Monitoring & Reporting Guidelines for Flare Reduction CDM Projects

Prepared by the Oil & Gas CDM/JI Methodology Workgroup

REPORT # 2
About this Document

This document was commissioned by the Oil & Gas Methodology Workgroup (WG) to assist in the designing and implementing of appropriate plans and methodologies for monitoring emission reductions from flare mitigation (gas recovery) projects.

Of the limited number of flare projects registered under the CDM/JI scheme to date, several have had problems with meeting industry standard monitoring requirements, which has resulted in delays of verification and issuance of CERs and, in some instances, inability to verify the emission reductions. According to the CDM Guidebook: Navigating the Pitfalls (Second Edition), there are various problems commonly identified during validation and verification of CDM project that relate to project monitoring and reporting. These are summarized as:

Pitfall 19: Insufficient information on the measurement methods and source of data as part of data/parameter description in monitoring plan
Pitfall 20: Deviations from monitoring methodology not justified sufficiently
Pitfall 21: Monitoring and project management procedures not defined

This document is therefore a contribution towards avoiding these and other specific issues that project developers may encounter. The guidelines, however, do not provide any guarantee on the likelihood of meeting validation and verification requirements or receiving CERs. Achieving this is down to the individual project developer, the opinion of DOEs undertaking verification, and ultimately the CDM Executive Board.

The document is meant to be living reference; therefore it should be updated regularly, based on periodic reviews that would allow to incorporate lessons learned by industry and practitioners, and to reflect any changes in the framework that regulates the creation of carbon offsetting projects.

Ideas, comments, suggestions or potential contributions, will be much welcomed. These should be sent to: ogmc@worldbank.org.

Acknowledgments

This product was led by the Global Gas Flaring Reduction partnership and prepared by consultants Paul Zakkour (Carbon Counts); Andrew Jakubowski (Camco); and Francisco Garcia Koch (Camco). Document QA by Wiley Barbour (Camco); Ron Collings (Ruby Canyon Engineering); and Francisco Sucre (GGFR). The document also benefited from the valuable input provided by: Greig Callaghan (Total); Raul Hurtado (Statoil); Steve Ross (ISR); and Lynn Hunter (TUV Nel Ltd).

Cover photo: from www.ap.emersonprocess.com/

1 The O&G Methodology Workgroup is part of the Carbon Finance Network of the Global Gas Flaring Reduction partnership (GGFR). The Workgroup is technically-oriented collaborating network of stakeholders involved in oil and gas operations, which contributes to emission trading schemes as an important part of the scaling up of emissions reduction efforts in the oil and gas industry (www.oilandgasmethgroup.org).
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<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
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<tr>
<td>AM</td>
<td>Approved Methodology (CDM)</td>
</tr>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>ASTM</td>
<td>American Society for Testing and Materials</td>
</tr>
<tr>
<td>CEN</td>
<td>European Committee for Standardization</td>
</tr>
<tr>
<td>CER</td>
<td>Certified Emission Reduction (the tradable unit issued for 1 tCO$_2$ of verified emission reductions from a CDM project, determined in accordance with the PDD monitoring plan)</td>
</tr>
<tr>
<td>CDM</td>
<td>Clean Development Mechanism</td>
</tr>
<tr>
<td>CDM EB</td>
<td>CDM Executive Board (the supreme body responsible for CDM implementation)</td>
</tr>
<tr>
<td>DNA</td>
<td>Designated National Authority</td>
</tr>
<tr>
<td>DOE</td>
<td>Designated Operational Entity (a third party accredited by the UNFCCC for the validation and verification of CDM projects)</td>
</tr>
<tr>
<td>EU ETS</td>
<td>European Union Emissions Trading System</td>
</tr>
<tr>
<td>IEC</td>
<td>International Electrotechnical Commission</td>
</tr>
<tr>
<td>ISO</td>
<td>International Organization for Standardization</td>
</tr>
<tr>
<td>MJ</td>
<td>Megajoule</td>
</tr>
<tr>
<td>MRGs</td>
<td>EU ETS monitoring and reporting guidelines</td>
</tr>
<tr>
<td>NCV</td>
<td>Net calorific value (both high and low heating value)</td>
</tr>
<tr>
<td>NM</td>
<td>New Methodology</td>
</tr>
<tr>
<td>OEM</td>
<td>Original equipment manufacturer</td>
</tr>
<tr>
<td>PDD</td>
<td>Project Design Document</td>
</tr>
<tr>
<td>QA/QC</td>
<td>Quality Assurance &amp; Quality Control</td>
</tr>
<tr>
<td>tCO$_2$</td>
<td>Tonne of carbon dioxide</td>
</tr>
<tr>
<td>UNFCCC</td>
<td>United Nations Framework Convention on Climate Change (and the Secretariat which supports implementation)</td>
</tr>
<tr>
<td>WG</td>
<td>CDM/JI Oil &amp; Gas Methodology Workgroup</td>
</tr>
<tr>
<td>VVM</td>
<td>CDM Validation and Verification Manual</td>
</tr>
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</table>
1 Introduction

This report sets out monitoring and reporting guidelines for flare reduction projects undertaken as clean development mechanism (CDM) project activities. The scope and focus of the document is on utilized recovered gas, which otherwise (if not for the CDM project) would be flared, and not on measurement and monitoring of direct flare gas.

To date, there has been mixed experiences with monitoring and reporting for flare reduction CDM projects, primarily due to poor formulation and implementation of monitoring plans – either through inappropriate collection of data or variation of the monitoring plan to that set out in the PDD. This has been an issue for achieving verification by Designated Operational Entities (DOEs) and ultimately has negatively affected the issuance of certified emission reductions (CERs) from the UNFCCC CDM Executive Board (EB). Ambiguity, variations and lack of clarity in existing CDM methodologies applicable to flare reduction projects are also major concerns for project participants. Unfortunately, these factors have created challenges for monitoring plan design, implementation and verification.

These guidelines are designed to assist project developers and operators understand the types of issues and approaches required to ensure CDM projects have effective monitoring standards in place which can properly determine the emission reductions achieved during both project implementation and operation. These guidelines are based on the available knowledge and experience from flare reduction CDM projects to date. Where applicable, these guidelines draw upon best practice examples at the time of writing, as covered in the European Union Emission Trading System (EU ETS), the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC GLs), and other relevant literature.

Therefore this document should be considered as a “living document” and as such should be periodically reviewed, updated and, when necessary, revised, to reflect changes in the underlying baseline and monitoring methodologies, development of new Baseline and Monitoring Methodologies and the solutions presented to problems encountered by the WG members during validation and verification, to ensure it remains relevant. The reader is kindly requested to contact the Document Manager to ensure the most up-to-date version of these Guidelines is available.

The guidelines cover the following aspects of monitoring and reporting:

- Principles of monitoring and reporting
- Pipeline flow measurements
- Batch measurements
- Training, maintenance and calibration requirements

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4 Document Manager: Staff from the World Bank-led Global Gas Flaring Reduction partnership, which facilitates the WG (currently Francisco J. Sucre – ojmsc@worldbank.org, +1-202-473-5479)
Uncertainty assessment

It is important to note that whilst certain industry standards and norms are often applied to monitoring and reporting of greenhouse gas emissions data in the oil and gas sector, such standards may not necessarily meet the requirements set down in CDM methodologies. Each project will need to be assessed against the specific Approved Methodology (AM) which is applicable to the project and the current monitoring practice covering the requirements.

Disclaimer: whilst every effort has been made to make these guidelines representative of the current state of the art knowledge on monitoring and reporting for emission reduction activities and projects, following these guidelines does not provide any guarantee on the likelihood of meeting validation and verification requirements or receiving CERs. This is down to the individual project developer, the opinion of DOEs undertaking verification, and ultimately the CDM EB.

2 Principles of and approaches to monitoring and reporting

This section covers two key aspects of monitoring and reporting of emissions:

2.1 Principles of monitoring and reporting: setting out the basis for which monitoring and reporting requirements should be approached

2.2 Commonly used terms: setting out the fundamental methodological basis for monitoring and reporting of greenhouse gas emissions

The information presented in these contexts is drawn from current best practice around the world including rules for the CDM, the European Union greenhouse gas emissions trading system (EU ETS) and the Intergovernmental Panel on Climate Change guidance on compilation of national greenhouse gas inventories.

2.1 Principles of monitoring and reporting

The following principles apply in monitoring and reporting of emissions (and emission reductions). It is these principles that form the basis for all considerations in design and implementation of a monitoring plan for a CDM project activity.

2.1.1 Accuracy and trueness

Checking for accuracy in the context of the CDM means for:

(a) quantitative data and information minimizing bias and uncertainty in the measurement process and the processing of data; and

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5 For example, the American Petroleum Institute Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (API, 2004) or other internal company standards or guidelines.

(b) non-quantitative information minimizing bias in favour of a particular result.

Sources of uncertainties should be identified by project developers and operators and reduced as far as practicable.

All metering or other testing equipment used to report monitoring data should be appropriately applied, maintained and calibrated and checked (see next Sections). Spreadsheets and other tools used to store and manipulate monitoring data should be free from error.

2.1.2 Relevance

Information can be considered relevant if it ensures compliance with the CDM requirements and the quantification and reporting of emission reductions achieved by a project activity. Unnecessary data and assumptions which do not have an impact on the emission reductions are not considered as relevant.

2.1.3 Credibility

Information can be considered credible if it is authentic and is able to inspire belief or trust, and the willingness of persons to accept the quality of evidence.

2.1.4 Reliability

Information can be considered reliable if the quality of evidence is accurate and credible and able to yield the same results on a repeated basis over time using the same monitoring method and data sets. Where accuracy can be improved, such efforts should be made and fully documented.

2.1.5 Completeness

Completeness refers to inclusion of all relevant information for all relevant sources of data that are required for assessment of GHG emissions reductions and the information supporting the methods applied as required.

2.2 Commonly used terms

There are a number of commonly used terms which are widely applied to describe the efficacy of monitoring systems. The two most important ones are accuracy and uncertainty. The European Union guidelines for monitoring and reporting under the EU Emissions Trading System\(^7\) apply the following definitions to these terms:

\[\text{‘accuracy’ means the closeness of the agreement between the result of a measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both, random and systematic factors;}\]

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\(^7\) Op cit.
'uncertainty’ means a parameter associated with the result of the determination of a quantity, which characterises the dispersion of the values that could reasonably be attributed to the particular quantity including effects of systematic and random factors expressed in per cent and describes a confidence interval around the mean value comprising 95 % of inferred values taking into account any asymmetry of the distribution of values.

The term ‘precision’ is also often used when describing monitoring and data, but should not be confused with accuracy. Precision describes the degree to which two measurements under stable and constant conditions result in identical outcomes or the repeatability and reproducibility of a particular result, irrespective of whether it is accurate (Figure 1).

![High accuracy, low precision](image1.png) ![Low accuracy, high precision](image2.png)

**Figure 1** The target example - difference between accuracy and precision

In order to maintain a high level of accuracy, equipment calibration is undertaken using standardised reference values (see Section 3.6.2) whilst uncertainty can be computed based on probability analysis and error propagation estimates for uncorrelated variables (see Section 13) to determine the margin of error. Uncertainty analysis can be used to account for the combined effects of both accuracy and precision.

Other commonly used methodological approaches to monitoring include the generalized emission calculation formula and the use of standard or normal conditions, as described in the following sections.

### 2.2.1 Generalized emission calculation formula

For liquid and gaseous fuels, the following generalized formula is applicable for calculating carbon dioxide (CO₂) emissions in most circumstances:

\[
\text{CO}_2 \text{ emissions} = \text{activity data} \times \text{net calorific value} \times \text{emission factor} \times \text{oxidation factor}
\]

Where;

- **CO₂ emissions** are the absolute emissions over a given period of time (in tCO₂)
- **Activity data** is the level of consumption of a particular product, usually in mass or volume (t or Nm³)
**Net calorific value** or lower heating value (LHV) is the heat released by combusting a unit mass and returning the temperature of the combustion products to 15 °C (Megajoules per unit mass or volume). ⁸

**Emission factor** is the carbon content of the gas (in tCO₂/MJ (in this example to standardise units))

**Oxidation factor** reflects inefficiencies in the combustion process that may leave some of the carbon unburnt or partly oxidised (in %; typically a figure of 1.0 is assumed as a conservative value).

For flare reduction CDM projects, the key objective of monitoring is the process of data collection to support this generalized formula, taking into account accuracy and uncertainty as defined previously. A number of different measurement points will generally be applied in order to determine baseline emissions and project emissions, the difference of the two providing the basis for emission reduction calculations. Where multiple measurements are used to determine a single value – as is often the case – it is good practice to determine the level of overall uncertainty (see Section 13).

### 2.2.2 Standard conditions and unit conversions

Two important issues to consider when ensuring accurate recording and measuring of emission reductions is the conversion of data to standard conditions and the use of appropriate unit conversions.

Standard or normal conditions for temperature and pressure are widely employed as follows:

- **Standard conditions**: 0°C (273.15°K) at 1.01325 bara (atmospheric pressure; 1 atm)
- **Normal conditions**: 15°C (288.15°K) at 1.01325 bara (atmospheric pressure; 1 atm)⁹

The reporting condition (i.e. either Standard or Normal) should be selected at the beginning of the project activity and stated clearly throughout the project design document, as well as in particular in the monitoring plan design.¹⁰

The EU ETS currently endorses the following for monitoring and reporting purposes:

- ‘standard conditions’ means temperature of 273.15 K (i.e. 0°C) and pressure conditions of 101,325 Pa defining normal cubic meters (Nm³).

Measurements can be converted to either condition using the universal gas law.

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⁸ The Net Calorific Value is the total quantity of heat released during combustion when all water formed by the combustion reaction remains in the vapor state. The Gross Calorific Value is the total quantity of heat released during combustion when all water formed by the combustion reaction is returned to the liquid state.

⁹ ISO 13443 Natural Gas Standard Reference Conditions; European Environment Agency. There is considerable uncertainty around what constitutes standard and/or normal conditions. Some literatures use 15°C, some use 20°C and some use 25°C.

¹⁰ This should include reference to the precise temperature and pressure conditions assumed for whatever reference conditions are selected. In practice, the precise definition of reference conditions vary significantly between different bodies and there is no universally accepted format applicable worldwide.
Ideal gas law

Conversion of field units to standard conditions can be achieved through the use of the ideal gas law based on the following:

\[ PV = nRT \quad \text{or} \quad \frac{V}{n} = \frac{RT}{P} \]

Where;
- \( P \) is the absolute pressure of gas in atm (1 atm = 1.01325 bara)
- \( V \) is volume in litres (\( = 0.001 \text{ m}^3 \))
- \( n \) is the number of moles of gas (determined through gas analysis)
- \( R \) is the universal gas constant (0.0820574587 litres \( \cdot \) atm \( \cdot \) K\(^{-1} \) \cdot mol\(^{-1} \))
- \( T \) is the temperature in °K (°C plus 273.15)

Example calculations for converting field measurements to standard conditions (Sm\(^3\) or scm)

The example case has the following field measurements:

- Start meter reading: 101,729 (in m\(^3\))
- End meter reading: 110,369 (in m\(^3\)) = 8,640 m\(^3\)
- Period: 24 hours
- Pressure: 2 bara (1.974 atm)
- Ave. Temperature: 22°C (295.15°K)
- \( n \): 16.0425 (g/mol for pure methane)

**Conversion field m\(^3\) to scm**

\[
P_S * \frac{V_S}{T_S} = P_F * \frac{V_F}{T_F} \quad \text{rearranging to} \quad V_S = V_F * \left( \frac{P_F}{P_S} \right) * \left( \frac{T_F}{T_S} \right) = 18,428 \text{ Sm}^3
\]

Where; suffix S = standard conditions; F = field measurement

**Conversion to mass flow**

\[
\text{Density} = \frac{Pn}{RT} = \frac{1.974 * 16.0425}{0.082057 * 295.15} = 1.307 \text{ kg/m}^3 \quad (0.7157 \text{ @ std cond})
\]

\[
\text{Mass flow (kg/hr)} = \frac{8640}{24} * \text{Density} = 360 * 1.307 = 470.7 \text{ kg CH}_4/\text{hr}
\]

A variety of real gas laws can be applied to convert the calculated mass ideal gas law to account for compressibility. This is because gases exhibit deviations from ideal behaviour when nearing a phase change (i.e. at condensation or critical point) or at low temperatures or high pressures). The adjustments are based on using equations of state.
based on empirical observations of behaviour to determine the factor \( Z \) to adjust calculations made using the ideal gas law. Therefore, for greater accuracy in situations where gas is near its condensation or critical point, or at very high pressures, it may be preferable to apply real gas laws to the calculation of mass flow. However, for most circumstances, the ideal gas law provides sufficient accuracy for the purpose of CDM monitoring requirements.

It is advisable to consult with metering specialist to understand whether results from metering is based on ideal gas or real gas laws when considering secondary instrumentation (see Section 3.4)

**Unit conversions**

Often oil & gas field measurements are made in imperial units. The following provides conversion factors for commonly used units.

**Table 1  Conversions for commonly used units**

<table>
<thead>
<tr>
<th>Unit</th>
<th>Abbreviation</th>
<th>Conversion</th>
<th>Unit</th>
<th>Abbreviation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Volume</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Millions of standard cubic feet</td>
<td>MMscf *</td>
<td>0.028317</td>
<td>Millions of standard cubic metres</td>
<td>MMscm</td>
</tr>
<tr>
<td>Millions of standard cubic feet per day</td>
<td>MMscfd</td>
<td>0.028317</td>
<td>Millions of standard cubic metres per day</td>
<td>MMscmd</td>
</tr>
<tr>
<td>Gallon</td>
<td>g</td>
<td>0.0037854</td>
<td>Cubic metre</td>
<td>m³</td>
</tr>
<tr>
<td><strong>Mass</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pounds</td>
<td>lb</td>
<td>0.45359</td>
<td>Kilogrammes</td>
<td>kg</td>
</tr>
<tr>
<td><strong>Pressure</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pound per square inch</td>
<td>PSI or lb/in²</td>
<td>0.068948</td>
<td>bar</td>
<td>bar</td>
</tr>
<tr>
<td>Megapascal</td>
<td>Mpa</td>
<td>10</td>
<td>bar</td>
<td>bar</td>
</tr>
<tr>
<td>Bar gauge</td>
<td>barg</td>
<td>n/a**</td>
<td>bar atmosphere</td>
<td>bara</td>
</tr>
<tr>
<td><strong>Heating value</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Million British thermal units</td>
<td>MMBTU</td>
<td>1.0551</td>
<td>Kilojoules</td>
<td>kJ</td>
</tr>
<tr>
<td>Megawatt hour</td>
<td>MWh</td>
<td>3600</td>
<td>Megajoules</td>
<td>MJ</td>
</tr>
</tbody>
</table>

* MM denotes 1,000 x 1,000 (= 1,000,000)

** Conversion from bar gauge to absolute pressure is achieved by adding measured gauge pressure to atmospheric pressure at the time.

3  **Pipeline Flow Measurement**

The measurement of flow in pipelines typically involves the use of a volumetric flow measurement device – a meter – to calculate the amount of gas passing through a
pipeline. In volumetric flow meters, metered flow measurement provides a flow rate or volumetric flow rate of the fluid in the pipe (in metres or cubic metres per unit time), which must be subsequently adjusted for temperature and pressure of the fluid to arrive at a volumetric measure of flow (in cubic metres per unit time). The density of the fluid may also be used to convert to a mass flow (e.g. kilograms per unit time, as described in the previous section). Consequently, flow meters must be calibrated against these parameters, with measurements usually converted to standard conditions as described above (Section 2.2.2).

An exception to these observations is the coriolis flow meter, which directly measures mass flow without the need to apply adjustments to convert volumetric flow to mass flow.

The measured volume or mass flow of gas provides the basis for the “activity data” within the generalized emission calculation formula presented previously in section 2.2.1.

3.1 Types of meters

Various types of metering instrumentation available for measuring volumetric gas flows including:

- Rotary/positive displacement
- Turbine
- Coriolis
- Orifice
- Ultrasonic

Coriolis meters are a type of meter that allows direct measurement of mass flow. There are important capabilities and limitations that should be carefully evaluated when selecting the type(s) of required meter. Aspects such as flow capacity, rangeability (i.e., ratio of the maximum to minimum applicable flow), and inaccuracy of each technology for ideal conditions involving fully-developed flow of clean dry gas (i.e., to provide a standard basis for comparison), are some of the considerations. A comparison of the flow measurement technologies that may be considered in vent and flare gas applications is shown in Appendix 1.

Presently no greenhouse gas emissions trading programs anywhere in the world provide prescriptive guidance on the type of meter to be employed for specific applications. This is because a range of different types could potentially be employed to meet the same objective. Performance in terms of accuracy and reliability will vary by manufacturer and product specification, and the manufacturer’s guidance will need to be referred to determine which is most appropriate for different circumstances (see Section 3.3 on Instrumentation Selection).\(^\text{11}\)

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The selection of meters has cost implications with high-end meter systems having installed costs of approximately US$20,000 - $100,000 per unit or more.

3.2 Metering objectives

A number of terms are widely used to describe the purpose of different metering systems. None of these terms are standardised in international handbooks or ISO codes, however they are often widely used in industry. A brief summary of some of the terms used are given below

- **Fiscal metering**: Sometimes referred to as custody transfer it does not imply any standard of performance but applies to its service. Fiscal meters are used where there is a transfer of ownership of the product in the pipeline, and hence are linked to transfer of money. For this reason, the accuracy requirements tend to be high. Certain standards may be applied (e.g., American Petroleum Institute) to define the tolerable levels of uncertainty. The exact level of uncertainty acceptable in the fiscal metering system will be determined by the contract established for the sale or production license for the oil and/or gas. Levels of overall uncertainty of ±0.25% for dry gas can typically be required.

- **Allocation metering**: Allocation metering is used to measure movements of oil & gas between different process, i.e., for the purpose of surveillance and flow assurance. It is also used to detect blockages leaks etc that could be restricting flow in certain parts of a plant. Allocation metering systems can be fairly accurate, but are not usually to fiscal standards, typically with overall uncertainty in the range ±3 - 5% for dry gas. However, this could be as high as ±10 - 20% or more depending on levels of maintenance and calibration carried out.

- **Check metering**: Check meters are usually simply employed to detect the presence of flow, in which case accuracy is less of concern. Check meters may also be used as temporary devices to check and calibrate the performance of other meters, such as clamp on (non-intrusive) ultrasonic meters.

In practice, terms are sometimes interchanged, for example: reference to production allocation metering could imply fiscal metering standards where the allocation determination is linked to royalty payments. Thus, it is recommended these terms are used with caution by project developers.

At the time of writing, AM0037 v2.1 suggests the use of “custody meters” for the measurement of volumes (m³) of associated gas utilised that enters the pipeline. Whilst this implies a high level of accuracy, it does not provide any direct assurance or clear benchmark against which to assess whether these conditions are being met. This point should be made clear in PDDs following this methodology, and additional quality assurance checks described in the PDD according to the actual checks that are carried out on the fiscal metering systems (where applicable).

3.2.1 “By difference” approach

Estimates of pipeline flow may also be made using an inventory or “by difference” approach, where the amount of flow in a pipeline is estimated from an allocation meter.
systems gathered from across an installation, the net amount unaccounted for being the estimated flow to a particular section. This approach is typically used for flare volume estimates, where the high range of flow conditions (pressure, density/fluid content) make accurate metering particularly difficult (see Field Instrumentation Selection), whilst safety requirements also restrict the scope for using intrusive or in line measurement techniques (because of the risk of blockages occurring in the flare line).

3.3 Field instrumentation selection
Field instrumentation selection for CDM projects will generally be determined by the level of accuracy required from the equipment to fulfil the principles of monitoring and reporting (see Section 2.1), taking into account the given operational and environmental conditions. As outlined previously, no greenhouse gas emissions trading programs anywhere in the world provide prescriptive guidance on the type of meter to be employed for specific applications. Therefore, project developers and operators need to account for a range of factors when selecting field instrumentation. These include:  

- Accuracy
- Fluid and flow conditions
- Operational requirements, safety and security

These factors are reviewed in more detail in the next sections.

A guide to metering type, application, rangeability and accuracy is provided in Appendix 1.

3.3.1 Accuracy
Accuracy requirements will generally be based on the purpose of the meter (see Section 3.2). Where the CDM is concerned, good practice would suggest selection of instrumentation that can provide uncertainty measurements within the tolerances provided in Table 2 (also see Section 13).

3.3.2 Fluid and flow conditions
A number of conditions effect meter choice in this context, which include:

- **Gas condition:** whether the meter is measuring dry gas or is installed on a multiphase flow line. Whether contaminants and/or moisture is present in the gas (which could allow acid to form), and the compatibility of component parts of the meter with the gas conditions.
- **Flow variation:** the choice of meter needs to consider the range of flow conditions (maximum, minimum) to which it will be subjected. The envelope of accuracy can

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12 A useful check list and guide to meter selection is available at: [http://www.omega.co.uk/prodinfo/flowmeters.html](http://www.omega.co.uk/prodinfo/flowmeters.html)

13 Multiphase flow measurement is a particularly challenging area for metering. A full analysis of this issue has not been possible within these guidelines.
fall off significantly outside of its design operating flow conditions. This characteristic is termed “rangeability.” The nature of flow in the pipe (linear or non-linear) will also affect accuracy of readings, and must be taken into account. In some cases, where non-linear flow is present, but other constraints mean that the meter must be placed there, calibration of the meter readings based on computational fluid dynamics (CFD) analysis may be required.

- **Pressure**: as for flow variations, some meters may only have limited accuracy outside of their design operating pressure. Pressure drop across the meter may also be an important consideration, especially in low pressure environments. In certain situations, restrictions on allowable pressure drop may and preclude the use of certain types of meters.
- **Temperature**: sudden changes in temperature of the gas may also affect meter accuracy.

A review of these factors for different meter types is contained in Appendix 1.

### 3.3.3 Operational requirements, safety and security

As well as accuracy requirements, other operational factors should be taken into consideration in meter selection. These include:

- **Reliability**: requirements may be determined by internal standards on equipment selection/procurement. Where access is difficult or the meter is remotely located, then the use of reliable meters which do not require high levels of calibration and maintenance will also dictate choices.

- **Safety**: in some circumstances, safety will be a consideration. Where there the meter poses the risk of blockage (e.g. on flare lines or where slugs are present in multiphase lines), non intrusive technologies may be required (e.g. ultrasonic meters).

- **Access**: if the meter is located in a remote location, then reliability needs are likely to increase. Furthermore, electronic signal output may be required, and a choice must also be made on whether there is a need for an external display. CDM QA/QC procedures relating to calibration should be observed and taken in to account when selecting and locating the meter (please refer to section 3.6.2)

- **Security**: some meter locations may present the risk of tampering, vandalism or theft. This may require the use of smaller more discrete units to avoid attracting attention.

### 3.4 Secondary instrumentation / system integration

Data that needs to be monitored needs to be reported to a standard condition of temperature and pressure and monitored at a frequency established in the corresponding CDM Baseline and Monitoring Methodology.

Instrumentation for temperature and pressure therefore also needs to comply with similar standards as that of the metering equipment.
The level of integration that is appropriate will be related to the CDM baseline and Monitoring Requirement. Therefore it is essential that instrumentation and systems specification be made taking into account the CDM requirements.

3.5 Design, installation and commissioning

The design of a monitoring and reporting system is a key feature to the success of a CDM project. Data integrity, validity, security and auditing are key components to successful gas flare emission reduction projects. The CDM methodologies are vague and do not provide much detail as to the specifications of design, installation, and commissioning of project monitoring and reporting systems for pipeline flows because this is a matter left to the operator to decide upon. What matters is that the installed system is designed and operated in a way that ensures the CDM Monitoring and Reporting Requirements are met. This section is aimed at providing more detailed information for general monitoring and reporting systems and standards that are applicable to all gas flare emission reduction projects, as well as details that relate to the requirements of specific CDM methodologies.

There are several reporting requirements that are important to all CDM methodologies, which cover emission data, uncertainty, and means of reporting. The basis of a monitoring and reporting plan should aim to meet all the requirements of the UNFCCC procedures to ensure an accurate and precise accounting of emission reductions.

The UNFCCC CDM methodologies state that project developers are required to provide a “detailed explanation of quality assurance and quality control procedures.” These quality assurance and quality control procedures should be aimed at providing and recording the data “parameters with medium or high uncertainty in an attempt to decrease uncertainty, and to ensure that emissions reductions calculations are not compromised.” Therefore it is of utmost importance to design, install and commission the monitoring systems in accordance with international best practice and in line with the requirements of the approved UNFCCC CDM methodologies for gas flare projects.

The approved UNFCCC CDM methodologies will change over time depending on methodology deviations and revisions which are submitted by CDM project developer and/or project participants. Currently, at the time of writing these monitoring guidelines the versions which are available that are related to gas flaring in the oil and gas sector are the following:

- Methodology AM0009 – Recovery and utilization of gas from oil wells that would otherwise be flared or vented, version 04
- Methodology AM0037 – Flare (or vent) reduction and utilization of gas from oil wells as a feedstock, version 02.1
- Methodology AM0055 – Baseline and Monitoring Methodology for the recovery and utilization of waste gas in refinery facilities, version 01.2

14 Taken from UNFCCC approved Methodology AM0055 Baseline and Monitoring Methodology for the recovery and utilization of waste gas in refinery facilities.
• Methodology AM0074 – Methodology for new grid connected power plants using permeate gas previously flared and/or vented, version 2

• Methodology AM0077 - Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users, version 1

• Methodology ACM00012 – Consolidated baseline methodology for GHG emission reductions from waste energy recovery projects, version 03.2

Each of these methodologies has design criteria of precisely which data parameters to measure and where in the monitoring system to measure them. In general, each of the designed, installed and commissioned monitoring and reporting systems should have meters which are “installed, maintained and calibrated according to equipment manufacturer instructions and be in line with national standards, or if these are not available, international standards (e.g. IEC, ISO).”

3.5.1 Design

Monitoring equipment not only has to be installed, maintained and calibrated in line with manufacturer’s instructions and national/international standards, but the design of the system should be in accordance with the latest approved UNFCCC CDM methodology that is applicable to the project at hand. In some instances, aspects of the monitoring and reporting systems will be consistent with what is expected as normal best practice for gas flaring projects. However, in the context of CDM projects, there may be additional monitoring and reporting requirements which are specific to CDM. As an example below is a discussion of some of the monitoring requirements for two types of CDM projects: 1) a project which recovers and utilizes waste gas in refinery facilities (CDM Methodology AM0055); and 2) a project which recovers and utilizes gas from oil wells that would otherwise be flared or vented to the atmosphere (CDM Methodology AM0009). The examples of the unique CDM requirements for proper design and installation will give a sense of how they may differ from best practice in similar non-CDM projects.

Recovery and utilization of oil well gas

The project type, which recovers and utilizes gas from oil wells that would otherwise be flared or vented to the atmosphere, has a few data points which need to be monitored and reported. Some of the points need to be monitored continuously and others at least once a month. The figure below is a schematic illustration of the CDM project activity with all the major components as well as the project boundary, i.e. the area of the project activity, which encompasses all the anthropogenic emissions by sources of greenhouse gases (GHG) under the control of the project participant, and are significant and reasonably attributable to the CDM project activity.

15 Taken from UNFCCC approved Methodology AM0037 Consolidated baseline methodology for GHG emission reductions from waste energy recovery projects.
Two important measurements need to be taken at Point F in Figure 2, which is just downstream of the pre-treatment of the recovered gas. The measurement at Point F includes during a given time period, the net calorific value (NCV) and the volume of the total recovered gas during a given period. The NCV is to be measured in TJ/Nm$^3$ and the volume in Nm$^3$.

The volumetric data of the gas should be measured using calibrated flow meters. They should be calibrated by a trained and qualified technician and should be taken at the point(s) where the recovered gas exits the pre-treatment facility.

Additionally, the NCV measurements should be undertaken in line with national and/or international fuel standards. As part of quality assurance and control the project participants should ensure the laboratories performing NCV measurements have ISO17025 accreditation or justify they can comply with similar quality standards.

The volume of gas should be completely metered with regular routine calibration of metering equipment. The measured volume of gas should be converted to the volume at normal temperature and pressure using the temperature and pressure at the time to measurement.

There are also sources of project emissions which need to be accounted for up to the points A and C in Figure 2. These project emissions are CO$_2$ due to the consumption of fossil fuels for the recovery, pre-treatment, transportation, and if applicable, compression of the recovered gas. In addition to the consumption of fossil fuels, CO$_2$ emissions due to the use of electricity for recovery, pre-treatment, transportation and if applicable, compression of the recovered gas up to the points A and C in Figure 2 need to be made.
**Recovery and utilization of waste gas in refinery facilities**

As with the previous project type which recovers and utilizes gas from oil wells this project recovering and utilizing waste gas in refinery facilities also has a few data points which need to be monitored and reported. The figure below is a schematic illustration of the CDM project with all the major components as well as the project boundary.

**Figure 3: Schematic illustration of the project activity from Methodology AM0055 – Baseline and Monitoring Methodology for the recovery and utilization of waste gas in refinery facilities**

There are a series of data points which need to be measured and the monitoring and reporting system should be designed and installed to ensure all of the points are accurately monitored. The monitoring system design should include the following:

- amount of recovered waste gas, but also;
- composition of recovered waste gas;
- amount of energy consumed by the project activity either from the grid or imported;
- data needed to calculate the emission factors from the electricity used in the project activity, either captive or imported;
- data needed to calculate the emission factors from fossil fuels used for process heating and steam generation within the refinery, and
• data needed to assure the recovered waste gas has in fact been used for heating process purposes;

In order to carry out these measurements the monitoring and reporting system design should incorporate the proper monitoring equipment.

Besides gasflow metering, a chromatography performed at an on-site refinery laboratory or at an external laboratory should be carried out to determine the gas composition and subsequent standard calculations to obtain the lower heating value (LHV) and density of the waste gas.

In order to maintain a high level of quality assurance and control the method of chromatography should follow a recognized standard such as American Society for Testing and Materials (ASTM), International Organization for Standardization (ISO), European Committee for Standardization (CEN), or American Petroleum Institute (API). As mentioned previously all the monitoring equipment should be maintained and calibrated regularly according to manufacturer’s requirements.

Volume of waste gas that will replace fossil fuel used for process heating can be measured with on-site flow meters placed at the point where waste gas is added in other fuel gases to be sent to the element process(es). For quality assurance and control purposes the flow meters should be maintained and calibrated regularly according to manufacturer’s requirements and international best practice.

These are just a few of data parameters to be measured in some example CDM projects and how best to ensure quality data. The figures should help to provide some guidance as to the design of the monitoring system and where flow meters should be placed and/or samples for chromatography be taken for the example CDM projects. The project participant should write a detailed monitoring and reporting plan, which will include design and regularity of monitoring the data parameters. This monitoring plan should be part of the CDM Project Design Document (PDD). This monitoring plan will be the basis for the DOE’s audit for validation of the CDM project and also will be used as a guidance tool throughout the crediting period of the project for annual verifications.

It should be noted that the criteria for location of the metering and instrumentation under the CDM Monitoring plans should not only comply with good engineering practice, it should also be consistent with the requirements of the CDM in terms of the flows that need to be measured. To this effect it is essential that the location of the metering points be consistent with those given in the CDM methodologies.

Thus when locating metering it is necessary to have up to date piping and instrumentation diagrams (P&IDs) to ensure the meter(s) measure the flow(s) that needs to be measured according to the CDM methodology monitoring requirements as shown in the corresponding diagrams in the CDM Baseline and Monitoring Methodologies.

Moreover caution needs to be exercised to prevent departure from single phase flow. This will change the properties of the fluid being metered and lead to erroneous metering of the gas flow. Liquid entrainment into the gas stream as a result of up stream process upsets or inadequate control may for instance cause plugging, slugs and/or interference with the meter’s operation. Hence good control of upstream process is important in assisting proper operation of downstream metering equipment, and thus quantification of emissions reductions. Proper metering system design should include a review of possible process variations that may affect the performance of downstream metering equipment,
and be taken into account at this early stage. Moreover, the Monitoring and Reporting Management system should contemplate procedures for managing and correcting where there is a possibility that these circumstances could arise.

Similarly the gas sampling points should be located on the appropriate streams and be readily accessible.

Interfacing between the CDM team and departments responsible for designing, specifying, installing and commissioning the metering system is thus important, especially in relatively complex situations involving multiple flows and pipes. What may not appear too important from an engineering standpoint might have a major impact from the CDM one.

Experience to date suggests that meter location can pose some challenges as it may in some cases be at odds with operations on the ground. In such cases the situation must be put forward to the DOE to assess whether a proposed solution is acceptable or whether it merits a request for Clarification, Deviation or Request for Revision of the CDM Baseline and Monitoring Methodology applied.

### 3.5.2 Commissioning

Although there is some guidance to the design and installation of monitoring systems as well as quality assurance and control best practices, there are no detailed methods for commissioning the flow meters and other monitoring equipment. Commissioning of the monitoring and reporting plan should be carried out in parallel with the commissioning of other equipment in the facilities. It would be best to ensure that as soon as the facility begins operation the monitoring and reporting systems are also initiated simultaneously. This is to ensure that as soon as the facilities are reducing emissions the monitoring equipment is commissioned and recording data for the calculation of how many tonnes of CO₂ equivalent are reduced, thereby maximizing CER delivery. This should therefore be taken into account when assigning the party responsible for commissioning the metering system so as to ensure the system is brought into proper operation in the shortest possible time.

### 3.6 Maintenance and calibration requirements

#### 3.6.1 Maintenance

Meter maintenance includes regular checks for problems such as blockage, component wear, component breakage, and systematic recording error (see Section 3.6.2 – Calibration for the latter). Typical maintenance requirements include cleaning, lubrication, replacement and calibration.

Considering that in active CDM projects, the performance of metering is linked directly to CER generation – which in turn is linked directly to operational revenues – regular meter maintenance should be obvious to site personnel. However, as most CDM projects are driven at corporate and not site level, the link is not always apparent to site staff. Consequently, it is vital that the project sponsor/owner at corporate level impress the importance of accurate and reliable meter maintenance to site level staff. Ideally, personnel responsible for meter maintenance and calibration should be identified and listed in the CDM PDD monitoring information (in Annex 4 of the PDD).
It should be noted that in many situations it will not be possible to access the meter during operational hours i.e. when flow is present. In such cases it will be important to prioritise meter maintenance as part of planned preventative maintenance schedules and activities, including any annual or more frequent planned plant shutdowns. Again, it will be important that the internal CDM project sponsor/owner makes site staff aware of this requirement.

In terms of preventative maintenance procedures, it is necessary that operators follow manufacturer’s guidelines, as these will be specific to the type of meter in use. Good practice suggests that in most cases maintenance should be carried out at least annually (see Table 2 and Table 3).

**The current CDM rules do not provide any guidance on the handling of missing data. In most cases missing data will likely result in loss of CERs unless credible alternative means of estimating flow can be established, proposed and accepted by the verifier. This is likely to require either the use of a “by difference method” to fill incomplete data series, check meter readings, or third party data linked to any supplies of fuel.**

Keeping up-to-date records of meter maintenance schedules, contracts and activities should be considered a core part of CDM monitoring activities. Such records can be used to provide evidence of good practice for meter management, and provided to the DOE during verification.

**Other examples of maintenance requirements**

The UK Environment Agency, the Scottish Environmental Protection Agency (SEPA) and the Environment and Heritage Service of Northern Ireland have produced guidance for assumed uncertainties for gas volumetric metered data based on certain maintenance undertakings, as described further below (Table 3).

### 3.6.2 Calibration of metered data

The term calibration is used widely in Approved CDM Methodologies for flare reduction projects, in the context of both metered data and gas analysis equipment and results (the latter is discussed further below). Under the EU ETS, calibration is defined as:

> ‘calibration’ means the set of operations, which establish, under specified conditions, the relations between values indicated by a measuring instrument or measuring system, or values represented by a material measure or a reference material and the corresponding values of a quantity realised by a reference standard;

In other words, for *in situ* calibration this usually involves the process of using a reference meter (or check meter) to adjust a particular meter to correct errors improve its accuracy. This can involve the use of a bolt on non-intrusive meter such as an ultrasonic device. Calibration can also be achieved through the use of he transit time method. This is based on the pulsed introduction a radiotracer into the fluid flow and measuring the transit time using radiation detectors placed on the exterior of the pipe (at a known distance). The result of the analysis can be compared to the meter result.
Sources of error

The main source of error in meters – aside from incorrect installation or calibration - is drift\(^\text{16}\), which occurs over time as fluids are passed through it (as a result of e.g. parts wear, corrosion, loss of lubrication etc). A range of other factors can also lead to inaccurate meter readings, including inaccuracy in other measurements used to adjust meter readouts (mainly temperature and pressure\(^\text{17}\)), environmental conditions (such as vibration and magnetic fields) and/or changes in flow conditions across the meter (e.g. presence of non-linear flow conditions\(^\text{18}\), wide ranges in flow, variations in pressure, and multi-phase flow).

Current CDM requirements

Current requirements for CDM approved methodologies requirements include\(^\text{19}\):

- Data should be measured using calibrated flow meters.
- Data should be measured using accurate and calibrated flow meters
- Flow meters will be maintained and calibrated regularly according to manufacturer’s requirements.
- Volume of gas should be completely metered with regular calibration of metering equipment

Calibration and maintenance of metering instrumentation will be carried out to manufacturer and reference standard requirements. Internal audit of metering system calibrations prior to each monitoring report. Data trend and production cross checks prior to each monitoring report.

On this basis, following both internal standards for meter calibration frequency and procedures, as well as ensuring that these are consistent manufacturers guidance, will be critical to ensuring that accurate and credible results can be reported as part of a CDM project monitoring program.

According to this guidance, good practice would also suggest that a calibration be carried out ahead of each verification, which generally implies an annual calibration process. Calibration of certain meters may require the plant to be under a controlled operating environment, which could impact on day-to-day activities at a site, and may be best reserved for scheduled maintenance intervals. In some cases, calibration ahead of

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\(^\text{16}\) Drift is evidenced by a tendency of measured data to trend away from the original data in a linear fashion over time, leading to a systematic over- or under-estimate of the true value (error) in recordings.

\(^\text{17}\) A ±0.5°C error in temperature readings can lead to flow correction error of about 0.2%, whilst a ±0.5 error in measuring absolute pressure can also lead to flow correction error of about 0.2%. Thus, minor errors in temperature and pressure readings can lead to almost 0.5% error in estimating flow.

\(^\text{18}\) In extreme cases, calibration of the flow meter using computation fluid dynamics (CFD) techniques may be required to correct systematic errors due to non-laminar flow.

\(^\text{19}\) Based on analysis of AM009 v4, AM0037 v2.1, AM0055 v1.2, AM0077 v01
verification could be costly for projects wishing to adopt a high frequency verification interval (e.g. quarterly) and should be taken into account for the planned verification intervals. Again, this should be factored in at the early design stages of the project.

**Managing conflict of interests during calibration**

The extent to which meter calibration can be carried out by third parties needs careful consideration when appointing a service provider. The current CDM rule state that:

> …if a DOE [designated operational entity] has provided services for the monitoring, the same DOE cannot provide verification/certification services. In the same context, for a given project activity a DOE performing the verification function cannot use services of a laboratory involved in the monitoring activity. The Board, however, agreed that in exceptional cases it may be allowed taking into consideration the specific nature and requirements of a project activity\(^{20}\).

And the CDM Executive Board further agreed that:

> …the possibility for a DOE or other units of the DOE or its parent companies to provide services, such as calibration and/or laboratory services may threaten their independence and impartiality of their operations even in case of validation services. The Board also agreed that, in exceptional cases, a DOE can request to perform such services. The CDM Methodology Panel shall assess the request in the light of the specific requirements of the methodology and make a recommendation to the Board\(^{21}\).

On this basis, if a DOE is providing any services in relation to calibration of metering equipment, or laboratory services, or even using the same laboratory services as used by the project participant, the DOE is disqualified from providing either validation or verification services for the CDM project activity.

**Other examples of calibration requirements**

Recent guidance from UK regulators to gas-fired power station operators on monitoring and reporting under the EU ETS has suggested guidelines for meter maintenance and calibration for different types of meters\(^{22}\). Guidance provided for assigning a fixed level of uncertainty for volumetric meters (for natural gas) that are operated and maintained to the original equipment manufacturers (OEM) instructions is shown below (Table 2).

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\(^{20}\) Report of the 32\(^{nd}\) Meeting of the Executive Board (EB32), para. 11

\(^{21}\) Report of the 33\(^{rd}\) Meeting of the Executive Board (EB33), para. 13

Table 2  UK Guidance on metering uncertainty for gas power stations in the EU ETS

<table>
<thead>
<tr>
<th>Meter type</th>
<th>Expanded Uncertainty</th>
<th>Uncertainty with EVCI</th>
<th>Frequency of calibration/cleaning</th>
<th>Life span of meter</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine</td>
<td>1.5</td>
<td>1.58</td>
<td>&lt; 5 years</td>
<td>25 years</td>
<td>Annual visual inspection; three monthly lubrication of bearings (if not permanently lubricated); pulsation free flow.</td>
</tr>
<tr>
<td>Orifice</td>
<td>1.5</td>
<td>1.58</td>
<td>&lt; 5 years</td>
<td>25 years</td>
<td>Annual calibration of ΔP meter and inspection of orifice/mountings; annual maintenance to OEM specification.</td>
</tr>
<tr>
<td>Venturi</td>
<td>1.5</td>
<td>1.58</td>
<td>&lt; 5 years</td>
<td>30 years</td>
<td>Annual calibration of ΔP meter and inspection of orifice/mountings; annual maintenance to OEM specification.</td>
</tr>
<tr>
<td>Ultrasonic</td>
<td>0.5</td>
<td>0.71</td>
<td>&lt; 5 years</td>
<td>15 years</td>
<td>Annual inspection of transducers and state of wall; annual maintenance to OEM specification.</td>
</tr>
<tr>
<td>Coriolis</td>
<td>1</td>
<td>1.12</td>
<td>&lt; 5 years</td>
<td>10 years</td>
<td>Annual check of sensors and transmitters; annual maintenance to OEM specification; monthly zero check.</td>
</tr>
<tr>
<td>EVCI</td>
<td>0.5</td>
<td>0.71</td>
<td>&lt; 4 years</td>
<td>10 years</td>
<td>Annual inspection and maintenance to OEM specification.</td>
</tr>
</tbody>
</table>

The guidance goes on to state that:

Provided that the meter is operated in accordance with the above listed requirements, a more detailed uncertainty analysis is not required, although evidence of calibration and associated tolerances must be provided by the Operator. In all circumstances, flow metering that is based on the measurement of differential pressure requires an annual calibration of the pressure sensor.

It is assumed that fuel gas flow meters within power stations are always compensated for temperature and pressure. If the meter is fitted with an Electronic Volume Conversion Instrument (EVCI), a fixed uncertainty of 0.5% can be assumed, as shown in the table.

The document goes on to provide specific advice on calibration and accuracy performance according to different standards.

Guidance from the UK Environment Agency, the Scottish Environmental Protection Agency (SEPA) and the Environment and Heritage Service of Northern Ireland provides additional views on assessing uncertainty for different types of meters according to the conditions outlined below (Table 3).

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### Table 3  Assigned uncertainty for different meters under given conditions

<table>
<thead>
<tr>
<th>Meter type</th>
<th>Uncertainty</th>
<th>Conditions (maintenance)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rotor meter</td>
<td>Uncertainty for 0-20% of the maximum measurement range: 3%</td>
<td>• Once per 10 year cleaning, recalibration and if necessary adjusting</td>
</tr>
<tr>
<td></td>
<td>Uncertainty for 20-100% of the maximum measurement range: 1.5%</td>
<td>• Annual inspection of the oil level of the carter</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Application filter for polluted gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Life span 25 years</td>
</tr>
<tr>
<td>Turbine meter</td>
<td>Uncertainty for 0-20% of the maximum measurement range: 3%</td>
<td>• Once per 5 year cleaning, recalibration and if necessary adjusting</td>
</tr>
<tr>
<td></td>
<td>Uncertainty for 20-100% of the maximum measurement range: 1.5%</td>
<td>• Annual visual inspection</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Once per three months lubrication of bearings (not for permanent lubricated bearings)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Application filter for polluted gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No pulsating gas stream</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Life span 25 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No overload of longer than 30 minutes › 120% of maximum measurement range</td>
</tr>
<tr>
<td>Bellows meter</td>
<td>Uncertainty for 0-20% of the maximum measurement range: 6%</td>
<td>• Once per 10 year cleaning, recalibration and if necessary adjusting</td>
</tr>
<tr>
<td></td>
<td>Uncertainty for 20-100% of the maximum measurement range: 4%</td>
<td>• Annual maintenance according to instructions of manufacturer / general instructions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• measurement principle</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Life span 25 years</td>
</tr>
<tr>
<td>Orifice meter</td>
<td>Uncertainty for 30-100% of the maximum measurement range: 1.5%</td>
<td>• Annual calibration of pressure meter</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Once per 5 years calibration of entire measurement instrument</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Annual inspection of abrasion orifice and fouling</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Annual maintenance according to instructions of manufacturer / general instructions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• measurement principle</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Life span 30 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No corrosive gases and fluids</td>
</tr>
<tr>
<td>Meter Type</td>
<td>Uncertainty Range</td>
<td>Guidelines for Building in Orifices: minimum of 4D free input flow length before the orifice and 2D after the orifice: smooth surface of inner wall.</td>
</tr>
<tr>
<td>------------------</td>
<td>-------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| Venturi meter    | Uncertainty for 20-100% of the maximum measurement range: 1.5% | - Annual calibration of pressure meter  
- Once per 5 years calibration of entire measurement instrument  
- Annual visual inspection  
- Annual maintenance according to instructions of manufacturer / general instructions  
- measurement principle  
- Life span 30 years  
- No corrosive gases and fluids |
| Ultrasonic meter | Uncertainty for 1-100% of the maximum measurement range: 0.5% | - Once per 5 years cleaning, recalibration and if necessary adjusting  
- Annual inspection of contact transducer with tube wall; when there is no sufficient contact, contact material has to be replaced according to specifications manufacturer.  
- Annual inspection on corrosion of wall  
- Annual inspection of transducers  
- Annual maintenance according to instructions of manufacturer / general instructions  
- measurement principle  
- Life span 15 years  
- No disturbances in frequencies  
- Composition of medium is known |
| Vortex meter     | Uncertainty for 10-100% of the maximum measurement range: 2% | - Once per 5 years cleaning, recalibration and if necessary adjusting  
- Annual inspection of sensors  
- Annual inspection of bluff body |

Guidelines for building in ultrasonic meters: minimum of 10D free input flow length before the meter and 5D after the meter.
- Annual inspection on corrosion of wall
- Annual maintenance according to instructions of manufacturer / general instructions
- Measurement principle
- Life span 10 years
- Set-up is free of vibration
- Avoid compressive shocks

Guidelines for building in vortex meters: minimum of 15D free input flow length before the meter and 5D after the meter

<table>
<thead>
<tr>
<th>Coriolis meter</th>
<th>Uncertainty for 1-100% of the maximum measurement range: 1%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Once per 5 years cleaning, recalibration and if necessary adjusting</td>
</tr>
<tr>
<td></td>
<td>• Monthly control of adjusting zero point</td>
</tr>
<tr>
<td></td>
<td>• Annual inspection of corrosion and abrasion</td>
</tr>
<tr>
<td></td>
<td>• Annual check on sensors and transmitters</td>
</tr>
<tr>
<td></td>
<td>• Annual maintenance according to instructions of manufacturer / general instructions measurement principle</td>
</tr>
<tr>
<td></td>
<td>• Life span 10 years</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>EVCI</th>
<th>Uncertainty for 0.95-11 bar and -10 – 40°C: 0.5%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Once per 4 years recalibration and if necessary adjusting</td>
</tr>
<tr>
<td></td>
<td>• Replace batteries (frequency is dependent on instructions manufacturer)</td>
</tr>
<tr>
<td></td>
<td>• Annual maintenance according to instructions of manufacturer / general instructions</td>
</tr>
<tr>
<td></td>
<td>• Measurement principle</td>
</tr>
<tr>
<td></td>
<td>• Life span 10 years</td>
</tr>
</tbody>
</table>

Similar levels of assigned uncertainty could be adopted in CDM projects, providing that the conditions for maintenance and calibration are met by project operators.

Further guidance on calculating overall uncertainty is provided below (Section 13).
4 Batch measurements

Batch measurements involve the periodic collection of samples for the purpose of determining the gas characteristics such as NCV and carbon content. The EU ETS MRGs define it as follows:

‗batch‘ means an amount of fuel or material representatively sampled and characterised and transferred as one shipment or continuously over a specific period of time;

The results of batch sampling and analysis provide the basis for the “net calorific value” and “emission factor” within the generalized emission calculation formula presented previously.

Two methods can be used to derive batch measurements:

- On-line analysers directly attached to the flow line and provide a readout of results and
- Sampling with on- or off-site analysis of gas properties

Current CDM AMs applicable to the oil & gas sector do not seemingly proscribe the use of either online or sampling methods to determine NCV and emission factors, so long as the following mixed requirements are met:\n
Measurements should be undertaken in line with national or international fuel standards.

Chromatography performed at an on-site refinery laboratory or at an external laboratory to determine the gas composition and subsequent standard calculations to obtain LHV

Sampling equipment, sampling procedure, gas analyser and analysis procedures shall comply with appropriate reference standards and where laboratory analysis is used the laboratory shall comply with national accreditation standards.

The laboratories performing NCV measurements should have ISO17025 accreditation or justify that they can comply with similar quality standards (AM0009 v4 only)

Therefore, choice of approach employed will be guided by similar factors as outlined for meter selection (see Section 3.3).

A discussion of current requirements and best practice for sampling, analysis procedures, calibration and sampling frequency as set down in the EU ETS MRGs is provided in the next sections.

\[24\] Based on analysis of AM009 v4, AM0037 v2.1, AM0055 v1.2, AM0077 v01
4.1 On line gas analyser measurement

A range of on-line gas analysers based on gas chromatography (GC) methods are currently available on the market. These devices can provide continuous measurement of a number of parameters relating to gas characteristics including:

- Net calorific value, and
- Gas composition (nitrogen, methane, propane, ethane etc. content)

Most OEMs claim high levels of accuracy, with minimum maintenance and calibration requirements. No guidance is provided in current CDM AMs with respect to the required level of accuracy and/or calibration requirements.

Current EU ETS MRGs require set down the following requirements for on-line analyser use:

- Limit application to gaseous fuels
- The operator operating the system is compliant with EN ISO 9001:2000
- The evidence that the operator is meeting ISO 9001 requirements can be demonstrated through an accredited certification of the system
- Calibration services and the supplier of calibration gases are accredited to EN ISO 17025:2005
- An initial and annually repeated calibration is carried out by a laboratory accredited against EN ISO 17025:2005 using EN ISO 10723:1995 *Natural gas — Performance evaluation for online analytical systems.* In all other cases the operator must commission:
  - An initial validation: this must include an appropriate number of repetitions of the analysis of a set of at least five samples representative for the expected value range including a blank sample for each relevant parameter and fuel or material in order to characterise the repeatability of the method and to derive the calibration curve of the instrument;
  - An annual inter-comparison: which must be executed once a year by a laboratory accredited according to EN ISO 17025:2005 involving an appropriate number of repetitions of the analysis of a representative sample using the reference method for each relevant parameter and fuel or material; The operator shall apply conservative adjustments (i.e. avoiding under-estimation of emissions) to all relevant data of the respective year in cases in which a difference is observed between the results derived by the results of the gas analyser or gas chromatograph and the accredited laboratory which might lead to an under-estimation of emissions. Any statistically significant (2σ) differences between the end results (e.g. the composition data) of the gas analyser or gas chromatograph, and the

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accredited laboratory shall be notified to the competent authority [regulator] and be immediately resolved under supervision of a laboratory accredited according to EN ISO 17025:2005.

ISO 10723:1995 Natural Gas – Performance evaluation of on-line analytical systems also provides further guidance on assessing the on-line systems.

The approaches outlined for the EU ETS MRGs can be considered as current best practice for on-line gas analysis for the determination of NCV and emission factors. Taking account of these requirements and also recognising any specific requirements set down in OEM guidelines, project developers could impose similar requirements to demonstrate best practice. However, the requirements set down must also be cognizant of the potential conflict of interest issues posed for maintenance and calibration services, which in some remote locations could prohibit the use of 3rd party services (Section 3.6.2).

The choice of whether to select on-line analysers will largely be determined by cost and ease of use. Typically for non-essential applications, sampling and laboratory analysis will be employed.

4.2 Batch measurements

4.2.1 Batch sampling

For batch samples which are sent to the laboratory, the following considerations are relevant:

- Sampling procedures
- Sample containers
- Sample contamination
- Sample deterioration

In these contexts, the following simplified rules should be adhered to:

- Use clean, dry and preferably stainless steel sample cylinders. Residues left in containers such as oil, grease, wax, water etc. can absorb or release components into the sample. Carbon steel should be avoided as these will oxidise (rust), making cleaning difficult and potentially adsorbing CO$_2$ present in samples.
- Contamination by air must be avoided through the use of a displacement medium prior to sampling (e.g. water, helium)
- Enrichment of samples through extraneous hydrocarbon contamination must be avoided as this will lead to an overestimate of the NCV and carbon content of the gas. Sampling from the top of a flow line, away from bends and obstructions should be undertaken, and carried out using a sampling probe that extends takes an extract from the centre of the flowline. A separator should be used where a large amount of liquid fraction is present.
- Refrigeration or depressurization during storage can cause heavier fractions to liquefy forming in the sample cylinder while lighter fractions can escape due to depressurization, leading to higher NCV and carbon content readings.
EN ISO 10715:2000 *Natural Gas – sampling guidelines* provides descriptions of the methods available (e.g. “fill and empty” method) for gas sampling, and should form the basis for developing gas sampling procedures.

### 4.2.2 Batch analysis

 Appropriately collected samples can be either analysed on-site at an appropriate laboratory or transported offsite for analysis. Current CDM rules do not discriminate against either approach, although under AM0009 v4:

> The laboratories performing NCV measurements should have ISO17025 accreditation or justify that they can comply with similar quality standards

In other CDM AMs, the following requirements are set down:

> The method of chromatography must follow a recognized standard such as that of ASTM, ISO, CEN, or API. Equipment will be maintained and calibrated regularly according to manufacturer’s requirements.

> Calibration and maintenance of analyser shall be carried out to manufacturer and reference standard requirements. Internal audit of analyser calibrations shall be carried out prior to each monitoring report. Data trend and production cross checks shall be carried out prior to each monitoring report.

> Carbon or Methane content of gas should be crossed checked with previous months’ data as well as with the owners of the oil and gas processing plant

The EU ETS MRGs impose similar requirements as AM0009, but further guidance is provided, which requires that\(^ {26} \):

- EN ISO 6976:2005 *Natural gas – Calculation of calorific values, density, relative density, and Wobbe index from composition*, be used as the basis for all analysis carried out.
- That sampling frequency, the sampling procedure and the sample preparation are critical factors (as discussed in the previous and next section)
- That laboratories used to determine NCV and emission factors comply with the following requirements:

**For accredited laboratories:**

- The laboratory used to determine the emission factor, net calorific value, oxidation factor, carbon content, the biomass fraction or composition data should be accredited according to EN ISO 17025:2005 *General requirements for the competence of testing and calibration laboratories.*

**For non-accredited laboratories:**

- Preference is for use of laboratories accredited according to EN ISO 17025:2005. The use of non-accredited laboratories shall be limited to

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situations in which the operator can demonstrate to the competent authority that the laboratory meets equivalent requirements to those laid out in EN ISO 17025:2005. The respective laboratories and relevant analytical procedures shall be listed in the monitoring plan for the installation.

Equivalence in respect to quality management could be demonstrated by an accredited certification of the laboratory against EN ISO 9001:2000. Additional evidence shall be provided that the laboratory is technically competent and able to generate technically valid results using the relevant analytical procedures.

Under the responsibility of the operator, each non-accredited laboratory used by the operator to determine results used for the calculation of emissions shall take the following measures:

- **At initial validation:** each relevant analytical method to be carried out by the non-accredited laboratory against the reference method shall be carried out by a laboratory accredited according to EN ISO 17025:2005. The validation procedure is carried out before or at the beginning of the contract relationship between operator and laboratory. It includes a sufficient number of repetitions of the analysis of a set of at least five samples representative for the expected value range including a blank sample for each relevant parameter and fuel or instrument;

- **An annual inter-comparison:** which involves an inter-comparison of the results of analytical methods, executed once a year by a laboratory accredited according to EN ISO 17025:2005 and including at least a fivefold repetition of the analysis of a representative sample using the reference method for each relevant parameter and fuel or material;

  - The operator shall apply conservative adjustments (i.e. avoiding under-estimation of emissions) to all relevant data of the respective year in cases in which a difference is observed between the results derived by the non-accredited and the accredited laboratory which might lead to an under-estimation of emissions.

  - Any statistically significant (2σ) differences between the end results (e.g. the composition data) derived by the non-accredited and the accredited laboratory shall be notified to the competent authority and be immediately resolved under supervision of a laboratory accredited according to EN ISO 17025:2005.

- That the full documentation of the procedures used in the respective laboratory for the determination of the emission factor and the full set of results shall be retained and made available to the verifier of the emissions report (equal to a monitoring report under the CDM).

The frequency of analysis is also a critical factor as described in the next section.
Frequency of analysis

Within the current flare reduction AMs, no consistent approach is taken as to the frequency of sampling and analysis of various batch measurements, as highlighted below (Table 4).

Table 4 Examples of current sampling frequency in flare reduction related AMs

<table>
<thead>
<tr>
<th>Methodology</th>
<th>Unit/measurement</th>
<th>Frequency of analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>AM0009 v4</td>
<td>TJ/Nm³, Net calorific value of recovered gas</td>
<td>At least monthly</td>
</tr>
<tr>
<td>AM0037 v2.1</td>
<td>tC/m³, Average carbon content of associated gas</td>
<td>Weekly (minimum)</td>
</tr>
<tr>
<td>AM0055 v1.2</td>
<td>GJ/Nm³, Lower Heating value of waste gas recovered</td>
<td>At least once per week</td>
</tr>
<tr>
<td>AM0074 v01</td>
<td>kgCH₄/kg of permeate gas, Average mass fraction of methane in the permeate gas</td>
<td>Weekly (minimum)</td>
</tr>
<tr>
<td>AM0077 v01</td>
<td>kgC/m³, Average content of carbon in the recovered associated gas</td>
<td>Monthly</td>
</tr>
</tbody>
</table>

The analysis of current requirements suggests that the most prudent approach would be to adopt a weekly sampling strategy where possible. Such an approach would be in line with current best practice as set down in the EU ETS MRGs, which require that:

- The determination of the relevant emission factor, net calorific value, oxidation factor, conversion factor, carbon content, biomass fraction or composition data shall follow generally accepted practice for representative sampling. The operator shall provide evidence that the derived samples are representative and free of bias. The respective value shall be used only for the delivery period or batch of fuel or material for which it was intended to be representative.
- Generally, the analysis will be carried out on a sample which is the mixture of a larger number (e.g. 10-100) of samples collected over a period of time.

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Sampling bias can be defined as circumstance where systematic error causes some members of the population to be less likely to be included than others. It is generally a result of sampling error, and can be reduced through appropriate sampling procedures.
from a day to several months) provided that the sampled fuel or material can be stored without changes of its composition.

- The sampling procedure and frequency of analyses shall be designed to ensure that the annual average of the relevant parameter is determined with a maximum uncertainty of less than 1/3 of the maximum uncertainty which is required by the approved tier level for the activity data for the same source stream.

- If the operator is not able to meet the allowed maximum uncertainty for the annual value or unable to demonstrate compliance with the thresholds, he shall apply the frequency of analyses as laid down in Table 5 as a minimum [for natural gas, this is at least weekly], if applicable.

4.3 Converting batch measurement results

The conversion of batch analysis results to the appropriate units can be readily achieved using the conversion factors provided in Table 1.

5 Analysis instrumentation

Typically gas analysis is carried out using gas chromatography and used to determine the NCV and the carbon concentration as required in the various Oil and Gas CDM baseline and monitoring methodologies

ISO17000 series laboratory requirement or equal standard – may not be practical in some jurisdictions.

In other CDM Approved Baseline and Monitoring Methodologies, the following requirements are set down:

*The method of chromatography must follow a recognized standard such as that of ASTM, ISO, CEN, or API. Equipment will be maintained and calibrated regularly according to manufacturer’s requirements.*

*Calibration and maintenance of analyser shall be carried out to manufacturer and reference standard requirements. Internal audit of analyser calibrations shall be carried out prior to each monitoring report. Data trend and production cross checks shall be carried out prior to each monitoring report.*

*Carbon or Methane content of gas should be crossed checked with previous months’ data as well as with the owners of the oil and gas processing plant*

The EU ETS MRGs impose similar requirements as AM0009, but further guidance is provided which requires that:

- EN ISO 6976:2005 *Natural gas – Calculation of calorific values, density, relative density, and Wobbe index* from composition, be used as the basis for all analysis carried out.

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• That sampling frequency, the sampling procedure and the sample preparation are critical factors (as discussed in the previous and next section)
• That laboratories used to determine NCV and emission factors comply with the following requirements:

For accredited laboratories:

• The laboratory used to determine the emission factor, net calorific value, oxidation factor, carbon content, the biomass fraction or composition data should be accredited according to EN ISO 17025:2005 General requirements for the competence of testing and calibration laboratories.

For non-accredited laboratories:

• Preference is for use of laboratories accredited according to EN ISO 17025:2005. The use of non-accredited laboratories shall be limited to situations in which the operator can demonstrate to the competent authority that the laboratory meets equivalent requirements to those laid out in EN ISO 17025:2005. The respective laboratories and relevant analytical procedures shall be listed in the monitoring plan for the installation.

Equivalence in respect to quality management could be demonstrated by an accredited certification of the laboratory against EN ISO 9001:2000. Additional evidence shall be provided that the laboratory is technically competent and able to generate technically valid results using the relevant analytical procedures.

Under the responsibility of the operator, each non-accredited laboratory used by the operator to determine results used for the calculation of emissions shall take the following measures:

• At initial validation: each relevant analytical method to be carried out by the non-accredited laboratory against the reference method shall be carried out by a laboratory accredited according to EN ISO 17025:2005. The validation procedure is carried out before or at the beginning of the contract relationship between operator and laboratory. It includes a sufficient number of repetitions of the analysis of a set of at least five samples representative for the expected value range including a blank sample for each relevant parameter and fuel or instrument;
• An annual inter-comparison: which involves an inter-comparison of the results of analytical methods, executed once a year by a laboratory accredited according to EN ISO 17025:2005 and including at least a

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23 The Wobbe Index (WI) or Wobbe number is an indicator of the interchangeability of fuel gases such as natural gas, liquified petroleum gas (LPG), and town gas and is frequently defined in the specifications of gas supply and transport utilities.
fivfold repetition of the analysis of a representative sample using the reference method for each relevant parameter and fuel or material;

- The operator shall apply conservative adjustments (i.e. avoiding under-estimation of emissions) to all relevant data of the respective year in cases in which a difference is observed between the results derived by the non-accredited and the accredited laboratory which might lead to an under-estimation of emissions.
- Any statistically significant (2σ) differences between the end results (e.g. the composition data) derived by the non-accredited and the accredited laboratory shall be notified to the competent authority and be immediately resolved under supervision of a laboratory accredited according to EN ISO 17025:2005.

- That the full documentation of the procedures used in the respective laboratory for the determination of the emission factor and the full set of results shall be retained and made available to the verifier of the emissions report (equal to a monitoring report under the CDM).

**Sampling Methods and Frequency of Analyses**

The determination of net calorific value, carbon content, or composition data should follow generally accepted practice for representative sampling. The operator shall provide evidence that the derived samples are representative and free of bias. The respective value shall be used only for the delivery period or batch of fuel or material for which it was intended to be representative.

Generally, the analysis will be carried out on a sample which is the mixture of a larger number (e.g. 10-100) of samples collected over a period of time (e.g. from a day to several months) provided that the sampled fuel or material can be stored without changes of its composition.

The sampling procedure and frequency of analyses should be designed to ensure that the annual average of the relevant parameter is determined with a maximum uncertainty of less than 1/3 of the maximum uncertainty which is required by the approved tier level for the activity data for the same source stream. Where prescribed in the Monitoring Methodology, the Monitoring frequency shall be adhered to.

**6 Maintenance procedures**

Metering, instrumentation and sampling maintenance procedures should be available to ensure their proper functioning. The objective is to ensure that the measured data’s integrity is not compromised, thus jeopardising emissions reductions to be claimed.

The impact that maintenance and operation of upstream equipment and pipe work on downstream meter performance should also be assessed. Where necessary, maintenance and operation procedures should be reviewed, and where possible improved to reduce carryover, fouling and overall meter wear and tear. This should be considered at
the project design stage and be taken into consideration when specifying the metering equipment.

Written maintenance procedures must be available and enforced, as part of a Monitoring and Reporting Management system.

7 Calibration certificates

As part of best practice for monitoring and reporting guidelines it is important to ensure all the key instruments, sensors, and monitoring equipment associated with the CDM project activity and calculation of emission reductions are subject to a quality control regime. The comprehensive quality control procedures should include regular maintenance and calibration program for all necessary equipment and procedures. As part of calibration program it is necessary to have detailed information about all the instruments which include their location, identification numbers, calibration data (i.e. last calibration date, next calibration date, who calibrated it, etc), and who the responsible personnel is.

Calibration certificates are an important source of documentation to ensure that all instruments and sensors are properly calibrated and operating to the highest standards. Usually, a calibration technician is the one entrusted to carry out the process and also signs the certificate. The calibrations certificate is a document that denotes a successful completion of an instruments calibration.

The calibration certificate will usually consist of, but not necessarily limited to the following items:

- Date of calibration
- Conditions the calibration was conducted under, i.e. pressure, temperature, etc
- Condition of the device or instrument “as received” and “as returned/left”
- Calibration method
- Calibration process
- Any international standards the calibration was performed to

Calibration is left to technicians who professionalise in the subject, but the process generally begins with a basic damage check to assess the condition of the instrument or monitoring equipment. It is important the calibration is carried out to the best possible international standards and that the person carrying out the calibration is accredited.

It is important to ensure that when calibrations are carried out, the certificates are carefully archived and readily retrievable during verifications. Certificates should also be scanned and stored electronically so that they can be distributed to the DOE ahead of or provided during a verification visit. For best practices of storing hard copy and electronic data refer to section 10 on data storage. Calibration certificates should be kept for at least two years after the end of the crediting period.

For more detailed information on the calibration requirements of instruments and sensors it is best to contact the manufacturer of the equipment. The manufacturer of the equipment will be able to provide information about how frequently the instruments should be calibrated based on the conditions it would be operating under. They should also be able to provide advice on which international standards are best suited to the instrument or sensor calibration.
8 Record keeping – log books and calibration results

8.1 Introduction to record keeping

Implementing a proper record keeping management strategy should be included in any thorough monitoring and reporting plan. The record keeping management system should focus on all the CDM parameters required by the CDM and necessary for the final calculations for the amount of greenhouse gas emissions which are reduced.

It is important that all the record keeping be carried out by authorised and trained personnel. A good record keeping management system will include a clear delineation between all of the personnel and technical staff to ensure a minimum amount of confusion over who is responsible for which instrumentation records. A data record keeping strategy involves a hierarchy of those with increasing management and oversight responsibilities up to the plant manager, who effectively is responsible for the entire plant’s personnel, maintenance, outputs, daily functioning, and CDM Monitoring Plan.

8.2 What is included with record keeping

According to the current methodologies covering flaring in the oil and gas sector, records should be kept for a minimum of two years. The recording management system should outline all the details associated with each piece of monitoring equipment and of the instrumentation, such as location, specialised unique coding or identification number, calibration status, and which personnel is responsible for ensuring the instruments are calibrated and operating according to manufacturer’s specifications.

The record logs could be set up and structured as the technician, operator, and management see fit, but it should clearly include for each data set, instrument and sensor the following items of information:

- identification number (ideally the serial number or a coding system linked to the serial number);
- type of equipment, meter, sensor, instrument, etc used;
- data source (e.g. location points, time);
- unit(s) the data is recorded in (e.g. m/s, CH₄/m³, etc);
- whether the data is measured, calculated, or estimated;
- recording frequency (e.g. continuous, hourly, monthly weekly, etc);
- archiving technique (e.g. log book, electronic, etc); and
- personnel recording the data.

In addition to the above list there should also be a note or comment section where personnel carrying out the record keeping could make any important notations. By adding
8.3 Transposition of records to electronic format

All the data that is recorded within log books should be transposed to electronic format. When the data log books are transposed to electronic format it should be notated in both in the log book and electronic version that this has been done. In addition, it is important to record who transposed the data set from the hard copy log book and the date it was transposed.

One of the easiest and well-known formats universally used is the Microsoft Excel Program. The spreadsheets which Excel creates can easily be set up and designed identical to the ruled log books making data transposition quite straightforward and simple. The electronic Excel spreadsheet records should be kept in an electronic filing system with clearly named files on the server which have been previously agreed upon and are known to all those within the CDM team and management who are responsible for its oversight. The Excel spreadsheets should be kept along with other CDM data such as the scanned calibration certificates to ensure all necessary information is centrally located for ease of verification audits by DOEs and printing out collating the data into monthly CDM.

All digital records should be kept for achieving purposes but also stored in easy to access and well-labelled electronic files which should have some access permission controls, which would only allow certain individuals to access to the files. Creating access control lists for the electronic filing system for all CDM related data will help minimise unknown personnel accidentally removing, tampering, or deleting the digital records that are integral to the CDM monitoring plan. It would be only those who are involved with the CDM monitoring component of the project to have access to such files. For information on how to manage electronic data storage see section 10 on data handling.

8.4 CDM monitoring report

Data sets which are recorded as part of the monitoring plan should be summed and calculated at the end of every month. This end of the month data should be transcribed to a monthly record log for the CDM Monitoring Report. This regular check of the data sets should help to ensure the absence of data which are beyond an acceptable uncertainty or deviation from one month to the next. If there is a large deviation from what was anticipated, this would help to immediately identify instrumentation or monitoring equipment that has failed or needs to be recalibrated. By regularly checking data sets to ensure they are inline and do not deviate much from expectations will help to minimize records that would half to be discarded due to uncertainty or loss of accuracy.

In addition, by regularly summing and calculating the figures into an end-of-the-month CDM Monitoring Report makes both DOE audits and preparation for verification much more straightforward and efficient. Well-kept, organized and thorough record keeping makes the DOE audit work much simpler and in general will expedite the verification process.

The end-of-the-month CDM monitoring figures should also be saved and clearly marked as such along with the names and where possible the ID numbers of the employees who executed and recorded the end-of-the-month figures to be audited. The individuals who are engaged in aspects related to CDM (i.e. record keeping and QA/QC of the
procedures) should have full understanding of the CDM and the importance of all the monitoring data. This will ensure the employees responsible for CDM related data realise the repercussions of their actions if data is mishandled and recorded incorrectly, as well as the loss of revenues due to the subsequent loss of associated certified emission reductions (CERs).

Proper record keeping in accordance with international best practice will help project participants keep all their data secure. In addition and more importantly, thorough and accurate record keeping will help in ensuring the audit with the DOE is considerably more efficient and assist with a successful delivery of CERs.

9 Measurement error and identification and correction

9.1 Types of errors

Accuracy is defined as the quality of being near to the true value and the accuracy of a measurement is the degree of closeness the measurements of a quantity are to that of the actual value. There are two types of error that arises when considering the degree of accuracy of samples and measurements to their true value. These types of error can be distinguished into two categories:

- **Systematic error**: which always occurs in the same way for the same instrument (unless it has been recently calibrated and adjusted). This can arise due to variations in environmental conditions, flow conditions, gas composition, incorrect recordings, calculations, etc; and

- **Random error**: which can vary from one observation to the next

Error propagation can also occur where a specific output is based on the function of a number of variables to derive its value.

Error propagation and both systematic and random error are handled through the use of statistical theory and the use of uncertainty analysis to calculate overall uncertainty (as described in Section 14). However, there are maximum levels of tolerable uncertainty that can be applied to set limits on the validity of certain sets of monitoring results.

Uncertainties in calculations and errors in monitoring need to be addressed by the project participant. There are efforts that can be taken to minimize errors in the final emission reduction calculation for CDM project activities. It is important to note that errors and uncertainty cannot be completely eliminated, although steps and procedures can be taken to minimize them through implementing sound, good, best practice monitoring procedures to derive at conservative best estimates.
9.2 CDM project activity and errors

The quality assurance and quality control (QA/QC) procedures of the monitoring plan should include how to manage and deal with errors. The UNFCCC Executive Board (EB), along with input from the Methodological Panel (Meth Panel), has provided some guidance for best practice of managing errors and uncertainties in calculations.

According to the 23rd meeting report of the CDM EB, "specific uncertainty levels, methods and associated accuracy level of measurement instruments and calibration procedures to be used for various parameters and variables should be identified in the PDD, along with detailed quality assurance and quality control procedures. In addition standards recommended shall either be national or international standards. The verification of the authenticity of the uncertainty levels and instruments are to be undertaken by the DOE during the verification stage."

Therefore, it is important that the project participants include any discussions of potential uncertainty levels and methods of quality assurance and quality control in the Project Design Document (PDD) for the CDM activity.

In addition, erroneous monitoring data sets are to be managed and ultimately decided upon by the DOE during the verification stage of the CDM project activity. It is important that project participants keep detailed records of all monitoring data discrepancies (e.g. time, date, notes as to what may have occurred, deviations, etc) to be discussed with DOEs at a later date as to what the best practice will be regarding the final emission reduction calculations.

Depending on the data parameter in question and the severity uncertainty errors or magnitude of lost/destroyed data, it may be possible to extract conservative figures for the volume of emission reductions from other non-CDM data, e.g. facility output production levels. However, this will be at the discrepancy of the DOE as to how they will manage the situation and what their recommendation will be to the CDM EB for CER volume issuance from the CDM project.

9.3 Approaches to minimizing errors/uncertainty

Project participants should have a comprehensive quality assurance and quality control procedures in place which are described in detail in the PDD for the project. The best practice for QA/QC procedures is to integrate them into the monitoring plan and apply them directly at the time of recording the data source. This can be done by integrating the QA/QC procedures as part of the training for personnel for when they are recording and capturing data. This is to help ensure that the individual recording the data collects it from the correct instrument, that the instrument is calibrated, that staff knows what to do if data seems abnormal, and that the process keeps in line with the monitoring plan as outlined in the PDD.

Also, possible errors in this process can be minimized if the entries for data are cross-checked to make sure they do not deviate drastically and seem to be unrealistic. It is important to resolve any data anomalies through proper communication between all personnel involved in measuring and analyzing data.

If errors or uncertainties cannot be minimised to the point of being able to neglect them, there are some approaches that can be followed to ensure the resulting estimate of emission reductions is conservative. However, as mentioned previously, whether or not the conservative estimate will be accepted is ultimately at the discrepancy of the DOE during verification.

Materiality is the concept of how errors, omissions, and/or misinterpretations could have an overall affect on the accuracy or validity of the final calculation of emission reductions. Therefore project participants should understand which data parameters have a high level of materiality and require more stringent monitoring and attention. Possibly setting a lower limit to the errors or uncertainty permitted for data parameters with a large impact on the final carbon emission reduction accuracy.

If a methodology provides different options to determine a particular data parameter (i.e. measured or default values), the project participant should utilize the method with the least possible affect on the final emission reduction calculation.

**9.4 Large errors and missing data**

In some cases monitoring equipment might go off-line and data might be lost/missing/damaged for number of different reasons. Unfortunately, there are no approved procedures on how to go about replicating, replacing, or calculating conservative estimates. However, with appropriate and thorough QA/QC procedures in place with proper data storage techniques, project participants should minimize any potential loss of data or unrealistic measurements.

The best practice for large discrepancies in measurements or missing data depends on the data parameter in question and the period of time that has elapsed since the last accurate measurement. In cases where data parameters are measured regularly (i.e. continuously, hourly, daily) and there is one data point which seems to have an unusually large error it could be possible to take the average of the two data point before and just after the error has occurred. However, any errors that occur or are rectified should be noted in the log book and their causes be investigated as soon as possible. Proper Monitoring and Reporting Management system will ensure that the effectiveness of any solution implemented to correct such problem is monitored, and where effective communicated to relevant parties, together with any written procedures that may need to be adhered to.

For other missing or erroneous data parameters which have a strong correlation to non-CDM data (i.e. data not required by the methodology to be monitored, but are monitored as part of industry practice) it may be possible to back calculate a conservative estimate of what the CDM data parameter was. Project participants should always err on the side of conservatism and note as part of good monitoring and record keeping practice all alterations to data as well as the original error.

What to do when there is missing or erroneous data has been left for the project participant’s best practice and the opinion of the DOE as an outcome of the verification. So, at best the project participant should take the most conservative estimate possible while recording all the steps taken in order to discuss with the DOE during verification.
10 Spares holding

Instrumentation and metering equipment is crucial to securing carbon revenue. The fact that the emissions reductions are real is of little value if they cannot be measured properly. Instrumentation and metering equipment in the CDM context can be therefore considered, as other items of plant equipment are, as critical items and therefore should be treated as such.

It is thus important that the proper spares be held in stock. Similarly it should also be ensured that analysis equipment such as gas chromatographs be also furnished with the necessary spares and material to ensure continuity of operation. Attention should be placed on local conditions that may impact on the timely supply of spares and materials and the risks associated with non availability.

Plans and provisions to mitigate such risks should be developed in conjunction with the relevant in-house departments, service providers and any other relevant stakeholder.

11 Training

Proper personnel training is a key aspect to ensure the monitoring and reporting plan is carried out according the Project’s Design Documents (i.e. PDD) and the CDM Validation and Verification Manual, as well as both international best practice and standards. The importance of accurate recording, sampling and analysis of meter and batch analysis data has been highlighted in previous sections. Consequently, there is a need to ensure that personnel employed at the site locations to oversee the day-to-day operation of the facilities as well as to read meters and take gas samples are all in accordance with the monitoring plan, which in turn should adhere to all applicable standards.

Personnel should also be instructed on how to recognise outlier readings and implement Quality Assurance and Quality Control (QA/QC) procedures to recheck data where inaccuracies are identified. The QA/QC procedures and equipment should be clearly set down in a dedicated Monitoring Plan for the project, and should be in accordance with the relevant approved CDM methodology, wherever applicable.

There should be at least one Managerial level employee who has been trained in all the monitoring procedures required by the CDM, i.e. methodology, DOE, DNA, Executive Board, etc. This will also include training and knowledge of all the calculations required and a thorough understanding of the necessary documentation, such as calibration certificates for various pieces of equipment and which will be needed during verification.

Inclusive in the monitoring plan, along with the roles and responsibilities of the all the staff and managers, there should be an outline of what type of training each of the employees should be getting and which individuals are responsible for the training. Some of these roles and responsibilities include, who would be organising and conducting the training programs on CDM, which employees from the plant facility would be supervising and training the operators and who is responsible for maintaining training records.

A good practice example of oil and gas sector monitoring and reporting training guideline is to establish a set of procedures for training those staff and operators responsible for monitoring. Well-developed procedures for training will include: Purpose, Scope, Responsibilities (both for each activity/position and oversight responsibilities), and
descriptions of the each of the personnel associated with the daily CDM monitoring and reporting data.

Some of the tasks which should be in a training plan include, but are not limited to the following:

- Orientation and induction training that will be conducted for all new operational staff stressing the importance of proper monitoring and reporting under the CDM, and the differences that may exist between conventional industry practices in this regard.

- Provide specialised training to the staff operating the equipment (e.g. flare gas recovery unit) and to those responsible for recording data parameters in accordance with the monitoring plan in the PDD and as required by the DOE and CDM EB.

- Continued on the job training conducted by in-charge managers for operators, coupled with supervision and follow up to ensure the staff operators are aware of the monitoring and recording requirements under the Monitoring Plan, PDD, and CDM EB.

- Keep track of all training records and make sure they are held in accordance with record keeping guidelines and they are signed off by the necessary individuals, i.e. trainers and trainees.

- Develop a mechanism for feedback of trained operators and staff so any difficulties or misunderstandings are raised and highlighted. The proper managers should address and attend to any difficulties to ensure the operators are fully trained.

Since all the calculations, monitoring, and record keeping associated with the requirements of CDM will be carried out by a dedicated team of staff personnel working at the project site, it is important they are all trained properly and understand the required procedures to ensure the emission reduction data is collected. Ignoring this poses a serious risk that the entire data set from which the emission reductions are to be determined may not be audited by the third party verifiers, thus leading to a loss or reduction of CER issuance.
12 Data handling – storage and reporting

How data is managed and stored is critical to the long term success of a CDM project. It is important that not only is the data recorded accurately, but that it is handled and stored according to international best practice. Data management practices should be developed for both digital data and hard copy recorded data. Electronic archiving and maintenance of paper records should be considered as standard practice and undertaken as part of general good housekeeping.

Data collected as part of a CDM monitoring program should be kept for at least two years based on the approved CDM methodologies. It will be important to not only ensure data is not lost, damaged or tampered with, it is also important that it is relatively accessible for audits by verifiers.

There should be a QA/QC procedure to transfer data to electronic format for any data recorded manually. In cases where data is recorded manually it is important to keep the original hard copy format. The main reason is if at a later date it is noticed a data point or figure seems to be incorrect it would be possible for the verifiers to audit the original hard copies for any discrepancies which may have arose while the data was being transposed and inputted to electronic format incorrectly.

12.1 Hard copy data

As mentioned above it is important not to discard any hard copy data. All hard copy data, whether handwritten or printouts from equipment which has this feature, should be time stamped and stored properly. The operator or technician recording the data should write in clear block letters with a permanent ball point pen that does not smudge, the following: day, time, equipment/meter identification number, name of the individual who took the reading and this should be accompanied by a signature or initials of the senior employee or manager in-charge overseeing data management.

If possible the hard copy of the data should then be transposed to an electronic format. Once the data has been inputted in electronic format has occurred it will be necessary to store the original hard copy in a secure, cool, dry place away from any outside weather elements which may destroy or damage the records. It would also be advisable to ensure the records are kept in a location where theft or tampering is unlikely to occur as well as the possibility of fire. Therefore, any storage location should use local and international best practice for fire detection as well as prevention.

12.2 Electronic data

Eventually all data should be transferred for electronic format. Instances when hard copy data is taken first in log books or certificates are issued it is important to still keep the hard copy data even once the data has been transposed or scanned to electronic format. Spreadsheets as part of Microsoft Excel software are an easy to use, versatile and are recommended as a good source to be used to store meter data and sample results. Also the Excel spreadsheets could include conversion calculations, however, all applicable formula should be clearly set out and made available in the spreadsheet. The Excel spreadsheets and applicable formula should be readily available for DOEs during verification.
The project participant should implement an electronic data management system to ensure all electronic data is kept and not lost, accidentally deleted, altered, or stolen. All electronic data should be kept in a clear, simple, and well labelled/named electronic filing system known to the appointed CDM personnel responsible for data management. In order to minimise data being copied, altered or deleted it is important to set an access control list (ACL) for the electronic file folders. This ACL will only allow certain individuals permission to copy, save, and delete any electronic data and files.

In addition, it will be important to back-up the electronic data whether it is stored on a server or the hard disk of a computer. The electronic data back-up should be done on a regular basis and the back-up data should be kept in a separate location from the original source of the data. This is to ensure that a fire or theft will not affect both the original and the back-up of the electronic data.

13 Uncertainty calculations

Uncertainty in monitoring data is a statistical estimate of the spread of individual results from the mean value, accounting for both systematic and random errors. It is established by repeating measurements so as to derive the standard deviation for a given value, which for a normal (binomial) distributed set of values provides the basis for determining the confidence limits for results. At a 95% confidence limit for normally distributed data, 95% of results will fall within 2 standard deviations of the mean.

The EU ETS MRGs define uncertainty as:

‘uncertainty’ means a parameter, associated with the result of the determination of a quantity, that characterises the dispersion of the values that could reasonably be attributed to the particular quantity, including the effects of systematic as well as of random factors and expressed in per cent and describes a confidence interval around the mean value comprising 95 % of inferred values taking into account any asymmetry of the distribution of values.

In simple terms, the calculated uncertainty provides an estimate of overall spread of an individual results in a dataset within an upper and lower range (±; or confidence limits) of the average calculated value from the dataset.

In emissions accounting terms, two important components should be considered

- Measurement of uncertainty: how to calculate the uncertainty for a given dataset
- Maximum permissible levels of uncertainty: what is acceptable to the regulator?

These two issues are discussed further below.

13.1 Measurement of uncertainty

For individual measurements, uncertainty will be linked to the estimated of accuracy of the device, based on OEM guidelines and other calibration activities. However, in most cases a single measurement over the entire monitoring period will not suffice for the purpose of CDM accounting and reporting. Thus, reported values collected over the monitoring period are typically made up of a number of components such as:
• Measurements of a number of different streams (e.g. several gas flows within the project);
• Many individual measurements for each stream (e.g. many meter readings/batch analyses results); and
• Calculation of values derived from a combination of multiple measurements (e.g. use flow, temperature and pressure to calculated mass flow).

In all of these cases overall uncertainty should be assessed and calculated using error propagation laws. The EU ETS MRGs provide the following approaches to calculating overall uncertainty:

(a) For uncertainty of a sum (e.g. of individual contributions to an annual value):

For uncorrelated uncertainties (equation 1):

\[ U_{\text{total}} = \sqrt{\left( U_1 \cdot x_1 \right)^2 + \left( U_2 \cdot x_2 \right)^2 + \ldots + \left( U_n \cdot x_n \right)^2} \]

\[ \frac{x_1 + x_2 + \ldots + x_n} \]

For interdependent uncertainties (equation 2):

\[ U_{\text{total}} = \frac{U_1 \cdot x_1 + U_2 \cdot x_2 + \ldots + U_n \cdot x_n}{x_1 + x_2 + \ldots + x_n} \]

Where:

\( U_{\text{total}} \) is the uncertainty of the sum, expressed as a percentage; and
\( x_i \) and \( U_i \) are the uncertain quantities and the percentage uncertainties associated with them, respectively;

(b) For uncertainty of a product (e.g. of different parameters used to convert a meter reading into mass flow data):

For uncorrelated uncertainties (equation 3):

\[ U_{\text{total}} = \sqrt{U_1^2 + U_2^2 + \ldots + U_n^2} \]

For interdependent uncertainties (equation 4):

\[ U_{\text{total}} = U_1 + U_2 + \ldots + U_n \]

Where:

\( U_{\text{total}} \) is the uncertainty of the product, expressed as a percentage; and
\( U_i \) is the percentage uncertainties associated with each of the quantities;

Practical guidance on handling approaches to uncertainty calculation has been provided by the UK Environment Agency, the Scottish Environmental Protection Agency (SEPA)
and the Environment and Heritage Service of Northern Ireland. This outlines the following proposed approach:

- Step 1: Assess the uncertainty of the measurement instrument;
- Step 2: Assess the additional uncertainty of “context specific” factors (i.e. how the measurement instrument is used in practice);
- Step 3: Assess the uncertainty of pressure and temperature corrections for gas meters;
- Step 4: Sum up the uncertainties of steps 1, 2 and 3;
- Step 5: Assess the uncertainty of the amount of the source stream.

Where:

**Step 1: Assess the uncertainty of the measurement instrument**

This step concerns the instrument specific uncertainty that is linked to the measurement principle of a meter. Table 3 outlines standard uncertainty levels for different meter types under certain conditions. Where these conditions cannot be met, the operator should substantiate and justify the conditions and the assumed uncertainty. Alternatively, OEM data may be used where this can be substantiated.

**Step 2: Assess the additional uncertainty of context specific factors**

To assess the additional uncertainty the following questions need to be answered:

- Is the measurement instrument installed according to the requirements of the manufacturer or, if those data are not available, according to general requirements that apply to that measurement principle?
- Is the medium (gas, fluid, solid substance) that is measured by the meter a medium for which the measurement instrument has been designed according to the requirements of the manufacturer or, if these data are not available, according to the general requirements applicable to that measurement principle?
- Are there no other factors that can have adverse consequences on the uncertainty of the measurement instrument? (e.g. multiphase flow conditions)

If the answer to all three above questions is yes, the operator can use an uncertainty of 0% for the outcome of step 2. If the answer to one or more of these questions is no, the operator has to make a conservative and substantiated judgement of the additional uncertainty that is connected to the factor or factors for which the operator has answered negatively. This judgement has to be done in consultation with the manufacturer of the measurement instrument or another expert.

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32 Where these no longer exist, general calibration and maintenance requirements that are applicable to the meter type may be employed.
33 This may be an in-house expert, so long as the DOE agrees with the view of the in-house expert.
Step 3: Assess the uncertainty of the pressure and temperature corrections for gas meters

Pressure and temperature corrections are only applicable to the determination of the amount of gas and not to the measurement of fluids or solid substances. For fluids and solid substances the operator can use an uncertainty of 0% for the outcome of step 3. The operator has to correct the actual amount of gas for pressure and temperature to normal conditions. This correction is compulsory since not correcting these elements may cause major systematic errors.

The reader is referred to the original document for further guidance in relation to specific examples.

Step 4: Sum up the uncertainty of step 1, 2 and 3

Steps 1, 2 and 3 lead to uncertainty levels that need to be summed up to determine the total uncertainty of the individual quantity measurement.

This can be accomplished using equation 3 outlined above.

Step 5: Assess the uncertainty of the amount of the source stream

In steps 1 to 4 the operator has determined the uncertainty of one individual (corrected) quantity measurement. If the amount of a source stream is determined by more measurement instruments, the operator has to sum up the uncertainties of these different individual measurements (the components of the measurement system) to determine the total cumulative uncertainty of the amount of the source stream.

This can be accomplished using equation 1 outlined above.

The reader is advised to review the following: Competent Authority Interpretation the Main Uncertainty Analysis Requirements resulting from the Revised Monitoring & Reporting Guidelines (MRG 2007). Available at: http://www.environment-agency.gov.uk/static/documents/Business/uncertainty_mrg_1807595.pdf to enhance their understanding of the approach described above. Additional useful guidance can also be found in the document: Addressing Uncertainty in Oil and Gas Industry GHG Inventories, Technical Considerations and Calculation Methods (IPIECA/API, 2009)

13.2 Maximum permissible uncertainty

The previous section has provided guidance on how to calculate overall uncertainty for monitored and reported data. The next step is to consider what acceptable levels of uncertainty are. In this context, both AM055 v1.2 and AM0077 v01 set down guidance on permissible uncertainty in monitoring data, as follows:

Uncertainty Assessment: ‘Permissible uncertainty’ shall be expressed as the 95 % confidence interval around the measured value, for normally distributed measurements. The uncertainty associated with each parameter should be assessed, for example, by calculating the probable uncertainty as the mean deviation divided by the square root of the number of measurements. If this uncertainty is within the 95% confidence interval, than it is considered permissible uncertainty, and no action must be taken.

This can be achieved following the steps described in the previous section. Both AMs go onto highlight that:
If not, then the uncertainty should be assessed as low (<10%), medium (10-60%) or high (>60%). Percent uncertainty may be calculated by dividing the mean of the parameter by the probable uncertainty and multiply by 100% to get percent uncertainty. If percent uncertainty is <10%, the uncertainty is considered low [and etc]. A detailed explanation of quality assurance and quality control procedures must be described for parameters with medium or high uncertainty in an attempt to decrease uncertainty, and to ensure that emissions reductions calculations are not compromised. In the case of a parameter with medium or high uncertainty, a sensitivity analysis should be performed to determine the potential of the uncertainty of the parameter to affect the emissions reduction calculation. The authenticity of the uncertainty levels will be verified by the DOE at the project verification stage.

This suggests that overall uncertainty calculated to within ±10% should be acceptable for CDM project reporting. These requirements are less onerous than required under the EU ETS MRGs, which state the following tolerable levels of uncertainty in relation to data collected for calculating combustion emissions (Table 5).

<table>
<thead>
<tr>
<th>Annual Emissions*</th>
<th>Fuel flow</th>
<th>Net calorific value</th>
<th>Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tier</td>
<td>Accuracy requirement</td>
<td>Tier</td>
</tr>
<tr>
<td>n/a</td>
<td>1</td>
<td>±7.5 %</td>
<td>Reference value</td>
</tr>
<tr>
<td>&lt;50ktCO₂/yr</td>
<td>2</td>
<td>±5 %</td>
<td>2a/2b</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2a/2b</td>
</tr>
<tr>
<td>&gt;50 &lt;500 ktCO₂/yr</td>
<td>3</td>
<td>±2.5 %</td>
<td>2a/2b</td>
</tr>
<tr>
<td>&gt;500 ktCO₂/yr</td>
<td>4</td>
<td>±1.5 %</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3</td>
</tr>
</tbody>
</table>

Table 5 Uncertainty requirements for gaseous fuels (EU ETS MRGs)
<table>
<thead>
<tr>
<th>laboratory or the fuel supplied in accordance with relevant requirements (see Section 4)</th>
</tr>
</thead>
<tbody>
<tr>
<td>laboratory or the fuel supplied in accordance with relevant requirements (see Section 4)</td>
</tr>
</tbody>
</table>

* The EU ETS MRGs use different “tiers” of approaches to reflect the materiality of the uncertainty levels on overall error in reported data i.e. the bigger the emissions, the smaller the overall uncertainty should be. This does not directly correlate with CDM approaches, although the annual emissions could be considered as equivalent to annual emission reductions under the CDM in terms of materiality to the net result.

As can be seen, the current requirements set down for “low” permissible uncertainty within the CDM in both Am0055 v1.2 and AM0077 v01 equate to the less than the tier 1 requirement under the EU ETS MRGs. The overall uncertainty described for the EU ETS MRGs in Table 5 can be considered as best practice for operators, and may be adhered to where possible.
14 References


- Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (1996 GLs);

- IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000 GPGs)

- 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 GLs)


- http://www.omega.co.uk/prodinfo/flowmeters.html


- Clean Development Mechanism PDD Guidebook: Navigating the Pitfalls - Second edition, UNEP Risø Centre on Energy, Climate and Sustainable Development

Appendix 1 – Comparison of flow measurement devices

A comparison of the flow measurement technologies that may be considered in vent and flare gas applications, and which are also generally applicable to pipeline measurement, is presented in Table A1 below.

The data presented is taken from the report “Guidelines on Flare and Vent Measurement” prepared for the World Bank GGFR by Clearstone Engineering Ltd34; it outlines the basic capabilities and limitations. The noted flow capacity, rangeability (i.e., ratio of the maximum to minimum applicable flow) and inaccuracy of each technology are for ideal conditions involving fully-developed flow of clean dry gas (i.e., to provide a standard basis for comparison.

A more detailed discussion of the key variables summarised in Table A.1 below is provided in that report, and the user is referred there for further reading.

<table>
<thead>
<tr>
<th>Type of Flow Meter</th>
<th>Type of Measurement</th>
<th>Applicable Pipe Diameter (D)</th>
<th>Flow Capacity and/or Rangeability</th>
<th>Straight Pipe Requirements</th>
<th>Net Pressure Loss</th>
<th>Inaccuracy</th>
<th>Composition Dependend</th>
<th>Suited for Wet or Dirty Fluid</th>
<th>Other Restrictions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Venturi Tube</td>
<td>ΔP</td>
<td>5 to 120 cm (2 to 48 in)</td>
<td>10:1 flow rangeability¹</td>
<td>6 to 20 D up 2 to 40 D down</td>
<td>10 to 20% of ΔP depending on β</td>
<td>± 1% to 2% of full scale</td>
<td>Yes</td>
<td>Yes</td>
<td>Eliminate swirl and pulsations. Gas temperature dependent.</td>
</tr>
<tr>
<td>Orifice Plate</td>
<td>ΔP</td>
<td>1.3 to 180 cm (1/2 to 72 in)</td>
<td>5:1 flow rangeability.</td>
<td>6 to 20 D up 2 to 40 D down</td>
<td>High relative to other ΔP meters</td>
<td>± 2% to 4% of full scale</td>
<td>Yes</td>
<td>Yes</td>
<td>Eliminate swirl and pulsations. Gas temperature dependent</td>
</tr>
<tr>
<td>Bellows (or Diaphragm)</td>
<td>Volumetric</td>
<td>Maximum of 13, 130 and 283 m³/h @ 34, 172 and 690 kPa (450, 4600 and 10,000 scf/h @ 10, 25 and 100 psig); Greater than 200:1 rangeability.</td>
<td>None</td>
<td>0.5 kPa (0.1 psi)</td>
<td>± 0.1% of flow rate.</td>
<td>No</td>
<td>No</td>
<td>Used for commercial and domestic gas service. A filter is normally installed immediately upstream of the meter to remove particulate.</td>
<td></td>
</tr>
<tr>
<td>Turbine</td>
<td>Volumetric</td>
<td>0.64 to 60 cm (1/4 to 24 in)</td>
<td>6,500 m³/h (230,000 scf/h) 20:1 up to 100:1 flow rangeability for large meters operating at 9,700 KPa (1400 psig); Greater than 200:1 rangeability.</td>
<td>10 D up 5 D down</td>
<td>34 to 41 kPa (5 to 6 psig) @ 6.1 m/s (20 ft/s)</td>
<td>± 0.1% of flow rate.</td>
<td>No</td>
<td>Limited</td>
<td>Flow straightening vanes beneficial. Do not exceed maximum flow. Susceptible to fouling.</td>
</tr>
<tr>
<td>Vortex Shedding</td>
<td>Velocity</td>
<td>2.5 to 30 cm (1 to 12 in)</td>
<td>0.30 to 6.1 m/s (1 to 30 ft/s)</td>
<td>10 to 20D up 5 D up down</td>
<td>34 to 41 kPa (5 to 6 psig) @ 6.1 m/s (20 ft/s)</td>
<td>± 2% of flow rate.</td>
<td>No</td>
<td>Limited</td>
<td>Flow straightening vanes beneficial. Susceptible to pulsation and vibration</td>
</tr>
<tr>
<td>Transit-time Ultrasound</td>
<td>Velocity</td>
<td>&gt;0.32 cm (&gt;1/8 in)</td>
<td>0.03 to 100 m/s (0.1 to 328 ft/s). 2000:1 flow rangeability</td>
<td>10 to 30 D up 5 to 10 D down</td>
<td>None</td>
<td>± 2% to 5% of value.</td>
<td>No</td>
<td>Moderate</td>
<td>Elimination of swirl.</td>
</tr>
<tr>
<td>Optical</td>
<td>Velocity</td>
<td>0.03 to 100 m/s (0.1 to 328 ft/s). 2000:1 flow rangeability</td>
<td>10 to 30 D up 5 to 10 D down</td>
<td>None</td>
<td>± 2.5% to 7% of value.</td>
<td>No</td>
<td>Moderate</td>
<td>Elimination of swirl.</td>
<td></td>
</tr>
<tr>
<td>Type of Flow Meter</td>
<td>Type of Measurement</td>
<td>Applicable Pipe Diameter (D)</td>
<td>Flow Capacity and/or Rangeability</td>
<td>Straight Pipe Requirements</td>
<td>Net Pressure Loss</td>
<td>Inaccuracy</td>
<td>Composition Dependent</td>
<td>Suited for Wet or Dirty Fluid</td>
<td>Other Restrictions</td>
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<td>------------------</td>
</tr>
<tr>
<td>Thermal Anemometer (Thermal Mass Flowmeter)</td>
<td>Velocity (mass)</td>
<td>1000:1 flow rangeability.</td>
<td>8 to 10 D up 3 D down</td>
<td>Very low</td>
<td>± 1% to 3% of flow rate.</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>Probe positioning critical. Highly fluid composition dependent for volume measurement. Gas temperature dependent. Susceptible to fouling.</td>
</tr>
<tr>
<td>Rotameter</td>
<td>Velocity</td>
<td>1.3 to 10 cm (1/2 to 4 in.)</td>
<td>10:1 flow rangeability.</td>
<td>None</td>
<td>Low</td>
<td>± 1 to 2% of full scale.</td>
<td>Yes</td>
<td>No</td>
<td>Must be mounted vertically. Gas temperature dependent</td>
</tr>
<tr>
<td>Micro-tip Vane Anemometer</td>
<td>Velocity</td>
<td>5 to &gt;91 cm (2 to &gt;36 in)</td>
<td>10:1 flow rangeability.</td>
<td>8 to 10 D up 3 D down</td>
<td>Low</td>
<td>± 2% of flow rate.</td>
<td>No</td>
<td>Limited</td>
<td>Probe positioning critical. Susceptible to fouling. Gas temperature dependent.</td>
</tr>
<tr>
<td>Pitot Tube</td>
<td>Velocity</td>
<td>5 to &gt;183 cm (2 to &gt;72 in)</td>
<td>3:1 flow rangeability.</td>
<td>8 to 10 D up 3 D down</td>
<td>Low</td>
<td>± 0.5 to 5% of full scale.</td>
<td>Yes</td>
<td>Limited</td>
<td>Critically positioned probes. Highly fluid composition dependent. Susceptible to fouling. Minimum Reynolds number of 20,000 to 50,000.</td>
</tr>
</tbody>
</table>

Note:  
1. The flow rangeability is the turndown ratio of the meter expressed as the ratio of the maximum flow to the minimum flow.  
2. Applies only to measurement of flow rates. To measure mass flow rates, gas density data is required for all meters.