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The Influence of Liquid Viscosity on Multiphase Flow Meters

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ABSTRACT

The objective of this paper is to provide an accurate description of the performance of differential pressure (DP) measurement devices when used in a viscous environment, and to discuss the underlying logic associated with this type of equipment. The paper embraces this fundamental question, firstly from a theoretical point of view, and then from the perspective of a leading commercial multiphase flow meter.

A persistent question that arises in upstream production measurement is: "Why should we use a multiphase flow meter rather than a test separator in the presence of Heavy Oil?"

Most agree that well testing operations of this kind are very complex and most conventional surface well testing equipment is very difficult to use to obtain reasonable accuracy. It is already complex, for example, to run a test separator in a normal environment and its measurements are usually unreliable due to vessel instability, foaming or separation issues. A basic problem is that the density of the oil is very close to that of the water, and the process of gravity separation in the conventional separators cannot work efficiently. The high viscosities encountered in Heavy Oil add to the challenge and further complicate the separator controls. Another associated phenomenon is that any bubbles of gas entrained in the fluid can no longer flow freely inside the viscous liquid, and stay trapped (in a gaseous state) inside the liquid phase. This can potentially lead to a large overestimation of the liquid volumetric flow rate. Furthermore, emulsion formation can only be mitigated through the injection of diluents. On the other hand, an in-line multiphase flow meter can sidestep most of these issues, as no separation is required, and it has the benefit of being compact, with lower logistics and reduced operating costs. Based on these advantages, they were one of the earliest technologies adopted by oil companies working in the Heavy Oil field.

Among the in-line multiphase flow meters, Schlumberger's Vx technology incorporates a very simple meter design and is based only on physical fluid parameters. This provides a comprehensive and easy way to understand each parameter's effect on the overall response of the meter. The core of the Vx Technology is an in-line tool, which acquires data from the point of well opening to the time of well shutting, independently of the water-cut, emulsion, foam or the passage of slugs. Vx technology therefore offers an easy and practical solution for this particular kind of well-testing operation; one of the main advantages being the insensitivity of the measurement to phase inversion and to the nature of the continuous phase (in other words to the WLR value).

To demonstrate the actual performance of a DP-based multiphase flow meter in a "heavy oil" environment, results are presented from tests conducted with the Vx technology at a third-party flow loop in high viscosity (emulsion) flow. The aim of this is to provide practical generic information and to share knowledge with a view to helping overcome the classical challenges met by all multiphase meters in this developing field.

1 OVERVIEW OF HEAVY OIL BUSINESS

"Heavy oil" is a type of crude oil that is highly viscous and does not flow easily (Figure 1). Common characteristics of heavy oils are their high specific gravities, low hydrogen-to-carbon ratios, high carbon residues, and high contents of asphaltenes. They may also contain heavy metals, sulphur and nitrogen. Heavy oils have high boiling points and high molecular weights, with typically over 60 carbon atoms per molecule. This makes compositional analysis with Gas / Liquid Chromatograph systems virtually impossible and other techniques must be adopted, including measurement of the molar weight of the C+ component.

In industry, heavy oil is defined as having an API gravity between 22.3° and 10° (equivalent to 920 to 1,000 kg/m^3), while extra heavy oils and bitumen[1] have an API gravity of less than 10° (i.e. > 1,000 kg/m^3). The latter are distinguished by their viscosity at line (or reservoir) conditions with Extra Heavy Oils falling below 10,000 cP, and bitumens lying above[2].

Fig. 1 – Heavy Oil.

Heavy oil deposits around the world share one key and common characteristic: they are extremely challenging to produce; but since bitumen, heavy oil and extra heavy oil deposits represent ~ 70% of the world's total oil reserves, large efforts have been expended to overcome the difficulties associated with their production. Related challenges – such as the artificial lifting of oil that does not readily flow, plus the control of sand, water and diluents – must also be overcome in a cost-effective way for the overall process to be economically viable, and different sets of technologies and methodologies have been developed with this aim.

As a result, and due to the continuously increasing oil price, heavy oil is now competing aggressively with conventional hydrocarbon resources. Current estimates of OIP ("Oil Initially in Place") range from 9 – 13 trillion barrels; of which only 30% consists of Conventional Oil, 15% is Heavy Oil, 25% is Extra Heavy Oil and 30% is in the form of Oil Sands or bitumen.

What, it may be asked, has led to this recent upsurge in Heavy Oil activity, bearing in mind the fact that non-conventional reservoir operations (production and well-testing) require specialist methods and specialist equipment, and only five to ten years ago heavy and viscous oil reserves were considered to be either wholly uneconomic or at least very unattractive resources to produce. Nowadays, however, oil companies have started to invest more and more in this sector, based on the increasing demand for energy worldwide and the growing premise that Heavy Oil represents the only viable future for the oil business.

Saudi Arabia, for example, is expected to produce 1MMbopd (one million barrels of oil per day) of Heavy Oil in the next 4 years. Kuwait is following the same trend, with 1MMbopd forecast for the next 5 years from more than 8000 new wells. From an economics point of view, the Heavy Oil market represents an attractive long-term asset (with project lifetimes ranging from 40 to 100 years) and promises sizeable returns on capital expenditure. Although recovery costs are generally higher than those of traditional operations, the price of Heavy Oil is only about 20% lower than that of conventional Brent Crude.

[1] Heavy Oil can be as viscous as honey, while Extra-Heavy Oil can be comparable to toothpaste. Bitumen is even thicker still.

[2] The Canadian government has only two classifications: "light oil" with a specific gravity of less than 900 kg/m^3 (greater than 25.7° API) and "heavy oil" with a specific gravity of greater than 900 kg/m^3 (less than 25.7° API).

Venezuela and Athabasca (Canada) have total oil deposits equivalent in size to those of Saudi Arabia, and are seen as critical for replacing the world's diminishing light crude reserves. However, oils from the Orinoco Belt in Venezuela and the Athabasca oil sands in western Canada tend to be very immobile, even within the reservoir, and with existing first recovery technologies (cold production) recovery rates (Table 2) up to now have been relatively modest (around 9 – 10% in Venezuela for example [30]).

Overall Canada and Venezuela hold 90% of the world's known Heavy and Extra Heavy oil reserves, and through aggressive development are forecast to be the world's two main exporters of oil in the next 5 years. Heavy Oil activity is also picking up in the Middle East (including Saudi Arabia, Kuwait, Iraq and Oman) and it is reported that a few million barrels per day could be produced from this area, into a market now mature for this type of oil. The ease by which light oil and gas were previously produced is no longer hiding the potential of our Heavy Oil reserves.

Table 2 – Current recovery levels and 2020 predictions.

	Current Recovery	**Estimated 2020**
ORINOCO[3]		Reserve: 300 bbn[4]
Cold Production[5]	> 10 %	> 25 %
Steam Flood	> 7 %	> 40%
ATHABASCA		Reserve: 300 bbn[6]
Mining	85 %	> 90 %
SAGD	10 %	> 50 %

As the largest source of untapped flowable hydrocarbons available today, Heavy Oil therefore has the capacity to be a long-term sustainable market, capable of meeting the world's growing energy demands for many decades to come. However, this will only be realised if sufficiently economical recovery solutions can be provided and, whatever the details of the production techniques implemented, accurate monitoring in real-time is widely considered as an essential part of this process. Conventional measurement techniques are extremely limited in this type of environment, and at present, the only way to achieve the quality of data required is with a multiphase flow meter.

2 WHY USE A MULTIPHASE METER RATHER THAN A TEST SEPARATOR?

The main issues in Heavy Oil recovery operations are the production rates and overall productivities of the reservoirs. It is widely agreed that well testing operations in heavy oil fields are very complex and that most conventional surface well testing equipment is very difficult to use in such applications with any reasonable level of accuracy. Errors in flow measurement of the order of 20 – 30% are not uncommon. It is complex, for example, to run a test separator and its measurements tend to be unreliable due to vessel instability, foaming or separation issues. The basic problem is that the density of the oil is very close to that of the water and therefore the current process of gravity separation (used in conventional separators) no longer works efficiently. The centrifugal separation device does not reach a

[3] Faja holds more than 1 trillion barrels of oil, while more than 80 billion are still available in Venezuela outside of Faja.
[4] This is the amount of recoverable oil, which makes Venezuela one of the largest holders of petroleum reserves in the world. Venezuela expects to produce 1.2 MMbpd of Heavy Oil from Faja in the next 5 years, with total Venezuelan production lying at around 5 to 6 MMbpd.
[5] The crude is usually upgraded with diluent or other oil from 16° to 32° API. Venezuela has also created an oil-water emulsion (called ORIMULSION) for burning in power generators.
[6] Canada also has a very aggressive production plan and is expecting to double its production over the next few years.

level of energy (or G Force), without moving parts, to be able to break this emulsion. In addition to this, most heavy oils are highly viscous, which leads also to higher retention times. Another associated phenomenon is that any bubbles of gas entrained in the fluid can no longer flow freely, and so they stay trapped (in a gaseous state) inside the liquid phase. This can potentially lead to a large overestimation of the liquid volumetric flow rate. On top of all this, there is also the possibility of emulsion formation, which constitutes an appalling operating condition for any separator, without the injection of diluent or de-emulsifier.

As multiphase meters are less sensitive to these effects, they were one of the earliest technologies adopted by oil companies[7] working in the Heavy Oil field – the main advantages being their ability to provide better surface measurements than a separator; to overcome general heavy oil measurement limitations; to provide reliable measurements of all of the fluid phases; to acquire data throughout the entire well testing operation (for better reservoir interpretation); to reduce the overall cost of well testing by using lighter, mobile equipment; and to reduce well test durations by rapidly stabilizing the test separator flow.

The Venezuela market, for example, with experience dating back to the mid 1990s, provides a perfect example of the uptake of this type of technology. In the early days of deployment of multiphase flow meter, there was a niche market driven by the fact that no other production monitoring options existed. Regardless of the qualification of the intrinsic multiphase technology for Heavy Oil environments, several types of meters were deployed early in the Venezuela fields. However, the recent explosion in oil prices means that this is no longer a niche but a huge market. There is also now a demand for higher quality measurement and, fuelled by this new challenge, a redistribution of the market segmentation is ongoing. Addressing this new market and these new market demands requires a proper understanding and improved operability of the metering challenges involved and the effect of the environment on the measurements performed.

3 Vx TECHNOLOGY

3.1 Manufacturer's Experience

Schlumberger was involved from an early stage with this type of viscous-oil measurement. As detailed later, several experiments were carried out on the CEPRO (high viscosity) flow loop as early as 1998 to demonstrate the strength of the model embedded within its Vx technology for heavy oil applications. Schlumberger has gathered heavy oil knowledge, mainly through well testing experience, from as early as 1999 in this most demanding and challenging application. Schlumberger has 80% market share in heavy oil operations in Brazil, with 70% of multiphase technology activity focussed in the Heavy Oil market. Similar types of activity exist in Mexico, Indonesia, Venezuela, Congo, and Russia. From data gathered worldwide, the current trend of the Heavy Oil market can be summarised as follows:

- More than 60% of the wells have API gravity between 8° and 18°.
- More than 80% of the well-test jobs are performed at a GVF lower than 50%.
- More than 60% of the data have a WLR lower than 20%.
- More than 80% of the wells have a very low GOR (<70 scf/stbbl).
- In more than 60% of cases, the temperature is in the range of 50 to 75 °C.
- In more than 80% of cases, the pressure is lower than 100 psia!

The compactness and ergonomics of the Vx technology probably explain the success of its deployment in Venezuela; compared to a test separator, which requires stabilization or flow calibration. The core of the Vx Technology is an in-line tool, which acquires data from the point of well opening to the time of well shutting; independent of water-cut, emulsion, foam or slugs that pass through the system. This allows the Vx technology to monitor and acquire all

[7] For example: Total, Statoil, PDVSA, ConocoPhillips, and StaatSolie.

surface data, even during the clean-up period. Upstream separation is not required for the Vx Technology (unlike some alternative solutions on the market); hence, it provides an easy and practical solution for this type of well test operation. Heavy oil operations are always challenging but Vx Technology has, to date, achieved excellent results [42 – 44]. Schlumberger has openly shared and disseminated much of this knowledge, while a proper consolidation of its experience is ongoing (Figure 2).

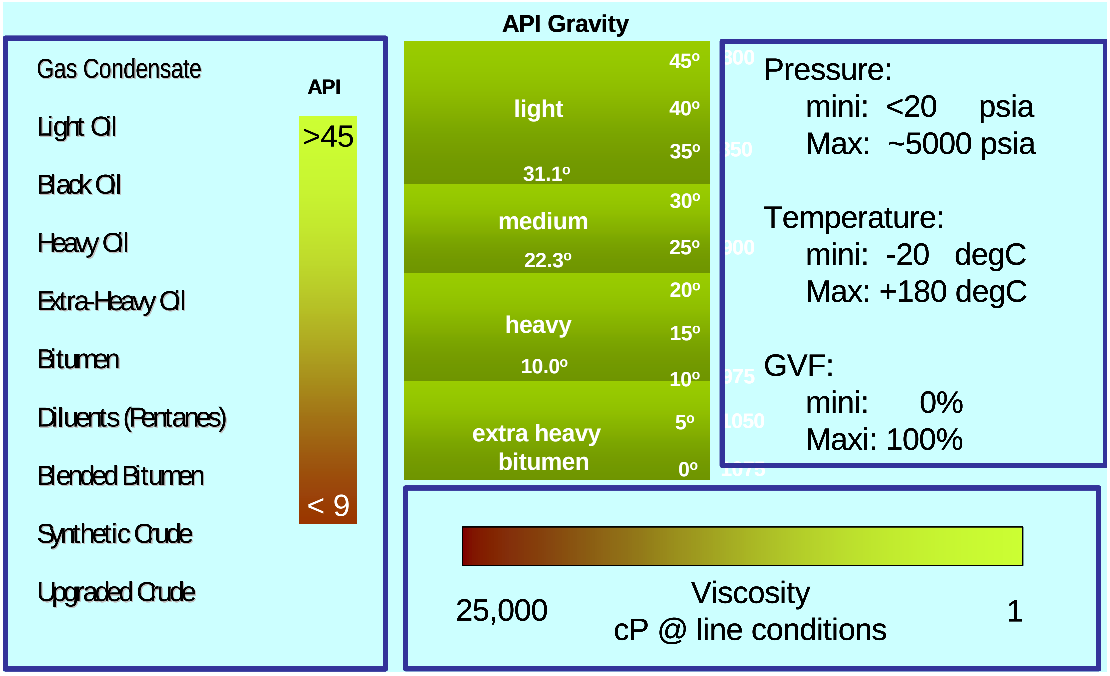

Fig. 2 – Vx technology: application experience.

Continuous improvements over time have gradually led to better accuracy, service quality and improvements in data interpretation; and with its simple combination of a Fraction Meter and Venturi element, Vx Technology is seen as ideally suited for this challenging environment.

Schlumberger's Fluid Research Centre in Edmonton is a centre of competence for Heavy Oil and, together with the Faja Centre of Excellence in East Venezuela, which focuses on reservoir modelling in Heavy Oil, provides a unique opportunity to understand and develop solutions for this type of environment. In fact, considerable effort has been spent over the past 2 years to address this specific market, covering all aspects from engineering research to field operations and team training. The operating conditions covered have also been wide ranging, reflecting the Vx Technology's ability to address different markets and applications with the same hardware (and hence same training) in both exploration and well-testing operations around the world.

3.2 Data Flow Process

Numerous papers have already been published on the Vx Technology and the reader is referred elsewhere for technical details: [1], [4], [5], [7 - 10], [15], [17], [18], [20 – 25], and [27]. However, it is informative in the context of Heavy Oil applications to review the data flow process. Vx multiphase meters constitute one of the simplest combinations of sensors and technology available on the market today (Figure 3). The ability to predict the response of the meter under a variety of process conditions, in particular in Heavy oil, is essential to the selection of the proper technology of measurement.

The Vx Technology is designed to measure the total mass or total volumetric flow rate, and then the oil, water and gas constituents of a producing well at line conditions. These flow rates are converted to standard conditions with a PVT package.

Two basic measurements are made in the measuring Venturi section:

(a) A DP measurement providing the total mass flow rate, Q, and the total volumetric rate, q.

(b) A nuclear gamma-ray fraction measurement, which provides the fraction of each component present in the mixture; and, based on knowledge of the density of each phase, leads also to a value for the mixture density.

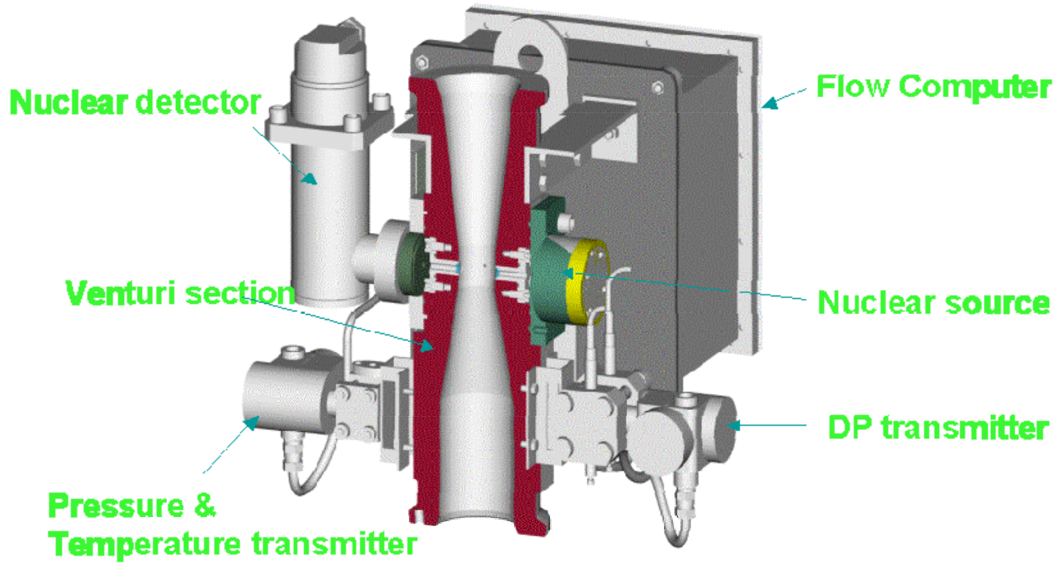

Fig. 3 – Schematic view of a PhaseWatcher Vx.

The meter has only four basic sensors:

1. Differential pressure across the Venturi named "DPV", which measures the differential pressure between the inlet and throat of the Venturi.

2. A nuclear dual-energy fraction meter, which measures the count-rate of gamma rays, transmitted from the source to the detector at two different photon energies.

3. Process fluid pressure sensor, which measures the line pressure at the Venturi throat.

4. Process fluid temperature sensor, which measures the fluid temperature upstream of the Venturi section.

The data flow processing (Figure 4) is summarised in the following sections.

The Vx Technology itself is built on only a few models and hypotheses:

- An experience-based semi-empirical model [12], [33 – 34], to describe gas-liquid slippage.
- Zero slippage inside the liquid phase (i.e. the oil and water have equal velocities).
- A modelled "Shape Factor" for multiphase environments.

The main outputs (at line conditions) are:

- The measured Gas Fraction (GF) or Gas Hold-up.
- The calculated water-liquid-ratio (WLR).
- The mixture density – based only on the nuclear fraction meter measurement.

The product of the mixture density with the Venturi differential pressure measurement provides the total mass flow rate. Therefore, the primary outputs are:

- Total Mass Flow Rate
- Water-liquid-ratio
- Gas Volume Fraction.

The second level of main outputs from the meter is the volumetric flow rates (oil, water and gas) at line conditions. These calculations are based only on a combination of the previous primary outputs. The volumetric flow rates at standard conditions are computed from the flow rates at line conditions using a PVT software conversion package (customized or not according to the accuracy needs of the client).

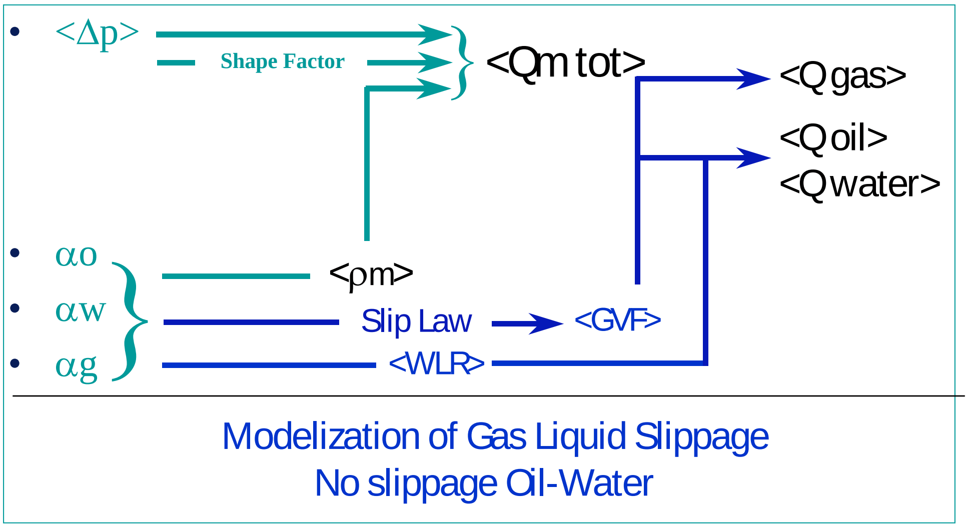

Fig. 4 – Schematic view of the Data Flow Processing at line conditions.

4 FUNDAMENTAL EQUATIONS

In this section, we address the dependency of the mass flow rate on the discharge coefficient for any system using a differential pressure measurement. We then look briefly, from a theoretical point of view, at how the discharge coefficient can be estimated. After reviewing the dependency of the discharge coefficient on the Reynolds number, as a corollary we address the challenges associated with the definition of the Reynolds number in multiphase flow. Then we consider the impact of the relative error on the discharge coefficient due to the uncertainties inherent in some parameters, and then through some propagation errors the impact on the mass flow rate and sequentially on the liquid and gas volumetric flow rate and what is the expected impact of low Reynolds number in these flow rate uncertainties. Finally, we address issues associated with the estimation of the liquid viscosity at line conditions.

4.1 Venturi Mass Flow Rate

All manufacturers today use Venturis or similar products to estimate / measure multiphase flow rates; yet one of the most protected and confidential items of proprietary information in multiphase measurement resides in the characterization of the Venturi response in multiphase flow over a large range of flow regimes, flowrates, GVFs, and fluid properties. Without divulging the secrets of the various manufacturers on their approach, one can gather, from the numerous papers presented in different conferences, that all take an approach similar to the Vx technology.

In the Heavy Oil domain, a major strength of the Vx Technology is its ability to measure total mass flow rate with reasonable accuracy. This is essentially a consequence of the type of technology used i.e. a Venturi (differential pressure measurement) coupled with a phase fraction meter at the Venturi throat. For multiphase flow, the total mass flow rate, Q_T, can be expressed as follows:

$$Q_T = a \cdot \sqrt{DP^*_{VENT} \cdot \rho_{MIX}} \qquad (1)$$

$$a = A_{VENT} \cdot \sqrt{\frac{2}{1-\beta^4}} \cdot C \qquad (2)$$

$$\rho_{MIX} = \rho_{LIQ} \cdot (1-\alpha_G) + \rho_{GAS} \cdot \alpha_G \qquad (3)$$

$$\rho_{LIQ} = \rho_{WAT} \cdot WLR + \rho_{OIL} \cdot (1-WLR) \qquad (4)$$

where

DP^*_{VENT}	:	Venturi Dynamic Pressure Drop
A_{VENT}	:	Venturi Cross Section
ρ_{MIX}	:	Mixture Density
ρ_{LIQ}	:	Liquid Density
α_G	:	Gas Volume Fraction

and C is a function of several coefficients: C = fn(C_{Rey}, Cc, Sf)

C_{Rey}	:	Discharge (Reynolds)
Cc	:	Dimensional
Sf	:	Multiphase Shape Factor

While specific details of the Vx meter are reviewed later, the above expressions represent a generic calculation method for the flow rate of any differential pressure based device, such as an orifice plate, wedge or Venturi. Since it is now standard within the multiphase industry to include at least one Venturi element within the multiphase metering system, the scope of this paper extends naturally beyond the Vx technology and in fact is equally applicable to monophasic as well as multiphase flow and for any meter using differential pressure measurement to access to the velocity of the mixture.

4.2 Discharge Coefficient and Reynolds Number

Venturi measurement has been used for decades by the oil industry, even in Heavy Oil applications. This device is, in fact, so popular that all major multiphase manufacturers use it today[8]. The Vx technology is based on a classical Venturi Design (ISO Standard) and needs corrected for the effects of Reynolds number (essentially the fluid viscosity or more precisely the liquid viscosity). The dependence on viscosity is addressed within the discharge coefficient *Cd*. Schlumberger introduced as early as 1998, a definition of Reynolds number in multiphase conditions [12], [32 – 33]. This solution is based on literature references and extensive observations in various multiphase flow loops, leading to the following statements about the discharge coefficient versus Reynolds number in monophasic flow [14] and in heavy oil[9] [15]. Venturi flow meters are usually designed to work at high Reynolds Number,

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[8] This includes Roxar (new multiphase meter generation), FlowSys, Pietro Fiorentini, MPM, Agar (2) and Haimo (2). (Roxar and Agar are the two major sellers in permanent applications within the Heavy Oil market, while Schlumberger are leaders in Heavy Oil well-testing operations worldwide).

[9] In the case of heavy oil, the discharge coefficient corrects for the wall friction of the fluid.

and the applicable correction can be found quite easily. When working at low Reynolds Number, the available literature is less pertinent even in monophasic flow [16], [31].

Reynolds Number is an important parameter in fluid mechanics and, in monophasic flow, the definition for liquid can be written as:

$$Re = \frac{\rho_{LIQ} \cdot V \cdot d}{\mu_{LIQ}} \tag{5}$$

where

V	:	Liquid Velocity
d	:	Characteristic Length (Pipe Diameter)
ρ_{LIQ}	:	Liquid Density
μ_{LIQ}	:	Liquid Dynamic Viscosity

Reynolds number represents the ratio of inertial forces (*V·ρ*) to viscous forces (*μ/d*) and, consequently, it represents the relative importance of these two types of forces for any given flow conditions. It is also used to identify and predict different flow regimes, such as laminar or turbulent flow. Laminar flow occurs at low Reynolds numbers, where viscous forces are dominant and is characterized by smooth, constant fluid motion; while turbulent flow, on the other hand, occurs at high Reynolds numbers and is dominated by inertial forces, which tend to produce random eddies, vortices and other flow fluctuations.

Reynolds number is related to the density, velocity, pipe diameter, and viscosity of the fluid. The first challenge in multiphase flow is to define the “multiphase Reynolds number”. Several studies have been made in the past [12], [31], yet regardless of the final definition proposed, the definition of the Reynolds number should, asymptotically, be identical to the definition applicable in monophasic flow.

Several studies have been made on the dependence of the discharge coefficient on Reynolds number [16], [31], including some related to heavy oil [34]. However, the usual definition of *Re* (Equation 5) contains an assumption that is no longer valid in multiphase flow i.e. that the “characteristic dimension” corresponds to the pipe diameter. Various generic expressions have been proposed in the form of:

$$Re = \frac{\rho_{LIQ} \cdot V \cdot d_{ref}}{\mu_{LIQ}} \tag{6}$$

with d_{ref} is a reference diameter associated to the liquid.

In fact, for a dominant liquid phase, the Reynolds number for multiphase flow can be related to the single-phase liquid Reynolds number via the introduction of an appropriate function:

$$Re_{LIQ\_MULTI} = Re_{LIQ\_MONO} \cdot f\left(K, \alpha_{GAS}, \rho_{GAS} / \rho_{LIQ}\right) = Re_{LIQ\_MONO} \cdot F_{CREY} \tag{7}$$

where

K	:	Coefficient related to Flow Structure
α_{GAS}	:	Gas Fraction
ρ_{GAS} / ρ_{LIQ}	:	Gas / Liquid Density Ratio
F_{CREY}	:	Correction function for multiphase flow

Rewriting the Reynolds number in this way (i.e. in multiphase terms) is consistent with the common understanding and interpretation of fluid viscosity; and the intuitive notion that it should be related more to the properties of the liquid phase than to the properties of the gas[10]. For example, the liquid has the effect of wetting the pipe wall and as such will create more friction that the gas. The gas viscosity is also extremely small, which would have the effect of generating a very large effective Reynolds number – counter to requirements. Overall then, using this approach, the required correction can be expressed via one simple, non-dimensional function.

The general variations of this function with α_{GAS} and ρ_{GAS}/ρ_{LIQ} is shown in Figure 5.

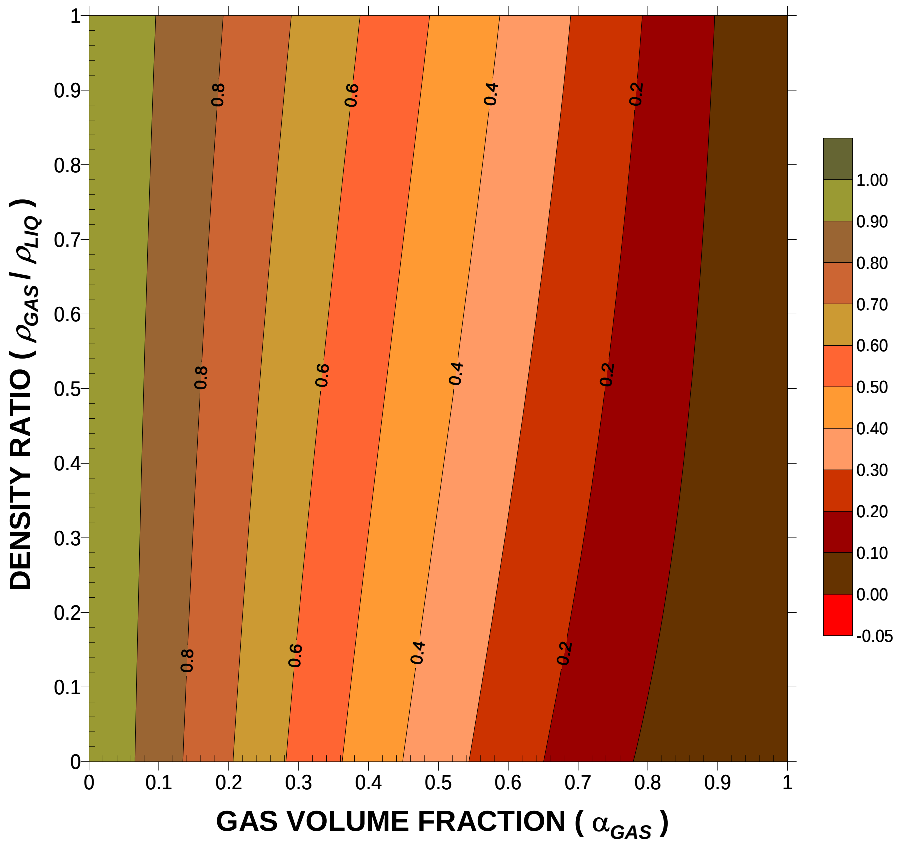

Fig. 5 – F_{CREY} as function of gas volume fraction and density ratio.

In practice, the discharge coefficient (Equation 2) for multiphase flow can be described by a function that covers three distinct regions of the Reynolds number range (Figure 6).

[10] F_{CREY} is a function that tends to 1 as the gas fraction tends to zero. As expressed, this function should, in some way, be a function of the gas fraction. Indeed if the pressure is high and the gas density becomes closer to the liquid density, then clearly the Reynolds number must be corrected for this. In essence, both the gas fraction and the density contrast have an effect on the gas present in the main pipe. Other ingredients are contained within this function, but are not relevant here. It should be noted, however, that the present discussion does not presuppose any special form for this function, allowing for the future re-interpretation of previous work without altering the analysis presented here.

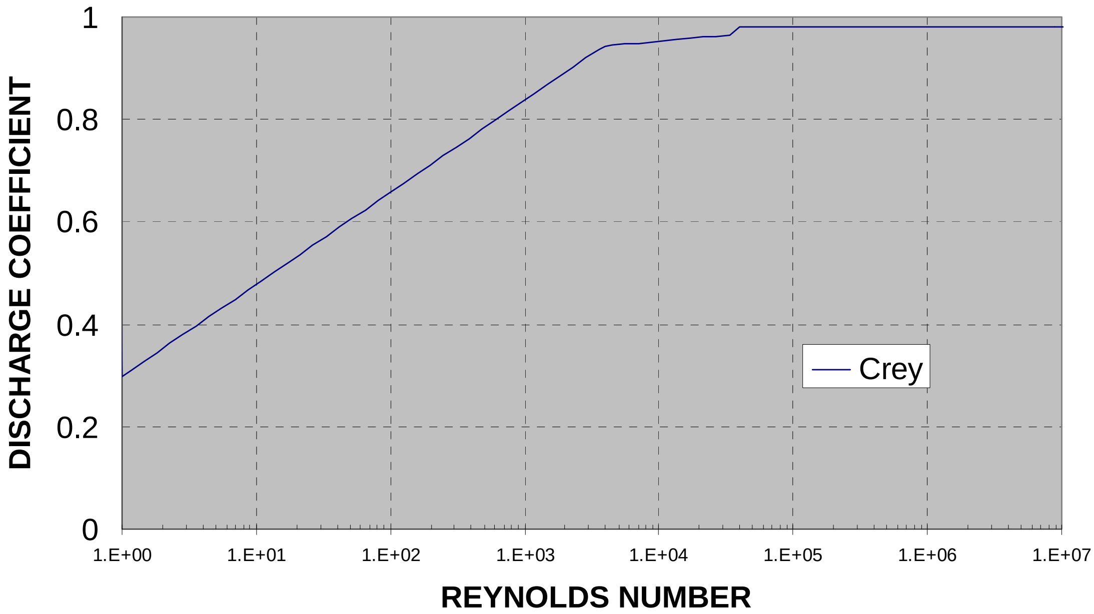

Fig. 6 – Discharge Coefficient in multiphase flow.

This leads to the following general analytical expression for the Reynolds-dependent discharge coefficient (as previously described in the literature [35]):

$$C_{REY}(Re) = A \cdot Log(Re) + B \tag{8}$$

where *A* and *B* are experimentally derived constants with values between 0 and 1, depending on the *Re* domain.

This type of curve presented above can be approached from a theoretical point of view, the ingredients are the following for a monophasic flow, and this can be extended to multiphase flow in similar way. The Reynolds number in monophasic flow is defined as follow:

$$Rey = \frac{\rho \cdot <U> \cdot d}{\mu} = \frac{4.\rho \cdot Q}{\mu.\pi.d}$$

with Q the volumetric flow rate
and <U> is the average velocity at the throat of the Venturi.

And the evaluation of the Discharge coefficient can be done based by:

$$C_{Rey}{}^{2} =< Q^{2} >.\left(\frac{\rho \cdot (1-\beta^{4})}{2.\Delta P}\right)\frac{1}{\left(\pi.d^{2}\right)^{2}.} =< U^{2} >.\left(\frac{\rho \cdot (1-\beta^{4})}{2.\Delta P}\right)$$

with ΔP the overall difference of pressure between both pressure tapings

Then <U> is evaluated based on the profile of the flow at the throat of the Venturi. This could be for example approached for a parabolic profile in low Reynolds Number (i.e. laminar flow) or with a flat profile with high Reynolds number (i.e., Turbulent)

In practice Q is the injected flow rate obtained from a reference measurement on a flow loop and the ΔP is the measurement obtained at a Venturi throat then the Crey can be evaluated versus different flow rate and viscosity and based on the two above equations it is possible to obtained the type of figure 6.

4.3 Relative Error in the Discharge Coefficient

The different parameters contained in the expressions above have been studied previously, to determine their influence on the Discharge Coefficient as a function of Reynolds Number. In 2007–08, Stobie and Basil [45 – 46], for example, investigated influences that might potentially affect Venturi accuracy in viscous fluids; while extensive work was performed by numerous researchers at Schlumberger during the previous years. Most of this latter work has not been published externally, but should be identified as being in existence and the main studies highlighted, i.e. Atkinson (1997), Atkinson and Taleb (1998), Sherwood (1999), Moussa (2001), Moussa (2003). The model was revisited in detail at the end of 2004 by Pinguet and Guerra; then further development and verification was carried out by Pinguet (2005), Heluey and Pinguet (2007), Bornia and Pinguet (2007), Zalamea and Pinguet (2008); and results published by Atkinson et al. [12, 14, 34], NEL [38], and Pinguet [42 – 44].

Our particular configuration, with a blind tee upstream of the multiphase flow meter, has led to a simple characterization of the discharge coefficient. Overall, more than 10 years of constant effort have been expended on this subject (*excluding* theoretical studies performed in parallel). Figure 7 shows the difference in the formulation derived for the discharge coefficient (as a function of Reynolds Number) from the work conducted over this period.

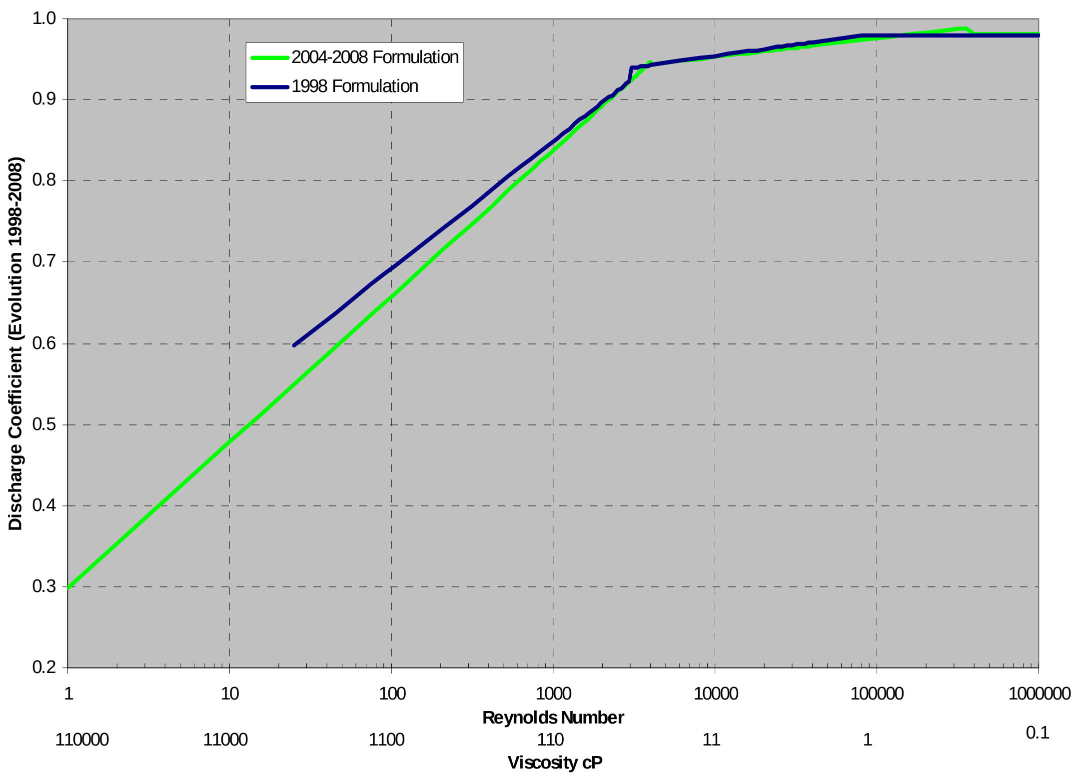

Fig. 7 – Evolution of Discharge Coefficient value over 10 years of investigation. The viscosity scale (only indicative) is given for a flow rate of 3000 bpd, mixture density ~ 900 kg/m3 and GVF ~50%.

The Discharge Coefficient values given by the old (1998) and new (2004-2008) formulations are fairly similar at Reynolds numbers above 3000; but, at low Reynolds number, the improved understanding for the recent experimental work are clearly visible. The formulations (of the type described in Equation 8) are based primarily on experimental work, conducted under well-defined conditions (i.e. injected flow). A discharge coefficient is then derived that best fits the response of the flow measurement sensor (a Venturi in this case) as a function of flow rate. Evolving a discharge coefficient formulation requires extensive validation, in particular to verify that it agrees with the very large amount of data already acquired in many operating conditions. The performance of the Vx technology has been reviewed several times on the different flow loops handling Heavy Oil around the world such as Atalaia (Brazil) owned by Petrobras and CEPRO (Venezuela) owned by PDVSA.

This obviously introduces some uncertainty into the values obtained for the fitted coefficients (*A* and *B*) within each *Re* domain. For coefficient *B* this uncertainty is of the order of 2% in the lower *Re* range, around 1% in the middle range and approximately 0.3% in the upper region. The respective values for coefficient *A* are around 0.8%, 0.2% and 0%. Once quantified in this way, it is then possible to look at the propagated effect of such uncertainties.

Firstly, the relative error in the discharge coefficient (Equation 8) can be expressed as:

$$\left(\frac{\Delta C_{REY}}{C_{REY}}\right)^2 = \left(\frac{\ln(Re)}{\ln(10)} \cdot \frac{\Delta A}{C_{REY}}\right)^2 + \left(\frac{\Delta B}{C_{REY}}\right)^2 + \left(\frac{A}{\ln(10) \cdot C_{REY}} \cdot \frac{\Delta Re}{Re}\right)^2 \qquad (9)$$

The dependency of this parameter on the individual uncertainties in *A*, *B* and *Re* is presented graphically in Figure 8.

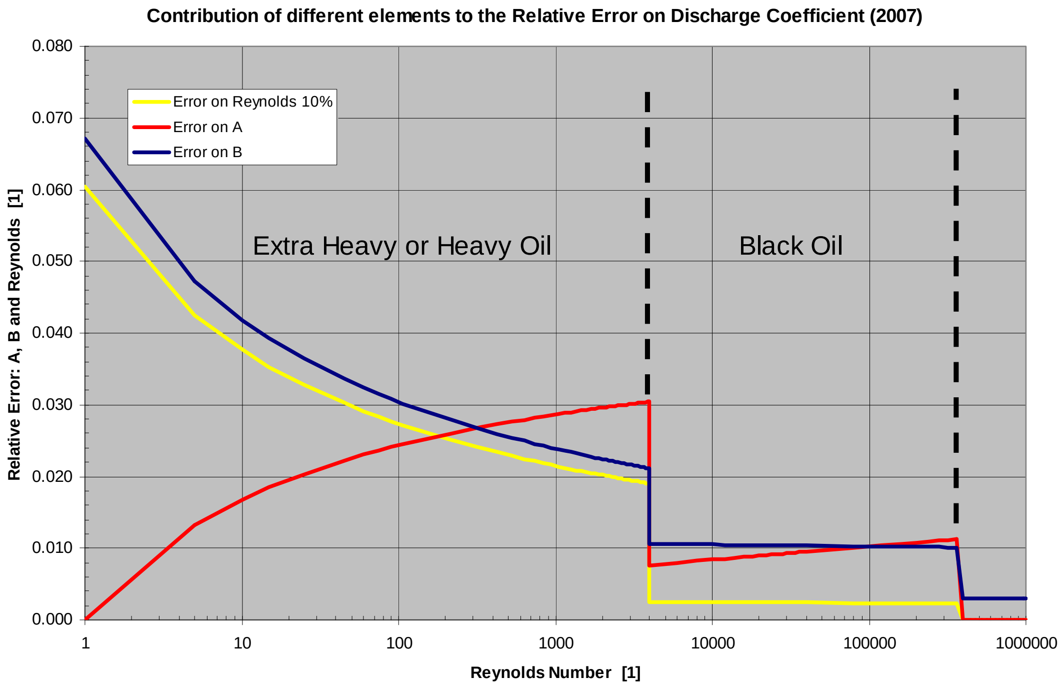

Fig. 8 – Error contributions from the 3 parameters used to describe the Discharge Coefficient. The Y-axis is fraction and 0.05 represent 5%. The discontinuity between each zone is due to the uncertainty in the coefficient A and B.

It is clear from Figure 8 that the relative error contributed by of each element of Equation 9 is lower than 1% over most of the Reynolds range, except below ~ 4000. The latter represents a relatively narrow range of Reynolds numbers but, as will be seen later, is typical of that encountered with extremely viscous oils. Even in the higher Reynolds range (> 4000), some efforts are still necessary[11] to reduce the uncertainties of the parameters (embedded in the discharge coefficient formulation) to an acceptable level.

[11] Among the ongoing efforts is an investigation by TUV NEL and Schlumberger started in 2007 to evaluate the response of Venturi meters in a viscous multiphase environments. This work, initiated under the UK Government's Department for Business Enterprise and Regulatory Reform (BERR) [ex DTI] Technology Programme, is currently being conducted, under well-controlled test conditions, at the TUV NEL Multiphase Flow Loop specifically upgraded for viscous fluid operation.

As two of the parameters (i.e. the fitting coefficients *A* and *B*) in the equations above are generic to any system, it makes sense to focus on the one related to Reynolds number. Consider then the impact of a 5, 10 or 20% relative error in the Reynolds number (or in the liquid viscosity if that contributes the largest uncertainty to *Re*) via the following simplification:

$$\left(\frac{\Delta C_{REY}}{C_{REY}}\right)^2 \approx \left(\frac{A}{\ln(10)\cdot C_{REY}}\cdot\frac{\Delta Re}{Re}\right)^2 \approx \left(\frac{A}{\ln(10)\cdot C_{REY}}\cdot\frac{\Delta\mu}{\mu}\right)^2 \qquad (10)$$

An error of 20% is not something impossible, knowing that the viscosity is not known at better than 5-10% following the equipment used and then the estimation of the velocity could lead easily each to more than 5-10% error relative, with finally error on the definition of the diameter characteristic of the flow in the range of 2-5%.

This can again be presented graphically (as shown in Figure 9):

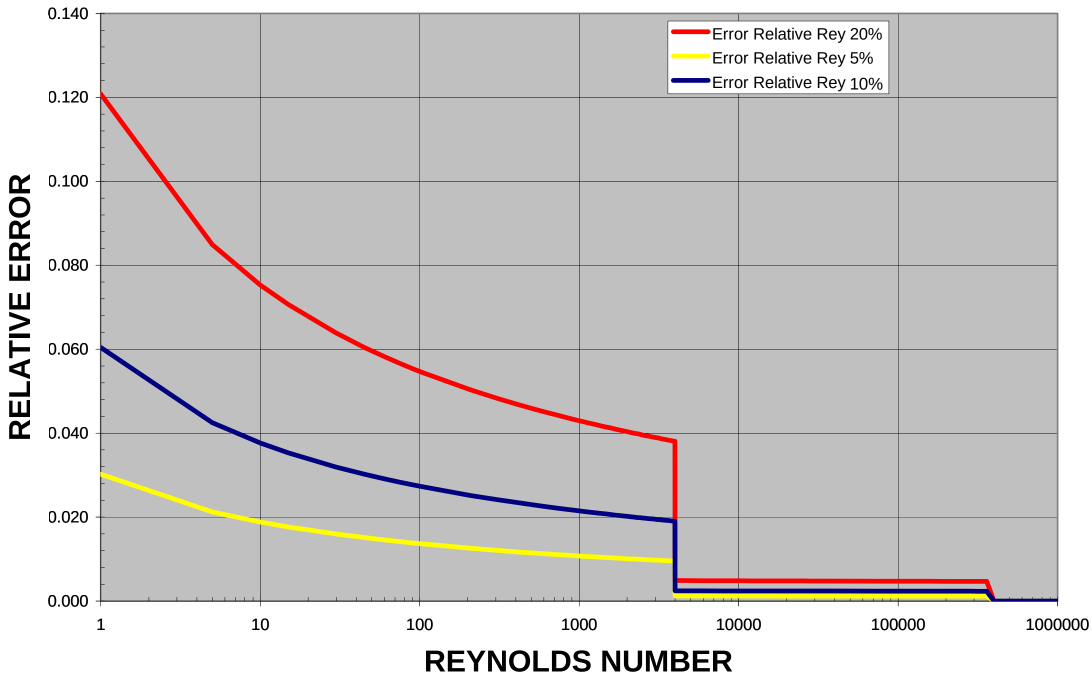

Fig. 9 – Relative error in Discharge Coefficient due to different Reynolds number uncertainty.

Several observations can be made from this graph. Firstly, even with an error of 20% in the Reynolds number (or viscosity), the relative error in the discharge coefficient is less than 0.5% over most of the Reynolds number range (i.e. 4000+). For *Re* < 4000, and for a Reynolds number uncertainty of 10%, the relative error in the discharge coefficient increases from ~ 2% (at *Re* ~ 4000) to ~ 6% (at extremely low Reynolds numbers)[12].

It can also be seen that a relative error below 5%, in the viscosity or Reynolds number, leads to an uncertainty in the discharge coefficient of less than 2% over almost the entire Reynolds number range.

[12] Assuming a liquid flow rate of 2000 bpd, a GVF ~ 50% and a liquid density ~ 900 kg/m^3 with a viscosity around 6 cP, the Reynolds number will be equal to 4000.

Propagation Error on Discharge Coefficient

Based on the different parameters and inputs described previously, it is possible to derive the relative error in the Reynolds numbers and then to review its effect on the discharge coefficient, which is ultimately related to the mass flow rate. The relative error in the Reynolds Number can, albeit with some assumptions, be written in the following form:

$$\left(\frac{\Delta Re_{LIQ}}{Re_{LIQ}}\right) = \sqrt{\left(\frac{\Delta\mu_{LIQ}}{\mu_{LIQ}}\right)^2 + \left(\frac{\Delta V_{LIQ}}{V_{LIQ}}\right)^2 + \left(\frac{\Delta D_{LIQ}}{D_{LIQ}}\right)^2 + \left(\frac{\Delta\rho_{LIQ}}{\rho_{LIQ}}\right)^2 + \left(\frac{\Delta F_{CREY}}{F_{CREY}}\right)^2} \quad (11)$$

where μ, V, D and ρ are defined at line conditions.

Considering only the effect of the viscosity and the definition of the Reynolds number in multiphase environment, this can be approximated[13] by the following expression:

$$\left(\frac{\Delta Re_{LIQ}}{Re_{LIQ}}\right) \approx \sqrt{\left(\frac{\Delta\mu_{LIQ}}{\mu_{LIQ}}\right)^2 + \left(\frac{\Delta F_{CREY}}{F_{CREY}}\right)^2} \quad (12)$$

The first term of the right hand side of Equation 12 is related purely to the liquid viscosity at line conditions and the second term to the definition of Reynolds number in a multiphase environment. It has been demonstrated that the main dependence of the second term is on gas volume fraction rather than the gas / liquid density ratio, which is always very small in heavy oil applications. It is then possible to estimate, at least to a first approximation, the magnitude of this first term (Figure 10). It is clear from this figure that the first term dominates the second term for gas volume fractions up to ~ 85%.

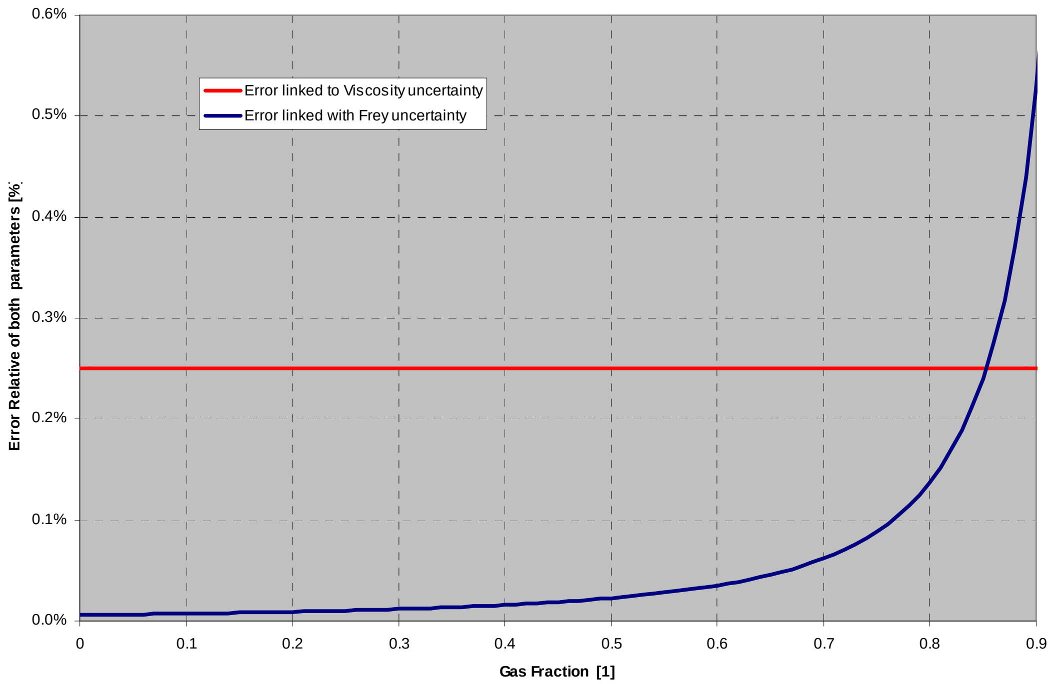

Fig. 10 – Importance of uncertainty in Reynolds number component parameters.

[13] For conciseness, the approximation is not derived here but will be explained in a separate paper by the same authors – to be published in 2009.

It is interesting to note that the second term is dominant at very high GVF. The explanation is that the quantity of liquid present in the pipe is becoming less and less important and the relative error associated with the characteristic dimension of the liquid at the throat of the Venturi (which is used in the definition of the Reynolds number i.e. Equation (6)) is becoming larger. It should be noted that even at 90% GVF the value is still lower than 0.5%; and at 93% GVF, the error is in the range of 1%. Heavy Oil wells do not produce large amount of gas and therefore the study at higher GVF becomes less relevant.

The error in the discharge coefficient can be calculated[14] from previous information included in this report:

$$\Delta C_{REY} \approx \frac{A}{\ln(10)} \cdot \frac{\Delta Re_{LIQ}}{Re_{LIQ}} \approx \frac{A}{\ln(10)} \cdot \frac{\Delta \mu_{LIQ}}{\mu_{LIQ}} \tag{13}$$

The coefficient *A* is defined in Section 4.2, and takes different values depending upon the Reynolds number range.

If the Reynolds number is above 40,000 then the uncertainty of the discharge coefficient[15] (due to viscosity) is effectively independent of the error in the viscosity and then this error is equal to 0.

Where the Reynolds Number is within the medium or lower range, the error in the discharge coefficient (due to the relative error in the liquid viscosity at line conditions) can be written as:

$$\Delta C_{REY} \approx D \cdot \frac{\Delta \mu_{LIQ}}{\mu_{LIQ}} \tag{14}$$

As a rule of thumb, it should be noted that the factor *D* is of the order of 1% for mid-range Reynolds numbers [4000-400000], and less than 8% for Reynolds numbers below 4000. The influence on the overall discharge coefficient error is therefore extremely small – its absolute value, in the case of a 5% relative error in viscosity, being only about 0.004 (Figure 11).

[14] The second term in Equation 12 is considered negligible in this case.
[15] In other words, whatever the error in the viscosity measurement, this has no effect on the discharge coefficient and therefore no implication on the total mass flow rate.

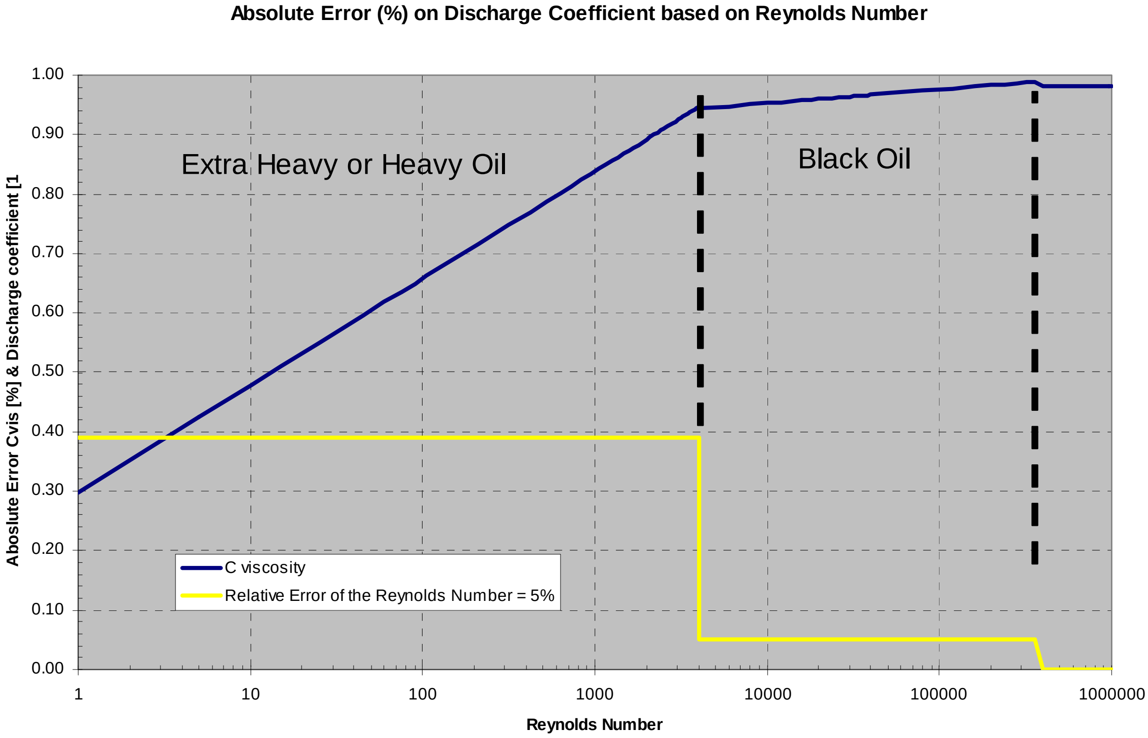

Fig. 11 – Discharge coefficient and its absolute error due a 5% uncertainty in viscosity.

Two basic comments follow from the study above. Firstly, assuming a 5% relative error in viscosity, we are looking for an uncertainty effect of less than 0.4% (where discharge coefficient values are generally in the range 0.5 to 0.95). The quantification of such effects becomes very challenging in experimental set-ups and requires a very high level of accuracy in flow loop testing in order to be able to confidently improve the relevant coefficients, controlling the discharge coefficient associated with the Reynolds number. Even a relative error of 10% in Reynolds number (viscosity) equates to an accuracy of better than 0.8%.

It is the authors' belief that the large shift of accuracy, at Reynolds numbers below 4000, is due to the lack of focus and lack of test work conducted on viscous fluids to date. Another point worth mentioning is that an error of 5% in viscosity has an effect on the final flow rate of less than 0.5% in the worst case, and less than 0.05% in the majority of cases (i.e. a factor of 100 lower), almost at the limit of the metrological performance of any flow loop.

It is clear that the challenge here is extremely high and requires large investments and accurate infrastructures to be in place. This is beyond the scope of most individual multiphase meter manufacturers, and would be better conducted under the framework of a Joint Industry Project (JIP) for example. We have started such initiative with the BERR in 2007 in a project going up to 2009.

4.4 Propagation Error on Mass Flow Rate

Reinterpreting the information given above, it is possible to approximate the relative error in the mass flow rate by taking into account only the viscosity effect i.e.

$$\left(\frac{\Delta Q_T}{Q_T}\right)_{VIS} = \left(\frac{\Delta C_{REY}}{C_{REY}}\right) \tag{15}$$

The total relative error in the mass flow rate can then be defined as:

$$\begin{aligned}\left(\frac{\Delta Q_T}{Q_T}\right)^2_{TOT} &= \left(\frac{\Delta Q_T}{Q_T}\right)^2_{NORMAL} + \left(\frac{\Delta Q_T}{Q_T}\right)^2_{VIS} \\ &= \left(\frac{\Delta Q_T}{Q_T}\right)^2_{NORMAL} + \left(\frac{D}{C_{REY}}\right)^2\left(\frac{\Delta \mu_{LIQ}}{\mu_{LIQ}}\right)^2 \\ &= \left(\frac{\Delta DP^*_{VENT}}{2\cdot DP^*_{VENT}}\right)^2 + \left(\frac{\Delta \rho_{MIX}}{2\cdot \rho_{MIX}}\right)^2 + E^2\left(\frac{\Delta \mu_{LIQ}}{\mu_{LIQ}}\right)^2\end{aligned} \tag{16}$$

The last term on the lower right is the one associated with the viscosity effect. Previous studies made on the other two arguments (i.e. excluding the viscosity parameter) had the following conclusion[16] :

$$\left(\frac{\Delta Q_T}{Q_T}\right)_{NORMAL} = \sqrt{\left(\frac{\Delta DP^*_{VENT}}{2\cdot DP^*_{VENT}}\right)^2 + \left(\frac{\Delta \rho_{MIX}}{2\cdot \rho_{MIX}}\right)^2} \approx 1.0\% - 1.5\% \tag{17}$$

i.e. that the relative error in mass flow rate is generally within the range 1 to 1.5%. The effect of the Reynolds number uncertainty (i.e. 5% in this case) on the total flow rate is in fact smaller than 1.4%, as indicated in Figure 12.

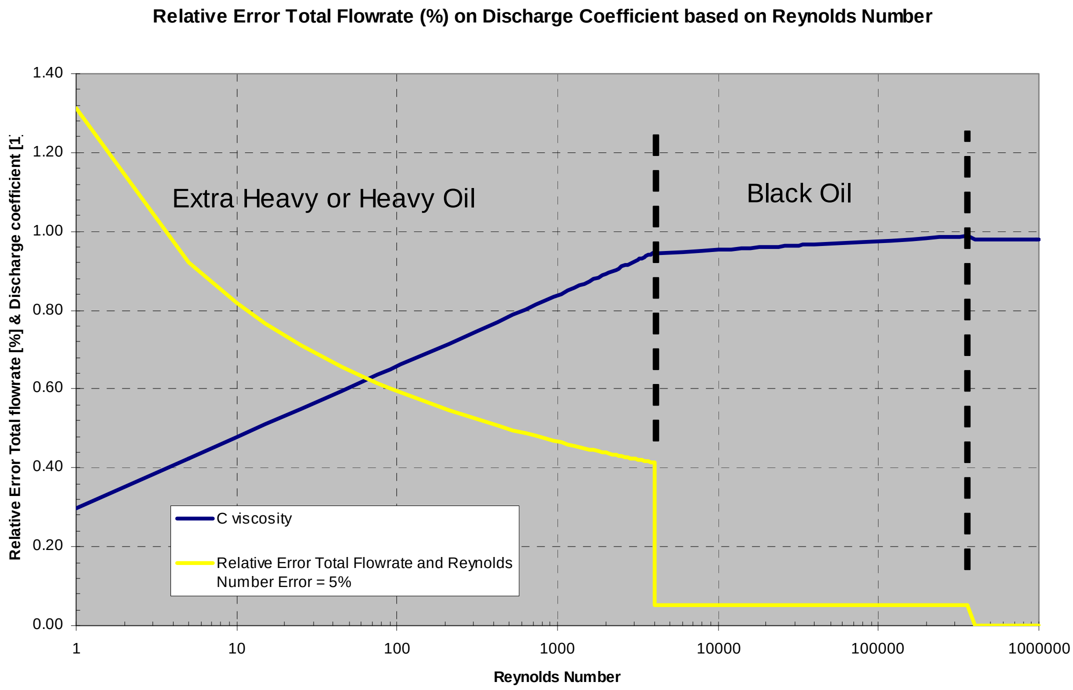

Fig. 12 – Relative error in total flow rate based on a 5% uncertainty in viscosity.

The effect of the viscosity is therefore of the same order of magnitude as the conventional uncertainties that contribute to the total mass flow error. Combining both the conventional and viscous effects leads to an overall error in mass flow rate as depicted in Figure 13.

16 A more detailed review of this statement is proposed by Pinguet *et al.* for issue in 2009.

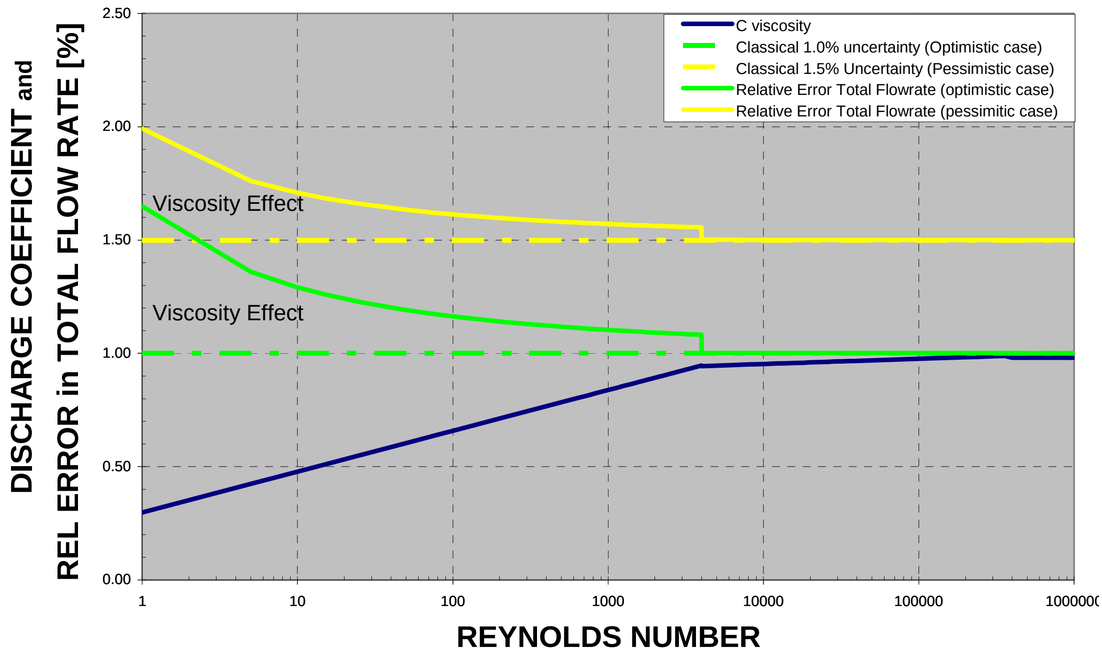

Fig. 13 – Relative error in total flow rate based on the combined uncertainties from viscosity and conventional effects. In this case "classical" means without viscosity effects (Re > 40000).

From Figure 13, it can be seen that the effect of the viscosity uncertainty is fairly marginal and, as expected, has an effect solely at very low Reynolds number (< 4000). The cumulative effect of these different uncertainties generates a maximum relative error ranging from 1.5% to 2.0%. (This is quite independent of the WLR value Ref [2 – 3] and [36 – 37] although this is not discussed in detail in the current paper). Overall, this means that the liquid viscosity in multiphase flow has a relatively weak influence, over a large range of Reynolds number. However, the key to this is a clear definition of the Reynolds Number in heavy oil and multiphase environments, and an understanding of its influence in high viscosity[17]. This result also demonstrates that the Venturi meter is an appropriate device for Heavy Oil environments and hence why it is so popular.

It should be remembered, however, that a low Reynolds number does not necessary mean a high viscosity. As previously defined, the Reynolds number is linked to the liquid diameter (or in one way or another to the complement of the gas fraction) and, as such, a system with low velocity and a fair amount of gas could have a small Liquid Reynolds number, which is the one that should be considered when looking at the friction effect.

4.5 Propagation Error on Gas Flow Rate

It is possible to pursue this theoretical study further and to look at the errors in both phases: liquid and gas. Since the combination of Venturi element and fraction meter constitutes a relatively simple system, it is possible to establish an equation for each phase. The definition of the gas flow rate is given by:

$$q_G = \frac{Q_T}{\rho_{MIX}} \cdot \text{GVF} \qquad (18)$$

However, the mixture density is also linked to the GVF and the total volumetric flow rate to the mixture density. It is therefore necessary to consider everything, such that the final dependency can be reduced to only two parameters: GVF and Q_T. After some laborious

[17] For a relative error in viscosity of 10%, the maximum contribution to the volumetric and total mass flow rate error is < 3% and < 2.8% respectively. (A 20% error leads to 5.5% and 5.4%).

calculations, it is possible to obtain the relative error in the gas flow rate in a simpler form, which can be approximated by:

$$\left(\frac{\Delta q_G}{q_G}\right) = \sqrt{\left((F+1)\cdot\frac{\Delta \mathrm{GVF}}{\mathrm{GVF}}\right)^2 + \left(\frac{\Delta Q_T}{Q_T}\right)^2} \tag{19}$$

where

$$F = \left|\frac{(\rho_{GAS} - \rho_{LIQ})\cdot \mathrm{GVF}}{\rho_{MIX}}\right| \tag{20}$$

In essence, the maximum relative error in the gas flow rate is GVF-dependent, with a contribution[18] of approximately 2 – 3% (assuming that ΔGVF is known to better than 0.5%), plus an added error of ~ 1.5 – 2.0% due to the overall total mass flow rate uncertainty (including the viscosity effect as shown in Figure 13). Therefore, the overall gas uncertainty is within 2 – 4%, which is actually very low[19].

4.6 Propagation Error on Liquid Flow Rate

The calculation of the liquid flow rate at line conditions involves a combination of GVF, total mass flow rate and mixture density, as expressed in the following formula:

$$q_{LIQ} = \frac{Q_T}{\rho_{MIX}}\cdot(1-\mathrm{GVF}) \tag{21}$$

The same hypotheses and calculation methods (as the previous section) can be used to derive an expression for the relative error in liquid flow rate i.e.

$$\left(\frac{\Delta q_{LIQ}}{q_{LIQ}}\right) = \sqrt{\left((G+H)\cdot \mathrm{GVF}\cdot\frac{\Delta \mathrm{GVF}}{\mathrm{GVF}}\right)^2 + \left(\frac{\Delta Q_T}{Q_T}\right)^2} \tag{22}$$

where

$$G = \left|\frac{1}{(1-\mathrm{GVF})}\right| \quad \text{and} \quad H = \left|\frac{(\rho_{GAS} - \rho_{LIQ})}{\rho_{MIX}}\right| \tag{23}$$

A detailed analysis has shown that *G* and *H* are in the same range, with a tendency for *G* to be around 2 to 3 times smaller than *H* for viscous fluids[20].

The first term in Equation 22 is in the range 1.0 – 1.5% in most cases. By adding to this the relative error in the total mass flow rate, the overall (relative) error in liquid flowrate can be approximated. In general this leads to an overall uncertainty of 2.0 – 2.5% in liquid flowrate.

Overall, this section shows how simply the impact of the viscosity can be taken into account; yet if it not properly taken care of how this can lead to additional terms of uncertainty in the overall meter performance. As previously mentioned, almost all multiphase meter

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[18] This number can be obtained by considering the overall properties of the fluids in heavy oil applications, such as the fact that the oil and water may be in the same density region. If it is assumed, as an example, that ρ_{LIQ} ~ 950 kg.m^{-3}, ρ_{GAS} ~ 10 kg.m^{-3} and GVF ~ 50%, then the factor *F* is approximately equal to 2·GVF.
[19] Oil companies usually require a gas flow rate uncertainty of less than 10%.
[20] The factor (*G* + *H*)·ΔGVF is of the order of 6% at GVF = 90% and much lower at 50% with ρ_{LIQ} ~ 950 kg.m^{-3}, ρ_{GAS} ~ 10 kg.m^{-3}.

manufacturers now use Venturi devices for one reason or another, and so this viscosity effect needs to be taken into account or compensated for in one way or another. It has been disclosed here how, with the right definitions and a bit of mathematical manipulation, a clear picture of a system can be given for a standard metering product.

Obviously, the effects described above were quantified assuming a reasonable accuracy in the liquid viscosity (in fact better than 5%). It is easy to repeat the same work with a higher uncertainty value on the viscosity and again observe the propagation of errors.

It is hoped that this analysis has enlightened a further part of the multiphase business – in this case its application to viscous fluids – and shown that a comprehensive approach can be made with simple physical arguments that do not require complex simulations. Clearly many details have been excluded here, for confidentiality purposes, but the key issues and requirements have been openly stated i.e. knowledge of the liquid viscosity at line conditions, and a proper paper definition of the Reynolds number in multiphase flow.

4.7 Calculation of the Liquid Viscosity at Line Conditions

Calculation of the liquid viscosity was presented before [36] and [42 – 44]. The liquid viscosity calculation (at line conditions) is not straightforward. First, it is usually necessary to establish the viscosity of the dead oil at line conditions[21]. Several correlations exist but their domain of validity is often limited, and it is recommended that ASTM D341 [47] be used. Several viscosimeters exist on the market and it is not the purpose of this paper to identify the best one to use in this configuration but a study is recommended among them before establishing some behaviours and extensive studies. It is however necessary to introduce the effects of dissolved gas. This correction will give an overall liquid viscosity slightly lower than the original estimate. Finally, the combination of oil and water must be considered; by using the WLR (water-liquid-ratio) and other parameters, along with a suitable mixing law, to derive an appropriate viscosity for the liquid phase at line conditions. Several options exist for performing these computations e.g. the Beggs-Robinson equation is commonly employed to take into account the effect of dissolved gas on the oil viscosity, while the Brinkman-Taylor mixing law provides reasonable results for oil / water viscosities [38].

Alternatively, the Einstein Law has been reported to give some good results, especially in high viscosity fluids[22]. More sophisticated models[23] are also available in the literature (such as Petrosky & Farshad and Kartoatmodjo [41]). Most of these correlations call for phase inversion[24] information, which is closely related to the WLR and vary from oil to oil. Experience in the laboratory demonstrates that the inversion point can be determined experimentally, using some special developed techniques.

It is common to assume that the inversion point for light oil will be in the region of 40 to 60%; while for Heavy Oil the inversion point is generally believed to shift to higher WLRs (in the region of 80% or above). However, field experience has shown that inversion points lower than 30% and higher than 90% can also be found in high viscosity oils. This area still needs more investigations.

Figure 14 describes more clearly how the Liquid Viscosity is calculated from the initial input measurement of dead oil viscosity.

[21] It is common to expect an accuracy of better than 10% in this quantity.
[22] Note, however, that the Einstein Law is based on the suspension of hard spheres and hence not the most appropriate way to describe one liquid phase dispersed within another.
[23] In principle, this step could be reduced or eliminated if a device was available to measure the viscosity of a mixture or single phase under pressure. Instead, a generic method for calculating this quantity at line conditions is taken into account.
[24] Many studies have been made and several correlations are available on phase inversion, which is clearly related to the superficial tension and other factors operating at the molecular or mesoscopic level.

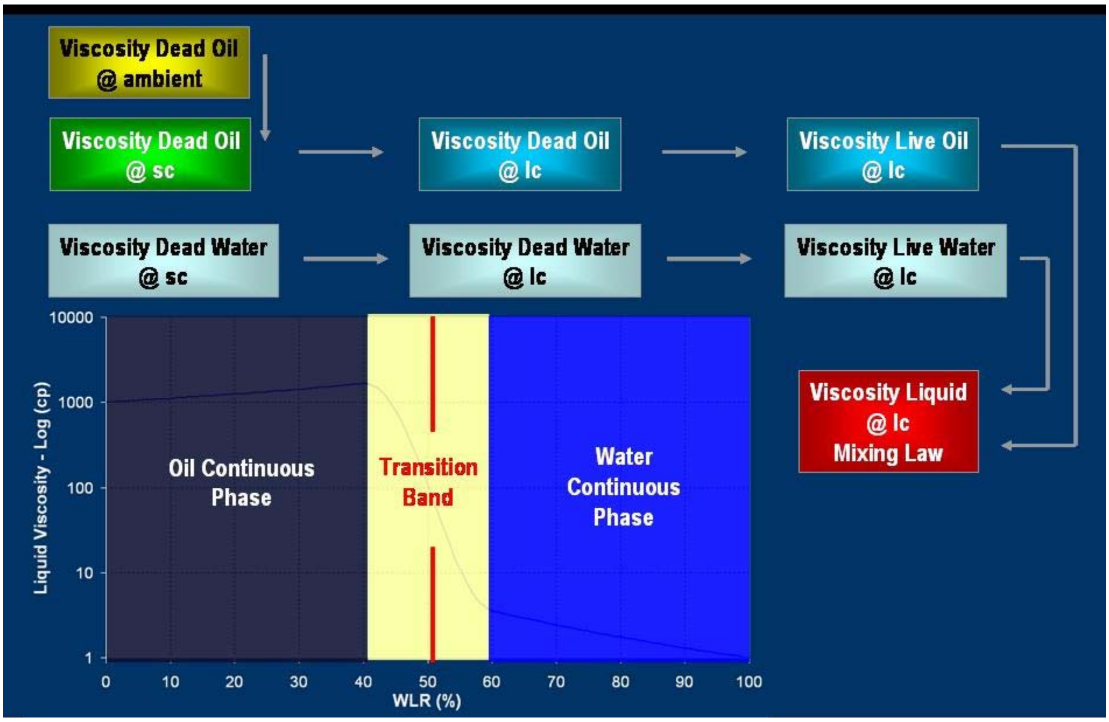

Fig. 14 – Vx liquid viscosity calculation process showing the different correlations used.

5 EXPERIMENTAL DATA

5.1 Previous Studies

Schlumberger has been one of the pioneers in addressing the problem of Heavy Oil viscosity. Back in 1998, the Vx technology had already been tested (private test) in the CEPRO facilities for Heavy Oil (Venezuela); where the performance of a prototype was investigated at viscosities up to 5000 cP [12]. The CEPRO-PDVSA (Centro Experimental de Production) multiphase flow loop operates on natural crude oils and gas. It is a large facility where the crude oils are stored in tanks with a capacity of approximately 1200 barrels each. The gas is a natural gas supplied directly from production facilities and vented after use. As for the crude oil, it can be either recirculated or used in an open circuit. After the gas injection point, the liquid and gas go through a static mixer and then via approximately 60 metres of horizontal 3-inch pipe, before reaching the multiphase test meter location. The overall uncertainty of the flow loop for liquid is around ± 2% to ± 2.5%, while the gas flow rate accuracy is within ± 4% over the entire range. Overall, the consistency of the reference meters is very good for a facility of this size[25].

Since 1998, Schlumberger has had a continuous presence in Heavy Oil; mainly through its Periodic Well Testing operations. The main countries where the technology is used daily are Mexico, Brazil, Venezuela, Russia, Colombia, and Congo [39]. In 2004, a review was conducted of the efforts made over previous years, and a validation of the viscosity study made on the smallest version of the Vx meter [34]. At the end of 2004, PDVSA proposed a performance review of several multiphase flow meters present on the market. In those days, only Schlumberger accepted the invitation to participate. This was a blind test, designed to measure meter performance over a period over 3 months, with oil viscosities ranging from 1 to 2750 cP, GVFs from 0 to 99% and WLRs from 0 to 80% (with different salinities). With several steps in the mid-range designed to gauge meter performance in the transition zone (oil to water phase continuous), such results could be achieved only due to the advantage of the Vx technology: i.e. the ability to measure the WLR with the same level of accuracy

[25] The gas density also contains uncertainties associated with the pressure measurement, gas dryness, PVT corrections etc.

whatever the nature of the continuous phase; even in the transition zone. This is because the nuclear measurement is completely insensitive to any phase dispersion[26]. In 2005, Schlumberger revisited the interpretation model to improve the accuracy of the meter.

Running single-phase oil or any combinations of multiphase flow (water / oil, oil / gas) led to an overall uncertainty (i.e. for the test meter and flow loop combined) of less than 2.5% to 5.0% for any GVF (up to 90%) and for any WLR (from 0 to 80%). Therefore, the relative error associated with the Vx meter alone was well within 2.5% to 3.0% on the liquid or total flow rate. Above this WLR range, the continuous phase changes to a water-continuous flow regime and measurement is restored to the classical domain of the Vx meter (as per its standard package). These results were confirmed over several test campaigns with different types of Vx meters and oil viscosities [34], [40], and the experience was not a unique one; with tests performed in Brazil (Atalaia), the Congo and CEPRO (twice) demonstrating the same trends. The gas flow rate was also well within 5 – 10 % in these different tests; as expected from the theoretical analyses previously performed. The overall WLR performance in CEPRO was better than 2.5% – 3.0% up to very high GVFs (≤ 98%) reaching the same level of accuracy as the flow loop.

5.2 TUV NEL Flowloop Tests (conducted for a commercial Subsea Application)

A further evaluation of the Vx Technology in viscous multiphase flow was conducted during the summer of 2006 at TUV NEL's Multiphase Flow Facility (Figure 15) in Scotland. The tests were commissioned by BHP as part of the meter selection process for a major subsea development. The emulsion forming tendencies of the forecast production fluids required a multiphase measurement solution capable of maintaining accuracy over a wide range of flowrates, GVFs, WLRs and liquid viscosities, for multiphase flow streams that could potentially be in the form tight emulsions.

5.2.1 TUV NEL Test Programme

The flowloop tests were conducted over a multi-point matrix – selected by the operator – consisting of a series of baseline measurements in conventional three-phase flow (i.e. crude oil, water and gas), followed by a more extensive set of tests in artificially emulsified flow.

The flow tests were preceded by a short laboratory investigation; the purpose of which was to optimise the chemical surfactants, concentration levels, and mixing methods required to create water / crude-oil emulsions of the type anticipated in the actual oilfield development. The information gained was then used to generate full-scale flowing emulsions (with a similar dependence of viscosity on WLR to the operator's oilfield samples) for dynamic testing of the Vx multiphase meter. Samples of the stable emulsions formed were drawn from the flowloop during testing and their viscosities measured offline using a Haake Falling Ball Viscometer. Figure 16 shows the variation in viscosity with temperature of these artificial emulsions, for different water-to-liquid ratios (WLRs).

To avoid any issue with the possible water cut measurement the separator was filled up with an emulsion at a given WLR and tests were done changing only the gas holdup and flow rate and then a new batch of emulsion with a different WLR was introduced. In order to be sure of a stability of the emulsion redundancy measurement was done in real-time. This shows the challenge that a reference flow loop needs to take into account in order to properly quantify the effect associated with the viscosity and cancel or minimize the uncertainty of the other parameters.

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[26] Accuracy levels of better than 3 – 5% in WLR have been proven with the dedicated detector used by the Vx for Heavy Oil (for all GVFs up to 98%). This "Smart Detector" and its electronics (patented) provide a guaranteed precision of better than 0.01% over one year, or 0.1% over 10 years. In practice, this means that a gamma-ray count rate of 10000 CPS (counts-per-second) recorded on January 1st will again be measured at 10000 ± 1 CPS on December 31st (allowing for the decay time of the radioactive source).

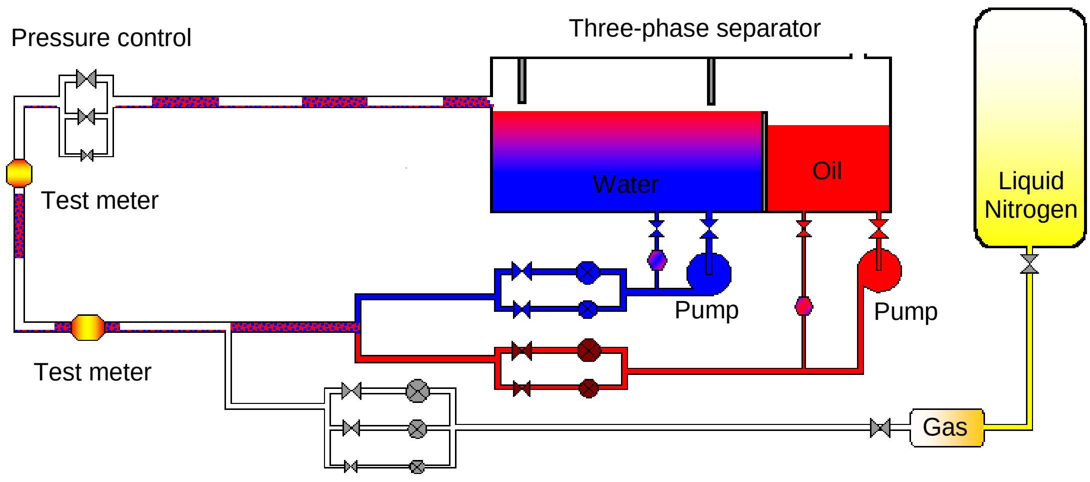

Fig. 15 – TUV NEL Multiphase Facility in its standard configuration, consisting of a three-phase separator (13 cubic meters), test section loop, and single-phase (oil, water, and gas) reference meters. The oil is a mixture of stabilised Forties / Oseberg crude, the water a magnesium sulphate solution and the gas phase compressed nitrogen. The reference uncertainty is ± 1% for oil and water flow and ± 1.5% for gas.

Presented below is a set of liquid viscosity data measured at 35, 40 and 45 ºC. The inversion point was found to lie at around 60%, and it should be noted that no measurements were made above 70% WLR. Above this point the continuous phase was water and beyond the WLR conditions expected by BHP in the future field development. Moreover, this corresponded to lower viscosity measurement conditions where the performance of the meter was already well known.

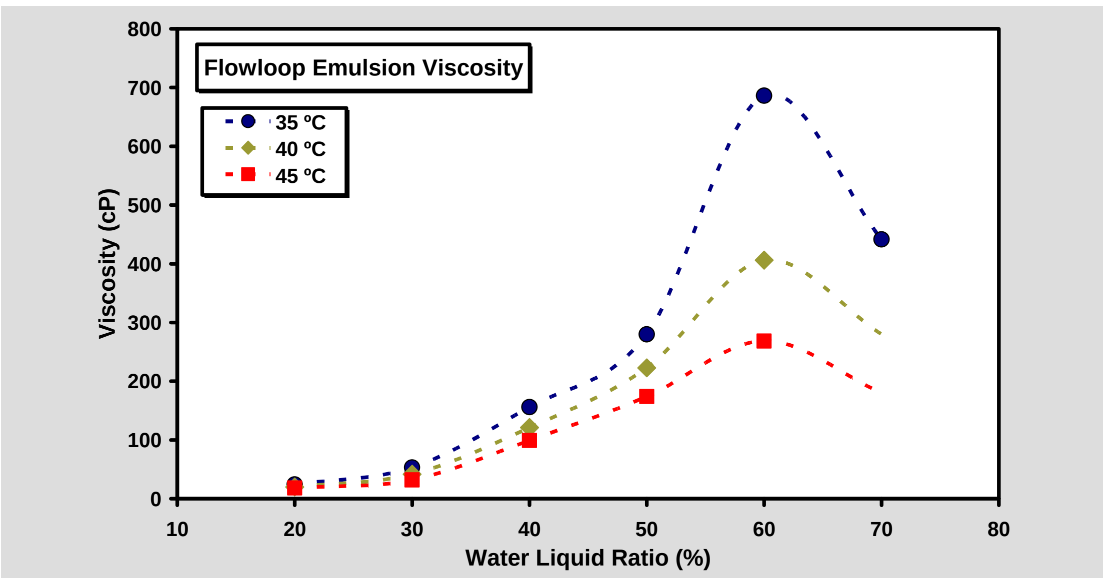

Fig. 16 – Viscosities of artificial emulsions at different WLRs and temperatures – based on extracted flowloop samples.

Based on these and other data measured at different temperatures, it was possible to estimate the overall behaviour of the liquid viscosity versus WLR (Figure 17) for a range of temperatures. It is important to note here that this in itself is already an estimate, and therefore will introduce some errors into the computation of the liquid viscosity. As discussed previously, this in turn impacts upon the total mass flow rate and therefore the individual volumetric flow rates of water and oil. A large increase in the peak viscosity can be seen between 50 and 70% WLR. (It was not needed in practice to run the flow loop at 20 ºC as values of viscosity of the order of 2000 cP at line conditions would have been reached and in excess of the field expectations).

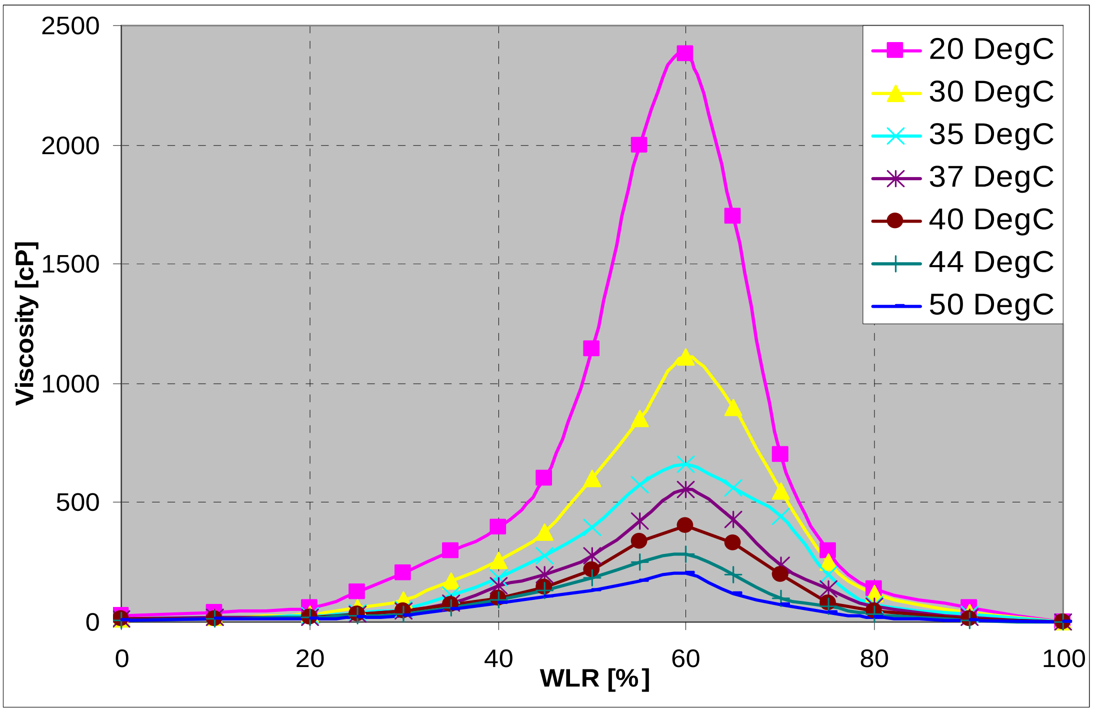

Fig. 17 – Viscosities of artificial emulsions *estimated* over the entire WLR range for different temperatures.

Focussing on the main range of temperatures and WLRs investigated in the present tests, Figure 18 shows where the majority of the flow loop test data lie (green area) and in contrast where virtually no data was recorded (red area). Overall, the current investigation essentially addresses viscosities below ~ 600 cP at line conditions.

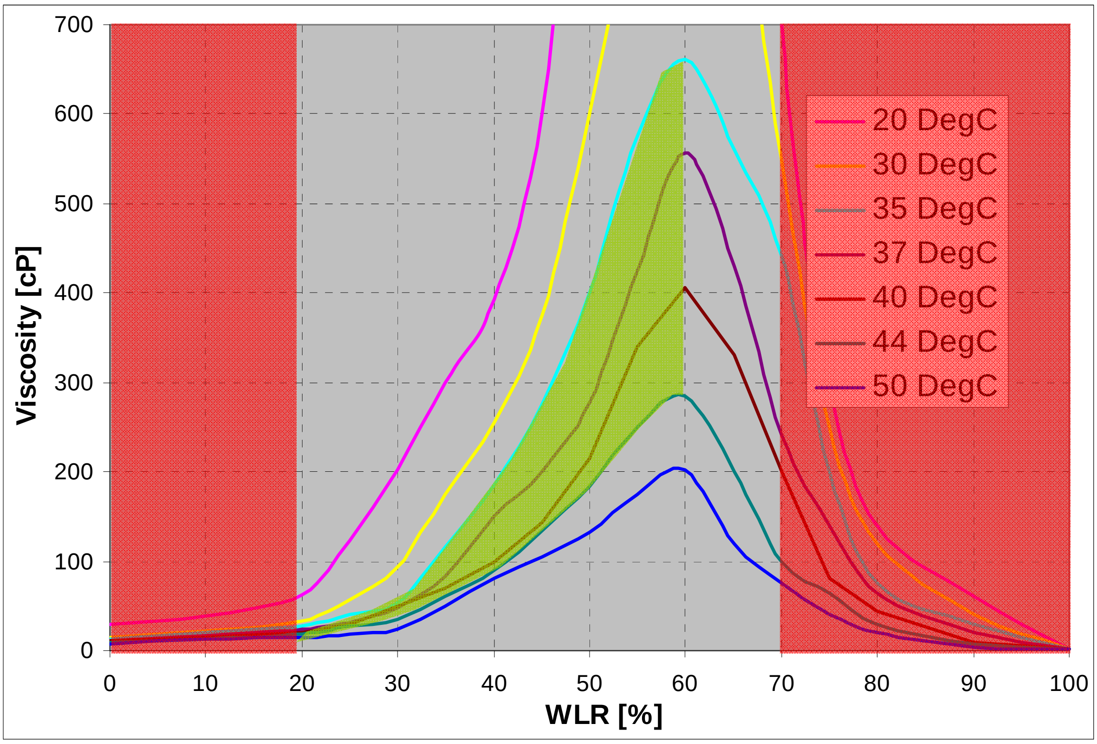

Fig. 18 – Range of viscosities investigated during testing versus WLR and temperature.

The Vx meter was installed on a horizontal 3-inch flowline, downstream of the gas injection point, with entry and exit arranged via 90º elbows (Figure 19). For the standard three-phase (i.e. non-emulsified) baseline tests, the required flow loop conditions were set up and allowed to stabilise for a period of ~ 5 minutes. The Vx meter and reference data acquisition systems were then started simultaneously, and the test point logged for 10 to 20 minutes. The test and reference results were collated and compared offline by TUV NEL and the oilfield operator.

For the emulsified flow tests, only the "water" (entry) side of the test separator was utilised. This was initially filled with 13 m^3 of crude oil, and water added in appropriate volumes throughout the course of the test to generate the required liquid water-cuts in turn (i.e. increasing from 10% to 20% to 30% etc.). Surfactant was injected into the multiphase flowstream in measured volumes, until the appropriate concentration level for each water-cut condition was achieved. The mixed fluids were then circulated for up to one hour, until a stable and uniform emulsion was formed. (The induced turbulence generated during re-circulation proved sufficient for this purpose).

It should be noted that the temperature of the flow loop was well controlled and the flow rate extremely stable during each flow test period; hence, large variations of the viscosity within a test point are not to be expected. As each flow test was less than 20 minutes long, this represents something of a challenge compared to the much longer recording periods typical in the field, where the averaging effect will have tendency to improve the overall performance.

Fig. 19 – Vx meter skid installed in the TUV NEL Multiphase Test Facility (Scotland).

For these tests, a 3-inch Coriolis meter was installed upstream of the gas injection point to measure the mass flow rate of the liquid emulsion. The reference gas flowrate was measured as before, but in this case the liquid volumetric flowrate was derived from the ratio of the Coriolis mass flow measurement and the Coriolis density measurement.

Since the base densities of the oil and the water phases were known from calibration, the density output of the Coriolis meter was also used as an online monitor of the liquid water-cut. (The oil density was corrected where appropriate for the dissolved surfactant content). A reference (Solartron) densitometer on the separator sampling loop provided a secondary density measurement, which was used as a crosscheck of the Coriolis reading. The emulsion water-cut was also periodically verified by manual sampling and offline Karl-Fischer analysis.

All three measurements of the emulsion WLR were found to track each other (within their respective uncertainties) i.e. +/- 1% absolute over the course of the test programme (Figure 20). The viscosity characteristics of the flowing emulsions have already been described (Figures 16 – 18).

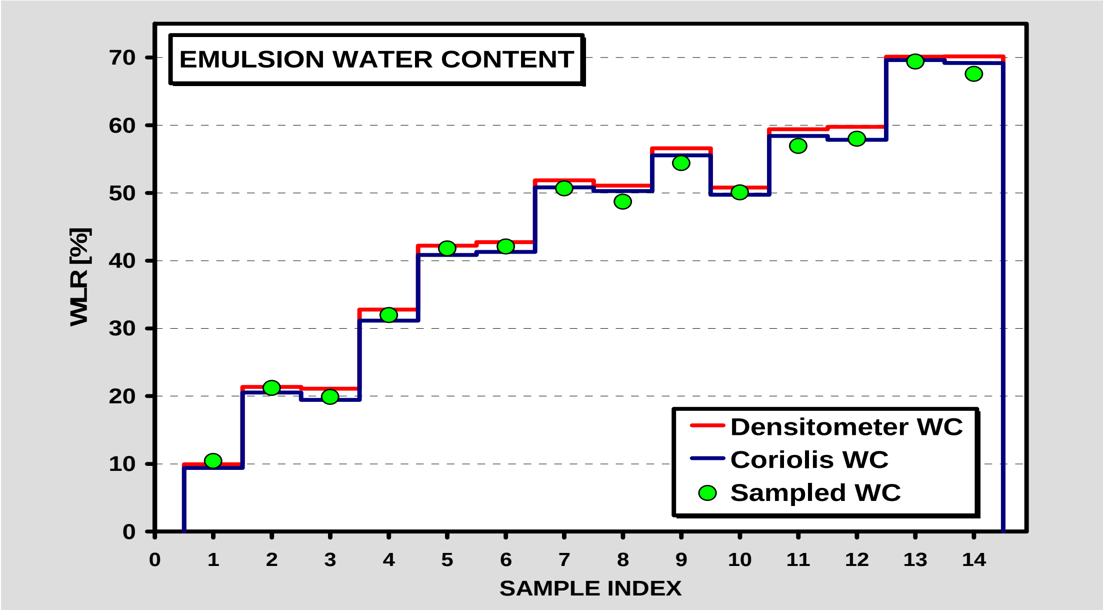

Fig. 20 – Derived WLRs from Coriolis meter, densitometer, and emulsion sample analysis.

Starting at a WLR of 10%, a series of test points were measured (at selected liquid flowrates and GVFs) in a similar manner to the three-phase tests. The water content of the loop was then increased to 20% and the process repeated. The entire procedure was re-iterated for water cuts of 30%, 40%, 50%, 60% and 70%, at which point the emulsion was no longer stable, and was observed to be breaking down rapidly.

From the mapping of WLR versus GVF presented in Figure 21, it can be seen that no GVFs above 95% were recorded and that the WLR was typically in the range 20 to 65%. In terms of Reynolds number, this corresponds to a range of investigation of 400 to 24000 (as per the oilfield customer's specific needs).

However, it should be mentioned that in Heavy Oil environments the GVF is expected to be usually very low; because most of the gas is usually no longer dissolved in the oil and, within the reservoir, has migrated away. Gas-lift is one of the possible production methods in Heavy Oil, but even in gas-lift operations, the GVF rarely exceeds 95% for reasons of economics. Overall, the study performed and reported in this document could have applications beyond the specific scope of this study.

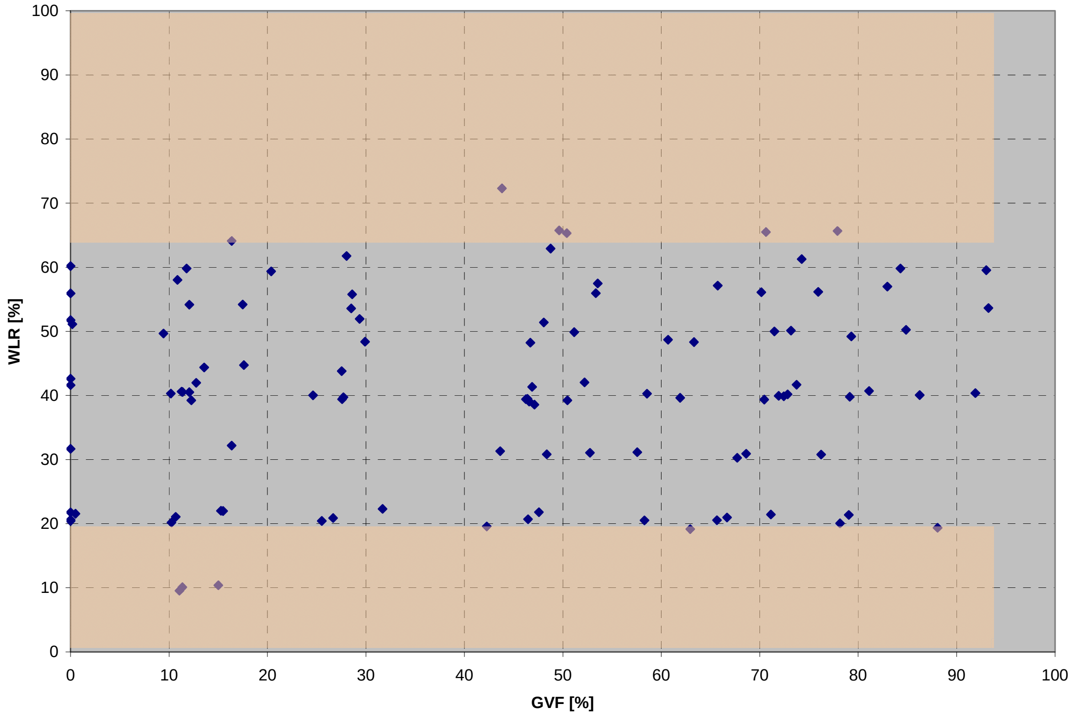

Fig. 21 – Mapping of WLR versus GVF at meter conditions.

5.2.2 Comparison of Reference Data versus Measurement Data

The data were post-processed and are presented in Figure 22 onwards. The WLR is properly measured by the multiphase flow meter with respect to the flow loop reference system. This is, in fact, a vital consideration, as in field use there is no *a priori* knowledge of the WLR. Furthermore, its measurement must be independent of the type of emulsion (water-oil or oil-water) formed. Failing to get the right WLR would lead to a wrong estimation of the liquid viscosity and in turn have a significant affect upon the total flow rate and associated volumetric flow rate. From this emulsion behaviour, study (Figure 18) we can see that such an error could be highly detrimental, especially in the WLR range around 45 to 75%. A separate study [48] also suggests that that the electrical properties of emulsions may be difficult to define with a high degree of repeatability, which could be problematic for some electromagnetic measurement techniques. Gamma rays, on the other hand, interact with the atoms of each component in the beam path independently of the macro structure of the flow (emulsion, foam or dispersed flow), making this a potentially better solution for WLR measurement in these applications.

From an experimental point of view, the analysis performed shows that the overall WLR difference versus GVF (Figure 22) is well within ± 3.5% absolute (at the 95% confidence level or 2 sigma probability) and within ± 2.2% (at the 90% confidence level) for the current GVF range of 0 to 95%. It is important to mention that this uncertainty is for the entire system (multiphase flow meter plus reference measurement). This is a fairly good achievement considering the fact that the WLR uncertainty on the flow loop alone is roughly within a range of 0.5 – 1%. This corresponds then to a multiphase meter uncertainty of 2 to 3% (with a confidence interval of 95%).

With the WLR being accurately measured, the total mass flow rate or the liquid volumetric flow rate can then be checked. Both follow the same trend, since the gas density is small in these tests due to the low line pressure and therefore contributes little to the total mass flow rate. The combined performance of the system flow loop / multiphase flow meter is presented in Figure 23, and exhibits an uncertainty of less than 4% (at the 95% confidence level) and around 3.4% (at a confidence level of 90%).

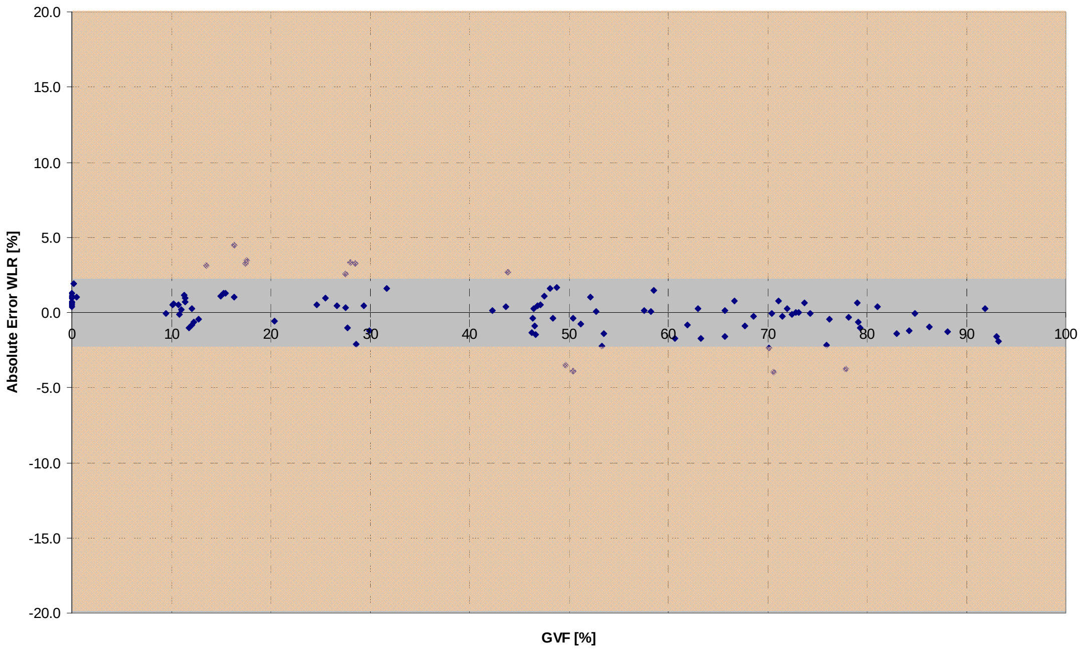

Fig. 22 – WLR uncertainty for the system flow loop / multiphase flow meter with on average a value of better than 2.2% (at the 90% confidence level) or 3.5% (at 95% confidence).

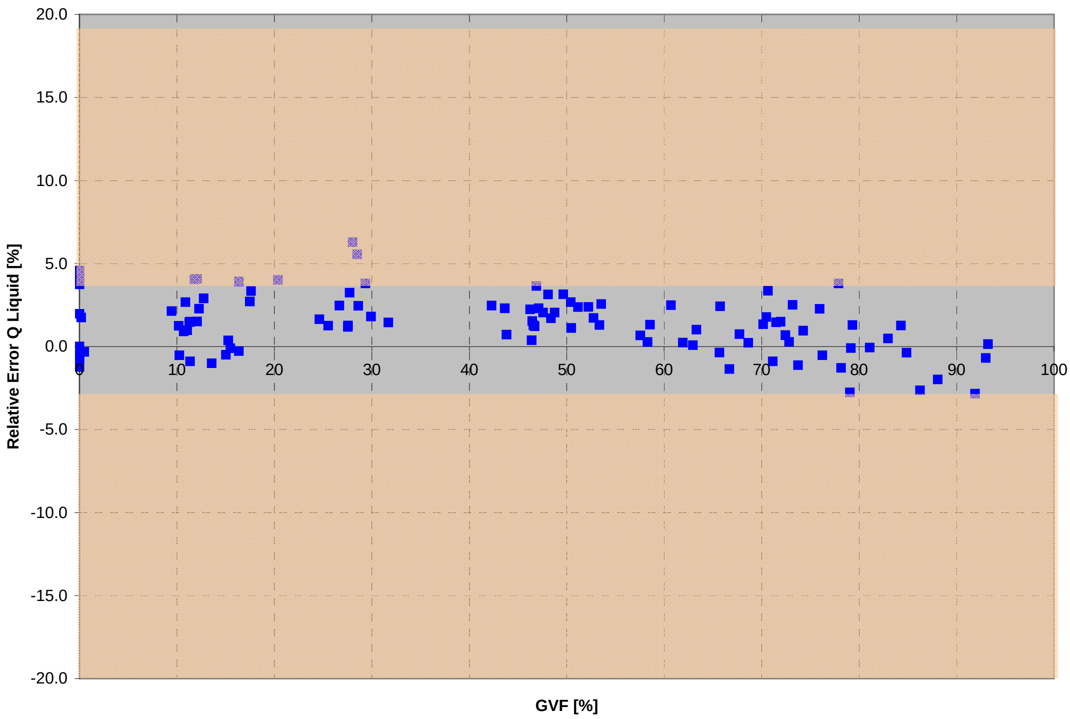

Fig. 23 – Relative uncertainty in the liquid flow rate for the system flow loop / multiphase flow meter with on average a value of better than 3.4% (at the 90% confidence level) or 4% (at the 95% confidence level).

The flow loop uncertainty is of the order of 1 – 1.5%, which means an intrinsic metrological performance for the multiphase flow meter volumetric flow rate within an uncertainty of 3 to 3.5%, for GVFs in the range 0 to 95% with a confidence of 95%. This is already an outstanding achievement under normal circumstances, but is even more impressive considering the heavy oil environment with Reynolds number ranging from 400 to 24000 i.e. covering the entire discharge coefficient range presented in the first part of the document.

It is interesting, after reviewing the proper performance of the meter versus reference, to see the effect of the viscosity and the uncertainty of the viscosity measurement. Shown below (Figure 24) is the same data as Figure 23 but now plotted against Reynolds number.

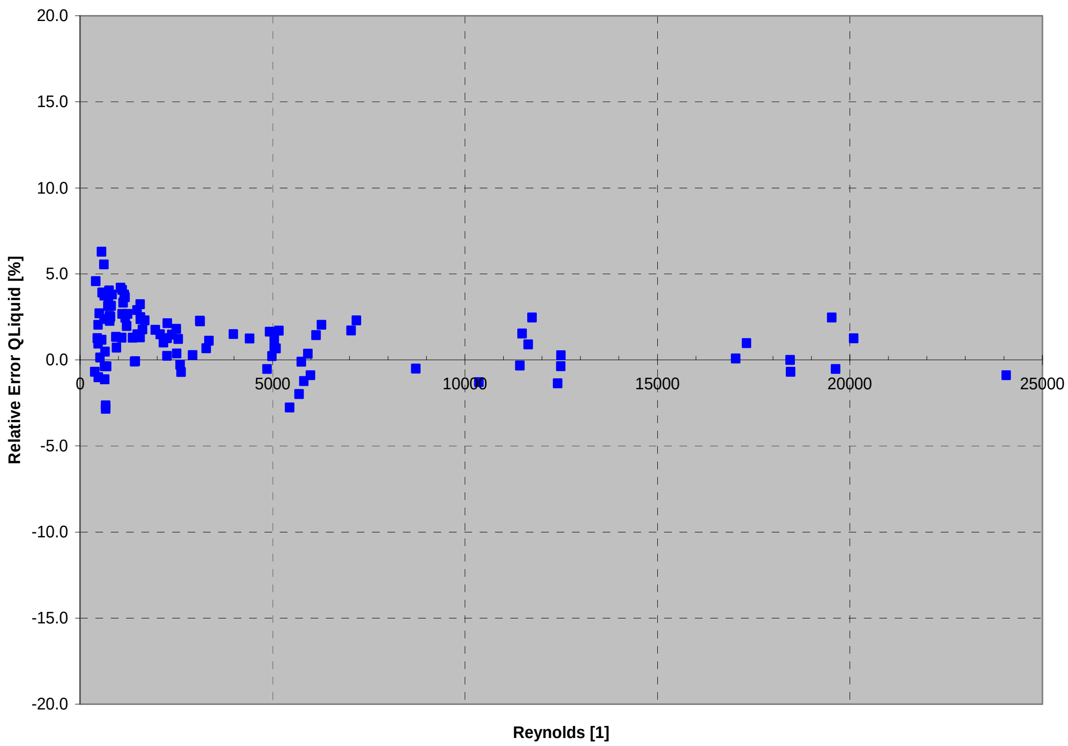

Fig. 24 – Relative Error in the liquid flow rate for the system flow loop / multiphase flow meter, plotted as a function of Reynolds Number.

It can be clearly seen on this plot that most of the uncertainty on the liquid flow rate is at Reynolds number, below 1200. Several statements can be made based on this observation. Firstly, the combined uncertainty (flow loop / flow meter) in liquid flow rate is less than 2.5% from very high Reynolds numbers down to around 1500. It can therefore be stated that the volumetric flow rate (or mass flow rate) is known to better than 2% for Reynolds numbers ranging from 1500 to beyond 25000.

Below a Reynolds number of 1500, the distribution of differences appears to be increasing, with a systematic bias (overestimation) of the real flow rate noted. In other words, the "discharge coefficient" estimated in this range (as a function of viscosity) seems to be too high (based on Figure 7 presented earlier). This suggests that the estimated viscosity measurement is low compared to the real value. The viscosity data in this range of Reynolds number are quite large and, as noted previously, the viscosity was not measured on-line but estimated with an assumed behaviour for the viscosity curve. This leads to the following statement from a practical and theoretical point of view: an understanding and a proper measurement of the liquid viscosity is a key factor in low Reynolds number applications in order to reduce the error associated with the discharge coefficient. There is no fundamental reason to consider 1500 as some cut-off criterion, but simply note that failing to input a proper viscosity measurement leads to an additional uncertainty of roughly 2% on the flow rate. In the case of the Vx technology, this increase can be considered as marginal in the sense that the volumetric flow rate uncertainty is simply shifted from an already outstanding value of 2% to something in the range of 4%, which is still excellent overall. The results also confirm the level of error predicted theoretically earlier in this document by assuming an uncertainty in the viscosity of the order of 10%.

As a general comment, the main step for success in Heavy Oil or viscous flow environments – in terms of metrology – is to have firstly a proper water cut measurement that is insensitive to the emulsion or phase mixture. Ideally, the multiphase meter WLR uncertainty should be as small as possible and at least less than 2 – 3%. (WLR uncertainty above 5% propagates to large an error on the estimation of the liquid viscosity). Another cornerstone for success is to have a proper understanding of the effect of viscosity on the response of the multiphase meter. It is hoped that this paper clarifies finally the effect of viscosity on multiphase meters based on differential pressure measurements; such as Venturis, Orifice plates etc.

Only when the uncertainty of the meter is tight enough, say within 2 – 3% on total mass flow (or liquid flow) rate, then the effect of the viscosity can be understood and reduced by a proper measurement of the liquid viscosity. Based on the present experience and theoretical analysis, an error in the viscosity measurement of less than 10% will add around 2% to the overall uncertainty, and this can still be tolerable depending of the application.

Finally, it should be noted that the measurement of the liquid viscosity could be approached in different ways. One such technique, used in the field on a daily basis, has been presented here i.e. where a proper viscosity curve is determined as a function of WLR at different temperatures. This can be performed before or after the flow test measurement, knowing that the Vx technology permits complete re-processing of the results, even after the raw data has been recorded. Of course, this is not the only approach possible but, as it would be too lengthy to describe the other techniques within the present paper, it is proposed that this subject be addressed in a further publication. In the meantime, it should be emphasised that while several mixing laws exist and could potentially be employed, these should be thoroughly evaluated before implementation. While some mixing laws have been found that are suitable for fluid viscosities in the range of 100 to 600 cP at line conditions, none have been identified that are yet capable of covering all heavy oil fluids in a reasonable way. Even worse, all of these failed to estimate the viscosity – even within 20% relative error – when its value exceeded 1000 cP. It is therefore fundamental to add these input parameters to any study or work in Heavy oil, and this should not be underestimated.

6 CONCLUSIONS

The industry is in need of a technological solution suitable for multiphase metering in heavy oil. The solution offered here consists of a combination of dual energy gamma ray and Venturi multiphase flow meter, combined with a complete field fluid service identification and determination of the liquid viscosity at various temperatures.

The solution based on the Vx Technology provides, in a Heavy oil environment, similar benefits of logistics and safety obtained in lighter oil, condensate and wet gas well testing. It is possible to obtain a tight range of uncertainty even in conditions of viscosities up to 1500 cP. Much higher values have been also successfully tested in the field.

The better the determination of liquid viscosity at operating conditions, the better the metrological performance of any Venturi based multiphase or single phase flow meter. A field service to attend this need is available and should be used to avoid significant errors on liquid flow rate measurements.

It took several iterations, a number of flow loop campaigns and seven years of engineering and research efforts to obtain and validate a model based on a discharge coefficient for viscous fluids in the multiphase environment. The consistency of the model, against the actual field flow regimes and fluid properties, must be addressed at all times for a robust deployment of the technology.

Recent flow loop tests with high accuracy have allowed adjustment of the discharge coefficient versus the Reynolds number for some designs of Venturi, but such changes can not be implemented blindly after the analysis of limited flow loop testing performed in the wake of a particular projects, as the actual flowing conditions in heavy oil will go way beyond the investigated envelope of any flow loop work.

Operations in heavy oil environments in Brazil, Chad, Congo, Venezuela, Mexico, Kuwait etc. are ongoing on a routine basis and the experience gained has been a key to the success of the metrology.

It has been identified in this document that heavy oil, or more appropriately viscous oil, with a high associated viscosity can be easily quantified if the physics of the multiphase flow is properly considered. It has been shown how simply the impact of the viscosity can be taken into account within the Vx technology and how this can reduce errors to maintain an overall high accuracy. This therefore represents an extension of the Vx technology to high viscosity after many years of significant effort. This also means that the same hardware can be used and the associated training can remain the same. Essentially, the reliability and effort spent over the last 7 years of commercialization are still valid and beneficial for this new product.

The Heavy Oil Business presents a new opportunity for Vx Technology (PhaseTester / PhaseWatcher) application. The enormous experience collected on flow loops, and worldwide with the well-service solution (PhaseTester for heavy oil well testing operations), position Schlumberger as a leader in well testing operations for Heavy Oil. Already “Exploration to Production” well testing operations have been performed around the world, in locations such as Brazil, Chad, Congo, Venezuela, and Mexico. All of them have joined their experiences in Heavy Oil operations using Vx to build up knowledge and extend the actual operating envelope of the Vx technology in Heavy Oil operations.

The benefits of this technology are accurate measurement from exploration to production, better estimation of the reservoir, a real-time solution with cost reduction by operation. Few suppliers, based on the available publications, are capable today of quantifying and demonstrating the entire performance of their metrology and even fewer have an in-depth understanding in Heavy Oil. Through the unique building of the Vx Technology for different markets, from Black Oil to Gas and Heavy Oil, it is possible to identify clearly the uncertainty. Having a simple measurement system that is predictable offers the advantage of a better understanding of the performance of the MFM for the life of the well and the ability to manage the accuracy within a narrow boundary. The Vx Technology enhances the PhaseTester and PhaseWatcher to become the first meters capable of accurately measuring three phases (oil, water, and gas) from Heavy Oil to Condensate production.

Overall, dealing with Heavy Oil is one step or one order of magnitude more challenging than dealing with high GVF (i.e. gas volume fractions above 90%), which is already an order of magnitude more challenging than dealing with classical black oil fluid. This explains also why there are very few manufacturers proposing a solution for Heavy Oil, and virtually only one currently dealing on a daily basis with Extra-Heavy Oil and Bitumen with success.

Finally, from a purely metrological point of view, it was possible to demonstrate that, in a well-controlled environment with Heavy Oil and emulsion conditions, the meter could perform with a WLR uncertainty of better than 2 – 3% (at the 95% confidence level) even with Reynolds number ranging from less than 400 to higher than 24000 and viscosities at line conditions varying from less than 10 cP to more than 600 cP.

An uncertainty of 2 – 3% in volumetric liquid flow rate was also demonstrated, for Reynolds numbers ranging from 1500 to beyond 25000. This uncertainty becomes only slightly higher, at around 3 – 4%, if the viscosity is not well known or measurements are made in the lower Reynolds number region of 400 to 1500. This is still an outstanding result and shows that the combination of Venturi with nuclear measurement is one of the most robust combinations on the market today for tackling the challenging Heavy, Extra-Heavy and Bitumen business.

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