Worldwide Review of 10 years of the Multiphase Meter Performance Based on a Combined Nucleonic Fraction Meter and Venturi in Heavy Oil

A simplified version of 10 years experience with exotic fluids

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1. ABSTRACT

70% of the oil in place around the world is classified as Heavy Oil (< 22.3 API). Heavy Oil has one common characteristic that is to be viscous and very challenging to produce. It is therefore essential to have the adequate equipment to first monitor and then be able to optimize the production.
The gravity contrast being smaller between oil and water any system based on separation is then strongly challenged in this environment. Most of the time the fluid is going through pipe restriction (valves, elbows) and often stable emulsion is created. On the other hand, the operation of <u>in-line multiphase flow meter (without any separation)</u> can sidestep most of these issues, as no separation is required and therefore have the benefit of being compact, with lower CAPEX and OPEX.
Inline Multiphase flowmeter became an alternative that has been contemplated to be used in these conditions since the end of the 90's and they have more and more been accepted as an alternative to the conventional equipment by the oil industry. It became quite successful over the last 5-10 years.

Venezuela has been one of the first areas to use these multiphase meters. Over the years the business has been growing worldwide (Africa, Canada, Latina America, Russia…). If the largest quantity of multiphase flowmeters is installed or used in oil wells with a liquid viscosity generally much lower than 500 cP at line conditions, this paper will highlight the performance from Heavy Oil Cold production, to Extra Heavy Oil with or without diluents, and up to bitumen in Hot Production. Additionally performance versus fiscal metering will be demonstrated. This paper will highlight the strength of the technology and then the main feature which allows working in any type of fluid under any type of conditions (foaming, emulsion, dispersed flow).

The objective of this review of a combined nucleonic fraction meter and Venturi is to provide a correct, fair, and accurate description of the overall performance of these multiphase flow meters. This document is based on information published in the previous years and presented by manufacturers or users. The goal is to answer the persistent questions that arise in upstream production measurement: "Why should we use this multiphase flow meter rather than the other one? Does it work with or without emulsion present? What could be the best combination of technology?"

This paper will address experience acquired with an innovative Nucleonic Fraction Meter combined with a Venturi around the world and showing the performance of the meter in well known conditions (several flowloops in Heavy Oil conditions around the world), then focusing on field experience and demonstration of the robustness of the technology.

2. OVERVIEW OF THE HEAVY OIL BUSINESS

Heavy oil is a type of crude oil which is very viscous and does not flow easily. The common characteristic properties are high specific gravity; low hydrogen to carbon ratios, high carbon residues, and high contents of asphaltenes it may contains heavy metal, sulphur and nitrogen. Heavy Oil has a high boiling point and a high molecular weight and usually over 60 carbon atoms in my molecules.

Figure 1: Heavy Oil[1]

Industry defines heavy oil and extra heavy oil as having an API gravity between 22.3° and 10° (920 kilograms/cubic metre to 1,000 kilograms/cubic metre), and extra heavy oil as having an API gravity of less than 10° (higher than 1,000 kilograms/cubic metre) with a viscosity lower than 10,000 cP The bitumen is defined with API lower than 10 and a viscosity higher than 10,000 cP.[2]
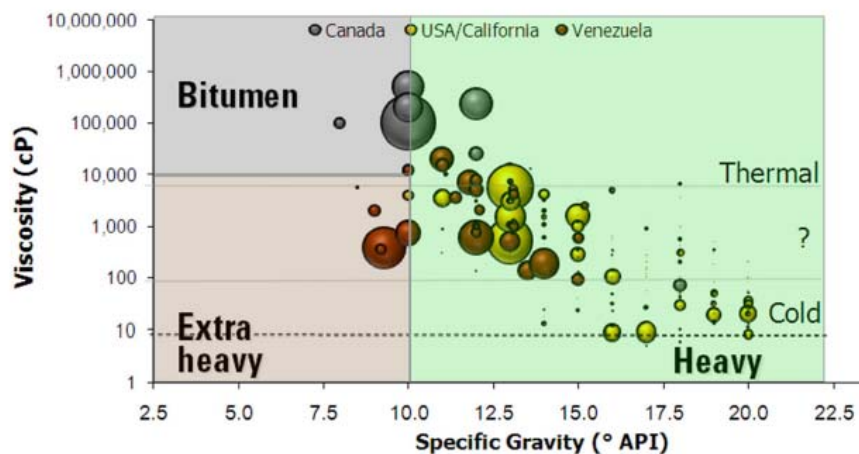

Figure 2: Heavy Oil Definition, bubble size indicates production rates [Ref 42]

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[1] Heavy Oil could be as viscous as a honey, and Extra Heavy Oil can be compared to the tooth paste up to peanut better when the bitumen is much thicker!
[2] The Canadian government has only two classifications, light oil with a specific gravity of less than 900 kilograms/cubic metre (greater than 25.7° API) and heavy oil with a specific gravity of greater than 900 kilograms/cubic metre (less than 25.7° API).
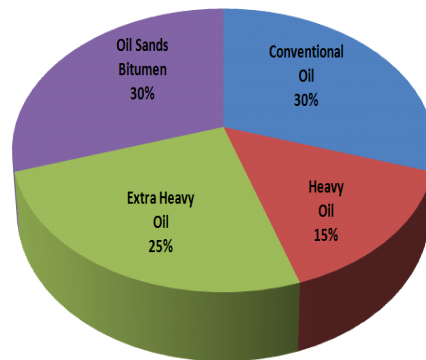
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Total World Oil Reserves

Figure 3: World Wide Reserves (Oil In Place) [Ref 43]

Why the rush on Heavy Oil? The answer is very simple the need for Energy. The IEA World Energy Outlook for 2008 and 2009 show Global energy demand growing by 40% between 2007 and 2030 with oil use rising by about 25%. On the supply side, Oil production will reach around 100 MMbpd in 2030, requiring roughly 15 MMbpd additional versus current production but with the declining of the field in production it is estimated up to 60 MMBPD of gross capacity additions. Then it is reasonable to see this race to access the Heavy Oil which is most of the time land for the largest reserves (Venezuela, Canada, Russia, Kuwait, Saudi, Mexico, China, Indonesia, Iran, Iraq, USA to name the common one) to play a significant role in the future hydrocarbon production stream.
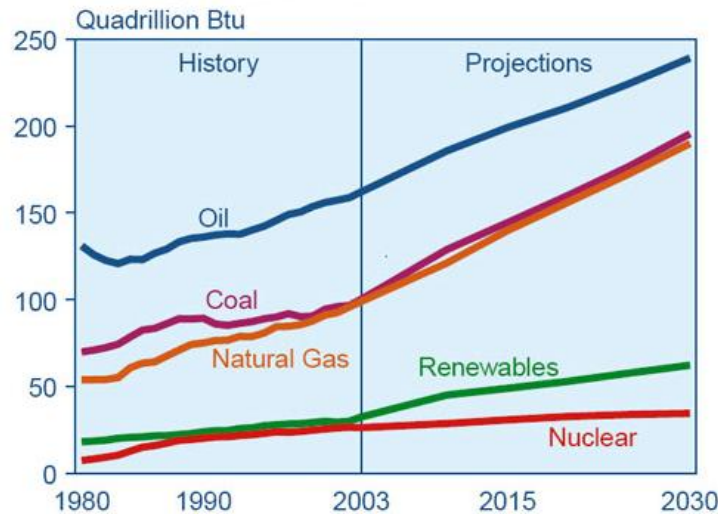

Figure 4: Projection of the energy needs and splits up to 2030 (Quadrillion Btu)

It is a fact that non-conventional reservoir well testing operations require special methods and equipments. 10 years ago, heavy and viscous oil reserves were considered non-economical resources or poorly attractive. Nowadays, oil companies based on the increasing need of energy worldwide started to invest more in this business considering as the premise: Heavy Oil is the future area to help to

renew reserve of each oil company. This can be already clearly seen with more than 26 different oil companies (national or not) present in Venezuela. Meanwhile, producing heavy oil with an objective of a fair recovery factor (>20%) requests a large up-front investment whatever the techniques used and a proper monitoring in real-time could be cost effective. The only way to target this business and get accurate and high quality data is to use multiphase flow meters. Conventional techniques are extremely limited in this type of environment. A specific point of Heavy Oil Market is long life assets (>40 year project life) with a typically Return on Capital Expenditure positive based on barrel of oil above 50-60 $ for thermal production and ~40 $ for CHOPS. A bit specific but it should not be forgotten that the collapse of the gas price by a factor 2 to 3 from 2008 plays a role in this outstanding ROI and increase of quest for Heavy Oil.

Heavy Oil is a sustainable market from an economics point of view. Heavy oil makes up the largest source of relatively untapped flowable hydrocarbons available today that can help to meet quickly the demand if economical recovery solutions can be provided. Furthermore, Venezuela oil reserves (proven) is now larger than Saudi Arabia (respectively 297Bn , and 265 Bn)[3] which represent almost for each of them the entire proven reserve of Iran & Iraq (151Bn & 143Bn) in comparison Norway or UK are respectively at 10 Bn, and 4.5Bn.

Meanwhile the Orinoco Belt Extra Heavy Oil (Venezuela) and the Athabasca oil sands (Alberta Canada) contain large amounts of heavy oil which is requiring specific techniques for the production and it will be highlighted later.
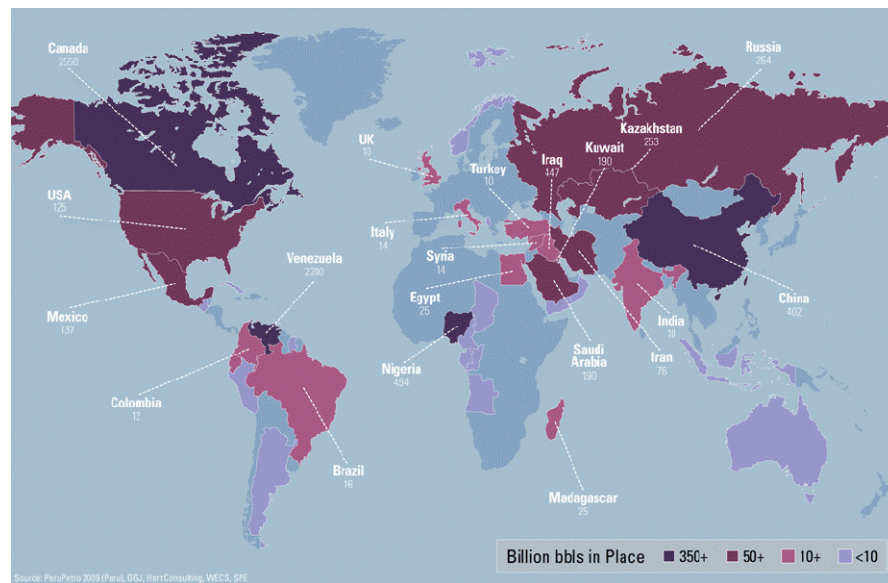

Figure 5: Heavy Oil in place around the world.

The oil in place reserve (not proven now) is estimated to 9-13 Trillions of oil barrel in place, Canada & Venezuela are currently having more than~5 trillion (respectively 2.5 and 3.2 Trillions). Overall Canada and Venezuela hold more than 80% of the known heavy oil and extra Heavy oil reserve. This production is not the easiest for sure, the fluid is very viscous and lifting process needs to be in place either by providing mechanical energy (pumping system or gas lift) or by reducing drastically the viscosity of the fluid at reservoir level and then be able to lift easily to surface the fluid. As we will see, using one technique or another lead to fundamentally different recovery factors and this is critical from the economics. This could also be driven by government asking a certain target, for example in Venezuela a

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[3] All are 2011 numbers, and for information Canada has 175 Bn

recovery factor is required for any new development to reach at least 20%. It should be mentioned that in some areas of the Orinoco belt today the cold production does not allow recovering more than 2% (natural flow) with any EOR.

	Typical Recovery Factor
ORINOCO	
Cold production	< 10 %
Steam flood	> 7 %
ATHABASCA	
Mining	>85 %
SAGD	>70 %

Table 1: Some current typical recovery factor

3. WHY SHOULD WE USE A MULTIPHASE FLOWMETER MORE THAN A SEPARATOR?

Today, the main issues are the production and productivity of the reservoir in Heavy Oil. All agree that well testing operations in heavy oil wells are very complex and most of conventional surface well testing equipment is very difficult to use in those operations to get reasonable accuracy. It is complex to run a test separator and its measurements are not reliable at all due to the vessel instability, low pressure, moving parts, calibration, foaming, emulsion, or other separation issues.

The main challenge is basically that the oil density is very close to the water density and therefore the process of gravity separation in the conventional separator is not anymore working properly. Added to this that most of the heavy oil is very viscous this should lead to have higher retention time (i.e. large vessel, and cost associated). Another associated phenomenon is that the bubbles of gas trapped inside the fluid cannot anymore flow freely inside the liquid and stay in gas phase but trapped inside the liquid. This is obviously leading to large overestimation of some of the liquid flow rate and by consequence then underestimate gas rate. Finally, it should be mentioned that phenomena of emulsion are appalling working conditions for any separators without any injected diluents or desemusifier.

Additionally, Oil operators started to be concerned about technical problems to exploit such heavy and viscous fluid, including deepwater environments. The first problem is how to bring this oil to surface. PSP, ESP in cold or hot production came out with solutions in combination with new recovery techniques such as Steam Assisted Gravity Drainage (SAGD). The second problem is how to evaluate the reservoir productivity including in the first stage of exploration.

Based on this numerous advantage the multiphase technology has been one of the earliest technology adopted by companies working in Heavy Oil. The main highlight will be providing better surface measurements than a separator, overcoming heavy oil measurements limitations, providing reliable measurements of all fluids, acquiring data during entire well testing operation for better reservoir interpretation, reducing overall cost of well testing by using lighter, mobile equipment, reducing well testing time by rapidly stabilizing the test separator flow. The Venezuela market with experience back into mid 90's is a perfect example. The fact that minimum or none exploration risk exists, and as mentioned previous these are long life reservoir production, and stable production profiles makes these oilfield projects extremely attractive.

Specifically from the Vx technology, the multiphase flowmeters is very simple and based only on physical fluid parameters. The core of the Vx Technology is an in-line multiphase meter acquiring data since the well opening to the shutting independently of water-cut, emulsion, foam or slugs that comes through. Vx Technology comes as an easy and practical solution for that kind well testing operations. One of the main advantages from the technology point of view is the independency of the measurement to phase inversion and continuous phase (in other word to the WLR value). The main benefit from client point of view is a better understanding on the emulsion behaviour demonstrating and helping him to review and adapt the production with other applications/devices such as pump. It is giving higher frequency response and better flexibility to meet Well Testing target required by government's body with a mandatory requirement about the number of well to be tested by month. Finally, it is the capability to get higher accuracy and more versatility to control the production which is becoming a key differentiation with the other metering techniques on the market...

Venezuela was a pioneer in the use of Multiphase flowmeter and as early as mid 90's some oil companies have been looking for multiphase flow meters to be able to monitor the oil production. Back to this period they were barely any multiphase flowmeters on the market (this was reduced to 1 or 2 manufacturers) as true commercial product. For more than 10 years this country was the leader in use of permanent multiphase flowmeters and essentially in two fields in the Orinoco Belt.

Use of the multiphase flow meter as a periodic well testing was not then anticipated or perceived as providing good information yet. ConocoPhillips (Ref [44]) shown the rate of failures and then the cost associated with the use of early multiphase flowmeter design. This was not a plug and play concept; the oil industry was in the infancy and learning process with this new equipment. The situation changed from a manufacturing point of view at the turn of the millennium with more manufacturers on the market, however as we will see later very little were capable to address the Heavy Oil market.

In the meantime, from a sales point of view, the light oil countries (whole Middle East driven by Saudi Arabia) started to order multiphase flow meters by large quantities for the use in the light oil, and greatly improve the production or back allocation with multiphase flowmeters.

One exception with PDO Company (Ref [45]) showing the effect of having misjudged or anticipating the use of a specific type of meter in its field and led to a deterioration of the back allocation factor demonstrating that performance of multiphase flowmeter need to be carefully assess technically in well controlled environment and not only judge from financial point of view.

When North Sea was contemplating viscosity in the range of 100 cP, some countries such as Brazil and Venezuela built flowloop facilities to be able to test meters in high viscous fluid (>1,000 cP). In 1998, it was already possible to test in CEPRO (PDVSA Flowloop close to Las Morochas – East Venezuela-) fluid with viscosity above 3,000 cP (line conditions). In Atalaia (North Brazil), CENPES (Research Group of PETROBRAS) had a same type of facility where the oil viscosity can be selected. Both flowloops used dead oil and water, and live gas. It should be noted that any meter to be approved for use in PETROBRAS needs to be tested on the Atalaia facility and passed the criteria (today in Multiphase only Vx technology has been approved and granted by INMETRO). This is reflected by essentially only two main manufacturers of multiphase flowmeter present inside the country[4].

PDVSA adopted a different procedure and decided to open in 2004 a JIP to test multiphase flowmeters; they contacted all manufacturers but among them only two worldwide well-known companies[5] were present. In total 4 meters (2 additional local suppliers using partial separation) were tested in same time. This lack of participant is showing the cold feet of most of the providers of solution in multiphase flow raising some doubts about some techniques of measurement available today and some issues about

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[4] Schlumberger (Multiphase), and ROXAR (Wet Gas Metering)

[5] Schlumberger, and Flowsys

real performance in such environment. The success to this test did not bring much more sales for Schlumberger and probably shown a limitation of this type of JIP project.

At the opposite the growth in periodic well testing was opposite and Venezuela is among the 5-10 best area in periodic well testing from Schlumberger. Numerous papers in collaboration with PDVSA were published in many conferences addressing the Heavy Oil, Extra Heavy Oil with or without Diluents proving this above statement.
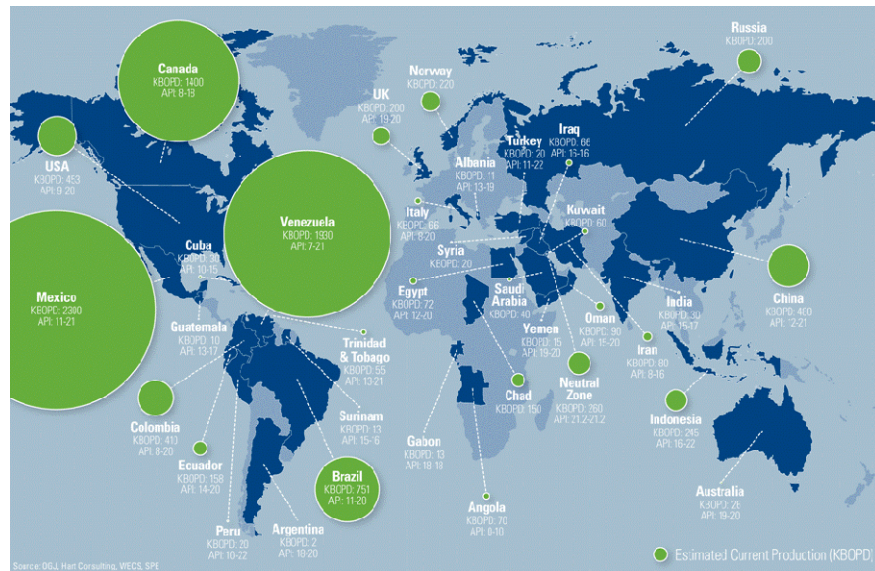

Figure 6: Heavy Production about the world

What was the situation in Canada at that time? Close to nothing, the interest for multiphase flow technology arrived around 2005. Discussions led to the test of few multiphase flowmeters (in thermal production), the main issue was that the high temperature which limit to say the least the use of some meters specifically the one with some sensors in direct contact with the fluid.

Furthermore, the fluid present inside the pipe is usually an emulsion at high temperature and then reduce further the number of technology working in this domain. In the paper [Ref 46], authors demonstrated based on public information available around the world that electromagnetism will have for example a challenge to work in this type of environment; furthermore any technology using cross-correlation (i.e. looking for a signature inside the main flow) will not work.

31. Schlumberger Deployment of Multiphase meter in Heavy Oil

Schlumberger was involved very quickly with this type of viscous oil, as explained later some experiments were carried on flow loop CEPRO (High viscous) as early as 1998 to demonstrate the strength of the model embedded inside the Vx technology for heavy oil application.

Schlumberger gathers the heavy oil knowledge mainly through the multiphase well testing experience as early as 1999 in this most demanding and challenging application. Additionally, Venezuela was among the 3 first countries used to deploy the Vx technology as early as 1999. Today, Schlumberger has made more flow tests than anybody else even if the permanent sales do not reflect totally this knowledge and experience yet.

Data gathered around the world give a trend on the Heavy Oil business from Periodic Well Testing point of view:
- more than 60% of the well have a API from 8 to 18,
- more than 80% of the jobs are done with a GVF lower than 50%.
- more than60% of the data have a WLR lower than 20%.
- more than 80% of the wells have a very low GOR lower than 70 scf/stbbl.
- more than 60% of the wells have a temperature within 50 to 75 degC (excluding thermal production which in this case is above 150 degC)
- more than 80% of the wells have a pressure lower than 100 psia!

Furthermore, Schlumberger has a disseminate experience much larger than anybody else and a consolidation of this experience is permanently ongoing, including special procedures to extend the initial working envelope of the multiphase flowmeter. The continuous improvement versus time led to gradually have a better accuracy, service quality and improvement in interpretation.
Heavy Oil is the business of the near future, the Vx Technology due to the simple combination of a Nucleonic Fraction Meter and Venturi is simple and a perfect solution to this challenging environment. Additionally, Schlumberger Fluid Research Centre in Edmonton (Canada) is the centre of competence for the Heavy Oil Fluid Behaviour, when Regional Technology Centre in Calgary (Canada) and Faja Centre of Excellence (East Venezuela) are more in touch with the reservoir characterization and EOR process.
Finally, Heavy Oil for Schlumberger was approached sequentially through the understanding of different types of Heavy Oil production (cold or hot production) with an effort over the last 5 years from Engineering to Field, including training continuously our team to address this specific market.

The operating conditions where the Vx Technology has been used in Heavy Oil operations are extremely versatile. This is due to the key points of the Vx Technology to address different market with the same hardware and therefore the same training for our client and same maintenance. Already, many clients recognized PhaseTester Vx as a surface meter for heavy oil periodic well testing operations. The field operations are going from exploration to production well testing operations around the world in Heavy Oil. This is again a unique experience in Multiphase Business.

4. SOME DESCRIPTION OF HEAVY OIL RESERVE AROUND THE WORLD

Heavy Oil is a generic term but beyond the world there are some different type of fluid and production, we want through this chapter briefly highlight some facts and the versatility of the production and the challenge of a multiphase flowmeter.

41. North Sea

Several fields in the North Sea contain heavy oil deposits in the range 20 - 25° API. More than 50% of the reserves in place are Heavy Oil. Water flooding is the main method used. The key challenges to production and metering have been identified as the formation of stable, viscous emulsions (up to 5,000 cP), the deposition of wax at low temperatures below 30 °C, the entrainment of gas in the viscous oil phase and the excessive formation of foam.

42. China

China has significant heavy oil deposits of more than 400 billion (oil in place). Oil viscosities range from 100 to 100,000 cP and, while high in resins, they generally have a low wax and asphaltene content. The first commercial heavy oil development in China was initiated in 1982, then the first cyclic steam injection pilot tests was be successful. Heavy oil production in China has been consistent for the last decade at 480,000 bopd, and oil recovery efficiency around 18%.

43. Canada

Canada has one of the world's largest reserves of oil sand, heavy oil and extra-heavy oil with around 2.5 Trillion barrels in place. These heavy oil reserves have a low API gravity of 8 - 18° and high viscosities of between < 1000 cP and >1,000,000 cP Most of the heavy oil reserves in Canada are oil sands. These oil sand reserves are mainly located in Alberta region, and cover an area of around 140,000 km^2n (Athabasca, Cold Lake, and the Peace River). The Alberta reserves amount to at least 85% of the world's total bitumen reserves.

There are four main methods used to extract the bitumen; namely surface mining, Enhanced Oil Recovery (EOR) technology, Cold Heavy Oil Production with Sand (CHOPS), and Steam Assisted Gravity Drainage (SAGD) with several variations around this theme. In Peace River and Cold Lake areas, oils sands are found at depths of around 2300 feet, and bitumen production is attained by using Enhanced Oil Recovery (EOR) techniques. Steam Assisted Gravity Drainage (SAGD) is commonly used, and this has allowed bitumen production rates to increase.

44. Brazil

The Santos and Campos basins off the coast of Brazil are estimated to hold significant volumes of high viscosity crude oil, approximately 16 billion barrels of heavy oil. Most fields lie at water depths of around 1,500 m with reservoir temperatures of ~ 50 °C. The rock is typically unconsolidated sandstone. Most recent discoveries have API densities in the range 13 - 17°, with viscosities between 20 and 400 cP at reservoir conditions.

Electric-submersible, hydraulic and subsea multiphase pumps, together with heated or insulated flowline, are seen as the key to production of these viscous deposits. Artificial (gas) lift of the heavy oil is also necessary, since the high viscosity oil, which may also contain emulsified fluid.

45. Venezuela

Venezuela's Orinoco belt (57,000 km^2) is estimated to hold around 3.2 Trillion barrels of extra-heavy oil (2010) with densities in the range 6 - 12° API. This represents the largest accumulation of heavy oil and extra heavy oil in the world. Similarly to Canadian heavy oil reserves, Venezuelan heavy oil is mainly found in unconsolidated sandstones. Venezuela has supplanted Saudi Arabia by 2008 as the country with the world's largest oil reserves (proven).

New production technologies are currently being developed to overcome the decrease in productivity. The favourable reservoir conditions in Venezuela, in comparison to those in Canada, have allowed the use of multilateral wells for the extraction of heavy oil. Additional pumping systems are often used such as ESPs, hydraulic pumps. However, this technique may not be suitable for extra heavy reserves due to high pumping costs, emulsion formation, and production towards the hot techniques is undergoing.

46. Middle-East

It is estimated that there are around 3 trillion barrels of heavy oil contained in carbonate formations worldwide, and 1 trillion is in Middle East (Saud Arabia: 190Bn, Iraq: 450Bn, Iran: 80Bn, and Kuwait: 190Bn for the most important). These heavy oil reserves are moderately high viscosity and vary from around 10 - 20° API gravity. Some experts believe that the amount of heavy oil deposits has been underestimated due to the large focus on the light oil reserves. Many EOR techniques have been successfully used in this region such as CO_2 injection, steam flooding, horizontal well technology and steam injection.

5. RECOVERY TECHNIQUES

A main challenge to the recovery of heavy oil is the combination of high fluid viscosity and low reservoir pressure, and only rarely natural flow will occur. Consequently enhanced oil recovery (EOR) is required. These methods range from "cold production" processes to "thermal production" techniques.

51. Surface Mining

Surface mining (down to a depth of around 100m) is employed on an enormous scale in the production of Canadian oil sands (and on a lesser scale in parts of Russia). This technique has reduced production costs to less than 30$ per barrel of synthetic crude oil. Albeit two tons of tar sands are required to make one barrel of oil, recent process enhancements in surface mining allow over 90% of the bitumen to be recovered from the oil sands. This is obviously something not addressed by multiphase flowmeters.

52. Natural Flow

This primary (cold production) oil recovery method relies solely on reservoir pressure, while natural flow may be regarded as a simple, inexpensive recovery technique, it involves a progressive depletion of the reservoir pressure and generally results in only a low overall recovery (sometimes less than 5 to 10%). Diluents (such as Naphtha) may be injected to reduce the oil viscosity and / or artificial lift techniques (electric-submersible or progressing-cavity pumps). Unfortunately, mixing and shearing effects introduced by the pumping process can in some cases lead to the formation of tight and viscous oil-water emulsions or complex emulsions Oil-Water-Oil (Ref [46]).
Compression / compaction can assist when the energy for oil production is provided by the collapse of the porous medium skeleton and expansion of the pore fluid when the reservoir pressure drops. This mechanism produces energy which increases the pressure in the reservoir and aids heavy oil extraction (in Maracaibo Lake - Venezuela). The mechanism of compression/ compaction is common in compressible, unconsolidated heavy oil wells such as those found in Canada and Venezuela.

53. Water Flooding with or without polymer

Fluid injection for void space replacement is the most common means of preventing low hydrocarbon recovery through pressure depletion. Cold water flooding is a relatively low cost example of this recovery method, but is best suited to lower viscosity heavy oils. This leads to poorer recovery factor later in the life of the well and, in general, produced fluids with a higher water-cut. Oil recovery can be improved by flooding with hot water, particularly if nitrogen, CO_2 and / or surfactants are added to the water to improve the displacement efficiency.
Polymer-augmented water flooding may be a possible optimisation process. This approach is used in North Sea, where oils with viscosities in the range 100 cP are produced from subsea horizontal wells to Floating Production Storage and Offloading vessels (FPSO).

54. Cold Heavy Oil Production with Sand (CHOPS)

The CHOPS technique is a "primary" extraction technique, which is commonly used in unconsolidated sandstones e.g. the oil sands of Canada.
A well using the CHOPS process will initially produce more than 25% sand by volume of liquid, but this generally decays to around 5% after a period of several months. Therefore, a metering technology that is not significantly affected by the presence of entrained sand is required for wells using this CHOPS method. CHOPS require also the use of multiphase pumps that are capable of handling the sand content (as well as varying combinations of oil, water, and gas.) CHOPS has been successfully applied to oil reserves ranging from 50 - 15,000 cP in viscosity and planned to be developed in some Middle East Countries.

55. Vapour-Assisted Petroleum Extraction (VAPEX)

Vapour-Assisted Petroleum Extraction (VAPEX) is a new technique, under development in Canada, to overcome the disadvantages of water flooding. Water flooding is not always productive because the water often flows under most of the oil and only reaches the lower parts of the reservoir. Therefore, a vapour is required to reach the upper parts of the reservoir, and this is why the VAPEX technique has been developed.

The VAPEX process involves injecting a vaporised solvent into a horizontal well located in the upper regions of the oil reservoir. The solvent dissolves in the oil by a diffusion / dispersion mechanism, and this lowers the viscosity of the heavy oil and creates an expanding solvent vapour chamber. The VAPEX technique has a number of advantages including low energy and water consumption. In principle, high recovery factors should be achievable (up to 60%) with relatively low energy consumption.

56. Heavy-Oil Solution Gas Drive

Solution gas drive is a process which uses the energy derived from the gas dissolved in the fluid for the transport and production of heavy oil. As the heavy oil enters the well-bore, a change in pressure conditions causes the gas to break from solution to create a commingled flow of gas and liquid which aids production. However, the fraction of original oil in place (OOIP) that can be recovered by this method tends to decrease with increasing oil viscosity.

For heavy oil reservoirs, the expected recovery factor by solution gas drive is typically around 5%. Solution gas drive has the advantages that it is simple, cheap. However, recoveries can be affected adversely by high viscosity heavy oils, and large amounts of gas can be entrained in the oil resulting in metering issues.

57. Steam Flooding

In steam flooding (or steam drive), wet steam enters the reservoir via an injection well, while oil is extracted on a continuous basis from a producing well. The steam provides both thermal energy (to reduce the oil viscosity) and additional drive pressure.

To optimise the ratio of oil production to steam injection and to mitigate the risk of steam breakthrough, accurate evaluation of the water content of the produced fluids is usually vital in steam flooding operations, and this can be a significant challenge in the high temperature, high water-cut environments that typically prevail.

58. Cyclic Steam Stimulation (CSS)

In the cyclic steam stimulation process[6], a finite volume of high-temperature saturated steam is injected into the reservoir via a single well bore, and allowed to "soak" for a period of several days or weeks. The heating effect of the steam serves to lower the viscosity of the heavy oil. The well is then re-opened and oil production resumed under natural drive. The method is suitable for highly viscous deposits (> 50,000 cP) and relatively deep reservoirs (~ 1500 m), and requires very little capital investment or facilities footprint. On the negative side, recovery factors are usually limited to less than 20%, as stimulation only occurs in the vicinity of the well bore. The CSS method is not new and was introduced in the same period than the SAGD.

59. Steam Assisted Gravity Drainage (SAGD)

Steam Assisted Gravity Drainage (SAGD) was developed in the 1980's by a Canadian government research centre and with the improvements in directional drilling technology in the 1990's, SAGD became an

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[6] Also referred to as "steam soak" or "huff and puff".

inexpensive method for assisting in heavy oil extraction. In this technique, two parallel horizontal wells are drilled; one at the bottom of the formation and the other approximately 15 feet above it. These wells are typically drilled in groups away from a central pad and can extend for miles. In each well group, steam is injected into the upper well, while oil is produced from the lower. The steam in the upper well lowers the viscosity of the heavy oil and allows it to flow to the bottom well by gravity, and the oil is then pumped to the surface.

This method has proved to be a breakthrough for heavy oil production as it is cheaper than CSS, and very high recovery factors (> 60%) are possible. However, the energy injection requirement is large. The steam / oil ratio can also become excessive, and has to be optimised for efficient recovery. An accurate multiphase flowmeter will be instrumental in this field.

### 510.	In-Situ Combustion / Toe to Heel Air Injection (THAI)

In-situ combustion of hydrocarbons within the reservoir, facilitated by air (and water) injection, can be an economic alternative to the above methods, especially for deep, thin, high-pressure reservoirs. In-situ combustion has the advantage that the energy is self-generating (through coke consumption) and has been shown to produce relatively high recovery factors (> 60%). To some extent the oil is partially upgraded in-situ, due to the effects of thermal cracking, but the overall process can be difficult to control.

Toe to Heel Air Injection (THAI) is a new and experimental combustion technique which combines a vertical air injection well with a horizontal production well. In this technique, the oil is ignited in the reservoir and this creates a vertical wall of fire moving from the "toe" of the horizontal well to the "heel". This wall of fire burns the heavier oil components and drives the lighter components into the production well, allowing the fluids to be pumped out easily. An additional advantage of this technique for tar/ oil sands is that the heat from the flames upgrades some of the heavy bitumen into lighter oil deep in the well.

Traditionally, fire-flood in-situ combustion methods have been neglected because it has been difficult to control the fires and it the propensity for the production well to combust, but some oil companies believe that the THAI method will be more practical and easy to control and reduce the energy costs which would normally be required to create steam. The Suplacu de Barcău oil field (Romania) was discovered in 1956. It started production in 1961 and produces oil with InSitu techniques. The total proven reserves of the Suplacu de Barcău oil field are around 130 million barrels, and production around 8,500 bpd with an oil a reservoir conditions of 2,000 cP demonstrating the success of this technique.

## 6.	PRODUCED FLUIDS FROM HEAVY OIL RECOVERY METHODS

Due to the large variations in thermal and cold production techniques used to aid the extraction of heavy oils, a wide range of produced fluid properties are encountered and an ideal multiphase meter must be able to cope with a broad range of fluid characteristics and conditions.

### 61.	Thermal Production Techniques

Thermally assisted heavy oil production techniques such as Steam Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS), Toe to Heel Air Injection (THAI), and steam flooding result in complex produced fluids which can cause problems for accurate flow measurement. Produced fluids which are of a high temperature, have large amounts of entrained gas, liquid and sand, or have formed tight emulsions are commonly encountered. SAGD and CSS are thermally assisted techniques which are used extensively to aid heavy oil extraction worldwide, but due to the large volume of steam used during these methods, complex produced fluids are created. SAGD is a common method used in the heavy oil fields of Canada, and the produced fluids from this technique have been found to form tight emulsions, and have

typical temperatures exceeding 150 ºC. Therefore, an ideal multiphase meter used to measure produced fluids from a SAGD or CSS assisted heavy oil well must be able to cope with high temperature / moderate pressure fluids and have the ability to accurately meter tight emulsions.

The tight emulsions produced by the SAGD and CSS processes are commonly very stable and require chemical treatment and processing to separate the oil and water phases. This causes significant flow measurement accuracy problems for time constrained gravity based test separators.

Steam flooding results in similar produced fluids to those by the SAGD and CSS techniques - high temperature, water-entrained oils. The THAI technique is another thermally assisted recovery technique which has the potential to produce high temperature/pressure fluid mixtures.

It is clear that although thermally assisted techniques enhance the extraction of heavy oil, the produced fluids can be very complex and extensive thought must be given to develop a suitable flow measurement technology. A multiphase meter whose accuracy is unaffected by tight emulsions, oils with entrained gas/liquid, and which can operate over a range of moderately high temperatures and pressures could significantly assist in the reservoir and production management of a thermally assisted heavy oil production well.

62. Cold Production Techniques

Complex produced fluids obtained from Cold Production methods can also have complex characteristics, which can adversely affect flow measurement technology choice and accuracy. Cold Production techniques such as natural flow, Cold Heavy Oil Production with Sand (CHOPS), VAPEX, gas-drive, and water flooding have the potential to result in produced fluids which have high volumes of water and sand entrained.

Natural flow refers to the situation where heavy oil is extracted using the natural reservoir pressure, although this is sometimes enhanced using artificial lifting pumps. However, artificial lifting pumps can result in more complex produced heavy oil fluids; as the high shear stresses produced by the pumps can result in emulsification of the produced fluids. Emulsification prevents the use of test separators for metering purposes and results in a requirement for accurate multiphase flowmeters. However, the accuracy of multiphase meters can be potentially affected by emulsification conductivity, and therefore care must be taken when selecting a suitable multiphase measurement technology.

The CHOPS process is commonly used to enhance heavy oil production by encouraging the flow of sand through the well by large perforation to help create "wormholes" that increase the flow rates of heavy oil. This technique can successfully enhance oil production, but it results in a produced fluid with large amounts of entrained sand. The entrained sand has the potential to cause significant technical issues and it is therefore necessary to have a multiphase flow measurement technology whose accuracy will be unaffected either by solid entrained particles or by erosion. The effect of sand on PD multiphase meters, for example, has been found to be most significant at process start-up and shut-down. At start-up and shut-down, sand production rates tend to peak and PD meters can become even more susceptible to foreign matter and this can result in the meter being worn, cored or seized. Sand and bitumen can also cause plugging in the pressure and differential pressure transmitter impulse tubing of certain multiphase meters.

During the VAPEX process, solvent vapour is injected into heavy oil to help reduce the viscosity and aid extraction, but this process can result in produced heavy oil which has large volumes of vapour entrained within it. This can result in foaming and this can have a significant impact on accurate measurement due to the very high gas volume fraction.

Water flooding is another Cold Production technique which has the potential to cause metering issues due to the large amounts of water which are used during the process. During the water flooding process, water is used to displace the oil by void space replacement. However, as the ratio of oil viscosity to water viscosity increases, the "displacement efficiency" tends to decrease and this may result in produced fluids with a high water-cut. Therefore, a measurement technology which is unaffected by high-water cuts is required to ensure accurate measurement of the produced fluids.

It is clear that Cold Production EOR techniques can have a significant effect on the composition and characteristics of produced fluids from heavy oil wells. Produced fluids which have a high water-cut, and large volumes of entrained gas and sand, are commonly encountered. Therefore, to overcome the issues surrounding these complex produced fluids, it is necessary to develop a measurement technology capable of metering fluids with high water-cuts, resistant to erosion / plugging and whose accuracy is unaffected by entrained gas or solid particles.

7. EFFECT OF VISCOSITY ON CONVENTIONAL METERING TECHNOLOGIES

This section will quickly review the main effect of the viscosity on conventional meter (monophasic) this includes Positive Displacement, Turbine, Ultrasonic, Coriolis and Differential Pressure meters Venturi.

71. Positive Displacement Meters

Positive displacement meters have been widely used for the fiscal metering of light oils since the 1960's. The primary source of error in a PD meter is slippage, and this is closely related to the viscosity of the fluid being measured. Slippage is caused by differential pressure across the measuring element and internal friction in the gear chain. At low flow rates the flow has insufficient momentum to turn the blades of the meter causing leakage from the measuring chamber. At high flow rates, increased differential pressure across the meter will cause leakage through the measuring chamber.

Specially designed, high-clearance rotors are often employed for high viscosity fluids, to reduce both the pressure losses and the shear stresses on moving parts. This may, in turn, serve to increase the operational life of the meters, but it should be noted that meters with high-viscosity rotor designs are likely to be less accurate in low viscosity applications.

Thermal expansion can also cause significant metering errors, especially when the rotor and the casing are made of dissimilar materials. Changes in operating pressure can cause expansion of the measuring chamber and a special design is required.

In general, the limiting factor on the use of PD meters is the pressure drop across the meter, caused by the shear forces developed between the rotors and the fluid as the elements rotate. As the viscosity increases then the pressure drop does until a point is reached at which the strength of the meter internals could even be compromised. PD meter have a total pressure lost larger than Venturi (pressure recovery being better with a Venturi).

72. Turbine Meters

Turbine flowmeters remain one of the most commonly used flowmeters for the high accuracy measurement of liquids low viscosity and gases. However, numerous studies have shown that these meters are unsuitable for metering oils with viscosities greater than 30 cP, and for higher viscosity fluids, helical rotor turbine meters are more frequently used. Manufacturers claim a very good repeatability

±0.02% when a meter is calibrated with a fluid of the same viscosity as the operating fluid. However, changes in fluid viscosity are altering the thickness of the fluid boundary layer on the walls of metering tubes and on the blade surfaces. This affects the lift forces that drive the turbine blades and hence their rate of rotation. Consequently conventional turbines can be quite sensitive to changes in fluid viscosity.

73. Ultrasonic Meters

Ultrasonic meters are now commonly used for custody transfer and allocation measurements within the oil and gas industry, developments over the past few years have improved the performance of USMs for liquid hydrocarbon measurement.

However, one fluid property that can adversely influence the performance of liquid ultrasonic meters is the fluid viscosity. The viscosity of the liquid affects the performance of the USM largely through the Reynolds number and the effect that this has upon the corresponding velocity profile. To maintain an accurate estimate of the flowrate, a liquid USM should ideally account for the change in the shape of the velocity profile that occurs as the Reynolds number varies, particularly when it is close to or below the laminar-turbulent boundary.
JIP in Heavy Oil made in NEL has been reported that even value of few percent of gas in heavy oil could affect the reading of the USM by more than 5-50% following the manufacturer.

74. Coriolis Meters

Coriolis meters measures directly the mass flow rate and density of the fluid. Key advantages of Coriolis meters are their high accuracy and perceived reliability in monophasic flow. API and AGA approvals have been attained and Certificates of Compliance with OIML R117 issued for some meters at viscosities as high as 160 cSt.

Coriolis meters contain no moving parts, apart from the vibrating flow tubes, which leads to an increased reliability and low maintenance requirement. The flow tubes have been developed in both straight and bent configurations. Straight tube versions have advantages in certain applications, such as lower pressure drop and a higher resistance to fouling, as the fluid doesn't have to travel in bent tubes.

The main drawback with Coriolis meters appears not to be a significant change in response with varying fluid viscosity, but rather the large pressure drop generated in very high viscosity flows. To some extent this can be overcome by careful meter selection e.g. in terms of the meter's nominal bore or flow tube geometry; with straight tubes generally inducing less pressure drop than U-Tube designs but in any case the differential pressure stay way above the Venturi differential pressure.

The entrainment of gas is also known to be a common occurrence in viscous fluids. Unfortunately, the presence has been found to have a detrimental effect upon the measurement capability of traditional Coriolis meters; although modern meters are now being designed that have a higher level of tolerance to two-phase flows. In general the meters are more tolerant if the two-phase mixture is homogeneous; whereas at the type of flow regimes can have a significant effect upon the Coriolis forces relied upon for accurate measurement. Most manufacturers are investing heavily in the development of meters that will solve this issue. Several study have shown that Coriolis measurement could be affected with gas fraction from value down to 5- 6% for the U-tube and Straight design. Lately, manufacturers are claiming to maintain liquid metering performance to gas fractions up to 20%, usually this has been done only in laboratory and a requirement for good mixing and minimal gas content is. A recent study done in JIP in TUVNEL has shown that in Heavy Oil conditions with as low as 5% of GVF the mass flow rate is affected by at least 3-30% and density measurement up to 5-35% following the manufacturer. We are far from the 20% Gas Volume Fraction tolerance claimed by some manufacturers.

75. Differential Pressure (DP) Devices

A common means of metering hydrocarbon fluids is through the use of Differential Pressure (DP) devices. The pressure drop varies with the primary element used (e.g. Venturi tube, Pitot tube, Orifice plate etc). The selection of primary element depends on the type of fluid which requires handling (e.g. multiphase, corrosive, dirty, erosive, etc), the flow conditions (Reynolds number, temperature, pressure etc) and the installation conditions (pulsating, steady flow, vibrations, etc).

The accuracy of a DP meter is related to the uncertainty associated with the flow calculations and the accuracy of the DP transmitter. Another important parameter of a DP meter's general flow equation is the fluid density. During the production of heavy oil, the total mixture density of the produced fluids can vary dramatically. Therefore, a suitable measurement system for heavy oil, employing a DP meter, will almost certainly require "live" density or fractions measurements, in order to minimise the errors from fluid density fluctuations.

A DP technology which is used commonly in the oil and gas industry is the Venturi meter. This type of meter can handle ±25% more flow than an orifice plate for a comparable line size and head loss. Venturi meters have the advantages that they are robust and not significantly affected by entrained solid particles (e.g. sand), they are highly insensitive to velocity profile effects and have a low total pressure lost. Due to all these advantages, this technology is highly suitable for viscous flow metering applications.

Unfortunately, only a limited amount of research has been carried out into the performance of Venturi meters in viscous fluids, such as heavy oil, and the conditions encountered during the metering of heavy oils are often beyond the range of applicability of the data given in current standards (Ref [13]) focus to turbulent flows, but laminar flows are commonly encountered during the metering of heavy oils due to their high viscosities.

76. SUMMARY AND CONCLUSIONS

This study has shown that there is a growing requirement for an accurate multiphase metering approach to the measurement of heavy oils. With diminishing quantities of easily accessible light oil reserves, heavy oil is becoming an increasingly valued resource. There is however very little measurement techniques suitable for the viscous multiphase fluids produced.

There are many technical challenges that affect the accurate flow measurement of heavy oils - due to high viscosity effects, reservoir conditions or the consequences of heavy oil Enhanced Oil Recovery (EOR) methods. Heavy oil reservoirs frequently have low temperatures and pressures, and there is often insufficient natural drive to extract the oil. Consequently, there is a requirement for EOR techniques to increase the productivity of many heavy oil wells. However, EOR techniques often result in produced fluids that are of high temperature or high viscosity; contain large volumes of entrained gas, water or solids; or have formed tight emulsions or foams. Therefore, it is often uneconomic or too difficult to use conventional test separators for accurate flow measurement purposes. Hence, there is a growing demand for accurate multiphase flowmeters, which do not rely on phase separation.

The results of this review suggest that an ideal multiphase flowmeter for high viscosity application should have the following features:

- High immunity to viscosity effects or proper characterization (e.g. high or varying liquid viscosity)
- Resistance to sand erosion
- Low overall pressure loss

- Accurate operation, unaffected by high gas fractions or water-cuts (including foams and emulsions)
- Low sensitivity to changes in mixture / emulsion (i.e. conductivity / permittivity)
- Accurate operation over a wide range of temperatures (50 to 200 DegC) at low pressure (<20 bara in general)
- Low sensitivity to velocity profile changes
- High accurate Fraction Meter in any oil/water/gas fractions

One of the most significant problems encountered by multiphase meters during the flow measurement of heavy oils is entrained sand. During heavy oil EOR techniques, such as Cold Heavy Oil Production with Sand (CHOPS), large volumes of sand can be entrained within the produced fluids and this can cause plugging and erosion issues for most multiphase flowmeters. One of the few multiphase measurement techniques which have some tolerance to the effects of sand is Differential Pressure (DP) measurement in the form of Venturi. Venturi design are common for multiphase measurement applications because they are very robust, resistant to entrained sand and introduce a relatively low pressure drop.

8. VX TECHNOLOGY or COMBINATION OF A VENTURI AND NUCLEONIC FRACTION METER

81. Schlumberger's Experience

Schlumberger was involved from an early stage with this type of viscous-oil measurement. As 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 (Ref [7, 8,22]) in Mexico, Indonesia, Venezuela, Congo, Canada, and Russia.

The compactness and ergonomic of the Vx technology probably justify the success of its deployment. 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 surface data (Ref [5, 6, 9, 12, 14, 16, 23, 24, 25, 32, and 33]). Upstream separation is not required for the Vx Technology (unlike some alternative solutions for heavy oil on the market); hence, it provides an easy and practical solution. Heavy oil operations are always challenging but Vx Technology has, to date, achieved excellent results [1, 39, 47 – 51]. Schlumberger has openly shared and disseminated this knowledge.
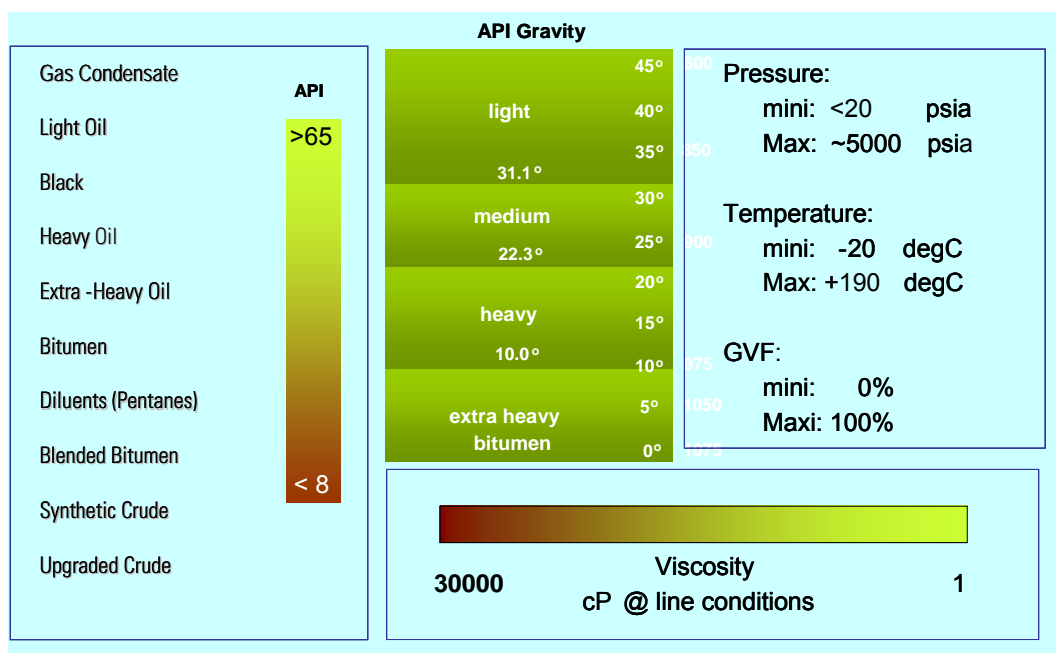
Figure 7 – Vx technology: application experience.

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 Ref [2-6, 10, 18-22, 24, 25, 27, 29]).

As mentioned, the synergy of Schlumberger's Fluid Research Centre in Edmonton (a centre of competence for Heavy Oil and Fluid Properties) together with the Faja Centre of Excellence in East Venezuela and the Regional Technology Centre in Calgary, which are focus on the Reservoir model in Heavy Oil, provides a unique opportunity to understand and develop solution for this type of environment. In fact, considerable effort has been spent over the past 7 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.

82. Quick Description of the data flow process

Several documents have been explaining already the way the Vx Technology is working. We feel it is important in the context of the Heavy Oil in this synthesis document to mention quickly the flow process. The reader will refer to other publications for more details (Ref. [1-5], [6], [9], [10], [12], [14], [18], [19], [20], [21], [22], [23], [24], [25], [27], [39], [47-49]).

It is the simplest combination of sensor and technology available on the market today without any moving part. This is a main advantage to be able to calculate and anticipate challenging environment. It is therefore very easy to predict the behaviour or response of the multiphase flow meter in any type of situation.
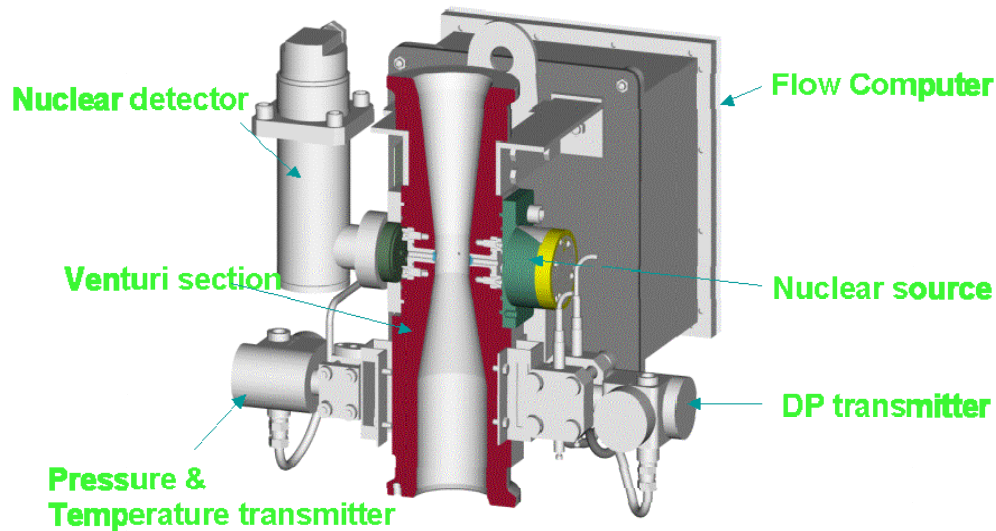
Figure 8: Schematic view of a PhaseWatcher Vx

The Vx Technology is designed to measure the total mass flow rates and then oil, water and gas of a producing well at line conditions. These flow rates are converted to Standard Conditions with a PVT Package. 3 basic measurements are made in the measuring Venturi section a DP Measurement and a fraction measurement which provides fraction of each constituent of the mixture at high frequency and based on the knowledge of the density of each phase leads to the mixture density and a pressure sensor to measure the line pressure at the Venturi throat. A temperature sensor is set upstream of the Venturi section. The physics developed for monophasic flow have been extended to multiphase conditions. They are very few additional hypotheses added (Ref [1, 2, 3, 6, 25, 27, 37, 48, 49]).

The main outputs (at line conditions) are the measured fraction or Hold-up of each phases leading to calculate the water-liquid-ratio (WLR) by using a Barium multi-energy gamma ray spectrum (insensitive to emulsion or phase distribution or inversion point oil continuous water continuous at the opposite of electromagnetism).

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, and 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 any conversion software PVT package (customized or not according to the accuracy needs of the client Ref [2-6 19, 32, 33, 48).

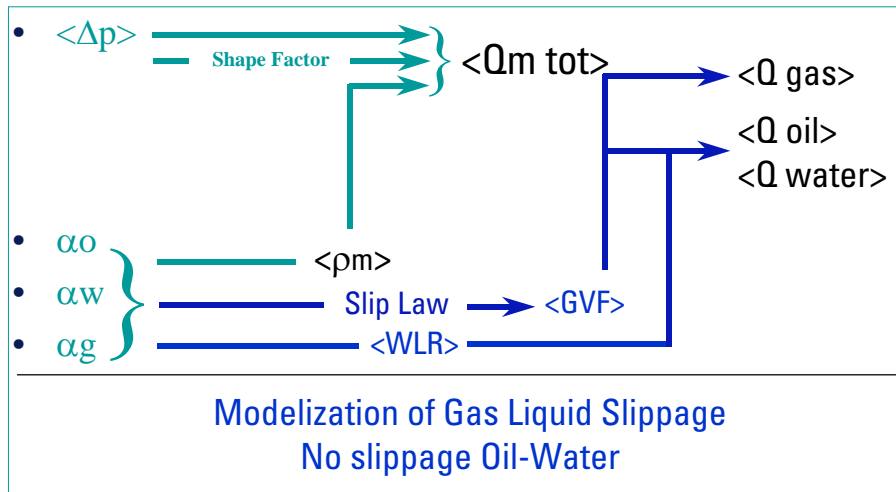The data flow processing can be summarized as presented hereafter.

Figure 9: Schematic view of the Data Flow processing at line conditions

Additionally to the hardware compact and simple packaging, the Vx Technology is built on few hypotheses: no slippage inside the liquid phase; an empirical approach of the Gas-Liquid Slippage Law based on experienced made at low pressures (2-30 bara) (Ref [1, 14, 31, 32, 34, 36, 37]) with immiscible fluid; and a model of a "Shape factor"[7] for multiphase environment (extending the concept developed for the monophasic to multiphase flow).

9. SOME FUNDAMENTAL EQUATIONS AND IMPACT IN HEAVY OIL CONDITIONS

This section is addressing the dependency of the mass flow rate versus the discharge coefficient for any system using a differential pressure measurement. First, we are looking at briefly from a theoretical point of view how the discharge coefficient can be estimated. After we are reviewing the dependency of the discharge coefficient versus the Reynolds number and as corollary, the challenge associated with the definition of the Reynolds number in multiphase flow. Then the impact of the relative error of the discharge coefficient is addressed due to some uncertainties inherent to some input parameters. Finally, through some propagation errors the expected impact on the total mass flow rate and sequentially on the liquid and gas volumetric flow rate is presented for low Reynolds number.

91. Venturi and Mass Flow Rate Measurement

One of the protected and secrecy in multiphase metering resides in the characterization of the response of a Venturi in multiphase flow over a large range of flow regime, flow rates, GVF, and fluid properties. All manufacturers today are using Venturi or similar product based on differential pressure measurement to estimate/measure multiphase flow rate. Without divulging secrets of the various manufacturers on their approach, one can gather from numerous papers presented in different conferences that all lead to an approach (Ref [1, 8, 11, 15, 17, 21, 26, 38, 41]) similar to the one used in this study (which is defined under commercial name by Vx technology).

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[7] that correct could be seen purely as a mathematical effect due to the difference between an average of a product and the product of an average. It is slightly more complicated but outside of this scope of work.

A major strength of this Vx Technology is its ability to measure total mass flow rate with reasonable accuracy, it is claimed in absolute error to be within commercially in average at $\pm$ 0.35 kg/s for a range of mass flow rate from 1 to 25 kg/s. For multiphase and monophasic flow, the total mass flow rate, Q_T, can be expressed as follows:

$$Q_T = a \cdot \sqrt{DP^*_{Venturi} \cdot \rho_{mix}}$$

$$a = A_{Venturi} \cdot \sqrt{2} \cdot \frac{1}{\sqrt{1-\beta^4}} \cdot C$$

$$\rho_{mix} = \rho_l \cdot (1-\alpha_g) + \rho_g \cdot \alpha_g$$

$$\rho_l = \rho_w \cdot wlr + \rho_o \cdot (1-wlr)$$

With

$DP^*_{Venturi}$: Venturi Dynamic Pressure drop.

$A_{Venturi}$: Venturi Cross Section

C is a product of several coefficients Cd.Cc.Sf :

Discharge Reynolds Cd,

Dimensional Cc

Multiphase Shape Factor Sf.

ρ_{mix} : Mixture density.

ρ_l : Liquid density.

Hereafter, the definition of the most current variables used in this document is given:

$$wlr = \text{Water - Liquid - Ratio}$$

$$\alpha_{gas} = \text{Gas Hold Up}$$

$$\rho_{liquid}(P,T) = \text{Liquid Density at P,T}$$

$$\rho_{gas}(P,T) = \text{Gas Density at P,T}$$

$$\rho_{mixture} = \rho_{gas} \cdot \alpha_{gas} + \rho_{liquid} \cdot (1-\alpha_{gas})$$

$$GVF = \text{Gas Volume Fraction}$$

$$Q_{total} = \text{Total Mass Flow Rate}$$

$$q_{gas} = \text{Gas Volumetric Flow Rate}$$

$$q_{oil} = \text{Oil Volumetric Flow Rate}$$

$$q_{water} = \text{Water Volumetric Flow Rate}$$

$$q_{liquid} = \text{Liquid Volumetric Flow Rate}$$

While specific details of the Vx technology are reviewed later, the above expressions represent a generic method of calculation 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 study can be extended naturally beyond the Vx technology. Moreover, this study 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.

92. Definition of the Discharge Coefficient and Reynolds

Venturi measurement has been used for decades by the oil industry including in Heavy Oil. This device is in fact so popular that all multiphase manufacturers used it today.[8] The Vx technology is based on a classical Venturi Design (ISO Standard Ref [13]) and needs to be corrected for the Reynolds number (i.e. by the viscosity and essentially the liquid viscosity). The dependence versus the viscosity is related to the discharge coefficient Cd.[9] Schlumberger came years ago with a definition of Reynolds number in multiphase conditions (Ref [1], [12], [23], [15], [31], [34], and [39]). This solution is based on literature knowledge and the study of the Reynolds in monophasic flow extended to multiphase.[10] Usually Venturi flow meters are designed to work at high Reynolds Number, and apply correction can be found quite easily. Working at low Reynolds Number, the literature is less important even in monophasic flow (Ref. [13]. The Reynolds Number is a common parameter in fluid mechanics and in monophasic flow the definition is (written here below for liquid phase).

$$\mathrm{Re} = \frac{\rho_{liq}.V_{liq}.D}{\mu_{liq}}$$

This number is related to the density, velocity, diameter of the pipe and finally viscosity. Several studies have been made and explained that and this number, asymptotically should be identical to the definition in monophasic flow. Based on this assumption, the Reynolds number for a multiphase flow can be approached with a function as described here below for dominant liquid phase:

$$\mathrm{Re}_{liqmultiphasic} = \mathrm{Re}_{liqmonophasic}.Fcrey^{11}$$

This rewriting of Reynolds in multiphase is showing a clear coherence with the common understanding and interpretation of the viscosity. Indeed, intuitively it should be related first to the liquid more than gas properties. Second, the applied correction can be expressed by a simple function, which is non-dimensional. Practically, (but not in a unique form) the discharge Coefficient curve is defined by a function in several different regions as shown generically for the discharge coefficient. This behaviour is well defined in the entire range of Reynolds number.

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[8] such as ROXAR (1), FLOWSYS (1), AGAR (2-3), HAIMO (2-3). SCHLUMBERGER and AGAR are the two major sellers in permanent plication in Heavy Oil market today, and Schlumberger leader in well testing Operation in Heavy Oil Worldwide. Number in bracket means how many Venturi are used inside the multiphase flowmeter.

[9] This parameter cannot be underestimated a priori and for sure this is not constant.

[10] The discharge coefficient is correcting for the wall friction of the fluid.

[11] Fcrey is a function which leads to 1 when the gas fraction is going to 0. This function should be in a way function of the gas fraction, indeed if the pressure is high and the gas density is close to the density of the liquid the Reynolds number should be corrected for this. Other ingredients are inside this function but irrelevant in this paper. It is important to mention that the entire discussion does not presuppose any special form of this function. This allows a possible reinterpretation of any previous work in the near future without altering the discussion here.
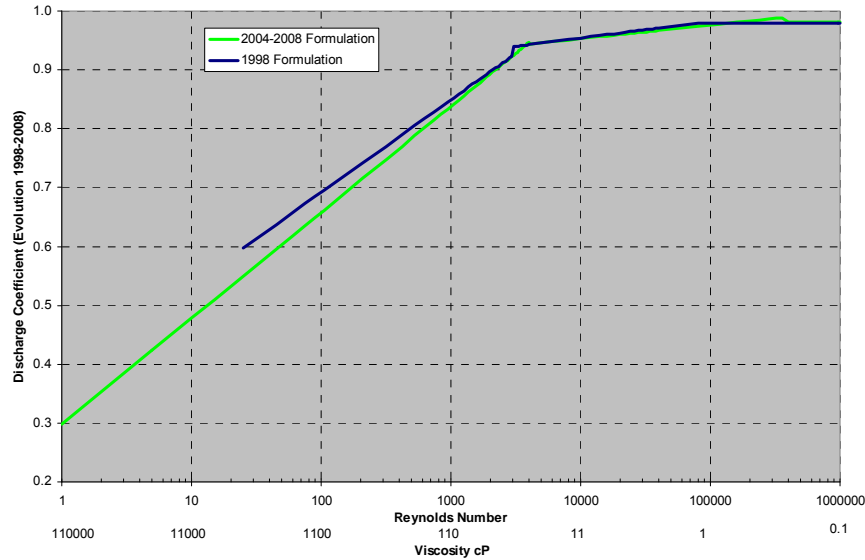
Figure 10 –Evolution of Discharge Coefficient value over 10 years of investigation. The viscosity scale (only indicative curve) is given for a flow rate of 3000 bpd, mixture density ~ 900 kg/m3 and GVF ~50%.

This leads to the following general analytical definition:

$$Cvis\ (Re) = B + A\ Log\ (Re)^{12}$$

93. Evaluation of the Relative Error in the Discharge Coefficient

The value of A and B 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, 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. [1, 32], and Pinguet et al.

In the particular configuration with a blind tee upstream of a vertical Venturi meter has led to a simple characterization of the discharge coefficient. The discharge coefficient values given by the old (1998) and more recent (2005) formulations are fairly similar at Reynolds numbers above 3,000; but, at low Reynolds number, the improved understanding from experimental work acquired in 2002-2004 are clearly visible. The evolution of the discharge coefficient is based primarily on experimental work, conducted under well-defined conditions (i.e. injected flow). 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 reviewed several times on the different flow loops handling Heavy Oil around the world such as Atalaia (Brazil) owned by

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¹² with A and B value constant between 0 and 1 following the area.

PETROBRAS and CEPRO (Venezuela) owned by PDVSA, it should be also mentioned NEL Heavy Oil Flowloop facility.

From a practical point of view, one of the latest evaluations was done against the Atalaia and CEPRO flow loop data (May 2004) where more than 100 data points have been recorded. The viscosity was fluctuating from 75 to 2,750 cP, and it was found that the total liquid flow rate was within the maximum of $\pm$ 2.5% reading (within the flowloop uncertainty) or $\pm$ 100 bpd (i.e. $\pm$ 0.66m3/h) with 95% confidence interval.[13]

94. Propagation Error on the Discharge Coefficient

The definition of the relative error of Reynolds Number could be after some laborious operations and hypotheses written with the following form:

$$\frac{\Delta \mathrm{Re}_{liq}}{\mathrm{Re}_{liq}} = \sqrt{(\frac{\Delta \mu_{liqlc}}{\mu_{liqlc}})^2 + (\frac{\Delta Fcrey}{Fcrey})^2}$$

The first term of the right side equation is purely related to the liquid viscosity at line conditions and the second term is related to the definition of the Reynolds number in Multiphase environment.[14] The discharge coefficient error can be calculated easily from the previous information available and it is equal to:

$$\Delta Crey = D \frac{\Delta \mu_{liqlc}}{\mu_{liqlc}}$$

If the Reynolds number is high enough (>400,000) the Error of the discharge coefficient is equal to 0 for the dependency to the viscosity.[15] As a rule of thumb, it should be noted that the factor D is of the order of $\pm$1% for mid-range Reynolds numbers [4,000-400,000], and less than 8% for Reynolds numbers below 4,000. The effect on the overall discharge coefficient error is therefore extremely small – its absolute value, in the case of a $\pm$ 5% relative error in viscosity, being only about $\pm$ 0.004 (Figure after). The influence on the overall discharge coefficient relative error is therefore 13 to 100 times lower than the relative error of the liquid viscosity. It is therefore easy to reinterpret the previous information given above and approximates the relative error of the total mass flow rate by taking into account only the viscosity effect with:

$$\frac{\Delta Q_{T}}{Q_{T}} \bigg)_{vis} = \frac{\Delta Crey}{Crey}$$

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[13] The typical flowloop performance of the Vx technology are below 90% GVF and with a 2 sigma interval confidence of $\pm$ 10% on the gas flow rate below 300 psia, $\pm$ 2.5% for the liquid flow rate, and $\pm$ 2.5% for the WLR. For a GVF above 90% and below 96%, it is respectively $\pm$ 15%, $\pm$ 5% and $\pm$ 5%

[14] The second term will be considered negligible in the discussion inside this study

[15] In other word, whatever the error in the viscosity measurement this has no effect on the discharge coefficient and therefore no implication in the total mass flow rate.
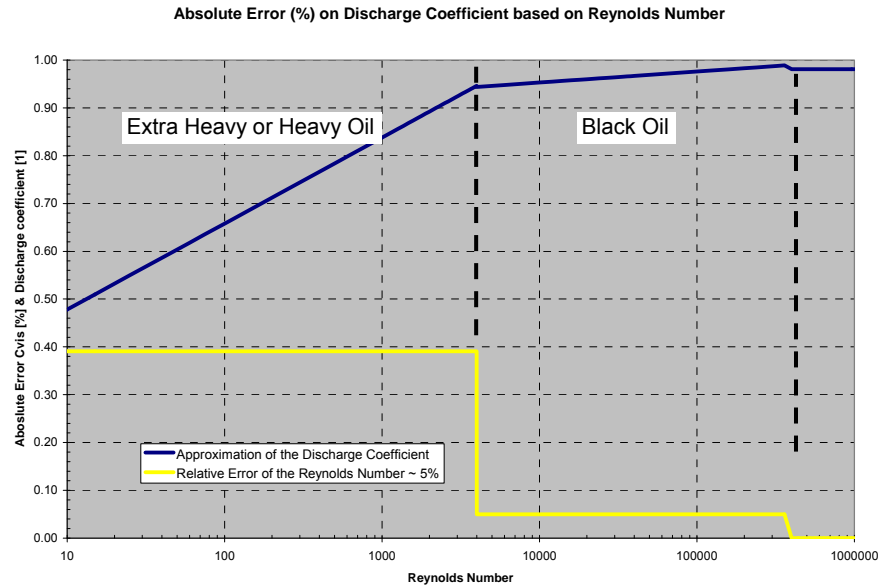
Absolute Error (%) on Discharge Coefficient based on Reynolds Number

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

Even a relative error of $\pm$ 10% in Reynolds number (viscosity) equates to an accuracy of better than $\pm$ 0.008. 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 A and B previously indicated, and controlling the discharge coefficient associated with the Reynolds number. It is clear that the challenge here is extremely high and requires large investments and accurate infrastructures to be in place.

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 $\pm$ 5%, $\pm$ 10%, or 20% relative error in the Reynolds number (or in the liquid viscosity if that contributes the largest uncertainty to *Re*).

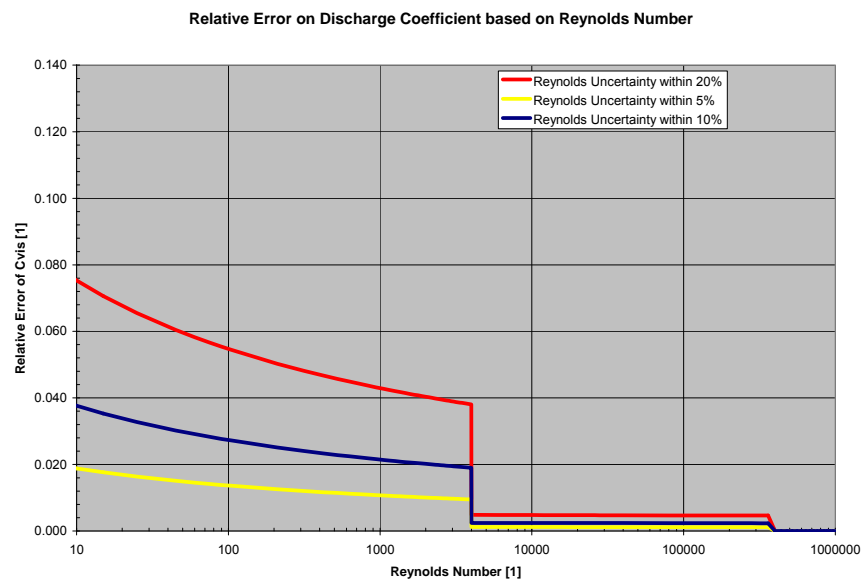**Relative Error on Discharge Coefficient based on Reynolds Number**

Figure 12 – Relative error in Discharge Coefficient due to different Reynolds number uncertainty.

Several observations can be made. 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. > 4,000). For *Re* < 4,000, and for a Reynolds number uncertainty of 10%, the relative error in the discharge coefficient increases from ~ ± 2% (at *Re* ~ 4,000) to ~ ± 6% (at extremely low Reynolds numbers)[16]. It can also be seen that a relative error below ± 5% of the viscosity or Reynolds number leads to an uncertainty in the discharge coefficient of less than ± 2% over almost the entire Reynolds number range.

95. Propagation Error on the Mass Flowrate

More accurately, we define the relative error of the total mass flow rate as presented here-below:

$$\left(\frac{\Delta Q_T}{Q_T}\right)^2_{TOT} = \left(\frac{\Delta Q_T}{Q_T}\right)^2_{NOR} + \left(\frac{\Delta Q_T}{Q_T}\right)^2_{VIS} = \left(\frac{\Delta Q_T}{Q_T}\right)^2_{NOR} + E^2\left(\frac{\Delta \mu_{liq}}{\mu_{liq}}\right) = \left(\frac{1}{2}\frac{\Delta DP^*_{Venturi}}{DP^*}\right)^2 + \left(\frac{1}{2}\frac{\Delta \rho_{mix}}{\rho_{mix}}\right)^2 + E^2\left(\frac{\Delta \mu_{liq}}{\mu_{liq}}\right)^2$$

The last term on the right is the one associated with the viscosity effect. A previous study made on the two first arguments on the right side of the equation (i.e. excluding the viscosity parameter) led to the following conclusion that the mass flow rate relative error is in the range of ±1-1.5%.

$$\left(\frac{\Delta Q_T}{Q_T}\right)_{NOR} = \left(\left(\frac{1}{2}\frac{\Delta DP^*_{Venturi}}{DP^*_{Venturi}}\right)^2 + \left(\frac{1}{2}\frac{\Delta \rho_{mix}}{\rho_{mix}}\right)^2\right)^{0.5} \approx 1 - 1.5\%$$

This can be explained easily, the accuracy of the entire chain of acquisition of the differential pressure sensor is within ± 1 mbar for a range of differential pressure from 0 to 5,000 mbar. The equation can then be approximated to fix the ideas by:

$$\left(\frac{\Delta Q_T}{Q_T}\right)_{NORMAL} \prec \left(\frac{\Delta DP^*_{VENT}}{2 \cdot DP^*_{VENT}}\right) \approx \left(\frac{0.5 - 1}{DP^*_{VENT(mbar)}}\right)$$

Differential pressure measurement should be above 50-100mbar to get an overall uncertainty on the total mass flow rate within ± 1-2%.

Therefore, the cumulative effect of these different errors shown above generates a maximum relative error from 1.5% to 2% versus the GVF (quite independent of the WLR value). The coefficient E, based on the input available in the literature is usually very small and can be estimated between 0 and less than 0.2 leading to a value for E^2 in the range of 0 to 0.03. This means that the underlined viscosity of a multiphase flow is having a weak influence in a large range of Reynolds number. However, the clear definition of the Reynolds Number in Heavy Oil and multiphase environment and understanding the influence in High Viscosity is key.[17] This demonstrates also that the Venturi is a right device for Heavy Oil environment and this is why we believe it is so popular.

The viscosity effect is therefore contributing from ± 0.4 to ± 0.8% of the uncertainties of the total mass flow rate. Combining both the intrinsic and viscous effects leads to an overall error in mass flow rate as depicted in 13.

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[16] Assuming a liquid flow rate of 2,000 bpd, a GVF ~ 50% and a liquid density ~ 900 kg/m3 with a viscosity around 6 cP, the Reynolds number will be equal to 4,000.

[17] Assuming an error relative on the viscosity of 10% this leads to a maximum overall contribution error on the volumetric or mass total flow rate of less than 1.6%.
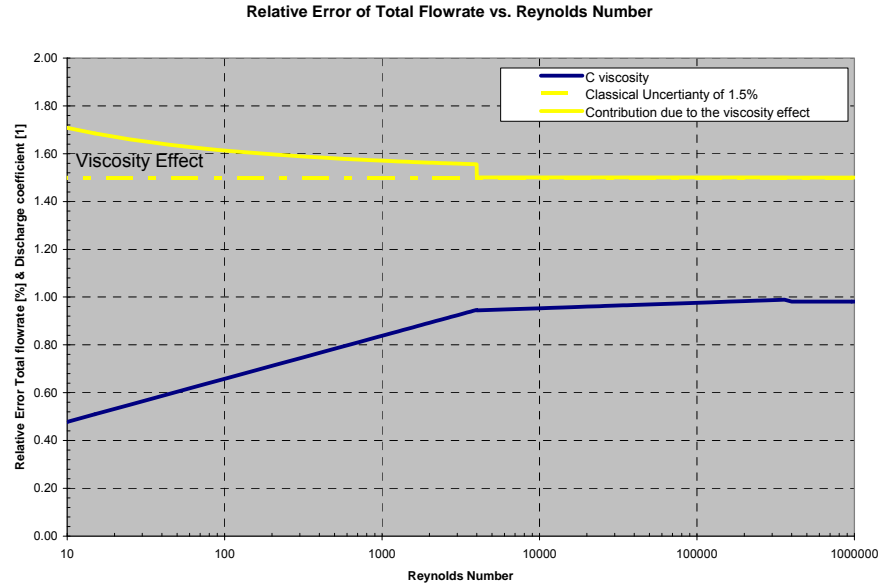
Relative Error of Total Flowrate vs. Reynolds Number

Figure 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 > 4,000).

From Figure 13, it can be seen that the effect of the viscosity uncertainty is marginal and, as expected, has an effect solely at very low Reynolds number (< 4,000). The cumulative effect of these different uncertainties generates a maximum relative error ranging from ±1.5% to ±2%. This is quite independent of the WLR value 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 in heavy oil and multiphase environments, and an understanding of its influence in high viscosity.

96. Propagation Error on the Gas Flowrate

The definition of the gas flow rate given by:

$$q_g = \frac{Q_T}{\rho_{mix}} \cdot GVF$$

and going through some calculations, it is possible to obtain the relative error of the gas flow rate in a simpler manner can be approximated by:

$$\frac{\Delta q_s}{q_g} \approx \left(\left((F+1) \cdot \frac{\Delta GVF}{GVF} \right)^2 + \left(\frac{\Delta Q_T}{Q_T} \right)^2 \right)^{0.5}$$

The maximum relative error of the gas flow rate is then essentially GVF dependent with a contribution around 3-4%, and an adding error of ~±1.5 to 2% due to the total mass flow rate contribution. The overall accuracy is, therefore, within a maximum of ±4% to ±6%[18], which is very good!

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[18] Usually the gas flow rate requirement from the oil companies is within 10%

97. Propagation Error on the Liquid Flowrate

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

$$q_{liq} = \frac{Q_T}{\rho_{mix}} \cdot (1 - GVF)$$

And then it is possible to calculate the error relative of the gas flow rate based on the following expression: and under the same hypotheses than in the previous section:

$$\frac{\Delta q_{liq}}{q_{liq}} \approx \left(\left((G + H).GVF \cdot \frac{\Delta GVF}{GVF} \right)^2 + \left(\frac{\Delta Q_T}{Q_T} \right)^2 \right)^{0.5}$$

A detailed analysis has shown that G and H are in the same range[19]. The first term is lower than 1% in most of the case and the error relative on the liquid flow rate can be approximated by the error relative on the total mass flow rate. Intuitively, we understand this statement by the fact that the mass and viscosity is essentially driven by the liquid.

98. Conclusions

Overall, this section show how simply the impact of the viscosity can be taken into account if the viscosity is not taken care properly how this can lead to an extra terms of uncertainty inside the overall performance. Again as mentioned previously the entire multiphase meter manufacturers are using Venturi today for one reason or another and therefore this viscosity effect needs to be compensated in a way or another or taken into account. We have proposed to reveal how with the right definition and a bit of mathematic a clear picture of a system can be given versus a standard product.

It is hoped that this analysis has enlightened a further part of the multiphase business 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 definition of the Reynolds number in multiphase flow.

We left outside the scope of this work the calculation of the liquid viscosity; this has been addressed and presented before in reference (Ref [2, 3, 6, 12, and 34]).

10. VISCOUS FLOWLOOP VALIDATION IN LATIN AMERICA (2004-2005)

Schlumberger has been one of the pioneers to address the problem of the viscosity in Heavy Oil. Back to 1998, Schlumberger was testing the Vx technology in CEPRO facilities (in Venezuela); the performance of the prototype was done with viscosity up to 2,000-3,000 cP. During this period from 1998 up to now, Schlumberger has been continuous present in Heavy Oil and mainly through the Well Periodic Testing. The main country where the technology is used daily is Mexico, Brazil, Venezuela, Russia and Congo (ref [39]). In 2004, a review of the effort done over the previous years and the validation of the viscosity study on a smallest version of Vx was done (Ref [34]). By end of 2004, PDVSA was proposing a review of the performance of the multiphase flow meters present on the market. The only main manufacturing multiphase company present on this market which accepted to participate was Schlumberger. This was a blind test to review the performance over more than 3 months of test with oil viscosity from 1 to 3,000

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[19] D is a function of GVF and E is a function of ratio of density. This (D+E).GVF ~ 6% at 90% GVF

cP with GVF from 0 to 99% and WLR from 0 to 80% with different salinity. Schlumberger in 2005 revisited again the interpretation model to improve the accuracy (Ref [40]). The CEPRO-PDVSA (Centro Experimental de Production) multiphase flow loop operates on natural crude oils and gas. It is a huge facility; the crude oils are stored in tanks of approximately 1200 barrels capacity 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 in a roughly 60-meter horizontal pipe of 3 inch before reaching the spot to test multiphase flow meters. For all three fluids the primary references are Coriolis based on mass flow (and density) meters. Duplication of the equipment along the pipe allows making some statements about the flow loop accuracy by comparing the 3 Coriolis inline. For the gas, both Coriolis meters are compared to the Vx used as a standard ISO gas venturi meter.[20]

Figure 14: PhaseTester Vx29 in CEPRO installations.

The preliminary review of the entire flowloop uncertainty related to the liquid line was ± 1 to 2%. Other tests demonstrated that the relative error of the total mass flow rate was within 2.5% for the entire set of data from 1 to 2.75 kg/s in monophasic water and was stated as the range of liquid accuracy for the flow loop facility. The gas flow rate accuracy is within ± 4% over the entire range of data. Overall, the consistency of the reference meters is very good for a facility of this size.[21] Heavy Oil tested was from 15 to 21 API and viscosity from 75 to 2,750 cP. A part of the test matrix is presented here after versus GVF and WLR with the working envelope of meter.

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[20] Prior to the tests, all the reference meters were verified by the official Venezuelan certification body. The Coriolis meters were found to be in accordance with the vendor specifications, within approximately 0.1% accuracy in their nominal range.
[21] The gas density is also associated with uncertainties coming from the pressure measurement, gas dryness, PVT.
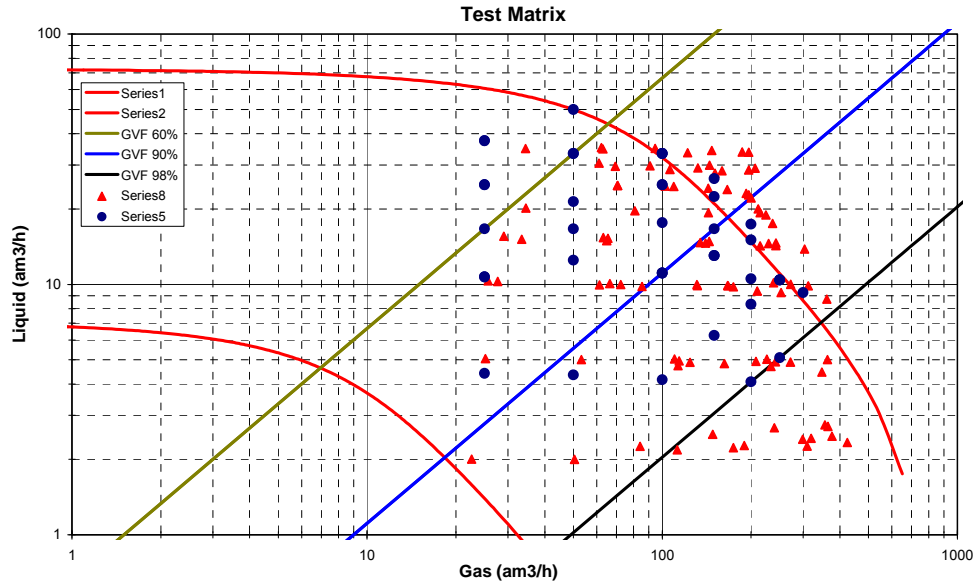
Figure 15: A subset of the test done in CEPRO (2005)

Here after data collected and reprocessed during several campaigns of test in CEPRO over the year 2000-2005 and with different type of Vx meters and oil viscosities. The relative error was stated at 2.5% which is very encouraging and well in comparison with the data recorded on other flow loop with viscous oil or in trial test. The gas flow rate was well within 5-10% in these different tests.
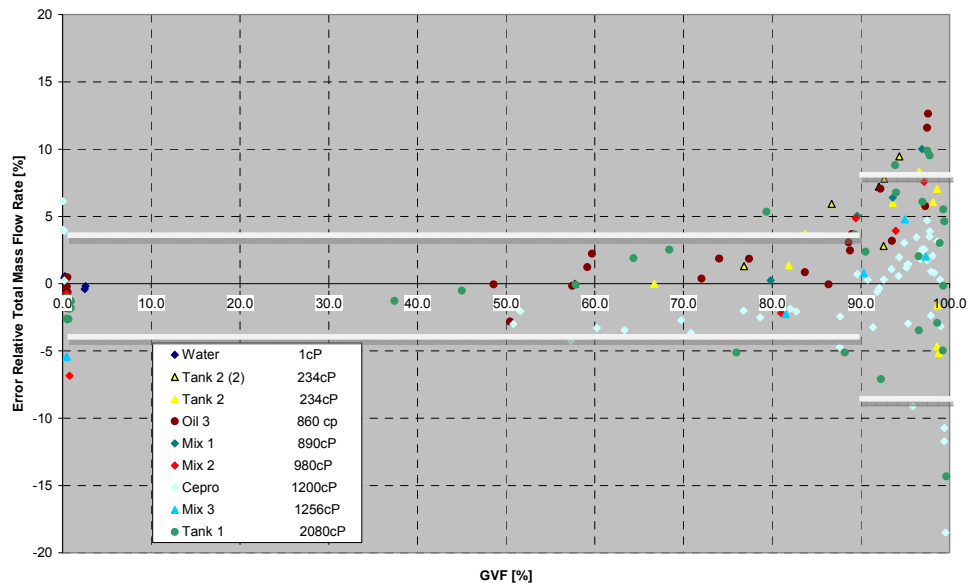

Figure 16: Global Uncertainty "Flowloop – Multiphase flow meter" - Demonstrating the performance of the meter in multiphase flow versus GVF (2005).

The main advantage of the Vx technology is the possibility to measure with the same level of accuracy the WLR whatever the continuous phase and even in the transition zone oil/water continuous. This is due to the fact that the nuclear measurement is absolutely insensitive to any phase dispersion. It could be argued that the measurement is however more difficult due to a lowest contrast in terms of nuclear

measurement existing between the oil and water. To avoid extensive demonstration this could be pictured on the famous nuclear triangle solution. Even in a narrower triangle, the response of the tool is exceptional as can be seen in the figure here after where it is possible to track the WLR with high accuracy from 0 to 100% GVF.
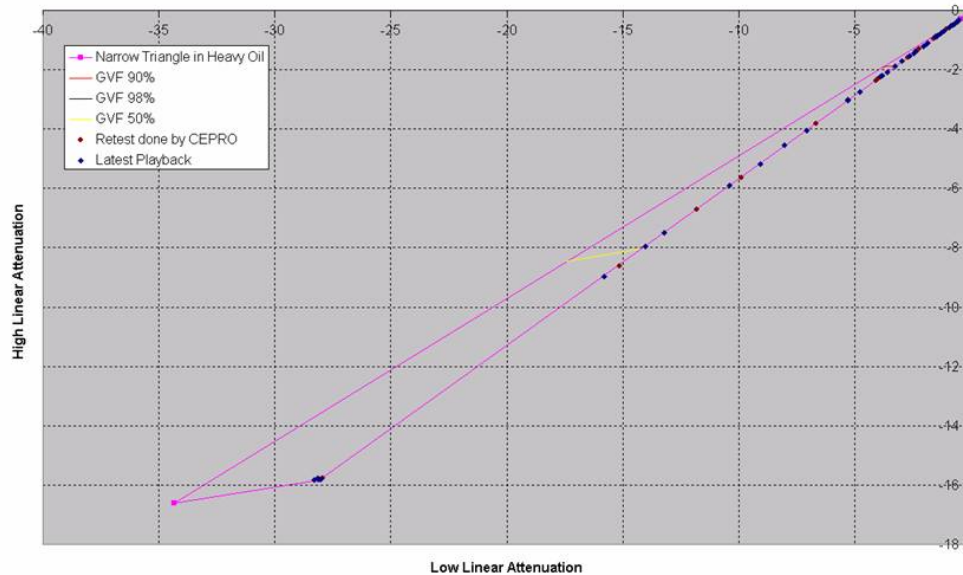

Figure 17: Evolution of the functioning point versus time when the gas injection (i.e. GVF) was increased

The overall performance in CEPRO is therefore very good with accuracy on the WLR lower than 2.5-3% up to very high GVF (98%) knowing that the accuracy of the flow loop. The nuclear fraction measurement device is very well appropriated to the heavy oil environment. The advantage against other techniques is that it is not phase dependent or distribution dependent such as electromagnetism system for example.

Nuclear fraction measurement being based on the composition and density contrast, it has been argued in the past that the heavy oil which may contain some H2S could be narrowing so much the triangle that no measurement could be possible. This is in fact based on the misconception of the fluid properties. The H2S is a highly soluble component in any fluid as the CO2 and therefore in average it can be approximated that the same quantity will be dissolved in the different phase. Then the triangle will not be narrower but it will only be shifted on the left side of the graph as typically shown above versus the H2S content. Therefore the presence or not of H2S will not change drastically the solution triangle size but will shift it. This has been demonstrated numerous times in Mexico for example with H2S content in the oil and water in the order of 3-5%, in permanent application in Kazakhstan (>15%) and in Saudi (>5%).

Furthermore, the level of accuracy reached with the nuclear detector, used for Heavy Oil, with stabilization and resolution has proved that the WLR measurement is well within 2% whatever the GVF even higher than 98%.

It should be mentioned that the nuclear measurement developed by Schlumberger is dedicated to the multiphase and huge effort has been spent in this high accurate acquisition system. It should be mentioned to give a picture of the accuracy here, that the Smart Detector used for Heavy Oil is stabilized in temperature including the electronics (patented) and it is guarantee with a precision better than 0.01% over one year or 0.1% over 10 years. This means that a source with 10 000 CPS recorded in January 1st and taken into account the decay time, will measure at December 31st again 10 000 +/-1 CPS.

11. FIELD EXPERIENCE IN TIGHT EMULSION AND VISCOUS ENVIRONMENT (2000-2011)

111.   Multiphase Flow meter performance demonstrated in Tight Emulsion (2000-2003).

In East Venezuela, an Operator had a field with several hundred wells producing with different techniques from Gas Lift to Schlumberger ESP active systems. The average oil production is very low per well less than several hundred bpd, with a degree API lower than 19 and a high BSW. Another important parameter to be emphasized is the high level of emulsion[22] found in some fluids, which produces high liquid viscosities even at high Water Cut values.

Some emulsions are very stable, while others may not emulsify or may form a loose emulsion that will separate quickly. Unless some form of treatment is used to accomplish complete separation, there will be a small percentage of water left in the oil even after extended settling. The water that remains inside the oil will be in small droplets that have extremely slow settling velocities. They will be widely dispersed so that there will be little chance for them to collide, coalesce into larger droplets, and settle. The amount of water that emulsifies within crude oil may vary from less than 1 to more than 60% in rare cases.

Figure 18: Left Picture shows a 100% Emulsion[23] with 70% WLR with Oil with 18 deg API, note the homogeneity of the liquid. Right Picture shows the same sample after the emulsion is broken and dissolved with 50% Xylen

To give an idea, the most common range of emulsified water in light crude oil (i.e. oil above 20° API) is from 5 to 20 volume % and for emulsified water in crude oil heavier than 20° API is from 10 to 35%.

The PhaseTester* was continuously used until December 2003 since 2000, where PhaseTester* complemented the whole Well testing activity shared with Client's test facilities and was used as

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[22] An emulsion is a heterogeneous liquid system consisting of two immiscible liquids with one of the liquids intimately dispersed in the form of droplets in the second liquid. An emulsion is distinguished from a simple dispersion of one liquid in another by the fact that, in an emulsion, the probability of coalescence of droplets on contact with one another is greatly reduced because of the presence of an emulsifier, which inhibits coalescence.

[23] The definition of emulsion for us in this section is the fluid that you collect and which is a mixture of oil and water after the sample has been left for a while settling down (~ 10 minutes) in order word it is the fluid without any free oil and water. If it is mention 70% emulsion this means after settling down 30% of the fluid was free fluid and could have been oil or water. These criteria give a level of the emulsion level and how strong it is. 0% emulsion means that after this setting time the fluid was totally separated in water and oil i.e. typical light oil.

Production Optimization Tool for Gas Lift and ESP systems. In Sep 2003 the Client wanted to drastically improve in the Well Production allocation. Once both systems were reviewed and ensure that acceptable comparison conditions were available a comparison test was conducted between PhaseTester* and the client's Test Separator.

Prior to this, a review of the inversion phase was done in laboratory following some specific protocol not described in this document. The viscosity was checked against two different techniques of measurement to get consistent value. This was done under proper control temperature. Below the summary of the viscosity profiles at line flowing temperature for different wells is presented. Usually, it is quite common to assume that the inversion point for light oil could be in the range of 40-60%.

Usually for Heavy Oil the inversion point is believed to shift to higher quantity of water (WLR) and value in the range of 80% or above has been found and this is the common perception. However, our past experience demonstrates that inversion point even lower than 30% can be found in High Viscous Oil. This complex subject has not been investigated in details up to now.
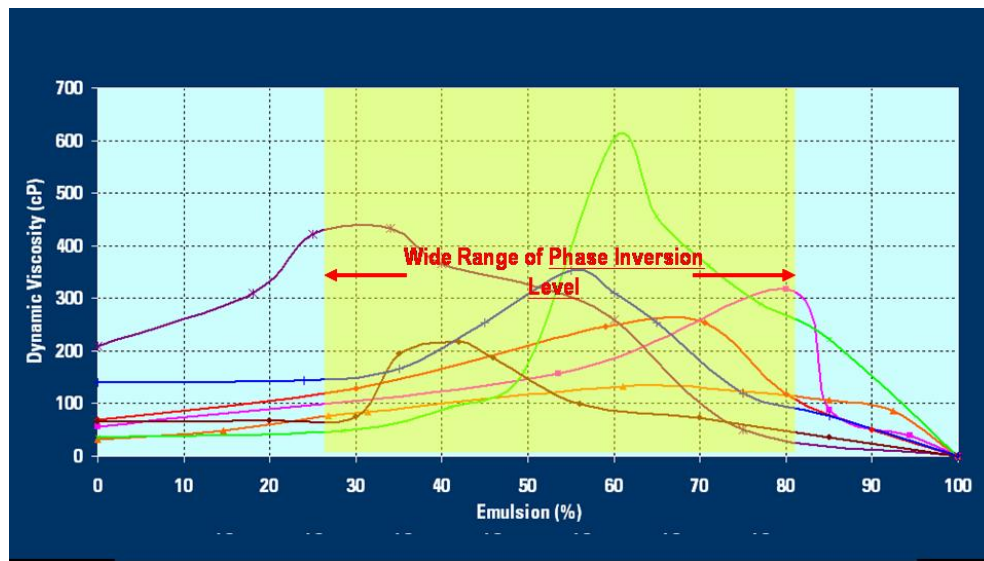

Figure 19: Inversion Phase versus WLR for different oils from same reservoir, different layers.

As it is observed in the figure 19, there is no clear path regarding Viscosity behavior, and the Phase Inversion Levels. It is going from 30 % to 85% from field samples of the same reservoir but different layers. To reinsure the quality of the Vx measurement against new reference, a selection of the 4 most emulsion well on the other hand, the reference measurement could not be known at better than 5-10% using Coriolis in this type of environment and the separation is always an issue.

Well	DPV mbar	GVF %	Error Liquid	Emulsion %
1	1113	85	-0%	0
2	1288	90	-3%	22
3	1543	83	-2%	18
4	1369	85	-2%	16

Table 2: Overall performance after GOR recalculation

 An underestimation is visible versus emulsion for the liquid flow rate in each test. This is indicating and demonstrating the main issue with separator in Heavy oil Environment, indeed Gas Bubbles have a

tendency to stay trapped inside the oil, this means that the "oil volume" going the flocometer will be then higher than expected, on the other side, the fact that there is less gas going through the gas line of the separator due to the carry under will lead to a under reading.

It has been possible through this test to demonstrate to the client the challenge to use separation equipment at the well site for absolute measurement. It has been also demonstrated the challenge when the flow was untestable, it should be mentioned that one test was cancelled due to the large fluctuation and the problem to settle liquid level inside the separator.

112. Drastic improvement of the accuracy through fluid behavior knowledge and worldwide experience (2000-2004).

The importance of the viscosity behavior in some specific field cannot be hidden and especially if a requirement for the highest level of accuracy should be achieved. In this chapter, it will be shown very briefly the advantage to have a proper fluid behavior package. As common in oil industry, it is necessary to use some conversions from line to standard conditions. However, Heavy oil behavior is not necessary the same behavior versus pressure and temperature than any other oil. This can be explained by the fact that most of the time this oil has a very low GOR and contains a large proportion of very long carbon chained at the opposite of the black or volatile oil. Therefore using a PVT package dedicated to this oil or having a measurement done at the well site for this type of oil will improve the overall performance of any multiphase flowmeter at standard conditions.

During heavy oil testing job in South of America, one of our main client has been using the PhaseTester Vx – PVT-Express combination, and achieved outstanding results when the Vx Fluids ID option was used to replace the standard Black Oil correlation. The VxFluidsID is a fit-for-purpose fluid behavior package based on the properties of the fluid flowing through the meter. This is a dedicated service based entirely on some parameters found in the classical PVT Report and reused adequately.
In this specific case, the fluids were lifted using an ESP pump, with low GOR and ~16 API. Then the PVT Package was not available immediately at the wellsite then the data were reprocessed and excellent results were achieved with an error lower than 1%!
In these tests, a comparison was made against tank measurements; indeed there is significant challenge to do a comparison against a separator. The main advantage of the tank it is to be close to the standard condition and the retention time is much longer leaving the time for most of the gas bubble trapped inside the oil to come out. Taking regular sample will help to do a shrinkage factor correction too. GOR measured with the Vx Meter was compared against those from PVT analysis having no info from the separator.

Black Oil Model		
Qoil_Vx [Sm3/d]	Qoil_Tank [Sm3/d]	Relative Error [%]
205	199	3
GOR_Vx [m3/m3]	GOR_PVT [m3/m3]	Absolute Error [m3/m3]
2.5	3.3	-0.8

Vx Fluids ID		
Qoil_Vx [Sm3/d]	Qoil_Tank [Sm3/d]	Relative Error [%]
202	199	1
GOR_Vx [m3/m3]	GOR_PVT [m3/m3]	Absolute Error [m3/m3]
2.6	3.3	-0.7

Table 20: Flow period#1 Result of the black Oil Model against VxFluidsID

Black Oil Model		
Qoil_Vx [Sm3/d]	Qoil_Tank [Sm3/d]	Relative Error [%]
227	213	6.5
GOR_Vx [m3/m3]	GOR_PVT [m3/m3]	Absolute Error [m3/m3]
2.5	3.3	-0.8
Vx Fluids ID		
Qoil_Vx [Sm3/d]	Qoil_Tank [Sm3/d]	Relative Error [%]
216	213	1.6
GOR_Vx [m3/m3]	GOR_PVT [m3/m3]	Absolute Error [m3/m3]
2.8	3.3	-0.5

Table 21: Flow period#2 Result of the black Oil Model against VxFluidsID

Black Oil Model		
Qoil_Vx [Sm3/d]	Qoil_Tank [Sm3/d]	Relative Error [%]
382	350	9.1
GOR_Vx [m3/m3]	GOR_PVT [m3/m3]	Absolute Error [m3/m3]
2.8	3.3	-0.5
Vx Fluids ID		
Qoil_Vx [Sm3/d]	Qoil_Tank [Sm3/d]	Relative Error [%]
350	350	0.0
GOR_Vx [m3/m3]	GOR_PVT [m3/m3]	Absolute Error [m3/m3]
3.5	3.3	0.2

Table 22: Flow period#3 Result of the black Oil Model against VxFluidsID

The capability to playback any recorded raw data as an original process is an instrumented feature with the Vx technology. Overall, the client was extremely satisfied with the final results and recognized the benefits of this combination, realizing that they will be able to analyze their reservoir more efficiently such as productivity index and more accurately. The VxFluidsID developed for this well could be reused at any time as soon as the reservoir is still producing at reservoir level in monophasic conditions

As a highlight of this experience, to have a clear understanding of any Multiphase Flow Meter performance, the overall performance has to be split between what is due to the technology (intrinsic uncertainties) and, what is purely related to the Fluid Properties knowledge. As reminder, all MPFM measurements are calculated at line conditions, therefore Fluid Properties or some PVT knowledge, such as densities at line conditions, shrinkage factor, and gas dissolved in oil are necessary to deliver the flow rates at standard conditions as expected by the client. An error on these input parameters will have at fortiori some errors on the final output at line conditions

113.   Optimization Experience in Heavy Oil (2006-2011)

Offshore Congo, one of the oil companies is operating a very complex reservoir. There are two major reservoirs very heterogeneous and with a very variable permeability produced through a single string. This creates uncertainties for the reservoir performance. Both reservoirs have multilayer, porosity around 20 to 30%, and permeability from 1,000 to 3,000 mD. The very low pressure drive in the reservoir makes it difficult to produce naturally and ESP is used. This field is in production since 1991 and the current operator acquired it in 2003 and started to put it in production immediately through a FPSO via 2 platforms. The oil specific gravity is between 16 to 31 API. The oil viscosity is between 100 to 200 cP at

reservoir conditions (130 degF) and around 2,200 cP at surface conditions (80 degF). The liquid viscosity is reaching 5,500 cP at standard conditions!

The reservoir production over the 2003-2006 has been very challenging, with a decrease by more than 35% reaching barely 10 000 bpd. In the same period the BSW increased from 70 to 80%. The monitoring of the production was showing clearly a large decrease over time with no hope to improve with the current equipment the trend. It was necessary to find a new strategy to produce better and monitor in real time the wells and in meantime (i.e. back allocation factor ~ 0.75) and fight with the rapid decrease of the ESP life expectancy over time. This was assumed to be due to the start/stop production and the large flowrate fluctuation from some most of the wells.

Large effort were made regarding conventional periodic testing however large variations between real production and well testing results were observed with up to 25% error. Moreover the BSW obtained from the separator and by centrifugation was largely under measured against the true value, probably double emulsion or tight emulsion. The calculated value based on the mass balance was leading to a value around 83% when the BS&W measured was more in the range of 75%. Additionally, the BSW measurement was not at all repetitive between two measurements on the same well and variations of up to 25% where observed
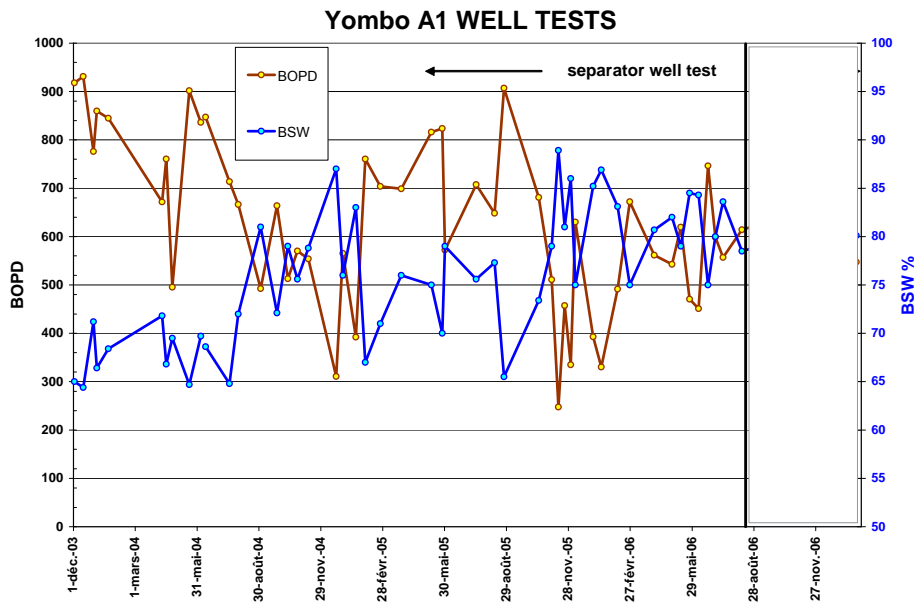

Figure 23: Typical oil production and WLR versus time

Adding to these issues the lack of accuracy of the test separator in viscous oil environment as demonstrated previously, it was not possible to fine-tune production parameters of wells when data could not be consistently quality stamped. And even worst be unable to size the pump (ESP) for each well leading to higher electrical consumption coming from the main-process plant installed on the FPSO. Overall it was not possible to optimize consistently the production well by well; this operator had to find an innovative solution in this high viscosity and high emulsion environment. Roughly 3 possible solutions were possible and explained in details (Ref [39]). The best one (cost effective and less risky alternative possible) was to install a multiphase flow meter with a good performance in Heavy and Viscous Oil. As explained previously Schlumberger had been involved in this business since a long time, the reliability of their equipment was well characterized. Additionally, there is no need for flow stabilization or

separation. There is no phase dispersion issue; this means that the flow could be in oil continuous or water continuous this will not be a problem in terms of accuracy on the WLR or BSW.

There is also the possibility to get a proper real-time monitoring (Well Heart Beat) as shown here after for one specific well.
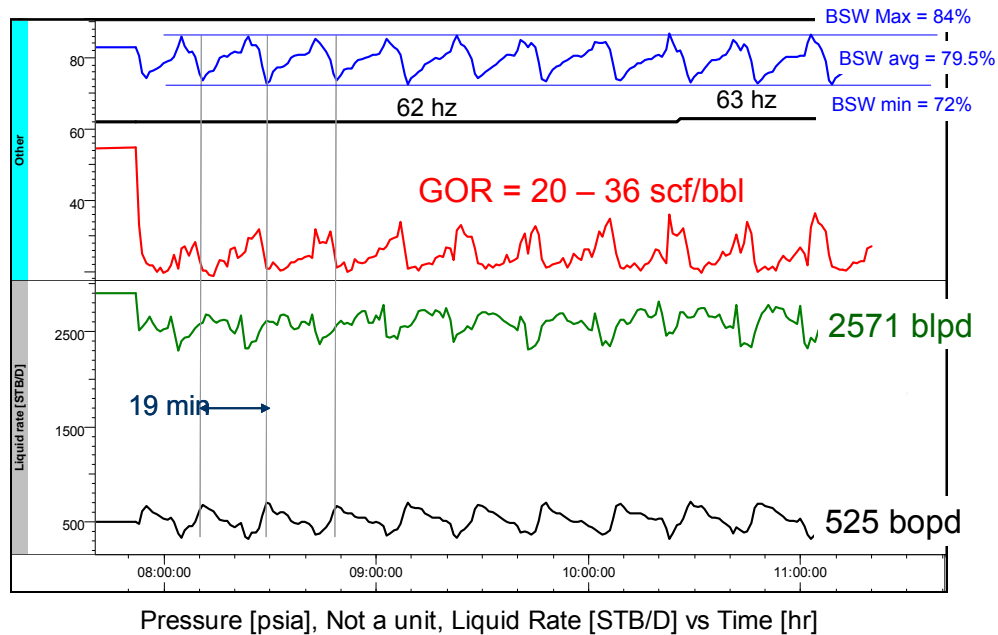

Pressure [psia], Not a unit, Liquid Rate [STB/D] vs Time [hr]

Figure 24: Heart beating of the well

Other main criteria were accurate and repeatable flow measurement, shorter well stabilization (more test per day), high resolution to detect small flow events, reduced pressure drop (test at producing conditions).

After field test with a PhaseTester (periodic well testing equipment), a 3 inch PhaseWatcher (permanent meter) were installed on each platform as presented here after.

Figure 25: Vx Meter 3 inch installed close to the test separator (at the back)

Immediately the benefit of the use of multiphase flow meter was noticed looking for example the oil flow rate and BSW versus time. Real time production has some key benefit, and leads to make quicker intervention in some wells to change the ESP and up-size the equipment.
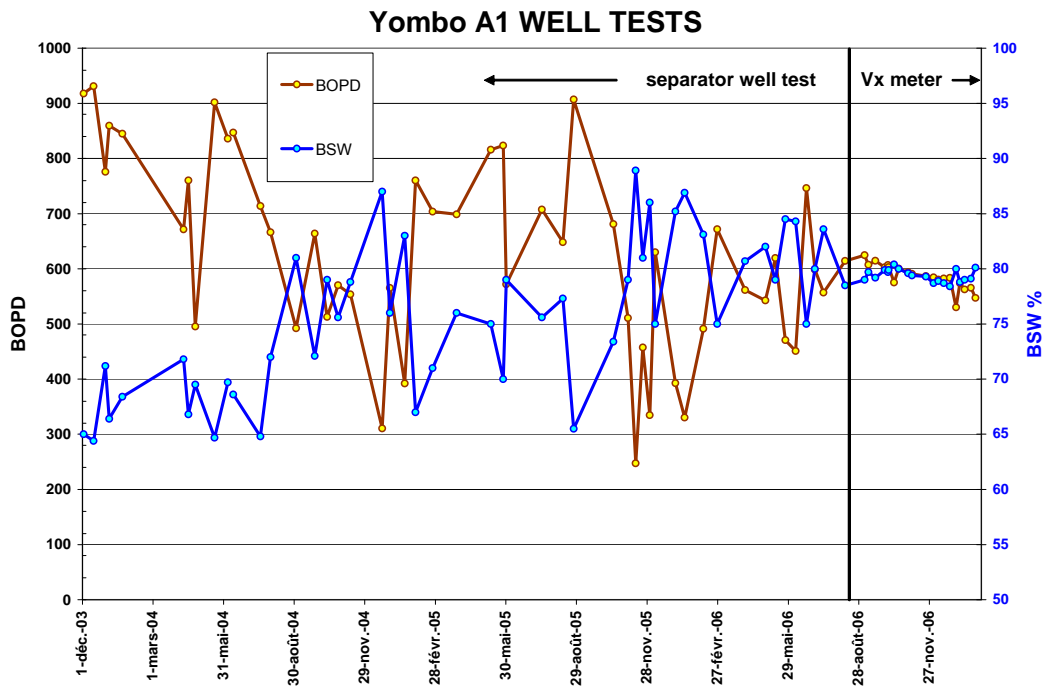

Figure 26: Benefit of the installation of the Multiphase Flow Meter

Overall the performance of the multiphase flow meter was found to be better than 0.5% in absolute for the BSW against manual sampling done at the meter. The liquid flow rate was better than 3-5% against the FPSO production (fiscal metering point). The oil flow rate cumulated over the platform was representative of what was measured at the FPSO. For the gassy well (i.e. high GOR) the gas flow rate measurement where more realistic with what was produced at the FPSO. For the low GOR well, it was usually impossible to measure the gas flow rate at the separator and be able to do comparison.

Based on these results, it was possible for this operator to look at the production optimization for the entire field and be able to gain oil production without increasing the water production due to limitation of the process water treatment plant available on the FPSO. The way to do it was by adjusting the PIP (Pump Intake Pressure); this has been explained in details in Ref [42]. This is achieved by changing the frequency of the pump. As said before the complex lithology present in this field with many layers lead to make some experiments or statements a bit counter intuitive, for example it has been found that reducing the PIP was beneficial to produce less oil and more water. In other case this was the opposite.

One of the other KPI is to monitor the allocation factor. Here below is presented the theoretical value of the oil production based on summing the different well tests done with the separator versus what was processed at the FPSO. The separator allocation factor was roughly at 0.75! This is very poor performance; again this should not be surprising if we refer to the comment given at the beginning of the document explaining the challenges to meet with a separator in this type of very viscous fluid.
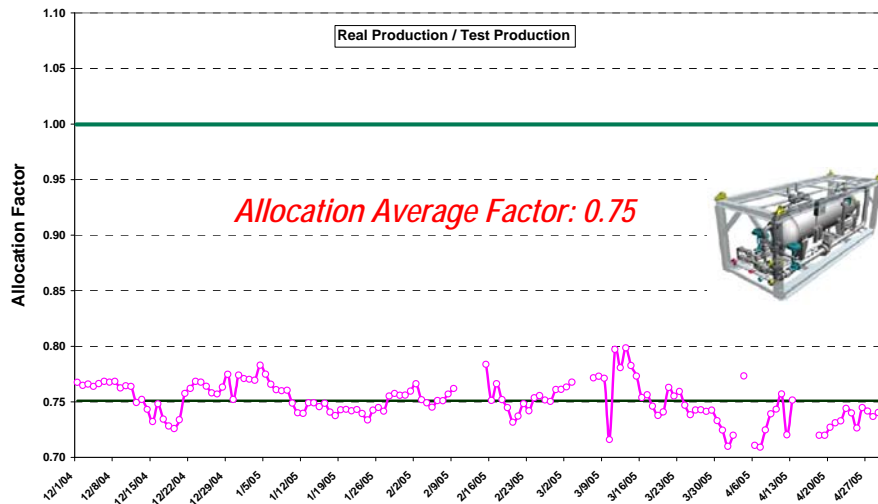
Allocation Average Factor: 0.75

Figure 27: Separator Allocation Factor

The installation of the Vx PhaseWatcher on each platform led to do the same comparison against the real production. The overall allocation factor is better than 0.97! This is a massive improvement.
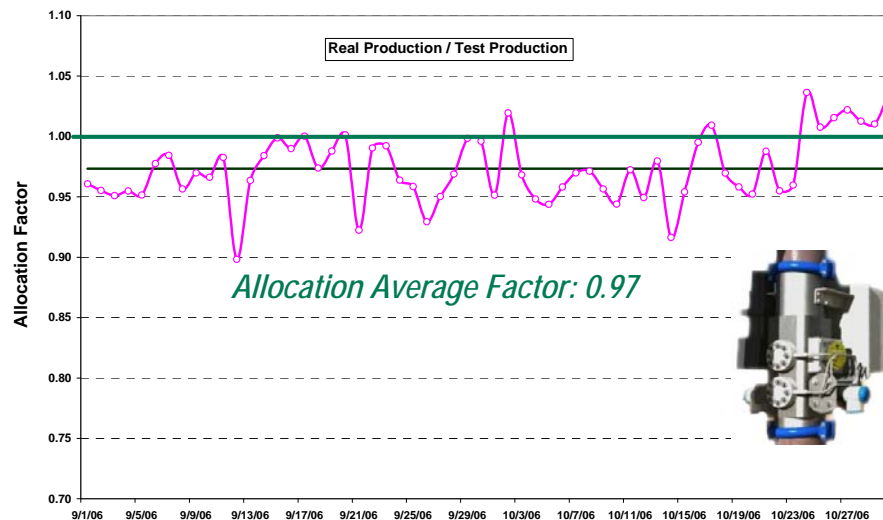

Allocation Average Factor: 0.97

Figure 28: Vx Meter Allocation Factor

The Key Performance Indicators:
- BSW and Net Oil were in accuracy better than 1% (absolute error) for BSW against production. It was more than 25% off when the conventional equipment with Separator was used.
- The allocation Factor was better than 0.97 against 0.75 for the Separator.
- Moreover with Vx meter the well is tested in conditions very close to production conditions, pressure drop through the meter is significantly less than through Separator.
- The High Viscosity & emulsion make the liquid separation impossible leading to poor result with conventional equipment.
- The High accuracy measurement with the Vx Meter allow selecting the right frequency for each pump and do a FINE TUNING to select the right size and range of pump versus the reservoir response,

- to optimize the production in real-time,
- controlling and monitoring the production in real time.

Overall, the optimization with the Vx Meter was not only on the ESP pump by "right" sizing, but also the energy used to drive ESPs: Amperage, Oil consumption. The reduce consumption of electricity, generated from oil collected on the FPSO increase the overall energy saving. The high frequency of well test available now with the Vx technology help to react quicker to well problem, optimize oil capacity for each well has been achieved and is reviewed continuously versus the previous month.

The decline of the reservoir production has been stopped overall and a better understanding of the reservoir production and optimization well by well has been obtained. A significant increase life of the downhole pump has been noticed. Finally the Vx was considered as virtually maintenance free with no moving parts

Projection of the production was reviewed after the installation of the Vx Meter. The trend from 2001-2004 was leading before installation of the multiphase flow meter to a production by Dec 2006 of 9000 bopd. The installation and the optimization of the well, by re-sizing (smaller or bigger) the ESP or changing the frequency or stopping some wells led to get a continuous production improvement over 16 months with a new production rate close to 10,500 bopd. It is more than 1,500 bopd additional production that has been produced versus the initial projection leading to an additional earning of 90 000$ per day (price of oil at that time). This means that the meters were payback over no-time on both platforms!

114.   SAGD and Extra Heavy Oil Hot Production (2007-2010)

Suncor and Schlumberger have been working over several years to establish the performance of multiphase flow meters and determine the accuracy and reliability of flow-testing equipment for thermal heavy oil production. The first test was carried out in 2007 and marked the first successful application of multiphase flow metering in Canadian thermal recovery operations.

The initial introduction leads to select a well for its dynamic conditions and production history factors such as flowrate, line pressure, line temperature, and fluid properties and to allow the connection of the Vx in series with an existing test separator.

The multiphase initial objectives were to measure oil, water, steam, and gas flowrates, understand the well's SAGD dynamics, and the impact of changes in ESP frequency to experience different production conditions, including line pressure, flowrates, phase fractions and ratios (i.e. Water/Liquid Ratio (WLR), and BSW), finally, to study the Vx's sensitivity and performance against a valid reference by defining the results for stability, dynamic response, repeatability and reproducibility. This leads to several papers presented in different conferences (Ref [47-49], and in the meantime to work closer to define what should be the optimal test of a cluster to have a full understanding of the technology and the potential for permanent installation.

In 2009, a second and more advanced field trial was initiated. A pad was selected as the location for this field test due to the large number of good producing wells and ideal set up of the conventional equipment. The MPFM was connected in series with the conventional test separator and the test was divided into three stages to fully evaluate the safety, reliability, accuracy, and advantages of the Vx meter over the conventional test separator equipment.

During the first stage, multiples wells were tested during the months of October and December 2009, ensuring that the MPFM was challenged against the full range of operating conditions of the SAGD wells. During these two months of extensive well testing and fluid sampling, no safety incidents were encountered and the MPFM reported well production rates continuously and without any performance degradation even during the extreme cold ambient temperatures recorded at the well site.

Figure 29: Vx Meter Allocation Factor

To demonstrate the reproducibility of the flow measurements using the MPFM, a stage#2 was completed, this time shortening the flow period from 12 hours to 6 hours and then be able to demonstrate the capability to do more well tests per month per well with the same quality data. Then, with the Vx meter only, the data of the 12 hours testing were reprocessed for 4 hours showing a very good consistency in the results with the 12 hours test.

Results, from thestage#2 confirmed that the data are identical for a 12 hours test versus the 6-hour test and versus the 4 hours test and has very good repeatability and prove the robustness and independence of the flow regime. These results reveal that testing for shorter period of time and more frequently gives more information and is likely preferred to be able to optimize production (Ref [27]).

A stage#3 more dedicated to optimization potential and the impact of changing chokes, steam injected rates and other numerous parameters was done.

An additional challenge for SAGD operations is to monitor at surface: Steam (i.e. Vapour of water), Natural Gas evolved from the Oil, Bitumen, and then Water (Liquid form). This means there are four phases versus the traditional three at line conditions. Therefore, it is necessary to use additional information to obtain this fourth phase measurement. The Vx device can provide four phase measurements and split the fractions of Steam and Natural Gas by using a dedicated Equation of State (EOS) package based on the knowledge of the fluid properties. This allows keeping the multiphase flow meter design as simple as possible without additional sensors, cost, and maintenance program.

The Vx technology has a unique application within SAGD operations due to the use of a specific heating device, which allows the entire nuclear-based instrument to be kept at a specific temperature, and can handle any fluctuation of the fluid temperature passing through with no impact on the accuracy of the fraction measurement.
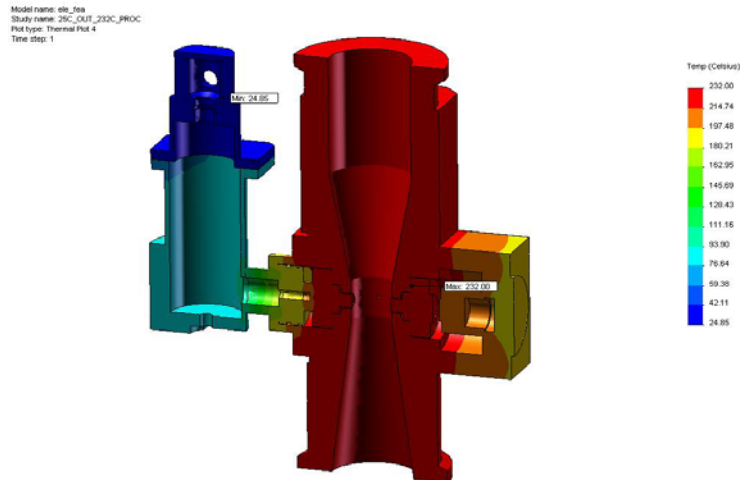
Figure 30: Study of the impact of the temperature on the Multiphase Flowmeter

Extensive testing has demonstrated that under the harsh conditions (no wind, ambient temperature at 25 degC, and flow temperature at 232 DegC) the sensor will not exceed 80-90 DegC in the worst conditions when the electronic has been designed to handle more than 100 degC in normal operation. In addition, the structural design of the Vx Multiphase Flow meters complies with the reference codes and standards of Canada or International.

The figure presents a comparison in footprint between the conventional Test Separator, the Vx PhaseTester (periodic applications) and the Vx PhaseWatcher (permanent installations).

Figure 31: Comparison Test Separator versus Multiphase Flowmeter solution

One of the important reliability considerations was to ensure that the Vx flow meter could operate at the extreme cold conditions during the winter season without any performance degradation. During the second month of the Vx trial at Firebag ambient temperatures close to -40C were recorded. The figure below shows an ambient temperature recorded (without wind chill factor) of -37.1 C at the well site.

Figure 32: Field Conditions in Canada in December

The meter itself has been used most of the time with or without hot air supply and working in the range of -15 to +15 DegC without showing any change in the performance. Data Recording below -20 DegC (ambient temperature at the meter) has been also done in exceptional cases and have demonstrated the robustness of the Vx technology in winter conditions, the issue being if working to too low temperature to plug the small liner very quickly (fill up with anti-freezing fluid).

The main conclusions of the test are first that all the initial objectives given for the testing program were met or exceeded. Second, the Vx multiphase meter managed to demonstrate all the operating requirements required by Suncor operations. The uncertainties of all the phases are as per below:

- Uncertainty of the total mass flowrates is within +/- 2% (relative error)
- Uncertainty of the Water Liquid Ratio or BSW is within +/- 2% (absolute error) and after correction of the reference measurement based on a global back allocation factor.
- Uncertainty of the total liquid flowrate is lower than +/- 2% (relative error)
- Uncertainty of the total liquid density is lower than +/- 1% (relative error)
- Uncertainty of the total gas flowrate is within +/- 2% (based on the typical hypothesis in conventional system that it is only made of vapour of water)

Third, the Vx technology was capable to capture the entire dynamic of the flow: Start-up, intermittent and pulsing flow. The meter was used above 180oC in this test. By the order of accuracy from the output of the meter, the sequence is as follows: Total mass (or volumetric) flow rate, liquid mass (or volumetric) flow rate, gas mass (or volumetric) flow rate, GVF, GLR, then WLR, and associated oil and water flow rate.

The Vx meter reveals good dynamic response, repeatability and accuracies of the flow rates and has shown promise to be able to be used as an optimization tool. This is likely the result of the design and robustness of the Vx meter, summarized with some key features such as no Tuning Factor, no Separation, no Flow Calibration, no issues with Foams or Emulsions, no moving part, no sensors in direct contact with the fluid, and improve water detection and accurate BSW monitoring.

12. REVIEW OF THE PERFORMANCE IN CONTROLLED ENVIRONMENT AND NEW VISCOUS FLOWLOOP FACILITY (2008)

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) (Ref [12]). However the reference measurements were limited and this could not demonstrate the entire potential of the Vx technology.

121. The new TUV NEL Viscous Flowloop facility

Based on interest from the UK Government, BIS (ex-DTI) has been helping to upgrade the flow loop facility in National Engineering Laboratory (TUV-NEL in Scotland). During this project, the identification of fluid having a large viscosity, well described viscosity behaviour, environmental friendly, and being transparent has been evaluated and used. One of the main improvement in the facility was to be able to use a cooler which allows controlling the temperature at better than ± 1 DegC and therefore provide a proper estimation of the viscosity at line conditions during the entire period of test.

The flowloop tests were conducted over two specific period of time during Q3 and Q4 2008. The fluids used are for the gas nitrogen and then an oil synthetic oil called Paraflex. To avoid the problem of stabilization and issue with emulsion and separation in the facility the entire test was run with a very little amount of water fix initially and the separator will be used only as a two phase separator gas-liquid[24]. The reference uncertainty is ± 1% for oil and water flow and ± 1.5% for gas. The flow tests were preceded by a laboratory investigation of the viscosity. A polynomial fit of the 5th order was used to estimate the dynamic viscosity.
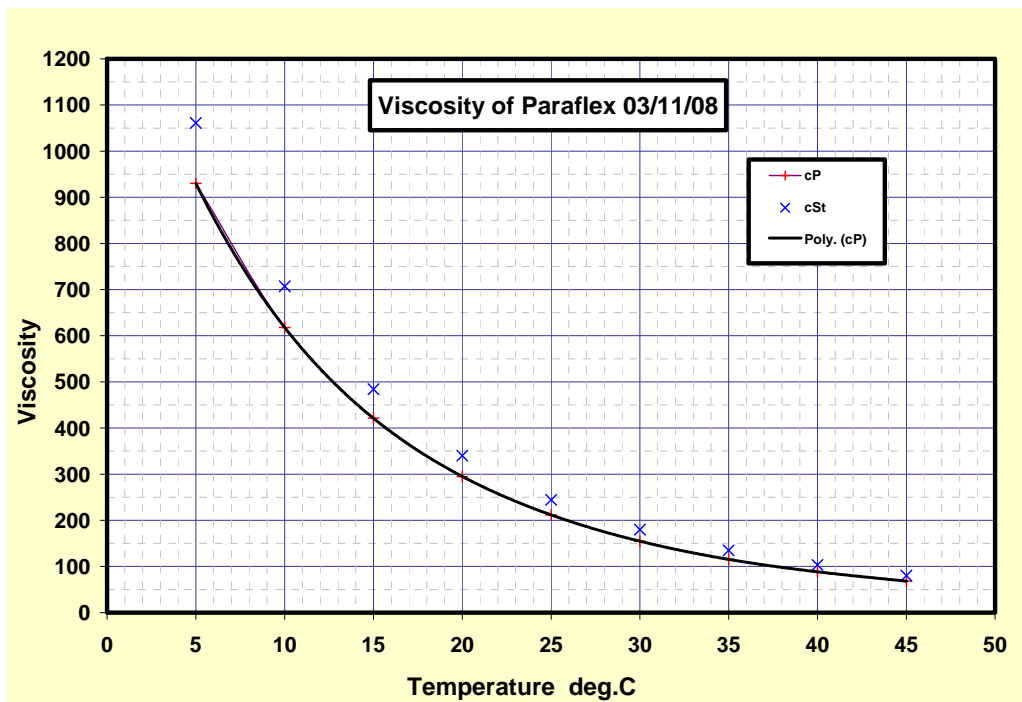

Figure 33 – Viscosity behaviour versus temperature based on extracted flowloop samples.

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[24] 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.

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

Figure 34 – Vx meter skid installed in the TUV NEL Multiphase Test Facility (Scotland).

The Vx meter was installed on a horizontal 3-inch flow line, downstream of the gas injection point, with entry and exit arranged via 90° elbows (Figure 19). It was necessary to find a balance between the responses of the meter, the duration of the test, and the quantity of point achievable in a limited period. In the field this will run for hours, this was not practical in our case. The original plan was then to log for 5 minutes any monophasic point. For 10 minutes, any flow conditions with a GVF lower than 90% GVF, 15 minutes if the GVF was within 90-95%, and 20 minutes above 95% GVF. The interest of this logging time is to ensure that the flow passing through the reference meter is the same than in the test meter, and then the statistic is building up in the definition of the uncertainty of the measurement at the reference and at the test meter. These numbers are by far much smaller than the recording time used in the field or even some operators required only one rate per hour.

122.   Matrix of test and protocol of test

Heavy oil is a fluid, which has lost on a geological scale most of the gas dissolved inside the oil at reservoir conditions. It is then heavier (density) and the GOR (gas oil ratio) is much smaller than with black oil. The Schlumberger field experience has shown that GOR can reach value much lower than 100 scf/barrel. In the same time, the pressure is usually low in this type of wells which are essentially pumped either with ESP or with PCP. A simulation has shown that the majority of the data (> 60%) have a GVF lower than 70%, and more than 95% of the data have a GVF lower than 90%. This wills analysis will be our first guideline for the definition of the test matrix, and including the field experience this leads to the following range of investigation presented in the working envelope of a Venturi versus gas flow rate and liquid flow rate at line conditions.
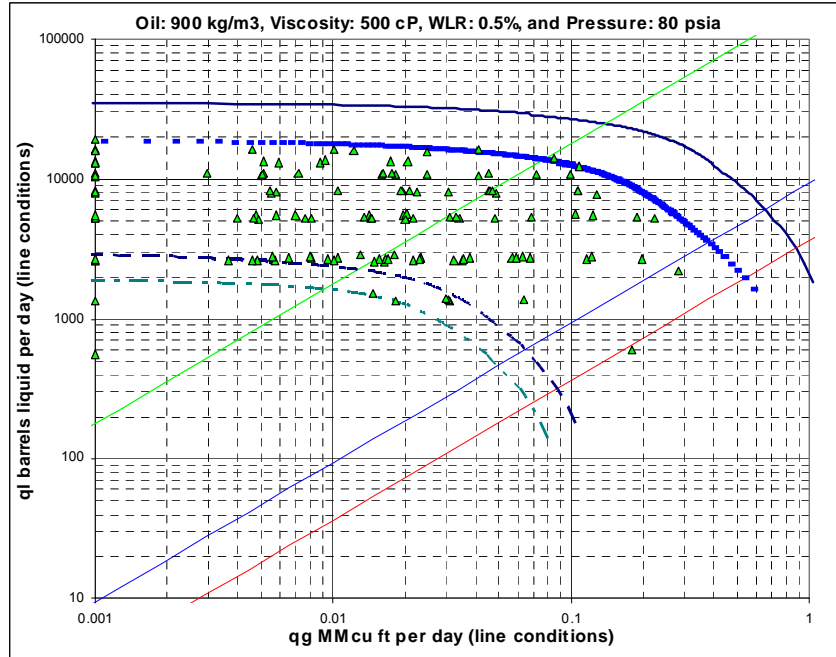
Figure 35 – Range of investigation versus liquid and gas flow rate at line conditions. The GVF lines (green, blue, and red) are respectively at GVF of 50%, 95% and 98%. The blue curve lines are representing the differential pressure respectively of 30, 50 1,500 and 5,000 mbar. A total of 133 point of measurement is shown, and an additional 38 data at DP below 50 mbar are not presented.

Taking into account the different constraint of operation, duration, and range of investigation it is more than 171 data points with essentially two viscosities that has been collected including 38 at low Differential Pressure for future analysis.

GVF [%]	0-1	<10	<20	<40	<60	<75	<90	<95	<100
Nb of data	27	8	16	38	31	19	22	7	2

Table 3: Number of recorded data point versus GVF range

The final analysis done for the selection of the equipment are based on the fact that we are limited in the selection of oil versus equipment (pump, back pressure, cleanliness) and also in the viscosity due to the cooler capability to keep constant the temperature for a given flow period (i.e. a recording time). As mentioned earlier the key point in the study of the heavy oil is essentially the Reynolds number and not the viscosity. Therefore, at a given viscosity and with a given limitation of differential pressure measurement it is only possible to play with the diameter of the Venturi used indeed, if we rewrite the Reynolds number versus this parameter we obtain:

$$\mathrm{Re}_{liq} = \frac{\rho_{liq} Qvol_{tot}}{D.\mu_{liq}} \frac{4}{\pi}.F_{CREY} \qquad (1)$$

In addition, it can be noted that at a given total volumetric flow rate, and other parameters being equal then the use of a larger diameter leads to a smaller Reynolds number for a same volumetric rate. The optimum size based on the equipment available was a Venturi with an internal 4-inch diameter having a throat diameter of 52mm and beta ratio of 0.5. The others dimensions are all in accordance with the ISO 5167.

123. WLR Measurement, Resolution, Accuracy with multi-energy gamma-ray

The technology associated with the absorption of the gamma ray has been described in numerous document, we will summarize hereafter the main information. Whereas usually the nuclear sources measure directly the density but not the different fractions, the use of dual- or multiple-energy gamma ray can do it. These sources are usually weak and emit several peaks and allow measurement of the fraction measurement of the different phases. Thus, the instrument gives <u>a simultaneous measurement of the gas, water, and oil fraction, and water/liquid ratio</u>.

The advantage of the gamma ray technique is that this can be used in any type of water/liquid ratio; it is also independent of the structure of the flow because the gamma rays interact with the atoms and do not interact with the macrostructure (i.e., foam, emulsion, or any other type of mixture). If the acquisition electronics are stable, the accuracy can reach a level of better than ± 0.001 to ± 0.003 in concentration for each phase. In principle, the measurement is also very easy to acquire, with only count rates to detect.

Cause of the chaotic behaviour and rapid change in the main flow the entire challenge is to design a detector capable of a high-frequency data processing. Vx technology uses a nuclear smart detector, designed specifically for the multiphase environment that is capable of one million operations per second. With this fast acquisition rate, it can capture any change in the fraction versus time. An extension of the dual-energy gamma ray is the multiple-energy gamma ray, which adds one or more energy levels to allow calculation of another fraction such as the scale inside the well. Schlumberger used it as early as 1999 and later published an SPE paper (Poyet, Segeral, and Toskey, 2002) or to do some real-time quality control. Recently, this application was updated for sophisticated cases (Pinguet et al., 2006 and 2008; Pinguet, Roux, and Hopman, 2007). Overall, having one more energy level leads to finding one more unknown such as scale, sand, wax, and asphalten deposition. The advantage and limitation are listed in the table 4.

WLR range	No limitation
GVF range	No limitation
Inversion-phase requirement	No limitation
Foam	No limitation
Emulsion	No limitation
Flow-pattern limitation	None with fast acquisition (Vx technology, Neftemer)
Composition change	Influence in some range of GVF and WLR with large compositional variation of heavy atoms
Measurement type	Diameter (simple implementation)
Safety	Radioactive source requires regulatory process. This is easier for a source with lowest activity, lowest energy level, and lowest half-life time.
Line temperature	No limitation with special design of detector (Vx technology)
Line pressure	None ; usually not in contact with the process fluid

Table 4: Strengths and weaknesses of the nuclear measurement

As conclusion, this multi-energy gamma ray technology can be used on the full range of WLR without affecting the uncertainty of the measurement, it is totally independent of the phase distribution and then it can be used on the full range of GVF.

Figure hereafter presents the WLR absolute accuracy versus the GVF, it is important to note, that the detailed analysis of the multi-energy spectrum leads to no scattering of the WLR measurement even at very high GVF.
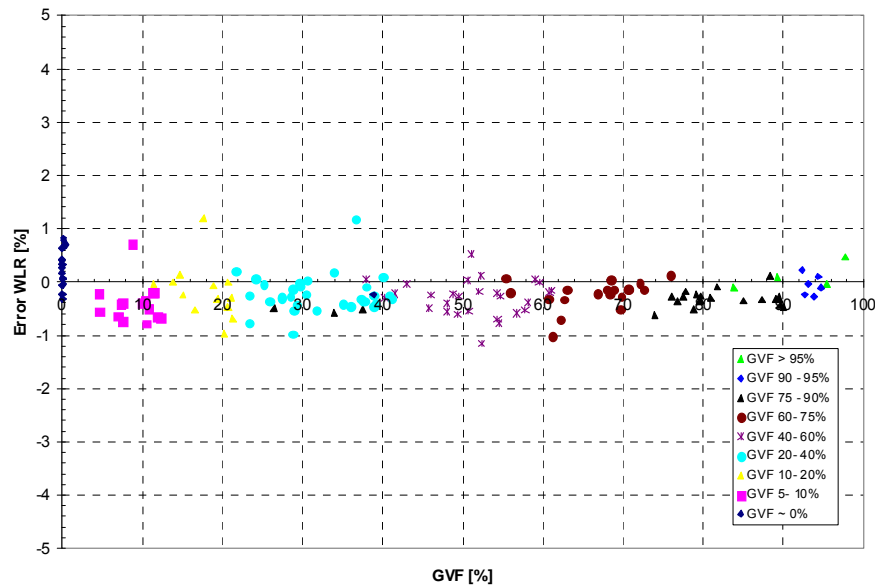

Figure 36 – Absolute error of the WLR measurement versus GVF for both set of experience.

It should be noted that the data analysed in this section have a differential pressure measurement from 4 to 1,400 mbar and as then albeit being outside of the range of the metrology for the flow rate measurement the fractions measurement is still accurate. Finally, the overall performance versus the WLR is presented in terms of the root mean square parameter (i.e. RMS).

	GVF [%]	0-1	<10	<20	<40	<60	<75	<90	<95	<100
WLR	RMS [%]	0.42	0.53	0.49	0.46	0.42	0.38	0.3	0.24	0.34
	Nb	27	8	16	38	31	19	22	7	2

Table 5: WLR performance (i.e. RMS) versus GVF segmentation. The number of point is also mentioned versus GVF.

An analysis of the performance of the WLR can be done versus the uncertainty measurement is presented in the Table 5.

WLR	Criteria	<0.25%	<0.5%	<0.75%	<1%	<1.25%
Total Number	Nb	72	133	160	167	171
171	%	42%	78%	94%	98%	100%

Table 6: WLR performance versus different criteria of uncertainty (158 data leads to 95% confidence interval based on the binomial distribution analysis with a sample of 171 data)

The uncertainty of the WLR measurement based on the nuclear measurement can be established for the Vx technology in Heavy Oil to a value slightly higher than $\pm 0.75\%$ with a 95% confidence interval.

The final demonstration of the robustness of the WLR measurement versus GVF and flow rate variation is presented Figure 37. This recording was done over more than 2 hours continuously at different flowrates and the GVF was changing from 0 to close to 99%.
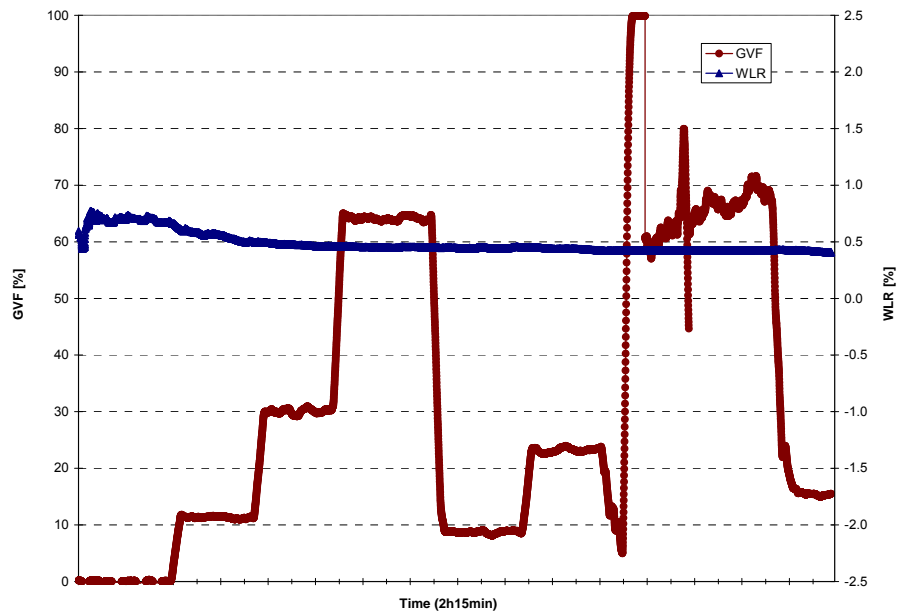

Figure 37 – Demonstration of the stability of WLR measurement at different GVF versus time (WLR measurement averaged done over 2 minutes). WLR expected around 0.5%.

### 124.	Mass flow rate Measurement, Resolution, Accuracy in monophasic conditions

If fraction measurements are essential to split the total mass flow rate, it should be mentioned that the total mass flow rate is also the only conservative value at any Pressure and Temperature conditions. It is then the second key parameter to evaluate and look at to evaluate the performance of a multiphase meter.

The first step of our analysis was to look at the evaluation done of the discharge coefficient based on the various flowloop data collected around the world. A subset of main set of collected data has been used to do this evaluation and using only the monophasic conditions. The Reynolds number investigation was from 60 to almost 3,000 with most of the data between 60 and 1,600 (86% of data).
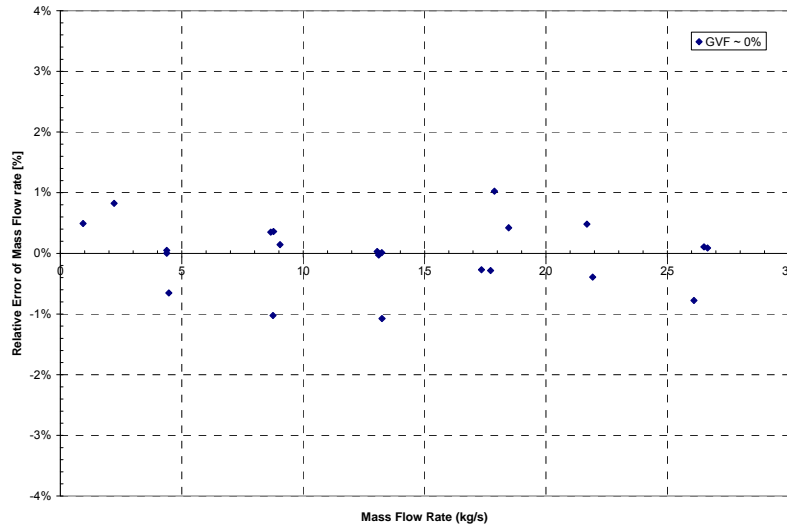
Figure 38 – Relative error of the monophasic subset of data versus total mass flow rate to demonstrate the performance of the Venturi in monophasic conditions. The full range of total mass flow rate from 1 to 27 kg/s has been investigated.

125. **How to address the performance of a multiphase flow meter or any sensor on a large scale of investigation**

This question is always an issue in multiphase conditions where it is expected that the gas flow rate for example could change by a factor 1,000 times. It is obviously reasonable to describe the performance of a sensor as a % of the reading when the values are quite large but for low value (i.e. low flow rate) this cannot be addressed anymore as a relative uncertainty.

Let us take for example the differential pressure sensor, which is used in this application. The uncertainty of the entire chain of acquisition has been evaluated to be in absolute within $\pm$ 1-2 mbar. The range of use of this sensor has been defined in the standard mode to be between 50 to 5,000 mbar. Therefore the uncertainty in the measurement is changing from $\pm$ 2/50 = $\pm$ 4% to $\pm$ 2/5,000 = $\pm$0.05%! Obviously, in this upper range of differential pressure measurement, it is not anymore an absolute value that should be taken into account but the performance of the differential pressure measurement as given by the manufacturer in relative error.

In the same way, representing only the performance of a system on a full range of application in relative error will lead to misconception. Let us assume for example that a volumetric flow rate meter has an accuracy of 1%, this means when flowing 100 m3/h the error is $\pm$ 1m3/h but now flowing only 1 m3/h, this means that the error of the measurement is $\pm$ 0.01m3/h! This is way below most of the standard accuracy of flow meter even in monophasic.

The most appropriate way to claim a performance of a meter is therefore the combination of a relative error of the measurement based on the reading and a constant value for a lower range and should be expressed by:

$$\pm \text{ Uncertainty of the parameter A} = \pm \text{ Max(x\% of A, B)} \qquad \textbf{(2)}$$

With A and B having the same type of dimension or unit, and X and B being defined by either theoretical analysis or most commonly by comparison with reference measurement such as on flow loop test. This way of representing performance avoids having uncertainty on a measurement of $\pm$ 150% for example! In addition, obviously the performance of a meter is better than another one if A and B are the smallest. Finally, one of the criteria that we will be using is the Root Mean Square (RMS) concept also known as

the quadratic mean, it is a statistical measure of the magnitude of a varying quantity versus a reference which has also its own uncertainty and then lead immediately to the performance of parameter based on the statistical analysis.

126.   Mass flow rate Measurement, Resolution, Accuracy in monophasic conditions

The absolute error of the total mass flow rate versus the mass flow rate is presented Figure 39 , and the error relative error versus the mass flow rate is in the Figure 40 .The performance of the total mass flow rate versus the Reynolds number is well within ± 2% and with a slight trend to larger value at low Reynolds number or low flowrate, the response of the Venturi is therefore identical for a given Reynolds number whatever the GVF value.
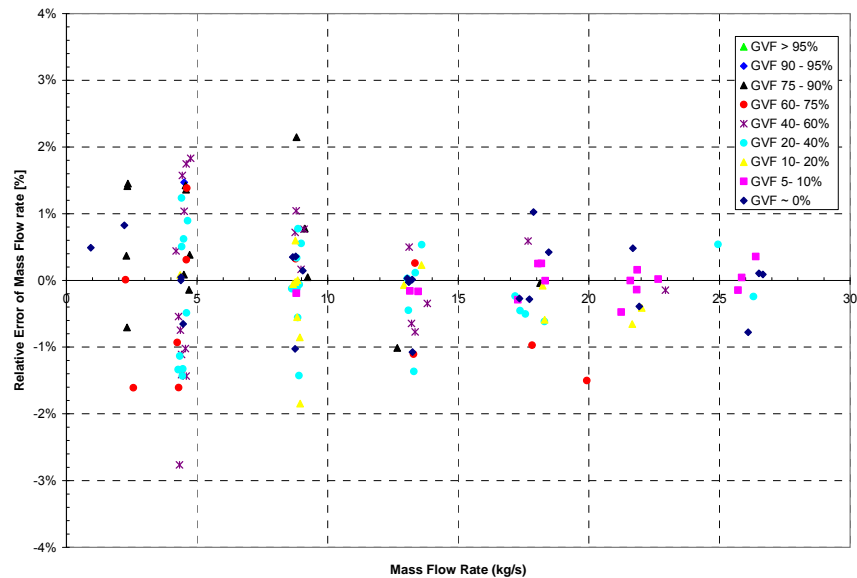

Figure 39 – Relative error of the mass flow rate versus mass flow rate for different GVF

At lower mass flow rate the uncertainty on the mass flow rate is increasing as this is expected from purely the mathematical analysis. The data are well within ±1% error relative at large mass flow rate 2-25 kg /s, and it is within ±2% at low total mass flowrate 5 kg/s. This analysis shows also no dependency to the GVF.
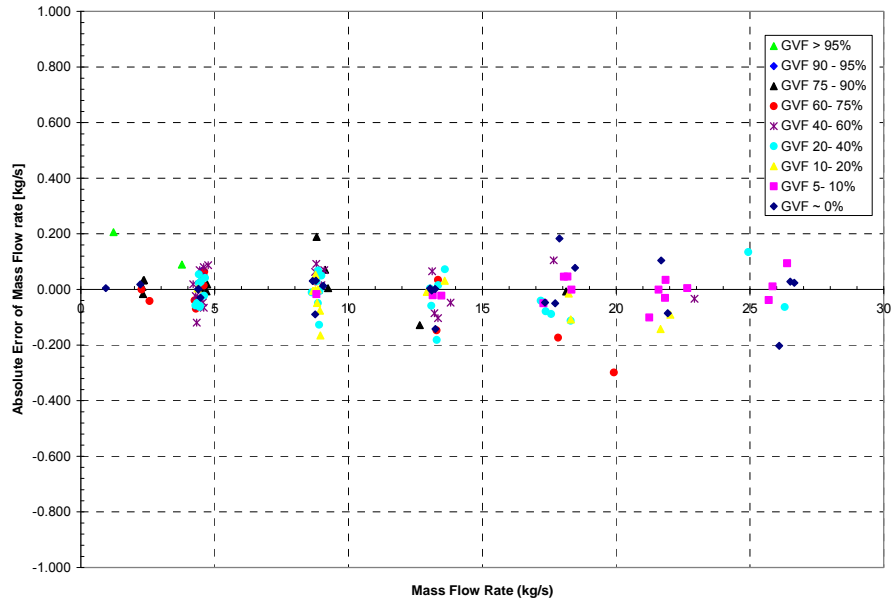
Figure 40 – Absolute error of the mass flow rate versus mass flow rate for different GVF.

The absolute error of the mass flow rate versus the mass flow rate does not show any specific trend. The evaluation of the RMS versus the GVF is presented inside the following table.

	GVF [%]	0-1	<10	<20	<40	<60	<75	<90	<95	<100
Mass	RMS	0.08	0.04	0.07	0.07	0.07	0.12	0.06	0.07	0.3
	Nb	22	8	16	32	23	13	14	1	2

Table 7: Mass flow rate performance (RMS) versus GVF including the number of point per GVF range

Expressing the performance of the combination Venturi – Nuclear measurement in low Reynolds number for the Total Mass Flow Rate can be defined by:

± Max of (1% of the total mass flow rate reading or 0.15kg/s).

Again we feel this approach is more generic than mentioning 0.16kg/s which in our sense represent only the performance for a specific range of mass flow rate studied on this flow loop (i.e. 1-27 kg/s).

Mass Specification		<0.5%	<1%	<1.5%	<2%	<2.5%
Total Point	132	66	96	120	127	128
		50%	73%	91%	96%	97%
	Max of	<0.5% <0.15 kg/s	<1% <0.15 kg/s	<1.5% <0.15 kg/s	<2% <0.15 kg/s	<2.5% <0.15 kg/s
		123	125	127	129	130
		93%	95%	96%	98%	98%

Table 8: Mass flow rate performance versus different criteria (122 data points represent 95% confidence interval based on the binomial distribution)

Achieving ± 1% accuracy in this range of viscosity and Reynolds number shows that the correction based on the monophasic knowledge can be extended to the multiphase flow conditions.

127.   Liquid flow rate Measurement, Resolution, Accuracy with Venturi

The liquid flow rate is based on the performance of the mass flow rate and the fraction measurement of the gas compensated by the slippage of the gas versus liquid flow rate.

From a mass flow rate point of view knowing that we are working at low pressure the mass flow rate of the liquid should be quite equivalent to the total mass flow rate and a priori the performance should be excellent. The absolute flow rate study shows that the RMS is equal to $\pm$ 0.35 m3/h and therefore 95% of the data are within $\pm$ 0.7 m3/h. This is an outstanding performance. All the data excluding the one at GVF above 95% are within $\pm$ 1% to $\pm$ 2% relative error of the liquid flow rate.

The analysis of the liquid performance versus GVF is given in the table hereafter:

	GVF [%]	0-1	<10	<20	<40	<60	<75	<90	<95	<100
Liq	RMS	0.32	0.36	0.28	0.32	0.31	0.42	0.27	0.3	1.2
	Nb	22	8	16	32	23	13	14	1	2

Table 9: Liquid flow rate performance versus GVF including the number of point per GVF range and RMS

The overall performance could be summarized as such for the liquid flow rate

$\pm$ Max of (1.25% of the liquid flow rate reading or 0.5 m3/h)

Liquid Specification		<0.5%	<1%	<1.5%	<2%	<2.5%
Total Point	132	45	101	118	124	130
		34%	77%	89%	94%	98%
	Max of	<0.5%	<1%	<1.5%	<2%	<2.5%
		<0.5 m3/h	<0.5 m3/h	<0.5 m3/h	<0.5 m3/h	<0.5 m3/h
		116	121	128	128	130
		88%	92%	97%	97%	98%

Table 10: Liquid flow rate performance versus different criteria (122 data represent the 95% confidence interval based on the Binomial Distribution)

128.   Gas flow rate Measurement, Resolution, Accuracy with Venturi

The gas flow rate is based on the combination of the mass flow rate and the fraction measurement of the gas compensated by the slippage of the gas and liquid flow rate. From a mass point of view knowing that we are working at low pressure the mass flow rate of the gas flow rate is small and then the contribution in the overall mass flow rate is low, it should be then expected some larger deviation versus the reference measurement in this type of conditions. The performance could be showing an extreme case versus the real field conditions where the density of the gas could be twice higher than what has been simulated here (3-5 Bara) and the recoding duration in the field being much longer.

It can be summarized that for gas flow rate measurement above 100 m3/h the relative error is well within $\pm$ 10%, and the relative error is increasing at low GVF or low gas flow rate with accuracy in this case between $\pm$ 10-15%. The absolute error of the gas flow rate at low flow rate is small and most of the data are within $\pm$ 2-4 m3/h for GVF lower than 40%. The analysis of the RMS versus GVF is presented in the following table.

	GVF [%]	0-1	<10	<20	<40	<60	<75	<90	<95	<100
Gas	RMS	0.12	0.45	0.83	1.96	3.65	2.98	8.86	1.1	8.14
	Nb	22	8	16	32	23	13	14	1	2

Table 11: Gas flow rate performance versus GVF including the number of point per GVF range and the average and RMS

Overall, on the full range of investigation it should be claimed that the performance of the gas flow rate at standard conditions is:

$$\pm \text{ Max of (10\% of gas flow rate reading or 5 m3/h)}$$

A specific analysis versus different criteria is presented in the Table 11.

Gas Specification		<2%	<4%	<6%	<8%	<10%
Total Point	132	45	67	88	99	110
		34%	51%	67%	75%	83%
	Max of	<2%	<4%	<6%	<8%	<10%
		< 2m3/h	< 2m3/h	< 2m3/h	< 2m3/h	< 2m3/h
		99	106	109	111	117
		75%	80%	83%	84%	89%
	Max of	<2%	<4%	<6%	<8%	<10%
		2 m3/h	3 m3/h	4 m3/h	5 m3/h	5 m3/h
		99	112	118	121	124
		75%	85%	89%	92%	94%

Table 12: Gas flow rate performance versus different criteria including the number of point per GVF range (122 data points represent the 95% confidence interval based on the binomial distribution)

129.   COMMENTS

A large set of data has been collected with a Reynolds number going from 60 to more than 3,000. This represents the range of Heavy Oil conditions that can be met without adding any diluents which lower the viscosity and then increase the Reynolds number. The purpose of this test was also to show that a multiphase technology could be used in this type of conditions and was provided robust measurements. The combination Venturi-Nuclear measurement demonstrates to work on the full range of Reynolds number, GVF from 0 to 96%, and mass flow rate from 1 kg/s to 27 kg/s. As a reminder, the study of very high GVF was not done because most of the gas is usually no longer present in the heavy oil reservoir and gas-lift operations are not common with Heavy oil production. Overall, the GVF rarely exceeds 95%.
It was demonstrated theoretically and experimentally with this viscous fluid that the discharge coefficient is a key parameter and leads to an adequate evaluation of the liquid viscosity at line conditions.

From an experimental point of view[25], the analysis performed shows with a 95% confidence level or 2-sigma probability and in the flowloop conditions that we met for this test that the following uncertainty for the main output parameters - Mass flow rate, liquid flow rate, gas flow rate, and WLR - are:

$$\text{Qmass Uncertainty} = \pm \text{ Max of (1.0\% of total mass flow rate reading or 0.15kg/s)[25]}$$
$$\text{Qliquid Uncertainty} = \pm \text{ Max of (1.25\% of the liquid flow rate reading or 0.5 m3/h)[25]}$$
$$\text{Qgas Uncertainty} = \pm \text{ Max of (10\% of gas flow rate reading or 5 m3/h)[25]}$$
$$\text{WLR Uncertainty} = \pm 1\% \text{ (Absolute Error)[25]}$$

NOTE: This is not a claim of new uncertainty, but the result of analysis performed in well controlled conditions and factual, obviously additional efforts could conclude to better results or alterate them in order to be more generic to any conditions.

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[25] The full GVF Range is essentially from 0 to 98% but more than 95% of the data are within 0-90%, and 2/3 of the data are below 75% GVF

These performances are much better than the typical performance published in previous papers (Ref [48-50]) and could be explained by a better performance of the flowloop at low Reynolds number, new advanced processing, and the better understanding of the fluid properties including the review of the discharge coefficient definition at low Reynolds number. Combining both works it can then be claimed that the liquid flow rate performance is known to better than ±1.5 - 2% for Reynolds numbers ranging from 100 to beyond 25,000. For the gas the performance should be well within ±10% at low pressure[26]. These are 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 Oil, Extra-Heavy Oil, and Bitumen business.

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 1-2% (absolute error). WLR uncertainty above 5% propagates to larger 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 and therefore a very accurate mass flowmeter. It is hoped that this document clarifies finally the effect of viscosity on multiphase meters based on differential pressure measurements; such as Venturi, Orifice plates etc.

Very few suppliers, based on the available publications, are capable today of quantifying and demonstrating the entire performance of their metrology and even less have an in-depth understanding in Heavy Oil. Through the unique building and simple combination of the Venturi and Multi-energy gamma ray, 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 Multiphase Flowmeter 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 Bitumen to Condensate production.

13. QUICK SUMMARY OF WORLDWIDE EXPERIENCE IN HEAVY OIL

Nowadays, the new challenges in the harvest of energy include heavy oil exploration/development in various conditions from shallow to deep water fields. When it comes to Well Testing solution as normal conventional or standard separators cannot be used to acquire accurate flowing data, being inadequate to handle in such environments extremely low gas rates, low contrast of density among the liquid, contamination of the different effluents, and the instabilities of the wells leading to carryover or carry under. The Vx technology based on inline multiphase metering (i.e. without separation) answered the issues mentioned here above. Moreover procedures have been developed in order to achieve better results in Heavy Oil and the development of improved processes in place to measure viscosities in fields with high oil viscosity scenarios. With these processes in place and a multiphase meter being used, heavy oil scenarios are often out of the standard PVT package usually based on Black Oil Correlations, in such environments a significant data enhancement on final results can be achieved by the combination of the Vx technology and accurate fluid properties to do conversion from line to standard conditions in order to increase the accuracy measurements at standard conditions by removing the uncertainty due to the fluid properties. A large effort has been done and is undergoing to extend even further this envelope through software modeling improvements.

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[26] 2.5 to 6 Bara

We are summarizing briefly the overall experience gather worldwide in heavy Oil versus time. This gives a quick overview of the tendency and behavior of the heavy oil worldwide. This is obviously more an indication than a real survey. The overall envelope covers a wide range of situations however the trend of this analysis show that the Vx Technology in Heavy Oil is focusing in general to Low GVF, Low WLR, Low GOR, which is widely used in Brazil, Chad, Congo, Russia, Mexico and Venezuela…

Some specific highlighted cases:

- In Brazil in deepwater exploration operations the dead oil density can go down to 15 API, and dead oil viscosity is around 1800 cP at 40 DegC with low Water Cut (WC).

- In Chad, in production facilities and high WC. Dead oil density was lower than 17 API and dead oil viscosity was around 500 cP at 40 DegC.

- In Mexico extensive operations are mainly offshore exploration with oil density around 8-10 deg API and low WC.

- In Venezuela the dead oil density can reach down to 8 API, and dead oil viscosity is up to 27,000 cP at line conditions within general low Water Cut (WC). Today the production with diluents is still common even if a new vision with hot production is coming.

- In Canada, the dead oil density can go down to 7 API, and dead oil viscosity is beyond the 50,000 cP at reservoir conditions, only thermal production is the way forward with then large WLR content and emulsion. Temperature is within 150 to 180 degC at surface.

- Romania has successful production In-Situ Combustion however the Vx Technology has never been tested in this type of production.

- Expected jobs in CHOPS production or with solid production are expected in 2011.

This Heavy Oil Business presents a new opportunity for Multiphase application. The enormous experience collected on flow loop and worldwide with the Vx technology position Schlumberger as a leader in Heavy Oil Business including in the number of papers published to explain challenges and achievements and in terms of application from Exploration to Production. Schlumberger is a leader of meter sold worldwide (by number in general) but one of the two leaders in the Heavy Oil business with the fastest growth over the last 5 years.

Technique	Process	Vx Technology Experience	Challenges in General for Multiphase Meter
Cold Production	Gas Lift	Yes	Low Reynolds Number High GVF High viscosity
	Downhole Pumping (ESP)	Yes	Low, and Very Reynolds High Viscosity Low Producer
	Surface Pumping (PCP)	Yes	Low, and Very Reynolds Low Producer High viscosity
	Rod Pump	Yes	Intermittent Flow Low producer High Viscosity Very Low Reynolds
Hot Production	Surface Heating	Yes	No Specific Limitation (Temperature < 150 degC in general)
	InSitu Combustion	No	High Temperature (>100C) No issue with Vx Low Producer
	THAI	No	High Temperature (> 170C) High GVF (Same challenge than SAGD)
	SAGD or InSitu Thermal Process with Pumping top side or downhole[27]	Yes	High Temperature (>150 degC) High GVF High WLR Emulsion
	Cyclic Steam Stimulation[28]	Yes	Low Flowrate Fair Temperature Low Pressure
	Vapour Extraction[29]	No	Same than SAGD
	SAGD with Gas Lift	Yes	Very HIGH GVF High Temperature High WLR Several Gas present (Vapor, Steam, oil, water)
Solid Production	CHOPS	No (2011)	Low Producer High quantity of solid Low GVF Low Reynolds
Diluents Production	Diluents[30]	Yes	Several Fluid Present (Viscosity change) Low GVF Low Pressure Low Flowrate

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[27] Steam Assisted Gravity Drainage SAGD: Using two wells horizontal one on the bottom to capture the heavy oil and one on the top for steaming injection.

[28] Cyclic steam stimulation: a three-stage process involving several weeks of steam injection, followed by several weeks of "soaking," followed by a production phase where the oil is produced by the same wells in which the steam was injected. As production declines, the injection phase is restarted. The high-pressure steam not only makes the oil more mobile, it creates cracks and channels through which the oil will flow to the wellbore

[29] Vapour extraction (VAPEX) is vaporized solvents such as ethane or propane is injected into the formation and creates a vapour-chamber through which the oil flows due to gravity drainage. Like steam assisted gravity drainage, the VAPEX process can be applied using single horizontal wells, paired horizontal wells or a combination of vertical and horizontal wells.

[30] Solvent: Impact of Fluid Properties and Phase Behaviour in Heavy Oil and you can reduce from 30 000 cp to less than 50 cP the oil viscosity

14. CONCLUSIONS

The industry is in need for a technological solution in heavy oil, the solution offered here consist of the combination of multi-energy gamma ray, Venturi multiphase flow meter combined. This solution provides in Heavy oil environment similar benefits of logistics and safety obtained in lighter oil, condensate and wet gas well testing. It is possible to obtain tight range of uncertainty even in conditions of viscosities up to several ten thousand cP at line conditions. An evaluation from 60 to more than 25,000 in terms of Reynolds number has been done and demonstrates the robustness of this combination. From a theoretical point of view it has been explained that the better determination of the liquid viscosity at operating conditions, the better the metrological performance of any multiphase flowmeter.

In Heavy Oil accurate flowrate measurement are achievable from exploration to production with Vx Technology, additionally a better estimation of the reservoir, or a Real-Time Delivery Measurement are obtainable and the most critical one a cost reduction by optimization of the gas lift injection, or a proper setting on the electrical submersible pump (frequency, sizing, slugging effect..) or PCP but also steam injection or SOR in hot production environment.

It took several iterations, a number of flow loop campaigns and 7 years of engineering and research efforts to obtain and validate a model based on a discharge coefficient for viscous fluids in the multiphase environment. These flow loop tests with high accuracy demonstrate performance of the meter in heavy oil.

It has been identified in this document that effect of viscous oil 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 and how this can reduce errors to maintain an overall high accuracy. 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 5 intensive years of work in Heavy Oil are valid and beneficial for this new product. Already well testing operations for Heavy Oil from "Exploration to Production" well testing operations have been performed around the world, in locations such as Brazil, Chad, Congo, Russia, Canada, Venezuela, and Mexico.

The main benefits of Vx Meters are a stand-alone meter, portable and no moving parts. There is no need for flow calibration by cross reference to another metering system or any calibration device. The measurement is independent of the flow regime (e.g. slug flow, annular, dispersed…) but also phase distribution independent (i.e. foaming, emulsion…). It has the widest operating envelope of any multiphase flow meter on the market from 0-100% GVF to 0-100% WLR with lately the additional capability of high quality sample. In addition, it offers real-time data management.

The robust physics behind the multi- energy gamma ray venturi multiphase flowmeter enables a strong and predictable performance of the meter in specific operating conditions. It is also possible to perform the error budget on the computed rates and quantify accurately the sensitivities to the input parameters of the flow meter. The meter acquires production rate, cumulative volume and operating condition data (including pressure and temperature) in real time without requiring separation (partial or total) of fluids and capturing the entire dynamics of the well response thanks to a fast acquisition. It had been demonstrated that the playback facility unique with this multiphase flow meter is a key element to review or improve accuracy best in new input parameters from fluid properties for example, this is key in Heavy Oil conditions.

There is continuous advancement in the current Vx Technology leading to a better precision and build on the experience over the last 10 Years, and extension of working conditions but also in terms of

operating conditions (i.e. temperature and pressure range (i.e. standard at 302ºF/5,000 psia up to HP/HT at 392ºF/10,000 psia and down to SAGD at 450ºF/5,000 psia)). Moreover, the Vx Technology provides now an entire multiphase solution, which addresses not only the metering and sampling to the knowledge of the fluid properties at the well site from Heavy Oil to Condensate with the same hardware.

The main benefits for the client are improved safety, data quality, logistics, and longevity of the field to a better reservoir management. Client are seeking for a technological solutions; and from this point of view, Schlumberger is becoming a solution provider with an excellent technical support. The Vx Technology impact is tremendous with an increase of client revenue due to increase productivity and decrease of the operational costs. Moreover, the Vx Technology is environmentally safer with no water separation, no disposal, and no tank reducing any oil spills.

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Very Few suppliers, based on the available publications, are capable today to quantify and demonstrate the entire performance of their metrology and even less have an in-depth understanding in Heavy Oil. Through the unique building of the Vx Technology for different market from Black Oil to Gas and Heavy Oil, it is possible to identify clearly the uncertainty. Having a measurement system simple that is predictable offers the advantage of a better understanding of the performance of the MULTIPHASE FLOWMETER for the life of the well and the ability to manage the accuracy within a narrow boundary. The Vx Technology enhance the PhaseTester and PhaseWatcher to become the first meter capable to measure accurately 3 phases (oil, water, gas) from Bitumen to Condensate.

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