

Manual of Petroleum Measurement Standards Chapter 20.3

Measurement of Multiphase Flow

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Introduction

This standard addresses how the user measures multiphase flow rates of oil, gas, and water present in the production stream.

This document does not describe allocation or well testing methods. Refer to API *MPMS* Chapter 20.1 for direction on allocation methods and API *MPMS* Chapter 20.5 for direction on well testing.

This document does not describe the flow loop testing protocols or methods. Refer to API *MPMS* Chapter 22.7, *Flow Loop Testing Protocols*.

In this document, the use of multiphase metering systems is focused on the role they can play in production measurement and allocation applications. However, there are numerous other instances in which they can be extremely helpful. To preserve the focus on production measurement and allocation, these other instances will not be discussed in any depth.

Measurement of Multiphase Flow

1 Scope

This document addresses inline multiphase flow measurement in the production environment, upstream of the custody transfer (single-phase) measurement point, where allocation measurement for onshore, offshore, or subsea is applied. For other multiphase flow measurement applications such as reservoir management, well tests, and flow assurance, the standard can be used as a reference or guide. However, the focus of this standard is on those applications where the accuracy of multiphase flow measurement for allocation systems is required.

This document refers to existing standards and recommended practices to supplement the guidance it provides in this subject area. The document addresses principles used in multiphase flow measurement, multiphase metering types and classifications, assessment of expected performance, and selecting and operating multiphase measurement systems. Operational requirements or constraints are addressed, including expectations for flow meter acceptance, calibration criteria, flow loop and in situ verifications, and other guidance specific to different multiphase flow metering applications. The document does not address specific meter configurations.

2 Normative References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

API Recommended Practice 17S, *Design, Testing, and Operation of Subsea Multiphase Flow Meters*

API MPMS Chapter 20.5, *Recommend Practice for Application of Production Well Testing in Measurement and Allocation*

API MPMS Chapter 22.7, *Flow Loop Testing Protocol*

3 Terms, Definitions, Abbreviations, and Symbols

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply. The definitions for many terms used in this document can be found in ISO/IEC Guide 98-3:2008 ^[13] unless specified otherwise.

3.1.1

actual conditions

Line conditions, flowing conditions, conditions of pressure and temperature of the fluid at the point where fluid properties or flows are measured or calculated.

3.1.2

allocation

The mathematical process of determining the proportion of produced fluids from individual entities (zones, wells, fields, leases, or producing units) when compared with the total production from the entire system (reservoir, production system, and gathering systems) to determine value or ownership to attribute to each entity.

3.1.3

allocation measurement

Measurement systems and procedures required to perform a fair and equitable allocation.

NOTE Such systems and procedures may not meet full custody transfer standards of measurement while still being sufficient for allocation purposes.

3.1.4

calibration

A set of operations which establish, under specified conditions, the relationship between the values indicated by a measuring device and the corresponding known values indicated when using a suitable measuring standard.

3.1.5

commingle

To combine the production streams from two or more wells, units, leases, production zones, or production facilities into common vessels or pipelines.

3.1.6

conductivity

The ability of a material to conduct electrical current. In isotropic material conductivity is the reciprocal of resistivity. Sometimes called specific conductance in units of Siemens/m or S/m.

3.1.7

emulsion

A suspension of fine particles or globules, or both, of one or more liquids in another liquid.

3.1.8

factory acceptance testing (FAT)

A series of functional tests and inspections that are performed by the manufacturer or third-party test facility prior to equipment acceptance. FATs are intended to demonstrate and verify that the equipment meets design and manufacturing specifications.

3.1.9

fiscal

Of or relating to financial matters. With respect to measurement, those that have a financial impact on custody transfer, allocation, royalty, or taxation.

3.1.10

fiscal measurement

Measurement systems and procedures that are required to determine a quantity that may be expected to have a direct financial impact to affected parties. As with custody transfer, allocation, or royalty measurement.

3.1.11

flow regime

The physical geometry exhibited by a multiphase flow in a conduit, the geometrical distribution in space and time of the individual phase components, i.e. oil, gas, water, any injected chemicals. For example, liquid occupying the bottom of a horizontal conduit with the gas phase flowing above.

3.1.12

Froude number

The ratio of the square root of the inertial force divided by the square root of the gravitational force for a particular phase.

$$F_r = v/(gd)^{1/2}$$

3.1.13

gas-oil ratio (GOR)

The ratio of gas volume flow rate to the liquid hydrocarbon volume flow rate at any point, expressed at standard conditions, usually in standard cubic feet per barrel (scf/bbl) or standard cubic meters of gas per cubic meter of liquid hydrocarbon (m³/m³).

3.1.14**gas void fraction**

The ratio of the local cross-sectional area in the conduit occupied by the gas phase divided by the cross-sectional area of the conduit at the same local position at line conditions, usually expressed as a percentage.

3.1.15**gas volume fraction****(GVF)**

The fraction of the gas volumetric flow rate to the total volumetric flow rate, at actual conditions, often expressed as a percentage.

$$GVF = \frac{Q_g}{Q_g + Q_l}$$

3.1.16**liquid hold-up**

The ratio of the local cross-sectional area in the conduit occupied by the liquid phase divided by the cross-sectional area of the conduit at the same local position at line conditions, usually expressed as a percentage.

3.1.17**liquid volume fraction****(LVF)**

The fraction of the liquid volumetric flow rate over the total volumetric flow rate, at actual conditions, often expressed as a percentage.

$$LVF = \frac{Q_l}{Q_l + Q_g}$$

3.1.18**Lockhart-Martinelli parameter**

A dimensionless parameter (usually shown in equations as X) used to indicate the degree of “wetness” of a wet gas at actual conditions, defined as:

$$X_{lm} = \frac{Q_l}{Q_g} \sqrt{\frac{\rho_l}{\rho_g}} = \frac{m_l}{m_g} \sqrt{\frac{\rho_g}{\rho_l}}$$

3.1.19**multiphase flow**

Flow of a composite fluid that includes natural gas, hydrocarbon liquids, water, and injected fluids, or any combination of these.

3.1.20**oil-continuous multiphase flow**

Multiphase flow in which the water and any other liquids present are distributed as droplets surrounded by liquid hydrocarbons (oil) in the liquid phase.

3.1.21**operating envelope****(OE)**

A description of the operating range of a multiphase flow meter with its expected performance in liquid and gas flow rates, gas volume fraction, and water-liquid ratio.

3.1.22**phase**

A term used in the sense of one constituent in a mixture of several. In particular, the term refers to oil, gas, water, or any other constituent in a mixture of any number of these.

3.1.23**phase mass fraction**

The mass flow rate of one of the phases of a multiphase flow, relative to the total multiphase mass flow rate.

3.1.24**phase volume fraction**

The volume flow rate of one of the phases of a multiphase flow at actual conditions, relative to the total multiphase volume flow rate, e.g. gas volume fraction (3.1.15).

3.1.25**pressure-volume-temperature (PVT) relationship**

The phase behavior and description of hydrocarbon fluid physical properties for a given set of composition, pressure, and temperature.

NOTE Physical properties of interest include relative phase fraction, gas-oil ratio (GOR), bubble point and hydrocarbon dew point, density, correction factors, compressibility, and viscosity.

3.1.26**reference measurement system**

A system of equipment and devices such as a separator, a single meter, a group of meters, a MPFM, analyzers, monitors, or other equipment, with the specific purpose to determine a mass or volume, used in comparison to a measurement system or equipment under validation.

3.1.27**salinity**

The amount of all dissolved salts that are present in the water (kg/m³). Sodium and chloride are the predominant ions in seawater, and concentrations of magnesium, calcium, and sulfate ions are also substantial and included in the salinity values.

3.1.28**SAT Site Acceptance Testing (SAT)**

A series of specific tests and inspections that are performed at the installation site to demonstrate and verify that the system is functional in the intended working environment.

3.1.29**SIT System Integration Testing (SIT)**

A series of tests performed to verify the behavior and functionality of the complete multiphase metering system's integrated hardware and software. This testing is conducted on a complete integrated system to evaluate the system's compliance with its specified requirements before it is installed on site.

3.1.30**slip**

Conditions that exist when the phases have different velocities at a cross section in a conduit.

3.1.31**slip ratio**

A means of quantitatively expressing slip as the phase velocity ratio between the phases.

$$S = \frac{U_g}{U_l}$$

3.1.32**specification**

An act of describing or identifying something precisely or of stating a precise requirement.

3.1.33**standard conditions**

Conditions of pressure and temperature that hydrocarbon fluid quantities are normalized to, for the standardization of volumetric units of measure (Std. bbls/ MSCF), used in hydrocarbon fluid measurement, production allocation and custody transfer quantity calculations for quantity determinations. As defined by API; 14.696 psia @ 60 °F or 101.325 kPa @ 15 °C. (This normalization to a standard unit of measure does not address mass transfer due to hydrocarbon fluid phase behavior.)

3.1.34**superficial phase velocity**

The flow velocity of one phase of a multiphase flow, assuming the phase occupies the whole conduit by itself. It is defined by the phase volume flow rate/pipe cross-sectional area.

3.1.35**validation**

The process or procedure of comparing a system of instruments to a reference measurement system to ensure its indication or registration is within a prescribed uncertainty or acceptance criteria.

3.1.36**verification**

The process or procedure of comparing a single instrument to a single reference standard to ensure its indication or registration is in satisfactorily close agreement, without making an adjustment.

3.1.37**phase fraction**

The cross-sectional area locally occupied by one of the phases of a multiphase flow, relative to the cross-sectional area of the conduit at the same local position, at actual conditions. (The phase fraction for gas is commonly called Gas Void Fraction. The phase fraction for liquid is commonly called the liquid hold-up.)

3.1.38**water cut
(WC)**

The water volume flow rate, relative to the total liquid volume flow rate (oil and water), both converted to volumes at standard pressure and temperature.

3.1.39**water-continuous multiphase flow**

Multiphase flow in which the oil and other liquids present are distributed as droplets surrounded by water in the liquid phase.

3.1.40**water-liquid ratio WLR**

The water volume flow rate, relative to the total liquid volume flow rate (oil and water), at the actual conditions (operating pressure and temperature), expressed as a percentage.

3.1.41**production profile**

This production profile is a prediction of the range of flow rates, composition, and operating conditions over a period.

3.1.42**wet gas**

A gas/liquid system with a Lockhart-Martinelli number smaller than approximately 0.3 and greater than 0. Hydrocarbon gases that contain heavy components that will condense out during further processing but behave as a pure gas at the measured pressure and temperature are not considered to be a wet gas.

3.2 Abbreviations and Symbols

For the purposes of this document, the following abbreviations and symbols apply.

A_{pipe}	pipe cross-sectional area
A_{gas}	cross-sectional area of pipe occupied by gas flow
A_{liquid}	cross-sectional area of pipe occupied by liquid flow
α_g	gas void fraction
α_l	liquid hold up
CTL	Correction for Temperature of a liquid
DP	differential pressure
EOS	equation(s) of state
FAT	factory acceptance test
GOR	gas-oil ratio
GUM	ISO Guide to uncertainty in measurement ^[13]
GVF	gas volume fraction
HC	hydrocarbon
I	system imbalance
LVF	liquid volume fraction
MCS	Monte Carlo simulation
MEG	monoethylene glycol
m_g	gas mass flow rate
m_l	liquid mass flow rate MPFM
m_o	liquid hydrocarbon (oil) mass flow rate
m_w	water mass flow rate
NFOGM	Norwegian Society for Oil and Gas Measurement
OE	operating envelope
P, T	pressure and temperature at actual conditions
P_{sc}, T_{sc}	pressure and temperature at standard conditions
PLET	pipeline end termination
psi	pounds per square inch
PVT	pressure-volume-temperature
$\bar{q}$	mean value of a random variable q
Q_g	gas volume flow rate

Q_l	liquid volume flow rate
Q_o	liquid hydrocarbon (oil) volume flow rate
Q_w	water volume flow rate
ρ_g	gas density
ρ_l	liquid density
R	universal gas constant
ROV	remotely operated vehicle
S	slip ratio
SAT	site acceptance test
SIT	system integration test
U	velocity of liquid or gas in a pipe at actual conditions
U_l	liquid velocity at actual conditions
U_g	gas velocity at actual conditions
$U_{g,SC}$	gas velocity of gas at standard conditions
$U_{s,g}$	superficial velocity of gas phase of a multiphase flow in pipe
$U_{s,l}$	superficial velocity of liquid phase of a multiphase flow in pipe
WLR	water-liquid ratio
X_{lm}	Lockhart-Martinelli parameter
Z	gas compressibility factor at actual conditions
Z_{SC}	gas compressibility factor at standard conditions

4 Overview—Multiphase and Wet Gas Flow

4.1 General

In-line MPFMs are characterized by the measurement of the total or individual phase volume or mass flow rates which are performed directly in the multiphase line with no phase separation. Multiphase flow is referred to as “three phase” and throughout this document multiphase measurement is referred to as a three-phase flow situation. This is a common practice and is the accepted vernacular within the multiphase industry.

Wet gas refers to a subset of multiphase flow in which gas is the dominant phase, with lesser quantities of liquid (oil/water) present. As such, for the sake of clarity, the term multiphase meter will be used to describe both a multiphase meter and a multiphase/wet gas meter throughout this document.

This standard will sometimes be used in conjunction with other standards or similar documents. When a need is encountered for addressing these situations, rather than directly discussing the subject in this document, the user is referred to the appropriate referenced documents for direction.

4.2 Multiphase-flow Fundamentals

4.2.1 Key Parameters and Definitions

For two-phase flow at actual conditions, the area fraction of gas or liquid that occupies the cross-sectional area of a pipe is known as the void fraction, α_g , and the liquid hold-up, α_l , respectively. These parameters can be calculated as shown in Equation (1) and Equation (2).

$$\alpha_g = \frac{A_{gas}}{A_{pipe}} \quad (1)$$

$$\alpha_l = \frac{A_{liquid}}{A_{pipe}} \quad (2)$$

The sum of the gas void fraction in Equation (1) and liquid hold up in Equation (2) should equal 1. The gas void fraction and liquid hold up are not to be confused with both the gas volume fraction, GVF, and the liquid volume fraction, LVF, as these parameters describe the relationship between the phase volume flow rate, Q_g or Q_l , and the total fluid flow rate, as shown in Equation (3) and Equation (4).

$$GVF = \frac{Q_g}{Q_g + Q_l} \quad (3)$$

$$LVF = \frac{Q_l}{Q_l + Q_g} \quad (4)$$

In Equation (3) and Equation (4), the phase volumetric flow rates can be determined by multiplying the cross-sectional area of the pipe with the respective phase superficial velocity, $U_{s,g}$ or $U_{s,l}$. These superficial phase velocities are determined by assuming an individual phase is flowing at a theoretical mean velocity if it occupied the entire conduit alone. A visual representation of the differences between the gas void fraction and liquid hold-up versus the gas and liquid volume fraction is shown in [Figure 1](#). For most of the two-phase flow, the liquid hold-up will be larger than the liquid volume fraction and the gas hold-up will be smaller than the gas fraction due to slip. The slip ratio, S , can be determined from the ratio of gas and liquid velocities as shown in Equation 5.

$$S = \frac{U_g}{U_l} \geq 1 \quad (5)$$

Only under no-slip conditions, when $S = 1$, will the two phases travel at equal velocities, and the gas void fraction or liquid hold-up will be equivalent to the gas and liquid volume fraction. The relationship between GVF , S , and gas void fraction, α_g , is shown Equation (6).

$$GVF = \frac{Q_g}{Q_g + Q_l} = \frac{A_g U_g}{A_g U_g + A_l U_l} = \frac{A_g}{A_g + \left(\frac{1}{S}\right) A_l} = \frac{\alpha_g}{\alpha_g + \frac{1}{S}(1 - \alpha_g)} \quad (6)$$

Rearranging Equation 6 and solving for α_{gas} results in the relationship shown in Equation (7).

$$\alpha_g = \frac{1}{1 + S\left(\frac{1}{GVF} - 1\right)} \quad (7)$$

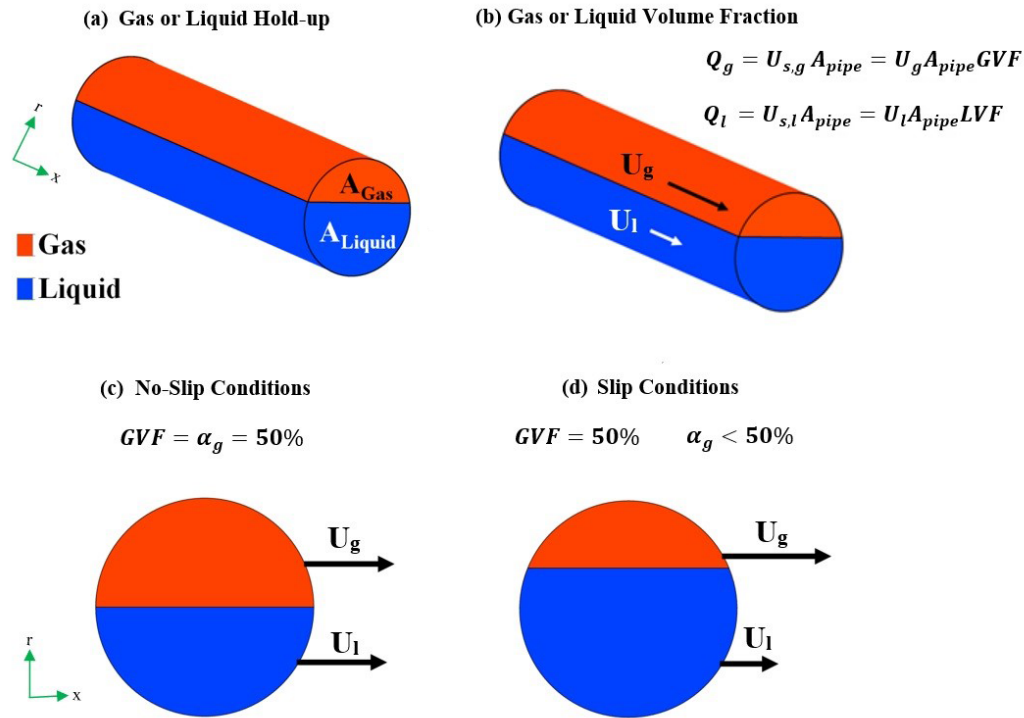


Figure 1—Visual Representation of (a) Gas Void Fraction and Liquid Hold-up (b) Gas or Liquid Volume Fraction (c) No-slip Conditions (d) Slip Conditions Used to Determine Individual Phase Velocities

4.2.2 Flow Pattern Classification/Maps

Multiphase flow structures are often classified into different flow regimes, the characteristics of which depend on several different parameters. These flow regimes have a significant effect on the accuracy of the MPFM measurement within the designed operating conditions and operating envelope (OE), as well as the meter's response to transitional changes between flow regimes.

The main parameters associated in forming the different flow regimes are:

- transient effects because of changes in system conditions (e.g. valve opening and closing),
- pipeline geometry, inclination, or terrain effects,
- hydrodynamic effects (e.g. fluid properties and flow rates), or
- a combination of these.

Although many different combinations of the above parameters result in different flow patterns, the hydrodynamic multiphase flow regimes can be grouped into the following categories:

- dispersed flow (e.g. bubble flow, mist flow), see [Figure 2](#);
- separated flow (e.g. stratified flow, annular flow), see [Figure 3](#);
- intermittent flow (e.g. elongated bubble, chum flow, slug flow), see [Figure 4](#);
- or a combination of these categories.