North Sea FLOW Measurement Workshop

Paper 4.3

Well Testing - An Evaluation of Test Separators and Multiphase Flow Meters

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28th International North Sea Flow Measurement Workshop
26th – 29th October 2010

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1 ABSTRACT

National and International Oil and Gas Companies and Government Regulators all have an interest in managing their, or their countries' assets in the most expedient manner possible. The assets are the oil and gas reserves in the ground. Management of these reserves is generally carried out by Production and Reservoir Engineers though the use of Well Testing. To date the 'gold standard' for well testing has been the 'test separator'.

Whilst many Regulators mandate the frequency of well testing (and in the UK North Sea sector this is generally every 30 days) there is little in the Regulations about the expected flow measurement uncertainties required.

This paper will review the test separators used and the 30 day timing and highlight what this can mean under 'real world' conditions and take a jaundiced look at the expected measurement uncertainties which might be achieved in the field.

The introduction of Multiphase Meters over the past 20 years might well have elicited dramatic improvements in Reservoir management performance – but the authors suspect that this has not been universally realised. This will be addressed in the paper.

This paper will also address, identify and review:

- some of the strengths and weakness of test separators
- alternative uses of test separators and how this might affect 'well testing efficiencies' and provide some 'real world' comparisons
- the flow measurement uncertainties which can be expected from a test separator and how this might affect reservoir management performance
- what the MPFM might add to the well testing scenario and performance
- the question of reconciling a MPFM against the test separator

In the hope of inserting some realism into the world of managing our major material assets.

2 INTRODUCTION

API RP 86 Recommended Practice for Measurement of Multiphase Flow Section E [1] discusses test separator performance and states that that general performance of the flow meters should not be used as a guide to the expected flow measurement performance when well testing.

The test separator is primarily required for Well, Reservoir and Field performance monitoring. As such it is used for the:

- Determination of fluid flow rates
- Determination of when changes in fluid flow rates/composition occur (i.e. water breakthrough etc)
- Identification of mechanical integrity issues

When flow rates have been determined these can (and are often) summated over all the flowing wells and an estimate of the overall production is made for the wells and system allocation. This data is often used as a guideline for the system productivity.

3 TEST SEPARATOR DESIGN

Test separators are the historical standard by which wells have been tested. There are several forms of test separator, and whilst the three phase (oil-water-gas) separator is predominant in the North Sea, in many places around the world, two phase (gas - liquid) separators are more common. As a rule of thumb, a horizontal three phase vessel might have a mass of 10000kg and a footprint of say – 7M(L) by 3.5M (D) by 5M high, whilst its equivalent two phase horizontal vessel might be 6500Kg and [4M(L) by 3M (D) by 4M high], and a vertical two phase vessel might be 5000kg with a smaller footprint.

Being smaller, the two phase vessels are lighter and include less instrumentation and controls - are less complex and are assumed to require less maintenance.

There are also compact separator systems, using the fluid energy and complex shapes to provide separation, which will not be dealt with here. Figure 1 shows a schematic of a three phase separator.

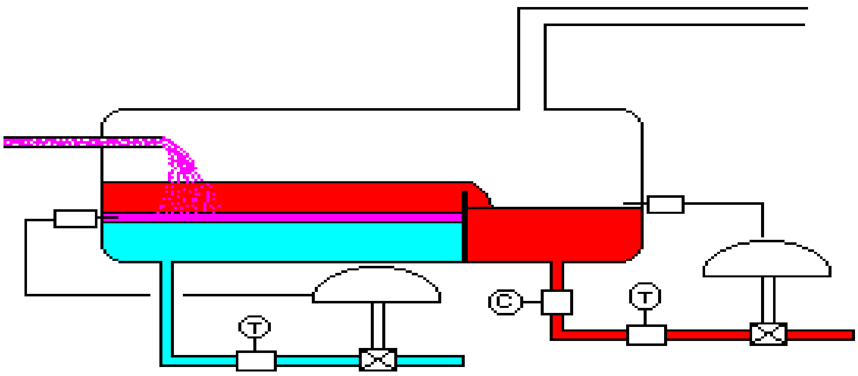

Figure 1: Schematic of a three phase separator

4 TRADITIONAL APPROACH TO WELL TESTING

The “traditional” approach comprises either:

- Separating the gas from the liquids (two phase) and measuring the streams using conventional single phase meters, with the oil/water split being measured using a water cut (WC) meter, or
- Separating all three phases, oil, water and gas and measuring each using a conventional single phase meter per Figure 1.

In the three phase system, a water cut meter might be an option to monitor water in oil or oil in water contamination. The three phase approach is often perceived to be the ‘best’ method available, offering the lowest measurement uncertainty for well testing.
This may well be the case when the following criteria are met:

- Separator sized appropriately for gas and liquid fractions. If the separator is under sized, the separation will not be complete, leading to the risk of gas carry-under in the liquid leg(s), and liquid carry-over in the gas leg.

- Interface levels are suitably maintained to avoid oil/water or liquid/gas contamination.
- Meters are adequately sized for the range of flow rates seen in operation.
- Meters installed in recommended orientation with required upstream and downstream straight lengths.
- Meters are regularly inspected for damage/wear and calibrated against traceable references in fluids similar to the process fluids – or better still the actual process fluids.
- Secondary instrumentation (pressure, Δp, temperature, etc) are regularly calibrated.
- Separator is regularly inspected for solids/sediment build up.
- Separator control are such that liquid (and gas) slugging does not occur (difficult when separators are under pressure and level control) and flow control – a necessity for flow meters – is not part of the overall control scheme

The list is not exhaustive and illustrates some of the number of design, operational and maintenance actions required to ensure accurate flow measurement performance. In practise well testing on an individual well is carried out for a set period every few weeks or months. Typically – in the North Sea- this might be a 12 to 24 hour test every 30 days. The length of the test will be selected by the Reservoir and Production Engineers.

Whilst the test separator is expected to provide accurate flow measurement, its intermittent service, and the lack of flow control adds to the flow measurement uncertainty when the short test period is amortised over an extended time (ie a 12 or 24 hour test is considered to be representative for 30, 60 or 90 days). In this case we assume that a short (sometimes as short as 4 hour s) flow test every 30 days is considered to be representative of the total monthly flow.

4.1 Test Separator Metering

4.1.1 Gas metering (orifice plate)

The orifice meter is the most common gas meter in service today. The Daniels Senior® orifice type fitting and its various clones provides the ability to change orifice plates easily and is generally considered as the de facto gas meter for a test separator. However some of the common orifice meter problems seen in test separator systems are listed below:

- Plate geometry (sharp edge worn, face scratched, contaminated, etc)
- Plate installed correctly (facing forward)
- Plate bent due to slug flows
- Poorly sized plate due to well rate variations, and low DP's
- Installation effects - short meter run, often just 10D with a 90° bend
- Infrequent calibration of secondary instrumentation
- Errors when running at low Δp's with Signal to Noise problems
- Liquid carry over – 'tide' marks being a common occurrence
- Sampling for density - infrequent spot samples with associated liquids
- Slug flows – bent plate. See Figure 2
- Liquids and solids in transmission tubing

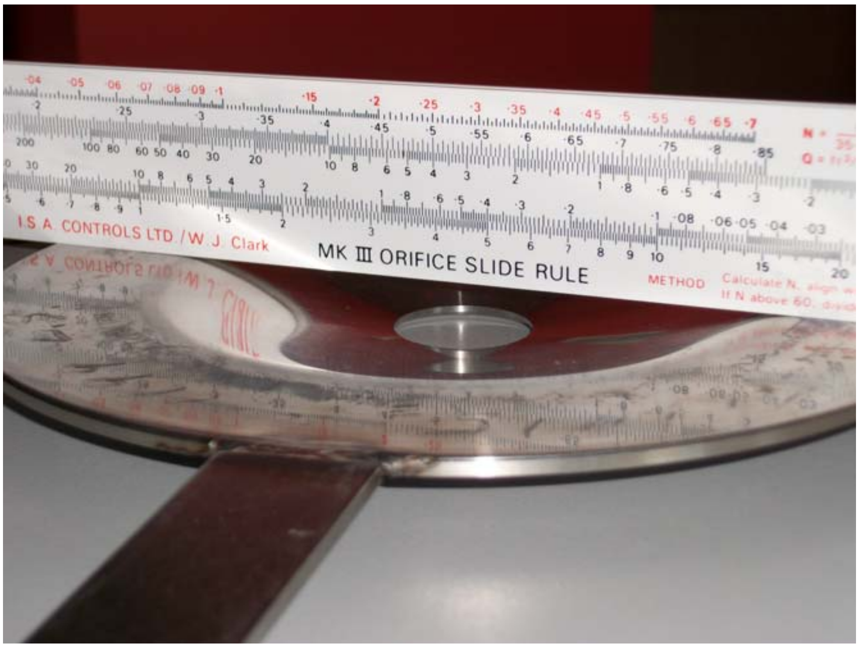

Figure 2: Bent orifice plate

4.1.2 Alternative differential pressure (DP) gas meters

Other DP meter types include Venturi and cone meters. Whilst these are excellent flow meters they are limited by their fixed Beta and the rangeability of the meter due to the ½√ρDP function at low flows, where 10:1 DP turndown represents at 3 or 4:1 turndown in flow.

The cone type meter is also particularly susceptible to damage from slug flows even though it is less susceptible to liquids and is self cleaning.

4.1.3 Alternative - non DP gas meters

Whilst the orifice meter is by far the most popular meter type used, non-DP meters have found a place in test separator metering. As an example – ultrasonic USM) and Coriolis meters have both been used. Both of these are excellent technologies – but each has its own (and different) limitations which need to be understood.

Coriolis meters are mass meters and there is often a lack of specification in the density output which may be used to convert the flows to volume, although there is concern that the density output could have a high uncertainty. These meters have a large turn down, but have a relatively high head loss potential due to the small meter bores used.

Ultrasonic meters are a volumetric meter, with a large turndown, and a minimal head loss (except where flow conditioners are deemed necessary) and have been and are used in test separators. Whilst there have been some successes – there have some reported (and possibly many unreported) cases where the USM has failed to meter correctly due to the liquids interfering with the transducers and signals.

Note: Flow conditioners in this service should be considered carefully as hydrates are a real risk [2]

4.1.4 General problem with test separator gas metering

The general problem with all meters used in first stage separator gas metering service is the lack of knowledge – or a lack of understanding - of the effect of gas 'wetness' and the way in which these meters perform in wet or saturated flows. It is all well and good to know that the meter over (or under) meters in wet gas – but when one does not know how wet the gas is, one is then unsure on how much the meter has over (or under) metered the gas. So there must always be a relatively high level of uncertainty in this measurement.

4.2 Liquid Metering

4.2.1 Turbine meters

The most commonly used liquid meter in test separator service has historically been the turbine meter. Whilst this meter is a solid fiscal meter when used with a prover, its relative weaknesses must be recognized. It is considered to be particularly susceptible to fluctuating flows, fluid viscosities and gas break out when at, or near the bubble point, and is further susceptible to entrained gases and any solids in the flow. Typically problems might be:-

- Physical state of the turbine
  - Damaged blades. See Figure 3.
  - Worn bearings
- Pipe roughness / wall contamination
- Infrequent calibration of primary and secondary instrumentation
- Contaminated liquids (water in oil – or- oil in water)
- Changing density/viscosity from well to well or from calibration to operation [3]
- Lack of sampling to determine density and viscosity.
- Presence of gas or gas breakout (cavitation) could results in large errors [4]. See Figure 4.
- Viscosity sensitivity - water oil mixes generally being more viscous mix than the base fluids. See Figure 5.
- Poor separation performance (emulsions, foaming, etc) leading to cross contamination of phases.

Figure 3:Turbine meter with damaged blades

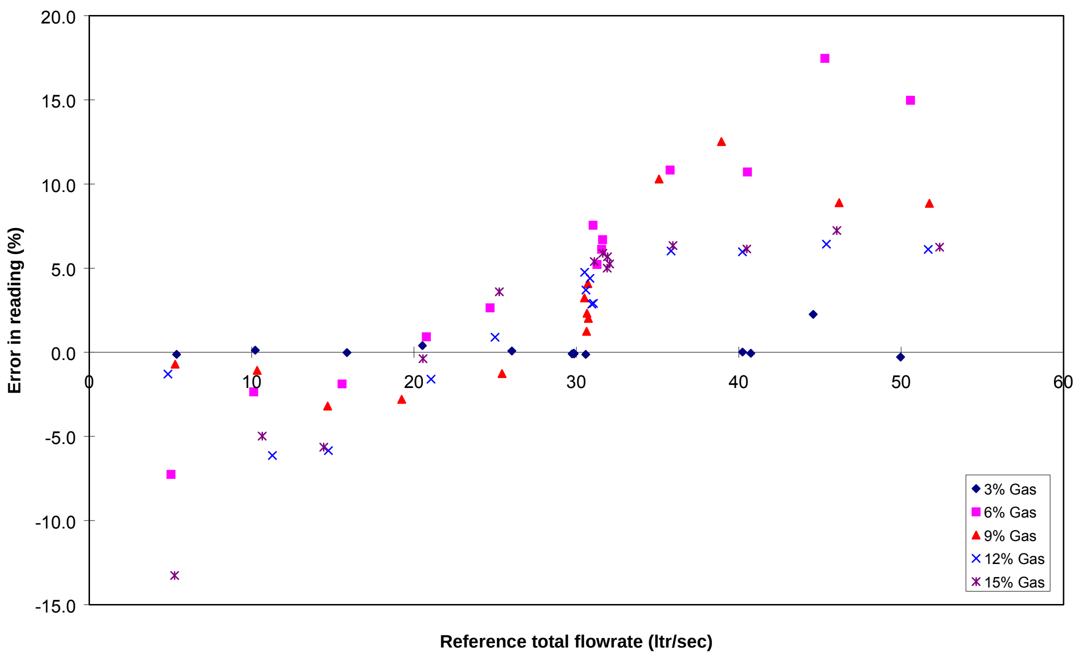

Figure 4:Turbine meter – error in liquid flow rate in cavitating flows

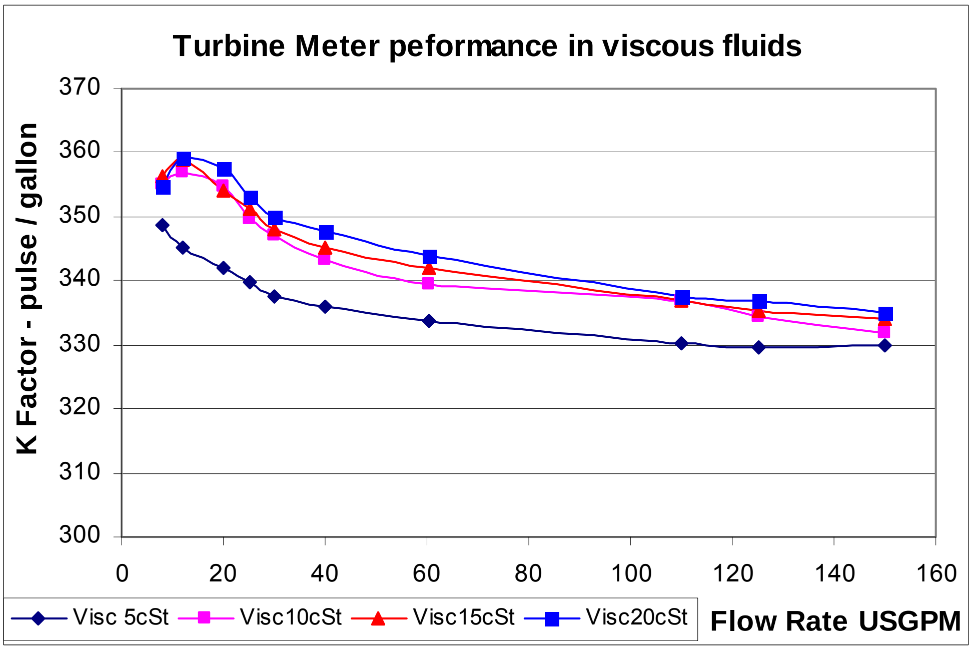

Figure 5: Turbine Meter K factors under various viscosity fluids

4.2.2 Alternative liquid meters

Alternative flow meters are now being used, the most common being ultrasonic and Coriolis meters

Ultrasonic meters (USM's) may be affected by swirl and asymmetry as they require a fully developed flow profile. USM's can tolerate oil/water mixtures but problems can arise when gas is also present. Liquid USM's are susceptible to free gas in the liquids. Some designs of USM can be susceptible to free water in oil and can be affected by water globules (the infamous 'Cousins Glob') at low flows [5]. USM's are non-intrusive meters and the pressure drop across them is negligible except where flow conditioners are mandated. In addition, USM's offer supplementary diagnostic information which can be used to identify issues such as gas carry-under [6].

Coriolis meters do not require upstream and downstream straight lengths as they do not require a developed flow profile. Care should be taken, however, to ensure the Coriolis meter is properly supported. Coriolis meters measure mass flow rather than volumetric flow so additional calculations are required for volumetric flows. That said, Coriolis meters will also give a density measurement, therefore it is possible to convert mass flow rate to volume flow rate, although this does add another element to the uncertainty. Coriolis meters will tolerate oil/water mixtures, but the addition of gas may generate significant errors. Over the past decade, advances in the Coriolis meter electronics have enabled diagnostic information on the meter and flows.

Coriolis meters will have a significant pressure drop, so it is common practice to over size the meter. This can increase the uncertainty of the liquid flow measurement as Coriolis meters perform less well at the bottom of their range due to meter zeroing requirements. Coriolis meters do not tend to scale well and the performance of a six-inch meter may not be as good as a four-inch meter.

4.3 Water Measurement

In a three phase separator the water will be metered by a stand alone meter – the conventional meter has been the turbine meter, although a number of different meter types have been used in the past few years including Coriolis, USM and electromagnetic meters.

In a two phase separator where the liquids are metered with a single meter and the oil and water phases are determined using a Water in Oil (WIO) monitor. This has a key role to play in the oil measurement and the resulting uncertainty. A greater understanding of the performance of the OIW/WIO monitor and its dependence on the water cut and salinity is needed.

4.3.1 Water Cut – WC monitor & NOC water cut calculations

Many water cut monitors are based on microwave technology, with a quoted uncertainty of ±1%. In water continuous flows (nominally WC >60%) with low gas volumes (2-5%), this uncertainty may increase to ±2 to 5%. It should be recognised that microwave WC monitors have limitations in performance at high water cuts, and when the salinity changes.

When using a Coriolis meter, it is possible to use the density based Net Oil Calculation to compute the net oil and water flows - however – this assumes:

- A knowledge of the oil and water densities
- Stable flows.
- WC in the mid-range - rather at the extremes i.e WC >25%, ,75%

4.3.2 Electrical Water Cut measurement and Water Salinity

To make an electrical measurement of WC, the salinity must be considered. Accuracy is likely to be compromised without salinity compensation. If the fluids are oil continuous - oil surrounds the water droplets at water cuts typically less than 60% - salinity has little affect on the WC measurement. The onset of the 'water continuous' state is not fixed and the effects can be seen from as low as 40% and as high as 80% depending on the flow regime.

Salinity is likely to be an issue in the water continuous phase, especially in fields being supported with a water injection system and water is being sourced from several locations. Salinity variation in produced water can easily vary by ±25%.

4.3.3 Water Cut stability in a well test

During well tests, water cuts are rarely stable and can and do change continuously Figure 6 below shows the changing water cut whilst flowing in a typical well test using a two phase separator with the fluid density oscillating between 1.025g/cc (water) and 0.78g/cc (oil) The oil water separation has been determined using a Net Oil Computation from a Coriolis meter. [7]. This rapid variations makes WC determination a difficult measurement to make obtain.

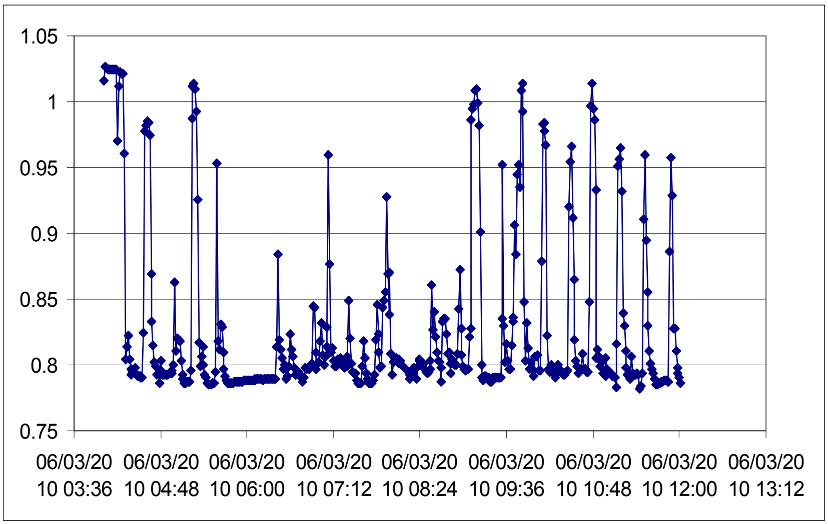

Figure 6:Coriolis liquid density (g/cc) indicating WC changes in time

4.3.4 Water Cut determination technologies

There are a number of different technologies available for measuring WC:

- Microwave – good for oil continuous liquids but uncertainty increases with increasing water content. Changes in water salinity can also be problematic for microwave water cut monitors as are emulsions.
- Electrical capacitance – again good for oil continuous liquids but uncertainty increases in water continuous fluids. Salinity changes can also be problematic as are emulsions.
- Infrared – works over the full range of water cut and not so affected by changes in fluid properties or the presence of gas, however a knowledge of the oil qualities may be required.
- Coriolis metering and Net Oil calculation – can be used for both the bulk flow measurement and water cut monitoring provided fluid densities are known.

4.4 Measurement Uncertainty

This section is not a rigorous examination of measurement uncertainty and merely reflects and acknowledges that measurement uncertainty needs to be considered in an overall evaluation of the test separator performance. The authors have taken the 'easy way out' and reproduced the uncertainties that might be expected in Test Separator Measurements from API RP 86Table E2 – under Table 1 below

Table 1 – Test Separator Meter uncertainties from API RP 86 Table E2

Subject	Gas	Gas	Oil	Oil	Water	Water
	Good	Extreme	Good	Extreme	Good	Extreme
Base meter	1	2	0.5	1	1	2
Meter Lengths (short)	0	2				
P, T Calibration	0.5	1	0.5	1	0.5	1
Range (exceeding turndown)	0	5	0	5	0	5
Sampling (sample & analysis)	1	4	1	4	1	4
Density/BSW/OIW/Viscosity	1	3	0.5	7.5	0.5	7.5
Surging/pulsation/gas breakout	0	3	0	3	0	3

4.4.1 Gas meter uncertainty

The best measurement uncertainty that could be expected on the gas leg of a test separator would be in the region of ±2%. However, it is more likely to be the case that an average uncertainty would be in the region of ±3% to ±6% with contributions from the some of the sources shown in Table 1. In extreme cases where some of the sources may contribute to significant additional uncertainties it would be possible to encounter uncertainties above ±6%, perhaps as high as ±10% to ±15%. When the uncertainty is as high as this, it is often due to some perceived bias in the measurement which may be quantified, reducing the uncertainty or recognised through an asymmetric uncertainty distribution.. Whilst these are listed with respect to an orifice meter, some of these will also affect other DP and non DP meters.

4.4.2 Liquid metering uncertainties

For liquids (oil or water in a three phase separator) it would be expected that the best measurement uncertainty that could be achieved would be in the region of ±1% to ±2%, with a more likely average approximately ±2% to ±5%. The extreme case for liquid measurement would be above ±5%, perhaps as high as ±10%.

In the case of a two-phase separator the performance of the water cut monitor could be a major source of error – especially in older fields, possibly leading to errors of 20% or more on calculated individual oil flowrates.

4.4.3 Water metering uncertainties

Table 1 does not address the two phase separator case for water measurement uncertainties, and by this omission does not address the uncertainty of the resulting oil measurement (1-%WC). However Section 4.3 has addressed some of the weakness known in the measurement of water cuts in the two phase flow.

5 TEST SEPARATOR PERFORMANCE

A separator should separate the fluids. In order to do this, it requires ‘residence time’, which is a function of the separator size and the flow rates – PLUS - heat and/or demulsifier chemicals or a combination of all three. It should:

Separate gas from the liquids. This is a function of the difference in the liquid and gas densities, the gas having a much lower density than the liquids plus the difference in fluid viscosities and the time allowed for separation. In a two phase separator these are the primary parameters for good separator performance, and unless the oil – or water-oil emulsion is particularly viscous, the density differences and time are the driving parameters. In very viscous liquids however, gas micro-bubbles can be a problem and may be entrained in the liquid for many hours or even days.

There is an expectancy that the separator will give up all its free gas, leaving only gas in solution. The free gas, whilst saturated will be relatively dry, and that when metered, the meter will be unaffected by the associated liquid.

- In a two phase separator, a small separator is used so that liquid-liquid separation does not take place and that the fluids are kept homogeneously mixed. There is then the problem of metering the mixed liquid and determining the quantities of the two fluids (oil and water).
- In a three phase separator the aim is to separate the oil, water and the gas. This is a function of the different (oil, water and gas) densities, the difference in the fluid viscosities, and the residence time. Here there is an assumption that the oil will be water free (and vice versa), often an unlikely occurrence.

5.1 Test Separator Disadvantages & Advantages

There have been a number of discussions in the Industry about the need or otherwise of replacing (or supplementing) the Test Separator with other means of flow measurement – typically the Multiphase Flow Meter.

There are a number **advantages** and **disadvantages** to the use of Test Separators.

5.1.1 Advantages

It should be realised that the test separator has other uses and it may not be convenient for it to be removed.
Test separators allow the sampling of single phase fluids after separation and are unaffected by wet gas flow patterns, except in the case of severe slugging which may cause liquid carry over in the gas leg. Test separators are also often used for:

- The start up of poorer performing, but otherwise beneficial wells after a shutdown
- The clean up of newly drilled or wells which have been reworked (scale squeezed, re-completed etc)
- A small group separator for low pressure wells

5.1.2 Disadvantages

In an offshore production facility the test separator may be considered to be a disadvantage with respect to:

- Size and weight, particularly for high pressure designs.
- Relatively high CAPEX and OPEX.
- Well measurement takes a long time (flush out previous fluids, wait for stable process conditions etc). Overall separator mass means that stabilization time can be prolonged when switching wells for testing (a 12 hour well test may take 4 hours to stabilize)
- Provide only a “average” measurement of the well flowrates and are generally unable to highlight individual flow patterns

- Periodic measurement represents a short sample or window (24hours per 30 days = 1/30 per month)

5.2 How Good Is Well Testing??

Over the decades there have been a number of discussions on the subject of *"how good is a test separator?"* As far as the authors are aware there is no guidance that would provide an answer to the question.

One method for demonstrating the veracity of well test data is by balancing the sum of the flows from a series of well tests to the facility disposal systems. This entails determining the sum of the well flows over a period and comparing them with disposals (fiscal oil and gas, fuel gas, flare, discharged water flows etc).

Typically

$$\sum \text{Well Flows} = \sum \text{Disposals or}$$

$$\sum \text{Well Flows}/\sum \text{Disposals} = 1.$$

Of course this assumes that the well flows and disposal measurements are in Mass Units – when in reality this is seldom the case.

The dichotomy here is that the users of well test data (Production and Reservoir) use volumetric data at standard conditions and this does not necessarily sit well with trying to balance the fluid disposals across a process facility where hydrocarbon liquids may be disposed of as gases and vice versa. The solution is to balance in mass terms, which is rare in the International Oil and Gas business.

When units are representative, it would be reasonable to report that a balance factor of 0.95 to 1.05 which is exceptionally good, and 0.9 to 1.1 which is probably more likely, although balance factors of 0.5 to 2 are not unheard of. A typical balance chart (or Field Allocation Factor) from well test data is shown in Figure 7 [8].

There are several facilities which have reported 'excellent' balance factors – and in a number of the cases reviewed these have been shown to be manipulated such that the well test data and the production data has been normalised, forcing the test data to merge with the fiscal data. This practise is questionable at best and does not allow the raw test data to be quality checked against the export figures.

From this point there may be the need to take and overall field allocation factor for all produced fluids and disposals to look at the individual fluids – oil/condensates – gas and gas liquids – water – and it here that the complexity will start to develop.

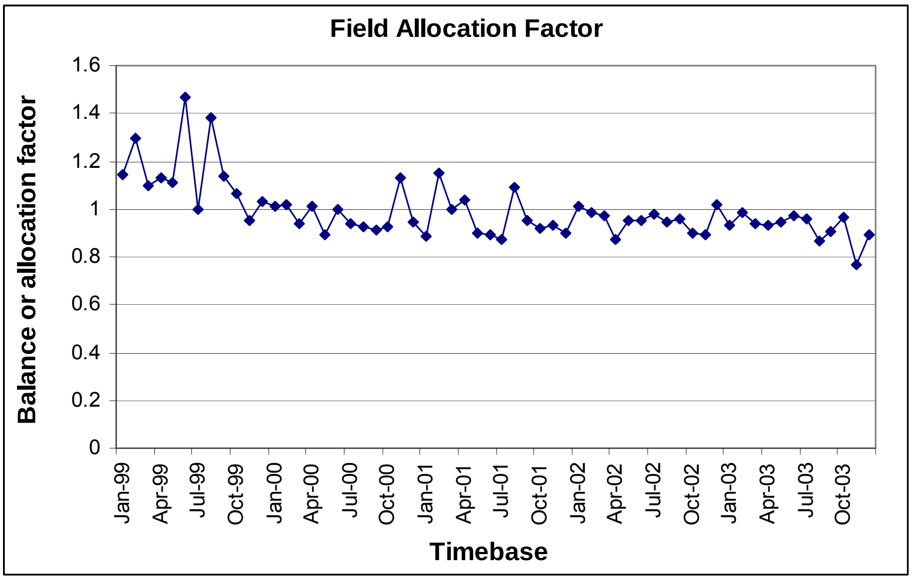

Figure 7: Well test to Fiscal out-turn Balance Chart

5.3 What Makes a Good Well Test?

What makes a good well test? This is probably the most troubling question to the Production, Reservoir and Measurement Engineers. And probably the one question which is rarely asked – or answered.

- One which follows the previous well tests demonstrating repeatability?...and in this case,
  - Do we know that the choke or GL rate has not been changed in the intervening period?
  - Have we accounted for the wells' natural decline in production
- One which is within the stipulated period of 30-60-90 days etc?
- One which has been carried out for the stipulated length of time (12 or 24 hours?)

The above might well be OK for 'ticking the boxes', but this is unlikely to provide a strong basis for proving that the well tests are 'good'. Certainly we should be using balancing techniques to assess whether the overall well test system balances against the facility out-turns – but this will merely give a 'warm and fuzzy' feeling that the system as a whole is good. It will not identify if particular wells are being poorly metered because of measurement difficulties with high or low rates, high WC's or high GVF's, slugging flows etc.

As such it is likely that we should be looking at the well tests and using some form of statistical significance to validate them. This may well include frequency, repeatability and duration but there are probably several other elements that need to be addressed.

Some Production Engineers advocate that some wells may do equally well with shorter well tests – possibly on a more frequent basis– but these need to be selected on a case by case basis.- typically these might be those wells which exhibit stable and appreciable flows of all the products – or wells with repeatable regular short cycles with appreciable flows.

Wells with irregular long cycles, small flows or a small flow of a single phase may in fact require longer more frequent well tests to flow an appreciable quantity and be statistically significant.

The figures below and overleaf are typical flow plots of gas lifted wells, and are produced as examples. It can be appreciated that they should be addressed differently with respect to flow testing.

The plots have been extracted from a multiphase meter and show:

- Top plot – oil, gas and water flows
- Middle plot: - meter differential pressure
- Bottom Plot: Water Cut (%WC) and Gas Void Fraction(%GVF)

Figure 8: Well Plot for Well XXX

Figure 8 shows a well with cycling fluid flows which may well provide satisfactory well test data from regular well spaced tests. The GVF is very high (>90%) with a stable WC in the 60% range.

Well YYY

Liquids – Green - Oil ,Blue – Water, Yellow - Gas

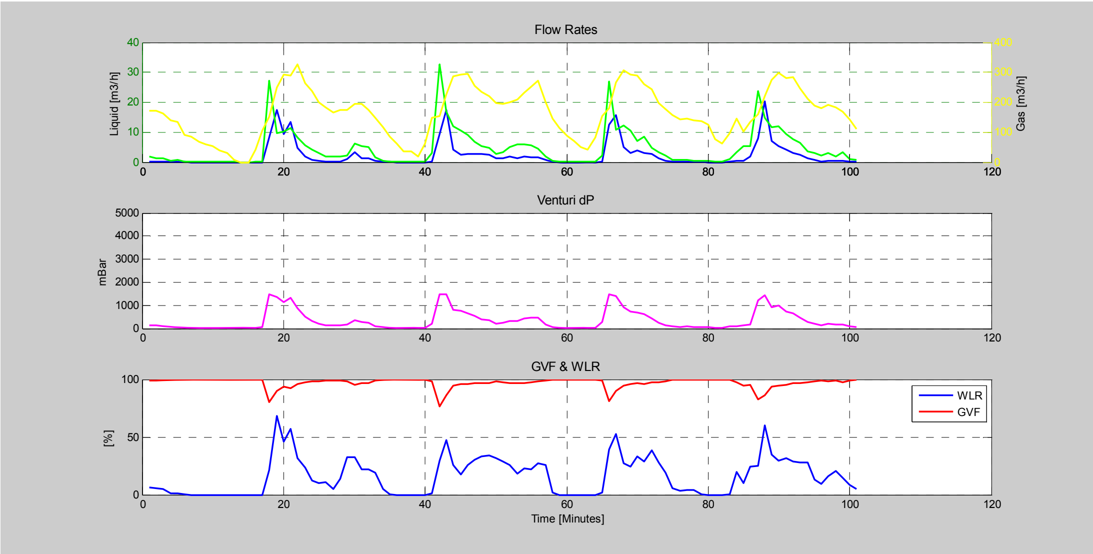

Figure 9: Well Plot for Well YYY:

Figure 9 shows an unstable slugging well with significant gas flows, limited liquid flows, and WC ranging from 0 to 70%. A short well test is unlikely to provide statistically good data as the slugs are of 20 minutes duration. A longer well test may be indicated.

Well ZZZ

Liquids – Green - Oil ,Blue – Water, Yellow - Gas

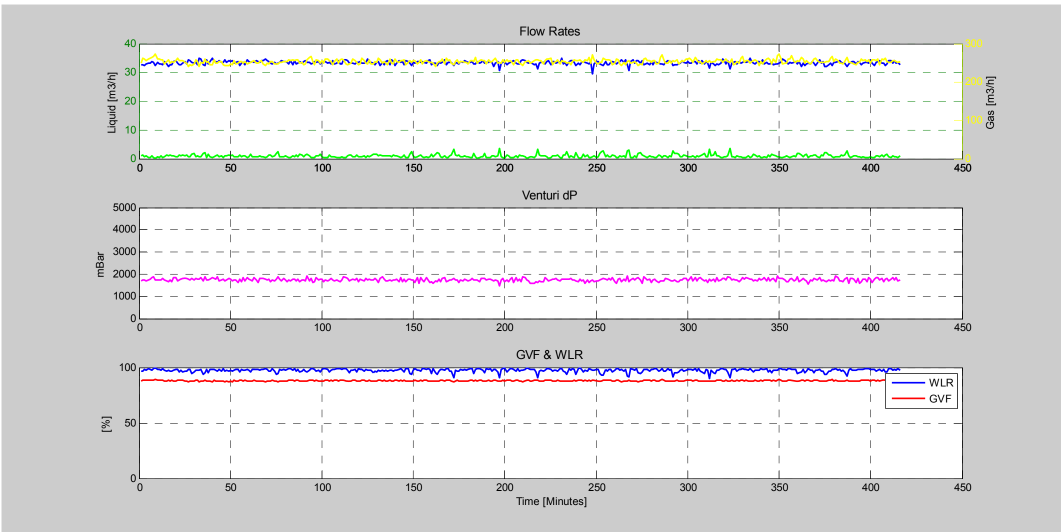

Figure 10: Well Plot for Well ZZZ:

Figure 10 shows a stable well with significant water and gas flows and very low oil flows showing WC and GVF in the >90% ranges. A short well test is unlikely to provide statistically good data for the target product – oil – and a longer well test may be called for.

The wells above need to be analysed and a test plan selected to ensure that significant flows of the target product – oil – in this case, are achieved. This may require flow tests of several days, however this may not feasible with a large quantity of wells and a very busy test separator schedule – and the question has to be, how can we improve well testing?

Apart from looking at the wells more closely and working with the Production and Reservoir Engineers to select a programme more in line with the individual wells' needs – how else can we improve the well test data? Typically we could, and should be doing more well tests- more frequently - and possibly - with better flow meters…..and it is here that the MPFM's can probably add value.

5.3 Test Separator Utilisation

The test separator is primarily required for Well, Reservoir and Field performance monitoring. As such it is used for the:

- Determination of fluid rates
- Determination of when changes in fluid flow rates/composition occur (i.e. water breakthrough etc)
- Identification of mechanical integrity issues

When the flow rates have been determined these can (and are often) summated over all the flowing wells and an estimate of the overall production is made for well and system allocation. This data is often used as a guideline for the system productivity.

There are, however, other uses for which a test separator has an important role. These are:

- Identify casing/tubing leaks
- Production optimisation of wells (be that Gas Lift (GL), Electric Submersible Pump (ESP) or other recovery techniques)
- Reservoir build up tests and other monitoring functions
- Well clean - up following re-work
- Assessment of near well-bore damage
- Other system failures

In addition the separator, ancillary instrumentation and controls all require maintenance, some of which will entail separator shutdown. These alternative functions and maintenance requirements can take a considerable amount of test separator time, meaning that it is often unavailable to carry out its primary (well testing) functions. As such the test separators 'well test utilization' can be - and is often - low.

This is unfortunate as one of the main tools to manage the oil and gas reserves is considered to be the well test data and the ability to carry out regular well tests is an essential key element. A stipulation by the Regulator/Licensee is to test each well 'periodically' – be that 30, 60, 90 or 180 days depending on the location and the Regulator's requirements. In addition, the Operators Reservoir Engineers will have their own requirements for well testing and build up tests etc., which might be driven by the reservoirs size, age and geophysical attributes and the type of depletion employed.

Table 2 has been prepared to tabulate some of the roles placed on a test separator and give an insight into the system availability for well testing. Based on a facility with say, 36 operational gas lifted oil wells, the authors have premised the separator utilisation. These times are a scenario and will vary with the field and producing scenarios (naturally flowing, gas lifted, pump lifted wells etc) and their age. From Table 2 it can be seen that in this particular case, the test separator on its own cannot reasonably be expected to fulfil all the functions expected of it.

Table 2: Test separator utilization example

ACTIVITY	Days/mth	Comment
Regular Well Testing (each well every month)		Assumes TS is operated 24/7
66% Normal tests (12 hrs)	11.88	Could be achieved by MPFM
34% Long Tests (24hrs)	12.24	Could be achieved by MPFM
Subtotal	**24.12**	
Other Well Tests		
Additional Test/Retest	2	Could be achieved by MPFM
Pro Optimisation – Gas Lift	5.1	Could be achieved by MPFM
Pro Optimisation – Choke Setting	0.7	Could be achieved by MPFM
Test after stimulation	0.5	Could be achieved by MPFM
Test after squeeze	1.9	Could be achieved by MPFM
Subtotal	**10.1**	
Separator use during Well Service Operations		
Test during PLT	0.7	Could be achieved by MPFM
Clean up after Stimulation	1.0	Separator needed
Clean up after squeeze	2.6	Separator needed
Clean up after initial Stimulation	0.1	Separator needed
Scale milling	0.1	Separator needed
Subtotal	**4.7**	
Other Test Sep Use		**Separator needed**
Start up of low pressure wells after Shutdown	1.4	Assumes 10% of wells require assistance to start up every 2 mth
Test MPFM	3	Assume multirate MPFM flow test required
Subtotal	**4.4**	
Separator maintenance & inspection		**Separator removed from service**
PSV's, Safety Systems	0.07	Assume 4 days every 2 years
Removal of solids	0.12	Assume 7 days every 2 years
Instrument calibration	0.09	Assume 5 days every 2 years
Subtotal	**0.28**	
TOTAL	**43.6**	**Separator overused**

In this case it may be necessary to utilise the services of a multiphase meter to enhance the test separators measurement capabilities per Figure 11 below.

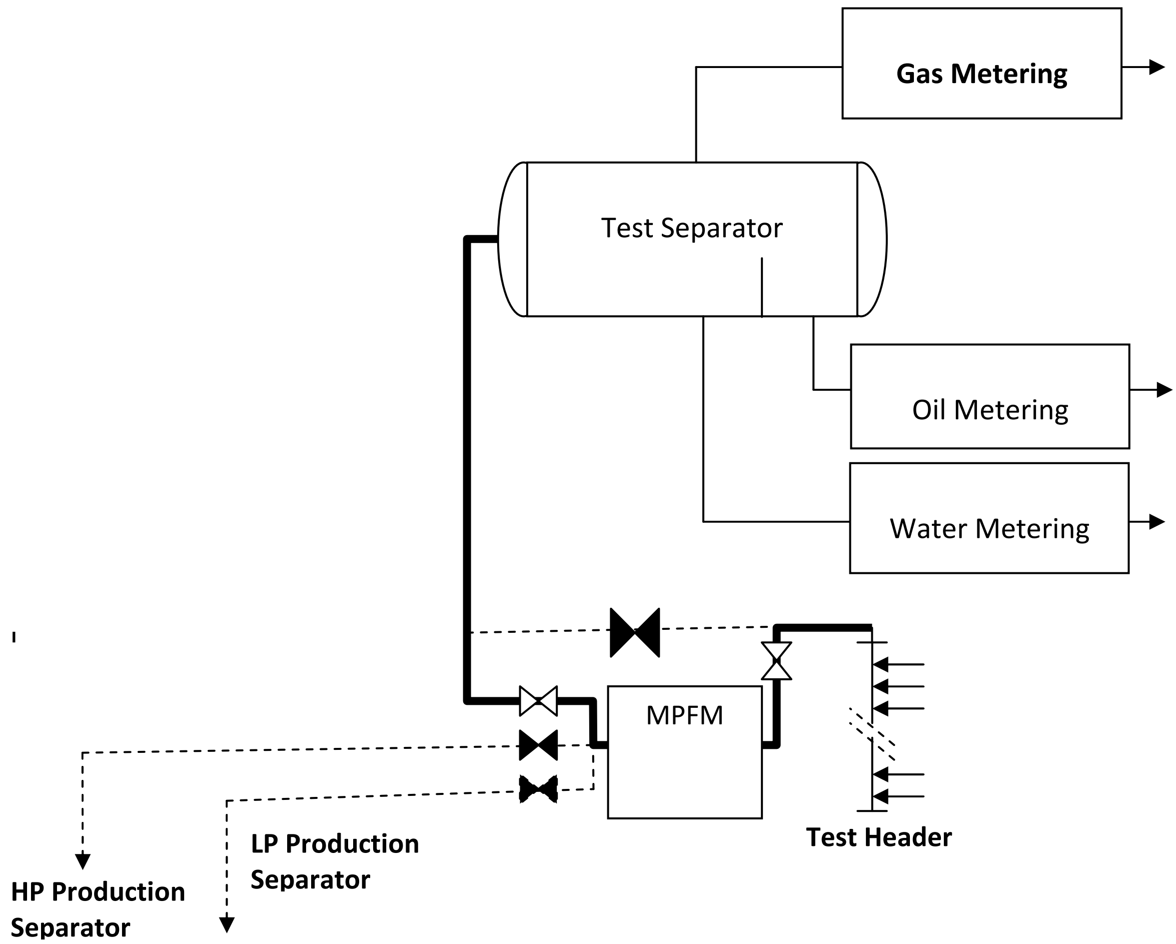

Figure 11: Test Separator and Multiphase Meter

6 MULTIPHASE FLOW METERS

The development of multiphase flow meters capable of measuring wet gas and multiphase flows continuously is seen as a key to the continuing economic development of smaller and more marginal fields [9, 10]. These may well provide substantial advantages for larger new build developments and some of the current and declining reservoirs where improved field surveillance may provide increased returns.

Multiphase meters have been around for about 20 years – the first MPFM paper presented at the NSFMW was in 1988 [11]. Some vendors have come and gone in that time. Many performance claims have been made and whilst some have been met, a considerable number have not. There has often been a reluctance to highlight the steps needed to achieve success and in some cases a reluctance to admit that – maybe - in particular cases - the MPFM may be not the most suitable tool to use.

There has also been some ‘less than full and frank disclosures’ about the hidden costs of the meter, and perhaps a reluctance to admit that there are weaknesses especially with respect to fluid sampling and meter performance as flows, flow conditions and fluids change with time.

There is also some resistance to learn with the Operators – or – maybe a resistance to teach by the vendors – although some – but not all - do hold regular User Forums in which interested parties can air the successes and failures. Even in this NFMW forum there is a reluctance to present a paper on meter failure by both the Operators and the Vendors.

Whilst there are a number of in-line MPFM's which have performed well, there has been limited discussion about:

- what the MPFM might add to well test performance, and
- reconciling an MPFM against the test separator

6.1 What the MPFM Might Add To Well Test Performance

One of the major advantages of an MPFM in a well test role is that they are capable of stabilising their process conditions (typically temperature) much more quickly than a test separator. This is a function of the smaller mass; stabilisation times of 4 to 6 hour (depending on local weather conditions) can be reduced to 30-60 minutes.

This aids significantly in reducing well test durations using an MPFM, leading to the potential of shorter test times (test time plus stabilisation time).

The ability to meter direct flow measurements rather than averaged or conditioned flows that we see from the test separator could indicate that the MPFM flow reports are more representative of the well flows. This may further aid in reducing well test durations using an MPFM.

6.2 Reconciling an MPFM Against the Test Separator

Based on the large number of trials that we have seen in flow labs and in operational fields – the request to test against another field systems is often – with good reason – looked at with less enthusiasm by some Operators' Flow Measurement Engineers. The feeling being that we are often trialling a perfectly good MPFM (as seen in the flow loops) against a field system that has many (potential) problems with fluids, system control and flow measurement.[12]

One of the major responses from potential users and project managers looking at implementing MPFM's is – "Can I trial a meter against my test separator?" The argument by many Operators is that they want to trial against 'their' fluids- the inference being that engineering technology and science changes in the North Sea, Alaska, or the GOM…..much like the Bermuda Triangle. Having said this – there are unusual fluids or processes that do need trialling, as the overall flow envelope has by no means been completely evaluated to everyone's satisfaction.

The risk of course is that some 'real world' field test sites do have unidentified problems with their fluids, control and measurements. Mastering these problems is never easy as the MPFM is the new 'black box' technology and the Operators' test separator is the known and trusted equipment, and accepted by the local Regulator. Identifying differences between the two sets of equipment always starts from the MPFM being 'wrong', and the credibility loss starts from there. It takes huge amount of tact for the MPFM service and engineering personnel to identify the problems with the clients (and potential customers) equipment. Hence reconciling an MPFM against a test separator is not necessarily an easy task, but must be carried out to assure the client and his business partners.

As mentioned earlier the majority of test separators report in volume units. An MPFM being flowed in line with a test separator may well be at significantly different process conditions and aligning volumes measured at the separator with the MPFM is by no means simple with fluid phase changes taking place. As a result the simplest comparison is in mass terms for bulk flows.
Whilst rarely done – the most suitable comparison would be:

$$\sum(\text{Oil+Gas+Water})_{\text{MPFM}} \text{ compared to } \sum(\text{Oil+Gas+Water})_{\text{TS}} \textit{ in Mass terms}.$$

Once this balance has been established then further work can be carried out to establish individual phase comparisons in both mass and volume terms. Without this first level check balance being carried out initially just diving into try and balance the phases in volumetric terms – especially when there are process differences is likely to be problematic.

6.3 MPFM Metering Performance

Typical claims for a few in line MPFM's performance are presented in Table 3 in a simplified and summarised form – readers should review the individual vendor data sheets.

Table 3: Typical claims for Nucleonic in Line MPFM Performance

	Liquid (Rel)	**Gas(Rel)**	**Water Cut (Abs)**
SLB Vx [13]	2.5-10, 0-100% GVF	2-5%, 0-100% GVF	2.5-8%, 0-100% GVF
Roxar 2600 [14]	2%, 0-100% GVF	5%, 0-100% GVF	2%, 0-100% GVF
MPM [15]	2.5-5%, 0-99%GVF 5-15%, 99-100% GVF	3-5%, 0-100%GVF	1-2%, 5-100%WLR

With MPFM's we have now moved forward from a goal of being able to meter the phases with an uncertainty of about ±10 to ±25% with a huge fear of the 'dark corner' - (GVF>85% and WC>85%) to building auto-switchable multiphase - wet gas meters with claimed uncertainties of better than±5% for liquids and ±2 to ±5% for gas flows and water detection better than ±2%.

In many cases these performance claims have been verified in flow laboratories as part of JIP's and in Operators' processes, however there are still some caveats.

Like single phase meters it is important to size MPFM's correctly. Meters that are either over or undersized will not operate well and their uncertainty is likely to be very much higher than stated. Understanding that declining fields will entail MPFM replacement should be in the Operators' ongoing development plan. It is better to have two (large and small) MPFM's than one oversized meter. It is also important to consider what conditions the MPFM will have to cope with as some technologies could be more suitable than others as their technologies are very different.

There is no doubt that the performance of MPFM's over the years has improved significantly. This has probably been the result of a number of factors including – and not exclusively:

- Competition between vendors
- Open and independent MPFM test JIP's
- Significant R & D expenditure by vendors, operators, universities etc
- Innovative alliances by vendors and Operators in JIP's
- Significant Standard type documents which are huge 'assists' to newcomers
- Users becoming 'MPFM aware' and resisting the 'black box' approach
- Flow model improvements
- Improvements in computing power, high speed electronics and secondary instrumentation (DP, PX & Tx)….and lastly – and by no means least -
- Some very awkward individuals asking very awkward questions

Improvements are such that we have seen in the last 5 years several installations where the MPFM has been installed and has positively identified problems with the test separator meters - which is a role reversal.

These installations plus – the relatively few – to date - fiscal allocation in the real world mean that MPFM's have reached a point where acceptance by the Operators and Regulators has reached unprecedented levels.

5 SUMMARY AND CONCLUSIONS

It is likely that, in practice, many test separators are not suitably maintained or operated to give the lowest measurement uncertainty achievable, and many, the metering requirements are regularly compromised. As a result it is probable that the, measurement uncertainties are probably in the range of ±4 to ±10% for each phase.

As a result of the multiple uses and the operational limitations placed on them, it is likely that in many high well count facilities it is probable that a single test separator is unable to provide the utilization to well test every 30 days per current UK and Norwegian requirements and it is likely that waivers are required.

It is possible that this is both detrimental to long term field management and short term production optimization
.
With the technological advances made in in-line MPFM's, their measurement envelopes have improved substantially and many are able to switch from wet gas to multiphase and vice versa. This facility makes them highly suitable for use in Operational well testing as a supplement to and with a Test Separator and will provide an increase in well test utilisation with a consequent improvement in field management and short term production optimization.

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