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Required Operating Envelope of Multiphase Flow Meters for Oil Well Production Measurement

by

Mr. C.J.M. Wolff,
Shell Researc, Rijswijk,
The Netherlands

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REQUIRED OPERATING ENVELOPE OF MULTIPHASE FLOW METERS FOR OIL WELL PRODUCTION MEASUREMENT

C.J.M. Wolff
Shell Research Rijswijk

SUMMARY

This paper presents a method which is useful in specifying the performance of multiphase flow meters. The first topic often raised in a discussion on the performance of multiphase flow meters is "accuracy". We propose that the "operating envelope" of a meter, which can be defined as an area on the two-phase map of gas and liquid flow rates, should be considered. First the production rates of wells are presented on a two-phase map for a number of oil fields. It is shown that the majority of these wells produce with gas volume flow fractions at well head conditions around 90%, with a range between 50% and 99%. Subsequently, the operating envelopes of some known multiphase meters are estimated. Unfortunately, the performance results published do not always permit a complete assessment of the operating envelopes. In those cases the published data are complemented with theoretically derived characteristics.

It appears that the estimated operating envelopes of the meters leave a significant number of the studied wells uncovered. Lack of coverage is particularly prominent for gas volume flow fractions above 90%. It is feared that this may be more generally the case. How severely surging well production affects a meter's potential performance is another aspect which should be further investigated.

INTRODUCTION

During the past year a number of development projects on multiphase flow meters have reached the stage of prototyping, and laboratory and field trials, so that once again the old question has arisen of how to characterise their performance. Everyone working in this field must have participated more than once in discussions on whether the target accuracy of a multiphase meter should be 10%, 5% or even better. However, there are other equally important characteristics which are not usually addressed: for example, the *operating envelope*, which is the multiphase equivalent of the range of a single-phase flow meter, and the ability of a meter to cope with *fluctuating flow rates*. Whilst these features have a fairly simple definition for single-phase flow meters, the definition is not obvious for multiphase meters. This paper discusses how to characterise and specify the performance of multiphase meters and introduces a graphical representation of the operating envelope. Typical well production characteristics and requirements are presented for a number of oil fields and the characteristics of a number of well-known multiphase meters are then evaluated against the fields. It thereby becomes apparent that it is much more difficult to develop an adequate multiphase meter for some field applications than for others.

TWO-PHASE MAP

There are a number of ways the production of an oil well, and hence the output of a multiphase meter, can be presented. The user of the measurement results usually wants to see:

Oil flow rate
Water flow rate
Gas flow rate

It is customary in the oil industry to express these quantities at standard conditions. However, from a measurement point of view this is pointless, since a meter will only see actual conditions. Therefore this paper will only consider actual conditions.

Other ways of presenting the measurement results are:

Gross liquid flow rate
Watercut (or BSW)
Gas Volume Flow fraction (GVF)

or

Gross liquid flow rate
Watercut
Gas flow rate

Obviously, the above quantities can simply be converted from one set to the other. However, the importance of the difference between the sets becomes apparent once uncertainty intervals are assigned to the quantities presented. It is our experience that the latter two sets have definite advantages over the first set. This is because they separate the specific problems of two-phase fluids (gas/liquid) from the liquid composition aspects (watercut). An even more important argument is that it allows graphical presentation of the flow rate data on a so-called two-phase map (Fig. 1). The map is similar to the well-known Mandhane map. Gas flow rate is along the horizontal axis, and liquid flow rate along the vertical one. Since the scale of the map is logarithmic, the diagonals of the map represent lines of constant gas–liquid ratio or gas volume flow fraction (GVF). This is a useful feature, since it will become clear from the field data that the gas volume flow fraction is probably the most critical parameter in multiphase metering. It appears that the majority of wells can be plotted on the map when the gas flow rate scale runs from 100 to 100 000 m^3/d (actual), and the liquid scale from 10 to 10 000 m^3/d. Note that the main diagonal of this square is the line of approximately 90% gas volume flow fraction.

WELLS AND FIELDS PLOTTED IN THE TWO-PHASE MAP

We have plotted the reported production of wells on the two-phase map for a number of fields. In some cases the reported data were at test separator conditions, in other cases they were at flowing tubing head conditions. The significant difference is that the lowest GVFs possible are found at flowing tubing head pressure, ahead of the choke. Further downstream the GVF only increases.

The data presented are for fields from different parts of the world. The selection was not systematic, but it is believed to be fairly representative (although this cannot be proven). The names of the fields have been replaced by codes, if the data are not in the public domain.

Fig. 1 shows a field in the UK sector of the North Sea, often considered typical for future (prolific) subsea wells. Data are at the test separator pressure of 3300 kPa.

Fig. 2 shows two new fields in the UK sector of the North Sea. It is not known whether data of #1 are at test separator or flowing tubing head pressure. The box for field #2 represents a general design well for another field. The lower gas volume flow fraction (76%) is at flowing tubing head pressure, whereas the higher GVF (92%) is at test separator pressure.

Fig. 3 is from Gullfaks B. The data are based on information taken from Refs. [1] and [2]. The well data are at a test separator pressure of 7600 kPa. Note that the GVF never exceeds 50%.

Fig. 4 shows some 45 wells in the Danish sector of the North Sea, taken at test separator conditions. The GVFs range between 80 and 98%.

Fig. 5 is an example of a field in South East Asia with gas lift: There are many wells with small production rates per well. Some wells do not need gas lift. They produce typically at a higher liquid rate than the gas lifted wells. All gas rates are given at flowing tubing head pressures, i.e. they are minimum values. The GVFs for the naturally flowing wells are less than for the gas lift wells. GVFs of 99% for both types of wells are not uncommon.

Fig. 6 shows data from Gabon at a test separator pressure of 600 kPa(a).

The following picture emerges from the data. For the North Sea the gas volume flow fractions are typically between 50 and 90%. The GVF of Gullfaks B of maximum 50% does not seem to be very representative for the other fields. The field in the Danish sector (Fig. 4) even has GVFs between 80 and 98%. The gas lifted wells observed seem to be operated typically at GVFs of 90% and above, so that GVFs of 99% are not exceptional. We also see that the gas lifted wells of the example in Fig. 5 have typically lower production rates than the naturally flowing wells. It should be noted that one would generally expect future subsea and offshore wells to be "prolific", i.e. producing at oil rates above 1000 m^3/d, since this will be required by the economics of new developments. It is concluded from the data that gas volume flow fractions of oil wells are typically in the range of 50% to 99%.

PRESSURE DROP

A very important characteristic of a multiphase meter is its pressure drop. Of course there are cases where the flowing tubing head pressure is very high and pressure is available to drive the fluids through the meter. But even in such cases it is probably not advisable to dissipate too much energy over the meter, as energy dissipation is tantamount to wear. Another, operational reason for limiting the pressure drop is in the envisaged application of the meters in satellite production stations. The available well head pressure will be required to transport the fluids from the well head to a gathering station or mother platform. Multiphase boosting is difficult and costly. The approach should therefore be to conserve the available pressure and not to waste it in a meter. A one bar (100 kPa) pressure drop is probably the maximum that can be tolerated, but even that could lead to a significant reduction of the production rate, and hence represent a high economic value. So the lower the pressure drop the better. In gas lift systems with flowing tubing head pressures of only 500 kPa, it is obvious that an extra loss of 100 kPa can be very important.

EXPECTED OPERATING ENVELOPES OF METERS

Four multiphase meters for which sufficient published data could be found were selected for analysis. These are (1) a combination of a positive displacement meter and a gamma ray absorption meter, (2) a combination of venturi flow meter and gamma ray absorption meter, (3) a meter of unknown principle but which explicitly gives its operating envelope, and (4) a flow meter based on slug flow.

1) Combination of PD-meter and Gamma ray. PD-meters typically have a maximum total volume flow rate, above which the friction in the internal moving parts becomes too high. One manufacturer of multiphase meters comprising a PD-meter indicates that the total pressure drop in gas will be lower than that in liquid, but more detailed information is not available [3]. So for simplicity's sake it will be assumed, that the maximum throughput of a PD-meter is given by a line of constant volume flow rate on the two-phase map. An example of such a line (at 2400 m^3/d) is shown in Fig. 7. The flow rate is selected from Ref. [3] as corresponding to one bar pressure drop over the 3"/4" version. A unit of this size was also used for the reported experiments [4]. Lines for larger or smaller sizes can simply be constructed by shifting the curve along the diagonal lines of constant GVF.

Many multiphase meters reported in the literature comprise a gamma ray composition meter. It is used to determine the average density of the mixture, and subsequently to split the total fluid flow into a gas and a liquid fraction. From basic principles we can expect that for very high gas volume fractions, the ability to determine the liquid flow rate will diminish [5]. Publications on the experimental performance of some multiphase meters confirm this [4, 6]. Results for gas volume fractions above 85% are not even reported. It should also be noted that it is virtually impossible to obtain a homogeneous mixture for GVFs higher than about 80%. This results in additional measurement uncertainties. Based on the above points, we selected a typical upper limit for such gamma ray densitometers of 85%. In Fig. 7 a line is drawn at 85% GVF, which together with the maximum throughput curve produces a theoretical operating envelope for the multiphase meter studied.

2) Combination of venturi flow meter and gamma ray. The maximum throughput of such meters is governed by the resultant pressure drop over the venturi. From our work with venturis we have learned that in multiphase flow, recovery of the differential pressure is insignificant. For practical purposes the pressure loss can be assumed to be equal to the differential pressure. If one further assumes that the fluid is homogeneous (this is not the case due to slip between the phases, but it does not invalidate this argument) then for a given throat diameter the maximum throughput of a venturi can be calculated. See Appendix A for details of the calculation. In Fig. 8 two lines of 100 kPa pressure loss over a 50 mm throat diameter are given for a combination of water and gas, one for a gas density of 5 kg/m^3, the other for 50 kg/m^3. Note that for GVFs smaller than 90% the difference between the two lines is small. We can also calculate that in order to cope with "prolific" wells, such as shown in Figs. 1 and 3, venturi throats of 70 or 100 mm diameter are required. This is a potential problem for dual energy gamma ray composition meters [6] that use very soft gamma rays, which can be strongly attenuated over such a long absorption path. The general argument about loss of accuracy with increasing GVF as presented under (1) is equally valid in this case. Therefore in Fig. 8 the theoretical operating envelope for this meter is completed with a similar line of maximum GVF = 85%. This is supported by the published data [6].

3) Agar multiphase meter. Recently a brochure was published by a manufacturer of multiphase meters [7], which does present the operating envelope of the products on offer as an area on the two-phase map. Unfortunately the operating principle of the meters is not disclosed, apart from the statement that they do not comprise a gamma ray absorption meter. To allow a fair comparison with other meters, the data from the brochure are represented in Fig. 9, but this time on the same scale as used throughout this paper. Note that although these meters have no gamma ray incorporated, the part of the operating envelope exceeding the 90% GVF line is also rather small.

4) Flow meter based on slug flow. One meter design makes use of and is therefore dependent on the occurrence of slug flow [8]. So to a first approximation the operating envelope of this meter will coincide with the slug flow area on the Mandhane map. In Fig. 10 the slug flow area ("intermittent flow") is depicted as calculated by a proprietary two-phase flow computer program for the example of a field in Gabon (Fig. 6). The slug flow area is seen to extend to or slightly beyond the 90% GVF diagonal. In reality the wells proved to be slugging indeed, and good measurements were made with the slug flow meter [9]. By selecting a different flow line diameter than the 4-inch line which was applicable, and a corresponding meter, the slug flow area can be shifted along the constant GVF diagonals.

FLUCTUATING FLOW RATES

The information usually reported from well tests contains only average values of liquid flow rate, BSW (base sediments and water) and gas flow rate. More detailed information about how the values fluctuate may be available but it is not reported. From a recent analysis of a limited number of detailed recordings of well tests, it became apparent that wells can exhibit strong surging behaviour. Surge periods of 15 minutes to one hour were observed. Obviously this has an impact on the requirements for multiphase meters. An example of a surging well is reported by

Brown [9] and also Cary et al. [10] report surging of production flows. The actual production occurs in peaks that are much higher than the average flow rate. The range of a multiphase meter has to be selected in order to cope with the peaks, but one does not know in advance how high the peaks will be. Obviously, if the meter range is too high, this will be at the expense of accuracy. From field measurements with multiphase flow meters and noise measurements made on a number of well heads, we already know that this kind of surging is not exceptional. Further investigation into the magnitude of this phenomenon seems necessary.

DISCUSSION

The usefulness of representing well production data and meter operating envelopes on a two-phase map has been shown. It allows an easy evaluation of the suitability of a specific meter for a certain well or field. It is also possible to plot observed accuracies in the map. This can be done either in the form of contour lines of constant error, or by plotting the reference value and the observed value for each observation on the same map. We have found both techniques useful. The main advantage of showing the data on the two-phase map is that full consideration is given to the conditions pertaining to the measurement, rather than primarily to the size of the measurement error.

Manufacturers of multiphase meters should be encouraged to present the operating envelopes of their meters graphically as an area on the two-phase map. This would allow users to assess quickly whether a meter would be useful for their application.

If we compare the operating envelopes of the multiphase meters discussed with the characteristics of the fields presented, then we see that many wells are not covered by the meters. Lack of coverage is particularly prominent for GVFs above 80 or 90%. It is feared that this applies to many more wells than those presented. It would seem that there is generally a need for multiphase meters that can cope with GVFs higher than 80%, where an upper limit of say 99% seems to be a good target.

One way of keeping the GVF as "seen" by a meter at a low value would be to install the meter as far upstream as possible, e.g. upstream of the choke. However, it should be realised that this would need a meter with a higher pressure rating. Whether or not this is attractive depends on the actual value of the pressure rating and the specific characteristics of the multiphase meter. Safety aspects also have to be taken into account.

CONCLUSIONS

(1) Typically oil wells produce with gas volume flow fractions between 50% and 99%.

(2) Reasoning from basic principles, many multiphase meters currently being developed are likely to have difficulty in achieving adequate performance for the higher gas volume flow fractions.

(3) A graphical presentation of the operating envelope of a multiphase meter allows easy evaluation of its suitability for a certain job.

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APPENDIX A Approximate pressure drop over a venturi in two-phase flow

Experience has shown that in two-phase flow, the pressure loss with a venturi flow meter is almost equal to the signal pressure. Hence the pressure recovery is negligible. The pressure drop can then be approximated by

$$dp = \tfrac{1}{2}\rho_t * v_t^2$$

where ρ_t is the mixture density and v_t is the mixture velocity in the venturi throat.

Assuming homogeneously mixed fluids gives

$$\rho_t = \alpha\rho_g \ + \ (1-\alpha)\rho_L$$

for the mixture density, where α is gas volume flow fraction, and ρ_g and ρ_L are the densities of gas and liquid, respectively.

Using $\alpha = Q_g/(Q_g+Q_L)$, and $v_t = Q_t/(\pi d^2/4)$ the pressure drop formula can easily be converted into

$$\rho_g * Q_g^2 + (\rho_g+\rho_L) * Q_g * Q_L + \rho_L * Q_L^2 = 2 * dp * (\pi d^2/4)^2$$

where Q_L and Q_g are the liquid and gas volumetric flow rates and d is the diameter of the venturi throat.

As an example we shall take dp = 100 kPa, d = 50 mm and ρ_L = 1000 kg/m^3 and ρ_g = 5 and 50 kg/m^3, respectively. The formula then reduces to

$$Q_L^2 + (1+\rho_g/\rho_L) * Q_L * Q_g + (\rho_g/\rho_L) * Q_g^2 = 0.0278\ \mathrm{m^3/s})^2$$
$$= (2400\ \mathrm{m^3/d})^2$$

The graphs are symmetrical around the diagonals given by

$$Q_g/Q_L = (\rho_L/\rho_g)^{1/2}$$

It then follows that for ρ_g = 5 kg/m^3 the graph is symmetrical around α = GVF = 93%, and for ρ_g = 50 kg/m^3 this is around GVF = 82%.

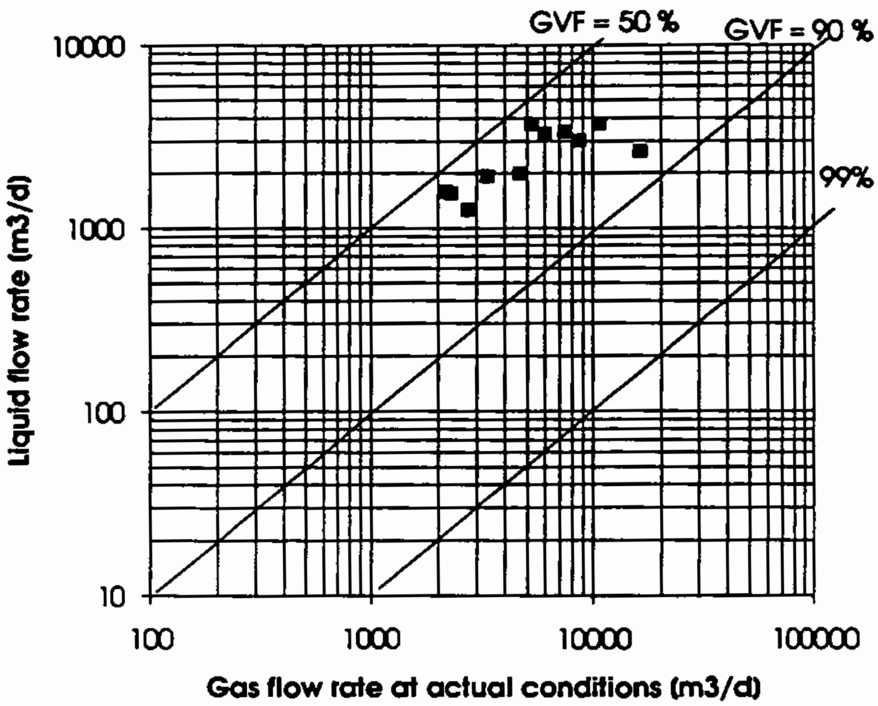

FIG.1 Two-phase map showing a typical field in the North Sea UK sector

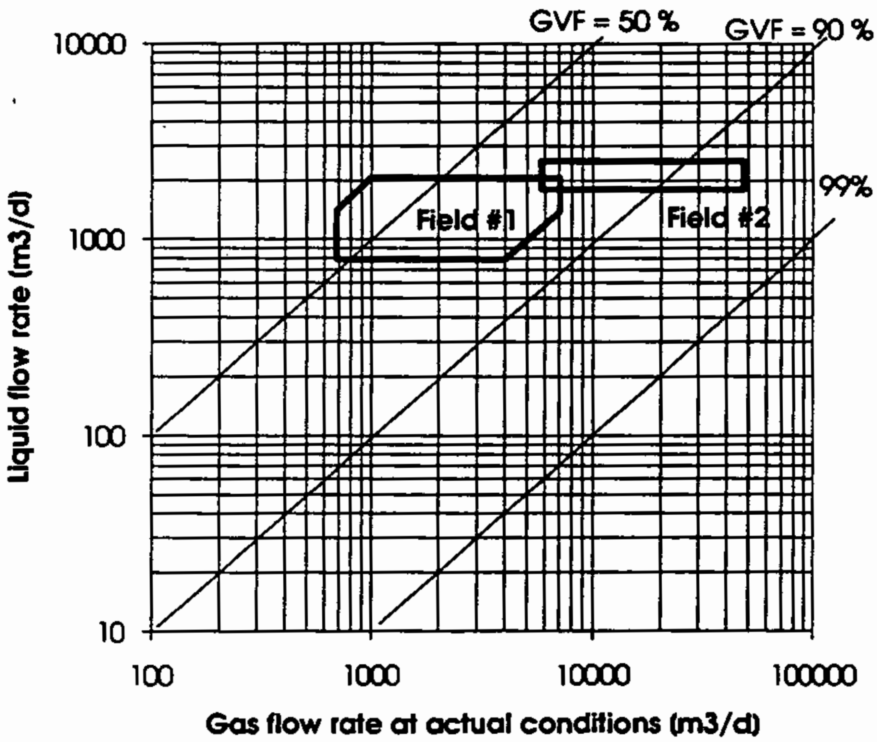

FIG.2 Two-phase flow map showing operating envelopes of two prospects in the North Sea UK sector

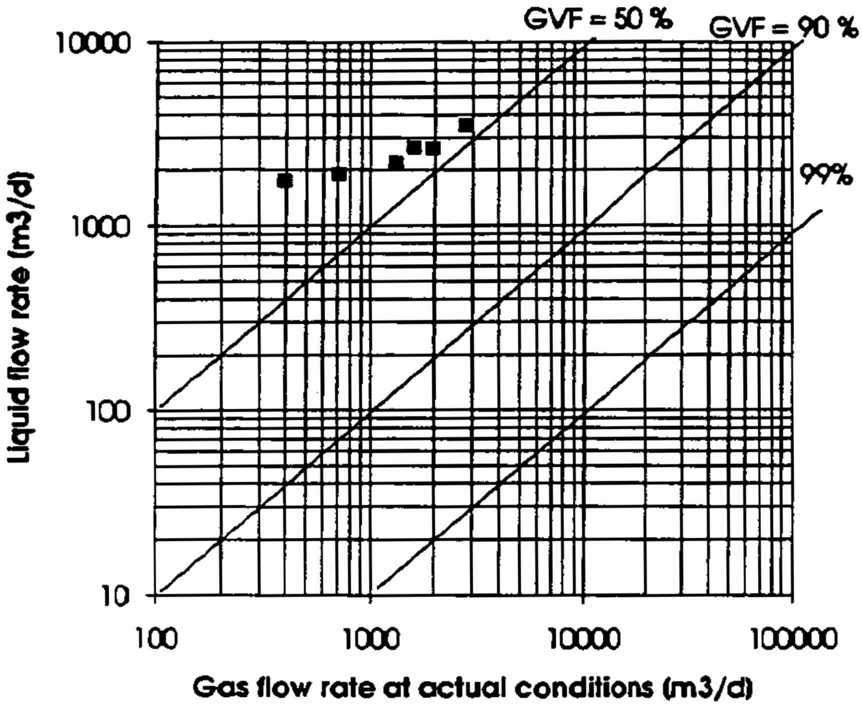

Fig.3 Gullfaks B wells in a two-phase map at test separator conditions (Interpretation from data published in (1) and (2))

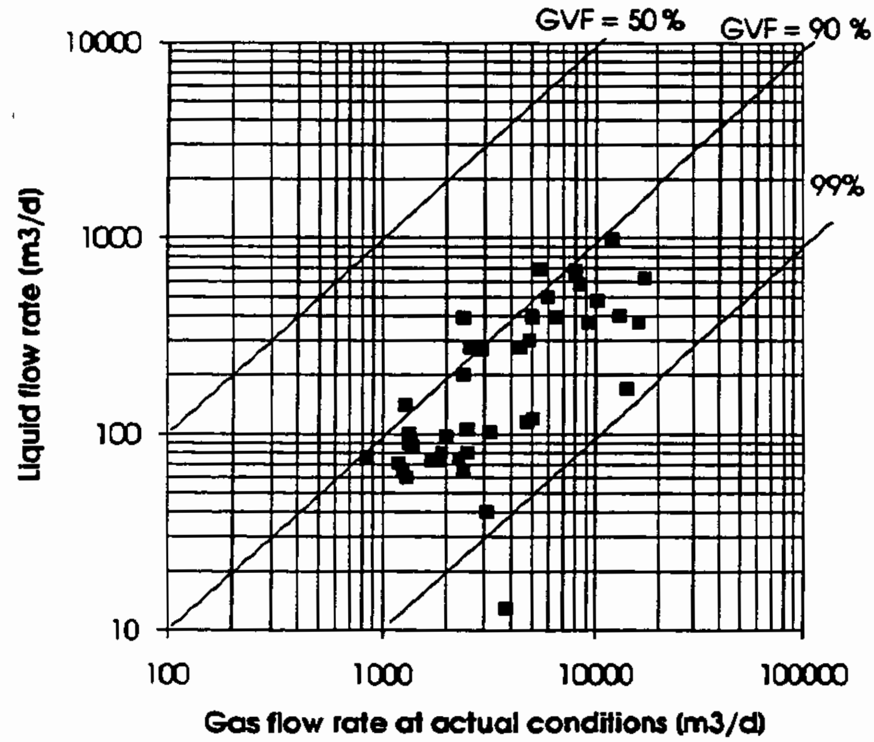

Fig.4 Two-phase map with wells from field in Danish sector

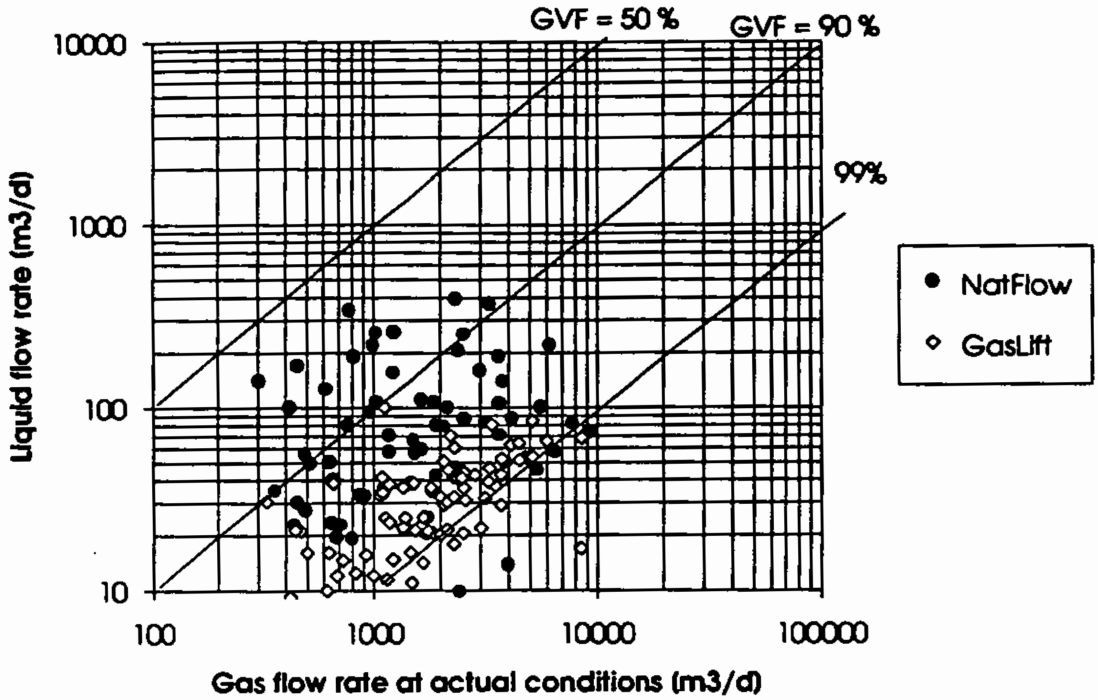

Fig.5 Two-phase map showing wells of a field (#1) in S.E.Asia at flowing tubing head pressures

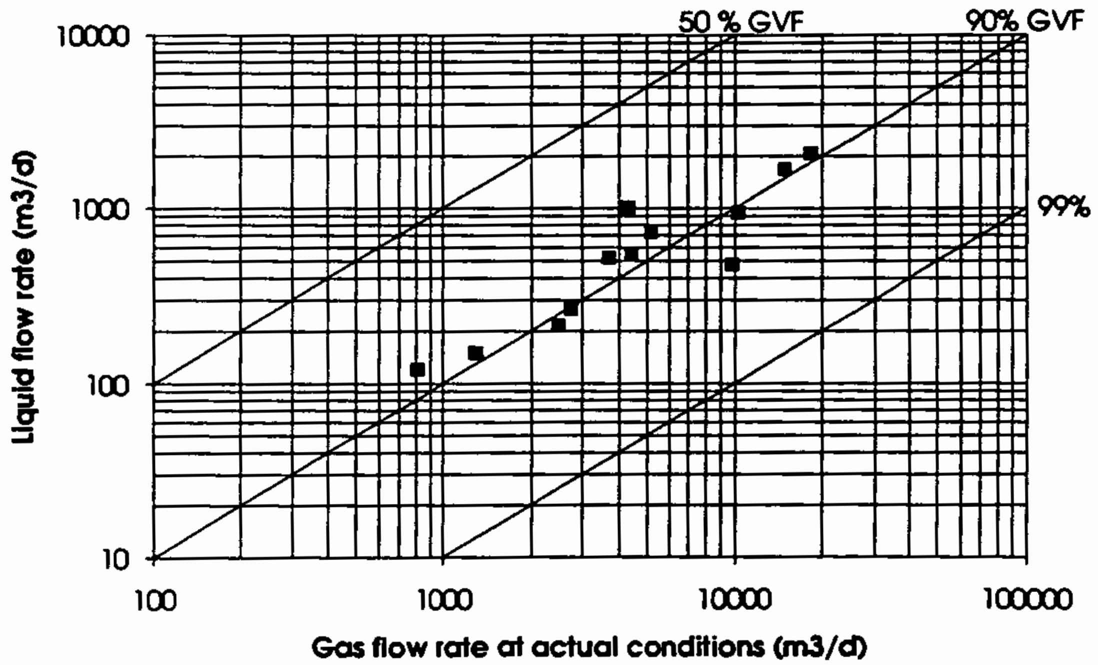

Fig.6 Two-phase map showing wells of field in Gabon at test separator conditions, 600 kPa(a)

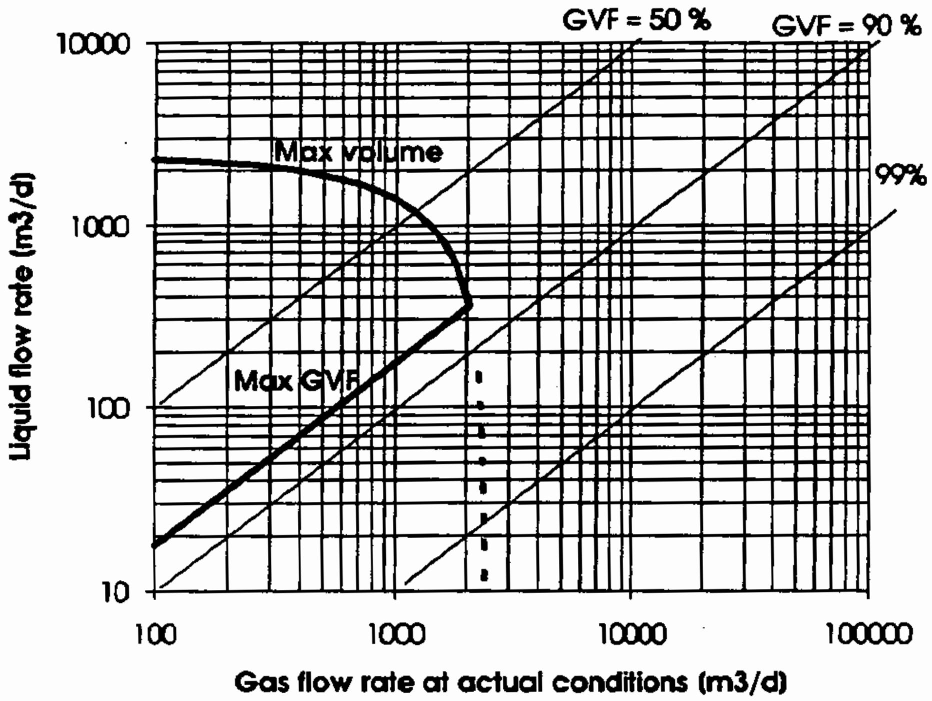

Fig.7 Theoretical shape of operating envelope of a PD-meter/gamma ray flow meter rated at 2400 m3/d

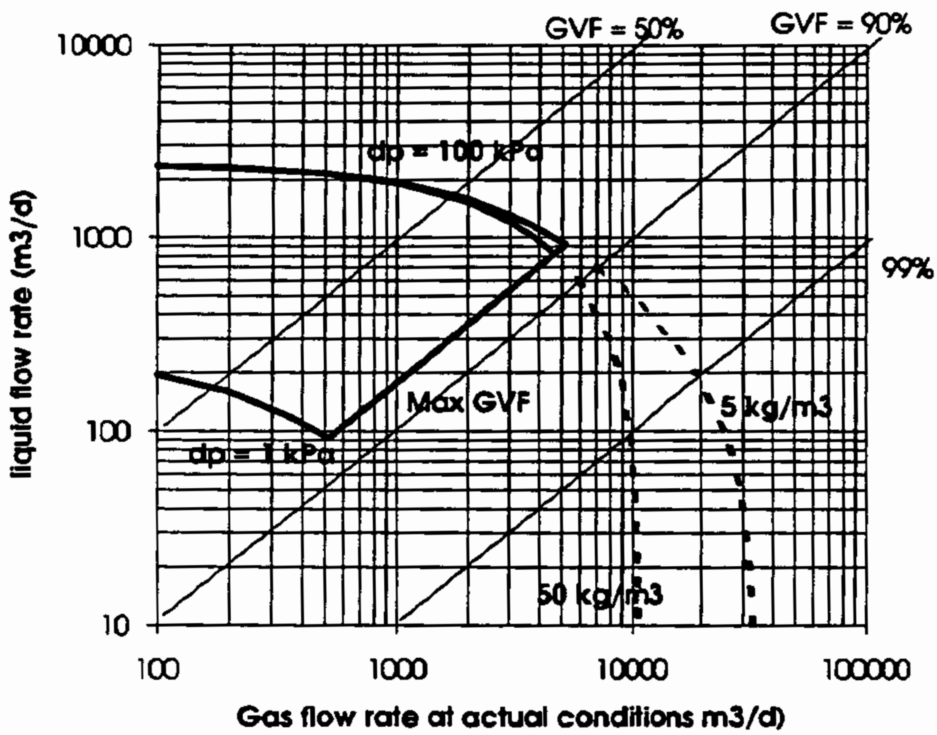

Fig.8 Theoretical operating envelope of a venturi/gamma ray meter with 50 mm diameter throat (Gas densities 5 and 50 kg/m3)

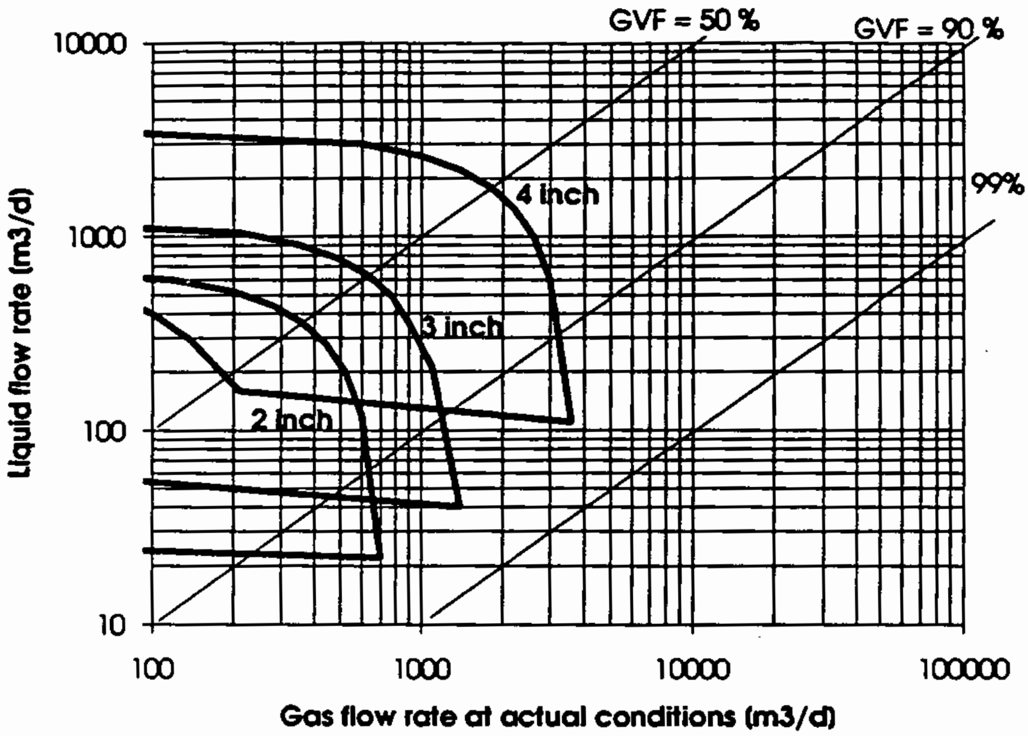

Fig.9 Operating envelopes of three Agar multiphase meters (Data taken from company brochure)

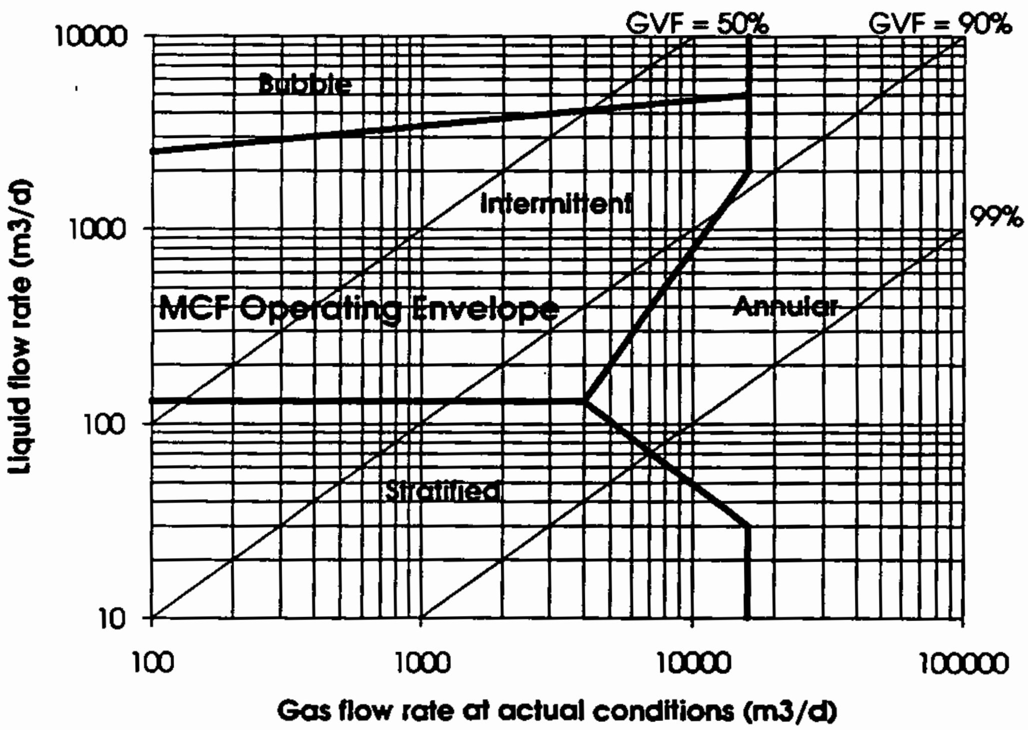

Fig.10 Expected operating envelope for 4" MCF slug (intermittent) flow meter for the field in Gabon shown in fig.6.