Practical Experiences Obtained with the Magnetic Resonance Multiphase Flowmeter

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1 INTRODUCTION

Magnetic Resonance (MR) is a measurement technology which is well known from its application in medical imaging. Next to this application in Healthcare, MR can also be applied in the upstream oil and gas industry to measure multiphase flow of oil/water/gas mixtures upstream of a separator. To this end, an industrial magnetic resonance multiphase flowmeter has been developed.

In previous papers [1],[2] the MR measurement principle is introduced, and explained how the flowrate of oil, water and gas are measured. Additionally, experimental results are shown of extensive tests performed at various independent multiphase flow loops. The main conclusion of that study is that MR is a powerful technique for measuring multiphase flow. Good accuracy can be achieved over a wide range of condition such as GVF ranging from 0-95% and Water Liquid Ratio (WLR) ranging from 0-100%, with a sweet spot of the flowmeter at high WLR of 85% or higher.

With the experience gained in research and development, and the lessons learned from the tests performed, further improvements have been made to the flowmeter and a first series of MR multiphase flowmeters has been produced (see Fig. 1). One of the flowmeters has been installed in a field trail by a Dutch exploration and production company at a production location in the Netherlands. The main focus of this field trial is to validate practical aspects of the multiphase flowmeter such as installation procedures and long term stability of the flowmeter in changing environmental conditions. Furthermore, the concept of in-line fluid characterization (without the need of taking samples) is evaluated. The practical experiences gained from the field trial are described in this paper.

Figure 1: The magnetic resonance multiphase flowmeter (M-PHASE 5000) as developed by Krohne and Shell.

2 DESCRIPTION FIELD TRIAL APPLICATION

After the successful tests on various multiphase test loops, the magnetic resonance multiphase flowmeter has been installed in a field trial by a Dutch exploration and production company on a production location in the Netherlands.

The field comprises 16 different wells that are connected to a main production line. Additionally, each well is connected to a test manifold. In this way, the production of each individual well can be tested by means of a test separator. During the field trial 9 wells have been tested. In the test separator the liquid and gas are separated, and each flow is measured separately. The oil-water mixture is measured using a Coriolis flowmeter and the WLR is determined based on density. Prior to the start of the field test, the base densities have been sampled. The gas flow is measured using a vortex meter. Both the Coriolis and the vortex meter have been calibrated before the start of the field test.

The magnetic resonance multiphase flowmeter has been installed upstream of the test separator (see figs. 2 and 3).

Figure 2: The magnetic resonance multiphase flowmeter (M-PHASE 5000) installed in a field test by a Dutch exploration and production company on a production location in the Netherlands.

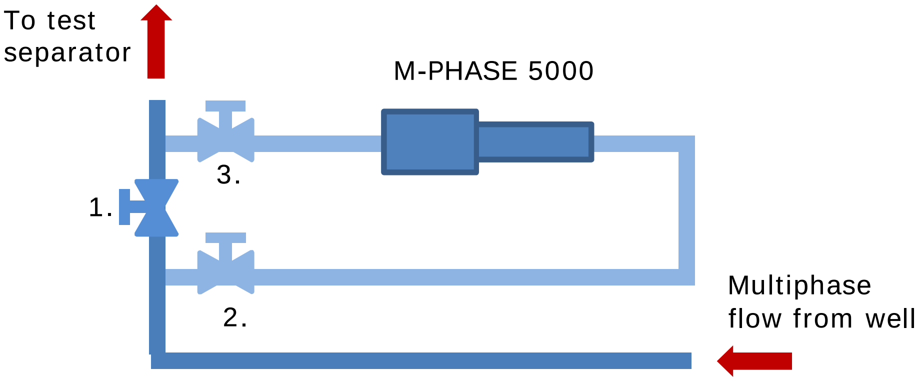

Figure 3: Schematic representation of the configuration at the field test. The flowmeter is positioned in a bypass, which can be controlled via valves indicated by 1, 2 and 3. When the flowmeter is in normal operation, valve 1 is closed and valve 2 and 3 are open; in this way the flowmeter is in-line with the test separator. In case the in-line fluid characterization is performed, valve 1 is open and valve 2 and 3 are closed to block the fluids in the meter.

At the start of the field test, it was clear that the flow conditions of the wells are outside the optimal application range of the flowmeter; for most wells the GVF is high (>95%) as significant gas lift is applied. Nevertheless, it was decided to perform the field test to gain valuable practical experience regarding the installation procedure, the in-line fluid characterization procedure and the robustness against environmental conditions. The Netherlands has a moderate maritime climate where on average the relative humidity is between 75% and 90% and the average precipitation (rain, snow, hail) per month is 70mm distributed over 15 days per month. The average ambient temperature ranges between 0 ^{o}C up to 23 ^{o}C, however during the field trial the temperature ranged between -4 ^{o}C and 34 ^{o}C.

3 INSTALLATION OF THE METER AND START UP

The meter was installed in October 2014. Before being allowed to install the meter all official documents had to be in place like material certificates, CE declaration, PED approval documents Lloyd’s, approval for applying the meter in a hazardous area, Site Acceptance Test documents, etc..

Since the meter didn’t have an explosion safety approval at the time of installation, an active nitrogen purge with flow control unit has been used to cover the explosion safety related aspect of the meter. Meanwhile, the MR meter has an explosion safety approval. Consequently, the nitrogen purge is not necessary anymore for new installations of the flowmeter. The installation of the meter went smoothly without difficulties. The same holds for starting up the meter.

4 IN-LINE FLUID CHARACTERIZATION

Advantage of In-line Fluid Characterization

One of the goals of this field trial is to test how the in-line fluid characterization procedure works out in the field. The outcome of this part of the test is very important, as the operating concept of the meter in the field becomes very straight forward: block-in the flowmeter for a certain moment, run the ‘auto-fluid-characterization’ procedure, open the valves and start the flow measurement.

This means that no samples are necessary anymore and testing procedures in the lab at similar pressures and temperatures are superfluous. Furthermore, issues like differences between live oil and dead oil properties are gone, no additional equipment is necessary, the hassle of sample handling is over, and so on, and so on.

Summarizing, we may conclude that in-line fluid characterization has many advantages compared to off-line characterization by means of samples.

Description of the In-Line Fluid Characterization

For a proper multiphase flow measurement, the MR meter requires the relaxation times (T_1 and T_2) and the Hydrogen Index (HI) both for oil and water [1]. These parameters can be measured by the MR meter itself. The only requirement is a static situation i.e. no flow.

The characterization procedure is as follows:

- The multiphase mixture is guided through the meter.
- Once the representative oil and water are present in the meter, valve 1 (figure 3) is opened and valves 2 and 3 are closed.
    - Note that the ratio of oil, water and gas doesn’t have to correspond to the multiphase flow composition. The only criterion is to have representative oil and water present in the meter.

  - Furthermore, the presence of gas is not necessary since T_1, T_2 and Hydrogen Index (HI) of gas is not critical in the gas measurement and can be calculated from the pressure and temperature.
- When the flow has been blocked-in and the multiphase mixture is static, the automated fluid characterization procedure can be carried out.
- At the end of the characterization procedure, the relevant fluid parameters are stored the meter.

Fluid Characterization Duration

At the very beginning of the field test, the in-line characterization procedure took 10 to 24 hours! This was partially caused by the fact that too much data was collected. Right from the start, it was concluded that such a long characterization time is not practical and therefore not acceptable.

By optimizing the routine, the characterization period has been reduced to about 45 minutes. It turned out that this time interval works out well in the field. Meanwhile, the characterization time is being reduced further. The current estimation is that it will be reduced with another factor of two.

Live Oil and Dead Oil

As mentioned before, differences in properties between dead oil and live oil are observed. In a dead oil sample the pressure is sufficiently low (typically ambient pressure) such that all dissolved gas and volatile fractions have left the oil phase. In a live oil sample (at a higher process pressure) part of the gas phase is dissolved in the oil phase. This dissolved gas fraction does affect the oil properties. One of the properties that is affected is the oil viscosity. Typically, the dissolved gas leads to a lower viscosity. Consequently the T_1 and T_2 times are higher. Very little quantitative information is available on the difference in relaxation times between live oil and dead oil.

The differences between live and dead oil are shown in figures 4 and 5. These figures show the logmean value of the T_2 time distribution as function of temperature for the live oil as obtained by the in-line fluid characterization procedure in the field (purple triangles).

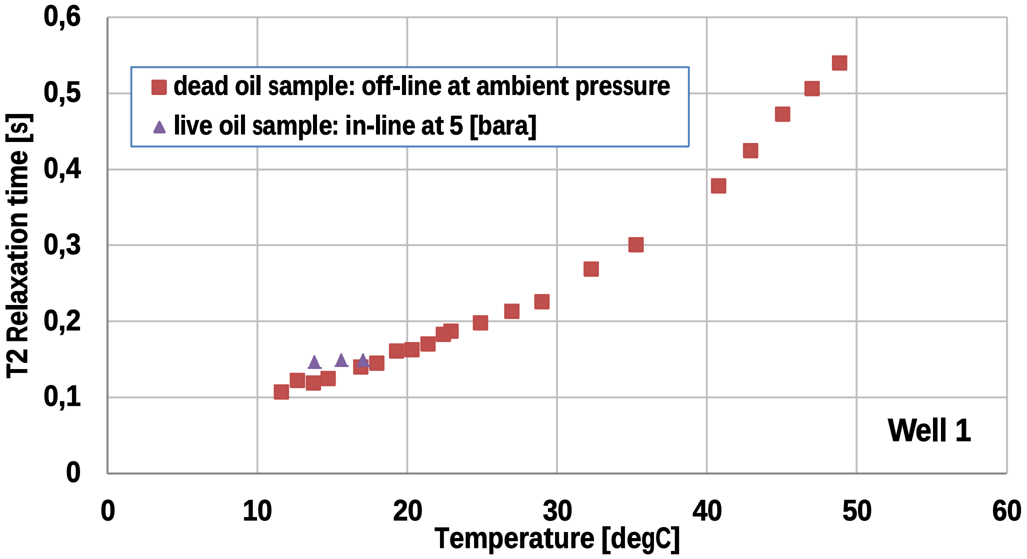

Figure 4: The logmean value of the T_2 distribution as function of temperature for the oil of well 1, obtained by means of in-line fluid characterization at a process pressure of 5 bara (purple triangles) and by means of off-line characterization performed in the laboratory at ambient pressure (red squares).

The dead oil results obtained off-line at ambient pressure in the laboratory are represented by the red squares. In order to protect confidential information of the Dutch exploration and production company the well numbers which are mentioned do not correspond with the well numbers from the field. Three T_2 measurements have been performed during the in-line characterization. During the measurements the fluid temperature has changed somewhat due to heat exchange with the environment. The dead oil samples have been measured in the laboratory over a temperature range of about 10 to 50 °C.

The T_2 time of the live oil sample is slightly higher than the T_2 time of the dead oil sample in the same temperature range. It is expected that the differences between dead and live oil are more pronounced for lighter crude oils which contain a larger fraction of short, volatile, hydrocarbon molecules. At ambient pressure, a relative larger part of the volatile components will be released from the oil. Consequently, the viscosity and T_2 time will be more heavily affected. This is confirmed by measurement results as shown in figure 5. The oil as shown in this figure has a somewhat higher T_2 value than the oil in figure 4. A higher T_2 time means a lower viscosity because of a relative larger part of shorter hydrocarbon molecules. The difference between the live oil (purple triangles) and the dead oil sample (red squares) is more pronounced.

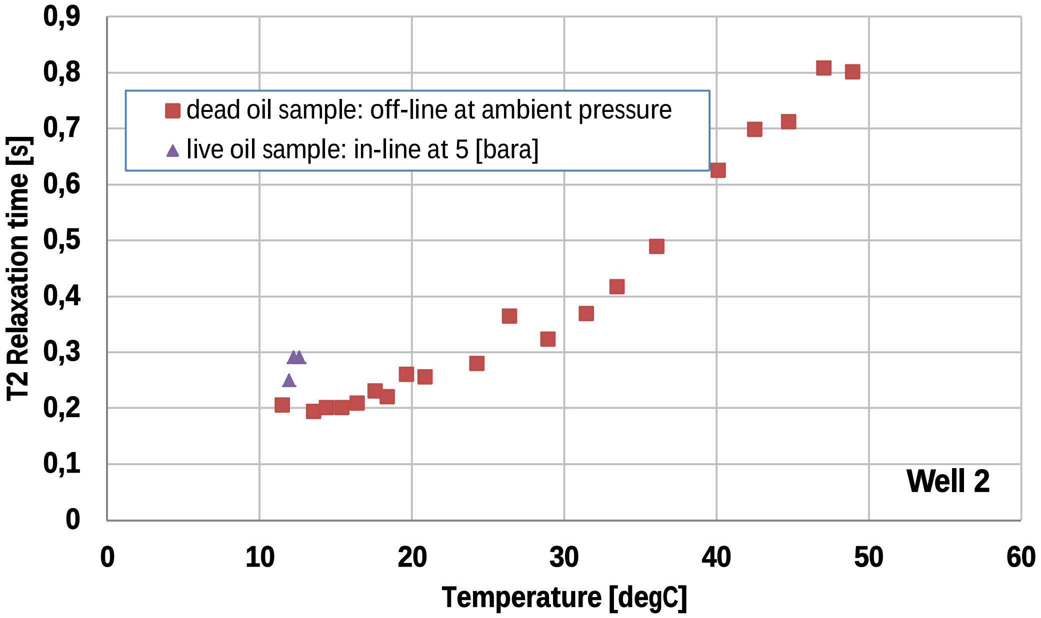

Figure 5: The logmean value of the T_2 distribution as function of temperature for a lighter oil obtained from well 2. The purple triangles are the results obtained by means of in-line fluid characterization at a process pressure of 5 bara. The red squares are the results from off-line characterization in the laboratory at ambient pressure.

Accuracy of In-Line Oil Characterization (Live Oil)

An important question is how accurate the in-line and laboratory fluid characterization is. But an even more important question is how an error in the T_2 determination propagates in the flow measurement results. Therefore, the sensitivity to T_2 has been quantified.

First of all, an estimation is made for the error in the in-line fluid characterization result. Both figures 4 and 5 show a clear temperature dependency of T_2. When this temperature dependency trend is used as a basis and the standard deviation of the variation in the in-line characterization result is quantified, a standard deviation of 6% is obtained in T_2 time for the in-line results as shown in figure 4. A standard deviation of 8% is obtained for the results as shown in figure 5. The standard deviation can be taken as a measure for the error in the T_2 measurement. The standard deviation in T_1 measurements is comparable to the standard deviation in T_2 measurements. Table 1 shows the effect of 8% standard deviation in T_1 and T_2 measurement of oil on the gas flowrate, the liquid flowrate and the WLR by means of a sensitivity analysis. This well has a WLR of 90%. ΔQ_{gas}[%] is defined as the percentage change in gas flowrate as result of the standard deviation (measure for the error) in relaxation time. The same definition holds for the liquid flowrate and WLR.

Parameter	$St. dev.$	ΔQ_{gas} [%]	ΔQ_{liq} [%]	ΔWLR [%]
T_1	8%	0.0%	0.7%	0.6%
T_2	8%	0.6%	0.3%	0.0%
HI	5%	0.1%	0.9%	0.8%

Table 1: Sensitivity analysis to clarify the relation between the inaccuracy in T_1 ,T_2 and HI for oil and the resulting inaccuracy in the measured flowrates of gas and liquid and WLR. This result is obtained on a well with a WLR of 90%.

Due to the high GVF (> 95%) in this study, the total amount of liquid present in the meter is small. This small amount of liquid is enough for T_1 and T_2 determination. However, it is not so obvious to accurately determine the Hydrogen Index (HI). For this situation the alternative solution is to use the HI for water as given in literature [3]. The uncertainty on HI by using this relationship is estimated to be 2%. A similar approach can be applied for oil. The uncertainty in the HI of oil by following this approach is 5%. The effect on the individual flowrates and WLR is quantified in tables 1 and 4.

Accuracy of Off-Line Oil Characterization at Ambient Pressure (Dead Oil)

In case an in-line fluid characterization is not possible (for whatever reason), the oil sample should be analyzed off-line at ambient pressure. For this situation the differences in T_2 time between the in-line and off-line measurements are more pronounced and vary from 11% for the measurement as shown in figure 4 to 50% for figure 5. The effect of this 50% shift in T_1 and T_2 time for the off-line characterization is quantified in table 2.

Parameter	$Shift$	ΔQ_{gas} [%]	ΔQ_{liq} [%]	ΔWLR [%]
T_1	50%	0.2%	4.2%	4.0%
T_2	50%	3.5%	2.1%	0.3%

Table 2: The effect of a difference of 50% in T_1 and in T_2 between live and dead oil on the measured flowrate of gas and liquid and WLR.

We expect that the differences are even more pronounced for higher process pressures, since a relative larger part of gas will be dissolved in the oil. Although the difference in T_1 and T_2 between dead and live oil can be quite significant, the effect on the measured flowrates is much more limited. It can be concluded that off-line fluid characterization is suitable, however a higher accuracy in measured flowrates can be achieved in case in-line fluid characterization is applied. It should furthermore be noted that the error in the off-line characterization can be reduced by introducing a model that accounts for the effect of the dissolved gas fraction in the oil.

Frequency of In-Line Fluid Characterization

Another item to be addressed is the frequency at which the fluid characterization has to be carried out. Is this for example once a month, once a year or only one time during the meter start-up after installation?

Of course, the answer to this question is related to the stability of the oil and water composition. As long as the composition of each phase hasn't changed, a fluid characterization is not required. In order to get a feel for the stability of oil and water composition, two samples from the same well have been analyzed which have been retracted with an intermediate period of two years. The result of this experiment is shown in figure 6. This graph shows the T_2 time as a function of temperature for both samples. The red triangles show the measurement results of the sample collected in February 2013. The red squares are the results of the sample collected in February 2015 from the same well.

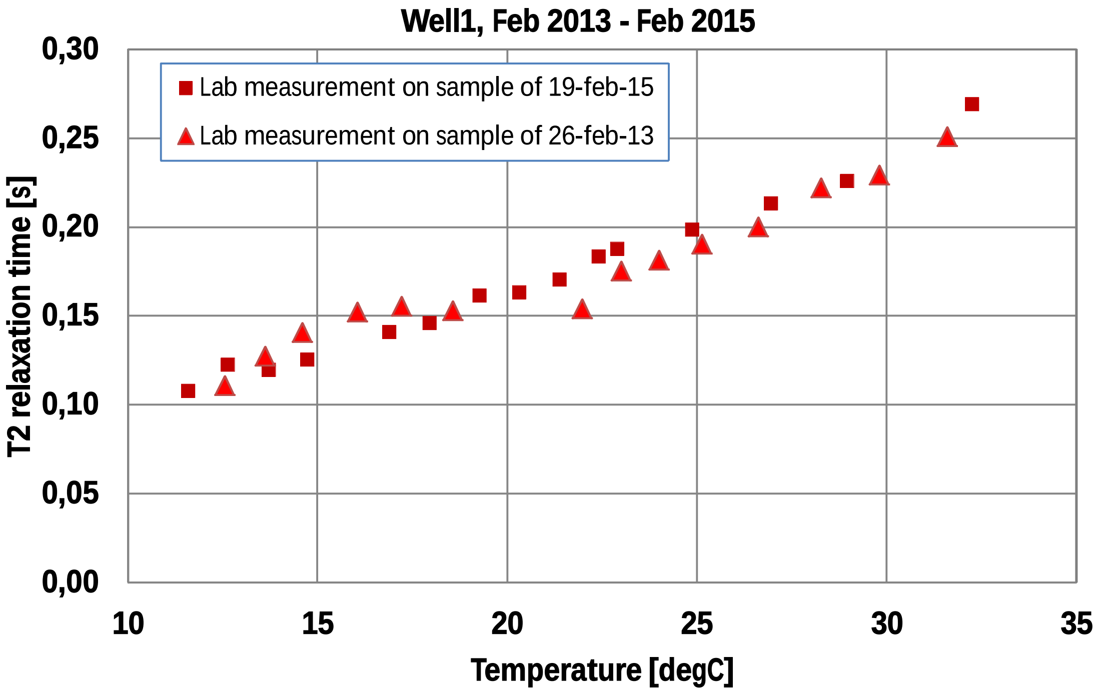

Figure 6: T_2 relaxation time as function of temperature for oil samples of the same well collected with an intermediate period of two years. These results are obtained by means of an off-line characterization and give an indication for the stability of the composition of both the oil and water phase in time.

The result as shown in figure 6 shows that the T_2 relaxation time for oil over time is pretty stable. The curve obtained on the 2013 sample is less smooth than the curve obtained from the 2015 sample. It is not clear yet what the reason is.

The standard deviation on the differences between the two T_2 curves is 11%. In accordance with the same sensitivity analysis as discussed before, the effect on the flowmeter reading can be quantified. The result is shown in table 3. This experiment seems to show that the fluid characterization procedure for this particular well can be carried out with a low frequency (e.g. once every 6 months), just to check the validity of the fluid parameters.

It should be noted that this well is producing for many years and seems very stable. Experience has to be collected for each well individually.

Parameter	$St.dev.$	ΔQ_{gas} [%]	ΔQ_{liq} [%]	ΔWLR [%]
T_1	11%	0.0%	0.9%	0.9%
T_2	11%	0.8%	0.5%	0.0%

Table 3: Sensitivity analysis to clarify the relation between the difference in T_1, T_2 of oil for two samples taken at a 2 year interval and the resulting deviation in the measured flowrates of gas and liquid and WLR.

It is recommended to run a fluid characterization more frequently during the first month after the installation of a multiphase flowmeter to quantify the stability of the oil composition and determine the fluid characterization frequency accordingly.

Differences between Wells from the Same Reservoir

Another interesting topic is the assessment of the differences between two wells from the same reservoir. A result of this comparison is shown in figure 7. This graph shows the T_2 relaxation times obtained in the laboratory as function of temperature for two different wells producing from the same reservoir. The vertical axis is in a log scale to show the constant off-set between the two curves over the entire temperature range.

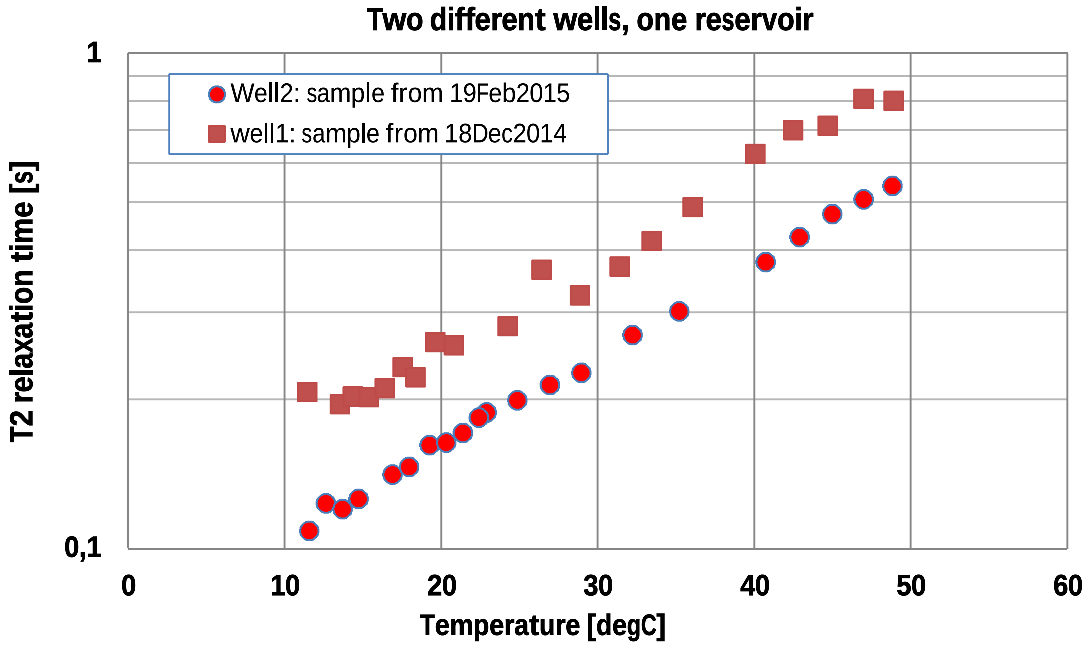

Figure 7: A comparison between the T_2 relaxation times obtained in the laboratory as a function of temperature for two different wells producing from the same reservoir.

This graph clearly shows that there are differences between wells from the same reservoir. It is hard to make a general statement on basis of this single set of data. For this specific situation, the error could be estimated on basis of the sensitivity analysis, in case the T_1 and T_2 relaxation time of one well is used for the other one. The error would end up in approximately 4% for the gas and liquid flowrate as well as the WLR. This is too much to neglect the difference in properties. So, in this case both wells should be characterized. Therefore, the software of the flowmeter is designed such, that the flowmeter can store (and retrieve) multiple sets of fluid characteristics, for example one set of fluid characteristics for each well that is connected to the flowmeter.

In-Line Water Characterization

Next to the oil characterization, the water has to be characterized. The in-line characterization of water is being carried out at the same time as the oil characterization. These are not two separate measurements, but carried out in the same characterization run. The same holds for the off-line characterization in the laboratory.

An example of an in-line and off-line water characterization result of well 1 is shown in figure 8.

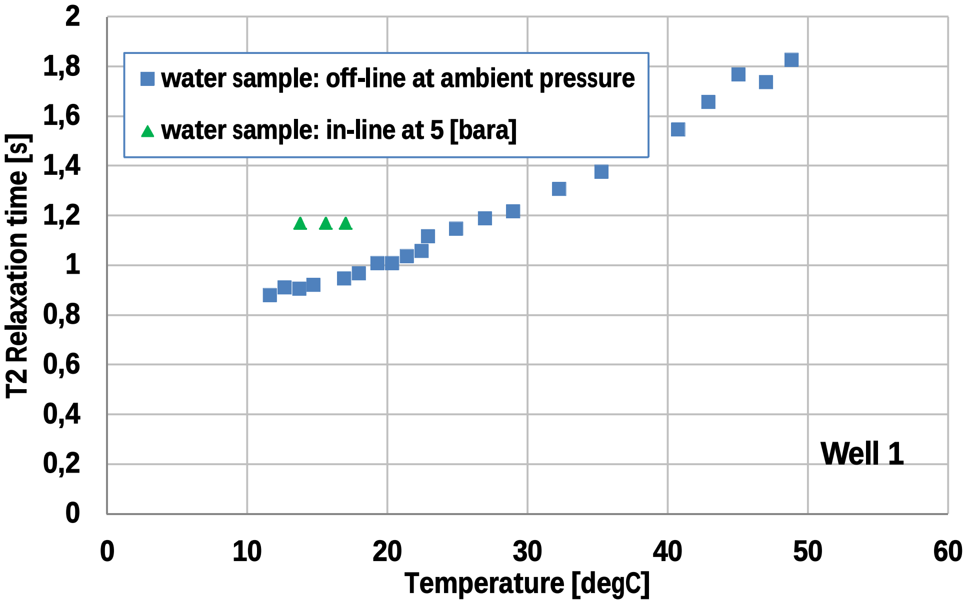

Figure 8: T_2 relaxation time as a function of temperature for an in-line (green triangles) and off-line water characterization run (blue squares) for well 1.

If we take the temperature dependency into account and determine the standard deviation on the relaxation times of the in-line results for the different wells, values in the range from 0.5 to 3% are obtained. Analogue to the oil results, the effect of this standard deviation can be translated to the estimated error in the individual flowrate and WLR determination. An overview is given in table 4.

$Parameter$	$St.dev.$	ΔQ_{gas} [%]	ΔQ_{liq} [%]	ΔWLR [%]
T_1	3%	0.0%	1.8%	0.1%
T_2	3%	0.0%	0.0%	0.0%
HI	2%	0.0%	1.6%	0.2%

Table 4: Sensitivity analysis to clarify the relation between inaccuracy in T_1 ,T_2 and HI for water and the resulting inaccuracy in the measured flowrates of gas and liquid and WLR.

This table shows that the determination of T_1 of water is important for the liquid flow determination. The other measurement values are very weakly dependent on the accuracy of the relaxation time. Something similar holds for HI. The HI value is important for the liquid flowrate and much less for the gas flowrate and WLR.

Another phenomenon that can be observed from figure 8 is the difference between the in-line and off-line characterization. Most likely, this difference is caused by oxygen diffusion into the water phase. The effect of oxygen on HI is negligible, but it is known from literature

[4][5][6] that the paramagnetic behavior of oxygen significantly reduces the T_1 and T_2 relaxation times (up to 20% at 15°C).

The sampling procedure during the field test has been carried out in the open air without any protective gas like e.g. nitrogen. The result as shown in figure 8 illustrates the importance to prevent oxygen being dissolved in the water during sampling. Another phenomenon that could lead to a pronounced difference in T_1 and T_2 for water between the in-line and off-line conditions is the presence of volatile components in the sample. An investigation to quantify this effect is ongoing.

It is important to note, that in case in-line fluid characterization is performed, the effect of oxygen and volatile components on the measured properties of water does not need to be taken into account, as the fluid characterization takes place under the actual line conditions.

5 OTHER LESSONS LEARNED

Process Temperature Variations

As mentioned earlier, measurements have been carried out at 9 different wells. The measurements at the different wells have demonstrated that the process temperature at the measurement location can vary significantly. For this field trial, the largest part of the temperature differences is caused by heat transfer to the environment. Due to the lower ambient temperature in combination with long distance between the well heads and the flowmeter (several hundreds of meters) and the differences in flowrates, the temperature change can be as large as 20 °C.

An illustration of such a process temperature change at the measurement location is given in figure 9. The purple line indicates the process temperature at the location of the multiphase flowmeter. The blue line is the process pressure. A very distinct temperature drop is observed during a well change at 19:00h. After the well change, we still observe a variation in the temperature. This is caused by the unsteady flow condition in the second well.

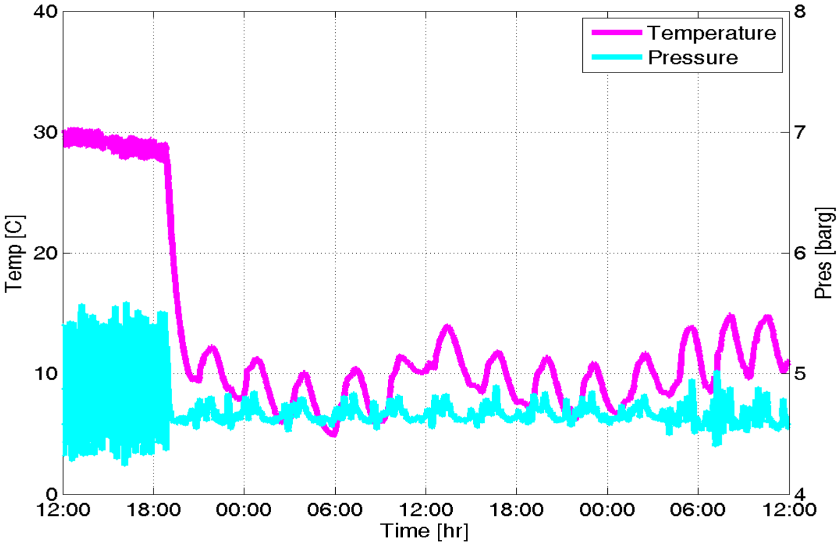

Figure 9: Process temperature and process pressure as function of time during a well change. The temperature between two wells can vary significantly. After the well change the temperature of the second is varying due to the nature of the unsteady flow in combination with heat transfer to the environment (ambient temperature is about 0°C).

The field test has shown that the multiphase flowmeter is able to cope without difficulties with these significant changes in process temperature over a short time.

Flowrate and Composition Variations

A very pronounced phenomenon that has been observed during the field tests is related to the unsteady nature of multiphase flow; the liquid flowrate can vary significantly over time. During the field test, time scales have been observed from tens of seconds up to hours. In addition, the fluctuations in water and oil flow can run out of phase and lead to large variations in the WLR. A clear example of such a situation is shown in figure 10. The upper graph shows the total liquid flow as function of time as given by the test separator. The second graph from the top shows the oil and the third graph from the top shows the water flowrate. By comparing the oil and water flowrates, it can be observed that there is a very strong variation in the WLR since the oil and water flowrate are running out of phase. The WLR is shown in the bottom graph. The vertical axis for the latter figure runs from 0 to 100%. This means that the WLR varies from less than 10% up to about 90%!

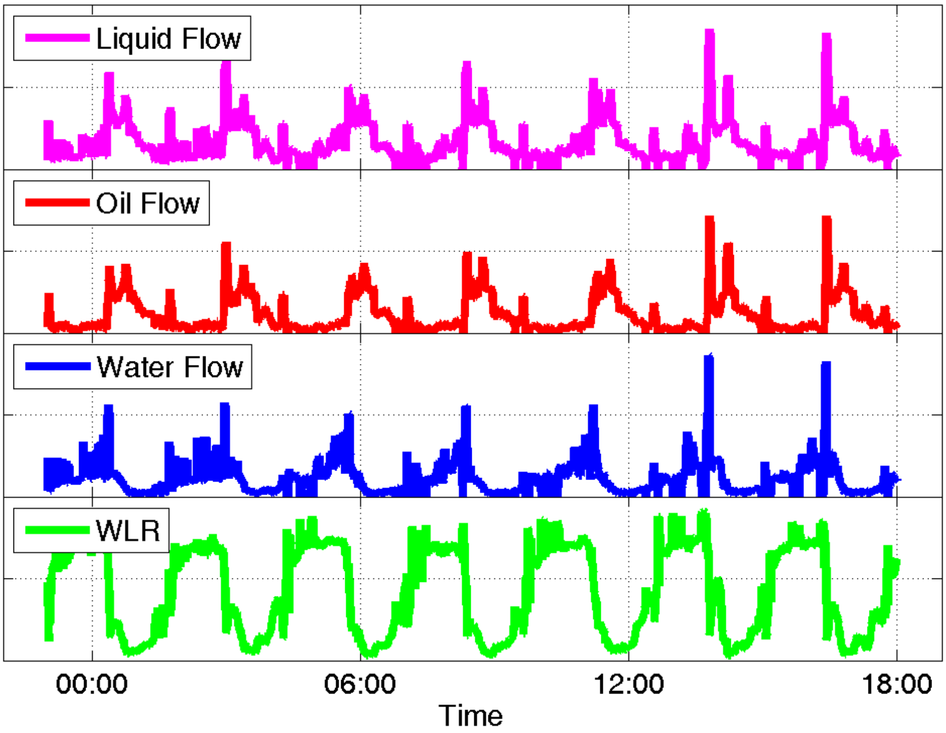

Figure 10: Illustration of the unsteady behavior of some wells. This holds for the flowrate as well as the WLR. The upper graph shows the total liquid flowrate. The second and third graph the oil and water flowrate respectively. It can be observed that the oil and water flowrates are running out of phase. This leads to a significant variation in WLR (fourth graph). Due to confidentiality reasons, the numbers on the vertical scale have been removed. The intercept of the horizontal axis with the vertical axis corresponds to a flow of 0 m^3/h for the upper three graphs. The vertical scale for the lowest graph runs from 0 to 100%.

The strong WLR variation could be a result of the relative long distance between the well head and the measurement location. Due to periods of low flowrate in combination with the oil-water density differences, it is likely that gravimetric separation takes place. The resulting stratification of the individual phase in combination with periodic slug flow could explain the strong variation in WLR. As these fluctuating conditions occurred during the field tests, this had to been taken into account. Therefore, during the field test a modification has been made to the flowmeter to be able to measure the flowrates under these fluctuating conditions.

A comparison between the separator measurement and the meter reading is shown in figure 11. The upper graph shows the total liquid flow of the separator. The lower graph shows the meter reading. The blue, red and green line is the liquid flowrate after applying 5 seconds, 1 and 5 minutes averaging respectively. It can be seen that applying averaging inside the flowmeter, results in deviations between the measured flowrate and the actual flowrate. Therefore, during the field test the measurement strategy of the flowmeter has been adapted, and single shot data is used for flowrate determination, instead of using averaged data.

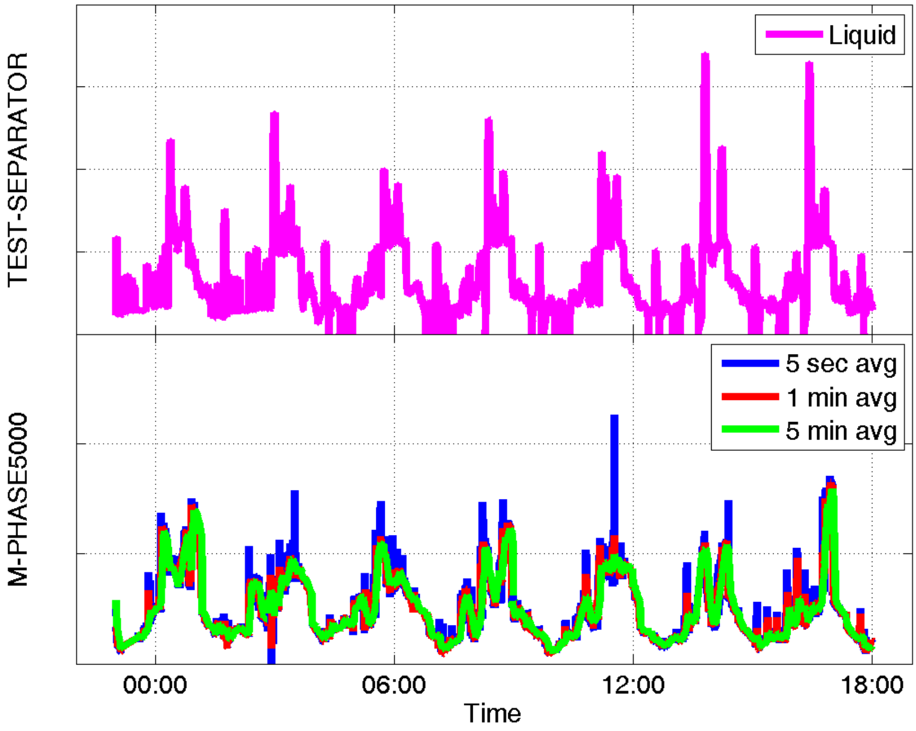

Figure 11: Comparison of the separator and the multiphase meter. The upper graph shows the total liquid flow of the separator. The lower graph shows the meter reading. The blue, red and green line is the liquid flowrate after applying 5 seconds, 1 and 5 minutes averaging respectively.

The separator shows more pronounced liquid flowrate variations than the multiphase flowmeter. This is most likely caused by the combination of the separator tank volume and the active level control operation. When the liquid level is too low, the flow to the liquid flow line is reduced or even stopped. And vice versa, when the liquid level is too high, the liquid flowrate is increased. This leads to larger variations in the liquid flowrate.

Another observation that has been made during the field test is the enormous dynamic range in flow velocity and volume flow that occur in practice. It is the task of the flowmeter to cover the entire range in flow conditions.

A test that demonstrates the enormous variation in dynamic range in flow velocities is shown in figure 12. In this graph the liquid hold-up as measured by the flowmeter is plotted versus the measured liquid flow velocity. The liquid flow velocity has been scaled by the maximum velocity and plotted along a log scale such that the reader is able to quantify the low flowrates as well. The liquid flow velocity is varying over a range of 1:33. When the dimensionless volume flowrates are derived from this graph (by multiplying the hold-up with the dimensionless velocity) one can see that dynamic range is even significantly larger (larger than 1:1000).

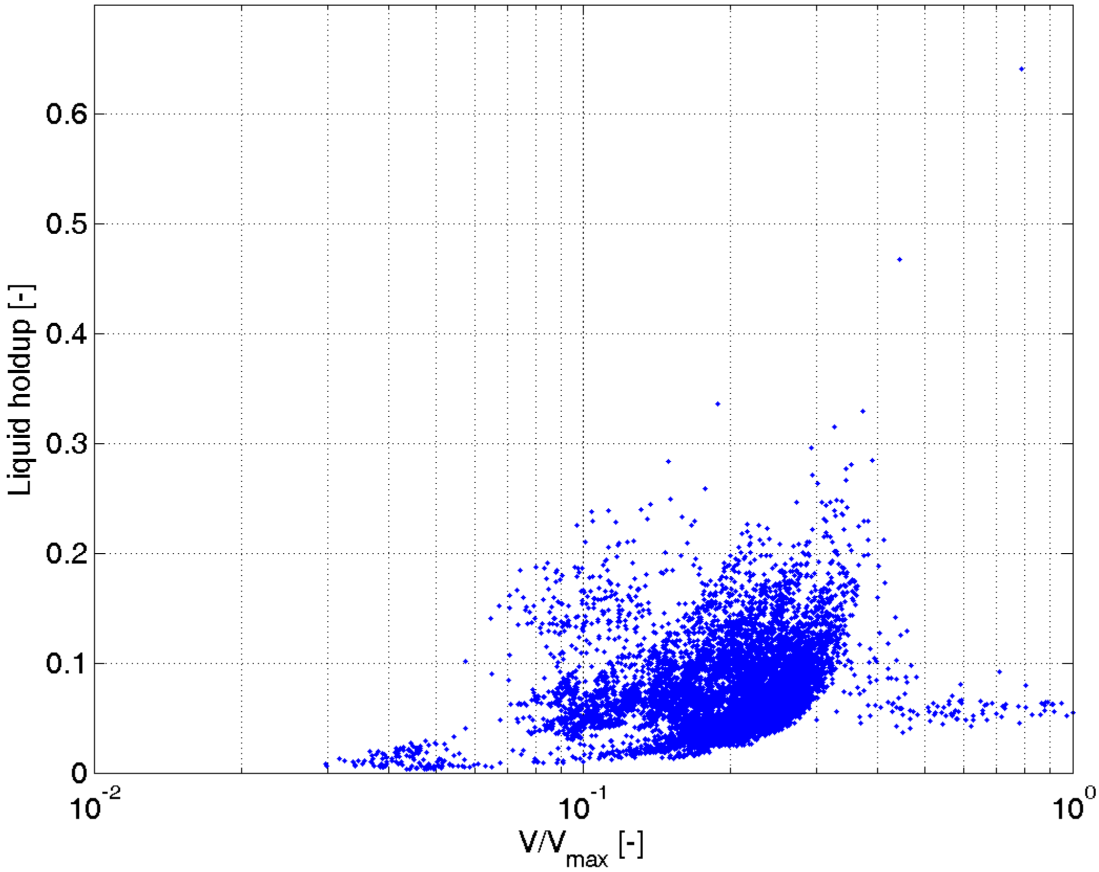

Figure 12: Liquid hold-up versus dimensionless flow velocity as measured by the flowmeter, over a period of 18 hours. This figure illustrates the enormous dynamic range in flow conditions. The velocity varies over a range of 1:33. The dimensionless volume flow variation (hold-up times the dimensionless velocity V/V_{max}*) is larger than 1:1000.*

The entire range of flow velocities must be covered by the multiphase flowmeter. Significant errors in the end result are obtained if the low flow velocities are not measured correctly. Note that one of the benefits of the magnetic resonance measurement principle is that it allows measuring the large range in liquid velocity and liquid holdup that are encountered in the field test.

An important lesson learned from the field test is that we have experienced that non-averaged flow measurement data should be used in the calculation of the individual phase flowrates. By doing so, the large variations in flowrates and composition are correctly taken into account and prevent the introduction of non-linear effects which lead to additional errors.

6 SUMMARY AND CONCLUSIONS

The M-PHASE 5000, the magnetic resonance multiphase flowmeter, has been installed and tested on an oil field, in which the flowmeter was connected to multiple wells via a test header. The installation and start-up of the flowmeter went smoothly. The flowmeter remained operational during the full 7 months of the field trial. The changing environmental conditions and process conditions during the test period had no effect on the performance of the flowmeter, which is in line with the results obtained earlier during environmental and robustness tests in specialized laboratories.

For proper operation of the flowmeter, the correct magnetic resonance fluid properties of the multiphase fluids need to be determined. The in-line fluid characterization procedure has been tested and optimized (the characterization time has been reduced to well below one hour). It has been shown that the in-line fluid characterization procedure is very convenient in practice; the fluid properties can be determined inside the flowmeter, without the need of taking samples. The accuracy of the in-line procedure is better than for the off-line fluid characterization which is based on samples in the lab. This is related to the fact that for in-line fluid characterization, the fluids are characterized under the actual line conditions, and there is no need for conversion from lab conditions to line conditions.

The flowrates encountered in the field test showed large fluctuations. The timescales of the fluctuations ranged from tens of seconds up to hours. As a result of these fluctuations, for one of the tested wells the measured dynamic range for fluid velocity was 1:33 and for the volumetric flowrate the dynamic range was over 1:1000. As the oil flowrate and water flowrate varied out of phase, the WLR ranged for a single well between 10% and 90%. In case averaging is applied to the raw measurement data, valuable information gets lost. Therefore, during the field test the measurement strategy of the flowmeter has been adapted to handle the raw measurement signal, without applying averaging. In this way the flowmeter is able to manage the fluctuating flowrates, as well as the very large dynamic range encountered in the field test.

7 OUTLOOK

Although in the current field test the field conditions were outside of the application range of the flowmeter, a quantitative analysis is being performed. This work is still ongoing. Furthermore, at present a second more extensive field test is being prepared at a different location, in the Middle East. In this field test the conditions will be inside the application range of the flowmeter, and the flowmeter will be tested for a large range of viscosities, WLR and GVF.
Next to this, the first series of commercial flowmeters has been produced and has been delivered to a customer.

8 ACKNOWLEDGEMENTS

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