MiQ STANDARD

for Greenhouse Gas Emissions Performance for Petroleum and Natural Gas Operations

Carbon Intensity Standard

v1.0

Contents

1 Background

1.1 Introduction

Greenhouse gas (GHG) emissions from oil and gas production are a significant contributor to climate change. The main GHGs emitted from oil and gas production are carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

CO_2 emissions from oil and gas systems typically arise from combustion of both gas (e.g. fuel gas, waste gas) and liquid (e.g. diesel) hydrocarbons during oil and gas production, treatment and transportation and the removal of naturally-occurring CO_2 in produced oil and natural gas. Within oil and gas systems, N_2O is formed as a combustion by-product when nitrogen-containing species react at high temperatures. Current estimates suggest that N_2O emissions are minor (i.e. <<1%) when compared to total GHG-equivalent emissions. 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]. Methane is emitted throughout both the oil and natural gas supply chains through venting, leaking and incomplete combustion from flares, burners and engines.

A complete greenhouse gas profile, including CO_2, N_2O and methane (CH_4), enables Facility Operators to fully report the greenhouse impact of their operations and differentiate the emissions performance for their handling of oil and natural gas products along their portion of supply chain operations of each product. Assurance of this information for the operated Facility enables stakeholders, including downstream buyers, to differentiate the products of individual Facilities based on emissions performance.

The purpose of the Carbon Intensity Standard (the Standard) is to enable a relevant, coherent, accurate and transparent assessment of an operator's individual GHG emissions and intensities for their Faciilty while avoiding double counting of GHG emissions. This supplements the operator's methane performance Grade and

[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.

corresponding Methane (CH_4) Intensity, as determined by the MiQ Standard for Methane Emissions Performance (the Methane Standard).

The Standard prescribes the calculation of individual emissions and intensities for each GHG. Each relevant GHG ultimately has an intensity calculated, allocated to individual co-products, expressed in grams of GHG per MMBtu of throughput (i.e g CO_2/MMBtu, g CH_4/MMBtu) for natural gas and grams of GHG per barrel of oil (i.e. g CO_2/bbl, g CH_4/bbl) for hydrocarbon liquids.

The Methane Standard uses a holistic approach of relevant Monitoring Technology Deployment and Company Practices standards to assure a more accurate methane intensity. To determine CO_2 and N_2O emissions addition of these pillars are deemed not relevant to assure CO_2 and N_2O intensities with similar accuracy.

2 Scope

This Standard and all methodologies in this document are globally applicable. This Standard may be applied, when in combination with the Methane Standard, and defines the criteria and requirements to determine individual GHG emissions and intensities associated with the Facility's operations. This Standard is intended to prescribe how to calculate the individual GHG emissions and intensities for each relevant GHG species, which shall always include CO_2, N_2O and, in conjunction with the Methane Standard, CH_4, for all segments of the oil and natural gas supply chain represented by the MiQ Methane Standard. Subsequent calculation of a Carbon Intensity, or total GHG intensity, expressed in mass units of CO_2e per unit throughput depends on the preferred Global Warming Potential (GWP) for the specific application and use cases of the data. MiQ recognizes the importance of reporting and abating short-term climate pollutants, such as methane, as individual GHG species and therefore does not prescribe a particular GWP or necessitate the calculation of CO2e in its program. The emissions and intensities calculated and assured to this Standard can be used as an input to determine the GHG emissions intensities of an entire system boundary for natural gas and/or hydrocarbon liquids in conjunction with other data inputs that meet the principles, requirements, guidelines and fit the framework of relevant life cycle assessment standards [4] [5].

3 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

- API Compendium of Greenhouse Gas Emissions Methodologies for the Natural gas and Oil Industry, 2021 [1]
- Intergovernmental Panel on Climate Change (IPCC) reports, 2021 [2]
- ISO 14067:2018 Greenhouse Gases, Carbon Footprint of Products Requirements and Guidelines for Quantification [3]

4 Petroleum and Natural Gas Systems

Petroleum and Natural Gas Systems include the following oil and gas industry segments. Operators following this Standard in combination with the Methane Standard shall reference the relevant Methane Standard(s) to determine the appropriate definition of Facility for their assets. An Operator may operate a Facility with contiguous operations that encompasses more than one of the segment descriptions below and follow this Standard for the entirety of their Facility. The Operator must apply consistent Facility boundaries for all GHG accounting and performance.

4.1 Exploration & Production[2]

Exploration: Various geological and geophysical surveys and tests, followed by exploratory drilling in likely areas. Exploration encompasses well drilling, testing, and completions. The predominant sources of emissions from exploration are hydraulically fractured oil and gas well completions and well testing. Other sources include well completions without hydraulic fracturing, and well drilling. The primary emission sources from exploration are the exhaust from internal combustion (IC) engines used in drilling operations; the venting or flaring of gas associated with well testing or completions; and mobile source emissions associated with

[2] API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry – November 2021

equipment used at the well site and to transport personnel and equipment to/from the site.

Production: Includes the extraction of oil and gas from underground reservoirs, located either onshore or offshore. Production segment includes all equipment on a single well or associated with a well, used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate).

Emissions from oil and gas production occur at the wellhead and may have different characteristics depending on the type and location of the producing reservoirs.

The boundary for the Exploration & Production segment will be consistent with the production Facility boundary under the relevant MiQ standard.

4.3 Crude Oil Transportation

The segment of the crude oil supply chain in which crude oil is transported from a production Facility to an end user. Typical modes of crude oil transportation include pipeline, rail and ocean vessel. There may be more than one segment of crude oil transportation within the supply chain.

4.2 Oil and Gas Gathering and Boosting

The oil and natural gas (O&G) gathering and boosting means gathering pipelines and other equipment used to collect oil and gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares.

4.3 Natural Gas Processing

Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. During natural gas processing, natural gas liquids may be recovered from the natural gas stream following the produced gas being treated to meet pipeline specifications for transmission. The emission sources include process vents from dehydration, gas sweetening, compressors, pneumatic devices, and non-routine activities; fugitive equipment leaks; combustion sources, such as boilers, heaters, engines, and flares.

Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment.

4.4 Natural Gas Transmission

Natural gas is typically moved from the gathering system – before or after natural gas processing - into the natural gas transmission system via transmission pipelines. Natural gas transmission includes the transmission pipelines and any compression that moves natural gas from Production (for example a basin or other Production Facility), Gathering & Boosting Facility or Gas Processing Facilities to natural gas distribution pipelines, LNG storage facilities, or into underground storage. The boundary between Gathering and Boosting and a Natural Gas Transmission segment is the custody transfer point between the transmission line and the Processing or Gathering & Boosting Facility.

A transmission compressor station may include equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. GHG emissions from the natural gas transmission segment include emissions from pipeline blowdown vent stacks, and emissions associated with compressors operations.

4.5 Natural Gas Storage

Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

4.6 Liquefied Natural Gas (LNG) Operations

The LNG operations chain consists of several interconnected operating segments such as: LNG storage; LNG export and liquefaction; LNG shipping and transport; and LNG import and regasification.

LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

LNG export operation means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location.

LNG import operation includes onshore or offshore equipment that receives LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system.

The emissions from shipping and transport include fuel to power LNG tankers, marine loading and unloading operations, liquification and re-gasification.

The emission sources include the following:

- Stationary combustion sources include but not limited to heaters, boilers and steam generators, dehydrator reboilers, fire pumps, IC engines, turbines, and submerged combustion vaporizers.
- Mobile combustion sources include but not limited to LNG carriers, off-road vehicles, aerial vehicles, marine boats, and support vessels.
- Waste gas control equipment include flares, oxidizers, combustors, incinerators.
- Process vent and other non-routine emission sources.
- Fugitive emission sources
- Indirect emission sources including electricity imports and process heat/steam imports.

4.7 Enhanced Oil Recovery (EOR) and Geologic Storage

Enhanced oil recovery and geologic storage include stationary and mobile combustion sources, waste gas combustion equipment, process, and other non-routine activities. CO_2 capture and geological injection refers to the chain of processes used to collect or capture a CO_2 gas stream, transport the CO_2 to a producing field, and inject the CO_2 into a geological formation.

The emissions associated with the capture phase include combustion and indirect emissions, vented and fugitive emissions. Transportation-related emissions include fugitive equipment leaks or evaporative losses during maintenance, emergency releases, intermediate storage, and loading/offloading. Combustion or indirect emissions will also occur from energy consumption to compress and move the CO_2 between the capture and injection locations.

Geologic storage emissions include vented, fugitive, combustion and indirect emissions from equipment and associated energy requirements at the injection site. In addition, emissions may result from physical leaks from the storage site; uncaptured CO_2 co-produced with oil and/or gas, and enhanced hydrocarbon recovery operations.

5 Terms and Definitions

The following definitions apply:

Global Warming Potential (GWP)

Measure of how much energy 1 mass unit of a certain greenhouse (i.e. CH_4, N_2O) will absorb over a given period of time, relative to the emissions of 1 mass unit of carbon dioxide (CO_2). Table 1 presents the currently accepted GWP values on 100-year and 20-year basis, associated with various compounds [2].

Table 1. IPCC 100-year and 20-year GWP Values

	100-year AR6 GWP	**20-year AR6 GWP**
Carbon dioxide (CO_2)	1	1
Methane (CH_4)	29.8	82.5
Nitrous oxide (N_2O)	273	273

CO_2 emissions Total Scope 1 and Scope 2 emissions of carbon dioxide from the Facility, calculated in mass units of CO_2

CH_4 emissions	Total Scope 1 and Scope 2 emissions of methane from all assets in the Facility, calculated in mass units of CH_4
N_2O emissions	Total Scope 1 and Scope 2 emissions of nitrous oxide from all assets in the Facility, calculated in mass units of N_2O
CO_2e emissions	Total greenhouse gas emissions (CO_2, CH_4, and N_20, reported to this Standard) converted to a carbon dioxide equivalence using Global Warming Potential.
Emissions Sources	Reported categories of emissions typically associated with types of equipment or common emitting events
Energy Consumed	Direct electricity and steam used and any other indirect electricity and steam used for the Facility.
LACT Unit	A Lease Automatic Custody Transfer unit, being a piece of oil and gas equipment used to sample and measure oil so it can be transferred
Throughput	The volume of the individual products, or functional units, that exit the Facility to a downstream segment of the supply chain. For purposes of this standard, the functional units are natural gas (in MMBtu) and hydrocarbon liquids (in barrels of oil)
Primary Data	Activity data, emission factors or another variable used for a GHG emission calculation that are typically derived from measurements or other direct means and may be averaged across all sites where the data is relevant. Also includes data developed outside of the Facility but still relevant to Facility operations (i.e. an empirically-derived regional emission factor) [10]. Can be separated into preferred data, derived from site-specific data that is representative of the processes for which they are collected, and alternate data, typically derived from regional or national studies deemed relevant to the Facility's operations but not representative of potential variations to the Facility's specific operations.
Secondary Data	Activity data, emission factors, or another variable used for a GHG emission calculation that is not specific to the Operator's Facility and is not based on measurement or other direct

	means. Secondary data includes data obtained from simulating proxy processes that have no reference to the actual Facility (i.e. estimated inputs while simulating process units typically within a stage of the supply chain using generalized industry studies) [7].
Site-specific data	This term can be used interchangeably with primary, preferred data and is a subset of primary data where activity data, an emission factor or another variable used for a GHG emission calculation is obtained from information within the Operator's Facility (i.e. actual count of devices, direct site methane measurements) and, as a result, is representative of the processes for which the data is collected.

6 Roles and Responsibilities

Table 2 lists all the individuals and groups engaging with the Standard and what their responsibilities are regarding this document.

Table 2: Roles and Responsibilities for the Carbon Intensity Standard

Roles	Responsibilities
Standard Holder	· defining and managing all aspects of the · development and dissemination of the Standard · publishing the Standards and supporting documents · managing updates and changes to the Standards
Auditor/Auditing Firm	· conducting Annual Audit in accordance with requirements defined by the Standard Holder in this Standard and the MiQ Program Guide. · Assuring an operator's Carbon Intensity · Making detailed recommendations for improving data quality in an Operator's GHG inventory · Providing Operator with an Audit Report providing assurance for total GHG emissions and GHG intensity

Operator	· registering Facilities with an Issuing Body; · selecting and contracting with an Auditor to fulfill the responsibilities of a Auditor Firm; · engaging with the Auditing Body to 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 Annual Audit (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

7 Carbon Intensity

Under this Standard, operators are required to calculate emission intensities for each GHG within their Facility. Operators must also refer to the relevant Methane Standard(s) for calculation of CH_4 emissions and CH_4 intensity can be referred to in the relevant Standard for Methane Emissions Performance. The outputs of this Standard are the GHG intensities for each individual GHG. Operators must keep detailed records of supplementary data inputs used in the Carbon Intensity calculation.

GHG intensities and CO2e Intensity are to be calculated annually.

7.1 Calculation

Under this Standard, a Facility's GHG emissions inventory are a summation of all emission sources defined in the 2021 API Compendium of Greenhouse Gas (GHG) Emissions Methodologies [1] and any other additional sources identified within this Standard or the relevant Methane Standard. These emission sources and the data quality for each source calculation are outlined in Annex A. Annex A also defines the applicable GHGs (CO2, CH4 and/or N2O) for each source. Operators must report the emissions intensity of each GHG separately.

Calculation of individual GHG emission intensities for natural gas and hydrocarbon liquid products is done using the following general equation:

$$GHG_i\ Intensity\ \left(\frac{g\ GHG_i}{MMBtu\ or\ bbl}\right) = \frac{Total\ emissions\ of\ GHG_i\ allocated\ to\ product_j\ \ (g)}{Product_j\ Throughput\ (MMBtu\ or\ bbl)} \qquad (1)$$

MMBtu is used as the normalization unit for emissions allocated to natural gas and barrels is used for emissions allocated to hydrocarbon liquids and, as applicable, natural gas liquids. To calculate the total emissions of each GHG allocated to each product, operators must calculate the percentage of energy throughput from each product relative to total energy throughput and apply this percentage to the total methane emissions for each product.

$$Total\ emissions\ of\ GHG_i\ allocated\ to\ proudct_j = GHG_I * Energy\ Ratio_{product\ j}\ (2)$$ [3]

where,

$$Energy\ Ratio_{product\ j} = \frac{Energy_{product\ j}}{Total\ Energy\ Throughput} \qquad (3)$$

where,

$$Energy_{product\ j} = V_j * EC_j \qquad (4)$$

where,

- V_j is the Facility's throughput in volumetric units of the product
- EC_j is the energy content, expressed as the higher heating value, of the product.

If necessary, reporting the intensities of more than one stream of hydrocarbon liquids shall include the same principle of energy ratio calculation as described in Equation 3 above.

For methane emissions intensity, operators must use the methane intensity threshold for the performance grade received through compliance with the Methane Standard for carbon intensity calculations, unless a measurement-informed inventory using an externally published measurement and reconciliation protocol is developed as part of compliance to the Methane Standard. In these

[3] For an operator following this Standard in conjunction with the corresponding Methane Standard for *Natural Gas Operations*, the operator must allocate emissions per source on the basis of the guidance in the corresponding Methane Standard for all relevant GHGs. Therefore, allocating total emissions to each product by just applying the energy ratio is only applicable for operators following the corresponding Methane Standard for Petroleum Operations and Natural Gas Operators with an energy ratio with all natural gas sales and no hydrocarbon liquids sales. For certain sources that only emit CO_2 and/or N_2O follow the allocation guidance in Annex A of this Standard.

cases, operators must follow the product-specific methane intensity calculation procedures of the relevant Methane Standard

7.2 Emission Sources

An operator's greenhouse gas emissions are evaluated source-by-source based on the data quality used in emissions calculations, in accordance with the data hierarchy applied in Annex A (See Section 8.1 for more information). The hierarchy includes methods used to calculate emissions by source. Data quality for the same source may differ for individual GHGs, and for different inputs within the same calculation. Operators are required to track the quality of their inputs for each GHG emission calculation.

A Facility's calculated intensities includes emissions from all Emission Sources (listed in Annex A to this Standard) that are present in the given Facility and documentation of the quality of data inputs (i.e. primary, preferred vs primary, alternate) utilized to determine the intensities based on the data quality hierarchies presented in Tables 4, 5 and 6.

8 Data Quality Assurance

8.1 Calibration and Accuracy of Calculations

Multiple oil and gas GHG quantification guidelines and lifecycle assessment methodologies define the level of data quality that must be used in an emissions inventory. Consistent with ISO14067:2018, two types of data are defined: primary data and secondary data. Consistent with certain oil and gas LCA methodologies[7],[8] such as the SGE methodology and GIIGNL methodologies, primary data is further split into two categories: primary, preferred and primary, alternate. Primary, preferred data is typically also site-specific data and must be used where it is available for material emission sources. Operators must define plans to increase the use of primary, preferred data for material emission sources over time. Secondary data may be used in some cases for emission sources where it is demonstrated that primary data does not exist, is immaterial to total emissions, or economically unfeasible to be gathered.

The most important processes and emission sources are those which contribute at least 95% of total GHG emissions for the Facility. Emissions that are considered immaterial do not need to have their data quality justified.

Table 3. Description of data quality inputs

Data Source	Description	Examples	Comment on Data Quality
Primary, preferred data	Site-specific metered activity data, actual representation of emission inputs, measured compositions of products and waste streams, and emission factors derived based off site-specific information	<u>Activity data example</u> Metered fuel volume Actual device count Actual count of leaking components Volumetric calculation of gas volume based on physical measurements (i.e. pressure) Metered venting volume <u>Emission factor example</u> Measured methane/CO_2 composition of gas Device-specific emission factor <u>Other example</u> Measured emission rate of a site, process, or component coupled with an estimated time duration for the measured rate.	Ensure data quality through routine meter calibration programs as a part of facility's routine maintenance activities Gas sampling and analyses needs to be frequent enough to ensure that it is representative.
Primary, alternate data	Emission inputs that based on estimation practices, mass balances partially based off of metered data, and default factors or other representations with non-site specific bases	<u>Activity data example</u> Estimated gas volume based on mass balance Default component counts, or other non-actual estimates Default population factors based on major equipment <u>Emission factor example</u> Regionally representative fuel gas composition Default regional emission factor	1. Vendor and default factors may not reflect actual operational parameters 2. Generic fuel gas composition may not be reflect site specific field gas characteristics. 3. The trade-off between data accuracy and ease of collection must be qualitatively analyzed to understand the impact on total emissions
Secondary data	Process unit or stage default emission factor	<u>Activity data example</u> Model defaults based on stage input throughput Assumptions on vent rate for individual processes <u>Emission Factor</u> Default methane composition Generalized industry-wide emission factors per major	1. Lack of process and equipment specific data. 2. No consideration of potential differences in emission profiles

		process	

8.2 Calibration and Accuracy Requirements

8.2.1 Calibration Procedures

This Standard provides guidance on calibration procedures, as an important aspect of accuracy and reporting of GHG Intensity. These requirements are limited to instruments measuring mass flows and volumetric flows of hydrocarbons that are used in emissions calculations, such as combustion emissions or leaks. These requirements are not applicable to devices that indirectly measure or monitor GHG emissions (see Monitoring Technology Deployment subsidiary document of the MiQ Standard for Methane Performance for more information). This section is typically applicable to operators that are metering fuel or vent streams that is considered primary, preferred data if all emissions are based directly on metered volumes, or primary, alternate data if only a few metered streams are used to develop a mass balance approach.

Calibration of an analyzer or instrument establishes the quantitative relationship between an actual value of a standard (e.g. mass flow, concentration, temperature etc.) and the analyzer response. Calibration compares the measurement of the meters and measuring devices with an instrument of higher accuracy to detect and quantify inaccuracies and to report or eliminate those inaccuracies by adjustment.

“Accuracy” means the closeness of the agreement between the result of the measurement and the true value of the quantity.

All flow meters and other measurement devices that provide data used to calculate GHG emissions must be calibrated according to either the manufacturer’s recommended procedures or other industry standards. The calibration method(s) used must be documented in the monitoring plan and meet the accuracy requirements specified under the Standard.

Recalibration of flow meters and other instruments used to measure critical activity data or emissions is recommended to be performed no less frequently than at one of the following intervals, whichever is shorter:

- The frequency recommended by the manufacturer.

- Immediately upon replacement of a previously calibrated meter.
- Immediately upon replacement or repair of a device that is deemed out of calibration.

Calibrations should be carried out at the field monitoring site by allowing the analyzer to sample test atmospheres containing known pollutant concentrations. The analyzer to be calibrated should be in operation for at least several hours (preferably overnight) prior to the calibration so that it is fully warmed up and its operation has stabilized. During the calibration, the analyzer should be operating in its normal sampling mode, and it should sample the test atmosphere through all filters, scrubbers, conditioners, and other components used during normal ambient sampling and through as much of the ambient air inlet system as is practicable. All operational adjustments to the analyzer should be completed prior to the calibration.

All measurement devices must also follow the below requirements:

- All standards used for calibration must be traceable to the National Institute of Standards and Technology or another similar national government body responsible for measurement standards.
- All flow meters and other measuring devices are installed and operated and maintained in a manner to ensure accuracy of ± 5% throughout the normal operating range of the device.
- All mass and volume measurement devices are to be calibrated as specified in the original equipment manufacturers (OEM) documentation. When using the three calibration points, one point must be at or near the zero-point, one point must be at or near the upscale point, and one point at or near the midpoint of the device's operating range.

8.2.2 Annual Field Accuracy

Operators must conduct an annual field accuracy assessment of mass and volume measurement devices to test for field accuracy in years between successive calibrations to ensure the device is maintaining measurement accuracy within ±5 percent. Device accuracy may be assessed using one of the following options:

- Engineering analysis: Various engineering techniques include, but are not limited to, comparison with upstream or downstream meters, and/or analysis of flow trends prior to and post calibration events.

- OEM calibration guidance or other OEM recommended methods: Manufacturers may have procedures designed specifically for "in-situ" assessments of meter accuracy without necessitating device removal or inspection. For example, some types of thermal mass flow meters are designed to allow for "in-situ" calibration checks, which confirm whether a meter has drifted or shifted from the original National Institute of Standards and Technology traceable calibration.
- Standard industry practices: Various industry practices that are commonly used to confirm meter accuracy. As an example, for pressure differential metering devices, some industries rely on meter temperature and pressure transmitter calibration checks (which demonstrate accuracy of the transmitters) combined with demonstration of orifice plate/primary element integrity (i.e. cleanliness and minimal corrosion).
- Portable instruments: Portable flow "comparison" instruments such as strap-on ultrasonic meters, meter "provers," and/or portable pitot tubes may be adequate to demonstrate accuracy of certain metering devices. In some instances, meter systems may not be engineered in a manner that allows for accurate use of portable equipment.

If the Operator is not able to demonstrate results of an initial calibration, recalibration, or field accuracy assessment in accordance with this guidance, then the Operator can demonstrate by other means that are subject to approval by the Auditor.

Financial transaction meters are exempted from the calibration requirements if the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Measurements performed using best available methods (BAM), are not subject to the specific calibration requirements but must meet the ±5 percent accuracy requirements.

The Operator must keep records including a comprehensive list that includes, at a minimum,

- all meters used for Carbon Intensity data,
- the dates of the last calibrations and primary element inspections for those meters,
- each meter's role in the reported data, and
- the postponement status of each meter, if applicable.

8.2.3 Sampling

Regular product sampling is key to ensuring quality of product and process data, and critical to the validity of an Operator's use of primary data. Product, byproduct and waste streams in oil and gas facilities will vary regionally and temporally, so extended analysis frequency should be determined by the Operator to ensure representative product quality. The chosen frequency must be included and justified in the monitoring plan. Quarterly analysis at minimum is suggested for process information that may have a material impact on total emissions if another frequency is not already determined.

8.2.4 Preventative Maintenance (PMs)

All equipment should be maintained in accordance with manufacturer's specifications and industry standards to minimize emissions. In addition to maintenance, all equipment, controls, and monitoring instruments should be inspected on a regular basis to ensure that it is operating properly. Records should be maintained to clearly document all maintenance and inspection activities.

Repairs should be carried out as soon as is practical to minimize unintended emissions. Operators should identify opportunities to coordinate repairs and routine monitoring/maintenance so that maintenance, startup, and shutdown (MSS) emissions are minimized.

Annex A. Source Descriptions

Table 4 . Typical emission sources for Onshore Production, Offshore Production, Gathering & Boosting, and Processing. Table includes descriptions of primary and secondary data source for activity data and emission rates fundamental to source-level emission calculations.

Source Category	Description /Notes	CO_2	CH_4	N_2O	Parameter	Primary Preferred Data	Primary Alternate Data	Secondary Data
Natural Gas Pneumatic Devices	Automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.	✓	✓		Activity	Site specific component count Run time	Site specific component count Run time	
					Emission Factor	Measured emission factor of normally operating and malfunctioning devices Device-specific emission factor	Default national or regional emission factor by type	Total pneumatic vent rate by supply chain stage
Natural Gas Driven Pneumatic Pumps	Pumps that uses pressurized natural gas to move a piston or diaphragm, which pump liquids on the opposite side	✓	✓		Activity	Actual count of pneumatic devices by type Actual count of malfunctioning devices	Estimated count of pneumatic devices by type and process unit	
					Emissi on Factor	Measured emission factor of normally operating and malfunctioning devices Device-specific emission factor	Default national or regional emission factor by type	Total pneumatic vent rate by supply chain stage
		✓	✓		Acti vity	Metered gas throughput Continuous vent metered data	Estimated gas throughput by mass balance	

Acid Gas Removal (AGR) Units[4]					Emission Factor	Measured CO_2 concentration in gas Measured CO_2 inlet/outlet rates CO_2/CH_4 direct measurement from regenerator vent	Representative CO_2 concentration in gas CO_2 removal % assumption (i.e. 100%)	
Dehydrator Vents / Desiccant[5]	Emissions from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere	✓	✓		Activity	Metered gas throughput Continuous vent metered data	Estimated gas throughput by mass balance	
					Emission Factor	Volumetric engineering calculation Simulated vent gas volume Simulated methane composition		
Well Venting for Liquids Unloading		✓	✓		Activity	Measured total gas volume Measured total volume of non-GHG gases	Oil flow rate Estimated duration of venting period GOR	Estimated site-wide well venting rate for liquids unloading events
					Emission Factor	Site specific gas composition	Representative gas composition	
Well Venting During Completions From Hydraulic Fracturing		✓	✓		Activity	Measured total gas volume Measured total volume of non-GHG gases	Oil flow rate Estimated duration of venting period GOR	Estimated site-wide well venting rate for completions w/ hydraulic fracturing
					EF	Site specific gas composition	Representative gas composition	
Well Venting During Workovers From Hydraulic Fracturing		✓	✓		Activity	Measured total gas volume Measured total volume of non-GHG gases	Oil flow rate Estimated duration of venting period GOR	Estimated site-wide well venting rate for workovers w/ hydraulic fracturing
					EF	Site specific gas composition	Representative gas composition	

[4] AGRU emissions must be allocated entirely to the gas product for Natural Gas Operations

[5] Dehydrator vent emissions must be allocated entirely to the gas product for Natural Gas Operations

Gas Well Venting During Completions and Workovers Without Hydraulic Fracturing		✓	✓		Activity	Measured total gas volume Measured total volume of non-GHG gases	Oil flow rate Estimated duration of venting period GOR	Estimated site-wide well venting rate for workovers and completions w/o hydraulic fracturing
					EF	Site specific gas composition	Representative gas composition	
Off-shore Completions		✓	✓		Activity	Measured total gas volume Measured total volume of non-GHG gases	Oil flow rate Estimated duration of venting period GOR	Estimated site-wide well venting rate for offshore completions
					EF	Site specific gas composition	Representative gas composition	
Atmospheric Storage Tanks	Atmospheric storage tanks containing crude oil or produced water. Includes flashing, working, and breathing losses.	✓	✓		Activity	Inputs into simulation model for individual tanks Number of pressure release events	Individual tank liquid throughput Default gas volume or evaporation rate	Total liquid throughput for entire stage
					Emission Factor	Simulated vent gas volume Simulated CO2/CH4 composition of vent gas	Default emission factor	Default total vent rate
Transmission Storage Tanks	Transmission storage tanks containing crude oil. Includes flashing, working, and breathing losses.	✓	✓		Activity	Measured dump valve leakage rate	Gas throughput into individual tanks	
					EF	Measured CO2/CH4 composition of vent gas	Default emission factor Default gas composition	
Well Testing Venting and Flaring		✓	✓		Activity	Measured total vent gas rate	Average oil flow rate and GOR Average gas flow rate Number of days of testing	Stage-wide assumed flaring rate
					Emission Factor	Measured hydrocarbon composition for CO2 Measured CO2/CH4 composition of vent gas Measured or design flare destruction efficiency	Default hydrocarbon composition for CO2 Default CO2/CH4 composition of vent gas Default assumption of flare destruction efficiency	

Associated Gas Venting		✓	✓		Activity	Measured total gas volume	Estimated total gas volume based on mass balance	Stage-wide assumed vent rate
					EF	Measured CO2/CH4 composition of vent gas	Default CO2/CH4 composition of vent gas	
Blowdown Vent Stacks	CO2 and CH4 vented to the atmosphere as a result of depressurizing vessels	✓	✓		Activity	Measured total gas volume Engineering estimate using other physical measurement (i.e. volumes, pressures)	Estimated total gas volume based on mass balance	Stage-wide assumed vent rate
					EF	Measured CO2/CH4 composition of vent gas	Default CO2/CH4 composition of vent gas	
Offshore Emergency Shutdown (ESD)		✓	✓		Activity	Measured total gas volume Engineering estimate using other physical measurement (i.e. volumes, pressures)	Estimated total gas volume based on mass balance	Stage-wide assumed vent rate
					EF	Measured CO2/CH4 composition of vent gas	Default CO2/CH4 composition of vent gas	
Flare Stack Emissions	Hydrocarbon gases sent to a combustion device to convert hydrocarbons to CO2	✓	✓	✓	Activity	Metered total waste gas flow rate	Estimated total waste gas flow rate by mass balance or gas-to-oil ratio	Stage-wide assumed flaring rate
					Emission Factor	Measured hydrocarbon composition for CO2 Measured CO2/CH4 composition of vent gas Measured or design flare destruction efficiency	Default hydrocarbon composition for CO2 Default CO2/CH4 composition of vent gas Default assumption of flare destruction efficiency Default N2O emission factor	
Centrifugal Compressor Venting[6]		✓	✓		Activity	Measured gas volume Actual compressor count		Stage-wide compressor vent rate

[6] Centrifugal compressor venting must be allocated entirely to the gas product for Natural Gas Operations

					Emission Factor	Measured CO2/CH4 composition of vent gas	Default emission factor for each type of vent source Default CO2/CH4 composition of vent gas	
Reciprocating Compressor Venting[7]		✓	✓		Activity	Measured gas volume Actual compressor count		Stage-wide compressor vent rate
					Emission Factor	Measured CO2/CH4 composition of vent gas	Default emission factor for each type of vent source Default CO2/CH4 composition of vent gas	
Fugitive Emissions		✓	✓		Activity	Quantified leakage rates per component Actual number of leaking components Actual component counts by device and service type	Component count estimates by major equipment counts or other indirect means	Stage-wide leak rate for all fugitives or individual components
					Emission Fact	Measured CO2/CH4 composition of gas	Default emission factor for each component Default CO2/CH4 composition of gas	
EOR Injection Pump Blowdown		✓	✓		Activity	Metered total blowdown vent rate Event-specific duration	Estimated total blowdown vent rate Historically-representative event duration	Stage-wide blowdown rate
					Emission Factor	Measured CO2/CH4 composition of gas Measured density of EOR injection gas at supercritical operating temperature/pressure	Default CO2/CH4 composition of gas Default density of EOR injection gas at supercritical operating temperature/pressure	
EOR Hydrocarbon Liquids Dissolved CO2[8]		✓	✓		Activity	Metered hydrocarbon liquids production volume	Estimated hydrocarbon liquids production volume	

[7] Reciprocating compressor venting must be allocated entirely to the gas product for Natural Gas Operations

[8] Allocate all emissions to hydrocarbon liquids

					Emission Factor	Measured solubility of CO2 / in hydrocarbon liquids at representative operating conditions	Literature data of solubility of CO2 in produced hydrocarbon liquids	Fraction of CO2 dissolved in total hydrocarbon liquids production associated with EOR
Combustion Equipment[9]	Includes generators	✓	✓	✓	Activity	Metered fuel usage	Estimated fuel usage using mass balance	Stage-wide calculated horsepower + energy requirements
					Emission Factor	Stack testing of CH4 slip Manufacturer-specific emission factor based off measurement results Measured hydrocarbon composition of fuel gas	Default equipment-specific emission factor Manufacturer-specific emission factor not based off measurement results Default hydrocarbon composition of fuel gas	Stage-wide default emission factors
Casing Gas Venting		✓	✓		Activity	Measured vent rate Actual vent duration	Estimated vent rate Estimated vent duration	Production-wide casing gas vent rate
					Emission Factor	Measured CO2/CH4 composition of gas	Default CO2/CH4 composition of gas	
Coal Seam Exploratory Drilling & Well Testing		✓	✓		Activity	Engineering estimates with a mass balance approach		

[9] Combustion emissions from natural-gas fired compressor drivers must be allocated entirely to the gas product for Natural Gas Operations

				Emission Factor	Measured CO2/CH4 composition of reservoir gas		
Upsets (Well blowouts, Pressure relief valve (PRV) venting, blowdowns) MSS (Blowdowns from pipelines and equipment for maintenance activities)		✓	✓	Activity	Measured vent rate Event duration	Conservative engineering estimate (using complete physical volumes as basis, where applicable)	Stage-wide estimated upset/emergency venting rates
				Emission Factor	Specific CO2/CH4 composition of reservoir gas Vent duration	Default CO2/CH4 composition of reservoir gas	
Onshore well mud degassing		✓	✓	Activity	Measured or metered mud degassing vent rate	Estimated mud degassing rate	Production-wide mud degassing vent rate Estimated number of mud degassing events
				Emission Factor	Measured CO2/CH4 composition of reservoir gas Drilling duration	Default CO2/CH4 composition of reservoir gas Default event-based emission factor	
Liquid Loading[10]	Liquid loading into trucks, railcars, or barges	✓	✓	Activity	Measured throughput Loading type (splash, submerged, etc)	Estimated or calculated throughput Loading type (splash, submerged, etc)	Stage-wide estimate of product loading volume Fractional estimates for type of loading

[10] Allocate all emissions to hydrocarbon liquids

					Emission Factor	Measured loading losses Site-specific product speciation Site-specific ambient temperature & pressure Loading type (splash, submerged, etc)	Default product speciation Regional ambient temperature & pressure Default emission factor based on measurement study	Default emission factor per loaded volume
Purchased Electricity	Electricity purchased from the grid	✓	✓	✓	Activity	Metered usage Energy consumed from energy suppliers Supplier invoices of energy usage	Engineering estimate of energy consumption based on design or throughput	
					Emission Factor	Market-based (provider and time of use for generation type)	Specific provider average energy mix	Default national/regional average
Mobile sources	Emissions from mobile sources for transporting personnel, equipment, or material	✓	✓	✓	Activity	Actual vehicle fuel consumption Actual vehicle mileage (distance) [Transported load (mass)]		Total estimated fuel consumption for entire stage
					Emission Factor	Vehicle inspection/emis sion records	Manufacturer's emissions certification Published emission factor based on specific vehicle make/model/year	Published emission factor based on generic vehicle make/model/year

Table 5. Typical emission sources for the LNG Storage, Transport, Export and Import segments. All emissions listed are allocated to the natural gas supply chain. Table includes descriptions of primary and secondary data source for activity data and emission rates fundamental to source-level emission calculations.

Source Category[11]	CO_2	N_2O	CH_4	Parameter	Primary, Preferred Data	Primary, Alternate Data	Secondary Data
Natural Gas Pneumatic Devices	✓		✓	Activity	Actual count of pneumatic devices by type Actual count of malfunctioning devices	Estimated count of pneumatic devices by type and process unit	
				Emission Factor	Measured emission factor of normally operating and malfunctioning devices Device-specific emission factor	Default national or regional emission factor by type	Total pneumatic vent rate by supply chain stage
Natural Gas Driven Pneumatic Pumps	✓		✓	Activity	Actual count of pneumatic devices by type Actual count of malfunctioning devices	Estimated count of pneumatic devices by type and process unit	
				Emission Factor	Measured emission factor of normally operating and malfunctioning devices Device-specific emission factor	Default national or regional emission factor by type	Total pneumatic vent rate by supply chain stage

[11] Operators in LNG segments must allocate all emission sources based on the product-specific guidance in the corresponding LNG Standard for Methane Emissions Performance

Acid Gas Removal (AGR) Units	✓		✓	Activity	Metered gas throughput Continuous vent metered data	Estimated gas throughput by mass balance	Total gas processing rate
				Emission Factor	Measured CO2 concentration in gas Measured CO2 inlet/outlet rates CO2/CH4 direct measurement from regenerator vent	Representative CO2 concentration in gas CO2 removal % assumption (i.e. 100%)	
Dehydrator Vents / Desiccant	✓		✓	Activity	Metered gas throughput	Estimated gas throughput by mass balance	
				Emission Factor	Continuous Emissions Monitoring data Measured outlet composition	Waste gas volume and composition Combustion emissions based on heat input rating, fuel usage, fuel characteristics and run time.	
Blowdown Vent Stacks	✓		✓	Activity	Measured total gas volume Specific event duration	Count of venting events Estimated event duration	Stage-wide blowdown volume
				Emission Factor	Measured CO2/CH4 composition of vent gas	Measured CO2/CH4 composition of vent gas	
Atmospheric Storage Tanks Methods	✓		✓	Activity	Metered throughput Inputs into simulation model for individual tanks Number of unintentional pressure release events	Individual tank liquid throughput and GOR based on low pressure separator or heater/treater	Total liquid throughput for entire stage

				Emission Factor	Continuous Emissions Monitoring data Measured outlet composition Simulated CO2/CH4 composition of vent gas	Estimated vent gas volume Default CO2/CH4 composition of vent gas	Default emission factor Default vent gas composition
Flare Stack Emissions	✓	✓	✓	Activity	Metered total waste gas flow rate	Estimated total waste gas flow rate by mass balance or gas-to-oil ratio	Stage-wide assumed flaring rate
				Emission Factor	Measured hydrocarbon composition for CO2 Measured CO2/CH4 composition of vent gas Measured or design flare destruction efficiency	Default hydrocarbon composition for CO2 Default CO2/CH4 composition of vent gas Default assumption of flare destruction efficiency Default N2O emission factor	
Centrifugal Compressor Venting	✓		✓	Activity	Measured gas volume Actual count		Stage-wide compressor vent rate
				Emission Factor	Actual leak rate based off LDAR Vendor-specific leak rate based off measurement study Measured CO2/CH4 composition of vent gas	Default emission factor for leak Default CO2/CH4 composition of vent gas	
Reciprocating Compressor Venting	✓		✓	Activity	Measured gas volume Actual count		Stage-wide compressor vent rate
				Emission Factor	Actual leak rate based off LDAR Vendor-specific leak rate based off measurement study Measured CO2/CH4 composition of vent gas	Default emission factor for leak Default CO2/CH4 composition of vent gas	

Fugitive Emissions	✓		✓	Activity	Quantified leakage rates per component Actual number of leaking components Actual component counts by device and service type	Component count estimates by major equipment counts or other indirect means	Stage-wide leak rate for all fugitives or individual components
				Emission Factor	Measured CO2/CH4 composition of gas	Default emission factor for each component Default CO2/CH4 composition of gas	
Combustion Equipment at Onshore Petroleum and Natural Gas Production facilities, Gathering and Boosting facilities, and Natural Gas Distribution facilities	✓	✓	✓	Activity	Metered total fuel usage	Estimated fuel usage using mass balance	Stage-wide calculated horsepower + energy requirements
				Emission Factor	Stack testing of CH4 slip Manufacturer-specific emission factor based off measurement results Measured hydrocarbon composition of fuel gas	Default equipment-specific emission factor Manufacturer-specific emission factor not based off measurement	
LNG Storage at or near constant cryogenic temp	✓		✓	Activity	Actual count of storage tanks		
				Emission Factor		Published EF	
Non-Routine Vented Emissions from LNG Storage Stations	✓		✓	Activity	Measured gas vent rate Durations of individual venting periods	Count of venting events Estimated venting rates	Assumed LNG-stage wide non-routine emissions vent rate

				Emission Factor	Measured CO2/CH4 composition of gas	Default CO2/CH4 composition of gas	
LNG Loading and Unloading - Pipe loss	✓		✓	Activity	Measured gas vent rate Duration of specific loading/unloading events	Count of venting events Pipe insulation type Estimated duration of loading/unloading events	Assumed loading and unloading loss rate
				Emission Factor	Measured CO2/CH4 composition of gas	Estimated CO2/CH4 composition of gas Default emission factor for loading/unloading events	
LNG Shipping	✓		✓	Activity	Ship volume		
				Emission Factor	Published EF		
Vented Emissions from LNG Import and Export Terminals	✓		✓	Activity	Measured gas vent rate	Measured gas vent rate	Count of venting events
				Emission Factor	Site specific gas composition Duration of the venting period.	Representative gas composition Duration of the venting period.	Published EF Representative gas composition Duration of the venting period.

Blowdown Vent Stacks	✓		✓	Activity	Measured gas vent rate	Measured gas vent rate	Count of venting events
				Emission Factor	Site specific gas composition Duration of the venting period.	Representative gas composition Duration of the venting period.	Published EF Representative gas composition Duration of the venting period.

Table 6. Typical emission sources for Enhanced Oil Recovery (EOR), Carbon Capture and Geologic Storage. Table includes allocation of emissions to the natural gas supply chain as well as descriptions of primary and secondary data source for activity data and emission rates fundamental to source-level emission calculations.

Source Category	CO_2	N_2O	CH_4	Allocation	Parameter	Primary, Preferred Data	Primary, Alternate Data	Secondary Data
Non-routine equipment blowdown from Carbon Capture	✓		✓	Ratio	Activity	Measured total gas volume Specific event duration	Count of venting events Estimated event duration	Stage-wide blowdown volume
					Emission Factor	Measured CO2/CH4 composition of vent gas	Default CO2/CH4 composition of vent gas Duration of the venting period.	
Incomplete capture efficiency - AGR vent & SMR tailgas from Carbon Capture	✓		✓	Ratio	Activity	Metered gas throughput Continuous vent metered data	Estimated gas throughput by mass balance	Total gas processing rate or material balance
					Emission Factor	Measured CO2 concentration in gas Measured CO2 inlet/outlet rates CO2/CH4 direct measurement from regenerator vent	Representative CO2 concentration in gas CO2 removal % assumption (i.e. 100%)	
CO2 stream dehydration processes and Pre and Post combustion Carbon Capture	✓		✓	Ratio	Activity	Test data	Metered waste gas flow rate	Simulated stage-wide waste gas flow rate

					Emission Factor	Actual hours of operation	Vendor data Composition	
Centrifugal Compressor Venting from Carbon Capture[12]	✓		✓	Ratio	Activity	Measured gas volume Actual count		Stage-wide compressor vent rate
					Emission Factor	Actual leak rate based off LDAR Vendor-specific leak rate based off measurement study Measured CO2/CH4 composition of vent gas	Default emission factor for leak Default CO2/CH4 composition of vent gas	
Reciprocating Compressor Venting from Carbon Capture[13]	✓		✓	Ratio	Activity	Measured gas volume Actual count		Stage-wide compressor vent rate

12 Centrifugal compressor venting must be allocated entirely to the gas product for Natural Gas Operations

13 Reciprocating compressor venting emissions must be allocated entirely to the gas product for Natural Gas Operations

					Emission Factor	Actual leak rate based off LDAR Vendor-specific leak rate based off measurement study Measured CO2/CH4 composition of vent gas	Default emission factor for leak Default CO2/CH4 composition of vent gas	
Natural Gas Pneumatic Devices from Geologic Storage	✓		✓	Ratio	Activity	Actual count of pneumatic devices by type Actual count of malfunctioning devices	Estimated count of pneumatic devices by type and process unit	
					Emission Factor	Actual count of pneumatic devices by type Actual count of malfunctioning devices	Estimated count of pneumatic devices by type and process unit	
Natural Gas Driven Pneumatic Pumps from Geologic Storage	✓		✓	Ratio	Activity	Site specific component count	Site specific component count	Estimated component count
					Emission Factor	Measured emission factor of normally operating and malfunctioning devices Device-specific emission factor	Default national or regional emission factor by type	Total pneumatic vent rate by supply chain stage
Centrifugal Compressor Venting from Geologic Storage[14]	✓		✓	Ratio	Activity	Measured gas volume Actual count		Stage-wide compressor vent rate

[14] See note 12

					Emission Factor	Actual leak rate based off LDAR Vendor-specific leak rate based off measurement study Measured CO2/CH4 composition of vent gas	Default emission factor for leak Default CO2/CH4 composition of vent gas	
Reciprocating Compressor Venting from Geologic Storage[15]	✓		✓	Ratio	Activity	Measured gas volume Actual count		Stage-wide compressor vent rate
					Emission Factor	Actual leak rate based off LDAR Vendor-specific leak rate based off measurement study Measured CO2/CH4 composition of vent gas	Default emission factor for leak Default CO2/CH4 composition of vent gas	
Fugitive Emissions from Geologic Storage	✓		✓	Ratio	Activity	Quantified leakage rates per component Actual number of leaking components Actual component counts by device and service type	Component count estimates by major equipment counts or other indirect means	Stage-wide leak rate for all fugitives or individual components
					Emission Factor	Measured CO2/CH4 composition of gas	Default emission factor for each component Default CO2/CH4 composition of gas	

[15] See note 13

Combustion Equipment at Onshore Petroleum and Natural Gas Production facilities, Gathering and Boosting facilities, and Natural Gas Distribution facilities[16]	✓	✓	✓	Ratio	Activity	Metered total fuel usage	Estimated fuel usage using mass balance	Stage-wide calculated horsepower + energy requirements
					Emission Factor	Stack testing of CH4 slip Manufacturer-specific emission factor based off measurement results Measured hydrocarbon composition of fuel gas	Default equipment-specific emission factor Manufacturer-specific emission factor not based off measurement results Default hydrocarbon composition of fuel gas	Stage-wide default emission factors

[16] Combustion emissions from natural-gas fired compressor drivers must be allocated entirely to the gas product for Natural Gas Operations

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 Carbon Intensity Standard.

Table 4: Version History

Version	Revision Date	Summary of Change
v0.9	2023-03	Pilot Version
v1.0	2024-05	Reference ISO 14067:2018 as a normative standard

Revised scope of Standard to emphasize the quantitative output as the calculation of individual GHG_i intensities

Defined allocation principles for both Petroleum Operations and Natural Gas Operations Facilities

Removed requirement to calculate total CO_2e intensity

Added standard definitions of hydrocarbon liquids intensity including defining the hydrocarbon liquids intensity metric

Updated definition of site-specific data to be an interchangeable term with primary, preferred data

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