



**NORWEGIAN OFFSHORE  
DIRECTORATE**

**Guidelines to the regulations relating to fiscal  
measurement in the petroleum activities (the  
measurement regulations)**

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## Introduction

The regulations relating to fiscal measurement in the petroleum activities (the measurement regulations) are issued pursuant to the Act relating to petroleum activities (the Petroleum Act), the regulations to the Act relating to petroleum activities (the petroleum regulations), and the Act relating to tax on discharge of CO<sub>2</sub> in the petroleum activities on the continental shelf (the CO<sub>2</sub> Tax Act). The measurement regulations set out the requirements for fiscal measurement (i.e. measurement for the purpose of providing a basis for calculating government revenues, including taxes and duties) of quantities of produced petroleum and quantities subject to CO<sub>2</sub> tax. The objective is to ensure that accurate and reliable measurements form the basis for the calculation of taxes and fees to the Norwegian State, as well as the licensees' revenues from the petroleum activities.

This guideline to the measurement regulations provides supplementary comments on the individual provisions and describes how the provisions may be fulfilled. The guidelines contain four appendices and describes how the provisions may be fulfilled. Appendix 1 contains a metrological glossary. Documents recommended for fulfilling the regulatory requirements are listed in Appendix 2. Appendix 3 addresses the evaluation of measurement data obtained from fluid flow measurement. Appendix 4 concerns uncertainty budgets for CO<sub>2</sub> tax measurements.

Hereafter, "these regulations" will refer to the measurement regulations.

## Re Chapter 1. Introductory provisions

### Re Section 1. Objective

#### First paragraph:

To ensure accurate measurements, these regulations impose requirements on the accuracy of measurement results and measuring systems. Accuracy of a measurement result means the degree of accordance between a measured or calculated value and a true value of the measurand (cf. JCGM 200:2012). Accuracy of measuring instruments and measuring systems refers to their ability to provide a value close to a true value of the measurand (cf. IEC 60050). The true value of the measurand is practically unknown, but it is understood, with a certain probability, to lie within a range defined by measurement uncertainty. A measurement result is more accurate if the measurement uncertainty is lower. Similarly, a measuring system is more accurate if the instrumental measurement uncertainty is lower.

To ensure reliable measurements, requirements are imposed on management systems, measurement methods, calibration, and metrological traceability. Reliability means that measurements should be reproducible and yield the same, or not more than a likely deviating, result.

#### Second paragraph:

The licensee may use standards and other recognised documents to comply with these regulatory requirements.

A *standard* is, according to NS-EN 45020:2006, Item 3.2 and ISO/IEC Guide 2:2004, defined as: "Standard document established by consensus and approved by a recognised body, that provides, for common and repeated use, rules, guidelines or characteristics for activities or their results, aimed at the achievement of the optimum degree of order in a given context." A national standard means a standard adopted by a national standardisation body, and an international standard means a standard adopted by an international standardisation body. Standards Norway is an example of a national standardisation body. ISO (International Organization for Standardization) and the International Organization of Legal Metrology (OIML) are examples of international standardisation bodies.

Other recognised documents refer to technical specifications, technical reports, and guidelines published by associations and industry and interest organisations. The International Group of Liquefied Natural Gas (GIIGNL) is an example of a recognised international association, and the Norwegian Society for Oil and Gas Measurement (NFOGM) is an example of a recognised national association. Offshore Norge is an example of a recognised industry and interest organisation.

Technical solutions described in relevant standards can generally be considered as pre-qualified solutions. Nevertheless, it is the licensee's responsibility and duty to ensure that the chosen solutions are fit for purpose.

When using technical solutions other than those recommended in these guidelines for a regulatory provision, the licensee must be able to document that the chosen solution fulfils the regulatory requirements.

Appendix 2 refers to standards and other recognised documents that the Norwegian Offshore Directorate considers to be particularly relevant for fulfilling the requirements of these regulations. The list is not necessarily exhaustive and does not rule out the existence of other relevant documents.

## **Re Section 2. Scope of application**

### First paragraph:

The scope of these regulations corresponds to the scope of the Petroleum Act. This is defined in Section 1-4 as: "petroleum activities in connection with subsea petroleum deposits under Norwegian jurisdiction," as well as the "utilisation of produced petroleum that takes place on Norwegian land territory or seabed subject to private property rights only when such utilisation is necessary to or constitutes an integrated part of production or transportation of petroleum." The scope is elaborated in *Ot.prp. no. 46 (2002-2003)* Chapter 2.1.3. On this basis, it is assumed that these regulations will apply to onshore facilities if petroleum is transported to the terminal by pipeline from the continental shelf, and the measurement is carried out onshore in Norway for practical reasons. In such cases, the Norwegian Offshore Directorate will coordinate supervisory activities with the Norwegian Metrology Service (Justervesenet), as specified in the cooperation agreement between the two agencies. At terminals abroad where Norwegian petroleum is landed by pipeline, the Norwegian Offshore Directorate will conduct metrological supervision in cooperation with the relevant authorities in the respective state. This is in accordance with the Petroleum Act Section 1-4, first paragraph, second sentence.

The requirements of these regulations apply to the planning, construction, installation, testing, and use of measuring systems for:

- a) measurement of quantities of produced petroleum
- b) measurement of quantities of petroleum that is flared and natural gas that is vented, as well as CO<sub>2</sub> separated from petroleum and discharged to air.

### Second paragraph:

MID - the Measuring Instruments Directive (Directive 2014/32/EU of the European Parliament and of the Council of 26 February 2014/EEA Annex to the Official Journal of the European Union No. 13/197) harmonises technical requirements for various instrument categories and aims to ensure the free movement of measuring instruments within the EU/EEA area. The Directive is aimed at manufacturers and suppliers of measuring instruments and measuring systems. Measuring instruments and measuring systems covered by the MID must fulfil the Directive's technical requirements before they are made available on the market. The pre-market control entails conducting a conformity assessment through a notified body (conformity assessment body) and conformity marking to show that the Directive's requirements are met.

The Measuring Instruments Directive is implemented in Norwegian law through the Regulations relating to units of measurement and measurement (FOR-2007-12-20-1723) and instrument-specific regulations, including the Regulations relating to requirements for measuring systems for continuous and dynamic measurement of fluids other than water (FOR-2007-12-21-1738). The Norwegian Metrology Service is an approved technical regulatory agency for conducting conformity assessments pursuant to the Measuring Instruments Directive.

As regards petroleum activities, requirements in the MID apply for measuring instruments and measuring systems for dynamic delivery measurements of oil and liquid gases. Special requirements and procedures for conformity assessments are established in Annex VII to the MID, Measuring systems for the continuous and dynamic measurement of quantities of liquids other than water (MI-005). The MID does not cover the parts of the measuring system that involve proving and sampling.

Measuring instruments and measuring systems that are approved pursuant to the MID will also be in accordance with the measurement regulations.

### **Re Section 3. Definitions**

A metrological glossary of terms and expressions used in these regulations and in these guidelines is provided in Appendix 1 to these guidelines. The glossary is primarily based on *JCGM<sup>1</sup> 200:2012 International vocabulary of metrology – Basic and general concepts and associated terms (VIM)*, 3<sup>rd</sup> edition (VIM3), and to a certain extent on standards from ISO, IEC and API (cf. Appendix 2). Terminological databases can be found at the following websites:

- Annotated VIM3: <https://jcgm.bipm.org/vim/en/index.html>
- ISO Online browsing platform: <https://dgn.isolutions.iso.org/obp/ui/en/>
- IEC Electropedia: <http://www.electropedia.org>

Abbreviations and symbols follow the recommendations from the Language Council of Norway. These can be found at <https://www.sprakradet.no/sprakhjelp/Skriveregler/Forkortinger/>

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<sup>1</sup> Joint Committee for Guides in Metrology, which is a committee with members from BIPM, IEC, IFCC, ILAC, ISO, IUPAC, IUPAP and OIML.

## **Re Section 4. Responsibility according to these regulations**

The first paragraph of the provision entails a substantive duty to comply with the provisions of these regulations and individual decisions made pursuant to these regulations. The duty to do this through the implementation of necessary systematic measures follows from Section 5.

## **Re Chapter 2. Requirements relating to management systems**

This chapter concerns requirements for management systems within the scope of both the Petroleum Act and the CO<sub>2</sub> Tax Act. Reference is also made to Sections 56, 57 and 58 of the Petroleum Regulations.

## **Re Section 5. Management system**

Management systems are the activities, systems, and processes that are used to plan, implement, evaluate and correct operations to ensure compliance with requirements stipulated in or pursuant to these regulations.

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for management systems.

### Second paragraph:

When assessing the risk of non-compliance with the requirements of these regulations, consideration should be given to the probability of errors, the consequences of errors, the possibility of detecting errors, and the possibility of correcting errors.

### Fourth paragraph:

Responsibilities and roles should be defined in organisation charts, job descriptions, and procedures.

### Fifth paragraph:

The requirement to define functions with responsibility for following up on measurements and measuring systems can be fulfilled by appointing a person responsible for measurements and measuring systems.

### Sixth paragraph:

The specification of how competence transfer is managed should include a specification of how experience transfer is handled during personnel changes and during the transition between the construction phase and operations phase.

## **Re Section 6. Internal audits**

The licensee may adapt the purpose, scope, and frequency of internal audits as it deems necessary to ensure compliance with regulatory requirements.

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for internal audits.

## **Re Chapter 3. Requirements relating to units of measurement and reference conditions**

### **Re Section 7. Measurement units**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for units of measurement.

### **Re Section 8. Reference conditions**

Appendix 2 refers to standards and other recognised documents that may be used for fulfilling the requirements for reference conditions.

## **Re Chapter 4. General requirements relating to measurement**

This chapter establishes general requirements for the measurement process, both experimental and mathematical, as well as for the quality of measurements, including measurement results and uncertainty limits.

### **Re Section 9. Measurement**

No comment.

### **Re Section 10. Measurands and uncertainty limits**

#### First paragraph:

*Petroleum* is all liquid and gaseous hydrocarbons existing in their natural states in the subsoil, as well as other substances produced in association with such hydrocarbons (cf. Section 1-6 (a) of the Petroleum Act).

*Oil* is petroleum which is liquid at the shipment point (cf. Section 2 (f) of the Petroleum Regulations). In practice, this means crude oil and other liquid petroleum products (cf. Dictionary, <https://www.sodir.no/en/about-us/use-of-content/dictionary/>).

*Net quantity (standard volume) of oil* is the standard volume of oil minus sediment and water. *Net quantity (mass) of oil* is the weight of oil in vacuum minus sediment and water.

The uncertainty limit refers to the value (number x measurement unit) of the quantity the measurement aims to quantify.

For allocation measurement, the licensee may define other uncertainty limits for measurands than those listed in Table 1, provided it can be documented that meeting these uncertainty limits is not technically feasible or would lead to unreasonably high costs. This exception mainly applies if the produced quantities from a field are to be determined by an allocation process that includes measurements of unprocessed (multiphase) petroleum or measurements at the outlets of separators (single-stage separation).

#### Second paragraph:

*Natural gas* comprises hydrocarbons in gas form and mainly consists of methane, ethane and propane, minor quantities of other, heavier hydrocarbons and traces of pollutants such as CO<sub>2</sub> and H<sub>2</sub>S, etc. (cf. Dictionary, <https://www.sodir.no/en/about-us/use-of-content/dictionary/>).

*Flare gas* refers to the surplus gas from the process that cannot be used or stored safely. This gas is burned for safety reasons. Flare gas may contain components of natural gas such as methane, ethane, propane, and butane, as well as other gases such as hydrogen, carbon dioxide, and sulphur dioxide. In addition, flare gas may contain water vapour and inert gases that either accompany the process or are added to ensure safe operation.

The measurand *quantity (standard volume) of flared petroleum* can be divided into several source-specific measurands, including:

- Quantity (standard volume) of flare gas burned in a flare (a safety device for burning off flare gas).
- Quantity (standard volume) of natural gas burned in a pilot burner (a small burner used to ignite the main burner in a flare).
- Quantity (standard volume) of petroleum burned in a burner boom (a system for burning off petroleum during well operations).

The requirements in these regulations for measurement of the quantity of flared petroleum are directed towards the measurement of flare gas burned in a flare and natural gas burned in a pilot burner.

Quantified content of inert gases and water vapour in the flare gas can be considered as identified effects that Section 14, second paragraph, allows for corrections.

Historically, there have been periods of burning petroleum over burner booms on fixed installations and mobile installations physically connected to fixed installations on the Norwegian continental shelf. However, technological advancements and stricter regulations have led to a significant reduction in this practice. Today, there is practically little or no burning of petroleum over burner booms. Therefore, the Norwegian Offshore Directorate has assessed that it is not appropriate to detail the regulation of measurements of this quantity. If burning of petroleum in burner booms occurs, it follows from Section 9 that the measurement requirements must be clarified with the Norwegian Offshore Directorate.

The measurand *quantity (standard volume) of natural gas emitted to air* refers to natural gas released directly into the air without being burned and can be divided into several source-specific measurands, including:

- Quantity (standard volume) of natural gas emitted directly to the air via common cold vent systems (dedicated piping systems for atmospheric venting of gas not directed to the flare).
- Quantity (standard volume) of natural gas emitted directly to the air via the flare.
- Quantity (standard volume) of natural gas emitted directly to the air from other sources, including process equipment, produced water, etc.

Appendix 2 refers to guideline *044 - Recommended guidelines for discharge and emission reporting*. Table 25 in this guideline contains a list of sources of direct emissions of natural gas. Measurands for natural gas emissions should be based on these sources.

The natural gas emitted directly to the air may contain water vapour and inert gases that either accompany the process or are added to ensure safe operation. Quantified content of inert gases and water vapour can be considered as identified effects that Section 14, second paragraph, allows for corrections.

If it is difficult to satisfy uncertainty limits for flared petroleum and natural gas emitted to air, the licensee may apply to the Norwegian Offshore Directorate for dispensation pursuant to Section 10. The Norwegian Offshore Directorate may grant dispensations for *particular reasons*. Examples of *particular reasons* that could necessitate increased uncertainty limits may include:

- a) Quantities of natural gas emitted to air during a measurement period that are less than 100,000 standard cubic metres (Sm<sup>3</sup>).
- b) Quantities of flared petroleum during a measurement period with little or no operational flaring and where inert gas (shielding gas) constitutes most of the measured flare gas.

The licensee must document the existence of *particular reasons*.

The uncertainty limit for diesel and other liquid petroleum used as fuel may be specified for consumption accumulated over a calendar year. It is expected that the specified uncertainty limit for is reasonable.

### **Re Section 11. Methods for measuring produced petroleum**

No comment.

### **Re Section 12. Methods for measuring burnt petroleum and gas emitted to air**

First paragraph:

By “other systems than common cold vent systems” (cold vent) in letter a), is meant systems for venting natural gas from process equipment, including through dedicated pipes connected to compressors, gas treatment, combustion engines, instruments, etc.

Appendix 2 refers to documents that may be used for fulfilling the requirements in the first paragraph, letter a) for indirect measurement of natural gas emissions. Nominal conversion factors from mass to standard volume may be used, provided they comply with the uncertainty limit for the measurand.

### **Re Section 13. Measurement principles**

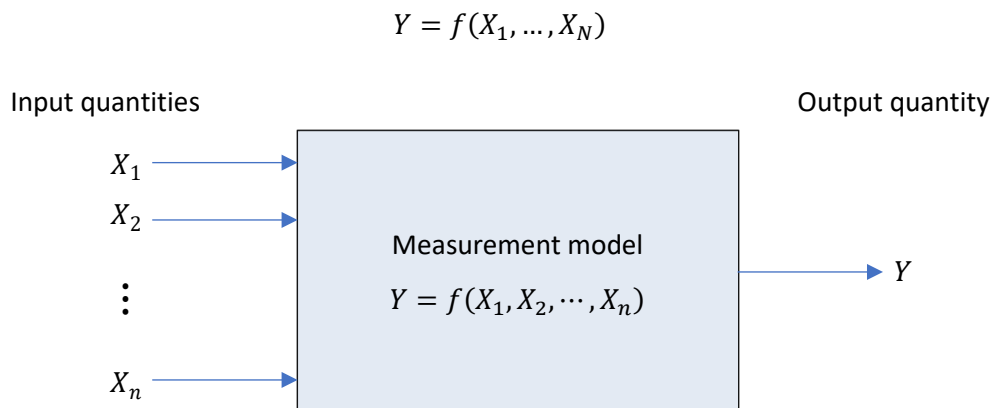
Measurement principles described in relevant, current recognised national and international standards for the type of measurement in question can normally be used as a basis for fulfilling the requirement to use measurement principles that are documented as suitable for the measurement in question.

### **Re Section 14. Measurement model**

First paragraph:

Appendix 2 refers to documents in the *GUM: Guide to the Expression of Uncertainty in Measurement* series issued by the Joint Committee for Guides in Metrology (JCGM). These and equivalent publications from other members of the JCGM, including ISO/IEC, are internationally recognised guidelines for evaluating and expressing uncertainty in measurement, and for the development and use of measurement models.

A measurand can usually be modelled as a functional relationship  $f$  between  $N$  input quantities  $X_1, \dots, X_N$  and an output quantity  $Y$  in the following form:



Measurement models can be linked, so that output quantities in one model can be input quantities in another. Measurement models can have more than one output quantity.

Examples of simplified resulting measurement models with output quantities that correspond to measurands in Section 10, as well as models for calculating the associated measurement uncertainty, are provided in the guideline for Section 15. The guideline for Section 28 addresses measurement models and associated uncertainty models for measuring systems, i.e., systems where output quantities are input quantities in the resulting measurement model.

Second paragraph:

Corrections may be applied to both input and output quantities in a measurement model. They can be introduced into the model to compensate for additive systematic effects (absolute) and multiplicative systematic effects (proportional to output quantities or input quantities).

A guideline for when a systematic measurement error is considered a *significant systematic measurement error* is if the systematic measurement error constitutes more than 0.02 % of the measured value.

**Re Section 15. Uncertainty budgets**

Documents in the *GUM: Guide to the Expression of Uncertainty in Measurement* series published by the Joint Committee for Guides in Metrology (JCGM), and equivalent publications from other members of the JCGM, including ISO/IEC, are internationally recognised guidelines for evaluating and expressing uncertainty in measurement. These publications are referred to in Appendix 2. Appendix 2 also refers to other relevant documents and to uncertainty programmes published on the Norwegian Society for Oil and Gas Measurement website, which can be used to fulfil requirements for uncertainty budgets.

For evaluating the uncertainty of replacement data, reference is made to *JCGM 100:2008*, Section F.2.3, titled *Imported input values*. This section of the GUM provides guidelines for using imported input values to replace missing measurement data and describes how the uncertainty associated with these data should be evaluated.

Relevant resulting measurement models and associated uncertainty models for measurands in Section 10 are provided below.

### Delivery measurements of oil

A resulting measurement model for delivery measurements of oil could be

$$V_{Net} = (1 - \phi_W)V_{Gross}$$

where  $V_{Net}$  is the net standard volume of oil,  $V_{Gross}$  is the gross standard volume of oil and  $\phi_W$  is the volume fraction of water in the oil.  $V_{Gross}$  is measured using a flowmeter and  $\phi_W$  is determined either through chemical analysis of oil samples, or as a direct measurement. Here,  $V_{Gross}$  and  $\phi_W$  are input quantities and  $V_{Net}$  is the output quantity. When no correlation between the input quantities is assumed, the uncertainty model becomes equal to:

$$u^*(V_{Net})^2 = \left( \frac{\phi_W}{1 - \phi_W} \right)^2 u^*(\phi_W)^2 + u^*(V_{Gross})^2$$

In many instances, the relative uncertainties  $u^*(V_{Gross})$  and  $u^*(V_{Net})$  can be calculated using the uncertainty programme *Fiscal Oil Metering Station Uncertainty* on the Norwegian Society for Oil and Gas Measurement (NFOGM) website, which provides the instrumental uncertainty in flow rate, or using an equivalent computer programme with calculation algorithms that comply with JCGM GUM. If the measuring system has functioned and been used as intended, it can normally be assumed that the relative uncertainty is approximately the same for both the flow rate and accumulated volume. The uncertainty  $u^*(\phi_W)$  can be found from laboratory certificates, possibly in combination with uncertainties related to the collection and handling of oil samples, or from specifications for measuring instruments used for direct measurement of the water fraction.

An example of indirect measurement is when two fields (Field A and Field B) deliver into the same pipeline. The delivery measurement for Field B (net standard volume) is based on direct measurement (measuring system). This also applies to the total net standard volume coming out of the pipeline. The quantity of oil in a delivery from Field A is then measured indirectly as the quantity of oil coming out of the pipeline minus the oil delivered from Field B. A relevant measurement model for this situation is:

$$V_A = V_{total} - V_B$$

where  $V_B$  is the accumulated net standard volume delivered from Field B (measured at Field B) and  $V_{total}$  is the accumulated net standard volume received and measured at the pipeline outlet.  $V_A$  is the accumulated net standard volume delivered from Field A (calculated using the direct measurements of  $V_B$  and  $V_{total}$ ). Here,  $V_B$  and  $V_{total}$  are input quantities and  $V_A$  is the output quantity. When it is assumed that there is no correlation between the input quantities, the uncertainty model for the accumulated net standard oil delivered from Field A is:

$$u^*(V_A)^2 = \left( \frac{V_{total}}{V_A} u^*(V_{total}) \right)^2 + \left( \frac{V_B}{V_A} u^*(V_B) \right)^2$$

The uncertainties  $u^*(V_{total})$  and  $u^*(V_B)$  can be found using a methodology for delivery measurements of oil using a single measuring system, as described above.

### Delivery and allocation measurement of gas

If the measuring system has functioned and been used as intended, it can normally be assumed that the relative uncertainty is approximately the same for both the flow rate and the corresponding accumulated quantity. In many instances, this uncertainty can be calculated using the uncertainty programme *Fiscal Gas Metering Station Uncertainty* on the Norwegian Society for Oil and Gas Measurement (NFOGM) website or using equivalent computer programmes with calculation algorithms that comply with JCGM GUM.

### Quantity of natural gas used as fuel for power and heat production

If the measuring system has functioned and been used as intended, it can normally be presumed that the relative uncertainty is approximately the same for both the flow rate and the accumulated volume. In many instances, this uncertainty can be calculated using the uncertainty programme *Fiscal Gas Metering Station Uncertainty* on the Norwegian Society for Oil and Gas Measurement (NFOGM) website or using equivalent computer programmes with calculation algorithms that comply with JCGM GUM.

### Quantity of diesel used as fuel for power and heat production

A resulting measurement model for the accumulated standard volume of diesel used as fuel could be:

$$V_{diesel} = V_{delivered} - V_{balance} - V_{not\ combusted}$$

where  $V_{delivered}$  is the volume of diesel delivered to the installation during a tax period, and  $V_{balance}$  is the change in diesel inventory during the measurement period, tax period or a calendar year.  $V_{not\ combusted}$  is the volume of diesel used for purposes other than fuel during the tax period, including well maintenance. If it is assumed that there is no correlation between the input quantities, the uncertainty model will be as follows:

$$u^*(V_{diesel})^2 = \left( \frac{V_{delivered}}{V_{diesel}} u^*(V_{delivered}) \right)^2 + \left( \frac{V_{balance}}{V_{diesel}} u^*(V_{balance}) \right)^2 + \left( \frac{V_{not\ combusted}}{V_{diesel}} u^*(V_{not\ combusted}) \right)^2$$

### Quantity of flared petroleum

A resulting measurement model for the accumulated standard volume of flared petroleum during a measurement period could be:

$$V_{flared\ petroleum} = (V_{flare\ gas\ (lit\ flare)} + V_{gas\ to\ pilot\ burner}) - (V_{inert\ gas} + V_{water\ vapour})$$

where  $V_{flare\ gas\ (lit\ flare)}$  is the accumulated standard volume of flare gas during periods with a lit flare, and  $V_{gas\ to\ pilot\ burner}$  is the accumulated standard volume of gas led to the pilot burner.  $V_{inert\ gas}$  and  $V_{water\ vapour}$  are the accumulated standard volume of inert gas and water vapour, respectively, in the flare gas. If no correlation is assumed between the input quantities, the uncertainty model will be as follows:

$$\begin{aligned}
 u^*(V_{flared\ petroleum})^2 &= \left( \frac{V_{flare\ gas\ (lit\ flare)}}{V_{flared\ petroleum}} u^*(V_{flare\ gas\ (lit\ flare)}) \right)^2 \\
 &+ \left( \frac{V_{gas\ to\ pilot\ burner}}{V_{flared\ petroleum}} u^*(V_{gas\ to\ pilot\ burner}) \right)^2 \\
 &+ \left( \frac{V_{inert\ gas}}{V_{flared\ petroleum}} u^*(V_{inert\ gas}) \right)^2 + \left( \frac{V_{water\ vapour}}{V_{flared\ petroleum}} u^*(V_{water\ vapour}) \right)^2
 \end{aligned}$$

If the measurement of the quantity of flare gas involves measurement results from multiple meters (e.g. primary meter and secondary meter), this is reflected in the model through multiple input quantities.

As regards measuring systems with an online gas chromatograph, one alternative way to correct for water vapour and inert gas could be:

$$V_{flared\ petroleum} = (V_{flare\ gas\ (lit\ flare)} + V_{gas\ to\ pilot\ burner}) \cdot f(Z_0, X_{natural\ gas})$$

where

$$f(Z_0, X_{natural\ gas}) = \frac{Z_{0\ natural\ gas}}{Z_{0\ total}} \cdot X_{natural\ gas}$$

where  $Z_{0\ natural\ gas}$  is the compressibility factor of natural gas at reference conditions.  $Z_{0\ total}$  and  $X_{natural\ gas}$  are the compressibility factor and the proportion of natural gas, respectively, in the gas flowing through the measuring system. The quantities included in the correction factor  $f$  can be calculated from the flare gas composition. When it is assumed that there is no correlation between the input variables, the uncertainty model is equal to:

$$\begin{aligned}
 u^*(V_{flared\ petroleum})^2 &= \left( \frac{V_{flare\ gas\ (lit\ flare)}}{V_{flared\ petroleum}} u^*(V_{flare\ gas\ (lit\ flare)}) \right)^2 \\
 &+ \left( \frac{V_{gas\ to\ pilot\ burner}}{V_{flared\ petroleum}} u^*(V_{gas\ to\ pilot\ burner}) \right)^2 + (u^*(f))^2
 \end{aligned}$$

### Quantity of natural gas emitted to air

A resulting measurement model for the accumulated standard volume of natural gas emitted to air during a measurement period could be:

$$\begin{aligned}
 V_{natural\ gas\ emissions} &= (V_{cold\ vent} + V_{flare\ gas\ (unlit\ flare)} + V_{other\ sources}) \\
 &- (V_{inert\ gas} + V_{water\ vapour})
 \end{aligned}$$

where  $V_{cold\ vent}$  is the accumulated quantity of water vapour and gas emitted to air through a cold vent system and  $V_{flare\ gas\ (unlit\ flare)}$  is the accumulated standard volume of flare gas emitted to air

through an unlit flare.  $V_{other\ sources}$  is the accumulated standard volume of natural gas vented directly to the air from other sources, including process equipment, produced water, etc.  $V_{inert\ gas}$  and  $V_{water\ vapour}$  are the accumulated standard volume of inert gas and water vapour, respectively, in cold-vent and flare gas. If no correlation is presumed between the input quantities, the uncertainty model will be as follows:

$$\begin{aligned}
 u^*(V_{natural\ gas\ emissions})^2 &= \left( \frac{V_{cold\ vent}}{V_{natural\ gas\ emissions}} u^*(V_{cold\ vent}) \right)^2 \\
 &+ \left( \frac{V_{flare\ gas\ (unlit\ flare)}}{V_{natural\ gas\ emissions}} u^*(V_{unlit\ flare}) \right)^2 \\
 &+ \left( \frac{V_{other\ sources}}{V_{natural\ gas\ emissions}} u^*(V_{other\ sources}) \right)^2 \\
 &+ \left( \frac{V_{inert\ gas}}{V_{natural\ gas\ emissions}} u^*(V_{inert\ gas}) \right)^2 \\
 &+ \left( \frac{V_{water\ vapour}}{V_{natural\ gas\ emissions}} u^*(V_{water\ vapour}) \right)^2
 \end{aligned}$$

For the quantity  $V_{other\ sources}$ , a complete quantitative theoretical uncertainty evaluation is often not appropriate. A simplified model based on reasonable assumptions and available information may be sufficient to estimate the measurement uncertainty associated with this quantity.

### Quantity of CO<sub>2</sub> separated from petroleum and emitted to air

If the measuring system has functioned and been used as intended, it can normally be assumed that the relative uncertainty is approximately the same both for the flow rate and the accumulated volume. This uncertainty can, in many instances, be calculated using the uncertainty programme *Fiscal Gas Metering Station Uncertainty* on the Norwegian Society for Oil and Gas Measurement (NFOGM) website or using equivalent computer programmes with calculation algorithms that comply with JCGM GUM. If the separated CO<sub>2</sub> is not pure, the measurement model and associated uncertainty model must reflect how the quantity of separated CO<sub>2</sub> is determined from the relevant measurements.

### Examples of resulting measurement models and associated uncertainty models

In the two examples below, it is shown how a measurement model and an uncertainty model are used to set up an uncertainty budget. The values given for relative uncertainties, coverage factors, and relative sensitivity coefficients are examples and not universally applicable.

#### Example 1: Uncertainty in indirectly measured quantity of delivered oil

Measurement model:

$$V_A = V_{total} - V_B$$

Input quantity and output quantity:

- Field B delivers 40 000 Sm<sup>3</sup> of oil in the pipeline, i.e.  $V_B = 40\ 000\ \text{Sm}^3$ .

- 100,000 Sm<sup>3</sup> of oil is measured at the pipeline outlet, i.e.  $V_{total} = 100\ 000\ Sm^3$ .
- This means that Field A delivers  $V_A = V_{total} - V_B = 60\ 000\ Sm^3$ .

Uncertainties in input quantities:

- On Field B, delivered oil is measured using a measuring system that satisfies the requirements for delivery measurements of oil and where the relative expanded uncertainty with a 95 % confidence level for net standard volume in its own studies is calculated to be 0.30 %. This means that the relative standard uncertainty is  $u^*(V_B) = \frac{0.30\ \%}{2} = 0.15\ \%$ .
- At the pipeline outlet, delivered oil is measured using a measuring system that satisfies the requirements for delivery measurements of oil and where the relative expanded uncertainty with a 95 % confidence level for net standard volume in its own studies is calculated to be 0.25 %. This means that the relative standard uncertainty is  $u^*(V_{total}) = \frac{0.25\ \%}{2} = 0.125\ \%$ .

Uncertainty in output quantity:

The relative standard uncertainty in the accumulated net standard volume of oil delivered from Field A ( $u^*(V_A)$ ) can be found using the uncertainty formula stated above:

$$u^*(V_A)^2 = \left( \frac{V_{total}}{V_A} u^*(V_{total}) \right)^2 + \left( \frac{V_B}{V_A} u^*(V_B) \right)^2$$

All quantities on the right side are quantified here, thus allowing calculation of  $u^*(V_A)$ :

$$u^*(V_A)^2 = \left( \frac{100000\ Sm^3}{60000\ Sm^3} \cdot 0.125\% \right)^2 + \left( \frac{40000\ Sm^3}{60000\ Sm^3} \cdot 0.15\% \right)^2 = 0.05340\ \%^2$$

$$u^*(V_A) = 0.231\ \%$$

The relative expanded uncertainty in the accumulated net standard volume of oil delivered from Field A can then be found by multiplying by the coverage factor ( $k = 2$ ):

$$U^*(V_A) = 2u^*(V_A) = 0.46\ \%$$

This can also be summarised in a table; for example, as follows:

	Stated relative uncertainty	Coverage factor	Relative standard uncertainty	Relative sensitivity factor	Relative variance
Measurement out of pipeline, $V_{total}$	0.25 %	2	0.125 %	$\frac{V_{total}}{V_A} = \frac{5}{3}$	0.04340 % <sup>2</sup>
Measurement on Field B, $V_B$	0.30 %	2	0.15 %	$\frac{V_B}{V_A} = \frac{2}{3}$	0.01000 % <sup>2</sup>
Sum of relative variances					0.05340 % <sup>2</sup>
Relative standard uncertainty of $V_A$					0.231 %
Relative expanded uncertainty ( $k = 2$ ) of $V_A$					0.46 %

As shown in the uncertainty budget, the requirement in Section 10 requirement for an uncertainty limit of 0.30 % is not met in this case for the measured quantity of oil delivered from Field A.

**Example 2: Uncertainty in quantity of flared petroleum**

Measurement model (simplified):

$$V_{\text{flared petroleum}} = V_{\text{flare gas (lit flare)}} - V_{\text{nitrogen}} = (V_{\text{primary}} + V_{\text{secondary}}) - V_{\text{nitrogen}}$$

Input quantities and output quantities:

- Primary meter measures 260 000 Sm<sup>3</sup> of gas, i.e.  $V_{\text{primary}} = 260\,000\text{ Sm}^3$ .
- Secondary meter measures 140 000 Sm<sup>3</sup> of gas, i.e.  $V_{\text{secondary}} = 140\,000\text{ Sm}^3$ .
- Correction is measured to be 100 000 Sm<sup>3</sup>, i.e.  $V_{\text{nitrogen}} = 100\,000\text{ Sm}^3$ .
- This means that the flared quantity of petroleum is  $V_{\text{flared petroleum}} = V_{\text{primary}} + V_{\text{secondary}} - V_{\text{nitrogen}} = 300\,000\text{ Sm}^3$ .

Uncertainties in input quantities:

- The primary meter is an ultrasonic flare gas meter where the relative expanded uncertainty at a 95 % confidence level in a separate study is calculated to be 5 %. This means that the relative standard uncertainty is  $u^*(V_{\text{primary}}) = \frac{5\%}{2} = 2.5\%$ .
- The secondary meter is a meter where the relative expanded uncertainty at a 95 % confidence level in a separate study is calculated to be 10 %. This means that the relative standard uncertainty is  $u^*(V_{\text{secondary}}) = \frac{10\%}{2} = 5\%$ .
- The correction is measured using a separate measuring system where relative expanded uncertainty at a 95 % confidence level in a separate study is calculated to be 1.5 %. This means that the relative standard uncertainty is  $u^*(V_{\text{nitrogen}}) = \frac{1.5\%}{2} = 0.75\%$ .

Uncertainty in output quantity:

The relative standard uncertainty in the accumulated net standard volume of flared petroleum,  $u^*(V_{\text{flared petroleum}})$ , can be determined based on the uncertainty formula stated above:

$$\begin{aligned} u^*(V_{\text{flared petroleum}})^2 &= \left( \frac{V_{\text{primary}}}{V_{\text{flared petroleum}}} u^*(V_{\text{primary}}) \right)^2 + \left( \frac{V_{\text{secondary}}}{V_{\text{flared petroleum}}} u^*(V_{\text{secondary}}) \right)^2 \\ &\quad + \left( \frac{V_{\text{nitrogen}}}{V_{\text{flared petroleum}}} u^*(V_{\text{nitrogen}}) \right)^2 \end{aligned}$$

All quantities on the right side are quantified here, thus allowing calculation of  $u^*(V_{\text{flared}})$ :

$$\begin{aligned} u^*(V_{\text{flared petroleum}})^2 &= \left( \frac{260,000\text{ Sm}^3}{300,000\text{ Sm}^3} \cdot 2.5\% \right)^2 + \left( \frac{140,000\text{ Sm}^3}{300,000\text{ Sm}^3} \cdot 5\% \right)^2 + \left( \frac{100,000\text{ Sm}^3}{300,000\text{ Sm}^3} \cdot 0.75\% \right)^2 \\ &= 10.201\% \end{aligned}$$

$$u^*(V_{\text{flared petroleum}}) = 3.19\%$$

The relative expanded uncertainty in the accumulated net standard volume of flared petroleum can then be found by multiplying by the coverage factor ( $k = 2$ ):

$$U^*(V_{flared\ petroleum}) = 2u^*(V_{flared\ petroleum}) = 6.4\ \%$$

This can also be summarised in a table; for example, as follows:

	Stated relative uncertainty	Coverage factor	Relative standard uncertainty	Relative sensitivity factor	Relative variance
Measurement with primary meter, $V_{primary}$	5 %	2	2.5 %	$\frac{V_{primary}}{V_{flared\ petroleum}} \approx 0.8667$	4.6944 % <sup>2</sup>
Measurement with secondary meter, $V_{secondary}$	10 %	2	5 %	$\frac{V_{secondary}}{V_{flared\ petroleum}} \approx 0.4667$	5.4444 % <sup>2</sup>
Measurement of deduction, $V_{correction}$	1.5 %	2	0.75 %	$\frac{V_{nitrogen}}{V_{flared\ petroleum}} \approx 0.3333$	0.0625 % <sup>2</sup>
Sum of relative variances					10.201 % <sup>2</sup>
Relative standard uncertainty of $V_{flared\ petroleum}$					3.19 %
Relative expanded uncertainty ( $k = 2$ ) of $V_{flared\ petroleum}$					6.4 %

As shown in the uncertainty budget, the requirement Section 10 for an uncertainty limit of 7.5% is fulfilled for the measured quantity of flared petroleum.

### Re Section 16. Measurement procedures

A measurement procedure should include a description of how measurement results are obtained and reported, including any calculations. The measurement procedure should also include a designation of uncertainty limits and error limits.

### Re Section 17. Measurement results

A measurement result is the final outcome of the process of determining the values for a measurand.

### Re Section 18. Replacement for missing measurement data

No comment.

### Re Section 19. Correction of measurement results

Examples of *systematic errors in a measurement result* can be errors that are not corrected for in the measurement model, and which are caused by factors such as:

- fault (error) in measuring system (equipment that does not satisfy performance requirements),
- deficient compliance with internal requirements and routines (management system),
- incorrectly read values,
- errors in calculations,
- errors in parameters entered in computer systems (incorrect parameters used in calculations).

Guidelines for when a measurement result is considered to have a *significant systematic error* are if all the following criteria are met:

- the systematic error constitutes more than 0.02 % of measured value
- the financial value of the error exceeds NOK 20,000
- the financial value of the error exceeds the cost of correction.

If it cannot be documented how long the systematic error has been present, a prudent method may be to correct for the errors in the last half of the maximum period of time which the error may have been present.

## **Re Chapter 5. Requirements relating to chemical analyses in laboratories**

Relevant measurement requirements in Chapter 4, including for documenting compliance with uncertainty limits in the uncertainty budget and metrological traceability, also apply for results from chemical analyses of oil and gas samples.

### **Re Section 20. Measurands and uncertainty limits**

Uncertainty budgets for trace quantities of water in oil samples should be based on uncertainty sources identified and addressed in standards and other recognised documents.

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements in this provision.

### **Re Section 21. Requirements for analysis methods**

First and second paragraph:

“Other methods” for analysing trace quantities of water in oil samples include the centrifuge method and distillation method.

A “representative test sample” means a test sample (cf. metrological glossary) with a composition similar to that of the sample from which it is taken, and in a quantity suitable for the analysis method/analyser. To achieve a representative test sample, the sample from which it is taken must be homogenised. A sample is homogenised by mixing it with an appropriate mixer for an appropriate period of time.

Syringes used to extract a test sample with a specific volume (from the sample) should have a digital read-out. The volume uncertainty should not exceed 0.5 %. Analytical balances used to weigh a test sample should have a resolution of at least 0.1 mg. To meet the traceability requirements for measurement results in Section 17, syringes and analytical balances used to determine the quantity of the test sample must be certified.

Fifth paragraph:

“Reference materials” here means solutions to verify the calibration of the Karl Fischer analyser, density standards to verify the calibration of the density analyser, and calibration gases to verify the gas chromatograph calibration. Certified reference materials should be used.

Appendix 2 refers to standards and other recognised documents that may be used to fulfil requirements for analysis methods.

## **Re Section 22. Laboratory requirements**

Laboratories that are accredited or that can document equivalent competence, and management will be able to fulfil the requirements for laboratories used for chemical analysis of petroleum.

The Norwegian Offshore Directorate regularly arranges an inter-laboratory comparison (ILC) in instrumental chemical analysis of trace quantities of water in oil samples. The ILC is considered to be an important measure to ensure the quality of such analyses. Each ILC is summarised in a report. The results from the participating laboratories will be anonymised in the report. In addition to the report, the individual laboratories will receive specific feedback with detailed results from the ILC. All laboratories associated with the petroleum activities on the Norwegian shelf, and which perform analyses regulated by these regulations, should participate in the ILC.

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements in this provision.

## **Re Chapter 6. Allocation requirements**

### **Re Section 23. Allocation system**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for allocation systems.

First paragraph:

A fair allocation means an allocation that e.g. does not contain identified biases.

An auditable allocation means an allocation that provides information that can be evaluated step-by-step in an independent manner to achieve the same results.

### **Re Section 24. Allocation procedures**

No comment.

### **Re Section 25. Verification and validation**

The first validation of the allocation system should take place within one year after it has been put into use, so that necessary corrections can be made in time.

## Re Chapter 7. General requirements for measuring systems for dynamic measurement

The requirements in Chapter 7 apply to the dynamic measurement of quantities of petroleum flowing in pipes. These requirements must be seen in conjunction with the measurement requirements in Chapter 4. Chapter 7 is supplemented by chapters with special requirements for measuring systems for measuring oil, gas and multiphase petroleum. The requirements in Chapter 7 and the supplemental chapters apply to the planning, construction, testing and operation and maintenance of measuring systems.

In these regulations, a “flow of oil” means single-phase flow of crude oil, condensate or NGL (including LPG). “Flow of gas” means a single-phase flow of dry gas, rich gas, flare gas, cold-vented gas, etc. “Flow of hydrocarbons in multiphase petroleum” means a multiphase flow of petroleum, including flows of wet gas.

“Single-phase flow of oil and gas” means the flow of fluid with a single thermodynamic phase. “Multiphase flow of petroleum” means the simultaneous flow of fluids with two or more thermodynamic phases. In these regulations, “single-phase” means a thermodynamic system with physical and chemical properties that, for practical purposes, can be considered to be homogeneous.

## Re Section 26. Design of measuring instruments and measuring systems

No comment.

## Re Section 27. Rated operating conditions

The requirement for documentation of rated operating conditions includes specification of metrological characteristics such as:

- a) working ranges
- b) type of fluid
- c) the fluid's relevant thermophysical characteristics
- d) pressure range limited by the fluid's minimum and maximum pressure
- e) temperature range limited by the fluid's minimum and maximum temperature.

## Re Section 28. Instrumental measurement uncertainties

Instrumental measurement uncertainty is normally achieved by calibrating a measuring instrument or measuring system. Information that is relevant for instrumental measurement uncertainty can be provided in instrument specifications.

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for instrumental measurement uncertainty.

### First paragraph:

If the instrumental measurement uncertainty for the relevant measuring system is within the relevant uncertainty limits in the table below, the requirements of Section 28 first paragraph will usually be fulfilled.

Type of measuring system:	Indication	Uncertainty limit
	Volume or mass flow of oil	0.20 %

Delivery measurement	Volume, mass or energy flow of gas	0.9 %
Allocation measurement	Volume or mass flow of oil	0.3 %
	Volume or mass flow of gas	1.4 %
	Volume or mass flow of multiphase petroleum	5 %
CO <sub>2</sub> tax measurement	Volume flow of gas for fuel	1.4 %
	Volume flow of gas to flare and cold-venting system	5 %
	Volume flow of vented CO <sub>2</sub>	5 %

Second paragraph:

As regards measuring the flow of oil and gas, uncertainty programmes on the Norwegian Society for Oil and Gas Measurement (NFOGM) website, or other programmes based on the guidelines from JCGM “*GUM: Guide to the Expression of Uncertainty in Measurement*”, can be used to prepare and maintain uncertainty budgets for instrumental measurement uncertainties.

As regards measuring the flow of gas to the flare (flare gas) using an ultrasonic flowmeter or other volumetric flowmeter, a simplified analysis can normally be used where uncertainty used in the volumetric flow rate is as specified by the supplier, as well as uncertainty associated with pressure, temperature and gas compressibility factor. In this instance, the measurement model can be written as follows:

$$q_{v0} = \frac{PT_0Z_0}{P_0TZ} q_v$$

where  $q_v$  is the volumetric flow rate at the relevant pressure and temperature,  $P$  is the relevant absolute pressure,  $P_0$  is the standard reference pressure (=1.01325 bara),  $T$  is the relevant absolute temperature (stated in Kelvin),  $T_0$  is the standard reference temperature (=288.15 K, equivalent to 15 °C),  $Z$  is the gas' compressibility factor at the relevant pressure and temperature, and relevant absolute pressure,  $Z_0$  is the gas' compressibility factor at the standard reference pressure and temperature, and  $q_{v0}$  is the volumetric flow rate at the standard reference pressure and temperature. Here,  $q_v$ ,  $P$ ,  $T$  and  $Z/Z_0$  are input quantities and  $q_{v0}$  is the output quantity.

When no correlation is presumed between the input quantities, the uncertainty model for the standard volumetric flow rate is as follows:

$$u^*(q_{v0})^2 = u^*(q_v)^2 + u^*(P)^2 + u^*(T)^2 + u^*(Z/Z_0)^2$$

where  $u^*$  represents the relative standard uncertainty. There is a weak correlation between pressure ( $P$ ) and compressibility factor ( $Z$ ) and between temperature ( $T$ ) and compressibility factor ( $Z$ ). However, this is so weak for flare measurements that it can be disregarded.

The uncertainty  $u^*(q_v)$  will normally be found in the flowmeter's specifications. Correspondingly, the uncertainties  $u^*(P)$  and  $u^*(T)$  can be calculated based on specifications and calibration results.  $u^*(Z/Z_0)$  depends on how this is implemented in the measuring system. This uncertainty can vary with pressure and temperature, in addition to varying with the gas composition. It is not usually necessary to examine the uncertainties in the gas components.

As regards measuring the flow of hydrocarbons in multiphase petroleum, a complete quantitative theoretical uncertainty evaluation will usually not be possible.

## **Re Section 29. Meter tubes and adjacent piping**

### First paragraph:

Fulfilling the requirement in letter a) presumes the installation of parallel meter tubes if the flow rate is too high for a single meter tube.

Fulfilling the requirement in letter b) may include the installation of parallel meter tubes if it is impractical to shut down the measuring system, and if frequent internal inspection and cleaning of meter tubes is necessary. Parallel meter tubes are not required in measuring systems for flare gas, and it is acceptable to plan to use replacement data for missing measurement data during maintenance periods. In fuel gas measuring systems, bypasses can be installed to ensure access for maintenance during operations. It can be planned to use replacement data during periods when the bypasses are in use for maintenance work on meter tubes. Meter tubes with two meters in series can be used instead of bypasses in measuring systems for fuel gas.

Fulfilling the requirement in letter c) presumes that measuring systems with parallel meter tubes have a common header upstream to ensure the most uniform conditions possible through the measuring system. As regards fluids containing particles (foreign objects), filters may be necessary upstream of the meter tubes. To minimise installation effects, pipe components, including valves and thermowells, should be installed so that they disturb measurements as little as possible.

### Third paragraph:

For measuring systems without spare meter tubes, the meter tubes should be equipped so that a failure in one part does not affect the operation of the measuring system as a unit.

Meter tubes with two meters in series should be designed and installed to minimise the risk of a disturbance causing the same error in both meters.

## **Re Section 30. Bypassing the measuring system**

### Second paragraph:

The measuring system should include interlocks (safety mechanisms) to prevent unintended flow of petroleum in bypasses around meters and measuring systems.

## **Re Section 31. Measurements of temperature and pressure**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for measuring temperature and pressure.

### Third paragraph:

Fulfilling the requirements in the third paragraph presupposes that:

- a) the instrument pipes connecting the pressure taps of the meter tube with the sensors are as short as possible
- b) the sensors for gas measurement and LNG measurement are placed higher than the pressure taps, and the instrument pipes have a continuous downward slope towards the pressure taps

- c) the sensors for oil measurement and multiphase measurement are placed lower than the pressure taps, and the instrument pipes have a continuous upward slope toward the pressure taps. For pressures higher than 500 kPa, the sensors can be placed in the same manner as for gas measurement, as indicated in letter b.

### **Re Section 32. Protection**

#### First paragraph:

Transmitters that are installed in locations exposed to large temperature fluctuations should be installed in temperature-controlled environments or cabinets.

Fulfilling the requirements for protection against disturbances caused by weather conditions presupposes that the meter tubes are equipped with thermal insulation to the necessary extent. For multiphase meters, thermal insulation may be necessary to reduce functional and performance problems associated with the formation and deposition of solids precipitated from the fluid.

### **Re Section 33. Monitoring and control**

#### Third paragraph:

Valves that are particularly important for the proving result (four-way valve and shut-off valves) should have automatic leak monitoring.

### **Re Section 34. Electronics**

“Electronics” means signal processing units in electronic meters and transducers/ transmitters that transmit measurement data and other information to the measuring system’s computer system.

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for electronics.

#### First paragraph:

The use of pulsed data from meters is an established practice and ensures traceability to calibration laboratories, since the calibration laboratories generally use pulses as the input signal from meters.

### **Re Section 35. Computer system**

“Computer system” means systems for general management, control, data acquisition and calculations (DCS, SCADA, Flow Computers).

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for computer systems.

#### Fourth paragraph:

To fulfil the requirement for an audit trail, the audit trail should include sufficient data and information to verify hourly and daily quantities.

#### Fifth paragraph:

Fulfilling the requirements to secure data against loss and manipulation presupposes securing data in the event of power outages and ensuring that all individuals who access the computer system are identifiable and responsible (authorised).

## **Re Chapter 8. Special requirements for measuring systems for dynamic measurement of oil**

The special requirements in Chapter 8 must be seen in conjunction with the measurement requirements in Chapter 4 and the general requirements for measuring systems in Chapter 7.

### **Re Section 36. Components of the oil measuring system**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for components of the oil measuring system.

### **Re Section 37. Calibration methods for oil meters**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for calibration methods for oil meters.

It follows from API MPMS 4.5 that a calibration method based on master meter prover results in significantly higher uncertainty than a calibration method that includes a displacement prover.

### **Re Section 38. Oil meter**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for oil meters. The performance requirements in Table 4 are explained in more detail in Appendix 3.

### **Re Section 39. Displacement prover**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for displacement provers.

#### Second paragraph:

Repeatability should be understood as a range of variation determined by the equation (cf. e.g. API MPMS 12.2.4 – 5):

$$\text{Repeatability \%} = [(Max - Min)/Min] \cdot 100$$

If the calibration result shows that the base volume of the displacement prover deviates by more than  $\pm 0.04$  % from the volume at the previous calibration, troubleshooting should be conducted to find the cause of the deviation.

### **Re Section 40. Master meter prover**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for master meter provers. The performance requirements in Table 6 are explained in more detail in Appendix 3.

#### Second paragraph:

If the calibration result shows that the flow-weighted mean error or calibration factor deviates by more than  $\pm 0.1$  % from the flow-weighted mean error or calibration factor at the previous calibration, troubleshooting should be conducted to find the cause of the deviation.

### **Re Section 41. Measuring instruments connected to the oil measuring systems**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for measuring instruments connected to the oil measuring system.

The requirements in Table 7 apply for measurement values read in the measuring system's computer system.

### **Re Section 42. Sampling equipment**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for sampling equipment (equipment used to extract samples from oil flowing through pipes).

### **Re Section 43. Algorithms and equations**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for algorithms and equations for use in oil measuring systems.

## **Re Chapter 9. Special requirements for measuring systems for dynamic measurement of gas**

The special requirements in Chapter 9 must be viewed in conjunction with the general measurement requirements in Chapter 4 and the general requirements for measuring systems in Chapter 7.

### **Re Section 44. Components of the gas measuring system**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for components of the gas measuring system.

### **Re Section 45. Calibration methods for gas meters**

#### Second paragraph:

A theoretical prediction procedure may include static tests and geometric measurements, depending on the technology.

For an ultrasonic flare gas meter, a procedure that includes metrologically traceable and sufficiently accurate measurements of geometric parameters and time delays will fulfil the requirements for a theoretical prediction procedure. The procedure should include measurements of:

- distances between transducers
- average internal diameter of meter tube
- cross-sectional area of meter tube
- time delays under zero-flow conditions.

For an orifice-type differential pressure meter, the primary element consists of an orifice plate, orifice plate holder, differential pressure taps, and meter tube. A procedure that documents compliance with the requirements in standards (e.g. ISO 5167) for the design and geometric dimensions of the primary element will fulfil the requirements for a theoretical prediction procedure.

### **Re Section 46. Gas meter**

Appendix 2 refers to standards and other recognised documents that could be relevant for fulfilling the requirements for gas meters. The performance requirements in Table 9 are explained in more detail in Appendix 3.

### **Re Section 47. Measuring instruments associated with gas measuring system**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for measuring instruments connected to the gas measuring system.

The requirements in Table 10 apply to values from measuring instruments read in the measuring system's computer system.

### **Re Section 48. Online gas chromatograph**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for online gas chromatographs.

#### First paragraph:

As regards verification and calibration of an online gas chromatograph, acceptance limits for the molar fraction of individual gas components should be determined by dividing the uncertainty limit of the measured molar mass (cf. Table 12) by the square root of the number of gas components.

For assessment of compliance with acceptance limits for molar fraction and with the uncertainty limit for calorific value (cf. Table 12), normalised values should be used to reduce the influence of weather conditions on the analysis results. Deviations in the molar fraction of individual gas components should not result in more than a 0.1 % deviation in calorific value or standard density.

### **Re Section 49. Sampling equipment**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for sampling equipment (equipment used to extract samples from gas flowing through pipes).

### **Re Section 50. Algorithms and equations**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for algorithms and equations for use in gas measuring systems.

## **Re Chapter 10. Special requirements for measuring systems for dynamic measurement of multiphase petroleum**

The special requirements in Chapter 10 must be viewed in conjunction with general measurement requirements in Chapter 4 and general requirements for measuring systems in Chapter 7.

### **Re Section 51. Components of the multiphase measuring system**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for components of the multiphase measuring system.

### **Re Section 52. Calibration methods for multiphase meters**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for calibration methods for multiphase meters.

### **Re Section 53. Multiphase meter**

Appendix 2 refers to standards and other recognised documents that could be relevant for fulfilling the requirements for multiphase meters.

### **Re Section 54. Separator measuring system**

No comment.

### **Re Section 55. Algorithms and equations**

Appendix 2 refers to standards and other recognised documents that could be relevant for fulfilling the requirements for algorithms and equations for use in multiphase measuring systems.

## **Re Chapter 11. Special requirements for measuring systems and measurement of LNG**

The requirements in Chapter 11 apply to measuring systems intended for static measurement of quantities (volume, mass and energy) of LNG. These requirements must be viewed in conjunction with the measurement requirements in Chapter 4.

### **Re Section 56. General requirements for measurement of LNG**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling general requirements for LNG measurement.

### **Re Section 57. Static measurement of volume and mass**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for static measurement of volume and mass.

### **Re Section 58. Sampling equipment**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for sampling equipment (equipment used to extract samples from LNG flowing through pipes).

### **Re Section 59. Gas chromatography**

No comment.

### **Re Section 60. Density and calorific value**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for calculating the density and calorific value from the LNG composition.

Samples collected during the loading of LNG to ships may, if representative of LNG loaded to tank trucks, be used to calculate the density and calorific value of LNG loaded to tank trucks.

### **Re Section 61. Measurement of the energy of displaced gas and consumed gas**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for measuring the energy of displaced gas and consumed gas.

### **Re Chapter 12. Requirements for verification and calibration before a measuring system is used**

The requirements in Chapter 12 apply for all measuring systems regulated by these Regulations. The requirements must be viewed in conjunction with requirements in Chapters 2, 3, 4, and 7, and depending on the type of measuring system, with requirements in Chapters 8, 9, 10 or 11.

### **Re Section 62. Preconditions for using measuring instruments and measuring systems**

No comment.

### **Re Section 63. Plans and procedures for verifications and calibrations**

No comment.

### **Re Section 64. Calibration and adjustment of measuring instruments**

Third paragraph:

An instrumental bias exceeding one third of the maximum permissible measurement error may, in many contexts, be considered significant.

### **Re Section 65. Use of laboratories for calibration**

An accredited laboratory refers to a laboratory (either stationary or mobile) that is accredited in accordance with the ISO/IEC 17025 standard for the relevant calibration methods. Documented compliance with relevant parts of ISO/IEC 9001 may fulfil the requirement for a non-accredited laboratory.

### **Re Section 66. Measurement standards**

The documentation requirement may be fulfilled by presenting a calibration certificate. The requirement for measurement uncertainty in the second sentence is explained in more detail in Appendix 3. The requirements for a measurement standard apply regardless of whether it is handled by an accredited or a non-accredited laboratory.

### **Re Section 67. Flow calibration of oil meters**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for flow calibration of an oil meter. The performance requirements in Section 38 are explained in more detail in Appendix 3.

First paragraph:

The requirement for the number of measurement points on the calibration curve is a minimum. Additional measurement points may be necessary to simultaneously fulfil the requirements in Section 64.

Fourth paragraph:

Fulfilling the requirement in the fourth paragraph includes collecting diagnostic data, also referred to as “fingerprints” in standards and other recognised documents, during calibration for meters capable of generating such data.

### **Re Section 68. Calibration of displacement provers**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for calibration of a displacement prover.

Second paragraph:

Proving should be tested with all base volumes.

### **Re Section 69. Flow calibration of master meters**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for flow calibration of a master meter. The performance requirements in Section 40 are explained in more detail in Appendix 3.

Fifth paragraph:

A baseline refers to a reference value or a set of data that represents the normal or expected performance of a measuring system under stable conditions. The baseline is used as a basis for comparison to identify non-compliance or changes in the system’s performance over time. Data collection during calibration may include data referred to as fingerprint data in standards such as ISO 17089-1.

### **Re Section 70. Flow calibration of gas meters**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for flow calibration of a gas meter. The performance requirements in Section 46 are explained in more detail in Appendix 3.

First paragraph:

The requirement for the number of calibration points on the calibration curve is a minimum. Additional measurement points may be necessary to simultaneously fulfil the requirements in Section 64.

Fourth paragraph:

A baseline refers to a reference value or a set of data that represents the normal or expected performance of a measuring system under stable conditions. The baseline is used as a basis for comparison to identify non-compliance or changes in the system’s performance over time. Data collection during calibration may include data referred to as fingerprint data in standards such as ISO 17089-1.

### **Re Section 71. Flow calibration of multiphase meters**

No comment.

### **Re Section 72. Calibration and verification of associated measuring instruments**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for calibration and verification of associated measuring instruments.

### **Re Section 73. Verification of gas chromatographs**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for verification of gas chromatographs.

### **Re Section 74. Verification of sampling equipment**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for verification of sampling equipment.

### **Re Section 75. Measurement and control of physical constants**

No comment.

### **Re Section 76. Verification of computer systems**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for verification of computer systems.

### **Re Section 77. Testing of assembled measuring systems and automatic sampling systems**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for testing of assembled measuring systems and automatic sampling systems.

## **Re Chapter 13. Requirements for operation and maintenance of measuring systems**

The requirements in Chapter 13 apply to the operation and maintenance of measuring systems regulated by these regulations. They must be considered in conjunction with the requirements in all preceding chapters.

Operation of measuring system refers to tasks and routines necessary to ensure that the measuring systems function as intended. Operation includes use, supervision and control, preparedness in the event of malfunctions and similar activities.

Maintenance refers to all measures, both technical and administrative, aimed at maintaining measuring systems at a defined quality level. Maintenance includes:

- 1) Corrective maintenance, a category of maintenance that, through repairs, inspections or replacement, restores the function of a damaged or defective measuring system so that it operates within defined acceptance criteria.
- 2) Preventive maintenance, measures to detect, prevent or reduce damage to measuring systems, with the aim of maintaining or extending their service life by controlling wear and faults to an acceptable level. Preventive maintenance includes:

- a) Periodic maintenance, a category of preventive maintenance of a measuring system where replacement, monitoring or testing is conducted at predetermined intervals, such as calendar time, operating time or number of cycles.
- b) Condition-based maintenance, a category of preventive maintenance of a measuring system that uses sensor data and diagnostics to determine the measuring system's current condition and to determine the type and schedule of maintenance. The goal of this approach, or type of maintenance, is to use the data collected during monitoring to ensure that maintenance is carried out at the right time and before a critical fault occurs.
- c) Predictive maintenance, a category of preventive maintenance that uses sensor data, diagnostics, aggregate sensor data and long-term trends to predict future wear and failure of a measuring system and to determine the type and schedule of maintenance. The goal of this approach is to plan maintenance on a future date when it is more practical and will have a minimal impact on production.

The Norwegian Offshore Directorate expects licensees, when selecting a maintenance system, to take into consideration the risk of non-compliance with the requirements of these regulations (cf. Section 5, second paragraph / guideline for Section 5 second paragraph).

## **Re Section 78. General requirements for operation and maintenance**

### First paragraph:

Fulfilling the requirement to operate measuring instruments and measuring systems as intended presupposes that they are used in accordance with specified working ranges and rated operating conditions for the measuring instruments and measuring systems.

### Third paragraph:

It is the licensee's responsibility to define what constitutes a reasonable timeframe for repairs and replacements. Timeframes will usually depend on multiple factors, including the criticality of the equipment for the measurement and the type of measurement.

## **Re Section 79. Maintenance programme**

### First paragraph:

The maintenance programme should include sub-programmes for

- verification of metrological characteristics between calibrations
- monitoring of diagnostic parameters of measuring instruments
- comparison of measurement data with data collected during calibration
- inspections
- testing
- preventive maintenance and similar activities.

### Second paragraph:

Charts (schematic representations of the relationship between quantities or the development of a quantity) should be used to monitor long-term trends in parameters that are important for the measurement result, such as calibration factors for meters and response and retention factors for gas chromatographs.

## **Re Section 80. Calibration programme**

Several factors should be considered when establishing and maintaining a calibration programme, including:

- uncertainty limits for relevant measurands
- the risk that the measuring instrument does not fulfil the requirements for maximum permissible measurement error and instrumental measurement uncertainty,
- the risk of financial loss due to the measuring instrument not having functioned appropriately over an extended period
- type of instrument
- instrumental drift and stability
- manufacturer's recommendations
- calibration history
- maintenance history (preventive and corrective maintenance)
- frequency and quality of checks between calibrations
- risk associated with transport
- calibration cost versus financial risk associated with longer intervals.

Measuring instruments should normally be recalibrated in their *as found* condition so that any changes in performance (instrumental drift and stability) since the previous calibrations can be quantified.

## **Re Section 81. Working standards**

### First paragraph:

The requirement for the accuracy of the working standard is further explained in Appendix 3.

## **Re Section 82. Evaluation of measurement data during verification**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for evaluation of measurement data during verification.

Appendix 3 provides a more detailed explanation of principles for evaluating measurement data when measuring fluid flow. The general principles presented in the Appendix are also applicable to other types of measurements, including temperature, pressure and density.

## **Re Section 83. Operation and maintenance of oil meters**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for the operation and maintenance of an oil meter.

### Second paragraph, letter b):

Acceptable and commonly used limits for reproducibility are 0.15 % or a three-standard-deviation-limit (see guideline for the fourth paragraph).

### Third paragraph:

A condition-based or predictive maintenance system may ensure that requirements for instrumental measurement uncertainty are fulfilled, provided the system takes into account:

- likelihood of corrosion, erosion and deposits in the meter tube and on sensors (transducers)

- the ability to detect corrosion, erosion and deposits in meter tube and on sensors (transducers)
- likelihood of changes in fluid properties, including changes in viscosity.

For meter tubes with two meters in series, acceptance limits for deviations in indications should comply with requirements in Section 82 Evaluation of measurement errors (cf. guideline for Section 82).

Fourth paragraph:

A control chart should be evaluated regularly so that a trend in one direction can be detected and acted upon early. The control chart may have a fixed deviation limit, and a commonly used limit is 0.15 %. If operating conditions are stable, statistical methods may be used to evaluate the reproducibility of calibration factors. For such methods, it is common to compare a new calibration factor with a three-standard-deviation limit based on previously determined calibration factors.

## **Re Section 84. Operation and maintenance of provers**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for operation and maintenance of a prover.

Fourth paragraph:

Fulfilling the requirements for documentation of unreasonably high costs presupposes an assessment of calibration cost against the financial risk of extended calibration intervals. Financial risk will, among other things, be determined by the economic value of the oil (quantity and quality) being measured.

To substantiate that the requirement for uncertainty in the base volume will be fulfilled with extended calibration intervals, the documentation should include an assessment of:

1. Calibration history
2. The likelihood of:
  - a) wear or damage to the displacement medium (ball or piston rings)
  - b) worn or defective detector switches
  - c) wear or damage to internal coatings
  - d) build-up of foreign matter

## **Re Section 85. Operation and maintenance of gas meters**

Second paragraph:

A condition-based or predictive maintenance system may ensure that the requirements for instrumental measurement uncertainty are fulfilled, provided the system takes into account:

- the likelihood of corrosion, erosion and deposits in meter tubes and on sensors (transducers)
- the ability to detect corrosion, erosion and deposits in meter tubes and on sensors (transducers)
- the likelihood of changes in fluid properties, including changes in density.

Data (fingerprint data) that may form part of the baseline for a meter should be collected immediately after the meter is put into operation.

For meter tubes with two meters in series, acceptance limits for deviations in indications should comply with the requirements in Section 82 Evaluation of measurement errors (cf. guideline for Section 82).

Third paragraph:

The metrological characteristics of flare gas meters at zero flow should be verified. Verification of metrological characteristics under dynamic conditions should supplement verification at zero flow.

Fourth paragraph:

The meter's sensitivity to the internal condition of the meter tube and the characteristics of the fluid should be taken into account when determining the inspection interval.

For meter tubes with orifice plates, internal inspection includes an inspection of the internal surface of the meter tube, the orifice plate and the pressure taps. Orifice plates in delivery measuring systems and CO<sub>2</sub> tax measuring systems should be inspected at least annually.

**Re Section 86. Operation and maintenance of multiphase meters**

No comment.

**Re Section 87. Operation and maintenance of associated measuring instruments**

No comment.

**Re Section 88. Operation and maintenance of online gas chromatographs**

Appendix 2 refers to standards and other recognised documents that may be relevant for fulfilling the requirements for operation and maintenance of online gas chromatographs.

**Re Section 89. Operation and maintenance of samplers**

The performance of a sampler should be verified as soon as possible once it has been installed and brought into operation.

Second paragraph:

A representative sample, as defined by these regulations, is an ideal. An acceptable sample is one that, with a certain degree of probability (here, a 95 per cent confidence level), can be considered representative of the composition of the quantity from which the sample was taken.

According to ISO 3171:1998 (see Appendix 2), for an oil sample to be acceptable:

- a) the performance factor for the automatic sampler shall be between 0.9 and 1.1
- b) the sampling shall be flow-proportional
- c) there shall be no interruptions in the sampling that could affect the performance factor beyond the limits specified in a).

The performance factor in a) is the ratio between the accumulated sample volume and the calculated sample volume.

**Re Section 90. Operation and maintenance of computer systems**

Third paragraph:

An unambiguous audit trail requires that changes to software are tracked. This can be done by logging the software version number and checksum.

## **Re Chapter 14. Requirements for materials and information**

### **Re Section 91. General requirements for materials and information**

This requirement must be considered in conjunction with the general provision in Section 10-4 of the Petroleum Act relating to materials and information and Section 55 of the Petroleum Regulations relating to the duty of safekeeping. The obligation pursuant to Section 10-4 of the Petroleum Act entails that documentation concerning fiscal measurement as referenced in these regulations shall be available in Norway, regardless of where the operating organisation is located. This does not imply a prohibition against storing the documentation abroad, provided it can be made available to the Norwegian Offshore Directorate within a reasonable timeframe. In certain instances, for example during audits at measuring stations located abroad, it may be most practical for the Norwegian Offshore Directorate to have access to the documentation on site. For operating organisations located outside Norway, the documentation should be available at the place of use and accessible to the Norwegian Offshore Directorate upon request.

### **Re Section 92. Information prior to BOV**

Prior to a Decision to Continue (BOV), the licensee shall inform the Norwegian Offshore Directorate of the measurement concept. This refers to information about:

- a) measurands
- b) measurement uncertainty
- c) technical solutions
- d) operation and maintenance
- e) economic considerations (cost-benefit assessment).

Measurement concept refers to a plan that forms the basis for the design of a measuring system.

### **Re Section 93. Information on measurement in PDOs and PIOs**

PDOs and PIOs shall, to the extent necessary, contain information about the measurement concept and any non-compliances from provisions in these regulations. This refers to information about:

- a) measurands and uncertainty limits
- b) measurement methods and principles
- c) technical solutions
- d) operation and maintenance
- e) economic considerations (cost-benefit assessment)
- f) any non-compliances, including which provisions are not complied with and the justification for each.

Approval of the PDO or PIO entails that the measurement concept, together with any non-compliance with these regulations, is approved. Any exemption applies only to non-compliance with regulatory requirements that is not identified in the PDO or PIO. An exemption refers to the authorities' decision to accept a non-compliance with regulatory requirements.

Reference is also made to Guidelines for plans for development and operation of a petroleum deposit (PDOs) and plans for installation and operation of facilities for utilisation of petroleum (PIOs).

### **Re Section 94. Applications for consent for start-up and continuation of measuring systems**

An application for consent pursuant to the second paragraph shall contain information demonstrating that the measuring system fulfils the requirements of these regulations. This refers to:

- a) specification of measurands and uncertainty limits
- b) a description of the measuring system
- c) piping and instrumentation diagram (P&ID)
- d) an overview of standards with which the measuring system (construction, installation, operation and maintenance) shall comply
- e) signed factory acceptance test (FAT) reports
- f) calibration certificates
- g) an uncertainty budget
- h) procedures for calibrations and verifications to be carried out in preparation for use of the measuring system
- i) procedures for operation and maintenance.

### **Re Section 95. Reporting of measured quantities**

Information on measured quantities shall be submitted to Diskos.

### **Re Section 96. Annual reports for onshore terminals**

It is recommended that Annual reports for onshore terminals follow the structure and content outlined below:

- **Introduction and summary:** Presentation of the terminal's location and main functions, a summary of findings, conclusions and recommendations, and a brief overview of the report's content.
- **Regulations and requirements:** Overview of relevant regulations and standards for fiscal measuring systems.
- **Measurands and uncertainty limits:** Description of measurands and compliance with uncertainty limits, including measures taken in the event of non-compliance.
- **Planned maintenance, including calibrations:** Brief overview of maintenance and calibration programmes, and an evaluation of their adequacy.
- **Corrective maintenance:** Description of corrective maintenance and measures taken in response to non-compliance.
- **Balances:** Description of relevant (mass, volume, energy) balances in the transport system.
- **Modifications and upgrades:** Information on modifications or upgrades, including schedules for calibration, testing and commissioning.
- **Audits:** Results of internal and external audits and planned follow-up actions.
- **Correction of measurement results:** Documented corrections of measurement results.

- **Non-compliances:** Overview of open non-compliances and corrective actions, including a brief summary of how the non-compliances affects operations and which actions are considered most critical.

The requirement for annual reports applies to terminals in Norway subject to the Petroleum Act. The requirement also applies to onshore terminals abroad if covered by specific agreements with foreign authorities.

## **Re Section 97. Information on measurements in the Annual Status Report for Fields in Production**

The *Guidelines for the Annual Status Reports for Fields in Production* provide a more detailed description of the information that must be included in an annual status report. These guidelines are available on the Norwegian Offshore Directorate's website:

<https://www.sodir.no/en/regulations/guidelines/>.

## **Re Section 98. Uncertainty budgets for CO<sub>2</sub> tax measurements**

Section 15 and the guideline to Section 15 describe how the requirement in Section 98 for an uncertainty budget shall be fulfilled.

According to Section 15, an uncertainty budget shall demonstrate that the uncertainty limits for values assigned to measurands in Section 10 are complied with. For CO<sub>2</sub> tax measurements, this applies to the accumulated volumes in Table 2 of these regulations. The guideline to Section 15 provides examples of measurement models and associated uncertainty models. Reference is made to NFOGM's handbooks and uncertainty programmes for measurement models and associated uncertainty models for flow measurements (input quantities in resulting measurement models).

The guideline to Section 28 provides a simplified measurement model and uncertainty model for the measurement of gas flow to the flare and cold vent systems. An example of an uncertainty budget for the quantity of flared petroleum is provided in Example 2 in the guideline to Section 15.

Appendix 4 contains a spreadsheet that may be used to submit uncertainty budgets for CO<sub>2</sub> tax measurements to the Norwegian Offshore Directorate.

## **Re Section 99. Other information**

### First paragraph:

The Norwegian Offshore Directorate will normally respond to information about errors that may provide a basis for major corrections of measured quantities of oil and gas within ten (10) working days.

### Second paragraph:

The term information about cargoes refers to cargo papers that document the quantity and quality of oil and other petroleum products, including methane, ethane and ethanol delivered to ships.

## **Re Chapter 15. General provisions**

### **Re Section 100. Supervisory authority – authority to make individual administrative decisions, etc.**

The Ministry of Energy is the appeals body for decisions made by the Norwegian Offshore Directorate pursuant to these regulations.

### **Re Section 101. Exemption**

An application for exemption should normally include:

- a) an overview of the provisions from which exemption is sought
- b) an explanation of the specific circumstances that make an exemption necessary or reasonable
- c) an account of how the exemption request has been handled internally within the organisation
- d) a description of the non-compliance and its planned duration,
- e) a description of any measures intended to fully or partially compensate for the non-compliance
- f) a description of any measures to correct the non-compliance, if it is of a temporary nature.

### **Re Section 102. Penal provision**

No comment.

### **Re Section 103. Entry into force and transitional provisions**

No comment.

## **Appendix 1. Metrological glossary**

This appendix contains a glossary of measurement-related terms and expressions used in these regulations and guidelines.

## **Appendix 2. Standards and other recognised documents**

This appendix contains an overview of standards and other recognised documents, organised in a spreadsheet.

## **Appendix 3. Evaluating measurement data obtained from fluid flow measurement**

This appendix addresses the evaluation of measurement data in fluid flow measurement, including uncertainty, during calibration and verification.

## **Appendix 4. Uncertainty budget for CO<sub>2</sub> tax measurements**

This appendix is a spreadsheet that may be used to submit uncertainty budgets for CO<sub>2</sub> tax measurements to the Norwegian Offshore Directorate pursuant to Section 98.