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North Sea FLOW Measurement Workshop

# Paper 9.1

# Online Gas Chromatography: A Technical and Historical Overview – Design and Maintenance Advices to Achieve An Accurate End Result

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# Online Gas Chromatography: A Technical and Historical Overview – Design and Maintenance Advices to Achieve An Accurate End Result

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## 1 INTRODUCTION

Gas chromatography was invented over 100 years ago by a Russian scientist. In the late 1940ies and early 1950ies the gas chromatograph principle was further developed by German and American scientists into an important practical analytical instrument. It was then used as a laboratory piece of equipment and the laboratory engineer/technician would have the full responsibility and control of the operation of the equipment.

Our business the offshore oil and gas business came a bit later. Our needs were connected to online sampling and analysis of natural gas. This was traditionally done by automatic sampling.

The main task for the Gas Chromatograph (GC) will then be to produce a correct component split for the gas analyzed. From the component split is then Gross Calorific Value (GCV) and density calculated. The GC can also be used for $H_2S$ measurement, but that will have to be a dedicated unit.

## 2 HISTORY IN THE NORTH SEA AREA

The development in Norwegian and UK waters have been very much the same. The first offshore online gas chromatograph I saw installed was on 2/4 S platform where the Statpipe gas was tied into the Ekofisk complex. This device was ready for operation in 1984, but it was not much of a success story. The operation was so poor that the automatic grab sampling system was absolutely not challenged by this device. Also the Statfjord platforms that were delivering rich gas into the Statpipe system upstream of Kårstø were equipped with online gas chromatographs from Combustion Engineering (later taken over by ABB). Credit to the U.S. oil companies, Mobil and Phillips (now ExxonMobil and ConocoPhillips). They were pioneers to introduce this technology. The Statfjord online GC case already was presented at this conference in 1988, by Endre Jacobsen. The challenge on Statfjord as on most rich gas installations was to prove that the C6+ components are presented in the GC within an acceptable uncertainty. As this was rich gas and the sample handling systems were not of todays standard, it was shown that it was an impossible task to reproduce the C6+ component in the GC. The gas chromatographs on Statfjord therefore just served as pipeline monitoring device for 20 years.

The pipeline monitoring requirements are, however, also important and it was soon laid down as a requirement from the engineers responsible for the gas transport systems that all entry points into the gas pipelines should be equipped with online gas chromatographs.

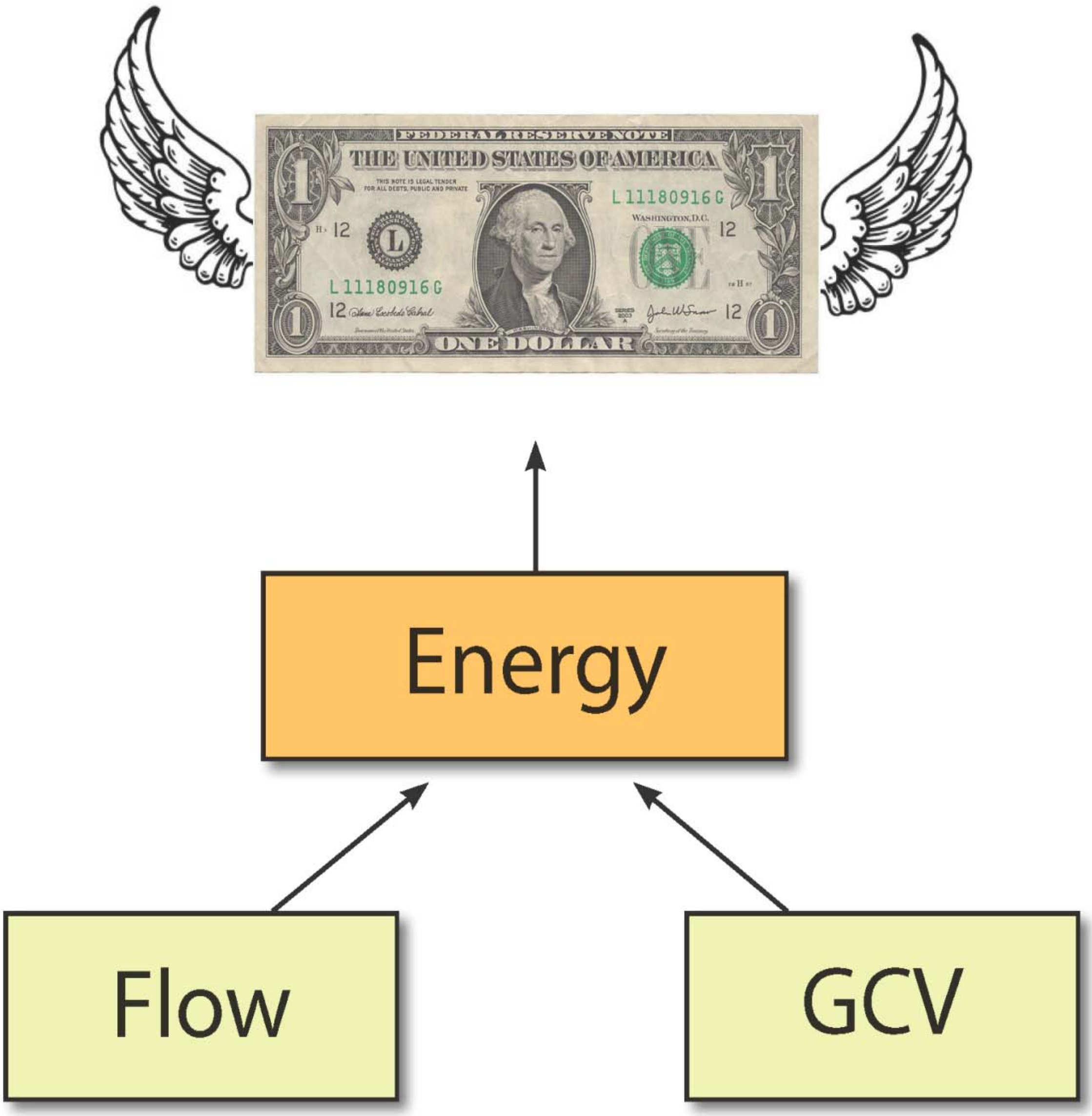
In 1993, we as Norwegian regulators were challenged at this NSFMW conference, then arranged at Solstrand near Bergen, Norway. The statement from the Elf (TOTAL) metering responsible was that the authorities were blocking the way for taking the online gas chromatographs in use for fiscal purposes. The response from the Norwegian Petroleum Directorate (NPD) was quite firm and easy. We had at that time not received any proposals for using the GC`s for fiscal purposes.

Later in the 1990ies things changed and the GC`s were gradually taken in service for fiscal purposes. First for dry gas systems, but then gradually also for rich gas systems.

It was several reasons for this:

- Sample handling systems with better equipment and design.
- More robust design of the GC itself.
- Easy to see all the benefits with GC compared to an automatic sample system.
- The GC`s were already in place for pipeline monitoring purposes.

**Fig. 1. Illustrates the importance of the online GC in a gas metering system**




The uncertainty of the analyzes from an online GC is of outmost importance to the companies that uses these figures in energy calculations, as that forms the basis for the economical transactions between seller and buyer. An online GC is, no matter how sophisticated it is, fully dependant on that a representative sample is delivered by the sample handling system.

## 3. A BRIEF DESCRIPTION OF A TYPICAL SAMPLE HANDLING SYSTEM

**Fig 2. Typical sample handling system**

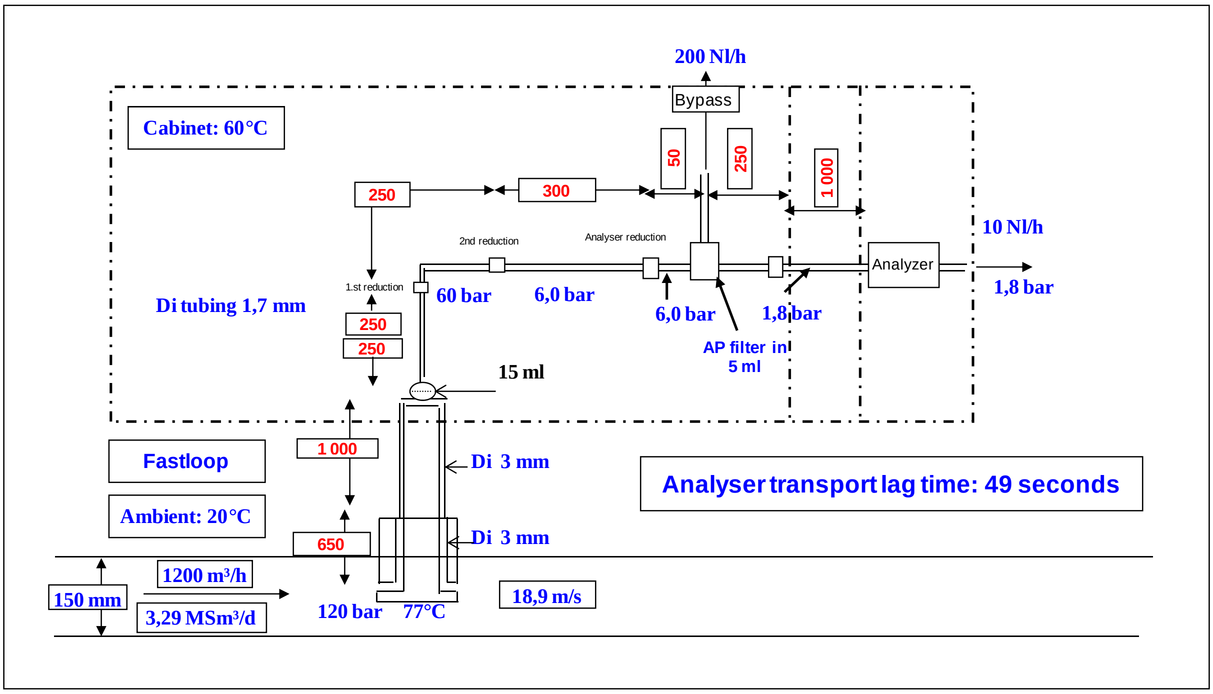
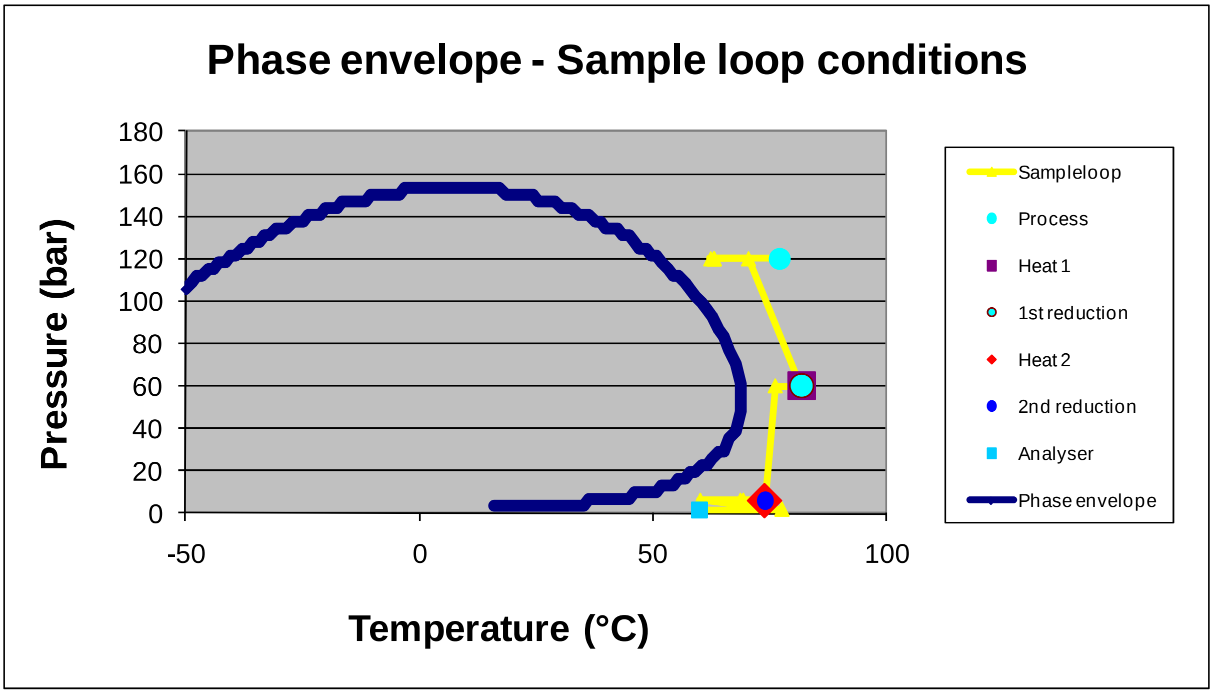



**Fig 3. An example of the phase envelope calculation**



### a) Overview

The phase envelope is given in figure 3.It is the ultimate calculation which always has to be done to ensure that the gas always stays is in gas phase during the transport through the sample handling system. A two step pressure reduction is shown on figure. A one step pressure reduction is, however, often possible and should be aimed.

The elements which the sample handling system consists of: sample conditioning, probes, regulators, filters, heat tracing, tubing. The principle sketch is given in figure 2.

A sample analyzer must have a sample that is representative of the process stream reliable and accurately delivered to its injection valve. The sample should be unaffected by ambient conditions with a minimum of time delay between the sample point and the analyzer. When a sampling system for an analyzer is designed, a thorough knowledge of the process fluid is necessary including limitation requirements for pressure, temperature, solids, liquid contamination and corrosiveness that could affect the sample. For process analyzers, the speed and quality of the sample loop are important factors. Regulators, filters, tubing size, and fittings all contribute to the time lag between the sample point and the injection valve of the analyzer. Regardless of how sophisticated the analyzer is, and how much it costs, the proper sample handling is imperative.

Some attention should also be paid to the material selection of hoses, tubing and couplings. Robust materials should be selected to avoid any assumptions of molecular diffusion from test gas or reference gas into the instrument lines.

### b) Some design considerations

The pressure is taken from the high pipeline pressure and down to analyser pressure. The various calculations to be performed in connection with this sample handling system are extremely important:

- The gas conditioning calculation as it ensures that the gas is always on the right side of the phase envelope.
- The transport time calculation as it ensures that the sample is really representative for the time frame set. It also fulfil regulatory or international standard requirements for transport lag time.
- Pressure and temperature measurement on various places for monitoring of the status of the sample loop and eventually take action if some faulty indication comes up. This is important as it is here any problems to stay on the right side of the phase envelope will be detected.
- A flow indicator should be mounted in the loop so that it can be followed up that the GC is getting the right sample amount at all times.
- A pressure reduction valve with heated body shall always be selected.

The P& ID drawing will normally give you more details but the complexity of this type of drawings make it not useful for such a presentation as this. The principle sketch is given in fig. 2, as illustration.

### c) Some key installation issues

The probe should be located in an area where there is positive velocity with minimum turbulence. In areas of high turbulence, the contaminations in the gas stream that normally travel along the bottom of the pipe or close to the pipe walls will be put in flight. While in flight , they may be ingested into the probe and become a part of the sample. If the contaminations are in the gas phase, they are a part of the gas stream. If, however, they are in flight because of turbulence, they are not part of the gas stream and should not be analyzed. The probe should be installed in an as long pipe as possible (20 D minimum). Stay away from headers, blow down stacks, dead end lines, meter manifolds and reduced bore valves.

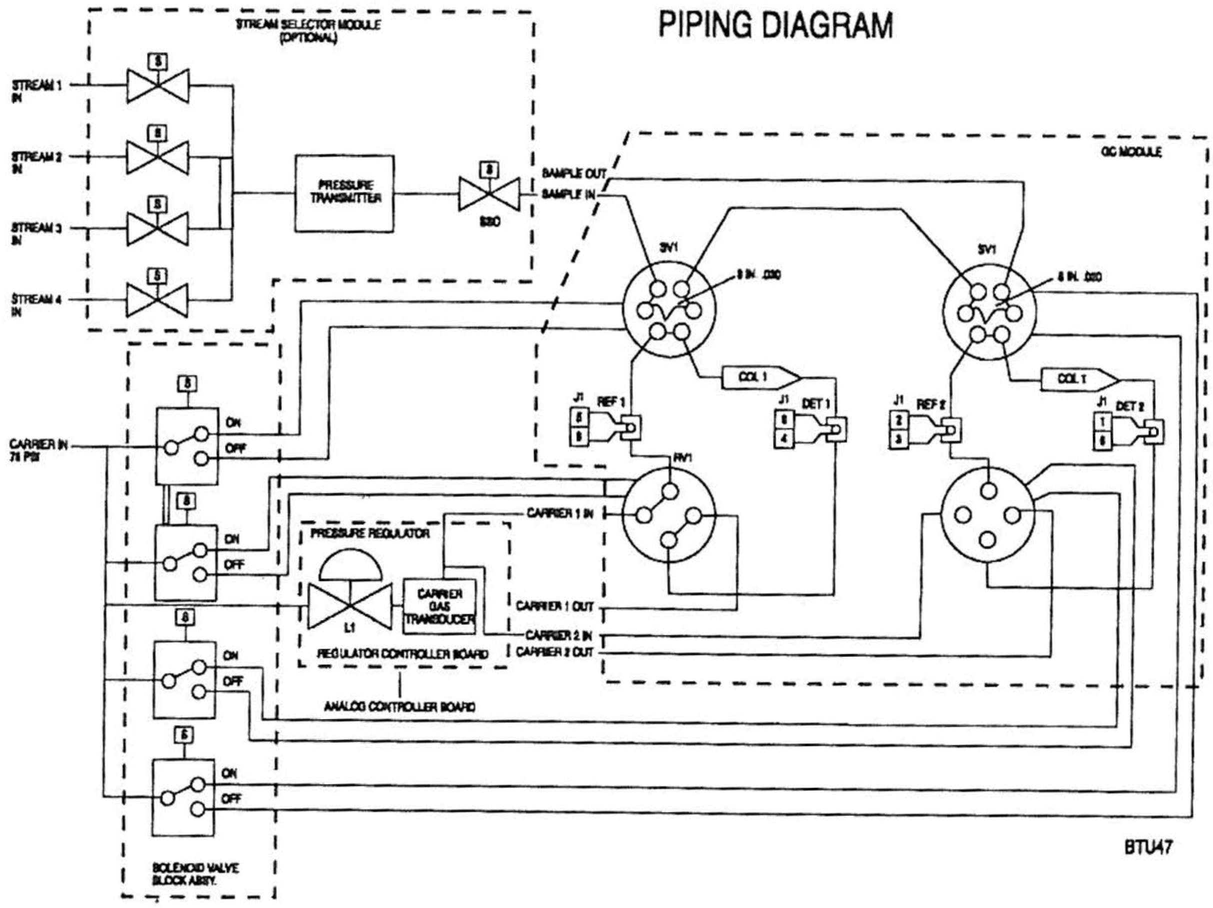
Install the probe on the top of the pipe with the probe 1/3 D into the pipe.

Install shut off valves on the outlet. The valves should be full bore valves which will not affect the flow of gas in open position.

By using a double pitot probe, a self driven fast loop can be made with outlet and return to the probe. Filter and regulator should then be the first equipment of the sample handling system. On the outlet side of the regulator a relief valve will have to be installed to protect the downstream system.

## 4. A BRIEF DESCRIPTION OF A TYPICAL GC UNIT

**Fig 4, A drawing from the AAI data book showing valves, columns and detectors.**




**GC Module Flow Diagram**

The Gas Chromatograph module could consist of the following components as shown in fig 4:

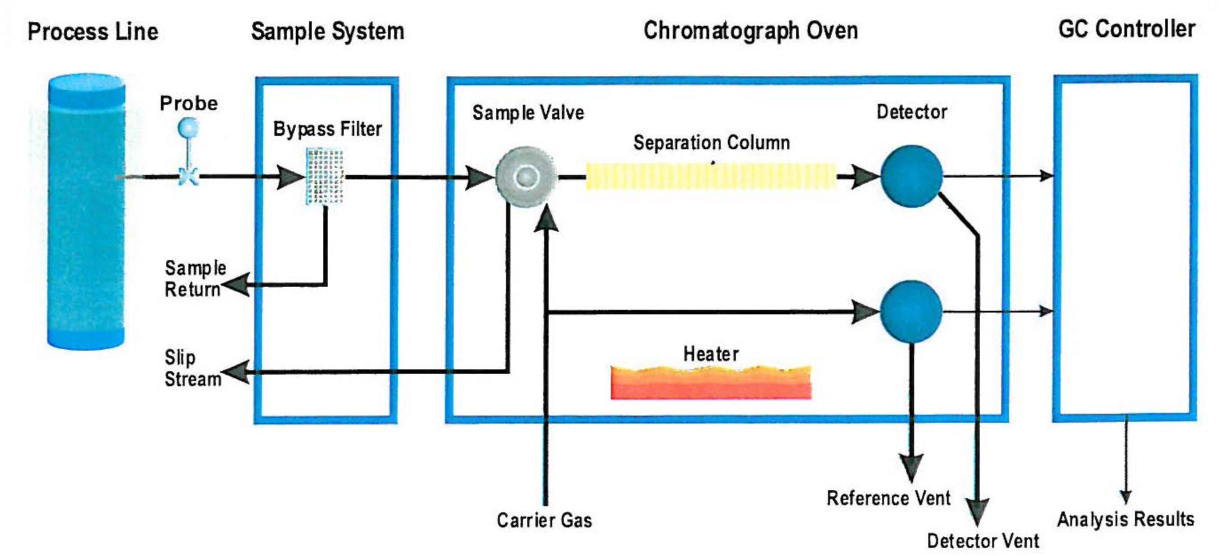
- Two sample valves, SV-1 and SV-2
- Two reverse valves, RV-1 and RV-2
- Two chromatograph stainless steel packed colomns, COL-1 and COL-2
- Two dual element thermal conductivity 30k ohm matched thermistor detectors, DET-1 and DET-2
- Two reference detectors REF-1 and REF-2

The temperature within the GC module should be 60 deg C (± 0,3 deg C).

The time for one sequence of a sample going through a column could be 60 seconds but the total time between two total cycles could be 180 seconds (3 minutes).

It is quite clear that when we speak of these small sample volumes and relative complex valves 6 port for sample valves and 4 port for the reverse valves, it is crucial important that all equipment operate according to their design to not disturb the analyzing result in any way.

**Fig 5, A drawing from the Emerson Daniel documentation which shows the principles of the GC and the gas flow through the system.**




Gas chromatography is in principle the separation of a mixture of chemical compounds due to their different migration rates through a separation column. This separates the compounds by boiling point difference, polarity differences or differences in molecular sizes.

The separated compounds then flow across a suitable detector (TCD) that determines the concentration of each component in the overall sample.

Knowing the concentration of the individual compounds makes it possible to calculate certain physical properties as Gross Calorific Value (GCV) or density based on standard equations from ISO 6976 or AGA 8.

## 5. AUTHORITY REQUIREMENTS

Natural gas for sales or allocation purposes has been under the jurisdiction of National metering authorities since the start up of the activity

.

The Department of Energy and Climate Change (DECC) in UK has in their Guideline section 4.3.5 to 4.3.8 some advices to avoid condensation problems when designing and during the operation of gas chromatographs.

The Norwegian Petroleum Directorate (NPD) has in their regulation section 8,11 and 17 with additional comments some requirements to Gas Chromatographs, in addition it refers to the NORSOK standard I-104 (2005), Fiscal measurement systems for hydrocarbon gas. This standard has in section 9 and Annex B several requirements for online GCs. It is setting maximum allowed requirements for uncertainty of various parts of the GC system and for linearity testing of the GC. The linearity check is required to be done with 3 gases.
A 48 hours stability check during the FAT is also required.

Some relevant ISO/ASTM standards are also referred to in the NORSOK document, ASTM 1945, ISO 6974 part 1 and 3, ISO 6976, ISO 10715, as well as AGA report no 8.

The general NPD requirements for calculation check of software (section 8) and to maintain the equipment to the standard it is when installed (section 23) are also applicable for the online Gas Chromatographs.

It has often been so that the international standards serve as a good tool for maintaining a good quality. Not everything has however been mandatory. Parts could have been left out based on a judgement of the practicality of the requirements.

Recently a new authority has entered the scene. The European Union has through the climate quota trading scheme imposed requirements on natural gas used for fuel and if possible also for flare that base the quality requirements on ISO 10723, which require linearity tests on GCs to be done with 7 test gases and repeated at regular intervals. National agencies responsible for climate and pollution control handle the measurement challenges in connection to the $CO_2$ climate quota trading scheme. This has lead to that on places where authority requirements already have been in place as in Norway, the requirements from a new agency comes on top and they are also sometimes more tight and stringent than the requirements that have been in place also for sales gas applications. This is in some way not logical, as the main money steam is still the sales gas. This has been a frustrating situation for the metering personnel in the oil/gas companies, and of course ourselves.

**Uncertainty calculation**
The overall uncertainty of the Gross Calorific Value (GCV) is in the NPD regulation (section 8) required to be less than 0,30%. The following components will have to be included on a component basis: Calibration gas uncertainty ($U_{cxi}$) + the linearity of the GC (from linearity test) ($U_{Lxi}$) + the repeatability of the GC (from linearity test) ($U_{Rxi}$). The sum will then have to be root squared.

In addition the basic uncertainty of the values in the standard for GCV and molar mass adds up to the total uncertainty. This is in the existing ISO 6976, described in section 9.2. The accumulated uncertainty contribution from these effects could be estimated to 0,052%. In the standard it is mentioned that this uncertainty contribution may be neglected when compared to the uncertainty in the analytical data from the analysis.

The new ISO 6976 is dealing with this aspect in a more complex way in section 11 and 12, but it is no reason to believe that the end result would differ very much.

## 6. NTERNATIONAL STANDARDS

**ASTM 1945-03 (Reapproved in 2010)**
Standard test method for Analysis of Natural Gas by Gas Chromatography. It gives a good explanation of the method. It describe the apparatus and define how various parameters should be calculated. It also give some guidance on accuracy for linearity and repeatability as well as for test gases.

ISO 6974 part 1,2,3,4,5 and 6 (2001)
The standard consist of 6 parts and gives a good guidance on the working principle as well as handling of data from the GC. The standard is now due for revision and the committee draft (CD) has recently been out for last comments/voting. It will then move into the Draft International Standard (DIS) phase, before it finally becomes an international standard.

ISO 6976 (1995) (reprinted and corrected 1996) (GPA 2172, used in US)
The standard contains the calculations for Calorific Value, Density, Relative Density and Wobbe Index from composition. Also this standard is now due for update and the CD has recently been out for last comments/voting. It will then move into the Draft International Standard (DIS) phase, before it finally becomes an international standard.

ISO 10715 (1997)

Natural Gas - Sampling guidelines. This standard will be updated in the near future and ISO is seeking experts for the working groups.

ISO 10723 (1995)
Natural Gas – Performance evaluation for on-line analytical systems. This standard is also now due for update and the CD has recently been out for last comments/voting.
It will then move into the Draft International Standard (DIS) phase, before it finally becomes an international standard.

It could seem that ISO structure related to the standards ISO 6974 and ISO 10723 cover very much of the same areas. They are also under the same committee, ISO /TC193. But now when all standards are due for new release it is unlikely that a simplification will happen. This could lead to situations where requirements are not similar and the logical question is what shall we then use. It is as far as we see it important to use all standards with the right objectivity so that equipment and testing are not over specified (or under specified) in any way. This requires a certain competence level in the oil/gas company to be able to make technical evaluations and make correct decisions.

The use of 7 calibration gases have been a discussion topic in relation to ISO 10723. Now it could be deducted that the standard is more open for flexible solutions in this area, That means use of 3 test gases as has been standard for FATs on Norwegian systems (as specified by NORSOK I-104, 2005).The precaution is that the area of each chromatogram for each component( C1 to C6) in relation to the measured amount (mol %) is presented by a polynomial function of the first order. Most vendors seems to use this method. (ref new ISO 10723 ch. 5.2.2 and 5.4.2).

## 7. SELECTION OF THE RIGHT GC EQUIPMENT AND SAMPLE HANDLING SYSTEM

Items to be aware when specifying a GC system:

- Components present
- Components to be measured
- Ranges of measurement
- Gas Conditions
- Standards to be met/used
- Legal requirements
- Sample handling
- Calibration method
- Carrier Gas
- Input/Outputs
- Alarms required
- Interface/communication links to onshore/vendor
- Duplication of various functions

The last item which mention duplication is something which is more and more used but we have to remember that to achieve a fully redundant system we have to duplicate also the sample handling system and the sampling probe and that is more seldom seen.

**Detectors**
As an example a typical thing which need consideration is the type of detector the GC should be equipped with.

The Thermal Conductivity detector (TCD) is the most commonly used but also the Flame Ionization Detector (FID) is used. They both have their advantages and disadvantages. In some applications they might be combined. Also other detectors for more special applications might be considered, but all this will have to be based on vendor recommendation. It is therefore so crucial important that the process information the vendor receives is correct.

A brief explanation of the two detector types are given underneath.

**TCD**

Since all compounds, organic and inorganic, have a thermal conductivity, all compounds can be detected by this detector. The TCD is often called a universal detector because it responds to all compounds, it will respond similarly to similar concentrations of analyse.

The TCD is a good general purpose detector The TCD is less sensitive than the flame ionization detector and has a larger dead volume it will not provide as good resolution as the FID. However, in combination with thick film columns and correspondingly larger sample volumes, the overall detection limit can be improved. The TCD is not as sensitive as other detectors but it is detecting all components and is non-destructive.

The TCD is also used in the analysis of permanent gases (argon, oxygen, nitrogen, carbon dioxide) because it responds to all these pure substances unlike the FID which cannot detect compounds which do not contain carbon-hydrogen bonds.

**FID (not allowed on many offshore installation for safety reasons)**

FID's are best for detecting hydrocarbons and other easily flammable components. They are very sensitive to these components, and the response tends to be linear across a wide range of concentrations.

However, a FID destroys most - if not all - of the components it is detecting. Contrarily, with a TCD the components can continue on to another detector after passing through the TCD; thus it is considered a non-destructive detector However, with an FID, most components are destroyed and no further detection is possible.

The current measured, between the electrodes corresponds roughly to the proportion of reduced carbon atoms in the flame. The response of the detector is determined by the number of carbon atoms (ions) hitting the detector per unit time. This makes the detector sensitive to the mass rather than the concentration, which is useful because the response of the detector is not greatly affected by changes in the carrier gas flow rate.

FIDs are insensitive to H2O, $CO2_2$ CS2, SO2, CO, NOx , and noble gases because they are not able to be oxidized/ionized by the flame

The Methanizer enables the Flame Ionization Detector to detect low levels of CO and CO2. The Methanizer is packed with a nickel catalyst powder. During analysis, the Methanizer is heated to 380 ºC. When the column effluent mixes with the FID hydrogen supply and passes through the Methanizer, CO and CO2 are converted to methane.

**Location of equipment**

The probe shall be located at a place where it is possible to achieve a representative sample.

The distances between the sample probe and the GC shall be as short as possible and similarly the reference gas and carrier gas should be conveniently located. We have over the years seen a large number of rather inconvenient installations. (For example GC and Gas bottle cabinet in a high location where it is very difficult to bring large bottles).

The distance between the sample probe and the GC is in many installations unnecessary long.

## 8. REFERENCE GAS

ISO 6142 (2001) – Gas analysis – Preparation of calibration gas mixtures – Weighing methods

ISO 6143 (2001) – Gas analysis – Determination of composition of calibration gas mixtures – comparison methods.

It is important that the reference gas is specified and produced to the highest standard at the production facility. It is, however, a long and winding road from the production facility to the place where it shall be used. The transport should therefore be done in a controlled way and precautions should be implemented when arriving at the place where it shall be used, so that the reference gas is in good shape when it is connected to the GC.

The reference gas is delivered with a traceable certificate where all critical data as components ordered and delivered as well as uncertainty will be stated. The normal validity of the gas is 3 years. Also the minimum storage temperature which often is 10 deg C will be stated, as well as the minimum bottle pressure. If some of this information is missing then the vendor shall immediately be contacted.

If the bottle has been exposed to temperatures below the preset limit, then retrograde condensation would have taken place. The bottles should then be kept in a heated cabinet for some time before they are connected so they are brought back to their original condition. Eventually rolling of the bottle should also be considered if necessary to bring bottle back to the original condition.

When bottles are changed then the system should be flushed and the regulator valves should be checked for any failure. This to ensure proper operation when the system is set back in service.

Flexible hoses should not be used as connecting lines between the reference gas and the GC as diffusion can take place. $O_2$ can enter into all materials except copper and stainless steel.

The $CO_2$ quota trading regime has imposed a requirement for accreditation of reference gas deliveries. This has created some difficulties as very few vendors had an accreditation certificate.

## 9. HOW TO MONITOR THE ONLINE GC`s DURING THE DAILY OPERATION

Vent system influence the raw data of the GC.
The vent system should therefore be designed to minimize these effects, by having the vent duct in a sheltered area. At least it should not be directly exposed to the weather as we have seen examples of.

It is primarily in the “raw” values we see this effect. Any calibration activity against the GC should therefore not be launched by a shift in the “raw” values alone. By using normalized values, the weather effect is masked.

a)
Various temperature and pressure and flow elements in the sample loop shall be verified to ensure the healthiness of the sample system at all times. Limits for the operation and relevant action shall be defined. All pressure reduction valves should be equipped with pressure and temperature monitoring equipment. Rich gas systems are obviously more exposed for difficulties in the sample handling system. If the gas composition changes then a verification of the sample handling system should take place to ensure that the gas is still outside the phase envelope.

Other items to be checked regularly in the sample loop:

- Filters to be checked or replaced at regular intervals
- Check of carrier gas consumption
- Check of calibration gas heater
- Check of calibration gas flow rate
- Check of carrier gas pressure

b)

**Fig 6, the Formula 1 cars are indicating the various components.**


We have hopefully all seen the chromatograms which the chromatographs gives out. The peaks are coming with a fixed shape and preset plan. If this is upset in any way then something is wrong. Just as Formula 1, therefore the illustration.(At least as people who are not fans of that sport could see it).

The chromatograms should be regularly examined to detect any weaknesses with the GC. The shape and position of the peaks should be examined. Some examples:

- Column failure will give valve timings not longer appropriate.

- If some small components misses then it can be a sign that the flow of carrier gas is too low.

- The shape of the peaks of the largest being too flat, indicate too high flow of carrier gas.

c)

The test against the reference gas (benchmark) is a standard test which is done regularly on all systems. It is here important that calibration activity is not launched as soon as we see a shift. Reasonable limits should be set for critical parameters and when some of these are over run then a calibration activity should take place. It should, however, not necessarily take place immediately. The weather effect as mentioned in item a) is influencing the injected volume. Therefore it should be set a band where it is acceptable to do calibration. If we are outside this band then a calibration should not be done. A calibration should then preferably be followed by a benchmark to verify that the situation has improved.

Changes in injected sample volume are affecting the small components heavily, therefore the control limits on these will have to be wider or evaluated by statistic.

The ASTM 1945 -03, has a requirement which says that the calibration gas components should be close to the real gas (limits are set). This can be hard to meet for the small components as they can vary significantly. It should, however, not be focused too much on this as it easily can be demonstrated that the impact on the overall uncertainty is small.

Calibration shall be done when it is necessary, but it should be as seldom as possible. The reason for this is that it changes the reference point and that reduces the ability to trace wear and tear in the columns, detectors and valves.

d)

If the gas chromatograph is duplicated as they often are (NPD requirement (section 11) on gas sales stations) then the two units should be compared against each other. Realistic deviation limits should be set and proper action should be taken if these are over run. It is a requirement in these situations that you should use unit 1, as long as both units are defined as healthy. An average value from both units is also possible to use and then switch to the healthy unit if one fails.

Some gas chromatographs now have double set of equipment within the same unit. Then same type of philosophy as above should be applied.

e)

**Response factor** = Area response from a detector for one component related to a reference

**The retention time** = The time it takes for a single component to pass through the column

The response factor and the retention time will have to be monitored regularly.

Realistic alarm limits will have to be set for both the Response factor and the Retention time. Trending should be performed. Both these parameters will if they exceed preset limits indicate column failure.

f)

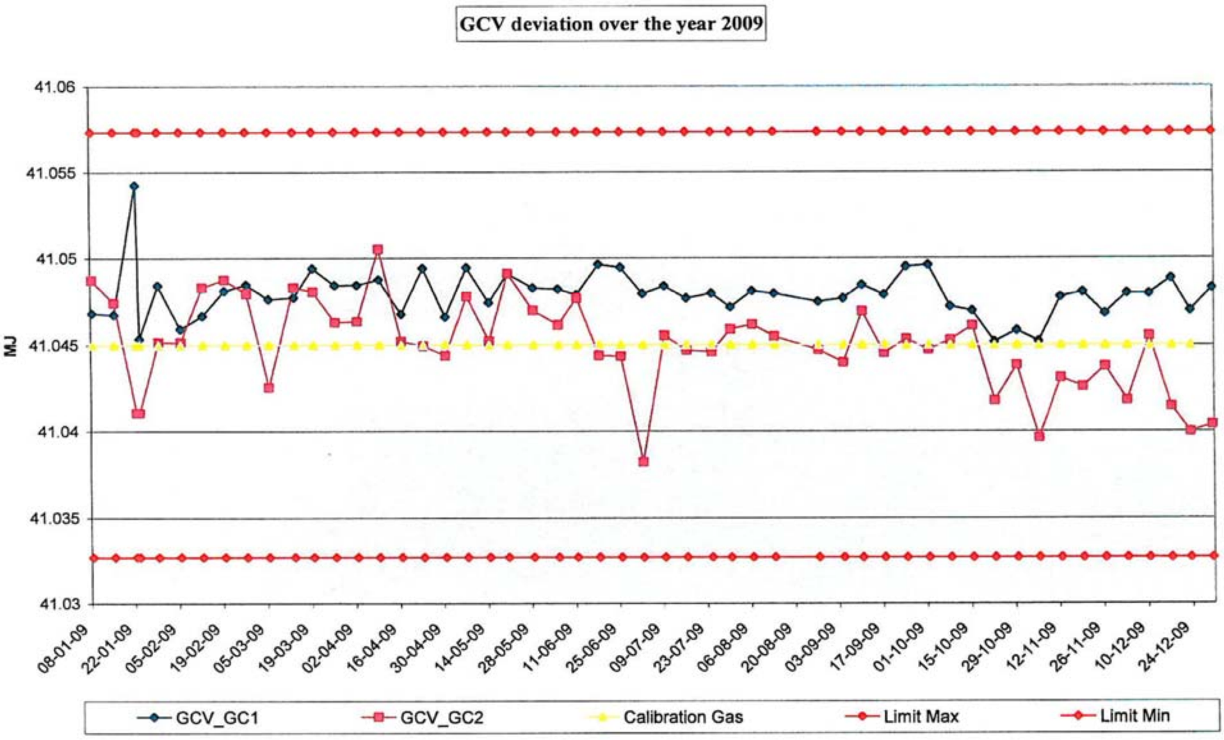
Regular linearity checks are done some places (land terminals), with seven test gases according to present ISO 10723. Some places 3 test gases are used. If the Gas Chromatograph is used at a stable GCV as it normally is, regular linearity checks should not be necessary. The regular benchmark and calibration should take care of the quality follow up together with other monitoring and maintenance activities on the equipment which is described in this paper.

If it is suspected any error or just to confirm the performance, a test with one reference gas with other data than the permanent reference gas can be done.

The updated standard ISO 10723, open for an evaluation of number of points to be used based on what will be the normal operating area of the GC, and that is positive.

g)

Trending of the final outcome of the GC, the GCV is an important monitoring tool if two GC`s are in place. Figure 7, is giving an example of this and the limits in use. Be aware of the alarm limit ± 0,03%.




h)

Regular maintenance support visits by GC specialist (vendor/independant) to verify the status of the chromatograph and also with the aim to transfer competence to maintenance personnel could be a part of the quality follow up strategy on the online gas chromatographs.

## 10. SUMMARY

The speed of the Gas Chromatographs have the recent years increased. 3 minutes or may be even also faster than that is now the cycle time on new units.

Some wish to specify as low cycle time as possible. We have however seen that this is not always a good idea. The unit need some time to be able to separate the components properly,
And that is of course the most important job for the chromatograph. If you therefore for one or another reason need high speed you better install two units and space them in time.

The Online Gas Chromatograph technology including sample handling now seems to have reached a level where it is fully capable of delivering high quality data to the public.

The human factor may always have a high potential for causing errors. The rich gas systems on the offshore installations are mostly exposed, due to heavier gas, less redundancy and more changing of people. The focus on staff, training, maintenance and quality control can also here never be underestimated. The management focus is also a part of this. To really get management acceptance that the GC is an important equipment for the cash flow in the company. (See figure 1 of this paper).

The Gas Chromatograph is a nice and sophisticated piece of technology which really need tenderly care to perform to its specification.

A GC maintenance strategy document to be developed. Alarm limits on different parameters should be set. Trends on different parameters should be logged and followed up. It should be clearly defined what work shall be done on the installation and what shall be done from coordinating engineering office or from vendor.

Recruitment and training is always important. This will have to be paid special attention as the tenderly care for the GC`s will have to be taken care of. Time is of course also important. The allocation of necessary time for the follow up job must be done.

Best judgement should be steering. Our aim should be to do technical actions based on that they improve quality and not because they are written in some documents for quite different applications. To be able to act in this manner we need competence both on the authority side and on the oil/gas company side, as well as with vendors and other contractors involved.

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North Sea FLOW Measurement Workshop

# Paper 9.2

# Celebrating Quarter of a Century of Gas Ultrasonic Custody Transfer Metering


**Klaus Zanker, Letton - Hall Group**

**Tom Mooney, Emerson Process Management, Daniel Division**


TÜV SÜD

nel technology for life

# Celebrating Quarter of a Century of Gas Ultrasonic Custody Transfer Metering

**Klaus Zanker, Letton - Hall Group**
**Tom Mooney, Emerson Process Management, Daniel Division**

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## 1 INTRODUCTION

25 years have passed since the first production prototype ultrasonic meters for gas custody transfer were deployed. This marked the beginning of a revolution in the metering industry with a migration from conventional mechanical devices to sophisticated electronic devices and the associated diagnostics information they afforded.

The study will commence with a detailed literature review that will capture the many significant advances that have been reported by vendors and operators over the years and so provide a comprehensive ready reference for interested individuals and the industry in general.

Although the target application for the technology was transmission pipelines, benefits such as no moving parts, no protrusion into the pipeline, large rangeability, reduced footprint and diagnostic information meant that the technology was quickly applied to more arduous applications. In the early days this extension of target applications proved to be painful for both vendors and operators alike, however it was an extremely beneficial process for the industry as a whole as it rapidly accelerated product development and operational expertise. Real life examples of the many trying applications of ultrasonic meters are revisited, with dedicated commentary from operators who were directly involved in these projects. This will provide the reader with first hand, detailed insight into the operational challenges faced, the resolutions developed and lessons learned.

The paper then goes on to provide an assessment of the state of the art. Particular attention is paid to the development and content of international standards.

Finally, a discussion on the future direction of ultrasonic metering is provided

## 2 LITERATURE REVIEW

### 2.1 Gas Ultrasonic Meter Origins

We can trace the development of gas ultrasonic meters for custody transfer through early patents and publications. Early publications include Williams (1960), Birger (1961), Zalivadnyi (1963) and Brown (1965). These papers focused on the theoretical application of the acoustic technology to flow measurement and paved the way for the practical application of the technology

The first steps toward a practical development can be traced through the first gas ultrasonic patents which appeared in the mid 1970s, in particular, Parkinson et al (1973), Husse (1976) and Gassmann (1976)

These patents further developed the theory of design from an acoustic / fluid flow perspective and also discussed the electronic design requirements but did not lead directly to the production of operational meters.

A significant step toward operational meters was made by Multon et al (1980) of Ultraflux. They recognized the procedures for measuring the flow of liquids using acoustic techniques could be applied to gasses, however noted that there were two specific challenges that need to be overcome in order for a gas meter to be successfully developed.

1. The frequency of the acoustic waves is of the order one to several hundred kilo-hertz.
2. The coupling between the electrical oscillator and the transducers transmitting the ultrasonic pulses is effected by means of an impedance transformer

Multon et al (1980) presents potential solutions to these challenges in their US patent 4202210, "Ultrasonic flow meter for gases 05/13/80", and this led directly to the development of a working gas ultrasonic flowmeter for non-custody transfer applications.

The first to consider gas ultrasonic meters for custody transfer was O'Hair and Nolan (1987) of British Gas. It is interesting to look at the introduction to the BG patent as it shows that the work goes back to 1984 and that BG considers custody transfer in gas transmission pipelines.

> "*This application is a continuation of application ser. N. 801,372 (1985) which is a continuation of Sr. No. 608, 410 (1984)…. With the advent of offshore of off-shore gas supplies it is necessary to provide an extensive network of transmission pipelines in order to distribute the gas, operating at a pressure ranging from 40 to 70 bar. At present the majority of the flow metering needed to operate this system effectively is being done using orifice plate meters. However there are some serious disadvantages with these meters, including their limited flow range (about 10:1), the pressure drop they cause, the need for long straight meter runs and the substantial maintenance required*".

Whereas much of the previous work on ultrasonics had been liquid based or in the case of gas, theoretical in nature, O'Hair and Nolan (1987) actually built and tested a multipath gas meter in 1985. Included in their findings were details on the meter geometry, recommendations for meter run design, flow disturbance testing, effects of pulsations, and diagnostic methodologies. These tests basically validated the concept of using multipath ultrasonic meters for custody transfer using actual prototype meters.

The numerical calculation scheme in the BG design was based upon the well known Westinghouse model, Malone et al (1971). Westinghouse made some important contributions to liquid meters that are also valid for gas meters. Malone et al (1971) introduced the idea of multi-path meters, and subsequently proposed accurate numerical integration techniques to obtain the average pipe flow velocity from the chord velocities, Westinghouse (1976).

Zanker (2003) presented a review of the Westinghouse scheme for 2, 3, 4 & 5-path chordal meters, figure 1, where $X_i$ represents the radial position of the $i^{th}$ chord, $V_i$ is the gas velocity measured by that chord and $W_i$ is the corresponding weighting for that velocity.

| | Radial Position | | Centerline | Radial Position | | Sum Wi |
|---|---|---|---|---|---|---|
| X2 | | 0.5000 | | -0.5000 | | |
| W2 | | 0.5000 | | 0.5000 | | 1.0000 |
| | | | | | | |
| X3 | | 0.7071 | 0.0000 | -0.7071 | | |
| W3 | | 0.2500 | 0.5000 | 0.2500 | | 1.0000 |
| | | | | | | |
| X4 | 0.8090 | 0.3090 | | -0.3090 | -0.8090 | |
| W4 | 0.1382 | 0.3618 | | 0.3618 | 0.1382 | 1.0000 |
| | | | | | | |
| X5 | 0.8660 | 0.5000 | 0.0000 | -0.5000 | -0.8660 | |
| W5 | 0.0833 | 0.2500 | 0.3333 | 0.2500 | 0.0833 | 1.0000 |

Figure 1. Review of Westinghouse Calculation Scheme

In the Westinghouse scheme all the paths are symmetrical about the center, and with an odd number of paths (3 & 5) one path is on the centerline. The centerline path reads about 5% higher than the average flow velocity (Zanker 2000), because the line integral is larger than the area integral. Another disadvantage with the centerline path over reading is that other paths must be closer to the pipe wall to compensate: the 3-path meter is at a radial position of 0.7071 compared to 0.500 for the 2-path, while the 5-path meter is at 0.8660 compared to 0.8090 for the 4-path.

Being close to the wall is good from a mathematical integration perspective, but not from an acoustic perspective, mainly due to shear forces and turbulence causing signal refraction and also due to signal reflection from the pipe wall. The 4-path Westinghouse meter largely avoids that issue. Another advantage of the four chord layout is that the inner chord velocity is above the average nominal velocity (1.042), while the outer chords are below the average (0.89), allowing better compensation for asymmetry. It is for this reason that British Gas selected a 4 path meter in their design, Zanker (2003).

While BG followed the Westinghouse scheme in terms of chord radial position and weighting factors, they made an important change in terms of chord layout. The Westinghouse design shows all paths in one vertical plane, however BG alternated them in two planes at right angles, with the intention of improving performance in cross flow (O'Hair and Nolan 1987); figure 2 is an extract from the original patent. It can be seen that paths 'a' and 'c' are configured in one plane and 'b' and 'd' are in a plane at right angles.

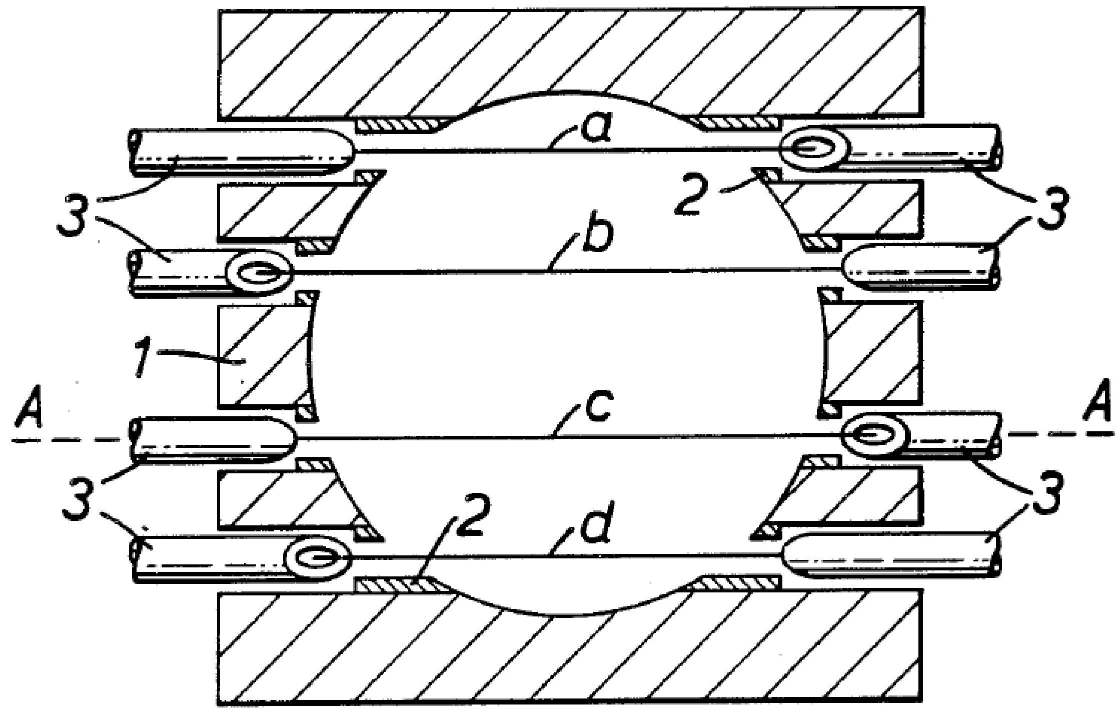


Figure 2, Original BG Path Layout for Gas Multipath Custody Transfer USM

Lunde et al (2000) present a schematic diagram of chordal meter for a single path, figure 3. Here Φ is angle of incidence of the acoustic path to the pipe axis, v is the axial velocity and $v_z$ is the transverse velocity (cross flow).

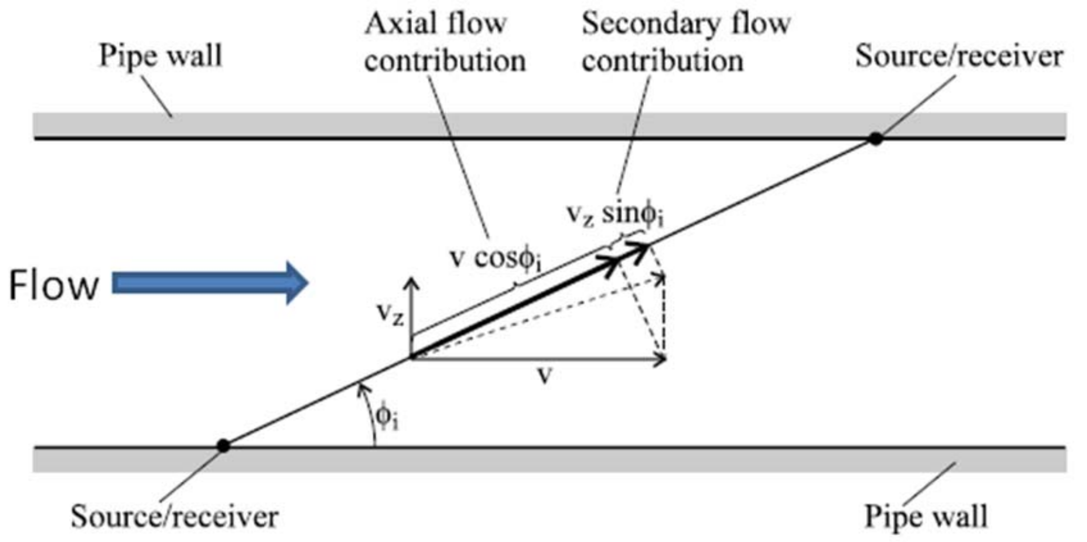


Figure 3. Schematic of a single path chordal arrangement

Both of the traditional approaches of Westinghouse and BG assume that all flow is in the axial direction, Froysa et al (2001). As such they assume that the velocity component from the flowing gas that impacts the transit times of the signals is simply v cos $\Phi_i$. However in a real flow metering system there will be transversal flow velocity components in addition to the axial flow components, Froysa (2001), Yeh et al (2001). This transversal flow can be seen to add a new component of velocity, $v_z$ sin $\Phi_i$ to the axial component, v cos $\Phi_i$ With all chords in one plane per the Westinghouse configuration, the transversal component impacts all chord velocity measurements in the same direction and cause a miss-measurement. However by setting the 'a' and 'd' chords in planes that are 90deg offset from each other, BG mitigated this effect since the cross flow component is additive in one case and subtractive in the other (recall the chords have the same weighting factor). Similarly this is the case for the 'b' and 'c' chords. The net effect of the cross flow component on the meter is thus negated. .

Freund et al (2004) present an interesting extension of the BG layout by defining three powerful diagnostics that can be used to identify flow disturbances using the BG design using the four chordal velocities.

- Asymmetry = (VA + VB)/(VC + VD)
- Cross flow = (VA + VC)/(VB + VD)
- Swirl = (VB+ VC)/(VA + VD).

Asymmetry compares the flow in the top half of the pipe with that in the bottom half; in good conditions it should be close to 1. Cross flow compares the chords in one plane with those in the other plane at right angles: in good conditions it should be close to 1. Swirl compares the inner chords to the outer chords and it is an indicator of swirl due to both the different radial locations and planes. In good conditions the swirl should be close to 1.042/0.89 = 1.17

Zanker (2003) points out that in general, four paths are not sufficient to resolve any arbitrary 3-dimensional flow field containing asymmetry, swirl and cross flow. However, fiscal flow measurement practice attempts to establish good flow conditions, which can certainly be verified by these ratios. Nevertheless, if the ratios differ significantly from their ideal value they can give a reasonable indication of the type of disturbance, especially if only one of the ratios has changed significantly.

Drenthen (1996) adopts an alternative approach to that described above. In his design, Drenthen (1996) utilizes a five path bounce (reflective) configuration where the signal is transmitted to the receiving transducer via a reflection from the pipe wall. The paths are arranged to measure asymmetry (single reflection centre-line paths) and swirl (double reflection outer paths), figure 4. In this arrangement acoustic waves make a total of twelve traverses of the pipe, thus providing more information on the flow than the 4 path Gaussian approach. It is argued that with this knowledge of asymmetry and swirl it is possible to make a more accurate flow measurement even in disturbed flows without any flow conditioning, Drenthen (1996).

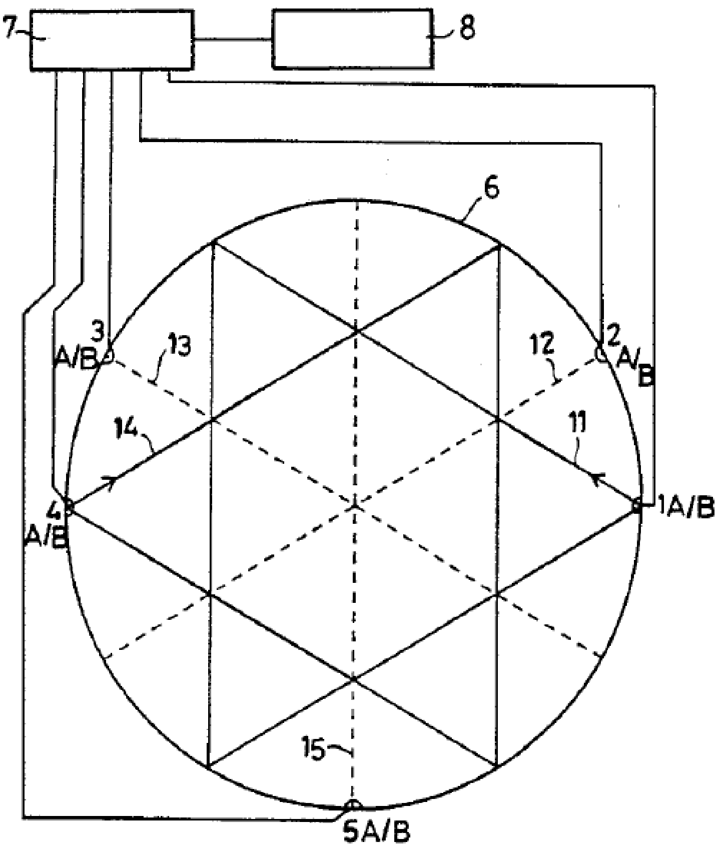


Figure 4 Alternative path arrangements for Gas Ultrasonic Meter, Drenthen (1996)

Drenthen (1996) acknowledges that with the Gaussian model “excellent results can be obtained in ideal flow conditions”, however he is concerned that it is only valid for fully axially symmetrical flow and that it does not utilize any other information relating to Reynolds number due to the fixed weighting factors. This is acknowledged by Zanker (2003) as mentioned above. Zanker (1999) describes how Reynolds number corrections are used to mitigate the circa 5% over-read associated with the centre path measurements (dotted lines 12, 13 and 15 in Figure 4) and that this correction is only valid for fully developed profiles.

Freund et al (1999) point out however that Reynolds number corrections in centre line meters are not only a function of Reynolds number but also of pipe wall roughness. The challenge here is knowledge of what the wall roughness is when the meter is installed and working. Without knowing this, the correction factor can be quite inaccurate, especially at high Reynolds numbers where the flow profile is heavily dependent on friction forces at the pipe wall, Zanker (1999).

The next significant development in gas custody transfer to take hold in the market place was the introduction of a 6 path chordal meter from FMC. This was first presented by Lygre et al (1992). The technology was developed by CMR, which was sponsored by the Norwegian Research Council, Statoil and Norsk Hydro. The result was the current 6-path design with 2 crossing paths in the two upper levels.

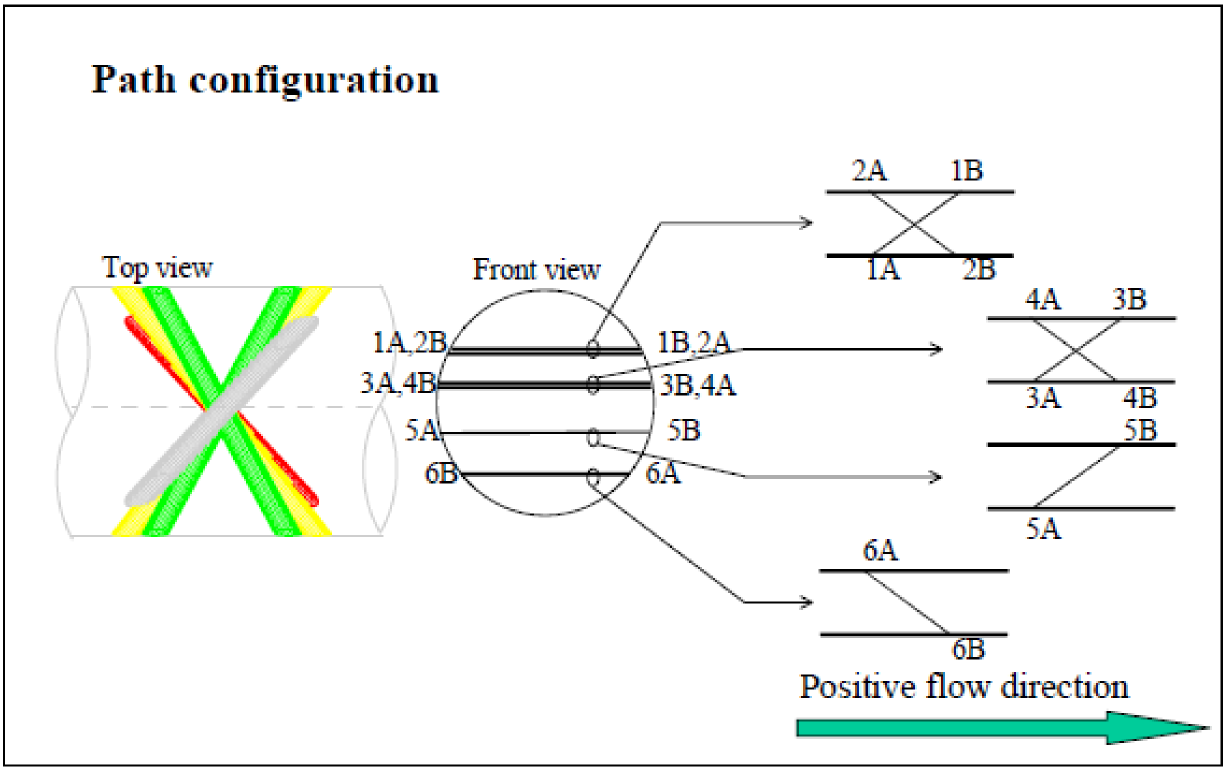


Figure 5 – FMC 6-Path Configuration

The first meters, then called FMU 700, were delivered in 1995 at the same time as the product was transferred to Fluenta, which was setup by CMR as an industrial outlet for their inventions. FMC then acquired the technology with all rights in 1996 from Fluenta.

The above review of the origins of multipath gas ultrasonic meters for custody transfer has focused primarily on patents, it is clear there was a huge amount of work done to get these early units designed and developed. The following section presents a summary of the major milestones and achievements of each on the long term manufacturers

## 2.2 Manufacturer Developments

### *2.2.1 Daniel Measurement and Control*

Daniel took the BG license to manufacture the gas ultrasonic meter in 1986.
The first improvement was to introduce Automatic Gain Control (AGC) to the received signal. This ensures that the received signal amplitude is independent of the gas pressure, temperature and composition. AGC simplifies the zero crossing detection of the received signal, which is used to measure the transit time. The value of the gain established by the AGC is a measure of attenuation along the acoustic path and makes a valuable diagnostic.

The original BG analog peak detection was replaced by Digital Signal Processing (DSP). The more sophisticated DSP provides a robust reliable way of detecting a consistent zero crossing. This is an important development as it ensures confidence in the transit time measurements which determine the velocity and hence flow rate reading of the meter. The DSP also produces many useful diagnostic parameters which can be used to monitor the functionality of the meter.

The original BG USM had the acoustic path at $45^0$ to the pipe axis and a maximum design velocity of 20 m/s. This was the design velocity of the complete transmission pipeline system, chosen to limit erosion and pressure loss. As industry began using ultrasonic meters more, the maximum velocity permissible in metering systems increased to as much as 30 m/s.

Daniel subsequently increased the acoustic path angle to the pipe axis to $60^0$, shortening the path length and hence increasing the maximum velocity specification of the meter to >30m/s.

In 1985 the BG specification of 1% accuracy without calibration was reasonable. However with the ever increasing demand and price of gas, users are now looking for 0.1% accuracy. This has led to USM being calibrated with high pressure natural gas. The calibrations facilities are expensive but have an uncertainty of 0.2 -0.3 %, so the original uncertainty specification of 1.0% has been greatly improved upon.

A major effort by Daniel has been to improve both the internal and external diagnostics with the ultimate aim of achieving condition based maintenance and re-calibration.

As an example, the BG USM measures the path velocity (V) and the path speed of sound (c). It does not need c to determine V, however both are derived using physical dimensions of the meter and measured transit times. Since c = L/t (where L = distance between transducers and t = transit time), when L is fixed geometry then c is a direct measure of t. The 4-path USM has paths of two different lengths, so if c is the same on both path lengths, it is extra confirmation that it is correct and hence V is also correct.

Diagnostic work was extended to look at process performance also. The USM has not only the ability to measure the flow, but also the ability to diagnose the flow measurement and flow profile produced by the meter installation. The 4-path meter can give a reasonable idea of the velocity profile in terms of asymmetry, cross flow and swirl. The batch process of measuring the four individual velocities allows an estimate of turbulence, or unsteady flow, on each path, which is yet another indicator of installation conditions. So given the confidence that the USM is working correctly (measuring the transit times), it can be used to diagnose the installation. As an example, a change in turbulence can indicate that there is a blockage at the flow conditioner.

A more detailed discussion on how these diagnostics have been used to construct a Condition Based Monitoring system is described later in the paper.

#### 2.2.2 Elster Instromet

Elster-Instromet's contribution in driving the adoption of ultrasonic flow metering internationally cannot be under-estimated. Together with Daniel, these two companies ramped the growth of the technology and positioned it as the fasted growing measurement device for custody transfer applications.

Elster first introduced coded multiple burst as a software solution for noisy applications and in-line mechanical silencers as a hardware solution. Elster showed that meters could be close coupled (flange to flange), without having any problems due to cross-talk. This allowed simpler installation of check meters and introduced redundancy. They have extended the boundaries of USM measurement to wet gas and introduce compact meter design and meter runs.

#### 2.2.3 FMC

The FMC meter has a long pedigree: it started at Christian Michelsen Research (CMR) with fundamental research, was handed to Fluenta for commercial development and then sold to FMC.

The contribution of CMR to the whole field of ultrasonic flow measurement is much greater than the FMC meter, as seen by the many references to CMR work in this paper. CMR has made a continuous sustained effort to improve the understanding of all aspects of ultrasonic flow measurements and shared it freely with the industry. CMR has contributed to USM standardization and the continuous improvement of accuracy

### 2.2.4 *New Entrants*

As the adoption of the technology gained traction, new entrants joined the market place. An example is Sick Maihak. Sick introduced one of the first industrial Ultrasonic gas flow meter for emission monitoring in stacks in1981. For custody transfer in gas transmission Sick returned to the Westinghouse arrangement of 4 paths in the same plane. They introduced two such meters in one body on two orthogonal planes to mitigate flow profile effects and also provide complete redundancy of measurement.

Sick's main advance is in sensor technology, which permits manufacturing transducers out of titanium and uses no epoxy. These hermetically sealed sensors can be hydrostatically tested in the field without damage and permit operation with cryogenic and high temperature applications (from -160 $^0$C to +280 $^0$C). Sensors can operate from atmospheric pressure to 7000 psig, which allows calibration with atmospheric air.

## 2.3 Metering Application Development and Challenges

Reidar Sakariassen of Statoil was the first to put a gas USM onto a platform in the North Sea in 1993. He has shared some of his experience with the authors; see Sakariassen (1995 and 1997) and Frøysa et al (1996).

To convince NPD that it performed to fiscal standards Reidar designed a system with pressure (P), temperature (T), density and composition (GC) measurements. These secondary devices allowed the calculation of density and SOS, using suitable equations of state. The calculated density could be compared with the measured density and the calculated SOS could be compared with the measured SOS by the USM. The redundant measurements made it possible to determine if any measurement was in error, Letton et al (1999). This was accepted by NPD and ultimately NPD (1997) demanded that calculated SOS should be compared with the measured SOS for all USM fiscal measurements. Comparing USM SOS with calculated SOS is now an industry standard practice universally done and is also documented in AGA10 (2003)

Reidar explained that the USM was not originally planned to be used on the platform, but instead was added as an afterthought because of the lack of space available and the smaller footprint it afforded. One of meters had a pressure control valve (PCV) in close proximity. The pressure drop across the PCV created noise in the USM, which came as a surprise because the PCV had a "whisper trim". He learnt that the whisper trim moved the noise from the audible range to the ultrasonic range to protect personnel; however the impact was that the ultrasonic noise interfered with the USM signals. The energy drop across the PCV was MegaWatts while the USM was limited to a few Watts due to its intrinsically safe design which meant signal to noise ratios were extremely small to the point where the meter struggled to function.

As a result of this experience, significant signal processing capability was developed within the meter that has hugely improved the performance in noisy environments. Moreover, a specific record and playback functionality was developed that allows post processing of signals in extreme noise environments.

Another experience was calibrating an USM at K-Lab (Norway) in the winter with the outside temperature $0^0$C and the gas temperature at $30^0$C. Early USMs had isolating valves on the transducer ports, to allow transducer removal. This meant that the transducer was significantly recessed from the flowing process and so there was a significant temperature gradient from the cold transducer to the warm flowing gas. This temperature gradient had a corresponding speed of sound gradient. The transmitted signal did not reach the receiver due to the corresponding refraction. A short term fix was made by insulating meters. A significant amount of research followed, Loland (1998), and longer term, the meter transducers were located at the inside diameter of the meter and an alternative mechanism for transducer removal was designed. Today all vendors have their transducers located close to the flow and most operators recommend that meters are insulated.

In the UK sector of The North Sea, Gordon Stobie of ConocoPhillips significantly extended the application of USMs. He put into practice much of the experience developed in the ULTRAFLOW (see Wilson et al) project and the associated meter prototypes were installed in the North Sea. Results were mixed for these early introductions; however valuable design lessons around piping arrangements, the use of flow conditioners, gas analysis, valve noise, uncertainty consideration and calibration / testing methodologies were learned, Stobie (1998 and 2002).

He also introduced the idea of installing USMs with very small footprints. Figure 6 shows a photograph of the allocation metering for the Jade project. This full assembly was successfully flow calibrated in order to capture the installation effects on the meter performance as a function of the meter factor, Stobie et al (2001).

Lastly, Gordon introduced the first Z-Skid, figure 7. Here two meters normally run in parallel, can be run in series by means of a cross over header and isolation valve assembly that allows them to be put in series for verification, Stobie (2002)


Figure 6. USM installed at test facility with 0D upstream straight pipes

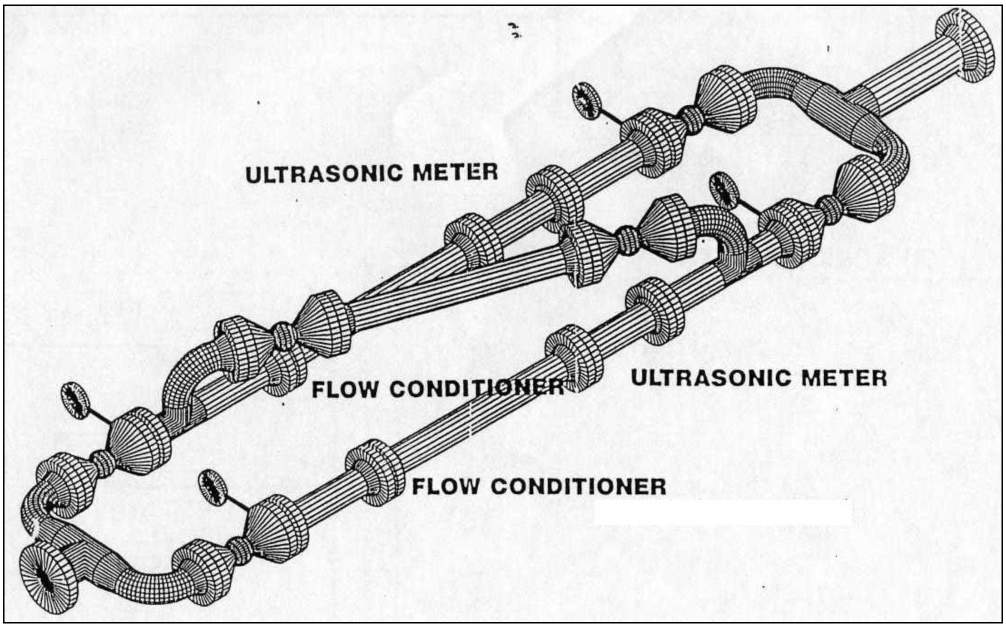


Figure 7. First instance of a z-configuration system layout for USMs

### 2.4 Diagnostics Development

The electronic nature of USM signal detection and timing hardware has meant that diagnostic data has been around for as long as the technology itself.
On the analogue hardware of early meters, information on the relative health of transducers was obtained using an oscilloscope to visually check the quality of the received ultrasonic pulses. Weakening transducers, cabling or circuitry could be identified, often before failure - a predictive diagnostic capability.

The advent of fully digital electronics brought about a step change in the development of USM diagnostics. Meters now use sophisticated digital signal processing (DSP) techniques, rather than simple voltage level triggers, and have fully automatic gain control (AGC), rather than manually configured, fixed, hardware derived gains.

It was now possible to store many digitized signals, and subject them to a series of tests to establish their suitability for inclusion in a flow velocity calculation. These tests could be carried out on individual signals or batches of signals; they could be statistical in nature, or concerned with voltage and signal levels, and pass / fail levels could be reported as “performance”, or “signal quality” indicators. These indicators, along with the ability to measure and report parameters like gain and signal-to-noise ratio made checking the health of the transducers and electronics far less of a burden.

The functional nature of these diagnostic parameters has been invaluable to operators looking to improve efficiency and lower cost of ownership through smarter maintenance. No unplanned shutdowns, no unnecessary interventions or routine replacements are required.

It is clear that these functional diagnostics offer a great deal in terms of maintenance advantages, but for the fiscal / custody transfer operator it was clear that other benefits could be gained.

The low uncertainty requirement of Custody Transfer requires multi-path meters to be used. The multiple flow velocity readings provided by these meters has greatly increased the information that the operator has about the flow conditions entering his meter. These velocity, or process, diagnostics, Zanker (2003) could be used to check for asymmetries in the flow, confirm and measure the presence or absence of swirl and cross flow, and detect and measure changes to the wall roughness of the upstream spool piece over time. Furthermore, the standard deviations of transit times within a measurement batch could be calculated, and any increase in this measurement of “Turbulence” was an excellent indicator of flow pulsation, or blockages in any upstream conditioner.

It became clear to the industry that these were powerful diagnostics tools. The most commonly occurring phenomena in gas pipelines, all of which were known to potentially affect metering uncertainty, could now be detected through diagnostics, rather than relying on costly and time consuming visual inspections e.g. Contamination of pipe and transducers; Liquid carry-over; Flow conditioner blockages and wall roughness changes.

The ability of the USM to measure the speed of sound of the process fluid has also had immense significance in the Custody Transfer metering world. Internationally accepted calculations, such as AGA-10, have given operators the ability to calculate speed of sound (SOS), based on gas composition, pressure and temperature. This information was already part of the measurement system calculations.

A comparison of the calculated and measured SOS is invaluable when trying to ascertain the health of the entire measurement system at start-up, and throughout its working life. Research into the uncertainties involved in the calculations, Letton et al (1999), meant that operators know what to expect from a well designed gas metering station, and for the first time, had a common variable which linked together all four pieces of instrumentation on the gas metering system.

Concerns about aspects of the metering system which normally go unverified can be tested using the SOS comparison e.g. is the sampler taking a representative gas sample? Is the pressure reduction system affecting the gas composition? These are all issues which would affect the calculation of energy, corrected and mass flows, but which can all be discounted if a low difference between measured and calculated SOS exists within the system.

Furthermore, in a typical Custody Transfer system, where the pressure and temperature transmitters, along with the gas analyzer, are routinely calibrated, they provide an independent verification of the calculated SOS, and can therefore confidently attribute any increased deviation to a change in the measured SOS – this would be indicative of a build up on the transducer faces which would influence the flow velocity calculations and the uncertainty of the USM.

In summary, we have diagnostics to tell us if the USM is failing or degrading, diagnostics to monitor for changes in the flow conditions entering the meter, and diagnostics to check overall system integrity, and check for transducer face contamination.

It was obvious that this metering technology had the potential to allow traditional calendar based maintenance and re-calibration regimes to be replaced by smarter, condition based methodologies. Nowhere in the world was this more apparent than the North Sea area where this potential was recognized in the measurement guidelines (BERR, 2003) of the UK DECC who saw it as a challenge to the industry to increase our knowledge and understanding of diagnostics to the point that the monitoring and analysis of these diagnostics could be used to confirm the ongoing stability of a meter and reduce the re-calibration burden that current legislation places on the operator.

One notable example of this is the gas metering system which was discussed in the 2008 NSFMW paper “On Line Condition Based Monitoring of Gas USM’s”. This paper detailed the technology and methodology that was implemented during an upgrade to a major gas import terminal in the Southern UK.
Prior to the upgrades the meters were removed on an annual basis for re-calibration, but had shown themselves to be exceptionally stable over the preceding years. By working with the DECC and the manufacturer, the operator was able to develop a data collection and analysis methodology which has been successfully used to defer calibrations on the meters since December 2007. It is not intended that this tool is used in place of traceable verification. This after all forms the very heart of international metrology. It does however; recognize the failings and issues with existing practices, Peterson et al (2008), and offers a practical alternative to bring about operational improvements for USM operators.

This work may also prove useful in coming years when, as is expected, the implementation of ISO-17089 becomes more common throughout other world areas. The ISO document acknowledges the power of USM diagnostics, and leaves the way clear for their use as a quality assurance tool, which can be used to extend calibrations intervals.

The latest development in diagnostics is that of actionable alerts. Here the manufacturers have responded to customer feedback that, although they appreciate the advantages of collecting diagnostics data, they need more practical information and less data. As understanding of diagnostics has increased it has become possible for manufacturers to identify common issues in gas pipelines, but, rather than generate data which has to be analysed by a metering specialist, the meter gives a simple description of the problem, along with some practical advice to the operator on what to look for. Some examples of these may be “abnormal profile”, “liquids detected in gas line”, “bore build up”, “conditioner blockage” or “SOS deviation”. This allows for meter maintenance without the necessity of having USM measurement expertise on site. If the maintenance cures the problem there is no need for a re-calibration.

It is also worth bearing in mind that the hydrocarbon industry faces a serious shortage of experienced engineers in the near future. Many operators are now looking to a “smart” or “integrated” operations philosophy where remote or un-manned locations are remotely accessed by a centralized maintenance team. The diagnostic ability of the USM, along with the remote connection ability of meters with, for example, TCP/IP Ethernet capability, greatly simplifies remote meter maintenance either by the customer, or by the manufacturer under a long term maintenance contract, further reducing operator OPEX and lowering the cost of good measurement.

One of the latest pieces of work done is by Pipeline Research Council International (PRCI). In this significant piece of work, members (end user operational companies) provided real data from field applications that was then compared with theoretical ideas. This was of significant benefit and details can be found in Floyd et al (2008)

## 3 STANDARDS DEVELOPMENT

It is difficult to exaggerate the importance of the role that fiscal metering operators from the North Sea area have played in the development of now globally used standards for gas ultrasonic flow measurement.

In 1998 the recommended practice report AGA-9 was released and subsequently revised in 2005. Although its committee was composed largely of members from North American gas pipeline companies, the report’s table of research literature and research activities was filled with entries from organizations from the North Sea.

Twelve years later, the industry is close to having an international standard, with ISOFDIS-17089 Measurement of fluid flow in closed conduits — Ultrasonic meters for gas — Part 1: Meters for custody transfer and allocation measurement being in the final draft stage. In the interim the widely used British Standard BS7965: Guide to the selection, installation, operation and calibration of diagonal path transit time ultrasonic flowmeters for industrial gas applications was released in 2000, then revised as recently as 2009.

Although 13 years will likely have elapsed between the release of AGA-9 and ISO-17089, the most striking feature of these documents is the amount that they have in common. This is simply a reflection of the amount of co-operation that exists between the different bodies, a reflection of the fact that safety and quality remain top priorities, and a reflection that flow fundamentals like pressure and temperature effects; wall roughness effects, protrusions and circularity etc. have not, and will not change regardless of developments in GUSM technology. Even meter uncertainty expectations have remained unchanged throughout this period.

The AGA-9 report does not classify meters, unlike the BS and ISO documents, but there is a commonality in the way they expect class 1 or “Custody Transfer” meters to perform both before and after and flow calibration, and all agree that a dynamic calibration should take place, whenever possible, to minimize uncertainty.

Unsurprisingly, the biggest evolution in the three documents is the way that they consider the diagnostic data that the meters produce, that have been discussed earlier in this paper. All three documents acknowledge the benefits of diagnostics, but it is ISO-17089 which opens up more possibilities for operators and measurement authorities. It is worthy of note that, again, the North Sea had an influential part to play. In Norway diagnostics have been used to check the health of Fiscal meters for as long as they have been in service, and the DECC opinion on USM diagnostics is very similar to the views expressed in the ISO standard.

It seems that the approach of ISO-17089, which opens the door for operators and authorities to consider and discuss the use of diagnostics to reduce re-calibration costs, is a pragmatic response to the realization that having a strict, calendar based validation methodology is proving ever more impractical and expensive, especially for the operators of larger meters in more remote areas. The industry desires the confidence all parties get from traceable metrology, but with facilities at full capacity, and an ever increasing number of meters in service around the world, it is clear that any technological advances which could improve the situation are worthy of consideration.

There has also been an evolution in the way the standards deal with installation of the meters, as the industry is acutely aware of the concerns about achieving low uncertainty performance on-site i.e. the validity of transferring laboratory derived correction factors to a customer site. It is of course possible to use flow velocity diagnostics to confirm the presence of a fully developed symmetrical flow profile, but start-up day is not the time to check for good installation!
It was therefore imperative that the standards address the issue, and it is interesting to compare the approaches.

With more of the commonality mentioned before, the earlier two documents have put the onus on the manufacturer to either:

1. Recommend at least one installation, with and without a flow conditioner, which will not create an additional error of more than +/- 0.3%, and which is supported by test data

Or

2. Specify the maximum allowable flow disturbances what will avoid creating the same additional error.

And while the original revisions of both documents also gave information of default installations, only the AGA-9 retains a default installation instruction.
Most manufacturers chose to recommend several installation options, usually backed up by independent test data, and were happy with the AGA-9 default installation recommendations

ISO-17089 has chosen a more involved " type testing" approach, where the manufacturer should provide a set of minimum upstream length requirements (Lmin) which specifies the installation requirements for the meter when installed downstream of a set of commonly encountered pipe configurations – one bend , two bends, reducer, expander etc. , and like the AGA and BS documents, the tests should be done with and without a flow conditioner, with the same limit of +/- 0.3% additional uncertainty being chosen as an acceptable deviation.

Notably, all three documents give warning to operators about the complexity of flow and installation:

"Asymmetric velocity profiles can persist for 50 pipe diameters or more downstream from the point of initiation. Swirling velocity profiles can persist for 200 pipe diameters or more. "

So there can be no doubt that operators are aware of potential pitfalls.

The fact that the standards have progressed and developed is beyond doubt, but has the development in standards improved the situation for the operators and designers of GUSM metering stations? It appears so.

For years the AGA-9 report has been a perfectly satisfactory de facto standard for the industry around the world. It's prescriptive and practical approach to selection, installation, operation and maintenance has served operators very well since its release.

Likewise, the British Standard has also been widely used outside the UK and North Sea area, and again many operators have found it invaluable. It still contains useful information on topics such as the benefits of thermal insulation, which does not appear in the ISO or AGA offerings.

If widely adopted, then the ISO-17089 looks set to further improve the work of the operator and designer. It keeps and confirms the established flow wisdom from its predecessors, but has the chronological luxury of being able to include new research and findings. It was certainly more manufacturer-centric than, say AGA-9, but in fairness the standard does not go lightly on the manufacturers, requiring them to carry out testing, and provide assurances that all are designed to make construction and operation easier. It leaves the door open for advancement in the use of diagnostics – recognising the difficulties faced by the industry, and, like the standards that have gone before, provides excellent references and appendices to improve understanding and promote development.

Here, perhaps, is a very strong case for the further integration of standards and reports, in an attempt to produce one globally accepted standard, with the obvious benefits it brings to both manufacturers producing for a global market, and also for operators as we see more and more projects transcend continents.

## 4 FUTURE DIRECTION

25 years have passed since the first gas ultrasonic flowmeters were used for custody transfer. In that time, a huge amount of theoretical, product development, practical application and standards development work has been done. As a result ultrasonic meters have become the technology of choice in the arena of gas custody transfer.

A major area of focus will be diagnostic utility. Currently, diagnostics serve three purposes. Firstly they monitor the meter's health and warn if there is a pending problem, e.g. transducer failure. Secondly they monitor the gas process and alert to any upsets there, e.g. pipeline contamination, blockages or liquids in the gas stream. Thirdly, diagnostics can alarm an operator if metering uncertainties are no longer being met, e.g. out of specification AGA10 comparison, as reported by Peterson et al (2008). In the future, meters will continue to offer these diagnostics, however in addition the technology will tend toward the ultimate position of being able to report a continuous and traceable, live uncertainty budget associated with its flow reading.

Moreover, meters will become self tuning. Today if a USM is confronted with a field issue, e.g. control valve noise; it is very unusual for that problem to be irresolvable. By having an engineer view the site data and diagnostics, a firmware fix can be applied to the meter. The knowledge required to arrive at that fix will be codified and implemented in the meter. As the device senses an issue it will implement a fix and so becomes auto-tuning.

Meters are predominately used in dry natural gas applications today. Future applications will build on our current wet gas knowledge, and meters will tend toward true bi-phase metering at custody transfer levels of uncertainty for both the gas and liquid components of the flow.

As the unit cost of USMs continues to fall with increased volumes being sold, the industrial bandwidth of the technology as it relates to custody transfer accuracy levels will increase. There will be a broader adoption of the technology within industrial gas applications.

Lastly there will be a commonality in methodologies and standards used in the global application of ultrasonic meters

## 5 ACKNOWLEDGEMENT

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# Paper 9.3

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


**Lex Scheers**
**Hint Engineering**


technology for life

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

**Lex Scheers, Hint Engineering**

## 1 INTRODUCTION

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

### 1.1 MPFM development history

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

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

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

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

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

### 1.2 MPFM and WGFM building blocks

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

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

## 2 CURRENT REQUIREMENTS FOR REMOTE APPLICATIONS

### 2.1 Remote locations

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

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

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

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

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

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

### 2.2 Redundancy

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

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

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

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

## 3 FLUID PROPERTIES

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

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

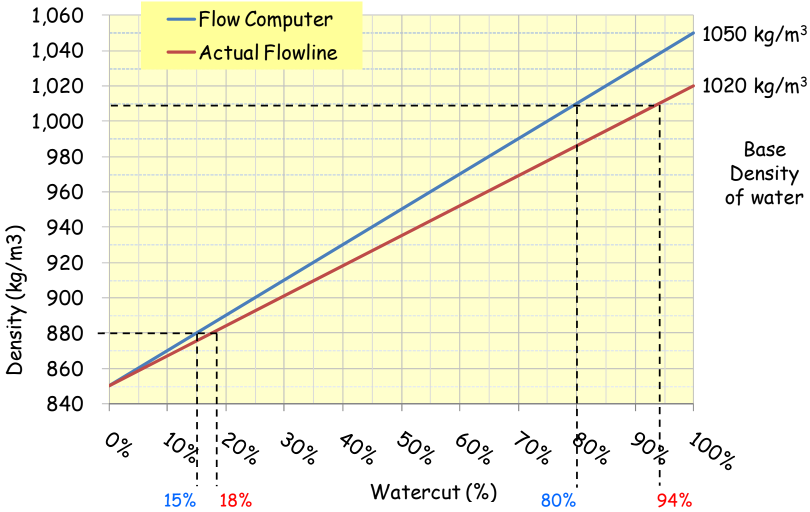


*Figure 1, Watercut determination using the density measurement of a Coriolis mass flow meter. The blue line is the flow computer and the red line is the actual density-watercut relation.*

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

### 3.1 Uncertainty (random errors) and systematic errors

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

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

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

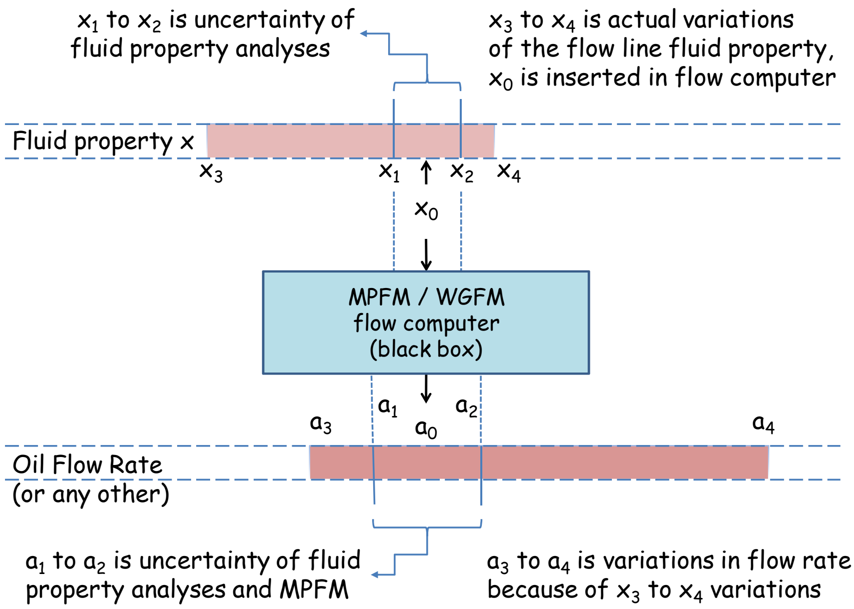


*Figure 2, Change in a fluid property has an effect on the output of a MPFM. This is a systematic effect which in case the MPFM is used for money transfer results in a loss or a gain.*

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

### 3.2 Single Energy Gamma Ray Technology

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

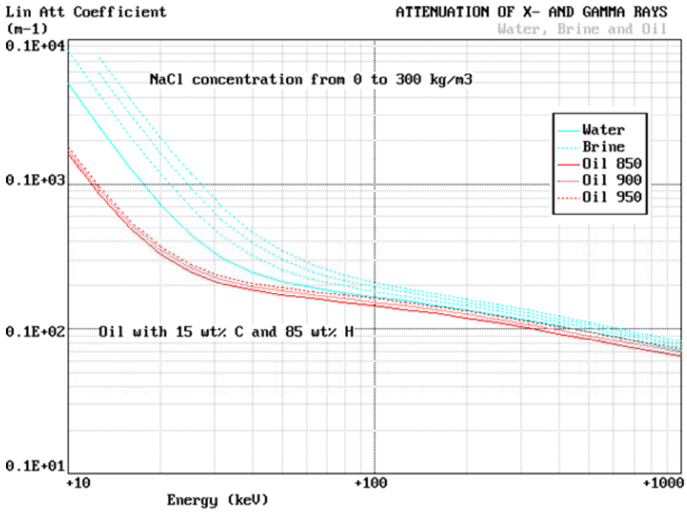


*Figure 3, For Single Energy Gamma Ray Absorption generally higher energy levels are used (mainly for gas and liquid measurement). For Dual Energy Gamma Ray Absorption lower energies need to be used to discriminate between the oil and water phases.*

### 3.3 Dual Energy Gamma Ray Technology

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

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

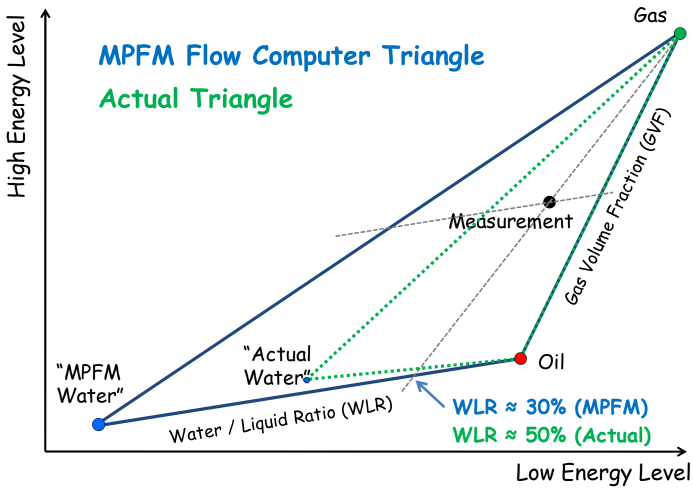


*Figure 4, The Oil-Water-Gas composition triangle for Dual Energy Gamma Ray Absorption technology with an "Actual Composition Triangle" and a "Flow Computer Triangle"*

### 3.4 Permittivity based technology

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

### 3.5 Comparison

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

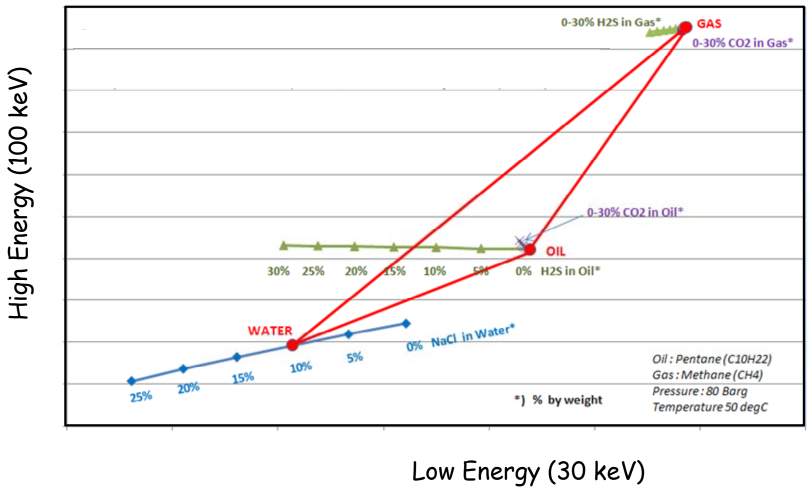


*Figure 5, Effect of heavy components on calibration triangle for a Dual Energy Gamma Ray Absorption (30 keV-100 keV) system*

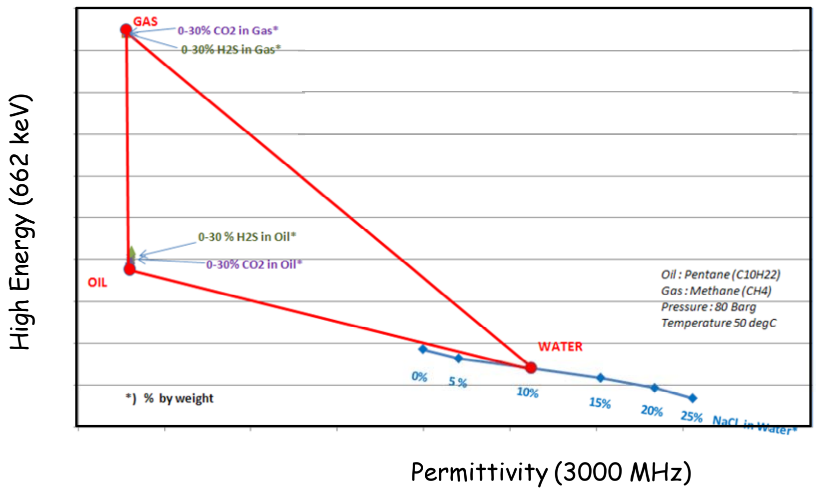


*Figure 6, Effect of heavy components on calibration triangle for a High Frequency (3000 MHz) Permittivity & Single Energy Gamma Ray (662 keV) system*

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

## 4 IN-SITU VERIFICATION

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

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

### 4.1 In-situ fluid property measurement

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

### 4.2 Use of additional components

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

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

[6] MEG : Mono-Ethylene Glycol

# 5 WHAT IS REQUIRED ?

## 5.1 OPEX and CAPEX considerations for MPFM applications

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

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

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

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

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

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

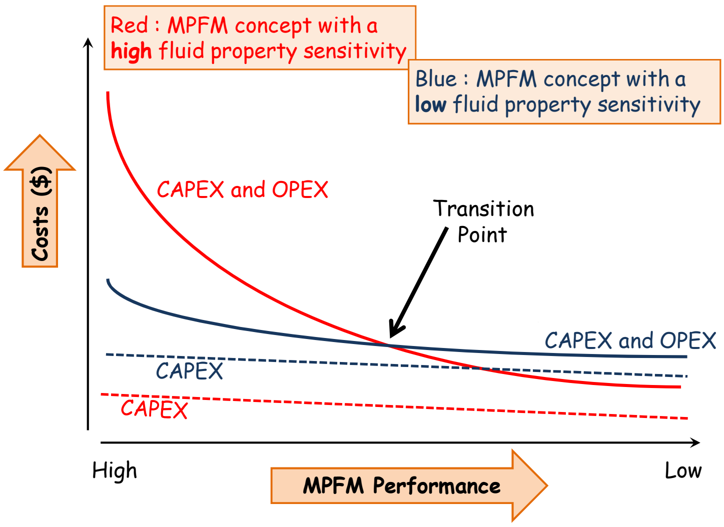


*Figure 7, Schematic of the CAPEX and OPEX for a MPFM with high OPEX due to regular maintenance (e.g. sampling and calibration) and a MPFM that can cope with changing fluid properties and thus a lower OPEX*

## 5.2 Testing MPFM's for changing fluid properties

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

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

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

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

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

1) In a flow loop exercise

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

2) Off-line with faked input signals

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

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[9]Factory Acceptance Test

[10]Site Acceptance Test

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

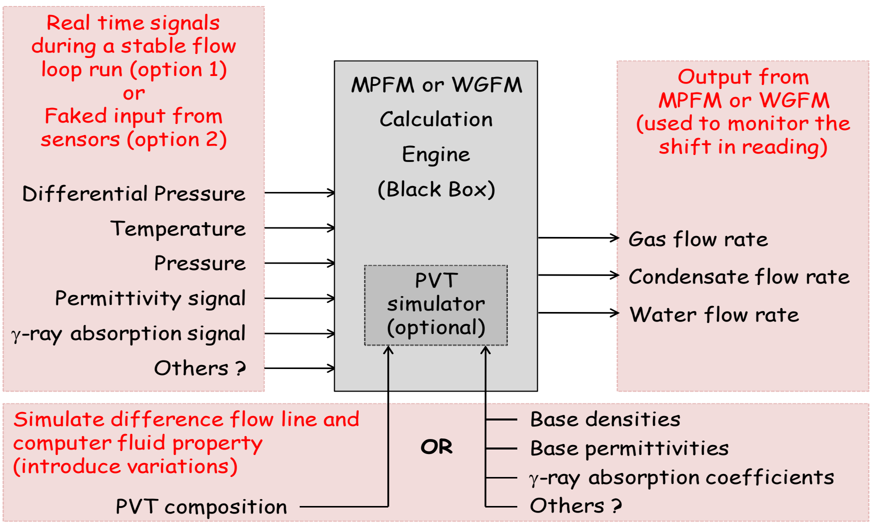


*Figure 8, Block diagram showing a method to determine the influence of changing fluid properties on a MPFM.*

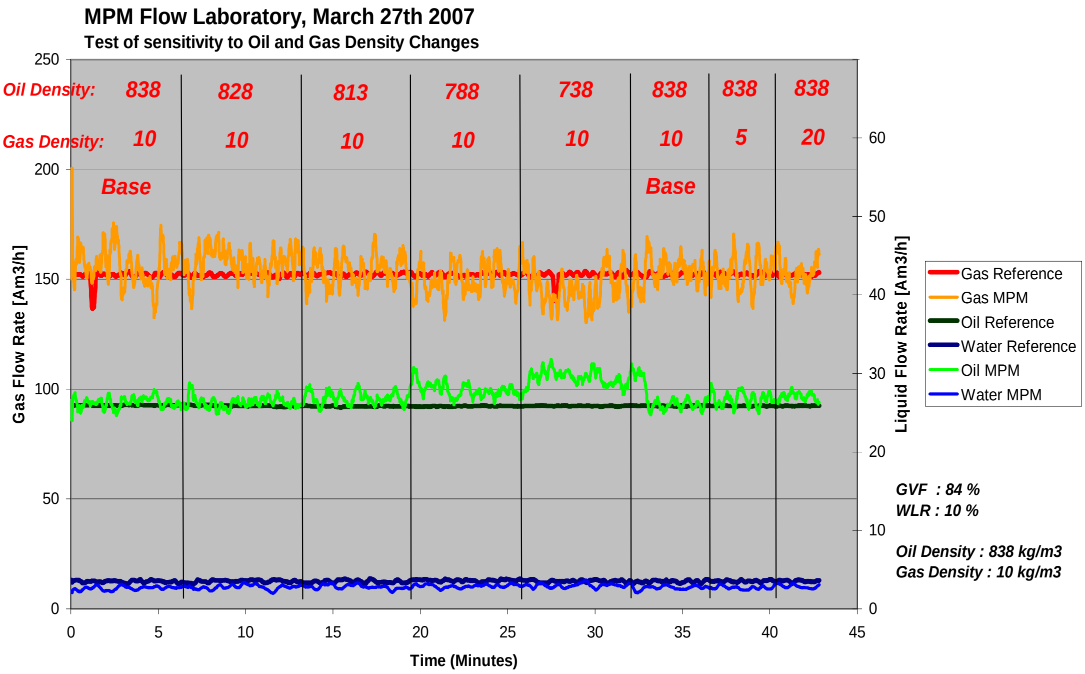


*Figure 9,*
*Flow loop run with actual oil and gas density of 838 kg/m$^3$ and 10 kg/m$^3$over time the oil and gas densities in the flow computer have been changed as indicated at the top of the graph*

## 5.3 Standard method to report the MPFM sensitivity

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

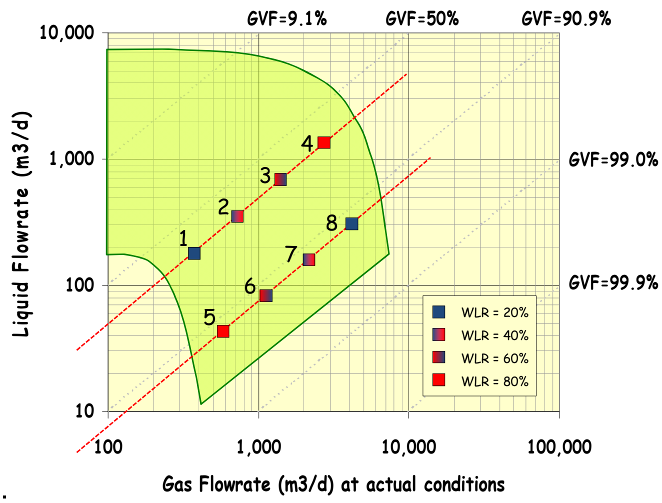


*Figure 10, As an example the fluid property sensitivity can be determined for a number of predefined points in the two-phase flow operating envelope of a MPFM, WLR should be varied in steps from 0 to 100%.*

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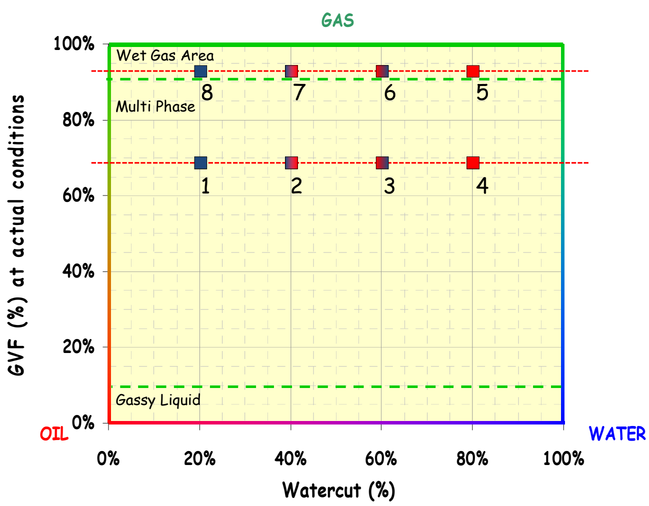


*Figure 11, The same point as in the two-phase flow map but now plotted in the composition map.*

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

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

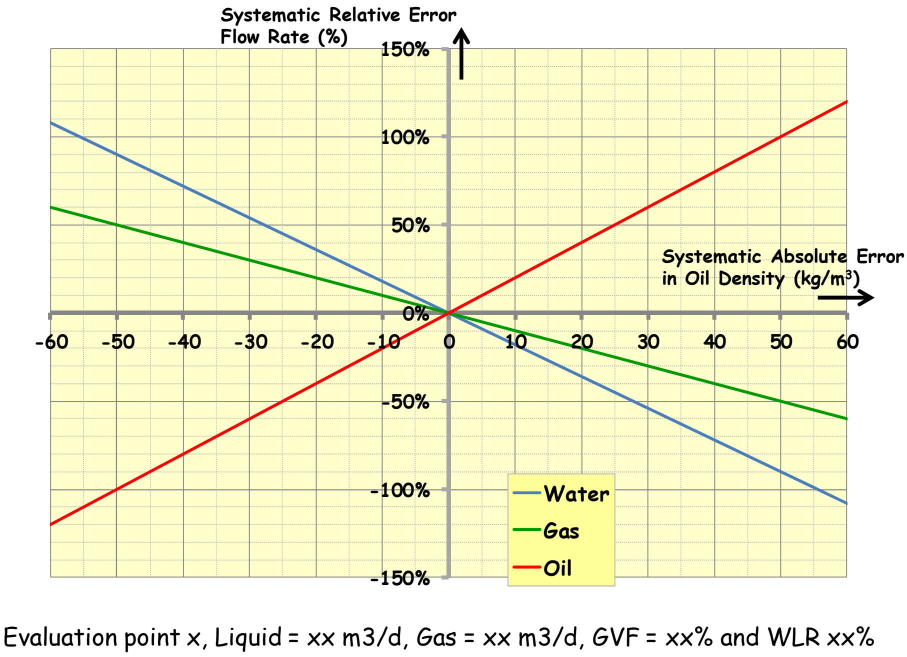


*Figure 12,*
*As an example, a standard way of plotting the systematic errors as function of difference between MPFM flow computer fluid property and the actual flow line fluid property*

## 6 CONCLUSIONS

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

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

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

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

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