

API Recommended Practice for Measurement of Multiphase Flow

API RECOMMENDED PRACTICE 86
FIRST EDITION, SEPTEMBER 2005



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API Recommended Practice for Measurement of Multiphase Flow

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 exist 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.

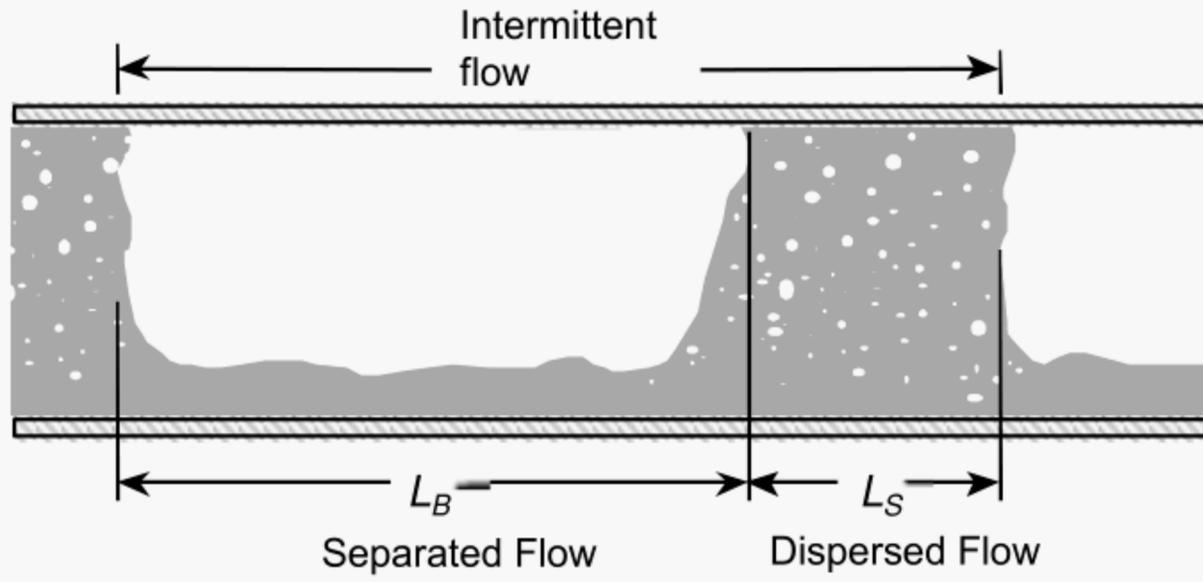


Figure 5.1—Multiphase Flow Regime

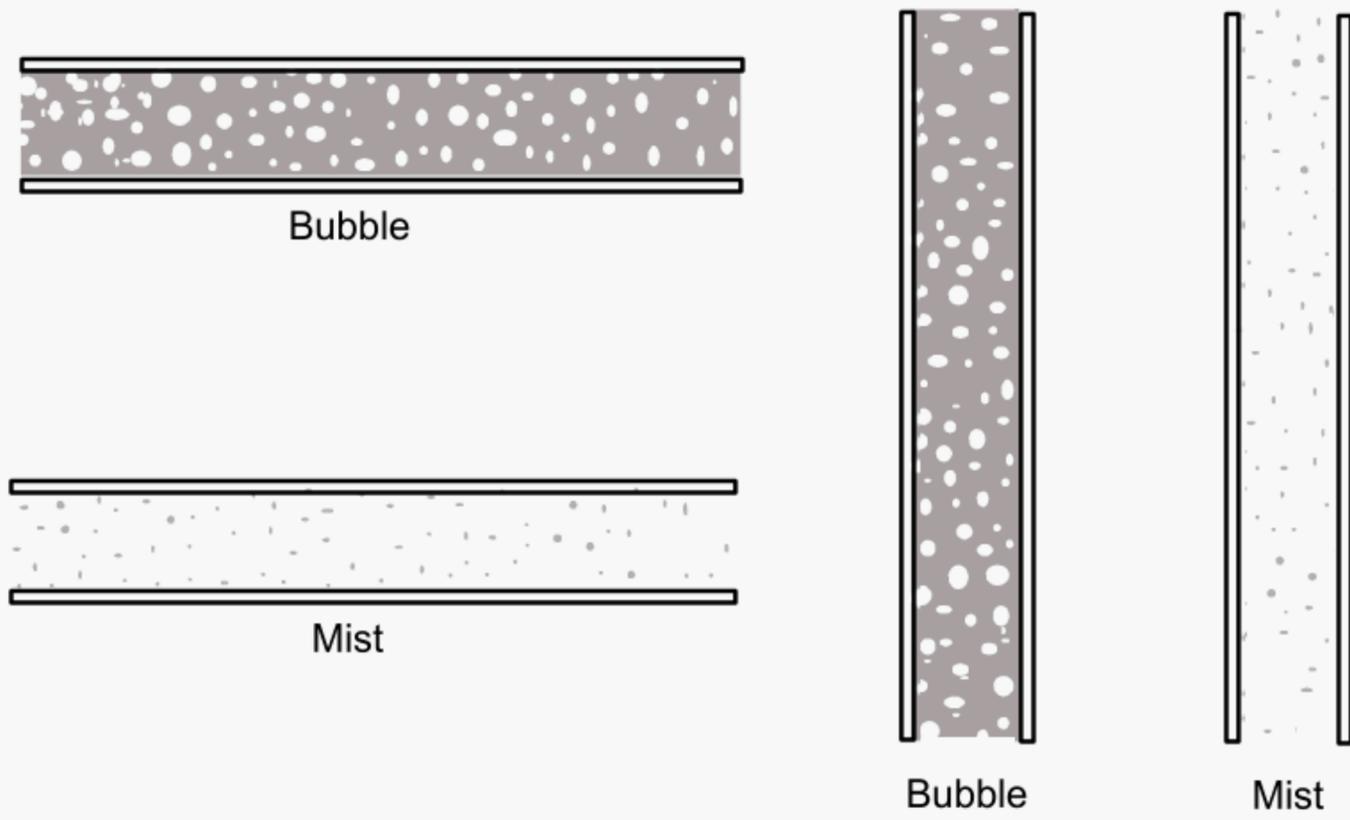


Figure 5.2—Dispersed flow

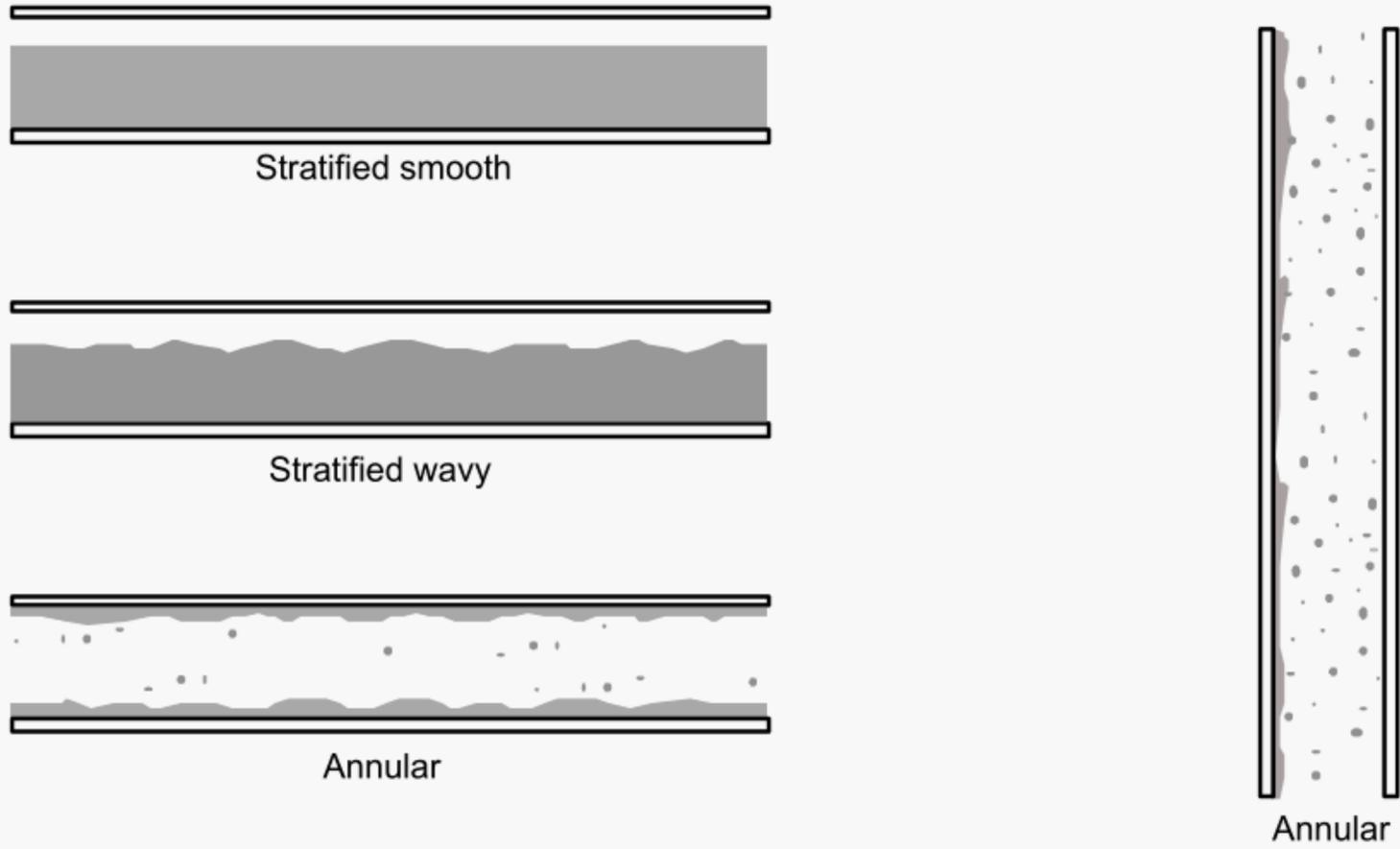


Figure 5.3—Separated Flow

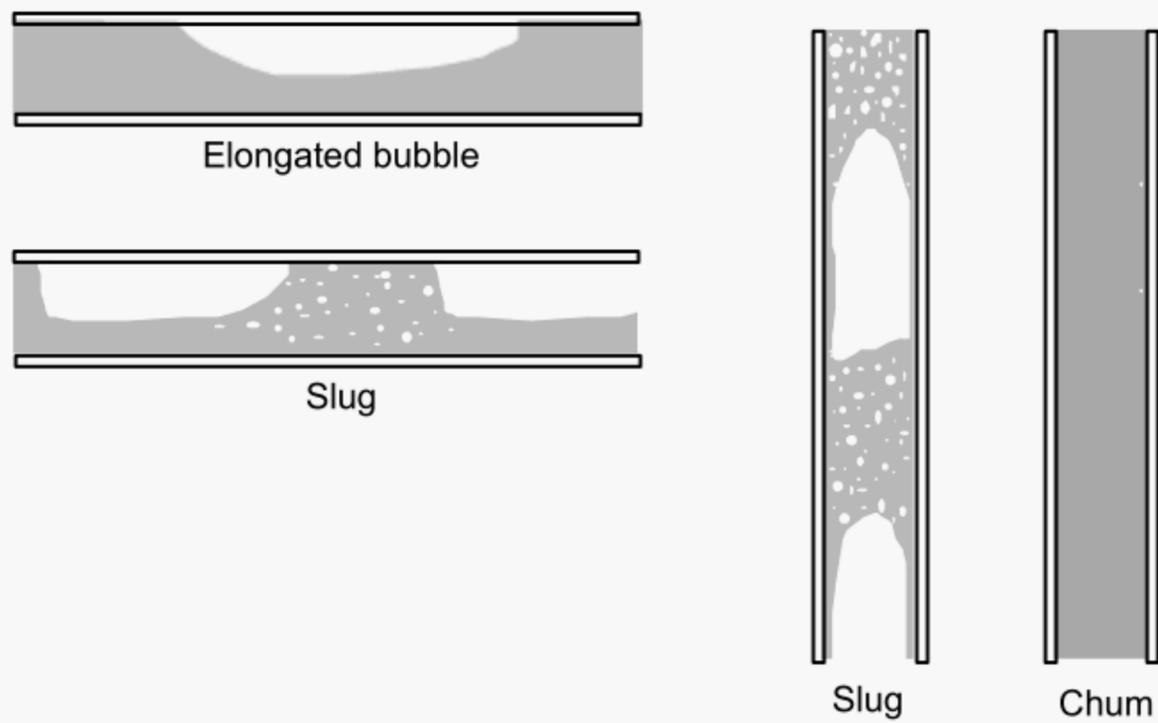


Figure 5.4—Intermittent Flow

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 ($v_{s, \text{gas}}$) 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.

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

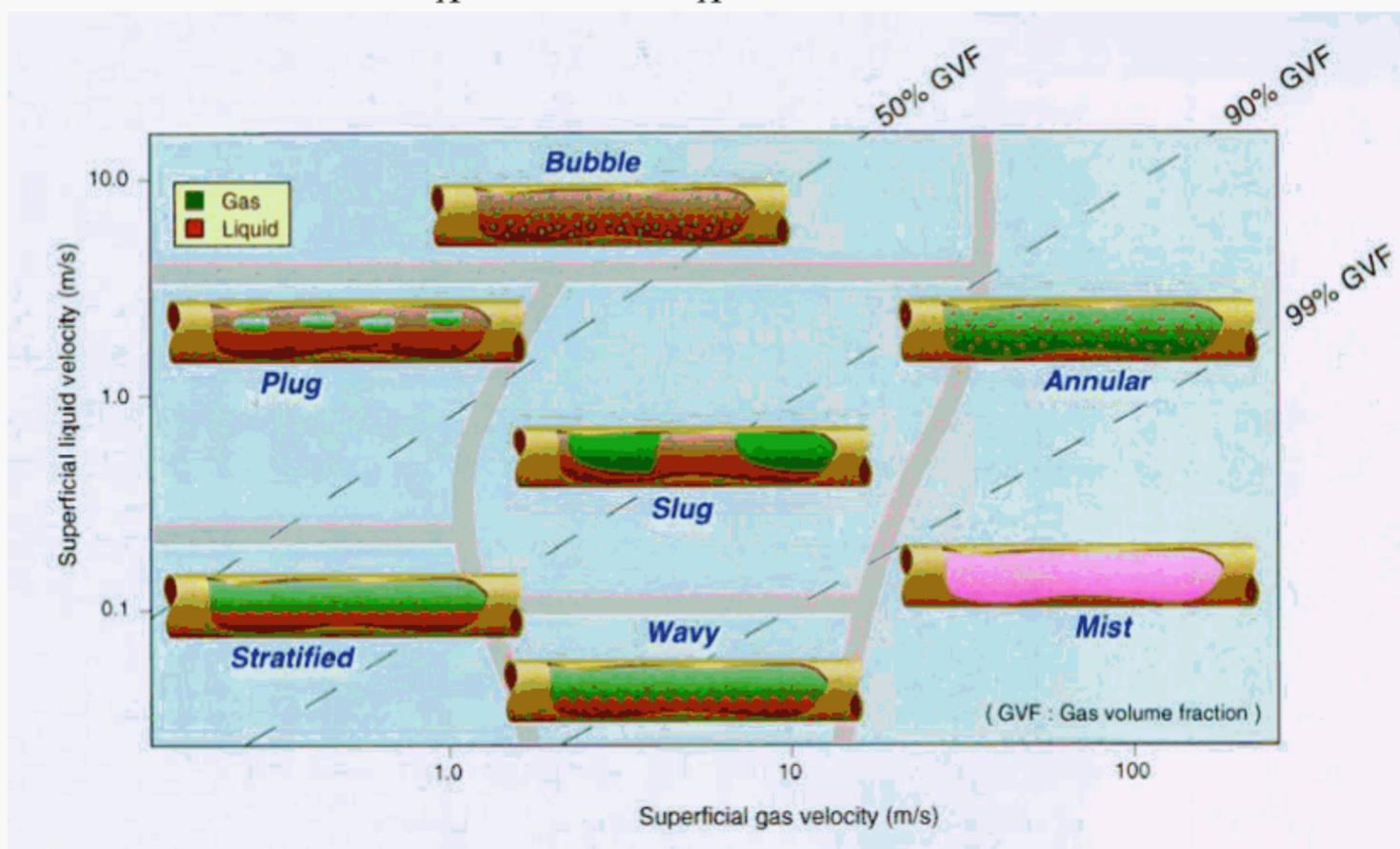


Figure 5.5—Generic Two-Phase Flow Map—Superficial Fluid Velocities Used Along Axes

The sum of the $v_{s, \text{gas}}$ and $v_{s, \text{liquid}}$ 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.

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

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 later, 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

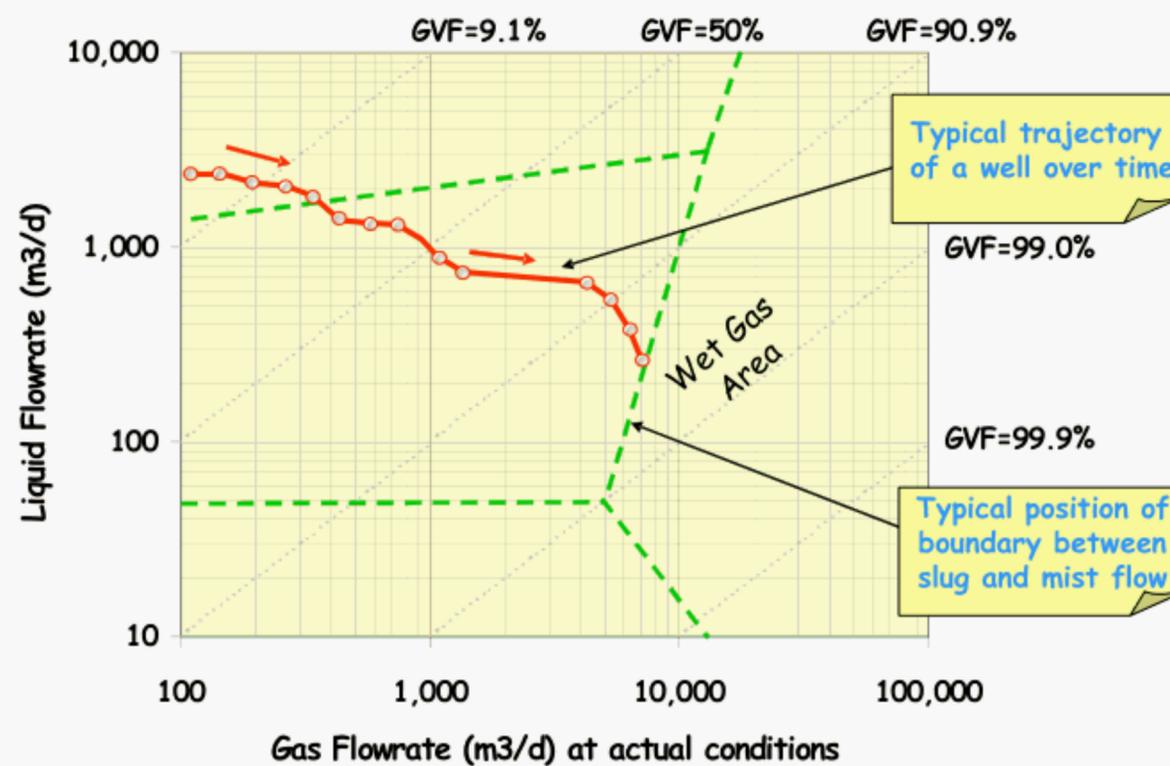


Figure 5.6—Example of Two-Phase Flow Map Used to Compare Expected “Trajectory” of Well (Production Envelope) and the Operating Envelope of a Multiphase Flow Meter

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 ,

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

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

$$\lambda_{liquid} + \lambda_{gas} = 1 \quad (5.5)$$

$$\alpha_{liquid} + \alpha_{gas} = 1 \quad (5.6)$$

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.

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

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

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

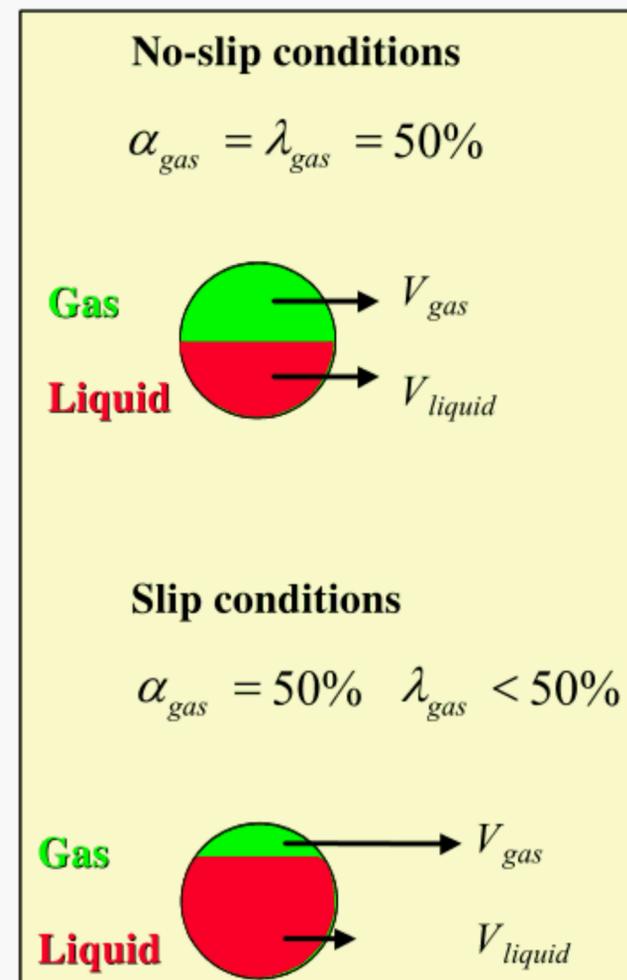


Figure 5.7—Difference between Gas Void Fraction and Gas Volume Fraction

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.

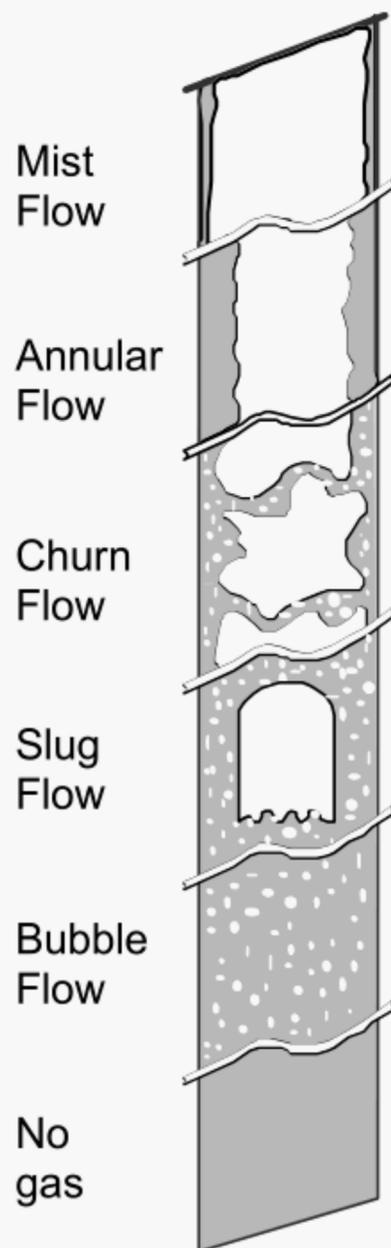


Figure 5.8—Schematic Transitions Between Flow Regimes in Oil Wells

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].

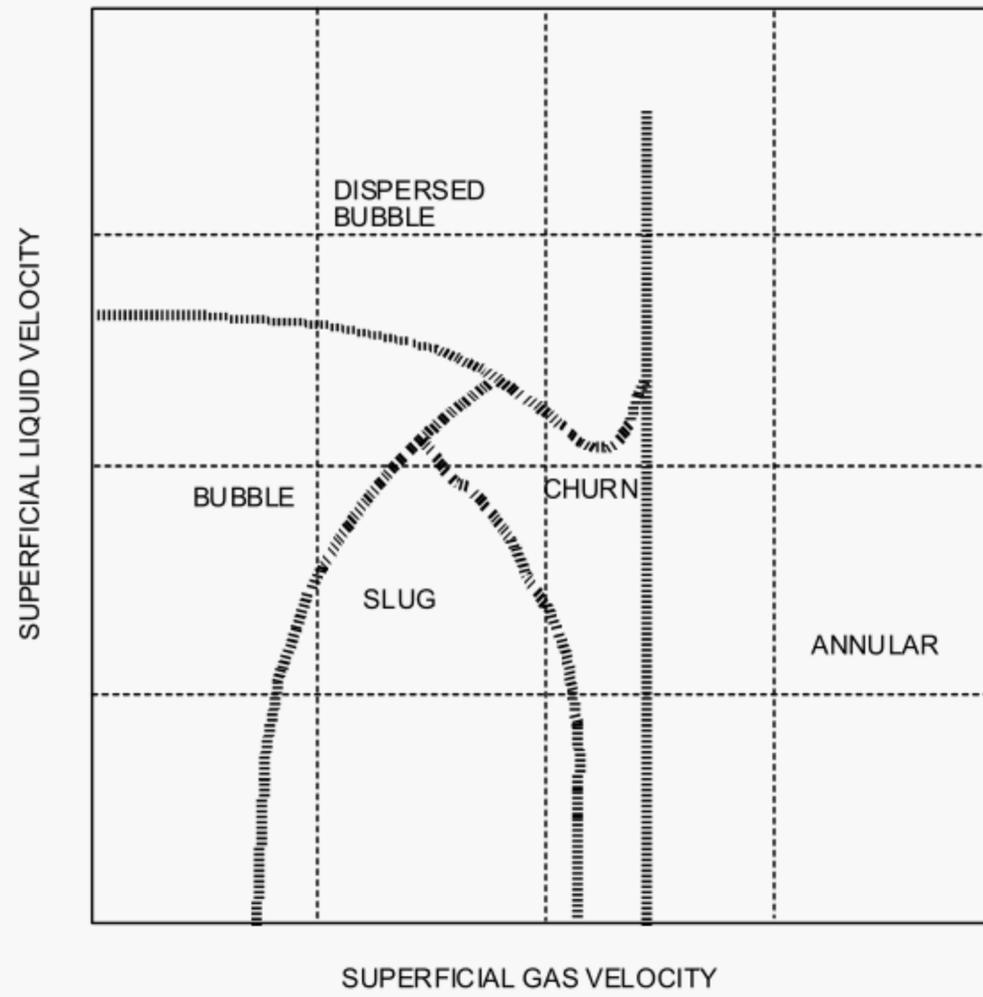


Figure 5.9—Two-phase Flow Map, Vertical Flow

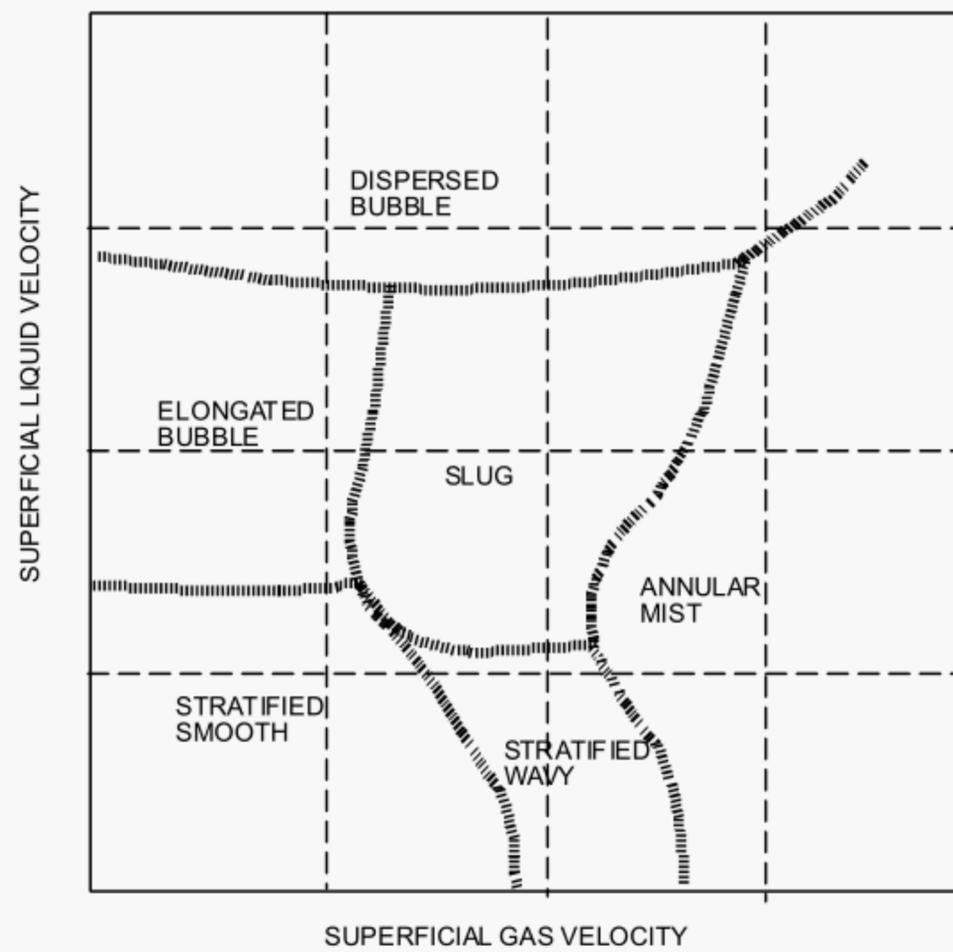


Figure 5.10—Two-phase Flow Map, Horizontal Flow

Trajectory in composition map

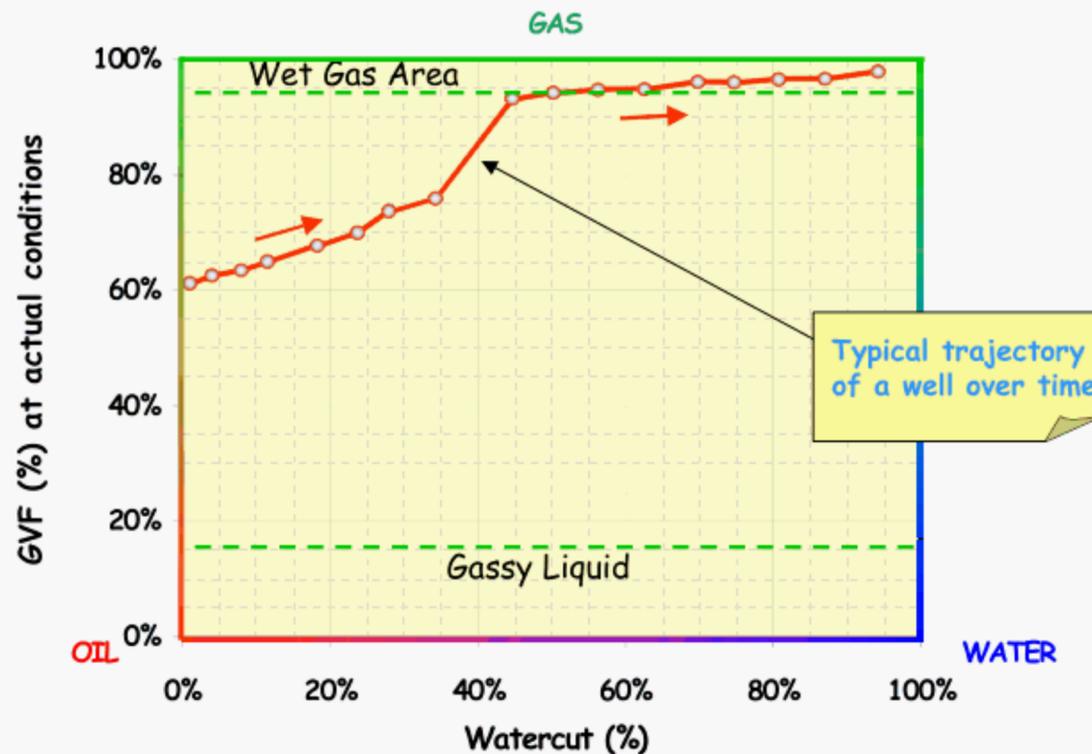


Figure 5.11—Composition Map “Trajectory” of a Well Using Gas Lift, Used to Compare Expected Fluid Composition with the Operating Envelope of a Multiphase Flow Meter

5.6.2 Separation

The other direction multiphase flow conditioning can take is that of separation, either partial or complete. If the latter, then the multiphase flow problem is essentially solved by destroying its multiphase nature. The price for doing this is high, however, since it likely requires large separator vessels and well-maintained control systems and single-phase meters. This solution can be costly in terms of equipment footprint and operating/design costs. Furthermore, this solution normally entails individual well tests, which, due to their periodic nature and to the variability of well-to-separator distances and path conditions, increase uncertainty in the well rate determination. The pipeline between the well and the separator may also experience liquid hold-up fluctuations, further requiring an extended test period.

From the perspective of measurement, a more interesting form of separation is partial separation, which is the separation of multiphase flow streams into a gassy liquid stream and a wet gas stream. What makes partial separation interesting is (1) the compactness that can be achieved for the separator plus meters, and (2) the possibility of improving the quality of the measurement. The reasons for improvement in measurement are discussed in 7.3. Numerous references can be found for various embodiments of partial separation [Biblio. 6,7].

6 Application of Multiphase Flow Measurement in Well Rate Determination

Because the range of applications for multiphase flow measurement is so broad and is expanding rapidly, it is difficult to specify a framework in which to describe how it is practiced. Here we choose to identify applications in two ways. First we attempt to characterize them by the physical locations where the meters will reside. Second, we identify all those functions in which some form of multiphase well flow rate determination is performed.

6.1 APPLICATION BY PHYSICAL LOCATION

6.1.1 Onshore Production Flow Measurement

Because the multiphase flow meters developed and commercialized to date have been expensive when considered for onshore applications, their use there has been much less frequent than offshore, though there are certain exceptions. In cases where production rates are sufficiently high, or where it is difficult to use separators at the point where measurement is required, multiphase flow meters may be found. Examples are Oman, with its high flow rates and

difficult measurement conditions, and the heavy oil regions of Venezuela, where emulsions make normal methods of measurement extremely problematic.

When individual well production rates are low and production is commingled prior to allocation or custody transfer measurement, it is common to determine well production rates through periodic well testing. The governing authorities ordinarily dictate the allowable period between such well tests.

In the past, such periodic well testing was often done using a “portable” test separator or a small permanent installation. Recently small rigs on the back of light trucks have emerged with multiphase flow meters and sufficient valves and other plumbing to perform well tests in a more efficient manner. Whereas previously a large truck and crew were needed to run a portable test that, in addition to actual measurement time, required a considerable period to fill and later empty the separator, now a much smaller truck and rig can do the job in far less time.

Although the high price of multiphase flow meters has hindered their widespread use in onshore applications in the past, in recent times the trend has been toward lower-priced devices. It is anticipated that this trend will continue, and as it does, more and more onshore locations will find multiphase flow meters both technically attractive and economically justifiable.

6.1.2 Offshore Topside Measurement

This is the spot where multiphase flow meters first came to be recognized as an alternative to test separators for determination of individual well flow rates. Since the beginning of the 1990’s their advantages over test separators have been exploited, some of which include the following:

- Reduction in space needed for measurement.
- Reduction in test time required.
- Reduction in weight.

Where the use of dedicated multiphase flow meters on individual wells is possible, continuous surveillance provides additional benefits, such as:

- Elimination of uncertainty due to well rate shifts between periodic tests.
- Reduced uncertainty caused by liquid hold-up variations in flow lines.

The use of well testing and test separators is still an acceptable means of well rate determination in most instances, and does offer some advantages over multiphase metering solutions, such as:

- The capability of collecting a sample is easier.
- Single-phase meters are less complex and more generally understood by personnel.

6.1.3 Offshore Subsea Measurement

Once the measurement community became comfortable with the concept and use of multiphase flow meters, the next step was to put them ever closer to the well. In particular, by placing a meter at the point where production exited the well, the operator could realize all the advantages mentioned in 6.1.2, but also some others as well. In particular, the placement of the meter at the wellhead eliminates the need for test flow lines from the wells and their associated plumbing to isolate each well for test. Further, by making the measurement this way, any uncertainty introduced by flow through a test line (which may be quite long) is eliminated.

6.1.4 Downhole Multiphase Flow Measurement

By moving the measurement of production into the borehole, further advantages can be gained in cases where the rates are sufficiently high. One of the most interesting possibilities is the opportunity to measure which zones in a well are producing specific fluids, and from this information to make choices about current and future production.

6.1.5 Virtual Meters and Nodal Analysis

Although downhole meters are conceptually of great importance, at this point in time they have not reached the point where they are economically feasible on any but the most expensive and exotic wells. In the meantime, downhole pressure and temperature sensors are becoming much more ubiquitous around the World. Using the outputs of these sensors – sometimes at multiple points along the well bore – models can be constructed that can estimate production with reasonable accuracy, both from the individual zones as well as from the well as a whole.

For more on how these measurements are used to obtain information on well rate, the interested reader is referred to 7.5.

6.2 APPLICATION BY FUNCTION

6.2.1 General Well Surveillance and Monitoring

Prior to the advent of multiphase flow measurement technology, it was normally impractical to monitor the state of flow from an individual well on a continual basis. Furthermore, the use of a flow line and a separator with periodic well tests to observe well performance meant that any short-term changes could not normally be detected.

Multiphase flow meters have changed all this. Eliminating the separator has meant that the performance of the well could be monitored in real time, and the ability to place the meter right at the wellhead has provided the opportunity to see changes as they take place. Not only does measurement by separators using periodic well tests reduce the opportunity to see these instantaneous changes, but the dynamics of separators actually further mask these effects because of the vessel volume and fluid flow control.

6.2.2 Reservoir Management

The ability to know how much oil, gas, and water a particular well is producing on a continual basis can be extremely beneficial in maximizing its life and cumulative hydrocarbon production. By observing not just pressures and temperatures but actual flow rates as well, one can spot trends, perform analyses, and take steps that otherwise would never have been possible.

Taking this reasoning a step farther, by measuring multiphase flow from individual zones in the well, an operator can make intelligent decisions in managing all the reservoirs supplying the well.

6.2.3 Allocation of Production

One of the most common applications where information on flow rates from individual wells is required is in the allocation of hydrocarbons that have been commingled. The allocation is based on whatever source of information is at hand— periodic well tests, multiphase flow meters, single phase meters, or any other means. Based on these data, the production that has been accumulated over a given period, measured at a point of relatively high accuracy, is allocated back to the production facilities, leases, units, and wells from which it was produced.

6.2.4 Other Allocation

In addition to allocating the hydrocarbon production from the contributing wells, there are often other allocations that are required in practice. For example, when byproducts of the process have a negative economic impact on the individual producers, these costs must be allocated in an equitable fashion. Two examples of this are produced water disposal and the taxation of flare gas in some jurisdictions.

7 Principles and Classification of Multiphase Flow Measurement

The goal of this section is to introduce the reader to the subject of multiphase flow measurement. Multiphase flow measurement is the measurement of a flow that does or will consist of both gas and liquid components during parts of its flow path.

The measurements are made using various combinations of sensors, sometimes in conjunction with ancillary devices, such as flow mixers or separation systems, and in other cases with no flow conditioning at all. Sometimes the flow is measured in a single-phase gas or liquid state (e.g. separation vessel outflow) but possibly before the gas and liquids are stabilized. Therefore, phase behavior computations must be applied when comparing these measurements to those made at downstream measurement points. In the context of hydrocarbon measurement, flow measured under these conditions is still defined as multiphase.

7.1 MEASUREMENT PRINCIPLES—COMPOSITION

7.1.1 Gamma Ray Technology

7.1.1.1 Single-energy Gamma Ray Densitometry

The use of gamma ray absorption in the multiphase fluid, typically from the attenuation of 667-keV photons from a Cs-137 source, is the most common way of measuring fluid density, one of the key parameters used in most multiphase flow meters.

7.1.1.2 Multiple-energy Gamma Ray Spectroscopy

By using a source which emits gamma rays with two or more different energies one can use these distinct spectral lines as input to a model of the multiphase fluid, then invert the spectral measurements to obtain the relative fractions of oil, water, and gas present. Several meters have been developed that use gamma-ray spectroscopy for phase fraction estimation [Biblio. 8, 9, 10].

7.1.2 Permittivity of Fluid

The measurement of permittivity (relative dielectric constant) is a means of estimating the aqueous phase(s) of a multiphase stream. In particular, permittivity measurement using *capacitance* or *microwave* sensors is a common means of estimating **watercut** or **water fraction** in oil-continuous or wet gas flows [Biblio. 5, 25].

7.1.3 Conductivity of Fluid

In some cases of multiphase flow, the amount of water is great enough that it is the dominant liquid phase. In these instances, permittivity sensors such as those mentioned above may have difficulty dealing with a conductive medium in the space where the measurement is to be made. Some meters therefore employ *inductive* methods to measure the bulk conductivity of the fluid rather than trying to estimate its permittivity [Biblio. 5, 25].

7.1.4 Coriolis Force

In flow lines where gas has been eliminated, Coriolis measurement has shown the ability to reliably estimate watercut of the two-phase liquid by use of its density measurement [Biblio. 18].

Recently Coriolis meters have been introduced which claim the ability to operate when GVF ranges from 0 – 25% or 75 – 100% [Biblio. 19].

7.2 MEASUREMENT PRINCIPLES—FLOW

7.2.1 Differential Pressure Devices

The most widely practiced method of multiphase mass flow measurement is through use of differential meters. The most common of these is the Venturi meter, which is attractive because of the ease with which liquids may pass through. Other forms of differential-pressure inducing elements used in these applications are orifice, wedge, V-cone [Biblio. 24], and certain forms of Venturi in which recovery pressures are measured [Biblio. 15].

Since meters making use of differential pressure have been extensively used and studied for many years, standards [Ref. 1, Chapter 14; Ref. 10] have been developed to guide the user in their efficient deployment to minimize problems. Although the manner in which these meters are used in a multiphase environment may be at odds with some requirements called out in these standards, the practical knowledge reflected in these documents should be used to suggest how the measurement might be optimized.

In some instances [Biblio. 5, 6] differential pressure is used as a means of density estimation.

7.2.2 Cross Correlation

Some multiphase flow meters are equipped with two or more identical sensors that are used for estimating the flow velocities by cross correlation methods, which provide an estimate of the difference in time when measured features are observed on the sensors.

This method could be employed using virtually any kind of sensor combinations, but has generally been employed using electrical (permittivity or conductivity) or gamma-ray sensors [Biblio. 5, 25].

7.2.3 Positive Displacement

The principle used in these meters can be used as an element in a multiphase meter to provide total volumetric flow rate [Biblio. 6].

7.2.4 Ultrasound

Although they have not seen wide usage, ultrasonic meters have been used in wet gas with some success [Biblio. 16, 17].

7.3 METERS USED WITH COMPACT OR PARTIAL SEPARATION

By separating the multiphase fluid stream into (a) wet gas and (b) gassy liquid streams, conceptually one can address the multiphase flow measurement problem using two meters, each of which operates in a favorable region of the multiphase map. The success of such a strategy is obviously dependent on how well the separation can be achieved, and how well each of the two meters performs on the partially separated streams.

The concept of metering using partial separation is illustrated in Figure 7.1.

This technique, which was briefly discussed in 5.6.2, is described in several references to specific instruments [Biblio. 6, 8, 20, 26].

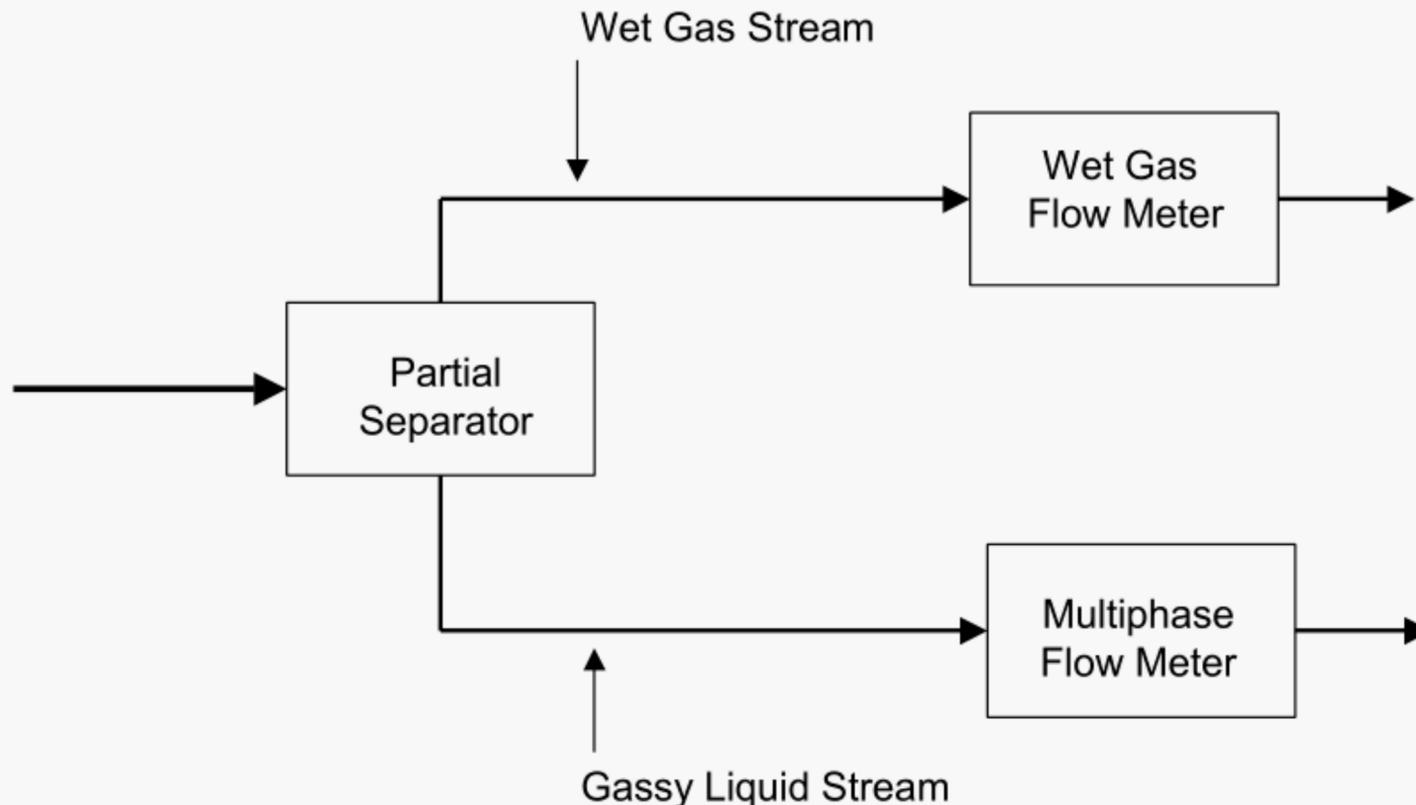


Figure 7.1—Illustration of Multiphase Flow Measurement Using Partial Separation

7.4 IN-LINE/FULL-BORE MULTIPHASE FLOW METERS

Inline or full-bore multiphase flow meters are characterized the complete measurement of phase fractions and phase flow rates being performed within the multiphase flow line, with no separation of the flow, either partial or complete.

The volume flow rate of each phase can be represented by its area fraction multiplied by the velocity of each phase. In a typical gas/water/oil application, six parameters must be measured or estimated—three-phase fractions and three-phase velocities. Some multiphase flow meters require that all phases travel at the same velocity, thus reducing the required number of measurements to the three fractions plus the common velocity. This is usually achieved through use of an ancillary device such as a mixer or a positive displacement (PD) meter.

Most of the commercially leading multiphase flow meters in use today are inline devices, each being based on a subset of the flow and composition measurement principles described in 7.1 and 7.2.

It should be observed that for most inline meters there is no practical reason why the device could not be used with a partial separation system if conditions warrant and the user desired to use it in this fashion.

7.5 USE OF TEST SEPARATORS

The process of test separation is characterized by the isolation of a single well's flow into a particular separator. While often the separation vessel used is dedicated only to testing wells, this is not necessarily the case. A standard well test involves the process of aligning a particular well's flow so that it alone flows into a separation vessel that is capable of measuring the flow characteristics of the liquid and gas outflow streams. The separation vessel during the time frame of such single-well isolation is a test separator, and the acquisition of the measurement data during that time is defined as a well test. Since normally many wells must use the same vessel(s) for testing, well testing by test separators is a

process of periodically sampling the flow rate of each well. Therefore, a (usually biased) measurement error exists in the use of test separators due to the variability of the well's production over time. As the true production rate of a well changes with time, ultimately declining, so does the error of the periodic well test. The decline rate of the well multiplied by the time period between tests indicates the error.

Another aspect of such well testing is the proximity of the test separator to the well. In cases where the test separator is located essentially at the well head (e.g. onshore or on dry-tree installations) the flow characteristics between the wellhead and the separator are not a major factor. But, in cases of remotely located separators (e.g. subsea tiebacks) the flow characteristics (liquid hold-up, gas line pack) affect the accuracy of the test. Liquid hold-up is a variable that may have a very long natural period in a well testing operation. The time for the liquid hold-up to revert from some equilibrium value (with some characteristic periodic variability) prior to a test and then change during test line-up and return to an equilibrium value for the test can be lengthy—perhaps even days. To be effective, well testing should encompass several whole or complete liquid hold-up periods. Thus, the periodic nature of well testing and the high variability of flow characteristics makes well rate determination by use of test separators highly variable and highly uncertain.

Finally, sometimes testing wells is practiced using test separators in a by-difference mode. This method allows for a total flow to be determined on a set of two or more wells. The process is repeated after shutting in one of the wells. The difference in total flow in each case (i.e. all wells versus all wells less one well) is called the by-difference well rate. This rate is assigned to the well which was shut in. For reasons already mentioned concerning the variability in liquid hold-up, this method is extremely uncertain. Furthermore, this method also burdens the well tested by difference with the total measurement uncertainty experienced by the combination of wells measured during the testing process. In practice this magnifies the relative uncertainty of the by-difference well rate by anywhere from 2 to 10 times the uncertainty of the combined well rate measurement. By-difference methods are not recommended in cases where financial exposure for any working interest or royalty owner exists because of this increased uncertainty.

In addition to what has been mentioned here, there are numerous other issues to be considered when using test separators for well rate determination. Appendix E is an attempt to catalog these in detail.

7.6 NODAL ANALYSIS, INTEGRATED MODELING AND VIRTUAL METERS

Nodal analysis as used in the petroleum industry is a viable and valuable method for Well Rate Determination, especially in those instances where accessibility to sensors and instrumentation is difficult, as in subsea and downhole flow measurement. It is used to predict instantaneous rates, pressures and temperatures of flow streams using known or estimated variables at various points (nodes) along the pipeline stream. A system may be made up of one well or several wells. Measured parameters can be modeled to predict unknown parameters. It is an axiom in the practice of this methodology that the greater the pressure difference between nodes, the greater will be the accuracy of the estimates.

The use of nodal analysis and integrated production modeling to predict flow rates from single wells and flow systems has grown rapidly and is becoming more prevalent, particularly in deepwater applications. This is mainly due to the emergence of powerful PC-based programs that perform sophisticated calculations and use varied correlations for pipe flow. Several companies provide software for these purposes. The ability to measure and record these parameters has proved invaluable for well surveillance in critical systems.

For well rate determination using nodal analysis, known pressures and temperatures are entered into a nodal analysis program and matched with flow correlations resulting in an estimated rate. For example, in Figure 7.2, nodes are identified at the reservoir, in the perforated section of casing (flowing downhole pressure), at the foot of the casing (with a downhole gauge), at the wellhead multiphase flow meter, at the manifold, at the pipeline end termination unit (PLET), and at the multiphase flow meters on the platform. Uncertainty can be minimized by increasing the number of pressure and temperature sensors within a system, and with a detailed compositional analysis of fluid flowing through the system.

Integrated modeling programs are software systems that allow analysis and prediction of multi-well systems from the reservoir to the sales point, either instantaneously or through time.

The cost of deepwater systems has caused the need to combine or commingle production from several wells subsea, before surface measurement occurs. This complicates production allocation between wells and units. Multiphase flow meters (MPFM) can be used for rate determination upstream and downstream of commingling, permitting allocation

based on these measurements. In the absence of such meters, nodal analysis and integrated modeling offers an alternative basis for allocation.

In an interesting combination of technologies, nodal analysis can be used with accurate topside measurement to create “virtual” metering. Multi-well systems can be allocated to the well level, and sometimes to the producing zone, by the use of nodal programs that monitor pressure, temperature and measured rates and “meter” individual well rates. It is very important to reservoir and production engineers to have accurate rates and volumes from a given well or zone.

MPFMs can further be used to fine tune surface measurements for virtual metering.

The following are recommended when using nodal analysis and virtual metering for rate determination and allocation:

1. Initially and at subsequent operational opportunities, the nodal analysis will be calibrated against other measurements, such as the outputs from multiphase flow meters and from devices located topsides.
2. MPFMs and separation equipment used for measurement must be well designed and maintained, and their accuracy cross-checked by independent means both on a periodic basis and when flowing conditions change dramatically. Either type of measuring device can cause errors in allocations if they are not designed and maintained properly. There is a common misconception that a separator is always the best method of measurement. Recent data shows that with new technology a well-designed MPFM can match a separator in accuracy, and can be far superior to a poorly designed or maintained separator.
3. As more points are included at which rate, pressure, and temperature are measured, the uncertainty of the results decreases. Sensors are beneficial but not required at bottom hole, the tree, manifolds, boarding, as well as at the surface on separation or metering equipment. The use of real-time sensors is preferred.
4. Nodes closest to the bottom of the wellbore are more important than those farther up the flow stream.
5. Hydrocarbon composition, PVT analysis, and Process Simulation Models (PSM) should also be monitored and updated in all calculations, both on a periodic basis and when flowing conditions change.
6. Methods of uncertainty as described in API RP 85 should be consistently applied throughout the system, but particularly if there is more than one measurement point in a system.
7. An increased number of wells in a system, without isolating flowlines, increases uncertainty.

Figure 7.3 is an example of a nodal analysis inflow-outflow curve. The plot is pressure, in this case downhole flowing pressure, versus flow rate. The green lines represent the inflow of the well, i.e., what the reservoir is capable of producing. Parameters such as fluid viscosity, skin (transition area or sand face (first foot or so) between the tubing and the actual reservoir at the well's perforation point), reservoir static pressure, permeability, height and geometry affect this curve. The red curve is the outflow of the well, i.e., what the well is able to produce from a mechanical standpoint. Tubing inner diameters, friction, tubing flow correlations, fluid fall back, choke settings, system configuration, and backpressure can affect this curve.

The intersection of the inflow and outflow curves is the solution for a given set of these parameters. In this example the predicted rate for the well is 5312 barrels of oil per day (BOPD), with a flowing downhole pressure of 8835 psi. The lack of intersection between curves doesn't mean that the well won't flow, but that its flow is unstable and beyond the capability of correlations to accurately predict rates.

With most nodal analysis programs, parameters for inflow and outflow can be varied and a series of sensitivities can be run. These are quite useful when combined with reservoir pressure transient analysis used to define critical variables of inflow.

Finally, it is important to note that governing regulatory authorities such as the U.S. Minerals Management Service (MMS) have allowed limited use of nodal analysis for rate determination.

7.7 DOWNHOLE METERS

Multiphase flow measurement downhole is of great interest in problems where production is emanating from two or more zones in the well. Although the techniques for making these measurements are in their early days, it is anticipated this will be an area of significant development in the future. Information on some of these emerging methodologies can be found in the papers by Johanssen and (Schlumberger?) [Biblio. 11, 12].

7.8 OTHER METERS

Other categories of multiphase flow meters include advanced signal processing systems, which estimate phase fractions and flow rates from analysis of rapidly varying signals from sensors in the multiphase flow line. Such sensors may be acoustic, pressure, differential pressure, or other types. The signal processing may be a neural network, or another form of pattern-recognition or statistical signal-processing system, for example. An example of such a system is described by Toral [Biblio. 13].

There are also multiphase metering systems which have been developed on the basis of process simulation programs combined with techniques for parameter estimation. Instead of predicting the state of the flow in a pipeline at the point of arrival, its pressure and temperature can be measured at the arrival point and put into the simulation program. The pressure and temperature of an upstream or downstream location also have to be measured. When the pipeline configuration is known along with properties of the fluids, it is possible to make estimates of phase fractions and flow rates.

7.9 METER SPECIFICATION AND SELECTION

It is impossible to give absolutely definitive advice for selecting multiphase flow meters from the information provided on these few pages. However, it is crucially important that potential users attempt to predict the environment in which the meter will operate during its lifetime, to as great an extent as possible. To assist in this activity, it is strongly recommended that the so-called “trajectories” of the flow expected through the meter during its lifetime be quantified by the user as accurately as is possible, and that the results be plotted on maps such as those shown in Figures 5.6 and 5.11. These flow and composition maps should then be shared among partners, meter vendors, and regulatory authorities. Such actions will result in a higher likelihood that the meters the user selects for the task will ultimately satisfy his measurement needs.

When the choice of meters has been narrowed to a few, plotting the expected trajectories of the well(s) and the known or measured operating characteristics of the meters in forms such as those shown in Figures 8.2, 8.3, and 8.4 can indicate which meters are likely to perform best for the application at hand.

Additionally, it should be pointed out that, in some instances, parameters that have been described as if they are constant over long periods may actually fluctuate considerably over shorter time frames. For example, in certain circumstances slug flow may occur, with instantaneous GVF ranging from 0 – 99%, but with an average GVF of 90%. A meter optimized for 90% may have difficulty during those times when the extremes in GVF are being experienced.

8 Measurement Uncertainty of Multiphase Flow Measurement Systems

Measurement uncertainty performance is a primary consideration in selection among various approaches of multiphase flow measurement for regulatory compliance and revenue exposure.

Uncertainty in flow measurement arises from the variability (or uncertainty) in one or more factors, e.g. the fluid properties, flow regime, flow rate, instrumentation, and quality of the measurement model. Multiphase flow meters measure unprocessed fluids with two or more phases simultaneously, thereby increasing the complexity of the measurement equations and model. This model is sensitive to the relative proportions of each phase, to the properties of the fluid (particularly fluid density), and to the flow regime.

Uncertainty in multiphase flow meters is mainly due to changes in process conditions, fluid properties, flow models, measurement devices, and sensors. The impact of these uncertainties on the uncertainty of each phase typically increases considerably as the water liquid ratio (WLR), gas volume fraction (GVF) and multiphase flow rate approach their limits.

Characteristically multiphase meter uncertainties are larger than those from single-phase meters used on properly separated streams. Furthermore, they may contain significant bias components, resulting in overall phase uncertainties which are much greater than the aforementioned single-phase measurement uncertainties. Acceptable measurements and uncertainties are achievable in the main areas of application by careful selection of a metering system based on analysis of uncertainty and sensitivity for the forecast production. Regular maintenance, calibration, and updating of the meter configuration to suit the actual fluid properties and production, contribute in equal part to minimization of uncertainty in service.

It is not the purpose of this section to solve, or even to completely specify all the uncertainties associated with multiphase flow measurement. Rather, the goal is to provide a guideline—whether for user, manufacturer, or regulator—so that a proper understanding of uncertainty issues can be developed.

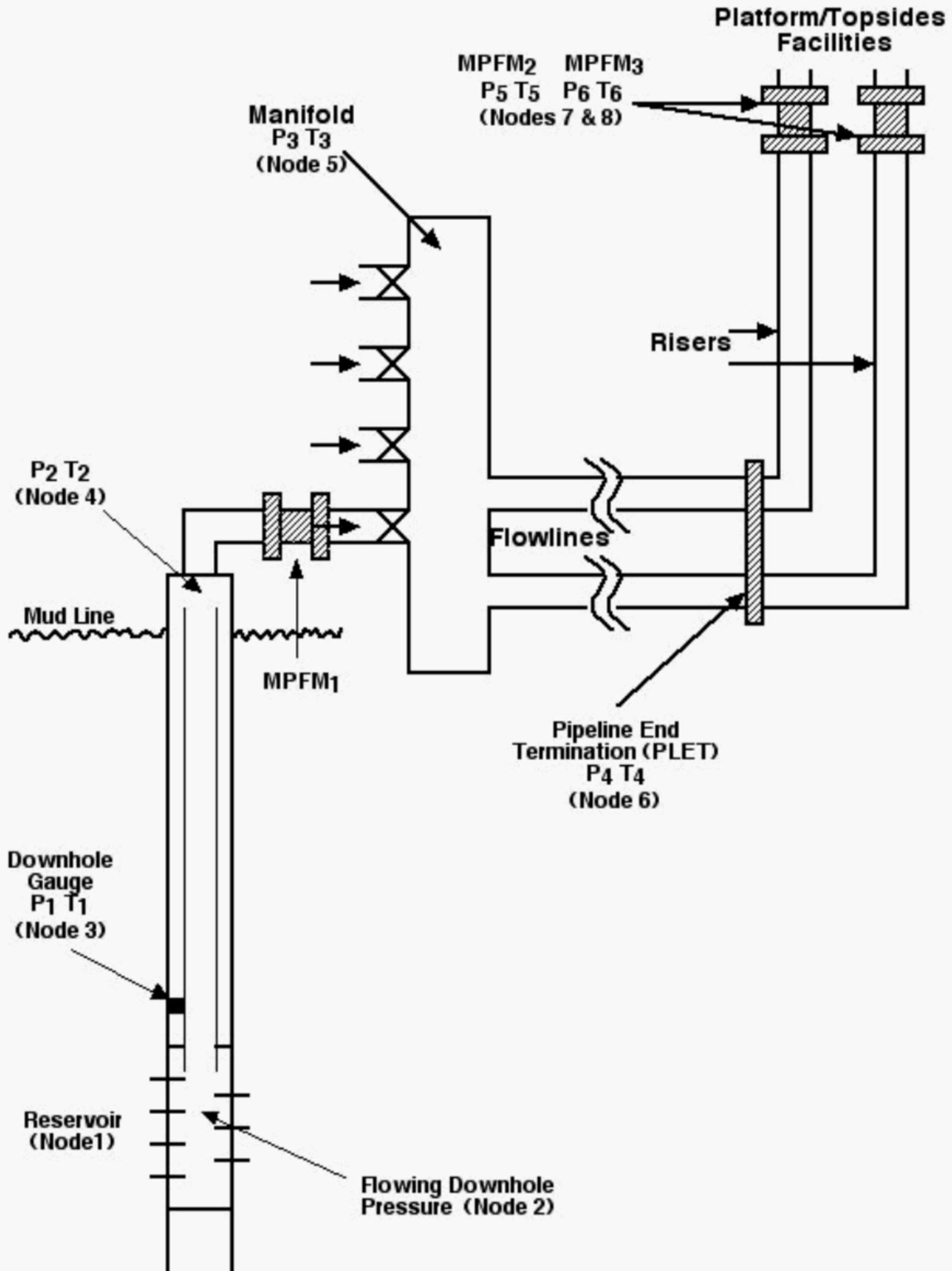


Figure 7.2—Schematic to Illustrate the Principle of Nodal Analysis, Virtual Metering

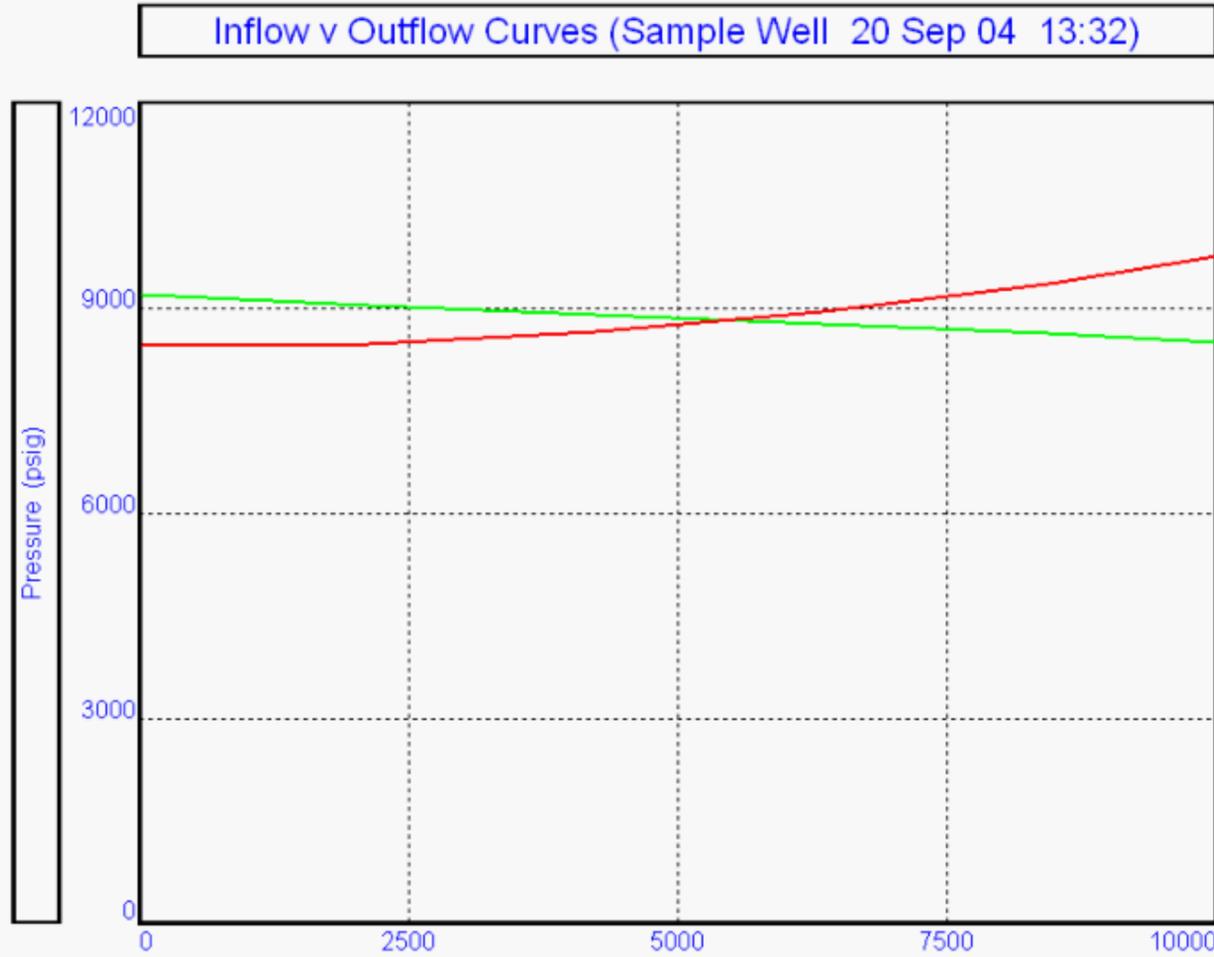


Figure 7.3—Well flow Rate Prediction through the Use of Inflow and Outflow Curves

8.1 OVERVIEW OF MEASUREMENT UNCERTAINTY

This section provides an appreciation of uncertainty covering terminology, analysis, and the techniques required to combine uncertainties. The main uncertainty terms are highlighted in *italics* and are defined in Section 3, Definitions and Nomenclature.

The basic concepts of uncertainty are discussed in Appendix A using methods from the mathematics of probability and statistics.

The *uncertainty (of measurement)* is a parameter that describes the variability of the *result of measurement*. Typically this is subject to further processing, including scaling into engineering units, functional relationships, and in combination with other measurement values and constants to find one or more final values.

8.1.1 Standards

Historically, measurement uncertainty has been described in numerous ways depending on the industry sector and nature of the measurement. These terms, such as accuracy, repeatability, precision, bias, systematic error, etc., have often been in conflict, confusing everyone, including the experts in these fields. The 1993 publication of the International Standards Organization (ISO) *Guide to the Expression of Uncertainty in Measurement*, [Ref. 6], known as the “GUM”, provided an overarching uncertainty standard with a common terminology that is internationally accepted.

The GUM is available, with minor changes, from several other standards organizations including the American National Standards Institute (ANSI) [Ref. 7], and British Standards Institute (BSI) [Ref. 8]. The GUM provides a recognized and consistent approach to uncertainty analysis which should be used as the basis for uncertainty assessment and comparison of multiphase flowmeters. Conformance with the GUM has been the goal in the construction of this section, wherever possible,

Two supplements to the GUM are currently being prepared dealing with Monte Carlo Simulation (MCS) uncertainty analysis methods and Covariance. Both areas are relevant to understanding the uncertainty of multiphase flowmeters.

The uncertainty standard ISO 5168 provides useful guidance in assessing uncertainty in flow measurement. The current document ISO TR 5168:1998 [Ref. 9] does not comply with the GUM, and has therefore been issued as a technical report. At the time of writing a GUM-compliant standard has been prepared and is awaiting publication.

The Handbook of Multiphase Metering published in 1995 by the Norwegian Society for Oil and Gas Measurement (NFOGM) [Ref. 3] provides a good introduction to MPFM. This document is in the process of being revised. The 1995 document can be downloaded from the NFOGM website at www.nfogm.no. The upcoming edition will be available Q2/2005 from the same website.

8.1.2 Sources of Uncertainty in Measurement

There are two basic sources of uncertainty manifested in measurement systems such as those addressed here. The first is that due to the measurement device and the imprecision observed in the sensor signals, which translate into uncertainty in the estimates of phase rates and other parameters of interest. The second is uncertainty due to inaccuracies introduced by the models used in the meters, as well as the manner in which the models are affected by the environment of the application, i.e. fluid properties, flow regime, flow conditions, etc.

8.1.2.1 Unsteady Local Conditions

Probably the single most important cause of uncertainty in multiphase flow measurement is related to the unsteady nature of the flow conditions. The instantaneous flow patterns and the interfaces between liquid and gas phases can be continually varying in a multiphase flow. This is most extreme in slug flow, where the liquid fraction can vary between almost zero in the film region after liquid slugs, to almost 100% liquid in the slug body. However significant fluctuations will also be present in annular and churn flow patterns.

The impact of fluctuating local gas fraction is linearly related to the density; but for other parameters, particularly differential pressure across a measurement element, it exhibits non-linearity. The pressure drop of a liquid slug passing through a Venturi meter can be 5 times higher than the average pressure drop for the flow; the minimum pressure drop in the same flow, corresponding to the 'film' region can be 20% of the average. A Venturi meter would experience pressure drops over a range of 25:1 at a nominally steady multiphase production condition. A fundamental principle of single-phase flow measurement—that readings should be taken under steady state conditions—clearly has to be abandoned in such circumstances.

To reduce the uncertainty associated with measurement of a parameter that fluctuates over such a wide range, a higher frequency of measurement sampling and proper selection of sensors are required over a relatively long measuring period. The measuring period will be unique to each application, so a good knowledge of the flow regime at the multiphase meter is important.

8.1.2.2 Unsteady Global Conditions

In laboratory multiphase flow loop evaluations, it is usually possible to ensure relatively steady input conditions to the multiphase flow line, so that the average oil, water and gas flow rates are stable over a period longer than that required by the multiphase meter to make its measurement.

However, in actual operating systems, steady flow is much less likely over longer time scales. Flow through a multiphase pipeline is influenced by the flow into the line (which may be combined from several wells), the flow patterns developing along the line, the topography of the line (the terrain it passes), the outlet pressure and other fluctuations caused by the downstream processing requirements.

Additionally, the location of the MPFM, topsides or subsea, has a major influence on measurement uncertainty and the meter's operating envelope. When located topsides, the higher GVF, and therefore lower uncertainty, with the greater likelihood of slugging is offset by the improved accessibility for maintenance and calibration.

These effects increase the measurement uncertainty of a multiphase meter in the field when compared to the uncertainties of measurement achievable in laboratory tests.

8.1.2.3 Incorrect Identification of Flow Regime

Most multiphase flow meters will use some empirical modeling of the flow in order to derive the individual phase flow rates from the measurements taken. This modeling has its greatest influence on the method of interpreting the pressure drop from a differential pressure device or the velocity obtained from a cross-correlation device.

If the flow conditions differ in practice from those assumed in the empirical models, then there will be an additional uncertainty in the measurements.

There are many ways in which this could occur. For example, the flow pattern may be affected by unexpected changes in the physical properties of the fluids or the operating pressure. In other situations the slug frequency or velocity may be different to that expected - this will have a similar effect to the factors described above.

To illustrate the potential for incorrect flow regime identification, it is not uncommon for differences such as those described above to occur when the same meter is tested in different laboratory test facilities. Very significant variations can therefore be expected in field conditions.

8.1.2.4 Uncertainty in Physical Properties of Fluids

To obtain the best achievable performance of a multiphase flow meter the initial calibration process must include filling the meter with each of the single phases in turn, and measurements made of relevant parameters such as the dielectric constants or gamma attenuation coefficients. This end-point information can then be entered into the meter set-up software. Most meters also require that the density of the individual phases are known, at least as a function of temperature, and for gas as a function of pressure as well. A good PVT model is therefore essential.

Under laboratory conditions it is usually a straightforward task to calibrate a multiphase flow meter with respect to the fluid properties, and to be confident that the properties of the fluids are constant over the course of a test. However, in the field, considerable thought needs to be given as to how this basic calibration is performed.

Typically, physical property calculations are performed by multiphase flow meters on the basis of the analysis of samples, and clearly there is a possibility for increasing uncertainty in this process. Methodologies for *in-situ* determination of the physical properties need careful consideration, and clearly there are many challenges to be overcome, not least of which is guaranteeing clean single phase flow for each end-point calibration. This can be best achieved by ensuring that, where possible, meters can be bypassed while measurements of physical properties are made. Small amounts of contamination will bias the results significantly and this will feed through in all subsequent multiphase flow measurements.

In circumstances where fluid properties will change appreciably with time, a methodology is required to allow the new physical property data to be downloaded to the multiphase meter. This can include a number of preset fluid properties that can be selected for predictable well combinations. Alternatively, some form of post processing routine may need to be applied to correct the measured data. Other techniques can be used to determine fluid properties including laboratory analysis of sample composition. Other techniques such as geochemical fingerprinting determine the flow from individual wells based on the ratios of fluid characteristics.

8.2 MULTIPHASE FLOW MEASUREMENT SYSTEMS UNCERTAINTY METHODOLOGY

As noted previously, multiphase flow is measured with a combination of measurement devices, sensors and empirical or mathematical models implemented in a series of steps. The basic uncertainties are introduced at the outset, and are propagated through the models in the succeeding steps as the calculations are made, all in the presence of environmentally introduced uncertainty. There are three levels at which it is useful to consider process uncertainty:

Level 1—Primary and Secondary Device: device and instrumentation observed readings and units, fluid properties inputs, etc.

Level 2—Observed Conditions: flow rates of gas, oil, and water at meter conditions, as well as GVF, WLR, mass rate, etc.

Level 3—Reference Conditions: flow rates of gas, oil, and water at reference conditions.

To fully analyze measurement system uncertainty, it follows that all sources of uncertainty should be understood for each step. While this can certainly be done, in practice uncertainty is generally introduced at the Observed Conditions Level 2, based on comparison of the meter's results in a flow loop or field installation. With this starting point, uncertainty can then be found for the flow rate of each phase at meter and standard conditions based on the same methods used to calculate and report these quantities in normal operation.

Level 1 (Primary and Secondary Device) uncertainty is generally only useful to the equipment vendor to determine the sensor measurement limits and to understand the influence on the uncertainty of the Level 2 results. However, some multiphase flow measurement systems which can be modeled at Level 1 such as compact separators with single phase metering, or dual differential pressure devices for wet gas, can apply Level 1 uncertainty estimation to determine phase flow rate uncertainties by mathematical modelling techniques [Biblio. 21, 22].

8.2.1 Level 1—Primary and Secondary Device

Instrument sensor outputs are in sensor measurement units, for example differential pressure in millibar or psi, radiation detector in counts, water content in capacitance or conductivity. For most inline multiphase flow meters, it is possible to build up uncertainty from this point; however to manage the uncertainty it is necessary to understand the main influences of the primary and secondary devices.

8.2.1.1 Manufacturer's Stated Sensor Uncertainty

The manufacturer states the uncertainty for the operating range of the sensor, including the configuration and environmental influences on the uncertainty such as pressure, temperature, and density. Uncertainties of the sensors are generally conservative, however they are typically specified under ideal single-phase conditions and can therefore be misleading.

8.2.1.2 Calibration and Acceptance

Sensor outputs are generally dependent on calibration or corrections based on data from offsite or in-service calibration. The uncertainty of the reference used for calibration should be accounted for, along with the frequency of calibration and the intervening instrument drift. The calibration may not be representative of actual operating conditions, so the additional uncertainty due to the deviation from calibration conditions should be included.

Acceptance checks may include a tolerance within which adjustments are not made, introducing an uncertainty equal to this tolerance in addition to the uncertainty of the device used for the check.

8.2.1.3 Range

The sensor should be selected based on the operating conditions; however there may be other operational requirements that limit this selection. An example is the upper range limit (URL) of differential and static pressure transmitters, which ideally is chosen close to the maximum measured value to minimize uncertainty. However, the URL may be selected to enable high pressure testing without pressure isolation of the sensor to avoid accidental damage, as well as for equipment standardization. This may introduce significant additional uncertainty, however the resulting measurement will be robust, an important requirement for subsea installations.

8.2.1.4 Configuration

Sensor configuration will depend on the type of device, range, zero, electrical or data interface, sample rate, damping.

The working range, or span, of the sensor output signal is the difference between the sensor minimum value, or zero, and the calibrated maximum. The span should be close to the operating range to minimize uncertainty. More than one sensor may be required to cover the working range with an acceptable uncertainty. Alternatively the sensor may be calibrated at a number of points over the working range and corrected by data processing software. The uncertainty can increase as the mass flow rate declines, and may become excessive. This particularly applies to Venturi differential pressure measurements, which are common, where a single differential sensor is used. At low differential pressures the influence of zero drift may also be significant and should be regularly corrected with equalization and zero adjustment or software correction.

A similar situation arises with detector pulse resolution at high count-rates. For example, when a nuclear gamma-ray detector is flooded with events, there is a finite probability that two or more particles will impinge on the detector in such a short time period that they cannot be distinguished from one another. The result is that counts will be missed, or pulse heights will be incorrectly measured. By using another physical configuration of detectors the problem could possibly be avoided. It is usually straightforward to handle the problem in a statistical sense as well, knowing the pulse-resolving and counting capabilities of the nuclear instrumentation.

Care is also needed in the selection of static pressure transducers at low operating pressure below 300 psia (20 bara) where the variation in atmospheric pressure of ± 1.5 psi introduces an uncertainty of 0.5% of reading with gauge transducers. At 75 psi this has increased to 2%, which will introduce an equivalent error in the gas fraction. Absolute transducers are preferred at low pressure, however care is required to account for atmospheric pressure during calibration checks.

Oil-continuous and water-continuous water cut detectors do not precisely overlap, leaving a band where the watercut measurement may be difficult for some sensors. The problem may be exacerbated by the flow regime if the fluid is constantly changing between measurement modes.

8.2.1.5 Inherent Characteristics

A sensor's inherent characteristics may influence the uncertainty, due to the sensor construction or to a response that may lead to averaging limited by the excursions of pulsations. An example is the case of small-bore pressure ports where the pressure excursions are not transmitted instantaneously to the sensor. Isolated diaphragm connection to differential pressure transducer can create a similar problem, and may introduce a small pressure offset at the sensor.

Commercially available devices may be specified with electronic or software averaging to produce a stable signal to reduce noise and for systems with a relatively low sample rate, but masking the true variability in the physical parameter. Some instrument loops, such as those using 4 to 20 mA signals, may have an inherently slow response due to electrical characteristics or slow data sampling rates.

Communications link bandwidth will determine the maximum update rate of measurement parameters or the numbers of parameters that can be handed off in a given period. Digital communication between the measurement systems and operators systems such as DCS systems may be required to handle a very large number of parameters and therefore the update rates should generally be optimized to minimize the data while providing the required update of the important measurement data. Some digital interfaces such as HART have a limited bandwidth, and may only be able to update a small number of measurement parameters. Care is required to optimize the sample rates and available system bandwidth, so that rapidly changing data takes priority over configuration data.

Processing data in some measurement systems may limit the rate at which the measurement results can be updated. In some extreme cases such as process simulation the update time is considerable. This type of processing is usually handled outside the measurement system, and does not generally need to be frequently updated. Simplified models can be developed that reflect the main characteristics of the process model. This can be best achieved by using the process model to find the sensitivity of final values to changes in the input over the operating range of the process model. The resulting sensitivity model may then be used for normal operational use. It is important that the limits and validity of simplified models are understood and that the model or sensitivity coefficients are periodically validated or updated.

8.2.1.6 Noise

Electrical noise, including thermal noise within the sensor and external electromagnetic interference, may introduce an additional uncertainty that is normally eliminated by proper grounding and screening of the sensor.

Mechanical noise of the sensor, particularly at the resonant frequency of the measurement system or individual sensor, may be unavoidable due to wellhead or flow line vibration.

8.2.1.7 Signal Final Use

The final use of sensor output may also influence the uncertainty at a later stage. For example, consider the case where a totalized quantity is required over a relatively long interval from a pulse output device. Using the total pulse count will yield a lower overall uncertainty than the integrated or averaged pulse frequency for the interval. If, however, conditions are variable, then a weighted average result based on the pulse frequency or period may yield a lower uncertainty. In many cases the type of equipment determines the method and it may be necessary to accept a solution that is less than ideal.

8.2.1.8 Covariance and Dependency

The sensor uncertainties may appear to be independent, however common environmental factors such as pressure and temperature may introduce a covariance factor between sensor outputs which must be considered if it is significant. Some sensors provide more than one output, in which case there will often be a dependency that must be considered in subsequent analyses if the outputs are used together to find a final value.

8.2.2 Level 2—Observed Conditions

Primary (sensor) measurements are used to derive intermediate values including WLR, GVF, and mass and volume flow rates and fluid velocities, using a model for actual conditions for the flow regime and fluid properties. The model ordinarily incorporates dynamic effects such as slip ratio and variation in discharge coefficient. These models are generally based on empirical data, and may have large uncertainties if operated outside their verified range of operability.

Level 2 measurement uncertainty is typically determined through comparative flow loop performance tests, with uncertainty described in terms of WLR, GVF and mass or volume flow rate. However, measurement uncertainty derived from flow loop testing only provides estimation at flow loop test conditions. Additional uncertainty will be

encountered when the metering system is extrapolated from flow loop conditions to actual operating flow conditions. An estimated level 2 uncertainty at operational conditions should combine the meter performance uncertainty, flow loop uncertainty, and the estimated flow extrapolating uncertainty. It may be necessary to back out the flow loop uncertainty and introduce a field uncertainty to avoid overstating the uncertainty of a particular parameter, e.g. density if the flow loop and field uncertainty are comparable.

The meter uncertainty should not cover extreme operating or failure conditions unless these are expected to influence the long term operating uncertainty or impact another party.

8.2.3 Level 3—Reference Conditions

The phase volumetric quantities and properties at reference pressure and temperature conditions are usually different from what is observed at the measurement conditions. Even in the case when verifying a multiphase meter against another meter at actual meter conditions, such as with a test separator, there is a need to make a correction. Reporting mass can eliminate many issues; however it may still be necessary to account for changes in the oil and gas mass fraction.

Some examples of reference conditions are the following:

1. Standard conditions – 60 °F, 14.67psia or 15 °C, 1.01325 bara.
2. Reservoir conditions.
3. Riser or flow line node conditions.
4. Separator conditions.
5. Pipeline export conditions for energy, volume, mass.

The corrections can be based on the PVT model used to find the meter phase changes, or maybe a different model based on retrospective or predictive analysis of samples. If used in allocation, the sample analyses will be normalized to export conditions based on single-phase flow measurement and flow proportional samples. In these instances fluids will be commingled and subject to processing. Care is required to ensure that the normalized properties are representative of the fluid properties during measurement.

A PVT model needs to be applied on wet gas, condensate, and black oil applications and the changes in uncertainty accounted for dependent on the fluid characteristics. However there are instances when multiphase fluid mixes can ignore this additional complication, such as those instances when the hydrocarbon liquids are 25°API or heavier.

The analysis of uncertainty must take account of uncertainty in models, which will typically include a process adjustment found by one or a combination of the following:

1. Process simulation.
2. Simplified mass component.
3. Separator flash/shrinkage factor based on PVT analysis.
4. Theoretical compressibility and thermal correction.

Due to the complexity, large number of variables and inherent dependencies, Monte Carlo Simulation is a practical approach to finding the combined uncertainty of the reference quantities.

The user should perform a thorough uncertainty analysis to determine how the uncertainty of phase quantities and properties are propagated from actual to reference conditions for well rate determination allocation.

The measurement uncertainty should be assessed to prepare a specification for selection of a suitable meter, with realistic consideration given to what can be achieved with the currently available equipment, weighed against the overall financial exposure and regulatory requirements. Overly stringent uncertainty requirements will be uneconomic and may not in practice be achievable, while assuming ideal conditions may lead to operational objectives not being met.

8.3 UNCERTAINTY CHANGES DURING FIELD LIFE

8.3.1 Forecast Production Trajectory

Over the life of a field, flow rates and production conditions will change as the field and individual wells decline and the relative proportions of gas, oil and water change. Production operations, including gas and water injection, gas lift, and well workovers, will also lead to changes in production.

The end user should establish the forecast production trajectory including forecast spread, and the impact on measurement uncertainty that these changes will produce. The use of the trajectory plots of Figures 5.6 and 5.11, coupled with the uncertainty graphs presented in Figures 8.2 and 8.3 which follow, is crucial to understanding how the uncertainty may change over the life of the well. The predicted trajectory should assist the user in selection of the meter, and in forecasting when the type of meter or measurement approach should change. The trajectory should be periodically updated to reflect current forecasts and operating conditions.

The uncertainty at a low flow rate may be high, however the risk exposure will be low; in some operating modes uncertainty may be excessive, and measurement may not be possible. If this is considered over a long period, the overall effect may not be significant. It is more important to identify bias than to be concerned with random uncertainty, which will in time average toward the mean value.

8.3.2 Operational Change

The field and well configuration will also affect production where a MPFM is fed by more than one well, or where wells are taken in and out of service. New field opportunities may arise which can utilize existing infrastructure.

The MPFM phase measurement uncertainty will vary as conditions change; production may move into a region in which the uncertainty is either not acceptable or the meter cannot operate. There are a number of options available, including replacing the meter, or re-ranging the existing instrumentation or flow element. If the flow rate is low, the absolute uncertainty in measurement quantities (rather than the relative uncertainty) may be tolerable.

It may be necessary to bypass the MPFM due to abnormal conditions or to prevent contamination from well operations. During these periods the flow rate should be estimated by some other means, for example by using historical or process data.

8.3.3 Reporting Period

True statistically random distributions, will tend towards the mean value with time for a given set of operating conditions; however in practice the operating environment is variable, with a relatively short reporting timescale. This is typically of the order of minutes to hours for daily operations, and daily to monthly for production management, performance, and accounting purposes. In addition to random uncertainties, multiphase flow meters are subject to biases arising from the instrumentation and the constants used in the derivation of results.

As the period increases, the impact on the overall uncertainty of periods with short-term high uncertainty due to difficult or abnormal operations decreases.

Uncertainty will differ with the period of interest:

- | | |
|-------------------------|---|
| 1. Instantaneous | monitor well activity, production management and control |
| 2. Well Test | well test rates, reservoir and well management |
| 3. Daily | facility production management and tentative daily allocation |
| 4. Monthly | monthly allocation, reservoir management |
| 5. Annual | nomination, partner obligations and regulatory requirements |
| 6. Field Life | partners, regulator, reservoir management |

8.3.4 Field Conditions

An error in the dry oil density or water density can introduce a watercut bias with some multiphase flow meters. In this case the dry oil density may be dependent on the particular mix of wells, and on the operating pressure and the water density due to chlorides in the produced formation water. A change in relative production rates of wells, operating pressure, or a well shut-in will change these densities and lead to a bias in measurement, unless the master meter constants are adjusted to suit the new conditions. Even then there will be small deviations, which at low or high watercuts may result in a significant bias in the oil and water quantities. Reservoir injection schemes including fresh water injection and miscible injection may also have a large impact on densities.

8.4 CALIBRATION

By characterizing the response of a multiphase flow meter over a range of flowing conditions, a calibration dataset can be created, which includes uncertainties. An uncertainty profile can then be extracted from this dataset for a forecast range of operating conditions by interpolation, extrapolation and other modeling techniques.

The calibration dataset uncertainty should be based on statistical findings corrected for the number of calibration runs at a calibration point, and including the uncertainty inherent in the flow loop, reported at the 95% confidence interval.

Calibration datasets sometimes are collected where the uncertainty is estimated from the spread of as few as three results at a calibration point. These are then reported with a 90% confidence interval, without accounting for either the sample size or the flow loop uncertainty. This does not yield a representative uncertainty, and is not acceptable as a basis for estimating meter uncertainty. Each of these issues is addressed below.

8.4.1 Flow Loop

When using a multiphase flow loop for flow calibration, one or more multiphase flowmeters are placed in series with a system for accurately measuring individual streams of gas, wet oil, S&W, and water phase flow (e.g. a 3-phase separator).

The phase volumes at each multiphase flow meter are measured and deducted from calibration reference quantities. This calibration run is repeated a number of times to find the spread in results and hence the measurement uncertainty of each phase at the calibration point.

Using this method of uncertainty characterization has pitfalls. One of these is the fact that using a small number of samples can lead to an error in calculating the *experimental standard deviation* of each quantity of interest. It can be shown that the uncertainty that is estimated must be corrected by a factor known as *Student's t* [Biblio. 1, p 4-6]. In practice, the standard deviation of the measurement differences for at least five points should be found and the *Student's t* applied.

Additionally, the uncertainty inherent in the flow loop facility itself should be known and accounted for in estimating the meter's uncertainty performance. This includes all input parameters such as density, single-phase flow rates, pressure, temperature, etc. While these may seem small by comparison, their effect will be to increase the estimated uncertainty of the meter under test unless they are accounted for. It is the responsibility of those who operate flow loops for calibration, qualification, or verification purposes to provide information which quantifies that facility's uncertainty.

The gas, water and dry oil density uncertainty in the flow loop should be closely controlled, leading to a correspondingly lower WLR and GVF uncertainty compared to field conditions, where density and other fluid properties may have larger uncertainties.

The flow regime in the flow loop is controlled and is likely to be different to field conditions. Most MPFM have proprietary flow or slip models that will depend on the flow regime and this should be taken into account in assessing the flow loop results.

Uncertainty of the flowloop references should be combined with the test meter performance uncertainty to derive the overall uncertainty of the flow meter.

8.4.2 Field Operation

When attempting to determine phase volume uncertainties for a multiphase flow measurement system while in service, the uncertainty of some fluid properties during calibration should be deducted so they are not double counted when the field uncertainty is applied. This particularly applies to density uncertainty for each phase during calibration, which must be backed out before applying the field density in subsequent uncertainty analyses.

In service these parameters are not closely controlled with short-term variation and bias that can be minimized by static calibration of each phase density. The additional density uncertainty must be included to obtain a representative uncertainty for WLR and GVF over the expected operating range.

The model is likely to include a fluid-properties model, based on PVT or process data, to find the densities and slip factors, and may also take account of other fluid properties such as chlorides, sulfur and other contaminants. It must be emphasized that this needs continuous attention to insure the meter is tuned to the current fluids. The flow regime and other factors such as the discharge coefficient in venturi meters will differ from the flow loop and should be taken into consideration.

8.5 REQUIREMENTS FOR UNCERTAINTY PRESENTATION

For a potential user or regulatory official to properly assess the merits of a given metering device, he must be able to gain a clear picture of the uncertainty of the device in its intended domains of use. Because the measurement problem is multi-faceted for multiphase fluid mixtures and flow conditions, selecting a set of figures which sufficiently provides such a picture is not easy. The following are intended to illustrate a meter's underlying uncertainty in conjunction with the levels of measurement described earlier.

8.5.1 Primary and Secondary Device Uncertainty (Level 1)

Since the primary and secondary devices are the building blocks for the flowing calculated parameters (e.g. GVF, WLR, etc.), the primary interest in Level 1 uncertainty is with regard to assessing their performance at ideal flow conditions or with respect to environmental effects, e.g., how a pressure sensor might vary with temperature. For this reason, it is recommended that complete documentary evidence be provided for each basic sensor and device regarding its ability to perform in a manner sufficient to achieve the results claimed at the higher levels described below.

If a flow device (such as compact separation device using single phase meters) that expresses all the flow parameters in a set of equations, and the flow rate uncertainties can be expressed in an analytical form, then Level 1 uncertainty presentation following the ANSI or GUM recommended procedures is sufficient.

8.5.2 Observed Uncertainty (Level 2)

Parameters such as mass and actual volume flow rates, GVF, gas and liquid velocities, and WLR have normally been calculated at this level. It is recommended that the performance of the device be monitored over a range of GVF and WLR that reflects the application to be used. This can be partially accomplished using the three chart forms shown in Figure 8.1.

While informative, these three figures are not sufficient to characterize the metering performance at the Observed Level 2. Two other figures improve one's understanding of the meter's ability to operate successfully away from its preferred metering region or "sweet spot". Using the charts of section 5, in particular the flow map of Figure 5.6 and the composition map of Figure 5.11, the charts shown in Figures 8.2 and 8.3 proposed by Scheers et al [Biblio. 5], are recommended. The virtue of these presentations is twofold. First, they show the meter's ability to estimate flow rates of gas and liquid together, and the composition parameters GVF and WLR together. Second, by using the format shown with "tadpole" error indicators, those areas where a meter bias might exist are highlighted. The use of log-log scales also provides a constant means of observing uncertainty, thus reducing the chart interpretation required to fully understand performance over the entire operating envelope.

In order to properly use the data collected under experimental tests such as is shown in the Figure 8.1, calculation of statistical quantities such as the *mean* and *experimental standard deviation* must be performed. It is recommended that uncertainty claims be made for confidence intervals of 95%, and that these boundaries be shown when presenting data such as that of Figure 8.1. Thus, for each of the three charts, only about 5% of the measured error points should land outside the error boundaries that are shown.

Because the concept of uncertainty in multiphase flow measurement is so difficult to deal with, any other tools that may shed light on the problem in addition to those discussed above are welcome additions.

A graphical presentation of the deviation in a flow test between a MPFM reading and the reference measurement is called a cumulative deviation plot is shown in Figure 8.4. The advantage of a plot like this is that it can show a direct comparison between two meters when tested over a prescribed range, using the same fluids and under the same flowing conditions. In Figure 8.4, the deviation between the MPFM measurement and the reference measurement is plotted along the *x*-axis, while the *y*-axis represents the percentage of test points that fall within the deviation criterion called out. This example shows that 90% of all the test points show relative deviations in liquid flow rate smaller than 7%, and that 100% of the test points show deviations smaller than 10%. For watercut, 90% of all test points show absolute deviations smaller than 3%. Finally, only 55% of the test points taken with this MPFM fulfill a 10% deviation criterion on gas flow rate [Biblio 5].

In general the uncertainties in flow rates, for oil, water, gas, or total fluid flow rate are quoted with relative uncertainties, while the uncertainties in WLR and GVF fraction measurements are quoted with absolute uncertainties. With this combination, the relative uncertainties in the oil and water flow rates are dependent on the actual watercut level. For example, in a high watercut stream, a small watercut uncertainty will cause a large oil flow rate measurement uncertainty. For this reason, the user may prefer to plot the cumulative oil flow rate deviation rather than the cumulative liquid flow rate deviation.

Caution must be taken when using this plot for comparing meters. **First**, very special attention needs to be paid that the meters are tested at *identical* conditions, lest one meter have an advantage over the other. **Second**, the testing range should reflect the production range expected when the meter is used in the field. **Third**, it should be recognized that this plot treats all test points with **equal importance**, a fact that may not be desirable in practice, since some conditions are more likely to be encountered than others. **Finally**, the test points should be distributed over the range of interest, not bunched in such a way that in effect they duplicate one another.

8.5.3. Reference Uncertainty (Level 3)

It may be necessary, dependent on the circumstances of the particular application, to transform the measurements and calculate the uncertainties of the relevant flow rates at conditions other than those used at actual measurement conditions (Level 2). When, for instance, the meters are used for fiscal purposes, e.g. allocation of production, the various meter readings must be harmonized to a common set of conditions, likely either standard conditions, or those at the sales or export meter. When such is the case, the measurement uncertainties and their presentations must be made to reflect uncertainty at the reference conditions.

In order to express flow rates at reference conditions, a PVT calculation must be performed to determine the thermodynamics effect of fluid properties in transforming the measurements from one state to another. There are two important sources of additional uncertainty that must be recognized as a result of applying the PVT transform. These are:

1. The act of sampling the multiphase stream in a representative manner is difficult. Even at best, it will introduce error. Since the PVT transform depends on knowledge of the physical properties of the fluid in the pipe, this error will be reflected in the computed values of the measurements.
2. There is no universally accepted “correct” method of performing PVT transformations. Indeed, in many instances the commonly used methods give different results. Thus uncertainty will be introduced by the application of the equations themselves.

The uncertainty which is introduced when applying the PVT model to calculate the change from actual to reference conditions, should be estimated and presented by whichever party (vendor or user) is responsible for this activity. The final Level 3 uncertainty is then the result of combining the Level 2 uncertainty presentation with the uncertainty attributable to PVT modeling.

8.6 EFFECT OF INFLUENCE QUANTITIES ON UNCERTAINTY

According to the GUM, an influence quantity is “a quantity that is not the measurand, but that affects the result of the measurement.” In virtually every instance, this influence is manifest through a *systematic error*, or *bias*, in the measurement. In 8.1.2 it was observed that the models used in estimating multiphase flow, as well as the manner in which the environment interacts with the fluids, are also a source of uncertainty in the final set of output measurements. Thus influence quantities affect not only sensors, but also the model results as well.

Table 8.6 lists some of the common forms of influence quantities which produce bias measurement errors.

8.7 SENSITIVITY ANALYSIS

A topic that is related to measurement uncertainty, but which is clearly different, is that of *sensitivity*. How sensitive a meter is to its various inputs and influence quantities has a large bearing on its uncertainty performance.

Using the techniques discussed here, it is possible for each meter to be tested for its sensitivity to different input parameters. It is recommended that each meter be evaluated using these methods prior to actual deployment, either mathematically or using experiments to determine the sensitivity coefficients. This should be done over a broad enough range to give users knowledge of how it is likely to perform in the application at hand.

8.7.1 Overview

Sensitivity Analysis (SA) studies how the variation in the output of a system is apportioned to variation in the inputs to the system. This may be done using a physical device, or a mathematical model, or, in the case of a MPFM, a combination of the two. The analysis should encompass forecasts of the field production operating conditions and flow rates, and should include an allowance for uncertainty of the forecast.

Understanding sensitivity of a MPFM is particularly important due to the large uncertainties over the operating range and the relatively large uncertainties of some inputs and outputs. A sensitivity analysis includes an uncertainty analysis so the uncertainty of each input to the MPFM measurement is weighted by the sensitivity to determine its true significance to the measurement process over the production life of the field and the MPFM.

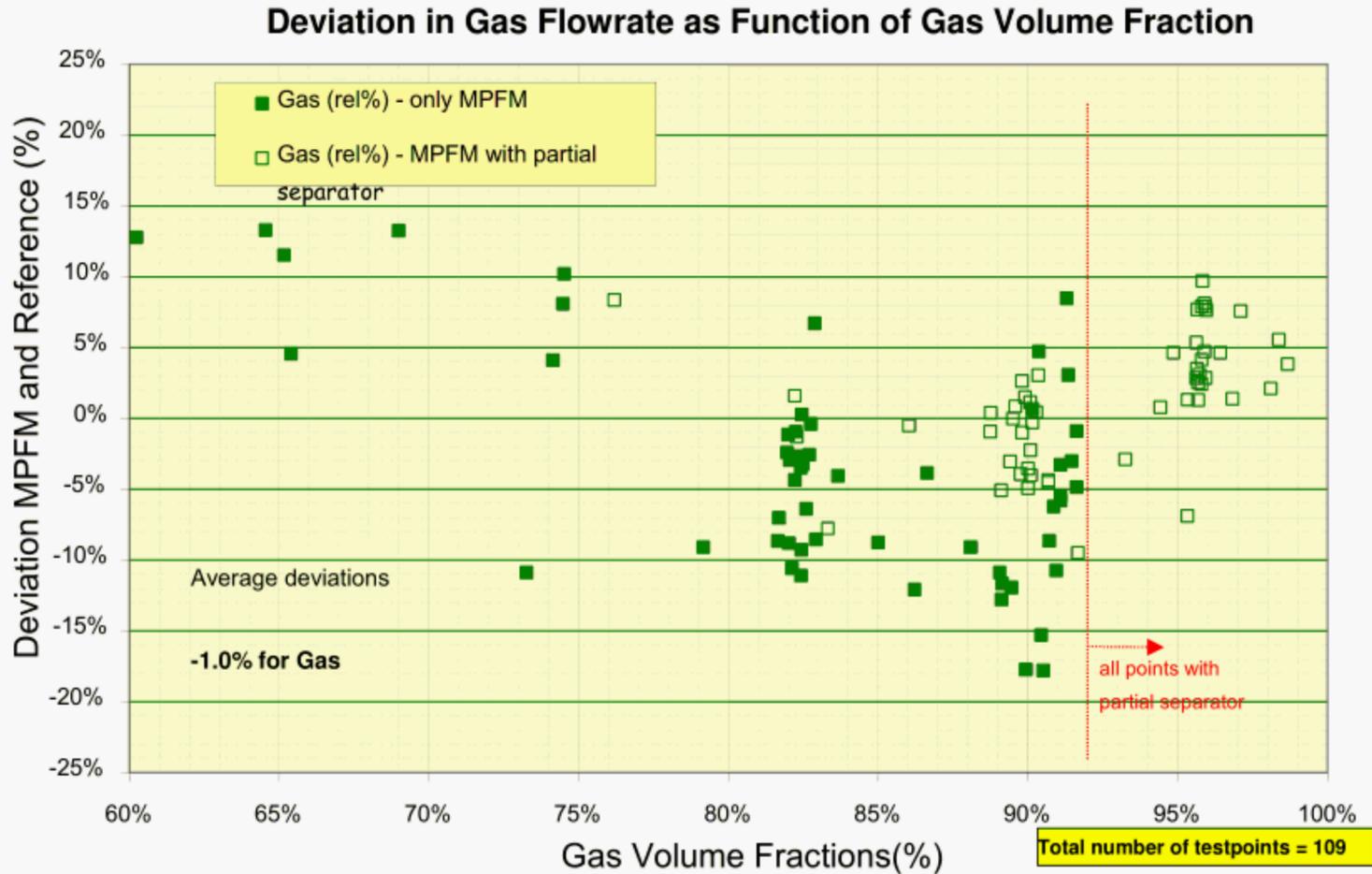


Figure 8.1(a)—Gas Flow Rate Deviation as a Function of Gas Volume Fraction

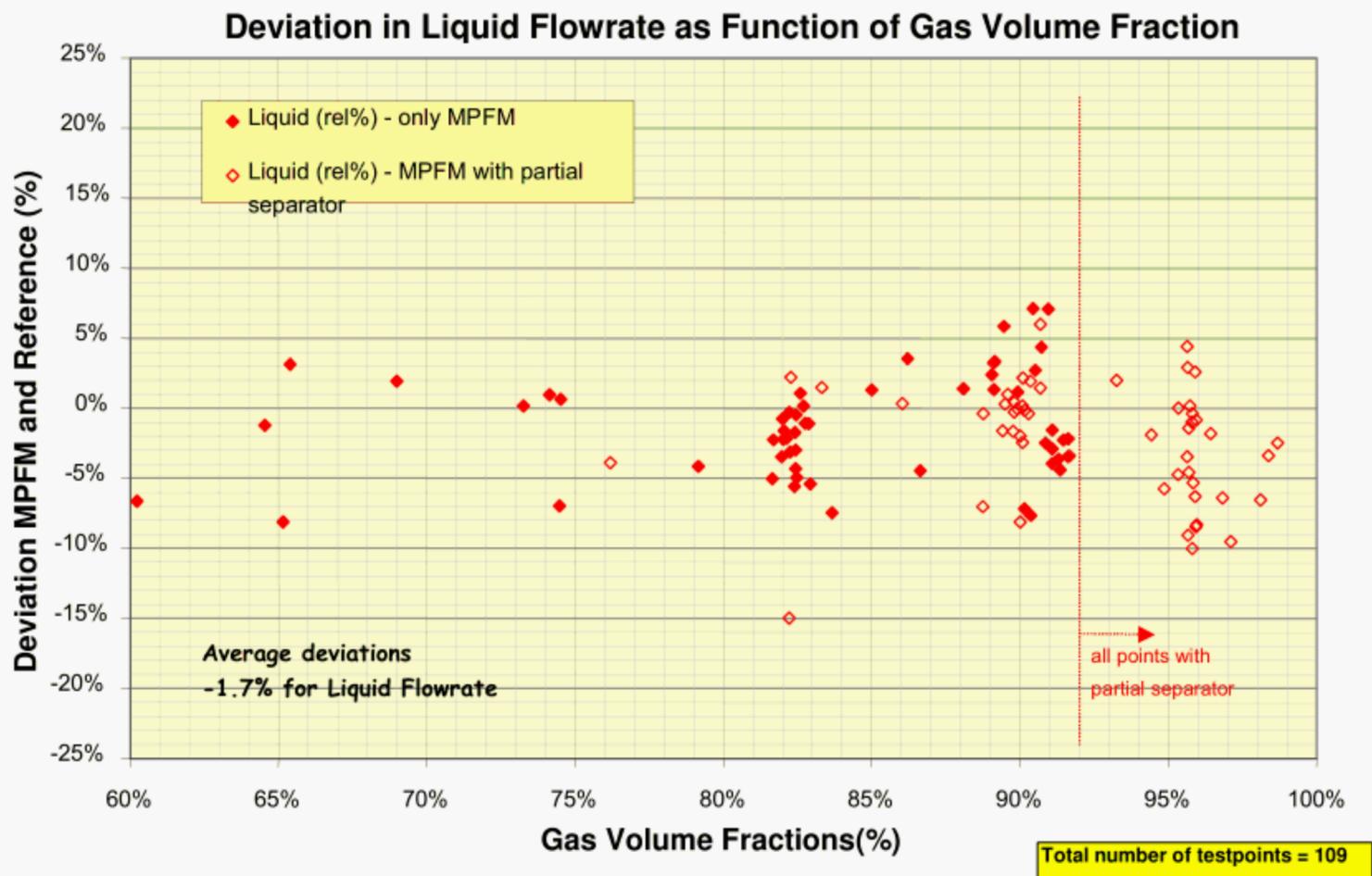


Figure 8.1(b)—Liquid Flow Rate Deviation as a Function of Gas Volume Fraction

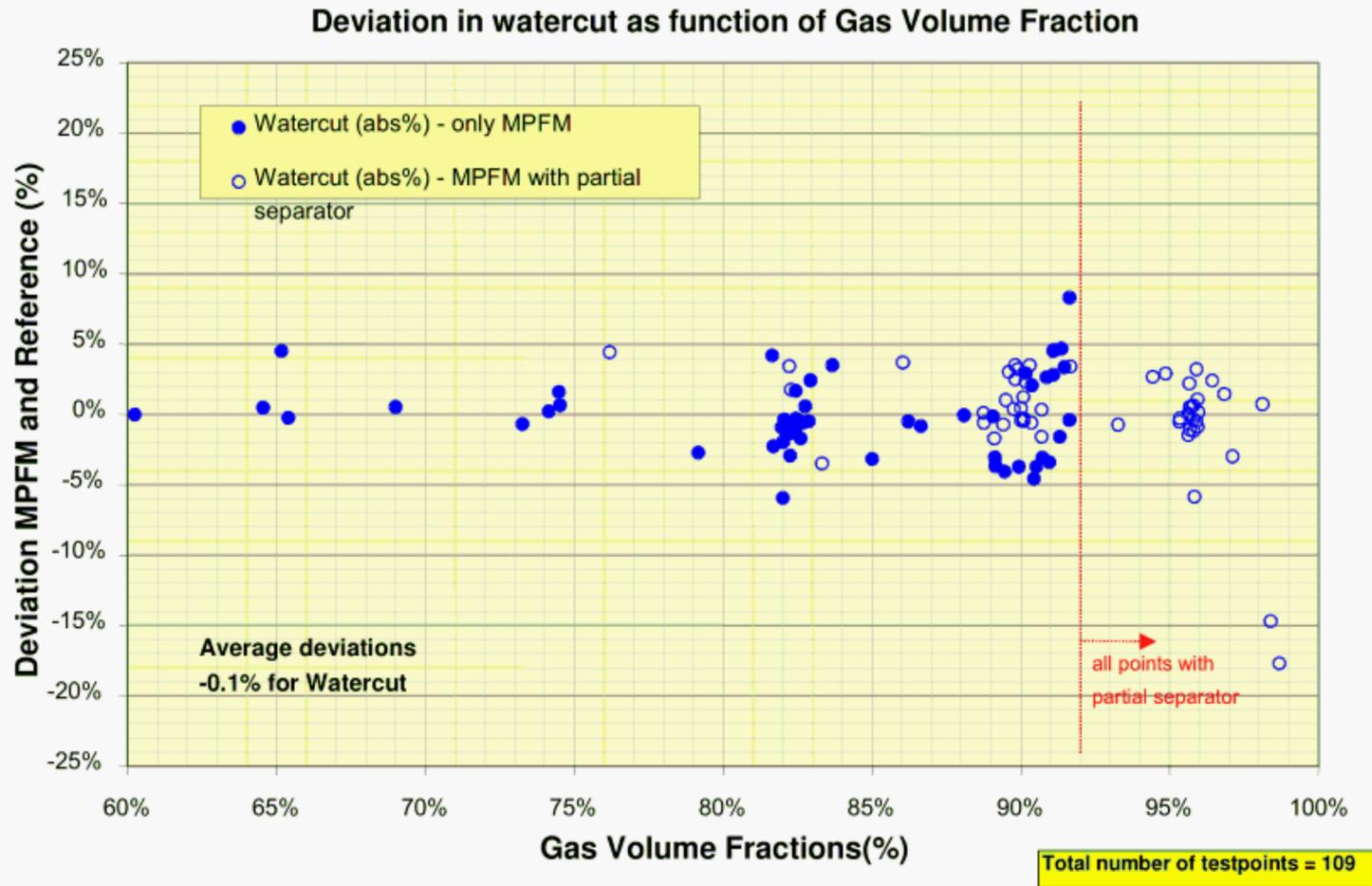


Figure 8.1(c)—Water-Liquid Ratio Deviation as a Function of Gas Volume Fraction

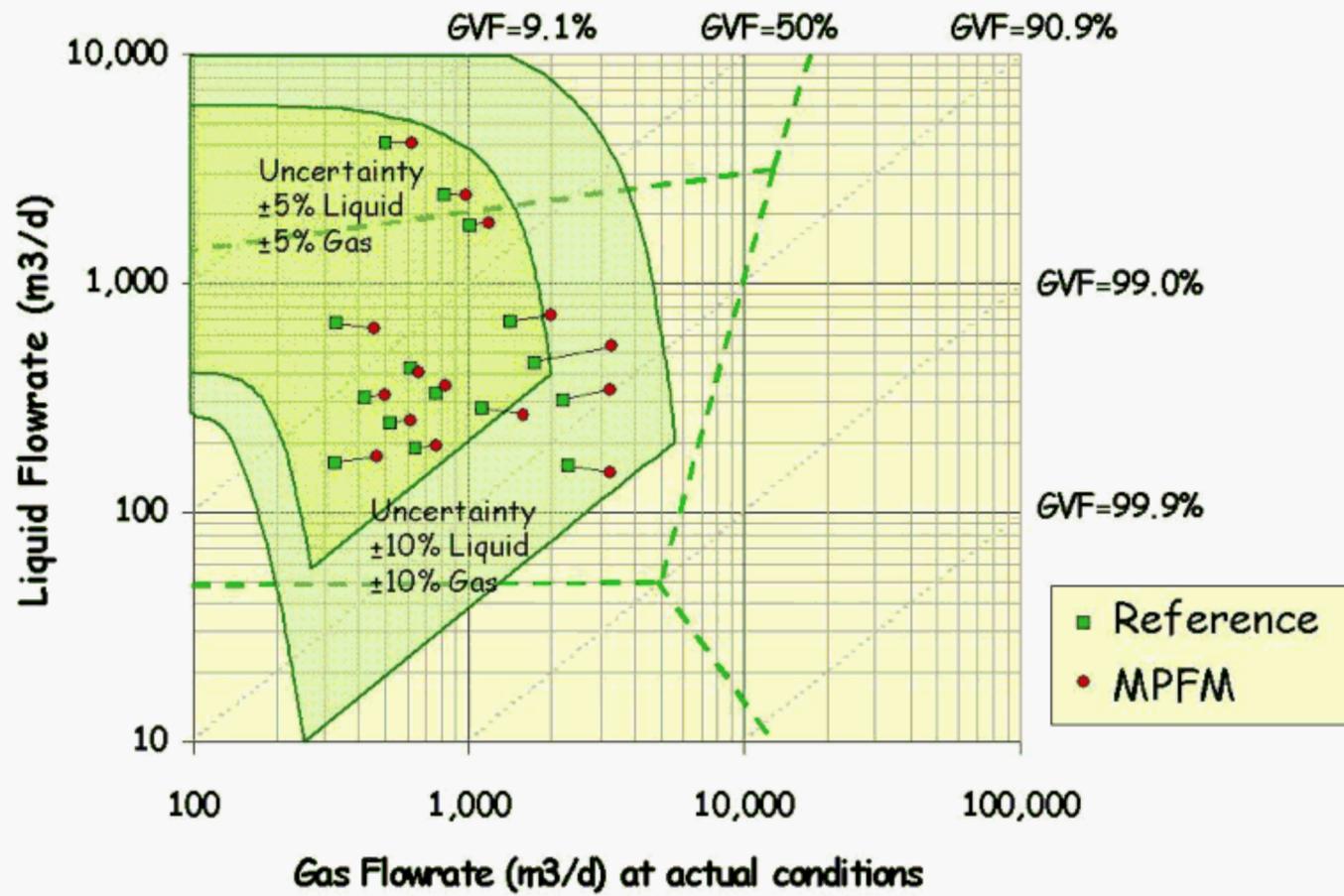


Figure 8.2—Meter Uncertainty Incorporated into the Multiphase Flow Map [Biblio.5]

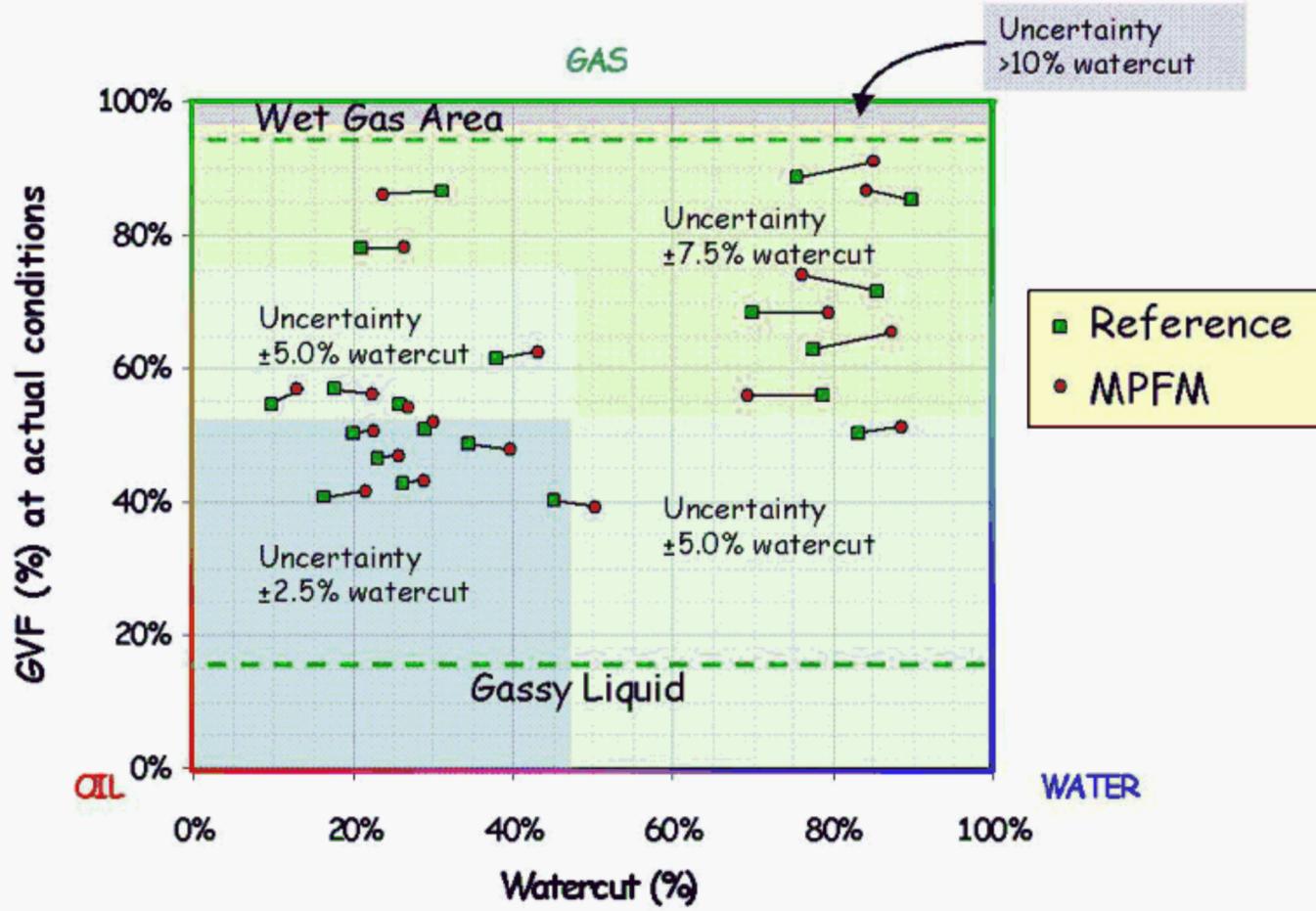


Figure 8.3—Meter Uncertainty Incorporated into the Multiphase Composition Map [Biblio.5]

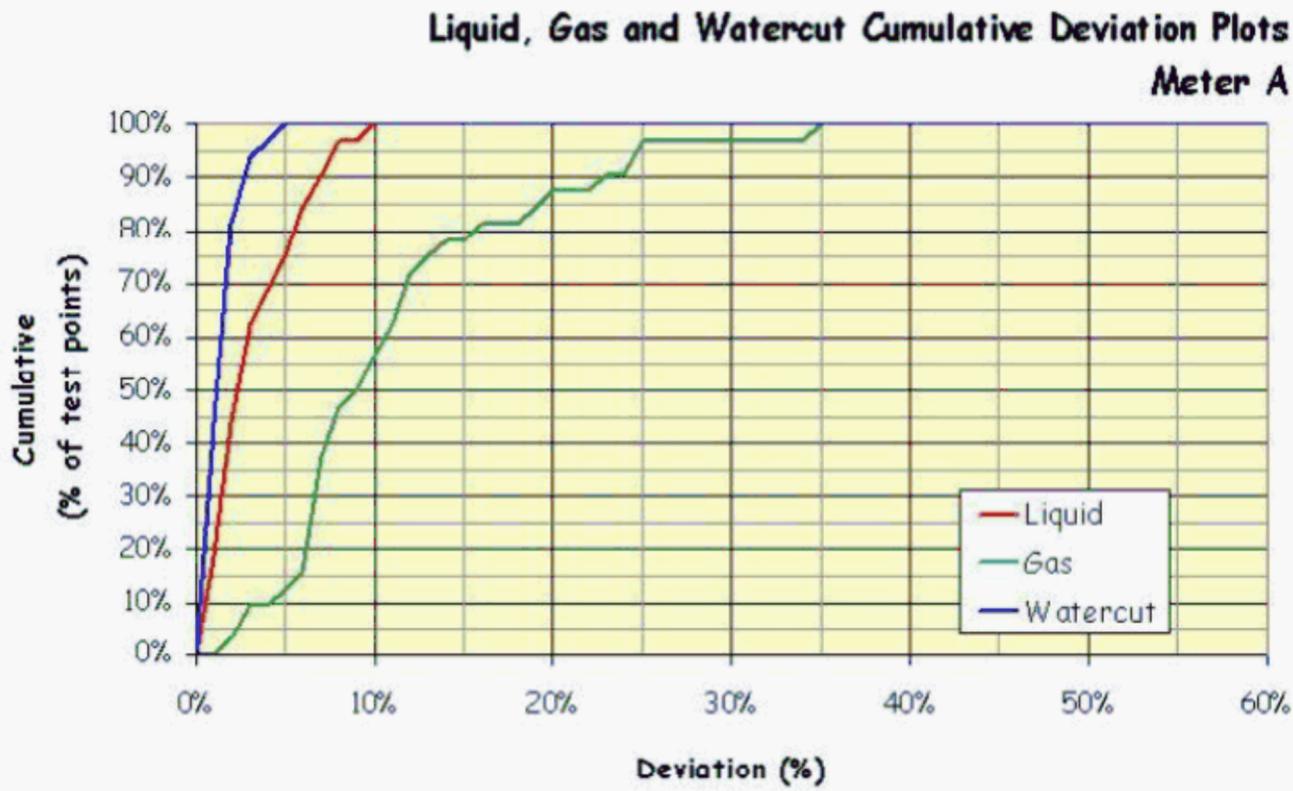


Figure 8.4—Meter uncertainty shown as Cumulative Deviation Plots [Biblio.5]

Table 8.6—Common forms of influence properties which produce measurement bias

Nature of Influence	Specific Influence	Effect on Measurement
Sensor Drift	Drift of DP, P , T	Bias calculations of flow rate, conversion to standard conditions, etc.
	Count Rate Drift	Cause bias in density or phase fractions.
	Radiation Detector Resolution	Causes errors in phase fractions for dual-energy gamma-ray instruments
Operating Environment	Pressure	Operating limits, transducer damage and offset due to static pressure
	Temperature	Operating limits, transducer damage, offset to low or elevated temperature
	Slip Ratio	Wrong correction made for slip between gas and liquid
	Flow Regime/Pipe Orientation	Bias introduced by use of incorrect flow model
Meter Geometrical Alteration	Erosion/Corrosion	Negative bias in calculated flow rate
	Buildup of Deposits (Wax, Scale, Asphaltenes, etc.)	Positive bias in calculated flow rate
	Pressure Effects	Depends on instrument
Other Meter Effects	Meter Finish Change (e.g. Scale Deposits)	Alter discharge coefficient C_d
Fluid Property Changes	Density	Inject flow rate bias.
	HC Composition	Affect phase fraction calculation
	Salinity	Affect phase fraction calculation
	Viscosity	Affect phase fraction calculation
	Other Additives (H_2O , H_2S , ...)	Affect flow and PVT models

8.7.2 Benefit

A high-level sensitivity analysis is used to find the financial exposure of the measurement options for input to the feasibility study for a proposed development.

During the conceptual phase of a project a more detailed sensitivity and uncertainty analysis is required to design the optimum measurement configuration and changes to the configuration throughout the field life.

During production an up-to-date sensitivity analysis gives the Petroleum Engineer the information required to minimize measurement exposure due to changes in the field performance and the production environment.

8.7.3 Scope

A thorough sensitivity analysis of a MPFM measurement system should consider all the aspects of the measurement, both quantitatively and qualitatively, including:

- Sensors—differential pressure, pressure, temperature, gamma densitometer, conductivity, capacitance
- Calibration—transducer span, absorption, source age
- Loop testing—MPFM type test, field test separator, field test MPFM
- Measurement model—slip factor, discharge coefficient, PVT, EoS, black oil, API thermal/compressibility, cross-correlation, venturi
- Data processing—GVF, WLR, phase quantities
- Fluid properties—phase densities, salinity, liquid/gas composition, fluid type
- Correction of phase quantities and properties to required conditions
- Vapor-liquid exchange in the process plant and flow-line to topsides
- Allocation of export quantities to producers.

This list encompasses the main areas depending on the measurement process and the purpose of the measurement. Only the first seven items need to be considered for well testing and reservoir management. In many instances the fourth item will not apply as there will be no measurement model. If only loop test data is available then sensor, the first item, and calibration, the second item, may not be required.

8.7.4 Analysis

The sensitivity can be found either by analysis of a model using any of a number of mathematical techniques, or empirically by observing the response of the measurement device caused by deviations in the inputs. This should be repeated for each output of the MPFM. In general sensitivity is found using several approaches described in more detail in A.2.3. The sensitivity methods are summarized below:

1. Model Sensitivity

- Analytical Sensitivity—partial differentiation of the model output with respect to each input.
- Numerical Sensitivity—each input to the model is deviated to find the ratio of the change in the output to the input deviation.
- Monte Carlo Filtering—observing the combined sensitivity of each model output with respect to each input.

2. Sensitivity

- Enforced Sensitivity—each input to the measurement device is deviated to find the ratio of the change in the output to the input deviation.
- Observed Sensitivity—changes to each input and the output are observed to find the ratio of the change in the output to the input deviation.

The validity of each sensitivity term should be considered for a given range of the input and the other inputs, since there can sometimes be dependencies between the inputs. Where strong dependencies exist between inputs, these should be accounted for in the sensitivity and uncertainty analysis.

Using sensitivity terms, a model can be constructed which mimics the operation of the measurement device. Such a sensitivity-based model can be used in place of a process simulation, which may be time-consuming and/or costly to develop and run.

8.8 VERIFICATION OF UNCERTAINTY VALUES

Verification of MPFM measurement and uncertainty is required to ensure the uncertainty standards for the installation are met for partners and regulatory authorities and to confirm the vendors stated uncertainty performance.

The meter type should be verified for specific areas of application to minimize subsequent verification work; the meter should then be verified for application prior to installation and in service.

Some meters continue to provide outputs when instrumentation has failed, which may allow continued operation with increased uncertainty—a useful trait. During normal operation this fallback data can be used for verification. In any case it should be recognized that the uncertainty is greater and accounted for in the uncertainty analysis for these modes of operation.

8.8.1 Vendor's Stated Uncertainty

The MPFM equipment vendor's stated uncertainties derived from these and other investigations should be verified for the type of meter and for the specific installation. This can be achieved at a calibration facility flow loop with representative fluids and conditions, using methods like those discussed in 8.3.3.1. The facility should be carefully selected; however it is unlikely that the field conditions will be precisely replicated, and this should be allowed for or corrections applied. Examples of this lack of replication include using calibration fluids such as nitrogen for gas, decane for dry oil, and relatively pure water. These fluids are stable, with predictable and small density variations, whereas in service the variation in density and other fluid properties may be greater and less predictable.

8.8.2 Verification in Service

Verification against a meter in service should be undertaken after commissioning and at regular intervals to confirm the operation of the meter. This should be at the phase flow rate level with mass balance or calibration against a reference and tracking the shifts in meter calibration. This also applies to the calibration of individual sensors and performance monitoring.

Monitoring of fluid properties and sensor drift should include regular sensor inspection, checks and calibration. This should include static tests of detector response with single-phase gas (or air), dry oil and water with a representative or known salinity. Trends in calibration shifts should be monitored with statistical methods to identify equipment failure and long-term drift which may not be immediately obvious. Where possible, calibration checks, both onsite and offsite, should include “As found” and “As left” identifiers, so drift from the previous calibration is not masked.

Sample points should be fitted to enable extraction of representative fluid samples at measurement conditions in order to configure the measurement systems. Generally the flow at the sample point should be well mixed. Traditional spot sampling will not necessarily yield representative samples in slug flow. If samples are to be taken in a flow regime that is experiencing severe slugging, the sampling should take place over the duration of at least one, and preferably many, slugging periods. Furthermore the sampling should be coordinated with the meter sensors (pressure, flow, etc.) in such a way that the sampling is done on a time-proportional or flow-proportional basis.

The meter skid should conform to API *MPMS* Chapter 20.1 requirements.

The subject of multiphase meter verification is discussed in greater detail in Section 9. In particular, the testing of in-service meters, to determine whether or not they are still performing as they did when first installed, is of great interest.

9 Multiphase Meter Acceptance, Calibration, and Verification

9.1 OVERVIEW

This section deals with the issue of the testing of multiphase flow meters for various purposes. Because the technology is relatively new and because no two meters are the same, it is an area to which users must pay very close attention.

In what follows, various kinds of tests that may be required are discussed.

9.2 TEST FACILITIES

In Appendix D are listed some of the major third-party facilities in which a wet-gas or multiphase meter may be flow tested, along with some of the facilities' characteristics.

In addition to those multiphase and wet-gas flow facilities shown, there are a number of similar flow loops owned and operated by the manufacturers of meters, as well as some of the larger users. Much of the data presented in papers on multiphase metering has been recorded in those facilities.

The data presented in Table D.1 are representative of the capabilities of the facilities shown at the time of this writing in 2004. These capabilities may have changed since that time, and new facilities not listed here may be available. The information is shown only for the purpose of providing the user with an overview of the topic of flow testing of multiphase flow meters, and no endorsement of any facility is implied.

Those interested in such tests are encouraged to contact the appropriate personnel at these facilities to explore the topic in greater depth.

9.3 REQUIREMENTS FOR FLOW TESTING OF METERS

Dependent on the purpose for which the meter is intended, different levels of testing should be performed.

9.3.1 Reservoir Management

Since the use of measurement in this application is for the purposes of managing the reservoir, it is often the case that the performance of each well relative to others, as well as to itself over time (trending), is more important than the absolute accuracy of measurement.

For this reason, the user should exercise judgment regarding a requirement for flow testing of meters to be used for this purpose. For instance, in cases where several meters that are identically manufactured (including software) are being acquired for use in similar conditions (GVF, watercut, flow rates, etc.), then the flow test data collected on a single meter may be sufficient to characterize the performance of all the meters in the group, provided all meters in the group make use of the same software for calculations and the meters are otherwise essentially identical.

If, however, the meters used in collecting flow test data are different from those to be used in the application, or if the conditions at which flow test data were collected differs from the conditions anticipated in the application, then flow testing of the meter at the relevant conditions is recommended. Relevant differences between meters might include

disparity in either meter construction or in the algorithms used to compute the outputs, such as flow rates, GVF, watercut, etc.

9.3.2 Fiscal Metering

These are applications for which financial consequences are associated with the results of measurement. Typically these are classified as either custody transfer (sales) metering or allocation metering. Since it is improbable that multiphase flow meters will ever be used for custody transfer, in this instance allocation and fiscal metering have the same meaning.

Unless there is sufficient evidence that conclusively demonstrates that it is not necessary, each meter to be used in a fiscal measurement application should be characterized in a flow test facility that mimics the application for which it is intended. This should take the form of a verification of the meter's performance over the range of the test matrix chosen to represent the application, not a calibration, i.e. no adjustments should be made based on the results of the test.

If the manufacturer can provide sufficient evidence that all meters in the group perform identically at flowing conditions, the user may grant an exception to this rule. This should take the form of a study in which randomly chosen meters that represent a statistically significant sample provide results that are identical. Again, the meters must be of the same design and use the same algorithms as those to be used in the application. This exception should only be granted if it is agreeable with all asset owners and with the governing regulatory authority.

Should the results of the verification be such that the meter falls outside the tolerance levels agreed prior to the test, the parties involved—user, vendor, and possibly the governing regulatory authority—must decide on a course of action to rectify the problem.

9.4 PRODUCT QUALIFICATION TESTS

In instances where a meter manufacturer is attempting to demonstrate the complete range over which his device is applicable, it is to his advantage to collect data from a test loop over as broad a range of conditions as possible in which the meter performs well. Prospective buyers are then more likely to find a range into which their specific application fits. Called Product Qualification Tests, these might actually be a collection of test results from various loops and even using different meters, perhaps even of varying sizes. One might argue that such a compendium of test data demonstrates the reproducibility of the meter under varying conditions, a desirable quality.

Results such as those shown in Figures 8.1, 8.2, and 8.3 are good examples of the kind of data one might expect to produce in a product qualification test.

9.5 FACTORY ACCEPTANCE TEST

When a user has purchased a multiphase meter for a particular application, it is recommended that the vendor demonstrate that the device is capable of meeting the specifications agreed to in the purchase agreement. Both a Static and Dynamic test should be included in the Factory Acceptance Test (FAT). These tests should be performed in an independent multiphase reference flow test facility to assess its performance.

It is recommended that a FAT procedure be developed for both the Static and Dynamic test and reviewed with interested parties prior to the test. The test procedure should include an agreed upon test matrix and the acceptance criteria defined prior to the test.

9.5.1 Performance Specification of Meter

It is of great importance that the performance of the meter be documented and agreed to by the user, supplier, and (if necessary) regulatory authorities. Using the presentation elements called out in 8.4, the range of pressures, temperatures, gas and liquid flow rates, gas volume fractions, and water-liquid ratios must be called out, as well as the performance of the meter in these conditions.

9.5.2 Test Matrix to be Used

It must be recognized from the outset that no FAT in a flow loop will exactly replicate the conditions to which the meter will be subjected in actual field operation. However, it is expected that during the FAT the loop will provide representative values of GVF and WLR, and simulate the flow regimes that are anticipated in the application.

Preparation of a test matrix in advance of the FAT such as that shown in Table 9.1 is not uncommon.

While the meter manufacturer will likely propose the test matrix to be used, it is of great importance that the user review what is proposed and concur with the choices made. The use of the flow and composition maps described in sections 5 and 8, with the operating envelope of the MPFM and the production envelope of the wells, can be used to advantage in this effort. For example, in the matrix shown below there is a large gap between WLR values of 35% and 75%, in which the flow goes from oil-continuous to water-continuous. If during the active life of the meter the user expects the WLR to fall in this range, it would be a mistake to accept the FAT matrix shown without adding points to test the meter in this range.

Table 9.1—Typical Flow Conditions Matrix Used in FAT for Multiphase Meter

	Test #	WLR(%)	GVF(%)	Qw(m ³ /h)	Qo(m ³ /h)	Qg(am ³ /h)
OC	1	0	60	0	30	45
OC	2	6	80	3	42	140
OC	3	10	75	5	40	135
OC	4	15	80	5	28	142
OC	5	20	90	4	16	184
OC	6	30	60	14	31	70
OC	7	35	75	10	19	90
WC	8	75	85	18	6	160
WC	9	85	80	28	5	136
WC	10	90	65	40	4	85

A final point to be made is that the reference loops in which these flow tests are conducted may be limited in their capacity to flow large amounts of gas and liquids. It may be necessary in many instances to perform reference loop measurements at low rates, then to verify the high-flow performance after arriving at the site where the meter is to be installed. Although less desirable than a flow test in which all measurements can be made in a single facility, sometimes it is simply not possible to get a meaningful flow calibration without resorting to such methods. Decisions as to what equipment are employed for such a site verification obviously depend on what kinds of facilities are available there, but might include production separators, LACT units, and the like.

9.5.3 Specific Tests Conducted

Within the general name of Factory Acceptance Tests, several individual tests are possible. Some of these are listed and discussed briefly below.

9.5.3.1 Static (Component) Test

Prior to testing the complete multiphase meter in a flowing exercise, the individual component pieces should be rigorously tested for faults. This includes, but is not limited to, static tests of all sensors, diagnostics on all computers and signal processing hardware, and checkout of power and communications lines.

9.5.3.2 Dynamic (Flow) Test

This is the test in a flow loop for which the matrix discussed earlier is developed. The meter supplier should have a well-defined procedure for its conduct, which he makes available to each observer in advance of the test.

During the conduct of the Dynamic Flow Test, it is mandatory that there be no alteration of the instrument settings of the meter under test, either through the meter hardware or through modification of software settings. Except in the most unusual of circumstances, the meter should be set up initially, then left in this state until the flow testing has been completed and the results of the test are recorded.

9.5.3.3 System Integration Test

In the case of large subsea production installations, there is the possibility that what is designed to fit together, both physically and electrically, will not do so. For this reason all major components should, wherever possible, be integrated both physically and electrically prior to their deployment. This is known as a System Integration Test.

9.5.4 Results of the FAT

For the individual test points shown in the matrix of Table 9.2, the vendor should provide the user his expectations of the uncertainty his meter will demonstrate in all the key parameters— phase rates, WLR, GVF, etc.—at each point. In order to determine how closely the meter meets this performance specification, two or three of the points in the matrix should be repeated enough times that estimates of the mean and experimental standard deviation of each parameter at those measurement points can be made, using the methods described in section 8. Any significant differences between the predicted results and those achieved must be explained.

The graphical displays recommended in Section 8 should be used to display the results collected in the FAT.

Appendix B provides a rather detailed listing of (a) items to have available for review before and during tests, (b) performance of Factory Acceptance Test, and (c) items to be made available to users at the end of the FAT. These are taken from the API COPM White Paper [Ref. 5].

9.6 INITIAL SITE VERIFICATION

After the user has satisfactorily tested the meter in a Factory Acceptance Test (FAT), ordinarily the next time it will be used is at the field location for which it was intended. Although this will not always be possible, a verification of static and dynamic meter performance under controlled conditions is highly recommended. Although the meter may have performed well in its FAT, there will likely be sufficient difference between flow loop and field conditions that having the additional data point provided at site may prove to be extremely important.

As an example, piping the meter in series with whatever separation facilities are present on the location can give early indications of any differences that might be observed once the device is in service. Of course, this form of verification must be performed with great care, especially for accuracy comparison, as the use of field separators as a reference for meter comparison can be fraught with peril, as has been described in other parts of this document (viz., 7.5, Appendix E).

9.7 FIELD VERIFICATION

It is essential that an active campaign of verification be an integral part of the routine operation of the field production.

Prior to approval by regulatory authorities and others to use multiphase flow meters, the user must declare what will be done to verify the correct operation of the meters as an ongoing, routine procedure. In this Verification Plan, a number of measures can be used, including the following.

9.7.1 Comparison of Redundant Sensors

A source of information when verifying the performance of the measurement system is a list of the sensors which are used. Since at least one level of redundancy is often present, it will be useful to compare data on the readings observed on the sensors relative to one another.

In the case of deepwater and harsh environments, it may prove cost effective to install additional transducers, which can be introduced into the measurement system by ‘software’ methods.

9.7.2 System Balance Check

This is the test most likely to be used as the primary verification tool. This first level of system auditing compares the *master quantity* with the sum of the *individual theoretical quantities*. The difference between the two over a pre-defined period of time, called the *system balance*, should lie within an error range defined by the uncertainties due to the subsea meters, to the reference meters, and to the equation-of-state and transport methodologies used. It should be performed on both the primary and secondary products to verify that measurement of both phases is within tolerance. More frequent balance checks are encouraged when used for diagnostic or other purposes.

Perhaps the most difficult part of the system balance check is the setting of thresholds and defining of criteria for declaring the system out of balance. This is challenging for two reasons: 1) the elimination of systematic errors must have been done well, or these will tend to skew the imbalance analysis, and 2) differences in relative production levels through meters may tend to mask a failure, i.e. a hard failure in a minimal producer may be hard to detect, and may resemble a marginal failure in a high producer. For these reasons, it will be necessary to look at many parameters in combination with the system balance to determine the overall health of the system.

9.7.3 Trending

Sometimes the most valuable piece of information in verifying the performance of the multiphase flow meters in a particular application is the determination of what has changed. This is often accomplished by means of data *trending*, whereby one collects historical data on various parameters of interest and then looks for deviations from the trend which has been observed over a period of months, or perhaps even years. Obviously the trends used in a particular instance are dependent on the nature of the application, and will likely be specific to its details.

An easily understood example of trending is the system balance described above. Although it will move up or down on a short-term (daily) basis, it should average to near zero over a longer period. If such is not the case, this suggests there are measurement problems which need investigation.

9.7.4 Sensor Zero and Offset Check at Shut-In

There will be occasions, scheduled and otherwise, when the individual wells will have their production shut in. Most governing regulatory bodies require regular testing of well equipment. The operator should ensure that these occasions are used to verify the zero offset and calibration of the sensors as part of an agreed program of verification.

9.8 IN-SITU (FIELD) RE-CALIBRATION

Until recently it was felt that flow-calibrating a meter in place could only be done on those that could be readily accessed and that could be connected to field reference devices, e.g. test separators, LACT units, etc. This restricted such practices to land-based or topsides meters. It now appears that calibration of subsea meters also may be possible [Biblio. 23].

In addition to flow-calibrating a meter in place, it is certainly possible to envision methods for performing limited calibrations of individual sensors. For example, as just mentioned in section 9.6.4, for differential pressure devices any zero shift can be detected and corrected by software means during periodic shut-in of the wells to test the down hole and surface isolation valves. Such methods for checking and re-calibration are recommended. In some cases differential pressure sensors may cover different ranges. In these instances, it may be desirable to re-scale a sensor to operate in a range of differential pressures other than that for which it was originally intended. The goal should be to use any opportunity to evaluate the sensor performance, and where possible to use software methods for re-establishing the desired sensitivity and zero offset. The meter vendor should be consulted to review this aspect of the design.

10 Installation, Reliability and Operability

Note: Much of the material in this section has been derived from section 6 and 7 of API RP 85 [Ref. 2].

10.1 OVERVIEW

The following guidelines are intended to cover subsea, topsides and onshore installations. The requirements for these different installations may differ, and will be highlighted where considered necessary. When installing measurement equipment, it is important that the correct installation, maintenance and operational procedures are understood and documented. The purpose of this section is to recommend procedures and practices for insuring that these goals are achieved.

10.2 NORMAL OPERATING CONDITIONS

The range of conditions in which the flow measurement systems are expected to operate must be defined. This should consider the total expected range of the field life.

It is standard practice prior to field development to create reservoir and production models showing how pressure, temperature and flow will vary and ultimately decline over the life of the field. Some of the parameters that should be addressed in this discussion are:

10.2.1 Pressure

Pressure measurement and monitoring is an important aspect of the reservoir/production model. Pressure is also an important quality of flow measurement. In general accurate measurement and compensation for pressure is essential.

10.2.2 Temperature

Some of the sensors and many of the calculations which will be used in flow measurement are affected by variations in temperature, so knowing its likely range and measuring it accurately is of importance. Many instruments have a limited thermal operating range, particularly at the extreme high and low limits, so the selection process requires an estimate of the temperature profile expected during the field life and from seasonal changes. Conversely, initial start-up temperatures may be “out-of-range” if careful consideration is not given to this aspect.

10.2.3 Flow Rates

Whilst the flow rates are generally within the Operator's control, anticipated flow rates (especially maximum and minimum) should be specified. This demonstrates that the metering solution chosen is capable of performing its function over the full range of flows, and that the meter has sufficient turndown. Gas and liquid flow rates over the well lifetime (the well trajectory) should be plotted together with the operating envelope of the meters using two-phase flow diagrams.

10.2.4 Gas and Liquid Volume Fractions (GVF/LVF)

A key set of parameters that should be reviewed is the relative production of gas and liquids from the field and their ratios in the overall flow. These may be defined in various ways, some of which are gas or liquid volume fractions, gas-liquid ratio, and the density based Lockhart-Martinelli parameter. The performance of virtually all wet gas and multiphase flow meters are dependent on the relative amounts of gas and liquid in the mixture.

10.2.5 Water Production

The water in each stream, as well as the amount of water relative to the hydrocarbon liquids anticipated, are important parameters. This is important not just from the economic perspective of hydrocarbon production, but also because flow meters often respond in different ways in the presence of water. Expected GVF and water cut over the lifetime of each well should be plotted in the two-phase composition map, and should be compared with the known operating envelope of the meter. Water cut is a production variable. In general it increases with the age of the field and can vary substantially ‘within day’ depending upon the field recovery techniques employed.

10.2.6 Fluid Properties

It is important to know as much as possible about the fluid properties of both the gas and liquid phases, particularly with regard to flow measurement. Parameters such as the gas density, the liquid densities for both water and the hydrocarbons, liquid viscosity, and water salinity are examples of typical fluid properties that may be needed as meter inputs. Often the molar composition is important and needed in order to calculate phase transformations during changing process conditions.

10.3 OPERATING ENVIRONMENT CONSIDERATIONS

Since the measurement system will normally be active for extended periods and may be subject to minimal intervention, insuring that it is properly designed for such operation is a key step. Listed below are some of the factors which should be considered.

10.3.1 External Design Pressure

During operation, conditions of low internal pressure may exist, e.g. installation, hydrate remediation, depressurization, etc. The meter and its components should be designed to sustain full external hydrostatic pressure where this is applicable. In subsea applications the meter system may be subjected to hyperbaric testing.

10.3.2 Internal Design Pressure

During hydro-testing, if included, the meters will experience high internal pressures, and should be designed to withstand the hydrostatic test pressure and depressurization. The absolute internal pressure may be experienced across transducers, which contain cavities at atmospheric pressure. These components should be designed to sustain the maximum absolute internal pressure and rapid depressurization. In general, hydrostatic testing should not include secondary instrumentation (pressure and differential pressure cells etc.) although thermowells should be considered as part of the meter body.

10.3.3 Pressure Taps

It is important to recognize that liquid drop-out in impulse lines is likely to occur, as the temperature of the gas will tend towards ambient once it leaves the meter stream. In extreme cases, hydrate plugs may form at the pressure taps.

The presence of either liquids or hydrates in impulse lines will introduce errors in the measurement of differential or static pressure.

Impulse lines connecting the flow meter's pressure tapings to a differential or static pressure transmitter should be as short as possible and inclined towards the vertical in order to drain entrained liquids. Liquid or hydrate accumulation can be further countered by the insulation of the impulse lines and the application of trace heating. In certain circumstances impulse lines may be filled with silicone fluids to inhibit process fluid contamination (extra heavy crude oil/bitumen). Care is needed to ensure a zero balance and additional equipment may be required to purge the protective fluids.

To minimize cooling by ambient conditions, Operators may consider placing the pressure transmitters and the impulse lines in a sealed enclosure. Consideration should be given to insulation and heat tracing where it is applicable.

Catchment pots located in the impulse lines may be effective at catching liquids. These may require frequent drainage to avoid liquid build-up and may not be effective in remote or un-manned installations.

10.3.4 Material Selection and Manufacture

Certain material combinations when exposed to extremes of temperature can cause corrosion and subsequent failure. In these cases, the material combinations to be used will need careful attention, particularly with regard to weld procedures and subsequent heat treatment. The Operator should demonstrate that he has considered the question of material selection for the environmental and production conditions, and has taken appropriate design steps to insure that the potential problems have been addressed. This should include compatibility with cathodic protection systems where necessary.

10.3.5 Erosion and Corrosion

In cases where access is a problem, it may be necessary to demonstrate that care has been taken to prevent alteration of the dimensions of the measurement device particularly by internal corrosion or erosion. For example, orifice plates suffer erosion when measuring the flow of raw well gas and the meter loses its accuracy, thus requiring replacement. For Venturi and similar meters, erosion is generally not considered to be a problem of the same magnitude, since its key dimensions are distributed over a larger area. A combination of special coatings and materials can mitigate these effects. There are many oil and gas producing areas around the world where sand erosion is a known problem and the design should take this into consideration.

Another consideration is the need for external coating selection and cathodic protection systems to mitigate the affects of external corrosion. The interested reader should consult API RP 17A on cathodic protection [Ref. 12].

10.3.6 Hydrate Susceptibly Analysis

A problem for oil and gas producers, is the possibility that water produced from the reservoir may lead to the formation of hydrates, which can reduce and even shut off production, as well as damage individual sensors. Where appropriate, it should be shown that the producer has considered strategies to prevent hydrate formation. Care should be taken to ensure that all the piping, meters, impulse lines, and sensors are considered as potential locations for hydrates thereby preventing accurate measurement. Consideration should be given to residual water, e.g. from installation and hydro-test, exacerbating the potential for hydrate formation, especially during start-up.

10.3.7 Scale or Wax Deposition

The production stream may contain fluids with scaling tendencies. Meters may experience internal scale buildup which will create erroneous measurements, such as differential pressure. The well stream must be treated to prevent scale, asphaltenes, and any other kinds of deposits that may build up in the meter, before they are likely to occur.

Some crude oils contain wax or paraffin that can also create a buildup in the meter. Heat or chemical treatments may be required in advance to reduce the likelihood that such buildups will occur.

10.3.8 Sensor Redundancy

Where necessary (i.e., subsea and other remote or critical locations), it is recommended that a high level of redundancy of sensors be provided. It is up to the Operator to design in the required level of system redundancy, and to describe the methods of using both primary and backup to validate proper operation or to detect failure.

Multiple sensors may provide a greater measurement range in some instances, such as differential pressure devices with enhanced turndown, where one DP sensor is used for low flow rates and another for higher rates. The Operator

should describe the level of redundancy and the method of combining the outputs of both sensors for flow measurement.

10.3.9 Leak Path Minimization

For some installations the reliability of the equipment can govern the ability of the system to function. Both internal and external leakage can cause environmental or ingress problems. To mitigate this potential hazard, the number of pipework connections used in the metering system should be minimized so as to reduce the likelihood of such connections becoming loose and thereby creating a leak. Where pipework or sense line connections are required, the highest attainable quality connection methods should be considered.

10.3.10 Installation and Removal from Service

In some cases—primarily those involving subsea meters—it may be a requirement that the system is removable. In such cases, the Operator may have to demonstrate that the pipework layouts are designed to permit installation and/or removal of the metering device. Attention should be paid to minimize external features that could hinder accessibility. The operator should also take account the available intervention tools to ensure that components can be operated and also that they cannot be overloaded and damaged by such interventions.

During installation it may be desirable to test parts of the system, especially the hydraulic integrity of the system. In subsea installations considerations such as submerged weight and methods of submerged weight control and the impact of submerged weight and the operating stresses on associated structures should be considered.

The use of a design which permits easy exchange of primary sensors within a metering system should be considered.

The design of the metering system should be such that it can be easily depressurized prior to removal of sensors or other parts of the meter.

10.3.11 Stresses Due to Environmental Conditions

The design envelope for systems involving subsea meters should take into account the following conditions.

10.3.11.1 Handling, Lifting and Installation

Loads due to stresses generated during these operations should be accounted for.

10.3.11.2 Thermal Effects

Thermal stresses, due to extremes from installation to operation, should be reviewed and accounted for in the mechanical systems. While construction and fabrication may occur in ambient temperatures of 120°F, produced gas may reach operating temperatures in excess of 300°F, and arctic temperatures may approach -40°F. Joule-Thompson effects across control valves etc can drop the production temperatures to -20 to -30°F. The thermal range should also take account Joule-Thompson effects which may be generated by depressurization.

10.3.11.3 Pressure. Operators must consider internal pressure ranges from atmospheric at installation to the maximum, which will usually be the pipeline hydrostatic test pressure.

10.3.11.4 Dynamic Loading.

Hydrodynamic loadings on subsea meters and their associated pipework may be significant. Flowlines and pipelines may attract current and wave induced loads that lead to high moments in the piping and flanges, especially where dynamic amplification could occur. Onshore installations can be subject to unusual soil dynamics, bridge loadings etc. Unusual profiles and features on equipment should be considered for extreme environmental conditions, e.g. during hurricanes, earthquakes etc. In cases of potentially high current velocity, care should be taken to ensure that vortex shedding is considered and mitigated by design. Vortex induced vibration (VIV), can lead to fatigue failures and must be considered, especially in jumper mounted meter installations.

Extreme loads can be applied to equipment as it is installed. Application of Dynamic Load Factors with and without the metering system should be considered [Ref. 13].

10.3.11.5 Impact Loading

During installation, large loads can be applied to the equipment as it is landed and when subsequent connections are made to it for supporting equipment. The installation rigging and resulting loads must be considered.

Impact loading may be a significant design case for meters. The design may also require a protective structure to protect the sensors, piping and cables

10.3.12 Collapse

An analysis may be needed to review the possibility of collapse of any pressure-bearing sections of the metering system in all phases—installation, operation, remediation, etc.

10.3.13 Other Factors

Some other design considerations of which an operator should be cognizant are listed below.

10.3.13.1 Sensor Accuracy

Sensor accuracy and maximum allowable drift relative to overall meter measurement accuracy for the required operating range should be addressed when sensors are being proposed or specified.

10.3.13.2 Power Requirements

Power demand from sensors relative to available power budget should be addressed early in the system selection process. Sensor drift with respect to power modulation should also be considered.

10.3.14 Mechanical Protection

Consideration should be given the potential for damage to flow meters during the operating life. Provision for appropriate and adequate protection from mechanical damage should be given consideration.

10.3.15 Software Development

There may be a requirement to develop, field install, and test appropriate flow meter algorithms. Appropriate (desired) units for mass, energy and volumetric flow rates, and measurement reporting requirements and format should be addressed.

API RP 17A [Ref. 12] should also be used as a guide for transportation, handling, installation, hook-up, commissioning, maintenance and abandonment of subsea equipment.

10.4 INSTALLATION EFFECTS ON MEASUREMENT

Many flow meter readings are affected by layout, dimensions, and internal obstructions in the pipework upstream of the meter. The Operator should demonstrate that these installation effects have been taken into account, based on the best information available from the manufacturer and on accepted industry knowledge and practice.

10.5 ABNORMAL OPERATIONS

10.5.1 Contingency Plan

An integral part of the operating strategy is a contingency plan for dealing with abnormal conditions. Abnormal conditions in measurement may be defined as those situations when malfunctions in the measurement chain cause the processes for allocation of gas and liquids to operate outside pre-determined acceptable limits. This can be malfunctions of the hardware, or inappropriate software to calculate the gas and liquid flow rates. Three aspects of an abnormal condition must be considered; namely, how the abnormal condition will be (a) detected, (b) verified, and (c) acted. These are discussed below.

As an aid it is recommended that the operator prepare a flow chart of the process which has been developed for the contingency plan.

10.5.2 Detection of Abnormality (Normal-Abnormal Boundary Definition)

There are several methods for the detection of an abnormal condition. They can be detected by observing the material balance or by observing the characteristics of the individual contributing meters. These are discussed below.

10.5.2.1 Material (System) Balance Check

As discussed in 9.6.2, a material balance check compares the field measurement inputs against the facility outputs. Other descriptions include the comparison of field meters against reference (fiscal) meters, however this does not necessarily include such measurements as fuel or flare which might lead to a systematic loss. Whilst many

measurements are often made in volumetric terms a material balance is best done in mass terms, as mass is not lost as process conditions change.

A potential pitfall is the possibility that systematic errors may be incorporated in a particular meter reading. A second is that differences in relative production levels through meters may tend to mask failures. Thus a hard failure in a minimal producer may be hard to detect, and may resemble a marginal failure in a high producer. For these reasons, it will be necessary to look at many parameters in combination with the Material Balance to determine the overall health of the system.

In volumetric terms it will be necessary to consider the System Balances of both the gas and liquid phases. However, for very dry gas it will likely become more difficult to use balance in the liquid measurement, due to the large relative uncertainties in these cases. Fortunately, in these cases the mass flow rate of the liquids is so small that this is not an issue of great concern.

As shown in Appendix E of Reference 2, the uncertainty of the calculated System Imbalance can be written as

$$E\{I^2\} = \sigma_z^2 + \sum_1^n \sigma_i^2$$

where the σ_i^2 reflect the physical conditions of the reference meter. If we set the Imbalance Limit T_I that is used to trigger an alarm condition at twice the standard deviation of the System Imbalance (95% confidence level), then

$$\begin{aligned} T_I &= 2\sigma_I \\ &= 2\sqrt{\sigma_z^2 + \sum_1^n \sigma_i^2} \end{aligned}$$

For gas measurement, comparing the System Imbalance with this Imbalance Limit will routinely be done, normally at a frequency which coincides with the accounting period, or monthly, whichever is shorter. For liquid measurement, the System Imbalance will ordinarily be calculated, but only where the mass flow rate of liquid is at least 5% or more of the mass flow rate of gas will the use of an Imbalance Limit be required.

The Imbalance Limit described above is properly called a *Specified Imbalance Limit* in contrast to an *Imbalance Upper/Lower Control Limit*. The Specified Imbalance Limit is determined by considerations such as contractual obligations and/or regulatory requirements. Imbalance Upper/Lower Control Limits indicate to those responsible for the process that something has changed and needs to be investigated. Unlike the Specified Limits, the Imbalance Upper/Lower Control Limits are fixed after some history has been gained on how the process performs “typically”.

10.5.2.2 Individual Meter Characteristics

In addition to looking at the measurement system as a whole, it may be possible to observe the fluid qualities of and quantities from individual meters, to detect abnormal conditions.

One method of accomplishing this is through the use of redundant sensors as described in 6.7.1.

Drift of any one set of transducers can be detected for the case of constant choke settings, since the flow should remain effectively constant, provided the wellhead pressure is constant and the pressure drop across the choke is large enough that the flow is critical (sonic).

These examples assume subtle failures of sensors, whereas experience shows many failures will be more obvious, such as a complete loss of signal, leading to a more straightforward identification of the system fault.

10.5.3 Investigation (Verification of Abnormality, Identification of Cause)

If an imbalance is detected and there is an obvious cause, such as a failed meter or sensor, the operator should revert to an alternative measurement scheme. If possible the onset of failure should be identified and the alternative measurement should be used to backfill data to that point in time.

In the case where there is no obvious failure of a meter or sensor which could cause the system imbalance problem, it is important to use all means available to identify the root cause of the Imbalance. Listed below are some strategies for this attempt.

10.5.3.1 Verify that Reference Meters are Measuring Correctly

Before overlooking the obvious, a thorough inspection of the reference (or fiscal) meters should be made.

10.5.3.2 Verify Proper Conversion Between the Subsea and Reference Measurements

Are PVT/EOS packages being applied correctly? Have temperature and pressure been measured correctly, and are they in the range within the PVT/EOS envelope, and is the correct composition being used to convert the measurements from one process condition to the other?

10.5.3.3 Test by Absence

Shutting in wells or production areas to identify a problem can be done, but it can be problematic, as a complete cycle through all meters may be required in case there is more than one faulty meter. It should be considered whether such a test is representative. With this method, longer tieback distances may be a problem due to the stored inventory. It should be noted that this may well entail a substantial loss in production, and therefore should be viewed as a last resort.

10.5.3.4 Other Testing by Absence

It may be faster to develop strategies for shutting in production groups (or wells) to identify the cause of imbalances.

10.5.3.5 Verify Zero Readings on all Meters and Transmitters During Shut-In

This could be further evidence of a faulty transmitter or meter. This should be the standard operating procedure, and the measurement system should have the capability to identify and mask any drift in the zero reading. Note that drift of the span cannot be detected during the shut-in.

10.5.3.6 Compare Readings from Redundant Sensors

It should be helpful to compare the outputs of redundant sensors for change. Rather than looking only at instantaneous readings, however, one should look at their difference over time to determine if there has been a significant departure from the “norm” since the System Imbalance was detected.

10.5.3.7 Other Diagnostic Parameters

Individual meter sensors may have their own characteristic signals, the monitoring of which may indicate the malfunction of a meter. As an example, meters which use gamma-ray densitometry can monitor voltage levels which indicate the health of their scintillation detectors. Changes in these signals might point to a failure.

10.5.3.8 Observe Evidence of Other Well Parameters (e.g. Bottomhole and Wellhead Pressure & Temperature)

Changes in these parameters (or lack thereof) can confirm or contradict what is being observed on the meter for an individual well, thus can be an important tool in investigating meter failures.

10.5.3.9 Compositional Analyses

There may be clues which can be derived from observing the composition of the process stream and comparing it with “normal” as well as with the compositions of the individual wells, especially with regard to the heavier components. This technique has been used with success in traditional multiphase problems through the technique called *geochemical fingerprinting*.

10.5.3.10 SCADA or Supervisory Metering System Malfunction

The performance of the Supervisory Control and Data Acquisition or the Supervisory Metering System should be examined for the possibility that errors might originate there.

10.5.4 Remedial Action

Once the investigation is complete, an appropriate method of alternative measurement should be used, both for future measurement as well as working back to when proper measurement ended. Acceptable alternatives are required as part of the contingency plan, and also should be included on the if that approach is taken.

Alternative measurement may have to be approved by the Governing Regulatory Authority prior to implementation.

Some alternative measurement methods are described below.

10.5.4.1 Dual-DP Meters

For dual-DP devices, using either DP meter as ‘back-up’ if the other fails is an acceptable remedial action.

10.5.4.2 Calibrated Choke

By measuring differential pressures across the chokes while the subsea meters are yielding good data for gas and liquid flow rates, in normal conditions this information can be used to “calibrate” the choke. The choke can then be used as a backup device if the primary meter is lost. It is recommended that this approach be used only in the case where the meter has failed totally.

If this approach is to be taken, it is important to record all choke data on a routine basis, in order to characterize its response as completely as possible. Transmitters should be re-zeroed whenever the well is shut in and a record of choke sensor readings versus meter sensor readings should be maintained for use as a calibration record. The planned frequency of calibration is generally specified in the Governing Regulatory Authority application (Appendix C) if this approach is planned for use as a backup. It is recommended that the user perform regular (e.g. quarterly) re-calibrations versus the primary device, corresponding to any mandatory wellhead shut-in testing. This form of measurement may be used for a limited time as a meter substitute if properly approved.

If there is any erosion of the choke or changes in fluid properties, the choke calibration will change, thereby requiring periodic re-calibration, or periodic changes in uncertainty values based on the date of the last calibration.

10.5.4.3 Other Transmitters

It may be that other sensors can be substituted (which may be less accurate), e.g. DP cells with a different measurement range. While this may reduce the measurement accuracy, it might be useable until a scheduled intervention.

10.5.4.4 Last Value Stand-in Proxy

A last known good measurement for the specific pressure and temperature may be acceptable. This should be agreed with the Governing Regulatory Authority and the other parties.

10.6. OPERATION OUTSIDE THE CALIBRATED ENVELOPE

It is not unlikely that occasionally the conditions in which a previously calibrated meter is operating will change to the extent that it is operating outside its performance envelope or the envelope for which it had originally been calibrated. In this instance the operator must carefully examine the overall system balance and any other evidence, then make a determination as to whether there is any indication that the meter is performing improperly. If there is reason to believe that such a condition exists, steps must be taken to either (a) remedy the problem or (b) justify why no action should be taken.

A possible remedy is the testing of a so-called proxy meter, i.e. a meter with identical dimensions and other characteristics to the operational meter, but which can be readily shipped to a calibration facility for testing in the extended operational range not originally covered. New calibration data extending the range would then be gathered and installed on the original meter.

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APPENDIX A—UNCERTAINTY CONCEPTS

A.1 MEASUREMENT UNCERTAINTY

Measurement uncertainty is illustrated graphically in Figure A.1 as a dispersion of results with a normal (Gaussian) distribution. This has a characteristic bell shape represented in measured units around a mean value or as percentage of the measured value. Each column has a width representing a range of values and a height which represents the number of measurement points falling within this range.

While there are many other forms of probability distribution, other than normal, some of which are shown in Figure A.2 below, it is by far the most widely used, and is tacitly assumed in all that follows.

A.1.1 Uncertainty Evaluation Type

In contrast to the GUM where uncertainty is described as Type A or Type B, in this RP the terms *random error* or *uncertainty* and *systematic error* or *uncertainty* will be used instead. Systematic errors are also known as bias errors. Random uncertainty is found by statistical analysis, while systematic uncertainty is found by other means. In both cases the uncertainty is treated as having been produced by random variations, thus simplifying combination of uncertainties using quadrature methods.

A.1.2 Confidence Interval and Coverage Factor

These terms are best explained using the example shown in Figure A.1. The confidence interval of the measurement variable is the range of values around the mean that will fall within a stated uncertainty. For example, the 68% confidence interval is the range of values about the mean (10.0) in which 68% of the measurements should fall, and is approximately equivalent to ± 1 standard deviation. In this instance, the 68% confidence interval is from 9.49 to 10.51. This means that, in a very large number of trials, the measured value will fall within this range 68% of the time. Likewise, the 95% confidence interval is the range from 9.00 to 11.00, and is approximately equivalent to ± 2 standard deviations. The measured value will fall within this range 95% of the time.

The two intervals chosen for this example were picked because they represent ranges of one and two standard deviations, or standard uncertainties, about the *mean value* [see section 3, Definitions and Nomenclature]. The number of standard uncertainties represented by any given confidence interval is called its coverage factor. Thus the 68% confidence interval has a coverage factor of 1.0 and the 95% confidence interval, 2.0. The 99% confidence interval shown has a coverage factor of 2.6, while the 90% confidence interval has a factor of 1.6.

A normal distribution is the basis for reporting uncertainty, and for combining uncertainty using quadrature methods to find a combined standard uncertainty, resulting from underlying uncertainties in several quantities, as described in A.3 below. The combined standard uncertainty can also be found using Monte Carlo Simulation (MCS) methods.

A.1.3 Other Distributions

Uncertainties with uniform (rectangular), triangular and other symmetrical distributions are ordinarily converted to their equivalent normal distributions to facilitate presentation and combination of uncertainty results using quadrature methods. When MCS is used to combine uncertainties, the actual distribution of values does not need to be symmetrical.

A.1.4 Reporting of Results

Uncertainty is often presented as a relative uncertainty U about the mean value. For the example in Figure A.1 of a distribution with mean of 10.00, a relative uncertainty of $U = 10.0\%$ is equivalent to an absolute uncertainty about the mean of $u = 1.00$ ($10.00 \times 10.0\%$). For either choice of description, the uncertainty is symmetrical about the mean of a normal distribution with a confidence interval of 95%, which is the de facto standard for presentation of uncertainty. For other confidence intervals the interval must be explicitly stated with a subscript; thus in the example of Figure A.1 the uncertainty for the 99% confidence interval, the relative uncertainty is stated as (10.00, $U_{99} = 13.2\%$) and the absolute uncertainty as (10.00, $u_{99} = 1.32$).

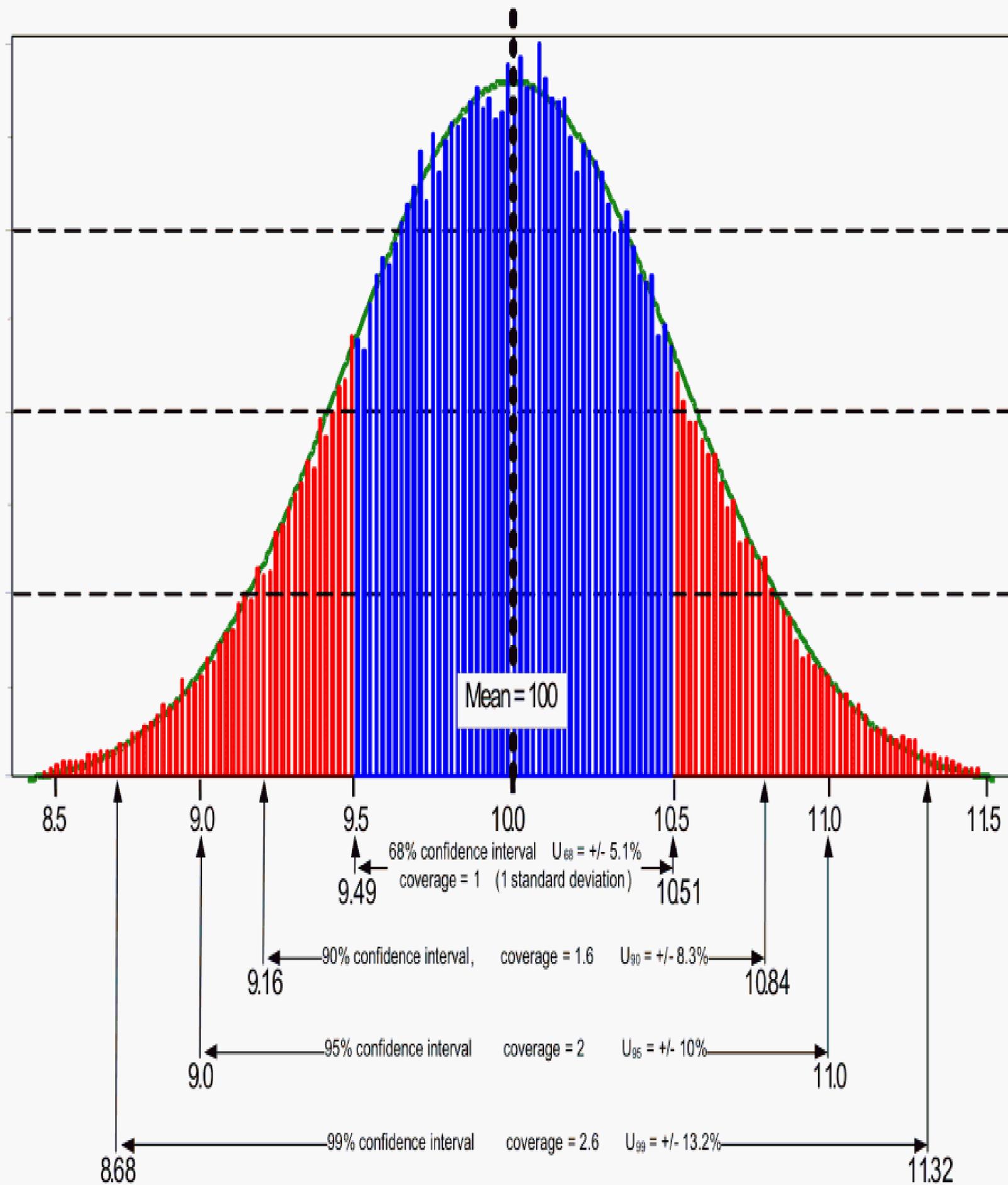


Figure A.1—Normal Distribution

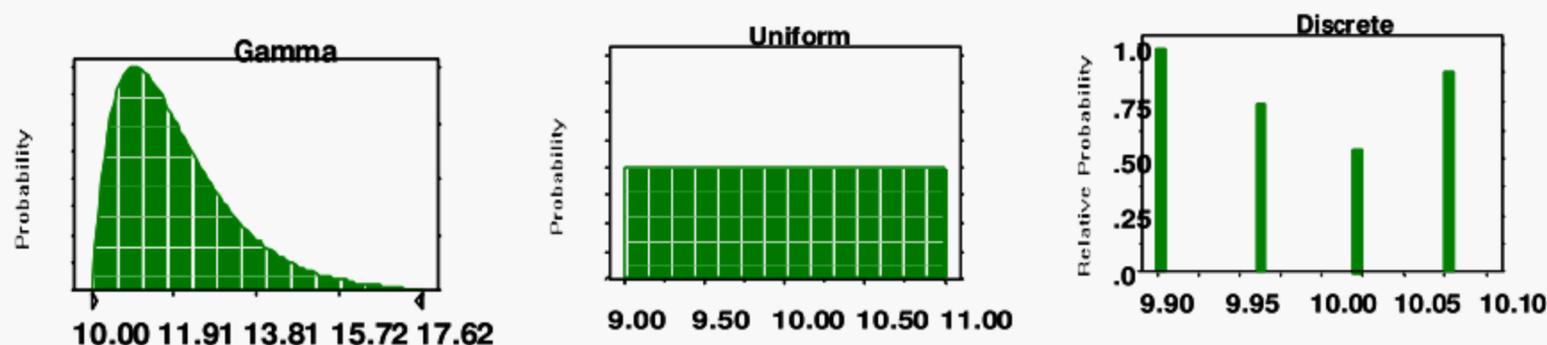


Figure A.2—Some Uncertainty Distributions

A.2 QUADRATURE COMBINED UNCERTAINTY

Multiphase fluid flow is invariably derived from a functional relationship between a number of measurements which must all be taken into account when analyzing flow measurement uncertainty. These complex relationships are often further compounded when the results are cascaded into another system such as an oil or gas pipeline allocation system.

Determining the uncertainty of these systems is problematic with conventional Root Sum Square (RSS) quadrature uncertainty methods. Monte Carlo Simulation (MCS) provides a reliable alternative systematic method of determining uncertainty that can also be used as an independent validation of quadrature uncertainty.

A.2.1 Analytical Quadrature Uncertainty

Uncertainty of individual flow measurements or flow measurement systems is found using Root Sum Square (RSS) quadrature methods. This technique is based on the Central Limit Theorem (CLT) whereby combinations of uncertainty distributions will tend towards a Normal distribution. In practice, resulting uncertainty distributions may not be Normal, leading to an under- or overstatement of uncertainty.

For a given functional relationship:

$$y = f(x_1, x_2, \dots, x_n) \tag{A.1}$$

The uncertainty U_y is found from the RSS of the product of each measurement uncertainty (U_i), measurement value (x_i) and the sensitivity (Θ_i) of the output to a change in the input to the measurement as follows:

$$U_y = \frac{\sqrt{(\Theta_1 U_1 x_1)^2 + (\Theta_2 U_2 x_2)^2 + \dots + (\Theta_n U_n x_n)^2}}{y} \tag{A.2}$$

A.2.2 Numerical (Perturbation) Quadrature Uncertainty

Uncertainty can also be found by deviating each input to the functional relationship by the uncertainty of the input. This method, also known as the perturbation method, takes account of sensitivity which does not need to be calculated separately.

The uncertainty is found for the functional relationship in Equation A.1 as follows:

$$U_y = \frac{\sqrt{\left(\frac{\Delta U_1 x_1}{\Delta y_1}\right)^2 + \left(\frac{\Delta U_2 x_2}{\Delta y_2}\right)^2 + \dots + \left(\frac{\Delta U_n x_n}{\Delta y_n}\right)^2}}{y} \tag{A.3}$$

A.2.3 Sensitivity

A detailed sensitivity analysis of each functional relationship in the measurement system is found from partial derivatives or by numerical means to find the sensitivity (Θ_i) of the output (y) of a functional relationship to each input (x_i).

Analytically sensitivity
$$\Theta_{Ayx_i} = \frac{dx_i}{dy} f(x_1, x_2, \dots, x_n) \quad \text{A.4}$$

The sensitivity (Θ_{Ayx_i}) for an input term (x_i) is found from the partial derivative of the output function ($y=f(x_1, x_2 \dots x_n)$) with respect to the input (i). This approach is well suited to simple relationships with a small number of input terms. Where the relationship is complex or discontinuous or there are a large number of inputs it is not practical and may not be possible to find the partial derivatives. It is recommended that partial derivatives be found using mathematical software.

Numerical sensitivity
$$\Theta_{Nyx_i} = \frac{\Delta x_i}{\Delta y_i} \quad \text{A.5}$$

The sensitivity (Θ_{Nyx_i}) for a function with a single input is found by making a small deviation, typically the absolute uncertainty ($\Delta x_i = ux_i$), to the input ($x_i \pm \Delta x_i$) and observing the change in the output ($\Delta y_i = f(x) - f(x_i)$). Where a function has more than one input this should be repeated for each input. Numerical sensitivity is useful for complex functional relationships or functions with a large number of inputs. In measurement models or systems with common inputs with more than one output, such as multiphase flow meters, the deviations of each output should be captured as each input is physically deviated.

Where a functional relationship exists which is very complex or inaccessible, such as in a process simulation, the sensitivity can be found by deviating the input and observing the change in the output.

Sensitivity may be found empirically by observation in a controlled environment, by physically deviating process variables to determine the change in the outputs. In some cases changing one input will impact another, and this must be taken into account. An example would be the manner in which changing a choke position will impact flow, well head pressure, and possibly tubing head pressure, which will also impact the GVF. It may be possible to use a PVT or process simulation model to find the sensitivity by deviating model inputs replicating some changes in order to isolate and quantify other changes that cannot be modeled.

A.3 MONTE CARLO SIMULATION COMBINED UNCERTAINTY

A.3.1 Monte Carlo Simulation Uncertainty Method

Monte Carlo Simulation (MCS) is a numerical technique in which the dispersion of sensor values around a measured value is simulated by randomly generated numbers with a normal or other representative distribution. The simulated trial value for each sensor is repeatedly applied to a functional relationship, as illustrated in Figure A.3, until a representative number of trial values have been generated. Uncertainty is found from the standard deviation of the resultant distribution of trial values using the relationship in Equation A.6.

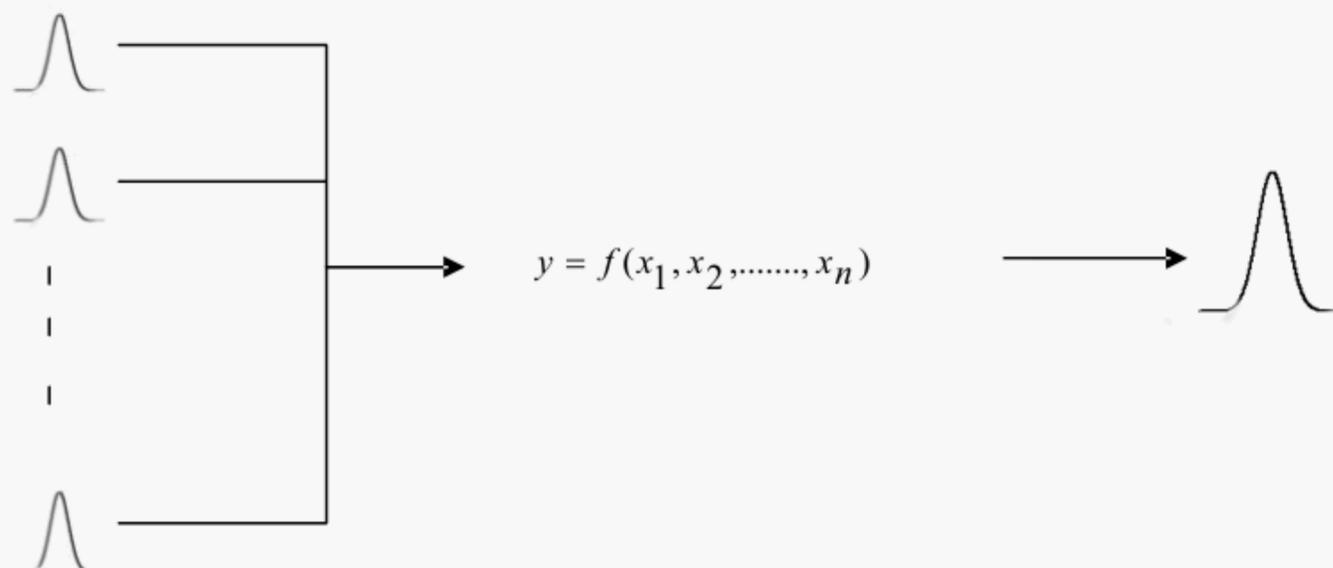


Figure A.3—Monte Carlo Simulation Uncertainty Propagation

$$U_y = \frac{2 \times \text{stddev}(\text{trials}(f(x_1, x_2, \dots, x_n)))}{\text{mean}(\text{trials}(f(x_1, x_2, \dots, x_n)))} \tag{A.6}$$

The main advantage of MCS is elimination of the need for detailed mathematical or numerical sensitivity analysis and as an independent means to verify *combined uncertainty* found by quadrature methods.

The uncertainty of sensors and other inputs with non-symmetric uncertainty distributions, dependency between inputs and biases are correctly propagated through the functional relationship to the output. If the resultant distribution is not symmetrical the uncertainty with a 95% confidence interval can be found from the 2.5% and 97.5% percentiles of the distribution.

A.3.2 Covariance and Dependency

In general, with single-phase flow measurement, covariance and dependency effects are small, due to the small uncertainties and relative independence of the calculations. With multiphase flow meters the uncertainties are large, with dependencies from common instrumentation that provides several parameters. Furthermore, the multiphase flow measurement model is generally complex, with much dependency among parameters.

Quadrature methods require the uncertainty of each input to be independent, so that the uncertainties of the inputs do not influence each other. Dependency can arise from ambient effects such as static pressure or temperature, from interaction between sensors, or from a mathematical relationship that is applied to related values in a subsequent calculation. In multiphase flow measurement the sensor values will be used in separate functional relationships to find WLR, GVF and multiphase flow and velocity. When these parameters are then used to find phase flow rates, there is a dependency that may lead to over- or understatement of the final uncertainty.

The phase flow rates are therefore not independent from one another, and care should be taken to allow for this in any subsequent processing including reference phase uncertainty, well allocation and pipeline product allocation.

A.3.3 Non-linear Functional Relationships

Quadrature uncertainty methods assume a straight-line functional relationship with a small deviation about a point due to uncertainty relative to the measured variable.

The large uncertainties of some variables in multiphase flow meters and non-linear functional relationships can lead to biases, particularly at the limits of a measurement range, as illustrated in Figure A.4.

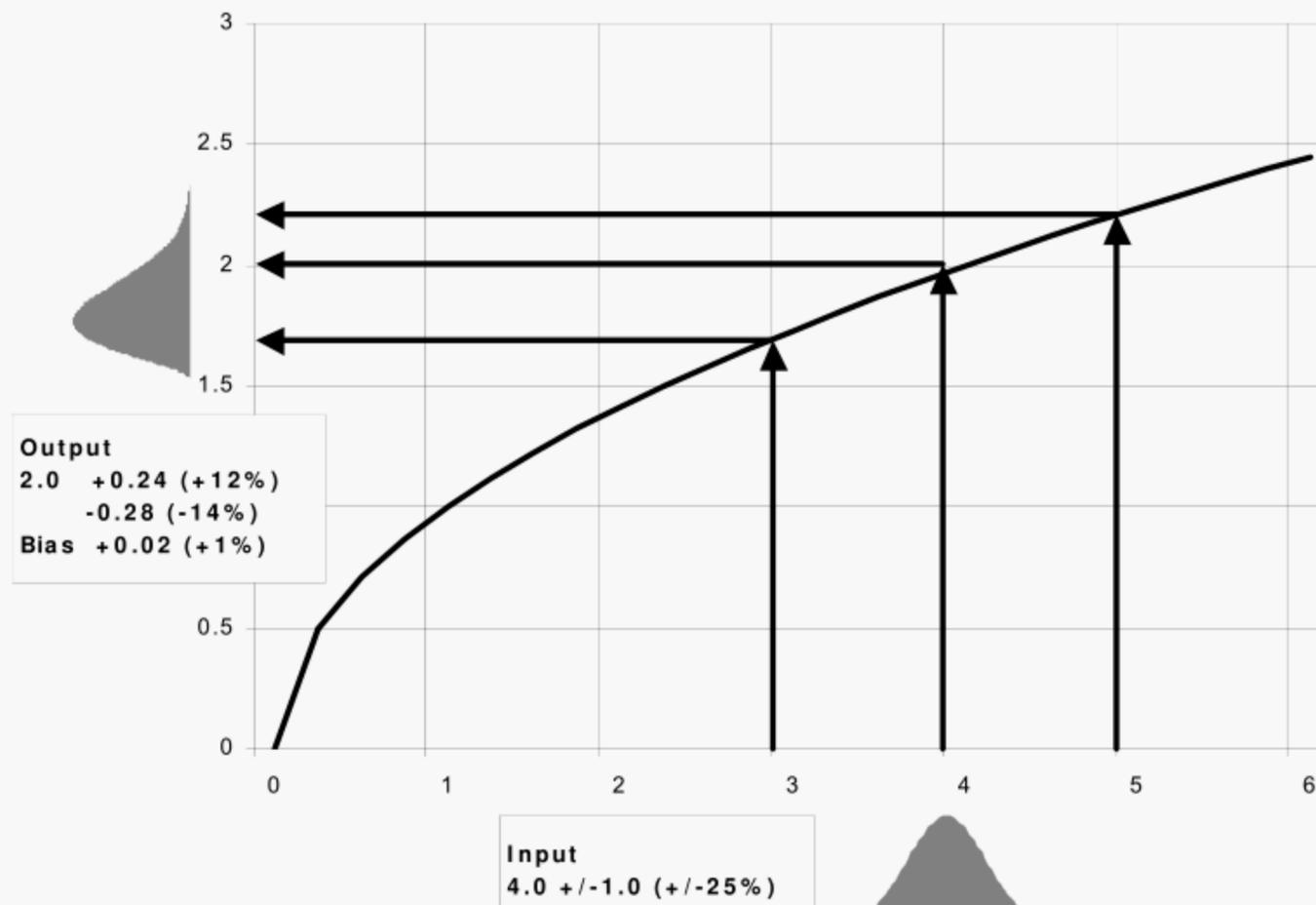


Figure A.4—Skewed Distribution Due to Non-Linear Function

The square root function in Figure A.4 is deliberately exaggerated to illustrate the impact of large uncertainties. MCS propagates the uncertainty of the sensor through the functional relationship leading to a representative distribution. Bias in the resulting distribution can be found from the difference between the measured value (nominal value) and the mean of the distribution shown in Figure A.5.

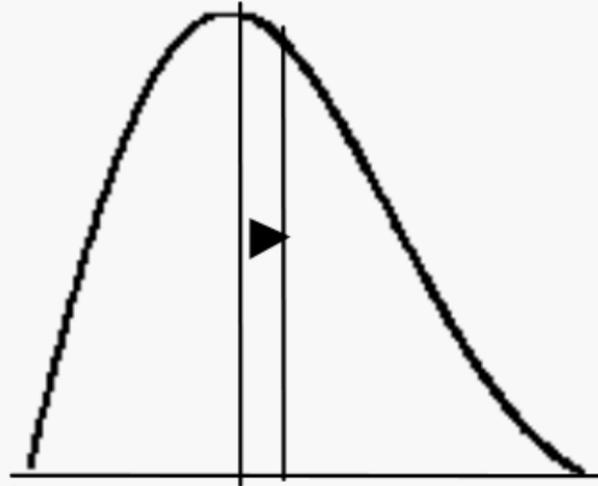


Figure A.5—Bias Due to a Skewed Distribution

APPENDIX B—CHECKLISTS FOR FACTORY ACCEPTANCE TESTS (FAT)

(After Ref. 5, API COPM Publication 2566, *State of the Art Multiphase Flow Metering*)

B.1 ITEMS TO HAVE AVAILABLE FOR REVIEW BEFORE AND DURING TESTS

- **Documents showing the accuracy and process capability of the test loop.** Because the test loop is establishing the credibility of the meter under test, then its integrity must be demonstrated. Flow loop personnel should be able to provide proof of recent certification of all loop instruments including temperature, pressure, and density instruments to metrology standards. An analysis of the fluids used should be provided, even if they are water, refined oil, and air. This is especially true if the water contains salts.
- **Vendor documents showing the theory of operation.** Descriptions can be given in the vendor's manual or by reference to open literature.
- **Installation requirements.** Include detailed piping and instrument layout and hook-up. This should include P&ID drawings, and detailed wiring interconnect, including communication cables.
- **Maintenance requirements.** Include calibration procedures for future field recalibration.
- **Basic calibration sheets.** Sheets should be available for all of the instruments with any special calibration requirements – i.e. fluids identified and their availability sourced and certification sheets and Material Safety Data Sheet (MSDS) sheets supplied.
- **Listing of special test equipment.** Identification of any special test equipment or test techniques required for calibrating all or parts of the multiphase flow measurement system.
- **Failure mode test requirements.** Many times the action taken by a flow computer, when one or more end devices fails or radically changes, is not clearly identified. The various process instruments should be subjected to simulated failures to demonstrate how the flow computer records the failures, with the actions recorded and reported. This will also test the recording of error messages and systems alarms.
- **FAT flow rate evaluation matrix.** For production operation one of the most important measurements made during a well test is the produced oil rate or volume. Therefore, it is vitally important to evaluate the measurement system's water cut measurement performance. These tests should include an appropriate range of gas rates. As part of these water cut tests, at various gas rates the liquid rate should be varied over the application's range. Although the requirement for each FAT is different, there should be sufficient variation in the gas rates, liquid rates, and composition to adequately simulate the anticipated metering environment over the life of the field.
- **Listing of proposed meter and system factors.** All settings for the meter, computation systems, test systems and associated equipment should be pre-defined.

B.2 PERFORMANCE OF FACTORY ACCEPTANCE TEST

- If at all possible these documents should be in electronic form including Computer Aided Design (CAD) drawings of the mechanical aspects of the equipment.
- Agreement between the way the manual says to hook up the equipment and what was actually done. It is suggested that the final setup be done in the presence of the customer.
- If the Multiphase flow measurement System utilizes one or more HMI's (Human-Machine-Interface) that have screen presentations, including graphics with dynamic data appearing on the displays, they must be validated for proper data placement, calculation, and update frequency.
- All valves, solenoids and other end devices that are part of the metering system need to be activated and performance tested to determine if they operate properly.
- If the multiphase flow measurement system is a wet gas system, water cut may not be a required output. Most watercut instruments may experience difficulty at these elevated gas volume fractions.
- It is recommended that the purchaser either personally witness the test, or have a third party witness the tests, or both. It must be made clear to all parties that the vendor cannot make any changes after the test has begun. The

flow loop operator must be involved in any pre-test meeting so he understands the plan for executing the FAT. The flow loop operator may have to determine the time of stabilization between each matrix point, so the conditions that constitute stability should be discussed and agreed to by all.

B.3 ITEMS TO BE MADE AVAILABLE TO USERS AT THE END OF THE FAT

- The vendor should supply a formal listing of all parameters and constants along with their values at the conclusion of the FAT. The accepted ranges and identification of those that can be changed by field personnel should also be supplied.
- There should be a sign-off sheet, acknowledging that the system met the agreed matrix of tests.
- Report of system measurement results should be created, with illustrations of the form shown in section 8 and discussed in section 9, and exception explanations should be provided.
- Signed calibration sheets for all instruments should be provided.
- Data sheets for all instruments with process variables and equipment model numbers, stating especially any changes in scaling or ranges done during the FAT.

APPENDIX C—APPLICATION TO GOVERNING REGULATORY AUTHORITY

A common activity in applying any methodology for Well Rate Determination is the application for permission to do so from the governing regulatory authority. What follows is a template, or “roadmap”, which can be used to consolidate all the requisite information required by that authority.

C.1. PROJECT IDENTIFICATION

C.1.1. Project Name

C.1.2. Lease Description

C.1.3. Partners

C.1.4. Operator(s)

C.1.5. Producer Representatives, Areas of Responsibility

C.2. PROCESS DESCRIPTION

Explain the flow of produced hydrocarbons from the individual wells through the host facilities, along with the function and location of each meter or metering system. Use simplified diagrams to show pipeline segments, production equipment, commingling points, and meters.

Information on each well’s characteristics should be supplied, not just for startup conditions, but for projected conditions (trajectories) over the life of the field. Some of these are:

- Range of anticipated flow rates, pressures, temperatures, gas/liquid volume fractions, Lockhart-Martinelli parameters, etc.
- Expected hydrocarbon composition, water volume fraction, fluid properties, etc. How these properties were determined.
- Quantities and types of chemicals to be injected.

C.3. MEASUREMENT DEVICES

C.3.1. Allocation Measurement. Data is required on each kind of meter or metering system to be used on all individual or commingled streams. For example, is a meter, test separator, or partial separation system being used? For all meters, identify the manufacturer, principle, sizing, planned installation pipework, and evidence of expected uncertainty performance in the application.

C.3.2. Reference Meters. Data is required on the kinds of meters to be used for sales/reference measurement of hydrocarbon gas and liquids. Information is required on manufacturer, principle used, sizing, and evidence of expected uncertainty performance in the application.

C.3.3. Wet Gas Liquid Measurement. For these applications, it is necessary to explain how liquid hydrocarbon flow rates will be measured or estimated. Evidence of expected uncertainty performance in the application should be provided.

C.4. PRE-INSTALLATION METER TEST PLANS

C.4.1 Flow Testing of Meters. Identify the test facility where wet-gas or multiphase meter tests will be conducted. Range of flow rates, pressure, temperature, and fluid composition/properties. If extrapolation of the measurement range is planned, provide a rationale for doing this. The requirements for flow testing of allocation measurement systems from section 9.3 of this RP should be applied.

C.4.2 Component Tests. Sensors, electronics, pressure on meter body.

C.4.3 Factory Acceptance Testing (FAT). Appendix B describes how Factory Acceptance Testing should be carried out.

C.4.4 Plan for Flow Testing Reference Meters. Identify the test facilities where the reference meters will be calibrated. Range of flow rates, any other requirements should be specified.

C.5 NORMAL OPERATING CONDITIONS

Discuss the range of conditions in which each multiphase flow measurement system is expected to operate during the total expected field life, with regard to temperature, pressure, flow rates, gas and liquid volume fractions (GVF/LVF), water volume fraction, and fluid properties.

C.6 OPERABILITY CONSIDERATIONS

C.6.1 Pressure Analysis. What pressures inside and outside the pipe are expected over the field life?

C.6.2 Pressure Taps. What measures will be taken to prevent liquid drop-out in impulse lines and hydrate plugs at the pressure taps?

C.6.3 Flow Dynamics. What flow regimes are anticipated over the life of the well? Is slug flow likely? If so, what is the probable size of the slug? Will the liquid slug fall within the flow range of the meter?

C.6.4 Flow Assurance Considerations. Are hydrates, wax, or scale anticipated? Measures to be taken should the problem occur.

C.6.5 Sensor Redundancy. Show how redundant sensors will be used.

C.6.6 Installability/Removability. Can the meters and instrumentation be removed/replaced if this is necessary?

C.6.7 Stress Analysis. Discuss what consideration has been given to the effects of stresses due to pressure, temperature, hydrodynamic forces, handling, and installation.

C.6.8 Sample Taking. Can a sample be recovered if this is necessary?

C.7 VERIFICATION PLAN

How will proper measurement operation be verified?

C.8 CONTINGENCY PLAN

What is the plan for detection, verification, and remediation of fault conditions? (Any remedial action must be approved in advance by the governing regulatory authority prior to implementation.)

C.9 REGULATORY COMPLIANCE

Discuss the manner in which compliance will be achieved with the *Code of Federal Regulations*, Title 30, Sub-part L, "Oil and Gas Production Measurement, Surface Commingling, and Security." Provide evidence of concurrence with this plan from each company with an interest in the hydrocarbon production that utilizes multiphase flow measurement system(s), as well as from each company that has an interest in other hydrocarbon production that will be commingled with the hydrocarbon production measured by these multiphase flow measurement system(s) prior to fiscal (custody transfer) measurement.

Appendix D—Multiphase and Wet Gas Flow Loops

The data presented in Table D.1 are representative of the capabilities of the facilities shown at the time of this writing in 2004. These capabilities may have changed since that time, and new facilities not listed here may be available. The information is shown only for the purpose of providing the user with an overview of the topic of flow testing of multiphase flow meters. Nothing here is intended to recommend one facility over another.

Those interested in such tests are encouraged to contact the appropriate personnel at these facilities to explore the topic in greater depth.

Table D.1 - Independent Multiphase and Wet-Gas Flow Test Facilities

Loop Name/Country	Liquid/Gas Flow Capacity	Max Press (bar)/ Max Temp (°C)	Fluids Used	Comments
NEL/Scotland Multiphase	15,000 BPD 1.27 MMSCFD	145 psi (10 bar)	N ₂ H ₂ O Dead Crude	
NEL/Scotland Wet Gas	1.19 MMSCFD < 10% LVF	910 psi (63 bar 59 to 77°F (15 to 25°C))	N ₂ Kerosene or Water	
SwRI/USA Multiphase/WG	20,000 BBL/DAY 30 MMSCFD	3600 psi (245 bar) 120 °F (49°C)	NG H ₂ O Condensate or Crude	
CEESI/USA Wet Gas	3750 BBL/DAY 45 MMSCFD	1200 psi (82 bar)	NG H ₂ O Decane	
Porsgrunn/Norway Multiphase	9000 BBL/DAY 19MMSCFD	1617 psi (110 bar) 316°F (140°C)	NG Dead Crude Formation H ₂ O	
CMR/Norway Multiphase	6000 BBL/DAY 170 KSCFD	30 PSI (2 BAR) 60 to 75°F (15 to 25°C)	Air H ₂ O Diesel	
K-Lab/Norway Wet Gas	34 KACFD to 1.69 MACFD (40 to 2000 ACM/HR)	290 to 2100 psi (20 to 146 bar)	NG H ₂ O Condensate	
Daiqing/China Multiphase	16,380 BBL/DAY 0.9884 MMSCFD	103 psi (7 bar)	NG Crude Formation H ₂ O	
IFP/France Multiphase		1450 psi (100 bar)		

Appendix E—Issues in Well Rate Determination by Well Test

The most common form of multiphase flow measurement in existence is the separator, thus the test separator is the single most popular “multiphase meter”. In this Appendix some of the issues that must be considered in well testing are addresses.

E.1 WELL-TESTING REQUIREMENTS

Well-testing data is required for a number of reasons, including:

- Well & reservoir performance monitoring
 - Determination of fluid rates
 - Determination of when changes in fluid flow rates or composition occur (i.e. water breakthrough etc)
- Identification of mechanical integrity issues
 - Casing/tubing leaks
 - Gas lift failures
 - ESP performance fall-off
- Assessment of near well-bore damage
- Summation of well–test data over all wells and time periods as an estimate of well pad flow rate for production.
 - The evaluation criteria for well test facilities must address a number of issues, such as:
- Regulatory requirements
- Health Safety and Environmental requirements
- Capex (Capital expenditure)
- Opex (Operational expenditure)
- Schedule
- Reliability
- Weight
- Deck or pad space
- Flow metering accuracy and metering repeatability
- Allocation metering
- Reservoir assessment
- Operability
- Maintenance

E.2 TEST SEPARATOR

The baseline for well testing has until now has been the test separator and its associated measurement systems. Separators rely on gravity in order for the three phases (Oil, Gas and Water) to naturally separate. Gas as the lightest fluid generally floats to the top easily, followed by the oil separating from the water. In a simple separation scenario the only requirement is time for the separation to take place, which is a function of separator size and the fluid flow rates.

However within the oil and gas industry the scenarios are rarely ‘simple’. It is not unknown for the oil and gas to combine in a ‘foam’ at the oil—gas interface and the foam is often carried over in the gas flows. Oil and water often combines in an ‘emulsion’ and this forms at the oil – water interface. To reduce or eliminate the foam and emulsions, chemicals (de-foamer and de-emulsifier) are required, that can affect the performance of the process systems further downstream. In addition to the chemicals mentioned, heat is also often required.

Test separation often requires a relatively large separator. Small ones can weigh 5 to 10 tons, but larger systems can be in the order of several hundred tons. These then require ‘services’ such as:

- drains and bunds
- vent and flare, plus a relief system
- firewater protection,
- insulation (for fire protection)
- extensive lifetime maintenance for the instrumentation and the basic vessel.

E.3 TEST SEPARATION METER SYSTEM PERFORMANCE

For many years the test separator has been the only method for conducting well tests. As such, it has become the benchmark for well rate determination, and in many areas of the world test separator design and its use has been legislated. However, this commonality of use has tended to hide areas where test separators may not in fact perform as desired, and where measurements made are not as good as declared on the respective meter 'nameplate'. What follows is an attempt to identify performance shortcomings of the method not covered in section 7.5.

E.3.1 Gas Measurements

The 'standard' meter for separator gas measurement has been the orifice plate meter.

In high quality fiscal gas measurement the accepted uncertainty is $\pm 1\%$. In a well designed, well maintained system this uncertainty is achievable. In a compact well test meter system, with variable gas densities (from variable gas sources), operator selected orifice plates and a maintenance regime less than 'fiscal quality' the standard gas measurement uncertainty will likely be significantly greater than $\pm 1\%$.

E.3.2 Liquid Measurements

The liquid measurement systems have the same problems as the gas measurements. Fiscal liquid measurement is often accurate to $\pm 0.25\%$, but this depends on rigorous maintenance and an established proving system. Table E.1 denotes the uncertainty ranges to be expected.

Table E.1—Meter Uncertainties That Might be Expected in Test Separator Measurements

Subject	Gas	Gas	Oil	Oil	Water	Water
	Good	Extreme	Good	Extreme	Good	Extreme
Base meter	1	2	0.5	1	1	2
Meter Lengths (short)	0	2				
P, T Calibration	0.5	1	0.5	1	0.5	1
Range (exceeding turndown)	0	5	0	5	0	5
Sampling (sample & analysis)	1	4	1	4	1	4
Density/BSW/OIW	1	3	0.5	7.5	0.5	7.5
Surging/pulsation/gas breakout	0	3	0	3	0	3

The table indicates that correctly sized, well maintained meters running in excellent flow conditions may be metered at best to about $\pm 2\%$ for all phases. However once outside the 'perfect envelope' then performance will fall off dramatically. Other extremes, like an orifice plate turned backwards, may produce errors of $\pm 20\%$.

There are other areas where measurement difficulties and accompanying errors are possible, depending on whether the separator has been designed for two- or three-phase separation. Two-phase separators flow the oil and water as a combined stream, while three-phase separation flows the oil and water as separate streams. Two-phase operation relies on the liquids (oil and water) being well mixed, the ability to meter the total flow, and a knowledge of the liquid mixture composition (i.e., the water and oil fractions).

In both cases the standard liquid meter has been the turbine meter, which is considered to be a relatively inexpensive, stable and well-understood meter. It is typically available with uncertainties of either $\pm 0.5\%$ or $\pm 1\%$. It is regularly used in fiscal meter skids and is there able to achieve accuracies of $\pm 0.25\%$, with regular maintenance and with 'proving' at the operating conditions.

The turbine meter has a number of drawbacks.

1. It is a piece of rotating equipment and begins to wear out from first use.
2. Its performance is dependent on flow, pressure, viscosity, and temperature.

3. It is affected by sand (and other solids) present.

An area where little work has been done is the area of turbine meter performance in cavitating flows. The liquids in a test separator are at their bubble point (by definition) and the turbine meter is one that induces cavitation.

In liquid flows it is usual to carry out temperature and pressure corrections to correct the volumes to standard conditions (generally 14.696 psia, 60°F). In two-phase separators (i.e. water and oil combined), temperature and pressure corrections cannot be carried out as there are no standard available for these mixtures. In addition the calibrations made on a new turbine meter are not normally tested with an oil-water mixture. Oil-water mixtures have variable fluid viscosities. There are significant viscosity shifts, which make the calibration data used with the turbine meter suspect.

The final part in this is the determination of the oil-water mixture, to apportion the bulk fluid flow into oil and water flows. Sampling should be done with a flow-proportional sample over the time of the test. Often, sampling is merely a ‘spot’ sample. Within a two-phase separator, even when the flows are considered stable, the oil-water outlet mixture varies with time. Thus a spot sample will read one figure and a second sample will read something very different, a circumstance that has often been demonstrated with oil-water monitor tests.

Using an oil-water monitor is considered a way around this, but even these instruments are often ineffective. Many tests have shown that they can be as good as +/-2%, but subtle changes in process conditions mean that the instruments can drift off, some by as much as +/-20%.

In a three-phase separator, many of the problems highlighted above still exist, with a few others added. One is that the separation is not 100% efficient, and in the oil stream a small percentage of water may exist. Experience has shown that this can be 0% to 10%. The same is also true for the water stream containing oil. In both cases the contamination is not constant, and will vary with time. Unless efficient sampling is carried out, this will create liquid test measurement errors.

E.4 Test Separator Maintenance and Operational Requirements

In general there are a series of instruments requiring inspection and/or calibration. Some are conventional and can be done ‘in-house’. Others are special and require technician training or vendor support. Nuclear sources require personnel trained in radiation safety. In other cases sampling is required.

Some typical maintenance and calibration requirements are shown in Table E.2.

Table E.2—Typical Test Separator System Maintenance Requirements

Maintenance Instrument Type/ sample	Calibration	Frequency	Time in hours/year
Vessel inspection (external)	N/A	Annual	10h/yr
Vessel inspection (internal) including sand removal	N/A	Every 5 years	200 hours i.e. 40hours/yr
Insulation inspection	N/A	Annual	10h/yr
Vessel supports/ fireproofing	N/A	Annual	10h/yr
Firewater system	N/A	Annual	20h/yr
System isolation test	N/A	Annual	10h/yr
LCV	In-house	Annual	10h/yr
PCV	In-house	Annual	10h/yr
Level transmitters & controllers	In-house	Annual	10h/yr
Pressure control loop	In-house	Annual	10h/yr
Pressure Relief	In-house	Annual	10h/yr
Fire & Gas detection	In-house	Every three months	40 h/yr
Shutdown system checks	In-house	Every three months	40 h/yr
Pressure transmitter	In-house	Every two months	27 h/yr
Temperature Transmitter	In-house	Every six months	8 h/yr
Differential pressure transmitter	In-house	Every month	24 h/yr
Exd survey	In-house	Annual	10 h/yr

Flow computer checks	In-house	Weekly	120 h/yr
Sampling	In-house plus lab	Every six months	48 h/yr
Meter cal check	In-house plus specialist	Annual	24 h/yr

E.5 Distance From Well Source

Test separator metered data is a product of the well flows, but the true flow rates can be masked due to pressure and level controls in the separator. As pointed out in 7.5, further masking may be due to the test flow lines if they are excessively long. It is strongly recommended that test flow lines be kept as short as possible.

E.6 Separator Well Testing versus Multiphase-meter-per-well

Using a multiphase meter for each well has the bonus of removing an expensive heavy test separator and its maintenance load, as well as the additional test lines and motorized valves.

The most significant advantage with this approach is that it allows measurement and monitoring of the well fluids continually, in contrast to typical well testing, which might allow 24 hours in a 30-day month, with the expectation that this will provide representative and adequate well performance monitoring.

The example in Figure E.1 demonstrates how a wellhead MPFM presents flowing data compared to an associated separator (16 km away). During well testing the liquid flows are 'resident' in the separator and are under both level and pressure control. This means the flows are measured in other than 'real time' with respect to the reservoir. However, the closely coupled MPFM is not conditioned in this way, and the flows reflect more closely the real time dynamics.

Finally, in the Table E.3 are listed factors to consider in looking at Separator Well Testing versus a Multiphase-meter-per-well strategy, assigning points from 1 to 5 for each approach based on the factors shown. The results clearly make a case in favor of the latter approach.

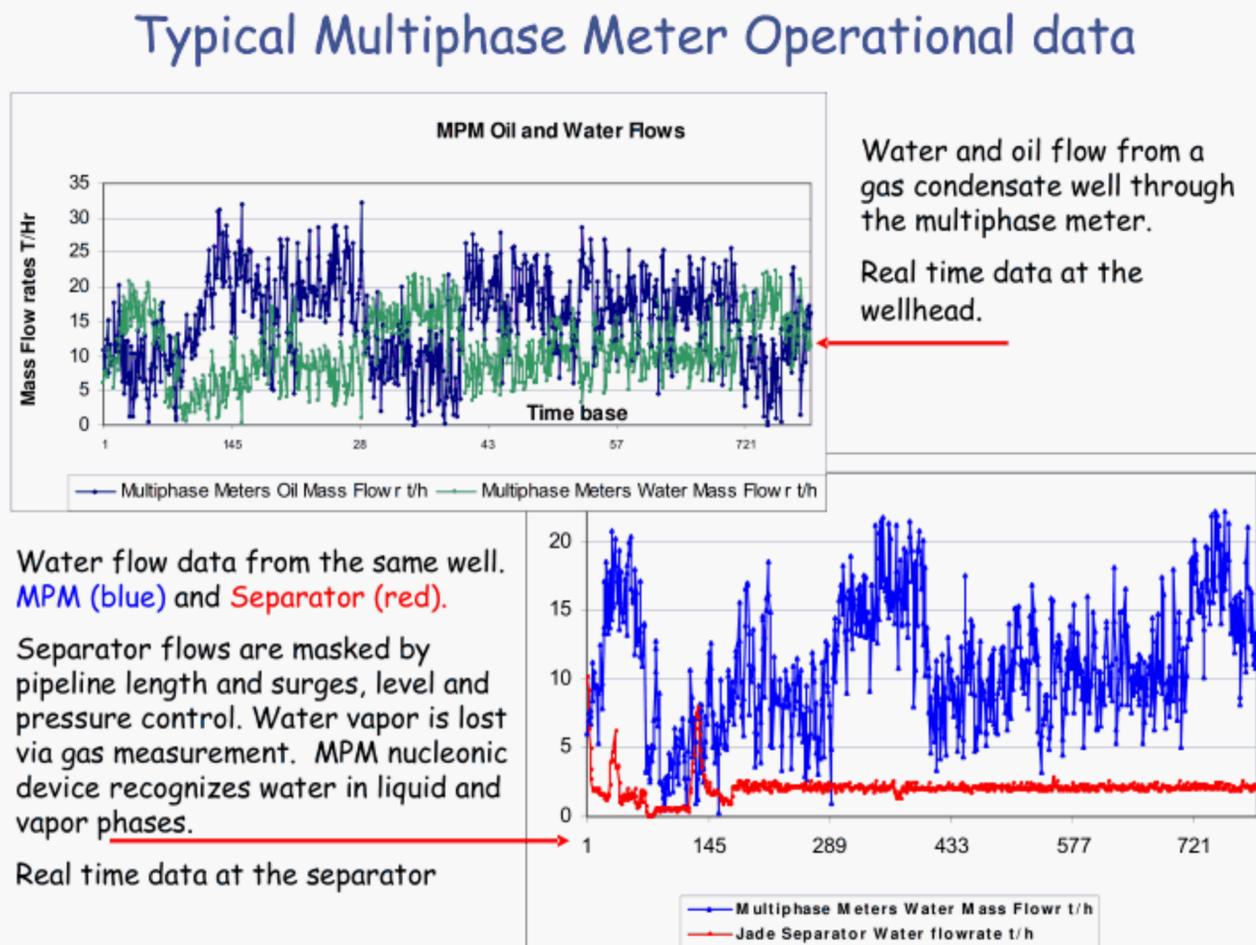


Figure E.1—Illustration of Disparity between Flow Measured at the Test Separator and at a Multiphase Meter at the Wellhead

Table E.3—Evaluation of Well Rate Determination by Test Separator vs. Multiphase Meter (points awarded shown in parenthesis)

Evaluation Criterion	Test Separator	Multiphase Meter/Well
Regulatory Authority Acceptance	Accepted as bench mark (5)	'New' and unknown (3)
Health Safety and Environmental requirements	Accepted as bench mark (5)	'New', and may be objected to if Nuclear sources are used (3)
Capex (Capital expenditure)	High (1)	Medium, depending on number of wells (3)
Opex (Operational expenditure)	High (1)	Medium, depending on number of wells (3)
Reliability	Complex, no redundancy (1)	Low complexity with high redundancy (5)
Weight	High (1)	Medium to low (5)
Deck or pad space	High (1)	Minimal (5)
Metering Accuracy, Metering Repeatability	Intermittent data for short flow periods(1)	Continuous real time data available for all well flows (5)
Reservoir Assessment	Intermittent data (0.03% of the time), data 'masked' (1)	Continuous monitoring, good view of data (5)
Operability	Poor but understood (5)	Generally not understood, needs training (3)
Maintenance	High (1)	Medium (3)
TOTAL POINTS	23	43

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