



BSI Standards Publication

Measurement of multiphase fluid flow

National foreword

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Measurement of multiphase fluid flow





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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights. Details of any patent rights identified during the development of the document will be in the Introduction and/or on the ISO list of patent declarations received (see www.iso.org/patents).

Any trade name used in this document is information given for the convenience of users and does not constitute an endorsement.

For an explanation of the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT), see www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 28, *Petroleum and related products, fuels and lubricants from natural or synthetic sources*, Subcommittee SC 2, *Measurement of petroleum and related products*.

Any feedback or questions on this document should be directed to the user's national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

The need for multiphase flow measurement in the oil and gas production industry has been evident for many years. Multiphase meters have been developed since the early eighties by research organizations, meter manufacturers, oil and gas production companies and others: different technologies and various combinations of technologies have been employed. Some technologies have been abandoned, whereas other meters have become commercially available: the number of applications and users is increasing.

The first Norwegian Society for Oil and Gas Measurement (NFOGM) handbook of multiphase metering (hereafter simply called the Handbook) was published in 1995 (see Reference [16]). Since then, multiphase flow measurement has matured. New applications of multiphase flow meters (MPFMs) have emerged, from simply being a replacement for the conventional test separator shared by a number of wells, towards more compact and low-cost meters with application on a one-per-well basis and installations on shore, topside and subsea.

Since multiphase flow metering technologies and applications had developed significantly since 1995, NFOGM updated the Handbook in 2003-5 to reflect these improvements and to make it the main guide for state-of-the-art multiphase flow measurement. That work was financed by NFOGM and The Norwegian Society of Chartered Technical and Scientific Professionals (Tekna).

Following calls from industry to produce an ISO document, NFOGM very generously allowed ISO to use the Handbook as the basis for this document.

This document is intended to serve as guidance for users, designers and manufacturers of multiphase metering systems.

The document can also serve as an introduction to newcomers in the field of multiphase flow measurement, with definition of terms and a description of multiphase flow in closed conduits being included.

Even if the individual flow rates of each constituent are of primary interest, often their ratios (e.g. water liquid ratio, gas oil ratio) are useful as operational parameters. Total hydrocarbon mass flow rate can be required in particular applications. Constituents other than oil, gas and water flow rates or ratios of these are not dealt with in this document.

The performance of a multiphase flow meter in terms of uncertainty, repeatability and range is of great importance, as this enables the user to compare different meters and evaluate their suitability for use in specific applications. [Clause 8](#) covers this issue in detail and proposes standard methods to describe performance.

Testing and qualification of MPFMs are required to verify performance. Guidance is provided to help optimize the outcome of such activities. Since MPFMs measure at line conditions, the primary output is individual flow rates and fractions at actual conditions (i.e. at the operating pressure and temperature). Conversion of these actual flow rates to flow rates at standard conditions requires knowledge of composition and mass transfer between the liquid and the gas phases, which can require sampling.

The clauses logically proceed from an introduction to multiphase flow measurement, via selection of technology, design considerations and performance specifications, to field installation and commissioning, and finally the operation of MPFMs.

The definitions in [Clause 3](#) have been extended and split into definitions relating to multiphase flows in a closed conduit (see [3.1](#)) and definitions relating to metrology that can be useful in characterizing the performance of a multiphase flow meter.

[Clause 5](#) provides a general introduction to multiphase flows. This clause includes extended descriptions of flow regimes and slip effects in multiphase flows.

[Clause 6](#) covers the aims of multiphase flow measurement, giving the reasoning for selection, installation and operation of multiphase flow metering systems in various applications.

[Clause 7](#) presents guidelines for designing MPFM installations using the two-phase flow map and the composition map.

Standardized performance specification of MPFMs is essential, both for comparison of measuring ranges and measurement uncertainties, but also for more efficient selection of technology ([Clause 8](#)).

[Clause 9](#) covers all aspects of testing, calibration and adjustment of MPFMs.

[Clause 10](#) provides recommended procedures and practices for field installation and commissioning of MPFMs. Although MPFMs cannot easily be sent to a test facility for recalibration, there is a need for regular testing to verify the meter performance.

The purpose of [Clause 11](#) is to provide guidelines on how to verify meter performance in the field during operation, assuming no test separator is readily available.

[Annex A](#) includes brief descriptions of the most commonly used measurement principles in MPFMs currently available on the market. Guidance on selection of technology and maintenance requirements is also provided. [Annex B](#) gives relevant information on hydrocarbon phase behaviour.

Aspects of safety are not dealt with in this document. It is the responsibility of the user to ensure that the system meets applicable safety regulations.

Measurement of multiphase fluid flow

1 Scope

This document establishes a common basis for, and assistance in, the classification of applications and multiphase meters, as well as guidance and recommendations for the implementation and use of such meters.

The so-called in-line multiphase flow meters (MPFMs) that directly measure the oil, water and gas flow rates, as well as the partial- and full-separation MPFMs are the main focus of this document. Conventional two- or three-phase separators are not included in this document. Only limited reference is made to wet-gas meters, since although wet-gas flow is a subset of multiphase flow, wet-gas measurement is covered by ISO/TR 11583 and ISO/TR 12748.

2 Normative references

There are no normative references in this document.

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- ISO Online browsing platform: available at <https://www.iso.org/obp>
- IEC Electropedia: available at <http://www.electropedia.org/>

3.1 Terms related to multiphase flow metering

3.1.1

actual conditions

meter *in-situ* process operating conditions of pressure and temperature, at which measured flow rates are reported, without conversion to a standard or reference fluid state

3.1.2

composition map

graph with *gas volume fraction* (3.1.9) and *water liquid ratio* (3.1.42) along the x- and y-axis, respectively

Note 1 to entry: Both the GVF and WLR are at *actual conditions* (3.1.1).

3.1.3

dispersed flow

flow where a particular *phase* (3.1.23) is broken up into multiple small bubbles or droplets carried within the body of another phase

Note 1 to entry: Examples of such flows are bubble flow and mist flow.

3.1.4

emulsion

colloidal mixture of two immiscible fluids, one being dispersed in the other in the form of fine droplets

Note 1 to entry: In multiphase fluids, discrimination should be made between oil-in-water emulsion and water-in-oil (3.1.21) emulsion; they respond differently to permittivity measurements.

3.1.5

flow regime

dynamic spatial and velocity distribution of flowing fluid *phases* (3.1.23) within a conduit

Note 1 to entry: This is also known as flow pattern.

Note 2 to entry: For example, in two-phase oil/water stratified flow in horizontal pipes free water occupies the bottom of the conduit with *oil* (3.1.21) or oil/water mixture flowing above.

3.1.6

gas

hydrocarbons in the gaseous state at the prevailing temperature and pressure

3.1.7

gas oil ratio

GOR

ratio of *gas* (3.1.6) *volume flow rate* (3.1.38) and *oil* (3.1.21) *volume flow rate*

Note 1 to entry: Both volume flow rates should be converted to the same pressure and temperature [generally at *standard conditions* (3.1.35)]. GOR is expressed in volume per volume, F_{GOR} , e.g. scft/bbl or m³/m³.

3.1.8

gas void fraction

ratio of the cross-sectional area in a conduit occupied by the *gas* (3.1.6) *phase* (3.1.23) and the cross-sectional area of the conduit

Note 1 to entry: This is also known as gas hold-up.

3.1.9

gas volume fraction

GVF

gas (3.1.6) *volume flow rate* (3.1.38), relative to the multiphase volume flow rate, at *actual conditions* (3.1.1)

Note 1 to entry: The GVF is normally expressed as a fraction or percentage.

3.1.10

homogeneous multiphase flow

multiphase flow in which all *phases* (3.1.23) are evenly distributed over the cross section of a closed conduit

Note 1 to entry: A homogeneous multiphase flow is, therefore, one in which the composition is the same at all points in the cross section and where the liquid and *gas* (3.1.6) velocities are the same (no-slip). Note that bubbly multiphase *flow regimes* (3.1.5) are probably the best approximation to homogeneous multiphase flow.

3.1.11

intermittent flow

flow characterized by being non-continuous in the axial direction, that is, exhibiting unsteady *phase* (3.1.23) hold-up locally

Note 1 to entry: Examples of such flows are plug, churn and slug flow (see [Figures 1](#) and [2](#)): the *flow regimes* (3.1.5) are all hydrodynamic (see [5.1](#)) two-phase gas-liquid flow regimes.

3.1.12

liquid hold-up

ratio of the cross-sectional area in a conduit occupied by the liquid *phase* (3.1.23) and the cross-sectional area of the conduit

3.1.13**liquid volume fraction****LVF**

liquid volume flow rate (3.1.38), relative to the multiphase volume flow rate, at *actual conditions* (3.1.1)

Note 1 to entry: The LVF is normally expressed as a fraction or percentage.

3.1.14**Lockhart-Martinelli parameter****X**

square root of the ratio of the liquid inertia to the *gas* (3.1.6) inertia if the *phases* (3.1.23) flowed alone at *actual conditions* (3.1.1), that is

$$X = \frac{q_{V,\text{liquid}}}{q_{V,\text{gas}}} \sqrt{\frac{\rho_{\text{liquid}}}{\rho_{\text{gas}}}} = \frac{1-F_{\text{GVF}}}{F_{\text{GVF}}} \sqrt{\frac{\rho_{\text{liquid}}}{\rho_{\text{gas}}}}$$

where

$q_{V,\text{liquid}}$ is the volume flow rate of the liquid;

$q_{V,\text{gas}}$ is the volume flow rate of the gas;

ρ_{liquid} is the density of the liquid;

ρ_{gas} is the density of the gas;

F_{GVF} is the GVF.

Note 1 to entry: The Lockhart-Martinelli parameter has a long and complicated history. There are several different definitions for this parameter, and they are not equivalent. This includes the original definition by Lockhart-Martinelli which is different from the definition stated above. The definition supplied in this document is now commonly used. Nevertheless, this issue continues to cause confusion in the industry. The different definitions are described in detail with historical context in References [30] and [13].

Note 2 to entry: In the second formula above, the relationship of the Lockhart-Martinelli number and the *GVF* (3.1.9) is a function of the density ratio.

Note 3 to entry: An increasing value of *X* means an increasing liquid content or wetness of the flow.

3.1.15**mass flow rate**

mass of fluid flowing through the cross section of a conduit in unit time

3.1.16**measuring envelope**

areas in the *two-phase flow map* (3.1.37) and the *composition map* (3.1.2) in which the *MPFM* (3.1.18) performs according to its specifications

3.1.17**multiphase flow**

flow consisting of two or more *phases* (3.1.23) flowing simultaneously in a closed conduit

Note 1 to entry: This document deals in particular with multiphase flows of *oil* (3.1.21), water and *gas* (3.1.6) in the entire region of 0 % – 100 % of the GVF (3.1.9) and 0 % – 100 % of the WLR (3.1.42).

3.1.18
multiphase flow meter
MPFM

device for measuring the individual *oil* ([3.1.21](#)), water and *gas* ([3.1.6](#)) flow rates in a *multiphase flow* ([3.1.17](#))

Note 1 to entry: The total package of measurement devices for composition and velocity, including possible conditioning unit, should be considered as an integral part of the meter.

3.1.19
multiphase mixture velocity

ratio of the *multiphase volume flow rate* ([3.1.20](#)) and the cross-sectional area of the conduit

Note 1 to entry: This is a fictitious velocity: only in *homogeneous multiphase flow* ([3.1.10](#)) does this velocity have a meaningful value. Multiphase mixture velocity is the sum of *gas* ([3.1.6](#)) superficial velocity and liquid superficial velocity.

3.1.20
total volume flow rate
multiphase volume flow rate

total volume flowing through the cross-sectional area of a conduit per unit time

3.1.21
oil

hydrocarbons in the liquid state at the prevailing temperature and pressure conditions

3.1.22
oil-continuous flow

flow in which water is distributed as droplets surrounded by *oil* ([3.1.21](#))

Note 1 to entry: Electrically, the mixture acts as an insulator.

3.1.23
phase
one constituent in a mixture of several

Note 1 to entry: In particular, the term refers to *oil* ([3.1.21](#)), *gas* ([3.1.6](#)) or water in a mixture of any number of the three. It is recognized that the terminology of the multiphase industry is different from that in much of science.

3.1.24
phase area fraction

cross-sectional area locally occupied by one of the *phases* ([3.1.23](#)) of a *multiphase flow* ([3.1.17](#)), relative to the cross-sectional area of the conduit at the same local position

3.1.25
phase flow rate

amount of one *phase* ([3.1.23](#)) of a *multiphase flow* ([3.1.17](#)) flowing through the cross section of a conduit in unit time

Note 1 to entry: The phase flow rate may be specified as *phase volume flow rate* ([3.1.38](#)) or as *phase mass flow rate* ([3.1.15](#)).

3.1.26
phase volume fraction

phase ([3.1.23](#)) *volume flow rate* ([3.1.38](#)) of one of the phases of a *multiphase flow* ([3.1.17](#)), relative to the *multiphase volume flow rate* ([3.1.20](#)), at *actual conditions* ([3.1.1](#))

3.1.27
production envelope

areas in the *two-phase flow map* ([3.1.37](#)) and the *composition map* ([3.1.2](#)) that are determined by a number of well trajectories or specified as possible flow rates and compositions that occur in a certain application

3.1.28**proving**

set of operations that establish, under specified conditions, the relationship between the values of quantities indicated by a device and the corresponding values as determined by a traceable reference device (proving system)

3.1.29**reconciliation**

process whereby pieces of information that include some redundancy are matched together to satisfy constraint formulae

Note 1 to entry: In *oil* ([3.1.21](#)) and *gas* ([3.1.6](#)) production, reconciliation is the process in which oil, water and *gas* ([3.1.6](#)) production figures that have not been measured with high *accuracy* ([3.2.1](#)) are recalculated to match production figures that have been measured with high accuracy (e.g. custody transfer measurements).

3.1.30**reference conditions**

conditions, in terms of pressure and temperature, at which fluid properties or *volume flow rates* ([3.1.38](#)) are expressed

3.1.31**salinity**

amount of dissolved salts that are present in water

Note 1 to entry: Salinity is normally expressed in units g/kg.

Note 2 to entry: Sodium and chloride are the predominant ions in seawater, and the concentrations of magnesium, calcium, and sulfate ions are also substantial.

3.1.32**slip**

flow condition that exists when the *phases* ([3.1.23](#)) have different average velocities

Note 1 to entry: The slip may be quantitatively expressed by the average phase velocity difference between the phases. See [5.3](#).

3.1.33**slip ratio**

ratio between two phase-average velocities

Note 1 to entry: See [5.3](#).

3.1.34**slip velocity**

phase ([3.1.23](#)) velocity difference between two phases

Note 1 to entry: See [5.3](#).

3.1.35**standard conditions**

conditions, in terms of pressure and temperature, at which fluid properties or *volume flow rates* ([3.1.38](#)) are expressed

EXAMPLE 101,325 kPa and 15 °C.

3.1.36**superficial phase velocity**

quotient of the *phase* ([3.1.23](#)) *volume flow rate* ([3.1.38](#)) and the pipe cross-sectional area

3.1.37

two-phase flow map

graph with superficial velocities of *gas* (3.1.6) and liquid along the x- and y-axes, respectively

Note 1 to entry: An example is the Mandhane flow map (see Reference [37]) for horizontal *multiphase flow* (3.1.17).

Note 2 to entry: Alternatively, the actual *gas* (3.1.6) and actual liquid *volume flow rates* (3.1.38) can be used.

3.1.38

volume flow rate

volume of fluid flowing through the cross section of a conduit in unit time

3.1.39

water-continuous flow

flow in which *oil* (3.1.21) is distributed as droplets surrounded by water

Note 1 to entry: Electrically, the mixture acts as a conductor.

3.1.40

water cut

WC

water *volume flow rate* (3.1.38), relative to the total liquid volume flow rate [*oil* (3.1.21) and water], both converted to volumes at standard pressure and temperature

Note 1 to entry: The WC is normally expressed as a percentage.

3.1.41

water fraction meter

WFM

device for measuring the *phase* (3.1.23) area fraction of water of a *multiphase flow* (3.1.17) through a cross section of a conduit

Note 1 to entry: The *phase area fraction* (3.1.24) is expressed as a percentage of the total pipe area.

3.1.42

water liquid ratio

WLR

water *volume flow rate* (3.1.38), relative to the total liquid volume flow rate [*oil* (3.1.21) and water], at *actual conditions* (3.1.1)

3.1.43

water volume fraction

WVF

water *volume flow rate* (3.1.38), relative to the multiphase volume flow rate, at *actual conditions* (3.1.1)

Note 1 to entry: The WVF is normally expressed as a fraction or percentage.

Note 2 to entry: A small absolute *error* (3.2.4) in the value of the WVF may be a large relative error, e.g. where the measured and reference values of the WVF are 1 % and 0,5 % respectively, the absolute error is only 0,5 %, but the relative error is 100 %; in this example the measured water volume flow rate is twice the reference value although the absolute error is only 0,5 %.

Note 3 to entry: $F_{WVF} = F_{WLR} \times F_{LVF} = F_{WLR} \times (1 - F_{GVF})$

Note 4 to entry: where

F_{WVF} is the WVF;

F_{LVF} is the LVF;

F_{WLR} is the WLR.

3.1.44**well trajectory**

production profile of a well over time in a *two-phase flow map* (3.1.37) and *composition map* (3.1.2)

3.1.45**wet gas**

gas (3.1.6) containing free liquids

Note 1 to entry: Generally wet gases are defined as gas/liquid systems with a *Lockhart-Martinelli parameter* (3.1.14) lower than approximately 0,3.

Note 2 to entry: Hydrocarbon gas that contains heavy components that condense during further processing (but at a particular pressure and temperature, behaving as a pure gas) is not considered to be a wet gas from a measurement point of view.

3.2 Terms related to metrology**3.2.1****accuracy**

closeness of agreement between a measured quantity value and a true quantity value of a *measurand* (3.2.6)

Note 1 to entry: The concept ‘measurement accuracy’ is not a quantity and is not given a numerical quantity value. A measurement is said to be more accurate when it offers a smaller measurement *error* (3.2.4).

[SOURCE: JCGM-VIM:2012, 2.13]

3.2.2**adjustment**

set of operations carried out on a measuring system so that it provides prescribed indications corresponding to given values of a quantity to be measured

Note 1 to entry: Types of adjustment of a measuring system include zero adjustment of a measuring system, offset adjustment, and span adjustment (sometimes called gain adjustment).

Note 2 to entry: Adjustment of a measuring system should not be confused with calibration, which is a prerequisite for adjustment.

Note 3 to entry: After an adjustment of a measuring system, the measuring system must usually be recalibrated.

[SOURCE: JCGM-VIM:2012, 3.11]

3.2.3**calibration**

operation that, under specified conditions, in a first step, establishes a relation between the quantity values with measurement uncertainties provided by measurement standards and corresponding indications with associated measurement uncertainties and, in a second step, uses this information to establish a relation for obtaining a *measurement result* (3.2.11) from an indication

Note 1 to entry: A calibration may be expressed by a statement, calibration function, calibration diagram, calibration curve, or calibration table. In some cases, it may consist of an additive or multiplicative correction of the indication with an associated measurement *uncertainty* (3.2.13).

Note 2 to entry: Calibration should not be confused with *adjustment* (3.2.2) of a measuring system, often mistakenly called “self-calibration”, nor with verification of calibration.

Note 3 to entry: Often, the first step alone in the above definition is perceived as being calibration.

[SOURCE: JCGM-VIM:2012, 2.39]

3.2.4

error

measured quantity value minus a reference quantity value

[SOURCE: JCGM-VIM:2012, 2.16]

3.2.5

limiting condition

extreme operating condition that a measuring instrument or measuring system is required to withstand without damage, and without degradation of specified metrological properties, when it is subsequently operated under its *rated operating conditions* ([3.2.8](#))

[SOURCE: JCGM-VIM:2012, 4.10, modified — the term has been modified from 'limiting operating condition' to "limiting condition".]

3.2.6

measurand

quantity intended to be measured

[SOURCE: JCGM-VIM:2012, 2.3]

3.2.7

measuring range

set of values of quantities of the same kind that can be measured by a given measuring instrument or measuring system with specified instrumental measurement *uncertainty* ([3.2.13](#)), under defined conditions

[SOURCE: JCGM-VIM: 2012, 4.7]

3.2.8

rated operating condition

operating condition whose fulfilment during measurement enables the measuring instrument or measuring system to perform as designed

Note 1 to entry: Rated operating conditions generally specify intervals of values for a quantity being measured and for any influence quantity.

Note 2 to entry: An influence quantity is a quantity that, in a direct measurement, does not affect the quantity that is actually measured but affects the relation between the indication and the *measurement result* ([3.2.11](#)).

[SOURCE: JCGM-VIM:2012, 4.9, modified — the term and the definition have been combined with JCGM-VIM:2012, 2.52 and, thus, Note 2 to entry has been added.]

3.2.9

repeatability

measurement precision under a set of repeatability conditions of measurement

Note 1 to entry: A repeatability condition of measurement is a condition of measurement, out of a set of conditions that includes the same measurement procedure, same operators, same measuring system, same operating conditions and same location, and replicate measurements on the same or similar objects over a short period of time.

Note 2 to entry: A condition of measurement is a repeatability condition only with respect to a specified set of repeatability conditions.

[SOURCE: JCGM-VIM:2012, 2.21 — Notes 1 and 2 to entry have been added.]

3.2.10**reproducibility**

measurement precision under reproducibility conditions of measurement

Note 1 to entry: A reproducibility condition of measurement is a condition of measurement, out of a set of conditions that includes different locations, operators, measuring systems, and replicate measurements on the same or similar objects.

Note 2 to entry: The different measuring systems may use different measurement procedures.

Note 3 to entry: A specification should give the conditions changed and unchanged, to the extent practical.

Note 4 to entry: Relevant statistical terms are given in ISO 5725-1:1994 and ISO 5725-2:1994.

[SOURCE: JCGM-VIM:2012, 2.25, modified — Notes 1, 2 and 3 to entry have been added.]

3.2.11**measurement result**

set of quantity values being attributed to a *measurand* (3.2.6) together with any other available relevant information

Note 1 to entry: A measurement result is generally expressed as a single measured quantity value and a measurement *uncertainty* (3.2.13).

[SOURCE: JCGM-VIM:2012, 2.9]

3.2.12**systematic error**

component of measurement *error* (3.2.4) that in replicate measurements remains constant or varies in a predictable manner

[SOURCE: JCGM-VIM:2012, 2.17]

3.2.13**uncertainty**

non-negative parameter characterizing the dispersion of the quantity values being attributed to a *measurand* (3.2.6), based on the information used

Note 1 to entry: Measurement uncertainty includes components arising from systematic effects, such as components associated with corrections and the assigned quantity values of measurement standards, as well as the definitional uncertainty. Sometimes estimated systematic effects are not corrected for but, instead, associated measurement uncertainty components are incorporated.

Note 2 to entry: The parameter may be, for example, a standard deviation called standard measurement uncertainty (or a specified multiple of it), or the half-width of an interval, having a stated coverage probability.

Note 3 to entry: Measurement uncertainty comprises, in general, many components. Some of these may be evaluated by Type A evaluation of measurement uncertainty from the statistical distribution of the quantity values from series of measurements and can be characterized by standard deviations. The other components, which may be evaluated by Type B evaluation of measurement uncertainty, can also be characterized by standard deviations, evaluated from probability density functions based on experience or other information.

Note 4 to entry: In general, for a given set of information, it is understood that the measurement uncertainty is associated with a stated quantity value attributed to the *measurand* (3.2.6). A modification of this value results in a modification of the associated uncertainty.

[SOURCE: JCGM-VIM:2012, 2.26]

4 Symbols and subscripts

4.1 Symbols

For the purposes of this document, the symbols given in [Table 1](#) apply.

Table 1 — Symbols

Symbol	Quantity	Dimension	SI unit
A	area (to denote the cross-sectional area of the pipe the subscript 'pipe' may be used)	L^2	m^2
C	capacitance	$M^{-1}L^{-2}T^4I^2$	F/m
D	internal pipe diameter	L	m
F	reconciliation factor	—	—
F_{GVF}	gas volume fraction	—	—
F_{LVF}	liquid volume fraction	—	—
F_{WLR}	water liquid ratio	—	—
F_{WVF}	water volume fraction	—	—
g	acceleration due to gravity	LT^{-2}	m/s^2
I_A	current (electric)	I	A
q_c	count rate	—	—
q_V	volumetric flow rate	L^3T^{-1}	m^3/s
R	resistance	$ML^2T^{-3}I^{-2}$	Ω
t	time	T	s
U	percentage uncertainty	—	—
V	volume	L^3	m^3
v	velocity	LT^{-1}	m/s
v_m	multiphase mixture velocity ($v_m = v_{s,gas} + v_{s,liquid}$)	LT^{-1}	m/s
v_s	superficial velocity	LT^{-1}	m/s
X	Lockhart-Martinelli parameter	—	—
ε_r	relative permittivity (or dielectric constant)	—	—
λ_{gas}	gas void fraction	—	—
λ_{liquid}	liquid hold-up	—	—
ρ	density	ML^{-3}	kg/m^3
σ	conductivity	$M^{-1}L^{-3}T^3I^2$	S/m

NOTE The phase to which density or other quantity relates is shown by the subscript 'gas' or 'liquid'.

4.2 Colours and symbols used in schematic drawings

	gas	Ratio	Rate
	wet gas		 single-phase meter
	water		
	water/oil mixture		 dual-phase meter
	oil		



multiphase flow



multiphase meter



mixer

5 Multiphase flow

5.1 General

Multiphase flow is a complex phenomenon which is difficult to understand, predict and model. Common single-phase characteristics such as velocity profile, turbulence and boundary layer are thus not sufficient for describing the nature of such flows.

The flow structures are classified in flow regimes, whose precise characteristics depend on a number of parameters. The distribution of the fluid phases in space and time differs for the various flow regimes and is usually not under the control of the designer or operator.

Flow regimes vary depending on operating conditions, fluid properties, flow rates and the orientation and geometry of the pipe through which the fluids flow. The transition between different flow regimes may be a gradual process. The determination of flow regimes in pipes in operation is not easy. Analysis of fluctuations of local pressure and/or density by means of, for example, gamma-ray densitometry has been used in experiments and is described in the literature. In the laboratory, the flow regime may be studied by direct visual observation using a length of transparent piping. Descriptions of flow regimes are, therefore, to some degree arbitrary, and they depend to a large extent on the observer and his/her interpretation.

The main mechanisms involved in forming the different flow regimes are transient effects, geometry/terrain effects, hydrodynamic effects and combinations of these effects.

- Transients occur as a result of changes in system boundary conditions. This is not to be confused with the local unsteadiness associated with intermittent flow. Opening and closing of valves are examples of operations that cause transient conditions.
- Geometry and terrain effects occur as a result of changes in pipeline geometry or inclination. Such effects can be particularly important in and downstream of sea-lines, and some flow regimes generated in this way can prevail for several kilometres. Severe riser slugging is an example of this effect.
- In the absence of transient and geometry/terrain effects, the steady-state flow regime is entirely determined by flow rates, fluid properties, pipe diameter and inclination. Such flow regimes are seen in long straight pipes and are referred to as “hydrodynamic” flow regimes.

All flow regimes, however, can be grouped into dispersed flow, segregated-phase flow or intermittent flow, or a combination of these.

- Dispersed flow, is characterized by liquid droplets throughout a continuous gas phase or gas bubbles throughout a continuous liquid phase. Examples of such flows are mist flow and bubble flow ([Figure 2](#)).
- Segregated-phase flow, is characterized by a non-continuous phase distribution in the radial direction and a continuous phase distribution in the axial direction. Examples of such flows are stratified and annular ([Figure 2](#)).
- Intermittent flow, is characterized by being non-continuous in the radial and axial directions, and therefore exhibits locally unsteady behaviour. Examples of such flows are churn and slug flow ([Figure 1](#)).

5.2 Multiphase flow regime maps

5.2.1 General

[Figures 1](#) and [2](#) are general illustrations of the flow regimes and indicate where the various flow regimes occur. Physical parameters like density of gas and liquid, viscosity and surface tension affect the flow regimes and are not included in this graph. A very important factor is the diameter of the flow line: if the liquid and gas flow rates are kept constant and the flow line size is decreased from 4 in (100 mm) to 3 in (75 mm), both the superficial phase velocities (gas and liquid) increase by a factor 16/9. Hence, in the two-phase flow map the operational flow point moves up and right along the diagonal to a new position. This could cause a change in flow regime, e.g. changing from stratified to slug flow or changing from slug flow to annular flow. Multiphase flow regimes do not have sharp boundaries but instead change smoothly from one regime to another.

The flow pattern maps shown in [Figures 1](#) and [2](#) are not accurate tools for flow pattern prediction: [Figures 1](#) and [2](#) provide an illustration of the general trends only.

Most oil wells have multiphase flow in part of their pipework. Although pressure at the bottom of the well may exceed the bubble point of the oil, the gradual loss of pressure as oil flows from the bottom of the well to the surface leads to an increasing amount of gas escaping from the oil. The diagram in [Figure 1](#) is a qualitative illustration of how flow regime transitions are dependent on superficial gas and liquid velocities in vertical multiphase flow.

The parameter superficial velocity is often used on the axes of flow regime maps. For example, the superficial gas velocity ($v_{s,gas}$) is the gas velocity as if the gas was flowing in the pipe without liquids, in other words the total gas throughput ($q_{v,gas}$ at operating temperature and pressure) divided by the total cross-sectional area of the pipe (A). For the superficial liquid velocity, the same can be derived, and the simple expressions are given in [Formula \(1\)](#):

$$v_{s,gas} = \frac{q_{v,gas}}{A}; v_{s,liquid} = \frac{q_{v,liquid}}{A} \quad (1)$$

The sum of $v_{s,gas}$ and $v_{s,liquid}$ is the multiphase mixture velocity, and the expression is given in [Formula \(2\)](#):

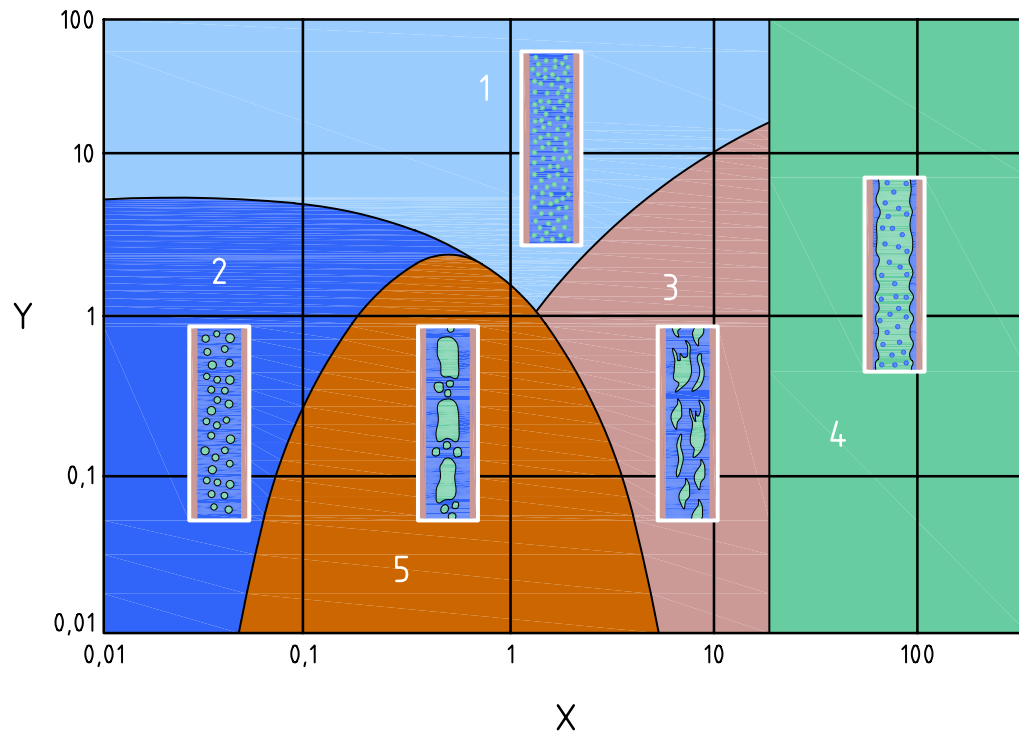
$$v_m = v_{s,gas} + v_{s,liquid} \quad (2)$$

However, the latter is a derived velocity and only has a meaningful value in homogeneous multiphase flow.

5.2.2 Vertical flows

The transitions in [Figure 1](#) are functions of factors such as pipe diameter, interfacial tension and density of the phases. [Figure 1](#) is a qualitative illustration of how flow regime transitions are dependent on superficial gas and liquid velocities in vertical multiphase flow. A map like this is only valid for a specific pipe and pressure and a specific multiphase fluid.

In vertical upward flows, the superficial gas velocity increases and the multiphase flow can change between regimes. Note that for some superficial gas velocities, the multiphase flow is annular for all superficial liquid velocities.



Key

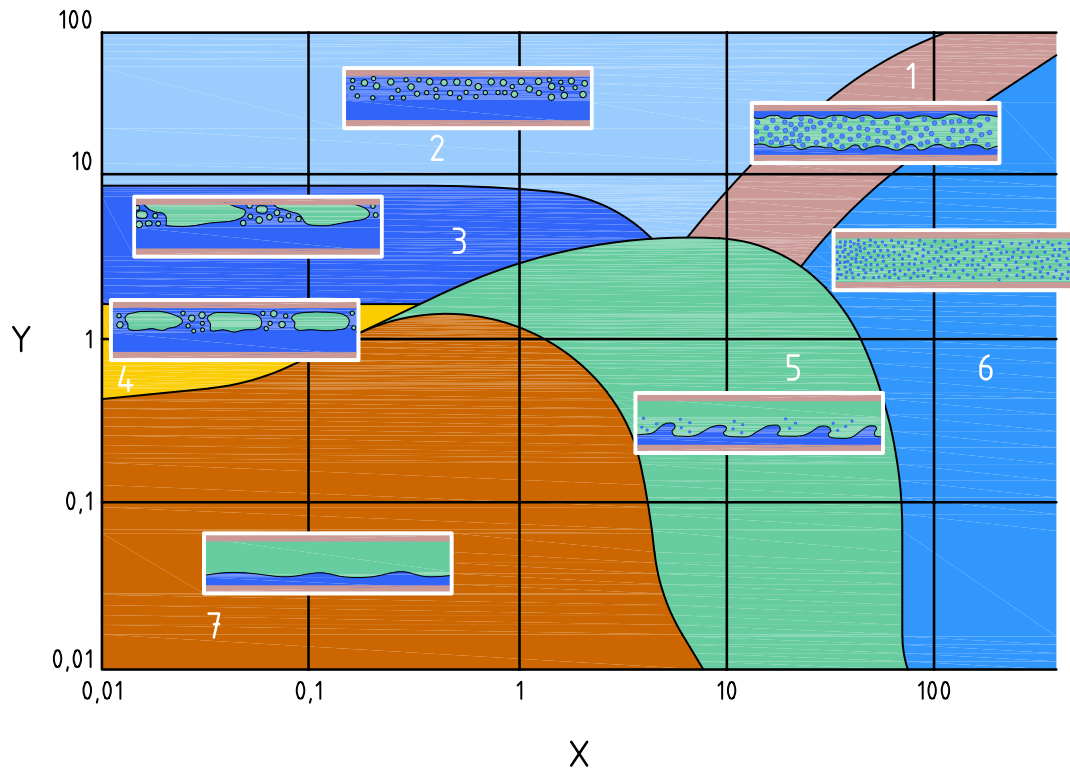
- X superficial gas velocity (m/s)
 Y superficial liquid velocity (m/s)
 1 finely dispersed bubble
 2 bubble
 3 churn
 4 annular
 5 slug

NOTE Superficial velocities are used along the axis.

Figure 1 — Generic two-phase vertical flow map

5.2.3 Horizontal flows

In horizontal flows too, the transitions are functions of factors such as pipe diameter, interfacial tension and density of the phases. [Figure 2](#) is a qualitative illustration of how flow regime transitions are dependent on superficial gas and liquid velocities in horizontal multiphase flow. A map like this is only valid for a specific pipe and pressure and a specific multiphase fluid.



Key

- X superficial gas velocity (m/s)
Y superficial liquid velocity (m/s)
- 1 annular
 - 2 bubble
 - 3 slug
 - 4 plug
 - 5 wave
 - 6 mist
 - 7 stratified

NOTE Superficial velocities are used along the axis.

Figure 2 — Generic two-phase horizontal flow map

5.3 Slip effects

When gas and liquid flow simultaneously in a pipe, the cross-sectional area covered by liquid generally is greater than it would be if the liquid and gas were moving at the same velocity, particularly in horizontal and upwardly inclined flows; this is due to bulk slippage between liquid and gas. The lighter gas phase normally moves faster than the liquid phase; the liquid has the tendency to accumulate in horizontal and inclined pipe segments. The liquid and gas fractions of the pipe cross-sectional area (A) as measured under two-phase flow conditions are known as liquid hold-up (λ_{liquid}) and gas void fraction (λ_{gas}): see [Formulae \(3\)](#) to [\(6\)](#).

$$\lambda_{\text{liquid}} = \frac{A_{\text{liquid}}}{A_{\text{pipe}}} \quad (3)$$

$$\lambda_{\text{gas}} = \frac{A_{\text{gas}}}{A_{\text{pipe}}} \quad (4)$$

$$\lambda_{\text{liquid}} + \lambda_{\text{gas}} = 1 \quad (5)$$

Similarly

$$F_{LVF} + F_{GVF} = 1 \quad (6)$$

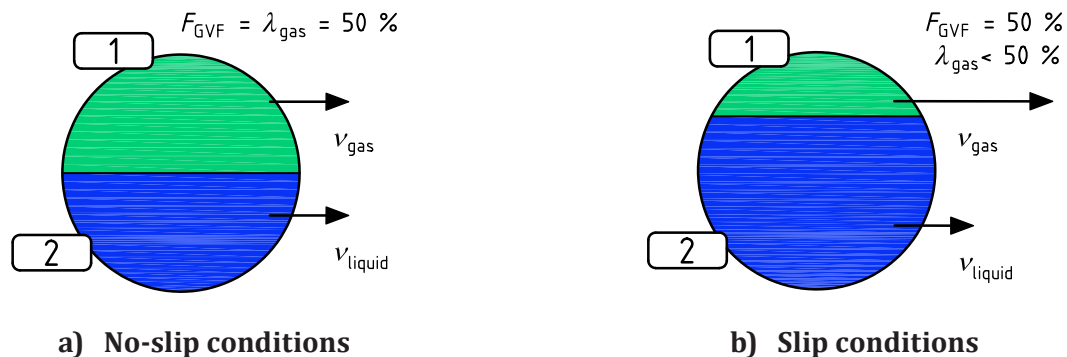
In the majority of flow regimes, the liquid hold-up is larger than the liquid volume fraction and the gas void fraction is smaller than the gas volume fraction (see [Figure 3](#)). These differences are due to slip and are particularly significant in horizontal and upwardly inclined flows. Liquid hold-up is equal to the liquid volume fraction (and gas void fraction equal to the gas volume fraction) only under conditions of no slip, when the flow is homogeneous and the two phases travel at equal velocities.

From the liquid hold-up and the actual phase velocities the superficial gas and liquid velocities can be calculated according to [Formulae \(7\) to \(9\)](#) (note that $v_{\text{gas}} \geq v_{\text{s,gas}}$).

$$\lambda_{\text{liquid}} \geq F_{LVF} \text{ and } \lambda_{\text{gas}} \leq F_{GVF} \quad (7)$$

$$v_{\text{s,gas}} = \frac{q_{\text{v,gas}}}{A_{\text{pipe}}} = \frac{q_{\text{v,gas}}}{A_{\text{gas}}} \cdot \frac{A_{\text{gas}}}{A_{\text{pipe}}} = v_{\text{gas}} \lambda_{\text{gas}} \quad (8)$$

$$v_{\text{s,liquid}} = \frac{q_{\text{v,liquid}}}{A_{\text{pipe}}} = \frac{q_{\text{v,liquid}}}{A_{\text{liquid}}} \cdot \frac{A_{\text{liquid}}}{A_{\text{pipe}}} = v_{\text{liquid}} \lambda_{\text{liquid}} \quad (9)$$



Key

- 1 gas
- 2 liquid

Figure 3 — Difference between gas void fraction and gas volume fraction

The slip ratio and slip velocity are also used in the field of multiphase flow fluid dynamics to quantify the phase slip.

5.4 Classification of multiphase flows

Another way to classify multiphase flow, apart from the classification according to the flow pattern, is by the GVF of the flow. This method of classification is relevant to multiphase metering; one would expect that a meter measuring predominately liquid with just a few percent gas would be significantly different from one designed to operate in what is generally understood as a wet-gas application. Four classes are defined in [Table 2](#).

Table 2 — Classification of multiphase flows

Class	Indicative GVF range	Comment
Low GVF	0–25 %	This low GVF range of multiphase flow can also be termed ‘gassy liquid’. In the lower end of this range, traditional single-phase meters can in many cases provide sufficient measurement performance. Increasing measurement uncertainty, and also the risk of damage or malfunction, should be expected as the GVF increases.
Moderate GVF	25 %–85 %	The moderate GVF can be considered as the ‘sweet spot’ of multiphase meters, i.e. the range where they have their optimum performance, and where traditional single-phase meters are not a viable option.
High GVF	85 %–95 %	Entering this high GVF range the uncertainty of multiphase meters starts to increase, with a rapid increase towards the upper end of the range, particularly for the liquid phases. This increase in uncertainty is not only linked to complex flow patterns but also occurs because the liquid measurement uncertainty increases as the liquid fraction, including the component of highest value (in this case the oil), decreases. In some cases, partial separation (see A.2.3.3) is used to move the GVF back into the moderate GVF range.
Very high GVF	95 %–100 %	This upper end of the multiphase range is termed the ‘wet-gas’ range. In the lower end of the very high GVF range, the measurement performance of in-line multiphase meters may still be sufficient for well testing, production optimization and flow assurance. For allocation metering, in particular at the high end of this range, often gas is the main ‘value’ component, and a wet-gas meter (see ISO/TR 11583 and ISO/TR 12748) is the preferred option. This corresponds to a Lockhart-Martinelli parameter (X) value in the range from 0 to approximately 0,3.

6 Aims of multiphase flow measurement

6.1 General

Conventional single-phase metering systems require the constituents or “phases” of the well streams to be fully separated upstream of the point of measurement. For production metering this requirement is usually met automatically at the outlet of a conventional process plant, since the main purpose of such a plant is to receive the sum of well streams in one end and to deliver (stabilized) single phases ready for transport (and hence also measurement) in the other end. Single-phase metering systems normally provide high-performance measurements of hydrocarbon production.

The need for multiphase flow metering arises when it is necessary or desirable to meter well stream(s) upstream of inlet separation and/or commingling. Multiphase flow measurement technology may be an attractive alternative since it enables measurement of unprocessed well streams very close to the well. The use of MPFMs may lead to cost savings in the initial installation. However, owing to increased measurement uncertainty, a cost-benefit analysis should be performed over the life cycle of the project to justify its application.

MPFMs can provide continuous monitoring of well performance and thereby better reservoir exploitation/drainage. However, this technology is complex and has its limitations; therefore care should be exercised when planning installations that include one or more MPFMs. One of the limitations of multiphase measurement technology is the uncertainty of the measurement. The main source for these higher measurement uncertainties of MPFMs in comparison with single-phase metering systems is the fact that they measure unprocessed and far more complex flows than what is measured by single-phase measurement systems.

A second limitation in a multiphase application is the possibility to extract representative samples. Whereas samples of the different fluids are readily captured from, for example, the single-phase outlets

of a test separator, no standard or simple method for multiphase fluid sampling is yet available. Since most MPFMs on the market need some kind of *a priori* information about the properties being measured (like densities, oil permittivity and/or water conductivity/salinity), this information should be made available and be updated on a regular basis.

A number of different MPFMs are available on the market, employing a great diversity of measurement principles and solutions (see [Annex A](#) and [Clause 8](#)). Outputs vary between MPFM designs, e.g. there can be gas, oil, and water mass or volume flow rates, total hydrocarbon mass flow, GVF, WLR, WVF. As there are different designs, calculation routines (slip models) and different outputs, it is not always straightforward to compare MPFMs directly. Different MPFMs are optimized to give minimum uncertainty to different outputs. One MPFM may be optimized to see water breakthrough (for flow assurance requirements) with a relatively poor flow rate prediction. Another may be optimized to predict total hydrocarbon flow to minimum uncertainty (for allocation requirements) with a relatively poor water breakthrough indicator performance. Thus, some MPFMs perform better in certain applications than others. Hence, a careful comparison and selection process is required to determine the optimal MPFM procurement and installation option for each specific application.

In selecting the optimal multiphase flow metering technology for a specific application, it is necessary first to investigate and describe the expected flow regime(s) from the wells to be measured and determine the production envelope (see [Clause 7](#) for more information about production envelopes). Subsequently it should be assessed whether there exist MPFMs with a corresponding measuring envelope making them suitable for the purpose of measuring the well streams in the specific application. Exploration/reservoir samples or well production forecasts can be used in these considerations, and a useful aid in selection of MPFMs is to use the two-phase flow and composition maps described in this document (see [Clause 7](#)).

The next step is to select an MPFM that is capable of continuously measuring the representative phases and volumes within the required uncertainties. The well stream flow rates vary over the lifetime of the well, and it is important to ensure that the MPFM measures within the required uncertainty at all times. Alternatively, the MPFM may be required to be exchanged at some later stage in the production life. This is an important issue to consider when deciding upon the sizing of the MPFM.

Careful selection of the type of MPFM is not the only important factor. In addition, the installation should include adequate auxiliary test facilities to allow calibration (and, if needed, adjustment) and verification during operation to ensure confidence in the measurements over the well lifetime (see [Clauses 9, 10 and 11](#)). If such periodic verification of the MPFM is not carried out, increased measurement uncertainty should be expected. Simple testing may be performed with a static measurement. More extended testing may be carried out by comparing the MPFM flow rate and WLR/GVF measurements against a test separator (static or transportable) or by other means (e.g. tracer methods). The extent of such regular testing depends on the criticality of the application and operation.

There are many possible applications for MPFMs. Owing to the higher measurement uncertainties, it is generally not recommended to use a multiphase flow meter to replace a high accuracy fiscal measurement; however, MPFMs are now being used in some cases of marginal field developments where the cost of processing facilities and metering downstream of separation cannot be justified.

Some general types of applications are briefly described in the next clauses:

- individual-well surveillance or monitoring;
- production optimization;
- flow assurance;
- well testing;
- production allocation metering;
- fiscal or custody transfer measurements.

Since this document is intended to be a guide for users, or potential users, of MPFMs in the oil and gas production industry, application areas in other industries are not included.

6.2 Individual-well surveillance or monitoring

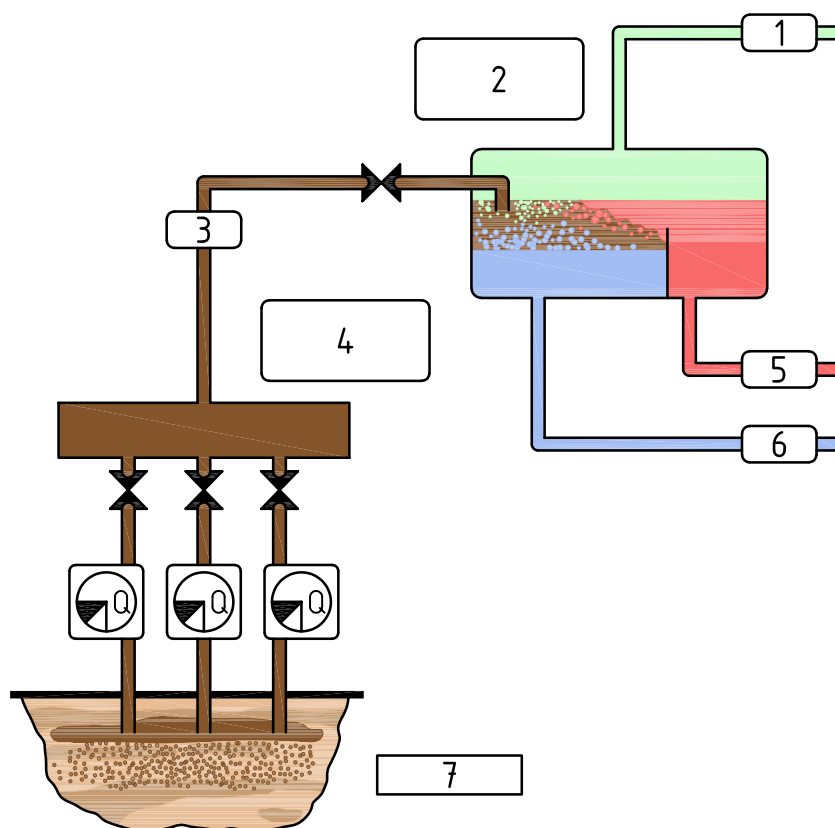
6.2.1 General

Using continuous monitoring with an MPFM, the time resolution of the information is higher than using random well testing with a test separator. Using an MPFM instead of a separator may therefore reduce the total uncertainty in well data, even if instantaneous phase flow rates are measured with increased uncertainty, while changes in performance between tests are not recorded by separators.

Access to continuous high-resolution data from an MPFM may be a valuable resource in various decision processes, for example in connection with well overhauls.

Installing a new MPFM can save space, weight and cost compared with the installation of a new test separator, and it can reduce the time occupation of existing test separators.

[Figure 4](#) shows the use of MPFMs on the flow line of each of a group of wells replacing a test separator and its instrumentation.



Key

- 1 gas
- 2 first stage separator
- 3 multiphase
- 4 production manifold
- 5 oil
- 6 water
- 7 oil wells

Figure 4 — MPFMs on the flow line of each well replacing test separator and its instrumentation

Well instability is a well-known problem during decline of production, and in many cases it is not acceptable that the well is connected to the production installation before some degree of control has been achieved. It may be difficult to detect variations in flow rates from unstable wells (gas-lifted wells for instance) using conventional separators, and in such situations MPFMs become a useful tool for the production engineer.

MPFMs may be considered useful for — or even an integral part of — subsea installations. In cases of subsea commingling and/or long flow lines (several kilometres), MPFMs may be used to monitor flow rate from individual wells or flow lines. It should be noted, however, that retrieval of an MPFM for maintenance or repair may be expensive, difficult or impossible. *In situ* calibration is normally not available, and other, less direct, verification methods may be required to be devised. Reliability and stability of subsea meters are of paramount importance and need to be addressed by the manufacturer of the MPFM, the subsea system integrator and the operator.

6.2.2 Production optimization

Production from oil wells may be assisted by gas lift for several reasons. Once gas lifting has been implemented it is required to optimize the gas-lift process (neither too much nor too little gas for lifting is economical, and there is a clear optimum for the amount of lift gas to be used to maximize the oil production). MPFMs can be of help in finding the optimum gas-lift injection rate as they are capable of instantaneously showing the oil flow rate as a function of injection gas flow rate. Conventional test separators would need more time to provide the same information. However, most gas-lift operations are relatively high GVF applications (adding even more gas to the system) and care should be taken that the MPFM is capable of handling this high GVF operation. Alternatively, a wet-gas meter could be used.

Other similar optimization considerations can be made for chemical injection, gas coning detection and water breakthrough detection.

6.2.3 Flow assurance

Flow assurance includes all aspects that are relevant to guarantee the flow of oil and gas from reservoir to the sales or custody-transfer point. It often involves facility engineers, production technologists and operations staff, and they evaluate and study the hydraulic, chemical and thermal behaviour of multiphase fluids. By more frequent (or continuous) measurement with MPFMs, it may be possible to identify potential blockages in the production system (e.g. hydrates, asphaltenes, wax, sand, scale). Often the trending here is more important than providing numbers with absolute accuracy. In other words, reproducibility, for a flow assurance type of application, is often more important than absolute accuracy.

6.3 Well testing

6.3.1 General

There is a need to monitor the performance of each individual well in order to optimize well production and the lifetime of the field. For many fields important decisions (e.g. shutting down of wells, drilling of new wells and reducing production rate from the reservoir) are based on well-test results.

Well testing is widely carried out by use of a test separator. An MPFM may be applied as a replacement for, or a supplement to, a test separator if:

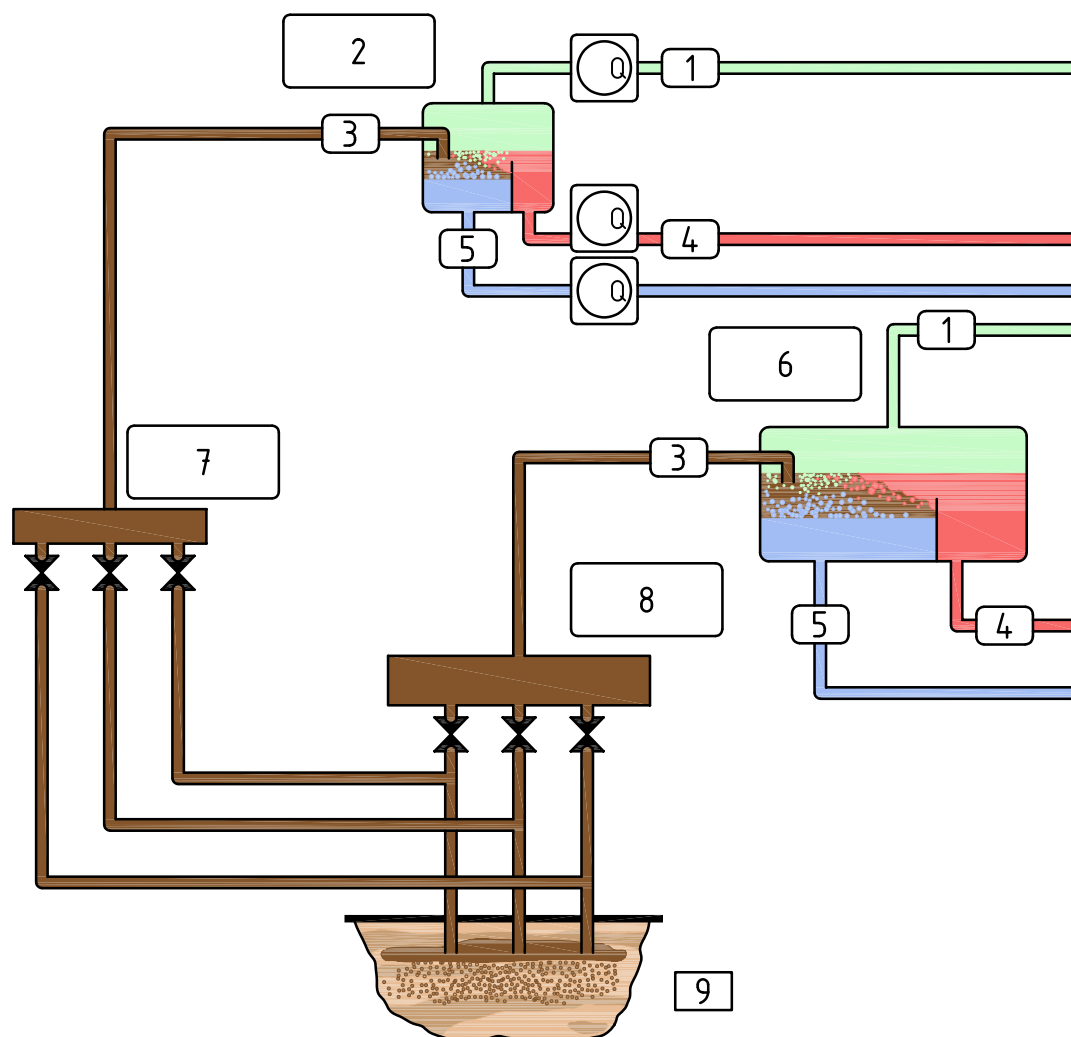
- it is decided not to install a test separator in the processing plant;
- there is a need to increase the capacity for well testing, or
- the test separator is left to other use, e.g. as an ordinary production separator (low pressure).

NOTE A test separator can also be used for purposes other than well testing and hence can be installed in any case.

An MPFM may give a higher or lower uncertainty of the phase flow rates than a test separator system, depending on the application considered. The response time of an MPFM, however, is significantly less (minutes) than that of a separator (hours), and more well tests may be carried out using the MPFM.

6.3.2 Conventional well testing

Conventional well testing is usually performed by means of a test separator. The well streams are measured by directing one well stream at a time through the test separator (see Figure 5). The well stream being tested is then separated into three “phases”: high vapour-pressure oil, gas and water, which are then measured by means of single-phase instrumentation at the outlets of the separator.



Key

- 1 gas
- 2 test separator
- 3 multiphase
- 4 oil
- 5 water
- 6 first stage separator
- 7 test manifold
- 8 production manifold
- 9 oil wells

Figure 5 — First-stage production separator and test separator

Today, a test separator can be designed with meters and instrumentation that are capable of measuring the gas phase with an estimated uncertainty better than 5 %, potentially as low as 2 % and 1 % for the water and oil phases, respectively, if effort is made to optimize the instrumentation and the separation is ideal.

During a well test, certain parameters such as choke opening, wellhead flow pressure, and separator pressure and temperature are recorded. Fluid samples are normally also captured at the test separator during these tests. Each well may be tested at one or more settings of the well's choke. For each choke setting, all the corresponding measurements are recorded.

The recorded information is used until the next well test is performed to calculate the theoretical contribution made by the well to the commingled output stream of the entire processing facility.

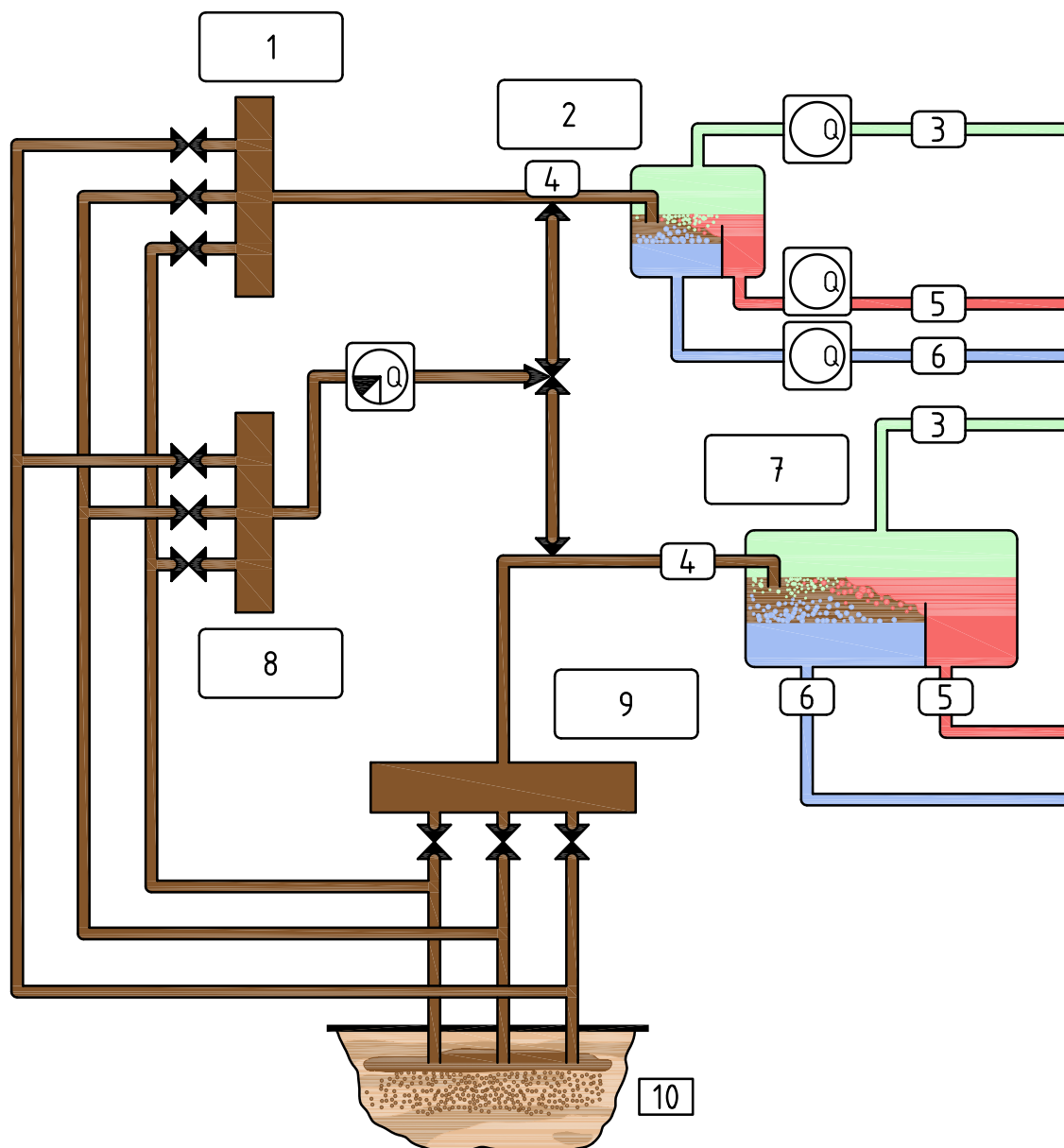
For wells where daily control is needed, for example to keep wells stable or to produce at optimum flow rates in order to utilize the full capacity of the production facilities, this conventional system may not be satisfactory.

6.3.3 Well testing by MPFMs

MPFMs may be installed and used in the same way as the test separator. If an MPFM is installed in addition to an existing test separator, this arrangement provides an increased flexibility.

There are two options: either both the test separator and the MPFM are used for well testing to increase the overall testing capacity, or only the MPFM is used for well testing and hence the test separator can be used as a normal production separator and thereby the total production capacity of the processing facility is increased (see [Figure 6](#)).

The main advantage of the MPFM over the test separator is the reduction in time to perform a measurement. While the separator must be allowed to fill and stabilize when changing wells for test, the MPFM responds more quickly to changes in the well fluids and needs less time to stabilize.



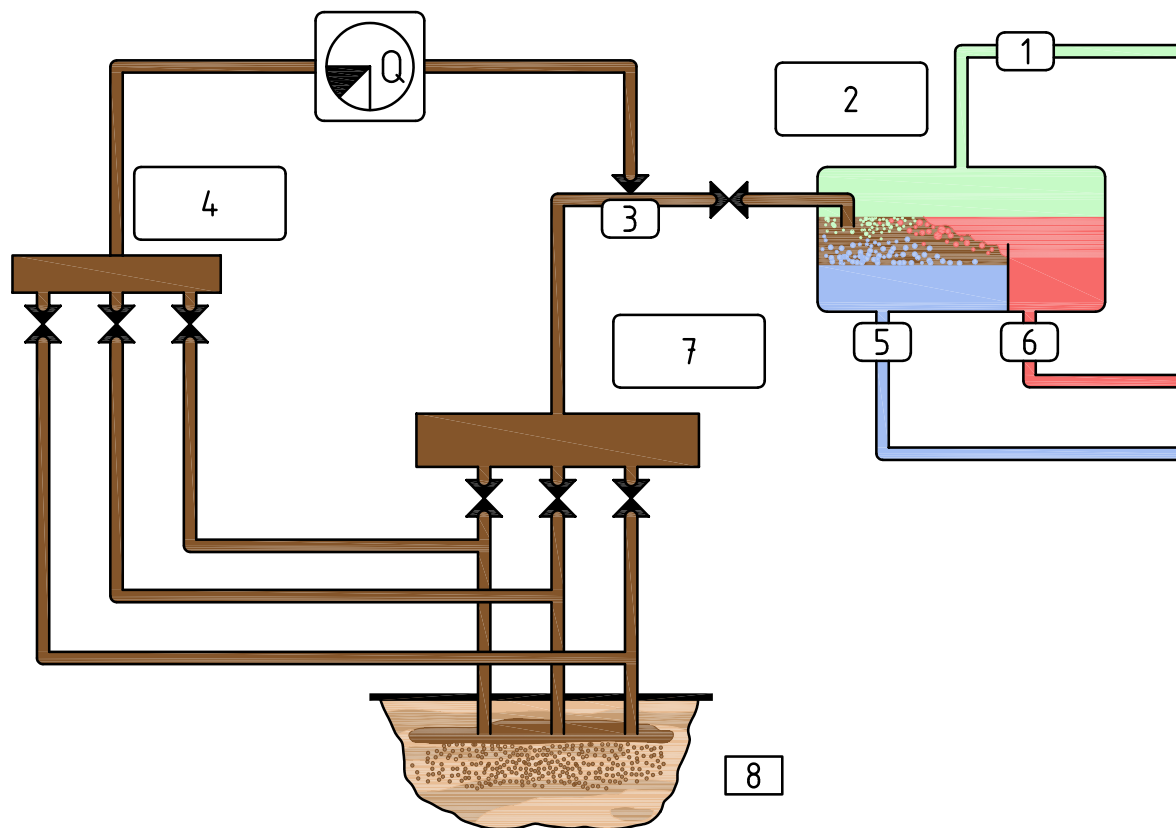
Key

- 1 test manifold 1
- 2 test separator
- 3 gas
- 4 multiphase
- 5 oil
- 6 water
- 7 first stage separator
- 8 test manifold 2
- 9 production manifold
- 10 oil wells

Figure 6 — Multiphase metering used to increase overall testing capacity

The MPFM might also replace the test separator completely (see [Figure 7](#)). This may be a solution for fields in the decline phase where the production from the well does not match the size of the test separator any more.

By using the two-phase flow map and the composition map, described in [Clause 7](#), it is possible to evaluate whether there is a need for more than one MPFM to test all wells, i.e. whether several MPFMs with different sizes and measurement ranges are required to cover all wells to be tested.



Key

- 1 gas
- 2 first stage separator
- 3 multiphase
- 4 test manifold
- 5 water
- 6 oil
- 7 production manifold
- 8 oil wells

Figure 7 — Multiphase metering replacing test separator and its meters

6.4 Production allocation metering

For production allocation measurements, stronger requirements in terms of measurement uncertainty, calibration of instruments and representative fluid sampling are usually imposed than those required for well testing.

A possible marginal-field solution for an unmanned wellhead platform is to have MPFMs on each individual well for well surveillance and to measure the main tie-in stream (into a manned installation) using a multiphase meter that is frequently “proved” to provide K-factors by a test separator equipped with measurement equipment to a fiscal standard. Long proving periods should be used to minimize uncertainties due to, e.g. slugging, when accumulated oil, water and gas flow rates measured by the MPFM are compared with the separator measurements, and in some cases proving should last for days. In this application the measurement of each well stream by means of MPFMs is replacing the