MiQ STANDARD

for Methane Emissions Performance for

Onshore Crude and Natural Gas Production

MAIN DOCUMENT

v2.0 – INTERIM FINAL VERSION





Except otherwise noted, the MiQ Standard ©2026 by the MiQ Foundation is licensed under Attribution-No Derivatives 4.0 International. To view a copy of this license, visit http://creativecommons.org/licenses/by-nd/4.0/.

MiQ and the MiQ logo are registered trademarks of MiQ Foundation.

Contents

1 Background 4
1.1 Introduction 4
1.2 About 5
1.3 Purpose 5
2 Scope 6
3 Terms and Definitions 6
4 Core Principles 15
5 Roles and Responsibilities 16
6 Methane Emissions Certification 17
6.1 Applicability 17
6.2 Grading System 18
7 Subsidiary Documents 20
Annex A: Conversion Factors 21
Annex B: Document Status 22
B.1 Document Development 22
B.2 Version History 22
References 27

1 Background

1.1 Introduction

Methane (CH_4) emissions from crude and natural gas production are a significant contributor to climate change. Methane, the primary component of natural gas, is a potent greenhouse gas (GHG) with a short-term climate impact more than 80 times[1] greater than that of carbon dioxide [1]. Methane is emitted throughout the crude and natural gas supply chains. This Standard addresses methane emissions associated with the production of crude and natural gas (including associated gas production).

Methane is emitted during the production of crude and natural gas through venting, leaks and incomplete combustion from flares, burners and engines. While technologies and practices that can prevent or significantly reduce methane emissions are well known, emissions abatement actions, whether voluntary or required by regulation, are not yet occurring with the consistency or at the scale necessary to limit global warming to the 1.5°C as envisioned by the Paris Agreement.

The MiQ Standard for Methane Emissions Performance (the Standard) combines three elements – (1) the measurement and quantification of methane emissions through Emissions Measurement and Quantification (EMQ), (2) a calculated Methane Intensity (MI), (3) Producer policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices, CP), to provide a robust and reliable method for certifying crude and natural gas production based on methane emissions management performance. The Standard is designed to incentivize continuous improvement in methane emissions management practices.

The Standard consists of two main types of documents (Main Document and Subsidiary Documents), to be read in the following order:

1. **Main Document – Onshore Crude and Natural Gas Production (this document)**
2. Subsidiary Documents
    a. *Subsidiary Document 1: Emissions Measurement and Quantification– Onshore Crude and Natural Gas Production*
    b. *Subsidiary Document 2: Methane Intensity – Onshore Crude and Natural Gas Production*

[1] According to IPCC AR6, the global warming potential (GWP) of methane is 82.5 times that of CO_2 over a 20-year period, and 25 times more potent than CO_2 over a 100-year period.

c. *Subsidiary Document 3: Company Practices – Onshore Crude and Natural Gas Production*

1.2 About

MiQ Foundation, a non-profit entity, is the Standard Holder for this Standard. MiQ was established to reduce methane emissions from the global crude and natural gas industries through a market-based crude and natural gas certification system.

1.3 Purpose

The purpose of this Standard is (i) to use quantitative metrics to evaluate methane emissions from a Facility, and (ii) to incentivize continuous improvement in methane emissions management practices. This Standard creates an opportunity for Producers to differentiate their crude and natural gas production based on methane emissions management performance. More specifically, the objectives of this Standard are:

a) to determine measurement-informed methane emissions intensity associated with the crude and natural gas products;

b) to accelerate the deployment of measurement and monitoring technologies that detect and measure methane emissions;

c) to accelerate the deployment of practices and technologies that mitigate methane emissions;

d) to increase transparency regarding the methane emissions management performance of crude and natural gas production, with a globally consistent methodology for emissions measurement, monitoring, reporting, and verification;

e) to enable producers, marketers, and buyers to transact crude and natural gas based on the methane emissions management performance of a Facility, and to demonstrate additional value to their customers;

f) to provide producers, buyers, and investors with a uniform, independently verified Standard consistent with environmental, social, and governance (ESG) reporting to address methane emissions from crude and natural gas production and consumption;

g) to complement regulations by incentivizing methane emissions measurement, monitoring, and abatement actions; and

h) to credibly recognize producers that demonstrate strong methane emissions management performance.

2 Scope

This Standard establishes a system for generating an MiQ Grade which reflects the Facility's methane emissions management performance. Performance is assessed based on the Facility's (1) deployment of methane emissions measurement technologies (Emissions Measurement and Quantification), (2) calculated Methane Intensity, and (3) policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices).

Furthermore, this Standard:

- is applicable to Facilities in the onshore crude and natural gas production segment (see Terms and Definitions);
- specifies a method for calculating the Methane Intensity of the crude and natural gas products (see *Subsidiary Document 2: Methane Intensity*);
- establishes general principles for an effective methane management program, including the deployment of methane measurement technologies (see *Subsidiary Document 1: Emissions Measurement and Quantification*) and policies and procedures focused on methane emissions prevention, detection, and abatement (see *Subsidiary Document 3: Company Practices);* and
- does not define requirements for the physical or chemical quality of crude and natural gas.

3 Terms and Definitions

For purposes of this Standard, the following terms have the meanings attributed below. All terms and definitions used in this Standard (including in Subsidiary documents) are defined here.

Term	Definition
Annual Audit	The systematic, independent, and documented assessment by the Auditor prior to the intended Certification Period, verifying and validating the information reported by the Producer conforms to the Standard.
Auditor/Auditing Body	Also referred to as third-party assurance provider, an individual, or organization composed of qualified individuals, that conducts assessments to determine whether a Facility meets the requirements of the Standard and recommend a performance Grade. An Auditor or Auditing Body must possess the demonstrated knowledge, skill, abilities, training, and experience necessary to provide assurance services, both remotely and onsite, to assess a Facility's performance against all diverse elements of the Standard.
Audit Report	A verification and validation document prepared by an Auditing Body that contains a comprehensive analysis of the Producer's conformity with requirements of the Standard.
Basin	A crude and natural gas producing region (a geologic sedimentary basin), as typically defined and referenced by national legislation.
Causal Examination	The process of investigating a detected emission event at the Site, Equipment or Component level to determine its likely cause. Such investigation may use Supervisory Control and Data Acquisition (SCADA) logs, maintenance records, operational logs, operator site visits, and Source Level surveys. At a minimum, the examination shall determine whether the emissions event was Intended or Unintended. Causal examinations are less formal than Root Cause Analyses and do not require the identification, recommendation, or implementation of systematic corrective actions.
Certification Period	The forward-looking period, not to exceed 12 months, during which a Facility's certified operations remain eligible to generate MiQ Certificates.

Company Practices	A document, program, policy or procedure, specific to the Producer that demonstrates the effective management of methane emissions within the boundaries of a Facility. Company Practices is also the title of one of the Subsidiary Documents to this Standard.
Component	A discrete piece of equipment, such as a flange, connector, pressure relief device (PRD), thief hatch, screw or compression fitting, stem packing in a valve, pump seal or compressor component.
Continuous Monitoring System	A methane monitoring system at a Facility that: (a) consists of a network of stationary but linked sensors, (b) autonomously collects, records, and reports emissions data, (c) has an automated detection alert such that the data is interpreted, without human intervention, to identify an emissions event above baseline normal operating conditions and trigger follow-up by operators, (d) collects, records and reports data within an envelope of operating conditions or documented runtime hours, (e) can localize an emissions event to the Site-Level for the purpose of meeting the MiQ Facility-Level monitoring requirements, and/or (f) can consistently pinpoint an emissions event to the component or Source Level to apply towards the MiQ Source-Level emissions detection and quantification requirements.
Crude Oil	A mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through separation equipment. The term may include lease condensate that is subsequently mixed/blended into the crude stream.[2]
Detection	A sensed or measurable indication of the presence of methane emissions detected using a monitoring technology or inspection methods.

[2] Consistent with definition of crude oil given by Energy Information Administration (EIA) per https://www.eia.gov/tools/glossary/

Directed Inspection and Maintenance Program	A documented program specific to a Facility that uses a risk-based process to develop effective inspection schedules designed to rapidly detect methane emissions from selected sources that have a higher emissions potential.
Emission Factor	A coefficient that quantifies the emissions of a gas per unit of activity, equipment, component, system, or event, based on measurement data or other quantification methods and averaged to develop a representative emission rate for a defined activity level and set of operating conditions. Emission factors may be expressed in units such as kg/km, kg/event, or kg/equipment type.
Equivalency Determination	The process of evaluating the effectiveness of an operator's proposed emissions measurement program against the Emissions Measurement and Quantification requirements of the Standard for the purpose of determining a specific rating, or Grade. The process generally consists of: 1) defining new methods, 2) applying controlled release testing results to characterize performance of each method, 3) conducting simulation modeling to predict the performance of the proposed programs and 4) performing field verification activities to evaluate the accuracy of the simulation modeling.
Equivalent Emissions Measurement Program	An emissions measurement program implemented by an operator that utilizes a combination of Facility-Level and Source-Level measurement and quantification tools, and is determined to provide a level of measurement, quantification, and emissions mitigation comparable to that required under the Standard for a given MiQ Grade over the course of a year. Substituted methods may include a range of measurement and monitoring technologies with demonstrated measurement and quantification capabilities.
Emissions Measurement and Quantification	A subsidiary document of this Standard which describes the requirements for the deployment and use of methane measurement technologies to satisfy the requirements for Source-Level quantification and Facility-Level measurement to inform methane emissions inventory and methane emissions management practices.

Facility	All onshore crude and natural gas production sites and associated equipment, including leased, rented, or contracted, located within a Licensed Area or contiguous aggregation of Licensed Areas, established by an applicable lease, concession, license, or equivalent legal instrument, or within a contiguous aggregation of such areas, and under the operational control of a common operator. For Onshore Production, the Facility boundary shall include all facilities and equipment directly engaged in or functionally integrated with production or initial processing from the applicable Licensed Area(s), and all associated upstream emission sources with the potential to emit methane, including wells and well pads, associated production facilities, dedicated gathering lines, storage tanks and tank batteries, and centralized or satellite separation, stabilization, compression, and treatment facilities.
Facility Scale Measurement	Methane emissions measurement surveys conducted by an operator using a method that evaluates all emission sources across the entire Facility, in three-dimensional space and is capable of measuring emission events above the specified minimum detection threshold limit (MDL).
Grade	The performance grade assigned to a Facility in accordance with this Standard by an Auditor and approved by the Issuing Body.
Greenhouse Gases (GHGs)	Carbon dioxide (CO_2) and other gases identified in the IPCC Sixth Assessment Report including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), chlorofluorocarbons, hydrofluorocarbons, and perfluorocarbons [1]. Greenhouse gases other than carbon dioxide can be expressed in terms of carbon dioxide equivalent (CO_2e), calculated using the applicable Global Warming Potential (GWP) for a specified time horizon.
Hydrocarbon Liquids	A general term encompassing all crude oil, lease condensate, and other liquid-phase hydrocarbons at the sales point of a Facility.

Intended Emission	A methane emission that is intentionally released by design, including emissions from equipment designed to vent, process vents, flares, and other combustion equipment operating within their design parameters. Emissions resulting from operation outside of design parameters are considered as Unintended Emissions.
Inventory	A documented compilation of emissions from all emission sources at a Facility, prepared on an annual basis.
Issuing Body	The entity responsible for registering Facilities under the MiQ Program, issuing MiQ Certificates, approving Audit Reports, and performing other functions prescribed by the MiQ Program.
Large Emission Events	Emission events with a methane emission rate exceeding a predefined threshold, typically resulting from abnormal process conditions. Such events are capable of significantly affecting a Facility's total emissions.
Leak Detection and Repair (LDAR)	A systematic process for detecting unintended methane emissions from equipment or infrastructure and taking corrective action to repair those emissions within a defined timeframe. LDAR practices often employ handheld, Source-Level emission inspection tools. For the purpose of this Standard, the term is expanded to include any monitoring, inspection, or survey program involving the systematic deployment of methane detection technologies across a collection of assets to detect, investigate, and repair emissions. An LDAR program should define the monitoring method, deployment and configuration strategy, temporal and spatial coverage, operating envelope, work practices, detection capabilities of the selected technologies, follow up, investigation, and repair procedures and timelines, and data management requirements.

Lease Condensate	Light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells. Lease condensate consists primarily of pentanes and heavier hydrocarbons and is typically incorporated into the crude oil stream after production.[3]
Licensed Area	The geographic area and associated production boundary established by the applicable lease, concession, license, permit, authorization, or equivalent legal instrument or instruments that authorize hydrocarbon extraction and related production activities.
Materiality	The relative significance of methane emissions from a source or source category in relation to total methane emissions within a defined reporting boundary, used to determine the appropriate rigor of quantification and related assessment, without excluding known emissions from the emissions inventory or report.
Measurement	The empirical determination of methane concentration, flow, or other relevant physical parameters using a measuring device or measurement system, from which methane emissions or an emission rate are directly determined or derived at a defined source, site, or facility scale.
Methane Intensity	A metric that quantifies methane emissions associated with production relative to the quantity of marketed crude and/or natural gas. It is typically expressed as a percentage or the mass of methane emitted per unit of marketed product or unit of energy produced.
MiQ Program	The framework governing the administration of the Standard, including governance, certification processes, and the operation of the MiQ Registry. Additional information is provided in the MiQ Program Guide.

[3] Consistent with definition of lease condensate given by Energy Information Administration (EIA) per https://www.eia.gov/tools/glossary/

Minimum Detection Limit	The lowest methane emission rate, or in some cases methane concentration, that a measurement technology can reliably detect with a specified level of confidence (probability of detection) under defined operating and environmental conditions.
Natural Gas Liquids	A group of hydrocarbons including ethane, propane, normal butane, isobutane, and natural gasoline, that are extracted from feedstock gas entering a natural gas processing plant. [4]
Onshore Crude and Natural Gas Production	The onshore crude oil and natural gas supply-chain segment comprising the extraction, production, recovery, lifting, stabilization, separation, treating, initial processing, storage, and conveyance of crude oil, natural gas, and condensate from the well through the sales, custody-transfer, or other meter that separates the production asset from a gathering or other downstream asset. Equipment may include, but is not limited to, compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, connecting pipework, dedicated production gathering lines, and portable non-self-propelled equipment, including well drilling and completion equipment, workover equipment, and leased, rented, or contracted equipment. Production equipment also includes associated storage and measurement vessels and all crude and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.
Producer / Operator	The owner and/or operator of a Facility, responsible for operating one or more wells that recover and bring crude and natural gas to the surface, whether or not such operations also produce associated byproducts.

[4] Consistent with definition of natural gas liqiuids given by Energy Information Administration (EIA) per https://www.eia.gov/tools/glossary/

Production Throughput	Natural gas production throughput is the quantity of natural gas marketed during the calendar year from wells. This includes natural gas that is routed to a pipeline but excludes gas that is vented or flared or used in field operations. It does not include gas injected back into reservoirs or shrinkage resulting from lease condensate production. Hydrocarbon liquids throughput is the total quantity of hydrocarbon liquids marketed from wells during a calendar year.
Quantification	Estimating an emission rate, such as mass per unit time or volume per unit time, or total emissions. This can be done directly through measurement of emissions, or indirectly through the use of representative emission factors, other engineering calculations, simulation tools, or a combination of such methods.
Reconciliation of Emissions	The iterative process of reviewing, comparing, prioritizing, and integrating a Source-Level emissions inventory with corresponding Facility-Level measurements and relevant operational data to identify, understand, explain, and resolve discrepancies, and produce a single, internally consistent annual emissions inventory that reflects the best available information for the Facility. In addition to the emissions quantities, reconciliation process should include an uncertainty estimate or characterization appropriate to each method so that reported emissions are more reliable, transparent, and representative of actual methane releases and suitable for the Methane Intensity calculation and Annual Audit.
Root Cause Analysis (RCA)	A documented procedure whereby a Producer follows up on detected events to determine the source of the emission, identify possible causal factors, determine the root cause, recording each event for data aggregation, and finally recommend and implement a solution.
Site	The well pad, tank battery, or other equipment pad encompassing a crude and natural gas production well (including multiple wells) and its supporting equipment, such as that used for separation, treating, compression, gathering, and storage. Supporting equipment need not be physically co-located with the well or well pad where it is operationally associated with that production Site.

Site-Level Measurement	Application of a Site-Level emissions measurement method that captures a complete overview of methane emissions from all sources within a defined Site boundary, using one or more measurement technologies capable of detecting and quantifying emissions across that Site within their demonstrated detection and quantification capabilities and operating envelope. Site-Level Measurement is conducted as part of a Facility-Scale measurement survey and shall provide sufficient spatial resolution to attribute measured emissions to the Site being assessed. Source-Level attribution or resolution is not a prerequisite for Site-Level Measurement.
Source / Emission Source	A specific piece of equipment or activity from which emissions originate. The sum of emissions from all emission sources is an input to a Facility's emissions inventory.
Source-Level Inspection	Application of a Source-Level emissions detection and identification method to directly inspect individual sources of emissions, down to the Equipment or Component level to identify and detect sources of methane leaks and other unintentional methane emissions.
Standard Holder	The organization responsible for defining and managing all aspects of the development of the Standard, including the processes for making changes to the Standard and its associated documents.
Unintended Emission	Any methane emission occurring outside equipment design specifications or normal operating conditions, including equipment leaks and failures (often referred to as fugitive emissions), unintended venting, and combustion equipment operating outside design parameters, and operator-managed emissions such as manual lifts, blowdowns, and compressor starts that exceed established operating procedures.

4 Core Principles

This Standard is based upon the following core principles (in no order):

1. **Relationship with ISEAL Credibility Principles**



In addition to the requirements of this Standard, the principles set out in International Social and Environmental Accreditation and Labelling (ISEAL) Credibility Principles shall apply [4]. Where this Standard establishes requirements that are more specific than those contained in the ISEAL Credibility Principles, the requirements of this Standard shall prevail.

2. Voluntary nature

The use and adoption of this Standard are voluntary. This Standard establishes requirements that enable Producers to differentiate the supply of their products based on methane emissions management performance. Application of this Standard is a voluntary action undertaken by a Producer.

3. Transparency

Certification under this Standard is based on objective and publicly disclosed criteria. Access to details of MiQ certificates issued under this Standard should be made available to users of MiQ Program.

5 Roles and Responsibilities

Table 1 lists all the individuals and groups engaging with the Standard and what their responsibilities are regarding this document.

Table 1: Roles and Responsibilities

Roles	Responsibilities
Standard Holder	· defining and managing all aspects of the development of the Standard · publishing the Standards and supporting documents · managing updates and changes to the Standards
Auditor/Auditing Body	· conduct Annual Audit in accordance with requirements defined in this Standard and the MiQ Program Guide. · Recommend a Grade for a Facility on methane emissions performance
Producer	· Requiring registration of Facilities by the Registry Operator;

	· selecting and contracting with an Auditing Body that fulfills the requirements of this Standard; · engaging with the Auditing Body to plan and prepare for the certification process; · providing all necessary information, data, and documentation as well as access to relevant personnel and field operations to the Auditing Body for it to carry out the Audits (see *MiQ Program Guide)* · Submitting Audit Reports to the Registry Operator
Registry Operator	· registering each Facility under the MiQ Program · approving Audit Reports under the MiQ Program issuing MiQ certificates ·

6 Methane Emissions Certification

6.1 Applicability

A Facility is eligible to be audited under this Standard using the following boundary definitions:

- **Physical boundary**

  The MiQ Standard seeks to determine a methane intensity and performance grade for a Facility in order to facilitate differentiation of crude and/or natural gas within the global supply chain. To this end, a Facility boundary must encompass and represent all upstream emission sources and corresponding throughput within the applicable Licensed Area or contiguous aggregation of Licensed Areas. Any aggregation shall be complete, consistently applied, traceable to the underlying Licensed Areas, and shall not be used to selectively include or exclude Sites, equipment, emission sources, emissions, or corresponding throughput. See the definitions of *Site* and *Facility* for further details.

- **Organizational boundary**

  Facilities must fall under the operational control of a common operator, sharing common management practices. Certification encompasses all equipment and sources with potential to emit, including leased, rented and operated equipment.

The ability of a Facility to qualify for certification is based on its methane emissions performance, which is determined by the following Standard elements:

Emissions Measurement and Quantification

The requirements to be complied with are defined in the *Subsidiary Document 1: Emissions Measurement and Quantification*.

1. **Methane Intensity**

   The requirements to be complied with are defined in *Subsidiary Document 2: Methane Intensity*.

2. **Company Practices**

   The requirements to be complied with are defined in the *Subsidiary Document 3: Company Practices*.

6.2 Grading System

Table 2 details the overall grading system established by this Standard. The Grade is based on the ***lowest*** score achieved across the two Standard elements: (1) Emissions Measurement and Quantification and (2) Methane Intensity. Company Practices are assessed separately and do not determine the letter Grade.

To achieve Grades C – F, a Facility must satisfy all minimum requirements for Emissions Measurement and Quantification. To qualify for Grades A – B, a Facility must achieve higher scores in Emissions Measurement and Quantification, as indicated in Table 2, by conducting more frequent Facility-Level measurements, or through an Equivalent Emissions Measurement Program, as described in *Subsidiary Document 1: Emissions Measurement and Quantification*.

Table 2: Grading system - score requirements for the three Standard elements

Score Requirements		
Grade	**Methane Intensity** **True Methane Loss (%)**	**Emissions Measurement & Quantification Points**
A	≤ 0.05%	12
B	≤ 0.1%	8
C	≤ 0.2%	Mandatory Minimum
D	≤ 0.5%	Mandatory Minimum
E	≤ 1%	Mandatory Minimum
F	≤ 2%	Mandatory Minimum

Operators shall satisfy all applicable Mandatory Company Practices as a condition of initial and continued certification. The Continuous Improvement Pathway described in this section is available only to Facilities located outside the United States. Facilities located in the United States are not eligible for this pathway and shall satisfy the Improved Company Practices scope corresponding to the applicable Grade at the time of certification (Table 3).

Table 3: Corresponding Company Practices for each MiQ Certification Grade

Grade	Mandatory Company Practices	Improved Company Practices Points
A	Mandatory	15
B	Mandatory	10
C	Mandatory	5
D-F	Mandatory	-

For Facilities eligible for the Continuous Improvement Pathway, the Operator should also satisfy the Improved Company Practices scope corresponding to the applicable Grade within three years, or an alternative agreed-upon timeline and, where applicable, established in a Continuous Improvement Plan. This framework allows a Facility to establish an independently verified performance baseline while requiring transparent and time-bound progression toward improved methane-management practices.

The MiQ Standard separately evaluates: (i) the Facility's MiQ Grade; and (ii) the Company Practices status demonstrated at the time of certification. The Company Practices status indicates whether the Operator has satisfied the applicable Improved Company Practices (as '*completed*') or is progressing toward satisfying them through a Continuous Improvement Plan (as '*on the pathway*'). Accordingly, the 'on the pathway' Company Practices status is not available to Facilities located in the United States. Additional details related to Company Practices can be found in *Subsidiary Document 3: Company Practices*.

7 Subsidiary Documents

The Standard is structured with subsidiary documents as shown in Figure 1

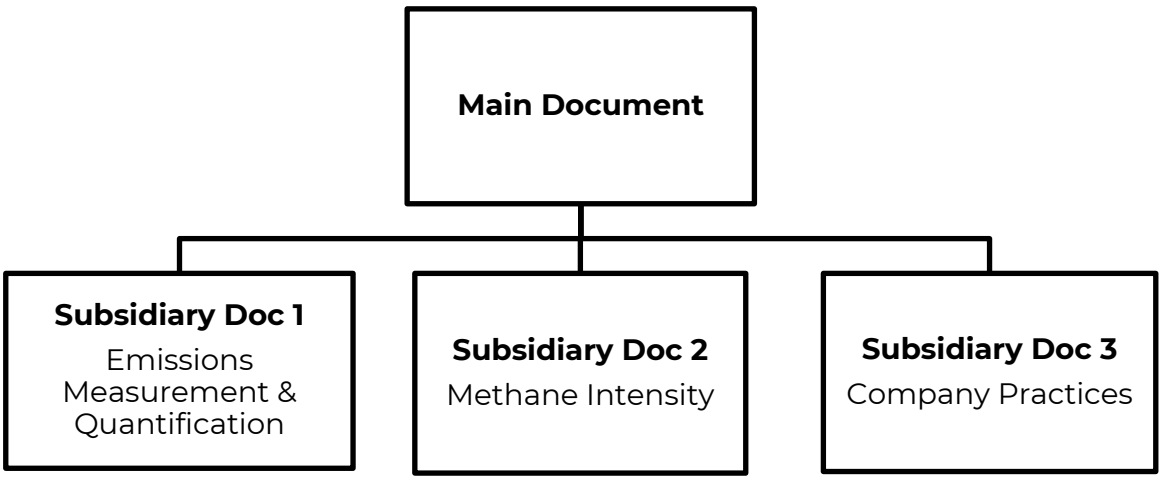


Figure 1: Document hierarchy

Annex A: Conversion Factors

For conversion factors, please follow the values as defined in Table 4:

Table 4: Conversion factors [5].

Megawatt-hour thermal [MWh]	**Million British thermal unit** [MMBtu]
1	3.412141286
0.2930711	1
Standard cubic meter [Sm^3]	**Standard cubic feet** [Scf]
1	35.31466672
0.028316847	1

For conversions related to different standard conditions and calorific values of natural gas volumes, please consult ISO 13443 – Natural gas – Standard reference conditions [6].

The higher calorific, gross or high heating value is the amount of heat produced by the complete combustion of a unit quantity of fuel [7].

Annex B: Document Status

B.1 Document Development

The MiQ Foundation, as the Standard Holder, has developed this Standard through extensive peer and stakeholder review. MiQ acknowledges the substantive contributions of industry experts, academic experts, consulting firms, auditing firms, environmental NGOs, and government officials.

MiQ reserves the right to update the Standard periodically to reflect new research, internal calibrations, and advancements in available technology accessible to Operators.

Producers currently undergoing certification must comply with the latest version of the Standard if their Annual Audit occurs more than 12 months from the publication date of this version.

B.2 Version History

The following table captures key changes made to the Onshore Standard.

Table 5: Version History

Version	Revision Date	Document	Summary of Change
v0.7	2020-08	All	Stakeholder Review
v0.8	2021-03	All	First Pilot Version and Stakeholder Review
v0.9	2021-07	All	First Online Publication
v0.95	2022-07	Main	Addendum for Removal of Ex-Post requirement with reconciliation of Methane Intensity during Annual Audit for immediate retirement of MiQ certificates
v1.0	2022-09	Main	Re-defined Ex-Ante Audit: *Annual Audit* with additional requirements Redefine Certification Bodies as Auditors and Auditing Bodies

			Section 3: Re-defined Production *Throughout* and corresponding calculation for Methane Intensity
			Removal of references to *Procedure Documents 1: Certification* and *Procedure Document 2: Non-Compliance*; now referring Standard users to the *Program Guide*.
		Methane Intensity	Section 3.3 Clarification to Emission Reconciliation Process Requirements
			Table 3: Clarification to Source-specific Emission Calculation Guidance and minimum criteria
			Table 3: Revised attribution of emissions to energy-allocated or gas-allocated sources
			A.2: updated guidance for calculation of Methane Intensity for allocation of emission sources
		Company Practices	Section 3.2: Update of final repair and repair verification to 30 days from date of detection (UMEP-2)
			Section 3.2: Addition of Root Cause Analysis procedures to improved practices (UMEP- 5)
		Monitoring Technology	Table 1. and footnotes 4: Clarification to duration in-between surveys
			Table 2. and footnote 6: Revision and clarification to Facility Scale and Sources Level monitoring requirements
			Section 3.2.1 and 3.2.2: Clarified role of continuous monitoring for Facility Scale and Source Level surveys
			Section 3.2.3: Update and Clarification to Equivalent LDAR program and Equivalency Determination
v1.0.0	2023-11	Main	Removal of terms *Applicable Criteria* and *Detection* from definitions section

	Added clarification between the difference between *Causal Examination* and *Root Cause Analysis*
	Clarified that the definition of *Methane Intensity includes allocation to separate products*
	Clarified that the definition of *Quantification* includes the process of calculating total emissions from an event or source
	Added definition of Natural Gas Liquids
Methane Intensity	Updated language in Section 3.3: *Emissions Reconciliation* to clarify the intent of the process
	Revised language in Section A.1.1 adding a description for the levels of data quality in methane emission inventories to assist in defining 'best available data' per emission source or emission event
	In Section A.2, Clarified allowable ways for an operator to allocate emissions that are included via the operator's reconciliation process
	Replaced term 'volume' with 'Throughput' in Section A.2
	Revised language for how methane intensity is converted into mass of emissions per unit energy, referencing the *MiQ Program Guide* as the governing document for conversions that are ultimately reflected on MiQ certificates
Company Practices	*UMEP-2 Source Level Detection Plan:* Corrected first attempt, repair and repair verification deadlines
	IMEP-7.2 *Managing Methane Emissions from Flares:* Revised requirement of ensuring "good" destruction efficiency to "design" destruction efficiency

		Monitoring Technology Deployment	Inserted a clause allowing for Source Level and Facility Scale inspection frequencies to be reduced upon confirmation of no additive detects within the last year Aligned text in Section 5.1: *Interconnection with calculated Methane Intensity* with Section 3.3: *Emissions Reconciliation* of the Methane Intensity subsidiary document
v1.0.0	2024-05	Main Document	Updated definition of crude oil, lease condensate, and natural gas liquids Added definition of hydrocarbon liquids Added a definition of *hydrocarbon liquids throughput* Clarified additional responsibility for producers to submit audit report to the issuing body
		Methane Intensity	Clarified in Section 5 that producers must document how hydrocarbon liquids throughput is measured
v2.0	2026-10	Main Document	Updated definitions Updated the language to be inclusive of both crude and natural gas production Revised grading system Restructured and renamed Subsidiary Documents
		Emissions Measurement and Quantification	Updated the language to be inclusive of both crude and natural gas production Included additional requirement for the Source-Level Quantification and Facility-Level Measurements

	Included additional requirements for emissions measurement and quantification
	Included additional recordkeeping requirements
	Revised Performance Scoring for Emissions Measurement and Quantification
Methane Intensity	Provided additional guidelines on emissions sources
	Included guidelines related to materiality of methane emissions
	Included MIQ's OGMP 2.0 Hybrid Options for the OGMP 2.0 L4 and L5.
	Adopted an energy allocation approach for Methane Intensity calculation method for both onshore crude and natural gas production
	Included additional guidelines for Reconciliation, including Measurement-Resolved Reconciliation and Aggregate Reconciliation.
Company Practices	Updated the language to be inclusive of both crude and natural gas production
	Moved Leak Detection and Repair requirements under Company Practices
	Revised Company Practices Performance Criteria

References

[1] Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, ... B. Zhou (2021). Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press. Retrieved from https://www.ipcc.ch/report/ar6/wg1/

[2] Brandt, A. R., Heath, G. A., & Cooley, D. (2016). Methane Leaks from Natural Gas Systems Follow Extreme Distributions. Environmental Science & Technology, 50(22), 12512–12520. https://doi.org/10.1021/acs.est.6b04303

[3] Zavala-Araiza, D., Alvarez, R. A., Lyon, D. R., Allen, D. T., Marchese, A. J., Zimmerle, D. J., & Hamburg, S. P. (2017). Super-emitters in natural gas infrastructure are caused by abnormal process conditions. Nature Communications, 8(1, 1), 14012. https://doi.org/10.1038/ncomms14012

[4] ISEAL Alliance. (2013). ISEAL Credibility Principles: Principles for Credible and Effective Sustainability Standards Systems. Retrieved from https://www.isealalliance.org/defining-credible-practice/iseal-credibility-principles

[5] Society of Petroleum Engineers (SPE). (2020, February 26). Recommended SI units and conversion factors. PetroWiki. Retrieved October 26, 2020, from https://petrowiki.org/Recommended_SI_units_and_conversion_factors

[6] International Organization for Standardization. (1996). ISO 13443:1996, Natural gas — Standard reference conditions. Retrieved from https://www.iso.org/standard/20461.html

[7] Engineering Toolbox. (2005). Heat Value. Retrieved October 26, 2020, from https://www.engineeringtoolbox.com/gross-net-heating-value-d_824.html

MiQ STANDARD

for Methane Emissions Performance for

Onshore Crude and Natural Gas Production

SUBSIDIARY DOCUMENT 1:

Emissions Measurement and Quantification

v2.0-INTERIM FINAL VERSION



Contents

1 Introduction 3
2 Scope of this Document 5
3 Emissions Measurement and Quantification Objective and Performance Criteria 5
3.1 Key Performance Parameters 6
3.2 Performance Scoring 7
3.2.1 Source-Level Emissions Quantification 8
3.2.2 Facility-Level Measurement 13
3.2.3 Equivalency Determination 16
4 Recordkeeping and Reporting Requirements 17
4.1 Minimum Recordkeeping and Reporting Requirements 19
4.2 Recordkeeping and Reporting Requirements for Continuous Monitoring Technology 20
5 Interconnections with other Standard Elements 21
5.1 Interconnection with calculated Methane Intensity 22
5.2 Interconnection with Company Practices 22
References 23

1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines three Standard elements – (1) the measurement and quantification of methane emissions through Emissions Measurement and Quantification (EMQ), (2) a calculated Methane Intensity (MI), and (3) Producer policies and procedures focused on methane emissions prevention, detection, quantification, and abatement (Company Practices, CP), to provide a robust and reliable method for certifying crude and natural gas and production according to its methane emissions management performance. The Standard is designed to incentivize continuous improvement in methane emissions management practices.

The Standard consists of two main types of documents, to be read in the following order:

1. *Main Document – Onshore Crude and Natural Gas Production*
2. Subsidiary Documents
    a. **Subsidiary Document 1: Emissions Measurement and Quantification – Onshore Crude and Natural Gas Production (this document)**
    b. *Subsidiary Document 2: Methane Intensity – Onshore Crude and Natural Gas Production*
    c. *Subsidiary Document 3: Company Practices – Onshore Crude and Natural Gas Production*

This Subsidiary Document outlines the requirements for the measurement and quantification of methane emissions.

Methane emissions measurement and quantification are key elements of methane emissions management for a Facility. Methane emissions measurement technologies can be deployed across a spectrum of spatial and temporal scales. Site-Level measurement approaches (e.g., aerial surveys using crewed or uncrewed aerial vehicles) assess methane emissions across all emission sources within a Site. The results of Site-Level measurements are aggregated as part of Facility-Level measurement surveys to estimate emissions over larger spatial scales, such as a Facility. In contrast, Source-Level measurement approaches are intended to evaluate individual emission

sources with higher spatial resolution while covering a limited area (e.g., using handheld devices).

Both Site-Level and Source-Level measurement approaches can vary in temporal scale, with more frequent deployment generally increasing the likelihood of observing emission events with different timing, duration, and characteristics. Measuring methane emissions lacks a "silver bullet" solution that addresses all the needs across various applications. As a result, a multi-tiered approach, involving an informed selection of complementary technologies, is often required for an effective methane emissions management system. Figure 1 illustrates simplified examples of methane measurement technologies in relation to spatial and temporal scale.

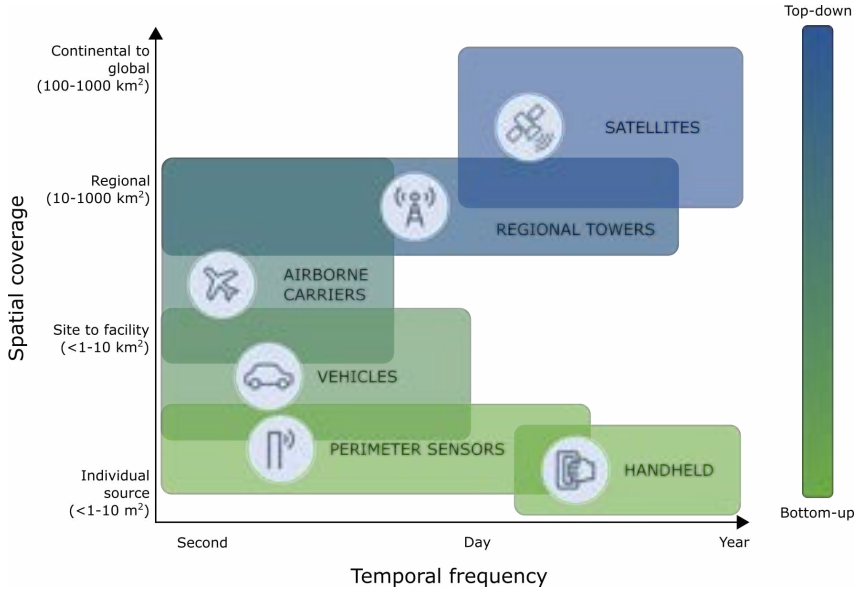


Figure 1: Methane measurement technology across a variety of spatial and temporal scales[1]

In practice, discrepancies are often observed between results obtained using different measurement modalities. To date, emissions reconciliation approaches continue to evolve through research and industry collaboration. The existing body of work indicates that top-down approaches can produce methane emissions estimates that are significantly higher than those derived from bottom-up approaches alone, by detecting emissions that are missing or

[1] Adapted from the National Academies of Science, Engineering, and Medicine, 2018 [1]. Note that the definition of Facility in this figure can be different from the MiQ's definition of Facility.

under-represented in the bottom-up emissions inventories [*2*, *3*]. Therefore, more frequent emissions measurement can contribute to developing more accurate emissions inventories, and support improved methane emissions management and mitigation. *Figure 2 outlines the spatial scales for methane measurement referenced in the Standard.*



Figure 2: Spatial scales utilized within the Standard, based on the definitions of Facility, Site, and Source provided in the *Main Document*.

2 Scope of this Document

This Subsidiary Document is part of the MiQ Standard and defines methane emissions measurement and quantification criteria and requirements for compliance with the Standard. As emissions measurement technologies advance, become more widely available, and demonstrate improved measurement uncertainty, this Standard will be updated to reflect evolving best practices.

3 Emissions Measurement and Quantification Objective and Performance Criteria

The primary objectives of Emissions Measurement and Quantification are to:

- facilitate data collection for the measurement and quantification of emissions at the Source Level and Facility Level,
- employ different sources of information to improve the accuracy of methane Emission Intensity calculation, and
- facilitate the development of a more complete measurement-informed emissions inventory using Source-Level quantification and Facility-Level measurement data.

These objectives align with other elements of this Standard to:

- provide assurance of the calculated Methane Intensity through reconciliation (see *Subsidiary Document 2: Methane Intensity); and*
- encourage Producers to undertake frequent Facility-Level measurement of emissions (see *Subsidiary Document 3: Company Practices).*

3.1 Key Performance Parameters

As detailed in the *Main Document*, the MiQ Grade is based on the lowest score achieved across the two Standard elements: (1) Emissions Measurement and Quantification and (2) Methane Intensity. A Facility's score for Emissions Measurement and Quantification is based on the key parameters outlined in Table 1.

Table 1: Key Parameters

Parameter	Description
Frequency of Emissions Measurement and Quantification	The minimum number of surveys per year. More frequent surveys reduce uncertainty associated with emissions measurements by providing a more complete and representative picture of the emissions profile over time, including the frequency, duration, and variability of intermittent emissions. The interval between surveys should not exceed 150% of the time indicated by the stated survey cadence[2].

[2] For example, quarterly surveys cannot be planned more than 4.5 months apart; triannual surveys cannot be planned more than 6 months apart; biannual surveys cannot be planned more than 9 months apart; annual surveys cannot be planned more than 18 months apart.

Sampling coverage of Emissions Measurement and Quantification	The minimum percentage of Sites required to be surveyed within a Facility boundary. Achieving and maintaining uniformly low methane emissions levels requires the deployment of measurement technology across a larger portion of Sites, integrating both Facility-Level and Source-Level approaches over a given time period.
Minimum Detection Limit (MDL) of Emissions Measurement and Quantification	The lowest emission rate (or in some cases methane concentration) that a measurement technology can reliably detect, with a specified level of confidence (probability of detection), under defined operating and environmental conditions. The technology solution required to achieve the desired MDL and probability of detection[3] must be applicable to the specific Facility and validated by the Auditor. A lower MDL enables the detection of smaller emission sources, improving inventory completeness and supporting earlier identification and mitigation of methane emissions.

3.2 Performance Scoring

Table 2 outlines the performance criteria and associated scores for Emissions Measurement and Quantification under the Standard. To be considered under this Standard, a Producer shall, at a minimum:

i. quantify all methane emissions at the Source Level using the applicable quantification methods specified in this Standard; and

ii. conduct at least one Facility-Level measurement annually with coverage of the entire Facility.

Producers can achieve a higher EMQ score by increasing the frequency of emissions measurement. More frequent emissions measurement can reduce

[3] The validity of an MDL must be shown through a Probability of Detection (PoD) metric, which is the number of true positive detections divided by the number of possible detections at the emission rate. This metric can be provided by technology providers who have conducted a controlled-released field assessment at a testing facility or similar. For the purposes of this Standard, a PoD of at least 90% must be achieved for a given technology.

uncertainty by providing a more complete and representative picture of the Facility's emissions profile over time. It can also support earlier detection of significant or abnormal emissions, enabling Producers to prioritize corrective action and accelerate emissions mitigation.

Beyond the minimum requirement of conducting at least one Facility-Level measurement annually with coverage of the entire Facility, the MiQ Standard employs the concept of Equivalency to fulfill the Emissions Measurement and Quantification requirements and achieve higher EMQ scores. The frequency and sampling coverage outlined in Table 2 serve as the reference performance criteria for achieving a given number of points. A methane emissions measurement program capable of detecting, characterizing, and mitigating an equivalent amount of methane emissions may be proposed, as demonstrated through a given Equivalency Determination (i.e., the model and modelling assumptions, see Section 3.2.3). The equivalent program shall include, at a minimum, one Facility-Level measurement per year covering the entire Facility. The details for Facility-Level and Source-Level surveys are outlined in Sections 3.2.1 and 3.2.2 , respectively.

Table 2: Technology Performance Criteria*

Facility-Level Survey** (Entire Facility)	**Source-Level Quantification**† (All Sources‡)	**Points**
Annually	Annually	Mandatory Minimum
Semi-annually	Annually	8
Quarterly	Annually	12

* Refer to the MiQ Standard for Methane Emissions Performance: *Subsidiary Document 2: Methane Intensity* for more details on how the emissions measurement data is used for developing annualized emissions inventories.

** With minimum detection limit of 25 kg/hr at 90% probability of detection or lower, selected in accordance with Section 3.2.2.

‡ This column only addresses Source-Level quantification requirements. Requirements for emissions monitoring through leak detection and repair (LDAR) surveys are addressed in *Subsidiary Document 3: Company Practices*.

† All methane emissions shall be quantified annually at the Source Level. For further information on materiality and the accepted Source-Level quantification methods for material and non-material emissions, see *Subsidiary Document 2: Methane Intensity*.

3.2.1 Source-Level Emissions Quantification

For Source-Level emissions quantification, the Operator should determine the circumstances under which each emission source is to be quantified. This

determination may be informed by whether the source is identified through screening (i.e., leaks), is a known or scheduled source (routine or process emissions sources), is associated with a defined operational event (non-routine emissions or incidents), or combines more than one of these characteristics.

- Screening-triggered methane emission sources are emission sources for which quantification is required following leak detection. This may include emissions identified through the detection step in leak detection and repair (LDAR), optical gas imaging, audio, visual, and olfactory inspections, fixed or temporary sensors, or other monitoring approaches used to identify anomalous emissions at the equipment or Component level.
- Scheduled or known sources are methane emission sources that are expected based on Facility design, process conditions, or operational practices. These include emission sources such as flaring and incomplete combustion, compressors, hydrocarbon storage tanks, well activities, pneumatic controllers and pumps, glycol dehydrators, acid gas removal units, blowdowns, pressure-control releases, venting, and purging. These sources should be included in the Source-Level inventory and quantified according to a predefined monitoring or quantification plan that specifies the source, method, frequency, data requirements, and approach for extrapolating emissions over time, regardless of whether emissions are detected during periodic LDAR or other screening activities.
- Event-triggered sources are methane emission sources associated with defined operational events or conditions that may lead to methane emissions. Non-routine emissions and incidents include emission sources such as unlit or malfunctioning flares, open thief hatches on storage tanks, maintenance activities, start-ups, shutdowns, purging, equipment upsets, and malfunctions. Where such an event occurs, the Operator should record the event and quantify emissions based on the best available information.

For hybrid sources where more than one of the above triggering mechanisms applies, the Operator should employ the relevant combination of scheduled quantification and trigger-based follow-up. For example, a source may be included in a routine monitoring plan but may also require additional

quantification if anomalous emissions are detected during screening or if a defined operational event occurs.

Operators must select a source-level quantification method that is appropriate to the emission source, operating conditions, and intended annualized estimate. Direct measurement shall be applied for material emissions where it is feasible and expected to provide a representative estimate. Direct measurement includes direct flow measurement and measurement-integrated approaches that use measured physical parameters in a calculation or model to derive an emission rate.

Where direct measurement is not feasible, or where it is technically possible but would introduce greater uncertainty or bias than a source-specific engineering approach, Operators may use specific emission factors derived from representative Source-Level measurements or sampling, event-based engineering calculations, process simulation tools, or a hybrid method. This may apply to episodic or process-driven sources, including blowdowns, well liquids unloading, flash emissions from atmospheric tanks, and glycol dehydrators. Operators may combine measurement, modeling, and factor-based approaches where doing so improves the accuracy, transparency, or completeness of the estimate.

Where more representative source-specific methods are not feasible, other specific emission factors may be used only where they are demonstrably appropriate to the equipment type, operating conditions, and site conditions, and where there is no credible evidence from Facility-Level measurements, reconciliation findings, or other relevant data that the factor is inadequate. Such factors must be equipment- or activity-specific and applied to actual equipment counts, activity rates, and emission profiles, including leaking-component types and counts identified through leak detection and repair inspections.

In all cases, Operators must document the basis for method selection, use actual operational activity data to the extent practicable, characterize relevant uncertainty, and when applicable, use Facility-Level measurement and reconciliation results to confirm that the selected methods do not omit or materially underestimate emissions. Note that an emission factor or quantification method is reasonable and appropriate when it is suitable for

the source or activity, relevant equipment configuration, operating and environmental conditions, relevant operating modes, and the intended quantification objective. Its application shall use actual operational and activity data to the extent available and, as applicable, account for equipment counts, throughput, event type, frequency and duration, and other parameters needed to quantify emissions over the applicable reporting period; any substitute data or assumptions shall be documented and justified. The factor or method shall be sufficiently representative of the source and conditions to which it is applied, and known sources of systematic over- or under-estimation shall be identified and, where practicable, addressed. Additional information regarding materiality of methane emissions can be found in the *Subsidiary Document 2: Methane Intensity*.

Where direct measurements are not performed, Operators should provide justifications for the selected method. Operators should also demonstrate continuous improvement by taking steps toward collecting representative Source-Level measurements from their assets in the future. For different sources or emissions, Operators should consider predominant sources of uncertainty in the emissions estimates (including emission rate, emission-event duration, or frequency) and attempt to constrain those uncertainties through the use of empirical data. Note that non-material emissions may be quantified using representative emission factors.

Source-Level measurement and quantification should be treated as a continuous improvement process. Source screening and inventories should be updated when there are changes in equipment or operations, or operational conditions, when further emissions reduction efforts are planned, when reconciliation identifies discrepancies, or when an additional potential source is identified.

The Producer shall provide sufficient supporting information and documentation to enable the assessment and verification of the Source-Level quantification methods employed. At a minimum, the supporting information should include:

- the quantification method applied to each emission source, including direct measurement, engineering calculation or process simulation, or other applicable alternative method;

- the key parameters used in the quantification, such as emission rate or emission factor, equipment count, operating hours, throughput, event frequency, or duration, as applicable;
- the sources of the underlying data and assumptions; and
- a statement, and as applicable, the documentation demonstrating that to the best of the Operator's knowledge, the Source-Level inventory accounts for all methane emissions associated with production assets within the applicable Licensed Area(s) and under the operational control of the Producer.

Where a measurement technology operating at the Facility-Level has appropriate detection capability and can resolve individual Sources, the resulting information may be used to inform Source-Level quantification, either directly, including through source-resolved measurements or the development of a measurement-based emission factor, or indirectly, by identifying or prioritizing Sources that require additional investigation or quantification to develop or improve the Source-Level inventory.

In other words, the same measurement technology or measurement campaign may be used to support both Source-Level quantification and Facility-Level measurement, provided that it meets the applicable requirements for each measurement scale. To do so, the technology or campaign must provide the required Facility-Level coverage and detection capability, reliably resolve and quantify emissions from individual Sources for Source-Level quantification, and maintain separately traceable outputs for the Source-Level and Facility-Level estimates.

Independent datasets shall also be used to inform the Source-Level and Facility-Level estimates during reconciliation. Where a single technology or campaign cannot adequately characterize all relevant Sources, the Operator shall use complementary quantification approaches as necessary to develop a complete Source-Level inventory.

This Standard is intended to be revised over time to align with evolving regulatory requirements, technological advances, scientific findings, and relevant internationally recognized standards as they emerge and gain broad acceptance.

3.2.2 Facility-Level Measurement

Facility-Level measurement is intended to:

i. quantify emissions from all sources within each production site, across all sites within the Facility, that emit above the applicable minimum detection limit (MDL). These measurements provide complementary information at a different observational scale from Source-Level quantification and support, through reconciliation, validation of the aggregate emissions from the collection of sources at each Site. They contribute to a more complete and representative picture of annualized emissions across the Facility; and

ii. provide assurance that the entire Facility is surveyed at an appropriate frequency to identify and quantify emissions above the MDL. This supports timely follow-up investigation, corrective action, and emissions mitigation.

For Facility-Level measurement, Operators must employ measurement methods that cover the entire Facility. Source-Level attribution or resolution is not a prerequisite for Facility-Level measurement. Attribution of the measured emissions to the applicable Site boundary satisfies the minimum spatial-resolution requirement for Facility-Level measurement.

For Facility-Level measurement, this Standard requires the application of technologies with a Minimum Detection Limit (MDL) of 25 kg/h or lower at the Site-Level at a 90% probability of detection. Within this requirement, the Operator should select and justify an MDL that is appropriate to the Facility's expected emissions profile and the intended measurement and reconciliation objectives, taking into account the expected magnitude and variability of emissions, measurement frequency and temporal coverage, quantification performance and uncertainty, site and operating conditions, and other available evidence.

Where an MDL of 25 kg/h would not provide sufficient sensitivity to identify anomalous emissions, events, or emissions behavior that may not be adequately represented in the Source-Level inventory, a lower MDL should be used. This Standard is intended to be revised over time to align with evolving regulatory requirements, technological advances and scientific findings, and relevant internationally recognized Standards as they emerge and gain broad

acceptance, including updates to Minimum Detection Limits or performance standards established by relevant authorities.

Technology selection and deployment shall be guided by the intended measurement and reconciliation objectives and a structured assessment of the factors most important to obtaining representative Facility-Level information. The assessment shall consider, as applicable, the expected magnitude and variability of emissions, relevant Site and operating conditions, material intermittent or episodic emissions, and the risk of large Unintended emission events. This Standard is technology-neutral; however, a measurement technology employed for the Facility-Level inspections:

- must cover the entire Facility including elevated and buried sources in three-dimensional space;
- must be deployed at the frequency designated in Table 2;
- must meet the selected MDL, which shall be 25 kg/h or lower, at 90% POD proven through single-blind, controlled-release testing (see Table 3 for additional record-keeping requirements), and quantify the methane emissions rate;
- at a minimum, must attribute the observed emission to a single site spatial boundary
- may utilize multiple methods in combination

Facility-Level measurements shall be scheduled to provide information representative of the Site types and operating conditions relevant to the reporting period. Where material emission sources are intermittent or episodic, the Operator should evaluate whether additional measurement frequency or temporal coverage is necessary to ensure representativeness.

Facility-Level measurements may identify both Intended and Unintended emissions. Emissions identified through Facility-Level measurements shall be evaluated in accordance with the emissions reconciliation process defined in *Subsidiary Document 2: Methane Intensity,* to ensure that their impact is properly reflected in the annualized emissions inventory. Additional details regarding emissions reconciliation can be found in *Subsidiary Document 2: Methane Intensity*.

Emissions requiring investigation under *Subsidiary Document 2* shall be investigated to determine whether the release is Intended or Unintended, and if Intended, whether the source exceeds the expected emission rate. This investigation determines whether the detection is associated with anomalous emissions and establishes whether the event requires emissions mitigation and/or follow-up inspection. Anomalous emission detected through Facility-Level measurements must be documented, repaired and/or mitigated in accordance with the timelines and requirements set out in *Subsidiary Document 3: Company Practices*.

Where Facility-Level measurements identify a discrepancy that cannot be resolved through operational, process-parameter, or other supporting data, the Operator shall evaluate and document whether additional measurement, increased Facility-Level measurement frequency, and/or additional targeted Site coverage is necessary to obtain a representative reconciled estimate.

If Facility-Level measurements across the previous 12 months confirm the accuracy of the source-level inventory without any further changes (i.e., there is no discrepancy between Source-Level inventory estimates and Facility-Level Measurements) for the entire Facility, the survey frequency can be reduced to the next lower score level, either through Table 2 or the Operator's equivalency determination. Operators may not reduce Facility-Level measurement frequency using this clause to less than once per year for the Facility.

An inspection record-keeping form and corrective actions log must be completed for each survey and made available for Audit (see Section 4).

Continuous Monitoring Systems (CMS) can be an important component of a multi-scale methane monitoring strategy by providing data that support Facility-Level measurement and reconciliation. However, CMS alone are generally insufficient to deliver robust, comprehensive Facility-Level emissions estimates that cover all the sources across the Facility. Operators should carefully assess whether a given CMS solution is fit for purpose, considering its performance under real-world operating conditions, its detection, localization, and quantification capabilities, and any limitations relevant to the intended application.

MiQ's OGMP 2.0 Hybrid Approach: Use of OGMP 2.0 Level 5 Site-Level Measurements and Reconciliation

OGMP 2.0 members reporting at the L5 level can use their existing Site-Level measurement toward meeting the Facility-Level measurement requirements under the MiQ Standard, provided the Site-Level measurement spatially covers the entire Facility. Each qualifying OGMP 2.0 Site-Level measurement shall count as one Facility-Level measurement under the MiQ Standard. Where the applicable MiQ Grade requires more than one Facility-Level measurement during the year, the Operator shall complete the remaining required Facility-Level measurement(s) in accordance with the applicable MiQ requirements.

Where an OGMP 2.0 member reporting at Level 5 elects to use an eligible OGMP 2.0 Site-Level measurement toward meeting the MiQ Facility-Level measurement requirements, the Operator may also use the corresponding OGMP 2.0 reconciliation toward satisfying the MiQ reconciliation requirements, provided that the reconciliation is applicable to the same Facility boundary and reporting period and meets the requirements set out in *Subsidiary Document 2: Methane Intensity*. Where additional Facility-Level measurements are required under the MiQ Standard, those measurements shall also be incorporated into the reconciliation process in accordance with *Subsidiary Document 2: Methane Intensity*.

3.2.3 Equivalency Determination

The frequency and spatial coverage of Emissions Measurement and Quantification in the Standard have been developed to apply to generic Facilities across varying geographies. Operators may employ other measurement modalities that provide a comparable level of measurement, quantification, and emissions mitigation performance over the course of a year, as required under the Standard for a given MiQ Grade. However, any equivalent Emissions Measurement and Quantification program must, at a minimum, provide the information needed for the quantification of all methane emissions at the Source Level using the applicable quantification methods specified in Section 3.2.1; and conduct at least one Facility-Level measurement annually with coverage of the entire Facility, in order to be considered under this Standard.

An Equivalency Determination may be provided using accepted models or simulations (such as FEAST [6], LDAR-SIM [7], or others). Evidence must be provided to the Auditor, including model inputs and assumptions supporting

the conclusion that a given monitoring strategy can meet or exceed the emissions measurement, quantification, and mitigation performance outlined in Table 2, in order to achieve the same number of points. Modeling inputs and assumptions include, at a minimum:

- emissions distribution curve representative of the Production Facility and included sources
- emissions durations or temporal intermittency
- measurement technology capabilities, frequency of deployment and spatial coverage
- latency in processing and reporting of emissions
- time to follow up and repair.

Equivalent methane emissions management programs must meet the same program, and recordkeeping requirements (see Tables 3 and 4) and minimum coverage requirements outlined above. Additional information regarding the Equivalency Determination methodology can be found in the *MiQ MI Equivalency Table Methodology* document.

4 Recordkeeping and Reporting Requirements

Producers are required to record and disclose information related to methane Emissions Measurement and Quantification plans and their implementation under the Standard. The Producer must provide relevant information supporting each measurement and quantification methodology used for each emission source where the methodology exceeds the minimum requirements of this Standard, including:

- For use of any chosen methodology: sufficient documentation on specifications of the methodology, such as cited performance criteria or independent scientific studies and use cases.
- For use of recognized external measurement protocols: relevant documentation outlining the approach, applied methodology and work practice.

- Where direct measurement is not feasible, operators must provide justifications for their method selection. Operators should also demonstrate continuous improvement by taking steps toward collecting representative source-level emissions data from their assets.
- For use of specific emission factors: details describing the measurement equipment and quantification level, site selection, sampling criteria, and measurement period.
- For use of specific emission factors: operators must document the source-specific data used, including emissions measurement and quantification, sampling, activity data, and other operational parameters, together with the underlying data source, reporting period, level of aggregation, and any substitute data or assumptions used. The documentation shall be sufficient to permit the Auditor to trace and, where applicable, recalculate the resulting emissions estimate.
- For use of representative emission factors: operators must document the justification for the selection of the emission factor, activity data, and other operational parameters, and assumptions used. The documentation shall be sufficient to permit the Auditor to trace and, where applicable, recalculate the resulting emissions estimate.
- For use of any measurement solution: technical specifications and results of controlled release testing, including calculated uncertainty, bias or confidence bounds.

A Source-Level emissions measurement recordkeeping form must be completed for each event and, if needed, made available to the Auditor. Changes to the Emissions Measurement and Quantification program arising from adverse weather conditions (affecting personnel safety and/or the technology operating envelope), difficult-to-monitor locations, and delays to repair or replacement for any other reason must be logged and communicated with the Auditor.

Deployment plans and supporting implementation information must be disclosed to the Auditor during the Annual Audit. Evidence of the implementation of each measurement technology solution must be disclosed to the Registry during the Certification Period and to the Auditor during the subsequent Annual Audit. Table 3 outlines the minimum recordkeeping requirements for Emissions Measurement and Quantification. Producers may aggregate the recordkeeping elements to minimize administrative burden.

Producers must have adequate Company Practices in place which underpin accurate recordkeeping and reporting.

4.1 Minimum Recordkeeping and Reporting Requirements

Table 3: Minimum recordkeeping requirements for Facility-Level and Source-Level surveys

Recordkeeping element	Details

Detection Technology Specifications	• Sensor and instrumentation details
	• Method by which the sensor was deployed (i.e., fixed-wing, drone-based, or stationary-mounted)
	• Performance specifications including minimum detection limit and probability of detection curves
	• Details of independent, single-blind testing, including
	  ○ The third party used to conduct testing;
	  ○ Confirmation of single-blind nature of testing;
	  ○ Operating conditions of equipment used for testing;
	  ○ Variables tested that could affect the sensitivity of the technology and the ranges tested (i.e. humidity, temperature, wind speed, ground cover, obstructions, solar irradiation);
	  ○ Calibration protocols used during testing; and
	  ○ If operator uses technology for quantification, characterization of emission rate uncertainty.

Work Practice Specifications	• Frequency of surveys and routes taken if sensors are not deployed in stationary positions; • Alarm criteria, including the alarm threshold used for each type of event; • Deployment specifications for individual Sites to replicate the location and environmental conditions established during controlled released testing:

	○ If a third party is contracted to conduct the survey, this should also include contractor or data service provider information; and ○ Include details for both Facility-Level measurement and Source-Level quantification.
Detection Follow up Protocols	• Emission detection and measurement workflow; • Emissions classification workflow (i.e., tracking new events, allowable emissions detected, and failed repair validations); • Data system used to store and manage data associated with detected emissions;
Facility-Level measurement and Source-Level quantification recordkeeping form	For each emission observation during Facility-Level measurement, include the time and location of the observation, source designation (if available), emission rate, and any additional details related to emissions duration and frequency. For Source-Level measurements, include the component or equipment type and ID, Site ID , the date of all the measurements, and measurement results.
QA/QC	Includes chain-of-custody sign-off on the data collected for accuracy (from the collector to an independent reviewer), analytical settings, as appropriate, calibration records of measurement equipment, and reference to the test method used.

4.2 Recordkeeping and Reporting Requirements for Continuous Monitoring Technology

As discussed in Section 3.2.2, where appropriate, a Facility may use data from a Continuous Monitoring System (CMS) deployed across all or a portion of its Sites to contribute toward meeting the requirements for additional Facility-Level measurements or Source-Level surveys, provided that the CMS is demonstrated to be fit for the intended purpose and satisfies the applicable requirements for the relevant measurement scale. The applicability of CMS data shall be evaluated based on the system's performance under representative operating and environmental conditions, including its detection, localization, and, where applicable, quantification capabilities,

spatial coverage, and relevant limitations. Table 4 outlines the minimum records a Producer must submit to the Auditor when CMS data are used toward meeting these requirements.

Table 4: Recordkeeping requirements for Continuous Monitoring Systems

Recordkeeping element	Details
Continuous/High Frequency Monitoring System details	Documentation should include details of the System, including, but not limited to: • Placement and coverage characteristics of monitors based on independent single-blind testing; • Probability of detection curve and MDL; • Temporal coverage or duty cycle; • Analysis used for monitor placement; • Data communication system (i.e., cellular network and wired data); • Meteorological data collected for source identification and emission rate determination; • Locations where meteorological data are collected; • Interconnection between the data collection system, alarm system and work order processing system: o Producer response to monitor downtime (i.e., backup monitoring plan); and • Monitoring equipment calibration protocols (i.e., frequency and technology-specific parameters that are calibrated).

5 Interconnections with other Standard Elements

Each of the Standard Elements (Emissions Measurement and Quantification, Methane Intensity, and Company Practices) is to be assessed separately; however, all are interconnected given their collective role in indicating

effective methane emissions management. Emissions Measurement and Quantification tangibly intersects with, and influences the score for, the other two Standard Elements.

5.1 Interconnection with calculated Methane Intensity

The information collected using Source-Level quantification is used in the development of bottom-up emissions inventories. Before calculating annual methane emissions for use in the Methane Intensity calculation, Producers must reconcile methane emissions identified through Facility-Level measurements. See *Subsidiary Document 2: Methane Intensity, Section 3.4* for the requirements for incorporating emissions identified during Facility-Level emissions measurement campaigns.

5.2 Interconnection with Company Practices

An Emissions Measurement and Quantification plan is required as part of the Company Practices to ensure appropriate follow-up when anomalous methane emission events are detected during a survey. Effective implementation of the Emissions Measurement and Quantification relies in large part on those and other Company Practices, including:

- employee training and awareness;
- estimating and measuring methane emissions; and
- other Practices designed to reduce Intended and Unintended methane emissions.

References

[1] National Academies of Sciences, Engineering, and Medicine. (2018). Methane Emission Measurement and Monitoring

Methods. In Improving Characterization of Anthropogenic Methane Emissions in the United States. Washington, DC: The National Academies Press. https://doi.org/10.17226/24987

[2] Allen, D. T. (2014). Methane emissions from natural gas production and use: Reconciling bottom-up and top-down measurements. Current Opinion in Chemical Engineering, 5, 78–83. https://doi.org/10.1016/j.coche.2014.05.004

[3] Brandt, A. R., Heath, G. A., Kort, E. A., O'Sullivan, F., Pétron, G., Jordaan, S. M., … Harriss, R. (2014). Methane Leaks from North American Natural Gas Systems. Science, 343(6172), 733–735. https://doi.org/10.1126/science.1247045

[4] Brandt, A. R., Heath, G. A., & Cooley, D. (2016). Methane Leaks from Natural Gas Systems Follow Extreme Distributions. Environmental Science & Technology, 50(22), 12512–12520. https://doi.org/10.1021/acs.est.6b04303

[5] Zavala-Araiza, D., Alvarez, R. A., Lyon, D. R., Allen, D. T., Marchese, A. J., Zimmerle, D. J., & Hamburg, S. P. (2017). Super-emitters in natural gas infrastructure are caused by abnormal process conditions. Nature Communications, 8(1, 1), 14012. https://doi.org/10.1038/ncomms14012

[6] Kemp, C. E. and Ravikumar, A. P. (2021). New Technologies Can Cost Effectively Reduce Oil and Gas Methane Emissions, but Policies Will Require Careful Design to Establish Mitigation Equivalence. Environmental Science & Technology, 55(13), 9140-9149. https://doi.org/10.1021/acs.est.1c03071

[7] Fox, T. A., Hugenholtz, C. H., Barchyn, T. E., Gough, T. R., Gao, M. & Staples, M. (2021). Can new mobile technologies enable fugitive methane reductions from the oil and gas industry? Environmental Research Letters, 16(6), 064077. https://doi.org/10.1088/1748-9326/ac0565

MiQ STANDARD

for Methane Emissions Performance for

Onshore Crude and Natural Gas Operations

SUBSIDIARY DOCUMENT 2:

Methane Intensity

v2.0- INTERIM FINAL VERSION



Contents

1. Introduction 3
2. Scope of this Document 4
3. Methane Emissions Inventory 4
3.1. Emission Sources 4
3.2. Materiality of Methane Emissions 6
3.3. Annualized Emissions Inventory 8
3.3.1. Source-Level Bottom-Up Emissions Inventory 8
3.3.2. Emissions Reconciliation 10
4. Methane Intensity 16
5. Scoring Parameters 19
6. Recordkeeping Requirements 20

1. Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines three Standard elements – (1) the measurement and quantification of methane emissions through Emissions Measurement and Quantification (EMQ), (2) a calculated Methane Intensity (MI), and (3) Producer policies and procedures focused on methane emissions prevention, detection, quantification, and abatement (Company Practices, CP), to provide a robust and reliable method for certifying crude and natural gas production based on methane emissions management performance. The Standard is designed to incentivize continuous improvement in methane emissions management practices.

The Standard consists of two main types of documents, to be read in the following order:

1. *Main Document – Onshore Crude and Natural Gas Production*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Emissions Measurement and Quantification – Onshore* Crude and Natural Gas *Production*
    b. **Subsidiary Document 2: Methane Intensity – Onshore Crude and Natural Gas Production (this document)**
    c. *Subsidiary Document 3: Company Practices – Onshore* Crude and Natural Gas *Production*

This Subsidiary Document outlines methodology for determining Methane Intensity under the Standard, including the development of the methane emissions inventory, emissions reconciliation, and the calculation of Methane Intensity. In general terms, Methane Intensity is the ratio of methane emissions to marketed production throughput, and serves as a baseline indicator of methane emissions management performance. See Section 3 for a detailed description of the Methane Intensity methodology used in this Standard.

2. Scope of this Document

This Subsidiary Document is part of the MiQ Standard and outlines methodology for determining Methane Intensity under the Standard, including the development of the methane emissions inventory, emissions reconciliation, and the calculation of Methane Intensity. The MiQ Standard requires all emissions to be accounted for as part of the emissions estimation methodology. This Standard and all methodologies in this document are globally applicable. This Subsidiary Document specifies a method for calculating the Methane Intensity of crude and natural gas production from onshore Facilities.

3. Methane Emissions Inventory

3.1. Emission Sources

Methane emissions from Onshore Production should be accounted for from all potential emission sources. Producers are required to aggregate methane emissions estimates from all relevant emission sources when calculating Methane Intensity.

Under this Standard, Onshore Production is defined as the crude and natural gas supply chain segment that includes all equipment, piping, instrumentation and controls and portable non-self-propelled equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate) located on a wellsite upstream of the transfer point to a gathering system[1].

Equipment may include, but is not limited to, compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and

[1] Up to and including the sales meter, custody-transfer meter, or other meter that defines the transfer of crude oil or natural gas from the production asset to the gathering asset. The applicable meter constitutes the boundary between the MiQ Onshore Crude and Natural Gas Production Standard and the MiQ Gathering & Boosting Standard. All equipment and piping downstream of this meter are outside the scope of the Onshore Crude and Natural Gas Production Standard and falls within the scope of the Gathering & Boosting Standard.

processing equipment, connecting pipework, gathering lines, and portable non-self-propelled equipment, including well drilling and completion equipment, workover equipment, and leased, rented, or contracted equipment. Production equipment may also include associated storage or measurement vessels and all production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

All relevant methane emissions within the Facility boundary shall be identified, quantified, documented, and reported, including both material and non-material emissions[2]. A Facility's calculated Methane Intensity must include:

(i) Source-Level methane emissions from all the following source categories that are present in a Facility:

a. Combustion sources: incomplete methane combustion from engines, heaters, and turbines

b. Venting sources: including, but not limited to natural gas-driven pneumatic devices, reciprocating compressor rod packing, centrifugal compressor (wet and dry) seals, glycol dehydrators, tanks (hydrocarbon and produced water), well liquids unloading, casinghead venting, hydraulic fracture completions and workovers, non-hydraulic fracture completions and workovers, unstabilized crude oil loading and offloading, and equipment blowdowns

c. Flaring: incomplete methane combustion and unlit flares

d. Component and equipment leaks

e. Other emission sources known to the operator that are not covered under the above source categories listed above (items a to d).

[2] Note that non-material emissions may be quantified using representative emission factors instead of direct measurement.

(ii) Emissions reconciliation outcomes resulting from the comparison of Facility-Level measurements with the Source-Level bottom-up emissions inventory.

Most emission sources should be captured in the categories outlined above; however, it is the Producer's responsibility to identify, quantify, and document other emission sources that may not be listed.

3.2. Materiality of Methane Emissions

Materiality assessment is used to prioritize methane quantification efforts within the Facility boundary, to determine which emission sources and emission types require higher-confidence quantification, monitoring, reconciliation, and audit evidence. Materiality shall not be used to exclude known methane emissions from the emissions inventory, methane intensity calculation, or certification assessment.

To perform a materiality assessment for each Facility, all emission sources and emission types shall be ranked from highest to lowest based on their estimated annual methane emissions. Emission sources and emission types that cumulatively account for at least 90% of total annual methane emissions within the Facility boundary shall be classified as material. The remaining emission sources and emission types are classified as non-material. Source-level materiality may be assessed by individual emission source, source category, emission type, or an appropriate grouping of equipment or components, provided that the approach is applied consistently and transparently.

Materiality should be assessed using absolute annual methane emissions, expressed as mass of methane. The Operator should use the best available data for the materiality assessment. At a minimum, the assessment should use source-level activity data and appropriate emission factors or engineering calculations. Where representative emission factors are used to perform the materiality assessment, the Operator shall initially and periodically confirm their applicability to the Facility. Where available data are insufficient to determine whether a Source or emission type is material, the Source or emission type should be treated as material until sufficient evidence supports a non-material classification.

The Operator should maintain a complete Source-Level inventory of all known emission sources within the Facility and should quantify material emission sources and source types in accordance with the guidelines set out in this Standard. Non-material sources should remain in the emissions inventory and should be quantified using a documented method. Representative emission factors may be used for non-material emissions where such factors are applicable, representative, and auditable.

If emissions measurement results indicate previously unaccounted-for or underestimated emissions, the Operator should investigate, update the inventory where appropriate, and reassess materiality. Materiality should be reviewed annually and fully reassessed at least once every three years. The Operator should also reassess materiality following significant operational, equipment, methodological, acquisition, divestment, startup, shutdown, incident, or emissions-profile changes that could affect the composition of the emission sources and emission types comprising at least 90% of total annual Facility methane emissions. Where the composition of material emissions changes, the Operator shall ensure that its Source-Level quantification efforts cover the revised set of material emission sources and emission types.

The Operator should retain an auditable materiality assessment document, including the Facility boundary, a complete list of emission sources and source types assessed, emissions estimates; data sources, emission factors, activity factors, assumptions, and calculation methods; the ranking used to identify the sources and emission types cumulatively accounting for at least 90% of Facility emissions; material and non-material classifications; evidence supporting the applicability of representative emission factors used in the assessment; and where applicable, reconciliation outcomes and changes from the prior assessment.

New Sites or production equipment added to a Facility during the Certification Period shall be incorporated into the Facility boundary and emissions inventory for the period under the Producer's operational control. The Operator shall document the date the Site or equipment became operational or came under its control and shall quantify emissions for the applicable portion of the reporting period using the best available data. Where

the addition could affect the applicable materiality classification, materiality shall be reassessed during the annual materiality review.

3.3. Annualized Emissions Inventory

This Standard requires Operators to quantify methane emissions at the Source-Level and additionally to measure emissions at the Facility-Level. Source-Level quantification is used to develop the Source-Level bottom-up emissions inventory. The final annualized methane emissions estimate is then determined by reconciling the Source-Level bottom-up emissions inventory with the Facility-Level measurements.

3.3.1. Source-Level Bottom-Up Emissions Inventory

When developing a bottom-up emissions inventory, activity data used in Source-Level quantification—including, as applicable, equipment counts, operating hours, throughput volumes, event counts or cycles, and event durations—shall be based on actual operational data to the extent available and shall be demonstrably consistent with observed Site conditions and the operating modes applicable to the reporting period. Where actual operational data are unavailable, the source, basis, and justification for any substitute data or assumptions shall be documented.

Additional information regarding Source-Level quantification and Facility-Level measurements can be found in the *Subsidiary Document 1: Emissions Measurement and Quantification*.

MiQ's OGMP 2.0 Hybrid Approach: Use of OGMP 2.0 Level 4 Inventory

This optional pathway is designed to enable Operators reporting relevant assets at OGMP 2.0 Level 4 or above to leverage their existing OGMP 2.0 Level 4 source-level emissions inventory as the bottom-up inventory used for MiQ certification, subject to the applicable MiQ requirements. The objective is to streamline the certification process, reduce duplicative reporting and data-management requirements, and avoid requiring Operators to maintain separate parallel bottom-up methane emissions inventories solely for OGMP 2.0 and MiQ purposes.

An Operator may elect to use its OGMP 2.0 Level 4 inventory as the bottom-up emissions inventory developed using Source-Level quantification, provided that the inventory is prepared on a Source-Level basis and aligned with the Facility boundary and certification period. An OGMP 2.0 Level 4 inventory is generally an appropriate starting point because it is intended to quantify emissions at the source-category level using source-specific methods, such as direct measurement, engineering calculations, source-specific emission factors, or other documented quantification approaches.

However, this should not be treated as an automatic equivalency determination; the operator remains responsible for demonstrating that the inventory is complete and suitable for the MiQ audit. Any methane emission source not captured in the OGMP 2.0 inventory shall be quantified and incorporated into the bottom-up emissions inventory.

This use should be subject to two conditions:

i. Through a source-category mapping exercise between the OGMP 2.0 Level 4 inventory and other applicable emissions inventories or reporting frameworks maintained by the Operator – such as the EPA Subpart W emissions inventory, internal corporate methane inventories, other applicable regulatory inventories, or asset-level emissions registers – the Operator should ensure that all relevant methane source categories, equipment types, operating modes, and event-based emissions within the MiQ assessment boundary are included. Any differences in source definitions, reporting boundaries, temporal coverage, activity data, calculation methods, or categorization should be clearly identified and resolved. Where a source appears in one inventory but not another, the operator should document whether it is included elsewhere, not applicable to the asset, already captured under another source category, below an applicable materiality threshold, or represents a gap requiring quantification.
ii. The Operator should provide sufficient supporting documentation to allow the MiQ Auditor to audit the bottom-up inventory in a transparent and reproducible manner. The Operator should also provide evidence demonstrating that it is an active participant in OGMP 2.0 and that the relevant assets or Facilities are reported at OGMP 2.0 Level 4. At a

minimum, the documentation reviewed in the course of the audit should allow the Auditor to trace reported emissions from the final inventory value back to the underlying source list, equipment counts, activity data, measurement records, emission factors, engineering calculations, operating assumptions, gas composition data, temporal extrapolations, uncertainty estimates, QA/QC checks, and any reconciliation or adjustment steps.

Accordingly, an OGMP 2.0 Level 4 inventory may be used as the MiQ bottom-up inventory where it is not merely submitted as a standalone dataset, but it is supported by a documented completeness review and an auditable evidence base. This approach preserves the value of the Operator's existing OGMP 2.0 work while ensuring that the MiQ Auditor can independently assess whether the inventory covers all relevant source categories and whether the reported source-level emissions are supported by appropriate data, methods, and records.

Where an OGMP 2.0 Level 4 inventory does not achieve Source-Level quantification coverage for sources and emission types representing at least 90% of methane emissions within the Facility, the Operator should provide a documented justification, consistent with OGMP 2.0 requirements explaining why the 90% threshold has not yet been achieved. Where this flexibility is applied, the OGMP 2.0 Level 4 quantification shall cover no less than 70% of the Facility's methane emissions. The Operator should also provide a time-bound implementation plan describing the actions, milestones, and expected timeline required to increase the OGMP 2.0 Level 4 coverage to at least 90% of methane emissions from the Facility.

3.3.2. Emissions Reconciliation

A Producer's emissions accounting methodology must include both Intended and Unintended methane emissions. The reconciliation process shall compare and integrate different sources of emission estimates and measurements to test the completeness and representativeness of the Source-Level bottom-up inventory and, where appropriate, adjust it in order to resolve discrepancies between them. A Facility is considered reconciled when the available Source-Level, Facility-Level, operational, and other relevant evidence has been

evaluated and integrated into a single, internally consistent annual emissions inventory that reflects the best available information for the reporting period.

Facility-Level measurements provide complementary evidence at a different observational scale from Source-Level quantification and, together with relevant activity data, operational data, and other supporting information, shall be used to assess whether the Source-Level inventory is complete and representative of the reporting period.

Where Facility-Level measurements or reconciliation findings indicate that Source-Level estimates or underlying inventory inputs may not adequately represent actual emissions or operating conditions, the Operator shall investigate and, where appropriate, update the relevant inventory inputs and resulting Source-Level estimates using the best available information.

Source-Level quantification and Facility-Level measurement shall be generated, quality-controlled, and retained as separately traceable assessments before reconciliation. Neither assessment shall be conditioned or modified solely to force agreement with the other. The assessments may subsequently be mutually informative through documented method refinement, discrepancy investigation, and adjustment of estimates.

Reconciliation shall be completed annually and shall be applied consistently across the Facility boundary and across comparable Sites and source categories in accordance with a written reconciliation procedure. Source-Level and Facility-Level estimates used in reconciliation should include an uncertainty estimate or characterization appropriate to the method and intended comparison. Any measurement or outlier excluded from reconciliation shall be identified and justified, and the treatment of non-detections and material data gaps shall be documented.

The outcome of reconciliation is a measurement-informed total emissions estimate that is inclusive of all observed Facility-Level measurements for the reporting period, with the emissions estimate supported by measurement evidence and uncertainty considerations. Where uncertainty exists, conservative estimates are acceptable to ensure completeness. Regardless of the approach used, the Operator shall select and report one final reconciled

annual emissions estimate. Separate unreconciled Source-Level and Facility-Level totals shall not be presented as alternative final estimates.

As part of this process, the Operator shall include reconciliation of reportable emissions, including Unintended emissions identified during Source-Level quantification and Facility-Level measurements performed as required by the Standard (see *Subsidiary Document 1: Emissions Measurement and Quantification*, for more detail), or through monitoring and measurement data from historical surveys, leak detection and report surveys, parametric monitoring, and any other inspections or observations for Facilities. Operators shall evaluate and document the relevance of other anomalous emissions detections from other information sources, including publicly available emissions observation records of which they are aware, where such information provides credible evidence of missing emissions, abnormal operating conditions, event duration, event frequency, or root cause.

The comparison of various emissions estimates may uncover credible evidence of discrepancies in the emissions inventory. Facility-Level measurements often identify discrepancies caused by (i) source categories that are not included in the bottom-up inventory (missing sources), or (ii) anomalous emissions from already included source categories that occurred under abnormal operating conditions not reflected in, or inaccurately characterized by, the inventory calculations (misrepresented sources).

Where the reconciliation process is unable to resolve a discrepancy, the Operator should consider additional emissions measurements or other relevant data collection to further investigate and resolve the discrepancy. Where sufficient information remains unavailable to reasonably resolve the discrepancy, the Operator should apply a conservative emissions estimate that minimizes the risk of underestimating methane emissions.

The outcome of reconciliation is a more comprehensive estimate of total annualized emissions, informed by Source-Level and Facility-Level information, as well as the associated uncertainty considerations. The reconciled estimate may be based on the Source-Level inventory, Facility-Level measurements, a combination of both, or a Source-Level inventory adjusted based on reconciliation findings. To ensure that the outcome of reconciliation represents the best estimate of total annualized emissions,

Producers are recommended to avoid double counting by distinguishing routine emissions already represented in the Source-Level inventory from missing sources, abnormal operating conditions, or non-routine emissions events.

An Operator can choose to conduct reconciliation using either of the following approaches, or an alternative method, provided that the method is appropriately justified and documented:

(i) a measurement-resolved approach, which evaluates Facility-Level measurements and detections at the most granular level supported by the data; or
(ii) an aggregate reconciliation approach, which compares aggregated emissions across defined source categories.

For each reconciliation comparison, the Operator shall assess and document:

a. quantitative factors, including the magnitude and direction of the difference, the relevant measured or estimated emission rate, the estimated annualized effect, and applicable uncertainty; and
b. qualitative and contextual factors, including the source of information, the nature of the emissions, persistence or recurrence, likely operational cause, and when applicable, operational conditions and temporal and spatial representativeness, measurement and quantification limitations.

Measurement-Resolved Reconciliation

In a measurement-resolved reconciliation approach, the Operator shall investigate all Facility-Level observations exceeding the minimum detection threshold of the Emissions Measurement and Quantification program the Operator has elected to follow. This approach aims to determine whether each detection (i) is appropriately represented in the existing bottom-up inventory, (ii) is missing from the inventory (including abnormal operating conditions not represented in the inventory calculations), or (iii) is misrepresented, miscalculated, or inaccurately characterized in the bottom-up inventory developed using data collected during Source-Level surveys. Based on this assessment, appropriate adjustments (such as adding

unaccounted-for emissions or correcting the magnitude of existing estimates) shall be made to ensure a more complete and accurate emissions inventory.

Measurement-resolved reconciliation may be conducted at either the Source Level or the Site Level (asset level), depending on the availability of source attribution data. When source-attribution data is available[3], reconciliation can be performed at the Source-Level by linking each detection to a specific emission source. In this case, Source-Level bottom-up inventory is used to derive an equivalent instantaneous emission rate for the detected source, aligned with the time of the measurement and the operating state of the source at that time.

Where reliable Source-Level attribution is unavailable for a Facility-Scale Measurement, the Site-Level measurement obtained as part of that Facility-Scale Measurement (i.e., emissions measurements that represent total site emissions from all sources within the Site) shall be used to evaluate whether aggregate emissions from the collection of sources within the Site are adequately represented by the Source-Level inventory. In this case, all sources within the Site boundary shall be considered when estimating the corresponding instantaneous Site-Level emission rate. This estimate shall reflect the operational state of the Facility at the time of detection and be informed by all relevant information, including operating parameters and environmental conditions, to ensure the representativeness of the measurement.

For each observation, if the Facility-Level measurement and the corresponding instantaneous Source-Level emission estimate do not align, the Operator shall investigate the cause of the discrepancy. This investigation shall determine whether the difference is due to (i) emissions that are missing from the inventory, or (ii) anomalous emissions from known sources operating under conditions that are not represented in, miscalculated in, or inaccurately characterized by the inventory. The operator shall then quantify and annualize

[3] Note that Source-Level attribution is not a prerequisite for Facility-Level measurement or for reconciliation.

the impact of the discrepancy by estimating the appropriate emission rate, duration, and frequency, and extrapolating these over the reporting period. The emissions inventory should be updated accordingly, with documented justification for any adjustments, or for the conclusion that no adjustment is warranted.

Aggregate Reconciliation

When an Operator selects an aggregate reconciliation approach, the Operator should compare the aggregated Facility-Level and Source-Level annual emissions for a specific source category (e.g., flares) across the entire Facility.

This approach aims to determine whether the Facility-Level observations, in aggregate, validate the Source-Level inventory. If discrepancies are identified between Facility-Level measurements and the Source-Level inventory, the operator shall investigate the cause of the discrepancies, including unaccounted-for or anomalous emission events, miscalculated emissions, inaccurately characterized sources, measurement errors, data completeness issues, and differences in technology capability or detection limits. The operator shall annualize the impact of the discrepancy (by temporally extrapolating emissions across the year based on an appropriate and documented emission rate, duration, and frequency), and shall make appropriate adjustments to the emissions inventory. The extrapolation logic shall be applied consistently and without bias across comparable source categories. Any bounding assumptions for event duration or frequency shall be documented, and potential biases shall be considered.

Reconciliation Documentation

Operators shall maintain documentation sufficient for the Auditor to be able to reproduce the reconciliation logic and trace the original Source-Level and Facility-Level results through to the final reconciled inventory. Documentation shall include, as applicable:

i. selected reconciliation approach(es), and datasets used;
ii. a list of emissions observations and associated information, including the measurement technology, date and time, location, quantified

emission rate, uncertainty or other applicable performance characterization, and relevant operating conditions;

iii. a list of identified discrepancies between Source-Level and Facility-Level results;

iv. the investigation performed and the evidence considered in the characterization of each discrepancy;

v. the annualization or extrapolation method, including assumptions regarding emission rate, event duration, event frequency, temporal and spatial representativeness, potential bias, and uncertainty;

vi. the resulting inventory treatment, or the basis for determining that no inventory adjustment is warranted, where applicable; and

vii. the final reconciled annual emissions estimate.

Operators shall appropriately map measurements to emission sources or, where Source-Level attribution is unavailable, to the applicable Site and source-category grouping. This process ensures that there is an inventory entry associated with each measurement.

Where reconciliation identifies credible evidence that an existing Source-Level estimate does not adequately represent emissions, the estimate shall be investigated and adjusted or replaced using an appropriate quantification method, and the records shall be retained.

Producers are required to use all relevant data available when preparing their annualized emissions inventory, including, but not limited to, historical emissions records, Source-Level emissions quantification, Facility-Level methane emissions measurements, applicable operational data, as well as the investigated results of any other anomalous emissions detections from other information sources, including publicly available emissions observation records of which the Producer is aware. Additional information regarding Source-Level surveys and Facility-Level measurements can be found in the *Subsidiary Document 1: Emissions Measurement and Quantification*.

4. Methane Intensity

Under this Standard, Producers are required to determine Methane Intensity annually in accordance with the criteria defined here and maintain detailed

records of the supplementary data inputs and methodologies used in the Methane Intensity calculation, as detailed in Section 6.

The methane intensity is the quotient obtained by dividing the mass of methane emissions attributed to the production of crude and/or natural gas from a Facility by the mass of marketed product (sales) throughput during a given 12-month period. The definitions in this section are adapted and modified from the Natural Gas Sustainability Initiative (NGSI) Protocol [1], as described by Johnson et al. [12]

To calculate Methane Intensity, the mass of methane emissions (ME) must first be calculated. Total methane emissions mass is calculated as the sum of the mass of methane emissions from all sources, including emissions associated with both natural gas and oil production, as reconciled in accordance with this document and reflected in the annualized emissions inventory.

Several methane emissions metrics can be used to assess and communicate the methane emissions performance of a Facility, each providing a different but complementary representation of emissions relative to production or energy output. The formulas below present the metrics used within this Standard. True Methane Loss is the metric used to determine the Facility's Methane Intensity grade; however, the other metrics may be useful for different reporting, benchmarking, comparison, or analytical applications. When methane emissions are allocated between oil and natural gas operations on the basis of energy production, these metrics are computationally and functionally equivalent and can be simply converted from one to another.

Methane Emission Factor

Methane Emission Factor (EF_{CH4}) is a metric that indicates methane emissions per unit of delivered energy. EF_{CH4}, is calculated as follows:

$$\mathrm{EF_{CH4}\ [g_{CH4}/MMBtu]} = \frac{\mathrm{ME\ [tonne/year]}}{\mathrm{E_{gas}[MMBtu/year]+E_{oil}[MMBtu/year]}} \times 10^6 \qquad \text{(E.1)}$$

where, E_{oil} is the total annual energy content of marketed hydrocarbon liquid throughput, and E_{ng} is the total annual energy content of marketed natural gas throughput, each calculated as:

$$E_{gas}\ [MMBtu/year] = V_{gas}[Mcf/year] \times EC_{gas}[MMBtu/Mcf] \quad \text{(E.2)}$$

$$E_{oil}\ [MMBtu/year] = V_{oil}[bbl/year] \times EC_{oil}[MMBtu/bbl] \quad \text{(E.3)}$$

where, $\mathrm{V_{gas}}$ and $\mathrm{V_{oil}}$ are the total annual marketed natural gas and oil throughput, respectively, and $\mathrm{EC_{gas}}$ and $\mathrm{EC_{oil}}$ are the energy contents (volumetric higher heating values) of natural gas and oil, respectively. The Facility-specific higher heating value of marketed natural gas should be used, where available, to calculate the total annual energy content of marketed natural gas throughput. Where a Facility-specific value is not available, a default higher heating value of $EC_{gas} = 1.235\ MMBtu/Mcf$ may be used. A default value of $\mathrm{EC_{oil}} = 5.7\ \mathrm{MMBtu/bbl}$ may be used in the calculation of the total annual energy of marketed oil throughput.

Methane emission factors can be used as a metric for direct comparisons across various energy production sectors. However, $\mathrm{EF_{CH4}}$ does not express results in percentage terms and it is not easily interpreted as a methane "loss rate" during natural gas and/or oil production.

Methane Intensity (True Methane Loss)

Where a Facility handles both hydrocarbon liquids and natural gas, emissions are allocated between hydrocarbon liquids and natural gas operations on an energy-production basis. For energy-allocated emissions, methane emissions shall be attributed to the production and handling of natural gas using Energy Allocation Ratio (EAR):

$$EAR = \frac{E_{gas}[MMBtu/year]}{E_{gas}[MMBtu/year] + E_{oil}[MMBtu/year]} \quad \text{(E.4)}$$

Methane Intensity ($\mathrm{MI_{LR}}$), also referred to as true loss rate, represents the percentage of marketed natural gas that is emitted before reaching the market:

$$MI_{LR}\ [\%] = \frac{\mathrm{ME[tonne/year]} \times EAR}{v_{gas}[\mathrm{Mcf/year}] \times MC[\%] \times \rho_{CH4}[tonne_{CH4}/Mcf]} \quad \text{(E.5)}$$

Where ρ_{CH4} is the density of methane (at standard oil and gas industry conditions of 15 °C and 101.325 kPa, $\rho_{CH4} = 0.01925\ \mathrm{tonne/Mcf}$), and MC is the mole fraction or volume fraction of methane in the marketed gas.

True Loss Rate can be calculated for any Facility, regardless of whether it produces natural gas, crude, or both. This makes $\mathrm{MI_{LR}}$ a useful loss-rate metric that can be applied consistently across crude and natural gas production operations. Note that MiQ grading for Methane Intensity is based on true methane loss.

Methane Energy Intensity

Methane energy intensity ($\mathrm{MI_e}$) is a unitless metric (often reported as a percentage), that represents the fraction of delivered energy lost due to methane emissions. Methane Energy Intensity is calculated as follows:

$$MI_e\ [\%] = \frac{ME[tonnes/year] \times HHV_{CH4}[MMBtu/Mcf]}{\rho_{CH4}[tonnes_{CH4}/Mcf] \times (E_{gas}[MMBtu/year] + E_{oil}[MMBtu/year])} \quad \text{(E.6)}$$

where, $\mathrm{HHV_{CH4}}$ is the volumetric higher heating value of pure methane (a default value of $\mathrm{HHV_{CH4}} = 1.01194\ \mathrm{MMBtu/Mcf}$ may be used). This Standard allows for use of some default values to calculate the Methane Intensity, though preference is given to facility-specific values. These values are listed in Table 1.

Table 1: Imperial default values for calculating Methane Intensity

		Default value	
Abbreviation	**Description**	**Units Imperial**	**Default Value**
EC_{ng}	Higher Heating Value natural gas	MMBtu/Mscf	1.235
EC_{liq}	Higher Heating Value hydrocarbon liquids	MMBtu/US barrel	5.7
MC	Methane Content of natural gas	volume fraction	0.833
ρ_{CH4}	Methane Standard Density	MT/Mcf	0.01925

5. Scoring Parameters

A Facility's Methane Intensity score is based on its calculated Methane Intensity (True Methane Loss), as detailed in the scoring requirements set out in Section 6.2 of the Main Document.

As part of the Annual Audit, Producers must submit an annualized methane emissions inventory that is reconciled with emissions identified during

Source-Level quantification and Facility-Level measurements completed and quantified in accordance with *Subsidiary Document 1: Emissions Measurement and Quantification*, as well as other relevant measurement campaigns undertaken by the Producer. Newly certified Producers must utilize results from previous emissions measurement and quantification, commissioned in-house or obtained from external regional campaigns. For all grades, this must include annual Source-Level quantification of all sources (using quantification methods appropriate to materiality, with material sources quantified using direct measurement or other higher-confidence source-specific methods, as applicable, and non-material sources permitted to use representative emission factors) AND at minimum one (1) Facility-Level measurement survey completed in each calendar year[4]. More frequent Facility-Level measurement is among the additional requirements for achieving MiQ Grades A and B. See the *Main Document* for further details.

6. Recordkeeping Requirements

In addition to the final calculated Methane Intensity value, Producers must document, for Auditor review, the components of the Methane Intensity calculation listed in Table 2 and identify the individuals or departments responsible for determining, at a minimum. The Producer shall retain copies of supporting documentation for at least five (5) years following the end of the applicable reporting period, or for any longer period required by applicable laws or regulations, GHG programmes, or contractual obligations.

Table 2: Recordkeeping Requirements

Aspect	Detail

[4] Duration between Facility-Level measurements may not exceed 150% of the intended periodicity. See *Subsidiary Document 1: Emissions Measurement and Quantification,* for more details.

Facility Description	Producers must document all Production Equipment or assets that make up a Facility, including Production Equipment added as a result of development activities or removed due to abandonment, shut-in, divestiture, or any other changes occurring during the Certification Period.
Production Throughput	Producers must document the natural gas and hydrocarbon liquids throughput used in calculating Methane Intensity, including the source of the data. Gas production throughput includes the quantity of marketed gas from wells during the year. This includes gas that is routed to a pipeline but excludes gas that is vented, flared, or used in field operations. It does not include gas injected back into reservoirs or volume shrinkage resulting from lease condensate production. Hydrocarbon liquids throughput is the total quantity of hydrocarbon liquids marketed from wells during the year.
Equipment Counts	For use in emissions calculations, Producers must document the total Equipment count associated with each emission source for all Equipment included within a Facility, as well as the method used to determine this count.

Activity data	For use in emissions calculations, Producers must document the activity data associated with each emission source , such as operating hours, throughput volumes, event counts or cycles, and event durations, including the underlying data source and applicable reporting period. Activity data shall meet the requirements stated in this Standard, be traceable to supporting operational or production records, and be cross-checked for completeness and consistency. Significant changes from prior reporting periods shall be investigated and documented.
Calculation method	For each emission source, the calculation methodology used must be documented and include the equipment counts, activity data, emission factors, and any engineering calculations or measurements used in calculations. Producers must document the method, the assumptions used and their rationale, and the application of the method to the calculation. For advanced quantification methods, Producers must document all calculation and/or modelling assumption and the technical specifications of the measurement technologies deployed.
Reconciliation Procedure	The Producer must retain detailed records of Facility-Level measurements and Source-Level quantification, emissions classification, quantification methods, and other information listed under Section 3.2.2.

Methane Intensity Calculation Inputs	*Energy content and Energy Allocation Ratio* The allocation of methane emissions between natural gas production and other hydrocarbon production must be documented and substantiated, including the factor used for the energy content of natural gas (whether a default raw gas value or a company-specific value) and the factor used for energy content of liquids (whether a default crude oil and condensate heating value or a company-specific value(s)). If Producers use company-specific values, the source and derivation of those values must be documented. *Methane content* The Production Throughput and calculated emission volumes are converted to mass of methane by using a Facility-specific methane content value. If Producers use a facility-specific value, the methodology used to determine methane content must be documented.
Processes and Responsibilities	Producers must document their processes for determining and internally reviewing Methane Intensity for accuracy. This should include a detailed record of internal changes to calculations resulting from operational incidents and planned events.

The Producer shall establish, implement, and document quality assurance and quality control (QA/QC) procedures appropriate to the activities used to prepare the annual methane emissions inventory and calculate Methane Intensity, including Source-Level measurement and quantification, data processing, Facility-Level measurement integration, reconciliation, emissions allocation, and reporting. These QA/QC include standard operating procedures and appropriate documentation as well as roles and responsibilities for data preparation, review, approval, and corrective action.

Before submitting required information to the Auditor, the Producer shall conduct and document an internal review to assess the accuracy,

completeness, consistency, and traceability of the reported information, including cross-checking equipment populations, activity data, operating parameters, throughput, event frequency and duration, and other inventory inputs against relevant operational, production, maintenance, and measurement records. The Producer shall also compare the results with prior reporting periods to identify significant changes in emissions, methodologies, reporting boundaries, source populations, activity data, or operating conditions that require investigation or explanation, and shall apply procedures for identifying anomalous, incomplete, duplicated, inconsistent, or otherwise potentially erroneous data. Significant differences and data-quality issues shall be investigated, corrected where appropriate, or explained and documented.

QA/QC controls shall be appropriate to each measurement and quantification method used. For measurement-derived data, the QA/QC process includes confirming that measurement equipment and technologies were operated and evaluated in accordance with applicable procedures, performance specifications, calibration or validation requirements, and operating limitations. For calculations, engineering models, emission factors, extrapolation, allocation, data processing, and reconciliation, sufficient controls shall be applied to confirm the accuracy and consistent application of the underlying data, inputs, equations, units, assumptions, temporal and spatial coverage, and aggregation logic.

Records and calculations shall be maintained in a form that permits independent verification and provides traceability from the final Methane Intensity and reconciled annual emissions inventory through the applicable emission sources or source categories and reconciliation adjustments to the underlying data, methods, and supporting evidence.

References

[1] Natural Gas Sustainability Initiative. (2021, February). NGSI Methane Emissions Intensity Protocol: Version 1.0. Retrieved from https://www.aga.org/contentassets/c87fc10961fe453fb35114e7d908934f/ngsi_methaneintensityprotocol_v1.0_feb2021.pdf

[2] American Petroleum Institute (API). Compendium of Greenhouse Gas Emission Methodologies for the Natural gas and Oil Industry, 2021. Retrieved from https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

[3] GTI Energy. (2022). GTI Energy Methane Emissions Measurement and Verification Initiative. Retrieved from https://www.gti.energy/veritas-a-gti-methane-emissions-measurement-and-verification-initiative/

[4] Oil & Gas Methane Partnership 2.0 (2022). Technical Guidance Documents. Retrieved from https://www.ogmpartnership.com/templates-guidance

[5] One Future (2021). Methane Emissions Estimation Protocol v4.0. Retrieved from https://onefuture.us/wp-content/uploads/2021/12/ONE-Future-Protocol-2021.pdf

[6] Roman-White, S.A., Littlefield, J.A., Fleury,K.G., Allen,D.T., Balcombe,P., Konschnik, K.E., Ewing, J., Ross,G.B., and George, F. (2021). LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting, ACS Sustainable Chem. Eng. 9, 32, 10857–10867. https://doi.org/10.1021/acssuschemeng.1c03307

[7] US Environmental Protection Agency (EPA). (2017, February 8). Inventory of U.S. Greenhouse Gas Emissions and Sinks. Reports and Assessments. Retrieved October 28, 2020, from https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

[8] US Environmental Protection Agency (EPA). 40 CFR Subpart W - Petroleum and Natural Gas Systems (2010). Retrieved from https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W

[9] Alberta Environment and Parks (2021) Alberta Greenhouse Gas Quantification Methodologies (Version 2.1). Retrieved from https://open.alberta.ca/publications/alberta-greenhouse-gas-quantification-methodologies

[10] Western Climate Initiative (2011) Final Essential Requirements of Mandatory Reporting. 2011 Amendments for Harmonization of Reporting in Canadian

Jurisdictions. Retrieved from https://www2.gov.bc.ca/assets/gov/environment/climate-change/ind/quantification/wci-2012.pdf

[11] Australian Government Department of the Environment and Energy. (2022) National Greenhouse and Energy Reporting Scheme Measurement (NGER) Technical Guidelines for the estimation of emissions by facilities in Australia. Retrieved from https://www.legislation.gov.au/Details/F2022C00737/

[12] Johnson, M.R., Conrad, B.M., Zimmerle, D.J., & Kleinberg, R.L. (2026). Methane by the Numbers: The Need for Clear and Comparable Methane Intensity Metrics. Environmental Science & Technology, 60(11), 8258-8265.

MiQ STANDARD

for Methane Emissions Performance for

Onshore Crude and Natural Gas Production

SUBSIDIARY DOCUMENT 3:

Company Practices

v2.0- INTERIM FINAL VERSION



Contents

1 Introduction ***3***

2 Scope of this Document *4*

3 Performance Criteria *5*

3.1 General Company Practices 8

3. 2 Company Practices for Managing and Reducing Unintended Methane Emissions 10

3.3 Company Practices for Managing and Reducing Intended Methane Emissions 16

3.4 Required Evidence Available to Auditors 20

References *21*

1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines three Standard elements – (1) the measurement and quantification of methane emissions through Emissions Measurement and Quantification (EMQ), (2) a calculated Methane Intensity (MI), and (3) Producer policies and procedures focused on methane emissions prevention, detection, quantification and abatement (Company Practices, CP), to provide a robust and reliable method for certifying crude and natural gas production according to its methane emissions management performance. The Standard is designed to incentivize continuous improvement in methane emissions management practices.

The Standard consists of two main types of documents, to be read in the following order:

1. *Main Document – Onshore Crude and Natural Gas Production*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Emissions Measurement and Quantification – Onshore Crude and Natural Gas Production*
    b. *Subsidiary Document 2: Methane Intensity – Onshore Crude and Natural Gas Production*
    c. Subsidiary Document 3: Company Practices – Onshore Crude and Natural Gas Production (this document)

Effective management of methane emissions from crude and natural gas production begins with a Facility design that minimizes inherent methane emissions and, to the greatest extent possible, eliminates the potential for unintentional emissions. Beyond calculated Methane Intensity, under the MiQ standard, Producers must demonstrate effective methane emissions management through Company Practices which exhibit an overarching cultural drive to improve methane emissions performance.

This Standard requires evaluation of Company Practices, which include policies and procedures a Producer employs to ensure it is managing and minimizing methane emissions. By establishing and implementing Company Practices to guide personnel in methane emissions detection and

quantification, repair, reporting protocols, and data evaluation, Producers can ensure methane emissions are managed appropriately throughout the operations lifecycle.

A Producer should maintain documentation demonstrating the implementation of its Company Practices and procedures and provide evidence that relevant personnel understand and consistently implement those practices in their assigned responsibilities.

2 Scope of this Document

This subsidiary document is part of the MiQ Standard and defines the Company Practices criteria and requirements for compliance with this Standard. This document outlines the mandatory and improved Company Practices related to methane emissions management, including monitoring for Unintended methane emissions, minimizing Intended methane emissions, reporting, and operator training. The required Company Practices are broken into three categories:

1. **General Company Practices**

   Outline the required general policies and procedures to demonstrate methane emissions management practices at a Facility, in accordance with a best practice approach.

2. **Company Practices for Managing and Reducing Unintended Methane Emissions**

   Outline the policies and procedures required to effectively identify and fix Unintended methane emissions at a Facility.

3. **Company Practices for Managing and Reducing Intended Methane Emissions**

   Outline the policies and procedures required to minimize Intended methane emissions at a Facility.

This subsidiary document covers Company Practices for onshore crude and natural gas production Facilities.

3 Performance Criteria

Under this Standard, a Producer is required to provide evidence of their Company Practices relevant to methane emissions management. Specific performance criteria are based on the presence, content, and implementation of these Company Practices.

The performance criteria can be demonstrated by a Producer through formal policy or procedure. In the absence of formal policy or procedure, the Producer may present other documentation of training, analysis, report generation, record keeping and/or implementation of Company Practices at the Facility.

The performance criteria for managing and reducing Unintended methane emissions and Intended methane emissions are categorized either as:

- **Mandatory**: Must be demonstrated by the Producer in order to qualify for the Standard; or
- **Improved**: Additional Company Practices corresponding to higher MiQ letter Grades

Three types of Company Practices include General Practices (GP), Unintended Methane Emissions Practices (UMEP), and Intended Methane Emissions Practices (IMEP).

The overall grading system for the Standard is detailed in the *Main Document*. The Grade is based on the lowest score achieved across the two Standard elements: (1) Emissions Measurement and Quantification and (2) Methane Intensity. Company Practices are assessed separately and do not determine the letter Grade.

Operators must satisfy all applicable Mandatory Company Practices as a condition of initial and continued certification. For Facilities located in the United States, the Operator must also satisfy all Improved Company Practices corresponding to the applicable Grade as a condition of certification at that Grade. Facilities located in the United States are not eligible for the Continuous Improvement Pathway. For Facilities located outside the United States, where the applicable Improved Company Practices have not been satisfied at the time of certification, the Operator may use the Continuous

Improvement Pathway and must satisfy the Improved Company Practices scope corresponding to the applicable Grade within three years, or according to an alternative timeline established through an operator-prepared Continuous Improvement Plan, where the applicable Improved Company Practices have not been satisfied at the time of certification. Table 1 includes the corresponding Company Practices for each MiQ certification grade. For purposes of Company Practices, the applicable Grade is the Facility's MiQ Grade determined in accordance with the Main Document based on Methane Intensity and Emissions Measurement and Quantification. This framework allows eligible Facilities to establish an independently verified performance baseline while requiring transparent, time-bound progress toward improved methane-management practices.

Where a Facility is located outside the United States and an Operator has satisfied all applicable Mandatory Company Practices but has not yet satisfied the Improved Company Practices corresponding to its applicable Grade, the Operator may be certified with a letter Grade, and a Company Practices status of "on the pathway," provided that a time-bounded Continuous Improvement Plan has been established for the outstanding requirements.

For a Facility certified with a Company Practices status of "on the pathway," the Continuous Improvement Plan shall, at a minimum: (i) identify the gap between the Company Practices demonstrated at the time of certification and the Improved Company Practices applicable to the Facility's Grade; (ii) identify the actions necessary to close each gap; (iii) establish implementation milestones, responsible parties, and a schedule for completing those actions; and (v) provide sufficient information to enable progress to be independently assessed during subsequent Annual Audits.

An Operator "on the pathway" to complete Improved Company Practices shall demonstrate progress against the Continuous Improvement Plan during each Annual Audit. Progress, completed actions, outstanding requirements, and any material changes to the implementation schedule should be documented and made available to the Auditor. The Continuous Improvement Plan should be updated, where necessary, to reflect verified progress, changes in Facility operations, or a change in the Facility's MiQ Grade that changes the applicable Improved Company Practices scope. Any alternative implementation timeline or material modification to an agreed

timeline shall be documented and agreed in accordance with the applicable MiQ Program requirements.

The improved performance criteria are assessed via a points-based scoring system. Points for improved practices are indicated in Tables 2, 3, and 4 of this document. These points are used to determine the Improved Company Practices scope corresponding to each MiQ Grade and to assess whether that scope has been satisfied. If a Facility demonstrates at least one of the elements listed for an improved practice topic, as outlined in Tables 2-4, it should receive all points nominated for that practice, except if two or more elements are related (indicated by the word “and”).

For performance criteria relevant to emission sources not found within a given Facility (i.e. flaring requirements for dry gas production), the Producer automatically receives the associated Improved Company Practices points for purposes of assessing the applicable Company Practices scope. Adjustments to company practices may be permitted in specific scenarios where the practices cannot be implemented as written, provided the intent of the requirements is still met. Any such adjustment shall be documented and shall not be used to avoid an otherwise applicable Mandatory Company Practice or the time-bound implementation of an applicable Improved Company Practice.

The MiQ Standard separately evaluates: (i) the Facility’s MiQ Grade; and (ii) the Company Practices status demonstrated at the time of certification. The Company Practices status indicates whether the Operator has satisfied the applicable Improved Company Practices (as ‘completed’) or is progressing toward satisfying them through a Continuous Improvement Plan (as ‘on the pathway’). Accordingly, the ‘on the pathway’ Company Practices status is not available to Facilities located in the United States. A status of ‘on the pathway’ therefore indicates that all applicable Mandatory Company Practices have been satisfied, but the Improved Company Practices corresponding to the Facility’s MiQ Grade remain subject to the applicable Continuous Improvement Plan. Upon verified completion of all such Improved Company Practices, the Company Practices status will be updated to ‘completed’.

Table 1: Corresponding Company Practices for each MiQ Certification Grade

Grade	Mandatory Company Practices	Improved Company Practices Points
A	Mandatory	15
B	Mandatory	10
C	Mandatory	5
D	Mandatory	-
E	Mandatory	-
F	Mandatory	-

Note: For Facilities located in the United States, all Improved Company Practices applicable to the Facility's MiQ Grade must be satisfied as a condition of certification at that Grade. The Continuous Improvement Pathway and the associated 'on the pathway' status are available only to Facilities located outside the United States.

3.1 General Company Practices

Facilities will employ general Company Practices to eliminate methane emissions to the greatest degree possible. This will include building a culture of eliminating methane emissions as well as employing design strategies for both operations and maintenance activities.

The general policies and procedures are listed in Table 2.

Table 2: General Company Practices (GP)

Practice	Character	Points
(GP- 1) Employee training and awareness		

Operations staff receive training that: • emphasizes the importance of eliminating methane emissions, equipment most likely to leak, signs of methane emissions including Audible, Visual, and Olfactory (AVO) observations that may indicate a problem, and actions to take in the event of an observation; **and** • details how to log and report methane emissions for purposes of annual methane emissions calculations; **and** • is offered at least annually (detailed version for new staff, refresher version for staff with >1 year experience).	Mandatory	-
(GP- 2) Reporting methane emissions observations and incidents • A reporting system is accessible for all staff to report methane emissions related observations or incidents; **and** • Recordkeeping guidance details what type of documentation needs to be submitted when methane emissions are detected outside routine LDAR inspections; **and** • Chain of command and notification processes are clearly outlined	Mandatory	-
(GP- 3) Estimating and measuring methane emissions At minimum, Producer's guidance for measurement methods and calculation of methane emissions, in line with regulatory GHG reporting where present, includes: • Quantification method for each emission source; **and** • Reconciliation process for ensuring all material Unintended Emissions are accounted for and included.	Mandatory	-
(GP- 4) Continual improvement		

Methane management is integrated into the Producer's company culture, as evidenced by: • a Health, Safety & Environment (HSE) communication plan that includes methane emissions reduction best practices, such as educational material or an emissions incident bulletin program; **and** • demonstrated knowledge of best practices to minimize emissions by the Facility's operations staff **and** • a key performance metric for methane emissions (such as Methane Intensity) that is tracked for the Facility and regularly communicated with the staff.	Mandatory	-

3. 2 Company Practices for Managing and Reducing Unintended Methane Emissions

Reducing Unintended methane emissions requires awareness and monitoring of areas where emission events may occur. Specific actions will include actively looking for Unintended methane emissions, tracking emission sources that have been repaired or replaced, developing preventative maintenance plans, and confirming that all required repairs have been completed and verified in an appropriate timeframe. Company Practices relevant to these actions are stated below in Table 3.

Table 3: Company Practices for managing and reducing Unintended Methane Emissions (UMEP)

Practice	Character	Point
(UMEP- 1) Employee training and awareness		

Operational and maintenance team training includes: • Audial, Visual, and Olfactory (AVO) trainings for field personnel that detail how and why to make routine checks for methane emissions during site visits; **and** Leak Detection and Repair (LDAR) method-specific trainings for: • Method 21 [1] or equivalent - Producer's personnel responsible for carrying out inspection are trained in proper use of instruments, instrument calibration, inspection methods and regulatory requirements; **and/or** • Optical Gas Imaging (OGI) – Producer's personnel responsible for use of OGI cameras are trained in the regulatory requirements for survey, calibration and proper use of the specific camera deployed by the Producer; **and** • in the event LDAR surveys are carried out by third-party personnel, the Producer should be in possession of training records documenting the training of personnel hired; **and/or** • alternative technology programs have consistent equipment operating and reporting procedures for consistent deployment	Mandatory	-

(UMEP- 2) Source level detection plan

LDAR Plan outlines at a minimum: • specific equipment / components included in LDAR survey (must reference process valves, connectors, compressor seals, open-ended lines, meters, pressure relief valves, regulators, and pneumatic controllers); **and** • leak definition; **and** • monitoring methodology (reference to equipment, frequency, conditions, reporting log); **and** • repair or replacement strategy, including when to take immediate corrective action and when delay of repair is permitted; **and** • first attempt at repair requirements within 30 days of detection; **and** • final repair attempt within 30 days of detection; **and**	Mandatory	-

- repair verification completed within 30 days of final repair attempt, if no safety concerns; **and**
- steps to be taken for delay of repair, including tagging, reporting, and tracking opportunities for follow-up repair, including equipment shutdowns; **and**
- clear roles and responsibilities for repair or replacement.

(UMEP- 3) Annual Source level emissions detection

The primary objective of Source-Level LDAR surveys is to support effective methane emissions management through the timely identification of Unintended methane emissions and implementation of appropriate corrective actions. Mandatory

Source-Level LDAR surveys conducted under this UMEP are intended primarily for emissions detection, localization, and follow-up and are distinct from the Source-Level emissions quantification requirements specified in Subsidiary Documents 1. Where a Source-Level LDAR survey also provides emissions quantification, those data may be used to support Source-Level quantification where the applicable quantification requirements are satisfied. Emissions identified through LDAR shall be appropriately reflected in the Source-Level emissions inventory in accordance with *Subsidiary Document 2: Methane Intensity*.

At a minimum, the Operator shall conduct one Source-Level LDAR survey annually, covering 100% of Sites within the Facility. Sites equipped with uncrewed stationary or Continuous Monitoring Systems are not exempt from this annual survey requirement.

A LDAR survey shall include all applicable equipment and emission sources within the Site boundary that have the potential to generate Unintended methane emissions. Source-Level survey method is technology-neutral; however, the selected method or combination of methods shall:

- provide spatial resolution sufficiently fine to reliably attribute confirmed emissions to the component or individual emission-source level;
- be deployed at or above the applicable frequency and coverage specified above;
- together with applicable follow-up procedures, be capable of distinguishing methane emissions



associated with incomplete combustion from fugitive leaks or excess vented emissions where these emissions occur in close proximity, including near exhaust or flare stacks; and
- permit the use of multiple complementary inspection or detection methods where necessary to satisfy these requirements.

A follow-up inspection performed in response to a detected emission may count toward an applicable additional Source-Level survey requirement (UMEP 3.1) where the inspection uses an approved Source-Level survey method and contributes to the required Site coverage for that survey round. Repair-validation inspections shall not count toward the required Source-Level survey frequency.

All confirmed Unintended emissions shall be addressed in accordance with the repair, delay-of-repair, and repair-validation requirements established under UMEP-2.

Confirmed emissions shall be scheduled for repair or replacement, and repair effectiveness shall be validated within the applicable timeframe.

A Source-Level LDAR survey record and repair log shall be completed for each survey event and made available to the Auditor/Verifier upon request.

At a minimum, the Operator shall maintain:

- documented detection and follow-up protocols, including the workflow following a detection or alarm, emissions-classification procedures, the data-management system used to track detected events, repair-planning and repair-validation procedures, and applicable Causal Examination procedures;
- for each detected emission, the applicable Site, equipment, and component identifier and type; detection date; repair attempts and associated dates; repair-validation date; outcome of repair or replacement; and, where applicable, the reason for a delay in repair or replacement and the date the issue was rectified; and
- a Source-Level/LDAR survey-location log identifying the Sites visited during each survey round using the Well ID or another unique Site identifier.

(UMEP- 3.1)

In additional to the mandatory annual Source-Level LDAR surveys (covering 100% of Sites) an Operator will receive one (1) Improved Company Practices point per additional survey rounds, each covering at least 50% of Sites, up to a total of three points. The interval between required LDAR survey rounds shall not exceed 150% of the applicable nominal survey cadence. For the additional surveys covering at least 50% of Sites, the Sites selected should be representative of the Facility while prioritizing locations where additional monitoring is expected to provide the greatest methane-management benefit. Site selection should consider, as applicable, Site type, operational characteristics, expected emissions profile, infrastructure age, historical LDAR observations, presence or absence of emissions-control equipment, and wells or Sites with higher expected emissions relative to production. The Operator should also seek to maximize coverage of the Facility population over the course of the year and capture different operating conditions and emissions variability. The Site-selection methodology and justification should be documented in the Operator's methane emissions management program. Additional Source-Level surveys conducted per UMEP-3.1 should follow general guidelines for reporting, recordkeeping, and follow-up as described under UMEP-3.	Improved	1-3

(UMEP- 4) Managing methane emissions from tanks

• Policies for managing tank emissions must address all key stages of tank use, including tank filling, tank breathing and tank cleaning; **and** • Producers inspect and monitor key areas that may result in methane emissions from tanks including vapor recovery systems, thief hatches, upstream dump valves, pneumatic controllers, and other areas; **and**	Mandatory	-

• policies and procedures for managing tanks include observation for methane emissions **and** preventative maintenance based on historical inspection findings.		
(UMEP- 4.1)		
In addition to the above, Producers elect to: • install tank pressure monitoring systems and alarms; **and/or** • remotely observe tank batteries using integrated operation centers; **and/or** • utilize automated tank gauging and reporting; **and/or** • install thief hatch monitoring and automated reporting systems; **and/or** • centralize tanks from multiple locations to eliminate sources of methane emissions; **and/or** • utilizes a vapor recovery tower to capture vapor and limit flash on atmospheric tanks; **and/or** • design facilities which eliminate the use of tanks	Improved	2
(UMEP- 5) Directed inspection and maintenance		
To manage methane emissions, Producers elect to: • target major equipment (i.e. pneumatic controllers, thief hatches, natural gas vents, vapor recovery equipment operation, compressor stations, flares) for observation; **and** • use cumulative data to develop preventative maintenance plans; **and** • determine equipment to target based on accumulated historical data from LDAR inspection records [2].	Improved	1
(UMEP- 6) Root Cause Analysis (RCA) of Unintended emission events		
• Producer has Root Cause Analysis (RCA) policies and procedures describing the process of conducting an	Improved	1

analysis of the cause of Unintended emission events and documentation of systematic corrective actions taken to limit and prevent reoccurrence.

3.3 Company Practices for Managing and Reducing Intended Methane Emissions

Though Facilities can be designed to minimize methane emissions, certain equipment operations and maintenance activities, by design or by definition, result in the release of natural gas (and therefore methane) to the atmosphere. By implementing Company Practices to reduce Intended methane emissions, Producers can ensure the amount of gas released is minimized.

Table 4: Company Practices for managing and reducing Intended methane emissions (IMEP)

Practice	Character	Point
(IMEP- 1) Venting - manual liquid unloading		
Company Practices require that the manual unloading process is monitored onsite by personnel, and that venting to atmosphere is shut off as soon as possible once liquids have been removed and gas begins to vent.	Mandatory	-
(IMEP- 1.1)		
Producers implement non-venting unloading processes (manual or automated). The Auditor must verify evidence that non-venting unloading processes are attempted before vented unloading where applicable.	Improved	1
(IMEP- 2) Venting - production equipment pumpdown		
Producer coordinates operational and routine maintenance repairs to minimize the number of pumpdowns required.	Mandatory	-
(IMEP- 2.1)		

Producers implement: • policies and procedures for removal of natural gas from equipment or systems scheduled for repair to the greatest extent possible prior to pumpdown, while maintaining safe operations; **and/or** • production equipment to service, which address purging the equipment of air prior to restoring operations while minimizing natural gas emitted during purging operations; **and/or** • natural gas vented during pumpdowns is routed to a flare to minimize methane emissions.	Improved	1
(IMEP- 3) Venting - pneumatic devices		
Producers with operations utilizing natural gas driven pneumatic devices must implement: • procedures to maintain accurate inventory of pumps and controllers (checked annually at a minimum); **and** • policies and procedures to ensure controllers are operating as designed (based on type of service (on/off, throttling) and type of venting (continuous or intermittent)) based on regulatory published limits or industry equipment standards; **and** • devices are included in regular inspection in LDAR plan as emission source.	Mandatory	-
(IMEP- 3.1)		
Producers have installed non-venting (i.e. no-bleed, electric, mechanical, or instrument air) pneumatic controllers, actuators and pumps in place of gas-driven pneumatics for >50% of inventory).	Improved	2
(IMEP- 3.2)		

Producers have: • implemented a program (dated >1yr prior to time of audit) to replace remaining natural gas driven devices with non-venting devices within 3 years of applying for the Standard, and have demonstrated progress against this program; **and/or** • implemented program that all new construction will include non-venting pneumatic devices.	Improved	1
(IMEP- 4) Venting - compressors • Producers implement policies to replace reciprocating compressor rings on a fixed schedule based on run hours; **and** • Producers have estimated methane loss from reciprocating compressor rod packing and evaluated the economic threshold for replacement.	Mandatory	-
(IMEP- 4.1) Producers have evaluated controls to address compressor seal methane losses and outlined a program to: • replace centrifugal compressor wet seals with dry seals or route seal oil gas such that it is recovered or flared; **and** • upgrade of reciprocating compressor packing cups, rings, gaskets, rods based on indication of leak from rod packing inspection, or gas emitted is routed to recovery or flare.	Improved	1
(IMEP- 5) Well completions and workovers • Producers implement a Reduced Emissions Completions (RECs) practice at hydraulically fractured wells, to capture natural gas that is produced during completions or workovers to limit venting to atmosphere; **and** • where implementing a REC is infeasible due to reservoir characteristics, gas is recovered and routed to a combustion device.	Improved	1

(IMEP- 6) Well operations

Producers implement policies and procedures to address casinghead gas venting by: • evaluating appropriate emission controls at oil wells based on operational considerations (well and reservoir characteristics); **and** • capturing and routing casinghead gas for onsite recovery, sales or flare where possible.	Improved	1

(IMEP- 7) Flaring

Producers must implement: • policies to define the use of flaring (routine and non-routine event categories, acceptable durations); **and** • flaring or combusting natural gas when recovery is not possible, and limiting gas routed to vent (including for oil wells at the facility); **and** • procedures which define stable operating range and criteria for all flare systems, considering emergency events, for good combustion efficiency [3];[1] **and** • policies and procedures to ensure flares[2] are managed and maintained to ensure flare functionality, flares are targeted during LDAR surveys, and design combustion efficiency is achieved through utilizing staff/consultants for inspections (AVO and engineering & maintenance inspections).	Mandatory	-

(IMEP- 7.1)

[1] Temporary flares used explicitly during well completion and short-term routine maintenance are exempt.

Producers have implemented policies to minimize the use of routine flaring (applicable to both gas and oil wells), except in the event of an emergency [2]. • Policies in place to check infrastructure takeaway is in place before well packages come online; **and** • Utilize a flare gas capture system to reduce the volume of gas flared. **(IMEP- 7.2)**	Improved	2
Flares are managed to ensure flaring functionality and efficiency through control and engineering design. Systems may include: • SCADA systems and logic controllers to monitor flare ignition; **and/or** • auto ignition system for unsupervised flare stacks with intermittent flaring; **and/or** • flare capacity and production level is maintained to ensure flare's combustion efficiency matches range of production and does not overload; **and/or** • thermocouples (temperature sensors) to ensure pilots stay lit or flame out detection device installed.	Improved	1

3.4 Required Evidence Available to Auditors

The Producer's Company Practices will be reviewed by the Auditor in advance of an onsite Audit. The purpose of onsite Audits is to interview personnel and observe operations activities to verify the understanding and implementation of the Company Practices for methane emissions management. The Auditor will use a combination of interviews and observations to determine whether the policies reviewed are effectively understood and implemented.

Required evidence of implementation of improved practices may include, but is not limited to, facility logs, equipment run time, P&IDs and maintenance inspection records. The Auditor may request additional documentation and metrics from the Facility for the purposes of the annual Audit or subsequent Audits.

References

[1] US Environmental Protection Agency (EPA). (2017). Method 21 - Determination of Volatile Organic Compound Leaks. Retrieved from https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks

[2] Methane Guiding Principles. (2019). Reducing Methane Emissions: Best Practice Guide. Retrieved from https://methaneguidingprinciples.org/best-practice-guides/

[3] US Environmental Protection Agency (EPA). (2012). Parameters for Properly Designed and Operated Flares. US EPA Office of Air Quality Planning and Standards (OAQPS). Retrieved from https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf