Wet Gas Metering – The Unexpected Challenge
Status and Trends on Technology and Applications

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Summary

Wet gas metering is now widely regarded as a well-established technique for metering hydrocarbons. However, wet gas metering encompasses such a wide range of fluid types and equipment that caution must be used when contemplating its application. The paper reviews briefly the history of wet gas metering and sets the various techniques in a general metering context, as there are significant overlaps with single-phase gas metering and other areas of multiphase metering. The main challenges of wet gas metering are discussed. Firstly, the measurement and detection issues. Considered as a multiphase mass flow, wet gas metering, far from being a small subset of the range of applications, deals with a very extensive range of applications with an enormous range of fluid compositions. Secondly, the logistical problems because the equipment is required to operate in a wide range of conditions, but usually remote and unattended. Thirdly in terms of the organisation required to support the implementation and further development of wet gas metering techniques. The paper concludes by saying that although wet gas metering has already gained wide acceptance, we are only at the start of using wet gas metering techniques. At present each application is best considered as being unique in terms of the challenges stated above. The appropriate solution for a specific application will often draw on more equipment and expertise than is normally available from a single supplier of metering equipment.

1 Introduction

"Wet gas metering" is currently a convenient term to describe a variety of multiphase metering applications characterised by a high to very high gas volume fraction at the point of measurement. There is no easy way to define what "wet gas" means, and in discussing a specific application it is easy for confusion to arise. For many process engineers, "wet" referring to a gas implies that the gas is saturated with water vapour, but there need not be free liquid. In the metering world, however, "wet" applied to a gas means that it contains free liquid, either hydrocarbon or water or both. The term then refers, at one extreme, to the humid gas from separators expected only to contain traces of entrained liquid. It can also refer to gas from separation systems with increasing amounts of liquid carryover. At the other extreme, for some people "wet gas" is a multiphase fluid containing up to about 5% by volume of liquid. Others, like myself, consider fluids with about 10% by volume of liquid still as "wet gas". In my case, this reflects my perception of the development of "wet gas" and "multiphase" meters where for some time there was a "no-man's land" between GVF of about 85 – 95% where metering was not practicable, and this region still remains difficult. Yet another definition of "wet gas" is to use the Lockhart–Martinelli parameter, which is the ratio of the liquid and gas Froude numbers. Choosing a fairly arbitrary upper limit of 0.35 corresponds to liquid volume fractions of approximately 7% and 12% for pressures of about 4 and 100 bar respectively.

There appear to be two main application areas for wet gas metering. The first is to meter partially separated gas, and to correct the gas flowrate for the entrained liquid with not too much attention paid to the liquid measurement. The second I shall call “high GVF multiphase metering”, where it is important to take account of the liquid. In the course of the paper I will argue that wet gas metering covers a very wide range of fluid conditions and is consequently an extremely challenging area of measurement. Currently, there are a number of approaches in development and it is encouraging to see that in project development, “wet gas metering” is no longer considered as a novelty, but as a range of techniques that the project teams hope are standard. This carries with it the danger that expectations for these techniques can be too high, as I believe that “wet gas metering” is still in its infancy.

I think it is important to set wet gas metering in the context of the likely future metering world. In addition to readily accessible reserves on land, oil and gas will be produced from formerly inaccessible reserves in deep seas, in high pressure/high temperature reservoirs, from smaller accumulations, and from rework of mature fields. The cost effective development solutions for these are varied. For the remoter and smaller accumulations, full scale local processing leads to prohibitive development costs. Thus if one can commingle production from several fields belonging to different operators and allocate the production accurately without local processing, the operators can choose where best to carry out the processing, and dramatic savings can be made on field development and operating costs. Of course, this view has been put forward for many years. It led to the whole development of multiphase meters and wet gas meters and we are now beginning to achieve the benefits that these meters can bring. However, we also have a better appreciation of the inherent difficulties in implementing the technologies successfully, and accordingly it is a good time to take stock of what is required to make them really work properly.

We can therefore expect a world in which a large variety of measuring techniques will co-exist. There will often be no economic reason to replace traditional orifice and turbine or PD meters on existing fields with newer technologies, nor will there be a technical reason to do so, as is not at all obvious that the newer technologies will be “better”. For new developments, it is equally true to say that the traditional systems are probably inappropriate, and that the newer technologies will provide cost effective solutions, installed on remote, unattended land facilities, on not normally manned offshore facilities, at subsea installations, or downhole.

In many companies measurements and metering are in the remit of different departments. Production technologists or well engineers deal with downhole metering; subsea engineers are responsible for subsea metering, and metering on surface and not normally manned facilities comes into the remit of surface process and instrumentation engineers. These departments have different requirements and indeed, different cultures. Consequently it may be difficult to put together the total company requirements. The traditional metering specialists may have had little exposure to the newer measurement technologies and the hydrocarbon accountants may be unhappy to get their metering data in unaccustomed forms. Yet the basic measurements to satisfy all of these groups are the same, although the hardware which makes the measurements may appear dramatically different, and the signal processing make also be different. For satisfactory implementation of wet gas metering systems it will be important to determine and address the common issues that affect all these users.

2 Outline of development of wet gas metering

I shall now give a brief outline from my perspective of the development of the two main areas of wet gas metering, firstly "high GVF metering" and secondly, "humid gas metering". For me, wet gas metering became of importance in the mid-1980's, when two Dutch companies wanted to allocate gas production between themselves without the need for full separation and fiscal quality metering. Both companies were prepared to relax the accuracy requirements because the economics of the developments did not justify the costs of fiscal metering. In addition, the companies needed to know when water breakthrough occurred to permit good reservoir management. Thus there was already the requirement to have well diagnostic capabilities built into the metering system as well as metering ones. The liquid content of the wells was up to about 4%, a significant challenge. The approach that was considered most suitable was that of Murdock and Chisholm in which the (over) reading for gas of a DP device is corrected for the effects of liquid entrained in the gas. Murdock and Chisholm did their work using orifice meters, but we considered that a Venturi meter would be a more practical field device to provide a continuous indication of hydrocarbon throughput. Tracers were seen as the most practical way of obtaining the condensate and water flowrates. Tracer measurement would be required relatively infrequently to track the relatively slow changes in well fluid composition and would effectively be used to calibrate out the over-reading due to the liquid. The emphasis was heavily on the gas allocation, and the savings in capital expenditure were considered to outweigh the uncertainty in the liquid allocation.

This development has been well reported and the tracer technique was licensed to two measurement companies. This approach was applied in the mid-90s for high accuracy wet gas metering on Southern North Sea facilities, leading to the elimination of the bulk separation facilities. A test separator was retained for determining the liquid content of the well streams, as the tracer technique had not been fully commercialised at the time. It is noteworthy that this early implementation of a "multiphase metering" technique in the North Sea was for a "near fiscal" application. Thus in at least some application areas, high accuracy multiphase metering is practical, and this should give encouragement to those who believe that the performance of multiphase meters can be dramatically improved. There has been much activity with many applications using Venturis and tracers. Other DP devices are being tried, and automated tracer systems are being developed. I shall discuss these developments later in the paper.

I shall now discuss "humid gas" metering. In the early 1990s multipath ultrasonic meters developed for high accuracy service on gas transportation pipelines were commercially available. An obvious extension of their application was for metering gas from separators on offshore installations to higher accuracy for allocation purposes. The advantages of the ultrasonic meter over DP meters were seen as its much greater turndown, its short installation requirements, its inherent redundancy, and its diagnostic capability. A joint industry project sponsored the development of a modified multipath ultrasonic meter. Its sensors were to be resilient to chemical attack by the hydrocarbon stream, liquid was not to build up in the transducer pockets with time, and the meter would recover from slugs of liquid. The project led to the application of ultrasonic meters of different manufacture on several "humid gas" applications, with mixed success that has been reported at these workshops. Where care has been taken to ensure the meter gets a good chance to work, results have been good, but often too much has been expected from the meters in terms of their reliability for the exposed conditions in which they have been installed. Ultrasonic meters clearly can have an important role for this type of service, but much work is needed to extend their capabilities. I shall return to the current developments later in the paper.

3 What information do we need from wet gas metering?

The drive to develop multiphase metering came from the realisation that if we can meter fluids produced from wells without having to separate them into oil, water and gas we can run our business more cost effectively. The relevant areas where the metering information is required are:

- well testing, for reservoir management
- allocation metering, for determining the proportion of hydrocarbons produced by individual operators in a multifield system
- sales or custody transfer metering, where ownership of the fluids changes or taxes are levied.

However, when we apply multiphase metering techniques it is evident that the three application areas can merge into one another in technical and commercial aspects. A sufficiently accurate multiphase meters on individual wells can be used to provide the information for reservoir management, allocation metering and sales metering. It is our claim that by providing better information for managing reservoirs, and giving field developers options as to where the fluid processing takes place, multiphase metering permits more economic field development.

Nevertheless, the metering information for managing reservoirs and for running hydrocarbon allocation systems and sales systems is not all we need to know. We need information to tell us when conditions in our reservoirs are changing, if we are getting build-up of undesirable components. We need information to protect pipelines and to control the quality of discharges. The specific measurements to be made depend on the fluid composition, the processing requirements, the need to detect specific components, and the overall commercial, contractual and legislative requirements. In conventional oil and gas processing the fluid is split up into near single phase components and these different measurement requirements are met by specific equipment. It may not be possible to realise the savings from multiphase processing unless these measurements can be made on multiphase fluids. From the applications I have been involved in, I have observed that this is more significant for wet gas metering applications than for more conventional multiphase applications.

I believe that it is a major, and largely unexpected, challenge for wet gas applications to combine metering and monitoring of important parameters in the same system. However, I also believe that it is straightforward to set out the metering and detection requirements if one bases one's approach on mass component metering and detection. One simply lists the components in the stream, the accuracy in mass flowrate required, or the concentration of a component that is to be detected. This approach is compatible with any reasonable metering system, and allows everyone to see that all requirements are dealt with. It lends itself to a systematic approach to all documentation required for a project, from basis of design through to metering functional specifications and operating procedures.

4 The particulars of wet gas metering

So far I have been trying to set wet gas metering in a general multiphase context. Now I want to focus on the particulars of wet gas metering. The multiphase triangle is a useful way of showing multiphase metering applications, their variations in time, and in giving an indication of the role a particular technique may play in the overall picture.

Wet gas categories:

- Humid gas from separators
- Humid gas with entrained liquid carryover and/or occasional slugs of liquid
- High GVF multiphase fluids, GVF > (say) 90%

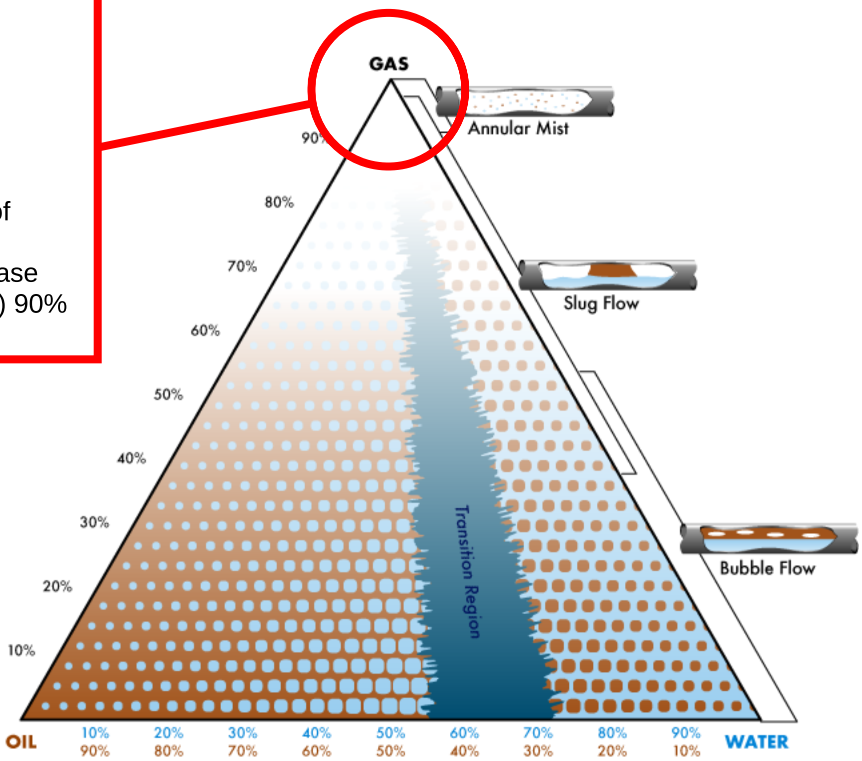

Figure 1 Multiphase Volume Fraction Triangle

Figure 1 shows the "wet gas" region at the top of the multiphase triangle in terms of volume fractions. The vertices of the triangle represent single phase gas, oil, water; the sides represent two phase mixtures of gas/oil, oil/water and gas/water; and the bulk of the triangle represents three phase mixtures. The transition region is shown where the liquid fraction can change between oil-continuous and water continuous, and some indication is given of the flow regimes for different fluid compositions.

Most multiphase meters measure primarily in terms of gas and liquid volume flowrates, and then split the liquid fraction into oil and water. Thus this representation is a valid indication of how multiphase meters work. On this plot, "wet gas" occupies the tip of the multiphase triangle, but there is no simple way of defining where the boundary with other multiphase applications lies. Some companies set it at about 5% by volume of liquids. Others, of whom I am one, extend it out to about 10% by volume of liquids. This simply reflects the history of the development of "multiphase" and "wet gas" meters as I have seen it. Several of the significant multiphase meter developments began as liquid/gas meters targeted at about 60-70% gas volume fraction, thus about 2/3 of the way along the oil/gas side of the triangle. With further development they could handle water and higher gas volume fractions, and so the performance envelope moved into the body of the triangle and up and down the oil/gas side of the triangle. It was difficult to extend the performance to GVF greater than about 85%. Wet gas metering development started at the apex of the triangle and development was targeted at handling more and more liquid. It was difficult to extend the performance to GVF less than about 95%. With the applications that I had to deal with there were several gas/condensate fields at 90% GVF. Thus there was a "no man's land" that could not be tackled by "multiphase" or "wet gas" metering techniques.

Thus wet gas appears to occupy a relatively small application area. I believe that there has been a tacit assumption that it cannot really be all that difficult to devise meters to operate in this region, but evidently we are all finding it difficult. So why, unexpectedly, is it so difficult to meter wet gas?

If we display the multiphase composition as mass fractions, rather than as volume fractions, a very different picture emerges. Figure 2 shows mass fractions for gas densities at the measuring point of 10, 50, and 200 kg/m^3 (corresponding very roughly to 10, 50 and 200 bar), oil density of 600 kg/m^3, (corresponding to a very light condensate), and water density of 1050kg/m^3 (corresponding to very saline produced water). We see how the tip of the multiphase volume fraction triangle expands to fill nearly the whole triangle at low gas density of 10 kg/m^3. 10% oil volume fraction corresponds to about 85% oil mass fraction. At medium pressures, with gas density 50 kg/m^3, it corresponds to about 55% oil mass fraction, and at high pressures, with gas density 200 kg/m3, it corresponds to some 25%. The figures also show how lower values of LVF translate into liquid mass fractions, and in particular show that for lower pressures, small quantities of liquid in volume terms account for a large fraction of the total mass. It is now clearly evident that "wet gas" occupies a very large part of the triangle, and that fluid composition varies enormously. And that, in a nutshell, is why wet gas metering is a challenging topic. Mass is a more appropriate parameter to use than volume when assessing the relative quantities and relative values of the hydrocarbon liquid and gas. At the present time, gas is worth about £100 per tonne, whereas oil is worth about £125 per tonne. Produced water has a zero or negative value – it costs you to dispose of it.

Figure 3 indicates the relative values of the liquid and gas taking into account the water cut, again for gas densities of 10, 50 and 200 kg/m^3. For lower operating pressures, the value of the oil even in high watercut liquid may be a significant fraction of the total value of the hydrocarbons. A clear message is that in deciding how to meter wet gas one needs to consider the relative values of the liquid and gas as the watercut increases. There will be a point at which it is best simply to meter the gas, and take any oil as a bonus.

These three Figures summarise much of the present status of wet gas metering. Figure 1, the multiphase volume fraction triangle, indicates how we tend to approach the topic. Figure 2, the multiphase mass fraction triangles, tell us that we must think of wet gas metering in mass fraction terms. Figure 3 tells us that there is a balance to be struck between the value of the oil in the liquid fraction, and the cost and difficulty of metering it.

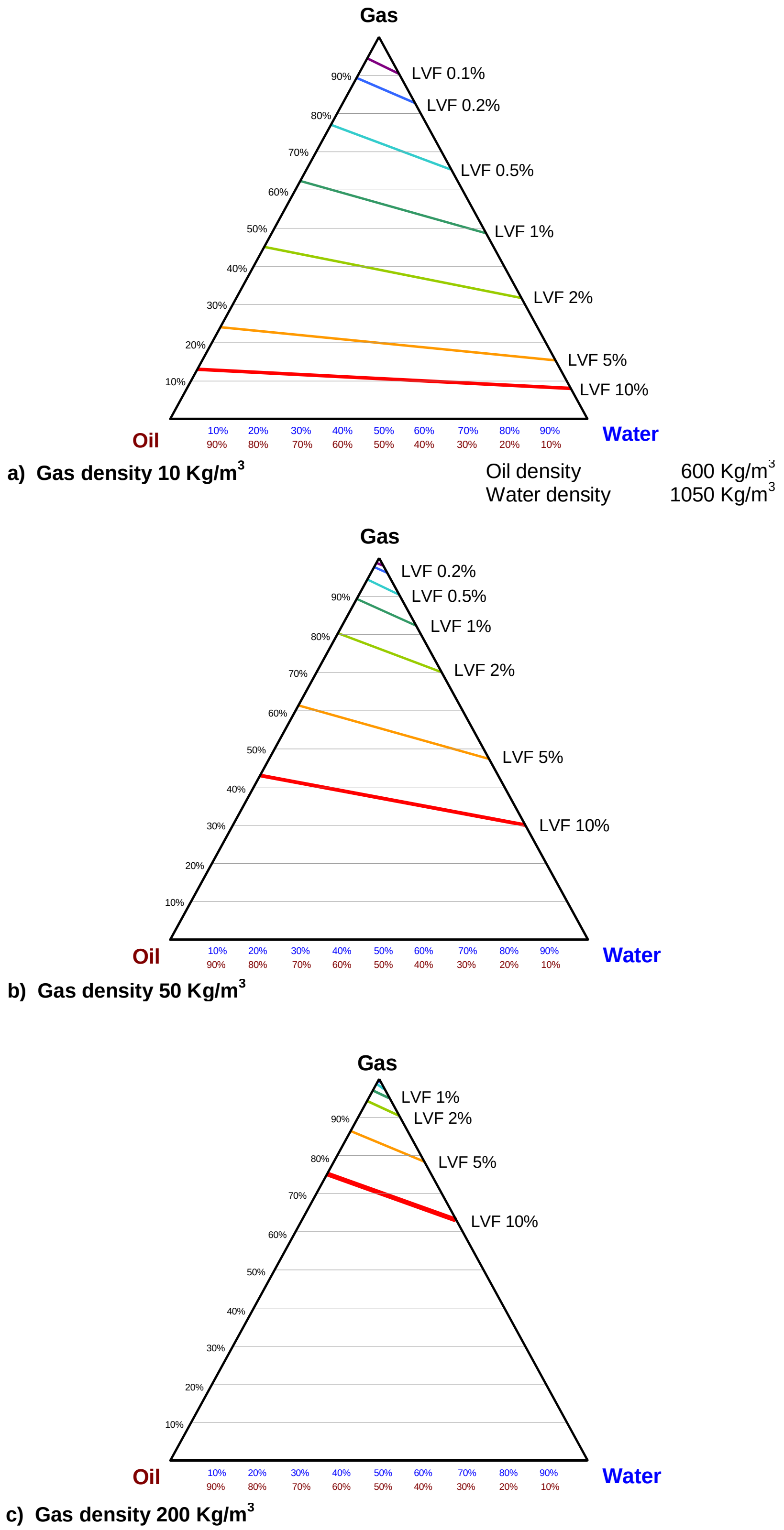

Figure 2 Multiphase Mass Fraction triangles showing Liquid Volume Fraction lines at three Gas Densities

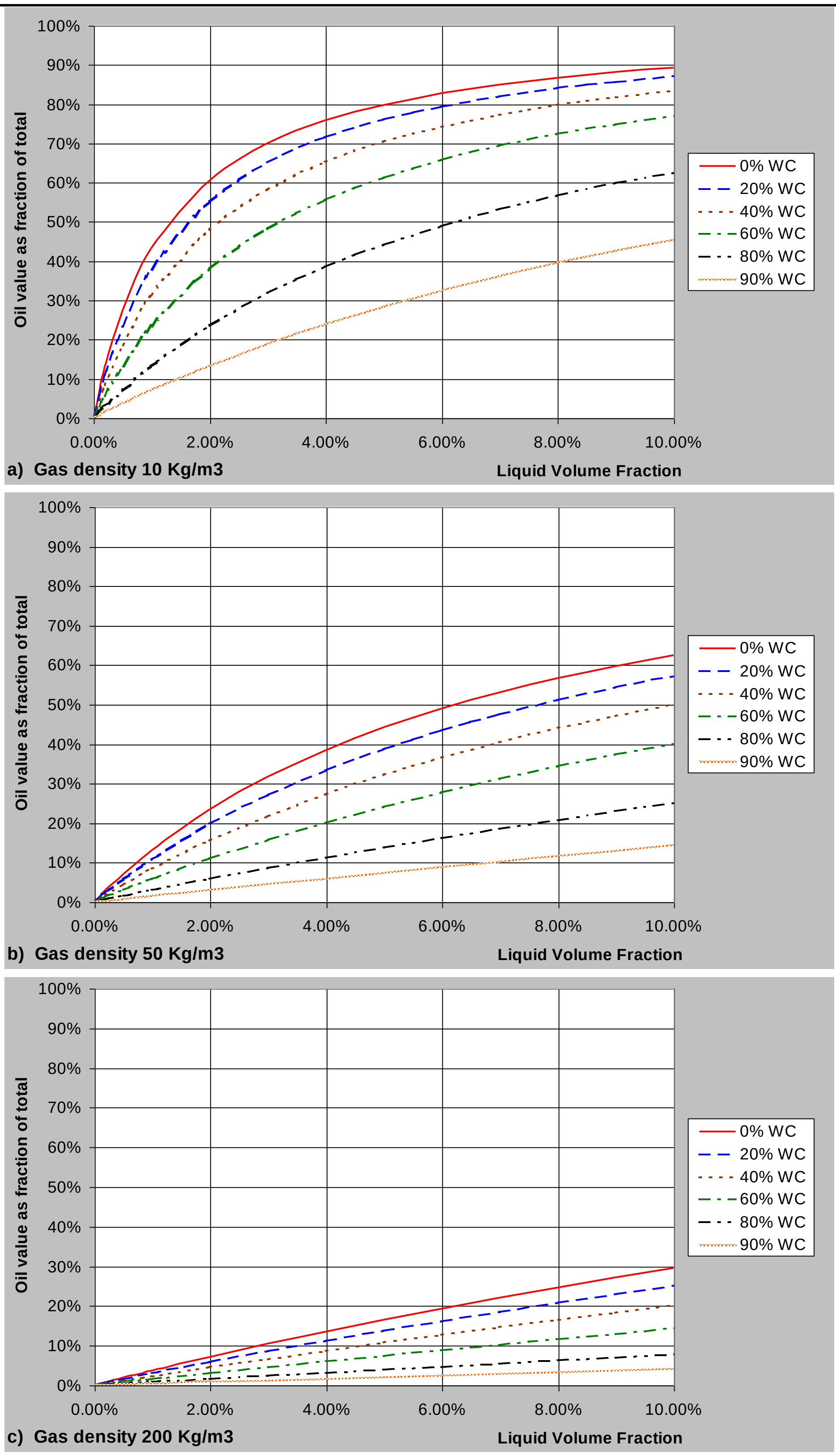

Figure 3 Oil value as fraction of value of hydrocarbons for several watercuts and three gas densities (oil/condensate density 600 Kg/m^3, water density 1050 Kg/m^3)

5 The technical challenges of wet gas metering

Ii is now evident that wet gas metering, far from being a small area of multiphase metering, actually covers an enormous range of conditions, and it is unreasonable to expect that there will be one solution that can cover all of them. I now review the technical challenges in wet gas metering.

5.1 Slip between the liquid and the gas

The major problem in wet gas metering, as with multiphase metering in general, is that the oil, water, and gas travel at different velocities. This means quite simply that the separate phases are only partially constrained by the pipe, and one no longer knows the shapes they occupy within the pipe.

5.2 Flow regimes

Flow regimes, how multiphase fluids arrange themselves, develop as a consequence of the shear forces between the phases of a multiphase flow and with the pipe wall. There are many interaction parameters that can affect the shear forces, and relatively weak interaction forces can have dramatic consequences on the appearance of the multiphase fluid. A major influence on flow regime is gravity. This is especially true for wet gas where the liquid fraction is often a light condensate that separates very quickly from the gas. For a horizontal flowline the liquid flows mostly as a stream along the bottom of the pipeline, and only at very high velocities do we get annular mist flow. At low pressures one can get slug flow persisting to high GVFs. For a vertical flowline, depending on velocity, there can be counter-currents in the flowline. The difficulties in knowing the flow regime and slip conditions for a particular application mean that it is difficult to model the flow, and without accurate flow models it is evidently difficult to convert sensor readings to accurate flow measurements.

5.3 Surfactants

In the liquid there will be natural surfactants, or there may be chemicals injected into the wells which have this effect. These affect the surface tension at the interfaces between the liquid and the gas, and between the water and the oil, modifying the shear forces between the phases with significant impact on the flow regime, and consequently on the measurements. The formation of foam in a flowline is a clear example of this.

5.4 Fluid parameter dependencies

Accurate fluid models for wet gas metering depend on knowledge of fluid parameters, and how they change with time, composition, temperature and pressure. It is well known that the viscosity of water/oil mixtures increases with water cut until the inversion point is reached and the mixture becomes water continuous instead of oil continuous. There is then a significant decrease in viscosity. Obviously, this affects the flow regime of the mixture. Viscosity, interfacial surface tension, and conductivity are strongly temperature dependent. The major effect of pressure is to change the gas density and consequently the shear forces between the phases and with the pipe wall. The relations governing the fluid properties are often highly non-linear, and poorly known for field conditions. This means that the fluid models relating sensor readings to measured flow rates have severe limitations. It is a major challenge to find practical ways to improve the fluid models.

5.5 Formation water

Breakthrough of formation water is an important issue in many wet gas developments, and is worth discussing in some detail to illustrate how the “wet gas” measurement system really has to provide more than just the metering information. A “wet gas” field may start its production life producing no formation water, and any water produced is condensed water vapour from the gas phase. An important parameter for reservoir management may be when saline formation water starts to be produced, as in a natural drive well this will be a strong indication that the well is nearing the end of its useful life.

One development option may be to close in the well on detection of saline formation water. This option may have been chosen to simplify hydrate prevention in a pipeline system. It also means that the wet gas measurement system does not have to cope with high watercut liquid and will probably have less challenging flow regimes to contend with. However, such a development option requires sensors to detect the change in salinity in the produced water. These can be installed either on the well flowlines operating in multiphase conditions, or on the total produced water stream. In the latter case extra work is necessary, because on detection of saline water in the total produced water stream, an investigation will be needed to find the individual well producing formation water.

A second development option may be to continue producing on detection of saline water. It may be that the formation water breakthrough is intermittent. In this case fairly large water handling facilities may be needed, giving rise to further metering and detection issues. If separation is done offshore from a normally unmanned facility, all of the issues of disposing of produced water arise. If, on the other hand, the full multiphase stream is being transferred onshore for processing, or to a host facility, the issues of protecting the pipeline from blockage by hydrates, or damage by corrosion arise, with again a requirement for further measurement and detection equipment.

From the discussion of this topic, it is evident that wet gas metering offers opportunities for reducing processing facilities, but to realise these benefits there are further requirements for detection and measurement equipment to give adequate control of other facilities. As these are often not sufficiently developed, the full benefits of using wet gas metering cannot be realised. It is therefore logical to include these functions in the wet gas metering system, and for suppliers of wet gas metering systems to consider providing the extra measurement and detection capability.

6 Types of wet gas meter

6.1 Those based on differential pressure devices

Currently differential pressure devices are the preferred primary elements for high GVF wet gas metering. The liquid content of the wet gas stream is determined separately at appropriate intervals, allowing a correction to be made to the gas reading and an estimate to be made of the liquid flowrate. In a sense, orifice plates fitted with drain holes have been used for wet gas metering for a long time. The work underlying the now frequently used corrections of Murdock and Chisholm was done with orifice meters on wet steam. It is likely that orifice meters will continue to be pressed into service for wet gas metering where dry condition change to wet and it is uneconomical to change to a different type of meter. Orifice meters are clearly not the best choice for new “wet gas” installations as they provide an excellent trap for debris and liquid, and there is no easy way of knowing if they are subject to build up of debris.

The current favourite primary element for wet gas metering is the Venturi meter, generally made according to ISO5167, but featuring modifications to deal with wet gas metering problems. The usual modification is to have only one tapping in the throat and upstream of the convergent section instead of the four specified by ISO5167. Obviously, if the meter is used horizontally, tappings at the bottom of the line are not much use. For some applications the divergent section has been shortened to make it fit the installation. Note that in the context of wet gas metering, ISO5167 simply provides instructions for making a Venturi meter that has a history of use in the oil and gas industry. It is convenient for vendors and users to build on this experience. ISO5167 does not cover wet gas metering using Venturis, nor even the use of Venturis for dry gas metering, although the forthcoming new edition will say something about the use of Venturis at high Reynolds numbers. The obvious advantage of a Venturi over an orifice plate is that the flow is unobstructed, and the obvious disadvantage that the throat tapping is exposed to very high velocity fluid.

A further potential advantage of the Venturi over other DP devices is to use the pressure recovery in the divergent section as an indicator of liquid fraction. In a Venturi, pressure energy of the fluid is converted into kinetic energy as the fluid accelerates into the throat, generating the DP between the upstream and throat tapping points. For single phase gas or liquid much of the DP can be recovered as the fluid decelerates in the divergent section of the Venturi. For multiphase fluids the fraction of pressure recovered is less and from the limited information available appears to be at a minimum at somewhat over 90% GVF. Between this minimum and 100% gas the fraction of recovered pressure should provide a good indication of liquid content. For several years users and vendors have been encouraged to fit a third tapping point downstream of Venturi meters to allow the total pressure drop across the meter to be measured and the fraction of recovered pressure to be calculated. It was anticipated that in a relatively short time sufficient data would have been gathered from test loops to allow useful algorithms to be developed and implemented at low cost and in the course of time eliminate the need for frequent determination of liquid content. This work still has to be done, but it still remains a promising approach to reduce the cost of wet gas metering

A competitor to the Venturi is the V-cone meter, which can be regarded as an "inside out" Venturi. It presents less obstruction to the liquid flow when used horizontally, and the downstream tapping is less exposed to the high velocity fluid. It is easier to make. There is much less experience with this meter in the oil and gas industry, but it is being tested by the industry and is being installed on some applications. It is really a matter of making this meter work by building up experience with it.

If we now consider differential pressure devices in general, any obstruction in the line can be used, for example a choke, an elbow, or even a straight section of pipe. Each device has to be characterised for wet gas conditions, entailing extensive testing on wet gas test loops, and when implemented, the characterisation needs to be checked in the field at some locations to ensure that it is valid.

Wet gas meters based on DP devices are generally regarded as over-reading the gas flowrate, with a correction applied for the liquid according to relations established by, for example, Murdock, Chisholm and de Leeuw. The over-reading varies with device type, giving different coefficients in the correction relations. If two different DP devices are put in series, it is possible to estimate the liquid content from the individual meter readings and the correction relations, potentially eliminating the need for the intermittent separate determination of the liquid flowrates. Several developers and manufacturers are pursuing this approach.

6.2 Those based on velocity sensors

Primary devices measuring velocity are used for "humid gas" metering, where the quantities of liquid are relatively small. Ultrasonic meters are most common, but I understand that evaluations of vortex meters are currently planned. In principle, velocity meters will over-read the gas velocity simply because some of the pipeline volume is occupied by liquid. If the gas is moving with sufficient velocity to entrain most of the liquid, the over-reading will approach the liquid fraction. At lower velocities there will be slip between the liquid and gas, effectively the liquid will occupy more of the pipe cross section, and the gas over-reading will increase. Multipath ultrasonic meters can determine gas velocity and velocity of sound at different heights in the pipe and it is possible that this information could be used to estimate the liquid fraction where that is part of the information requirements. To be really useful, however, this needs to be combined with density and composition to generate mass component flowrates. However, the applications where liquid fraction is important tend to require individual well flowline meters, with diameters less than 6". Unfortunately it is impractical to fit the smaller diameter ultrasonic meters currently available with enough sensors to give sufficient profile data to allow the liquid fraction to be determined.

I believe that the niche for velocity based meters, especially ultrasonic ones, is where one wants a meter for a near fiscal application, with redundancy and built in diagnostics to tell when there are problems, but where the effect of the liquid content can essentially be ignored for the application in hand. Note that at low pressures, Figures 2 and 3 show that it takes very little liquid to have a significant effect on the meter performance. Looking at further development, the sensors of velocity measuring meters, namely the piezo-electric transducers of ultrasonic meters and the variety of detectors used in vortex meters have fast response times. Accordingly they can produce a great deal of information that could be used to characterise multiphase flows and could be used in pattern recognition meters.

6.3 Multiphase meters

Extending the capability of "conventional" multiphase meters to high GVFs is an obvious way to tackle wet gas metering, and several manufacturers have already sold their products for this service. One need not be surprised if a multiphase meter that contains a Venturi flow element performs well in metering the gas fraction of a wet gas stream. The real issue is whether the oil/condensate and water fractions are metered sufficiently accurately for the application in hand, and cost effectively. At high GVFs measurement of watercut is still relatively poor, about 5% uncertainty for the best multiphase meters. This has a large impact on the oil/condensate uncertainty. From one viewpoint, a multiphase meter may appear to be an expensive way of buying a Venturi meter with some additional capabilities, but from another viewpoint it may be cost effective to buy a reasonably complete package from a reliable vendor who can provide comprehensive service. The real alternative, which I think is technically better at present, is to build up a wet gas metering system for the application in hand from individual components to meet all the metering and detection requirements. However, this may put demands on internal resources that are too high or simply not practicable for many project teams.

There are few means at present of testing a multiphase meter for operation on a wet gas application under representative conditions. The laboratory test loops that are available have difficulty in accurately reproducing field conditions, and the algorithms developed using them may be flawed. It is practicable today to monitor data from field installations and learn much from occasions when comparative data is available, but again this means dedicating resources for data monitoring that many companies are not prepared to do.

6.4 Tracers

Tracer measurement techniques have been important for wet gas metering since its inception. The principle is simplicity itself and it is an absolute one. One chooses as tracers substances that mix well with one of the oil, water and gas phases of the wet gas flow, but not with the other two phases. The substances are ones whose concentrations can be determined accurately using appropriate equipment. The substances are either injected directly into the flowline or made up to a known concentration and then injected. The injection rate is measured. Some distance downstream, sufficient to allow the tracers to mix well with their respective phase, one takes samples of the three phases. It does not matter that these samples be representative of the multiphase fluid, only that the tracer concentration in each phase reflects the average flow rate of that phase over the injection period. The flow rate of the phase in question is then given by the injection flowrate of the tracer multiplied by the ratio of the injected and sampled tracer concentrations.

Put like this, tracer measurement should be an analyst's dream. One can choose the tracer substance; one can choose the method of detection from the vast range available. In principle by increasing the accuracy of the injection flowrate and by choosing more sensitive detection methods one can achieve very high accuracy, certainly better than near fiscal accuracy. Automating the process to make it suitable for not normally manned facilities or even subsea is a matter of good engineering, as there are no fundamental problems in doing this. The range of applications is the whole range of multiphase compositions, with different accuracy requirements depending on application.

In practice, tracer measurement for wet gas has progressed significantly, but not nearly as far as was expected some ten years ago. One can give a long list of reasons for this, but it really comes down to lack of sufficient applications where the technology is perceived by the users in the oil and gas companies to be really needed to focus development. The consequence for the suppliers is that they have to carry the very considerable costs of developing equipment for an uncertain market, and therefore they can only progress where they can see realistic returns.

Although the principles of tracer measurement are simple, in practice considerable skill is required to make good, reliable measurements. Choosing the correct injection rates and making sure the samples are taken properly is time consuming and details may vary significantly from application to application. The tracers currently available are fluorescent dyes, suitable for water and condensate/oil. Extensive experimentation is still ongoing to find a good tracer for the gas phase, thus there is as yet no complete multiphase tracer system. Work is ongoing to develop reliable high-pressure analysis for the fluorescent dyes. For the time being, the liquid samples have to be flashed to atmospheric pressure for analysis, and correction made for the shrinkage. This limits the accuracy obtainable, but it is still practicable to get oil/condensate and water measurements to about 1 – 2%, significantly better than can currently be achieved with multiphase meters. Automating the systems for use on unmanned facilities is in practice difficult, going further and making the systems suitable for subsea application and compatible with standard wellhead configurations is orders of magnitude more difficult.

Another serious problem is what to do if the flowrate of a phase varies significantly within the time that a sample is gathered. Because the tracer concentration decreases as the flowrate of the phase to be sampled increases, the average concentration of tracer over the sample gathering time does not correspond to the average flowrate, leading to significant errors. A way round this is to sample faster than the variations in the flowrate, or to monitor the tracer concentration in the sample continuously, neither of which is easy to do.

It is also possible to use natural tracers to allocate the production coming from different fields. The condensate/oil and water may contain low concentrations of readily identifiable compounds. The concentrations of these in wells of a particular field are unlikely to vary significantly, but are likely to be quite different in another field. In the geochemical fingerprinting technique, the oil/condensate phases of the different fields are analysed for several, say eight, tracer compounds and their relative proportions established for each field. From the proportions of the trace compounds in the combined stream it is possible to work out the relative contributions from the contributing fields. This approach has been applied on lower GVF fields, but could be applied to wet gas fields if there are suitable trace compounds. This approach has the advantage of low capital cost, requiring only sample points to give the individual well fluids and the total production fluid. It is subject to the same constraints on varying flow rate as the normal tracer technique, and it does require considerable expertise to achieve good results.

I believe tracer techniques are vital to multiphase metering in general, and wet gas metering in particular. Tracer techniques offer the potential of a practical, absolute means of checking or calibrating multiphase or wet gas meters, but much work has still to be done before a comprehensive service can be provided for the enormous range of applications and potential locations.

6.5 Pattern recognition approach

These systems are characterised by their use of simple sensors combined with complex signal processing. I believe that these systems have the potential to offer the cheapest hardware combined with the highest metering performance. A major benefit from this approach will be targeting low cost solutions for specific applications.

The signals from sensors used in most metering applications are damped to reduce noise and give a good average value of the measured parameter. In the pattern recognition approach the fluctuations are what is important, and the average value may not be used at all. An analysis is carried out of the amplitude and frequency fluctuations of the sensor signals and a large number of "features" are calculated. These characterise various aspects of the signal. Thus each sensor, instead of generating only one parameter, can generate perhaps thirty "features".

There are tests available find the most significant features and then neural networks are used to calculate the oil, water and gas flowrates. Other mathematical techniques could have been used, however. The essential point is that the fast fluctuations in multiphase flow carry most of the information. By using heavily damped sensors the fine detail is lost with the consequence that multiphase meters using heavily damped sensors are unlikely to achieve high accuracy. Using fast sensors and pattern recognition signal processing, virtually unlimited accuracy should be possible, but one is faced with the difficulty of providing highly accurate calibration data for the meter.

Applying this approach to wet gas metering is a question of testing sensors in wet gas conditions and finding those that generate the most useful features. The signal processing system must then be trained to recognise accurately the range of flow conditions for the application in hand. One of the characteristics of the wet gas region of the multiphase triangle is that the liquid mass content varies rapidly. I find it difficult to believe that one cannot find sensors that respond sensitively to the liquid content.

7 The logistical challenges of wet gas metering

Wet gas metering can be applied in many different areas of the world, and in different parts of the process, for example downhole, subsea, or on the surface. The measurement and detection techniques are fundamentally the same, as are the data processing techniques. Nevertheless, in many companies these applications are handled in quite different ways. The packaging of the equipment has to be appropriate for its environment and will therefore be different, but this should not determine the function that the equipment has to perform. It is a major challenge to align the different approaches of the various departments within companies on measurement issues.

As one of the main reasons for using wet gas metering is to reduce the cost of production facilities, this means that there will be few personnel at the production facilities, whether they are on land or offshore. The few personnel who are on site are unlikely to have a deep technical knowledge of the wet gas metering system. Furthermore each wet gas metering system will have its own novelties. Put altogether, this means that companies using wet gas metering have to address significant logistical problems in where to locate equipment and staff, and in how to handle equipment failure. At one extreme, one can have all equipment and trained personnel on or adjacent to the facility. At the other extreme, one can have only the sensors on the facility, their readings transferred to a central location, say, by Internet, and all computations done at the central location. The sensors on the facility would be mounted in a redundant configuration, with built in diagnostics to give warning of problems so that maintenance can be scheduled within the normal visits. And there can be all the variations in between these extreme options. I believe that the fully automated option is the one that will give the most cost-effective systems, but much work is required to make it fully practical.

8 Organisational issues

I now consider the organisational context of wet gas metering. Figure 4 gives a representation of the interfaces involved in any metering and measurement system. I shall describe these in general terms, and then discuss wet gas metering in this context.

At the centre of the diagram there are three circles designating facilities and their design and upgrading. These are the parts of organisations where facilities are operated, upgrades are implemented, and new facilities are designed and constructed. In general, staff operate on relatively short timescales. Operators are concerned with the day to day and week to week requirements of keeping facilities running. Those involved with upgrades are concerned with achieving the upgrade in the coming shutdown, and those involved with the design and construction of the new projects concentrate on achieving these in the shortened timescales of fast track projects. In these areas of activity, equipment has to be tested and proved before installation – there is no time for developing new equipment.

Round the central area is a ring of activities that I have split up into operational support, audit, and new technology. Staff employed in these areas requires to interface inward with the central activities and outward to a variety of organisations in the outside world. The horizontal line halfway across the diagram splits those activities needed to keep facilities running from those needed when an operation is actively developing new fields and is

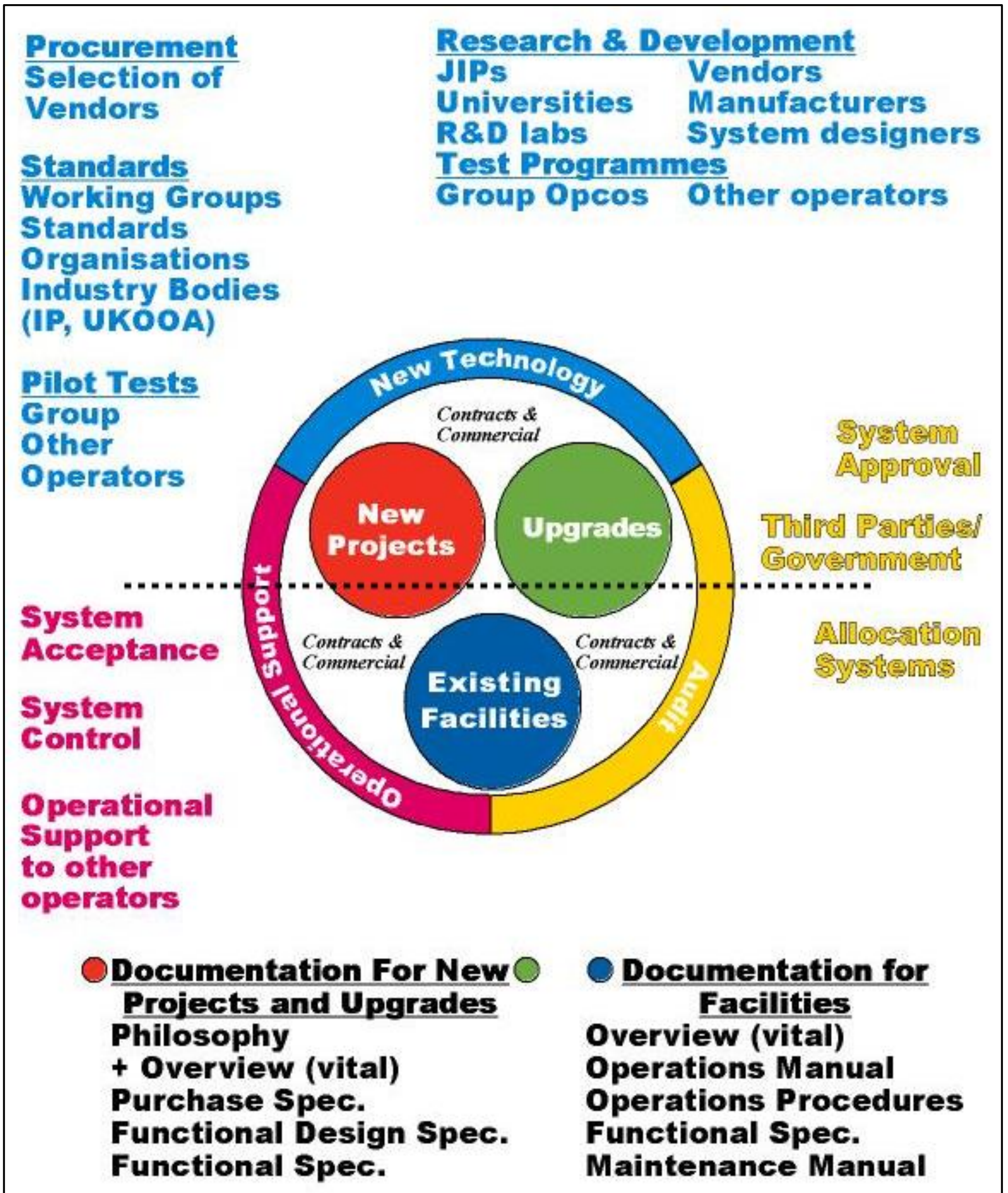

Figure 4 Overview of organisation, constraints and interfaces involved in implementing metering technologies

actively pursuing innovative approaches. It is evident that almost all of the external interfaces are associated with new technology.

Commercial and contractual issues are a significant feature and are best considered as a background environment against which other activities take place. A similar diagram could be drawn from a commercial viewpoint, but there everything takes place in a technical environment. This simply emphasises the fact that commercial and contractual constraints impact on technical solutions, and correspondingly, technical constraints determine the practicality or otherwise of commercial and contractual agreements. When applying new technology or novel commercial and contractual strategies the consequences of not considering other viewpoints may be significant.

Obviously the relative sizes of the activity areas vary from company to company, but my experience in the North Sea has been that the distribution of activities was about as shown before the fall in the oil price in 1998. Currently, I would say that the balance of activities in the North Sea has moved distinctly to keeping things running, with the emphasis on new technology moving to other parts of the world. This is dangerous for the long-term future of the North Sea oil and gas industry, as I believe that clever approaches will be required to keep the North Sea viable.

I have also added two boxes dealing with documentation requirements for new projects and upgrades, and documentation for running facilities. Much documentation supplied is not user friendly – it is often very difficult to get an overview of what a metering system is supposed to do, and often functional design specifications are compilations of vendor literature that frequently are not relevant to the job in hand. Operations manuals and maintenance manuals can be obscure and difficult to keep up to date. I consider that documentation can be made more effective if it is written around an overview of the information flow through the metering and measurement system. Information is gathered from the sensors, is processed in the flow computers, and is handed off to the user. In modern systems, information within the system can be passed back to the sensors from the stream or supervisory flow computers. If the documentation is a collection of manuals of the individual items in the system, it is difficult for anyone to follow what is going on. If one begins with a diagram giving an overview of the information needed to manage the operation and where it comes from, the system documentation becomes a set of descriptions of the information flow in different terms. This can start with the earliest equipment enquiry. The vendor can respond in a way in which nothing is missed. The functional design specification for constructing the system can be readily transformed into a functional specification that can be a live document throughout the facility lifetime. In a similar way, the operating and maintenance manuals can be written around the diagram of information flow through the system. Further, the overview diagram, if integrated into the system electronics, provides a natural entry point to electronic documentation. This approach to documentation is especially relevant to wet gas metering because of the fragmented responsibility amongst the parties putting the system together.

I will now discuss wet gas metering in the context of Figure 4. Although wet gas metering is reasonably well established in some companies, across the industry as a whole the technology is not really mature. The enormous range of potential applications on the multiphase triangles of Figure 2 confirms this. Thus for most companies, wet gas metering is essentially new and just about every item shown on Figure 4 is a learning point. To use wet gas metering effectively, they need to participate with other companies and organisations to address the interface issues. At present, the division of responsibilities between operator, project team, design contractor, metering vendors and their subcontractors, combined with the contractual processes commonly used, make it difficult to implement new technology, where there is a good chance of something unexpected interfering with project plans. Furthermore, the contractual and commercial infrastructure for trading wet gas is not well established. Again, the wide range of applications calls for a flexible approach rather than trying to force all applications into standard categories.

There are as yet no standards for "wet gas metering". In my view, it is not practicable at this time to write definitive standards to cover such a wide range of potential applications. Guidance to prospective users is clearly needed, but as many users will be tackling new situations, they will have to do things that are implicitly non-standard. In the UK the standard approach is for a licensee to propose a metering solution for a development which is backed up by standards, test data, operational experience, and reasonable extrapolations from these to cover the new situation. Acceptance is given, usually with a requirement that there be a fall back position if the extrapolations to the new situation are not realised in practice. Sometimes there is no realistic fall back position because the metering scheme was proposed to reduce the total capital and operational costs involved in a conventional system. In such cases one has to be even surer that extrapolations regarding performance of an unproved system are reasonable.

Such an approach is flexible and encourages innovation, and in my opinion is essential to bring wet gas metering to maturity. The UK authorities maintain confidentiality on such proposals, but in my opinion there is little commercial advantage to be gained from keeping the details of metering systems confidential. However, there is a lot to be gained by every one if details were readily available. Operators could be encouraged to make details of their systems available. In this way a portfolio of good and less good practices could be built up, and at appropriate intervals could be distilled into recommended practices to be issues by standards authorities.

9 Conclusions

"Wet gas metering" is clearly an important and challenging area of multiphase metering. It is difficult to give an all-embracing definition, and at present each application is best considered unique. Consequently it is better to focus on the measurement and detection requirements of applications and design systems accordingly, rather than seek a "standard" solution. In practice detection of critical parameters is as important as metering unseparated flow if the full benefits to a field development are to be obtained.

Liquid content varies enormously over the "wet gas" range. The small liquid volume fractions translate into large mass fractions, and so a large fraction of the value of the produced fluids comes from the oil or condensate. This means that wet gas metering systems should be based on mass component flow.

To improve the performance of wet gas metering systems much work is required. There is a need for better fluid models, better sensors and a better understanding of how they behave over the wet gas range; extension and improvement of tracer techniques; and application of pattern recognition techniques. There is also a need to gather performance data from test installations that accurately represent field conditions, and to develop practical methods of gathering comparative performance data from the field.

The industry wide infrastructure for wet gas metering is rudimentary. There is relatively little experience in operating companies, design houses or among vendors. Standards organisations are only beginning to tackle the task of producing meaningful guidance. I believe a flexible approach is needed, setting functional requirements rather than prescribing equipment that must be used.

Although wet gas metering is a complex area of metering, it is clear from the work and effort to date that there are no really fundamental obstacles to improving wet gas metering. It simply remains for the industry to make the investment to realise the benefits.

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.