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IMPORTANCE OF THE FLUID PROPERTIES AND PREDICTABLE MEASUREMENT IN MULTIPHASE FLOW METERING TO ENSURE ACCURATE REPORTING IN HIGH WATER CUT CONDITIONS AND/OR HIGH CO2 CONCENTRATION

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1 INTRODUCTION

Multiphase flow measurement technology has been the centre of attention in the oil and gas industry for the past years. Due to continuous improvements in multiphase flow measurement standards and, cost-effective applications of this technology; the utilization of the multiphase flow meter (MFM) in field operations has become a widely accepted practice (Ref [23]). Many operating companies have tested this type of technology in their fields over the past years and currently various utilize MFMs in their field operations (Ref [2], [4], [7], [11]). MFMs were traditionally deployed at a fixed location in a mature field for production well testing.

However, Vx Technology which is based on a multi-energy gamma ray / Venturi flow meter combination offers by its design a larger variety of applications from Oil to Gas wells with a unique hardware. Worldwide, Vx Technology has been used in periodic well testing, exploration and appraisal well testing, well clean-up operations and in combination with production logging, in optimizing gas lift, (Ref [12], [15], [16]) and measuring accurate rates and pressure in exploration (Ref [17]) and appraisal well testing (Ref [18]) and even in fiscal allocation (Ref [24]). A continuous improvement of this technology has been applied over the years bringing it as a leader on the Multiphase Market including recently the seamless integration of the FluidID (i.e. dedicated Client PVT or special Fluid Behavior Modelization) and sampling fluids.

This paper describes and reports the benefits and limitations of the MFM. A focus on the metrology and advantage of the Vx Technology will be presented including a clear physical and understandable solution of the use of embedded fluid properties (Ref [13]). The special advantage of the multi-energy nuclear measurement will be demonstrated showing a totally predictable system bringing serious benefits and a clear understanding of the overall performance along the well life over years. Reviewing quickly the effect of inappropriate correlations on two key parameters Bo and pb will highlight the importance of Fluid Properties. Then a sensitivity study of the water cut in large presence of reservoir and fresh injection water will be presented.

2 MULTIPHASE FLOW METERING PRINCIPLES

A multiphase flow meter is designed to measure the total volumetric flow rates of oil, water and gas of a producing well at line conditions. These flow rates are converted to standard conditions with a PVT Package embedded for the Vx Technology. The first focus is to lay the ground for the basic principles of multiphase flow metering by understanding the Dual Energy/Venturi Technology (See **Fig. 1**). The MFM is also characterized by advanced instrumentation, lightweight and small size in comparison to a separator. Moreover, it has been designed to provide a measurement with better accuracy than separators.

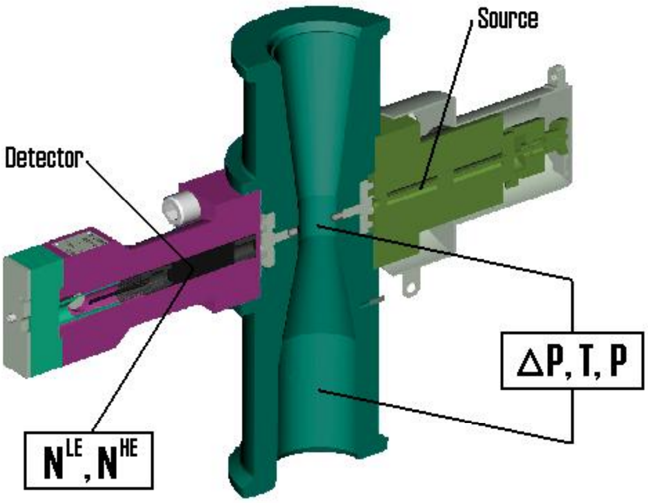

Fig. 1.- Cross section view of typical dual energy Venturi Multiphase Flow Meter

The Vx Technology used two combined basic measurements made at in the same measuring section:

- A Nuclear Gamma-ray Densitometer, which provides mixture density and the fraction of each constituent at the Venturi throat at high frequency or phase hold up, $a_{o,g,w}$. They are determined from the solution of three simultaneous equations: two related to the gamma ray attenuation (Low and High energy) and one fraction balance equation;
- A Venturi section, which gives the total mass flow rate, Q, and the total volumetric flow rate, q. In a classical Venturi with vertical flow, the total mass flow rate, *Q*, is related to the differential pressure, DPV, across the device by applying the Bernoulli equation from the combination of pressure differential measurement across the Venturi and the mixture density measured by the dual energy attenuation:

$$Q = C \cdot Sf.k \cdot (2 \cdot r_m \cdot (DPV - r_m \cdot g \cdot h_V))^{0.5}$$

$$C = \text{Discharge Coefficient}$$

$$\text{k} = \text{Constant depending on Venturi dimensions}$$

$$\text{h}_\text{V} = \text{Distance between the pressure tappings}$$

$$r_\text{m} = \text{Fluid Density}$$

$$\text{Sf} = \text{Shape Factor}$$

Fluid properties such as oil density and viscosity, water density with the associated temperature, and gas specific gravity are required for the computations. Pressure and temperature measurements enable the prediction of PVT properties at line conditions. Further details of the system are described in **Ref [3], [6], [7], and [8]**.

There are 3 main steps in this process with a possibility to compare data each time:

- The primary outputs are based on the nuclear measurement: the gas fraction, the water-liquid-ratio and the mixture density. The latter combined with the Venturi differential pressure measurement provide the total mass flow rate. In terms of comparing the outputs of the meter against reference values the total mass flow rate and water-liquid-ratio are the best candidates. It can be noticed that the water liquid ratio (which is a measurement at line conditions) can be compared to the BSW re-calculated at line conditions by just using the properties of the fluids. The Gas Fraction or Holdup is not available as a reference measurement due to gas-liquid slip. The terms *Holdup* and the *Cut* (also called Volume Fraction) are different (**Ref [1],**

[25]). An independent model is used to calculate the Gas Volume Fraction from the Gas Holdup Input.

- The secondary outputs from the meter are the volumetric flow rates (oil, water and gas) at line conditions. These calculations are based only on the combination of the previous primary outputs (See **Fig. 2**).
- Finally, the volumetric flow rates at Standard Conditions are computed from the flow rates at line conditions using a PVT Software Package.

This entire process can be summarized by the following graph

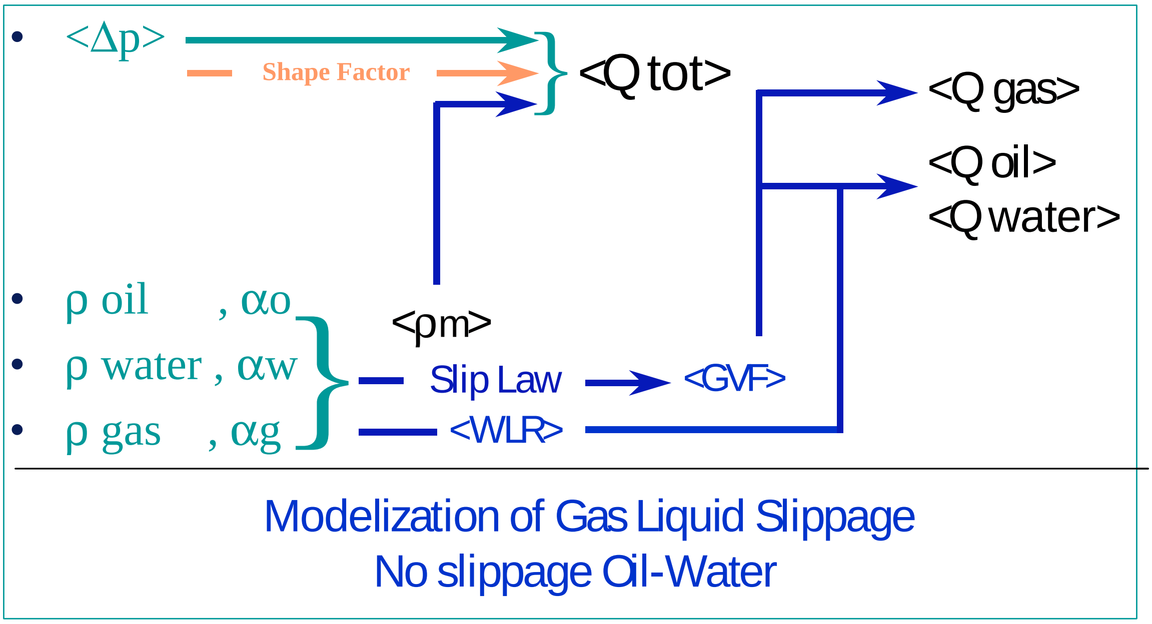

Fig. 2.- Primary and Secondary Outputs

The Vx Technology has proven its capability to constantly measure multiphase flow and it is fully independent of the upstream regime, or emulsion or water liquid ratio. One of the great advantages of using a multi-energy gamma meter for fraction measurements is that the device is completely independent of the liquid composition even if it is dominated by any of the constituent (Oil, Water) or even the flow configuration (dispersed phase inside a continuous one, Emulsion, Foam…). The measurement is accurate in the full range of the working envelope. Nevertheless, the quality of the input value can have an impact on the accuracy following the conditions of flows (High GVF, presence or absence of Sulphur, Salt). This is why the fluid properties are important and key to achieve an accurate measurement. This will be demonstrated later in the document.

The basic principle of the nuclear measurement is that the fractions of oil, water and gas are calculated based on the attenuation of γ-rays at the Venturi section. This means the attenuation probability of a γ-photon is a function of the interaction probability with the actual material (Liquid, Gas in our case). The attenuation of a beam of γ-photons is given by:

$$N = N_0 \cdot e^{-r \cdot m \cdot l}$$

where N (cps) is measured or detected number of photons at the receiving end. No?(cps) is the number of photons that would have been received if there was no attenuation (Vacuum condition), ρ (kg/m^3) is the density of the attenuating material, μ (m^2/kg) is the mass attenuation[1] which is specific for a <u>given photon energy</u>, and l (m) is the traveled distance

[1] Finally, it should be noticed that the attenuation coefficient for a specific fluid could be calculated based on the weight average of the attenuation coefficients for the various components that the material consists of. That is:

$$m_{mix} = \sum_i m_i \cdot \frac{m_i}{m_{tot}}$$

through the material (i.e. Diameter in our case). The combined attenuation of the photon beam if passing through layers of oil, water and gas is given by a generalization of the previous formula for a given photon energy:

$$N = N_0 \cdot e^{-r_o \cdot m_o \cdot l_o} \cdot e^{-r_w \cdot m_w \cdot l_w} \cdot e^{-r_g \cdot m_g \cdot l_g}$$

Measuring the length fraction of oil, water and gas along a path line requires three equations. This is obtained by using two different energy levels (high and low energy) and the third equation is given by the sum of length fraction equals to the pipe diameter. This is summarized here below, where d is total path length (usually diameter of the Venturi throat).

$$1 = l_o + l_w + l_g \mid Length - fractions$$

$$\frac{\ln\left(\frac{N^{he}{}_o}{N^{he}}\right)}{d} = r_o \cdot m^{he}{}_o \cdot l_o + r_w \cdot m^{he}{}_w \cdot l_w + r_g \cdot m^{he}{}_g \cdot l_g \mid Highenergy$$

$$\frac{\ln\left(\frac{N^{le}{}_o}{N^{le}}\right)}{d} = r_o \cdot m^{le}{}_o \cdot l_o + r_w \cdot m^{le}{}_w \cdot l_w + r_g \cdot m^{le}{}_g \cdot l_g \mid Lowenergy$$

2.1. Solution Triangle - Nuclear Measurement

The above equations can be solved graphically using the “solution triangle” which is a powerful tool for analyzing the behavior of the fraction meter. The summits of the triangle are defined as the monophasic phase of each component (Oil, Water and Gas). That is, all flow mixtures consisting of only gas and oil will in the solution triangle be positioned on a straight line between the pure oil point and the pure gas point. All points consisting only of water and gas will be positioned on the straight line between the pure water point and the pure gas point. Flow mixes consisting purely of oil and water will be positioned on the straight line between the pure oil and pure water point (See **Fig. 3**).

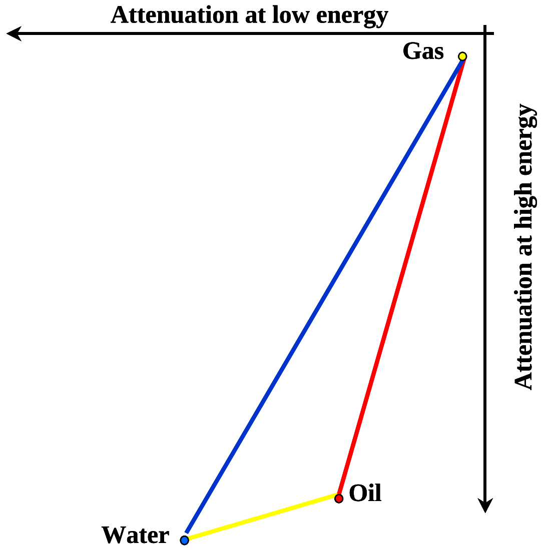

Fig. 3.- Representation of the solution triangle

where m_{tot} (kg) is the total mass and m_i (kg) is the mass of the i-the component. In other word, having a proper composition of the different component of the fluid, it is possible to calculate the mass attenuation. A classical PVT Report delivers enough information to obtain this value and therefore avoid any special fluid characterization or measurement at the well site.

Any mixture of the 3 components will be inside the solution triangle and the 3 defined areas will be delimited by the working conditions and the summits of each colored triangle will represent the fractions of each component as presented here after (See **Fig. 4**).

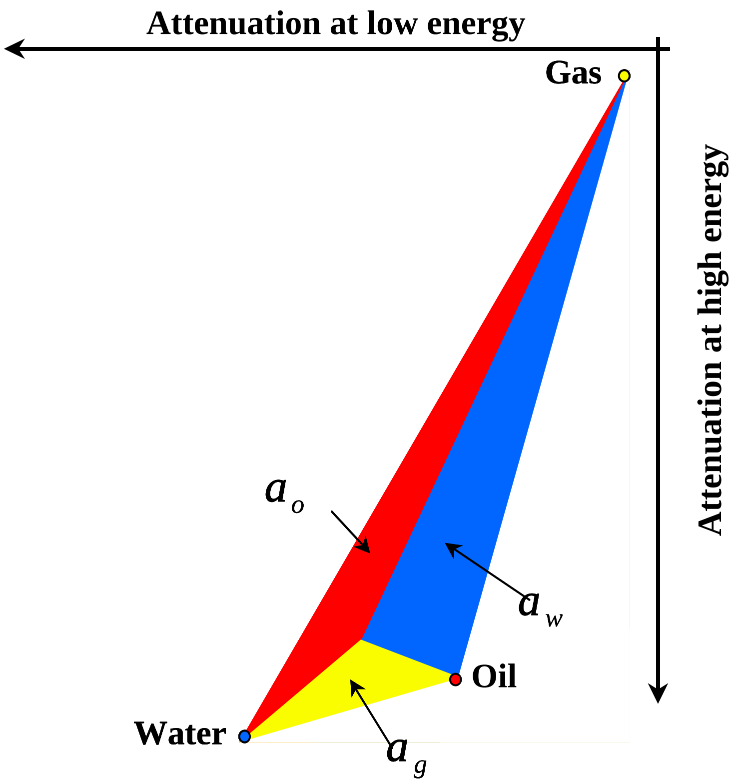

Fig. 4.- Representation of the different fraction for GVF ~ 25% and WLR ~ 60%

The amount of gas is defined by the yellow triangle, and the WLR by the red and blue areas. As a consequence, measuring WLR with accuracy becomes more challenging with increasing GVF.

3 OPERATING CONDITIONS:

Multiphase Flow Meters are usually operated at pressures well above separator ones; this is one of the main advantages of these products. Yet, again it is compulsory to have a full and clear understanding of the PVT, error budget and MFM performance to ensure it is fit for purpose. Indeed, under these circumstances, the usual PVT properties model developed for the separator reaches its limits.

To set up the acquisition parameter of a MFM, two approaches are doable:

- The first using published correlations to estimate oil, water and gas properties. This simple approach leads to acceptable metrological results up to 1500 PSIA. For a range 1500-5000 PSIA, this application can be extended with some careful assumptions (**Ref [8], [20]**). Indeed, PVT behavior of fluids may differ significantly from the aforementioned correlations. For more detail about the correlation limitation, the reader should refer to the Pinguet <u>and alt</u> (**Ref [14] , [26])**.

- The second is a preferable alternative using experimental data or simulated from a PVT tool such as Hysim, Eclipse-PVTi, PVTSIM, PVTPro etc… However, all of these software packages require a competent person to generate the relevant information and require doing a quality control on the generated data (**Ref [26]**).

The **Fig. 5** here below illustrates the topology of a production line were the MFM is located directly upstream the separator.

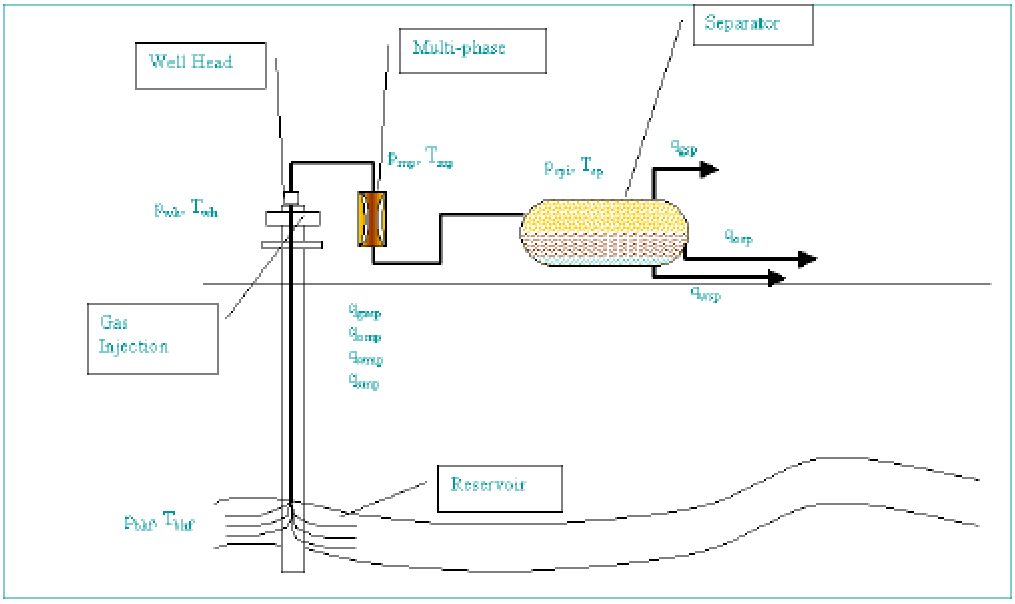

Fig. 5.- Schematic of a typical multiphase meter set-up

In this broader working range (i.e. higher pressure and temperature) where fluid properties correlations developed for separators are limited. The quality of the fluid properties inputs for conversion from line to standard conditions and vice-versa is more critical, leading to affect seriously the overall performance of the meter if not taking care properly. A possible production path from the initial static pressure to the surface measurement is presented with a dashed line in **Fig. 6**.

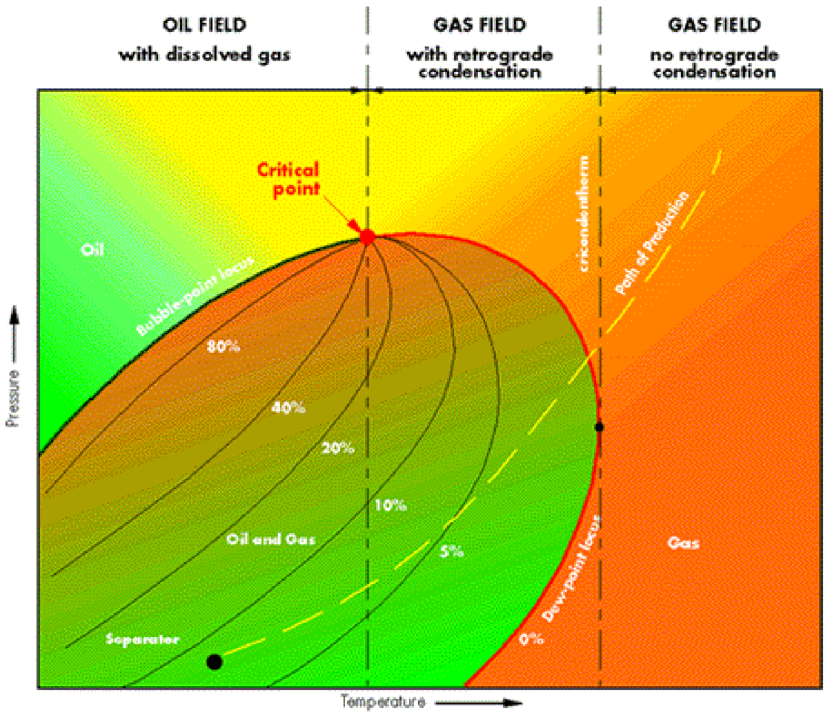

Fig. 6.- General phase diagram

Fig. 7.-

This production path is for a constant system composition where Pressure and Temperature changes in the process from reservoir to production separator as per the dotted line. Wet Gas meter, which can perform measurement at much higher pressure than traditional separator could be located anywhere on this line up to the well head flowing temperature and pressure.

It is important to mention that the metrological performance of a meter is a directly function of the accuracy of these required input parameters. MFMs are based on physical measurements and therefore the need of fluid properties is essential. In the **Fig. 7,** a schematic diagram to explain the generic fluid flow path from line to standard conditions for any type of MFM is presented:

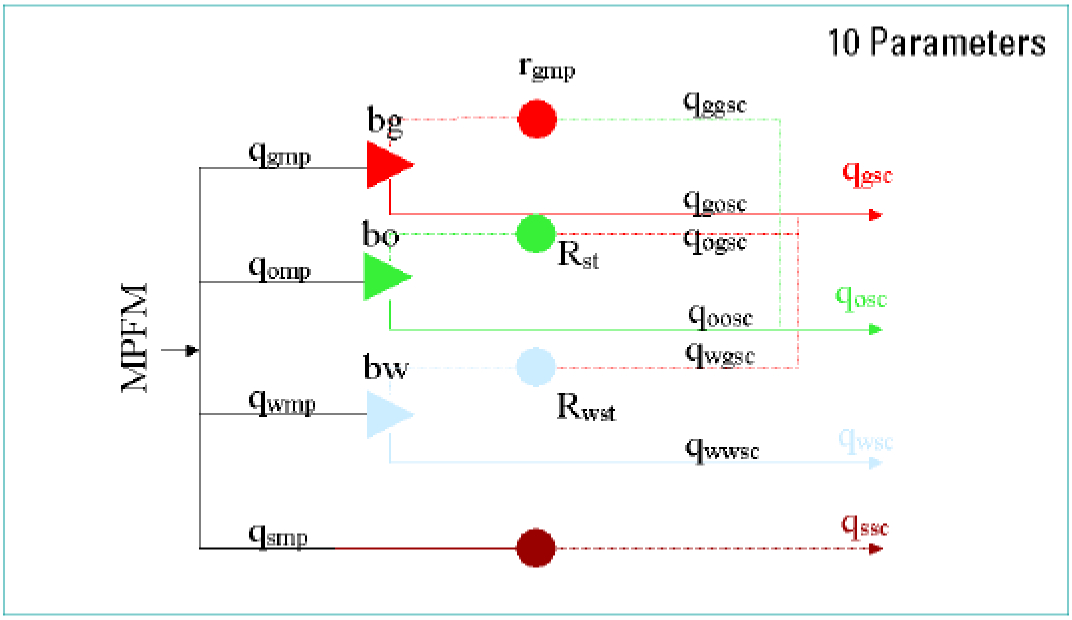

Fig. 8.- Flow Path from line to standard conditions

On the left, the information coming out from the Multiphase Flow meter, these values will go through a process which will convert them to standard conditions taking into account the gas and liquid dissolved in various phases.

q_{gmp} is the gas volumetric flow rate at MPFM conditions. This gas splits into 2 parts at standard conditions, which are a **q_{ggsc}** (gas flow rate) and a **q_{gosc}** (oil flow rate) due to the lower pressure and temperature. **q_{omp}**, which is the oil at MPFM conditions, splits into 2 parts: **q_{oosc}** dead oil at standard conditions and **q_{ogsc}**, which is the gas, evolved from the oil at standard conditions. **q_{wmp}** will follow the same path as the oil with **q_{wwsc}** and **q_{wgsc}**. **q_{smp}** is referring to possible solid phase. The sum of the different relevant output gives the total volumetric flow rate of gas, oil and water at standard conditions.
To summarize, for computing flow rates at standard conditions, three sets of data are required: densities, volumetric conversion factors from line conditions to standard conditions (bo, bw, bg) and Solution Ratio (Rst, Rwst, rgmp).[2] These values can be obtained from a classical PVT laboratory (**Ref [14]**).
Even if it is not directly related to the PVT, the **viscosity of the liquid at line conditions** is also a pertinent parameter, which is in this case depending primarily of the WLR, temperature and dissolved gas.[3] Then it is a total number of 10 parameters maximum that is necessary to obtain a full PVT Profile.

[2] Volume Factors: ***bo, bw, bg***; densities: Oil, Water and Gas; Gas Phase Condensate Gas Ratio: ***rgmp;*** Stock tank Gas Oil Ratio: ***Rst;*** Stock Tank Gas Water Ratio ***Rwst;*** Gas Deviation Factor ***Z***.

[3] The dissolved gas and therefore pressure has a greater influence on the viscosity than temperature

4 APPROACHED BY CORRELATIONS OF THE PVT PACKAGE

Extensive analytical tests and study on the issue of the impact of fluid property measurement and modelling error on Vx Technology flow rate uncertainty which has relevance for all MFMs has been carried out by Schlumberger over the years (**Ref [14], [26]**). This has been possible due to totally predictable effect on the MPFM measurement. This uniqueness in the comprehension of the physics allows demonstrating the advantage against changing conditions, or extreme cases such as exotic fluids.

A correlation is a mathematical model of a set of experimental data, based on a limited amount of cases, and the selected parameters do not include all properties that govern the physics.[4] Usually it is several correlations, which are necessary, **Fig. 8,** to obtain the pertinent information for a MFM such as Gas and Oil density measurements at line conditions.

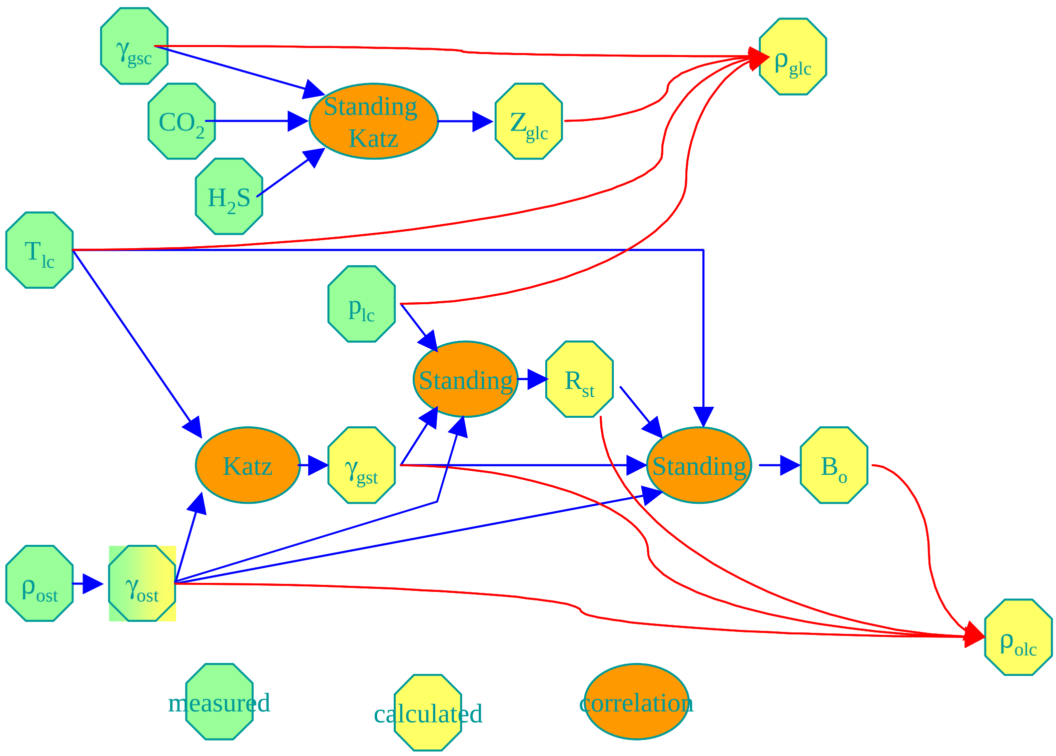

Fig. 9.- A possible way to calculate the Gas and Oil densities (Standings' correlation are used only as example)

The top path is related to the gas density measurement using a Stanging-Katz correlation for estimating the Z deviation factor from the gas gravity and some amount of non hydrocarbon (CO2, H2S) content. It should be noted that no correlation have been developed in a generic way for large concentration of CO2 or other heavy element such as H2S. This is definitively a limitation in Argentina unless a Client PVT Model is used in this type of conditions.
The bottom path is dedicated to the oil density measurement, to get an estimate of the stock tank gas gravity from line temperature and stock tank oil gravity using a first correlation, then by estimating the stock tank gas oil ratio (Rst) from line pressure API gravity and average gas gravity, using a Standing correlation up to the oil density at line conditions calculated from a material balance.

[4] The correlations are mathematical objects that are not necessarily commutative (inverted equation) and could lead to inaccurate results if not used as mentioned by their author. This correlation gives relationships between fluids at bottom hole versus surface conditions.

Any type of correlations and assumptions when used in series propagate and increase the overall uncertainty of the final output. It is proposed to review quickly the effect of two industry standard parameters; bubble point pressure and oil formation volume factor hereafter.

4.1. OIL FORMATION VOLUME FACTORS AND BUBBLE POINT PRESSURE AGAINST CORRELATIONS

The oil formation volume factor (Bo) is defined as the ratio of the volume of the oil phase at the prevailing reservoir conditions to the volume of dead oil at standard conditions.

$$B_o = \frac{V_o}{V_{osc}}$$

Different papers have been published containing correlation surveys either using local area data (mostly) or worldwide one. Pinguet and Alt in a latest paper (**Ref [14]**) reviewed 17 well-known correlations published from 1947 to 1999. They demonstrate the limitation of this type of correlation against a large worldwide database. Although no correlation gives a perfect answer all over the range, a few of them provide a reasonable estimation of Bo when compared with the referenced database. Over all the average relative error was lower than 5% for the most well known but punctually the maximum error for these ones could reach 30% or above leading in this case to disastrous measurement.

In the same paper, an identical exercise was carried on a second key parameters the Bubble point pressure, which is the highest pressure where the first gas bubble, appears. This information is used among others to determine the amount of free gas that will be encountered at each set of pressure and temperature in the process and then the shrinkage of the oil from the line to standard conditions. Experimental data have shown that the saturation pressure correlations are often predicting values that can be far from the experimental ones because they used limited inputs parameters available at the well site such as bottom hole temperature, amount of gas in solution, gas and oil gravities.

These parameters are important to saturation pressure, but other properties that are not included here can also have a strong influence. Indeed, saturation pressure depends on fluid composition, where components solubility is important. Components like N_2 and CH_4 will increase the bubble point pressure as others like CO_2, H_2S will decrease it. For example, Gas gravity, which is supposed to reflect the overall gas property in this type of correlation, is an average measurement that will mask composition differences such as gravity of CO_2 (1.519) is similar to the C_3H_8 (1.522) one, or N_2 gravity (0.967) is similar to C_2H_6 one (1.038).

Among the 15 correlations presented, as general comments the correlations for estimating bubble point pressure are giving scattered results, which is not a surprise for people experienced in PVT of oil reservoirs, with average relative error in the order of 20% to 50% and the maximum relative error was between 80% to more than 1000%. Most of correlations exhibit a large discrepancy at high pressure; this demonstrates again the difficulties in the wet gas business.

5 UNCERTAINTY ON THE MEASUREMENT FROM MFM & SEPARATOR AND COMPARISON WITH SEPARATOR DATA

This section assesses the uncertainty and statistical measurement of a separator against a multiphase flow meter (**Ref [9], [10], [21]**). Doing comparison between different devices is a key to assess in a proper manner a new technology. Meanwhile, the uncertainty of the measurement should be first properly identified in order to help to conclude correctly on any studied case. Uncertainty represents the deviation between a recorded and a reference measurement and involves errors that are either random or systematic. Uncertainty, being a statistical value, is associated with a confidence level usually selected around 95%.

In this test presented here below, MFM measurement uncertainties were determined by taking the surface test separator as the only reference (**Ref [21], [22]**). **Fig. 13 and 14** illustrate the responses from both devices over the same average data acquisition periods. The recording versus time is presented on the left side of the graph and the data distribution on the right side.

It can be noticed a large error margin on the separator readings compared to reasonable variation on the MFM measurements**.** This large uncertainty in the separator rates is due to the limitations in tool response. Indeed in this case, the wells were slugging and this oscillatory behaviour was affecting the performance of the separator. The rate changes are drastically in the surface test separator varying within a range 2,000 STB/D to 5,000 STB/D. Failure to accommodate the sluggish behaviour of the well rates might be interpreted as the separator's response rather than the actual dynamics of the system. **Fig. 14** presents the data with a nonuniform normal distribution with an average value of 3,445 STB/D and a large standard deviation of 750 STB/D.

The dynamics of the reservoir is properly captured by MFM in **Fig. 13**. The well oscillates within a band of 3,000 STB/D to 3,800 STB/D. Data set is distributed normally within the 95% confidence interval (i.e., blue lines) as expected and the standard deviation is 384 STB/D and average liquid rate is 3,418 STB/D. The MFM readings comfortably fall within the separator's wide error bands showing in the same time exceptional data quality against the supposed best reference available in the field today with a separator.
This demonstrate that in any comparison job the accuracy of the measurements should be under scrutiny and a clear understanding of the technology and reference measurements should be properly evaluated before going further in the data comparison. Comparing only a final average value could lead to misunderstand or interpret an overall comparison or see the benefit of one technology against another.

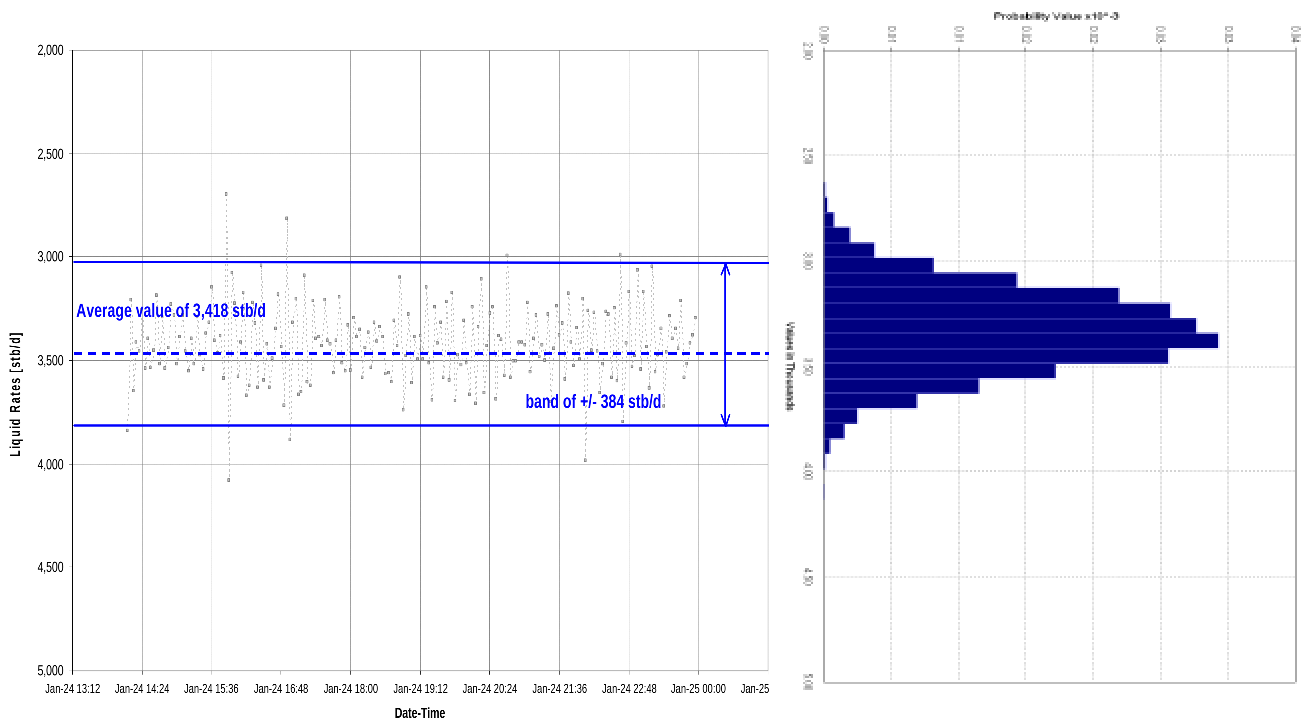

Fig. 10.- Analysis of the MFM Data

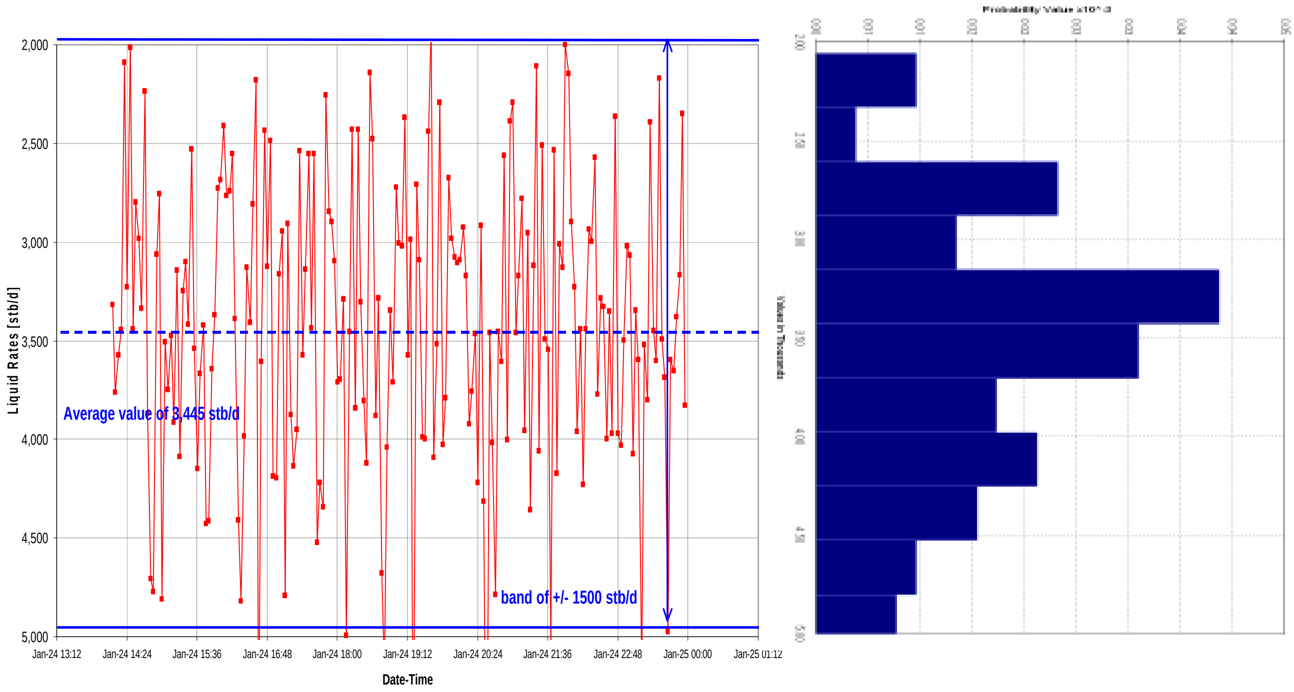

Fig. 11.- Analysis of the Separator Data

6 SALINITY EFFECT ON THE WLR MEASUREMENT

As presented previously the Vx Technology is based on fluid properties and as such is totally predictive. From general information collected in Argentina usually WLR are in the range of 50% to 95%, which lead to some concerns about the performance of meter when there is variation of the salinity. This could be for example representing a reservoir where a water injection with a different salinity is used assuming that over the years when the salinity of the reservoir is changing none recharacterization or monitoring of the water properties is done (i.e. no surface sampling or BSW) is done. 3 different simulations have ben done against salt contents and oil density.

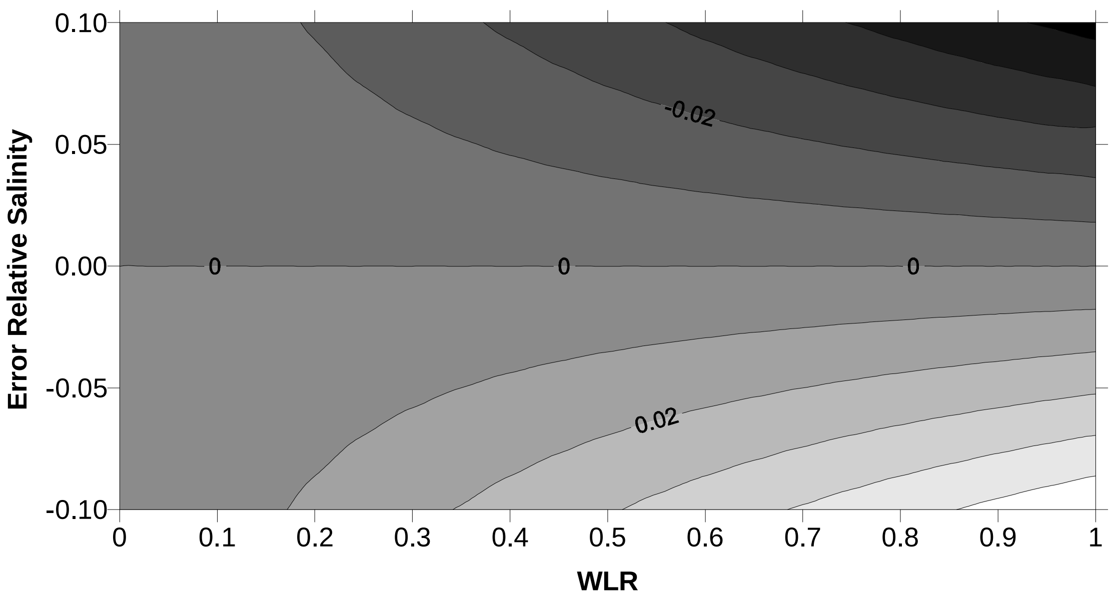

Fig. 12.- WLR Error versus the WLR and the Salinity Relative Error – Oil density 855 kg/m3 and Salt 190 kppm

The WLR error absolute in the case of large salty water and large oil density is less than 5% with a variation of the salinity of more than 10%. The effect is higher at large WLR as expected due to the large amount of Water present in this case. Value lower than 2 % in low WLR range or low salinity change can be clearly seen in the **Fig. 16**.

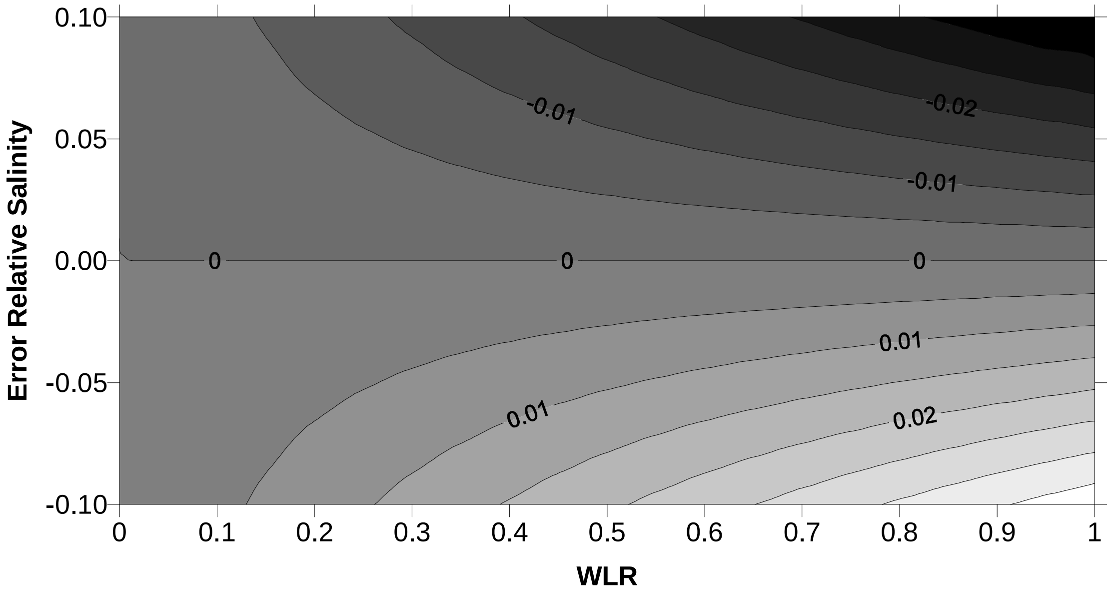

Fig. 13.- WLR Error versus the WLR and the Salinity Relative Error – Oil density 840 kg/m3 and Salt 120 kppm

The WLR Error Absolute in the case of medium salty water and medium oil density is less than 4% with a variation of the salinity of more than 10%. Less than 1% in the lower range of WLR or with 5% error relative on the salinity are observed leading to demonstrate the small impact fo the salinity change in most of the range of WLR.

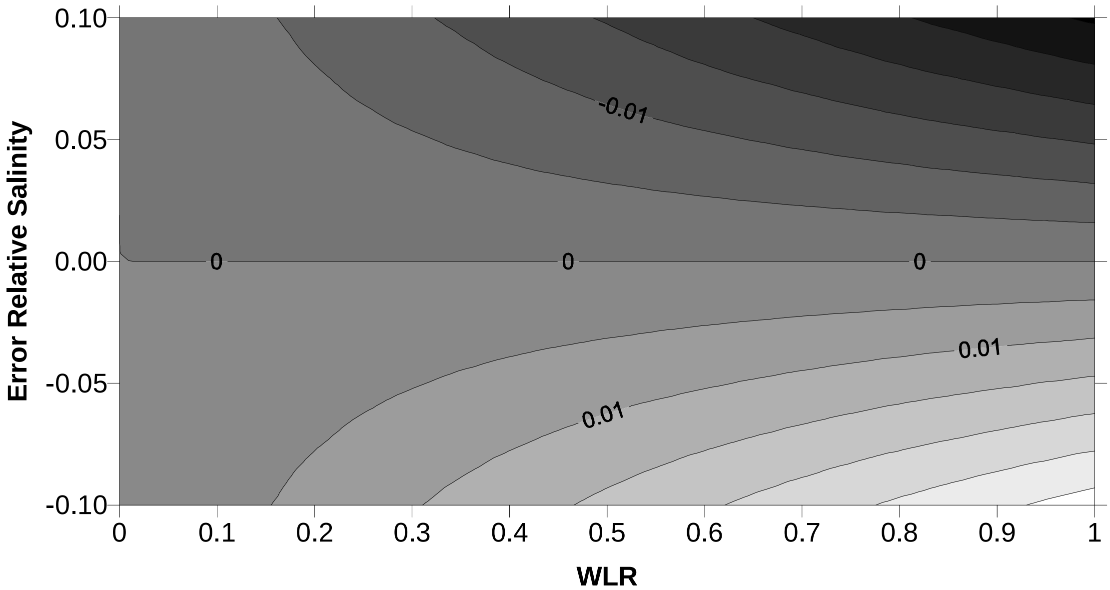

Fig. 14.- WLR Error versus the WLR and the Salinity Relative Error – Oil density 835 kg/m3 and Salt 100 kppm

The WLR Error Absolute in the case of light salty water and light oil density is less than 3% with a variation of the salinity of more than 10% and lower than 1% in most of the entire range.

From this simulation based on Argentina field it is interesting to see that the associated error due to a large variation of salinity is minimum and well understood and characterized by the Vx Technology. It is possible to correct this effect with a proper measurement or monitoring time to time of the salinity or density of the water. The software allow to recalculate the equivalent salinity of the water and the associated fluid properties base only on the density of the water given at any temperature such as during a BSW Sample. This can be done during the service of the meter for example each half-year or at any other occasion following the production management.

7 INFLUENCE OF SOME PARAMETER AT HIGH WLR

Flow rates at standard conditions being required by the industry implies that PVT model must be embedded in the MFM to provide real time information. Thus, overall accuracy of the MFM will vary with the accuracy of PVT model. The PVT model could become more preponderant than the intrinsic quality of MFM measurement in the overall performance of the meter. A proper understanding of fluid properties and the effect is crucial.
This is the case already for reservoir management; even production engineers require fluid properties and phase behaviour to design the surface process facilities and manage production efficiently. All multiphase flow meters, whatever the technology used, similarly require fluid properties measured at either line or standard conditions to convert from some physical properties measurements through an inversion model to calculate the flow rate or fraction. Therefore nothing new in the need of input information to produce relevant measurements but how do the errors in the fluid properties and phase behaviour inputs impact the accuracy of the multiphase flow meter?

This question is seldom proposed and answered by any manufacturer, Schlumberger through the Vx Technology and the development of a service business associated to the Multiphase Metering is capable to answer it. An extensive propagation error study to focus on the issue of the impact of fluid property measurement and modelling error on MFM flow rate uncertainty which has relevance for all MFM's was made lately (**Ref [26]**). Pinguet and alt have performed a comprehensive matrix of fluid property inputs for different WLR, GVF and type of fluid from Black Oil to Condensate. Their primary objective was to demonstrate the relative importance of fluid property measurements in different MFM applications and to allow customer in the future to tailor fluid sampling and PVT need with surface services such as the PVT Express[5] to optimise the entire performance following the expected accuracy.

To summarize, beyond the intrinsic error of any multiphase measurement technology that can in itself be significant, characterizing the produced fluid properties can be crucial to the successful deployment and application of multiphase flow meters. On the other hand, each multiphase flow meter is dependent on several intrinsic features, measurements and models such as Hardware, Physical Measurement, Accuracy or model validity… Overall, there are more than 10 to 20 parameters, which could significantly affect any multiphase measurement accuracy.[6] Some can be adequately checked or controlled but others, such as the validity of models and some physical measurements, are more complex to understand and may lead to error. This is what we have called the intrinsic measurement performance that is only a part of the overall performance. The global uncertainties of a MFM encompass a second distinctive source of errors related to fluid properties to convert from the line condition measurements to standard conditions or vice versa.

[5] Mark of Schlumberger

[6] Such as the diameter of the venturi throat, or the distance between sensor for system using cross correlation…

To simulate the error propagation for any MPFM, a set of PVT parameters were required and gathered for different fluid such as black oil presented in Table 4.

	Black Oil
bo	0.857
bg	17
bw	1
Density Oil (sc)	849
Density Gas (sc)	0.792
Density Water (sc)	1035
Rst	500
Rgmp	Negligible
Rw	Negligible
Pressure (psia)	315
Temperature (DegF)	100

Table 4: PVT input parameters for the different simulations associated with the black oil

Several combinations of GVF and WLR were considered as detailed in Table 5, giving the opportunity to analyse the different error patterns and highlighting the importance of PVT parameter measurement accuracies in the cases where the sensitivity to these uncertainties increase as the combinations stretches the limit of the MPFM operation envelope.

	Black Oil	
Simulation	WLR	GVF
1	50	70
2	50	90
3	50	96
4	50	98
5	90	70
6	90	90
7	90	96
8	90	98

Table 5: Combinations of GVF and WLR for the simulation

The required accuracies necessary to generate the propagations error were collected directly from a poll of internal expert users and a search of the literature. These values were the result of years of practical use and their quantification was at the discretion of the experts interviewed and may be considered conservative. The accuracies proposed could be challenged but the discussion associated to the relative performance will not be affected in this study.[7]

[7] It should be noted that the liquid viscosity and gas dissolved in the water have not been taken into account due to negligible effect on the overall results.

Parameter	Error
	Black Oil
Rst	1.0%
Rgmp	1.0%
Rw	2.0%
bo	1.0%
bg	1.0%
bw	1.0%
Rho oil (sc)	0.5%
Rho gas (sc)	1.0%
Rho water (sc)	0.5%
Viscosity (line)	10.0%

Table 1: Accuracy achievable with a laboratory measurement for example and black oil.

The main outputs presented after are at line conditions: Gas Fraction (GF), water-liquid-ratio (WLR), mixture density, total mass flow rate, volumetric flow rate gas and liquid. The other main outputs based only on the combination of the previous outputs at standard conditions are BSW, oil, Water, Gas volumetric flow rate. The performance with black oil is presented for medium and high WLR and for different GVF values.

Error Associated with Fluid Properties					
		GVF ~			
ERROR	WLR	71%	92%	97%	98%
QtotMass	Med	1.2%	1.0%	1.1%	0.9%
	High	1.7%	1.6%	1.4%	1.2%
GF	Med	0.003	0.001	0.001	0.001
(-)	High	0.005	0.003	0.001	0.000
GVF	Med	0.004	0.001	0.000	0.000
(-)	High	0.005	0.001	0.000	0.000
WLR	Med	0.01	0.01	0.01	0.01
(-)	High	0.03	0.02	0.02	0.02
QvolGas lc	Med	2.9%	2.7%	2.6%	1.7%
	High	4.2%	3.8%	3.5%	3.2%
QvolLiq lc	Med	1.3	0.6	0.2	0.2
(m3/h)	High	1.7	0.7	0.4	0.3
BSW	Med	0.03	0.03	0.02	0.03
(-)	High	0.07	0.06	0.06	0.05
QvolGas sc	Med	3.7%	2.6%	2.3%	2%
	High	12.0%	5.1%	3.6%	3%
QvolOil sc	Med	0.8	0.4	0.2	0.2
(m3/h)	High	0.9	0.5	0.2	0.2
QvolWater sc	Med	0.9	0.4	0.2	0.1
(m3/h)	High	1.8	0.9	0.4	0.2

Fig. 15.- On the left, the error related to the fluid properties; on the right, the value used to generate these errors.

A clear dependency of the fluid properties on the overall performance of the meter is presented in the **Fig. 19.** The error associated to the Total Mass Flow Rate may lead in the worst case up to 1.5%. The liquid flow rate could be affected by around 200 bpd as absolute error. The gas flow rate performance could reach up to 4% maximum relative error. This numbers are obviously specific to the flow rate values used to do the calculation but it demonstrate without any ambiguity that the fluid properties have a key contribution to measurement accuracy and they need to be taken in account in particular applications or/and unusual fluids.

Again, it is worth to mention that this is a generic approach for the entire Multiphase Flow Metering Industry and it is not related to any specific technology. It is reasonable to believe that such simple fluid property data can be made available or should be used in adequate embedded PVT Software associated to the multiphase flow meter when set against the considerable advantages that MFM technology brings in other areas such as capital and operating cost, range of operation (High P&T), small size, handling difficult fluids, handling slugging, allocation and high frequency of flow rate & fraction data for production troubleshooting.[8]

In conclusion, determining the global uncertainty of a MFM one must not only consider the intrinsic measurement performance, such as the limits of the inversion model, fluid dynamics and other specific physical properties measurements of the fluid (e.g. electrical or optical) used as input, but also the effect of the fluid property or phase behaviour measurements. The global uncertainties, therefore, hide two distinctive sources of errors, which have the potential to mislead the community in determining the real performance of one meter against another.

Despite being expensive, time-consuming and limited in scope, flow loop tests are still our only real option to determine the performance of an MFM. However they should be used with caution in understanding the true performance of an MFM across the full range of fluid properties that might be experienced in field operations. Tests performed in flow loop using static and non-miscible fluids enable to only compare the metrological performances of the MFM against a highly accurate reference in stable flow. Generalising the results of a comparative flow loop tests or a specific successful field experience to make decisions about an application elsewhere where the fluid properties are substantially different could lead to disappointment in the selected MFM's performance.
On the other hand, when comparing meter performances in field trials with live effluents and providing a most realistic conditions in a dynamic environment that cannot be easily reproduced in flow loops especially with effluents difficult to separate such as foaming, hydrates, solids… few comments or none are given about the PVT either about the difference in the computation between MFM and reference meters (i.e. PVT correlations) or between metrological performances and global accuracies.

8 DISCUSSION

Over the recent years, a number of articles, documents and data have been published allowing the comparison and evaluation of the different multiphase meters against known references. Few manufacturers have been investigating and spend time to go beyond the simple device and provide more information to the user and the entire community. *Schlumberger* came with a first solution in beginning of 2000 and later with a PVT Client solution for any type of problem and it is still nowadays at the edge of the competition.

The dual-energy gamma ray / Venturi technology has been tested by many operating companies in their fields over the recent years. In addition to testing wells periodically, monitoring clean-up operations and evaluating reservoir performance in combination with production logging, Vx Technology is also used for optimizing gas lift, sampling fluids and measuring accurate flow rates, pressure and temperature. The meter acquires production rate, cumulative volume and operating condition data (including pressure and temperature) in real time without requiring separation of fluids and capturing the entire dynamics of the well response thanks to a relative fast acquisition MFM. There is continuous advancement in the current Vx Technology (**Ref [16], [23]**) leading to a better precision, and extension of working conditions on the entire GVF range from 0 to 100% through two innovative models and in terms of temperature and pressure (i.e. 302ºF/5,000 psia up to 392ºF/10,000 psia).

[8] In their study Pinguet and Alt (**Ref [26]**) went further in the analysis and demonstrated and quantified clearly the benefit of some type of equipment against each other in different environment such as Laboratory Measurements, Well Site Dedicated Measurement, Correlation or Equation of state.

The main benefits of using a combination venturi / dual energy gamma ray flowmeter are: a stand-alone meter, portable and no moving parts. There is no request for flow calibration. The measurement is independent of the flow regime, e.g. slug flow, foaming. It has a wide operating envelope with the capability of sampling from fluid sampling ports. In addition, it offers real-time data management. The main benefits for the client are improved safety, data quality, logistics, and longevity. It had been demonstrated that the playback facility is a key element in this type of conditions.

In general, Multiphase technology is complex and this may lead to difficulty to handle it or to understand. Multiphase meters have been built to handle high pressure, high temperature or exotic fluid that cannot be handle properly through the past generic solution of the separator (heavy Oil, H2S large contents…). It is then key to have a system based on simple model and robust basic measurement to get first a good apprehension of the device and then be able to quantify accurately the effect of some possible parameters. Input parameters based on fluid properties are necessary to setup multiphase flow meter whatever the technology.

A generic summary of sensitivity analysis in the determination of the flow rates of oil, gas and water associated uncertainties was presented. Quantifying these uncertainties is important to provide a suitable confidence level in the data, as these will be used for analyses indeed Multiphase Flow Meters are usually operated at pressures well above a separator ones. Under these circumstances, the usual PVT properties model developed for the separator reaches its limits. Yet, again it is compulsory to have a full and clear understanding of the PVT, error budget and multiphase meter performance to ensure it is fit for purpose. As discussed herein, one of the main benefits of the Vx Technology is the built-in PVT package. The Vx Technology is build on this very deterministic way and it is very simple concept based on 100% physics and fluid properties

9 CONCLUSIONS

The introduction of the multiphase technology worldwide has passed the paradigms shift about multiphase metering uncertainties, thanks to the recent technology upgrades. A number of articles, documents and data have been published and produced allowing the different meter performances to be compared and evaluated against known references. Meanwhile, the major operators have developed global and local expertise in multiphase flow metering to rip the benefits of the technology with the economical and logistical aspect as main drivers. So no doubt the market and knowledge has been increasing very drastically in the last couple of years and this is the trend for the next years.
Oil companies have largely accepted the Vx Technology for their well testing and monitoring applications. The high sampling rate of the Vx Technology helped to diagnose the well response in real time and demonstrates how the Venturi / Dual energy gamma ray combination technology enables monitoring of the dynamic response of the reservoir independently of the flow regime. The data quality and frequency of sampling allow completion diagnostics and/or possible problems and, not the least, a better understanding of multiphase flow behaviour from the well (i.e. reservoir management). As demonstrated the Vx Technology data set were significantly superior when compared to the large error margin of the separator versus linearity and repeatability in real conditions.

Some sensitivity analyses were made on the acquired data emphasizing the importance of the fluid properties, as they are used as inputs in the computation of the rates and fractions. Usually, the fluid properties or phase behaviour input accuracy requirements are rarely challenged, even where this may have a major effect on the global uncertainty such as in high pressure or wet gas conditions but all MFM have as minimum output the Oil, Water and Gas flow rates at line conditions. However the industry reports its production at standard conditions and therefore, the flow rates at line conditions need to be converted to standard condition using PVT model in a way or another. The mass and volume flow rate accuracy converted from line to standard condition combine with the intrinsic accuracy of the multiphase flow meter provides the global accuracy of the measurement of live effluent.

The global uncertainties, therefore, hide two distinctive sources of errors, which have the potential to mislead the community in determining the real performance of one meter against another. Flow loop tests are most of the time used by oil companies to determine the performance of an MFM, however generalising the results of a comparative flow loop tests or a specific successful field experience to make decisions about an application elsewhere where the fluid properties are substantially different could lead to disappointment in the selected MFM's performance. It is therefore valuable to be able to quantify the global uncertainty of a meter as a function of the separate uncertainties in the prime measurement and from fluid properties inputs for any given application.

Trough the unique specific combination of the Vx Technology it is possible to identify clearly the global error and the intrinsic performance of the PhaseTester or PhaseWatcher. As example, a focus on the metrology and advantage of the Vx Technology even in dedicated cases such as issue of mixing reservoir & fresh injection water. Having a measurement system totally predictable bring serious advantage and a clear understanding of the overall performance of multiphase flow meter along the well life over years and allow to demonstrate how to keep the accuracy within a narrow boundary.
Extrapolated or applied to the specific Argentinean market, Multiphase measurement are strongly related to the Fluid Properties as a consequence it is necessary to use a dedicated PVT Client to handle the large high concentration of CO_2 or other heavy element. This is definitively an advantage of the nuclear & venturi multiphase flowmeters.

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