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Natural Gas — Wet gas flow measurement in natural gas operations

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National foreword

This Published Document is the UK implementation of ISO/TR 12748:2015.

The UK committee, advises users to reference to ISO/TR 11583:2012 when applying this PD, in particular to the equations for wet-gas measurement using Venturi tubes found in Clause 6 of ISO/TR 11583:2012, since their use reduces the bias found at low liquid levels using other commonly used correction factors.

The UK participation in its preparation was entrusted by Technical Committee CPI/30, Measurement of fluid flow in closed conduits, to Subcommittee CPI/30/2, Differential pressure methods.

A list of organizations represented on this committee can be obtained on request to its secretary.

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Natural Gas — Wet gas flow measurement in natural gas operations

*Gaz naturel — Mesurage du débit de gaz humide dans les opérations
de gaz naturel*



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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).

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For an explanation on the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the WTO principles in the Technical Barriers to Trade (TBT), see the following URL: [Foreword — Supplementary information](#).

The committee responsible for this document is ISO/TC 193, *Natural Gas*, Subcommittee SC 3, *Upstream Area*.

Introduction

Oil and gas companies started developing Wet Gas Flow Meters (WGFM) and Multiphase Flow Meters (MPFMs) through extensive R&D activities in the late 1980s. During this period, WGFM and MPFM were typically perceived as two distinct technologies for different applications: MPFMs were designed for liquid continuous flow conditions and WGFM were designed for gas continuous flow conditions. In recent years, however, the operating range of these two technologies has increasingly overlapped, blurring the distinction between a WGFM and MPFM. As wet gas flow is presently considered a subset of multiphase flow, a WGFM is an MPFM that specializes in gas-dominant multiphase flow conditions. In this Technical Report, such technologies will be referred to as WGFM.

There are many factors that contributed in the decision to replace a separator with a WGFM, with each application warranting careful consideration. A well-designed and maintained separator working within an appropriate flow condition range should produce accurate flow measurements. A primary concern for oil and gas companies was to reduce costs by replacing complex and bulky test separators, as well as to further simplify the upstream infrastructure, in particular for offshore and subsea projects. WGFM typically require lower capital¹⁾ and operational²⁾ expenditures than fully equipped test separators. More savings in CapEx may be achieved by omitting dedicated test lines in satellite developments. In addition, there is a significant benefit for offshore developments, in terms of weight and space conservation, by using the much smaller footprint of WGFM.

Due to various operational problems, a conventional test separator does not continuously provide accurate and reliable well test data, giving only relevant information when the well is switched to the test separator. With the use of WGFM testing well production more frequently or even continuously becomes possible. WGFM developments and extensive testing over the last two decades have resulted in WGFM technology that is a viable alternative to a test separator. Modern WGFM now offer continuous well monitoring (per installation on individual wells).

WGFM technology is an attractive option for multiphase wet gas flow measurement. Over the last two decades, some WGFM have been developed from prototypes into very mature, robust, advanced, and field-proven measurement devices, increasing their application scope. Although originally intended for use mainly in reservoir and well production allocations, WGFM have evolved into a technology that spans even fiscal product allocation. In the latter case, the output of a WGFM is used to determine money transactions between operating companies or between an operating company and a host government.

This Technical Report focuses on the measurement of wet gas flow, i.e. terminology, models, and principles, and the design, implementation, testing, and operation of WGFM.

1) Capital expenditure (CapEx) or costs for purchasing and installing a WGFM/MPFM includes all hardware to operate the WGFM (data transmission, verification facilities, sampling arrangements, etc.)

2) Operating expenditure (OpEx) or costs to operate a WGFM/MPFM (maintenance, verification processes, sampling for fluid properties, etc.)

Natural Gas — Wet gas flow measurement in natural gas operations

1 Scope

This Technical Report describes production flow measurement of wet natural gas streams with WGFM in surface and subsea facilities. Wet natural gas streams are gas-dominated flows with liquids like water and/or hydrocarbon liquids³⁾ (see 2.67 for a detailed definition). This Technical Report defines terms/symbols, explains the various concepts, and describes best practices of wet gas flow meter design and operation. It addresses metering techniques, testing, installation, commissioning, and operation practices such as maintenance, calibration, and verification. It also provides a theoretical background of this comprehensive, challenging and still evolving measurement technology.

There are four general methods in measuring wet natural gas flow. Each approach is detailed below.

- Single-phase gas flow meter with correction factor: Uses a single-phase gas flow meter (often a conventional gas flow metering device) with a correction factor for the effect of liquid on the metering system. In these cases, the liquid flow rate required to determine the correction factor, should be estimated from an external source.
- Two-phase WGFM: The gas and liquid (both water and hydrocarbon liquid combined) flow rates are predicted with no additional external information regarding the liquid flow rate required. This is generally known as a two-phase WGFM and will be referred to in this Technical Report simply as WGFM.
- WGFM: A flow meter that measures the gas and liquid flow rates, and also the gas, water and hydrocarbon liquid ratios (or “phase fractions”) with no external information required regarding the liquid flow rate.
- Phase separation/Measurement after phase separation: This traditional and conventional method of wet gas flow metering uses a two- or three-phase separator with single-phase flow meters measuring the outgoing single-phase flows.

The first three of these methods, which emerged in the last two decades, may be described as in-line wet gas flow metering, i.e. wet gas flow measurement is executed with WGFM without separating the gas and liquid phases. This Technical Report discusses in detail these first three methods. Several best practice documents have already been issued to describe, among other topics, wet gas flow measurement^{[9][10][11][12]}.

The last method is more conventional and describes wet gas flow measurement after the gas and liquid phases have been separated. Wet gas meters can be used in multiphase flow metering systems that utilize partial separation technologies. This method is only briefly discussed in this Technical Report.

2 Terms and Definitions

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

2.1 adjustment

act of altering an instrument's performance in any way, e.g. software, mechanical or electrical modifications, in order for the instrument's indication to match the reference values indicated by a test stand

3) In this Technical Report, the term hydrocarbon liquid includes both oil and condensed hydrocarbons

2.2 calibration

set procedure under specified conditions where the output/performance of an instrument is checked against a reference, usually a test stand

Note 1 to entry: The result of calibration determines the deviation between the instrument indication and the references. This deviation can assign an uncertainty value to the measurand and could indicate a requirement for an adjustment.

2.3 capacitance

the ability of a body to store an electrical charge

Note 1 to entry: Any object that can be electrically charged exhibits capacitance (e.g. a parallel-plate capacitor).

2.4 composition map

map with *water liquid ratio* or *WLR* (2.63) along the horizontal axis ($0 \% \leq \text{WLR} \leq 100 \%$) and *gas volume fraction* or *GVF* (2.22) along the vertical axis ($0 \% \leq \text{GVF} \leq 100 \%$); used to show WGFM operating envelopes and/or *well trajectories* (2.65)

Note 1 to entry: The combination of a *two-phase flow rate map* (2.59) and a composition map is beneficial to evaluate WGFM applications. See 8.1.3.

2.5 conductivity

ability of a material to conduct electrical current

Note 1 to entry: In isotropic material, conductivity is also the reciprocal of resistivity, sometimes called specific conductance.

2.6 density ratio DR

ratio of gas density to liquid density at line conditions, or

$$\text{DR} = \rho_g / \rho_l$$

Note 1 to entry: In multiphase wet gas flows, the liquid density is typically considered to be the density of a homogenous mix of liquid components. See Formula (6).

2.7 dry gas

fluid that is solely in a gaseous phase

Note 1 to entry: The mix of fluid components flowing may cause the gas to have a finite relative humidity but the flow at the flow meter is only in a gaseous phase.

2.8 emulsion

colloid substance consisting of water and hydrocarbon liquid mixes

Note 1 to entry: Emulsions can be water continuous or hydrocarbon liquid continuous, as these have different characteristics.

2.9 equation of state EoS

equations that relate the properties of a given substance to its thermodynamic condition

2.10

film thickness

thickness of the liquid film in annular flow

2.11

flow regime

flow pattern

physical dispersion of phases of a two-phase flow (either wet gas or multiphase) in a conduit

Note 1 to entry: For a particular case of wet gas flow, the flow regime descriptions usually discuss gas and liquid interaction only, with no individual mention of water and hydrocarbon liquid.

2.12

flow quality

dryness fraction

gas mass fraction

GMF

x

ratio of the gas mass flow rate to the total mass flow rate, or

$$x = \text{GMF} = \frac{\dot{m}_g}{\dot{m}_g + \dot{m}_l}$$

Note 1 to entry: In multiphase wet gas flows, the liquid flow rate is typically considered to be the sum of the liquid components (for example, hydrocarbon liquids, water and liquid chemical inhibitors).

2.13

flow regime (pattern) map

graph describing the wet gas flow regime across a range of flow conditions

Note 1 to entry: There is no agreed form for flow regime maps, and different maps can use different parameters on the graph axes. Gas and liquid superficial velocities are common choices. Flow regime maps are almost always created from experimental observation, and sometimes include theoretical considerations.

Note 2 to entry: to entry : Flow regime transitional boundaries/regions should be taken as approximations.

2.14

fluid

any substance that continuously deforms under a continuous infinitesimal shear force.

2.15

foams

mixture of gas and liquids, where the gas is held in a liquid structure

Note 1 to entry: With wet gas, this tends to be more prevalent with gas/water flows than gas/liquid hydrocarbon flows due to the higher interfacial tension of water compared with that of liquid hydrocarbons.

2.16

free liquid

liquid components in a wet gas flow that are in a liquid form, not including evaporated liquid held as vapour state with the gaseous component of flow.

2.17

gamma rays

electromagnetic radiation of a kind arising from the radioactive decay of an atomic nucleus

2.18

gas

gaseous component of a wet gas flow, which includes any liquid vapour with relative humid gases

2.19

gas densiometric Froude number

square root of the ratio of the gas flow inertia (if it were to flow alone) to the liquid's weight, or

$$Fr_g = \sqrt{\frac{\text{Superficial Gas Inertia Force}}{\text{Liquid Gravity Force}}} = \frac{\bar{U}_{sg}}{\sqrt{gD}} \sqrt{\frac{\rho_g}{\rho_l - \rho_g}} = \frac{m_g}{A\sqrt{gD}} \sqrt{\frac{1}{\rho_g(\rho_l - \rho_g)}}$$

2.20

gas expansion factor

term used to indicate the volume change in gas between two different conditions, which may include standard conditions

2.21

gas to oil ratio

GOR

ratio of gas to hydrocarbon liquid volume flow rate

Note 1 to entry: GORs are stated at standard conditions, but may commonly use different units (e.g. sm³/sm³ or MMscf/bbls) resulting in different numerical values.

2.22

gas volume fraction

GVF

ratio of gas to total fluid volume flow rate at actual flow conditions, or

$$GVF = \frac{\dot{Q}_g}{\dot{Q}_g + \dot{Q}_l}$$

Note 1 to entry: The GVF is a dynamic measurement of volume flow rates that inherently accounts for slip (2.52) between the gas ($\dot{Q}_g$) and liquid ($\dot{Q}_l$) phases. The liquid volume flow rate consists of the sum of the liquid flow rates, e.g. hydrocarbon liquids, water, and liquid chemical inhibitors. This is **not** to be confused with *gas void fraction* (2.23). GVF may be expressed as a ratio or a percentage.

2.23

gas void fraction

α_g

ratio of gas cross sectional area to total pipe cross sectional area, or

$$\alpha_g = \frac{A_g}{A}$$

Note 1 to entry: Gas void fraction is a static measurement at a moment in time and it does **not** account for slip (2.52) between the gas and liquid phases. The existence of slip between the phases differentiates GVF from gas void fraction.

Note 2 to entry: Phase fraction devices in WGFM designs tend to measure the gas void fraction in the system's line-of-sight, not the GVF. The WGFM slip model then derives the GVF from inputs including the gas void fraction and other subsystem measurements.

2.24

homogeneous hydrocarbon liquid/water flow

flow of water and hydrocarbon liquid where the phases are evenly distributed throughout the fluid mix and there is no slip between the water and the hydrocarbon liquid

Note 1 to entry: The composition of a homogeneous water and hydrocarbon liquid mix is constant throughout the conduit. However, homogeneous distribution of the phases is rare.

2.25

infrared

electromagnetic radiation with longer wavelengths than visible light

2.26

intermittent flow

unsteady flow, where the GVF varies with time, e.g. slug flow

2.27

line conditions (actual, process, or operating conditions)

thermodynamic conditions of the fluid passing through the meter, i.e. the fluid conditions at line (metering device) pressure and temperature

2.28

liquid densiometric Froude number

square root of the ratio of the liquid flow inertia (if it were to flow alone) to the liquid's weight, or

$$Fr_l = \sqrt{\frac{\text{Superficial Liquid Inertia Force}}{\text{Liquid Gravity Force}}} = \frac{\bar{U}_{sl}}{\sqrt{gD}} \sqrt{\frac{\rho_l}{\rho_l - \rho_g}} = \frac{m_l}{A\sqrt{gD}} \sqrt{\frac{1}{\rho_l(\rho_l - \rho_g)}}$$

2.29

liquid hold up

α_l

ratio of liquid cross sectional area to total pipe cross sectional area, or

$$\alpha_l = 1 - \alpha_g = \frac{A_l}{A}$$

Note 1 to entry: The liquid hold up gives effectively the same information as the *gas void fraction* (2.23).

Note 2 to entry: The liquid hold up is a static measurement at a moment in time and it does **not** account for slip between the gas and liquid phases. That is the liquid hold-up gas and *liquid volume fraction* (2.31) differ due to the existence of slip between the phases.

Note 3 to entry: With multiphase wet gas flow the liquid hold up can be split into its constituent liquid components. For example, with a gas, condensate and water flow where hydrocarbon liquid hold-up (α_{hcl}) and water hold up (α_{water}) are:

$$\alpha_{hcl} = \frac{A_{hcl}}{A}$$

$$\alpha_{water} = \frac{A_{water}}{A}$$

$$\sum \alpha = \alpha_g + \alpha_{water} + \alpha_{hcl} = 1$$

2.30

liquid loading

qualitative description of the relative amount of liquid in a wet gas flow

2.31

liquid volume fraction

LVF

ratio of liquid to total fluid volume flow rate at actual flow conditions, or

$$\text{LVF} = 1 - \text{GVF} = \frac{\dot{Q}_l}{\dot{Q}_l + \dot{Q}_g}$$

Note 1 to entry: The LVF is a dynamic measurement of volume flow rates that inherently accounts for slip between the gas ($\dot{Q}_g$) and liquid ($\dot{Q}_l$) phases. The liquid volume flow rate consists of the sum of the liquid flow rates (for example, hydrocarbon liquids, water, and liquid chemical inhibitors). This is **not** to be confused with *liquid hold up* (2.29). LVF may be expressed as a ratio or a percentage.

2.32

Lockhart-Martinelli parameter

square root of the ratio of the liquid inertia to gas inertia if the phases flowed alone at line conditions, or

$$X_{LM} = \sqrt{\frac{\text{Inertia of Liquid Flowing Alone}}{\text{Inertia of Gas Flowing Alone}}}$$

that is:

$$X_{LM} = \frac{Fr_l}{Fr_g} = \frac{\dot{m}_l}{\dot{m}_g} \sqrt{\frac{\rho_g}{\rho_l}} = \frac{\dot{Q}_l}{\dot{Q}_g} \sqrt{\frac{\rho_l}{\rho_g}} = \frac{1 - GVF}{GVF} \sqrt{\frac{\rho_l}{\rho_g}}$$

Note 1 to entry: The Lockhart-Martinelli Parameter has a long 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 stated definition here. The definition supplied in this Technical Report 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 [12] and [13]

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

2.33

mass flow rate

mass of fluid flowing through a conduit per unit time

2.34

measurand

particular quantities subject to measurement

2.35

meter operating envelope

areas in the *two-phase flow rate map* (2.59) and/or *composition map* (2.4) in which a WGFM is to perform/or stated to be capable of performing

Note 1 to entry: This envelope may vary with changing operating condition and fluid properties.

2.36

microwave

electromagnetic radiation, typically in the frequency range 0,3 GHz to 300 GHz

2.37

multiphase flow

flow of gas, water, and hydrocarbon liquid phases

Note 1 to entry: Each of these three components is designated as a separate “phase”. Multiphase flows may also have other “phases” such as salinity of water or chemical injection phases. A multiphase flow is a subset of a two-phase flow where the liquid consists of two or more components, typically water and hydrocarbon liquid. There is no limit to the relative quantity of liquids in a multiphase flow, i.e. the GVF range is $0 \% < GVF < 100 \%$.

2.38

multiphase flow meter

MPFM

device that measures the oil, water and gas flow rates in a multiphase flow

2.39

multiphase/phase fraction device

device that measures the phase area fractions of the individual phases of a multiphase flow

Note 1 to entry: These devices tend to measure the area occupied by a particular phase across a given cross-sectional area. This is not the same information as the phase volume flow rate ratios due to the existence of a *slip* (2.52).

2.40

oil continuous liquid

oil external emulsion

liquid flow consisting of the two “phases”, hydrocarbon liquid and water, where the hydrocarbon liquid phase encases the water phase suspended in water droplets in the hydrocarbon liquid phase

2.41

operating envelope

see 2.35

2.42

over-reading

ratio of a single-phase gas flow meter’s erroneous gas mass flow rate prediction (i.e. the “apparent gas mass flow rate”) to the actual dry gas mass flow rate

Note 1 to entry: In the case of DP devices, this is often approximated to the square root of the wet gas to dry gas DP ratio.

2.43

permittivity

measure of the ability of a dielectric medium to be electrically polarized when exposed to an electric field

2.44

phase

used in WGFM applications to describe each of the three components gas, water and hydrocarbon liquid. Other components such as glycol and methanol can also be referred to as “phases”

2.45

phase flow rate

amount (in mass or volume) of a specific phase passing a referenced point in the conduit per unit time

2.46

phase mass fraction

ratio of the mass flow rate of one phase to the total mass flow rate

2.47

production envelope

collection of possible well production trajectories (gas flow rates and liquid flow rates) over time in the *two-phase flow rate map* (2.59), see [Figure 23](#)

2.48

relative humidity

ratio of water liquid vapour present in a gaseous fluid relative to the maximum (or saturated) amount of water liquid vapour possible for that given gaseous fluid to hold at a given thermodynamic condition

2.49

Reynolds number

Re

ratio of the inertial to viscous forces, or

$$Re = \frac{\rho U.D}{\mu} = \frac{4\dot{m}}{\pi\mu.D}$$

Note 1 to entry: The Reynolds number is important in many single-phase meter calibrations or characterizations. In the common event of dry gas meters being used for wet gas flow measurement the Reynolds number term can be important. Note that there is no consensus on how to define Reynolds number for a multiphase flow

2.50
salinity

quantification of any dissolved salts in water, expressed as either a percentage or a concentration

2.51
shrinkage

volume change in liquids between two different thermodynamic operating conditions (may include standard conditions); comprises shrinkage due to pressure, temperature, and mass transfer between phases (e.g. gas coming out of solution)

2.52
slip

qualitative term used to describe differences in velocity between different phases in a wet gas or multiphase flow

Note 1 to entry: Typically, gas and liquid phases do not travel at the same velocity. The existence of slip significantly complicates wet gas and multiphase flow metering techniques.

2.53
slip ratio

S_R

ratio of average velocities of any two phases in a wet gas or multiphase flow, or

$$S_R = \frac{\bar{U}_g}{\bar{U}_l}$$

Note 1 to entry: For example, the slip ratio between gases and liquids, hence making the GVF and gas void fraction different parameters.

Note 2 to entry: Similarly, slip between water and gas, hydrocarbon liquids and gas, and water and hydrocarbon liquids exist. However, many manufacturers claim that the slip between water and hydrocarbon liquids in multiphase wet gas flows is negligible.

2.54
slip velocity

S

average velocity difference between two phases in a wet gas or multiphase flow, or

$$S_R = \bar{U}_g - \bar{U}_l$$

Note 1 to entry : For example, the difference in velocity between gas and liquid phases.

2.55
standard conditions

user-defined pressure and temperature, usually (but not always) a pressure of 101,325 kPa and a temperature of either 15 °C or 60 °F (15,55 °C)

Note 1 to entry : Further references are found in ISO 13443[46].

2.56
superficial gas velocity

average gas velocity that would exist if the gas of a wet gas flow was to flow alone in the pipe, or

$$\bar{U}_{sg} = \frac{\dot{m}_g}{\rho_g A}$$

2.57

superficial liquid velocity

average liquid velocity that would exist if the liquid of a wet gas flow was to flow alone in the pipe, or

$$\bar{U}_{sl} = \frac{\dot{m}_l}{\rho_l A}$$

2.58

two-phase flow

flow of a gas phase with a liquid phase

Note 1 to entry: In the definition of two phase flow the liquid is considered a single phase regardless of its composition. In the definition of multiphase flow the different liquid components (e.g. hydrocarbon liquid, water, chemical inhibitor etc.) are considered different phases.

2.59

two-phase flow rate map

used to show two-phase flow regimes, WGFM operating envelopes, and/or well trajectories

Note 1 to entry: A two-phase flow rate map has the gas flow rate as horizontal axis and the liquid flow rate as vertical axis, see 8.13. The combination of two-phase flow rate map and composition map are beneficial to evaluate WGFM applications.

2.60

x-rays

electromagnetic radiation of a kind arising from the electrons outside the nucleus

2.61

water continuous liquid

water external emulsion

liquid flow consisting of the two “phases”, hydrocarbon liquid and water, where the water phase encases the hydrocarbon liquid phase suspended in hydrocarbon liquid droplets in the water phase

2.62

water cut

water to total liquid volume flow rate (for example, hydrocarbon liquids, water and liquid chemical inhibitors) at standard conditions, usually expressed as a percentage, or

$$Watercut = \left(\frac{\dot{Q}_w}{\dot{Q}_l} \right)_{standard\ conditions}$$

2.63

water liquid ratio

WLR

water to total liquid volume flow rate (for example, hydrocarbon liquids, water and liquid chemical inhibitors) at line conditions, may be expressed as a ratio or a percentage, or

$$WLR = \left(\frac{\dot{Q}_w}{\dot{Q}_l} \right)_{actual\ conditions}$$

2.64

water liquid mass ratio

WLMR

water to total liquid mass flow rate (for example, hydrocarbon liquids, water and liquid chemical inhibitors), usually expressed as a percentage or

$$WLMR = \left(\frac{\dot{m}_w}{\dot{m}_l} \right)$$

2.65

water volume fraction

WVF

water volume flow rate to the total mixture volume flow rate at operating conditions, or

$$WVF = \left(\frac{\dot{Q}_w}{\dot{Q}_g + \dot{Q}_l} \right)_{actual\ conditions}$$

2.66

well trajectory

trajectory over lifetime in the *two-phase flow rate map* (2.59) and *composition map* (2.4) of a well based on production forecast

Note 1 to entry: A collection of well trajectories for a gas field is called the production envelope of the gas field.

2.67

wet gas flow

subset of two-phase flow where the flow is gas dominant by volume

Note 1 to entry: The wet gas flow can have a gas flow with one or more liquid components, i.e. water only, hydrocarbon liquid only, a mix of water and hydrocarbon liquid flows, or a mix of water, hydrocarbon liquids and other liquids such as liquid chemical inhibitors, etc.

2.68

wet gas flow meter

WGFM

device that measures the gas, or gas and liquid flow rates of a wet gas flow, and may or may not meter the hydrocarbon liquid and water flow rates of the wet gas flow's liquid phase

3 Symbols

Symbol	Description	Dimension	SI unit (common field unit)
A	Meter inlet area	L^2	m^2 (in ²)
A_g	Gas cross sectional area	L^2	m^2 (in ²)
A_l	Liquid cross sectional area	L^2	m^2 (in ²)
A_t	Minimum (or throat) area of a DP meter	L^2	m^2 (in ²)
C_d	DP meter discharge coefficient	Dimensionless	Dimensionless
C_{ch}	Chisholm parameter	Dimensionless	Dimensionless
D	Meter inlet pipe diameter	L	mm (in)
DP or ΔP	Differential Pressure	M/LT^2	Pa (psi)
NOTE Dimensions: L = Length, M = Mass, T = Time, θ = Temperature			

Symbol	Description	Dimension	SI unit (common field unit)
DR	Gas to liquid Density Ratio at operating conditions	Dimensionless	Dimensionless
E	DP meter's velocity of approach factor	Dimensionless	Dimensionless
$f_n(a, b, \dots)$	Unspecified function with variables a, b, ...	N/A	N/A
Fr_g	Gas densiometric Froude Number	Dimensionless	Dimensionless
$Fr_{g, strat}$	Gas densiometric Froude Number at the stratified/annular mist flow regime border	Dimensionless	Dimensionless
Fr_l	Liquid densiometric Froude Number	Dimensionless	Dimensionless
g	Gravitational constant	L/T ²	m/s ² (ft/s ²)
GMF or x	Gas Mass Fraction at operating conditions	Dimensionless	Dimensionless
GOR	Gas Oil Ratio at Standard Condition	Dimensionless	sm ³ /sm ³ (MMscf/bbls)
GVF	Gas Volume Fraction at operating conditions	Dimensionless	Dimensionless
K_o	Concentration of injected tracer liquid	Various	Various
K_s	Concentration of tracer in liquid sample	Various	Various
LMF	Liquid Mass Fraction	Dimensionless	Dimensionless
LVF	Liquid Volume Fraction at operating condition	Dimensionless	Dimensionless
M	Murdock coefficient	Dimensionless	Dimensionless
$\dot{m}_g$	Gas mass flow rate at the point of measurement	M/T	kg/s (lbm/s)
$\dot{m}_{g, apparent}$	Uncorrected gas mass flow rate predicted by gas meter with wet gas flow	M/T	kg/s (lbm/s)
$\dot{m}_{hcl}$	Hydrocarbon liquid mass flow rate	M/T	kg/s (lbm/s)
$\dot{m}_l$	Liquid mass flow rate	M/T	kg/s (lbm/s)
$\dot{m}_w$	Water mass flow rate	M/T	kg/s (lbm/s)
n	Chisholm exponent	Dimensionless	Dimensionless
n_{strat}	Chisholm exponent for stratified flow regime	Dimensionless	Dimensionless
OR	Over-Reading	Dimensionless	Dimensionless
P	Operating pressure	M/LT ²	Pa (psi)
PLR	Ratio of a DP meter's traditional PPL to DP	Dimensionless	Dimensionless
PPL	Permanent Pressure Loss across a pipe line component, such as a DP meter	M/LT ²	Pa (psi)
PVT	Pressure, Volume and Temperature Equation of State Calculations	Not Applicable	Not Applicable
$\dot{q}$	Tracer fluid injection volume flow rate	L ³ /T	m ³ /hr (ft ³ /hr)

NOTE Dimensions: L = Length, M = Mass, T = Time, θ = Temperature

Symbol	Description	Dimension	SI unit (common field unit)
$\dot{Q}$	Volume flow rate	L ³ /T	m ³ /hr (ft ³ /hr)
$\dot{Q}_g$	Gas volume flow rate at operating conditions	L ³ /T	m ³ /hr (ft ³ /hr)
$\dot{Q}_{hcl}$	Actual hydrocarbon liquid volume flow rate	L ³ /T	m ³ /hr (ft ³ /hr)
$\dot{Q}_l$	Actual liquid volume flow rate	L ³ /T	m ³ /hr (ft ³ /hr)
$\dot{Q}_w$	Actual water volume flow rate	L ³ /T	m ³ /hr (ft ³ /hr)
Re	Reynolds number	Dimensionless	Dimensionless
S	Slip velocity	L/T	m/s (ft/s)
S_R	Slip Ratio	Dimensionless	Dimensionless
T	Temperature	Θ	°C, K (°F, R)
U	Velocity of a fluid	L/T	m/s (ft/s)
$\bar{U}_g$	Average actual gas velocity in two-phase flow	L/T	m/s (ft/s)
$\bar{U}_l$	Average liquid velocity in two-phase flow	L/T	m/s (ft/s)
$\bar{U}_{sg}$	Superficial gas velocity	L/T	m/s (ft/s)
$\bar{U}_{sl}$	Superficial liquid velocity	L/T	m/s (ft/s)
V_g	Volume of gas in a unit length of pipe	L ³	m ³ (ft ³)
V_l	Volume of liquid in a unit length of pipe	L ³	m ³ (ft ³)
Water Cut	Water Volume flow rate to Total Liquid Volume flow rate at Standard Conditions	Dimensionless	Dimensionless
WLR	Water Volume flow rate to Total Liquid Volume flow rate	Dimensionless	Dimensionless
WLMR	Water Mass flow rate to Total Liquid Mass flow rate at operating conditions	Dimensionless	Dimensionless
WVF	Water Volume Fraction, i.e. Water Volume flow rate to Total Fluid Volume flow rate at operating conditions	Dimensionless	Dimensionless
x or GMF	Gas Mass Fraction, equivalent to Steam quality (dryness fraction), i.e. Gas Mass flow rate to Total Fluid Mass Flow rate	Dimensionless	Dimensionless
X_{LM}	Lockhart-Martinelli Parameter	Dimensionless	Dimensionless

NOTE Dimensions: L = Length, M = Mass, T = Time, Θ = Temperature

Symbol	Description	Dimension	SI unit (common field unit)
Y or Y_g or ε	Expansibility coefficient for a DP Meter	Dimensionless	Dimensionless
Y_{tp} or Y_{gtp}	Expansibility coefficient for a DP Meter Calculated with Use of ΔP_{tp}	Dimensionless	Dimensionless
ΔP_g or ΔP_g	Single Phase Gas Differential Pressure	M/LT ²	Pa (psi)
ΔP_{tp} or ΔP_{tp}	Actual wet gas/two phase DP	M/LT ²	Pa (psi)
ΔP_{PPL} or ΔP_{PPL}	Head Loss/Permanent Pressure Loss	M/LT ²	Pa (psi)
$DP_{PPL,tp}$ or $\Delta P_{PPL,tp}$	Head Loss / Permanent Pressure Loss with two-phase flow	M/LT ²	Pa (psi)
α_g	Gas Void fraction	Dimensionless	Dimensionless
α_{liquid}	Liquid hold up	Dimensionless	Dimensionless
α_{hcl}	Hydrocarbon liquid hold up	Dimensionless	Dimensionless
α_{water}	Water hold up	Dimensionless	Dimensionless
β	Square root of a throat to meter inlet area ratio of a DP meter	Dimensionless	Dimensionless
δ	Fluctuation	Various	Various
κ	Isentropic exponent	Dimensionless	Dimensionless
ρ	Density of a fluid	M/L ³	kg/m ³ (lbm/ft ³)
ρ_g	Density of gas	M/L ³	kg/m ³ (lbm/ft ³)
ρ_l	Density of liquid	M/L ³	kg/m ³ (lbm/ft ³)
ρ_w	Density of water	M/L ³	kg/m ³ (lbm/ft ³)
ρ_{hcl}	Density of hydrocarbon liquid	M/L ³	kg/m ³ (lbm/ft ³)
μ	Dynamic viscosity of fluid	M/LT	Pa.s
ω	Frequency of a parameter measurement	1/T	Hz
NOTE Dimensions: L = Length, M = Mass, T = Time, θ = Temperature			

4 Objectives of wet gas flow measurement

There are varying objectives that all come under the generic term wet gas flow measurement. The specific objectives will often dictate the wet gas measurement techniques applied. These techniques range from the simple and inexpensive, e.g. orifice, Venturi arrangements, to the highly complex and more expensive three-phase WGFMs⁴⁾. The economic justification should include CapEx and OpEx considerations as well as the value of the information that is delivered by the meter. For the latter, the user should also understand the measurement objectives, i.e. the purpose of the measurements, the

4) The term WGFm means both two-phase and multiphase WGFMs. This distinction is made between two-phase WGFMs and multiphase WGFMs, where necessary.

sensitivities of the measurements, as well as the boundary conditions and limitations. As an example, the costs caused by a hydrate-plugged subsea gas line (production deferment and remedial activities) are many times more than the installation of a WGFM that is able to measure the water content and facilitate proper hydrate management.

The following are some common measurement objectives:

- reservoir and well management;
- production optimisation;
- production (gas, condensate and water) allocation (see [4.2](#));
- formation water breakthrough detection;
- flow assurance, e.g. hydrates, scale, salt deposition (see [4.3](#));
- optimization of chemical injection.

The following are limitation and boundary conditions that should also be considered:

- economic justification,
- total lifecycle cost, e.g. capital, operational, decommissioning (see [4.4](#));
- intended location (onshore, offshore, subsea, remote, accessible);
- size/physical/power limitations;
- impact of changing fluid properties on the meter performance (hydrocarbon compositional changes, density, H₂S, salinity, etc.), particularly for co-mingled flows;
- impact of wax, salts and scale.

A more comprehensive check list can be found in [Annex A](#).

4.1 Common production scenarios

The following is a list of various production scenarios.

- a) The asset is primarily for natural gas production. The fluid flow is wet gas but the main focus is on the measurement of the gas flow. The liquid flow is only an inconvenience affecting the accuracy of the gas measurement.
- b) The asset is primarily for hydrocarbon liquid production. The flow is wet gas but the objective is the measurement of the hydrocarbon liquid flow. The gas flow is only providing the liquid hydrocarbon carrying mechanism. After phase separation the gas may be re-injected back into the reservoir as part of the production cycle.
- c) The asset contains both valuable natural gas and hydrocarbon liquid flow. There is minimal water content in the wet gas flow. The operator is required to accurately measure the gas and liquid hydrocarbon flows. This situation is relatively common at many gas fields from early life through end of life production flows.
- d) The production flow contains natural gas, hydrocarbon liquid and water flow. There is significant water content in the wet gas flow. The operator is required to accurately measure both the natural gas flow and the hydrocarbon liquid flow for production. The operator also requires to accurately measure the water flow for water treatment and disposal costs. The water flow rate may also be required to judge the level of hydrate and scale chemical inhibitors to be injected.
- e) The production flow contains natural gas and hydrocarbon liquid flow and initially no condensed or formation/produced water flow. However, as the well ages water may appear. This phenomenon is commonly termed water breakthrough. The presence of water can adversely affect the measurement

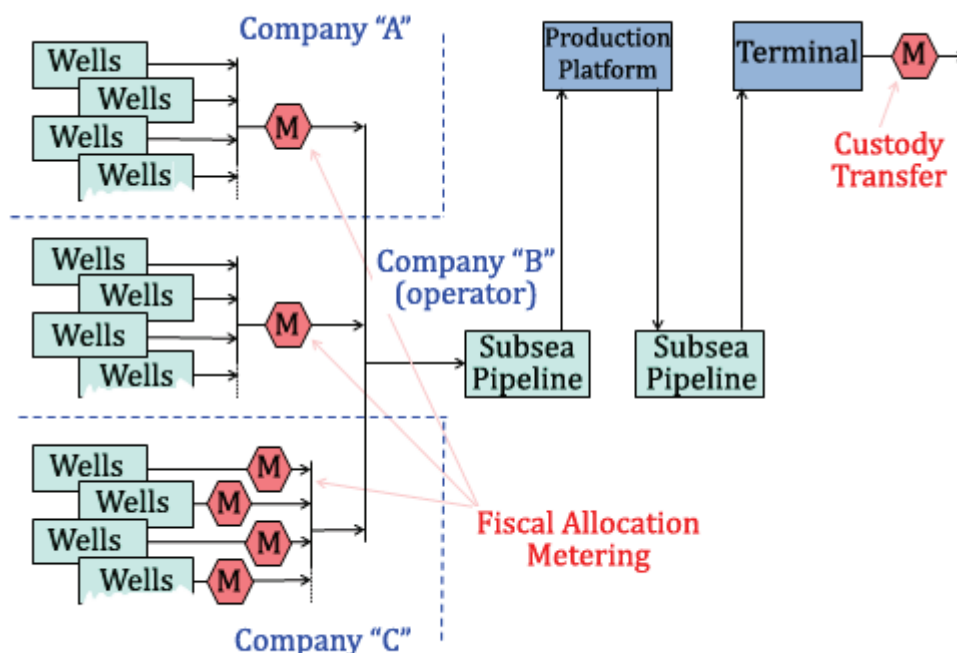
of the pipeline due to hydrate formation, scale, or salt deposition. For these reasons WGFM's or (indirect) water fraction sensors may be utilized primarily as water breakthrough monitors or for determining chemical inhibitor injection rates. In these applications the water monitoring capability of the meter is the primary requirement for flow assurance purposes.

4.2 Production allocation

In recent years, WGFM's are increasingly used for fiscal applications where the output of the meter determines money flow between oil companies or between companies and host governments (e.g. sales allocation, transportation fees, custody transfer, and royalty payments). The move of WGFM's into this application is due to the upstream oil and gas business becoming increasingly complex in terms of infrastructure, i.e. facilities are being shared between various producing companies and commingling is done much further upstream in the process.

The modern trend of subsea co-mingling the wet gas production streams (see [Figure 1](#)) calls for a new measurement approach and different philosophies for allocating the condensate, gas, and water to the respective sources. In those complex subsea infrastructures, the use of WGFM's is very beneficial, but the use of these meters creates operational challenges. As an example, in subsea applications, it is expected that these WGFM's will continue to operate for a long time without the ability to retrieve the meter or to access the meter for maintenance, verification, sampling or calibrations.

There exists a large diversity in applied physical concepts, which makes it difficult to select an adequate WGFM for a particular development. It is often difficult to judge all the future operational effects on the WGFM in a remote and inaccessible location. One issue that is not well documented and still creates uncertainty in the long term operation is the effect of changing fluid parameters on the oil/condensate, water and gas flow rate readings. Mismanagement of these fluid properties can have a significant impact on the money flows between operating companies or operating companies and host government or may jeopardize flow assurance.



NOTE "M" denotes meter location

Figure 1 — WGFM's installed at the seabed at the entry of a commingled subsea pipeline will ultimately determine the money flow between companies A, B and C

4.3 Flow assurance aspects

In order to ensure a continuous production of hydrocarbons, flow assurance is a critical aspect of flow metering system design. For instance, the management of water production is essential; water in the production lines can cause scale, salt and hydrate formation, which can ultimately block flow lines. The subsequent financial loss from such a production interruption or facility damage can be substantial. In order to optimize the scale and hydrate deposit inhibition, it is important that water production rates are measured. For many fields it is also important to know the salt content of the produced water, not only as a fluid property input to the flow rate calculation, but also in order to prevent corrosion in the pipelines and production facilities. Next to the above flow assurance aspect, knowledge about salt content is also important from a reservoir management perspective. Discrimination between salt and fresh water can be used to identify the origin of produced water, as either condensed water vapour or produced formation water.

Flow assurance is a critical task during deep water oil and gas production because of the high pressures and low temperature (approximately 4 °C) involved.

4.4 WGFM considerations

Once the decision has been made to use WGFM in a project, either for well and reservoir management, for sales allocation, for legal requirements or for operational control or flow assurance, the WGFM selection process is started. Given the diversity in commercial WGFM concepts this is not an easy task. Each metering concept has its benefits and challenges regarding measurement performance, engineering requirements and cost.

The cost of purchasing, installing and operating the WGFM is an important aspect that needs upfront consideration. There is a relatively large spread in purchasing costs (dependent on pressure rating and meter size) and subsea flow meters can be often multiple times more expensive than the equivalent for a topside application. However, the total life cycle cost of a WGFM should include the purchasing, engineering and installation costs (all considered CapEx) and the costs to operate the WGFM, i.e. maintenance, verification processes, sampling for fluid properties, etc. (all considered OpEx). Hence, in the WGFM selection process it is recommended to consider these life cycle costs next to the performance driver (i.e. uncertainty, repeatability and availability).

The WGFM performance over the entire operating range and the practicality of the maintenance requirements are important considerations to be weighed against the total life cycle of the WGFM.

4.5 Reliability in remote WGFM installations

An important aspect in remote or subsea metering WGFM is reliability. Subsea WGFM are installed for a long service life, 25 years up to 30 years in some cases. The mean time between failure (MTBF)⁵⁾ specified by vendors are also within that time span, but with subsea WGFM technology having been around less than 25 years, these theoretical MTBF numbers are unreliable.

A WGFM often contains a number of measurement systems (subsystems or building blocks) and if one system fails it would be very beneficial if its functionality could be taken over by another measurement system or a combination of other measurement systems. Having this redundancy (duplication and/or over-determined systems) allows the operator to execute verification checks on the meter as a particular measurement can be done twice with the benefit of being able to compare the two readings. For those applications with no or limited access, it is strongly recommended to apply systems that have as much redundancy as practically possible.

In addition, evaluation of the use of a virtual metering system (VMS) as fall-back is an option (see 6.8). Virtual metering systems are relatively low cost and easy to install. However, their ongoing maintenance often requires specialist involvement which can be costly, and also their uncertainty is often more difficult to assess. Note that a virtual metering system is not a replacement for conventional measurements or WGFM systems, and also is difficult to qualify.

5) MTBF is the predicted elapsed time between inherent failures of a system during operation.

5 Flow regimes

WGFMs may be influenced by flow regimes.

Brief descriptions for two-phase flow, multiphase flow and wet gas flow have already been provided in [2.58](#), [2.37](#) and [2.67](#) respectively. Both multiphase flow and wet gas flow are subsets of a two-phase flow (see [Figure 2](#)). For multiphase flows, there should be a minimum of three phases present (oil, water, and gas) and the GVF should range from 0 % to 100 %. For wet gas flows, gas flow — in terms of volume flow — should be dominant; thus, resulting in high GVF and the relatively small liquid volume flow can either be one-phase (two-phase wet gas flow) or more (multiphase wet gas flow). However, the differentiation between a two-phase wet gas flow and a multiphase wet gas flow is not always made in practice and generally just the term wet gas flow is used. This approach is also used in this Technical Report and, only where essential, the terms two-phase or multiphase are added to wet gas flow or wet gas flow measurement.

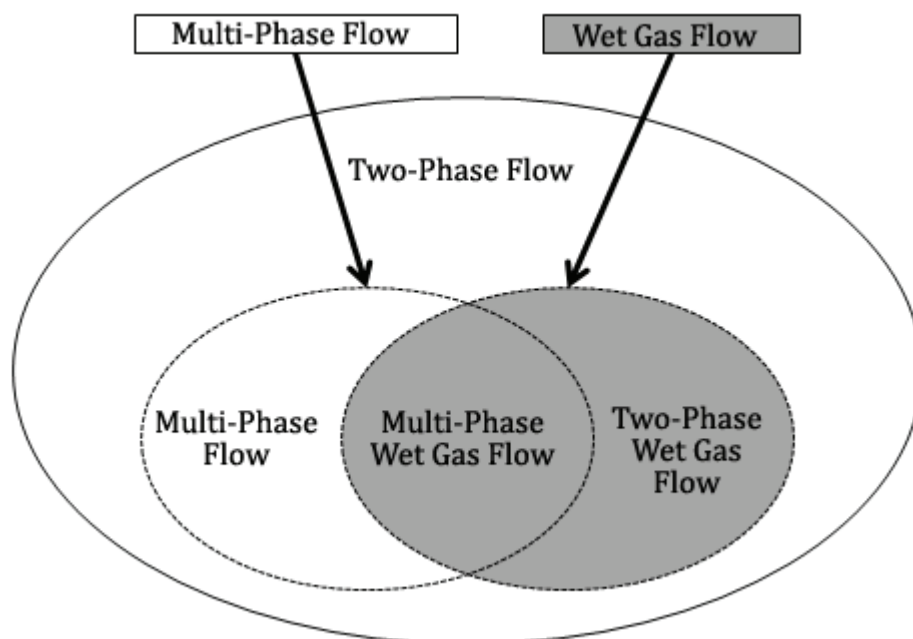


Figure 2 — Multiphase and wet gas flow shown as both a subset of a two-phase flow

The flow regime is a physical description of the way the liquid phase is dispersed in the gas flow. The flow regime is important in wet gas flow metering, as the dispersion of the liquid can influence the performance of flow meters. Many WGFMs designs perform better in a particular flow regime or attempt to induce a preferred flow regime.

Flow regimes are dictated by complex phenomena and are difficult to describe precisely. Fluid properties, phase flow rates, meter orientation, pipe geometry, and the line pressure and temperature all affect the flow regime. The transitions between different flow regimes are gradual with varying influencing parameters.

Flow regimes are presented depending on flow orientation. Given these complexities, these presentations are approximations and only representative of flow in long straight pipes. [Figure 3](#) shows typical horizontal and vertical flows. Most WGFMs are installed in one of these two orientations.

5.1 Horizontal wet gas flow regimes

For all horizontal wet gas flow regimes, the gas velocity is higher than the liquid velocity, i.e. there is slip between the phases.

5.1.1 Stratified flow

For a given gas to liquid flow rate ratio at relatively low pressure and gas velocity, i.e. a low gas dynamic pressure, the liquid weight is the dominant force on the liquid phase. In this case, the fluid phases are stratified. This is commonly termed “stratified flow” (or “separated flow”). The interface between the two phases can be smooth, but commonly has a disturbed (i.e. wavy) interface.

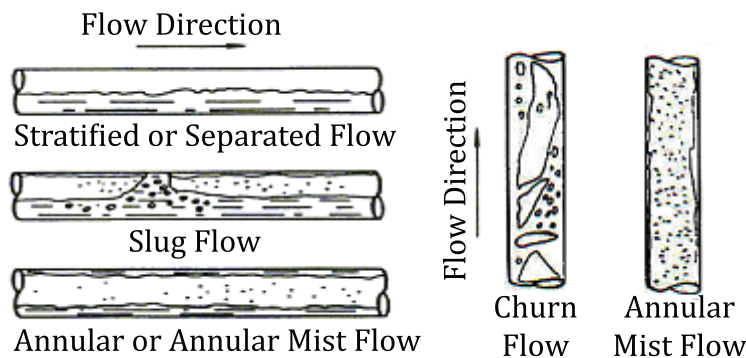


Figure 3 — Horizontal and vertical upward flow regimes

5.1.2 Slug flow

Excessive waves that nearly or completely fill the pipe cross section are termed slug flow. This is unstable flow and it is therefore generally not desirable to attempt to meter wet gas flow with a slug flow regime. Slug flow is one example of what is often called “intermittent flow”.

Slug flow should not be confused with “severe slugging”. Severe slugging is the irregular surge of a plug of collected trapped liquids in the upstream piping. This volume of liquid travels at relatively high speed and is potentially damaging to downstream equipment. The subsea riser or pipeline over rugged terrain are locations where severe slugging can occur. Slug catchers are common components in hydrocarbon production pipe lines. Severe slugging can have adverse performance effects on WGFMs.

5.1.3 Annular mist flow

At high dynamic gas pressures, i.e. high gas velocity and/or density, and higher gas-to-liquid ratio (higher GVF), the prevalent flow regime is annular mist flow.

The horizontal flow can have an asymmetrical ring of liquid around the periphery of the pipe with the gas flowing in a central core laden with entrained liquid droplets. As the gas dynamic pressure increases the entrainment increases, the annular ring depth reduces and the average drop size decreases.

At the extreme condition of the liquid being fully entrained, droplets are well dispersed in the gas phase. This mixture can be approximated as a pseudo-single-phase flow of averaged fluid properties as the slip ratio tends to unity. This condition is termed either mist flow, fully dispersed flow, or homogenous flow.

5.2 Vertical up wet gas flow regimes

Vertical and horizontal wet gas flows can have different flow regimes due to the influence of gravity.

5.2.1 Churn flow

For a given gas-to-liquid flow rate ratio at relatively low gas dynamic pressure, the wet gas flow is highly unstable. This flow regime is called “churn flow” and is generally undesirable for wet gas flow metering. It can exhibit the particular characteristic of having fluid structures that are momentarily moving against the bulk flow direction, or with a strong radial velocity component. Churn flow is another example of what is often called “intermittent flow”.

5.2.2 Annular mist flow

For a given gas-to-liquid flow rate ratio at higher gas dynamic pressure, the liquid's weight can be overcome and the flow becomes a symmetrical annular mist flow. As the gas dynamic pressure increases, annular mist flow behaves in the same way as it does in horizontal flow. The flow regime can be described as alternatively mist flow, dispersed flow or homogenous flow.

5.3 Vertical down wet gas flow regimes

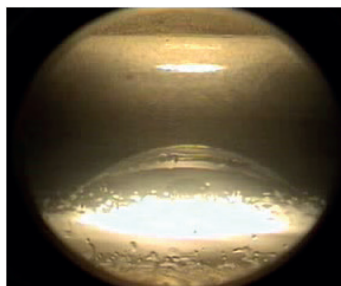
There are no diagrams presented for vertical down flow. All vertical down flow is considered to be annular mist flow as gravity acts in the same direction as the gas flow. For vertical down annular mist flow, the slip between the phases can be considerably different than with vertical up annular mist flow. This can cause the meter performance to be different.

5.4 Inclined flow

Knowledge of inclined pipe flow regimes is not well documented relative to that of horizontal and vertical flow regimes. It is known that even a few degrees positive or negative deviation from the horizontal can significantly affect a flow regime.

5.5 Examples of wet gas flow regimes

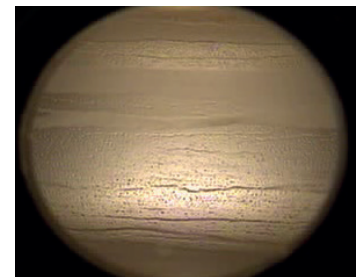
These pictures are photographs taken through a view port in the side wall of the pipe with the light source located at -120° from the camera angle.



a) Nominally stratified flow

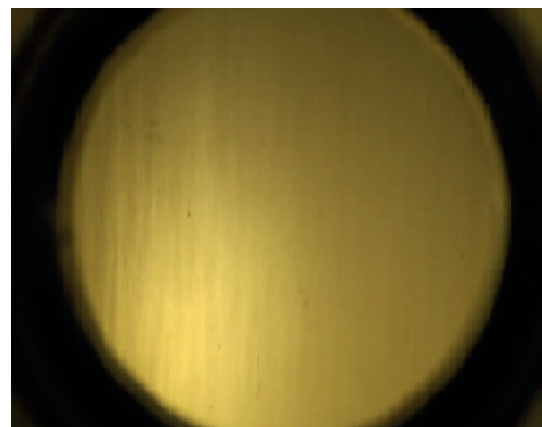


b) Annular mist



c) Transition between stratified and annular mist

Figure 4 — Examples of horizontal wet gas flow regimes



a) Vertical up churn flow

b) Annular mist vertical up flow

Figure 5 — Examples of vertical up wet gas flow regimes

[Figure 4](#) and [Figure 5](#) show a small set of examples of horizontal and vertical up wet gas flows. Real flow regimes generally behave in a more complex and unsteady way than suggested in the idealised diagrams of [Figure 3](#). Often, the actual flow regime is some hybrid regime in transition between two flow regimes.

In addition, most wet gas flow regime descriptions only discuss a gas and a liquid component. Most wet natural gas flow metering applications have liquid phase mixtures of both water and hydrocarbon. This can further alter wet gas flow regimes, both complicating the wet gas flow regime description and affecting the WGFM response.

- [Figure 4](#) a) shows nominally stratified flow. The fluids are natural gas and water. However, the water phase has gas bubbles entrained within it. At the same flow conditions natural gas and hydrocarbon liquid flow does not have gas bubbles in the liquid.
- [Figure 4](#) b) shows natural gas with a hydrocarbon liquid. The flow regime is annular mist.
- [Figure 4](#) c) shows natural gas with both hydrocarbon liquid and water. The flow regime is in transition between stratified and annular mist. Streaks of water, or “rivulets”, can be seen on the wall. Such behaviour is not known to occur if the gas flows with water alone or hydrocarbon liquid alone. That is, the mixture of water and hydrocarbon liquid causes a shift in flow regime compared to if the gas flows with only a single liquid component.
- [Figure 5](#) a) shows natural gas and water vertical up churn flow.
- [Figure 5](#) b) shows a natural gas and hydrocarbon liquid annular mist vertical up flow.

This complexity of flow regimes is one of the reasons why WGFM designs largely rely on semi-empirical correlations (sometimes called “slip models”). However, the slip models correlations are often confidential and considered Intellectual Property of the vendors.

5.6 Flow regime maps

Wet gas flow regime maps present qualitative illustrations of the different flow regimes at various conditions in a graphical format. Many such maps are for general two-phase flow where the wet gas region is a section of the overall flow condition range considered. Flow regime maps may be used to educate about wet gas flow behaviour and to predict the expected flow regime. Flow regime maps are typically not used as part of the metering process.

[Figure 6](#) shows a typical example of a horizontal flow map in the wet gas region for a nominally 4-inch line size, with natural gas and hydrocarbon liquid. Like many flow regime maps it is created from physical observation. There are no guidelines on how to create a flow regime map. For this reason flow regime maps can have different parameters on the axes. In this particular example these are the gas and liquid densimetric Froude numbers. It should be noted that flow regimes change gradually when the relevant parameters vary. The borders between the flow regimes do not represent step changes but rather the centre of transition regions.

The flow regime may change as the flow progresses through the WGFM. For example for DP meters the reduction of cross sectional area causes further local flow regime change. The acceleration of the flow causes the local flow regime to tend towards annular mist flow.

Although [Figure 6](#) may infer that slug flow will not occur with wet gas, it should be noted that this figure is only applicable across a specific range of flow conditions. When considering other wet gas flow conditions, the boundaries shown in this map change position, and there are wet gas flow conditions where slug flow does occur.

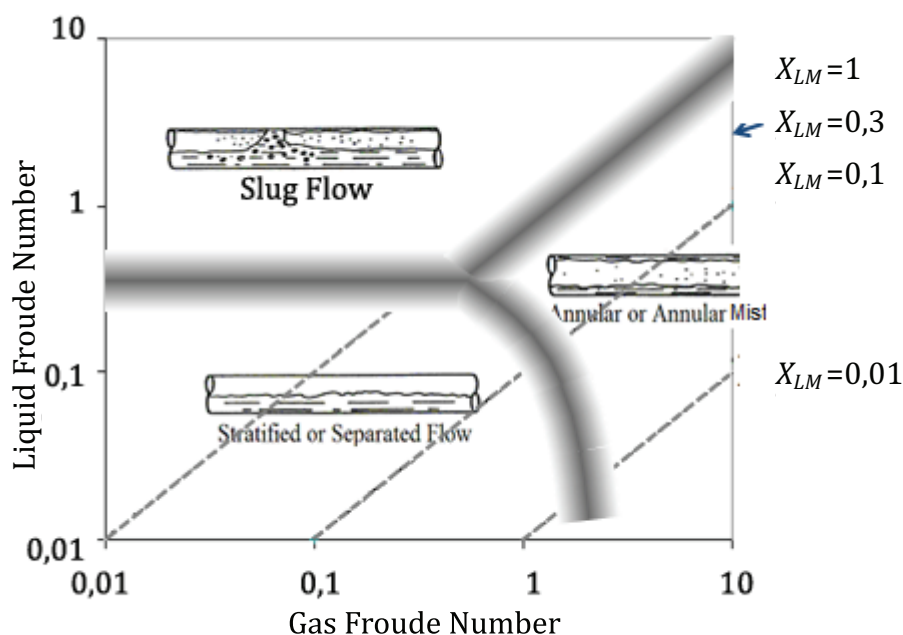


Figure 6 — An example of a natural gas and light liquid hydrocarbon horizontal flow regime map for a 4-inch line

5.7 Different wet gas flow parameters

It is common for different operators and WGFM manufacturers to use different parameters to describe liquid loading terminology. Hence, conversion between liquid loading terms is required.

Common parameters describing the “wetness” of a wet gas flow are the Lockhart-Martinelli parameter (X_{LM}), the Gas Volume Fraction (GVF), the Liquid Volume Fraction (LVF), the quality (x), the liquid to gas mass flow rate ratio or the liquid to gas volume flow rate ratio. These parameters are not all directly interchangeable. Some are related through the gas and liquid densities, and conversion equations for various wet gas flow parameters are given in [Annex B](#).

Defining the maximum value for liquid content of a wet gas flow has proved contentious. Academia, WGFM manufacturers and operators often have different ways of describing the wetness of gas flows. Furthermore, when one named parameter is chosen, there may still be debates on the precise definition of that parameter and what maximum value of that parameter constitutes the limit of wet gas flow.

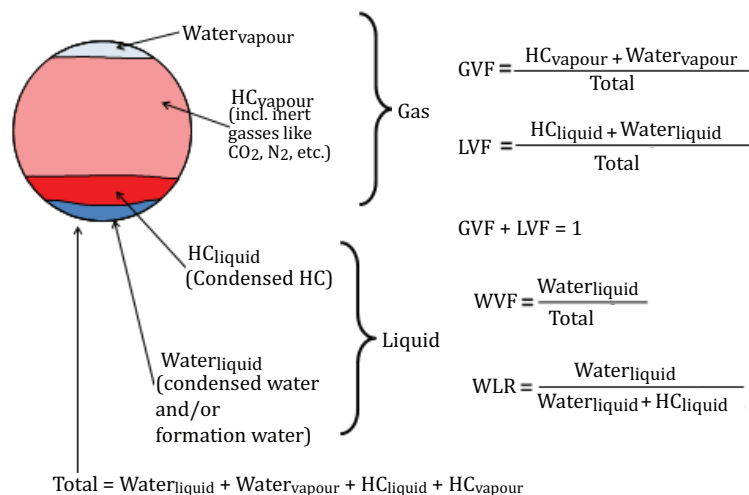
However, the Lockhart-Martinelli (X_{LM}) parameter (as defined in [2.32](#)) has become the most prominent parameter to be used to describe the liquid loading of a wet gas flow. A common definition for wet gas flow is a Lockhart-Martinelli parameter value less than approximately 0,3. This boundary value is intended to represent the approximate lower flow regime boundary from non-intermittent to intermittent flow regimes (see [Figure 6](#)). It should be noted that intermittent flow is an adverse flow condition for WGFM. Both the operator and the WGFM vendor should mutually understand the liquid loading and the WGFM operating range in terms of gas and liquid flow rates and flow regimes.

5.8 Water in wet gas flow

Water molecules can be present in either the liquid phase or the gas phase. Water in the gas phase is generally called water vapour and originally present in the reservoir gas. The water in the liquid phase can be a mixture of condensed water (condensed from the reservoir gas in the production process) and water from the reservoir aquifer (formation water). The latter is often saline water and should in principle not be produced; however, that cannot always be avoided. In particular, at a later stage in

the production process this water is breaking through in the well bore. In [Figure 7](#) a schematic cross sectional area is given of a wet gas flow with an indication of where water molecules can be found.

WGFMs are in principle able to measure the water content in the well production stream but it is not always straight forward what vendors actually mean by measuring water flow rate or WVF and this needs further clarification with the vendors.



NOTE Water in gaseous form tends to be called “water vapour”.

Figure 7 — A schematic figure showing where water molecules are present

6 Wet gas flow metering principles

6.1 General

In-line WGFMs measure a wet gas flow without the requirement for phase separation. In-line measurement of a wet gas flow is usually approached via three general methods.

- Single-phase gas flow meter with correction factor — Use a single-phase gas flow meter (often a conventional gas flow metering device) with a correction factor for the effect of liquid on the metering system. In these cases the liquid flow rate, required to determine the correction factor, must be estimated from an external source (see [6.2.1](#)).
- Two-phase WGFM — The gas and liquid (both water and hydrocarbon combined) flow rates are predicted with no additional external information regards the liquid flow rate required. This is generally known as a two-phase WGFM and will be referred to in this report as just WGFM (see [6.2.2](#)).
- Multiphase WGFM — A method that is characterized by the WGFM measuring the gas and liquid flow rates and also the gas, water and hydrocarbon liquid phase fractions. No external information is required regarding the liquid flow rate. In order to determine the correction factor, two methods can be used. In the first case, this correction factor is deduced from fully empirical or semi-empirical correlations deduced from tests. In the second approach a physical model is used taking into account the different interactions between the phases in the WGFM (see [6.2.3](#)). The physical model produces a semi-empirical correlation.

All three methods require the application of empirical or semi-empirical correlations, deduced from experimental data sets.

- Empirical correlations (i.e. mathematical data fit) apply a mathematical expression that is found to best represent a stated data set. There is no physical meaning to the chosen mathematical expression.
- Semi-empirical correlations apply a mathematical expression formed around a physical model. There is physical meaning to the chosen mathematical expression and only constants within the expression are fitted to a data set.
- The complexity of physical modelling, and hence the complexity of semi-empirical correlations, can vary widely between metering systems. Increasing the complexity and robustness of physical modelling, and the associated semi-empirical correlations, is at the fore-front of WGFM research and development.

This Technical Report addresses all three of these generic in-line WGFM technologies mentioned above.

The fourth approach to wet gas metering is phase separation. This traditional method uses a two- or three-phase separator to separate the natural gas, liquid hydrocarbon and water phases. Single-phase flow meters are used at the separator single-phase flow outlets. This wet gas metering system concept is simple, technically transparent and common. There are many applications where this is a successful technology. There are other applications where the use of a separator is not ideal as production conditions, and common financially driven operator practices, can adversely affect this multiphase wet gas metering methodology. This Technical Report briefly discusses these issues but concentrates on the in-line WGFM technologies.

There are examples of technologies that are hybrids of these different general methodologies.

6.2 In-Line wet gas flow meters

6.2.1 Single-phase gas flow meter with correction factor

Single-phase gas flow meters are often operated with wet gas flow. A single-phase gas meter will have a gas flow rate prediction error induced by the presence of liquid with the gas flow. For Differential Pressure (DP) meters these errors tend to be reproducible. For known fluid properties and liquid flow rate information (obtained from an external source) the gas flow rate prediction error tends to be correctable. This “wet gas correction factor” can be called a “wet gas correlation”. A wet gas correlation can be empirical or semi-empirical. Most commercial products using wet gas correlations have a heavy reliance on data fitting.

The liquid flow rate measurement is usually a spot measurement technique, including, but not exclusively using

- test separator historical data,
- tracer dilution methods, and
- PVT predictions.

The gas flow rate prediction uncertainty is influenced by the wet gas correlation, fluid property and liquid flow rate assumption uncertainties. Extrapolation of any wet gas correlation beyond the set laboratory flow conditions on which it was based can lead to gas flow rate prediction biases.

A DP meter with a wet gas flow correlation is a widely understood metering technology and is the most common way of measuring wet gas flow.