MiQ STANDARD

for Methane Emissions Performance for Natural Gas Operations

MAIN DOCUMENT – Onshore Production

v1.1

Document Title: MiQ STANDARD for Methane Emissions Performance for Natural Gas Operations

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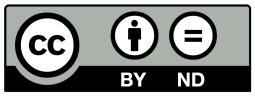
Note: Other MiQ standards for methane emissions performance will be revised in due course to align with this draft.



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1 Background

1.1 Introduction

Methane emissions (CH_4) from oil and 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 over 80 times that of carbon dioxide [*1*][1]. Methane is emitted throughout both the oil and natural gas supply chains. This Standard addresses methane emissions from the production of natural gas (including associated gas production).

Methane is emitted in the process of producing natural gas through venting, leaking and incomplete combustion from flares, burners and engines. While technologies and processes that can prevent or significantly reduce methane emissions are well known, emissions abatement actions, whether voluntary or enforced through regulation, are not yet occurring with the sufficient consistency or scale necessary to limit global warming to the 1.5 degrees put forward in the Paris Agreement.

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) measurement and quantification of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method for certifying 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 three main types of documents, to be read in the following order:

1. **Main Document – Onshore Production (this document)**
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – Onshore Natural Gas Production*
    b. *Subsidiary Document 2: Company Practices – Onshore Natural Gas Production*
    c. *Subsidiary Document 3: Monitoring Technology Deployment – Onshore 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.

1.2 About

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

1.3 Purpose

The purpose of this Standard is to incentivize continuous improvement in methane emissions monitoring and abatement practices by creating an opportunity for Producers to differentiate their natural gas production by its methane emissions management performance. More specifically, the objectives of this Standard are:

- to accelerate deployment of practices and technologies that mitigate methane emissions;
- to accelerate deployment of monitoring technologies that detect and measure methane emissions;
- to increase transparency regarding the methane emissions management performance of natural gas production, with a globally consistent methodology for emissions measurement, monitoring, reporting, and verification;
- to enable producers, marketers, and buyers to transact natural gas based on the methane emissions management performance of a Facility, and to demonstrate additional value to their customers;
- to provide producers, buyers, and investors a uniform, independently verified Standard consistent with environmental, social, and governance (ESG) reporting to address methane emissions from natural gas production and consumption;
- to complement regulations by incentivizing methane emissions measurement, monitoring and abatement actions; and
- to credibly recognize producers with strong methane emissions management performance.

2 Scope

This Standard establishes a system for the generation of an MiQ Grade which captures the Facility's methane emissions management performance. Performance will be assessed according to the Facility's (1) calculated methane

Intensity, (2) policies and procedures that are focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) deployment of methane emissions monitoring technologies (Monitoring Technology Deployment).

Furthermore, this Standard:

- is applicable to Facilities in the upstream natural gas production segment (see Terms and Definitions);
- specifies a method to calculate the Methane Intensity of natural gas (see *Subsidiary Document 1: Methane Intensity*);
- establishes general principles for an effective methane management program – including policies and procedures focused on methane emissions prevention, detection, and abatement and deployment of methane monitoring technology (see *Subsidiary Document 2: Company Practices* and *Subsidiary Document 3: Monitoring Technology Deployment*); and
- does not define requirements for natural gas' physical or chemical quality.

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 the information reported by the Producer against the Standard.

Auditor/Auditing Body	Also called third-party assurance provider, an individual, or organization made up of individuals, that carry out assessments to determine if a Facility meets the requirements of the Standard and recommend a performance Grade. An Auditor or Auditing Body must possess the combined demonstrated knowledge, skill and abilities, along with documented training and experience required to provide assurance services, both offsite and onsite, to determine. Facility's performance against all diverse elements of the Standard.
Audit Report	A verification document prepared by an Auditing Body that contains a comprehensive analysis of the Producer's adherence to the Standard.
Basin	An oil and gas producing region (a geologic sedimentary basin), as typically defined and referenced by national legislation.
Causal Examination	The act of following up to a detected event at the Site, Equipment or Component level to determine the likely cause of the emission, using SCADA logs, maintenance logs, operational logs, operator site visits, and Source Level surveys. Examinations should also, at minimum, include determination of emissions as Intended or Unintended. Causal examinations are less formal than Root Cause Analyses and do not require a systematic corrective action to be identified, recommended or implemented as part of the examination process.
Certification Period	The forward looking period (maximum 12 months) during which certified operations at a Facility is eligible for MiQ certificates
Company Practices	A document, program, policy or procedure, specific to the Producer that identifies effective management of methane emissions within the Facility boundaries. Company Practices is also the title of one of the subsidiary documents to this Standard.
Component	A smaller 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.

Lease Condensate	Light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells. Mostly pentanes and heavier hydrocarbons. Normally enters the crude oil stream after production.[2]
Continuous Monitoring System	A methane monitoring system at a Facility that: (a) is made up 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 interference, 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 pinpoint an emissions event to the Site Level to apply towards the MiQ Facility Scale monitoring requirements, and/or (f) can consistently pinpoint an emissions event to the component or source level to apply towards the MiQ Source Level detection and quantification requirements.
Crude Oil	A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passage through separation equipment. May include lease condensate that is later mixed into the crude stream.[3]
Detection	A sensed or measurable indication of methane emissions obtained using a monitoring technology or another means of inspection.
Directed Inspection and Maintenance Program	A documented program specific to the Facility that utilizes a process to develop effective inspection schedules for the purposes of detecting methane emissions quickly from selected sources that have a higher potential to emit.
Emission Factor	A multiplier indicating typical emissions per unit of activity of a component or part of the gas system (e.g., valve, pipeline section) or from an event and can have units like [kg/km], [kg/event], or [kg/equipment type].

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

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

Equivalency Determination	The process of evaluating the effectiveness of an operator's measurement and quantification technology method(s) against the monitoring technology deployment requirements prescribed by the Standard in order to achieve a specific rating, or Grade. Generally, it consists of 1) the definition of new methods, 2) application of controlled release testing results to define performance of each method, 3) simulation modeling to predict the performance of new programs and 4) field verification efforts to evaluate the accuracy of the simulation modeling.
Equivalent Emissions Measurement Program	An emissions measurement program undertaken by an operator utilizing a combination of Facility-Scale and Source-Level measurement and quantification tools, and is determined to provide a comparable level of measurement, quantification, and emissions mitigation over the course of a year as required under the Standard for a given MiQ Grade. Substituted methods may include various monitoring technologies with proven measurement and quantification capabilities.
Facility	All contiguous onshore natural gas production sites and equipment (including leased, rented, or contracted) located in a single geologic basin, field, or subfield under the responsibility of a common owner or operator. The Facility boundary for Onshore Production may include all upstream emissions with the potential to emit, including wellsite compression, gathering lines and treatment.
Facility Scale Measurement	Methane emissions measurement surveys undertaken by an operator using a method that covers the entire Facility's emission sources in three-dimensional space and must be capable of measuring and quantifying emission events above the minimum detection threshold limit (MDL). Facility-scale measurement is a collection of site-level measurements that covers 100% of assets/sites located within a facility boundary.
Grade	The performance grade of a Facility determined in accordance with this Standard by an Auditor and approved by the Issuing Body.
Greenhouse Gases (GHGs)	Carbon dioxide (CO_2) and other gases defined in the IPCC Sixth Assessment Report including methane, nitrous oxide, sulfur hexafluoride, chlorofluorocarbons, hydrofluorocarbons, and perfluorocarbons *[1]*. Greenhouse Gases other than carbon

	dioxide can be expressed in terms of carbon dioxide equivalent (CO_2e), which is calculated using a timeframe-specific Global Warming Potential (GWP).
Hydrocarbon Liquids	A general term encompassing all crude oil, lease condensate and any other liquid-phase hydrocarbons at the sales point of the Facility
Intended Emission	Intentional releases of methane emissions by design, such as from equipment designed to vent, process vents, flares, and other combustion equipment within design parameters. Any emissions operating outside of design parameters are considered as Unintended.
Inventory	A documented compilation of emissions from each emission source, compiled on an annual basis for a Facility.
Issuing Body	The entity responsible for registering each Facility under the MiQ Program, for issuing MiQ certificates, and for approving Audit Reports under the MiQ Program, amongst other responsibilities.
Large Emission Events	Emission occurrences with a methane emission rate exceeding a pre-defined threshold, usually caused by abnormal process conditions, which can significantly affect the total emissions of a Facility.
Leak Detection and Repair (LDAR)	A systematic process for detecting unintended emissions from equipment or infrastructure and taking corrective action to repair those emissions within a defined timeframe. LDAR practices often employ hand-held, Source Level emission inspection tools. The term is expanded in this Standard to describe any monitoring inspection or survey which includes the systematic implementation of methane detection tools across a collection of assets to detect and repair emissions. An LDAR program describes the sensor(s), deployment or configuration strategy, temporal and spatial coverage, their operating envelope, work practices, detection capabilities of solution, follow up and repair procedures and timeline, and data management standards.
Methane Intensity	The ratio of methane emissions and a selected variable. It accounts for natural gas throughput relative to crude and condensate throughput by allocating emissions that are attributable to the handling of natural gas.

MiQ Program	The framework for handling all issues related to governance, the process of certification and use of the MiQ Registry. Please see the MiQ Program Guide for more details.
Minimum Detection Limit	The lowest emission rate (or in some cases concentration level) of methane that a measurement technology can reliably detect, with a defined level of confidence (probability of detection), under specified operating and environmental conditions.
Monitoring Technology Deployment	A subsidiary document of this Standard which describes the requirements for the usage of methane monitoring technologies to comply with the requirement for Facility Scale measurement and Source Level surveys to inform emissions management practices.
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 Natural Gas Production	The oil and 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) contained on a wellsite upstream of the transfer point to a gathering system. Equipment may include, but not limited to, compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, connecting pipework, gathering lines, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment. Production equipment may also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island..
Producer / Operator	The owner and operator of a Facility, responsible for operating a well or wells that recover and bring oil and gas to the surface, whether or not in conjunction with byproducts.

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

Quantification	Estimating an emission rate, such as mass per time or volume per time, or total emissions. This can be done directly through measurement of the emissions, or indirectly through engineering calculations, simulation tools, or a combination of such methods.
Reconciliation of Emissions	The iterative process of comparing aggregated source-level emissions quantification (source-level emissions inventory) to corresponding site-level measurements in order to identify, understand, and resolve discrepancies and improve emissions reporting over time. In addition to the emissions mass, this comparison should include the uncertainty associated with each method so that reported emissions are more reliable, transparent, and representative of actual methane releases.
Root Cause Analysis (RCA)	A documented procedure whereby a Producer follows up to detected events to determine the source of the emission, identify possible causal factors, determination of the root cause, recording each event for data aggregation, and finally recommending and implementing a solution.
Site	The wellpad, tank battery, or other equipment pad encompassing a natural gas Production well (including multi wells) and its supporting equipment, such as that used for separation, treating, compression, gathering and storage. Inspections conducted at the Site level must be able to narrow the location of the methane emission to a single wellpad or localized area for a follow up Causal Examination and mitigation efforts.
Source / Emission Source	A specific piece of equipment or activity that emissions originate from. The sum of emissions from all emission sources is an input into a Facility's inventory.
Site Level Measurement	Application of a Site Level emissions measurement method, as part of a facility-scale measurement campaign which uses technology capable of capturing and measurement of emissions at the site level.
Source Level Survey	Application of Source Level emission survey methods focused on identifying and characterizing emissions at the level of individual sources, combining emission source detection methods and, where feasible, direct measurement techniques. The information collected as part of Source-Level surveys in combination with representative equipment counts, and activity rates are then used to develop source-level emission estimates.

Standard Holder	The organization responsible for defining and managing all aspects of the development of the Standard, including managing the processes for making changes to the Standard documents.
Production Throughput	The quantity of gas sold in the calendar year from wells. This includes gas that is routed to a pipeline but excludes gas vented or flared or used in field operations. This 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 sold in the calendar year from wells.
Unintended Emission	Any methane emission occurring outside equipment design specifications or normal operating conditions, including all 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 best 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 as International Social and Environmental Accreditation and Labelling (ISEAL) Credibility Principles shall apply [*4*]. Where this Standard provides for more specific requirements than the ISEAL Credibility Principles, the specific requirements shall apply.

2. **Voluntary nature**

   The use and adoption of this Standard is voluntary. This Standard provides requirements for Producers to differentiate the supply of their product based on its methane emissions performance. The application of this Standard is a voluntary action taken by a Producer.

3. **Transparency**

   Certification under this Standard is based on objective and publicly disclosed criteria. Access to details of the MiQ certificates Issued under this Standard should be made available to users of the 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 Standard and supporting documents · managing updates and changes to the Standard
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	· registering Facilities with an Issuing Body; · 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 Report to the Issuing Body
Issuing Body	· registering each Facility under the MiQ Program · issuing MiQ certificates · approving Audit Reports under the MiQ Program

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 an operating asset in order to facilitate differentiation of gas within the global supply chain. To this end, a certification boundary must encompass and represent all contiguous upstream emission sources and corresponding throughput within an operating basin, subbasin or geologic field. See the definitions of *Site* and *Facility* for further details.

- **Organizational boundary**

  Facilities must fall under the responsibility of a common owner or 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:

1. **Methane Intensity**

   The requirements to be complied with are defined in *Subsidiary Document 1: Methane Intensity*.

2. **Company Practices**

   The requirements to be complied with are defined in the *Subsidiary Document 2: Company Practices*.

3. **Monitoring Technology Deployment**

   The requirements to be complied with are defined in the *Subsidiary Document 3: Monitoring Technology Deployment*.

6.2 Grading System

Table 2 details the overall grading system for the segment reflected within the Standard. The Grade is based on the ***lowest*** achieved score of the three Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

To achieve grades D – F, a Facility must achieve all the mandatory Company Practices and the minimum requirements for Monitoring Technology Deployment. To qualify for grades A – C, a Facility must obtain higher scores for both Company Practices and Monitoring Technology Deployment, as indicated in Table 2.

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

	Score Requirements		
Grade	**Methane Intensity (%)**	**Company Practices** (Improved Practices points)	**Monitoring Technology Deployment**
A	≤ 0.050%	≥ 12	12
B	≤ 0.10%	≥ 8	8
C	≤ 0.20%	≥ 4	4
D	≤ 0.50%	Mandatory minimum	Mandatory minimum
E	≤ 1.0%	Mandatory minimum	Mandatory minimum
F	≤ 2.0%	Mandatory minimum	Mandatory minimum

7 Subsidiary Documents

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

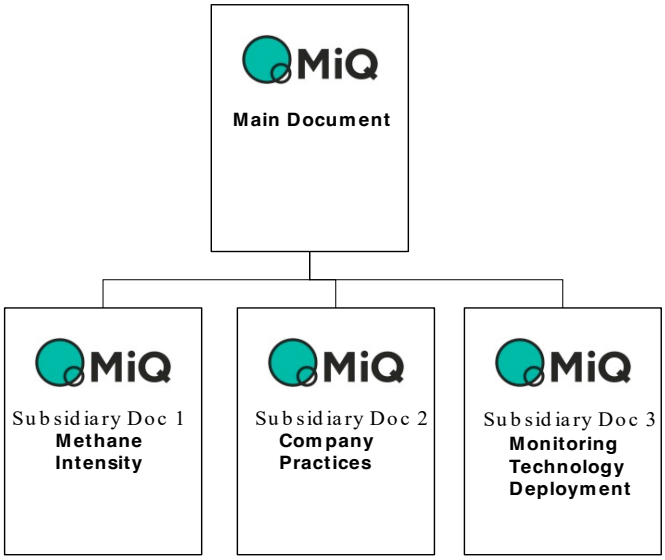

Figure 1: Document hierarchy

7.1 Subsidiary Documents

The following subsidiary documents are defined to supplement this Standard:

- *Subsidiary Document 1: Methane Intensity*
- *Subsidiary Document 2: Company Practices*
- *Subsidiary Document 3: Monitoring Technology Deployment*

Annex A: Conversion Factors

For conversion factors, please follow the values as defined in *Table 3*:

Table 3: 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 would like to acknowledge the substantive contributions from industry experts, academic experts, consulting firms, auditing firms, environmental NGOs, and government officials.

MiQ reserves the right to make updates to the Standard on a periodic basis to conform with new research, internal calibrations, and operator access to best available technology.

Producers currently undergoing certification must comply with the latest version of the Standard for their Annual Audit if it falls greater than 12 months from publication date.

B.2 Version History

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

Table 4: 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

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*

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[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 Natural Gas Operations

SUBSIDIARY DOCUMENT 1: Methane Intensity – Onshore Production

v1.1

1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer policies and procedures focused on methane emissions prevention, detection, quantification, and abatement (Company Practices), and (3) measurement and quantification of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify 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 three main types of documents, to be read in the following order:

1. *Main Document – Onshore Production*
2. Subsidiary Documents

    a. **Subsidiary Document 1: Methane Intensity – Onshore Production (this document)**

    b. *Subsidiary Document 2: Company Practices – Onshore Production*

    c. *Subsidiary Document 3: Monitoring Technology Deployment – Onshore Production*

This subsidiary document outlines the calculation of Methane Intensity as it pertains to the Standard. In general terms, Methane Intensity is a ratio of methane emissions relative to natural gas throughput, which is a baseline indicator of methane emissions performance. See *Section 3* for a detailed overview of the Methane Intensity methodology used in this Standard.

2 Scope of this Document

This subsidiary document is part of the MiQ Standard and defines the criteria and requirements to determine the Methane Intensity of a Facility. MiQ is a Standard and program designed to differentiate the natural gas supply chain by its methane intensity. The MiQ Standard requires all sources to be accounted for as part of the emissions estimation methodology. However, specific sources and their minimum requirements for determination are outlined within this document. This Standard and all methodology in this document are globally

applicable. This subsidiary document specifies a method to calculate the Methane Intensity of production from onshore Facilities.

3 Methane Intensity

Under this Standard, Producers are required to calculate Methane Intensity and keep detailed records of supplementary data inputs used in the Methane Intensity calculation (detailed in Section 5).

Methane Intensity is to be projected annually, using the best available data, including but not limited to historical emission records, Source Level emission surveys and Facility Scale methane emission measurements, applicable operational data, as well as the investigated results of any other anomalous emission detections from other information sources, including publicly available emissions observation records of which they are aware of.

3.1 Calculation

Methane Intensity is defined as the ratio of methane emissions relative to throughput, adapted and modified from the Natural Gas Sustainability Initiative (NGSI) Protocol [1*]*. Under this Standard, a Facility's Methane Intensity is to be calculated following the methodology detailed in *Annex A*. It enables Producers to calculate an annual Facility Level Methane Intensity from emission sources reconciled with emissions from facility scale measurements conducted in accordance with *Subsidiary Document: Monitoring Technology Deployment, Section 4.2*.

The Methane Intensity for natural gas metric is the quotient of the mass of methane emissions (after allocation and in kg CH_4) attributed to the production of natural gas from a Facility by the mass of methane throughput sent to sales. It is calculated every 12 months as a unitless ratio and communicated as a percentage. For example, a Producer can calculate its natural gas methane intensity using the following equation:

$$\textit{Methane Intensity} = \frac{\textit{Methane Emissions}}{\textit{Production Throughput} \times \textit{Methane Content}} \times 100\%$$

Methane Intensity represents the amount of methane emitted at any given Facility for a given year as attributed to the production and handling of natural gas using the gas ratio or allocation to the gas phase, as outlined in *Table 3*.

Unit conversion factors necessary to complete the Methane Intensity calculations can be found in the *Main Document, Annex A: Conversion Factors*

3.2 Emission Sources

A Facility's calculated Methane Intensity must include:

(i) methane emissions from all the following sources 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 unclassified significant emission sources

(ii) additional sources identified and quantified as part of Facility Scale measurements or Source Level surveys, and

(iii) Source Level- Facility Scale reconciliation outcomes.

Most emission sources should be captured in the sources outlined above, but it is the Producer's responsibility to document other emission sources that may not be listed.

3.3 Emissions Estimation

This standard requires operators to quantify methane emissions at Source Level and additionally measure emissions at Facility Scale. The results of Source Level quantification and Facility Scale measurements are used to estimate annualized methane emissions.

Source Level emission surveys focus on identifying and characterizing emissions at the level of individual sources, combining emission source detection methods and, where feasible, direct measurement techniques. The information collected as part of Source-Level surveys in combination with representative equipment counts, and activity rates are then used to develop source-level emission estimates. For different sources or emissions, operators should consider predominant source of uncertainty in the emissions estimations (including emission rate, emission event duration, or frequency) and attempt to constrain that by employing empirical data.

For the Source Level emissions quantification, operators are required to use direct measurements, when feasible. Where direct measurement of source-level emissions is not feasible, then the use of specific emission factors based on Source Level quantification or sampling should be considered along with engineering calculations, process simulation, or a hybrid method. Where neither the use of direct emissions measurement nor specific emission factors based on Source Level quantification, sampling, engineering calculations or process simulations is feasible, other emission factors that are the most representative of the equipment type and site conditions can be employed in the emissions estimation process. These must be based upon representative equipment counts, activity rates, and emissions profile (e.g., leaking component types and count) as indicated by leak detection and repair inspections.

Where direct measurements are not performed, operators should provide justifications for their method selection. Operators should also demonstrate continuous improvement by taking steps toward collecting future representative source-level measurements from their assets. For all source level emissions quantification, producers must ensure that:

- The emissions estimations properly reflect the findings of the LDAR surveys, by accounting for the emissions from the detected leaking components
- Emissions estimates are based on representative activity rates and/or other operational parameters

For Facility Scale measurement, operators should employ measurement methods that cover the entire facility. At this point, for Facility Scale measurement, this standard requires the application of technologies with a minimum detection level of 25 kg/hr or lower at the site level. This protocol is intended to be revised in the future to align with evolving regulatory requirements and scientific findings, including updates to minimum detection limits or performance standards established by relevant authorities.

Producers are encouraged to utilize quantification methods specific to their Facility. The Producer must provide relevant information for each emission source where a quantification method is used that 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.
- For use of specific emission factors: details describing the measurement equipment and quantification level, site selection, sampling criteria, and measurement period.
- Where direct measurement is not feasible, operators should 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.
- Operators should describe the use of representative source-specific data, including emissions measurement and quantification, sampling, activity data, and other operational parameters.
- For use of any measurement solution: technical specifications and results of controlled release testing, including calculated uncertainty, bias or confidence bounds.

3.4 Emissions Reconciliation

A Producer's emissions accounting methodology must include both intended and unintended methane emissions. The reconciliation process aims to compare and integration different sources of emission estimations and measurements to better understand and resolve sources of discrepancies between them.

In the context of this standard, emissions reconciliation is performed using a Source-Level inventory and corresponding Facility Scale measurement datasets. As part of this process, producer should include reconciliation of reportable emissions, including unintended emissions identified during Source-Level surveys and Facility-Scale measurements performed as a requirement of the Standard (see Subsidiary Document 3: Monitoring Technology Deployment, Section 5.1 for more detail), or via monitoring and measurement data from historical surveys, parametric monitoring and any other inspections or observations for Facilities in Year 1 of the certification process (See Section 4 for more detail). Operators should include the investigated results of other anomalous emission detections from other information sources, including publicly available emissions observation records or which they are aware of. For

simplification purposes, all methods used to detect emission events to be reconciled are referred to as "applicable methods."

Reconciliation may uncover credible evidence of discrepancies in the emissions inventory. Facility-Scale measurements often identify discrepancies cause by (i) source categories that were systematically excluded from the bottom-up inventory, or (ii) anomalous emissions from already included source categories that occurred under abnormal operating conditions not reflected in the inventory calculations. The outcome of reconciliation is a more comprehensive estimate of total annualized emissions, informed by Source Level and Facility Scale information as well as the associate uncertainty considerations. Reconciliation can be performed using a detection-based approach for different site-level detections (the findings of the Facility Scale measurement campaigns) or using a source-group approach for different source categories.

Detection-Based Reconciliation
In detection-based reconciliation approach, the operator must reconcile all the detections identified during Facility Scale measurement campaigns. This approach aims to determine if a detection is missing or mis-represented in the Source Level (bottom-up) inventory, so proper adjustments (additionality of the event or adjustment of the magnitude) are applied to have a more comprehensive emissions inventory.

Detection-based reconciliation can be performed at the Source Level (when source-attribution data is available) or Site Level (for the measurement technologies that only produce Site Level measurement estimates). When detection-based reconciliation is performed at the Source Level, the bottom-up inventory (emission quantification at the Source Level) is used to estimate an instantaneous emission rate associated the detection.

For Facility Scale reconciliation at the Site Level, all the sources present within the site boundary are considered in determining the instantaneous Site Level emission estimate. All available information should be used to determine an instantaneous emission rate that accurately reflects the specific time and location of the detection, including representative operating parameters and environmental conditions.

For each detection, if emission rates from Facility Scale measurement and instantaneous Source Level emission estimate do not align, then the operator should investigate any sources of discrepancies, including unaccounted for (uninventoried) or anomalous emission events, then annualize the impact of discrepancy (by temporally extrapolating emissions across the year based on proper emission rate, duration and frequency), and make appropriate adjustments to the emissions inventory.

Source-Group Reconciliation
When reconciliation is performed for different source groups, an operator should compare the aggregated Facility Scale and Source Level annual emissions for a specific source category (e.g., flares) across the entire facility. This approach aims to determine if the Facility Scale detections, in aggregate, validate the Source Level inventory. If discrepancies are identified as a result of comparing Facility Scale measurements and Source Level inventories, then the operator should investigate any sources of discrepancies, including unaccounted for or anomalous emission events, annualize the impact of discrepancy (by temporally extrapolating emissions across the year based on proper emission rate, duration and frequency), and make appropriate adjustments to the emissions inventory.

Reconciliation Documentation
Operators should document their reconciliation methodology and records, including (i) accuracy and appropriateness of Source Level quantification and Facility Scale measurement methods, (ii) uncertainties associated with different measurements and estimates, (iii) discrepancies discovered as part of the reconciliation effort, (iv) extrapolation logic (including the methods for the determination of event duration and frequency), (v) potential biases in the reconciliation process, (vi) root-causes of discrepancies, and (vii) modifications (additive or substitution) made to resolve each discrepancy.

For accurate reconciliation, operators should appropriately map measurements to emission sources. This process will ensure that there is an inventory entry associated with each measured site. Producers are required to employ all the relevant data available in the process of preparing their emissions inventory to ensure that the numbers achieve the highest level of accuracy possible. Additional information regarding Source Level surveys and Facility Scale measurements can be found in the *Subsidiary Document: Monitoring Technology Deployment*.

4 Scoring Parameters

The overall grading system for the Standard is detailed in the *Main Document*. The Grade is based on the combination of individual scores for each of the Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

A Facility's Methane Intensity score is based on its calculated Methane Intensity, as detailed in the score requirements in the *Main Document, Section 6.2*.

As part of the Annual Audit, producers must submit a methane emissions inventory that is reconciled with emissions identified during Source Level surveys and Facility Scale measurements completed in accordance with *Subsidiary Document 3: Monitoring Technology Deployment* and quantified, or other relevant measurement campaigns undertaken by the Producer. New certified Producers must utilize results from previous emission surveys, commissioned in house or obtained from outside regional campaigns. For all grades, this must include the results of at minimum one (1) annual Source Level survey AND at minimum one (1) Facility Scale measurement surveys[5].

5 Recordkeeping Requirements

In addition to the final calculated Methane Intensity value, Producers must document the following aspects that make up the Methane Intensity calculation for Auditor review (and note the individuals or departments responsible for determining) at a minimum:

Table 1: Recordkeeping Requirements

Aspect	Detail
Facility Description	Producers must document all Production Equipment or assets that make up a Facility, including Production Equipment added as a result of development activity, or removed due to abandonment, shut-in, divestiture, or any other changes made 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 data.
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, and the method used to determine this count.

[5] Duration between Facility Scale surveys may not exceed 150% of the intended periodicity. See *Subsidiary Document 3: Monitoring Technology Deployment, Section 3.2* for more details.

Activity data	For use in emissions calculations, producers must document the activity data associated with each emission source (e.g. operating time, vessel or well volume criteria, estimated leaking time for leaker emission sources). Producers must also document their observations from source level surveys (see *Subsidiary Document 3: Monitoring Technology Deployment, Section 5.1* for more detail).
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 calculation or measurement used in calculations. Producers must document the method, assumptions used along with its rationale, and its application to the calculation. For enhanced quantification methods, Producers must document all calculation and/or modelling assumptions, and/or technical specifications of measurement technologies deployed.
Reconciliation Procedure	Producer must provide a detailed procedure outlining their process for emission reconciliation in accordance with *Subsidiary Document 1: Methane Intensity – Onshore Production*, or other relevant LDAR or measurement campaigns, within their inventory, including details of their Facility Scale measurements and Source Level surveys, emissions classification, and quantification methods (see Section 3.2).
Methane Intensity Calculation Inputs	*Energy content and Gas Ratio* The allocation of methane emissions between natural gas production and other hydrocarbon production must be documented and substantiated, including the factor used for energy content of natural gas (whether default raw gas value or company-specific value) and the factor used for energy content of liquids (whether default crude oil and condensate heating value or 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, methodology used for determining methane content must be documented.
Processes and responsibilities	Producers must document their processes for determining and internally reviewing their Methane Intensity for accuracy. This should include a detailed record of internal changes to calculations based on operational incidents and planned events.

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MiQ STANDARD

for Methane Emissions Performance for Natural Gas Operations

SUBSIDIARY DOCUMENT 2: Company Practices – Onshore Production

v1.1

1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer policies and procedures focused on methane emissions prevention, detection, and abatement (Company Practices), and (3) detection and mitigation of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify natural gas production according to its methane emissions performance. The Standard is designed to incentivize continuous improvement in methane emissions monitoring and abatement.

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

1. *Main Document – Onshore Production*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – Onshore Production*
    b. Subsidiary Document 2: Company Practices – Onshore Production (this document)
    c. *Subsidiary Document 3: Monitoring Technology Deployment – Onshore Production*

Effective management of methane emissions from oil and gas production begins with a Facility design that will achieve minimal inherent methane emissions and eliminates, to the greatest degree possible, 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 be able to produce documentation of their Company Practices and procedures, and demonstrate that employees understand, implement, and comply with those practices.

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:

3. **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.

4. **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.

5. **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 production from onshore 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**: By demonstrating these practices, a Producer can achieve the additional points required to qualify for higher MiQ Grades.

The overall grading system for the Standard is detailed in the *Main Document*. The MiQ Grade is determined based on the lowest of the individual scores for each of the Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

For a Facility to be certified under this Standard, **each** mandatory Company Practices performance criteria outlined below must be met. Facilities which adopt improved practices for reducing methane emissions are eligible for higher MiQ Grades (*see Main Document, Section 7.2.1*). The improved performance criteria are assessed via a points-based scoring system. Points for improved practices are indicated in Tables *1, 2, 3* below. If a Facility demonstrates **at least one** of the elements listed for an improved practice topic, as outlined in Tables *1-3* 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 improved points. 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.

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 1* [6] categorized according to their character ('Mandatory' or 'Improved').

[6] Company Practices are numbered by type. Practice types include General Practices (GP), Unintended Methane Emissions Practices (UMEP), and Intended Methane Emissions Practices (IMEP).

Table 1: 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 Audial, 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 including all unintended emissions	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 2*.

Table 2: 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**	Mandatory	-

- first attempt at repair requirements within 30 days of detection; **and**
- final repair attempt within 30 days of detection; **and**
- 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) 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** • Policies and procedures for managing tanks include observation for methane emissions **and** preventative maintenance based on historical inspection findings.	Mandatory	-

(UMEP- 3.1)

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- 4) 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- 5) Root Cause Analysis (RCA) of unintended emission events		
• Producer has Root Cause Analysis (RCA) policies and procedures describing the process of conducting an analysis of the cause of unintended emission events and documentation of systematic corrective actions taken to limit and prevent reoccurrence.	Improved	1

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 3: 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 hydraulic 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];[7] **and** • policies and procedures to ensure flares[8] 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	-

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

(IMEP- 7.1)		
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.	Improved	2
(IMEP- 7.2)		
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.

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MiQ STANDARD

for Methane Emissions Performance for Natural Gas Operations

SUBSIDIARY DOCUMENT 3: Monitoring Technology Deployment – Onshore Production

v1.1

1 Introduction

The MiQ Standard for Methane Emissions Performance (the Standard) combines several Standard elements – (1) a calculated Methane Intensity, (2) Producer policies and procedures focused on methane emissions prevention, detection, quantification, and abatement (Company Practices), and (3) measurement and quantification of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify 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 three main types of documents, to be read in the following order:

1. *Main Document – Onshore Production*
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – Onshore Production*
    b. *Subsidiary Document 2: Company Practices – Onshore Production*
    c. **Subsidiary Document 3: Monitoring Technology Deployment – Onshore Production (this document)**

This subsidiary document outlines requirements for Monitoring Technology Deployment for measurement and quantification of methane emissions.

Methane emissions measurement and quantification are key elements of methane emissions management for a Facility. Emissions event measurement and quantification are essential in developing best-estimates of total emissions, prioritization of mitigation activities, optimization of operational practices, and improving engineering designs.

Methane emissions monitoring technologies can be deployed along 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-Scale measurements campaigns to estimate emissions over larger spatial scales, such as a Facility. Whereas 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-Leve and Source-Level measurement approaches can vary in temporal scale, with improved emissions detection capability with more frequent

deployment. Measuring methane emissions lacks a "silver bullet" solution to address all the needs for various applications. As a result, a multi-tiered approach, with an informed selection of the combination of technologies, is often required for an effective methane emissions management system. *Figure* 1 illustrates simplified examples of methane monitoring technologies in relation to spatial and temporal scale.

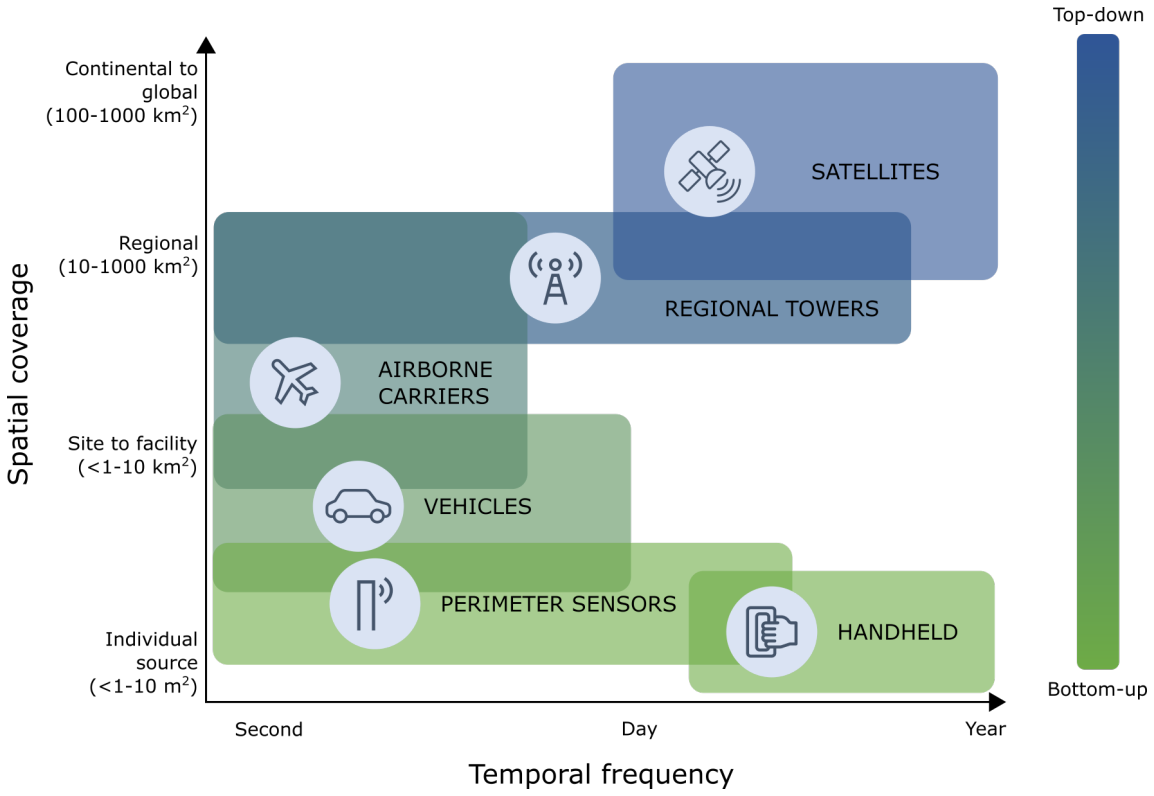

Figure 1: Methane monitoring technology across a variety of spatial and temporal scales[9] (adapted from the National Academies of Science, Engineering, and Medicine, 2018 [1])

In practice, a discrepancy is often observed between the results of measurement using different methods. To date, emissions reconciliation approaches continue to evolve through research and industry collaborations. The existing body of work indicates that top-down approaches often produce methane emissions estimates that are significantly higher than those from bottom-up approaches alone.[2, 3][10] These studies indicate that one cause of this divergence is the under-representation of abnormally high-emitting sources, commonly referred to as

[9] 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.

[10] For example, David Allen et al. [2] and Adam Brandt et al. [3] examine the notable discrepancies between top-down and bottom-up methane emissions estimates.

super emitters [4][11]. These emissions typically arise from a source, or from closely connected sources at a site, emitting at a rate greater than 100 kg/h. Such emissions are often spatially and temporally dynamic, and the conditions that give rise to them can vary. Therefore, identification of super emitters, along with other emissions, at both the facility scale and source level, at a greater monitoring frequency, is essential to developing accurate emissions inventories and effective methane emissions management and mitigation.

Spatial scales referenced within the Standard, specifically with regards to methane emissions detection, are outlined below in *Figure 2*.

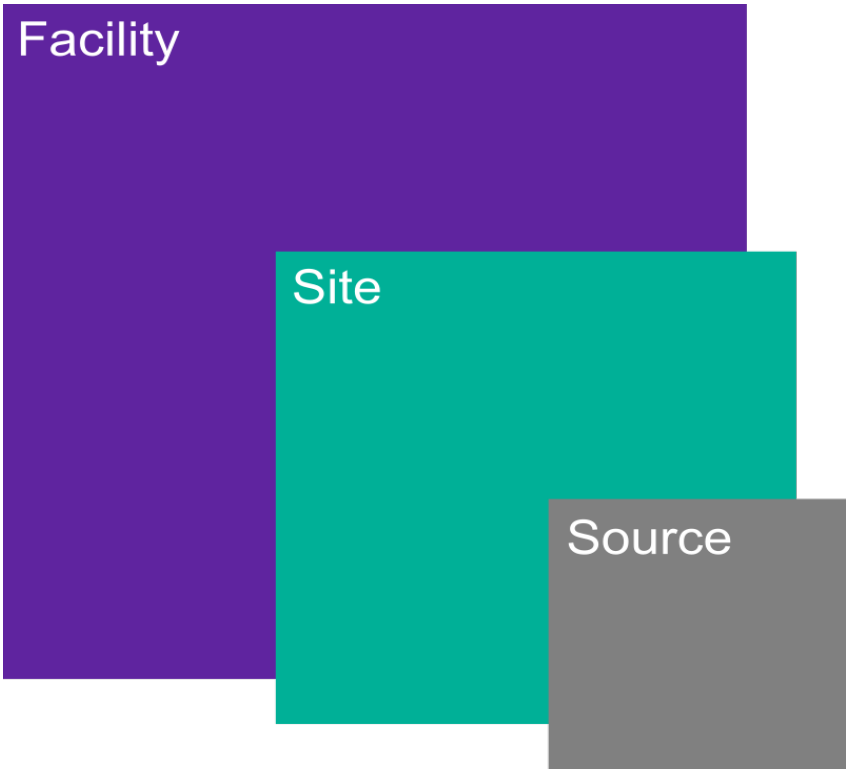

Figure 2: Spatial scales utilized within the Standard, referencing the definitions of Facility, Site, and Source as outlined in the *Main Document*, see there for reference.

2 Scope of this Document

This subsidiary document is part of the MiQ Standard and defines the Monitoring Technology Deployment criteria and requirements for compliance with the Standard. Monitoring Technology Deployment is considered a part of a holistic

[11] Brandt et al [4] examines the over representation of a majority of emissions (50%) from a small number of sources (5%) typically found in the super-emitter category.

technology solution, which takes into consideration the sensor capabilities, deployment protocols, analysis methods and follow up protocols.

This document outlines the requirement for Monitoring Technology Deployment for the measurement and quantification of methane emissions. As part of a reconciliation effort, aggregated source-level emissions quantification (source-level emissions inventory) should be compared to corresponding site-level measurements to identify, understand, and resolve discrepancies and improve emissions reporting over time. (see *Subsidiary Document 1: Methane Intensity Section 4*). Producers are required to employ all the relevant data available in the process of preparing their emission inventories. Details of a Producers calculations methods for quantifying or measuring detected emissions must be submitted as part of their reconciliation procedure.

As measurement technologies and their uncertainty improve and become available at scale, the Standard will be updated to reflect new required best practices.

3 Technology Deployment Objective and Performance Criteria

The primary objectives of Monitoring Technology Deployment are to:

- facilitate data collection for the measurement and quantification of emissions at the source level and facility scale,
- employ different sources of information to improve the accuracy of methane emission intensity calculation,
- facilitate the development of accurate measurement-informed emissions inventories using Source-Level quantification and Facility-Scale measurement data, and
- demonstrate effective management of methane emissions through identification of emission events, followed with necessary corrective actions.

These objectives harmonize with other elements of this Standard, to:

- provide assurance of the calculated Methane Intensity using reconciliation (see *Subsidiary Document 1: Methane Intensity)*
- implement better operating practices and equipment design for reduced methane emissions; and
- encourage Producers to undertake Source-Level surveys and quantification as well as Facility-Scale measurement of emission sources at their assets.

3.1 Key Performance Parameters

The overall grading system for the Standard is detailed in the *Main Document*. The MiQ Grade is determined based on the individual scores for each of the Standard elements: (1) Methane Intensity, (2) Company Practices, and (3) Monitoring Technology Deployment.

A Facility's score for Monitoring Technology Deployment is based on the following key parameters. These parameters are outlined in *Table 1*.

Table 1: Key Parameters

Parameter	Description
Frequency of Monitoring Technology Deployment	The minimum number of surveys per year. More frequent surveys (i) provide higher assurance in the identification of emission sources and support timely repair and abatement, (ii) 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 duration in-between surveys should not exceed 150% of time indicated by the stated cadence[12].
Sampling coverage of Monitoring Technology Deployment	The minimum percentage of Sites required to be surveyed within a Facility boundary. Achieving and maintaining uniformly low methane emissions levels will require detection technology deployment at a larger fraction of Sites integrating both Facility Scale and Source Level approaches over a given time-period.
Minimum Detection Limit (MDL) of Monitoring Technology	The lowest emission rate (or in some cases concentration level) of methane that a measurement technology can reliably detect, with a defined level of confidence (probability of detection), under specified operating and environmental conditions. The technology solution required to achieve the desired MDL and detection probability[13] must be applicable for the specific Facility and validated by the Auditor.

[12] 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.

[13] 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

3.2 Performance Scoring

Table 2 outlines the performance criteria and associated score for Monitoring Technology Deployment under the Standard, including Facility Scale measurements and Source Level surveys.

A Producer is required, at a minimum, to conduct one (1) baseline Source Level survey (either to undertake measurement and quantification directly, or to inform source level quantification) AND one (1) Facility Scale measurement, both over the entire Facility annually in order to be considered for the consideration under this Standard. Producers can achieve a higher score by increasing the frequency and coverage of Source Level surveys and Facility Scale measurements.

Beyond these minimum requirements, the MiQ Standard employs the concept of Equivalency to fulfill the Monitoring Technology Deployment requirements to achieve higher MTD scores. The Frequency, sampling coverage, and MDLs outlined in Table 2 should be considered a benchmark for achieving a given number of points. An Equivalent methane emissions measurement and monitoring program capable of detecting, characterizing, and mitigating an equivalent amount of methane emissions may be proposed to the auditor, as demonstrated through a given Equivalency Determination (i.e. model and modelling assumptions, see Section 3.2.3). The details for Facility Scale and Source Level surveys are outlined in Sections *3.2.1* and *3.2.2* , respectively.

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.

Table 2: Technology Performance Criteria[+]

Facility Scale Survey*		Source Level Survey***	Points
annually	Entire Facility	Annually, All Sites**	minimum requirement
annually	Entire Facility	Annually, All Sites, Plus Semi Annually, 50% of Sites	4
semi annually	Entire Facility	Annually, All Sites, Plus Tri Annually, 50% of Sites	8
quarterly	Entire Facility	Annually, All Sites, Plus Quarterly, 50% of Sites	12

[+] Please refer to the MiQ Standard for Methane Emissions Performance for Natural Gas Operations - SUBSIDIARY DOCUMENT 1: Methane Intensity – Onshore Production v1.0.0 for the details on how the emissions measurement data is used for emissions quantification.

* with minimum detection limit of 25kg/hr at 90% probability of detection.

** All producers are required to conduct a minimum annual Source Level survey over 100% of sites (this survey may include direct measurement and quantification or inform source level quantification). Sites deployed with uncrewed stationary or continuous monitors are not exempt from this requirement.

*** Semiannual, triannual or quarterly inspections over at least 50% of sites are *in addition to* the annual Source Level survey. The 50% coverage of sites should be chosen to be representative of the facility as a whole, taking into account factors such as site type, operational characteristics, and expected emissions profiles, while also seeking to maximize coverage across the facility over the course of the year. For example, to achieve 12 points a producer may conduct 100% + 50% + 50% + 50% for a total of 250% coverage for the upcoming year. However, each quarterly source-level survey should be planned to ensure maximum site count coverage (as opposed to repeated visits to the same sites) throughout the year.

3.2.1 Facility Scale Measurement

The intentions of a Facility Scale surveys are to measure emissions from all sources within the boundaries of production sites that emit at a rate higher than the minimum detection limit. The results of Facility Scale measurements complement emissions estimations based on Source Level quantifications to provide a more comprehensive picture of Facility-wide annualized emissions. They will also provide assurance that the Facility is frequently surveyed to identify and quantify potentially abnormally high emissions.

For Facility Scale measurement, operators should employ measurement methods that cover the entire facility. At this point, for Facility Scale measurement, this standard requires the application of technologies with a minimum detection level of 25 kg/hr or lower at the site level. This protocol is intended to be revised in the future to align with evolving regulatory requirements and scientific findings, including updates to minimum detection limits or performance standards established by relevant authorities.

This Standard is technology neutral, however a Site Level measurement technology that is employed for the Facility Scale inspections:

- must cover the entire certified Facility including elevated sources in three-dimensional space and buried sources
- must be deployed at the frequency designated in Table 2 above
- must meet the designated MDL of 25kg/hr[14] at 90% POD proven through single blind, controlled release testing (see *Table 3* for additional record keeping requirements), and quantify the methane emissions rate
- must attribute the source to a single site spatial boundary for follow up inspection
- may utilize multiple inspection methods in combination

Facility Scale measurements may identify both intended and unintended emissions. All emissions identified through Facility Scale measurement should be investigated as part of the emissions reconciliation process to ensure that their impact is properly reflected in the annualized emissions inventory. More details related to emissions reconciliation can be found in *Subsidiary Document 1: Methane Intensity – Onshore Production*.

Identified emissions must be investigated to determine whether the release is intended or unintended, if intended, whether the source exceeds the expected rate. This investigation determines if the detection is associated with anomalous emissions and establishes whether the event requires emissions mitigation actions and/or follow-up inspection. Emission detections via Facility Scale measurements must be documented, repaired and/or mitigated following the timelines and requirements listed in Subsidiary Document 2: Company Practices.

If Facility Scale measurements across the last 12 months detect no additive emissions[15] for the entire Facility, the survey frequency can be reduced to the next lower score level, either via Table 2 or the Operator's equivalency determination. For Operators using Facility Scale measurement technologies with a MDL less than 25 kg/hr at a 90% probability of detection, survey frequency can also be reduced if the operator does not detect additive emissions from any site that total greater than 25 kg/hr. Operators may not reduce Facility Scale inspection

[14] Facility Scale MDLs chosen to best encompass possible super-emitters from the supply chain, based on learnings from Brandt et al [3] where the largest 5% of leaks which are responsible for more than 50% of the total volume or the highest-emitting 1% of sites in a site-based distribution (Zavala-
Araiza et al. [5].

[15] Additive emission/detection: An emission detected through facility-scale measurement at a rate above the minimum detection limit (MDL) of the site-level measurement technology used to conduct the survey.

frequency using this clause any lower than once per year for the Facility and achieve at least 4 points.

An inspection recordkeeping form and corrective actions log must be populated for each survey and available for Audit (refer to *Section 4*).

3.2.2 Source Level Survey

The overall objective of performing Source Level surveys are to:

1. identify and detect sources of unintended methane emissions to the equipment and component level, for repair or replacement and as a key ingredient of operational hygiene.
2. quantify methane emissions at source-level, when feasible.

For the Source Level emissions quantification, operators are required to use direct measurements, when feasible. Where direct measurement of source-level emissions is not feasible, then the use of specific emission factors based on Source Level quantification or sampling should be considered along with engineering calculations, process simulation, or a hybrid method. Where neither the use of direct emissions measurement nor specific emission factors based on Source Level quantification, sampling, engineering calculations or process simulations is feasible, other emission factors that are the most representative of the equipment type and site conditions can be employed in the emissions estimation process. These must be based upon representative equipment counts, activity rates, and emissions profile (e.g., leaking component types and count) as indicated by leak detection and repair inspections.

For different sources or emissions, operators should consider predominant source of uncertainty in the emissions estimations (including emission rate, emission event duration, or frequency) and attempt to constrain that by employing empirical data. Where direct measurements are not performed, operators should provide justifications for their method selection. Operators should also demonstrate continuous improvement by taking steps toward collecting future representative source-level measurements from their assets. For all source level emissions quantification, producers must ensure that:

- The emissions estimations properly reflect the findings of the LDAR surveys, by accounting for the emissions from the detected leaking components
- Emissions estimates are based on representative activity rates and/or other operational parameters

The Source Level survey methods employed by the Producer must be detailed in the Producer's methane emissions management program. This Standard is

technology neutral, however the following are applied to Source Level measurement methods:

- Spatial resolution must be sufficiently low to reliably attribute emission sources to the component level for repair, maintenance, or mitigation
- be deployed at or above the specified frequency outlined in Table 2, unless using an Equivalent methane emissions management program.
- distinguish methane emissions from incomplete combustion from fugitive leaks or excess vented emissions, especially in the case of vented emission sources that are located near an exhaust stack.
- may utilize multiple inspection methods in combination

Sampling coverage is defined in the Standard as the percentage of Sites covered, inclusive of all equipment necessary to support production activities. For example, 50% of Sites monitored at the source level, may include wellheads, separation, treating, compression, manifolds, storage (i.e. tank batteries) or pipelines. A minimum percentage of Sites monitored is intended to enable a Producer to focus their methane emissions program on targeted sources based on cumulative data or maintenance programs, as outlined in *Subsidiary Document 2: Company Practices*. Monitoring sites should be chosen to be representative of the facility as a whole, taking into account factors such as site type, operational characteristics, and expected emissions profiles, while also seeking to maximize coverage across the facility over the course of the year. The monitoring location selection criteria and justification must be disclosed in a company's methane emissions management program and could, for example, include:

- selection of marginal producers or wells with a higher ratio of emissions to production;
- age of infrastructure;
- presence of emission reduction equipment; and
- historical observations.

Follow-up of an emission detected (the identification of an emission source or leak that exceeds a defined monitoring threshold or leak-definition standard during an inspection or monitoring activity) to using a Source Level survey method *can count* towards a producers' compliance with the requirements in Table 2.

For Sites which have no Source Level detections over the last 12 months, the survey frequency can be reduced to the next lower score level, either via Table 2 or through results of the Operator's equivalency determination. Equivalency

determinations must still be made at the score the Operator is being evaluated at (see Section 3.2.3 for more detail). Operators may not reduce Source Level survey frequency using this clause any lower to once per year for any Site or Production Equipment.

Sources with confirmed detections must be scheduled for repair or replacement, as per the Producer's LDAR program. The validation of repaired leaks must be specified in the program and occur within the time period defined in *Subsidiary Document 2: Company Practices*. Repair validations completed with the approved Source Level inspection methodology *do not* count towards the Source Level survey frequency.

A Source Level survey recordkeeping form and repair log must be populated for each survey event and available to the Auditor. Changes to the Monitoring Technology Deployment program arising from adverse weather conditions (affecting personnel safety and/or the technology operating envelope), difficult to monitor locations, and delay to repair or replacement for any other reason must be logged and communicated with the Auditor (refer to *Section 4*).

3.2.3 Equivalency Determination

The frequency and spatial coverage of monitoring technology deployment in the Standard have been constructed to apply to generic Facilities in varying geographies. Operators can select to 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 program should at a minimum, include one (1) baseline Source Level survey (either to undertake measurement and quantification directly, or to inform source level quantification) AND one (1) Facility Scale measurement, both over the entire Facility annually in order to be considered for the consideration under this Standard. Equivalency determination may be provided using accepted models or simulations (such as FEAST, LDAR-SIM [6][7], or other). Evidence must be provided to the Auditor including models inputs and assumptions supporting the conclusion that a given monitoring strategy can meet or exceed the same emissions measurement and mitigation, as that outlined in *Table 2*, in order to achieve the same number of points. Modeling inputs and assumptions include, at minimum

- emissions distribution curve representative of the Production Facility and included sources
- emissions durations or temporal intermittency
- monitoring technology capabilities, frequency of deployment and spatial coverage

- latency in processing and reporting of emissions
- time to follow up and repair.

Equivalent methane emission management programs must meet the same program and recordkeeping requirements (see Table 3 and 4) and minimum coverage requirements outlined above.

4 Recordkeeping and Reporting Requirements

Producers are required to record and disclose information related to methane emissions Monitoring Technology Deployment plans and implementation under the Standard. Deployment plans and supporting implementation information must be disclosed to the Auditor during the Annual Audit. Proof of implementation of the deployment of each monitoring technology solution must be disclosed to the registry during the Certification Period and to the Auditor during the subsequent years' Annual Audit. Table 3 outlines the minimum recordkeeping requirements for Monitoring Technology Deployment. Producers can choose to aggregate the recordkeeping elements to minimize administrative overhead. Producers must have adequate Company Practices in place which underpin accurate recordkeeping and reporting structures.

4.1 Minimum Recordkeeping and Reporting Requirements

Table 3: Minimum recordkeeping requirements for Facility Scale and Source Level survey

Recordkeeping element	Details

Detection Technology Specifications	• Sensor and instrumentation details
	• Method in which the sensor was deployed (i.e. fixed-wing, drone-based, stationary-mounted)
	• Performance specifications including minimum detection limit and probability of detection curves
	• Details of independent, single-blind testing, including
	  o Third party used to conduct testing
	  o Confirmation of single-blind nature of testing
	  o Operating conditions of equipment used for testing
	  o Variables tested that could affect the sensitivity of the technology and the

	ranges tested (i.e. humidity, temperature, wind speed, groundcover, obstruction, solar irradiation) o Calibration protocols used during testing o If operator uses technology for quantification, characterization of emission rate uncertainty o
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 location and environmental criteria determined during controlled released testing. o If a third party is contracted for the survey, this should also include contractor or data service provider information. o To include details for both Facility Level measurement and Source Level surveys.
Detection Follow up Protocols	• Emission detection and measurement workflow (i.e. follow-up processes taken after alarm) • Emission classification workflow (i.e. tracking new events, allowable events detected, and failed repair validations) • Data system that stores and manages data associated with detected emission events • Repair planning and repair validation procedure • Causal Examination procedures
Facility Scale measurement and Source Level survey recordkeeping form	For each emission source, includes component/equipment/site ID and type, date of all the measurements, repair efforts (first attempt, additional attempts, final attempt), repair validation date, success of repair or replacement, and (if applicable) a reason for delay to repair or replace and the date rectified.
Source Level/LDAR survey location log	Includes a list of survey locations (for at least the Certification Period) and visited for each survey (categorized by of Well ID or similar unique identifier).

QA/QC	Includes chain of custody sign off on data collected for accuracy (collector to independent reviewer), analytical settings as appropriate, calibration of monitoring equipment, and reference to the test method used.

4.2 Recordkeeping and Reporting Requirements for Continuous Monitoring Technology

As discussed in *Section 3.2.1* and 3.2.2, when appropriate, a Facility may choose to utilize a Continuous Monitoring System over all or part of their Sites towards meeting the requirements of a Facility Scale measurement or Source Level survey. *Table 4* outlines the minimum records a Producer must submit to the Auditor for use of Continuous Monitoring System.

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. cell tower, wired data) • Meteorological data collected for source identification and emission rate determination • Location where meteorological data is taken • Interconnection between data collection system, alarm system and work order processing system o Producer response to monitor downtime (i.e. backup monitoring plan) • Monitoring equipment calibration protocols (i.e. frequency, technology-specific parameters that are calibrated)

5 Interconnections with other Standard Elements

Each of the Standard Elements (Methane Intensity, Company Practices, and Monitoring Technology Deployment) is to be assessed separately; however, all are interconnected given their collective role in indicating effective methane emissions management. Monitoring Technology Deployment tangibly intersects with, and influences the score for, the other two Standard Elements.

5.1 Interconnection with calculated Methane Intensity

When calculating annual methane emissions for use in the Methane Intensity calculation as required by *Subsidiary Document 1: Methane Intensity*, Producers must reconcile methane emissions discovered from measurements using the technology's quantification capabilities, engineering calculations, simulations or a combination of such methods to quantify emissions. See *Subsidiary Document 1: Methane Intensity, Section 3.3* for requirements of incorporating emissions discovered during emissions measurement campaigns.

This Standard guides Producers to incorporate Facility-level measurement methodologies to characterize a Facility's methane emissions profile more accurately (refer to *Subsidiary Document 1: Methane Intensity, Annex A, Table 2* for more detail). Inspections undertaken by the operator that include emissions measurement capabilities must be utilized when the operator develops specific Emission Factors for individual emission sources.

5.2 Interconnection with Company Practices

A Monitoring Technology Deployment plan is detailed as required Company Practices, to ensure follow up actions are taken from an inspection where anomalous methane emission events are detected, specifically:

- Monitoring Technology Deployment for LDAR;

and its implementation in large part rests on the effectiveness of these 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

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