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# Paper 4.1

# The Development of and Initial Data from a New Multiphase Wet Gas Meter


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## 1 INTRODUCTION

Over the last decade, Wet Gas flow metering has been a significant growth area in the Upstream Oil and Gas market. Wet Gas flow meters are now deployed world wide for hydrocarbon allocation, well testing and reservoir optimisation.

Solartron ISA has over 20 years of experience successfully deploying the Dualstream range of Wet Gas meters into more than 200 gas fields.

There have been previous papers at North Sea Flow Measurement Workshops detailing Dualstream 2 and other Solartron ISA developed technologies (see [1] to [8], for example). This paper provides an insight into the experience of developing a new Wet Gas flow meter – the Dualstream 3 – from initial concepts to a product ready for the marketplace.

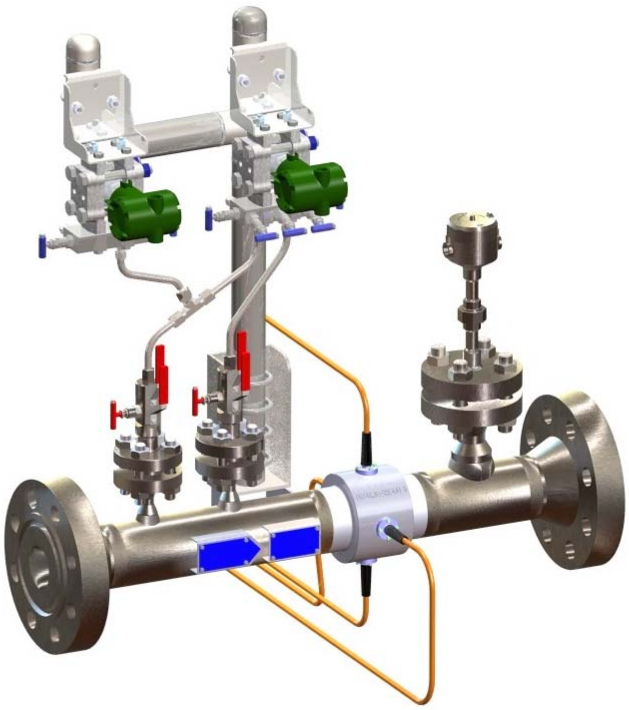

*Figure 1: Dualstream 3 Topside Wet Gas Flow Meter*
*(Flow left to right)*

## 2 HISTORY

Established forty years ago, Solartron ISA began by producing primary flow measurement equipment (then under the name ISA Controls) mainly for operators in the North Sea. With increasing experience and working with several North Sea Operators, they branched out to provide dedicated Wet Gas metering based on a venturi, marketed as Dualstream 1 flow meters, utilizing standard wet gas correction principles detailed at previous North Sea workshops (such as [9]).

During the late 1990s and early 2000s, a partnership with BG Technology and flow testing at NEL (National Engineering Laboratories in Glasgow, UK) led to the development of the Dualstream 2 technology, correlating measurements from two dissimilar differential pressure (DP) devices to accurately determine the gas and liquid mass flow rates. This testing was also part of the NEL Wet Gas Joint Industry Project (JIP) conducted in 2000.

Further testing resulted in the "Advanced" range of meters making use of the Pressure Loss Ratio effects, improving the accuracy of high gas volume fraction cases (where the GVF is typically greater than 98%), and providing determination of gas, condensate and water phases.

For a number of years Solartron ISA has been working on further developing the range of Dualstream meters by incorporating water fraction measurements. Initial work with research groups at two universities proved the concept of utilizing microwaves to measure the water fraction within a wet gas flow, and led to the development and testing of an initial prototype. This demonstrated that some of the underlying methods functioned as the theory indicated, whilst it also brought to light a number of issues for further investigation.

Throughout this time there has been an iterative process based around improved theoretical understanding, computer simulation of relevant properties, and testing of prototypes. Working closely with experts from a number of different specialities, the meter has developed into a straightforward yet sophisticated system for the accurate multiphase measurement of Wet Gas flow rates.

## 3 DUALSTREAM 3 – DESIGN AND PERFORMANCE

The Dualstream 3 is a combined DP and Microwave Water Fraction meter, making use of patent-pending techniques to measure the water fraction, and thus provide improved corrections of the liquid content passing through the sensors.

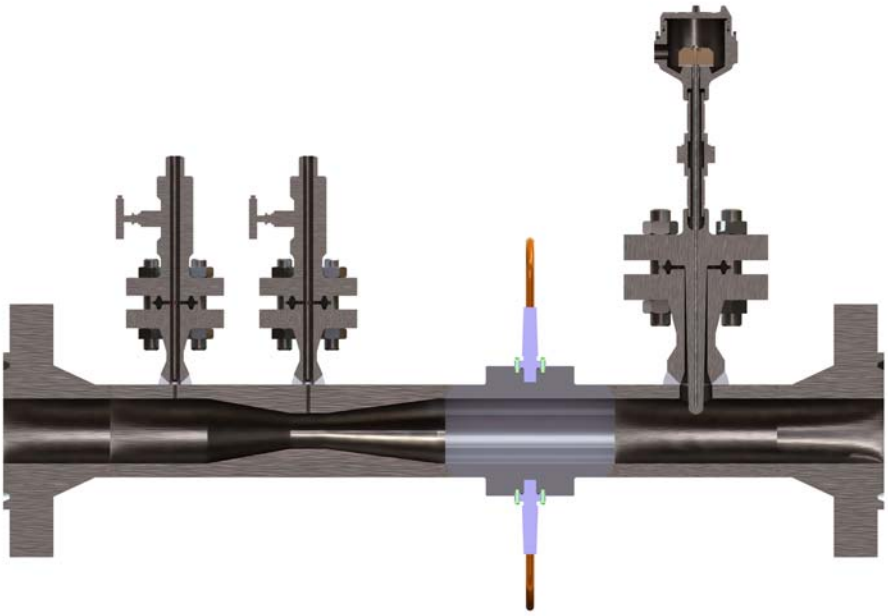

*Figure 2: Dualstream 3 Internals (Simplified) showing Venturi and Microwave metering techniques*

The underlying differential pressure technology is similar to that deployed in the Dualstream 1 flow meter, utilizing a venturi as the primary flow element. Downstream of this is a microwave resonant cavity with integral sensors embedded inside the wall, thus avoiding the use of "wetted" sensors; aspects of this system are currently patent pending. By incorporating the Pressure, Temperature and Differential Pressure (DP) measurements with the multiple sensors of the Water Fraction device, individual phase flow rates can be resolved.

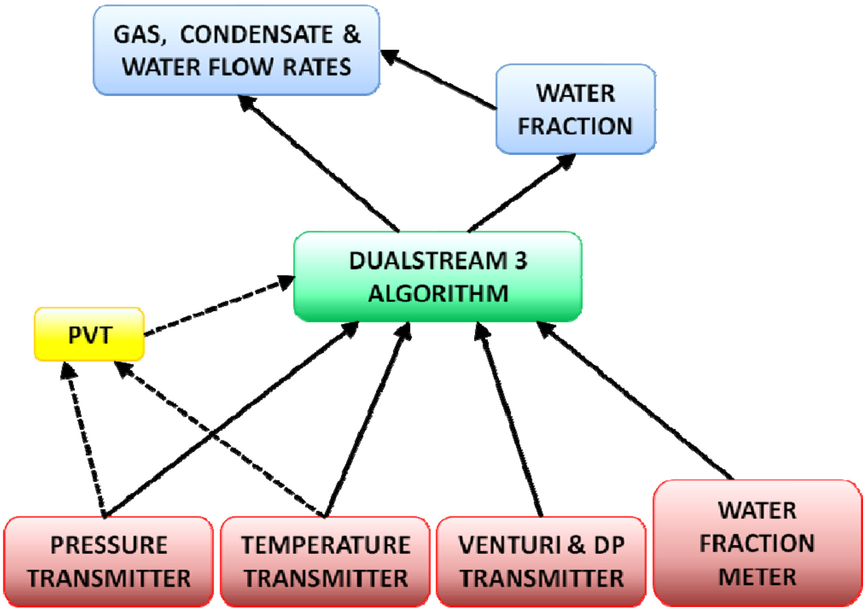


*Figure 3: Dualstream 3 Calculation Block Diagram, indicating reduced reliance on PVT*

The Dualstream 3 flow meter has been developed to meet or exceed the following specification:

| | |
|---|---|
| Operating Range: | 90% – 100% GVF |
| Water to Liquid Ratio (WLR): | 0% – 100% |
| Gas Mass Flow Rate: | ±2% relative (typical) |
| Water Volume Fraction: | ±0.1% absolute |
| Condensate Mass Flow Rate: | ±10% relative (Two-Phase mode) or |
| Condensate Volume Fraction: | ±0.25% absolute (Three-Phase mode). |

(Uncertainties specified to 95% confidence).

## 4 OVERCOMING ISSUES WITH WET GAS TECHNOLOGY

Although wet gas flow meters have existed for over 20 years, it is recognised that there are limitations with all existing wet gas metering solutions, regarding both the general measurement principles and the specific flow measurement techniques employed.

### 4.1 Hy drates

The build up of gas condensate hydrates (solid crystalline compounds, typically containing hydrocarbon molecules trapped in a lattice of water molecules, with a snow-like appearance) in colder parts of the pipe-work – for instance, in impulse lines – can impede the flow and prevent accurate measurements. In extreme cases they can even block the main pipeline, particularly under abnormal conditions such as shut-down.

MEG (Monoethylene Glycol), Methanol or other hydrate inhibitors will typically be injected upstream for situations where hydrates are considered likely to form. However, it is still necessary for metering manufacturers to design products that reduce the risk of hydrates becoming an issue at any of the conditions that the meter is likely to see.

### 4.2 Scaling, Erosion and Sand

For all types of flow meters that have been in service for a number of years, inspection of the line may reveal that solid particles have accreted from the well fluids onto the pipe walls. In just the same way that scaling can cause a build up, erosion (particularly in flow containing a larger proportion of sand or other rough solids) can cause a wearing away of critical aspects of the flow meter, particularly in high velocity areas which can lead to alteration of the flow meter geometry.

Even though sand may be considered to be part of the cause of erosion, it can also create deposits where it is able to fall out of slowly moving flow and remains relatively undisturbed; for instance, in blind-T's. Significant deposition could therefore cause an alteration of the flow pattern in that area, thus potentially affecting metering.

### 4.3 Non-Robust Technology

Flow meter technology should be able to withstand many years of operation under less than optimal conditions. Anything that alters the flow pattern or impedes the flow may be susceptible to sizeable forces, and therefore the mechanical strength of those components should always be rigorously investigated.

Similarly, a component may mechanically resonate under certain flow conditions – for instance, a thermowell or other intrusive element. It is therefore essential for the flow meter manufacturer to evaluate those issues and ensure that situations that could cause operational concern, ranging from inaccurate measurement to objects breaking off in the flow, are mitigated as far as practically possible.

There is also the possibility that the flow meter may face many different pressure or temperature cases throughout its life. Material selection and the robustness of sensors and electronics are essential aspects of developing reliable metering technology.

### 4.4 Radioactivity

Many manufacturers make use of the effects of radioactivity to determine flow rates or other parameters associated with the fluids. Operationally, much has already been said of the issues regarding using radioactive sources (i.e. drift, temperature effects etc.); however, there are also other pragmatic issues in the use of radioactive sources requiring licensing or import and export issues, depending on the end user's country.

### 4.5 Accuracy and Sensitivity

As wet gas flow meters have developed, along with the increasing ability to accurately perform wet gas flow loop tests to high quality reference standards, the fundamental accuracy and sensitivity of flow meters have improved. It is therefore pertinent for flow meter manufacturers to ensure that their products are relevant to the current market requirements for accurate flow measurements.

### 4.6 PVT

PVT (Pressure, Volume, Temperature) calculations provide models for the behaviours of mixtures of hydrocarbon and other chemical compounds under changes in the physical conditions that the fluids are subjected to. All wet gas and multiphase flow meters make some use of these kind of techniques, requiring a hydrocarbon composition (or parameters derived from this information). Whilst, in an ideal system, this should not pose an issue, as the interval between sampling extends, the accuracy of the flow metering could be affected. It is therefore desirable to reduce the reliance upon PVT modelling, particularly in cases such as subsea metering where sampling is both more complicated and expensive, if available at all.

### 4.7. Salinity

Certain techniques for measuring wet gas can be affected by the salinity of the water element, and, although this can be used as a useful measurement technique in determining water breakthrough, it can also provide a potential failure point for flow metering.

### 4.8 Flow Regime

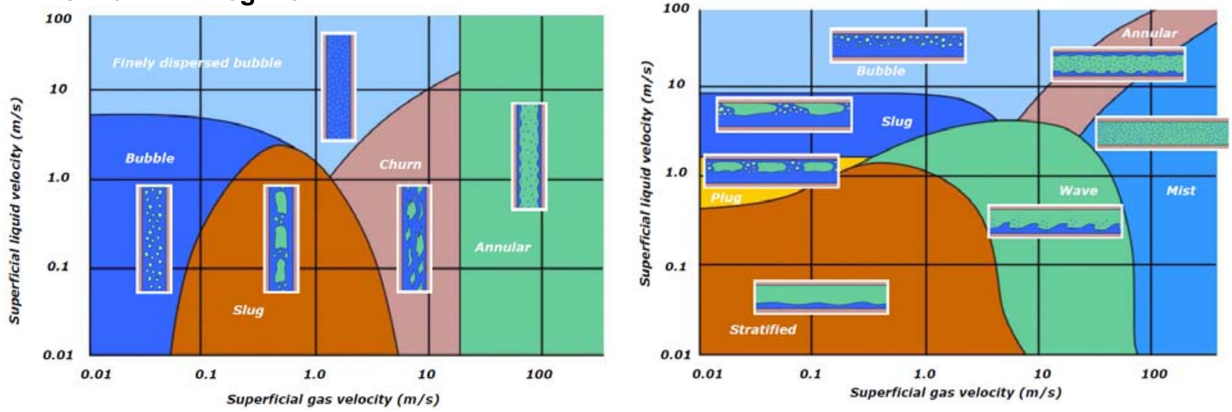


*Figure 4: Wet Gas Flow Regimes taken from*
*Fig 6.1 and 6.2, NFOGM [13]*

As can be seen in the diagrams above, there are many different flow regimes, depending on both the gas and liquid flow rates and the orientation of the meter. Some of these flow patterns are simpler to measure than others, whilst also reliant upon the measurement technique employed; this may provide limitations to the range of flow rates measurable, or indicate that the flow needs to be conditioned in some way before being metered.

### 4.9 Liquid Continuous Conditions

In mixtures of condensate and water the two liquids will establish themselves such that one is the continuous phase and the other is the dispersed phase (discrete pockets of liquid surrounded by the continuous phase). For example, if water is the continuous phase then the liquid is said to be water continuous. Typically, water continuous conditions will prevail if the liquid is predominantly water and condensate continuous conditions will prevail where the liquid is predominantly condensate. Where approximately equal volumes of the two liquids are present then we can expect to see a transitional region within which there are temporal and spatial fluctuations between water and condensate continuous.

Some flow meters operate effectively in only one of the regimes. The transitional region is recognised to be difficult to meter, particularly as it can switch from one regime to the other within subsections of the flow. The end user should be aware of the limitations of metering techniques utilizing these schemes.

### 4.10 Reliance on High-Technology Solutions

Although wet gas flow meters increasingly use more complex technology for providing accurate measurements, this may provide more potential points of failure than a simpler technology. Flow meter manufacturers need to consider the issues of long term reliability and stability of the solutions that they provide.

## 5 DUALSTREAM 3 WET GAS FLOW METER

The Dualstream 3 is specifically designed for gas condensate wells for the metering of wet gas flow conditions. It therefore is designed to overcome the issues highlighted in section 4, resulting in a more accurate, reliable and versatile flow meter.

### 5.1 Accurate and Sensitive

The primary purpose of a wet gas flow meter is to correctly measure the flow rates of the fluid phases passing through the device. The Dualstream 3 meter incorporates technology enabling a direct measurement of the water phase, which leads to a more accurate determination of the overall flow rates, and a reduced dependence on PVT models.

The Dualstream 3 technology increases the sensitivity, particularly to water in the liquid flowing through the electromagnetic sensing element. An accurate measurement is a necessity, but being sensitive to very small changes of water, particularly when looking for water breakthrough, is an added advantage.

### 5.2 Robust

A flow meter may be subject to a harsh environment throughout its life – transported from manufacturer to site, installation, followed by many years of operational service. It is an expectation that any industrial flow meter should be more than able to deal with these issues, without reliance upon overly fragile technology or components.

Therefore, the main metering technology of the Dualstream 3 is a venturi, widely regarded as an accurate and robust flow meter in Wet Gas environments, generally performing well when flow conditions include issues such as scale, erosion or sand. The beta ratio (the diameter of the narrowest part of the venturi divided by the pipe diameter) is chosen such that the DP measurements and flow velocity are of a suitable range.

Whilst, for a topsides meter, hydrates can be mitigated by appropriate insulation and heat tracing of suitably sloped impulse tube, the subsea Dualstream 3 will be available with diaphragm seal connections to the Pressure and DP transmitters. These significantly reduce the hydrate risk as the wet gas fluid cannot pass beyond the close-coupled diaphragms.

The electromagnetic sensing section of the meter is placed immediately downstream of the venturi outlet cone as a smooth continuation of the pipeline bore. It is a relatively short section and imposes no intrusion into the pipeline, thus minimising any impediment to the fluid flow. This is made possible by having the non-wetted sensing elements embedded within the device wall, which also has the benefit of protecting the sensors from erosion, scaling and damage from the flowing fluids.

### 5.3 Meter Size and Weight

Although flow meters are typically not often moved once installed into their working environment, it is useful for them to be relatively small and light. This reduces the issues with installation, as a smaller meter is easier to fit into a given piping structure, and simplifies the structural calculations that may be needed in certain locations to ensure that the meter does not significantly alter the centre of gravity point or exceed the envelope or weight allowance for the tree, etc.

With no requirement for an upstream spool or mixing device, and with the water fraction meter section being relatively short, the Dualstream 3 is a small, and, therefore, a relatively light flow meter.

### 5.4 Range of Sizes

As with many applications, in flow measurement, a “one-size-fits-all” approach is rarely successful. The Dualstream 3 is therefore initially available in a range of pipe diameters (nominally 4 to 8 inches), allowing the meter to be sized appropriately for the expected flow conditions.

### 5.5 No requirement for Mixing

Intrinsic to the requirement to be small and light is the removal of any need for upstream conditioning of the flow, thus reducing the upstream length included in the metering section. Based on the test information available, the meter works in either horizontal or vertical down flow direction with no requirement for a blind-T, additional straight lengths upstream or any other mixing device.

### 5.6 Low Permanent Pressure Loss

One advantage of a venturi meter included in the Dualstream 3 is a low permanent pressure loss across the metering section. With no mixing device and the water fraction section operating at the pipe diameter, the DP section and thermowell are the only impediments to the flow.

### 5.7 Fully Functional in all Liquid Conditions
The Dualstream 3 meter has two distinct regions of operation, corresponding to water continuous and condensate continuous conditions. The meter makes real-time calculations to determine the prevailing continuous phase and is capable of taking into account rapid changes of continuous phase and adjusting the flow calculations several times per second if required, and will therefore find the best solution, even in the transition region.

The meter has been tested at different Wet Gas facilities across a wide range of pressures, flow rates, liquid content and salinities, in order to characterise its performance at all conditions likely to be encountered in the field.

### 5.8 Utilizing Microwaves to measure Water Fraction
Fundamentally, the Dualstream 3 meter includes microwave technology (with no use of radioactive components) to enable finer measurements of the water fraction. This method has not been without its critics [11, for example]; however, the Dualstream 3 utilizes patent-pending methods of overcoming the potential failure areas highlighted by Hans van Maanen. This has been expanded upon in section 7.

### 5.9 Computer-Controlled Electronics and Processing
In this example the electronic system serving the resonant cavity is controlled by an embedded computer which also acquires pressure, differential pressure and temperature measurement signals and uses them in its flow metering calculations.

Implementation of wet gas flow algorithms is generally performed by remotely sited flow computers that read in the various process measurements and generate corrected flow measurements. It has been found in trials of the Dualstream 3 meter that embedding the computing element of the system locally with the meter increases the capabilities and flexibility of the system, for example, providing diagnostics functionality.

## 6 DEVELOPMENT OF DUALSTREAM 3 FLOW METER

The development of the Dualstream 3 meter has been no small task, with many specialists bringing specific theoretical knowledge or practical experience to the process. Solartron ISA utilize modern development procedures, such as a Development Gating System and Design Failure Mode and Effects Analysis (FMEA), which have ensured the progression of this project through each design and prototype towards the commercially available flow meter.

### 6.1 Theory
The theory behind utilizing microwaves to measure water content within multiphase gas fluids has been established for a number of years, with products that apply aspects of this theory already on the market. The Dualstream 3 technology applies a particular aspect to generate the necessary sensitivity to water. Resonance mode conditioning is applied as part of the process of extracting the desired signal from the extraneous noise.

#### 6.1.1 Sensors
The different types of sensors utilized for detecting electromagnetic waves can be categorized in one of five ways [11] - Transmission, Reflection, Resonator, Radiometer and Imaging sensors.

Electromagnetic Resonator sensors are able to measure the complex permittivity of materials, as the wavelengths and energy losses of electromagnetic waves propagating through a dielectric material are dependent upon this parameter.

Resonant frequencies and the quality factors of a resonant cavity will vary for different materials within the cavity. Since the complex permittivity of water differs significantly from that of gas, condensate or oil, it can be shown that electromagnetic resonator-based measurements are well suited to the accurate determination of water in a hydrocarbon flow.

However, there are a couple of subjects concerning Resonant Frequency Electromagnetic sensors that need to be addressed.

Firstly, there are, theoretically at least, an infinite number of resonance modes for any electromagnetic resonant cavity that occur across the frequency spectrum from the fundamental mode onwards. Undesired modes can make it difficult to discern the useful modes by merging with them or obscuring them completely, with the relationships between modes further altering as the dielectric material within the cavity changes.

Secondly, the resonance mode most commonly used in the Oil and Gas industry is the fundamental modes which occupy the lowest frequency resonance for the cavity [14]. This is a suitable mode to use for the measurement of pure or fresh water. However, the water fraction of a multiphase flow from a hydrocarbon well may comprise saline rather than fresh water. It has been observed that lower frequency modes appear to be more heavily attenuated in the presence of saline water, and therefore are not always ideally suited for use in typical Oil and Gas metering.

**6.1.2 Mode Conditioners**

The solution that Solartron ISA has employed in the Dualstream 3 to solve the two issues mentioned in section 6.1.1 is to include mode conditioners in the design of the electromagnetic resonator water fraction sensor. The inclusion of these mode conditioners suppresses most undesired modes, whilst enhancing the ones particularly useful for measurement. This thus has the effect of increasing the signal-to-noise ratio and creating a clear frequency window for the chosen modes. Also, as the conditioners are within the walls of the resonant cavity they do not have any contact with the process fluids, and so are not subject to erosion.

The summation of these effects results in a useful, measurable signal, even in the presence of saline water, in which the mode's response to Gas Volume Fraction (GVF) and Water Fraction are clearly visible.

The principles detailed above can be seen in the simulations shown in figures 5 and 6, demonstrating the effect of the mode conditioners (where the frequency is linearly scaled, and the transmission is logarithmic) for a gas-only flow and for a gas/saline water annular flow through the meter respectively. Figure 5 shows that for a sensor without the mode conditioners there are four peaks with the last three relatively close together, whereas incorporating the conditioning structures widely spreads the remaining three peaks, enhancing the discrimination between the peaks and thus improving the measurement.

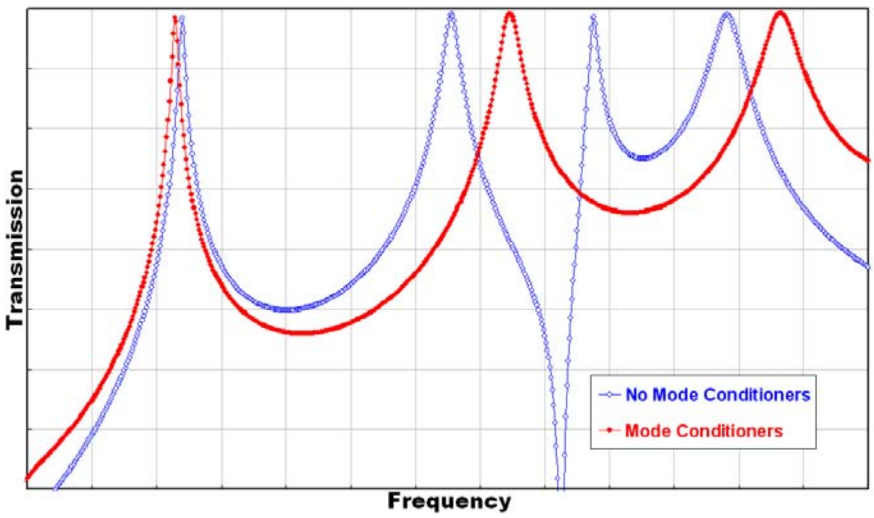


*Figure 5: Comparison of Frequency Traces for a resonant cavity structure with and without mode conditioners (Gas only)*

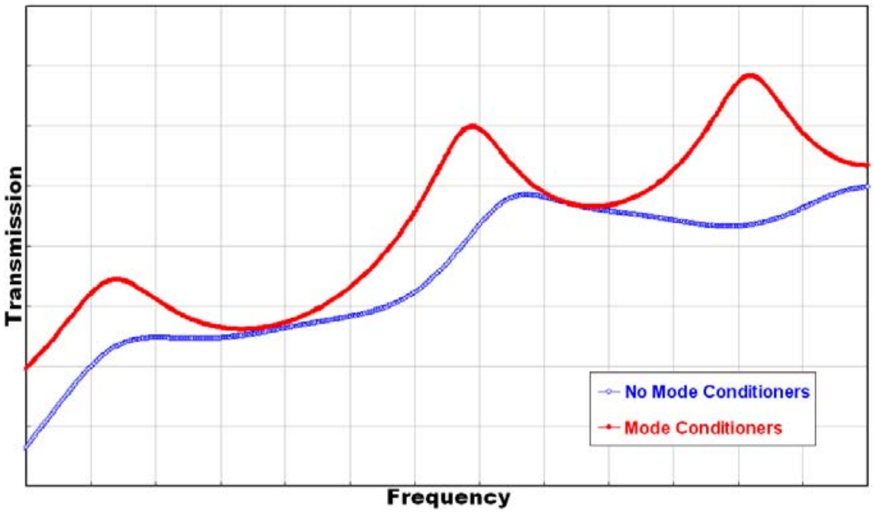


*Figure 6: Comparison of Frequency Traces for a resonant cavity structure with and without mode conditioners (Gas and Salt Water, annular flow)*

Figure 6 illustrates that in the presence of salt water the peaks are almost universally attenuated, as is typical for this sort of condition. However, by the inclusion of mode conditioners all three peaks are significantly reinforced or enhanced, and thus can be clearly distinguished.

#### 6.1.3 Metering Device Simulations

Extensive electromagnetic simulations have been carried out to establish a significant database regarding the response of electromagnetic fields to various dielectrics within specified containment and mode conditioning structures.

In addition, a mechanical model was created using a 3D CAD package for the purpose of stress analysis using Finite Element Analysis methods. From the results, the device has been optimised for 10k psi rated applications.

#### 6.1.4 Metering Methodology

A simplistic method for determining the wet gas properties of the fluids within the sensor can be seen in the simulated data of figure 7 below. This details the frequency response of one mode peak within a frequency window for GVF between 90% and 100%, for both fresh and saline water.

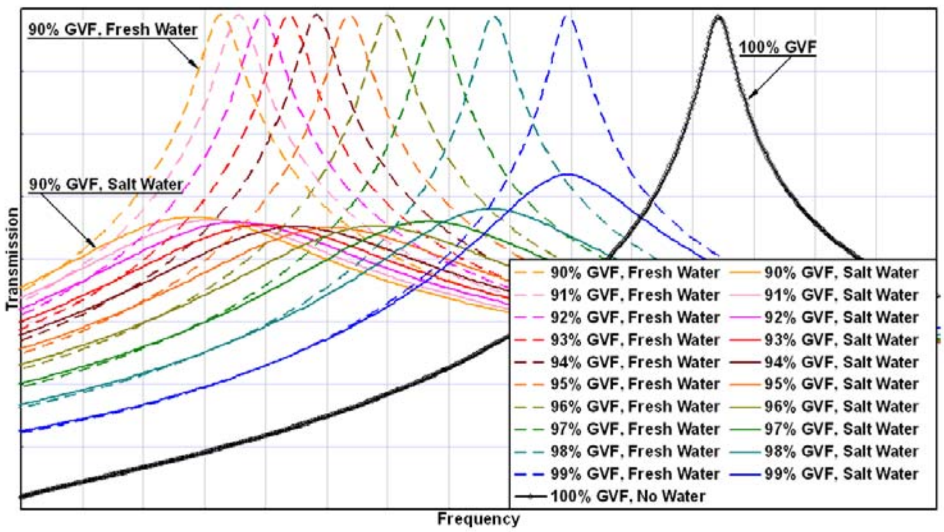


*Figure 7: Frequency response to GVF sweep from 90% to 100% for both fresh and saline water*

For each GVF, only one peak appears within the frequency window for either fresh or salt water. With the increase in water, the peak position shifts towards a lower frequency, while, with the addition of saline water, the peak amplitude decreases and the peak width increases. Therefore, it is possible to see that a function of this parameter for one or multiple peaks should create a system for the direct measurement of water content and salinity.

### 6.2 Simulation

Extensive electromagnetic simulations of the water fraction sensor have been performed. These have included four main design processes:

#### 6.2.1 Conceptual Design

The initial simulations were to create a basic model of the sensor and verify that it should function adequately in various situations. These incorporated modelling different wet gas flow regimes (annular, stratified, misty etc.) and different fluids, including both fresh and saline water.

#### 6.2.2 Optimisation of Design

Once the fundamental principles of the meter design were better understood, the design was improved by optimising various dimensions of the sensor, thus maximising the performance of the sensor across a wide range of conditions.

#### 6.2.3 Tolerance Analysis

Whilst within simulations conditions can be idealised, in engineering every machining process or measurement is achievable only to within a given tolerance. This stage simulated the effect on the sensor with each dimension of the meter being subjected to a range of changes.

#### 6.2.4 Systems Analysis

Finally, a complete metering system was simulated in detail to analyse the overall performance of the meter. These complex simulations provided expected results to be compared with those from physical tests of the meter, thus demonstrating the level and accuracy of our understanding of the underlying processes.

### 6.3 Prototypes

Based on the results from the simulations, several prototypes have been built and tested.

The initial design was based on a liquid resonator cavity using oil with a well defined constant of dielectric permittivity as the dielectric material. The oil containment structure required a pressure compensation system to balance the pressures between the flow line and the cavity. However, early trials demonstrated that this system was difficult to manufacture and prone to failure; in addition, the electric permittivity of the cavity fluid was found to be highly sensitive to temperature, making it unsuitable for use in the field.

Later prototypes utilize a solid material for the resonant cavity, using a ceramic with high mechanical strength and greater independence of the permittivity from temperature effects. This required a significant redesign of the meter as the higher permittivity of the ceramic meant that the size of the resonant cavity could be reduced.

Further improvements have also been made in the overall design of the meter, where the original "wafer" design (with the water fraction meter sandwiched between two flanges) has been replaced with a fully welded spool. This has reduced the length and weight of the meter, as well as the number of potential leak paths, and has simplified the alignment between the venturi and water fraction sections.

#### 6.3.1 Prototype Trials

The prototypes have been physically tested to prove their suitability for use in field conditions.

Hydrostatic and gas leak pressure tests demonstrate that the product is physically able to withstand the internal design pressures likely to be faced by a wet gas meter in service, demonstrating the sealing of critical components, and prove that the design, simulations and manufacturing tolerances described above have been appropriately applied to create a device fit for purpose.

Dry gas tests can also be used to provide a baseline calibration for the water fraction meter.

Temperature trials have also taken place in an environmental chamber at a Test Laboratory. This has been able to test the meter over a range of temperatures to demonstrate that the permittivity of the cavity varies as expected by the simulations. As can be seen in figure 8 below, there is a small temperature variance that is due to effects such as the meter material expansion. By quantifying this change the effect can be calibrated out within the meter algorithm.

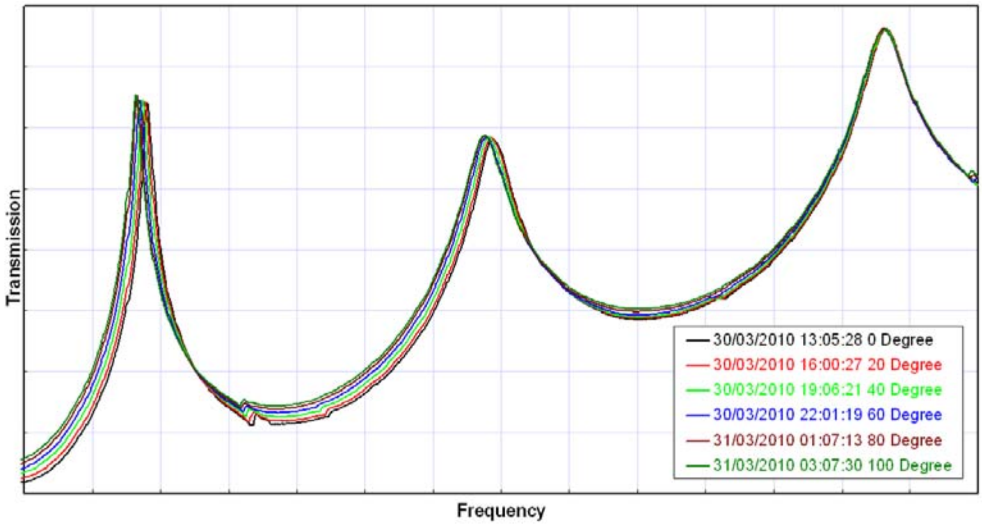


*Figure 8: Frequency response to changing temperature conditions (0°C to 100°C plotted)*

### 6.3.2 Wet Gas Testing

Wet gas testing of the Dualstream 3 flow meter has taken place at CEESI and SwRI wet gas calibration loops. This vital addition to the theoretical understanding enables the testing of the various algorithms needed to quantify the water fraction measurement, and latterly to include other parameters such as salinity. It also can allow for the verification of the meter performance, proving that under blind test conditions the meter can perform significantly inside its uncertainty specifications.

Figures 9 and 10 are a visual representation of this verification, detailing data taken at CEESI to demonstrate the accuracy of the Dualstream 3 flow meter for a range of gas velocities and 0% to 100% water fraction. It is clear from this data that the meter is performing well within its target accuracies of ±2% relative on gas mass flow rate, and ±0.1% absolute on water volume fraction.

The use of multiple test facilities has proved necessary, as no individual calibration site can provide the full range of flow rates and associated parameters to fully qualify the meter for the conditions it is likely to see in service. This testing is indispensable as it significantly increases the understanding of the flow meter performance, and allows for the determination of boundary conditions with that prototype, enabling further development to be appropriately directed.

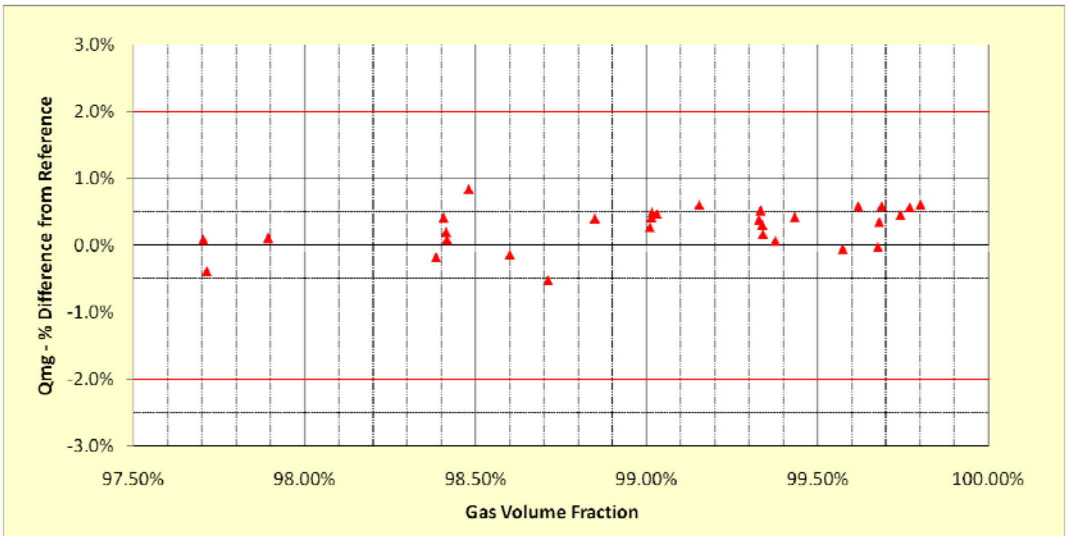


*Figure 9: CEESI data verifying the Gas Mass Flow Rate accuracy for Dualstream 3 (red lines indicate target specification)*

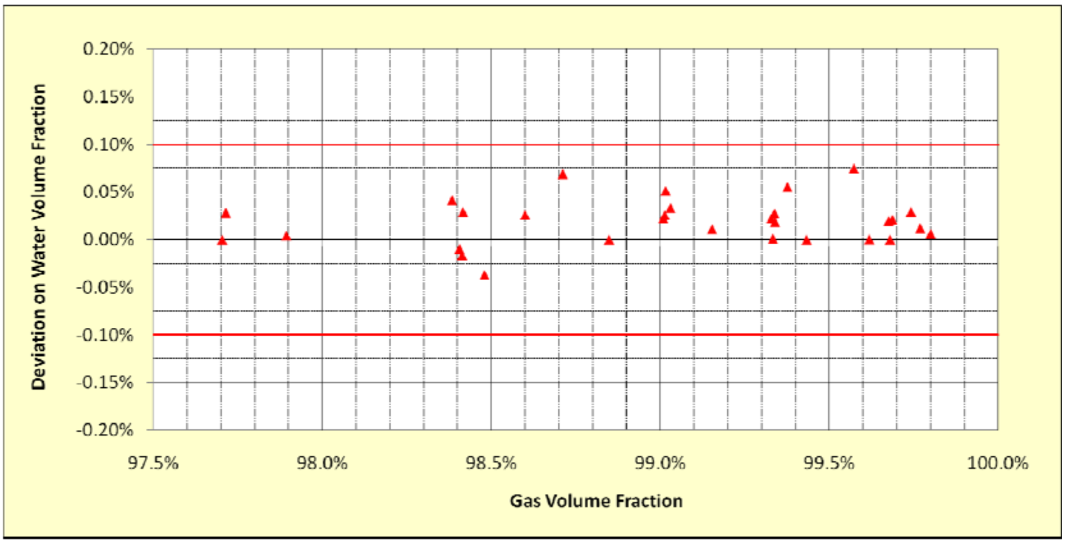


*Figure 10: CEESI data verifying the Water Volume Fraction accuracy for Dualstream 3 (red lines indicate target specification)*

## 7 MINIMISING THE RELIANCE ON PVT MODELLING

As equation of state (EOS) type calculations are based on theoretical models and there are sometimes problems obtaining reliable compositional data under field conditions, it is important for wet gas meters to be as independent of EOS inputs as possible. It is intended that the Dualstream 3 will have two modes of operation:

(i) a two-phase mode which requires knowledge of condensate content from an EOS,
(ii) a three-phase mode in which condensate content is derived independently of EOS modelling.

For the purpose of this paper only the two-phase mode has been considered in the sections below.

The Dualstream 3 meter has been specifically designed to be very robust with respect to the condensate to gas mass ratio (CGMR) input required from the EOS. It is therefore important to note that, although the two-phase mode of operation depends on a value of CGMR returned by the EOS in order to derive condensate content, the gas and water measurements returned by the Dualstream 3 still exhibit good insensitivity to any errors in the input CGMR.

Van Maanen [10] drew attention to a number of potential pitfalls of microwave based meters being used to measure water content of wet gas. He used theoretical models to demonstrate the sensitivity that such meters may exhibit to uncertainty in parameters such as condensate content, gas composition and density and water vapour partial pressures. The sensitivity performance of the Dualstream 3 meter, with respect to CGMR and gas density inputs, is summarised in sections 7.1 and 7.2. The presence of water in vapour form must also be accounted for in higher temperature applications. This is discussed further in section 7.3.

The principal EOS inputs required by the Dualstream Meter flow calculations are the Gas Density, and the Condensate to Gas Mass Ratio (CGMR), both at line conditions. Further inputs are required for conversion to base conditions, but these are not meter specific and so are not considered here.

The sensitivity analysis was performed using the following procedure.

a) Reverse calculate Dualstream 3 input signals over a wide range of GVF and WLR. This was done using a Dualstream 3 calibration previously obtained from a wet gas calibration facility.

b) Run Dualstream 3 flow calculations, using the simulated Dualstream 3 input signals and known EOS parameters.

c) Run a further set of Dualstream 3 flow calculations, again using the simulated Dualstream 3 inputs, but forcing errors on to the known EOS parameters, prior to input.

d) Compare the water volume fraction, gas volume flow rate and hydrocarbon mass flow rates returned by the Dualstream 3 for the two cases.

The simulations were performed for a 4 inch Dualstream 3 meter at nominal gas density of 60kg/m3 and gas volume flow rate of 500am3/h.

### 7.1 Sensitivity of Dualstream 3 (Two-Phase mode) to Condensate Content

Van Maanen used the Bruggeman model for spherical inclusions to predict that, for 2-phase mixtures in gas, water would typically cause an increase in fluid dielectric constant of around 4.5 times greater than that caused by an equivalent volume of condensate. This has implications for a meter that requires an EOS model to estimate the condensate content of a well stream, as any condensate present, but unaccounted for by the EOS, could appear to the meter as a smaller but possibly significant volume of water.

Van Maanen also went on to consider the effect that inter-phase slip would have on the dielectric constant of the fluid. He suggested that the liquid could be considered to be split into two contributions. Some of the liquid will be dispersed through the gas, affecting the dielectric constant of the bulk fluid, whilst the remainder of the liquid will form a layer on the wall of the pipe. The dispersed or entrained liquid will travel more slowly than the gas, so causing it to be over represented in terms of its contribution to the permittivity. The liquid layer may not be seen by the meter, due its being in contact with the pipe wall but may effectively change the internal dimensions of the meter (although this assumes a conducting pipe wall).

He acknowledged that in flowing multiphase fluids, the ability to model the multiphase flow “plays an essential part in the calculations”.

We have reproduced and are in agreement with van Maanen’s theoretical calculations. We also have experimental data derived from multiphase flow facilities. Our findings have been that in 2-phase conditions, water added to gas causes shift in measured peak frequency in the order of 20 times greater than that seen for condensate in gas. An example is shown in Figure 11 below.

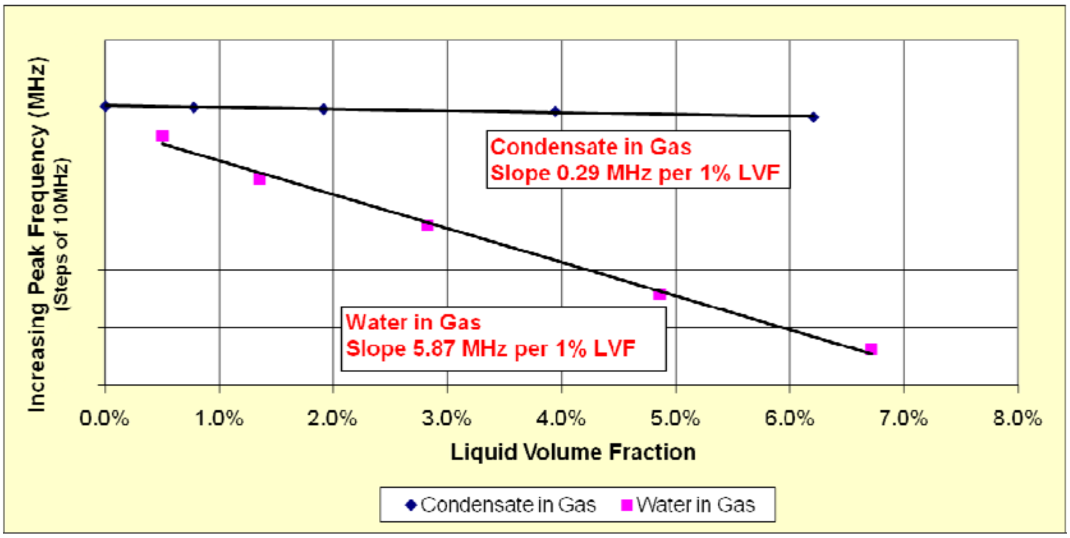


*Figure 11: Dualstream 3 – frequency shifts for water and condensate in gas. Data taken from SwRI in 2009 at 135bar*

We cannot fully explain the discrepancy between the theoretical prediction and the experimentally observed data in quantative terms, but we do understand that models such as Bruggeman's make assumptions as to the shape of the inclusions, the way in which they are distributed and the interaction between inclusions. Also the theoretical models do not take account of the inter-phase slip.

In 3-phase flowing fluids we actually find that the response of the Dualstream 3 to water and condensate is complex and is dependent upon many of the prevailing fluid parameters, including the water liquid ratio. Because of this, it is most sensible to treat the sensitivity to EOS inputs such as condensate content in terms of the effect on calculated output caused by a given change in EOS input. To be consistent with the sensitivity analysis in [13] we have selected a change in CGMR of 10% for this analysis. Figures 12, 13 and 14 show the effect of this change on the water volume fraction, gas volume flow rate and total hydrocarbon mass flow rate returned by the Dualstream 3.

Water fraction measurement shows very little sensitivity with respect to input CGMR. Absolute errors on water volume fraction are well below 0.1% except in regions of high water content, where relative error becomes more meaningful and is still very small.

Gas volume flow rate is also tolerant to changes in input CGMR, with relative errors remaining under 3% across the full range of conditions.

As would be expected, hydrocarbon mass flow rate is more sensitive to input CGMR. This is especially true for high condensate content, where condensate represents a bigger fraction of total hydrocarbon.

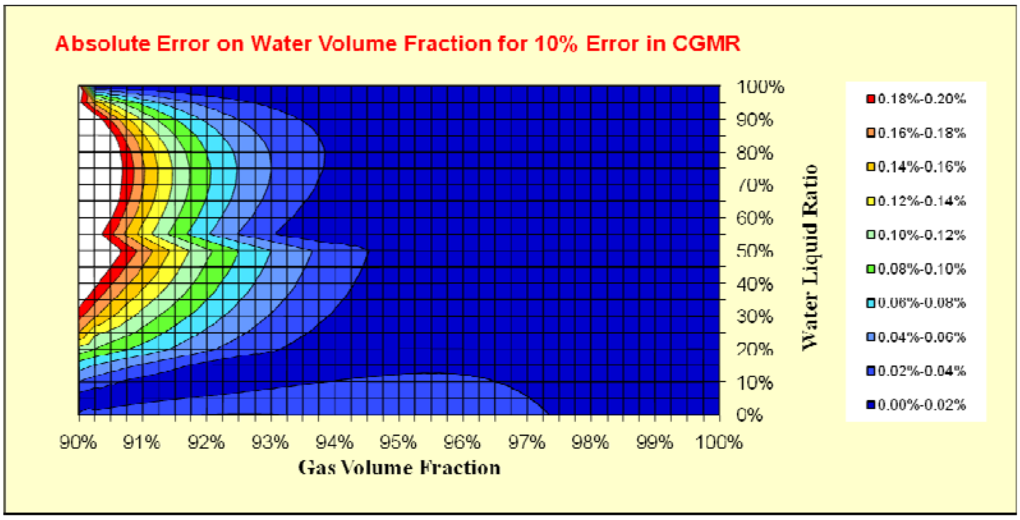


*Figure 12: Dualstream 3 - absolute error on water volume fraction caused by 10% error in CGMR*

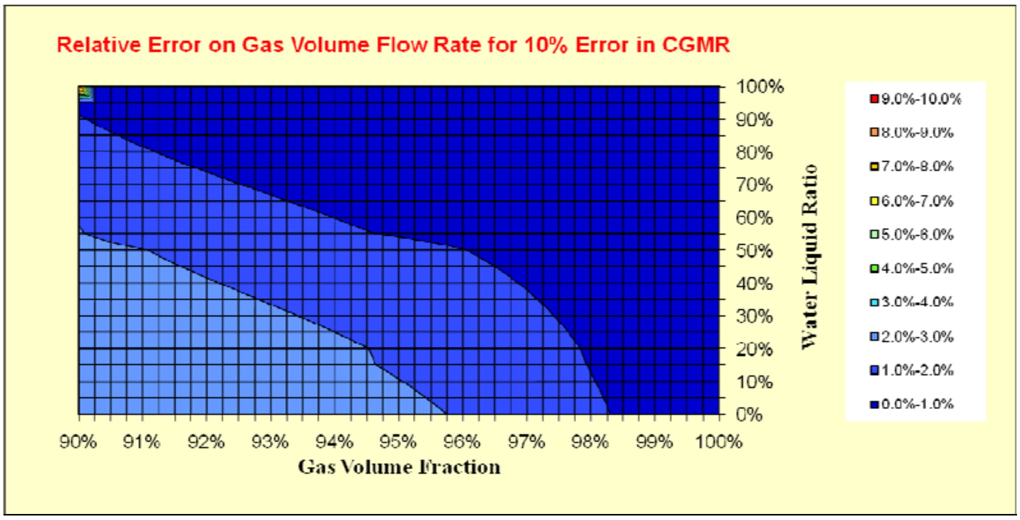


*Figure 13. Dualstream 3 - relative error on gas volume flow rate caused by 10% error in CGMR*

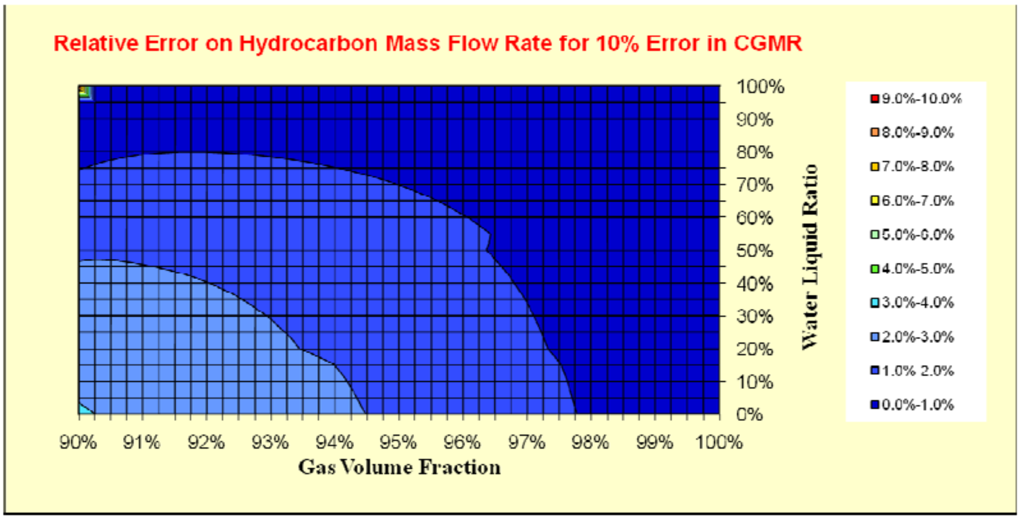


*Figure 14: Dualstream 3 - relative error on hydrocarbon mass flow rate caused by 10% error in CGMR*

### 7.2 Sensitivity of Dualstream 3 (Two-Phase Mode) to input gas density

Van Maanen's theoretical treatment of the effects of changing gas density predicted that, as an approximation, at a pressure of 100bar, changing the gas pressure by 3bar would cause a similar change in fluid dielectric constant to that caused by a change of 0.1% of liquid water by volume.

Our experimental observations from CEESI and SwRI suggest that a change of around 13bar would typically be necessary to cause the same change in peak frequency as is caused by 0.1 % water by volume in flowing conditions. Figure 11 showed a response of 5.8MHz per 1% water by volume, or 0.58MHz for a 0.1% water. Figure 15 below shows a response to gas pressure of 0.043MHz per bar.

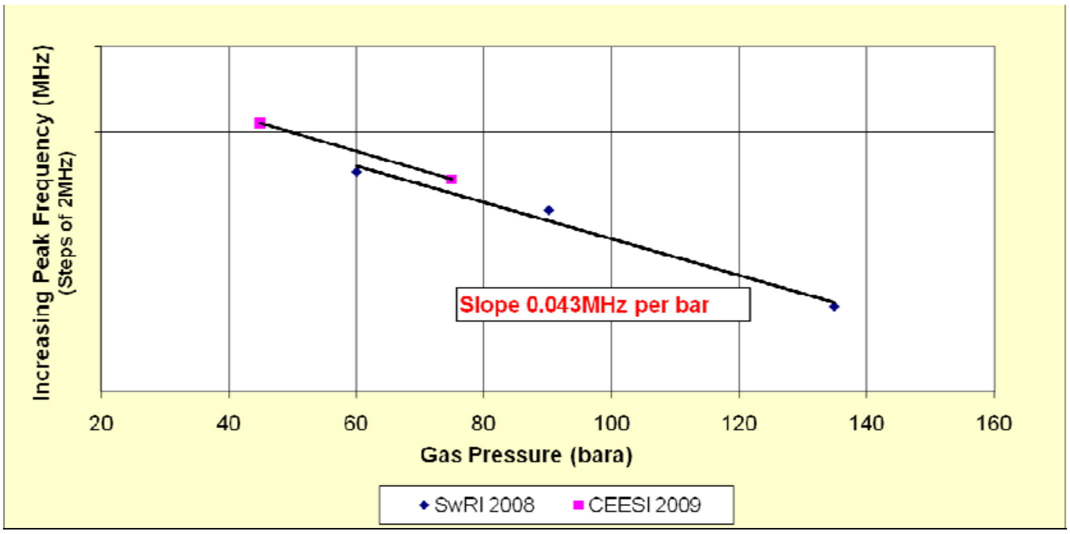


*Figure 15: Dualstream 3 - dry gas peak frequency at different pressures. Data taken from SwRI 2008 and CEESI 2009*

To demonstrate the sensitivity to gas density and be consistent with [13], the change in Dualstream 3 outputs caused by a 5% change in input gas density has been calculated, over a range of GVF and water liquid ratio. This data is shown for water volume fraction, gas volume flow rate and hydrocarbon mass flow rate in figures 16, 17 and 18 respectively.

The water fraction measurement shows little sensitivity to changes in input gas density. Again absolute errors are very small except for regions of high water content where the relative error becomes more meaningful and is still very small.

As would be expected, the effect on gas volume flow rate is dominated by the effect that gas density has on the venturi differential pressure flow calculation. The gas density also impacts to some extent on the meter wet gas calibration parameters. This tends to partially compensate for, rather than add to, the effect on the venturi calculation.

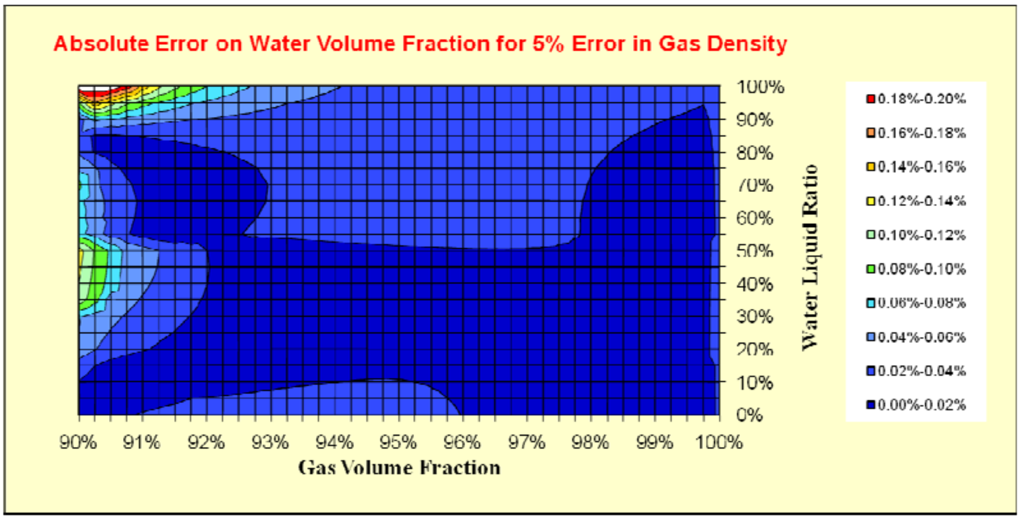


*Figure 16: Dualstream 3 - absolute error in water volume fraction caused by 5% error on gas density*

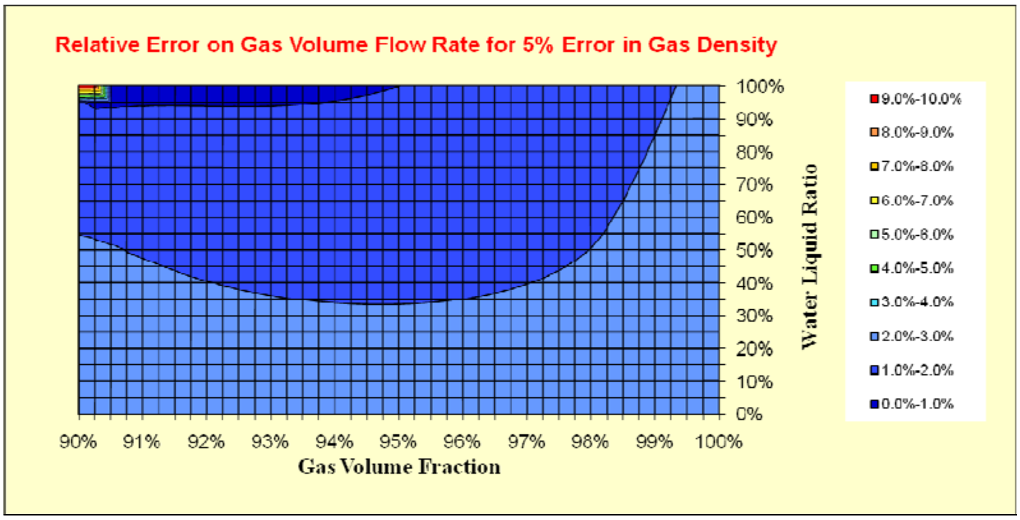


*Figure 17: Dualstream 3 - relative error in gas volume flow rate caused by 5% error on gas density*

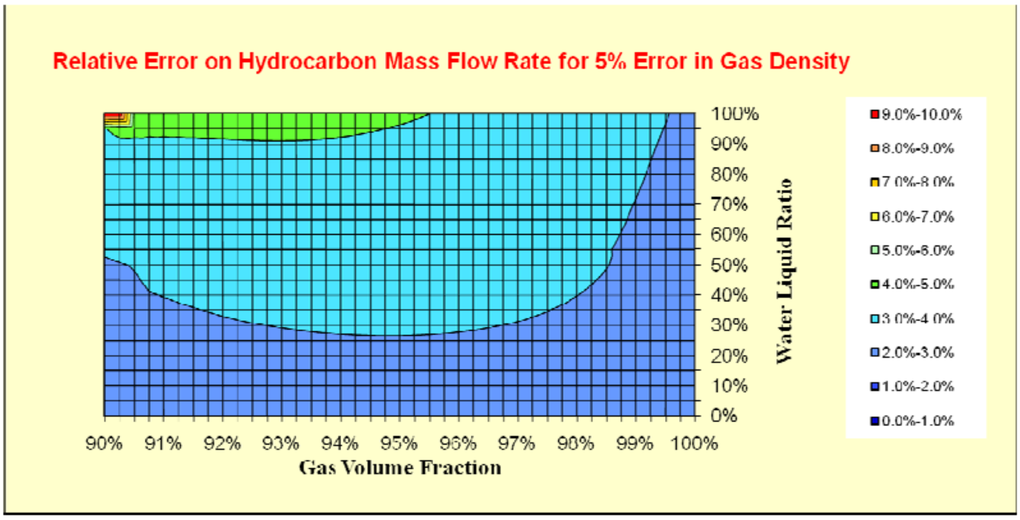


*Figure 18: Dualstream 3 - relative error in hydrocarbon mass flow rate caused by 5% error on gas density*

### 7.3 Considerations of Water Vapour

Van Maanen [10] predicted that for a microwave type measurement, "the contribution of water vapour to the primary measurement is significantly stronger than the same amount of liquid water in mass terms" and also that the rapid change of water vapour fraction due to temperature and pressure changes "could give rise to serious errors when the temperature and pressure are not measured with a very high accuracy".

We have performed our own modelling of the take up of water, as vapour and liquid, into a hydrocarbon gas and the effect this has on fluid dielectric constant.

The results shown below are for methane, but similar trends were obtained when the gas composition was varied. Four different temperatures are shown at a nominal gas density of 60kg/m3. Pressure was varied to maintain gas density.

The distribution of water into liquid and vapour phases was calculated using the London Research Station EOS [15]. Figure 19 shows the apparent liquid water volume fraction, WVF_apparent (assuming no water in vapour form) on the x-axis, and the actual liquid water volume fraction WVF (once water vapour has been accounted for) on the y-axis. What we see is that at first when water is added it goes into vapour form. As more water is added the gas becomes saturated and all further water goes into liquid form. The water content at which saturation occurs is very much dependent on temperature.

At 40°C virtually no water is taken into vapour form and WVF is effectively equal to WVF_apparent. At 70°C a small amount of water is in vapour form, but this is still likely to be significantly less than the uncertainty specification of the meter. At 100°C the WVF is almost 0.1% less than WVF_apparent. That is to say, that if the water held in the vapour isn't accounted for, then the meter will effectively be subject to an error of almost 0.1% on its WVF measurement due to this factor alone. Although, if the water vapour is modelled using an EOS, the calculation wouldn't need to be precise to keep the resultant error to much smaller than 0.1%. At 130°C we are clearly moving into the region where it is necessary to have a more precise EOS calculation and accurate measurement of temperature and pressure, as stated by van Maanen.

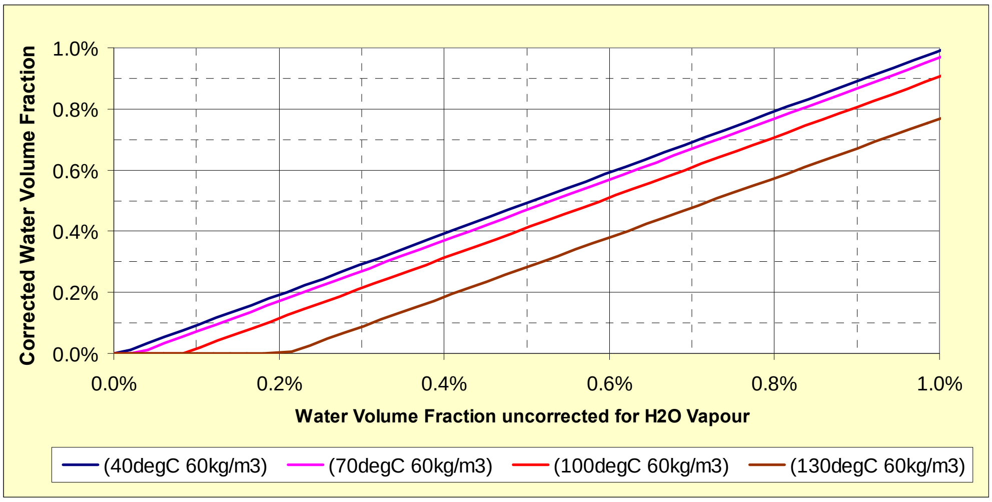


*Figure 19: Liquid water fraction if all water in liquid form (x-axis) against liquid water fraction after subtracting water vapour (y-axis)*

The dielectric constant of the gas was calculated using the Clausius-Mossotti-Debye equation, the liquid dielectric was calculated using the Kirkwood equation and the fluid dielectric was calculated using the Bruggeman equation, assuming that the liquid is held in the gas as a mist. Figure 20 shows predicted fluid dielectric constant as water is added to methane. As predicted by van Maanen, the water vapour "contributes far more to the permittivity than the same amount of water as liquid". The slope of the curve is much steeper in the region where the water is going into the vapour, than it is after the saturation point has been reached. However, because the quantity of water taken into the vapour is small, in absolute terms, the change in dielectric constant caused by the water vapour is still relatively small compared to the change caused by the liquid water. This is especially true at the lower temperatures, although once again it is acknowledged that at higher temperatures it will be increasingly important to accurately predict the water vapour content and take account of its contribution to the fluid dielectric constant.

It should also be remembered that in flowing conditions we can expect the liquid water to make a bigger contribution to the fluid dielectric than is predicted by theory, as discussed in section 7.1.

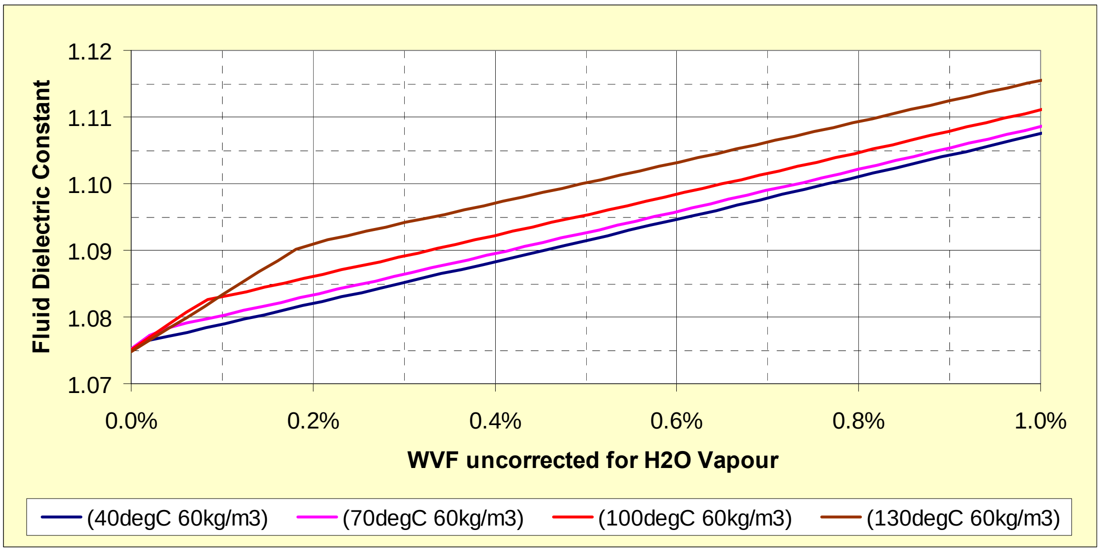


*Figure 20: Fluid dielectric constant predicted from theory against liquid water fraction assuming all water in liquid form.*

## 8 AREAS FOR FURTHER INVESTIGATION

The Dualstream 3 meter, although now released to the marketplace, is still undergoing a further process of continual development to further improve and expand the specification of the device.

### 8.1 Subsea Meter

Expansion of the Dualstream 3 meter range to include a subsea variant is now underway. This is a necessarily complex process, as whilst the metering needs of a subsea meter are much the same as for the topsides meter, there are also greater requirements in terms of robustness, heightened flexibility, connections, and reliability specific to working down to 3000 meters water depth.

Subsea meters need to comply with the standards imposed upon them in order to allow for accuracy and reliability in this demanding environment. There are also further considerations to be made in terms of redundancy and retrievability.

### 8.2 "Bolt-on" to existing metering solutions

Dualstream meters have been supplied to many wet gas fields around the world. It is being investigated whether a "bolt-on" additional product can be supplied to enhance existing systems.

### 8.3 Salinity Measurement

The Dualstream 3 meter has already been tested at various salinities, and it has been proven that it can operate across a wide range. However, it is believed that the data processed from the water fraction meter also provides sufficient information to measure the salinity, based upon the complex relationship between water content and salinity and the position and amplitude of the resonant mode peaks as shown in figure 7 above.

The development of this algorithm is currently underway, with the aim of providing a robust means of measuring this additional parameter. Initial meters should be upgradeable in future to take account of this by means of a software update.

## 9 CONCLUSIONS

Solartron ISA has successfully developed the Dualstream 3 flow meter to be placed on Wet Gas condensate wells for the Upstream Oil and Gas Market. The development of Wet Gas meters has been shown to be a non-trivial undertaking; this paper has therefore used the Dualstream 3 to highlight how Solartron ISA has sought to address these issues.

The Dualstream 3 successfully reduces the reliance on PVT modelling. Meter sensitivity to error in input CGMR of 10% and gas density of 5% have been investigated for the Two-Phase Mode of operation. It was found that the sensitivity of the water fraction measurement to these errors was smaller than the specified uncertainty of the meter, across a wide band of GVF and WLR.

The current Wet Gas validation data from CEESI also indicates that the Dualstream 3 operates inside its uncertainty specification.

As predicted by van Maanen, the presence of water vapour in the gas stream is an important consideration. However, at lower temperature the quantities of water vapour and its effect on the primary measurement of the meter are minimal. At higher temperatures it is important that the presence of water vapour is accounted for.

## 10 ACKNOWLEDGEMENT

We would like to acknowledge the continued support by ConocoPhillips in this project.

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North Sea FLOW Measurement Workshop

# Paper 4.2

# In-Situ Measurement of Fluid Properties and Integrity Verification for Multiphase and Wet Gas Metering Applications

**Arnstein Wee**
**Multi Phase Meters AS**

**Øystein Lund Bø**
**Multi Phase Meters AS**

TÜV SÜD

nel technology for life

# In-Situ Measurement of Fluid Properties and Integrity Verification for Multiphase and Wet Gas Metering Applications

**Arnstein Wee, Multi Phase Meters AS**
**Øystein Lund Bø, Multi Phase Meters AS**

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## 1 INTRODUCT ION

Accurate flow measurement of all three components in multiphase and wet gas applications can be extremely challenging. For a multiphase meter to manage it, it must be capable to operate and provide reliable results for all combinations of oil, water and gas rates. In most field applications, the fluid properties may vary over time and the meter must be able to provide accurate results even if the PVT properties change. Frequent sampling and associated lab analysis are preferably to be avoided, especially in remote sites, to reduce OPEX and HSE risks.

The dominating PVT configuration parameter for measurement of small volume fractions of a well stream component is the properties of the fluid occupying the largest volume, which is a fundamental property for any multiphase or wet gas meter. As an example, in order to achieve reliable measurements of the tiny water amounts in a wet gas, it is very important to know the real gas PVT properties. Similarly, it is important to have good control of the PVT properties of water for wells with high watercuts, to correctly measure the correspondingly small oil flow rates. This is in particular the case for water flooded reservoirs where the salinity and density may change significantly over time.

There is currently an installed base of multiphase and wet gas meters of more than 2000 units [23]. It is also well known that the measurement integrity of multiphase and wet gas meters is influenced by uncertainty and changes in PVT configuration data. As a consequence, frequent sampling and analysis of the PVT configuration data could be required in order to maintain the measurement integrity of the meters [2], [24] and some vendor recommends fluid sampling on a regular basis and in-line sampling systems even for remote subsea installations [24] .

In this paper a combined multiphase and three-phase wet gas flow meter is described. It is based on electromagnetic broadband technology and utilizing tomographic reconstruction techniques, in combination with high energy gamma mass attenuation measurements and a Venturi. The meter has proven to be very tolerant to errors and variations in the PVT configuration data. An additional and unique feature of this meter is its capability of measuring "in-situ" the fluid properties of gas and water of the wells, which enable automatic configuration with respect to water density, water conductivity, water viscosity, gas density and gas permittivity of the produced wells. This feature minimizes and in many cases completely eliminates the need for fluid sampling of the wells.

Many field applications contain significant amounts of $H_2S$ and $CO_2$ which constitutes another challenge for a multiphase meter, particularly if the content changes over time. This paper also describes the metering challenges in such an environment including the theoretical basis for how $CO_2$ and $H2_S$ impact the field calibration parameters of a multiphase and wet gas meter and how variation in $CO_2$ and $H_2S$ content can be handled without compromising on the measurement performance.

## 2 MPM 3D BROADBAND™ TECHNOLOGY

The MPM meter 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 radial symmetrical 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.

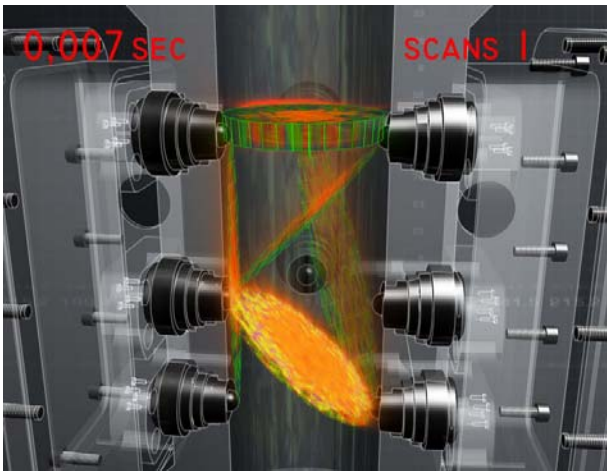



Figure 1: 3D Broadband™ tomography based meter

The 3D Broadband™ system is a high-speed electro-magnetic (EM) wave based technique for measuring the water liquid ratio (WLR), the water salinity 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 measurement is based on permittivity measurements performed at many simultaneous measurement frequencies at many planes within the sensor. The measurement frequencies cover a range of 20-3700 Mhz.

The MPM meter has a dual mode functionality, which means that the meter it is a combined multiphase and a wet gas meter. In wet gas mode, the 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). Two-phase mode is used for verification purposes, and requires the GOR as an additional configuration parameter. The GOR is typically calculated based on the well composition.

At ultra-high GVF, when the liquid volume is extremely small compared to the gas volume, the Droplet Count® functionality significantly improves the measurement resolution of the liquid fraction. By using Droplet Count® , the MPM meter can make precise measurements of minuscule liquid volumes in a GVF range where no conventional technology is capable to make true three-phase measurements. The method is even highly tolerant towards changes in fluid PVT properties, such as the oil and gas density and water properties. This is achieved through a patented (pending) methodology with a significantly higher resolution on mixture density as compared to gamma based density measurements, and for which the liquid metering accuracy actually increases with increasing GVF.

More information about the MPM meter can be found in reference [5]-[11].

# 3 FIELD CONFIGURATION OF MULIPHASE AND WETGAS METERS

## 3.1 Multiphase meter technologies

Some of the most widely used multiphase meter technologies for fraction measurement are dual gamma systems and permittivity in combination with high energy single gamma density. The most common permittivity measurement is based using capacitive and inductive sensors [23].

Permittivity measurement based on capacitance and inductive sensor technology typical use a low frequency signals in order to measure the permittivity of the multiphase mixture (typical below 20 kHz [25]). Other multiphase and wet gas meters based on microwave technology perform permittivity measurements at higher measurement frequencies, which may be in the Mhz or Ghz region of the frequency spectrum.

Momentum rate meters, such as Venturi, V-Cone or special dP devices, are the most common velocity measurement devices. Some meters also deploy PD meters or cross-correlation techniques.

More detailed description of the available multiphase and wet gas metering technologies can be found in the Norwegian Handbook of MultiPhase Metering.

## 3.2 General configuration requirements

All multiphase meters require a set of configuration or PVT data describing the properties of the different flow constituents (oil, water and gas).

The PVT data is normally used for two purposes namely:

1) Calculation of fluid properties at actual temperature and temperature conditions (temperature and pressure at the location of the multiphase meter) which is used as input parameter to configure the measurements of the multiphase meter
2) Conversion of the measured flow rates at actual temperature and pressure conditions to a standard reference conditions such as 15 ºC and 1 bara.

The second purpose is common to all meters and is a general requirement when converting flow rates of hydrocarbons and water from one temperature and pressure conditions to another one.

For the first purpose, the amount and type of PVT data varies with the different metering technologies applied, as do the different technologies sensitivity to variations (errors) in the PVT configuration parameters. Therefore, some technologies may require more detailed and more accurate PVT configuration data whereas other technologies are more tolerant to variations in the PVT properties [2], [24], [7], [6].

As a consequence, the field experience gained with one type of metering technology may not be relevant for meters using other measurement principles. Until recently there has been little guidance in the industry related to the required precision in PVT data for the various metering technologies and there has been a perception that all multiphase and wet gas meters are equally highly influenced by errors in the PVT. One solution to this “problem” have been to do frequent (and expensive) sampling of the wells or to install a sampling unit as a part of the multiphase meter [24]. However, this “solution” may not be a needed for all metering technologies.

### 3.3 Obtaining reliable PVT data

The oil and gas PVT properties are typically calculated in a PVT simulation program based on the total hydrocarbon composition and downloaded as a temperature and pressure dependent look-up table.

Reliable PVT data is often hard to obtain, and therefore 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, characterization process and EoS calculations. 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 characterization process. Commonly used Equation of State (EoS) models are also known to contain uncertainties, 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 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 wet gas 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.

For water flooded wells, the water properties may also vary significant over relatively short intervals. For reservoirs with high salinity formation water which is flooded with sea water or fresh water injection, the change in water properties such as density, conductivity and mass attenuation at low energies can be quite significant. A salinity change in the water salinity from 10% by weight to 5% by weight is not uncommon, and a multiphase meter must be able to cope with these variations without any intervention, and without compromising on the measurement performance.

## 4 EFFECT ON PVT DATA FROM FLUID VARIATIONS

### 4.1 Changes in $H_2S$ and $CO_2$ content

An increasing number of oil and gas wells contain $H_2S$ and $CO_2$. $H_2S$ and $CO_2$ levels may vary from very small to large fractions (ppm to percentage levels) and poses specific challenges for multiphase meters in two areas:

1. Mechanical integrity
2. Measurement integrity

In a particular well or production zone, the $H_2S$ and $CO_2$ content in the gas and oil phases may change over time, either as a result of

- Variations in temperature and pressure causing transfer of the $H_2S$ and $CO_2$ from the oil to gas phase or vice versa whereas the mol fraction of $H_2S$ remains constant in the total hydrocarbon fraction.
- Variation in $H_2S$ and $CO_2$ mol fraction, due to changes in the reservoir, reinjection of $H_2S$ and $CO_2$ rich (or lean) gas, changes in reservoir composition etc. This also changes the mole fraction of $H_2S$ in the total hydrocarbon fraction

$H_2S$ and $CO_2$ variations will impact the mass attenuation factors as well as the permittivity as outlined further below.

#### 4.1.1 Mass Attenuation Coefficient

In the figure to the right is plotted the mass attenuation coefficients for various hydrocarbons, water solutions in addition to $H_2S$ and $CO_2$. As can be seen, certain energy levels (like Barium in the lower range) are very much influenced by the various fluids, fluid solutions and their mass attenuation properties. At low energy, in particularly $H_2S$ have a significantly higher mass attenuation coefficient compared to the hydrocarbon fractions. $CO_2$ also have a considerable higher mass attenuation coefficient compared to hydrocarbons at low energy.

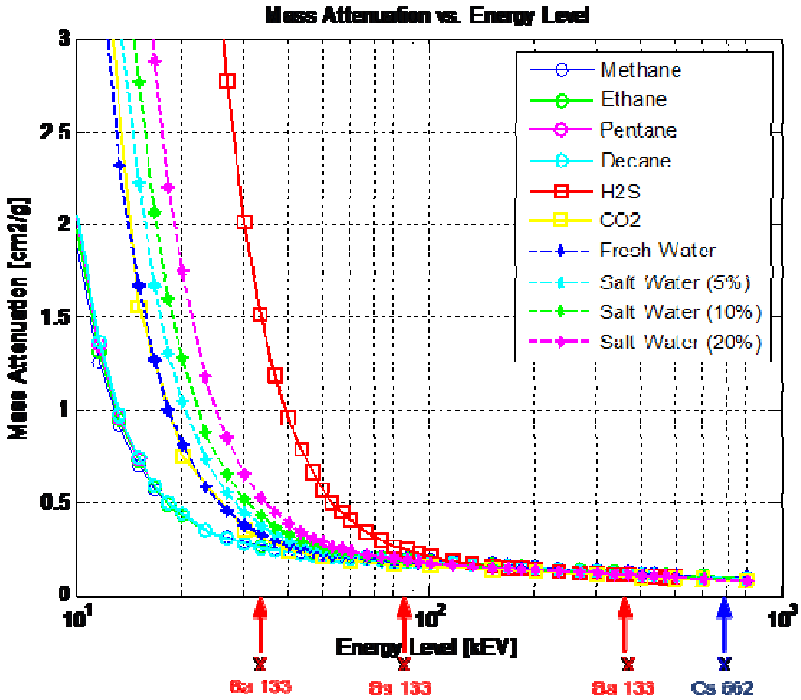



*Figure 2: Mass attenuation coefficient vs Energy Level (Source: NIST)*

The count rate at the gamma detector, density and mass attenuation coefficient of the fluid within the pipe relates according to the following equation:

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

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

The Caesium high energy gamma technology (single energy at 662 keV) has a significant higher energy compared to traditional dual gamma system. At this energy level the mass attenuation coefficient is almost constant and does not change much as a function of the composition. Hence the measurement is virtually a true density measurement which makes a system based on this energy level less dependent on fluid sampling. This is also illustrated in the graph in figure 2 which shows that the mass attenuation coefficient is almost constant for all the stated materials at the 662 kEV energy. Hence, when using high energy (662 keV) gamma technology, the GVF and density measurement of the Caesium meter is virtually unaffected by changes in the $H_2S$ and $CO_2$ content compared to low energy systems.

### 4.1.2 Permittiv ity

It is well known that permittivity measurements at high frequency (typically above 1 Ghz - microwave and RF based techniques) are much more tolerant towards variation in the composition of the oil compared to permittivity measurements at low frequency (kHz region - capacitance based techniques) [14].

Below are two graphs (figure 3 and 4) illustrating the frequency dependency of the permittivity for different oil compositions, published by Friisø et al [14].

Figure 3 and 4 below shows the real part of the permittivity of an oil example with different asphaltene fractions (the concentration dipolar fractions like N, S, and O are highest in heavier fractions like asphatlenes) [14]. The lower end of the scale is at 1 kHz which is a frequency region often used by capacitance based meters (typical 2-50 kHz). The right corner of the scale is at 1 Ghz.

The MPM meter uses frequencies up to 3.7 Ghz as illustrated by the arrow on the chart. As seen from the graph, the variation in permittivity as a function of asphaltenes is far less at high frequency compared to the permittivity at low frequency ($H_2S$ has a similar impact as asphaltenes). Hence using a high measurement frequency is essential in order to obtain a permittivity measurement which is tolerant towards variations in the composition of the oil.

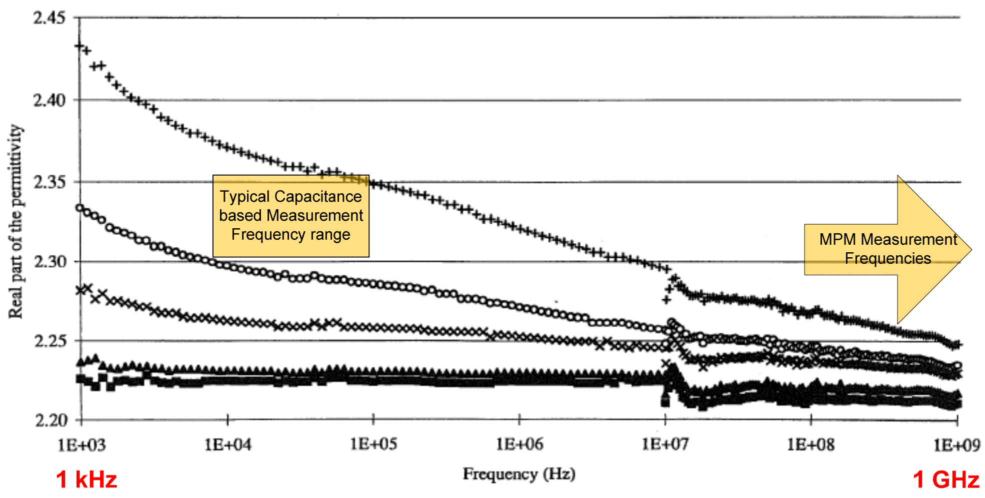



FIG. 1. The real part of the permittivity spectra for n-decane/toluene 1:1 by volume (■), 1% (▲), 5% (✕), 10% (○) and 17% (+) n-pentane asphaltenes in n-decane/toluene.

*Figure 3: Oil Permittivity (real part) vs. measurement frequency [14]*

Below is the corresponding figure for the imaginary part of the permittivity.

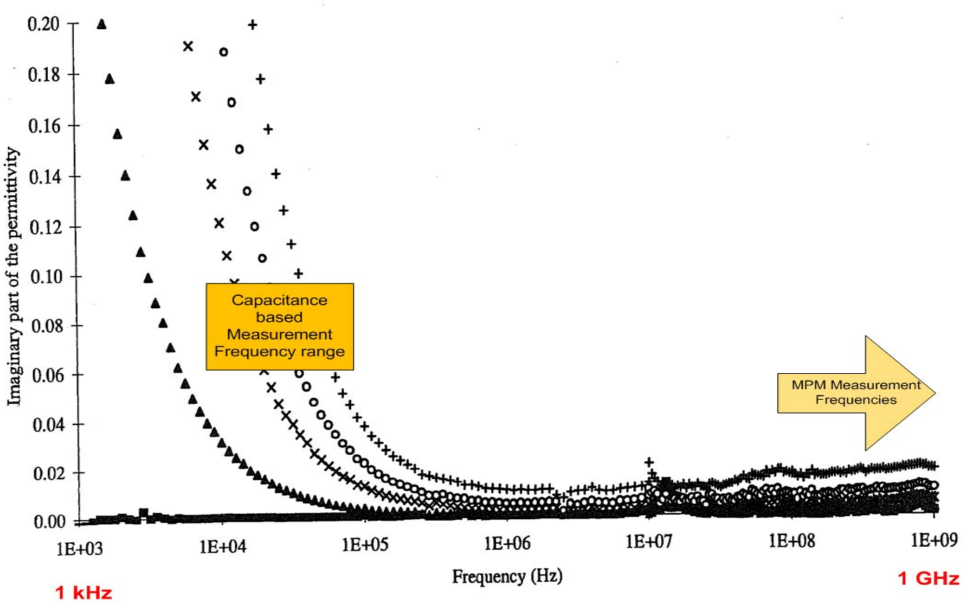



FIG. 4. The imaginary part of the permittivity spectra for n-decane/toluene 1:1 by volume (■), 1% (▲), 5% (×), 10% (○) and 17% (+) n-pentane TIAF in n-decane/toluene.

*Figure 4: Oil Permittivity (imaginary part) vs. measurement frequency [14]*

As seen from the graphs in figure 3 and 4 above, the spread in the imaginary part of the oil permittivity is significant at low measurement frequencies whereas the permittivity is almost constant at the high measurement frequencies used by the MPM meter. Hence, a high frequency permittivity measurement is much more tolerant towards changes in the compositions of the oil. The permittivity used in the mixing formulas (like Bruggerman) is based on the effective permittivity of the oil. Effective permittivity is defined by the following equation:

$$\varepsilon_{eff} = \frac{\varepsilon^{'}}{2} * \{1 + \sqrt{1 + (\frac{\varepsilon^{''}}{\varepsilon^{'}})^2}\}$$

where ε' is the real part of the permittivity and ε'' is the imaginary part of permittivity.

Based on the above equation for the effective permittivity for oil it is seen that the variation in the oil permittivity at high frequency is typical ± 0.5 - 1% due to asphaltenes whereas the variation at low frequency permittivity measurements typical is 4 times higher (or more) when adding up the impact from the real and imaginary part. The density dependence of the permittivity of any dielectric substance is fundamentally governed by Clausius-Mosotti type relations ref, W. Greiner – “Classical Electrodynamics” [5], as shown in equation 1 below.

$$N\,\gamma = \frac{3}{4\pi}\,\frac{\varepsilon_r - 1}{\varepsilon_r + 2} \quad \text{(c.g.s units)} \quad (1)$$

where $\varepsilon_r$ is the relative permittivity, $\gamma$ is the molecular polarizability which depends on the type of material, and $N$ is the number of molecules per unit volume which is proportional to density. The density dependence of any substance is hence given by an expression of the type:

$$C\,\gamma\,\rho = \frac{\varepsilon_r - 1}{\varepsilon_r + 2} \qquad (2)$$

where $C$ is a constant and $\rho$ is the density. There is no fundamental difference between hydrocarbons, $H_2S$ and $CO_2$ in this respect. The MPM meter is calculating the permittivity of the oil and the gas utilising the Clausius-Mosotti relationship and empirical measurements of oil and gas permittivity. The permittivity models are based on $CO_2$ and $H_2S$ free oil and gas and is corrected for presence of $H_2S$ and $CO_2$ using the Clausius-Mosotti relationship and physical properties of $H_2S$ and $CO_2$ found in [15].

## 4.2 Changes in $H_2S$, $CO_2$ and Water Salinity

### 4.2.1 Calibra tion triangle

For dual gamma systems, it is common to illustrate the effect of changes in PVT properties using the calibration triangle. A typical calibration triangle for a dual gamma system with a 30 keV low energy and 100 keV high energy is shown in figure 5.

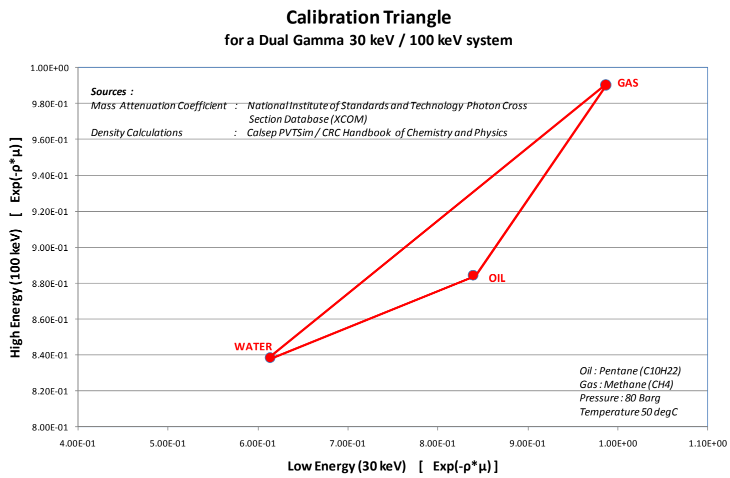



*Figure 5: Calibration triangle for a 30/100 keV Dual Gamma System*

For this example, the mass attenuation coefficient for oil water and gas is calculated using the National Institute of Standards and Technology (NIST) XCOM photon cross section database which is found at http://physics.nist.gov/PhysRefData/Xcom/Text/XCOM.html . Pentane $C_{10}H_{22}$ is used for oil and Methane $CH_4$ is used as gas and the water is saline water containing 10 % NaCl by weight. Based on the measured low and high energy level, which should fall within the calibration triangle, it is possible to calculate the fractions of oil, gas and water.

A similar calibration triangle can also be used for a system like the MPM meter, as shown in the next figure. The Y-axis is the product of the density and mass attenuation for the 662 keV single energy gamma measurement and the X-axis is the permittivity. The oil and gas point will be located at a fixed position. The water permittivity will change as a function of the measurement frequency as described by the Debye Relaxation Law for calculation of the effective permittivity of water [10].

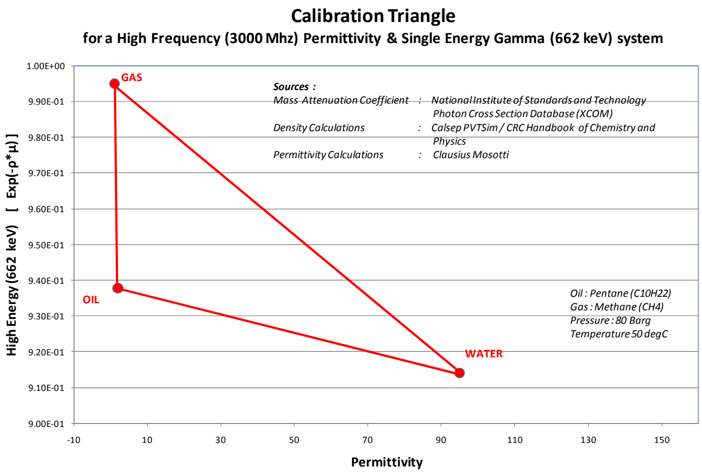



*Figure 6: Calibration triangle for a High Frequency Permittivity and 662 keV single Gamma System*

Since the MPM meter is using many simultaneous measurement frequencies, there will be many simultaneous calibration triangles. In the example above, a measurement frequency of 3000 Mhz has been used. It is also worth mentioning that the fractions are not a linear function of the value of the X and Y axis and it will also be different in oil and water continuous flow. However, the calibration triangle is a useful tool to illustrate how the measurements are influenced by changes in the oil, water and gas PVT properties which is used to configure the meter.

### 4.2.2 Sensitivity to changes

Changes in the PVT properties for oil, water and gas will have the effect of moving the calibration points in the phase triangle. Hence, if the change in PVT properties is not accounted for by updating the position of the calibration point, it will introduce a measurement error in the calculation of the phase fractions of oil, water and gas.

In this section the effect of such errors will be analysed by some case examples. All the cases have been calculated at an operating temperature of 50 º and operating pressure of 80 barg. Calsep PVTSim is used for calculation of the oil and gas density based on the composition of Methane and Pentane with $H_2S$ and $CO_2$.

Calculations have been performed for the following cases:

1) Oil and Gas with 0-30% (weight) dissolved $H_2S$
2) Oil and Gas with 0-30% (weight) dissolved $CO_2$
3) Water salinity change from 0 – 25% NaCl by weight

Figure 7 shows the effect on the calibration triangle for a 30/100 keV Dual Gamma system and figure 8 shows the effect for a 662 keV gamma, high frequency permittivity system.

From figure 7 and 8 it is seen that the water point is influenced similarly by changes in water salinity changes in both cases, which illustrates the importance of in-line measurement of the water salinity at high watercuts. However, the impact of $H_2S$ and $CO_2$ is very different for the two systems.

For the Dual Gamma system, $H_2S$ dissolved in the oil have a large impact on the low energy calibration point for oil which in particular has a large influence on the measured watercut. For the Dual Gamma system, the “triangle” becomes a straight line when the $H_2S$ content is approximately 12 % and hence the meter would be unable to perform any measurements of the WLR. For $H_2S$ content above 12%, the triangle ”flips”.

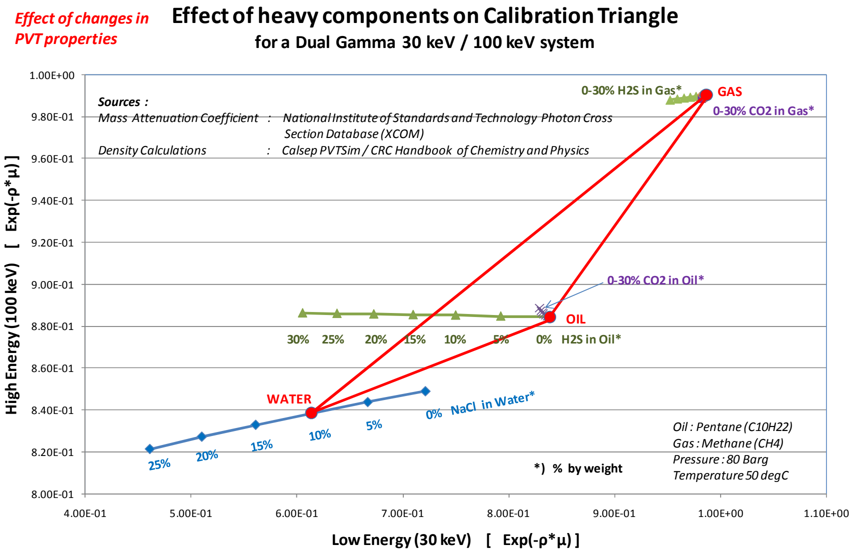



*Figure 7: Effect on the calibration triangle for a Dual Gamma 30/100 keV system for changes in $H_2S$, $CO_2$ and NaCl content*

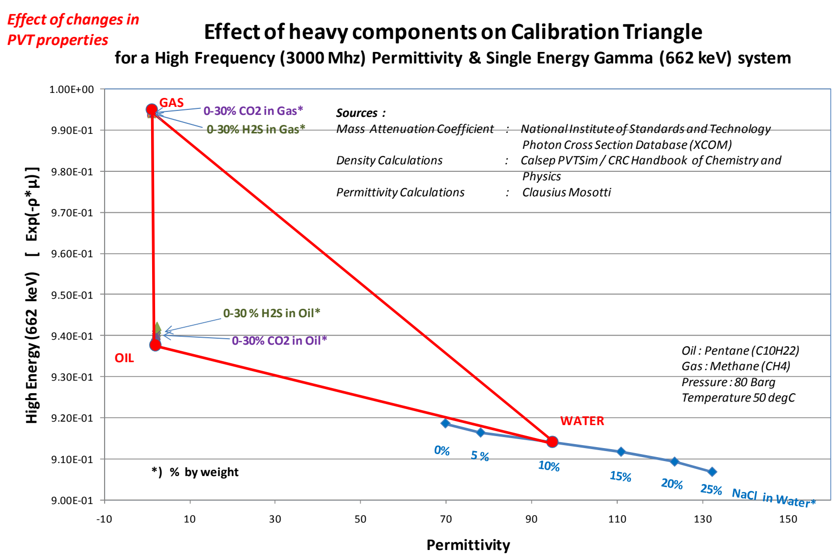



*Figure 8: Effect on the calibration triangle for a High Frequency Permittivity and 662 keV single energy system for changes in $H_2S$, $CO_2$ and NaCl content*

For the HF permittivity/660 keV gamma system, a 0-30% change in the $H_2S$ content has a marginal impact on the triangle. $H_2S$ in the oil influences the oil/gas ratio and introduces a small zero shift of the watercut measurement.

For the Dual Energy system, dissolved $H_2S$ in the gas also have a quite large impact on the low energy calibration point for the gas, whereas dissolved $H_2S$ have a small impact on the gas point for the HF permittivity/662 keV gamma system. In both cases, dissolved $CO_2$ in the gas have a small impact.

The example above illustrates the need for fluid sampling when using a 30/100 keV Dual Gamma system, particularly for applications containing $H_2S$ and $CO_2$. The example also demonstrates that the field experience gained with one type of multiphase meters may not be directly transferred to meters based other metering principles. It is also worth noting that a dual gamma system which uses higher energy levels will be less influenced by $H_2S$ and $CO_2$, whereas a dual gamma system that uses lower energy levels will be even more influenced which further complicates the issue of comparing different metering technologies.

The PVT robustness of the MPM meter, being a HF permittivity/662 keV gamma tomgraphic based meter, is an important enabling factor for simplified field configuration and In-Situ measurement of fluid properties. It also make it possible to use a more generalised fluid compositions for calculation of oil and gas properties, particularly when this is combined with automatic configuration of water and gas PVT properties using the salinity and in-situ gas measurement functionality of the meter.

## 5 MPM WITH IN-SITU MEASUREMENT OF FLUID PROPERTIES

### 5.1 Unique methodology

The MPM meter has three methods for In-Situ measurement of fluid properties that represent further increased robustness against uncertainties of the PVT properties for the MPM technology.

1) Measurement of water salinity of the water phase. This is an in-line continuous measurement which is performed while the well is flowing. Separate methods are used for water continuous conditions multiphase flow conditions and wetgas flow conditions.
2) Measurement of gas density and permittivity by utilising the DropletCount method to detect periods with pure gas within the pipe. During these periods, the permittivity and density measurement is used to measure, verify and correct the PVT calculated values for permittivity and density. The method can also be used to measure the permittivity and density of oil
3) In wetgas, the MPM meter incorporates three different methods for measurement of the fractions and flow rates of the wetgas which can be used to determine PVT properties. This is also an in-line continuous measurement which is performed while the well is flowing based on recalculation of the following measurement modes;
   a) two-phase mode with GOR Input
   b) three-phase mode
   c) three-phase mode with Droplet Count®

   These three methods behave differently when errors are introduced in the PVT configuration data which can be used to calculate an estimate of the PVT configuration data.

### 5.2 Measurement of Water Properties

The MPM meter can measure the conductivity of the produced water. The measured conductivity is converted to salinity, and the water density is calculated assuming a certain composition of the salt (e.g. NaCl). Based on the measured temperature and salinity of the water, the viscosity of the water can also be calculated by the meter. The measurement method is based on RF measurements and MPM's patented 3D Broadband™ technology.

The MPM meter can automatically measure the water conductivity and density in water-continuous emulsions.

For low watercut, 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 changes 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 conditions have been seen at the lower end and the upper end depending on the general flow regime and fluid properties. If slugging is expected, measurement of 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 incorrectly 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 25ºC as a configuration parameter, since the water conductivity in most cases is measured in a laboratory at room temperature and converted to 25ºC. The multiphase meter requires the water conductivity at actual conditions, and hence the water conductivity needs to be converted from 25ºC 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 water conductivity/salinity measurement is based on a patented method using dielectric measurements carried out locally at the pipe wall, using a differential principle with one transmitting and two receiving 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.

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 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 salinity measurement is further described in reference [7]-[9].

## 5.3 Measurement of Gas Properties

A patented (pending) method for in-situ measurement of gas properties has been developed and implemented in the MPM meter [17]. The method uses the Droplet Count® function [26] 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 9 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.

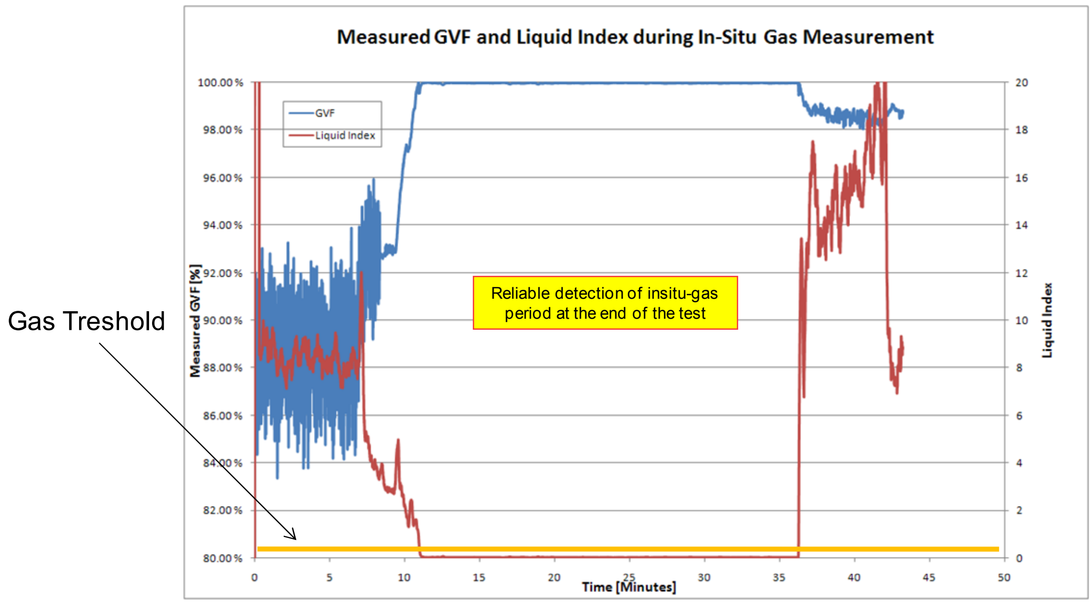



*Figure 9: Example of detection of gas in the meter*

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™ section performs measurement of permittivity at multiple frequencies 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 used 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 PVTSim 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 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 traceability 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.

### 5.4 Comparrison between measurement modes

As mentioned above, the MPM meter incorporates three different methods for measurement of the fractions and flow rates (2-Phase mode, 3-Phase mode, 3-Phase mode with DropletCount) which all are influenced differently by errors in the PVT configuration data.

Error in the PVT configuration data is one potential source for the discrepancy between the two measurement modes. In [7] the influence of PVT configuration parameters in wetgas mode was analyzed in 2-Phase mode and 3-Phase mode without DropletCount. As shown in the contour plots in section 3 of [7] , the gas and hydrocarbon mass rates are very little influenced by error in the gas PVT data for both measurement modes.

In 2-Phase mode operation, the gas density and GOR input mode have the largest impact on the measurement result. The contour plots in section 3 of [7] also show that 3-Phase mode and 2-Phase mode are influenced differently by error in the configuration data. The water fraction is little influenced by error in the gas density in 3-phase mode operation, whereas it has a significant impact on the water fraction in 2-phase mode. Similarly, the gas density have a large relative impact on the liquid flow rate in 3-Phase mode without droplet count, but as little influence on the measured liquid flow rate when the DropletCount function is used in 3-Phase mode or when the meter is operating in 2-phase mode.

This difference in behavior can be used to investigate the most likely source for the discrepancy and provide an estimate of corrections to the PVT configuration data used by the meter. This is done by using logged raw data within the meter which is then used to reprocess the measurements in 2-Phase mode, 3-Phase mode and 3-Phase mode with Droplet Count for a range of Gas Densities and GOR inputs. The density and GOR range is typical selected such that it spans around the PVT calculated values.

The measured water fraction and liquid flow rate is plotted vs. the Density and GOR range for all measurement modes, and by inspecting the interception points between the modes, it is possible to obtain an estimate of the gas density and GOR input which minimizes the discrepancy between the different measurement modes. These data can be used together with in-situ gas measurement to validate the PVT data and even trend changes in the PVT data.

## 6 SIMPLIFIED FIELD CONFIGURATION

The robustness of the MPM meter towards errors in the PVT data and the ability to perform in-line measurement of the water and gas properties have enabled MPM to implement a simplified procedure for field configuration of multiphase and wetgas meters.

Simplified field configuration means that the meters are delivered ready field configured from the MPM factory and are therefore fit for field service upon delivery from the factory. For subsea applications the operator can install and commission the meters and start producing wells without any assistance from MPM. For topside meters, some assistance may be needed in connection with installation and calibration of the gamma source, but apart from that, the operator can do all the needed work to put the meters in operation.

In order to use the simplified configuration scheme, it is required that the PVT configuration of the meter is handled during the production phase of the meters. During this period, the operator should provide MPM with the most recent (or relevant) PVT data for the reservoirs or wells where the meter is going to be used. In order to do the evaluation, the total hydrocarbon composition is needed for the various reservoirs, preferable as a fully characterised fluid to avoid errors in the characterisation process. Alternatively, a characterised oil and gas fluids can be used which MPM can recombine to generate a relevant total composition.

Based on the available data, MPM will evaluate the expected range in PVT data. This analysis will reveal if a generalised PVT composition can be used for all the flow cases or if several different PVT setups are needed.

If the water salinity measurement option and in-situ gas measurement option is enabled, the meter will be configured to use the measured water salinity to calculate the water conductivity, water density and water viscosity based on the measured water conductivity. Similarly, the meter can also be configured to use the In-Situ measured gas PVT to correct the PVT calculated values for gas. Alternatively, the PVT calculated and in-situ measured values will be logged in the database and use to manually correct the PVT configuration data when the meter has been in operation for a while.

MPM will then issue a configuration report which describes the recommended configuration of the meter with respect to PVT data for oil, gas and water and use of the water salinity measurement and in-situ gas PVT measurement. At the end of the FAT test in the MPM factory, the MPM meter will be configured according to the configuration report, witnessed by the operator, and the meter is fit for field service.

After the meter has been in operation for a while, it is recommended to perform a verification of the PVT data in the meter using the in-situ verification functionality. If the installation is equipped with a remote connection to MPM, the in-situ verification can easily be done remotely by MPM. At present, approximately 50% of the MPM meters in operation can be accessed remotely. Several field commissions have also been done remotely from MPM.

## 7 CASE EXAMPLES

### 7.1 Multiphase and WetGas

Most MPM meters in operation are using the simplified configuration scheme as described in section 6 above.

In [6] (2009), the operational experience with a MPM meter, configured with one common PVT configuration for all the wells at the Ekofisk field in Norway, is described. The Meter was configured in October 2007. Even though there was some scatter in the PVT properties for the different wells, one common (average) PVT configuration was used for all the wells. In addition, the meter was delivered with automatic configuration of water properties, based on the measured conductivity. The operating conditions at Ekofisk are typical *multiphase flow,* represented by high watercuts, GVF over a large span and severe slugging.

Based on the operational experience, ConocoPhillips concluded that:

> *"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."*

and

> *"The meter handles extreme salinity changes without recalibration."*

Similar experiences have been gained at many other locations and presented in various papers and conferences [5], [7], [8], [9], [10], [11], [18], [19], [20], [21], [22].

## 7.2 We tgas

### 7.2.1 Measurement mode comparrison

In this section is given an example where the in-situ gas PVT measurement functionality is used in a high pressure wetgas application.

As outlined in section 5.4, the MPM meter incorporates three different methods for measurement of the fractions and flow rates of the wetgas which can be used to determine PVT properties. The three methods behave differently when errors are introduced in the PVT configuration data, which is a feature that can be used to calculate an estimate of the PVT configuration data.

The four charts in figure 10 and 11 below show the measured gas volume rate, hydrocarbon mass rate, liquid volume rate and water fraction for three wetgas conditions (GVF, 93%, 97% and 99.5%). The measurements are performed at an operating pressure of approximately 100 barg. In the charts, results are shown for measurements in 3-phase and 2-phase mode.

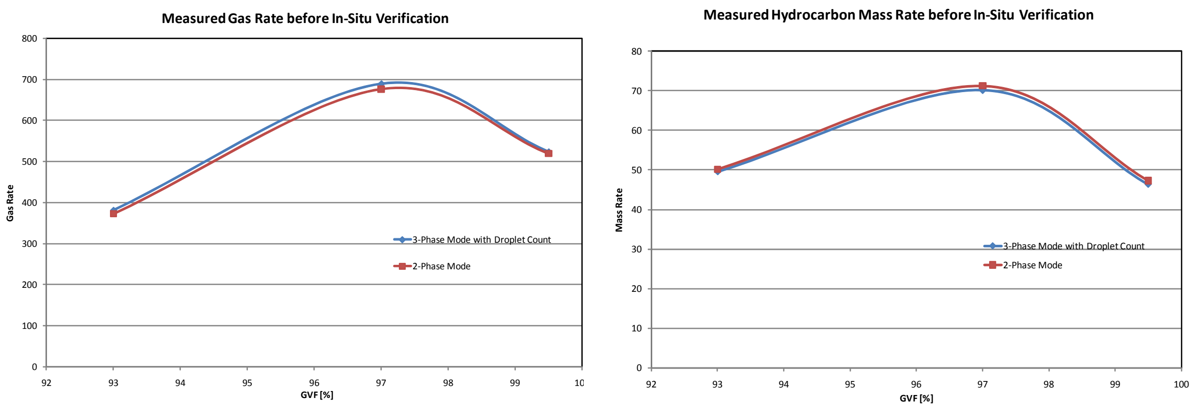



*Figure 10: Measured Gas and Hydrocarbon flow rate for 3 GVF cases in 2-Phase and 3-Phase mode operation*

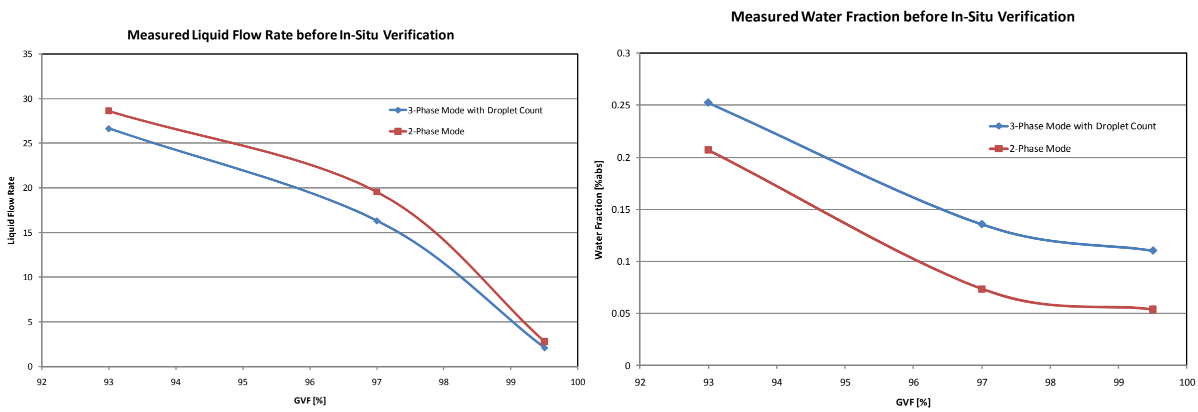



*Figure 11: Measured Liquid and water fraction for 3 GVF cases in 2-Phase and 3-Phase mode operation*

From the charts above it is seen that the measured gas volume rate and hydrocarbon mass rate agree well between 2-Phase and 3-Phase mode, whereas a bias is seen between the measured liquid and water fraction in the two measurement modes. Droplet Count is used for GVF of 99.5%, but not for the 97% and 93% GVF case. At high GVF, the dominating PVT configuration parameters are the PVT calculated density for gas and the PVT calculated GOR input in 2-phase mode [7].

### 7.2.2 In-Situ Measurement of Gas density

From theory and experience, we know that the water fraction measurement in 3-Phase mode is little influenced by an error in the gas density whereas the water fraction measurement in 2-Phase is highly influenced by an error in the gas density. Since the two methods have different sensitivity to error in the gas density, this can be used to determine the most likely value of the gas density based on identifying the gas density which gives the best match in both measurement modes. This is done by varying the gas density and identifying the crossover point on the water fraction between 2-Phase and 3-Phase mode. The cross over point defines the value of the gas density which gives the best fit.

Similarly, the liquid flow rate in 2-Phase and 3-Phase mode with DropletCount is very little influenced by the gas density whereas the liquid flow rate can be highly influenced by the gas density in 3-Phase mode without DropletCount. By varying the gas density and identifying the crossover point on the liquid flow rate between 2-Phase and 3-Phase mode it is possible to find an estimate of the gas density.

Figure 12 below shows the recalculated water fraction (denoted measured water fraction) and the recalculated liquid flow rates (denoted measured liquid flow rates), when an error span of ± 5% is introduced in the PVT calculated gas density for 3-Phase and 2-Phase mode. This is done for the tests at a GVF of 93 %. Recalculated results mean that the raw sensor data from the original test are used, only with a different set of configuration parameters.

As seen in figure 12, the water fractions calculated in the two measurement modes change as a function of the relative change in the gas density and intercepts at a gas density error of -2%. Similarly, the calculated liquid flow rate changes as a function of the error in the %relative change in the gas density, and the liquid flow rates in the two measurement modes intercept at a gas density error of -3.8% indicating a negative density error in the range 2-4% in the PVT calculated gas density.

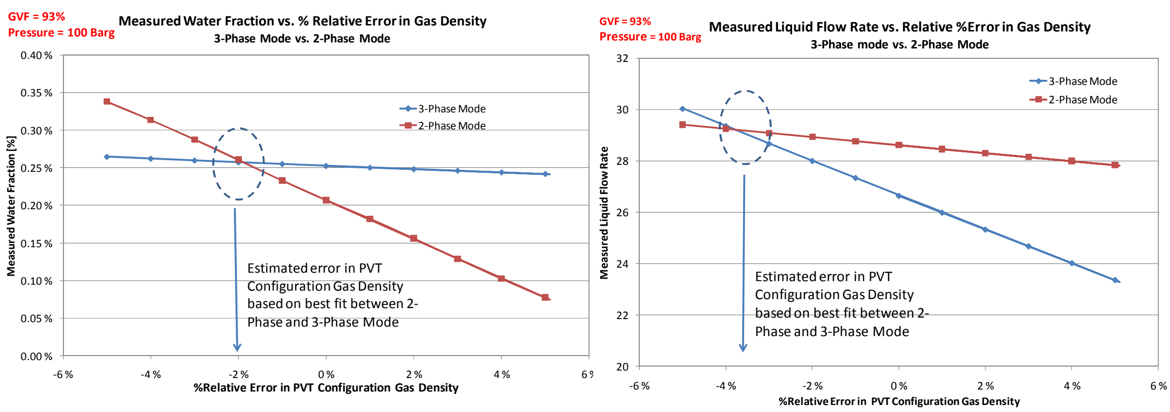
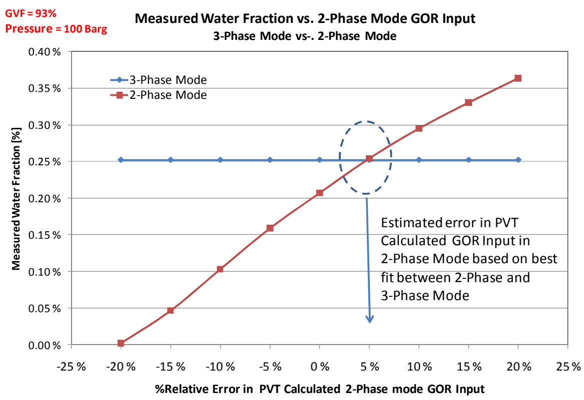



*Figure 12: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the gas density for 3-Phase and 2-Phase mode operation at GVF of 93%*

### 7.2.3 Verification of GOR input value

The above assumes that the entire discrepancy is due to an error in the gas density. The error may, however, also be in the PVT calculated GOR input in 2-Phase mode. In order to study the effect of error in the PVT calculated GOR input, a similar recalculation study can also be performed. E.g., by varying the GOR and identifying the crossover point for the water fraction and liquid flow rate between 2-Phase and 3-Phase mode, an estimate for the potential error in the GOR can be found. This procedure can again be repeated for different values of the gas density in 3-phase mode which would give rise to a set of likely errors in the gas density with corresponding errors in the GOR input.

Figure 13 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 25% error in the PVT calculated GOR input for 2-Phase mode. As seen on the graph, the water fraction and liquid flow rate in 2-Phase mode changes as a function of the relative error in the GOR input. Since the GOR input is not used in 3-Phase mode, the calculation in 3-Phase mode is unaffected by changes in the GOR input. From figure 13 below it is seen that the discrepancy in the measured water fraction and liquid flow rate between 2-Phase and 3-Phase mode may also be due to a 5-15 % error in the PVT calculated GOR input for 2-phase mode.



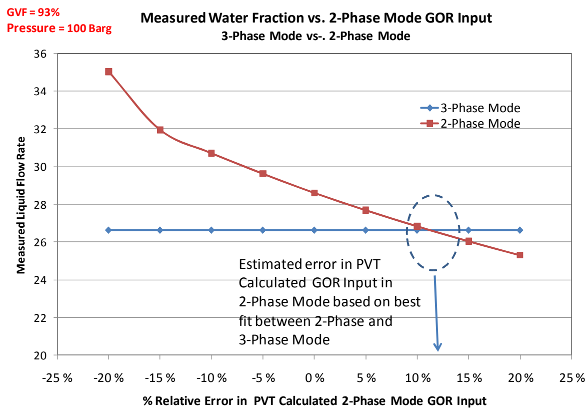




*Figure 13: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated GOR input in 2-Phase mode for 3-Phase mode and 2-Phase mode operation at GVF of 93%*

### 7.2.4 Further analysis at different GVF's

From the analysis in the sections above it is seen that the source of the discrepancies in results for 2- and 3- phase mode can be either a 2-4% negative bias in the PVT calculated gas density used by both measurement modes, or a 5-15% positive bias in the PVT calculated GOR input in 2-phase mode. In most field applications, a 2-4% error in the PVT calculated gas density may be equally realistic as a 5-15% error in PVT calculated GOR input, and hence, more measurements or evidence would be required in order to identify the source of the discrepancy. However, the tests have revealed that there is a PVT discrepancy which needs to be further investigated and monitored.

Figure 14 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 5% error in the PVT calculated Gas density for 3-Phase and 2-Phase mode for the same case. In this case, another set of raw data are used; those obtained at a GVF of 97%.

As seen in figure 14, the water fractions for this case intercept at a gas density error of -2.5% and the liquid flow rates intercept at a gas density error of -2.8%. Quite interestingly it is seen that, at a GVF of 97%, both the water fraction and the liquid test indicate a negative density error in the range of 2.5 - 3% in the PVT calculated gas density. This is very similar to the error range calculated at a GVF of 93%.

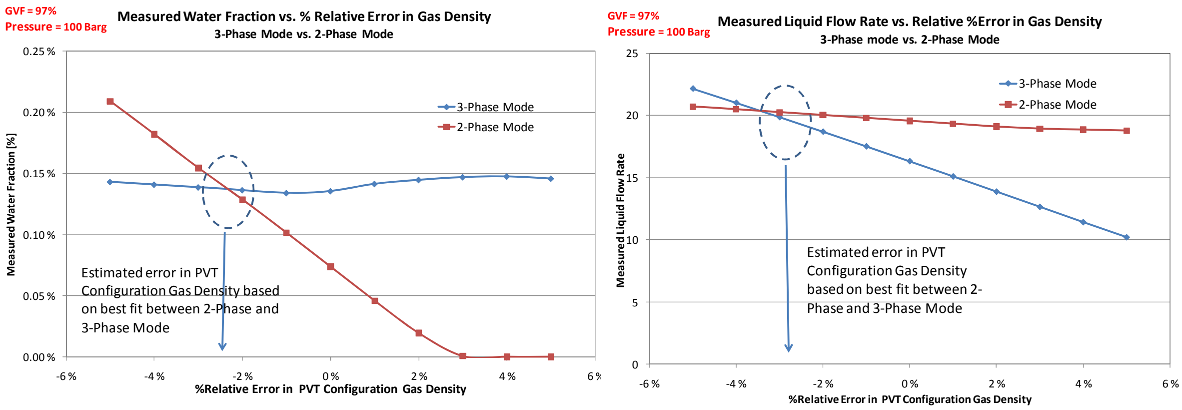



*Figure 14: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated gas density for 3-Phase mode and 2-Phase mode operation at GVF of 97%*

Figure 15 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 50% error in the PVT calculated GOR input for 2-Phase. From figure 15 below it is seen that the discrepancy in the measured water fraction and liquid flow rate between 2-Phase and 3-Phase mode may also be due to a 40-50 % error in the PVT calculated GOR input for 2-phase mode. A 40-50% error in the PVT calculated GOR is in most cases considered to be quite significant which indicates that the most likely source of the error is in the gas density. This is further confirmed by the fact that the error in the gas density at a GVF of 97 % is within the same range as for the calculation at 93% GVF, whereas the potential error in the GOR input have increased from a 5-15 from 93-97% GVF.

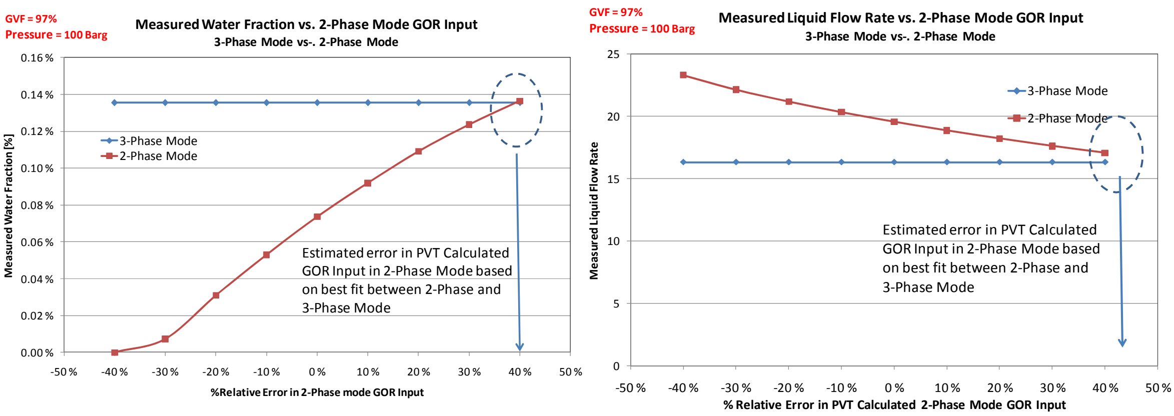



*Figure 15: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated GOR input in 2-Phase mode for 3-Phase mode and 2-Phase mode operation at GVF of 97%*

Figure 16 below shows the recalculated water fraction and the recalculated liquid flow rate for yet another value of GVF, this time 99.5%. Again, results are shown for a ± 5% error in the PVT calculated Gas density for 3-Phase, with and without DropletCount and 2-Phase mode.

As seen in figure 16, the water fractions intercepts at a negative gas density error in the range 2.5%- 4%. 3-Phase mode without Droplet count is indicating a density error of -4% and with DropletCount the density error is also negative in the range 2.5-3%. Now there is also a bit more variation (ripple) in the curves which is due to short logging interval (3 minutes). By using longer logging intervals, the ripple would have been significantly reduced.

The liquid flow rate of figure intercepts at a negative gas density error in the range 2%- 3%. 3-Phase mode without Droplet count is indicating a density error of -3% and with DropletCount the density error is approximately -2 %.

It is also seen that the liquid flow based on 2-Phase mode and 3-Phase mode with Droplet Count are far less influenced by density errors compared to 3-Phase mode without DropletCount. The 3-Phase measurement with DropletCount is in particularly stable with respect to errors in the gas density. At a GVF of 99.5%, the measurement of the density error is consistent with the 93% and 97% GVF case indicating a negative error in the range 2-4%.

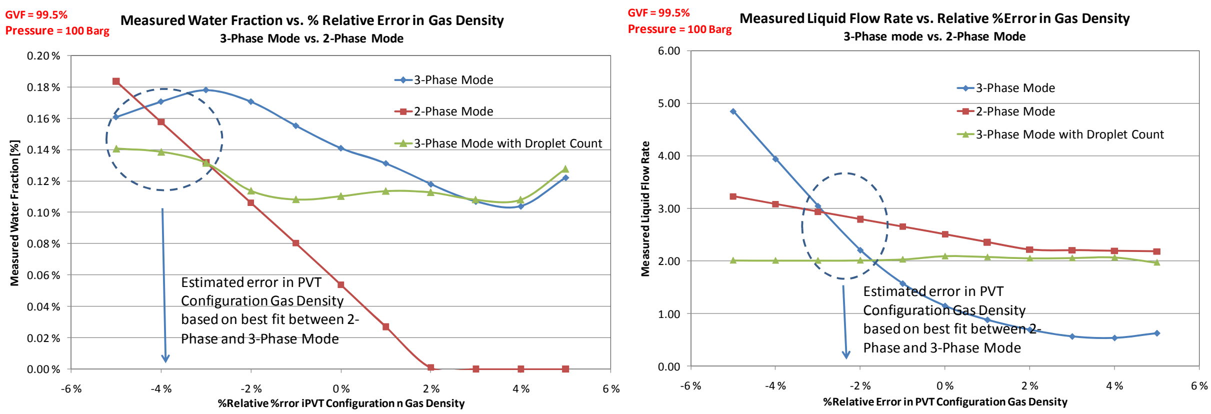



*Figure 16: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated gas density for 3-Phase mode and 2-Phase mode operation at GVF of 99.5%*

Figure 17 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 200% error in the PVT calculated GOR input for 2-Phase. From the recalculated water fraction, is seen that even a 200% error in the GOR is not sufficient in order to obtain an interception between the 3 different measurement modes. The liquid flow rate show an interception between 2-Phase mode and the two versions of 3-Phase mode at a GOR error of 50% and 200%. In other words, the water fraction test shows a GOR error in excess of 200% (from the slope of the curve it looks like 500%) whereas the liquid test shows a GOR error of 50-200%.

The test at 99.5% GVF indicate that the observed discrepancy in the measured liquid and gas flow rate observed at 99.5% GVF may be caused by a negative density error in the range 2-4% or a GOR error in the range 40-500%. The density error is consistent with the previous GVF cases whereas the GOR error is different in all the cases. Moreover, the GOR error is not consistent when it is compared against the two 3-Phase modes (with and without Droplet Count), which by itself is an indication of a GOR input.

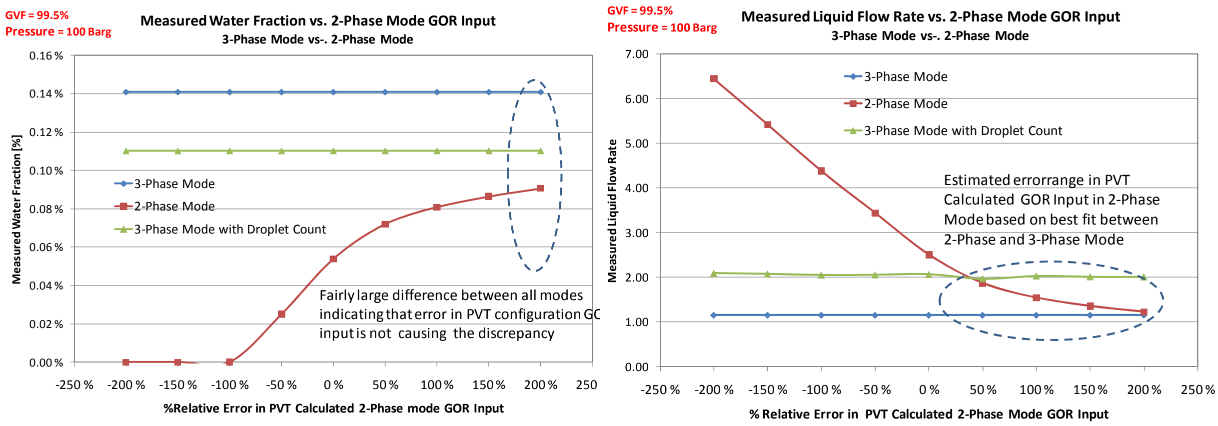



*Figure 17: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated GOR input in 2-Phase mode for 3-Phase mode and 2-Phase mode operation at GVF of 99.5%*

### 7.2.5 Summarizing the In-Situ evaluations

Based on the cases above a negative bias in the gas density in the range 2-4% would explain the observed discrepancy between the measurement modes. There also appears to be a small error in the GOR input, but this is marginal compared to the density effect.

The uncertainty of the PVT calculated density was discussed with the vendor of the PVT software. Based on the gas and condensate composition for this for this application, the vendor expected a positive bias in the PVT calculated density in the range 1-3% due to the cubic nature of the EoS models which does not give sufficient precision at this range introducing a bias in the calculation. The expectation from the vendor was also confirmed by an in-situ measurement of the gas phase as shown in figure 18 below.

The graph to the left shows the liquid index goes below the gas threshold followed by an in-situ gas period of approximately 15 minutes before the flow starts again. The graph to the right shows the measured gas density and permittivity vs. the PVT calculated values for the same period. As seen from the graph, the in-situ measurement of the gas properties shows that there is a negative bias of 2.8% of the PVT calculated gas density vs. the measured one, and a negative bias of 0.2% on the PVT calculated gas permittivity. This is consistent with the calculations performed during the water fraction and GOR test for the three cases at GVF of 93%, 97% and 99.5%.

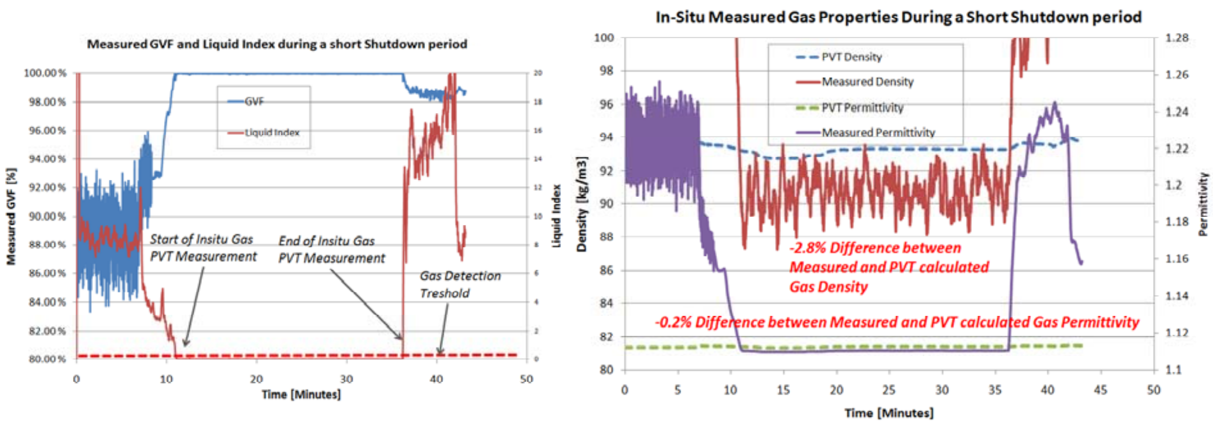
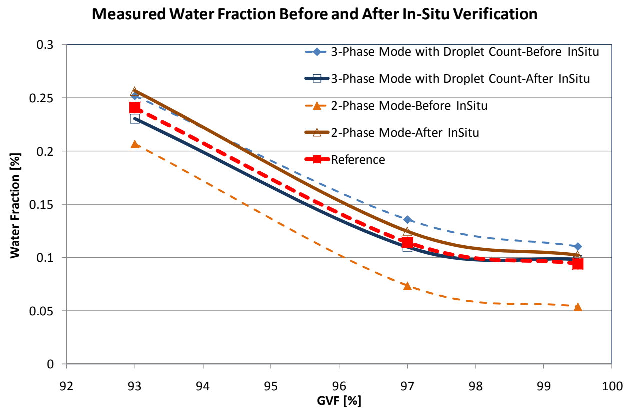



*Figure 18: Measured Liquid Index, GVF, Gas Density, Gas Permittivity, PVT calculated gas density and PVT calculated Permittivity during the In-Situ Gas Measurement*

Figure 19 below shows the recalculated measurement in 2-Phase and 3-Phase mode using the in-situ measured gas PVT data. The measurements performed with the original PVT configuration data is denoted as ("Before In-Situ") and the recalculated measurement where the error in the gas density and permittivity have been corrected is denoted ("After In-Situ").

From the graph it is seen that there is a good fit between 2-Phase and 3-Phase mode in the entire GVF range for both the water fraction measurement and liquid measurement when the in-situ measured gas PVT properties are used. The recalculated measurements, based on the in-situ measured PVT data, also agree well with the red stipulated reference value.



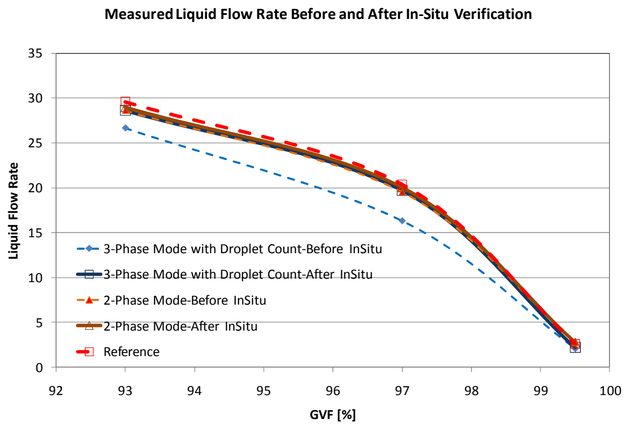




*Figure 19: Measured Water Fraction and Liquid Flow Rate vs. when using the In-Situ Measured Gas Density*

The example above illustrates how the different measurement modes together with in-situ gas measurements can be used to identify and correct potential errors in the PVT calculated data without performing any sampling of the well and while the well is flowing. In-Situ measurement of gas, using the DropletCount function to detect pure gas in the meter, can together with the above measurements be used to correct the PVT configuration data used by the meter. The correction can either be implemented based on a manual procedure or performed fully automatic by the meter. Both cases are used by MPM meters in operation.

## 8 CO NCLUSIONS

This paper shows that all types of multiphase and wetgas meters, independently of what technologies they are based on, are depending on a set of configuration data in order to provide accurate and reliable flow rates.

It is well known that the dominating PVT configuration parameters for measurement of small volume fractions of a well stream component are those of the fluid occupying the largest volume. The paper demonstrates that different technologies applied for multiphase and wetgas metering have very different requirements and sensitivities with respect to what configuration data is required. More important, the different technologies have different sensitivity to errors and variations in the PVT configuration data. This is particularly the case for $H_2S$ and $CO_2$ rich applications, wetgas fields which require accurate water measurements and water flooded fields with high watercuts.

As a consequence, the field experience gained with one type of metering technology may not be relevant for meters using another measurement principle and the operational procedures (including frequent sampling) deemed necessary for one type of meters may not be needed for meters based on other measurement principles.

The MPM meter is based on a technology which is very tolerant towards potential errors in the PVT configuration data. The meter has in-built functionality for in-situ measurement of water and gas PVT properties which is used to measure and compensate for changes in the PVT properties. This unique combination eliminates the need for fluid samples or installation of in-line sampling systems, which otherwise would be important particularly for subsea and $H_2S$ rich applications.

The PVT robustness of the MPM meter makes it also possible to use a generalised fluid composition for calculation of oil and gas properties. The generalised fluid composition can be verified in-situ and further enhanced by using the automatic configuration option based on the in-built functionality for measurement of water and gas PVT properties.

The robustness of the MPM meter towards errors in the PVT data and the ability to perform in-line measurement of the water and gas properties have enabled MPM to implement a simplified procedure for field configuration of multiphase and wetgas meters. Simplified field configuration means that the meters are delivered ready field configured from the MPM factory and are therefore fit for field service upon delivery from the factory. For subsea applications the operator can install and commission the meters and start producing the wells without any assistance from MPM. For topside meters, some assistance may be needed in connection with installation and calibration of the gamma source, but apart from that, the operator can do all the needed work to put the meters in operation.

## ACKNOWLEGDEMENTS

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 Southwest Research Institute. Nine oil companies; ENI, Chevron, ConocoPhillips, Gaz de France, Shell, StatoilHydro, Petronas, Total and Woodside are also participating in a 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.

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North Sea FLOW Measurement Workshop

# Paper 4.3

# Well Testing - An Evaluation of Test Separators and Multiphase Flow Meters

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TÜV SÜD

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28th International North Sea Flow Measurement Workshop
26th – 29th October 2010

# Well Testing - An Evaluation of Test Separators and Multiphase Flow Meters

**Amy Ross, TUV NEL**
**Gordon Stobie, ConocoPhillips**

## 1 ABSTRACT

National and International Oil and Gas Companies and Government Regulators all have an interest in managing their, or their countries' assets in the most expedient manner possible. The assets are the oil and gas reserves in the ground. Management of these reserves is generally carried out by Production and Reservoir Engineers though the use of Well Testing. To date the 'gold standard' for well testing has been the 'test separator'.

Whilst many Regulators mandate the frequency of well testing (and in the UK North Sea sector this is generally every 30 days) there is little in the Regulations about the expected flow measurement uncertainties required.

This paper will review the test separators used and the 30 day timing and highlight what this can mean under 'real world' conditions and take a jaundiced look at the expected measurement uncertainties which might be achieved in the field.

The introduction of Multiphase Meters over the past 20 years might well have elicited dramatic improvements in Reservoir management performance – but the authors suspect that this has not been universally realised. This will be addressed in the paper.

This paper will also address, identify and review:

- some of the strengths and weakness of test separators
- alternative uses of test separators and how this might affect 'well testing efficiencies' and provide some 'real world' comparisons
- the flow measurement uncertainties which can be expected from a test separator and how this might affect reservoir management performance
- what the MPFM might add to the well testing scenario and performance
- the question of reconciling a MPFM against the test separator

In the hope of inserting some realism into the world of managing our major material assets.

## 2 INTRODUCTION

API RP 86 Recommended Practice for Measurement of Multiphase Flow Section E [1] discusses test separator performance and states that that general performance of the flow meters should not be used as a guide to the expected flow measurement performance when well testing.

The test separator is primarily required for Well, Reservoir and Field performance monitoring. As such it is used for the:

- Determination of fluid flow rates
- Determination of when changes in fluid flow rates/composition occur (i.e. water breakthrough etc)
- Identification of mechanical integrity issues

When flow rates have been determined these can (and are often) summated over all the flowing wells and an estimate of the overall production is made for the wells and system allocation. This data is often used as a guideline for the system productivity.

## 3 TEST SEPARATOR DESIGN

Test separators are the historical standard by which wells have been tested. There are several forms of test separator, and whilst the three phase (oil-water-gas) separator is predominant in the North Sea, in many places around the world, two phase (gas - liquid) separators are more common. As a rule of thumb, a horizontal three phase vessel might have a mass of 10000kg and a footprint of say – 7M(L) by 3.5M (D) by 5M high, whilst its equivalent two phase horizontal vessel might be 6500Kg and [4M(L) by 3M (D) by 4M high], and a vertical two phase vessel might be 5000kg with a smaller footprint.

Being smaller, the two phase vessels are lighter and include less instrumentation and controls - are less complex and are assumed to require less maintenance.

There are also compact separator systems, using the fluid energy and complex shapes to provide separation, which will not be dealt with here. Figure 1 shows a schematic of a three phase separator.

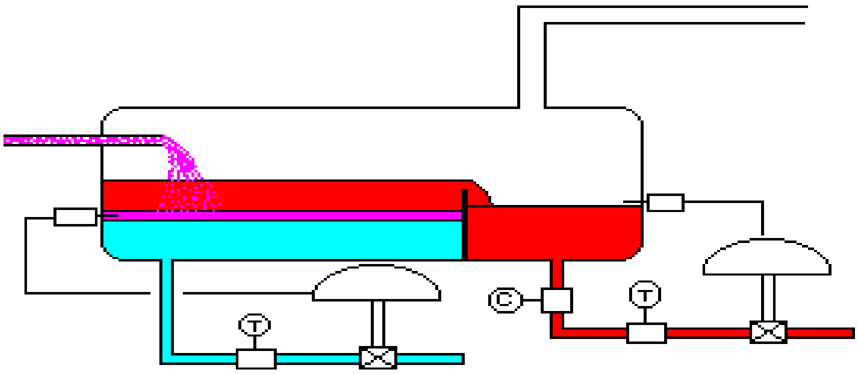


**Figure 1: Schematic of a three phase separator**

## 4 TRADITIONAL APPROACH TO WELL TESTING

The “traditional” approach comprises either:

- Separating the gas from the liquids (two phase) and measuring the streams using conventional single phase meters, with the oil/water split being measured using a water cut (WC) meter, or
- Separating all three phases, oil, water and gas and measuring each using a conventional single phase meter per Figure 1.

In the three phase system, a water cut meter might be an option to monitor water in oil or oil in water contamination. The three phase approach is often perceived to be the ‘best’ method available, offering the lowest measurement uncertainty for well testing.
This may well be the case when the following criteria are met:

- Separator sized appropriately for gas and liquid fractions. If the separator is under sized, the separation will not be complete, leading to the risk of gas carry-under in the liquid leg(s), and liquid carry-over in the gas leg.

- Interface levels are suitably maintained to avoid oil/water or liquid/gas contamination.
- Meters are adequately sized for the range of flow rates seen in operation.
- Meters installed in recommended orientation with required upstream and downstream straight lengths.
- Meters are regularly inspected for damage/wear and calibrated against traceable references in fluids similar to the process fluids – or better still the actual process fluids.
- Secondary instrumentation (pressure, Δp, temperature, etc) are regularly calibrated.
- Separator is regularly inspected for solids/sediment build up.
- Separator control are such that liquid (and gas) slugging does not occur (difficult when separators are under pressure and level control) and flow control – a necessity for flow meters – is not part of the overall control scheme

The list is not exhaustive and illustrates some of the number of design, operational and maintenance actions required to ensure accurate flow measurement performance. In practise well testing on an individual well is carried out for a set period every few weeks or months. Typically – in the North Sea- this might be a 12 to 24 hour test every 30 days. The length of the test will be selected by the Reservoir and Production Engineers.

Whilst the test separator is expected to provide accurate flow measurement, its intermittent service, and the lack of flow control adds to the flow measurement uncertainty when the short test period is amortised over an extended time (ie a 12 or 24 hour test is considered to be representative for 30, 60 or 90 days ). In this case we assume that a short (sometimes as short as 4 hour s) flow test every 30 days is considered to be representative of the total monthly flow.

## 4.1 Test Separator Metering

### 4.1.1 Gas metering (orifice plate)

The orifice meter is the most common gas meter in service today. The Daniels Senior® orifice type fitting and its various clones provides the ability to change orifice plates easily and is generally considered as the de facto gas meter for a test separator. However some of the common orifice meter problems seen in test separator systems are listed below:

- Plate geometry (sharp edge worn, face scratched, contaminated, etc)
- Plate installed correctly (facing forward)
- Plate bent due to slug flows
- Poorly sized plate due to well rate variations, and low DP's
- Installation effects - short meter run, often just 10D with a 90° bend
- Infrequent calibration of secondary instrumentation
- Errors when running at low Δp's with Signal to Noise problems
- Liquid carry over – 'tide' marks being a common occurrence
- Sampling for density - infrequent spot samples with associated liquids
- Slug flows – bent plate. See Figure 2
- Liquids and solids in transmission tubing

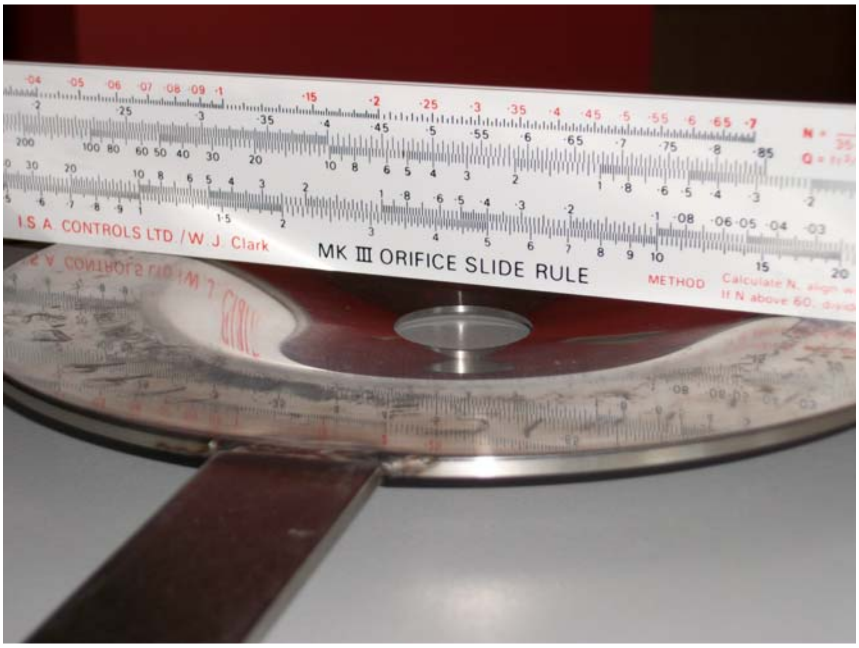


**Figure 2: Bent orifice plate**

#### 4.1.2 Alternative differential pressure (DP) gas meters

Other DP meter types include Venturi and cone meters. Whilst these are excellent flow meters they are limited by their fixed Beta and the rangeability of the meter due to the ½√ρDP function at low flows, where 10:1 DP turndown represents at 3 or 4:1 turndown in flow.

The cone type meter is also particularly susceptible to damage from slug flows even though it is less susceptible to liquids and is self cleaning.

#### 4.1.3 Alternative - non DP gas meters

Whilst the orifice meter is by far the most popular meter type used, non-DP meters have found a place in test separator metering. As an example – ultrasonic USM) and Coriolis meters have both been used. Both of these are excellent technologies – but each has its own (and different) limitations which need to be understood.

Coriolis meters are mass meters and there is often a lack of specification in the density output which may be used to convert the flows to volume, although there is concern that the density output could have a high uncertainty. These meters have a large turn down, but have a relatively high head loss potential due to the small meter bores used.

Ultrasonic meters are a volumetric meter, with a large turndown, and a minimal head loss (except where flow conditioners are deemed necessary) and have been and are used in test separators. Whilst there have been some successes – there have some reported (and possibly many unreported) cases where the USM has failed to meter correctly due to the liquids interfering with the transducers and signals.

Note: Flow conditioners in this service should be considered carefully as hydrates are a real risk [2]

#### 4.1.4 General problem with test separator gas metering

The general problem with all meters used in first stage separator gas metering service is the lack of knowledge – or a lack of understanding - of the effect of gas ‘wetness’ and the way in which these meters perform in wet or saturated flows. It is all well and good to know that the meter over (or under) meters in wet gas – but when one does not know how wet the gas is, one is then unsure on how much the meter has over (or under) metered the gas. So there must always be a relatively high level of uncertainty in this measurement.

### 4.2 Liquid Metering

#### 4.2.1 Turbine meters

The most commonly used liquid meter in test separator service has historically been the turbine meter. Whilst this meter is a solid fiscal meter when used with a prover, its relative weaknesses must be recognized. It is considered to be particularly susceptible to fluctuating flows, fluid viscosities and gas break out when at, or near the bubble point, and is further susceptible to entrained gases and any solids in the flow. Typically problems might be:-

- Physical state of the turbine
  - Damaged blades. See Figure 3.
  - Worn bearings
- Pipe roughness / wall contamination
- Infrequent calibration of primary and secondary instrumentation
- Contaminated liquids (water in oil – or- oil in water)
- Changing density/viscosity from well to well or from calibration to operation [3]
- Lack of sampling to determine density and viscosity.
- Presence of gas or gas breakout (cavitation) could results in large errors [4]. See Figure 4.
- Viscosity sensitivity - water oil mixes generally being more viscous mix than the base fluids. See Figure 5.
- Poor separation performance (emulsions, foaming, etc) leading to cross contamination of phases.

**Figure 3:Turbine meter with damaged blades**

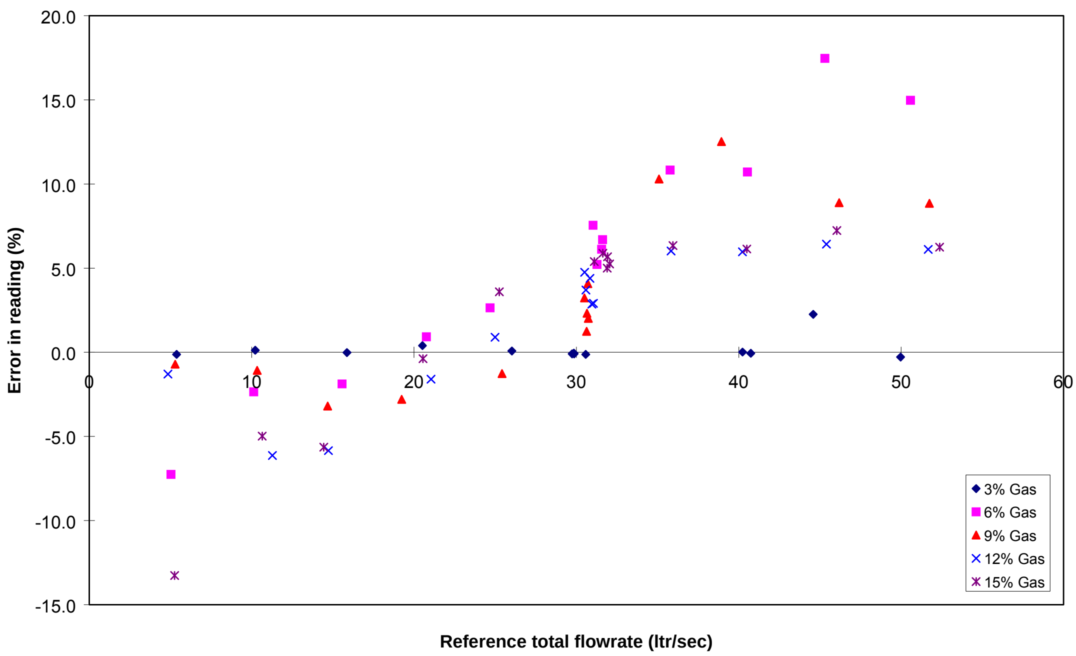


**Figure 4:Turbine meter – error in liquid flow rate in cavitating flows**

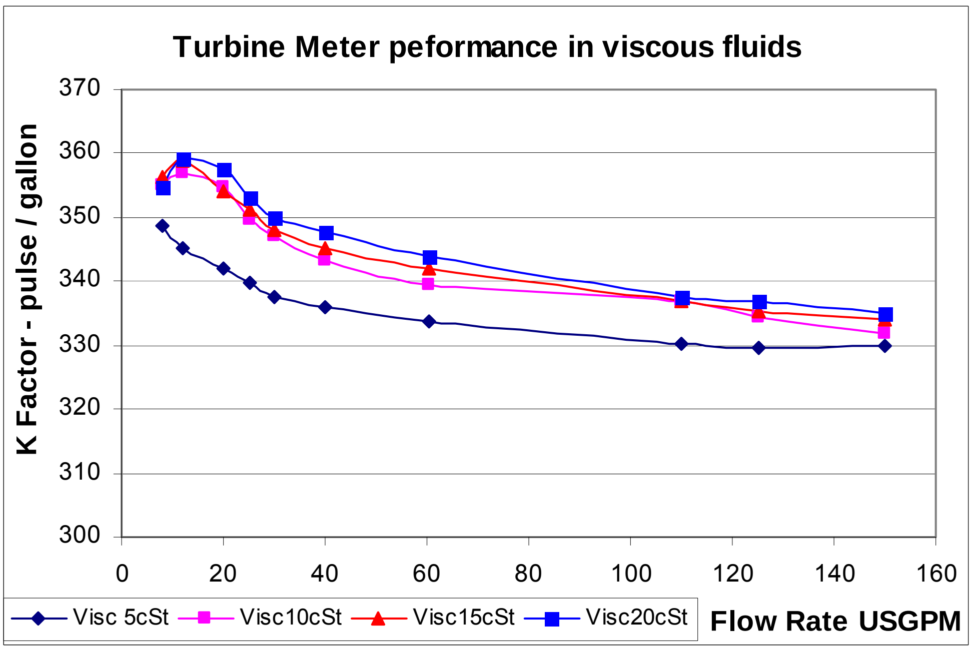


**Figure 5: Turbine Meter K factors under various viscosity fluids**

### 4.2.2 Alternative liquid meters

Alternative flow meters are now being used, the most common being ultrasonic and Coriolis meters

Ultrasonic meters (USM's) may be affected by swirl and asymmetry as they require a fully developed flow profile. USM's can tolerate oil/water mixtures but problems can arise when gas is also present. Liquid USM's are susceptible to free gas in the liquids. Some designs of USM can be susceptible to free water in oil and can be affected by water globules (the infamous 'Cousins Glob') at low flows [5]. USM's are non-intrusive meters and the pressure drop across them is negligible except where flow conditioners are mandated. In addition, USM's offer supplementary diagnostic information which can be used to identify issues such as gas carry-under [6].

Coriolis meters do not require upstream and downstream straight lengths as they do not require a developed flow profile. Care should be taken, however, to ensure the Coriolis meter is properly supported. Coriolis meters measure mass flow rather than volumetric flow so additional calculations are required for volumetric flows. That said, Coriolis meters will also give a density measurement, therefore it is possible to convert mass flow rate to volume flow rate, although this does add another element to the uncertainty. Coriolis meters will tolerate oil/water mixtures, but the addition of gas may generate significant errors. Over the past decade, advances in the Coriolis meter electronics have enabled diagnostic information on the meter and flows.

Coriolis meters will have a significant pressure drop, so it is common practice to over size the meter. This can increase the uncertainty of the liquid flow measurement as Coriolis meters perform less well at the bottom of their range due to meter zeroing requirements. Coriolis meters do not tend to scale well and the performance of a six-inch meter may not be as good as a four-inch meter.

### 4.3 Water Measurement

In a three phase separator the water will be metered by a stand alone meter – the conventional meter has been the turbine meter, although a number of different meter types have been used in the past few years including Coriolis, USM and electromagnetic meters.

In a two phase separator where the liquids are metered with a single meter and the oil and water phases are determined using a Water in Oil (WIO) monitor. This has a key role to play in the oil measurement and the resulting uncertainty. A greater understanding of the performance of the OIW/WIO monitor and its dependence on the water cut and salinity is needed.

#### 4.3.1 Water Cut – WC monitor & NOC water cut calculations

Many water cut monitors are based on microwave technology, with a quoted uncertainty of ±1%. In water continuous flows (nominally WC >60%) with low gas volumes (2-5%), this uncertainty may increase to ±2 to 5%. It should be recognised that microwave WC monitors have limitations in performance at high water cuts, and when the salinity changes.

When using a Coriolis meter, it is possible to use the density based Net Oil Calculation to compute the net oil and water flows - however – this assumes:

- A knowledge of the oil and water densities
- Stable flows.
- WC in the mid-range - rather at the extremes i.e WC >25%, ,75%

#### 4.3.2 Electrical Water Cut measurement and Water Salinity

To make an electrical measurement of WC, the salinity must be considered. Accuracy is likely to be compromised without salinity compensation. If the fluids are oil continuous - oil surrounds the water droplets at water cuts typically less than 60% - salinity has little affect on the WC measurement. The onset of the 'water continuous' state is not fixed and the effects can be seen from as low as 40% and as high as 80% depending on the flow regime.

Salinity is likely to be an issue in the water continuous phase, especially in fields being supported with a water injection system and water is being sourced from several locations. Salinity variation in produced water can easily vary by ±25%.

#### 4.3.3 Water Cut stability in a well test

During well tests, water cuts are rarely stable and can and do change continuously Figure 6 below shows the changing water cut whilst flowing in a typical well test using a two phase separator with the fluid density oscillating between 1.025g/cc (water) and 0.78g/cc (oil) The oil water separation has been determined using a Net Oil Computation from a Coriolis meter. [7]. This rapid variations makes WC determination a difficult measurement to make obtain.

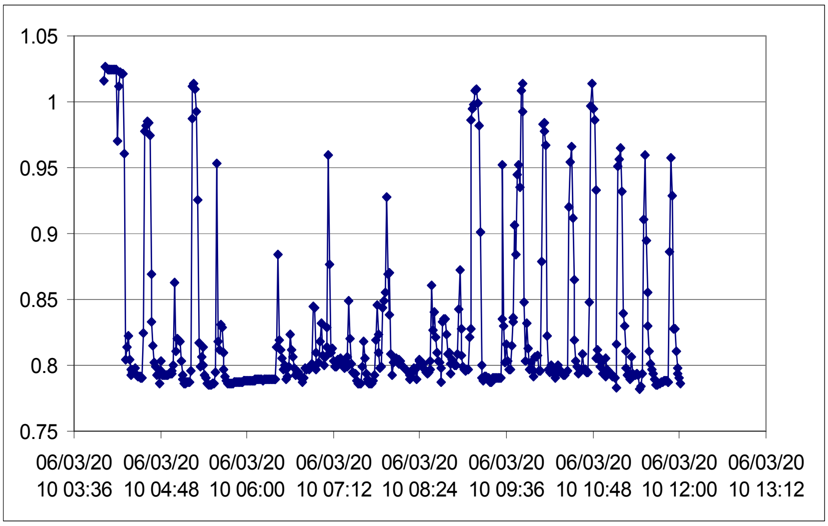


**Figure 6:Coriolis liquid density (g/cc) indicating WC changes in time**

#### 4.3.4 Water Cut determination technologies

There are a number of different technologies available for measuring WC:

- Microwave – good for oil continuous liquids but uncertainty increases with increasing water content. Changes in water salinity can also be problematic for microwave water cut monitors as are emulsions.
- Electrical capacitance – again good for oil continuous liquids but uncertainty increases in water continuous fluids. Salinity changes can also be problematic as are emulsions.
- Infrared – works over the full range of water cut and not so affected by changes in fluid properties or the presence of gas, however a knowledge of the oil qualities may be required.
- Coriolis metering and Net Oil calculation – can be used for both the bulk flow measurement and water cut monitoring provided fluid densities are known.

### 4.4 Measurement Uncertainty

This section is not a rigorous examination of measurement uncertainty and merely reflects and acknowledges that measurement uncertainty needs to be considered in an overall evaluation of the test separator performance. The authors have taken the ‘easy way out’ and reproduced the uncertainties that might be expected in Test Separator Measurements from API RP 86Table E2 – under Table 1 below

**Table 1 – Test Separator Meter uncertainties from API RP 86 Table E2**

| Subject | Gas | Gas | Oil | Oil | Water | Water |
|---|---|---|---|---|---|---|
| | Good | Extreme | Good | Extreme | Good | Extreme |
| **Base meter** | 1 | 2 | 0.5 | 1 | 1 | 2 |
| **Meter Lengths (short)** | 0 | 2 | | | | |
| **P, T Calibration** | 0.5 | 1 | 0.5 | 1 | 0.5 | 1 |
| **Range (exceeding turndown)** | 0 | 5 | 0 | 5 | 0 | 5 |
| **Sampling (sample & analysis)** | 1 | 4 | 1 | 4 | 1 | 4 |
| **Density/BSW/OIW/Viscosity** | 1 | 3 | 0.5 | 7.5 | 0.5 | 7.5 |
| **Surging/pulsation/gas breakout** | 0 | 3 | 0 | 3 | 0 | 3 |

#### 4.4.1 Gas meter uncertainty

The best measurement uncertainty that could be expected on the gas leg of a test separator would be in the region of ±2%. However, it is more likely to be the case that an average uncertainty would be in the region of ±3% to ±6% with contributions from the some of the sources shown in Table 1. In extreme cases where some of the sources may contribute to significant additional uncertainties it would be possible to encounter uncertainties above ±6%, perhaps as high as ±10% to ±15%. When the uncertainty is as high as this, it is often due to some perceived bias in the measurement which may be quantified, reducing the uncertainty or recognised through an asymmetric uncertainty distribution.. Whilst these are listed with respect to an orifice meter, some of these will also affect other DP and non DP meters.

#### 4.4.2 Liquid metering uncertainties

For liquids (oil or water in a three phase separator) it would be expected that the best measurement uncertainty that could be achieved would be in the region of ±1% to ±2%, with a more likely average approximately ±2% to ±5%. The extreme case for liquid measurement would be above ±5%, perhaps as high as ±10%.

In the case of a two-phase separator the performance of the water cut monitor could be a major source of error – especially in older fields, possibly leading to errors of 20% or more on calculated individual oil flowrates.

#### 4.4.3 Water metering uncertainties

Table 1 does not address the two phase separator case for water measurement uncertainties, and by this omission does not address the uncertainty of the resulting oil measurement (1-%WC). However Section 4.3 has addressed some of the weakness known in the measurement of water cuts in the two phase flow.

## 5 TEST SEPARATOR PERFORMANCE

A separator should separate the fluids. In order to do this, it requires ‘residence time’, which is a function of the separator size and the flow rates – PLUS - heat and/or demulsifier chemicals or a combination of all three. It should:

Separate gas from the liquids. This is a function of the difference in the liquid and gas densities, the gas having a much lower density than the liquids plus the difference in fluid viscosities and the time allowed for separation. In a two phase separator these are the primary parameters for good separator performance, and unless the oil – or water-oil emulsion is particularly viscous, the density differences and time are the driving parameters. In very viscous liquids however, gas micro-bubbles can be a problem and may be entrained in the liquid for many hours or even days.

There is an expectancy that the separator will give up all its free gas, leaving only gas in solution. The free gas, whilst saturated will be relatively dry, and that when metered, the meter will be unaffected by the associated liquid.

- In a two phase separator, a small separator is used so that liquid-liquid separation does not take place and that the fluids are kept homogeneously mixed. There is then the problem of metering the mixed liquid and determining the quantities of the two fluids (oil and water).
- In a three phase separator the aim is to separate the oil, water and the gas. This is a function of the different (oil, water and gas) densities, the difference in the fluid viscosities, and the residence time. Here there is an assumption that the oil will be water free (and vice versa), often an unlikely occurrence.

### 5.1 Test Separator Disadvantages & Advantages

There have been a number of discussions in the Industry about the need or otherwise of replacing (or supplementing) the Test Separator with other means of flow measurement – typically the Multiphase Flow Meter.

There are a number **advantages** and **disadvantages** to the use of Test Separators.

#### 5.1.1 Advantages

It should be realised that the test separator has other uses and it may not be convenient for it to be removed.
Test separators allow the sampling of single phase fluids after separation and are unaffected by wet gas flow patterns, except in the case of severe slugging which may cause liquid carry over in the gas leg. Test separators are also often used for:

- The start up of poorer performing, but otherwise beneficial wells after a shutdown
- The clean up of newly drilled or wells which have been reworked (scale squeezed, re-completed etc)
- A small group separator for low pressure wells

#### 5.1.2 Disadvantages

In an offshore production facility the test separator may be considered to be a disadvantage with respect to:

- Size and weight, particularly for high pressure designs.
- Relatively high CAPEX and OPEX.
- Well measurement takes a long time (flush out previous fluids, wait for stable process conditions etc). Overall separator mass means that stabilization time can be prolonged when switching wells for testing (a 12 hour well test may take 4 hours to stabilize)
- Provide only a “average” measurement of the well flowrates and are generally unable to highlight individual flow patterns

- Periodic measurement represents a short sample or window (24hours per 30 days = 1/30 per month)

### 5.2 How Good Is Well Testing??

Over the decades there have been a number of discussions on the subject of *"how good is a test separator?"* As far as the authors are aware there is no guidance that would provide an answer to the question.

One method for demonstrating the veracity of well test data is by balancing the sum of the flows from a series of well tests to the facility disposal systems. This entails determining the sum of the well flows over a period and comparing them with disposals (fiscal oil and gas, fuel gas, flare, discharged water flows etc).

Typically

$$\sum \text{Well Flows} = \sum \text{Disposals or}$$

$$\sum \text{Well Flows} / \sum \text{Disposals} = 1.$$

Of course this assumes that the well flows and disposal measurements are in Mass Units – when in reality this is seldom the case.

The dichotomy here is that the users of well test data (Production and Reservoir) use volumetric data at standard conditions and this does not necessarily sit well with trying to balance the fluid disposals across a process facility where hydrocarbon liquids may be disposed of as gases and vice versa. The solution is to balance in mass terms, which is rare in the International Oil and Gas business.

When units are representative, it would be reasonable to report that a balance factor of 0.95 to 1.05 which is exceptionally good, and 0.9 to 1.1 which is probably more likely, although balance factors of 0.5 to 2 are not unheard of. A typical balance chart (or Field Allocation Factor) from well test data is shown in Figure 7 [8].

There are several facilities which have reported 'excellent' balance factors – and in a number of the cases reviewed these have been shown to be manipulated such that the well test data and the production data has been normalised, forcing the test data to merge with the fiscal data. This practise is questionable at best and does not allow the raw test data to be quality checked against the export figures.

From this point there may be the need to take and overall field allocation factor for all produced fluids and disposals to look at the individual fluids – oil/condensates – gas and gas liquids – water – and it here that the complexity will start to develop.

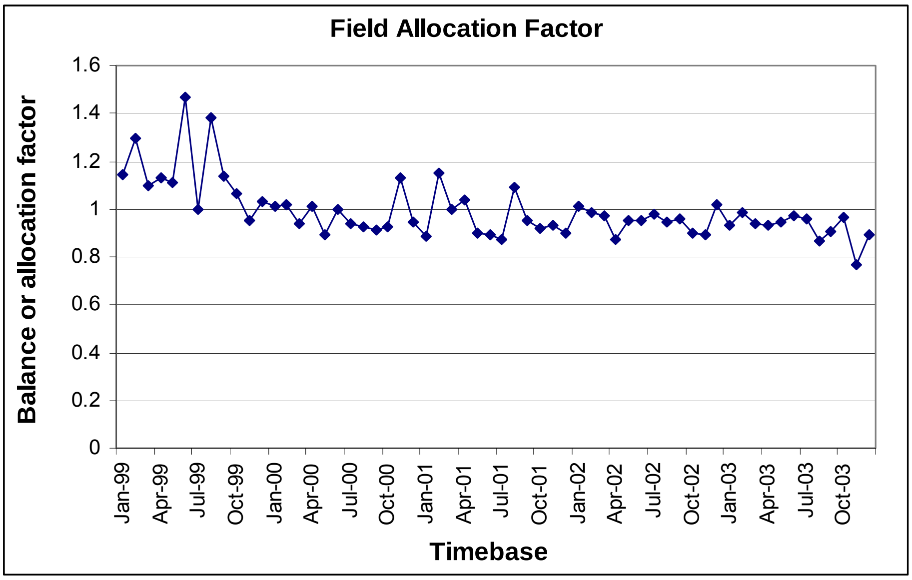


**Figure 7: Well test to Fiscal out-turn Balance Chart**

### 5.3 What Makes a Good Well Test?

What makes a good well test? This is probably the most troubling question to the Production, Reservoir and Measurement Engineers. And probably the one question which is rarely asked – or answered.

- One which follows the previous well tests demonstrating repeatability?...and in this case,
  - Do we know that the choke or GL rate has not been changed in the intervening period?
  - Have we accounted for the wells' natural decline in production
- One which is within the stipulated period of 30-60-90 days etc?
- One which has been carried out for the stipulated length of time (12 or 24 hours?)

The above might well be OK for 'ticking the boxes', but this is unlikely to provide a strong basis for proving that the well tests are 'good'. Certainly we should be using balancing techniques to assess whether the overall well test system balances against the facility out-turns – but this will merely give a 'warm and fuzzy' feeling that the system as a whole is good. It will not identify if particular wells are being poorly metered because of measurement difficulties with high or low rates, high WC's or high GVF's, slugging flows etc.

As such it is likely that we should be looking at the well tests and using some form of statistical significance to validate them. This may well include frequency, repeatability and duration but there are probably several other elements that need to be addressed.

Some Production Engineers advocate that some wells may do equally well with shorter well tests – possibly on a more frequent basis– but these need to be selected on a case by case basis.- typically these might be those wells which exhibit stable and appreciable flows of all the products – or wells with repeatable regular short cycles with appreciable flows.

Wells with irregular long cycles, small flows or a small flow of a single phase may in fact require longer more frequent well tests to flow an appreciable quantity and be statistically significant.

The figures below and overleaf are typical flow plots of gas lifted wells, and are produced as examples. It can be appreciated that they should be addressed differently with respect to flow testing.

The plots have been extracted from a multiphase meter and show:

- Top plot – oil, gas and water flows
- Middle plot: - meter differential pressure
- Bottom Plot: Water Cut (%WC) and Gas Void Fraction(%GVF)

# Well XXX

**Fluids – Green - Oil,Blue – Water, Yellow - Gas**

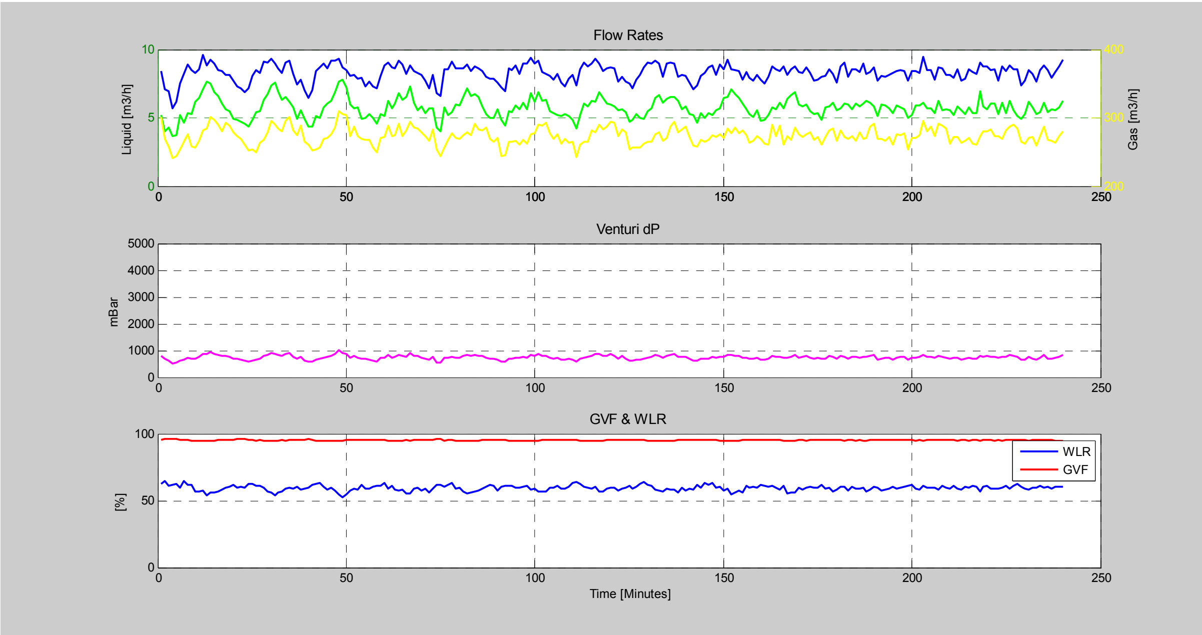


**Figure 8: Well Plot for Well XXX**

Figure 8 shows a well with cycling fluid flows which may well provide satisfactory well test data from regular well spaced tests. The GVF is very high (>90%) with a stable WC in the 60% range.

# Well YYY

Liquids – Green - Oil ,Blue – Water, Yellow - Gas

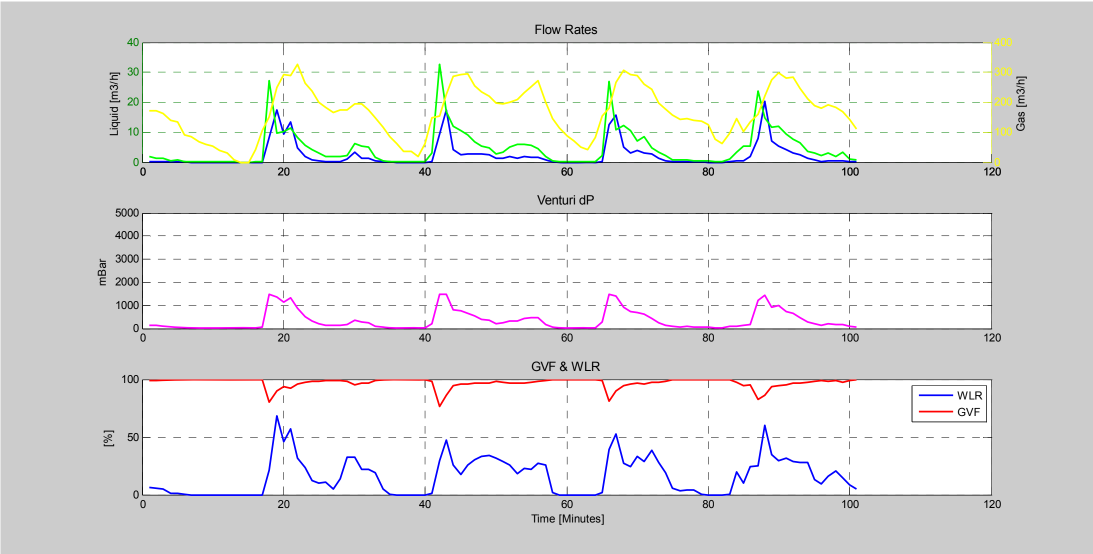


**Figure 9: Well Plot for Well YYY:**

Figure 9 shows an unstable slugging well with significant gas flows, limited liquid flows, and WC ranging from 0 to 70%. A short well test is unlikely to provide statistically good data as the slugs are of 20 minutes duration. A longer well test may be indicated.

# Well ZZZ

Liquids – Green - Oil ,Blue – Water, Yellow - Gas

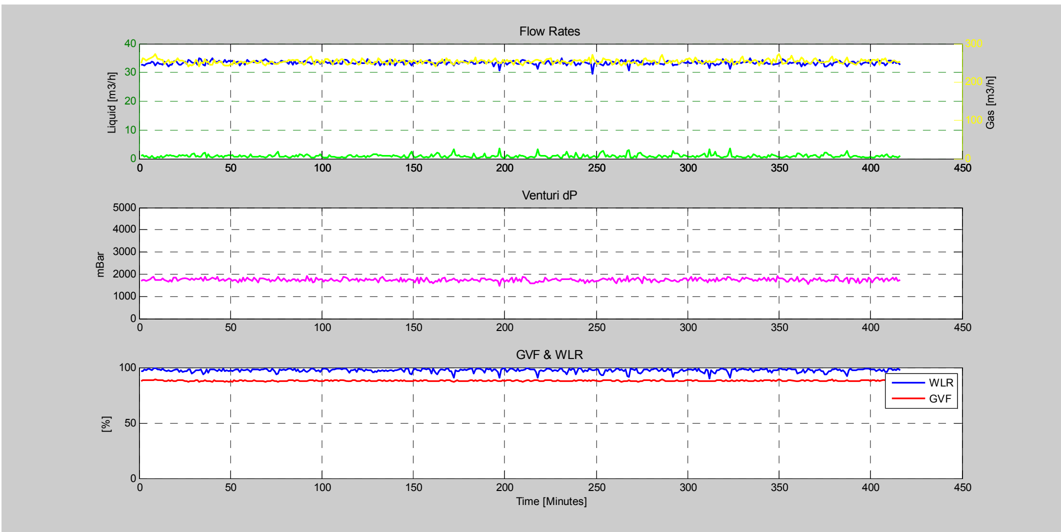


**Figure 10: Well Plot for Well ZZZ:**

Figure 10 shows a stable well with significant water and gas flows and very low oil flows showing WC and GVF in the >90% ranges. A short well test is unlikely to provide statistically good data for the target product – oil – and a longer well test may be called for.

The wells above need to be analysed and a test plan selected to ensure that significant flows of the target product – oil – in this case, are achieved. This may require flow tests of several days, however this may not feasible with a large quantity of wells and a very busy test separator schedule – and the question has to be, how can we improve well testing?

Apart from looking at the wells more closely and working with the Production and Reservoir Engineers to select a programme more in line with the individual wells' needs – how else can we improve the well test data? Typically we could, and should be doing more well tests- more frequently - and possibly - with better flow meters…..and it is here that the MPFM's can probably add value.

### 5.3 Test Separator Utilisation

The test separator is primarily required for Well, Reservoir and Field performance monitoring. As such it is used for the:

- Determination of fluid rates
- Determination of when changes in fluid flow rates/composition occur (i.e. water breakthrough etc)
- Identification of mechanical integrity issues

When the flow rates have been determined these can (and are often) summated over all the flowing wells and an estimate of the overall production is made for well and system allocation. This data is often used as a guideline for the system productivity.

There are, however, other uses for which a test separator has an important role. These are:

- Identify casing/tubing leaks
- Production optimisation of wells (be that Gas Lift (GL), Electric Submersible Pump (ESP) or other recovery techniques)
- Reservoir build up tests and other monitoring functions
- Well clean - up following re-work
- Assessment of near well-bore damage
- Other system failures

In addition the separator, ancillary instrumentation and controls all require maintenance, some of which will entail separator shutdown. These alternative functions and maintenance requirements can take a considerable amount of test separator time, meaning that it is often unavailable to carry out its primary (well testing) functions. As such the test separators 'well test utilization' can be - and is often - low.

This is unfortunate as one of the main tools to manage the oil and gas reserves is considered to be the well test data and the ability to carry out regular well tests is an essential key element. A stipulation by the Regulator/Licensee is to test each well 'periodically' – be that 30, 60, 90 or 180 days depending on the location and the Regulator's requirements. In addition, the Operators Reservoir Engineers will have their own requirements for well testing and build up tests etc., which might be driven by the reservoirs size, age and geophysical attributes and the type of depletion employed.

Table 2 has been prepared to tabulate some of the roles placed on a test separator and give an insight into the system availability for well testing. Based on a facility with say, 36 operational gas lifted oil wells, the authors have premised the separator utilisation. These times are a scenario and will vary with the field and producing scenarios (naturally flowing, gas lifted, pump lifted wells etc) and their age. From Table 2 it can be seen that in this particular case, the test separator on its own cannot reasonably be expected to fulfil all the functions expected of it.

**Table 2: Test separator utilization example**

| ACTIVITY | Days/mth | Comment |
|---|---|---|
| **Regular Well Testing ( each well every month)** | | Assumes TS is operated 24/7 |
| 66% Normal tests (12 hrs) | 11.88 | Could be achieved by MPFM |
| 34% Long Tests (24hrs) | 12.24 | Could be achieved by MPFM |
| **Subtotal** | **24.12** | |
| **Other Well Tests** | | |
| Additional Test/Retest | 2 | Could be achieved by MPFM |
| Pro Optimisation – Gas Lift | 5.1 | Could be achieved by MPFM |
| Pro Optimisation – Choke Setting | 0.7 | Could be achieved by MPFM |
| Test after stimulation | 0.5 | Could be achieved by MPFM |
| Test after squeeze | 1.9 | Could be achieved by MPFM |
| **Subtotal** | **10.1** | |
| **Separator use during Well Service Operations** | | |
| Test during PLT | 0.7 | Could be achieved by MPFM |
| Clean up after Stimulation | 1.0 | Separator needed |
| Clean up after squeeze | 2.6 | Separator needed |
| Clean up after initial Stimulation | 0.1 | Separator needed |
| Scale milling | 0.1 | Separator needed |
| **Subtotal** | **4.7** | |
| **Other Test Sep Use** | | **Separator needed** |
| Start up of low pressure wells after Shutdown | 1.4 | Assumes 10% of wells require assistance to start up every 2 mth |
| Test MPFM | 3 | Assume multirate MPFM flow test required |
| **Subtotal** | **4.4** | |
| **Separator maintenance & inspection** | | **Separator removed from service** |
| PSV's, Safety Systems | 0.07 | Assume 4 days every 2 years |
| Removal of solids | 0.12 | Assume 7 days every 2 years |
| Instrument calibration | 0.09 | Assume 5 days every 2 years |
| **Subtotal** | **0.28** | |
| **TOTAL** | **43.6** | **Separator overused** |

In this case it may be necessary to utilise the services of a multiphase meter to enhance the test separators measurement capabilities per Figure 11 below.

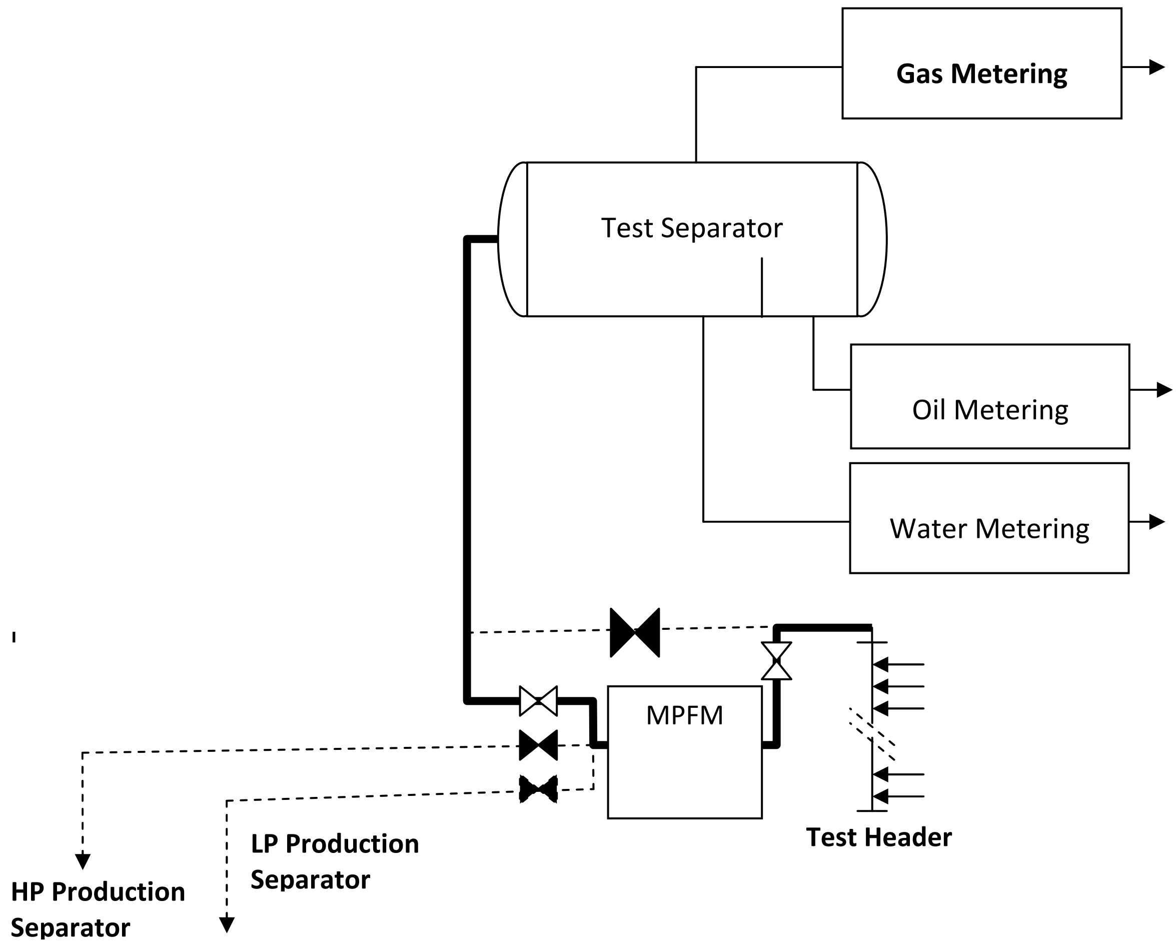


**Figure 11: Test Separator and Multiphase Meter**

## 6 MULTIPHASE FLOW METERS

The development of multiphase flow meters capable of measuring wet gas and multiphase flows continuously is seen as a key to the continuing economic development of smaller and more marginal fields [9, 10]. These may well provide substantial advantages for larger new build developments and some of the current and declining reservoirs where improved field surveillance may provide increased returns.

Multiphase meters have been around for about 20 years – the first MPFM paper presented at the NSFMW was in 1988 [11]. Some vendors have come and gone in that time. Many performance claims have been made and whilst some have been met, a considerable number have not. There has often been a reluctance to highlight the steps needed to achieve success and in some cases a reluctance to admit that – maybe - in particular cases - the MPFM may be not the most suitable tool to use.

There has also been some 'less than full and frank disclosures' about the hidden costs of the meter, and perhaps a reluctance to admit that there are weaknesses especially with respect to fluid sampling and meter performance as flows, flow conditions and fluids change with time.

There is also some resistance to learn with the Operators – or – maybe a resistance to teach by the vendors – although some – but not all - do hold regular User Forums in which interested parties can air the successes and failures. Even in this NFMW forum there is a reluctance to present a paper on meter failure by both the Operators and the Vendors.

Whilst there are a number of in-line MPFM's which have performed well, there has been limited discussion about:

- what the MPFM might add to well test performance, and
- reconciling an MPFM against the test separator

### 6.1 What the MPFM Might Add To Well Test Performance

One of the major advantages of an MPFM in a well test role is that they are capable of stabilising their process conditions (typically temperature) much more quickly than a test separator. This is a function of the smaller mass; stabilisation times of 4 to 6 hour (depending on local weather conditions) can be reduced to 30-60 minutes.

This aids significantly in reducing well test durations using an MPFM, leading to the potential of shorter test times (test time plus stabilisation time).

The ability to meter direct flow measurements rather than averaged or conditioned flows that we see from the test separator could indicate that the MPFM flow reports are more representative of the well flows. This may further aid in reducing well test durations using an MPFM.

### 6.2 Reconciling an MPFM Against the Test Separator

Based on the large number of trials that we have seen in flow labs and in operational fields – the request to test against another field systems is often – with good reason – looked at with less enthusiasm by some Operators' Flow Measurement Engineers. The feeling being that we are often trialling a perfectly good MPFM (as seen in the flow loops) against a field system that has many (potential) problems with fluids, system control and flow measurement.[12]

One of the major responses from potential users and project managers looking at implementing MPFM's is – "Can I trial a meter against my test separator?" The argument by many Operators is that they want to trial against 'their' fluids- the inference being that engineering technology and science changes in the North Sea, Alaska, or the GOM…..much like the Bermuda Triangle. Having said this – there are unusual fluids or processes that do need trialling, as the overall flow envelope has by no means been completely evaluated to everyone's satisfaction.

The risk of course is that some 'real world' field test sites do have unidentified problems with their fluids, control and measurements. Mastering these problems is never easy as the MPFM is the new 'black box' technology and the Operators' test separator is the known and trusted equipment, and accepted by the local Regulator. Identifying differences between the two sets of equipment always starts from the MPFM being 'wrong', and the credibility loss starts from there. It takes huge amount of tact for the MPFM service and engineering personnel to identify the problems with the clients (and potential customers) equipment. Hence reconciling an MPFM against a test separator is not necessarily an easy task, but must be carried out to assure the client and his business partners.

As mentioned earlier the majority of test separators report in volume units. An MPFM being flowed in line with a test separator may well be at significantly different process conditions and aligning volumes measured at the separator with the MPFM is by no means simple with fluid phase changes taking place. As a result the simplest comparison is in mass terms for bulk flows.
Whilst rarely done – the most suitable comparison would be:

$$\sum(\text{Oil+Gas+Water})_{\text{MPFM}} \text{ compared to } \sum(\text{Oil+Gas+Water})_{\text{TS}} \textit{ in Mass terms}.$$

Once this balance has been established then further work can be carried out to establish individual phase comparisons in both mass and volume terms. Without this first level check balance being carried out initially just diving into try and balance the phases in volumetric terms – especially when there are process differences is likely to be problematic.

### 6.3 MPFM Metering Performance

Typical claims for a few in line MPFM's performance are presented in Table 3 in a simplified and summarised form – readers should review the individual vendor data sheets.

**Table 3: Typical claims for Nucleonic in Line MPFM Performance**

| | **Liquid (Rel)** | **Gas(Rel)** | **Water Cut (Abs)** |
|---|---|---|---|
| **SLB Vx** [13] | 2.5-10, 0-100% GVF | 2-5%, 0-100% GVF | 2.5-8%, 0-100% GVF |
| **Roxar 2600** [14] | 2%, 0-100% GVF | 5%, 0-100% GVF | 2%, 0-100% GVF |
| **MPM** [15] | 2.5-5%, 0-99%GVF<br>5-15%, 99-100% GVF | 3-5%, 0-100%GVF | 1-2%, 5-100%WLR |

With MPFM's we have now moved forward from a goal of being able to meter the phases with an uncertainty of about ±10 to ±25% with a huge fear of the 'dark corner' - (GVF>85% and WC>85%) to building auto-switchable multiphase - wet gas meters with claimed uncertainties of better than±5% for liquids and ±2 to ±5% for gas flows and water detection better than ±2%.

In many cases these performance claims have been verified in flow laboratories as part of JIP's and in Operators' processes, however there are still some caveats.

Like single phase meters it is important to size MPFM's correctly. Meters that are either over or undersized will not operate well and their uncertainty is likely to be very much higher than stated. Understanding that declining fields will entail MPFM replacement should be in the Operators' ongoing development plan. It is better to have two (large and small) MPFM's than one oversized meter. It is also important to consider what conditions the MPFM will have to cope with as some technologies could be more suitable than others as their technologies are very different.

There is no doubt that the performance of MPFM's over the years has improved significantly. This has probably been the result of a number of factors including – and not exclusively:

- Competition between vendors
- Open and independent MPFM test JIP's
- Significant R & D expenditure by vendors, operators, universities etc
- Innovative alliances by vendors and Operators in JIP's
- Significant Standard type documents which are huge 'assists' to newcomers
- Users becoming 'MPFM aware' and resisting the 'black box' approach
- Flow model improvements
- Improvements in computing power, high speed electronics and secondary instrumentation (DP, PX & Tx)….and lastly – and by no means least -
- Some very awkward individuals asking very awkward questions

Improvements are such that we have seen in the last 5 years several installations where the MPFM has been installed and has positively identified problems with the test separator meters - which is a role reversal.

These installations plus – the relatively few – to date - fiscal allocation in the real world mean that MPFM's have reached a point where acceptance by the Operators and Regulators has reached unprecedented levels.

## 5 SUMMARY AND CONCLUSIONS

It is likely that, in practice, many test separators are not suitably maintained or operated to give the lowest measurement uncertainty achievable, and many, the metering requirements are regularly compromised. As a result it is probable that the, measurement uncertainties are probably in the range of ±4 to ±10% for each phase.

As a result of the multiple uses and the operational limitations placed on them, it is likely that in many high well count facilities it is probable that a single test separator is unable to provide the utilization to well test every 30 days per current UK and Norwegian requirements and it is likely that waivers are required.

It is possible that this is both detrimental to long term field management and short term production optimization
.
With the technological advances made in in-line MPFM's, their measurement envelopes have improved substantially and many are able to switch from wet gas to multiphase and vice versa. This facility makes them highly suitable for use in Operational well testing as a supplement to and with a Test Separator and will provide an increase in well test utilisation with a consequent improvement in field management and short term production optimization.

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