Measurement of Water in a Wet Gas

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1 INTRODUCTION

Accurate measurement of liquids in a wetgas stream is a complex and challenging task. Acceptable performance in detection of extremely small liquid volumes requires a highly sensitive measurement system.

Furthermore, measurement of water fractions is particularly important since it has a direct impact on scale, hydrate and corrosion management in long pipelines on the seabed. Water measurement is conversely, the most challenging one since water typically constitutes the smallest volume fraction. Water volume fractions may be as low as 0.001 % of the total volume in the pipe.

In order to perform accurate measurement of water, the measurement principle must be repeatable over time and able to sense small variations in the water content. Furthermore, the measurement principle must be able to tolerate significant variations in the hydrocarbon PVT properties. Operationaly, regular measurement of PVT properties is both expensive and time consuming and low dependence on sampling is desirable for the overall success of the measurement system.

The dominating configuration parameter for measurement of the phase that occupies the smallest volume fraction is the PVT properties of the dominating phase. Hence, in order to achieve reliable water measurements in wetgas, it is critical that the system be tolerant to changes in the gas PVT properties.

Picture of a 5"MPM Subsea meter tested at SwRI, San Antonio, Texas

An extensive operator driven development and subsequent qualification program has been executed by 10 oil companies in co-operation with MPM to find a workable solution to the challenge. Tomographic techniques for measurement of liquid content and methods for dealing with variations in the hydrocarbon PVT properties have been developed and tested. The measurements proofed to be very robust, even with significant changes in the PVT properties of the gas.

The paper presents the technical principles, results from the test and qualification program that in particular focused on the water measurement in a wet gas environment.

1.1 Why is water measurement important

In order to ensure a continuous production of hydrocarbons from remotely located subsea wells, management of water production is essential. Water in the production lines can cause scale and hydrates, which can block the pipes. In order to optimise the scale and hydrate inhibition, it is important that water production rates are accurately measured such that safe production can be achieved at the optimum production capacity. For many fields it is also important to know the salt content of produced water in order to prevent corrosion in the pipelines and production equipment. In addition, knowledge about salt content is also important from a reservoir management perspective. Discrimination between salt and fresh water can be used to identify the origin of produced water, either condensed water vapour or produced formation water.

1.2 Measurement of small liquid fractions

For wetgas applications, the challenge is clearly the accurate measurement of tiny liquid fractions in a gas dominated production stream. Even once the liquid volumes have been successfully measured, this tiny liquid fraction must then be split into water and hydrocarbons. Hence, the requirement for a metering system that is capable of extremely high resolution.

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 volume 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.

Typical configuration parameters for commercially available wetgas flow meters are density, permittivity (dielectric constant), mass absorption coefficients and viscosity data for the three phases. If the determination of phase fractions is entirely based on the measurement of the average dielectric properties, or the average density of the phases, the result is often liquid measurement errors of several hundred percent.

As an example, a density based fraction measurement and a typical wetgas case with an operating pressure of 150 bar, the measured mixture density may be 112.7 kg/m3. Assuming an input configuration gas density of 110 kg/m3 and condensate density of 650 kg/m3, the calculated GVF becomes 99.5 vol% i.e. 0.5% of the volume in the pipe is liquid. If on the other hand, the input configuration gas density was wrong by 5% such that the true gas density was 104.5 kg/m3 instead of 110 kg/m3, then the calculated GVF becomes 98.5 vol%, which corresponds to a liquid fraction of 1.5 vol%. Hence, for the example above, an error in the input configuration gas density of 5% (which is not unusual) results in a measurement error in the liquid fraction (and correspondingly the liquid flow rate) of 200%.

The measurement uncertainty of the liquid phases relative to uncertainties in the gas density increases exponentially as the gas fraction in the pipe increases. The same type of argument can be used for dielectric based measurements of liquid or water content when an average mean field approach is being used. This problem has been highlighted by Hans van Maanen at the 2008 North Sea Flow Measurement Workshop [2].

1.3 PVT Configuration Data

All multiphase flow meters need to be configured with the fluid properties of oil, water and gas. The fluid properties of oil and gas can easily be calculated based on the total hydrocarbon composition for the well using Equation of State programs such as Calsep PVTSim. Similarly the water properties can be obtained by sampling. The MPM meter is also capable of measuring the water salinity from which all required water parameters such as density, conductivity and mass absorption can be calculated.

In most gas production applications the fluid properties may 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 variations in the PVT configuration data since it is difficult, if not impossible, to maintain accurate PVT data over time for such installations.

Many multiphase flow meters are also used on comingled well streams from subsea tie backs or from wells producing from multiple reservoir zones, and under such circumstances significant variation in the PVT properties can easily occur. In order to obtain accurate measurement over time it is therefore important that a wetgas (and multiphase) meter is able to cope with significant variations in the PVT configuration data. Alternatively, sampling systems and operating procedures have to be put in place for regularly sampling of the well streams. If a frequent update of PVT data is required, the life cost of obtaining PVT data can easily exceed the cost of the wetgas/multiphase flow meter. In addition sampling may also introduce significant HSE issues (high pressure, H_2S), complicated logistics and is clearly highly undesirable in subsea installations.

1.4 Uncertainty in PVT Data

PVT data is required for configuration of all wetgas and multiphase meters. Reliable PVT data is often hard to obtain and thus errors should be expected in such configuration data. There are two issues which then must be addressed. The first issue is the real uncertainty in the PVT data originating from the sampling and characterisation process.

The second issue is the variations in the PVT data that might occur at a later stage due to changes in the reservoir, wellbores effects, or variations in the instantaneous contributions from individuals sections of a multi-reservoir completion.

In a real field application there can be significant errors in the PVT data, which may originate from several sources. Some of the error sources may be due to lack of representative samples of the fluids and errors in the characterisation process. Commonly used Equation of State models are also known to contain errors, which typical give a bias in the calculation of the PVT data. Tests based on gas densities calculated based on Equations of State have shown that a positive bias is quite common at higher pressures and may typical be in the range 1-3% for the gas density.

All PVT models for calculating single phase properties at actual conditions rely on input of temperature and pressure. Temperature and pressure inputs may also contain a bias, which introduces shift in the configuration data for the meter. Finally, the fluids of the well may change during the period of the test or installation, further introducing errors in the PVT configuration data.

In a real field application, a 2-5% uncertainty in the PVT data would be considered as normal. Even a 10% change (error) in the gas density and gas permittivity can be expected for comingled well applications where the gas composition can change significantly over time. In order to provide reliable measurement of water production of a wetgas well, the measurement system needs to be able to handle uncertainties of 5-10% in the configuration fluid properties like gas density and gas permittivity and still maintain an accurate and repeatable water measurement.

1.5 Flow Effects

At high GVF’s, the liquid fraction is marginal. For gamma-ray based systems, the natural variation in the gamma-ray absorption signal, where the measurement is already at the limit of the GVF range, may cause the GVF to instanteously exceed the 100% limit, itroducing a positive bias in the liquid measurement. Averaging can to some extent overcome this; however since gamma ray absorption is a non-linear phenomena, this introduces systemic errors in slug or wave flow conditions. In order to achieve accurate measurements at high GVF, the measurement needs to be able to provide reliable measurements very close to the 100% GVF limit without actually crossing it.

Other common flow effects are liquid recirculation introduced by mixing devices. Mixing devices creates turbulence in the gas stream, which can cause liquid re-circulation and unpredictable local holdup of liquids. The amount of liquid re-circulation is also highly dependent on the velocity and viscosity of the fluids and difficult to predict. Liquid re-circulation will have a particularly large influence on the water fraction measurement since it is the smallest fraction within the pipe and hence most vulnerable to unpredictable noise/uncertainty in the measurement signals. For reliable and accurate water measurement in a wetgas, mixing devices for homogenizing the flow should be avoided.

1.6 Measurement of water production in a wet gas

The current commercially available wetgas flowmeters capable of measuring water production are either based on permittivity measurements or dual-energy gamma absorption.

Some meters are able to realise a full three-phase measurement in wetgas i.e. all three phases present in the wetgas (water, condensate and gas) are invidually metered. Other meters are based on a two-phase measurement and rely on additional input parameters such as a PVT predicted GOR. Some meters use mixers in order to homogenize the flow whereby the mixer is integrated with a common flow measurement device such as a V-cone. Other meters are based on measurement of the natural flow conditions in the pipe.

2 The MPM 3D Broadband™ technology

The MPM HighPerformanceFlowmeter uses a combination of a Venturi flow meter, a gamma-ray detector, a multi-dimensional, multi-frequency dielectric measurement system [5] and advanced flow models [1, 4], which are combined to a multi-modal parametric tomographic measurement system. The Venturi is used to create a stable radially symmetric flow condition in the 3D Broadband**™** section downstream the Venturi, which would be the natural flow condition if the pipe were infinitely long. These flow conditions are ideal when using 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 the type of tomography used in medical applications.

In the oilfield, the challenges are however far different than in a hospital. Firstly, the meter is measuring fluids and gases under high temperature and high pressure. Secondly, the multiphase mixture can be mowing at velocities of more than 30 meters per second inside the pipe, and the volumes of gas, water and oil are not in thermodynamic equilibrium and do not have constant phase fractions over the cross-sectional area of the pipe.

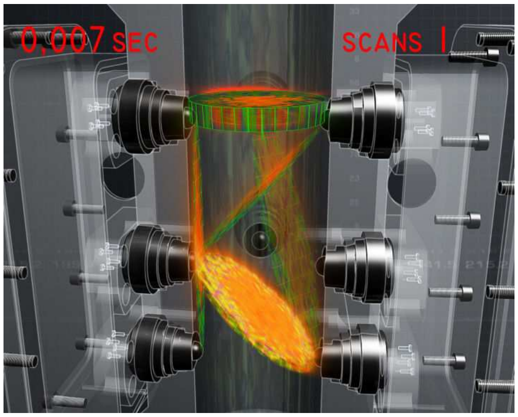

Figure 1 -

3D Broadband™ tomography based meter

The 3D Broadband™ system is a high-speed electro-magnetic (EM) wave based technique for measuring the water liquid ration (WLR), the composition and the liquid/gas distribution within the pipe cross section. By combining this information with the measurements from the

Venturi, accurate flow rates of oil, water and gas can be calculated.

The MPM meter is extremely fast. 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 functionality, which means that both multiphase and wetgas applications are addressed with the same hardware, and its capability to measure water salinity, the MPM meter bridges the existing measurement gap between multiphase and wetgas meters.

In wetgas mode, MPM Meter can either operate in three-phase mode or in two-phase mode. In three-phase mode, the meter measures all the fractions of the flow (oil, water and gas). In two-phase mode, the MPM Meter needs the GOR as an additional configuration parameter which is typically calculated based on the well composition.

2.1 Tomography based fraction and rate measurements for wet gas flow

The MPM meter performs measurements on the natural flow conditions occurring in a vertical pipe. It uses the swirl created by the Venturi to obtain natural vertical flow conditions in the tomographic measurement section downstream the Venturi.

Established correlations for calculating the flow rate of liquid and gas at wetgas conditions assume that the GVF is known. The GVF in this context means the gas volume flow rate divided by the total volume flow rate. The GVF is a parameter which is extremely challenging to measure since the liquid is distributed partly as liquid film along the wall and partly as droplets in gas phase in the centre of the pipe. Measurement of the GVF is further complicated by the fact that the velocity of the liquid film is significantly lower than the velocity of the average droplet (can be more than 10 times lower). Even at such large differences between the film and droplet velocity, most of the liquid flowing in the pipe may originate from the film since it typically occupies a larger portion of the cross sectional volume of the pipe. Hence, in order to obtain a correct GVF measurement, the film thickness, film velocity, droplet volume, droplet velocity and gas velocity need to be known. The use of a tomographic measurement principle is one solution to this problem.

In the MPM meter, the cross section of the pipe is parameterised as liquid film with thickness *m* along the pipe wall and liquid droplets with a diameter *Dd* and number of liquid droplets *Na*. The liquid fraction in the cross section of the pipe then becomes the area of the liquid film divided by the total flow cross section plus the relative volume of liquid droplets present in a certain flow volume element which can be calculated from *m, Dd* and *Na*. By multiplying the liquid droplet fraction in the cross section of the pipe with the velocity of the liquid droplets, the liquid droplet flow rate is obtained. Similarly, by multiplying the liquid film fraction in the cross section of the pipe with the velocity of the liquid film, the liquid film flow rate can be obtained. The total liquid flow rate is the sum of the liquid droplet flow rate and liquid film flow rate.

The gas flow rate is obtained by multiplying the gas fraction in the cross section of the pipe with the velocity of the gas. The flow pattern is illustrated in [3] and shown in Figure 2 below for a Venturi with vertical downward flow.

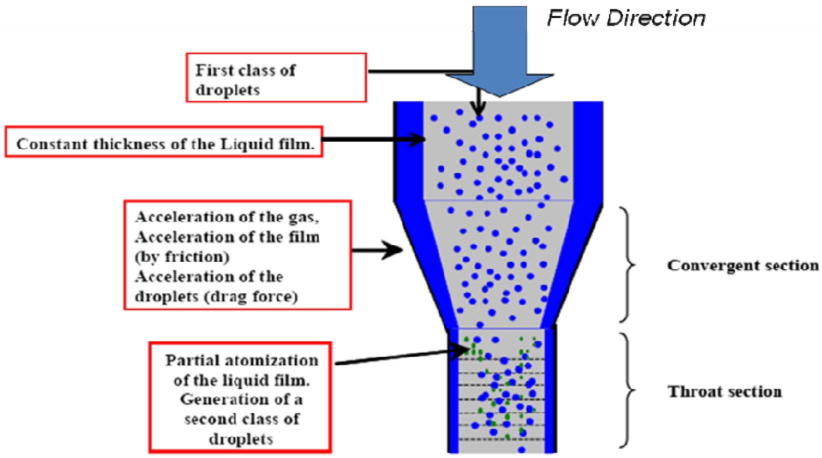

Figure 2 - Flow pattern of a wet gas stream in a Venturi

The various 3D Broadband™ measurements have different sensitivity to the film and droplets in the cross section of the pipe and are also influenced by the amount of water in the liquid phase. This is used together with physical models for the fluid distribution within the cross section of the pipe (i.e. values of *m*, *Dd* and *Na*), the physical properties of oil, water and gas such as surface tension, viscosity and density, measured WLR, measured Venturi dP, and energy conservation equations to calculate the flow rate of liquid and gas. The outcome of these calculations gives the velocity of the liquid film, velocity of the liquid droplets and the gas velocity, hence the GVF can be easily inferred. The GVF, together with the physical properties of liquid and gas are then used together with Venturi-correlations in order to calculate the liquid and gas flow rates. The result from the Venturi correlations is then compared with the outcome of the energy conservation equations for calculating the GVF. If there is a difference between these two approaches then the calculations are repeated in an iterative fashion until the two GVF measurements converge.

As a result, the flow rates of oil, water and gas are derived. In addition, the following parameters are obtained:

- Liquid film thickness
- Droplet diameter,
- Number of droplets
- Velocity of liquid film
- Velocity of liquid droplets
- Velocity of gas.

Using this methodology, the GVF and flow rates of liquid and gas can be determined without use of any mixing device to homogenise the flow or the use of empirical slip correlations. This makes it straight forward to scale the measurement principle over a broad range of sensor dimensions, fluids and operating pressures. This also eliminates measurement errors due to liquid recirculation which is often seen in wetgas meters that use mixing devices.

At ultra-high GVF the Droplet Count® functionality is an add-on feature that contributes to significantly improving the measurement resolution in a regime where liquid volumes are infinitesimally small. 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 make precise measurements of minute liquid volumes in a GVF range where and conventional technologies are no longer able to make true three-phase measurements. The method is furthermore highly tolerant towards changes in fluid PVT properties (i.e. gas density and water properties). This is achieved by a patented (pending) methodology with a far higher resolution on mixture density as compared to gamma based density measurements, and for which the liquid metering accuracy actually increases with increasing GVF.

Liquid droplets flowing with the gas stream in a pipe cause statistical variations in electromagnetic measurement signals. The statistical variation is primarily a function of the liquid droplet size, the number of droplets and the permittivity of the droplets. Hence the PVT properties of the gas phase (i.e. density and permittivity) are not a part of the measurement loop. This makes the GVF measurement based on droplet counting insensitive to uncertainty and changes in the gas PVT properties.

The method uses the 3D Broadband™ ultra-fast electromagnetic measurements scaled to the pipe diameter and the permittivity of the material within the pipe. The measurement field is uniformly distributed within the cross-section of the pipe with low sensitivity to the liquid film along the pipe wall, and high sensitivity towards the droplet flow at the centre of the pipe.

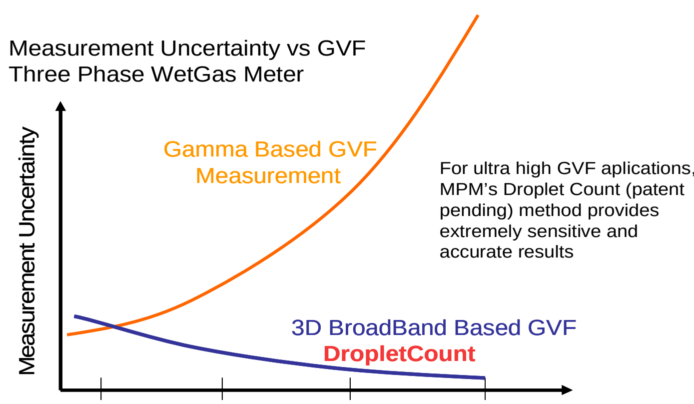

Figure 3 - Uncertainty of Gamma Ray GVF measurement and Droplet Count GVF measurement

The measurements are extremely sensitive to small variations in permittivity caused by droplets flowing in a pipe.

2.2 Combined Wetgas and Multiphase flow meter

The MPM meter is a combined multiphase and wetgas flow meter. The meter can be software configured to operate using either its multiphase or wetgas models. These are often referred to as multiphase and wetgas modes. In addition, the Droplet Count® further enhances the range of the MPM meter models to fully cover the 0-100% GVF range.

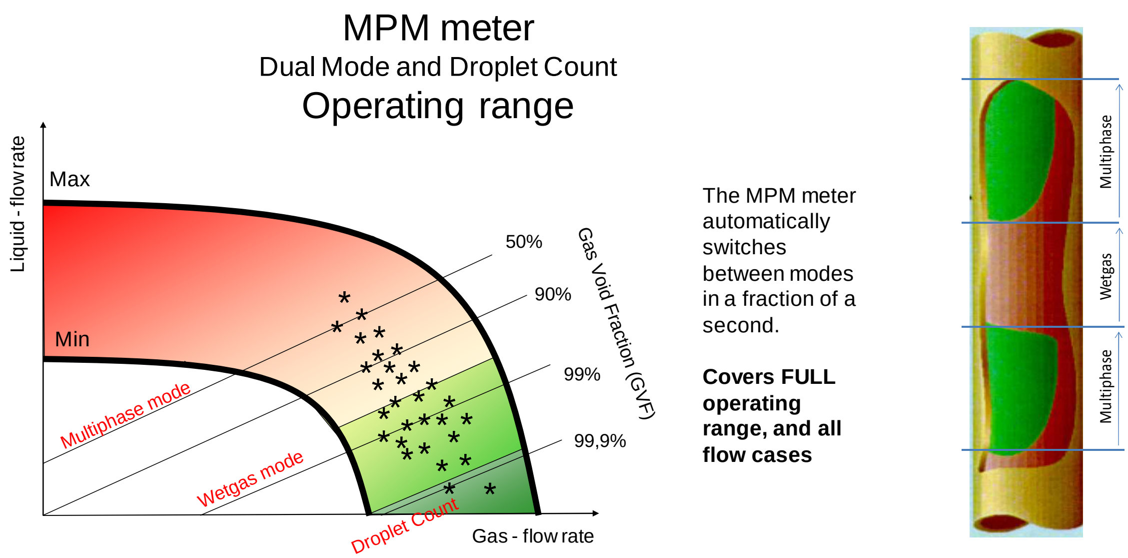

Figure 4 : Dual Multiphase and Wetgas mode

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 simply the software.

2.3 Water Salinity

In wetgas applications, the salinity measurement method implemented in the MPM meter is split into two stages:

- First, it is determined whether salt is present in the stream or not (by a so-called salt water index)
- Second, if salt is present, then the salinity is measured quantitatively.

The reason for this two-step approach is that some measurement plans of the

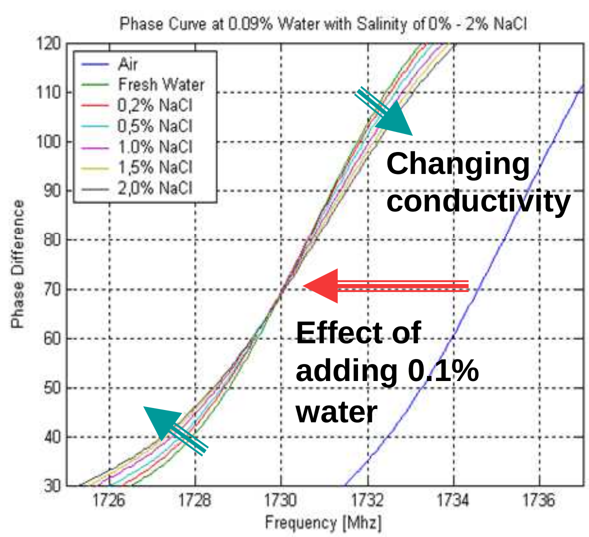

Figure 5 - Water conductivity measurement principle for wet gas applications

3D Broadband™ are very sensitive to presence of salt, whereas others are useful to determine quantitatively the degree of saltiness. This feature is also used as a type of quality assurance.

Another reason for splitting the salinity measurement into two stages is to make the formation water break-through measurement robust with respect to discrepancies in the configuration data such as the dielectric properties of the gas phase. The water salinity measurement is related to the water fraction measurement such that any error in the water fraction measurement will relate to an error in the measured water salinity. As an example, the dielectric properties of the gas is a configuration parameter for the meter and a discrepancy in the dielectric constant for gas may cause a measurement error on the water fraction and hence the water salinity. The salt water index on the other hand, is virtually independent of the gas properties and as a consequence, reliable detection of salt (or formation water) can be achieved irrespective of significant discrepancies in the dielectric constant of gas.

The curves in Figure 5 illustrate the basic measurement principles. Using the 3D Broadband™, many cross-sectional planes are measured and analysed simultaneously to determine the liquid and particularly the water content. Some of the measurements are based on frequency sweeps, which are performed in each direction with a step in the phase of the electromagnetic waves.

The frequency location of a differential phase shift between two receiving antennas is related to the water fraction of the wetgas and the slope of the phase shift vs. frequency is related to the conductivity of the water fraction. An increase in water conductivity causes a decrease in the slope of the curve. The measurement is based on a differential measurement within the pipe. Hence, any discrepancies in the cables, antennas and electronics are cancelled out. The water salinity is then obtained from the measured conductivity and measured temperature.

This measurement can be performed in all the 27 measurement directions used by the 3D Broadband™ system. In order to maintain a high speed measurement principle, 10-15 of the measurements are performed and 5-10 of the measurements are used. This is considered an appropriate trade-off between speed and number of measurements.

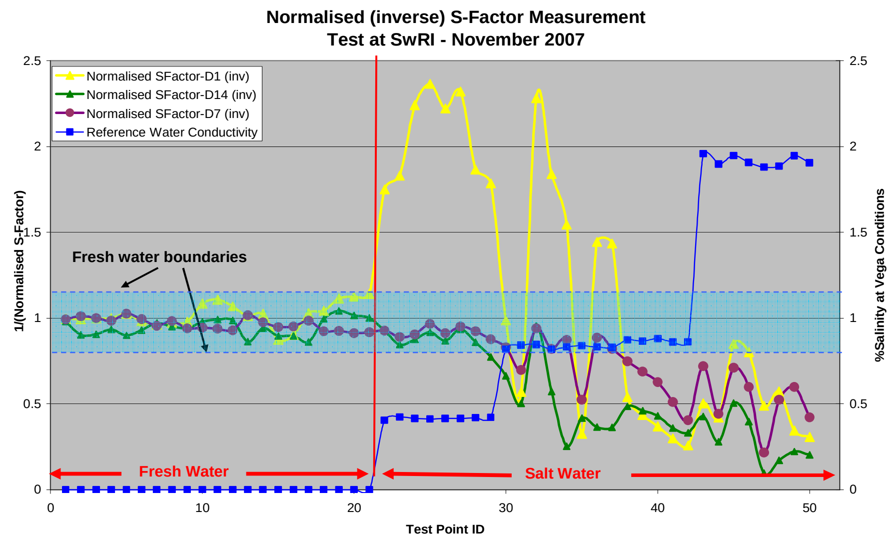

Figure 7 - Raw measurements of salinity factors for different measurement directions of the 3D Broadband sensor

For each measurement direction a so-called normalised S-factor is calculated. The S-factor is a number which is related to the slope of the frequency sweeps. It is defined to be one for fresh water and deviates from one for increasing salinities. Typical, the normalised factor increases when the salinity increases.

Figure 7 shows the inverse normalized S-factor for a few measurement directions. The measurements were logged at South West Research Institute (SwRI) in San Antonio, Texas, October 2007 where a 5" subsea version of the MPM meter was tested in a blind test sponsored by 8 international oil companies. The chart shows all the test points at SwRI with reference to the test ID on the x-axis, with a total of 52 test points. Each test point was logged for a period of 2-4 minutes (to maintain stable conditions in the flow rig).

The first 21 test points were performed using fresh water, with maximum variations in the other parameters (95-99.5% GVF and 0-0.2% water fraction). The subsequent test points, from 22 to 52, were performed using saline water. As can be seen in the chart, the water salinity was increased in steps from 0.4% to 0.8% and finally to 1.9%. The saline water test points were run with similar variations in GVF, water fraction and velocity.

As the graph demonstrates, the normalized S-factors remain within the fresh water boundaries for all test points with fresh water, irrespective of the GVF, water fraction or velocity. The inverse of the S-factor is shown to better visualise the connection between an increase in the water salinity versus a change in the normalised S-factor. Once salt water is used, the normalized S-factor for measurement direction D1 moves outside of the fresh water boundaries. As the salinity increases, more and more S-factor measurements fall outside of the fresh water boundaries.

A clear indication of salt water means that one of the S-factor measurements is outside of the fresh water boundaries. The greater the number of measurements that fall outside of the fresh water boundaries, the higher the confidence level for detection of saline water. At the two highest salinities, almost all the normalized S-factor measurements are outside the fresh water boundaries.

4.1 Salt water Index and Early Detection of Salt Water Production

A salt water index is a number between 0 and 100% and is a function of the salt water detection from all measurement directions in the 3D Broadband™ system.

In principle:

$$S_{Index} = S_{Index}(S_{Factor1}, S_{Factor2}, S_{Factor3}, \dots)$$

If the salt index is 0 then the water is certainly fresh whereas if it is 100 then the water certainly contains salt. Salt water is detected if the salt water index is measured to be above a given threshold value. Hence, the detection of salt water is independent of the water fraction measurement and of the PVT properties of the gas.

Figure 8A illustrates how the salt water index is used for wetgas conditions (GVF of 99.5%).The example shows results for measurements at a WLR of 10% in fresh water performed on a 3" Topside meter installed at K-Lab in November 2006. Here, the index is a very small number and far below the threshold.

Figure 8B illustrates a measurement at a WLR of 5%, and a water salinity of 3%. As salt is present, the index jumps to 100, and subsequently the salinity is calculated. The salinity is correctly measured, even at short time intervals. When some averaging is applied, the salinity value will be stable and change only if a real salinity change appears. Note that at GVF of 99.5% and a WLR of 5%, the absolute water fraction of the flow is only 0.025%.

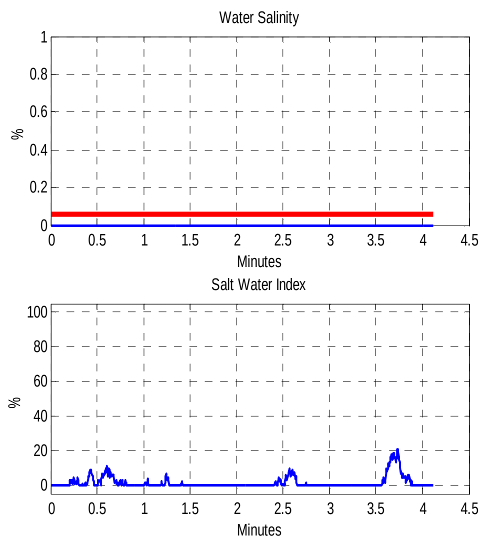

Figure 8A - Salt Water Index in a Wetgas case with fresh water

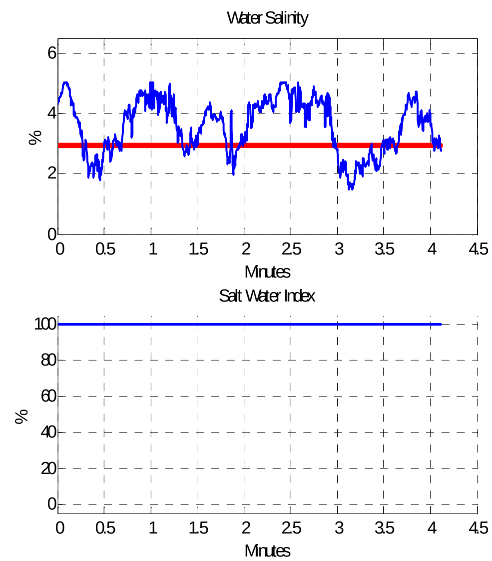

Figure 8B - Salt Water Index in a Wetgas case with saline water

4.2 Quantitative Measurement of Water Salinity

Once the salt water index, S_{Index} exceeds its threshold value, corresponding to a reliable detection of salt, functionality for actual quantitative measurement of the water conductivity and salinity is started. This routine is based on the measured water fraction and on the measured S-factors. In this step, accurate water fraction measurements are required as well as information about the gas PVT properties. Measurement error is minimised through an iterative process.

3 SENSITIVITY TO GAS CONFIGURATION PARAMETERS

As previously mentioned the gas properties are the most important configuration parameters for a wetgas flow. Since gas is the dominating phase and water is (normally) the smallest phase in the pipe for a wetgas, any error in the gas configuration PVT properties have the largest influence on the water measurement.

The MPM meter can operate as either two-phase or a three-phase wetgas meter. In two-phase mode, the PVT predicted GOR is needed as an additional input configuration parameter (similar to other two-phase meters). The GOR input is not needed nor used in three-phase mode.

A 3" MPM Meter was tested at K-Lab in 2006 with a second 5" subsea version tested at SwRI (South West Research Institute) in 2007 as a part of an operator driven JIP program involving 9 international oil companies.

Data from the tests at K-Lab and SwRI (approx 200 test points) have been used to generate the plots below by re-simulation the tests with a 5% error in the input configuration gas density. The sensitivity plots are for gas flow rate (volume), hydrocarbon mass flow rate and water fraction in both two-phase and three-phase mode (without Droplet Count). When the density is known, the permittivity of the gas can be calculated using the Clausius Mosotti equation which shows that the permittivity for the gas is proportional to the gas density [2]. Hence a 5% error in the gas density will also introduce an error in the gas permittivity.

The sensitivity plots are generated at 120 bar based on re-simulation of the raw datafiles logged at K-Lab and SwRI. The error in the measurement is plotted as a contour plot with GVF on the x-axis and WLR on the Y-axis. From figure 9A and 9B it is seen that the error on the gas flow rate due to a 5% error in the gas density is quite small in both two-phase and three-phase mode.

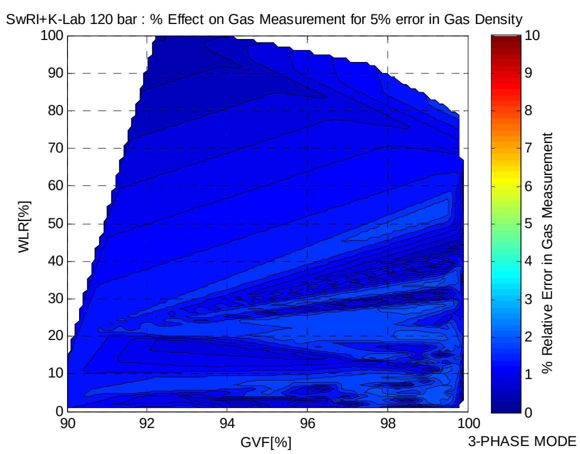

Figure 9A – 3-Phase Mode Effect on gas rate for 5% error in gas density

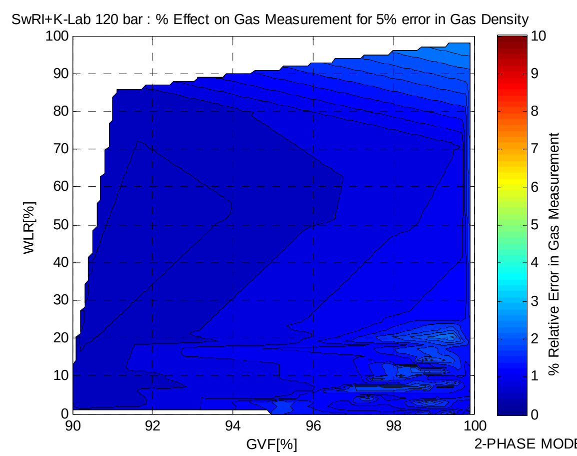

Figure 9B – 2-Phase Mode Effect on gas rate for 5% error in gas density

The hydrocarbon flow rate is slightly more influenced by the error as compared to the gas flow rate as can be seen in figure 10A and 10B below. It is also worth noting that the hydrocarbon mass flow rate is less influenced by error in the gas density in three-phase mode compared to two-phase mode.

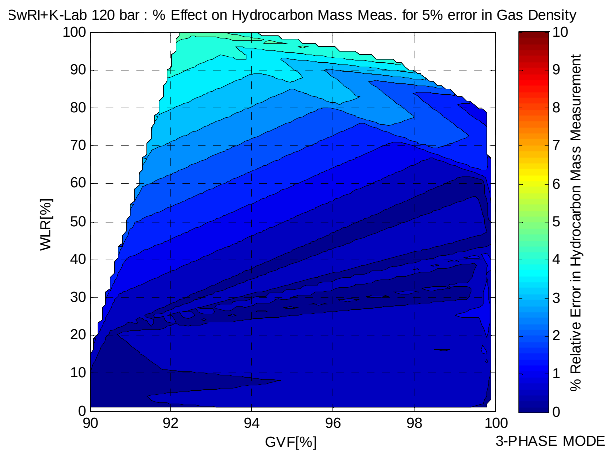

Figure 10A – 3-Phase Mode Effect on gas rate for 5% error in gas density

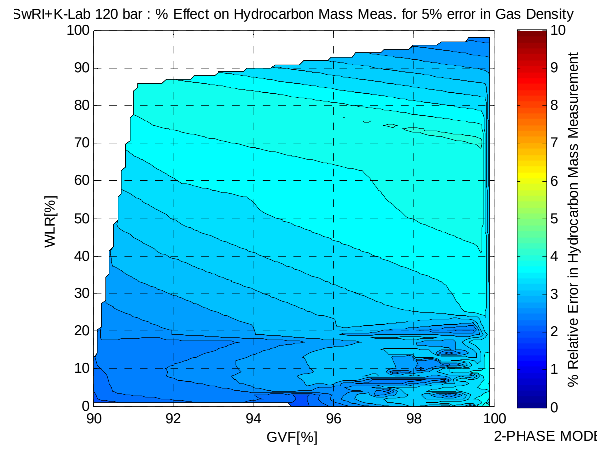

Figure 10B – 2-Phase Mode Effect on gas rate for 5% error in gas density

Figure 11A and 11B below show the effects on the measured water fraction for a 5% error in the gas density for both two-phase and three-phase mode. Clearly the three-phase mode is more robust towards errors in the gas density. In particularly the zero point of the water fraction measurement is far less influenced by errors in the gas density in three-phase mode operation as compared to two-phase mode. As seen from figure 11B, the zero point of the water fraction measurement is almost unaffected by a 5% change in the gas density in three-phase mode whereas an offset is introduced on the two-phase mode measurement as shown in figure 11A. A stable zero point in the water fraction measurement is essential for full confidence in any indications of formation water break through on a previously water-dry well.

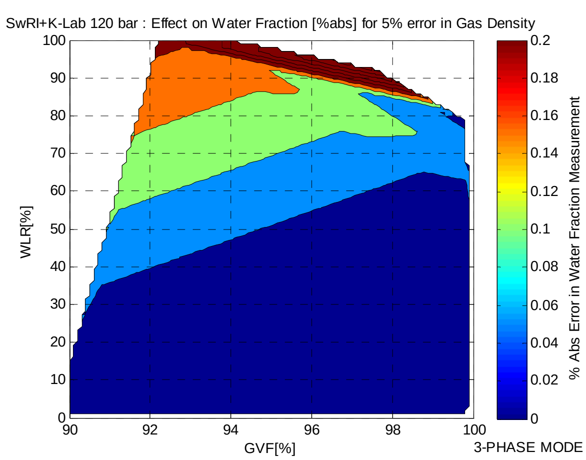

Figure 11A – 3-Phase Mode Effect on gas rate for 5% error in gas density

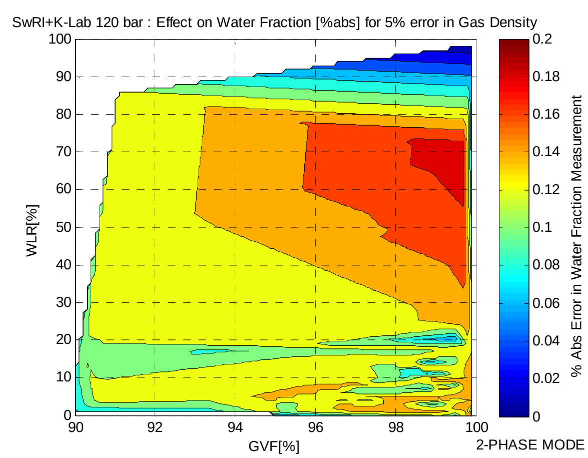

Figure 11B – 2-Phase Mode Effect on gas rate for 5% error in gas density

In the two-phase mode of operation, the PVT predicted GOR is required as an additional configuration parameter. The GOR is typically calculated using a compositional study for the well fluids. Figure 12A and 12B below show the influence on the water fraction measurement and hydrocarbon mass flow measurement for a 10% error in the GOR input. From figure 12A it is seen that the error on the water fraction measurement increases as the GVF falls. An error in the GOR also influences the zero point of the measurement, particularly for lower GVFs. The influence on the hydrocarbon mass flow rate measurement is less pronounced.

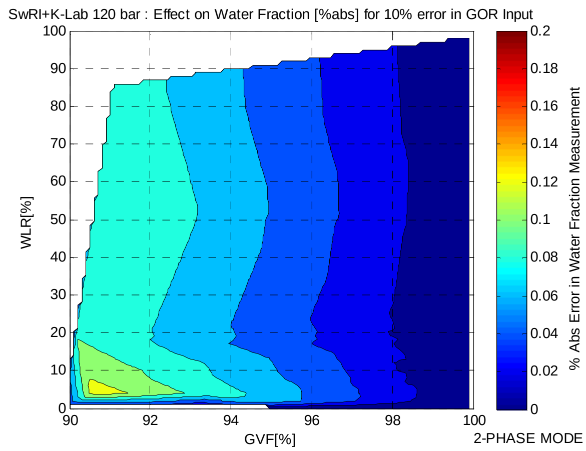

Figure 12A – 2-Phase Mode Effect on water fraction for 10% error in GOR input

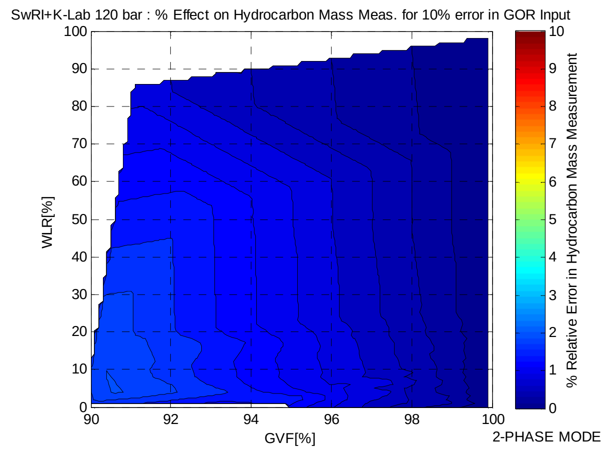

Figure 12B – 2-Phase Mode Effect on Hydrocarbon mass flow rate for 10% in GOR input

4 IN-SITU MEASUREMENT OF GAS PROPERTIES

Since June 2008 a dedicated JIP project, involving 9 international oil companies, have targetted towards developing methods for in-situ verification of measurement values. One of the key goals for the project has been to develop and qualify a method for in-situ measurement of the gas density and permittivity in order to eliminate the distorting effects of uncertainty in the configuration data for gas.

A patented (pending) method for in-situ measurement of gas properties has been developed and implemented in the MPM meter. The method uses the Droplet Count® function to detect short periods of time where pure gas flows through the measurement section of the meter. Alternatively the meter can be bypassed and gas filled during a scheduled shut-in of the well or during the passage of long gas slugs.

Figure 13 below shows the measured GVF and the liquid detection signal, called the Liquid Index, for a gas filled period in the measurement section. The yellow line is the threshold value for gas detection.

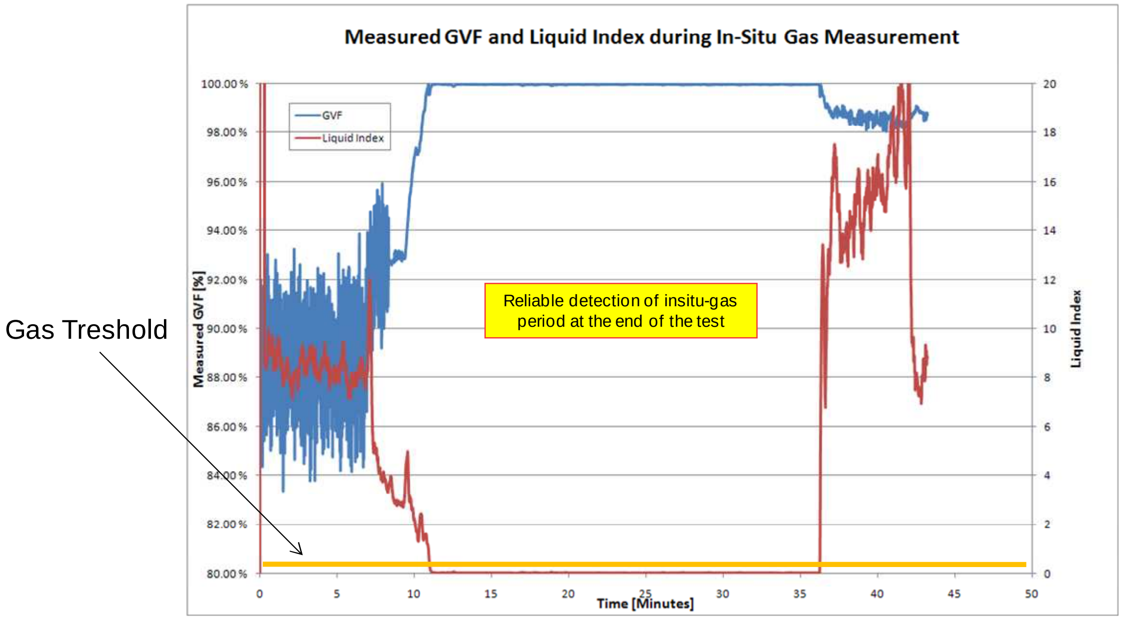

Figure 13– Example of detection of gas in the meter

When pure gas is present, the permittivity and the density of the gas are measured using the 3D Broadband section and the gamma densitometer. The Droplet Count® is so sensitive to droplets that it immediately detects when condensation of liquid starts to occur, due to falling temperature, such that the in-situ gas measurement can be halted in due time.

Since the 3D Broadband measurement performs measurement of permittivity at multiple frequency and on multiple measurement planes, many different measurements of the gas permittivity and density can be made. These all should give the same result and thus the gas in-situ gas measurement has a built-in quality verification function of the 3D BroadBand measurements. Such measurements can also be usd to verify the integrity of the 3D Broadband sensors during flow.

The in-situ measurement can either be used to calculate correction factors to the input configuration gas density and gas permittivity, or to adjust the composition of the well fluid and generate new look-up tables using a sub-service based on the Calsep PVT Sim routines.

Two methods for use of the in-situ gas measurement have so far been implemented: a manual procedure and a method based on automatic update. The automatic method is well suited for applications where frequent variations in the gas properties are expected. In the manual version, an in-situ report is then generated where the in-situ measurements are documented together with a calculation of the effect any changes in the gas configuration data may have on historical measurements. A recommendation for potential corrective action is also added to the report before it is issued to the operator for final approval. If the operator approves the corrective actions, the in-situ measured corrections to the gas density and permittivity are implemented in the MPM meter and the date and time of the implementation is noted in the in-situ report.

This manual procedure ensures full tractability of any changes performed on the gas configuration data and the procedure is particularly suited for applications where the MPM meter is used for fiscal applications. This procedure is typically used as a part of the commissioning of the meter. Most MPM meters are pre-configured with the field PVT data prior to delivery as a part of the FAT procedure. The MPM meter is then fit for service immediately at start up of the wells. Following successful commissioning of the field and the individual wells, any in-situ measurements made can then be inspected to validate the pre-configured PVT data in the meter.

Evaluation of the in-situ gas measurements may also be performed on a regular basis as part of the metering quality assurance plan. Using pre-agreed acceptance limits for the in-situ gas measurements allows the operator to efficiently process the in-situ reports. This procedure also ensures that the operator has full documentation of the validity of the configuration data for the meter. Documentation of the integrity of the measurements from the meter is also obtained by inspecting the historical trend of the multi-frequency and multi-directional measurements from the 3D Broadband sensor in gas.

In wetgas, the MPM meter incorporates three different methods for measurement of the fractions and flow rates of the wetgas, namely

1) two-phase mode with GOR Input
2) three-phase mode based on the gamma densitometer
3) three-phase mode based on Droplet Count®

As outlined above, these three methods behave differently when errors are introduced in the input configuration data for gas density and permittivity. By comparing the measurement results from these three different operation modes it is also possible to verify the quality of the input PVT configuration data for gas. This can also be trended as a PVT quality index where 100% means good agreement between the different operation modes and 0% means poor agreement due to errors in PVT input configuration data.

5 TEST RESULTS

The MPM Meter has been through an extensive test and qualification program and more than 10 meters are now in continuous operation.

This section summarizes some of the test results obtained in field.

5.1 SwRI (2007) and K-Lab (2006)

A 5” subsea meter was tested in a blind test at SwRI in 2007. A year earlier, a 3” topside meter was tested at K-lab. The plots below give an overview of some of the test results in both two-phase and three-phase mode operation. The measurements are performed without the Droplet Count function since this was not commercially released at the time of the test.

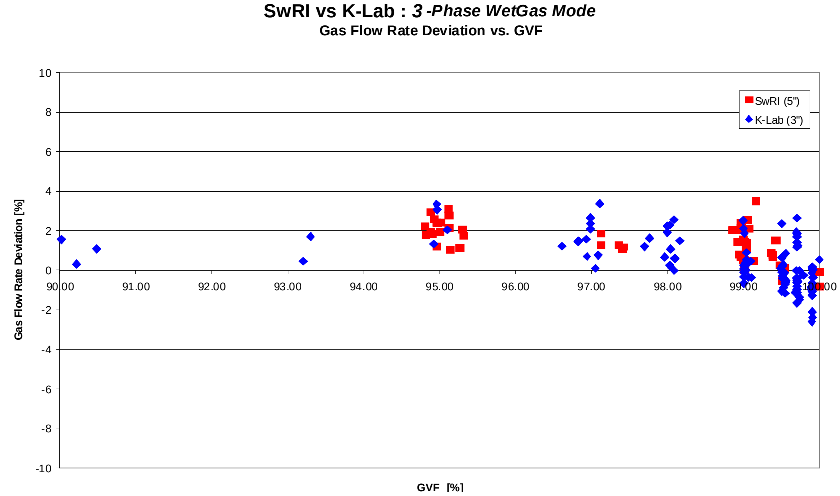

Figure 14A– Difference for Gas flow rate in three-phase Mode

Figures 14A and 14B shows the difference between the measured and reference gas flow rates in three-phase and two-phase mode operation. From the figures below it is seen that the performance in two-phase and three-phase mode are more or less identical.

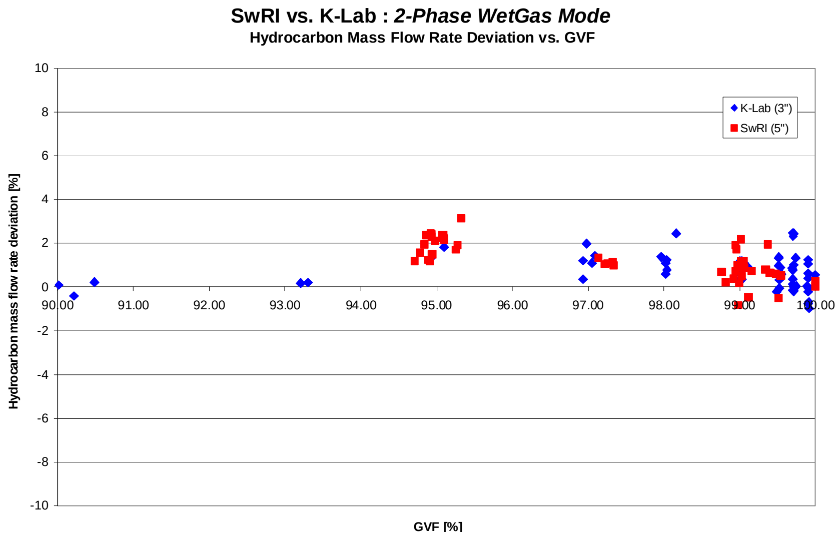

Figure 14B– Difference for Gas flow rate in 2-phase mode

Figures 15A and 15B shows the difference between the measured hydrocarbon mass flow rate by the reference measurement and the MPM meter.

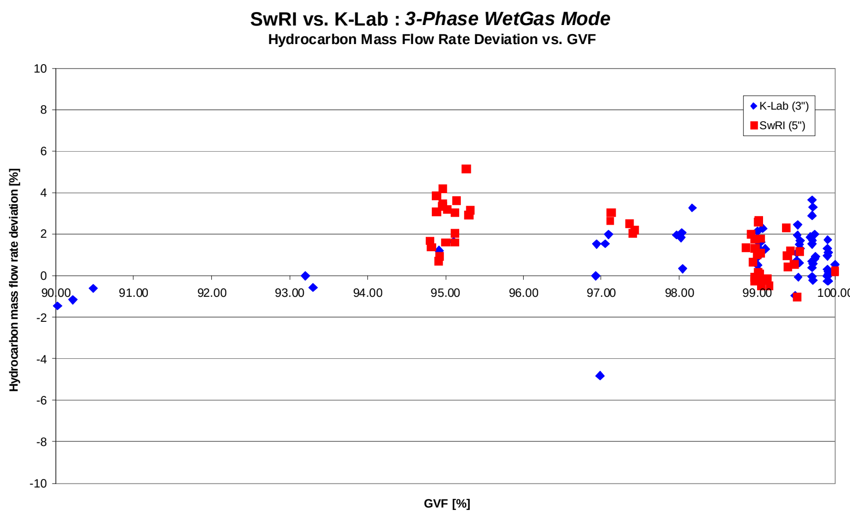

Figure 15A– Difference for hydrocarbon mass flow rate in 3-phase mode

This measurement follows more or less the same trend as the gas flow rate measurement. Slightly higher spread in the measurement is obtained in 3-phase mode, particularly at SwRI.

The spread is partly due to very short test durations at SwRI where many of the points had duration of 2-3 minutes in order to prevent liquid carry over and gas carry under in the test separator.

At SwRI many of the test points also were performed at dPs in the range 15-25 mBar giving a larger spread in the data.

The graphs in figure 16A and 16B show the difference between the measured water fraction and the reference water fraction as a function of GVF.

For the test at SwRI, the average deviation in 3-phase mode operation is -0.008% and in 2-phase mode operation the average deviation -0.007% abs.

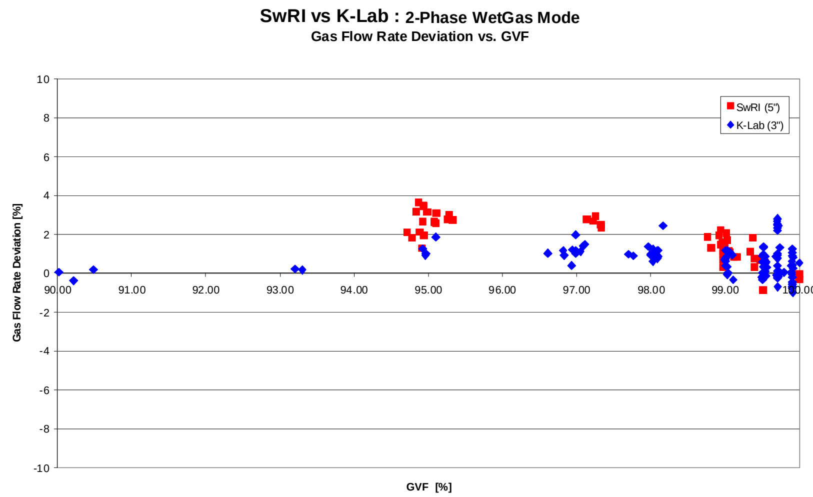

Figure 15B– Difference for hydrocarbon mass flow rate in 2-phase mode

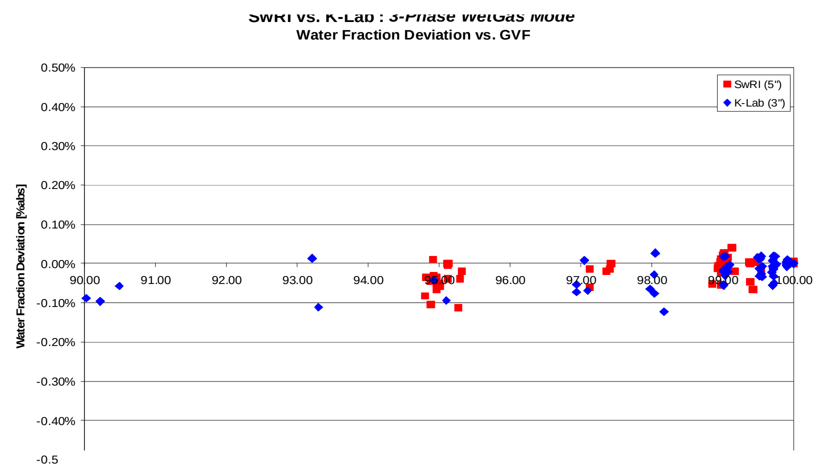

Figure 16A– Difference for measured water fraction in 3-phase mode

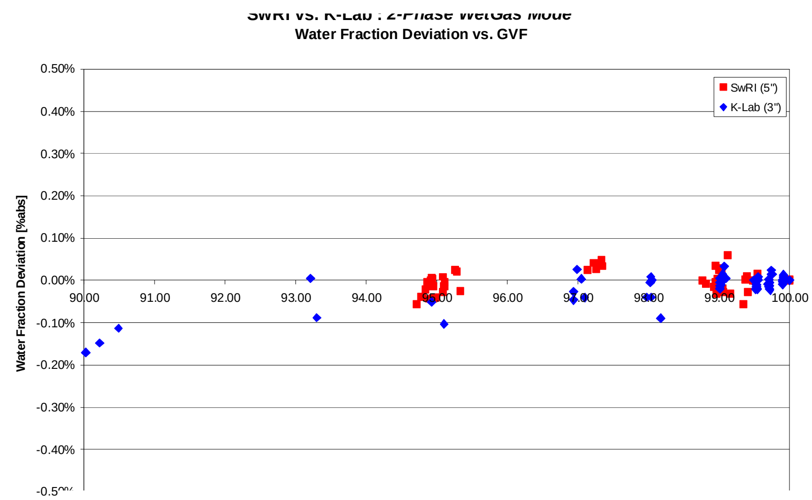

Figure 16B– Difference for measured water fraction in 2-phase mode

5.2 Test with Droplet Count® Function

The first version of the Droplet Count® function was tested out in 2007 based on data from SwRI and the result is shown in figure 17.

From the graph it is seen that the GVF measurement performed by the droplet counting function agrees very strongly with the reference GVF. The time scale is in seconds.

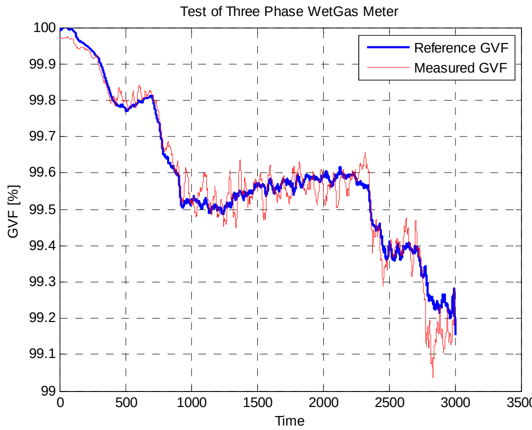

Figure 17– Droplet Count Measurement

Prior to using it in a field location, the function had been tested by re-simulating historical measurements based on raw data captured in previous field test.

The chart in figure 18 to the right shows the measured water fraction from a K-Lab test in 2006 when the tests have been re-simulated with the Droplet Count function. From this graph it is seen that the difference between the measured and reference water fraction is well within a margin of ± 0.02% abs.

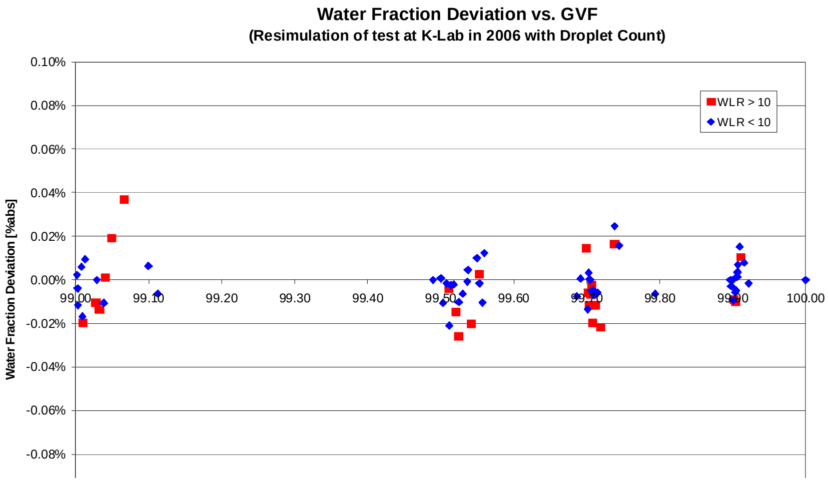

Figure 18 : Resimulation of test results at K-Lab in 2006 with Droplet Count

5.2 Test of 10” MPM Meter at K-Lab – 2008 & 2009

A 10” MPM meter has been in continuous operation at K-Lab since April 2008.

The meter is equipped with both the Droplet Count® function and in-situ measurement of gas density and permittivity. Since November 2008, the meter has been configured to automatically correct the input configuration data for gas density and permittivity based on in-situ measured density and permittivity for gas.

At K-Lab the composition of the gas changes frequently due to loading and re-loading of both gas and condensate in the flow rig. Frequent pressure changes caused by adding and flashing gas also produced significant changes to the

Picture of 10” MPM Meter at K-lab

configuration data. The density of the gas may easily change by 5-7 % due to compositional changes of the gas. Without the in-situ measured correction factors to the input configuration data, the configuration parameters for gas would then be expected to incorporate a 5-7 % error.

Since November 2008 the original input PVT configuration of the MPM meter at K-lab has remained unchanged and the in-situ gas measurement has automatically adopted the PVT configuration data to the frequent changes in gas properties.

StatoilHydro is continuously logging the data from the MPM Meter, and the graph in figure 19 below shows a test of the GVF measurement from the MPM meter performed in May 2009 and presented by StatoilHydro at the MPM user forum in June 2009. As seen, the GVF measurements obtained with a 10" MPM meter at K-Lab in 2009 are markedly similar to the measurements obtained with a 5" subsea meter at SwRI in 2007 (ref figure 17).

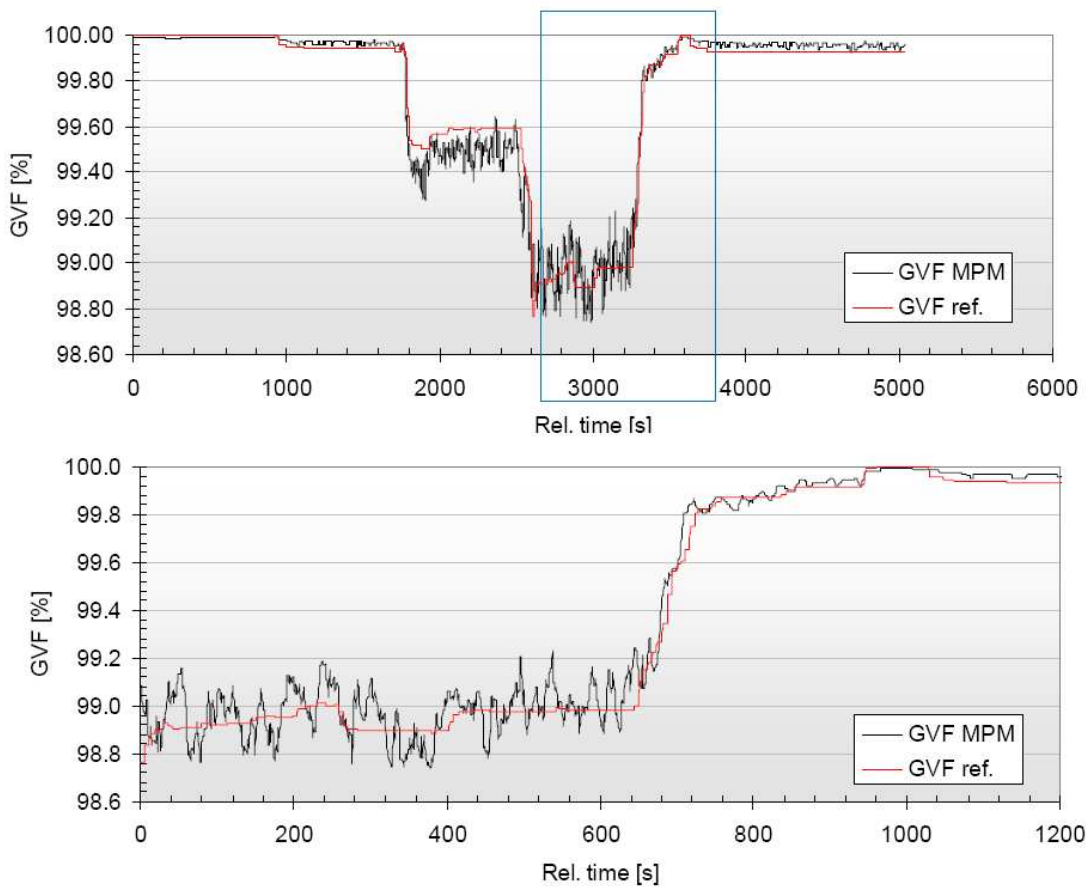

Figure 19– Test of Droplet Count GVF Measurement at K-Lab

Figures 20A and 20B below show the result of a sensitivity test for the liquid and water measurement performed in November 2008. From figure 20A it is seen that the sensitivity of the GVF measurement is better than 0.002% abs. Similarly, the zero point of the water fraction measurement is approximately 0.001 % abs and a change in the water fraction of only 0.0018% is measured with high precision.

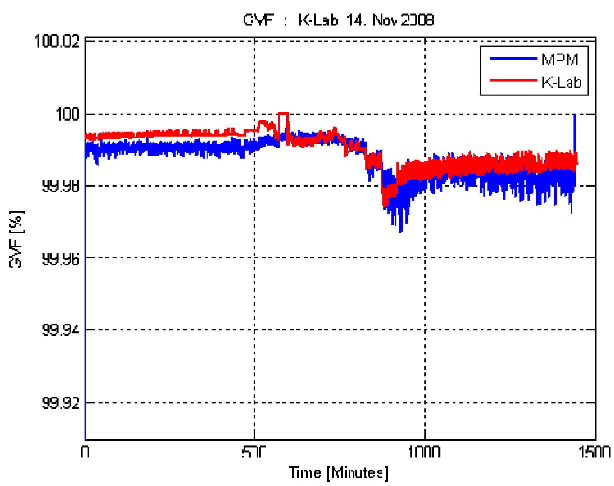

Figure 20A– Sensitivity test of Droplet Count GVF Measurement

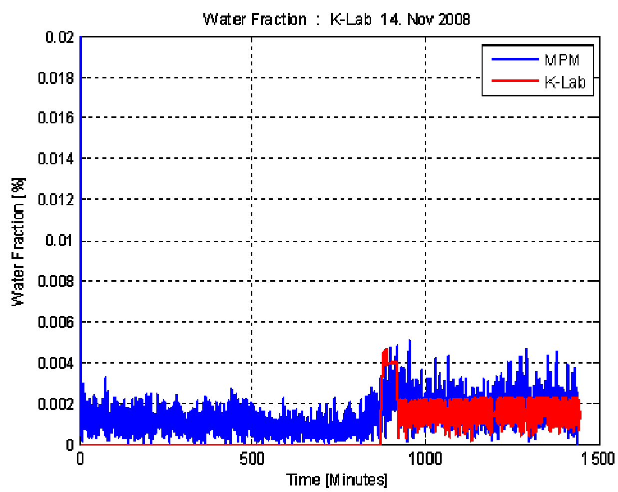

Figure 20B – Water Fraction measurement with Droplet Count

Figures 21A and 21B below show the liquid detection signal and GVF measurement for a short shut down period. The green and blue line of figure 21A is the liquid detection signal and the red line is the pure gas threshold value. In connection with the shut down, there is a short period with pure gas in the meter where an in-situ measurement is performed. After approximately 20 minutes condensation of liquid start to occur and the liquid raw signal moves above the red liquid detection threshold – thus halting the in-situe measurement.

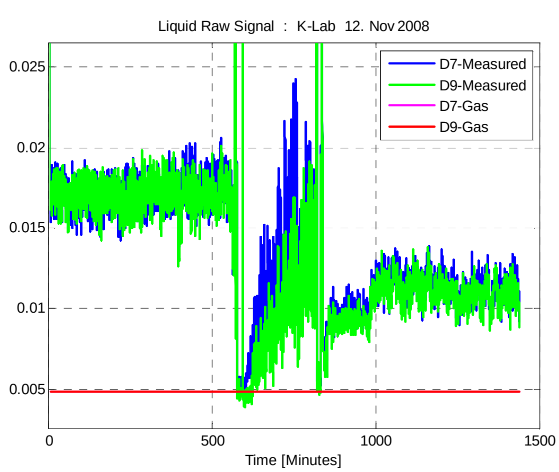

Figure 21A–In-situ detection of pure gas

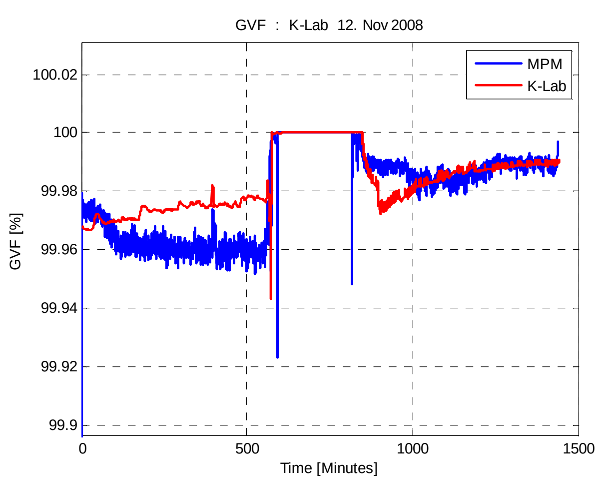

Figure 21B–GVF during in-situ measurement

Figure 22 below shows the measured water fraction before and after the in-situ gas measurement. The reference water fraction (red line) is approximately 0.002 % abs both before and after the shut down. As seen from the graph of the water fraction measurement, there is a negative bias on the measured water fraction measurement from the MPM meter (blue line) prior to the in-situ measurement is performed. This is due to the error in the input configuration data for gas causing a negative bias on the zero point for the water measurement. After the gas permittivity and density have been automatically corrected with the in-situ measurement, the negative bias is removed and the measurement from the MPM meter (blue line) follows the reference measurement of 0.002% abs water (red line).

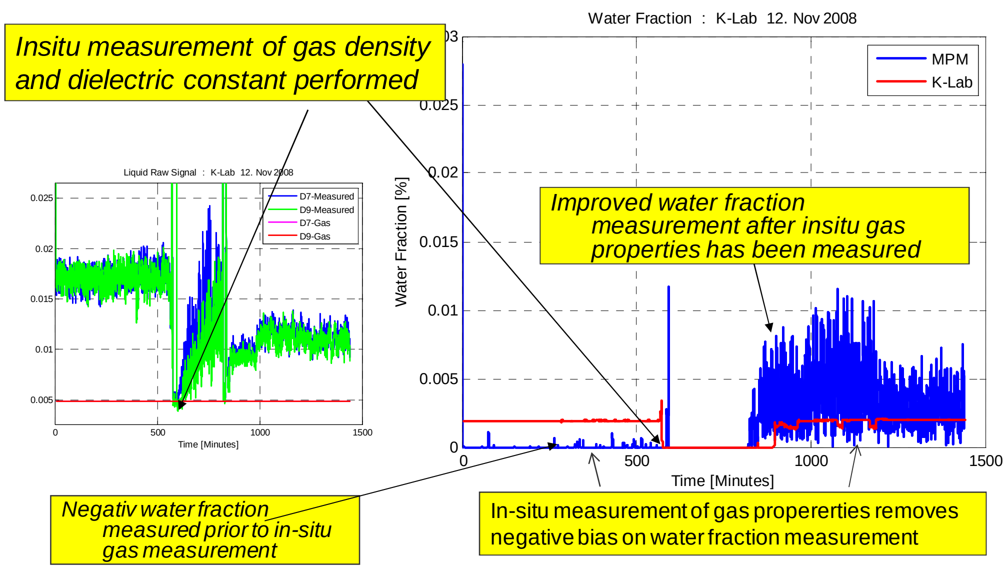

Figure 22–Water fraction measurement before and after in-situ gas measurement

Figure 23 below shows the measured water fraction with in-situ gas measurements for a 14 day period in November 2008. Initially, the water fraction varies in the range from 0 – 0.05% by volume and for the remaining 14 day period the water fraction is mainly well below 0.01 %. The pressure during this period varies from 25 to 55 barg. From the graph it is seen that the water fraction measurement tracks the small variations in the water fraction well and a stable zero point is maintained for the entire period; despite significant changes in the operating pressure (and hence gas properties) of the flow rig.

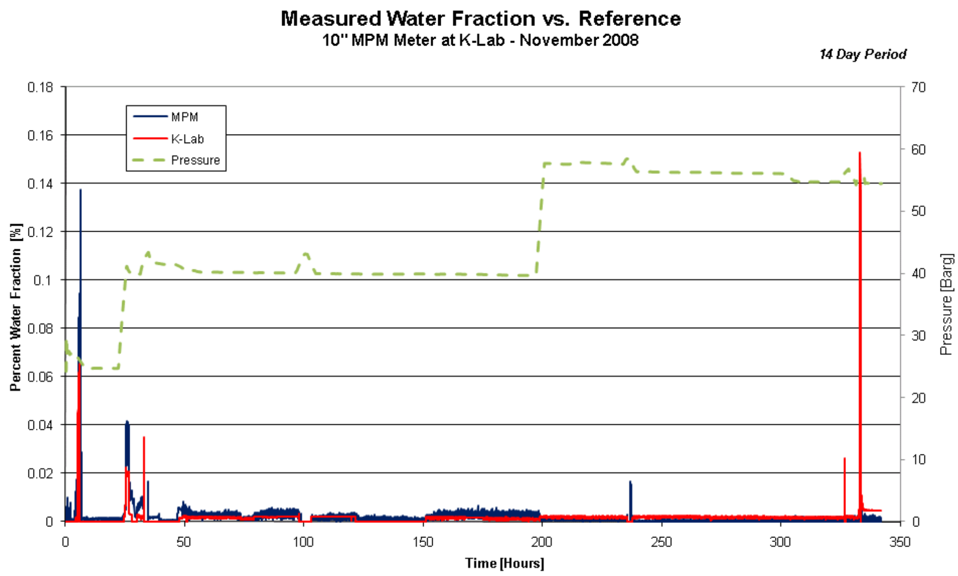

Figure 23–14 day period with automatic in-situ gas measurements

Figure 24 below shows the measured fraction in September 2009, after 10 months continuous operation with in-situ gas measurements. The setup configuration data of the meter has been untouched during this entire period despite significant changes to the gas composition due to frequent loading and discharge of the gas in the flow rig.

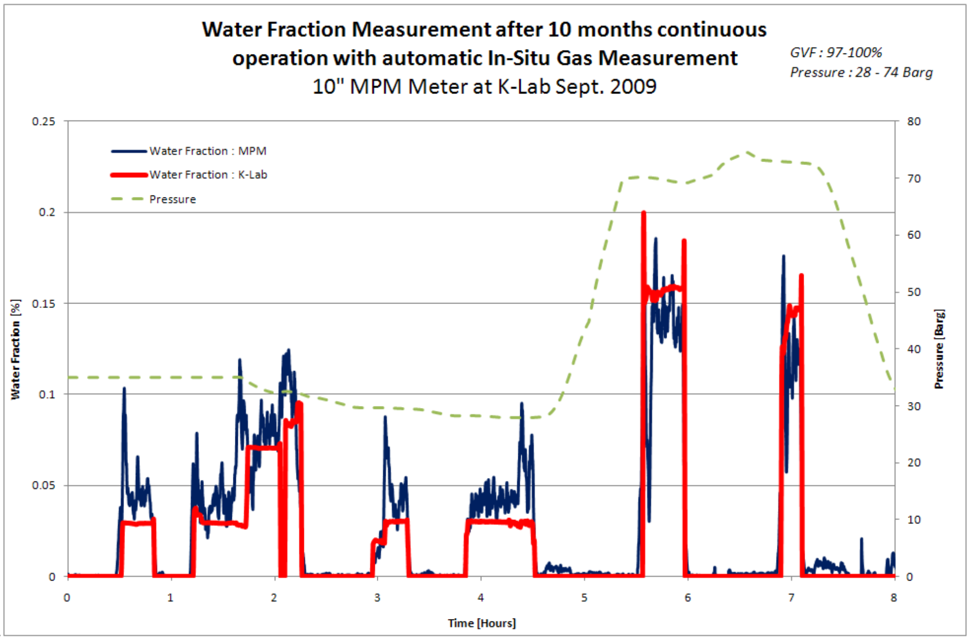

Figure 24–Water Fraction measurement after 10 months with automatic in-situ gas measurements

The pressure varies from 28 to 74 barg during the test in September without any noticeable effect on the zero point on the water fraction measurement. The water fraction measurement of the meter is generally within ± 0.02% abs of the K-Lab reference measurement for the entire GVF and pressure range with a zero point stability well within 0.002% abs.

Figure 25 to the right shows a close up of the water fraction measurement at the start of the test shown in figure 24 above. From the graph it is seen that the zero point, after 10 months of continuous operation, is still well within a 0.002% margin. In fact, the zero point is also within 0.001% in this case.

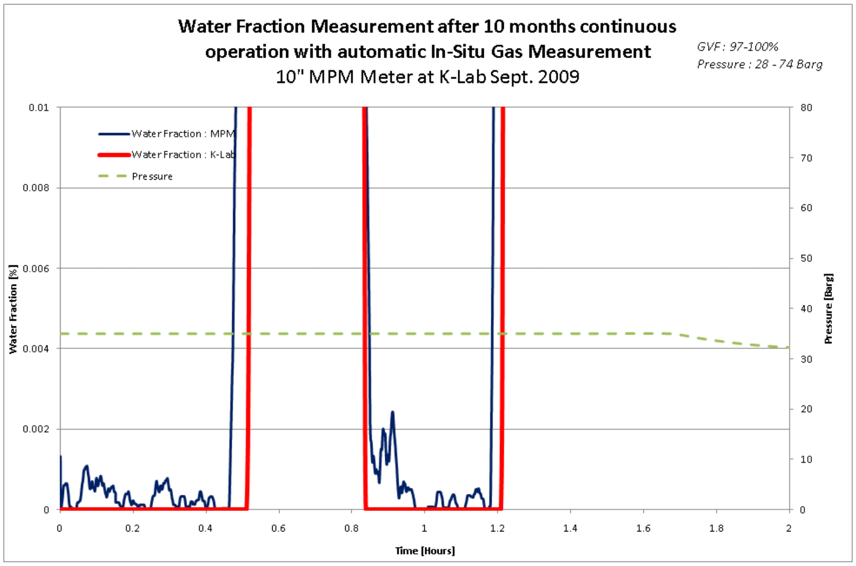

Figure 25– Zero point stability of water fraction measurement after 10 months of operation

6 SUMMARY & CONCLUSIONS

In this paper, a true three-phase wetgas flow meter, which is in addition capable of measuring the water production of wetgas wells, has been presented. The meter has proven to be insensitive to errors in the initially input fluid properties and is similarly able to cope with changes in fluid properties that generally occur during the production of wetgas.With this design, the challenges in measuring water production of wetgas fields, as pointed out by Hans van Maanen at the North Sea Flow Measurement Workshop in 2008 [2], have been mitigated.

The wetgas meter has been designed to handle the naturally occurring flow conditions of wetgas in a vertically upward flow direction without the use of a mixing device. This has been an important design criterion for the meter and is essential in order to avoid turbulence in the gas phase, which would otherwise cause severe liquid re-circulation and local hold up of liquid – thus deteriortating the water measurement.

The meter is equipped with functionality for in-situ measurement of PVT gas properties which, when combined with a naturally high tolerance to variations in the gas PVT properties, enable sensitive, accurate and repeatable water fraction measurement over time, with a zero point stability that is better than 0.002% abs.

The meter also been shown to be capable of measuring the salinity of the water fraction which can be used for early detection of formation water break through.

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 JIP to develop and qualify operational procedures to automatically monitor and verify the measurement integrity of the MPM meter. Flow models implemented in the MPM meter have been developed in collaboration with Onera, Total and Gaz de France.

7 REFERENCES

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