How to Reduce OPEX (i.e. Calibration/Maintenance Frequency) thru Generic In-Situ Flow Validation for any Wet Gas and Multiphase Flowmeter

Dr Bruno PINGUET, TÜV SÜD National Engineering Laboratory
Dr Brian MILLINGTON, TÜV SÜD National Engineering Laboratory
Hamza MATTALAH, TÜV SÜD National Engineering Laboratory

1 INTRODUCTION

Accurately measuring oil, water, and gas flow rates is a significant difficulty for the oil and gas sector. Multiphase flow meters or wet gas flow meters (both meaning simplified under MPFM) have opened the door to the development of marginal assets and promote more efficient exploitation of larger fields. However, these MPFM must be calibrated, and a correct uncertainty assessment is necessary, particularly for the allocation method. The new paradigm of the oil and gas industry is to calibrate them in field and especially for the ones used in allocation, as well as to achieve in situ validation, in order to significantly cut OPEX. Indeed, MPFM's manufacturers frequently charge a monthly fee to ensure the technology's performance over time without being able to independently assert the MPFM's actual or field performance, requiring the end-user to conduct their own tests to determine the MPFM's true field performance.

How do we address the in situ of MFPM performance?
There are two methods that can address this. The first method is to take the manufacturer's statement, literature and the laboratory's knowledge to establish the performance at line conditions. To ensure the estimations are accurate, an exclusive Monte Carlo simulation analysis is devised and established by TÜV SÜD NEL. Innovating algorithmic computing delivers a unique view of MPFM response based on a small amount of recorded data. It is possible to define the key parameters to monitor in order to determine whether the MPFM are still in a healthy condition and are within the sweet range by using the learning machine (LM) technique. But in this extremely conventional and conservative business, this strategy is sometimes viewed as not as strong as the second and too much data computational driven. This document will not discuss this method already presented in previous documents.
The second method, MPFM performance reviews, is stated at the well site, either by a remote witnessing or a physical third party service. This is typically done if there are any uncertainties about the MPFM's performance that require supplementary equipment to verify that is expected to perform better in the absolute to indicate the permanent MPFM installed's performance. We are frequently consulted at an early stage to advise on what might be required as the best metering solution to define and use as a reference, bearing in mind that space, timing, and most importantly, measurement principles must be simple to comprehend in order to establish or confirm the performance of the so-called reference flowmeter.

Our research has established that reported MPFM performance is, on average, too optimistic, based on the manufacturer's claims only. Additionally, it was demonstrated that manufacturers rarely disclose the predicted output specification (i.e. uncertainty) of oil, water, and gas flow rates to the end user. Rather than that, they provide a mixture of various parameters at line conditions. And, because they lack the competence in fluid characteristics necessary to convert to standard circumstances, there is no way to establish a performance statement for standard conditions, which is the end user's true requirement. This leaves the end-user to translate/calculate/convert any stated numbers to the expected parameters and associated values by themselves. Sometimes, the manufacturers have provided them with enough relevant data or information to achieve this. As this is left to manufacturers' discretion, there are no standard requirements that can be applied directly and a multiphase metering expertise is requested to achieve such a statement. This should, of course, include the traceability or uncertainty for the worst associated with the PVT package, which is unlikely to happen in 99% of the cases that we have seen.

In summary, to precisely describe the uncertainty and define the calibration frequency, and hence the performance of MPFMs, expertise and precise calculations are required. A thorough mapping of MPFM performance to its in situ application should be established by oil and gas operators or third-party multiphase flowmeter experts – and validated at a calibration facility when possible. Utilising a third-party is advantageous because it avoids buyer-seller conflict and restores the business to its normal state. For example, when you fill up your car's tank, you do not contest the reading from the pump because an organization such as TÜV SÜD NEL or NIST has stated and verify the true performance of the flowmeter (single phase in this case) used on your behalf, fostering a healthy business.

2 FIRST MAIN TECHNICAL POINT

2.1 Type of application for the use of MPFM/WGFM

Before even beginning a comparison test, the first question to ask is: do we need this comparison? What are our intentions? What were we doing prior to utilising the multiphase? Finally, what is the type of application or domain of application we are expecting for such selected flowmeter?

2.1.1 Is it a well allocation application?

Indeed, the most typical application is "well allocation," which entails assigning production on a well-by-well basis. Typically, the obligation is imposed by the authorities, with one test per month per well during 6 – 12 hours of recording. In the event that this is not done, penalties/fees must be paid. Surprisingly, there is no necessity for measurement uncertainty in this application; a high level of repeatability and reproducibility is sufficient. Oil and gas operators do not require a comparison; they should focus on equipment that is likely to be less expensive than standard MPFMs, and having a good "trending meter" (i.e. flowmeter capable of trending the reading based on some inputs) will suffice.
Today, the majority of allocation applications fall into this category, accounting for over 60 % of the total MPFM population in use.

2.1.2 Is it much more a partner allocation?

The term "partner allocation" refers to the process of allocating production from wells that operate under the same fiscal regime (such as the same block). This means that regardless of the measurement inaccuracy, the fiscal authorities will remain unaffected, as the unified tax and royalty rate provides transparency. As in the prior case, a monophasic fiscal flowmeter is located at the process plant's outflow and will be used as a reference for tax computation. While there is no fiscal utilisation, there is a custody transfer agreement between partners and the level of uncertainty that is acceptable and how the difference in production metered by each party would be allocated. The allocation of the difference can

follow different methods based on uncertainty of each MPFMs versus the fiscal meter outputs (UBA), or proportional to the reported production for each party (PBA).
Again, uncertainty is unnecessary required in circumstances where both MPFMs are from major manufacturers and a Proportional Based Allocation (PBA) is used at the contrary of the Uncertainty based allocation (UBA). It may be relevant to take uncertainty into account if the MPFM technologies exhibit a considerable performance difference when certain fluid characteristics or flow regimes vary over time. Meanwhile, there is a "gentleman's agreement". We may limit the use of MPFMs to the fundamental KPIs of repeatability and reproducibility for some cases described above, and a trending flowmeter may suffice as long as partner agrees.
The cost savings and benefits of simple MPFM technology may be the primary driver, with over 25 % of all MPFMs operating in this sphere of activity with use or not of the uncertainty performance of the MPFM.

2.1.3 Is it much more a custody transfer application?

The "custody transfer" allocation is based on the same tax system as above; however, because the parties are not partners on the same block, the relationship is different, and any potential issues are resolved through the terms negotiated between both parties early in the production process. We may expect that the demand for accuracy or, in a better phrase, uncertainty, will apply in this case compared to the prior applications discussed above, despite the absence of a specific requirement.
In this scenario, we seek an MPFM that satisfies the preceding standards for repeatability and reproducibility while simultaneously exhibiting acceptable intrinsic performance (i.e. uncertainty) in the domain of expected or observed flow circumstances.
The last words are critical, as it is not always the same MPFM purchased years ago or in different fields that should be used consistently.
Using an MPFM capable of demonstrating/establishing without a doubt, the genuine performance is self-evident. This is roughly 10 % of the total MPFM population.

2.1.4 Is it much more a fiscal metering allocation?

MPFM's "fiscal allocation" occurs infrequently.The key word is fiscal, and this refers to a fiscal flowmeter that results in a revenue gain or loss for the tax authorities. Obviously, the accuracy requirement is usually better than above cases and it can be expected to be lower than ± 5 %. However, this should not be interpreted as a rigid requirement. Indeed, authorities will consider multiphase measurements regardless of whether another MPFM is present at the custody transfer point (i.e. a traditional single-phase fiscal accuracy at ± 0.x %). The government's practical approach and declaration is that "it is preferable to produce oil with reduced uncertainty than not to produce at all," because this method generates cash for the government.
Less than 0.5 % of the entire population of MPFM are used in such domain of application. In certain circumstances, high-end MPFM may fall inside this specification. According to the scenarii, one technology may be a better answer than another in terms of performance, depending on the client's requirements.

In summary, if we look at the flow metering requirement, we can conclude that a cost-effective MPFM solution (based on a trending solution or trending meter); and possibly a modular solution that can be upgraded over time, could meet most of the requirements of oil and gas companies, based on the domain of applications definition mentioned above.
As a result, we believe that there is a clear trend toward significant price reductions for MPFM on the market, with some newcomers offering less exotic techniques, or simpler solutions with modular elements (for example, no radioactive element), or clamp-on concepts that address specific customer needs. The MPFM business may become a more mature market after 30 years, but it will require more and more in situ validation process to ensure that the performance is still within some ranges following the allocation processes.

2.2 Comparison strategy

The problem of comparison is exacerbated because any MPFM is doing measurement at a observed conditions (wording from the ISO or API) that we refer as line conditions for most of us. Indeed, the overall uncertainty of any flowmeter system (i.e. single phase, multiphase) is based on 3 key steps: (1) the uncertainty associated with the metering technology. For example, a nuclear system may be sensitive to some H2S or salt variation; an electromagnetic measurement will be at the salinity composition and concentration. [Δ: Keep in mind, there is no technology immune to all the phenomena happening inside a well. If so, it could not discriminate between the three main phases and this is all the purpose to select the one relevant on the mission profile for the well or field with time. Couple of technologies could be right but because of the EOR expected in the future, there is only one suitable solution]; (2) the conversion of the flow measurement made from line conditions to standard conditions, and this is called the fluid behaviour and use a PVT Package or Equation of states (EOS). None of the MPFM can be immune to this calculation, indeed any flowmeter is doing measurement at the given line conditions and this measurement needs to be converted to standard conditions (Figure 1). The more accurate is this PVT package, the better is the uncertainty at standard conditions for the reporting of oil, water, and gas flow rates. It is important to have also traceability on the PVT package which is very often overlooked at; [Δ: Remember, the path taken by the flash from line to standard conditions may differ somewhat from the path taken by the direct flash. It is critical to grasp this concept when comparing to a reference MPFM located downstream of the permanent MPFM under test. If a manufacturer claimed that there are using non-PVT package or fluid behaviour calculation, then ask them to remove the pressure and temperature sensor. You will save money and then they will show to you the magic random generator box that they have]; (3) the data processing and the averaging techniques used to calculate the flow rates, and the different ratio. [Δ: The authors have seen so much bias introduced by using equations like defined for a separator and not understanding that the separator had a fundamental role that MPFM do not own which is to stabilise the flow (dump the fluctuation) and under the hypothesis of an expected stable liquid-gas interface inside the separator, some of the simplified mathematic used is relevant but cannot be applied for MPFMs].
It is the combination of these 3 elements makes the overall uncertainty of any MPFM.

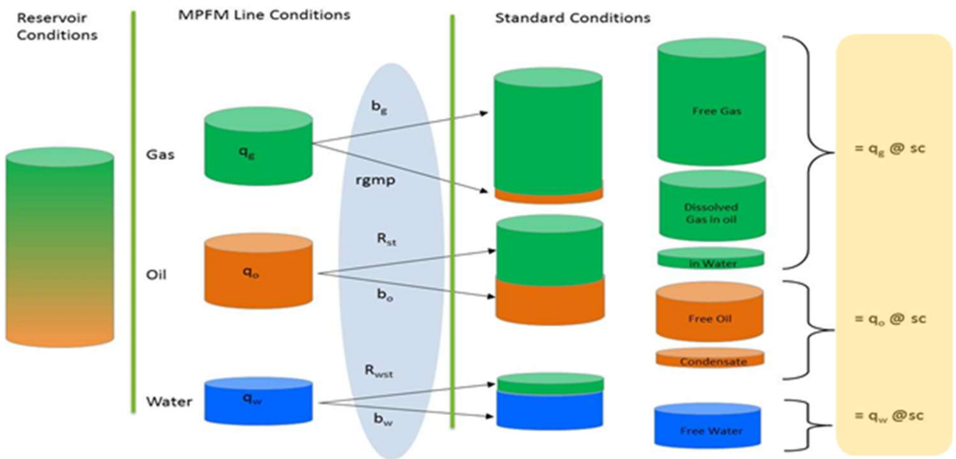

Figure 1: From reservoir conditions with a monophasic flow of hydrocarbon to multiphase conditions measurement at wellhead, and the mass transfer (gas dissolved in oil and water; or condensate coming out of gas) represented graphically because of large pressure and temperature change and finally the reported flow rates at standard conditions

In our proposed method, we attempt to eliminate or reduce as much as possible two of the three key sources of overall uncertainty, which is accomplished by forestalling the mobile one (MPFM or traditional solution i.e. separator), which we will refer to as the "reference flowmeter", as close as possible of the permanent MPFM to be tested. This results in the same PVT package being used and limitation in the propagation of error, for example.

2.3 A statistical approach to the comparison is necessary

There is still an abuse of the accuracy and uncertainty concepts, and manufacturers sometimes do so intentionally to boost their sales presentation. This should be clearly understood with the help and relevant statement made by the multiphase community. Accuracy is the degree to which a measurement agrees with the expected real or correct value. As a result, accuracy needs two separate observations using two distinct flowmeters. Without knowing or being able to recognise the genuine or most probable value, accuracy cannot be discussed meaningfully. It is a statement of quality. This is not to be confused with deviation or error, which can be expressed quantitatively in either relative or absolute terms and also involves two flowmeters.
On the other hand, uncertainty of a measured value is an interval around an average value that is generated by repeated measurements and asserts that the true value is contained within this interval at a particular confidence level stated in terms of value (i.e. standard deviation).
The multiphase metering community has followed the 95 % confidence interval (Figure 2) or the coverage factor k=1.960 to produce the expanded uncertainty measurement that should report performance of any MPFM and then make them easily comparable. This means when a measurement is made repetitively (continuous flow, for example), then a standard deviation measurement can be calculated based on the many data collected and this is defined as "1 σ" – 1 sigma – or 68.3 % of the data are within this interval defined by [average - 1 σ; average + 1 σ].

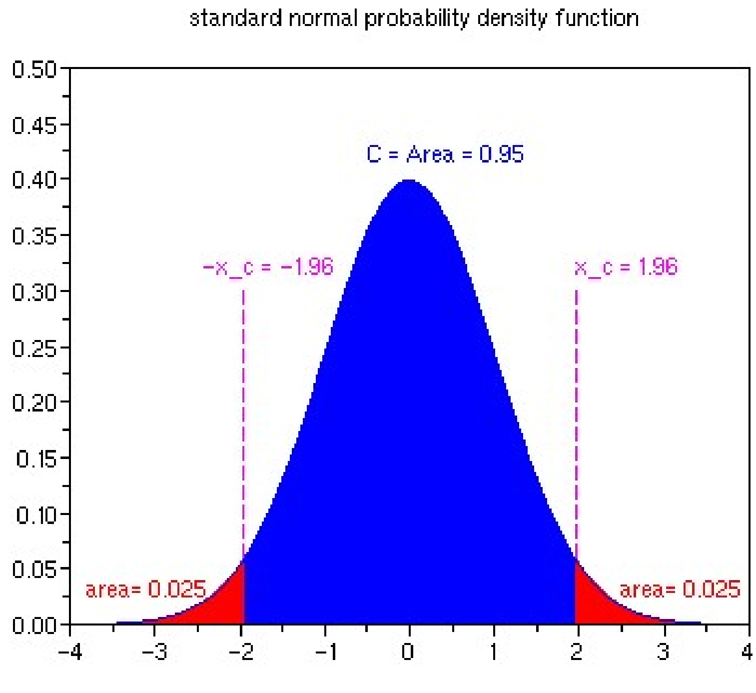

Figure 2: A representation of the uncertainty with 95 % confidence interval for a given flow rate measurement. Note that the coverage factor is not 2.000 but 1.960.

To highlight accuracy, error or deviation, and the uncertainty concepts, all are presented in the figure 3 during a comparison between two flowmeters. The black line represents a flowmeter with a low scattering and then a low uncertainty measurement (i.e. high quality measurement); the green line represents a meter with a higher uncertainty (worst quality) or larger spread of the measurements around a mean value in stable conditions. The top of each distribution curve provides a statement of the deviation or error in absolute between both flowmeters (as presented in the figure 3) or relative that could be calculated.

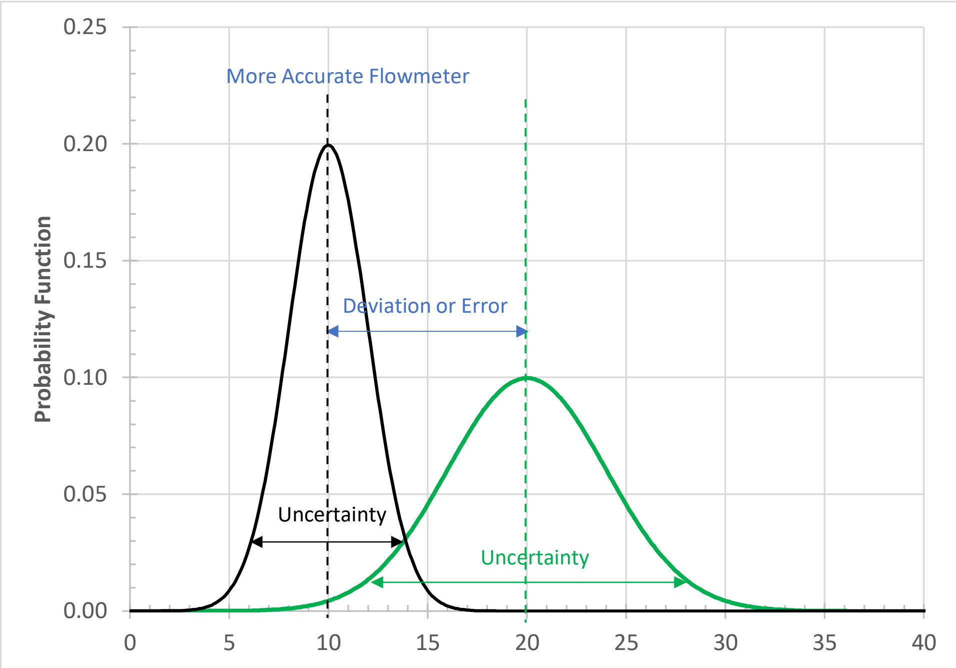

Figure 3: Concept of uncertainty, error or deviation, and accuracy.

The fundamental concepts associated with flow metering measurement are clearly highlighted above. The critical question at this point is which flowmeter is being used as a reference and which is being under test. While there is a difference between them, there is no statement about their accuracy, and there is no statement about a flowmeter serving as the reference, we may have some thoughts about the deviation between them, either absolute or relative, which we may refer to as error. The statistic analysis is given us some ideas in this case, we can see a meter being much more stable (less scattering) during the recording period. This indicates that the flow measurement is more sensitive than the other.

Δ: We observe no skewnesses or kurtosis effects in the current scenario and, this example contains no outliers, which are all excellent indicators to state about the measurement quality.

About data filtering, it is critical to remember that outliers should be eliminated solely based on certain specified statistical criteria. Again, the authors saw a plethora of odd criteria being applied that contradicted any international standards, hence biassing the overall uncertainty measurement.

There is process well identified and applied in the solution proposed by us to achieve this filtering which is fully auditable and inline with the international standards.This step, usually overlooked, is essential, and it is the first analysis to look at outliers during a test. Outliers are defined as data that are recorded but that do not fit with the overall behaviour (i.e. normal distribution). It is not necessarily the min and max that should be checked. There are numerous statistical strategies for addressing such issues. It is only through these statistical analysis approaches that some points can be eliminated and should be noted as outliers in a document rather than disappearing; this requires an explanation and an audit of the specific data point to justify this unexpected behaviour. In our analysis, we use following the case, with less than 30 data collected, the criteria based on "Dean and Dixon Test" or "Dixon's Q Test"; when with for larger data collection, the significance thresholds of Pearson and Hartley are used. In our review and comparison, some additional criteria are used based on the physics, like the relationship between mass flow rate and choke opening.

2.4 Repeatability and Reproducibility

The previous section reported only the MPFM's present performance under flow conditions; it made no mention of the MPFM's overall uncertainty. A proper uncertainty assessment includes knowledge of the repeatability, reproducibility, stability, resolution (which is typically rather modest), and other effects of the technology utilised, including environmental change. It is critical to note that some of the predicted characteristics are not immediately accessible; in fact, most manufacturer's MPFM specifications do not specify performance on oil, water, or gas flow rate, but rather on a considerably diverse selection such as WLR, liquid, and gas flow rate. There is then some error propagation calculation to perform on specific flow rates to obtain the required parameters such repeatability, reproducibility for oil, water, and gas flow parameters.
Without establishing the entire or overall uncertainty for the three flow rates, there is no tool in place to accurately state the comparison and agreement between the two flowmeters. It should be noted that the uncertainty of both flowmeters is likely to be close to one another, and thus there is no one that can be treated as being four times better than the other and then declared as a "true" reference flowmeter, and it is the uncertainty of both flowmeters that determines the PASS/FAIL criterion and why they will need to be used and established correctly to make a proper statement.
If we remember the MPFM' applications presented earlier, most of them are requiring first a strong validation of the repeatability and reproducibility, then this could be the first step to do.

2.4.1 Repeatability

Indeed, any end-user of MPFM wants to be sure that the measurement is repeatable; this means if the MPFM is reporting observed data under a given condition, and for one reason or another this MPFM is switched off and switched on again, everything else being equal then the observed data after powering up are expected to be identical prior to the shutdown. Any MPFM should achieve this bare minimum level. It is very easy to determine the response and performance of a MPFM versus repeatability; on a given flow rate - everything being equal- a shutdown of the whole MPFM can be done (not just the acquisition but the entire MPFM, including the transmitters and so on); and after rebooting and powering up, it is possible to see if the data are identical pre and post shutdown.
The repeatability performance will be for the best MPFM, reaching the level of resolution of the MPFM, or at least a tenth of the primary claimed uncertainty of the MPFM. This can be compared against the so called " reference meter" which will not be shutdown. Values should be comparable for the reference meter before the shutdown and the restart. This will define the baseline and then the comparison of the repeatability of the permanent MPFM can be established. The same process should be done on the reference flowmeter after.

2.4.2 Reproducibility

The reproducibility is more specific - in this case, the MPFM that is already in a given flow conditions is (on purpose) changed (ESP frequency changed, choke size changed, etc.…) to either lower or higher flow rate or different fractions setting, and then after a while it is back to the original flow conditions. Here, theoretically, the same value should be read again when back to the original conditions. This reproducibility test could be seen as looking for any hysteresis in the MPFM measurement. This is something a bit more challenging to do with a MPFM, because the change from a given set of conditions to another one and the way back to the previous condition is not straightforward due to the competition among the different fluids flowing versus pressure and temperature. This requires a bit more time to do such a fundamental test.
The performance is stated in terms of confidence level and it could be expected in this case that the reproducibility is a fraction of the primary claimed uncertainty of the MPFM. As in the repeatability case, the so-called reference flowmeter reproducibility uncertainty that

should be done as for the permanent MPFM. Both being evaluated, a review of performing one against the other can be established.

It should be understood, these two types of test should be repeated at different flow rates and do not refer to uncertainty measurement of the MPFM at this stage. This is the crucial point highlighted earlier, a MPFM before anything else needs to deliver REPEATABILITY and REPRODUCIBILITY measurement. This is the minimum requirement for back allocation and some of the partner allocation.

2.5 Overall Uncertainty

To establish the performance of a flowmeter or also called "budgeting the uncertainty" we need:

- (1) the calibration outcome against a single-phase meter at least 3 to 4 times better than the device in order to have a minimum or no impact on the overall uncertainty budget for the calibrated meter.

- (2) the repeatability performance of this device; there is a technique to calculate the overall repeatability over a full test, but this is not presented in this document, refers to the authors for further explanation.
  It is a piece of very important information for the end-user because, in case of a shutdown and up again, the difference in the flow measurement needs to be understood if related to flowmeter performance or more fundamental behaviour from the reservoir or other equipment installed in the field..

- (3) the reproducibility; there is also a specific technique to address it generically during an entire test on a facility.

- (4) the drift which is a systematic uncertainty that should be considered. Essentially, drift determines how the error in the measurement process changes over time.

- (5) the bias could be a source of uncertainty. This is very well treated in the ISO 21748 (Ref [4]) if this is happening and how to cancel as much possible the effect.

- (6) the stability will be a parameter to consider if they have been multiple calibrations (a minimum of 3 seems reasonable but larger is the number and better this value will improve) done with the same flowmeters, this will be the standard deviation of the calibration results.

- (7) the resolution should be considered, even if the contribution is generally tiny.

We show graphically figure 4 the concepts mentioned above about repeatability, reproducibility, and flow measurement uncertainty at line conditions, and how a test could be made for a flow condition. It is based on this information that a comparison and PASS/FAIL statement can be made. The large blue ovals highlight the reproducibility after an ESP pump frequency has been changed (see frequency on the top of the figure). The repeatability is highlighted with the green circles. The uncertainty is showed by the black arrows that define the width or the bandwidth of the data distribution around a central value. The deviation between both flowmeters can be defined by looking at the average difference between the light and dark-coloured diamonds.

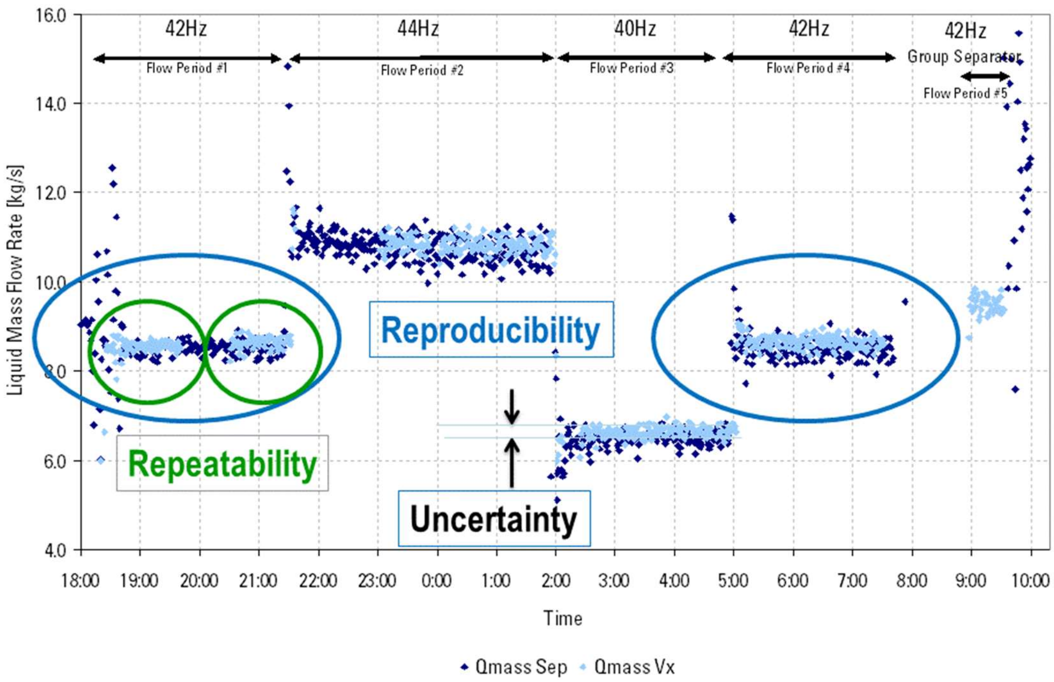

Figure 4: Typical test to check the performance of two flowmeters in series and state the repeatability, reproducibility, deviation, and uncertainty at line conditions

3 STABILITY

3.1 A Requirement about Stable Flow

There will always be competition between the oil, water, and gas (for the least) phases in multiphase or wet gas flows, and the relative holdup (i.e. fraction) or cut (volume fraction) will never be constant with time. On the other hand, the production of a well is proportional to the differential pressure exerted between two points on a production line. This differential pressure can be linked to the mass flow rate, or to the total mass flow rate more precisely (i.e. oil, water and gas together). To confirm that the flow is stable and, more importantly, to eliminate bias in the comparison, the test process is to simply look at the DP measurement, which is a typical measurement performed over an orifice or with any MPFM or on a length of pipe for a given period. If this DP reading remains within specified limits, this indicates a stable flow. The authors have extended the concept and are providing four criteria to define the limits and stability requirements without introducing any bias in the flow regimes or data collection:

- (1) The first criterion is purely related to the Root Means Square (RMS) of the Differential Pressure (DP) based on a short sliding averaging (e.g. 10-60 seconds) versus the long sliding averaging (e.g. 20-30 minutes). The recording should allow to get enough measurements (e.g. > 100 data). The ratio RMS/<DPj> is the criteria of stability used by the authors and expected not to exceed ± 10 % to consider the flow as stable. This parameter will spot any large fluctuations if this happens.

- (2) The second criterion is important and verify that the Square Root Error (SRE) that is defined is below ± 5 % over the same period selected above (i.e. > 100 data). The square root of DP is proportional to the mass flow rate. Here, it will highlight the unsteadiness of the flow using the square root of the average versus the average of the square root values of the instantaneous.

- (3) The third criterion is related to the line temperature, which should stay within Root Means Square (RMS) ± 5 %. These criteria are easily achievable and it will show any fluctuation because of other external devices (valves opened somewhere else, gas lift changed in different wells…).
- (4) The fourth criterion is related to the line pressure, which should stay within Root Means Square (RMS) as defined below ± 5 %. These criteria are obtained easily and it will indicate any fluctuation because of other external devices (valves opened somewhere else, gas lift changed on different wells…).

If all requirements are met, the flow is sufficiently stable to allow a comparison of the two flowmeters as detailed below. The interesting aspect of the criteria formulation is that it does not presuppose any circumstances regarding the individual flow rate, so it will not bring bias into the comparison by intentionally excluding any range of data.
For instance, if the well produced at a high GVF and the described criterion was used to keep the gas flow rate within a certain range, a bias will be established, misrepresenting the true flow behaviour and flowmeter performance. As you may imagine, the well is anticipated to flow under specific parameters that have not changed during the test.

3.2 Duration of the recording for a proper comparison

The length and threshold values specified above for each criterion should be regarded as suggestions that may be contested and adjusted in light of the applications. Everybody wants to collect a large number of data points and then minimise the duration of each data point or test. As a precondition, it is necessary to establish the "dead volume" between the two flowmeters. If they are located far apart, the test recording should be at least three times the "dead volume". This will ensure that sufficient fluid has been displaced to reflect the flow at both flowmeters, and then a time shift should be made in accordance with the "time flight," which is the time required for a fluid travelling from flowmeter#1 to reach flowmeter#2. The authors witnessed a test with a distance of nearly 10 kilometres between the two flowmeters; clearly, the flow seen at time#T_1 was not identical at both metres, and such tests should be extremely carefully designed and avoided whenever feasible, except for subsea applications.
It is critical to estimate the average value appropriately throughout a test and to collect enough data to obtain a normal distribution and to verify that the measurement is useful for comparison. This is clearly related to the measurement frequency, but also to the well flow regime. Multi-mode analysis os sometime called modularity is examined but adds complexity to the analysis; nonetheless, this is something that will help identify the type of flow regime and why an MPFM may not perform appropriately in this domain with a certain technology.
Once stability period is achieved, one to two hours should be enough as soon as both flowmeters are in the vicinity. Any MPFM requiring more should be considered suspicious and probably not measuring but analysing data and pattern and are not a direct flow measurement technology.
The new separator provides data continuously, and not the average each 10-15 minutes (i.e. 4 to 6 data per hour), and this could avoid using the typical well test data report based on 4 to 12 hours basis, which should be considered the upper limit for duration in case of old separator data acquisition system. Meanwhile, a quick analysis of the 2 to 4 first hours of stable flow versus the 6 to 12 hours could demonstrate that the results are identical and then an optimum value could be used. The authors never asked for more than a couple of hours. Deviations from this generic statement were made with unconventional fluid (high viscosity or extremely volatile one in particular environmental conditions), or multi-mode flow signature requiring an extended set of data), or the use of very slow acquisition frequency system to build a relevant distribution curve.
Prior to the comparison, it is critical to verify that the well has not been stopped and restarted recently, as this could show that a separation occurred inside the vertical section of the well (i.e. tubing), and for a time, the fluid flowing did not represent the genuine well performance.

4 WHAT AND HOW SHOULD WE COMPARE

After completing all the preceding procedures, it's time to establish some comparison criteria. This is arguably the least understood stage in the comparison test because it involves determining whether or not the test was successful by considering the uncertainty of both flowmeters. Frequently, people still expect to obtain identical values when comparing two systems that both have a considerable degree of uncertainty.
The authors had seen companies challenging the result when less than ± 1.5 % relative deviation was recorded between two devices in field conditions. For an expert, this was quite amazing to achieve such matching, and it will have been immediately, for sure, approved. Some people have been challenging, for example, a MPFM performance for ± 0.1 % in the match when the fiscal allocation measurement is claimed to be within ± 0.25 %. It is obvious that people have lost sight of the greater picture. Again, a third party can bring back the pertinent statement and standard to comply with, as well as the pertinent data analysis procedures.

Although the two exceptional occurrences do not occur consistently, one should not automatically conclude that the MPFM under test is incorrect without considering the uncertainty associated with each measurement made by both flowmeters. Additionally, as previously stated, no measurement has a genuine value. It is worth remembering that the definition of uncertainty is the probability that the true value is within the confidence interval (defined in flow measurement at a 95 % confidence level).

4.1 The key parameters to compare

Due to the fact that oil and gas businesses deal with living fluid, there is always a mass transfer as a function of pressure and temperature, and the total mass flow rate (i.e. oil, water, and gas combined) is the only constant parameter regardless of line pressure and temperature. Any tonne or kilogramme of fluid at given conditions T_1, P_1 will be identical (in mass) at given conditions T_2, P_2 but it will not be necessary having the same volume! This is the concept of mass conservation, and hence the first parameter to compare should be the overall mass flow rate. If they cannot find a proper match, it is irrational to proceed knowing that the split of the oil, water, and gas would only get worse.

The following section contains the recommendation and the sequence in which the parameters should be compared. It should come as no surprise that the process compares mass flow rates before volume and from line to standard conditions. This process demonstrates unequivocally that the lower down in this list, here below, a given parameter is, the more operations (data processing) are performed and the propagation of uncertainty increases. If the pressure and temperature are sufficiently different, a correction should be done (be cautious if two flowmeters are extremely close together but a choke is employed between them or a by-pass is leaking between both flowmeters!).

- (1) Total mass flow rate at line conditions versus the second meter (i.e. reference)
- (2) Liquid mass flow rate at line conditions (if making sense, i.e. both flowmeters run at the same P and T unless correction must be applied
- (3) Liquid volumetric flow rate at line conditions
- (4) Gas mass flow rate at line conditions
- (5) Gas volumetric flow rate at line conditions

- (6) WLR (if making sense, i.e. both flowmeters are run at exactly the same P and T unless a correction should be applied). Additionally, it should be important to calculate correctly WLR especially if the WLR is not stable

- (7) Oil volumetric flow rate at line conditions based on the WLR measurement (from MPFM) at line conditions

- (8) Water volumetric flow rate at line conditions based on the WLR measurement (from MPFM) at line conditions

- (9) Total liquid volumetric flow rate at standard conditions

- (10) Total gas volumetric flow rate at standard conditions

- (11) BSW is the parameter that could be also checked between both meters, and versus the sampling taken at an adequate time. It is important to remember that sampling is only a measurement made at that time and for the given duration of the sampling, and cannot be extended beyond that
  A reminder the BSW and WLR will be different and they should not be compared without correction (shrinkage for the least)

- (12) Oil volumetric flow rate at standard conditions

- (13) Water volumetric flow rate at standard conditions

While most manufacturers do not give uncertainties for water and oil, information can be requested, or a third-party expert can provide a comprehensive review of the MPFM performance versus GVF and WLR. The end-user can then expect the level of performance that could be achieved in this test but also in the necessary allocation.

4.2 How to do a comparison

A measurement "X" done multiple times can be defined by $X = U \pm k.\sigma(x)$ with U the average value, and σ the standard deviation (i.e. , $\sigma(x) = \sqrt{Var(X)}$ and k being the coverage factor 1.960 to represent 95 % of confidence level (MPFM metrology standard), please note that Var is the variance or the square of the standard deviation.

In our comparison case, we will look at the parameter Z=X-Y with X being the reading from the MPFM and Y the reading from the so-called reference flowmeter. Based on mathematical argument, the variance of Z can be expressed by $Var(Z) = Var(X - Y) = Var(X) + Var(Y)$ because the data recorded with X and Y are not correlated then the covariance of (X, Y) will be 0. What we see clearly from the above expression is the use of the uncertainty associated with each flowmeter. The criteria of acceptance are then defined as follows (for our application) generically by the calculation of the Zeta-score or Zeta function (or ζ–score) which has no unit. If the absolute value of ζ–score is below ± 1, then the comparison is excellent and well within the specification of both flowmeters. The comparison test has PASSED. If the absolute value of ζ–score is below ± 2, then the comparison is satisfactory and within the specification of both flowmeters. The comparison test has PASSED. If the value of the ζ–score is between ± 2 and ± 3, this is a questionable performance in terms of comparison. This should be carefully examined and graded as FAILED without explanation of the stability criteria or any other factors that may have influenced the performance. A ζ–score greater than 3 indicates that the comparison test FAILED.

Now, the PASS/FAIL test should be performed on a minimum of the following five parameters: (1) Total mass flow rate, (2) Liquid volumetric flow rate, (3) Water volumetric

flow rate, (4) Oil volumetric flow rate, and (5) Gas volumetric flow rate. Flowmeter manufacturers provide information about line conditions. The test should be conducted as close to the same line conditions if the guideline above are followed and the results can be extrapolated to standard conditions. In case of large distance or large difference in P and T readings at each flowmeter, the same PVT package is utilised between both flowmeters, the comparison is done at standard conditions.
We give below some examples of ζ–score in a comparison context. Here, it is synthetic data are presented to fix the idea. Figure 5 the flowmeter measurement is 110 versus 99 for the reference flowmeter and the standard deviations are respectively 3 and 0.99, giving a ζ–score of 3.5. The comparison clearly fails in this case.

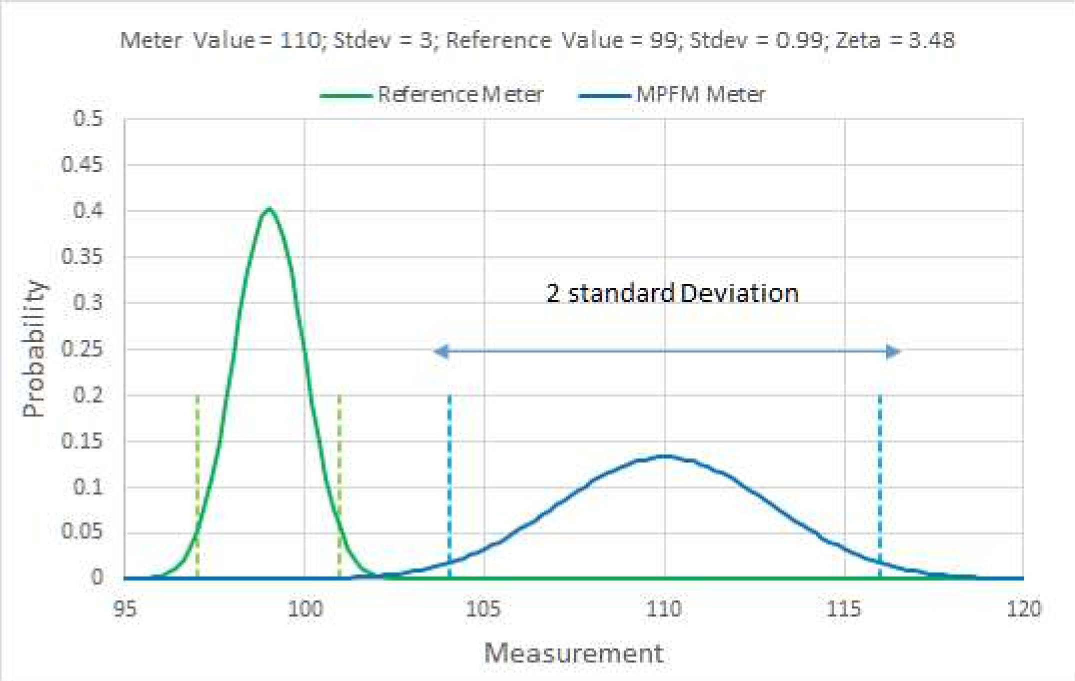

Figure 5: Comparison permanent flowmeter vs. reference flowmeter with a ζ–score of 3.5

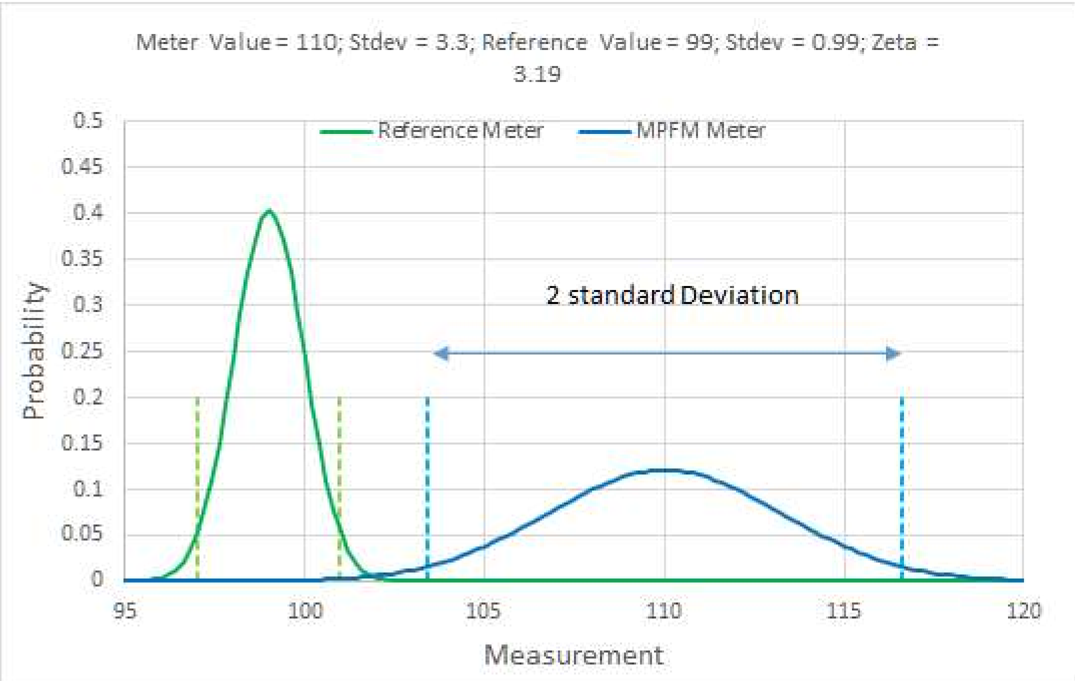

Figure 6: Comparison permanent flowmeter vs. reference flowmeter with a ζ–score of 3.2

Figure 6, the flowmeter measurement is 110 versus 99 for the reference and the standard deviations are respectively 3.3 and 0.99, giving a ζ–score of 3.2. The comparison clearly fails in this case.

Figure 7, the flowmeter measurement is 110 versus 99 for the reference and standard deviations are respectively 5.5 and 0.99, giving a ζ–score of ~ 2.0. The comparison could be barely valid. Interesting, the absolute deviation is 11 and the relative deviation is ~ +11 % against the reference measurement, and it could be considered quite far, but the uncertainty on both flowmeters are in relative ~ ± 2 % and ± 10 %. This leads to a validation. Obviously, investigation of the broad uncertainty of the permanent flowmeter versus the reference should be made. Again, skewness, kurtosis multi-mode, outliers should be investigated before concluding.

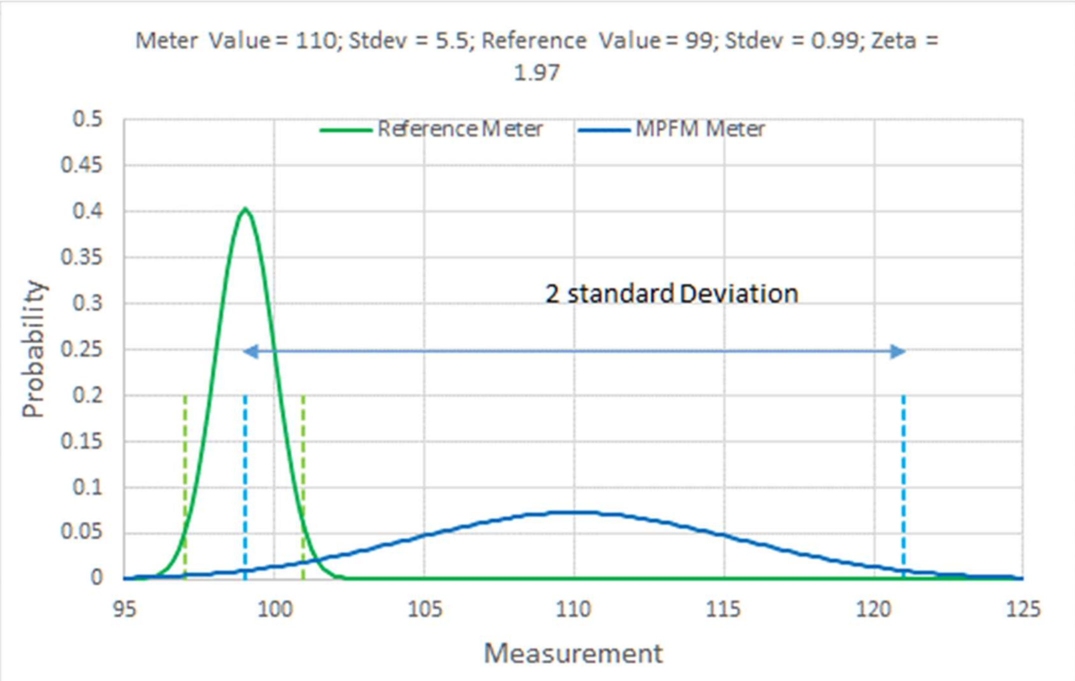

Figure 7: Comparison permanent flowmeter vs. reference flowmeter with a ζ–score of 3.5

Figure 8, the flowmeter measurement is 105.5 versus 99 for the reference and standard deviations are respectively 3 % and 3 % giving a ζ–score of 1.5. The comparison clearly passed in this case. Qualitatively, a large part of the distribution of both flowmeters is overlapping.

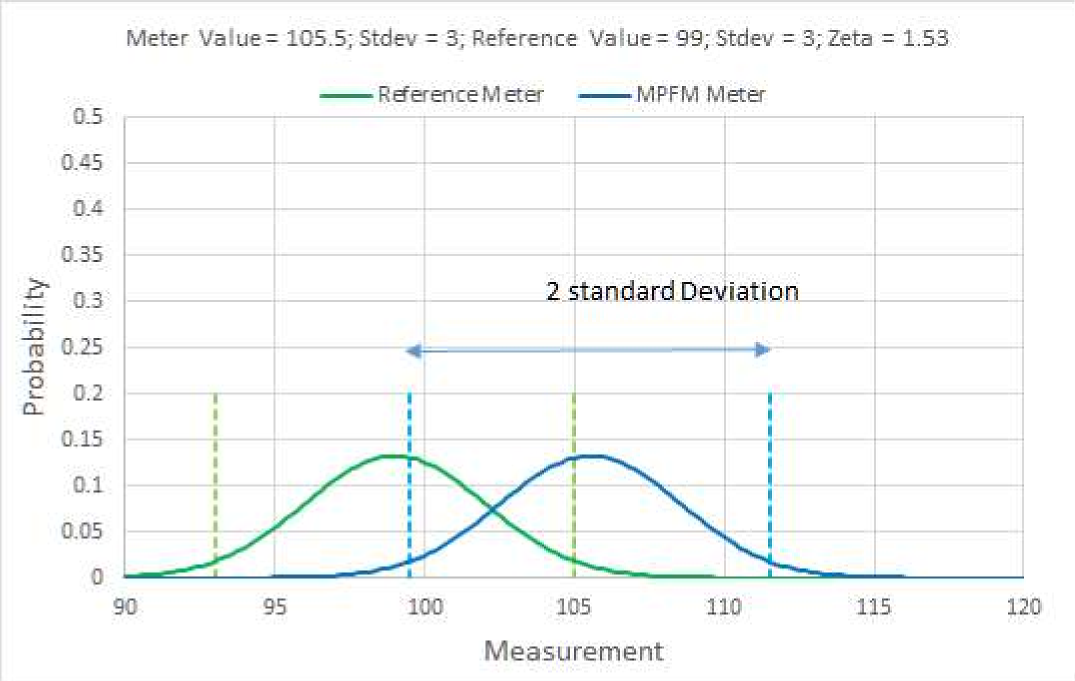

Figure 8: Comparison permanent flowmeter vs. reference flowmeter with a ζ–score of 3.5

Figure 9, the flowmeter measurement is 101.1 versus 99 for the reference and standard deviations are respectively 3 % and 3 % leading to a ζ–score of 0.5. The comparison clearly passed and qualitatively, both distributions are almost overlapping. It is close to a perfect match.

Figure 9: Comparison permanent flowmeter vs. reference flowmeter with a ζ–score of 3.5

4.3 Reference Flowmeter: Separator

The reference measurements (which are typically a test separator or another MPFM) must be taken with the same attention and precision as those taken on the MPFM under test. The classic separator contains about 300 moving parts (positive displacement metre, control valve, etc.), all of which must be thoroughly inspected, particularly the bypass valves. Certain claims are included below for clarification, but the list is not exhaustive in order to keep the document manageable in length. The point is to emphasise unequivocally that this is not a simple activity. For example, the horizontal well test separator should be used for oil wells and the vertical well test separator should be used for gas wells. It should ideally be sized for the gas or liquid capabilities, with sufficient retention time and a minimum of one minute under all expected test conditions (to reduce carryover or under). Additionally, it should be ensured that the well is not too sluggy, as this could result in potential separation concerns during some of the testing periods.

As previously stated, a separator is not an empty tank, and a visual inspection of the internals should be performed prior to the test; this requirement varies by service business, but at least one inspection should have been performed within the previous year. Solids produced in the reservoir can build at the bottom of the separator, reducing the volume of the separator accessible for separation and hence the retention time, which can result in carryover or carry under. The entire valve set, including the bypass, must be pressure checked to discover any leaks. Ascertain that all single-phase flowmeters on the separator have been calibrated and are within the calibration validity period, as well as that they have been mounted properly in accordance with the manufacturer's specifications (distance upstream and downstream). All of this should be documented and verified by the parties prior to the tests — unfortunately, this is rarely done and documented —.

The authors saw a situation in which an expected test that should have taken only a week was delayed by over three months in order to bring the separator back into compliance with the standard and resolve all concerns. This separator had been in service for years and was clearly not providing accurate flow rates. The rules by which we have operated for many years are no longer valid, and an appropriate procedure should be followed. Finally, the match between the two devices was excellent, and the local well testing company now had an ideal tool for providing service in the area. The MPFM had always worked in favourable settings.

Because the separator is design-limited, the separators used in the service business are attempting to provide a versatile solution ranging from extremely high gas rates to very low gas rates; this results in the erroneous broad assumption that the separator is expected to perfectly separate the fluid. The reference flowmeter is only capable of measuring single-phase flow, therefore, it is critical to watch for any possible carryover or under-measurement during the test. A full sequence of events must be recorded; this is particularly beneficial during the final review to identify any issues that were not detected during the test; it also provides information about outliers. Indeed, this record may assist in identifying any aberrant conditions or events that may occur throughout the test and impair the accuracy of any measurements (i.e. carryover, problems with separator sensors or meters, etc.). This method should be followed regarding both devices.

4.4 Reference Flowmeter: A specific design

Taking everything into account correctly will lead to a type of analysis as presented here below (Table 1); it should be kept in mind that the type of distribution (or covering factor to be used) is different following the parameter and then a careful calculation should be done. In this example, it can be seen that the uncertainty of ± 3.00 % for calibration is becoming ± 3.13 %, everything being considered. This is a 4 % difference in the claimed performance, and the case presented was with tight uncertainty on all parameters. It will not be surprising to see an increase of + 50 % to + 100 % on the initial claimed

performance following the cases or flow conditions. In other word, if this is making more sense, a multiplying factor of 1.5 to 2 can happen in order to establish the overall uncertainty.
Additionally, the drift was set to zero in the example because this was a new analysis following calibration; however, if the MPFM remains uncalibrated for a few years without calibration, this drift uncertainty should be considered and doubled for two years or appropriately calculated in several days if the uncertainty is reported in terms of days.
Fundamentally, uncertainty should rise with time. Bear in mind that the same analysis should be performed on the reference flowmeter, which could be another MPFM or separator.

Table 1: A typical process to establish the uncertainty of a flowmeter (not related to any specific flowmeter or technology)

OIL VOLUMETRIC FLOWRATE UNCERTAINTY AT LINE CONDITIONS — *Edit the BLUE cells only*

Source	Units	Value	Expanded Uncertainty Abs	Expanded Uncertainty (%)	Ref Unc	Probability	Divisor	Standard	Sensitivity	Uncorrelated Product	Correlated Product	Variance	
Oil Volume at LC	m^3/h	20.000	0.600	3.000		Normal (95%)	1.960	0.306 1	1.000	3.061E-01	0	9.371E-02	92.2%
Repeatability	m^3/h	20.000	0.100	0.500		Normal (95%)	1.960	0.051	1.000	5.102E-02	0	2.603E-03	2.6%
Reproducibility	m^3/h	20.000	0.100	0.500		Normal (95%)	1.960	0.051	1.000	5.102E-02	0	2.603E-03	2.6%
Resolution	m^3/h	20.000	0.020	0.100		Rectangular	1.732	0.011 5	1.000	1.155E-02	0	1.333E-04	0.1%
Drift per year	m^3/h	20.000	0.000	0.000		Rectangular	1.732	0.000	1.000	0.000E+00	0	0.000E+00	0.0%
Stability	m^3/h	20.000	0.002	0.010		Rectangular	1.732	0.001 2	1.000	1.155E-03	0	1.333E-06	0.0%
Bias	m^3/h	20.000	0.000	0.001		Rectangular	1.732	0.000 1	1.000	1.155E-04	0	1.333E-08	0.0%
Ref. Standard Uncertainty	m^3/h	20.000	0.100	0.500		Normal (95%)	1.960	0.051	1.000	5.102E-02	0	2.603E-03	2.6%
Ref. Standard Stability	m^3/h	20.000	0.010	0.050		Rectangular	1.732	0.005 8	1.000	5.774E-03	0	3.333E-05	0.0%
Oil Volume at SC	m^3/h	**20.000**	**0.625**	**3.125**		**Normal (95%)**	**1.96**	**0.318 9**	**1.000**	**0.319**	**0**	**1.017E-01**	**100.0%**

A generic statement is that the specification/uncertainty stated is for the reading or current measurement only and does not include the entire uncertainty associated with the deployed instrument; this is true for pressure, temperature, or differential pressure transmitters. All information is typically available in a variety of formats within the documentation that comes with each device and should be carefully retained.

4.5 Providing a unique and innovative hardware for a reference solution

A typical test separator consists of a storage vessel, a multi-meter measuring system for determining oil and gas flow rates, relief values to avoid excessive pressure, and sample sites for extracting effluent for analysis. The following configurations are available for test separators: (1) 2-phase separators: these are the simplest designs, as they separate gas (phase one) from liquid – oil and water – (phase two); (2) 3-phase separators: these are the most complex designs, as they separate the 3 phases. A three-phase separator enables more sophisticated analysis but it I slightly more complex to operate; (3) 4-phase separators are the most sophisticated separators, extracting sand separately from oil, gas, and water.
Well test separators are essential equipment in the exploration, development and production of active wells. They provide an ongoing return on investment by giving onsite decision-makers crucial information that facilitates the more efficient extraction of valuable resources. Test separators are used in a variety of applications, including but not limited to onshore and offshore exploration, well development, well production and resource extraction, and post-production cleanup.
Typically, a test separator consists of a vessel, an oil flow measurement system with dual flowmeters, the same design for the water line, a gas flow measurement system, multiple sample points for each effluent phase, and at least one relief valve to prevent the vessel from overpressure. To ensure precise measurements, the test separator is equipped with regulators that control valves on the oil and gas exits to maintain a consistent pressure and liquid level inside the vessel. A deflector plate, coalescing plates, a foam breaker, a vortex breaker, a weir plate, and a mist extractor are all included in the test separator. These components eliminate the potential of carryover (liquid in a gas line) and carry under (gas in a liquid line), which would impair the accuracy of flow rate monitoring.

Separators are often designed with a gas/liquid gravity separation section that facilitates the formation and fallout of big liquid droplets. A coalescer stage may be included in the gravity separation segment (either a mesh type or one type coalescer). Following the fallout of bulk liquids, the demisting phase ensures that finer mist particles are removed. Liquids are degassed, and the light (oil) and heavy liquid (water) phases are separated into the liquid separation portion. This section is extensive enough to allow gas bubbles to escape from the liquids and oil and water droplets to reach the oil-water contact. As can be seen, the separator is far from being an empty tank, and the required adaptability, combined with the size constraints imposed by road travel, creates issues for guaranteeing proper gas and liquid separation at the end, and causing the addition of significant equipment such as mist removal devices, coaleascer plates, and moving weir plates to facilitate the separation of oil and gas.

To summarise, we believe that a significantly better design is achievable if we begin with a white paper and utilise concepts and methodologies tested over the last 20-40 years versus 150 years. By combining the various components in the proper order, it is possible to create a compact and even modular solution that can manage low to high flow rates by adding modular elements as needed. This method achieves a complete two-phase separation, which is optimal for the well test. Over the last decade, advancements in the water cut meters have been so remarkable that it is now possible to achieve a water liquid content measurement with a low uncertainty value on full bore pipe. After reviewing and defining a novel method for handling and ensuring a good gas-liquid separation without the use of any additional equipment other than the element based on physics principles, it is possible to achieve an uncertainty far below what is currently available on the market using no moving parts. This is the second part of the design of a full solution from a hardware standpoint when it is necessary to address the in situ performance of MPFMs in the oil and gas industry.

TÜV SÜD NEL, as an independent organisation responsible for certification and validation of measurements, cannot operate or manufacture such equipment; instead, the solution (idea and drawings) is offered to local enterprises with knowledge in field operation and how to conduct effective tests. This approach delivers the measurement, the accompanying uncertainty, and, finally, the corresponding confidence level in real time. This fits fully with international standards, which require the inclusion of these three values (measurement, uncertainty, confidence level).

4.6 Provide a unique flowmeter health check for a full reference solution

The hardware solution is completed by a sophisticated health check data processing that allows for the review of the performance of the various flowmeters utilised and the establishment of the device’s uncertainty and sweet spot. This system, which includes a real-time uncertainty calculation, can offer an optimal level of uncertainty as a reference flowmeter. The technology can perform a prediction measurement based on historical data and then determine whether the well’s stability remains valid for the test. An ad hoc approach enables the determination of the best recording time required to optimise the duration of the well test for the verification of the MPFM permanently installed.

Several figures are used below to emphasise various points made in the previous statement. The data have been altered to make them anonymous. The figure 10 is presenting one of the typical mistakes that people are doing in the averaging when the flow is not stable. The flowmeter works correctly, but the reporting is done incorrectly and leading to bias in the result. In orange are the data as collected, the black line is the average calculated incorrectly, and the system can establish immediately the uncertainty in the average flow with 95 % confidence level. The black line shows the average estimated overtime, the grey area shows the measurement uncertainty with a 95 % confidence level. Obviously, with longer recording time, the uncertainty is smaller (i.e. the width of the grey zone) and an average with an adequate level of uncertainty can be obtained. What is not captured in this current process is the fact that the performance of the well or some conditions have been changed and then this is not considered. It is seen clearly that the flow is much smaller in the second part of the recording than in the first one.

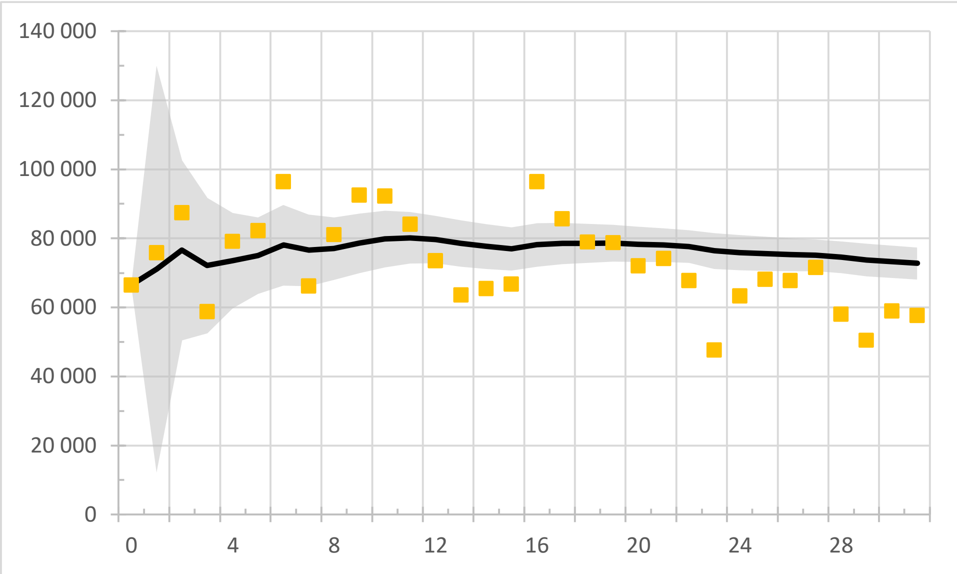

Figure 10: Change in the flow measurement and stability of the well – classical process –

The same data set as recorded before (orange data point) is present in figure 11 but this time associated with a correct data process, the averaging is then following the well performance and leading to an average of 61 123 ± 5 359 against 72 772 ± 4 605 both with 95% confidence level. If the uncertainty is slightly higher, the tracking of the well performance is better. Not presented here, but the automatic check of the well stability will have trigger to continue to record and exclude the primary section based on the criteria of stability presented earlier. The automatic data analysis has provided no multi-mode solution, and the well is not sluggy.

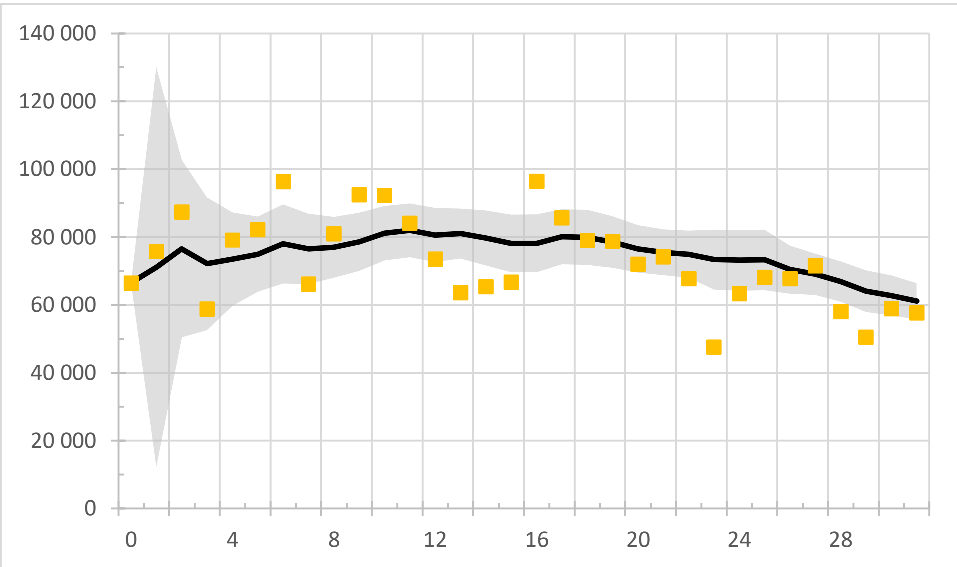

Figure 11: Change in the flow measurement and stability of the well –advanced process –

Another example is presented hereafter. The two figures (12 and 13) show data recorded versus time and the uncertainty establish either on the data set (figure 12) or on the average value (figure 13) versus time. The figure 12 reveals that the raw data are well within the 95% confidence level, even if it is obvious the data seems to be quite scattered.

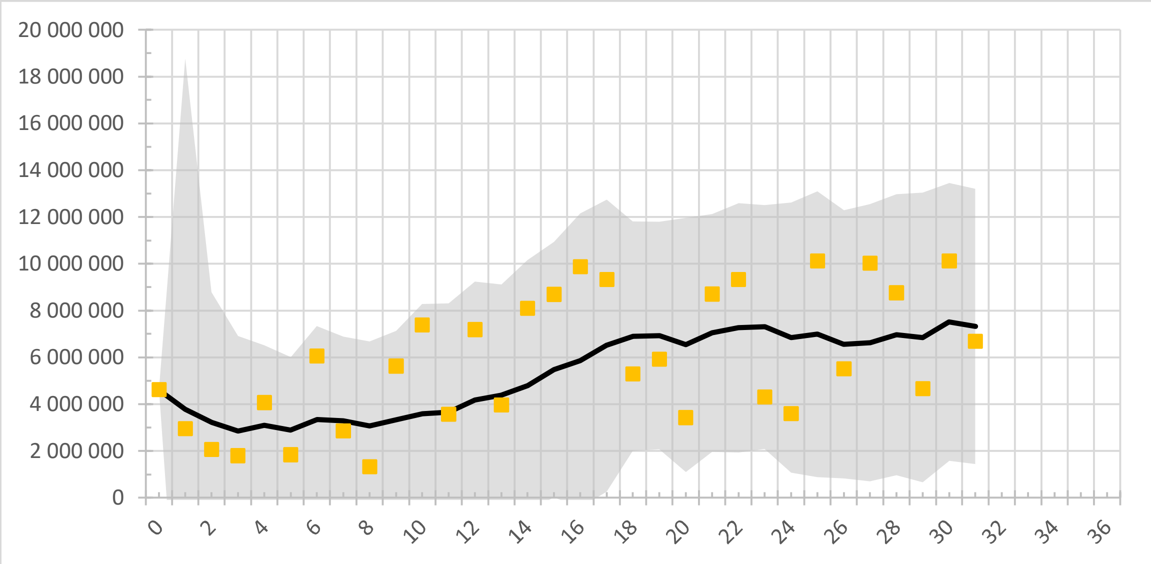

Figure 12: Change in the flow measurement and stability of the well

Figure 13 demonstrates the stability associated with the average value and that there is a multimodal signature in this flow for the second half of the flow recording.

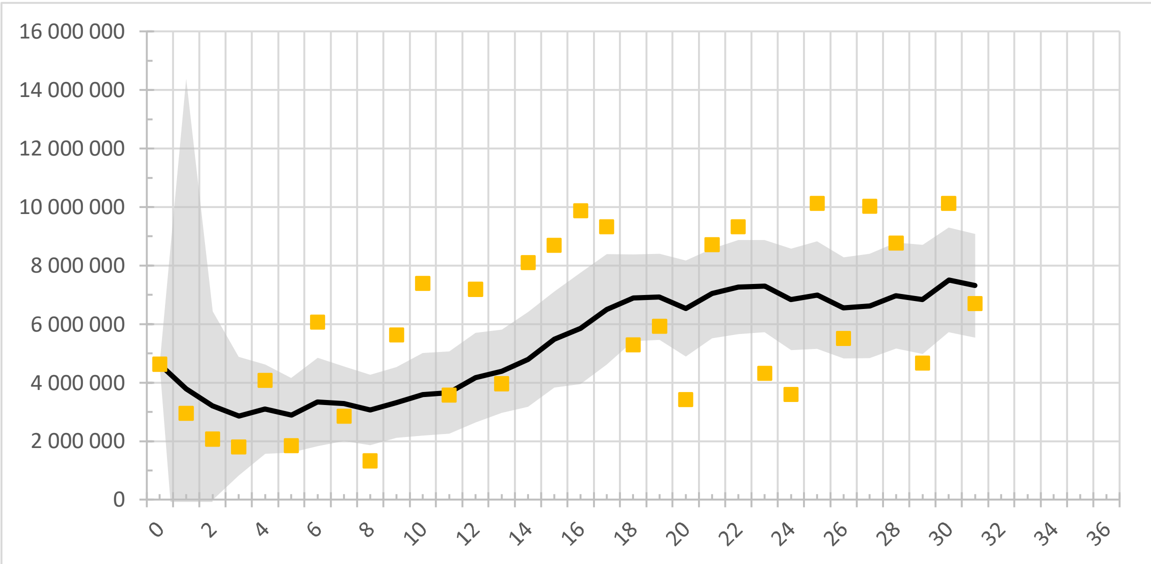

Figure 13: Recording of flow reaching stability and having a multi-mode

What is important to understand is that the specific data analysis allow to spot the modularity, and this is an essential part to estimate the next data based on the historical one. This is a predictive solution and then allows to check if everything is as expected from a flow measurement point of view. The new recorded data can be checked against the expected predictive ones, as presented in Figure 14.

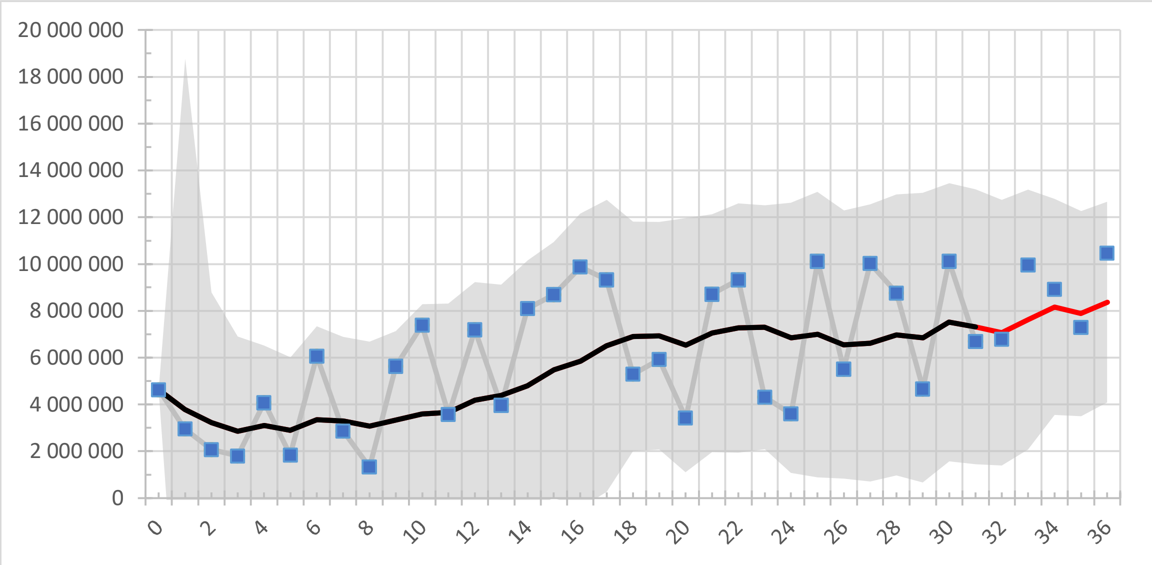

Figure 14: Predictive analysis on the stable recording considering the multi-mode

Figure 15 shows the average value, and the trend expected with the predictive data using the multimodal signature of this flow, as highlighted earlier for the second half of the flow recording.

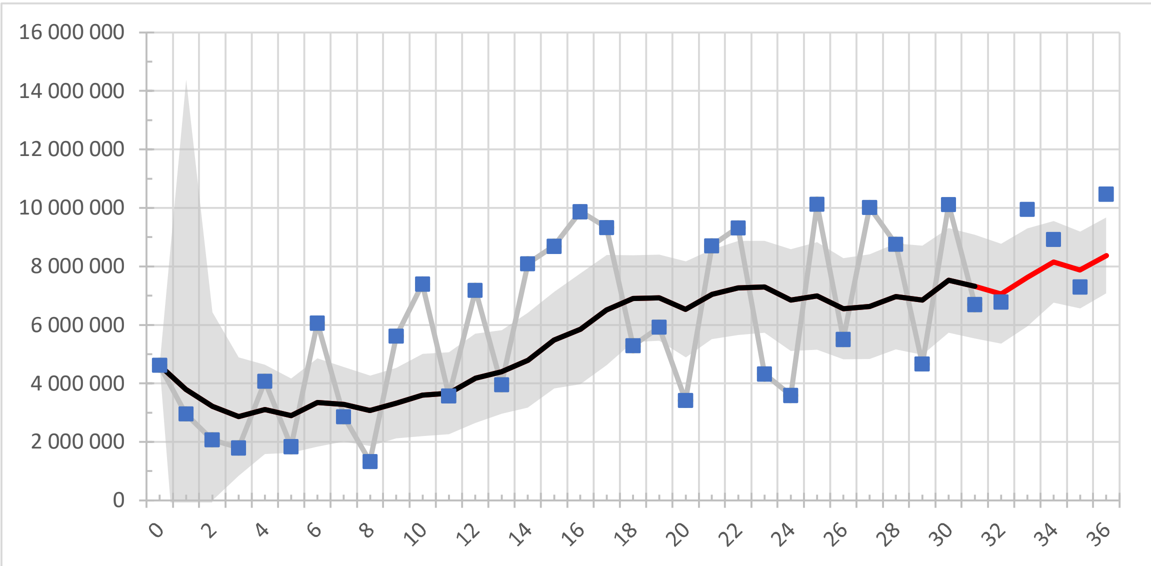

Figure 15: Predictive analysis of the average flow rate considering the multi-mode

4.7 Traceability of the Fluid Properties on the critical path for performance evaluation

Any type of flow metering device provides information about the flowmeter's operating conditions (i.e. at line pressure and temperature). Coriolis, vortex, and orifice plates, for example, provide no information on the process occurring downstream of the observed conditions. The fluid will flow through the line until it reaches standard conditions, at which point it can only report the volumetric flow rate at the observed conditions.
Meanwhile, the volumetric flow rates of water, oil, and gas must be estimated under standard conditions due to the business need that any fluid be sold under stabilised conditions referred to as standard conditions. To convert them from flowmeter observed

conditions to standard conditions, extra information on fluid properties (PVT) and phase transfer in response to pressure and temperature changes is required, regardless of the flowmeter or technology utilised. MPFMs are majorly affected by the usage of PVT data for two primary reasons. To begin, they can operate at extremely high pressures and temperatures, necessitating a considerable correction to establish the recorded flow rates at standard conditions. Second, a significant proportion of gas can be dissolved inside the oil, or certain condensates may be in the gas phase when they become liquid under standard conditions.

Numerous published documentation demonstrate the flowmeter's performance under well-controlled settings, however, there are few publications on the effect of fluid characteristics. This section covers the approach to take when evaluating the overall performance of the flowmeter, which is applicable to all MPFMs. Utilising a pertinent PVT is not sufficient, as access to the PVT's uncertainty performance is required. TÜV SÜD NEL is offering one of only two products on the market capable of addressing this uncertainty; both solutions are based on the same initial work begun over 40 years ago and are built on the foundation of a vast database of composition that is unique because it is based on physical measurements collected over time, in contrast too many PVT simulators that aggregate many equations of state (EOS) with a minor consideration of the validity.

Without the assignment of uncertainty, a pure number created as a result of a calculation is meaningless. A number on its own provides no indication to the user whether the value is appropriate for the purpose intended. Calculations of phase equilibria, which are essential for any MPFM, typically require many steps to arrive at a final conclusion; each step has an associated uncertainty. When the earliest computer applications for phase equilibria and thermophysical property computations arrived, they did not include an uncertainty statement and frequently displayed results to many significant figures. This is still a regular occurrence among PVT thermodynamic packages. Recently, organisations such as the Design Institute for Physical Property Research (DIPPR) and TÜV SÜD National Engineering Laboratory with Physical Properties Data Service — PPDS — have worked to close this gap through. This is the value of a National Measurement Institute — NMI — providing a commercial solution for end customers and spearheading industry standard development with the required information a value, an uncertainty and a confidence level.

The next step is to combine both the MPFM and EOS performance uncertainties and propagate them to standard conditions. This allows to establish, with no ambiguity, the performance and how the meter will behave in field conditions. In some specification situation, at the well site, it is possible to reduce the impact of PVT package is both flowmeters are complying strictly with some of the statement made earlier.

As a reminder, a comparison test is conducted because there are some reservations about the permanent MPFM's performance or because the annual in situ verification needs the use of a reference flowmeter, which is hoped to be defined as the reference. As previously demonstrated, the uncertainty associated with field circumstances is far greater than that associated with well-controlled conditions, such as those seen at third-party facilities ISO 17025. In general, the effort required to precisely estimate the uncertainty, and hence MPFM performance, involves expertise and precise computations. A thorough mapping of MPFM performance to its in situ application should be established by oil and gas operators or third-party multiphase flowmeter experts — and validated at a calibration facility when possible — . We would advise against leaving this work to the MPFM's manufacturers, as they may be overconfident in their product's performance, or the test may result in the situation that we have seen where statements were made punctually to each point to reject one or the other reference values or removing of the lowest or highest deviation, multiple statements were made to demonstrate the reference issues (not the MPFM, of course) and not consistent between themselves that even the end-user could not understand or approved and was asking support to get a proper evaluation. The recommendation is to use third party support in the test definitions and the capability to witness the entire procedure, even remotely, if necessary, to assure compliance with international standards and data analysis.

Figure 16 illustrates a typical mass transfer process from one set of P and T conditions to another set of P and T conditions. Note that the water at line conditions (called reference conditions in the figure) may contain some gas inside, the oil may contain some gas too, and the gas could contain some oil and water in the gas phase (steam for water and some C5 or C6 for example for hydrocarbon). The process of phase or mass transfer by changing P and T and can be written with some transfer function from one type of conditions to other conditions. It should also be kept in mind that most of the documents referring to conversion are forgetting the dissolution of gas inside the water and the possibility of steam.

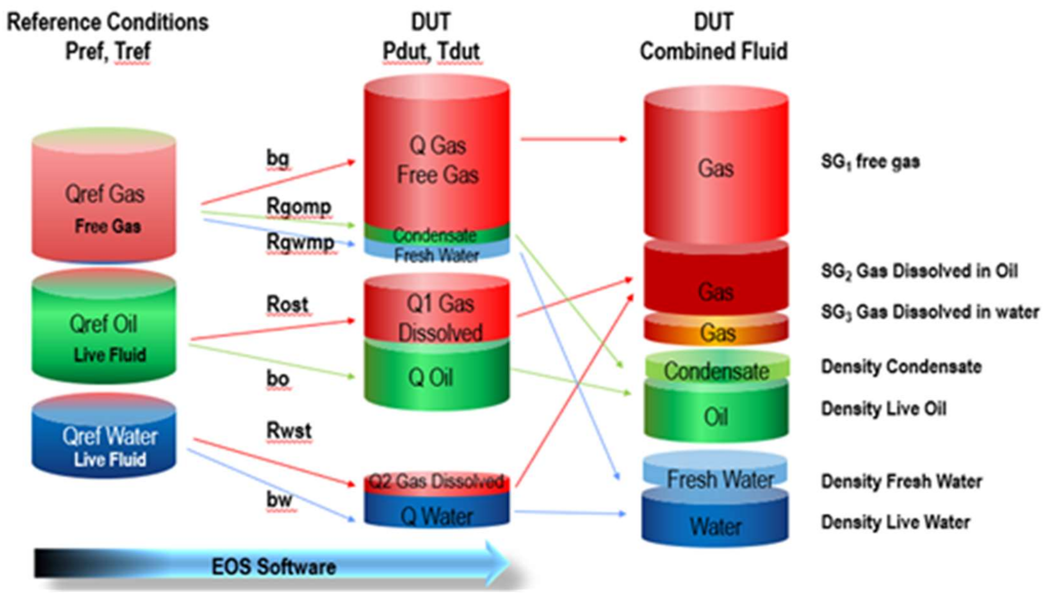

Figure 16: Mass transfer from an observed condition (called reference) to another pressure and temperature conditions.

Finally, while many people envision a direct flash from line to standard circumstances, this should be considered throughout the process if a comparison to standard conditions is possible. The authors have seen some "magic" shrinkage factor value used in separators compared to MPFM, and when questioned, the value was given by process engineers as the most optimised solution to provide value as close to the final process as possible at standard conditions — and this was probably correct —, but this information was not provided to the MPFM manufacturer using a relevant PVT package during this in situ validation. This was leading to a relative deviation already higher than + 10 % because of two different PVT packages used.

This path of multistage flashing through which the fluid travels, which is not linear at all, must be carefully addressed. This is the purpose of the production engineering and optimisation of the gas or liquid production processes. Finally, very frequently, documents refer to the conversion to standard conditions through the use of black oil correlations or models, which is far from the case with subsea business or the trend in the oil and gas industry to develop more and more gas reservoir formations. The bare minimum for comparison is the use of the same PVT package; the PVT may be incorrect, but the comparison will be meaningful, as stated differently.
However, we advocate performing the job in the best possible manner because this enables annual analysis of the well performance when the permanent MPFM and reference flowmeter are used in conjunction and allows for the creation of a correct database on the well performance or profile versus time.

4.8 Complete Solution

From this analysis, it can be highlighted that the performance given by MFPM manufacturers is, in general, overly optimistic (not enough data collected in each range of GVF and WLR). Not necessarily evaluating the low, medium and high range of the flow performance of the meter or DP value for Venturi based MPFM has been addressed within this set. Unless the number will need to be increased, without doing such work, in general, it is not a Z-distribution but a T-distribution that should be applied with by convention with a 95 % confidence level lead to much larger data than what is claimed.

Additionally, it was shown that manufacturers do not always offer the intended output specification for the end-user, which includes oil, water, and gas flow rates. There are numerous ways to convey performance today, and this is always done to the manufacturer's advantage by displaying some low figures on performance. If this is understood commercially, it means that the end-user is responsible for establishing the expected performance/uncertainty of oil, water, and gas flow rates. This is not clear, and occasionally there is insufficient information to correlate the performance to the three traditional output characteristics, such as the separator providing oil, water, and gas flow rates.

This sometimes leads end-users to believe and purchase more of one technology over another because they cannot comprehend the specification; again, the use of a third-party specialist in multiphase metering will result in the selection of the best MPFM for given field conditions. This will avoid a disastrous start for both the end-user and the manufacturer, who would be forced to deal with suboptimal or worse MPFM technology for many years because of the projected flow conditions. It should be emphasised immediately that there are numerous combinations of technologies available on the market, but none of them address the full range of parameters allowed in multiphase or perform consistently better than the others. It is critical to have accurate mapping, which is based on the expected output profile. Avoid the end-user plague of assuming because you bought so many X technology before; for the new field in development, you should use them again. The reservoir profile may be completely different, and the small amount of money saved on standardisation will be squandered on OPEX and recurring difficulties over the years. Again, an unbiased and independent third-party could provide a short-list of technologies that work in a given field and could establish the appropriate level of uncertainty for the given technologies on some specific output parameters that correspond to the field's or well's key performance indicators.

When an MPFM is chosen to define the thru performance under standard conditions, the fluid behaviour must be addressed. This stage is critical because it establishes the level of uncertainty that should be maintained for the various fluid characteristics encountered in field situations. If a black oil model is employed with condensate fluid, or if there is a lack of understanding of the fluid's properties, significant uncertainty in the MPFM performance under field conditions will occur. This may result in certain assertions about the MPFM's lower performance when, in reality, the fluid characteristics are deficient. Perhaps this is not as noticeable with a separator, but this is primarily due to the pressure rating rarely exceeding 1 400 psi(a) and frequently falling below 700 psi(a), whereas an MPFM, and particularly a sub-sea flowmeter, may encounter few 1 000 psi(a) working pressure due to their placement upstream of a choke or much closer to the wellhead sub-sea flow conditions.

Finally, there are only two EOS software programmes that we are aware of that can develop an accurate uncertainty budget for typical fluid properties parameters (shrinkage, gas dissolution…), this is because they are based on a databank that includes the uncertainty associated with measurements collected over a 40-year period. Additionally, PPDS employs a novel particular error propagation technique to offer appropriate uncertainty based on macro measurements, but is not presented in this study because of length constraints.

5 STATEMENT, AND RECOMMENDATION

MPFMs have been available on the market for over 30 years, and their acceptance is gradually increasing, with over 10 000 units sold worldwide (2020). The extremely conservative oil and gas industry, along with often unrealistic specifications from MPFM manufacturers, maintains a high level of suspicion among end users regarding the true performance of MPFMs. To add to this fear of MPFMs, the fact that several "new" technologies are present in a confined space and require significant effort to understand thoroughly frequently necessitates conducting field test comparisons to establish a true statement of whether it is working or comparison tests to ensure that the MPFM continues to work correctly when results are out of client's expectations or reservoir model forecast.

A flow test comparison under well-controlled conditions (i.e. in a world-class flow loop facility) should be systematic and conducted on a high-quality facility (ISO 17025) with an appropriate uncertainty budget calculated to demonstrate performance that is at least three to four times (minimum) less than the MPFM performance expected. This will determine the MPFM's best performance in field conditions and provide the target. It will be impossible to go lower than this level of uncertainty. It is advised that this test be conducted with a wide variety of flow conditions to accurately represent the wells' operating envelope. The number of points should be sufficient to support the adoption of the Z-distribution over the T-distribution, and this should be the criteria used to compare the true expected performance of the facility to the theoretical (and very certainly unattainable in field conditions) objective of uncertainty. MPFMs are occasionally used in financial transactions, and the same standards that apply to single-phase flowmeters should apply to multiphase flowmeters, including a correct examination of repeatability and reproducibility. This stage should not be missed; it is a critical component of the process of purchasing MPFMs, and if in doubt, a range of technologies can be utilised, in series, to determine the performance and sweet spot against flow conditions, flow regimes, and so on for each of them in one go.

When live fluids are employed, the comparison becomes more difficult and time-consuming, and should be conducted in field conditions in this case. Indeed, in situ validation entails the mass transfer necessary to accurately determine the flow rate under flowmeter circumstances. Another layer of complexity is the so-called reference flowmeter (e.g. separators, tanks, other correlation-based trending devices, or another MFM) with an uncertainty of the same order of magnitude as the MPFM under validation, necessitating consideration of both devices' uncertainty and then a proper audit of their performance. TÜV SÜD NEL developed analysis techniques that can determine the flowmeter's health; predictive analysis also allows for tracking the flowmeter's trend and determining whether there is any "modularity" or multi-mode in the flow regimes, allowing for establishing the minimum duration of the recording required to validate a data point.

Most documents (international standards or major guidelines) that authors read or study are looking for a black oil model in order to perform certain conversions from line to standard circumstances. There are no guidelines on the importance of knowing the set point for pressure and temperature vs the critical point. There is no information regarding the multi-flash fluid process occurring during the flow, and worst of all, there is no uncertainty connected with the usage of Equation of States (EOS). It is worth noting that the overall uncertainty of the system in field conditions is determined by the performance of the MPFMs under process conditions and the application of the appropriate PVT package from line to standard conditions. If this overall uncertainty differs significantly from the specification used in the manufacturers' claim for the MPFM, this should not be seen as a contradiction. Indeed, the manufacturer of the MPFM is an expert in flow measurement, leaving, usually, fluid behaviour responsibility to others, and frequently to the end user. What could be advantageous for the entire MPFMs business is to state it plainly rather than attempting to fix or conceal this issue. This will be acknowledged as being based on the application of two distinct types of expertise that MPFMs producers lack, and due to the difficulty of establishing performance, the end-user may encounter difficulties establishing performance on its own.

6 CONCLUSION

In situ validation necessitates a thorough examination of the reference devices. Because of a lack of understanding of the role of uncertainty in both device measurements in the comparison, incorrect statements about PASS or FAIL comparisons will be made based on incorrect assumptions. A specific sequence should be followed for in situ validation or verification, and one is provided in this study, progressing from the least demanding data processing (total mass flow rate) to the most complex (oil, water, and gas flow rate at standard conditions). However, before proceeding with the comparison, stability criteria have been recommended to ensure that the comparison is based on a meaningful set of conditions. We expect that the newly developed in situ validation will enable the MPFM community to move forward and third-party companies to assist all stakeholders in future comparison tests to validate the test and establish the relevant conclusions.

We believe that it is critical to use a third party that is not only familiar with field well test operations (oil and gas single-phase standard flow metering devices, multiphase flow metering devices), but also with flowmeter calibration, certification, and, if possible, fluid properties expertise, to validate such validation test campaigns. This avoids dispute over who is correct or incorrect and results in a conclusive declaration based on statistical analysis, physics, and field expertise. This effort should not be placed in the hands of MPFM manufacturers, or companies with some interests in the multiphase business or sales of MPFM, who, as the authors saw, can be excessively optimistic about their products' performance. The MPFM business is expected to grow significantly in terms of sales and usage if specific procedures and processes are in place to report performance consistently and down to the oil, gas, and water flow rate, rather than a combination of sometimes complex parameters used to establish relevant performance for end-users.

From a business standpoint, the manufacturer frequently requests a monthly fee per MPFM to ensure the technology's performance over time without being able to independently state the MPFM's true performance uncertainty in field conditions, leaving the buyer to conduct his own tests to determine the true or field performance. Under such a scheme, the OPEX expense exceeds the CAPEX cost and adds no benefit. The authors always advocate a third-party audit or in situ validation to guarantee that everything is carried out according to the accepted plan and method. The authors have witnessed MPFM's manufacturer frequently providing no flowmeter expert, expecting that this job will be straightforward. Often, this resulted in problems with the comparison and a negative judgment of performance by the potential buyer (i.e. an oil company or an EPC), or the manufacturer requesting some playbacks or post-processing of the data which is not happening on the daily basis in permanent application. This always left reasonable suspicions. Lack of effort in employing expertise at the right time is a recipe for disaster. Some oil corporations have already imposed the presence of specific expertise during such tests or processes/protocols that must be properly followed.

The full solution (hardware-software or purely software) provided by TÜV SÜD NEL and combined with the witnessing and real-time analysis impartially for the benefit of both buyer and seller can result in a "callout solution". Indeed, it can be imagined that a fleet of MPFMs is connected to a specific place where data analytics is carried in real-time, a comparison of the current data recorded versus the predictive ones can be done and a warning system is triggered following some criteria and discrepancies between both data. At this stage, the end-user will identify the faulty MPFM, with the third-party involvement or not, and be capable of identifying the potential problem and referring it to the manufacturer, allowing them to reduce MPFM downtime, and optimise the intervention. This will reduce drastically the OPEX for the end-user, optimise the resource and the spare equipment for the manufacturer, allowing to reduce the CAPEX or sustaining budget. The overall relationship between the buyers, sellers will be improved, the adoption of the different technologies will be better and the fact that this is done under third party analysis following the international standards will be instrumental for the equity and fairness of the business. We hope that this paper demonstrates a path forward, and we will be glad to apply this type of assessment more broadly in the future for the benefit of the community.

7 REFERENCES

[1] B. PINGUET "Fundamentals of Multiphase Metering" ISBN-13: 978-097885305-

[2] ISO 17025:2017 "General requirements for the competence of testing and calibration laboratories."

[3] BIPM JCGM 100:2008 – "Guide to the Expression of Uncertainty in Measurement."

[4] ISO 21748:2017 – "Guidance for the use of repeatability, reproducibility and trueness estimates in measurement uncertainty evaluation."

[5] B. PINGUET, T. LEONARD – "The Generic Way to Establish the True Statement about the Uncertainty of Facilities for MPFM/WGFM Validation" North Sea Flow Measurement Workshop 2019

[6] Manual of Petroleum Measurement Standards Chapter 20.3:2018 – "Measurement of Multiphase Flow."

Tekna

NFOGM
NORWEGIAN SOCIETY FOR
OIL AND GAS MEASUREMENT

TABLE OF CONTENTS