North Sea FLOW Measurement Workshop

Paper 9.3

Challenges in Multiphase- and Wet Gas Flow Metering For Applications with Limited Accessibility

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1 INTRODUCTION

The upstream oil- and gas business is facing some new challenges if it comes to the application of Multi-Phase Flow Meters (MPFM's) or Wet Gas Flow Meters (WGFM's)[1] in remote areas. In the past these meters where mainly used for well testing and well/reservoir allocation. Their uncertainty and repeatability were considered adequate for this purpose. However, today we see that MPFM concepts are being used in applications where money flow between oil companies or between oil companies and host government is dependent on the MPFM flow rate readings (e.g. sales allocation, transportation fees, custody transferand royalty payments)[1].The move of MPFM's into this application is a consequence of the fact that the upstream oil and gas business is becoming more complex in terms of infrastructure, i.e. facilities are being shared between various producing companies. In those complex infrastructures the use of MPFM's is very beneficial from a project economics point of view but at the same time the use of these meters creates a few challenges from an operational point of view.As an example in subsea applications it is expected that these MPFM's will continue to operate for a large number of years without the need to retrieve the meter and the need for operations to access the meter for maintenance, verification or calibrations.At the same time the MPFM technologyis getting more advanced. There exists a large diversity in applied physical concepts, which makes it not very easy to select an adequate MPFM for a particular development. It is often difficult to see the wood from the trees and judge all the future operational effectson the MPFM in a remote and non-accessible location.One issue that is not well documented and still creates uncertainty in the long-term operation isthe effect of changing fluid parameters on the oil, water and gas flow rate readings. It will be explained further below that mis-management of these fluid properties can have a significant impact on the cash flows between operating companies or operating companies and host government.

1.1 MPFM development history

In the late 80's the oil and gas industry started to develop MPFM's, often in Joint Industry Projects with a particular vendor.The drive to reduce costs, by replacing complex test separators and simplify the upstream infrastructure by using MPFM's, stimulated a lot of research and development work with both vendors and oil companies. Generally the MPFM's are an order of magnitude lower in CAPEX[2] and OPEX[3] than a fully equipped test separator. In addition for offshore developments there is a significant benefit with the weight and space savings that can be achieved with MPFM's. The first applications for MPFM's were mainly for well testing and well/reservoir allocation. But with the steadily increasing experience and the

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[1] In this paper the abbreviation MPFM will be used for both Multi-Phase Flow Meters and Wet Gas Flow Meters

[2]Capital Expenditure, costs for purchasing and installing a MPFM, this includes all hardware to operate the MPFM (also sampling arrangements)

[3]Operating Expenditure, costs to operate a MPFM this includes all costs to maintain and operate the MPFM (including verification processes and sampling for fluid properties)

more and more advanced technology the application area for MPFM's have been extended from the well testing business to applications where the output of the meter actually determines money flow between oil companies.

1.2 MPFM and WGFM building blocks

Looking to the MPFM market there is a large diversity in the technologythat is used. Basically flow rates (gas and liquid flow rates) and composition (oil, water and gas fractions) are required to calculate the individual oil, water and gas flow rates. For flow rate determination cross correlation methods, Venturi or V-cone mass or volumetric measurement methods are being applied. For the oil, water and gas composition measurements each vendor uses a different combination of physical measurement concepts;electric permittivity measurements (in many different forms), single energy gamma ray absorption and dual energy gamma ray absorption measurements are the most popular ones. A recent development even uses advanced permittivity based tomography methods. Flow rate and composition measurement are often linked, e.g. a Venturi or V-cone meter basically measures the momentum of the flow and density is required to convert this into either volume of mass flow rates.Next to these measurements there are algorithms needed to describe the fluid dynamics of the gas/liquid flow (two-phase flow models or slip models).

In conclusion, each MPFM is a combination of different building blocks, whereby each building block needs to have some information on the base fluid properties of the oil, water and gas. And it is not only the physical measurements for flow rates and composition that require these fluid properties, also the two-phase flow models or a "simple" factor like the Venturi discharge coefficient do have a dependency on the fluid properties.It is these flow models that are far from transparent to the users as vendors consider these flow models as propriety information. For users the MPFM's are basically a "black box". In the MPFM flow computer the fluid properties are often inserted at 15 °C and 101.325 kPa condition, subsequently they are corrected to the actual flow line conditions before the oil, water and gas flow rate calculations are carried out at flow line conditions.Subsequently these actual flow rates are then corrected to standard conditions. From the above it is clear thatthose fluid propertiesand the PVT models are a key issue in the MPFM physical building blocks as well as in the algorithms and will be further discussed in 3.

2 CURRENT REQUIREMENTS FOR REMOTE APPLICATIONS

2.1 Remote locations

If MPFM's in remote applications are mentioned, one might in first instance think of subsea applications where there is very limited access to the metering equipment (or sometimes there is no access at all). During the last decade there was a significant increase in the water depths where the MPFM technology was required and currently water depths of over 3 km are not unusual (300 bar external pressure). These very deep water applications call for a new approach and different philosophies for metering and allocating the oil, water and gas to the respective sources. In shallow water it was common practice to develop subsea fields as "company fenced projects", i.e. wells, platforms, pipelines and process facilities are operated by one single company and commingling between companies was done mostly at a topside facility (a host facility). Given the space and weight constraints topside MPFM's werethen usedon the host facility to allocate the production back to the various sources and owners.

However, for very deep water developments the economics forced the operators to do the commingling at the seabed and use just one single shared riser instead of each project installing their own riser and topside facilities. Without any further fluid processing at the seabed this commingling is done in a multiphase flow environment and thus calls for subsea multiphase flow measurement. With various companies involved in subsea commingling or with production from different tax and royalty concessions, these MPFM applications can be classified as a fiscal or a sales allocation application. Any systematic error made by the MPFM will thus have a direct systematic impact (gain or loss) on the money transfer between the operating companies(through sales allocation algorithms) or between the operating companies and the host government (through royalty payment). Hence, it sounds very obvious that these applications call for MPFM's that have a very high level of confidence, an uncertainty that is adequate,a high reliability and an availability of close to 100%. Possibilities to verify the meter performance or even better possibilities to carry out in-situ measurements to re-configure the meter are obviously of great benefit.

Next to the subsea applications there are other applications that can be classified as "remote applications". Examples are those applications in an artic or harsh environment which are developed with a philosophy of unmanned operations. Also applications, where huge amounts of H_2S are present and where safety rules prevent operators to enter the premises during normal operations.But also even "simple" desert types of applications where the operator likes to reduce staff movement because of road safety are MPFM applications with limited accessibility.

For all MPFM applications, with limited or no accessibility, there are 3 important operating features that a MPFM needs to have.

- Redundancy
- No or minimumdependency on changing fluid properties (changing pVT)
- In-situ verification processes

Above 3 operating features are further discussed below, only from a measurement viewpoint. Mechanical engineering aspects related to the marinisation are not further discussed in this paper. Furthermore only so-called in-line meters are considered, meters that require an upstream flow conditioning unit (e.g. a full or partial separation unit) with all the auxiliary equipment for control purposes are generally not considered attractive in subsea applications.

2.2 Redundancy

The name of the game in subsea metering is redundancy. Subsea MPFM's are installed for a service of many years, up to 25-30 years. The MTBF[4] specified by the vendors are also in that range but with the subsea MPFM technology around for less than that period of 25-30 years it is difficult to prove those MTBF numbers are absolutely right.

In section 1.2it was indicated that a MPFM concept contains a number of physical building blocks. If one building block fails it would be very beneficial if its functionality can be taken over by another building block or a combination of other building blocks. Having redundancy on board also allows the operator to execute verification checks on the meter as a particular measurement can be done twice with the benefit to compare the two readings.For those applications with no or limited access it is strongly recommended to apply concepts that do have intrinsic redundancy on board. In addition it is recommended to use virtual metering

[4]Mean Time Between Failure, the predicted elapsed time between inherent failures of a system during operation

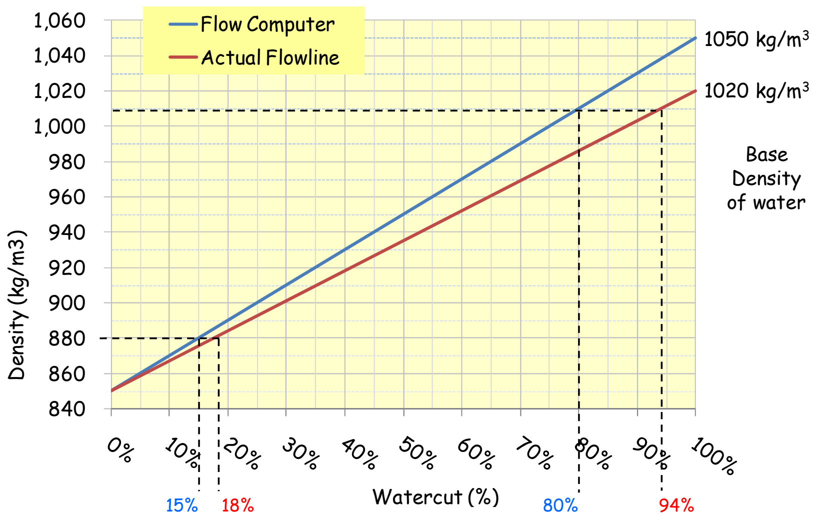
systems as back-up. Virtual metering systems are relatively low in costs and easy to install, however their uncertainty is often difficult to assess. It is the author's opinion that a virtual metering system is not a replacement for conventional measurement or MPFM systems. However, by having a virtual metering system in place in addition to other metering system, there are possibilities to execute all the learning of the virtual metering system in the first years of a development;this is the period it is expected that MPFM's still work properly. If over the years a MPFM starts to fail, this initial learning might be sufficient to fill in the gap that is created with a broken MPFM.

3 FLUID PROPERTIES

In single phase (or oil/water) flow rate measurement some of the used technologies show a dependency on the fluid properties, i.e. if the actual fluid property deviates from the fluid property that is inserted into the flow computer the measurement will start to show systematic errors. Obvious examplesare simple orifice plate measurementsand the use of Coriolis meters for the measurement of oil and water flow rates in an oil/water mixture. In case of the Coriolis meter the flow computer needs the base density of oil and water, together with the measured density of the oil/water mixture, to calculate the mass or volume flow rates of oil and water. In addition to the base densities (i.e. at 15 °C and 101.325 kPa) the Coriolis flow computer also need to have correlations on board to convert the base oil and water densities to the oil and water densities at actual line conditions.Figure 1below shows this phenomenain a graphical way. If the Coriolis flow computer contains a value of 850 kg/m^3 and 1050 kg/m^3 for base oil and water density respectively, but the actual water density is only 1020 kg/m^3, the watercut will be measured with a systematic error of approx. -13%. As can be seen in the graph the error or the misreading in watercut and thus in net-oil measurement is dependent on the actual watercut level.A systematic watercut error of approx. 13%, at a watercut level of 94%, results in a systematic error in the net-oil measurement of over 200%.

The above Coriolis example is a very simple and straight forward one and can be simulated and understood by everyone. However, in the MPFM's or WGFM's this phenomena is not very straight forward and is certainly not very transparent. Calculation algorithms, the two-phase flow models, the slip models and discharge coefficient calculations are not publically available because vendors consider this as their own intellectual property. But even if these calculation routines are available, it is often much more complex to run sensitivity analyses similar to the Coriolis meter example above. This because MPFM's and WGFM's often use a number of physical measurement principles (the building blocks) to determine the oil, water and gas flow rates. And these building blocks are not the nice linear relations that we see with the Coriolis example.

Figure 1, Watercut determination using the density measurement of a Coriolis mass flow meter. The blue line is the flow computer and the red line is the actual density-watercut relation.



It was also demonstrated in earlier publications[2] that if small amounts of one phase needs to be measured, e.g. the water flow rate in a wet gas stream for hydrate control, that it is extremely important to know the fluid property of the dominant gas phase extremely well. Small errors in that gas fluid property have a large impact on the water flow rate measurement (compare with the 94% watercut net-oil example of the Coriolis meter).

3.1 Uncertainty (random errors) and systematic errors

Each measurement has intrinsic measurement errors, and so have MPFM's and WGFM's. This measurement uncertainty is something that we, in principle, cannot influence and is given by Mother Nature. Examples are the noise in electronic signals, noise generated by electronic components and radioactive decay in case a MPFM concept is based on gamma ray absorption. Only measurements over a longer period and under stable conditions can reduce these uncertainties but in a fast changing multi-phase flow environment these long measurements are generally not desired. The uncertainty specifications as quoted by the vendors often refer to the above mentioned uncertainty (also known as random errors[5]).

Next to these random errors, there are systematic errors. These are errors that do have a well-defined reason, i.e. something is systematically wrong. This can be a bias in the calibration, a wrong Venturi discharge coefficient, a wrong parameter in the flow computer, etc. etc. It is common practice in fiscal or sales allocation applications, that systematic errors are removed immediately once they are detected. A wrong fluid parameter in the flow computer, like described in the above Coriolis meter application, should also be considered as a systematic error, i.e. the meter systematically shows an over- or under-reading. For MPFM's and WGFM this is not different. Any deviation between the fluid property that sits in the MPFM flow computer and that same fluid property in the flow line will create a systematic error in the oil, water or gas flow rate reading.

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[5] random indicates that they are inherently unpredictable, and have null expected value, namely, they are scattered about the true value, and tend to have null arithmetic mean when a measurement is repeated several times with the same instrument

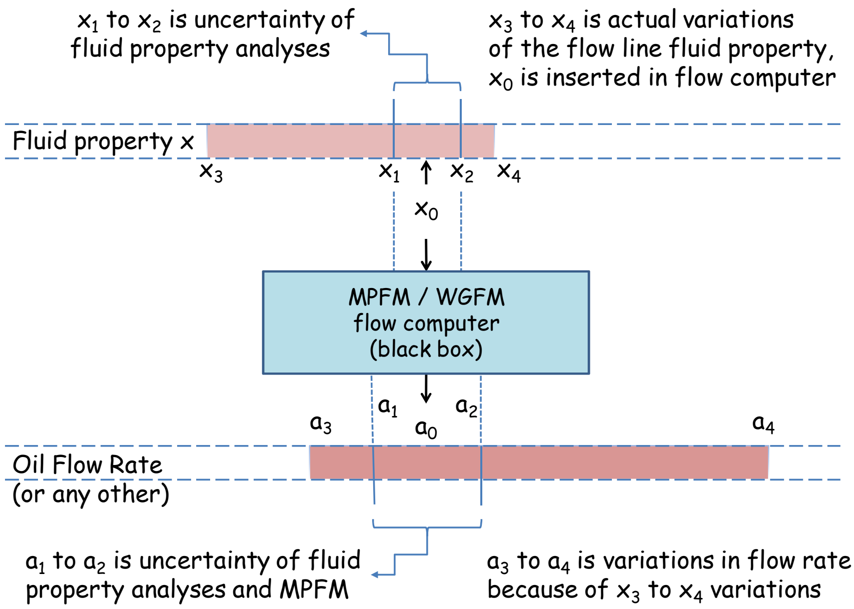

Figure 2, Change in a fluid property has an effect on the output of a MPFM. This is a systematic effect which in case the MPFM is used for money transfer results in a loss or a gain.

Figure 2 illustrates this graphically, the uncertainty of the fluid property (x_1 to x_2) and the uncertainty of the MPFM will result in the uncertainty of the output of the MPFM (a_1 to a_2). However, what is the guarantee that the basic fluid property (x_0) inserted into the flow computer will stay in-line with the actual flow line fluid property over the years that the MPFM is operated.Moreover, sometimes the MPFM measures a commingled flow and then the fluid property depends on the relative contribution of each stream. In other situations the salinity of the production water changes because of water injection (different salinity). In particular at locations where there is noaccess to the meter, or access is difficult and expensive, it is extremely important to know what the impact is of a change in fluid property. Examples are deep subsea installations where it is very cumbersome and extremely expensive to run a sampling exercise in order to determine a new value for a fluid property. Also for remote and unmanned operations or applications where sampling cannot be tolerated from a safety point of view (e.g.operations with a high H_2S composition in the gas) it is important to make anupfront consideration regarding the actual change in fluid property and the type of MPFM concept and the MPFM sensitivity to changing fluid properties.

3.2 Single Energy Gamma Ray Technology

In principle gamma ray absorption measurement is applicable for all possible combinations of two-and three-phase flow. In MPFM concepts that use a single energy gamma ray absorption concept, a high energy level is used for reasons of transmission through the pipe wall. This measurement is used to discriminate between liquid and gas (basically a two-phase measurement) and determine the density of the multiphase fluid. Similar to the example of the Coriolis meter information on the base fluid properties is required. In Figure 4 the absorption coefficient of gamma rays is plotted versus the energy levels for a number of oil and water compositions. At the higher energy levels there is not a large effect if the actual flow line fluid property differs from the MPFM flow computer fluid property.

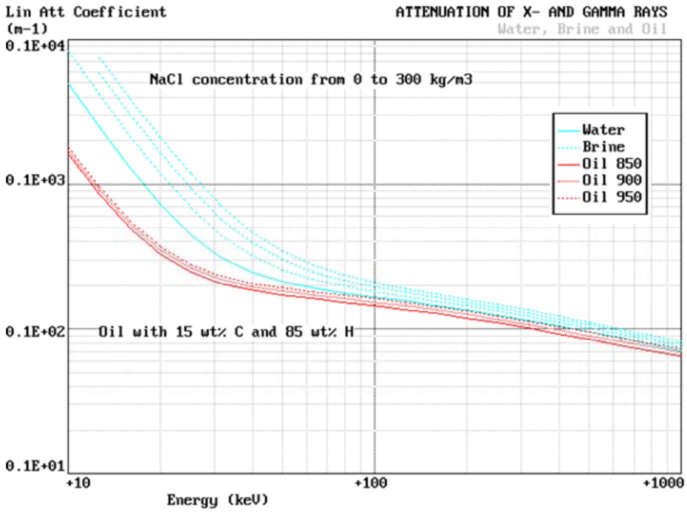

Figure 3, For Single Energy Gamma Ray Absorption generally higher energy levels are used (mainly for gas and liquid measurement). For Dual Energy Gamma Ray Absorption lower energies need to be used to discriminate between the oil and water phases.

3.3 Dual Energy Gamma Ray Technology

For Dual Energy Gamma Ray Absorption, it can be seen from Figure 4 that the most optimum energy levels for discriminating between oil, water and gas are the lower energies. However, too low energies are not good because than the transmission of gamma rays is insufficient. Hence, an optimum for good oil, water and gas measurement needs to be found and generally this sits in the 20 to 80 keV energy region. The disadvantage then is that line size is limited to maximum 4-6”.

The Dual Energy Gamma Ray Absorption principle is schematically presented in Figure 4 below. Basically this is a similar figure as the Coriolis example but now in two dimensions and for three phases, oil, water and gas. The same arguments can be used, if the MPFM flow computer fluid property is not the same as the actual flow line fluid propertythis will result in systematic errors. In particular salinity of the production water and heavier components in the hydrocarbon stream, like H_2S and CO_2, do have a large impact on the composition triangle.Hence, accurate knowledge of the fluid properties is always required for Dual Energy Gamma Ray Absorption concepts.

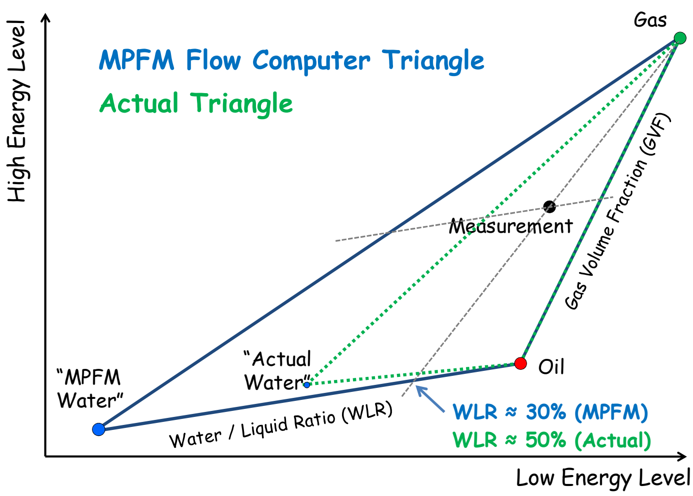

Figure 4, The Oil-Water-Gas composition triangle for Dual Energy Gamma Ray Absorption technology with an ”Actual Composition Triangle” and a "Flow Computer Triangle"

3.4 Permittivity based technology

Similar to the above example of Dual Energy Gamma Ray Absorption, a MPFM concept that uses a combination of Single Energy Gamma Ray Absorption and Permittivity measurements can also be represented in a so-called composition triangle.And similarly systematic errors in the oil, water and gas flow rate readings will creep in if the composition in the MPFM flow computer differs from the composition in the flow line.Like for Dual Energy Gamma Ray Absorption concepts, where the energy levels will influence the size of the triangle, for a system based on high energy gamma rays and permittivity, the frequency used for the permittivity measurement will influence the size of the triangle. The larger the triangle is the better the measurement resolution.

3.5 Comparison

Users need to assess the influence of changing fluid properties and should include that in their MPFM selection process. The size of the composition triangle and in particular the distortion that takes place due to changing fluid properties, need to be known. Figure 5 and Figure 6 below are two examples as presented in an earlier publication (ref 3).

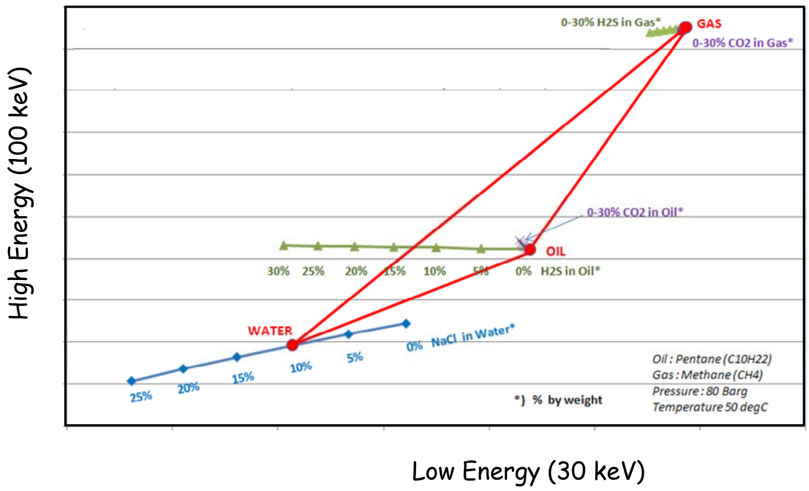

Figure 5, Effect of heavy components on calibration triangle for a Dual Energy Gamma Ray Absorption (30 keV-100 keV) system

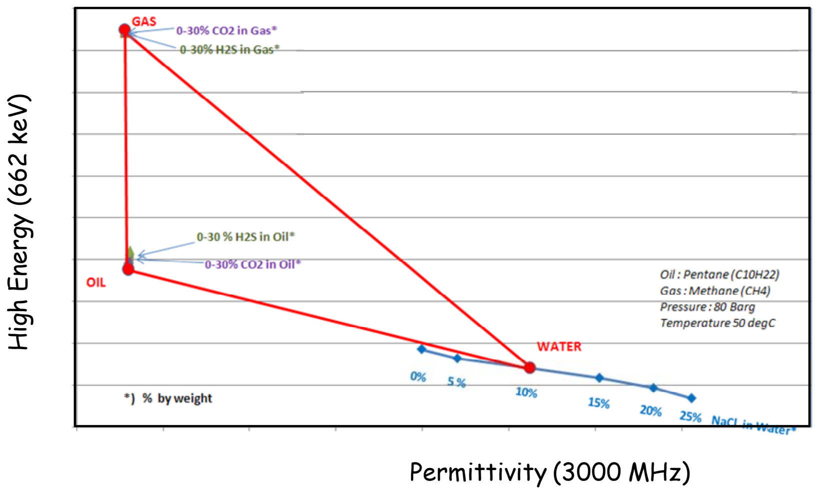

Figure 6, Effect of heavy components on calibration triangle for a High Frequency (3000 MHz) Permittivity & Single Energy Gamma Ray (662 keV) system

In this comparison, both concepts are strongly affected by the salinity of the production water and it is almost a must to include a salinity measurement to automatically correct the “water point” of the composition triangle. This is the easy part; it is more difficult to make the corrections required for the hydrocarbon compositions. Filling the MPFM with 100% oil or gas is an option but is a process that is cumbersome in installations where there is no access to the MPFM. Making provisions to separate the production stream at the MPFM location, such that a single phase oil, water and gas stream can be flown through the meter is feasible but obviously also very cumbersome from an engineering and measurement control point of view. Using the maximum and minimum readings that are detected over a longer period, assuming those measurement conditions are close to 100% single phase is another option but also can be subject to large errors as there is not always a guarantee that it is indeed 100% of that phase. The easiest way out is to select a MPFM concept that is not influenced by changes in the hydrocarbon composition.

4 IN-SITU VERIFICATION

From the above it is clear that achange in fluid property, without updating the fluid property in the MPFM flow computer, can create unacceptable over- or under readings. It is not only important to know what the effect of a possible changein fluid properties is but it is also important to be able to correct for this change. Preferably this should be done without complex and cumbersome sampling and analyses. Note that in conventional single phase fiscal flow metering or sales allocation metering any systematic error in the system is expected to be corrected immediately. But in those applications the frequency of sampling (or a proper calibration) is much higher than in a subsea application.

For remote and subsea applications it is recommended to always run a flow loop test before the meter is installed. The costs of a flow loop evaluation are relatively small compared to the huge operating costs if a subsea MPFM needs to be retrieved and replaced. Moreover, running a flow loop tests also results in a “fingerprint” of the meter and should be used as a reference during later operations.

4.1 In-situ fluid property measurement

If the sensitivity for a particular fluid property is significant the only way to cope with that is to update the fluid properties as and when required. However, often we don’t know when this is required. Being too late in updating the fluid property will result in unwanted systematic errors in oil, water and gas flow rates. Hence, methods to determine in-situ the fluid properties are under development and some MPFM vendors are providing solutions for this. Basically the MPFM selects those conditions where there is 100% oil, water or gas in the meter and then makes measurements of the permittivity, the density or determines the absorption coefficient of the gamma rays. It is almost impossible to know exactly whether it is really 100% of that one phase that is present or whether there are still small amounts of the other phases present. One vendor has developed an independent method to check for a 100% gas condition. This is the so-called droplet-count method[4]which is very sensitive for droplets and actually can determine whether there are no liquids present and thus a correct and proper gas fluid property measurement can be done. Sometimes the production can be shut in to allow the MPFM to be filled with one single phase and then execute a fluid property measurement. But this is not always that easy, in a gas environment the conditions might be below dewpoint and with shutting in the production liquids can be formed because of lowering temperatures. In order to still use the in-situ gas property measurement method a liquid free condition may need to be artificially created, i.e. by closing in the well for a short period of time and draining all the liquid from the measurement section. The measurement section will cool down with the consequence of more undesirable condensation of hydrocarbons and water. A solution to avoid this is to passively insulate (or even add heat tracing)the measurement section to keep the temperature stable at the operating temperature for a short period of time (minutes). This then would allow the in-situ gas property measurement to be executed. A proper temperature measurement in the meter is required to keep track of the correct temperature during this in-situ verification process. Also the mechanical arrangements need to be such that this in-situ verification process is not disturbed by liquid condensation further downstream of the meter or pressure fluctuations from the flow line.Above insulation or heat tracing options are not complicated and should be considered as straight forward engineering.

4.2 Use of additional components

In some applications there is a possibility to use the injection of an additional component (for flow assurance purposes) into the production stream. As an example, in a wet gas environment this could be MEG[6] which is used to prevent hydrate formation in wet gas flow lines.MEG is normally injected downstream of the WGFM such that the WGFM reading is not affected by the MEG. However, the flow of MEG through the WGFM that is using electric permittivity measurements can also provide information on the WGFM responds. Note that MEG, in those WGFM's, will be seen as water and condensate. Exact correlation (x m^3 MEG will show up as y m^3 of water and z m^3 of condensate)and its dependency on pressure and temperature needs to be established upfront.Once established this then can be used in an in-situ verification process by checking the WGFM reading with a short period of upstream MEG injection. Note that only the responds of the WGFM to water (water/MEG) can be checked and no zero drift checking can be done. Frequency of this MEG injection exercise needs to be determined by the readings taken from the past.This would require an additional tie-in and an additional injection valve at the upstream WGFM location and in principle this switching and monitoring process can be fully automated. By comparing the WGFM water readings, with upstream and downstream injection, it is possible to check the MEG/water ratio which than can be checked with the MEG/water ratio that is injected into the subsea distribution system. If they are not the same this is a trigger for running the in-situ gas property measurements exercise (see 4.1).

However, the droplet count method mentioned above, and which does not need any additional engineering to be done, only works with the high sensitivity of the permittivity measurement for liquids. Concepts based on Dual Energy Gamma Ray Absorption do not have such an equivalent. In conclusion, whatever vendor will be selected, it is strongly recommended to fully check/test any in-situ calibration functionality before installing meters at remote locations.

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[6] MEG : Mono-Ethylene Glycol

5 WHAT IS REQUIRED ?

5.1 OPEX and CAPEX considerations for MPFM applications

Once the decision has been made to use MPFM's in a project, either for well and reservoir management or for sales or company allocation, the MPFM selection process is started to determine which MPFM is best suited for the job. This is not easy as there is a large diversity in commercial MPFM concepts and it is obvious that each MPFM concept has its pro's and con's from a measurement point of view, from an engineering point of view, from a commercial point of view, etc., etc.

The costs for purchasing, installing and operating the MPFM's are important aspect that needs extensive consideration. There is a relatively large spread in purchasing costs (dependent on pressure rating and size)and subsea MPFM versions are often 3-4 times more expensive as their equivalent for a topside application. However, in the total life cycle costs of a MPFM the purchasing, engineering and installation costs (all considered CAPEX[7]) arejust a relatively small part. For most applications the costs for operating these MPFM's, i.e. maintenance, verification processes, sampling for fluid properties, etc. (all considered OPEX[8]) for the years these MPFM's are in service is often a magnitude higher. Hence, in the MPFM selection process it is strongly recommended to consider both the CAPEX and OPEX very carefully. In the end it is the total life cycle costs that should be the driver from an economic point of view, this next to the performance driver (i.e. uncertainty and repeatability). Two examples, although extreme, are given below for MPFM's that have similar performance in terms of uncertainty:

1) A lower cost MPFM with large dependency on fluid properties. The requirement for extensive sampling and analyses for fluid properties will increase the CAPEX slightly. The actual sampling and analyses during operation will make the OPEX high, in particular in applications where accessibility to the MPFM is low.
2) A higher cost MPFM, generally higher CAPEX, but if the MPFM has no or minimum dependency on fluid propertiesor if the MPFM has possibilities to perform in-situ fluid property measurement, it will take less operational activity to determine these fluid properties and thus the OPEX will be much lower than in example 1.

In conclusion, if fluid sampling and analyses is required to properly tune a MPFM and the location is remote (or subsea) this will increase the OPEX significantly. Executing subsea sampling at 2 to 3 km water depth for this purpose is not only very cumbersome and extremely expensive but also carries an environmental risk. In Figure 7 the relation for CAPEX and OPEX is plotted schematically.

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[7]Capital Expenditure, costs for purchasing and installing a MPFM, this includes all hardware to operate the MPFM (also sampling arrangements)

[8]Operating Expenditure, costs to operate a MPFM this includes all costs to maintain and operate the MPFM (including verification processes and sampling for fluid properties)

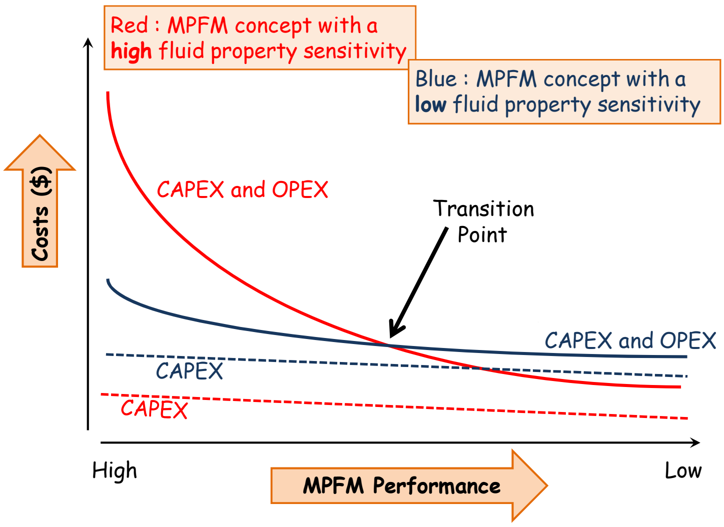

Figure 7, Schematic of the CAPEX and OPEX for a MPFM with high OPEX due to regular maintenance (e.g. sampling and calibration) and a MPFM that can cope with changing fluid properties and thus a lower OPEX

5.2 Testing MPFM's for changing fluid properties

Selecting a MPFM concept is a process where vendor and operator need to co-operate intensively. It is the operator that needs to provide the data that is required by the vendor to properly size the meter. This data generally is flow rates, pressure, temperature and composition. Subsequently, with this dataset the vendor determines the size and the specific configuration of the MPFM. The data provided by the operator often is given in ranges, i.e. minimum and maximum flow rates, minimum and maximum watercut, etc. Also for the fluid properties a minimum and maximum value should be provided, e.g. minimum and maximum oil density or minimum and maximum water salinity.

After the MPFM has been manufactured, the MPFM often will be tested in a flow loop. Here the meter is set-up in the flow loop, properly configured for the fluids present in the flow loop, and subsequently oil, water and gas flow rates will be varied within the MPFM operation envelop to compare MPFM flow rates with the reference flow loop rates. The issue of changing fluid properties does not really exist in these evaluations as the fluid properties in the loop are either constant or continuously monitored and subsequently up-dated in the MPFM flow computer.In a real world application, with limited or no access to the facilities, we do not know these fluid properties. If we are lucky we know the properties from exploration well testing or early production testing. It should be doubted whether these tests are representative for the production at a later stage. The alternative is to determine these fluid properties through sampling and analyses during the production. However, for applications with difficult accessibility this is cumbersome, will be very expensive or is even impossible.

As explained above the operator should provide data regarding the expected changes in fluid properties and the vendor should provide the information on how these changes will affect the oil, water and gas flow rate readings of a MPFM or WGFM. Preferably the outcome should be reported in a standardized way (see 5.3) that allows the operator to compare the various MPFM concepts and judge whether costs (both CAPEX and OPEX) and the uncertainty of the measurementsare acceptable.

The uncertainties of MPFM's, as quoted by vendors, are based on both theoretical considerations and on extensive evaluation programs in multi-phase flow loops. However, the conditions under which these evaluation programs have been carried out are not always clear and can certainly not compared with each other. As an example,flow loop evaluation programs can be complete blind tests, where the vendor has no clue what is happening in the flow loop and the MPFM just provides the data to an independent body for comparison with reference data from the flow loop. No “check points” have been made in the flow loop prior to running the actual “test runs”, i.e. the MPFM is just setup as if it was installed in a deep subsea application. This obviously is the best way of testing MPFM's and WGFM's. Other flow loop evaluation programs are executed where vendors do have knowledge on the loop or executed even after some “check points”have been done prior to the start of the evaluation and running the actual “test runs”. The latter is done with the argument of being able to set-up the meter but running these “check points” obviously should be avoided. In a real application with no access to the MPFM, like a subsea installation, there is also no possibility to run “check points”. Moreover running an evaluation (or a FAT[9] or SAT[10]) with these “check points” in advance, is more a repeatability test than a proper independent third party test to determine the uncertainty of the meter.

Running evaluation programs in flow loops has been described in many earlier publications and is also extensively described in the 2nd version of Norwegian Handbook for Multiphase Flow Metering (ref 5) or the API RP86 (ref 6).The main focus is always on the oil, water and gas flow rates which are compared with the reference flow rates or on the measured fractions (WVF, WLR, etc.) which are compared with the reference fractions. Moreover, all the flow loop evaluations are always done under ideal conditions with dedicated staff around and sufficient attention for the issue of fluid properties, i.e. fluid property in the MPFM flow computer is the same as fluid property in the flow loop.Testing for sensitivity of fluid parameters is not well known and rarely done, but in the light the inherent sensitivity of the oil, water and gas flow rate measurements for changes in fluid parameters is a valuable extension. Magnitude of these errors is difficult to determine theoretically, mainly because the calculation routines, used by the various vendors, are proprietary information and sit in black boxes. A practical way to get some information on the meter sensitivity to PVT is presented in the two options below

1) In a flow loop exercise

   Running tests with changing flow loop fluid properties and keeping the MPFM flow computer properties unchanged is very cumbersome or almost impossible. A work around could be to run the MPFM or WGFM in the testloop under stable flow rates and subsequently simulate changing fluid parameters by varying the input fluid properties in the MPFM flow computer. In this way the misreading in the individual flow rates will show up as biases. In order to map the sensitivity of this property, a range of values needs to be inserted. An example from one MPFM vendor is presented in Figure 9.

2) Off-line with faked input signals

   This can be a desktop exercise, no flow loop is required. The input from the various physical measurements is simulated, i.e. the DP cells, pressure, temperature, gamma ray absorption and permittivity signals are faked (e.g. with 4-20 mA signals or other). Subsequently the fluid properties in the MPFM flow computer can be varied in exactly the same way as under 1 above.

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[9]Factory Acceptance Test

[10]Site Acceptance Test

Above methods are often much better that complicated sensitivity calculations through Monte Carlo simulations which again are not always open because Intellectual Property issues. Moreover, by running sensitivity analyses like this the entire meter configuration will be evaluated, i.e. sensors, two-phase flow models, discharge coefficient, etc. The Figure 8below shows this process schematically. In practical terms this would mean that vendors need to be approached and they should be requested to provide the sensitivity figures through one of the above methods as a means to pre-qualifying for flow loop testing. The desktop exercise is the bare minimum, if the outcome can be verified later in possible flow loop, this is even better. It is recommended that above activities are done in cooperation with and witnessed by oil company representatives.

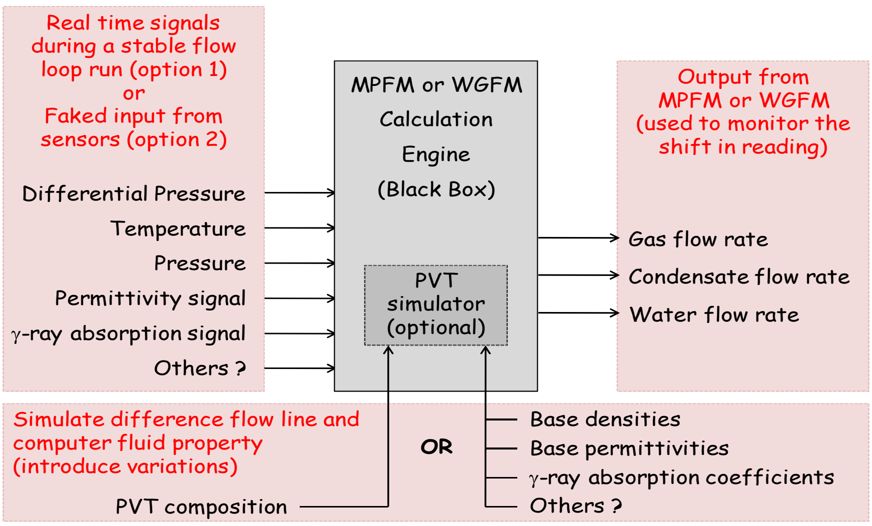

Figure 8, Block diagram showing a method to determine the influence of changing fluid properties on a MPFM.

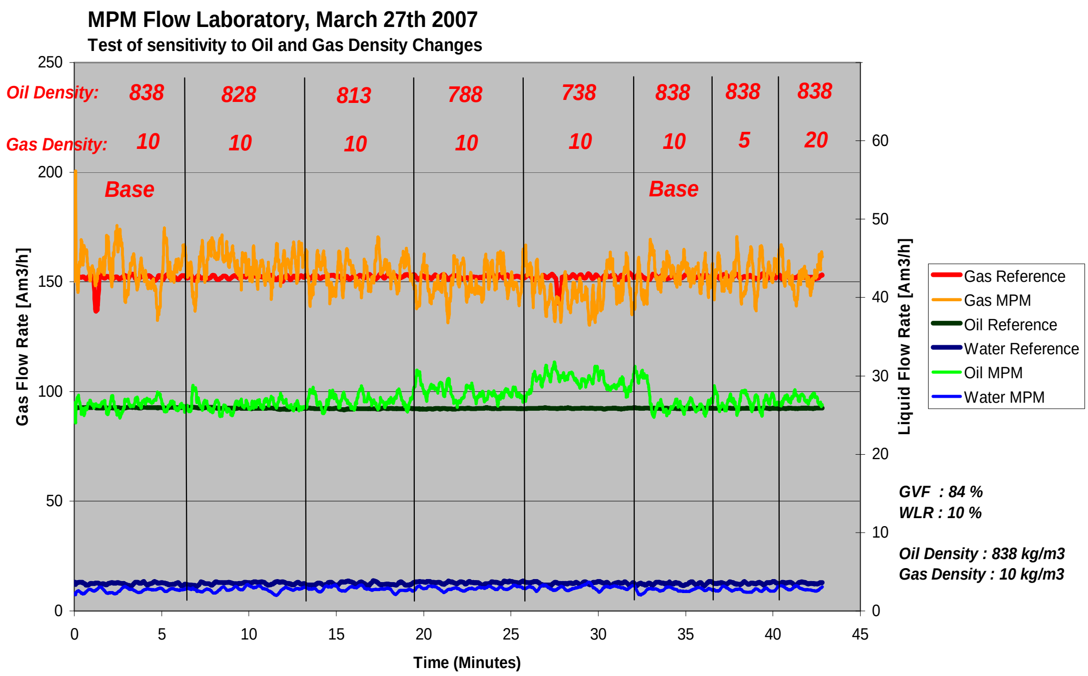

Figure 9,
Flow loop run with actual oil and gas density of 838 kg/m^3 and 10 kg/m^{3}over time the oil and gas densities in the flow computer have been changed as indicated at the top of the graph

5.3 Standard method to report the MPFM sensitivity

In earlier publications[7] two maps where introduced to describe conveniently the performance of a MPFM. The first one is the two-phase flow map, in which the actual gas and liquid flow rates are plotted along the axis. Here,the operating envelope of the MPFM and the production envelope or predicted flow rates (the well trajectories) can be indicated. The second map is the composition map, in which the WLR and the GVF are plotted along the axis. These two maps can now also be used to indicate where evaluations for sensitivity should be done. As an example, the operating envelop of a random MPFM is plotted in Figure 10 below. For two GVF's and four different WLR's a total combination of eight gas and liquid flow rates are selected which should be used to evaluate the influence of changing fluid parameters. In Figure 11 these eight points are also plotted in the composition map. Note that these eight points are just indications and it is up to the MPFM vendor and the operator to come to an agreement which conditions should be selected. Next to the flow rates, WLR's and GVF's it is also recommended to agree on the fluid properties that needs evaluation for sensitivity. As an example, for MPFM's based on dual energy gamma ray absorption it could be oil density or water density (salinity), molar percentage of other components, for permittivity based concepts it could be the dielectric constants of oil and gas or the conductivity of the water (salinity).But also the effect of other components, like H_2S or CO_2, or additional chemicals like MEG, could be selected.

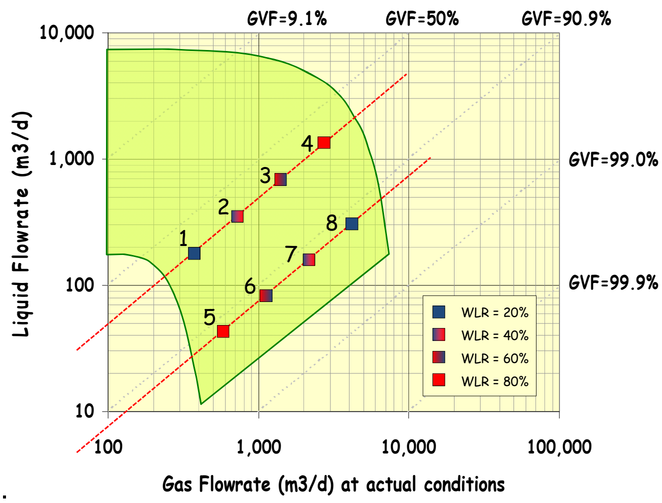

*Figure 10,
As an example the fluid property sensitivity can be determined for a number of predefined points in the two-phase flow operating envelope of a MPFM, WLR should be varied in steps from 0 to 100%.*

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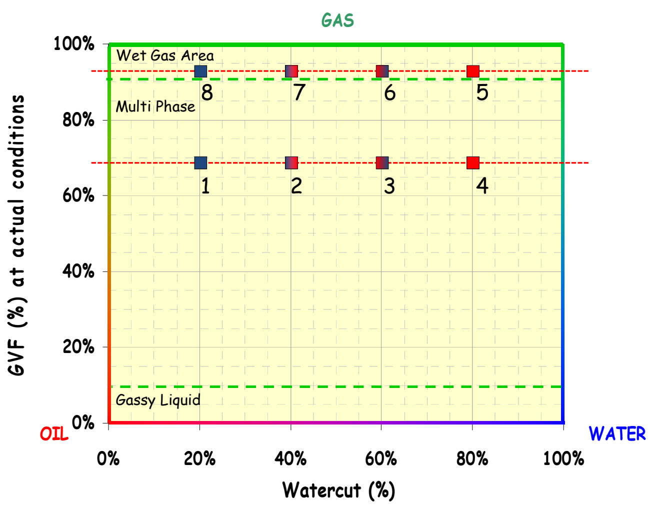

*Figure 11,
The same point as in the two-phase flow map but now plotted in the composition map.*

Once all the sensitivities have been determined the next step is to report these sensitivities in a standard way such that it is relatively easy to compare the various MPFM concepts or vendors with each other. In Figure 12 below an example is presented how this can be done. The example shows the difference of actual fluid property and MPFM flow computer fluid property, in this case the oil density, along the x-axis and the systematic under or over-reading in oil, water and gas flow rate along the y-axis. If the eight points, as discussed above, are used in the evaluation process it is convenient to plot all the results in just one graph.

Finally it is recommended to include a process, as described above, in the upcoming revisions of best practice documents for MPFM's, like the Norwegian Handbook of Multi-Phase Flow Measurement (ref 5) and the API Recommended Practice RP86 (ref 6).

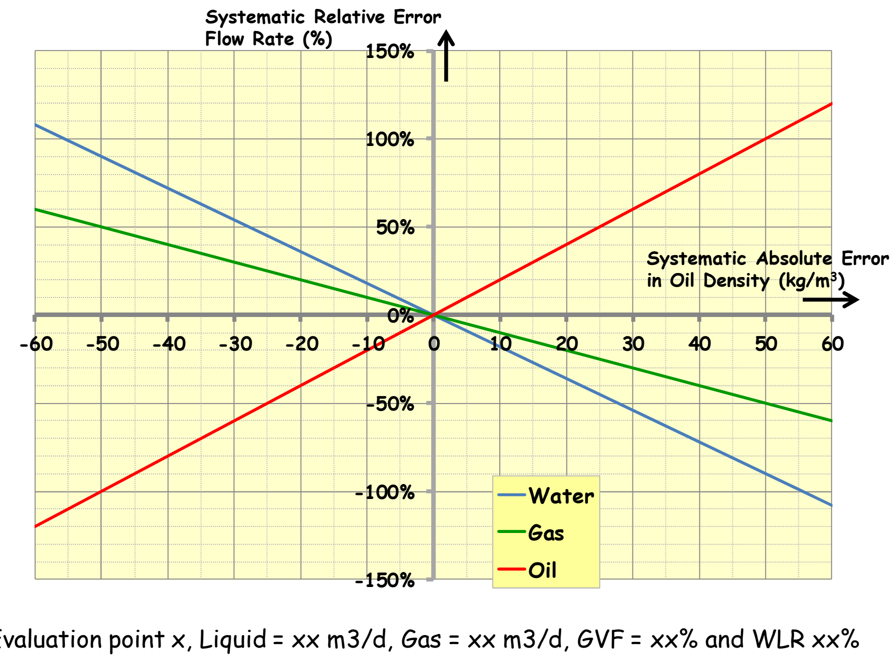

Figure 12,
As an example, a standard way of plotting the systematic errors as function of difference between MPFM flow computer fluid property and the actual flow line fluid property

6 CONCLUSIONS

For those MPFM and WGFM applications, where the output of the meters will be used to determine money transfer between oil companies (custody transfer, sales allocation, transportation fees, etc.) or oil companies and host government (royalty payments), there is obviously a lot of focus on the uncertainty of the MPFM and WGFM. Uncertainty in MPFM reading is linked to uncertainty in money transfer. Generally it is the random uncertainties, which are determined in a not too well defined and not very transparent process of mathematical simulations and/or various flow loop evaluations. In particular the comparison of the various flow loop evaluations needs extreme care, some evaluations are just repeatability tests with upfront vendor involvement and some are full blind test without any vendor involvement. Furthermore all these mathematical evaluations and flow loop evaluations are often done under ideal conditions and will thus give a most optimistic uncertainty figures.During these flow loop evaluations there is no difference between the fluid properties in the MPFM flow computer and the flow line fluid properties (often flow loop fluid property is constant because a refined product is being used). For some real life applications this is significantly different as it is difficult to determine the flow line fluid property or the actual flow line fluid property is changing because of varying flow rates from different sources.Having a wrong flow line fluid property in the MPFM computer will create systematic errors in the reading and the random uncertainty, quoted by the vendor,can easily be outshined by these systematic errors.

In the MPFM selection process it is strongly recommended to consider the total life cycle costs (CAPEX and OPEX) of a MPFM, next to the performance (i.e. uncertainty and repeatability). For remote or subsea applications the OPEX can increase significantly if it is necessary to sample and analyse frequently for fluid properties. The use of MPFM concepts that have features on board to execute an in-situ fluid property analyses or, even better, MPFM concepts that are less (or not) sensitive to changes in fluid properties are obviously preferred.

The sensitivity of a MPFM for changing fluid property needs further evaluation, documentation and publication. This allows the operator to assess the risk of over- or under reading (and in sales allocation applications the risk of over- or under payment).Evaluating the MPFM sensitivity for changing fluid properties can be done in either a flow loop or in a desk-top exercise.

It is further recommended to extend the next versions of the existing best practice documents, like the NFOGM multi-phase flow meter handbook[5] or the API RP86[6], with recommendations to test, report and document the sensitivity of MPFM's for changing fluid properties.

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