MULTIPHASE FLOW MEASUREMENT IN THE OFFSHORE OIL INDUSTRY

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ABSTRACT
In recent years, considerable research has been conducted into the development of a three-phase flowmeter suitable for use in an offshore environment, and oil/gas/water three-phase metering becomes an important aspect in multiphase flow measurement. This paper discusses the importance of three-phase flow measurement in offshore oil industry, describes the current development in this area, and points out the principal strategies which may be used to meter three-phase flow.
Keywords:multiphase flow measurement, oil/water/gas metering, offshore oil industry

1. INTRODUCTION
Multiphase flow measurement is a term that has been increasingly hard since about 1980 amongst operators in oil companies and designers of oilfield facilities. They saw a need to simplify the design and improve the control of production facilities. They considered that, unless multiphase measurement techniques were improved, it would be virtually impossible to know what was happening in the advanced subsea systems or on the unmanned satellite platforms that were being planned. In addition they could not see how future enhanced oil recovery systems could be operated effectively without these measurements.

Therefore, the development of multiphase metering systems which eliminate the need for separators and test lines has attracted much attention in oil industry, especially in offshore environment. It is an emerging technology which offers the potential for major reduction of capital cost as well as to improve and optimize flow management and production operation due to accurate real-time in-situ data.

The demands on multiphase measurement systems are very high. For example, the meter must accurately measure in all flow regimes and it should not be affected by changes in fluid properties like density and dielectric properties. Moreover, there is a need for non-intrusive metering systems and a robust design which also works in harsh environments. 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.

As realistic multiphase metering solutions are being developed to meet current needs, some new and more difficult targets are being proposed in the offshore oil industry. 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, many methods are tried to be used to handle this issue.

This paper discusses why three-phase flow measurement is important and why it has proved such a difficult problem to solve, outlines measurement strategies for multiphase flows and introduces the method of tomographic technique to the problem of three-phase flow measurement.

2. THREE-PHASE METERING APPLICATION IN OFFSHORE OIL PRODUCTION
Owing to the adverse environments and limited operation space, offshore oil production is rather keen on multiphase metering technology to simplify the design and improve the control of production facilities. There are several applications in offshore oil production for multiphase metering, with each application requiring different standards of accuracy in components fraction or mass flow rate measurement.

2.1 Reservoir Management
In order to optimize the production and lifetime of an oil field, it is necessary to monitor the output of each well at regular intervals. The measurement sought is the amount of water that the well is producing. In conventional platform-based production, the multiphase flow produced from a well is collected in a large separator tank, and the fluid allowed to separate into its constituent components. The flow rate of each component can then be measured using conventional single-phase flow measurement techniques. Thus, a test separator is required to initially separate the oil, water and gas

is expensive and takes up valuable platform space. In addition, the output from each well must be individually diverted into the separator (figure 1.a). If a multiphase flow meter is installed on each well, all the test separator and diversion line can be cancelled, and this can save a lot of expenditure and platform space (figure 1.b).

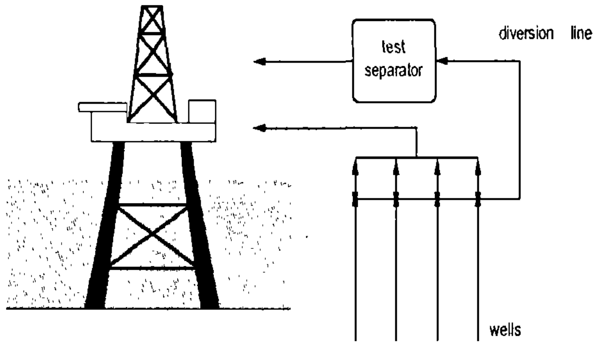

Fig.1 (a) Well testing with test separator

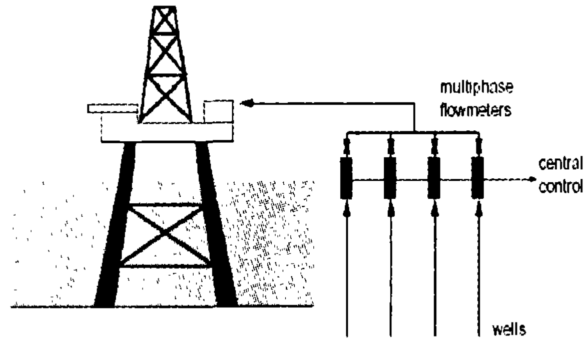

Fig.1 (b) Well testing with on-line multiphase flowmeter

It has been estimated that more than 50% of the world's oil and gas reserves are located in water depths greater than 1000m (King, 1990). Production from deep sea marginal fields requires a radically different approach to conventional production from shallow sea fields to be economically viable. To facilitate development of those resources, the use of expensive fixed platforms for each field is being phased out and smaller satellite fields developed (Figure 2). The multiphase flow from each well in a satellite field is collected at a manifold and transported via a common pipeline to a central production platform with shared separation and processing facilities. In satellite well based fields, subsea multiphase meters are very desirable and perhaps the only viable option for well testing. A subsea multiphase flow meter should be able to measure water cut to an accuracy of at least ±5% to be useful for reservoir management purposes.

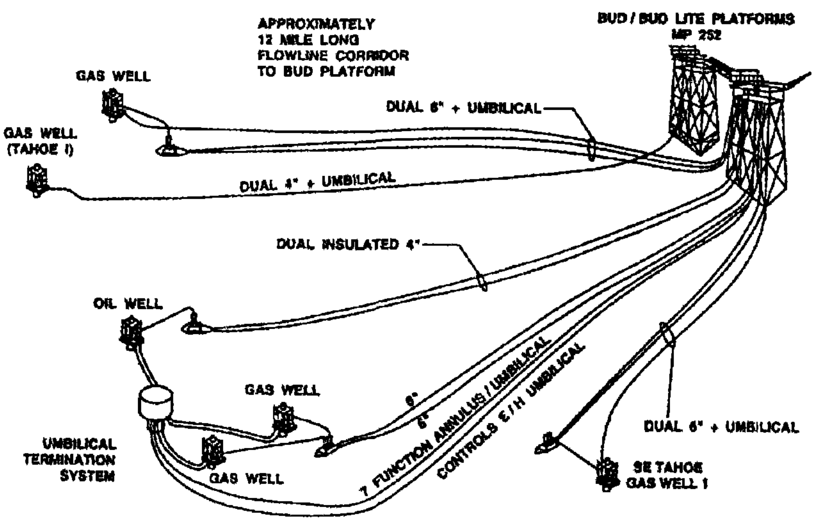

Fig.2 Oil field based on satellite well production

2.2 Allocation and Fiscal Metering

In addition to well testing for reservoir management, there are two other applications where multiphase flow meters will replace the current metering methods based on separation. As with well testing, in satellite well based production the use of multiphase flowmeters in these applications will bring significant benefits and may be crucial in the exploitation of new discoveries. In fact, the cost of production using subsea multiphase flowmeters compared to that of using conventional separator based technology in all aspects of satellite well metering has been estimated to be around 50%. The applications known as allocation metering and fiscal metering require higher standards of accuracy to that for well testing.

Individual satellite wells in a field may be owned and operated by different companies. When a common pipeline is used to transport fluids to a processing facility, metering is required to allocate the oil once it has arrived. Conventionally, fluids from each well are diverted into a test separator before entering the common pipe. This process requires a test pipeline for each well, in addition to the drawbacks mentioned above in relation to test separators. The generally accepted accuracy requirement for oil and water mass flowrates in allocation metering is in the range of ±2~5%.

Measurements of the quantity of oil exported from a field are required by government agencies for taxation and control purposes, a process known as fiscal metering. Fiscal metering requires a more stringent accuracy in oil and water mass flowrate measurement than the applications discussed previously, with a accepted range of ±0.25~1%. The standards of accuracy required for fiscal metering are widely considered an impossible target for a three-phase flowmeter.

3. CONCEPT OF OIL/WATER/GAS THREE-PHASE METERING

3.1 Oil/Water/Gas Three-Phase Flow Property

The biggest obstacle to the successful implementation of multiphase metering is the general lack of understanding of what it is about. It is difficult to explain simply why multiphase metering is so complex. Various ways have been proposed to show how the multiphase flow characteristics of a well or a field change with time, and to show the operating envelopes of multiphase meters.

As we know, in gas/liquid pipeline flows, the two-phase will adopt various dynamic geometric configurations, or flow regimes. The major flow regimes found in horizontal pipes are bubbly flow, plug flow, stratified flow, wavy flow, slug flow, annular flow and mist flow; while in vertical gas/liquid up-flow in a pipe of circular cross-section are bubbly flow, slug flow, churn flow and annular flow. In oil/gas/water three phase flows, owing to the presence of different liquid phases, extra complexity to the flow pattern will introduced depending on the degree of mixing of the components comparing to that of gas/liquid two-phase flows. In a well developed oil/water/gas multiphase flow, the oil and water may be become separated and flow as distinct phases. Under certain condition of oil and water flowrates, the oil and water may be well emulsified and the oil and water can be considered as a single liquid phase in term of flow regime and flow velocity. We can use a triangle proposed by Jamieson to display properties of oil, water, gas three component mixtures (Fig.3).

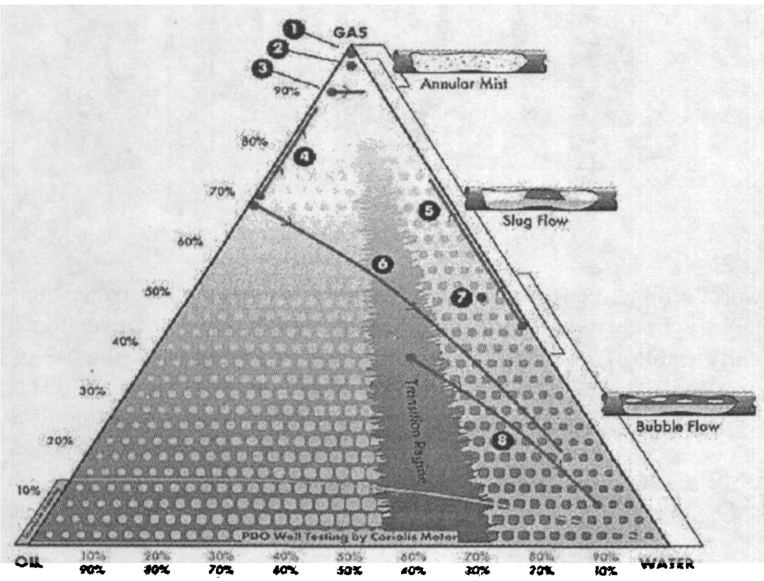

FIG. 3 MULTIPHASE COMPOSITION TRIANGLE

In this figure, the vertices of the triangle represent single-phase gas, oil and water, the three sides of the triangle represent two-phase mixtures and any point within the triangle represents a unique three-phase mixture. The transition region indicates where the liquid fraction changes from water-in-oil to oil-in-water. The ranges of common multiphase flow regimes, which are affected by temperature, pressure, viscosity and flow-line orientation, are indicated at the side of the triangle.

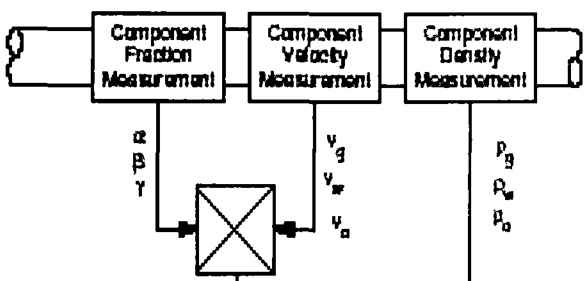

Fig.4 Three-phase flowrate measurement

Most of the work over the last two decades has concentrated on developing two-phase meters i.e. oil/gas. New advances in measuring three-phase flow allow us to operate over a larger fraction of the triangle.

It is easy to use the triangle to show why multiphase metering is so complex. If we have difficulty with the single phases, which are so obviously different from each other, we can expect measurement to be at least as difficult for any multiphase composition in the triangle. We have to add to that the complexity from the flow regimes. Flow regime maps have been determined by subjective observation in laboratory test-loops, almost always for two-phase mixtures, say oil-gas or water-gas. These maps vary for temperature, pressure, viscosity, and pipe orientation. There have been only a few attempts to make three phase flow regime maps, and these are very complex.

This means that it is not practical to predict the performance of multiphase meters from first principles and that detailed empirical testing will be needed. Obviously, the higher the performance demanded from the meter, the better the test facilities need to be. In time, when enough applications have been examined we should be able to see generalities, but for the next few years at least each application will need to be treated on its own merits.

3.2 Multiphase Flowrate Measurement

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 4).

Since density information on the oil, water and gas phases (ρ_o, ρ_w and ρ_g) 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 phase fractions (α, β and γ):

$$M = \alpha v_g \rho_g + \beta v_w \rho_w + \gamma v_o \rho_o \tag{1}$$

Thus the multiphase flowrate measurement is to measure the flowrates of each component $\alpha v_g \rho_g$, $\beta v_w \rho_w$ and $\gamma v_o \rho_o$ and obtain M.

4. MULTIPHASE FLOW MEASUREMENT STRATEGIES

Multiphase flowrate measurement strategies should be taken according to equation (1). From the equation, we can see that if we can homogenize the multiphase mixture as a single phase component, we can obtain the multiphase flowrate by measuring the velocity and density of the homogenized mixture; if we separate the multiphase mixture into single phases, then we can obtain the multiphase flowrate by applying mature single phase flowrate measuring methods, otherwise we must measure the oil, water and gas velocity (v_o, v_w and v_g) and phase fractions(α, β and γ) to obtain the total flowrate.

4.1 Separation Based Multiphase Metering

This is a traditional method to deal with multiphase flow: a test separator combined with its instrumentation in fact forms a multiphase flowmeter. In this type, the multiphase flow measurement system is formed by one or more a separators and three single phase flowmeters. Owing to the huge separation system, this method is not used in onshore oil fields, say nothing of offshore cases. Therefore, a compact partial separation system is developed to perform a rough separation of the well flow into liquid and gas streams which are then metered using meters that can tolerate small amounts of the other phase. The liquid must be further split up into oil and water. An example of this type of system which has been developed by Technomare S.p.A[11] is shown in Figure 5. 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. Although this system has been reported to be tested in some topside and subsea cases, it is still not an ideal measurement means in offshore circumstance for its complexity layout.

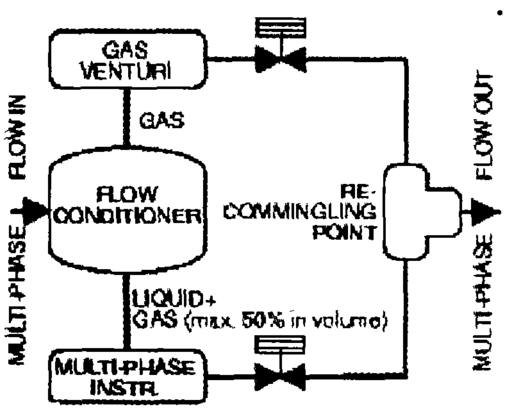

Fig.5 Partial separation multiphase flowmeter

4.2 Homogenization Based Multiphase Metering

The maximum difficult in three-phase metering is six variables must be identified: three velocities and three fractions. If only one velocity and one density are needed measuring in stead of three velocities and three fractions, the situation will be much simplified. Thus the concept of homogenization based multiphase flow measurement is proposed wherein the flow is conditioned so that the phase velocities are similar and a homogenized density of the multiphase mixture is taken to calculate the flowrate. In order to obtain the flowrate of each phase, three component fractions and a mixture velocity need measuring. In recent years, many technologies have been utilized to measure fractions and velocity.

4.2.1 Component Fraction Measurement

Several technologies have been used to measure the fractional component of the multiphase stream produced from an oil reservoirs, with varying levels of success. The most commonly used approaches are γ-ray attenuation, electrical capacitance, or electrical impedance.

The γ-ray attenuation coefficient $\mu(E)$ in an oil/water/gas mixture flow can be represented by

$$\mu(E) = \alpha\mu(E)_o + \beta\mu(E)_w + \gamma\mu(E)_g \tag{2}$$

where $\mu(E)_o$, $\mu(E)_w$ and $\mu(E)_g$ are the linear attenuation coefficients of the oil, water and gas, and α, β, γ are the respective volume fractions. The transmitted intensity I through a thickness t of a oil/water/gas mixture from the original intensity I_0 is therefore:

$$I = I_0 \exp[-(\alpha\mu(E)_o + \beta\mu(E)_w + \gamma\mu(E)_g)t] \tag{3}$$

If the transmitted flux I_1 and I_2 at two energies E_1 and E_2 is measured, the volume fractions can be calculated if the linear attenuation coefficients of the flow components at E_1 and E_2 are known since

$$\begin{aligned} \ln(I/I_0)_1 &= -[\alpha\mu(E_1)_o + \beta\mu(E_1)_w + \gamma\mu(E_1)_g]t \\ \ln(I/I_0)_2 &= -[\alpha\mu(E_2)_o + \beta\mu(E_2)_w + \gamma\mu(E_2)_g]t \\ \alpha + \beta + \gamma &= 1 \end{aligned} \tag{4}$$

i.e. there are three equations with three unknowns namely the volume fractions α, β and γ.

The basic system for phase fraction measurement with capacitance sensors consists of two or more electrodes placed inside the pipe which measure the capacitance of a two-phase fluid. If the relative permitivities of the two phases are sufficiently different, for example oil and water where $\varepsilon_{oil} = 2$ and $\varepsilon_{water} = 80$, the volume fractions of each phase can be determined.

When oil and water two phases present in the sensor volume, the capacitance C_{2phase} reading will be:

$$C_{2phase} = K\varepsilon_{2phase} \quad \text{where } \varepsilon_{2phase} = \frac{V_{oil}}{V_S}\varepsilon_{oil} + \frac{V_{water}}{V_S}\varepsilon_{water} \tag{5}$$

if V_{oil} is the volume occupied by oil, V_{water} is the volume occupied by water and V_s is the total volume between the sensors, and K is a constant reflecting the dimensions and separation of the electrodes and including the permitivity constant ε_0. A measurement of C_{2pahse} yields a value for ε_{2phase} which then is used to calculate the volume fractions of each phase, since $V_s = V_{oil} + V_{water}$.

In a three-phase system, gas will also present and the sensitive volume V_s will not be filled completely by the liquid phase. This means that an independent measurement of the gas volume fraction is required if absolute measurements of oil and water volume fractions are to be made, rather than the water cut only. A single energy γ-ray transmission device is often used to quantify the gas volume fraction.

Impedance sensors were developed for use in water continuous flow where the electrical conductivity of the fluid causes problems for capacitances based meters. The basic,sensor consists of two electrodes, similar to the geometry of the capacitance system, except that the measured quantity is now the electrical impedance of the fluid. This is measured by passing an electrical current between the electrodes through the fluid, with the gas volume fraction determined independently (again, usually with a γ-ray transmission device). In common with the capacitance technologies, the sensor must be calibrated according to the prevailing flow regime since the conductivity measured between the electrodes is strongly dependent on the spatial distribution of the fluid components.

4.2.2 Component Velocity Measurement

Component velocity measurements are usually based on cross-correlation techniques. Cross-correlation involves the measurement of the transmit time of any disturbance or inhomogeneous feature between two sensors placed a known distance apart in the flow medium. Fluctuations in photon linear attenuation coefficient, dielectrical constant, electrical conductivity or acoustic impedance are commonly cross- correlated to measure flow velocities.

To carry out the cross-correlation, two sensor systems x and y should be placed a known distance apart along the pipeline and successive measurements of the fluctuation parameter are compared to find the time elapsed τ_c between maximum similarities in the two measurements. A mathematical relation defining the cross-correlation function $R_{xy}(t)$ is required to compute the maximum similarity in the measurements:

$$R_{xy}(\tau) = \lim_{T\to\infty}\frac{1}{T}\int_0^T x(t+\tau)\cdot y(t)dt \tag{6}$$

where $y(t)$ is the upstream sensor measurement at time t, $x(t+\tau)$ is the measurement made by the downstream sensor after a time delay τ, and T is the integration time. The time delay τ is varied and the calculated cross-correlation function $R_{xy}(t)$ plotted as a function of τ. A peak will occur at $\tau = \tau_c$ in the function when the two sensor measurements are most similar. Since the separation of the sensor systems is known, the average flow velocity may be calculated from the relation $\bar{v} = l/\tau_c$, where l is the separation between the sensor systems.

Many oil companies, manufacturers and researchers have developed multiphase flow metering systems according to this measurement principle, but some of them combine with partial separation manner. Perhaps the most successful commercial homogenization based multiphase meter is developed by Framo (Fig.6). In the meter the flow is pro-conditioned with a mixer, and the homogenized components directed to a venturi tube where the total volume flow rate is measured. A dual energy γ-ray transmission device, in which Ba^{133} sources provide photon energies of 30 and 350 keV, is used to measure the phase fractions. This kind of multiphase flow meter can be operation on topside and subsea installations for both well testing and allocation metering. The main drawbacks of this method are that relatively larger measurement error may occur owing to the big difference between phase velocities at some flow regimes, and that pro-condition mixer to homogenize the flow will cause maintain problems.

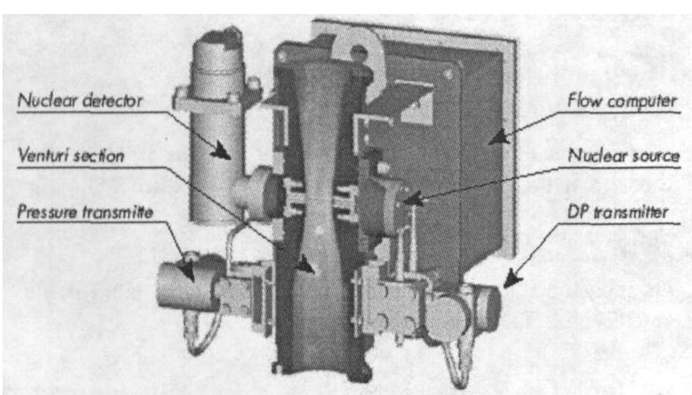

Fig.6 Homogenization based three-phase flowmeter

4.3 Direct Multiphase Metering

The most intuitional method to obtain multiphase flowrate based on equation (1) is directly measuring six variables: oil, water and gas velocity (v_o, v_w and v_g) and phase fractions (α, β and γ). The most benefit from this approach is simplicity of the measuring system because no separation and pro-condition device are needed. For phase fractions' measurement, γ-ray attenuation, electrical capacitance, or electrical impedance can be used as in the homogenization based multiphase metering system, but how to measure the three-phase velocities simultaneously still remains unsolved problem, and the velocities of each component do be strongly flow regime dependent. That is why so far the real direct oil/water/gas three-phase metering has not realized yet. As we known, the multiphase metering system used in offshore environment should be non-intrusive, tiny, easy to commission, operate and maintain, fewer shut-downs and breakdowns, robust, high reliability, less maintenance, fewer even no moving parts, and most importantly flow regime independent. Needless to say, direct multiphase metering should be the most favorite being used in offshore oil industry. The problem is how to develop a direct multiphase flowmeter to meet all those requirements?

5. TOMOGRAPHIC TECHNIQUE FOR THREE-PHASE FLOW MEASUREMENT

In multiphase flow measurement for the oil industry, process tomography can be used in three different ways. Firstly, the tomographic system can form the basis of multiphase flowmeter itself, measuring both component fractions and flow velocities. Secondly, a tomographic instrument can be used in conjunction with one of the component fraction measurement modalities mentioned above to offset flow regime dependency, if the spatial distribution of the flow components is known, the flowmeter can be calibrated accordingly. And thirdly, tomographic imaging can be used to display and monitor multiphase flow regimes dynamically, to optimize the production management, and to diagnose the production process.

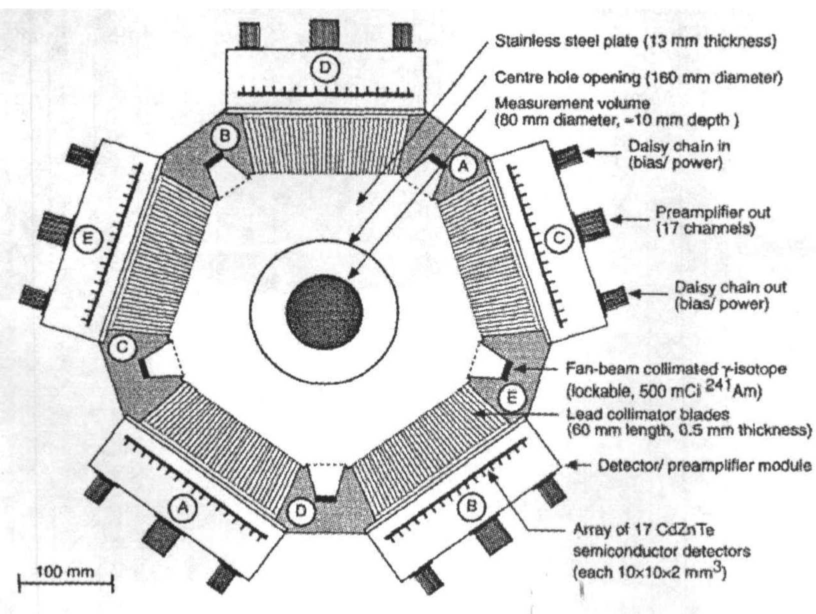

Fig.7 A cross-sectional view of the gγ-ray tomography

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.

Taking γ-ray tomography as an example here, using dual energy γ-ray sources and detector arrays placed as in Figure 7, 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. The cross-sections of oil-water-gas flows can be reconstructed using this tomographic technique combined with capacitance tomography. The γ-ray tomography reconstructs the gas/liquid distribution, while the water/oil distribution is determined by the capacitance tomography. Individual oil, water and gas velocities are then determined by using cross-correlation technique and analyzing quantitatively the images and flow regimes.

However, process tomography is not really used in oil industry in oil/water/gas multiphase flow metering. This is because the accuracy and operating envelops of the existing tomographic systems are currently considered insufficient, although it is generally accepted that tomography will play an important role and many kinds of tomography techniques are under development.

6. CONCLUSIONS

Challenging targets have been set for the performance of multiphase meters used in offshore oil industry and multiphase metering is at the stage of development where oil companies can deploy them to bring large benefits. Apart from the obvious financial benefits, they allow operators and reservoir engineers to monitor oil and gas production in ways not possible before, thus aiding production optimization. In the long term, this will probably be the biggest benefit from the use of multiphase metering.

Existing multiphase meters or indeed any multiphase meter likely to be developed can be fitted into one or a combination of the four approaches currently used in multiphase metering. These approaches offer different levels of technical complexity and require different levels of understanding. Enough development and testing has now been done to show that high performance multiphase meters for third party allocation and for near fiscal measurement are practical, and that their realization need not be too far off. In this respect the pattern recognition approach, on its own or in combination with the hardware from the other approaches is most relevant.

The potential market world wide for multiphase metering systems is very large. Widespread implementation of multiphase metering cannot take place until expertise is spread more widely throughout the oil industry. Most of the expertise in multiphase metering is held by specialists in oil companies, by developers and by manufacturers. Metering consultants and facility design houses are slowly beginning to build their expertise.

ACKNOWLEDGEMENTS

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NOMENCLATURE

C	capacitance
E	energy
I	intensity
M	mass flowrate
T, t	time
V	volume
α, β, γ	gas/water/oil phase fraction
ρ	density
v	velocity
μ	attenuation coefficient
τ	time delay

Subscripts

g	gas
o	oil, original
s	sensor
w	water