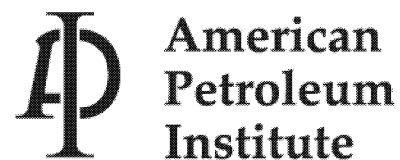


State of the Art Multiphase Flow Metering

API PUBLICATION 2565
FIRST EDITION, AUGUST 2004



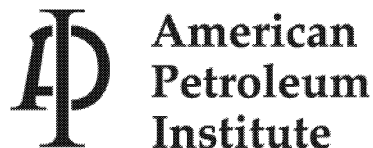
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State of the Art Multiphase Flow Metering

Measurement Coordination

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API – COPM WHITE PAPER STATE OF THE ART – MULTIPHASE FLOW METERING

This “White Paper” provides information on multiphase flow metering systems gleaned from more than 150 published documents that are in the public domain. The documentation was prepared from information obtained through mid-2002. No additional research has been funded in the development of this report. It should be noted that the indicated performances data stated in these published documents have not necessarily been verified by an independent body. The listing of these references in the Appendix 2 is intended to provide a comprehensive source of data and information on multiphase metering; the reader needs to carefully review the source of the data in the documents when utilizing the information.

The “White Paper” was commissioned by the American Petroleum Institute (API) – Committee on Petroleum Measurement (COLM) to be used as a framework in the development of “Recommended Practices” on the application of multiphase flow meters in Upstream Production Operations. The format of this white paper follows substantially the outline developed for this project by the Multiphase Metering Standards Task Group.

The term “multiphase metering” in its broadest interpretation is referred to both the wet gas metering as well as the measurement of oil, water, and gas streams. Whether one is conducting a “wet gas” or “multiphase” measurement typically depends on which fluid, (oil or gas) is the primary production as well as the type of equipment used. At the time of gathering this information there were over 1000 installations worldwide that use the multiphase metering technology to achieve improved production measurements and well testing. These multiphase metering systems have utilized four major processes, as shown in Figure 7 of the report, to obtain single-phase flow rates from a multiphase flow stream. The four processes include the conditioning of flow stream, volumetric component measurements, component velocity measurements, and modeling of the multiphase flow. These subjects are discussed in Sections 1-7 of the report. The objective of these sections is to provide the reader with a working knowledge of the principle techniques used in multiphase measurements. This background is used, in Section 8, to propose a classification for multiphase metering systems. Sections 9 and 10 review methods used to specify and assess the performance of the multiphase meters.

The developments in wet gas metering have come from two different directions. A large amount of effort has gone into developing “correction factors” to improve the accuracy of single-phase gas metering devices that are used in conditions

where a small amount of liquid is present. On the other hand, elements of the multiphase metering technology have been modified to develop wet gas metering systems. Sections 12-15 discuss types of wet gas, measurement techniques used in wet gas metering, and the performance of wet gas metering systems.

Performance assessment and verification of multiphase and wet gas meters are complicated by the lack of commonly accepted protocol and standards. Current approaches used by operators and industry projects to address these issues are discussed in Section 17. Guidelines to be used for installations, qualification testing, and field testing of multiphase and wet gas metering systems are discussed in Sections 18-21.

The users of multiphase and wet gas meters face three major technical challenges in addition to justifying the cost and risk of the deploying new technology. These challenges are:

- Selecting and qualifying multiphase meters for different applications.
- Assessing the performance of the multiphase meters after installation.
- Getting approval to use multiphase meters from appropriate regulatory bodies.

There is currently no single document that users of multiphase metering systems can consult to address the above issues. Users have relied on vendor information for procurement of multiphase metering systems in a majority of the current installations. There is concurrence within the industry that a “Standard” or “Recommended Practice” (RP) be created to establish a common language to describe the performance of these systems. There is also a need to develop a commonly accepted protocol and procedures to evaluate the performance of multiphase metering systems. Should API decide to pursue the development of a “Standard” or a “Recommended Practice” on multiphase flow meters, the information in this report, as well as a number of currently available specifications listed in Section 22, should provide helpful direction and technical resource for the development of the new document.

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API – COPM WHITE PAPER

STATE OF THE ART – MULTIPHASE FLOW METERING

1- INTRODUCTION

This report documents information available in open literature, and from vendors, on the state of the art of multiphase metering systems. The term “multiphase metering” in its broadest interpretation can be used to refer to both wet gas metering, as well as, the measurement of oil, water, and gas portions of commingled streams, which is commonly referred to as “multiphase metering”. Whether one is conducting a “wet gas” or “multiphase” measurement typically depends on which fluid (oil or gas) is the primary \ production, as well as, the type of equipment used. This report documents both wet gas and multiphase metering systems. There are many more multiphase metering installations than wet gas metering installations. Also, the amount of literature and practical field tests available for multiphase meters is much more extensive than for wet gas metering. This imbalance in available information and literature is reflected in the coverage of the two subjects in this report.

The information in this report is intended to guide the American Petroleum Institute – Committee on Petroleum Measurement, and other API Task Groups, in the development of “Recommended Practices” or “Standards” applied to the multiphase measurements of fluid streams in Upstream Production Operations. The format of this white paper follows substantially the format specified by the Multiphase Metering Standards Task Group in the scope of work for this project.

There are currently over 1000 installations worldwide (IV-30)* that utilize the new multiphase measurement technology to conduct production measurements in oil and gas producing fields. The pace of these installations has accelerated significantly over the past 5 years (IV-30). During this period a large amount of data related to the performance of multiphase and wet gas metering devices have been published as listed in Appendix 2.

Multiphase measurement is a maturing technology (II-3). Significant amount of field and performance data are available (II-4, II-6, II-11, II-12, IV-1) to be utilized into some form of guideline to direct the forthcoming demand for the application of this technology. The operators in the North Sea, who were the early users of this technology, have undertaken a number of regulatory initiatives to develop such guidelines (XII-3, XII-8). The need for guidelines is also anticipated by the operations in the Gulf of Mexico (XII-1, XII-2, XII-4, XII-7). This issue is discussed further in Section 22 of this report. The gathering of the information on multiphase flow measurement technology, which is the objective of this “White Paper”, would be a first step in development of API specifications or standards on multiphase meters. To assist the API effort, the nomenclature, terms and

* Numbers in parenthesis designate references in Appendix 2. V-30 is reference 30 in Section V.

definitions used by other bodies attempting to develop multiphase metering specifications have been adopted and used throughout this report.

2- NOMENCLATURE AND TERMS USED IN MULTIPHASE FLOW

A number of terms and definitions are employed in describing multiphase flow and measurements. The Norwegian Society For Oil and Gas Measurement (NFOGM) have catalogued these terms in their Handbook Of Multiphase Metering” in reference XII-3. As a contribution to further the use of common terminology, and acknowledgement to the NFOGM efforts, this report has adopted these terms rather than develop new definitions. These terms and nomenclature, described in Appendix 1, are taken from reference XII-3 and will be used in this report to describe multiphase flow and measurement processes.

3- THE NEED FOR MULTIPHASE AND WET GAS METERS

Multiphase meters are devices that measure oil, gas, and water flow rates of a well stream without separating these components into individual phases. The new multiphase metering techniques were developed to replace the conventional two and three-phase gravity based test separators that have been making multiphase measurements in production operations. Well tests are conducted routinely to monitor the flow rates from wells and forecast production. The well test data are also used for reservoir management, production diagnostics and optimization and in some cases even production measurement. To obtain accurate and consistent test results from conventional well testing systems, the equipment requires high maintenance, field personnel intervention, and time to perform tests.

The interest in the new multiphase meters for well testing was stimulated by several factors:

- The cost and size of conventional two and three phase test separators, particularly offshore (II-23).
- The testing time, high maintenance and field personnel required to get accurate and consistent test results from conventional gravity based separators.
- Chemical or mechanical interventions that may become necessary when foaming or tight emulsions create problems separating phases using conventional gravity based test separators (IV-2, IV-14).
- Field personnel intervention needed to get fluid samples for water cut analysis (II-26, IV-13). These interventions further increase the cost and contribute to the inaccuracy and lack of repeatability of well tests (II-17, XI-8).
- Systems that could be installed subsea

The attractiveness of the new multiphase metering systems, operating unattended and without the need for phase separation, stemmed from their potential to avoid or overcome some of the above operational problems. Multiphase meters provide a system that can be installed subsea. In addition, these advantages can produce significant savings especially in offshore operations. The less bulky and lighter weight of multiphase meters was a major attraction for the installation offshore and therefore a significant influence in the evaluation of the technology, especially for operators in the North Sea (II-19, II-22) and the Gulf of Mexico.

The oil industry has recognized the potential benefits of the new multiphase meters (II- 10 to 16). A systematic effort was undertaken in the 90's by several North Sea operators to identify potential multiphase metering applications, reservoir engineering needs, and meter performances for a number of asset developments in North Sea (II-22). For the past 10 years, considerable effort has gone into developing multiphase meters that can measure gas, oil, and water flow rates at wellhead conditions (II-1). These efforts have led to the development and marketing of several types of multiphase meters. In the past five years, the meter manufacturers and operators have jointly tested multiphase meters under a variety of field conditions to evaluate their performances. In the next sections of this paper, we shall look at the trends in installations of multiphase metering systems.

Wet gas metering is a more recent area of development in multiphase measurements. Wet gas metering covers a variety of measurements in production streams with high to very high gas volume fractions. There is a need for direct measurement of gas under these conditions in such applications as gas condensate and high GOR fields as well as many production operations where gas from separation systems may contain liquid (III-1). Furthermore, significant amount of gas will be produced in the future from remote and subsea fields where production, capital investment, and operating costs must be optimized. As an example, gas production from deep waters in the GOM (III-4) has increased in the last several years. Real time measurement of gas and liquid flow rates are critical in a subsea production system to improve well allocation, optimize reservoir production, and enhance flow assurance. In many of the deepwater reservoirs, the economic developments dictate that several fields be commingled together and processed at a central facility. In such cases, it is critical to be able to measure the produced gas at the wellhead in order to be able to allocate the oil and gas assets to partners in each reservoir (XII-4). These trends have provided much support to the development of more robust and accurate wet gas metering systems.

4- MULTIPHASE METER AND WET GAS METER INSTALLATIONS

The numbers of multiphase meter installed have increased steadily since the first detailed survey was published in 1997 (II-8). Figure 1 shows the trend in the number of multiphase meter installations. This Figure is based on annual surveys of commercial multiphase meter vendors (II-11, II-12, II-14, II-15, IV-30). No such surveys were conducted for wet gas meters. But an informal survey of wet gas vendors indicates that the number of installations using wet gas meters – i.e. gas metering systems that can measure gas and liquid on-line - is about 100.

In the last several years the number of worldwide installations have increased substantially. Currently, there are about 1,000 multiphase meter installations in various areas around the world. While this number is a small fraction of the total number of potential well testing sites, the rate of growth has been substantial and widespread.

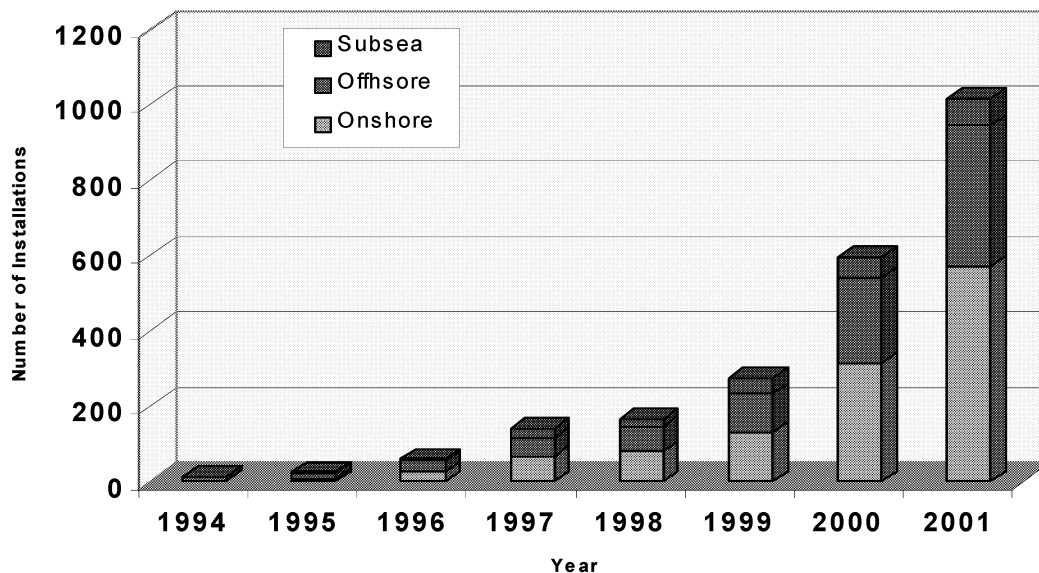


Figure 1 – Multiphase Meters Installed World-wide

The initial interest in the technology was confined to offshore and subsea applications, but over half of the current installations are now in on-shore operations as shown in Figure 1. Onshore operators are using multiphase meters to reduce the cost of well testing. As we will see in the “Application” section of this report, multiphase meters can reduce the cost of well testing by reducing the time needed to conduct a well test. This allows the operator to test more wells with multiphase meters than conventional test separators, which is very important to the management of many marginal onshore reservoirs.

Another trend in the number of installations is the broader application of multiphase metering technology by operators in many production regions. While most of the initial installations were limited to the major operators in the North

Sea, the current distribution of the installations, as shown in Figure 2, indicates broader acceptance of the technology by operators in all production regions.

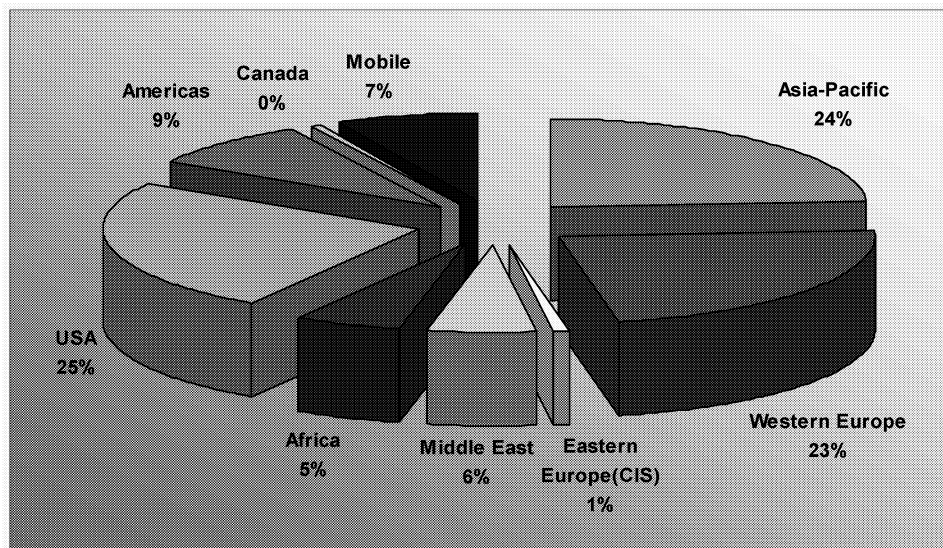


Figure 2 – Regional Distribution of Multiphase Meter Installations.

Two major factors have contributed to the wider spread of the technology:

- Development of efficient compact separators (II-28) has resulted in the availability multiphase metering systems utilizing partial separation (off-line). In contrast to the in-line multiphase meters, which accept the full stream, the off-line systems depend on the removal of most of the gas from the liquid flow stream. The temporary separated gas and liquid streams are subjected to measurements before being recombined into the initial full stream. These off-line multiphase metering systems are less complex and still offer some, if not all, of the advantages of the in-line multiphase measurement systems – i.e. real time measurement, shorter test time, and smaller size and weight relative to traditional gravity separation vessels, but larger than multiphase meters. The development of these systems is discussed in more detail later in this report.
- The compact size of multiphase meters has also resulted in the deployment of mobile systems. Mobile systems have enabled operators to use the multiphase metering technique in remote regions or in operations where a conventional well testing facility would not be available. Trailer-mounted multiphase meters have been used for well testing in fields where wells are scattered over a large area (IV-10, IV-13). In the past 3 years the number of mobile systems have increased significantly.

If one uses the number of installations as a measure of acceptance, then the installation trends shown in Figures 1 and 2 appear to point out that the multiphase metering technology is improving and is gaining acceptance by the industry. It is fair to say that multiphase metering techniques have suffered their share of setbacks and field problems during this period of growth (II-3). The performance of multiphase meters is examined in Sections 10 - 17 of this report.

5- MULTIPHASE FLOW REGIMES

The flow of a mixture of oil, water, and gas in a pipe produces a wide range of patterns that contain various fractions of the fluid components. A number of attempts (I-1, I-2, I-5, I-6, I-7) have been made to define these flow patterns or flow regimes and characterize their impacts (I-3, I-4, I-7, I-8) on the multiphase measurement techniques. The term “flow regime” refers to the geometrical configuration of the gas and the liquid (oil and water) phases in the pipe. Since the three phases of interest can be distributed in a large number of configurations, the characterization of these patterns can be simplified by considering the distribution of gas and liquid phases separately from the distribution of the oil and water (I-7).

When gas and liquid flows simultaneously in a pipe, the two phases can distribute themselves in a variety of flow regimes. The regimes differ from each other in the spatial distribution of the interfaces, resulting in different flow characteristics. The existing flow regime in a given two-phase flow system depends on the following variables:

- Gas and liquid flow rates – superficial velocity of gas and liquid.
- Pipe diameter and inclination angle.
- The physical properties of the two phases i.e. gas and liquid densities, viscosities and the surface tension.

The process of multiphase measurement in any practical application requires that the measurement system be able to perform under a variety of flow regimes. In most field applications, there can be no prior determination of the actual flow regimes. Furthermore, the flow regimes can change quickly with common operational interventions - e.g. closing and opening of a valve. For this reason considerable effort had to be made in the development of multiphase meters to make them able to operate in all flow regimes (I-8). This issue is discussed later when examining the principles of operation of different flow metering techniques. Brief discussion of flow regimes in this section is to orient the reader with common terminology used to describe flow regimes.

In the past, there has been a lack of agreement between two-phase flow investigators on the definition and classification of flow regimes. Shoham (I-6) attempted to define an acceptable set of flow regimes, which is used in this report. The definitions are based on experimental data acquired over the entire

range of inclination angles, namely horizontal flow, upward and downward inclined flow, and upward and downward vertical flow. Tables 1 and 2 provide a general definition and description of the flow regimes in horizontal and vertical pipes as affected by the relative superficial velocity of gas and liquid. A detailed description of the flow regimes-velocity relationships is provided in reference I-6.

Table 1 - Flow Regimes in Horizontal /Near Horizontal Pipe (Reference I-6)

<i>Superficial Gas Velocity Ft/s</i>	<i>Superficial Liquid Velocity Ft/s</i>	<i>General Description of Flow Regimes See The Schematics in Figure 3</i>
0.3 – 30	0.01 – 0.3	Stratified flow – Where gas-liquid interface can be either smooth or wavy as the gas flow rate is increased
3.0 – 30	0.03 – 18	Intermittent Flow – alternate flow of liquid and gas resulting in slug flow
30 – 300	0.02 – 20	Annular Flow – The liquid flows along the pipe wall, gas flows in the core with entrained liquid
0.06 – 3	0.3 – 20	Dispersed Bubbles- Gas phase is dispersed in the continuous liquid phase

Table 2 – Flow Regimes in Vertical /Sharply Inclined Pipe (Reference I-6)

<i>Superficial Gas Velocity Ft/s</i>	<i>Superficial Liquid Velocity Ft/s</i>	<i>General Description of Flow Regimes</i>
>100	0.01 – 10	Annular Flow – The liquid flows along the pipe wall, gas flows in the core with entrained liquid
10 – 100	0.01 – 5	Churn Flow – Similar to slug flow but higher gas flow rates eliminates the boundary between the two phases
1 – 10	0.01 – 10	Slug Flow – Large gas pockets followed by liquid slugs that bridge the pipe cross section
0.1 – 1	0.01 – 10	Bubble Flow – Gas dispersed in continuous liquid phase

Figure 3, taken from reference XI-1, shows schematics of flow regimes associated with the different gas and liquid flow rates in horizontal and near horizontal pipes. Different investigators have used different terms to define flow regimes as noted by the comparison of the flow regimes in Table 1 and Figure 1. Although in a majority of applications the operator does not have control over the changes in flow regimes, it is nevertheless important to recognize the impact of the flow regimes on the performance of the multiphase meters. The superficial gas and liquid velocities in Figure 3 are related to the flow rate of gas and liquid

from a well. Thus, plotting of the well flow rates from different wells on a plot similar to Figure 3, can be used to identify the expected flow regime(s) in the well(s), a field, or in operating areas.

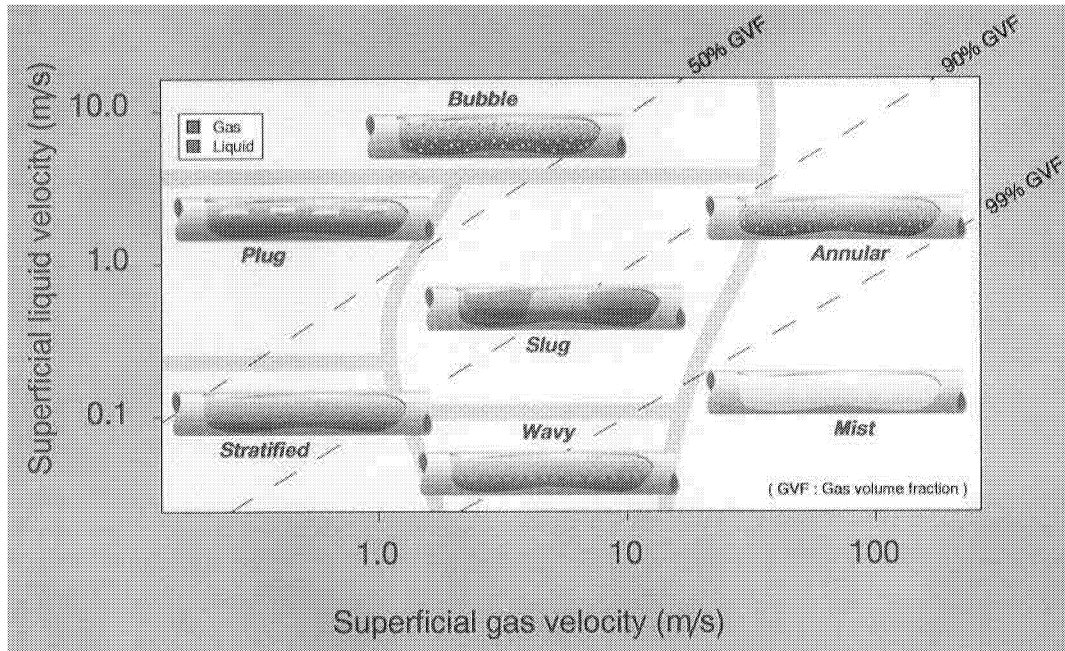


Figure 3 – General Flow Patterns Observed in Horizontal/ Near Horizontal Pipe (Reference XI-1)

Figure 4 shows a plot, similar to the one shown in Figure 3, for a number of wells from South America (SA), Alaska (ALAS), Middle East (ME), and North Sea (NS). Instead of superficial velocity, the gas and liquid flow rates are used for the X-Y axis. Comparison of Figures 3 and 4 shows that most of these wells are expected to be operating in the “Slug Flow “ regime. The impact of flow regimes on the performance of multiphase meters is discussed later. The type of gas-liquid flow rate mapping, shown in Figure 4, can be used to match the performance of multiphase meters with the expected flow regimes in the wells of an operating area.

6- PRINCIPLES OF MULTIPHASE MEASUREMENTS

The primary information required in the measurement of oil or gas multiphase flow streams is the flow rates of oil, water, and gas. The ideal method to obtain this data is to have a multiphase flow meter that would make direct and independent flow rate measurements of these components. Unfortunately, such a device does not exist as yet. Consequently, much of the extensive development in multiphase metering has been directed toward inferential

techniques that use the instantaneous velocity and cross sectional fraction of each component to make these measurements. An application of these techniques as applied to multiphase meters used for oil, water and gas measurements is discussed in the next section. Later in this report, how these techniques are applied to wet gas meters is also evaluated.

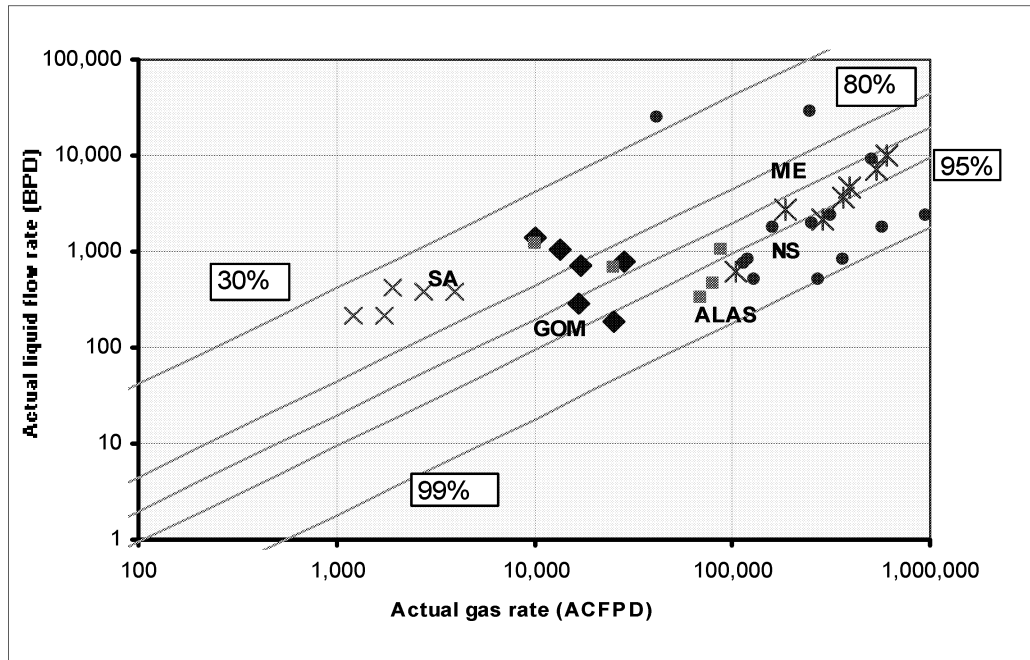


Figure 4 – The liquid and gas flow rates for a number of wells in different operating areas. The diagonal lines delineate the Gas Volume Fraction lines.

7- MULTIPHASE MEASUREMENT TECHNIQUES

For single-phase liquid or gas travelling through a pipe of cross sectional area **A** at an average velocity **V**, the volumetric flow rate **Q** can be calculated by:

$$Q = AV \quad (1)$$

When an oil, water and gas mixture is flowing through the same pipe, the calculations of the volumetric flow rates are complicated by the distribution and the velocity of each phase. A simple approach to estimate the volumetric flow rates for each phase is to establish the distribution of each phase by assuming that each phase is occupying a fraction of the total cross-sectional area at any instant, which is determined by the following relationships:

$$f_o = A_o/A, \quad f_w = A_w/A, \quad f_g = A_g/A \quad (2)$$

$$f_o + f_w + f_g = 1 \quad (3)$$

Where f_o , f_w , and f_g are the volume fractions (fraction of cross sectional area A) of the oil, water, and gas phases in the mixture. The volumetric flow rate Q of each phase and the total (mixture) flow rate are then determined by:

$$Q_o = A f_o V_o, \quad Q_w = A f_w V_w, \quad Q_g = A f_g V_g \quad (4)$$

$$Q_t = Q_o + Q_w + Q_g \quad (5)$$

Where V_o , V_w , and V_g are the phase velocities of the oil, water, and gas phases in the mixture. The task of any multiphase meter is to estimate the volume fractions and the individual phase velocity in the above equations. In order to accomplish this, the developers of the multiphase meters have employed different technologies and modelling of the multiphase flow to simplify the task (II-11, II-13, II-24). Over the last 10-15 years we have seen the emergence of some 18-20 vendors of multiphase metering systems (II-27, II-4) who have used these techniques to develop commercial products. However through mergers and acquisitions the number of vendors has significantly changed. The following three sections discuss techniques used for determination of volumetric fraction as well as component velocity.

7.1- VOLUMETRIC FRACTION MEASUREMENTS USING NON-NUCLEAR METHODS

Several Multiphase Metering Systems use electrical properties to estimate fluid fractions. The ratio of oil, water and gas can be inferred from these electrical properties of the fluid mixture bathing the sensor. The relationship between the fluid mixture fractions and these electrical properties is very complex and requires sophisticated models of sensor geometry and fluid flow in order to determine the required fluid fractions. The following provides a very brief discussion of these methods and their relative merits.

Dielectric Permittivity is a property of matter that resists electrical fields and can be measured by determining the Electrical Impedance. The concentration and spatial distribution of the components of the mixture will impact the resistance, capacitance and inductance of the fluid mixture in the sensor. These electrical properties affect the signal loss and transmission speed of electrical signals in the mixture. Measurement of any combination of these properties can allow the fluid component ratios to be estimated. Electrical Impedance is generally defined as the ratio of Voltage to Current for a specific volume i.e. the multiphase meter wetted elements and can be mathematically modelled as a combination of resistance, capacitance and inductance at a specific frequency. From these impedance measurements instruments can utilize lookup tables to determine water cut and other fractions. Alternatively some more sophisticated systems extract information on the dielectric constant of the fluid mixture and use this property in models to predict fluid fractions.

Multiphase Metering Systems tend to use combinations of sensors, frequencies and models to measure an electrical property that enables an estimation of the fluid fractions to be made. Frequency methods from kilohertz up gigahertz have been used in phase fraction measurement devices, as the value of the electrical properties is dependent on frequency. All methods have advantages and disadvantages however there is no published data to show any marked superiority of one method.

Some units measure capacitance of a plate capacitor while others determine the inductance of a coil with fluid running through the coil. In general all units use some kind of model and some kind of empirical calibration to support the accuracy required by the end user.

Meter systems employing separation can have greater flexibility of choice in sensors as the fluid streams are assumed to be less complex. However care has to be taken not to under estimate the complexity of the fluid streams. For liquid streams coming out of these separators, water cut monitors as well as the coriolis density-based methods (II -13) can be used to obtain phase fraction information.

7.2- VOLUMETRIC FRACTION MEASUREMENTS USING GAMMA RAY ATTENUATION

Gamma rays are electromagnetic radiation resulting from nuclear transitions. Gamma rays used in multiphase metering systems are produced by chemical sources that decay with time. When the gamma rays pass through an oil, water, and gas mixture, they interact with the electron and nuclei of molecules within the mixture. This interaction results in the attenuation of the radiation as it passes through the fluids. Thus, if a gamma radiation source is placed on one side of a pipe with an internal diameter d , through which an oil, water, and gas mixture is flowing, the intensity of the beam after it has passed through the pipe is reduced relative to that of an empty pipe. If I_0 is the intensity of the beam for the empty pipe, the intensity due to the mixture I is governed by the following relationship:

$$I = I_0 C \exp [-d (f_o u_o + f_w u_w + f_g u_g)] \quad (6)$$

Where C is a constant related to the source and geometry of the set up and f_o , f_w , and f_g , are fractions of oil, water, and gas in the mixture as defined previously. The u_o , u_w , and u_g are the linear attenuation coefficient for the oil, water, and gas components. The linear attenuation coefficients of oil, water, and gas vary with the energy of the gamma rays. If the above set up is repeated with two different gamma ray energy sources, two independent equations similar to the above attenuation equation can be written. These two equations plus a third relationship, which is that the sum of volume fractions must equal to unity, can then be used to calculate the oil, water and gas fractions in a mixture using the

dual gamma ray technique. Figure 5 shows a graphical representation of the dual gamma ray method.

Although gamma ray attenuation provides a relatively low cost non-intrusive method for component fraction measurements, in practice a number of issues must be taken into consideration (II-20). The use of a nuclear source requires safety precautions and compliance with regulations. The gamma ray method can be used over the complete range of component fractions, but accurate component density input is required to calculate accurate component fractions.

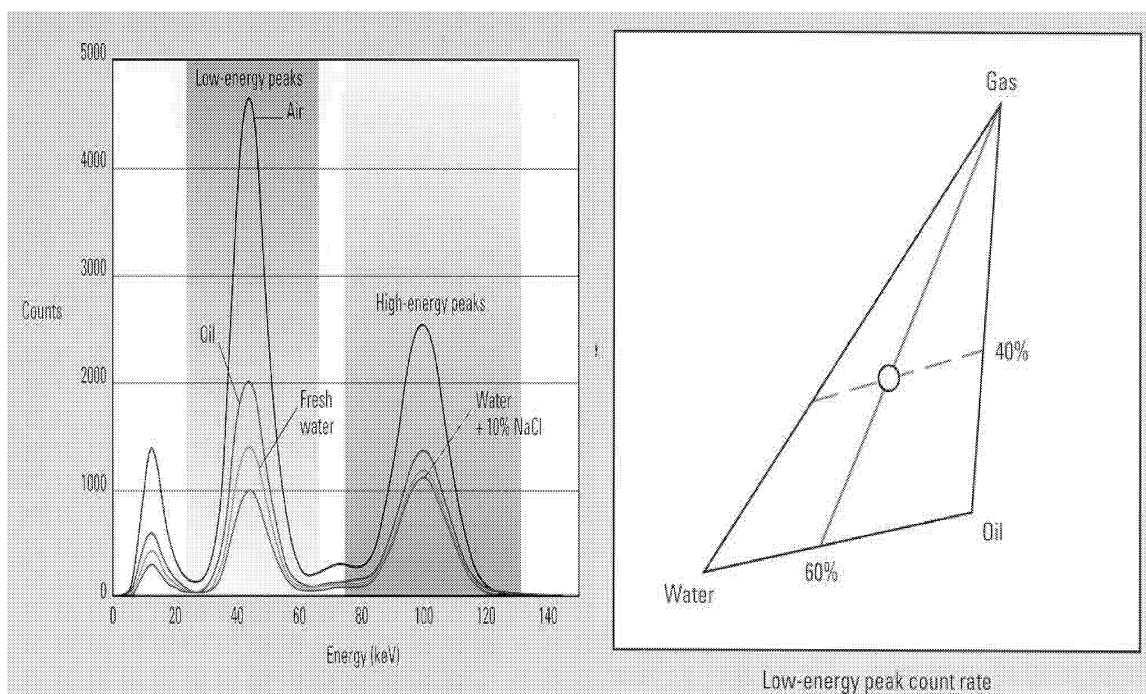


Figure 5- Graphical representation of the dual gamma ray method. The graphs (on the left side) show the attenuation of gamma rays by air, oil and water. Count rates from the high and low energy peaks are used to determine the fraction of each phase. The triangle (on the right side) is a plot of high-energy (vertical axis) and low-energy (horizontal axis) peak count rates associated for an oil-water-air mixture with water cut of 40% and gas volume fraction of 60% (Reference II-31).

The salinity of water can affect the linear coefficient of attenuation for water in the above equation (6) (II-21). Thus a change in water salinity will cause significant error in the measured water fraction if the meter does not compensate for this factor. This density dependent characteristic may require periodic calibrations.

It must be noted however that changes in water salinity also affect other volume fraction determination methods and has to be addressed in any multiphase meter. A Multiple Energy Gamma Ray Absorption (MEGRA) measurement technique has been developed (II-21) to compensate for the salinity changes.

Most dual-energy gamma ray methods use a single radiation source. The “single beam” method has the limitation of being flow-dependent (II-24). Thus, the component fractions derived from the attenuation equation will only represent the actual flow cross section if the oil, water, and gas are “homogeneously” mixed. Reference II-32 describes the development of a dual energy fraction meter that is flow regime independent. Scanning the flow stream and processing the data at very high rates achieve the flow independence feature.

7.3- MEASUREMENT OF COMPONENT VELOCITIES

Venturi devices and the cross-correlation technique are the most commonly used tools for component velocity measurements. When the flow is well mixed – i.e. using a mixing chamber or device – the Venturi meter has been used to measure the bulk velocity of the mixture. For non-homogeneous flow the Venturi meter can also be used if the gas fraction is known (II-42).

The cross-correlation technique is used either with the Venturi meter or by itself to measure the component velocities. The principle of this technique is shown schematically in Figure 6.

Two sensors, separated by a distance L , are used to measure the variation in some properties of the flowing mixture. Thus, each sensor can be used to measure the variation in density or dielectric properties. The time delay between the outputs of the two sensors seeing similar variations in the fluid properties can be calculated by a correlation function ($R_{xy(t)}$) measured over a period of time. The time lag (T_{max}) at which this correlation function is maximized - i.e. both locations show similar variation in the property - is taken as the transit time of flow between the two sensors. The velocity is then determined by dividing the distance separating the two-sensor (L) to the time lag (T_{max}). The accuracy of this technique depends on the validity of the assumptions used to derive the velocity of a particular component in the flow stream from the velocity calculated by the correlation function (II-24).

The cross-correlation method measures the velocity of the dispersed phase in the mixture (II-24). In the case of oil/water/gas mixture, the liquid (oil and water) may be travelling at a different velocity than the gas. This difference in the velocity (slip) must therefore be taken into account. Otherwise, the velocity measurement by cross-correlation becomes inaccurate.

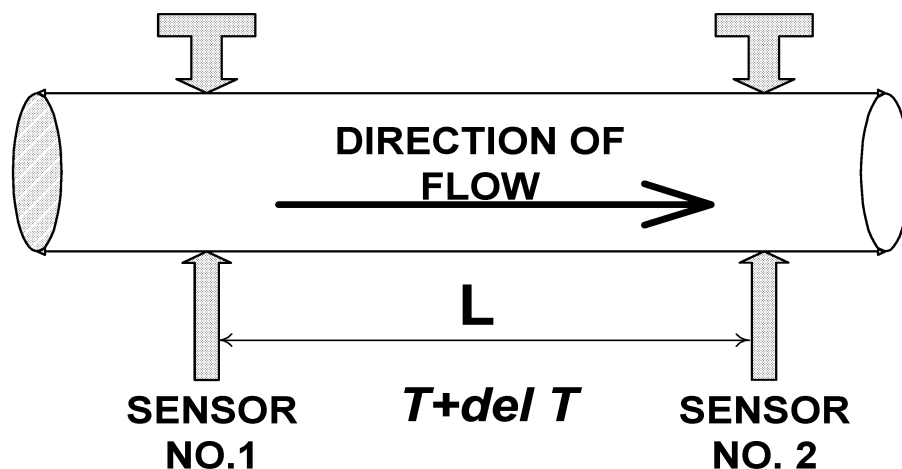


Figure 6 – Schematic of cross-correlation technique used for component velocity measurements.

8- CLASSIFICATION OF MULTIPHASE METERS

Multiphase measurements systems used in production operations utilize a diverse range of equipment from full three-phase conventional separators to in-line multiphase meters that consist of a spool piece with no separation. From the perspective of users, these systems have one common purpose – i.e. to provide accurate flow rates for oil, water and gas. In each system, however, the processes schematically shown in Figure 7 must occur. The processes shown in Figure 7 consist of some type of fluid conditioning, mixture density determination, mixture rate determination, mixture composition determination, and application of a flow model. These functions can be supplied by an instrument or by an assumption in a model (III-4).

The volumetric fraction and component velocity measurement techniques described in sections 8 and 9 are commonly used in these systems. Several references, listed in Appendix 2, have attempted to categorize the multiphase metering systems (II-4, II-11, II-18, II-24, III-4, XII-3). Terms such as on-line and off-line have been used to describe various systems. There is considerable confusion and even an argument that the term multiphase meter should only be applied to systems that can make multiphase measurements without the separation process. The following classification of the multiphase metering systems is proposed as a way to develop a commonly accepted language for multiphase metering. It is proposed that we use the following definitions to designate three types of multiphase metering systems.