Three-Phase Flow Measurement in the Offshore Oil Industry Is There a Place for Process Tomography?

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Abstract - *The problem of how to meter oil/water/gas mixtures is still a significant one in the oil industry. Considerable research has been conducted into the development of a three-phase flowmeter suitable for use in an offshore environment, and a number of commercial instruments are now available. This paper discusses why three phase flow measurement is important, the principal strategies which may be used to meter three-phase flow, and the way in which tomographic imaging techniques can applied to the problem of three-phase flow measurement.*

Keywords – multiphase flow, flow measurement, process instrumentation

1. INTRODUCTION

The problem of how to meter oil-water-gas mixtures has been of interest to the petroleum industry since the early 1980s. Since then considerable research has been conducted into the development of a three-phase flowmeter suitable for use in an industrial environment [1]. Ideally such an instrument needs to be reasonably accurate (typically ± 5 % of rate for each phase), non-intrusive, reliable, flow regime independent, and suitable for use over the full component fraction range. In spite of the large number of solutions that have been proposed in recent years, no commercially available three-phase flowmeter yet meets all these requirements, although some are now very close.

However, as realistic multiphase metering solutions are being developed to meet current needs, then so new and more difficult targets are being proposed. For instance, in addition to the continued need for traditional topside three-phase flowmeters, developments in reservoir management and production techniques have resulted in the requirement for three-phase flowmeters which can be used at the sea bed and in downhole metering applications.

Three-phase flow measurement therefore remains a problem, and not surprisingly, features in the National Measurement System Flow Programme for 1999 – 2002 which is currently being developed [2].

Process tomography is a discipline which has seen a significant growth over the last five years, with laboratory imaging systems having been developed for a number of multiphase applications. It is not yet clear whether such techniques can be used to measure component flowrate any more accurately than existing solutions. However, these techniques may have the potential to enhance the performance of existing commercial flowmeters.

This paper discusses why three-phase flow measurement is important, and why it has proved such a difficult problem to solve. Examples of current commercial three-phase flowmeters are briefly described and their limitations considered. Finally the way in which tomographic techniques can be applied to the problem of three-phase flow measurement are discussed.

2. THE CHANGING NEEDS FOR THREE-PHASE FLOW MEASUREMENT

The output of an oil/gas reservoir can vary greatly, depending on the location and age of the well. In addition to the oil and gas components, water, sand and wax may also be present in the produced well stream. Since the location and output of a well can vary so widely, then not surprisingly, the systems that have been designed to collect and process this output also vary considerably.

While the early dream of developing a universal three-phase flowmeter to replace the traditional separation/single phase metering solution currently used the fiscal monitoring of a well's output have yet to be realised, multiphase meters are becoming more commonly used in other parts of the production process [3].

Multiphase flowmeters are now increasingly used for well testing and allocation measurement. In order to optimise the production and life of a field, operators need to be able to regularly monitor the output of each well in the field. The conventional way of doing this is to use a test separator. Test separators are expensive, occupy valuable space on a production platform and require a long time to monitor each well because of the stabilised flow conditions required. In addition test separators are only moderately accurate (typically ± 5 to 10 % of each phase flowrate) and cannot be used for continuous well monitoring. A three-phase flowmeter could be used in the first instance instead of a test separator and in the long term as a permanent installation on each well. Such an arrangement will save the loss in production normally associated with well testing. This loss has been estimated by Espedal [4] to be approximately 2% for a typical offshore installation.

Allocation metering is needed when a common pipeline is used to transport the output from a number of wells owned by different companies to a processing facility. This is currently achieved by passing the output of each well through a test separator before it enters the common pipeline. However, in addition to the disadvantages of the test separator described above, dedicated test pipelines to each well are also required. A permanently installed three-phase flowmeter would offer significant advantages for allocation metering.

New concepts are being continually being developed to take account of the difficult locations of new finds (such as deep water) and the increasingly competitive economic conditions. In the North Sea sector for example, in order to facilitate the development of small and marginal fields, the move has been away from the use of expensive fixed platforms for each field, and towards subsea satellite fields with shared separation and processing facilities using floating production and storage offtake (FPSO) vessels or semi-submersible platforms.

As the design of production facilities change then so do the multiphase metering requirements. For instance the Åsgard field currently being developed in the Norwegian sector of the North Sea will use a subsea multiphase flowmeter on each of the production wells in order to reduce production losses during well testing and improve the monitoring and optimisation of production [5].

Although the absolute economic advantage to be gained by using multiphase flowmeters will depend on the field configuration, in general the use of multiphase flowmeters should result in increased production, increased recovery and a lower investment cost.

The development of "smart" well technologies has resulted in the requirement to not only be able to monitor total reservoir output at the well head, but also at different zones within the reservoir. While permanent down hole well monitoring techniques have been used for over 25 years, these have been limited to well temperature and pressure, and more recently total flowrate and oil/water ratio. The use of techniques such as artificial lift completion have also produced the need for permanent downhole three-phase flowmeters.

3. PERFORMANCE REQUIREMENTS

Most people in the petroleum industry would agree that the ideal three-phase flowmeter does not yet exist. However there is far less agreement on the target specification that flowmeter developers should be aiming for in order to produce an instrument which is of use.

An ideal three-component flowmeter should be able to measure accurately over the complete fraction range of each component, but what range and accuracy is good enough until that ideal flowmeter is developed? A group of major oil companies reviewed their multiphase metering needs and identified common range and accuracy requirements [6]. A gas volume fraction range of 0-99%, and a water cut range of 0 - 90%, with the ability to measure total liquid flowrate and gas flow rate with a relative error of less than 5% - 10% was suggested. The more accurate performance being required for production allocation applications. It was also suggested that the absolute error in water cut measurement be less than 2%. The reason for this is that companies are now operating in fields where oil can be economically produced with water fractions above 90%. In such circumstances the water fraction has to be accurately measured in order to optimise the life of the field. While the above are of course only a guide, they show how changes in production techniques and the exploitation of marginal fields are producing the need to meter over wider and wider component fraction ranges.

The requirement for multiphase flowmeters that can be used for downhole applications presents some particularly challenging operating conditions. Although the range of flow regimes and phase fractions may not be as wide as that required for topside applications, downhole meters are required to operate at pressures of up to 12500 psi (860 bar) and temperatures of 300 °F (150 °C). In addition the meter would be required to operate at any angle of orientation, and since it is not retrievable it requires a MTBF in line with the life of the zone (typically 5-10 years) [7].

4. MEASUREMENT STRATEGIES

The primary information required from the user of a three-phase flowmeter is the mass flowrate of the oil, water and gas components in the flow. An ideal flowmeter would make independent direct measurements of each of these quantities. Unfortunately, direct mass flowmeters for use with two-phase flows are rare and do not exist at all for use with three-phase flows.
The alternative to direct mass flow measurement is to use an inferential method. An inferential mass method requires both the instantaneous velocity and cross-sectional fraction of each phase to be known in order to calculate the individual component mass flowrates and total mixture mass flowrate M (Figure 1)

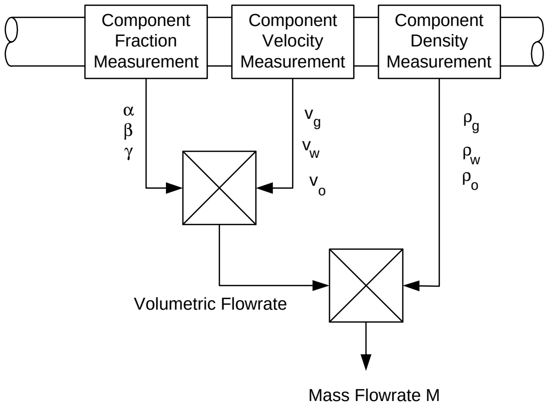

Figure 1 : Three-phase flow measurement using inferential methods

Since density information on the oil, water and gas phases is readily available from other parts of the production process, the problem is therefore to measure the oil, water and gas velocity (v_o, v_w and v_g) and two of the phase fractions (usually gas void fraction α and water fraction β):

$$M = \alpha v_g \rho_g + \beta v_w \rho_w + [1-(\alpha+\beta)] v_o \rho_o \tag{1}$$

where ρ_g, ρ_w and ρ_o are the density of the gas, water and oil fractions.

Since a combination of measurements are required to determine mass flowrate then in order to obtain uncertainties in phase mass flow rates of less than 5%, individual parameters need to be measured with much lower levels of uncertainty. Millington [8] has shown that this presents a significant problem, even for flows under steady state conditions.

Two strategies have been used to try and reduce the difficulty of the above measurement; partial separation and homogenization [9]. Partial separation of the three-phase flow, into for instance gas and liquid components allows more conventional single and two-phase techniques to be used for measurement of each of the separated flows.

Since mathematical models which can be used to reliably predict flow regimes of three-phase flows are still some way off [10] then homogenization of the flow can be used to ensure that the flow regime being metered is always known. In addition, if the flow is homogenized before being measured then it is assumed that the phase velocities are equal, and that the density of the mixture is the same across the pipe cross-section, thus reducing the number and difficulty of measurements required.

5. COMMERCIAL THREE-PHASE FLOW METERING SYSTEMS

Table 1 gives an overview of three-phase flow metering systems which are currently commercially available, or at an advanced stage of development. Most of these systems use combinations of phase density, fraction and velocity measurements to determine phase mass flowrate.

The metering systems shown in Table 1 can be classified into three basic groups. Those which partially separate the flow before measurement, those which homogenize the flow before measurement, and those which use no form of flow pre-conditioning.

5.1 Partial separation based systems

As their name suggests partial separation based measurement systems partially separate the flow, usually into predominately liquid and predominately gas streams, before measurement. As a result, each flow stream then only needs to be measured over a limited range of phase fractions. A number of techniques have been used to partially separate the flow including gravity separators and flow diverters.

A example of this type of system which has been developed by Technomare S.p.A is shown in Figure 2 [11]. In this flowmeter, the oil-water-gas mixture is separated into two streams, one mainly gas and one mainly liquid using a gas-liquid separator. The flowrate of the wet gas is measured using a venturi meter. A combination of a low frequency impedance meter, a gamma densistometer and a venturi meter is used to measure the phase fraction flowrates of the liquid dominated stream. The gas and liquid streams are recombined into a single stream before leaving the measurement system.

	Three-Phase Flow Measurement System												
	1	2	3	4	5	6	7	8	9	10	11	12	13
Component Fraction Measurement Method													
Single energy γ-ray absorption					X				X		X		
Multi energy γ-ray absorption			X	X		X				X			
Impedance (capacitance and/or resistance)					X			X			X		
Microwave		X							X			X	
Pulsed Neutron Activation (PNA)	X												
Component Velocity Measurement Method													
Cross-correlation			X		X			X	X	X			
Venturi		X		X	X	X			X		X		
Pulsed Neutron Activation	X												
Other										X			
Other measurement Methods													
PD flowmeter - mixture volumetric flowrate		X					X						
γ-ray densitometer - mixture density							X						
single phase gas meter		X										X	X
single phase liquid meter												X	X
on-line mixture analysis													X
Flow separation required	N	Y	N	N	N	N	N	N	N	N	Y	Y	Y
Homogenized flow required	N	N	N	Y	N	Y	Y	N	N	Y	Y	N	N

Key - Developing Organisations

1 - AEA Technology, UK
2 - Agar Corporation Inc, USA
3 - Kvaerner FSSL
4 - Daniel Industries Inc,USA/Shell
5 - Fluenta AS, Norway
6 - Framo Engineering AS, Norway
7 - ISA Controls, UK/BP
8 - Kongsberg Offshore AS, Norway/Shell
9 - Multi-Fluid International AS, Norway
10 - Jiskoot Autocontrol Ltd/Imperial College, UK
11 - Tecnomare/AGIP, Italy
12 - Texaco, USA
13 - WellComp, USA

Table 1: Three-phase flow metering system

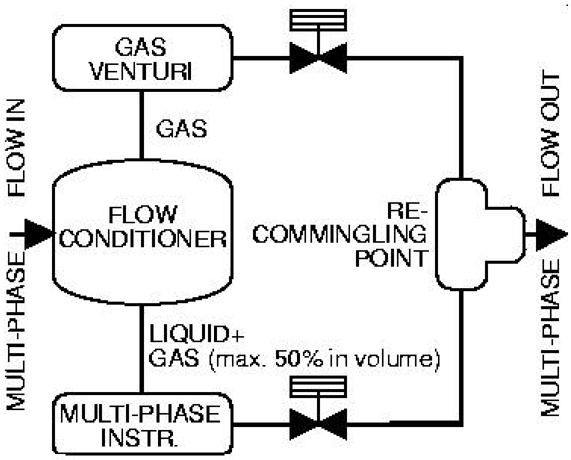

Figure 2 : Example of a three-phase flowmeter which uses partial flow separation

This system has been developed for both topside and subsea applications, and has been tested over a range of flow regimes and for void fractions up to 90% and water cuts of up to 80%. Results have shown that under these conditions liquid flowrate, water cut and gas flowrate can all be measured with uncertainties of less than 8.2%, 3.7% and 9.3% respectively.

Other three-phase flowmeters which partially separate the flow before measurement have been reported by Golike *et al* [12] and Tuss [13].

5.2 Homogenization based systems

In homogenization based systems the flow is pre-mixed to try and ensure that all measurements are made with a homogenous flow, thus removing the problem of flow regime dependency.

An example of a commercially available three-phase flowmeter which uses this strategy is shown in Figure 3.

The Framo multiphase flowmeter uses a tank mixer to homogenize the flow both radially and axially. The homogenized flow then passes through a venturi meter which is used to measure the velocity of the mixture, and a dual energy γ-ray attenuation meter which uses two different energy lines of the Barium 133 isotope to determine the oil, water and gas fractions. The flowmeter has been tested on a three-phase flowloop and on an offshore installation. Oil and water flowrate was measured to an uncertainty of better than ± 5% of total flowrate over the full fraction range. Gas fractions were measured to an uncertainty of better than ± 5% of total flowrate for gas fractions less than 70%. Tests were performed over a wide range of flow regimes[14]. The flowmeter has now been constructed for use subsea [15].

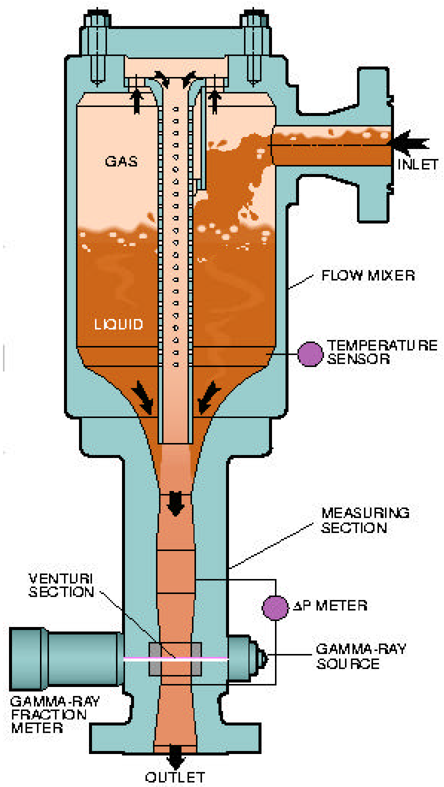

Figure 3: Example of a three-phase flowmeter which uses flow homogenization (courtesy of Framo Engineering AS)

Other three-phase flowmeters which homogenize the flow include those reported by Hewitt *et al* [16] and Priddy [17]. Although the measurement uncertainty of systems such as these are not generally flow regime dependent, the intrusive homogenization section produces an increased pressure drop and can present difficulties if the pipeline needs to be pigged.

5.3 Systems requiring no flow pre-conditioning

An example of a commercially available flowmeter which requires no pre-conditioning of the flow is the Fluenta 1900VI (Figure 4). This instrument uses a single energy γ-ray attenuation method combined with an electrical capacitance sensor for oil continuous mixtures and a conductivity sensor for water continuous mixtures to measure component fractions of the flow. Both the cross-correlation technique and a venturi meter are used to measure phase velocity.

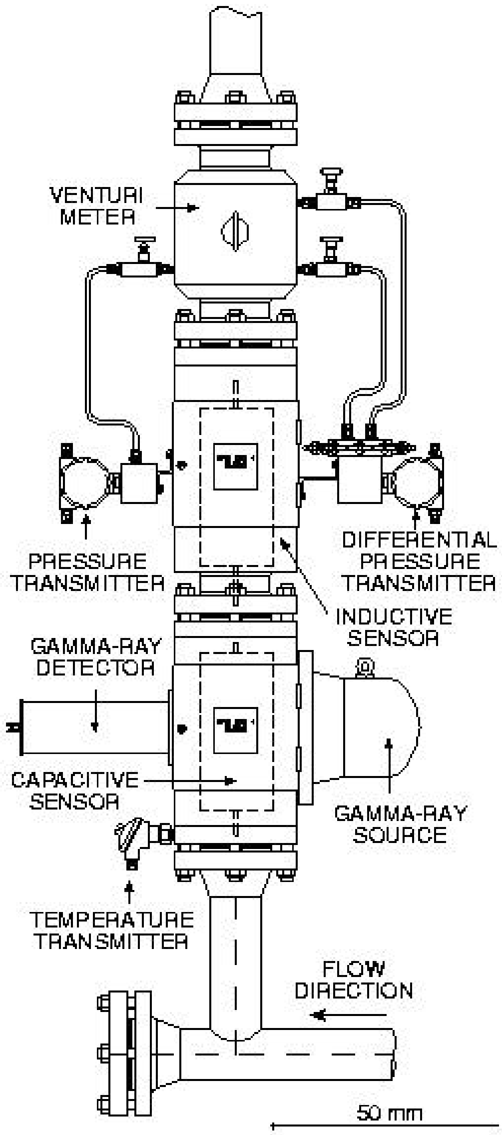

Figure 4:Example of a three-phase flowmeter which uses neither flow separation or homogenization (courtesy of Fluenta AS)

The flow regimes which can flow through the meter are limited to bubble, churn, slug and annular by restricting installation to vertical upwards flow. Gas flowrate has been measured with an uncertainty of ± 10% of actual flowrate over gas fraction ranges of 30 to 60%, and 80 to 100%, with the uncertainty increasing to ± 15% over the range 60 to 80%. Total liquid flowrate can be measured with a typical uncertainty of ± 10%, and water cut with a typical uncertainty of ± 7% [18]. A version of this meter has been marinised and installed for subsea operation in the South Scott field [19].

Other three-phase flowmeters which require no flow pre-conditioning include those reported by Roach and Watt [20] and Scheers and Letton [21].

5.4 Limitations of Current Commercial Three-Phase Metering Systems

Commercial three-phase flowmeters are now generally capable of measuring individual phase fraction's flowrate to an uncertainty of less than 10% over a reasonably wide range of flowrates and phase fractions.

There are two areas of operation which need further investigation if flowrate uncertainty is to be reduced still further using current combinational measurement techniques; flow regime dependency and individual phase velocity measurement. Process tomography techniques have the potential to solve both of these problems.

6. USING TOMOGRAPHIC TECHNIQUES FOR THREE-PHASE FLOW MEASUREMENT

Tomographic techniques can be used to two main ways for three phase flow measurement; either to produce a stand alone tomographic three-phase flowmeter or to enhance the performance of existing instruments.

6.1 Tomographic Three-Phase Flowmeters

The use of tomographic techniques for imaging multiphase flow produce a challenge not faced in most industrial or medical imaging applications; that is the process being imaged moves quickly (typically up to 10 m/s) and can change structure continuously. As a result large amounts of data need to be processed quickly if a real-time system is to be feasible.

An example of a tomographic three-phase imaging system is the dual sensor tomograph developed by the University of Bergen in co-operation with Christian Michelsen Research AS and Norsk Hydro AS [22]. This instrument uses an eight electrode capacitance tomograph and a γ-ray tomograph with five radiation sources and 85 compact detectors (Figure 5). The sensor and read-out system is capable of producing images at rates of several hundred frames per second, provided sufficient computing power is available for reconstruction and visualization.

Tests performed on static phantoms have shown that cross-sections of oil-water-gas flows can be reconstructed using this dual mode tomographic technique [23]. The γ-ray tomograph reconstructs the gas/liquid distribution accurately. However at present, the system's performance is limited by the relatively poor accuracy with which the water/oil distribution is determined by the capacitance tomograph. The problem of how to measure phase velocity has yet to be addressed in the development of this system.

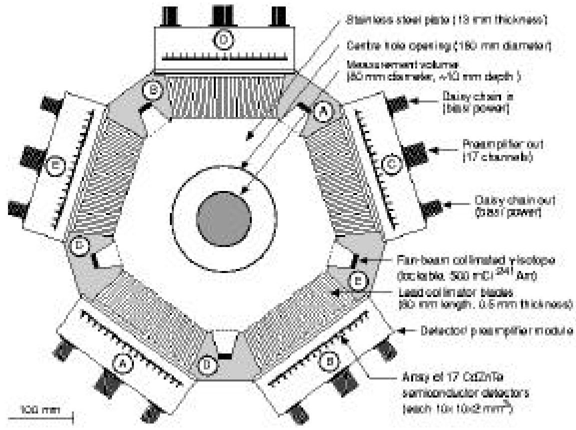

Figure 5: A cross-sectional view of a dual sensor tomography system

Dual mode tomography systems are also being developed by other groups using ultrasound and capacitance, and ultrasound and microwave combinations.

None of the above systems are commercially available and although the performance of tomographic flowmeters is likely to be independent of flow regime, it is not yet clear whether such instruments are capable of matching the measurement uncertainty of existing commercial three phase flowmeters.

6.2 Enhancing Performance of Existing Three-Phase Flowmeters Using Tomographic Techniques

Tomographic techniques have the potential to enhance the performance of existing three-phase systems in two ways; by detecting the flow regime present or by enabling the velocity of individual phases to be measured.

As was discussed in Section 5 a number of manufacturers try to reduce the problem of flow regime dependency by mixing the flow before it passes through the measurement section. This results in an unnecessary pressure drop in the pipeline, and the difficulty of achieving the same degree of mixing across all phase fraction ranges and flowrates. If the flow regime present could be identified then the meter could be optimised for each flow condition.

The flow regime present in a pipeline can be detected using traditional statistical analysis of a single sensor's output [24] or from the identification of tomographically reconstructed images. γ-ray densitometry and neural network techniques have been used for reliable flow regime detection in two-phase flows [25]. Since it has been demonstrated that three-phase flows can be imaged using tomographic techniques, then the flow regime can also be determined from the reconstructed image in a number of ways. The pattern can be analysed after the image has been reconstructed, although this will require advanced pattern recognition techniques. It may of course not always be necessary to fully reconstruct the flow image in order to be able to obtain the information required to identify a flow regime. An alternative strategy is to use the measured output from each electrode and compare this with stored patterns for a range of flow regimes [26].

The cross correlation technique is commonly used for component velocity measurement in three-phase flowmeters. This technique has been incorporated into three-phase flowmeters using a variety of sensors such as micowave, γ-ray and capacitance. The accuracy of this method depends on the validity of the relationship used to connect the velocity inferred from the correlation function's peak position, to the mean velocity of the flow. In the case of an oil-water-gas flow, since what is actually being measured is the velocity of one of the dispersed phases, then if slip is present between the components measurement errors will occur.

Two methods are currently used to reduce the velocity measurement errors due to slip. The first is to homogonise the flow upstream of the sensors, to try and ensure that all components are travelling at the same velocity. Traditional in-line mixers are not suitable for this, since they cannot homogonise the flow over the wide fraction ranges and velocity range that would be required in most flow measurement applications. Hewitt *et al* [16] have used a mixer based on a twin cell rotational principle and claim good homoginisation over a velocity range of 2 to 6 m/s. The disadvantages of all in-line homoginisation methods are the increased pressure drop created by the device, and the restriction it places on pigging operations.

Fluenta AS have used an alternative strategy to reduce errors due to slip [18]. Capacitance sensors are used to measure the the velocity of the gas phase. Two sets of sensors are used, one to measure the velocity of large gas bubbles which is assumed to be the velocity of the dispersed phase, and the second to measure the velocity of the small gas bubbles which it is assumed are travelling at the same velocity as the non-dispersed liquid phase.

An alternative approach is to determine the fluid velocity at each position across the pipeline by cross-correlating two axially separated reconstructed images of the flow. By cross-correlating the information from pixel positions rather than the sensor electrodes, it is possible to measure the velocity of the oil, water and gas components independently of each other. In addition such a technique will be independent of the flow velocity profile.

Hayes et al [27] has used twin plan correlation techniques to determine the flow velocity profile of the gas phase in an oil/gas flow, although flow profile calculation was performed off-line. More recently Loh *et al* [28] have used the twin plane correlation technique for on-line measurement of slurries.

7. CONCLUSIONS

A considerable amount of effort has been directed towards the development of an oil-water-gas flowmeter over the past ten years. A number of commercial three-phase flowmeters now exist, with more on the way, but the target uncertainty of ± 5% of reading over all fraction ranges and flow regimes has yet to be reached.

Tomographic techniques can be used for three-phase flow measurement in two main ways; either to produce a stand alone tomographic three-phase flowmeter or to enhance the performance of existing instruments. Although the feasibility of a tomographic three-phase flowmeter has been demonstrated in the laboratory, commercial versions of such instruments are still some way off.

In the short term, tomographic techniques are most likely to be of benefit for flow pattern recognition and for the measurement of individual phase velocities. Reliable measurements of these could be used to reduce the measurement uncertainty of existing three-phase instruments over the increasingly wide range of operating conditions required by industrial users.

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