MULTIPHASE FLOWMETER MEASUREMENT UNCERTAINTIES

by

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SUMMARY

The paper describes the state of the art in multiphase flow metering from a theoretical point of view, giving brief details of how the individual mass flowrates of each phase are derived. The limitations imposed by using such calculation procedures are then fully explained in terms of metering uncertainties.

By referring to previous theoretical work, the level of uncertainty in the individual mass flowrate measurements for a typical multiphase flowmeter are shown to be in excess of 10 per cent for virtually all possible combinations of oil, water and gas phase fractions. Most importantly though, it is shown that the individual mass flowrate uncertainties are very dependent upon the flow composition. It is therefore concluded that for any multiphase flowmeter, uncertainty data must be qualified with a statement of the flow composition to which it applies.

NOTATION

m_g	*mass flowrate of gas*
m_o	*mass flowrate of oil*
m_w	*mass flowrate of water*
Q_t	*total volumetric flowrate at the metering conditions*
α_g	*gas phase fraction at the metering conditions*
α_o	*oil phase fraction at the metering conditions*
α_w	*water phase fraction at the metering conditions*
β	*liquid water content*
μ	*liquid fraction of the multiphase mixture*

ρ_g *gas density at the metering conditions*

ρ_o *oil density at the metering conditions*

ρ_w *water density at the metering conditions*

ρ_t *total multiphase density at the metering conditions*

ρ_L *liquid density at the metering conditions*

1 BACKGROUND

Throughout the late 1980's and early 1990's the transportation and measurement of multiphase flows, especially oil/water/gas flows, has come under increasing scrutiny because of the economic advantages to be gained by using the technology to avoid platform based separation processes. One of the key short term objectives that has been identified is to replace test separators with multiphase flowmeters, saving both weight and space on platforms. In the medium term subsea multiphase flowmeters located on each well will give near instantaneous flow data for reservoir control and allocation purposes, and in the longer term multiphase meters will be used for fiscal purposes. The economic gains to be made are considerable and will greatly improve the viability of some of the more marginal fields, and will certainly aid the exploitation of fields in deeper water.

Most oil companies are therefore vigorously pursuing the development of multiphase flowmeters which would be capable of replacing the test separators, and which can also be located subsea. At the present time the authors are aware of 18 separate multiphase flowmeter development projects worldwide.

In the haste to achieve an operational prototype multiphase meter, some of the fundamental measurement difficulties have often been overlooked. It is the purpose of this paper to rectify this situation, giving a balanced assessment of the likely measurement uncertainties involved in this type of metering, and identifying the major problems.

This information will be of interest to both the developer and user alike, and it is hoped it will provide a basis for realistic performance aims for first generation multiphase flowmeters.

2 MULTIPHASE FLOWMETER DESIGNS

Ideally a multiphase flowmeter would make 3 separate, but simultaneous measurements: one of the oil flowrate, one of the water flowrate, and one of the gas flowrate. Each of the separate measurements not being influenced by the fact that the other two phases are present. This type of meter is not yet technically possible, and it is unlikely that such a meter will be available within the next 10 years.

However, instrumentation is available which is capable of discriminating between two flow components; water-in-oil monitors are a good example. By combining a number of indirect measurements it is possible to determine the flow composition of 3-phase flows, and coupling this information with a measurement of the total volumetric flowrate it is then possible to determine the individual mass flowrates of each phase. All of the present multiphase meters under development use this same basic technique, although the measurements made vary from meter-to-meter.

An example of a typical system configuration is shown in fig.1. In this design the three key measurements are the water content in the liquid after sampling and removing any entrained gas; the total oil/water/gas density; and the total flowrate. The procedure used to calculate the oil, water and gas phase fractions and flowrates is given below. (For simplicity it is assumed that pressure and temperature variations are accounted for)

Consider the flow to be gas-liquid with a liquid fraction of μ, then the total density can be written:

$$\rho_t = (1-\mu)\rho_g + \mu\rho_L \tag{1}$$

Similarly, if the water content in the liquid is denoted by β then the expression for the liquid density is

$$\rho_L = (1-\beta)\rho_o + \beta\rho_w \tag{2}$$

Substituting the expression for the liquid density into equation (1) gives an alternative expression for the total density

$$\rho_t = (1-\mu)\rho_g + \mu(1-\beta)\rho_o + \mu\beta\rho_w \tag{3}$$

where the coefficients of the oil, water and gas densities are the volumetric phase fractions, therefore

$$\alpha_g = 1-\mu$$

$$\alpha_o = \mu(1-\beta)$$

$$\alpha_w = \mu\beta$$

So if μ and β can be measured or calculated then the flow composition can be derived.

In the system shown in fig.1 assume that the water content in the liquid is found by measuring the liquid density, then from equation (2)

$$\beta = \frac{\rho_L - \rho_o}{\rho_w - \rho_o} \tag{4}$$

where the oil and water densities are known from the well characteristics.

Likewise from equation (1) the liquid fraction μ can be found by re-arranging to give

$$\mu = \frac{\rho_t - \rho_g}{\rho_L - \rho_g} \tag{5}$$

where the liquid density and the total density are measured, and the gas density is known from the well characteristics.

Having calculated the phase fractions using the values of μ and β, the individual mass flowrates of each phase can be found by obtaining a measurement of the total volumetric flowrate

$$m_g = \alpha_g \rho_g Q_t$$

$$m_o = \alpha_o \rho_o Q_t$$

$$m_w = \alpha_w \rho_w Q_t$$

There are many technical difficulties in achieving a working system of this type, but from a theoretical point of view the above analysis is the basis common to all of the multiphase flowmeters under present development.

3 MULTIPHASE FLOWMETER MEASUREMENT UNCERTAINTIES

3.1 The key problems

The technique outlined above is a perfectly acceptable method of calculating the individual flowrates of oil, water and gas, but there are fundamental limitations on the measurement uncertainties achievable.

Unlike a single phase flow in which any measurements made relate directly to the liquid or gas present, the measurements taken to define the flow composition of a two-phase or multiphase flow are indirect, and relate to 2 or more phases. If the phase fraction of the required flow component is low, then in relative terms the measurement uncertainties in the instruments used can have a major effect on the uncertainty in the mass flowrate calculation.

To demonstrate this effect a simple analogy using distances to represent phase fractions can be used. Consider two points A and C with a third point B lying on the line between A and C, but located quite close to C. The distances AB and BC can therefore be thought of as the phase fractions of two flow components in a two-phase mixture: one with a high phase fraction, the other with a relatively low phase fraction. The short distance BC can be measured by two ways, either a single direct measurement, or by measuring AC and AB and subtracting AB from AC.

To estimate the uncertainty in the values obtained let AB $= a$, BC $= b$, and AC $= c$, and take the percentage uncertainty in any measurement of distance to be 1 per cent. Then for the direct measurement of BC the absolute uncertainty in the reading would be

$$e(b) = \left[\frac{1}{100}\right] b \tag{6}$$

By the indirect technique the uncertainty in BC would be

$$e(b) = \sqrt{e^2(a) + e^2(c)} \tag{7}$$

Substituting for the absolute uncertainties in AC and AB, this equation reduces to

$$e(b) = \left[\frac{1}{100}\right] \sqrt{a^2 + c^2} \tag{8}$$

To give an indication of the potential difference in measurement uncertainty between the two methods, set c $= 100$ *mm* with a $= 95$ *mm* and b $= 5$ *mm*. Then the absolute uncertainty in BC using both methods would be

$$\textit{Direct measurement} \quad e(b) = 0.05\,mm$$

$$\textit{Indirect measurement} \quad e(b) = 0.9513\,mm$$

so the uncertainty in the deduced value of BC would be 19 times greater than if a single direct measurement were made. In percentage terms the indirect method of measuring BC would have a random uncertainty approaching 20 per cent, compared to the 1 per cent associated with the direct measurement.

The above analogy highlights quite clearly the limitations of taking multiple indirect measurements to determine flow composition. The only way of overcoming these difficulties is to have extremely low uncertainties on all such measurements, but because of the multiphase flow environment this is very difficult to achieve.

There are two principal difficulties: the natural structure of the flow can vary considerably, and measurements involving two of the flow components can be hampered by contamination by the third phase. Liquid water content monitors are an excellent example of this because the measurement technologies presently used tend to give erroneous readings if there is gas in the flow.

However, it is the spatial and temporal variations in the flow structure which are technically most challenging. For example, a common technique used in multiphase flowmeters is gamma densitometry, in which the absorption of gamma rays gives a measure of the total flow density. If the flow is well mixed then a reasonable average density measurement will be obtained quite quickly, but if the flow is slugging it becomes much more difficult to define an average density let alone measure it. In such circumstances the longer the averaging period the better, but there is obviously a practical limitation if real time readings are required. A balance has to be struck, which is inevitably to the detriment of the uncertainty in the total density measurement.

Finally, and perhaps most importantly, any instrument within a metering system that requires an input from another instrument in order to interpret its own measurement is clearly at risk of having an increased uncertainty. An example of this is described in the next section.

3.2 An assessment of the uncertainties involved

Consider the multiphase metering system shown in fig.1, with the three key measurements being the water content in the liquid, the total flow density, and the total volumetric flowrate. These measurements being made by a vibrating tube densitometer, a gamma densitometer and a venturi, respectively.

To calculate the liquid water content, phase fractions and individual mass flowrates the

following must be known:

Liquid water content

- the representivity of the liquid sample stream
- the liquid density
- the oil density
- the water density

Phase fractions

- the liquid water content
- the gamma densitometer path length (internal pipe diameter)
- the gamma densitometer count rate with dry pipe
- the gamma densitometer count rate under flowing conditions
- the mass absorption coefficient of the oil
- the mass absorption coefficient of the water
- the mass absorption coefficient of the gas
- the gas, oil and water densities

Individual mass fractions

- the individual phase fractions
- the multiphase density
- the venturi differential pressure
- the oil, water and gas densities

The first thing to be noted is that the interpretation of the gamma densitometer measurements requires knowledge of the liquid composition in order to assign the mass absorption coefficients correctly. Likewise the venturi requires the total flow density measurement from the gamma densitometer to correctly convert the differential pressure measurement into a measurement of volumetric flow. So if the water content measurement has a high random uncertainty associated with it, then this will add additional uncertainty to the total density measurement and this in turn will be transferred through to the volumetric flowrate measurement.

This interdependence makes a rigorous derivation of the uncertainties in the oil, water and gas mass flowrates lengthy, and consequently unsuitable for inclusion in this paper. The full derivation can however be found in reference 1.

Using the equations derived in reference 1 a computer program was written to perform the calculation of the uncertainties in the individual mass flowrates over a wide range of oil, water and gas phase fractions. Table 1 gives an example of the data produced, and from this it is evident that the percentage uncertainty in the individual mass flowrates of oil varies considerably according to flow composition, and can be extremely high. (Note that this data was produced using best estimates of the measurement uncertainties in each parameter listed above, and these values are shown in Table 2)

Tables showing the uncertainties for the water and gas mass flowrates are available in reference 1, and they show similar trends to that of Table 1. Summarising all the uncertainty data produced gave the following ranges:

oil	13.8 - 181.2 per cent
water	10.9 - 169.8 per cent
gas	7.1 - 76.2 per cent

There is a lot of information available from the full uncertainty analysis, particularly regarding the sensitivities of each measurement uncertainty. However, there are two points of major importance:

a A multiphase flowmeter using a series of indirect measurements to find the individual mass flowrates can only be expected to attain an uncertainty of approximately 10 per cent of the actual mass flowrate over a very limited range of flow compositions. To cover a wider operating range a target uncertainty of 15 - 20 per cent of the actual mass flowrate would be a more realistic goal.

b All things being equal, the flow composition has the greatest affect on the percentage uncertainty in the individual mass flowrates. For credibility the uncertainty figures for any multiphase flowmeter <u>must</u> be quoted at a specific flow composition. Ideally an upper and lower limit (as above) should be given.

4 CONCLUDING COMMENTS

The main points arising from the study of multiphase flowmeter uncertainties are:

4.1 Present designs are far from ideal, because they do not measure the individual mass flowrates directly. Inferring the mass flowrates from a collection of less direct measurements gives scope for large uncertainties to develop.

4.2 In such systems the interpretation of signals from some instruments often requires precise measurements from other instruments. An uncertainty in one measurement can therefore have considerable knock-on effects.

4.3 A full uncertainty analysis of a typical multiphase metering system has shown the minimum uncertainty that can reasonably be expected is 10 per cent, and this occurs when the phase fraction approaches unity (ie nearly single phase).

4.4 As the phase fraction reduces, the percentage uncertainty in the individual mass flows increases and can be over 100 per cent as the phase fraction approaches zero.

4.5 In the light of 4.3 and 4.4 it is <u>essential</u> that multiphase flowmeter uncertainty data is quoted along with the phase fraction at which it applies.

4.6 The complexity of specifying multiphase flowmeter uncertainties will inevitably lead to confusion, and it is therefore of paramount importance that a standardised method of quoting the uncertainties is developed in the near future which is easy for manufacturers to understand and comply with, yet conveys the maximum amount of information to the user. NEL are actively pursuing suitable techniques at present.

ACKNOWLEDGEMENT

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REFERENCE

MILLINGTON, B. C. An uncertainty analysis for the proposed design of the NEL/SGS multiphase flowmeter. NEL Flow Measurement Memo 418. East Kilbride, Glasgow: National Engineering Laboratory, September 1991.

LIST OF TABLES

LIST OF FIGURES

TABLE 1

THE PERCENTAGE UNCERTAINTY IN THE OIL MASS FLOWRATE MEASUREMENTS AS A FUNCTION OF FLOW COMPOSITION

(The water cut is the percentage water in the liquid)

		Gas fraction in the multiphase flow, (%)								
		10	20	30	40	50	60	70	80	90
	5	13.77	14.03	14.40	14.96	15.85	17.37	20.29	26.98	49.43
	10	13.91	14.17	14.53	15.07	15.93	17.41	20.26	26.80	48.91
	15	14.15	14.39	14.73	15.25	16.08	17.52	20.29	26.69	48.42
	20	14.47	14.70	15.03	15.53	16.33	17.71	20.39	26.63	47.98
	25	14.90	15.12	15.43	15.91	16.67	17.99	20.58	26.64	47.59
	30	15.46	15.66	15.96	16.41	17.13	18.39	20.87	26.74	47.26
	35	16.16	16.35	16.63	17.05	17.73	18.92	21.29	26.95	47.01
	40	17.04	17.21	17.47	17.86	18.50	19.62	21.86	27.29	46.84
Water	45	18.13	18.30	18.53	18.90	19.48	20.53	22.63	27.80	46.79
Cut	50	19.51	19.66	19.87	20.20	20.74	21.71	23.66	28.55	46.90
(%)	55	21.25	21.38	21.58	21.88	22.36	23.24	25.04	29.60	47.22
	60	23.49	23.61	23.78	24.05	24.48	25.27	26.89	31.10	47.86
	65	26.44	26.54	26.69	26.92	27.30	27.99	29.44	33.24	48.99
	70	30.44	30.53	30.65	30.85	31.18	31.77	33.02	36.39	50.91
	75	36.13	36.20	36.31	36.47	36.74	37.23	38.29	41.16	54.17
	80	44.77	44.83	44.91	45.04	45.25	45.65	46.49	48.84	60.00
	85	59.32	59.36	59.42	59.52	59.68	59.97	60.60	62.38	71.28
	90	88.63	88.66	88.70	88.76	88.87	89.06	89.48	90.67	96.88
	95	177.04	177.05	177.07	177.11	177.16	177.25	177.46	178.05	181.22

TABLE 2

THE PERCENTAGE UNCERTAINTY IN EACH OF THE PARAMETERS USED TO CALCULATE THE OIL, WATER AND GAS MASS FLOWRATES

Path length of gamma ray across the pipe	2.0
Gamma densitometer calibration count rate	0.5
Gamma densitometer count rate	1.0
Oil mass absorption coefficient	5.0
Water mass absorption coefficient	5.0
Gas mass absorption coefficient	5.0
Liquid sample representivity	1.0
Water monitor (vibrating tube densitometer)	0.5
Oil density	1.0
Water density	0.5
Gas density	4.0
Total volumetric flowrate	3.0

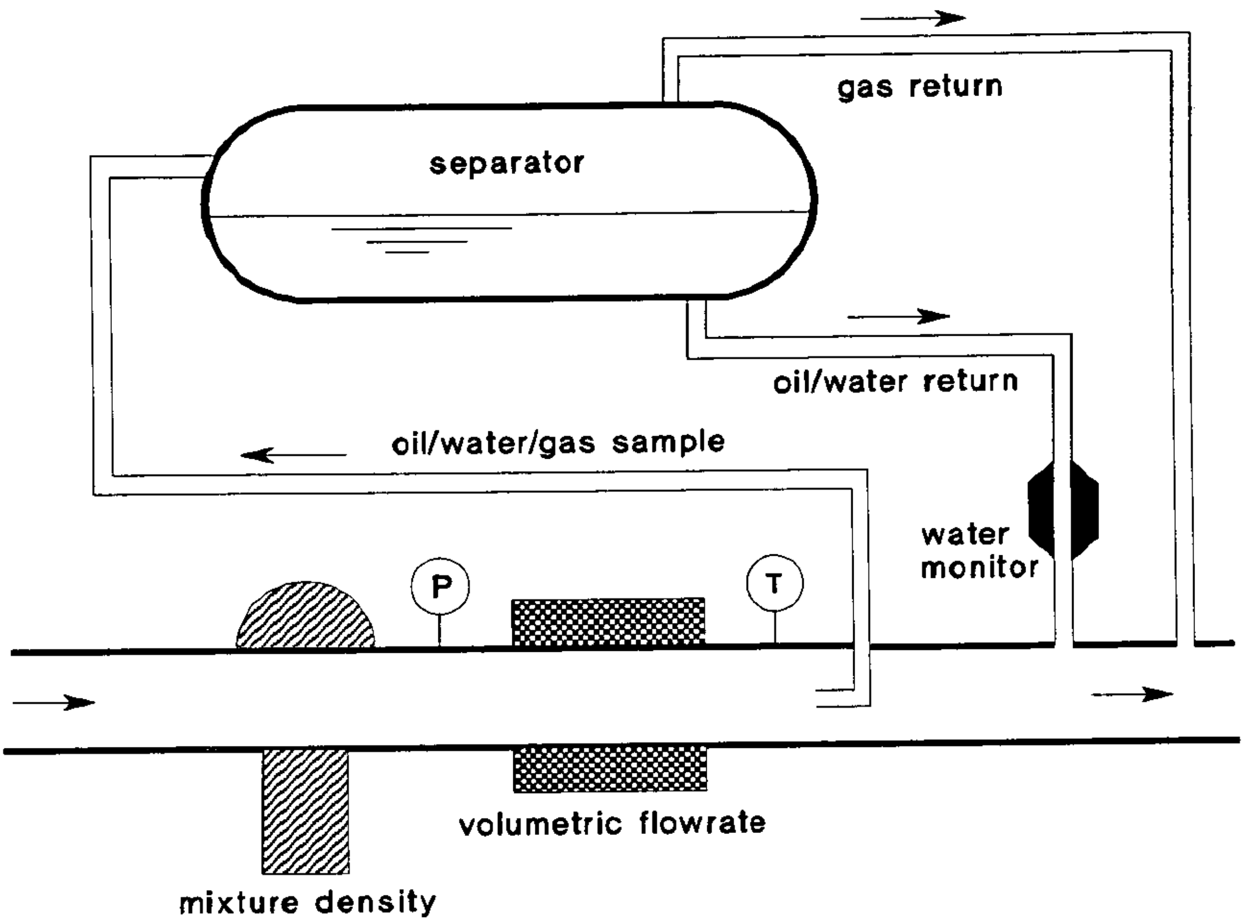

Fig.1 Schematic Diagram of a Multiphase Metering System