

API Recommended Practice for Measurement of Multiphase Flow

API RECOMMENDED PRACTICE 86
FIRST EDITION, SEPTEMBER 2005



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Upstream Segment

API RECOMMENDED PRACTICE 86
FRIST EDITION, SEPTEMBER 2005

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API Recommended Practice for Measurement of Multiphase Flow

1 Scope

This API Recommended Practice arose from a series of meetings that were held during 2003 among measurement experts from several producers who were active offshore in the Gulf of Mexico. This group, the Upstream Allocation Task Group, set out to address the general shortage of standards and recommended practices governing the measurement and allocation of flow in the upstream domain.

The group that developed this Recommended Practice (RP) was called the Well Rate Determination Subgroup, with the charter to make recommendations regarding measurement of flow rates from individual wells. However, as their work unfolded, the charge was slightly broadened to cover the more general subject of multiphase flow measurement, whether that flow was from a single well or the combined flow of two or more wells.

1.1 USE WITH OTHER RECOMMENDED PRACTICES

It is intended that this RP be used in conjunction with other similar documents to guide the user toward good measurement practice in *upstream* hydrocarbon production applications. The term *upstream* refers to those measurement points prior to, but not including, the custody transfer point.

Specifically this document will address in depth the question of how the user measures (multiphase) flow rates of oil, gas, water, and any other fluids that are present in the effluent stream of a single well. This requires the definition not only of the methodology which is to be employed, but also the provision of **evidence** that this methodology will produce a quality measurement in the intended environment. Most often, this evidence will take the form of a statement of the uncertainty of the measurement, emphasizing how the uncertainty statement was derived.

This RP will prove especially important when used in conjunction with other similar documents, such as those that address how commingled fluids should be allocated to individual producers. For example API RP 85 *Use of Subsea Wet-Gas Flowmeters in Allocation Measurement Systems* [Ref. 2] describes a methodology for allocation based on relative uncertainty, the identification of which is discussed in detail in section 8.

1.2. MULTIPHASE FLOW CLASSIFICATIONS

For the purposes of this document, the measurement of multiphase flow must address all possible conditions likely to be encountered in the production of oil and gas. Since it is impossible to prescriptively write a RP that addresses all possible conditions that might be encountered in actual practice, this will not be attempted here.

However, there are no conditions of the multiphase environment found in typical hydrocarbon production that are specifically excluded here. Conditions of individual phase flow rates, pressures, temperatures, densities, up- and downstream conditions, pipe orientation, or other parameters can and will be considered. Rather than addressing each case with a prescription of how measurement is to be performed, this RP asks that the prospective user first demonstrate that all aspects of the measurement problem for the application at hand are considered, and then describe in a quantitative, rigorous manner why the approach will be successful when implemented. Furthermore, the user should indicate how the RP's recommendations regarding measurement uncertainty at testing and field operating conditions will be applied in the allocation process.

1.3. FLOW RATE DETERMINATION METHODS

The methods for determination of individual well flow rate that might be covered by this RP are many. The following have been considered.

- conventional two- and three-phase separators with associated single-phase meters.
- in-line multiphase flow meters.
- multiphase flow meters which use two-phase, gas-liquid partial separators.
- techniques which make use of downhole measurements to estimate flow rates, e.g. nodal analysis or virtual meters

- downhole meters.

Of those listed here, all will be addressed further in this RP except the use of single-phase meters with conventional two- and three-phase separators. The interested reader is referred to the *Manual of Petroleum Measurement Standards* [Ref. 1] for an extensive discussion of those methods. The use of two- and three-phase separators in periodic well rate determination, from varying well-to-separator distances and configurations relative to the flow of the producing wells, is discussed further in this RP.

1.4 Other Relevant Work

API RP 85 was published in 2003. While the subject it addressed was different from that considered here, there is sufficient overlap in these two subjects that some topics are common to both. For example, much effort in the creation of RP 85 was expended in the area of calibration and verification of wet-gas meters. Although the methodologies of measurement and the multiphase flow regimes that are considered here are broader than those used in RP 85, it is clear that much of the material which was developed for RP 85 can be used largely without alteration in this Recommended Practice.

Likewise the Norwegian *Handbook of Multiphase Metering* [Ref. 3], published by the Norwegian Society for Oil and Gas Measurement (NFOGM), is a rich source of material which has recently been revised. With permission of the NFOGM, material from this document has been incorporated into this RP.

Some sections from the *Guidance Notes for Petroleum Measurement* [Ref. 4] which is published by the UK Department of Trade and Industry (DTI) have been included, particularly in section 8 on Uncertainty in Measurement.

Parts of a White Paper developed by the API Committee on Petroleum Measurement (COPM) (API Publication 2566, *State of the Art Multiphase Flow Metering*) has been used in detailing what a Factory Acceptance Test (FAT) consists of [Ref. 5].

Finally, some sections have been appropriated from an unpublished draft of a forthcoming ASME paper on wet-gas metering [Ref. 11].

2 Referenced Publications

1. American Petroleum Institute (API), *Manual of Petroleum Measurement Standards (MPMS)*.
2. American Petroleum Institute (API), Recommended Practice 85 *Use of Subsea Wet-Gas Flowmeters in Allocation Measurement Systems*.
3. Norwegian Society for Oil and Gas Measurement, (Norsk Foreing for Olje og Gassmåling), NFOGM, *Handbook of Multiphase Flow Metering*, currently under revision, expected publication date Q2/2005.
4. UK Department of Trade and Industry, *Guidance Notes for Petroleum Measurement*, Issue 7, December 2003.
5. American Petroleum Institute (API) Committee on Petroleum Measurement, Publication 2566, *State of the Art Multiphase Flow Metering*, May 2004.
6. International Organization for Standardization (ISO), *Guide to the Expression of Uncertainty in Measurement*, ISBN 92-67-10188-9, ISO, Geneva, 1993. [Corrected and reprinted, 1995].
7. American National Standards Institute (ANSI), *U.S. Guide to the Expression of Uncertainty in Measurement*.
8. British Standards Institute (BSI), Vocabulary of metrology, Part 3, *Guide to the expression of uncertainty in measurement*, BSI PD6461:Part 3:1995.
9. International Organization for Standardization, *Measurement of fluid flow—Evaluation of uncertainties*, ISO/TR 5168:1998.
10. International Organization for Standardization, *Measurement Of Fluid Flow By Means Of Pressure Differential Devices Inserted In Circular Cross-Section Conduits Running Full*, ISO 5167:2003.
11. ASME MFC Sub-Committee 19, Committee on Wet Gas Metering, *Wet Gas Flow Metering Guideline*, May 2005 (currently in draft form).

12. American Petroleum Institute (API), Recommended Practice 17A *Design and Operation of Subsea Production Systems*.
13. American Petroleum Institute (API), Recommended Practice 2A *Planning, Designing, and Constructing Fixed Offshore Platforms*.

3 Definitions and Nomenclature

3.1. DEFINITIONS

3.1.1 accuracy of measurement: The closeness of agreement between the result of a measurement and the true value of the measurand. [Ref. 6, B.2.14] A measurement system's ability to indicate values closely approximating the true value of the measured variable.

3.1.2 actual conditions: The actual or operating conditions (pressure and temperature) at which fluid properties or volume flow rates are expressed.

3.1.3 allocation: The (mathematical) process of assigning portions of a commingled production stream to the sources, typically wells, leases, units, or production facilities, which contributed to the total flow through a custody transfer or allocation measurement point.

3.1.4 allocation measurement: Measurement of production from individual entities (wells, fields, leases or producing units) in order to determine the percentage of hydrocarbon and associated fluids or energy contents to attribute to each entity, when compared to the total production from the entire system (reservoir, production system, gathering system). It is required when the entities have two or more different working interest owners, or when they have different royalty obligations.

3.1.5 allocation meter: A device used to measure the flow rates from a single well or input flowline for the purpose of *allocation*, as defined above; not to be confused with the *reference meter*.

3.1.6 arithmetic mean or average: The result one would obtain if a measurement were made an infinite number of times and the arithmetic average of the measurements were calculated; an estimate of the mean value based on averaging n samples is given by [Ref. 6, C.2.19]:

$$\bar{q} = \frac{1}{n} \sum_{k=1}^n q_k$$

3.1.7 calibration¹: The three step process of:

- 1) verifying the accuracy of an instrument at various points over its operating range, possibly in both the ascending and descending direction. See the definition of **Verification**.
- 2) adjusting the instrument, if it exceeds a specified tolerance, to conform to a measurement or reference standard.
- 3) re-verification, if adjustments were made, thus providing accurate values over the instrument's prescribed operating range.

3.1.8 combined standard uncertainty: The standard uncertainty of the result of a measurement when that result is obtained from the values of a number of other quantities, equal to the positive square root of a sum of terms, the terms being variances or covariances of these other quantities weighted according to how the measurement result varies with changes in these quantities [Ref. 6, 2.3.4]

3.1.9 commingle: To combine the hydrocarbon streams from two or more wells, units, leases, or production facilities into common vessels or pipelines.

3.1.10 compact separation: The separation of fluids in a production stream using equipment that is much smaller than that normally employed, and which can result in either *full* (complete) or *partial separation*.

¹ This definition of **Calibration** is entirely consistent with that of the API *Manual of Petroleum Measurement Standards (MPMS)* [Ref. 1], but is fundamentally different from that used by the International Standards Organization (ISO). Whereas both this definition and that found in the MPMS prescribe an adjustment to the meter should it be found out of range, the ISO definition does not permit such an adjustment. Indeed, although "the calibration may indicate a need for adjustment of the measuring instrument or measuring system", this is identified as a separate activity, not a part of calibration. The ISO definition of calibration is similar to what is defined in this document as **Verification**.

3.1.11 corrected result: The result of a measurement after correction for systematic error. [Ref. 6, B.2.13]

3.1.12 correction: The value added algebraically to the uncorrected result of a measurement to compensate for systematic error. [Ref. 6, B.2.23]

3.1.13 correction factor: A numerical factor by which the uncorrected result of a measurement is multiplied to compensate for systematic error. [Ref. 6, B.2.24]

3.1.14 coverage factor: A numerical factor used as a multiplier of the combined standard uncertainty in order to obtain an expanded uncertainty. [Ref. 6, 2.3.6]

3.1.15 custody transfer: Measurement of high accuracy where custody of a product is transferred from supplier/deliverer to the shipper/receiver, normally accompanied by a financial transaction based on this measurement.

3.1.16 emulsion: Colloidal mixture of two immiscible fluids, one being dispersed in the other in the form of fine droplets.

3.1.17 equations of state (EOS): Equations which relate the compositions, pressures, temperatures, and various other physical properties of gases and liquids to one another, and are used to predict the transformation of physical state when conditions change (see *PVT Analysis* below).

3.1.18 error (of measurement): The result of a measurement minus a true value of the measurand. [Ref. 6, B.2.19]

3.1.19 estimate: A measurement which has been corrected to remove the effects of *influence quantities*.

3.1.20 expanded uncertainty: A quantity defining an interval about the result of a measurement that may be expected to encompass a large fraction of the distribution of values that could reasonably be attributed to the measurand. [Ref. 6, 2.3.5]

3.1.21 experimental (sample) standard deviation: For a series of n measurements q_k of the same measurand, the quantity $s(q_k)$ characterizing the dispersion of the results; the positive square root of the experimental variance, given by the formula

$$\sigma_q = s(q_k) = \sqrt{\frac{1}{n-1} \sum_{k=1}^n (q_k - \bar{q})^2}$$

where $\bar{q}$ is the arithmetic mean of the n measurements. [Ref. 6, B.2.17]

3.1.22 experimental (sample) variance: For a series of n measurements of the same measurand q_k , the quantity $s^2(q_k)$ characterizing the variability of the results, given by the formula

$$\sigma_q^2 = s^2(q_k) = \frac{1}{n-1} \sum_{k=1}^n (q_k - \bar{q})^2$$

where $\bar{q}$ is the arithmetic mean of the n measurements. [Ref. 6, B.2.17]

3.1.23 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, etc. For example, liquid occupying the bottom of a horizontal conduit with the gas phase flowing above.

3.1.24 fluid: A substance readily assuming the shape of the container in which it is placed; e.g. oil, gas, water or mixtures of these.

3.1.25 full separation: The separation of fluids in a production stream in which the resulting streams are not multiphase, i.e. there are no liquids in the gas stream nor gas in the liquid stream.

3.1.26 gas-liquid ratio (GLR): The ratio of gas volume flow rate to the total liquid 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 total liquid (m^3/m^3).

3.1.27 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 (m^3/m^3).

3.1.28 gas volume fraction (GVF): The fraction of the total volumetric flow at *actual* conditions in the pipe which is attributable to gas flow, normally expressed as a percentage.

$$GVF = Q_g^v / (Q_g^v + Q_l^v)$$

3.1.29 hold-up: 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.

3.1.30 imbalance upper/lower control limit: A limit on System Balance (or Imbalance) that is established for the purpose of maintaining control of the overall process.

3.1.31 individual allocated quantity: A contributing meter's share of the master quantity that incorporates a calculated share of the system imbalance, so that the sum of all the allocated quantities equals the master quantity.

3.1.32 individual quantity: The quantity determined by an individual contributing meter or measurement point.

3.1.33 individual theoretical quantity: The quantity represented by an individual contributing meter or measurement point after conversion to a theoretical value by applying an Equation of State (EOS) or other correction factor, usually done in order to adjust the measured quantity for comparison at the same pressure and temperature base as the Master Quantity.

3.1.34 influence quantity: A quantity that is not the measurand, but that affects the result of the measurement. [Ref. 6, B.2.10]

3.1.35 liquid volume fraction (LVF): The fraction of the total volumetric flow at *actual* conditions in the pipe which is attributable to liquid flow, normally expressed as a percentage.

$$LVF = Q_l^v / (Q_l^v + Q_g^v)$$

3.1.36 Lockhart-Martinelli parameter: A parameter (usually shown in equations as X) used to indicate the degree of "wetness" of a wet gas, defined as

$$X = \frac{Q_l}{Q_g} \cdot \sqrt{\frac{\rho_g}{\rho_l}}$$

3.1.37 master quantity: The quantity measured by the reference meter(s) after commingling the individual streams.

3.1.38 material balance: The difference between the measured Master Quantity and the sum of the Individual Theoretical Quantities. Also called the System Balance.

3.1.39 measurable quantity: An attribute of a phenomenon, body or substance that may be distinguished qualitatively and determined quantitatively. [Ref. 6, B.2.1]

3.1.40 measurand: A particular quantity subject to measurement. [Ref. 6, B.2.9]

3.1.41 measurement: A set of operations having the object of determining a value of a quantity. [Ref. 6, B.2.5]

3.1.42 multiphase flow: Flow of a composite fluid which includes natural gas, hydrocarbon liquids, water, and injected fluids, or any combination of these.

3.1.43 oil-continuous multiphase flow: Multiphase flow in which the water and any other liquids present are distributed as droplets surrounded by liquid hydrocarbons (oil). Electrically the liquid mixture acts as an insulator, except in certain special cases involving heavy crudes.

3.1.44 partial separation: The separation of production fluids resulting in streams that are likely to be multiphase, i.e. wet gas and gassy liquid streams.

3.1.45 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.

3.1.46 phase mass fraction: The mass flow rate of one of the phases of a multiphase flow, relative to the total multiphase mass flow rate.

3.1.47 phase volume fraction: The volume flow rate of one of the phases of a multiphase flow, relative to the total multiphase volume flow rate.

3.1.48 pressure-volume-temperature (PVT) relationship: Application of Equations of State (EOS) to a composite fluid to calculate the change in properties in going from one set of conditions (P and T) to another.

3.1.49 random error: The result of a measurement minus its arithmetic mean, i.e. the error which deviates about the mean in an unpredictable, bipolar fashion. [Ref. 6, B.2.21]

3.1.50 reference meter: A flow meter used for the specific purpose of measuring the flow rate of one phase of the commingled stream, e.g. the liquid hydrocarbon flow rate. Sometimes reference meters are used to measure more than one phase, e.g. when total liquid flow and watercut are measured to determine oil and water rates.

3.1.51 relative error: The error of measurement divided by a true value of the measurand. [Ref. 6, B.2.20]

3.1.52 repeatability: The closeness of the agreement between the results of successive measurements of the same measurand carried out under the same conditions of measurement. [Ref. 6, B.2.15]

3.1.53 reproducibility of results of measurements: The closeness of the agreement between the results of measurements of the same measurand carried out under changed conditions of measurement, such as different location, time, reference standard, etc. [Ref. 6, B.2.16]

3.1.54 result of a measurement: A value attributed to a measurand, obtained by measurement. [Ref. 6, B.2.11]

3.1.55 slip: Conditions that exists when the phases have different velocities at a cross-section of a conduit.

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

3.1.57 slip velocity: The phase velocity difference between two phases.

3.1.58 specified imbalance limit: A limit on System Balance which is established for the purpose of satisfying contractual obligations and/or regulatory requirements.

3.1.59 standard conditions: A set of standard (or reference) conditions, in terms of pressure and temperature, at which fluid properties or volume flow rates are expressed.

3.1.60 standard deviation: The square root of the variance of a random variable.

3.1.61 standard uncertainty: An uncertainty of the result of a measurement expressed as a standard deviation. [Ref. 6, 2.3.1]

3.1.62 superficial phase velocity: The flow velocity of one phase of a multiphase flow, assuming that the phase occupies the whole conduit by itself. It may also be defined by the relationship (Phase volume flow rate / Pipe cross-sectional area).

3.1.63 system imbalance: The difference between the measured Master Quantity and the sum of the Individual Theoretical Quantities, sometimes referred to as the System Balance.

3.1.64 systematic error: The difference between the mean that would result from an infinite number of measurements of the same measurand, carried out under the same conditions, and the true value of the measurand. [Ref. 6, B.2.22]

3.1.65 true value: The underlying characteristic of the measurand which would be recorded if the measurement were perfect, i.e. there were no random or systematic measurement errors.

3.1.66 type A evaluation (of uncertainty): A method of evaluation of uncertainty by the statistical analysis of a series of observations. [Ref. 6, 2.3.2]

3.1.67 type B evaluation (of uncertainty): A method of evaluation of uncertainty by means other than the statistical analysis of a series of observations. [Ref. 6, 2.3.3]

3.1.68 uncertainty of allocation meter: The uncertainty of an Individual Theoretical Quantity relative to the flowing conditions experienced by the meter, which includes the uncertainty of the meter, any uncertainty in EOS application, as well as the uncertainties due to errors of ancillary devices such as pressure and temperature.

3.1.69 uncertainty of measurement: A parameter, associated with the result of a measurement, that characterizes the dispersion of the values that could reasonably be attributed to the measurand, often expressed in terms of its variance or standard deviation. [Ref. 6, 2.2.3, B.2.18]

3.1.70 uncertainty-based allocation: A method of hydrocarbon allocation in which the relative uncertainties of the measurements are taken into consideration, including measurements made by each of the allocation meters, by the reference meters, and by any other instrumentation, the readings from which affect hydrocarbon flow measurement.

3.1.71 uncertainty of reference meter: The uncertainty of the Master Quantity relative to the flowing conditions experienced by the meter.

3.1.72 uncorrected result: The result of a measurement before correction for systematic error. [Ref. 6, B.2.12]

3.1.73 value (of a quantity): The magnitude of a particular quantity, generally expressed as a unit of measurement multiplied by a number. [Ref. 6, B.2.2]

3.1.74 value of a measurand, true value of a measurand: These are equivalent, and preferred to the term “true value”. They represent the value that would be obtained by a perfect measurement. [Ref. 6, B.2.3]

3.1.75 variance: The expected value of the square of the difference between the measurement and its mean value.

3.1.76 verification: The process of confirming the accuracy of a meter or instrument by comparing its output to that of a Measurement Standard, a Reference Standard, or to the value of a Reference Material. Properly specifying a Verification process requires that an operating range has been defined for all the significant variables of interest, e.g. flow rates, pressures, temperatures, *gas volume fractions*, etc. and over which the device is expected to function. Also required is the specification of the tolerances that the various outputs of the device must achieve with respect to the Reference Standards used. See the definition of **calibration**.

3.1.77 void fraction: The cross-sectional area locally occupied by the gas phase of a multiphase flow, relative to the cross-sectional area of the conduit at the same local position.

3.1.78 watercut (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. The WC is normally expressed as a percentage.

3.1.79 water-liquid ratio (WLR): The water volume flow rate, relative to the total liquid volume flow rate (oil and water), at the pressure and temperature prevailing in that section.

3.1.80 well trajectory: The trajectory of production parameters displayed by a well over time, sometimes shown in a flow or composition map [e.g., see 5.2 and 5.5].

3.1.81 wet gas: A particular form of multiphase flow in which the dominant fluid is gas and in which there is a presence of free-flowing liquid.

3.2. Nomenclature and Symbols

Symbol	Meaning
A	Pipe cross-sectional area, or fractional cross-sectional area occupied by either gas or liquid
API	American Petroleum Institute
α_i	Liquid or Gas Volume Fraction
BOPD	Barrels of Oil per day
EOS	Equation(s) of State
ESP	Electrical Submersible Pump
FAT	Factory Acceptance Test
GOR	Gas-Oil Ratio

GLR	Gas-Liquid Ratio
GUM	ISO Guide to Uncertainty in Measurement
GVF	Gas Volume Fraction
I	System Imbalance
ISO	International Standards Organization
λ	Liquid Holdup or Gas Void Fraction
LVF	Liquid Volume Fraction
M	Murdock Coefficient
MCS	Monte Carlo Simulation
MPFM	Multiphase Flow Meter
MMS	US Minerals Management Service
m_g	Gas Mass
m_l	Liquid Mass
NFOGM	Norwegian Society for Oil and Gas Measurement
P, T	Pressure and Temperature at a Measurement Point
P _s , T _s	Pressure and Temperature at Standard (Reference) Conditions
psi	Pounds Per Square Inch
PVT	Pressure-Volume-Temperature
$\bar{q}$	Mean Value of a Random Variable q
Q_g	Gas Mass Flow Rate
Q_g^v	Gas Volume Flow Rate
Q_l	Liquid Mass Flow Rate
Q_l^v	Liquid Volume Flow Rate
Q_o	Liquid Hydrocarbon (Oil) Mass Flow Rate
Q_o^v	Liquid Hydrocarbon (Oil) Volume Flow Rate
Q_w	Water Mass Flow Rate
Q_w^v	Water Volume Flow Rate
ρ_g	Gas Density
ρ_l	Liquid Density
σ	Standard Deviation of a Random Variable
σ^2	Variance of a Random Variable
V	Velocity of Liquid or Gas in a Pipe
WC	Watercut
WLR	Water-Liquid Ratio
X	Lockhart-Martinelli parameter
x	Gas Mass Fraction

4 Introduction

4.1 GENERAL

As mentioned earlier in *Scope*, it is not intended that this Recommended Practice be used alone, but in conjunction with other similar documents to guide the user toward good measurement practice in upstream production applications.

Having said this, it is important to recognize that well rate determination is the single most important task which is to be undertaken in the measurement of oil and gas production and the subsequent allocation to individual wells and reservoirs, and for this reason, it is crucial to examine in great detail the various methods used for this task, and how each is influenced by its environment.

This section is an overview of the multiphase flow measurement environment, and of some of the methods employed to measure multiphase flow.

4.2 MULTIPHASE FLOW IN PIPES

In contrast to the case of single-phase flow, because the constituents of multiphase flow vary in their physical properties (density, viscosity, chemical composition, etc.), describing multiphase flow characteristics is usually quite difficult.

One typically identifies the various ways in which the constituents travel through the pipe in terms of their *flow regime*. This simply means the geometrical distribution in space and time of the individual phase components, i.e. oil, gas, water, any injected chemicals, and so on.

Which flow regime is assumed in a particular instance is not simply a function of the relative proportions of the individual constituents, but to other factors such as orientation of the pipe and the velocity of flow, among others.

Specific information regarding the kinds of flow regimes possible and the conditions in which they normally exist is provided in Section 5.

Another complication which must be recognized in attempting to characterize multiphase flow is the possibility that a change of the physical state of the flowing medium may occur. A multiphase fluid is made up of natural gas, hydrocarbon liquids, water, other fluids (some of which may have been injected into the stream), or any combination of these. Because pressure and temperature conditions may differ at various locations along the flow path between reservoir and points downstream, the fluid may exist solely as a vapor (gas), solely as a liquid, or as a mixture of both gas and liquid. Furthermore, these conditions can be expected to change over the lifetime of the reservoir is produced. The problem of measurement is raised to a new level of difficulty when compared to more traditional measurement of separated and stabilized gas and liquids.

4.3 APPROACHES TO WELL RATE DETERMINATION

The determination of flow rates of oil, gas, water, and other constituents can be accomplished in a number of ways, five of which shall be considered here:

Single-Phase Meters with Full Separation. The traditional method of measuring multiphase flow has been to separate the flow into either multiple single-phase streams (three phase separation) or a gas and liquid stream (two-phase separation). Single-phase meters are then used to measure the flow of the separated streams. This method ordinarily uses gravity separation in the form of a large vessel, but alternatively can employ a compact separator if total separation can be achieved. While these means of measurement can be accomplished using meters on a production separator, in the case of commingled flows from several wells a common embodiment is to use one or more specialized test separators periodically to test all the wells connected to a production platform. Because (1) such tests are by definition periodic, and (2) the length and path characteristics between the well and the test separator can vary between different wells, this approach inherently increases the uncertainty of the measurement.

Meters Used with Partial Separation. Recent years have seen the introduction of a number of innovative devices for phase separation. Although not as efficient at full separation as traditional devices, they offer certain advantages, such as smaller size and faster response. For metering applications, they may enhance the use of multiphase and wet gas meters by creating more favorable conditions to measure the partially separated streams, i.e. gassy liquid and wet-gas streams.

In-Line, Full-Bore Multiphase Flow Meters. This approach makes no attempt at separation, but simply measures physical characteristics of the fluids and their flow through the pipe to determine the flow rates of the phases.

Virtual Meters, Nodal Analysis. With the advent of downhole pressure and temperature sensors, one can create models to estimate multiphase flow rates by the combination of downhole and surface sensors in a virtual meter.

Downhole Meters. Finally, it is now possible to measure flow rates of the multiphase constituents as they leave the reservoir using downhole meters. Although meter design and operation is far more difficult than at surface conditions, the flow regimes encountered there may be more benign, and therefore easier to deal with from a measurement perspective.

In Section 6, a number of specialized applications of these general measurement methods are discussed.

4.4 MEASUREMENT UNCERTAINTY

Perhaps the most important single factor in the development of a strategy for well rate determination is the uncertainty in measurement that will result from various alternative schemes. However, because of the extremely complex nature of multiphase flow, there is no single number or curve, which can describe the performance of a measurement approach over the complete range of conditions which will be encountered in practice.

Because of this high level of complexity, a large portion of this Recommended Practice is devoted to the subject of measurement uncertainty. Some of the following topics are covered in Section 8 and its companion Appendix A:

- Commonly Used Uncertainty Standards and Methods
- Uncertainty Methodology
- Requirements for Presentation and Specification of Uncertainty
- Metering Performance Sensitivities
- Uncertainty Changes During Field Life
- Uncertainty from Calibration Measurements
- Effect of Influence Quantities on Uncertainty
- Uncertainty Verification

4.5 MULTIPHASE METER ACCEPTANCE, CALIBRATION AND VERIFICATION

Once a particular solution has been chosen for an application, procedures are required to demonstrate that the system is indeed satisfactory for the task at hand, not just initially but on a continuing basis.

Some aspects of this process are the following:

- *Test Facilities.* There are a limited number of multiphase flow facilities in the World. The facility used to prove a method's worth is of interest.
- *Acceptance Tests.* The program of acceptance testing and acceptance criteria, at the factory or elsewhere, is of great interest.
- *Meter Calibration.* The methods through which the sensors and flow calibrations take place should be documented and acceptable to both vendor and user.
- *Performance Verification.* In addition to verifying the meter's performance when accepting it, it is crucial to know that it is operating properly when in field operation.

4.6 INSTALLATION AND OPERABILITY OF MULTIPHASE FLOW METERS

When installing measurement equipment, whether on a topside platform, inland facility, or on the sea floor, it is clearly of great importance that the proper installation and normal operation be well understood and documented in detail. For this reason, a section is devoted to recommend procedures for insuring that this is, in fact, both documented and achieved in practice.

5 Multiphase Flow²

5.1 GENERAL

Multiphase flow is a complex phenomenon that is difficult to understand, predict and model. Common single-phase characteristics, such as velocity profile, turbulence, and boundary layer, are normally inappropriate for describing the nature of such flows.

The flow structures are often classified in flow regimes, the characteristics of which 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 is a gradual process. The determination of flow regimes in pipes in operational situations is not easy. Analysis of fluctuations of local pressure and/or density by means of gamma-ray densitometry has been used in experiments, and is described in the literature. In the laboratory, flow regimes may be studied by direct visual observation using a section of transparent piping. The description of flow regimes is therefore somewhat arbitrary, since their identification depends to a large extent on the observer and his interpretation.

The main mechanisms involved in forming the different flow regimes are (a) transient effects, (b) geometry or terrain effects, (c) hydrodynamic effects, and (d) a combination of these. 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 (not including pipe cross-sectional area) or pipeline 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 kilometers; severe riser slugging is an example of such an effect. In the absence of transient and geometry/terrain effects, the steady state flow regime is entirely determined by hydrodynamic effects, i.e. flow rates, fluid properties, and pipe diameter. A flow regime seen in purely straight pipes is referred to as a “hydrodynamic” flow regime. These are typical flow regimes encountered at a wellhead location.

All flow regimes however, can be grouped into dispersed flow, separated flow, intermittent flow, or a combination of these, as illustrated in the drawing, Figure 5.1. Dispersed flow ($L_B = 0$) regimes occur when small amounts of one phase are dispersed in a second, dominant phase. Examples of such flows are bubble flow and mist flow (Figure 5.2). Separated flow ($L_s = 0$) 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 (with low droplet entrained fraction), as shown in Figure 5.3. Intermittent flow is characterized by being non-continuous in the axial direction, and therefore exhibits locally unsteady behavior. Examples of such flows are elongated bubble, churn and slug flow (Figure 5.4). The flow regimes shown in Figures 5.2 – 5.4 are all hydrodynamic two-phase gas-liquid flow regimes.

Flow regimes effects caused by liquid-liquid interactions are normally significantly less pronounced than those caused by liquid-gas interactions. In this context, the liquid-liquid portion of the flow can therefore often be considered as a dispersed flow. However, some properties of the liquid-liquid mixture depend on the volumetric ratio of the two liquid components.

² The explanations and figures in this chapter were largely drawn from the Norwegian *Handbook of Multiphase Metering* [Ref. 3], published by the Norwegian Society for Oil and Gas Measurement (NFOGM), with their permission.

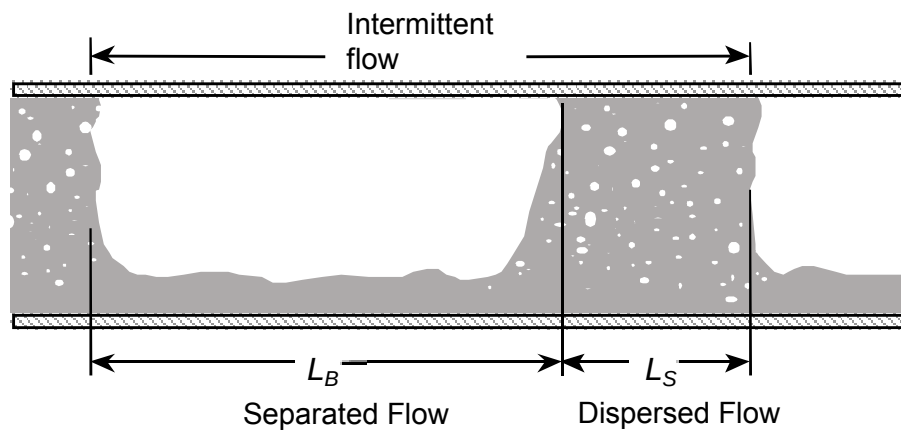


Figure 5.1—Multiphase Flow Regime

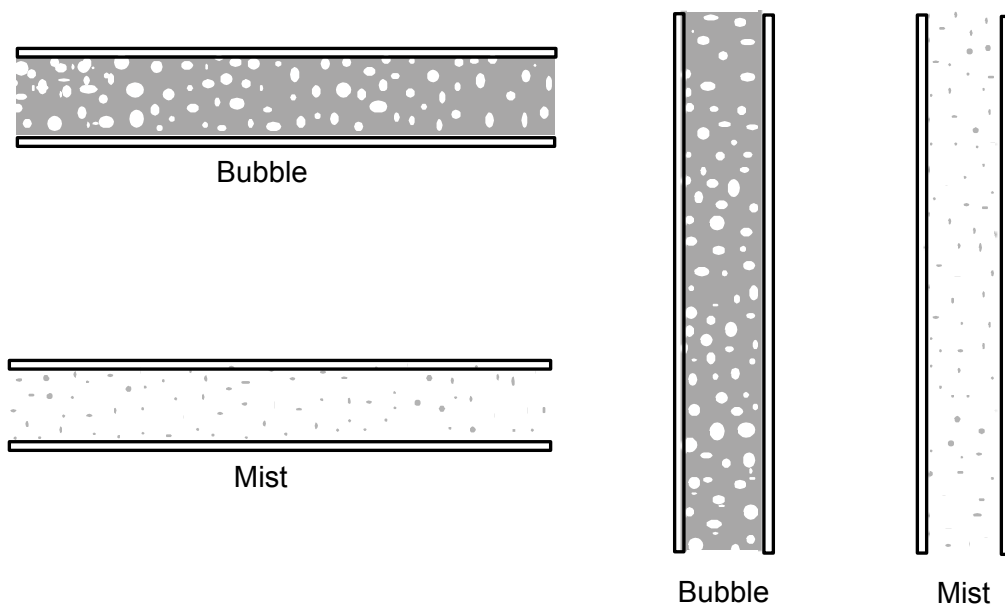


Figure 5.2—Dispersed flow

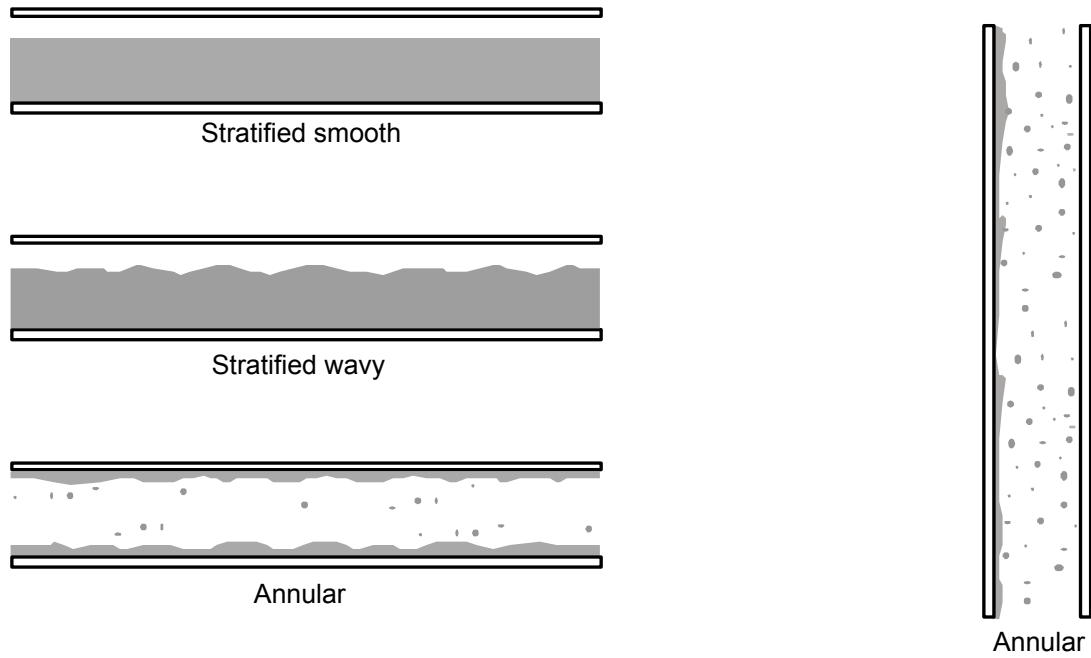


Figure 5.3—Separated Flow

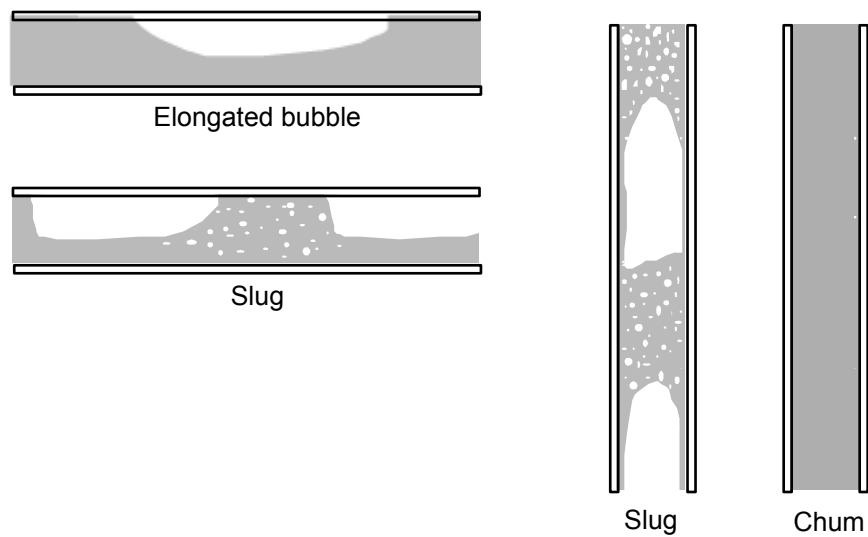


Figure 5.4—Intermittent Flow

5.2 TWO-PHASE FLOW MAP

It can be helpful to use graphical tools to assist in the understanding of multiphase flow, since the physics of the problem can be highly difficult to comprehend [Biblio. 5]. Perhaps the most used and well-developed tool for this purpose is the two-phase flow map, in which flow regimes are plotted on a two-dimensional map of superficial liquid velocity against superficial gas velocity.

The superficial gas velocity ($v_{s,gas}$) is the velocity at which the gas would flow if it were the only fluid in the pipe. In other words, superficial gas velocity is the total gas throughput Q_{gas} at actual operating conditions of temperature and pressure, divided by the total cross sectional area of the pipe (A). The superficial liquid velocity is defined in the same manner.

$$v_{s,gas} = \frac{Q_{gas}}{A} \quad v_{s,liquid} = \frac{Q_{liquid}}{A} \quad (5.1)$$

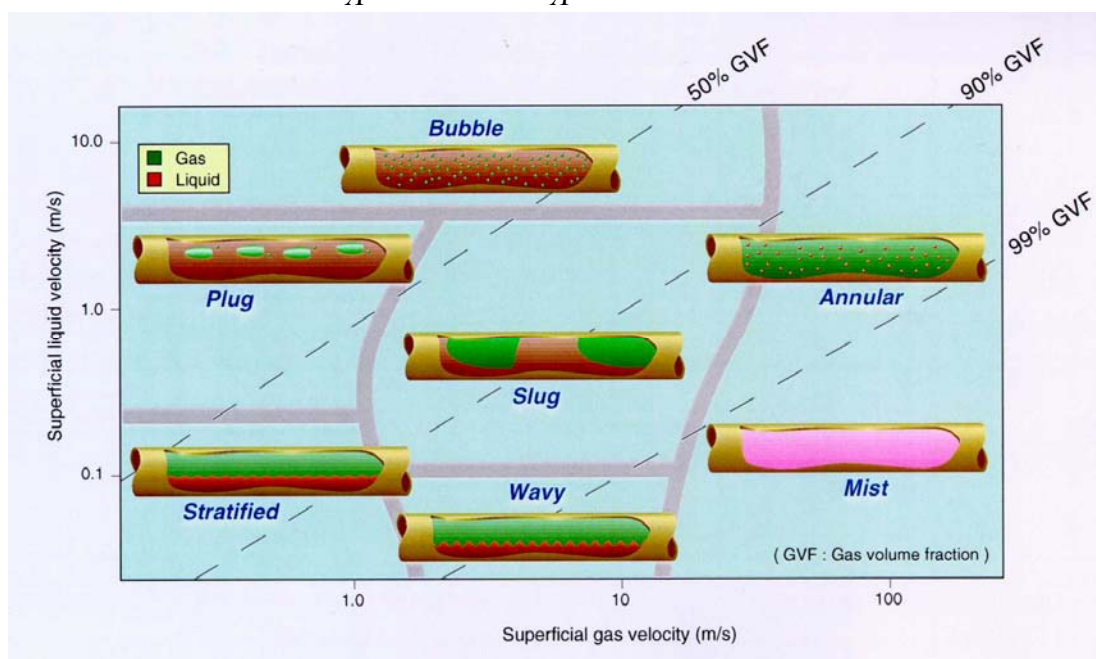


Figure 5.5—Generic Two-Phase Flow Map—Superficial Fluid Velocities Used Along Axes

The sum of the $v_{s,gas}$ and $v_{s,liquid}$ is the multiphase mixture velocity. However, the latter is a derived velocity and only has meaning if (a) the multiphase flow is homogeneous, and (b) both liquid and gas phases travel at the same real velocity.

$$v_m = v_{s,gas} + v_{s,liquid} \quad (5.2)$$

Figure 5.5 is a very general picture, and only approximates where the various flow regimes occur in horizontal flow, and where their boundaries with other regimes occur. Physical parameters like density of gas and liquid, viscosity, surface tension, etc. clearly do affect the flow regimes, but their effects are not included in this graph. A very important factor in locating the proper place on the flow map is the diameter of the flow line. For example, if the liquid and gas flow rates are kept constant and the flow line size is decreased from 4 inches to 3 inches, both the superficial gas and liquid velocities will increase by a factor of 16/9. Hence, in the two-phase flow map this point will move up and right along the diagonal to a new position. This alone 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 also have no sharp boundaries, but rather change smoothly from one regime to another.

The diagonal lines in this two-phase flow map are lines of constant gas volume fraction (GVF), which is defined as the fraction of the total volumetric flow at *actual* conditions in the pipe which is attributable to gas flow, normally expressed as a percentage. Generally oil fields operate in a GVF range between 40% (high pressure operations) and

90 – 95% (low pressure and/or gas lift operations). Oil field operations at high flow rates, located at the top right corner of the flow map, means higher productivity wells. However it also suggests higher maintenance costs due to the mechanical vibrations and erosion of production facilities, a mechanical rather than a fluid flow issue. Operating at lower flow rates, in the lower left corner of the two-phase flow map, means less than expected production rates, and thus oversized flow lines. Both these corners of the flow map should be avoided. The most commonly encountered flow regime in oil field operations is slug flow, in the center of the flow map. Gas field operations generally are situated on the right side of the flow map.

The two-phase flow map as presented in Figure 5.5 is a very general one and uses the diameter-dependent superficial velocity along the axis. A more practical and convenient presentation is the so-called Mandhane [Biblio. 27] two-phase flow map. Along the x and y -axis now the logarithm of the actual gas and liquid flow rates are plotted, respectively. For most applications it is sufficient to cover three decades along each axis. A number of flow regimes have been defined to make flow modeling and visual interpretation more straightforward. The actual boundaries between flow regimes are not as sharp as is indicated in Figure 5.5; they depend on density, viscosity, pressure, geometry, etc. The boundaries plotted here were determined experimentally in a low-pressure, four-inch, multiphase flow test loop, using diesel and air as the fluids.

Well production can be plotted in this flow map, and over time it will follow a certain trajectory as both the liquid and gas flow rates change. A collection of these trajectories can be used to define the production envelope of an oil field. Often this production envelope is defined as the region between minimum and maximum liquid and gas flow rates. As will be explained latter, multiphase flow meters likewise have preferred operating envelopes. It should be obvious that the production envelope of the well and the operating envelope of the meter should match. This is the first step in the selection of a suitable multiphase meter for a particular application.

Trajectory in 2-phase flowmap

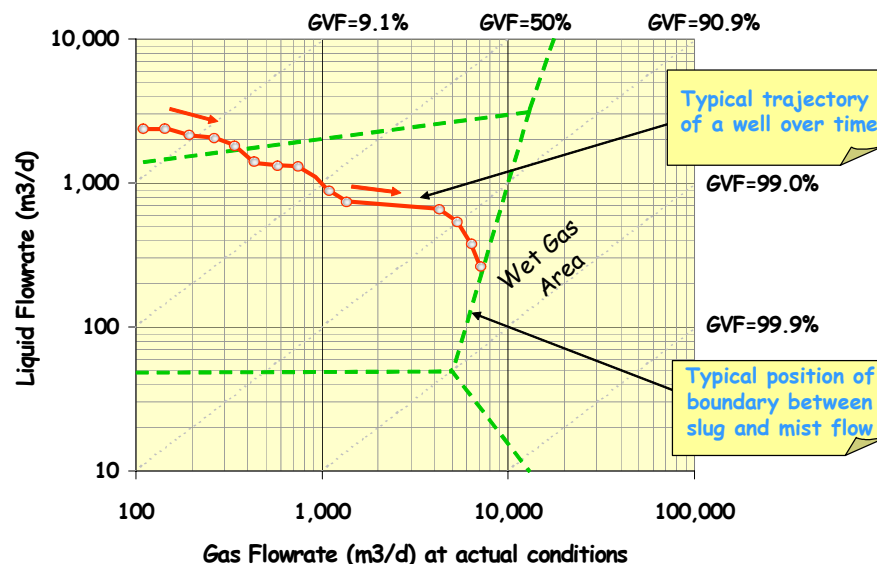


Figure 5.6—Example of Two-Phase Flow Map Used to Compare Expected “Trajectory” of Well (Production Envelope) and the Operating Envelope of a Multiphase Flow Meter

When gas and liquid flow together in a pipe, the fraction of the pipe’s cross-sectional area covered by liquid will be greater than it is under non-flowing conditions, due to the effect of slip between liquid and gas. The lighter gas phase will normally move much faster than the heavier liquid phase, and in addition the liquid has the tendency to accumulate in horizontal and inclined pipe segments. The liquid and gas fractions of the pipe cross-sectional area, as measured under two-phase flow conditions, is known as liquid hold-up and gas void fraction, respectively. Owing to slip, the liquid hold-up will be larger than the liquid volume fraction. Liquid hold-up is equal to the liquid volume fraction only

under conditions of no slip, when the flow is homogeneous and the two phases travel at equal velocities. With liquid hold-up and gas void fraction represented as λ and gas and liquid volume fractions represented by α ,

$$\lambda_{liquid} = \frac{A_{liquid}}{A_{pipe}}, \text{ Liquid Hold-up} \quad (5.3)$$

$$\lambda_{gas} = \frac{A_{gas}}{A_{pipe}}, \text{ Gas Void Fraction} \quad (5.4)$$

$$\lambda_{liquid} + \lambda_{gas} = I \quad (5.5)$$

$$\alpha_{liquid} + \alpha_{gas} = I \quad (5.6)$$

Only in no-slip conditions is the Gas Void Fraction (λ_{gas}) equal to the Gas Volume Fraction (α_{gas}) and the Liquid Hold-up (λ_{liquid}) is equal to the Liquid Volume Fraction (α_{liquid}). In the majority of the flow regimes, the Liquid Hold-up will be larger than the Liquid Volume Fraction and the Gas Void Fraction will be smaller than the Gas Volume Fraction (see Figure 5.7).

With the liquid hold-up and the actual velocities the superficial gas and liquid velocities can be calculated. Note that $V_{gas} \geq V_{s, gas}$ always.

$$\lambda_{liquid} \geq \alpha_{liquid} \text{ and } \lambda_{gas} \leq \alpha_{gas} \quad (5.7)$$

$$V_{s, gas} = \frac{Q_{gas}}{A_{pipe}} = \frac{Q_{gas}}{A_{gas}} \cdot \frac{A_{gas}}{A_{pipe}} = V_{gas} \cdot \lambda_{gas} \quad (5.8)$$

$$V_{s, liquid} = \frac{Q_{liquid}}{A_{pipe}} = \frac{Q_{liquid}}{A_{liquid}} \cdot \frac{A_{liquid}}{A_{pipe}} = V_{liquid} \cdot \lambda_{liquid} \quad (5.9)$$

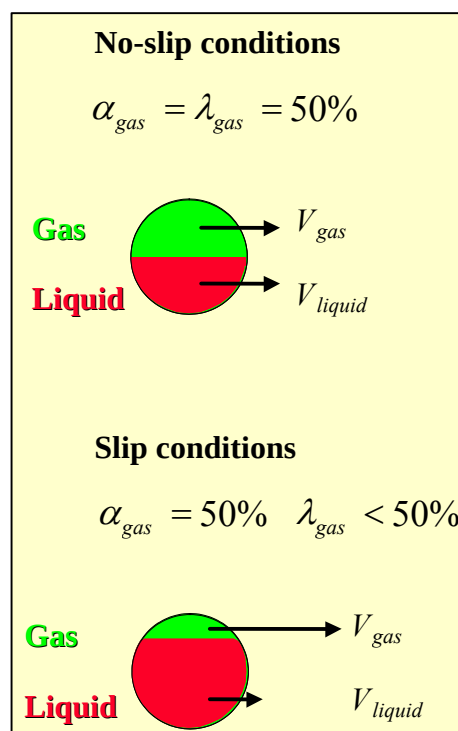


Figure 5.7—Difference between Gas Void Fraction and Gas Volume Fraction

5.3 FLOW REGIMES IN VERTICAL FLOW

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, as well as an increase in the volume occupied by the gas, both of which contribute to increases in Gas Void Fraction and Gas Volume Fraction.

Transitions between flow regimes in the vertical tubing of an oil well are illustrated in Figure 5.8, which shows the different hydrodynamic flow regimes which may occur in vertical liquid-gas multiphase flows.

It should be noted that Figure 5.8 is only a schematic illustration which is intended to show the transitions between the flow regimes as the superficial gas velocity increases from the bottom of the well up to the wellhead. In real production tubing it is rare that more than two or three flow regimes are present at one time.

Figure 5.9, similar to Figure 5.5, is a qualitative illustration using the two-phase flow map of how flow regime transitions are dependent on superficial gas and liquid velocities in vertical multiphase flow. As was pointed out previously, the transitions are also a function of several other parameters, e.g., tubing diameter, interfacial tension, density of the phases, and other fluid properties.

Note that, while the axes of Figure 5.9 are plotted on linear scales, in contrast to those of Figure 5.5, the essential data regarding flow regimes is unchanged.

5.4 FLOW REGIMES IN HORIZONTAL FLOW.

In horizontal flows too, the transitions are functions of factors such as pipe diameter and fluid properties. Figure 5.10 is another qualitative illustration, like Figure 5.5, of how flow regime transitions are dependent on superficial gas and liquid velocities, in this case in horizontal multiphase flow. It should be recognized that a map like Figure 5.10 will only be valid for a specific pipe, pressure, and multiphase fluid.

5.5 MULTIPHASE COMPOSITION MAP

An additional helpful tool in the selection process of multiphase flow meters is the composition map, with sediment and water (S&W) or watercut (WC) (in either % or fraction) on the *x*-axis and gas volume fraction (in either % or fraction) on the *y*-axis. An example of such a composition map is shown in the Figure 5.11.

Although at the outset a producing well would occupy a point on the map, a trajectory for the well can be plotted on the composition map, similar to the well trajectory in the two-phase flow map, as the WC and GVF increase over time. The region that is traversed by the well's trajectory defines its production envelope in the composition map. Similarly, a multiphase flow meter has its characteristic operating envelope in the composition map. Obviously the two envelopes should match if measurement is to be successful.

5.6 CONDITIONING OF MULTIPHASE FLOW

Just as in the case of single-phase flow, it can be advantageous for some measurement methods to employ devices for conditioning the flow characteristics prior to the actual making of the measurement. This generally takes one of two forms, either (1) mixing the fluid in an attempt to achieve either a homogeneous sample or no slip or both, or (2) the separation—either partial or complete—of liquid and gas streams for the purpose of improving the overall multiphase flow measurement.

5.6.1 Multiphase Flow Mixing

For many meters, it can be advantageous to know whether their sensors are influenced by the composite (average) or localized characteristics of the flow, and that the sensing element is not overly influenced by one phase over the others. For example, if a density measurement were to be made at the top of a horizontal pipe experiencing stratified flow, it would measure something close to the gas density. Conversely, if it measured at the bottom of the pipe it would measure the liquid density. Neither would give a true reading of the average density of the flowing material, so mixing the phases is an attempt to achieve these average measurements for obtaining mass flow rate in this case.

There are numerous examples in the literature of flow mixing [e.g. Biblio. 8].

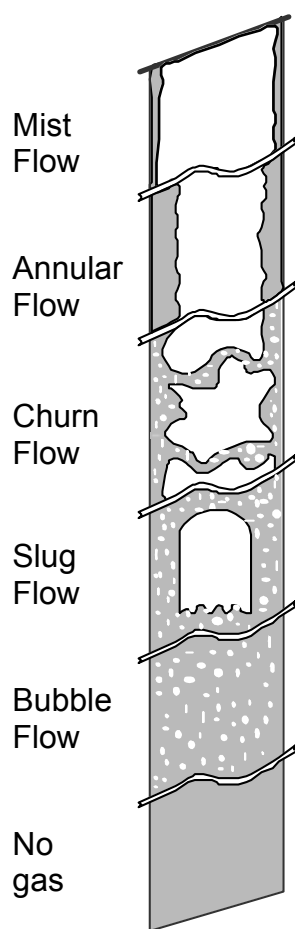


Figure 5.8—Schematic Transitions Between Flow Regimes in Oil Wells

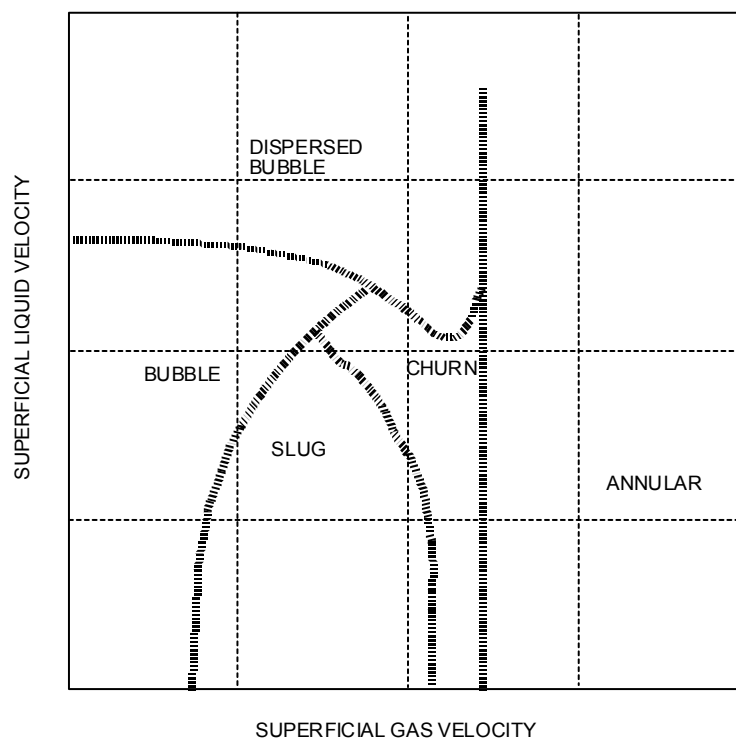


Figure 5.9—Two-phase Flow Map, Vertical Flow

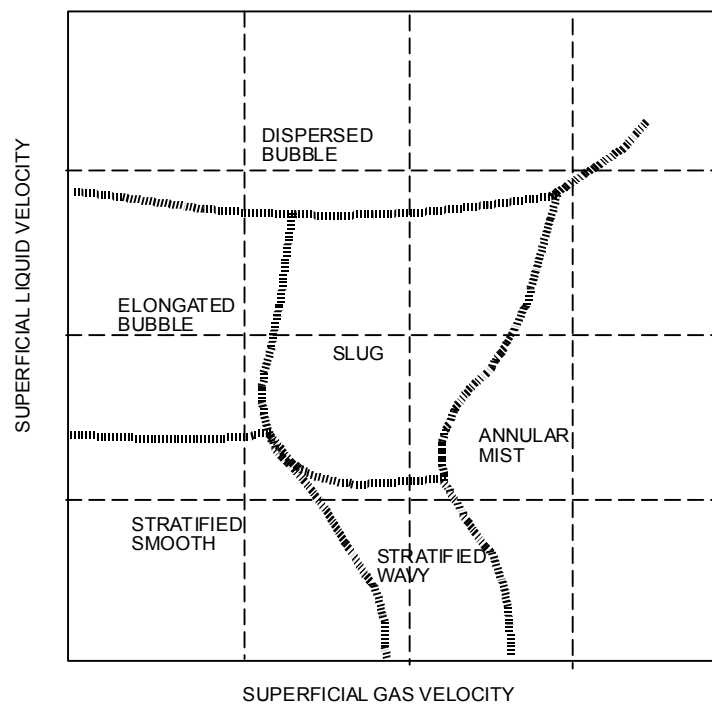


Figure 5.10—Two-phase Flow Map, Horizontal Flow