Department for
Business, Energy
& Industrial Strategy

BEIS OFFSHORE ENVIRONMENT UNIT (OEU)

The Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013 -Offshore Emissions Monitoring Guidance

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Document Revision Record

Revision	Issued Date	Description of changes
1	April 2007	Revision relating to offshore emission monitoring in support of the offshore IPPC combustion processes.
2	Aug 2009	Revision to provide clearer guidance on what constitutes “Best Practices” with respect to using BAT references and CEN / ISO techniques and procedures within the offshore context.
3	Dec 2016	Revision to provide offshore monitoring guidance in support of the updated LCP BREF expected to be agreed, early in 2017, and to reformat guidance.

Abbreviations

AEL	Associated Emission Level
AQO	Air Quality Objective
BAT	Best Available Techniques
BEIS	(Department for) Business, Energy and Industrial Strategy (environmental regulator for the offshore industry)
BREF	BAT Reference
BS	British Standard
BSP	British Standard Pipe
CEMS	Continuous Emission Monitoring System
CEN	European standards organisation
CO	Carbon Monoxide
DECC	Department of Energy and Climate Change (former name for BEIS)
EA	Environment Agency
EF	Emission Factor
ELV	Emission Limit Value
EN	European Standard
EEMS	Environmental Emissions Monitoring System
FT-IR	Fourier Transform Infra-Red (analysis technique)
GT	Gas turbine
IED	Industrial Emissions Directive
IR	Infra-Red (analysis technique)
ISO	International standards organisation
LCP	Large Combustion Plant
LOD	Limit of Detection
MCERTS	(Environmental Agency) Measurement Certification Scheme
MW_{th}	MegaWatt thermal
NO	Nitrogen Monoxide (nitric oxide).
NO_2	Nitrogen Dioxide, generally the minor component of the total NO_x emission
NO_x	Nitrogen oxides, includes NO and NO_2
nmVOC	Non-methane Volatile Organic Compound
NPT	National Pipe Thread (US Standard)
PPC	Pollution Prevention and Control
PEMS	Predictive Emission Monitoring System
PTFE	Polytetrafluoroethylene (inert material for sample conditioning and transport)

QMS	Quality Management System
SEPA	Scottish Environment Protection Agency
SO_2	Sulphur Dioxide
SSP	Site Specific Plan
STA	Source Testing Association
STP	Standard temperature and pressure, for standardisation of emission concentrations in the UK this is 0ºC and 101.3 kPa.
UHC	Unburnt Hydrocarbons
UKAS	United Kingdom Accreditation Service
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

Overview

Offshore operators holding a permit under the Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013 (the Regulations) are required to carry out stack monitoring. The offshore monitoring programme shall meet quality requirements as defined in this guidance.

This Offshore Emissions Monitoring Guidance describes the Department for Business, Energy and Industrial Strategy (BEIS) overall approach to stack emissions monitoring and provides guidance on appropriate techniques and methods. The scope of this document covers the following areas:

i. the scope of measurements required under the Regulations;
ii. an outline of the relevant measurement methods that are commonly employed for onshore monitoring programmes;
iii. comment on the applicability of measurement Standards and techniques;
iv. the issues in offshore emission monitoring;
v. use and development of emission factors;
vi. reporting requirements

The main emissions to atmosphere considered by the Regulations are:

- Oxides of nitrogen (NO_x);
- Sulphur dioxide (SO_2);
- Carbon monoxide (CO); and
- Volatile organic compounds (VOCs).

There is no requirement to monitor offshore particulate emissions, and emissions from flares are outwith the scope of this document.

How to use this guidance

The main body of this document covers general guidance on monitoring and recommended practices. Guidance is provided on the development of a Site Specific Protocol (SSP). The appendices cover specific monitoring techniques and methods. The latter provide an overview of recommended techniques classified by substance to guide users in the decision-making process.

1 Introduction

The operation of combustion plant offshore results in emissions to air which contribute to local, regional and global environmental impacts. Consequently emissions from combustion plant are regulated and appropriate monitoring of emissions must be carried out. This guidance summarises the reasons for carrying out stack monitoring including the relevant regulatory and associated reporting requirements. Applicable standards and techniques for stack monitoring are outlined and discussed in the context of offshore operations. Finally, the guidance defines how stack monitoring results should feed into reporting requirements.

1.1 Reasons for Stack Monitoring

1.1.1 Regulatory Context

The Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013 (“the Regulations”) transpose the appropriate provisions of Directive 2010/75/EU on Industrial Emissions (Integrated Pollution Prevention and Control) - commonly referred to as the Industrial Emissions Directive (“the IED”) - in respect to offshore installations undertaking oil and gas production and gas and carbon dioxide unloading and storage operations, where the combustion equipment has an aggregated thermal capacity of $50MW_{th}$ or more. The Department for Business, Energy and Industrial Strategy (BEIS) is the regulatory authority for the Regulations.

The prescribed pollutants under the Regulations are: sulphur dioxide (SO_2), oxides of nitrogen (NO_x), carbon monoxide (CO) and volatile organic compounds (VOCs). Whilst other pollutants are listed in Schedule 2 of the Regulations these are not typical of combustion plant offshore and should be dealt with on a case by case basis in consultation with BEIS.

Article 14 of the IED requires the permit conditions to include suitable emissions monitoring requirements. Monitoring must be carried out of the prescribed pollutants which will be emitted as a result of operation of the combustion plant. The permit application must include an emissions monitoring plan. This must set out a high level plan stating the combustion plant to be monitored, the status of plant with respect to sampling ports and the intention to monitor specific plant in line with the permit conditions and associated guidance.

The offshore industry is excluded from the requirements of Chapter III of the IED; “Special Provisions for Combustion Plants” and the associated emission limit values (ELVs) set out in Annex V. However, individual items of combustion plant which are $>50MW_{th}$ are defined as Large Combustion Plant (LCP) and covered by the provisions of the LCP Best Available Techniques (BAT) Reference Document (BREF), and are therefore required to comply with the BAT Conclusions therein. Section 10.4.3 of the LCP BREF presents the BAT Conclusions for the combustion of gaseous fuels on offshore platforms, and includes associated emission levels (AELs) for NO_x and indicative emission values for CO for open-cycle gas turbines operating at >70% baseload power available on the day (see Section 4 for further discussion).

1.1.2 Emissions Reporting

Emissions are reported annually to verify compliance with the emission limits set out in the permit (tonnes of pollutant per year). The emissions monitoring results should be compared against the pollutant concentrations used to calculate the permit limits, which are often based on the Environmental Emissions Monitoring System (EEMS) factors. The EEMS Emission Factors (EFs) are expressed in tonnes pollutant per tonne of fuel combusted and are currently derived from industry-wide stack monitoring data.

1.1.3 Fate of Pollutants Offshore

Pollutant discharges from onshore combustion processes can have implications for local air quality but the environmental and health impacts are likely to be less significant. This is because facilities are usually located many miles from onshore locations, or from each other, and contributions to onshore ground level concentrations (and the effect on the general public) are therefore likely to be of low significance. The emissions do however contribute to overall releases of pollutants, including greenhouse gases, to the atmosphere.

Whilst it is theoretically possible that emissions from offshore installations could impact other nearby offshore facilities, the contribution to ambient concentrations at those facilities will usually be negligible and well within the appropriate exposure limit values for the pollutants of concern (NO_x, SO_2, CO and VOCs). Potential impacts at the facility where the combustion process is sited will also be very small; but there may be situations where pollutant emission rates are high and dispersion poor and, in those instances, the contribution to ambient concentrations on the source facility may be significant. However, this is extremely unlikely.

Some pollutants may give rise to secondary products; for example, NOx can undergo a photochemical reaction with unburnt hydrocarbons (UHCs) to produce ozone. This can contribute to damage to flora and fauna, but studies have shown that the remote location of the offshore facilities will mean that this effect is not significant[1]. In addition, CO could react with hydroxyl radicals to yield carbon dioxide (CO_2), thereby increasing the contribution to the "greenhouse" effect. However, CO is fairly stable, with a half-life of around a month, and the contribution is also small.

As discussed in Section 1.1.2, pollutant concentrations determined from stack monitoring form the basis of the EFs that are used to estimate total pollutant emissions. These emission estimates are represented in air dispersion modelling studies which form part of an application for a permit. The purpose of the air dispersion modelling is to assess the predicted pollutant concentrations resulting from operation of the combustion plant against air quality objectives (AQOs), to demonstrate that there is no local impact on air quality.

[1] NILU (Solberg, S., Walker, S.E., and Lazaridis, M.). The contribution of British NOx and VOC offshore and onshore emissions for nitrogen deposition and surface ozone. Report prepared by NILU for the United Kingdom Offshore Operators' Association Ltd. 1999.

Consequently stack monitoring data is critical to validate emission levels and for the assessment of local air quality impacts.

The estimated contribution of emissions from offshore combustion plant to UK totals[2] for 2014 are summarised in Table 1-1.

Table 1-1 Contribution of offshore combustion plant emissions to UK total 2014

Pollutant	UK total emissions (Mtonnes)	Offshore contribution to UK total (%)
CO_2 (as carbon)	253.87	3.33%
NO_X	2.59	1.10%
SO_2	0.75	0.18%
CO	4.28	0.20%
CH_4	4.32	0.06%
VOC	1.84	0.01%

Note that the estimates in Table 1-1 exclude emissions from drilling, flaring and non-combustion releases and relates only to emissions from power generation turbines in production operations.

1.2 Accreditation and MCERTS

The Environment Agency (EA) is the competent authority for onshore sites which fall under IED in England. The EA developed the Monitoring Certification Scheme (MCERTS) which provides a framework of standards in relation to environmental monitoring. MCERTS covers the standards of performance that the monitoring equipment must meet as well as proficiency of individuals and organisations undertaking emission monitoring. The main objective is to ensure organisations provide environmental measurements which are of an appropriate quality and reliability.

Wherever possible, offshore operators are required to use MCERTS qualified personnel as well as MCERTS accredited equipment and laboratories to support offshore stack monitoring campaigns. However it is acknowledged that offshore execution of the monitoring in line with the relevant standards indicated in the MCERTS performance standards may not be possible given the constraints on offshore facilities (see Section 1.3). MCERTS and associated standards are discussed in Section 2.

1.3 Offshore Issues and Constraints

It is recognised that the offshore operational environment on the majority of the UKCS offshore installations covered by the Regulations can be significantly different from onshore processes. This presents site-specific issues and constraints which need to be considered as part of both planning and implementing the offshore monitoring. BEIS will continue to take a pragmatic approach with respect to site-specific issues and constraints, providing the operator makes all reasonable endeavours to follow MCERTS monitoring

[2] From National Atmospheric Emission Inventory, offshore contribution derived from operator data submitted through EEMS. Information on NAEI at: http://naei.defra.gov.uk/

approaches in a manner that is considered fit for purpose. BEIS will review exceptions to the recommended approach on a case-by-case basis, taking account of site-specific issues. Section 4 discusses potential challenges associated with offshore stack monitoring in more detail and highlights recommended approaches.

1.4 Monitoring Frequency

Offshore stack monitoring campaigns fall under one of two categories:

- Baseline monitoring; or
- Subsequent emission monitoring.

The baseline monitoring is primarily required to provide verification or adjustment of the annual emission estimates in the permit application. The scope and frequency of any subsequent emissions monitoring will be determined by BEIS on a case-by-case basis, taking account of:

- Information included in the permit application;
- The results of the initial survey;
- Significant changes to the mode of operating the combustion plant; and
- Changes to the Regulatory framework

Stack monitoring may be required in order to assess compliance with new or amended regulatory requirements. For example the revised LCP BREF which is expected to be agreed, early in 2017.

2 Stack Monitoring Standards

Permit conditions require offshore monitoring to be carried out on the combustion plant exhaust stacks. This must be carried out to an appropriate standard to ensure the quality and reliability of the data. BEIS requires permit holders to comply with MCERTS requirements so far as is practicable within the constraints of the offshore operating environment. This section outlines the different aspects of MCERTS and the associated standards and guidance. Section 4 discusses the practicality of implementing some aspects of MCERTS offshore and the recommended approach which operators should employ where MCERTS standards are not entirely achievable.

2.1 MCERTS

MCERTS is intended to provide assurance to regulators and operators that emissions monitoring is fit for purpose. It is largely to provide assurance that emissions data collected from sites, equipment, and conditions, is reliable relative to emissions compliance limits (which onshore are generally concentration-based emission limit values, ELVs). MCERTS was originally applied to continuous emissions monitoring systems (CEMS) equipment to provide analyser type approvals, so that process operators and regulatory authorities could have confidence that CEMS would be fit for purpose. In 2002 MCERTS was extended to periodic test organisations undertaking regulatory and compliance monitoring, as an extension of ISO 17025[3] accreditation under UKAS.

MCERTS is a framework of standards that covers:

- The standards of performance that your monitoring equipment must meet;
- The level your staff must be qualified to; and
- Accrediting laboratories and inspecting sites in line with European and international standards.

MCERTS guidance documents on a range of topics related to monitoring of emissions to air are available and are summarised in Table 2-1.

[3] EN ISO/IEC 17025 General requirements for the competence of testing and calibration laboratories

Table 2-1 MCERTS Guidance on Emissions to Air

MCERTS Guidance Document	Applicable Offshore?	Comments
MCERTS: performance standard for continuous ambient air quality monitoring systems	No	Ambient air quality monitoring not currently required for offshore
MCERTS: performance standard for indicative ambient particulate monitors	No	Particulate monitoring not required for offshore
MCERTS: performance standard for open path ambient air quality monitoring systems	No	Ambient air quality monitoring not currently required for offshore
MCERTS: examination syllabuses for manual stack emission monitoring	No	Exam syllabus, not relevant
MCERTS: performance standard for organisations monitoring manual stack emissions	Yes	See Section 2.1.1
MCERTS: performance standard for portable emission monitoring systems	Yes	See Section 2.1.2
MCERTS: performance standards and test procedures for automated dust arrestment plant monitors	No	Relates to particulate monitoring and hence not applicable.
MCERTS: performance standards and test procedures for automatic isokinetic samplers	No	Relates to particulate monitoring and hence not applicable.
MCERTS: performance standards and test procedures for continuous emission monitoring systems	Yes for LCP equipment	See Section 2.1.3
MCERTS: personnel competency standard for manual stack emission monitoring	Yes	See Section 2.1.4

The EA has also published Technical Guidance Notes (TGNs) to provide further guidance on monitoring. Those pertinent to periodic stack monitoring are:

- TGN (Monitoring) M1 Sampling Requirements for Stack Emissions Monitoring
- TGN (Monitoring) M2 Monitoring of Stack Emissions to Air

Section 2.1.5 provides an overview of these guidance documents which indicate the standards that should be adhered to for stack monitoring. Further detail on the standards of most relevance to offshore stack monitoring is provided in Appendix A.

Accreditation of an organisation to EN 17025[3] and MCERTS can be checked through the UKAS website. Search for 'MCERTS' and, when prompted, select Environment samples ‘stack emissions-sampling’. The entry provides a list of accredited organisations and the scope of accreditation of each organisation.

MCERTS also covers type-approval certification of equipment used for emission monitoring such as CEMS and portable emission monitoring equipment. The MCERTS accreditation status of monitoring equipment, individuals and companies can be obtained from the scheme administrators (SIRA Environmental Ltd).

Further details of MCERTS can be found at:

- http://www.siraenvironmental.com/mcerts/ and
- http://www.mcerts.net

Pertinent points related to MCERTS guidance documents are noted in the following sections however the performance standards should be referred to in full. The MCERTS requirements are generally achievable offshore however implementation of some aspects may be difficult. This is discussed further in Section 4.

2.1.1 MCERTS Performance Standard for Monitoring Manual Stack Emissions

This performance standard sets out technical requirements in relation to manual monitoring in the following areas:

- Personnel - those carrying out stack monitoring should have an appropriate level of MCERTS certification. The tasks which may be carried out are dependent on the level of training and experience (see section 2.1.4);
- Accommodation and environmental conditions - appropriate sampling facilities should be available in line with TGN M1 in order to reduce the risk of contamination of the samples;
- Test Methods & Validation - the methods outlined in TGN M2 should be used for monitoring;
- Equipment - appropriate equipment selection, handling and cleaning;
- Measurement Traceability - identify calibration aspects of methods that can contribute to uncertainty of measurement (equipment , calibration gases)
- Sampling - site review in order to produce a Site Specific Protocol (SSP)
- Handling of Test Items - chain of custody record for collected samples;
- Assuring the Quality of Test Results - in line with EN ISO 17025 (section 2.2)
- Reporting of Results - a standard report format should be used, any deviations from the SSP or the monitoring method should be noted.

2.1.2 MCERTS Performance Standard for Portable Monitoring Equipment

Performance characteristics and test procedures for portable emissions monitoring systems are specified in this performance standard. Where a process falls under the LCP BREF requirements (see Section 1.1.1), portable systems that perform to a high standard are required and are covered separately under the performance standard for CEMS; for example, use of calibration gases is required (Section 2.1.3).

The performance standards states that test procedures for portable monitoring systems should meet EN 15267: Part 3[4]. Testing systems should be certified by the Certification Body as meeting the required standards and equipment should have a unique designation identifying it as a certified model. MCERTS certificates are valid for five years.

2.1.3 MCERTS Performance Standard and Test Procedures for Continuous Emission Monitoring Systems

The performance standard reflects the requirements of EN 15267: Part 3[4]. Some additional provisions are included for flow monitors. As mentioned above, portable equipment used to monitor LCP equipment should meet this performance standard, i.e. be designed to perform to the same high standards as required for CEMS. These types of portable system are referred to as Transportable Systems.

Performance criteria are set out in the CEMS performance standard for monitoring aspects including for measurement of gaseous components and for flow measurement. In essence, a Transportable System will require calibration gases during use and should be considered as semi-portable for offshore work.

2.1.4 MCERTS Personnel Competency for Manual Stack Emission Monitoring

The required training and experience to achieve the MCERTS qualification levels are set out; entry level (trainee), Level 1 (Technician), Level 2 (Team Leader). The requirements around personnel certification and details of the MCERTS register of certified personnel are provided.

2.1.5 EA Monitoring Technical Guidance

TGN M1 provides guidance on BS EN 15259[5] and how to go about meeting the requirements. The following areas are covered:

- Designing a representative measurement location
- Principles of representative sampling
- Periodic sampling using grid measurements
- Representative sampling of gases
- Sampling requirements for CEMS
- Sampling facilities for stack monitoring
- Risk management of site work

An important aspect of exhaust stack monitoring is to obtain a representative sample from the exhaust stack. In order to achieve this there are requirements around ensuring homogeneous flow at the sample location and also in relation to the number of samples required. TGN1 and EN 15259:2007 set out appropriate sampling strategies i.e. number and positioning of sample points, for circular and rectangular ducts of different sizes.

[4] EN 15267: Part 3 Certification of automated measuring systems. Performance criteria and test procedures for automated measuring systems for monitoring emissions from stationary sources

[5] BS EN 15259 Stationary source emissions – Requirements for measurement sections and sites and for the measurement objective, plan and report

TGN M2 sets out guidance on the development of a monitoring strategy; taking into account the substances to be sampled, when to sample, duration of sampling, number of samples and methods to be used for sampling and analysis. MCERTS requires the sampling strategy to be documented in the form of a SSP (Section 2.1.1).

Selection of monitoring technique (i.e. the analytical principal such as infrared absorption) and the monitoring method (published or documented procedure such as British Standard, BS) are essential elements of the monitoring strategy. An index of acceptable standard reference methods is available in TGN M2, classified by the substance to be measured e.g. NOx, for both periodic and continuous measurement and including information on the application and limitations of each method. Further information on measurement standards is presented in Section 2.2.

Guidance is given in TGN M2 on how to convert measured concentrations to mass emission rates including correction for temperature, pressure and moisture and oxygen content.

2.2 Measurement Standards

In general, the UK regulatory authorities assign the following hierarchy to measurement Standards:

1. European Standard (EN)
2. International Standard (ISO)
3. National Standard (BS)
4. Other recognised method

EN 15259:2007 is one of the key standards for offshore stack monitoring. EN 15259 is the standard for “Stationary source emissions – Requirements for measurement sections and sites and for the measurement objective, plan and report”.

Accreditation of the test organisation to EN 17025[3] is commonplace, and is mandatory for organisations undertaking compliance and check monitoring of IED sites onshore and offshore.

The standards most relevant to offshore stack monitoring are discussed in Appendix A.

2.3 Source Testing Association

The Source Testing Association (STA) is an industry association representing emission testing organisations, process operators, monitoring equipment manufacturers and others. The STA produces guidance on reporting standards, test methods, safety and quality. Information on MCERTS and other useful guidance, including minimum standards of testing and reporting for STA members, is available from the website.

The STA produces a useful annual guide to its membership organisations and the services they provide, including details of UK organisations accredited to ISO 10725 under MCERTS. A large number of these organisations operate mobile field laboratories for the purpose of periodic stack emissions testing. A significant number have the capability, resources and experience to meet the offshore testing requirements using CEN / ISO

Standards. A sub-set of these organisations will also already have experience of successful offshore testing.

3 Emission Measurement Techniques & Methods

3.1 Overview

Selection of monitoring **technique** (i.e. the analytical principal such as infrared absorption) and the monitoring **method** (published or documented procedure such as British Standard, BS) is an important element of the SSP. These definitions of "technique" and "method" are in line with TGN M2.

Measurement methods can be classified under a number of headings. For example, they may be:

- **Extractive methods**, where a sample is removed from a duct for analysis on a continuous or periodic (short-term) basis;
- **Non-extractive methods** analyse the flue gases within the duct, and include
    - cross-duct measurement methods (where the duct becomes a part of the measurement equipment) or
    - *in-situ* measurement methods (where sensors are placed within the duct – usually in a small filtered enclosure at the end of a probe), and are usually associated with continuous measurement systems.
- **Manual or automated instrumented methods** can be employed for periodic measurements, but automated systems are required for continuous measurements. Manual techniques usually involve extraction of a sample for later analysis in a laboratory.

EN 15259[5] should form the backbone of an emissions monitoring strategy, and BEIS expect to see evidence of its consideration within the SSP. EN 15259 is already implemented in onshore UK as an integral part of MCERTS.

TGN M2 provides general guidance on emission sampling methods and standards for emission monitoring. The methods and standards included in TGN M2 relevant to offshore are summarised in Appendix A. Methods for SO_2 stack sampling and analysis are briefly mentioned as, although BEIS normally require SO_2 to be quantified based on the sulphur content of the fuel, SO_2 monitoring is required for installations that use crude oil as a fuel source.

A further source of emission monitoring data is the USEPA, which provides free access via the internet to its monitoring methods[6]. Relevant USEPA methods which may wish to be considered for use as part of the monitoring survey are also indicated in Appendix A.

[6] USEPA Methods can be found at http://www.epa.gov/ttn/emc/

Contact details for MCERTS certified equipment suppliers are provided at:

http://www.siraenvironmental.com/mcerts/ and http://www.mcerts.net.

3.2 Portability of Monitoring Equipment

The issue of portability of the monitoring equipment is an important factor in selecting the measurement technique. Experience has shown that this is a more important factor for offshore monitoring work than it is for onshore monitoring.

Fully Portable - In the context of offshore surveys, this should be taken to mean a single piece of equipment that is hand transportable, battery driven and which is safe to transport by helicopter. For example, equipment that employs compressed gas cylinders or chemical solutions would not be fully portable. Some equipment classed as 'portable' onshore can only be viewed as 'semi-portable' in the offshore context.

Semi-Portable - This should be taken to mean equipment that may be made up of several modules, each of which must be hand transportable. The system may require a mains electricity supply, and may employ compressed gases (or chemical reagents) that would not be accepted for transport by helicopter. In the offshore context such equipment will typically require one or more temporary power sockets (110V x 16A) close to the test location.

Transportable - This should be taken to mean equipment that may be made up of several modules, few, if any, of which are hand transportable. The term "transportable" is used in MCERTS to refer to **semi-portable** equipment which meets the same high standards as required for CEMS (see Section 2.1.3). The equipment usually requires a mains electricity supply, and employs compressed gases (or chemical reagents) that would not be accepted for transport by helicopter. Onshore such systems are commonly used for periodic testing and are typically located in a mobile laboratory. Offshore, supply boat transportation and crane handling is often necessary to locate such equipment at a suitable test site on the installation and/or to relocate the equipment between test sites / modules.

Fixed – This should be taken to mean equipment permanently installed on a duct and not intended for movement to other installations. The equipment invariably requires a mains electricity supply, and employs compressed gases for calibration and support. Onshore CEMS are typical of such fixed systems.

An indication of the portability of the equipment associated with the methods discussed in Appendix A is provided in Table 3-1. The level of uncertainty achievable with a given technique is indicated in Table 3-2.

Table 3-1 Portability of Instrumented Emission Analysis Systems

Portability	Techniques											
	NO/NO_x			SO_2			CO		O_2		VOC	
	EC	IR	CL	EC	IR	UV	EC	IR	EC	PM	FID	IR
Fully	✔	-	-	✔			✔	-	✔	✔	-	-
Semi	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Transportable	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Fixed	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔

Notes:

Analytical techniques: EC = electrochemical cell, IR = Infra-red systems, UV = ultraviolet systems,
CL = Chemiluminescence, PM = Paramagnetic, FID = Flame ionisation detector.

Table 3-2 Uncertainty of Instrumented Emission Analysis Systems

Portability	Uncertainty, %					
	EC	IR	UV	CL	PM	FID
Fully	25/50	-	-	-	25	-
Semi	10/25	10/25	10/25	10	10/25	10/25
Transportable	10/25	10/25	10/25	10	10	10/25
Fixed	10	10	10	10	10	10

Notes:

Analytical techniques: EC = electrochemical cell, IR = Infra red systems, UV = ultraviolet systems,
CL = Chemiluminescence, PM = Paramagnetic, FID = Flame ionisation detector.

4 Offshore Monitoring Requirements, Sampling Facilities & Special Considerations

Under the Regulations, a permit application must include an emissions monitoring plan containing details of the proposed measurement methodology and the intended evaluation procedure (see Section 1.1.1). A condition is included in permits which requires installations to complete an initial survey within a timeframe agreed with BEIS. The frequency of subsequent monitoring is dependent on various factors as discussed in Section 1.4.

The Regulations require operators of permitted installations to report combustion emissions on an annual basis. At present, this is undertaken via the EEMS reporting system[7]. The EEMS system incorporates equipment-specific NO_x emission profiles for many models of gas turbines operating offshore and default EFs for other pollutants. The EFs are calculated based on running hours or other activity statistics such as fuel consumption to allow operators to estimate combustion emissions. An operator can overwrite the default factors with more appropriate data if it is available, although this is required to be agreed with BEIS prior to changing the EFs. The last update to the EEMS NO_x emissions profiles was carried out in 2015, using information compiled from the results of all offshore stack monitoring carried out prior to that date.

Appropriate sample ports are required to conduct stack monitoring; the design and positioning of which should be in line with the relevant standards. Ports deemed acceptable for previous monitoring surveys will remain acceptable for future surveys. However as previously mentioned, it is often not possible to meet all the relevant standards due to the nature of offshore facilities. The requirements for sample port design, challenges faced offshore and recommended approaches are discussed in Sections 4.5 to 4.6.

4.1 Combustion Equipment to be Monitored

A risk-based approach can be adopted to identify the main (i.e. primary) emission sources (e.g. electricity generation or gas compression turbines in continuous use) and the combustion plant which are of minor relevance to annual emissions. For example standby or emergency equipment with low use and low thermal input need not be monitored. This allows the operator to define a measurement programme that provides detailed coverage of the major combustion plant and an acceptable level of data for smaller combustion units.

[7] Information on EEMS is at https://www.gov.uk/guidance/oil-and-gas-eems-database

Emissions from the combustion installations are required to be characterised over a range of operating conditions considered to be representative of the normal operating regime. Where such conditions may change over time, or where it is recommended that monitoring should be undertaken under specific conditions, this should be taken into consideration in the SSP.

Development of a monitoring programme and SSP is discussed further in Section 5, and clarification is provided on the selection of combustion equipment for inclusion in a stack monitoring programme.

4.2 Monitoring of Large Combustion Plant (LCP)

Chapter III of the IED and the associated ELVs set out in Annex V. However, LCP are required to comply with the requirements detailed in the LCP BREF. Section 10.4.3 of the LCP BREF presents the BAT Conclusions for the combustion of gaseous fuels on offshore platforms, and includes BAT AELs for NO_x for open-cycle gas turbines operating at >70% baseload power available on the day.

All LCP operated offshore will be required to undertake stack monitoring, subject to possible exceptions, detailed below. Stack monitoring will normally be required over the turbine's load range, including >70% baseload power where this is viable. BEIS has interpreted "*baseload power available on the day*" in line with the definition of Potential Maximum Power in API Standard 616[8], i.e. *"the expected power capability when the gas turbine is operated at maximum allowable firing temperature, rated speed, or under other limiting conditions as defined by the manufacturer and within the range of specified site values"*. This definition gives a value ~ 5% to 15% lower than the ISO rating of the gas turbine, as it takes into account the various mechanical losses. It is therefore a more meaningful parameter and can be obtained by calculation / operational history.

4.2.1 Possible Exceptions to Monitoring Requirement

It is recognised that the offshore operational environment on UKCS offshore installations covered by IED can be significantly different from onshore. This presents site-specific issues and constraints, including safety issues relating to obtaining access to the stacks, sampling problems because of the configuration of the stacks and minimising the potential for a plant upset, all of which will need to be considered as part of both the planning and implementing of the offshore monitoring. BEIS will continue to take a pragmatic approach with respect to site-specific issues and constraints, providing the operator makes all reasonable endeavours to follow MCERTS monitoring approaches in a manner that is considered fit for purpose. BEIS will review exceptions to the recommended approach on a case-by-case basis, taking account of site-specific issues detailed in the proposals submitted to BEIS.

Emissions from the LCP are required to be characterised over the range of operating conditions considered to be representative of the normal operating regime, but wherever possible this should also **include monitoring at >70%** baseload power even if this is not within the normal operating regime. Where normal operating conditions may change over

[8] API Standard 616 Gas Turbines for the Petroleum, Chemical, and Gas Industry Services

time, this aspect should also be taken into consideration. Where it is not viable to conduct stack monitoring over the range of operating conditions, including the monitoring of LCP units at >70% baseload power, a justification for the exception must be included in the SSP submitted to BEIS. Exceptions will not be possible solely on the grounds that units are normally only operated at low baseload powers. Note that testing relating to demonstrating compliance with the LCP BREF requirements will only be required for gaseous fuels, but where baseline survey requirements are detailed in the permit conditions, testing of dual fuel units must be undertaken on both liquid and gas fuel operation.

If a facility has a number of turbines of the same type and performing the same duty (e.g. power generation or gas compression) then it may be sufficient to characterise the emission profile for one machine over the normal operating regime (including above the 70% baseload power), but measurements on any “sister” units could be undertaken at a single load or over a more limited range of loads – i.e. spot measurements - assuming they are performing the same duty and using the same gas supply.

If there are several units of the same type, but the units differ because some have been modified (for example uprated or de-rated), then a full range of measurements would be necessary for each unit to assess and demonstrate the differences in the emission profiles. Where the same type of units are used for different duties (for example electricity generation and gas compression) then one example for each duty should be characterised over the normal operating regime (including above the 70% baseload power), with spot measurements over a single load or a more limited range of loads for the sister unit(s). Data obtained will allow extrapolations to be made to determine whether the emission limits for >70% baseload power will be achieved or not, as this must be determined for all LCP units.

Exemptions from undertaking the monitoring for installations that are close to decommissioning must be supported by robust evidence of the decommissioning proposals. This could be acceptance from the Oil and Gas Authority (OGA) that Cessation of Production (CoP) has been agreed, and operators must discuss the potential exemption with BEIS.

4.3 Measurement Techniques & Standards

BEIS requires best endeavours to carry out monitoring in line with MCERTS and the use of Standard CEN / ISO measurement techniques for the main pollutants. By inference this should incorporate the use of on-site calibration gases in order to verify measurement data before and after a test run, using competent personnel & suitable test procedures. Recommended CEN / ISO measurement techniques are discussed in Section 2 and Appendix A.

4.4 Sampling Facilities

TGN M1, ISO 10396[9] and other documents provide general guidance on choosing sampling locations and the provision of sampling facilities. The key requirements are for a sampling position as far away from flow disturbances (for example bends and dampers) and joining ducts as possible in an effort to ensure homogeneous flow. Grid sampling i.e. sampling at multiple points on a grid across the stack measurement plane, is used to determine if flow is homogeneous.

It is recognised that, in the offshore context where ports often have to be retrofitted to existing stack infrastructure, the selected locations will often be a compromise position between the 'ideal' and 'readily accessible' locations. In this respect, it should be noted (as indicated in TGN M1) that the requirements for measuring emission concentrations of gaseous species of pollutants are much less onerous than the requirements for measuring particulates. Since particulate measurement is not required offshore, a fit-for-purpose interpretation of TGN M1 is therefore appropriate. Generally homogeneous flow is achieved with at least 5 hydraulic diameters of straight duct upstream of the sampling plane and 2 hydraulic diameters downstream (5 hydraulic diameters from the top of a stack to avoid air entrainment[5]). It may be possible to demonstrate that sampling from a single point is adequate and grid measurements are not required as gases are often well mixed. A spatial and temporal assessment of concentrations in the stack would be required for this purpose.

It is recommended that, if in doubt, operators should seek guidance from their emissions monitoring consultant.

Sampling ports are required to access the exhaust gases and, where practicable, should be located to allow a traverse of the ducts across two diameters (to assess mixing at the sampling position). If only gaseous concentration measurements are required, then a minimum 1 inch BSP (British Standard Pipe) or NPT (National Pipe Thread, US Standard) socket and safe working access are all that are required. However, it should be noted that some test houses prefer a minimum 2 inch sockets to accommodate adequate tip pre-filters when undertaking testing for diesel fuel. For gas turbines without heat recovery, a flange connection is recommended (flanges appear to be less prone to seizing). To avoid discharge of hot gases at the sampling position, an isolating valve is recommended for exhaust ducts which are at higher than ambient pressure. These requirements should be discussed at the planning stage, as different operators have different requirements in relation to the provision of isolation valves under integrated safe systems of working, and requirements can therefore be very site specific.

Safe working access and a work platform are required. Although the equipment used at the stack port may be hand-portable, it can include long sampling probes (up to 3m) that are difficult to manoeuvre if the sampling platform is too small. For this reason, adequate clearance must be provided around the port when considering the detailed design of any retrofit connections.

[9] Stationary source emissions - Sampling for the automated determination of gas emission concentrations for permanently-installed monitoring systems

Provision of additional larger sockets and platforms would be required for flow measurements or more elaborate emission measurements. However, this is not an offshore requirement.

Protection of equipment and personnel from radiant heat needs to be considered where exhaust ducts are not insulated.

Access to a workshop or other work area is required to allow the recharging of batteries, the storage and use of calibration gas cylinders and the installation of the VOC analyser (if not deployed to the sampling position).

Transportation of non-portable items (gases, semi-portable / transportable analysers) to an offshore installation will normally be via supply boat from the operator's onshore supply base. Transportation will normally have to be arranged in appropriate offshore certified containerised cargo units.

4.5 Main Issues in Offshore Measurements

The main issues encountered during offshore emission surveys are:

- **Logistics** – This includes the transporting of personnel, equipment and calibration gases to and between facilities. There are limited flights and limited space on flights; in addition there are safety issues concerned with transporting compressed gases or chemicals by helicopter. Following advice from the platform operators and shipping agents, calibration gases can be taken offshore for baseline measurements. Stack testing has been successfully conducted offshore where calibration gases have been used; and their use is regarded as an essential element of best practice. Where a test programme includes multiple platforms, sufficient time needs to be allowed in the programme to transfer the gas cylinders required for calibration between platforms.

- **Sampling facilities** – The gas turbine exhaust ducts on offshore facilities generally have limited provision for emission sampling. Although there are comparatively long flues, which should allow adequate mixing of flue gases, the most accessible locations for sampling are frequently at the turbine exhaust duct immediately downstream of the GT enclosure and this is not an ideal sampling location. The absence of insulation on some exhaust ducts can also prevent access at other locations due to high radiant temperatures. It is important to remember that only monitoring of gaseous species of pollutants is required offshore (and not particulates) – so appropriate less onerous requirements of TGN M1 should be followed. Where offshore installations do not have existing sample ports, the retrofit of sampling facilities at a conveniently accessible location (often a compromise) will be a key factor during the early stages of planning a survey. New installations must ensure sample ports are incorporated at the design stage.

- **Access** – Individual gas turbines in the gas compression and electrical generation modules are usually at different locations and at different levels on the platforms. Hand portable equipment may be moved comparatively easily to and between the various sampling locations. However, movement of heavier test equipment would be significantly more difficult. Crane access is not always possible near the sampling positions, and crane operations must be halted in medium to high winds. The selection of transportable equipment may therefore be suitable for some platform configurations, but not others, and in many cases semi-portable arrangements will be the most appropriate compromise.

- **Flameproof zones** – Short-term measurements using fully-portable and semi-portable equipment should not be an issue providing appropriate permits are in place and flammable and toxic gas personal monitors are used. Use of other semi-portable mains driven VOC emission monitoring equipment may be undertaken at a workshop location (i.e. sample collected in bags and returned to the workshop for analysis). The workshop should also provide a convenient location for storage and use of calibration gases. In order to meet the CEN / ISO Standards, the necessary risk assessments must be carried out to allow the required equipment to be used under strict Permit to Work arrangements. This is an important element of the pre-planning.

- **Equipment reliability** - Older portable emission analysers may stop operating at low ambient temperatures (this was a 'feature' of the design of these analysers, to avoid damage to the equipment from condensation of moisture present in the sample gas). Modern equipment incorporates more sophisticated sample drying systems, allowing operation at lower temperatures. Power supply issues due to frequency and voltage differences also should not be a problem.

- **Communication** – Communication routes between the test personnel, facility personnel and the onshore facility and test house management can be difficult, and planning is needed to ensure communication is sufficient to quickly address any issues.

- **Plant instrumentation** – The data available to characterise the operation of combustion equipment may be quite limited, particularly on older facilities and for smaller combustion units.

- **Equipment warm-up time** – Some analyser equipment may have long warm-up times (e.g. up to 4 hours) and may not be suitable for expedient use unless it can be located in a non-hazardous zone and left on power overnight (between working shifts). In many instances, where equipment must be located and used in the process environment under suitable hot work / spark potential permit, it is more appropriate to make sure that the test team selects equipment that has a short warm-up time (e.g. 1 hour or less), providing this does not compromise the CEN / ISO Standards and procedures.

- **Temporary utilities** – Systems that can achieve full compliance with CEN / ISO Standards, including many semi-portable systems, will require a temporary or permanent electricity supply (sockets) in the vicinity of the sampling location. Typically one or more 16A 110V supplies will be required, and this should be clearly identified at the planning stage and, if necessary, the facilities put in place in the run-up to scheduled testing.

- **Monitoring over the turbine's load range** – See section 4.2

It should be noted that a high level of co-operation from the platform personnel is essential when carrying out offshore emission monitoring work. Where possible, an operative from the facility should be assigned to liaise and assist with the measurement task. This approach allows issues that arise to be resolved quickly. This is particularly important where emissions are being characterised across operating load range, since a dedicated authorised operative is required to co-ordinate load changes to critical production plant (e.g. power generation / gas compressor turbines).

The availability of combustion equipment for testing during or shortly after commissioning can be difficult. Operation of the facility is not stable and operators can be very reluctant to modify operating conditions to provide (for example) changes in load on individual combustion plant. This has implications for completing a monitoring survey in a timely manner. This aspect should be discussed early on in the planning stages so as to minimise impact at time of testing. BEIS will take a pragmatic view if there are genuine reasons why a particular item of combustion plant is not available for testing.

The main barriers to the use of higher quality emission monitoring equipment for periodic monitoring are probably movement of the equipment around the facility; location of the equipment; and operation of the test and ancillary equipment in flameproof zones. A short reconnaissance survey of the installation is therefore recommended to provide input to the development of the SSP and baseline survey test procedures, which should be undertaken well in advance of the scheduled test window.

4.6 Recommended Approaches

Based on previous stack monitoring, various issues were identified with conducting stack monitoring offshore. The key considerations and recommended approaches are as follows:

1. The quality of each survey is important and likely to be a key factor in agreeing subsequent monitoring requirements with BEIS. It is in operators' interests to aim for good measurement quality and good emissions characterisation for the main combustion equipment. The BEIS emphasis in relation to periodic measurements is one of high quality / low frequency in preference to low quality / high frequency, as this will allow the objectives to be achieved in the optimal manner for all stakeholders. Where poor data is found, the sampling will be required to be repeated within a shorter time period and this potential requirement should be identified during the measurement phase so that measurements can be repeated where necessary to avoid further complications.

2. The use of Standard CEN / ISO measurement techniques is considered best practice and is recommended as part of a programme to ensure good quality results. By inference this incorporates the on-site use of calibration gases, in order to verify measurement data immediately before and after a test run, using competent personnel and suitable test procedures.

3. The use of direct instrumented stack measurement techniques (whereby a flow of gas is extracted from the stack for immediate analysis using an approved detection principle) is recommended, in preference to the use of 'classic' wet chemical-based manual extractive methods, or integrated sample bag methods. In common with onshore regulatory guidance, and based on offshore experience to date, direct instrumented techniques are considered best practice for baseline surveys and the periodic monitoring of gaseous pollutants from combustion plant, and are suitable for use under offshore permit to work systems.

   The key components in relation to undertaking quality measurements are; an agreed SSP, a good (or characterised) sampling position, the application of a standard method, the use of competent test personnel, and a clear, detailed test report[10] to demonstrate the traceability of the measurements.

4. A risk based approach can be used to identify the main emission sources that warrant monitoring, and the minor sources that may either not require monitoring or could be monitored less frequently, or monitored using portable devices.

5. Appropriate attention should be given in the planning stages as to how data relating to fuel flow, gas turbine load parameters, gas composition data, and stack velocity are to be measured and recorded in parallel with measurements of the stack emission concentrations. These parameters are important for the characterisation of emissions, and for the comparison with, or validation of, EEMS profiles and defaults. They will generate additional uncertainty which should be minimised to ensure good overall quality of the data.

6. Monitoring programmes should aim to characterise emissions profiles over a range of representative operating conditions and, where appropriate, for relevant fuel types (i.e. gas and/or diesel).

7. The recommended approach, which is closely aligned with MCERTS and onshore practice, is considered to be one that incorporates;

    - use of a suitable SSP (see Section 5.4);
    - strategic assessment of monitoring and sampling requirements (to EN 15259[5] or ISO 10396);
    - direct application of the CEN / ISO Standards detailed in Appendix A of these guidelines, or a measurement procedure with demonstrated equivalence to those standards; the use of MCERTS certified analytical equipment; and, by inference, the use of on-site calibration gases;
    - involvement of MCERTS competent personnel; with, as a minimum, overall planning, review and on-site supervision by Level 2 Team Leader and on-site testing (as a minimum) by a Level 1 Technician;
    - use of Quality Management System (QMS) procedures undertaken by a UKAS 17025-accredited "test house";
    - a record of any exceptions to standards resulting from site specific constraints;
    - detailed characterisation of all types of main combustion plant on the installation, across their load range and on applicable fuels; subject to any site specific constraints agreed with BEIS as part of the monitoring programme (e.g. operational constraints that restrict current load range).

8. BEIS recognises that operational or logistics constraints may inevitably mean that all elements of the recommended approach may not be achievable. Hence BEIS will review exceptions to achieving the recommended approach on a case-by-case basis. For example, stack access restrictions or health and safety concerns may genuinely prevent the use of CEN / ISO Standards and lead to

[10] See standardised test report format as per "*Environment Agency (2011) Manual Stack Emission Monitoring Performance Standard for organisations*".

deviations and these should be fully described in both the monitoring proposals and the final survey emissions report.

9. BEIS will expect operators to achieve the recommended approach in most circumstances. This is considered necessary to meet the permit condition requirements or as directed by the Department.

10. The most straightforward way to demonstrate that recommended approach is met and the core elements of the measurement technique and related procedures are included, and to ensure formal reporting of overall emission measurement and uncertainty, is to use analysis equipment with MCERTS type approval for the appropriate pollutants and ranges, operated on site by a MCERTS competent operative with the use of on-site calibration gases under UKAS accredited procedures.

11. If there is a requirement to demonstrate equivalence to CEN standards, then CEN TS 14793 "*Intra-laboratory validation procedure for an alternative method compared to a reference method*" should be consulted prior to the documentation of detailed procedures by competent personnel, and the methodology and results should be detailed in the test report[10].

12. It is recognised that the offshore operational environment can be significantly different to that found onshore, and that the onshore and offshore monitoring objectives are different. BEIS will therefore continue to take a pragmatic approach with respect to site-specific issues and constraints, as long as all reasonable endeavours to achieve the recommended approach in a fit for purpose manner. BEIS will review deviations from the recommended approach on a case-by-case basis and any changes must be fully described and justify why the deviation is necessary.

13. The current EEMS-based approach to calculating combustion plant emissions based on thermal input profiles and fixed emission factors is, in essence, a simple PEMS approach. It is acknowledged that there are more robust PEMS approaches available, but that these will generally rely on additional parameters such as online links to combustion plant signals (e.g. via the Distributed Control System, DCS) and verification against baseline measurements. Demonstration that an operator is using a PEMS technique that offers improved fidelity compared to fixed EEMS profiles / factors, and has been verified by a monitoring survey, would be taken into consideration when determining the future monitoring frequency.

14. The data obtained from the initial baseline survey sampling should be used to;

- Validate manufacturer / supplier data used to derive emission factors;
- Check the annual emission loads detailed in the permit application, and/or to amend the annual emission loads detailed in the permit conditions;
- Review and potentially amend default emission factors used for EEMS returns; and

- Determine subsequent monitoring requirements, taking account of the quality of the baseline data, including overall uncertainty; repeatability of measurements; and the degree of consistency with existing good quality baseline data across similar combustion plant types when burning similar fuels.

5 Offshore Emissions Survey

The operator needs to satisfy the Regulator that the emissions survey will characterise emissions from the facility's combustion plant. This does not require that the operator should measure emissions from every combustion source on a facility. The most significant sources on a facility are likely to be gas turbines used for electricity generation or gas compression.

The survey will require four main activities which are discussed in this section:

1. A review of the combustion plant;
2. Develop a site specific protocol (SSP);
3. Undertake measurements; and
4. Produce a survey emissions report.

The SSP should build on the emissions monitoring plan submitted as part of the application (see Section 1.1.1). There will be interaction between the operator, the emission monitoring contractor and BEIS to finalise the requirements. This section discusses the main areas where appropriate attention should be given to recording process data in parallel with the measurements of stack emissions to allow calculation of EFs. Also discussed, are best practices with respect to planning, conducting and reporting on the baseline surveys.

5.1 Review Combustion Plant

The contribution of the various combustion plant to the annual emissions should have been estimated as part of the permit application. Emission estimates may be based on vendor information or default emission factors, and this will provide a useful starting point to screen the plant which should be included in the baseline survey. Alternatively, the equipment type, size, fuel (type and use) and anticipated or actual operating hours can be used to determine the scope of proposed measurements.

The scope of the survey should aim to characterise the most significant sources including, where relevant, emissions when burning standby or alternative fuels. The measurements should determine, NO_x, CO and VOCs at a range of loads (SO_2 concentrations are normally determined from fuel analysis rather than stack monitoring, but if crude oil is being used as a fuel source then SO_2 monitoring will normally be required). As a minimum, monitoring should be undertaken at loads that are considered typical of normal operations but, if possible, the entire load range should be assessed for the major sources as this may provide information relevant for future operation of the facility or to demonstrate compliance with any relevant standards.

If a facility has multiple combustion units of the same type, model and fuel supply, with no difference in blends of gas (if applicable), and are performing the same duty (e.g. power generation or gas compression), then it may be sufficient to characterise the emission profile for one machine over the full load range, and the other unit(s) would then be sampled at the normal operating load and the resulting data checked to determine whether it fits within the range of the unit that was sampled across its full load range. If the data does not fit into the same range, then sampling over the full load range might be required, including a load above 70% baseload power available on the day for LCP, even if this is not within the normal operating regime.

If there are several units of the same type, but the units differ because some have been modified (for example uprated or de-rated), then a full range of measurements will be necessary for each unit to assess the differences in the emission profiles.

Where there are units of the same type but they are used for different duties (for example electricity generation or gas compression) then one example for each duty should be characterised over the full load range, i.e. not restricted to current operating loads, with measurements for a single load or a more limited range of loads for the sister units.

Where units are dual-fired or dual-fuelled (typically gas oil and gas), emissions should be characterised for both fuels. If machines can operate on a wide range of gas supplies then it may also be necessary to undertake baseline measurements on more than one gas supply. Units that operate on tri-fuel (gas oil, fuel gas and crude oil) must be measured for each fuel type and across the load range, and this may be relevant for boilers, diesel engines and turbines.

Operator's may choose to optimise the monitoring with production operations and planned shut-downs, to mitigate against impacts on production or any process upsets.

Section 4.2.1 details possible exceptions to the monitoring requirements in relation to the LCP BREF. It should be noted that exemptions will not be granted solely on the grounds that the LCP units have previously been monitored. It should also be noted that LCP monitoring is only required for gas fuel operation, i.e. measurements are not required for liquid fuel operation.

5.2 Pollutants to be Monitored

Stack monitoring aims to characterise the emissions from the combustion installations and includes measurement of NO_X, CO and VOCs. SO_2 measurement is not required as SO_2 is quantified based on the sulphur content of the fuel, unless crude oil is being used as a fuel source. If possible VOCs should be further characterised to determine the fractions of CH_4 and non-methane volatile organic compounds (nmVOC). However, where it is not possible to characterise the VOCs, this should be documented along with a justification and the split of VOCs into CH_4 and nmVOC may be assumed to be the same as that determined for the fuel gas. Any site specific obstacles encountered during measuring the prescribed pollutants should be detailed within the survey emissions report.

5.3 Planning Considerations

The key components to achieve quality measurements are; a SSP agreed with BEIS, a good (or characterised) sampling position, application of a standard method, use of competent test personnel, and a clear, detailed test report[10] to demonstrate the traceability of the measurements.

Appropriate attention should be given in the planning stages to the measurement and recording of data relating to fuel flow, gas turbine load parameters, gas composition data, and stack velocity, in parallel with measurements of stack emissions. These parameters are important for characterisation of emissions and will generate additional elements of uncertainty that should be minimised to ensure good overall quality of data.

Best endeavours should be made to meet the requirements of the MCERTS guidance and associated standards which are outlined in Section 2. However Section 4.6 outlines the recommended approach for offshore stack monitoring taking into account some of the constraints relating to offshore facilities. Any proposed deviations from the recommended approach should be documented within the SSP and agreed with BEIS prior to undertaking any monitoring.

Since many onshore test houses have limited familiarity / experience with offshore working environment and associated constraints, it is also recommended that the test team includes appropriate assistance from the operator or their contractor personnel.

With regard to UKAS, 17025[3] and the equivalence to CEN standards, the UKAS guidelines indicate that accredited stack emissions testing organisations and personnel are expected to use CEN / ISO standard reference methods and compliant equipment as part of their work procedures. An organisation may use an alternative instrumental technique to that specified in the CEN / ISO standard reference methods, but the test party is then required to demonstrate that, not only are the equivalent performance criteria to the standards being met, but also that the alternative technique works on the intended process application. This can be achieved in one of three ways:

- Firstly, by using a MCERTS certified piece of equipment as part of the UKAS procedure;
- Secondly by carrying out field tests under ISO 17025 accreditation, to compare the instrument against the CEN / ISO reference method; or
- Thirdly by carrying out tests, using an appropriate test rig, under ISO 17025 accreditation, to compare the instrument against the reference method.

It is a UKAS and regulatory requirement that such field tests / rig tests should meet the requirements of CEN TS 14793 "*Intra-laboratory validation procedure for an alternative method compared to a reference method*". Use of alternative methods such as NDIR for NOx, and Zirconia sensor for Oxygen are examples of valid techniques that have been demonstrated as alternative methods with appropriate test equipment.

Where measurement techniques do not comply with either the standard or an alternative method accreditation, such techniques are more appropriate for ball park spot checks, rather than quality baseline surveys, and should not be considered best practice. Whilst it is an important factor, it is not sufficient to state that calibration gases will be used as a means of addressing the standards, as CEN TS 14793 requires the uncertainty and performance criteria of the complete end-to-end system to be field proven against a standard reference system.

5.4 Develop Site Specific Protocol for Monitoring

A SSP should be developed which describes the work to be undertaken, the methods, equipment and, if applicable, the relevant standards. It should build on the emissions monitoring plan submitted as part of the application. The SSP needs to convert the scope of that plan into a practical measurement programme reflecting issues such as access, safety requirements and the duration of the tests.

Annex D of the MCERTS Performance Standard for Monitoring Manual Stack Emissions provides a framework for the SSP as follows:

Part 1

Contact details, monitoring dates and personnel

- operator name
- operators address and contact information
- permit number (including permit variation number, if applicable)
- installation name
- name of operator's contact
- date and report number of previous monitoring campaign submitted to BEIS (if applicable, i.e. no previous monitoring undertaken as the installation is newly permitted under the Regulations).
    - LCP combustion units monitored (make, model, tag number)
    - Operational range units were monitored.
- planned date of monitoring campaign
- name and address of the company undertaking the monitoring
- name, role during monitoring campaign, MCERTS registration number, certification level and technical endorsements held of the persons who will be involved in the monitoring (the date when the certificates expire is to be included)

Note 1: Part 1 is updated before each monitoring visit

Part 2

Monitoring objectives

- the overall aim of the monitoring campaign
- the pollutants to be monitored at each emission point
    - emission limit value
    - reference conditions at which the results are expressed
    - details of monitoring method(s) to be used for each pollutants
- the overall uncertainty of the method(s)

Process conditions

- the type of process
- a description of the process
- if batch process whether the whole of the batch is to be sampled or the details of the part of the batch sampled
- the fuel type and feedstock
- the normal load, throughput or continuous rating of the plant
- any unusual occurrences that take place during the process
- what type of abatement system is fitted (if applicable)
- what type of CEM system is installed and details of the data information system (if applicable)

- the process details that need to be collected over the monitoring period

Sample location

- dimensions of the stack(s) and monitoring facilities
- a description of the location of the sampling plane for each release point
- for each sampling plane, a description of the type of sampling port (accessibility, correct size, sufficient number, properly located)
- for each sampling plane, a summary of the number, arrangement and orientation of the sample line(s), and the number of sampling points per line
- access to the stack
- adequate work area at the sampling positions
- availability of required utilities (electrical, lighting, water)
- a Pitot tube traverse of the velocity profile*
- temperature and moisture of the stack gas*
- homogeneity test*
- restrictions on using equipment, e.g. intrinsically safe areas
- physical restrictions to using required apparatus
- appropriate measurement equipment for the application
- for each sampling location, a summary of compliance with BS EN 15259 / EA TGN M1 (e.g. flow criteria, homogeneity, access to sample line(s) and sample point(s)

Note 2: *Historical information from previous measurement reports may be used. A note of the reports date and ID number shall be included in the site review.

Details of monitoring

- expected emission values
- the equipment used for each pollutant monitored
- the sampling duration and number of samples for each measurement, including blanks (the duration of sampling must continue until stable data of the respective pollutants has been achieved - see selected Measurement Standards for further details)
- for manual methods, the proposed sample flow-rate, volume and minimum sampling times
- for instrumental methods, the proposed span-gas concentration
- the measurement concentration range and lower detection limit
- for manual methods requiring a separate chemical analysis stage, details of the analytical method, the laboratory carrying out the analysis
- any modifications to the technical procedure, with justifications
- an explanation why any pollutant(s) in the monitoring objectives will not be monitored
- an explanation why any pollutant(s) will not be monitored in accordance with the monitoring method

Note 3: Part 2 is updated when there are changes to the monitoring. It may be necessary to update the SSP following changes to the operator's permit or to the monitoring contractor's procedures. For example, the monitoring contractor's procedures may change due to the publication of a new monitoring standard. Depending on the significance of these changes

The SSP should be submitted in advance of the monitoring survey, allowing sufficient time for BEIS review and comment. Newly permitted installations that are yet to undertake stack monitoring should discuss the timings with BEIS.

In relation to the LCP monitoring, BEIS requires operators to submit their SSPs by the end of Q1 2017 or earlier, and to clearly state when the monitoring is expected to be undertaken. The SSPs will be reviewed by BEIS and checked against the guidance, and any deviations from the guidance must be fully justified in the SSP or this could lead to delays in meeting the required deadline. All LCP monitoring must be completed by 1st April 2019 and the monitoring reports must be submitted to BEIS within two months of completion of the surveys.

5.5 Measurements

The use of standard methods is recommended as far as possible, with the use of calibration gases to check instrument response. Measurements should be carried out under steady operating conditions. Although gas turbines respond quickly to load changes and the emissions are generally very stable, it is nevertheless recommended that a minimum of 15 minutes should be allowed following a load change, and that the duration of the test period at the stabilised load should be at least 30 minutes.

Semi-portable (transportable) systems can be deployed offshore for monitoring surveys. Fully portable systems can also be effectively deployed, but the use of certified calibration gases to check the response of the instrument on the facility (preferably before and after use) is the recommended approach and any deviation should be documented and justified. The use of calibration gases has an impact on the logistics of undertaking the survey and should be appropriately considered at the planning stage.

At present, the most portable combustion emission monitoring systems available are based on electrochemical cell detection (for NO_X, CO and Oxygen) and flame ionisation detection (for VOCs). Fully-portable detection systems tend to have a higher uncertainty than semi-portable, transportable or fixed equipment but the portable electrochemical cell devices are lower cost and are easy to use. To ensure reliable data the testing organisation needs robust quality assurance and control systems. For offshore testing this should include daily spot checks before and after use using calibration gases.

5.6 Equipment used During Offshore Surveys

Whilst there are a significant number of analyser products that comply with CEN standard reference techniques and/or have MCERTS product type-approval, many of these are only suitable for use in transportable systems. Offshore experience has shown that the deployment of transportable equipment for emissions survey testing offshore is only practicable in certain situations. Specifically where analyser equipment can be located in a weatherproof non-hazardous area of the installation within reach of the stack sampling facilities, and left powered up as a normal laboratory device. Otherwise, long warm-up times (up to 4 hours), lack of portability between test locations, and associated logistics issues, may hamper their effective use and can prolong or compromise testing activity. It is recommended that this aspect along with all other practical issues should be assessed when developing the SSP, as part of a site reconnaissance survey.

Technology advances and product certification have meant that there are now a number of products of a portable nature which utilise the Standard CEN / ISO methods and/or have been certified to MCERTS product standard. Together suitable portable elements can be assembled into a semi-portable system and used in partnership with certified calibration gases to conduct quality emissions survey tests to the levels of uncertainty specified by the standards. These semi-portable systems are ideal for most offshore situations since they address the majority of practical concerns regarding the use of transportable equipment, without compromising on quality of measurement. They meet the required performance standards in a more cost-effective and robust manner, have quicker warm-up times (<1hour), are readily moved around the installation, can be maintained if they malfunction, and are in general less intrusive to normal site activity. Quantity of data can therefore be maximised without a detrimental effect on the quality of the data.

Further details of instrumented analyser equipment type-approvals can be obtained from the equipment reference list on the Sira website. [11]

By inference, using the CEN / ISO standards for manual stack sampling implies the involvement of competent personnel. Therefore, the involvement of a UKAS accredited organisation is recommended for the purpose of conducting the emissions surveys. This will generally mean specifying the services of an engineer / technician registered under MCERTS for personnel competency to be involved in the baseline survey. A MCERTS Level 2 Team Leader with appropriate technical endorsements should ideally be involved in the detailed planning stage and, at the least, a Level 1 Technician involved in the testing (stack measurements).

Experience shows that, because offshore testing involves particular work procedures and logistical requirements, it is also advisable for the test team to include a rotating equipment (gas turbine) engineer with a knowledge of offshore gas turbine testing; to co-ordinate the overall test procedure and to ensure that all parallel process and control system parameters are recorded alongside with the stack emissions measurements. This engineer will usually be a member of the operator’s or a specialist contractor’s staff, and should have the authority to take overall supervisory responsibility for the test under the installation’s Permit-To-Work system. This implies a certain level of installation-specific awareness and training.

5.7 Data Standardisation and Reporting

Emission concentrations should be standardised to appropriate reference conditions (oxygen, moisture, temperature and pressure). Guidance is given in TGN M2 on how to convert measured concentrations to mass emission rates including correction for temperature, pressure and moisture and oxygen content. The measured pollutants must also be reported (tabulated) in the format mg/Nm^3 at the respective load for each combustion unit being measured. The previous monitoring data collected must also be tabulated and clearly highlight which measurement period this refers to.

[11] Sira MCERTS type approvals available at http://www.siraenvironmental.com/mcerts/

EFs can be developed from the emission concentrations to allow calculation of annual emission estimates. Appendix B provides details of the standardisation and emission factor calculations.

Appendix E of the MCERTS Performance Standard for Monitoring Manual Stack Emissions provides a format for reporting of stack monitoring results. The survey emissions report shall be a complete account of the measurements and the development of the measurements into EFs and annual emission estimates. Deviations from the requirements of MCERTS must also be documented in the report along with a justification as to why the MCERTS requirements were not achievable if this related to problems encountered during the monitoring that were not identified in the SSP.

Appendix A
Measurement Standards

A.1 Extractive Manual Methods

A.1.1 General Approach and Limitations for Use Offshore

The 'classic' manual wet chemical-based methods involve drawing an extracted sample of flue gas through glass or other inert collection vessels containing absorbent solutions. The target species is absorbed and is quantified by a suitable volume change, titration, ion selective electrode, colorimetric technique or, more commonly by ion chromatography. The volume of gas sampled is measured by a gas meter or flow rate meter. The collected sample is often analysed some time later at a central laboratory facility.

Extractive manual methods for organic compounds are available, but these usually involve capture of organic material on a substrate such as carbon that is usually present in a sorbent tube.

Although manual methods are generally well established (see Table A-1 for standard methods), there are problems associated with their use. The main difficulties with wet chemical techniques are that they require skilled operators and analysts to achieve acceptable repeatability and accuracy, and offshore production laboratory technicians are not typically trained in the specific analytical techniques required for exhaust pollutants. Also, the use of hazardous chemicals, albeit in small quantities, and glassware in the vicinity of a stack environment can be difficult. In most cases these systems should be considered as **semi-portable**. The main benefits are that, in hazardous areas or zones, an intrinsically safe sampling system can be deployed and the collected samples can often be sub-divided to provide an archive sample for repeat analysis if the data is in dispute.

A.1.2 Standard Extractive Manual Methods

A summary of available Standards is provided in Table A-0-1 and the following paragraphs summarise and compare the main features for each pollutant.

Table A-0-1: Extractive Manual Method Standards

Standard	TGN M2	Title	Comment
NO_X			
BS:ISO 11564	No	Stationary source emissions – Determination of the mass concentration of nitrogen oxides - Naphthylethylenediamine photometric method.	Integrated method, photometric determination
USEPA Method 7d	No	Determination of nitrogen oxide emissions from stationary sources (alkaline permanganate/ion chromatographic method).	Integrated method, ion chromatography determination
VOCs			
BS EN 13649	Yes	Stationary source emissions – Determination of the mass concentration of individual gaseous organic compounds - Activated carbon and	Sampling for determination of speciated organic compound determination.

Standard	TGN M2	Title	Comment
		solvent desorption method	
USEPA Method 18	Yes	Measurement of gaseous organic compound emissions by gas chromatography	Method for speciation of organic compounds using gas chromatography (GC)
CO			
Instrumental techniques more appropriate			
SO_2			
BS EN 14791:2005	Yes	Stationary source emissions. Determination of mass concentration of sulphur dioxide. Reference method	Instrument method
ISO 11632:1998	No	Stationary source emissions. Determination of mass concentration of sulphur dioxide. Ion chromatography method	Integrated method, ion chromatography determination
USEPA Method 6	No	Determination of sulphur dioxide emissions from stationary sources.	
O_2			
USEPA Method 3A	No	Gas analysis for the determination of molecular weight	ORSAT method, also covers CO_2 and high concentrations of CO
Water			
EN 14790	No	Stationary source emissions - Determination of the water vapour in ducts	condensation/adsorption technique
USEPA Method 4	No	Determination of water content in stack gases	condensation/adsorption technique

Nitrogen oxides: There are several wet chemical standard techniques in common use. The ISO Standard is not recommended (it involves sampling into an evacuated flask and it can be particularly difficult to obtain reliable data using this method). The US Environmental Protection Agency (USEPA) Method 7D involves passing a measured volume of flue gas through alkaline potassium permanganate solution. The absorbent solutions are then sealed and analysed for nitrate ion content using ion chromatography.

Carbon monoxide: Manual wet chemical methods (for example ORSAT) have poor limits of detection and are generally only suitable for high CO levels in excess of 0.1% (1000 ppm). Therefore, for offshore gas turbines with typical CO levels at 10 – 200 ppm instrumented techniques are more appropriate.

Sulphur dioxide: There are several wet chemical standard techniques in common use. For example, BS EN 14791:2005, and ISO 11632:1998. The methods all involve passing a measured volume of flue gas through hydrogen peroxide solution. The absorbed sulphur dioxide is oxidised to sulphate ion that is subsequently quantified by ion chromatography or barium perchlorate titration using thorin as an indicator. The BS EN 14791:2005 Standard allows both methods of determination and has replaced BS 6069:4.1:1990 (the ISO 7934:1989 titration method).

Oxygen: Wet chemical techniques include the ORSAT and Fyrite systems, which are both suitable for spot determinations. Such equipment gives oxygen concentrations on a wet basis whereas a dry measurement is usually required. However, the moisture content of the gas turbines should be easily calculated from the fuel analysis. Alternatively, moisture content can be measured using the extractive manual US EPA Method 4, where moisture is condensed or absorbed in an extractive sampling train and the collected mass of water determined by weighing. Although ORSAT is a current method in the USEPA suite of source emission analysis methods (Method 3A), it is no longer in common use in the UK.

Volatile Organic Compounds (unburnt hydrocarbons, UHCs)**:** Manual chemical sampling methods can be used for determining some UHCs including VOCs. However, the main components of the combustion flue gases in this context are methane, ethane and other low molecular weight hydrocarbons, and these species are not particularly amenable to chemical absorption. Adsorption techniques (for example sorbent tubes with subsequent desorption or extraction and gas chromatography-based analysis) can be limited for the lighter hydrocarbons, but are commonly applied for higher molecular weight compounds. Monitoring for the speciated VOC associated with combustion normally involves the use of automated instrumental techniques to separate and quantify the VOC components in one or more integrated samples. The complexity of such techniques means that the analysis is not usually undertaken at the measurement site. Use of integrated samples without absorption or adsorption can be undertaken for UHC, where difficult sampling conditions apply, such as very wet flue gas conditions; where there is an explosion risk; where there is a fire risk; or where there are many vents to be sampled in difficult or cramped locations. In such cases, it is often advisable to collect an integrated sample in a plastic membrane bag (or stainless steel canister), perhaps diluted, and to transport them to a central location for instrumental analysis (see Section A2 for more details).

A.2 Instrumented Methods

A.2.1 General Approach and Limitations

Automated instrumented techniques employing various detection principles are used for continuous or periodic emission measurements. Automated monitoring systems (AMS) include instruments routinely used for periodic testing, and permanently installed instruments to provide a continuous emission monitoring systems (CEMS). An AMS can be either extractive, cross stack or *in-situ*. However, the instrumented systems for periodic investigations are usually extractive. A number of Standards exist for instrumented analysis techniques (Table A-2).

Although instrumented methods are well established, there are problems associated with their use. The main difficulties with use offshore are three fold:

i) The Standards and best practice require use of calibration gases to verify performance of the equipment before and after use. The requirement for calibration gases means that measurement systems cannot be considered fully portable;
ii) Most AMS instruments have been developed for onshore fixed CEMS or periodic monitoring via onshore mobile laboratory; and
iii) Most instrumented techniques used for periodic monitoring are not designed or certified to be used in hazardous environments.

These systems are usually **semi-portable**. Fully portable systems (effectively use of the instruments without calibration gases) are available for NOx, CO and Oxygen but these are unlikely to meet the quality requirements for baseline monitoring, and it may be necessary to demonstrate performance criteria equivalence, even when calibration gases are used.

A.2.2 Standard Instrumented Methods

A summary of available Standards is provided in Table A-2. The following sections summarise the main features for each pollutant.

Table A-2: Instrumented Emission Analysis Standards

Reference	TGN M2	Title	Comment
NO_X			
BS:EN 14792	Yes	Stationary source emissions. Determination of mass concentration of nitrogen oxides (NOx). Reference method: chemiluminescence	Validated for sampling periods of 30 min in the range of 0-300 mg NO_2/m^3 for LCP
ISO 10849	No	Stationary source emissions - Determination of the mass concentration of nitrogen oxides - Performance characteristics of automated measuring systems	Extractive and non-extractive systems in connection with a range of analysers that operate using the following principles: — chemiluminescence; — non-dispersive infrared spectroscopy; — non-dispersive ultraviolet spectroscopy; — differential optical absorption spectrometry
USEPA Method 7E	No	Determination of nitrogen oxides emissions from stationary sources (Instrumental Analyser Procedure)	
CO			
BS EN 15058	Yes	Stationary source emissions - Determination of the mass concentration of carbon monoxide (CO) Reference method: non-dispersive infrared spectrometry	Validated for sampling periods of 30 minutes in the range 0-400mg/m^3 for LCP
ISO 12039	No	Stationary source emissions - Determination of carbon monoxide, carbon dioxide and oxygen Performance characteristics of automated measuring methods	Extractive and non-extractive systems in connection with several types of instrumental analyser based on the following techniques: — paramagnetism (O_2); — magnetic wind (O_2); — differential pressure (Quinke) (O_2); — magnetodynamics; — zirconium oxide (O_2); — electrochemical cell (O_2 and CO); — infra-red absorption (CO and CO_2).
USEPA Method 10	No	Determination of carbon monoxide emissions from stationary sources	
SO_2			
BS6069:4.4:1993		Stationary source emissions - Determination of the mass concentration of sulphur dioxide – Performance characteristics of automated measuring methods	ISO 7935:1992

Reference	TGN M2	Title	Comment
USEPA Method 6C		Determination of sulphur dioxide emissions from stationary sources (Instrumental Analyser Procedure)	
VOCs			
BS EN 12619	Yes	Determination of the mass concentration of total gaseous organic carbon at low concentrations in flue gases - Continuous flame ionisation detector method	For total VOC in the concentration range up to 1,000 mg/m^3
USEPA Method 25A		Determination of total gaseous organic concentration using a flame ionisation analyser	
USEPA Method 18	No	Measurement of gaseous organic compound emissions by gas chromatography	Method for speciation of organic compounds. Using portable GC.
O_2			
BS EN 14789	Yes	Stationary source emissions - Determination of volume concentration of oxygen (O_2) - Reference method; Paramagnetism	
ISO 12039	No	Stationary source emissions -- Determination of carbon monoxide, carbon dioxide and oxygen	See under CO
USEPA Method 3A	No	Determination of oxygen and carbon dioxide Concentrations in emissions from stationary sources (Instrumental Analyzer Procedure)	

Nitrogen Oxides

BS EN 14792, ISO 10849 and USEPA Method 7E describe the sampling system and performance criteria for automated measurement of NO_x emission concentrations.

Additional relevant methods are ISO 11042[12] and USEPA Method 20[13] which each specify a sampling procedure, performance specifications and the equipment to be used for determination of NO_x emissions from gas turbines. These methods are not specified by UK regulatory authorities for compliance monitoring; therefore, in the UK they are only infrequently employed (e.g. for commissioning and acceptance tests).

Chemiluminescence detection – This is the most established technique for instrumented determination of NO_x emissions, although the use of other techniques are allowed by the ISO and USEPA standards as long as the performance criteria are satisfied. Analysers employing chemiluminescent detection are fairly complex and are not portable, but semi-portable units are now available. The majority of analysers are best suited to fixed CEMS use, as they can require rigorous sample conditioning to achieve reliable operation, but semi-portable units (including units with MCERTS product type approval) are used by emission monitoring contractors for high quality onshore compliance work, and are beginning to be used for similar work offshore as they offer a wide measurement range suitable for offshore combustion plant. Semi-portable multi-functional analysers, allowing more than one gaseous species to be determined by the same analyser, including chemiluminescence for NOx have also recently become available.

[12] ISO 11042-1 Gas turbines - Exhaust gas emission - Part 1: Measurement and evaluation
[13] Method 20 - Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions From Stationary Gas Turbines

It should be noted that NO_x comprises nitrogen monoxide (NO) and nitrogen dioxide (NO_2), but chemiluminescent analysers determine only NO. To determine total NO_x a catalyst (converter) is used on a parallel analyser transport line to reduce the NO_2 component to NO. Passage through the converter gives total NO_x, whilst sequential measurements can give the relative proportions of NO and NO_2.

Infrared detection – This approach is commonly used for NO_x determination but, although simpler and generally lighter than chemiluminescent analysers, the infra-red analysers are generally only semi-portable. Most infra-red systems require sample conditioning to remove moisture from the sample as this interferes with detection. The extractive type of infra-red instruments have a poorer limit of detection than chemiluminescent units, but this would be unlikely to be an issue as gas turbines without NO_x control have comparatively high emission concentrations. These systems are often used for high quality compliance CEMS or periodic monitoring work. As with the chemiluminescent unit, the infrared analyser measures NO only and total NO_x is measured using a catalyst (converter) to reduce the NO_2 fraction to NO.

Some installed CEMS do not contain converters but instead assume that the NO_2 component is a fixed fraction of the measured NO concentration. Consequently, they apply a factor to calculate the total NO_x. The factors employed are often default values but can be confirmed periodically by measurement. The number of such CEMS used onshore is decreasing, as regulators consider measurement of total NO_x to represent BAT.

Semi-portable infrared analysers using Fourier Transform Infra-Red (FTIR) detection are available. Some of these are very good for satisfying high quality compliance monitoring requirements, whether for continuous or periodic work.

To ensure high quality results, all the above instrumented systems rely heavily on the use of standard gas mixtures for calibration. This normally is provided by traceable gas standards contained in cylinders. However, equipment is available with small calibration cells containing known amounts of the target species, and this can obviate the requirement for cylinders.

Electrochemical cells - This is a comparatively recent analysis technique for NO_x but there are now several manufacturers of such analysers. Many of the instruments are fully portable and most are multi-functional, allowing more than one gaseous species to be determined by the same analyser. However, use in conjunction with a measurement protocol based on Standards requires use of calibration gases to check performance criteria, which makes the technique semi-portable for offshore work.

Many units offer an electrical calibration facility and claim not to require gas standards in routine use. This approach to calibration is not consistent with the Standards and should be treated with caution, particularly for baseline surveys. Chemical cell analysis systems have also been incorporated in installed CEMS applications for IPPC combustion processes, and some units have MCERTS and other type-approval. The main issue with the technique is that the chemical cells have a limited life, which can impact on performance.

<u>Carbon Monoxide</u>

ISO 12039 and USEPA Method 10 describe the sampling system and performance criteria for automated measurement of CO emission concentrations. The latest CEN Standard is

EN 15058:2006. Instruments using infrared detection are well-established in both standalone and multi-functional units. In addition to their use in installed CEMS, there are semi-portable high quality infrared based CO analysers available for periodic use. Again, use of Standards with such equipment normally entails the use of cylinder gases to check calibration. However, some equipment incorporates calibration cell systems which may offer a means of avoiding the use of calibration gases for spot checks.

Electrochemical cell detection is a comparatively recent analysis technique for CO and there are several manufacturers of fully portable emission analysers. The better units offer electrical calibration but again the Standards require use of calibration gases. As with NO_x, the main issue with using chemical cell detection in installed CEMS or for periodic monitoring is that the cells have a limited life, and they also suffer from interference and the accuracy associated with measurements is generally poorer than with infra-red based CEMS. They are therefore not currently regarded as best practice and, if used for offshore baseline surveys, it will be necessary to demonstrate equivalence of the performance criteria relative to the Standards.

Oxygen

EN 14789 and ISO 12039 describe sampling systems and performance specifications for on-line oxygen determinations. US EPA Method 3A also provides a methodology for the measurement of O_2 using an instrumented technique. There are two main instrumented technologies for determining oxygen concentrations in flue gas. Most installed CEMS and boiler control systems employ either zirconia oxide probes (a form of chemical cell) or paramagnetic detection. Chemical cell and paramagnetic technologies are also well established in portable analysers for oxygen.

VOCs / Unburnt Hydrocarbons

A number of standard methods are available for the automated instrumented monitoring of UHC from combustion processes. These include EN 12619 and USEPA Method 25A, which use flame ionisation detection (FID) to provide a total organic carbon measurement (see below). In all cases a representative sample of flue gas is extracted, filtered and transported to the analysis instrument. A gas handling and transport system is employed which uses inert materials and maintains the gases above the dew point. The Standards also lay out procedures for calibration of the sampling and analysis system. Analytical detection techniques for UHC are summarised below.

Flame Ionisation Detectors (FIDs) - For Methods 25 A and EN 12619, the use of a heated flame ionisation detector is specified for analysis. Such instruments are the widely-accepted technique for monitoring unburnt hydrocarbons from combustion sources. They normally require a mains electricity supply, compressed gas standards (typically propane) and fuel gases (hydrogen). Consequently, they can only be considered as semi-portable systems. Intrinsically safe FIDs for emission analysis are now available for use in hazardous areas (mostly for leak detection), but these still require the use of compressed gas cylinders.

Infrared detection – USEPA Method 25B allows the use of a non-dispersive infrared (NDIR) analyser for determination of VOC. These systems offer good sensitivity and a quick response. However, they are generally not fully portable, as they require a mains electricity supply and sample conditioning modules to remove moisture. They also normally require calibration gases, although there have been recent advances in systems with internal calibration cells.

Analysers for VOCs are also available which use Fourier Transform Infra-Red (FTIR) detection. These can deliver high quality source monitoring requirements, whether for continuous or periodic work, but again require a mains electricity supply and compressed gas cylinders for calibration. Consequently, they are, at best, semi-portable.

Photo ionisation detection (PIDs) - These devices can also be employed to monitor VOCs from processes. They are also semi-portable, but less suited to detecting alkanes than FID and NDIR systems.

<u>Sulphur Dioxide</u>

There are several automated instrumental standards for monitoring SO_2 from stationary sources and these include ISO 7935 and US EPA Method 6C. ISO 7935:1992 provides performance standards for the monitoring method. The Standard does not prescribe any particular analytical technique, and indicates that there are several commonly employed detection systems and that these include: (i) absorption by infrared or ultra violet radiation; and (ii) fluorescence employing ultra violet radiation, interferometry and conductometry. The Standard only requires that the stated performance criteria are satisfied by the chosen system.

US EPA Method 6C covers both performance specification and sampling procedures. Any infrared, ultra violet and fluorescence detection systems meeting the stated performance criteria can be used.

All the above techniques would be expected to provide good sensitivity, accuracy and fast response characteristics. The various systems should all be considered as semi-portable, as they require a mains electricity supply and compressed gas calibration standards.

Electrochemical cell detection is a comparatively recent analysis technique for SO_2 and there are several manufacturers of fully portable battery driven emission analysers. The better units allow presentation of calibration gases to the analyser but such units should therefore be viewed as semi-portable for offshore use. As with NO_x, the main issues associated with using chemical cell detection is that the cells have a limited life and can suffer from interference.

A.3 Other Techniques

A.3.1 Integrated Samples for Analysis

The use of sample bags or canisters offers an alternative to classical wet chemical sampling and direct instrumented measurements. This technique is particularly useful for sampling in explosion risk or fire hazard areas. An integrated flue gas sample is collected into a suitably inert sample container, and the contents analysed later at a safe location using suitable instrumentation. This approach is not encouraged by the UK onshore regulatory authorities, due to issues such as sample stability and losses. Sample transformation can be a significant issue, particularly for NO_X measurement, as the NO component will oxidise to NO_2 particularly if exposed to daylight and, if analysis is delayed, significant NO_X errors can be introduced.

However, several USEPA instrumented monitoring standards allow for bag sampling where direct measurement is not practical. Therefore, it is recognised that such an approach may be useful offshore, as intrinsically safe sampling equipment can then be deployed at the sampling location.

5.7.1 A.3.2 Predictive Emission Monitoring Systems

A further technique for assessing NO_x emissions is the use of predictive emission monitoring systems (PEMS). These systems do not measure emissions but use a computer model to predict emission concentrations based on process data (e.g. fuel flow, load, combustor temperature and ambient air temperature).

Onshore and offshore experience shows that standard annular combustion (SAC) gas turbines burning clean stable fuel compositions exhibit emission profiles that lend themselves to PEMS techniques, providing good quality baseline emissions data and the necessary plant input signals are available to develop robust PEMS algorithms that can track turbine gas-path performance and unit condition. It is recognised that manufacturer's data relating to emissions quality over time may be scarce, and in many cases such data must be treated with caution. This is a secondary reason why the measurement of emissions and characterisation of the unit profiles should be undertaken to appropriate quality standards. For example, if one gas turbine's emissions can be characterised both before and after an axial air compressor wash then the degree to which the emission levels / profiles are affected by short to medium term degradation and the relationship with turbine parameters can be documented.

The PEMS model is based on either measurements at the source or from generic emission information provided for the gas turbine. This approach is comparatively rare at present in the UK and the EA and SEPA onshore regulators require any operator using PEMS rather than CEMS for monitoring to periodically verify the PEMS using CEN / ISO Standard measurement methods (via MCERTS), as a means of demonstrating compliance with the conditions of the permit. As NO_x emission concentrations from gas turbines are relatively consistent, compared to those of boiler installations the use of a PEMS could provide a good approach to the documentation of reliable emission data for new gas turbines, and wider application may be feasible following good stack monitoring surveys. (NB. EEMS is a simple offline PEMS).

A.3.3 Fuel Analysis

Sulphur dioxide emission factors can also be predicted from the sulphur content of the fuel. For oil fuels, the mass of SO_2 emitted (tonnes of SO_2 emitted / tonne of fuel burned) can be deduced by multiplying the percentage sulphur by 0.02. This assumes 100% conversion of sulphur to SO_2. However, a small proportion of the sulphur may be oxidised to sulphur trioxide or inorganic sulphate and the multiplying factor could be slightly reduced.

For gaseous fuels the emission factor for oxidation of hydrogen sulphide to sulphur dioxide (tonne of SO_2 emitted / tonne of fuel burned) can be deduced by multiplying the percentage mass of hydrogen sulphide in the fuel gas by 0.0188. This assumes 100% conversion of H_2S to SO_2. Fuel analysis is also required to develop pollutant emission factors from the emission concentrations, and the results of the analyses can therefore be considered as a potential alternative to the use of direct stack measurement.

Appendix B
Deriving Emission Factors from Monitoring Data

Following completion of an offshore survey, an emissions survey report should be prepared as discussed in Section 5.7. Emissions data should be presented in a standard format to allow comparison with relevant standards and permit details. This appendix details how to convert survey data to standard conditions and also how to derive an EF which can be compared against those currently in the EEMS reporting guidance.

B.1 Default Emission Factors

EFs relate the release of a pollutant to an activity statistic, for example mass of pollutant per unit of fuel used, and are commonly applied to provide annual emission inventories (for example the EEMS database). Offshore emissions inventories have been estimated using pollutant EFs and operating data from various sources. However, published EFs, for example default EFs published by the USEPA for uncontrolled gas turbines (that is machines without NO_x control systems), are based on emission measurements from older, comparatively small gas turbines, and they tend to underestimate NO_x emissions from modern uncontrolled gas turbines. The USEPA default factors also tend to overestimate CO and UHC emissions from modern gas turbines that have higher combustion efficiencies than the older machines.

EFs are used to estimate annual emissions but there is a need for more reliable emissions information for current installed plant.

B.2 Developing Emission Factors

EFs can be developed from survey emissions data, and these can then be used in preparing annual emission inventories. The development of an EF for a pollutant requires knowledge of the pollutant emission concentration, the oxygen concentration of the emission and analysis of the fuel gas. It is therefore recommended that fuel samples are collected and analysed to allow calculation of EFs.

Appropriate attention should be given at the planning stages in relation to the measurement and reporting of fuel flow, gas turbine load parameters, gas composition data, and stack velocity, in parallel with the measurements of stack emissions. These parameters are important for characterisation of the emissions and will generate additional element of uncertainty, which should be minimised to ensure good overall quality of data.

The EEMS database uses turbine-specific emissions profiling for EPER / EPRTR and permit compliance reporting. Much, but not all, of the turbine-specific profiling developed for EEMS has been based on data collected using CEN / ISO standards and equipment. Where anomalies in the database have been noted these have generally been traced to the less stringent adherence to the standards. Nevertheless, gaps remain in the database of offshore combustion plant, and it is in the interests of all stakeholders that consistent standards are used going forward to enhance the EEMS database and the reporting. This has been a critical consideration in the development of best practice guidelines for stack monitoring.

Standardisation of emission data

Measured emission concentrations are standardised to a mass concentration in dry flue gas at the relevant reference oxygen content and at 0°C, 101.3 kPa. The reference oxygen concentration is 3%, for boilers and other furnaces burning gaseous or liquid fuels or, 15% for gas turbines or diesel engines.

The calculation is detailed below:

$$[X]_{15\%} = [x]_m \cdot \frac{MW}{22.4} \cdot \frac{(20.9-[O_2]_{ref})}{(20.9-[O_2]_m)}$$

Where:

$[X]_{15\%}$ is the standardised mass concentration of the pollutant in mg m^{-3}.
$[x]_m$ is the measured concentration in ppm by volume for a dry flue gas.
MW is the relative molecular mass of the pollutant (see note below).
22.4 is the volume occupied by 1 mole of an ideal gas at 0°C, 101.3 kPa.
$[O_2]_m$ is the measured O_2 concentration on a dry basis.
$[O_2]_{ref}$ is the reference O_2 concentration on a dry basis (3 or 15%)

This calculation is appropriate where pollutant and O_2 concentrations are measured on a dry basis.

NO_x emission concentrations and emission factors are defined in terms of NO_2. Hence, the relative molecular mass used for NO_x is 46.

VOC emission concentrations and emission factors are usually defined in terms of carbon. Hence, the relative molecular mass used for VOC is 12 but this may be modified further for a FID measurement to account for different response factors due to choice of calibration gas.

Calculation of Emission Factors

An EF relates the release of a pollutant to a process activity. For combustion processes, EFs are commonly described as the mass of pollutant released per unit of fuel burned.

An EF can be calculated in several ways; the approach adopted uses the standardised pollutant emission concentrations and the fuel analysis. This approach avoids measurement of exhaust gas flow and fuel flows. Measurement of exhaust gas flow can have a high uncertainty and may not be practical at many industrial plants.

Emission Factors for Gaseous Fuel

Gaseous fuel analysis data are for inerts (for example CO_2, N_2) and for hydrocarbons (for example CH_4, C_2H_6). An example fuel analysis is provided in Table B1 below.

Table B1: Example fuel analysis

Component	Mole %
N_2	1.38
CO_2	0.27
CH_4	97.65
C_2H_6	0.67
C_3H_8	0.02
nC_4H_{10}	0.00
iC_4H_{10}	0.01
nC_5H_{12}	0.00
iC_5H_{12}	0.00
C_6+	0.00
	ppm
H_2S	1 (max)

Notes:

The fuel analysis and combustion calculations are used to determine the stoichiometric air requirement and dry flue gas volume per cubic metre of fuel gas. The calculations assume an ideal gas. A dry flue gas volume was then calculated for an O_2 concentration of 15%. Generally, the flue gas volumes generated from combustion of each fuel gas component were calculated in accordance with the following equations.

$$C_XH_Y + (X+(Y/4)O_2 = X\ CO_2 + (Y/2)\ H_2O$$

For combustion in air, each cubic metre of oxygen is associated with (79.1/20.9) cubic metres of nitrogen. C6+ Hydrocarbons were treated as hexane.

The calculated dry flue gas volume at stoichiometric conditions ($DFGV_{SC}$) can then be calculated ($DFGV_{15}$) for the required oxygen content. For example at 15% oxygen:

$$DFGV_{15} = DFGV_{SC} \cdot (20.9/(20.9-15))$$

For the example fuel analysis, the dry flue gas volume at 15% oxygen was calculated to be 30.0 m^3 per m^3 of fuel at 0°C, 101.3 kPa (note that fuel gas volumes are generally reported at 15°C).

A pollutant EF can hence be calculated by multiplying the standardised pollutant concentration by the dry flue gas volume at the same reference oxygen content. For example at 15% oxygen:

$$EF = [X]_{15\%} \cdot DFGV_{15}$$

EFs are reported in several ways and these are generally recalculated using physical or other properties of the fuel.

For example, a thermal EF can be derived by dividing the EF calculated above by the calorific value of the gas. This is usually the net (inferior) CV but USEPA tends to use the gross (superior) CV.

$$EF_{thermal} = \frac{EF}{CV}$$

Where:

$EF_{thermal}$ is the thermal EF expressed in units to suit the user (for example g GJ^{-1}).

CV is the calorific value in appropriate units or factors to suit the final units of the emission factor.

Similarly, a mass EF can be derived using the fuel density:

$$EF_{mass} = \frac{EF}{d}$$

Where:

EF_{mass} is the mass based EF, expressed in units to suit the user (for example g kg^{-1}, tonne $tonne^{-1}$).

d is the density of the fuel gas incorporating appropriate units or factors to suit the final units of the EF.

It should be noted that many gaseous fuel conditions are defined for a gas volume at a temperature of about 15°C. However, all concentrations and EFs presented in this report have been prepared for a gas volume at 0°C.

Emission Factors for Gas Oil Fuel

Unlike gaseous fuels, gas oil fuel used offshore tends to be much more consistent. The US Environmental Protection Agency (USEPA) provides stoichiometric dry flue gas volume for fuel oil. The USEPA data can be found in USEPA Method 19 (US Code of Federal Regulations, Title 40 Part 60, Appendix A)[14]. The USEPA data is presented as the volume of dry flue gas at 20°C associated with the gross thermal input of the fuel. These USEPA conditions are not consistent with UK practice and consequently some manipulation of the data is required. Calculations assume an ideal gas.

The gas oil properties assumed for the fuel used are detailed in Table B2.

Table B2: Gas oil properties

Property	Data	Source
Sulphur content, % w/w	0.15	Maximum sulphur content
Density, tonne m^{-3}	0.857	DTI Energy statistics
CV (gross), MJ kg^{-1}	45.6	DTI Energy Statistics
CV (Net), MJ kg^{-1}	42.8	Gas oil data sheet
USEPA F_D factor, m^3 J^{-1} dry stoichiometric flue gas volume at 20°C, gross heat input	2.47×10^{-7}	USEPA Method 19
CO_2 emission factor, tonne $tonne^{-1}$	3.14	National Atmospheric Emission Inventory

[14] Available at http://www.epa.gov/ttn/emc/methods/method19.html

The USEPA dry flue gas volume at stoichiometric conditions was recalculated to provide the flue gas volume ($DFGV_{ref}$) for the required oxygen content (3 or 15%). For example at 15% oxygen:

$$DFGV_{15} = F_D \,.\, (273/293).(20.9/(20.9-15)).\,(45.6 \times 10^6)$$

The dry flue gas volume at 15% oxygen was calculated to be 37.2 m^3 per kg of fuel.

A pollutant EF can hence be calculated by multiplying the standardised pollutant concentration by the dry flue gas volume at the same reference oxygen content. For example at 15% oxygen:

$$EF = [X]_{15\%} \,.\, DFGV_{15}$$

EFs are reported in several ways and these are generally recalculated using physical or other properties of the fuel.

For example, a thermal EF can be derived by dividing the EF calculated above by the calorific value of the gas. This is usually the net (inferior) CV but USEPA tends to use the gross (superior) CV.

$$EF_{thermal} = \frac{EF}{CV}$$

Where:

$EF_{thermal}$ is the thermal EF expressed in units to suit the user (for example g GJ^{-1}).

CV is the calorific value in appropriate units or factors to suit the final units of the EF.

Similarly, a volume EF can be derived using the fuel density:

$$EF_{vol} = EF \,.\, d$$

Where:

EF_{vol} is the volume based EF, expressed in units to suit the user (for example g $litre^{-1}$).

d is the density of the fuel gas incorporating appropriate units or factors to suit the final units of the EF .

Annual Emissions

These can be derived from the annual fuel consumption for each combustion device (or installation) and the pollutant EF derived for the typical load. Fuel consumption data may be available or can be calculated to reflect the actual or predicted installation ratings. For example for a combustion device typically running at 90% load.

$$Q_f = Q_I \times (3600) \times (0.9)/CV$$

Where:

Q_f = Hourly Fuel flow (volume or mass basis)
Q_I = Net rated thermal input of installation (MW_{th})
CV = Inferior calorific value on volume or mass basis

The annual emission of a component is given by:

Annual emission = typical fuel flow x annual hours x emission factor

For a field lifetime of 15 years and assuming the parameters will remain the same, the total emission of would be 15 times the annual emission.

Example Calculation

For a gas turbine producing 3 MW electricity, the following emission data were obtained:

Gas Turbine	Generation MW	Measured O_2 %, dry	Average concentrations, ppm by volume, dry		
			NO_x	CO	UHC
GT1	3	18.43	49.4	8.33	1.5

The standardised emission concentrations are given by the following equations:

For NO_x

$$[NOx]_{15\%} = [49.4] \cdot \frac{46}{22.4} \cdot \frac{(20.9-15)}{(20.9-[18.43])}$$

$$= 242.7 \text{ mg m}^{-3} \text{ (as } NO_2 \text{)}$$

For CO

$$[CO]_{15\%} = [8.33] \cdot \frac{28}{22.4} \cdot \frac{(20.9-15)}{(20.9-[18.43])}$$

$$= 24.9 \text{ mg m}^{-3}$$

For UHC

The measured values are expressed as propane (C3) equivalent concentrations. The standardised concentration is expressed as carbon and hence the molecular weight is 36 (12 x 3).

$$[UHC]_{15\%} = [1.5] \cdot \frac{(36)}{22.4} \cdot \frac{(20.9-15)}{(20.9-[18.43])}$$

$$= 5.8 \text{ mg m}^{-3} \text{ (as C)}$$

NO_x Emission Factors

The EFs were calculated as described above using the example fuel analysis to derive the following fuel properties for a gas at 0°C, 101.3 kPa:

Stoichiometric dry exhaust gas volume = 8.47 m^3 per m^3 fuel
Dry exhaust volume at 15% O_2 = 30.0 m^3 per m^3 fuel

Inferior (NET) Calorific Value (for CV reference conditions of 15°C, 101.3 kPa but a gas volume at 0°C, 101.3 kPa) = 35.5 MJ m^{-3}

Gas density (at 0°C, 101.3 kPa) = 0.73 kg m^{-3}

EF	=	$[X]_{15\%}$. DFGV$_{15}$
	=	(242.7) . (30.0) . 10^{-3}
	=	7.28 g m^{-3} (g NO_2 per m^3 fuel at 0°C, 101.3 kPa)
$EF_{thermal}$	=	$\frac{EF}{CV}$
	=	$\frac{7.28}{35.5} \cdot 10^3$
	=	205 g GJ^{-1} (g NO_2 per GJ net thermal input)
EF_{mass}	=	$\frac{EF}{d}$
	=	$\frac{7.28}{0.73} \cdot 10^{-3}$
	=	0.0099 tonne tonne-1 (tonne NO2 per tonne fuel)

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