

Fiscal metering systems for hydrocarbon liquid and gas

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Foreword	3
Introduction	3
1 Scope	4
2 Normative and informative references	4
2.1 Normative references – hydrocarbon liquid and gas systems	4
2.2 Normative references – hydrocarbon liquid systems	4
2.3 Normative references – gas systems	5
2.4 Informative references – hydrocarbon liquid systems	5
2.5 Informative references – hydrocarbon gas systems	5
3 Terms, definitions and abbreviations	6
3.1 Terms and definitions	6
3.2 Abbreviations	8
4 General requirements	8
4.1 Introduction	8
4.2 Documentation	9
4.3 Traceability	10
4.4 Units	10
4.5 Uncertainty	10
4.6 Condition monitoring	10
5 System requirements	11
5.1 General	11
5.2 Capacity / availability / sizing / products and services	11
5.3 Measurement systems with multiple meter runs	11
5.4 Measurement systems with single meter run	12
5.5 Maintenance requirements	12
5.6 Drain / vent / relief and flushing connections	12
5.7 Thermal insulation	13
5.8 General requirements for instrumentation	13
5.9 Pressure and differential pressure measurements	14
5.10 Temperature measurements	14
5.11 Density	15
5.12 Spot sampling	15
6 Liquid measurement systems	16
6.1 General	16
6.2 Turbine and positive displacement meters	16
6.3 Ultrasonic meter	16
6.4 Coriolis meter	16
6.5 Proving systems	17
6.6 Online water in oil	18
7 Gas measurement systems for sales and allocation	18
7.1 General	18
7.2 Orifice	18
7.3 Ultrasonic	19
7.4 Coriolis	19
7.5 Other types of meters	19
8 Fuel gas meter	19
8.1 General	19
8.2 Orifice	20
8.3 Ultrasonic	20
8.4 Coriolis	20
8.5 Other types of meters	20
9 Flare gas meter	20
10 Computer part	20
10.1 General	20
10.2 Computer design	21
10.3 Operational requirements	23

10.4	Calculations	24
10.5	Prover calibration of flow meters	25
10.6	Reports	26
10.7	Alarms and events	26
10.8	Gas metering systems	28
10.9	Liquid metering systems	28
11	Liquid sampler system	28
12	Gas chromatograph systems	30
12.1	General	30
12.2	Equipment/schematic	30
13	Automatic gas sampler	35
ANNEX A	Testing and inspection (normative)	36
ANNEX B	Statistical evaluation of repeatability (normative)	40
ANNEX C	System selection criteria (informative)	41
ANNEX D	Water in oil calculations (informative)	42
ANNEX E	Guidelines to implementation of ISO 3171 (informative)	49
ANNEX F	Example of performance calculation of online gas chromatograph (informative)	51
ANNEX G	Content of reports (informative)	61

Foreword

The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are, as far as possible, intended to replace oil company specifications and serve as references in the authorities' regulations.

The NORSOK standards are normally based on recognised international standards, adding the provisions deemed necessary to fill the broad needs of the Norwegian petroleum industry. Where relevant, NORSOK standards will be used to provide the Norwegian industry input to the international standardisation process. Subject to development and publication of international standards, the relevant NORSOK standard will be withdrawn.

The NORSOK standards are developed according to the consensus principle generally applicable for most standards work and according to established procedures defined in NORSOK A-001.

The NORSOK standards are prepared and published with support by the Norwegian Oil and Gas Association (Norsk olje og gass), the Federation of Norwegian Industries, the Norwegian Shipowners' Association and the Norwegian Petroleum Directorate.

NORSOK standards are administered and published by Standards Norway.

Annexes A and B are normative. Annexes C to G are informative.

Introduction

This NORSOK standard replaces NORSOK I-104 Fiscal measurement system for hydrocarbon gas (Rev. 3, November 2005) and NORSOK I-105 Fiscal measurement systems for hydrocarbon liquid (Edition 3, August 2007). These two standards have been combined and restructured to avoid duplication, increase readability and reduce volume. The basis for this NORSOK standard has been the previous version of I-104 and I-105 combined with general industry experience over the last years.

The revision has been carried out by NORSOK expert group EG IM "Metering" with members from end users (oil companies), authorities, contractors, consultants and metering system vendors.

1 Scope

This NORSOK standard describes the functional and technical requirements for fiscal, custody transfer and allocation metering systems, for liquid and gas hydrocarbons based on dynamic methods. Further, this NORSOK standard provides criteria for selection of such systems or main components thereof.

2 Normative and informative references

The following standards include provisions and guidelines which, through reference in this text, constitute provisions and guidelines of this NORSOK standard. Latest issue of the references shall be used unless otherwise agreed. Other recognized standards may be used provided it can be shown that they meet or exceed the requirements of the referenced standards.

2.1 Normative references – hydrocarbon liquid and gas systems

ANSI/ASME,	<i>Performance Test Code PTC 19.3</i>
BIPM, et.al.*),	<i>OIML P17, Guide to the expression of Uncertainty in Measurements</i>
IEC 60751,	<i>Industrial platinum resistance thermometer sensors</i>
ISO 6551,	<i>Petroleum liquids and gases – Fidelity and security of dynamic measurement - Cabled transmissions of electric and/or electric pulsed data</i>
ISO 10790,	<i>Measurement of fluid flow in closed conduits – Guidance to the selection, installation and use of Coriolis meters (mass flow, density and volume flow measurements)</i>
ISO 17025	<i>General requirements for the competence of testing and calibration laboratory</i>
ISO 80000,	<i>SI units and recommendations for use of their multiples and of certain other units</i>
NORSOK I-001,	<i>Field instrumentation</i>
NPD Regulations,	<i>Regulations relating to measurement of petroleum for fiscal purposes and for calculation of CO₂-tax</i>
ISO/IEC Guide 98-3:2008	<i>Uncertainty of measurement – Part 3: Guide to the expression of uncertainty in measurement</i>
NFOGM	<i>Handbooks for uncertainty calculations</i>

*) On behalf of BIPM, IEC, IFCC, ISO, IUPAC, IUPAP and OIML.

2.2 Normative references – hydrocarbon liquid systems

API MPMS, Chap. 4.2,	<i>Displacement provers</i>
API MPMS, Chap. 4.5,	<i>Master meter provers</i>
API MPMS, Chap. 5.1,	<i>Metering – General considerations</i>
API MPMS, Chap. 5.3,	<i>Measurement of Liquid Hydrocarbons by Turbine Meters</i>
API MPMS, Chap. 5.8,	<i>Measurement of Liquid Hydrocarbons by Ultrasonic Flow meters Using Transit Time Technology</i>
API MPMS, Chap. 8.3,	<i>Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products</i>
API MPMS, Chap. 10.9,	<i>Standard Test Methods for Water in Crude Oils by Coulometric Karl Fischer Titration (corresponds to IP 386/99 and ISO 10337)</i>
API MPMS, Chap. 11.2.2M,	<i>Compressibility Factors for Hydrocarbons</i>
API MPMS, Chap. 12,	<i>Calculation of Petroleum Quantities</i>
API MPMS, Chap. 20,	<i>Allocation Measurement</i>
ASTM D1250-08,	<i>Standard Guide for the use of Petroleum Measurement Tables</i>
IP 386/99,	<i>Determination of water content of crude oil – Coulometric Karl Fischer method</i>
ISO 3171,	<i>Petroleum liquids – Automatic pipeline sampling</i>
ISO 5024,	<i>Petroleum liquids and liquefied petroleum gases – Measurement – Standard reference conditions</i>
ISO 7278-3,	<i>Liquid hydrocarbons – Dynamic measurement – Proving systems for volumetric meters – Part 3: Pulse interpolation techniques</i>
NFOGM	<i>Handbook of Water Fraction Metering</i>

2.3 Normative references – gas systems

AGA 7,	<i>Measurement of gas by turbine meters - AGA Transmission Measurement Committee Report No. 7.</i>
AGA 8,	<i>Compressibility factors of Natural Gas and other related hydrocarbon gases, AGA Transmission Measurement Committee Report No. 8.</i>
AGA 10,	<i>Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases</i>
ASTM D1945,	<i>Standard Test Method for Analysis of Natural Gas by Gas Chromatography</i>
ISO 5167-1,	<i>Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full – Part 1: General principles and requirements</i>
ISO 5167-2,	<i>Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full – Part 2: Orifice plates</i>
ISO 5167-4,	<i>Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full – Part 4: Venturi tubes</i>
ISO 6976,	<i>Natural gas – Calculation of calorific values, density, relative density and Wobbe index from composition</i>
ISO 9951,	<i>Measurement of gas flow in closed conduits - Turbine meters</i>
ISO 10715,	<i>Natural gas sampling guidelines</i>
ISO 12213-1,	<i>Natural gas – Calculation of compression factor – Part 1: Introduction and guidelines</i>
ISO 12213-2,	<i>Natural gas – Calculation of compression factor – Part 2: Calculation using molar-composition analysis</i>
ISO 17089-1,	<i>Measurement of fluid in closed conduits – Ultrasonic meters for gas – Meters for custody transfer and allocation measurement</i>
ISO 17089-2,	<i>Measurement of fluid in closed conduits – Ultrasonic meters for gas – Meters for industrial applications</i>
ISO TR 9464,	<i>Guide to the use of ISO 5167</i>

2.4 Informative references – hydrocarbon liquid systems

API MPMS, Chap. 4.1,	<i>Proving Systems Introduction</i>
API MPMS Chap. 5.6,	<i>Measurement of Liquid Hydrocarbons by Coriolis Meters</i>
API MPMS, Chap. 8.2,	<i>Automatic sampling of petroleum and petroleum products</i>

2.5 Informative references – hydrocarbon gas systems

AGA 11	<i>API MPMS Chap. 14.9, Measurement of Natural Gas by Coriolis Meters</i>
IEC 61285	<i>Industrial-process control – Safety of analyser houses</i>
ISO 6974-1,	<i>Natural gas – Determination of composition with defined uncertainty by gas chromatography – Part 1: Guidelines for tailored analysis</i>
ISO 6974-2,	<i>Natural gas – Determination of composition with defined uncertainty by gas chromatography – Part 2: Measuring-system characteristics and statistics for processing of data</i>
ISO 6974-3,	<i>Natural gas – Determination of composition with defined uncertainty by gas chromatography – Part 3: Determination of hydrogen, helium, oxygen, nitrogen, carbon dioxide and hydrocarbons up to C8 using two packed columns</i>
ISO 6974-5,	<i>Natural gas – Determination of composition with defined uncertainty by gas chromatography – Part 5: Determination of nitrogen, carbon dioxide and C1 to C5 and C6+ hydrocarbons for laboratory and on-line process application using three columns</i>
ISO 10723,	<i>Natural gas – Performance evaluation for analytical systems</i>
ISO 15970,	<i>Natural gas – Measurement of properties – Volumetric properties: density, pressure, temperature and compression factor.</i>

Handbooks of uncertainty calculation, including tools; issued by CMR, Norwegian Petroleum Directorate and NFOGM. (www.nfogn.no and <http://gasmetering.azurewebsites.net>)

3 Terms, definitions and abbreviations

For the purposes of this NORSOK standard, the following terms, definitions and abbreviations apply.

3.1 Terms and definitions

3.1.1

accreditation

official recognition to the effect that an organisation is operating in accordance with a documented quality assurance system and that it has demonstrated competence to carry out specified tasks

3.1.2

allocation

distribution of sold/produced quantities of hydrocarbons between owner groups and owner companies

3.1.3

allocation metering system

Metering system used for allocation of products between owner groups and owner companies

3.1.4

benchmark

point of reference by which analysis results can be compared

3.1.5

calibration

the process of adjusting the output or indication on a measurement instrument to agree with value of the applied standard, within a specified accuracy.

3.1.6

can

verbal form used for statements of possibility and capability, whether material, physical or casual

3.1.7

carrier gas

gas used to transport sample through the columns, normally helium, hydrogen or mixture of helium and hydrogen

3.1.8

column

tubes inside the temperature controlled oven of the online gas chromatograph packed with material suitable for separating the components of natural gas when flowing the sample through using carrier gas

3.1.9

custody transfer metering system

metering system used for sale from one party to another.

3.1.10

fiscal metering system

Metering system used for measurement of fluids for calculation of taxes and royalties. Refers to metering systems that is a point of a commercial transaction such as when change in ownership takes place

NOTE The term "fiscal " refers to the function of the measurement system, not its level of measurement uncertainty.

3.1.11

group of components

group of components with so low concentrations that their measurement as individual would be difficult or require excessive time

NOTE Hydrocarbons heavier than pentanes (denoted as C6+) is example of such a group.

3.1.12**in-line**

concept where the main pipe volumes flows through the in-line unit

3.1.13**may**

verbal form used to indicate a course of action permissible within the limits of this NORSOK standard

3.1.14**molar mass (M)**

a measure of the sum of the atomic weights of the atoms in a molecule

3.1.15**must**

verbal form used to indicate compulsion, obligation, requirement or necessity

3.1.16**online gas chromatograph calibration**

determination of the response of the detector for a given component with known concentration given on the certificate of the calibration gas or comparing the reading from online gas chromatograph with values given on the certificate of the calibration gas

3.1.17**prover unit**

conventional pipe prover, compact prover, master meter or other applicable method to calibrate the flow element

3.1.18**quantity**

measure of the hydrocarbon medium, by volume, mass or energy

3.1.19**shall**

verbal form used to indicate requirements strictly to be followed in order to conform to this NORSOK standard and from which no deviation is permitted, unless accepted by all involved parties

3.1.20**should**

verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred, but not necessarily required

3.1.21**standard gross volume**

oil volume at standard conditions including water

3.1.22**verification**

the process of establish the truth, accuracy or validity of something

3.2 Abbreviations

AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BIPM	International Bureau of Weight and Measure
CEN	The European Committee for Standardization
CMR	Christian Michelsen Research
EN	European Standard
IEC	International Electrotechnical Commission
IFCC	International Federation of Clinical Chemistry
ISO	International Organization for Standardization
IUPAC	International Union of Pure and Applied Chemistry
IUPAP	International Union of Pure and Applied Physics
MPMS	Manual of Petroleum Measurement Standard
M	molar mass
NFOGM	Norwegian Society for Oil and Gas Measurement
NPD	Norwegian Petroleum Directorate
NEA	Norwegian Environment Agency
OIML	International Organisation of Legal Metrology
P&ID	pipng and instrument diagram
Pt-100	platinum resistance thermometer
SI	International System of Units
IMS	Information Management System .

4 General requirements

4.1 Introduction

This Norsok standard shall be read in conjunction with the project specific metering requirements, the metering concept defined by Company and agreed with the national authority. Authority consent for metering concept, including expected uncertainty and cost benefit analysis are given through the plan for installation and operation of facilities for transport and utilization of the petroleum application process.

The measurement system which fulfils the functional and technical requirements and has the lowest life cycle cost shall be selected. For offshore installations, a compact design is encouraged to reduce space requirements and weight.

Measurement systems for hydrocarbon liquid and gas include all systems for

- sales and allocation measurement of liquid,
- water in oil measurement,
- oil sampling,
- sales and allocation measurement of gas,
- measurement of fuel and flare gas,
- gas sampling,
- gas chromatograph.

NOTE: Authority regulations exists regarding measurement/reporting of diesel. These requirements are not included in this Norsok standard.

For system with no system specific requirements in this NORSOK standard, the design shall, when standards are available, be based on the following (in order of priority):

- international standards (preferably ISO or CEN);
- the manufacturer's recommendations.

Additional specific project requirements not covered in this document shall be developed and included in the project specification. The project specific requirements shall ensure that the metering systems are suitable for the project specific frame conditions. Requirements that can be included in the specification are:

- flow rates and ranges;
- fluid properties;
- working environment;
- piping specification;
- material specifications;
- general weather protection;
- fire isolation / piping class;
- painting and surface treatment;
- spillage collection / drip tray;
- public address system;
- gas detectors;
- acoustic noise;
- lighting;
- blast load;
- lifting equipment;
- material handling;
- thermal expansion;
- process design.

Temporary required spool pieces for in line instruments for calibration, flushing, pre-commissioning or commissioning tasks may be part of delivery.

4.2 Documentation

For the purpose of documentation to authority, traceability and quality management the following shall be documented:

- flow calculation;
- detailed functional design specification and description;
- P&ID;
- general arrangement;
- flow meter sizing and pressure drop calculations;
- uncertainty analysis calculations;
- time lag time calculations for analyser systems;
- fast loop calculation;
- thermowell vibration calculation;
- factory acceptance test procedures;
- factory acceptance test report;
- geometrical dimensional report;
- critical parameters relating to electronics and transducers;
- installation effects which may affect flowmeter performance; such as acoustic noise and flow profile;
- material constants;
- prover sizing calculation;
- mixing calculation for liquid analyser and sampler systems;
- Spare Parts Interchangeability Records (SPIR);
- online GC test, documented according to annex F.

Sufficient documentation shall be available in order to perform an independent verification of calculations in the computer.

The vendor shall develop a functional specification for the computer part. This document shall clearly specify all functions and features, e.g. the applied algorithms, the sequences of the system, operator responses and error handling. Refer to clause 10 Computer Part for details.

Additional documents shall be developed according to project requirements.

4.3 Traceability

All instruments, field variables and geometrical dimensions used for fiscal calculations or comparison with fiscal figures shall be traceable calibrated to international/national standards and according to ISO 17025. Calibration by an accredited laboratory fulfils these requirements.

All geometrical dimensions used in fiscal calculations shall be traceable to international/national standards.

4.4 Units

All systems shall give readings and report in SI-units according to ISO 80000.

When generally used for the facility, the following apply:

- bar shall be used for presentation of pressure;
- °C shall be used for presentation of temperature;
- mPa·s shall be used for presentation of dynamic viscosity.

Reference conditions for hydrocarbon gas shall be 15 °C and 1,01325 bara. For calculation of gross calorific value (superior) and Wobbe index a combustion reference temperature of 25 °C and metering reference temperature of 15 °C shall be used.

Reference conditions for hydrocarbon liquids with a true boiling point at 15 °C lower than 1,01325 bara shall be 15 °C and 1,01325 bara as per ISO 5024.

Reference conditions for hydrocarbon liquids with a true boiling point at 15 °C higher than 1,01325 bara shall be 15 °C and the true boiling point pressure as per ISO 5024.

Liquefied petroleum gas measurement could use other reference conditions in accordance with recognized standards.

Flow rates shall be presented in quantity per hour.

Velocity shall be presented in meter per second.

Other units may be used for presentation if generally used in the process plant or otherwise specified.

4.5 Uncertainty

Uncertainty limit (95 % confidence level) for the measurement system and all components in the measurement system shall be according to the Norwegian Petroleum Directorate (NPD) measurement regulations and the regulations from the Norwegian Environment Agency (NEA).

Other uncertainty limits may be applicable for allocation metering systems due to sales, tie-in, processing or other agreements.

The measurement uncertainty shall be documented in accordance with ISO/IEC Guide 98-3:2008. NFOGM handbooks for uncertainty analysis is recognized method for uncertainty calculation.

4.6 Condition monitoring

The fiscal measurement systems shall be designed for fully automated condition monitoring. This includes the ability to automatically verify the current condition of all measured values that are of importance to the integrity of the fiscal measurement system. Monitored values are typically pressure, temperature, density, differential pressure, flow values, diagnostic parameters, level in sampling container (compared to calculated level).

The condition monitoring may be carried out using duplicated equipment or by other relevant method accepted by the customer.

Where required, comparative monitoring of parallel meter runs shall be carried out, i.e. when two or more meter runs are in operation.

5 System requirements

5.1 General

Metering systems shall be designed and tested such that systematic errors are avoided or compensated for.

It shall not be possible for fluids to bypass the metering system unnoticed or without measurement. Any bypass shall have double block and bleed valves and facilities to detect for possible leakages.

5.2 Capacity / availability / sizing / products and services

Capacity

The measurement system shall be capable of measuring the full range of planned quantities without exceeding the uncertainty limits for the system.

Availability

The measurement systems shall be designed for continuous measurement of all expected flow rates.

Flare gas measurements can be unavailable during transducer replacement.

Sizing

Metering systems shall be designed and calibrated to measure the expected maximum flow within the flow meters nominal design range.

Flare gas system shall be capable of measuring the design rate of gas through the measurement system.

The sizing of the meter station shall ensure that the pressure drop from inlet to outlet of the metering station does not exceed

- 1,5 bar during normal operation,
- 2,5 bar during calibration of the meters.

Products and services

All fluids shall be maintained in single phase. The operating pressure/temperature shall be maintained so that vaporisation of gas in liquid metering and condensation of liquids in gas metering is prevented in the metering station.

For 1st stage separator measurement gas systems it is recognized that process gas may contain liquids; hence flow meter shall be designed to tolerate presence of liquids without significant effect on the gas measurement.

For flare gas systems it is recognized that process gas may contain liquids; hence a reduced performance may be experienced for short periods.

5.3 Measurement systems with multiple meter runs

5.3.1 General

Use of parallel metering runs may be required by agreements, authority, regularity, turn-down requirements, restrictions in calibration facilities or by a risk evaluation.

NOTE: NPD measurement regulations require one spare meter run for a sales metering station.

The metering system may need facilities for pressurization of the metering system at high differential pressures across closed valves. A bypass arrangement for pressurization shall be provided as required. Remotely operated valves shall have interlocks to prevent opening at high differential pressures.

In automatic mode, the measurement system shall control opening and closing of meter runs that are in service mode, as required by the amount of flow being measured.

The meter runs shall have at least one remotely operated valve.

Health and safety requirements may specify additional needs for actuated valves.

Facilities for automatic or manual detection of leakage shall be provided for valves affecting the integrity of the metering system and for valves intended for maintenance during operation.

The selection of valves shall be subject to a multidiscipline evaluation in order to meet all relevant requirements.

5.3.2 Valves in gas metering systems

Gas metering run isolation valves shall have double block and bleed functionality in accordance with the project piping and valve specification. Be aware that for high pressure systems some high integrity valves may not satisfy double block and bleed barrier requirements as needed during maintenance.

5.3.3 Valves in liquid metering systems

High integrity double block and bleed valves and flow diverter valve in the prover unit shall be of a make and type suitable for liquid metering applications. Use of such valves shall be subject to prior approval by each project. Be aware that for high pressure systems some high integrity valves may not satisfy double block and bleed barrier requirements as needed during maintenance.

Block valves critical for meter calibration and calibration of prover unit, shall be of double-block-and-bleed type, shall have no contact with sealing during operation, and shall have positive shut-off (dual expanding seals).

Other types of valves may be considered for the stream inlet valves.

The leakage detection shall be by automatic or manual monitoring of block valves. There shall be automatic monitoring of the flow diverter valve in the prover unit.

The block valves for stream control and meter calibration control shall have automatically operated actuators with failsafe function "stay in position". Flow direction shall be clearly stated on valve bodies.

Remotely operated actuator shall be used, in addition the valves shall be equipped with limit switches for open and close position.

5.4 Measurement systems with single meter run

Use of single metering runs is preferred if supported by a cost benefit analysis, uncertainty analysis, risk evaluation and relevant authority acceptance.

Measurement systems with single meter run shall preferably have two flow meters in series to facilitate condition monitoring and provide redundancy.

This requirement is not applicable for flare gas meters. For fuel gas metering systems, reference is made to the section for fuel gas.

A single flow meter may be sufficient if documented and supported by a cost benefit analysis.

For metering stations consisting of a single metering run, valves may be part of the general process design and not included in the metering system.

5.5 Maintenance requirements

There shall be easy access to any part that requires calibration or maintenance.

It shall be possible to maintain and inspect the mechanical part of the system, including internal surface of the meter run, without dismantling the manifolds (or similar).

The need for weather protection for maintenance personnel depends on external conditions and maintenance / calibration strategy such requirements should be included in project specific requirements.

5.6 Drain / vent / relief and flushing connections

Sufficient quantity and correctly located vent, drain and flush connections shall be provided for all metering systems to ensure possibility for maintenance and/or replacement of inline components.

For metering stations consisting of a single metering run: vent, drain and flushing connections shall preferably be part of the general process design and not be included in the metering system.

Designs promoting entrapped pockets of liquid and sediments shall be avoided.

Vent, drain, relief and flushing connections shall not compromise the measurement integrity of the metering system. Spectacle blinds or double block and bleed arrangements shall be used to ensure integrity. Double block and bleed arrangements shall have facility to check for potential leakage. Interlock and lock arrangements to prevent maloperation shall be added as required when the metering station is put in operation unless otherwise agreed.

To ensure the integrity of liquid prover system, pressure relief valves shall not be located between the flow meter and the calibrated volume of the prover.

5.7 Thermal insulation

The metering tube and associated equipment shall be insulated upstream and downstream for a distance sufficient to prevent temperature changes affecting the instruments that provide input signals for the fiscal calculations.

Other requirements related to fire protection, technical safety, HSE, wax strategy, hydrate prevention may apply.

The insulation/heat trace shall be removable for test and field calibration of instruments in the measurement system.

Enclosures

If ambient conditions can affect the field instrumentation or its performance and functionality, then the instrument shall be sheltered by use of weather protection/protective shades, hoods or enclosures.

Instrument enclosures shall be in accordance with Norsok I-001.

5.8 General requirements for instrumentation

All instruments used in flow calculation shall be installed so that representative measurements are achieved as input for the fiscal calculations.

Pressure and temperature shall be measured in each of the meter runs.

Temperature shall be measured downstream of the flow meter.

For fiscal measurement applications; temperature measurement, differential pressure transmitters and pressure transmitters shall be installed in parallel for mutual surveillance, i.e. if the duty transmitter fails the hot stand-by shall be used automatically until the duty transmitter is repaired.

Pressure, temperature and differential pressure transmitters shall have an integrated local indicator displaying the measurement result.

Signal transmission from pressure, differential pressure and temperature transmitters shall be by digital communication. 4-20 mA signals may be used for non-fiscal measurements.

The transmitters shall automatically compensate for ambient temperature to avoid errors from temperature variation.

Transducers for ultrasonic meters shall be identified by serial number or similar to identify their location in the meter body. A report stating the transducers critical parameters shall be issued.

The electrical supply for field instrumentation used for fiscal measurement systems including the computer system, shall be powered from instrument panels supplied from uninterrupted power supply.

Hydrocarbon liquid

Pressure and temperature shall be measured at the inlet and outlet of a sphere prover unit.

If density measurement is required, density shall be measured by two densitometers.

For batch loading or hydrocarbon liquefied "product" systems, density may be determined based on representative sampling.

Displacer detector switches for sphere provers shall be of EEx d type, as intrinsic safe barriers may affect signal transfer.

Fiscal and allocation gas systems

Density shall be measured by densitometer or calculated based on input from the online gas chromatograph. Density determination shall be duplicated, either by:

- two densitometers; or
- one online gas chromatograph and one densitometer; or
- two online gas chromatographs.

When orifice meters are utilised, the upstream flange tap position shall be used for pressure measurement and the density shall be measured or calculated to the upstream flange tap condition.

For condition monitoring the metering system shall compare the results derived from the gas composition measured by a gas chromatograph with other measurements in the system:

- results from two gas chromatographs installed in parallel;
- density measured by a densitometer(s);
- velocity of sound measured by ultrasonic flow meter(s).

Fuel and flare

Density for fuel gas may be based on spot sampling and AGA 8 calculation (ref the NPD measurement regulations).

Density for flare gas may be based on indirect method utilizing measured velocity of sound.

5.9 Pressure and differential pressure measurements

For pressure and differential pressure transmitters the stability shall be equal or better than $\pm 0,1$ % of upper range limit for 12 months.

Pressure and differential pressure transmitters shall be installed according to Norsok I-001.

Sufficient instrument isolation valves shall be included in order to be able to perform calibration and removal of one transmitter with the other in operation.

The tubing length should be kept as short as possible.

For differential pressure transmitters, sufficient space shall be provided around transmitter to ensure access for torque wrench.

Instrument tubing for differential pressure transmitters should be kept symmetrical with respect to pipe/instrument interface, where tubing diameter changes and isolation valves are installed.

Flare gas systems static pressure shall be measured by absolute pressure transmitters.

For liquid; differential pressure measurement shall be installed across strainers.

5.10 Temperature measurements

For temperature transmitters the stability shall be equal or better than $\pm 0,1$ °C for 24 months.

The total uncertainty for the temperature measurement shall be better than 0,15 °C.

The Pt-100 element should as a minimum be in accordance with IEC 60751, tolerance Class A.

NOTE: Different flow meters require different downstream lengths in front of obstruction by thermowell.

The Pt-100 element and temperature transmitter may be installed as one unit where the temperature transmitter is head mounted onto the Pt-100 element (4-wire or 3-wire system), or separately mounted via a 4-wire system. Pt-100 element's curve-fitted variables shall be downloaded to the temperature transmitter before final calibration.

Unless limited by design requirements from the standards, all thermowells shall at least be inserted $\frac{1}{3}$ Internal pipe Diameters into the pipe, but less than $\frac{1}{2}$ Internal pipe Diameters. Thermowell vibration calculation shall be made according to ANSI/ASME PTC 19.3 TW.

The second thermowell shall be installed within 2 internal pipe diameters from the primary thermowell; care shall be taken not to install them in line; problem of vortex shedding can be minimized by spacing the thermowell radially around the pipe.

Thermowells shall be installed to allow for filling heat conducting material in the well.

Thermowells inner diameter suitable for elements of 6 mm should be used.

Thermowells shall be mounted in such a manner that the temperature element can be installed and removed from the well for maintenance.

5.11 Density

5.11.1 General

The measured density shall be corrected to the conditions at the fiscal measurement point. For density transmitters of by-pass type, temperature and pressure compensations shall be applied. The compensation shall be based on recognized methods.

Calculation of gas density from online gas chromatograph shall be based on AGA 8 or ISO 12213-2.

Model uncertainty in Z and/or uncertainty in pressure and temperature measurements may cause calculated density outside the NPD measurement regulations uncertainty requirement for gas density. The uncertainty in total flow rate may, however, still be within requirements.

An uncertainty analysis should therefore be performed and the need for densitometer should be clarified and agreed with the customer before the design documents are finalized for review.

5.11.2 Direct density measurement of hydrocarbon liquid

The density shall be measured by the vibrating element technique. There shall be direct transmission of densitometer pulses/frequency signal to the computer part or transfer of the measurement result by digital communication.

5.11.3 Direct gas density measurement of allocation and fiscal systems

The gas shall be in a measurable form at the density measurement point i.e. well above the hydrocarbon dew point. The density shall be measured by the vibrating element technique. Guidelines for installation are given in ISO 15970. The density shall be corrected to the conditions at the fiscal measurement point.

The transducer pulse/frequency signal shall directly or via smart communication be transmitted to the computer.

5.11.4 Density determination of fuel gas

Density shall be calculated by AGA 8 or ISO 12213-2, based on representative gas composition data. If the gas composition varies significantly, the density should be measured or calculated from an online gas chromatograph.

5.11.5 Density determination of flare gas

Density or M shall be estimated based on measured velocity of sound from the flare gas meter.

5.12 Spot sampling

All single phase metering stations (except flare metering stations) shall have a facility for manual spot sampling. The manual sampling point shall be suitable for sampling using a single piston, variable volume, constant pressure cylinder. The manual sample point shall be equipped with quick connectors / face seal

fittings for the sampling cylinder, valves, flare, vent and drain connections as required. The manual sampling point shall also have an arrangement where the sample cylinder can be placed during spot sampling.

The sampling probe shall be placed at a location where a representative sample will be obtained. A mixing device may be required.

Manual spot sampling shall be available also with automatic sampling/fast loop out of service.

6 Liquid measurement systems

6.1 General

The design shall be according to API MPMS Chap. 5. General considerations for measurement by meters shall be based on API MPMS Chap. 5.1. Symmetrical reducers/expanders shall be used between meter run strainer and flow meter. Sufficient upstream lengths of pipe shall be installed, including space to allow for necessary filters, strainers and flow conditioners.

If measurement system does not include proving capabilities, the installation and product effects caused by differences between calibration laboratory and operational conditions shall be documented. Extended testing with different fluids, piping configuration, pressure, temperature and density may be specified.

6.2 Turbine and positive displacement meters

Performance requirements for positive displacement meter shall be according to the measurement regulation for turbine meter.

There shall be dual pulse train with direct transmission of flow meter pulses from the turbine meter to the computer part.

The turbine meter rotor shaft shall be supported upstream and downstream of rotor. The rotor shall be hydrodynamically balanced between the supports.

Turbine meter design shall be according to API MPMS Chap. 5.3 and displacement meter design shall be according to API MPMS Chap. 5.3.

6.3 Ultrasonic meter

Ultrasonic meters shall be according to API MPMS Chap. 5.8 with the following clarifications:

- the number of paths for ultrasonic meters shall be determined by required uncertainty limit;
- the meter shall be designed and installed so that any accumulation in the form of gas or solid particles in the vicinity of the transducers is avoided;
- for the meter run, the minimum straight upstream and downstream lengths shall be according to API MPMS Chapt. 5.8, clause 9.1. Strainers may be required to protect associated equipment, including meter provers or pumps. It is not recommended to install strainers upstream the meter;
- ultrasonic meters may be used bi-directionally. For installation requirements, reference is made to API MPMS Chapt. 5.8, clause 7;
- gaskets between meter run and pipe section shall not protrude into the meter run;
- the ultrasonic flow meter shall be designed such that measurements of acceptable quality can be achieved when one transducer pair is out of service.

For the ultrasonic flow meter, critical parameters shall be determined. It shall be possible to verify the quality of the electric signal, which represents the acoustic pulse, by automatic monitoring procedures in the instrument or by connecting external test equipment.

6.4 Coriolis meter

Coriolis meter shall be designed according to ISO 10790. Informative reference is API MPMS Chapter 5.6. By selecting Coriolis flowmeter for metering applications, the type of meter must be suitable for the application and shall satisfy the NPD measurement regulations. Manufacturer recommendations must be carefully followed. For Coriolis meter with two parallel tubes, asymmetric distribution of flow through the meter shall be avoided. Coriolis meter shall include a pressure enclosure for the measuring tubes. Signal output to the flow computer should be flow pulses in mass flow unit.

Sizing and pressure drop

Special care shall be addressed to the selection of meter size in conjunction with process flow velocity and pressure drop across the meter.

Installation consideration

It must be possible to drain and remove the flowmeter for inspection, maintenance and calibration. Valves with leakage monitoring must be installed upstream and downstream the flowmeter to allow in line zero check. Piping system for meters in parallel must have a design that will give balanced flow between the parallel meter runs. The Coriolis meter must be installed according to the manufacturer recommendation to avoid liquid build-up, sediments, stress on metering pipe and disturbing vibration from external sources.

NOTE: If heat tracing is installed, special care shall be taken to avoid disturbances from electromagnetic inductance and heat radiation.

Process consideration

The process fluid must be in single phase condition.

6.5 Proving systems

Connections for in-situ calibration of volume provers shall be installed.

If master meters are used as prover, calibration of master meter may be performed in-situ or at external laboratory. If in-situ calibration is used, connections shall be provided.

It shall be possible to isolate the prover unit from the process for uninterrupted metering during calibration of the prover.

The prover shall be designed to calibrate the meter at the expected maximum flow rate.

API MPMS Chapter 4.1 is a general introduction to the subject of proving.

Conventional pipe prover

Three blinded connections with block valves shall be installed to enable serial calibration of the prover unit both with process fluid and with calibration fluid from a closed loop. The prover unit shall be calibrated before delivery from the manufacturer.

The prover shall be bi-directional or unidirectional, according to API MPMS Chap. 4.2 Interpolation may be used to achieve 0,01 % pulse resolution. The prover shall have four distinct, calibrated volumes with two detector switches at either end.

The prover shall be equipped with

- quick opening cover on displacer home chamber,
- specially designed flanges in pre-run/calibrated section.

The inner surface, rubber sealings, lining of prover, etc. shall be of a material that is compatible with and can withstand the oil flowing through.

In order to enable a reduced cycle time of four-way valve of large size, hydraulic actuators should be considered.

The design shall minimise dynamic forces during diverter valve operation.

Compact prover

The prover shall be designed in accordance with API MPMS Chap. 4.2.

Master meter

Master meter provers shall be designed in accordance with API MPMS Chap. 4.5.

Corresponding meter type requirements from the measurement regulations shall apply. A flowmeter used as master flowmeter has to perform significantly better with respect to linearity (30 %) than the type requirements given in §8 in the NPD measurement regulations.

6.6 Online water in oil

The water-in-oil meter shall automatically and continuously measure the percent of produced water by volume at line conditions. In addition the percent of produced water shall be calculated by volume at standard condition and on mass basis. The meter may be installed in-line (fullbore) or in a bypass. Recognised methods and requirements for water fraction metering are NFOGM Handbook for water fraction metering and ISO 3171.

The water-in-oil meter shall perform within the required uncertainty limits for the full turndown ratio of the measurement station.

The water-in-oil meter shall only be mounted in locations where there is a sufficiently well mixed flow-regime for the type of meter in use.

Vertical mounting will help to ensure adequate mixing. It should be assured that the meter is installed where the fluid velocity is sufficient. A mixing device may be installed upstream of the water-in-oil meter to ensure good mixing. The water-in-oil meter should be located as close as possible to the fiscal measurement station.

The water-in-oil meter shall automatically compensate for changes in process and/or ambient conditions influencing the accuracy of the meter, reference is made to process data sheet (project specific). For conversion calculations from flowing conditions to reference conditions, see Annex D.

It shall be possible to isolate the unit without interruption of metering during maintenance. The output values from the water-in-oil meter shall be transmitted by digital communication.

Version number shall identify the present software program version(s). Change of version number shall be implemented every time permanent program data is altered. It shall be possible to determine the present program version directly from a visual display unit and/or printouts.

The computer shall be prepared for check of sensor calibration against reference fluids.

7 Gas measurement systems for sales and allocation

7.1 General

The metering system shall not be installed in locations where any liquid may be accumulated.

Meter run and header design shall ensure adequately developed flow profile at the flow meter. This can be achieved when the cross sectional area of inlet manifold is, as a minimum, equal to the area of the meter runs in operation. For large measurement stations, placing the inlet pipe in the center of the manifold may reduce the inlet manifold diameter. This is valid unless it is verified and documented that the flow meter is not influenced by the layout of the meter runs and header in such a way that the overall uncertainty requirements are exceeded.

7.2 Orifice

The orifice meter runs shall be designed in accordance with ISO 5167-1 and ISO 5167-2 without additional uncertainty. If the measurement system has an inlet manifold, it shall be in the same plane as the meter tubes.

7.3 Ultrasonic

The ultrasonic meter shall be designed in accordance with ISO 17089-1 Class 1 with the following clarifications:

- For the meter run, the minimum straight upstream length shall be 15 internal pipe Diameters. The minimum straight downstream length shall be 3 Internal pipe Diameters. Flow conditioner of a recognized standard shall be installed 10 internal pipe diameters upstream the meter. If it is documented that the ultrasonic meter is not influenced by the layout of the piping upstream in such a way that the overall uncertainty requirements are exceeded, other designs based on computerized flow modeling or testing can be allowed.
- Ultrasonic meters may be used bi-directionally. In this case both ends of the meter shall be considered as upstream.
- The number of paths for ultrasonic meters shall be determined by required uncertainty limit.
- The meter shall be designed and installed such that any accumulation in the form of liquid or solid particles in the vicinity of the transducers is avoided.
- The ultrasonic flow meter shall be designed such that measurements of acceptable quality can be achieved when one transducer pair is out of service.
- For reduced bore meters, ISO 17089-1 specify special requirements for location of pressure tapping.

Ultrasonic flow meters shall not be installed in the vicinity of pressure reduction systems (valves etc.), which may affect the signals. Refer to ISO 17089-1 Clause 8.

It shall be possible to verify the quality of the electric signal, which represents the acoustic pulse, by automatic monitoring procedures in the instrument or by connecting external test equipment. All parameters relevant for verifying the condition of the meter shall be included in the self-check or be available for manual verification of the meter.

Signal output to the computer system should be flow pulses in unit actual volume.

7.4 Coriolis

Design consideration for gas coriolis meters is equivalent to liquid coriolis meters. Refer to subclause 6.4. Informative reference is AGA 11 / API MPMS Chapter 14.9.

7.5 Other types of meters

Project may specify other meters. Venturi meter runs shall be designed in accordance with ISO 5167-1 and ISO 5167-4 without additional uncertainty.

Flow calibration of venturi meters is required. AGA report no. 7 and ISO 9951 are recognized methods for gas turbine meters.

8 Fuel gas meter

8.1 General

The metering system shall not be installed in locations where liquid may accumulate. Continuous measurement of the gas flow shall be maintained during regular calibration of the field instruments and in case of failure of a single field instrument.

For single meter configuration, a bypass line shall be installed. The bypass line arrangement shall be designed to facilitate flow meter inspection and maintenance. When the system is in bypass mode, flow accumulation shall continue based on a user selectable flow, this is usually the last valid average flow(1h) prior to opening the bypass.

Alternatively two ultrasonic flow meters can be installed in series without bypass line.

Block valves

Isolation and bypass valve arrangement shall be of double block and bleed type with functionality for vent and leakage detection in accordance with the project piping and valve specification.

The bypass valve shall be equipped with limit switches, which shall trigger the bypass calculation routine.