Successful Implementation and Use of Multiphase Meters

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1 INTRODUCTION

Allocation of production using multiphase meters offers significant benefits in terms of both CAPEX and OPEX. For successful implementation, it is important to have thorough understanding of the application and identify the main issues which influence the performance of the multiphase meter. In order to find a workable solution, the need for metering functions, installation requirements and operation procedures must be addressed.

Figure 1 - MPM High Performance Meters installed in the MPM flow

In order to perform accurate measurement of oil, water and gas production the measurement principle needs to be able to cover a wide range of flow rates and combinations of oil water and gas. This is particularly important for slug flow applications where the flow may instantly change from multiphase to wetgas flow conditions and improper use or design of the meter may introduce significant measurement uncertainties.

It is also important to understand the influence on the measurements related to uncertainty in PVT configuration data and how this can be dealt with in a practical and cost effective manner.

An extensive operator driven development and qualification program has been performed by 10 oil companies in co-operation with MPM to develop a solution that can handle a wide range of operating conditions and be tolerant to significant uncertainties in the PVT configuration data.

This paper presents the technical principles of the MPM meter, some multiphase metering challenges which needs to be overcome and the test results from a blind test of the meter at Ekofisk, a field located in the North Sea, operated by ConocoPhillips.

1.1 The well dynamics challenge

Many fields may start out as an oil field in the early years of production and develop into a gas field as the pressure is reduced. Production from multiple zones in a reservoir may also cause significant changes in the GVF over time. The watercut may also increase over time, particularly for water flooded reservoirs.

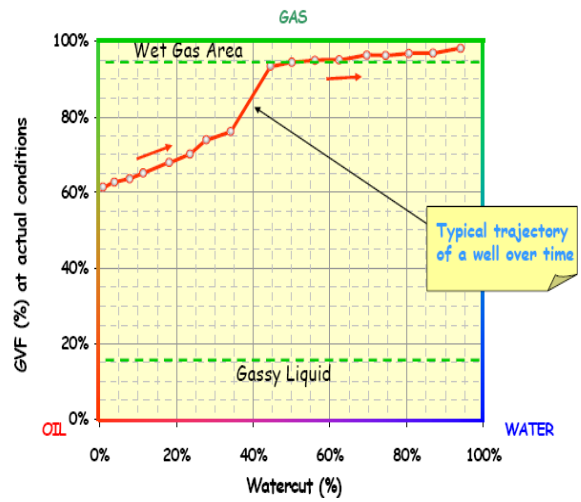

Figure 2 - Typical well trajectory over time

As a consequence, the watercut and GVF in the multiphase flow may change significantly over time. For such fields it is quite common that a multiphase meter is required in the early years of production, however, as the field matures, a wetgas meter would be the more correct choice. A typical well trajectory for such a field is shown in Figure 2.

In the example above, the GVF may change from a multiphase GVF of 60% to a wetgas GVF condition of 95%+ in several years where the switching between multiphase and wetgas occurs gradually.

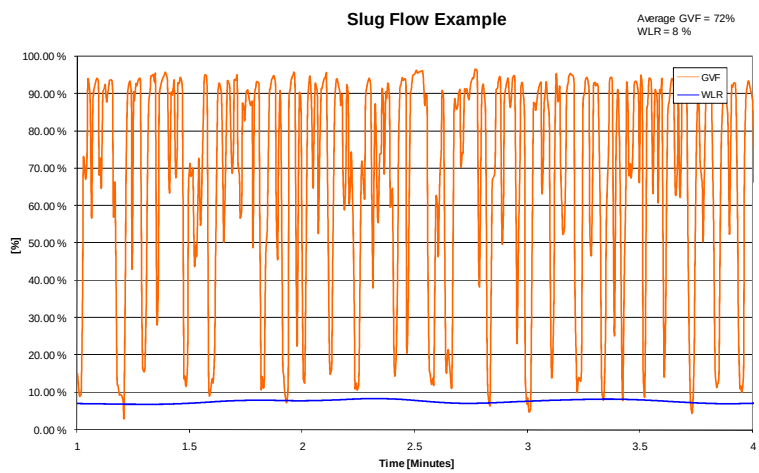

Figure 3 - Slug Flow Example for a GVF of 72%

In other cases, such as gas lifted wells or long horizontal wells at low pressure, the GVF may continuously change from multiphase to wetgas conditions as illustrated in Figure 3. Here the GVF is continuously changing from 5-95% in a matter of seconds. This corresponds to sudden changes in flow conditions from multiphase to wetgas. These conditions have traditionally been difficult to handle for multiphase and wetgas meters. However they are typical for many field applications in the real world.

1.2 The wet gas challenge

For wetgas applications, the challenge is clearly the accurate measurement of small liquid fractions in a gas dominated production stream. Once the liquid volumes have been successfully measured, the small liquid fraction must then be split into water and

hydrocarbons. Hence, a metering system that is capable of extremely high resolution is required for this task. On top of this, operators would often like to know the conductivity and salinity of the produced water in order to determine its source.

In many real applications the makeup of a wetgas production stream could correspond to as much as 99.9 vol% gas, 0.05-0.1 vol% condensate and a water fraction of only 0.01-0.05 vol%. In such cases, variations in the properties of the dominating phase (gas) will usually correlate strongly to the measurement uncertainties as pointed out by H. van Maanen in [2]. It is therefore essential, as far as possible, that the metering system be insensitive to variations in the gas properties. This has been a particular area of focus in development of the MPM meter.

1.3 The gamma challenge

There are different types of gamma meters used in multiphase metering applications. The MPM meter uses a single high energy (Cesium) gamma source, with an energy level of 662 keV, and an associated half-life of 30.7 years.

The measured count rate N of a gamma detector is described according to the following equation:

$$N = No * e^{-\mu\rho x}$$

where

N : Gamma Photon Count Rate
No : Empty Pipe Calibration Value
μ : Mass attenuation coefficient
ρ : Density
x : Pipe diameter

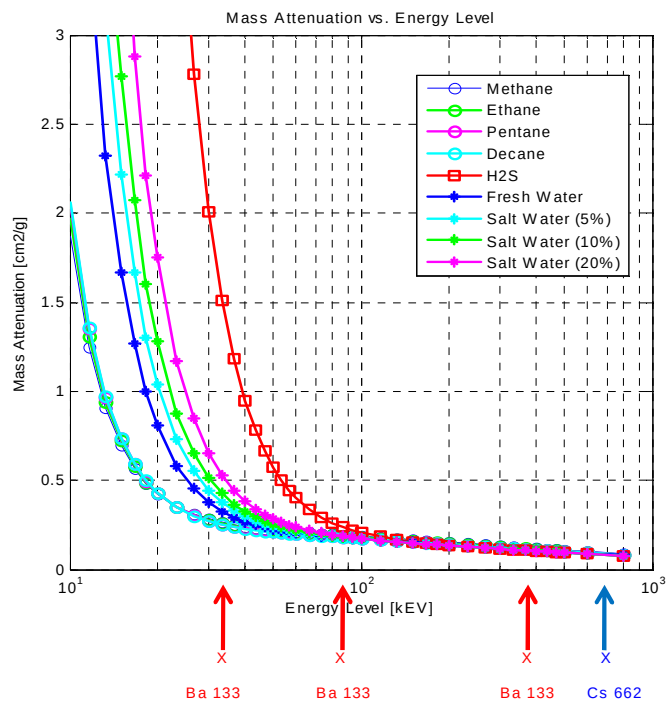

Figure 4 : Mass attenuation as a function of energy level

Source : National Institute of Standards and Technology,

Figure 4 shows the calculated mass attenuation coefficient for some selected hydrocarbon fractions, H2S and water in the salinity range 0-20% NaCl. The mass attenuation is calculated using the XCOM database at National Institute of Standards and Technology [1].

For high energy levels, the mass attenuation coefficient is almost constant for all materials, whereas the mass attenuation coefficients vary quite significant at lower energy levels. In particularly the H2S content of the flow will have a large impact on the mass attenuation coefficient.

For high energy levels like the 662 keV received from Cs 137 source, the gamma measurement is almost a ”true” density measurement, since the mass attenuation for gas and condensate is almost constant at this energy level, and the mass attenuation coefficient for water is a function of water salinity.

For lower energies such as the energy levels obtained with Barium 133 (32, 80 and partly 356 keV), the mass attenuation coefficient is much more dependent on the composition comparred to the 662 keV energy level. As a consequence, detailed information of the composition of the hydrocarbon fluids and water is required when using a low energy gamma source. In particularly the H2S content has a large influence on the mass attenuation coefficient for the 80 and 32 keV energy levels. Using 662 kEV makes the gamma measurement much more tolerant towards changes in the PVT properties of oil, gas and water comparred to low energy gamma measurements.

As a consequence, a simple field configuration of the meter can be done avoiding the need for detailed composition data in order to calculate the mass absorption coefficient of oil, water and gas as required for lower energies.

1.4 The PVT challenge

All multiphase meters using a gamma source need to be configured with the fluid properties of oil, water and gas. In most applications the fluid properties will change significantly over time. If the meter is installed on a test header with many wells from different reservoirs, it is important that the meter is tolerant with respect to uncertainty in the PVT configuration data since it is difficult, if not impossible, to maintain accurate PVT data over time for such installations.

Many multiphase meters are also used on comingled well streams from subsea tie backs or used to measure the production from wells producing from multiple zones. Under such circumstances, significant variation in the PVT properties can and do occur. Sea or fresh water flooded wells will also experience changes in the water properties as the amount of injected water dilutes the water from the formation. This is particularly the case if there is a large salinity difference between the injected and reservoir water. In order to obtain accurate measurement over time, it is therefore important that a multiphase meter is able to cope with significant variation in the PVT configuration data. Alternatively, procedures have to be put in place for regularly sampling of the well streams.

If frequent updates of PVT data is required, the lifecycle cost (OPEX) of obtaining PVT data can easily exceed the cost of the multiphase meter itself and may also introduce significant HSE issues, particularly for subsea, H2S rich well streams and HP/HT applications.

There may also be significant time delay from a sample is taken to the results are received from the lab. In most cases the oil is fairly stable, however the water conductivity may change quickly particularly in connection with well stimulation operations. If the user wants to check the well after a stimulation job is completed, the

changes in water conductivity may ruin the oil/water split if the meter is not capable of handling variations in the water conductivity.

Figure 4 shows a typical example from Ekofisk where the water conducitivty from the lab samples taken of the well showed a change from 10 S/m to 6 S/m in less than two months.

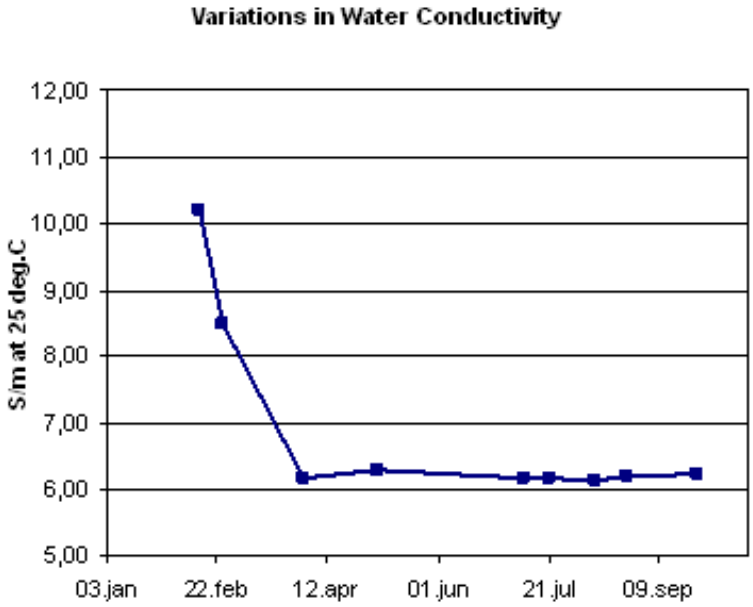

Figure 4 : Measured water conductivity (samples) for a typical well at Ekofisk

Another practical problem arrises is if the multiphase meter is connected to a header. At Ekofisk a header typical contains 15-20 wells. Even taking one sample/ Well/month involves a considerable amount of work. More samples would be required if the meter is not capable of handling variations in the water properties.

The logistics involved in handling test samples and implementing the result into the meter is also significant and prone to human error. Typically it may also take as much as 1-2 months from the time the sample is taken until the data is entered into the multiphase meter. During this time period the well may have changed significantly as illustrated in Figure 4.

Another practical issue which may introduce errors in the PVT models is related to the method for obtaining the GOR for recombination of the oil and gas samples. The GOR when the sample is taken may vary significantly due to the changing slug flow. In such cases, should the average GOR or instantaneous GOR be used when recombining the oil and gas samples?

If the instantaneous GOR is used, how should the instantaneous GOR be calculated if the gas sample and oil sample is not taken at exactly the same time? The different vendors of multiphase meters have quite different views on this matter which makes it even more complicated from a users perspective.

2 MPM 3D BROADBAND™ TECHNOLOGY

The MPM HighPerformanceFlowmeter is based on patented and licensed technology (5 patents and 2 pending) using a combination of a Venturi flow meter, a gamma detector, a multi dimensional - multi frequency dielectric measurement system [6, 10, 11] and advanced flow models [3-5], which are combined to a multi modal parametrical tomographic measurement system. The Venturi is also used to create radial symmetric flow condition in the 3D Broadband™ section downstream the Venturi. These flow conditions are ideal for use of tomographic inversion techniques.

The technology is marketed as 3D Broadband™ and is used to establish a three dimensional picture of what is flowing inside the pipe. The basis for the technology is often referred to as 'process tomography' which has many parallels to tomography used in medical applications.

In the oilfield, the challenges are however different than in a hospital. Firstly, the meter is measuring fluids and gases under high temperature and pressure. Secondly, the multiphase mixture can be moving at velocities exceeding 30 meters per second inside the pipe, and the amounts of gas, water and oil are unstable and changing all the time.

The 3D Broadband™ system is a high-speed electro-magnetic (EM) wave based technique for measuring the water liquid ratio (*WLR*), the composition and the liquid/gas distribution within the pipe. By combining this information with the measurements from the Venturi, accurate flow rates of oil, water and gas can be calculated.

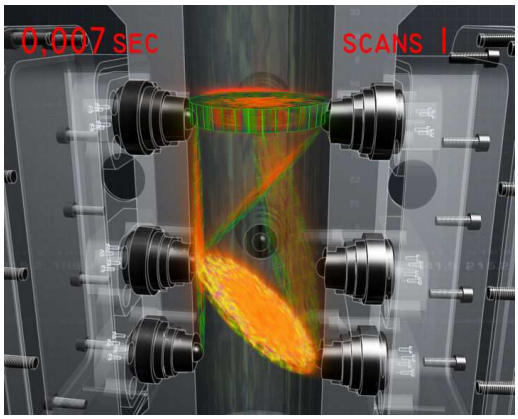

Figure 5 -

3D Broadband™ tomography based meter

The MPM meter is extremely fast where all the measurement directions are measured in the entire frequency range in a tenth of a second. Averaging of measured raw data is limited, to avoid errors due to non-linearity in the flow. The result is a measurement with an unparalleled performance in multiphase and wetgas flowing regimes. With its dual mode (multiphase/wetgas with automatic switching) functionality, both multiphase and wetgas applications are addressed with the same hardware and software, bridging the measurement gap between multiphase and wetgas meters.

2.1 Full three phase wetgas measurements

For ultra high GVF's the Droplet Count® functionality is an add-on feature that contributes to significantly improving the measurement performance. The Droplet Count® was commercially released in 2009 but has been in field operation in MPM Meters since early 2008. By using Droplet Count®, the MPM meter can perform precise measurements of small quantities of liquid and is very tolerant towards

uncertainties in fluid PVT properties (i.e. gas density and water properties). This is achieved by a patented methodology with unique properties compared to a gamma meter, and for which the measurement accuracy is better the higher the GVF. The the Droplet Count® functionality is further described in [12].

2.2 Dual Measurement Mode

The MPM meter is a combined multiphase and wetgas meter. The meter can be software configured to operate either as a multiphase or as a wetgas meter. This is often referred to as multiphase or wetgas mode.

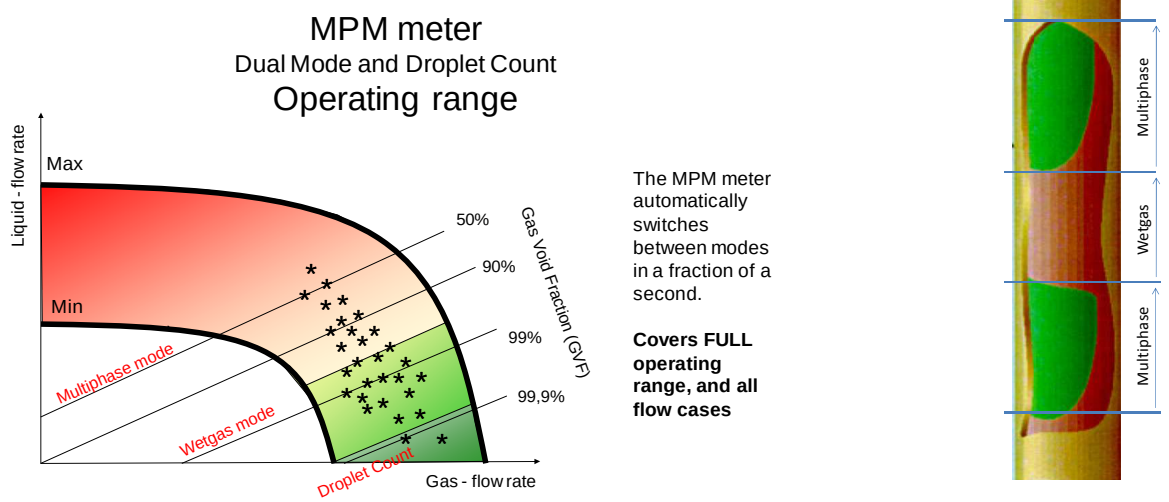

Figure 7 - Dual Mode Operating Range

The standard MPM meter is delivered either as a multiphase or a wetgas meter. The hardware parts are, however, identical and the difference between the two meter versions is the software. It has two modes: one for wetgas and one for multiphase flowing regimes. Equipped with MPM Dual Mode®, the meter can be configured to automatically switch between the two modes. The switching is done in less than 0.2 seconds. The switching pointy is selectable by the user.

2.3 Water Salinity

The MPM meter can measure the conductivity of the produced water. The measured conductivity is converted into water salinity and the water density is calculated, assuming a certain composition of the salt (for instance NaCl). The measurement method is based on RF measurements and MPM's patented 3D Broadband technology.

All multiphase meters require information about the gas and fluid properties (PVT data) as configuration constants. Even though the MPM meter has a low sensitivity to changes in the water salinity, the water properties are important for accurate measurement of the oil flow rates for wells with high water contents.

The MPM meter can automatically measure the water conductivity and density in water-continuous emulsions. This eliminate the need for sampling and analysis in order to

obtain the water properties. For subsea, H2S rich and HP/HT applications, this is particularly valuable.

For low watercuts, the water conductivity has little effect on the measurement uncertainty, provided the specified value is within reasonable limits of the true value. If, however, the Water Liquid Ratio (WLR) is expected to increase during the life of the field and the flow turns to water continuous, then configuring a multiphase meter with the correct water conductivity is important.

With MPM's automatic configuration the water conductivity and water density are automatically and continuously measured by the meter. This eliminates the risk of getting wrong measurement as a consequence of incorrect configuration data. It also eliminates the need to take the produced water/ liquids samples in order to update the configuration constants when the watercut is increasing, and when the salinity of the produced water is changing. This is very valuable for unmanned and remote operations, as well as for subsea installations.

The Watercut for which the flow turns into water-continuous depends on the application, but normally it occurs when the watercut gets in the 30-60% range – although water-continuous has been seen at the lower end and the upper end depending on the general flow regime and fluid properties. If slugging is expected, then measuring the water conductivity could be important even for lower watercuts. The reason is that if the water comes in slugs, then the watercut during the slug can be well above the water-continuous threshold. If so, and if the water conductivity is wrongly specified, the oil and water flow rates will be heavily distorted.

Another benefit of the method is that the water conductivity is measured at actual temperature conditions avoiding discrepancies in the models which convert the conductivity from one temperature to another. As an example, it is common to use the conductivity at 25 ºC as a configuration parameter since the water conductivity in most cases is measured in a laboratory at room temperature and converted to 25 ºC. The multiphase meter requires the water conductivity at actual conditions, and hence the water conductivity needs to be converted from 25 ºC to the actual line temperature which may differ significantly. This conversion model may be quite inaccurate, introducing a secondary source of error for meters which rely on the water conductivity as a configuration parameter. This is avoided when the water conductivity is measured at line conditions.

The salinity measurement is based on a patented method using a dielectric measurements carried out locally at the pipewall using a differential principle with one transmitting and two receieving antennas. Electromagnetic phase measurements are performed over a broad frequency range, and each measurement frequency provides a separate independent equation. All the measurements are combined in such a way that the measured water conductivity represents a "best fit" of the measured water fraction for all the measurement frequencies assuming that the ratio between the real and imaginary part of the dielectric constant of the multiphase mixture is related to the ratio between the real

and imaginary part of the dielectric constant for pure water. The salinity measurement is further described in reference [9] and [10].

3 TEST RESULTS

The MPM meter has been subject to a very comprehensive user-driven qualification program as outlined in [8].

3.1 Tests at Ekofisk

In 2007 ConocoPhillips purchased a topside MPM Meters in order to test it in a real field application. The test was performed as a blind test where MPM had no knowledge about the test program before or during the test. Following successful testing, the MPM meter has now been installed permanently and is used for well testing and well optimization.

3.2 Test Configuration

The 5" topside MPM Meter was installed in series with the test separator at EKOM as shown in Figure 8 below.

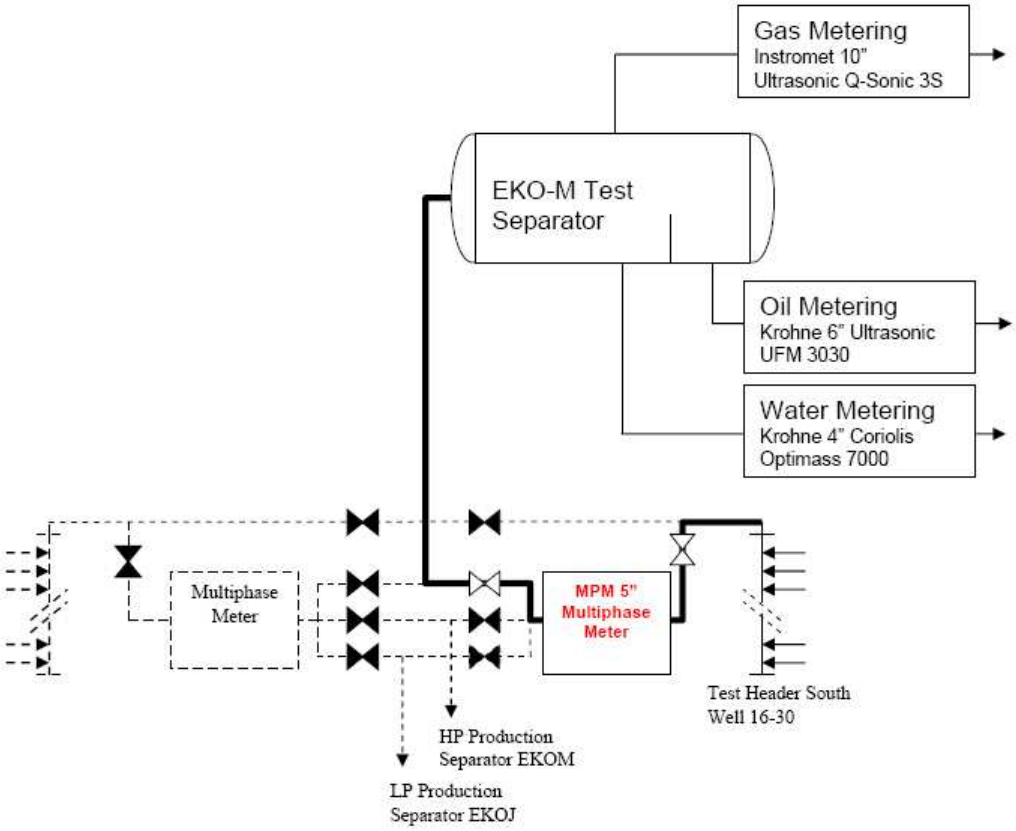

Figure 8 - Ekofisk Test Setup

The MPM meter was installed in series with the test separator for the wells on the south test header. A picture of the MPM meter is shown in Figure 9.

The gas outlet on the test separator is measured by a 10” Instromet Ultrasonic Q-Sonic 3S wetgas meter. The oil leg is measured by a Krohne 6” ultrasonic UFM 3030 and the water is measured by a Krohne 4” Coriolis Optimass 7000.

Figure 9 - MPM Meter at Ekofisk

A total of 15 wells could be routed through the MPM meter with the following range of fluid and process characteristics:

- GVF : 88-97%
- WLR : 1.5 – 48%
- GOR : 10 – 43 m3/m3
- Pressure : 20 – 22 barg
- Temperature : 26 – 96 °C
- Oil Density : 810 – 840 kg/m3 at 15 °C and 1 bara
- Gas Density : 0.72 – 0.83 kg/m3 at 15 °C and 1 bara
- Water Density : 1030 – 1100 kg/m3 at 25 °C and 1 bara
- Water Conductivity : 50 – 170 mS/m at 25 °C and 1 bara

As seen from the listing above, there is significant variation in the PVT properties for both oil, gas and water.

The test also contained both oil and water continuous wells with stable flow and slug flow conditions.

At the start of the test, the test separator reference flow measurement uncertainty were assessed to be within ± 5% for all phases.

The measurements from the multiphase meter and test separator were comparred at process conditions without flashing the multiphase meter to test separator conditions. This was considered to be a good approach since the meter and test separator operates at virtually the same temperature and pressure such that the introduced additional uncertainty is deemed to be small.

3.3 Meter Configuration and Comissioning

The MPM meter is very tolerant towards uncertainties and variation in the PVT configuration data. Prior to commissioning of the MPM meter, the variation in PVT data was inverstigated and it was decided that a common PVT setup could be used for all the wells. Using a common PVT configuration was considered to be a great benefit since there would be no need for sampling, analysing and management of multiple PVT data configuration setups for the wells.

The PVT configuration was obtained by calculating look-up tables for each well based on the available composition prior to commissioning of the meter. Based on the individual tables, an average look-up table was prepared. Prior to delivery from MPM, the meter was configured with the average look-up table and the meter was therefore fit for service upon delivery to Ekofisk. The 'average' look-up table has been used for all the wells, and it has remained unchanged since commissioning of the meter in 2007.

The MPM Meter was commissioned in October 2007 as per standard procedures. The meter was mechanically installed and then connected to 24 volt supply and a fibre cable for communication with the MPM Terminal in a local control room. The software on the MPM terminal was later installed on an exisiting terminal server onshore. The MPM service engineer performed a check of the meter and an empty pipe calibration of the gamma detector was performed. The entire commissioning, including mechanical installation of the meter were performed over several days. Once the meter was electrically and mechanical commissioned, the remaining tasks of the commissioning was done in less than four hours.

No flow testing or tuning towards the test separator were performed during the commissioning of the meter and the MPM service engineer left the platform before there was flow to the meter. The meter have been untoutched by MPM and COP personel since commissioning in October 2007.

3.4 Test Procedure

The test of the MPM meter was performed as a blind test. Hence, MPM did not get any information of flow rate neither during commissioning of the meter nor during the testing of the meter. Measurement data was logged continuously by COPNO and handed over to MPM on a regular basis together with start and stop times for the test periods. COPNO then received average flows and time series during the well test periods from MPM.

The MPM data was flashed to test separator conditions. The test separator data was also corrected for differences in liquid volume (levels) in the separator between start and end of the test. Test separator water was measured as mass flow and converted manually to volume flow using water density for each well. No corrections were made for water in the oil leg of the separator.

The test period started 14th December 2007 and ended 17th February 2008 comprising a total of 364 test hours based on 76 well tests from 13 wells.

At the end of the test, when COPNO had received all the data from MPM and made comparison tables with the test separator, the data was handed over to MPM for comments.

The MPM meter is still in operation, delivering measurement data with the same quality as obtained during the testperiod in 2007 and 2008, without any calibration or maintenance need since it was installed in October 2007.

3.5 *Test Results*

Below are chart of the liquid, oil, water and gas measurements for all the well tests.

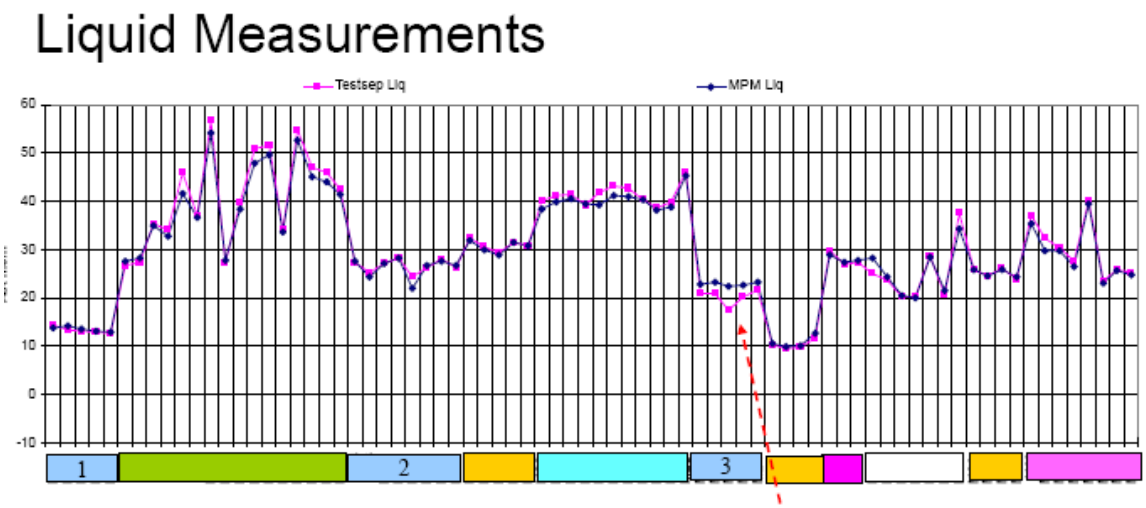

Figure 10 - Liquid Measurements

The average GVF range is 88.3 – 97.7%.
94% of the liquid flow rate measurements are within ±10% and 82% of the data are within ±5%. Well 3 appear to deviate more than the others. Excluding well 3, all tests are within +/- 10% difference and 90% of the data is within ± 5%. It is not clear why well 3 deviated more during the test.

For GVF's in the range 80-95%, the uncertainty spec of the MPM Meter is ± 5%. For GVFs above 95%, the uncertainty spec is ± 10%. Hence, the measurements are well within the specification of the meter.

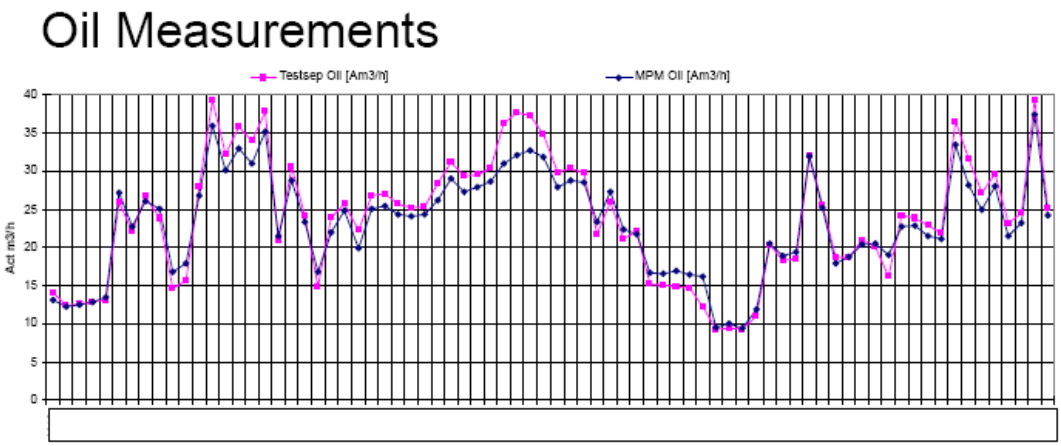

Figure 11 - Oil Measurements

83% of the data is within ± 10%.
No correction is made for water in the oil leg of the separator, it is therefore expected that the test separator oil measurement will be slightly higher compared to the MPM meter.
The oil content constitutes 2.7 to 7.7 % of the total multiphase flow.

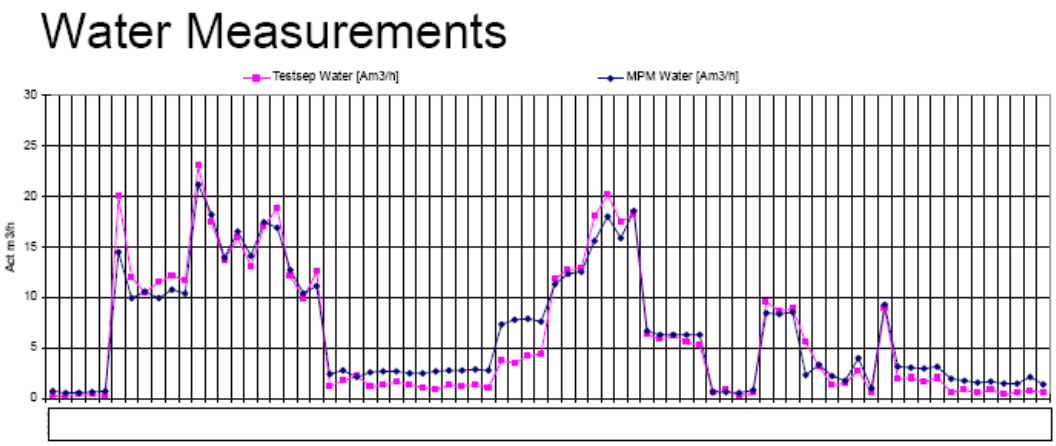

Figure 12 - Water Measurements

The WLR is in the range 1.5% to 47.3% and the water content constitute 0.2% to 5.5% of the total multiphase flow. Some of the wells were both oil and water continuous.

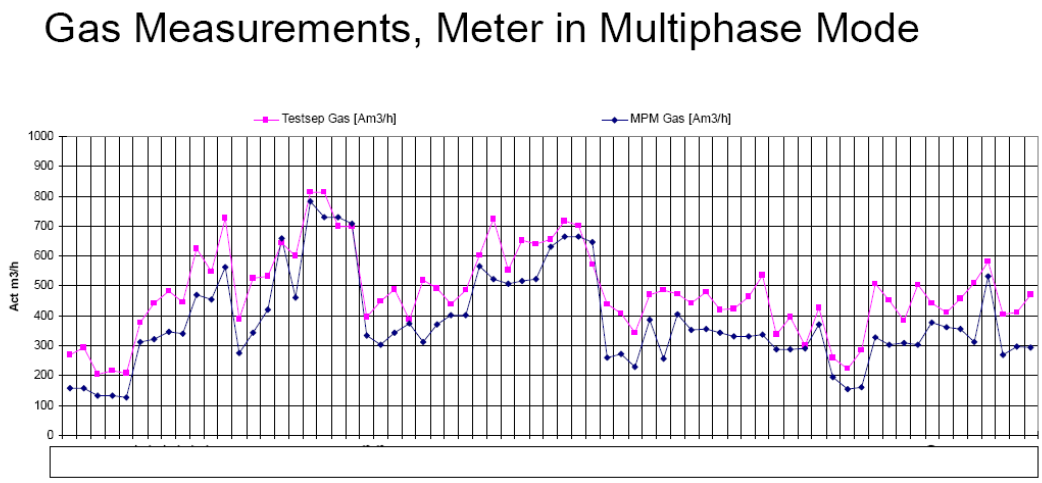

Figure 13 - Gas Measurements

A larger deviation was seen on the gas measurement which caused some concern. The test separator was fairly new and instrumented with an ultrasonic meter so the MPM gas measurement was initially considered to be suspect.

3.6 Investigation of Gas Measurement Discrepancy

MPM investigated the gas flow rate measurement in more detail to look for potential issues which could explain the observed discrepancy.

Some of the wells contained severe slugging with fairly long periods with almost pure gas followed by a short liquid slug as seen in Figures 14 and 15.

During the periods indicated with red circles, the dP is extremely low and the MPM meter does not measure flow due to a preset cutoff value for the dP transmitter.

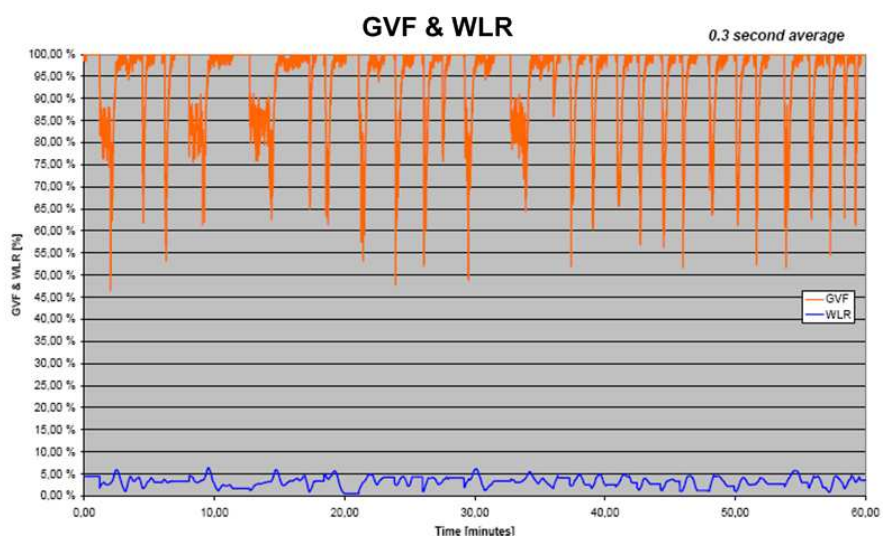

Figure 14 -GVF & WLK for slugging Well

When the well is producing mostly gas, the dP is under the cutoff value and it sets the flow to zero. This caused a small under reading of the gas for some of the wells. The cutoff value was reconfigured to a lower value, however there was still a large deviation between the gas measurement from the separator and MPM meter.

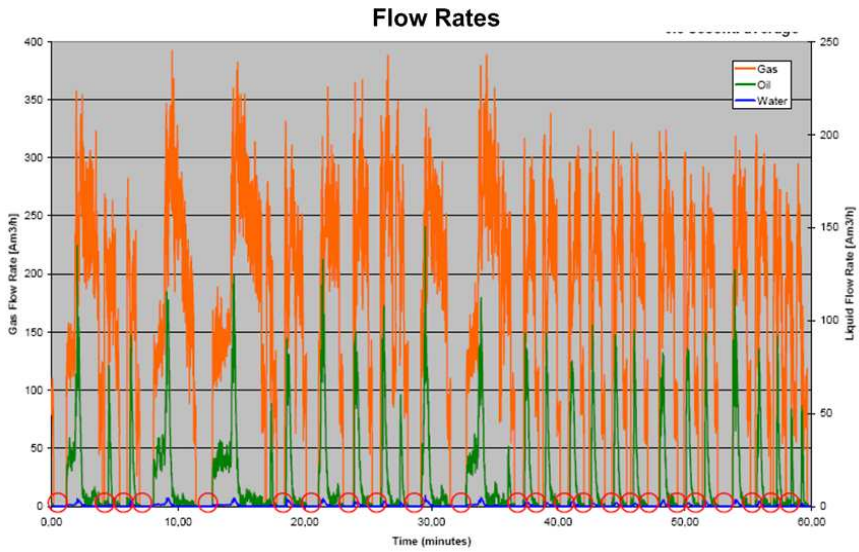

Figure 15 -Flow Rates of a slugging well

The test results were also re-simulated by MPM with automatic switching between wetgas and multiphase mode (dual mode). When the MPM meter was commissioned in October 2007, automatic switching between wetgas and multiphase mode was not available and the meter was therefore configured to operate in multiphase mode. Figure 16 shows a re-simulation of the entire test using automatic switching between multiphase and wetgas mode.

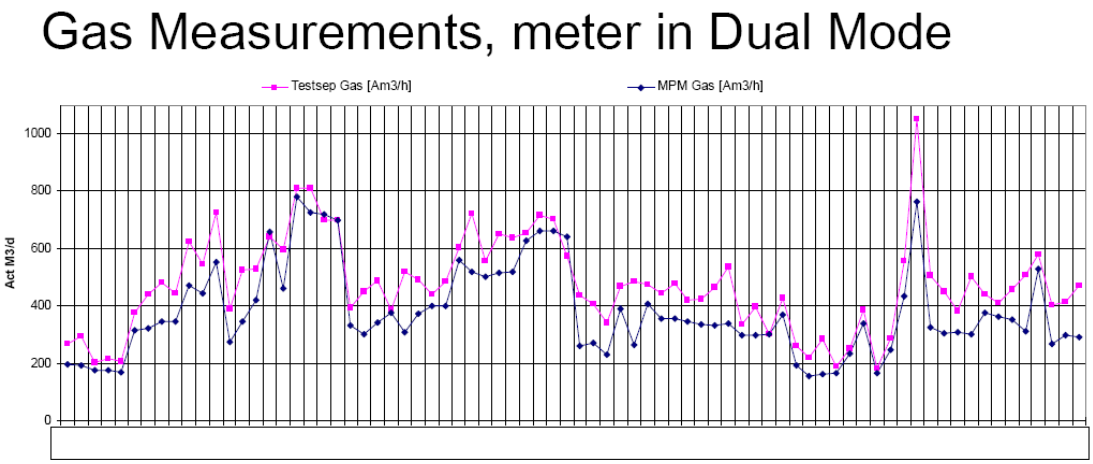

Figure 16 -Resimulated gas measurement in Dual Mode with automatic switching

The difference between the test separator and MPM meter was reduced with an average value of approximately 2%. In general, the measurements from the MPM meter are lower compared to the test separator measurements (only 3 tests are higher on the MPM meter).

Automatic switching between measurement modes also improved the liquid measurement at high GVF, removing some of the positive bias on the liquid flow rate for these wells.

Based on a deeper analyse of the measurements of the MPM meter, it was concluded that the measurements between the MPM meter and test separator was different and further investigation was required.

There was no correlation between the observed deviation on the gas flow rate and parameters such as temperature, pressure, gas rate, liquid rate, flow conditions (stable or slug flow), GVF, WLR or date and time. However, comparing the measured GOR of the MPM meter and the test separator towards the 30 year historical trend of the GOR for the wells at Ekofisk, it was determined that the GOR measured by the MPM meter was more in line with the historical trend . This suggested that a closer look at the test separator gas measurement was required.

Further tests and investigation of the test separator gas measurements revealed that a reason for the observed discrepancy was related to liquids in the USM transducers causing the ultrasonic signals to fall out periodically. In adition, liquid was causing cycle jump/pulse detection problems leading to wrong velocity measurements on some of the paths.

The measurement from the test separator was improved by removing some of the measurement chords and rotating the meter in order to minimise the cycle jumps/pulse detection problems. The chart below shows the comparison between the test separator and MPM meter for all the wells on the test header after correcting the gas measurement on the test separator. The difference between the test separator and the MPM meter is now found to be wthin 5-7% for most of the tests. (Figure 17).

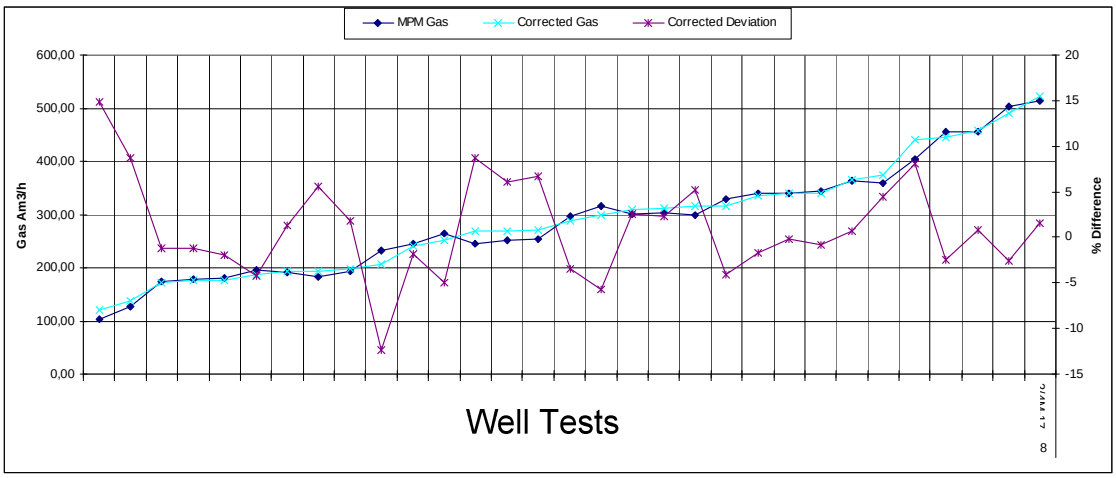

Figure 17 -Test of gas measurement after correcting the test separator gas measurement

3.7 *Oil/Water Continuous liquid flow*

Two of the wells had nominal WLR averages in the range 30-45%. During the well test, the WLR was observed through the MPM meter as varying in the range 0-100%. This has been observed many times though the use of multiphase meters. The MPM meter handles transitions between oil and water continuous flows and no difference in performance compared to other wells has been observed. Later well tests has indicated that the WLR has increased in some of the wells. Fugure 18 indicates the observed water liquid ratio (through a MPM) of a well with a nominal 60% WLR.

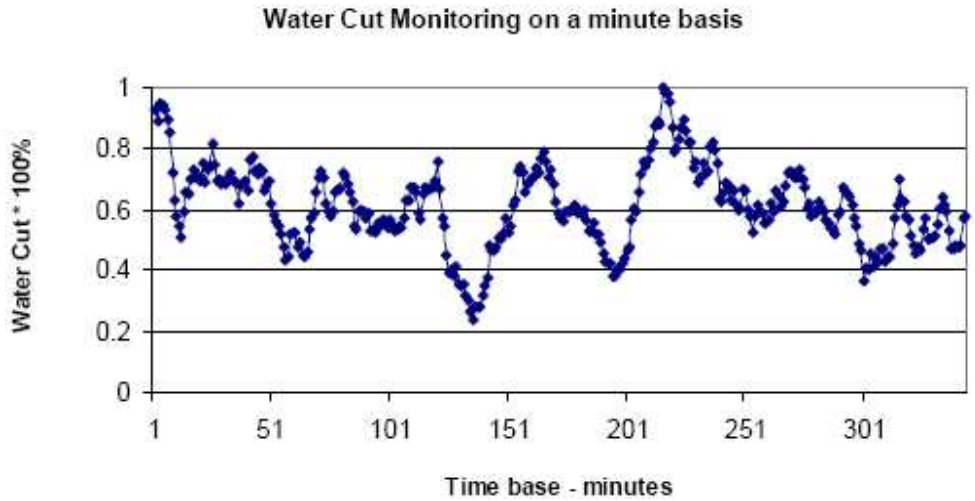

Figure 18 –Example of water separation in the well

Oil and water flow, in the short term, may give an irregular cycle and give unstable data with respect to WLR measurement. This is due to low velocity in the pipe such that separaction occurs and also the dynamic head and liquids 'available for lift' in the reservoir. Hence, there may not be enough force to drag the water together with the oil. As seen from the graph to the right, the WLR varies in the range from 20 to almost 100 % during a few hours. These WLR changes often form a repeatable pattern over time.

4 OBSERVATIONS AND EVALUATIONS

4.1 Well test timing

By using a multiphase meter, it is possible to test the wells in a significantly shorter time compared to the test separator.

The chart in Figure 19 shows the measurement from the MPM meter when a new well is routed through the meter. After approximately 5 minutes, at 10:50, averaging 15 minutes will give the same results as the average over the whole period (within ± 1.5%). The chart shows the same period for the test separator. The normal well test is 4 hours. In addition, the well requires 1 – 1.5 hour to stabilise. For the test separator, a 3.5 hour

average is required in order to give the same result over the whole test period (within ± 1.5%).

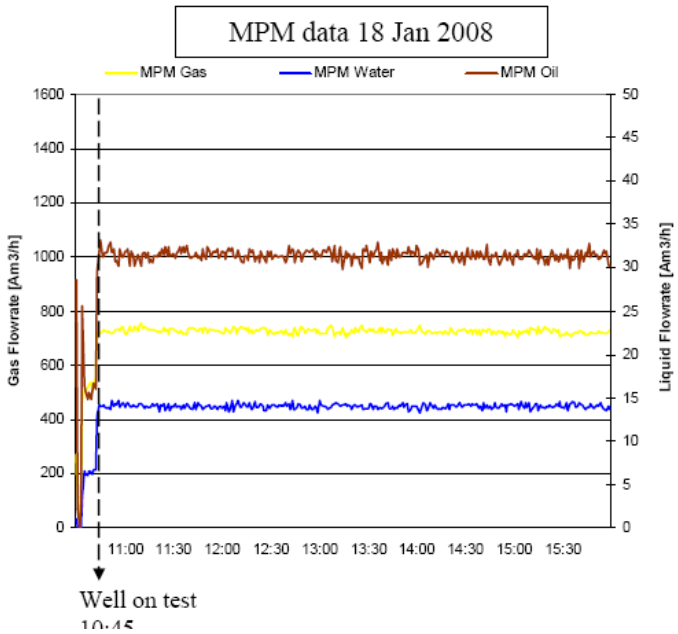

Figure 19 –Well stabilisation on MPM Meter

Clearly using shorter well tests, significantly more frequent well testing can be achieved with a multiphase meter compared to the test separator, which can only increase well testing accuracy.

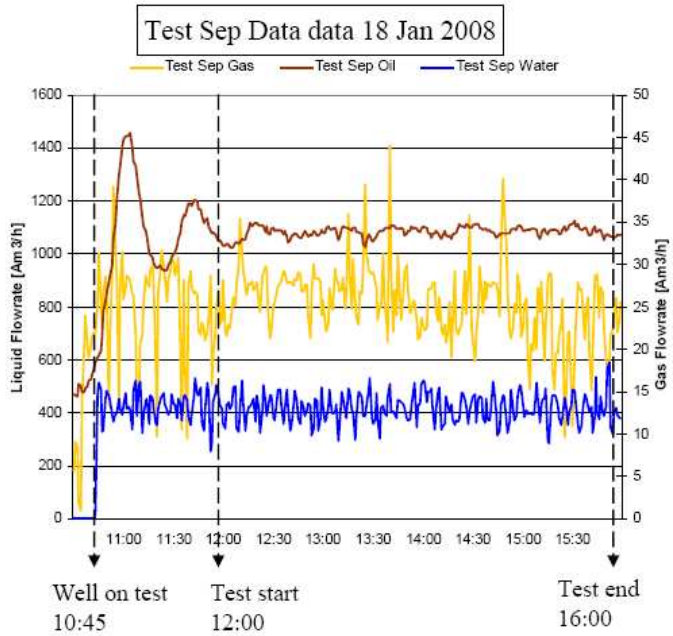

Figure 20 –Well stabilisation on Test Separator

4.2 Observation during installation, commissioning and testing

The following points summarises the main observations by COPNO from the installation, commissioning testing phase:

- The installation of the meter was supervised by MPM personel .
- In general there were no problems during installation, commissioning and operation. Configuration and commissioning of the meter once the mechanicall installation was complete in less than 4 hours. The MPM meter was configured with PVT data based on an average for all wells at the factory. A single look up table for oil and gas density and viscosity and oil/gas surface tension was created.
- Communication to COP offshore was trouble free.
- After a few weeks, MPM personnel checked the status of the meter from the onshore computer. A problem with a sub-supplier software module was discovered. This was a known software bug, detected a year earlier. The error was corrected from onshore and the meter (and test) was restarted. No problems thereafter and the meter has been continuously in use with an uptime of 100%.
- During the test period, MPM checked the status of the meter every two weeks and downloaded rawdata log files from the offshore service computer.
- The flow tests were completed during normal offshore operations. The test separator/MPM meter was used during well cleanups, milling operations (to remove scale) and scale squeeze operations etc. All tests were logged and reported. It is considered that these operations have no impact on the MPM meter performance.

4.3 *Design and FAT Test Points*

Prior to delivery, the MPM meter was configerred based on the latest well data. A standard FAT, containing approximately 20 test points, was performed in the MPM flow lab prior to delivery.

Figure 21 shows the two-phase flow map for the design well data and the FAT test points as recommended in the Handbook of MultiPhase Flow Metering [7].

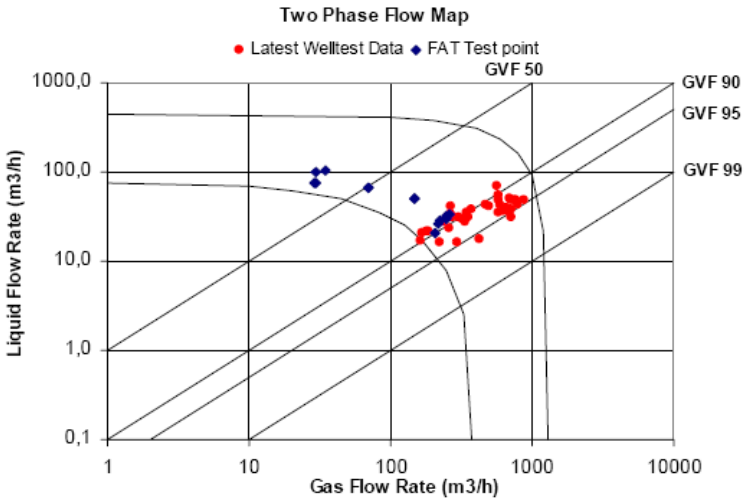

Figure 21 –Design & FAT Data in Flow Map

The chart in figure 21 shows the same data in a flow regime map. See Figure 22. From the charts it is seen the GVF would expected to be in the 90-95 % area with a mix of churn and annular flow conditions.

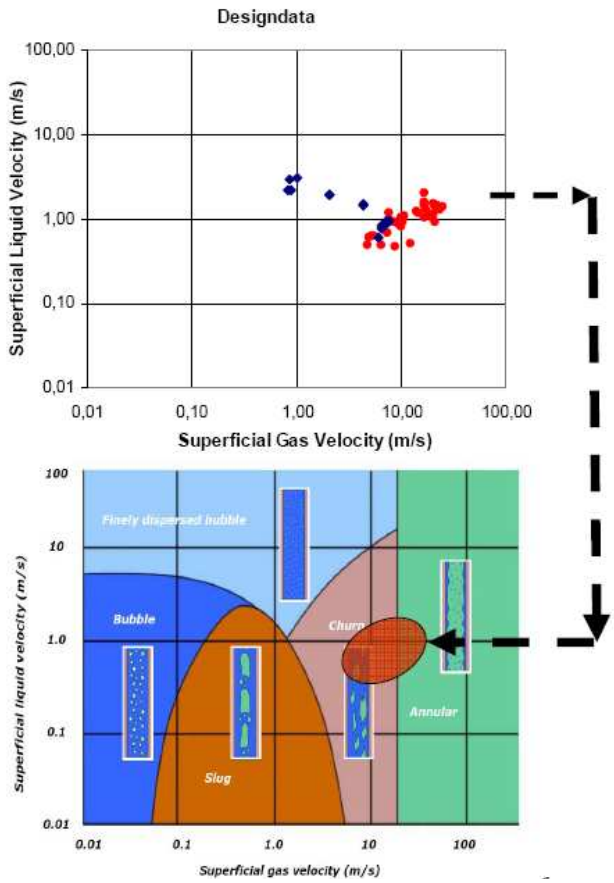

Figure 22 –Design & FAT Data Flow Regime Map

Whilst we often specify a well's performance as a single point in time on the Two Phase Flow map, the Real World is very different in that in a short period of time many wells exhibit considerable changes. Typically this is shown in Figure 23

The red points are the average flow rate during the test whereas the scattered datapoints are all the individual measurements from 12 wells during a one hour period at a resolution of 0.3 second. The black lines are the designed minimum and maximum operating limits for the meter.

From Figure 23 it is seen that in real life, the GVF varies in the entire range from 50-100% GVF. with a much larger variations in the flow conditions than can be expected from the average data. In fact, the measurements are outside the design envelope for the meter for some wells a significant part of the time.

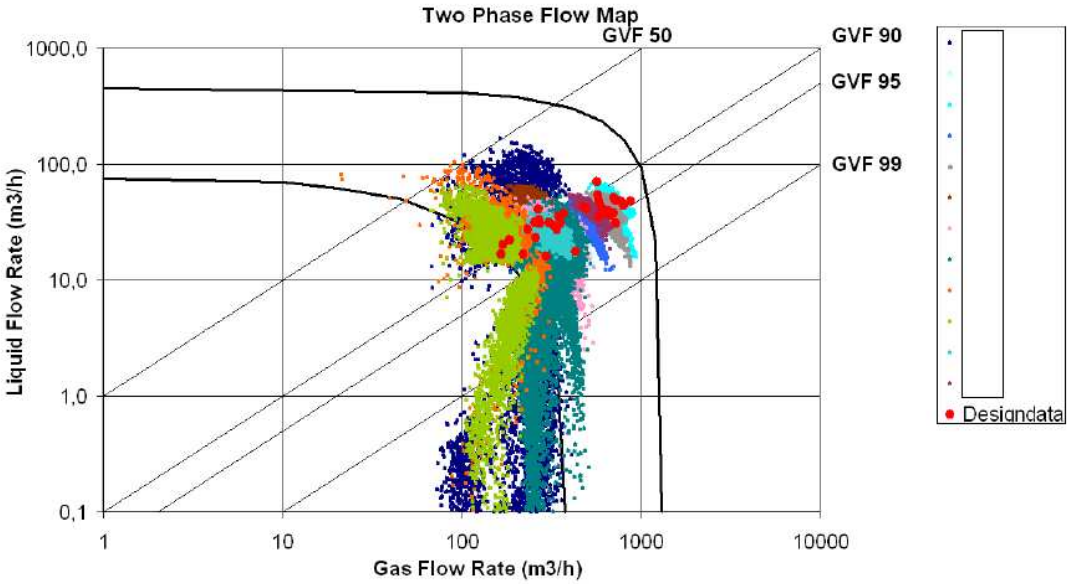

Figure 23 –Real Life Data – in Flow Map

Figure 24 below shows the span in the real flow conditions and the well characteristics. Whereas the expected flow map was limited to churn and annular flow as indicated by the brown oval ring, the real flow condtions covered both annular, churn, slug and dispersed bubble flow as shown by the larger red rectangle. The real well characteristics is also summarized in the Figure 24 as:

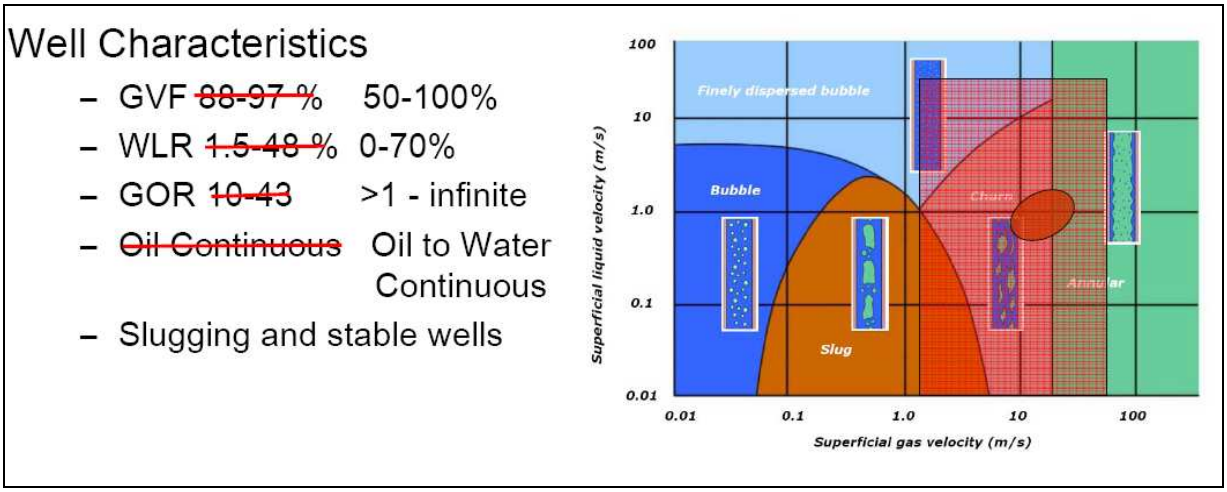

Figure 24 –Real Life Data – Flowregimes

From this it may be concluded that a multiphase meter for this application needs to be designed to handle all flow conditions. If slug flow is expected, care must be taken when using "average flow rates" as it is likely that the meter will have to operate beyond its normal operational envelope.

During slug flow, the dP of the liquid slug may peek to a value many times greater than the average value. Similarly, the venturi dP during the gas slug may be just a fraction of the average dP for the well, and possibly below its normal dP cutoff point. Automatic switching between multiphase and wetgas is an important feature for these flow conditions.

4.4 Future use of Test Separators

The existing EKOM design with two headers is a product of the high well count used on Ekofisk (30 wells is current and 40 and 50 wells are envisaged in the future). With a single header and a high well count effective well testing can only be carried out with two headers and two MPFM's. The design adopted however with the two MPFM able to access a Test Separator is an acknowledgement of the fact that a test separator is required by operations for many purposes.

These are:

- The ability to test the MPFM against a recognised flow measurement 'standard' – although as has been shown here – not all test separator measurments are necessarily 'good'. Test separator is required by operations to verify performance of multiphase meter. This is also useful in order for operations to gain confidence in the measurements from the multiphase meters.
- The need for fluid samples – multiphase sampling is currently a 'leap into the unknown' and samples from a separator are a known technology, effective and comparitively safe.
- The ability to kick off low pressure wells after a shutdown later in field life can only be done effectively from a test or an independent LP separator. This is a known and valid economic driver in order not to leave 'oil in the ground'.
- The ability to clean up wells after well work. Whilst this does no good to the test seperator meters, arguments from metering engineers against this policy are rarely effective – as the replacement of flow meetrs is seen as small compared to the extended stay of a drilling rig and specialised clean up and product disposal procedures.

5 SUMMARY AND CONCLUSIONS

- The MPM meter has been developed, tested and qualified in JIP's together with 9 major oil companies.

- In 2007 an MPM Meter was installed at Ekofisk. The MPM meter has been in continuous operation since it was installed in 2007 without any operational problems. The meter is considered to be a good tool for well testing and production optimisation.

- The MPM meter has had no operational problems during the test period. It is now in continuous operation following the test program.

- One common PVT configuration has been used for all the 15 wells at the test header, and the measurements from the MPM meter have proved to be robust with respect to variation in the PVT configuration data with no need for sampling of the wells.

- The MPM meter operates well – over a large operating envelope brigding the gap between multiphase and wetgas meters.

- The meter handles oil and water continuous flows, high and low GVF's and the transitions with no discernable loss of perfromance.

- The meter handles extreme salinity changes without recalibration.

- For all process conditions observed, the MPM meter has operated equally well.

- The user interface is easy to use and the log files are a good diagnostics tool.

- The MPM meter does not seem to be affected by the different well operations (scale squeeze, milling operations, clean-up, or water conditions) experienced.

- The existing EKOM design with a multiphase meter on each header seems to be a practical and cost effective implementation of multiphase meters for well optimisation and well testing for the Ekofisk field.

- The MPM meter is still in operation, delivering measurement data with the same quality as obtained during the testperiod in 2007 and 2008, without any calibration or maintenance need since it was installed in October 2007.

6 ACKNOWLEDGEMENTS

The development of the MPM HighPerformanceFlowmeter has been supported technically and financially by the six oil companies; ENI, ConocoPhillips, Hydro, Shell, Statoil, and Total. In addition, Anadarko, Chevron and Gaz de France have participated in the test of the MPM subsea meter at South West Research Institute. Nine oil companies; ENI, Chevron, ConocoPhillips, Gaz de France, Shell, StatoilHydro, Petronas, Total and Woodside are also participating in an ongoing "In Situ Verification JIP" to develop and qualify in-situ operational procedures and functions to automatically monitor and verify the measurement integrity and configuration data of the MPM meter. Flow models implemented in the MPM meter have been developed in collaboration with Onera, Total and Gaz de France.

The Ekofisk field is operated by ConocoPhilips and the partners in the field are Total, ConocoPhilips, ENI, Petoro and StatoilHydro.

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