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FIELD EXPEREINCE IN GAS WELL TESTING FROM 0-100% GAS VOLUME FRACTION

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Abstract

The multiphase flow meters in field operations have now become a widely accepted practice especially in the range of GVF from 0 to 85%. There is still some doubt about the performance of this type of device especially in the High (92-96%) or Very High GVF (96-98%). Most of the purchasers put a cut off in the range of 85-92% GVF following the type of technology. Most of the time these criteria are based on past experience or special cases, which could be several years old. A split in terms of naming is even commonly accepted in the multiphase business between Multiphase Flow Meter and Wet Gas Meter. In this paper we will review the benefit of the Vx Technology now capable with a single meter to meter oil and gas wells. The focus put years ago on a combination of robust and simple measurements now leads Schlumberger to propose a solution for any type of wells. This brings the advantage and benefit of the very well known Vx Technology such as reliability, training, and expertise over the previous years spend on the dedicated oil wells. Numerous statements could be done and it can be mentioned that Gas Well Testing is now quicker and more efficient. The time, cost and spaces saved on board (offshore application) including rig time are among the immediate client benefits. On the QHSE point of view, installation and operation safety is improved greatly and leads to use the meter in much higher working conditions (Pressure, Temperature). From the metering point of view, accurate flow rates through fluid characterization services provides finally robust and direct measurements of WLR (Water Liquid Ratio), GOR (Gas Oil Ratio) and CGR (Condensate Gas Ratio). The issue about separation requirement or slug, foam, mist flow does not exist anymore. We will review the benefits of this new product/service through a campaign of tests done in Argentina made on high producing gas wells, which has been successfully cleaned up and tested using Vx Technology in Gas Mode in 2005. Exceptional results against conventional test separator will be presented with a maximum error of 2-3% for the gas. A special emphasis on the liquid flow rate accuracy against the separator will be presented.

1. Introduction and Challenges

The Carina-Aries gas fields' development is a project that started in 1981 when these two reservoirs were discovered respectively 80km and 30km offshore Tierra del Fuego in Argentina. Total with its partners was convinced that the Vx technology could help to optimize rig time while measuring flow rates during the clean-up/ well test of both fields.

Permeability of those sandstone reservoirs varies from 100mD to 1D with porosity over 25%. The wells are completed with Horizontal Open Hole Gravel Pack and 9"5/8 mono bore completion. In Aries field, acid jobs were performed and nitrogen was used to lift the completion brine: access to the volumes of injected liquids recovered was the critical piece of information to estimate how much liquid had been lost in these very permeable reservoirs.

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Tqqhe objective of the well tests was to perform a successful clean up without damaging the completion or the zone near the well bore, allowing stress state in the formation and gravel pack to stabilize. In order to reach this objective the clean up strategy was driven by minimizing the drawdown and thus constant flow rates monitoring and downhole pressure measurements were required. Then sandface drawdown was estimated for each flow rate step.

Total Austral was the first companies to use the Vx technology with a new interpretation model dedicated to the gas/condensate wells and called Gas Mode. Years of research and development on the Vx concept have enabled Schlumberger and Framo Engineering to propose a measurement solution for any type of wells through the selection of Oil or Gas computational models. The new development for multiphase gas well testing brings the advantage and benefit of the very well known Vx technology such as reliability, dynamic response, post-processing capabilities and expertise.

A PhaseTester Vx in the middle range of the portfolio was used to account for the large gas flow rates expected during the clean-up (limited to 1.5 MM m3/d for each reservoir for heat radiation and surface equipment rating purposes). As part of the field test plan, a complete conventional well test set consisting of a 1440psi separator, a surge tank and a heater was installed in series and downstream of the PhaseTester Vx, in order to compare the results.

Figure 1: Picture of the rig-up for the conventional equipment and PhaseTester Vx.

Figure 1 gives an overview of the well test area with the separator, the surge tank and the PhaseTester Vx visible. The footprint, and thus logistics and crane lifts of the conventional well testing equipment versus the multiphase solution (which would not require the use of the separator and its associated safety equipment) can be inferred (weight reduce by 60%). The time, cost and space saved (slightly more than 60%) on board including rig time are among the immediate client benefits. On the QHSE point of view, installation and operation safety are improved greatly in these high pressure, high temperature and high flow rates environments. Also, the ability to use the meter in much higher working conditions (Pressure, Temperature) allows to flow in closer conditions to those of the future production set up.

2. Clean-up Results

The paper is focusing on Aries-1 field, which was by far the more challenging due to the fact that two sandstone structures, Hidra and Argo, were tested separately or commingled. Hidra is the name of the lower sands, and Argo the upper ones. The well test was split into 5 job sequences (as shown on the fig. 2) with as Sequence# I: a pre-acid flow was performed in Hidra alone, Sequence# II: a post acid flow period was recorded on Hidra alone; Sequence# III: both zones were tested together, Sequence# IV: a pre-acid flow was performed on Argo alone, Sequence# V: a post acid flow period was recorded on Argo alone.

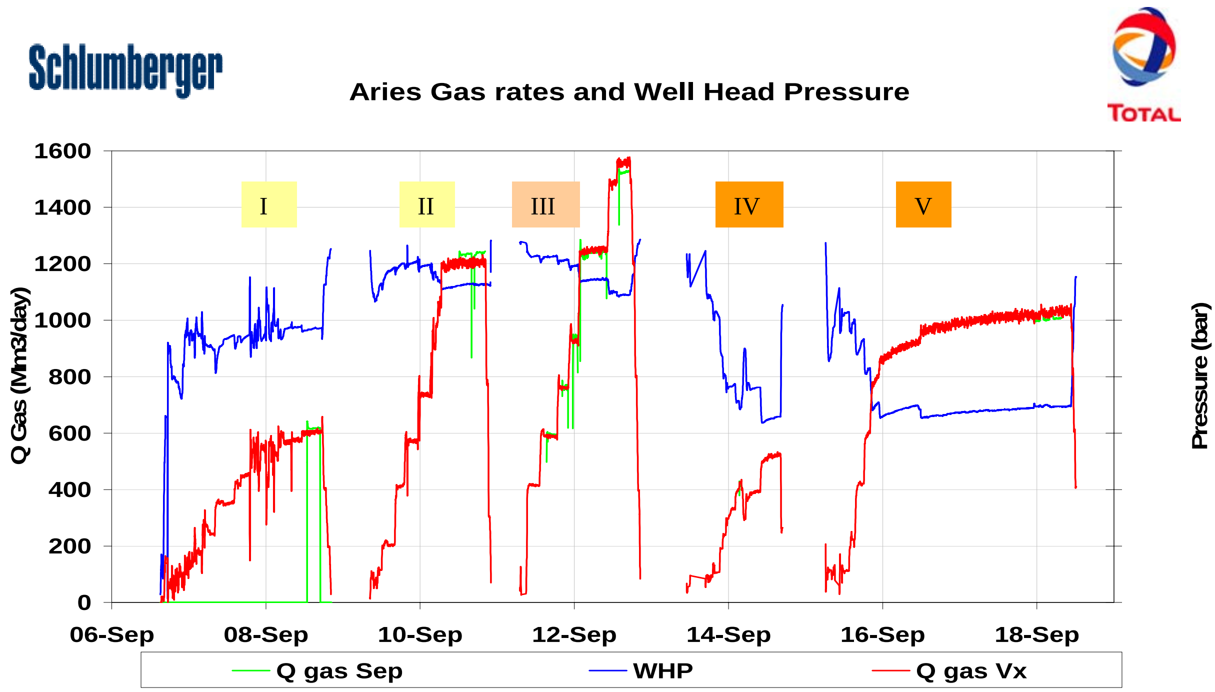

Figure 2: Different sequences of work on Aries field versus time

Here-above are presented the wellhead pressure (WHP, blue) and the gas flow rate obtained at the separator (Q gas Sep, green) and from the PhaseTester Vx (Q gas Vx in red). Due to large quantities of slugs, acid flowback and unstable conditions, it was only possible to use the separator sporadically. On the contrary, the PhaseTester Vx provided clear and consistent data during the entire job.
The first benefit was the possibility of visualizing the flow rates in real time, even during the clean-up phase in a complex fluid and production environment, allowing the reservoir engineering team to decide a choke size increase after the stabilization period had been reached. Due to the high reservoir productivity, the stabilization of the flow rates at surface was very quick: monitoring the rates in real time has reduced significantly the overall job and saved significant rig time while providing very accurate flow measurements. In the sections where both equipments were recording data, a good agreement can be found, typically within 3-5% at standard conditions.

Meanwhile another advantage of the Vx technology is to follow the non-hydrocarbon returns as the well is gradually opened on larger chokes during the clean up. Thanks to the benefit of a continuous monitoring of the flow rate, it was possible for each sequence to produce a cumulative of non–hydrocarbon liquids, monitoring the quality of the clean up and giving the possibility to determine when the clean up was achieved. Furthermore continuous monitoring of the Water Liquid Ratio (WLR) versus time was possible (fig. 3), as well as an estimation of the non-hydrocarbon produced (acid, completion brine or reservoir water). This capability is unique to this approach to well testing with the PhaseTester Vx and it brings significant benefits as will be explained below.

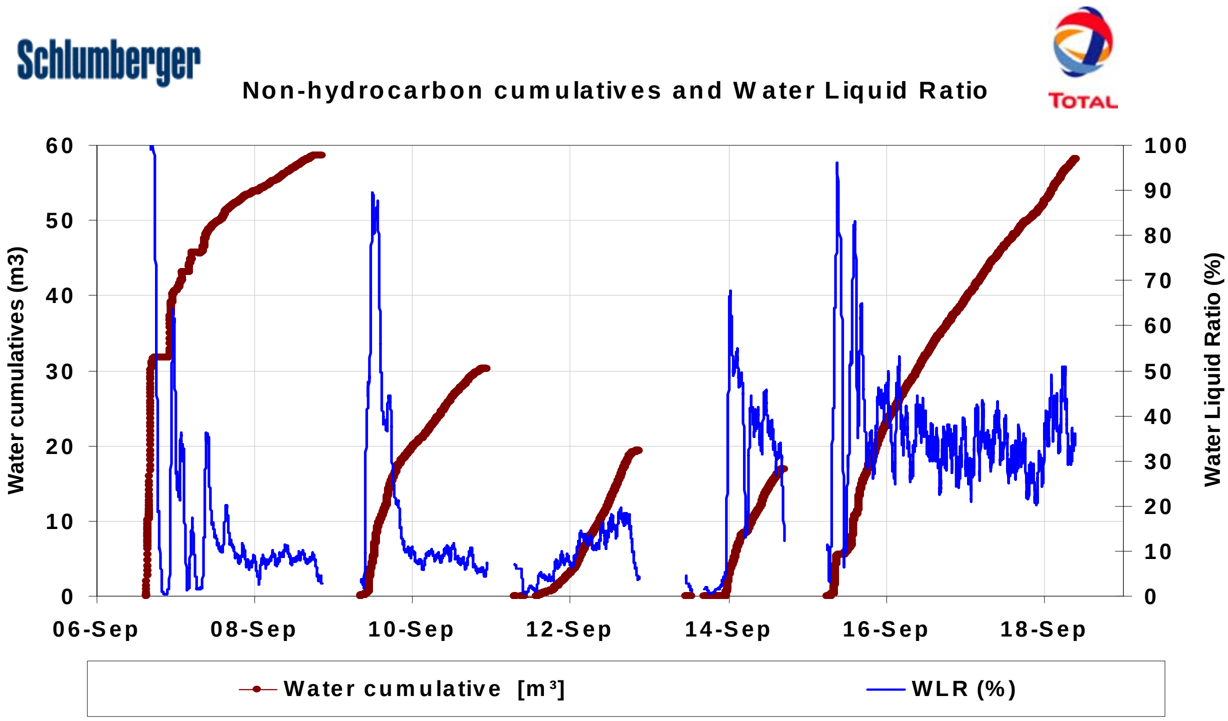

Figure 3: Quality of the clean up versus time.

The overall predictions of non-hydrocarbon cumulative from the PhaseTester Vx are:

- Total volume produced Hidra (I): 58m3
- Total volume produced Hidra (II): 31m3
- Total volume produced Argo + Hidra commingled (III): 20m3
- Total volume produced Argo alone (IV): 17m3
- Total volume produced Argo alone (V): 58m3

The PhaseTester Vx 52 estimated the production of recovery fluid between 89m3 to 109m3 from Hidra and from 75m3 to 95m3 from Argo (depending on which reservoir we attribute the returns for the job III to, as the two reservoirs were producing together during this sequence).

Analysing in dtials these data as shown on the the figure 4, it is possible to calculate the cumulative derivative versus time. It can be clearly noticed that for Hidra alone (I and II), this value is close to 0 at the end of each flow. This means that at this point, either the reservoir is cleaned from all foreign water and not producing reservoir water; or the reservoir forces acting on the fluids are not sufficient to move the non-hydrocarbon fluids out of the reservoir, due possibly to the difference in viscosity between gas and liquid, differential wettability and mobility, and formation of gas channels.

In the case of Argo, the stabilization to a higher value can be seen. This demonstrates that the reservoir is producing at the same time hydrocarbons and water. Even after more than 24 hours of flow, some water is still coming out. Not only with the Vx Technology, it is possible to measure quite small amounts of water that would have been otherwise extremely difficult to detect, but thanks to the sensitivity of the nuclear measurements to the water salinity, it is also possible to demonstrate that this non hydrocarbon fluid is in fact completion fluid (refer to Ref [5]).

The explanation of the production of non-hydrocarbon can be explained by the fact that permeability and the porosity of the reservoir are such that the completion brine and the acid went far away inside the formation. When the reservoir is then produced, gas channels form and the water mobility, is limited. It will only partially and slowly come back to the surface.

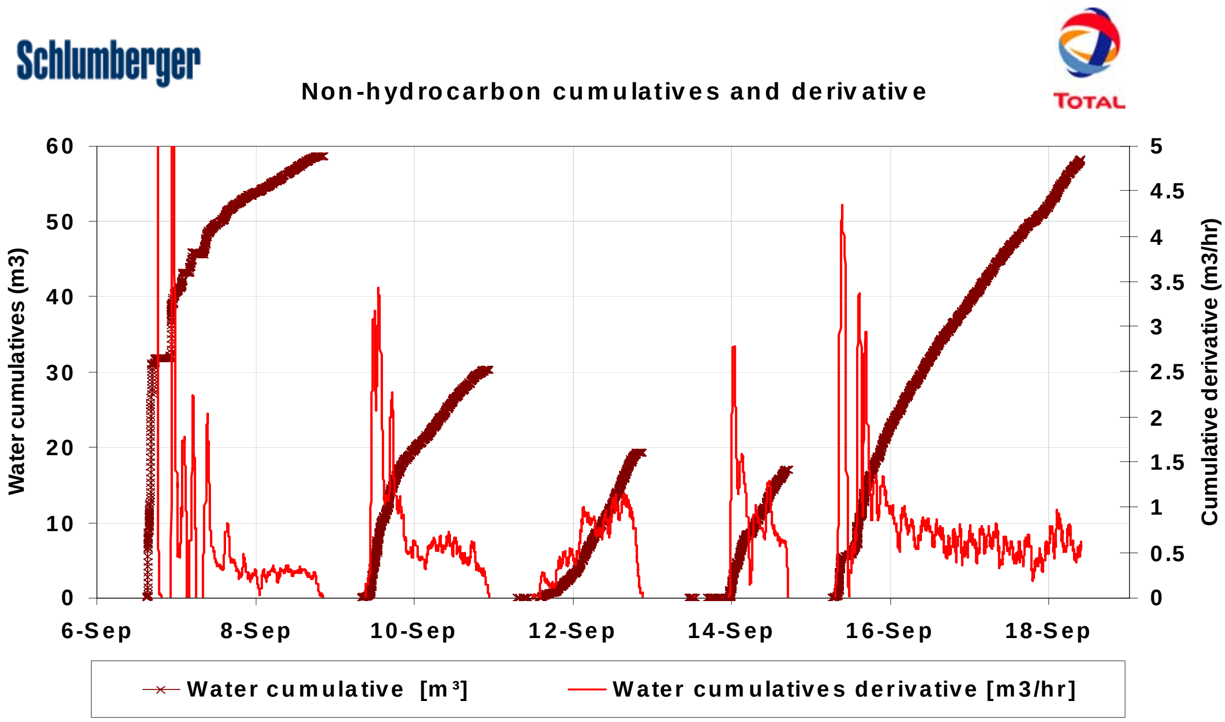

Figure 4: Cumulative Derivative versus time.

Volumes injected at the wellhead were later disclosed by TOTAL and confirm the large values found with the PhaseTester Vx:

- Total volume injected in Hidra (as reported): 120 m3
- Total volume injected in Argo (as reported): 188 m3

When compared to the total volumes of non hydrocarbon fluids recovered, (Hidra: 89 to 109 m3 Argo between 75 and 95 m3 with the variation due to commingled flow), a few points can be inferred, supposing (and we will see why this assumption is made later on) that reservoir water is negligible:

- The volumes of water recovered predicted by the Vx meter are below the volumes injected,
- The trends showed in the cumulative derivative are in accordance with the volumes that are still thought to be in the reservoirs (less residual water in Hidra than in Argo)
- Permeability and porosity of the formation are so large that it is not expected to be possible to remove under normal flow conditions in this type of gas well the entire fluid injected inside the reservoir. Indeed, gas channelling will be forming quicker than the liquid will be pushed out, leaving inside the reservoir some residual water.
- These results were obtained accurately by splitting the five main sequences in smaller sequences and processing the raw data after the test, using the appropriate water properties. This unique feature used with the Vx Technology allowed Total to benefit from a best in class quality assurance.

3. Gas and Condensate Measurements associated with fluids properties

3.1 Phase Envelope

In gas wells with high GVF and in high pressure environment, the fluids property characterization is key to delivering an accurate condensate and water flow rate at standard conditions as demonstrated by Pinguet and al (Ref [2 & 3]). The flexibility of the Vx Technology allows fluid properties to be input in the meter in various methods. The ultimate option is to be able to introduce a fit for purpose, reservoir-specific fluid characterization called Vx Fluids ID into the meter set-up parameters. This is independent of the acquisition and permits a post processing of the acquired raw data with any kind of fluid properties input. For Aries, the Vx flow rates calculations at standard conditions were done using the phase behaviour of the reservoir fluid.

The reservoir pressure is around 160bar, with a static temperature of 81degC. For the purpose of this paper, the flowing temperature is considered to be equal to the static one (a differential pressure of 15bar from wellhead to bottomhole has been considered in the calculations, and is based on the assumption that the tubing is empty). The assumption is made that the reservoir fluid is the same in both Hidra and Argo, which was confirmed by PVT analysis.
The downhole operating area is overprinted on the following figure with the phase envelope of the reservoir fluid including the iso-line of gas fraction:

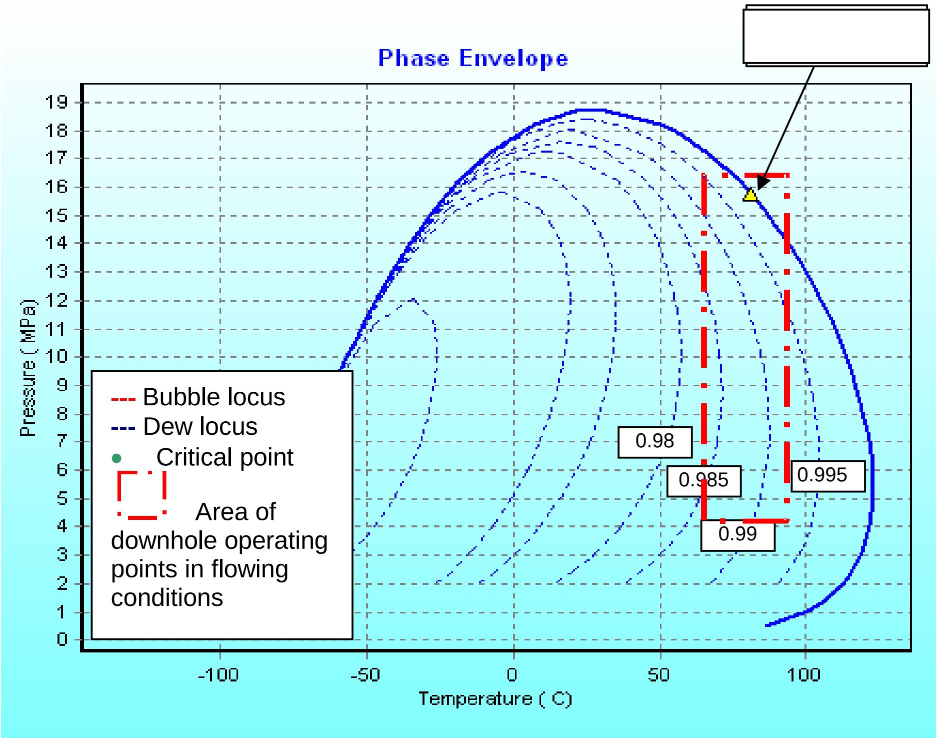

Figure 5: Phase Envelope and area of investigation for Aries reservoir fluid

Figures 6 depict three different events corresponding to A: small choke opening on Hidra; B: maximum drawdown on Hidra; C: maximum drawdown on Argo. As the choke is opened, the wellhead and bottomhole pressures drop, crossing iso-gas volume fraction loci.
At point A, the production of liquid is close to 0.5% (iso gas volume fraction close to 0.995) the pressure being very similar to that of the reservoir. This is the characteristic of a large gas reservoir. At point C, during the Argo maximum drawdown, there is as much as 1.3% liquid in volume already separated at the reservoir level. The great drawdown is in this case creating diphasic conditions in the reservoir. This fluid can be seen as deposited in the formation, due to the large permeability and porosity. Indeed, the liquid will have a tendency to stay in place due to the friction force in comparison with that of the gas (i.e. poor efficiency for the gas to play a role as a piston on the liquid to push it outside of the reservoir). As this liquid containing the heaviest components stays in the formation, more gas in volume will be brought to surface, increasing Gas Condensate Ratio (GCR).

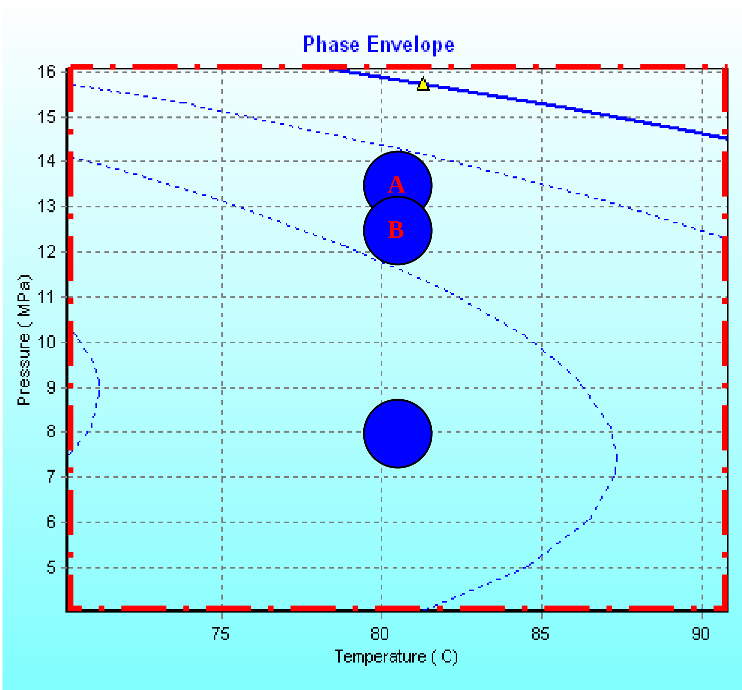

Figure 6: Zoom of the phase envelope on the previous highlighted section

This “unexpected” increase in GCR was encountered while producing Argo, refer to figure 10.

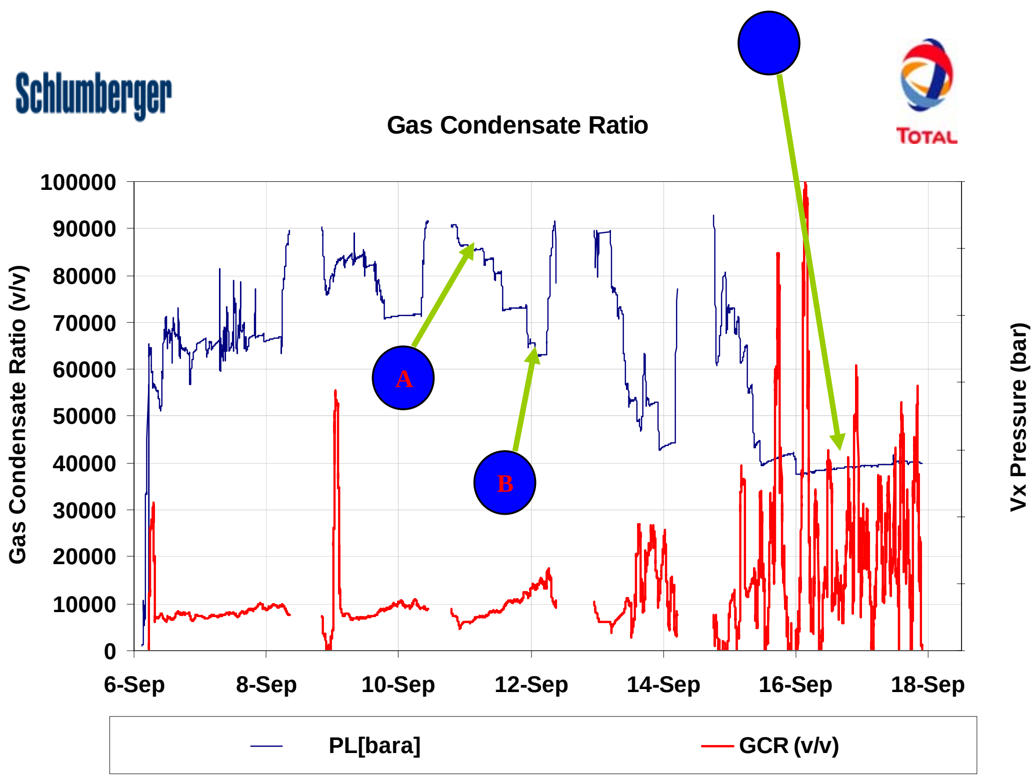

Figure 7: GCR and well head pressure versus time

It should be noted that not only is the GCR becoming larger due to less fluid produced, but it is also becoming noisier at surface. This can be explained by the fact that the gas at reservoir level is not capable to entrain the liquid which is being deposited in the pores. However, after a certain period some liquid present at the wellbore or in the bottom of the column is carried out to the surface, creating this slugging effect.

3.2 Phase Envelope and comparison PhaseTester Vx vs. Separator

The Vx being upstream of the choke manifold, it is operating at higher pressure and temperature than the separator. The Aries phase diagram is described in figure 11 showing the various operating conditions. As can be seen on the diagram, both devices have different working conditions and are not situated on the same iso-gas line, that is, at the meters conditions, the proportions of fluid in liquid and gas phases are not the same, which can also be expressed by saying that the GCR1 will be different.

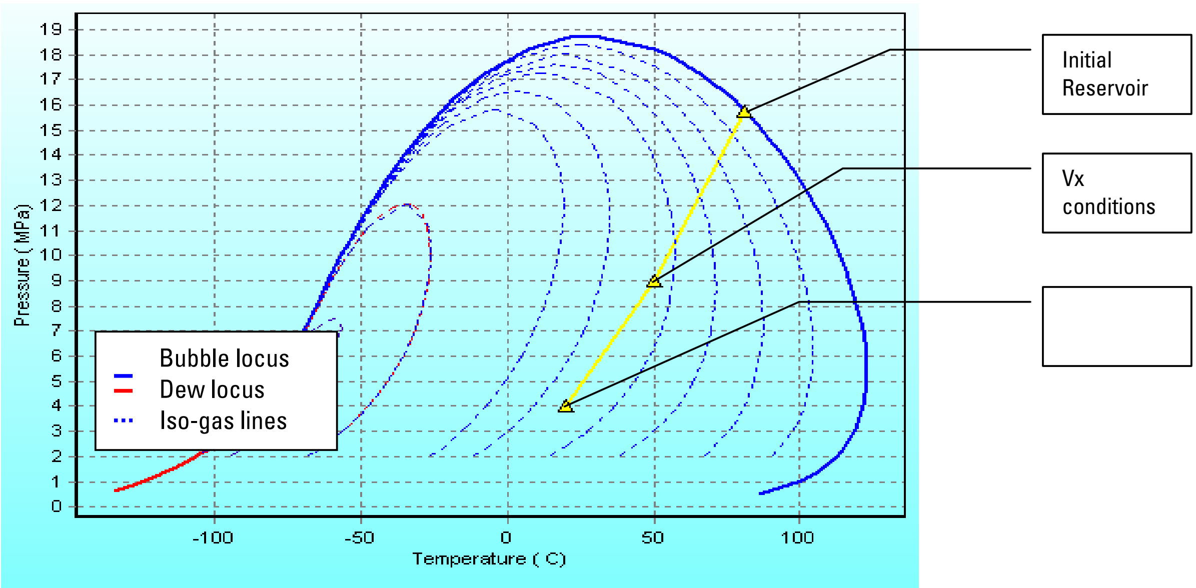

Figure 8: Typical Separator and Vx operating point in the Aries phase diagram.

Furthermore, the composition and the properties of the two different phases will be different and this is what is measured by the different meters. Even if the separation in the separator was perfect, what is 'totally liquid' at the Vx conditions of pressure and temperature might well be 'partially Liquid and Gas' at separator conditions. In the extreme case of a retrograde gas condensate, in theory, the fluid could be gas at reservoir conditions, producing liquid at the meter conditions, which would go back in gas phase at standard conditions.

The Vx uses the reservoir fluid information to compute the results at standard conditions. On the other side, the separator separates and measures what is liquid and what is gas at its working conditions; correlations are then used to compute volumetric flow rates at standard conditions from the two measured flows, including a prediction of the gas dissolved in the liquid at separator conditions, or GCR2. It will not, in most cases, predict the amount of liquid still in vapour phase at separator conditions.

The path between the working conditions of the multiphase meter and the separator is not following any iso-line, so not only is the GCR1 different, but a simulation can show that the GCR 2, thus the total GCR will also be different between the two systems. This is due to the non-linearity of the path followed by the reservoir fluid. Simulations done by the Equation of State simulator PVTPro for Aries with the typical values of flowing conditions shown in figure 8 give the following results:

Vx GCR1 :	**13792 m^3/m^3**	**Separator GCR1:**	**10074 m^3/m^3**
Vx GCR2:	**163 m^3/m^3**	**Separator GCR 2 :**	**99 m^3/m^3**
Vx Total GCR:	**13955 m^3/m^3**	**Separator Total GCR:**	**10173 m^3/m^3**

This is not due to any form of carry over or carry under, but only to thermodynamics. As other main result it should be clearly kept in mind that GOR Total or CGR Total are not a constant value are so often presented or mentioned. This is is due to the fact that the gas liberation of any liquid pahse is not linear with pressure and temperature and there is always an minimum on these parameters as illustrated for an oil well here below figure 9. The egality between two devices (Tank/Separator or Tank/Vx) is possible only if both of them are working at a pressure and temperature identical or very close (separator/Vx)!

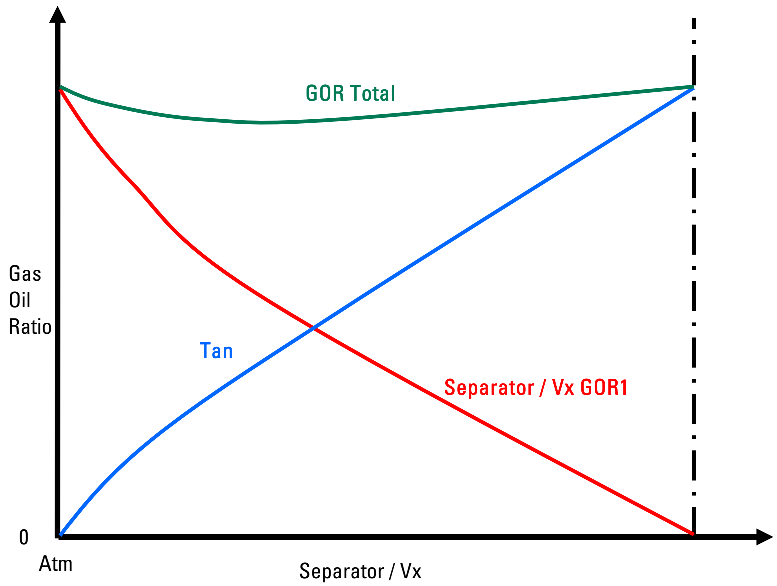

Figure 9: GOR line calculated for two different devices not working at the same pressure and temperature

In summary, the fluids measured by each tool and the PVT model used to calculate output at standard conditions are not the same, therefore the comparisons between the separator and the PhaseTester Vx, in this cleanup, must be made carefully and taking account all the variables as operating pressure, temperature and changes in fluid composition.

In figure 10, the phase diagram of the Aries reservoir fluid is presented, as well as a typical Vx operating point. In theory, if it was possible to sample the gas and the liquid phase at Vx conditions, and make a phase diagram of each phase, they will be as presented below. This is only true because thermodynamic equilibrium is achieved at the meter throat. An equivalent set of diagrams could be made for the separator.

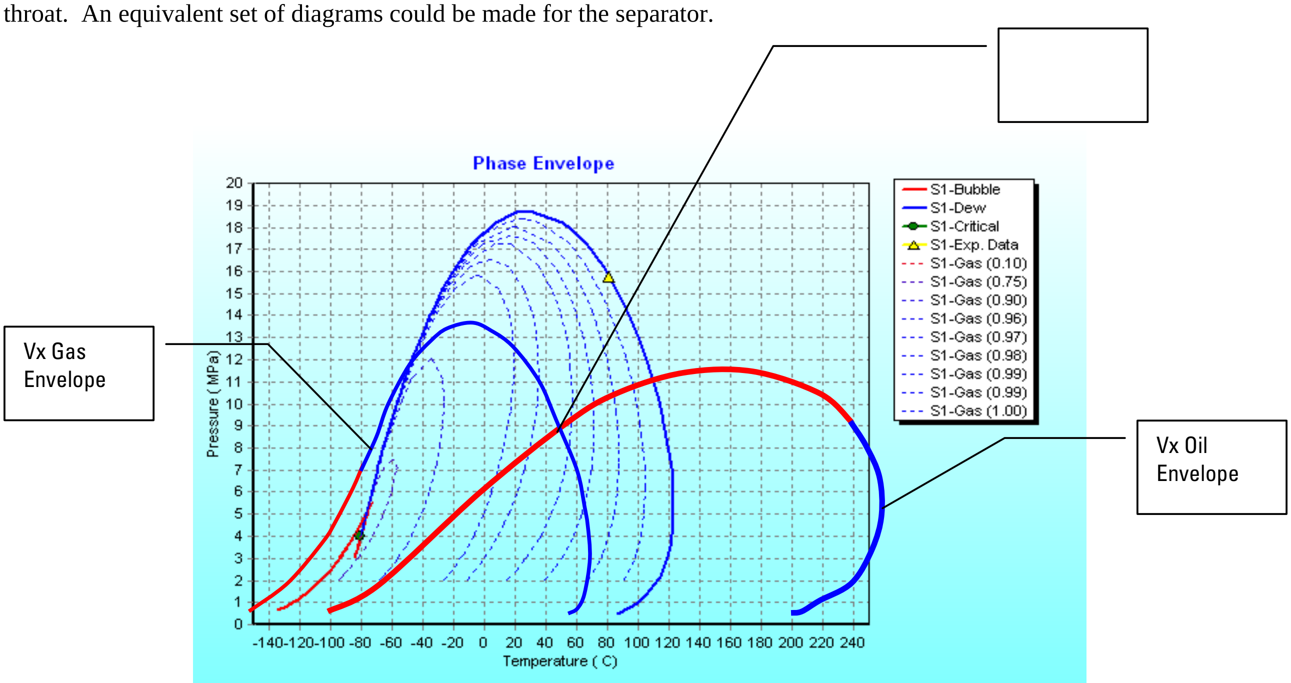

Figure 10: Vx operating point in the phase diagram with the representation of the two phases oil and gas

In fact, it is possible to simulate some phase diagrams at various points in the flow. This is expressed by the phase diagram flow path here below. Figure 11 should be looked at as some snapshots of liquid and gas phase diagrams at various stages of Pressure and Temperature, corresponding to a path the fluid could follow during a well test, typically.

A reservoir fluid with its own phase diagram (A) is flowing to the surface being at its saturation pressure in the reservoir. While coming up in the tubing (which also corresponds to moving from reservoir to Vx in figure 11), the fluid looses pressure and temperature. As the fluid penetrates the two-phase area (inside the curve delimited by the red and the blue lines) some condensate forms. The fluid reaches the surface in two phases, one liquid and one gas, well before reaching the separator. Diagrams B and C are the same as the ones shown in figure 10, respectively for the Gas and the Liquid phases. Again it should be mentioned that the fluid has not passed through the separator yet.

This two-phase fluid will then flow to the separator where a physical separation will take place: we now have two flows: gas and liquid. The gas, under the hypothesis of a perfect separation, will be a dry gas flow (D). This fluid will not evolve anymore and the phase diagram of this monophasic dry gas will be unchanged up to the atmospheric pressure (while the operating point will move in the diagram D as the pressure and temperature decrease).
Meanwhile the liquid (phase diagram E) coming out from the separator, theoretically in monophasic liquid phase, will then go to the production line, the tank or the burner.
This monophasic liquid, at separator conditions, will then itself split into two phases as the pressure and temperature drop, as it still contains dissolved gas. Again, two phase diagrams could be drawn: one representing the dead liquid (G) and the other one presenting the gas dissolved in the oil and coming out of the solution (F).

It should be noted that the scale of the graphs has been kept identical for the different fluids and it can clearly show how a monophasic fluid at reservoir level separates into various fluids during the production process.

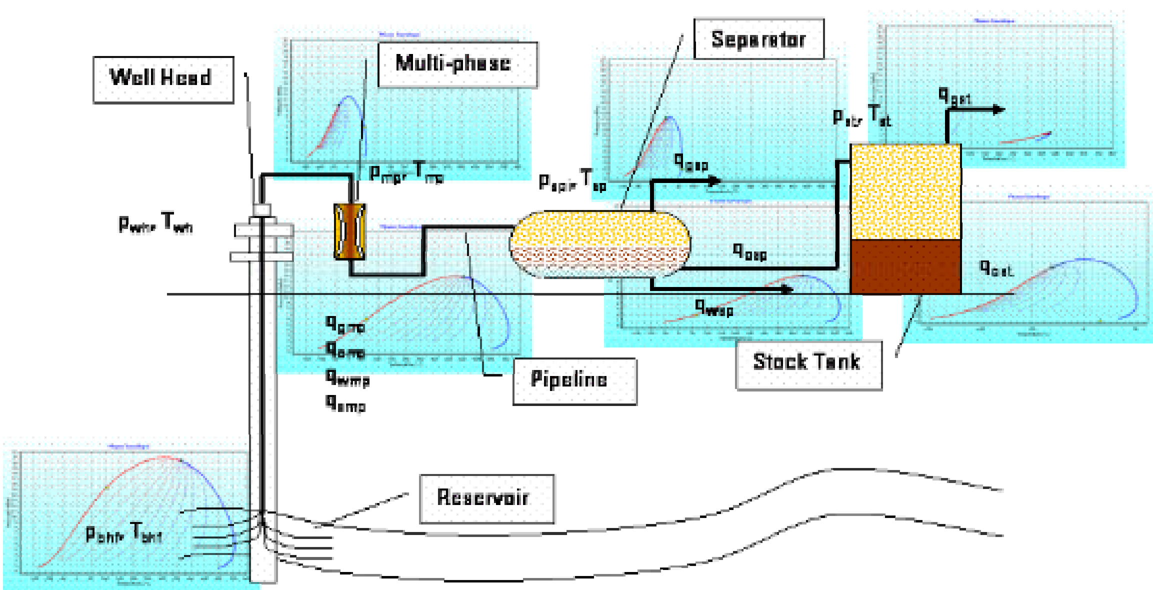

Figure 11: The fluid process during the variation of pressure & temperature and separation

3.3 Liquid and Gas Flow rates.

When producing the two zones at the same time, the choke size was first increased and then decreased in steps, allowing comparison in the flow rates, during the drawdown (or DD) and the shut in (or Build-Up BU) in steps as presented in figure 12. The condensate flow rates while decreasing the choke (C, BU) are much lower than their corresponding values while increasing the choke size (C, DD), at equivalent gas flow rates (G, DD and G, BU). It can be seen that for the same pressure drawing down or building up (green line), the GCR is vastly different (purple line).

The drawdown pressure during this job passed below the dew point at sandface level, most probably creating a deposit of condensate deep inside the reservoir. The condensate irreducible saturation around the sandstone grains, combined with the volumes of non-hydrocarbon liquids still in the reservoirs create complex patterns of differential flows, and the transitory period to get the entire reservoir back to dew point will explain this hysteresis in condensate rates and thus in GCR.

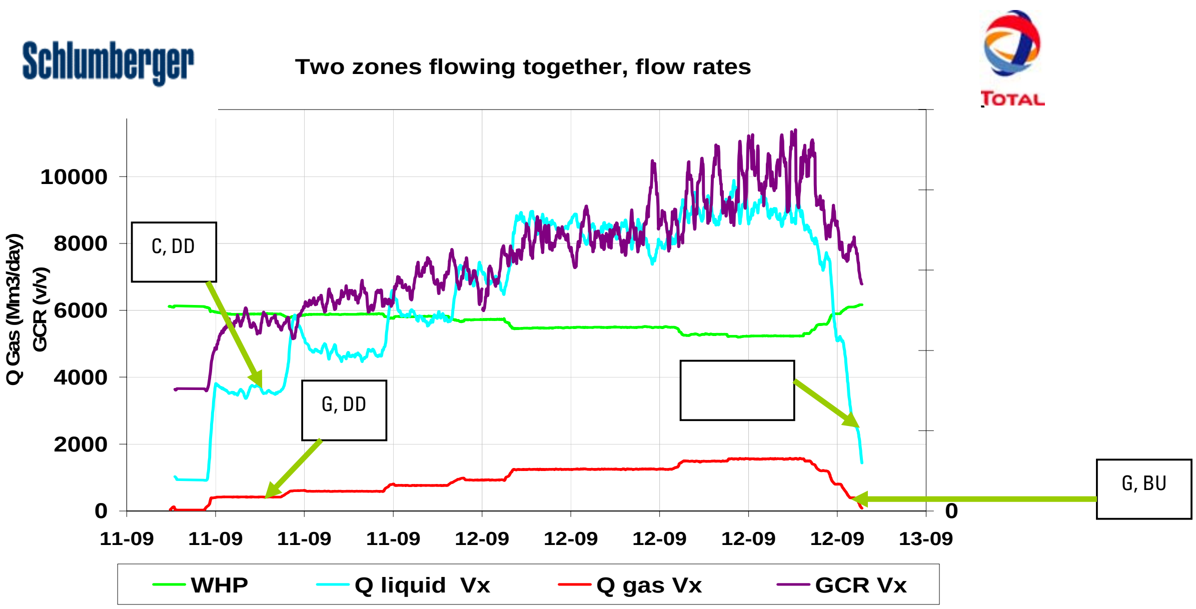

Figure 12: Hysteresis on the gas liquid flow rates versus choke size.

4. Conclusion

In this paper, the benefit of the Vx Technology, developed for evaluation well testing and permanent production applications has been reviewed. With the recent new development for gas well, which is capable to meter wells with gas volume fractions varying from 0 to 100%, it is now possible to test both gas, condensate and oil wells with a state of the art tool.
Comparisons when separator data is existing are excellent, taking into account the limitation of the test separator process, the thermodynamics and the separator correlations from separator to standard conditions. One should not underestimate carry -over or -under as well as poor gravity separation related issues in condensate gas wells. The liquid values measured at the tank after trying to correct for the right fluid properties are closer to those of the Vx meter.
With the PhaseTester Vx in gas, condensate and water flow rates are monitored at all time in a challenging environment, allowing a precise clean up keeping the sand screens integrity. The real-time data acquired during the clean up gave Oil company the means to make key decisions in a short time period, without jeopardizing the quality of the data.
Numerous other statements have been brought and explained in this paper such as reservoir behaviour of this field in terms of fluid properties and fluids mechanics.

It should be mentioned that Gas Well Testing is now quicker and more efficient even in situation where it was not possible. The time, cost and deck space saved on board (offshore application) including rig time are among the immediate client benefits. On the QHSE point of view, installation and operation safety is improved greatly and allows the use of the meter in much higher working conditions (Pressure, Temperature).
From the metering point of view, accurate flow rates through fluid characterization services provide robust and direct measurements of WLR and GCR, the issue about separation requirement or slug, foam, mist flow being irrelevant.

Exceptional results against conventional test separator have been presented with a maximum error of couple of percent for the gas. A special emphasis on the liquid flow rate accuracy against the separator has been presented, which led the following quoting from Alain-Michel Bourgeois, Total Austral Offshore Drilling Manager, “we are thinking of using the Vx alone for our next campaign”.

5. Acknowledgements

A special thank to Patrick Destarac [Schlumberger] and to Claude Aroles [Consultant] for helping us in the various phases of this case study.

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