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Paper 5.2

Multiphase Flow Metering Per Well – Can It Be Justified?

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Multiphase Flow Metering per Well, can it be justified ?

by

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Summary

Currently Multi-Phase Flow Meters (MPFM's) are developing from a "nursing technology" to "mature technology" and an increasing number of meters are being installed worldwide. However, the majority of the MPFM installations are still shared by a number of wells, i.e. replacement of the conventional test separator and only a few applications have MPFM's installed per individual well. In the decision whether to implement a shared MPFM or single-well MPFM, various aspects need to be taken into account, e.g. the uncertainty in MPFM flow rate measurements, value of the MPFM information and the various hardware and operating costs related to MPFM's. With respect to the later MPFM's are often considered too expensive to be included by default on a per well basis.

Over the last year Shell has spent a significant effort in evaluating MPFM's, which are "low cost", are relatively compact in size and do not use radioactive sources (these sources call for additional licensees, procedures, staff, costs, etc.). In addition multiphase metering concepts that have the potential to be further developed for the use in downhole applications also have gained a lot of interest. A new relatively low cost and compact MPFM concept, manufactured by FlowSys has the potential to be used on a per well basis. The meter has been extensively evaluated at a production station in Gabon (May/Jul 2001) and in a test facility, using live crude oil and natural gas, in China (Sep/Oct 2001 and Aug 2002). The FlowSys concept does not require a radioactive source but instead uses advanced electric permittivity and conductivity measurements combined with a conventional Venturi for both composition and gas/liquid velocity measurement. The test results revealed that, within the operating envelope of the meter, relative errors in the order of 10% for liquid and gas and absolute errors of 5% in watercut are achievable.

1 Introduction

In the area of production measurement, three major hardware developments have taken place during the last decade; the introduction of Coriolis meters for single-phase liquid, the large scale implementation of UltraSonic flow meters for single-phase gas flow rate measurement and the development and implementation of the first series of flow meters for multi-phase and wet gas flow regimes. Initial developments for the two single-phase flow meter concepts started in the early 80's and the instruments have been applied in the field since the early 90's. It has taken about 10 years from the initial development to reach the stage of fully accepted field use. The advantages of these two meters over conventional flow measurement equipment (orifice plate, Venturi or turbine meters) have been demonstrated in a large number of publications. Although their applications are still more complex than conventional flow metering devices, the Coriolis meter and the UltraSonic flow meters have now gained an appropriate place in the oil and gas industry and are being applied on a large scale, both in new projects and in revamping existing facilities. Internationally accepted standards for these meters have been developed or are under development. However, with the introduction of these two meters, the oil and gas industry has not made a drastic simplification in the infrastructure and process facilities. Layout and configuration of production facilities have remained the same

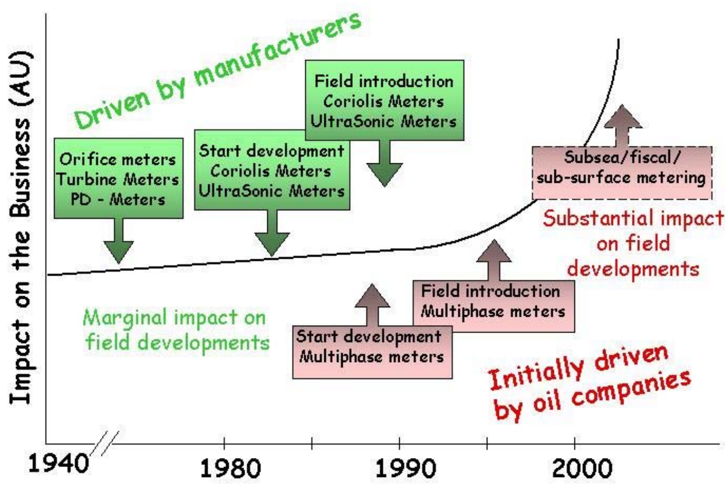


Figure 1, Impact on the business of new metering equipment.

over the years; in fact one single-phase metering concept was replaced with another single-phase metering concept.

During the late 80's the oil and gas industry started to realise that the availability of MPFM's could have an even much larger economic impact on the infrastructure of oil and gas developments, e.g. replacement of test separators, removal of subsea test lines and manifolds. In particular for sub-sea applications these cost benefits are huge. This was the reason why the development of MPFM's, in contrast with the above-mentioned single-phase flow meters, was primarily driven by the oil industry (see figure 1). The late 80's and the early 90's saw various research programs being initiated, both in-house with the oil companies and through Joint Industry Programs (JIP's). At present we see MPFM's being installed in the field but it is still too early to conclude that they have been fully utilised and accepted in the field. For sure the developments have not been completed. In comparison with the earlier mentioned Coriolis and UltraSonic flow meters, the MPFM is far more complex, both in terms of hardware and in terms of fluid flow dynamics. There is still a long way to go before the industry has reached the stage of routine field acceptance and more effort is required. This, in particular, is the case with MPFM's used for fiscal or allocation purposes and for MPFM's for sub-surface applications.

Worldwide the application of MPFM's is growing. Some companies have adopted the philosophy that MPFM's are the first choice for new developments and only if the application of the MPFM is not suitable the fall back application of a test separator is used.

The ultimate vision is to have a low-cost "plug & play" MPFM on every single wellhead or downhole MPFM's in multi-lateral wells. Although not yet feasible there are indications that within the next couple of years a significant step in that direction will be made. Also in the near future, translating the surface MPFM technology into concepts that are suitable for the downhole applications is the obvious next step. Downhole multiphase flow conditions are generally more favourable for MPFM's applications than surface conditions, this because downhole measurement is often done under much lower Gas Volume Fractions (GVF's). The challenges, however, are in the designs for high temperature and high pressure, the reliability of the equipment and in particular the size of the equipment.

2 Impact of MPFM's on production facilities

The conventional way of developing smaller fields, in the vicinity of an existing production facility, is through the use of a test separator on the existing facilities. This can either be an existing test separator or a new test separator that is fully dedicated for the satellite production. In this way the satellite platform is kept as simple as possible with. Only wellheads and a test and bulk header are required to direct the production streams to the test- or bulk separator on the existing platform (see figure 2). With such a configuration extreme care should be taken on how representative the well test is. The further the satellite is located from the existing facilities the more carefully the test results should be interpreted. If a new dedicated well test unit for the satellite development is considered, the space and weight limitations, on the existing facilities, often results in the selection of a MPFM. This only has economic benefits; it does not take away the measurement problems related to representative testing. A rough indication for test separator cost is in the order of 800 to 1500 kUS$ (dependent on size and pressure), this is for onshore and for topside applications, respectively. Above costs are only hardware costs, i.e. the test separator including its associated instrumentation. The operating expenditures should also be taken into account and it is obvious that for offshore applications the operational expenditures are much higher than for the easier accessible onshore locations. At present, rough indications are in the order of 20 k$ to 80 kUS$ per year for onshore and topside locations, respectively. For the presently available commercial MPFM's, a rough price indications is between 100 and 250 kUS$ and there seems to be a relatively small difference between onshore and topside applications. The good news is that at present also meters for under 100 kUS$ have been offered to the market. Hence, MPFM's are approx. a factor 5 - 10 cheaper than test separators. MPFM's for subsea applications are roughly a factor 2-3 higher than their topside equivalent.

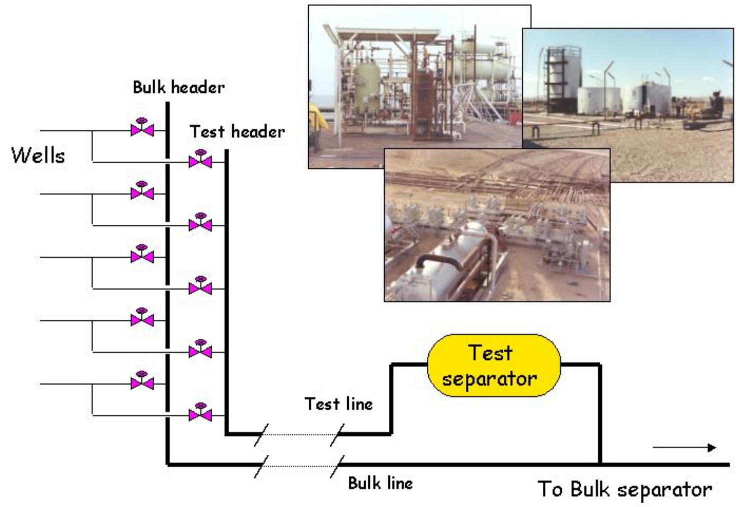


Figure 2, Conventional way of linking satellite field to existing facilities

In terms of operational expenditures, it is often mentioned that MPFM's require less maintenance than traditional test separators. Although this might become the case in the future, it is clearly not the case for the present situation. Lack of experience with MPFM's makes it necessary to carefully guide the implementation of this new technology. Dedicated staff is required to commission the equipment, to execute calibrations, to provide necessary maintenance and manage all the softer issues. Costs during the implementation phase, which might be as long as a few months, may easily run as high as 25% of the multi-phase meter hardware costs, depending on the local circumstances. This is comparable with the operating costs of a test separator. Once the meter is up and running, an estimate for the operational cost is 10 to 40 k$ per year, depending whether it is an offshore or onshore applications. Then the operating costs will become less than that of a test separator. In conclusion a MPFM application offers significant cost savings, both in terms of capital and operational expenditures. However, the implementation phase should not be under-estimated and should be planned well in advance. With all these cost savings that can be achieved, it is vital to spend sufficient effort in the commission, implementation and operator training phase. Allocating insufficient attention will almost certainly increase the later operating costs significantly. Since the replacement of a test separator with a MPFM on the existing production platform can save both capital and operational expenditures, a major further saving can be made if test lines can be stripped from the production facilities. Costs for test flow lines differ significantly in onshore and offshore applications. For carbon steel flow lines of approx. 4-6 inch, costs are in the order of 200-400 k$ per km and offshore costs are a factor 2-4 higher. For higher quality materials (e.g. duplex) costs can be again twice as high. Hence, with the omission of test flow lines major significant savings can be made, at least an order of magnitude higher than the costs of MPFM's. By moving the multi-phase meter to the satellite platform an increase in operating costs is expected (more intervention then only wellheads and manifolds). Above still is under the assumption that the MPFM is shared between wells.

Further stripping of the facilities is possible by replacing the test- and bulk manifold with a multi port selector valve. This type of valve can provide a cost effective method of connecting individual flow lines into a common bulk header and simultaneously provide the ability to direct any of the flow lines to the test facilities. Costs for multi-port selector valves depend on size, pressure rating and material, but a rough estimate is 100 k$. Operating costs seem to be comparable with normal manifold valves and the required plot space for multi-port selector valves is much less than for a test/bulk manifold. The costs for manifolds, e.g. a 5 well manifold, are in the order of 500 k$ and the operating costs per year are estimated at 10 k$. For sub-sea applications the manifolds are almost 10 to 20 times more expensive than for topside applications, this is because sub-sea valves are designed such that they do require a minimum intervention.

From the above it can be concluded that with just one MPFM installation (instead of a test separator) there is a significant economic benefit to be made. This is even true if a worst-case scenario is applied (i.e. low costs for separator, flow line and manifold and high costs for multi-phase metering). Although the end result of a well test with a test separator and a MPFM is the same (both give cumulative oil, water and gas flow rates over the test period but the uncertainties might be different), from a data collection point of view there is an advantage. The MPFM gives continuous information on variations in the production rates, e.g. large variations in the gas flow rate compared to the liquid flow rates, which might indicate that there are problems with the gas lifting system or large variations in liquid production flow rate which might indicate severe slugging of the well. The value of this information should be taken into account as well.

A further increase in the value of the production data is achieved if MPFM's are installed on a per well basis (see figure 3). However, with the above-mentioned capital and operating figures, it becomes clear that a multi-phase meter installation on a per well basis, in a development with more than 4-5 wells, may be difficult to justify with only economic considerations on the facility layout. However, other economical justifications, like reservoir engineering reasons, might be valid to use MPFM's on a per well basis and some examples will be given in the next section.

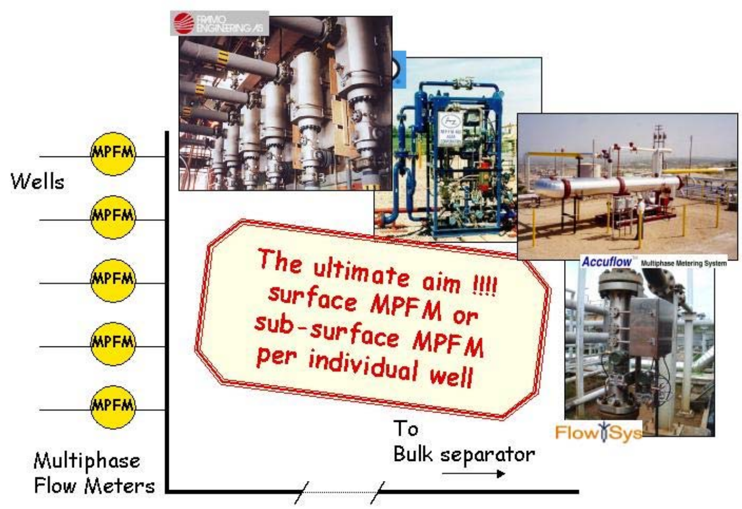


Figure 3, Ultimate aim is to have low-cost MPFM's per well, either at surface or sub-surface

3 The economic impact of well production measurements

Well measurements, whether single-phase or multi-phase, have an economic impact on the business. The implementation of these well measurements not only costs money, but also delivers data that is used in measuring the economic returns and used in decision-making processes. To illustrate this lets take the Ultimate Recovery (UR) for a particular field. Initially only appraisal well test results, logging information, geophysical data; etc is available to determine the UR and its uncertainty. Regular well testing and the production data that become available in the lifetime of the field will be used as input to the reservoir model and consequently lower the uncertainty band of the UR. How fast this uncertainty band will decrease depends on the uncertainty of the information used. With highly accurate data it is obvious that the decrease is faster that with very poor quality data (see figure 4). How much money are we willing to spend on production measurements in order to minimise the risk of further investments or future decisions.

It can be argued that each project has its own optimum uncertainty requirement for the production measurements. It could well be the case, that for a particular project, an accuracy of 25% in oil flow rate is sufficient, or in another project 5% accuracy is required. In the 25% case the application of multi-phase metering becomes suitable where as in the 5% case the application of multi-phase metering is probably not yet suitable. There is an urgent need to better quantify the measurement accuracy requirements for each individual project. Some examples are given below.

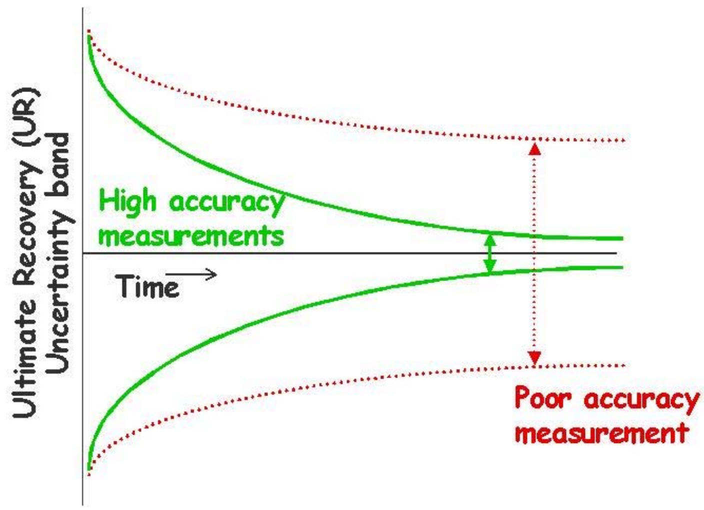


Figure 4, Better quality data reduces the uncertainty in the UR faster.

3.1 <u>Optimising oil production from a thin oil layer</u>

Consider an onshore field with a small thin oil bearing reservoir and horizontal wells to produce the oil (see figure 5). Production is expected to decline very rapidly from a 120,000 bpd to some 20,000 bpd in 6 years time. This means that, if the decline is linear in time, the total oil still to be recovered is approx. 150 million bbl (with a 15 US$/bbl this represents a value of approx. 2.25 billion US$). With a sub-optimum production, e.g. with gas coning in the reservoir and thus excessive gas production from the above gas cap, the oil rim will move upwards. In that case the horizontal wells will show a decrease in oil production and an increase in water production. Note that this is not deferred oil but lost oil, as it can't be produced anymore with the existing layout of wells. How much oil will be lost is difficult to assess but lets take a very conservative approach of only a few percent of the oil not being recovered. In terms of money this is a loss of a few percent of the 2.25 billion US$ or in other words several tens of million US$.

With this amount of money at risk, it is important to see where measurement efforts need to be concentrated on. In this particular field development the gas production, or even better the Gas Oil Ratio (GOR) is a very critical parameter to maximise the total oil recovery. Any sharp increase in GOR (and this can happen in days) will indicate gas breakthrough

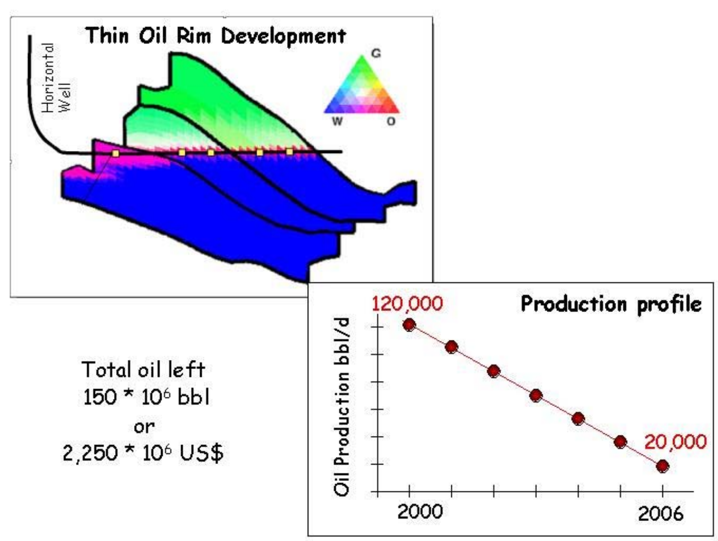


Figure 5, Horizontal wells in a very thin oil reservoir.

and further depletion of the gas cap. When this happens an immediate reduction of the production rate is required to stop gas coning. GOR is not a direct measurement and its value is determined through other measurements like liquid flow rate, watercut, gas flow rate, etc. A sensitivity analyses for the GOR determination shows that the watercut measurement is a very critical measurement and any investment should be focussed on that particular measurement, either with a conventional three- or two-phase test separator or with MPFM's.
In this particular development with approx 100 wells and with several tens of million US$ are at stake, it still is felt that only with MPFM's that fall in the 40-60,000 US$ range realistic considerations for a individual well application is possible. With prices of 80,000 US$ and above it is still required to share a MPFM with a number of wells. However, even with this latter choice, the advantage of using a MPFM over conventional test separators is the fast response and consequently the more frequent testing that can be done (earlier detection of gas breakthrough).

3.2 High watercut abandonment

Many wells produce with high watercut (say > 90%) and at some point in the well life a decision has to be made whether the well should be abandoned or whether production is still economic. At the lower watercut generally the oil revenue is significantly higher than the operating costs, but with increasing watercut the water handling and disposal costs will start to play a more dominant role. As an example lets assume the oil revenue is approx. 100 US$/m^3 (16 US$/bbl) and the water handling and disposal costs are 2 US$/m^3 (0.30 US$/bbl). A simple equation shows that the breakeven point with the above figures is around a watercut of 98%. Once this breakeven point is determined, the question is how accurate the watercut measurement needs to be in order to make a good abandonment decision. If the watercut measurement shows a systematic error (this can be due to a wrong base density in a Coriolis meter based net-oil computer or a wrong parameter setting in a MPFM) the well can be shut in too early or too late. With a systematic over-reading in the watercut measurement the well is shut in too early there is obviously loss of revenue. On the other hand if there is a systematic under-reading in the watercut measurement the well is shut in too late and there is excessive cost for water handling and disposal. Let's take an example well of 500 m^3/d gross liquid production well and a systematic error of only +2% in the watercut measurement, here this could lead to a missed revenue of approx. 380,000 US$/year.

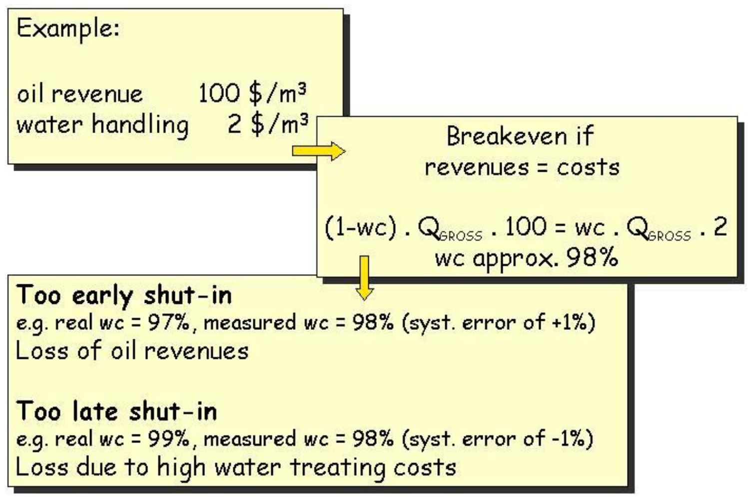
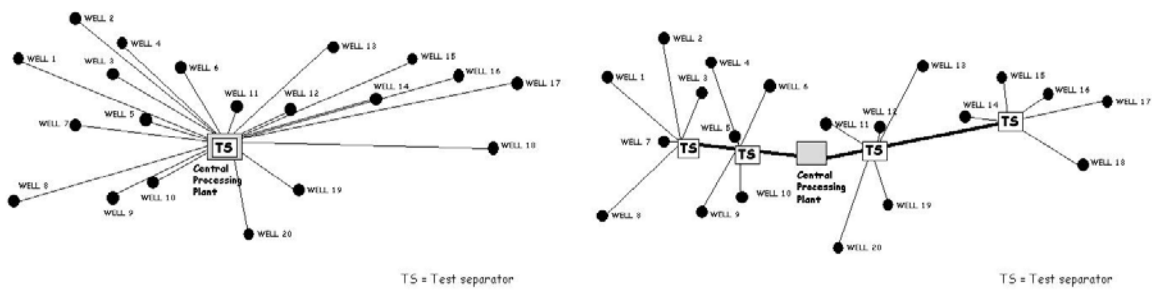


Figure 6, At what watercut level should a well be abandoned.

3.3 Gas development with wet gas metering

In the design phase of this desert field (300 MMscft/d of gas and 50,000 bbl/d of condensate and some 20 wells) various configuration options have been investigated. One option was with just one central test separator facility. The second option was to use test separator facilities in 4 production stations and thus saving pipeline costs. The third option was with two large headers and no test separators at all but using a continuous on-line wet gas meter on every individual well and a reconciliation process. This not only resulted in savings in flow lines costs but also in saving the test



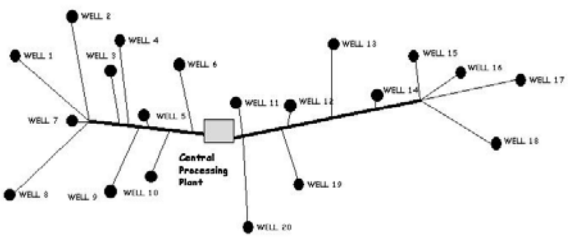


Figure 7, Simplifying production facilities through individual well metering.

Figure 8, Wet gas Venturi.

separator costs. A reduction of approx. 10 million US$ is likely to be typical for this particular desert type of location. The Shell developed wet gas metering technology, used in this development, utilises a conventional Venturi flow measurement, a tracer dilution concept and dedicated wet gas overreading correlation's. This technology is now leaving the nursing stage and within the Shell group there are a number of applications. With a wet gas-meter on each individual well it is possible to have continuous readout of the gas flow rate. Although the Opex with the wet gas-metering concept is slightly higher, this is only a fraction of the Capex savings. The implementation of wet gas metering in this field has been guided carefully, field trials have been conducted to demonstrate the technology and to train operations staff. Operational procedures and software programs have been developed to facilitate proper custodianship of the technology and operational procedures are being developed.
For this particular project with the Venturi/Wet gas metering on a per well basis the additional hardware costs per well are approx. 50 kUS$.

3.4 PDO's (Petroleum Development Oman) philosophy on MPFM

PDO has gone a long way in the implementation of MPFM technology. Various MPFM's have been tested in the past, some with positive and some with negative results. Based on the large amount of experience, the new strategy in PDO is that for well testing purposes, multiphase meters shall be used instead of test separators. This is because MPFM's have been proved to be as accurate as or even more accurate than test separators. Moreover they are easier to operate (once properly commissioned) and lower in cost.

The cost of the MPFM's implemented in PDO recently, ranges from 100 to 150 kUS$, depending on the size and pressure. This includes the cost of a Factory Acceptance Test (FAT) and 4 days training and commissioning. Above costs are exclusive of the operating cost but it is expected that the operating costs after proper implementation are relatively low and certainly lower than that for test separator. The above pricing does still not still justify the use of MPFM on a per well basis, and therefore the current arrangement is to install the MPFM in the gathering stations or in a remote manifold with Multiport Selector Valve (MSV.)
Although it may be still too early to assess the performance of multiphase meters because of the limited operation experience, it can be said that operations staff in the field are satisfied with those MPFM's currently running. It should be noted that this smooth operation could only be achieved after a careful selection process and proper guidance by MPFM specialists. The implementation of multiphase meters has still not reached the stage of "fit and forget". A lot of selection criteria have to be followed in terms of spelling out the correct process parameters; i.e. minimum and maximum of oil, water and gas flow rate, gas volume fraction, water cut, operating pressure and temperature, densities and viscosity. Their variations over shorter and longer time are also very important. If one of these parameters is not taken into account lots of operation problems might be the result.
Despite all the positive things about the multiphase meters, there are still few difficulties in the use of this technology especially when it comes to high GVF and high watercut application, here the performance will deteriorate. The high GVF application can be overcome by installing a partial separation device (cyclone) and reduce the actual GVF in the MPFM. The measurement uncertainty high watercut has still not been solved. The uncertainty of the oil flow rate at high watercut (WC > 90%) can be as bad as 50% or higher. This is a fundamental problem that can hardly be solved with improved watercut measurement.
One of the other difficulties in the existing multiphase meters is the use of the radioactive sources; most of the current commercial MPFM are using radioactive sources in their measurement principle. Although the radiation level from these meters is low (a transatlantic flight will give you a higher doses than sitting next to the meter for a year), there is still some fear with people to use such devices. Currently, the policy of PDO is not to own the radioactive sources that are used in the MPFM's. The ownership remains with the manufacturer, who is also responsible to do 6 monthly wipe tests to check for any possible source leaks. The custodianship of the radioactive sources is in hands of PDO's Health, Safety and Environment (HSE) department and the Government is the custodian of all the licenses required to use the radioactive sources. Because of the additional operational activities on source checking and the management of the HSE and licensing issues, PDO feels that there is still a need for a MPFM that does not contain a radioactive source.

The examples above demonstrate that each project has its own economics and its own production measurement requirements, hence also each project has it's own MPFM prize at which larger scale MPFM well installations become attractive. However, it is felt that for the majority of the onshore projects in the Shell Group these considerations are only made with MPFM prices between 40-60,000 US$ (this under the assumption that the performance/accuracy is equal to what is offered today). This price level of 40-60,000 US$ can potentially be met by two companies and one of them is FlowSys, a new Norwegian MPFM manufacturer. They developed an interesting concept with permittivity/conductivity measurements in the throat of a Venturi. This MPFM concept also perfectly fits in some of the Shell Research objectives for MPFM development, e.g.:

- Development of relatively low costs MPFM (aim is 40 to 60,000 US$),
- No use of radioactive sources (it should be noted that MPFM's with radioactive sources on board are not accepted in some Shell operating companies),
- Small and compact design,
- Concept suitable for surface, subsea and downhole applications.

Further below the FlowSys concept is discussed in more detail and a summary of the results obtained in 3 test programs will be presented.

4 FlowSys MPFM concept

The major parts of the FlowSys TopFlow meter are the Venturi and the electrodes incorporated inside the throat of the Venturi insert. The flow rates of oil, water and gas are calculated based on the measurements obtained by the electrodes and the measurement of the differential pressure across the Venturi inlet. No separation devices flow conditioners, mixers, by-pass lines or radioactive sources are used in the TopFlow concept.

A picture of the FlowSys TopFlow meter as was installed in Shell's Rabi field in Gabon is presented in figure 9 and the principle of operation can be summarised in the block diagram of figure 10.

The ΔP is measured across the inlet and throat of the Venturi insert. The electrodes inside the Venturi throat measure the capacitance or conductance of the mixture flowing through the Venturi insert. The velocity is found from cross-correlating the high-resolution time signals from pairs of electrodes within the Venturi insert.

Figure 9, FlowSys meter installed at Rabi station (Shell Gabon).

As there is no gamma densitometer, the FlowSys meter does not measure the fluid mixture density directly, unlike most other meters. However, the density is determined indirectly, through the momentum equation of the Venturi. The set of equations utilised in the calculations of the fractions are listed below:

$$Cap/Con = f\left(\alpha_{oil}, \alpha_{water}, \alpha_{gas}, \varepsilon_{oil}/\sigma_{water}\right)$$

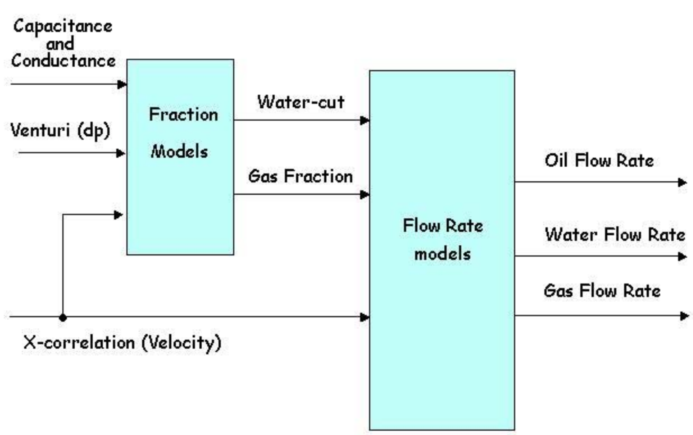
$$Density = f(\Delta P, Velocity) = f(\alpha_{oil}, \alpha_{water}, \alpha_{gas}, \rho_{oil}, \rho_{water}, \rho_{gas})$$

$$\alpha_{oil} + \alpha_{water} + \alpha_{gas} = 1.0$$

Note that capacitance and oil permittivityl (ε_{oil}) apply for oil-continuous mixtures while conductance and water conductivity (σ_{water}) applies for water-continuous mixtures. The capacitance or conductance, ΔP and velocity are the input measurements and are being measured by the electrodes and ΔP transmitter. The permittivity of the oil (ε_{oil}), water conductivity (σ_{water}) and

Figure 10,

Schematic diagram of FlowSys meter.



densities of oil, water and gas (ρ_o, ρ_w, ρ_g) are input parameters entered into the user interface. The fractions of oil (α_{oil}), water (α_{water}) and gas (α_{gas}) are calculated from the equations above. The Water-in-Liquid Ratio (WLR) or watercut is defined as:

$$WLR = \frac{a_{water}}{a_{oil} + a_{water}}$$

The set of equations for the calculation of flow rates Q_{oil}, Q_{water} and Q_{gas} are listed below:

$$Q_{oil} = A \cdot V \cdot a_{oil}$$
$$Q_{water} = A \cdot V \cdot a_{water}$$
$$Q_{gas} = A \cdot V \cdot a_{gas}$$

The cross sectional area of the pipe (*A*) is known based on the geometry of the Venturi, the velocity (*V*) is measured by cross-correlating the electrical signals from the electrodes and the fractions of oil, water and gas are found from the set of three equations for the fractions, as indicated above.

5 Test results

Earlier NEL and CMR test on the FlowSys meter showed very good results (see figure 11 and 12) and based on those test results two Shell operating companies, Petroleum Development Oman (PDO) and Shell Gabon, together with Shell Global Solution International (SGSI) have decided to further field trial the meter. Main driver for this extensive testing was the promising technical concept, the small and compact configuration of the meter, the fact that the meter doesn't require a radioactive source and the potential for subsea and downhole applications. The Shell Gabon installation was at a production gathering station where the meter was installed is series with a test separator and a test tank. The PDO testing was done in a testloop in Daqing (China) where live crude oil, actual production water and natural gas could be used.

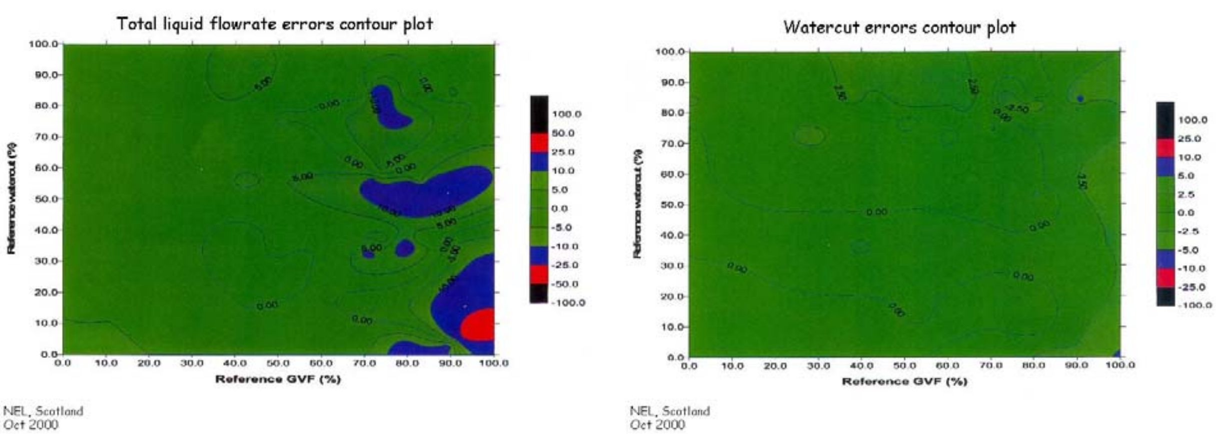
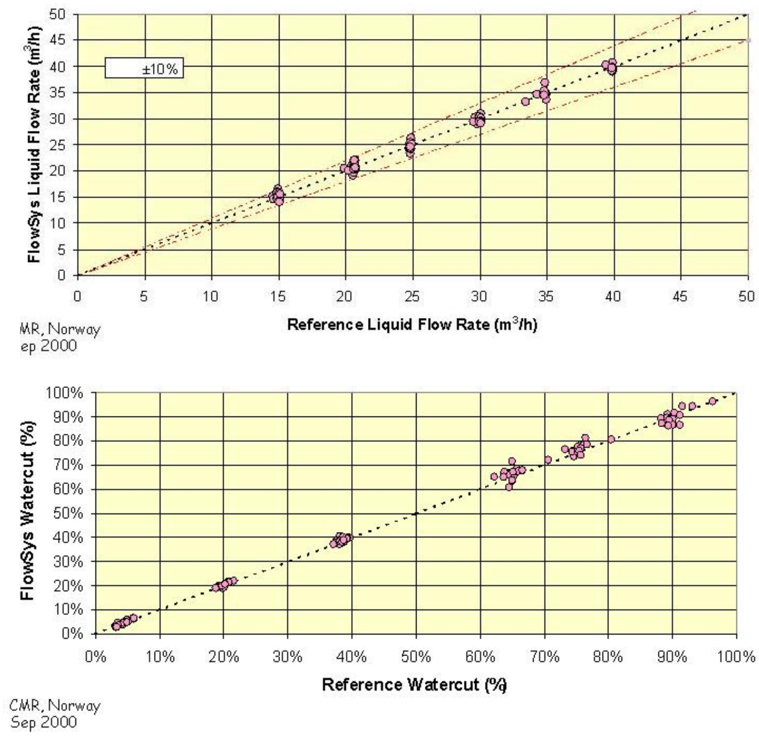


Figure 11, Test results obtained in the NEL test loop, Oct 2000.

Figure 12

Liquid flow rate reading (top) and watercut reading (bottom) of the FlowSys MPFM versus the reference measurement in the CMR loop



5.1 <u>Shell Gabon experience (Rabi-A production station, May 2001)</u>

A 4” FlowSys prototype meter was tested at a gathering station in series with a two-phase test separator and a test tank. Extensive work was carried out to prepare and calibrate the test separator and its associated measurement equipment, this to ensure proper reference measurements. The Gas Volume Fractions (GVF) on some of the Rabi wells are not only very high but fluctuates a lot due to long horizontal pipelines between well heads and gathering station. These long horizontal pipelines also generate severe slugging and fluctuating water cut, which is a challenge for any multiphase meter. The operating pressure for the multiphase meter at the gathering station was about 10-12 bar.

Prior to the start of the Shell test campaign, FlowSys discovered that the meter requires a minimum liquid flow rate to operate accurately, this because with upward flow through the MPFM liquid might

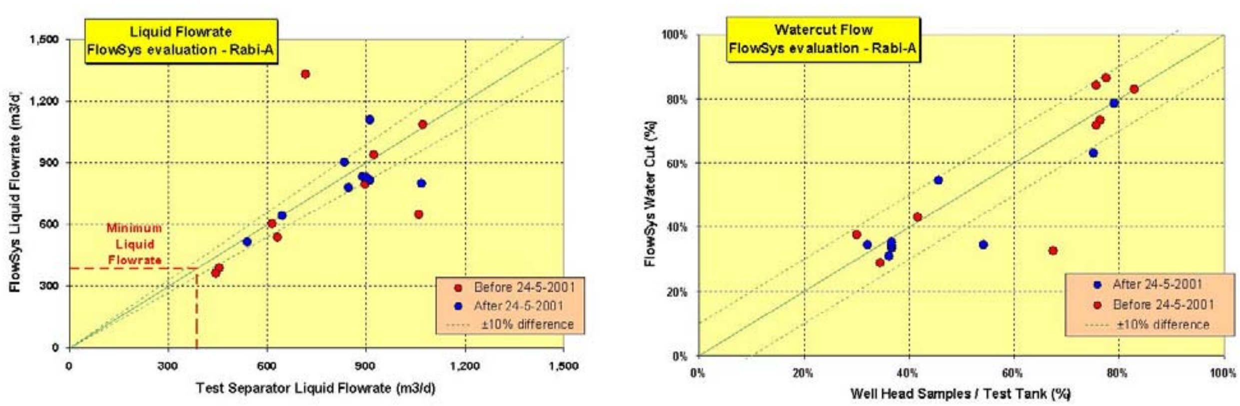


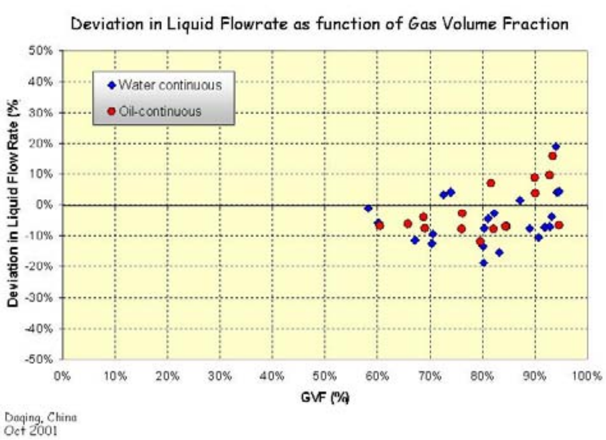
Figure 13, Liquid flow rate and watercut as measured by FlowSys versus the test separator/test tank.

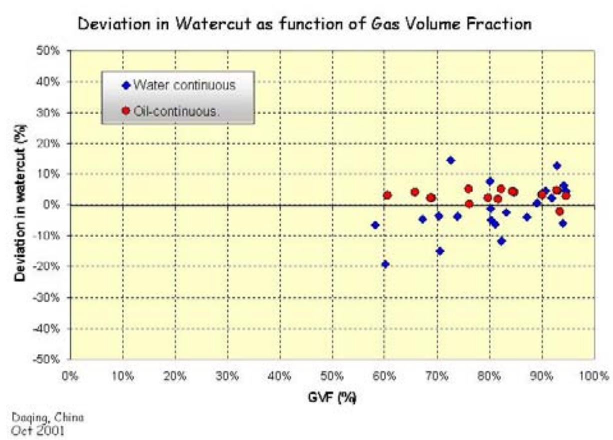
fall back at the low velocities. This discovery resulted in a reduction in the operating envelope of the meter and unfortunately more of the Rabi wells fell below this limit. Consequently not all wells could be tested, however, the wells whose rates were within the operating envelope and with sufficiently low GVF’s (<90%), the FlowSys meter could measure the liquid within plus or minus 10%. For the higher GVF's the deviation between the references and the FlowSys meter were higher. For the water cut in particular it was seen that also by comparing the two available references (well head samples and tank dipping) a ±10% difference were also seen between the references (see figure 13).

One has to bear in mind that this was a prototype and that further developments have been carried out on the software and hardware after this test program. In general it should be noted that MPFM's work better at the lower or moderate GVF's and this calls for installation upstream of the choke. However, this again requires MPFM installation per well, which again is only feasible with low-cost MPFM's.

5.2 SGSI/PDO experience (done in DOD test loop in China, Oct 2001)

The same 4" FlowSys meter was tested at DOD during September/October 2001. A 4" meter is a bit large when considering the operating envelope of the DOD test facility. Consequently only liquid flow rates in the low range of the operating envelope of the 4" meter were tested. The test consisted primarily of low liquid flow rates and GVF’s of 60% and above (see figure 14). The operating pressure at the DOD test facility is low (2-5 bar). The trial at DOD revealed a need for further development of the software models especially for high water cuts and in the transition between oil and water-continuous flow.





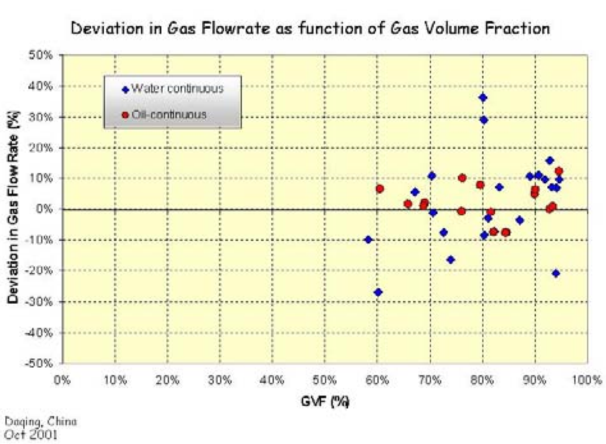


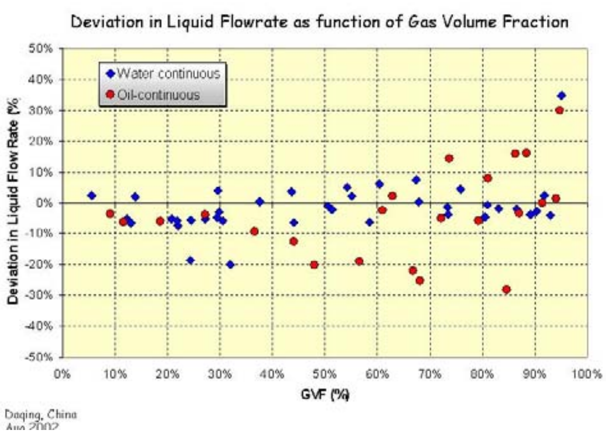
Figure 14, Test results obtained during testing at DOD, Daqing, China (Oct 2001).

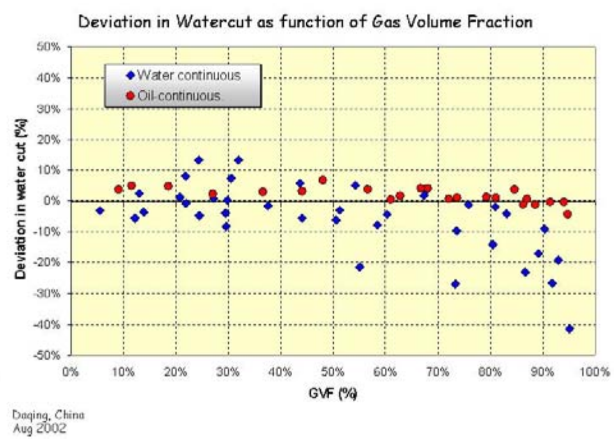
As a consequence of the low operating pressure special considerations needs to be taken when converting the gas flow rate to standard conditions or when comparing the gas flow rate with a reference single phase measurement. Due to the existence of the Venturi insert there are local fluctuations in the pressure along the length of the multiphase meter. It was concluded that from a theoretical point of view the location of the pressure transmitter should have been moved to inside the throat were the flow rates are being measured. For the prototype tested, the pressure transmitter was located in the upstream section of the FlowSys meter. With a few exceptions, generally the liquid flow rates were within ±10% and the absolute deviation in watercut measurements were also within the ±10% range (the oil-continuous points were measured more accurately than the water-continuous points).

5.3 SGSI testing (done in DOD test loop in China, Aug 2002)

A 1.5” FlowSys meter was tested at DOD for three days during August 2002. A wider range of the operating envelope of the multiphase meter could be tested this time compared to the trials with the 4” unit during October 2001. The meter was tested without doing any three-phase calibration tests prior to start-up and was operated continuously without any operational problems. The test results are shown in figure 15 and 16.

The results show that the meter follows the trending of the references. The water cut was measured again more accurately at low water cut region compared to high water cut region. This could also be seen from the CMR testing (figure 12) and is inherent to the physical concept used in the MPFM. The future challenge is to improve the measurements at the highest GVF's and highest water cuts.





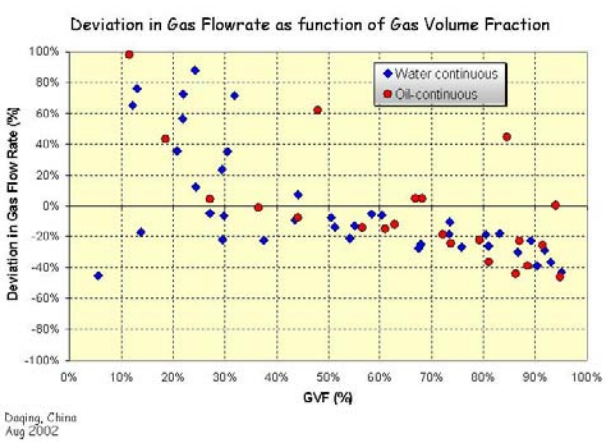
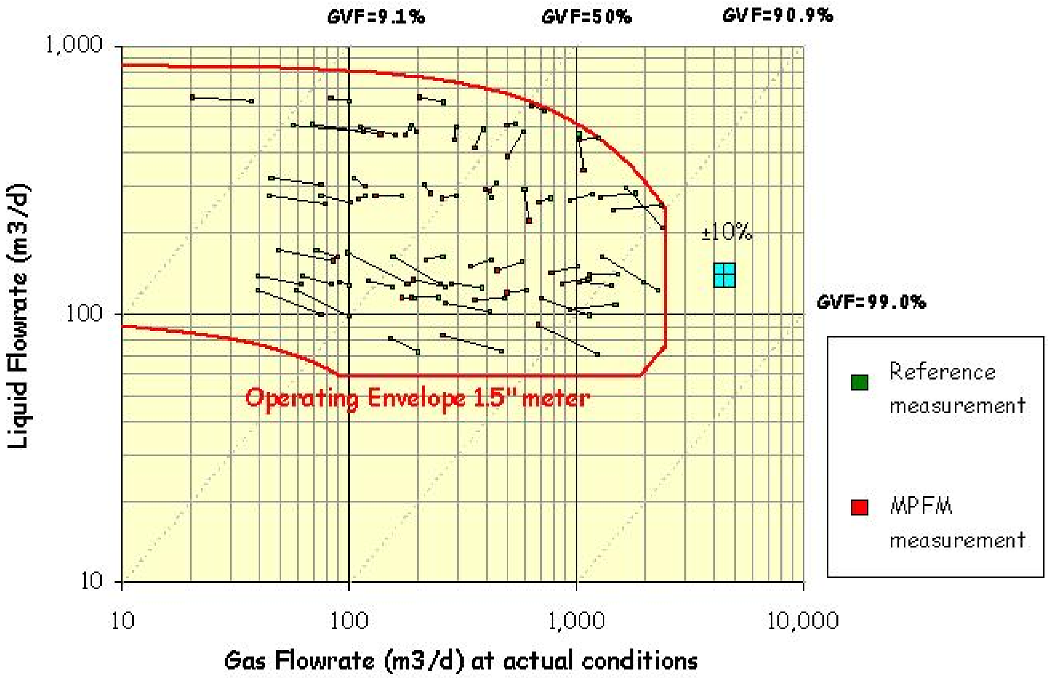
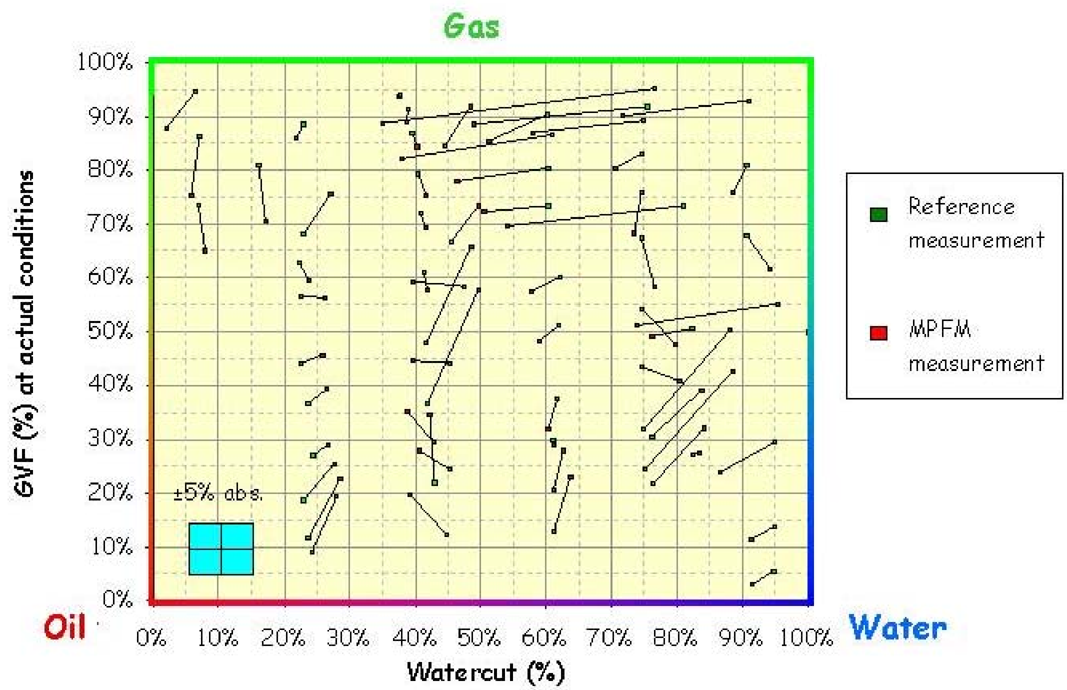


Figure 15 Test results obtained during testing at DOD, Daqing, China (Aug 2002).



Daqing, China
Aug 2002



Daqing, China
Aug 2002

Figure 16, Results of the Aug 2002 test plotted in the two-phase flow map and the composition map. Length and slope of the connecting lines between reference and MPFM points indicate size and direction of deviation.

The potential in the meter can be illustrated when studying the liquid flow rates for the tests carried out in water-continuous flow. Here 92% of the tests were within an uncertainty limit of 7.5%. The largest improvement in the performance of the meter during the two DOD trials was seen in the liquid flow rate at high water cuts. Also the water cut in oil-continuous flow was improved between the two trials. A new software model was implemented for calculating the water cut in water-continuous flow and data was gathered to further optimise the flow model. The liquid flow rates at low water cuts were not measured as good as expected, but there is no reason why the liquid flow rates should not achieve the same level of accuracy in oil continuous flow as is the case in water continuous flow. The large relative error in the gas flow rate at lower GVF's is due to the relatively small amount of gas being present in the fluid.

6 Conclusions

Each project in the oil and gas industry has its specific requirements for production measurements. These requirements are driven by the hardware costs and the value of information obtained by the measurements (this includes the uncertainty of the measurement). MPFM's can contribute significantly to cost savings if they are used as a replacement for conventional test separators. The need for MPFM on a per well basis very much comes from other than production facility layout considerations, here sub-surface or production optimisation considerations are more dominant. For the majority of onshore developments in the Shell Group it is felt that when MPFM prices fall in the order of 40-60 kUS$ the MPFM installations per individual well become feasible at a much larger scale (provided the performance is similar to what is offered today).

In the search for these low-cost, relatively small and non-nucleonic MPFM's, that also have the potential to be used in a sub-sea or downhole environment, tests have been carried out on a the new MPFM that is manufactured by FlowSys in Norway.

The FlowSys meter has been extensively tested in the described test programme. The test results revealed that, within the operating envelope of the meter, relative errors in the order of ±10% for liquid could be achieved. For watercut measurement a distinction between oil continuous and water continuous emulsions need to be made. For oil continuous emulsions the watercut measurement is within ±5% (absolute) while for the water continuous emulsions ±10% (absolute) is a more realistic number. The test programme has shown that the FlowSys meter is robust in the way that no operational problems of any kind or failure of any parts have been experienced and that the meter is an attractive candidate in the low-cost MPFM market.