MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

MAIN DOCUMENT – Offshore Production

v1.0

Contents

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 very 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 oil and natural gas.

Methane is emitted in the process of producing oil and 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) detection and mitigation of methane emissions through Monitoring Technology Deployment – to provide a robust and reliable method to certify methane emissions from oil and 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 (this document)**
2. Subsidiary Documents
    a. *Subsidiary Document 1: Methane Intensity – Offshore Production*
    b. *Subsidiary Document 2: Company Practices – Offshore Production*

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[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.

Subsidiary Document 3: Monitoring Technology Deployment – Offshore Production

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 industry through a market-based oil and gas certification system.

1.3 Purpose

The purpose of this Standard is to incentivize continuous improvement in methane emissions monitoring and abatement by creating an opportunity for Producers to differentiate their oil and natural gas production by its methane emissions performance.

More specifically, the objectives of this Standard are:

a) to accelerate deployment of practices and technologies that reduce and/or eliminate methane emissions;

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

c) to increase transparency regarding the methane emissions performance of oil and natural gas production, with a globally consistent methodology;

d) to enable Producers, marketers, and buyers to transact oil and natural gas based on the methane emissions performance of a Facility, and to demonstrate additional value to their customers;

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

f) to complement regulations by incentivizing methane emissions detection and abatement actions that exceed regulatory requirements; and

g) to credibly recognize Producers who are leading their peers in methane emissions management.

2 Scope

This Standard establishes a system for the generation of an MiQ Grade which captures the Facility's methane emissions 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-detecting and monitoring technologies (Monitoring Technology Deployment).

Furthermore, this Standard:

- is applicable to Facilities in the offshore production segment (see Terms and Definitions);
- specifies a method to calculate the Methane Intensity of petroleum operations (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 oil's or natural gas' physical or chemical quality.

While the Standard is designed to grade a Facility on its methane emissions performance through the use of an independent Auditor and is an integral ingredient of the MiQ Program, it does not define certification procedures, issuance of MiQ certificates, or non-compliance events. (see the *MiQ Program Guide* for application of the MiQ Standard to the MiQ Program).

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 this Standard.

Audit Report	A verification document prepared by an Auditing Body that contains a comprehensive analysis of the Producer's adherence to the Standard.
Auxiliary Product Handling Site	A site, either onshore or offshore, with the purpose of, including but not limited to, treating and/or processing oil and gas or transferring gas to a downstream operator, and is under responsibility of the same common owner or operator. This includes but is not limited to acid gas removal, compression, separation, stabilization, dehydration, water treatment, metering and regulation, and power generation equipment. To be included in the Facility under this Standard, the bulk of gas throughput should originate from the production platforms in the Facility.
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[2] logs, maintenance logs, operational logs, operator site visits, and Source Level detection 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.

[2] Supervisory Control and Data Acquisition

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.[3]
Continuous Gas Detection System	A monitoring system at a Facility, usually part of the Facility's more broad personnel and process safety management plans, that includes the installation of fixed devices with the primary purpose of detecting and alarming gas releases. Continuous gas detection monitors that fall under this definition include, but are not limited to, lower explosive limit (LEL) monitors and acoustic gas leak detectors. A monitoring system must be inclusive of all areas in which the possibility of fire or explosion hazard may exist under normal or abnormal conditions due to the presence of flammable, combustible or ignitable gases that have the potential to include methane. Hazardous classified location definitions determined by other safety or environmental standards can be used to determine the extent of coverage required for deployment of continuous gas monitors.

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

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 monitoring 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.[4]
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].

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

Equivalency Determination	The process of comparing an operator's Leak Detection Methods with those in an LDAR program as prescribed by the Standard to achieve a certain evaluation, 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 LDAR Program	An LDAR program undertaken by an operator utilizing a combination of Facility Scale, Source Level and Continuous Monitoring detection tools deemed to offer the same probability of detection and emission mitigation potential over the course of the Certification Period as the those required under the Standard for a given MiQ Grade. Substituted Leak Detection Methods may apply various technologies with proven detection capabilities such as manned/unmanned aerial vehicles, fixed-wing aircraft, continuous monitoring devices, mass balance methods, or other methods to detect, track, repair, and report fugitive emissions, in addition to Source Level methods such as OGI surveys.
Facility	Offshore production well sites, subsea completions/tiebacks, offshore platforms, and Auxiliary Product Handling Sites (if under common ownership) where produced oil and natural gas flows. The Facility boundary typically ends either at a custody transfer metering point or another type of transfer point of operational ownership.
Facility Scale Inspection	Inspections undertaken by an operator using a method that covers the entire Facility's emission sources in three-dimensional space and must be capable of detecting and pinpointing the source of emissions to the Site Level at a minimum.
Gas Ratio	The ratio defined as the total energy of natural gas throughput and the total energy of both natural gas and hydrocarbon liquids throughput of the Facility.

Grade	The performance grade of a Facility determined in accordance with this Standard by an Auditor.
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.
Leak Detection and Repair (LDAR)	LDAR is frequently used to describe the regulatory practice of systematic emission detections using hand-held, source-level tools. The term is expanded in this Standard to describe any monitoring 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 data management standards.

Methane Intensity	The ratio of methane emissions (in mass units) relative to the entire throughput of all natural gas and hydrocarbon liquids products.
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.
Monitoring Technology Deployment	A subsidiary document of this Standard which describes the requirements for the usage of Leak Detection Technology, Leak Detection Methods and LDAR Programs implemented by Producers to mitigate Unintended Emissions.
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.[5]
Offshore Oil and Natural Gas Production	The oil and gas supply chain segment that includes all equipment, piping, instrumentation and controls (including compressors, generators, or storage facilities), and portable non-self-propelled equipment (including well drilling and completion equipment, workover equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, or lifting of petroleum and/or natural gas (including condensate) at an offshore platform. This equipment also includes associated storage vessels and measurement and all enhanced oil recovery (EOR) operations using CO2.
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.
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 emission factor methodologies, engineering calculations and modeling.

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

Reconciliation of Emissions	A quantitative assurance process required to ensure a more complete emissions estimate. The process cross-references top-down detections and quantified emissions with a bottom-up inventory to ensure an operator's methane intensity falls within a designated MiQ Grade band.
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	A localized area of offshore oil and natural gas production equipment within a Facility (i.e. production platform, auxiliary handling site, pipeline segment). Leak detection at the Site level must be able to narrow the location of the methane emission event to a single localized area or component or piece of equipment for 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 makes up a Facility's inventory.
Source Level Inspection	Application of a Source Level detection method which uses technology that can directly inspect individual sources of emissions, down to the component level.
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.
Super-Emitter	A Super-Emitter's emission rate threshold is not universally defined however these events are typically considered the largest 5% of leaks which are responsible for more than 50% of the total volume of leakage [2] or the highest-emitting 1% of sites in a site-based distribution [3]. In any case, super-emitters are a high-emitting emission event, due usually to abnormal process conditions, which can significantly affect the total emissions of a Facility.

Throughput	Natural gas throughput is the quantity of natural 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. Hydrocarbon liquids throughput is the total quantity of hydrocarbon liquids sold in the calendar year from wells.
Unintended Emission	Any emission occurring outside equipment designs or ideal operating procedures, including all equipment leaks and failures (sometimes known as fugitive emissions), vents, and combustion equipment operating outside their design values, 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 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 have emissions performance for oil and natural gas operations certified under this Standard under 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 oil and 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.

  For offshore Producers, the Facility boundary must include the production platform(s) where oil and natural gas originates from and can include connected subsea development(s) and auxiliary product handling, if and only if owned and operated by the same organization that owns and operates the production platform. See Figures 1-4 for an overview of physical boundary applicability and some common scenarios.

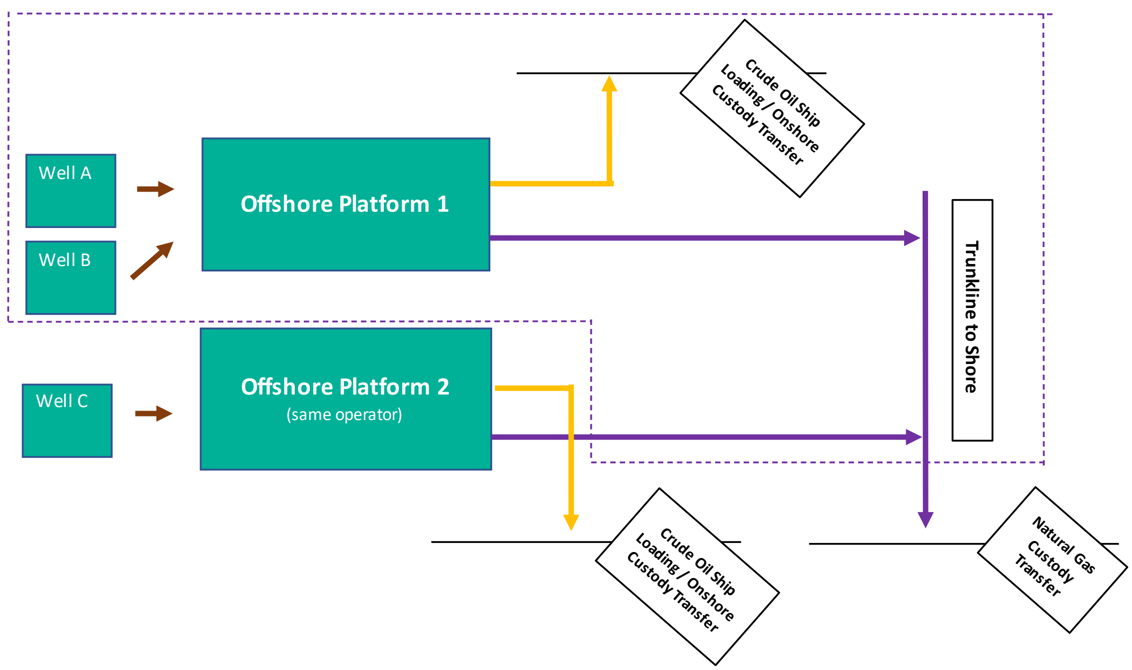

Figure 1: Facility boundary of Offshore Platform 1 ending at the custody transfer metering point after the trunkline downstream of Offshore Platform 1.

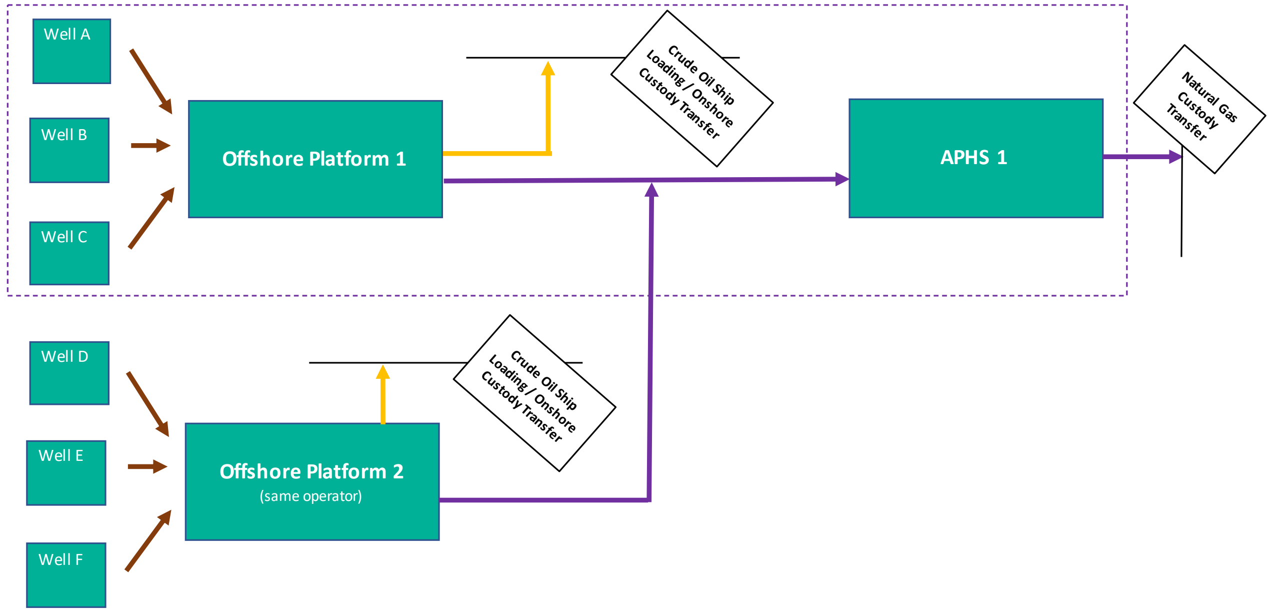

Figure 2: Facility boundary of Offshore Platform 1 ending at the custody transfer metering point downstream of Auxiliary Product Handling Site (APHS) 1, which is owned and operated by the operator of Offshore Platform 1 and does not handle any significant (>50% of Facility Throughput) third-party flows.

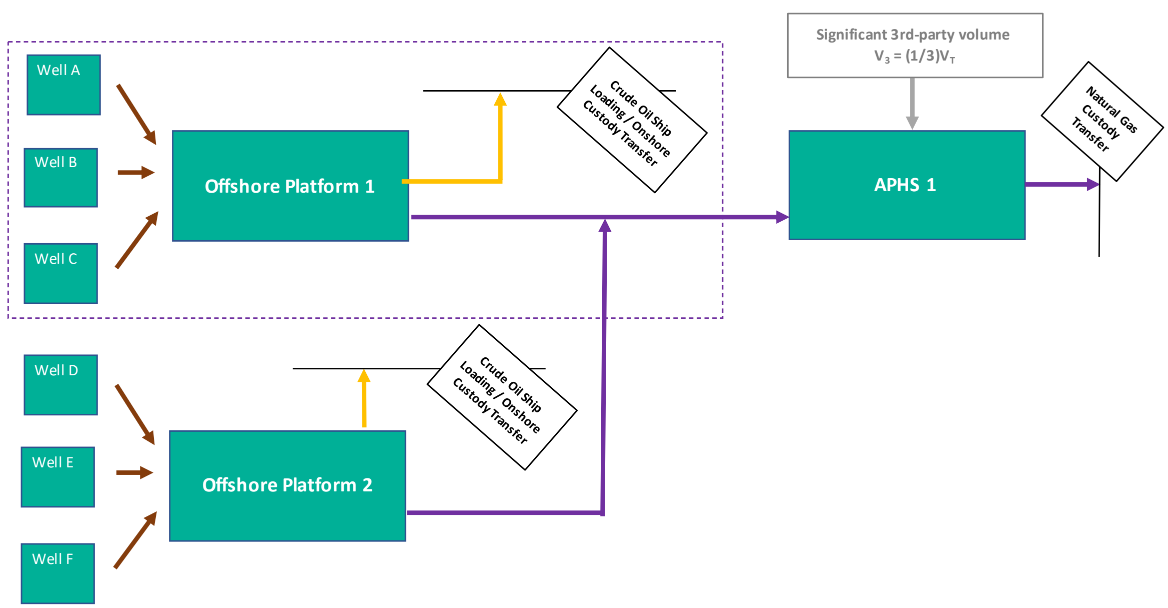

Figure 3: Facility boundary of Offshore Platform 1 ending at the point in which significant (>50% of Facility Throughput) third-party party flows are combined with the Facility's Throughput.

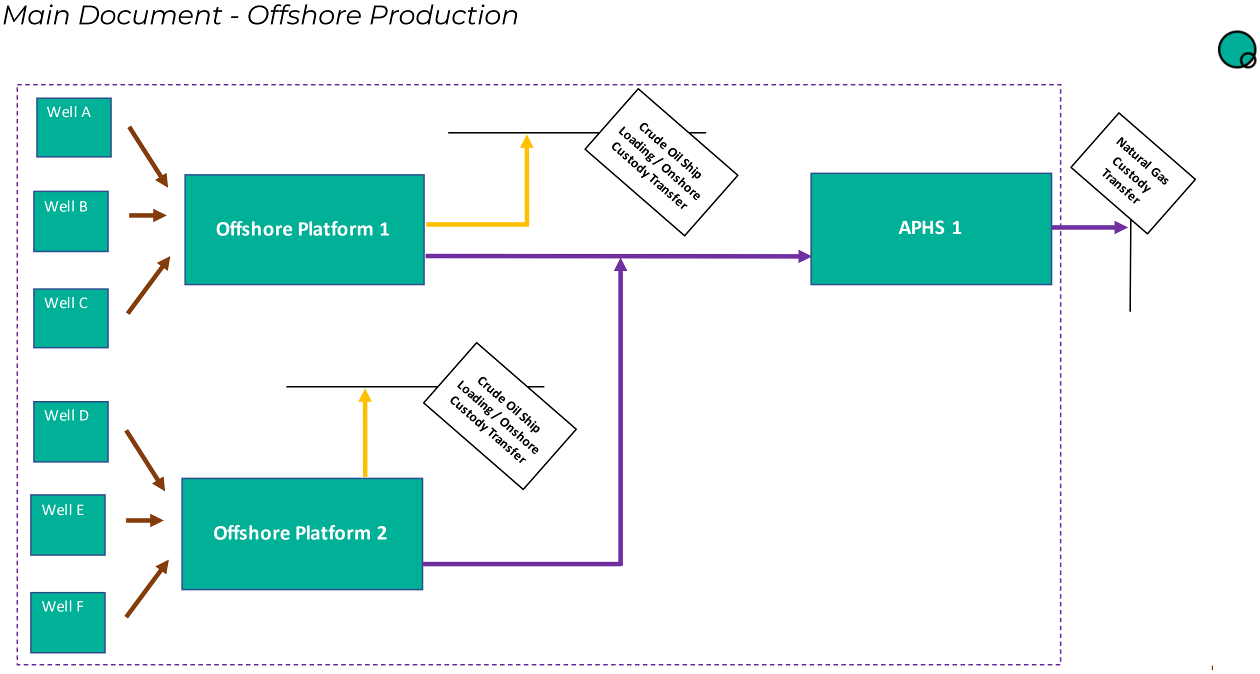

Figure 4: Facility boundary of Offshore Platform 1 and 2 ending at the custody transfer metering point downstream of APHS 1, which is owned and operated by the operator of Offshore Platforms 1 & 2 and does not handle any significant (>50% of Facility Throughput) third-party flows.

Flowchart Key

Brown arrow	Produced oil and natural gas (pre-separation)
Yellow arrow	Produced oil and associated liquids (post-separation)
Purple arrow	Produced natural gas (post-separation)
Purple dashed box	Facility Boundary applicable for Methane Intensity, Company Practices, and Monitoring Technology Deployment
APHS	Auxiliary product handling site

- **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.

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

	Score Requirements		
Grade	**Methane Intensity (g CH_4/BOE total throughput)**	**Company Practices** (Improved Practices points)	**Monitoring Technology Deployment**
A	≤ 50.0	≥ 14	12
B	≤ 100.	≥ 10	8
C	≤ 200.	≥ 5	4
D	≤ 500.	Mandatory minimum	Mandatory minimum
E	≤ 1000.	Mandatory minimum	Mandatory minimum
F	≤ 2000.	Mandatory minimum	Mandatory minimum

7 Subsidiary Documents

The Standard is structured with subsidiary documents as shown in Figure 5.

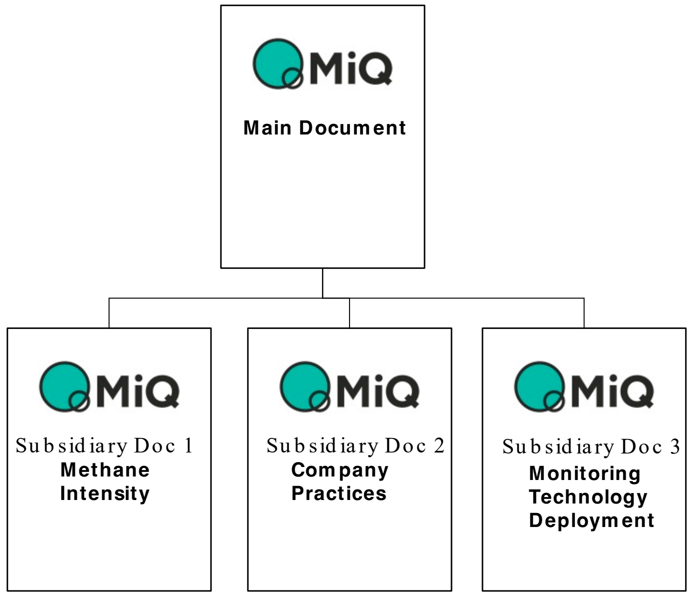

Figure 5: Document hierarchy

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

B1. 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.

B2. Version History

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

Table 4: Version History

Version	Revision Date	Document	Summary of Change
v_draft	2024-02	All	Stakeholder Review
v1.0	2024-04	All	Final Standard version

References

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

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

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

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

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

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

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

MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

SUBSIDIARY DOCUMENT 1: Methane Intensity – Offshore Production

v1.0

Contents

1 Introduction

The MiQ Standard for Methane Emissions Performance from Petroleum Operations (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 methane emissions from oil and natural gas production according to its methane emissions performance.

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

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

This subsidiary document outlines the calculation of Methane Intensity as it pertains to the Standard. Methane Intensity, as defined in Section 3 of the *Main Document,* is is a baseline indicator of methane emissions performance. See Section 3 of this document 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 oil and natural gas supply chain by its methane emissions intensity and performance. The MiQ Standard requires all sources to be accounted for as part of the emissions calculation methodology. Specific sources and their minimum requirements for determination are outlined within. This Standard and all methodology in this document are globally applicable.

This document, where helpful, makes specific reference to national or generic inventory methods to guide users, yet allows for national differences in methodologies (where existing and detailed by legislation).

This subsidiary document specifies a method to calculate the Methane Intensity of oil and natural gas production from offshore 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 calculations, measurements, as well as detected leaks or abnormal process conditions from Facility Scale and Source Level methane monitoring surveys.

3.1 Calculation

Under this Standard, a Facility's Methane Intensity is to be calculated following the offshore methodology detailed in Annex A. It enables Producers to calculate an annual Facility-level Methane Intensity from identified emission sources reconciled with emissions from surveys conducted in accordance with *Subsidiary Document: Monitoring Technology Deployment*.

Methane Intensity is calculated every 12 months, in g CH_4/BOE (barrel of oil equivalent) of total energy throughput. For example, a Producer can calculate the Methane Intensity of its Facility operations using the following equation:

$$Methane\ Intensity = \frac{Methane\ Emissions\ (mass\ units)}{Total\ Energy\ Throughput\ (energy\ units)}$$

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

3.1.1 Auxiliary Product Handling

The Methane Intensity calculation can include emission sources from auxiliary sites that handle gas and/or hydrocarbon liquids from the production platform(s). Therefore, the physical Facility boundary for the Methane Intensity calculation includes the Production platform(s) seeking certification and its auxiliary handling capacity (which may exist on a separate platform or onshore), where applicable. To calculate Methane Intensity, the Producer is required to aggregate methane emissions from all relevant emission sources from the production platform(s) and the Auxiliary Product Handling Site(s) under the Producer's operational control.

Auxiliary product handling emissions refer to the emissions that are associated with oil and gas handling at a Facility at an auxiliary site (including facilities that are potentially onshore but still part of the producer's Facility). Where an auxiliary site handles oil and gas produced from third-party facilities, Methane Intensity does not include third-party throughput without any associated upstream emissions included within the Facility's Methane Intensity calculation.

3.2 Emission Sources

A Facility's calculated Methane Intensity must include methane emissions from all of the emission sources (outlined in Annex A) that are present in a Facility. Most emission sources should be captured in the sources outlined in Annex A, but it is the Producer's responsibility to document other emission sources that may not be listed. The methods in this Standard to calculate methane emissions utilize a combination of emission factors, engineering calculations, and direct measurements. While this Standard does not prescribe a specific calculation methodology for each source, it does require a minimum level of facility-specific data based on the emission source as specified in Annex A.

Producers are encouraged to utilize quantification methods specific to their Facility. In each case, 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 facility-specific emission factors: details describing the measurement equipment, site selection, sampling criteria, and measurement period.

- For use of any measurement solution: technical specifications and results of controlled release testing, including calculated uncertainty, bias or confidence bounds.

3.3 Emissions Reconciliation

A Producer's accounting methodology must also include reconciliation of detected emission events, including all sources identified during leak detection surveys deployed 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. For simplification purposes, all methods used to detect emissions to be reconciled are referred to as "applicable methods."

Operators must utilize a structured set of written principles, or a written protocol, to reconcile emissions that are detected through applicable methods with the emissions inventory that is submitted following the minimum requirements set forth in Annex A.1.2. The process of reconciliation must then be rolled up to calculate an annual methane emissions inventory to be used in the operator's Methane Intensity, as set forth in Annex A.2. Operators may develop a protocol that establishes principles for the evaluation of commonly detected and attributed emission event types and emission sources, or that evaluates each emission event separately. The operator's protocol must be able to be applied to potential unintentional emission events or uncharacterized intentional emissions that could reasonably occur at the Facility.

An operator's reconciliation protocol must include sufficient detail explaining:

1. How emissions detected through applicable methods are classified, including, but not limited to, attribution to site, equipment group, and emission source
2. How the additionality of detected emissions to a Facility's emissions inventory subject to Annex A.1.2 are analyzed, unless all detected emissions are representatively added into the inventory indiscriminately.
3. How the data gathered through all applicable methods are used to quantify emissions and affect the Facility's emission inventory submitted via Annex A.1.2. This must include explanation of the data used by operators to quantify emission rates and estimate time durations of events, or annualize emissions through other methods.

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 emission events identified during emission surveys 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 1 annual Source Level LDAR survey. For grade C or higher, this includes at minimum 1 Facility Scale monitoring surveys[1] or 3 months of continuous monitoring results from a sample of a Producer's Facility that can be shown to be representative of its entire methane emissions footprint.

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) outlined in Table 1. The recordkeeping aspects must be presented for both the production platform(s) (Facility) and processing/treatment sites where relevant.

Table 1: Recordkeeping Requirements

Aspect	Detail

[1] 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.

Facility Description	Producers must document all Production Equipment, Production Platform(s), and Auxiliary Product Handling Sites 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.
Methane Intensity Calculation Inputs	Producers must document the oil and natural gas throughput used in calculating Methane Intensity including the source of data for throughput. If necessary for purposes of calculating product-specific methane intensities, the factor used for energy content of natural gas (and the basis for this value) and the factor used for energy content of liquids (and the basis for this value) must be disclosed.
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.
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 of leaking components using LDAR (see *Subsidiary Document 3: Monitoring Technology Deployment, Section 5.1* for more detail).
Calculation Methods	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 reconciling emission events identified during detection surveys completed in accordance with *Subsidiary Document 3: Monitoring Technology Deployment*, or other relevant LDAR or measurement campaigns, within their inventory, including details of their Facility Scale and Source Level inspections, emissions classification, and quantification methods (see Section 4.2).
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.

Annex A: Methane Intensity calculation methodology

This annex outlines the Standard's recommended method to calculate Methane Intensity for offshore oil and natural gas production Facilities. This methodology leverages recommended calculation methods and hierarchies from other national and voluntary protocols. This Standard attempts to capture most emissions in an accurate, credible, and replicable way that is consistent with existing frameworks for reporting and disclosure.

In addition to disclosing the Facility-specific Methane Intensity, it is recommended that the additional data elements, broken down by source and outlined in Table 2, be collated by the Facility to assist in evaluating the intensity calculation.

Table 2: Facility disclosure elements

	Production Platform(s) (Facility)	**Auxiliary Product Handling Site(s)**
Total methane emissions (aggregated by source)	√	√
Natural gas Throughput	√	√
Hydrocarbon liquids Throughput	√	√
Methane emissions intensity	√	

A.1 Emissions Calculation methods and Emission Sources

A.1.1. Emissions calculation methods

Table 3 outlines the types of calculation methods that can be used to quantify methane emissions. In general, data quality and specificity to the Facility increases in ascending order in Table 2. There are many exceptions to this rule, however, and in cases of exception, such as the usage of engineering calculations over direct measurement, the Operator should record justification for the unique approach. Table 4 outlines specific sources to be quantified and the minimum methodology requirements for each source. Producers shall, in their emissions reporting, indicate the method(s) used to quantify each emission source.

Measurement-informed inventories are highly encouraged throughout the Standard. Producers seeking to submit a measurement-informed inventory may do so in compliance with published measurement and reconciliation protocols such as GTI Energy's Veritas Protocol [1] or OGMP 2.0 Level 4/5[2], and confirmed by the Auditor.

Table 3: Types of Calculation methods

Calculation method type	Clarification
Direct Measurement	Direct measurement can occur by any means which allows for a methane emissions rate to be determined at the particular source. Typically, through a measured methane concentration and flowrate. The method of conversion and other data points used must be disclosed. The frequency of direct measurement must be disclosed.
Indirect Measurement	Quantifies methane emissions indirectly (by proxy). Typically, this involves measuring methane volume to a specific piece of equipment through a flow instrument installed in the (fuel) supply header and multiplying this volume with an Emission Factor to quantify emissions from that piece of equipment. Additional forms of proxy measurements involve advanced spectral or concentration sensors which derive an emissions flux by applying an algorithm to a group of individual measurements in space. The frequency, spatial coverage, and uncertainty as determined by controlled releasee testing of indirect measurement must be disclosed.
Engineering Calculation	

	Utilizing simulation software such as HYSYS, Unisim, or an Excel model or mass balance, to estimate emissions with direct and indirect measurements and asset data as inputs.
Measurement-based Emission Factors	Emission Factors derived from studies undertaken at a Facility or an area representative of the facility. Different measurement-based emission factors for the same emission source should be developed for each operating condition or type of equipment that may yield a different emission factor (i.e. HDPE vs. cast iron piping, or outlet compressor pressure buckets for compressor venting)
Equipment-specific Emission Factors	Emission Factors derived from vendor information or determined for individual types of emission sources based on peer-reviewed studies.
Generic Emission Factors	Generic Emission Factors are often provided or referred to in national legislative reporting requirements. A factor or ratio for converting an activity measure (e.g. number of times a controller actuates) into an estimate of the quantity of methane emissions associated with that activity, usually expressed in emissions per activity unit and derived from representative measurement campaigns.

A.1.2 Emission Sources from Offshore Oil and Natural Gas Production Facilities

Methane emissions from offshore production are to be accounted for from all potential emission sources. Producers are required to aggregate methane emissions estimates from all relevant emission sources in the production and auxiliary product handling segments to calculate Methane Intensity.

Under this Standard, Offshore Oil and Natural Gas Production is defined as:

> The oil and gas supply chain segment that includes all equipment, piping, instrumentation and controls (including compressors, generators, or storage facilities), and portable non-self-propelled equipment (including well drilling and completion equipment, workover equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted

equipment) used in the production, extraction, recovery, or lifting of petroleum and/or natural gas (including condensate) at an offshore Platform. This equipment also includes associated storage vessels and measurement and all enhanced oil recovery (EOR) operations using CO2.

Under this Standard, an Auxiliary Product Handling Site is defined as:

A site, either onshore or offshore, with the purpose of, including but not limited to, treating and/or processing oil and gas or transferring gas to a downstream operator, and is under responsibility of the same common owner or operator. This includes but is not limited to acid gas removal, compression, separation, stabilization, dehydration, water treatment, metering and regulation, and power generation equipment. To be included in the Facility under this Standard, the bulk of gas throughput should originate from the production platforms in the Facility.

Emission sources and recommended calculation methods for each are outlined in Table 4. An Operator should include all emission sources within its Facility, including those that are not specifically stated in Table 4. An Operator can use alternative calculation methods to the methods specified in Table 4 as long as the inputs are determined at a level that is equally or more representative of the actual emission sources at the Facility.

Table 4: Minimum Calculation Requirements by Offshore Production Emission Sources

Emission Source[2]	Minimum Emission Calculation Requirements[3]	Examples of Accepted Methodologies[4]

[2] A Producer's bottom-up emissions inventory does not have to be formatted as per Table 4. However, all emission sources present at the Facility must be accounted for and included in the Facility's inventory that is submitted for the Annual Audit.

[3] These requirements are for a Producer's bottom-up emissions inventory. The reconciliation requirements listed in Section 3.3 are applicable along with compliance with the requirements in Table 3.

[4] These reference methods are a non-exhaustive list of acceptable methods for a Producer to calculate each emission source in their bottom-up inventory. The calculation methods referenced are regionally

Acid Gas Removal Units	Emission-factor based calculation using an emission factor representative of AGRU venting, along with the number of AGRUs.	GOADS 4.2.1 / AQS Manual A.1 [3][4][5] ; API Compendium 6.3.8.4 [5]; OGMP TGD Purging and Venting (L3) [2]
Cold Vents	Engineering Calculation using volume of gas vented, including periods of upset venting. *Venting from blowdowns, upsets, compressor starts, and unlit flares must be included.*	GOADS 4.2.16 / AQS Manual A.37 [3][4][5] ; NEA Guideline 044, Appendix B 3.2 [7]; OGMP TGD Purging and venting (L4) [2]; NGER 3.3.2.3, 3.3.3.4, 3.3.9A.2 (Method 1 and 4) [8]
Combustion Units (Gas compressor drivers)	Emission-factor based calculation using an emission factor of incomplete combustion representative of the combustion unit type, along with fuel consumption volumes and fuel composition data.	GOADS 4.2.11 thru 4.2.12 / AQS Manual A.23 thru A.28 [3][4][5]; Guideline-044 7.3.6 [7]; API Compendium 4.5.2 [5]; OGMP TGD Incomplete combustion (L3-L4) [2]; NGER 2.3.5 (Method 2) [8]
Combustion Units (Non-compressor drivers)	Emission-factor based calculation using an emission factor of incomplete combustion representative of the combustion unit type, along with fuel consumption volumes and fuel composition data. *Combustion emissions from well drilling, testing, completions, and workovers must be included.*	GOADS 4.2.2 thru 4.2.4, 4.2.11 thru 4.2.12 / AQS Manual A.2 thru A.10, A.23 thru A.29 [3][4][5]; NEA Guideline-044 7.3.6 [7]; API Compendium 4.5.2 [5]; OGMP TGD Incomplete combustion (L3-L4) [2]; NGER 2.3.5 and 2.4.5 (Method 2) [8]

specific in some cases but reinforce that Producers have multiple options to calculate their bottom-up inventory.

[5] Offshore Producers in the Outer Continental Shelf (OCS) report emissions through the Bureau of Ocean Energy Management's (BOEM) Air Quality System (AQS), whose calculation methodology is referenced by larger reporting frameworks like the GHGRP, GHGI, and WCI.

Compressor Venting (Centrifugal – dry seals)	Emission-factor based calculation using an emission factor that best represents seal venting emissions based on seal type and compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of seals).	API Compendium 6.5.4.2 [5]; OGMP TGD Centrifugal compressors (L3-L4) [2]; 40 CFR 98.233(o) [9]; WCI.363(l) [10]
Compressor Venting (Centrifugal – wet seals)	Emission-factor based calculation using an emission factor that best represents seal venting emissions based on seal type and compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of seals).	API Compendium 6.5.4.2 [5]; OGMP TGD Centrifugal compressors (L3-L4) [2]; 40 CFR 98.233(o) [7]; WCI.363(l) [12]
Compressor Venting (Reciprocating compressors)	Emission factor-based calculation using an emission factor that best represents rod packing venting emissions based on compressor operating conditions along with actual, relevant activity data (i.e. number of compressors or number of cylinders).	API Compendium 6.4.3.1 [5]; OGMP TGD Reciprocating compressors (L4) [2]; NGER 3.3.6B.1 (Method 2) [8]; 40 CFR 98.233(p) [9]; WCI.363(m) [10];
Dehydrator Vents	Engineering Calculations or computer modeling dependent on the type of dehydrator.	GOADS 4.2.7 / AQS Manual A.19 [3][4][5]; NEA Guideline-044, Appendix B 3.3 - 3.4 [6]; API Compendium 6.3.8.1 thru 6.3.8.3 [5]; OGMP TGD Glycol dehydrators (L3-L4) [2]; 40 CFR 98.233(e) [9]
Equipment Leaks (All fugitive components)	Population emission factor-based method using emission factors that best represent conditions and practices of the Facility. *Note that equipment leaks identified by non-regulatory LDAR surveys including those undertaken to meet Monitoring Technology Deployment requirements MUST also be included.*	GOADS 4.2.6 / AQS Manual A.13 thru A.18 [3][4][5]; API Compendium 7.2.1.2 thru 7.2.1.4 [5]; NEA Guideline-044, Appendix B 3.11.2 [6]; OGMP TGD Leaks (L3-L4) [2]; NGER 3.3.6B (Method 3) [8]

Flare Stacks	Engineering Calculation using flare gas flow rate, flare gas composition, and a representative destruction efficiency. *Flaring from well drilling, testing, completions, and workovers are included here.*	GOADS 4.2.5 / AQS Manual A.11 thru A.12 [3][4][5]; NEA Guideline-044 7.1.4 [7]; API Compendium 5.1 [5]; OGMP TGD Flare efficiency (L3-L4) [2]; NGER 3.3.9A.10 (Method 2A) [8]
Flashing Losses	Engineering Calculation using throughput volume, GOR of each vessel, and gas density.	GOADS 4.2.9 / AQS Manual A.21 [3][4][5]; API Compendium 6.3.9.1 [5]
Gas-driven pneumatic controllers	Emission factor-based method using an actual inventory of each type of pneumatic device and an emission factor representative of the vent rate and actuation frequency of the device.	GOADS 4.2.14 / AQS Manual A.31 [3][4][5]; API Compendium 6.3.6 [5]; OGMP TGD Pneumatics (L3-L4) [2]; NGER 3.3.9A.4 (Method 1) [8]
Gas-driven pneumatic pumps	Emission factor-based method using an actual inventory of each type of pneumatic pump and default or manufacturer-specific emission factors.	GOADS 4.2.13 / AQS Manual A.30 [3][4][5]; API Compendium 6.3.7 [5]; OGMP TGD Pneumatics (L3-L4) [2]; NGER 3.3.9A.5 (Method 1) [8]
Loading Operations	Engineering Calculation using total barrels transferred, operating hours, Reid vapor pressure and bulk temperature of the liquid, average ambient temperature, and tank characteristics (paint color and condition). Emission controls used must also be taken into account.	GOADS 4.2.8 / AQS Manual A.20 [3][4][5]; NEA Guideline-044 7.3.9 [6]; API Compendium 6.10.1 [5]; NGER 3.3.4 (Method 2) [8]

Storage Vessels (Hydrocarbon, Floating and Fixed-roof)	Engineering Calculations or process modeling tools such as AspenTech HYSYS or TankESP accounting for parameters including upstream separator temperature/pressure and composition, API gravity and production rate of stabilized oil, and ambient conditions.	GOADS 4.2.15 / AQS Manual A.32 thru A.35 [3][4][5]; NEA Guideline-044, Appendix B 3.15 [6]; OGMP TGD Unstabilized liquid storage tanks (L4) [2]; NGER 3.3.9A.3 (Method 1) [8]; API Compendium 6.3.9.1 thru 6.3.9.3 [10];
Well Drilling (Mud Degassing)	Emission factor-based calculation using the number of drilling days and an emission factor representative of the mud type.	GOADS 4.2.10 / AQS Manual A.22 [3][4][5]; NEA Guideline-044, Appendix B 3.14 [6]; API Compendium 6.2.1 [5]; OGMP TGD Purging and venting (L3) [2]
Other emission sources	Producers must disclose other emission sources at their Facility, document total emissions and demonstrate representative emission calculation methodologies for each source. Other sources for offshore production may include produced water tanks, produced water handling, non-platform support vessels, transport of equipment and personnel to and from the platform, gas analyzers and testing stations, purge and blanket gas, and non-platform support vessels.	GOADS 5.2 / AQS Manual 4 [3][4][5]; NEA Guideline-044, Appendix B 3.18 [6]; API Compendium 2.2.2.3 [5]

A.2 Methane Intensity Calculations

The methodology for calculating Methane Intensity associated with Offshore Production Facilities is as follows:

Calculate the total methane emissions (metric tons) as the sum of methane emissions from all sources and reconciled according to Section 3.3. of this subsidiary document. Divide total methane emissions by the total energy throughput of the Facility in energy units.

$$Methane\ Emissions\ (ME) = total\ CH_4\ emissions\ of\ the\ Facility \tag{1}$$

Where, ME is in metric tons,

Methane Intensity is then calculated as follows,

$$Methane\ Intensity = \frac{ME}{E_{ng}+E_{liq}} * 10^6 \tag{2}$$

Where:

- *E_{ng}* is the total annual energy of natural gas throughput (as barrels of oil equivalent [BOE[6]])
- *E_{liq}* is the total annual energy of hydrocarbon liquids throughput (as BOE)
- *Methane Intensity* is in units of grams CH_4 emissions per BOE of total energy throughput

In certain cases, including when an operator reports a measurement-informed inventory using an external, published measurement and reconciliation protocol, the operator may need to calculate a product-specific Methane Intensity. In this case, the operator must calculate Methane Intensity as follows:

$$Methane\ Intensity_{ng} = \frac{ME * GR}{E_{ng}} * 10^6 \tag{3}$$

$$Methane\ Intensity_{liq} = \frac{ME * (1 - GR)}{V_{liq}} * 10^6 \tag{4}$$

Where:

- *E_{ng}* is the total annual energy of natural gas throughput (in MMBtu)
- *V_{liq} is the total annual volume of hydrocarbon liquids throughput (in barrels of oil)*
- *Methane Intensity$_{ng}$ is in units of grams CH_4 emissions per natural gas throughput (in MMBtu)*
- *Methane Intensity$_{oil}$ is in units of grams CH_4 emissions per hydrocarbon liquids throughput (in barrels of oil), and*
- $$GR = Gas\ Ratio = \frac{E_{ng}}{E_{ng}+E_{liq}} \tag{5}$$

[6] Operators must calculate BOE of natural gas by dividing natural gas volumetric throughput by the conversion rate of 5.8 Mscf/BOE (see Table 5)

Default values are listed in the tables below. For Imperial units see Table 5 and for SI units see Table 6. Reference values are taken from the API Compendium [5].

Table 5: Imperial default values for calculating Methane Intensity

Default value			
Abbreviation	**Description**	**Units Imperial**	**Default Value**
-	Conversion rate for natural gas volume to kBOE	Mscf/BOE	5.8
EC_{liq}[7]	Higher Heating Value for hydrocarbon liquids	MMBtu/US barrel	5.8

Table 6: SI default values: Standard conditions, for calculating Methane Intensity

Standard at 15°C	Default value		
Abbreviation	**Description**	**Units SI Standard**	**Default Value**
-	Conversion rate for of natural gas volume to kBOE	Sm^3/BOE	0.20
EC_{liq}	Higher Heating Value hydrocarbon liquids	MJ/Sm^3	38500

[7] Operator may choose to use a Facility-specific value along with documentation on how that Facility-specific value was determined

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[10] Western Climate Initiative (2011) Final Essential Requirements of Mandatory Reporting. 2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions. Retrieved from https://www2.gov.bc.ca/assets/gov/environment/climate-change/ind/quantification/wci-2012.pdf

MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

SUBSIDIARY DOCUMENT 2: Company Practices – Offshore Production

v1.0

MiQ

Contents

1 Introduction

The MiQ Standard for Methane Emissions Performance from Petroleum Operations (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 methane emissions from oil and 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 two main types of documents, to be read in the following order:

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

Effective management of methane emissions from oil and gas production begins with a Facility design that will achieve minimal Intended methane emissions and eliminates, to the greatest degree possible, the potential for Unintended Emissions. However, review of the Methane Intensity calculation alone is not a sufficient indicator of a Facility's effectiveness in methane emissions management. Beyond calculated Methane Intensity, 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 repair, reporting protocols, and data evaluation,

Producers can ensure methane emissions are managed appropriately throughout during operations.
A Producer should be able to not only produce documentation of their Company Practices and procedures, but also demonstrate that its employees 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:

1. **General Company Practices**
   Outline the required general policies and procedures to demonstrate methane emissions management practices at a Facility, in accordance with a best practice approach.
2. **Company Practices for Managing and Reducing Unintended Methane Emissions**
   Outline the policies and procedures required to effectively identify and fix Unintended methane emissions at a Facility.

3. **Company Practices for Managing and Reducing Methane Emissions from Individual Equipment Classes**

   Outline the policies and procedures required to minimize methane emissions at a Facility from specific equipment.

This subsidiary document covers Company Practices for offshore 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 and 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 overall Certificate 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.

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. The improved performance criteria are assessed via a points-based scoring system. Points for improved practices are indicated in Tables 2-8 below. If a Facility demonstrates **at least one** of the multiple elements listed for an improved practice topic separated by the word **"or",** as outlined in Tables 2-8, it should receive all points nominated for that practice.   If two or more elements are related by the word **"and"**, each improved practice must be demonstrated to receive all points. For performance criteria relevant to emission sources not found within a given Facility the Producer automatically receives the improved points.

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

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 and components 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	Mandatory	-

[1] Company Practices are numbered by type or emission source. Types and emission sources include General Practices (GP), Unintended Methane Emissions Practices (UMEP), Compressor Emission Practices (COMP), Pneumatic Device Emission Practices (PD), Storage Tank Emission Practices (ST), Flare Emission Practices (FLR), and Venting Emission Practices (VENT).

methods and calculation of methane emissions, in line with regulatory GHG reporting where present, includes: • Quantification method for each emission source; **and** • Equipment to be used for measurement and the specific applications for that equipment; **and** • Reconciliation process for including all unintended emissions sources		
(GP-4) Continual improvement Methane management is integrated into the Producer's company culture, as evidenced by: • Documentation or communication plans that references Methane Emission reduction best practices; **and** • demonstrated knowledge of methane emission minimization strategies by 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 fugitive emissions 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	Points
(UMEP-1) Employee training and awareness Operational and maintenance team training includes: • Audial, Visual, and Olfactory (AVO) specific trainings for	Mandatory	-

field personnel that detail how and why to make routine checks for methane emissions during platform 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.
- 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**
- Alternative technology programs have consistent equipment operating and reporting procedures for consistent deployment.

(UMEP-2) Monitoring Technology Deployment for LDAR Mandatory -

LDAR plan outlines at a minimum:

- specific equipment / components included in LDAR survey; **and**
- equipment/components that are unsafe to monitor along with justifications; **and**
- leak definition; **and**
- monitoring methodology (reference to equipment and components, frequency, conditions, reporting log); **and**
- repair or replacement strategy, including when to take immediate corrective action and when delay of repair is permitted; **and**
- first attempt requirements within 30 days of detection; **and**
- final repair attempts (maximum 30 day allowance from time of detection); **and**
- repair verification completed within 30 days of detection if there are no safety concerns; **and**

• steps to be taken for delay of repair, including tagging and reporting; **and** • recordkeeping and tracking for delay of repair to ensure appropriate follow-up action is taken; **and** • clear roles and responsibilities for repair or replacement.		
(UMEP-3) Directed inspection and maintenance To manage methane emissions, Producers elect to: • target equipment and components (i.e. thief hatches, natural gas vents, or vapor recovery equipment) for observation; **and** • use cumulative data to develop preventative maintenance plans; **and** • determine equipment and components to target based on accumulated historical data from LDAR inspection records or other relevant datasets.[2]	Improved	1 point
(UMEP-4) 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 the corrective actions taken to limit and prevent reoccurrence	Improved	1 point
(UMEP-5) Managing Methane Emissions from pipelines and subsea completions Company practices are in place to ensure the pipelines and subsea completions are as inherently safe as possible by applying Best Available Techniques (BAT) for the design or modification of these items. This is to ensure fugitive emissions from pipelines and subsea completions are as low as reasonably practicable. This may include: • minimal appendages are used; **and/or** • flanges are applied with ring type joints, which are less sensitive for leakages.	Improved	1 point

3.3 Company Practices for Managing and Reducing Compressor Emissions

By implementing Company Practices to reduce methane emissions from compressors, Operators can ensure the amount of gas released is minimized.

Table 3: Company Practices for managing and reducing Methane Emissions from Compression Equipment (COMP)

Practice	Character	Points
(COMP-1) Managing Methane Emissions from Compressors • Compressors are included in LDAR surveys; **and** • Operators implement preventative maintenance strategies for all compressors and their critical components based on run time. This includes compressor overhauls and inspection and maintenance of critical components (ex. compressor rings, packing, seals, bearings etc.); **and** • · Whenever maintenance occurs (or more frequently), operator/contractor inspects for and repairs causes of excessive leakage; **and**	Mandatory	-
(COMP-2) Improved Practices for Compressors	-	-
In addition to the above:		
(COMP-2.1) • Company evaluates projects to reduce emissions from wet seal oil degassing systems by routing gas to a control device, routing to beneficial use, using a dry seal or another solution and demonstrates progress against project plans	Improved	1 point
(COMP-2.2) • Operators replace natural-gas driven compressor starts with non-venting compressor starts for at least 50% of compressor inventory or wherever compressed air or electric starts are feasible, whichever is larger	Improved	1 point
(COMP-2.3) • Facility has policies and procedures to keep compressors pressurized before and during downtime and/or routes compressor blowdown vent line to fuel when technically feasible; **or** • Facility uses another solution to minimize emissions before and during compressor downtime.	Improved	1 point

3.4 Company Practices for Managing and Reducing Pneumatic Device Emissions

By implementing Company Practices to reduce methane emissions from pneumatic devices, Operators can ensure the amount of gas released is minimized.

Table 4: Company Practices for managing and reducing Methane Emissions from Pneumatic Devices (PD)

Practice	Character	Points
(PD-1) Managing Methane Emissions from Pneumatic Devices • Procedures to maintain accurate inventory of pumps and controller counts by model that are 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, based on published vent rates for the model; **and** • Gas-driven pneumatic devices are included in LDAR surveys.	Mandatory	-
(PD-2) In addition to the above, Operators:	-	-
(PD-2.1) • Have installed non-venting (e.g. no bleed, mechanical, electric, or instrument air) pneumatics in place of gas-driven pneumatics for at least 50% of pneumatic devices.	Improved	1 point
(PD-2.2) • Has a program in place to replace remaining venting devices with non-venting devices within 3 years of applying for Certification, where technically feasible, and have demonstrated progress against this program; **and** • Has a policy in place to install non-venting pneumatics on all new equipment installations.	Improved	2 points

3.5 Company Practices for Managing and Reducing Storage Tank Emissions

By implementing Company Practices to reduce methane emissions from storage tanks, Operators can ensure the amount of gas released is minimized.

Table 5: Company Practices for managing and reducing Methane Emissions from Storage Tanks (ST)

Practice	Character	Points
(ST-1) Managing Methane Emissions from Storage Tanks • Producers inspect and monitor key areas that may be a source of methane emissions from tanks including vapor recovery systems, thief hatches, pressure relief vents, and other issue areas; **and** • Policies and procedures for managing tanks include not only observation for methane emissions but also preventative maintenance based on historical problems (ID'd and recorded on specific pieces of equipment).	Mandatory	-
(ST-2) In addition to the above, the Producer:	-	-
(ST-2.1) • installs tank pressure monitoring systems and alarms; **and/or** • remotely observes tank batteries using integrated operation centers; **and/or** • utilizes automated tank gauging and reporting; **and/or** • installs thief hatch monitoring and automated reporting systems; **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 points

3.6 Company Practices for Managing and Reducing Flaring Emissions

By implementing Company Practices to reduce methane emissions from flares, Operators can ensure the amount of uncombusted gas is minimized.

Table 6: Company Practices for managing and reducing Methane Emissions from Flares (FLR)

Practice	Character	Points
(FLR-1) Managing Methane Emissions from Flares	Mandatory	-

Producers must implement: • policies to define the use of flaring (routine and non-routine event categories, acceptable durations); **and** • procedures which define stable operating range and criteria for all flare systems, considering emergency events, for good destruction efficiency[3];[2] **and** • policies and procedures to ensure flares are managed and maintained to ensure flare functionality, flares are targeted during LDAR surveys, and good destruction efficiency is achieved through utilizing staff/consultants for inspections (AVO and engineering & maintenance inspections).		
(FLR-2) In addition to the above:	-	-
(FLR-2.1) 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; • auto ignition system for unsupervised flare stacks with intermittent flaring; • flare capacity and production level is maintained to ensure flare's combustion efficiency matches range of production and does not overload; • thermocouples (temperature sensors) in combination with an automated ignition action to ensure pilots stay lit or flame out detection device installed.	Improved	1 point

3.7 Company Practices for Managing and Reducing Venting 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

[2] For reference, flare performance studies by the US EPA determined a 98% conversion of organic compounds to carbon dioxide, or greater, as good combustion efficiency. This good combustion efficiency is achieved through flare design, flame stability, and operating envelope parameters (heat content, velocity, gas composition etc).

implementing Company Practices to reduce Intended methane emissions, Producers can ensure the amount of gas released is minimized.

Table 7: Company Practices for managing and reducing Venting Emissions (VENT)

Practice	Character	Points
(VENT-1) Equipment pumpdown prior to maintenance Producers implement: • operational repairs coordinated with routine maintenance repair schedules to minimize the number of blowdowns required; **and** • operator documents rate and duration of each venting event and documents reasoning for the event.	Mandatory	-
(VENT-2) In addition to the above, Producers implement:	-	-
(VENT-2.1) • Policies to minimize routine venting and flaring (applicable to both gas and oil wells), except in the event of an emergency; **and** • Policies to check that infrastructure takeaway is in place before wells come online; **and** • utilize a vent gas capture system to reduce the volume of gas vented and/or flared.	Improved	2 points
(VENT-2.2) • Policies and procedures for removal of natural gas from equipment or systems scheduled for repair to the greatest extent possible prior to blowdown, while maintaining safe operations; **and** • natural gas vented during blowdowns is routed to a flare or recovered to minimize methane emissions.	Improved	2 points
(VENT-3) 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. Where implementing a REC is infeasible	Improved	1 point

due to reservoir characteristic, gas is recovered and routed to a combustion device.

3.8 Required Evidence Available to Auditors

The Producer's Company Practices will be reviewed by the Auditor in advance of an onsite Audit. For unmanned platforms, the audit shall be held on the Host Platform or at the onshore office with the operation personnel. 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. Observations can be conducted in a separate visit or on technical documentation from the Facility. Required evidence of implementation of improved practices may include, but is not limited to, facility logs, equipment run time, P&IDs and maintenance inspection records. The Auditor may request additional documentation and metrics from the Facility for the purposes of the Annual Audit or subsequent Audits.

References

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

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

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

MiQ STANDARD

for Methane Emissions Performance for Petroleum Operations

SUBSIDIARY DOCUMENT 3: Monitoring Technology Deployment – Offshore Production

v1.0

MiQ

Contents

1 Introduction

The MiQ Standard for Methane Emissions Performance from Petroleum Operations (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 methane emissions from oil and 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 two main types of documents, to be read in the following order:

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

This subsidiary document outlines requirements for Monitoring Technology Deployment for detection of Unintended methane emissions sources.

Detecting and abating Unintended Sources of methane emissions is a key element of methane emissions management for a Facility. Detecting and tracking Emission Sources helps a Facility prioritize repair and maintenance activities, manage operational practices, and improve engineering design. Methane emissions can originate from many types of equipment and processes; therefore, effective and frequent detection is essential to quickly identify and remediate Unintended methane emissions. Methods for both detection and measurement of methane emissions include approaches that are widely available and commonly implemented (including specified by regulation), as well as new and emerging technology solutions.

Methane emissions monitoring technologies can be deployed along a spectrum of spatial and temporal scales. Top-down approaches aggregate methane emissions from multiple emission sources at larger spatial scales (e.g. using aerial surveys or satellites), whereas bottom-up approaches are intended to detect individual emission sources at smaller spatial scales (e.g. using handheld devices or perimeter sensors). Both top-down and bottom-up monitoring approaches can vary in temporal scale based on factors such as cost and time to complete, with improved emissions detection capability with more frequent deployment. Continuous monitoring methods provide greater temporal coverage, however can provide variable spatial coverage and completeness. Gimbled scanning systems or regional towers often provide more complete spatial coverage, particularly for elevated sources, compared to fixed point monitors (perimeter sensors). Figure 1 illustrates simplified examples of methane monitoring technologies in relation to spatial and temporal scale.

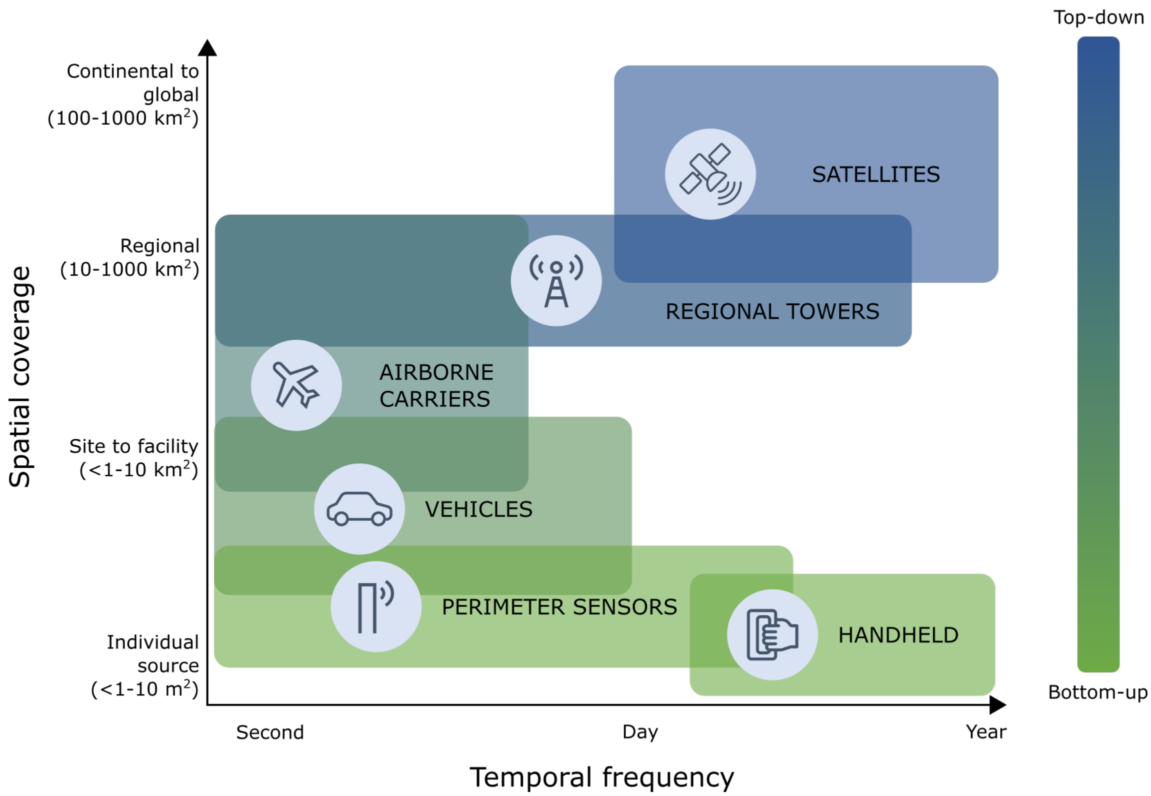

Figure 1: Methane monitoring technology across a variety of spatial and temporal scales (adapted from the National Academies of Science, Engineering, and Medicine, 2018 [1])

Efforts to reconcile top-down and bottom-up quantification approaches continue to develop through research and industry collaboration. The existing body of work reveals that top-down approaches often produce methane emissions estimates that are significantly higher than those from bottom-up approaches alone [2–7][1]. These

[1] Allen et al. [2], Brandt et al. [3-4] examine the notable discrepancies between top-down and bottom-up Methane emissions estimates. Gorchov et al. [4] and Ayasse et al. [5] analyze the results of individual top-

studies indicate that under-representation of abnormally high emission sources, commonly referred to as Super-Emitters, is one cause of this divergence [7][2]. Super-Emitters are spatially and temporally dynamic, and the characteristics that cause these emissions vary. Therefore, detection at both the Facility Level and Source Level, and at increased frequencies, is key to 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.

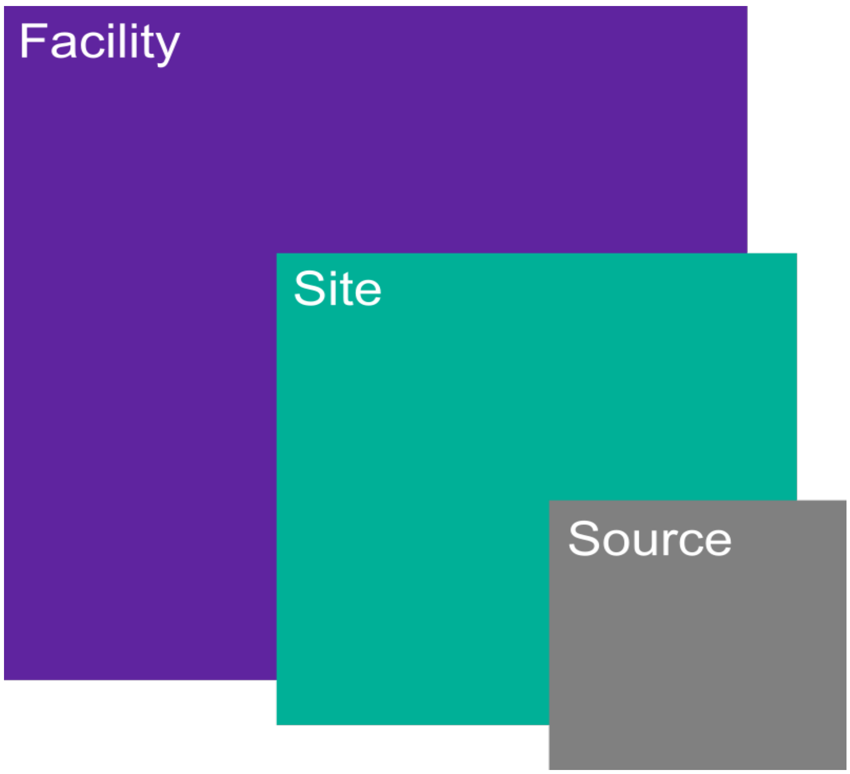

Figure 2: Spatial scales utilized within the Standard, referencing the definitions of Facility, Site, and Source as outlined in the *Main Document*, see there for reference.

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down campaigns on offshore platforms. Ayasse et al. [5] find that offshore platforms in the Gulf of Mexico exhibit "highly skewed super emitter behavior" mostly occurring from tanks, vent booms and stacks.

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

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 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 **detection** of methane emissions. This version does not require measurement directly through the technology deployment required by this standard. However, all detected emissions must be reconciled in a Producer's inventory *(see Subsidiary Document 1: Methane Intensity, Section 4)*. Details of a Producer's calculation 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 objective of Monitoring Technology Deployment is to:

- demonstrate active management of methane emissions through identification of Unintended Sources, including Super-Emitters, followed up with necessary corrective actions.

This objective harmonizes with other elements of this Standard:

- to provide assurance of the calculated Methane Intensity by reconciliation (see *Subsidiary Document 1: Methane Intensity*);
- to implement better operating practices and equipment design for reduced methane emissions; and
- to encourage Operators to work towards measurement or quantification of emission sources at their Facilities.

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 provide higher assurance in the identification, repair and abatement of emission sources. The duration in between surveys should not exceed 150% of time indicated by the stated cadence.[3]
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 minimum rate of methane emissions detectable by a specific technology solution. Technologies with lower MDL can identify more (including smaller) methane emission sources. The technology solution required to achieve the desired MDL and detection probability[4] must be applicable for the specific Facility and validated by the Auditor.

[3] For example, semi-annual surveys cannot be planned more than 9 months apart and have to take place within the same Certification Period.

[4] 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 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.

3.2 Performance Scoring

Table 2 outlines the performance criteria and associated score for Monitoring Technology Deployment under the Standard. Both Facility Scale Inspection for Site level Super-Emitters and Source Level Inspections are specified.

A Producer is required, at a minimum, to conduct a baseline Source Level inspection in order to be certified under this Standard. Producers can achieve a higher score by increasing the frequency and coverage of Source Level Inspections, as well as Facility Scale Inspections to identify Site level Super-Emitters.

The MiQ Standard employs the concept of Equivalency to fulfill the Monitoring Technology Deployment requirements. The Frequency, Sampling coverage, and MDLs outlined in Table 2 below should be considered a benchmark for achieving a given number of points. An Equivalent LDAR program capable of detecting, characterizing, and mitigating an equivalent amount of methane emissions may be proposed to the Auditor, as demonstrated through an Equivalency Determination (i.e. model and modelling assumptions, see Section 3.2.4).

The details for Facility Scale Inspection for Super-Emitters and Source Level Inspection for leaks is outlined in Sections 3.2.1 and 3.2.2, respectively. To receive the points associated with a Continuous Gas Detection System, the Producer must adhere with the requirements listed in Section 3.2.3.

Table 2: Technology Performance Criteria

Facility Scale Inspection[5]		**Source Level Inspection**		**Points Earned**
semi-annually (MDL 25kg/hr)	entire Facility	annually	entire Facility	12
annually (MDL 25kg/hr)	entire Facility	annually	entire Facility	8
Continuous Gas Detection System (see Section 3.2.3)[6]		annually	entire Facility	4

[5] The "entire Facility" means that a Facility Scale Inspection must be representative of all major Emission Sources at a Facility. The Producer must submit documentation if there are areas of the Facility or specific equipment or components that are unable or unsafe to be monitored either via Facility Scale or Source Level Inspection methods.

[6] The points earned from having a continuous gas detection program can be additive. For example, a producer that achieves 8 points through annual Facility Scale and Source Level Inspections can achieve 4 extra points with their Continuous Gas Detection System.

N/A	-	annually	entire Facility	0

3.2.1 Facility Scale Inspection

The intention of a Facility Scale Inspection is to provide assurance that potential abnormally high emissions are being monitored while more efficiently screening for unintended emissions sources that may be followed up for Source Level detection and repair prioritization. This Standard is technology neutral, however a Facility Scale Inspection:

- 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[7] at 90% POD proven through single blind, controlled release testing (see Table 3 for additional record keeping requirements)
- must attribute the source to a single site spatial boundary for follow up inspection
- may utilize multiple inspection methods in combination
- Continuous Monitoring Systems are an accepted form of Facility Scale Inspection provided they meet the performance criteria above (See Table 3 and Table 4 for additional LDAR program and recordkeeping requirements)
    - Producers may choose to demonstrate equivalent monitoring using Continuous Monitoring Systems over a subset of Sites (<100% coverage) paired with Source Level methods and/or other periodic Facility Scale survey methods, to achieve the same level of detection and mitigation potential as outlined in Table 2 (see Section 3.2.4 for more information on Equivalency Determination).

Emission events detected via Facility Scale Inspections must be documented, repaired and/or mitigated following the timelines and requirements listed in *Subsidiary Document 2: Company Practices*. Facility Scale Inspections may also identify emissions from planned events or from intended sources that are already

[7] 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 [7].

accounted for in a Facility's emission inventory. The detected source must still be investigated to determine if the source exceeds the expected rate and ascertain if the event requires follow-up or mitigation.

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 Inspection

The intention of the Source Level Inspection is to 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. The Source Level inspection methods employed by the Producer must be detailed in the Producer's LDAR program.

This Standard is technology neutral, however the following are applied to Source Level monitoring methods:

- Spatial resolution must be sufficiently low to reliably attribute emission sources to the component or equipment level for repair, maintenance, or mitigation
- be deployed at or above the specified frequency outlined in Table 2, unless using an Equivalent LDAR 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
- Continuous Monitoring Systems which meet the above criteria may be applied towards Source Level Inspection over the percentage of Sites where it is deployed. For such usage, detection capabilities based on placement, data analysis and relay, must be evaluated by the Auditor during the Annual Audit (refer to Section 4.2 for required evidence).

Follow-up of an emission detected using a Source Level inspection method *can count* towards a producers' compliance with the requirements in Table 2.

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 inspection frequency.

An LDAR Site inspection 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 Continuous Gas Detection Requirements

Offshore oil and gas platforms are at high risk for flammable material creating an explosive environment if exposed to an ignition source. As a result, personnel and process safety practices on offshore oil and gas platforms are often stringent and require the use of a monitoring program to detect large gas releases.

The requirements of the gas detectors used in such a program are unspecified in this Standard but must be deemed by the Auditor to meet or exceed the norms of technologies deployed to meet the purpose of gas detection. The program should include the installation of gas detectors in all areas in which the possibility of fire or explosion hazard may exist under normal or abnormal conditions due to the presence of flammable, combustible or ignitable gases that have the potential to include methane.

Definitions of hazardous-classified locations can be determined by other safety or environmental standards and used to determine the extent of coverage required for deployment of continuous gas monitors, but in general, any area that could have a hydrocarbon gas leak should be included in the list of locations.

3.2.4 Equivalency Determination

The frequency and spatial coverage of monitoring technology deployment in the Standard has been constructed to apply to generic Facilities in varying geographies. Demonstration of equivalent emissions detection and mitigation capabilities from a substitute or Equivalent LDAR program utilizing a combination of aerial, ground-based, Continuous Monitoring, or other methods for a given Facility may be provided using accepted equivalency models or simulations (such as FEAST, LDAR-SIM[8][9], 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 detection 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 LDAR 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 inspection

Recordkeeping element	Details
Detection Technology Specifications	• Sensor and instrumentation details • Method in which the sensor is used (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
	  ○ Third party used to conduct testing
	  ○ Confirmation of single-blind nature of testing
	  ○ Operating conditions of equipment used for testing
	  ○ Variables tested that could affect the sensitivity of the technology and the ranges tested (i.e. humidity, temperature, wind speed, groundcover, obstruction, solar irradiation)
	  ○ Calibration protocols used during testing
	  ○ If operator uses technology for quantification, characterization of emission rate uncertainty

Work Practice Specifications	• Frequency of surveys and routes taken if sensors are not deployed in stationary positions
	• Alarm criteria, including the alarm threshold used for each type of event
	• Deployment specifications for individual Sites to replicate location and environmental criteria determined during controlled release testing.
	  ○ If a third party is contracted for the survey, this should also include contractor or data service provider information.
	  ○ To include details for both Facility Level and Source Level inspections.

Detection Follow Up Protocols	• Emission detection 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 detected emission events • Repair planning and repair validation procedure • Causal Examination procedures
Facility Scale and Source Level/LDAR inspection recordkeeping form	For each Emission Source, includes component/equipment/site ID and type, date of all repair efforts (first 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 monitoring location log	Includes a list of monitoring locations planned (for at least the Certification Period) and visited for each survey.
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 and Continuous Gas Detection Technology

As discussed in Section 3.2.3, a Facility may use a Continuous Gas Detection System to meet Facility Scale inspection requirements. A Facility may also use a Continuous Monitoring System to meet the requirements of either Facility Scale of Source Level Inspection. Table 4 outlines the additional required records if a Continuous Gas Detection System or a Continuous Monitoring System is employed.

Table 4: Recordkeeping requirements for Continuous Gas Detection and 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 or other results certification systems for the technology. • Expected MDL of the system considering typical or average relevant conditions in the Facility

- Temporal coverage or duty cycle
- Analysis used for monitor placement
- Data communication system (i.e. cell tower, wired data)
- Interconnection between data collection system, alarm system and work order processing system
- Operator response to monitor downtime (i.e. backup monitoring plan)
    - Location where meteorological data is taken (if CMS is used)
- 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 an inspection using the technology's quantification capabilities, engineering calculations, or other methods representative of emissions events discovered.

All events captured by either Source-Level or Facility-Scale inspections must be quantified and added to a Facility's methane emissions inventory if the event is not already captured in the inventory via other means (i.e. intended emission source). Operators must calculate unintended methane emissions discovered from an inspection using Best Available Techniques (BAT) which can include quantitative algorithms of leak detection and quantification technology, engineering calculations considering specific process information related to an event or the appropriate emission factors referenced in the Producer's methane emissions quantification plan. It is considered best practice for a Producer to compare emissions calculated via quantitative algorithms of LDAQ technology or emission factors with engineering calculations, if able, to ensure each event's emission estimate falls within a feasible range.

A Producer can use the results of Facility-Scale and Source-Level inspections to meet the requirements of emissions reconciliation, as specified in *Subsidiary Document 1: Methane Intensity,* but is not required to do so. The Producer may conduct additional measurement campaigns with the same or different measurement technologies to complete the emissions reconciliation requirements. It is generally true that more measurement data from multiple-vetted measurement technologies will lead to a more accurate reconciliation, so Producers are encouraged to collect as much measurement data as possible over time to continually improve the accuracy of reconciliation efforts.

Unintended abnormally high emissions (Super-Emitters) detected from Facility Scale inspection must be estimated or quantified using best available techniques (BAT), reconciled and included in the Facility's emissions inventory.

5.2 Interconnection with Company Practices

A Monitoring Technology Deployment plan is detailed as a required Company Practices, specifically:

- Monitoring Technology Deployment for LDAR;
- Verification requirements of repaired or replaced equipment.

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.

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