressor source from each mode-source combination that was measured during the calendar year; use reporter-specific emission factor for mode-source combinations not measured in the reporting year.
	40 CFR 98.233(o)(1)(iii) 40 CFR 98.233(o)(8)	Manifolded "as found" measurements can be taken at the common vent stack and volumetric emissions calculated for the manifolded group.
	40 CFR 98.233(o)(1)(ii) 40 CFR 98.233(o)(1)(iv) 40 CFR 98.233(o)(7) 40 CFR 98.233(o)(9)	Subpart W – continuous source monitoring can be used to measure volumetric emissions and calculate annual emissions (individual or manifolded). If manifolded, emissions calculated for the manifolded group.
	40 CFR 98.233(o)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in Subpart C. If venting is routed to vapor recovery system, 40 CFR 98.233(o)(1) through (11) do not apply. 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.[39]

[39] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 42 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Compressors, Reciprocating (not applicable to Transmission Pipeline)	40 CFR 98.233(p)(1)(i)	Subpart W – Individual reciprocating compressor source "as found" measurements taken at least once annually and based on compressor mode: • Operating mode <u>or</u> standby-pressurized mode: blowdown valve leakage and rod packing emissions • Not-operating-depressurized mode: isolation valve leakage (no measurement required if blind flanges and no operation).
	40 CFR 92.233(p)(6)	Calculate volumetric emissions from "as found" measurements for individual compressor source from each mode-source combination that was measured during the calendar year; use reporter-specific emission factor for mode-source combinations not measured in the reporting year.
	40 CFR 98.233(p)(1)(iii) 40 CFR 98.233(p)(8)	Manifolded "as found" measurements can be taken at the common vent stack and volumetric emissions calculated for the manifolded group.
	40 CFR 98.233(p)(1)(ii) 40 CFR 98.233(p)(1)(iv) 40 CFR 98.233(p)(7) 40 CFR 98.233(p)(9)	Subpart W – continuous source monitoring can be used to measure volumetric emissions and calculate annual emissions (individual and manifolded). If manifolded, emissions calculated for the manifolded group.
	40 CFR 98.233(p)	If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n). If venting is routed to combustion, calculate and report emissions as specified in Subpart C. If venting is routed to vapor recovery system, 40 CFR 98.233(p)(1) through (11) do not apply. 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 reciprocating compressor measurements.[40]

[40] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 42 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Crankcase Vents (for each reciprocating internal combustion engine ("RICE") crankcase vent with heat capacity > 1mmBtu/hr or equivalent of >130 hp) **(not applicable to Transmission Pipeline)**	40 CFR 98.233(ee)(1) 40 CFR 98.233(ee)(2) 40 CFR 98.233(ee)	Subpart W – Calculation Method 1 using direct measurement to determine annual RICE emissions. Subpart W – Calculation Method 2 using default emission factor applicable per hour per RICE. If venting is routed to a flare, calculate and report emissions under flare stack emissions per 40 CFR 98.233(n).
Dehydrator Vents, Glycol (not applicable to Transmission Pipeline or LNG Storage)	40 CFR 98.233(e) 40 CFR 98.233(e)(1) 40 CFR 98.233(e)(2) 40 CFR 98.233(e)(4) 40 CFR 98.233(e)(5)	Subpart W – Glycol dehydrator methodology based on annual average daily natural gas throughput and/or emissions routing: • ≥ 0.4 mscf/day use Calculation Method 1. • > 0 mscf/day and < 0.4 mscf/day use either Calculation Method 1 or 2. • If vents are routed to vapor recovery system, use methods in 98.233(e)(4). • If vents routed to regenerator firebox/fire tubes or other non-flare combustion units, use methods in 98.233(e)(5). • If vents routed to flare, calculate and report emissions under flare stack emissions per 40 CFR 98.233(n). Subpart W – Calculation Method 1 using computer modeling for both still vent and, if applicable, flash tank vents. Required if software program is used for compliance with federal or state regulations, air permit requirements or annual emission inventory. Subpart W – Calculation Method 2 using emission factors and population counts for glycol dehydrators. Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n). Subpart W – Calculation for combustion emissions when routed to non-flare combustion unit using flow and composition. If CEMS is installed on a combustion device, use Tier 4 Calculation Method in Subpart C.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Dehydrator Vents, Desiccant (not applicable to Transmission Pipeline or LNG Storage)	40 CFR 98.233(e) 40 CFR 98.233(e)(5)	Subpart W –dehydrators of any size that use desiccant must use Calculation Method 3 to calculate amount of gas vented during depressurization for desiccant refilling. Desiccant dehydrator emissions calculated via Method 3 do not have to be calculated separately using the method specified in 40 CFR 98.233(i) for blowdown vent stacks. Subpart W – For periods vented directly to atmosphere from dehydrators typically routed to vapor recovery system, flare, or non-flare combustion device, use engineering estimate and best available data to calculate total emissions vented to directly to atmosphere. Periods of reduced capture efficiency must be included. If emissions routed to an unlit flare, calculate and report as flare stack emissions as specified in 40 CFR 98.233(n). For any desiccant dehydrator emissions routed to a non-flare combustion unit, calculate the combusted emissions as specified in 40 CFR 98.233(e)(5)(i) through (iii).
Equipment Leaks – Transmission Compression (excluding thief hatches or other openings on storage vessels)	40 CFR 98.233(q)(2) 40 CFR 98.233(q)(3)	Subpart W – Calculation Method 1, must use facility-specific leaker emission factor if available (calculated per 40 CFR 98.233(q)(4)) or use appropriate default total hydrocarbon leaker emission factors for compressor components and non-compressor components in gas service. Subpart W – Calculation Method 2 if leaks are detected during survey, may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor per 40 CFR 98.233(q)(4). For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses an average <u>company</u> emission factor (as opposed to a facility-specific factor) based on all company-specific Subpart W leak surveys.[41]

[41] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 41 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Equipment Leaks – Underground Natural Gas Storage Station[42]	40 CFR 98.233(q)(1) 40 CFR 98 233(q)(2) 40 CFR 98 233(q)(3) 40 CFR 98.233(q)(4)	Subpart W – Calculation Method 1 for underground natural gas storage, must use facility-specific leaker emission factor if available (calculated per 40 CFR 98.233(q)(4)) or use appropriate default total hydrocarbon leaker emission factors for storage stations in gas service. Subpart W – Calculation Method 2 if leaks are detected during survey may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor per 40 CFR 98.233(q)(4). 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 factors based on all company-specific Subpart W leak surveys.[43]
Equipment Leaks – Underground Natural Gas Storage Wellheads[42]	40 CFR 98.233(q)(1) 40 CFR 98 233(q)(2) 40 CFR 98 233(q)(3) 40 CFR 98.233(q)(4) 40 CFR 98.233(r)	Subpart W – Calculation Method 1 for underground natural gas storage, must use facility-specific leaker emission factor (calculated per 40 CFR 98.233(q)(4)) or use appropriate default total hydrocarbon leaker emission factors for storage wellheads in gas service. Subpart W – Calculation Method 2 if leaks are detected during survey may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor per 40 CFR 98.233(q)(4). Subpart W calculation methodology for underground natural gas storage using each component count listed in Table W-3 and default population emission factors. 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 factors based on all company-specific Subpart W leak surveys.[43]

[42] In NGSI Version 2.0, this source was included under the aggregated category *Equipment Leaks – Underground Storage and LNG Storage*. As part of the NGSI Version 3.0 update, this source was separated to improve granularity and ensure alignment with GHGRP.

[43] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 42 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Equipment Leaks – LNG Storage Station[42]	40 CFR 98.233(q)(1) 40 CFR 98 233(q)(2) 40 CFR 98 233(q)(3) 40 CFR 98.233(q)(4) 40 CFR 98.233(r)	Subpart W – Calculation Method 1 for LNG Storage, must use facility-specific leaker emission factor if available (calculated per 40 CFR 98.233(q)(4)) or appropriate default methane leaker emission factor for LNG or gas service. Subpart W – Calculation Method 2 if leaks are detected during survey may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor per 40 CFR 98.233(q)(4). Subpart W calculation methodology for LNG storage using number of vapor recovery compressors count listed in Table W-5 and default population emission factors. 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 factors based on all company-specific Subpart W leak surveys. [43]
Equipment Leaks – Transmission Pipeline Interconnect Metering-Regulation Stations[44]	40 CFR 98.233(q)(1)(vi) 40 CFR 98.233(q)(2) 40 CFR 98.233(q)(3) 40 CFR 98.233(r)	Subpart W – Calculation Method 1, if available must use facility-specific leaker emission factor (calculated per 40 CFR 98.233(q)(4)). Subpart W – Calculation Method 2 if leaks are detected during survey may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor per 40 CFR 98.233(q)(4). Subpart W – Calculation using the appropriate default methane population emission factors listed in Table W-5. 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.[45]

[44] In NGSI Version 2.0, this source was included under the aggregated category *Equipment Leaks – Transmission Pipelines*. As part of the NGSI Version 3.0 update, this source was separated to improve granularity and ensure alignment with GHGRP.

[45] Alternate method is adapted from the ONE Future program alternate method for Transmission and Storage: Equipment Leaks (Compressor Stations). *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 41 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Equipment Leaks – Transmission Pipeline Farm Tap/Direct Sale Metering-Regulating Stations[44]	40 CFR 98.233(q)(1)(vi) 40 CFR 98.233(q)(2) 40 CFR 98.233(q)(3) 40 CFR 98.233(r)	Subpart W – Calculation Method 1, if available must use facility-specific leaker emission factor (calculated per 40 CFR 98.233(q)(4)). Subpart W – Calculation Method 2 if leaks are detected during survey may elect to measure volumetric flow or use default rate for component and site type. If measuring volumetric flow, must calculate a facility-specific component-level leaker emission factor per 40 CFR 98.233(q)(4). Subpart W Calculation using the appropriate default methane population emission factors listed in Table W-5. 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.[46]
Equipment Leaks – Transmission Pipelines	40 CFR 98.233(r)	Subpart W - Calculation using the appropriate default methane population emission factors listed in Table W-5.
Flare Stacks (not applicable to Transmission Pipeline)	40 CFR 98.233(n)(5) 40 CFR 98.233(n)(6) 40 CFR 98.233(n)(9) 40 CFR 98.233(n)(10)	Subpart W – Calculation using applicable default destruction and combustion efficiencies, alternative test method, or directly measured destruction and combustion efficiencies for Tier 1, Tier 2, Tier 3, or alternative test method for the pilot, flow determination, gas composition. For CEMS with a CO_2 concentration monitor and volumetric flow monitor for combustion gases from the flare, must follow Tier 4 Calculation Method in Subpart C. Disaggregate total emissions from the flare as applicable to each source type that routed emissions to the flare.

[46] Alternate method is adapted from the ONE Future program alternate method for Transmission and Storage: Equipment Leaks (Compressor Stations). *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 41 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Natural Gas Pneumatic Device Venting (Low-Bleed, Intermittent-Bleed and Hi-Bleed) (not applicable to Transmission Pipeline or LNG Storage)	40 CFR 98.233(a)(1) 40 CFR 98.233(a)(2) 40 CFR 98.233(a)(4)	Subpart W – Calculation Method 1 using continuous measurement via flow monitor of natural gas supply line dedicated to device(s). Subpart W – Calculation Method 2 using periodic measurement to develop site-specific measurement-based emission factors by device type. Facilities with 26 or more devices can perform measurements over multiple years. Subpart W – Calculation Method 4 using default emission factors for low-bleed, high-bleed, and intermittent-bleed devices, as applicable.
Condensate Storage Tanks, Transmission Compression, and Underground Natural Gas Storage (not applicable to Transmission Pipeline or LNG Storage)	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. If emissions from compressor scrubber dump valve leakage are routed to a flare, calculate and report under methodology for flare stack emissions as specified in 40 CFR 98.233(n). For the facilities not subject to reporting under Subpart W, an alternate calculation method can be used. This alternate calculation method uses actual condensate storage tank counts and an average company emission factor based on all company-specific Subpart W condensate storage tank measurements.[47]

[47] Alternate method comes from the ONE Future program. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 41 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Other Large Release Events (“OLRE”)	40 CFR 98.233(y)(1)	You must report an OLRE if it meets either of these emission thresholds at any point during a release: • **Unreported Sources**: If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions). • **Reported Sources**: If methane emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported using methodologies found elsewhere in 40 CFR 98.233(a)–(h), (j)–(s), (w), (x), (dd), or (ee).
	40 CFR 98.233(y)(2)–(5)	Subpart W – Calculation based on measurement data, if available, and/or process knowledge and engineering estimates and composition of the gas released. If multiple release points have a common root cause (*e.g.*, system overpressure), treat them as one OLRE. For multi-year events, apportion emissions across years by event duration or variable rates.
	40 CFR 98.233(y)(6)	Include emissions upon receipt of EPA-provided notification under the super emitter program or an applicable approved state plan or federal plan.
	40 CFR 98.238	OLRE does not include blowdowns calculated pursuant to 40 CFR 98.233(i).

Transmission & Storage Segment Throughput

For companies with transmission and storage operations, segment throughput is intended to reflect volumes of gas handled. In this Version 3.0 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.[48]

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.[49]

[48] Companies that do not report throughput using PHMSA Form F 7100.2-1 Part C may use an alternative source of throughput data for their transmission assets. Potential options can include EIA Form 176, FERC Form 2 or 2A, data reported to a state-level pipeline regulatory agency, or internal company data on measured and reported pipeline throughput. If a company uses an alternative source for throughput data (*i.e.*, other than the NGSI default of using PHMSA Form F 7100.2-1 Part C), NGSI recommends including an explanatory note in the company’s disclosure materials.

[49] 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.

To calculate transmission and storage segment intensity, the emissions and throughput estimates must be converted to like units of methane. This can be on a mass basis or a volumetric basis. Companies reporting methane 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 12. Information should be reported at the company level; companies may find it useful to also report certain elements at the facility level.

Table 12 . 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 natural gas distribution segment definitions are consistent with the definitions in the May 2024 revisions to GHGRP Subpart W:

- **Natural gas distribution**[50] 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**[51] means 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 13 and 14. Table 13 lists sources that are estimated using the GHGRP quantification method. Table 14 lists sources that are estimated using GHGi emission factors. Except where noted otherwise, the GHGi emission factors used in NGSI Version 3.0 are from the 2025 GHGi. In addition to the individual emission sources listed in Table 13, a general emission source called "Other Large Release Events" ("OLRE") is also included in Table 13 as a new source consistent with the May 2024 Subpart W revisions. This emission source generally refers to non-routine, high-volume, unintentional releases of GHGs due to equipment failures, accidents, or emergency releases. The Version 3.0 updates are summarized below:

- OLRE is defined as any planned or unplanned uncontrolled release of gases or liquids from wells or other equipment not covered by other calculation methods in 40 CFR 98.233.[52] Examples include:
    - Well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire or explosion
- OLRE is distinct from routine emission sources like flares, blowdown vents, pneumatic devices, and equipment leaks.
- Not every release is required to be measured. However, compliance with super-emitter response protocols under 40 CFR 60.5371, 60.5371a, or 60.5371b is required. If EPA or facility-funded monitoring or measurement data demonstrates that a release meets, exceeds, or may be reasonably anticipated to meet or exceed the applicable emissions threshold criteria listed below for the event, then emissions must be calculated and reported.

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[50] *See* 40 CFR 98.230(a)(8).

[51] *See* 40 CFR 98.238.

[52] *See* 40 CFR 98.238 for full definition.

- Emission thresholds that trigger reporting include either of the following:
    - **Unreported sources**: If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions)
    - **Reported sources:** If emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported under 40 CFR 98.233 (a) through (h), (j) through (s), (w), (x), (dd), or (ee).
- This protocol recognizes that there are some sources represented in the GHGi that also could meet the definition and threshold of OLRE. For Distribution, this includes Dig-ins (Distribution Upsets: Mishaps). **<u>Important</u>: To avoid potential double counting of these emissions, the following additional guidance is given for this source.**
    - For Dig-ins (Distribution Upsets: Mishaps), if emissions equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology. Zero distribution-pipeline miles should be entered into the calculation template for that facility.
    - Other emission sources with the theoretical potential for double counting include meters and pressure relief valve ("PRV") releases from routine maintenance. However, because these sources' GHGi factors are relatively small and are not likely to meet the OLRE threshold of 100 kg/hr, they present an unlikely risk of double counting so no additional steps are required.

Table 13 includes the OLRE emission source, GHGRP regulatory references, and general applicability and reporting methodologies. For further details on qualification for OLRE and/or calculation methodology, please refer to 40 CFR 98.233(y). In addition, Appendix B includes additional detailed guidance regarding OLRE.

More generally, the purpose of Table 13 is to provide simplified, top-level regulatory references and general estimation methodology for user convenience ***only***. You should always review regulatory text directly in the Code of Federal Regulations ("CFR") when making any regulatory compliance decisions. ***Please do not rely solely on this Protocol to determine the applicable GHGRP emission estimation methodology(ies) and detailed reporting requirements for any emission source***.

Table 14 lists the GHGi emission factors for distribution pipelines. All distribution mains and service activity factors (*i.e.*, mileage and counts) should use data reported to the U.S. Pipeline and Hazardous Materials Safety Administration ("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.

Table 13. Distribution Segment Emissions Calculated Using GHGRP Methodology

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Blowdown Vent Stacks (Equipment and Pipeline) with volume ≥ 500 ft^3	40 CFR 98.233(i)(1) 40 CFR 98.233(i)(2) 40 CFR 98.233(i)(3)	Subpart W – To determine applicability, calculate unique physical volumes between isolation valves (if available) or using engineering estimates based on best available data (*e.g.*, diameter of the pipeline and length of isolated section). Subpart W – Calculation method using engineering calculation method by unique physical volume. Subpart W – Calculation method using direct measurement of emissions using a flow meter. 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.[53]
Combustion Units (stationary fuel combustion sources)	40 CFR 98.233(z)	Subpart W – only external combustion units greater than 5 MMBtu/hr and internal combustion units greater than 130 hp are applicable. Subpart W, as applicable based on fuel type and specifications – for each unit, calculate emissions for applicable Tier or higher heating value ("HHV") using methods in Subpart C. Use fuel usage records and measured or estimated composition for calculations. Subpart W – For natural gas internal combustion engine or turbine, use either a measurement-based emission factor, manufacturer-based emission factor, or default methane emission factors in Table W-7.
Crankcase Vents (for each reciprocating internal combustion engine ("RICE") crankcase vent with heat capacity > 1mmBtu/hr or equivalent of >130 hp)	40 CFR 98.233(ee)(1) 40 CFR 98.233(ee)(2) 40 CFR 98.233(ee)	Subpart W – Calculation Method 1 using direct measurement to determine annual RICE emissions. Subpart W – Calculation Method 2 using default emission factor applicable per hour per RICE. If venting is routed to a flare, calculate and report emissions under flare stack emissions as specified in 40 CFR 98.233(n).

[53] Alternate method is adapted from the ONE Future program alternate method for Transmission Station Blowdowns. *See* ONE Future, Methane Emissions Estimation Protocol V6.2023 at page 43 (Dec. 15, 2023), https://onefuture.us/wp-content/uploads/2024/11/ONE-Future-Protocol_Version-2023-for-CY2022-Emissions_12.15.2023.pdf

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Equipment Leaks, Distribution Mains	40 CFR 98.233(r)	Subpart W – Equipment leaks calculated using population counts and emission factors in Table W-5: • Cast Iron Mains • Plastic Mains • Protected Steel Mains • Unprotected Steel Mains
Equipment Leaks, Distribution Services	40 CFR 98.233(r)	Subpart W – Equipment leaks calculated using population counts and emission factors in Table W-5: • Copper services • Plastic services • Protected steel services • Unprotected steel services
Equipment Leaks, Above Grade Transmission-Distribution (T-D) Transfer Stations	40 CFR 98.233(q)(2) 40 CFR 98.233(q)(3)	Subpart W – Calculation Method 1 to develop a population emission factor based on equipment leak surveys. Subpart W – Calculation Method 2 if leaks are detected during survey, may elect to measure volumetric flow or use default rate for component and site type.
Equipment Leaks, Below Grade T-D Transfer Stations	40 CFR 98.233(r)(6)(i)	Subpart W – Calculate emissions using population counts and the emission factor in Table W-5.
Equipment Leaks, Above Grade Metering-Regulating (M&R) Stations	40 CFR 98.233(r)(6)(ii)	Subpart W – For above-grade M&R stations that are not above-grade T-D transfer stations, calculate emissions using population counts and meter/regulator run population emission factor calculated with Equation W-31 from 40 CFR 98.233(q). Facilities that do not have above-grade T-D transfer stations are not required to calculate emissions for above-grade M&R stations.
Equipment Leaks, Below Grade M&R Stations	40 CFR 98.233(r)(6)(i)	Subpart W – Calculate emissions using population counts and the emission factor in Table W-5.
Natural Gas Pneumatic Device Venting (Low-Bleed, Intermittent-Bleed and Hi-Bleed)	40 CFR 98.233(a)(1) 40 CFR 98.233(a)(2) 40 CFR 98.233(a)(4)	Subpart W – Calculation Method 1 using continuous measurement via flow monitor of natural gas supply line dedicated to device(s). Subpart W – Calculation Method 2 using periodic measurement to develop site-specific measurement-based emission factors by device type. Facilities with 26 or more devices can perform measurements over multiple years. Subpart W – Calculation Method 4 using default emission factors for low-bleed, high-bleed, and intermittent-bleed devices, as applicable.

Emission Source	GHGRP Reference(s)	Description of Quantification Method(s)
Other Large Release Events ("OLRE")	40 CFR 98.233(y)(1)	You must report an OLRE if it meets either of these emission thresholds at any point during a release: • **Unreported Sources**: If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in 40 CFR 98.233 (*e.g.*, fires, blowouts, explosions). • **Reported Sources**: If methane emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported using methodologies found elsewhere in 40 CFR 98.233(a)–(h), (j)–(s), (w), (x), (dd), or (ee).
	40 CFR 98.233(y)(2)–(5)	Subpart W – Calculation based on measurement data, if available, and/or process knowledge and engineering estimates and composition of the gas released. If multiple release points have a common root cause (*e.g.*, system overpressure), treat them as one OLRE. For multi-year events, apportion emissions across years by event duration or variable rates.
	40 CFR 98.238	OLRE does not include blowdowns calculated pursuant to 40 CFR 98.233(i).

Table 14. Distribution Segment Emissions Calculated Using GHG Inventory Emission Factors[54]

Emission Source	Description of Quantification Method	GHG Inventory CH_4 Emission Factor
Distribution Mains, Cast Iron	GHG Inventory emission factor multiplied by miles of pipeline	1,157.27 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	96.75 kg/mile
Distribution Mains, Plastic	GHG Inventory emission factor multiplied by miles of pipeline	28.85 kg/mile
Distribution Mains, Plastic Liners or Inserts*	GHG Inventory emission factor multiplied by number of services (uses plastic main emission factor)	28.85 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
Distribution Mains, Ductile Iron*	GHG Inventory emission factor multiplied by number of services (uses cast iron main emission factor)	1,157.26 kg/mile

[54] The mains and services emission factors were updated in the May 2024 GHGRP Subpart W revisions, making them only slightly different than the 2025 GHGi emission factors. Thus, the calculation should result in methane intensity values for mains and services that will be similar whether the 2025 GHGi factors or the May 2024 updated Subpart W factors are used. Even though the two sets of emission factors are now only slightly different from each other, Version 3.0 of the NGSI Protocol is still including both approaches for consistency with the prior versions of the NGSI Protocol and to allow comparison of methane intensity values against earlier reporting years that also included both approaches.

Emission Source	Description of Quantification Method	GHG Inventory CH_4 Emission Factor
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	14.49 kg/service
Distribution Services, protected steel	GHG Inventory emission factor multiplied by number of services	1.30 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	4.90 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
Dig-ins (Distribution Upsets: Mishaps)	GHG Inventory emission factor multiplied by miles of pipeline (mains and service) Companies should use the average service length reported annually to PHMSA to convert services counts to services mileage. If an average service length is not available, companies should use PHMSA's default length of 90 feet/service.	30.03 kg/mile (mains + services)
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	1.49 kg/outdoor meter
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
PRV releases, Routine Maintenance	GHG Inventory emission factor multiplied by miles of main	0.93 kg/mile (mains only)

Emission Source	Description of Quantification Method	GHG Inventory CH_4 Emission Factor
Note: GHG Inventory emission factors are published in Annex 3.6, Table 3.6-2 (Average CH_4 Emission Factors) of the 2025 GHGi. *** Pipeline main and service materials not included in the GHGRP and GHGi are given surrogate GHGi emission factors from other materials.** **** Region-specific outdoor meter ratios are available in Table 12 of EPA's document describing changes to the 2014 GHG Inventory. Available at: https://www.epa.gov/sites/default/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf** **† 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 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. As of the date of this Version 3.0 of the NGSI Protocol, this data is publicly available on the NOAA-CPC website and distribution segment companies can download the HDD data for the states in which they operate. However, NGSI updates the distribution segment template for each reporting year to incorporate the latest HDD data for all states, therefore users are not obligated to download their own state-specific HDD data.

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 3.0 of the NGSI Protocol continues to use the current 12-month period of July 1 to June 30 for the HDD data.

Under Version 3.0 of the NGSI Protocol, companies will report throughput as reported to EIA and on a normalized basis by applying the methodology shown below. This methodology is already incorporated into the distribution segment template, which auto-calculates normalized throughput for each company.

1. Identify the population weighted HDD value for the states[55] 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.[56]

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:

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

[55] 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/.

[56] 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 15. Information should be reported at the company level; companies may find it useful to also report certain elements at the facility level.

Table 15. 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: Summary of Updates to Subpart W Incorporated into Protocol Version 3.0

This section summarizes some of the new and updated definitions, measurement requirements, and calculation methodologies in Subpart W that have been incorporated in Version 3.0 of this NGSI protocol. The finalized updates to 40 Code of Federal Regulations ("CFR") Part 98, Subpart W, were published on May 14, 2024, and must be implemented for reporting purposes on March 31, 2026, for the 2025 GHGRP reporting year.

Onshore Natural Gas Production Segment

- Segment definition updated to include all equipment on or associated with a single enhanced oil recovery ("EOR") well-pad using CO_2 or natural gas injection.
- New or revised sources for reporting year 2025:
    - Blowdown vent stacks
    - Storage tanks now include produced water storage tanks and floating roof tanks
    - Nitrogen removal unit vents added to Acid Gas Removal Unit Vents
    - Centrifugal Compressor venting includes both wet seal and dry seal oil degassing
    - Equipment leaks from major equipment including wellheads, separators meters/piping, compressors, dehydrators, heaters and storage vessels for Production and Gathering and Boosting segments.
    - Other large release events
    - Drilling mud degassing
    - Crankcase vents

Onshore Natural Gas Processing Segment

- Segment definition revised to "the forced extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. . . [and] does not include a Joule-Thomson valve, a dew point depression valve, or an isolated standalone Joule-Thomson skid."
- New or revised sources for reporting year 2025:
    - Nitrogen removal unit vents
    - Natural gas pneumatic device venting
    - Centrifugal Compressor venting includes both wet seal and dry seal oil degassing
    - Other large release events
    - Hydrocarbon liquids and produced water storage tank emissions
    - Crankcase vents

Onshore Natural Gas Transmission Compression

- The name of emissions source "Transmission storage tanks" was changed to "Condensate storage tanks"
- New or revised sources for reporting year 2025:
    - Centrifugal Compressor venting includes both wet seal and dry seal oil degassing
    - Other large release events
    - Dehydrator vents
    - Crankcase vents

Underground Natural Gas Storage

- New or revised sources for reporting year 2025:
  - Centrifugal Compressor venting includes both wet seal and dry seal oil degassing
  - Other large release events
  - Dehydrator vents
  - Blowdown vent stacks (>50ft^3)
  - Condensate storage tanks
  - Crankcase vents

LNG Storage

- New or revised sources for reporting year 2025:
  - Nitrogen Removal Unit vents and Acid Gas Removal Unit vents
  - Centrifugal Compressor venting includes both wet seal and dry seal oil degassing
  - Other large release events
  - Blowdown vent stacks (>50ft^3)
  - Natural gas pneumatic device venting
  - Crankcase vents

Natural Gas Distribution

- Sources added for reporting year 2025:
  - Other large release events
  - Blowdown vent stacks (> 500ft^3)
  - Natural gas pneumatic device venting
  - Crankcase vents
- For equipment leaks at above-grade transmission-distribution transfer stations, source-specific methodology under 40 CFR 98.233(q) must be followed and leak survey performed.
- May elect to perform leak survey and follow source specific methodology under 40 CFR 98.233(q) for other equipment leaks in this section.

Gathering and Boosting

- Sources added for reporting year 2025:
  - Nitrogen removal unit vents
  - Storage tanks now include produced water storage tanks and floating roof tanks
  - Equipment leaks from major equipment including wellheads, separators meters/piping, compressors, dehydrators, heaters, and storage vessels for Production and Gathering and Boosting segments.
  - Centrifugal Compressor venting includes both wet seal and dry seal oil degassing
  - Other large release events
  - Crankcase Vents

Natural Gas Transmission Pipeline

- Sources added for reporting year 2025:
  - Other large release events
  - Equipment leaks from transmission company interconnect metering-regulating stations

- Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters at transmission company interconnect metering-regulating stations
- Equipment leaks at farm tap and/or direct sale metering-regulating stations
- Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters at farm tap and/or direct sale metering-regulating stations
- Transmission pipeline equipment leaks

Table 16. Summary of New and Updated Source Definitions in Subpart W

(NOTE: This table is not a complete listing but rather a summary of definitions for the more common or newly added source types in Subpart W.)

Source	Definition from 40 CFR 98.238
Crankcase venting	The process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine. This does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process (*e.g.*, closed crankcase ventilation system, closed breather system) or if the vent blow-by is routed to another closed vent system.
Drilling mud degassing	The practice of safely removing pockets of free gas entrained in the drilling mud once it is outside of the wellbore.
Internal combustion	The combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and -pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.
Other large release events	Any planned or unplanned uncontrolled release to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies in § 98.233 other than under § 98.233(y) to appropriately estimate these emissions. *Other large release events* include, but are not limited to, well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire, or explosion. *Other large release events* also include failure of equipment or equipment components such that a single equipment leak or release has emissions that exceed the emissions calculated for that source using applicable methods in § 98.233(a) through (h), (j) through (s), (w), (x), (dd), or (ee) by the threshold in § 98.233(y)(1)(ii). *Other large release events* do not include blowdowns for which emissions are calculated according to the provisions in § 98.233(i).
Routed to combustion	For onshore petroleum and natural gas production facilities, natural gas distribution facilities, and onshore petroleum and natural gas gathering and boosting facilities, that emissions are routed to stationary or portable fuel combustion equipment specified in § 98.232(c)(22), (i)(7), or (j)(12), as applicable. For all other industry segments in this subpart, *routed to combustion* means that emissions are routed to a stationary fuel combustion unit subject to subpart C of this part (General Stationary Fuel Combustion Sources).
Vented emissions	Intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Appendix B: Summary of Other Large Release Events ("OLRE")

Appendix B is included for your convenience. Only the regulatory text in 40 CFR 98 Subpart W should be relied on for compliance purposes.

What are "Other Large Release Events"?

Generally, refers to non-routine, high-volume, unintentional releases of greenhouse gases ("GHGs") like methane ("CH_4"), carbon dioxide ("CO_2"), and nitrous oxide (N_2O) due to equipment failures, accidents, or emergency releases. These events are separate from routine emission sources like flares, blowdown vents, pneumatic devices, and equipment leaks. Reporting includes CO_2, CH_4, and N_2O emissions released during these incidents.

Definition of OLRE (40 CFR 92.238)

Any planned or unplanned, uncontrolled atmospheric release of gases or liquids from wells or other equipment not covered by other calculation methods in 40 CFR 98.233 other than 98.233(y).

- Examples include but are not limited to:
  - Well blowouts
  - Well releases
  - Pressure relief valve releases (excluding storage tanks)
  - Fires or explosions
  - Equipment rupture or failure
  - Maintenance activities such as tank cleaning
  - Releases exceeding emissions calculated using source-specific methods elsewhere in Subpart W
- OLRE does <u>not</u> include blowdowns calculated according to 40 CFR 98.233(i).

All Subpart W Industry Segments Are Required to Report OLRE

Industry Segment	Citation
Offshore petroleum and natural gas production	§ 98.232(b)(2)
Onshore petroleum and natural gas production	§ 98.232(c)(23)
Onshore natural gas processing	§ 98.232(d)(9)
Onshore natural gas transmission compression	§ 98.232(e)(9)
Underground natural gas storage	§ 98.232(f)(9)
LNG storage	§ 98.232(g)(8)
LNG import and export equipment	§ 98.232(h)(10)
Natural gas distribution	§ 98.232(i)(8)
Onshore petroleum and natural gas gathering and boosting	§ 98.232(j)(13)
Onshore natural gas transmission pipeline	§ 98.232(m)(2)

Emissions Thresholds That Trigger Reporting
You must report an OLRE if it meets either of these thresholds:

1. Unreported Sources: If methane emissions ≥ 100 kg/hr from a source not already covered elsewhere in § 98.233 (*e.g.*, fires, blowouts, explosions).
2. Reported Sources: If emissions exceed normal calculated values by ≥ 100 kg/hr for sources already reported under § 98.233(a)–(h), (j)–(s), (w), (x), (dd), or (ee).

Emission Quantification Methods:

- You must calculate:
  - Total volume of gas released (in standard cubic feet)
  - Methane emission rate (in kg/hr)
  - Composition of released gas (CH_4 and CO_2 fractions)
  - CO_2 and CH_4 emissions (in metric tons)

- These calculations use:
  - Direct measurement per § 98.234(b), or
  - Engineering estimates, process knowledge, and best available data if direct data are unavailable.

- Additional details:
  - Variable flows must be modeled with peak and average rates.
  - Fire/explosion releases assume max 92% combustion efficiency for estimating GHGs.

Special Notes:

- If multiple release points have a common root cause (*e.g.*, system overpressure), treat them as one OLRE.
- For multi-year events, apportion emissions across years by event duration or variable rates.

How does NGSI address potential double-counting of OLRE and non-GHGRP (GHGi) emissions?
NGSI recognizes that the addition of the OLRE emission source created the possibility of double-counting emissions from certain emission sources that use GHGi methodology. This issue is not applicable to the Processing and Transmission & Storage segments because NSGI Version 3.0 uses the GHGRP methodology for all emission sources in those segments. NGSI addresses this issue in the other three segments as follows:

- Compressor Starts – Production; Gathering & Boosting: The GHGi default factor of 172 kg CH_4/compressor creates the possibility that a given Compressor Start emissions event could exceed the OLRE threshold of 100 kg/hr on a short-term basis. For any Compressor Starts that equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology. To avoid double counting, the GHGi methodology should only be applied when a Compressor Start event is not reported under OLRE. If a Compressor Start event is included in OLRE, the GHGi calculation should assume zero Compressor Start emissions for that event.

- Damages/Dig-ins (Mishaps) – Gathering & Boosting; Distribution: OLRE uses an instantaneous emission rate, whereas the GHGi uses a mileage-based emission factor for damages/dig-ins, so it is difficult to identify whether double counting has occurred. To avoid the possibility of double counting, if emissions from damages/dig-ins equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology. Zero gathering-pipeline miles should be entered into the calculation template for that facility.

- <u>Pressure Relief Valve ("PRV") Releases – Production</u>: For any PRV releases where the valve emissions equaled or exceeded 100 kg/hr, those emissions should be included only under the OLRE source and excluded from the GHGi methodology.
    - The Distribution segment also uses the GHGi methodology for pressure relief valve ("PRV") releases from routine maintenance. However, because the GHGi factor is relatively small and is not likely to meet the OLRE threshold of 100 kg/hr, it presents an unlikely risk of double counting so no additional steps are required. The same is true for the GHGi factor for emissions from Meters in the Distribution segment.

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). "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.
- EPA (2025) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2023. U.S. Environmental Protection Agency. Available at: https://www.edf.org/freedom-information-act-documents-epas-greenhouse-gas-inventory (not officially published by EPA but released to Environmental Defense Fund via Freedom of Information Act Request).

Appendix D: 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 17. Potential Emissions Sources to Include in Future Versions of the NGSI Protocol

Segment	Potential Future Source
Production	• Casing bleed and venting • Catalytic heaters • Starting gas vented for turbine and reciprocating engine drivers (defined as a separate emission source from blowdowns) • Small combustion sources (<130 horsepower)* • Small heaters (<5 MMBtu/hour)* • Fugitive emissions from truck loading of hydrocarbon liquids/produced water • Blowdowns from equipment with a unique physical volume < 50 ft^3
Gathering & Boosting	• Starting gas vented for turbine and reciprocating engine drivers (defined as a separate emission source from blowdown vent stacks) • Blowdowns from equipment with a unique (physical volume < 50 ft^3) • Small combustion sources (<130 horsepower)* • Small engines (<5 MMBtu/hour)* • Catalytic heaters • Fugitive emissions from truck loading of hydrocarbon liquids/produced water
Processing	• Natural gas driven pneumatic pumps • Small combustion sources (<5 MMBtu/hour)* • Blowdowns from equipment with a unique physical volume < 50 ft^3 • Starting gas vented for turbine and reciprocating engine drivers (defined as a separate emission source from blowdowns) • Catalytic heaters
Transmission & Storage	• Catalytic heaters • Natural gas driven pneumatic pumps • Starting gas vented for turbine and reciprocating engine drivers (defined as a separate emission source from blowdowns)) • Odorizers • Blowdowns from equipment with a unique physical volume < 50 ft^3
Distribution	• Catalytic heaters • Compressed natural gas (CNG) stations • Odorizers • Small combustion sources (<130 horsepower)* • Small engines (<5 MMBtu/hour)* • Storage facilities operating within distribution segment boundaries • Blowdowns from equipment with a unique physical volume of < 500 ft^3
***** Must report total number of units and type, and ID per 40 CFR 98.236(z), although emissions not reported under Subpart W.	

Appendix E: 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. In particular, NGSI may 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 3.0 relies on some existing, emissions factor-based approaches and the May 2024 updates to GHGRP Subpart W, 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 3.0 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.

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 3.0 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.[57] NGSI will work with stakeholders to incorporate advancements in this area in future versions of the Protocol.

For distribution companies, Version 3.0 of the NGSI Protocol retains the two approaches to estimating throughput for the purpose 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 D. NGSI will continue to collaborate with companies and other stakeholders to advance the NGSI Protocol, including the scope of emission sources, as appropriate. Stakeholder feedback will indicate whether additional sources will be added to NGSI beyond those required under the 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

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[57] 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.

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 would 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 (*i.e.*, denominator) for each industry segment in which a company has operating assets. Version 3.0 of the NGSI Protocol does not offer a segment-additivity standard, though that may be offered in future versions.