North Sea FLOW Measurement Workshop

1998

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PAPER 1 • l

AMERADA HESS LTD'S FIELD EXPERIENCE AND REQUIREMENTS FOR FLOW MEASUREMENT AND PRODUCTION ALLOCATION.

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AMERADA HESS LIMITED'S FIELD EXPERIENCE AND REQUIREMENTS FOR FLOW MEASUREMENT AND PRODUCTION ALLOCATION

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1 INTRODUCTION

The object of this paper is to review the Amerada Hess' experience of metering in the last ten years, and explain the rationale for its current requirements for flow measurement. It also suggests the direction that we would like future developments to be focused.

Amerada Hess first operated North Sea production was in 1989. Since then, the Product Movements Section of the Company has been responsible for metering and allocation of a variety of oil fields operated from fixed platforms and floating production vessels. The various metering requirements for these facilities are determined by the need to safeguard the interests of the fields' Partners, the Government's tax revenues and the interests of the pipeline and downstream processors' shareholders, but also by commercial pressures to keep costs down.

As the UK's North Sea province has matured and the amount of premium rate Petroleum Revenue Tax has declined so has the need for the DTi to act as the Government's policeman in metering matters. There has been a change from the prescriptive formulas used a decade ago to the pragmatic approach being adopted today. This change is very much appreciated by the industry, and has made it possible to use new metering technology in marginal field developments, raising economic return to both oil companies and Government.

However, the industry has a long way to go before it can truly be considered up-to-date.

A major limit on progress is the continued use of rigid measurement provisions in inter-company contract agreements, which were possibly appropriate once, to ensure minimal standards across the board, but now often just result in expensive equipment and manpower being assigned to measure and allocate small value products. This is particularly a problem for oil producers with associated gas and NGL production.

The objective of construction project teams to minimise capital investment is often at odds with Product Movements' needs for hardware and software which remains useable for a significant period of time. This conflict can sometimes be worsened if the project engineer is unfamiliar with the specialised equipment used in oilfield flow measurement.

2 FIELD EXPERIENCE

The experience we have had with the AH001 semi-sub. production platform is typical of our experience with other facilities, and will be described in some detail. The other facilities, the Scott platform, and the leased Uisge Gorm and Glas Dowr will be described only to highlight other issues.

2.1 AH001

The metering equipment installed on the AH001 semi-submersible, AHL's first production facility, was typical of many platforms up to the late 1980s. It was installed with subsea tie-backs to three operated fields, Ivanhoe, Rob Roy and Hamish (IRRH), each fiscally distinct.

Export of oil is by pipeline to Flotta, and export of gas is to British Gas, via the Frigg pipeline system. The metering systems were designed to satisfy DTI, British Gas, and Pipeline Operator stated criteria.

2.1.1 Oil Fiscal Meter

Three parallel turbine meter streams complete with Meter prover, Twin densitometers, grab sampler, and manual sample/pyknometry point in pumped by-pass loop

The original Sarasota Flow Computers were replaced soon after start-up by Solartron 7915 instruments.

Spot samples were taken every 4 Hours for determination of water-in-oil by centrifuge in the Installation's Laboratory (for dry oil allocation)

A Weekly composite sample is taken and assayed onshore (for dry oil valuation)

2.1.2 NGL

Originally an orifice meter was used to measure the NGL spiked into the crude upstream of oil meters. Flow calculations used a fixed density with no pressure or temperature corrections within the Servelec Database system.

This was replaced by a Coriolis mass meter soon after start-up.

2.1.3 Gas Fiscal Meter

Three parallel orifice meter streams fitted with dual DP cells, originally connected to Sarasota Flow Computers. These were replaced soon after start-up by Solartron 7915 Flow computers.

H_2S, H_2O, grab sampler, on-line chromatograph (fitted soon after start up), and manual sample point in a vented fast sample loop.

Originally, weekly composite samples were taken and analysed onshore (for Pipeline allocation)

2.1.4 Test Separator

Gas Orifice Meter with single range DP cell. Fixed density was used in the Servelec Metering Database. No allowance was originally made for well testing.

The Liquid Orifice plate meter was replaced by a Coriolis mass meter soon after start-up

Produced Water measurement is by an Electromagnetic Meter

Manual sampling points for oil, water and gas.

The sample points were all upgraded to sample probes shortly after start up.

All flows were originally calculated in the Servelec Database Computer. A dedicated Solatron 7915 Flow Computer was fitted soon after start up.

2.1.5 Production Separator

Gas Orifice Meter with single range DP cell. Fixed Density was used in the calculations being made in the Servelec Database Computer. Upgraded to dual DP cells, and dedicated Solatron 7915 Flow Computer shortly after start-up.

Produced Water measurement is by an Electromagnetic Meter

Manual sampling points

All metering data was collated, reports printed, etc., by a Servelec Database Computer changed out shortly after start-up for a custom built MaxiVis / DAI computer (including parallel onshore workstation) soon after start-up

A schematic of the AH001's current equipment is shown in Fig 1.

2.1.6 Equipment Replacement

The need to replace some of the AH001's equipment so soon after first oil start-up has been typical of our experience in several developments.

The replacement flow computer and database software is easily configurable in the field, handles all the major calculation routines with ease and the mechanical and electronic hardware operation has been trouble-free since installation in 1991.

The installation of the Solatron computers gave the opportunity to replace the database computer. The chosen replacement was of industry-standard manufacture. The computer itself, with an engineer's keyboard and monitor and its I/O electronics, resides in an equipment room offshore. The primary colour display, specialist operator keypad, and colour printer are located on the console in the Central Control Room. A workstation onshore in Aberdeen provides a comprehensive 'mirror' of the offshore facilities, with the additional facility of a WORM disk system. (The WORM drive was used as the long-term archiving facility for the data, reports, and trend information, allowing us to look back in detail at any production period since the system was commissioned. These functions have been superseded to a large extent by our AMADAES system, although we kept the WORM facility in use until recently.)

Using a combination of a security key held by the OIM offshore and separate passwords held by the offshore technician and by the metering engineer in Scott House, it is possible to modify configuration data from onshore, and to operate some of the facilities. This capability was used during early operator training actually to conduct proving from Aberdeen.

This computer is capable of a wide range of useful functions:-

Versatile input / output handling, including analogue current loops, voltage status signals, current or voltage pulse handling, and frequency counting. Not all of these are used in our application.

2.1.7 Configurable Database

A powerful operator-programmable spreadsheet capability exists, with security protection. We use this facility to generate automatic period reports, printed proof reports, Well Test reports, automatic gas nomination telexes, etc. If we need to add new data to a report, for example, this is easily achieved from the onshore workstation, under security protection. An added reassurance on security is that the system archives previous versions of updated configuration files.

A powerful operator-configurable trending utility is available, usable on any tag in its database, with a selectable time base. This is used by the onshore metering engineer (as easily as it is by the offshore technician) for diagnostic purposes if there is any question on the performance of e.g., field instrumentation, or on process upset. Snapshots of trends may be sent to a colour printer if required.

The system is powerful, but simple to operate, with the facility to build mimics. These are used for example:-

> To allow the Control Room Operator to control meter proving (including the opening and closing of block valves, or sending a set point to flow control valves) from the integrated keypad.
>
> To give an overview of flow, temperature, pressure and ESD valve status throughout the Flotta and Frigg pipeline systems
>
> or to monitor / initiate well tests, etc.

2.1.8 Water-in-Oil Determination for Allocation

We believe it is worth the effort to continuously monitor the allocation results from the various pipelines into which we export our fluids. Although much of our effort is automated this is still manpower intensive.

This monitoring made us aware of continuous anomalies in the allocation of fluids from one pipeline system, which had substantial financial implications to the Partners. These anomalies were examined by a major, multi-discipline Third Party Audit, whose broad conclusion was that imbalances could probably be ascribed to the determination of water in oil elsewhere in the pipeline system. Subsequent prolonged discussion and R&D at NEL led to the adoption across the system of a determination of water-in-oil content by Karl Fischer coulometry, based upon new 24-hour flow-proportional samples acquired by a separate grab sampler. We anticipate upgrading this to on-line Water-in-Oil measurement in the near future. Current balances are now effectively low to neutral.

2.1.9 Gas Analysis for Allocation

A pipeline system gas allocation is calculated on the basis of the composition of each contributing field's inputs into the pipeline. This was traditionally determined by analysis onshore of weekly flow-proportional samples from each field.

The management and handling of sample containers both full and empty is invariably labour-intensive, occupying a specialist technician (who needs to know what he is about) for several hours weekly. When they go astray, shore-based Product Movements, Materials, and Logistics personnel know just what a time-consuming nuisance they can be. In addition, there is always the question of just how representative is the sample acquired in the event of inevitable process upset or minor miss-handling of the container.

The chromatograph's frequency of analysis is such that its results accurately reflect the composition of gas fed into the pipeline, and is automatically recorded along with the flow at all times. The instrument is calibrated automatically at least once per week. Otherwise, its operation is, to all extents and purposes, 'hands off'. In the event of anomaly in the results from the weekly sample sent onshore, chromatograph results were used.

The results from the on-line gas chromatograph are continuously recorded and archived automatically by our metering database/supervisory computer on the AH001. Because of the onshore workstation, results can be scrutinised by specialists, and compared with historical trends, at any time.

Results from the onshore analyses were also logged, and compared with those from the chromatograph.

The proven reliability of the on-line chromatograph, the accuracy of its determinations, and of our automatic recording of its output were all acknowledged by Pipeline Operator, the gas

Buyer, and by other pipeline users, who agreed to its use in the allocation system in place of the weekly composite sample.

We have saved several hours of expert technician time each week. We are more comfortable with the timeliness of the analysis data going into the allocation system on our behalf, and we were running the chromatograph and monitoring and recording its results in any case.

We have adopted the same approach to analysis for gas allocation in our later systems where possible and appropriate. However, we may still be forced by rigid agreements to acquire and analyse onshore periodic samples.

2.1.10 Renee-Rubie Fields

The advent of the Phillips Petroleum Company operated R-Block fields (Renee and Rubie), whose production is expected to start this year as subsea satellites to the AH001, has necessitated major changes to the installation's process equipment, and therefore to its metering systems as shown in Fig. 2. As these fields have relatively short field life a major objective has been to keep metering costs as low as possible, and in particular to make use of the recent advances in ultrasonic metering technology to remove the need for bulky and expensive separate multi-stream meters and meter provers.

A new First Stage Separator has been installed. It is dedicated to R-Block fluids. Vapour from this separator is fed forward to the shared compression and drying facilities. Its hydrocarbon liquid stream joins the feed from the IRRH wells to be input into the existing, now shared Production Separator.

Water from the R-Block Separator is processed in a dedicated hydrocyclone system.

R-Block Separator vapour flow is determined by two single-path ultrasonic meters in series with a flare line take off between them. The hydrocarbon liquids are metered by a 5-path ultrasonic meter with a pumped fast loop containing an on-line water-in-oil meter, density transducer and manual sample point. Produced water is measured by an electromagnetic meter. New Solartron flow computers have been installed to interface stream measurement (see Fig.2).

The AH001 MaxiVis metering supervisory/database computer has been upgraded to cope with the new inputs and will perform the allocation calculations on an hourly basis. Each calculation will have separate reports archived for input data used, output data calculated hourly allocation report and most importantly, a validation report giving details of possible inaccurate allocation.

Inter-Field oil allocation will be by quantifying the dry oil leaving the Renee Rubie Separator, and calculating the IRRH share of Oil Export by difference. The Flotta Operator will carry out value adjustment, to take account of the different qualities of the respective fluids. Gas Allocation is somewhat more complicated and includes calculation of the ownership of the NGL spike. An offline calculation is performed to provide pseudo-oil export assays, based on well compositional data.

2.2 Scott and Telford fixed platform

Scott is a major oilfield located about 8km north of the AH001. In essence it has a similar separation system to the AH001, except that NGLs are recycled through the main separation process, rather than being spiked into the main oil line export, as on the AH001.

When Telford, a subsea satellite field with different field Partners, was tied into Scott two years ago the drive to reduce capital expenditure lead to the decision to use process simulation to determine the hydrocarbon allocation between the fields. This was principally because the size of the meter that would be required to measure total flow was large, and thus expensive, and the uncertainty in the measurement of the large Scott flow would magnify the uncertainty in the calculation of the Telford share of the Oil Export flow. However, the use of equation-of-state process simulation has proved to be difficult and time consuming in operation. We spent a lot of money in attempting to fully automate this allocation system, but found this to be an almost impossible task. The system is currently an off-line manual calculation.

2.3 Uisge Gorm and Glas Dowr Floating Production and Storage vessels

2.3.1 Uisge Gorm

Two fields are currently processed on the Uisge Gorm, Floating Production Storage and Offtake (FPSO), with a third field being brought on later this year. The lack of gas export, and straightforward oil-export by tanker means that overall metering on this facility is very simple.

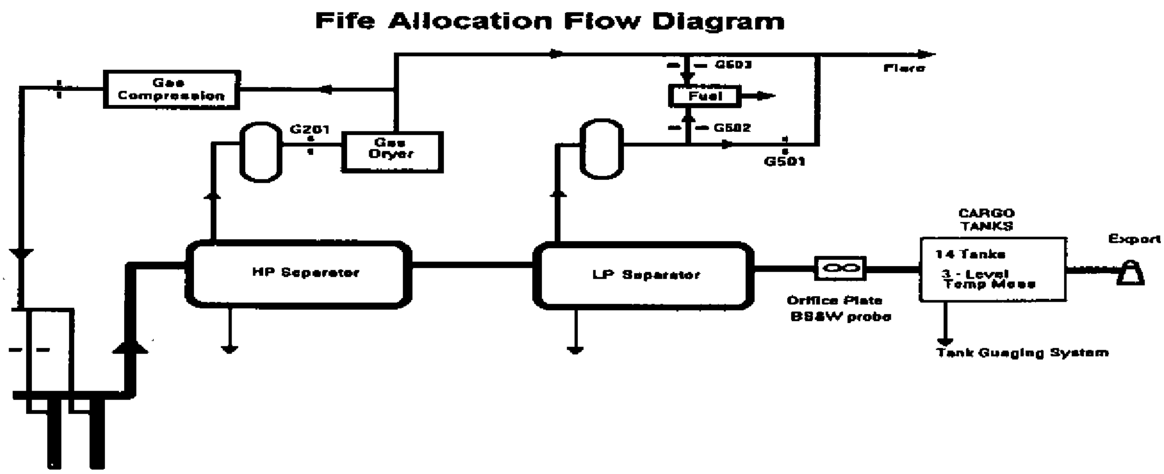

Fig 3 Flow measurement equipment on the Uisge Gorm FPSO.

The allocation of production to fields is by well test.

Originally crude oil in storage was to be measured by radar tank gauges. This proved to be unworkable. Instead the stabilised oil export to the shuttle tanker is measured by a clamp-on ultrasonic flow meter. There is no gas flow measurement, apart from on the test separator.

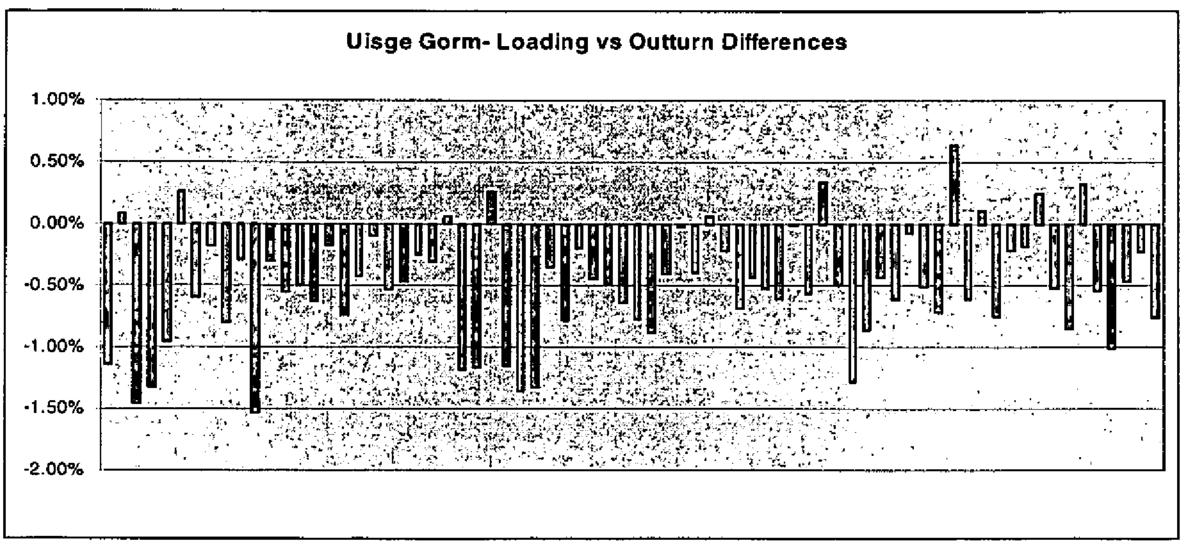

Fig 4 – Outturn discrepancies Uisge Gorm.

Tracking the quantities determined on the Uisge Gorm (see Fig. 4) with respect to those determined at discharge ports has shown marked differences between the two locations. With the exception of a very few cargoes, these are overwhelmingly negative. We would normally have expected the differences to be closer to zero, with an approximately equal number of positive as well as negative discrepancies.

Either the vessel's meters are inaccurate, or the method of determination at the ports is inaccurate. It is not possible to say which is the correct method.

2.3.2 Glas Dowr

As a result of our experience with the Uisge Gorm, the Glas Dowr which is currently on Durward and Dauntless fields, utilises an extensive network of ultrasonic meters. These have the advantage of low maintenance and enhanced accuracy, giving major benefits for process and field management.

The more sophisticated measurement system on the vessel, where the fluids produced are tracked as accurately as possible at various stages throughout the process, is expected to add the reassurance of internal consistency to the performance of the meters, and to safeguard our interest if cargoes must be discharged when the vessel's export meter is not available for some reason.

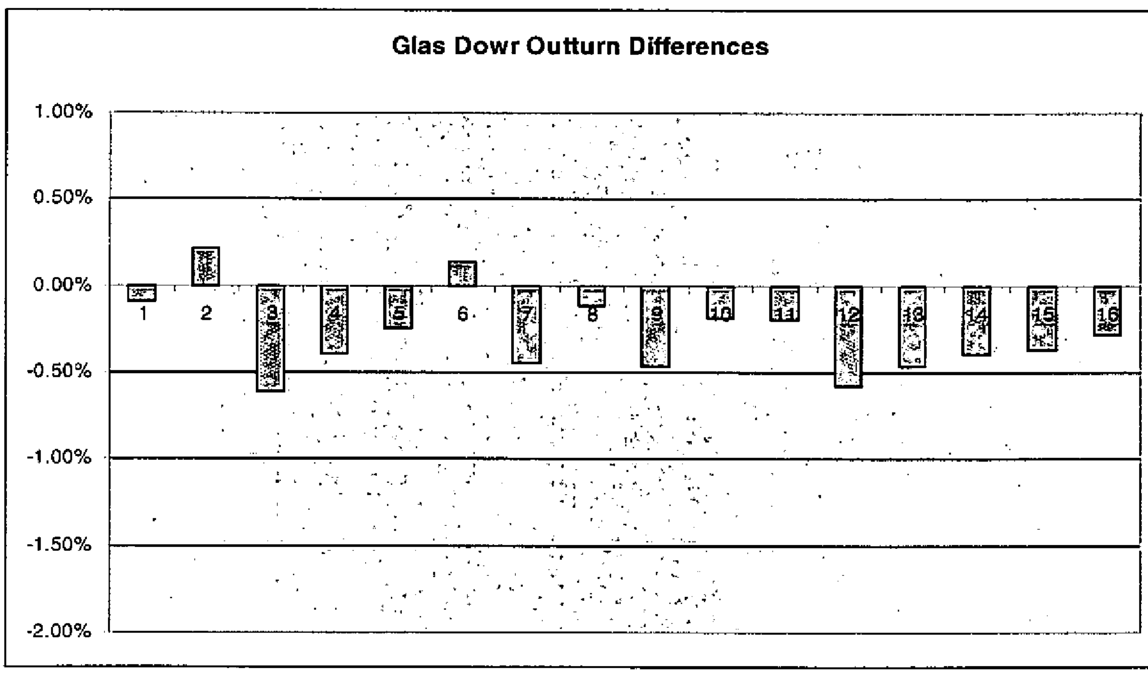

Fig 5 – Outturn discrepancies Glas Dowr

3 PROJECT CONSTRAINTS

The need to replace much of the AH001's equipment so soon after first oil start-up has been typical of our experience in several developments.

Much of it is the direct result of the pressures construction projects face to minimise capital investment. The other influence is the frequent lack of metering experience of the project engineer involved, for whom this equipment is 'just instrumentation'.

This tends to force them to buy equipment considered to be that 'always used' for the particular category of service, or "fit for purpose" i.e., minimal specification and cheap equipment which is not suitable for the installation's lifetime use. Unsuitable, for example, by virtue of the fact that it requires frequent attention offshore from scarce, expensive, specialist technicians, or because its use forces the need for repeated manual transcription of its data within the allocation calculations, etc.

For example, the conventional wisdom as seen by many project engineers, and frequently by the commercial person drafting an agreement, is that an orifice meter is the method of choice for gas flow determination even though, because of the limited measurement range of an orifice plate meter they require duplicate pipework and meters, which is very expensive in terms of weight and space. The benefits - technical, financial and in operational use - available from using, instead, a multi-path ultrasonic meter, which appears initially to be a very expensive instrument, may not be apparent to either project or commercial personnel.

We sometimes suspect that a project engineer's judgement of an equipment's 'fitness for purpose' may be based on uncritical acceptance of claims made by its manufacturer. The Amerada Hess Product Movements Section's consistent approach is to urge aspiring suppliers of equipment to have the equipment's performance verified by e.g., NEL or similar independent body, or by extensive testing under 'real life' operating conditions.

4 ALLOCATION

The objective of allocation is to split costs and revenues equitably according to the contracts developed by the companies involved in the production and transportation of hydrocarbons.

A good Allocation System should follow the following rules:-

1. It should be Fair and Equitable
2. It should be fully Auditable
3. It should as far as possible, reflect Reality!

4.1 Non-systematic Errors

Broadly speaking measurement errors which are likely to be random and non-systematic are unlikely to be of concern if they cause relatively small overall miss-allocation of costs or revenues.

For example, a common situation might be two oil fields, owned by different Partnerships, being produced through a single FPSO. Modelling the effect of errors in each measurement in the system, for typical flow rates and measurement uncertainties, might look as follows:-

		Typical Value	Uncertainty %	Dry Volume Error % Field A	Dry Volume Error % Field B
Oil to Storage					
Volume	m^3	15000	0.15	0.15	0.15
Temperature	degC	35	0.5	-0.014	-0.014
Pressure	barg	2	0.5	0.001	0.001
Oil density	kg/m^3	850	0.2	0.007	0.007
BS&W	%	2	1.0	0.0007	-0.0007
Water Density	kg/m^3	1050	0.5	-0.0003	0.0003
Effect of uncertainty in Field A's separator oil outlet measurements					
Volume	m^3	9000	0.15	0.06	-0.09
Temperature	degC	44	0.5	-0.008	0.01
Pressure	barg	40	0.5	0.0007	-0.001
Oil density	kg/m^3	820	0.5	0.008	-0.01
BS&W	%	15	1.0	-0.06	0.1
Water Density	kg/m^3	1030	0.5	0.03	-0.05
Effect of uncertainty in Field B's separator oil outlet measurements					
Volume	m^3	5000	0.15	-0.05	0.08
Temperature	degC	40	0.5	0.006	-0.01
Pressure	barg	30	0.5	-0.0005	0.001
Oil density	kg/m^3	830	0.5	-0.03	0.05
BS&W	%	10	1.0	0.2	-0.3
Water Density	kg/m^3	1040	0.5	-0.02	0.03
Effect of uncertainty in Test Separator oil outlet measurements					
Volume	m^3	1000	0.15	-0.009	0.02
Temperature	degC	40	0.5	0.001	-0.002
Pressure	barg	30	0.5	-0.0001	0.0002
Oil density	kg/m^3	830	0.5	-0.001	0.002
BS&W	%	25	2.0	0.03	-0.06
Water Density	kg/m^3	1045	0.5	-0.01	0.02
Overall Error %				0.25	0.36

The errors listed above are for positive applied errors. Because of the differences in production between the two fields, and the different oil and gas properties and gas-oil ratios, the effect of negative applied errors is not quite the same as for positive applied errors, but the absolute size of the difference is very small compared to the overall size of the error.

Clearly the most important measurement is the oil volume measurement, as all other measurements lead to very small overall errors, and if both Fields A and B were owned by the same Partnership there would be very little need to meter these to the accuracy shown above, unless there were some over-riding fiscal requirement because of, e.g., different PRT status for one of the fields.

The real usefulness of the spreadsheet used above is to investigate the effect of deviations from expected operational performance. For example, should the water content determination in Field A's separator oil outlet drift, for example, to 10 percent, then the overall error would be expected to increase from 0.25% to 0.64%.

4.2 Systematic Errors

Most oil companies would not be concerned to measure to these accuracies if they were thought to be truly non-systematic. Although the actual value of the miss-allocation is relatively high, for example a 0.25 % error in 80 Mbopd is equivalent to £0.8 million/year, it is still only 0.25% of the total annual revenue. The error could be in either field's favour.

However, we do need to ensure that unfair advantage may not be gained because one party or another plays on anomalies in the assessment of 'random' uncertainty.

The real value of vigilant metering and hydrocarbon accounting occurs when the errors are not systematic. This is generally the case in the North Sea for oil fields of different stages of maturity exporting in to common pipeline systems. Most of the major oil pipeline systems were put in by the owners of the giant oil fields found in the early days of North Sea development. These fields are generally producing at high water contents, through platforms which are no longer in their first flush of youth, where there is little commercial incentive to export essentially dry crude, and uncertainties in the determination of their export water content may be significant for the allocation of commingled fluids to other users of the shared pipeline. This is in contrast to the small fields which Amerada Hess has typically produced from over the last decade. These relatively small fields start off dry, so they have rather different characteristics to the giant fields.

Because of our experience of the effect of miss-allocation of water and oil in shared pipeline systems we place particular emphasis on water content determination in oil exported from our operated platforms. However, we have not yet defined internally exactly what our standard for this should be. It still is the case that the cost of measuring water content to a high standard is still a small fraction of the potential harm that can arise through not paying sufficient attention to this source of error. Typical measurement errors which we feel comfortable with at the present time are those listed above, although we would welcome new technological advances which would help improve the water content determination further.

5 RECENT CHANGES IN REGULATORY REGIMES

5.1 Change in DTI Policy

The changes that the Department of Trade and Industry have made to offshore metering requirements have been profoundly beneficial. The dictum 'Let commercial forces dictate standards and methods' is exactly what is required, bearing in mind that Government is also one of the commercial forces acting on oil companies producing in the North Sea, and that the DTi has statutory obligations, including a new emphasis on environmental concerns.

This sensible approach is welcomed, with the only caveats that:-

- The shortcomings of others are very difficult/expensive to prove
- Data is difficult to gather from others, and everybody's allocation is inter-dependent
- Many Operators are short-handed, so can not scrutinise allocation properly
- It is difficult for a single Operator to complain effectively in the face of inertia from others

The DTi, however, can and has acted swiftly to right wrongs. Commercial pressure can be slow-acting, and if disputes go to law the resulting costs can be expensive and time consuming.

The DTi has had a major influence in promotion of new technology within the UK metering business. For example, the use of onshore computer terminals at the DTi linked to AHL's offshore installations has reduced the need for DTi audit inspections offshore, with consequent savings to both Operator and Government.

However, as the DTi scales down its operation there is a need for another organisation to take the lead, and set direction for the future. The North Sea Flow Measurement Workshop should be part of the debate that is required.

5.2 Gas

One of the most significant changes in the UK North Sea is the changed position since BG lost its monopoly position as buyer of gas. The Network Code now sets ground rules, while individual agreements specify the detail. This has considerably enhanced the economic attractiveness of the numerous small gas accumulations in the Southern North Sea, as their owners can sell their gas to the independent gas marketers, as for example, Amerada Hess Limited has done to its downstream subsidiary Amerada Gas.

Making agreements which are appropriate for the new fields with the long-standing agreements for gas transportation and sales is one of the major challenges affecting oil companies. There is a need to strike a balance between getting agreements as tight as possible, because recourse to the Law is very expensive, but also the relatively small size of most of the new fields precludes lengthy negotiation.

The large variations in gas prices that are available to sellers may invite disruption, regardless of agreements, since it may be more profitable for the buyer to accept legal cost than to accept supply. This may have a major impact on oil production.

As gas may now be traded as a commodity, with an hourly nomination regime, the timescale for needing operational production data has become much smaller, forcing increased dependence on accurate current data, with minimal operator intervention. Fortunately the technology needed to achieve this is available, and this trend is forcing more standardisation of software and hardware.

6 FUTURE NEEDS, FUTURE TRENDS

Equipment reliability and maintainability has improved dramatically. From an Operator's perspective we hope this will continue to get even better in the future. There is thus a gradual shift in AHL's effort, from focus mainly on metering matters requiring technical specialists, to more and more attention to allocation issues.

The DTi, BG and Pipeline Operators all have audit rights, and the Pipeline Operator has a special duty to protect interests of other users. As offshore equipment improves, the need for frequent audit is reduced.

There is a substantial effort by several meter manufacturers to make multiphase flow meters, some for subsea operation. There is no doubt that this technology will be of very great value to Operators, but so far our experience has been that we have had more value from downhole flow measurements than from topsides or subsea multiphase meters. However, we are still very enthusiastic about the potential of the technology. It has however, a poor track record for reliability, mainly because of interface problems between equipment from different suppliers.

Although the current low oil prices have meant that the North Sea exploration activity has reduced, the industry will respond and we expect to bring on more fields in the years to come. The economics however, are likely to be marginal, so, once project sanction is given, the timescale for any development will always be short. To help make sure that we keep overall life of field costs down we are in the process of developing company standards to allow flow measurement to be better integrated into the Project schedule than we have achieved in the past.

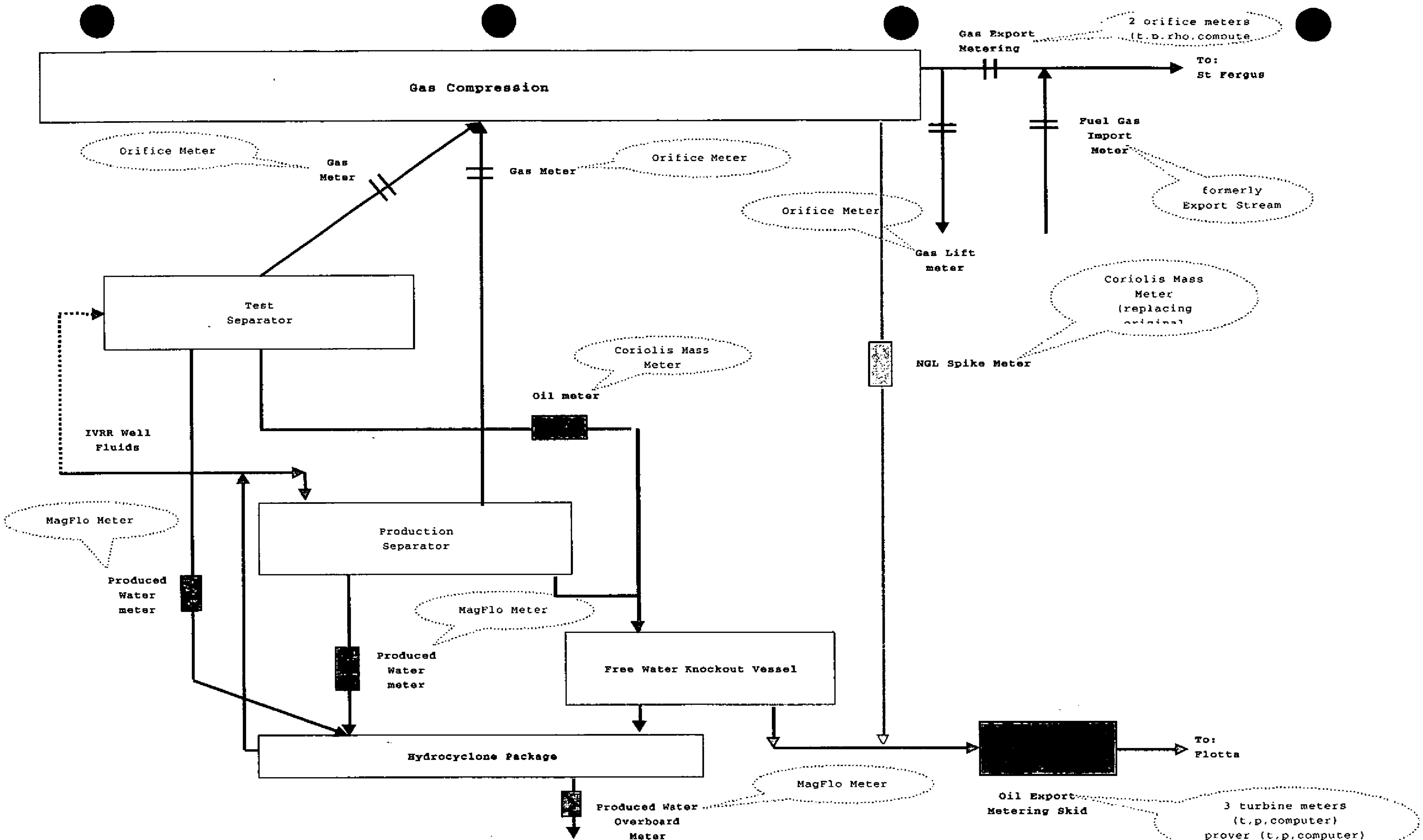

Fig. 1 AH001 original metering system

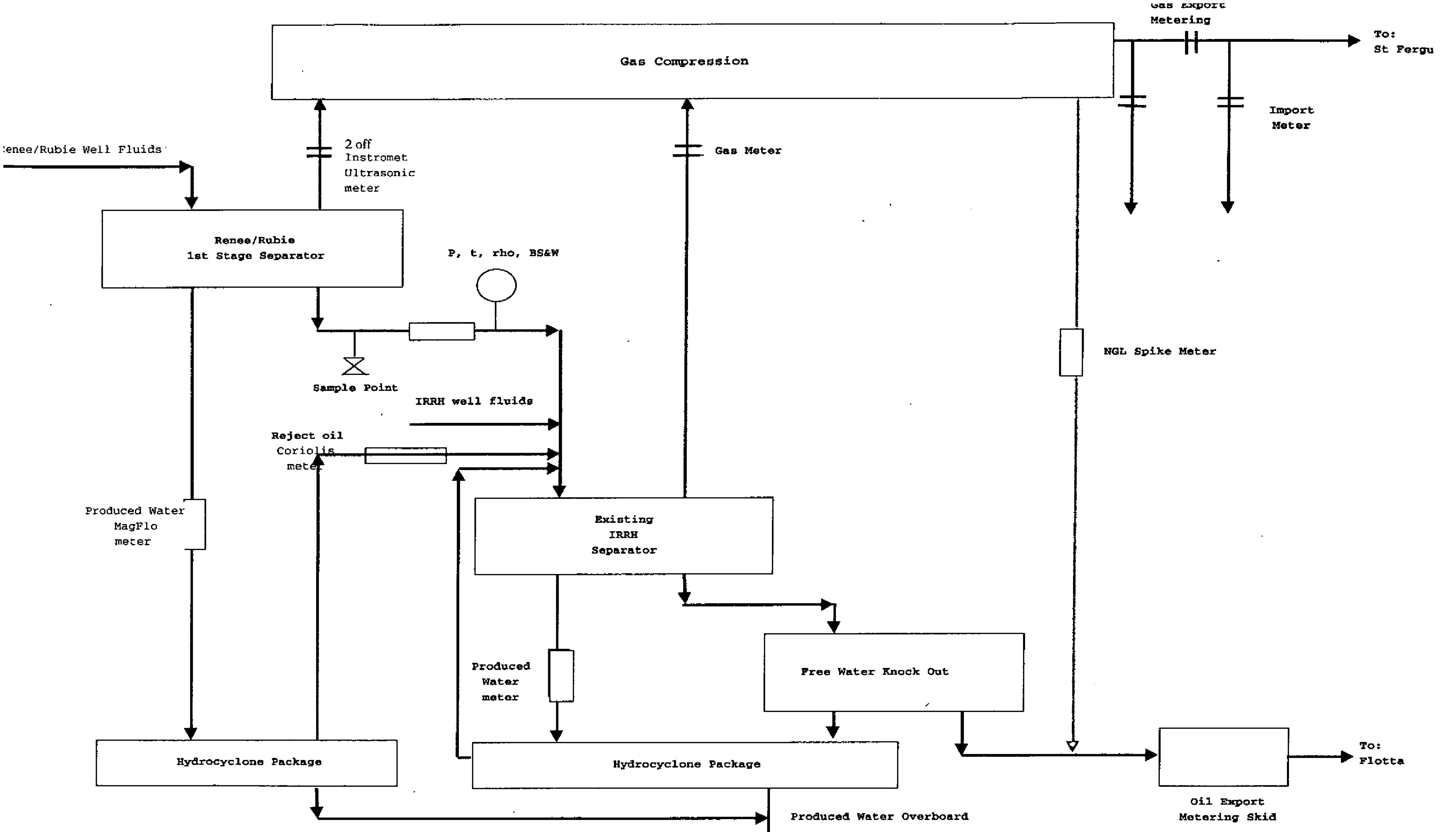

Fig. 2 AH001 Current metering system

North Sea

FLOW

Measurement Workshop

1998

PAPER ~~2~~ 1.2

FISCAL FLOW MEASUREMENT IN THE MILLENNIUM - AN OPERATORS VIEW.

M Leigh, Conoco (U.K.) Ltd.

Fiscal Flow Measurement in the Millennium
An Operators View

Mark Leigh - Conoco (U.K.) Limited

ABSTRACT

A key factor in the continued successful production of hydrocarbons into the next century will be the development of low cost, fit for purpose metering and allocation systems. This paper outlines where the industry could be going, and addresses accounting, technical and organisational issues. The underlying themes of the paper are to challenge the *status quo*, and to promote commercial views on what has been hitherto a mainly technical subject.

The paper describes a typical gas (and associated liquid) commingling agreement explaining the key points in the allocation and attribution of energy to the field owners. The concept of borrowing and lending within a "pool" is outlined, and the overall accuracy of the measurements is put into typical value terms. A case is made to remove technical description from commercial agreements.

The current technical requirements, and a summary of possible future metering arrangements, are outlined, and placed in the context of the drive to increase overall production through existing assets.

The importance of Audit, proper planning and budgeting or work, and the steps made to align differing interests with a common goal to achieve "good metering" in the context of a commercial operation is described.

ABOUT THE AUTHOR

Mark has worked in the oil/gas industry since 1980, following a Short Service Commission with the RAF. He spent a period with a drilling company, followed by three years in Libya on a Methanol plant. Mark joined Conoco in 1984, and has worked in offshore operations, facilities and project engineering, and is currently Team Leader of the Production Management & Reporting group for Conoco (UK) Ltd, based in Aberdeen. The group is responsible for flow measurement, production control and subsequent hydrocarbon accounting processes. Mark is a Chartered Engineer and Corporate Member of the Institute of Measurement & Control.

1 INTRODUCTION

The Theddlethorpe Gas Terminal (TGT) is situated on the Lincolnshire coast in the East of England. It is a 2 Billion Standard Cubic Feet per day plant (2Bscf/d) and has the capacity to process approximately 20% of the UK daily gas supply.

The terminal began life in 1972 with the development of the Viking Gas Field, and has continued to be developed and expanded as further offshore fields have come into production. A brief chronology follows: (A glossary of terms is provided at the end of the paper)

- 1972 - Viking Field and Gas Terminal (VGT) developed
- 1984 - Victor Field comes on stream - commingled with Viking
- 1988 - LOGGS and LGT installed for V Fields
- 1989 - Audrey (Phillips) comes through LOGGS and LGT
- 1991 - Anglia (Ranger) added to LOGGS system
- 1992 - Pickerill (Arco) comes through new PGT
- 1993 - Caister (Total), Murdoch (Conoco) and Ann (Phillips) Fields developed. Terminal is integrated to allow for blending. TACA goes live.
- 1995 - Jupiter comes on stream through LOGGS
- 1996 - Schooner (Shell) is introduced through CMS
- 1998 - Phoenix (Viking Extensions)

In terms of both physical infrastructure and commercial activity, the TGT area represents significant challenge and complexity. Along with the increase in field development and gas production, there have been significant changes to the commercial environment:

As it was
- Monopoly Buyer
- Managed Market
- Depletion Contracts
- Stability of Long Term Contracts
- Known Price
- Unknown Demand
- UK Only

As it is
- Multiple Buyers
- Multiple Sales Contract Types
- Gas-to Gas Competition
- lower consumer prices
- lower beach prices
- Continental Opportunities from 1998
- Volatility in beach price
- Buyers keen to re-negotiate

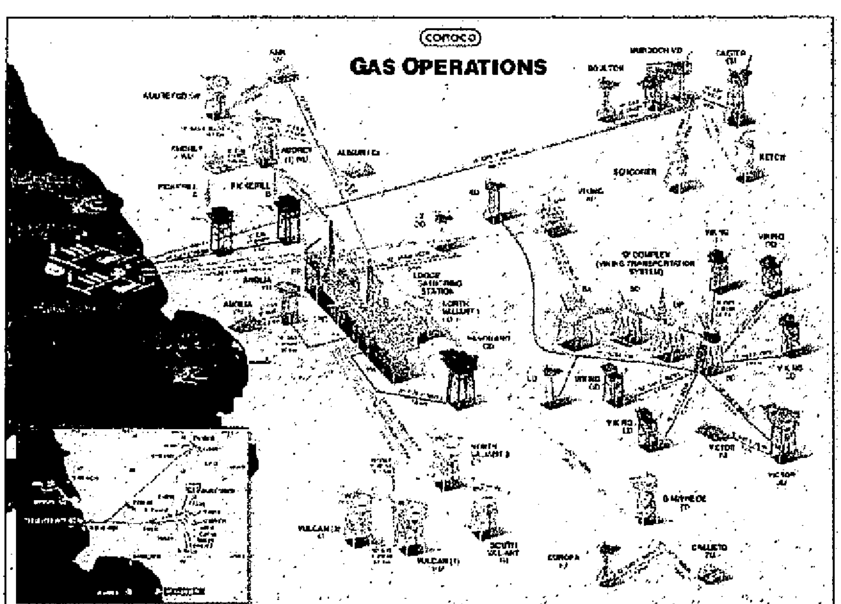

Figure 1 - Diagram of SNS Operations Area

The offshore infrastructure comprises some 100 producing wells, situated on over 30 platforms and 5 sub-sea manifolds. (See Figure 1). The offshore production is commingled at three manned gathering centres, where separation, metering and compression takes place. The fluids are then recombined for transport to TGT via 4 trunk lines. At the terminal, the fluids are again separated, with condensate being recovered and sent via dedicated pipeline to the Conoco refinery on

Humberside and the dry gas redelivered across three delivery points - two for Transco and one to Kinetica.

"In the day" activity is managed from TGT, with overall commercial activity and management being carried out in Aberdeen.

2 COMMERCIAL FRAMEWORK

There are a number of commercial arrangements that allow for the processing, transportation and delivery of gas to the customer. These include:

- Gas Lifting Agreement (GLA's) - these allow for owners of fields to produce their share of the hydrocarbons in place.
- Transportation Agreements (TA's), and Transportation and Processing Agreements (TPA's)- these permit the fields to be processed and handled by the gathering complexes
- Allocation and Commingling Agreements - these set up arrangements for the borrowing and lending of gas in a "pool" concept. These exist at an overall SNS level in the form of TACA (Theddlethorpe Allocation and Commingling Agreement) and also at sub-user level where required.
- Sales Agreements - initially field dedicated between producers and a single buyer, increasingly these are "supply" contracts, pulling gas from a number of fields to meet short term gas needs.
- Joint Operating Agreements (JOA's) - these define how the operator acts on behalf of the other field owners.
- Production / Services agreements - allow for the sharing of maintenance and other operational costs.

3 DEFINITION OF TERMS

There are terms used in allocation and commingling agreements which have specific meanings. These definitions sometimes differ from common usage, and may be specific to different agreements. For example;

- Production - the amount of gas (and liquids) that is actually produced from a field and measured at a metering station.
- Allocation - this is the share of gas produced by a field , after taking account of fuel gas and linepack adjustments. It is carried out on a component basis, and is derived from comparing the total gas redelivered at TGT with the ratio of the gas coming in from the fields. It determines the ownership of gas leaving TGT. See Table 1 in the following Section for details of this process.
- Attribution - this is the process by which the buyers demands, submitted in the form of a "nomination" are met. If there is a difference between the amount of gas "allocated" to a field and the amount required, then gas may be borrowed or lent by the field to make up the difference. There are limits to how much gas may be borrowed or lent, normally set in terms of a number of days booked Firm Capacity (FC).

The management of the TACA gas pool is carried out by Conoco as Theddlethorpe Operator. Whilst a fairly simple process in theory, the practice is somewhat more complex, due to changes in field production capacity, alterations to nominations and the need to manage the blend of the gas leaving TGT to meet the TRANSCO specifications.

Collection of metering data in real time, nomination handling, allocation and attribution calculations, daily, monthly and annual report generation are all achieved by using a computer system based on the Logica Prodis framework (TRACS - Theddlethorpe Reporting and Allocation Computer System).

The number of daily nominations received will be at least 18, and has been as many as 90 changes in one day; typically there will be 30 nominations. The degree to which flexibility is required has been brought about largely by the changes in the market place outlined above, with the move away from long term field dedicated contracts to shorter term non-dedicated supply agreements.

The commercial framework can be summarized by the following diagram, (Figure 2) where the "TACA Envelope" is shown by the dashed line:

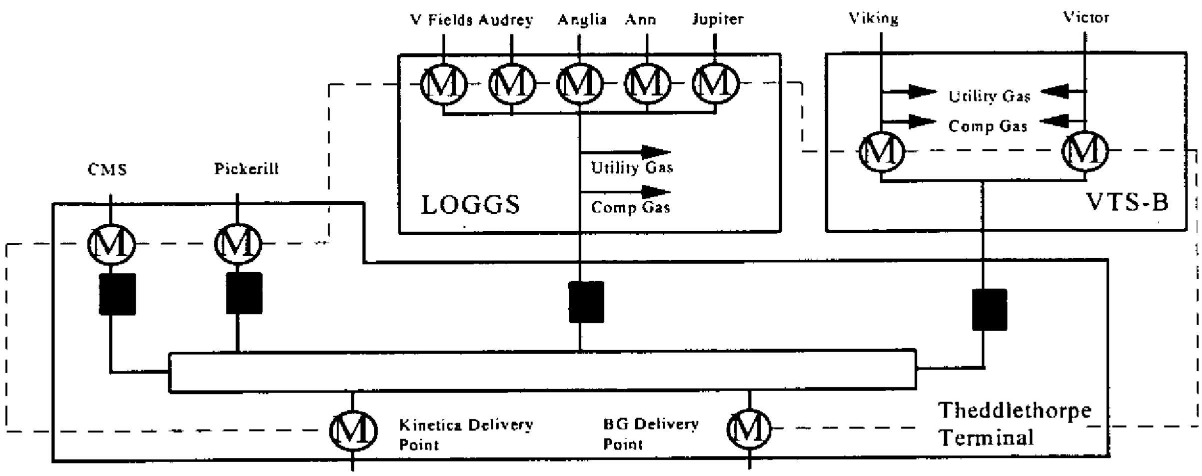

Figure 2 - Schematic of TACA Envelope

Allocation and attribution is calculated in terms of energy, and is expressed in Millions of Megajoules (MMJ). Consequently sampling and analysis, either by manual sampling/well tests, grab samples or on-line chromatographs all play an important part in the overall measurement process. An audit committee comprising key company technical representatives is in place (Joint Audit Steering Committee - JASC) to ensure that all interested parties are treated fairly.

4 COMMERCIAL AND TECHNICAL CONFLICTS

It is very important when fields are in the early stages of development that the commercial and technical teams work closely together. This will help ensure that what is commercially desirable is technically possible. Commercial documents should also be written in a way that allows recognition of changing priorities as fields decline.

The wording of many existing allocation agreements is very prescriptive in terms of the methods of measurement to be used. They often describe the equipment that is to be used for the measurement, specify the equations to be implemented and the hardware to be fitted. Whilst this was a good approach in the market at the time, it now means that new fields wishing to join the allocation system have to comply with old technology requirements.

Typically, no account is taken of the relative value of the produced hydrocarbons, and measurement requirements are normally specified in terms of a maximum permitted uncertainty in the production - 1.0% for gas measurement and 0.5% for liquids, irrespective of production volume or value. It should be noted that agreements below primary allocation level, (sub-allocation agreements) may allow for metering with increased uncertainty tolerance at 2 or 3%.

No provision is made in the agreements to relax the measurement uncertainty limits for low producing fields, and due to the prescriptive technical nature of the measurement schedules, alternative measurement technologies are not permitted without modifying the principle agreements, which may require the signatures of many separate organizations. (35 companies are signatories to TACA, for example.)

The following Table (Table 1) illustrates the inter-dependence between fields using a common allocation and commingling system. In this example, each field produces a given quantity of gas and is allocated an amount expressed as a percentage of the total redelivered to the customers, determined by the proportion input to the system. If we now assume that a given field has been in error at +1.0%, a new allocation is produced. It can be seen that the field in error (for example Field Beta) "picks up" the additional gas, but not the full 1%. Similarly, all the other field's allocation would be reduced by an amount proportional to their input quantities. In the second example, the small producer Field Alpha is assumed to have an error - again all fields are affected.

FIELD	GAS PRODUCED	GAS ALLOCATED	ERROR IN BETA @1%	GAS ALLOCATED	% CHANGE	ACTUAL CHANGE
ALPHA	50	48.00	50	47.81	-0.40%	-0.19
BETA	100	96.00	101	96.57	0.60%	0.57
CHARLIE	100	96.00	100	95.62	-0.40%	-0.38
TOTAL	250	240.00	251	240.00		
DELIVERED	240					
			ERROR IN ALPHA @1%			
ALPHA	50	48.00	50.5	48.38	0.80%	0.38
BETA	100	96.00	100	95.81	-0.20%	-0.19
CHARLIE	100	96.00	100	95.81	-0.20%	-0.19
TOTAL	250	240.00	250.5	240.00		
DELIVERED	240					

Table 1 - Basic Allocation Example

Another problem that is often not considered concerns the relative value of the condensate and gas produced, and how the quantity produced impacts the overall value returned from

Field Alpha - Condensate Tonnes	125
Field Alpha Gas Tonnes	6660
Value of Gas	299700
Value of Condensate	10625
Value of 1% Gas	2997
Value of 0.5% of Condensate	53
Ratio	57

Figure 2 - Error Value Ratios

the field. Consider the case of Field Alpha, a declining gas field, with some liquid production. The table in Figure 2 shows that the value of 1% of the gas production is approximately 57 times that of 0.5% of the condensate production, on an average monthly basis. Put another way, we would need to mis-measure the condensate in the order of 25-30% to have the same *value* error as 1% of the gas production. This has clear implications in the way in which the systems should be designed and operated. The graph in Figure 2 shows different ratios for a typical range of fields. The interdependence of the fields in the system, and the differing relative values means that design, operation, maintenance and audit must be holistic in their approach. In the future, measurement and allocation systems will need to concentrate on *total* field value, rather than on each phase individually.

5 SPECIFIC COMMERCIAL CHALLENGES

Metering costs are often included in the tariff the field pays to the transporter, or may be allocated on a shared basis amongst different fields as part of an Operating Services agreement. This approach effects the way future value can be generated. It is important that the cost of measurement is clearly identified so that where cost saving ideas have been identified, there is advantage to the field to implement them, and an incentive to drive through changes. Where measurement and allocation costs and processes are not properly understood, with costs being unidentified, there is no incentive to discuss changes through field life. Operating costs are therefor maintained at an unnecessarily high level. Ensuring a linkage between metering costs and field costs helps reinforce the link between the commercial and technical management of the asset and so will assist in future development options.

Where commercial documents contain technical description, future marginal fields requiring entry are obligated to install high Capex equipment, thus elevating project costs and reducing the amount of new low cost gas coming into the gas pool. It is no exaggeration to say that a traditional approach to measurement and allocation in the future will inhibit future hydrocarbon reserve developments.

For very low liquid producing fields, the cost of measurement can be higher than the revenue produced. It is illuminating to consider the cost of measurement on a "by field" or "per MMJ" basis. The following graphs (Figures 3 and 4) show that some fields are more cost effective than others - typically onshore metering is less expensive than offshore, and meters with complex commercial commitments are more expensive than those with simpler arrangements. Note that this analysis is based on Opex only; when cost of capital, design, procurement and construction is considered, more fields are pushed into the marginal category.

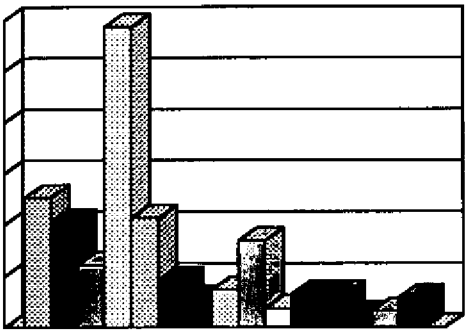

Figure 3 - Cost per MMJ/Year

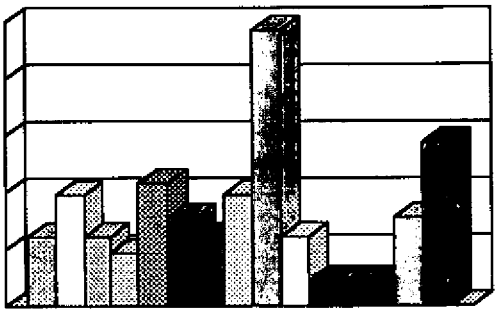

Figure 4 - Cost per Meter System/Year

In the case of declining fields, it is worth noting the relative value of an error in measurement as the field declines. The graph (Figure 5) shows the value of 1% of the production, assuming a systematic error that existed for a 24 hour period. It can be seen that in the early part of the life of the field, the value of the error is quite large, but that towards the end of field life the value of the same magnitude of error is quite small. However, the commercial agreement in place does not allow for the modification of practices or procedures to recognise this shift. Is $\pm$ 1% the correct uncertainty limit for this field? The other significant item about the decline curve when expressed in error value is the increase in 1998/99. This is due to the transportation of a new field through the existing line. In terms of increasing value to the company, it therefor follows that our attention from a metering and hydrocarbon accounting perspective must be focused on increasing throughput, and not by "chasing" errors in measurement at the end of field life.

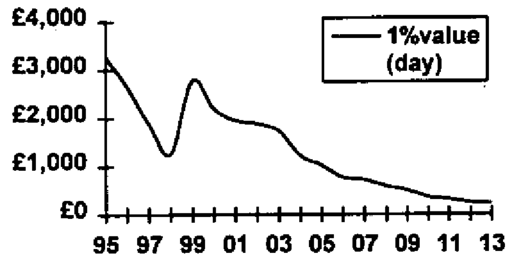

Figure 5 - Value of 1 day, 1% error over time

6 COMMERCIAL AND CONTRACTUAL ENABLERS TO INCREASE VALUE

There are a number of items that can increase value in a mature or declining gas province. These will include establishing the correct commercial framework within which the technical community must operate, and establishing relationships with vendors, suppliers and service companies that focus on adding value to the whole, rather than on short term "win-lose" arrangements.

Early commercial work will have an effect on the whole field life. It is very important that commercial agreements recognise that the field will have changing measurement priorities, and must be worded so as to allow changes to be made with the minimum cost, whilst assuring appropriate standards. This may mean that technical requirement are not embodied in the main text of the agreements, but are contained in a separate technical manual.

The uncertainty allowed in measurement systems has been determined by regulatory guidelines and, typically, detailed in agreements. In the future, uncertainty limits will be determined by agreement between co-venturers and regulators.

The ownership of the technical manual for the transportation system should be under the guidance of a steering committee made up of the key technical staff from the co-venturers. This team will oversee the audit process, and have the authority to make and allow changes to metering and allocation practice through field life.

The importance of having the right incentive to discuss change has been mentioned earlier; having the cost of measurement clearly identified and charged to the field, instead of the transporter, will help ensure that optimum design, operation and maintenance is carried out. This approach will also ensure that fields which do not modify their requirement through field life will pick up the correct cost.

The interdependence of the metering systems, and the reliance of good data transfer into computer allocation systems has been discussed in Section 3. This means that organisations must be set up that cross discipline boundaries. An effective allocation group will need to include metering, hydrocarbon accounting, communications and software skills.

In the SNS, we have increasingly developed relationships with our maintenance and metering service companies to give them more accountability and responsibility for the metering function. The metering staff are employed by the service company, and the establishment of procedures, project interfaces and ownership of maintenance planning rests with them.

There are many advantages in having a metering company "own" more of the problem. They can better manage career development for technicians, establish strong links with sub-suppliers and so reduce costs, and can provide detailed technical engineering and consultancy knowledge to solve specific problems. With a suitably incentivised contract, the service company can share in the cost savings achieved through improved management processes. Ideally, the service company should be able to take ownership of the entire metering system, adopting a "cradle to grave" approach including design, maintenance, operation, data transfer/validation and allocation processes.

There are a number of key performance indicators that can be put in place, the following list is indicative of the type of measurements that can be made to assess, and reward, performance.

- Stream/system availability
- audit performance
- staff competency
- safety record
- minor project performance - budgets, schedule, as builts
- sub-vendor selection /management

The "outsourcing" approach does leave the threat that the long term "corporate memory" of the operator can decline, so in addition a Staff metering engineering position, and A Staff Hydrocarbon Accountant, are still seen as being key roles in the organisation.

7 TECHNICAL CHANGES

A number of technical breakthroughs have been made in recent years that change the approaches possible for gas field metering, for example the advances made in Ultrasonic Flow Meters (USM), the development of high stability differential pressure cells, acceptance of coriolis meters and the increased understanding and use of venturi meters for wet gas metering. In addition, modern digital electronics and communications has lead to the development of more reliable data transfer, and the ability to carry out remote diagnostics and fault sensing. These developments will drive down both Capex and Opex.

8 ULTRASONIC FLOW METERS

The principle of USM for fiscal flow metering are now well established [1], [2], and will not be discussed in detail in this paper. However the marked increase in turndown ratio, and the inherent redundancy of the devices when multiple paths are used means that a substantial decrease in deck weight and space can be achieved, due to elimination of multi-tube meter systems [3]. Once the principle of metering by USM is established in a transportation system, the subsequent addition of gas fields will be easier to achieve.

Together with good communications, the ability exists now to put all the meter data, in real time, onto the desk of the metering and allocation staff in the office [4]. Given their inherent reliability and fault tolerance, USM's are more suited to remote un-manned operation than conventional ISO-5167 orifice plate meter skids.

In the future, it is possible that these devices will also operate in two-phase mode, and hence give a reasonable measurement of the liquid production. This will allow the addition of future reserves into existing infrastructure by using sub-sea production systems or minimum facility platforms.

9 HIGH STABILITY INSTRUMENTATION

New devices are on the market, based on resonant frequency technology, that allow maintenance intervals to be extended to six monthly or longer. The reduction in Opex over field life from the use of these devices will be substantial.

Where multiple instruments are fitted, these can be compared, and provided drift between instruments is within limits, a significant reduction in manned intervention can be achieved, with no compromise to system uncertainties. So in the case where there are older metering systems that cannot support the cost of retrofitting with USM, there is the opportunity to reduce operating costs.

10 THE FUTURE

So what could the future SNS look like, from the measurement and hydrocarbon accounting perspective? A possible future scenario is outlined below.

- All new fields are metered using USM. Substantial liquid production is metered using coriolis devices, with small liquid producers being metered using wet gas corrected figures, fixed ratios, or not at all.
- All metering data is transmitted to the metering and allocation team on the beach. Offshore intervention is practically eliminated.
- Where legacy orifice plate meters are still in use, these are all fitted with advanced instruments in comparison mode, requiring minimum intervention maintenance only.
- The ownership of spares and maintenance procedures rests with the metering service company, who are well rewarded for gains in efficiency and cost reduction. The field metering crews are working as a unified team, with no cross functional/location interface problems.
- A "cradle to grave" approach is accepted as the best way forward, with total ownership of the metering system and data transfer being with the service companies.
- New small gas fields are brought on stream at minimum cost, and effective best practices are incorporated in the design, installation and operations phases.
- Metering costs are being paid by the producing fields.
- The Joint Audit Steering Committee is embodied in the agreements, and has authority to alter metering requirements. The Partners view SNS as being "best in class" for its metering and allocation services.

11 REFERENCES

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[2] T COUSINS, Review of operation of ultrasonic time of flight meters, Paper 10, 1996 North Sea Flow Measurement Workshop.

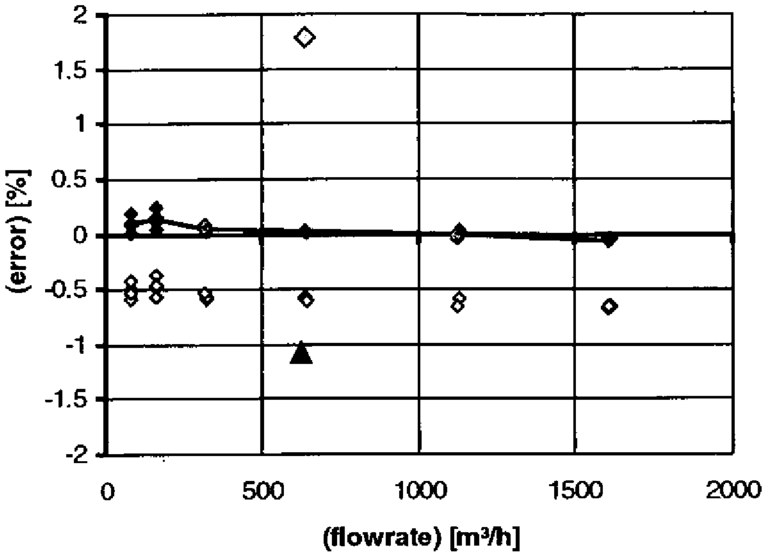
[3] DTI OIL AND GAS OFFICE, Guidance notes for standards for petroleum measurement, Section 3.2.4, September 1997, Issue 5.

[4] P ROBBINS, Ultrasonic metering on an offshore gas platform, Paper 11, 1996 North Sea Flow Measurement Workshop.

12 GLOSSARY

A&A	Allocation and Attribution
CMS	Caister Murdoch System
GLA	Gas Lift Agreement
JOA	Joint Operating Agreement
LGT	LOGGS Gas Terminal
LOGGS	Lincolnshire Offshore Gas Gathering Station
LTS	LOGGS Transportation System
MMJ	Million Mega Joules (1×10^{12} J = 9478 Therms = 1×10^{6} SCF approx)
PGT	Pickerill Gas Terminal
PSA	Production Services Agreement
SALA	Sub Allocation Agreement
SATA	Sub Attribution Agreement
TA	Transportation Agreement
TACA	Theddlethorpe Allocation and Commingling Agreement
TPA	Transportation and Processing Agreement
VGT	Viking Gas Terminal
VTS	Viking Transportation System

4.3 Three path meters



◇ (Error as measured), 21.08.98	◆ (Error corrected, Adjust factor =), 21.08.98
▲ Disconnected Single path	◇ Disconnected Swirl path

The meter shown was undergoing factory acceptance testing, the opportunity was taken to establish its footprint curve and some of its operating characteristics. The meter was found to be linear in response with a negative 0.5% offset. In order to ascertain the meters response to path failures we disconnected in turn the single path then a swirl path.

The resultant shift with the single path disconnected was a negative 0.5%, while the swirl path shifted a positive 2.2%. Having ensured the meter was reconnected for all paths the original curve was adjusted to the zero datum line and two check flows completed.

These tests would indicate the performance of the three-path meter follows that of the five-path meter, regarding single path and dual path failures. Single path failures, although shifting the value, could possibly be acceptable for short periods whilst a replacement probe or suitable window for rectification is planned. The swirl path (which is used in the swirl calculation altering the single path values), however, has a much larger impact on the resultant output and renders the meter virtually unusable.

5 ADVANTAGES AND DISADVANTAGES OF ULTRASONIC METERS

As a quick reference guide we have outlined some of the disadvantages and benefits of ultrasonic meters:

Disadvantages of ultrasonic meters

- Internal surface condition of meter effects the measurement accuracy.
- Process noise can effect the measurement integrity.
- Lack of local facilities, at present, capable of performing annual recertification of the meters leading to expensive transport costs and long turn around times.

Advantages of ultrasonic meters

- No line obstruction.
- No pressure loss.

- Minimal installation requirements. Only 10 diameters of straight matching pipe upstream and 3 diameters downstream to achieve accuracy.
- Bi-directional capability. If this is a requirement, then 10 diameters of straight matching pipe must be present in each direction. Testing should be done in both flow directions.
- No moving parts.
- No lubrication or periodic maintenance.
- Large turndown ratio.
- Digital waveform sampling and detection.
- Powerful noise reduction technology.
- Extensive self-diagnostics.
- Immediate alarm reporting.
- Ultrasonic paths configuration means better measurement of asymmetric and swirling flow.
- Built in redundancy, measurement can continue after path failures.

6.0 CONCLUSIONS

Ultrasonic meters have been shown to be suitable for application in fiscal service, achieving the dual objectives of cost reduction and high accuracy.

The design and operating principles of ultrasonic meters give accurate measurement of velocity. However, changes in the surface conditions of the meter result in variations in the value of flow rate.

Ultrasonic meters tell us much more about the flow conditions inside the pipes than previous technologies. They have revealed issues that have been hidden up to now. In practice, for the measurement of gas flow they are as good as if not better than other meter types.

At present it is essential to calibrate ultrasonic meters for a particular installation until the historic evidence shows that the meters are stable.

Our understanding of this technology, whilst improving all the time is still relatively small. Manufacturers and the test facilities have been very proactive in the discussion and resolution of the development / teething problems we experienced. This networking must be actively encouraged.

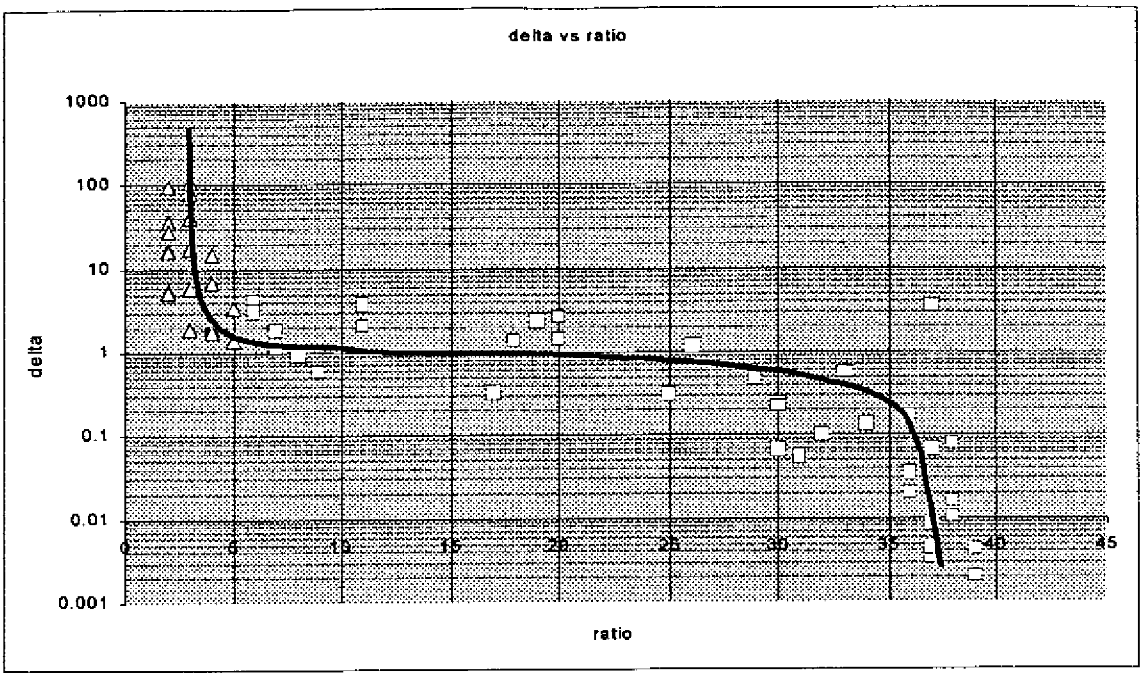


Figure 5 - Good functionality of the ultrasonic flowmeter

Figure 5 shows a typical graph of the AGC_ratio (Autmatic Gain Control_ratio) versus the δ-factor. As long as the AGC ratio is larger than 5 the instrument is functioning properly (level has not reached the limit). Figure 5 shows that a rapid decrease of the AGC ratio occurs starting from a δ-value of about 1.

8 CONCLUSION

The objective was to establish a model capable of predicting the performance of an ultrasonic flowmeter in a specific application.

This report shows that based on installation (piping) drawings, the control valve characteristics and relevant process parameters, it is possible to calculate a δ-factor value that predicts whether the ultrasonic flowmeter can function properly in a specific application. If not, it can be calculated to which extent additional measures are required to assure proper operation of an ultrasonic meter in the installation under study.

9 FINAL REMARK

For the calculation of the indicator (δ) a first approach can be made by using a valve characteristic value N_v of 1 as default value. For a more accurate assessment it is recommended to use the valve characteristic value. In case this value is not available Instromet has the equipment and capability to perform measurements on a site where a representative model of the particular valve is in operation as long as provisions can be made to install ultrasonic measuring microphones. In this way most applications can be analyzed for acoustic noise behavior and an advice can be given for the applicability of our ultrasonic gasflowmeters analyzers.

ACKNOWLEDGEMENT

Instromet wants to thank Verbundnetz Gas for organising and conducting this project. Especially the enthusiastic co-operations of Dr. Stoll, Mr. Slawig, as well as the support of Mr. Müller from PLE are greatly appreciated.

We also want to mention Dr. Dane who contributed in the processing and analysing of the ultrasonic sound measurement data.

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PAPER ~~3~~ 1·3

PRESENT & FUTURE OIL COMPANY NEEDS IN THE AREA OF FLOW MEASUREMENT.

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PRESENT AND FUTURE OIL COMPANY NEEDS IN THE AREA OF FLOW MEASUREMENT

Mr Harald Danielsen, Statoil
Mr Endre Jacobsen, Statoil

1 INTRODUCTION

The purpose of this presentation is to put forward some operator viewpoints on needs for improvements within the area of flow metering.

The focus of this paper is mainly on fiscal metering; both for existing and future offshore platforms.

Fiscal metering in this respect includes export metering of oil and gas, plus the ownership allocation metering; i.e. metering of hydrocarbon streams between field owners.

2 SUMMARY OF VIEWPOINTS ON PRESENT/FUTURE NEEDS

The essence of this paper regarding the needs within the area of flow metering can be summarised as follows:

- Need of an "un-manned" fiscal oil metering and water fraction concept with a lower frequency of repair and intervention than conventional concepts.
- Need of lighter, smaller oil metering systems with known uncertainty.
- Need of metering systems proven to operate accurately for oil at the bubble point.
- Need of performance data from multiphase meters working in a real system.
- Need of further development of ultrasonic meters (USM) within a number of areas.

3 GENERAL

When planning a new metering system there are always one or more of the areas listed below where particular needs are highlighted:

- Weight
- Compactness
- Price
- Delivery time
- Accuracy
- Reliability
- Amount of maintenance and calibration
- Conformance with accepted standards and regulations

Which of the areas that has the strongest needs may vary from case to case.

You can never get a high score in all of these areas. If you want a system that is compact, light and inexpensive, you won't get the maximum score on high accuracy.

In the first phase of the North Sea oil and gas era, there was a strong emphasis on the areas of accuracy and conformance with standards and regulations. Today, however, it has become necessary to weigh needs in different areas against each other. This is because there has been a number of changes in the area of field economy and field development, some of these changes are reflected in the sections below.

4 UN-MANNING OF PLATFORMS

There is now more focus on un-manned platforms for marginal fields.

A typical un-manned production platform will accomodate wellheads, a 1st stage separator and may have a need of fiscal metering of the oil and gas output streams. These two streams may after metering, be commingled in a multiphase pipeline or leave in separate multiphases pipelines to be brought into the processing plant of existing platform(s).

On this typical un-manned platform there may be no living quarter, no equipment that needs large amounts of power and equipment that needs frequent maintenance (and calibration) will be avoided.

The streams to be fiscally metered are "raw" streams, coming directly from the separator outlets. Pressures and temperatures may be high. A power consuming heat exchanger or other facilities to dry the gas before metering, is out of the question. So the gas has to be metered in a saturated or "wet" condition.

Further, there may be no power consuming, maintenance adding booster pump to provide back pressure for the oil stream to be metered. The oil stream will only get the pressure boosting available as hydrostatic head, typically a maximum of 5-10 metres.

Also, the oil may contain large fractions of free water.

The special needs of flow metering for such a platform include a number of the areas of the list in Section 3: Low weight,small size, high reliability, low frequency of maintenance and calibration. In addition, there are these extra needs:

- The oil, in spite of being on the verge of starting to form bubbles at the slightest pressure drop, must be metered with a reasonable uncertainty. This uncertainty must have a reasonable value which must be known and documented in such a way that all involved parties can agree on it.
- The gas is also on the verge of condensing at the slightest drop of pressure or temperature and has the same requirement to have a reasonable known and documented metering uncertainty.
- An automatic oil sampling system or water in oil meter which is reliable and accurate for monthly averaging of water content of the oil at 1st stage separator conditions. Automatic oil samplers are, however, not reliable. Water in oil meters need a bubble free stream after oil has passed through the static mixer which leads to a pressure drop which again may lead to bubble formation.

As stated above, it is not possible to find a system which have a high score for all of the areas of metering. In a typical case with an unmanned production platform for a marginal field, two sacrifices can normally be made:

- The price of the metering system is, within reasonable limits, not critical
- The accuracy requirements may in many cases be relaxed

There is however a problem when you leave the conventional concept of turbine meters and prover which has a lot of standards and history to back it up: you tend to end up with a system for which it is very difficult to document figures for uncertainty. If you cannot do that, it is impossible to make any cost/benefit evaluation that you will need to gain acceptance for such a system from partners, NPD and other "interested parties".

On the gas metering side, we are in a better position when it comes to meeting requirements for low weight, small size etc. and proven accuracy when gas is on the verge of condensing. The ultrasonic metering systems are now available as an accepted fiscal metering concept. It should be noted that further needs within ultrasonic gas metering is dealt with in one of the sections below.

5 TIE IN OF A SATELLITE FIELD'S SUBSEA WELLS TO AN EXISTING PRODUCTION PLATFORM

Instead of installing a wellhead platform with pipeline to the neighbouring platform, as described in the previous section, a new field may be produced by subsea wells with multiphase pipeline(s) to an existing platform. At the receiving platform, there are, mainly, two ways to deal with the incoming stream:

- The stream is lead into the 1st stage separator of the existing process plant. In such a case the only way to "meter" the quantities of oil and gas from the satellite field is to use a test separator for "flow sampling" or to combine the use of multiphase meters and testseparator. Use of the test separator in combination with well performance plots and wellhead pressure measurement is a rather rough method of fiscal metering. On the other hand, cost/benefit analyses using NPV of field reserves and differences in field ownership and royalty for the satellite field and the existing field, will often justify the risk of 5-10% metering error of a test separator metering scheme. The ideal situation would of course be to have accurate, well proven multiphase meters to perform continuous metering. However, we are waiting for more real life data from the new fields with such meters installed to demonstrate the present state of multiphase metering over a wide range of applications. The need for data from real life operation and other needs in connection with multiphase metering, is dealt with in a separate section of this paper.
- An alternative to let the satellite field's production enter the existing field's separator, is to install a dedicated 1st stage separator for the satellite field. As far as metering is concerned, we are then back to a similar situation to that of the unmanned platform of the previous section. There is a difference, however, that frequent maintenance and reliability is not such a big problem, since the platform is manned. The main need here is an oil metering system with lower weight and smaller size than a conventional system and with documented figures for the accuracy in real life use.

6 WEIGHT SENSITIVE PLATFORMS

The fields in the Norwegian sector have gradually moved from shallow to deeper water. The heavy concrete platforms with their large weight carrying capacity now seem to belong to history. The new platforms for deep waters are floaters, a lot of them are ship constructions. So far, weight and and size of topside equipment have not become a particular problem for this type of floater.

However, ship constructions are not always the optimum floater for production facilities. Where no storage facilities for oil is needed as part of the construction, floating platforms like the semi-submersible drilling platforms, seem to be preferred. The experience with such platforms, from a metering engineer's point of view, is that they seem to have a very high marginal cost per ton of topside equipment, compared to the old platforms.

In pre-engineering studies, marginal platform costs as high as 1000NOK per kg of topside equipment, has been used for concept optimisation. As a typical price level per kg for large conventional metering systems are of the order of 200-400 NOK/kg, this means that the building site costs may be up to 5 times the cost of the equipment itself.

From the trend of platform design it may be concluded that there is a very strong need to reduce weight of metering systems.

For a floating production platform which is now under construction, one gas meter run with two ultrasonic meters in series, will be installed as a fiscal export gas metering station. There will be a very strong need that this concept is proven in real life to be as accurate and reliable as a conventional multi-run orifice metering station, so that such a system becomes a generally accepted concept for fiscal gas metering.

7 CRUDE OIL METERING SYSTEMS FOR OFFSHORE TANKER LOADING FROM A MARGINAL FIELD

Traditionally, offshore measurement of crude oil batches to marine tankers have been made by metering packages with turbine meters and prover.

Such systems are very accurate and reliable. However, for smaller fields they may be far too big, too heavy and too expensive to maintain.

It was the "giant" oilfields of the seventies and eighties that set the standards for metering practices and governmental regulations in the North Sea. The enormous monetary value of the oil reserves in these fields could justify almost any level of cost of measurement.

As time went by the new oilfields got smaller and the oil companies had to pay more attention to the cost benefit ratio of using traditional measurement systems. Also the governmental regulations were amended so that it was easier to get acceptance of less expensive metering schemes if justified by cost/benefit evaluations.

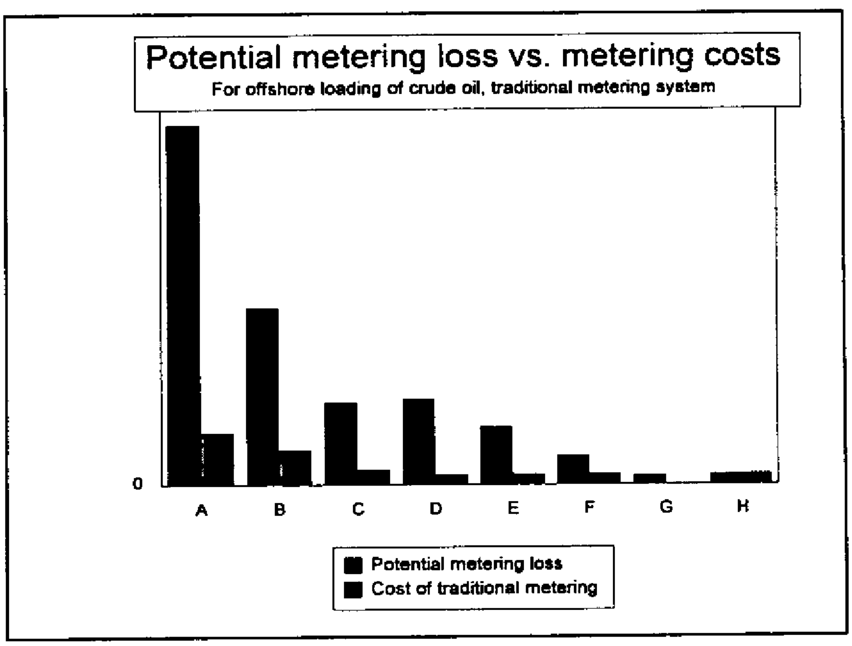

Figure 1 - Cost/benefit relationship

Figure 1 illustrates the cost/benefit relationship for traditional oil metering packages for some offshore loading oil fields in the North Sea. The chart shows the NPV of 0.5% of the platform's export quantity during its lifetime (dark bar) together with the total lifecycle costs for a traditional metering package (grey bar).

The value of 0.5% is used here as a potential metering loss when there is no measurement made at the exporting platform. It should be noted that this figure has been chosen as a parameter in the cost/benefit evaluations of crude oil measurement systems because 0.5% is very often used as a maximum deviation limit in crude oil transactions. It is not based on any data beyond this.

The two fields, A and B, in the left part of the chart, belong to the "giant" category of oilfields of the early eighties. As we move to the right in the chart, we find some of the fields that has been developed during the late eighties and the nineties.

Fields C, D and E have a reasonable margin between metering costs and a potential metering loss of 0.5%.

Field G delivers all of its export oil to a terminal which has a traditional turbine meter/prover measurement system, operated and maintained in accordance the offshore measurement regulations. Based on this, it was accepted that no fiscal measurement needed to be made at the platform.

For field H, the cost of its traditional metering system, marginally outweighs the value of a potential metering loss of 0.5%. This fact was acknowledged at the time when the technical concept of the field development was settled, but for a number of reasons it was not possible to get all involved parties to agree on a less expensive metering scheme.

The main reasons for this were probably as follows:

In the "world of the North Sea flow measurement" there is presently only one undisputable standard for crude oil fiscal measurement. This standard is represented by the traditional equipment, of turbine meters and prover, calibrated, maintained and operated at high costs with specialised personell.

For situations where there is a need of a less expensive fiscal metering scheme, we have not yet managed to establish a standard for 2nd class of fiscal oil measurement which is acceptable to all people involved in the production, transport, sale and purchase of crude oil.

In the authors' opinion, the following is needed to establish such a standard:

- More real life, operating experience with alternative metering systems, for example liquid ultrasonic meters schemes, with the emphasis on long term stability and reproducibility from laboratory conditions to field use.

- Open presentation of all such operating experience by the users, including both positive experience and negative experience.

- A written standard for this 2nd class of fiscal oil measurement, known to be based on real life experience, with technical details and specific figures for measurement uncertainty.

8 FISCAL GAS MEASUREMENT

8.1 General

In traditional systems up to the early nineties, orifice "technology" for several reasons, has been the dominant concept for fiscal gas metering. In purely dry gas service, on sales-metering onshore; gas turbine meters are however in use.

Traditionally; orifice metering systems have been quite large, heavy and a lot of capital and maintenance effort have been put into these systems. In order to achieve sufficient straight pipe on the Ekofisk 2/4-S riser platform, the gas metering station was the controlling equipment for the plattform length!

To be able to meet the field and pipeline development requirements for more compact and cheaper systems; at least two concepts have been in focus for fiscal use the last 5 – 10 years. The first one is orifice with flow straightener in combination with extended beta ratio and higher delta p, and the second is ultrasonic meters (USM).

8.2 Ultrasonic meters (USM)

The need of more compact systems compared to orifice, was obvious; and earlier studies ref (1) indicated space savings in the order of 80-90 % and weight savings in the order of 50-60% using USM. For a particular project it has been found "site" cost reductions of approx. 90% utilizing USM technology compared to traditional orifice meters.

Besides, it looks like the orifice meter has, for many years, been at the end of the road with respect to improvements of accuracy. The USM however is still in its youth with a high potential for further improvements.

The benefits given below is commonly accepted for an USM system:

- reduced costs (capital, maintenance & operational) compared to orifice systems.
- improved turndown.
- improved selfdiagnostic.
- improved understanding of metering installations' flow profile and swirl.

However, even if the USM technology is accepted by NPD, they give no "standard" permission to utilize a USM without spare meter tube. Full redundancy is not achieved for two meters in series before we are able to perform full transducer changeout on one meter; while keeping the other in service. This fact forces the operators to continiously collect experience data with regard to long term stability and reliability.

With respect to USM improvements it should be focus on the following key topics:

- improve the ultrasonic technology in respect of:
  high temperature range (100 - 130(C)
  high pressury (>200 bar)
- generally improve the documentation to establish the effect of upstream disturbances.
- noisy conditions; generated in the flow/pressure control valves.
- further move towards wet gas metering.
- extended use of "raw" data from the meter ie performance monitoring, density measurement, liquid fraction metering etc.
- intelligent meters with built in methods for indicating if actual flow profile is within acceptable limits.
- establish well proven methods with respect to how to verify that the meter output is still valid after typical 5 years in service without recalibration.

9 MULTIPHASE FLOW METERING

Accurate metering of unseparated well streams is of vital importance in subsea satelite field development projects, but the technique also provides significant benefits in standard platform-based production cases. Application for multiphase flow metering include well monitoring, reservoir management, production well allocation and process control

Utilizing the multiphase metering technique will add value in the following ways:

- reduce the need of subsea test lines from remote wellheads
- reduce time needed for well testing
- release test separator for low pressure production

- immediate detection of changes in well performance (gas/ water breakthrough)
- optimize process plant performance

The following items indicate some forthcoming challenges with respect to multiphase metering. It is assumed that a lot of work still must continue from where we are at the moment

- Increased field experience for topside and specially subsea real use of the meters output data. The experience with topside meters is limited and it is not known any published experience data for subsea meters.
- General meter improvements in co-operation with the manufacturer. There will still be needs of further optimizing the meters. It is reason to believe that real life experiences will lead to revised meter software. Also the meter's dependancy on fluid properties is very attractive to reduce.
- Optimize meter calibration method in order to further improvement of meters performance. In order to establish well proven calibration methods a lot of details regarding well composition, fluid data, flow regime, reference meter performance etc. must be under "control". In order to be able to control and understand the MFM performance, it will be essentiall to establish the complete "uncertainty" budget for this kind of metering system.
- Developing alternative calibration methods and optimize systems for a limited flow regime envelope. In order to reduce the need of a test separator it is also very attactive to establish the MFM performance (i.e. calibration factor) on a more cost effective basis. It is believed to be a realistic goal to be able to put MFM in service (topside or subsea), leave them and use the results for allocation purposes.
- Utilizing MFM system for fiscal use for marginal fields. There are very high expectations among operators for using the MFM as a fully recongized metering system. The meter is assumed to cover all needs regarding reservoir control, well monitoring, plant optimizing, production reporting, well allocation and ownership allocation. An improved metering concept selection process covering all aspects in the design and operational phase is essential.

10 OTHER TRENDS

Further on there are several good reasons to believe that there will be strong needs to improve todays metering solutions with respect to the following subjects.

- need for various metering concepts; detailed analysis may conclude that for marginal fields there is a need of simpler metering concepts as well as more flexible and tailor made systems.
- measure "secondary" parameters due to demand of A) quality control and B) fluid characterization & modelling. (CO_2-content, dew point, water content)
- increased need for mass-flow figures; specially for calibration of multiphase meters.
- further development of condition based maintenance methods.
- extended use of existing metering equipment.

At the bottom line there will always be a need of highly and relevant qualified personell during concept, selection, design, engineering, construction, commisioning, maintenance and operation of a metering system.

Finally there is a continiuos need for sharing of relevant information and experience between the oil companies, the suppliers, manufactorers, contractors and R&D environment.

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North Sea

FLOW

Measurement Workshop

1998

PAPER 4 - 7.4

THE STATUS IF FISCAL MEASUREMENT LEGISLATION IN THE UK AND NORWAY.

Section A: L Philip, DTI Oil&Gas Office, UK
Section B: S Fosse, NPD, Norway

The Status if Fiscal Measurement Legislation in the UK and Norway.

Section A: L Philp, DTI Oil&Gas Office, UK

THE STATUS OF FISCAL MEASUREMENT LEGISLATION IN THE UK AND NORWAY

Mr L Philp, DTI Oil & Gas Office, UK

1 INTRODUCTION

The basic philosophy underlying the UK's regulatory regime in relation to the measurement of oil and gas produced in the UK and on its continental shelf is that regulations, which are secondary legislation, made under the authority of Acts of Parliament, which are primary legislation, provide for the inclusion within Petroleum Production Licences of terms and conditions which the licensee is obliged to comply with. For the purposes of the legislation "petroleum" is defined in the 1934 Petroleum (Production) Act as:

"petroleum includes any mineral oil or relative hydrocarbon and natural gas existing in its natural condition in strata, but does not include coal or bituminous shales or other stratified deposits from which oil can be extracted by destructive distillation."

2 LEGISLATION

The principle legislation which applies to the oil and gas production industry particularly in relation to petroleum measurement is as follows.

The Petroleum (Production) Act 1934.

The Act vests ownership of the petroleum which exists in its natural condition in strata in Great Britain and beneath the territorial waters of the United Kingdom in the Crown and gives the Secretary of State, on behalf of the Crown, the exclusive right to grant licences to search and bore for and get petroleum. The Act also authorises the Secretary of State to make regulations which, inter alia, prescribe the model clauses for incorporation into such licences.

One of theses clauses is referred to in shortened form as the measurement model clause. This clause states what the duties of the licensee are in relation to the measurement of petroleum produced from the licensed area.

The most recent issues of these regulations are:

The Petroleum (Production) (Seaward Areas) Regulations 1996 and,
The Petroleum (Production) (Landward Areas) Regulations 1995.

The Continental Shelf Act 1964

The Act extends the powers conferred by the 1934 Act to the United Kingdom Continental Shelf.

The Petroleum and Submarine Pipelines Act 1975

An act which among other things make further provision about licences to search for and get petroleum.

The Petroleum Act 1987

Sections 17 and 18 and Schedules 1 and 2 to this Act amend the measurement model clauses which were incorporated into licences in force at the time it was enacted.

There has since been a new consolidating act,

The Petroleum Act 1998

This Act draws together the provisions of the other acts. This act has received the Royal Assent but has not yet, at the date of writing, been brought into force. After the coming into force any future regulations will cite the new act as the governing primary legislation.

3 MEASUREMENT MODEL CLAUSES

The measurement model clauses in the seaward regulations are:

(1) The Licensee shall measure or weigh by a method or methods customarily used in good oilfield practice and from time to time approved by the Minister all petroleum won and saved from the licensed area.

(2)* If and to the extent that the Minister so directs, the duty imposed by paragraph (1) of this clause shall be discharged separately in relation to petroleum won and saved -

(a) from each part of the licensed area which is an oil field for the purposes of the Oil Taxation Act 1975,

(b) from each part of the licensed area which forms part of such an oilfield extending beyond the licensed area, and

(c) from each well producing petroleum from a part of the licensed area which is not within such an oilfield.

(3)* If and to the extent that the Minister so directs, the preceding provisions of this clause shall apply as if the duty to measure or weigh petroleum included a duty to ascertain its quality or composition or both; and where a direction under this paragraph is in force, the following provisions of this clause shall have effect as if references to measuring or weighing included references to ascertaining quality or composition.

(4) The Licensee shall not make any alteration in the method or methods of measuring or weighing used by him or any appliances used for that purpose without the consent in writing of the Minister and the Minister may in any case require that no alteration shall be made save in the presence of a person authorised by the Minister.

(5) The Minister may from time to time direct that any weighing or measuring appliance shall be tested or examined in such a manner, upon such occasions or at such intervals and by such persons as may be specified by the Minister's direction and the Licensee shall pay to any such person or to the Minister such fees and expenses for test or examination as the minister may specify.

(6) If any measuring or weighing appliance shall upon any such test or examination as is mentioned in the last forgoing paragraph be found to be false or unjust the same shall if the Minister so determines after considering any representations in writing made by the Licensee be deemed to have existed in that condition during the period since the last occasion upon which the same was tested or examined pursuant to the last foregoing paragraph.

* Paragraphs (2) and (3) are not incorporated into licences which contain the model clauses in Schedule 6 to the Petroleum (Production)(Landward Areas) Regulations 1991.

Petroleum measurement is implied by obligations in the licence in addition to those contained in the measurement model clause. This is discussed below.

4 INTERPRETATION

A number of phrases in the measurement model clauses of the Petroleum (Production) Regulations do not have clearly defined legal meanings and so are open to interpretation. In order that oil companies, which are required to conduct their operations according to the provisions of these regulations, may have a framework within which they can lay plans and make decisions in the knowledge that their proposals are likely to meet with government approval, the DTI issues guidance notes which provide a framework for metering of petroleum without imposing over prescriptive requirements.

These guidelines, the current version (issue 5 September 1997) issued by the DTI Oil and Gas Office are:

"GUIDANCE NOTES FOR STANDARDS FOR PETROLEUM MEASUREMENT

Under the Petroleum (Production) Regulations"

These guidance notes are not prepared by the DTI in a vacuum but are the result of extensive consultation between the department and a number of organisations with a known interest and expertise in the subject. The principal industry representative bodies whose views are sought are, UKOOA, BRINDEX, and The Institute of Petroleum. While the views of industry and government may not always be exactly aligned every effort is made to include as many of the suggestions as possible.

4.1 Critical Words

The Licensee **shall** measure or weigh by a method or methods **customarily used** in good oilfield practice and from time to time **approved** by the Minister all petroleum won and saved from the licensed area.

I have emboldened some words in the first part of the measurement model clause to emphasise some important aspects.

4.1.1 Shall

"shall" is used. This signifies that there is no discretion here either for the licensee or for the minister. This means in practice that all oil and gas production measurement systems must be "approved" .

4.1.2 Customarily Used

The phase **"customarily used"** would in some interpretations imply that no new technology is admissible. However it has never been the view in the DTI that this phrase was intended to inhibit innovation. One could argue that the oil and gas industry has a good track record developing innovative solutions and by inference that the search for and use of innovative solutions is oil industry custom and practice. However great care must be exercised in the selection and deployment of new technology to ensure that it is relevant to the proposed application.

4.1.3 Approved

The use of the word **"Approved"** sometimes gives rise to misunderstandings. In a situation where the pattern and construction of instruments frequently require official scrutiny and the issuance of a "type approval" document it is easy to assume that something similar is intended by the regulations. This is not so. It has always been the view that, as the approval is for a method of measurement rather than for specific instrument types or classes, "approved by the minister" uses the lay meaning of the word in that the minister does not disapprove of the method of measurement. It is in this context that no formal approval has ever been given under the Petroleum (Production) Regulations. Letters of non-objection or of agreement are therefore considered more appropriate in signifying satisfaction with measurement proposals.

5 METHOD OF MEASUREMENT

Where petroleum is delivered to the UK via a pipeline which serves as a common transportation route for a number of fields then the "method of measurement" will include the measurement of petroleum at the terminal serving the relevant pipeline as well as the metering system at the input to the pipeline and the allocation procedures used to determine each contributing field's share of the petroleum used at or exported from the terminal.

A "method of measurement" comprises not only the metering hardware but also the operating procedures and procedures for periodic verification of the continued satisfactory performance of the individual components in a metering system.

Where the purpose of measurement is not for product accounting but is for example for reservoir management other methods will be appropriate. These methods traditionally use test separators to make intermittent measurements of the wells' flowing characteristics but may also involve continuous measurement using a variety of measurement techniques.

5.1 Supervisory Activity

In order to satisfy the Secretary of State that no unauthorised alterations to the approved method of measurement have been made, officers from the OGO may at their discretion inspect metering systems at any stage from construction through commissioning into production. Throughout the producing life of a field operators may expect that fields liable to pay Royalty or PRT or being co-produced or transported with such fields will routinely be inspected by officers of the OGO on an annual basis. Additional non-routine inspections may be required if circumstances warrant. Fields with no impact on Royalty or Petroleum Revenue Tax (PRT) are liable to be inspected on commissioning and thereafter at the discretion of the OGO on a less frequent basis than Royalty or PRT sensitive fields.

Officers from the OGO are authorised by the Secretary of State for Trade and Industry to "enter into and upon any land, installations or equipment" for the purposes laid down in the schedules to the Petroleum (production) Regulations.

5.2 Other Powers

The Petroleum (Production) Regulations provides for a number of powers to be includes in the terms of a production licence. Most of these powers relate to the regulation of the development and production activity of licensees. Those powers which have relevance to petroleum measurement are annotated in the regulations as the :- "Power to execute works" and the "Power of revocation"

5.2.1 Power to execute works

This clause states, "If the licensee shall at any time fail to perform the obligations arising under the terms and conditions of any of clauses 14, 19, 22, 23, or 26 of this licence, the Minister shall be entitled, after giving to the Licensee reasonable notice in writing of such his intention, to execute any works and to provide and install any equipment which in the opinion of the Minister may be necessary to secure the performance of the said obligations or of any of them and to recover the costs and expenses of so doing from the Licensee."
These clause numberings are particular to the 1988 seaward regulations but in whichever set of regulations are relevant the clauses will be appropriately numbered. In the 1988 regulations clause 14 is the measurement model clause.

5.2.2 Power of revocation

This clause states, "If any of the events specified in the following paragraph shall occur then and in any such case the Minister may revoke this licence and thereupon the same and all the rights hereby granted shall cease and determine but subject nevertheless and without prejudice to any obligation or liability incurred by the Licensee or imposed upon him under the terms and conditions hereof." Among the events referred to in the foregoing paragraph is:-
"(b) any breach or non-observance by the Licensee of any of the terms and conditions of this licence;"

6 CONCLUSION

No mention of meters is made in the regulations. The closest the regulations come to the mention of "meters" is where they state that "any weighing or measuring **appliance** shall be tested or examined". This underlines the principle that the regulations should not be viewed as prescriptive but rather should enable decisions to be made on a sound engineering evaluation of what constitutes "good oilfield practice" on a case by case basis taking fully into account all relevant special circumstances, both technical and economic.

The Status if Fiscal Measurement Legislation in the UK and Norway.

<u>Section B</u>: S Fosse, NPD, Norway

NSFMW-98
Gleneagles Hotel

- The status of Fiscal Measurement legislation in Norway

- Author:
  Principal Engineer
  Steinar Fosse

OD

NSFMW-98
NPD regulatory status

D

Norwegian Petroleum Directorate

- 1984 First regulation related to fiscal measurement of oil and gas was issued
- 1991 A major update of the regulation took place
- After 1991 it has been three updates which has been done to make it more precise and to include new experience

Norwegian Petroleum Directorate

- The regulatory regime in NPD is flexible so that adjustments/changes can be implemented into the regulatins every year. It is of course not the intention to do updates that frequent
- The updates have been done every second year

Norwegian Petroleum Directorate

- The update 1998 is mainly due to the fact that two new Norsok standards were issued 2.6.98. Fiscal measurement systems for hydrocarbon gas I-104, and Fiscal measurement systems for hydrocarbon liquid I-105.
- NPD reduces its guidelines to the regulations and instead refer to relevant sections in Norsok

Main Index

North Sea FLOW Measurement Workshop 1998

PAPER # 2.1

AN ULTRASONIC GAS FLOW MEASUREMENT SYSTEM WITH INTEGRAL SELF CHECKING.

C Letton, Daniel Measurement & Control.
D J Pettigrew, Daniel Measurement & Control.
B Renwick, Daniel Measurement & Control.
J Watson, National Engineering Laboratory

16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

AN ULTRASONIC GAS FLOW MEASUREMENT SYSTEM WITH INTEGRAL SELF CHECKING.

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Douglas Pettigrew, Daniel Measurement and Control
Brian Renwick, Daniel Measurement and Control
James Watson, National Engineering Laboratory

1 INTRODUCTION

Ultrasonic flow meters are becoming increasingly accepted for fiscal measurement of natural gas, as reflected in the latest standards, regulations, and codes of recommended practice such as NPD Regulations and Guidelines 1997 [1] and AGA 9 [2].

Since this is a new method of measurement to many operators, there is a need for diagnostic information which:

- gives confidence that the equipment is functioning correctly,
- shows, e.g. by trending, that there has been no long term shift in the measurement, and
- provides, where possible, 'health checks', i.e. advance warning of any future problems allowing suitable action to be taken in advance.

This need is reflected in the standards, which are moving towards systems which provide continuous on-line quality control and health checks to verify the correct operation of all devices. For example:

NPD, 1997 [1]: Guidelines:

"Trending of various critical parameters should be done"

"When using ultrasonic flow computers, the supervisory computer should calculate VOS (velocity of sound) based on P,T, and gas composition to monitor the VOS calculated by the ultrasonic flow meters."

AGA 9 [2]: Field Verification Tests:

"Some performance aspects of the UM's condition should be evaluated by comparing the Speed of Sound (SOS) value reported from the meter to a SOS calculated from the A.G.A. Report No. 8, Detail Characterization Method Equation of State. A chromatographic analysis ... is required for valid comparison".

For a specific Field Verification Test, this AGA 9 recommendation is met by taking a single sample of gas for off-line chromatographic analysis.

However, a typical field system for measuring energy and mass flow will include a gas chromatograph to provide the gas composition. In this case, full use of the extra diagnostic information available can and should be made by doing the comparison continuously and on-line. Note that the ultrasonic measurement of SOS is a direct measurement based on measured times and dimensions, and thus is totally independent of the SOS calculated from the gas composition, pressure, and temperature.

If a densitometer is also installed, then in a similar way we can compare the direct measurement of density with the density calculated from the chromatographic analysis, also using AGA 8. Figure 1 illustrates this concept schematically.

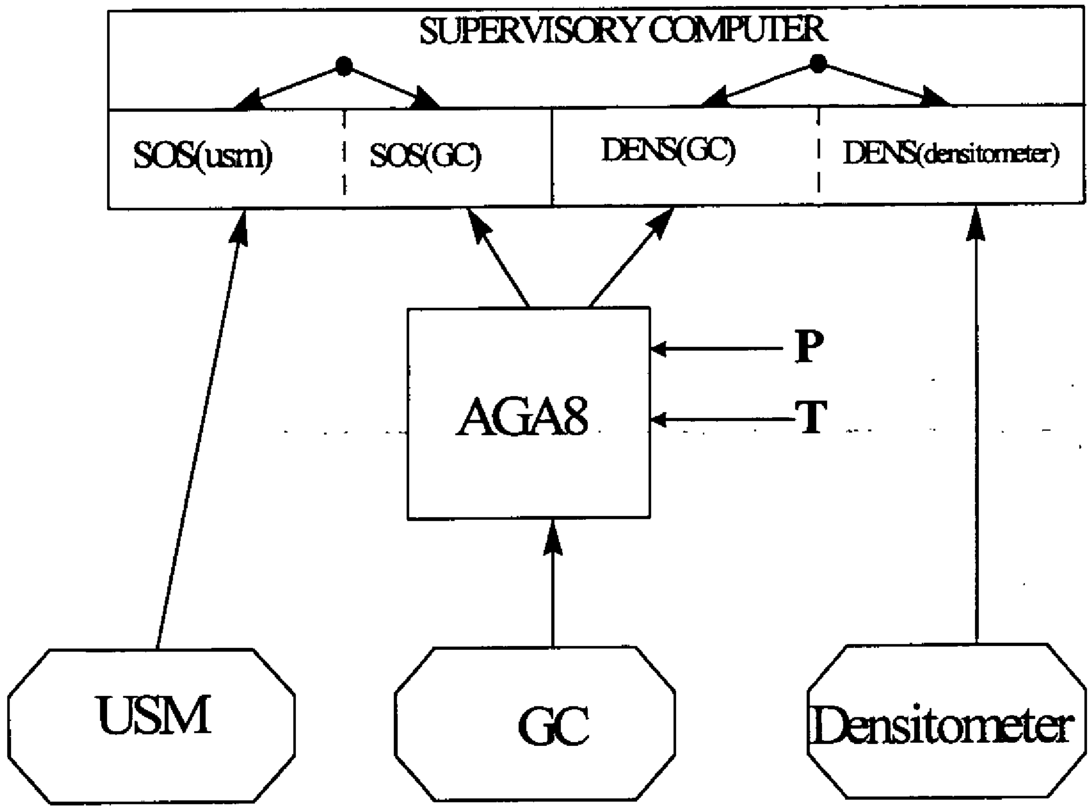

Figure 1 - Ultrasonic gas measurement system

R. Sakariassen [3] has already shown the value of trending Speed of Sound (comparison between 4 paths) and derived density; we now want to look at absolute comparisons using a gas chromatograph and densitometer.

With this system (Ultrasonic meter + Gas Chromatograph + Densitometer), the three main instruments give two independent measures of Speed of Sound and two independent measures of density. It is therefore possible to cross check all 3 instruments against each other, deduce which is the odd one out if there is a disagreement, and also provide some extra redundancy should one of them fail.

The remainder of this paper looks in more detail at the self checking and the diagnostic information available in each component of such a system. Also evaluated are the uncertainties in the dual measurements of Speed of Sound (SOS) and density, and the theoretical limits within which the above components should agree. Finally these theoretical limits are compared with actual data derived from ultrasonic metering systems, to show how cross checking could be used in operational practice.

Specific topics in the rest of this paper include:

- review of ultrasonic flow meter basics.
- self checking in ultrasonic flow meters.
- self checking and uncertainty in gas chromatographs
- accuracy of speed of sound measured by ultrasonic meters
- use of the AGA 8 equation
- the applicability of AGA 8 to rich natural gases
- calculation of the speed of sound using AGA 8
- an integrated configurable system
- experimental data
- field implementation.

2 REVIEW OF ULTRASONIC METER BASICS

Before looking at the main topics of consideration here, it is worth reviewing the basics of ultrasonic transit-time flow measurement. Consider the case shown in Figure 2 below.

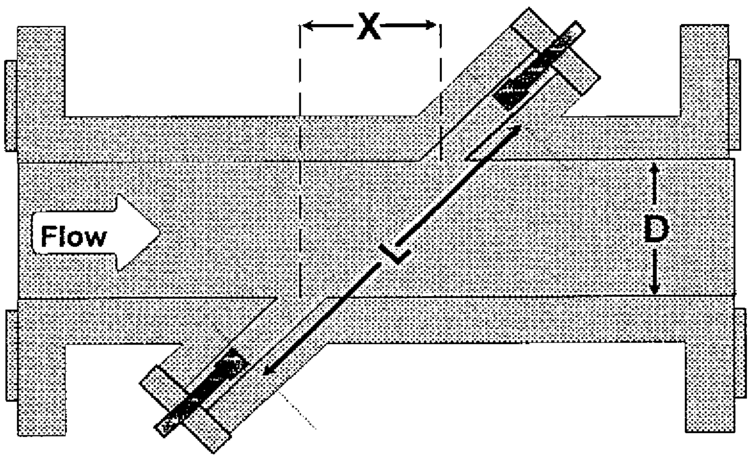

Figure 2 - Ultrasonic Meter

If L and X are the direct and lateral (along the pipe axis and in the flowing gas) distances between the two transducers, C is the Speed of Sound and V the flow velocity of the medium, and T_{12} and T_{21} are transit times in each direction,

then

$$T_{12} = \frac{L}{C+V\cdot\frac{X}{L}} \qquad (1)$$

and

$$T_{21} = \frac{L}{C-V\cdot\frac{X}{L}} \qquad (2)$$

Inversion of these two equations yields

$$V = \frac{L^2}{2X}\left(\frac{T_{21}-T_{12}}{T_{21}\cdot T_{12}}\right) \qquad (3)$$

and

$$C = \frac{L}{2}\left(\frac{T_{21}+T_{12}}{T_{21}\cdot T_{12}}\right) \qquad (4)$$

Thus, by measuring dimensions and transit times in pursuit of the average flow velocity along the path between transducers, we have also measured the Speed of Sound along this path. This will prove to be an extremely useful parameter in determining the overall performance of the meter.

3 SELF CHECKING IN ULTRASONIC METERS

One of the principal attributes of modern ultrasonic meters is their ability to monitor their own health, and to diagnose any maladies which may be detected. Multipath meters offer the ultimate in this regard, as they can compare certain measurements between different paths, as well as checking each path individually.

Measures which can be used in this self-diagnosis include the following.

<u>Gain</u>. One of the simplest indicators of a meter's health is the presence of strong signals on all its paths. Properly designed multipath meters will have automatic gain control on all receiver channels, hence an increase in gain on any channel indicates a smaller signal on that channel, perhaps due to transducer deterioration, fouling of the transducer ports, or even liquids in the line [4]. Caution must be exercised to normalize for other factors which affect signal strength, such as pressure and flow velocity. Whatever the cause, if it persists and threatens good signal detection, it is a cause for further investigation.

<u>Signal Quality</u>. This expression simply refers to the influence a detected signal has on a meter's ability to make a proper detection. Since this is highly dependent on the detection scheme employed by a given meter, one cannot simply jot down general equations which describe this parameter for any meter. The vendor of any given meter should, however, be able to supply some figure of merit describing how good his signal detection is for each ultrasonic path, i.e. the <u>signal quality</u> for this path. Note that this measure may be either statistical (percentage of good detections) or structural. A good instrument will monitor both.

<u>Signal to Noise Ratio</u>. This should also be monitored as an independent indicator. Note that the noise may be gas borne, (e.g. from pressure reduction valves), or from coupling of sound from the transducer to the meter body, or electrical. Stacking can be used to overcome some kinds of noise problems.

<u>Sanity Checks</u>. Correct meter operation dictates that certain parameters will have well-defined ranges, and that any measurement or estimate outside that range indicates that an error has occurred. Likewise, ranges exist for parameter changes. Alarms or warnings can be raised for out-of-range values for either.

<u>Velocity Profile</u>. Once a meter is placed in a specific gas pipeline configuration, the velocity profile of the gas for a particular average velocity should not vary a great deal. If the multipath meter in use is capable of measuring the velocity profile, then significant departures of this profile from normal should be viewed as a cause for concern.

<u>Speed of Sound</u>. Since an n-path ultrasonic meter has **n** paths of the type shown in Figure 1, it has **n** independent means of measuring and comparing the Speed of Sound (SOS) of the gas in the pipeline.

<u>Statistical Measures</u>. An ultrasonic meter will typically fire pulses and measure the transit times at as high a sampling rate as possible, then average the results from a 'batch' of several measurements. The standard deviation of the individual readings in the batch from the mean values can be used to indicate meter operation. Deviations can indicate the onset of problems.

4 SELF CHECKING AND UNCERTAINTY IN GAS CHROMATOGRAPHS

4.1 Self checking in Gas Chromatographs

Most on line process gas chromatographs have a variety of self checking procedures, the exact details of which are dependent on the manufacturer. Listed below are a set of self checks suitable for a process gas chromatograph operating with a thermal conductivity detector.

Status of Detector. The thermal conductivity detector has to be balanced to provide a good analytical measurement. Detector voltage balance is checked at the start of every run when only carrier gas is present. Deviations from the balance point indicate a change in detector circuit conditions and if the signal drifts beyond pre-set limits this should be investigated.

Signal from Detector. The analogue signal from the thermal conductivity detectors is subjected to various degrees of amplification. Limits on the allowable range of this signal, for example, between 5% and 95% of full scale, are automatically set and checked during data acquisition. Values outside the limits will indicate a fault condition.

Analysis Results - Un-normalised Total. There are always small variations between successive gas chromatograph analyses of the same gas. Furthermore, with atmospheric pressure sample injection systems the size of sample injected changes proportionally with variations in ambient pressure. However, in a correctly configured and calibrated system the un-normalised component total (i.e. the actual quantity of component detected) should always be close to 100%. Significant deviations from 100% indicate that there is a potential problem with the analytical set up. In the UK it is normal fiscal metering practice to set the un-normalised total limits for gas chromatograph analysis to $\pm$ 2%.

Analysis Results - Range Limits. If the gas composition is known to be relatively stable then limits for the ranges of individual component measurements or calculated physical properties can be set.

Calibration. Regular calibration of process gas chromatographs provides a method of updating response factors for small changes in local conditions. However, for most process gas chromatographs detector response is constant over a long time period. Perhaps the most significant feature of regular calibration is that it gives a performance check, i.e. a comparison of current performance with a known standard against the last good calibration with that standard. Limits are set on response factor and retention time deviation, and changes outside these indicate a significant change in the performance of the analytical unit.

4.2 Uncertainties in Gas Chromatograph Analysis

It is outside the scope of the current paper to discuss the uncertainties associated with on line gas chromatograph analysis, and a fuller discussion can be found elsewhere [5, 6]. Briefly, the principal causes of uncertainty in process gas chromatographs measurement are the following. First are uncertainties in the calibration gas concentrations. Next are uncertainties due to variation in instrument response, i.e. repeatability of the process gas chromatographs. Third are bias errors caused by non-linearity of detector response. Fourth are uncertainties associated with the values used in the calculation of physical properties, such as density. At best, with no bias errors and a top quality approved calibration gas, this can give a density uncertainty of 0.05%. However, when bias errors are introduced and/or poor quality calibration gases are used, errors of 0.3% or greater are possible.

5 ACCURACY OF SPEED OF SOUND MEASUREMENT BY ULTRASONIC METERS

The "dry calibration" of ultrasonic meters is accomplished by making precision measurements of the meter geometry and transducer delay times. The transducer delay times are determined by measurements taken in a test cell filled with a known gas (nitrogen) at known temperature and pressure. The speed of sound of nitrogen is thus known to within 0.1%. When the complete ultrasonic meter is later assembled, a final check is done by filling the meter with nitrogen. Measured speeds of sound on all chords must agree within 0.1%, which takes into account the uncertainty in the geometry (chord length) and transit time measurements.

For a flowing gas, there may be additional effects due to the inability of simple ray theory to fully describe the complex interaction of the ultrasonic pressure wave with the flow. (For a more complete explanation, see AGA 9 [2], Appendix C.) This phenomenon is evident by looking at how the velocity of sound values vary from inner to outer paths. In the data presented later in this paper, using four-path meters, it was found that at the highest flow velocities (28 m/s), the four individual speed of sound readings fell within a range of 0.1% of the average. At lower velocities this figure dropped to 0.05%. It therefore seems reasonable to bound these errors in flowing gas to about 0.1%.

Overall then, the uncertainty in the speed of sound measured by a multi-path ultrasonic meter from these three kinds of errors is estimated to be $\pm\sqrt{(0.1^2 + 0.1^2 + 0.1^2)} = \pm 0.17\%$.

6 USE OF THE AGA 8 EQUATIONS.

If the gas composition, pressure, and temperature are known, then both the gas density and the Speed of Sound can be calculated from the gas equation of state. The accepted standard equation of state for lean natural gases is the current revision of AGA Report No 8 [7], using the Detail Characterization Method (complete gas composition).

This equation is valid for lean natural gas mixtures over a wide range of conditions.

In principle, the gas chromatographic technique for the determination of density should be as effective as that using a fully calibrated and traceable densitometer, given that the measurements of pressure, temperature, and the gas composition are made to a sufficiently high standard.

6.1 AGA 8 Accuracy - Lean Natural Gases

The accuracy of the AGA 8 equation of state depends on the composition of the natural gas and on the temperature and pressure at the metering conditions. The targeted uncertainties (at two standard deviations) for the AGA 8 equation of state in terms of temperature and pressure are:

Table 1

Region	Temperature Range	Absolute Pressure Range	Uncertainty in Density
1	-8 to 62°C	0 to 120 bar	0.1%
2	-60 to 120°C	0 to 170 bar	0.3%
3	-130 to 200°C	0 to 700 bar	0.5%
4	-130 to 200°C	0 to 1400 bar	1.0%

The AGA 8 equation is claimed to meet these expected or targeted uncertainties for gas mixtures having a *normal range* of compositions, see below, within Region 1, and in parts of Regions 2, 3, and 4. For the *expanded range* of compositions given in the following Table, the uncertainties are expected to be higher.

Table 2

	Normal Composition Range		Expanded Composition Range	
Component	Lower limit (mole%)	Upper limit (mole%)	Lower limit (mole%)	Upper limit (mole%)
Methane	45	100	0	100
Nitrogen	0	50	0	100
Carbon dioxide	0	30	0	100
Ethane	0	10	0	100
Propane	0	4	0	12
Butanes	0	1	0	6
Pentanes	0	0.3	0	4
Hexane's plus	0	0.2	0	dew point

7 THE APPLICABILITY OF AGA 8 TO RICH NATURAL GASES.

The application of the AGA 8 equation to rich natural gases (approximately 60% methane with the balance being heavier hydrocarbons), as encountered in gas condensate fields in the North Sea, has only recently been tested.

The UK National Engineering Laboratory (NEL) has been involved in a Joint Industry Project to investigate the applicability of the AGA 8 equation to rich natural gas mixtures. A measurement program was launched, firstly, to determine the magnitude of the differences between AGA 8 and reference-quality density data for ten natural gas mixtures in the range 80 to 180 bar and 40 to 80°C; and secondly, to provide reference-quality density data for subsequent refinements to the AGA 8 equation. The reference-quality data were obtained using NEL's primary standard densitometer.

The evidence from this major research program has established that:

- calculated densities for mixtures with compositions in the *expanded range* are better than expected.
- the maximum differences between measured and calculated densities occur for those mixtures with component compositions above, or close to, the upper limit of the *expanded range* of compositions; and
- the upper composition limit for carbon dioxide (30%) for *normal range* application is much too high.

8 CALCULATION OF THE SPEED OF SOUND.

The Speed of Sound of the gas mixture can be calculated by an extension of the equations given in the AGA 8 standard.

The necessary equations are detailed in a GRI report [8], which uses essentially the same equation of state as found in the 1985 version of the AGA 8 standard. These equations should be upgraded to be consistent with the latest (1994) edition of AGA 8. Also, the equations require a knowledge of Cp, the ideal specific heat of the gas at constant pressure.

All calculated values of Speed of Sound in this paper were derived using the implementation of the AGA 8 equations by Daniel Measurement and Control for use on their systems. Similar calculations are available as PC based programs from various sources, e.g. the AGA 8 package from NEL, which supplies a complete range of calculated properties, including Speed of Sound, and is supplied in Excel compatible form.

8.1 Uncertainty of the calculated Speed of Sound

The uncertainty in the calculated Speed of Sound depends upon:

- the uncertainty inherent in the equation of state calculations.
- the uncertainty in line pressure and temperature
- the uncertainties in the measured gas composition

The accuracy of the AGA 8 equation of state depends on the gas composition, pressure and temperature. The equations are less accurate at high gas density (lower temperatures and higher pressures), and with richer gases, or gases containing relatively large amounts of CO_2.

The accuracy of the Speed of Sound calculation (Daniel implementation) has been quantified by comparing the calculated values with experimental data published by NIST [9], which has a stated accuracy of ± 0.05% on measured Speed of Sound values.

The NIST data uses 4 natural gas mixtures, 2 of which (Gulf Coast and Amarillo) are lean gases within the *normal* range of AGA 8. The third mixture used (Statoil Dry gas) is only slightly outside the *normal* range (ethane = 13%), and is included in the results below as a *normal* gas. The final mixture is Statoil Statvordgass, which is a richer gas in the AGA 8 *expanded* range.

For lean natural gas above 0°C and below 130 bar, the agreement (95% limit) between calculation and measurement was found to be ± 0.07%.

The results for a wider range of conditions are summarised in Table 3.

Table 3

Gas Composition	Temperature	Pressure	Uncertainty in calculated SOS (95% limit)
Normal	> 0°C	< 100 bar	0.07%
"	"	100 to 130 bar	0.16%
"	-23°C to 0°C	< 100 bar	0.13%
"	"	100 to 130 bar	0.64%
Statoil Statvordgass*	25°C to 75°C	< 60 bar	0.11%
"	"	60 to 105 bar	0.90%

* The Statoil Statvordgass composition is:

methane	74.348%
ethane	12.005%
propane	8.251%
normal butane	3.026%
normal pentane	0.575%
normal hexane	0.230%
nitrogen	0.537%
carbon dioxide	1.028%

Similarly, the uncertainties due to measurement of gas composition, pressure and temperature have been estimated numerically by observing the effect on the calculated Speed of Sound, independently varying each parameter. If we postulate uncertainties of 0.3°C and 0.2 bar in the measurement of pressure and temperature (maximum allowed by NPD requirements for fiscal systems) and feed these into the Speed of Sound calculations, the added uncertainty in Speed of Sound is roughly 0.07%.

Similarly, the uncertainties in composition from a typical gas analysis system results in an added error of roughly ± 0.05%.

In summary then, the overall uncertainty (95% confidence limit) in **calculated** (AGA 8) Speed of Sound, for a *normal* gas below 100 bar and above 0°C, is:

from NIST measurement:	0.05%
from equation of state:	0.07%
from P and T:	0.07%
from gas analysis:	0.05%
Total (square root rule) =	**0.12%**

For richer gases, lower temperatures or higher pressures, the uncertainty will be greater, as indicated above.

9 AN INTEGRATED CONFIGURABLE SYSTEM

Refer to the system shown in Figure 1. This is an integrated system for volume, mass and energy flow with additional checking, in the sense that the three main components provide two independent measures of both Speed of Sound and density. They can therefore cross-check one another, as well as provide an extra level of redundancy. However it is also configurable in the sense that various components can be switched off, or even omitted entirely to give reduced cost for suitable applications.

It is worth noting that the Speed of Sound is used as a correction to the densitometer measurement, and therefore in this system, the densitometer accuracy can be increased by using the live Speed of Sound measurement from the ultrasonic meter (backed up by the gas chromatograph).

Possible reduced configurations are:

1) USM +GC (no densitometer):
Still provides volume, mass and energy measurement with cross checking on Speed of Sound.

2) USM + densitometer (no GC):
Provides volume and mass flow. The 'fall back' for energy would be to enter a fixed gas composition, or fixed heating value.

3) USM only.
This is suitable for certain kinds of systems, and can be useful if the gas composition is well known and does not vary significantly from week to week.

10 EXPERIMENTAL DATA COMPARING SPEED OF SOUND AND DENSITY

In order to investigate the degree of agreement that can be expected in normal operation, between the dual measurements of Speed of Sound and density, data has been collected from flow calibration tests of Daniel 4-path ultrasonic meters with nominal sizes of 6", 8", 10" and 12". In each case the data covers flow velocity ranges of approximately 2 to 28 m/sec, using typical lean natural gases, pressure ranges of roughly 30 to 50 bar. The 8" meter data was obtained during approval tests at the Gaz de France facility at Alfortville, Paris. The remaining data were obtained during flow calibrations carried out at the British Gas flow test and calibration facility at Bishop Auckland, UK. The gas chromatograph at Bishop Auckland was a Danalyzer, that at Alfortville was by another manufacturer. The authors gratefully acknowledge the help and co-operation received at both of these sites.

10.1 Speed of Sound

The preceding sections show that the expected uncertainties (2 standard deviations) in Speed of Sound are:

USM measurement	± 0.17%	
Calculated (AGA 8)	± 0.12%	(lean gas, P < 100bar)

In actual practice, using lean natural gas below 100 bar, we would therefore hope to find that 95% of readings agree within about 0.21% (about 0.8 m/sec).

The actual data for the 4 meter sizes is summarised in what follows. Each figure shows trended values covering 2 to 3 hours.

First shown is data from the 8" meter in Figure 3, comparing the **average** Speed of Sound over the 4 paths with the AGA 8 calculated value.

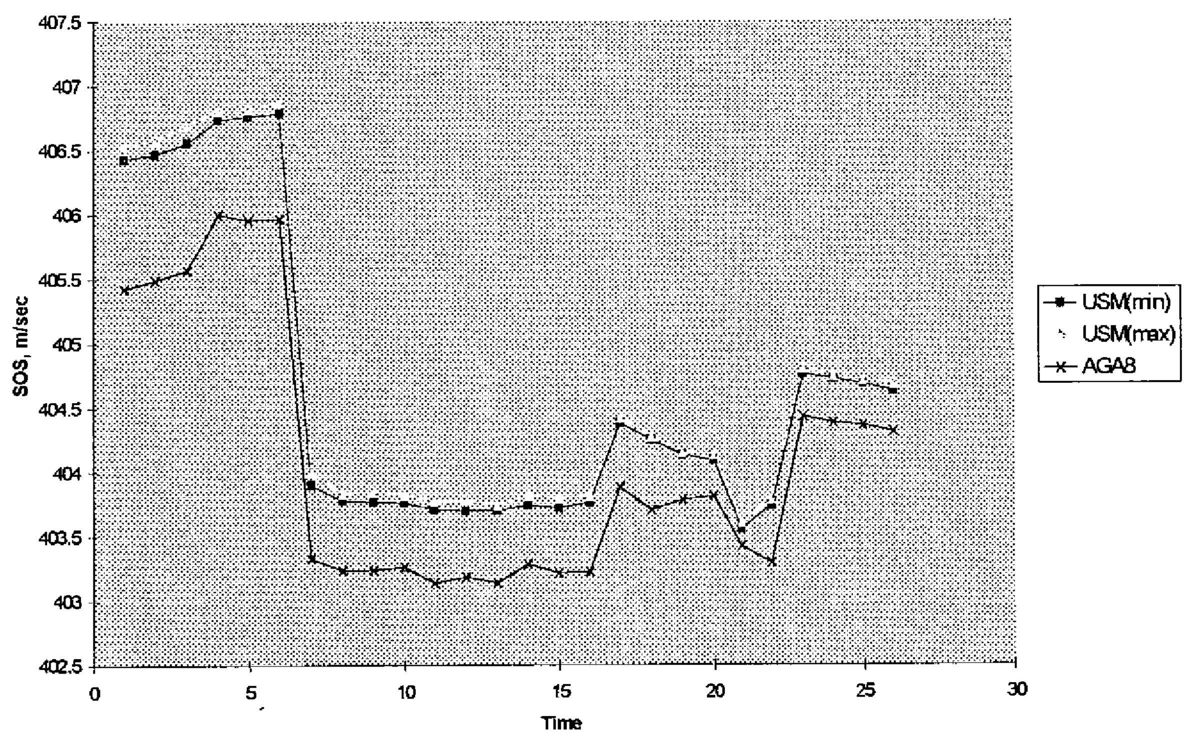

Figure 3 - 8" meter. Measured vs. calculated SOS

At each measurement point, ten successive values of the ultrasonic meter Speed of Sound were logged. The two curves which show the minimum and maximum values from each of these sets demonstrate a repeatability in the SOS measurements of better than 0.03%.

Figures 4 through 6 show the AGA 8 calculated Speed of Sound trended against the individual Speed of Sound readings from the four paths. Note that in each case the agreement on all chords is roughly as expected, but that the agreement on the two central paths (chords B and C) is significantly better than on the outer paths (chords A and D).

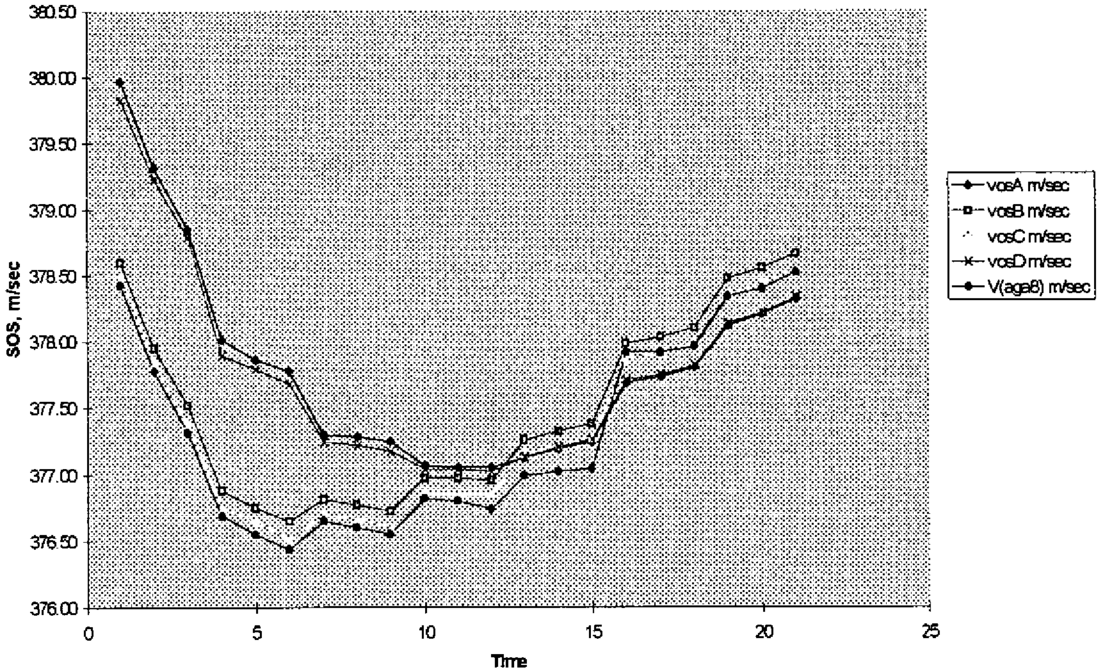

Figure 4 -Six-inch meter. Measured Speed of Sound on four chords vs. AGA 8 calculation

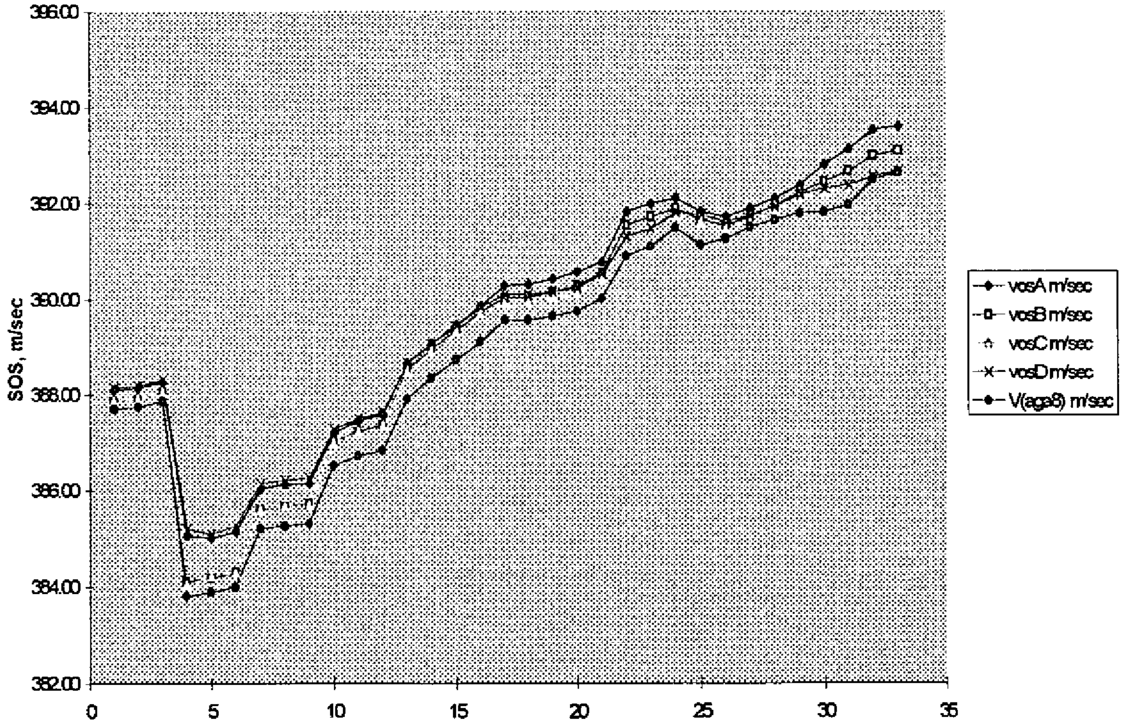

Figure 5 - Ten-inch meter. Measured Speed of Sound on four chords vs. AGA 8 calculation

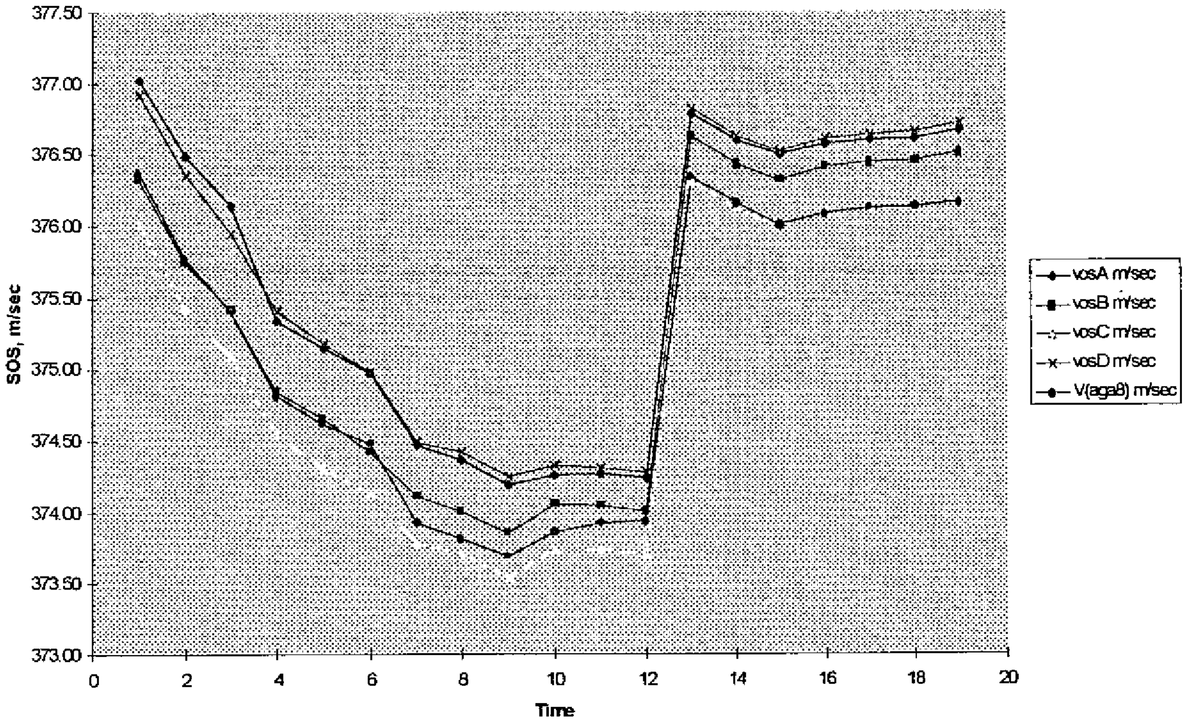

Figure 6 - Twelve-inch meter. Measured Speed of Sound on four chords vs. AGA 8 calculation

From the above results, it is clear that on a multi-path meter, absolute Speed of Sound comparison is best done using the central paths. As pointed our in our earlier discussion, this is due to the complex nature of wave propagation in the flowing medium, which seems to most greatly affect the outer chords.

The Table below shows the rms and maximum deviations between AGA 8 and USM observed, using the mean values of SOS on the central (B and C) chords for each meter (except the eight-inch, for which individual chord readings were not recorded).

Meter Size	rms deviation	Maximum Deviation
6"	0.04%	0.08%
10"	0.11%	0.15%
12"	0.04%	0.06%

This suggests that when using on-line cross-checking of Speed of Sound, a reasonable approach would be to set an alarm limit of about ± 0.3%.

10.2 Test Data - Density

The expected uncertainties (2 standard deviations) in density are:

Densitometer measurement: ± 0.3%
Calculated (AGA 8) density: ± 0.1% (*normal* gas, region 1)

In real operation, using lean natural gas, we would therefore expect the difference between the two derivations of density to fall within ± 0.33%. (95% limit).

Figures 7 and 8 show density data (densitometer v. AGA 8) from the tests of the eight-inch meter at Alfortville. The second figure shows the same data set as the first, expanded to show more detail.

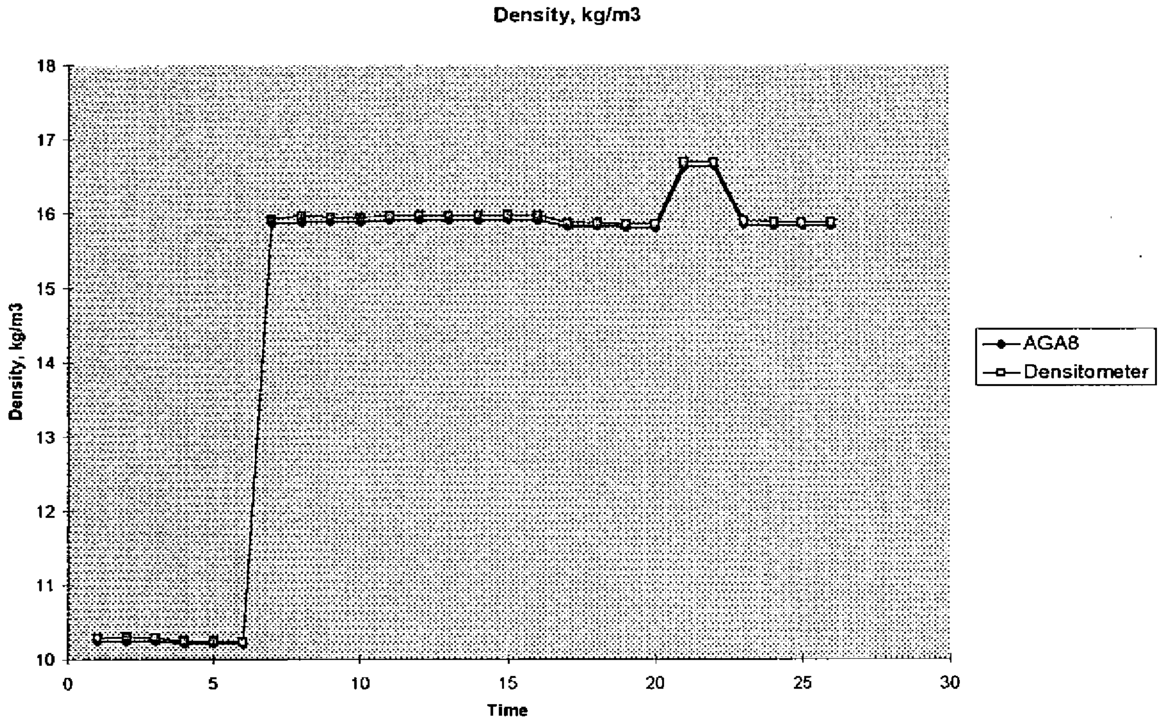

Figure 7 - Measured density vs. calculated density (AGA 8)

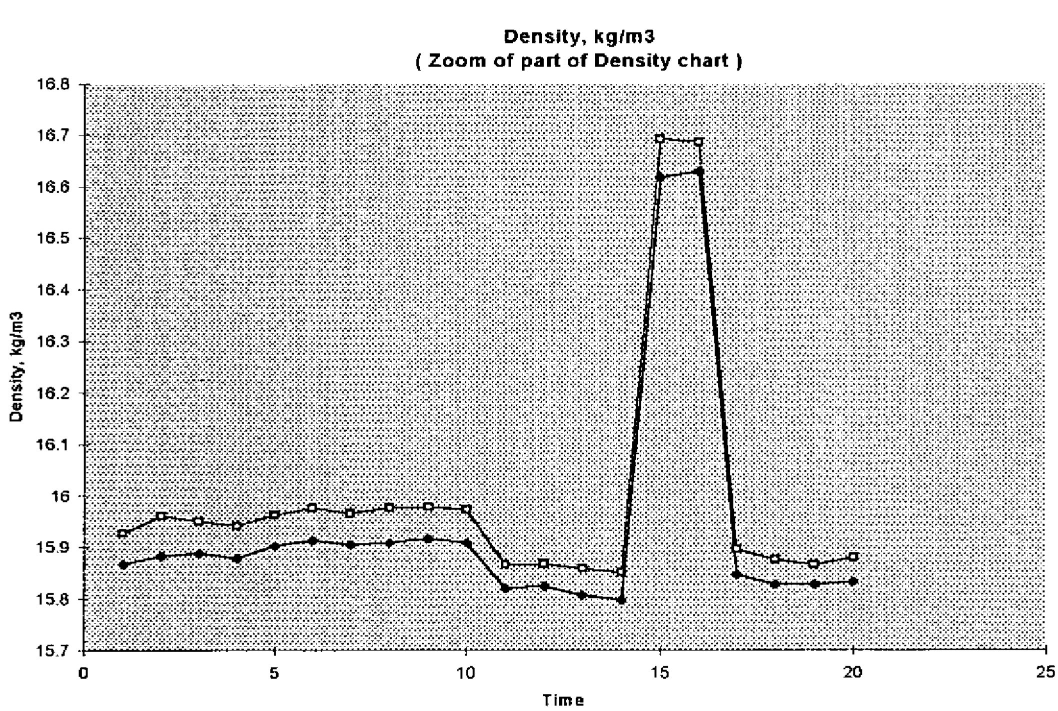

Figure 8 - Measured density vs. calculated density (AGA 8)

Once again, the two measurements track well, with a small systematic offset. The deviations between the two measurements range from 0.45% to 0.24%, slightly outside the theoretical predictions, but broadly as expected.

The result and theory both suggest that when using density as a health check, a reasonable limit for raising an initial warning alarm would be a difference of ± 0.9%. This may depend on the specific densitometer being used.

11 FIELD IMPLEMENTATION

What we have shown here is a method whereby three instruments can yield independent estimates of two key parameters, thereby permitting the user to detect a malfunction in any of the three. The calculations shown were all performed on a PC, which raises the question of how the method will be implemented in field operation. Must a PC, either standalone or as part of a supervisory system be present in order to perform the algorithms?

Fortunately, the next generation of panel-mounted flow computers will be capable of performing tasks such as this, which formerly required a standalone computer. One recent introduction incorporates a fast 32-bit processor, and is thus fully capable of performing the AGA 8 calculations, as well as interfacing to the ultrasonic meter, the gas chromatograph, and the gas densitometer.

12 CONCLUSION

The above results indicate that, in addition to the internal checks available within an ultrasonic meter, it is both practical and useful to incorporate both gas chromatographs and densitometers to give independent checks. Practical operational limits for initial warning alarms would appear to be about ± 0.3% deviation in Speed of Sound, and ± 0.9% in density.

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PAPER 6 2·2

OPERATIONAL EXPERIENCE OF MULTIPATH ULTRASONIC METERS FOR FISCAL GAS SERVICE

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16TH NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

Operational Experience of Multipath Ultrasonic Meters in Fiscal Gas Service

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1 INTRODUCTION

This paper has been written with the intent of sharing an operator's experience associated with the application of ultrasonic gas meters in fiscal service. The paper starts on general calibration issues and then focuses on the performance of a five-path meter, which has been in fiscal service for the last three years. Some further experience from the testing of three and four path ultrasonic devices will also be covered. Issues from initial testing, routine maintenance, in service operation and general observations will be discussed to increase awareness of the areas of concern and potential pitfalls.

The historical trends obtained from the progressive testing of the five-path meter demonstrates the suitability of this device for the demanding application of sales gas metering with the associated tight uncertainty requirements. Use of such meters will give operating companies many benefits and cost savings in project development and in day to day operations, while the customer can have confidence in the accuracy and repeatability of the instrument. With the increasing demands to reduce operating costs, the reduction of maintenance and recertification activities must be actively pursued.

As this technology is still in its infancy all associated parties need to communicate actively and work together to improve our common understanding and knowledge of this type of meter.

Areas that offer the largest potential gains are:
- Effects on the meter response to differing surface conditions of the meter internal pipe wall and the associated upstream and down stream meter tubes.
- Simple methods for insitu testing, removing the requirement for frequent testing at calibration facilities, (e.g. the possibility of a simple method for zero checking the meter).
- The effects of noise from external sources and system design to avoid such problems.

2 CALIBRATION

2.1 Selection of a suitable test facility

If the meter is new and under going acceptance trials the test venue will normally be selected by the manufacturer. This choice of venue should be discussed and agreed with the customer. The manufacturer may have built up an understanding with a particular test facility but it may not be the most cost-effective venue for the customer. To establish traceability, the meter will ideally be returned to the same facility a number of times. This will be an on going cost for the customer.

Before the initial tests a clear understanding of the program of events and procedures being used should be discussed and agreed, so all parties are aware of the deliverables required and the acceptance criteria.

The operator is then faced with a problem on subsequent tests, should he repeat the test at the same location or can he be more flexible and tender the recalibration, thereby obtaining a better deal elsewhere. The operator is required to build up a history of calibration data of a meter in Fiscal service. He must demonstrate to both customers and government bodies that the meter is reading without bias and accurately over the operating range and that it is being operated and maintained within the terms of the commercial agreements. This usually means that once a particular facility has been chosen, it will be used repeatedly (assuming testing meets the requirements) until historical evidence and an understanding of the instrument's performance has been built up.

2.2 OPERATOR EXPECTATIONS FOR THE CALIBRATION

The following three areas give the expectations of the operator, when interfacing with the test facilities and the meter vendor during calibration testing.

2.2.1 Actions to be considered and undertaken by the operator

- The test facility chosen must be traceable to a recognised International standards authority, with the primary calibration test records available for inspection at the facility.
- The facility should be accessible, both from testing availability (given reasonable notice) and location (transport and accommodation).
- Have the ability to reproduce the operators pipework configuration for the test i.e. Upstream & downstream lengths, inlet bend ('T', curve or 90^{o}) and pipework classification.
- The ability to meet the requirement to quickly change pipework configuration, giving the possibility of completing multiple tests on one day.
- Having the availability of suitable quality test gas to enable the full operating range of the instrument to be tested.
- Have access to all aspects of the testing facility for inspection during the test (if safe to do so).
- The meter should be ready to test (even if this requires the vendors to perform a pretest).

2.2.2 Information requirements of the calibration facility

- Prior knowledge of the instrument to be calibrated, both size & body rating and interface requirements for the electronics.
- Information on the required test configuration.
- What is the full range of flow, how many test points and repeats are required. Considerations for repeat tests as a mirror image.
- What type of factor adjustment is required i.e. linear interpolation or 'Nth' order curve fit.
- If repeat test points are required after factor adjustment has been applied as a check reference.
- If any extra testing will be required and for what purpose i.e. removing probes, altering surface conditions of the meter.
- The number of people attending and whether they require reports of the test results.
- Any preparation works prior to installation in the line i.e. surface cleaning.
- The format, including what language, of the test certificate.

2.2.3 Service provision from the vendor if requested to be present at the test

- Sufficient quality and quantity of equipment to allow testing to commence i.e. power supplies, interface boxes, diagnostic software.
- Ability to obtain parts at short notice so that calibrations can continue even if a component failure occurs.
- Offer full technical support, on operation of all associated equipment, the analysis of the results and possible suggestions from operational experience.
- Clearly written user manuals giving details of the meters build and operational calculations.

2.3 Actual calibration

2.3.1 Preparation

The preparation prior to testing determines the success of the exercise. If everyone associated with the activity is aware of the tasks, procedures and deliverables, the calibration can be completed in a reasonably short space of time and in a controlled manner.

Once the operator/vendor establishes the need for a calibration and has determined the type of testing required, a discussion with the test facility is recommended. This will produce availability dates of the facility for the test, an estimate on time required for the proposed testing required and highlight any need for procurement of new spools. Agreement on the upstream and downstream straight lengths is a must.

The required flow range must be determined, the number of points across the range should be checked and the number of repeats at each point agreed. This decision depends on the service the meter has seen. At present for a new meter a full comprehensive check is almost essential, whereas repeat calibrations can be less ownerous depending on previous calibration history. For a new meter, a minimum of six flow rates at equidistant points across the flow range are required, with three repeats at the four higher flow rates and five repeats at the two lowest flow rates. Using the high flow rates first gives better temperature stabilisation. After a factor adjustment has been applied, two spot checks within the range shall be made. In principle, as our understanding increases, it should be possible to use the manufacturer's factory calibration, derived from metrology of the meter, for the initial settings.

The cost of testing can vary from facility to facility, charges can be against the number of required flow ranges, or the number of repeats per flow range (the total amount of runs required), or even based solely on the time period for which the facility is being utilised by the customer. The costs can normally be adjusted during discussion with the facility personnel.

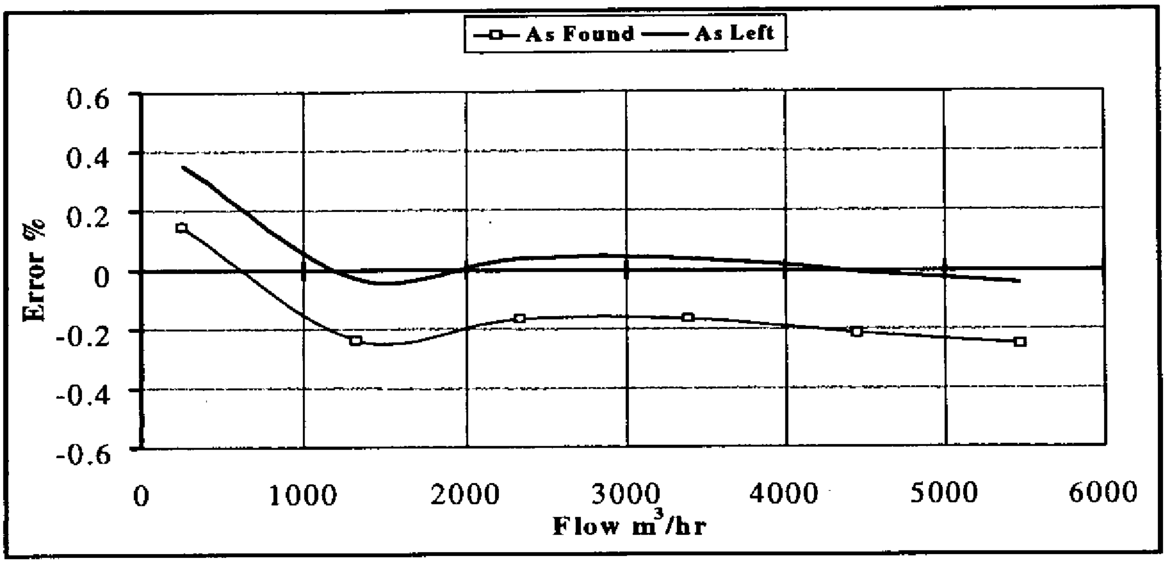
As each test run is completed a resultant performance curve will become evident. The method of factor adjustment should be considered. This may depend on the software available in the meter's electronics or the associated flow computer being used. Also different manufacturers meters produce different shaped curves, so another method of adjustment may be required. The required test certificate / report information should also be defined with inclusion of test temperature and pressure.

2.3.2 Flow factor adjustment techniques

This section aims to explain and demonstrate the current techniques and philosophies used to adjust the meter to read without bias and accurately. For all the correction demonstrations, actual calibration data has been used.

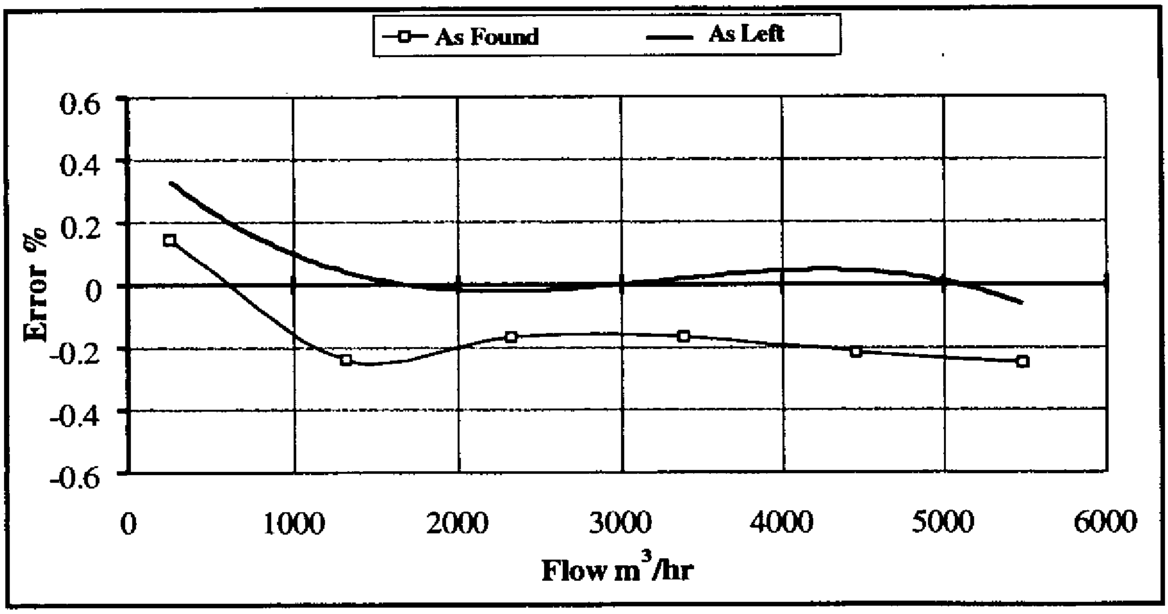
Average flow factor

The average offset over a selected range is calculated arithmetically and applied as a one-off correction.



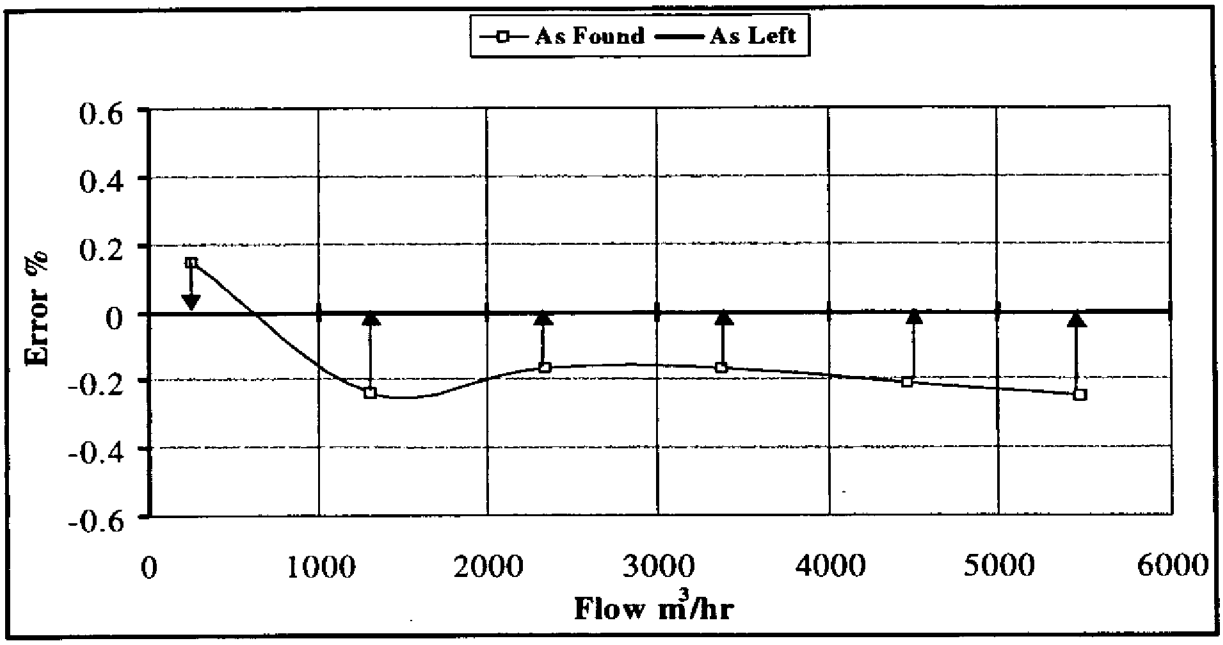
Third order polynomial

A third order polynomial is fitted to the data and the flow coefficients determined.



Linear interpolation

Each calibration point is adjusted to give zero offset. From a look up table containing the flow rate against offset, a value can be predicted over the whole flow range by using linear interpolation.



As an operator we have selected linear interpolation because:

- The method is already in use on turbine meters.
- The method is easily demonstrated to auditors.
- The resultant curve lies exactly along the datum line.

The reasons we don't like the second option of 3rd (or indeed Nth order) curve fit:

- A decision has to be made as to which order the curve is corrected.
- It's difficult for auditors to check the curve fit calculation easily.

The operator, government authorities and customers must agree the method of adjustment used. Whilst details of any adjustment must be recorded, provision of these details may not necessarily form part of the scope of work of the calibration facility.

2.3.3 Testing

The meter and pipework associated with the calibration activity must be inspected prior to insertion into the test configuration.

Meter:

Pay particular attention to the internal surface condition and make a sketch for the record (taking photographs of the internals is very difficult). The manufacturers often apply corrosion inhibitor to the inner surfaces. This must be removed prior to testing, as any residue discovered after the event will mean the calibration test is null and void. The surface conditions will change in use dependent on operational parameters. Surface corrosion, erosion or component deposits may be evident – other than for a new meter no attempt should be made to clean or wipe the internal surface as this will have direct effect on the calibration result.

Pipework:

It is important that no steps are evident, no protruding welds are present and the correct flange types are being used (ISO5167 is a useful guide). This is to obtain the required flow profile at the meter. Records should be kept of the test spools used for future reference.

If the meter is new, consideration should be given to testing additional aspects before the final calibration run. This will mean slightly higher calibration costs but may save on operational cost – possibly saving on a retest after equipment or component failure. As an example, we consider sensor failure and replacement. First establish the basic meter curve, with two repeats at each flow rate across the whole range. Then assess relative probe failures on each individual path, and various combinations of failures (easily achievable by disconnecting the relevant cable) recording resultant meter performance after each test. Finally remove a pair of probes from the meter (observing all operational and safety implications), replacing them in the opposing locations (swapping the relative positions). Recheck the meter at two points on the curve to determine whether shifts have occurred, again keeping appropriate records of the test.

The test runs can now start in earnest following the agreed procedures. The application of an automatic data acquisition system speeds up processing and enhances confidence in the results.

When recalibrating the meter an 'as found' curve must be produced first. Then the factor adjustment can be applied. All data associated with the test should be captured in electronic and paper format. The configuration list of parameters, the temperature and pressure must be included with the calibration certification and report.

3 ROUTINE MAINTENANCE

3.1 Periodic checks

The following section details the maintenance carried out on the ultrasonic meters:

Daily checks

Visual checks performed on each of the stream flow computers.

- Ensure that no alarms are standing that would indicate poor meter performance.
- Ensure flow rate information is being received and is updating. Confirm updates are not displaying large step changes, indicative of poor meter performance or bad process conditions.
- If more than one stream online, ensure flow rates are comparable taking into account any known flow bias.
- On off line streams ensure that flow has not been accumulated. If so, confirm that it has not been recorded on the station daily report.

Weekly checks

Take a data log from each of the meters, review the logs as follows:

- Check the health state of each of the five flow paths. This is determined by the quantity of good flow signals processed for each flow path.
- Compare flow velocities of online meters, taking into account any known flow bias.
- Monitor the automatic gain control (AGC) level for each of the transducer pairs. This indicates how strong the signal level needs to be in order to transmit the ultrasonic signals through the process medium.
- Carry out a physical inspection of the meters, including all cabling and probes for any signs of damage.

An example of the meter data log is shown below:

Samples /sec	Performance Per Path %					Sound Velocity	Corrected Gas Vel	Gross Vol Flowrate	Stb
	Path 1	Path 2	Path 3	Path 4	Path 5				
13	100	100	100	100	100	421.68	2.71	7.2E+02	3
14	85	100	100	100	100	421.69	2.691	7.2E+02	3
13	100	100	100	100	100	421.71	2.734	7.3E+02	3
14	100	100	100	100	100	421.71	2.711	7.2E+02	3
14	100	100	100	100	100	421.71	2.695	7.2E+02	3
13	100	100	100	100	100	421.7	2.741	7.3E+02	3
14	100	100	100	100	100	421.7	2.704	7.2E+02	3
13	100	100	100	100	100	421.69	2.721	7.3E+02	3
14	85	100	100	100	100	421.67	2.715	7.2E+02	3
13	92	100	100	100	100	421.67	2.689	7.2E+02	3

AGC Level of transducer pair path A/B										Maximum AGC Level
1A	1B	2A	2B	3A	3B	4A	4B	5A	5B	
5475	5600	8415	8415	5125	5400	8160	8160	5325	5325	65025
5350	5650	8925	8415	5300	5300	8160	8160	5275	5275	65025
5525	5525	8415	8415	5325	5325	8415	8415	5325	5325	65025
5600	5600	8160	8160	5175	5500	8160	8160	5325	5325	65025
5450	5575	8925	8160	5125	5250	8415	8415	5225	5225	65025
5500	5500	8415	8415	5025	5350	8160	8160	5300	5300	65025
5450	5775	8670	8670	5350	5350	8415	7905	5225	5225	65025
5350	5850	8160	8160	5100	5425	8670	7905	5225	5225	65025
5350	5475	8415	8415	5325	5325	8160	8415	5025	5150	65025
5425	5550	8670	8670	5100	5450	7905	7905	5350	5350	65025

Note: On the system that we were monitoring, after one year, detailed data logging was terminated. It was felt that sufficient confidence had been gained in the meters self-diagnostic mechanism.

Monthly checks

Validate the ultrasonic meter configuration, ensuring all constants are as per the calibration certificate.

Annual checks

Remove the meter from service and return it for re-calibration and certification.

3.2 Calibration frequency

One of the main drivers behind the use of this technology is the potential to reduce the testing regime required, saving possible production deferment and maintenance costs. To this end the testing performed so far has been focused on performance between calibrations. It should also be noted that if a system has two or more meters, only one of the meters should be used to determine the performance between calibrations and then the resultant agreed frequency applied across all the meters in the system.

Meter	New							
		3 Months		3 Months		12 Months		As Agreed
1	Test1	——▷	Test2	——▷	Test3	————▷	Test4	——▷
		3 Months		As Agreed				
2	Test1	——▷	Test2	————▷				
		3 Months		As Agreed				
3	Test1	——▷	Test2	————▷				

Note: The calibration interval given above is actual service period, not time period.

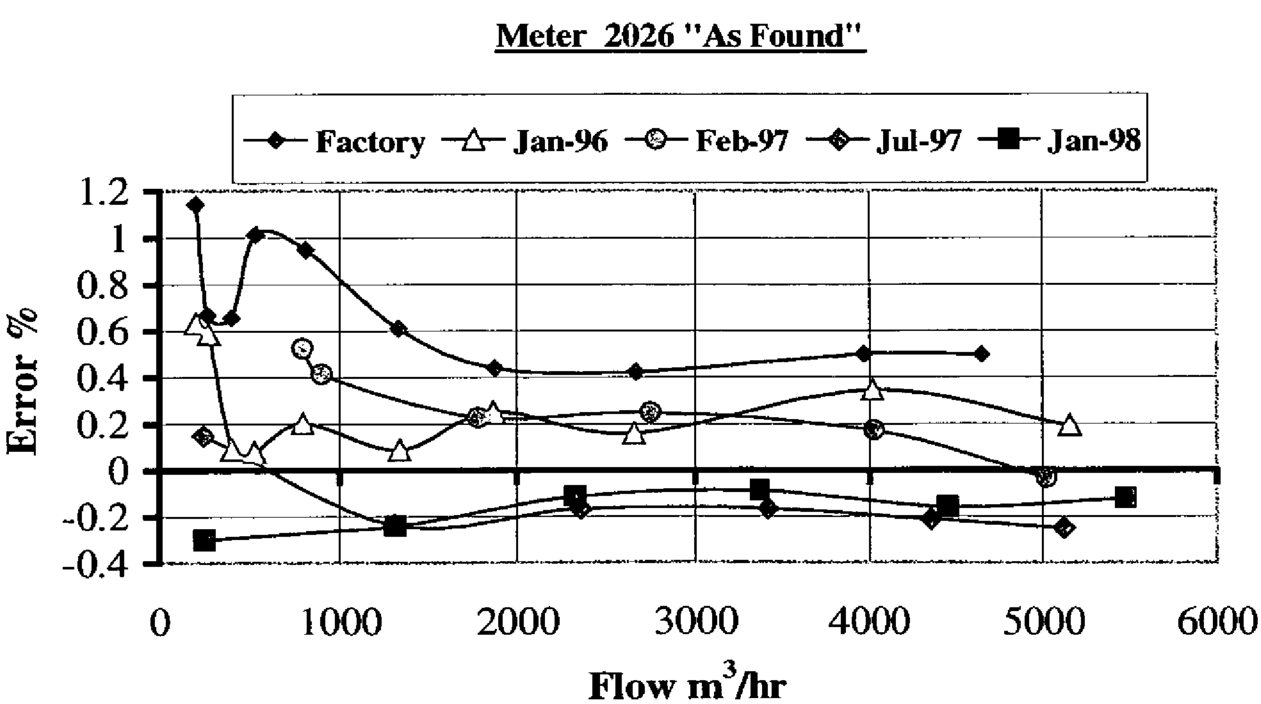
Depending on the results of the tests, the frequency can be adjusted to suit the interested parties. The table above is only a suggestion, but it is supported by our test results to date. Agreement must always be reached between all parties prior to changing any frequencies.

4 OPERATIONAL EXPERIENCE OF ULTRASONIC METERS

4.1 Five-path meters

4.1.1 Performance over a three year period

The following graph shows the calibration performance of a 5-path meter, which has been in fiscal measurement service at an onshore facility over a 3-year period.

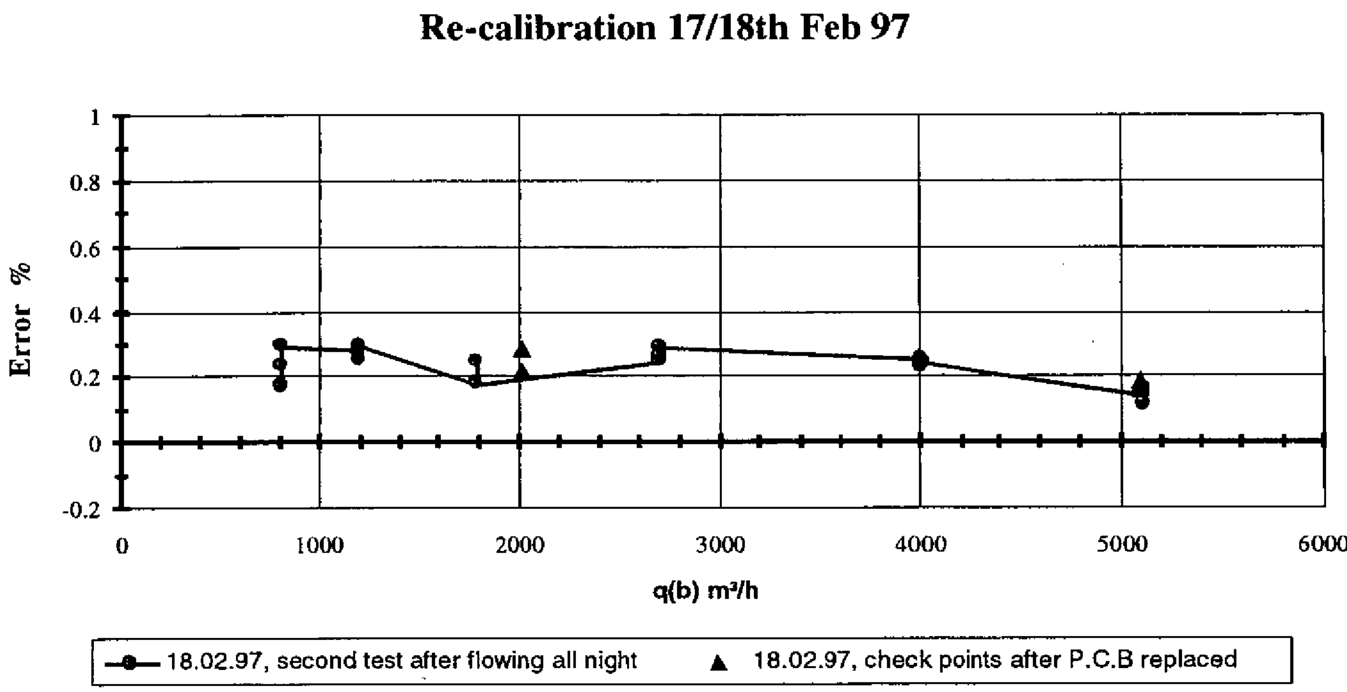


The first curve was produced at the factory acceptance tests. The internal meter surfaces were clean and had a smooth, machined finish. After four months of service, the meter was returned for calibration at the same test site. The internal surface condition had changed, some fine dust / metal oxide coated the whole surface area.

From the graph it can be seen that after initial adjustment subsequent recalibrations have stayed within a tolerance of +/- 0.25%, between 1000 and 6000 m3/hr. Allowing for the fact that the calibration house has a measurement uncertainty of 0.25%, the performance of the meter over time has been excellent. It should be noted that after adjustment the curves shown were moved to the datum line, reading with out bias and accurately.

It is very important not to interfere with the surface coating, because this layer on the internal surface has built up in operational service and is the best representation of normal in line conditions. A calibration in the 'as found' condition allows for the best operational adjustment. Experience has shown, any cleaning of the surface, even a wipe with a rag, will affect the calibration adjustment and may lead to bias offsets when returned to service conditions.

4.1.2 Changing electronics



During one of our tests, we took the opportunity to upgrade our equipment with new electronics. Having completed an 'as found' run with the original equipment, the electronic boards were replaced and four spot checks were subsequently carried out. The points were superimposed on the 'as found' curve. They fell perfectly in line with the curve.

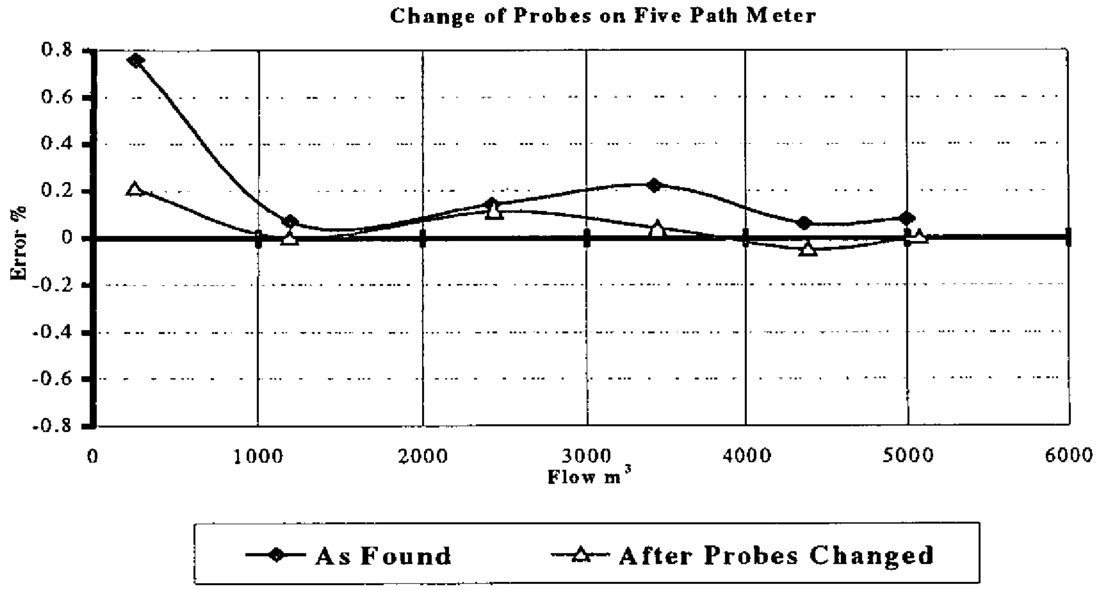
This test shows that it is possible to change the electronic boards without unduly affecting the calibration. Thus in the case of an electronic failure in the field, the need to replace the board would not necessitate an immediate return of the unit for calibration.

4.1.3 Noise problem and probe replacement.

During periods of operational use deterioration in the meter performance was detected. This was traced to an upstream regulation valve and a slightly heavier mix of gas. As the volume flow increased the meter performance dropped off. This coincided with an increase in pressure drop across the valve. Noise was being generated at the valve and was masking the signals being produced at the meter.

After discussions with the meter manufacturer, the remedial action was the replacement of the meter probes. The new probes operate at a frequency outside of the noise produced by the valve.

The graphs below show two stages of testing, an 'as found' calibration with the old probes and an 'as left' calibration with the new probes. The meter factor shift of 0.09% across the operating range indicates that changes can be made between probes without large shifts taking place.



4.1.4 Surface condition effects

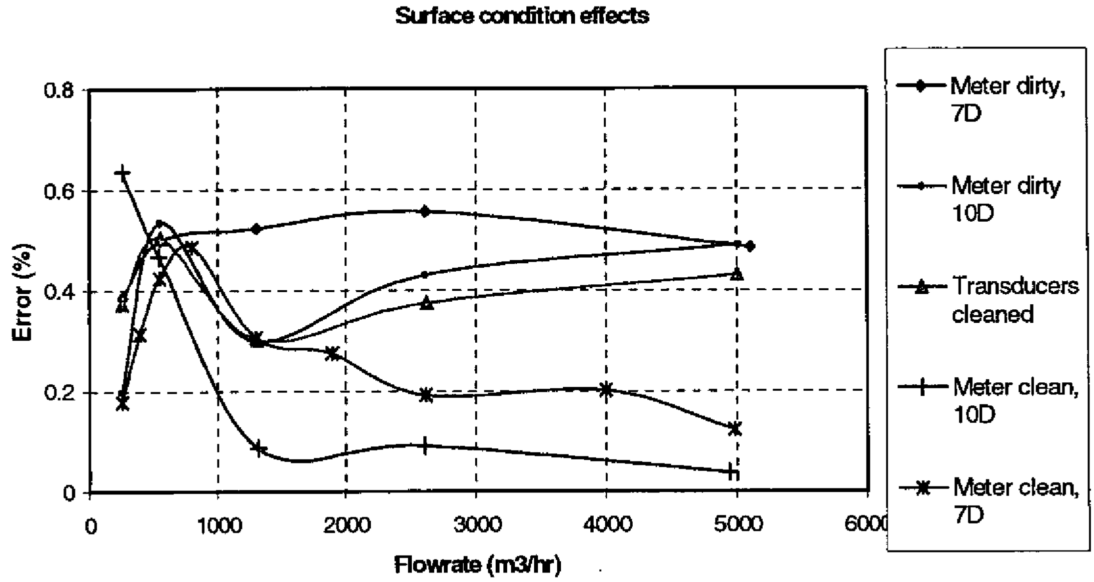
In the course of our recalibration of the St Fergus meters we were surprised to discover that a very fine layer of dust (probably of the order of a few tens of microns) can affect the calibration. When the first of the three meters was recalibrated there was a shift of +0.3% from the initial manufacturer's calibration. We considered at that time that this was within the range of variation that could be expected from a station with a stated uncertainty of 0.25%.

When the second meter was recalibrated a few months later it showed a shift of +0.45%, well outwith what could be attributed to the calibration station. We removed the meter for examination, decided to clean off the coating of dust, and retested the meter. The shift was reduced to 0.28%. We also examined the traceability of the calibration station and concluded that although it had a claimed uncertainty of 0.25% in absolute terms, for repeat calibrations the repeatability of the station from year to year was probably nearer to 0.1%, making the residual 0.28% well outwith what could be attributed to the calibration station. Possible causes could be movement of the transducers (unlikely as all five pairs would have to move in a similar way to give path length changes of several millimetres), or variations in the master clock frequency (again unlikely as this would have to be wrong by the equivalent of several minutes in a day).

The meter was then left with the manufacturer who carried out a series of tests and concluded that the shift might be explained by the use of shorter upstream straight lengths (7D) on the initial calibration compared to the 10D used for the second.

We decided to use the third meter to establish whether this explanation was valid, and whether the dust layer did have a significant effect. Accordingly the dirty meter was tested with 7D and 10D upstream straight lengths. Our customer was also concerned that dust on the transducer faces might have an effect, so a third test was done with the transducer faces cleaned, but not the inside of the meter body. For the fourth test the inside of the meter was cleaned and tested with 10D upstream straight lengths. Finally the clean meter was tested with 7D upstream straight lengths.

The results of the five tests are shown in the graph below. There may be a small effect from the difference in upstream straight lengths (compare the top two and bottom two traces). The effect of cleaning the transducer faces is within the scatter of the measurements (compare the second and third traces from the top). There is however, a very marked effect from cleaning the meter body of the order of 0.4% (compare the first and fourth traces for 7D, and the second and fifth traces for 10D). Thus there was clear evidence that the dust layer was responsible for most of the shift in calibration.



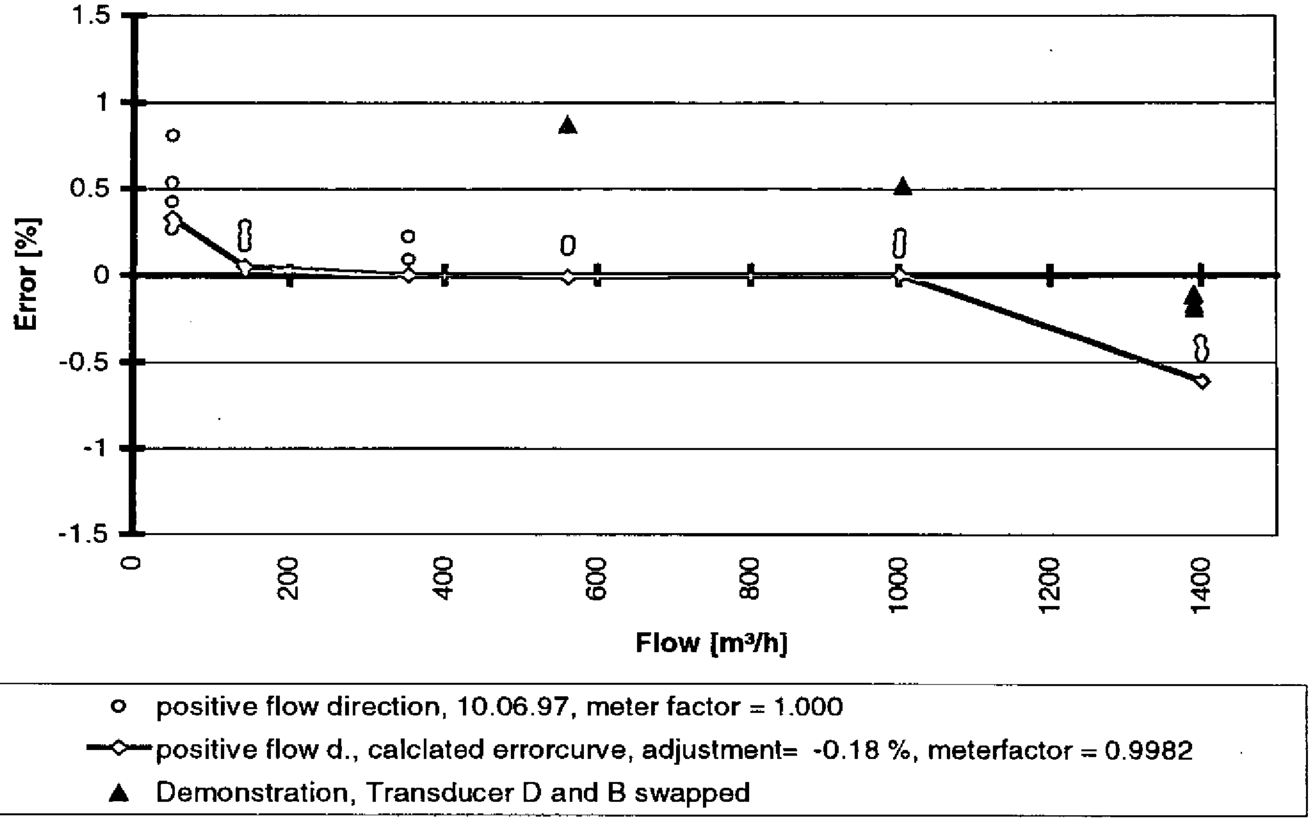
This was a startling conclusion, as there is no obvious reason that it should only apply to ultrasonic meters. We speculate that changes in the meter body surface lead to changes in the thickness of the boundary layer on the pipe wall. This is the thin layer of gas that is stationary. For a given volume flow rate this has the effect of varying the gas velocity. Nevertheless we are also convinced that in practice we may not be too inconvenienced. Provided the surface of the meter body does not change, the calibration will not change. Our recommendation, therefore, is not to clean ultrasonic meters before recalibrating them. Furthermore all the changes in calibration shown are contained in a band 0.5% wide, which can be compared of the basic uncertainty of the discharge coefficient of an orifice plate of +/- 0.6%.

Points of note

- The meters output curve is affected by micro surface conditions.
- The meters inner surface of a meter should not be tampered with prior to, during or after calibration.
- If the meter is being used on a slightly wet gas, the resultant output will be offset from the dry gas calibration.
- Any advantage gained from the material used for manufacture of the meter body or the application of an inner surface coating will be offset by operational environment in which the meter operates.
- The internal surfaces of the upstream & down stream pipework was not touched (so any attributable effects from pipework could be discounted)
- When the meter was removed from the test line, it was found to be dry.
- If any moisture is present on the internal surface, the resultant curve will be skewed. We have seen this effect repeated at other calibrations. Results should not be accepted if moisture or liquids are found on the internal surfaces of the meter or spools pre or post the calibration run. This is due to the fact that it will not be representative of the process conditions for which it is to be used.

- As only the internals of the meter were affected, an understanding of the cause of this phenomenon is still to be found. We speculate that boundary layer changes are altering velocity profiles, variable with flow rates

4.2 Four path meters



The shape of the curve can be variable on this type of meter, but the points have proven to be repeatable. With the implementation of a curve fit it has proven to be suitable for this specific type of application.

It should be noted that the operating philosophy of this meter is different to the three and five path meters, having only direct paths and different calculation algorithms.

The calibration test undertaken included the exchange of probes from transducer D and B. As can be seen from the results a large shift was experienced. This raises the question that whether probes failing in service can be replaced without the need for recalibration. At present the answer for meters in fiscal service is no.

Depending on the adjustment techniques used on the curve, care is required with the slope at the higher flow rates. A large bias is introduced and would be unacceptable if this was within the normal operating range of the instrument.

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ULTRASONIC NOISE CHARACTERISTICS OF VALVES WITH RESPECT TO ULTRASONIC GAS FLOW METERS

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16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

ULTRASONIC NOISE CHARACTERISTICS OF VALVES WITH RESPECT TO ULTRASONIC GAS FLOWMETERS

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ABSTRACT

The subject of this paper is a series of tests with an ultrasonic gasflow meter, control valves of three different designs and silencers of three different designs, operating under various conditions regarding pressure cut and flow rate.

The paper is split up into two sections, the first section, prepared by Verbundnetz Gas, deals with the issues of specific interest of Verbundnetz Gas, that is the design of a suitable solution and the verification of its functionality for the expansion of the measuring facilities at the location Sayda.

The second section, prepared by Instromet Ultrasonics, presents, based on the data acquired during the tests at Sayda, a more general approach for characterising the ultrasonic noise aspects of control valves and piping elements. Based on this characterisation a model is presented that can be used to predict whether an ultrasonic meter can function properly under specific conditions.

SECTION 1: ULTRASONIC NOSIE TESTS WITH VALVES, SILENCERS AND AN ULTRASONIC METERS AT SAYDA

1 WHO IS VERBUNDNETZ GAS (VNG) AG?

VNG AG is the second-largest gas importer in the Federal Republic of Germany. It operates in the new federal states and in Berlin, and has, in this supply area, a comprehensive network of around 8100 km of high-pressure gas pipelines with operating pressures ranges up to 25, 45 and 84 bar.

VNG operates 7 underground gas storage's with a storage capacity of approx. $2{,}4 \cdot 10^9$ m³ as well as 5 compressor stations with a total power of 60 MW.

This network is connected to the Western European and Eastern European gas transit systems at three points and thus makes it possible to obtain gas both from Western European sources and from Russia.

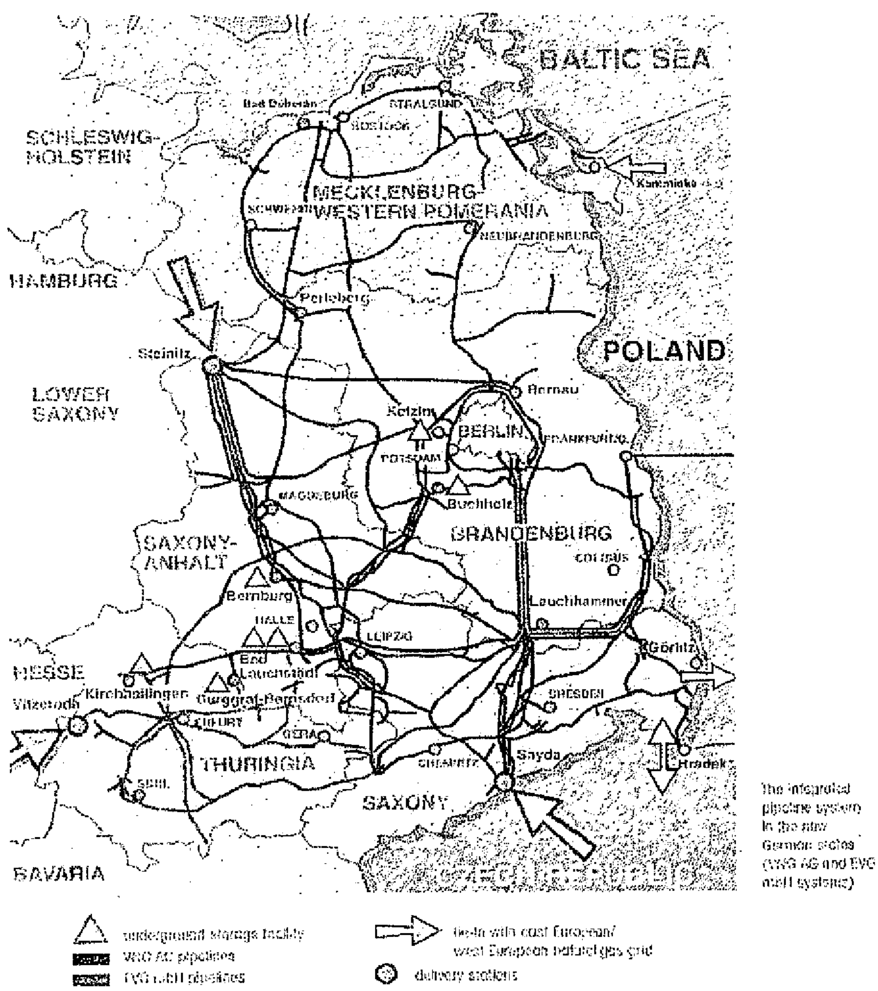


Figure 1 - VNG

2 WHAT WAS THE PROBLEM?

VNG AG had to reconstruct one of its main feed stations in Sayda. The purpose of the new plant was to measure and regulate the gas flows for all outgoing gas pipelines, and to ensure a flexible combination and switching between different flows.

In order to meet these requirements, the measuring and control devices must be used bi-directional. In order to avoid high cost of bypasses (this would have resulted in additional costs of approx. DM 1.5 mill.), the concept provided for using bi-directional ultrasonic measurement devices and operating some of the control valves in a reverse direction.

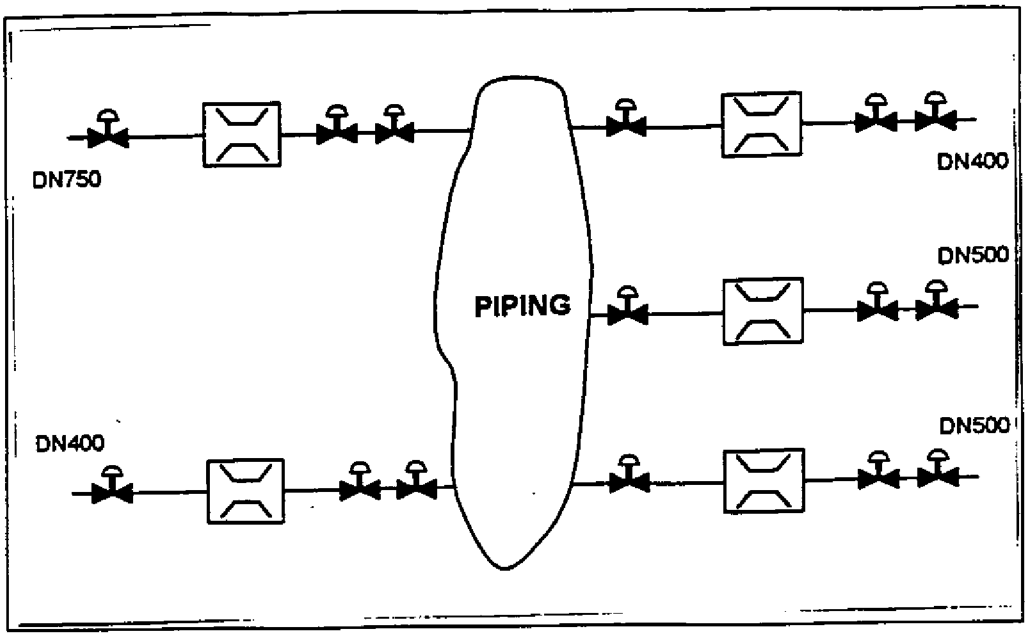


Figure 2 - Sayda

Our own experience, as well as discussions with partners from other gas supply companies, as well as the company Instromet, had shown that ultrasonic measuring devices which are located in close vicinity of control valves may suffer from interference from the ultrasonic noise generated in the control valves. This can lead to complete failure of the measurement.

The ultrasonic meters used by VNG AG so far were either located at sufficient distance from the control valves, or acoustically de-coupled by installing heat exchangers between the control valve and the ultrasonic meter. Noise produced at pressure differentials of 30 bar across the control valve and flow rates of 30 m/s did not interfere with the measurement.

3 WHAT HAS BEEN DONE?

In order to make sure that the planned plant design would function well we decided to:

... Test several control valves with regard to their noise emission in the ultrasonic range at different flow rates (also reverse)

... Develop and test silencing devices which can be installed between the control valve and the ultrasonic meter and provide high attenuation in the relevant ultrasonic range (100-200 kHz)

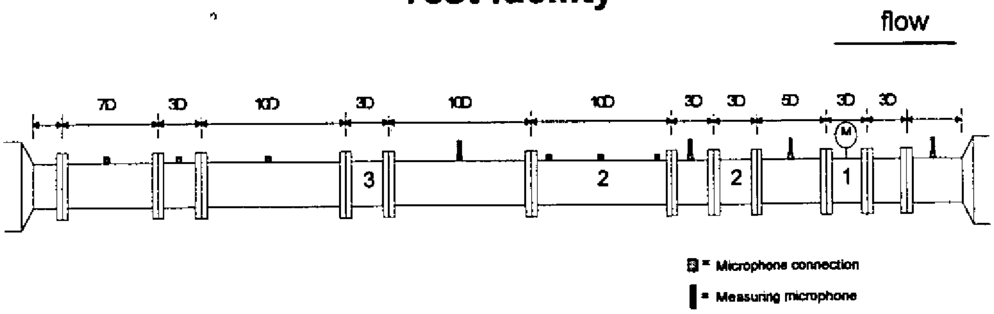
... Determine limits for the noise level up to which ultrasonic meters are able to work reliably.

For this purpose, a test run was built at Sayda in DN 300, PN 84, the basic design of which is presented in Figure 3. In the direction of the flow, the control unit (1), the silencer (2) and the ultrasonic meter (3) with inlet and outlet piping were flanged to each other via spool pieces.

The spool pieces between the units were equipped with appropriate connections for measuring microphones so that it was possible to measure the sound pressure before and after the control valve and directly at the meter.

The sound level was simultaneously measured in the frequency range from 1 kHz to 1000 kHz at 4 measuring connections using a storage oscilloscope.

Test facility



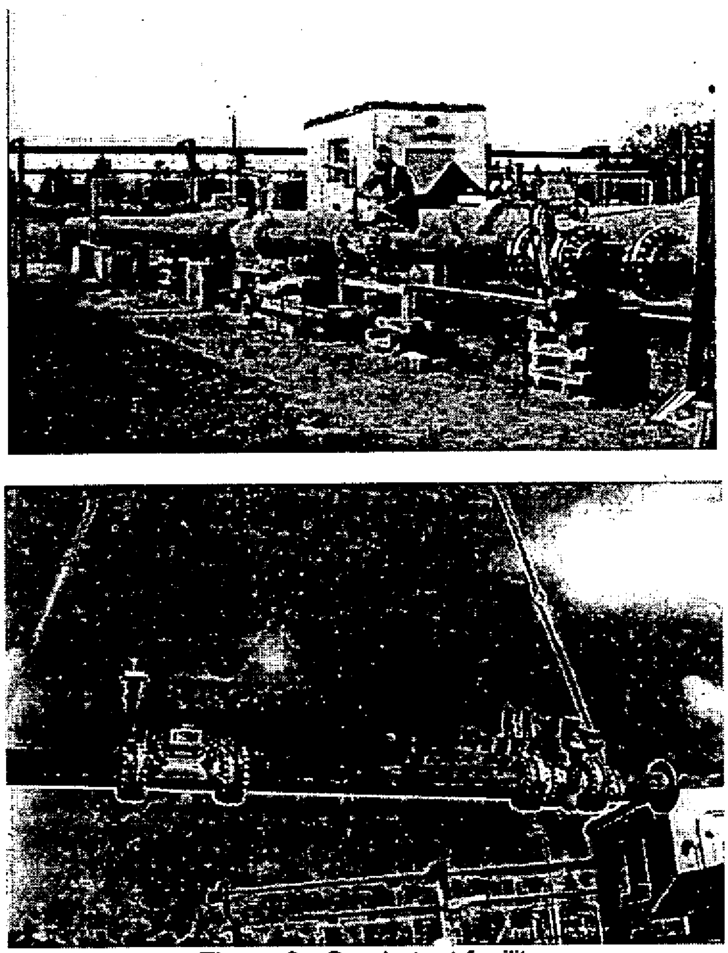


Figure 3 - Sayda test facility

In addition, suitable software was used to record the difference between the actual gain as set, and the maximum allowable gain as calculated, for the automatic gain control function, that controls the signal levels of the individual paths. Indirectly, these measured parameters supplied information about the signal-to-noise ratio.

The measuring arrangement was changed several times during the tests. The following devices were used:

1)	Ultrasonic meter	5-path US meter
2)	Control unit A	Control valve with multiple cage
	Control unit B	Ball valve type control valve

3) Silencer S1 — 10 D spoolpiece with 2 internal pipe bundles
Silencer S2 — 3 D adapter with perforated plates parallel to the flow direction
Silencer S3 — 13 D adapter consisting of pipe fittings

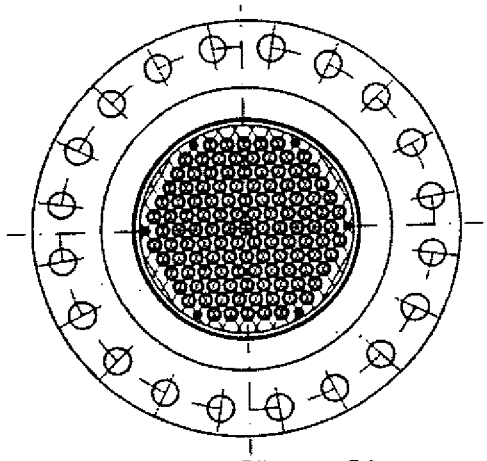


Figure 4 - Silencer S1

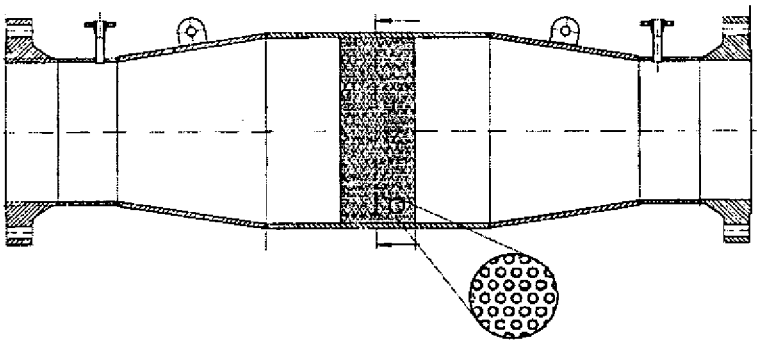


Figure 5 - Silencer S2

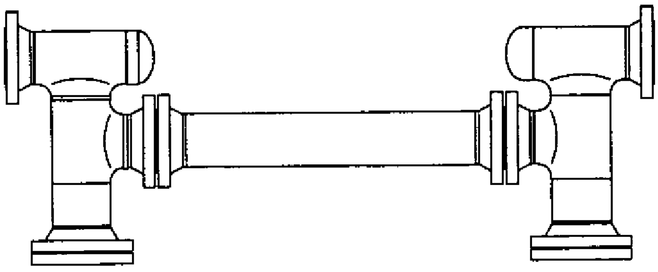


Figure 6 - Silencer S3

4 WHAT ARE THE RESULTS?

The results described below are examples from a series of measurements where sound spectra were recorded at various measuring points in the test section. At the same time the function of the US meter was monitored. The configuration of the test section was changed several times, and flow and pressure conditions were varied as much as possible.

4.1 Normal Operation of Control Devices

Figures 7 and 8 show the sound spectra of 2 control devices at different pressure differentials ΔP. The flow rate for all tests was in the range of 7 to 9 m/s. It becomes obvious that the control device B, due to its design and the associated higher K_v value, generates a smaller pressure loss in the fully opened state. Thus noise generation in the US range is lower than with control device A. For a partially opened valve where ΔP is of equal magnitude for both units, the noise generation in this example is comparable, independent of valve design.

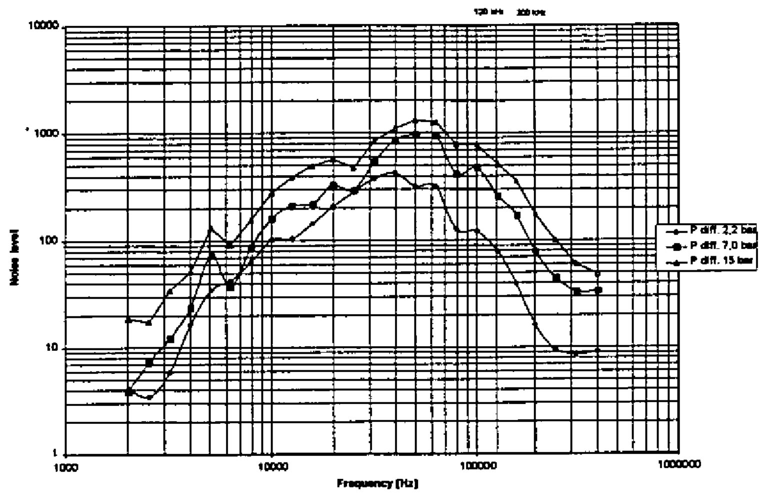


Figure 7 - Sound spectra for control device A

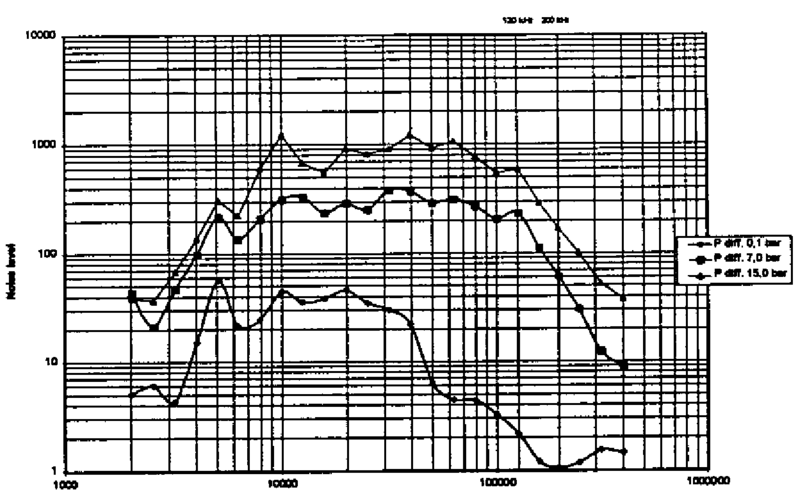


Figure 8 - Sound spectra for control device B

4.2 Reverse Operation of Control Devices

Figure 9 shows the sound spectra obtained when the units are installed in the gas flow direction (normal) as envisaged by the manufacturer compared with the results obtained for reverse installation. In both modes of operation, the ultrasonic sound emission levels differ only slightly between the units. For both units, they are lower by the factor 2 - 3 in the case of reverse installation. This means that the envisaged bi-directional use of the control devices will not bring any additional risks for meter interference.

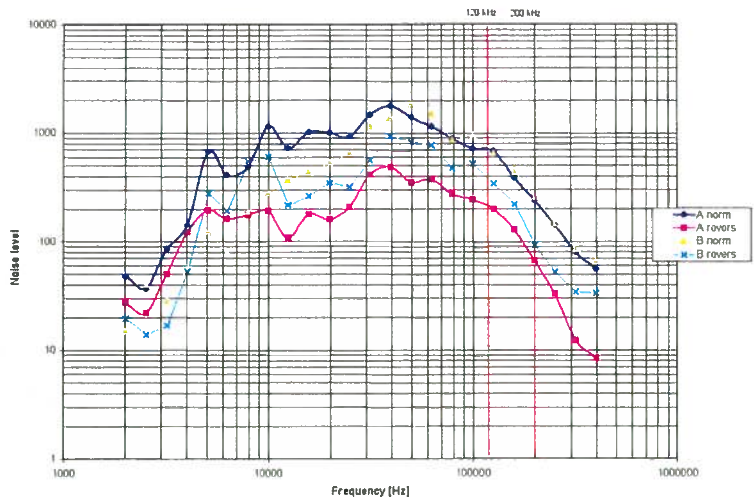


Figure 9 - Sound spectra for control devices A / B normal and reverse

4.3 Silencers

Another test was carried out to study the attenuation characteristics of the 3 silencer designs. Figure 10 shows this for a flow rate of approx. 6 m/s. In the frequency range relevant for the transducer, the sound absorbers S2 and S3 show an attenuation of more than 20 dB. Silencer S1 requires further optimisation for this range, as an attenuation of more than 20 dB is only reached in the range of 65 - 110 kHz.

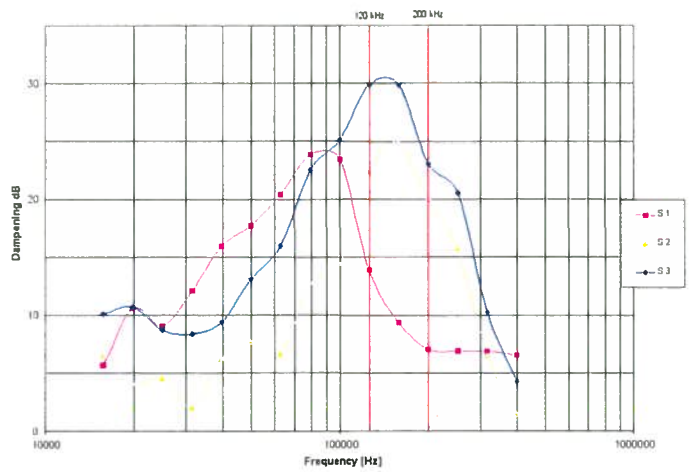


Figure 10 - Attenuation curve of the 3 silencers

4.4 Meters

The log file from the meter electronics was recorded as long as the ultrasonic meter was fully operational. This file contains, among other data, the values of automatic gain control levels and automatic gain control limits of the individual paths. The ratio reflects the actual signal to noise ratio and can be seen as a gain margin.

Previous tests showed that a reliable function of the US meter is ensured up to a gain margin of > 10 dB.

The Figures below show the flow rates at definite points of time together with the associated gain margin of the critical path (in general path 2b).

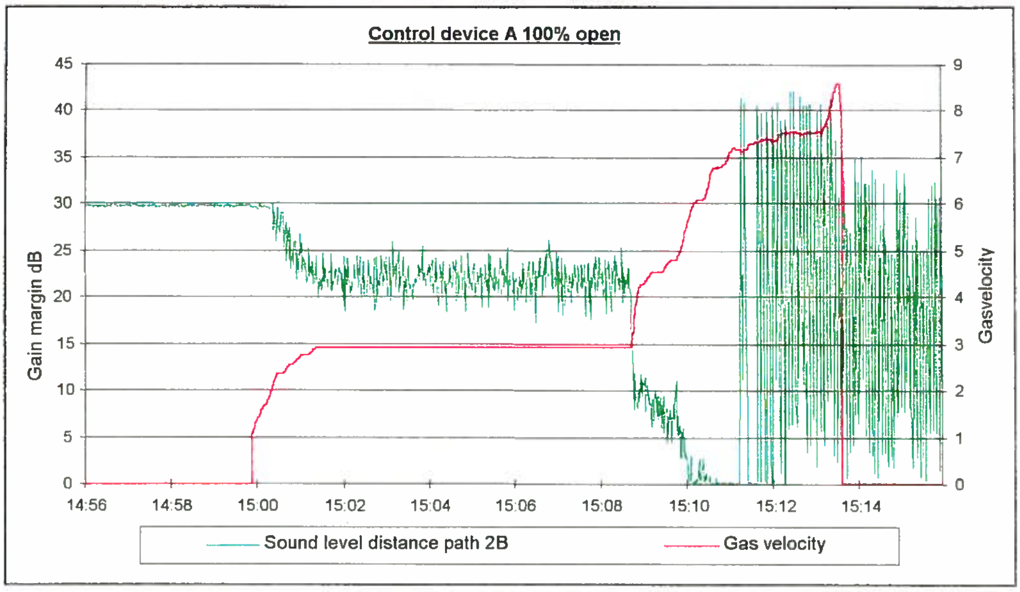


Figure 11 - Functionality of flowmeter w.r.t. gasflow (control valve A)

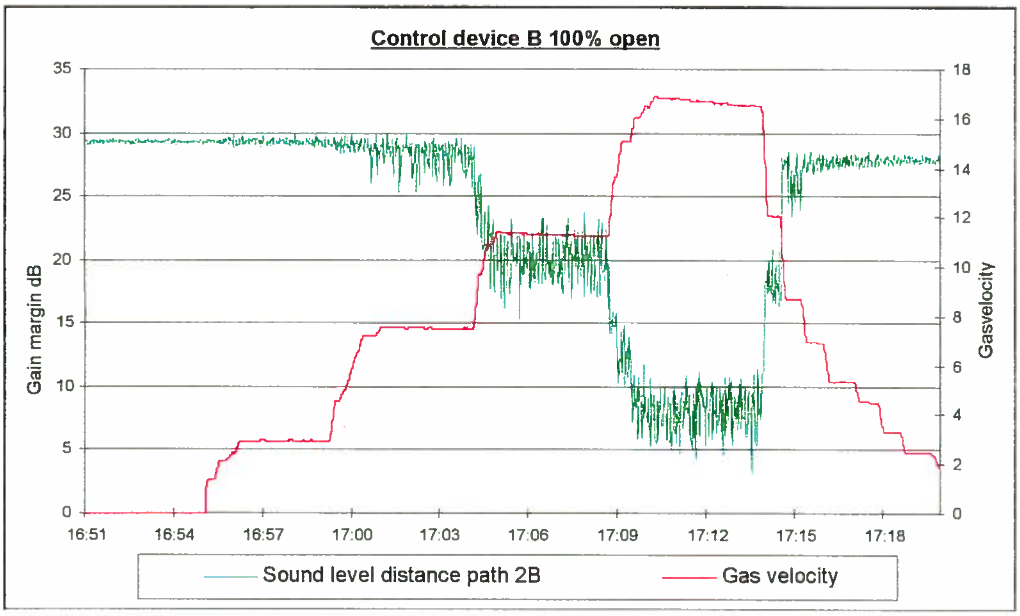


Figure 12 - Functionality of flowmeter w.r.t. gasflow (control valve B)

Figures 11 and 12 show that the US meter fails despite the 100% opening of control device A at a gas velocity of approx. 7 m/s. With control device B (high K_V value), reliable operation is possible up to about 16 m/s. Meter failure is characterised by oscillation of the gain control. As long as other, less critical paths are still operational, the meter will still indicate a flow rate, eventually with reduced accuracy. This behaviour is in agreement with the measuring results from the sound spectra.

For the next tests, a silencer with an attenuation of approx. 20 dB was installed between the control device B and the US meter (version S3).

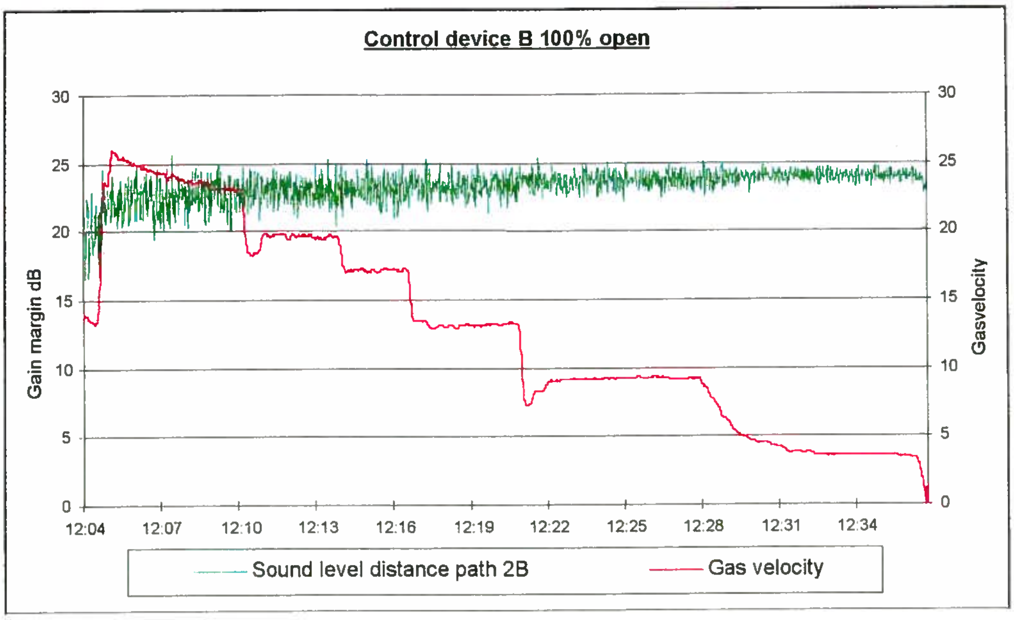


Figure13 - Functionality of flowmeter w.r.t. gasflow (silencer S3, control valve B)

Figure 13 shows clearly that in this case even flow rates of 25 m/s (100 % opening) do not result in any significant reduction in the gain margin.

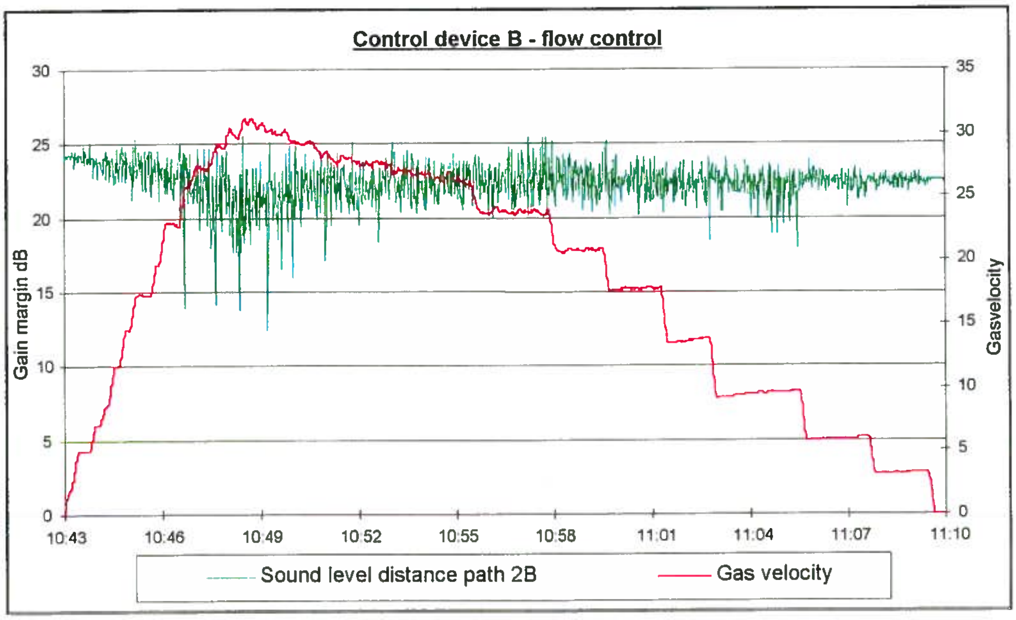


Figure 14 - Functionality of flowmeter w.r.t. gasflow (silencer S3, control valve B)

Figure 14 shows the result of a flow using control unit B between

> full load 34 m/s = 8,000 m³/h and
> partial load 0.4 m/s = 100 m³/h.

This corresponds to the future application (flow control). Again, the gain margin stays in the safe functional range so that there is no risk of meter interference.

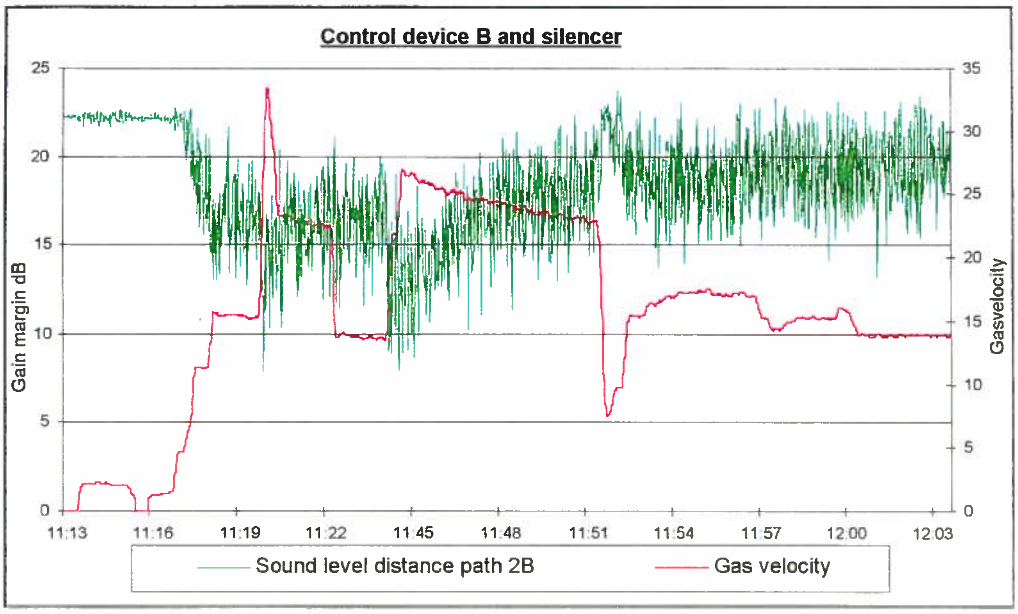


Figure 15 - Functionality of flowmeter w.r.t. gasflow (control valve B, silencer S3)

The last figure (15) shows the conditions at a high differential pressure across the control device and different flow rates. It can be seen clearly that even for the most critical operating case (V = 26 m/s, ΔP = 8.9 bar, opening degree 67%) which can be reached during the test, the installation of the silencer will ensure a gain margin > 10 dB and thus the reliable function of the meter.

5 SUMMARY

The examples shown demonstrate that because of a possible interference in US meters caused by control valves, some important aspects have to be taken into account during plant design. If it is not possible to acoustically de-couple the meter and the control device by existing elements such as bends, tees, heat exchangers etc, the installation of specifically designed sound absorbers may be a good alternative.

ACKNOWLEDGEMENT

The authors wish to thank the companies INSTROMET, RMG, ARTEC and MOKVELD which were involved in the tests, for their commitment and help. Without the many years of close co-operation with the gentlemen Drenthen, de Boer and Kurth from INSTROMET such a comprehensive test program would not have been possible.

Thanks also to Dr. Dane and Mr. Vermeulen for the processing of the comprehensive test material.

SECTION 2: VALVE CHARACTERISATION AND NOISE MODEL

1 INTRODUCTION

As outlined in the previous section Verbundnetz Gas performed an extensive series of test in order to assess the performance of the Q-Sonic Ultrasonic flow meter when subject to ultrasonic noise as generated by control valves. The tests included a variety of

- operating conditions (pressure cut and flowrate)
- equipment arrangements and flow directions
- pressure or flow control valves

The operation of the Q-Sonic was judged by comparing the measured flow rate to another flow meter (turbine meter) and by observing the performance indicators presented by the meter's internal diagnostics.

Instromet supported the test program by providing flow meters, instrumentation for measuring acoustic noise levels and assistance in the processing and analysing of the acquired data. The data from this test program was of great value in the framework of Instromet's research on ultrasonic noise affecting ultrasonic flow meters.

2 HISTORY

Since the successful introduction of Instromet's ultrasonic flow meters for measuring gas flow (late eighties: single path meters; early nineties: multipath meters) such flow meters are operating satisfactorily in an increasing number of applications.

However, with the increase in numbers, some applications were encountered where ultrasonic noise created by pressure or flow regulators caused problems. When Instromet started to investigate this problem area it became apparent that hardly any information on noise was available, especially in the ultrasonic range and in high-pressure pipelines. Although models were available describing the ultrasonic noise generation for the audible range, extensions of these models to the ultrasonic range were hardly supported by any experimental data.

For this reason Instromet started a research program to measure and investigate the ultrasonic noise generated and perceived in high-pressure gas pipelines, where pressure regulators appear to be the most prominent sources for such noise.

3 OBJECTIVE

The objective of measuring and analysing the ultrasonic noise was:

- to obtain basic data and information needed for designing ultrasonic flow meters with improved noise immunity, and
- to obtain data for building a model that can be used to predict, in the first place, the noise levels generated and, secondly, the performance of an ultrasonic flow meter subject to the ultrasonic noise levels thus predicted.

Needless to say that Instromet's first objective is to improve the noise immunity of its ultrasonic flow meter family. Data characterising the ultrasonic noise is essential information for that purpose. We expect that the application of advanced signal processing techniques will introduce improvements, but will still not resolve every problem. For a limited number of applications it may remain inevitable to use additional noise abating equipment such as a silencer. This requires tools to asses a particular application in terms of expected ultrasonic noise levels and to calculate - if necessary - the amount of attenuation of the ultrasonic noise required and that has to be implemented by means of a silencer or other measures. In addition to this the effectiveness of silencing devices has to be addressed.

4 THE MODEL

4.1 Theory on Noise Generation

Pressure regulators are seen as the main source of ultrasonic noise. Therefore pressure regulators should be characterised in terms of noise generation, dependent of operational conditions such as pressure drop and flow rate.

For this characterisation a good starting point is the model described by Reethof and Ward. The acoustic power produced by a control valve can, according to Reethof and Ward, be described as:

$$W_a \propto \Phi_m \cdot c_1^{\,2} \cdot \left[\frac{2}{\gamma - 1} \left\{ \left(\frac{P_1}{P_{vc}} \right)^{\frac{\gamma-1}{\gamma}} - 1 \right\} \right]^{5/2} \left(\frac{P_1}{P_{vc}} \right)^{\gamma + \frac{1}{\gamma} - 1} \tag{1}$$

Where W_a is acoustic power, Φ_m is massflow, c_1 is velocity of sound upstream, $\gamma = C_p/C_v$, P_1 is pressure upstream and P_{vc} is the pressure in the vena contracta. P_{vc} is related to the valve characteristics and can be described by the pressure recovery coefficient F_L:

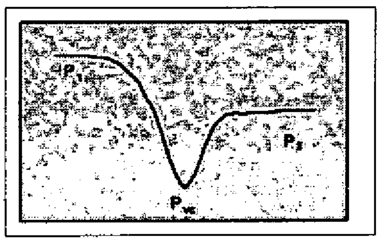


Figure 1 - Pressure change

$$F_L = \frac{P_1 - P_2}{P_1 - P_{vc}} \tag{2}$$

Remarks:

- When $P_1 = P_2$ (high recovery) than $F_L = 0$,
- When $P_2 = P_{vc}$ (no recovery) than $F_L = 1$, and
- F_L can be related to the opening of one type of valve (α_v).
  Example: $F_L = 1 - 0.45\alpha_v$.

The acoustic power can be calculated acording to expression 1 To determine the functionality of an ultrasonic analyzer we do not use acoustic power but acoustic pressure. According to Morse and Ingard the acoustic pressure is:

$$p_a = 2 \cdot \sqrt{\frac{W_a \cdot \rho \cdot c}{A}} \tag{3}$$

Here p_a is the acoustic pressure, ρ is the gas density, c is the velocity of sound and A is the surface of the cross area of the pipe.

4.2 A Practical Indicator

Expressions (1), (2) and (3) indicate that important parameters for estimating the ultrasonic noise levels are the massflow and pressure ratios. However these expressions are not very practical for direct use and the validity in the ultrasonic range needs further investigation as well. Additionally we are in fact not interested in the noise level but looking for a method of calculation for an indicative value, predicting whether the meter can perform satisfactory under given conditions or not.

Therefore not only the noise level (acoustic pressure) generated by the valve should be taken into account but ultrasonic flow meter characteristics and properties of piping, such as elbows and tee's, and silencers (if applicable) should be represented as well. The indicative value looked for can be seen as reflecting the signal to noise ratio as perceived by the ultrasonic flowmeter. By convention we will use a value proportional to the inverse (noise to signal ratio). Hence, a large number will represent severe conditions whereas a smaller number will represent more relaxed conditions.

4.3 Piping Elements

Based on linear systems theory we assume that effects from piping elements can be represented by a number indicating the attenuation of ultrasonic sound in the relevant frequency band. The effect of several piping elements is represented by a number N_d, which is the multiplication of the contributions of all separate elements.

4.4 Valve Representation

Instead of using complex expressions modelling specific valve design details, a more simple and general model based on the energy dissipation in the valve was adopted. A specific valve is characterised with a number N_v, which is proportional to the noise emission of that design in comparison to other valves, when operated at identical conditions. We defined N_v to be 1 for an "average" type of valve. Valves generating higher or lower noise levels, compared to the "average valve", will have a value N_v higher respectively lower than 1 (range of N_v between 0.2 and 4). As it is found that valves do exhibit different noise emission levels in upstream and downstream direction, two different numbers, one for the upstream emission and one for the downstream emission may be needed.

4.5 Practical Model

Based on the assumptions made above, a simple and practical model predicting the performance of an ultrasonic meter subject to noise can be written as:

$$\delta = k \cdot F(..) \cdot N_v \cdot N_d \tag{4}$$

In this expression F(..) reflects the noise to signal ratio due to the valve and the ultrasonic meter characteristics under the given operating conditions and k is a constant in order to make the result dimensionless.

In order to represent the noise level generated by the valve and with reference to expressions (1), (2) and (3). Variables that may appear in the expression for F(..) are P1, P2 or ΔP, Φ, ρ, c and D.

Parameters relevant for the ultrasonic meter's signal strength are P or ρ or c and D.

A reasonable and acceptable fit with empirical data was found when the expression for F(..) reads as:

$$F(..) = F(P, \Delta P, \Phi, T, D) = \frac{\Delta P}{P}\sqrt{\frac{\Phi \cdot D^2}{T}} \tag{5}$$

Here P [bar] is the pressure at the ultrasonic flowmeter, ΔP [bar] is the pressure difference across the control valve, Φ [Nm^3/h] is the normalised flow, D [m] is the diameter of the pipeline and T [s] is the integration time.

5 NOISE EMISSION DATA OF VALVES

At the test site in Sayda the parameters relevant to the ultrasonic meter's signal strength such as size and static operating pressure can be supposed to be constant. The expression F(..) should then be proportional to the strength of the ultrasonic noise generated by the valve. In the test configuration the acoustic noise up- and downstream of the valve are measured at different flow rates and pressure drops accross the control valve.

Figure 2 shows the correlation between the measured noise level and the calculated value of the function F(..). The results of three types of valves are referenced as A, B and C. The valves are tested in the normal way (Figure 2) and in reverse direction (not presented in this paper). Also the noise is measured downstream (D, Figure 2) and upstream (not presented) of the valve. Upstream and downstream is always referenced relative to the gasflow direction.

The graph shows the actual measured data by means of the symbols. There is a more or less linear relation between the measured acoustic noise and the calculated value of the function F(..) which is represented by the regression lines shown as well. The slope (tangent) of the regression line is proportional to N_v in the expression (5). N_v is dependent of the type of valve and as well dependent of the flow direction in the valve (normal or reversed).

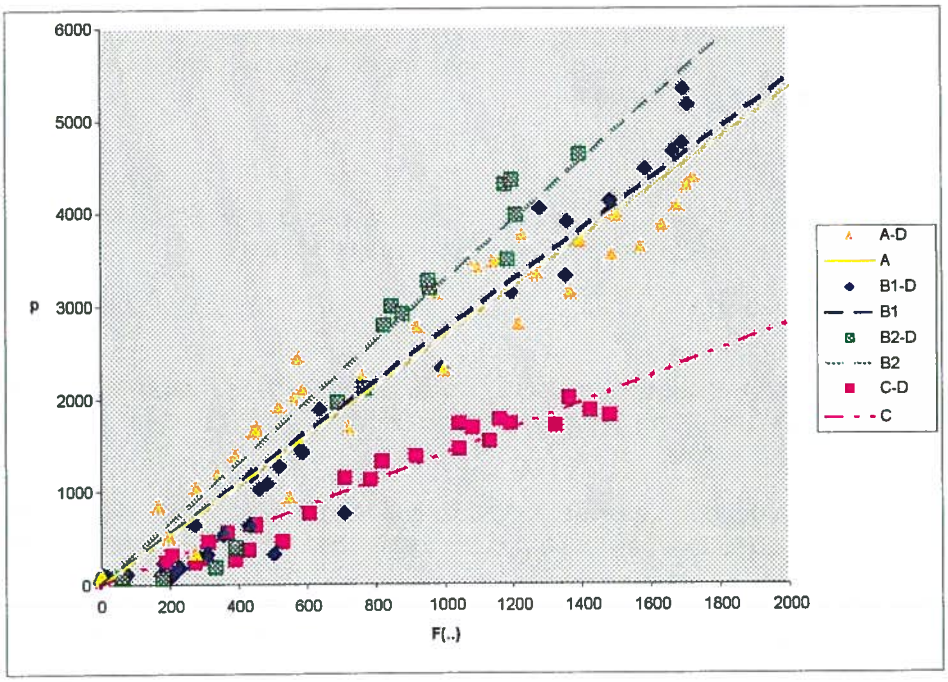


Figure 2 - Relation between F(..) and p_a (estimation of N_v)

6 EFFECT OF PIPING ELEMENTS E.G. SILENCERS.

All elements present in an installation generate or attenuate acoustic noise. The attenuation is frequency dependent and can also be flow dependent. The attenuation of a piping element can be estimated by comparison of the noise levels up- and downstream of that element. Table 1 shows the attenuation due to different piping elements.

Analyzing the frequency spectrum of the noise (see Figure 3 for one example of valve C it can be concluded that the spectra are broad banded with a maximum somewher between the 30 and 90 kHz.

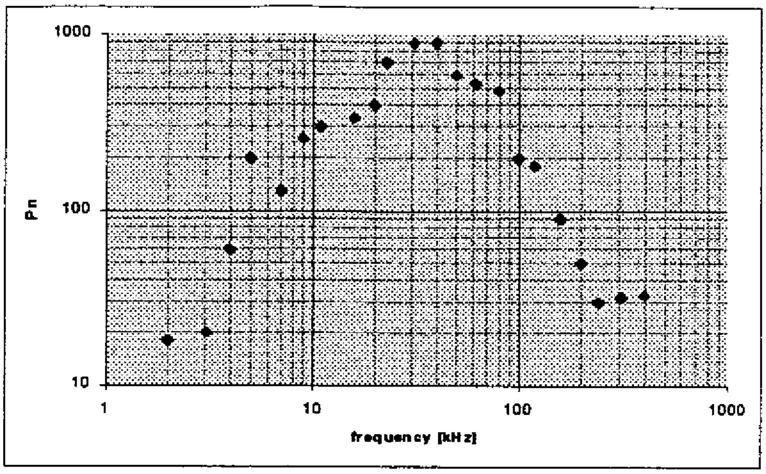


Figure 3 - Spectra of the acoustic noise of valve C, P: 51.4>39 bar, F=180.000 Nm^3/h

Previously it was supposed that designs for so called "low noise" valves ("low noise" in this case stands for low energy levels in the audible frequency range) shifted the noise emission to the higher frequency range. Comparing the frequency spectra and noise levels of different valves shows that this is not necessarily true.

Whereas bends and tee's show significant attenuation of ultrasonic noise, straight pipe has little to almost no effect. In case the noise level exeeds acceptable limits, additional bends or tee's can be installed to act as silencer or silencers specifically designed for this purpose can be used. Such a silencer has to be engineered for a specific kind of application (e.g. dependent of frequency). At Sayda three types of silencers (S_1, S_2 and S_3) were tested by measuring the attenuation of the ultrasonic noise.

The results of the acoustic measurements are shown in Figure $4^{a\text{-}c}$. This Figure shows the relation between the acoustic noise level entering the silencer (p_{in}) and the acoustic noise level leaving the silencer (p_{out}). The ratio represents the degree of attenuation.

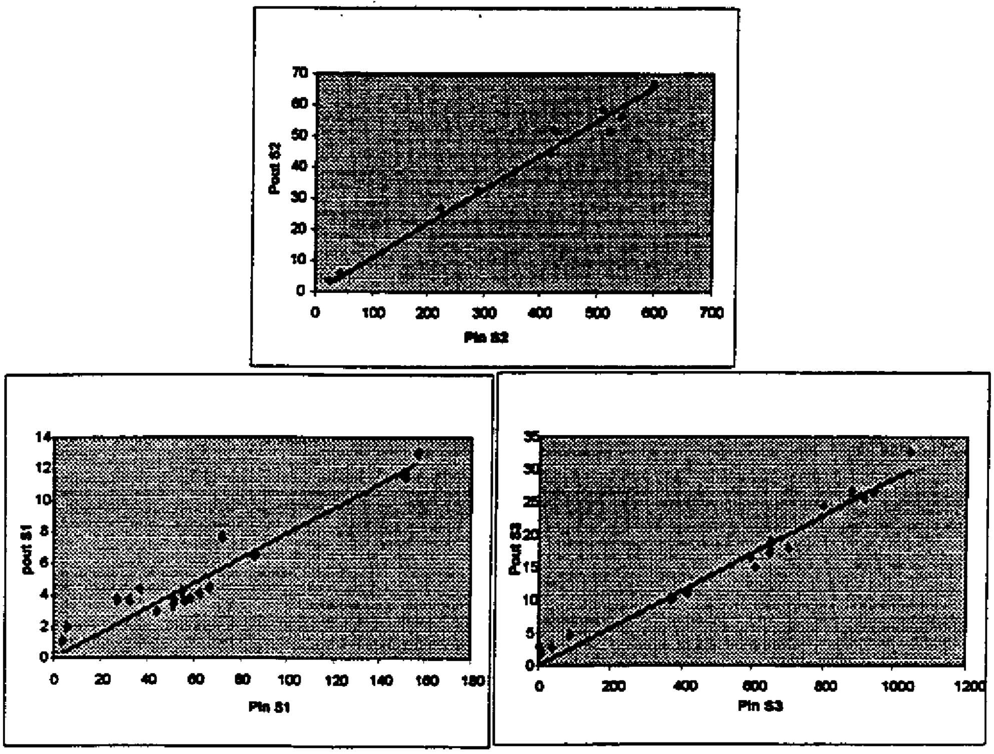


Figure $4^{a\text{-}c}$ - Attenuation of ultrasonic noise in the frequency band of a standard transducer

A usual way to present the ratios is in dB. Because we use here the acoustic pressure (instead of acoustic power) the ratio in dB is:

$$Ratio[dB] = 20 \cdot Log\left[\frac{p_{out}}{p_{in}}\right] \tag{6}$$

Table 1 - Attenuation of Piping Elements

	Factor Type 1	DB Type 1		factor	dB
S_1	0.079	22	Bend 90°	0.32-0.56	5-10
S_2	0.11	19	Bend 45°	0.79	2
S_3	0.029	31	Bend out of plane	0.10-0.20	14-20
			100 m pipeline	0.56	5

A typical phenomenon occurring with one type of silencer is that the attenuation is dependant of the gas velocity. It appears that at high gas velocities the silencer S_2 starts to generate noise. The explanation for this is the exitation of resonance frequencies of the cavities inside the silencer at high gas velocities. This phenomenon is only relevant when the meter is installed downstream of this type of silencer. For bidirectional applications the remedy is to keep the gas velocity inside the silencer below a certain value.

7 FUNCTIONALITY OF THE ULTRASONIC FLOWMETER

The equations and data presented so far show that an indicative value proportional to noise present at the ultrasonic flowmeters position can be calculated. The next step is to demonstrate the correlation between the performance of the ultrasonic flowmeter and the calculated value of the indicator (δ).

The performance of the meter can be assessed using the indicators calculated and showed by means of the diagnostic functions implemented in the software belonging to the meter. The meter can be classified as operational or not operational based on it's "valid data signal". When the meter is operational, the percentage of accepted signal pulses shows how well the meter operates. In ideal conditions this percentage should be close to 100%, say between 70 and 100 %. This percentage drops rapidly when the ultrasonic noise level pevents the meter to operate normally.

Another feature of the diagnostics of the ultrasonic gasflowmeter is that it calculates an AGC-limit value. This is based on the ultrasonic background noise level which is measured between succesive signal pulse transmissions. This values indicates the maximum gain that will keep the noise level below an acceptable value. The actual gain (AGC-level) needed to amplify the signal to the required normalized value should stay well below the value of the AGC-limit. A satisfactory margin can be expressed in terms of the ratio of AGC-limit/AGC-level, this indicates how much margin is left before there is a risk of the meter having problems due to noise.

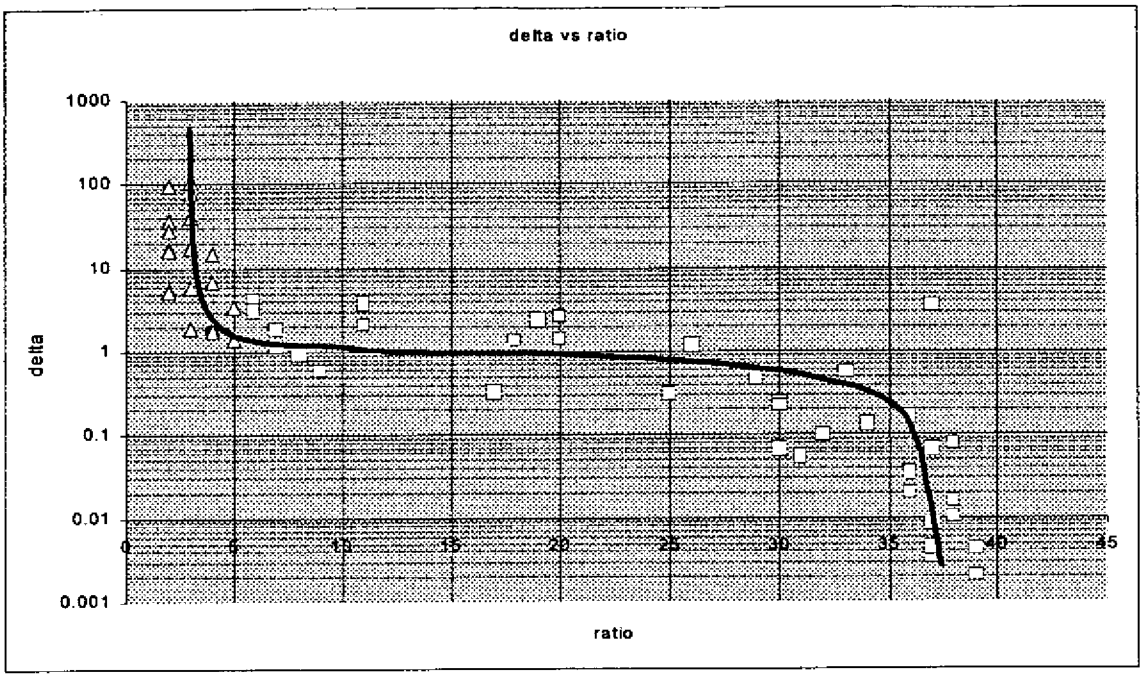


Figure 5 - Good functionality of the ultrasonic flowmeter

Figure 5 shows a typical graph of the AGC_ratio (Autmatic Gain Control_ratio) versus the δ-factor. As long as the AGC ratio is larger than 5 the instrument is functioning properly (level has not reached the limit). Figure 5 shows that a rapid decrease of the AGC ratio occurs starting from a δ-value of about 1.

8 CONCLUSION

The objective was to establish a model capable of predicting the performance of an ultrasonic flowmeter in a specific application.

This report shows that based on installation (piping) drawings, the control valve characteristics and relevant process parameters, it is possible to calculate a δ-factor value that predicts whether the ultrasonic flowmeter can function properly in a specific application. If not, it can be calculated to which extent additional measures are required to assure proper operation of an ultrasonic meter in the installation under study.

9 FINAL REMARK

For the calculation of the indicator (δ) a first approach can be made by using a valve characteristic value N_v of 1 as default value. For a more accurate assessment it is recommended to use the valve characteristic value. In case this value is not available Instromet has the equipment and capability to perform measurements on a site where a representative model of the particular valve is in operation as long as provisions can be made to install ultrasonic measuring microphones. In this way most applications can be analyzed for acoustic noise behavior and an advice can be given for the applicability of our ultrasonic gasflowmeters analyzers.

ACKNOWLEDGEMENT

Instromet wants to thank Verbundnetz Gas for organising and conducting this project. Especially the enthusiastic co-operations of Dr. Stoll, Mr. Slawig, as well as the support of Mr. Müller from PLE are greatly appreciated.

We also want to mention Dr. Dane who contributed in the processing and analysing of the ultrasonic sound measurement data.

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THEORY AND APPLICATION OF NON INVASIVE ULTRASONIC CROSS CORRELATION FLOW METER IN HARSH ENVIRONMENT.

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PRESENTED BY

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16TH NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

THEORY AND APPLICATION OF NON INVASIVE ULTRASONIC CROSS-CORRELATION FLOW METER IN HARSH ENVIRONMENT

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1. INTRODUCTION

The concept of the ultrasonic cross-correlation flow meter was first proposed in the early seventies. This technique demonstrated clear advantages over the more conventional transit-time method. However, cross-correlation meter was not commercialized due to the complicated data processing algorithm required and lack of understanding of underlying physical phenomena.

At the present time, enormous computing power of the PC and availability of commercial data acquisition and analysis software have eliminated the problem of data processing. On the other hand, better understanding of the physics involved in the interaction between ultrasonic waves and turbulence structures existing in a flowing fluid has resulted in development of a very accurate, reliable and affordable instrument.

The ultrasonic cross-correlation flow meter, known as CROSSFLOW™, has been used successfully in nuclear industry for non-invasive flow measurements at high temperaturesand high radiation fields. The meter has been installed for continuous on-line measurements, as well as used for periodic flow verification. The main advantage3 of the CROSSFLOW, from the point of view of flow measurements in harsh environment, is simplicity of transducer design, which allows installation in only a few minutes even under very poor access conditions. Data from on-line installations have confirmed very high meter reliability and insensitivity of the measurements to changes in external conditions. Experience gained from using the CROSSFLOW in nuclear industry points to ability of the meter to perform accurate and reliable flow measurements in other applications, including oil industry.

In this paper, fundamentals of the cross-correlation technique are discussed. Results of CROSSFLOW calibration, performance evaluation and examples of meter application are presented.

2. ADVANTAGES OF ULTRASONIC CROSS-CORRELATION TECHNIQUE

The design of the ultrasonic cross-correlation flow meter is based on the fact that when ultrasonic beam travels across a pipe in certain pipe cross-section "A" it is affected by random turbulent fluctuation of the flow parameters. After the received signal is processed a random signal Xa(t) - a signature of turbulence fluctuation in the flow in cross-section "A", can be obtained. If one transmits a second ultrasonic beam a certain distance L downstream of the first beam (in pipe cross-section "B"), it produces another random signal Xb(t). If distance L is small enough then approximately $X_a(t) = X_b(t + \tau^*)$ and value $Vm = L / \tau^*$ is interpreted as a measure of the flow velocity in the pipe [1]. (See Figure 1.)

This method has the following advantages over a more conventional transit time approach:

- Flow velocity is measured directly by measuring time of travel between two cross-sections. Typical magnitude of τ^* is of the order of 100 ms, in contrast to transit time meters, where typical difference in transit time is of the order of 1 μs.
- The result of measurement does not depend on speed of sound in the pipe material and in the fluid, which means the meter can work in a wide temperature range and for different materials;
- Direction of the ultrasonic beam is perpendicular to the pipe wall so the instrument is not very sensitive to installation and temperature changes during operation.
- The meter can operate for multiphase and mixed flows.
- Measured flow velocity is determined only by the axial velocity in the pipe and is not sensitive to the radial velocity component.

In spite of these advantages the cross-correlation meters were used only for specific applications such as water - sand or water -coal mixture, where application of other instruments was not feasible. Two major reasons prevented further development of the cross-correlation meters for pure liquids:
a) Calculation of the cross-correlation function was associated with bulky and expensive analog equipment. At the present time this problem is resolved by use of computers.
b) Physical interpretation of measured velocity in terms of the average flow velocity is not as transparent as for transit time meters, and the cross-correlation technique is considered as a purely empirical.

3. DEVELOPMENT OF THE NEW NON-INVASIVE ULTRASONIC CROSS-CORRELATION FLOW METER

One of the examples of successful application of this technique is associated with non-invasive ultrasonic cross-correlation flow meter for pure liquids, developed in earlier seventies by Canadian General Electric for Ontario Hydro [2]. The meter was calibrated at Ontario Hydro Research at the high temperature, high Reynolds number calibration facility. Calibration results and the use of the meter in Ontario Hydro nuclear power plants confirmed its high accuracy and its temperature stability [3]. However lack of quantitative understanding of the physics of meter operation, prevented optimization of the system and its application to a wide range of flow velocities and pipe diameters.

In 1995 Advanced Measurements and Analysis Group Inc. carried out rigorous analysis of the physics of ultrasonic cross-correlation flow measurements under Canadian Government grant-IRAP. Based on this analysis the following was achieved:

- Optimum magnitudes of the system parameters and data processing algorithm were related to the flow parameters such as pipe diameter, flow velocity and Reynolds number.
- Methodology of the flow meter calibration and of extrapolation of calibration results to the range of parameters outside of the calibration conditions was developed and tested.
- Numerical method based on k-e turbulence model was developed to calculate the ratio of the measured velocity to the average flow velocity for different pipe geometries, including bends and bend combinations. This method was used to extrapolate calibration results to high Reynolds Numbers for specific configurations of the pipe-lines. [4]
- Design of the acoustical system was optimized. Methodology was developed for adjusting acoustical parameters of the meter to acoustical parameters of the pipe and the fluid.

This work has resulted in a design of a significantly improved cross-correlation flow meter known as CROSSFLOW ™ . This meter has been installed for on-line high temperature flow measurements at a number of nuclear power plants in Canada and USA. The meter has also been used for short term flow measurements in number of facilities, including nuclear power plants in Canada, USA, Argentina, Romania, Brazil, France, Spain; water supply system; acid flow in chemical plant, etc.

The CROSSFLOW system includes a transducer frame, mounted on a pipe; ultrasonic probes (transmitters and receivers) mounted on the frame; multiplexer, capable to monitor up to eight pipes;

Signal Generating and Processing Unit; Personal Computer and Software (see Figure 1). The software controls the system, performs data acquisition, processing and analysis; records and stores data and can be easily adjusted to meet customer's needs.

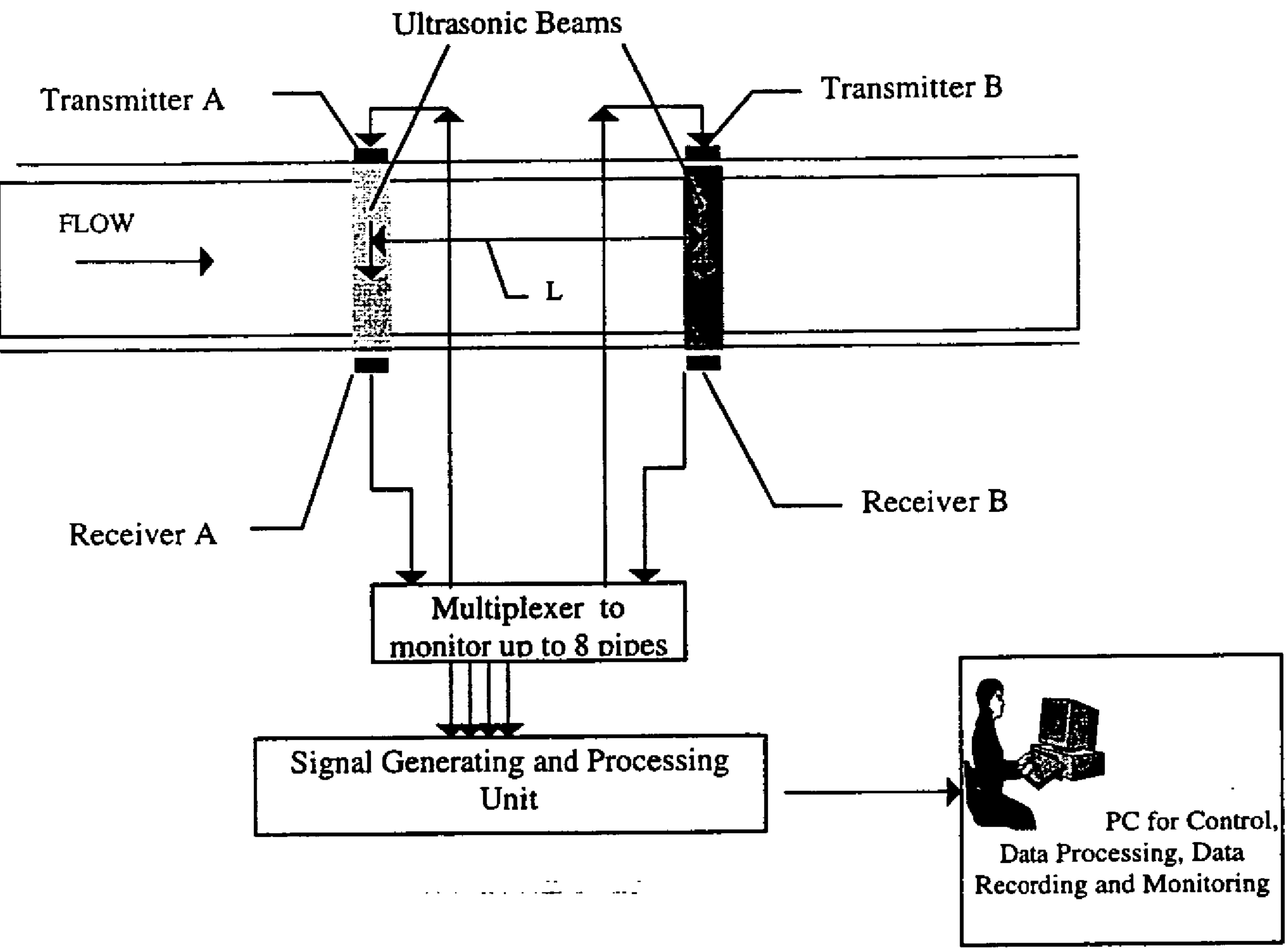

Figure 1. Ultrasonic Cross-Correlation non-invasive flow meter CROSSFLOW.

To enable the development of the improved meter, part of the project was dedicated to the theoretical analysis of the interaction between ultrasonic wave and turbulence in a pipe. This study resulted in a more accurate interpretation of the measured velocity in terms of the average velocity in a pipe. Quantitatively it gives the ratio of the average flow velocity Va to the measured velocity Vm as a function of Reynolds number. This relation was confirmed by calibration of the meter for Reynolds numbers up to 10 million. Good agreement with experiment allowed to use this relation for high temperature measurements with Reynolds Number 20 - 30 millions, which is much higher then calibration facility can provide.

4. THEORY OF CROSS-CORRELATION ULTRASONIC FLOW METER. ULTRASONIC WAVE – TURBULENCE INTERACTION.

4.1 Measured velocity - Vm

Fundamental problem of the theory of ultrasonic cross-correlation flow measurement is relation of measured velocity Vm to the averaged flow velocity Va.

Measured flow velocity

$$Vm = L / \tau^* \qquad (1)$$

is determined by the constant distance between ukltrasonic beams - L and by time delay between two signals Xa(t) and Xb(t). The time delay τ^* is calculated as a position of maximum of the cross-correlation function R_{ab}

$$R_{ab} = \int X_a(t) X_b(t+\tau) dt \qquad (2)$$

Signals Xa(t) and Xb(t) are the result of the effect of turbulence on the ultrasonic beam in the pipe. Usually it is assumed that Vm is an average of the velocity distribution in a pipe along the ultrasonic beam, directed along pipe diameter. This assumption probably is correct if signals Xa(t) and Xb(t) are produced by a turbulent feature, uniformly distributed along pipe diameter, such as concentration of passive second phase.

In more general case the measured velocity Vm is related to velocity distribution in the pipe as follows:

$$Vm = \int_0^D U_x(r) \cdot F(r) dr \qquad (3)$$

where D is pipe diameter, $U_x(r)$ - time averaged axial flow velocity and weight function F(r) depends on the nature of the signals Xa(t) and Xb(t). Relation between measured velocity Vm and velocity distribution in the pipe depends on the following major factors:

a) the nature of perturbation of the ultrasonic wave - perturbation due to fluctuation of temperature or velocity or concentration of a second phase in the flow, etc.

b) on the type of processing of the received signal - amplitude or phase demodulation of the ultrasonic wave or filtering, saturation, amplification of the demodulated signal etc.

Therefore interpretation of measured velocity Vm requires more deep quantitative analysis of the process of ultrasonic wave perturbation by the flow.

4.2 Effect of turbulence in a pipe on ultrasonic wave in a pure liquid

Normally the amplitude of velocity and pressure fluctuations in ultrasonic wave is very small, and flow velocity field (including turbulent velocity fluctuation) is not effected by ultrasound.

Total velocity field in the flow under ultrasonic irradiation U*(r,t) can be described as a superposition of undisturbed turbulent velocity field Uo (r,t) and disturbed ultrasonic wave U:

$$U^* = Uo + U \qquad (4)$$

Ultrasonic wave in a turbulent flow can be described approximately by linear wave equation with coefficients, which are functions of time and coordinates and are determined by known turbulent velocity distribution Uo and its derivatives. [1] Maximum frequency of turbulent flow pulsation in a pipe is estimated as Va / λ_k where λ_k is Kolmogorov scale [5] . This frequency for typical pipe flow is order of 1 KHz and is much smaller then typical frequency of the ultrasonic wave. Then ultrasonic wave can be presented in the form of high frequency periodic function with low frequency disturbed amplitude A and phase φ:

$$U(r,t) = A(r,t)\cos(\omega \cdot t + k \cdot r + \varphi) \qquad (6)$$

Analysis of the wave equation shows that in equation (6) the amplitude A is determined by solution of differential equation. Coefficient in this equation are determined by turbulent velocity field Uo.. In contrast, phase φ has a simple physical interpretation. If an ultrasonic wave is induced by the ultrasonic source at r = 0 then at r = D

$$\varphi(t) = \varphi_0 + (\omega / C^2)\int_0^D U_{0r}(r,t)dr \qquad (7)$$

where Uor is radial component of the velocity Uo (projection of the velocity vector Uo on the direction of the ultrasonic beam), C is speed of sound in the liquid, φ_0- constant.

Thus, if signals Xa (t) and Xb(t) represent phase change of the ultrasonic wave then they are determined by expression (7) and they can be expressed in terms of turbulent parameters of the flow..

4.3 Estimation of the measured velocity for a straight pipe.

The integral in equation (7) is approximately proportional to the product of intensity of turbulent velocity pulsation u_t and scale of turbulence λ_t and therefore is proportional to the turbulent viscosity μ_t [5].

$$\int_0^D U_{0r}(r,t)dr \approx u_t \cdot \lambda_t \approx \mu_t \qquad (8)$$

Parameter μ_t is widely used in many turbulence models and can be calculated for different pipe configurations. Typical shape of μ_t is shown in Figure 2. This shape, according Nikuradze [6] is independent on Reynolds Number.

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[1] Derivation of the wave equation and more detale analysis of the problem will be published separately.

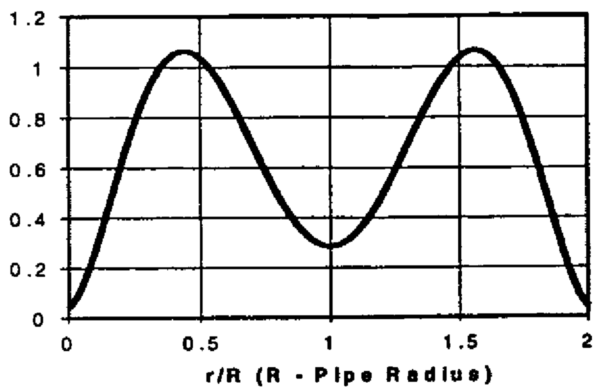

Figure 2. Qualitative Distribution of Effective Turbulent Viscosity in a pipe.

Using Nikuradze data on velocity and turbulent viscosity distribution in a pipe [6] and equation (8), one can obtain dependence of the measured velocity Vm on the average flow velocity Va in the form:

Va = Vm C(Re)

where Re is Reynolds Number. Function C(Re) is known as the Velocity Factor and is shown in Figure 3.

Equations (7) and (8) also used to optimize characteristics of the flow meter and signal processin algorithm. For example distance between probes, frequency range for signals Xa(t) and Xb(t), time of correlation and others depending on pipe's diameter, flow velocity and Reynolds Number.

5. CALIBRATION OF ULTRASONIC CROSS-CORRELATION FLOW METER FOR STRAIGHT PIPS

5.1 Calibration methodology

The curve presented in Figure 3 was obtained assuming a perfect correlation between signals Xa and Xb . This assumption means that

a) distance between probes A and B is smaller then "distance of life" of turbulence structures in the flow and

b) signals Xa and Xb include sufficiently wide range of turbulent spectrum in the pipe.

To satisfy these conditions the characteristics of the flow meter, have to be adjusted to the pipe diameter, flow velocity and Reynolds number. Then calibration curve will be function of only Reynolds Number irrespective of pipe's diameter and flow velocity.

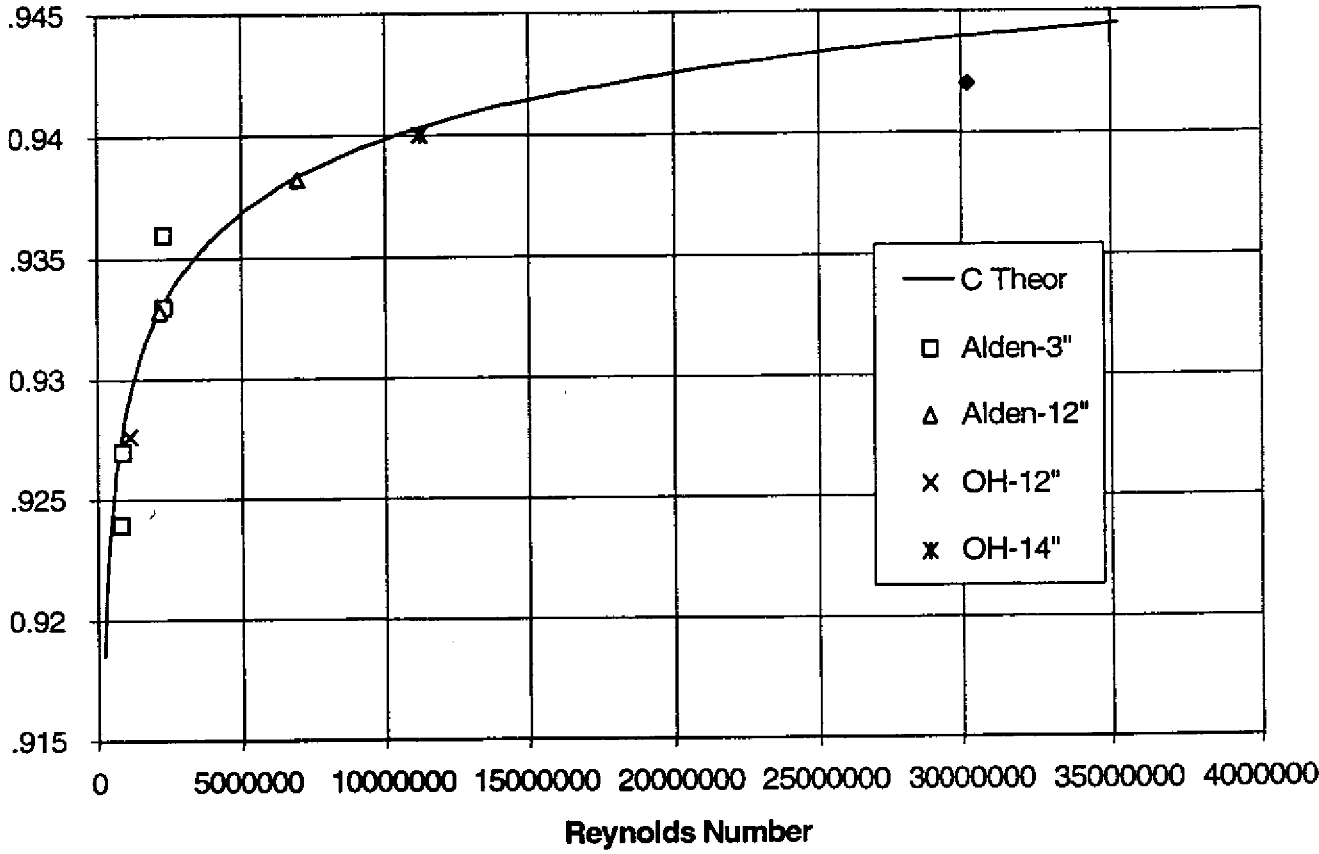

Figure 3. Velocity Factor C (Re). Theory and Calibration. Point ◆ - comparison with calibrated venturi nozzle in nuclear power plant.

5.2 Calibration results

In Figure 3 the curve for the calibration coefficient C is presented together with experimental data. Experiments were carried out in Alden Research Laboratory (USA) and in Ontario Hydro Research Laboratory (Canada) with high temperature flow. Measurements were performed on plastic pipes and carbon steel pipes with diameters from 2 inches (5 cm) to 16 inches (40 cm) in the range of Reynolds numbers from 700,000 to 10,000,000. Data for high temperature flow (Reynolds number from 7,000,000 to 10,000,000) were obtained in Ontario Hydro Research Laboratory. Special facility in this laboratory allowd to get flow temperature up to 200 C. Flow was measured by the venturi nozzle with accuracy 0.5% [3]. In Alden Research Laboratory flow was mea by weigh tank with accuracy 0.25%. Maximum Reynolds Number was around 5 millions.

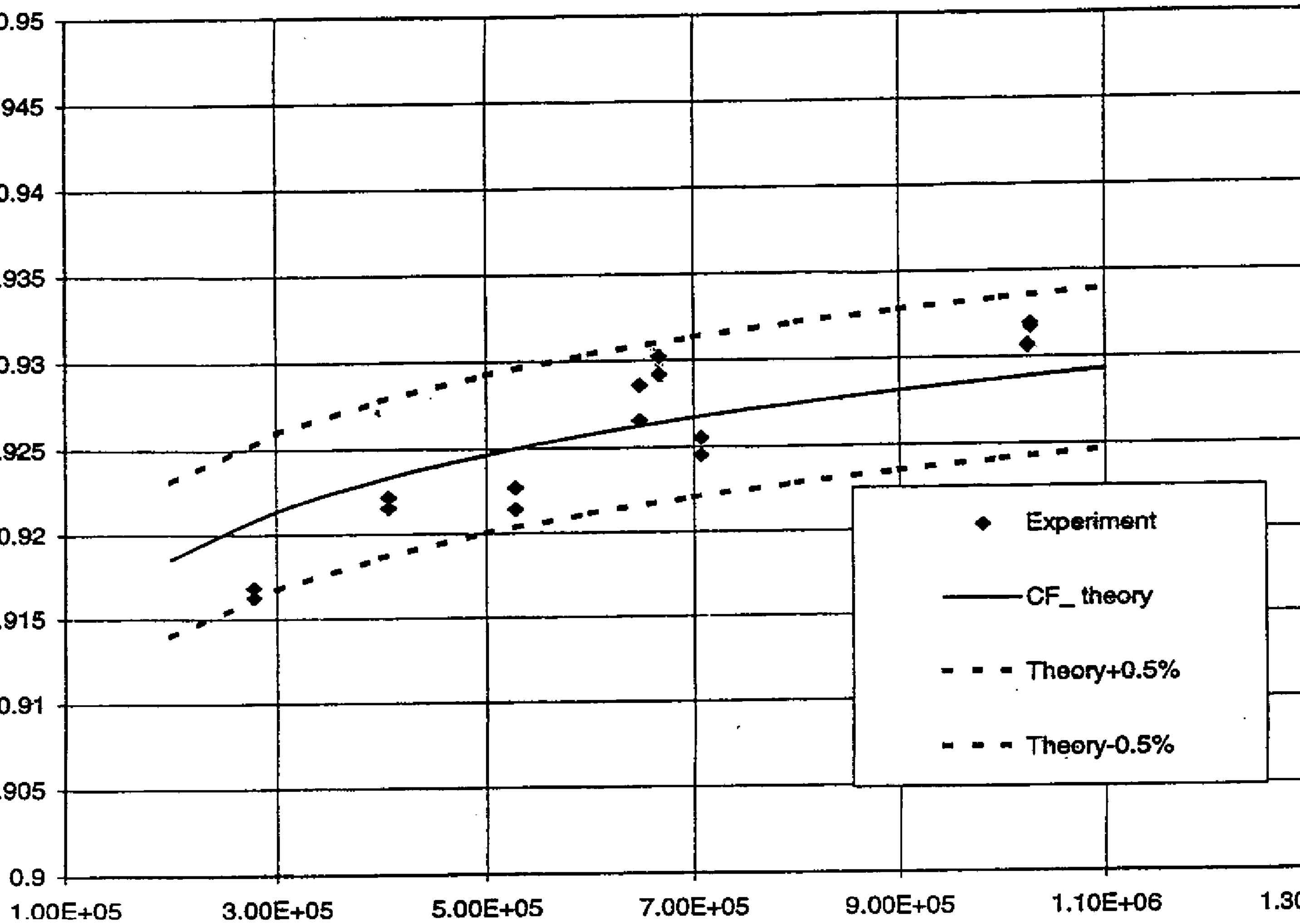

Figure 4. CROSSFLOW Calibration for 300 000 <Re< 1 000 000

Calibration for Reynolds numbers 300 000 < Re < 1000000 was carried out in Ontario Hydro Flow Test Laboratory on 12 inch pipe. Results are presented in Figure 4. In this figure all experimental points are within ± 0.5% interval from the theoretical curve. The flow in Ontario Hydro Flow Test Laboratory is produced by head tank and is measured by weigh tank. Accuracy of flow measurements using weigh tank is 0.5%. Maximum Reynolds number is 1 million.

The results of calibration shown in Figures 3 and 4 demonstrate that the difference between the theoretical curve and experimental data is within the accuracy of the experiment. Statistical analysis of the data shows that in the range of Reynolds Number from 0.3million to 10 million the curve gives calibration coefficient C with uncertainty better then 0.05%.

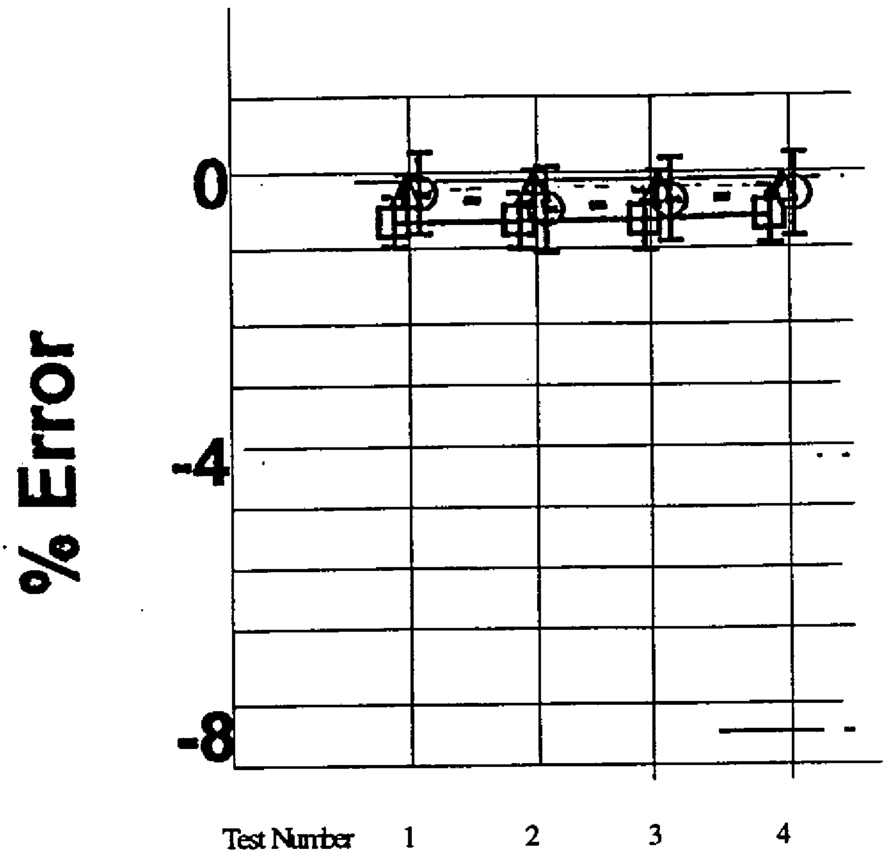

Figure 5. CROSSFLOW Reproducibility (see text for details)

5.3 CROSSFLOW Reproducibility

Results of the meter's reproducibility are shown in Figure 5. The tests were carried out in National Institute of Standards and Technology in Washington on 10 inch stainless steel pipe. The flow was provided by the pump. CROSSFLOW measurements were compared with weigh tank measurements. The error in the graph is calculated as a difference between weigh tank data and flow measurement using instrument under test. Test number 1 is a normal flow measurement. Test number 2 is a measurement after the pump was re-started. For test number 3 the ultrasonic probes were re-mounted on the frame. For test number 4 the frame with ultrasonic probes was re-mounted on the pipe. The three meters under test are: electro- magnetic meter, previously calibrated on the same position on the pipe - O; Ultrasonic transit time flow meter with four ultrasonic paths, installed invasively - Δ; CROSSFLOW - . The results demonstrate reproducibility around 0.2%.

6. CROSSFLOW APPLICATION IN HARSH ENVIRONMENT

One of the applications of the non invasive cross-correlation flow meter CROSSFLOW for high temperature flows is Feedwater flow measurement in nuclear power plants. Typical parameters of this flow are: pipe diameters 12– 30 inches, water temperature approximately 230 C°, pipe material- carbon steel, pipe wall thickness 1 – 2 inches, Reynolds number up to 30,000,000,

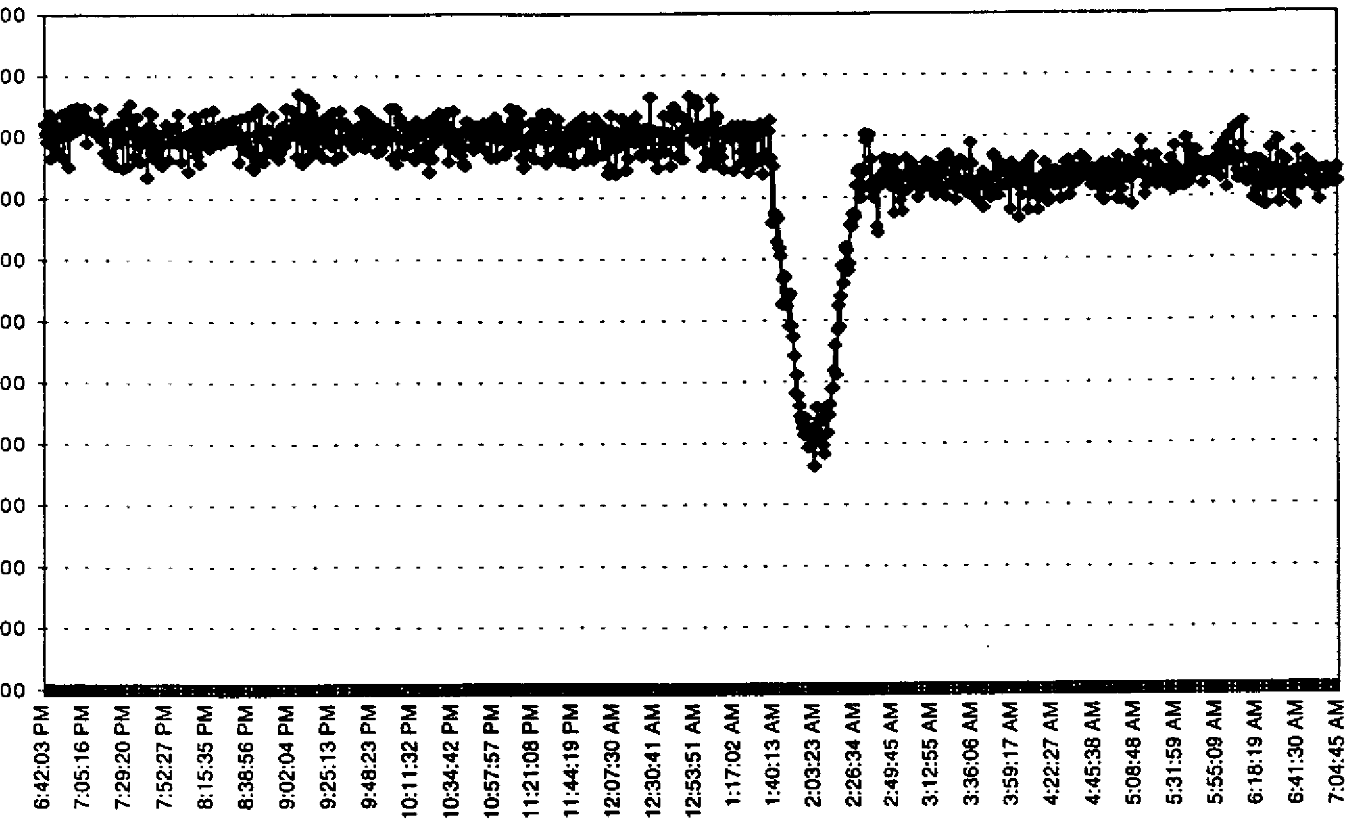

Figure 6. Typical Flow Measurement. Pipe temperature 230C. Flow change from 100% to 90% to 99% of normal value.

which is normally not achievable in a laboratory environment. Depending on particular case the meter installation is carried out under high temperature up to 45-50C° ; high radiation field and difficult access to the pipes. The pipe temperature itself during installation and operation is around 200C. Surrounding temperature during operation is 45-50C°

Other important application of the CROSSFLOW is reactor coolant flow measurement with flow temperature approximately 300 C° and pipe diameters 2 – 20 inches. Specifics of this measurement are:

a) High environmental temperature - 300 C°, which practically exclude possibility of cooling of the ultrasonic probes and use of rubber coupling.

b) High radiation fields, which reduces limit for time of installation to a 10 - 15 minutes.

c) Excess to the transducer is impossible during plant operation, which requires high reliability of the system without maintenance service during 1- 2 years.

Typical result of the flow measurement is shown in Figure 6. In this application the plant power is proportional to the flow. During time interval shown on the graph the plant power changes from 100% to 90% and to 99% of the normal value. From the graph it is clear that the meter's resolution is high enough to resolve significantly smaller flow change then 1%.

7. CONCLUSION

Present stage of the ultrasonic cross-correlation technology allows to provide flow measurements with accuracy around 0.2%. The measurements can be performed in a wide range of pipe diameters, pipe materials, pipe wall thickness, liquides and flow velocities. The only limitations of the technology are:

a) the pipe and the flow have to be transparent to the ultrasonic wave;
b) The ultrasonic wave has to be effected by the random fluctuation of the flow parameters. In case of pure liquids it is a turbulent pulsation of the flow velocity. In case of multiphase liquids it could be fluctuations of concentration of the second phase.

The technology allows providing non-invasive flow measurements in harsh environment and in situations were installation is complicated by difficult access to the pipe or by other specific requirements.

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NEW A.G.A REPORT NO9. MEASUREMENT OF GAS BY ULTRASONIC GAS METERS.

J Stuart, Pacific Gas and Electric Co.
K Warner, Daniel Europe Ltd

With regard to the second paper within submitted by Mr John W Stuart, the following re-print has been accepted in good faith by the organisers with responsibility for all permissions being accepted by the authors.

The Essence of A.G.A. Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters

KEVIN L. WARNER, Ultrasonic Product Manager, Daniel Industries.

ABSTRACT

The American Gas Association has recently published (June, 1998) a new recommended practice; *Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters*. This paper reviews some of the contents of A.G.A.-9 including recommended meter performance requirements, design features, testing procedures, and installation criteria. This paper is a companion to John Stuart's paper which was presented at the 1997 A.G.A. Operations Conference in Nashville, Tennessee entitled, *New AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Gas Meters*. It is also included here for easy reference. The topic selected in this paper were chosen based on the author's opinion of the audience's interests.

A.G.A-9 was drafted by the A.G.A. Transmission Measurement Committee which incorporated many of the recommendations in the GERG Technical Monograph 8 (1995) and certain related OIML recommendations. After over a year of technical discussions, balloting, and revisions, the document represents the consensus of several dozen metering experts in the US and Canada. It is hoped that A.G.A.-9 will soon be considered by ISO/TC 30 as the basis for a new ISO standard.

SELECTIVE REVIEW OF A.G.A. REPORT

Scope of Report

A.G.A.-9 was developed for multipath ultrasonic transit-time flow meters, typically 6" or larger and used for the measurement of natural gas. A multipath meter is defined as one with at least two independent measurement paths.

Meter Requirements : Codes and Regulations

A.G.A.-9 makes many statements which are essentially design instructions for manufacturers of meters. One reason this approach was taken was to insure the end user that an ultrasonic product would be safe and consistently manufactured. Unless otherwise stated, the meters are to be suitable for use in an area which is subject to the requirements of the U.S. Department of Transportation's regulations in 49 C.F.R. Part, 192, Transportation of Natural and Other Gas by Pipeline : Minimum Federal Safety Standards.

Meter Requirements : Meter Body

Manufacturers are urged to publish the overall lengths of their ultrasonic meter bodies. This is to help skid and other designers who may not be familiar with ultrasonic metering to define metering section dimensions.

The inside diameter of the ultrasonic meter should be within 1% of the upstream tube's diameter. The value of 1% was based mainly on early European studies and also work performed at Southwest Research Institute in San Antonio, Texas. Other meter requirements in this include anti-roll devices (feet), pressure tap location on the meter, and standard meter markings. These requirements were based on field experience and the lessons learned from other metering technologies.

Meter Requirements : Ultrasonic Transducers

Ultrasonic transducers are not common pipeline devices and many operators are unfamiliar with their properties. A.G.A.-9 includes clear directions to the manufacturer for the specification, marking, and testing of transducer pairs. These instructions are valuable because they will alert users as to the pertinent information which may affect the performance of the meter. A.G.A.-9 also requires that transducers be manufactured so that they may be exchanged and requires instructions for the exchange process.

Meter Requirements : Electronics

Much discussion was given to the issue of electronics and its evolution with time. The goal of the committee was to require electronics which were well tested and documented, but to allow improvements without placing a larger than necessary burden on the manufacturer. This idea is evident throughout the document but is especially relevant in the electronics and firmware sections.

The electronics output section includes two suggested types, serial and frequency, along with a list of others. Serial communication is suggested because the ultrasonic meter is clearly a very "smart" instrument and much of its usefulness relies on the internal information contained in the meter. The frequency output is a convenient option, especially in locations which are configured for turbine meter inputs. A.G.A.-9 also mentions analog outputs, direction indicator, a low-flow cutoff, and volume accumulators.

Meter Requirements : Computer Programs

Since ultrasonic meters are electronic, the computer programs and information contained in the electronics of the meter are extremely important. A.G.A.-9 requires that it be possible to interrogate the meter and determine its calibration parameters. It also requires that the meter be securable, so that accidental or undetectable changes can be prevented.

Alarms and diagnostic functions are clearly addressed under the computer programs heading. These sections were difficult to compose because of the subtle differences associated with every different path configuration imaginable. The data which is required is of three main types, gas velocity, speed-of-sound, and electronic failure. The velocity data is to indicate flow profile irregularities or velocity range exceptions. The speed-of-sound data is to be used as a diagnostic tool to check for erroneous transit time measurement errors. Other data is required to judge the quality of the data such as "% of accepted pulses."

Performance Requirements

The heart of A.G.A.-9 is contained in the Performance Requirements section. A.G.A.-9 separates ultrasonic meters into two categories, smaller than 12" and meters which are 12" and larger. The division was created to allow looser performance requirements for smaller meters where tolerances are more difficult to maintain. The flow regime is also divided into regions. Essentially there are two regions, one low flow region and one high flow region. The flowrate dividing them is called the transition flowrate. Manufacturers are to provide the numerical values for minimum, maximum, and transition flowrates. There is a requirement that the maximum value be at least ten times greater than the transition flowrate.

The maximum error allowable for an ultrasonic flow meter is +/- 0.7% for large meters and +/- 1.0% for small meters. This error expands to +/- 1.4% below the transition flowrate. Within the error bands, the error curve for any individual meter may not span more than 0.7%, or one half the height of the error bounds for large meters. This is the linearity specification written in terms of the error curve. The repeatability of the meters must be +/- 0.2% for the higher velocity range and is doubled for the lower. These limits specify the performance of the meter prior to the application of any flow calibration adjustment, or in other words are a dry calibration requirement. A.G.A.-9 was written in this fashion to provide a very clear and logical picture in which to view a meter's performance based on readily available data, the error curve. The dry calibration requirement itself was deemed necessary to discourage any haphazard construction of meters with the intention of "correcting" them in the final stages through flow calibration.

Individual Meter Testing Requirements

Individual meters are to be tested to strict tolerances for leaks and imperfections. A.G.A.-9 also specifies a Zero-flow Verification Test and a Flow-Calibration Test procedure (although a flow-calibration is not required). These requirements were written mainly for consistency. After flow calibration, the user is given any number of options for adjustment (within the dry calibration limits described above), however the flow-weighted mean error method is suggested. More sophisticated multi-point schemes are also allowed.

Installation Requirements

A.G.A.-9 was written from the perspective of experienced gas measurement experts however each person freely admitted that they were still learning. This is evident and factually stated in the sections on installation requirements. Rather than specify numerical values for up- and down-stream pipe diameters, A.G.A.-9 requires test-supported recommendations from manufacturers of ultrasonic flow meters. These recommendations can take one of two forms. The manufacturer may define an up- and down-stream meter configuration which will not be biased by more than 0.3% from an installation effect (both with and without a flow conditioner) or the manufacturer may specify the flow profile deviation which will not bias the output of the meter by more than 0.3%. The user is also cautioned that protrusions, internal surface condition, thermowell position, valve noise, and flow conditioners may influence the meter's performance characteristics.

ACKNOWLEDGEMENT

Grateful acknowledgement is given to John Stuart for his contributions to this paper, accompanying presentation, and A.G.A.-9. It is this author's opinion that without John's diligent work ethic and patience there would be no A.G.A.-9.

New A.G.A. Report No. 9, Measurement of Gas by Multipath Ultrasonic Gas Meters

JOHN W. STUART, Principal Engineer, Pacific Gas and Electric Company

ABSTRACT

The new technology of multipath ultrasonic gas meters has been rapidly accepted by pipelines throughout the world as the meter of choice for high capacity meter stations. A.G.A.'s Transmission Measurement Committee has just finished writing *Report No. 9, Measurement of Gas by Ultrasonic Meters.* The contents of this new recommended practice for ultrasonic meters is summarized.

BACKGROUND

Ultrasonic technology has been used for liquid metering since the 1950's. In the early 80's, British Gas developed a multipath ultrasonic meter (UM) suitable for natural gas applications. During the past few years, several hundred multipath ultrasonic gas meters have been installed in pipelines all over the world. Indeed, the UM is the most significant metering technology adopted by the gas industry since the high pressure turbine meter was introduced in the 1960's.

STATE OF TECHNOLOGY

In 1995, GERG (Group European of Research Gas) published a very comprehensive technical monograph, *Present Status and Future Research on Multipath Ultrasonic Gas Flow Meters.* In 1996, A.G.A. published an Engineering Technical Note, *Ultrasonic Flow Measurement for Natural Gas Applications.* At the time this paper was written, UMs have been approved for legal metrology in twelve countries. Now that UMs have been accepted by the gas industry because of their high accuracy and low maintenance costs, the process of developing national and international standards is under way.

During the past few years, research results and flow calibration data have shown that UMs are very accurate when measuring gas with a good flow profile as found in calibration facilities. However, when measuring flow profiles disturbed by some combinations of upstream fittings and valves, UMs have exhibited a small amount of error. The amount of error is dependent on the type and severity of flow disturbance, and each manufacturer's unique methods of compensating for non-ideal profiles.

Therefore, unlike A.G.A.-3, no specific meter designs, or upstream piping configurations are recommended in A.G.A.-9. Instead the manufacturers are requested to provide technically defensible test data that demonstrate that their meters meet or exceed the performance requirements of A.G.A.-9 when installed in a piping system compatible with their meter.

PURPOSE OF A.G.A. REPORT

A.G.A.-9 will be published as a recommended practice and has been written in the format of a performance based specification. Specifications for meter accuracy, functionality, and various testing requirements are included along with some installation recommendations for the user. The intent is that A.G.A.-9, as a recommended practice, will be suitable for referencing in the following types of documents by anyone wishing to use UMs:

- Bid Specifications for furnishing and delivering an ultrasonic meter (Material Purchase Specifications)
- Engineering Contracts for A&E firms designing and constructing metering stations with ultrasonic meters
- Inter-Pipeline Operating Agreements for mutual agreement of using ultrasonic meters for custody transfer
- State and Federal Tariffs and Regulations for including ultrasonic meters as an alternative to orifice meters

SUMMARY OF A.G.A.-9 CONTENTS

Scope

The scope of A.G.A.-9 is limited to multipath ultrasonic natural gas flow meters, 6" and larger in diameter. Typical applications include measuring large flow rates at transmission pipeline interconnects, storage facilities, gas processing plants, city gate stations, and at power plants or other large end-use customer meter sets.

Principle of Measurement

Ultrasonic meters derive the gas flow rate by measuring the transit times of high frequency sound pulses. Transit times are measured for sound pulses traveling diagonally across the pipe, downstream with the gas flow, and upstream against the gas flow. The difference in these transit times is proportional to the average gas flow velocity along the acoustic paths. Numerical calculation techniques are then used to calculate the average axial gas flow velocity and the flow rate (acf/hr) through the meter.

The flow rate capacity range of an UM is determined by the actual velocity of the gas flowing through the meter, typically from 1 ft/s (0.3 m/s) to over 70 ft/s (21 m/s). Inherent in their design, UMs are bi-directional, measuring flow in either direction with equal accuracy.

The accuracy of an ultrasonic gas meter depends on;

- precise measurements of the meter body geometry,
- the accuracy of the transit time measurements,
- the quality of the flow profile and uniformity of the gas, and
- the flow profile integration technique.

Accuracy Requirements

A.G.A.-9 requires that the manufacturers test each UM design in a flow calibration facility to demonstrate that the UM design can meet the accuracy requirements specified below without actually adjusting or calibrating each meter.

- Maximum permissible error: ±0.7% of measured value
- Mean Flow Weighted Error (see below): less than ±0.5%

To further reduce a meter's measurement uncertainty, the user may as an option, have individual meters calibrated, i.e. output factors adjusted, based on flow tests at a calibration facility.

Presented at A.G.A. Operations Conference, May 19-21, 1997, Nashville Tennessee.

Users of UMs should also carefully follow the manufacturers installation recommendations, as any installation effects will add to the overall measurement uncertainty after the meter is installed.

The Flow Weighted Mean Error (FWME) is introduced as a way to quantify a meter's performance with a single number. FWME was developed in Europe, and uses a weighting factor proportional to the tested flow velocity to emphasize the accuracy at higher flow rates. FWME = SUM [(*Vi/Vmax*) • *Ei*] / SUM (*Vi/Vmax*), where *Vi/Vmax* is the weighting factor, and *Ei* is the error deviation indicated at the tested flow velocity *Vi*.

Electronics Design Tests

Manufacturers must also test the design of their electronic systems, including power supplies, microprocessors, ultrasonic transducers, and signal processing components. Unlike most traditional gas meters, ultrasonic meters inherently have an embedded microprocessor system. Therefore, A.G.A.-9 has included by reference, a international standardized set of testing specifications applicable to gas meter electronics. These electrical and mechanical tests serve to demonstrate the acceptable performance of the meter's design under different influences and disturbances; e.g., temperature, humidity, vibration, static electricity, voltage spikes, and radio transmissions.

Factory Zero Flow Tests

After the fabrication of each meter is completed, the manufacturer must perform a comprehensive set of shop tests to verify that all mechanical and electronic components meet specifications. For example, the internal diameter of the meter, and the distance between ultrasonic transducers must be carefully measured, verified, and documented.

An important test, key to the UM's ability to accurately measure at any flow rate, is the Zero Flow Verification Test done in the shop without any flow. Since UM flow rate measurements use the difference in acoustic pulse transit times, the most demanding test is at zero flow, where the measured transit times, upstream and downstream, must be exactly the same to indicate a zero flow rate. Another shop test is the speed of sound test which uses the average transit times to measure the speed of sound, which is then compared to a theoretical value based on the latest A.G.A.-8 equation of state.

Flow Tests

A flow calibration of each meter should not be necessary to meet the accuracy requirements specified in A.G.A.-9. However, flow calibrations guidelines are provided should a user want to verify the meter's accuracy, or to adjust the meter's output to minimize its measurement uncertainty. Flow calibration tests should be carried out at gas densities and velocities (i.e. flow profiles) near the expected operating condition.

Users are encouraged to release UM test results to the gas industry, before and after calibration factors are applied. This will enable manufacturers to demonstrate the accuracy of their un-calibrated meters, and facilitate research to improve UM technology. The Gas Research Institute currently has a project to collect this type of UM data.

Installation Effects

A.G.A.-9 alerts users that if an UM is installed with certain upstream piping configurations, it may exhibit measurement error if the flow profile has been disturbed to such an extent that the meter's design cannot correctly compensate. Research work on installation effects is on-going, and users should consult with the manufacturer and review the latest test results to determine if a specific UM design may be affected by the planned upstream piping configuration, and to evaluate any benefits of installing a flow conditioner or altering the piping configuration.

Maintenance

Manufacturers are requested to publish recommended maintenance procedures. Periodic maintenance may be as simple as using a remote PC to monitor several diagnostic measurements, such as ultrasonic signal quality and speed of sound for each acoustic path. Also, it may be possible to detect an accumulation of deposits on the transducer faces by measuring a reduction in the received ultrasonic pulse strength.

Whenever possible, users should verify that the UM measurement returns to near zero when gas stops flowing through the meter. When performing this test, users are cautioned that any meter run temperature differences will cause thermal convection currents of gas to circulate inside the meter which the UM can measure as a very low flow rate.

The internal surface of UMs should be kept clean of any deposits, which will reduce the meter's cross-section area. Accurate UM operation depends on knowing the precise cross-section area to convert gas velocity into a cubic volume flow rate. If a layer of deposits accumulate inside the UM, the cross-section area will be reduced, causing a corresponding increase in gas velocity and positive measurement error. For example, a 1/32" thick layer deposited around the inside of a 12" meter will cause a +1% flow rate error!

Inspection and Auditing Functions

UMs are required to have an audit function where the meter's configuration parameters, calibration factors, meter dimensions, and diagnostic values being used by the meter's signal processing system can be examined while the meter is in operation.

Field Verification Tests

A.G.A.-9 requests the manufacturers to develop a field verification test procedure to test various aspects of the UM to assure that it is operating properly and remains within the specified uncertainty limits. These procedures may include a combination of a zero flow verification test, speed of sound measurement analysis, internal inspection, dimension verification measurements, and other mechanical or electrical tests.

The manufacturers should also provide a rigorous uncertainty analysis to demonstrate that their field verifications tests are sufficient to preclude the need for periodic flow calibrations.

Appendix: Ultrasonic Technical Note

Included in the appendix of A.G.A.-9 as a comprehensive source of technical information on ultrasonic gas meters is, A.G.A. Engineering Technical Note M-96-2-3, *Ultrasonic Flow Measurement for Natural Gas Applications.*

CONCLUSION

While the ultrasonic meter has already been approved by the governmental authorities of a dozen foreign countries, the publication of A.G.A-9 will signal the acceptance of this new metering technology by the gas industry in the United States.

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EXPERIENCE FROM OSBERG C WITH A PROTOTYPE 6" MULTI-PATH ULTRASONIC GAS FLOW METER IN WELL DEVELOPED FLOW, SWIRL FLOW AND FLOW STRAIGHTENED CONDITIONS, COMPARED TO AN ORIFICE GAS FLOW METER.

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EXPERIENCE FROM OSEBERG C WITH A PROTOTYPE 6" MULTI-PATH ULTRASONIC GAS FLOW METER IN WELL DEVELOPED FLOW, SWIRL FLOW AND FLOW STRAIGHTENED CONDITIONS, COMPARED TO AN ORIFICE GAS FLOW METER

Trond Folkestad, Norse Hydro ASA

1 INTRODUCTION

Norsk Hydro has an installation for measuring fuel gas on the Oseberg C platform comprising a 6" multi-path Ultrasonic gas flow meter in series with an Orifice gas flow meter downstream. The Ultrasonic gas flow meter is a Fluenta 6-path FMU 700 while the Orifice gas flow meter is a simplified installation consisting of an orifice plate between orifice flanges. The Orifice gas flow meter is used as a qualitative check meter to evaluate the long-term performance of the Ultrasonic gas flow meter.

The flow conditions inside the Ultrasonic gas flow meter can change from a fairly well developed flow to a severe asymmetric swirl flow, coming from two different sources with different piping arrangements. After one year in continuous operation a flow conditioner was installed 9.9 D upstream of the Ultrasonic gas flow meter to eliminate the swirl flow.

This paper will share the experience gained with the original flow regimes and with the flow conditioner installed and the paper will conclude with a recommendation for installation and use of this type of Ultrasonic gas flow meters.

2 BACKGROUND

The simplified Orifice gas flow meter was the originally installed fuel gas measurement system on the Oseberg C platform. Soon after the introduction in 1993 of the new regulation from the Norwegian Petroleum Directorate (NPD) relating to measurement of fuel and flare gas for calculation of CO_2 tax, Norsk Hydro was requested by NPD to improve the fuel gas measurement installation on the Oseberg C platform.

There is very limited space available for the fuel gas measurement system on the platform. After performing several studies in 1993 and 1994 evaluating possible measurement principals and installation solutions with space requirements, it was decided to install a prototype 6-path Ultrasonic gas flow meter. It was also decided to retain the original installation as a qualitative check meter.

The Ultrasonic gas flow meter was ordered from Fluenta 01.11.1994. With the installation of a prototype meter the mandatory delays were inevitable and the meter was finally installed at the Oseberg C platform in October 1995 after extensive testing at K-lab and considerable software development. After the commissioning phase and after several errors had been corrected in the software the Ultrasonic gas flow meter was finally put in operation 13.02.1996.

3 MEASUREMENT PRINCIPALS

3.1 The Ultrasonic Gas Flow Meter

The 6-path Ultrasonic gas flow meter has an acoustic path arrangement as seen in Figure 1. Acoustic paths A and B are in the top half of the meter, and paths C and D are in the bottom half. This acoustic path arrangement should enable the meter to measure and correct for a symmetric swirl flow, and also to measure the secondary transversal flow component.

Calculation of CO_2 tax is based on the amount of gas used measured as standard volume (Sm^3) of gas.

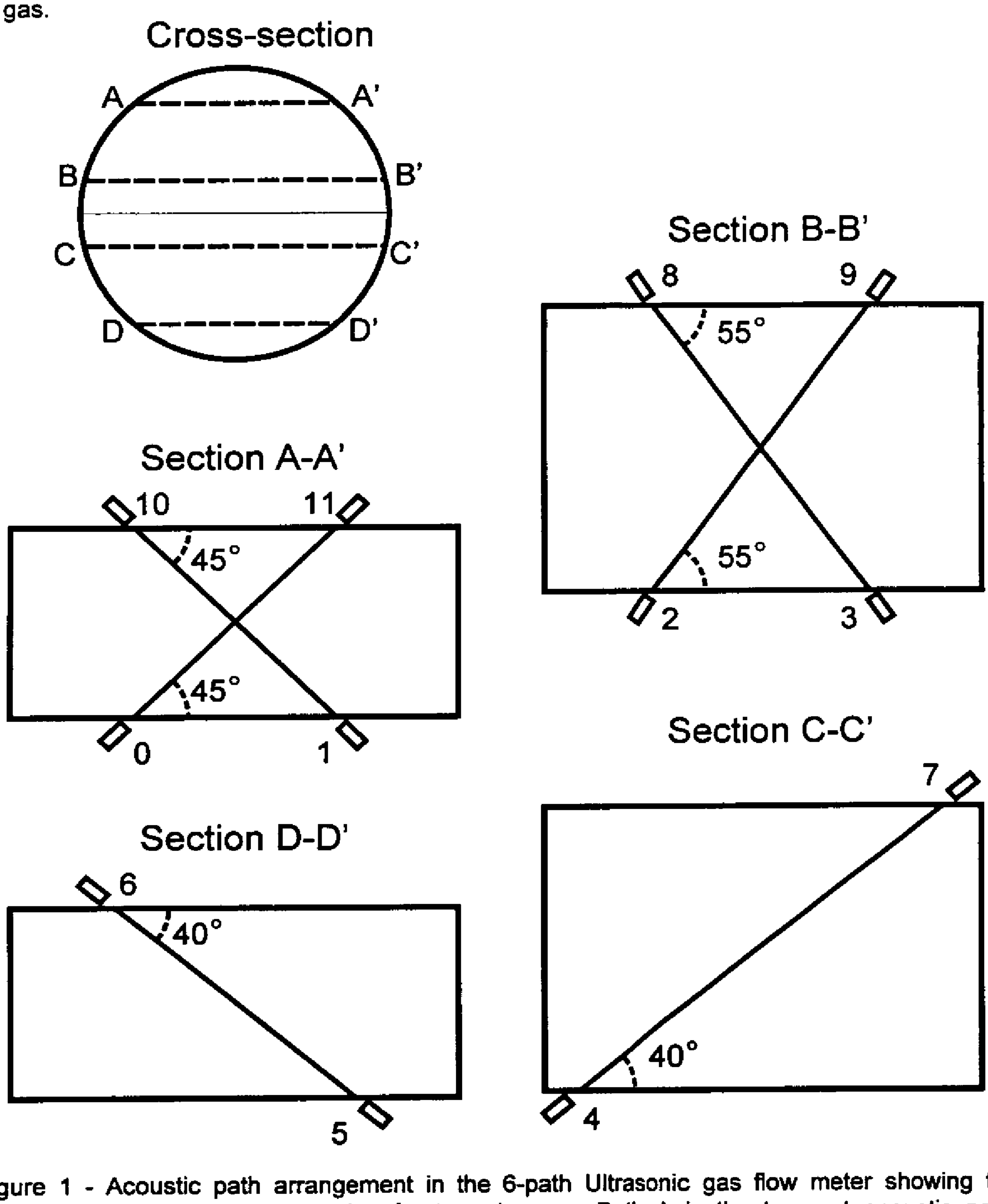

Figure 1 - Acoustic path arrangement in the 6-path Ultrasonic gas flow meter showing the position and numbering convention for transducers. Path A is the topmost acoustic path. Internal diameter is 146.25 mm.

The Ultrasonic gas flow meter measures actual volume flow and using PZT correction gives the standard volume flow, see Equation (1).

$$V_S = V_A \cdot \frac{P_A \cdot Z_S \cdot T_S}{P_S \cdot Z_A \cdot T_A} \qquad [Sm^3/h] \qquad (1)$$

Temperature and pressure are measured using transmitters with HART protocol.

3.2 The Orifice Gas Flow Meter

The Orifice gas flow meter is a 6" orifice plate between orifice flanges. The differential pressure, temperature and pressure are measured using 4 – 20 mA transmitters connected to the platform control system. This arrangement tends to give flow also at zero flow since no cut-off limit has been implemented and the zero accuracy of the 4 – 20 mA differential pressure signal is limited.

The flow calculations in the platform control system is simplified with no iterative compensation for flow, see Equation (2).

$$V_S = K \cdot \sqrt{\frac{\Delta p_A \cdot P_A}{MW \cdot T_A}} \qquad [Sm^3/h] \qquad (2)$$

The constant K in Equation (2) has been calculated using typical gas composition, flow rate, temperature and pressure, and has not been changed since installing the Ultrasonic flow meter in series. The molecular weight (MW) is changed when adapting a new gas composition.

4 CALIBRATION

The multi-path Ultrasonic gas flow meter has been zero calibrated by Fluenta and then flow calibrated two times at K-lab. The calibrations were performed at 55°C and 37 bar a, while the conditions at Oseberg C are 58 – 62°C (regulated) and 39 bar a.

The first calibration of the 6-path Ultrasonic gas flow meter was performed at K-lab in May / June 1995. The calibration curve shoved unexpected large deviations from reference, which could not be explained, see Figure 2. The calibration was repeated several times but the same curve was obtained. The calibration curve was then implemented in the flow computer to eliminate the offset error.

A large effort was put in to try to find the cause of the peculiar calibration curve but so far no explanation has been found.

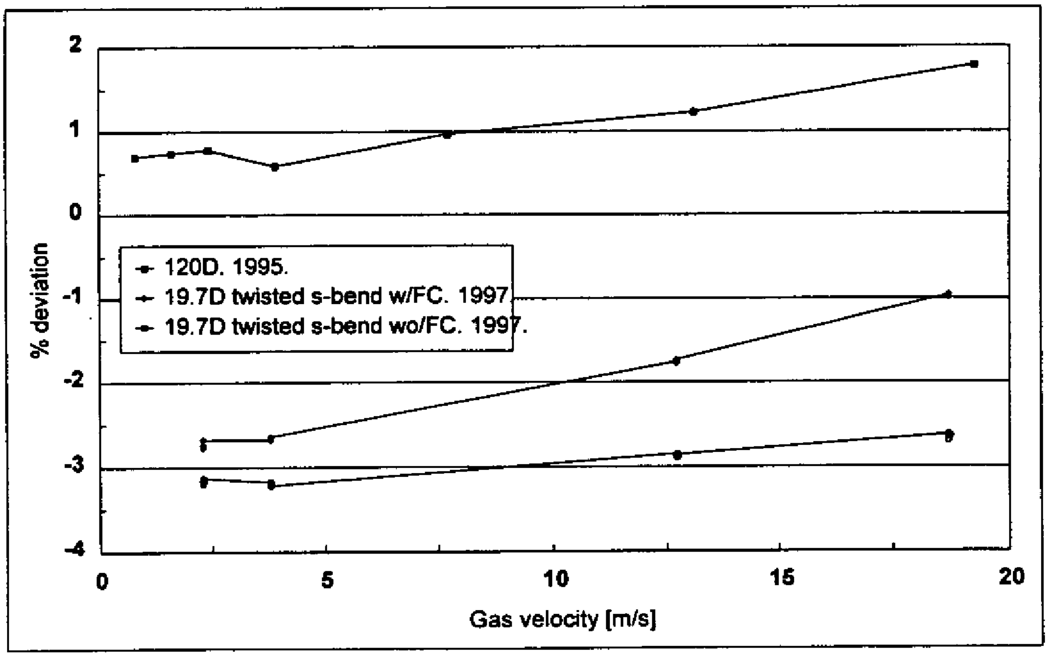

Figure 2 - Calibration curves from calibrations at K-lab in 1995 and 1997.

Errors in geometric dimensions were suspected and thoroughly checked but all angles, lateral positions and acoustic path lengths used in the flow computer were either measured values or were within acceptable design tolerances.

The second calibration was performed at K-lab in June 1997, after some modifications to the transducer face, reducing the length of each transducer. This modification was done to enable higher gas temperatures through the meter. The significant shift, exceeding 3%, between the calibration curves before and after modification demonstrates that a small bore Ultrasonic gas flow meter must be flow calibrated before installation.

The calibration curve was implemented in the flow computer to eliminate the offset error.

As can be seen from Figure 2 the Ultrasonic gas flow meter is in this case underestimating the flow with a swirl through the meter. This swirl is rotating in the opposite direction and is not so severe as the one at the Oseberg C platform. The swirl is generated by two 90° bends out of plane, with 5.5 D between the bends, 20 D upstream of the Ultrasonic gas flow meter. With flow conditioner installed there is a positive shift in the calibration curve as well as a change in the curve gradient towards the gradient seen during calibration in June 1995.

5 IN OPERATION

During final commissioning (05 – 06.02.1996) everything looked in order. We got a nice symmetrical "flow velocity profile" see Figure 3, and a fairly constant sound velocity profile. Refer to Figure 1 for transducer numbering and path positions convention.

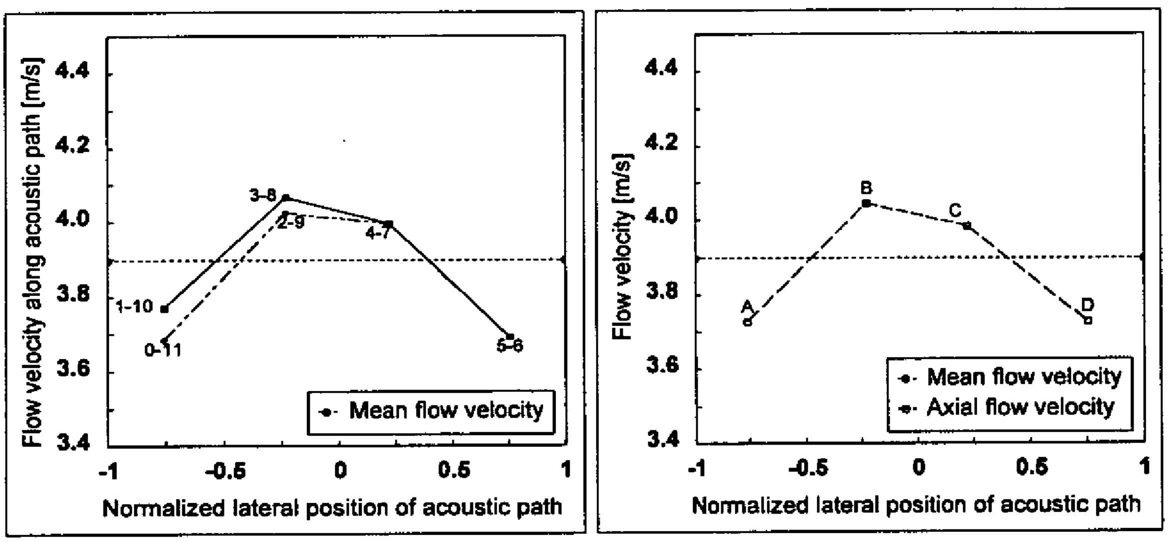

Figure 3 - Gas from Fuel gas heater A. The transducer numbering and the path positions refer to convention defined in Figure 1.

When we left the platform, the Ultrasonic gas flow meter seemed to function almost 100%, only two minor software errors remained. On our next visit 7 days later (13.02.1996) to implement the corrected software, nothing seemed in order. The "flow velocity profile" had suddenly as if by magic changed to a severe asymmetric swirl profile, see Figure 4.

"What is wrong with this meter!?" "First the calibration and now this!?" Nothing it turned out. Everything was re-checked and double-checked then finally some good detective work by Fluenta revealed that the fuel gas supply had been changed by the process operator during the night after we had left the platform (07.02.1996) from Fuel gas heater A to Fuel gas heater B.

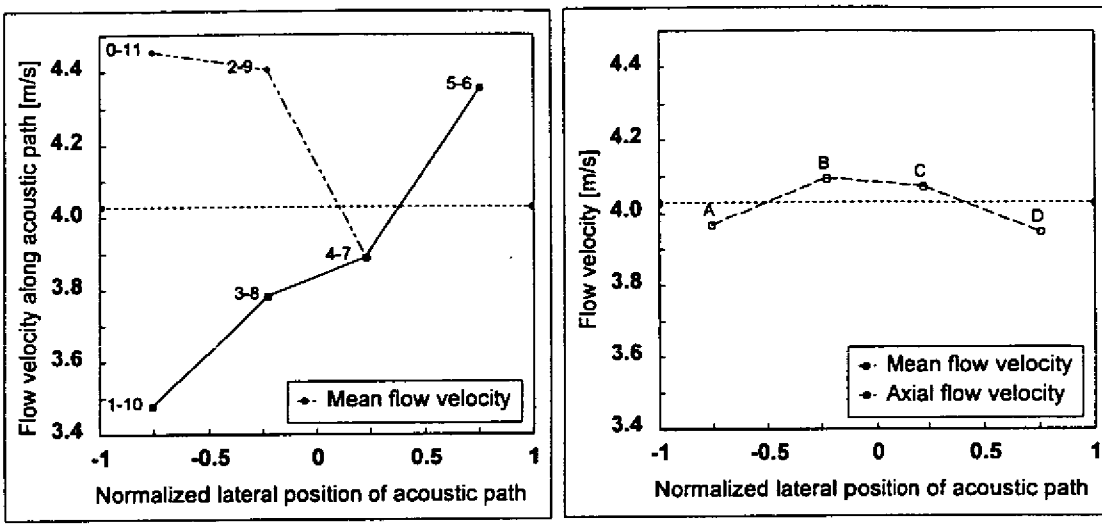

Figure 4 - Gas from Fuel gas heater B. Severe asymmetric swirl flow. The transducer numbering and the path positions refer to convention defined in Figure 1.

The "flow velocity profiles" in both Figure 3 and Figure 4 are interpreted as symmetric swirl flow by the algorithms used in the flow computer of the Ultrasonic gas flow meter.

The Swirl in Figure 3 is very small while the Swirl in Figure 4 is severe, asymmetric and rotates in the opposite direction from that in Figure 3. The calculated axial flow velocity profile in Figure 4 indicates a very flat swirl profile, while the one in Figure 3 is more parabolic but still flat.

Changing back to Fuel gas heater A (14.02.1996) returned everything back to "normal", see Figure 5.

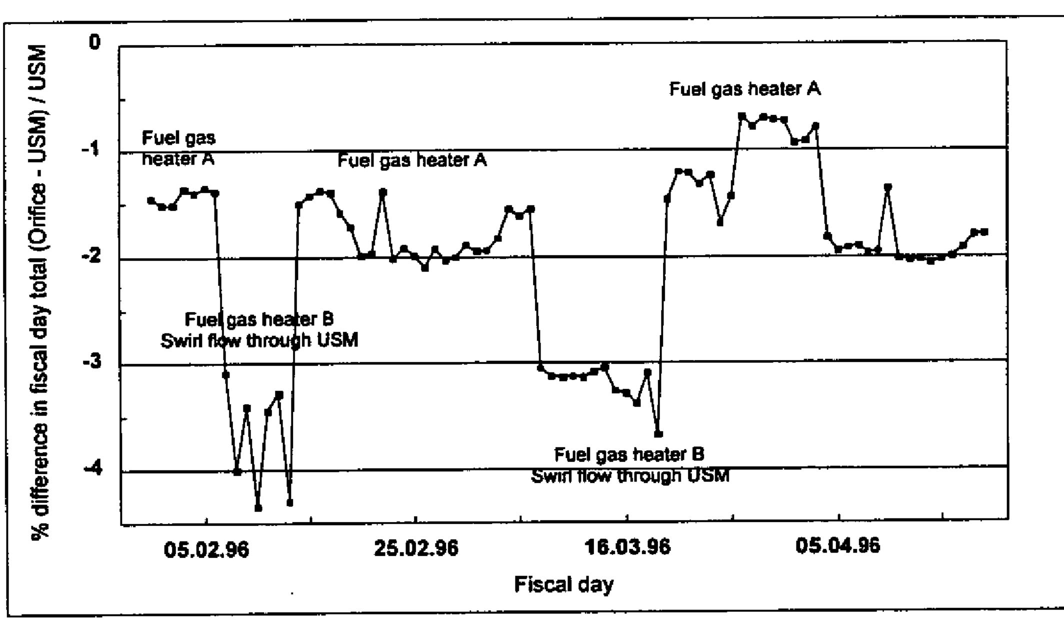

Figure 5 - Percentage difference between the Ultrasonic gas flow meter and the Orifice gas flow meter with and without swirl flow through the Ultrasonic gas flow meter.

The process operators were instructed to use only Fuel gas heater A until the problem could be resolved. The original layout drawings were not to scale and revealed no apparent reason for the observed change in flow regime.

A new test was performed (08 - 19.03.1996) with Fuel gas heater B to verify the observation, see Figure 5.

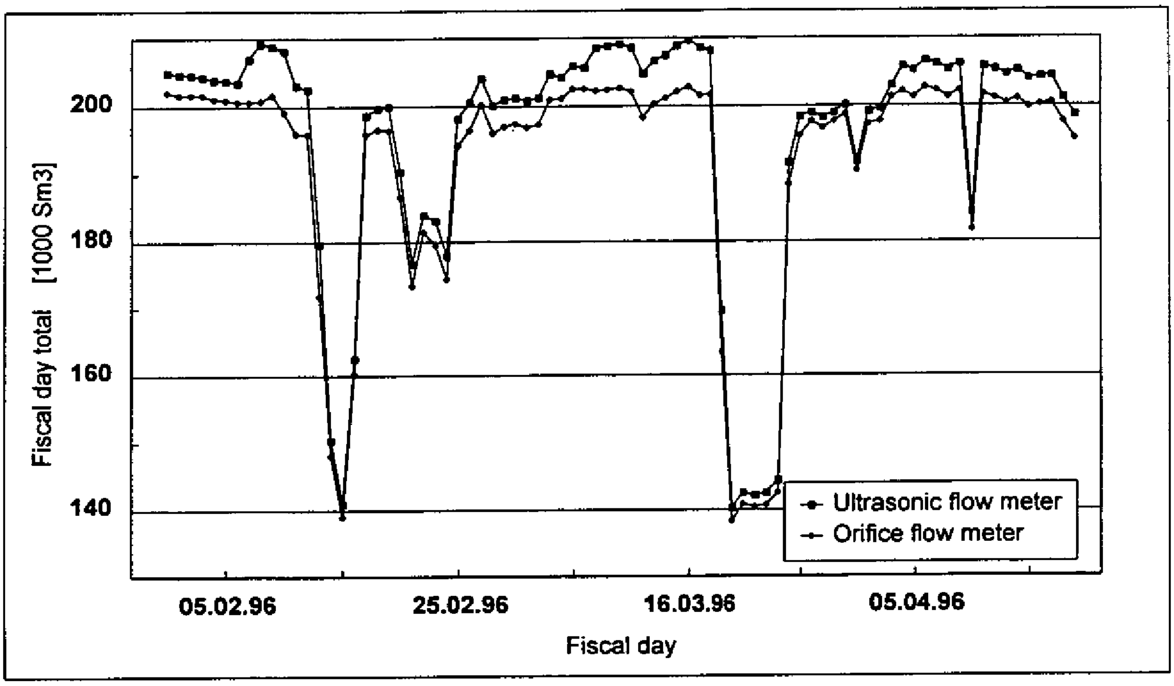

Figure 6 - Fiscal day total from the Ultrasonic gas flow meter and the Orifice gas flow meter with and without swirl flow through the Ultrasonic gas flow meter.

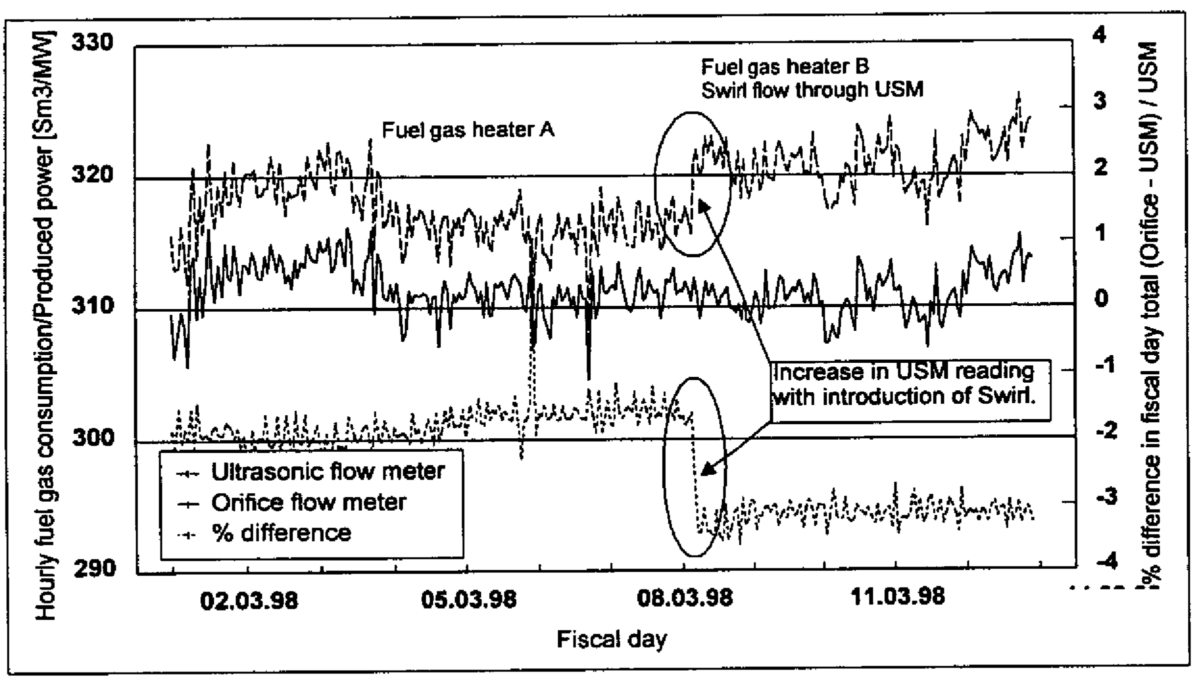

Figure 7 - Hourly fuel gas consumption per MW produced power for the Ultrasonic gas flow meter and the Orifice gas flow meter with and without swirl flow through the Ultrasonic gas flow meter. The Ultrasonic gas flow meter experiences a systematic increase in flow rate reading when the flow changes to severe asymmetric swirl flow. The flow rate from the Orifice gas flow

meter remains constant throughout this change. Not easily seen from the plot in Figure 6 of fiscal day totals but very clearly seen when the time series for hourly fuel gas consumption per MW produced power is plotted in Figure 7.

There appears to be well-defined bands for the percentage difference between the flow rates from the Ultrasonic gas flow meter and the Orifice gas flow meter. One band with fairly well developed flow when gas from Fuel gas heater A is used, and another band with severe asymmetric swirl flow when gas from Fuel gas heater B is used, see Figure 5 and 7.

The severe asymmetric swirl with gas from Fuel gas heater B, was found to be due to two 90° bends out of plane 39.2 D upstream of the Ultrasonic gas flow meter, easily detected when the layout is drawn to scale, see Figure 8.

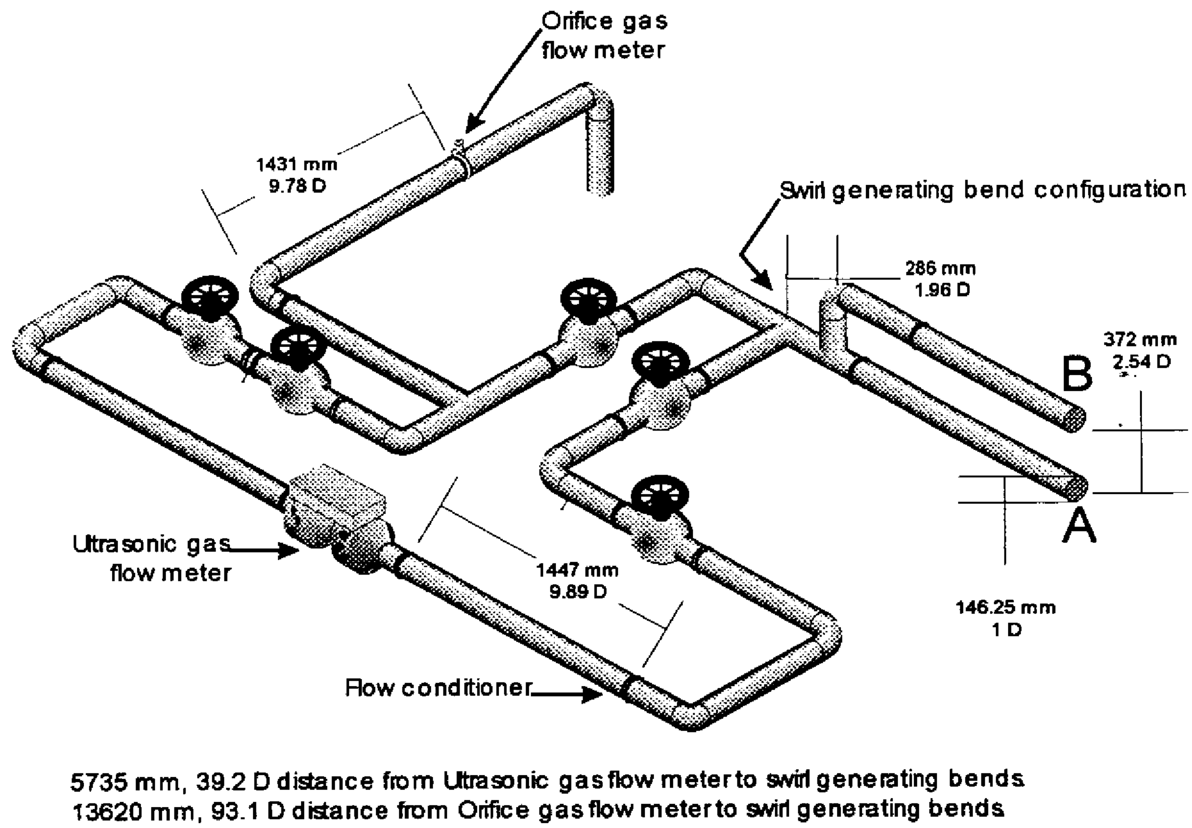

Figure 8 - Layout to scale reveals swirl generating bends.

The two 90° bends out of plane are very closely coupled with less than 2 D between the centre lines of each bend and they are also tee bends. In addition a third 90° bend is located only 2.5 D upstream of the two bends possibly adding some cross-flow to the swirl.

With gas from Fuel gas heater A, the flow is only passing through 90° bends in the same plane resulting in a reasonably well behaved flow, as could be expected.

5.1 Time Synchronisation Problems

The Orifice gas flow meter uses the platform control system as flow computer. Therefor the hourly and daily values from the Orifice gas flow meter are always time-synchronised.

For the Ultrasonic gas flow meter the flow computer is a PC with a real time clock. The real time clock has an uncertainty less than 0.001%. However, in the first 7 months after the Ultrasonic gas flow meter was put in operation the fiscal day total was calculated using a fiscal day that was reduced with approximately 40 sec. (-0.046%) every day. This was due to an error in the accumulation software and not the real time clock. This effect can be seen as the gradient in Figure 9.

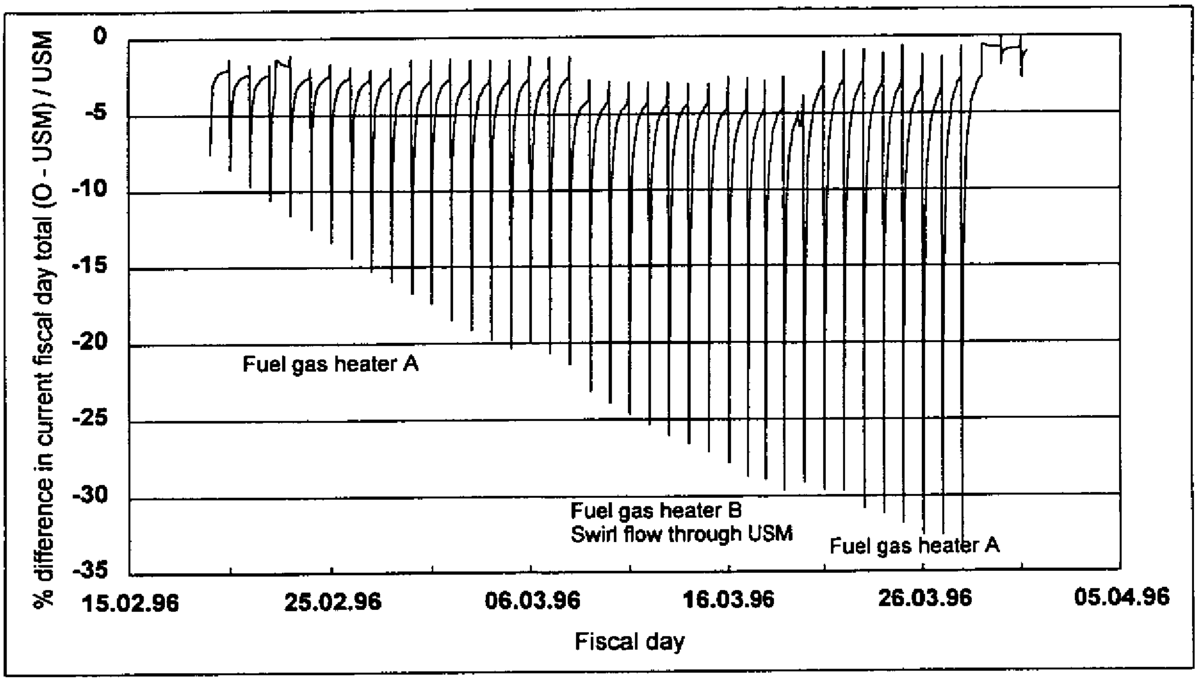

Figure 9 - Percentage difference in accumulation of current fiscal day totals every hour between the Ultrasonic gas flow meter and the Orifice gas flow meter. The positive going peaks are at 00:00 every day while the negative going peaks are at 01:00 every day.

Because of this the Fiscal day in the Ultrasonic gas flow meter starts earlier every day. The time offset from midnight (00:00) can be seen from the plot of percentage difference between the hourly values of current fiscal day totals in Figure 9, as a negative peak at 01:00. -10% difference (- 2% offset) indicates that the start of the Fiscal day is approximately 6 minutes before midnight. This of course made the comparison between the two meters difficult.

The platform control system log values every 10 minutes. The current Fiscal day totals for the Ultrasonic gas flow meter and the Orifice gas flow meter are calculated and logged every hour as the maximum value of the 6 last 10 minutes values. In addition the previous Fiscal day total for the Ultrasonic gas flow meter is logged every hour.

Knowing this, the data containing the timing problems illustrated in Figure 9 can be time-synchronised. To do this one has to derive the time synchronised hourly values. By accumulating the 24 hourly values thus found, the time synchronised Fiscal day total at midnight (00:00) for the Ultrasonic gas flow meter have be calculated for the data presented in this paper.

The daylight sawing time was implemented as an automatic time function from Microsoft in the flow computer for the Ultrasonic gas flow meter, but the time selected was the time on Hawaii and not Central European Time. This error has been corrected.

5.2 In Operation With Fuel Gas Heater A

The Ultrasonic gas flow meter was taken out of operation in March 1997 and sent for modification at Fluenta AS and re-calibration at K-lab. Figure 10 shows typical percentage difference between the two meters before this modification.

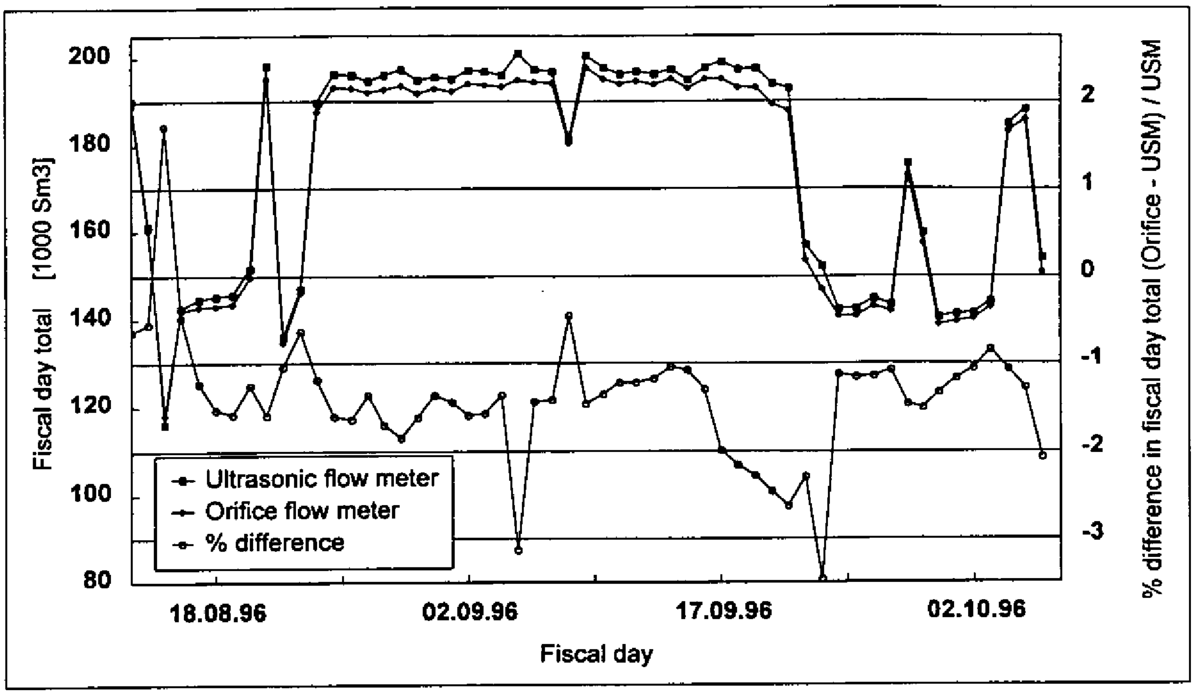

Figure 10 - Typical percentage difference for various fuel gas levels. Gas from Fuel gas heater A.

The percentage difference between the two meters is fairly constant between 1 – 2 % but some larger variations are also seen when the flow rate changes.

6 RECALIBRATION AND INSTALLATION OF FLOW CONDITIONER

The Ultrasonic gas flow meter was recalibrated at K-lab in June 1997, see Chapter 4 and Figure 1.

The Ultrasonic gas flow meter was reinstalled in August 1997 together with a K-lab Model Laws flow conditioner Type 1-6-12 (holes), with the new calibration curve implemented in the flow computer. The percentage difference between the measured flow from the Ultrasonic gas flow meter and the Orifice gas flow meter is back to the level seen before modification, with gas from Fuel gas heater A, see Figure 11.

The flow conditioner has eliminated the swirl and shaped the profile as can be seen in Figure 12 and Figure 13.

Figure 12 is comparable to Figure 3 while Figure 13 is comparable to Figure 4. The axial flow velocity profiles are now more parabolic in shape with gas from both Fuel gas heater A and B. The K-lab Model Laws flow conditioner both stops the swirl and shapes the flow profile.

The "flow velocity profiles" in both Figure 12 and Figure 13 are interpreted as symmetric swirl flow by the algorithms used in the flow computer of the Ultrasonic gas flow meter.

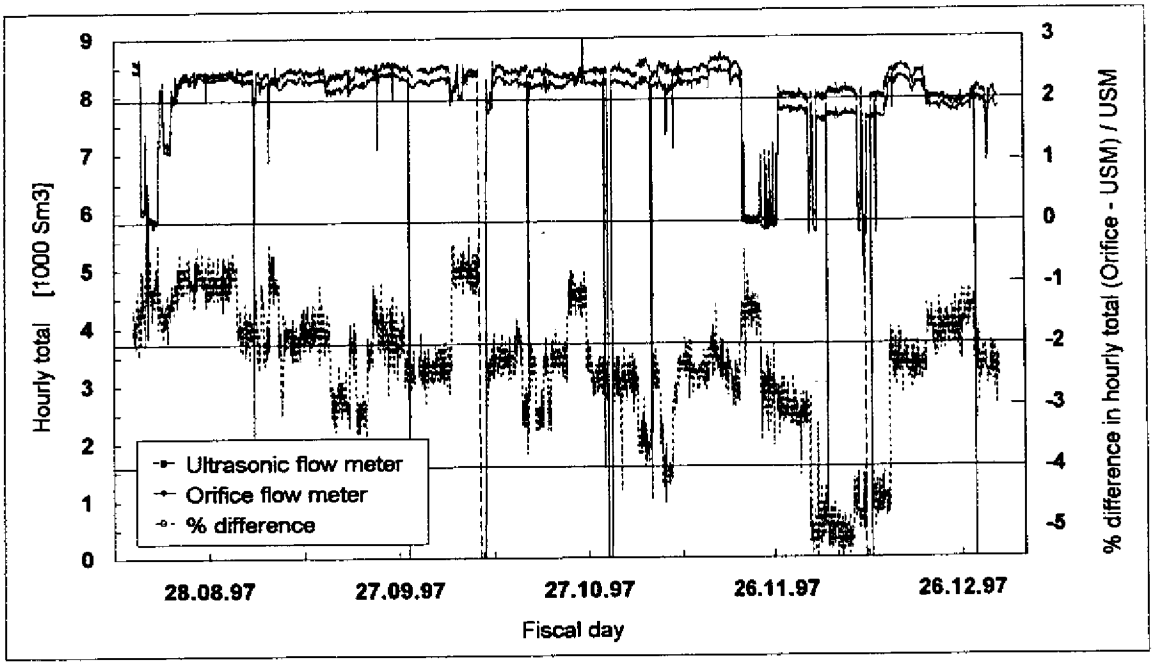

Figure 11 - Typical percentage difference for various fuel gas levels, with flow conditioner.

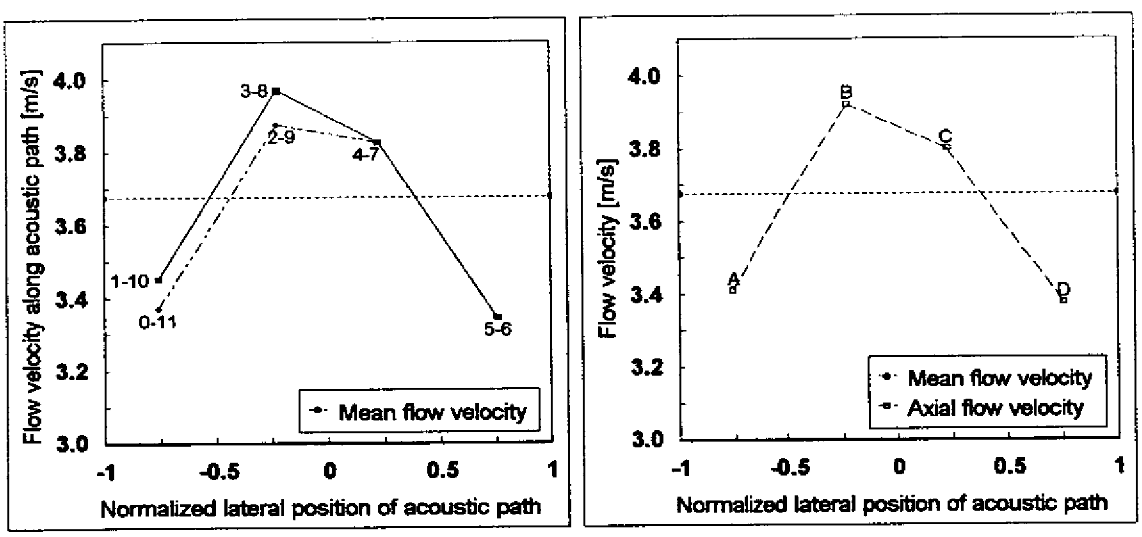

Figure 12 - Gas from Fuel gas heater A, with flow conditioner. The transducer numbering and the path positions refer to convention defined in Figure 1.

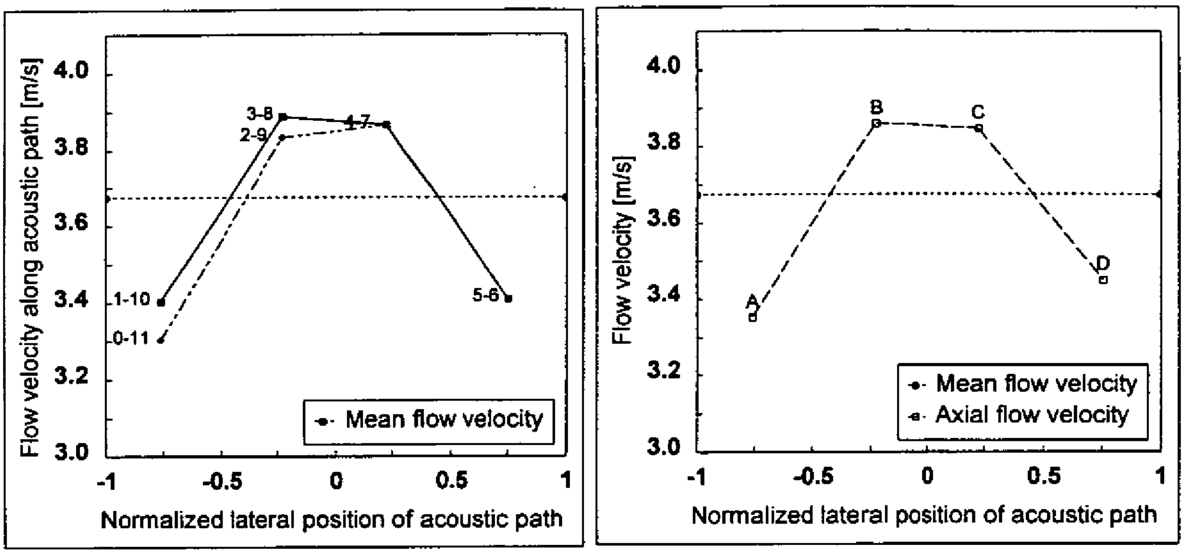

Figure 13 - Gas from Fuel gas heater B, with flow conditioner. The transducer numbering and the path positions refer to convention defined in Figure 1.

From calculations of the transversal flow velocity components in path position A and B the improvement with flow conditioner is clearly seen in Figures 14 and 15.

In Figure 14 an asymmetric swirl line is added to the measured values to indicate what the transversal flow velocity components might be in the lower half of the pipe, in path positions C and D. This indicates that the swirl is probably not symmetric i.e. the axis of rotation in the swirl does not coincide with the axis of the pipe.

In Figure 15 symmetric transversal flow velocity components are added in the lower half of the pipe, in path positions C and D, as assumed and used by the flow computer, see Figure 15.

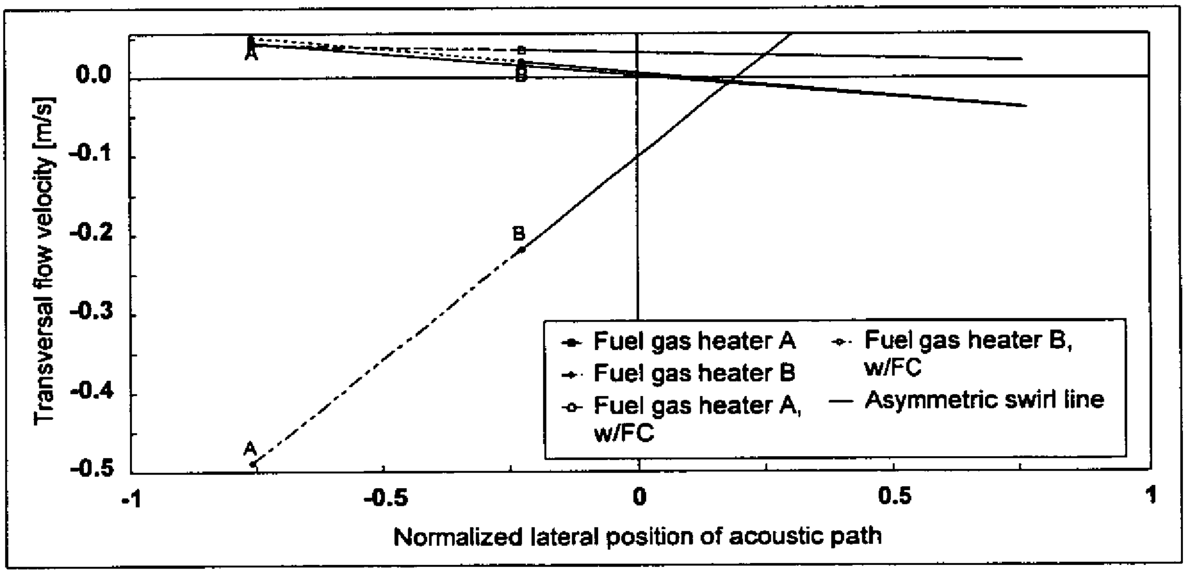

Figure 14 - Transversal flow velocity components indicating asymmetric swirl. The path positions refer to convention defined in Figure 1.

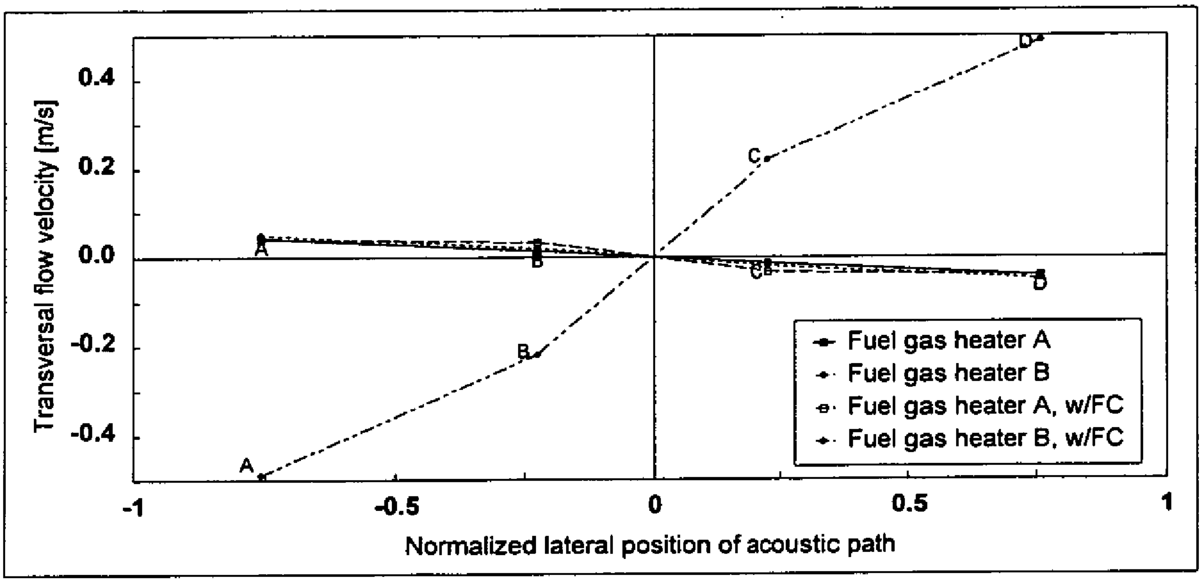

Figure 15 - Transversal flow velocity components used in the flow computer, assuming symmetric swirl. The path positions refer to convention defined in Figure 1.

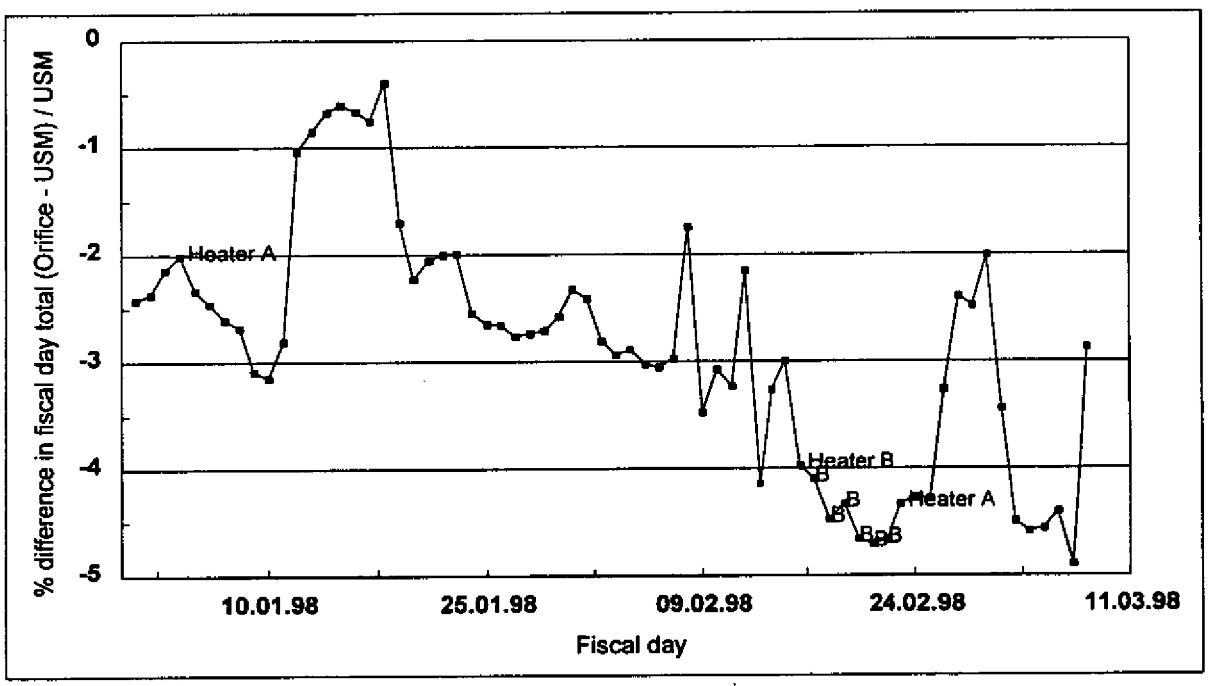

Figure 16 - Typical percentage difference with gas from Fuel gas heater A and B, with flow conditioner. Verifying the performance of the flow conditioner.

The severe asymmetric swirl flow, with gas from Fuel gas heater B has been effectively eliminated by the flow conditioner. A test was performed in February 1998 to verify the performance of the flow conditioner, see Figure 16. With flow conditioner, no significant shift can any longer be seen when changing from Fuel gas heater A to B and back to A.

We experienced some trouble with tuning in the pulse detection criteria after modification of the transducers, resulting in the use of the Orifice gas flow meter as master fuel gas meter for some time after reinstallation. Also a defective A/D converter giving odd pulses as a result was discovered. These problems have now been fixed.

6.1 Variations In Gas Composition

Another reason for the shifts in percentage difference was found to be due to the adaptation of new gas compositions in both the Ultrasonic gas flow meter and the Orifice gas flow meter. In the flow computer for the Ultrasonic gas flow meter the gas composition is used and a full calculation of compressibility is performed, see Chapter 3.1. For the Orifice gas flow meter only molecular weight (MW) is used and no iterative calculation is performed, only a simplified model with constant K is used, see Chapter 3.2.

Figure 17 illustrates the effects of changing gas composition. The Orifice gas flow meter is experiencing shifts in reading due to changing MW while the reading from the Ultrasonic gas flow meter remains unaffected. This also explains some of the shifts seen in other Figures in this paper, especially in Figure 11.

In December 1997 the major gas producing well was permanently closed down resulting in larger variations in gas composition.

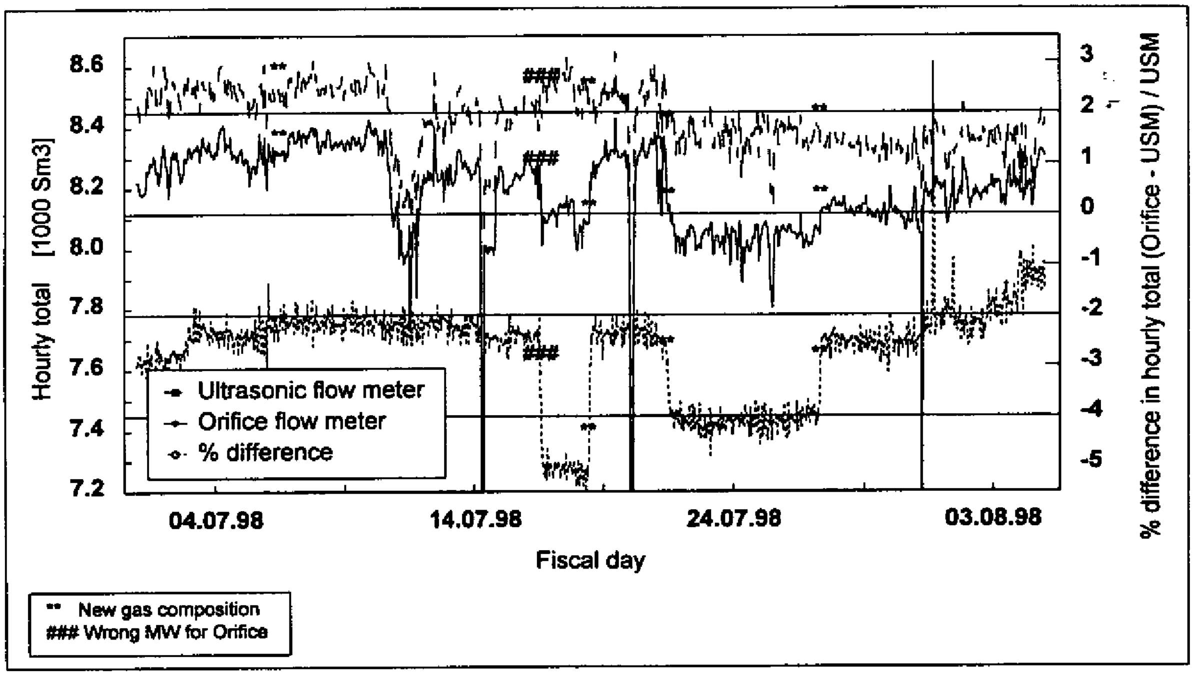

Figure 17 - Typical shifts in percentage difference and in the Orifice gas flow meter readings after adapting new gas compositions.

7 ENHANCEMENTS TO THE ULTRASONIC GAS FLOW METER

Several features were added to the flow computer of the Ultrasonic gas flow meter to make the meter as user friendly as possible. All configuration, currently measured values and software verification test data were made available via Modbus.

A PC in the central control room (CCR) on the platform collects this data. All these values can be printed as a 7 pages long Configuration report printing approximately 410 values. The Daily report seen in Figure 18 contains the same data as in the first part of this Configuration report.

```
Daily report for FMU 700
Date: 06.02.96 16:31:25

Program version.....................................: 6.2
Configure audit no....................................: 7
Start of fiscal day.................................: 0 hr
Line Volume Flowrate................................: 238.664108276367 m3/hr
Standard Volume Flowrate............................: 8477.021484375 Sm3/hr
Mass Flowrate.......................................: 7254.849609375 kg/hr
Mean Flow velocity..................................: 3.9936249256134 m/s
Line Temperature....................................: 57.7221145629883 Deg C
Line Pressure.......................................: 38.4959716796875 Bar A
Line Density Calculated AGA-8 (1985)................: 30.3977395944137 Kg/m3
Line Compressibility factor AGA-8 (1985)............: .928581542388127
Standard Compressibility factor ISO 6976 (1983)...: .996894349409422
Daily Total, Line Volume today, Forward.............: 520 m3
Daily Total, Line Volume yesterday, Forward.........: 0 m3
Daily Total, Std. Volume today, Forward.............: 19060 Sm3
Daily Total, Std. Volume yesterday, Forward.........: 0 Sm3
Daily Total, Mass today, Forward....................: 15543 kg
Daily Total, Mass yesterday, Forward................: 0 kg
Non-Resettable Total, Line Volume, Forward..........: 520 m3
Non-Resettable Total, Std. Volume, Forward..........: 19060 Sm3
Non-Resettable Total, Mass, Forward.................: 15543 kg
Gas Composition Methane.............................: 82.84 Mol%
Gas Composition Ethane..............................: 8.27 Mol%
Gas Composition Propane.............................: 4.02 Mol%
Gas Composition n-Butane............................: 1.13 Mol%
Gas Composition i-Butane............................: .42 Mol%
Gas Composition n-Pentane...........................: .3 Mol%
Gas Composition i-Pentane...........................: .21 Mol%
Gas Composition n-Hexane............................: 0 Mol%
Gas Composition n-Heptane...........................: .42 Mol%
Gas Composition n-Octane............................: 0 Mol%
Gas Composition Nitrogen............................: .74 Mol%
Gas Composition Carbon dioxide......................: 1.65 Mol%
Gas Composition H2O.................................: 0 Mol%
Gas Composition H2S.................................: 0 Mol%
Mean Flow velocity along transducer path #1.......: 3.78926753997803 m/s
Mean Flow velocity along transducer path #2.......: 3.84272813796997 m/s
Mean Flow velocity along transducer path #3.......: 4.13601016998291 m/s
Mean Flow velocity along transducer path #4.......: 4.16018295288086 m/s
Mean Flow velocity along transducer path #5.......: 4.08981275558472 m/s
Mean Flow velocity along transducer path #6.......: 3.79233145713806 m/s
Mean Sound velocity along transducer path #1......: 403.946685791016 m/s
Mean Sound velocity along transducer path #2......: 403.918304443359 m/s
Mean Sound velocity along transducer path #3......: 403.641632080078 m/s
Mean Sound velocity along transducer path #4......: 403.629608154297 m/s
Mean Sound velocity along transducer path #5......: 402.193145751953 m/s
Mean Sound velocity along transducer path #6......: 403.378021240234 m/s
Measurements % used #1..............................: 100
Measurements % used #2..............................: 100
Measurements % used #3..............................: 92.9577484130859
Measurements % used #4..............................: 100
Measurements % used #5..............................: 100
Measurements % used #6..............................: 100
Measurements % used #7..............................: 100
Measurements % used #8..............................: 100
Measurements % used #9..............................: 98.591552734375
Measurements % used #10.............................: 100
Measurements % used #11.............................: 100
Measurements % used #12.............................: 100
```

Figure 18 - Typical daily report.

The only real problem with the Ultrasonic flow meters is the vast number of configuration data, making it a tedious task to verify the correct set-up of such a meter. (In addition this data is not always readily available in all Ultrasonic flow meters.)

As a consequence the software verification task was completely automated. All data needed to carry out complete software verification test is entered on a separate page in the flow computer. As there is a problem guessing at a sensible set of transit times to start with, the flow computer suggests using the current values. So all one really has to do is set the duration of the test. The software verification test can be run while the meter is measuring so there is no need to take the meter out of operation in order to verify the software. When the test is finished all configuration values and test results are collected by the PC in the CCR and stored to file.

A verification program developed by Fluenta then reads this file and prints a software verification test report as documentation, see Figure 19. What used to be a very tedious task to perform requiring an expert on the measurement principal, can now be performed by any maintenance technician using a fraction of the time needed previously.

```
Filename: H:\GAI\SANDSLI\TROND\T_BRGASS\960213C3.TXT

Results from Fluenta FMU 700 Verification program. Ver1.3
Logged: 11:30:48  13/02/1996

--------------- TR.DELAY [us] ------ T.CORR. [us]  ----- CAVITY [mm] ------
Path 0-11        1.119400e+001      -1.300000e-003        18.360000
Path 1-10        1.110600e+001       3.100000e-003        17.830000
Path 2-9         1.122400e+001       2.100000e-003         8.160000
Path 3-8         1.113000e+001      -2.900000e-003         8.120000
Path 4-7         1.121500e+001      -7.000000e-003        13.280000
Path 5-6         1.126400e+001      -1.900000e-003        20.180000
Path 6-5                                                  20.190000
Path 7-4                                                  13.290000
Path 8-3                                                   8.120000
Path 9-2                                                   8.160000
Path 10-1                                                 17.820000
Path 11-0                                                 18.360000

Pipe diameter                       146.250000 [mm]
Flow calibration coefficient          0.060900
Flow calibration offset               0.552500


--------------- ACOUSTIC PATH [mm] -- TR.ANGLE [deg]  --------------------
Path 0-11           135.140000        45.000000
Path 1-10           135.140000        45.000000
Path 2-9            173.890000        55.000000
Path 3-8            173.890000        55.000000
Path 4-7            221.570000        40.000000
Path 5-6            148.660000        40.000000


---------------------- MOLFRACTIONS [%] ------------------------------------

Component     Entered fractions    Normalized fractions
 Methane         82.840000            82.840000
 Ethane           8.270000             8.270000
 Propane          4.020000             4.020000
 N-Butane         1.130000             1.130000
 I-Butane         0.420000             0.420000
 N-Pentane        0.300000             0.300000
 I-Pentane        0.210000             0.210000
 N-Hexane         0.000000             0.000000
 N-Heptane        0.420000             0.420000
 N-Octane         0.000000             0.000000
 Nitrogen         0.740000             0.740000
 CO2              1.650000             1.650000
 H2O              0.000000             0.000000

 Sum            100.000000           100.000000


------------- GAS COMPOSITION CALCULATIONS ---------------------------------
Zmix ISO 6976                          0.996740
Zmix AGA-8 85                          0.930545
Sound velocity                       400.210832 [m/s]
Density                               29.829650 [kg/m3]
Temperature                           59.000000 [deg C]
Pressure                              38.000000 [BarA)


-------- TOTAL TIME-OF-FLIGHT [us] -- VELOCITY [m/s] ----------------------
Path 0-11     4.32000000e+002         5.163846
Path 1-10     4.40000000e+002         5.046137
Path 2-9      4.78000000e+002         5.739229
Path 3-8      4.85000000e+002         5.736217
Path 4-7      6.20000000e+002         5.762602
Path 5-6      4.85000000e+002         5.689737
Path 6-5      4.77000000e+002
Path 7-4      6.32000000e+002
Path 8-3      4.78000000e+002
Path 9-2      4.85000000e+002
Path 10-1     4.34000000e+002
Path 11-0     4.38000000e+002


-------------------- FLOW CALCULATION RESULTS -----------------------------

Duration                             5.030288217       [min]


                Calculated                    Measured                  Deviation [%]
Velocity 5.597587477e+000 [m/s]     5.597587480e+000 [m/s]         0.000000054
Act.Rate 3.354962178e+002 [m3/hr]   3.354962180e+002 [m3/hr]       0.000000045
Std.Rate 1.169185574e+004 [Sm3/hr]  1.169185570e+004 [Sm3/hr]     -0.000000320
Act.Vol. 2.812737786e+001 [m3]      2.812737790e+001 [m3]          0.000000155
Std.Vol. 9.802234025e+002 [Sm3]     9.802234030e+002 [Sm3]         0.000000056
Density  2.982965017e+001 [kg/m3]   2.982965020e+001 [kg/m3]       0.000000102


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Prepared by:                        Signature:         Date: 13/02/1996

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Approved by: Trond Folkestad        Signature:         Date: 13/02/1996

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Figure 19 - Typical software verification report.

8 CONCLUSION

The multi-path Ultrasonic gas flow meter operated continuously for the first year without any major difficulties and demonstrated good long-term stability.

The multi-path Ultrasonic gas flow meter can not handle a severe asymmetric swirl flow to fiscal accuracy. A flow conditioner / straightener can be used in front of the Ultrasonic gas flow meter to eliminate error in measurement due to swirl.

The 6" Ultrasonic gas flow meter must be flow calibrated before installation and the calibration curve must be implemented in the flow computer.

It is critical that all geometrical dimensions in the meter spool are certified and entered into the flow computer.

Upstream bends should be kept in the same plane for at least 50 D, then it should be sufficient with 10 D straight pipe upstream of the Ultrasonic gas flow meter. If this can not bee achieved a flow conditioner should be installed.

This type of Ultrasonic gas flow meter is now recommended for use in fiscal gas metering systems operated by Norsk Hydro.

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PAPER 11 ~ 3.3

IS A WET GAS (MULTIPHASE) MASS FLOW ULTRASONIC METER JUST A PIPE DREAM?

D Beecroft, Arco British Ltd

16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

IS A WET GAS (MULTIPHASE) MASS FLOW ULTRASONIC METER JUST A PIPEDREAM?

David Beecroft, ARCO British Limited

1 ABSTRACT

Ultrasonic meters are, by nature, gross volumetric meters and have generally only been applied to wet gas (post separator) metering systems. For mass flow applications PTZ density is derived from the gas composition but this has a number of disadvantages for fiscal, high accuracy applications including a requirement to provide a chromatograph or sampling facilities with a high maintenance and logistic overhead and a not insignificant impact on the uncertainty budget. Currently separators are required to remove free liquids from the process stream prior to metering with this type of meter which has a large impact on project costs, often making small developments commercially non-viable.

Seeing the potential for developing the ultrasonic meter further ARCO British Ltd (ABL) embarked on two trials, using existing systems, to determine the feasibility of developing a mass flow/multi-phase meter. These are:

1. The density trial utilises two multi-path USM's and an on-line gas chromatograph measuring gas production from differing fields. Initial data analysis indicates that the calculation of density is possible and work has commenced on developing a portable equation for this calculation.

2. A trial USM has been installed upstream of a production separator and the data from this meter is compared with existing gas and liquids meters installed post-separator. Performance data from the USM has indicated that the meter will function in this environment although this is yet to be qualified.

The initial indications from both trials are good and work continues on refining models to describe the meter behaviour.

The use of ultrasonic flow meters is relatively new in the area of fiscal metering [1] and users are currently gaining confidence in their performance. Anomalies in the calibration results had been identified on meters operated by other companies following periods in service when a shift of the whole calibration curve was noted. This has not been the case with the stainless steel bodied meters used by ABL resulting in the acceptance of this type of meter alongside orifice plate metering systems on two developments this year.

2 INTRODUCTION

Ultrasonic metering technology is moving at a tremendous pace with the use of multi-path meters for the measurement of natural gas starting to gain acceptance throughout the industry. However, being a gross volumetric meter, density has to be derived from another source in order to obtain a mass quantity for allocation purposes. A densitometer can provide a density value direct or it can be calculated from the gas composition using PTZ algorithms. The only problem with the latter is it requires either an on-line chromatograph to be installed or regular samples to be taken. Both of these options have a significant impact on the system uncertainties and can present substantial maintenance and logistics problems. One answer to this is to use the velocity of sound (VOS) measurement from the ultrasonic meter.

Another problem facing operators is the development of marginal fields and the impact of installing separators and metering systems on minimum facility platforms. If a multi-phase USM can be developed allowing separators to be removed from the platform design it will save significant project and operational costs (potentially £1M - £2M on a field) for small field developments.

One answer to these problems, or rather challenges, would be to develop a meter that can derive its own density measurement and also cope with free liquids passing through it without loss of measurement capability. The title of this paper poses a question that not too many years ago would probably have elicited an affirmative reply. However, the results of work carried out by ABL and Instromet, amongst others, indicates that this might no longer be the case. This paper describes the ongoing investigations into current meter performance, density derivation from the VOS measurement and ability of a USM to cope with gas containing free liquids.

3 IN SERVICE ULTRASONIC FLOWMETERS - AN UPDATE

Following the acceptance by the DTI of Ultrasonic meters (hereafter referred to as USMs) as part of the allocation metering for the Trent and Tyne fields [2] the meters were installed, commissioned and introduced into service in the autumn of 1996. A spare 12" 900# Q.Sonic-5 (manufactured in duplex stainless steel) was obtained to allow the installed meters to be removed for calibration at the end of one year's service. Due to operational requirements it is impossible to remove, re-certify and return a meter to its installed position during the routine annual platform shutdown. After two years service, therefore, one meter has been certified three times and the other two twice. Long term stability and reliability are seen as advantages in this type of meter. This should lead to extended calibration periods, thereby reducing the maintenance budget on the system. ABL are keen to prove this hypothesis.

For various reasons, other operators have experienced shifts in the calibration curves following periods of service and also noted differences in meter response at different test centres. A concentrated effort was therefore made by the Metering and Allocation Group at ABL to ensure that, wherever possible, the meters would be tested at only one test centre, to remove any test centre effect. Any differences observed between calibration curves would, in the main, be attributable to meter response. Knowing that some carbon steel bodied meters exhibit a shift, both ABL and Instromet were keen to see the results for the three duplex stainless steel units and the trial carbon steel meter in order to determine whether the duplex stainless bodied meters would suffer in a similar manner. An opportunity arose that allowed one 12" S/S meter to be calibrated at 3 test centres whilst it was out of service.

3.1 Annual Re-certification

The two original 12" Q Sonic 5 S/S meters were initially tested at Gas Unie, Westerbork on 29th November 1995 prior to being installed on the Trent platform. Both meters were removed after approximately one year in service. Meter S/No 2034 was re-installed in 1997 and removed for its third check calibration in 1998. The two figures overleaf show the individual calibration curves superimposed on each other. Figure 1 is for meter S/No 2034 and Figure 2 for meter S/No 2035.

It is readily apparent that, in both cases, there is very little difference between the curves apart from the low flow region. A calibration factor of 1.0 had been entered into both meters at the original calibrations and these have not been adjusted at any of the subsequent calibrations. It is therefore concluded that there are no significant shifts between calibrations undertaken at the same test centres.

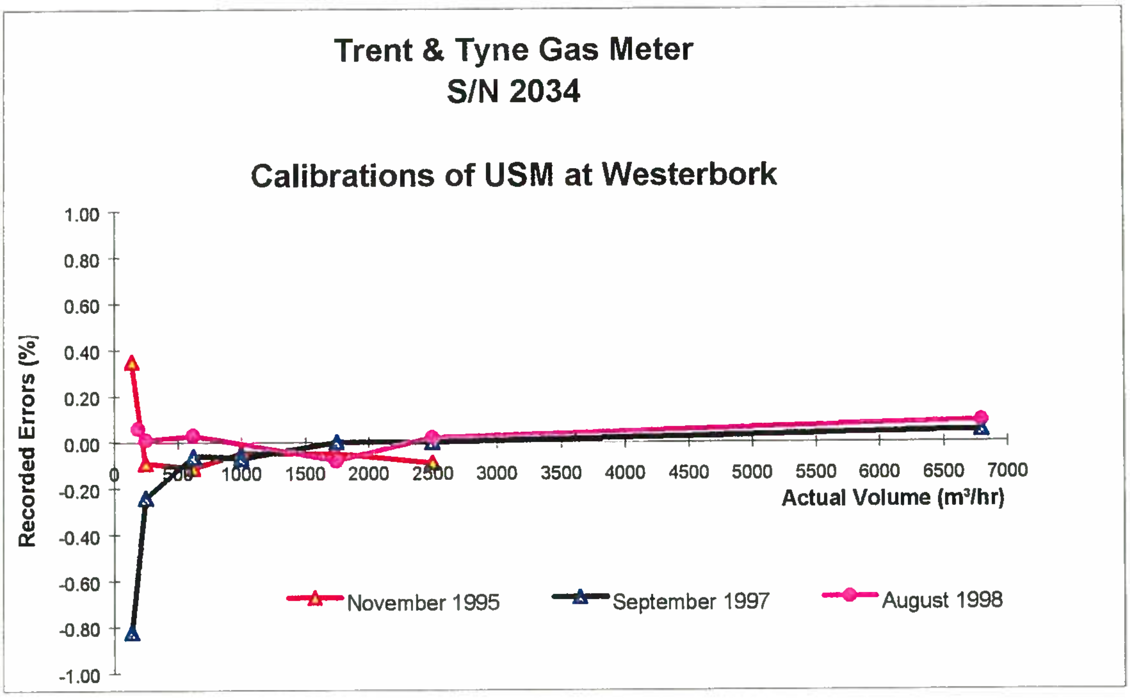

Figure 1 - Meter S/No 2034 calibration results

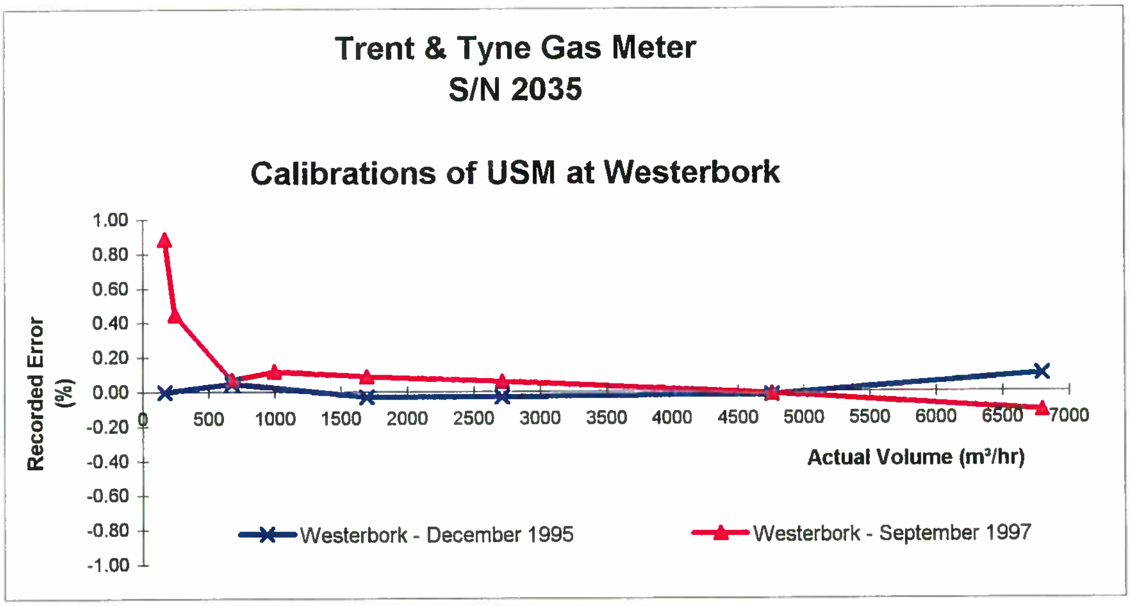

Figure 2 - Meter S/No 2035 calibration results

Meter S/No 2091 is a meter that was obtained in 1997. It was calibrated at PIGSAR, Dorsten and re-calibrated at Westerbork. The results of the calibration are shown in Figure 3.

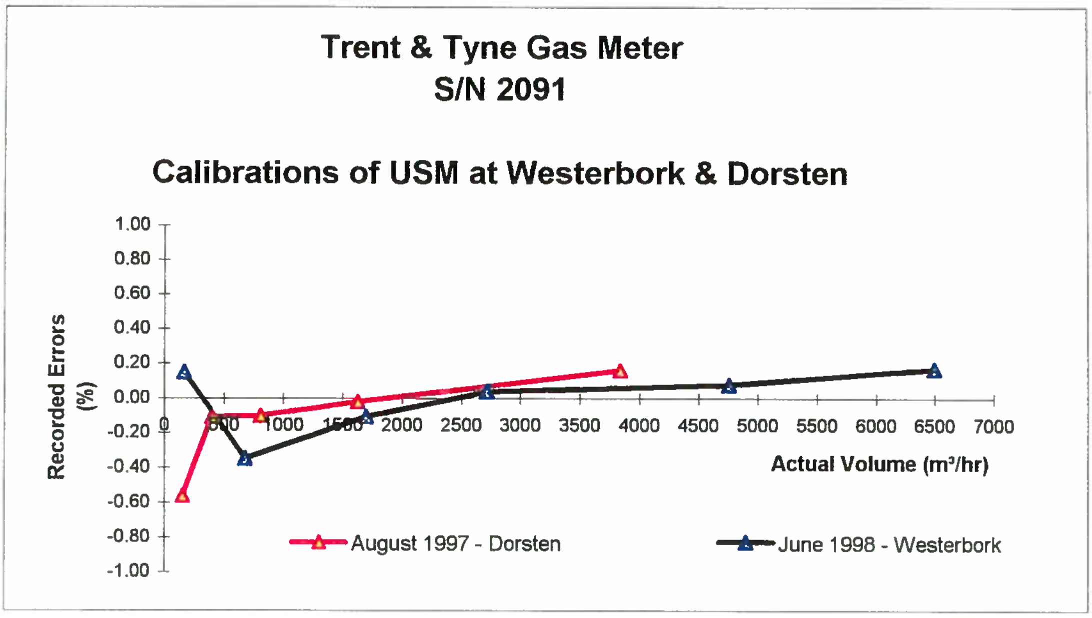

Figure 3 - Meter S/No 2091 calibration results

The difference in response was not considered to be significant and the meter factor has not been changed. It should be noted that this meter suffered a lost transducer which was replaced prior to the test. The reason for the loss has not been determined as the tip could not be found. This is the first incident of this type experienced by Instromet. However, previous testing on this type of meter [2] [3] has shown that the loss of and/or change of a transducer has minimal effect on the meter performance.

Interestingly, when the carbon steel bodied meter was re-calibrated following the first trial a shift was noted [2].

3.2 Multi Centre Tests

Following the annual re-certification of meter S/No. 2035 at Westerbork the opportunity arose for the meter to be tested at PIGSAR in Germany and also at BG Technology's facility at Bishop Auckland in the UK. All of the tests were carried out during the period the meter was retained as a spare unit. No work, e.g. cleaning, was carried out on the meter between tests except to prove functionality prior to testing. An Instromet engineer was present at all tests. The results of the three calibrations can be seen in Figure 4.

Whenever possible flow rate calibration points were repeated at all tests and the pressure held at a similar value. Whilst this information is not new it is noteworthy that a difference does exist between the test centres i.e. test centre effect. Owing to limited time and space the reasons behind this will not be explored in this paper. However, it is ABL's advice to others to include an element for test centre uncertainty within the USM uncertainty budget rather than relying on a value for repeatability and stability alone as this could be exceeded if a different centre is used.

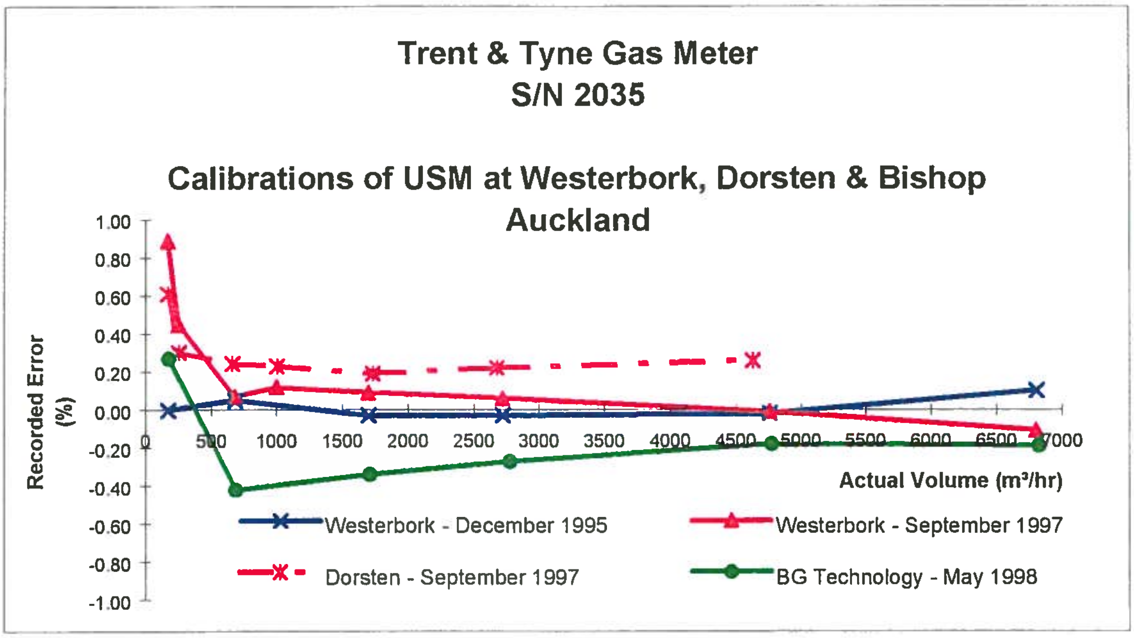

Figure 4 - Multi Centre Calibration Meter 2035

3.3 Update Conclusion

The performance of the meters on Trent and Tyne has been excellent and, as a result of this, an application has been submitted to the DTI for relaxation of the calibration period. We hope they will look favourably on this application.

The results have also satisfied the various interested parties involved in the Bure West, Deben and Waveney developments enabling ABL to install a 6" Q.Sonic-3 path S/S meter for each of the allocation metering points. All of these systems have a total uncertainty budget of ±1% and were scheduled to come onstream in October 1998.

4 DENSITY

In his paper at last year's NORFLOW conference, Cousins [4] advocated the use of the velocity of sound in calculating density as a check against a densitometer or chromatograph. If the former is a vibrating element type and it is installed on a wet gas system, commonly found both onshore and offshore, it is unlikely that it will work for long. On the other hand, chromatographs will work on wet gas systems provided we take and handle the sample correctly [5], but this imposes a relatively high maintenance requirement. Sakariassen [6], in his paper delivered to the workshop in 1995, described a method of calculating the velocity of sound based on a relationship between pressure, temperature and finally density measured by a densitometer. It is interesting that he also hints at finding the relationship to calculate density from VOS for a known gas. We, like many others, want to go the whole way and use the velocity of sound from the USM to calculate the density so that we do not need to install densitometers or chromatographs.

There are a number of studies in progress at the present time that are investigating this very topic. Some of them are based at research and development centres and others, like ABL, are looking at real world data in association with the meter manufacturers. The first of two trials described in this paper is aimed at developing a suitable algorithm to calculate density from the velocity of sound. The ultimate target is to have an equation that is truly portable and can be applied to any system without prior knowledge of the gas composition. However, at present, we know that there are a number of components which have a significant impact on the VOS. Nitrogen and carbon dioxide (CO_2) have a considerable affect on the generated velocity of sound. Currently, knowledge of the gas composition is required to allow an accurate calculation of density and is likely to remain that way for the foreseeable future.

The aim of the trial is to derive an algorithm that will allow the density of the gas passing through the meter to be calculated from the VOS with the result having an uncertainty of less than or equal to ±0.6% i.e. comparable to PTZ density using a gas chromatograph. The target Instromet and ABL hope to achieve is ±0.3% which is comparable with the uncertainty of a densitometer.

4.1 Installation

The metering systems installed on the Trent platform (43/24) to meter gas from the Trent and Tyne fields, as part of EAGLES, have all the equipment required to provide the data necessary to determine whether density can be derived from the velocity of sound (VOS) measurement. As can be seen in Figure 5 gross volumetric flow rate is determined by an Instromet Q.Sonic-5 USM which interfaces with a Daniel's Europe (Spectra-Tek) S500 flow computer. Pressure and temperature signals from transmitters mounted close to the meter are also routed to the flow computer. Gas samples are drawn from the flowline, conditioned and analysed by a Daniel's Turbo Danalyser Chromatograph on an alternating stream basis. The resulting analyses are downloaded to the flow computers via a metering database/data acquisition computer. The flow computer uses the pressure, temperature and compositional information to determine compressibility and density in accordance with the AGA8:1994 algorithms. A satellite link provides a means of communicating with the onshore export tracking and allocation reporting station. The diagnostic software provided by the meter manufacturers allows data relating to the performance of the meter to be recovered from the meter electronics module.

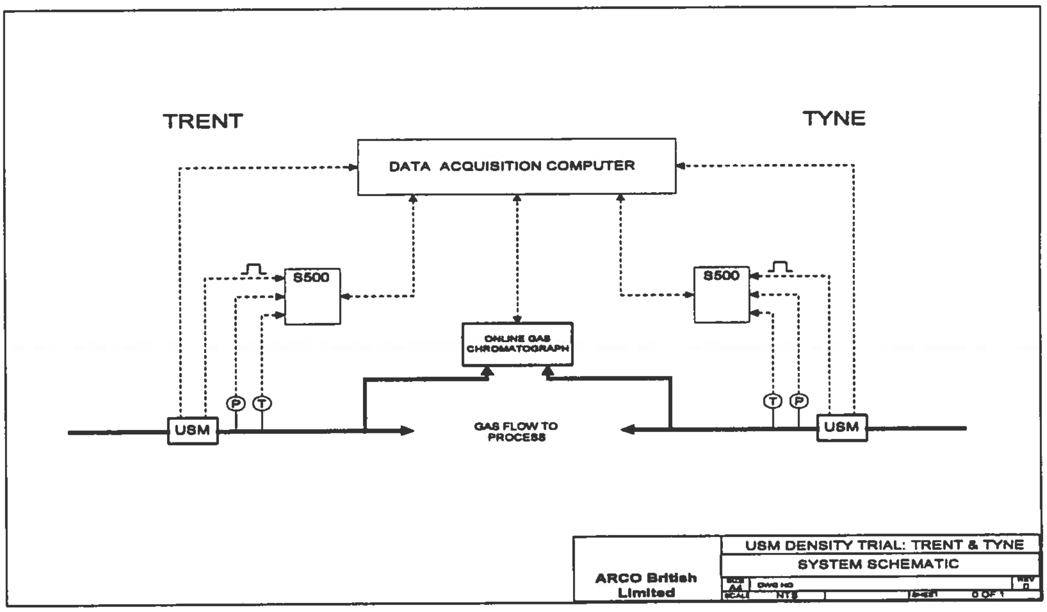

Figure 5 - Schematic of density trial

Every parameter required to carry out a study on the relationship between VOS and density is therefore readily available.

A data collection module was coded into the software of the Data Acquisition Computer. This collects information related to the USM, flow conditions and the composition from the chromatograph. A snapshot of all data is collected on a frequent time basis and stored in a file on the data acquisition computer. The data files are recovered and the information within them tested for validity. For example, if the chromatograph fails the system reverts to a default analysis. Whilst this is acceptable from a metering perspective it invalidates the trial data as the composition of the gas used by the flow computer and recorded as part of the trial is not exactly the same as that flowing through the meter.

5 WET GAS TRIAL

The second of the two trials that ABL is currently conducting is located on the Thames AP (49/28AP) production platform. It utilises the 12" Q Sonic carbon steel meter used for the original trial conducted on this platform in 1995 [2].

In brief, the USM has been installed upstream of the production separator used for the Thames field (one of four systems on the platform) and the results compared with the quantities measured, post separation, of gas, condensate and water. This type of meter would normally be installed downstream of the separator.

The objectives of the trial are listed as four questions:

1. Does it work?
2. If so, how well does it work?
3. Can the liquid content of the combined stream be measured by the USM alone?
4. Can the water/condensate split be predicted using information from the meter?

It is obvious that some tough questions are being posed in this trial and that the answers may not be found quickly. Whilst the trial started almost two years ago, various problems have been encountered that have interrupted and delayed progress. These are described in a later section.

One other question that requires consideration is 'what is wet or multiphase gas'? A difficult one to answer. Is the product just saturated? Does it have free liquid, in which case it is two phase or multiphase? Stobie [7], in a recent paper, shared his thoughts on this very subject. For the purposes of this paper a simplistic view has been taken. The fluid produced from a well is a multiphase fluid with a high gas fraction, containing free hydrocarbon condensate and water and is metered before any form of separation takes place. The system on which the trial meter is installed is a typical Southern North Sea natural gas that produces 0.01 bbls/mmscf condensate and 0.04 bbls/mmscf water. This equates to approximately 1.5% liquids in the gas stream. Typical process conditions are 20 to 40 bar g, 8 to 30°C and flow up to 30 mmscf/d.

5.1 Wet Gas Meter Installation

Production from 6 wells that form the Thames field is routed to a dedicated production separator where free liquids are 'knocked out' of the gaseous stream. The resultant wet [8] gas is then routed to the allocation metering station. This system has 2 × 100% 10" meter tubes each fitted with Daniel's Senior orifice fittings. The standard configuration of 2 differential pressure (dP), pressure and temperature transmitters connected to a dedicated Daniel's S500 flow computer is used on each stream for flow totalisation. The gas composition is derived by chromatographic analysis allowing PTZ density to be calculated within the flow computer. Figure 6 shows a simplified arrangement for clarity. The system has a ±1% uncertainty budget. The separator has sufficient dwell time to allow the liquids to separate into condensate and water fractions. Each is metered using Micro Motion D type coriolis meters and the flow is dependent on the liquid level within the vessel.

The Instromet 12" Q Sonic 5 path meter has been installed directly upstream of the Thames separator together with pressure and temperature transmitters. The system configuration is the same as used on Trent and Tyne with a pulse signal proportional to gross volumetric flow, routed from the USM to a S500 flow computer, together with pressure and temperature signals.

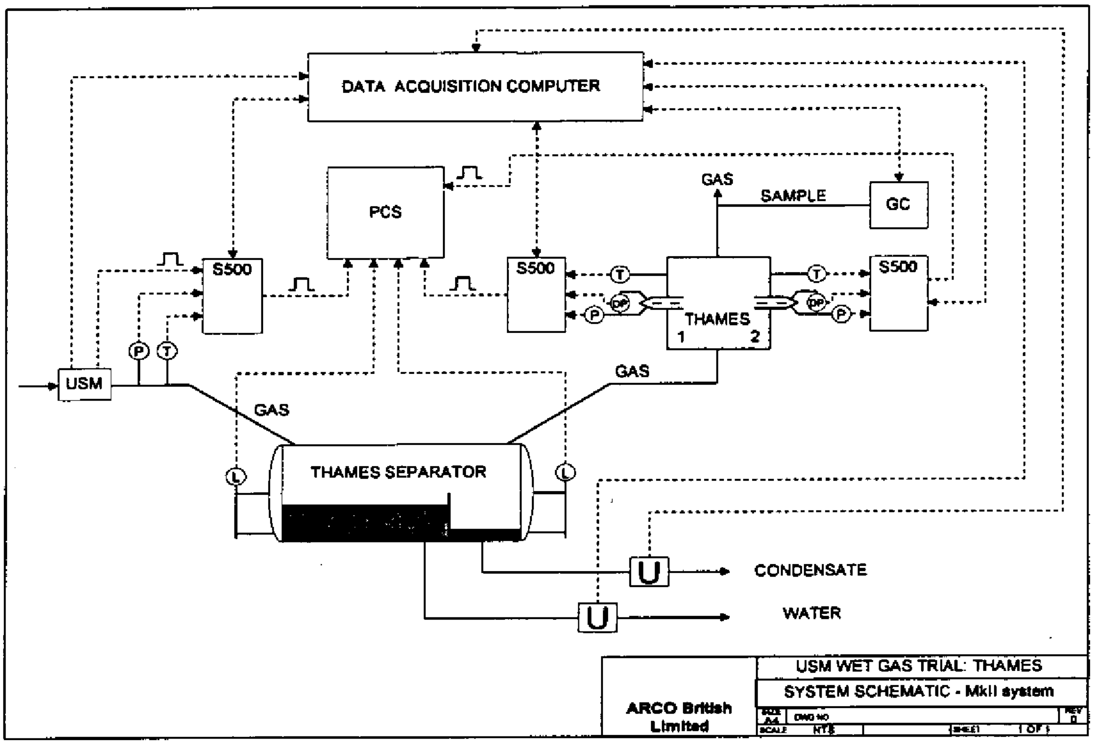

Figure 6 - Schematic of wet gas trial

The composition used in the trial USM flow computer is from the chromatograph sampling post separator gas and is not truly representative of the product flowing through the meter (this will be discussed in more detail later).

5.2 Data Collection

Initially, data could only be collected via the PCS (Process Control System) as the database installed on the allocation metering system could not accommodate data from the trial USM. Latterly, however, the situation has been improved allowing data to be retrieved through two systems. The data connections in Figure 5 (dashed lines) indicate the current position. A software module has been coded into the new metering database allowing all of the data required to be captured in one file. This has only recently been introduced following a major software upgrade. The data includes cumulative flow totals for all fluids, process conditions and separator level indications. The metering database module also records the downloaded composition and USM diagnostic information.

The PCS data is captured via a reporting PC located in the ABL Great Yarmouth Control Room and automatically uploaded to a network server. The data from the metering database is stored locally on the DAC offshore. The files are manually retrieved via the onshore server of a dedicated metering network.

6 PROBLEMS, OH PROBLEMS

6.1 Wet Gas Trial

The wet gas trial has been fraught with problems and can be held up as an example to others of the things that can and do go wrong in any trial or experiment, particularly one on a live, operational system. Murphy's Law certainly applies.

Installing the Meter

The installation of the meter required an angled spool to be fabricated to allow the USM to be inserted in the line. Arrangements were made to cease production for a day, isolate and purge the system and remove a spool so that the new spool and meter could be installed. All went well until the new spool was offered up to the separator. Unfortunately the flange angle of the spool did not match the separator. This necessitated putting the system back as it was incurring considerable cost and delaying meter installation another 6 months.

PCS Data Gathering

Whilst the PCS can in no way be considered to be an intelligent machine, i.e. one that is capable of modifying its own behaviour [9], one began to wonder about the data file that was generated for the trial. It would, all by itself(!):

- stop producing data files after the 13th of the month (sometimes)
- randomly change the file name format from YYMMDD.usm to YYDDMM.usm
- transposed the density and pressure data

Even though the engineers responsible 'dealt' with this problem it did recur a few times. This caused numerous problems when data processing was taking place and also lost quite a bit of good data.

Data Gathering Via Metering Database

A system upgrade to replace the original metering database that was planned for the end of 1997 had to be deferred for several months due to operational difficulties. The improved data collection module could not be implemented when originally desired.

Coriolis Metering Problems

The liquids metering system suffered from several equipment malfunctions. The original level control system (now replaced) would occasionally malfunction causing the condensate level to be lost and consequently the liquids data to be corrupted for the day. The condensate meter exhibited intermittent flow anomalies and finally failed to give any sensible reading, again giving erroneous data.

General Operations

The requirement whether or not to produce gas is not under our direct control. ABL are duty bound contractually to produce gas when nominated. This has led to some periods of inactivity.

Money

More precisely the lack of it. In order to remove the meter for calibration the production system needed to be isolated, vented, and nitrogen purged for removal and installation. This would have cost £60,000 for the nitrogen purges alone. Unfortunately, no other work was scheduled for the system this year so the meter calibration was postponed.

6.2 Density Trial

In contrast to the wet gas trial the density trial has suffered relatively few problems and these can be classified as follows:

General Operations

Routine maintenance and the occasional failure of the chromatograph have led to the loss of a small amount of data. As the platform is a normally unattended installation routine work can be delayed by, for example, bad weather which has resulted in helium carrier gas running out on the chromatograph and the metering database reverting to a default analysis.

Data Validation

It is important that the data used in generating a mathematical model of a system is representative of the process. The inclusion of inappropriate data will result in a poor model being produced. With the large quantity of data that is being collected for this trial, difficulties have arisen in sorting through the data sets for each field and removing invalid data, e.g. default analyses and data from malfunctioning instruments.

7 RESULTS

7.1 Density Trial

A large quantity of data has been gathered over a two year period from both the Tyne and Trent metering systems. Following validation checks to ensure that all of the data is suitable for analysis work has commenced on the development of a mathematical model. It is vital that the data does not contain any fixed parameters, e.g. pressure, temperature or composition, as these will have an adverse affect on the model.

The results of an analysis on a small data set for each field (500 records for Tyne and 250 for Trent) suggested that density could be calculated to a reasonable degree of accuracy from VOS, pressure and temperature for the Tyne field. However, Trent poses a somewhat greater challenge. The density calculated from the VOS using a polynomial equation was compared with the density calculated using the AGA8:1994 equations of state in the flow computer with the resultant relative errors plotted in Figures 7 and 8. It can be seen that for Tyne the spread of error is approximately ±0.4% but for Trent it is far greater, by a factor of 10. Data collection continues with a database of 4300 records for Trent and 6400 for Tyne available to both Instromet and ABL for data analysis and model generation.

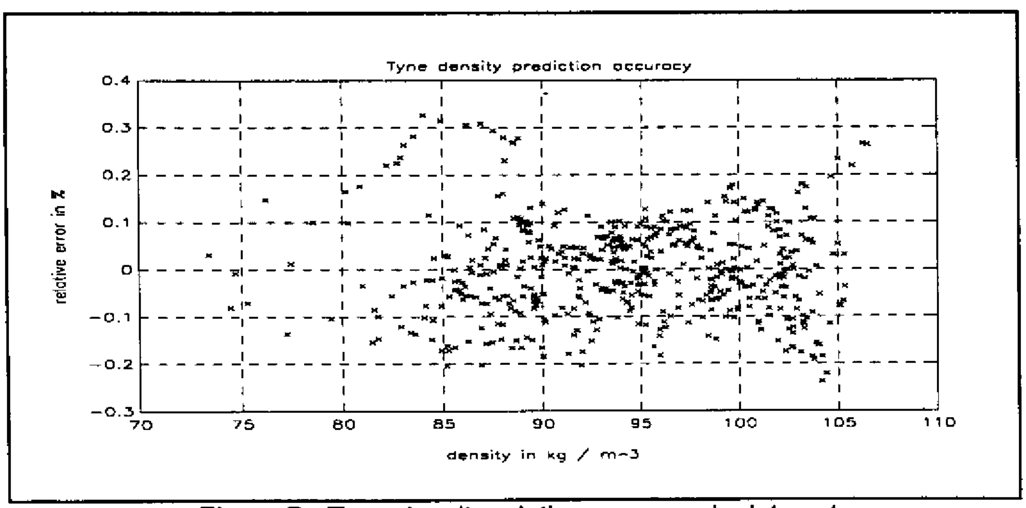

Figure 7 - Tyne density relative error - early data set

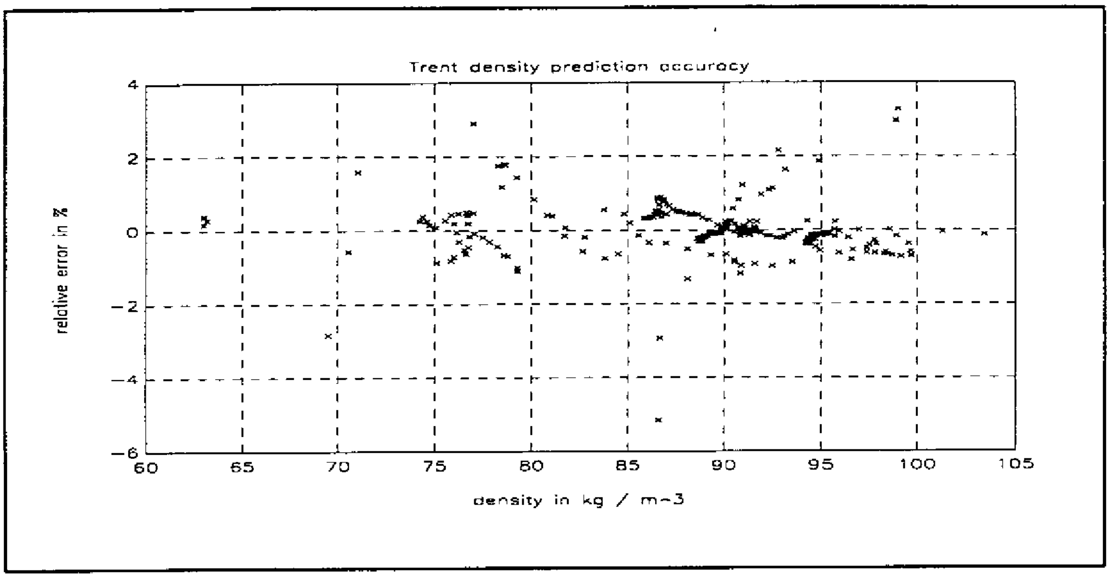

Figure 8 - Trent density relative error - early data set

Whilst most of ABL's work has concentrated on data validation an investigation was carried out to determine whether the nature of the relationship between VOS and density could be modelled by a simpler, linear equation. The classical equation for the calculation of VOS, Equation (1), has been utilised for this purpose. This equation is for ideal conditions and it is known that when the ratio of specific heats is used the results do not equate to those found in the non-ideal trial. The equation was transposed and a k factor substituted for cp/cv, Equation (2).

$$c = \sqrt{\frac{\gamma \ P}{\rho}} \tag{1}$$

where c = VOS,
γ = low pressure ratio of specific heats (cp/cv), and
P = pressure.

$$\rho = \frac{k\,P}{c^2} \tag{2}$$

where k = composite factor.

As pressure has a greater effect than temperature on the ratio of specific heats the k factor was plotted against pressure and the linear approximation derived. This has been incorporated into Equation (2) and the relative error calculated for the two data sets. From the error plots for both fields, Figures 9 and 10, it can be seen that the correction improves the results but it is still not correct thereby reinforcing the view that a polynomial function should be used as a basis for the model in preference to a linear function. The impact of pressure and temperature is evident when they are plotted alongside the density error, as illustrated in Figures 11 and 12.

Preparations are under way to extend the trial and collect data from the Bure West and Deben developments installed this year.

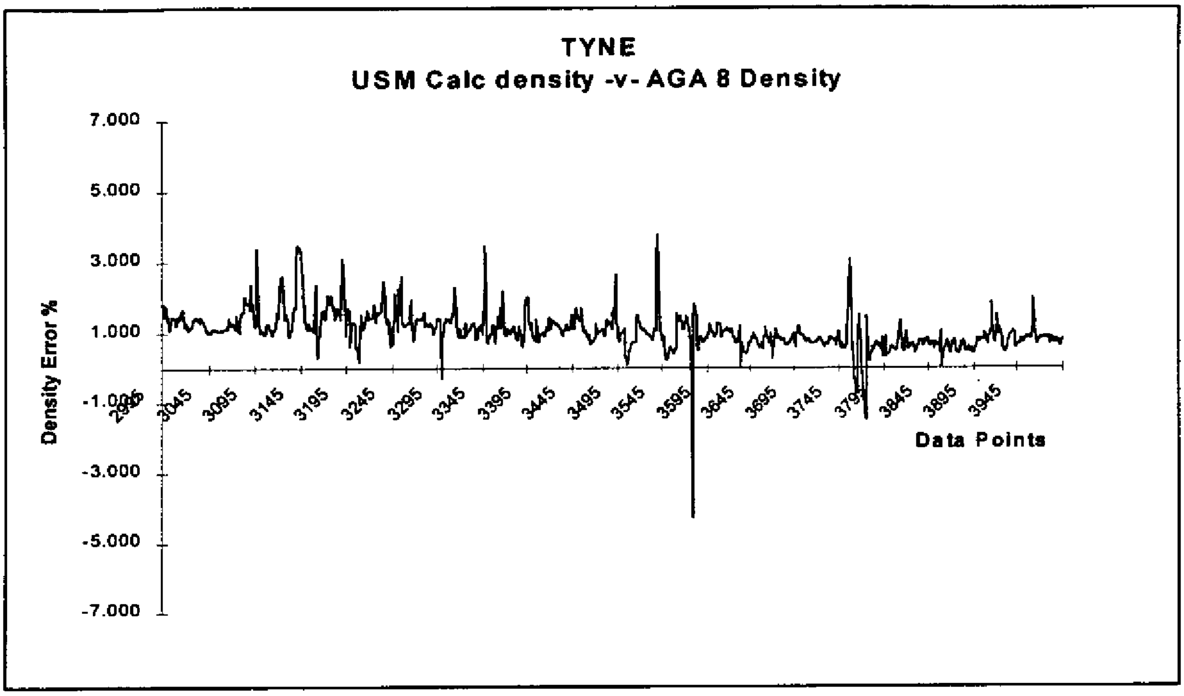

Figure 9 - Density error - Tyne field

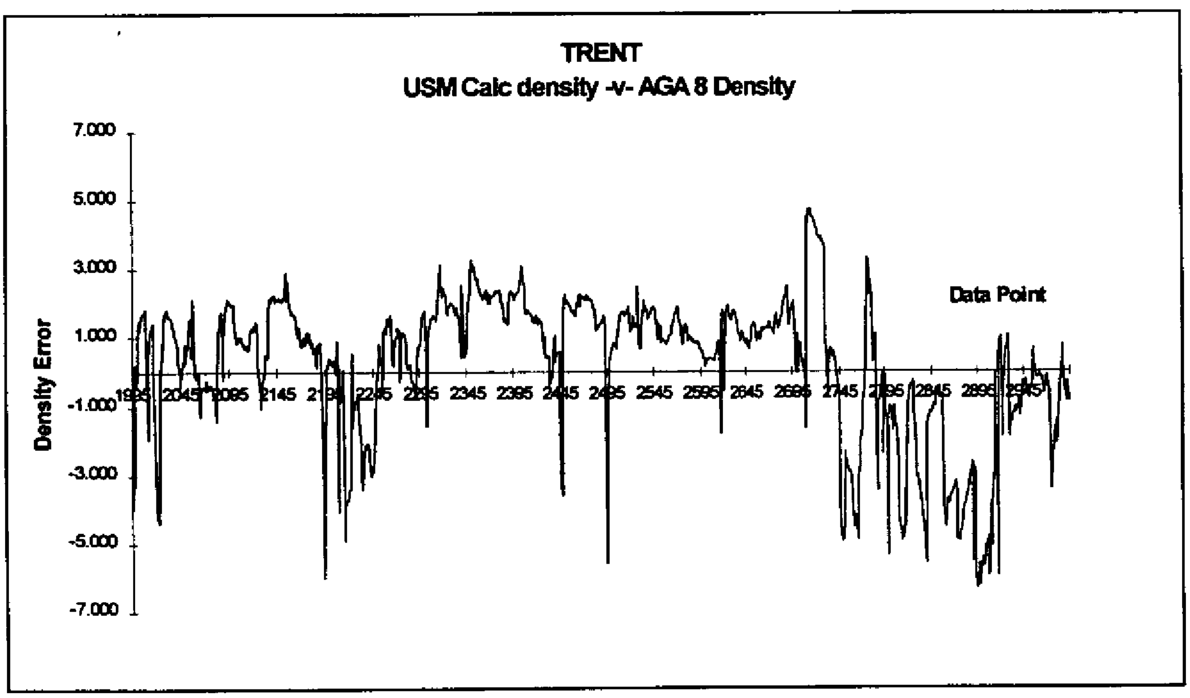

Figure 10 - Density error - Trent field

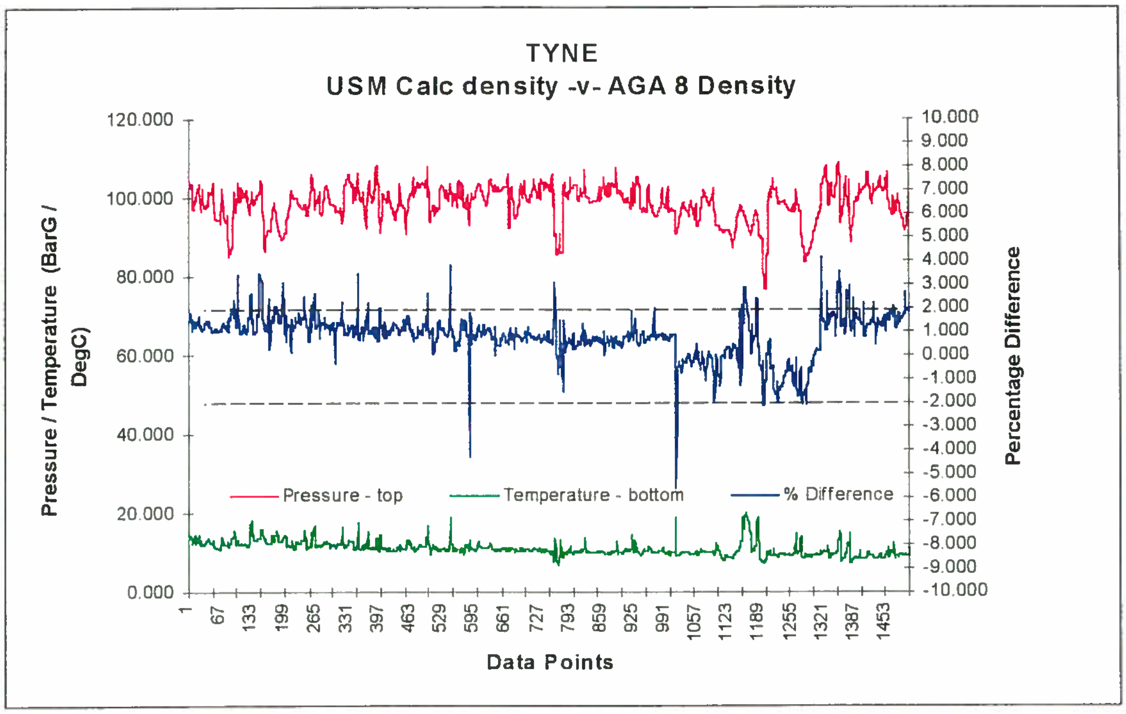

Figure 11 - Impact of pressure and temperature - Tyne

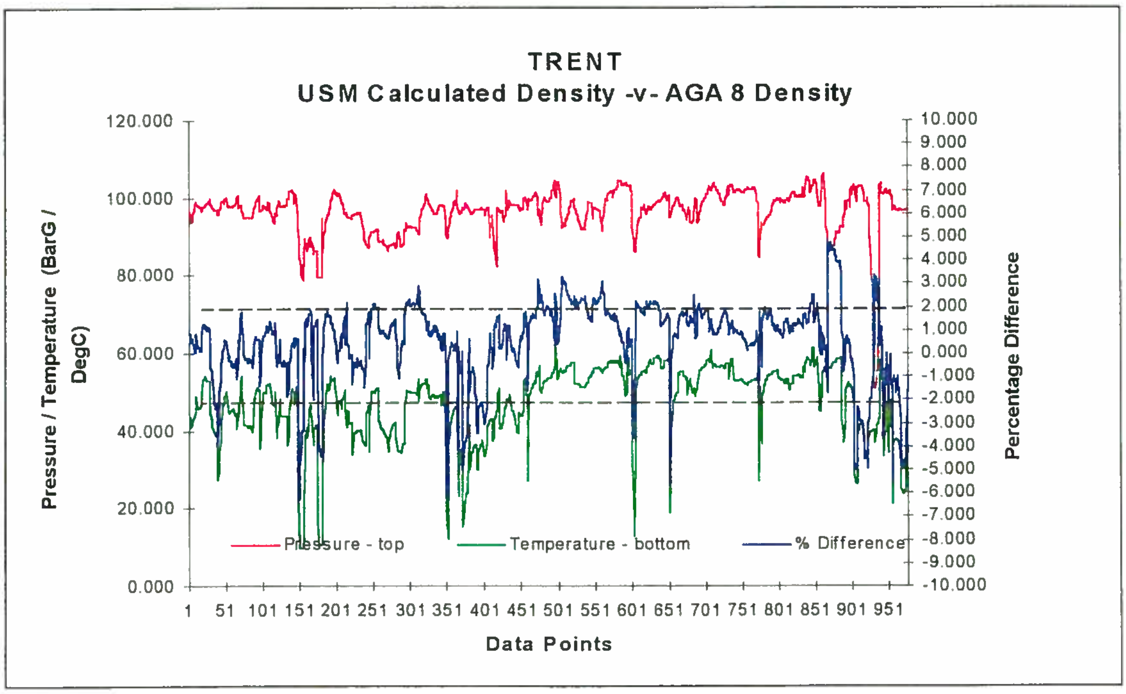

Figure 12 - Impact of pressure and temperature - Trent

7.2 Wet Gas Trial

The original concept for evaluating the data from this trial was to use the Gross Volume measurement from the USM and compare it with the orifice plate metering system results. As this is the primary variable from the USM no corrections would be required to this value. However, owing to the quantity and quality of data that is available the initial comparison between the two metering systems has been based on the metered masses only. This has, at least, given an indication that the meter does work under the installed conditions and answers the first of the four objectives cited in Section 5. Figure 13 illustrates the production and also the relative error. The relative error when referred to the orifice meter is approximately +10%.

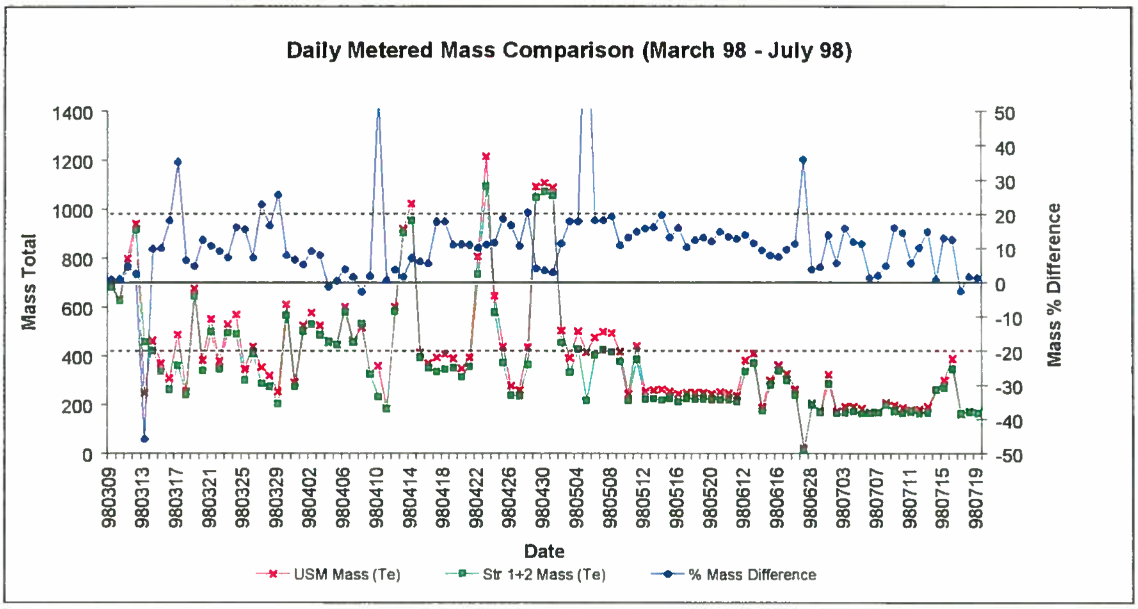

Figure 13 - Metered flow errors

There are a number of points which should be noted, however:

- this does not take account of the metered condensate and water quantities
- the composition used in the USM is that of the orifice metering station
- the pressure and temperature of the two systems are slightly different

Expanding on the point, it is recognised that for a more realistic comparison the composition used by the USM should be one based on a combined gas and liquid analysis if a representative density is to be used in the mass calculation.

The question of how well it performs has, in part, been answered by the comments above. Taking this further, an offline review of the application of a flow factor to the USM results indicates that the meter could be factored to give a reduced error of 1.65% (average), Figure 14, making this type of meter of possible use for secondary or tertiary allocation applications. If this was the case then there would not be a requirement for dedicated separators providing a suitable meter were installed post-separator to provide a reference point for the factorisation.

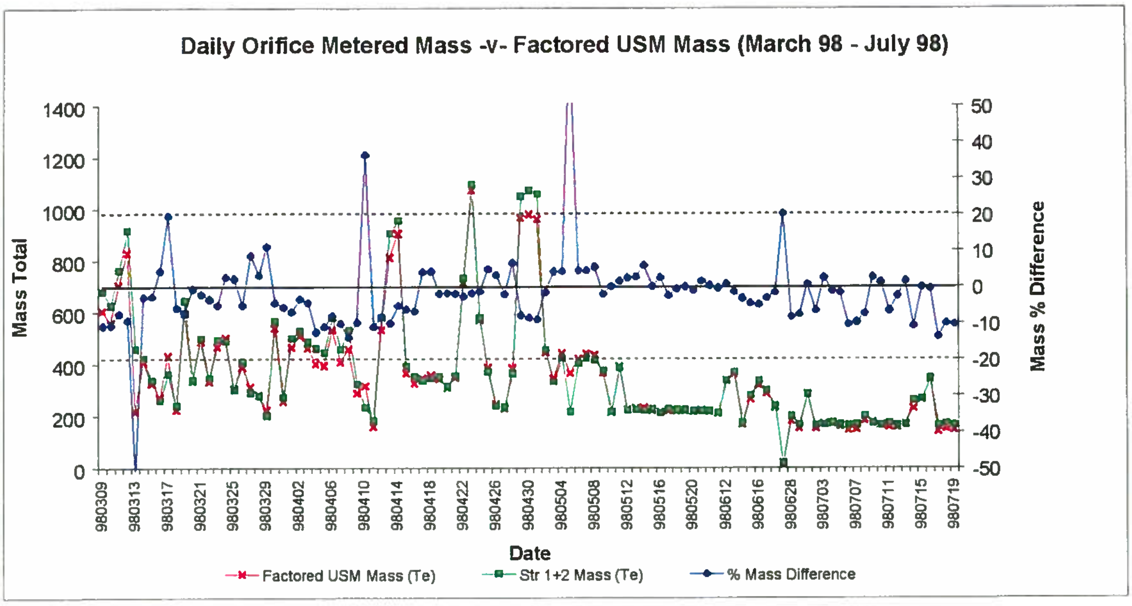

Figure 14 - Factored flow errors

As to the last two questions, i.e. liquid content and fractions, no conclusions can, as yet, be made but performance data from the USM is being collected for analysis by Instromet.

8 CONCLUSIONS

The initial results from the trials are encouraging and work continues in both areas within ABL and Instromet. Unlike many research and development projects, these trials are being conducted in real world situations with real time data being collected for analysis. If compared to pure research projects conducted under controlled conditions any developments may appear slow by context. It should be remembered, however, that once developed equipment has often to be ruggedised to withstand the harsh environment in which it is to be installed. Naturally, this process takes time. ABL and Instromet have effectively combined both phases by adopting this type of trial.

A mathematical model is currently under development to calculate density from the VOS for a known gas composition that will also account for the effects of pressure and temperature. It will not be long before algorithms similar to those available in software packages such as the ones produced by SonicWare and NEL are applied to USMs in the field. The wet gas meter functions in its installed environment. Considerable work is required to determine how well it works and whether the uncertainty of this measurement is acceptable for use in sub-allocation metering systems.

With the advances in metering and signal processing technology the development of an ultrasonic mass flowmeter should be considered a distinct possibility. Nevertheless, it is too early to tell whether a wet gas meter will be developed that is acceptable to the industry at large for fiscal use. As more data becomes available the remaining questions relating to meter performance and liquid fraction derivation can be tackled. Who knows, in a year or two the application of USMs to this area of measurement may be far more than just a pipedream.

NOTATION

ABL	ARCO British Limited
bbls/mmscf	barrels per million standard cubic feet of gas
DAC	Data Acquisition Computer
DTI	Department of Trade and Industry: Oil and Gas Office
EAGLES	East Anglian Gas and Liquids Evacuation System
PCS	Fisher Rosemount RS3 Process Control System
S500	Daniel Europe (Spectra Tek) Sentinel 500 flow computer
S/S	Stainless steel - in this case duplex stainless
USM	Ultrasonic meter
YYMMDD	Digits to represent year, month and day in a file name

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ACKNOWLEDGEMENTS

The author gratefully acknowledges the assistance of the following in the preparation of this paper:

Instromet Ultrasonics B.V. and Dr. H. J. Dane for their technical assistance.

ABL Metering and Allocation Group: particularly Paul Howard and Chris Smith for the data handling.

Gwilym Foulkes of FlowMAC Ltd. For his technical assistance.

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ULTRA-SONIC WET GAS MEASUREMENT - DAWN GAS METERING A "REAL WORLD" SYSTEM

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ULTRA-SONIC WET GAS MEASUREMENT DAWN GAS METERING A "REAL WORLD" SYSTEM

Klaus J Zanker, Daniel Industries Inc
Gordon J Stobie, Phillips Petroleum Company

1 INTRODUCTION

In 1995 Phillips Petroleum Co UK Ltd decided to exploit the Dawn reserves in the Southern North Sea via a subsea well and existing facilities on the Hewett 48/29C platform. Following the resolution of the Ultraflow Wet Gas JIP [1] it was decided to use the prototype JIP Ultrasonic Meters as the production meters for Dawn.

A short meter skid was designed to incorporate the two 6 inch USM's and NEL (Spearman) flow conditioners and was flow tested at the British Gas facility at Bishop Auckland. The results of these tests demonstrated the performance of the meters and the flow conditioners and may be found in Reference [2].

In brief the metering skid enables Dawn gas to be metered following primary liquid separation via one or two 6 inch Daniel Ultrasonic meters. The skid can be configured to meter the gas in a simplex, duplex serial or parallel meter mode. See Figures 1 and 2 for further information.

The design of the meters is also covered in Reference [1] and consisted of reduced size acoustic transducers housed in large ports so that liquid build up does not cause an acoustic link between the transducers and the body of the meter.

This paper details our experiences with wet gas measurement and the results from these specialised meters when used in liquid saturated gases in harsh process conditions.

2 PRE-COMMISSIONING

Following the flow testing at Bishop Auckland the meter skid was shipped offshore for installation. Once all the installation had been completed pre-commissioning and commissioning took place.

i. In pre-commissioning we set up the skid with nitrogen at 10 to 15 bar g to test the USM transducers and found that the signals from otherwise previously perfect transducers were not particularly good. Following some investigative work we found that the meters had been hydro-tested complete with the transducers. We were assured that the pressure had been let down "slowly" ... but we reckoned that the pressure let down had detached the 0.005" shim from the USM transducers.

The shim seals the epoxy face from the "nasties" we often find in the gaseous products ... methanol, H2S etc.

The shim is part of the transducer and is acoustically bonded, but the pressurising and depressurising allowed the shim to detach and thus break the acoustic bond.

As there was no H2S in this case we were able to grind off the shims and rescue most of these transducers and get on with the commissioning after only a few days delay.

ii. Whilst we were setting up the meters we found that the lower chord transducers would fail on a regular basis. Each time we removed the transducer pair we found that liquids had accumulated in the bottom of the meter which was a low point in the process pipework ... a design failure on our part, but one of those things that happen when retrofitting a skid to existing facilities ... which in any new design we would certainly design out ... we hope.

We were at a loss to find out where the water was coming from, but we are convinced now that it was hydrotest water from both upstream and downstream of the process.

Our "low point" design certainly cost us time with these problems, and has probably affected us since in normal operation.

3 IN OPERATION

3.1 Flow Conditions

ISO 5167 states that good flow conditions exist when the flow profile is <±5% of the 100D flow profile and swirl is less than two degrees. Experience shows that the swirl figures are difficult to achieve and have a considerable effect on the meters' performance.

In the last decade interest was generated by work done in Europe and the USA when people began to realise that plate conditioners being developed by Laws and NEL in the UK, K-lab in Norway, Gallagher in the USA and others have all been shown to work to varying degrees. All the rules that apply to dry gas with respect to developed flow profiles and swirl are equally applicable to wet gas.

The Dawn installation is a short metering skid with Ultrasonic Gas flow meters and upstream flow conditioners. We took the skid to BG's test site at Bishop Auckland for flow testing with and without the conditioners to demonstrate that the conditioners developed a good flow profile.

The results were reported in Reference [2].

However once we got to site, we found that the picture was somewhat different ... some interesting flow profiles were observed ... most were fully developed and a few were skewed. Figure 3 shows a normal and a skewed profile. When the conditioner was removed it was found that some of the perforations were fully or partially blocked with hydrates, giving rise to the unusual profile.

We knew later that the DP across the conditioner was about 10 psi with an operating pressure of 300 psig, which is well within the hydrate range so the presence of hydrates should have been expected.

It is not advocated that flow conditioners be installed in a wet gas environment ... unless it is absolutely sure that hydrates cannot be formed or hydrate inhibitors are to be used as a matter of course.

3.2 Hydrates

Hydrocarbon gases containing free water can at certain pressures and temperatures form "ice" plugs - hydrates. This problem can be suppressed or removed by one or a combination of the following ... but remember that its always easier to engineer the problem out at the start rather than try to retrofit solutions afterwards.

1. Operate above the hydrate point on the pressure/temperature curve for the gas. From Figure 4, which is a typical hydrocarbon hydrate curve, it is seen that the most efficient suppression process is to raise the temperature.

   For many reasons it may be impossible to raise either parameter. Temperature is often governed by external factors - sea temperature, pipeline length, flow rates etc.

2. Remove the water ... a difficult solution for wet gas measurement!

3. Hydrate suppression with methanol or glycol. If this is considered always arrange for the installation of the injection points before start up. In the case of subsea metering, retrofitting could well be impossible, and the additional costs for the umbilical to transmit inhibitors may well be prohibitive.

4. Heat tracing is sometimes an effective process and should always be considered in the design.

3.3 Pipework Configuration

Pipework design has always been recognised as important. With wet gas it is probably more so: all the dry gas rules apply plus a few new ones too! It doesn't help to install the meter at a low point - makes sense doesn't it?

Now consider some of the meter layouts out there in the field.

- Lowered to grade for operator access ... OK for dry gas but then the Design mentality sticks and we do the same for a wet gas installation creating a low point in the meter tubes for all those liquids to accumulate.
- Pipework slope: sloping the pipework away from the meter may help, provided that the liquid is effectively drained and not held up so that it will slug towards the meter.
- Piping orientation: horizontal or vertical, and if vertical is the flow up or down?

The Ultrasonic Meter Bi Phase JIP has conducted tests with wet gas in vertical pipework for both up and down flow. t was expected that down flow, with gravity, would be self draining and easier than up flow. However, preliminary results show that errors are less with up flow, demonstrating once again the complexity of multiphase flows.

3.4 Liquid Slugs

With wet gas metering there is the risk of liquids accumulating somewhere in the pipework and being moved towards the meter by the flowing conditions.

Typically liquids slugs accumulate in:

- production tubing during well shutdowns.

On resuming production a subsea meter may be presented with several hundred feet of liquid in the production tubing (say 75 cubic feet/2 M3 of liquids).

- subsea pipelines laid on the seafloor.

The seafloor is neither smooth nor flat and pipelines have a series of high-low points in which liquids accumulate, and are driven towards the pipeline riser.

Liquid removal is also subject to the performance of the separator. For any number of reasons these may not be as efficient as the Process Engineer would wish especially when redundant equipment is being reused.

3.5 Gas Composition

Regardless of the meter it is important to know the fluid composition through the meter. This will be required to determine base and line density and for energy determination. How the gas is sampled is dependent on the system design and the location of an accessible sample point.

In cases where a number of fields are tied into a single pipeline the ability to purge the line to get a representative gas sample may be impossible. The minimal size of the development may preclude the CAPEX and OPEX of a chromatograph, not that running wet gas through a chromatograph would do (it) much good.

3.6 Meter Recovery

Having established that the meter is likely to be subject to hydrates and liquids, it is also likely to be in a remote spot - either subsea or on an unmanned platform. Knowing this, it is also essential to establish the failure and recovery mode. Figure 5 shows the recovery of a wet gas ultrasonic multiphase meter after flooding as tested in the Ultraflow Wet Gas JIP. In one of the Dawn meters we extracted a failed transducer, which was fractured as a result of hydrates, but the meter continued working.

When all 4 chords are working the meter stirs the velocity profile and uses that information to make substitutions when chords fail.

In service we have seen these meters fail and recover many times in a day, with minimal effect on the overall outcome.

3.7 Noise

With conventional meters noise from valves is not a problem ... but it really is with an ultrasonic meter, so resist the temptation to put one near a choke valve or pressure control station ... experience shows that the USM signals collapse with loss of measurement when exposed to large pressure drops across a device.

Many of the commercial USM's have filtering, stacking and other sophisticated digital signal processing that can help improve the signal to noise. However they cannot totally eradicate noise and loss of signal is often the common result.

It is preferable to place the meter upstream of the noise generator and pipework, fittings, bends, blind tees between the meter and noise source all help to attenuate the noise. Sharing the pressure drop across two valves can considerably reduce noise problems, and it is often much easier to solve these problems in the design stage than by retrofit engineering.

3.8 Metering Results

In late 1995 we commenced gas production and sales. It became apparent that there were problems being experienced by the Operations staff.

However, we were not convinced that the problems were all with the meters.

- Having been through the problems with liquids it was determined that corrections needed to be made to the vertical separator packing trays and a liquid drain tube. Correcting this removed some of the liquid carry over.
- The low temperature (approx. 5 to 10 Celsius) at the meters was addressed by insulating/heat tracing the hydrocarbon feed line/meter skid.
- The local drain line upstream of the skid was converted into a chemical injection point for additional hydrate suppression.

These modifications improved the meter performance, but failures were still evident and we could no longer hide any defects behind any apparent process problems as we had done all we could to improve or eradicate these.

Monitoring the two meters during late 1995/1996 & early 1997 we found that there were a significant number of failures in both meters.

3.8.1 1995/1996/1997 Flow measurement results

The first series of data in late 1995, 1996 and 1997 indicate that whilst the meters were tracking each other quite well, it was evident that they were failing and recovering.

At this point in time the flow test results from the meters appeared to look good, even promising and an initial set of results from July 1996 are shown in Figure 6.

However once the process was settled down we had to start looking at the meter reports and what came back was not so reassuring.

A thirty day period in July 1996 was logged and can be seen in Figures 7 and 8. The spread looks like +/- 10% with outliers in the +/- 15% range. A form of histogram (Figure 8) shows that about 90% of the measurements are within the +/- 6% range.

During the production period of 1997 the word coming back was that there were large numbers of "**Warning** – Chord Failures" and "**Fatal** - Chord Failures". "Warning" was to announce a single chord failure, not in itself a calamitous event as the signal processing is able to cater for this until the chord recovers. "Fatal" was to announce that all 4 chords had failed, which is far more serious and could lead to exceptional errors. D-Chord failures are not all bad, as they indicate the presence of liquids.

Figure 9 shows the chord failures recorded during a 20 day period in February 1997 attributed to the two meters. Meter 2 appeared to be worse with significantly more failures than meter 1.

Once Meter 2 was modified (see Section 4) chord failures reduced significantly. Figure 10 shows the chord failures recorded in a similar period in February 1998 and Figure 11 is Figures 9 and 10 superimposed. The reduction is from an average of 10 per day to less than 4 chord failures per day.

4 MODIFICATIONS

Following discussions with the Operating Group and Daniels it was agreed that the "Bad" meter (2) would be modified during the zero nomination period (summer) of 1997 ready for 1998.

The original British Gas Ultrasonic Meter was designed for clean dry sales gas. The main practical feature of the design to fail in wet gas was the small clearance between the transducer (1 1/8" Dia.) and port (1 ¼" Dia.). This 1/16" (1.6 mm) radial clearance is very easily bridged by liquids, which causes acoustic coupling to the steel meter body and noise to appear in the received signals.

It is quite easy to cure the problem by increasing the clearance to ¼", making the port Dia. = 1 1/8 + ½ = 1 5/8". Unfortunately, this is not possible with 6" and 8" meters because the ports on the outer chords break through the pipe bore and leave a trap that fills with liquid. The only possibility with these small meters is to reduce the transducer size. Keeping a ¼" clearance from the 1 ¼" port gives a 1 ¼ - ½ = ¾" (19 mm) diameter transducer.

The Ultraflow specification for the ¾" transducer was:

Pressure	10 to 180 bar
Temperature	-10 to 150°C
Liquid	< 1% volume fraction
Corrosion	< 2% H_2S

This proved very difficult to achieve and in hindsight was over ambitious! We probably threw out some good ideas because they did not meet all our criteria. To meet the severe corrosion conditions, the transducer was built into a sealed Hasteloy can. This led to two other major problems:

1. It is difficult to manufacture.
2. It is prone to acoustic coupling with the steel body.

Eventually a compromise was reached, see Figure 15:

- a PEEK acoustic isolator was used to connect the transducer to the flange
- 'O' rings were used to seal against corrosive gases
- the epoxy matching layer was protected with a thin metal shim

The small wet gas transducer used a 10 mm Dia. Piezoelectric crystal compared with the standard 20 mm crystal, leading to considerable losses:

- treating the crystal as a piston, it has ¼ of the area and ¼ of the power
- with a speed of sound = 400 m/s and a frequency = 120 kHz, the wave length in gas is about 3.3 mm. The beam from the 20 mm crystal will spread with an half angle of 10° while the 10 mm crystal will spread at 20°, further dispersing the energy.
- the shim is yet another interface between crystal, epoxy and gas, incurring more transmission losses
- the possibility of the shim delaminating is a potential hazard, which would lead to complete loss of signal.

Many of these shortcomings were unfortunately realised during the field trials, hence the decision to revert to standard transducers, with a few changes:

- the acoustic isolation between transducer and flange was improved, to make it harder to couple the transducer to the body
- the system improvements reduced the liquid content of the gas
- most liquid problems were with the bottom D-chord in the horizontal layout
- loss of the D-chord did not cause significant errors, due to the substitution algorithm
- the D-chord recovers after flooding

On the basis of these considerations, the bad Dawn meter (2) was upgraded to the almost standard transducers. It has showed considerable improvement in performance, and meter (1) has been upgraded this summer and is ready for use offshore.

5 POST MODIFICATION RESULTS (1998)

Figures 12 and 13 show the flow test results for a 20 day period in February 1998. This is with the old "bad" meter (2) replaced with "standard" transducers and the old "good" meter (1). The plots show the discrepancy in percent terms between the two meters and Figure 14 is a histogram of the discrepancies.

As can be seen from Figure 12, the hourly data over 20 days is very tight around +/- 1% with only a few outliers. There is one at +15% which accounts for the day when 11 chord failures occurred. On the daily data comparison (Figure13) the error between the two meters does not exceeds +/- 1%.

In addition the histogram of all hourly data shows 91.2% of all measurements are within +/-1%.

6 CONCLUSIONS

The modifications put in place in the process improved the primary metering results. The 1998 results are much improved from a band of +/- 6%, to +/- 1% which is very satisfactory for a wet gas meter.

The 1996 hourly data (390 points in total) has a flat histogram with around 90% of the results within +/- 6%, whilst the 1998 hourly data (460 points in total) has a normal histogram and shows that 91.2% is within +/- 1%.

However it must be stressed that the transducer alone did not effect a cure, good system design is essential:

- avoid low points for the meter
- ensure self draining, by gravity
- do not make flow and gravity fight one another
- avoid hydrate formation

It is expected that the modifications installed for 1998/1999 will improve matters even further.

Remember to think wet gas at the design stage and avoid expensive corrective action in the field.

If you have to go wet gas metering ... read the Standards ... but do not follow them slavishly. Use your brain ... its as good as anyone else's .... especially those of the guys who write the Standards!!

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ACKNOWLEDGEMENTS

The authors wish to thank Daniels Industries and Phillips Petroleum and their Hewett Partners for permission to present this paper and colleagues and friends who have helped and encouraged in the work presented herein.

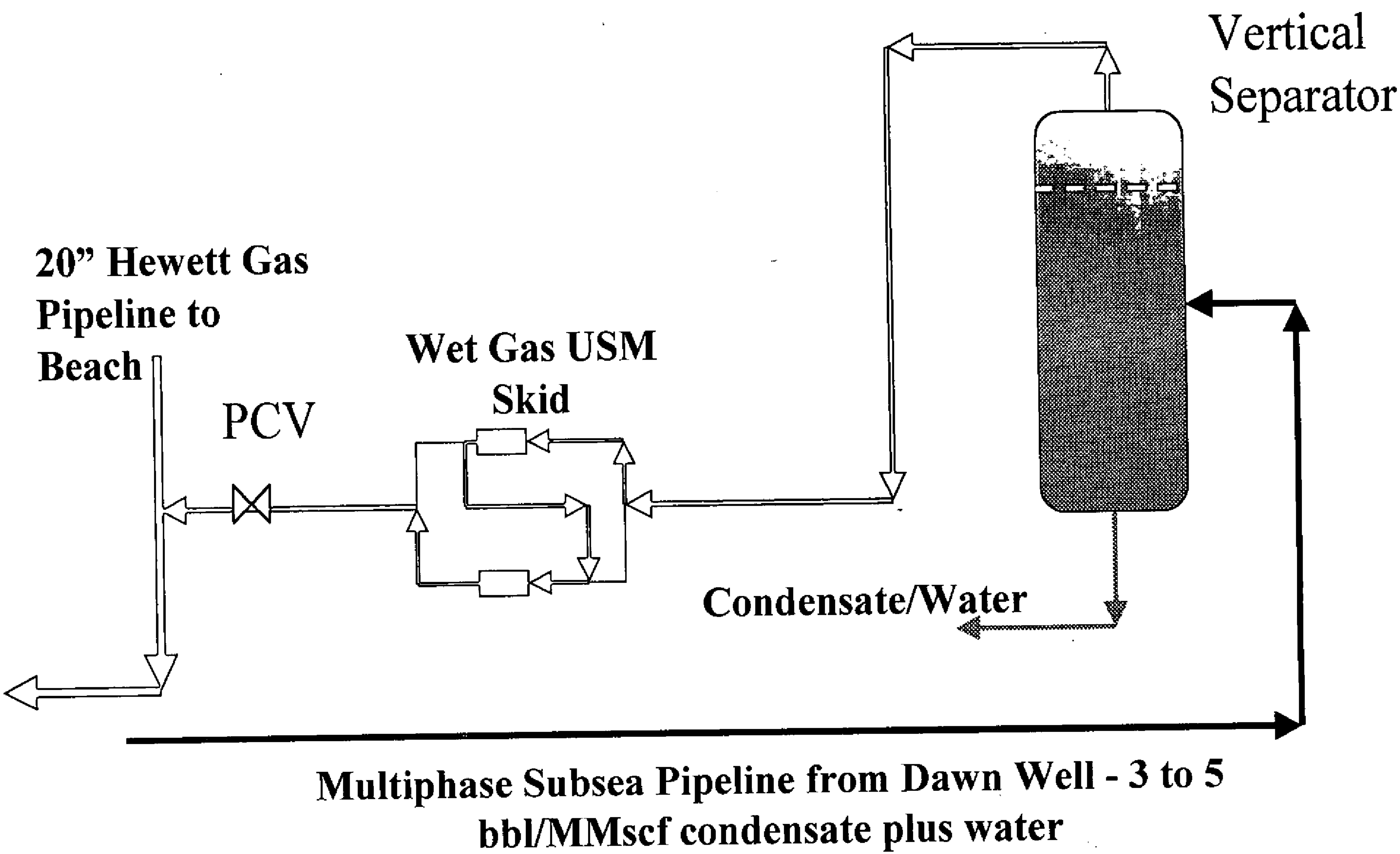

Vertical
Separator
20" Hewett Gas
Pipeline to
Beach
Wet Gas USM
Skid
PCV
Condensate/Water
Multiphase Subsea Pipeline from Dawn Well - 3 to 5
bbl/MMscf condensate plus water

Figure 1

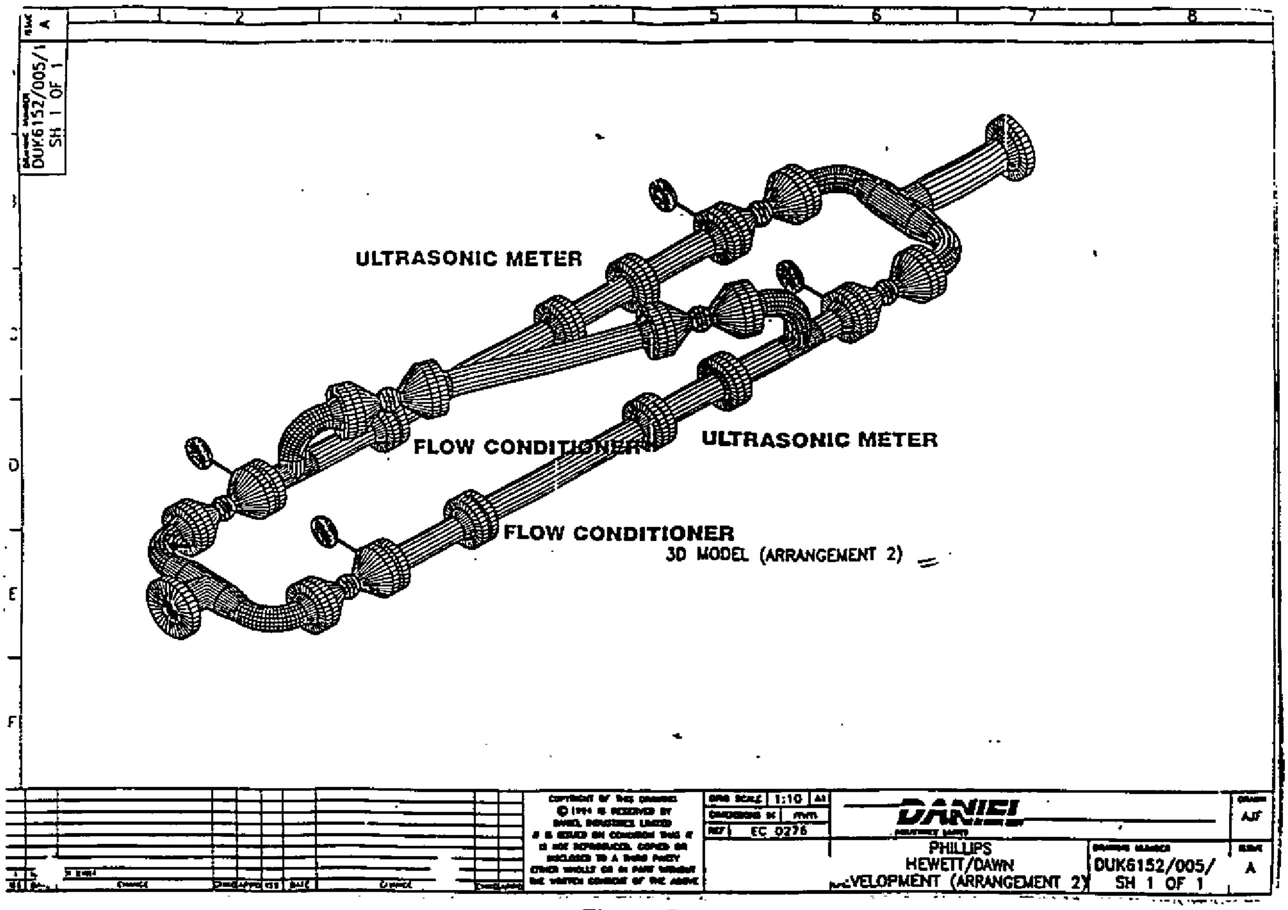


Figure 2

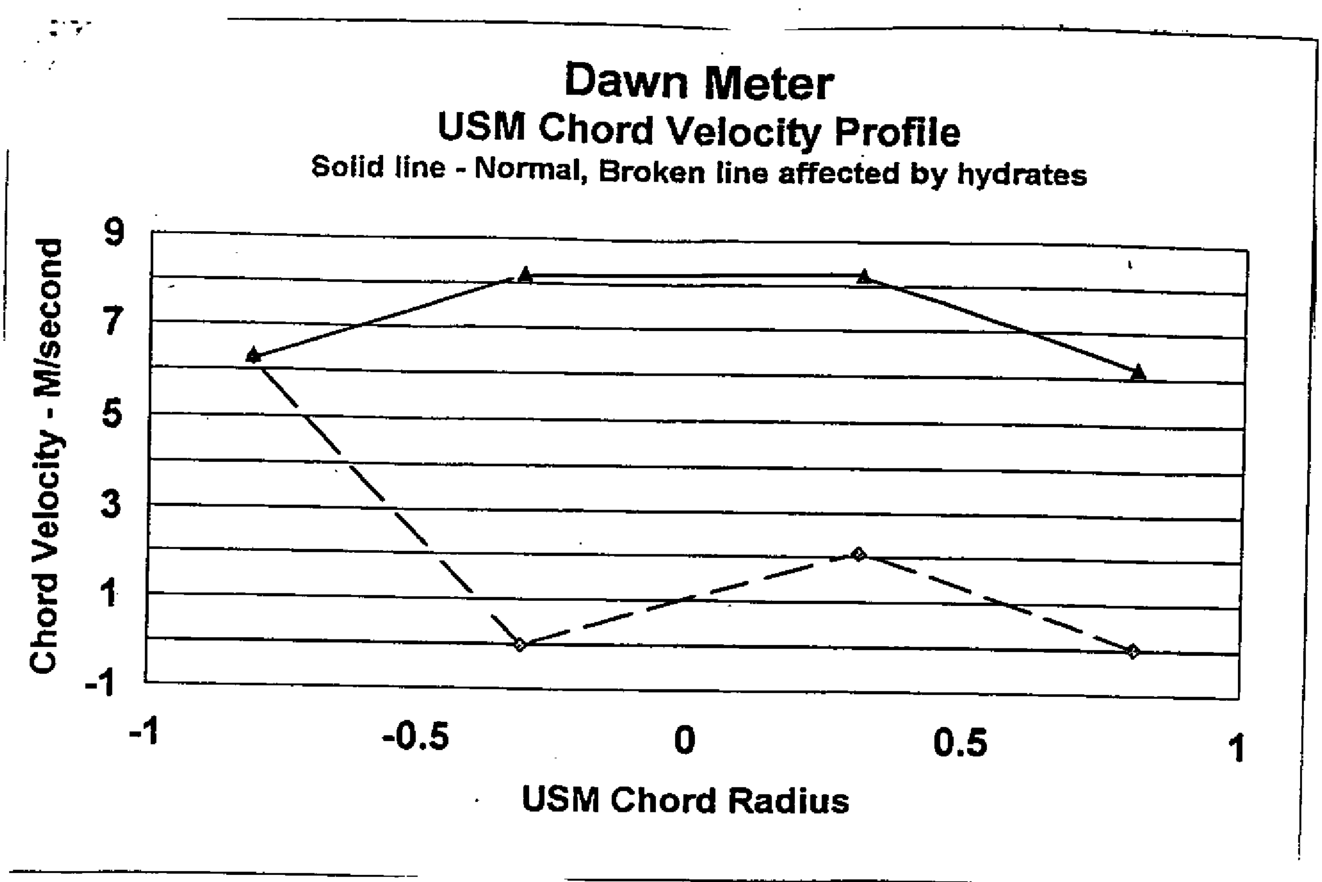


Figure 3

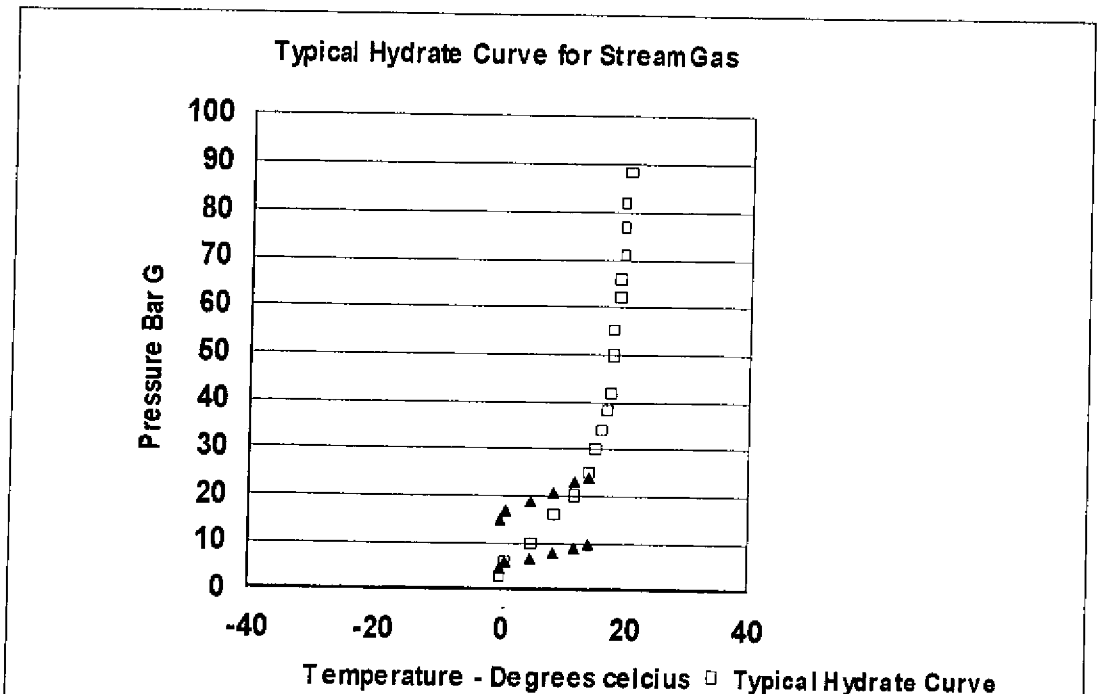


Figure 4

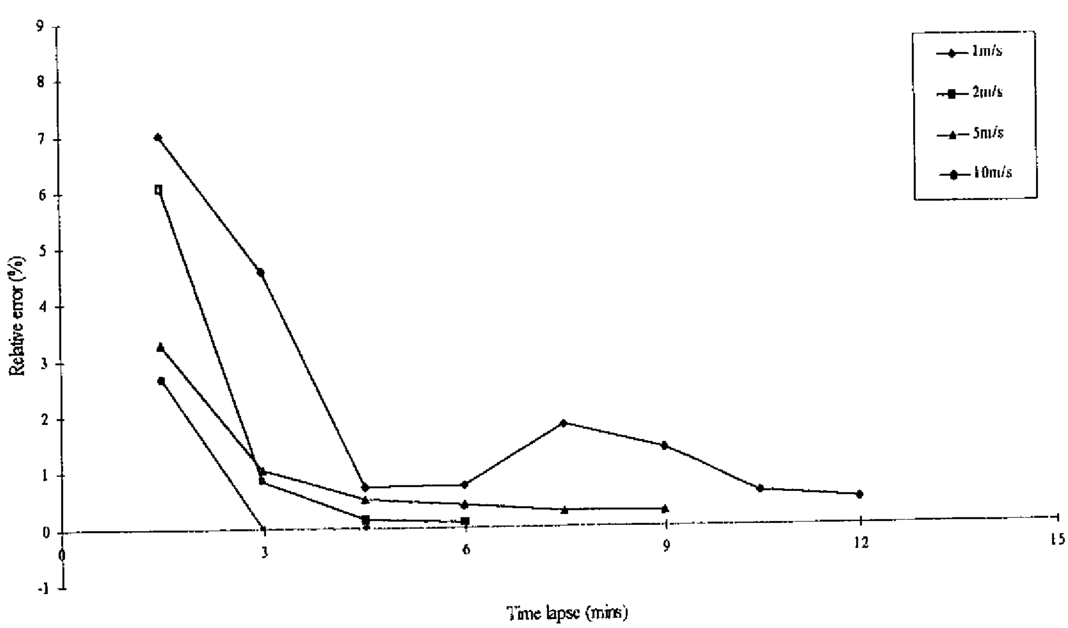


Figure 5

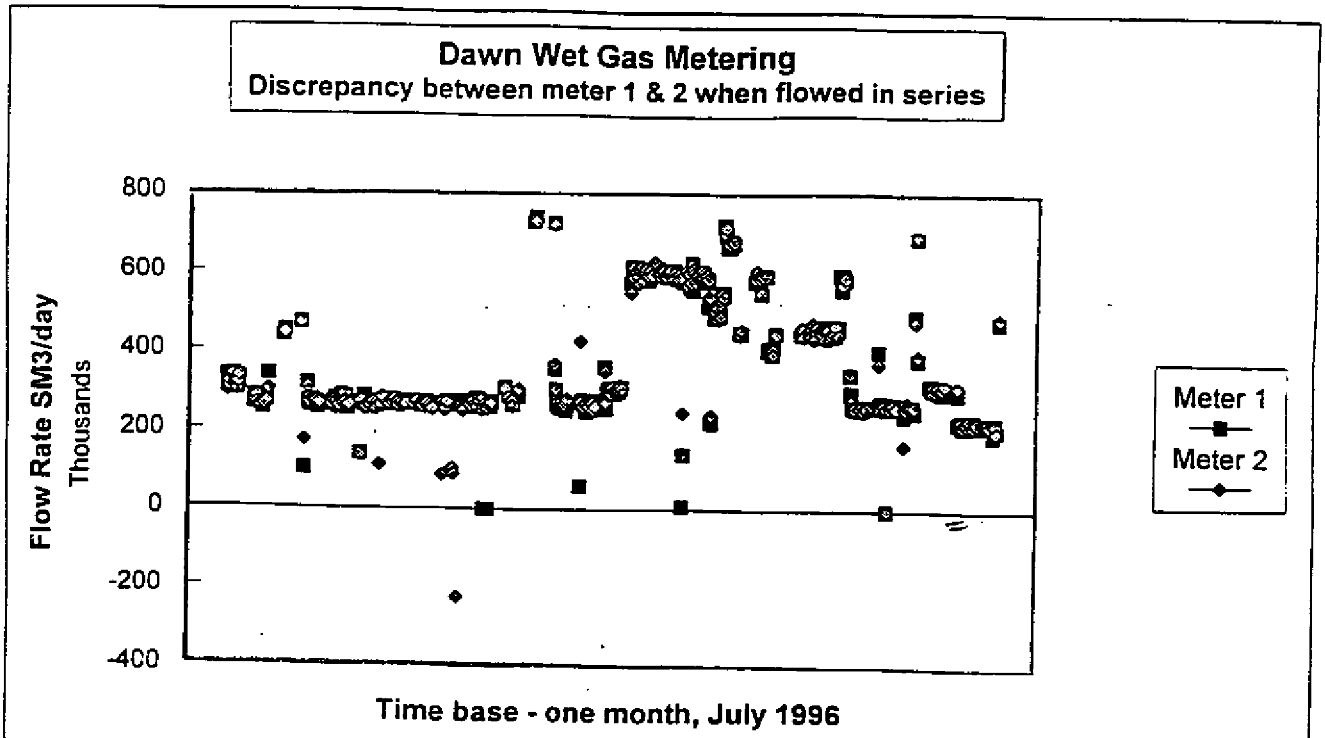


Figure 6

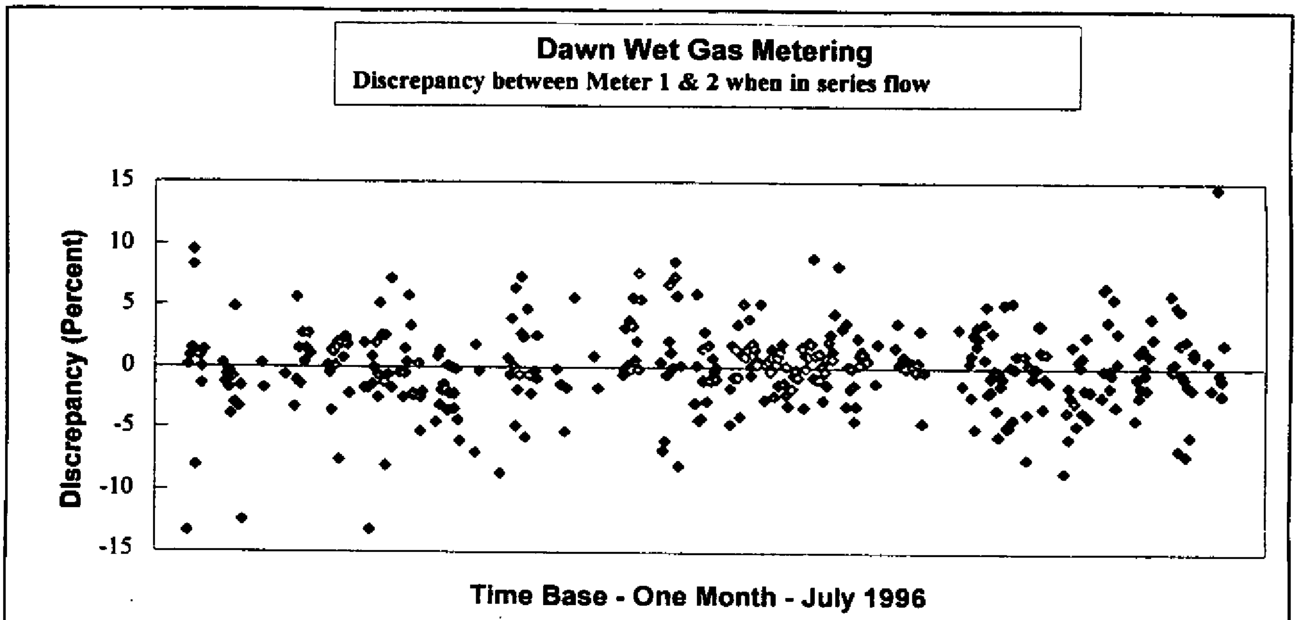
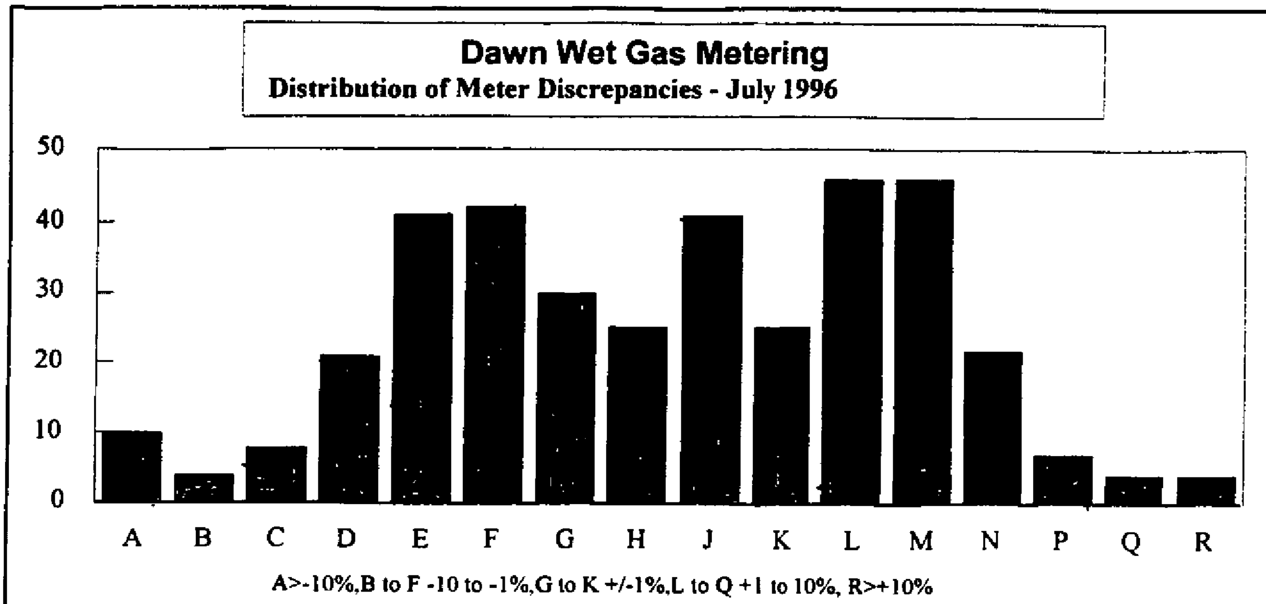


Figure 7



D to N represents a spread of +/-6% which is 90.1% of all measurements
Hourly Measurement data, total measurements = 376points
Figure 8

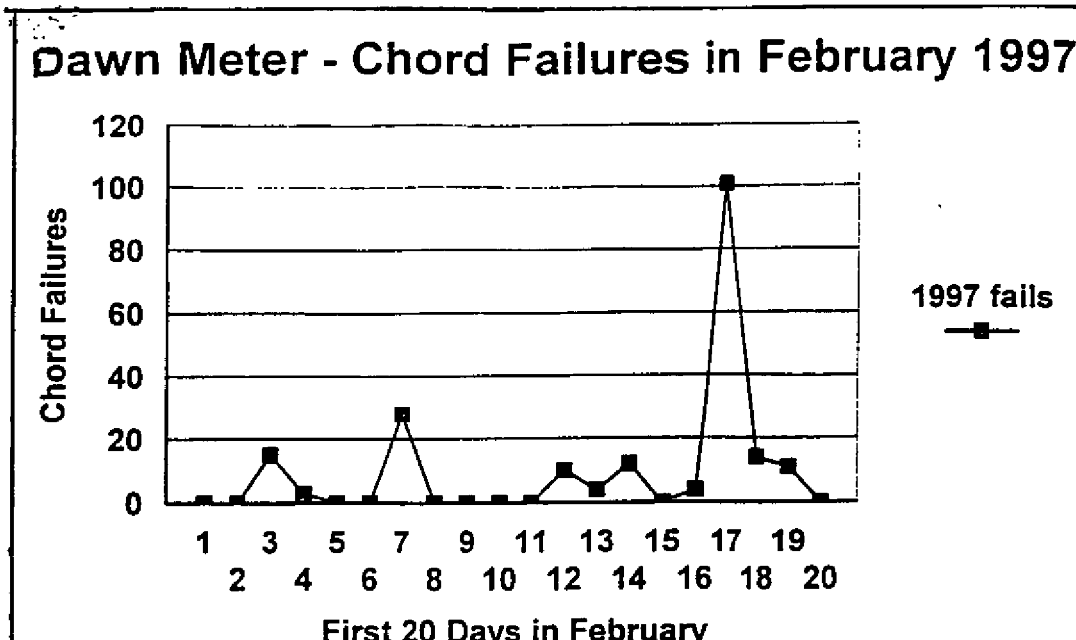


Figure 9

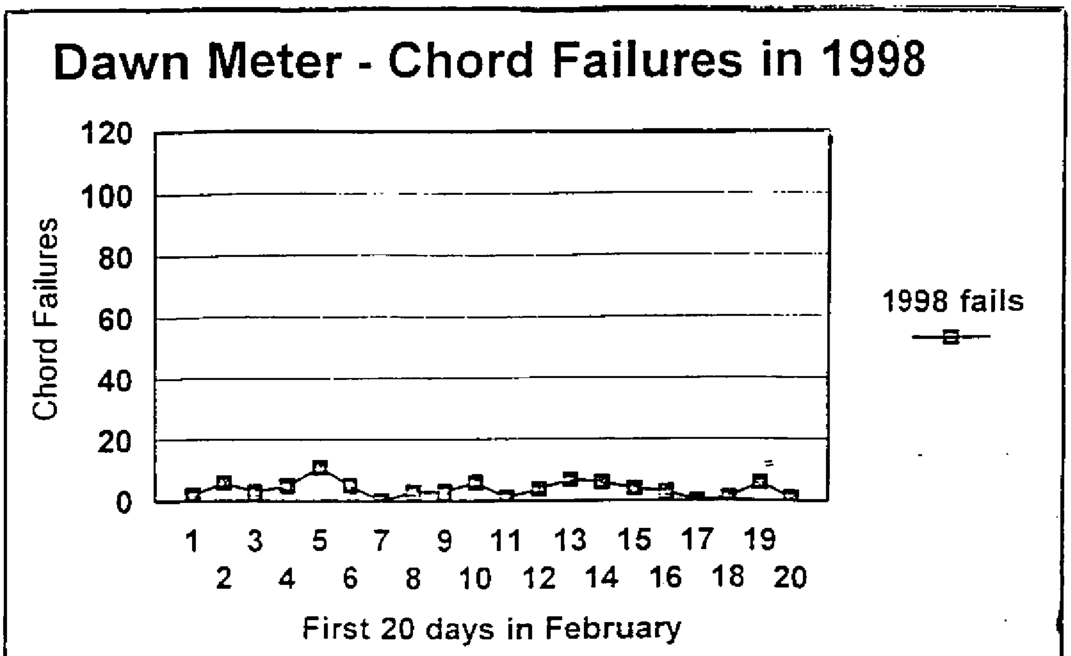


Figure 10

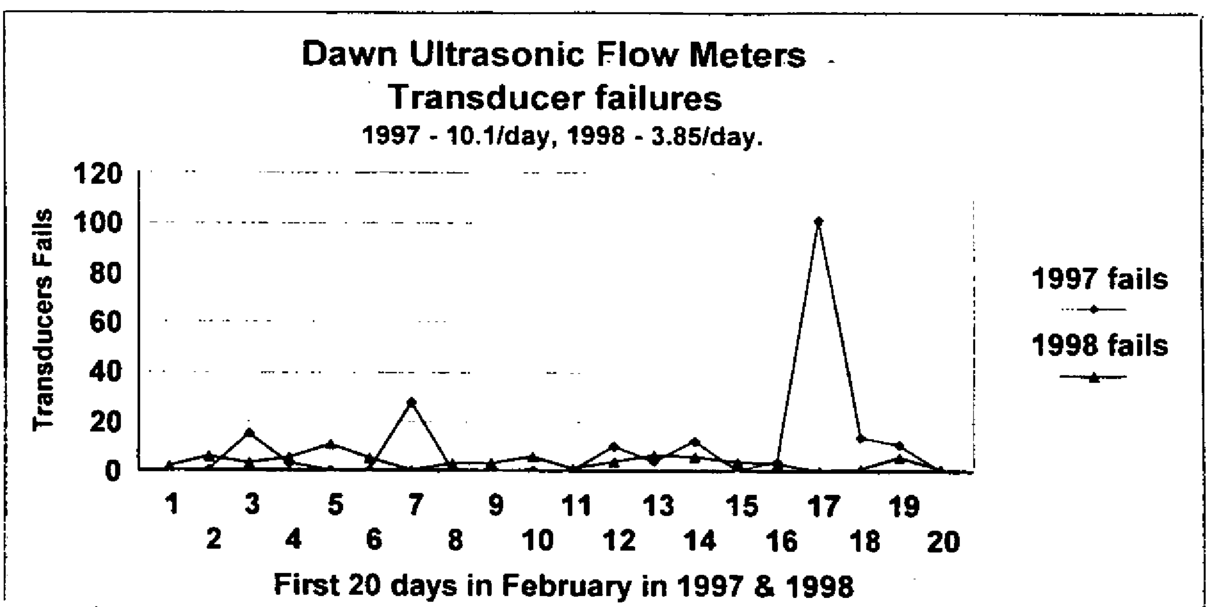


Figure 11

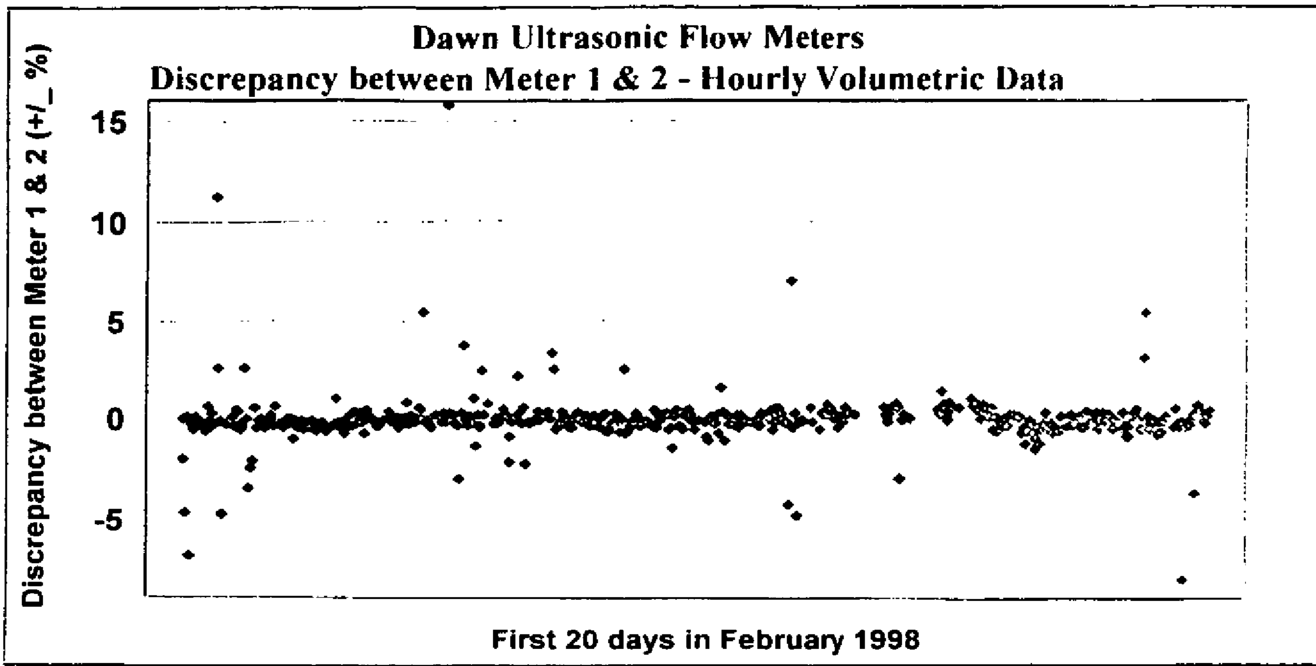


Figure 12

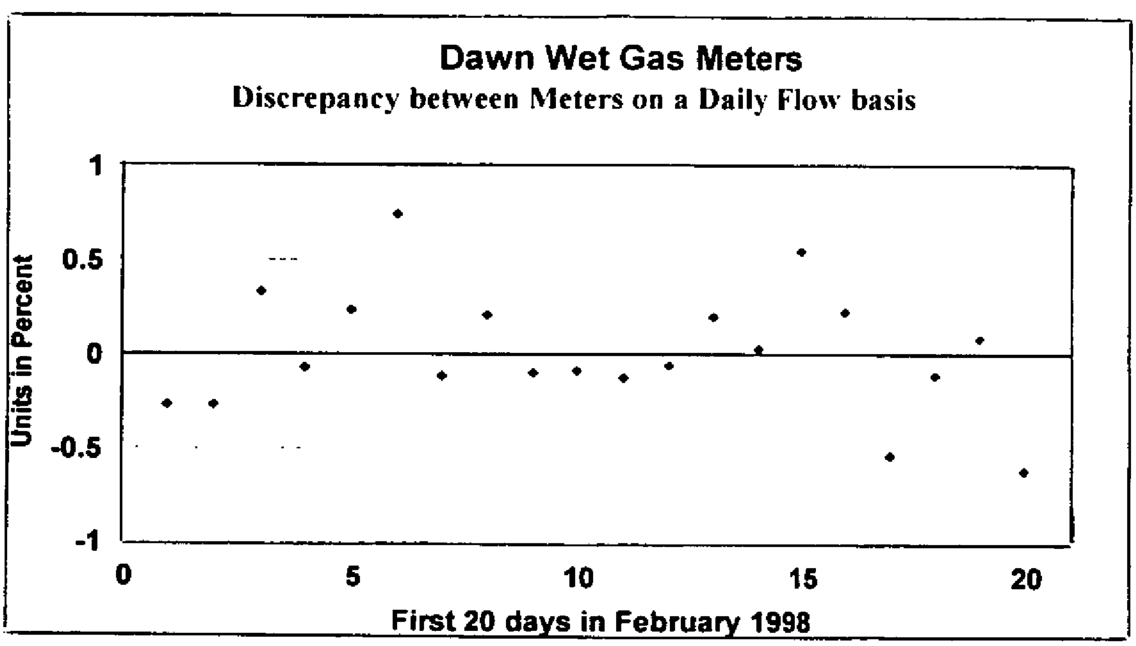


Figure 13

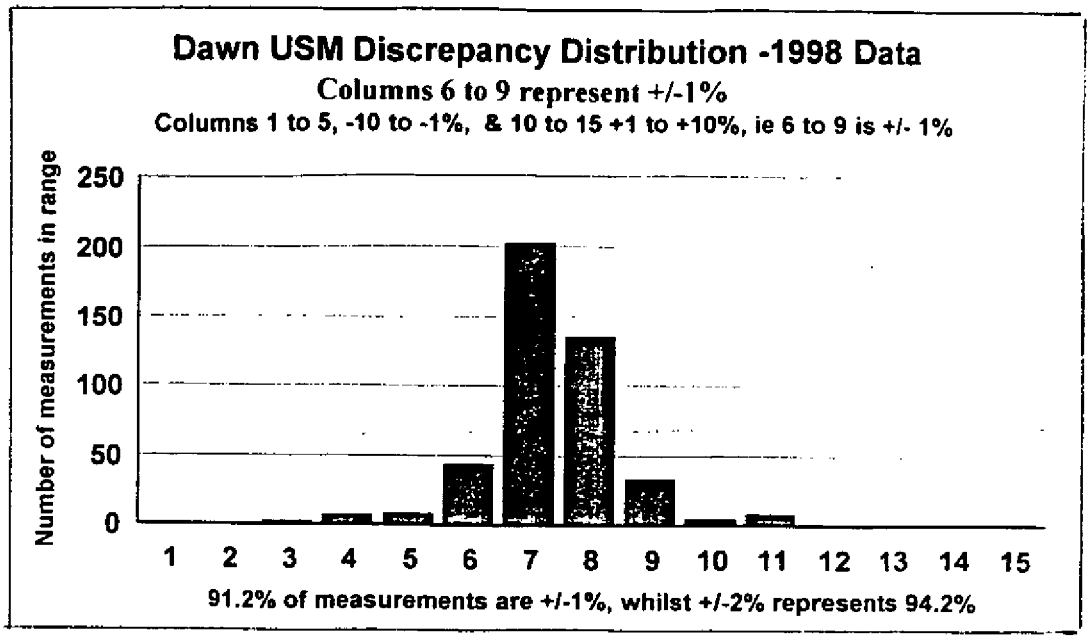
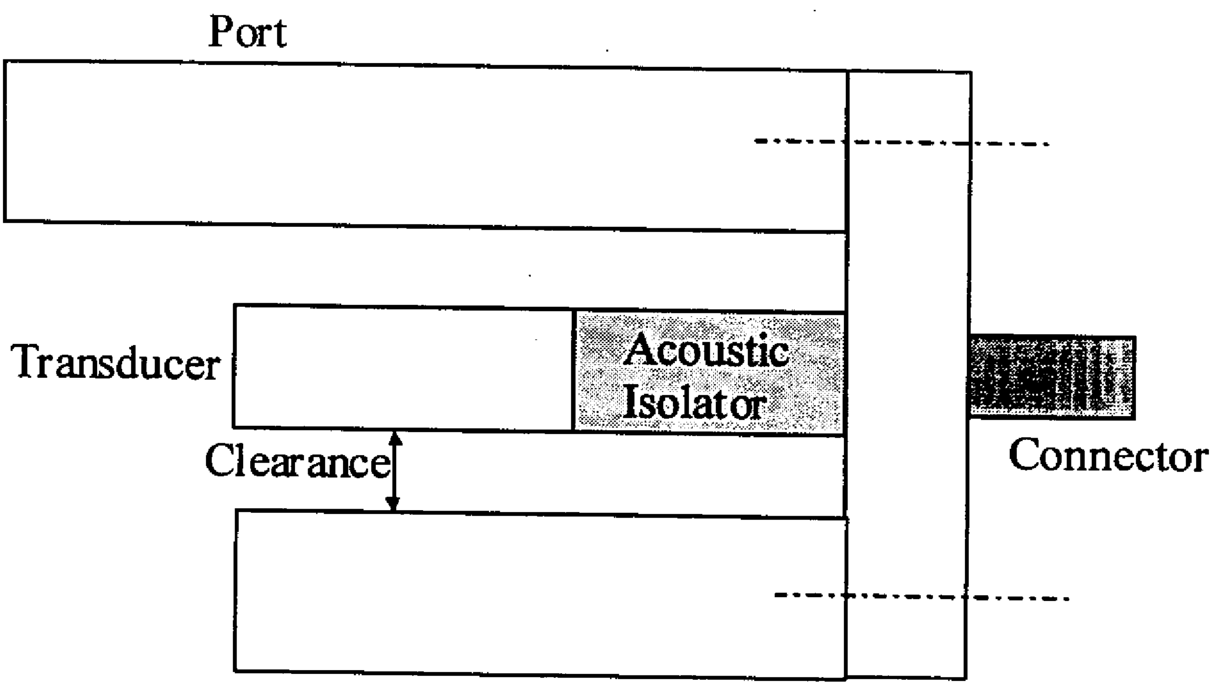


Figure 14

Wet Gas USM Metering



Wet Gas Transducer Design
Figure 15

North Sea
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PAPER 13 - 4.1

MULTIPHASE METERING - THE CHALLENGE OF IMPLEMENTATION

A W Jamieson, Shell Expro

16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

MULTIPHASE METERING – THE CHALLENGE OF IMPLEMENTATION

Mr A.W. Jamieson, Shell U.K. Exploration and Production

1 INTRODUCTION

"Multiphase flow measurement" is a term that has been increasingly heard since about 1980 amongst operators in oil companies and designers of oilfield facilities. For some, it promised measurement capabilities under new and trying conditions. They saw a need to simplify the design and improve the control of production facilities. They considered that, unless multiphase measurement techniques were improved, it would be virtually impossible to know what was happening in the advanced subsea systems or on the unmanned satellite platforms that were being planned. In addition they could not see how future enhanced oil recovery systems could be operated effectively without these measurements. For others, multiphase flow measurement was less appealing. They envisaged even more intricate measuring systems, which would be difficult to maintain, and which would only complicate the design and operation of the facilities – without producing a single extra barrel of oil.

It is now clear that the first view is being confirmed. After a long gestation period, reflecting the technical difficulties involved, multiphase meters with adequate performance for selected applications are now commercially available. Oil companies are keen to deploy them. At present Shell Expro has operational multiphase meters on four facilities in the North Sea and can show savings in capital expenditure of about £40 million through their use. The second view must not be ignored however. As multiphase meters are deployed in our operations unexpected difficulties will appear, as with any new technology. If these are not addressed promptly and effectively, multiphase metering will get a bad name, operator confidence will be lost and full implementation of the technology could easily be delayed for, say, five to ten years.

Multiphase flow measurement is not new. Indeed, such measurements are made routinely at most production facilities: a test separator combined with its instrumentation in fact forms a multiphase flowmeter. What is new is the changed attitude towards these measurements. Oil companies have decided on detailed requirements for such measurements, and together with scientific and industrial instrumentation specialists are working towards satisfactory multi-disciplinary solutions for specific applications. The long-term aim is a low cost multiphase meter per well.

Shell Expro has been proactive in the development of this technology, supporting development at Shell laboratories, Universities, and in Joint Industry Projects. The areas of application are varied and include wet gas metering, well testing, optimising production to delay abandonment, and allocation metering. The biggest savings come when it is possible to deploy subsea meters and performance is good enough to allocate production to third parties. By 2010 Capex savings totalling £180-280 million should have been made. Large savings in operating costs over field lifetimes should also be achieved.

None of this will happen by itself. Currently expertise in multiphase flow measurement resides in a few specialists in oil companies, manufacturers and testing laboratories. Know-how must be transferred to project teams, metering consultants; design contractors and operating staff before this technique can realise its full potential.

In this paper, I will outline the types of multiphase meters now available to the oil industry and consider a variety of applications. I think that this is the best way of illustrating the challenges that face the oil industry in implementing multiphase metering in a reasonable time scale, and also of illustrating the opportunities that multiphase metering will continue to open up for well into the new millennium.

2 OVERVIEW OF MULTIPHASE METERING

The oil industry began to take a serious interest in developing multiphase meters around 1980. The problem is simple to state: we want to obtain the gas, oil, and water volume flowrates at line conditions. (At present there is a strong preference for volume rather than mass flowrates, but this preference may change.) These are the measurements that are in principle obtainable from a test separator, the oldest type of multiphase meter. Today I would identify four general approaches to multiphase metering, all of which are being actively developed and are being applied in the field.

Compact separation systems

These devices perform a rough separation of the well flow into liquid and gas streams. These are then metered using meters that can tolerate small amounts of the other phase. The liquid must be further split up into oil and water. These systems are being applied worldwide, but are bulky and do not bring the full benefits of multiphase metering with them. Typical cost £100 – 200k.

Phase fraction and velocity measurement

These meters attempt to identify the fractions of oil, water and gas and measure the phase velocities, which are not usually the same. In practice manufacturers try to condition the flow so that the phase velocities are similar, and the differences in velocity are corrected using multiphase and slip models. Most of the multiphase meters deployed in the North Sea are of this type. Typical cost £100 – 200k surface, £200 – 400k subsea.

Tracers

Multiphase flow is measured by injecting at known rates tracers (e.g. fluorescent dyes) that mix with the individual phases. By analysing a sample of the multiphase fluid taken sufficiently far downstream of the injection point, and combining this with the injection rate, the individual flows can be determined. Currently tracers are only available for oil and water. The technique is particularly suited for wet gas measurement. Costs are closely related to day rate for work and hire of equipment, say £1500 per day.

Pattern recognition

These systems are characterised by their use of simple sensors combined with complex signal processing. Potentially they 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. Cost is more variable, but within the range £20 – 60k, depending on the number and type of sensors used.

I believe that any multiphase meter can be fitted without much difficulty into one of these four categories or a combination of them. This is not to say that multiphase metering is now a mature technology and that there will only be minor improvements. Quite the reverse. I think a useful comparison can be made with the development of the motor car. The modern car is clearly similar to cars of 100 years ago. There were no fundamental breakthroughs in knowledge required to transform the car of then to what we have now, but unquestionably there has been enormous development and improvement.

The pattern recognition approach is the least familiar and most mysterious approach to multiphase metering for most people. Yet the operator who puts his ear to a pipe to listen to the flow, or who feels the temperature of a pipe to judge whether there is a flow inside it is practising a crude form of flow measurement by pattern recognition. It is therefore worthwhile pointing out some of the general features of this approach that distinguish it from the other approaches to multiphase metering. As an example, the pattern recognition meter described in the paper by Toral et al [1] presented at this workshop uses differential pressure, pressure, capacitance and conductance sensors to sense relatively fast (approx. 25 – 500Hz) fluctuations in the multiphase flow. 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".

In principle we can write an equation for each "feature" in terms of the unknown oil, water and gas flow rates. This means that for the meter referred to above which has five sensors, we can write perhaps 150 independent simultaneous equations in terms of the oil, water and gas flow rates. In an ideal world one could hope to find a feature that responded only to oil, another to water and a third to gas. So far, nature does not appear to be so kind and practical methods have to be used to solve this complicated mathematical problem. In the meter above a feature saliency test is used to 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 accuracies. 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. I believe that it is practical to achieve relative accuracies per phase of 5% by 2005, and 1 – 2%, near fiscal quality, in certain applications by 2010.

3 THE MULTIPHASE TRIANGLE

The biggest obstacle to the successful implementation of multiphase metering is the general lack of understanding of what it is about. It is difficult to explain simply why multiphase metering is so complex. When discussing multiphase metering with colleagues working on prospect development, the general expectation they seem to have is that there can be a universal multiphase meter that can measure all three phases to high accuracy simultaneously over a wide range of flowrates, different for each phase. They tend to assume that measurements from test or production separators are of relatively high quality, because measurements have been made that way for a long time.

Various ways have been proposed to show how the multiphase flow characteristics of a well or a field change with time, and to show the operating envelopes of multiphase meters. The most useful I have found are the plots of application multiphase flow and meter envelopes on a two phase plot of liquid flowrate against gas flowrate, Fig. 1, and a plot of application watercut against gas volume fraction, Fig. 2 [2,3,4].

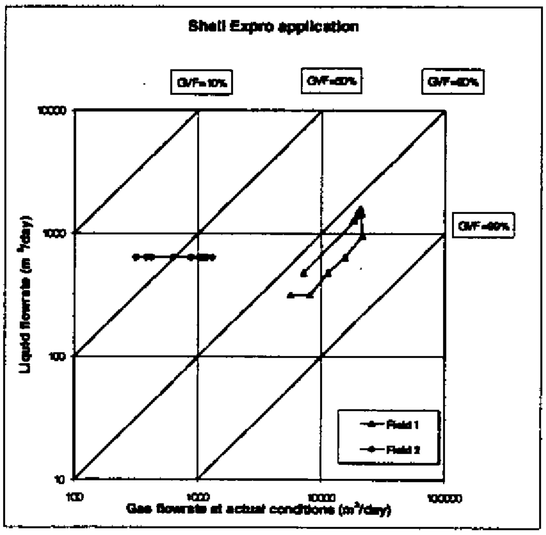

FIG.1 TWO-PHASE FLOW MAP

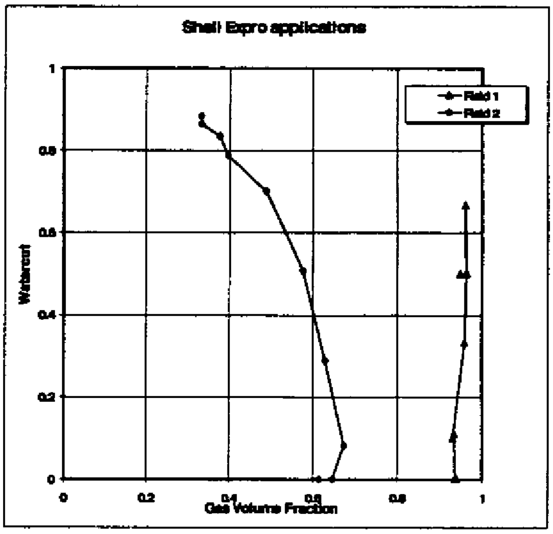

FIG. 2 MULTIPHASE COMPOSITION

Such plots are essential when planning to install a multiphase meter, but they do not give the uninitiated person a grasp of how a specific application fits into the whole multiphase picture.

I have found that in explaining multiphase flow, the "Multiphase Triangle", Fig. 3, is more useful and more readily understood than Fig. 2 above. It is an approach commonly used in other disciplines for displaying properties of three component mixtures.

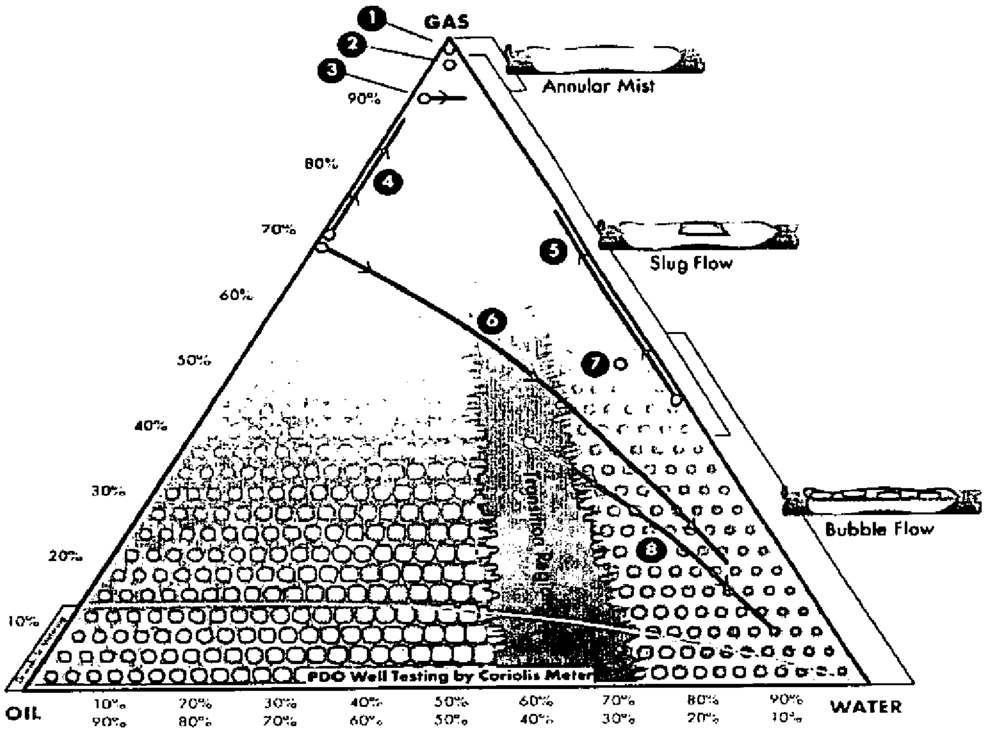

FIG. 3 MULTIPHASE COMPOSITION TRIANGLE

The vertices of the triangle represent single-phase gas, oil and water, while the sides represent two phase mixtures and any point within the triangle represents a unique three-phase mixture. The transition region indicates where the liquid fraction changes from water-in-oil to oil-in-water. The ranges of common multiphase flow regimes, which are affected by temperature, pressure, viscosity and flowline orientation, are indicated at the side of the triangle.

Most of the work over the last two decades has concentrated on developing two-phase meters i.e. oil/gas. New advances in measuring three-phase flow allow us to operate over a larger fraction of the triangle.

A former colleague, Rob Smeenk, proposed this approach in the early 1980's. At that time the triangle was quite bare. We could only measure single-phase flow of oil, water and gas; we could also measure part of the way along the oil-water line. A real indicator of the progress that has been made since then is the detail that has been added to the triangle.

It is easy to use the triangle to show why multiphase metering is complex. If we have difficulty with the single phases, which are so obviously different from each other, we can expect measurement to be at least as difficult for any multiphase composition in the triangle. We have to add to that the complexity from the flow regimes. Flow regime maps have been determined by subjective observation in laboratory testloops, almost always for two-phase mixtures, say oil-gas or water-gas. These maps vary for temperature, pressure, viscosity, pipe orientation. There have been only a few attempts to make three phase flow regime maps, and these are very complex.

This means that it is not practical to predict the performance of multiphase meters from first principles and that detailed empirical testing will be needed. Obviously, the higher the performance demanded from the meter, the better the test facilities need to be. In time, when enough applications have been examined we should be able to see generalities, but for the next few years at least each application will need to be treated on its own merits.

4 APPLICATIONS

I have shown applications that lie in different regions of the triangle. Discussion of these in turn shows how we can build on experience from one application to tackle a more difficult one, and why it is wise not to try to install a multiphase meter in too difficult an application.

Application 1 in Fig. 3 is topsides wet gas metering, using venturi meters, with about 1% by volume of liquid at operating conditions. The corrections to gas flow because of the liquid are derived from a test separator. This is a high quality measurement: the accuracy claimed is about 1.5%.

Application 2 is a gas condensate field with about 2% by volume of liquid, so it is similar to Application 1. To be economically viable, it will probably be developed as a subsea installation. This precludes the use of a test separator. Initially metering is required for well testing for reservoir management, but later in field life may need to be used for third party allocation. Subsea tracer injection to determine the liquid/gas ratio is a possibility, or using the fact that pressure recovery of a venturi meter is related to the liquid/gas ratio. Pattern recognition techniques are also likely to be suitable. In any case, special studies will be required for the initial application, and even more for third party allocation.

Application 3 is another gas condensate field, with about 10% by volume of liquid. Again, to be economically viable, this field will probably have to be developed subsea. It is obviously more difficult to use wet gas metering, but limited studies to date indicate this is probably feasible. Again, the initial application will be reservoir management, but there may be need to meter for third party allocation later in field life.

These three applications illustrate the progression of wet gas metering from dry gas to about 10% liquid, or 90% Gas Volume Fraction (GVF). Compact separators are also practical in high GVF applications, albeit not in Shell Expro's circumstances. Moreover, the phase fraction and velocity measurement approach, which was originally targeted at 50-60% GVF, has been extended to GVFs of over 90% in special circumstances, so that I think it is now best to treat wet gas metering simply as an important subset of multiphase metering.

Application 4 is a very long subsea tieback, with a multiphase meter required for well testing and reservoir management. The well will be natural drive throughout its life, so the reservoir engineers expect hardly any water. This will most likely be Shell Expro's first subsea multiphase meter, and from the multiphase triangle it is easy to see why this is an ideal first application. We only have to measure two phase flow, and have the capability of detecting water breakthrough should it happen. We could do that ten years ago, so from the measurement point of view we can be confident that we can make that measurement subsea. The stiffer challenge is in getting the operational aspects of the installation right to minimise the need for expensive maintenance.

Application 5 is unusual in that it is to measure the water/gas mixture produced in the depressurising of a reservoir. The accuracy required for this two-phase measurement is about 10%, but equipment must be low cost. Again, we know that this measurement can be done by a variety of equipment. As with all multiphase metering, it is not a trivial matter to get it right.

Applications 6 and 8 are subsea tiebacks to a floating production installation where there is a multiphase meter for well testing instead of a test separator. The trajectories followed by these wells across the multiphase triangle show how the small reservoirs being developed in the North Sea today decline rapidly to water.

Application 7 is on an old field, where there is no test separator and well testing had to be done by deferring about £800,000 worth of production each year. If one can reduce this deferment, it is evident that this will help in delaying abandonment. The measurement had to be low cost, and a pattern recognition approach is being evaluated.

I have also included two other fairly general areas of application. In Oman, there are many low-pressure wells with no gas at wellhead conditions, and so are two phase oil-water mixtures. These are tested using Coriolis meters, with the density measurement used to determine the oil and water flowrates.

Well engineers are considering downhole multiphase metering, especially for multilateral wells where there is a need for a meter in each branch of the well. To me, the main advantage in metering downhole is to suppress the gas fraction and reduce the measurement to an oil/water measurement. I would expect the GVF to be low for this area of application, and the meters need to be designed accordingly.

In Shell Expro, apart from the high accuracy wet gas meters, we have found it very difficult to make direct comparisons of the several multiphase meters we have installed with other metering, usually test or production separators. Without exception, however, the multiphase meters have shown up deficiencies in traditional separator measurements. From evaluations carried out in test labs and offshore, I think it is fair to say that several multiphase meters perform as well as traditional test separators.

5 THE MARKET

With this review of multiphase meter applications I think it is clear that there can be no single multiphase meter that can satisfy all requirements. This is good news for multiphase meter manufacturers and developers. Through much of the last two decades, manufacturers and oil companies have chosen a particular approach and have concentrated on that to the exclusion of other approaches, hoping that their approach would be "the winner".

Table 1 WELLS WORLD WIDE (source KOP)

LOCATION	NUMBER	AVERAGE PRODUCTION BBL/DAY
USA	572,000	11
Venezuela	15,000	191
Argentina	13,000	57
Canada	47,000	29
Western Europe	6,420	990
Rest of World	251,000	188

The best way to use multiphase meters is to have one per well. Table 1 shows the number of wells in different regions of the world. There are about one million. Many of these have very low production rates by North Sea standards, but I suggest that a modest target would be for the oil industry to install multiphase meters on 1% of the wells by 2010. That means 10,000 meters, or about 900 a year between now and 2010. I think most of these wells are on land, and that the meters would be used for well testing. Thus with a relatively modest improvement in performance multiphase meters can be deployed widely. At an average cost per meter of £100,000 that is a market of £l Billion. I think there is room for a few winners in that market.

For the North Sea the picture is different. There are about 1000 wells in the North Sea, and I suggest that a reasonable target is about 100 multiphase meters by 2010. Most of these would be subsea for well testing or third party allocation, and will therefore cost more, say an average of £200,000, giving a market of only some £20 Million, less than £2 Million a year between now and 2010.

6 THE FUTURE OF MULTIPHASE METERING

We in the countries around the North Sea like to think we are leading the development of multiphase meters. We have set challenging targets for multiphase meter performance, but it is evident that the North Sea market for multiphase meters is not big enough for manufacturers on their own to develop, say, multiphase meters for third party allocation. For Shell Expro, if the performance of multiphase meters stops at "well testing" standard, we will not require many multiphase meters topsides or subsea, but neither will we get the benefits from using them. Clearly for the North Sea operators there is a major challenge to improve the performance of multiphase meters significantly over, say, a five-year period.

There is little appreciation of the time it takes to develop and test multiphase meters. Last year I made what was intended to be an upbeat presentation to colleagues working on new developments, and told them that we could reasonably expect to develop multiphase meters for third party allocation by 2005. Their response was that they already needed that quality of performance for projects they were working on and that they could not wait for that length of time.

From the testing we have done on multiphase meters offshore, and what I have seen done by other companies, I believe that it is impractical to verify the performance of multiphase meters offshore to high standards except in very exceptional circumstances. Valves on test separators or on production manifolds frequently pass sufficiently to make detailed verifications impossible. It is often difficult to maintain stable operation of separators to allow detailed comparison. To put it simply, if we have the facilities to carry out such verification, we probably don't need to install a multiphase meter.

The consequences of this are that most of the testing to show that a multiphase meter has a high performance will have to be done at special test facilities that can simulate realistic operational conditions. There are one or two facilities that may be suitable, but they are unlikely to be able to cover the likely range of flow conditions. It is unlikely that tests done on current laboratory test loops will be sufficiently convincing.

7 CONCLUSIONS

Multiphase metering is at the stage of development where oil companies can deploy them to bring large benefits:

Multiphase meters are now being applied successfully by a number of companies. Apart from the obvious financial benefits, they allow operators and reservoir engineers to monitor oil and gas production in ways not possible before, thus aiding production optimisation. In the long term, this will probably be the biggest benefit from the use of multiphase metering.

Existing multiphase meters or indeed any multiphase meter likely to be developed can be fitted into one or a combination of the four approaches currently used in multiphase metering. These approaches offer different levels of technical complexity and require different levels of understanding. Operating companies can therefore choose a multiphase metering system suited to their specific needs.

Enough development and testing has now been done to show that high performance multiphase meters for third party allocation and for near fiscal measurement are practical, and that their realisation need not be too far off. In this respect the pattern recognition approach, on its own or in combination with the hardware from the other approaches is most relevant.

The potential market world wide for multiphase metering systems is very large. No single type of meter or metering approach can hope to cover all applications. Although we can expect that some manufacturers will withdraw, others may enter the market. There is clearly room for several suppliers.

However:

Multiphase metering systems are most certainly not "fit and forget" equipment in their present state of development. They should only be deployed where there are clear financial benefits and where there is real commitment to making them work.

Widespread implementation of multiphase metering cannot take place until expertise is spread more widely throughout the oil industry. Most of the expertise in multiphase metering is held by specialists in oil companies, by developers and by manufacturers. Metering consultants and facility design houses are slowly beginning to build their expertise.

Multiphase metering is a complex subject. It is important to develop ways to explain the complexities in a readily understandable way. The Multiphase Triangle approach appears to be a useful tool.

The market situation in the North Sea is different to the rest of the world. The technical requirements for most likely applications are really beyond the capabilities of the products that manufacturers can reasonably supply at present. The North Sea market for multiphase meters on its own is unlikely to bring sufficient return on investment for manufacturers to develop the higher performance meters required in the North Sea.

If North Sea operating companies wish to gain the very large benefits of multiphase metering, they will have to provide the financial backing to support the development of higher performance meters.

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PAPER 14 - 4.2

USE OF A SUBSEA MULTIPHASE FLOW METER IN THE.WEST BRAE/SEDGWICK JOINT DEVELOPMENT.

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16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

USE OF A SUBSEA MULTIPHASE FLOW METER IN THE WEST BRAE/SEDGWICK JOINT DEVELOPMENT

Mr A Kennedy, Marathon Oil U.K Ltd
Mr I Simm, Marathon Oil U.K Ltd

1. INTRODUCTION

The West Brae/Sedgwick joint development in the Brae area of the Central North Sea came onstream in October 1997 and is currently producing in excess of 35,000 barrels per day. The joint field development comprises a single Sedgwick production well tied back to the West Brae subsea manifold, where commingled flow is piped to the Marathon operated Brae 'A' platform. There, Sedgwick and West Brae fluids are processed for onward transportation through the Brae and Forties pipeline systems. Under the terms of the Joint Development Agreement, production is allocated 67.5 per cent to the Brae Group and 32.5 per cent to the Sedgwick Group

This paper outlines the development of the project and discusses in detail the performance of the Framo subsea multiphase meter both in terms of its long term repeatability and in terms of its accuracy when compared with the host platforms measurement systems.

2. THE WEST BRAE/SEDGWICK FIELDS AND INFRASTRUCTURE

The West Brae/Sedgwick fields are just two of 20 fields that use the Brae area infrastructure. This is based on three platforms interconnected by gas and oil pipelines and an electricity ring main system to provide processing and export routes for oil to the Forties system and gas to the SAGE system.

2.1. West Brae/Sedgwick fields

The West Brae/Sedgwick fields are located 160 miles North-Northeast of Aberdeen in 350 feet of water and are comprised of two hydrocarbon bearing sands, the Balder and the under lying Flugga. Sedgwick is located in a block adjacent to West Brae and was initially thought to contain a separate accumulation from West Brae. However subsequent drilling has shown that continuity exists at least in the Balder horizon.

Both the Balder and the Flugga are turbidite deposits composed of well sorted, fine grained sands with permeability's in the productive areas in excess of 2000 millidarcies. The Balder is a saturated system with an extensive gas cap overlying the West Brae portion of the field. Water is being injected into the Balder.

The field is drained using horizontal wells with a horizontal section of up to 3000'. The reservoir sand is not competent and sand control is achieved by the use of a sand screen.

Fluid properties are:

- Oil density 890 kg/m^3 (27.5 API)
- gas-oil-ratios (GOR) 250 scf/stb
- In situ oil viscosity's are 3 to 5 centipoise.

At the seabed where the multiphase meter is situated additional fluid parameters are:

- Gas Volume Fraction (GVF) 0.4 to 0.6
- Water Fraction (BSW) 0 rising through field life to in excess of 90%

Recoverable reserves are estimated to be 40 mmstb.

2.2. West Brae/Sedgwick Infrastructure

Fig 1 West Brae\Sedgwick Infrastructure

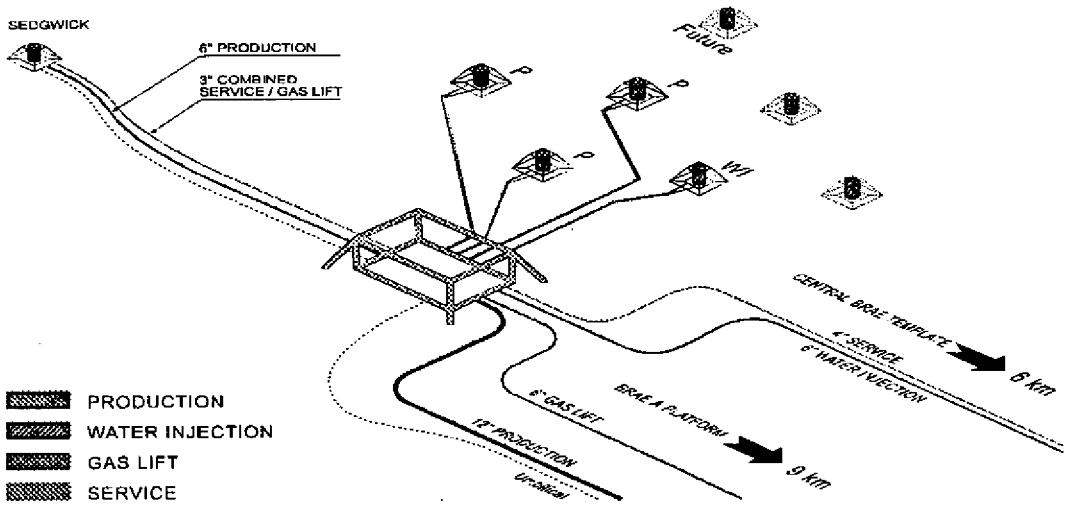


Figure 1 shows the West Brae/Sedgwick Infrastructure, a small part of the Brae area infrastructure. The West Brae/Sedgwick fields are developed using a subsea manifold and well cluster arrangement. The field is essentially ROV friendly but the well tie-ins and any future choke changes require diver intervention. The subsea multiphase flow meter was chosen late in the design of the West Brae/Sedgwick manifold and although the device is of the ROV retrievable type, electrical connections and plating on the manifold would necessitate diver intervention.

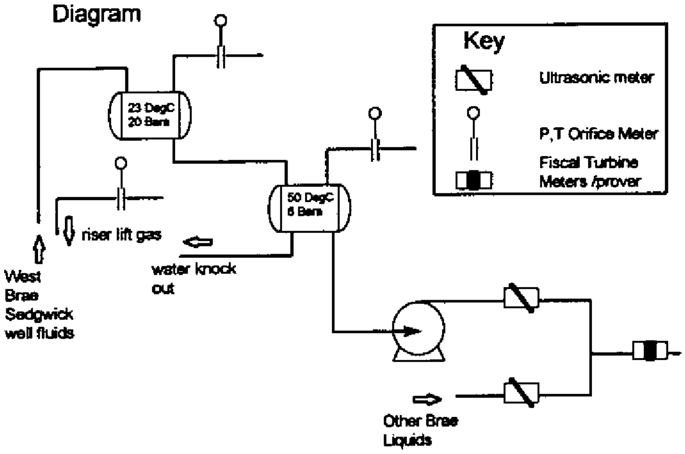
The fields are tied back to host platform (Brae Alpha) which is 8.8 km from the West Brae Manifold. The Sedgwick extension is approximately 2.2 km from the manifold. Gas lift is supplied from Brae Alpha. Water injection and service line facilities are supported from another subsea field (Central Brae) which is approximately 6.2 km from the West Brae/Sedgwick manifold.

3. HOST PLATFORM MEASUREMENT SYSTEMS

Although the Brae A host platform handles numerous fluids from Brae and third party fields, the West Brae/Sedgwick fields have a dedicated process train with full instrumentation. These facilities are described in the following paragraphs.

3.1. Host Platform: Separation and Instrumentation

Fig 2. West Brae/Sedgwick - Simplified Platform Flow Diagram



The West Brae/Sedgwick process train on the Brae A platform (Figure 2) has a two stage separation, with an intermediate electrostatic water separator and oil heater (not shown) to break emulsions anticipated from the fields. The first stage separator is sized to act as a slug catcher.

Gas metering off the separators consists of orifice metering with P,T,Z corrections. These corrections, in addition to ISO 5167 equations, are performed on a continuous basis by the platforms process monitoring computer. ISO 5167 straight length requirements are not fully met.

Riser base lift gas, the only lift gas system commissioned, is used to minimise slugging and improve start up. It is measured in an identical manner to the separator off gas.

Oil metering is performed by an ultrasonic metering tube at the outlet of the booster pump. The tube contains a Danfoss dual path ultrasonic meter and pressure and temperature transducers. A dedicated fiscal standard flow computer continuously computes flow at standard conditions. An identical installation is to be found on the process train handling South and Central Brae production before the two flows are combined and metered by a fiscal export metering package with 4 inch turbine meters and dedicated prover. Typical uncertainty for this later type of fiscal metering is +/-0.25%. Entrained water in the oil is determined by spot samples at the booster pumps and by flow proportional sampling at the fiscal metering.

Water metering from the separators will be by ultrasonic meters to be commissioned when flows become sufficient to measure.

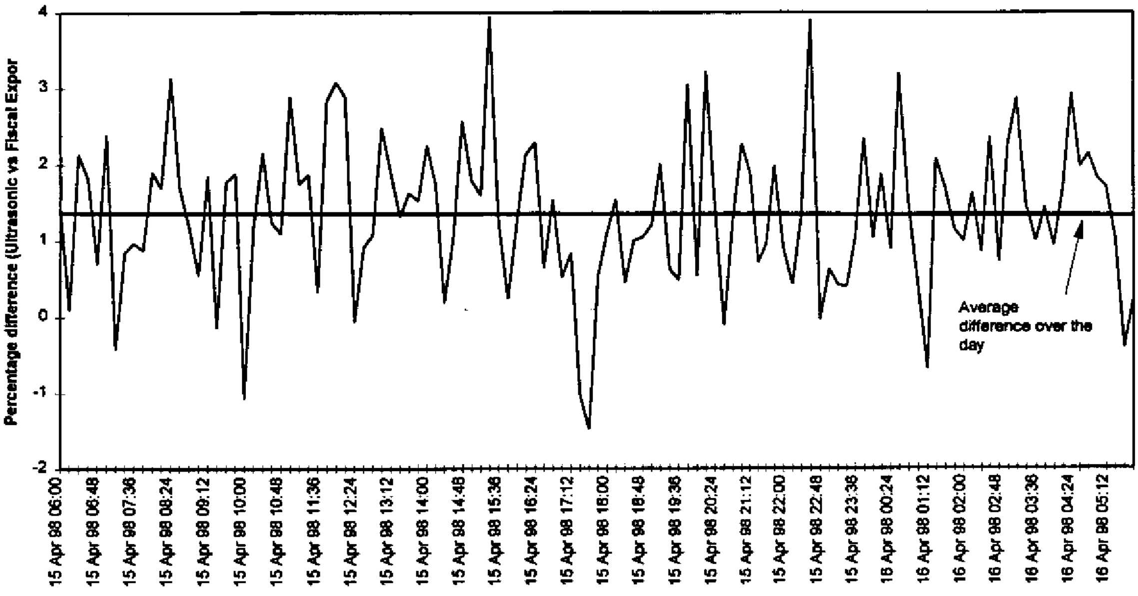
Data produced by the platform instrumentation is gathered by the platforms process monitoring computer. Instruments are scanned at 30 sec to 1 minute intervals. All data presented in this paper are based on 12 minute averages of these readings.

3.2. Host Platform: Performance of Instrumentation

No detailed assessment of the process instrumentation uncertainty is presented. However the oil metering, due to its close proximity to a dedicated fiscal metering package, can be assumed to have an accuracy of +/- 1%. The gas metering on the other hand is assessed as having only a +/-10% accuracy. The following graphs (taken on a typical day) and discussion are made in support of these claimed accuracy's.

Figure 3 below shows the percentage difference between the liquid quantities measured by the sum of the two ultrasonic meters and the fiscal export meters.

Fig 3 Comparison of Ultrasonic Oil Meter with Fiscal Export



The variations in the twelve minute average data points are largely caused by the surging within the process trains and associated pipework. The average difference over the day of 1.3% is typical of the daily balance that has remained within the range 1.1% to 1.5% since start-up.. The Danfoss meters were calibrated on water during factory acceptance tests and are still using their original calibrations with no adjustments. Furthermore, during periods when one of the process trains has been shut in, the balance has remained stable indicating that both ultrasonic meters have the same bias. When, later in this report, a comparison is made between the Framo multiphase meter and the platform ultrasonic liquid meters, account is taken of this bias by reducing the ultrasonic meter reading by the bias relevant for the period of the comparison.

Fig 4 Comparison of Gas Rates During Periods of Varying Lift Gas

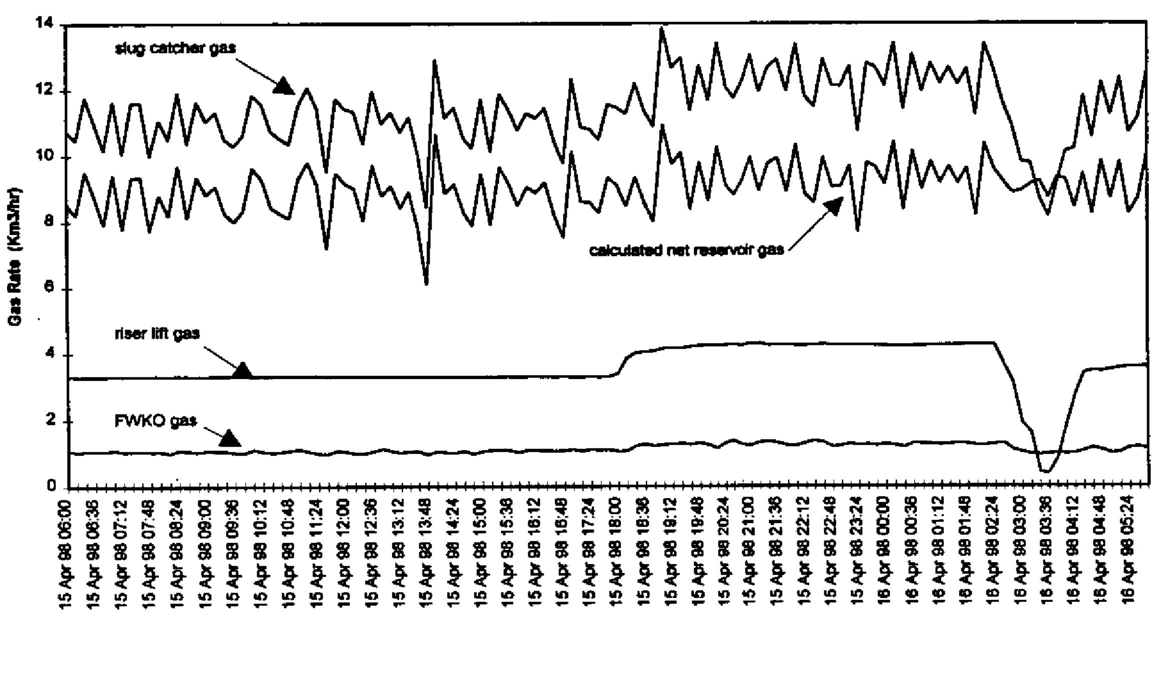


Figure 4 shows the platform measured gas rates over the same twenty four hour period as Figure 3.

The period was chosen to show the effect of riser lift gas on calculated net gas production from West Brae/Sedgwick as riser lift gas rates varied. The calculated net reservoir gas is the sum of the two separator off gas measurements minus the riser lift gas measurement. It can be seen from the graph that the effect of changes in lift gas rate on the calculated net gas are effectively compensated for, allowing the calculated net reservoir gas to be compared with the gas metered by the multiphase meter.

4. FRAMO SUBSEA MULTIPHASE METER

The Framo subsea multiphase meter has been working continuously and reliably since first installed in October 1997. The fluid parameters used in the meter were entered before start-up and were based on exploration data. This data has proved to reasonably reflect that seen during actual production. The Framo meter is capable of using individual data sets for wells with different fluid properties but recorded fluid data to date has shown no variations on a well basis that has necessitated the use of this facility.

Initially the meter was grossly over responsive to the presence of water. This was traced to an erroneous value of the water mass attenuation coefficient, μ_w, set into the meter's software and was corrected some 25 days after commissioning.

The meter's instrumentation was calibrated at the factory prior to delivery and, apart from the correction of the erroneous water mass attenuation coefficient, no onstream adjustments or "calibrations" have been performed.

4.1. Principle of Operation

The Framo meter relies on three principal equations:

- The equation of flow through a differential pressure device

$$Q_{total} = C\sqrt{\frac{\Delta p}{\rho_{mix}}} \tag{1}$$

- The equation relating the dependence of gamma ray attenuation upon fluid mass attenuation coefficients. For a three phase fluid this equation is:

$$N = N_o e^{-x[(\mu_o \rho_o OVF)+(\mu_w \rho_w WVF)+(\mu_g \rho_g GVF)]} \tag{2}$$

- The equation ensuring that the three volume fractions sum to 1, i.e.

$$OVF+WVF+GVF = 1 \tag{3}$$

The Framo meter uses a dual energy gamma radiation source and therefore two forms of Equation (2) are established and, in conjunction with Equation (3), are solved simultaneously to give oil, gas and water fractions OVF,GVF and WVF.

Having established volume fractions a mixture density is calculated for use in Equation (1) to determine the volume flow at metering conditions.

Constants used in the above equations are based on the configuration of the instrument (physical dimensions), and the characterisation of the three fluid components in terms of density and mass attenuation coefficient. For water this latter coefficient is predominantly a function of salinity.

4.2. Conversion of Measured Fluid Rates to Platform Conditions

The fluid rates for the three phases measured by the multiphase meter are at metering conditions. For a true comparison with platform measurements three corrections have to be made, viz.

- A correction to allow for the fact that at platform separator conditions some of the liquid will be evolved as gas (liquid shrinkage) ;
- A correction to convert fluids metered subsea to standard conditions of pressure and temperature (1 bara and 15°C) as used by the host platform metering systems, and;
- A correction to allow for the fact that wells manifolded to the subsea meter experience an increased back pressure and resultant drop in flow rate when compared with when they are manifolded directly to the flow-line.

A liquid shrinkage factor was obtained by using the process simulation software HYSIM™. The simulation was fed by a well stream analysis based on extensive fluid sampling and analysis. Fluid components analysed included N2, CO2, C1, C2, C3, iC4, nC4, iC5, nC5. The hexane plus was characterised in weight percents by a 16 cut distillation analysis with cut properties of density and molecular weight determined. A liquid shrinkage factor of 0.96 by volume and a corresponding gas factor of 1.36 were obtained from the simulation. These factors have been used to correct the rates measured by the multiphase meter and allow a direct comparison with the host platform flow measurements.

Normally the West Brae/Sedgwick wells are routed on an approximately weekly basis through the Subsea meter while the remaining wells continue to flow straight from the well to the 12 inch flow-line and on to the host platform for that week. Wells are never started while manifolded to the multiphase meter to avoid possible hydrate damage. When a well is routed to the subsea meter test manifold the back pressure on the well increases causing the flowing bottom hole pressure, as measured by down hole gauges, to rise by 0.1 to 2.2 psi depending on the well and flow rate. From a knowledge of the productivity indices of the wells a good estimate of the reduction in flow rate seen by the meter when compared with the host platform measurement has been calculated and corrected for in the comparison recorded below. The reduction in flow rate when a well is routed through the subsea test manifold is estimated to be 3% on average.

5. COMPARISON OF SUBSEA METER WITH HOST PLATFORM MEASUREMENTS

It would have been ideal to have a dedicated test flow-line from the subsea flow meter to a dedicated test separator on the platform to create a comparison. However, this would have defeated the cost saving intent of installing the subsea meter in the first place. West Brae/Sedgwick wells have been quite stable and therefore the comparison made in this section, between the host platform measurements and the sum of the subsea meter's individual well measurements, is a useful comparison in the absence of the ideal situation.

In order to try and form a comparison between the subsea multiphase meter and the host platform measurements the platform staff were instructed to put each of the four West Brae/Sedgwick wells through the subsea meter over a twenty four hour when the platform process was stable. Except for this instruction the day may be considered to be selected at random and the readings from the platform instrumentation and the subsea meter as typical of the type of data received.

5.1. Comparison of Oil Rates

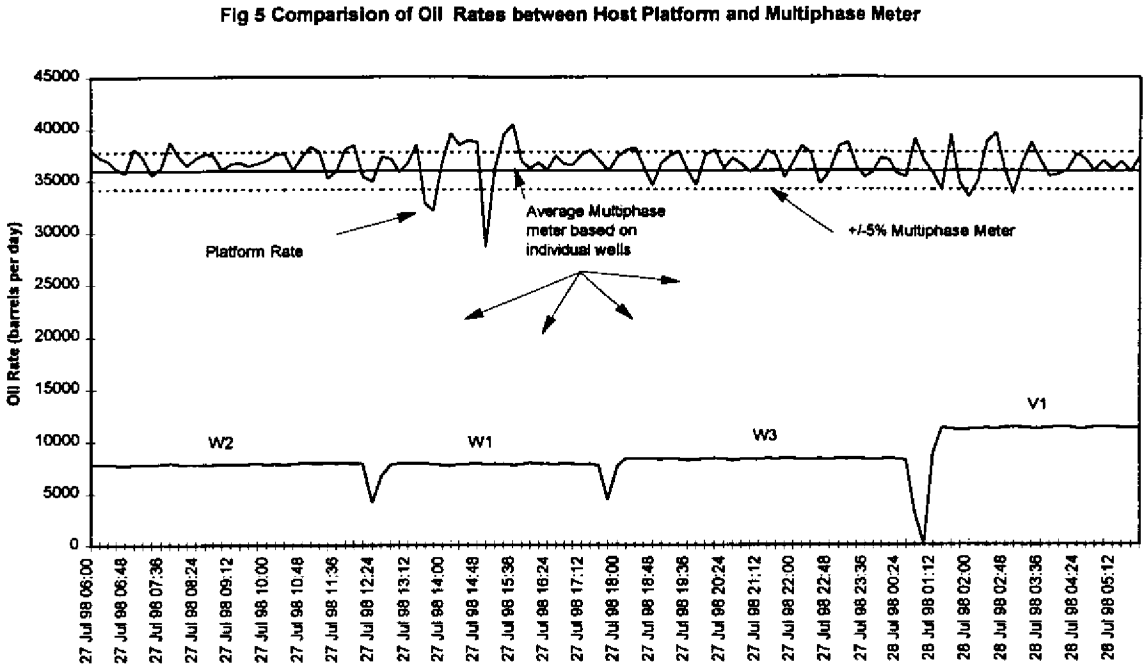


Figure 5 shows the oil flow rates of the individual wells being sequentially put through the multiphase meter for approximately 6 hour periods. Each well can be seen to be steady in rate. The sum of each well average rate while in the multiphase meter is represented by the straight line with +/- 5% dotted deviation limits. The varying platform oil rate over the period is shown. The daily average of the platform oil rate can be judged to be well within 5.0% of the daily average of the multiphase meter.

In the graph the average rate for the sum of the wells through the multiphase meter has been corrected for the effects noted in Section 4.2, while the platform rate has been corrected for the bias in the ultrasonic meter referred to in Section 3.2 and also for an average water cut measured during the day.

5.2. Comparison of Gas Rates

Fig 6 Comparison of Gas Oil Ratios (GOR) between Host Platform and Multiphase Meter

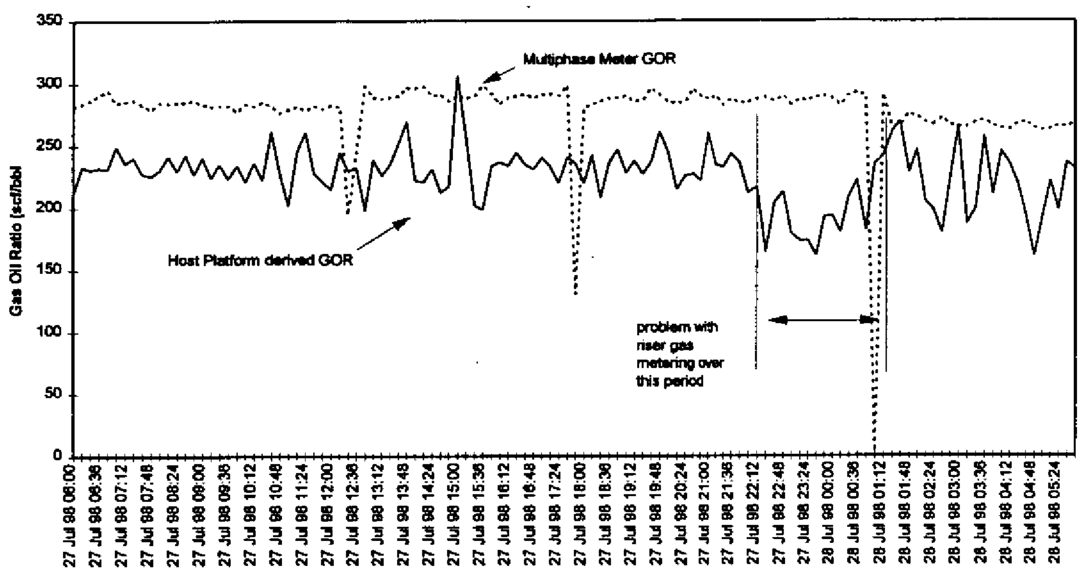


Figure 6 shows the individual well Gas Oil Ratio's (GOR's) as each well is cycled through the multiphase meter over the twenty four hour period. Also shown is the host platforms measured GOR. During an approximately 4 hour period near the end of the day the riser lift gas meter became erratic and therefore the host platform data is suspect over this period.

This apparently large difference in GOR as measured by the multiphase meter when compared with the host platform has not significantly detracted from the usefulness of the meter as a reservoir tool as its long term repeatability, as discussed in Section 6, appears remarkably good.

5.3. Comparison of Water Rates

Fig 7 Comparison of Water Contents (BSW) between Host Platform and Multiphase Meter

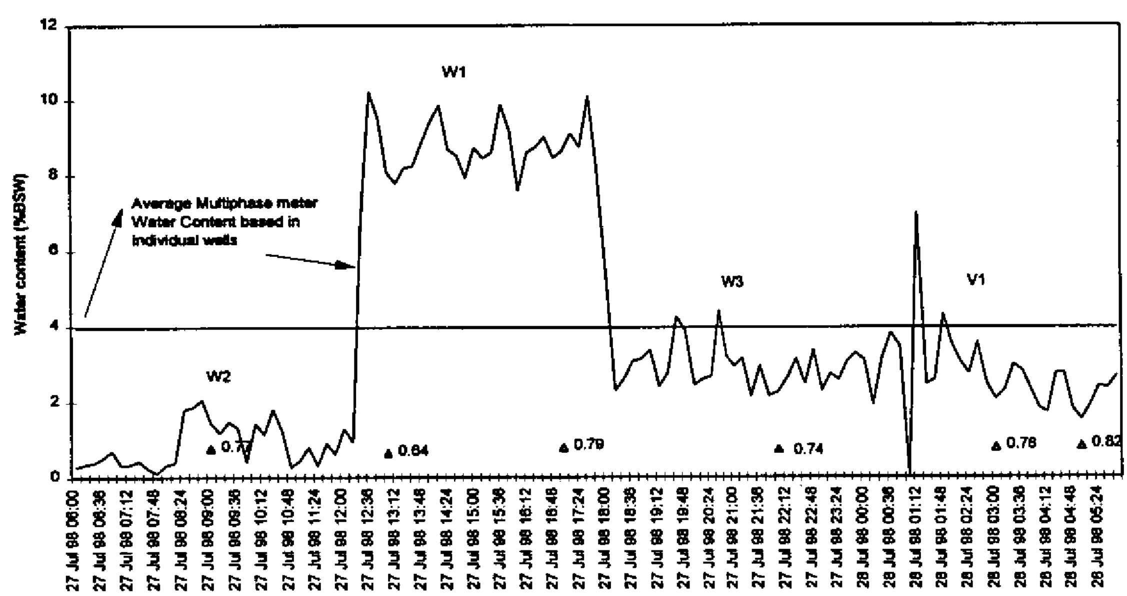


Figure 7 shows a comparison of the average water content determined by the multiphase meter with that of the host platform aggregate determined by spot sampling and analysis through out the day. After the conclusion of the test, and despite trying to ensure that all water legs from the separators were closed during the test, it was discovered that the coalescer water leg was slightly open. Therefore flow line samples at the inlet of the slug catcher were immediately taken and showed a water content of 1.3%. Flow line samples are notoriously difficult to take and therefore may only be considered as indicative. The multiphase meter measured a flow weighted average of 4% for the wells over the 24 hour period.

5.4. Summary of Comparison

The comparison in section five may be summarised by the Table below

	OIL bpd % Difference	GAS mscfd % Difference	WATER CUT measured Difference
RAW DATA	36603	8197	4%
	-0.3%	-6.6%	2.7%
Shrinkage corrected	35146	11177	negligible effect
	-4.3%	27.4%	
Back Pressure corrected	35977	11442	negligible effect
	-2.1%	30.4%	
P&T Corrected	included in Shrinkage Correction	included in Shrinkage Correction	included in RAW DATA

Figure 8 - Summary of Comparison between Multiphase Meter and Host Platform

The data further down the table incorporates previous corrections above in the Table. The percentage differences in the table represent: (multiphase meter - host platform meter) / (host platform meter)*100 and indicate positive when the meter over reads in comparison with the host platform systems.

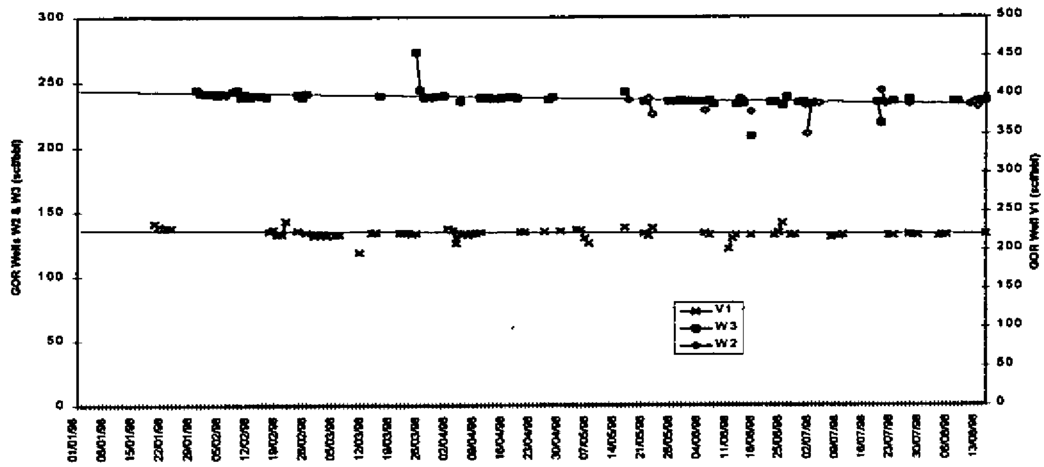
The meter is well within the manufacturers claimed accuracy on both oil and water measurements. The differences found between the multiphase meter and the host platforms gas measurements are unexplained despite extensive efforts to do so. The manufacturer's opinion is that the physical principles on which the meter relies precludes error combinations of this nature and magnitude. The only other information relevant to this comparison is the early drillstem samples whose analysis showed a GOR closer to that recorded by the multiphase meter.

6. SUBSEA METER LONG TERM STABILITY AND REPEATIBILITY

The stability and repeatability of the meter has allowed small changes in well fluid rates to be detected. This is best illustrated by the following graphs and discussion of GOR's over a period from January to August this year.

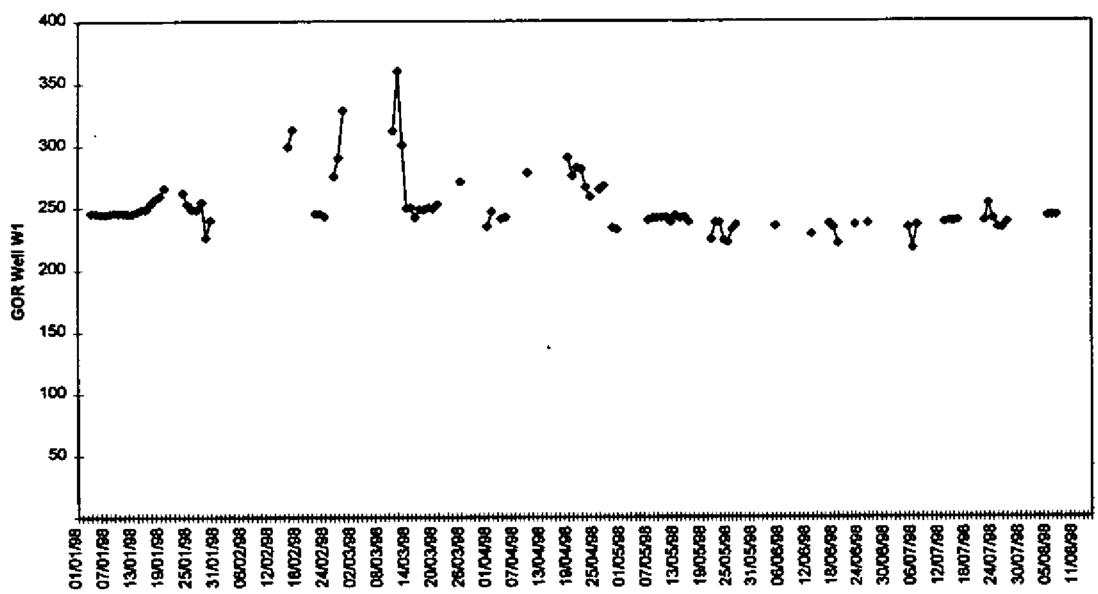
Wells W3 and W2 are located in an area of the reservoir that has a common gas cap and are expected to have a common GOR, as opposed to V1 that is located in an area believed to have a different gas cap and therefore a different GOR. Figure 9 below shows GOR's measured by the multiphase meter have indeed the GOR's expected.

Fig 9 - Well GOR Trends



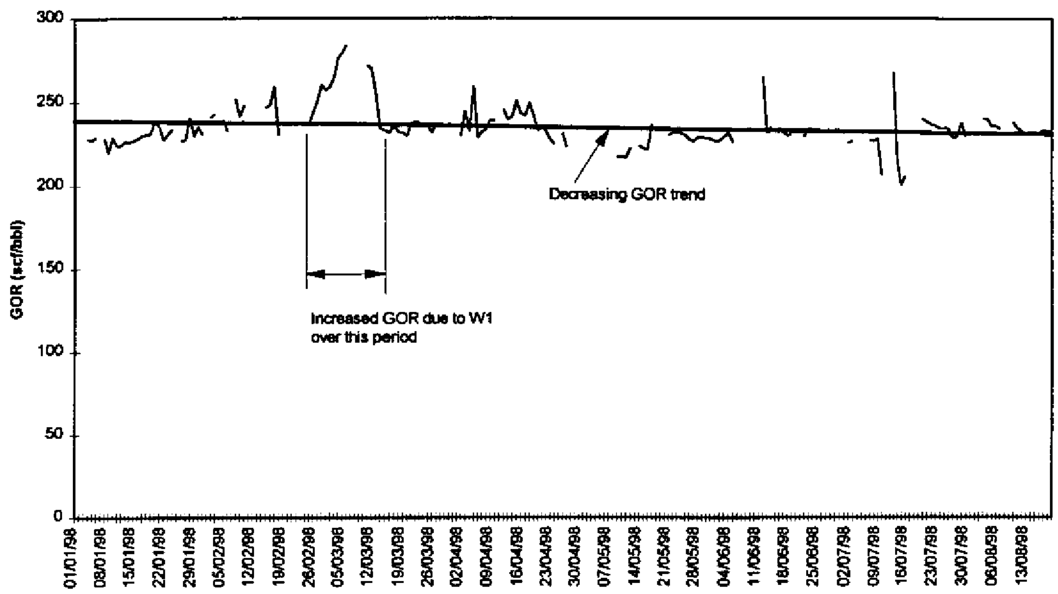
Well W1 was noted to have a rising GOR in February this year and the well was choked back. The resulting response of the well in terms of GOR is shown in Figure 10.

Fig 10 - Well W1 GOR Trend



Overall the wells indicate a slowly declining GOR with time which is being reflected in platform measurements (Figure 11). Also to be seen in the platform measurements is well W1's increased contribution to platform GOR in the February/March period.

Fig 11 - Host Platform Measured GOR Trend



Similar data has been recorded for water content where small changes in water content over time have been recorded by the subsea multiphase meter and subsequently confirmed by platform measurements.

7. CONCLUSIONS

With this meter two overriding benefits are being obtained in reservoir management.

- the ability to relate changing fluid receipts on the host platform to individual well changes.
- the ability to detect changing individual well behaviour at an early stage while it is otherwise indiscernible from general variations on the host platform.

To obtain these benefits "repeatability" and "reliability" are crucial parameters and to date the Framo meter seems to have excelled in these areas.

Manufacturers claimed accuracy for oil and water measurement are supported in the range measured. At this time, and despite extensive efforts, the cause of the difference in gas measurements is unresolved. The difference is beyond that that can be explained by even the combined uncertainties of the multiphase and host platforms instruments (Section 5.4 refers).

The decision to install a sub-sea multiphase meter instead of a dedicated test flow line has been justified. As a result of changing well GOR's and water cuts measured by the multiphase meter, reservoir decisions have been taken early to optimise production.

8. ACKNOWLEGEMENTS

The authors wish to acknowledge the support of Marathon's partners in the West Brae/Sedgwick development and in particular their support in using what at the time was considered innovative technology.

Marathons co-venturers in the West Brae/Sedgwick development are:

BG Exploration and Production Limited; BP Exploration Operating Company Limited; Burlington Resources (U.K.) Inc.; British-Borneo Oil & Gas Limited; Kerr-McGee Oil (U.K.) PLC; Lundin Oil & Gas Limited; Talisman Energy (UK) Limited; Summit Oil UK Limited.

North Sea
FLOW
Measurement Workshop
1998

PAPER 15 - 4.3

OPERATIONAL EXPERIENCE OF A MULTIPHASE METER ON HYDRO'S BRAGE PLATFORM

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OPERATIONAL EXPERIENCE OF A MULTIPHASE METER ON NORSK HYDRO'S BRAGE PLATFORM

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1 SUMMARY

A multiphase flowmeter (MPFM) has been installed at Norsk Hydro's Brage platform, for allocation metering of a well in the Sognefjord formation. Due to limited, and uncertain, hydrocarbon production potential, an inlet separator with conventional metering could not be justified for economical reasons. Amongst several options available for a metering system, one multiphase meter upstream of the test and production manifolds was selected. The multiphase meter is verified/calibrated periodically against the test separator. The test separator measurements had to be upgraded, in order to provide useful references.

The multiphase meter has been in operation since 31.10.97, with some periods of well shut-down. In this period the meter has failed twice: once for software reasons, the other for hardware reasons. Otherwice, the meter has operated normally.

Approximately 95 calibrations against the test separator have been carried out. The adjustment factors obtained show more scatter, and more deviation away from the ideal factor 1, than what is considered comfortable. In particular this applies to the adjustment factors for oil. However, oil production is lower than predicted, while water production is significantly higher. It is quite possible that meter performance is within what can be expected.

Upgrade of test separator meters has improved the quality of measurement significantly, even if the gas meter is not yet up to 100% performance.

2 INTRODUCTION AND BACKGROUND

In 1997 a well from the Sognefjord formation was tied in to the Brage platform in the Norwegian sector of the North Sea.

The Sognefjord formation is close to the Brage field, and wells can be drilled from the Brage platform. The ownership of Sognefjord is different from Brage Unit. The production of hydrocarbons from Sognefjord must be allocated to the owners. Hence, there is need for allocation metering. The NPD regulations for fiscal metering are applicable to allocation metering.

For the following reasons it was rather obvious that "full fiscal metering" could not be justified economically:

- The hydrocarbon reserves are limited - and uncertain. The first Sognefjord well was completed for test production and formation evaluation.
- The ownership of Sognefjord is very similar to Brage Unit. There are minor differences in the respective shares, in Brage Unit and in Sognefjord.

A simplified metering system was proposed for Sognefjord, and accepted by the Norwegian Petroleum Directorate (NPD).

3 METERING CONCEPT

3.1 Options for allocation metering

Several options are available for allocation metering:
- Inlet separator, and metering of separated phases oil, gas and water,
- Well stream metering by multiphase meter,
- Upstream choke pressure (UCP)/Choke differential pressure measurement,
- Model/calculation, eg. IDUN,
- Well testing.

The frames, within which to work, are given by:
- The NPD regulations for fiscal measurement of oil and gas,
- Cost/benefit of metering

3.2 Cost/benefit analysis

Simplified allocation may be used if there is an apparent disproportion between the cost of a metering installation and the benefit which will be achieved from it (NPD regulation § 23, § 9, with Guidelines). If simplified metering is proposed, the Operator must submit a cost/benefit analysis for justification.

In case of Sognefjord, a cost/benefit analysis was carried out, with the following input:
- Oil and gas production predicted profiles,
- Oil and gas prices,
- CapEx risk factor of 0.25, ie. we are willing to spend 0.25 NOK in order to potentially save 1 NOK,
- Ownership (share) of Brage Unit and Sognefjord,
- Uncertainty in quantity determination is reduced by 15 % by introduction of a multiphase flowmeter on the well stream.

On this basis, the value - after allocation - of a possible measurement error is calculated. For Sognefjord, this value was found to be approx. 4.5 MNOK.

3.3 Well stream flow metering

The conclusion was that this first Sognefjord well A-37 was to be equipped with a multiphase meter for allocation metering. The multiphase meter would be verified periodically against the Brage test separator.

3.4 Test separator measurements

Existing test separator measurements were:
- Oil: Single line, orifice meter, 3 exchangeable plates, γ-density meter, pressure and temperature from separator vessel,
- Gas: Single line, orifice meter, 3 exchangeable plates, 7812 density meter, temperature, pressure from separator vessel,
- Water: Single line, electromagnetic meter

It was found necessary to upgrade test separator flow measurement, including secondary instrumentation and signal handling, in order to provide useful reference measurements for the A-37 multiphase flowmeter.

4 EQUIPMENT AND FUNCTIONALITY

4.1 Multiphase flowmeter

After evaluation a multiphase meter from Multi-Fluid was selected for this application.
Based on predicted production profiles, a DN100 FR meter was selected. Velocity measurement is cross correlation only. No venturi section is included.
The meter is installed downstream of the well valve tree and upstream of the choke valve.

The installation is according to the manufacturer's instructions, in a vertical line, between horizontal inlet and outlet DN200 piping. Fluid flow is vertically upward. The meter installation is shown in Figure 1. A more comprehensive description of the multiphase meter is given in Section 8: Appendix 1: Multiphase flowmeter description

Wellstream phase densities of oil, gas and water phases are calculated from initial simulated PVT data, using gradients around an assumed/nominal operating point. For variations in temperature and pressure around this operating point, coefficients are used to calculate phase densities.

<u>On-line</u> PVT calculations are not implemented in this system.
A PVT package could be used for several purposes:

- Calculation of phase densities at multiphase meter operating conditions,
- Calculation of mass transfer from liquid phase to gas phase when the well fluid pressure is decreased across the choke valve (ref. Section 4.3),
- Calculation of phase densities at Standard conditions (and further calculation of Standard volumes.)

4.2 Reference flow measurements/Test separator instrumentation

The test separator measurements were significantly upgraded, to the following standard:

- <u>Oil</u>
  Two-beam ultrasonic meter, density meter 7835 Advanced (Hart, digital mode) in pumped loop, temperature and pressure (Hart, digital mode), full profile water-cut meter.
  The oil from the test separator is close to its bubble point. The liquid head from the gas/oil interface in the separator to ultrasonic meter level is 1.5 - 2 meters. Some of the pressure difference is lost due to fluid flow fictional losses. The static pressure is further reduced by an amount $\frac{1}{2}\rho v^2$. A DN100 meter has a flow range which is more optimal, considering expected oil flowrates. However, linear velocity in the meter would be too high and potentially reduce the static pressure below the bubble point. A DN150 meter was selected,

- <u>Gas</u>
  Three-beam DN200 ultrasonic meter, density meter 7812 in a separate heated box, temperature and pressure (Hart, digital mode),

- <u>Water</u>
  Existing DN100 electromagnetic meter in continued use (after repair), piping modified to safeguard meter always running full,

- <u>Signal handling</u>
  A single flowcomputer handles all measurements: flowmeters for oil, gas and water, as well as all secondary measurements of densities, water-in-oil, temperatures and pressures. The flowcomputer is communicating with the process control system (DISCOS) to provide flow data and batch (well test) functions.

While this upgrade was initiated by the allocation metering for well A-37, it is also useful for testing of all other wells in Brage Unit, providing more accurate well test data. The advantage of not having to change orifice plates, is recognized by the Platform Operations.

4.3 Calibration of multiphase flowmeter against references (test separator)

"Calibration" of the multiphase meter against the test separator is an integral part of the metering system for well A-37. Periodically the well is routed through the test separator. Flow for each phase oil, gas and water, as measured by the multiphase meter, is compared with test separator measurement. "Adjustment factors" for oil, gas and water phase flow are calculated and may be implemented.

Manual recording of data and manual calculation of adjustment factors was considered not practical. A semi-automatic function is implemented, using the platform process control system DISCOS. Flow measurements from the multiphase meter electronic unit and from the test separator flowcomputer are transmitted to DISCOS on serial communication. A comparison of multiphase meter and test separator measured flowrates is carried out by DISCOS. Once the comparison/calibration process is started by the control room operator, it will continue to run until it is terminated by the operator. New adjustment factors are calculated by DISCOS and presented to the operator, who can elect to accept the new factors or not. Any combination of 0 (!), 1, 2 or 3 (oil, gas, water) may be accepted. It is possible to apply manually entered adjustment factors.

It should be noted that phase flowrates, measured by the multiphase meter and the test separator, are compared on <u>mass basis</u>. Some of the fluid, which is measured as liquid oil at the multiphase meter, will evaporate when the pressure is reduced across the choke valve. Hence the test separator will measure a lower oil mass flowrate and a higher gas flowrate, compared to multiphase meter readings. This mass transfer from the liquid oil phase to the gas phase is calculated and accounted for in the automatic comparison. The calculation is rather simplistic: $\Delta_{mass} = B_1 + B_2\Delta_{pressure}$. Coefficients B_1 and B_2 are based on initial process simulation.

5 EXPERIENCE

In this Section we shall discuss some of the experience from commissioning and operation of the multiphase meter. Since the upgraded test separator measurements are important for the evaluation, experience with the test separator measurements will be discussed briefly.

5.1 Multiphase flowmeter

A multiphase meter may be evaluated in two aspects:

- Function: Whether or not the meter works, most of the time or all of the time,
- Accuracy: How accurate are the measurements ?

5.1.1 Commissioning

The multiphase meter was commissioned in October 1997. The gamma density meter was calibrated in air, and the meter was configured with the process fluid densities. The measurements from the multiphase meter were checked against the test separator. With the present instrumentation of the test separator, the measurements of the multiphase meter was within its specification. Initially the water-cut of the well was approx. 30%. However, within a few weeks the water-cut was increasing to 50%, and the well liquid phase was changing from oil continuous to water continuous, together with an increase in the total production from the well.

5.1.2 Function

Well A-37 was started up 31.10.97, at 2200 - 2300 hrs.
The multiphase meter started up normally.
(The test separator measurements for oil and water failed completely for the first few hours, when well A-37 was started. Most likely, oil and water formed a stable emulsion, which did not separate in the test separator. Neither the ultrasonic oil meter nor the electromagnetic water

meter would work with this emulsion. Oil and water separated only after emulsion breaker was added.)

Well A-37 has been closed in periods:
1. Operational reasons: 02.-08.11.97, 15.-18.11.97, 08.-10.12.97, 14.12.97-01.01.98
2. Problems with "neighbor" well: 17.02. - 04.03.98
3. Problems with the MPFM (amp. board): 05.05. - 17.05.98
4. Piping & MPFM inspected for scaling: 16.05. - 17.05.98
5. Operational reasons: 13.06. - 27.07.98

During period Item 2 above, drilling mud from a different well came with the well stream for A-37. It took some time before the problem was solved. It is reported that the multiphase meter for well A-37 re-started measuring without the need for any action, like cleaning, maintenance etc.

Increased scaling may result from high water production. During period Item 4 above, the pipework was inspected for scaling. While significant scaling was observed downstream of the choke, it is reported that the multiphase meter was clean, with no deposits whatsoever.

During period Item 5 well A-37 was closed due to its high water production. Water treatment capacity at Brage was limited, until new hydrocyclones were put in operation.

The multiphase meter has been operative since start-up, except for two periods:

- 08.11. - 11.11.98
  Shortly after (2^{nd}) start-up in November the meter started to show occasional drop-outs. 10.11.98 the meter failed completely, when a regular well test of A-37 was to be carried out. Vendor assistance was called. Even if the cross-correlation was 90%+, meter reading was zero. It transpired that the software was unable to handle the high flowrate through the meter at the time: probably 30 - 35 m/s. A software modification was downloaded (11.11.98), and the meter readings came back immediately. The meter was previously never tested to such high flowrates during qualification tests.

- 28.04.98 and 02.05.-17.05.98
  In April '98 the multiphase meter failed occasionally, and then completely 02.05.98. The meter again started working 18.05.98, but a faulty electronic card was identified during an Vendor service visit 20.-21.05.98. The card was replaced, and a new software version was installed. The meter has been working normally since.

Two examples of readings from "a working meter" is shown in Figure 2 and Figure 3: when well A-37 is shut in and later re-started.

5.1.3 Accuracy

Accuracy is evaluated by considering the adjustment factors that have been obtained since meter start-up. Initially many calibrations were carried out to gain experience with the meter. Approximately 95 calibrations have been carried out since meter start-up late October '97.

It has been considered a problem that adjustment factors have been less stable than we would like to see. In particular this is true for the oil phase measurement, ref. Figure 5. The reason(s) for this scatter of data is not really established, but the following points could be noted:

- The well stream was oil continuous only for a few days. The meter has been working in the water continuous regime almost since start-up,
- Oil phase volume fraction was initially $\approx$ 20 - 25%. Current oil volume fraction is 5 - 7%,
- It is important that well produces with stable flow, pressure and temperature, during the calibration operation,
- A faulty electronic board was replaced 20.05.98. Even if the fault was classified as "not critical", it is possible that meter performance - and adjustment factors - were affected.
- Reference measurements (ie. test separator measurements) must be fully operative and accurate to within, say, $\pm$ 2%.

A verification of the multiphase meter and the test separator measurements were carried out 24. - 26.08.98, looking at :

- Multiphase meter functionality and setup,
- Multiphase meter calibration,
- Test separator measurements,
- DISCOS and OPIS functions.

Well A-37 was routed via the test separator 23. - 25.08.98. For well A-37 bottom hole pressure is available, and the control room technicians are able to evaluate well flow stability, from this pressure. Data were recorded directly from the test separator flowcomputer and from the multiphase meter Graphical User Interface (GUI), independent of any DISCOS or OPIS functions. Several calibrations were carried out 24. - 25.08.98, ref. Table 1 below.

Table 1 - Multiphase meter calibrations 24. - 25.08.98

Cal No	Date & time	Base operating conditions & densities				Adjustment factors		
		Press. barg	Temp. °C	Density kg/m^3				
				Oil	Gas	Oil	Gas	Water
1	24.08.98 05:53-06.54	46.078	79.090	762.094	35.627	1.05444	1.03662	0.92761
2	24.08.98 15:34-18:12	- " -	- " -	- " -	- " -	0.946777	1.013672	0.988953
3	24.08.98 21:09-22:57	- " -	- " -	- " -	- " -	0.972046	1.015808	0.982849
4	24.08.98 08:40-14:25	- " -	- " -	- " -	- " -	0.969971	1.010071	0.975464
5	25.08.98 15:04-17:33	46.078	79.090	762.094	35.627	0.913147	1.013123	1.003235
6	25.08.98. 17:54-20:18	*24.500*	*80.699*	*793.781*	*20.699*	1.131226	0.943176	1.010132
7	25.08.98 20:32-22:32	46.066	79.090	762.094	35.627	1.10382	0.98914	1.01874

Cal No	Date & time	Actual conditions MPFM		Flowrates, tonnes/h					
		Press. barg	Temp. °C	Multiphase meter			Test separator (MPFM c.)		
				Oil	Gas	Water	Oil	Gas	Water
1	24.08.98 05:53-06.54	26.536	80.910	28.51	9.238	144.4	30.05	9.580	134.0
2	24.08.98 15:34-18:12	26.039	81.019	30.13	7.997	130.6	28.52	8.108	129.1
3	24.08.98 21:09-22:57	26.109	81.041	29.21	8.040	130.9	28.40	8.169	128.6
4	24.08.98 08:40-14:25	26.275	80.992	29.38	8.015	131.3	28.50	8.098	128.1
5	25.08.98 15:04-17:33	27.394	80.952	29.39	7.481	122.6	26.83	7.581	123.0
6	25.08.98. 17:54-20:18	27.291	80.948	23.66	8.016	121.7	26.78	7.562	123.0
7	25.08.98 20:32-22:32	27.377	80.953	24.26	7.653	120.6	26.77	7.570	122.9

We have tried to compare multiphase meter readings with test separator measurements with one-minute time resolution, to see if flow variations at the multiphase meter can be seen at the test separator, ref. Figure 4. It would appear that for such low oil flowrates the test separator tends to have a smoothening effect on small flow variations.

During this verification no malfunction or errors were identified. The multiphase meter is working, and so are the test separator measurements, even if the gas meter is working off one path only.

It is concluded:

1. System operation, as observed 24. - 26.08.98, reflects the performance that can be achieved with the current system, except that work continues to determine if other phase densities should be used,

2. In practical operation, it has been found that the initial requirements for reproducibility and repeatability - as described in Section 5.3 - were somewhat tight. In September '98 the calibration procedure was changed, and the reproducibility/repeatability requirements were somewhat relaxed, ref. Table 5. (It should be noted that "% reproducibility" and "% repeatability" is calculated on actual phase flow for each phase, not on total flow.),
3. We believe that the requirement for ± 5% reproducibility/repeatability is difficult to achieve when the oil volume fraction is down to 5 - 7%.

5.1.4 Sizing of multiphase meter

The prediction of the production flowrates and MPFM operating conditions was not very accurate. The well was producing at a higher total phase flowrate than expected (lower oil phase flowrate, but significantly higher water phase flowrate). After a few weeks, the well was producing outside the recommended operating envelope for the multiphase meter. After the software modification mentioned in Section 5.1.2, the meter is capable of measuring up to 40 m/s.

This point also illustrates one of the advantages of the cross-correlation meter. If the multiphase meter had been designed based on the predicted flow rates using a venturi velocity meter, there would have been a significant pressure drop across the multiphase meter. However, since the cross-correlation velocity meter is non-intrusive and has a turndown in terms of velocity, the multiphase meter was working even though it was operating outside the recommended velocity envelope.

5.2 Reference measurements (test separator)

It should be noted that there are no references against which the test separator measurements can be compared, once the meters are installed. Initially, all meters were flow calibrated by the manufacturers, and we have to assume that these calibrations are maintained, and valid, once the meters are installed and put in operation.

The experience can summarized as follows:

- Oil flow
  The meter failed occasionally on well A-37 and some other wells: ultrasonic beam failure. This was eventually attributed to solid particles in the liquid, not gas bubbles. The meter is now working better, but there are still some occasional errors, even at less than 5% water-in-oil. Above 10 – 15% water-in-oil, the meter readings become more unstable, until the meter fails severely above 20% water content.

- Oil density
  Very satisfactory performance. An oil sample was drawn from the test separator and analyzed for density (at density meter operating conditions) by an independent laboratory: Results are shown in Table 2 below.

Table 2 - Verification of test separator oil density meter

Description	12.11.97	Comment
Measurement/read-out Density meter, kg/m^3	803.36	
Lab. analysis, (independent on-shore lab.) kg/m^3	803.3	Recalculated to 1 vol-% water content
Difference %	-0.01	

Recently the density meter has been out of operation. The meter was due for periodic calibration, and the Hart interface card (inside the 7835 electronic unit) was damaged when the Hart circuit was opened/closed while with supply voltage still connected.

- Oil pressure and temperature
  Very satisfactory.

- Water-in-oil
  Very satisfactory. Water content is measured up to meter maximum, which is 20 vol-%. The meter has been working reliably since start-up. In-line calibration has been carried out three times. The results are shown in Table 3 below:

  Table 3 - In-line calibration of water-cut meter

All table values are vol-% water-in-oil	08.11.97	11.11.97	03.02.98
Measurement/read-out Water-Cut meter	2.2	0.77	0.190 - 0.187
Brage Lab. analysis, re-calc. to line conditions	2.3	0.22	0.181
Difference	-0.1	+ 0.55	ca. + 0.1
"Current correction" Water-Cut meter	+ 0.20	-0.34	-0.32

  It should be noted that in-line calibration of a water-cut meter on test separator oil is not easy. The water content has to be stable, which in most cases means low. It cannot be assumed that manual sampling and laboratory analysis gives error-free results. Results for absolute errors, as given in Table 3 above, is considered satisfactory for well testing purposes. It is considered satisfactory also for multiphase meter calibration.

- Gas flow
  When the ultrasonic meter was chosen for test separator gas, it was realized that the gas potentially contains some liquid, and that any such liquid might affect the ultrasonic flowmeter. However, the ultrasonic meter has several advantages over the orifice meter, and Brage decided to install the ultrasonic meter. There are six transducer ports for three beams. One of these ports is located such that liquid may accumulate in the port, while the other five other ports will drain any liquid back to the pipe.
  Most of the time one path is failing due to liquid build-up in one of the transducer ports. Since the failing path is one of the double-reflecting paths, the other double-reflecting path is disabled. Effectively the ultrasonic meter is working as a single beam/single reflection meter. The single-reflecting beam is operating with close to 100% performance all the time.
  It has been observed that when the gas flowrate increases, the "failing beam" comes back, probably because the liquid is sucked out of the port. When the flowrate decreases, the beam will again fail.
  (Note. The manufacturer has now changed the design of meters for this application, such that all ports drain liquid back to the pipe. An upgrade is planned also for Brage.)

- Gas density
  The density meter has been working satisfactory since start-up.
  Direct measurement of gas density, when the gas is close to its hydrocarbon - and water - dewpoint is recognized as difficult. As soon as liquid is condensed or collected in the measurement chamber, the density meter fails completely. Disassembly, cleaning, drying and re-calibration is then required.
  In case of Brage, great care was taken to avoid liquid drop-out in the measurement chamber. The density meter is installed 0.5 m above the process pipe, with maximum sloping sample lines. The density meter is heated and thermally insulated. The temperature is 90°C, approximately.
  A manual spot sample of test separator gas was analyzed for composition, except that water content was not analyzed. Assuming that the gas is saturated with water vapor, the mole-% were recalculated. Gas density at operating conditions were calculated for dry gas as well as wet gas, ref. Table 4 below.

Table 4 - Verification of test separator gas density meter

Description	12.12.97	
	without water vapor	with water vapor
Measurement/read-out Density meter, kg/m^3	8.05	8.05
Laboratory analysis (Brage) kg/m^3	8.035	8.115
Difference %	0.19	-0.80

- <u>Gas temperature and pressure</u>
  Very satisfactory.

- <u>Water flow</u>
  The water meter now seems to be working satisfactory.

- <u>Signal handling</u>
  Flowcomputer handling of flow and secondary measurements provides much improvement in functionality and accuracy over previous handling carried out by DISCOS. Improved measurement provides more accurate well test data, which is of importance mainly for reservoir management.
  For the test separator measurement data are generated by the flowcomputer, while DISCOS provides data transport functions and operator interface. DISCOS functionality is considered adequate for these purposes.

  Production data are transmitted to the Oseberg Production Information System (OPIS), for reporting and filing purposes. OPIS is not always stable, and sometimes reports are not generated correctly. On one occasion the OPIS computer stopped completely for a couple of days. When OPIS is down, no reports are written to file, and quantities are "lost".

  The multiphase meter electronics act as a flow transmitter. There is no handling or filing of daily totals. For allocation metering purposes supervisory computer functions are required. For applications where the hydrocarbon production is large, production data should be gathered in metering-type supervisory computers.

5.3 Control room functions

The multiphase meter is verified - or calibrated - on a (quasi-) periodic basis. The calibration is initiated - and accepted - by the control room technicians. A "Work description", which describes calibration of the multiphase meter, has been prepared.

The multiphase meter is calibrated whenever:

- The choke position is changed,
- Well A-37 is again opened after shutdown,
- Operating conditions are changed by more than 20% (pressure, temperature, flowrates),
- 1 month has elapsed since the last calibration,
- New configuration data are downloaded to the multiphase meter, or the multiphase meter is restarted after shutdown.

Certain conditions must be met, for a calibration to be carried out and new adjustment factors accepted:

Table 5 - Procedure and acceptance criteria for multiphase meter calibration

Description	February 1998	September 1998
Choke position	No change last 12 hrs	Stable
Well stream, and well stream temperature		Stable
Test separator trend curves	Test separator measurements working OK	Test separator measurements working OK
Stabilization time test separator	2 hrs	4 hrs
Calibration duration time	2 hrs	4 hrs
Reproducibility all phases oil, gas and water (Difference from calibration "previous month")	5%	10%
Repeatability all phases oil, gas and water (Difference from calibration "the same day")	5%	10%

If the adjustment factors do not repeat within required tolerance from the calibration "the previous month", a new calibration may be attempted. The second set of adjustment factors must agree with the ones from the first set ("the same day") within required tolerance. Otherwise the Senior Instrument Technician is called to investigate the matter, and a non-conformance report is filed.

It appears that the calibration process is operated comfortably by the control room technicians.

5.4 Physical properties of single phases oil, gas and water

With no on-line PVT calculations, phase densities are calculated for operating conditions in temperature and pressure, using a 2nd order polynomial. Phase densities are needed at the time when well production is started and hence must be calculated from previous well test fluid data. This data may be verified or recalculated once fluid samples are available after start-up. Also mass transfer coefficients have to be calculated from initial well test data and later verified.

The first problem was that actual operating conditions were not very close to what was predicted (ref. Section 5.5). In particular pressure was significantly lower at multiphase meter conditions. The "coefficient method" for calculation of densities away from the nominal operating point is probably not very accurate. It was therefore necessary to recalculate phase density to actual operating conditions. However, when flowrate varies, the fluid pressure in the multiphase meter varies, and measurement uncertainty increases due to the inaccurate correction method.

It proved more difficult than expected to obtain density data after start-up. Oil, gas and water was sampled at the test separator 1.5 months after well start-up. The samples were kept pressurized and sent to an on-shore independent laboratory for a rather comprehensive set of analyses, PVT analysis included. It was several months before complete analysis data - and recalculated phase densities - were available.

It is possible to calculate the effect of using wrong densities (sensitivity analysis). On 25.08.98 base densities were changed, to see the effect on the adjustment factors - in practice. Subsequently, the base densities were changed back to original values: The results are shown in Table 1, in Section 5.1, Calibration nos. 5 - 7. (Selected results are shown below, also.)

Cal No	Date & time	Base operating conditions & densities				Adjustment factors		
		Press. barg	Temp. °C	Density kg/m³				
				Oil	Gas	Oil	Gas	Water
5	25.08.98 15:04-17:33	46.078	79.090	762.094	35.627	0.913147	1.013123	1.003235
6	25.08.98. 17:54-20:18	*24.500*	*80.699*	*793.781*	*20.699*	1.131226	0.943176	1.010132
7	25.08.98 20:32-22:32	46.066	79.090	762.094	35.627	1.10382	0.98914	1.01874

Cal No	Date & time	Actual conditions MPFM		Flowrates, tonnes/h					
		Press. barg	Temp. °C	Multiphase meter			Test separator (MPFM c.)		
				Oil	Gas	Water	Oil	Gas	Water
5	25.08.98 15:04-17:33	27.394	80.952	29.39	7.481	122.6	26.83	7.581	123.0
6	25.08.98. 17:54-20:18	27.291	80.948	23.66	8.016	121.7	26.78	7.562	123.0
7	25.08.98 20:32-22:32	27.377	80.953	24.26	7.653	120.6	26.77	7.570	122.9

As can be seen from the table, operating conditions at the multiphase meter are similar for all Calibration nos. 5 - 7. Flowrates at the test separator are also similar. Even if a rather large change in the adjustment factor for oil is observed between Cal. nos. 5 and 6, a similar change in the opposite direction is <u>not</u> apparent between Cal. nos. 6 and 7, when the base densities from Cal. no. 5 was re-established. We have no explanation, except that the oil volume fraction was rather low: 6 -7%, "magnifying" any sort of real measurement scatter. The gas adjustment factor seem to show more "consistent" behavior. The water adjustment factor is little affected.

If we consider Calibration no. 5, the mass transfer from the hydrocarbon liquid phase to the gas phase - when fluid pressure is reduced across the choke - is calculated as 3.3% of total hydrocarbon mass (4.4% and 13% of hydrocarbon liquid and gas, respectively). Hence, this mass transfer is not small, and model errors will affect apparent performance of the multiphase meter.

5.5 Predictions of production flowrates and MPFM operating conditions

Before start-up, production profiles and wellhead pressure and temperature profiles were predicted from simulation/model calculations.

In the first place, multiphase meter sizing is based on predicted production profiles. Next, multiphase meter operating pressure and temperature - and hence phase densities - are determined. The operating pressure depends on flowrate and well fluid density. With a high water fraction, pressure loss is increased.

Actual production proves to be significantly different from predicted profiles. Water production is much higher, while oil production is rather low. Actual multiphase meter operating pressure is 20 – 30 barg, vs. predicted close to 90 barg.

Current fluid velocity through the DN100 meter is 20 m/s, which is quite high. Pipework upstream and downstream of the meter is DN200.

6 OVERALL EVALUATION

The overall evaluation is that the multiphase meter is working. Two failures have occurred, one software and one hardware. Adjustment factors show more scatter and more deviation from the ideal factor 1. This particular this is true for the oil phase. But the oil volume fraction is low: initially 20% and now down to 5 - 7%. It is quite possible that current performance is as good as can be expected.

Handling of phase densities at multiphase meter conditions was more difficult than expected. Use of on-line PVT calculation could possibly have improved the situation. However, an additional computer would have been required, adding to system complexity and cost.

Predicted production profiles were not very accurate. Inaccurate profile prediction may lead to incorrect meter sizing. It is fairly obvious that well A-37 produces significantly less oil than expected.

The upgrade of test separator measurement is considered a significant improvement, for accuracy as well as for operations. Work continues to make the gas meter work as intended.

The multiphase meter installation, with all associated functions, turned out to be quite expensive. Also upgrade of test separator measurements was expensive, but this effort is useful for all Brage wells.

7 ACKNOWLEDGEMENT

Many persons have spent a considerable effort with this project, during the project planning/engineering, installation, commissioning and operation phases.

Two years ago, very few multiphase meters were installed for allocation metering. Even today the number of applications is very limited. By selecting a multiphase meter for allocation metering of the Sognefjord well A-37, tied in to the Brage platform, it is felt that Brage Operations Group has contributed significantly to increase the experience base within Norsk Hydro. This experience has been utilized in two projects that followed.

The verification 24.-26.08.98, of the metering system for Sognefjord well A-37, was carried out by H. Tunheim and H. Moestue of Norsk Hydro.

8 APPENDIX 1: MULTIPHASE FLOWMETER DESCRIPTION

8.1 Introduction

The MFI Multiphase Meter culminates twelve years of R&D, much of it sponsored by seven international oil companies: Statoil, British Petroleum, Phillips Petroleum, Elf Aquitaine, Total, Saga Petroleum and Shell.

The MFI Multiphase Meter uses a unique, patented microwave technology. However, the fundamental physical principals involved are simple. Multi-Fluid's technological platform is based on the ability to adopt and apply these fundamental principals to the challenging technological task of measuring fractions and flow rates of different components flowing simultaneously in a pipe, without any prior separation of the phases.

8.2 Development of the MFI Meter

1986	In 1986 Statoil makes a technological and market survey with the purpose of developing continuous measurements of oil, water and gas flowing from wells and in pipes.
1987	Statoil and SRI International begins the initial research program at SRI International in Menlo Park, California in 1987. The initial research based on an idea of utilising microwave electronics is promising and Statoil continues to fund further development.
1989	In 1989 Multi-Fluid Inc. is founded in California in anticipation of future commercialisation of the technology. Hitec becomes part owner of Multi-Fluid Inc. later in the year and takes responsibility for the further development of the company. Hitec builds the first test loop in Norway in 1989. The first multiphase meter project started and the product is called MFI Multiphase Meter. Multi-Fluid invites other oil companies to participate in the project. BP, Elf, Phillips, Saga and Total join to fund and support the program.
1991	In 1991 the owners of Multi-Fluid Inc. establish Multi-Fluid International AS.
1992	The MFI WaterCut Meter was commercialised in 1992.
1993	In 1993 Multi-Fluid Inc. begins its commercial activities in the US. The company relocates all activities to Denver, Colorado.
1995	In 1995 Statoil, Norsk Hydro and Saga undertake an extensive qualification test of competing multiphase meters. The MFI Multiphase Meter showed very favourable results.
1996	Hitec becomes the majority owner of the Group. The Multiphase Meter project was completed and the subsea version launched. The MFI Multiphase Meter passed qualification tests in Porsgrunn (Hydro), at Shell Gannet and at Gullfaks B. The MFI SubSea Multiphase Meter qualified for use at Gullfaks Satellites and Åsgard. The Company has its commercial break-through as it wins several new contracts.
1997	Multi-Fluid International AS changes its name to Multi-Fluid ASA. Multi-Fluid ASA purchases Multi-Fluid Inc. and becomes the parent company of the Group. Multi-Fluid ASA is listed at Oslo Stock Exchange. Multi-Fluid Inc is moved to Houston. Multi-Fluid Subsea is established to take care of subsea activities.

8.3 System Description

8.3.1 The Sensor

The sensor is a compact, straight spool piece with no moving parts. A four inch, 1500 lb. sensor with ANSI flanges is less than 700 mm (28 inches) long.

The MFI sensors can accommodate high pressure requirements. They are machined from a solid bolt of steel. Pressure containment is achieved using standard methods. The sensor body is metal pipe and needs no special seals, while the microwave probes use traditional metal and/or O-ring seals.

8.3.2 System Architecture

MFI Multiphase Meters perform all measurements and calculations in the field electronics. Consequently, only final results are transmitted from the field using simple analogue or digital outputs. With this architecture, Multi-Fluid's meters can be used as stand-alone, remotely operated devices without the need for support facilities. This can dramatically reduce the cost of installing and using multiphase meters in remote or unmanned facilities.

8.3.3 Multiphase Composition Meter

Instantaneous oil, water and gas fractions are measured using 1) a patented microwave measurement device for measuring mixture dielectric properties (dielectric constant and conductivity) and 2) a commercial Cs 137 gamma density meter for measuring mixture density. Multi-Fluid's composition meter offers a unique combination of features.

It functions over the full 0 - 100% water cut range. Separate sensors are not required for low and high water cut measurements.

The microwave measurement system has unparalleled sensitivity. The microwave sensor works by measuring a characteristic microwave frequency that is inversely proportional to the square root of the mixture dielectric constant. A change from 100% gas to 100% water can result in a change in the measured microwave frequency of over 100 to 1. This sensitivity is many times greater than is possible with other techniques such as dual energy gamma technology. As a result, the meter can measure the water cut, oil flow rate, and water flow rate of multiphase mixtures with superior accuracy, particularly at high GVF.

The composition meter accurately measures component volume fractions several times per second. Thus, it is possible for it to function with any flow regime in the line, even intermittent plug flow. Another benefit of 'real-time' measurement is that the meter can be used to determine which flow regime is present in the line. Many other multiphase technologies integrate raw data over tens of seconds to get meaningful results, thereby losing useful real-time information.

8.3.4 Cross-correlation Meter

The primary element for measuring multiphase flow velocity is Multi-Fluid's Cross-correlation Meter. This device uses two identical microwave sensors (such as used in the composition sensor) separated by a known distance in the pipe to measure velocity. By statistically comparing measurements from the upstream sensor with those of the downstream sensor using cross-correlation methods, one can determine the mean transit time for the mixture to move between the sensors. The sensor spacing and the measured transit time give velocity. Multi-Fluid has developed a slip flow model to determine respectively the gas and liquid velocities from the measured velocity using, among other inputs, the statistical data from the composition meter to characterise the flow regime. These two velocities are combined with the readings from the composition meter to obtain the actual oil, water and gas flow rates. The Cross-correlation Meter has a number of advantages compared to other multiphase velocity meters (including Venturis) Turn-down ratio of up to 35:1

No moving parts

High sensitivity. It functions with zero water cut and fine bubble flow such as might be present during early production.

No differential pressure taps that can foul or dP transmitters that can drift

Easily used in high pressure systems without sacrificing accuracy

8.3.5 Venturi Meter

An optional element for measuring multiphase flow velocity is a Venturi meter. The suitability of a Venturi is assessed on a case-by-case basis. The beta ratio for the Venturi meter is tailored for each application to maximise the turn-down ratio and thus improve accuracy. It is possible to achieve a turndown ratio of 10 : 1 in mass flow terms.
Combining the Cross-correlation Meter with a Venturi gives some redundancy. The MFI Meter can continue functioning even if the Venturi Meter or the Cross-correlation Meter should fail. Either velocity meter can be used to measure liquid and gas velocities, when used in conjunction with Multi-Fluid's slip flow model. In some applications the Venturi meter is used to obtain condition dependent maintenance. Hence, by adding a venturi in addition to the cross-correlation meter, it is possible to detect a failure in both the gamma density meter, venturi meter and cross-correlation meter.

8.4 Installation Requirement

The sensor must be mounted vertically with flow directed upwards. In order to enhance mixing a blind T is installed upstream of the meter. Meter sizing will be evaluated on a case by case basis to optimise performance.

8.5 Field Configuration

Once the sensor and electronics have been installed and all field wiring is completed, the meter must be configured for specific field conditions. This is done in 15 minutes in a two step process. Step 1 - Measure the 'zero' density calibration point of the density meter. Step 2 - Enter the data necessary to characterise the oil, gas and water respectively using the User Interface Software.
Oil density at mean process pressure and temperature to an accuracy of ± 2%
Two factors describing the change in oil density with temperature and pressure
Gas density at mean process pressure and temperature to an accuracy of ± 10 %
Two factors describing the change in gas density with temperature and pressure
Water density at standard conditions to an accuracy of ± 1 %
Water conductivity to an accuracy of ± 10 % for oil continuous and ± 1 % for water continuous applications.
The oil and gas data can be calculated from a standard process analyser. The water data can be measured from a sample of production water. The only critical calibration data is the water conductivity, and even then only for high water cut applications.
No measurements of pure oil, water and gas are required in the field in order to calibrate MFI's Multiphase Meters.

9 FIGURES

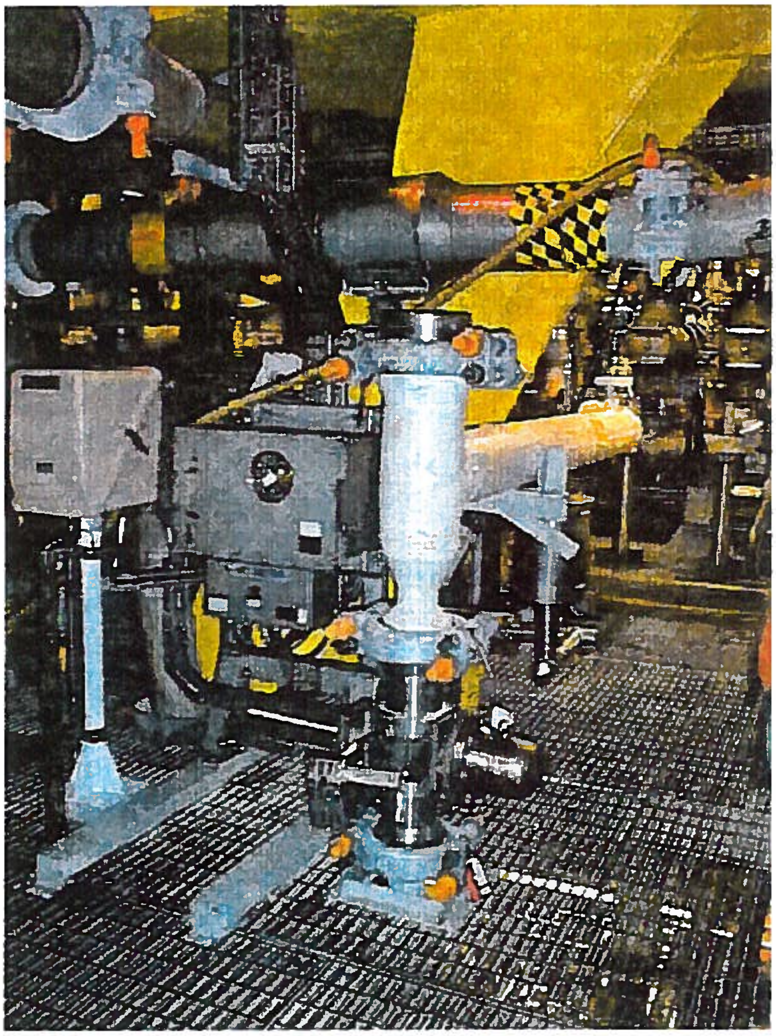


Figure 1 - Multiphase meter installation for Sognefjord/Brage well A-37

Figure 2 - Multiphase meter response at close-in of Brage well A-37

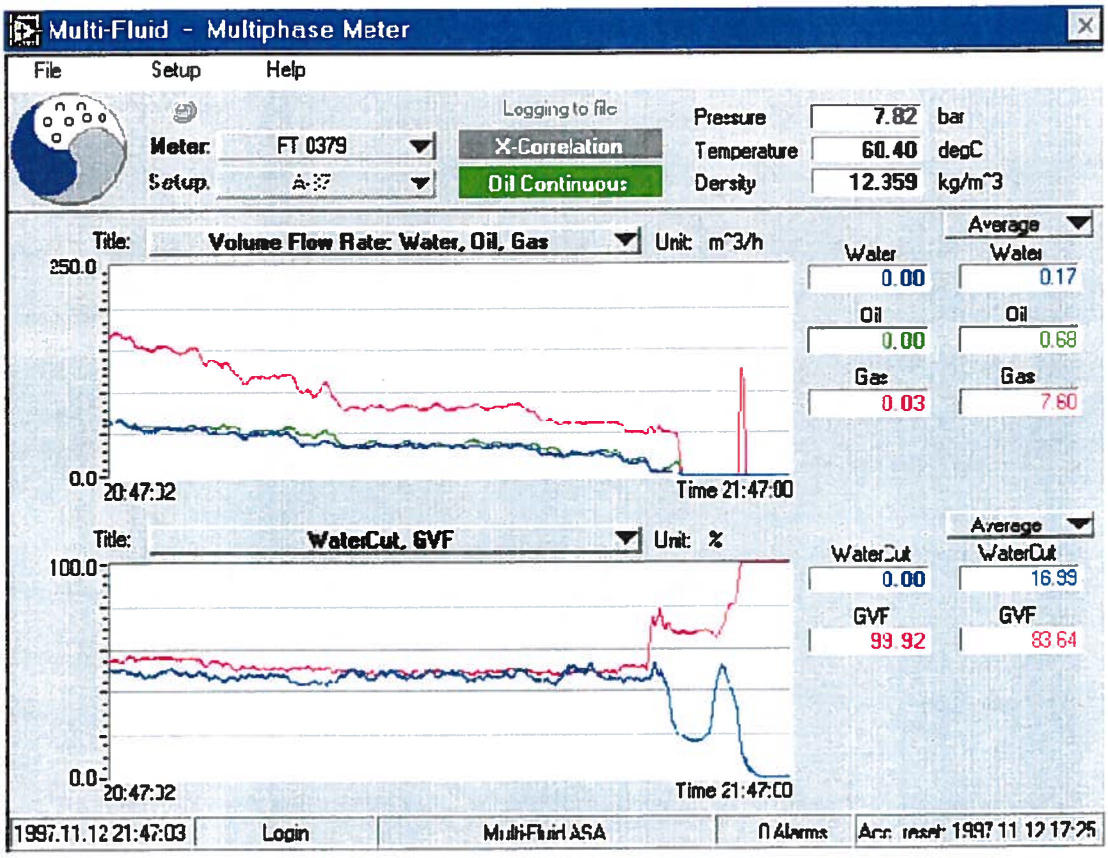


Figure 3 - Multiphase meter response for re-start of Brage well A-37

Figure 4 - Comparison multiphase meter and test separator

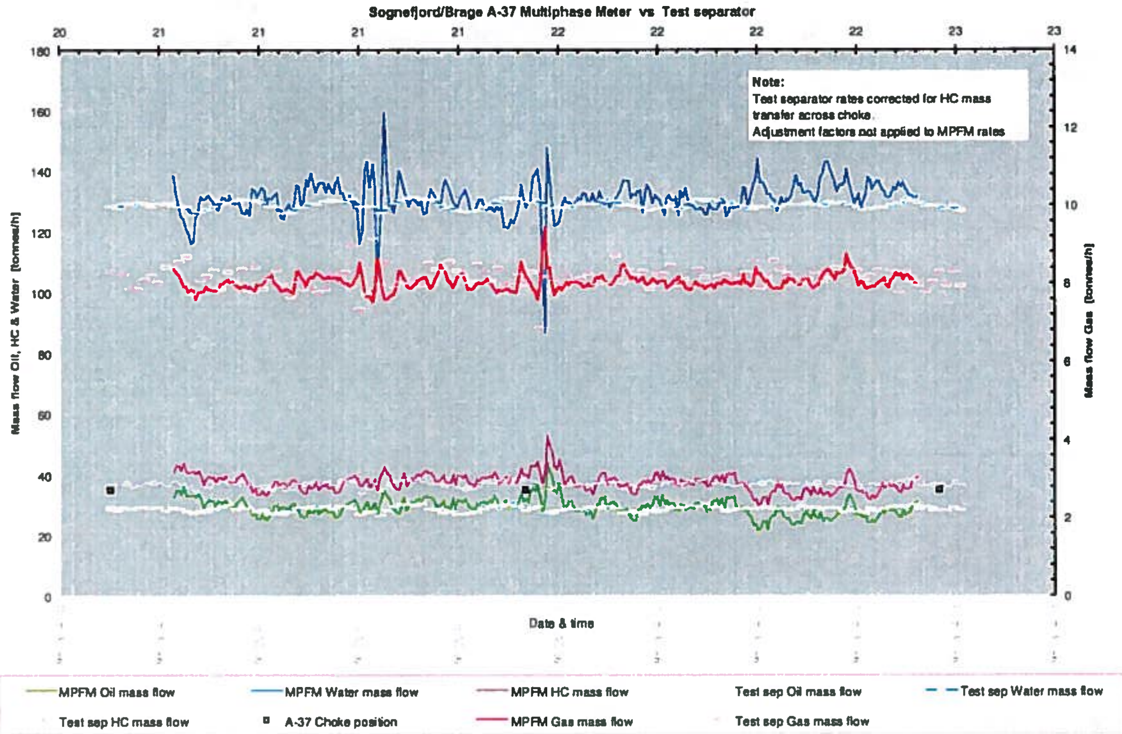
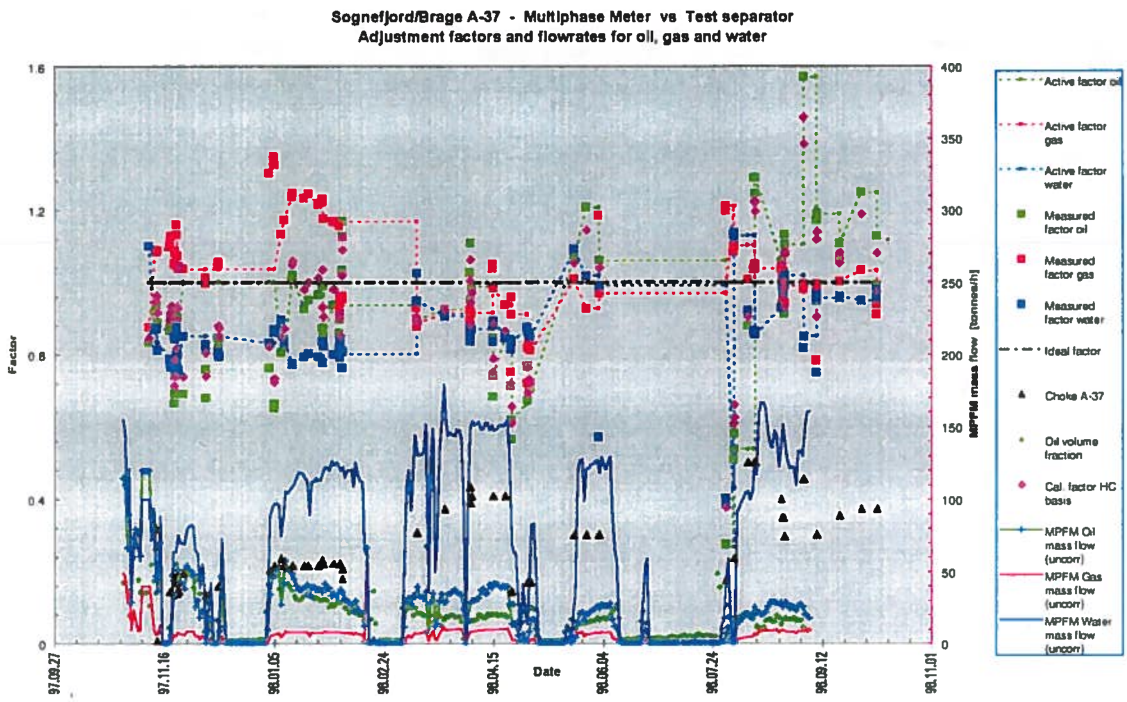


Figure 5 - Adjustment factors for multiphase meter



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BP MULTIPHASE METER APPLICATION EXPERIENCE

W J Priddy, BP Exploration Operating Co. Ltd.

BP MULTIPHASE METER APPLICATION EXPERIENCE

Dr W J Priddy, BP Exploration Operating Company Limited

1 INVOLVEMENT HISTORY

BP, like other oil majors, commenced funding of research activity in the early 1980s aimed at developing multiphase meters. The objective was to provide low cost, compact, in-line metering as an alternative to well test systems using separator vessels and single phase flow meters.

Several research programmes have been funded by BP. Principal among these, (and emerging commercially in the industry today) were the Christian Michelsen Research (CMR)/Fluenta, Framo and MFI JIPs and an in-house development which was licensed to ISA Controls Ltd in 1995.

BP conducted a series of field and flow loop test programmes involving the CMR/Fluenta and in-house technologies. These included substantial evaluations at the Wytch Farm (UK) and Prudhoe Bay (Alaska) oil fields from 1989 to 1993 [1, 2, 3].

In 1994, the emphasis was switched owing to concern about the high cost of these programmes and lack of clarity on foreseeable business benefit. The level of funding on hardware development and test was reduced and effort concentrated more on understanding the benefits the technology could offer to BP's business assets.

As part of this, BP explored dialogue with Shell and Statoil and continues now to share the leadership of a multiphase meter users' forum with these companies which provides a useful vehicle for exchanging experience.

Through these efforts, two applications have so far emerged where multiphase metering offers significant benefits: in the ETAP field - subsea; and on land in the Cusiana oil field and Cupiagua gas condensate field in Colombia. The purpose of this paper is to report the latest status of these applications now that multiphase meters are in the early stages of operation.

Some funding of test and development activity on multiphase metering continues. BP is a participant in the Multiflow JIP run at the UK National Engineering Laboratory (NEL). This is a valuable benchmarking exercise which is one of the ways in which knowledge of technology status is maintained. It can also be one of a number of contributory sources of guidance for selecting multiphase meters for application.

Multiphase meter technology is not "proven", as some in the industry misleadingly claim. For example, the capability to measure water cut continuously, on-line at the wellhead, to acceptable accuracy and cost (1% - 2% absolute; one meter on every well) has still to be demonstrated, particularly for mature oil fields producing gas-prone wells with high water cut. BP continues to support research on this aspect. The current applications are another substantial phase in bringing the industry multiphase production measurement capability forward. This will be developed as a contribution to an acknowledged key role of technology in allowing BP to strive for competitive edge.

2 ETAP (EASTERN TROUGH AREA PROJECT)

The Eastern Trough Area Project (ETAP) integrated development in the North Sea comprises seven separate oil and gas fields (Monan, Mungo, Machar, Marnock, Skua, Heron and Egret), Figure 1. The development consists of a two-platform Central Processing Facility (CPF) located at Marnock and a smaller Normally Unattended Installation (NUI) at Mungo. The other fields have been developed as subsea satellites and flow, via multiphase production lines, back to the CPF which also provides oil and gas export facilities.

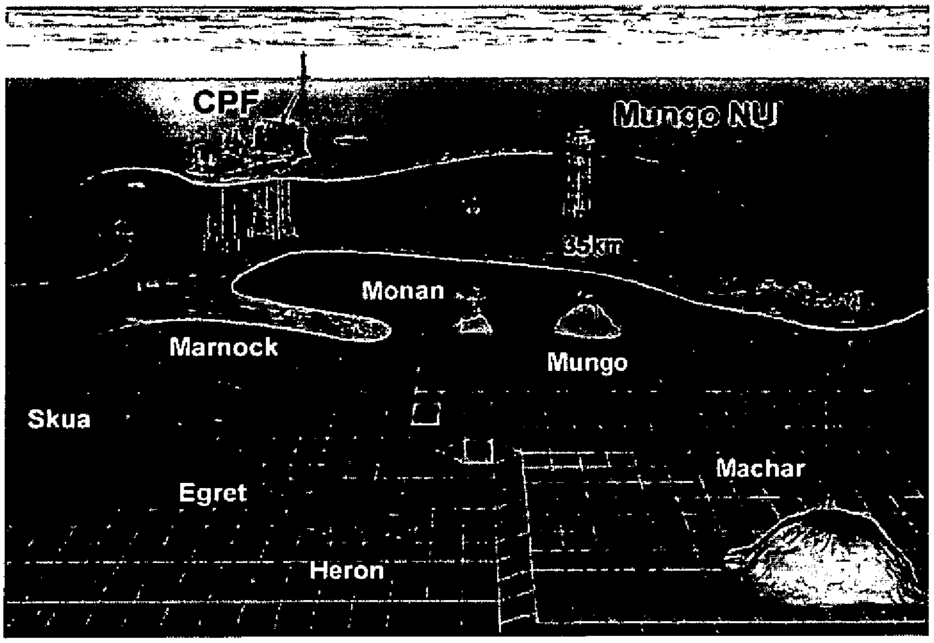

Figure 1 - ETAP Overview - Topside, Sub-Sea and Sub-Surface

The operator for the "M" fields; Marnock, Monan, Mungo, and Machar, is BP. Shell is the operator of the Heron, Egret and Skua fields. BP is the operator for the combined ETAP development. BP's partners are Shell, Esso, Agip, Murphy, Total and Mitsubishi.

Over the last decade or so, a number of feasibility studies have shown that, when considered in isolation, the economic viability of each of the fields was marginal. In 1992, BP Exploration proposed to group together a number of fields into a single development which, when developed together, would deliver a sufficiently robust economic solution. The number of fields has gone through a number of iterations but has finally been refined into what is now known as ETAP.

2.1 Well Production Measurement Needs

There is a requirement to test each of the ETAP wells at a frequency of approximately once per month. The reason behind the well tests and the information required differs between the ETAP fields but in all cases is for reservoir management. These measurements are not required for allocation between the partners.

Multiphase metering was selected for two of the subsea fields, Machar and Monan. The development team studies and processes to establish that these subsea multiphase meters would provide acceptable well testing for these two fields were described in [4]. That paper discussed the criteria used to select the meters.

2.2 Benefits and Service Duty

The Machar and Monan subsea satellite fields are connected to the CPF from a distance of 35 km and 15 km respectively. Conventional test separation metering over these tie-back distances would have been expensive although the CAPEX in each case was not a sole distinctive influence when comparing against the cost of multiphase meters installed subsea.

Considering through-life costs (CAPEX, OPEX and lost production), the case was heavily influenced by the income lost (or deferred) as a result of shutting wells for test by difference. Also, operational difficulties were expected with long test lines. There were concerns about wax and hydrates, compounded by the fact that the test pipelines would have been of smaller diameter than the production pipelines. Control of flow switchovers would be difficult over such distances in view of the multiphase flow dynamics, would have required unacceptable levels of manning, and would also carry some risk of process upsets and deferral of production. Test line metering over these long distances would require excessive purge and stabilisation periods and would alter the wellhead pressure thereby compromising accuracy in terms of representing the flow rates to the production pipeline.

It was concluded that well testing either using a test line or by difference over such distances would not be practical or accurate, especially given the drive towards minimum manning for the operation of the ETAP facilities.

The most cost-effective solution for Machar and Monan uses a single multiphase meter installed in a subsea test manifold with actuated divert valves. This was felt to offer the additional advantage that systematic measurement errors should, to some extent, be compensated in comparing the relative performance of wells.

Multiphase meters were also evaluated as an option for topsides service on the CPF at Marnock and Mungo NUI. For Marnock, they could provide continuous monitoring for two particular "rich" gas condensate wells to allow close control of condensate banking. The most economic (and the original) design case for Mungo was based on topside multiphase metering for reservoir management. For Mungo, the flow measurements are needed to optimise production (on the basis of relative GORs) from eight wells producing with drive from water and gas injection schemes. The control of the injection systems on the basis of the well test measurements is critical.

In both cases, the decision not to install multiphase meters was strongly influenced by lack of confidence that multiphase metering was sufficiently developed for application. Accurate CGR (condensate-gas-ratio) readings are required in the Marnock application (for which a test separator is available).

In view of the relative high value of the Mungo field, and the number of wells and nature of the scheme for recovery, the multiphase meter option posed an unacceptable level of risk. A relatively late decision was made to install a test separator on Mungo, at some additional cost to the project and increase in the level of maintenance presence required on the platform. The decision was also influenced by the requirement to provide a proppant receptacle.

This is in contrast to the Machar and Monan subsea fields which will produce from five and two wells respectively. For the former field, the primary function of the multiphase meter will be to monitor for water break-through during a water injection phase. In the Monan case, the intention is to be able to optimise production from the two wells on the basis of GOR. Monan production ties into the production pipeline from the Mungo field before reaching the CPF. The Monan multiphase meter readings will be judged against the rates of the eight producers in the Mungo field metered by test separator.

In both subsea cases, the project had little alternative to well-site multiphase metering for well testing. This, coupled with an underlying philosophy of the ETAP project to use and advance new technology (of which multiphase metering is just one example being deployed) convinced the project team (BP/Brown and Root) of the argument to proceed. The Machar and Monan subsea multiphase meters are not production critical.

2.3 Selection of the ETAP Subsea Meters

The selection process is described in more detail in [4]. The choice incorporated an analysis of the responses from a number of vendors to a formal questionnaire incorporating a listing of carefully considered criteria.

Framo Engineering A.S. were successful in winning the order for the supply of the two subsea meters in June 1996. This multiphase meter has been described previously on numerous occasions. In brief, it uses a Venturi and dual energy gamma ray flow sensor combination downstream of a novel mixer vessel.

A key factor in making the selection was established experience in designing and supplying subsea engineering hardware. Fluenta were the only other supplier with a subsea sensor package at that time.

It is important to point out that latest flow loop data available to BP from the NEL facility and the high pressure (live hydrocarbon) multiphase flow loop operated by Norsk-Hydro at Porsgrunn from recent JIP test programmes were consulted to the extent made possible by references to them in the vendor answers to the questionnaire. These test data did not present unambiguous evidence in support of the selection process.

The Framo meters are designed for retrieval by ROV and for rapid change-out with a spare sensor cartridge should the need arise. Ideally, remote subsea flow meters should require minimum requirement for calibration adjustment. The subsea engineering team of the ETAP project preferred the Framo mixer technique compared to other systems which attempt to model flow behaviour and rely on in-service factoring.

The selection questionnaire included a key behavioural criterion emphasising the requirement for willingness to work openly with BP ETAP.

2.4 Operating Experience - Start-Up

Test Loop

Prior to delivery, the Machar multiphase meter was subjected to a BP witnessed 3-day test matrix using the Framo three-phase flow test loop at Flatøy, Bergen. Following set up and checking by Framo during the preceding week, this test confirmed the functioning of this particular meter. The extra expense incurred by BP in taking this option and tight project schedule prevented a similar test of the Monan meter.

Comparing against single phase reference flow measurements obtained by calibrated V-cone meters, the measurements by the multiphase meter for bulk liquid and gas rate were mostly within ±10% relative and for water cut within ±7% absolute under conditions of GVF expected in the Machar application, ranging 60% - 80%. The test points covered nominal water cuts of 0%, 50% and 80%. This included some repeats at the end of the period. This level of performance in service, if repeatable, is considered adequate for the management of the Machar reservoir. The loop does not use hydrocarbons under pressure and clearly could not simulate the length or topography of the subsea pipework (multiphase meter 40 to 100 metres from wellheads).

The Monan meter is expected to 'see' GVFs reaching 97% during service. The detail of its mixer internals differ to those of the Machar meter. Both meters use a 65 mm Venturi throat which offered economies of manufacture. Both are designed as nominal 6" units to class 1500 rating.

Onshore

Functional checks were made in the UK at the various stages of integration testing within the subsea manifolds and transport offshore. These included communication links and sensor signals such as the empty pipe gamma photon count readings.

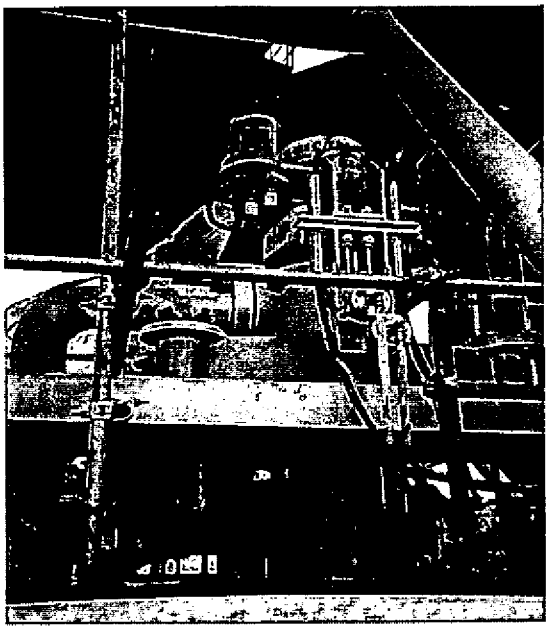

Figure 2 - Multiphase Meter - Monan Manifold

Prior to load-out off-shore, the gamma detector in the Machar meter was found to be suffering degradation with loss of signal. It was necessary to change out the sensor cartridge with the spare insert purchased by BP as a back-up for the Monan and Machar multiphase meters.

The replacement insert is fitted with a gamma detector manufactured by a new supplier to Framo. It emerged, after detailed questioning, that work had been in progress for some time with the previous supplier to improve detector reliability. The difficulties encountered did not become apparent before the Monan meter, with the earlier detector design, was installed on the seabed. This is regrettable.

Partnership and co-operation in order to ensure the earliest opportunity to address technical challenges in the course of commercial applications (and to assist vendors to overcome them) are to be encouraged in the best interests of all parties.

The ETAP subsea multiphase metering schemes were designed with the intention of little need for intervention during field life (sixteen years for Machar and nine years for Monan). Theoretically, in the Machar case, the decayed Barium gamma source of the Framo meter may require change-out after ten years.

Following installation of the replacement insert in the Machar meter, two of its components failed. The multi-channel signal analysis card failed. This component is not duplicated in the meters so any further failure, in service, would result in loss of meter use. The DP cell also needed replacement owing to erratic signal fluctuations and, in service, such failure would have affected the total volume reading from the Venturi.

BP ETAP is now aware of the possibility of the need for an intervention and retrieval of a subsea meter early in service. Some expectation and budget for this is in place in the context of other equipment installed on the subsea manifolds. It could be argued, in a positive sense, that this early intervention, if it arises, will be an opportunity as part of the technology advance and learning which has underpinned the ETAP philosophy. It would test the capability to change-out multiphase metering hardware subsea in an operational setting.

Offshore

After installation of the Machar manifold subsea, function tests showed that all elements of its multiphase meter were working and that the meter was communicating with the host facilities. At the time of writing, after several months since installation on the sea-bed, commissioning of the Monan meter was in progress.

3 COLOMBIA (CUSIANA/CUPIAGUA)

The Cusiana oil field and Cupiagua gas condensate field are operated by BP Exploration on behalf of a consortium including Ecopetrol, BP, Total and Triton. hey are located in the Casanare province in the eastern foothills of the Andes mountains. The discovery of these fields in the early 1990s doubled Colombia's oil reserves by adding over 1.5 billion barrels.

The development of these fields has proceeded in two phases. Phase I involved a first stage of development of the Cusiana field and peaked at a production rate of over 190 mbpd. During the current Phase II expansion of Cusiana and start-up of Cupiagua, oil production is being increased to 500 mbpd.

A combination of hilly and difficult terrain coupled with a complex and unstable geological structure has necessitated the use of geographically dispersed wells. Drilling is relatively expensive in these areas and scope for deviated well-bores is limited. The multiphase production fluids are transported through a flow-line/trunk-line system to central processing facilities (CPF), Figure 3. The multiphase fluid dynamic behaviour through the pipelines over the hilly terrain has needed special study by BP Exploration including field trials using clamp-on gamma densitometers.

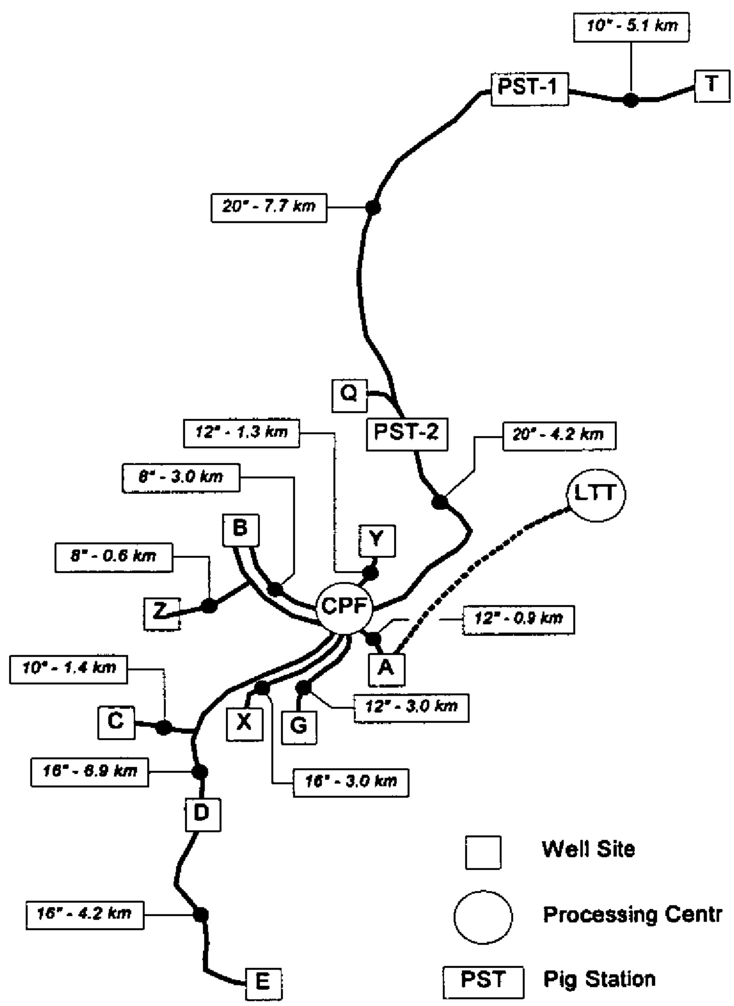

Figure 3 - Cusiana Oilfield Multiphase Production Flowline Network (June 1995)

3.1 Well Production Measurement Needs

Tests of every well are required once per month as a minimum. The production data are critical to effective management of the reservoirs but are also needed for allocation. It is a requirement of the Colombian regulatory authorities that these monthly data are obtained accurately to the best standards expected of a good test separator system. Local royalty and ownership interests vary depending on well location.

3.2 Benefits and Service Duty

Conventional fixed well testing infrastructure including test lines, for the majority of wells, which are remote, would be too expensive and difficult to operate. The well tests during phase one production from the Cusiana field used portable conventional metering systems to cover the more remote of twenty four early production wells. A permanent test separator has been used at the CPF for wells in closer proximity and where a dedicated test line was available. The truck-mounted test separators require choke-back for the high potential wells due to their limited flow capacity. They are expensive and cumbersome (logistics include additional truck mounted auxiliary equipment): in 1996, a total of seventy five well tests was achieved at a significant service cost (~$30,000/test) and with production losses.

During Phase 2 - (full field expansion) - the number of wells for Cusiana and Cupiagua fields combined will exceed ninety. For the Cupiagua field, which sits in more elevated terrain and vegetation, a well test using the portable test separation equipment can take four days minimum to complete and as for Cusiana, in some cases, requires the use of two test sets in parallel to achieve useful flow range, with potential operational difficulties.

Multiphase metering offers substantial benefit in these circumstances, both economic and logistical. Cost savings in furnishing well test equipment, for a five year period, have been estimated at levels comparable to those expected of remote offshore applications. Each meter would permit up to sixty well tests per month. On the basis of Cusiana experience in 1996, this compares to six tests achievable per month for each of three portable conventional equipment sets. In addition to these considerations, there is a significant revenue implication in being able to test to full well capacity. Multiphase metering permits this. Furthermore, the limitation on test capacity to date, imposed by the conventional equipment, has led to some uncertainty in production rates under normal operation and has deprived the asset of important information on, for example, variation of GOR with rate.

The strategy with regard to the deployment scheme using multiphase meters is being developed following field tests and as further experience is gained from operation with the portable multiphase meters used for the trial.

3.3 Field Trials

Recognising the significant benefit potential of multiphase metering, BP Exploration Colombia begun planning field trials in 1996 with assistance from the BP Multiphase Production Technology group. Further confidence was needed before committing to commercial orders for full field deployment. For example, the technology needed to be demonstrated using large meters capable of operating to the full capacity of the high potential wells. BP had substantial experience from across its test and development participation but all involving meters and test facilities restricted to 4" nominal pipe and below. The wells in Colombia typically need 8" multiphase meters.

Furthermore, the viscosity of the Cupiagua condensate (41° API) is 0.3 cP under line conditions, lower than anything experienced previously. Cusiana oil is also light: 35° API; 0.7 cP at line conditions typically.

A short-list of manufacturers was screened in order to select a metering principle which could deliver the required accuracy, repeatability and functional reliability. On the basis of fundamental metering principle, demonstrated and consistent track record and performance, and BP's considerable trials experience at Wytch Farm and Prudhoe Bay [1, 2, 3], the ISA "Multistream" meter was selected for the trial. The positive displacement principle of this technique has been detailed in the above references. An order for two 8" meters was placed in January 1997.

Cupiagua production is dry (apart from water of condensation). Some Cusiana wells are beginning to cut water (up to 20% in a few cases). At the time of order, the ISA system did not include an in-line water cut monitor. Current multiphase meters with this capability have not demonstrated the required accuracy on flow rate. Furthermore, particularly at gas void fractions (GVFs) approaching and exceeding 90%, which is the case for both Cusiana and Cupiagua well streams, they do not exhibit the required accuracy in measuring water cut.

Test separator equipment will remain for well clean-up and related work. This equipment will also provide one means of periodic verification. It can be used to measure water although the companies currently providing the portable well testing service typically route total liquids through the oil leg and resort to samples taken from the multiphase well stream to determine water cut. BP Exploration Colombia also purchased a "WellComp" unit in 1995 for service in the Cusiana field. Some reliability problems have recurred with this unit, but it remains in use. It has not been subjected to a rigorous systematic evaluation but experience in Colombia and sparse data available external to BP show that accurate water cut measurements can be made with this equipment.

The sampling approach was recommended for use with the ISA multiphase meter. As already noted, research to develop water cut sensors of the required accuracy and acceptable cost is ongoing.

In July, 1997, ISA delivered two 8" multiphase meters designed for up to 20 mbopd and 80 mmscfd at Cupiagua wellhead conditions (approximately 1000 psi). The delivery comprised truck mountable skids including: by-pass piping, valves, 8" meters, flow computers, flexible connection hoses and spares, to ANSI 900 rating.

<u>UK National Engineering Laboratory (NEL)</u>

A trials meter was tested at the NEL as a functional check prior to despatch to Colombia. This also facilitated training of Colombian personnel in the form of a one-day programme of lectures and flow loop tours designed in co-operation with the NEL. The NEL has subsequently developed a course and offered it to the industry at large. The NEL resource has been of value in helping BP take multiphase metering into application.

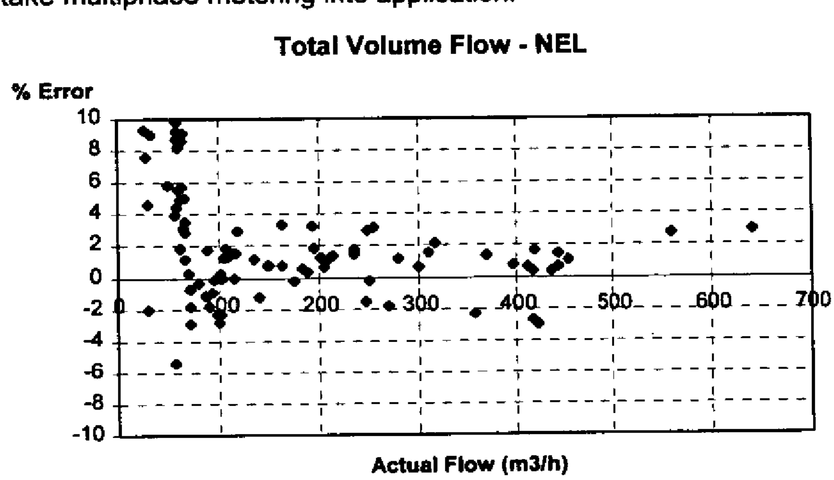

Figure 4 - Relative Error in Total Volume Flow Rate - 8" ISA Meter

Figure 4 shows the relative deviation between the total volumetric flow stream measurement by the multiphase meter and the reference measurements of the NEL test loop. These data cover GVFs ranging from 0% to 99%. The increased scatter below 60 m3/h is associated with frictional drag of the rotor-bearing system of the 8" test meter and is below design range of flow. The meter could be tested over the lower half of its flow rate range using full blow-down of the NEL facility to atmospheric pressure. It exhibits a flat characteristic within ±3%, - close to the NEL reference system uncertainty (up to ± 2.5% estimated by the author, with allowance for pressure differences which must be measured by transducers at the reference station and the test section to correct reference gas volume; and using NEL quoted uncertainties for the single phase reference streams). The multiphase meter is calibrated on single phase water. This was performed against a turbine meter in the ISA factory using the manufacturer's calibration.

The agreement in the comparison concurs with the absence of solubility effects of the NEL test fluids (dead crude oil, Nitrogen and simulated brine - test pressure a few bar at most).

Cusiana Central Processing Facility (CPF)

For an initial phase of testing, a meter was installed in a purpose-built by-pass loop tied into the test pipeline in the manifold area of the CPF. This allowed direct comparisons with a fixed test separator and relatively close proximity to workshop facilities during commissioning.

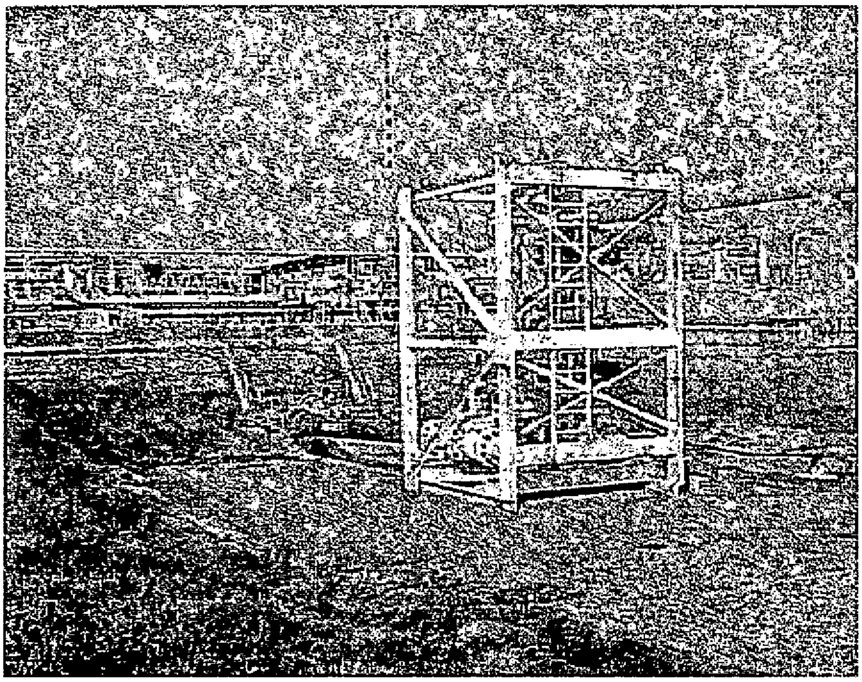

Figure 5 - Multiphase Meter Skid at Cusiana CPF

After two months of difficulties and delays, partly associated with the site, a series of well tests was conducted and some good comparisons emerged, Figure 6. These data were limited in the selection of wells but demonstrated the repeatability of the meter whilst the trials team gained in confidence in the operation of the equipment. These good comparisons were obtained only after the turbine meters in the liquid legs of the test separator were replaced. This followed the discovery of damage to those meters during investigations to assess if larger deviations initially observed were attributable to the multiphase meter.

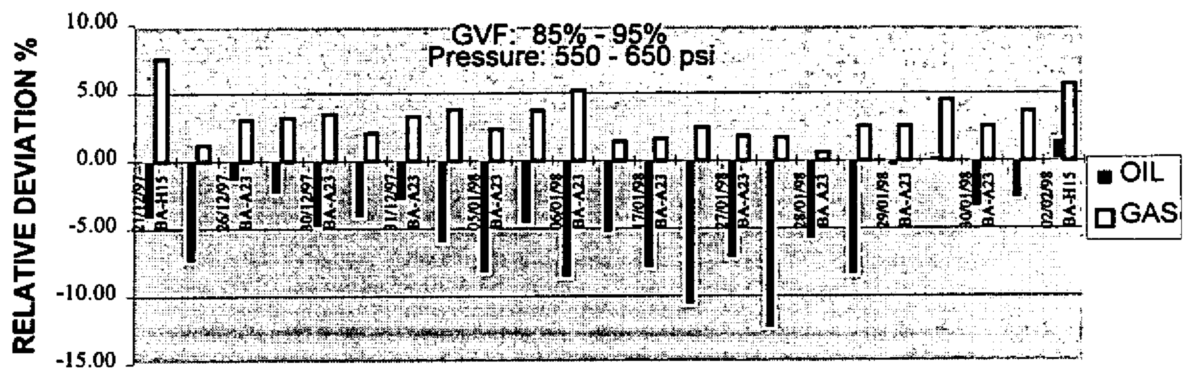

Figure 6 - Multiphase Meter Versus CPF Test Separator - Cusiana Field

(The deviation bars are labelled alternately for clarity. The tests are repeats using wells BA-A23 and BA-H15).

Tests using other wells were attempted early in the trial at the nominal maximum flow range of the meter. Two attempts were made but on both occasions mechanical failures occurred after several hours of operation. One rotor set was returned to the ISA factory for examination and the trials were continued with the second meter to obtain the above results but restricted to half intended full rate. It was concluded that the journal bearings were breaking down under excessive lateral loading at high flow rates.

During factory experimentation and a fast-track study of rotor dynamics lasting four months, ISA established that the rotor design was mechanically unstable owing to an inherent static out-of-balance. This factor had not been understood by the original design team responsible for developing the smaller prototype prior to ISA's involvement. As a result of the factory studies, ISA successfully developed the manufacturing process to compensate for out-of-balance rotor dynamics. Good vibration characteristics have now been demonstrated across range.

<u>Well Pad Tests.</u>

In parallel with the factory investigations, field tests were continued using the second meter (restricted to half range) to assess the accuracy and repeatability of the measurements at different well locations in the Cusiana oil field. This allowed some assessment of reliability, not only by accumulating run-hours in various well streams (with the meter rotors in an out-of-balance state) but additionally by subjecting the equipment to transport on the poor track surfaces in the oil field. As well as having a poor surface in some places (including river crossings), the tracks are narrow with sharp bends around hilly terrain. The ISA skid pivots on a base frame which enables it to lay low on the back of the truck during transport.

At first, poor results were obtained from comparisons with the portable test separation equipment (errors of up to -40% on liquid phase flow rate; up to 20% on gas flow rate). The explanation for this was clouded by the fact that simultaneous testing with the multiphase meter and test separator connected in series was not attempted. Significant differences in wellhead pressure between the two cases (up to 100 psi) could result owing to large pressure drops associated with the test separation equipment and the measurements by the two systems were typically separated by a few days. Nevertheless, it was felt that the errors were too large.

Tests were repeated against the CPF fixed test separator on a well previously used for the earlier successful phase of testing. The errors were unacceptably high with the meter located at the well pad. The meter was then relocated at the CPF manifold area test loop site but the earlier good agreement was not repeated with the multiphase meter reading a low oil rate and high gas rate relative to the CPF test separator. The magnitude of the deviations was not repeatable as tests were repeated.

Thorough investigation of the multiphase meter on site revealed no faults. Its readings indicated well behaviour not inconsistent with that observed earlier when good agreement between systems had been seen. In view of the volumetric accuracy of the multiphase meter observed against the traceable references of the NEL, site operational personnel were advised to check the test separation facilities. In particular, the system consisted of a number of branches with single block valves, between the multiphase meter and the test separator, which could pass fluid.

Thinking had become polarised at several levels of the BP organisation in Colombia that the multiphase meter did not work. The reluctance to question the existing (and familiar) systems was rapidly dissolved on the discovery of a number of leaking valves, both within the CPF manifold area and some by-pass legs of the portable and well pad facilities. There was some evidence that this problem had been aggravated by operational debris, including proppant ("frac" sand).

The testing campaign was renewed with the return of the rotor set from ISA incorporating the improved state of balance. A further series of well tests was conducted, including some at maximum nominal total volume rate. These were more rigorous, using the service company test separation sets coupled directly in series with the multiphase meter at the well pads. Careful attention was paid to valve integrity, reference meter condition and calibration (which included local gauge tank facilities, dead weight tester, etc), and regular hourly sampling for carry-over in the separator gas leg streams in addition to monitoring of level and pressure controls. In some cases, two parallel test separators were needed in series with the multiphase meter to cope with capacity. Good comparisons followed as shown in Figure 7.

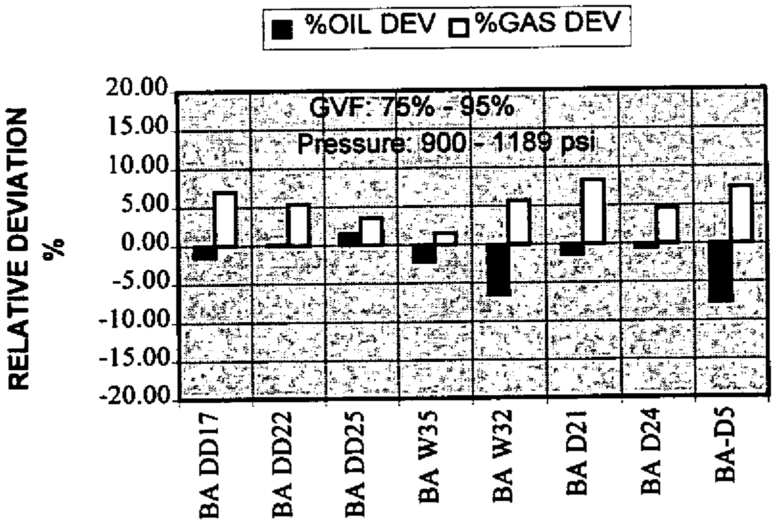

Figure 7 - Multiphase Meter Versus Portable Test Separators - Well Pads - June/July 1998

This follows on from the good earlier results obtained at the Cusiana CPF. There, the meter was located approximately half a mile downhill from (and upstream of) the test separator and a few kilometres, over terrain, from the wellheads. Eight hour test periods, with a preceding purge, were typically used. This was needed to allow for liquid hold-up effects in the flow-lines. Generally, the trial has demonstrated to site operations how, with the meter located at the well pad, a reduced test time can be used, allowing considerable logistical benefits.

Increasing attention was paid to the test separator equipment. The high gas fractions of the well streams, 75% to 95%, dominate the total volumetric reading of the multiphase meter, which, being of a positive displacement design, could be expected to show some under-read of gas flow rate. On average, the opposite has been observed. Sampling and purging from the test separator gas metering runs, which use Daniel senior orifice plate fittings, has revealed instances of liquid carry-over. In some cases, buckling and slight wear of plate edges has been noted. Such effects may have caused these reference gas meters to read low.

Persistence has been needed to ensure consistency between the different metering systems in the use of PVT equations. The specialist equation of state methods employed for the trial and supporting fluid property measurement data are beyond the scope of this paper. The pre-existing equations used for the various test separator systems were all different. Both these systems and the multiphase meter rely on fluid property data as input in order to derive phase volume flow rates and report in standard units. Analysis of the sample data and equation of state correlation on which this input depends continues for meter testing on the Cupiagua gas condensate fluids.

Site operational engineers are using the multiphase meters as stand-alone units on the basis of the results obtained and having demonstrated benefits in their use. The evaluation of reliability continues in service. Questions remain regarding the conventional test separation metering systems, including the liquid (turbine) meter gauge tank systems. These aspects will be pursued further as opportunities arise within operational schedules (including more in-series comparisons with the multiphase meters) in order to tighten the understanding of the comparisons further.

It is important to re-emphasise that the multiphase meter was factory calibrated on single phase water. Apart from repeatability checks of the gamma densitometer counts during commissioning operations in the field, no adjustment or re-calibration has occurred at any stage through the testing at the NEL and in Colombia. The accuracy and repeatability of this metering principle, demonstrated during previous field trials of the 4" prototype [2, 3], is now being confirmed for larger designs. The insensitivity of its calibration to flow conditions and installation sites is key to the practical use of multiphase meters, particularly for applications such as in Colombia.

4 CONCLUDING STATEMENTS

The purpose of this paper was to present the current status of BP's first applications of multiphase metering. These applications are the next major step in taking development of the technology from the research and test phase towards confident commercial deployment.

A key part of this early phase of deployment is the process of verification. One of the main ways in which multiphase meters will gain acceptance is by comparing measurements at operational sites with those from separation metering systems; - commonly, test separators. During technical forums on multiphase metering, much has been said about the accuracy (or lack of it) of test separator metering systems.

Provided the test separator and associated equipment are correctly designed, operated and maintained, meaningful evaluations of multiphase meters are possible. The failings of separation measurements across the industry, where they occur, often result from a lack of adequate attention to these areas, particularly with today's pressures of reduced manpower. Clearly, the verification process can be more difficult over long tie-backs off-shore, such as with the ETAP subsea meters. The field trial experiences presented here have highlighted the importance of a rigorous approach.

Simple, transparent and reliable multiphase metering techniques will greatly diminish the quality assurance burden. Through its development of such multiphase metering methods, incorporating sound fundamental physical principles, BP Exploration can substantiate these concluding statements with a series of consistent and repeatable field data, both recent, from fields in Colombia, and from earlier trials at Prudhoe Bay [2].

With a willingness of the meter manufacturer to co-operate in an open way to ensure successful operation, BP is already realising some business benefit in its first applications of multiphase meters. Demonstration of reliability will now be important to the evolution of multiphase metering in BP's ETAP and Colombian oil fields.

5 ACKNOWLEDGEMENTS

The author acts as a consultant to the BP assets represented in this paper. The work described was performed by BP ETAP and BP Exploration Colombia in conjunction with Framo Engineering a.s. and ISA Controls Ltd respectively and is presented on their behalf.

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FIELD TESTS OF THE ESMER MULTIPHASE FLOW METER

H Toral, Petroleum Software Ltd.
S Cai, Petroleum Software Ltd.
E Akartuna, Petroleum Software Ltd.
K Stothard, Daniel Europe Ltd
A W Jamieson, Shell Expro

FIELD TESTS OF THE ESMER MULTIPHASE FLOWMETER

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1 INTRODUCTION

It is said that necessity is the mother of invention but several necessities had to come together for the development of ESMER (Expert System for Multiphase Flow Regime Identification and Metering). The first was the need to work within a low budget in setting up a new laboratory at Imperial College in 1986. The brief was to set up a multiphase laboratory and conduct a research programme in topics which are of interest to the oil industry. One topic which appeared to be of interest to the oil industry was multiphase flow metering. A commercially available multi-phase flow meter did not yet appear to be available. To stay within budget the team chose a development path based on simple off-the-shelf sensors and electronics, avoided spool designs more complicated than a straight piece of pipe (no mixers) and placed maximum emphasis on modeling the natural features of multiphase flow by software. At this time Personal Computers were just beginning to offer adequate power for on-line digital signal processing. The strategy to keep hardware simple and to build a flow meter with standard off-the-shelf components has remained to date.

The second necessity was the long term requirement from Shell Expro for low cost, high performance multiphase meters. It was evident that the major benefit to Shell Expro from multiphase meters would come when it was practical to use them to allocate production from several operators feeding into common facilities. When approached by Imperial College in 1989 to co-sponsor further ESMER development, Shell Expro saw the potential of the technique, but asked that another two guiding principles be followed. A multiphase meter using simple hardware was to be developed as a low cost meter in its own right, but the signal processing electronics was to be kept sufficiently general that there would be the possibility of enhancing the performance of other manufacturer's meters without having to change out the hardware. Shell Expro has remained the largest industrial sponsor for ESMER.

The third necessity was a metering system supplier willing to participate in field prototype development and commercialisation. By 1995 ESMER was in danger of becoming yet another good idea that failed to reach the market. The concepts involved in ESMER were perceived as being quite strange and were not readily received by companies who considered measurement from a mechanical viewpoint, rather than a signal processing one, Companies already working on multiphase meters had enough to do in developing their own ideas. Spectra Tek (later bought by Daniel Industries) wanted to be involved in multiphase metering, but did not wish to develop expensive hardware. They had set up a subsidiary company for marketing complete metering systems that was an ideal vehicle for developing field prototypes.

This paper describes the first field prototype flow meter which has been working at Shell's Auk Platform since July 1997 and discusses the tests that have been carried out to establish its performance.

2 MULTIPHASE FLOW

It is necessary to take a brief look at the fundamentals of multiphase flow to understand the ESMER methodology.

There have been two fundamentally different schools of study of multiphase flow. The traditional school began by visual observation of the flow aiming to construct a universal flow regime map [1]. For reasons described next, an unequivocal a-priori determination of the flow regime was central to the traditional approach.

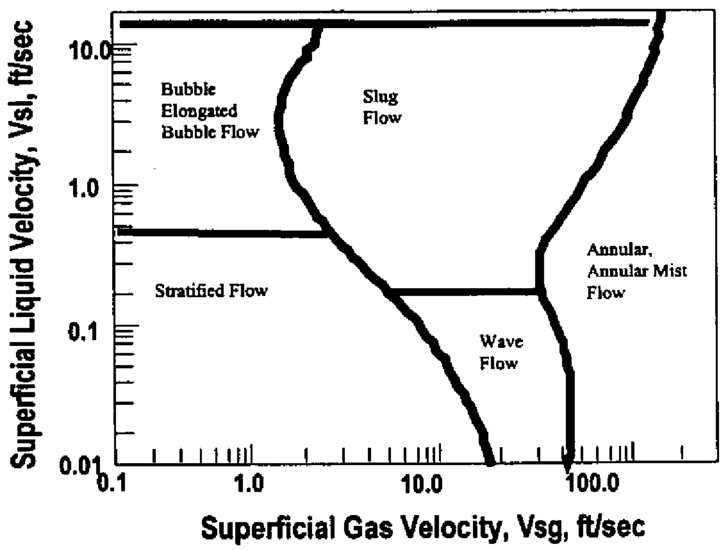

Figure 1 Mandhane Flow Regime Map

"Universalisation" was hampered not just by complex fluid behavior but also by the subjective nature of the visualisation effort and the language of the descriptions. "Wavy whist" flow regime can be cited as an extreme example. For mathematical modeling the traditional school adapted the theory of single phase fluid mechanics to multi-phase flow by adding adjustment coefficients into the deterministic Newtonian fluid mechanics models. Those serving engineering interests preferred the Bernoulli equation and those serving scientific interests the Navier Stokes equation as the foundation on which adjustments were applied. The reasons given for the adjustments were the characterisation of shear stresses between the phases in different flow regimes. For example, in bubbly flow these would be modeled one way, in annular flow in another way often with reference to a simplified and deterministic "wire diagram" of the flow regime.

A new school of multiphase investigators appeared in the late seventies provoked by new developments in sensors and electronics. These observed multi-phase flow at sampling frequencies matching the time scales of the turbulence in the flow and chose probabilistic methods for mathematical modelling of the observations [2, 3, 4, 5, 6, 7, 8, 9, 10].

3 EXPERT SYSTEM FOR MULTIPHASE FLOW METERING

This is when the team at Imperial College entered the foray. It was still early days of application of digital signal processing in multiphase investigations. Quite a number of our predecessors in the "new" school were equipped with analogue electronics analysers which gave them a limited range of mathematical capabilities. The precursor of ESMER was the freedom of mathematical analysis offered by the digitisation of the random time series of the turbulent hydrodynamic signals. The whole range of signal processing mathematics as applied from voice recognition to seismic analysis to medical science could now be imported off-the-shelf. An extensive programme of theoretical and laboratory investigations was conducted at Imperial College between 1986 and 1994 examining and classifying the random characteristics of multiphase flow by digital signal analysis methods [11, 12, 13, 14, 15, 16, 17, 18, 19].

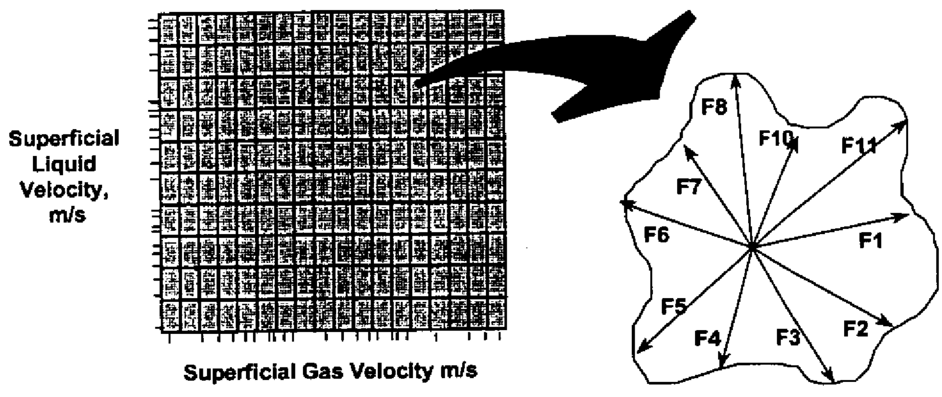

Figure 2 ESMER Feature Contour Map and Feature Vector Grid

The concept of ESMER can be generalised as "learning from experience". As a start one can classify the approach as an application of artificial intelligence to multiphase metering. To put it into context; ESMER learns that certain combinations of the flow rates of individual phases give rise to particular characteristics of the random turbulence signals. That is, ESMER characterises and classifies the properties of the turbulence signals in terms of the individual phase flow rates. When the experience is sufficiently mature and reproducible ESMER can begin "predicting" the flow rates from an observation of the characteristics of the random turbulence signals.

There are two further points which must be clarified on a conceptual level. First, one must "purify" the experience as manifested by the surrogates of the turbulence (i.e. the pressure signal). This means enhancement by feature extraction and filtering. Second one should assist the classification by human experience. A simple example of such experience is to "tell" the system that a certain observation is taking place in a horizontal flow line rather than a vertical flow line. It is this second point which has permitted us to call the methodology an "Expert System". The expertise of the human investigator can be and should be imparted into the model in many ways. For instance with reference to an operator's experience on a particular well or with reference to the legacy of classical fluid mechanics. ESMER has taken advantage of this legacy in selecting the "training targets".

To summarise the philosophy of ESMER and to define its distinctive character, we can say that ESMER is a flow measuring system that learns by example rather than being dictated by the conceptual and deterministic fluid mechanics models.

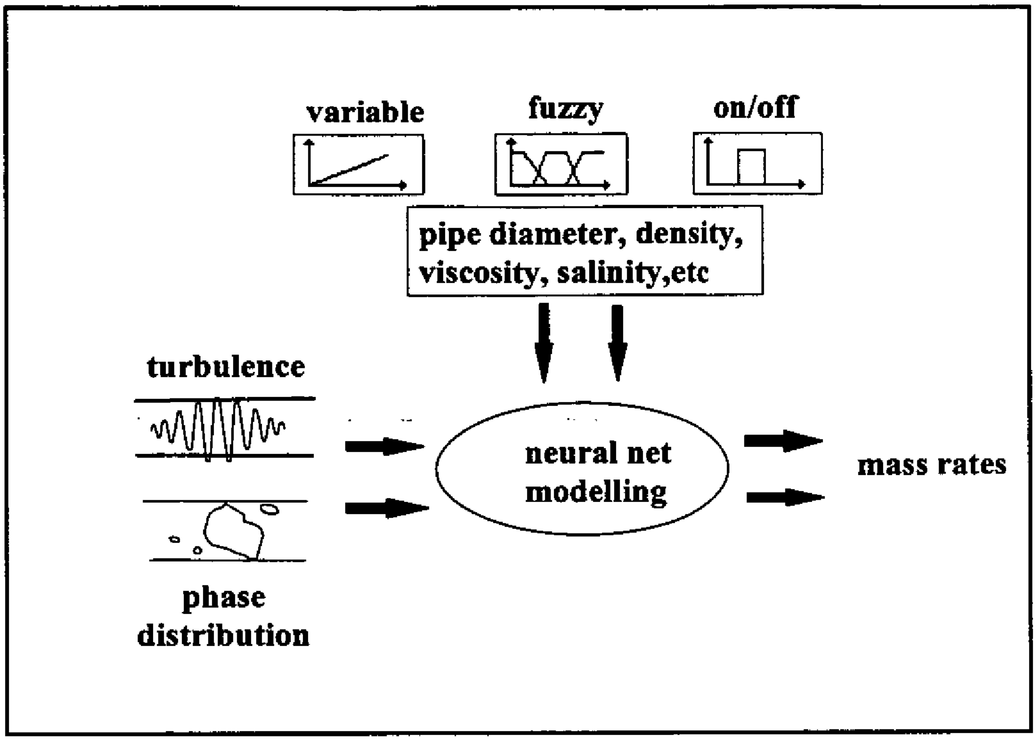

Figure 3 ESMER Conceptual Model

4 EQUIPMENT

The prototype flow meter (named AukESMER) comprised a non-intrusive 4 inch diameter pipeline spool of 2m length fitted with high frequency pressure sensors (Druck and Statham) and impedance sensors (Meridian). The spool was assembled by Daniel Europe Ltd.

The electronics comprised an impedance meter (PSL) and a PC (Gateway) fitted with a multi-channel A/D. A software system developed by PSL ran on the PC Windows platform for sampling, analysis and graphical display of the measurements.

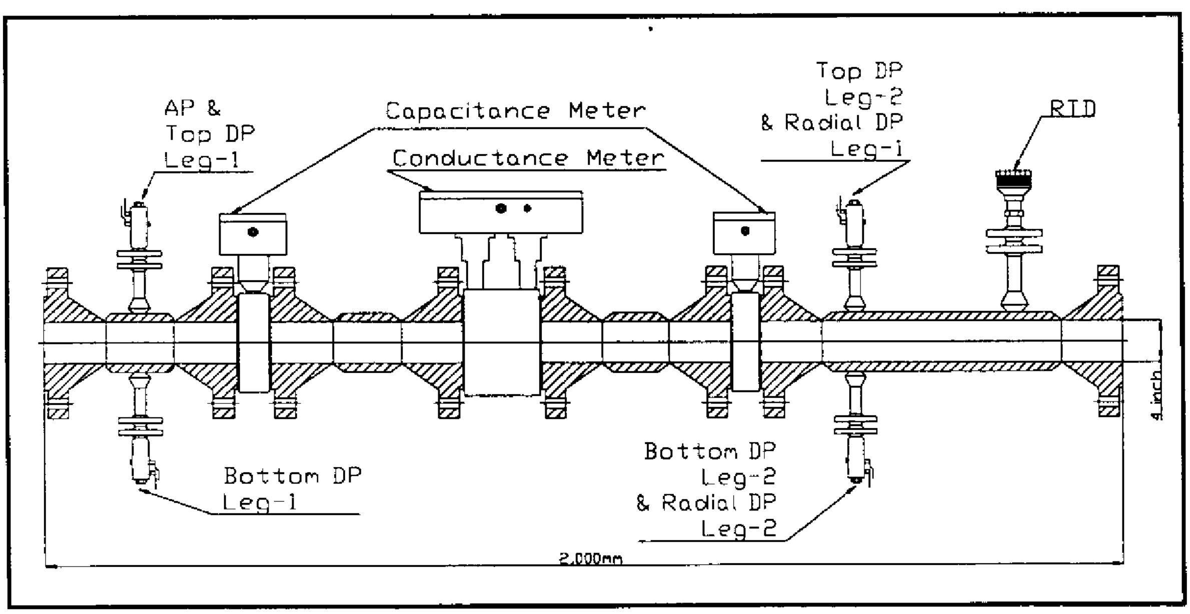

Figure 4 GA Drawing of Spool Piece

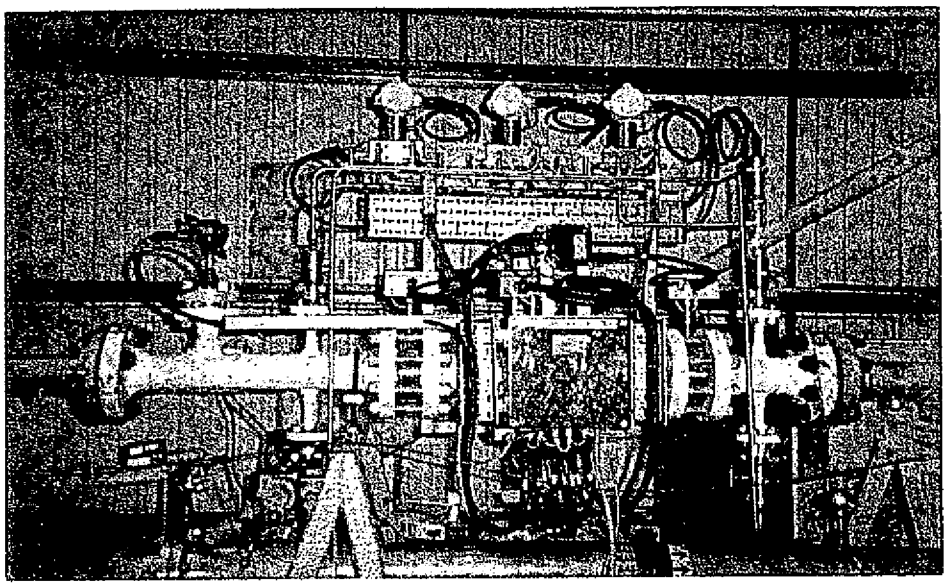

Figure 5 Photograph of Spool Piece

The signal sampling parameters were as follows: sampling frequency of 800 Hz, sampling period of 40.96 s, processing time of 30 secs. The measurement frequency was once every three minutes. A set of features were derived from AP, Top DP, Bottom DP, radial DP and conductance signals under the above sampling conditions.

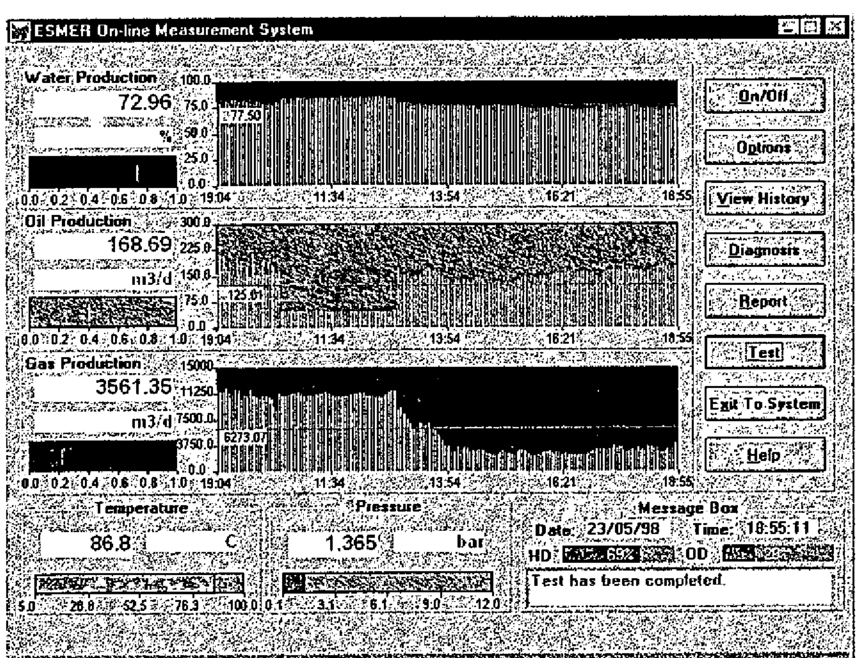

Figure 6 AukEsmer User Interface

A distinctive character of the equipment is that there is no flow conditioner which aims to impart on the equipment the "conceived" properties of an ideal flow regime. To the contrary, the equipment benefits from the "natural" occurrence of the flow regimes existing under a given set of pipeline and physico-chemical conditions.

This last statement gives rise to the justifiable concern that ESMER requires some in-situ calibration. This is true but the difference between ESMER and any other commercially available technique appears to be one of degree as we shall proceed to demonstrate.

5 CALIBRATION

The primary calibration of the system was conducted at the National Engineering Laboratory. Tests were conducted under the following range of conditions:

Water cut (25g/l MgSO4 and 50g/l MgSO4): 5% to 75%
Oil flow rate (Forties Crude/D80 Kerosene Mix 70/30): 0.2 to 4 m/s
Gas flow rate (Nitrogen): 0.4 to 20 m/s

The data samples were separated into two groups. One group was used for calibration and the other for testing.

The calibration procedure was as follows. A set of features were derived from each sensor, an optimum feature set was selected and a back propagating neural net was trained against reference measurements of the flow rates of individual phases.

The test procedure was as follows. The test group of samples were passed through the neural net predictor algorithms and the result of the predictions were compared against the recorded reference (single phase) measurements for those test points. The results are shown in the following figures. Relative error is defined as (Measurement - Actual) / Actual.

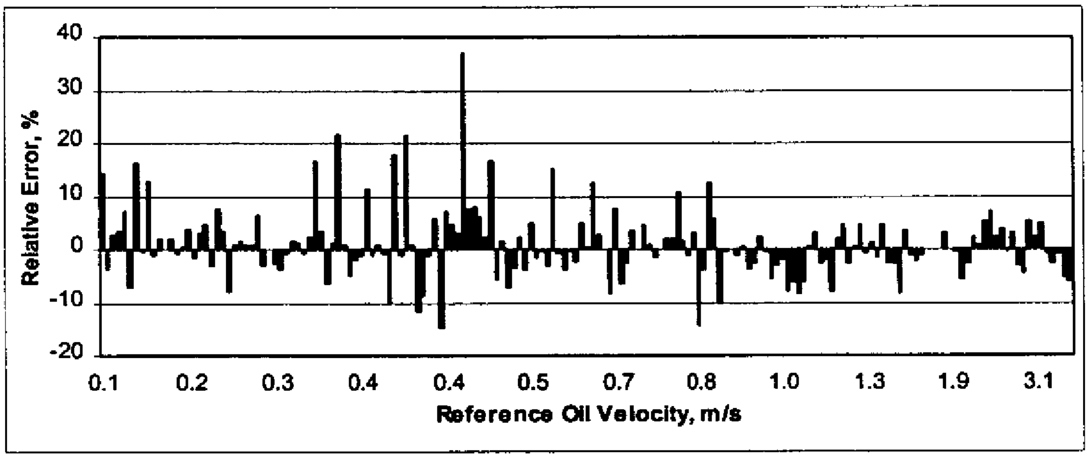

Figure 7 Oil Velocity Relative Accuracy

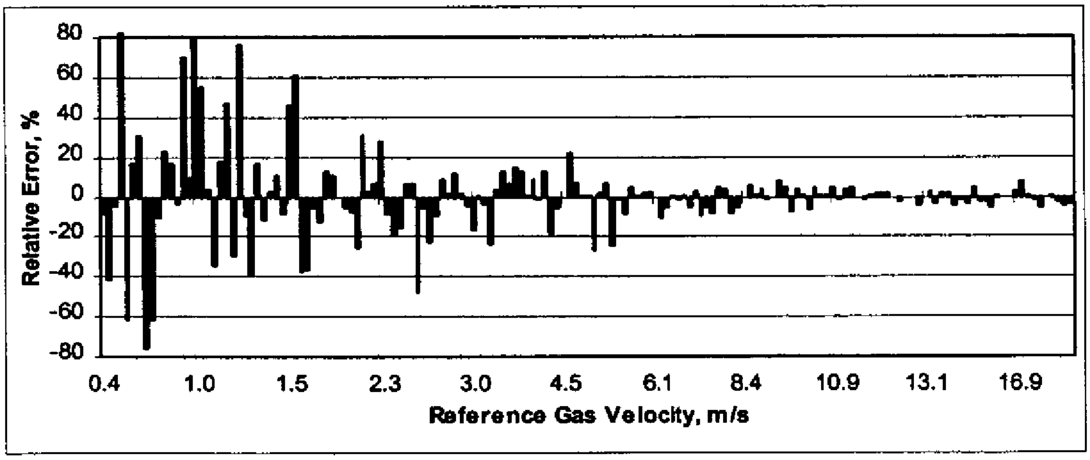

Figure 8 Gas Velocity Relative Accuracy

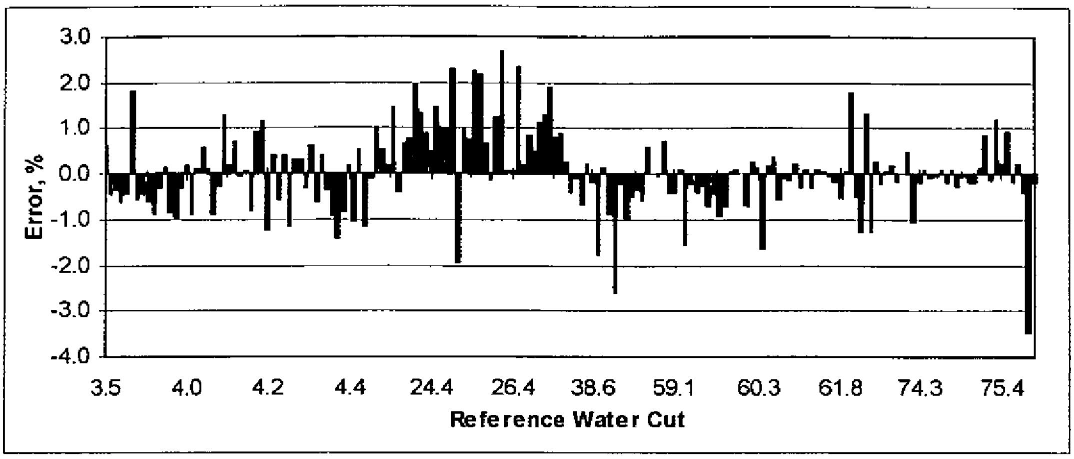

Figure 9 Water-Cut Accuracy

The next figure shows the statistical distribution of error. The scatter is symmetrical and the resulting average (e.g. daily) flow rate should exhibit a smaller error than individual measurements.

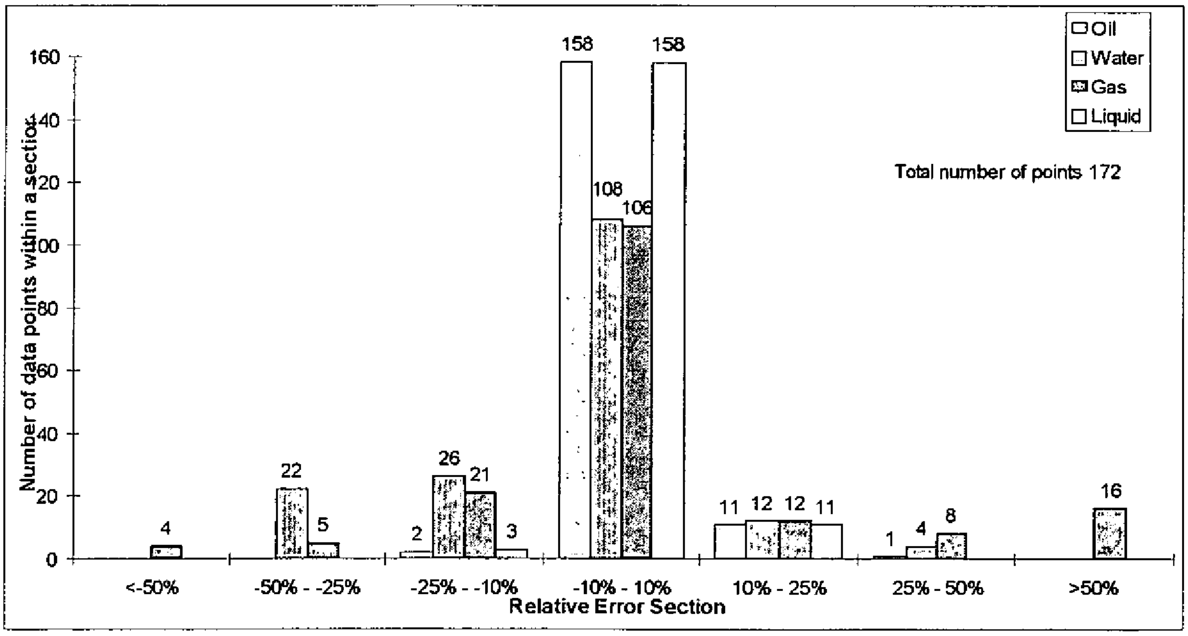

Figure 10 Statistical Distribution of Measurement Accuracy

6 FIELD TEST OVERVIEW

AukESMER was installed on the Shell Auk Platform in the North Sea in June 1997. The neural net obtained from the laboratory tests at NEL became the primary "factory" calibration with the intention for it to be "tuned" for field conditions (with as few in-situ measurements as possible). On the first two trials in July and October 1997 no secondary reference measurements were available to execute this strategy. The meter was left in an operational condition gathering original turbulent data samples which were shipped to base for analysis on a regular basis.

The first quantitative field re-calibration and tests took place between 29 April and 4 May 1998. During these tests a production separator was dedicated to the well. It was run by the platform supervisors and TracerFlow measurements were carried out by SGS Redwood to provide the reference flow rates. Three reference points were collected at 100, 75 and 50 percent of the full operational flow rate. The flow rate was controlled by varying the water injection rate into the well. Water-cut reference was measured by base sand and water (BS&W) measurements well. Water-cut reference was measured by base sand and water (BS&W) measurements collected on an hourly basis. The gas flow rate was measured by an orifice located at the gas outlet of the low pressure (LP) separator, and the oil flow rate was measured by a turbine located at the oil outlet of the low pressure (LP) separator. Within the time permitted on the platform, the ESMER factory calibration was re-tuned with the inclusion of two points drawn from the separator measurements at 100 and 75% flow rates.

Upon return to base, a detailed program of study was started to analyse the extensive data gathered from the platform to develop / propose more advanced methods for fine tuning the factory calibration. In the first stage of the study, the factory calibration was re-tuned by drawing data from three flow conditions described qualitatively as 100%,75% and 50% of the full operational conditions. The tune up data was drawn from measurements conducted on a single day (1.5.98) and constituted a sparse contribution to the factory calibration database.

Measurements were then simulated for three days of operation (two days of which is independent of the data used in tuning up the calibration) and compared with the average reference measurements. This means a moving average of one hour against the separator and ten minutes against the tracer. Under stable operating conditions ESMER matched the separator and the tracer measurements with an accuracy of better than ±10 percent. The match was better than ±15 percent at low flow rates. The disagreement is thought to be largely due to the instability of the flow conditions at low flow rates where large changes were observed in the flow rates over the respective averaging periods.

On-line record of measurements taken by ESMER, updated every three minutes, show that ESMER correctly trends the changes in the flow rates in real time. As these changes were imposed by the operators cutting down on water injection rate into the well, there is an accurate time log of the expected changes. These accord very well with ESMER's predictions.

7 FIELD TEST DETAIL

7.1 Reference measurements

Reference flow rates were provided by the operators from a separator and by the service company, SGS Redwood, from a TracerFlow technique.

The separator sampling conditions were:

- Time weight average oil production rate (equivalent to "bucket and stop watch method") over 0.5 or 1 hour.
- Time weight average water flow rate from Bs&W and oil production rate as above.

TracerFlow sampling conditions were:
"Snap-shot" measurement of the oil /water production rate every ten minutes.

7.2 Test procedure

The time table of the events and numbers of samples collected during the calibration process is summarised on the next table. The tests were conducted in three phases by successively cutting down on the production rate by reducing the water injection rate into the well. These are referred to as Phase A-100%, B-75%, C-50% of full operational conditions with a period of change / stabilization in between. The percentage stated here is an intended effect of the cut back. In reality, the calibration and testing exercise was based on the on-line reference measurements obtained from the separator and tracer flow. These measurements do not in fact corroborate the intended cut-back but the % labels are retained for ease of reference.

Table 1 - Summary of Calibration Reference Measurements

Date/Time 1 May 1998	Production Condition As a "Notional" % of Operational Flow	Number of Separator Samples	Number of Esmer Samples	Number of Tracer Samples
12:00 - 15:00	100 %	3	52	10
15:00 - 16:30	reducing flow rate stabilisation time		24	
16:30 - 19:00	75%	4	33	10
19:00 - 20:00	reducing flow rate stabilisation time.		7	
20:00 - 22:00	50%	6	38	

7.3 Tuning the factory calibration

For the Liquid / Gas Neural Net the training data set (the calibration database) comprised 50 factory points and three field measurements obtained on 1 May 1998 at 100, 75 and 50 percent flow rate data. For the Water Cut Neural Net the training data set comprised 133 factory points and three field measurements on 1 May 1998 at 100, 75 and 50 percent flow rate data. The in-situ calibration requirement exemplified in this study, which we believe shall prove to be typical for ESMER, does not appear to be more demanding than the requirement faced by other multi-phase flow meters. In due course, the learning concepts underlying ESMER should in fact aid to reduce the in-situ tuning requirement further. This will be achieved with reference to a universal database of multi-phase flow characteristics maintained at base.

7.4 ESMER vs Separator

We begin with tests conducted on 1 May 1998. While the training and test data overlap for this date, the range of data and observations offer greater variety and a better opportunity for verification of the compliance of ESMER with trends than the observations and measurements made on the preceding two dates. Besides, TracerFlow measurements are only available for this day.

The tests were conducted in three stages by successively cutting down on the production rate by reducing the water injection rate into the well. These are marked as Phase A-100%, B-75%, C-50% of full operational conditions with a period of change / stabilization in between. The following charts show the results of the predictions point by point every three minutes (with a moving average of 5 points / 15 minutes) between 12.01 and 22.30 hours. (The gap between 19:00 and 20:00 is due to a shut down of the sampling procedure). It is seen that ESMER trends the known variations extremely well for all three phases. These are reported individually in turn.

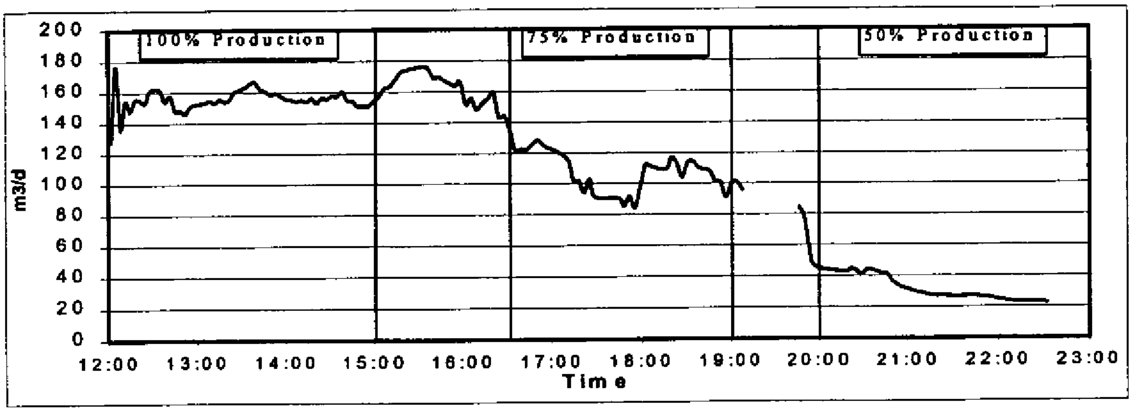

Figure 11 Oil Production at Well AA06 on 01/05/98

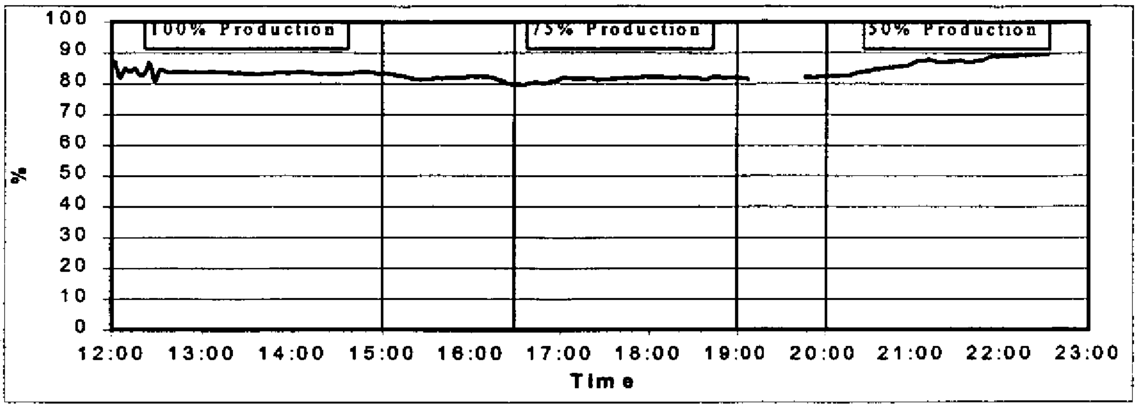

Figure 12 Water Cut Measurement at Well AA06 on 01/05/98

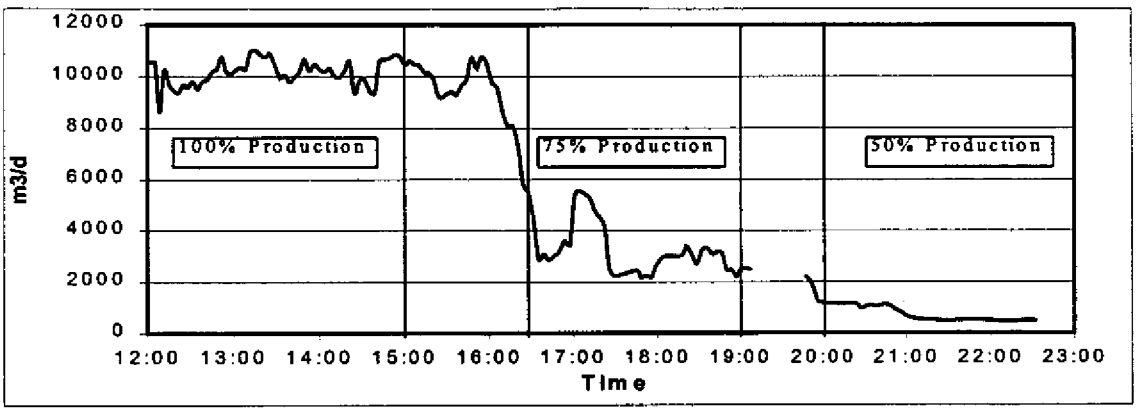

Figure 13 Gas Production at Well AA06 on 01/05/98

The results of tests for 30 April 1998 are reported next. On this day well AA06 was connected to the LP separator and measurements were taken on an hourly basis from 8:00 to 10:00 at "100% of full production" and from 10:00 to 12:00 at "50% of full production". The results shown in following diagrams are in excellent agreement with the known trends.

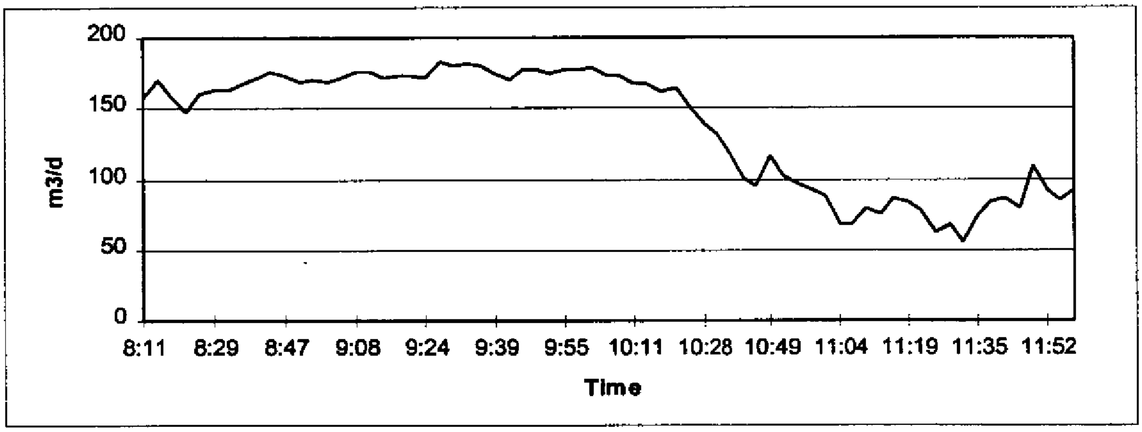

Figure 14 Oil Production at Well AA06 on 30/04/98

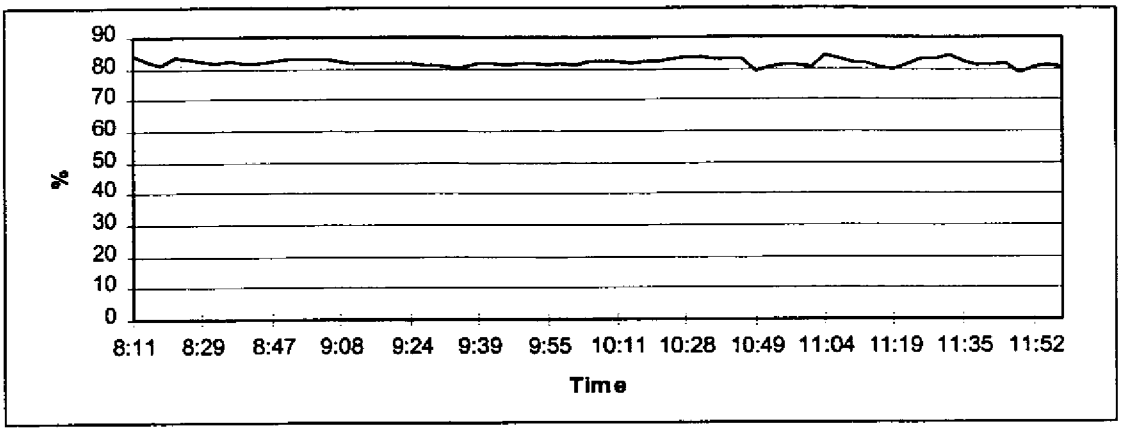

Figure 15 Water Cut Measurement at Well AA06 on 30/04/98

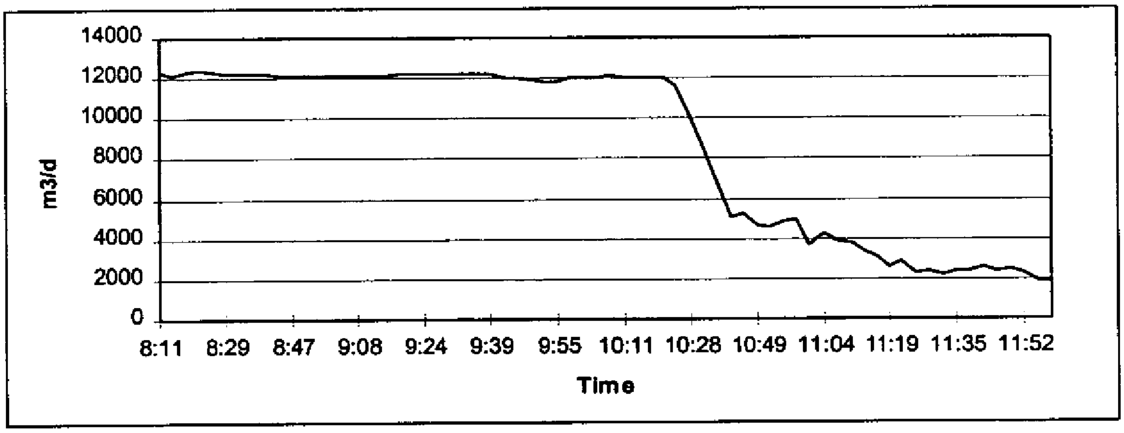

Figure 16 Gas Production at Well AA06 on 30/04/98

7.5 Average measurements

Flow rates predicted by ESMER every three minutes were evaluated against the reference measurements provided by the separator over an averaging period dictated by the separator. Separator measurements were obtained every hour, compared with every three minutes for ESMER and every ten minutes for TracerFlow. Thus a comparison was facilitated by averaging ESMER's predictions and the TracerFlow measurements over the course of one hour. The deviation between the average oil flow rates measured by ESMER and the Separator over the three stages of the tests are summarised in the table below.

Table 2 Comparison of Average Measurements over a Period of Observation ESMER vs Separator

Date/Time 1 May 1998	Production Condition As a "Notional" % of Operational Flow	Deviation (ESMER-Separator) /ESMER*100% Oil Flowrate	Deviation (ESMER-Separator) /ESMER*100% Water Cut	Deviation (ESMER- Separator) /ESMER*100% Gas Flowrate
1May 12:00 - 15:00	100 %	-4.5%	0.6%	-4.1%
16:30 - 19:00	75%	+6.1%,	-1.5%	n/a
20:00 - 22:00	50%	+14.9%	-0.2%	n/a
30Apr 9:00 - 10:00	100 %	+1.2%	-1.2%	+0.5%
11:00-12:00	50%	-6.4%	n/a	+60%
29 Apr 15:00 - 19:00	100 %	8.3%	-0.7%	2.8%

A large discrepancy was observed for gas flow rate on 30 April. We believe that this is simply due to the mis-match between the averaging periods of the two measurement systems when the flow conditions have not yet stabilised. For example, at 10 am, when ESMER averaging process starts (for the 11 am average at 7905 m^3/d), the gas flow rates is still at the initial full production level.

7.6 ESMER vs TracerFlow

First a few words about the Tracer Technique itself. Two types of chemicals (fluorescent dyes) are injected into the well head. One dye is soluble in oil and the other is soluble in water only. The injection continues at a constant rate for about 100-120 minutes. The technique requires approximately 100 pipe diameter distance between injection and sampling points for complete mixing. Since it is impossible to find a straight pipe section of this length on platform, the distance was kept shorter with the assumption of complete mixing of the dyes with the individual oil and water phases considering the effect of several bends on the way. The sampling point was set at about 4-5 m downstream of ESMER spool. The samples were collected by leaking flow into test tubes at 10 minute intervals during a 90 minute period. The samples were given 3-4 hours for separation and then analyzed under fluorescent light to detect the amount of dye in each phase. The main disadvantage of the technique is that it requires stable and homogenous flow. The slug flow regime does not produce reliable results.

The benchmark tests were based on the same calibration system described above. That is, the TracerFlow data was not used in the calibration exercise up to this point. However, it should be said that there is no fundamental objection to using the TracerFlow measurements in the primary factory calibration /re-tuning of the ESMER system (under those flow regimes where it works). In principle TracerFlow should offer a better spatial and temporal match for the characterisation of the flow conditions in the pipeline than the separator. As shown on the diagrams below the TracerFlow measurements were obtained every ten minutes and they facilitate a comparison between TracerFlow and ESMER drawn on a ten minute averaging period.

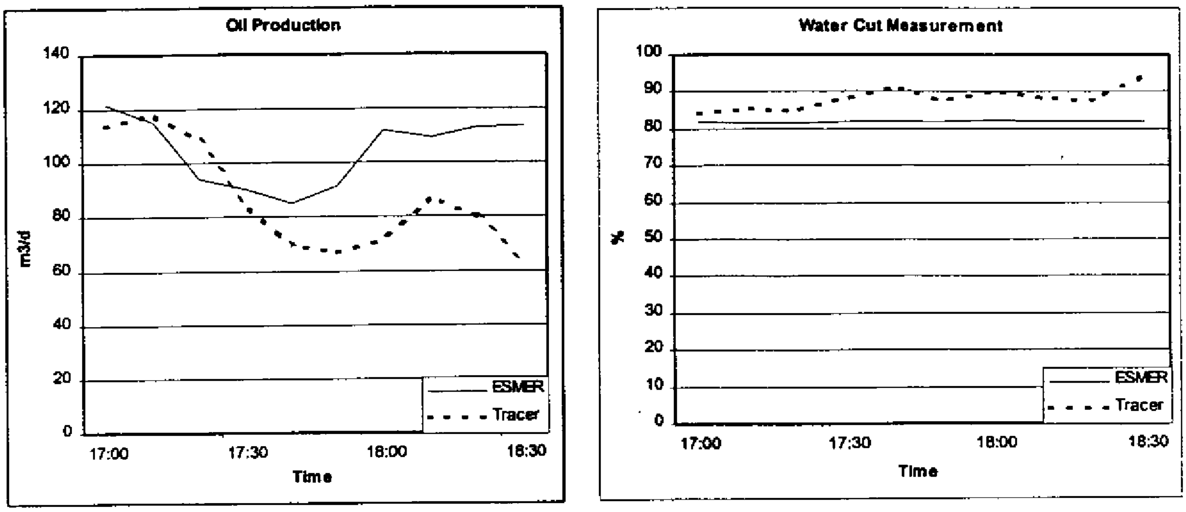

Figure 17 Comparison of ESMER vs TracerFlow at 75% production

The next table summarises the average deviation between the two measurement systems. The average is applied as an arithmetical average of measurements taken every ten minutes over the full course of the two stages of the tests labeled as 100% and 75% production conditions.

Table 3 Average Deviation between ESMER vs Tracer

Ref	Date/Time 29 Apr 1998	Production Condition As a "Notional" % of Operational Flow	Deviation (ESMER- Tracer) /ESMER*100% Oil Flowrate	Deviation (ESMER- Tracer) /ESMER*100% Water Cut
A	13:45 - 15:15	100%	-6.3%	-3.2%
B	17:00 - 18:30	75 %	17.4%	-7.8%

8 CONCLUSIONS

The ESMER approach to multiphase metering, using simple sensors and complex signal processing, can be readily applied in oil field applications. However, there are relatively few people at present with a feeling for how the ESMER approach works. This has been the main difficulty in promoting ESMER during its development to date.

The system tested on Auk, comprising a straight pipe with off-the-shelf pressure and impedance sensors, gives results which bear good comparison with any available multiphase meter. The accuracy of the meter is about 10-15% relative on all three phases.

Adjusting the laboratory derived meter calibration to field conditions proved relatively straightforward. A few field sample points based on the operators' experience were added to the laboratory data and the system was retrained.

The ESMER approach is particularly suited to low cost/medium accuracy applications, but there are no fundamental limits to the performance that can be achieved using this approach. This means that with improved sensors, and, more importantly, with better quality training data, high performance multiphase metering is perfectly feasible without significant increase in hardware costs.

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10 ACKNOWLEDGEMENT

This paper was written jointly by PSL, Daniel Europe Ltd and Shell Expro. So far, the partnership between the companies has been an excellent example of spinning off University based R&D into an industrial application. It is therefore appropriate for the authors to acknowledge the support from their respective companies. PSL provided the ideas behind ESMER and the academic ability to turn these ideas into a working system. Shell Expro provided on-going financial support and technological input on equipment, methods and requirements of the oil production industry. Daniel Europe engineered the hardware for the prototype system and gave encouragement and advice on the industrial exploitation of the innovation. Without the keen involvement of the three companies ESMER might have left a slight impression in the academic world but it would not have been our fortune to see it through to exploitation in industry. We must also thank the Auk staff for their willingness and enthusiasm to field test ESMER. Without their supportive involvement no real results could have been obtained. Acknowledgement is also due to the European Commission Thermie Programme for enabling the continuation of the project reported in this paper.

Main Index

North Sea FLOW Measurement Workshop 1998

PAPER 18 5 · 3

LONG TERM USE AND EXPERIENCE OF MULTIPHASE FLOW METERING

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TRIAL OF THE PROTOTYPE KVAERNER DUET MULTIPHASE FLOW METER

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ABSTRACT

The Kvaerner DUET multiphase flow meter (MFM) determines the flow rates of oil, water and gas in pipelines from oil wells. The MFM consists of two specialised gamma-ray transmission gauges, and pressure and temperature sensors, which are mounted on a pipe spool carrying the full flow of the well stream, and processing electronics which are located in a control room.

The prototype MFM has recently completed, what the authors believe to be, the longest ever operational period of an MFM anywhere in the world: from November 1994 to September 1998. This paper details the associated testing and method of using the MFM to reduce load on the facilities offshore. A description of the condition of the MFM at removal, including the physical condition of the composite windows, MFM electronics and the flow tube, and to the state of the head electronics is given. Also, the flow rate algorithms for the production MFM have been tested on existing MFM data and comparisons made between each trial result.

1 INTRODUCTION

The Kvaerner DUET MFM originally was developed by CSIRO (Commonwealth Scientific Industrial Research Organisation). In 1997 Kvaerner Oilfield Products signed an exclusive licence agreement with CSIRO for production and further development of the DUET MFM.

The field trial of the prototype MFM occurred on the West Kingfish offshore oil platform from November 1994 – September 98. The platform is located in the Bass Strait off the South Eastern Australian coast and is operated by Esso Australia. This installation was chosen as test site because of the quality of flow measurements available from an up-rated test separator and metering skid

During the trial, well streams were sequentially routed past the MFM which was mounted on a pipeline between the test manifold and the test separator. The bore of the test pipeline is 139.7 mm. The typical test pressure is about 15 bar, and fluid temperatures up to 96°C.

This paper describes the MFM installation and use over the almost four years of continuous operation. A detailed description of the excellent condition which the MFM was found to be in after removal is given and the flow algorithms are tested on existing MFM data.

2 THE DUET MFM

2.1 Principles

The DUET MFM consists of two specialised gamma-ray transmission gauges, and pressure and temperature sensors, which are mounted on a pipe spool carrying the full flow of the well stream. In the prototypes the processing electronics were located in a control room. The first gauge, a density gauge, measures the intensity of 662 keV gamma-rays (^{137}Cs) transmitted through the fluids in the pipeline. The second, a dual energy gamma-ray transmission (DUET) gauge, measures the transmitted intensities of 59.5 and 662 keV gamma-rays from ^{241}Am and ^{137}Cs.

All flow rates are calculated from separate determinations of water cut (WC) and flow rates of liquids and gas. Water cut is determined by dual energy gamma-ray transmission. The flow rates of liquids and gas are determined mainly from measurements of mass per unit area of liquids across a diameter of the pipeline by the density gauge; flow velocity from cross-correlation of the outputs of the two gamma-ray transmission gauges; and operating pressure and temperature in the pipeline. Gas volume fraction is calculated from the internal diameter (I.D.) of the pipe, the densities of oil and formation water at the line operating pressure and temperature, and the combined thickness of oil and water in the gamma-ray beam. In calculation of liquids and gas flow rates from these measurements, corrections are applied to make an allowance for slip between the liquid and gas phases in different flow regimes. Oil and water flow are respectively determined by multiplying liquids flow by (1-WC) and by WC.

The DUET gauge determines the mass fractions of oil and water in the liquids. The basis of this determination is the difference in atomic number of the oil and the formation water. The intensity of the transmitted 59.5 keV gamma-rays depends both on the atomic number of the fluid constituents and the mass per unit area of the fluids in the gamma-ray beam. The intensity of the transmitted 662 keV gamma-rays depends on the mass per unit area of fluids in the gamma-ray beam. Water cut is determined by combining these two measurements and the densities of the oil and formation water at the pressure and temperature of the flowing stream of multiphase mixture.

2.2 Hardware and Software

The DUET gauge requires low atomic number windows to ensure adequate transmission of the low energy (59.5 keV) gamma-rays. Thick windows of carbon fibre reinforced epoxy composite are incorporated into the DUET MFM. The inside surface of the carbon fibre epoxy window, exposed to the multiphase fluid, is shaped to match the curvature of the cylindrical inner walls of the ring, which has the same I.D. as that of the production pipeline. These windows are sealed with O rings to contain the process fluids [pressure tests at up to 10,000 psi have proved the integrity of the system], and, for the production version, a fully metal-to-metal sealed containment system surrounds the windows to prevent escape of production fluids in the unlikely event of leakage.

The very narrow beam of gamma-rays emerging from the radioisotope source containers traverse a diameter of the pipeline. The transmitted gamma-rays are absorbed in the NaI crystal of the scintillation detector. For the DUET gauge, the intensities of the ^{241}Am and ^{137}Cs gamma-rays are separately determined using pulse height analysis. The detector systems are mounted in explosion proof housings. The electrical signals from the detectors are carried via armoured cables, first to a flameproof junction box and from there to the processing electronics. Power is carried by the same armoured cable. The processing is undertaken by a fast nuclear counting system, and the outputs, in the form of counts, are processed by an industrial computer. The computer outputs the flow rates, water cut, and various other parameters which are displayed in computer graphics. The MFM presents the flow rates of oil, water and gas to the platform control system by a serial interface.

3 WEST KINGFISH PLATFORM

Esso Australia Ltd. operates, for the Esso/BHP Joint Venture, all the oil platforms and gas production facilities in the Bass Strait, Australia. The MFM trials were undertaken on the West Kingfish oil platform which lies 70 km from the coast in 80 m depth of water.

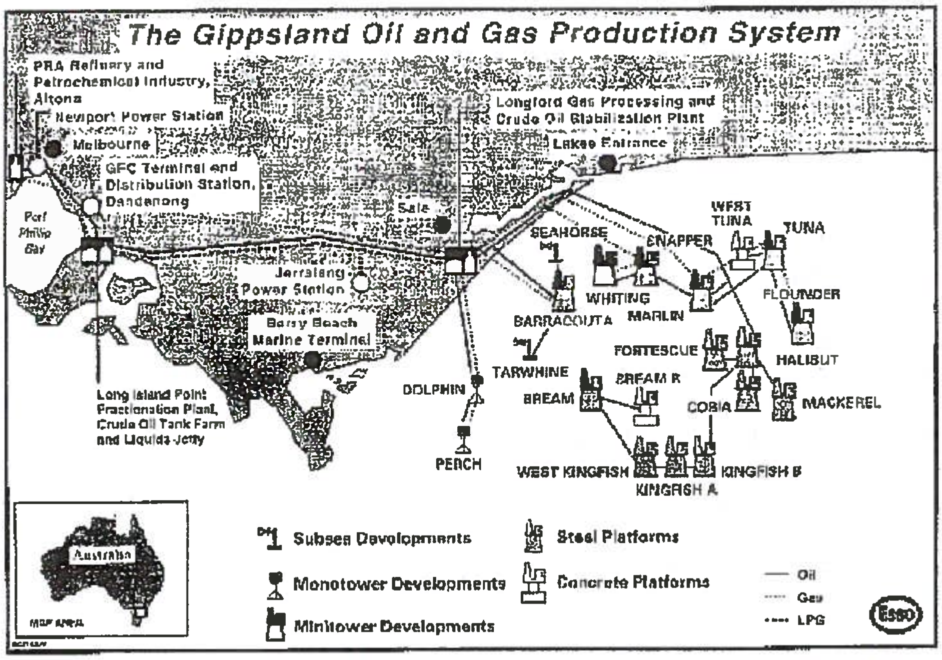

Figure 1 - Oil and Gas production systems in the Bass Strait, operated by Esso Australia Ltd

There are about 20 wells in production on the platform. The densities of stabilised oil and formation water are respectively 0.802 and 1.023 g cm^{-3} at STP. The flows from each of the 20 production wells are measured by the test separator twice a month.

Figure 2 shows the MFM was mounted on a vertical upflow section (ID: 139.7 mm) of the test pipeline which carries the full flow of the multiphase mixture from the test manifold to the test separator. The length of straight vertical pipe upstream of the density gauge was 1500 mm (11 pipe bores).

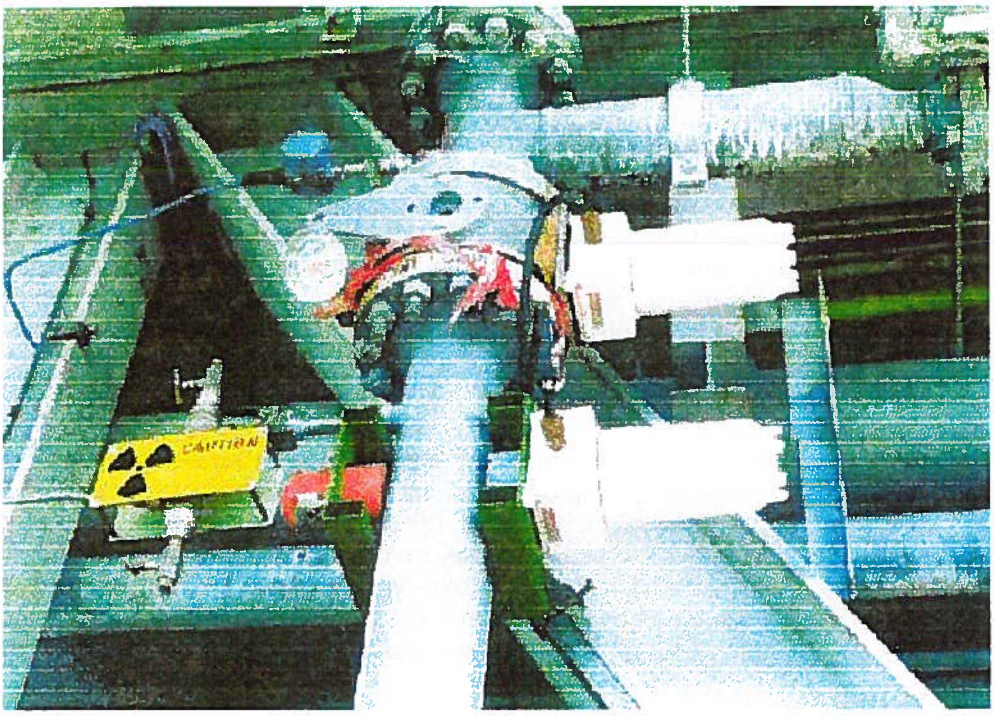

Figure 2 - The West Kingfish MFM about one month after installation

3.1 Eighteen Week Trial

The eighteen week trial of the MFM on the West Kingfish platform was undertaken from November 1994 and March 1995. Prior to start of trial, all meters at the separator outputs were upgraded/replaced to ensure the best accuracy and reliability possible. Sand is produced from some wells and so the test separator was cleaned out to ensure good water/oil/gas interface control.

3.2 Routine Use on Platform

Esso has continued to use the MFM on the WKF platform since the eighteen week trial. The MFM has been in routine operation, 24 hours per day, until its recent removal. After the initial 18 week trial, it soon became apparent that, for a good assessment of the MFM, a continuous record, over the one hour period of each well test, of the flows measured by the test separator output meters was required. This recording of separator flows was achieved in February 1996, with 30 second updates fed to the MFM computer.

The experience from the comparison of MFM and test separator flow determinations from March to the present date is that the MFM and separator determinations of liquids, water and gas flow rates generally agreed well. The accuracies for the MFM were maintained as for the 18 week trial throughout the remainder of the four year deployment.

The Texaco Humble field trial (1996) and subsequent ten month laboratory stability test (1997-1998) of an identical MFM as on West Kingfish, led to further development of hardware and software. The most important changes involved the use of lower capacitance cable and the development of new algorithms for water cut calculation. These changes improved the accuracy and stability of water cut determination, especially over a period of years. The ESSO MFM had approximately quarterly 'health' checks of the MFM performance compared with the test separator to maintain confidence in the DUET MFM performance. The hardware changes and the updated algorithms for water cut determination have been incorporated into the production versions of the DUET MFM. Trials of 6-inch and 4-inch production versions of the Kvaerner DUET MFM have been carried out subsequently using the NEL multiphase flow facility and have affirmed the performance improvements.

3.3 Condition of MFM Ring Gauge after Removal

The prototype DUET MFM was removed from the West Kingfish Platform during September 1998. This intervention provides the opportunity to determine the condition of the hardware following a demanding four year installation, in conditions which included large variations in environmental conditions and flows containing sand. The physical condition of the ring gauge and CFRE (Carbon Fiber Reinforced Epoxy) windows was of particular interest. No inspection of the windows had been carried out since the MFM was installed. Although health monitoring by regular checks of empty pipe gamma-ray intensities had indicated that there was no wear of the CFRE windows in the gamma-ray beam it is important to confirm this by inspection.

The MFM was installed near the eastern side of the platform, with only a walkway between the MFM and the edge of the platform. The walkway consisted of metal grating with the ocean visible directly below. The main deck overhead extended about 3m past the MFM and provided some shelter from the weather. However, the MFM was mostly open to the elements and as a result, after almost 4 years, and absolutely no maintenance, the surface of the MFM was coated with salt and other foreign material. After removing the MFM from the pipe, it was dismantled into its three basic components: source pots, electronic head units, and the ring itself, and then packed into a sea container and shipped back to CSIRO Sydney for complete dismantling.

Figure 3 - Inside bore of the ring gauge. The white spots are dried salt

Figure 4 - CFRE window after removal. Note the lack of wear

Figure 3 shows the inside bore of the ring with one of the CFRE windows still in place. The ring was forged from low corrosion carbon steel. The inside of the ring showed no evidence of erosion, nor was there any scaling or buildup of wax. The small white spots are salt. The CFRE window extended slightly in to the pipe after installation. No wear was apparent on the outer face or edge of the window.

The window galleries were sealed from the weather by an outer O-ring joining the ring gauge to source pot or head unit electronics. The seals were unbroken. The oil used during installation of the collimators and threaded parts provided further protection, and each part showed very little evidence of aging.

Figure 4 shows a CFRE window after removal and cleaning in soapy water. Inspection of the O-ring sealing surface of both windows revealed no corrosion or damage to the seal surface. There was no evidence of any wear, corrosion or damage to the front window surfaces. Neither was there any evidence of hydrocarbon or production water seepage into the epoxy. Similarly, the window mating surface of the steel body, Figure 3, was completely intact and showed no sign of any corrosion or wear. Put quite simply, in CSIRO's opinion, the O-rings could have been replaced and the original windows (except for the chip caused by the removal tool) put back into the ring, and the whole MFM reinstalled for another 4 years!

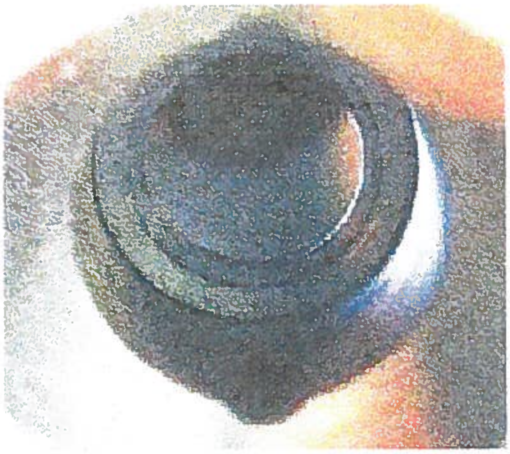

Figure 5 - Window mating surface in the metal ring

Figure 6 - O-ring after removal

The O-rings were slightly flattened, and in parts were plastically deformed to conform with the slight irregularities of the window sealing surface. However, the rubber remained smooth and flexible and showed no other signs of damage or wear, including the inside surface of the O-rings which were in contact with the produced well fluids and gas.

3.4 Condition of MFM External Head Unit Electronics

Both of the external head unit electronic containers have never been opened since the day they were installed. The NaI crystals, photomultipliers and pre-amplifiers of both units have operated without any faults at all. This is a remarkable achievement, especially considering that the initial specification was for the eighteen week trial only, with the possibility of an approximately one year extension if the MFM was found to be successful. The electronics has been powered continuously, interrupted only occasionally by power resets typical of offshore platforms.

The greatest concern upon receiving the head units back at CSIRO was that the Aluminium housing, used for the prototype, may have seized closed. As it turned out there was no need to worry: a little tight, but not unduly so. Upon opening the vessels, the electronics was found to be in near perfect condition. The only faults were a burnt out neon indicator light in the DUET head unit, and seized air circulation fans in both units. The indicator light has no effect on the meter and the fans were found to be unnecessary in 1996 and are not incorporated in the production DUET MFM.

4 DISCUSSION

Comments are now made on various aspects of the DUET MFM based on CSIRO and Kvaerner experience in its use, particularly in field trials. All data collected during field and laboratory trials is processed through the flow rate algorithms.

4.1 Comparison of Trials

4.1.1 Determination of water cut

The accurate determination of water cut is a consistent feature of the Kvaerner DUET MFM. The determination of water cut by the DUET gauge is independent of flow regime, water cut, and emulsion. Sand and corrosion inhibitor at levels normally occurring in well streams do not affect water cut measurement. The water cut has been consistently measured during field and laboratory trials to better than ±2% at up to 70% GVF and ±4% at up to 95% GVF (Figure 7).

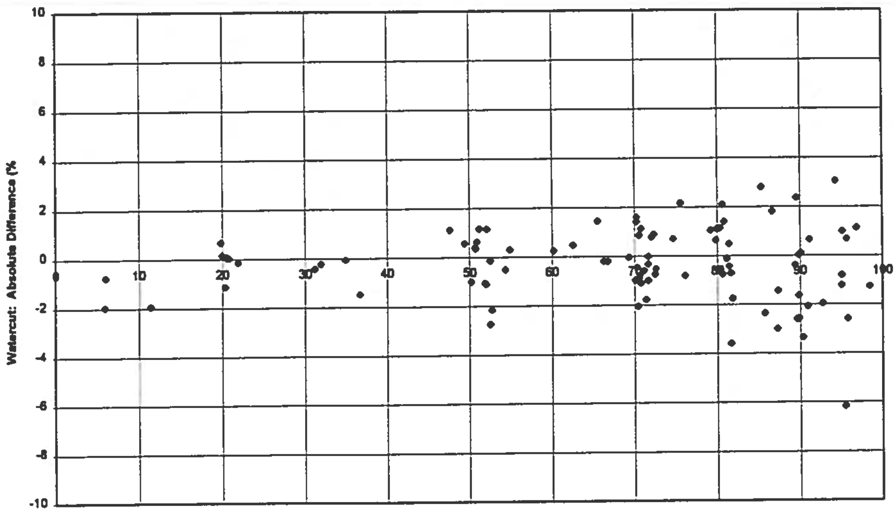

Figure 7 - Watercut results

4.1.2 Determination of liquids and gas flow rates

The algorithms used to calculate the gas and liquids flow rates from the parameters measured by the DUET MFM have been developed progressively. The same algorithms have been applied to data gathered during all trials, using physically different flowmeters and different trial sites. The results from a trial at the Humble test facility are illustrated in Figures 8 and 9 below.

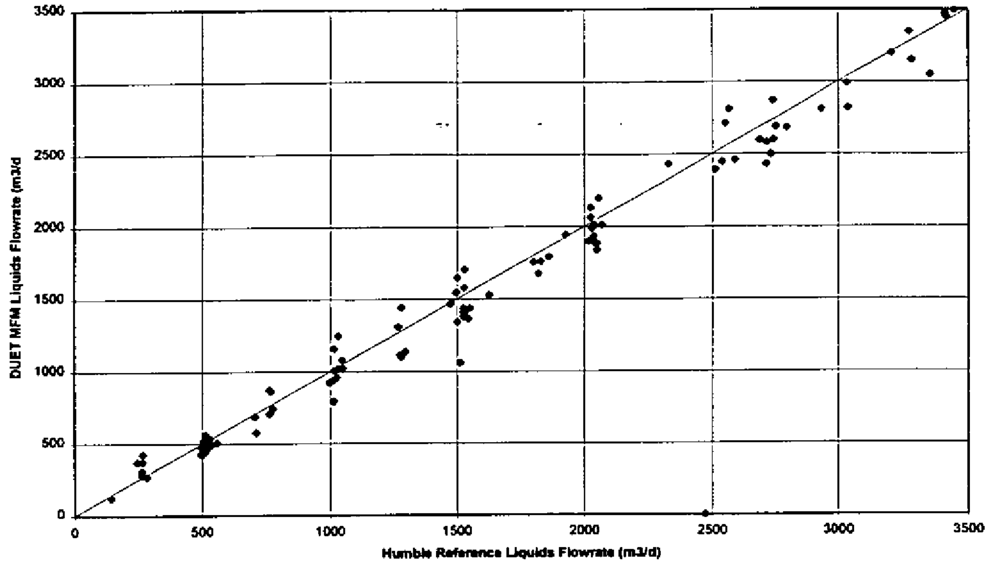

Figure 8 - Liquid flowrate results

These sample data are indicative of the results from all DUET field trials and show that liquids and gas flow rates are determined to accuracies of ±10%, independent of whether the flow regimes in the DUET MFM are dispersed, intermittent or separated.

Differences between the fluids used in the different trials have not caused systematic offsets in the flow rates determined by the MFM and have shown that the measurement accuracy is not dependent on the pipeline fluids.

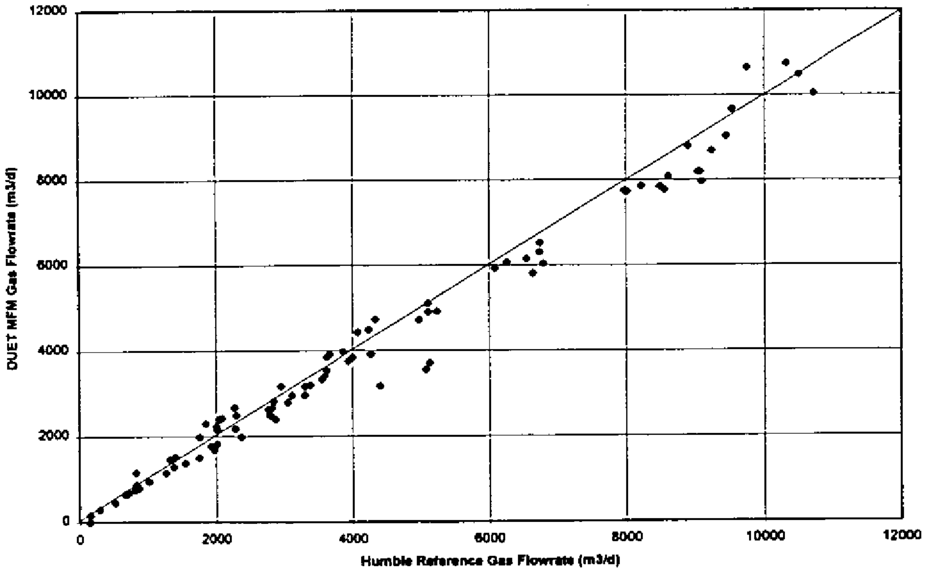

Figure 9 - Gas flowrate results

4.2 Reliability

The DUET MFM has proved to be reliable on the West Kingfish platform. The carbon fibre epoxy windows in DUET gauge ring have been demonstrated successful, with the windows showing no detectable wear over 43 months on-line. There have been five failures of the MFM equipment over the extended period of its operation on the platform: a hard disk crashed irretrievably within 2 weeks of installation, a fan in the processor box failed after 7 months of operation and again after almost 3 years. The heater control circuit needed modification after 2 years. Both the fan and heater unit have been phased out of the production versions of the Kvaerner DUET MFM. A modem also failed after one of the lads used it as a saw bench! All of these breakdowns occurred in the processing electronics in the control room where access and repair were simple, and none have occurred in the head units mounted on the pipeline. In fact, the two electronic head units in the field have never been opened, and have operated without incident since installation. These head units remained installed at all times, without maintenance intervention, during the four year trial.

One reason for the reliable operation of the MFM is that it is non-intrusive and does not depend on use of moving parts as with, say, turbine meters. The West Kingfish trial has demonstrated that the DUET MFM is highly suited to unattended operation on offshore oil platforms.

4.3 Calibration

The determination of water cut is now well understood, and calibration has now been simplified to making sequential measurements with the pipe filled with (static samples) oil, formation water and gas, and knowledge of the densities of oil and formation water, and the solubility of the gas in the fluids, as a function of pressure and temperature. The gamma-ray measurements required for calibration on static samples can be undertaken on-line at the field site, using samples at factory calibration or by calculation from fluid composition data.

4.4 Operational Advantages

The Kvaerner DUET MFM has important operational advantages over the test separator/output meters system. The DUET is more reliable and requires far less operator support and time for determination of the well flows than test separator systems. The MFM operates continuously with operator intervention only being required to switch the appropriate stream through the pipe on which the MFM is mounted.

Since the DUET MFM can be mounted on the pipeline between the manifold and the production separator, there is no need for stabilisation of the well flow prior to the MFM measurement. An Esso operator explains; "There can be a bottleneck which can lead to back pressure on the well. It can take up to two hours to stabilise the well flow before testing. On top of this the separator's turbine meters are prone to blockages which can lead to delays for hours as well as wear and tear." (The Tiger, 1995)

Operator intervention is also required with the test separator when there is a considerable change in flow rates of oil or water or gas to ensure that the single phase output streams are routed to the appropriate output meter. For example, on the West Kingfish platform, the output oil and water streams are monitored by turbine meters, with both high and low flow meters on each stream. The gas flow output is metered by a high range orifice plate and a low range vortex meter. The one DUET MFM on the West Kingfish platform measures all the component flow rates from all the wells fed to the platform; six single phase flow meters are required for use with the separator. The MFM has been shown to operate over a much wider range of flow rates of liquids, oil, water and gas than can be handled by the test separator and its output meters.

4.5 Engineering and Other Developments

The MFM can be adapted for use on a wide range of pipe diameters simply by adapting the design of DUET meter body. The DUET gauge with the ^{241}Am and ^{137}Cs radioisotope pair is suitable for use on pipelines with diameters between 4 and 12 inches.

The current limits of the DUET MFM operating range have been extended to up to 95% GVF, with velocity up to 25 m/s. It is expected that further development of the MFM will extend the operational envelope up to 98% GVF in the very near future.

5 CONCLUSION

The DUET MFM has been successfully demonstrated in the almost four years of continuous operation on the West Kingfish platform. Further concurrent trials of prototype and production standard DUET flowmeters at the Humble and NEL multiphase flow facilities have demonstrated that the performance of the flowmeter is transportable across physically different hardware and to different sites with differences in the composition of the hydrocarbons and produced water. Each of these trials has demonstrated reliable and consistent operation and measurement performance of the DUET MFM.

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ACKNOWLEDGMENTS

The authors wish thank Mr. Tom Dermott of Esso Australia Ltd., and staff on the West Kingfish platform, for their encouragement and support relating to all aspects of work on West Kingfish platform and for their assistance with this paper.

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WELL TESTING ISSUES AND A NEW COMPACT CYCLONE SYSTEM

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16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

WELL TESTING ISSUES AND A NEW COMPACT CYCLONE SYSTEM

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ABSTRACT

Well testing is the basis for reservoir management, allocation of production from various wells, and a key tool to quantify investments. In the past, well testing has been seen by many operators more as a requirement for obtaining numbers for management instead of use as a tool for planning and management of resources.

New technologies from computing power, integration of command and control into basic measurement instruments, and mathematical modeling of the fluid dynamics of complex systems has opened up new opportunities to improve management of fields. A few of these changes and their impact on well testing will be covered in this paper. The challenge for the future will be for reservoir and production engineers to utilize the data which these systems will provide. This information can then be presented to management with the chance to greatly improve the decision process about field upgrades, tertiary recovery opportunities, and improvements in manpower utilization.

Examples of relationships between data and the production of oil will be discussed. Equipment, which has been designed to incorporate technologies to enhance data obtained will also be described. A fundamental change in the methods and perspectives of personnel about well testing data is required to maximize the use of the new technologies.

1 INTRODUCTION

In the past, geological and reservoir engineers have focused on interpretation of data obtained by wirelines and other bore hole techniques along with summary production numbers to determine and optimize well production. Most of this information is obtained at a very high cost and can change overnight due to many factors beyond the engineer's control. Data such as water or miscible injection rates and production pressures, temperatures, flow rates of oil, water and gas are obtained on a regular basis and are shared among the various engineering groups. This latter data is the day-to-day operational information for evaluation of the production from a given field. The most fundamental information is contained in the well test data. This well test data is typically taken once or twice a month in most fields in the Americas.

It is interesting to look at some expectations of prior periods in time. In 1964, the following was stated by George Kite [1]:

> "Various arrangements for three-phase separators are in wide use but are often unnecessarily expensive and complicated; frequently they leave much to be desired insofar as accuracy, operator convenience and adaptability to automation are concerned.
>
> The instrumentation system discussed automatically and continuously meters and monitors an oil water stream containing ... or any combination thereof, and, without physical treating or separation, provides an accurate digital readout of net clean oil volume, directly in barrels.

No calculations, conversion factors, or interpretations are required; data are presented instantly, continuously and cumulatively in the most usable form. In addition, electrical digital signals for remote counting and an electrical analog signal for remote percentage water indication or recording are available at the computer terminal block."

Today, the industry is still stating that the current systems are expensive, operator intensive, inaccurate, and difficult to maintain. The proliferation of Seminars, Joint Projects, Conferences and Workshops concentrating on "Multiphase Measurement" emphasizes the industry is looking for better technology. The perfect solution would be compact, non-intrusive, low pressure drop, accurate, inexpensive and simple to use. This is a good description of what "Multiphase Measurement" is trying to accomplish. The question is how long will it take to get there and to what specifications and price can each of the markets requiring this withstand. In the meantime, the industry has not yet solved the basic problems which have been plaguing them for 30 years.

2 WELL TESTING ISSUES

There have been many forms of well testing, from tank strapping to three phase separators, two phase separators and now to three phase meters. The "ideal" well test system would be one that could be put anywhere and give accurate, repeatable results for oil, water and gas measurement with no additional back pressure on the well. This system would be flexible enough to be put in any kind of service and be portable enough to be moved from location to location.

Traditionally, the well test designs have been done by various groups throughout the industry sizing and specifying various components of a testing system. The vessel itself may be purchased from a separator design company with the remainder specified by an engineering company. In too many instances, the designer is twice or further removed from the person specifying the field parameters and needs. In many instances the company designing the equipment will never actually visit the field or talk to the end users of the equipment that he is designing. This makes this effort very dependent on the communications between the various operating groups and leads to many problems once the equipment is on site. Unfortunately, the well testing system is only too often considered secondary to the rest of the engineering efforts. Once the equipment arrives on the site and commissioned by a third party the operation is turned over to the field production groups. The result is that the end user must make it work. The burden is then on the field technical support groups.

Different segments of the market require different solutions depending on whether the customer is in the Arctic, South America, or the North Sea. The difference may not necessarily be in the technology but, more in the application of technology to the field. Heavy oil vs light oil applications require very different approaches to well test skids. Another difference could be in the method of presenting the data to the end user. In many cases in the Americas, the data is taken by operators writing down the various numbers at the site. The equipment may need to be designed for simplicity or complexity depending upon the measurement needs, capital money available, and knowledge and sophistication of the operators of the fields. Several other design parameters than can affect well testing include: fluid viscosity, water cut, gas oil ratio, oil density, water salinity, gas composition, distance of test equipment from the well head, flow stability, and reporting requirements of the operation. Asking questions of various operators, field production personnel, and design companies have led to the following comments about well testing:

1. Reliability and Maintenance – Today, fewer technicians are available, higher reliability is required; maintenance must be straight forward and simple to identify the problems. Complex systems must be made understandable.

2. Often there is inadequate understanding of the application at the beginning which then affects design decisions, selection of equipment, their sizes and capabilities.

3. Installation, documentation and support of equipment in the field are insufficient.

4. Presentation of data that is concise and pertinent to the operation.

5. Understanding and evaluation of methods used to validate well testing results which are often not consistent with accuracy or reproducibility.

Until the measurement, research, and engineering community begins to address these basic concerns, the industry solution required 30 years ago will still be a dream for tomorrow. The required outcome of a successful well test is not a measurement system but, instead, is the data obtained. How the data was obtained is not important as long as it meets the requirements of the end user of the data.

One of the most basic problems is that these solutions require very diverse types of professionals to implement a complete design. Contributing professionals to a successful design may include: fluid dynamics engineers, process engineers, instrumentation/electrical engineers, physicists, computer engineers, and involvement with the actual site reservoir, production, and maintenance personnel. When the requirements in a particular field are studied, many cases can be seen where the range of liquid and gas flow turndowns may exceed typical capabilities of a given design. This is because one site may have new wells and very old ones with varying tertiary methods of recovery. Another common concern is when a new facility design is completed which was based upon results from one or two exploratory wells that may not be representative of the range or rates once the field is in production. Oil and gas measurements are primary concerns but the water issues should not be forgotten. Important economic decisions based on the water production can be made about chemicals for corrosion and scale control. If the current and future needs of the same site are considered, the design of one system to address the solution will be unacceptable, yet this is the solution commonly chosen. If the professionals could model the designs and communicate with the field and reservoir engineers, a more flexible design may solve these issues. Too often, well testing is not considered important enough to concentrate the up front efforts required to implement a good system. This is surprising since the petroleum company makes its money on efficient use of its resources for production optimization.

Since each company, and in many cases each field, will have different computing systems and protocols, the data collection and storage is not an easy issue to address. The method of data collection may affect the results to a great extent. The system was designed without giving enough thought to the effects of how the data was gathered and manipulated. An example of this is when data is collected through a PLC to a DCS system. The PLC polls the equipment every 1 second, the results are integrated over a 3-5 minute time frame and then the DCS polls the PLC for the data. The graphs available to the operator are only the integrated data points each point separated by a 3-5 minute period. At the actual equipment it is obvious that the fluids are slugging from 60 m^3 to 600 m^3 over a 30 to 60 second time frame because the separator is out of control. The 3-5 minute integration is long enough that the data does not show the severe problem that actually exists. In another case, the dump/fill cycle of the separator was only 30-45 seconds and the emulsions went from oil continuous to water continuous and then back to oil continuous. This dramatic change in the fluid properties created considerable problems in the measurement equipment, and separator control. Since the data collection was every minute, extremely long well tests were required to obtain reasonable data.

The actual proposed use of the well test data is not always specified in the beginning. Whether for field evaluation, development and allocation of production of a new field, process control, and/or payment of taxes, the manner in which the data was obtained is important to the validity of the use of the data for the stated purpose. Field evaluation may only require a +/- 10% accuracy while fiscal measurement will place much tighter requirements on the design. If the data is obtained by integration over 10 minute intervals, the problems in separator efficiency, slug handling, and level control may not be observable in the data. Conversely, if the data is obtained and displayed on a 5 second interval, most operators would not interpret the data in a favorable light. The perceived operation of a system versus the actual operation is very different in some cases. The rapid changing of data due to fluid characteristics may be interpreted as a problem with the system. Thus, if the same data had been integrated and presented differently, the same operator would believe the system is okay. Although unacceptable to the operator, this "fast" data may be of much interest to the production engineer or the reservoir engineer since it may shed light on the actual performance of the well, separator and the control system. Data for fiscal use may only be the sum total oil/water/gas production per day with all periods less than one day inconsequential. Any other presentation of the data would be a problem to interpret by the actual user of the information.

Although the selection of the measurement instruments is very important to the end accuracy and generation of worthwhile data, the instruments are but one part of the system. The system must work as a whole and the data obtained must be consistent with the end use. The algorithms used to interpret the data collected from the separate instruments are critical to the operation of the whole. This is true whether it is a complex state-of-the-art multiphase analyzer or a two phase vessel with standard instrumentation. The combination and handling of the whole system is critical to performance in the application.

Next, the incorporation of high technology into these systems is both a problem and a blessing. "High tech" is frequently thought to be too complex and hard to understand by operators and technicians alike. Like the first microwave ovens that required an engineering degree to set the clock or to defrost and then cook a meal. Usually the "High tech" industry likes the whistles and bells in lieu of common sense straightforward methods. "High tech" is good in the sense that it gives an opportunity to address problems with solutions that were not possible before. Implementation of new technology typically provides a supply of ideas which will mature into better solutions than the existing technology. Unfortunately, these solutions become usable industry standards only after the technology is given a chance and the analyzer industry corrects the initial problems and redirects some of the methods. The first sales of these complex systems must go through the various stages of acceptance before the need merges with the knowledge and technology.

Finally, some of the greatest difficulties in development of new process technologies lie in understanding which questions to ask and how to obtain valid answers. The operations people may not be able to help since the people that need the technology most don't necessarily understand the problems and questions that are being asked. Therefore, they may not be sure how to answer the question. The technologist asking the questions may totally misunderstand the answers given. Truly, they may not understand the solution proposed because the fundamental issue that they question is why a different approach needs to be taken. In other cases, the new technology may appear as a threat to their existence in a particular job position. This issue alone can completely undermine a valid technology and the use of it in a well suited application. These issues must be carefully addressed during the information gathering process.

3 EXAMPLES OF WELL TESTING SITUATIONS

Since very early in the 1950's the need for well testing and good data from these tests has been pursed. Results have been very good in fields where steady production flow rates with low water cuts exist. Other cases exist where the two or three phase separators have been designed for good control and the oil and water separate readily with standard process methods or due to the properties of the fluids. In many cases, the data taken for well testing has not been analyzed completely and therefore important opportunities for improvement have been hidden. Several interesting cases will be described in the following discussion.

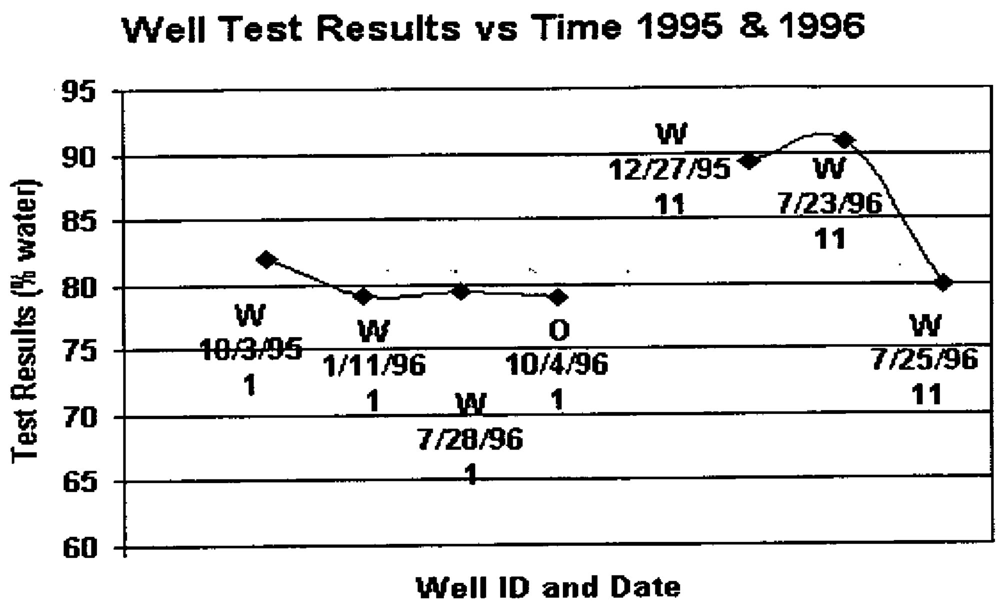

Figure 1 - Well Test Summary Results

Figure 1 shows two wells with results from testing over time. Well #1 shows consistent test results over a one year time frame. The "W" or "O" alongside the data represents the phase of the emulsion; water or oil continuous respectively. Notice the change from water continuous to oil continuous from 7/28/96 to 10/4/96. This change was due to the addition of gas lift to the well. A very tight and viscous emulsion was formed causing high pressure at the wellhead and lower production rates when the gas lift was initiated. The properties of the oil supported a phase inversion from the oil continuous to the water continuous phase at approximately 82% to 84% without other factors being involved such as gas lift injection. The gas lift altered the inversion point and maintained the oil continuous phase. The well was returned to production without gas injections to reduce the wellhead pressures and decrease viscosity which increased flow. Well #2 demonstrates a change in water cut of over 10% over the same time frame but, the emulsion type remained constant. The reason for this increase in oil production was a change in the pumping rate. Results from these tests allowed improvement in production of oil and understanding about production from this reservoir with data supporting the changes. The emulsion phase of the fluids is very important in understanding the behavior of wells. Most sites do not record this phase information as part of the historical well test data.

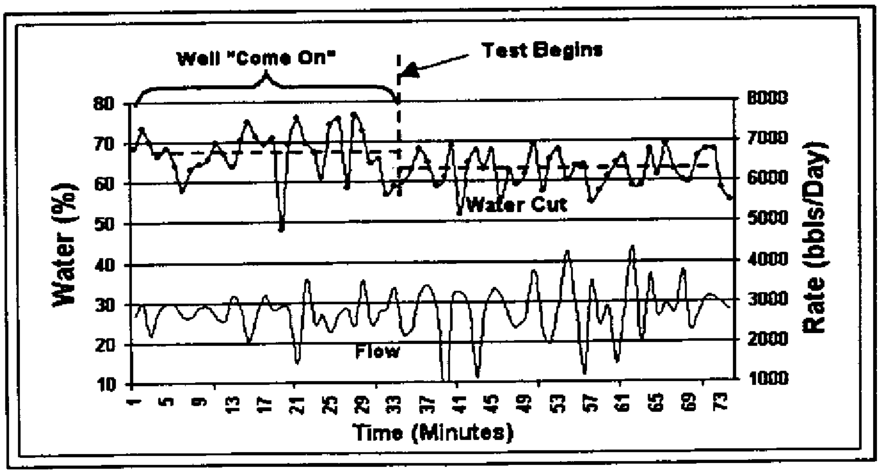

Figure 2 - Throttling Type of Separator Performance

Figure 2 shows real time data for a well to demonstrate that there is a time period for the measurement system to settle out once it is switched into the test separator. The wait of approximately 30 minutes was necessary for the well to "come on" and arrive at a steady rate of production and for the 2 phase separator to arrive at equilibrium. The remaining 12 hours of well test time was similar in nature although only a portion is shown in the graph. This system is a throttling type of two phase separator. This gives a relatively constant flow rate and therefore, eliminates many of the measurement problems seen with the dump-fill type of separators. Problems can occur with throttling types of separators when the design was not made to handle the control problems at very low and high flow rates. Data from throttling type of separators appears to be more consistent and verifiable than others. Pulling a sample when the water cut is maintaining a mean value is less difficult than a dump-fill type of separator where the cycle is changing the water cut rapidly through the dump portion. Therefore, a throttling type of cycle is easier to verify the performance of a system. Both the flow measurement and water cut instrumentation have higher potential of delivering good data due to the more consistent emulsions, flow and water cuts.

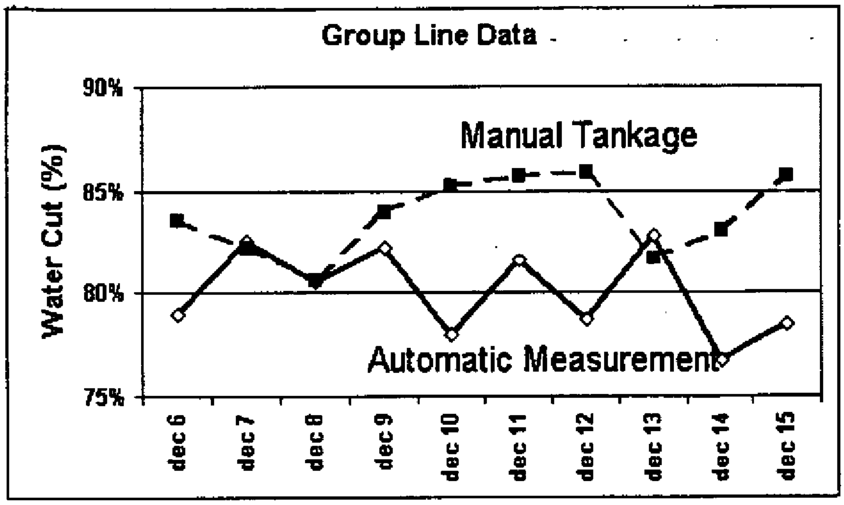

Figure 3 - Group Line Study

Figure 3 shows a common header where approximately 100 wells are merged into a "group line" and the test results from this line. Although not specifically defined as "well testing" this situation is part of the well allocation and production balance accounting. In the normal routine, testing was done by tank strapping each day. A 4" in line water cut analyzer was installed with a flow meter input to obtain net oil and to help in automation of the area. Tank tests results typically gave higher water cuts than the automated system. This problem was partially solved when the operator determined that another line merged with the free water knockout vessel, which was before the main strapping tank. This second line had flow metering problems of its own. Therefore, the second flow line numbers were taken as accurate measurements when they were not. The results proved that the automatic method was more reliable and reproducible than the manual method. In addition, the automatic method provided for better overall accounting of production balance. Installation of the automated system found problems for production, which would have been difficult to spot prior to automation.

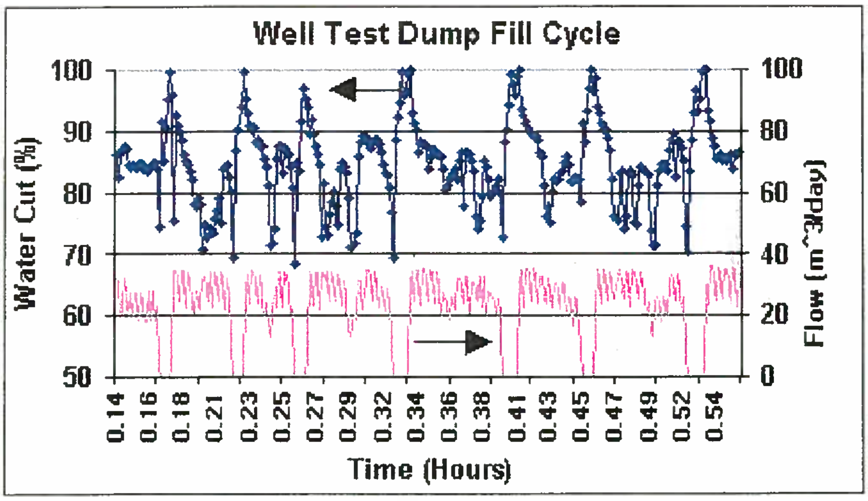

Figure 4 - Dump-Fill Type of Separator Performance

The well test results in Figure 4 are typical of a dump and fill type of two phase separator where the flow rates are relatively constant but not continuous. The flow can be seen to give relatively repeatable dump fill cycles of about 2.5 minutes for each cycle. One of the main difficulties with dump fill separators is that often the flow cycle will be reduced to less than 1 minute. This usually occurs as the well production matures and water flood is begun, or due to undersized vessels. At this point it becomes more difficult to accurately measure water cut and rates since the cycle time is too short to allow everything to come to a state of equilibrium. In addition, both types of emulsions are most likely to appear during this cycle. This creates a great deal of measurement uncertainty due to the great change in viscosity for heavier oils. In these cases a mass type of flow measurement is best.

4 CYCLONE SEPARATORS

Cyclone separators have many advantages other than the economic and facilities issues. Figure 5 demonstrates one advantage that is the very short time required switching over wells and achieving stability. The liquid capacity of the cyclone is typically very small. This small volume coupled with the closeness to the well manifold makes for a very short time to the next test. The typical well test can now be reduced to 2-4 hours instead of the normal 6-24 hours. Decreased time to test means more wells can be tested in a month. This helps in reservoir management and in production control. Wells with problems can be discovered before they become an issue and better allocation of production to wells can be accomplished.

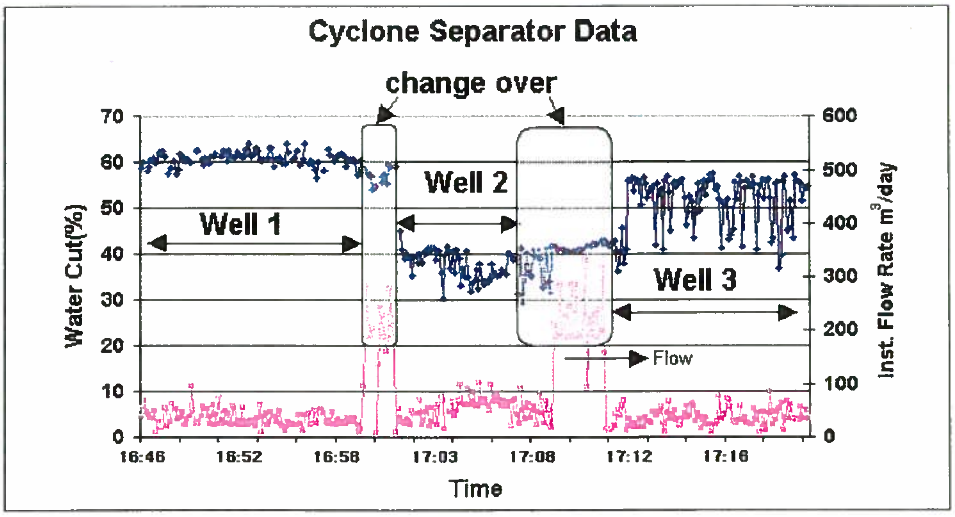

Figure 5 - Cyclone Separator Data

4.1 Compact Cyclone Multiphase System (CCM)

A unique design for a Compact Cyclone Multiphase (CCM) measurement system was designed to provide a very small physical footprint with performance in excess of existing methods of measurement. Field and laboratory data supporting its operation has also been completed with two systems installed in oil fields in North and South America.

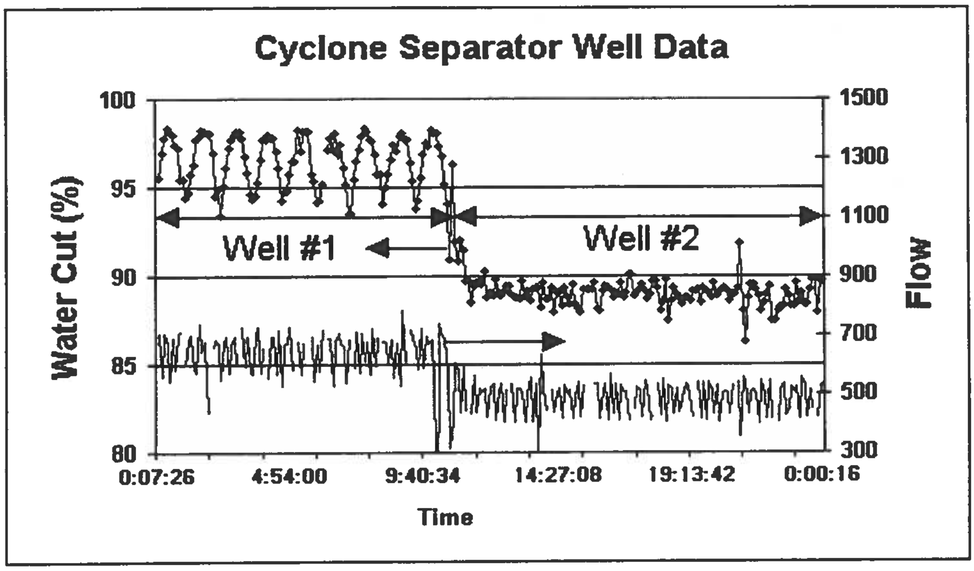

Figure 6 - Compact Cyclone Multiphase Data for 3 Wells

A novel gas blockage arrangement developed and patented by Kvaerner and Statoil a.s., is used which provides high centrifugal forces to be applied to the gas and liquid mixtures. This gives increased gas separation capabilities along with better control of the dynamics of the separator. The resulting design is optimized for the oil fields in which it will be used through modeling of the fluid dynamics within the gas/liquid separator. The concept for this system was invented and proven in use as an inlet device for gravity separators in the North Sea during the past two years. Approximately 20 oil production separators are now operating with this inlet device in the North Sea. The separator package for the CCM uses this unique device to eliminate the gas from the liquids so that conventional instrumentation can be used for the liquid stream.

The Kvaerner cyclone coupled with a Phase Dynamics' microwave water cut measurement, a coriolis flow and density measurement and appropriate gas measurement, provides a complete well testing system. Complete system control is integrated into the water cut measurement electronics to provide for minimum redundancy of electronics and maximum reliability. Integration of the water cut analyzer to the compact cyclone was accomplished as a joint venture between the two companies. The key is to solve the 30 year old problem mentioned in the beginning of this paper, and to provide an industry solution where one vendor is responsible for the entire design, instrumentation and support.

Data obtained from Porsgrunn supports the operational envelope of the CCM. Field data has also demonstrated the ability to remove gas and provide a measurement which conventional separators have had difficulties managing. The ability to look at almost real time well performance provides a unique opportunity to manage fields and wells unlike any point in the past.

Figures 5 and 6 show different wells under test with each having a unique signature of its own. The two wells in Figure 6 were from the same type of formations. The flow data is smooth and regular in both cases. Submersible pumps were the source of the flow. Looking at six different wells at the same site demonstrated that the characteristic of the data was unique to each well. The Well #2 in Figure 5 was later run for a long period of time to verify the data was representative after approximately 5 minutes of settling time. The long switching time between Well #2 and Well #3 was due to engineering curiosity where several wells were switched in at once to see the response. Data for the operator was integrated and displayed in a different format.

Figure 7 shows the basic compact cyclone separator. The cyclone portion is static and it makes use of the centrifugal force as the driving force for separation. Liquid and gas enters the cyclone distribution chamber through a spin section which will set up a rotational velocity. The spin section can be made up of vanes or tangential ports. The swirling flow induces a centrifugal field, typically 50-100 G's, which separates the liquid and the gas with the liquid leaving the separation chamber at the bottom.

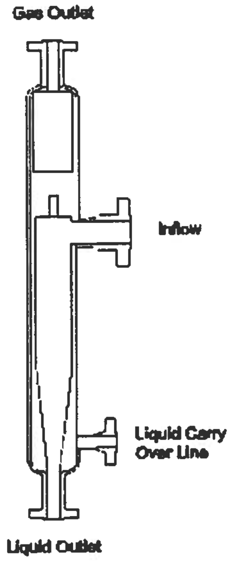

Figure 7 - Basic Cyclone

The cyclone is equipped with a gas blockage arrangement that directs the gas toward the overflow of the cyclone cylinder body. The gas and the remaining entrained liquid leave the first separation stage at the top and enter the second stage polishing unit. This second stage is the scrubber and polishing portion which separates the last of the liquid from the gas and then the gas leaves the top of the cylinder body. The liquid from the gas scrubbing stages is carried over into the annulus between the main cylinder body and the inner cyclone body. The liquid discharges out the liquid carry over line as part of the regulation and pressure balance of the system.

The multiphase meter includes a control system with up to three regulating valves depending upon the turn down ratios and gas oil ratios. The control is automatic and due to the unique design is very robust across the operational envelope

This system including the flow (liquid and gas) measurement, water cut analyzer and system control makes up the CCM. One of the key elements of this system is that every component can be identified and repaired because of the exact similarity to existing two phase separators. Existing personnel will be able to work on each section without additional training except for the control system itself.

The Phase Dynamics, Inc., water cut instrument was originally developed during the 1985-1992 time period with ARCO Oil and Gas and has been in worldwide use for approximately 5 years. Over 1000 systems are installed with the majority being used in well testing situations. The key is a microwave based measurement which provides an accurate measurement from 0% to100% water content in oil. This analyzer provides information about the phase of the emulsions for reservoir management and is very friendly to install, troubleshoot and use.

The water cut analyzer is well known throughout the world but, with the largest concentration in the North and South American Continent. The microwave based measurement is simple in the approach and rugged in real world applications. The unique "Oscillator Load Pull" patented technology provides for the extraordinary sensitivity of up to 3 MHz change in frequency for a 1% change in water cut for low range systems. The full range systems utilizes this sensitivity improvement in order to make a reproducible measurement even in the water phase at salinities up to saturation (27% salt by weight). The sensitivity improvement was brought about simultaneously with a very simple circuit. This combination provides the reproducibility, accuracy and reliability for field use that has been requested by the petroleum industry for many years. The design eliminates the complex microwave sources and down conversion circuitry required on typical microwave systems.

The CCM has been designed with the end user in mind by incorporation of the understanding from many fields and users of such equipment. These issues of reliability and maintenance, understanding of the application by the designer of the equipment, installations and support have been addressed in the design of the CCM system. Additionally, data which can be obtained from the use of this type of continuous flow systems has just begun to be understood.

4.2 Porsgrunn Test Results

A test of the prototype CCM was done at the Norsk Hydro Test facility in Porsgrunn during January, 1998. More than 60 points were tested at 23 and 35 bar pressure. The fluids were Norsk Hydro's Troll Oil, hydrocarbon gas and salt water with following properties:

- Temperature: 60°C
- Pressure: 23 and 35 bar
- Density water: 998.3 kg/m^3 at 60°C
- Density oil: $0.0035P^2 - 0.6879P + 871.22$ kg/m^3 at 60°C (25.7 API)
- Density gas: $0.0002P^2 + 0.6867P + 0.4829$ kg/m^3 at 60°C

Densities of oil and gas are best-fit lines of PVT data at 60°

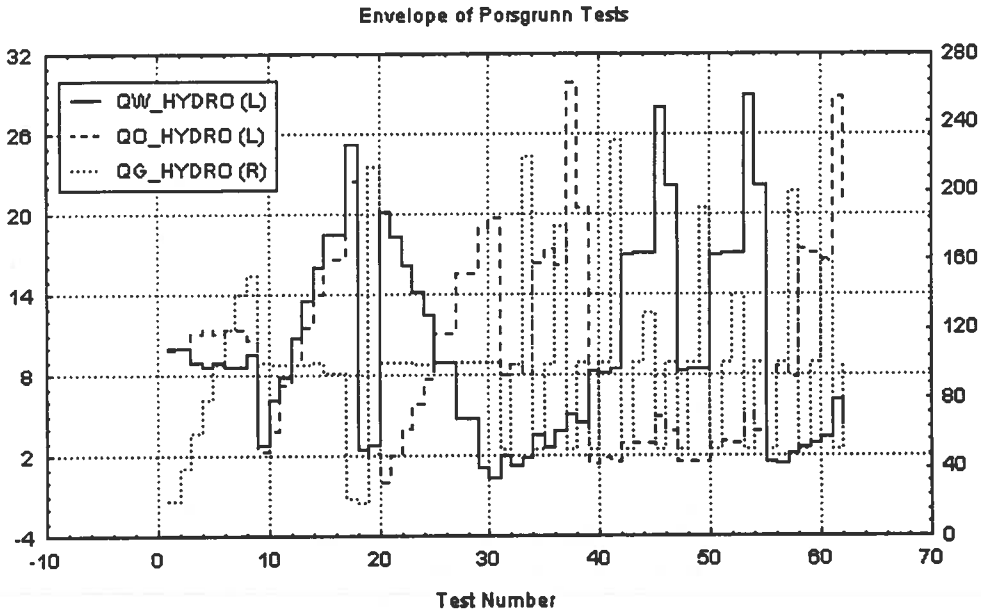

Figure 8 - Test Envelope

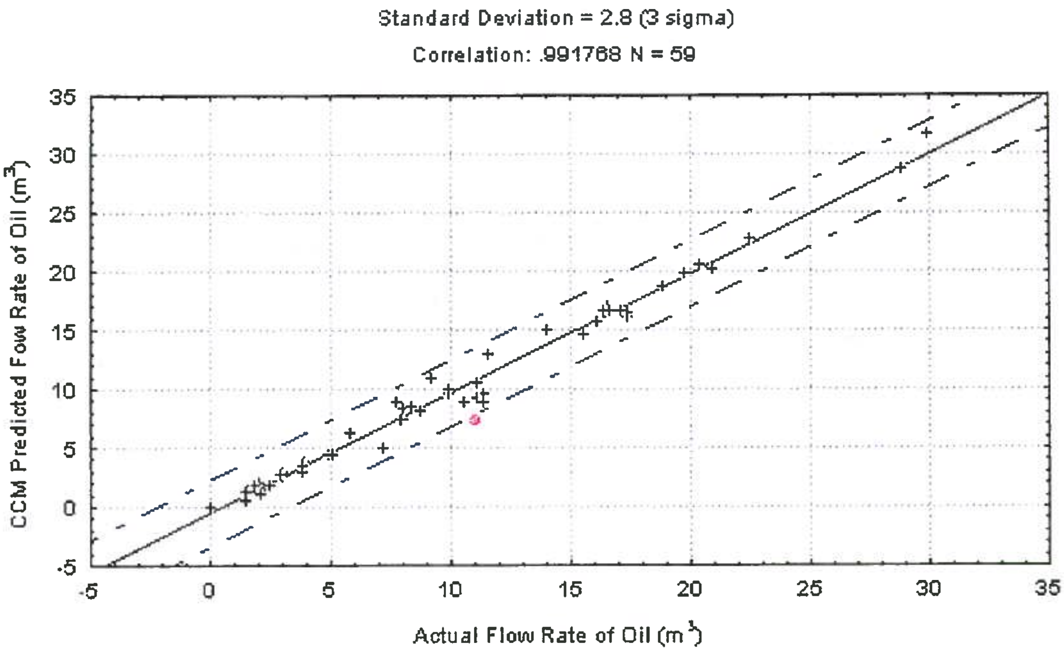

Figure 9 - Test Results for Oil Totals at Various Water Cuts and GVF

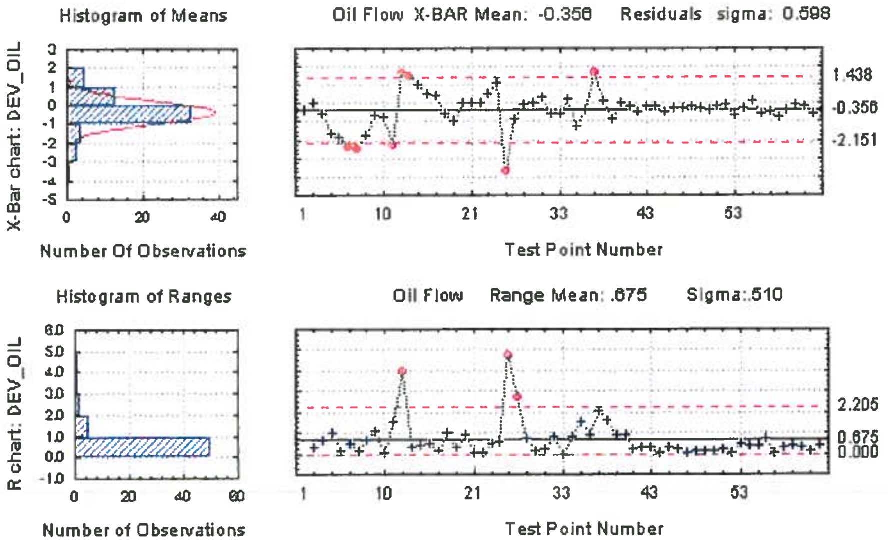

Figure 10 - Statistical Information on Oil Flow Errors

The objectives of the test were to test the new control system enabling the meter to function at GVF range from 0 – 100% at all pressures, and to test some design changes of the internals. Figure shows the gas/oil/water rates for the various test points. The control system worked according to expectations and the accuracy of the meter was increased somewhat compared to previous tests taken during 1997. Figure shows the results from 61 test data points giving flow rates for oil rates for the CCM versus the Hydro standards using a best line fit. The results are statistically very good as shown in Figure which gives the X-bar Chart and Range statistics for the error in Oil Flow. The X-Bar Chart is the result of the distribution of the differences between the two data sets. This distribution is "Normal" and therefore, is more valid than the best fit line data. The mean of the residuals is –0.35 with a standard deviation of 0.6 (3 sigma of 1.8). The second or Range Chart shows that the majority of the data points had less than a 0.67 error.

The internal design changes to the 2nd stage separator were sufficient although they could be improved upon above 100 m^3/hr rates. In Figure gas readings show a standard deviation of 5.1 m3/hr (3 sigma = 15.3) for a best fit line. Figure shows the X_bar and Range Charts for all of the points. The X_bar chart gives the statistics for the distribution of the data and also provides a plot of the differences between the CCM and Porsgrunn gas data, the mean and standard deviation. Again, the distribution of the data for the best fit line is not very "Normal." If the data was processed only for below 100 m^3/h gas flow rates, the Standard Error of Estimate is reduced to 3.6 from the 5.16 for all of the points. The 2nd stage separator is now redesigned through CFD (Computational Fluid Dynamics) calculations and laboratory experiments in order to improve the higher gas ranges.

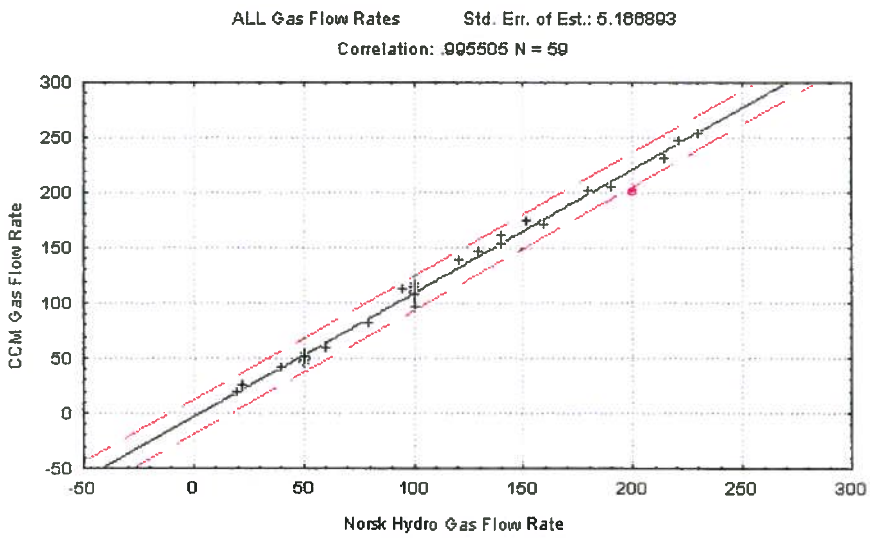

Figure 11 - All Points of Gas Measurement

In theory the accuracy of the CCM should be as good as the individual meters combined. In practice this is not easy to obtain because of the small volumes in the separator, which are comparable to an equivalent length of piping. This is a source of uncertainty in slug flow cases. About 3 – 4% error is added in slug flow. This uncertainty is not because of degraded separation efficiency, but mainly because each meter sees a transient, oscillatory flow.

The separator will work in any given GVF, but the flow and fraction instrumentation installed will restrain the metering due to their unique turn down ratios. If the system was designed for optimal reading at a GVF of 50%, good liquid reading would be obtainable at GVF ranging from 0 and up to approximately 99%, whereas good gas readings would be obtainable at GVF ranging from 5% and up to 100%. This means that the meter can be designed for optimal reading of both gas and liquid at any given GVF. The ability of the meter to function in high GVF flows (>95%) is particularly interesting for fields with high quantities of gas, and where the gas, condensate and water need to be measured. Full range water cut readings are standard.

These tests at Porsgrunn demonstrate that performance can be achieved from a very compact design using standard instrumentation. The accuracy envelope exceeds typical existing installations in the Americas. Improved accuracy can be achieved by designing for the oilfield's particular envelope of operation in an attempt to reach the measurement ccuracy of the various instruments. The real time data achieved through the use of the CCM should benefit management of the fields and accounting methods.

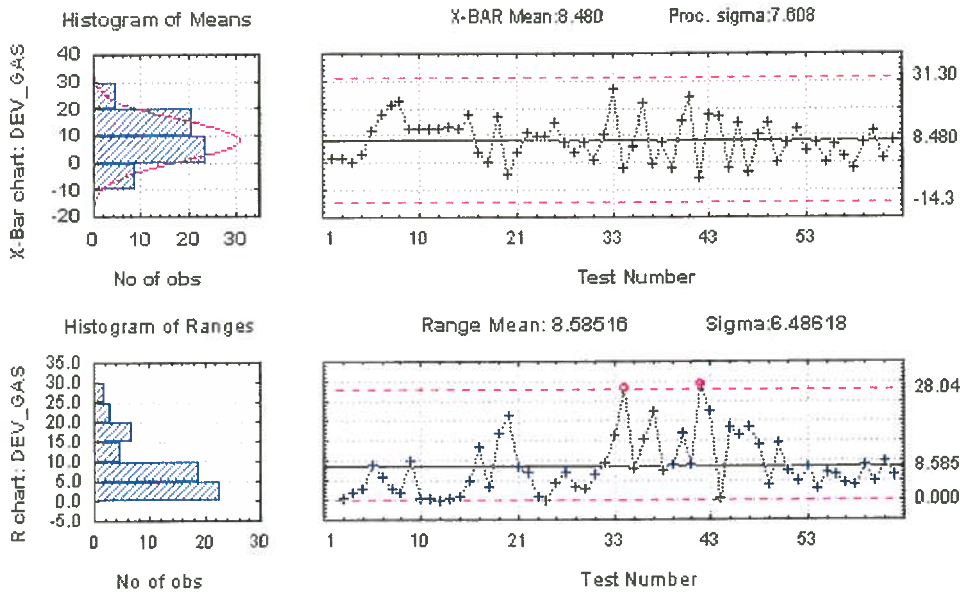

Figure 12 - Statistics for Gas Measurement

5 CONCLUSION

Reliance solely on conventional methods of reservoir management, fiscal accounting, and personnel managing the well test systems, must be changed to meet modern quality control of these processes. Use of real time analysis, expert systems, and statistical process control must be preceded by equipment designed to obtain more consistent information. The CCM is a step into this direction for the future.

What petroleum companies require is data representing the production and optimization of processes. The difficulty will be to balance the system complexity, degree of automation, required accuracy, size and back pressure allowed in order to produce the required data. The measurement industry needs to supply equipment where they have taken on the burden of providing sample system design, applications engineering for the site where it will be used, analyzer selection and engineering including requirements for installation and maintenance. The petroleum industry's prejudices about specific analyzers and methods would be eliminated if good data was supplied. This would help to free up talent in the equipment industry and would help to remove many constrains imposed upon new technology for use in the industry.

Involvement of the measurement industry's personnel in the measurement process will provide the additional insight into the use of the data that will become available as these new technologies unfold. Just obtaining megabytes of data on a well performance will not be sufficient. Information will be lost without proper interpretation and statistical manipulation of the data. With modern data acquisition systems the shear volume of data which can be obtained tends to cloud the solution to problems.

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North Sea

FLOW

Measurement Workshop

1998

PAPER 20 7.1

FLOW METERS IN SAND SERVICE CONDITIONS

J S Peters, National Engineering Laboratory
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16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

FLOWMETERS IN SANDY SERVICE CONDITIONS

Mr John Peters, National Engineering Laboratory
Mr Stewart Nicholson, National Engineering Laboratory

ABSTRACT

This paper describes the findings of a project undertaken by NEL for NMSPU, Department of Trade and Industry to investigate and quantify the performance of flowmeters in sandy service conditions.

This paper presents a summary of results covering the testing of three 100 mm nominal bore (NB) turbine meters, four 50 mm nominal bore turbine meters, and a 100 mm nominal bore wedge meter together with a 75 mm nominal bore Coriolis mass meter. The initial calibration of each test meter took place in clean water followed by comparison tests in three sand concentration levels, at various velocities, over extended operating periods. This was followed by a strip-down and internal examination of each meter for any damage/wear.

Overall conclusions are given on the performance of each meter manufacturer, meter type and meter nominal bore size. Particular interest is given to the intercomparison between each group of meters with regard to meter type, size, material of construction and wear.

1 TEST SERIES BACKGROUND

Flowmeters are widely used in the offshore industry in downhole locations and increasingly used during separation. They are also utilised for exploration and production of oil and gas fields, and by other industries in dirty fluids.

In these conditions they are often subject to a variety of abrasive materials being entrained in the measurement fluid. As little performance data was available which quantified the effect of abrasive flow conditions on flowmeters, the Department of Trade and Industry, under the National Measurement Policy Unit Flow Programme decided to sponsor a programme of work to investigate this. It was decided that the test programme would cover a number of different turbine meters of 100 mm and 50 mm nominal bore as well as a Coriolis mass flowmeter and a differential pressure wedge meter. Each meter was representative of the type of meter commercially available and used in the field in these applications.

The meter evaluations were carried out in the NEL Abrasive Flow Test Facility and entailed simultaneous calibration of each group of meters, in series, against a reference electromagnetic (em) flowmeter installed upstream of the test meters. Prior to the start of the test programme the em meter was calibrated in-situ against a calibrated turbine meter traceable to the NEL Primary Standards.

Establishing and quantifying any change in the performance of the test meters is the objective of this test series. It must be noted that determination of flowrate errors from the test meters is not the objective of this test series. Hence, the initial clean water calibration of the meters is used as a datum from which all abrasive flow calibrations will be judged.

2 INTRODUCTION

Each group of meters was tested simultaneously (in series) during each section of the test programme, ie clean water calibration followed by various sand content tests. This allowed for direct comparison between meters of equal size as the test programme progressed. All sand percentages in this report are defined as percentage sand content by weight. Appendix I describes the sand specification. The sand used during this test series remained within specification for approximately 250 hours running time. After this, or sooner if sand samples indicated necessary, the test fluid and sand was replaced to ensure that the test condition remained constant.

3 SELECTION OF METERS

A functional specification for flowmeters in sandy flow service was sent out to manufacturers inviting them to tender for the supply of suitable flowmeters. Some manufacturers stated that they would not usually specify meters for this duty but would supply a meter typical of the meters used in the oil sector. For this reason the names of meter manufacturers detailed in this report were anonymised. The same meter manufacturers were used to provide 50 mm NB and 100 mm NB turbine meters, with the addition of one meter manufacturer (Manufacturer A) in the 50 mm NB tests. This was due to the test facility pipe lengths allowing for four 50 mm NB meters and only three 100 mm NB meters to be tested. Test meter results in this report are designated to Manufacturers A - D for 50 mm NB turbine meters, Manufacturers B - D for 100 mm NB turbine meters and Manufacturers E and F for wedge and Coriolis mass meters respectively. Details of test meter materials, turbine blade number, turbine blade shape, etc are shown in Tables 1a and 1b.

The meter types and the manufacturers for these tests were selected on the following criteria:

- Popularity of manufacturers meter in field use.
- Meter internal construction.
- Price and delivery.

It was obviously important to select meters that were being widely used to enable realistic data to be produced which would assist users. The differential pressure meter and one turbine meter were chosen as they were designed specifically for abrasive flow service. The remaining meter manufacturers have large numbers of meters in oil field use, although not specifically for abrasive flow applications they were selected as major meter manufacturers. Coriolis mass meters are now being used in many offshore applications therefore this type of meter was selected because of its increasing popularity in the oil industry and its 'non-intrusive' design.

4 METER INSTALLATION AND INSTRUMENTATION

The meters were tested in the abrasive flow test facility as described and shown schematically in Appendix II.

Each group of meters was installed in horizontal pipework, in series, in the facility to enable them to be tested and calibrated simultaneously. To ensure that meter performance was not influenced by the facility, or by another test meter, each meter was installed according to the manufacturers installation instructions with appropriate lengths of upstream and downstream straight pipe.

The test meter flowrate readings were logged simultaneously with the reference meter flowrate and velocity, temperature, line pressure and time of day. Sand samples were taken from the test line and measured at 250 hour, run time, intervals.

The test meter readings and meter flowrates were input into an EXCEL spreadsheet and the performance data calculated. Ten of these points were taken, from each meter, to obtain an averaged reading which represented one data point. Temperature, velocity (derived from the test meter nominal bore size and reference flowrate) and pressure drop were monitored in a similar manner to the reference meter and input into the spreadsheet for analysis. Test line pressure was also monitored to ensure cavitation did not take place.

5 TEST PROGRAMME

For each test series, dictated by meter size and type, the test programme was as follows:

- Run meters in clean water over a range of flowrates for a minimum of 24 hours. This acted as a "run-in" period for the test meters.
- Calibrate the meters in clean water, over a range of flowrates (within flow range of the meters or the facility), against the facilities reference electromagnetic flowmeter. Minimum test run period of 12 hours.
- Test each meter series at a minimum of two flowrates using three sand concentrations.
- Strip down test meters and complete an examination of meters for wear/damage.

6 TEST RESULTS

6.1 Clean Water Calibration of Reference Electromagnetic (em) Meter

The test facility reference em meter has been used for a number of years and therefore has a known history of stable calibration against calibrated turbine meters. The em meter was calibrated in-situ against a reference turbine meter immediately prior to the start of the test series and was subsequently used throughout the test period. A copy of the em meter calibration is shown in Fig. 1.

Error was calculated using:

$$\frac{\text{Reference meter - test meter}}{\text{Reference meter}} \times 100.$$

6.2 Clean Water Calibration of Turbine Flowmeters

All test meters were calibrated against the facilities reference electromagnetic flowmeter. This produced a "datum" (reference) clean water calibration from which future abrasive flow test results could be compared.

6.3 Evaluation of Test Meters at Optimum Performance Flowrate Using Three Sand Concentrations

Meter tests were completed at a flowrate that was considered to be representative of their optimum performance flowrate. For the turbine meters this represented a rate nominally mid-way in the manufacturers recommended flow range. The wedge meter was tested towards its upper flow limit because it has a very low turn down limit and would therefore perform best at a flowrate near its maximum. This flowrate corresponded to a flowrate approximately 50% of the Coriolis mass meter's maximum flowrate and therefore allowed these meters to be tested in series. The flowrates selected during this test were nominally 9 l/s for the 50 mm NB turbine meters, 35 l/s for the 100 mm NB turbine meter and 30 l/s for the Coriolis mass and differential pressure wedge meter.

6.3.1 Optimum flowrate abrasive flow tests on 50 mm NB turbine meters (Nominal 9 l/s)

This flowrate represents nominally 50% of the test meters maximum flowrate.

Fig. 2 shows the data obtained from the 50 mm NB turbine meter tests along with data taken from their original clean water calibrations at a similar flowrate. (Nominal 9 l/s.)

It should be noted that there is no sand test data for Manufacturer A. This meter seized after two hours running at 0.126% sand content and was removed from the test programme at this point.

During the abrasive flow tests Manufacturer B's test meter produced a similar result to the clean water calibration. The flowrate percentage error shows a slight improvement as the sand percentage and test period increased. It should be noted that this meter is recommended by the manufacturer specifically for abrasive flow duty.

Manufacturer C's, 50 mm NB turbine meter, initially produced an improved flowrate error compared to the initial clean water calibration, but this rapidly increased throughout the 0.126% sand tests where it peaked at nominally 3.4% after 172.5 hours abrasive flow duty. The flowrate error remained at this level until the end of the 0.364% sand content tests (256.5 hours abrasive flow duty) when this meters flowrate error increased to 81%. The meter was removed from the test facility to find that the meter's rotor blades had disappeared. This may have been due to erosion to the root or by the blades being torn away at the blade root.

The 50 mm NB turbine meter from Manufacturer D produced a similar flowrate error as the clean water calibration for the initial 20 hours of abrasive flow service at 0.126% sand content. The flowrate error gradually increased throughout the abrasive flow tests until it reached a peak of nominally 2.6% after 300 hours sand service. Following this the final data point at 324.5 hours, after 0.126%, 0.364% and 0.644% sand content runs showed an improvement compared to previous data.

6.3.2 Optimum flowrate abrasive flow tests on 100 mm NB turbine (Nominal 35 l/s)

This flowrate represents nominally 47% of the test meters maximum flowrate.

Fig. 3 shows the data obtained from the 100 mm NB turbine meter tests along with data taken from their respective clean water calibration at a similar flowrate. (Nominal 35 l/s.) As previously stated, only three 100 mm NB meters were tested due to facility pipe length restrictions. Manufacturer A was not requested to submit a test meter for this phase.

Manufacturer B's, 100 mm NB turbine meter, showed an immediate rise in flowrate percentage error of 0.25% when compared to the clean water calibration data at a nominal flowrate of 35 l/s. The flowrate percentage error remained at this level, approximately 2%, for the remainder of the test period encompassing 0.126%, 0.315% and 0.617% sand percentages over a 261.5 hour test period. It should be noted that this meter is recommended by the manufacturer specifically for abrasive flow duty.

Following the clean water calibration of Manufacture C's meter showed an immediate rise of 0.35% when 0.126% sand was added. The percentage error remained relatively constant at 1.50% throughout the following 57 hours at a sand content of 0.315%. After the sand content was increased to 0.617% the flowrate error remained relatively constant at 1.50% although the meter output was erratic towards the end of this sand percentage at this flowrate.

The initial 0.126% sand content test data from Manufacturer D's 100 mm NB turbine meter showed an improvement in flowrate percentage error from the clean water data, at a similar flowrate. This percentage error, 1.4%, continued for the 149 hour test period at 0.126% sand content. When the sand content was increased to 0.315% the flowrate percentage error immediately increased until after 26 hours the flowrate error was 1.75%. Over the following 31 hours, at this sand content, the flowrate error decreased back to the previous level, 1.4%. After the percentage sand was increased to 0.617% the flowrate error increased to a high of 2.1% but later returned to 1.6%, a similar figure to the initial clean water calibration, after a total of 261.5 hours in abrasive flow.

6.3.3 Optimum flowrate abrasive flow tests on 100 mm NB wedge meter and 75 mm NB mass meter (Nominal 30 l/s)

This flowrate represents nominally 67% of the test meters maximum flowrate.

Fig. 4 shows the data obtained from the 100 mm NB differential pressure wedge meter and the 75 mm NB Coriolis mass meter tests, Manufacturers E and F respectively, along with data taken from their original clean water calibrations at a similar flowrate.
(Nominal 30 l/s.)

During the 0.156% sand tests the differential pressure wedge meter from Manufacturer E, produced a rise of approximately 2.5% compared to the clean water calibration at 30 l/s. The flowrate percentage error remained at this level, 3%, throughout the 0.156% and 0.352% sand tests, a total abrasive flow period of 244.5 hours. It should be noted that the percentage error figures were erratic during this period showing large percentage spreads from the mean flowrate error.

The sand content was increased to 0.777% and following a further 129 hours at this level the flowrate error decreased slightly to 2% with an improvement in the spread of the error results.

During the 0.156% sand tests the Coriolis mass meter from Manufacturer F, produced a similar flowrate percentage error,(0.8%) to its clean water calibration. This continued throughout the 0.352% sand content tests for 244.5 hours, with the exception of two data points.

When the sand percentage was increased to 0.777% the flowrate percentage error reduced to 0.5% and remained there for 45.5 hours before rising over the following 20 hours and then reducing to 0.25% after 373.5 hours.

6.4 Evaluation of Test Meters at Low Flowrates Using Three Sand Concentrations

During this test the meters were run at a flowrate that was considered to be with-in the manufacturers recommended flow range. For the 50 mm NB turbine meters this represents a rate nominally 33 percent of their recommended maximum flowrate. The 100 mm NB turbine meter low flow data was collected at nominally 20 percent of the manufacturers recommended maximum flowrate. The mass and wedge meter low flow data was collected at approximately 20 percent of the manufacturers recommended maximum flowrate.

6.4.1 Low flowrate abrasive flow tests on 50 mm NB turbine meters (Nominal 6 l/s)

This flowrate represents nominally 33% of the test meters maximum flow range.

Low flowrate data points were taken towards the end of each sand content percentage test period.

After completing the sand content tests the test facility was run with clean water at low flowrate and data taken from the test meters to act as a comparison with the original clean water calibration.

Fig. 5 shows the data obtained for the 50 mm NB turbine meter tests along with data taken from the original and final clean water calibrations at a similar flowrate.
(Nominal 6 l/s.)

Data taken from Manufacturer B's 50 mm NB turbine meter, at the end of 172.5 hours of 0.126% sand content, showed an improvement on the original clean water data at a similar flowrate. The data taken after 84 hours at 0.364% showed a slight increase on the previous sand data but this represented a return to the percentage error shown in the original clean water calibration. Following the 0.644% sand tests the flowrate percentage error showed an increase of approximately 8.0% with poor repeatability.

The final clean water data showed a slight increase in the repeatability of the flowrate percentage error, compared to the original clean water calibration, but this may be due to more test data being recorded during the final clean water test.

Test data from Manufacturer C's, 50 mm NB turbine meter, at the end of 172.5 hours of 0.126% sand content tests showed a percentage error increase of approximately 1.5% compared to the original clean water calibration. During the 0.364% sand content tests the meter's flowrate percentage errors increased to unacceptable levels (82%) and the meter was removed from the test facility after 256.5 hours. After investigation it was discovered that this meter's rotor blades had been removed. This may have been due to persistent erosion or they could have been shorn off at the root.

Manufacturer D's 50 mm NB turbine meter low flow 0.126%, sand content flowrate percentage error test data showed an increase of approximately 0.4%, after 172.5 hours, compared to the original clean water calibration at a similar flowrate. Following a further 84 hours at 0.364% sand content the meters flowrate error had increased by a further 0.4%. After a further 68 hours at 0.644% sand content, a total abrasive run time of 324.5 hours, the meters flowrate error was approximately 9%. This represents a rise of approximately 8.5% from the original clean water test data. The final clean water test data shows a return to approximately 2% flowrate error. This represents a rise of approximately 1.5% compared to the original clean water data at this flowrate.

6.4.2 Low flowrate abrasive flow tests on 100 mm nb turbine meters (Nominal 15 l/s)

This flowrate represents nominally 20% of the test meters maximum flowrate.

Low flowrate data points were taken towards the end of each sand content period.

Fig. 6 shows the data obtained from the 100 mm NB turbine meter tests along with data taken from their original clean water calibrations at a similar flowrate. (Nominal 15 l/s.)

Data points taken at nominally 15 l/s for Manufacture B's 100 mm NB turbine meter, after 149 hours sand service at 0.126%, showed no change from the original clean water calibration. Following a further 57 hours at 0.315% sand concentration the flowrate percentage error increased by 0.25% and at the end of the 0.617% sand tests, a total abrasive flow test period of 250 hours, the flowrate error had increased a further 0.2%. This shows a combined increase of 0.45% after 261.5 hours abrasive flow service compared to the original clean water calibration.

Manufacturer C's, 100 mm NB turbine meter, showed similar results after 149 hours of 0.126% sand concentration tests as the original clean water calibration. Following a further 57 hours at 0.315% sand concentration the flowrate error had increased by 0.3% from the original clean water calibration. The sand concentration was further increased to 0.617% and after 53 hours the flowrate error increased by a further 0.5%. This showed an over all increase of 0.8% from the original clean water calibration after 258.5 hours sand service at various sand concentrations. Shortly after the final sand concentration test points the flowrate was increased and the meter seized.

The 100 mm NB turbine meter from Manufacturer D, following 149 hours service at 0.126% sand concentration, showed similar results to the clean water calibration. Data recorded after a further 57 hours service at 0.315% sand concentration showed a flowrate percentage error rise of 0.5% from the 0.126% sand concentration data. A further rise of 0.5% occurred following the next 55.5 hours service at 0.617% sand concentration. This gives a total flowrate percentage error increase of 1% after 261.5 hours abrasive flow service.

6.4.3 Low flowrate abrasive flow tests on 100 mm NB wedge meters and 75 mm NB mass meter (Nominal 9 l/s)

This flowrate (9 l/s) represents nominally 20% of the test meters maximum flowrate.

Low flowrate data points were taken towards the end of the 0.352% and 0.777% sand content test period.

It should be noted that this flowrate is below the 3:1 manufacturers recommended turndown ratio for the wedge meter. Therefore this meter could be expected to produce data out-with the manufacturers limits although the Coriolis mass meter is with-in its flow turn-down limits at this flowrate.

Fig. 7 shows the data obtained from the 100 mm NB wedge meter and 75 mm NB Coriolis mass meter tests also data taken from their original clean water calibrations at a similar flowrate. (Nominal 9 l/s.)

The 100 mm NB wedge meter, from Manufacturer E, showed a 15% increase in flowrate percentage error following 244.5 hours at 0.126% and 0.352% sand concentrations. A further rise of 5% was shown after 129 hours at 0.777% sand concentration. This shows a total increase in flowrate percentage error of 20% from the original clean water data at a similar flowrate.

The 75 mm NB Coriolis mass meter, Manufacturer F, showed an increase of 0.25% in flowrate percentage error after 244.5 hours at 0.126% and 0.352% sand concentrations. Following a further 129 hours at 0.777% sand concentration the flowrate percentage error had reduced to a level similar to the original clean water calibration at this flowrate.

6.5 Evaluation of Test Meters at High Flowrates Using Three Sand Concentrations

During this test the 50 mm NB turbine, 75 mm NB Coriolis mass and 100 mm NB wedge meters were run at a flowrate that was considered to be close to the maximum manufacturers recommended flow range. The test facility used had a maximum flowrate of 35 l/s. This flowrate had already been achieved during previous 100 mm NB meter tests. For the 50 mm NB turbine meters this flowrate represents a rate nominally 83% of their recommended maximum flowrate.

Flowrate data points were taken towards the end of each sand content test period.

Fig. 8 shows the data obtained from the 50 mm NB turbine meter tests along with data taken from their original clean water calibrations at a similar flowrate. (Nominal 15 l/s.)

Manufacturer B's, 50 mm NB turbine meter, data taken after 172.5 and 84 hours at 0.126% and 0.364% respective sand concentrations showed improvements of 0.56% and 0.8% respectively. The data collected at the end of the next 68 hours at 0.644% sand concentration tests, a total abrasive flow period of 324.5 hours, showed an increase of 1% from the previous sand data. This represents a total increase of 0.28% from the original clean water calibration at a similar flowrate.

Manufacturer C's, 50 mm NB turbine meter, showed an immediate increase of 2% after 172.5 hours at 0.126% sand content. The sand content was increased to 0.364% but the flowrate error reached unacceptable limits and the meter was removed from the facility to find that all the meter's rotor blades had been removed.

Data from the 0.126% sand content tests on the 50 mm NB turbine meter, Manufacturer D, after a 172.5 hour period showed a percentage error of approximately 2.5%. This represents a flowrate error shift of 3% from the original clean water calibration. Following the next 84 hours at 0.364% sand content the calculated error was1.8%, a rise of 1.1% from the clean water calibration. Following a further 68 hours at 0.644% sand concentration, a total abrasive flow test period of 324.5 hours, a further increase of 0.56% was shown compared to the previous sand content data. This represents an increase of 1.7% when compared to the original clean water calibration at a similar flowrate.

6.6 Intermediate Flowrate Abrasive Flow Tests on 75 mm NB Mass Meter and 100 mm NB Wedge Meters (Nominal 15 l/s)

This flowrate represents nominally 33% of the test meters maximum flow range.

Flowrate data points were taken towards the end of the 0.126% and 0.777% sand content periods.

Fig. 9. shows the data obtained from the 100 mm NB wedge meter and 75 mm NB mass meter tests, Manufacturers E and F respectively, along with data taken from their original clean water calibrations at a similar flowrate. (Nominal 15 l/s.)

A 15 l/s flowrate is within Manufacturer E's recommended 3:1 turn-down ratio for the wedge meter. Test meter accuracy levels, within the manufacturers error limits, should have been achievable.

Following 139.5 hours at 0.126% sand concentration Manufacturer E's test meter shows a rise in flowrate error of nominally 8% compared to the original clean water calibration. Following a further 105 and 129 hours at 0.352% and 0.777% sand content respectively, totalling 373.5 hours of abrasive flow service, the meters flowrate error showed a further increase of 5% compared to the previous sand content data. This represents a rise of 13% compared to the original clean water calibration at a similar flowrate.

Manufacturer F, the Coriolis mass meter, showed an increase of 0.6% between the original clean water calibration and the 0.126% sand content data after 139.5 hours. Following a further 105 and 129 hours at 0.352% and 0.777% respective sand contents, totalling 373.5 hours of abrasive flow service, the flowrate error showed an improvement of 0.15% from the original clean water calibration at a similar flowrate.

7 CONCLUSIONS

The entire test series entailed testing nine meters. Four 50 mm NB turbine meters, three 100 mm NB turbine meters, one 100 mm NB wedge meter and one 75 mm NB Coriolis mass meter. Test meter details are summarised in Tables 1 and 2.

7.1 Performance, Size

7.1.1 50 mm NB turbine meters (all data) compared to reference flowmeter

Fig. 10 shows the 50 mm NB turbine meter test data, Manufacturers A, B, C, and D, compared to the reference electromagnetic flowmeter.

Manufacturer A's 50 mm NB turbine meter seized following 2 hours of abrasive flow testing at 0.126% sand concentration and was removed from the test schedule.

Manufacturer B's 50 mm NB turbine meter results show that this meter consistently performed within ±1.0% of the reference flowmeter with the exception of the 0.644% sand concentration points at 6 l/s. Here the percentage error increased from nominally 0.5% to 10%. This meter was specifically designed for abrasive flow duty. The wear on the upstream edge of this meter's rotor blades is shown in Fig. 11.

For Manufacturer C's 50 mm NB turbine meter, this shows that during the clean water calibration the meter was more accurate at lower flowrates with an average error of 1.09%. During the 0.126% sand concentration tests, over the flow range, the average error was nominally 2.5% (with the exclusion of a few data points at 9 l/s with errors between -1% and 3.1%). The 0.364% sand tests initially show the flowrate error increased to 3.5%. After approximately 250 hours abrasive flow the error had risen to 23% and after 256.5 the error had further increased to 82%. The meter was removed from the test facility where inspection revealed that the rotor blades had disappeared. Fig. 12 shows the wear on the rotor blade assembly and Fig. 13 the erosion on the inlet flow straightener.

Manufacturer D's, 50 mm NB turbine, clean water results show that this meter consistently performed within 1% of the reference flowmeter. The 0.126% sand content data shows an increase in error to nominally 1.5%, with the exception of data at 15 l/s which showed errors of 2.8%. The 0.364% sand content tests show a rise in error across the flow range to nominally 2%. The error increases again during the 0.644% sand tests to nominally 2.5% with the exception of low flowrates (6 l/s) when the percentage error increases to 12%. The wear on this meter's rotor is shown in Fig. 14.

7.1.2 100 mm NB turbine meters (all data) compared to reference flowmeter

Fig. 15 shows the 100 mm NB turbine meter test data, Manufacturers B, C and D, compared to the reference electromagnetic flowmeter.

Manufacturers B's 100 mm NB turbine meter clean water calibration shows an average 1.56% error over the flow range with the 0.126% sand content test results showing a similar error at low flowrates and a 0.39% increase at the optimum flowrate. The 0.315% sand test results show a shift of 0.25% across the flow range compared to the previous sand content data. The 0.671% sand tests show a further increase of nominally 0.5% across the flow range compared to the 0.315% sand tests. Fig. 16 shows the wear on this manufacturer's rotor. Fig. 17 shows the rotor shaft wear on this manufacturer's meter.

Increases in sand concentration appear to have a direct effect on the meter performance, particularly with respect to repeatability results. It should be noted that the overall increase in flowrate error between the clean water calibration and the last sand concentration tests is within 1%. This manufacturer's meter was specifically designed for abrasive flow service.

Manufacturer C, 100 mm NB turbine meter, produced the most accurate clean water calibration with a nominal flowrate error of 1% across the flow range. The 0.126% sand concentration tests showed little deviation from this figure particularly at low flowrates. Data from the 0.315% sand tests showed an increase of 0.39% across the flow range compared to the clean water data. The 0.671% sand tests produced similar results as the 0.315% sand data at the optimum flowrate. The low flowrate data showed an initial flowrate increase of 0.5% with the meter output becoming erratic until at 258.5 hours sand service when the meter seized. This meter was removed from the test series. Visual inspection showed that the rotor shroud had seized onto the meter bore as demonstrated in Figs 18 and 19.

The 100 mm NB turbine meter, Manufacturer D, clean water calibration showed a gradual increase in flowrate error towards the higher flowrates. The 0.126% sand data showed a slight improvement in flowrate percentage error across the flow range. During the 0.315% sand test the error increased to 2% at the low flowrates (15 l/s) with the optimum flowrate data remaining similar to the clean water and 0.126% data. This pattern was repeated for the 0.671% sand test data, giving a 0.89% increase at low flowrates compared to the clean water calibration; the optimum flowrate error remained virtually unchanged.

Manufacturer D's 100 mm NB turbine meter's accuracy was obviously affected (2%) by sand service at low flowrates (15 l/s) with only marginal increase at higher flows. The meter bore showed severe abrasion in the area of the rotor blades as well as slight rounding of the rotor blade leading edge.

7.1.3 75 mm NB wedge meter and 100 mm NB Coriolis mass meter (all data) compared to reference flowmeter

Fig. 20 shows the 75 mm NB mass meter and 100 mm NB wedge meter test data compared to the reference flow meter. Both meters were designed for use in abrasive flow service.

The 100 mm NB differential pressure wedge meter, Manufacturer E, clean water calibration showed an average flowrate error of 0.33% across the flow range. The optimum flowrate data at 0.156% sand showed an increase of 1.75% compared to the clean water calibration with the low flowrate data producing a 7.71% increase from the clean water data. The 0.352% sand tests showed a similar pattern to the 0.156% sand tests with the meters optimum flowrate figures equalling the previous sand data, but the low flowrate figures producing a further large shift of 8% from the previous sand test. The final 0.777% sand data again showed no difference from previous data at the meters optimum flowrate but the low flowrate error (even with-in the specified 3:1 turndown ratio) continued to rise to 20%.

The Coriolis mass meter, Manufacturer F, clean water calibration produced an average flowrate error of 0.68% across the flow range. The 0.156% sand test showed a negligible increase at the optimum flowrates with a 0.4% increase at low flowrates. The 0.352% sand tests showed no change from the clean water calibration with the 0.777% sand test producing no change at low flowrates and an improvement of 0.5% at the optimum flowrates compared to the clean water calibration at a similar flowrate.

Overall this meter's accuracy was not affected by abrasive flow with only slight polishing of the surface material at the meter's inlet manifold. The internal flow tubes could not be inspected.

7.2 Manufacturer, Type of Meter

The turbine meters performed with varying degrees of success. On the whole the 100 mm nominal bore meters performed better than the 50 mm nominal bore meters.

Two 50 mm turbine meters failed with one (Manufacturer C) being completely stripped of its rotor blades and Manufacturer A's meter seizing immediately after the introduction of sand into the test fluid. The 50 mm nominal bore, Manufacturer D, had 60% of its rotor blades worn and would probably not have survived for much longer at this rate of wear.

Manufacturer B did out-perform the other meters in the 50 mm nominal bore size, although it did show large errors at low flowrates with the highest sand percentages. It should be noted that this meter is specifically designed for abrasive flow use.

Only one (Manufacturer C) of the three 100 mm turbine meters failed to complete the test series and that was only by three hours. The 100 mm NB turbine meters showed similar results as the 50 mm NB turbine meter tests, although as previously noted this size of turbine meter did prove more reliable than the smaller size. Manufacturer B, in the 100 mm NB size, meter gave slightly better results across the flow range than Manufacturer C, until Manufacturer C's meter seized with Manufacturer D's being less accurate particularly at the lower flowrates. Once again Manufacturer B was the only meter in the 100 mm NB range to be recommended specifically for abrasive flow duty although Manufacturer D's meter did provide comparable results though suffered increased wear.

The differential pressure wedge meter (Manufacturer E), the second most expensive meter in the test series, produced comparable results to the mass meter at high flowrates but became significantly inaccurate, although remaining quite repeatable, at low flowrates close to and below the manufacturer's 3:1 flowrate turn-down ratio. Although this meter is of robust construction and showed little sign of wear during the test series there were indications that corrosive build up on the bore of the pressure tappings could become a problem during long term operation. This would obviously be dependant on the metered fluid and its compatibility with the meter's construction material.

The Coriolis mass meter, Manufacturer F, produced the most consistent results through out the test series with the abrasive flow test data showing little deviation from the original clean water calibration. This meter also had the advantage of a large flowrate turn-down ratio and alternative outputs, ie temperature, derived volume flowrate etc. The meter was more expensive than the other test meters therefore consideration would have to be given regarding cost against accuracy, reliability and convenience. This meter would be particularly suited to high performance, long term, maintenance free utilisation. The meter showed very little sign of abrasion/wear during the test series with only slight material polishing at the inlet manifold.

7.3 Material, Construction Details

Where a manufacturer supplied two sizes of meter these were both of the same model and design. All of the turbine meters tested were constructed with stainless steel rotor blades and meter bodies. Various grades of stainless steel were utilised ranging from austenitic stainless steel blades on Manufacturer B's turbine meters, to 430 grade stainless steel in Manufacturer C's blade construction.

Of the three manufacturers that provided meters of both 100 mm and 50 mm NB sizes only Manufacturer C's meters failed to complete the tests for each size. This manufacturer's blade thickness was also relatively thin in comparison to other meters in their respective bore size. The other meter to fail during the sand tests was Manufacturer A's 50 mm NB meter. This meter along with the 50 mm and 100 mm NB meters supplied by Manufacturer C's were constructed with flat profiled rotor blades, as opposed to the other meters' helical type blade profile.

For these tests the number of blades alone appears to have no significance on the outcome of the abrasive flow tests. However, the combination of rotor blade profile and thickness are likely to have some effect on a meters' overall performance in abrasive flow. It was also noted that turbine meters fitted with rotor blade shrouds did not perform well, with both shrouded meters failing during testing.

As expected the Coriolis mass and wedge meters were not, as dramatically, affected by sand abrasion and wear as the turbine meters. This was mainly due to both meters having no moving parts in the test fluid. Slight polishing was witnessed on both meters but this was considered minimal and was unlikely to affect the meters' performance. The wedge meter did show considerable material build up on the pressure tapping internal bores. This was after careful material selection by the manufacturer.

The mass meter model used in these tests was selected mainly due to its user popularity and was provided with hastelloy measurement tubes. In theory, this material should perform better than stainless steel in most abrasive flow duties.

8 THE WAY FORWARD

Points for consideration:

NEL would welcome the opportunity to discuss the results of these tests further and to identify other potential projects involving dirty service activities for UK industry.

A number of points that merit for future consideration and examination have been highlighted during this test series and are briefly outlined below.

- Testing meters over longer test periods. The test periods used in this series of tests are short and not fully representative of in-field operating times because the tests were 'accelerated' by using relatively high sand content levels.

- Test other alternative meter types that are available, to get a benchmark on the capabilities of all meter types in sandy service fluids, eg Venturi, Vee-cone and positive-displacement and Ultrasonic meters.

- Look at the effects of different particle sizes (eg - fine, coarse) and types on meter performance.

- For turbine meters, the effects of different turbine meter blade combinations and geometries, bearing design, running clearances and materials.

ACKNOWLEDGEMENT

NEL acknowledges the sponsorship of Department of Trade and Industry and the National Measurement System Policy Unit Flow Programme for the work. Guidance notes and full reports of all Flow Programme Projects are available from NEL.

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17 Manufacturer B. 100 mm diameter meter, rotor shaft wear

18 Manufacturer C. 100 mm diameter meter, rotor ring wear

19 Manufacturer C. 100 mm diameter meter, meter bore wear

20 Coriolis mass and wedge meter data compared to reference flowmeter. Manufacturers E and F

TABLE 1a

TURBINE METERS (50 mm NOMINAL BORE)

Test Meter	Manufacturer A (50 mm)	Manufacturer B (50 mm)	Manufacturer C (50 mm)	Manufacturer D (50 mm)
Nominal bore	50 mm	50 mm	50 mm	50 mm
No of blades	8	4	8	8
Blade shape	Flat	Helical	Flat	Helical
Blade thickness (@ mid point)	0.685 mm	2.0 mm	0.43 mm	0.90 mm
Blades on outer ring	No	No	No	No
Blade material	410 SS	Austenitic SS	430 SS	Stainless steel
Meter body material	Stainless steel	Stainless steel	304 SS	Stainless steel
Upstream flow straightener	Yes	Yes	Yes	Yes
Downstream flow straightener	No	Yes	Yes	No
Manufacturers quoted flow range	1.87 - 18.70 l/s	2.5 - 23.3 l/s	1.4 - 14.3 l/s	1.9 - 18.9 l/s
Manufacturers quoted accuracy (over flow range)	±0.25%	±0.20%	±0.25%	±0.15%
Manufacturers quoted repeatability	±0.02%	±0.01%	±0.02%	±0.02%
Test hours duration (clean water)	88.5	88.5	88.5	88.5
Test hours, 0.126% sand	2	172.5	172.5	172.5
Test hours, 0.156% sand	-	-	-	-
Test hours, 0.315% sand	-	-	-	-
Test hours, 0.352% sand	-	-	-	-
Test hours, 0.364% sand	-	84	84	84
Test hours, 0.644% sand	-	68	-	68
Test hours, 0.671% sand	-	-	-	-
Test hours, 0.777% sand	-	-	-	-
Total hours in sand service	2	324.5	256.5	324.5
Degree of wear	Rotor blades seized onto meter bore. This was caused by sand entrapped between blade tip and bore. Wear high spots on meter bearing.	Wear on upstream edge of rotor blades.	All rotor blades removed at root.	Approx. 60% of rotor blades eroded from upstream edge. Slight wear path around rotor area of meter bore.

T A B L E 1b

TURBINE METERS (100 mm NOMINAL BORE), WEDGE AND CORIOLIS MASS METERS

Manufacturer B (100 mm)	**Manufacturer C (100 mm)**	**Manufacturer D (100 mm)**	**Manufacturer E Wedge meter (100 mm)**	**Manufacturer F Coriolis meter (75 mm)**
100 mm 8 Helical 2.2 mm No Austenitic SS 316 SS Yes Yes 6.25 - 74.97 l/s ±0.20% ±0.02%	100 mm 6 Flat 0.76 mm Yes 430 SS 304 SS Yes Yes 8.16 - 81.65 l/s ±0.25% ±0.02%	100 mm 12 Helical 1.3 mm No Stainless steel Stainless steel Yes No 8.16 - 81.65 l/s ±0.15% ±0.02%	100 mm Not applicable Not applicable Not applicable Not applicable Not applicable Carbon steel (wetted parts) No No 13.8 - 41.4 l/s ±0.5 ±0.2	75 mm Not applicable Not applicable Not applicable Not applicable Not applicable Hastelloy (wetted parts) No No 1.0 - 47 l/s ±0.1 ±0.02
22.25	22.25	22.25	75	75
149	149	149	- 139.5	- 139.5
57	57 - -	57 - -	- 105 -	- 105 -
- 55.5 -	- 52.5 -	- 55.5 -	- 129	- 129
261.5	258.5	261.5	373.5	373.5
Slight wear on upstream edge of rotor.	Extensive scoring on rotor outer ring. Wear on meter bore at rotor ring/bore interface. Wear high spots on rotor bush. Meter seized after 258.5 hours sand service.	Severe sand abrasion on meter bore at rotor area. Slight rounding of rotor blades.	Slight polishing of wedge apex. Corrosion on upstream and downstream pressure tappings. Heaviest on upstream tapping.	Polishing of inlet manifold apex.

TABLE 2a

TURBINE METERS (50 mm NOMINAL BORE)

	Manufacturer A (50 mm) % Error	Manufacturer B (50 mm) % Error	Manufacturer C (50 mm) % Error	Manufacturer D (50 mm) % Error
	Flowrate: 5 l/s	Velocity: 2.7 m/s		
Clean water	0.26	0.52	0.73	0.65
0.14% sand	Meter removed	0.27	2.5	0.3
0.34% sand	Meter removed	0.55	81	2.3
0.70% sand	Meter removed	-9.1	Meter removed	11.63
	Flowrate: 9 l/s	Velocity: 4.7 m/s		
Clean water	0.33	0.53	0.91	0.61
0.14% sand	Meter removed	0.52	1.67	1.38
0.34% sand	Meter removed	0.12	10	2
0.70% sand	Meter removed	0.4	Meter removed	2.4
	Flowrate: 15 l/s	Velocity: 7.5 m/s		
Clean water	0.8	0.85	1.42	0.64
0.14% sand	Meter removed	0.22	3.2	-2.8
0.34% sand	Meter removed	- 0.06	76	1.9
0.70% sand	Meter removed	0.94	Meter removed	2.2

TABLE 2b

TURBINE AND WEDGE FLOW METERS (100 mm NOMINAL BORE), CORIOLIS METER 75 mm NOMINAL BORE

	Manufacturer B (100 mm) % Error	Manufacturer C (100 mm) % Error	Manufacture r D (100 mm) % Error	Manufacturer E Wedge Meter % Error	Manufacturer F Coriolis Meter % Error
	Flowrate: 10 l/s	**Velocity: 1.3 m/s**			**Velocity: 2.3 m/s**
Clean water				-0.08	0.55
0.14% sand				Not available	Not available
0.34% sand				16.14	0.64
0.70% sand				20	0.5
	Flowrate: 15 l/s	**Velocity: 1.9 m/s**			**Velocity: 3.4 m/s**
Clean water	1.47	0.94	1.47	0.34	0.57
0.14% sand	1.45	0.88	1.5	8.1	1.2
0.34% sand	1.78	1.33	1.86	Not available	Not available
0.70% sand	2.06	1.72	2.23	Not available	Not available
	Flowrate: 30 l/s	**Velocity: 3.8 m/s**			**Velocity: 6.8 m/s**
Clean water				0.47	0.81
0.14% sand				3	0.97
0.34% sand				2.6	0.71
0.70% sand				3	0.5
	Flowrate: 35 l/s	**Velocity: 4.5 m/s**			**Velocity: 7.9 m/s**
Clean water	1.61	1.07	1.6	0.47	0.81
0.14% sand	2	1.27	1.36	0.88	0.67
0.34% sand	2	1.46	1.71	1.3	1
0.70% sand	2.1	1.41	1.68	Not available	Not available

Note: All error, flowrate, velocity and sand percentage values are nominal figures
Not available indicated that flowrate and velocity were not undertaken

APPENDIX I

SAND SPECIFICATION

The quarry sand used throughout this test series had a sub-rounded/rounded particle shape and was graded between 500 microns and 125 microns via an aperture sized mesh. The average particle size was 275 ± 25 microns.

Using BS 410 grading technique, the sizing distribution of the sand particles was similar to that shown below:

ANALYSIS OF SAND PARTICLE SIZE.

Particle size Aperture/Mesh size microns	% Retained by Weight to BS410
710	0.7
500	3.9
355	16.2
250	44.8
180	28.4
125	5.5
<125	0.5

APPENDIX II

THE NEL ABRASIVE FLOW TEST FACILITY

Description of Facility

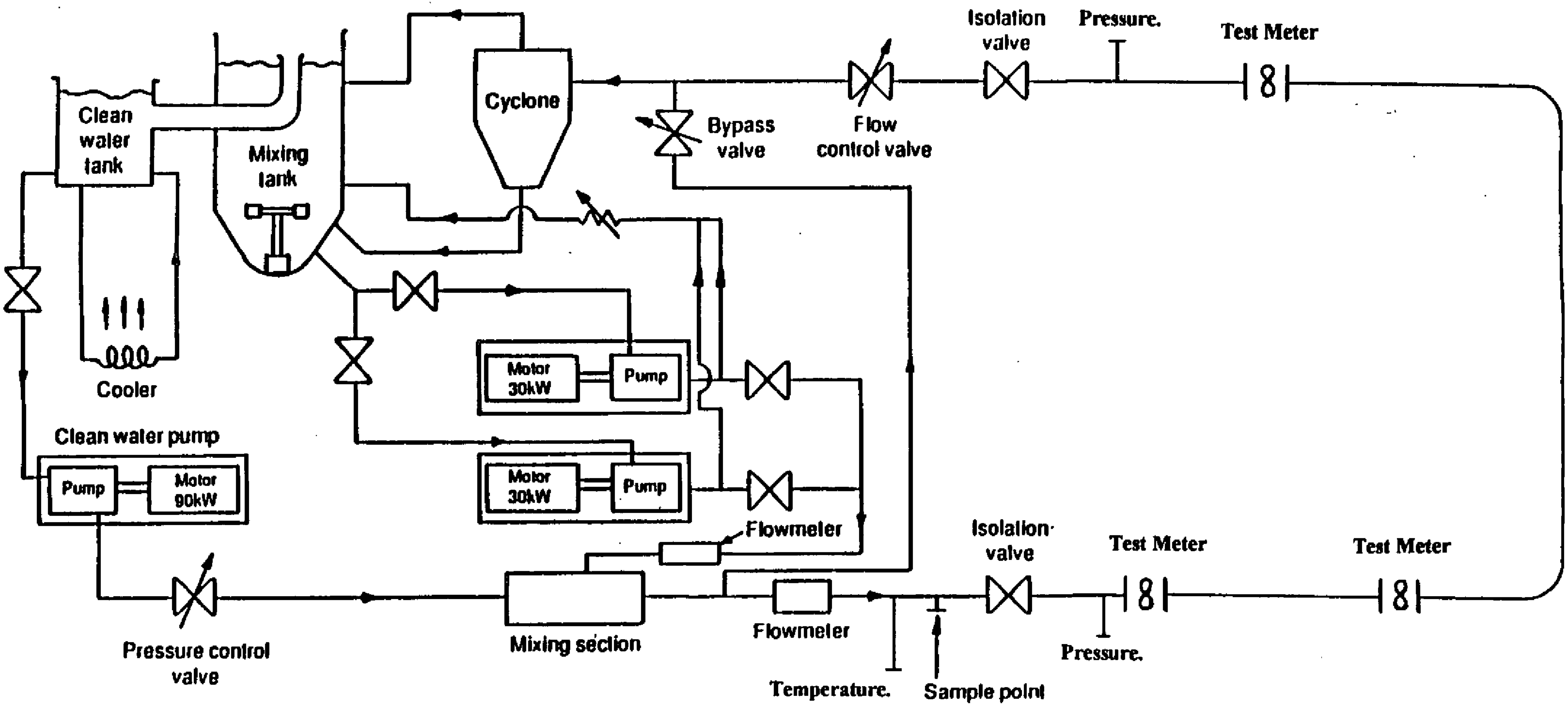
A diagram of the facility is shown in Figure II.1 of this Appendix. Clean water is taken from a storage tank by a pump and discharged into pipework where concentrated sandy water is injected by a positive displacement pump into the flow stream in a mixing section. The concentrated sandy water is supplied from a mixer tank which is constantly agitated.

The turbulent flow of the fluid, in conjunction with a number of right angle bends in series, ensure that the sand is fully mixed in the pipe before it enters the test facility test section where the test meters were mounted in series.

For 50 mm NB meter four can be installed at the one time but this was reduced to three for 100 mm NB meters due to facility pipe length restrictions with respect to appropriate up and down stream pipe lengths between test meters. After the test section the fluid passes through the flow control valve and returns to the mixing tank through cyclone separators. The cleaned water returns to the mixing tank and passes through filters before overflowing back to the clean water tank. The concentrated sandy water falls to the bottom of the mixing tank and the whole process repeats. The pipework and mixing tank were carbon steel and were not painted or coated internally. The clean water tank was painted internally with a corrosion resistant paint.

For test purposes the required flowrate and line pressure in the test section are set by adjusting the flow control valve, together with the bypass and pressure control valve. An electromagnetic flowmeter measured the flow through the test section with a similar, but smaller nominal bore, meter measuring the flow of concentrated sandy water in the injection line.

By varying the speed of the injection pumps and the concentration of the sand in the mixing tank the sand concentration in the test section can be altered as required. Test fluid samples are taken from the test section at regular intervals. An air blast cooler enables the test fluid to be temperature controlled between 40 and 70°C.



Appendix II. Schematic of NEL abrasive Flow Test Facility.

Fig. 1: CALIBRATION OF REFERENCE EM METER.
FLOWRATE % ERROR vs REFERENCE FLOWRATE

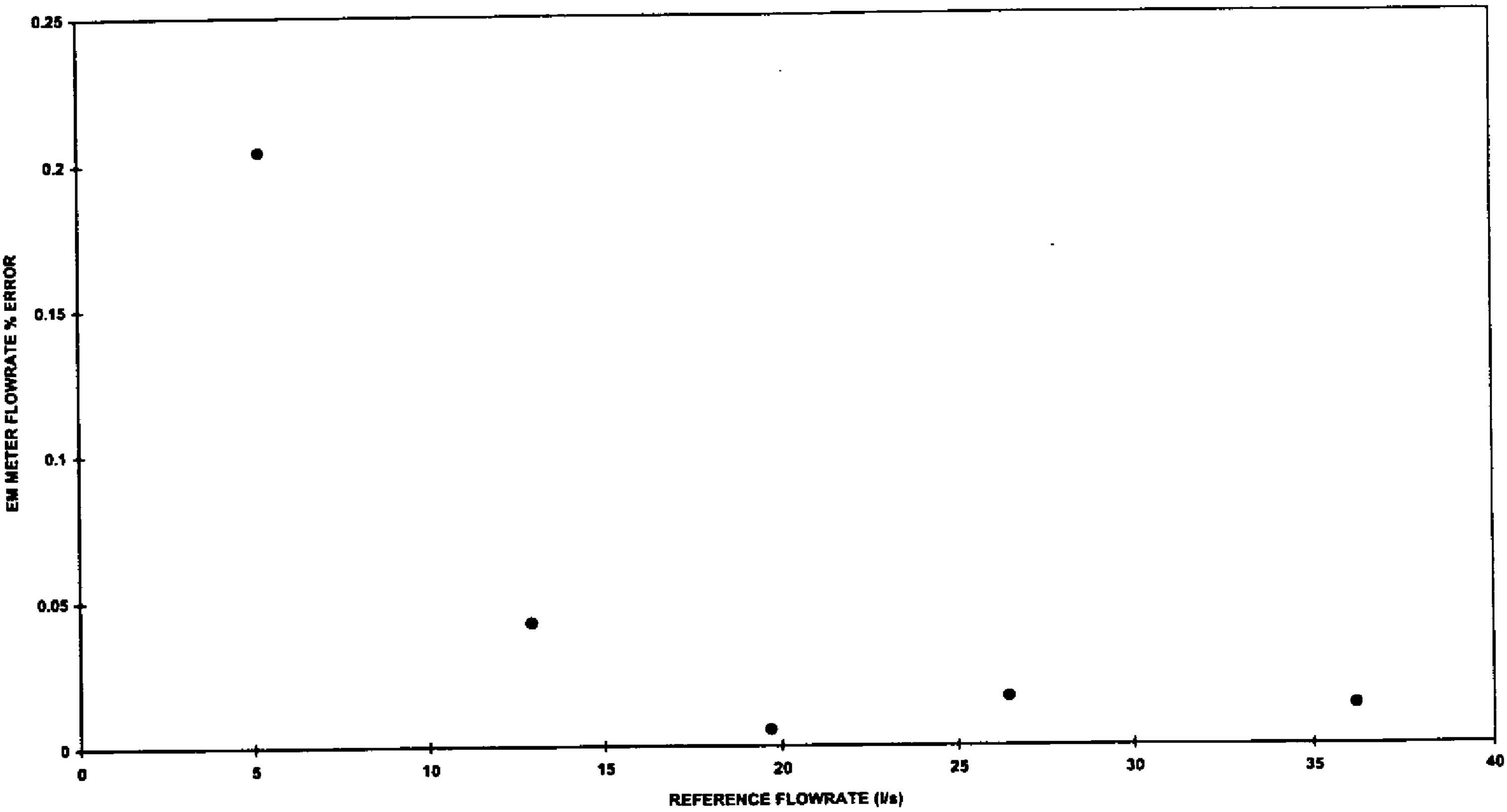


Fig. 2: 50 mm NB. TURBINE METER DATA - NOMINAL FLOWRATE 9 l/s

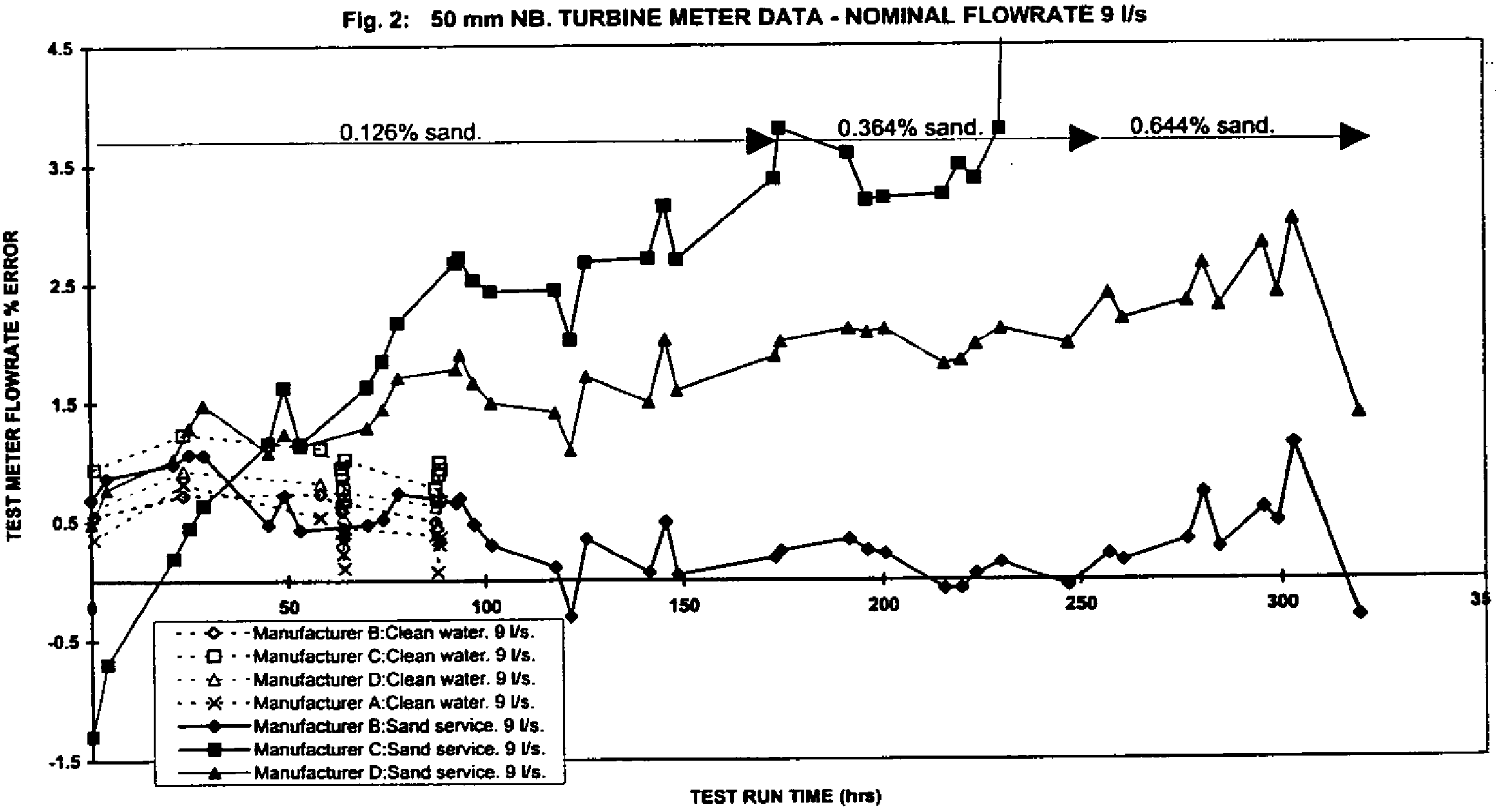


Fig. 3: 100mm NB. TURBINE METER DATA
NOMINAL FLOWRATE 35 l/s

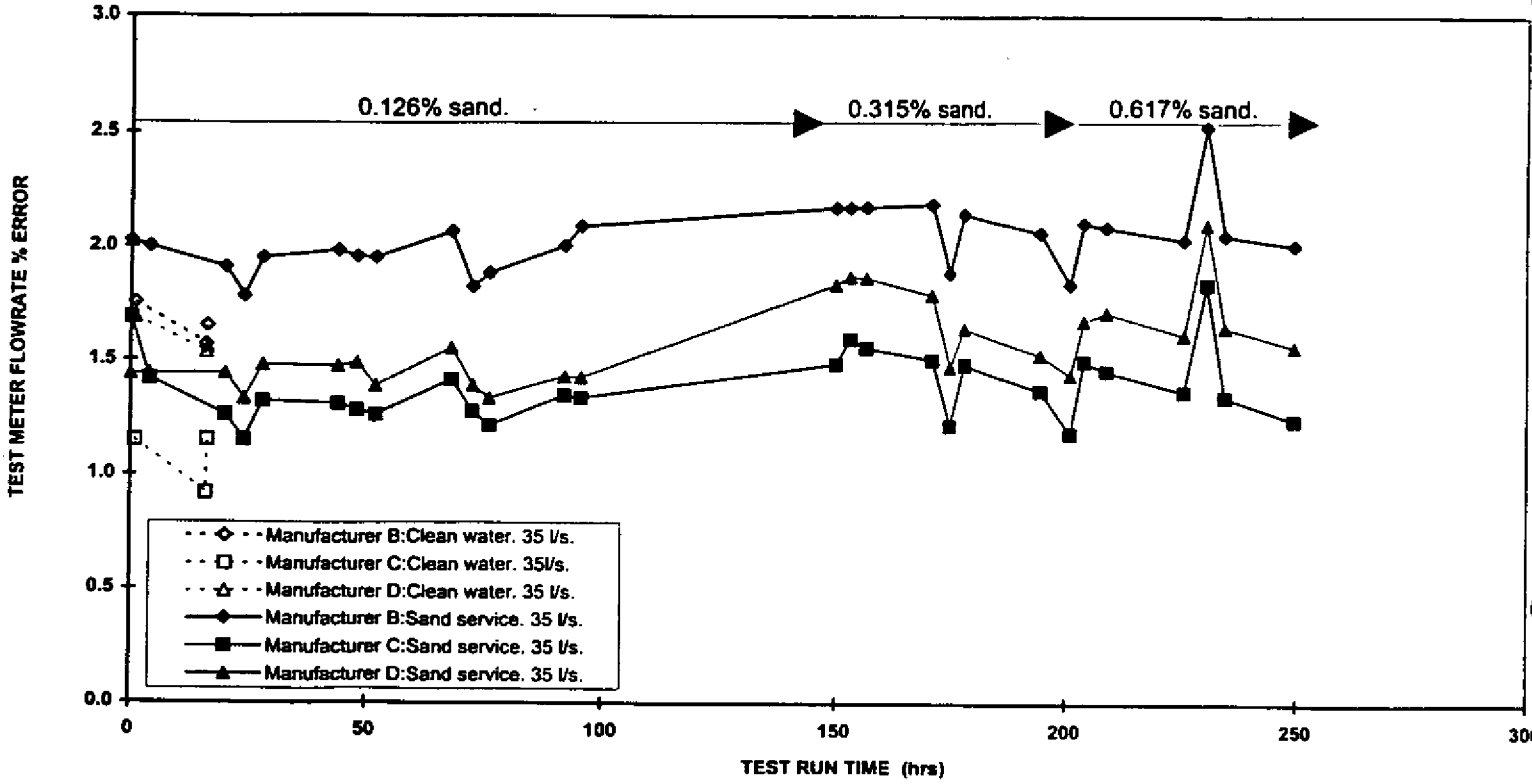


Fig. 4: CORIOLIS MASS AND WEDGE METER DATA
NOMINAL FLOWRATE 30 l/s

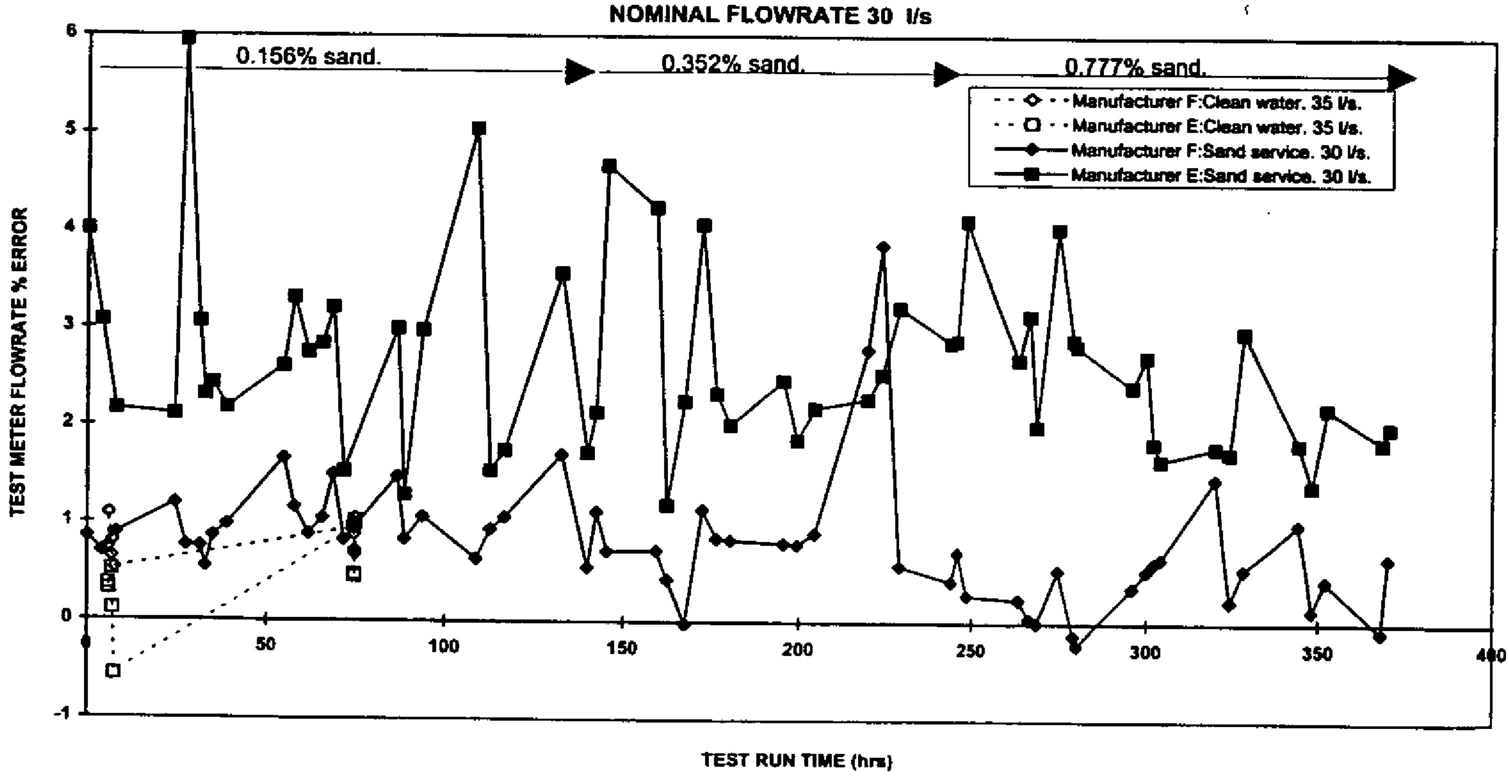


Fig 5: 50 mm NB. TURBINE METER DATA- NOMINAL FLOWRATE 6 l/s

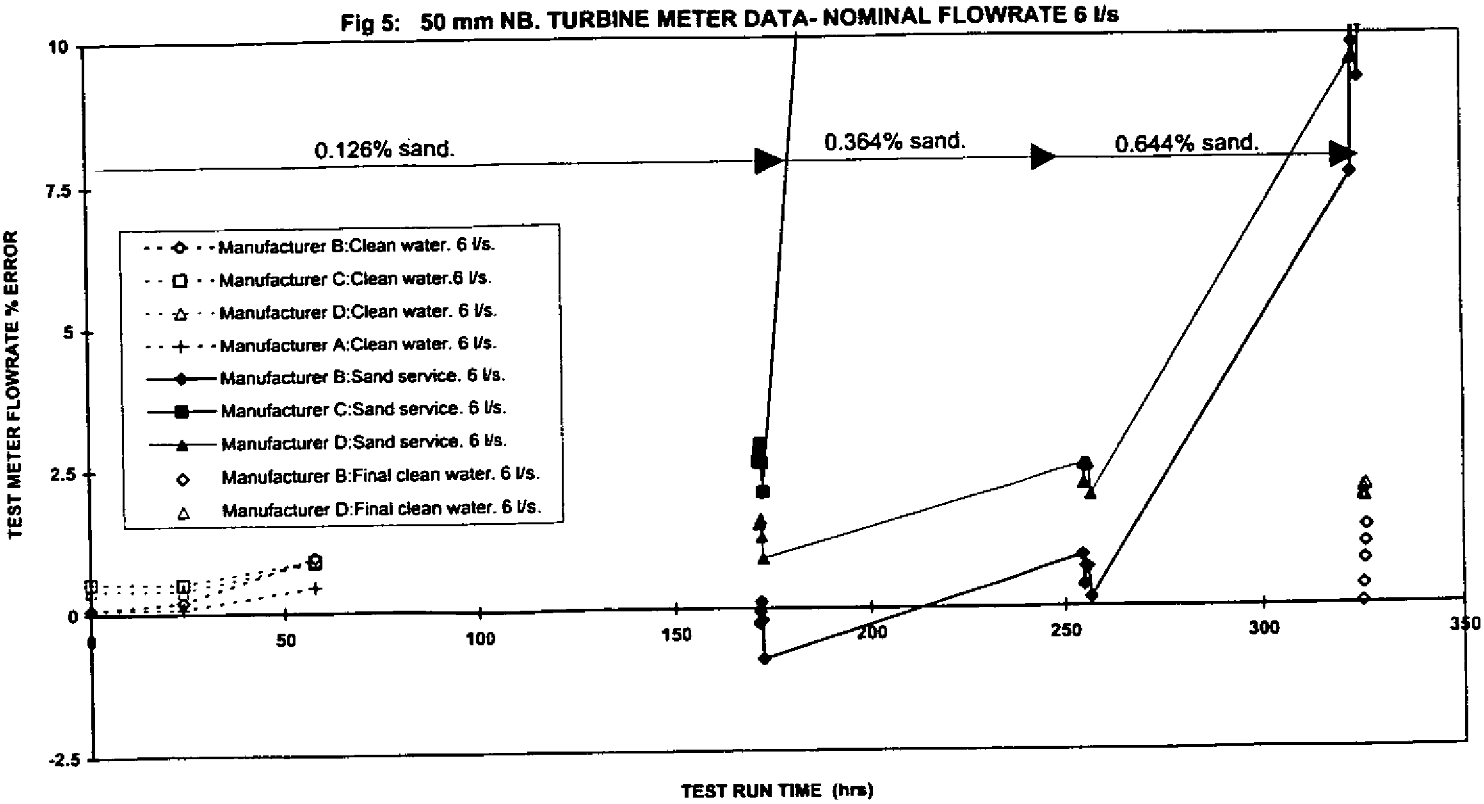
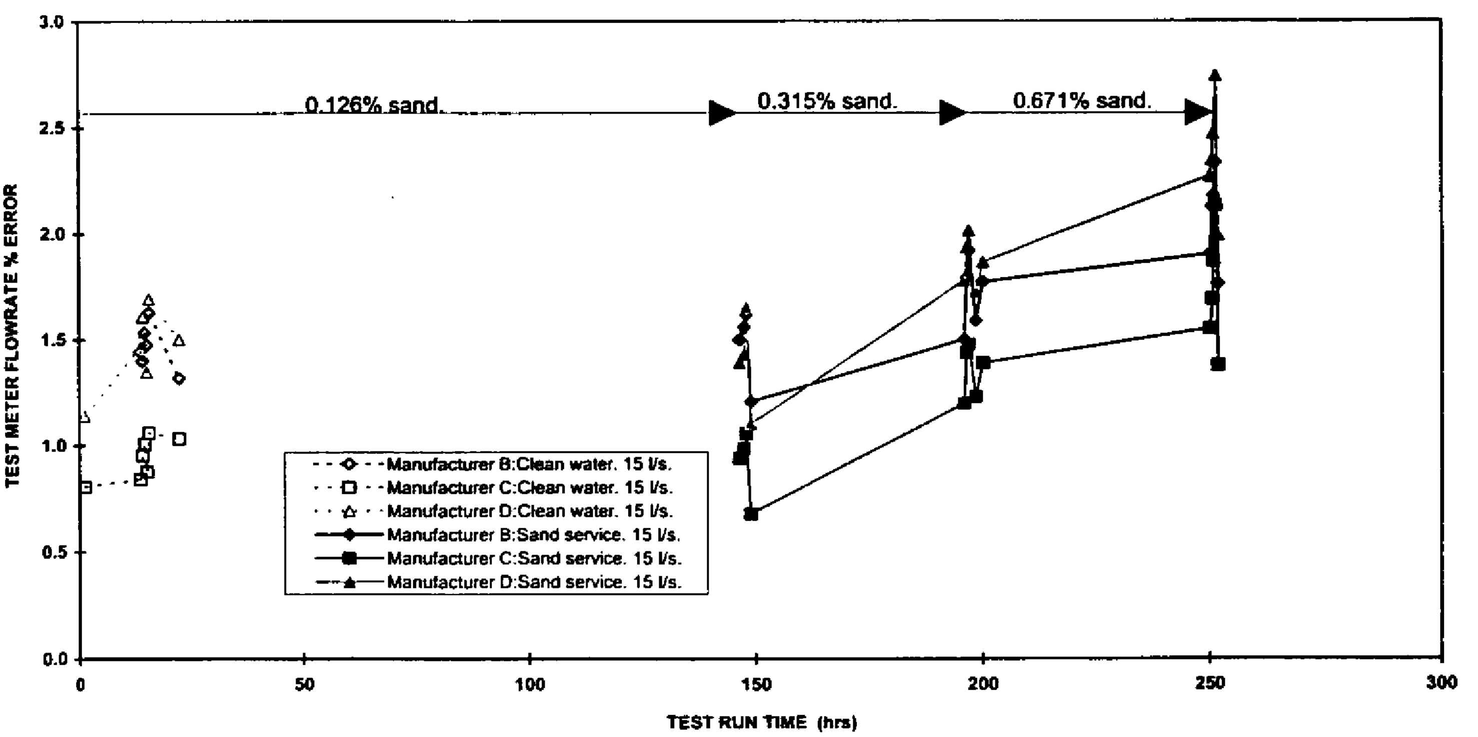


Fig. 6: 100 mm NB. TURBINE METER DATA
- NOMINAL FLOWRATE 15 l/s



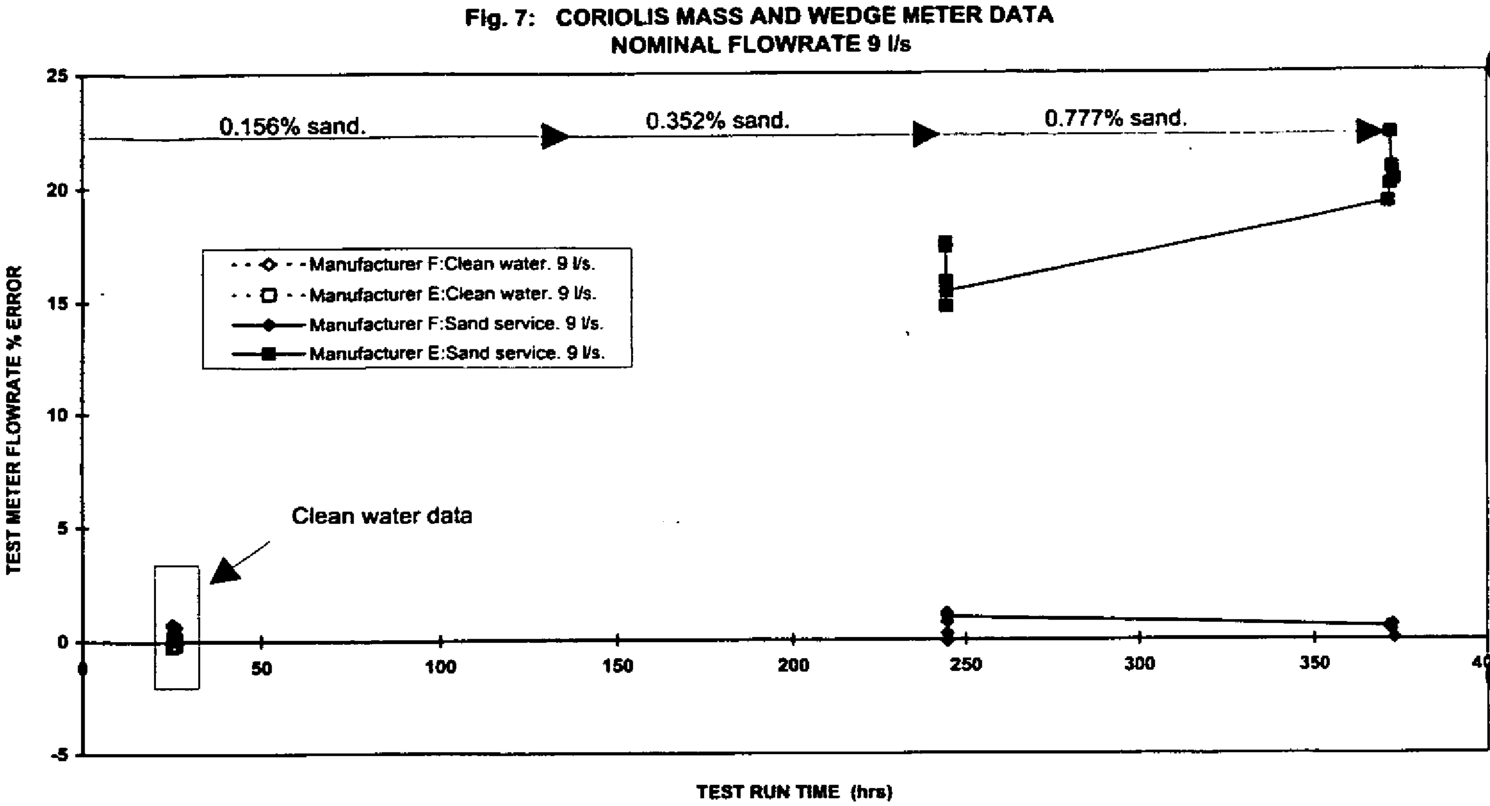


Fig. 7: CORIOLIS MASS AND WEDGE METER DATA
NOMINAL FLOWRATE 9 l/s
0.156% sand.
0.352% sand.
0.777% sand.
Manufacturer F:Clean water. 9 l/s.
Manufacturer E:Clean water. 9 l/s.
Manufacturer F:Sand service. 9 l/s.
Manufacturer E:Sand service. 9 l/s.
Clean water data
TEST METER FLOWRATE % ERROR
TEST RUN TIME (hrs)

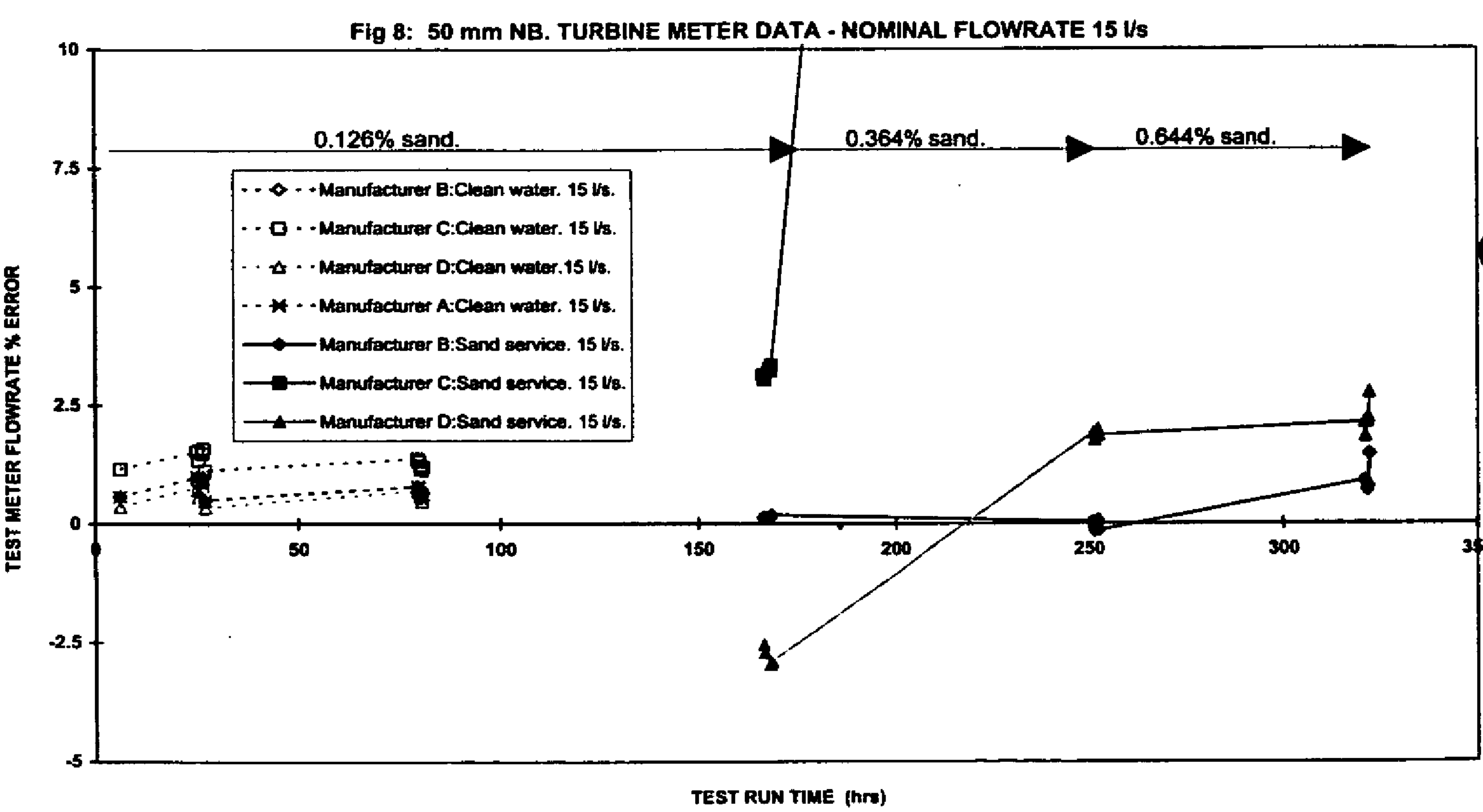


Fig 8: 50 mm NB. TURBINE METER DATA - NOMINAL FLOWRATE 15 l/s
0.126% sand.
0.364% sand.
0.644% sand.
Manufacturer B:Clean water. 15 l/s.
Manufacturer C:Clean water. 15 l/s.
Manufacturer D:Clean water.15 l/s.
Manufacturer A:Clean water. 15 l/s.
Manufacturer B:Sand service. 15 l/s.
Manufacturer C:Sand service. 15 l/s.
Manufacturer D:Sand service. 15 l/s.
TEST METER FLOWRATE % ERROR
TEST RUN TIME (hrs)

Fig. 9: CORIOLIS MASS AND WEDGE METER DATA
NOMINAL FLOWRATE 15 l/s

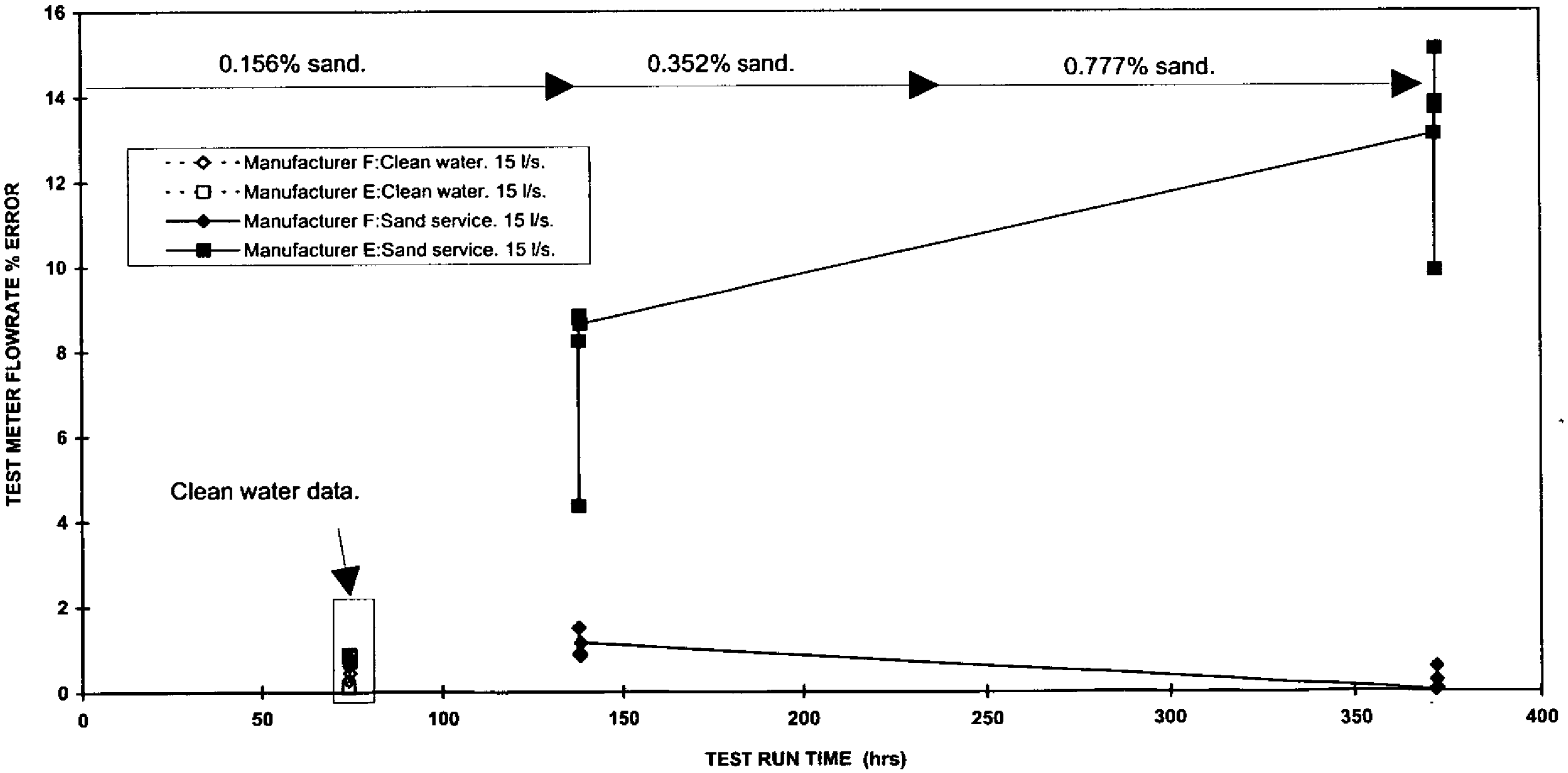


Fig. 10: 50 mm NB. TURBINE METER DATA COMPARED TO REFERENCE FLOWMETER.

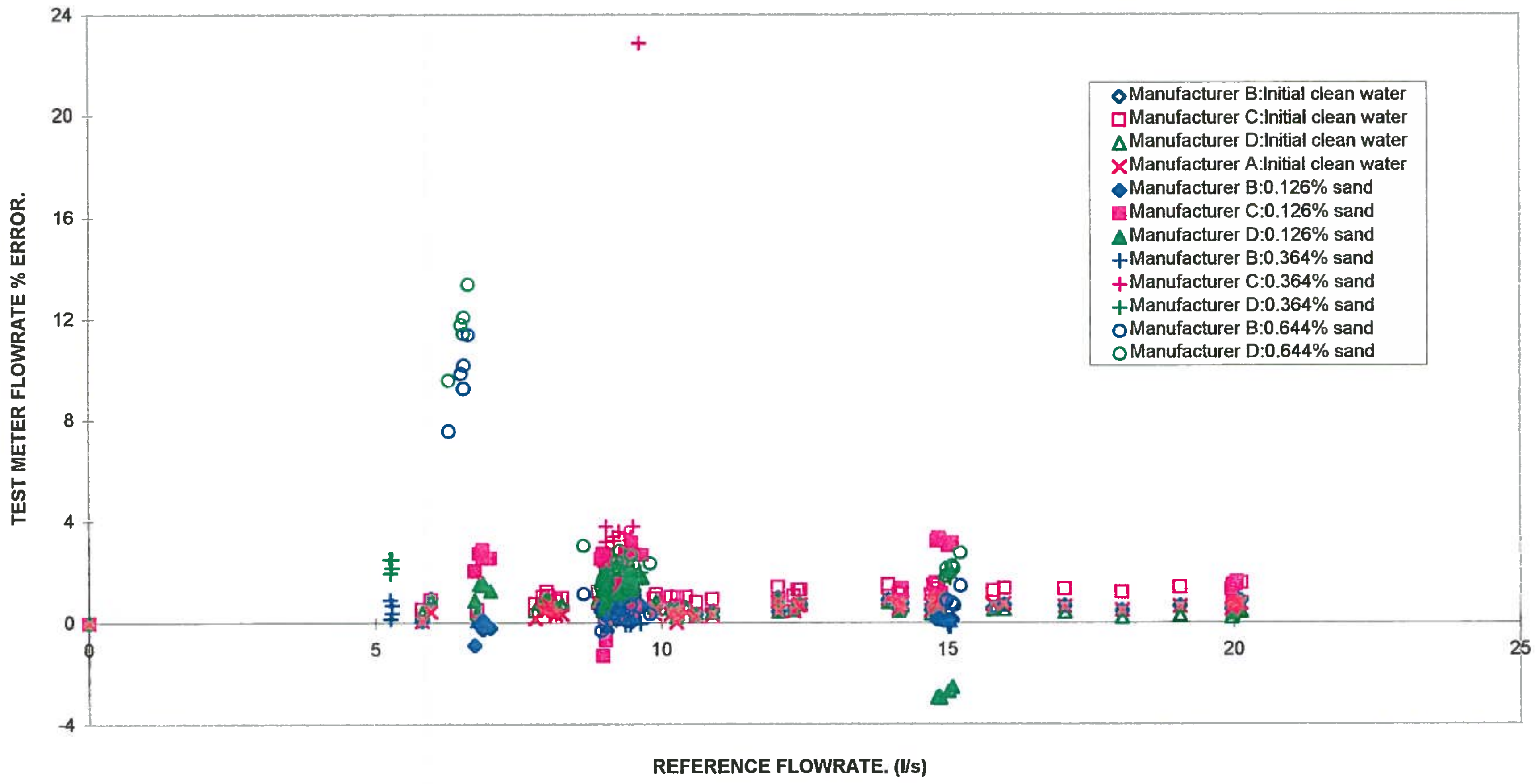


Fig 11 MANUFACTURER B. 50 mm DIAMETER METER, ROTOR BLADE WEAR

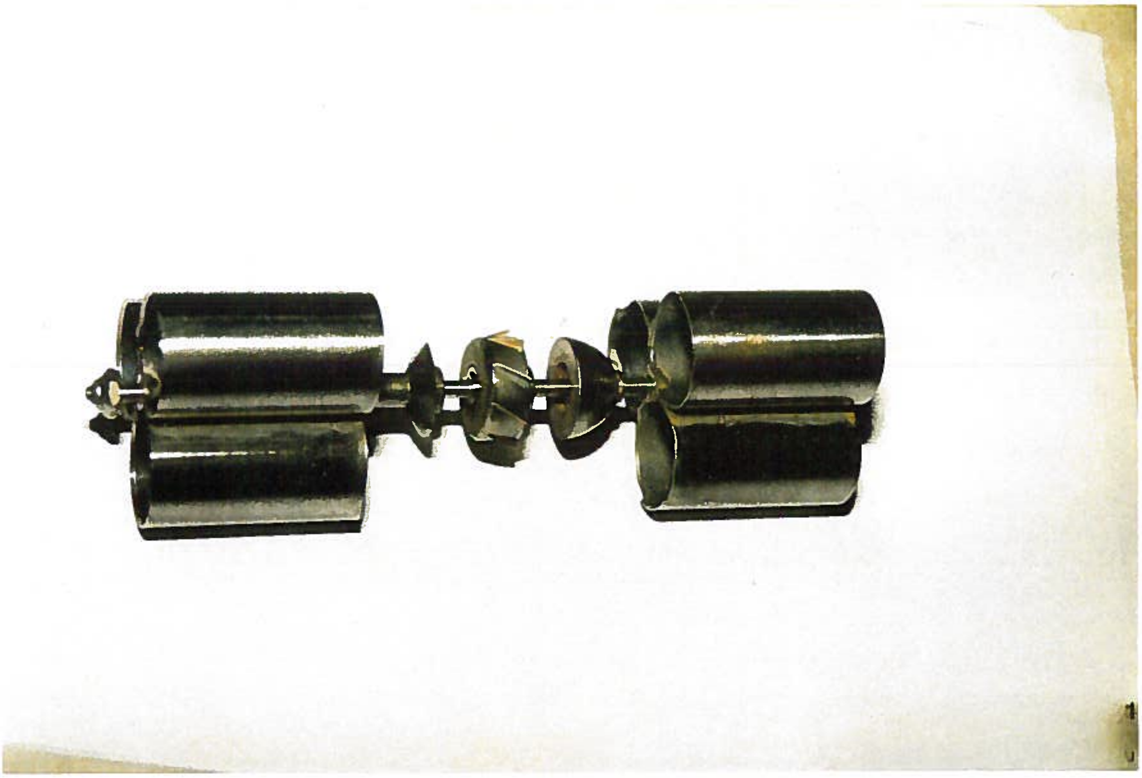


Fig 12 MANUFACTURER C. 50 mm DIAMETER METER, ROTOR SHAFT WEAR

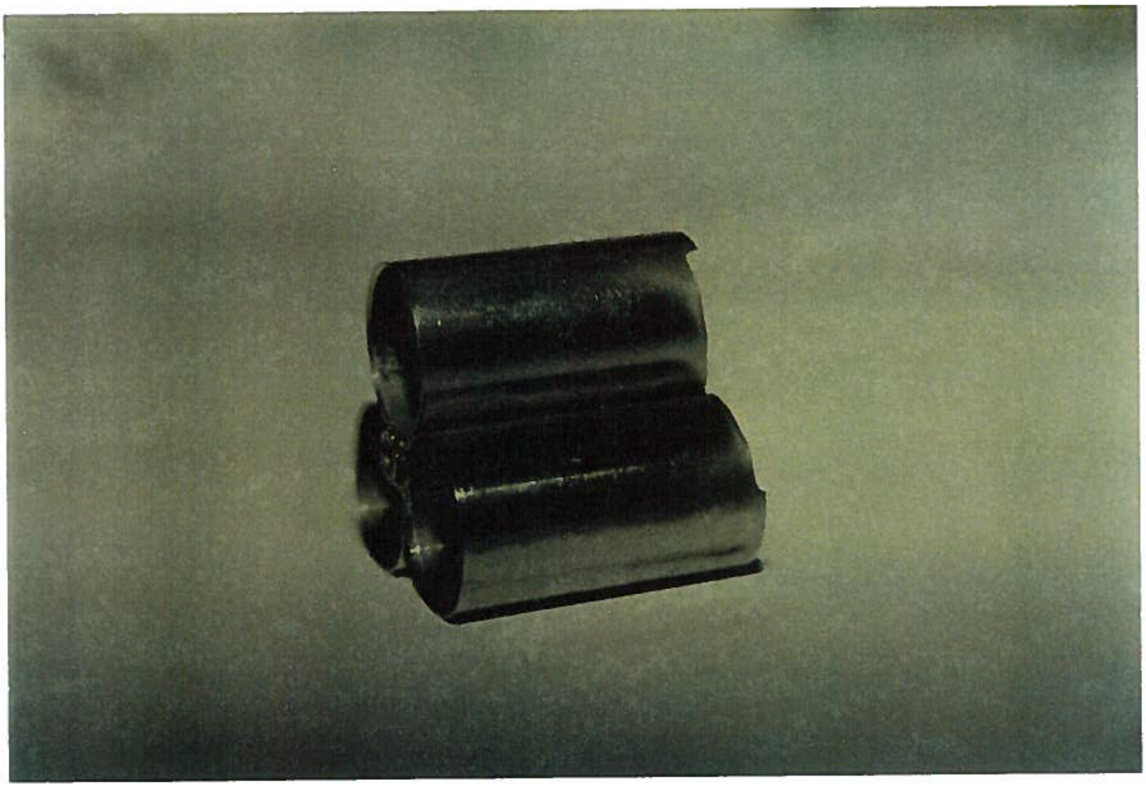


Fig 13 MANUFACTURER C. 50 mm DIAMETER METER, FLOW STRAIGHTENER WEAR

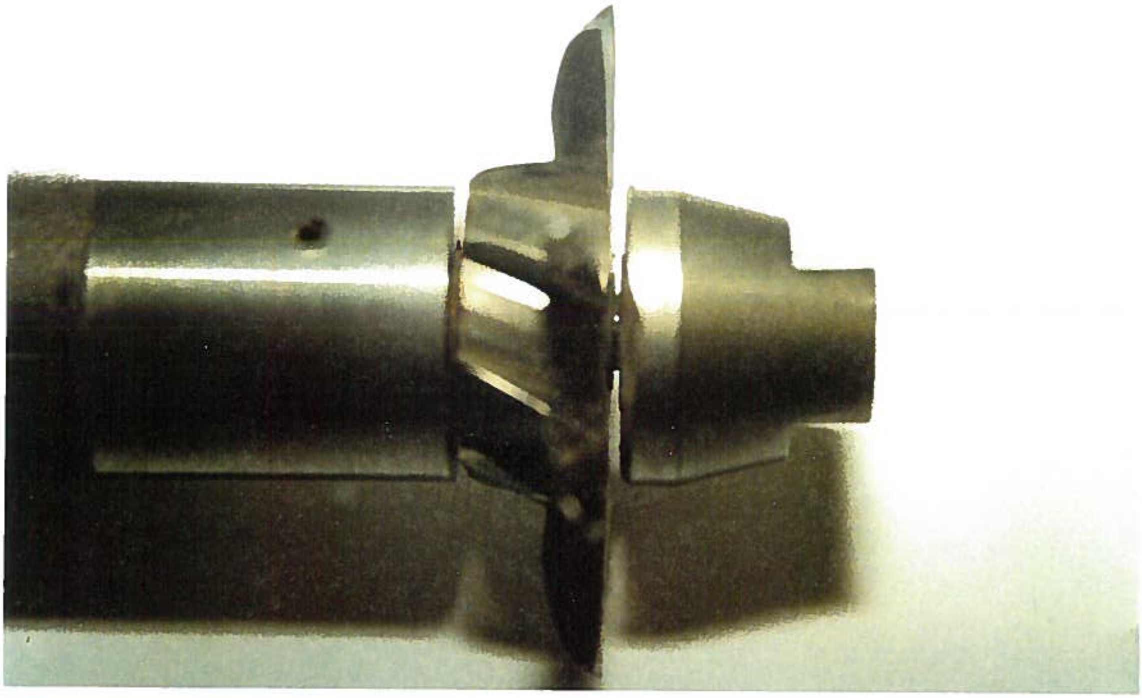
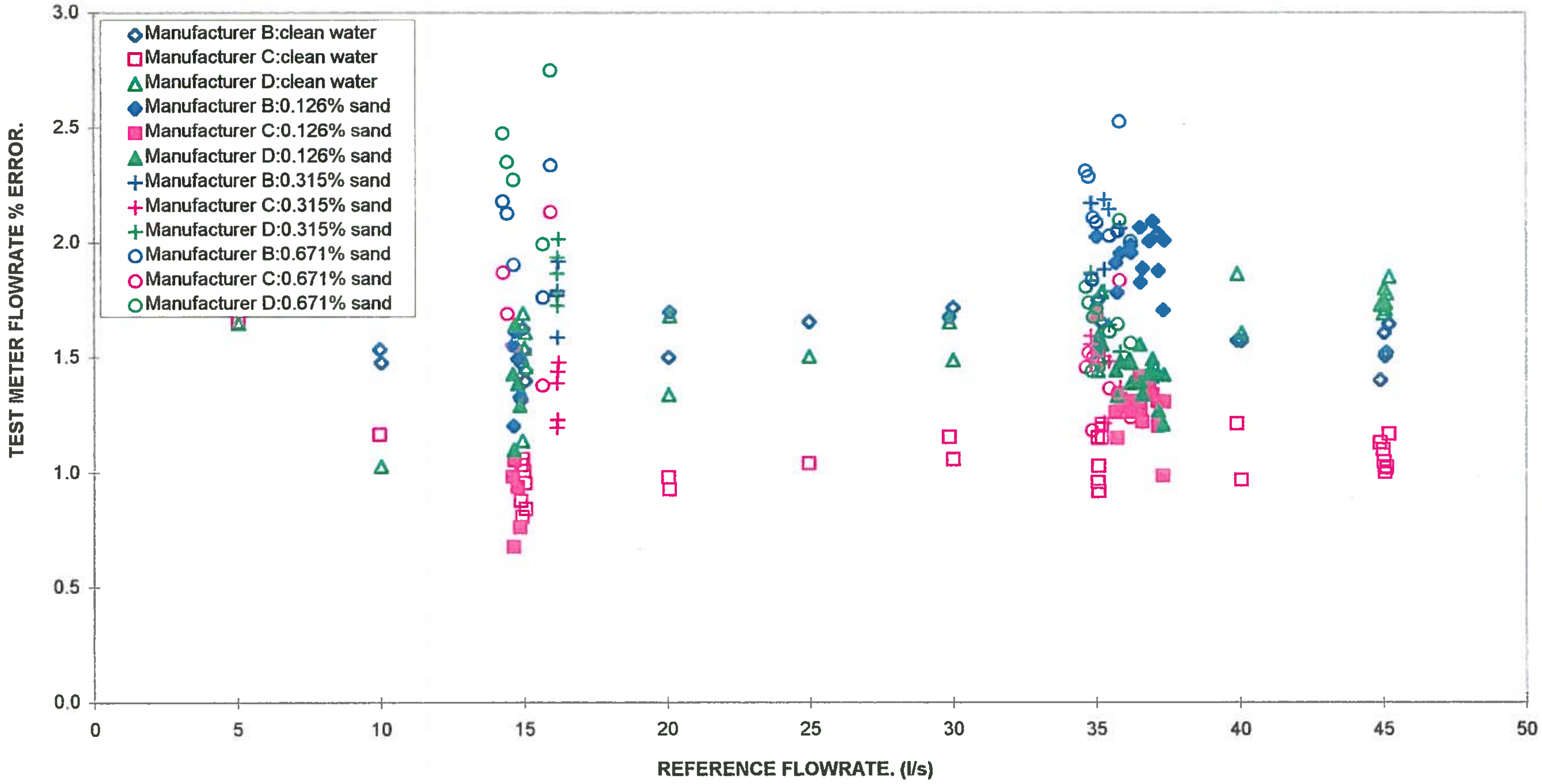


Fig 14 MANUFACTURER D. 50 mm DIAMETER METER, ROTOR BLADE WEAR

Fig.15: 100 mm NB. TURBINE METER DATA COMPARED TO REFERENCE FLOWMETER.



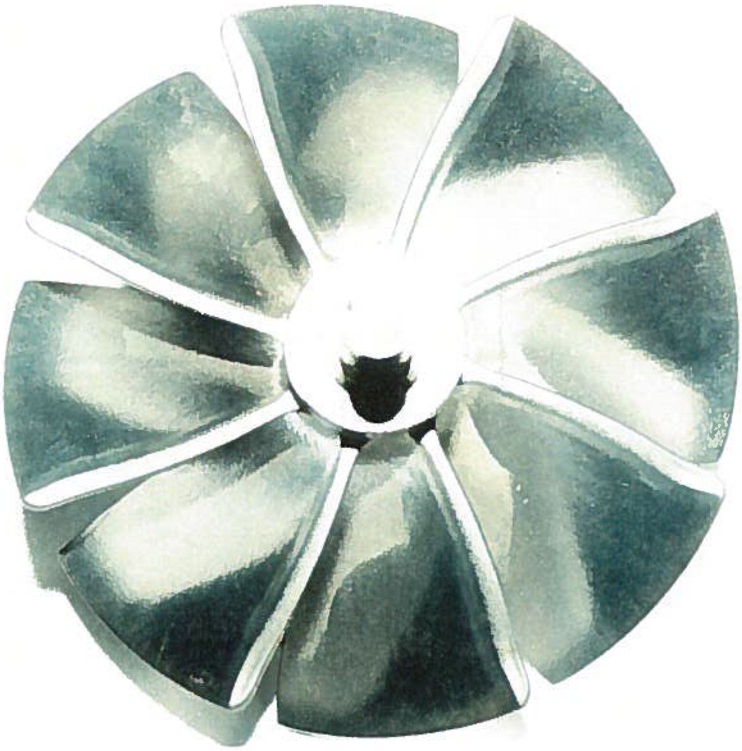


Fig 16 MANUFACTURER B. 100 mm DIAMETER METER, ROTOR BLADE WEAR

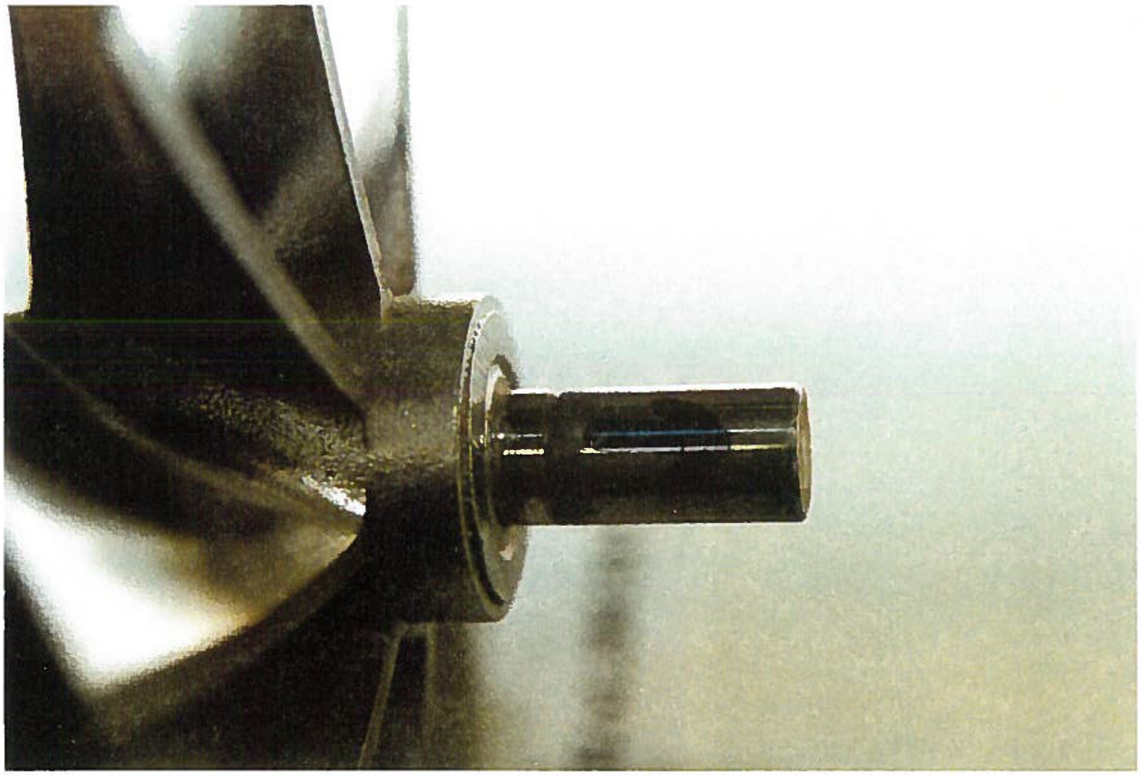


Fig 17 MANUFACTURER B. 100 mm DIAMETER METER, ROTOR SHAFT WEAR

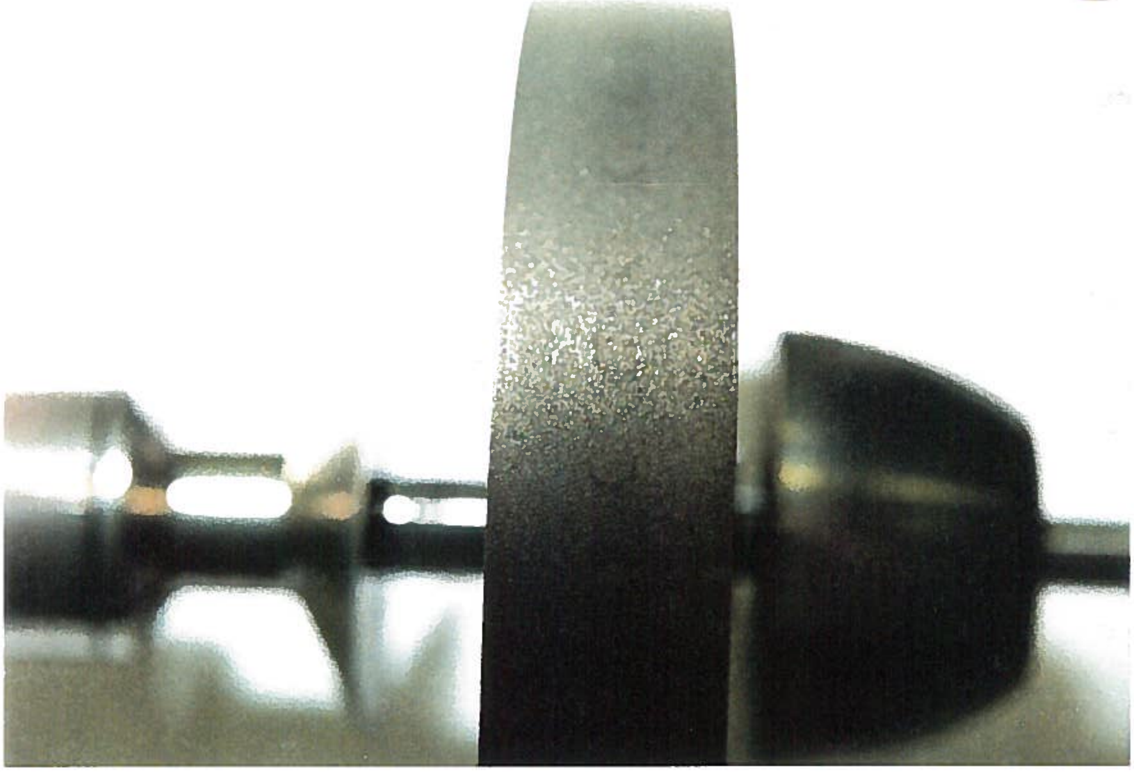


Fig 18 MANUFACTURER C. 100 mm DIAMETER METER, ROTOR RING WEAR

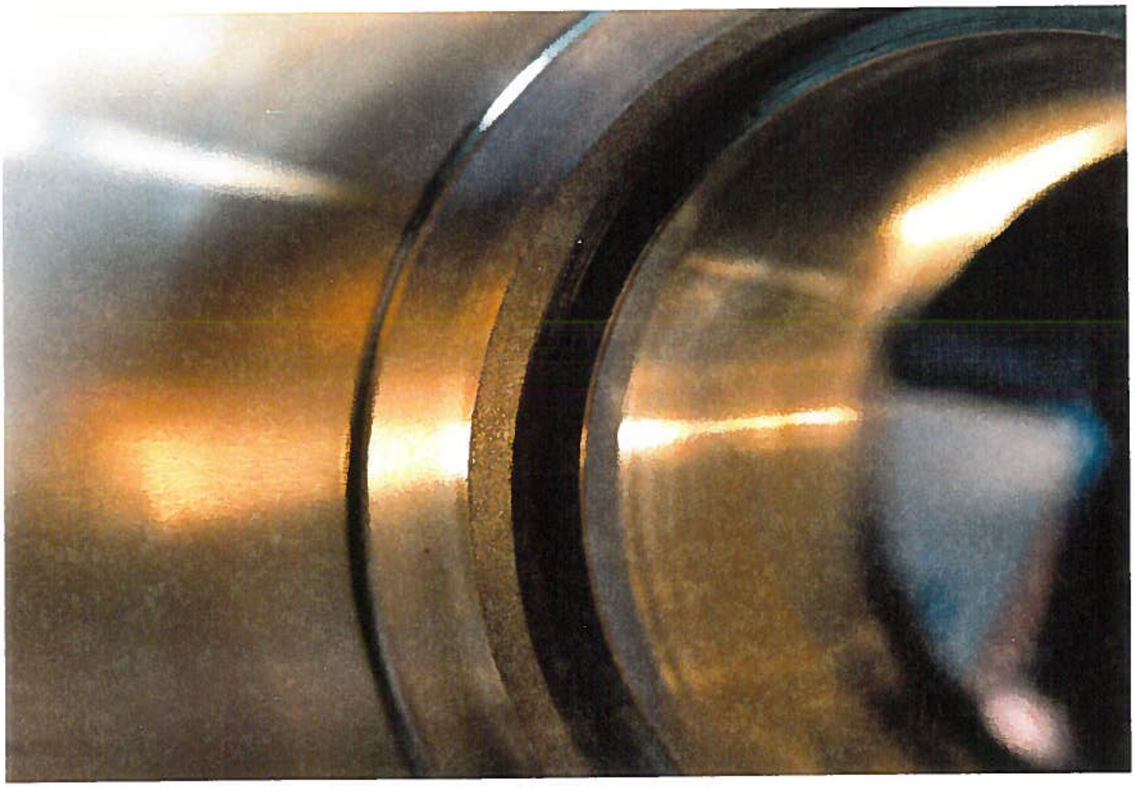
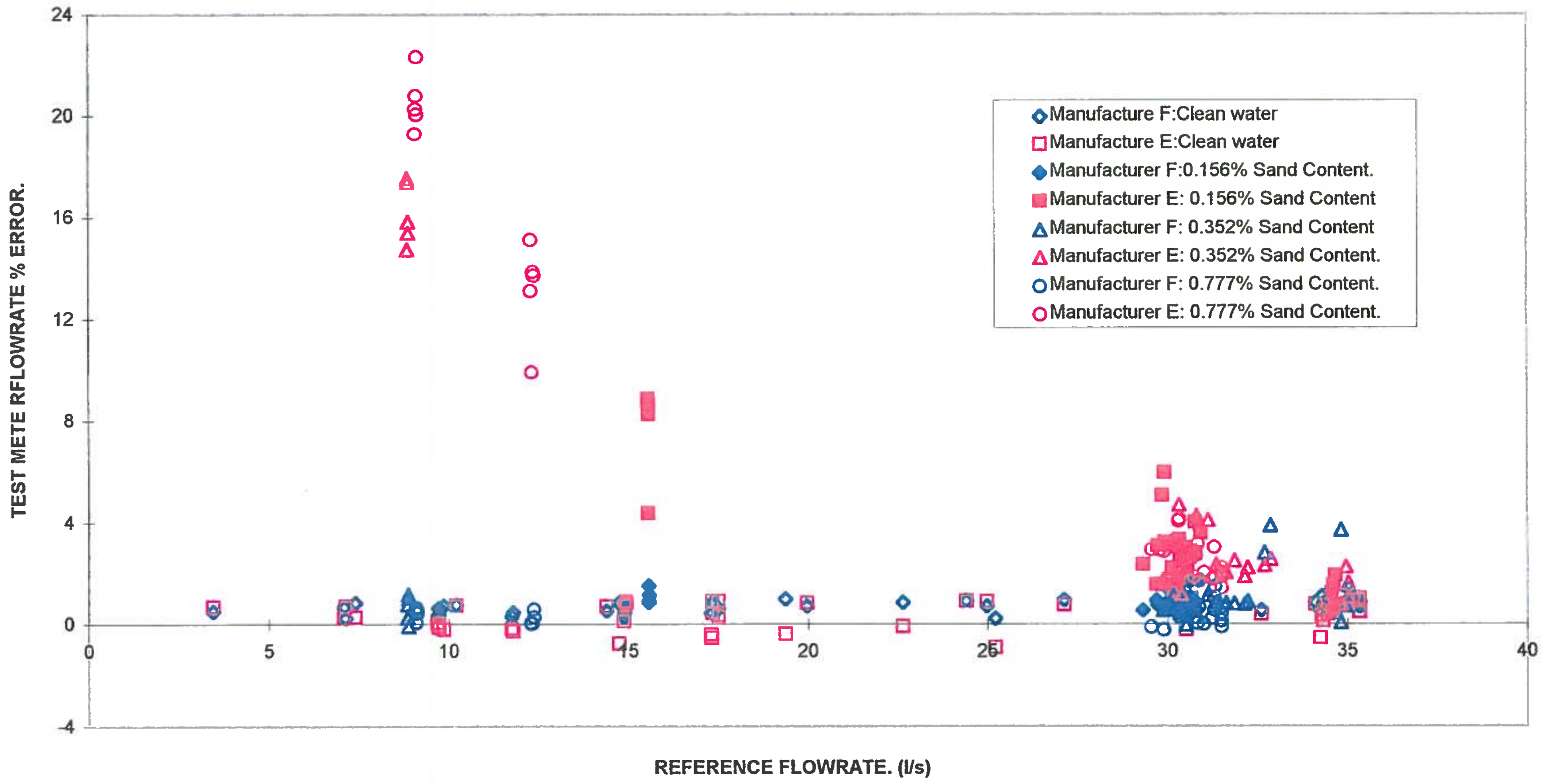


Fig 19 MANUFACTURER C. 100 mm DIAMETER METER, METER BORE WEAR

Fig. 20: CORIOLIS MASS AND WEDGE METER DATA
COMPARED TO REFERENCE FLOWMETER.



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PAPER 21 - 7.2

MONITORING OF DISSOLVED AND DISPERSED HYDROCARBONS IN PRODUCED WATER BY PHOTOACOUSTIC SPECTROSCOPY

H A MacKenzie, Heriot Watt University
S Freeborn, Heriot Watt University
J Hannigan, Heriot Watt University
G High, Kvaerner Oilfield Products Ltd

MONITORING OF DISSOLVED AND DISPERSED HYDROCARBONS IN PRODUCED WATER BY PHOTOACOUSTIC SPECTROSCOPY

Hugh A. MacKenzie; Scott Freeborn; John Hannigan, Heriot Watt University
Geoff High, Kvaerner Oilfield Products Ltd

1 INTRODUCTION

Photoacoustic spectroscopy is a long established technique which has been revitalised by the availability of new optoelectronic components from the telecommunications industry. The combination of near infrared diode laser sources, optical fibres and fibre optic components all contribute to continued development of a new generation of analytical instruments for applications in both the environmental and health care areas. In addition, when the advantages of the photoacoustic technique are allied to state of the art electronic devices and advanced computing modules an innovative instrument becomes feasible which overcomes many of the limitations of current techniques.

Photoacoustic generation is complex interaction involving physical and optical parameters which include the specific heat capacity c_p, the thermal expansion coefficient β and the velocity of sound v so that the magnitude of the photoacoustic signal can be expressed as

$$V_{pa} = k.\frac{E\ \alpha\ \beta\ v^{\frac{1}{2}}}{c_p}$$

where k is a constant of the instrument, E is the laser pulse energy and α is the optical absorption. A typical photoacoustic signal is shown in Figure 1 where the time interval between the start of the trace and photoacoustic signal at 4μS is the acoustic transit time from the optical beam to the acoustic detector and may be used to measure the velocity of sound in the liquid.

In general the peak to peak amplitude of the photoacoustic signal, **PA**, at a selected wavelength is used to measure the concentration of a particular analyte and to compensate for energy fluctuations, the amplitude is divided by. **E**, the energy of the optical pulse. Thus **PA/E** is the normalised photoacoustic amplitude which is used throughout our results.

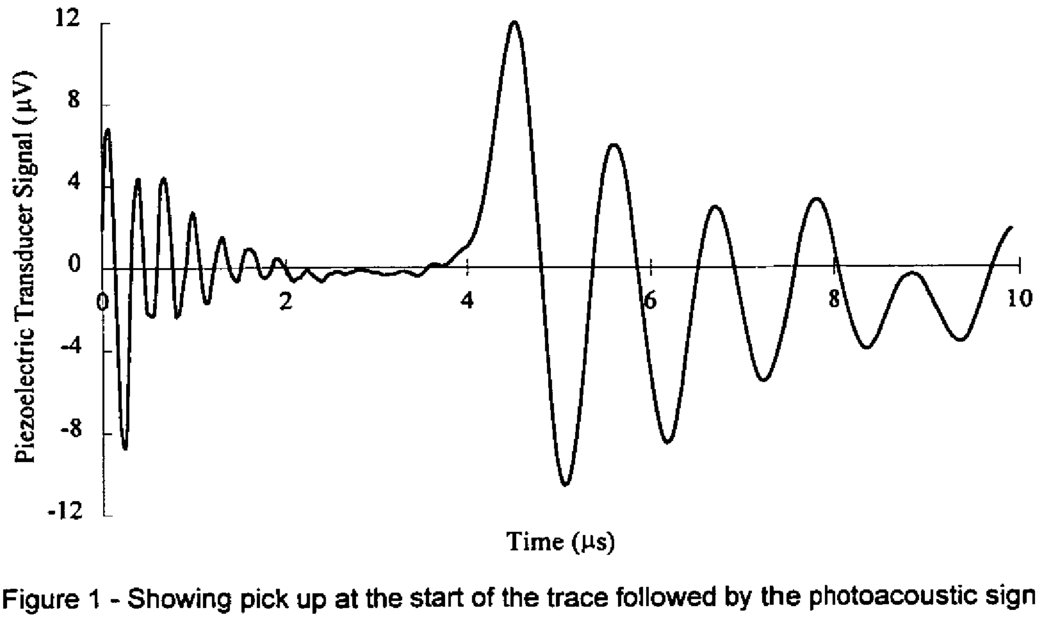

Figure 1 - Showing pick up at the start of the trace followed by the photoacoustic signal

The combination of physical parameters for water do not favour a strong photoacoustic response whereas those for many hydrocarbons yield a favourable set of properties and as a consequence the near infrared (NIR) spectrum of is comparatively weak and the spectral response for hydrocarbons is relatively strong.

The basic principles of sensing oil in water have been established both in the laboratory and through preliminary testing at the Orkney Water Test Centre and a typical response to Flotta crude is shown in Figure 2. These tests also served to show, within the limits of the tests, that the photoacoustic response was not affected by droplet size or flow velocity. Based on the success of the laboratory sensor, the design requirements for a dedicated instrument for offshore use has been achieved.

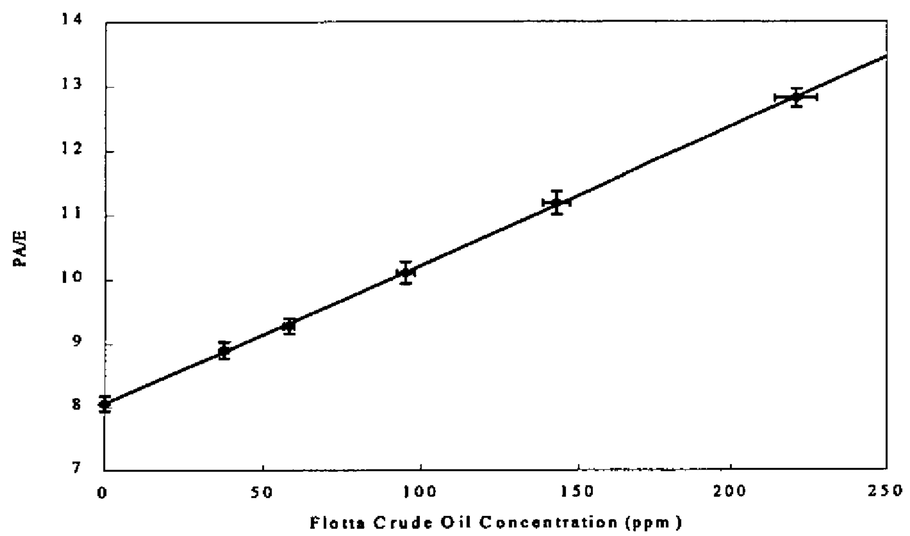

Figure 2 - The photoacoustic sensor response to changes in oil concentration in the test facility at the Orkney Water Technology Centre (ERT)

2 EXPERIMENTAL RESULTS

In the project proposal, some twelve key areas were identified to map out the progress of this project and at this halfway point, seven of these areas have been investigated in detail and in the following section, the experimental results will be presented for a laboratory photoacoustic sensor which was utilised to explore the use of photoacoustics in offshore applications, the results of which were applied during the design and development of a dedicated instrument for this project. The preliminary results of the hydrocyclone test rig development will also be discussed.

2.1 Performance in the Presence of Chemical Additives

In an offshore environment , the sensor will be required to monitor the level of oil concentrations in the presence of complex additives such as dispersants and corrosion inhibitors. We have conducted initial studies using additives at concentrations up to 1000 ppm and have found that the sensitivity to oil detection is unimpaired but there are changes in the baseline response. As we are using a dual wavelength system, this aspect will be included in the calibration algorithm.

Figure 3 shows the basic response of Flotta crude in salt water. It should be noted that the sensitivity to oil is characterised by the slope of the line which in this case is 0.011. The base line corresponds to the response in the absence of oil and in this case has a value of 17.2. When 1000 ppm of Methanol was added to the sample the response was as shown in Figure 4.

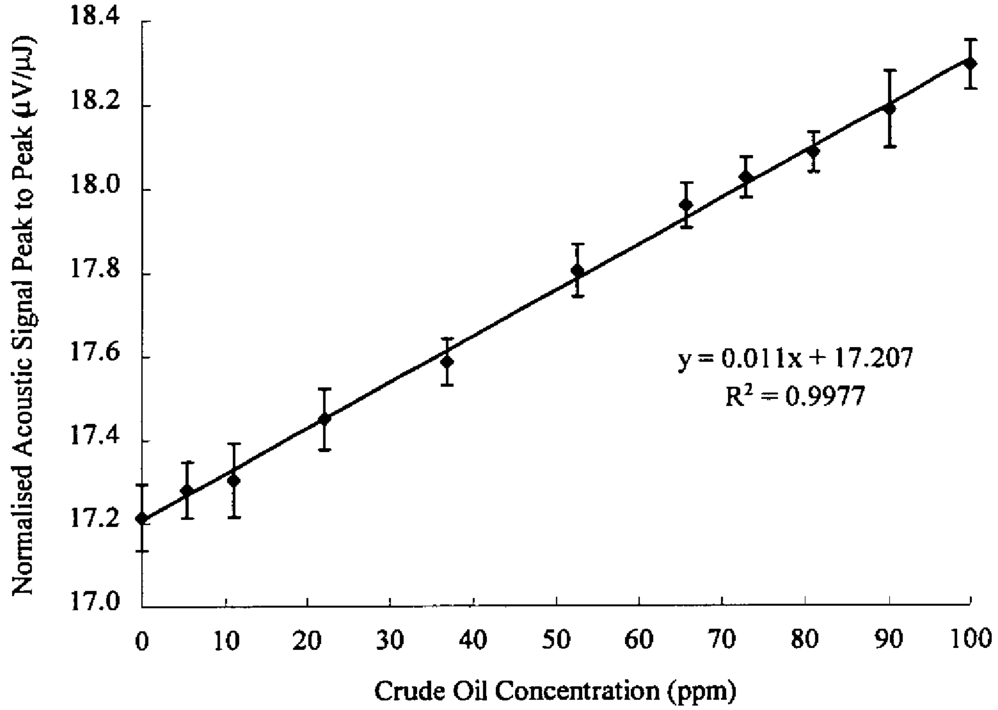

Figure 3 - Showing the response to changes in Flotta crude concentrations in salt water

It will be seen that the slope of the response remains approximately as before but the intercept at 0 ppm is now at 19.5. In the same way, when 1000 ppm of corrosion inhibitor is added, the sensitivity remains constant but the base line changes as shown in Figure 5.

The initial conclusion from these experiments is that the sensitivity of the photoacoustic sensor to oil concentrations is not affected by the presence of additives but baseline compensation will be required in the data analysis. For this reason , two wavelengths are used in the practical instrument: One for baseline compensation and the other for analyte measurement.

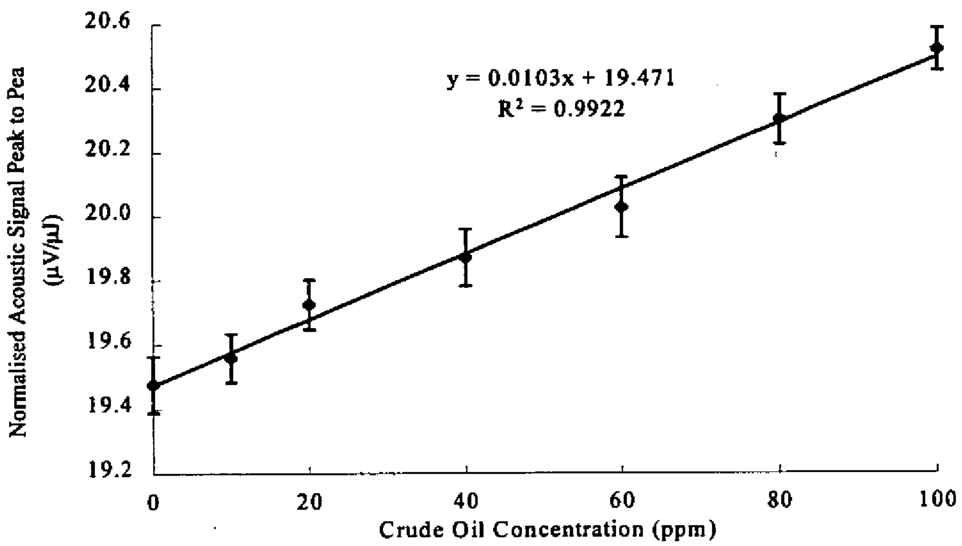

Figure 4 - Low crude oil concentration photoacoustic response in salt water with 1000ppm of methanol present

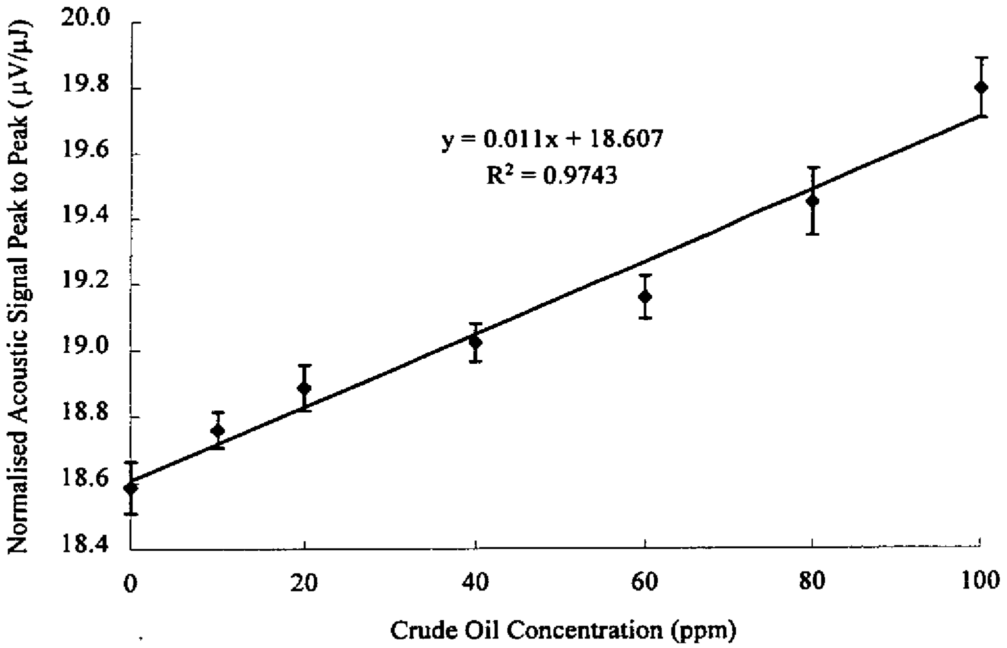

Figure 5 - Low crude oil concentration photoacoustic response in salt water with 1000 ppm of corrosion inhibitor present.

2.2 Performance at High Pressure

The operation of the photoacoustic sensor in hydrocyclone applications requires a system which will operate at pressure. When a high pressure cell was made available, investigation of the photoacoustic response at high pressure was undertaken. The high pressure values of the key physical parameters for water are available from tables in textbooks and scientific references. From this data and by substitution in the basic photoacoustic equation, the predicted photoacoustic response over a pressure range was calculated and is shown in the pressure range 1 to 350 bar as the straight line in Figure 6. A set of data points from photoacoustic measurements is also shown and there is clearly an excellent correlation between predicted and actual response. The continued functionality at high pressure is an interesting pointer to the possibility of subsea applications.

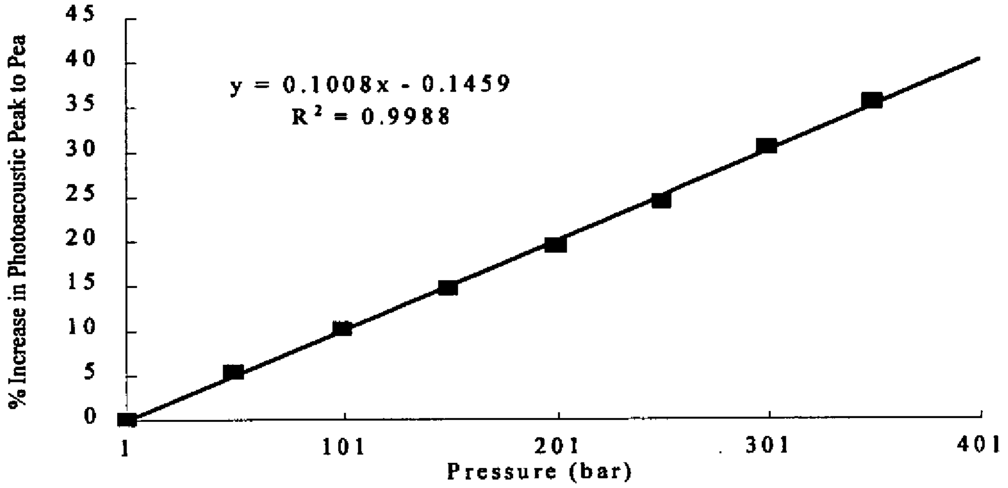

Figure 6 - Comparison of experimental results (symbols) and theoretical prediction (line) of the effect of pressure on the photoacoustic response from water

2.3 Performance with Different Crude Oils

A key factor in the calibration of the photoacoustic sensor is knowledge of the spectral response to different crude oils. Clearly if there was a dramatic and unpredictable difference in response it would create formidable calibration problems. To explore this aspect, samples of seven different crude oils were investigated and the resultant spectra are shown in Figure 7 below.

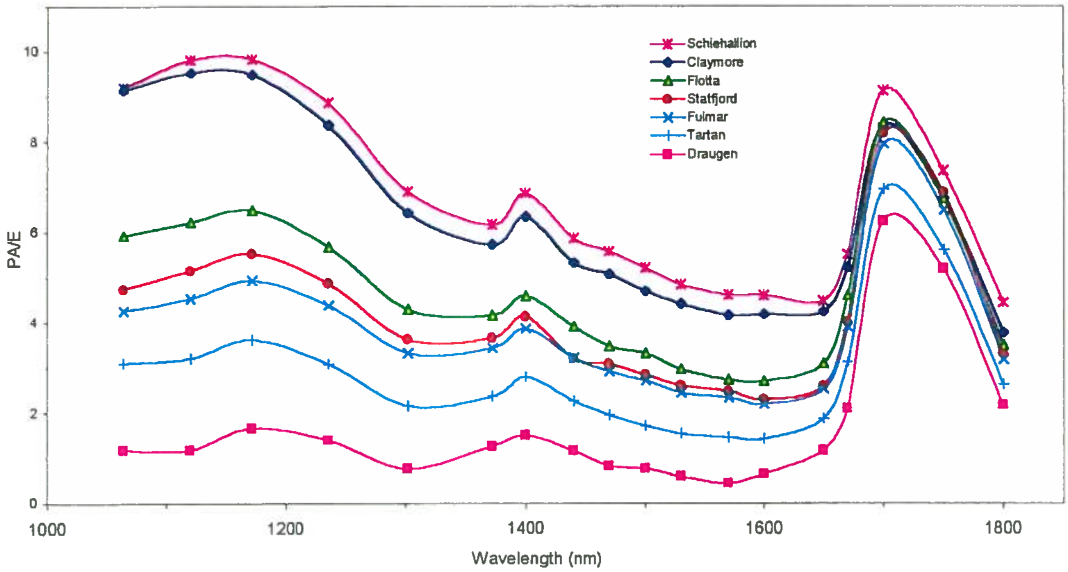

Figure 7 - Photoacoustic Spectra of various crude oils

It will be seen from these results that all the oils show the same general features of spectral peaks which are common to most hydrocarbons and a background response which is attributed to asphaltene products. Clearly with multi-reservoir systems, the changes in oil type would need to be included in the calibration process but it seems at this stage that different crude oils have substantially the same spectroscopic response against a background of broad band absorption from complex asphaltene compounds.

2.4 Temperature and Salinity Tests

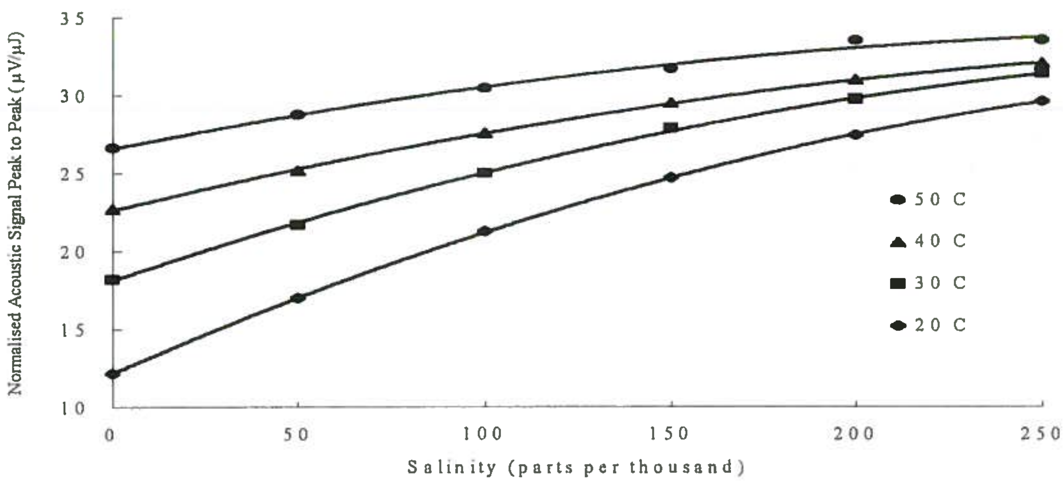

Figure 8 - Photoacoustic response from water with various salinities and temperatures

In the current sensor head there is an accurate temperature probe and there is a simple linear relationship between salinity and the velocity of sound in salt water. The velocity of sound in the sample may be measured from the delay time between the optical pulse and the onset of the photoacoustic signal. These measurements are an integral part of the calibration algorithm.

2.5 Response of Crude Oil Components

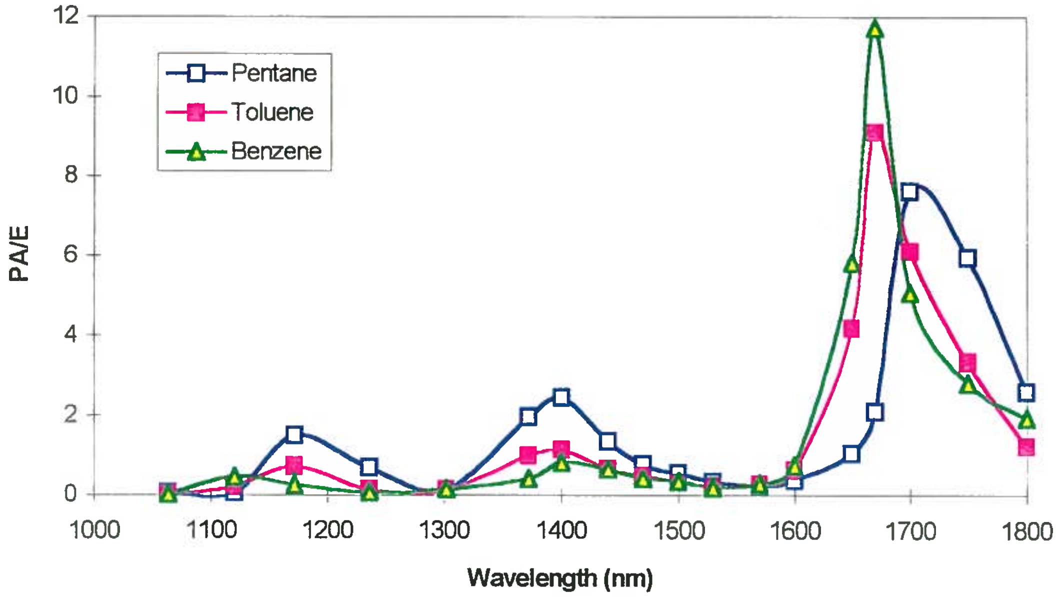

Figure 9 - Photoacoustic spectra of Pentane, Toluene and Benzene

Raw crude oils are complex liquids which comprise many components both volatile and non volatile. The spectra of Pentane, Toluene and Benzene are shown in Figure 9 below and have the characteristic spectra of light hydrocarbons. It is interesting to note in Figure 9 that the differences in peak positions around 1650 to 1700 nm is as predicted from conventional spectroscopy of these materials and suggests that an analytical photoacoustic instrument may be a possibility at a later date.

To investigate the role of the different components of a typical crude in creating the overall photoacoustic response a sample of Statoil crude was fractionated into four components and the photoacoustic spectrum of each component was recorded as shown in Figure 10. It will be seen that the lighter fractions, for example F1, have spectrum which are similar to those shown in Figure 9 whereas the heavier fractions such as F4 have a comparatively smooth and featureless response which increases at the shorter wavelengths in keeping with the background response expected from the heavier components.

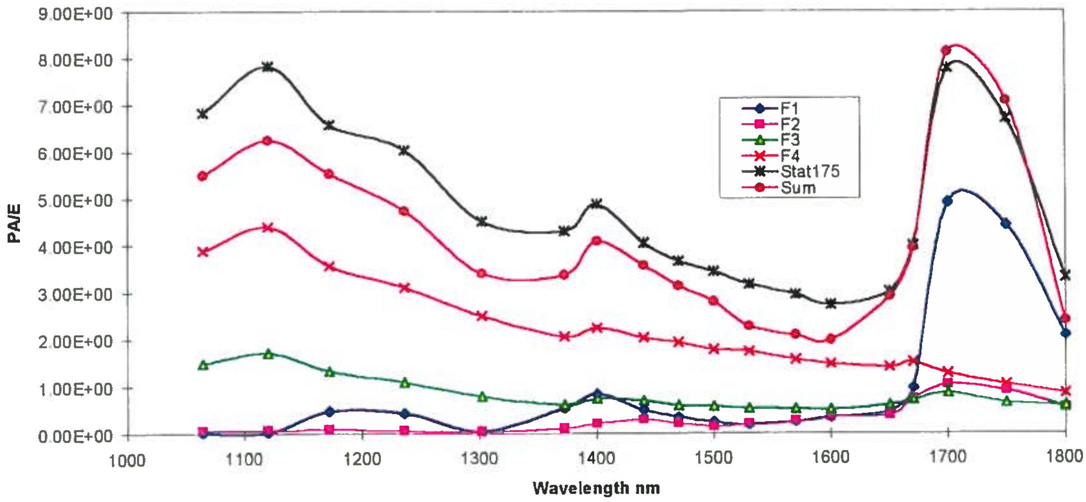

Figure 10 - Photoacoustic Spectra of crude oil fractions

2.6 Response at High Oil Concentrations

The original specification for this type of photoacoustic sensor was for the topside discharge of produced water with oil concentrations in the 10 to 100 ppm range. To establish the suitability of the photoacoustic sensor for monitoring the input side of a hydrocyclone, measurements were made at higher oil concentrations. Figure 11 shows the photoacoustic response in the range 0 to 8000 ppm of crude oil and it can be seen that the response is completely linear up to the highest concentrations.

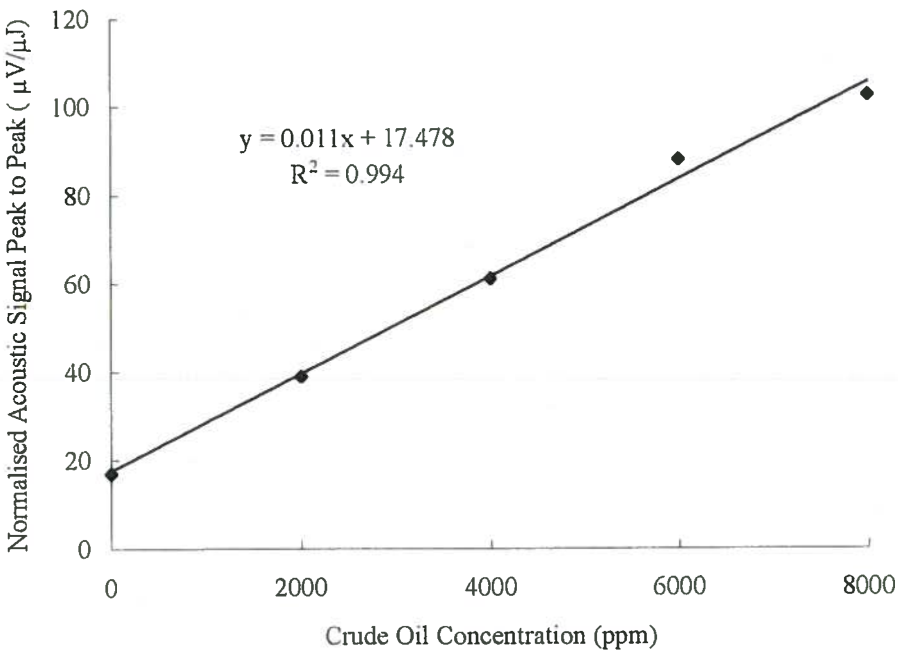

Figure 11 - High concentration measurements on Flotta Crude oil in water with laboratory system

At the higher concentrations, it was difficult to maintain the oil concentrations in emulsion for a reasonable time interval and it was decided to explore percentage oil concentrations in carbon tetrachloride. This liquid does not have spectral features in the relevant spectral region and is an ideal solvent for this application. The results of these experiments are summarised in Figure 12 which has measurements in the 0 to 20% oil concentration range. The response is fairly linear up to 10% and there is a roll off in sensitivity up to 20%. As mentioned previously, the detector head was designed for optimum response at lower oil concentrations and it should be possible to optimise the response in a similar way for higher concentrations.

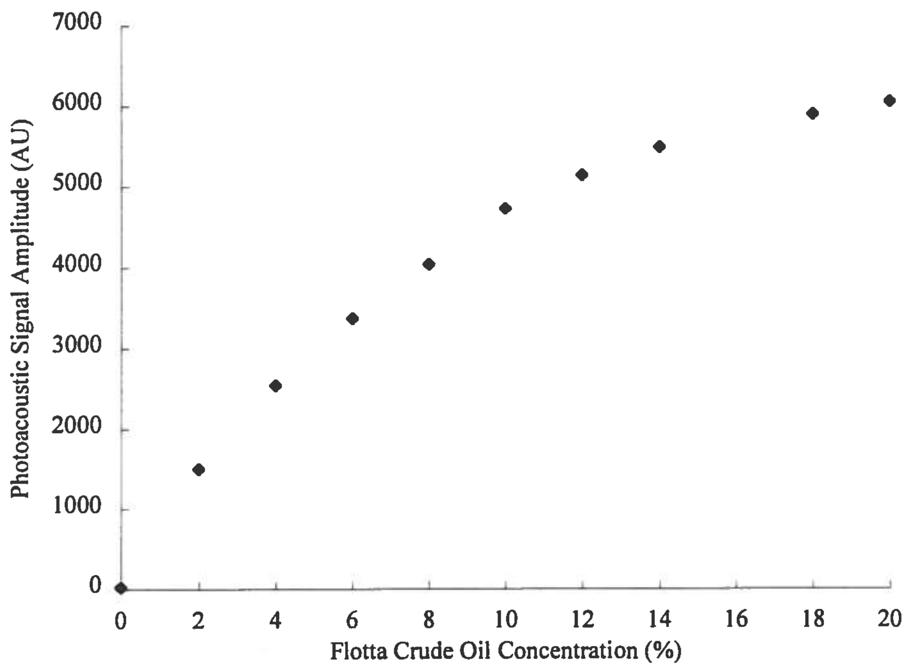

Figure 12 - Photoacoustic response for crude oil in carbon tetrachloride

2.7 Design Considerations

The sensor head consists of a 38 mm diameter stainless steel tube with the photoacoustic sensor system at one end and a 5 m umbilical to the control system at the outer end. The tube can be fitted into the test system either by a flange or by compression fittings. The photoacoustic sensor system consists of an optical system which directs a focussed laser beam through a sapphire window into the measurement region where the photoacoustic response is generated and detected by a curved piezoelectric element which detects the acoustic signal. The signal is then amplified by an in-head preamplifier before being interfaced with the measuring system at the end of the umbilical. The head also contains a temperature sensor and an energy monitor system to check on the energy of the diode laser pulses. The entire head has been designed to an Ex-d specification in consultation with SIRA. This system is scheduled for offshore testing this year.

3 DISCUSSION

The photoacoustic technique although it has been in existence for one hundred years it has not previously been deployed in the manner described above. This is because the recent advances in technology have generated components which are very well suited to pulsed laser photoacoustic sensors. At this time, the sensor has been tested in the laboratory and at Orkney (ERT) and thus far the results are generally good. It is clear that the real test of the system will be from extended offshore testing to determine the true operational envelope and that is the next stage of development.

4 ACKNOWLEDGEMENTS

Thanks are due to the MTD, CMPT, EPSRC, COSWASS, Shell Expro, Kvaerner OPL.

5 PUBLICATIONS

MacKenzie, H.A.; Christison, G.B.; Hodgson, P.; Blanc, D.; "A laser photoacoustic sensor for analyte detection in aqueous systems" Sensors and Actuators, B, 11, 213, 1993.

Hodgson, P.; Quan, K.M.; MacKenzie, H.A.; Freeborn S.S.;, Hannigan J., Johnston, E.M.; Greig, F.; Binnie, T.D.; "Application of Pulsed Laser Photoacoustic Sensors in Monitoring Oil Contamination in Water", Sensors and Actuators B , 29, 339 (1995)

A pulsed photoacoustic instrument for the detection of crude oil concentrations in produced water
S S Freeborn, J Hannigan, F Greig, R A Suttie and H A MacKenzie.
To be published in the November issue of *Review of Scientific Instruments.*

Main Index

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PAPER 22 7.3

THE REVISION OF ISO 5167 - AN UPDATE

M Reader-Harris, National Engineering Laboratory

16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

THE REVISION OF ISO 5167 - AN UPDATE

Dr Michael Reader-Harris, National Engineering Laboratory

1 INTRODUCTION

ISO TC30/SC2 WG11, of which I am Convener, is responsible for producing a draft of ISO 5167 which takes into account the work on differential pressure flowmeters which has been done in recent years and will provide a thorough revision of ISO 5167-1 [1]. WG11 was established in 1996 and a Committee Draft was issued to SC2 for discussion at ISO TC30/SC2 in June 1998. A revised Committee Draft incorporating comments should be issued at the end of this year with the expectation that a revised International Standard will be published in 2001.

This paper brings the North Sea Workshop up to date on the current situation with regard to the revision of the standard. It describes the planned changes and gives at least an indication of the research on which the changes are based.

ISO 5167 will be divided into 4 parts: general (ISO 5167-1), orifice plates (ISO 5167-2), nozzles and Venturi nozzles (ISO 5167-3), and Venturi tubes (ISO 5167-4). Many users will only require the general part and one other part. The most significant areas of change from the existing ISO 5167-1 are given below. It is likely that further changes will take place in the next three years.

2 ORIFICE PLATE INSTALLATION EFFECTS AND FLOW CONDITIONERS

A very large amount of data on installation effects on orifice plates has been collected in recent years, particularly in the USA and in Canada but also in the UK and in Germany. The data and the methods of analysis are given in [2]. Revised straight lengths based on an analysis of these data, initially undertaken by API but in which representatives of countries outside North America are now involved, will be included. The data downstream of two bends were taken with various distances between the two bends, and the required distances between pairs of bends will be included in the table. The table of required upstream straight lengths included in the Committee Draft of ISO 5167-2 discussed at SC2 in June 1998 is given here as Table 1. Only thermowells smaller than 0.03D will be permitted upstream of the orifice. Some pairs of bends in perpendicular planes with small separation gave very large shifts in discharge coefficients, although other pairs of bends with the same separation gave much smaller shifts. It will be recommended that if there is a possibility of a fitting creating severe swirl, as two bends in perpendicular planes with separation less than 5D or a header may do, a flow conditioner should be used.

In ISO 5167-1 a compliance test for flow conditioners will be included: using a primary device of diameter ratio 0.67 the shift in discharge coefficient from that obtained in a long straight pipe must be less than 0.23 per cent when a flow conditioner is used in each of four situations:

a) in good flow conditions,

b) downstream of two bends in perpendicular planes (ratio of bend radius to pipe diameter approximately equal to 1.5; separation between curved portions of bends less than two pipe diameters)

c) downstream of a half closed gate valve (or D-shaped orifice)

d) in conditions of high swirl downstream of a device producing a high swirl (the device should produce a maximum swirl angle across the pipe of 25 - 30° 18D downstream of it or 20 - 25° 30D downstream of it).

Table 1 - Required straight lengths between orifice plates and fittings without flow conditioners

Values expressed as multiples of internal diameter D

Diameter ratio β	Upstream (inlet) side of the orifice plate																								Downstream (outlet) side of the orifice plate	
	Single 90° bend Two 90° bends in same plane ($S > 30D$)* Two 90° bends in perpendicular planes ($S > 15D$)*		Two 90° bends in the same plane: S-configuration ($10D \geq S$)*		Two 90° bends in the same plane: S-configuration ($30D \geq S > 10D$)*		Two 90° bends in perpendicular planes ($5D > S$)*		Two 90° bends in perpendicular planes ($15D \geq S \geq 5D$)*		Single 90° tee		Single 45° bend Two 45° bends in the same plane ($S > 22D$)*		Reducer $2D$ to D over a length of $1{,}5D$ to $3D$		Expander $0{,}5D$ to D over a length of D to $2D$		Full bore ball valve fully open		Abrupt symmetrical reduction		Thermometer pocket or well** of diameter $\leq 0{,}03D$		Fittings (columns 2 to 11) and the densitometer pocket	
1	2		3		4		5		6		7		8		9		10		11		12		13		14	
	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A	B
0,20	6	6	10	10	10	10	***	***	19	19	9	9	****	****	5	5	16	8	12	6	30	15	5	3	4	2
0,40	18	9	10	10	13	10	50	30	44	19	9	9	30	18	5	5	16	8	12	6	30	15	5	3	6	3
0,50	30	16	30	10	18	16	95	60	44	19	19	9	30	18	6	5	18	9	12	6	30	15	5	3	6	3
0,60	44	30	44	30	30	18	95	50	44	19	29	18	30	30	9	5	22	11	14	7	30	15	5	3	7	3,5
0,67	44	30	44	30	44	30	95	50	44	30	36	30	44	30	12	6	27	14	18	9	30	15	5	3	7	3,5
0,75	44	35	44	30	44	30	95	65	44	30	44	30	44	30	22	11	38	19	24	12	30	15	5	3	8	4

*) S is the separation between the two bends measured from the downstream end of the curved portion of the upstream bend to the upstream end of the curved portion of the downstream bend.

**) The installation of thermometer pockets or wells will not alter the required minimum upstream straight lengths for the other fittings.

***) There are insufficient data for this configuration: the lengths for $\beta = 0{,}4$ should be used.

****) There are no data for this configuration: the lengths for $\beta = 0{,}4$ are at least sufficient.

NOTES:

1. The minimum straight lengths required are the lengths between various fittings located upstream or downstream of the orifice plate and the orifice plate itself. Straight lengths shall be measured from the downstream end of the curved portion of the nearest (or only) bend or of the tee or the downstream end of the conical portion of the reducer or expander.
2. Lengths for $\beta < 0{,}2$ can be taken to be equal to those for $\beta = 0{,}2$.
3. Most of the bends on which the lengths in this table are based had a radius of curvature equal to $1{,}5D$, but it may be used for bends with any radius of curvature.
4. Column A for each fitting gives lengths corresponding to 'zero additional uncertainty' values (see 5.2.3).
5. Column B for each fitting gives lengths corresponding to '0,5% additional uncertainty' values (see 5.2.4).

This last installation was included to give a swirl similar to that found downstream of a header tested at NEL. As well as the test for $\beta = 0.67$ the flow conditioner must pass the high-swirl test (d) for $\beta = 0.4$. This test for $\beta = 0.4$ is included because, although for non-swirling flow shifts in discharge coefficient increase with β, this is not necessarily true for swirling flow. Provided that the flow conditioner is geometrically similar for all pipe diameters this compliance test need only be passed for one diameter, and if it is passed for a range of Re_D greater than 3×10^6 it will be taken to have been passed for all $Re_D > 3 \times 10^6$. If a flow conditioner passes this test it may be used with no additional uncertainty downstream of any fitting with any diameter ratio up to 0.67. If it is desired to use the flow conditioner for $\beta > 0.67$ additional testing is required. Required distances between the primary device and flow conditioner and between upstream fittings and flow conditioner will be determined in the course of the tests since a flow conditioner will not pass for all distances. The compliance test is included in ISO 5167-1 because the same test is applied whichever primary device is used; however passing the test with one type of primary device does not imply that the test would have been passed with all types of primary device.

Tests were undertaken with orifice plates at SwRI to check that there are flow conditioners which meet these compliance tests with reasonable overall distances between fittings and orifice plate. These showed that there is a location for a 19 tube bundle of defined geometry at which the compliance test is satisfied provided that the overall length between orifice plate and tube bundle is at least $30D$; similarly there is at least one location at which both the Gallagher and the K-Lab Laws Nova 50 E pass this test provided that the overall length between orifice plate and either flow conditioner was at least $18D$. These lengths are not minimum upstream length requirements using the tube bundle or the flow conditioners; they are lengths at which successful tests were carried out. Measurements of required length are taken from the orifice face to the upstream fitting itself so that the weld neck is included within the straight length; for example the distance is measured to the downstream end of the curved portion of a bend. The results are presented without naming the conditioners in [2], but names are given in [3].

The installation requirements given in the current draft of Part 2 of API 14.3 [4] are almost identical to those proposed in ISO 5167. This is significant progress.

3 EXPANSIBILITY EQUATION FOR ORIFICE PLATES

The orifice plate discharge coefficient equation has been revised on the basis of data collected in the last 20 years, and it is appropriate that the same process of revision should occur for the expansibility factor.

The existing equation for the orifice expansibility factor was derived by Buckingham [5] on the basis largely of data collected at tests in Los Angeles in 1929. Using these data Buckingham derived the equation:

$$\varepsilon_1 = 1 - (0.41 + 0.35\beta^4)\frac{\Delta p}{\kappa p_1}, \tag{1}$$

where ε_1 is the expansibility coefficient, Δp is the differential pressure across the orifice plate, p_1 is the static pressure at the upstream tapping and κ is the isentropic exponent.

It is significant that in analysing the data Buckingham neglected the effect of Reynolds number on the grounds that above a throat Reynolds number, Re_d, of 2×10^5 the discharge coefficient is constant. It is now known that the discharge coefficient continues to change with Re_d above this value. The work of Bean and Buckingham has nevertheless set a pattern for subsequent workers in this area.

As part of the EEC Orifice Project data were collected on expansibility factors. At NEL on the 100 mm (4-inch) pipe run data were collected for three diameter ratios, 0.2, 0.57 and 0.75, in air with 140 kPa < p_1 < 800 kPa. Details of the analysis of the data are given in Reference [6] together with references to the individual data sets from all the laboratories whose data were used. This work followed that of Kinghorn [7]. Gaz de France collected data on the 100 mm (4-inch) pipe run for a diameter ratio of 0.66 in natural gas at $Re_D = 1.2 \times 10^6$.

Gasunie did not collect data on expansibility factor directly but within the data collected by them on the 100 mm (4-inch) pipe run for the discharge coefficient database it is possible to identify sets of data taken over both a significant range of static pressure and a small range of Reynolds number. These data are for diameter ratios 0.2, 0.57 and 0.66. Similarly CEAT did not collect data on expansibility factor directly but within the data collected by them on the 250 mm (10-inch) pipe run for the discharge coefficient database it is possible to identify sets of data taken over both a significant range of static pressure and a small range of Reynolds number. These data are for a diameter ratio of 0.2.

In addition to the European work CEESI on a 50 mm (2-inch) pipe run collected data for six diameter ratios, 0.242, 0.363, 0.484, 0.5445, 0.6655 and 0.726 in air with 115 kPa $< p_1 <$ 2150 kPa.

In order to analyse the NEL (and similar) data a common method has been to calculate

$$\varepsilon_1\big|_{\text{calc}} = \frac{(C\varepsilon_1)_{\text{measured}}}{C_{\text{water}}} \tag{2}$$

where $(C\varepsilon_1)_{\text{measured}}$ is taken from the gas tests and C_{water} from a previous water calibration of the same orifice plate and then to use the method of least-squares to determine the constants in

$$\varepsilon_1\big|_{\text{calc}} = 1 - a - b\,\mathrm{f}\left(\frac{\Delta p}{p_1}, \kappa\right) \tag{3}$$

and then to fit the slope terms, b.

The problem with this method is that there is always some bias between a gas flow laboratory and a water flow laboratory. So a better estimate of ε_1 is given by

$$\varepsilon_1\big|_{\text{calc},2} = \frac{\varepsilon_1\big|_{\text{calc}}}{1 - a} = 1 - \frac{b}{1-a}\mathrm{f}\left(\frac{\Delta p}{p_1}, \kappa\right) \tag{4}$$

which is equivalent to fitting $(C\varepsilon_1)_{\text{measured}}$ as $C_{\text{incompressible}}(1 - b^{*}\mathrm{f})$ without assuming a value for $C_{\text{incompressible}}$.

In the case of the Gaz de France data the value of C obtained when ε_1 is as close as possible to 1 had been used as the reference value (equivalent to C_{water} in Equation (2)); this reference value is a single measurement, and so in [6] all the data including the reference value were fitted and values of $b/(1 - a)$ calculated. The data from CEESI had already been analysed in a similar manner to that used here and so in most cases a was calculated to be 0.

For the data from Gasunie and CEAT the Reynolds number was not constant and so it was necessary to apply corrections to the measured values of $C\varepsilon_1$ so that all the values are effectively taken at one Reynolds number. To do this the dependence of C on Reynolds number given in the Reader-Harris/Gallagher Equation [8] was assumed.

For each set of data calculations were performed for two functions, f:

$$\mathrm{f}\left(\frac{\Delta p}{p_1}, \kappa\right) = \frac{\Delta p}{\kappa p_1} \tag{5}$$

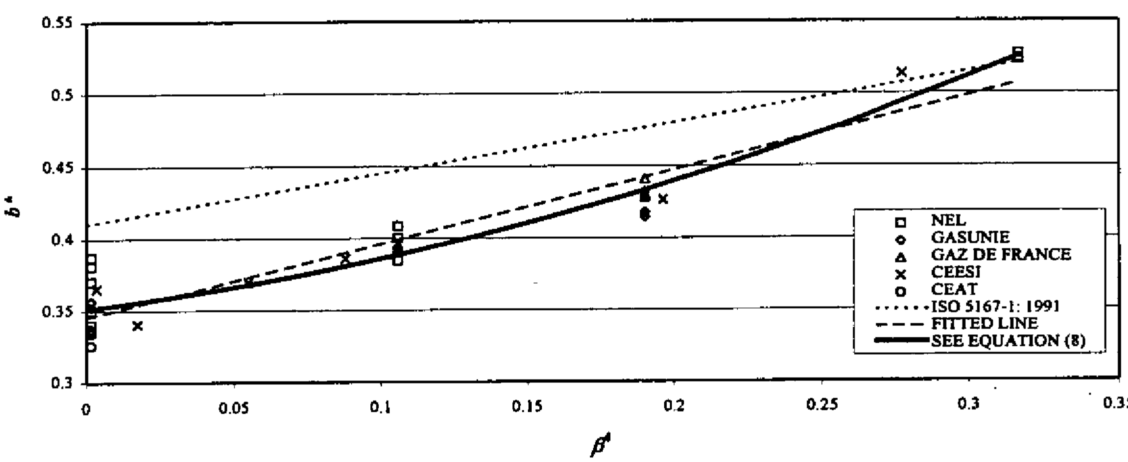
and

$$f\left(\frac{\Delta p}{p_1},\kappa\right)=1-\left(\frac{p_2}{p_1}\right)^{1/\kappa}, \tag{6}$$

where p_2 is the static pressure at the downstream pressure tapping. The first equation is simpler but the latter is based on the best physical understanding. It was clear that where there is a wide range of values of p_2/p_1, that is in the NEL, Gaz de France and CEESI data, using Equation (6) gives a smaller standard deviation of the data about the obtained fit, and so Equation (6) is used to reduce bias in the final equation. More complex forms of equation than Equations (5) and (6) were tried but only gave marginal improvements in quality of fit. The values of b^* (for use with f in Equation (6)) are dependent on β and are shown in Figure 1. For $\beta \leq 0.66$ there is a linear dependence on β^4. At higher diameter ratios the measured values lie above a fitted line and so, to avoid bias at small β due to the points for large β, b^* has been fitted as follows:

$$b^*=a_1+a_2\beta^4+a_3\beta^8. \tag{7}$$

Fig. 1 Experimental data: coefficients of f in Equation (4) (f as in Equation (6))



Different functions of β did not give a worthwhile improvement in fit. On fitting the data the following equation was obtained:

$$\varepsilon_1=1-(0.351+0.256\beta^4+0.93\beta^8)\left\{1-\left(\frac{p_2}{p_1}\right)^{1/\kappa}\right\}. \tag{8}$$

The standard deviation of the values of b^* about the quadratic fit in β^4 was 0.0148.

The uncertainty of the value of ε_1 is considered in Reference [6] and it is proposed that the relative uncertainty of ε_1 given in ISO 5167-2 should be

$$3.5\frac{\Delta p}{\kappa p_1}\ \text{per cent.} \tag{9}$$

Because the present equation for ε_2 is in error and it is little used it will be omitted.

3 ECCENTRICITY LIMITS FOR ORIFICE PLATES

Debate on the requirements continues. There is a difference between the ISO and API standards, because there are small differences between the sets of data [9, 10] on which the two standards are based; the data are in good agreement in general, but since the permitted eccentricities are based on giving shifts in discharge coefficient of less than 0.1 per cent it is not surprising that different data sets give different permitted eccentricities. The proposed ISO requirements have been determined so that shifts using either set of data are less than 0.1 per cent. The present ISO requirements are sufficient to ensure good measurement. Under certain circumstances they are, however, more demanding than is necessary. To obtain a clause which describes the experimental data more accurately it is necessary to consider the eccentricity in its two components, parallel to a pressure tapping and perpendicular to the pressure tapping, since eccentricity parallel to a pressure tapping has more effect on the discharge coefficient measured using it than eccentricity perpendicular to it.

To determine the eccentricity the distance e_c between the centre-line of the orifice and the centre-lines of the pipe on the upstream and downstream sides is measured, and for each pressure tapping the components of the distance between the centre-line of the orifice and the centre-line of the pipe in which it is located in the directions parallel to and perpendicular to the axis of the pressure tapping is determined. If there is to be no additional uncertainty e_{cl}, the component in the direction parallel to the pressure tapping, must for each pressure tapping be such that

$$e_{cl} \leq \frac{0.002\,5D}{0.1 + 2.3\beta^4}, \tag{10}$$

and e_{cn}, the component in the direction perpendicular to the pressure tapping, must for each pressure tapping be such that

$$e_{cn} \leq \frac{0.005D}{0.1 + 2.3\beta^4}. \tag{11}$$

If the eccentricity is purely parallel to the tapping this is the same requirement as in the existing ISO 5167-1; otherwise it gives a larger tolerance.

4 FLATNESS TEST FOR ORIFICE PLATES

Clause 8.1.2.1 in the existing ISO 5167-1 in which the slope of a straight line connecting any two points of its surface must be less than 0.5 per cent relative to a plane perpendicular to the centre-line of the orifice plate bore is too demanding since measurements can be made with the two points very close together. A simplified test based on that in the API standard (the current draft revision is reference [4]) is proposed in which a straight edge of length D is laid across any diameter of the plate and the maximum gap between the plate and the straight edge is measured. The plate is considered to be flat when the gap is for every diameter less than $0.005(D\text{-}d)/2$. This will ensure that the mean slope from the pipe wall to the orifice edge is less than 0.5 per cent. The API standard allows twice as large a gap; the ISO limit has been chosen so that when the effect of deformation under pressure is added the slope can still be less than 1 per cent.

5 TEMPERATURE CORRECTION

Work at British Gas [11] and Gasunie [12] has shown that in a gas flow to estimate the temperature upstream of the orifice plate from that measured some distance downstream an isenthalpic correction is appropriate, and the standard will be revised accordingly. The British Gas report covers a wide range of diameter ratios, whereas the Gasunie report has studied the flow through one orifice of diameter ratio 0.5 in more detail. The Gasunie report compares the change in temperature with the differential pressure; even better agreement with that predicted by an isenthalpic correction would have been achieved if the change in temperature between upstream of the plate and that at the temperature tapping location downstream had been compared with the pressure loss, $\Delta\varpi$. The data show that an isentropic expansion is still correctly assumed from upstream of an orifice plate into the vena contracta. However, to use an isentropic correction between upstream of the plate and the temperature measured at the usual temperature tapping location downstream of the plate can lead to significant error.

In many cases it can safely be assumed that the downstream and upstream temperatures of the fluid are the same at the differential pressure tappings. However, if the fluid is a non-ideal gas and the highest accuracy is required and there is a large pressure loss between the upstream pressure tapping and the temperature location downstream of the primary device, then it is necessary to calculate the upstream temperature from the downstream temperature (measured at a distance of $5D$ to $15D$ from the primary device), assuming an isenthalpic expansion between the two points. To perform the calculation the pressure loss $\Delta\varpi$ should be calculated from the differential pressure. Then the corresponding temperature drop from the upstream tapping to the downstream temperature location, ΔT, can be evaluated given the rate of change of T with respect to p at constant enthalpy:

$$\begin{aligned}\Delta T &= \left.\frac{\partial T}{\partial p}\right|_H \Delta\varpi \\ &= \frac{R_g T^2}{pc_p}\left.\frac{\partial Z}{\partial T}\right|_p \Delta\varpi,\end{aligned} \tag{12}$$

where T is the absolute temperature, R_g is the universal gas constant, c_p is the heat capacity at constant pressure and Z is the compressibility factor.

6 PIPE ROUGHNESS LIMITS UPSTREAM OF ORIFICE PLATES

New roughness limits for pipework upstream of orifice plates have been included. These are derived from a physical understanding of the effect of pipe roughness on orifice plate discharge coefficients and the knowledge of the roughness of the pipes on which the new discharge coefficient equation is based. Pipe roughness limits have been calculated to ensure that roughness will not shift the discharge coefficient from that given by the discharge coefficient equation by more than an appropriate fraction of its uncertainty.

The arithmetical mean deviation of the roughness profile, R_a, or the friction factor, λ, (or both) was measured for each of the pipes used to collect the data to which the discharge coefficient equation was fitted. Using these data it is possible to fit a discharge coefficient equation containing an explicit friction factor term; this was done at the time when the PR14 equation was developed and, using the PR14 tapping terms, the following equation for the C_∞ and slope terms was obtained:

$$\begin{aligned}C &= 0.5945 + 0.0157\beta^{1.3} - 0.2417\beta^8 \\ &\quad + 0.000514(10^6\beta / Re_D)^{0.7} \\ &\quad + (3.134 + 4.726A_p)\beta^{3.5}\max\{\lambda, 0.1704 - 35(Re_D/10^6)\}\end{aligned} \tag{13}$$

where

$$A_p = \left(\frac{2100\beta}{Re_D}\right)^{0.9}$$

Reference [13] gives the details.

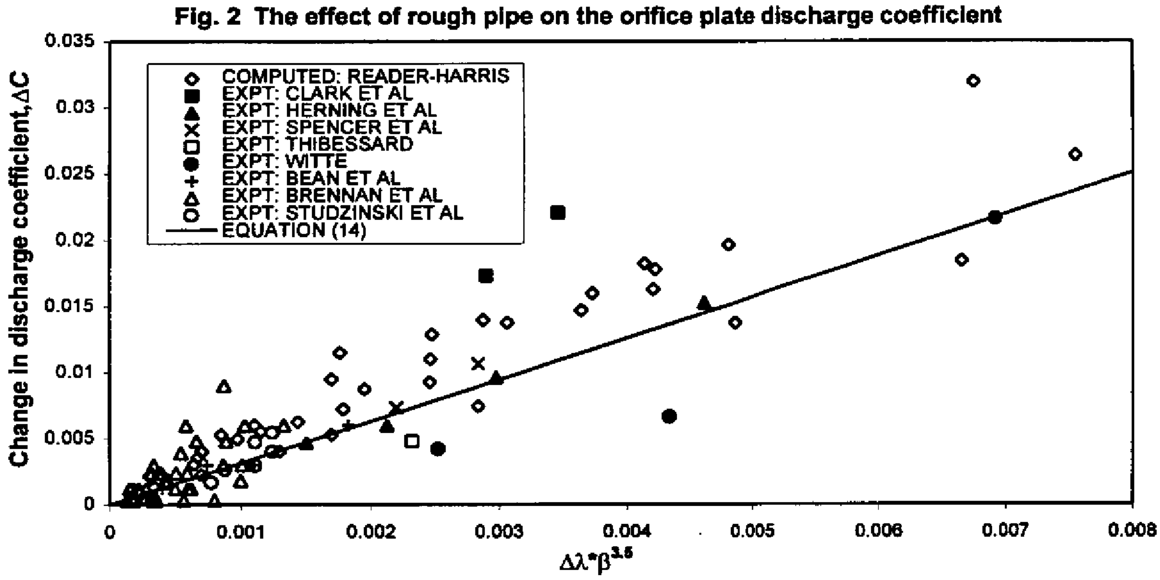
This gives the change in friction factor due to roughness, ΔC_{rough}, as

$$\Delta C_{rough} = 3.134\beta^{3.5}\Delta\lambda. \qquad (14)$$

provided that Re_d is sufficiently large that A_p is negligible.

Figure 2 gives measured and computed (using CFD) values of ΔC as a function of $\beta^{3.5}\Delta\lambda$ (see Reference [14] for complete references). The computed values and the European experimental data were obtained using corner tappings. The North American experimental data (Bean et al, Brennan et al and Studzinski et al) were obtained using flange tappings. In Reference [14] the effect of roughness on discharge coefficients obtained with different pairs of pressure tappings is considered and it is shown that the effect of pipe roughness on the discharge coefficient using D and $D/2$ tappings is about 20 per cent less than on that using corner tappings. Since all the computational and most of the experimental data in Figure 2 were collected using corner tappings this may explain why equation (14) lies below the mean of the plotted data.

Fig. 2 The effect of rough pipe on the orifice plate discharge coefficient



Nevertheless there is a large scatter in the plotted data, and so a single equation is used to describe the effect of pipe roughness for all tappings. The equation used to determine limits of pipe roughness is again taken from Equation (13), but the A_p term is included:

$$\Delta C_{rough} = (3.134 + 4.726A_p)\beta^{3.5}\Delta\lambda. \qquad (15)$$

It is not known whether the effect of change in friction factor increases for small Re_d, but it is safer to include the term in A_p in calculating the limits of pipe roughness. Moreover there is little disadvantage in its inclusion since it causes a slight reduction in the limits of pipe roughness in a range of Reynolds number where they are already wide.

In order to calculate the limits of pipe roughness for the new discharge coefficient equation it is necessary first to use the measured values of relative roughness for each pipe to obtain a typical pipe relative roughness for the data (and thus for the equation fitted to it). This is a function of Re_D: the estimates are given in Table 2. The values of friction factor are consistent with the values of relative roughness if the Colebrook-White Equation (see Reference [15]) is used.

Table 2 - Values of *k/D* and λ associated with the database

Re_D	10^4	3×10^4	10^5	3×10^5	10^6	3×10^6	10^7	3×10^7	10^8
$10^4k/D$	1.75	1.45	1.15	0.9	0.7	0.55	0.45	0.35	0.25
λ	0.031	0.024	0.0185	0.0155	0.013	0.0115	0.0105	0.010	0.0095

The maximum permissible shift in *C* depends on *U*, the uncertainty of *C*. It is assumed here that the percentage shift, *P*, should not exceed

$$\begin{array}{ll} 0.5\beta & \beta \le 0.5 \\ 0.25 & 0.5 < \beta \le 0.6 \\ 0.5(1.667\beta - 0.5) & 0.6 < \beta \le 0.71 \\ 1.13\beta^{8.5} & 0.71 < \beta \end{array} \qquad (16)$$

This restriction ensures that for $\beta \le 0.5$, where other sources of error are dominant, $P/U < \beta$; for $0.5 < \beta \le 0.71$, where pipe roughness is a major cause of error, $P/U < 0.5$; for $0.71 < \beta$, where pipe roughness is one of the two largest causes of error, the maximum value of P/U increases from 0.5 at $\beta = 0.71$ to 0.55 at $\beta = 0.75$.

Given the value of *P* in Equation (16) and the value of λ associated with the data in the database (and thus with the equation) in Table 2, it is possible from Equation (15) to calculate the maximum and minimum values of λ and hence of k/D for use with the equation for each Re_D and β. It has been decided to write ISO 5167 in terms of R_a rather than *k* for specification of pipe roughness, since this will be more convenient for users. On the basis of a simple computation with a roughness profile in the shape of a sine wave it has been assumed that $k \approx \pi R_a$. (The use of R_a will apply for all primary devices. *k* will still be mentioned.) The maximum and minimum values of R_a/D for pipes upstream of orifice plates are given in Tables 3 and 4.

Table 3 - Maximum value of $10^4R_a/D$

Re_D / β	$\le10^4$	3×10^4	10^5	3×10^5	10^6	3×10^6	10^7	3×10^7	10^8
≤0.20	32	32	32	32	32	32	32	32	32
0.30	32	32	30	24	19	17	15	14	13
0.40	21	15	10	7.2	5.2	4.1	3.5	3.1	2.7
0.50	11	7.7	4.9	3.3	2.2	1.6	1.3	1.1	0.92
0.60	5.6	4.0	2.5	1.6	1.0	0.73	0.57	0.46	0.36
≥0.65	4.2	3.0	1.9	1.2	0.78	0.56	0.43	0.34	0.26

Table 4 - Minimum value of $10^4R_a/D$ (where one is required)

Re_D / β	$\le3\times10^6$	10^7	3×10^7	10^8
≤0.50	0.0	0.0	0.0	0.0
0.60	0.0	0.0	0.003	0.004
≥0.65	0.0	0.013	0.016	0.012

It will be stated that the requirements of this section are satisfied in both the following cases:

1 μm $\le R_a \le$ 6 μm, $D \ge$ 150 mm, $\beta \le 0.6$ and $Re_D \le 5 \times 10^7$.
1.5 μm $\le R_a \le$ 6 μm, $D \ge$ 150 mm, $\beta > 0.6$ and $Re_D \le 1.5 \times 10^7$.

The roughness shall meet requirements given above for 10D upstream of the orifice plate. The roughness requirements relate to the orifice fitting and the upstream pipework.

The minimum values represent exceedingly smooth pipes. The tables prescribe $k/D \leq 0.01$ even if the calculated value is higher. The limits for $Re_D = 10^4$ can be used for smaller Re_D. Although the limits for very large Re_D are much tighter than those in ISO 5167-1: 1991, for $Re_D = 3 \times 10^5$ they are very similar, an unsurprising agreement since the limits in ISO 5167-1:1991 were probably derived from data collected at around that Reynolds number.

It might be argued that an equation with a friction factor term included explicitly should have a lower uncertainty. Such an equation was rejected on the grounds that it would be difficult to use.

7 PULSATION EFFECTS

A short clause which will clarify the acceptable limits for pulsations will be included: the flow is considered sufficiently steady for ISO 5167 to apply when

$$\frac{\Delta p'_{\mathrm{rms}}}{\overline{\Delta p}} \leq 0.10, \tag{17}$$

where $\overline{\Delta p}$ is the time-mean value of the differential pressure and $\Delta p'_{\mathrm{rms}}$ is the r.m.s. value of $\Delta p'$, the fluctuating component of the pressure. This clause is consistent with ISO/TR 3313 [16]. $\Delta p'_{\mathrm{rms}}$ can only be measured accurately using a fast-response differential pressure sensor; moreover, the whole secondary system in undertaking this measurement should conform to the design recommendations specified in ISO/TR 3313. It will not, however, normally be necessary to check that this condition is satisfied.

8 THROAT THICKNESS FOR NOZZLES

For long radius high-ratio nozzles 9.2.2.5 of ISO 5167-1: 1991 states that the thickness F of the throat shall be between 3 mm and 13 mm. However, it has been pointed out that for large pipe diameter this may be too small to prevent distortion due to machining stresses. ASME MFC-3M: 1989 [17] gives (in ISO 5167-1 nomenclature) $2F \leq D - d - 6$ where F, D and d are expressed in millimetres. There is also a problem for small pipe diameters: if $D = 50$ mm and $\beta = 0.8$ it is not possible to satisfy 9.2.2.4 and 9.2.2.5.

Following Japan's suggestion no maximum for F in the revision of 9.2.2.5 will be specified. The maximum can be deduced from 9.2.2.4 and will be the same requirement as was given by ASME MFC-3M. 9.2.2.5 will also be revised to take account of small pipe diameters and the second half of the draft clause reads as follows: 'The thickness F of the throat shall be greater than or equal to 3 mm, unless $D \leq 65$ mm, in which case F shall be greater than or equal to 2 mm. The thickness shall be sufficient to prevent distortion due to machining stresses.'

9 STRAIGHT LENGTHS UPSTREAM OF VENTURI TUBES

The present straight length requirements upstream of Venturi tubes have been shown by data collected in the UK and Germany to be too short, and revised lengths will be included in ISO 5167-4.

Three Venturi tubes, of diameter ratios 0.4, 0.6 and 0.75, were calibrated at NEL (in addition to baseline measurements) with a contraction, an expansion, two bends in perpendicular planes, a single bend, and two bends in the same plane at various distances upstream of them. In each case the distance was increased until the magnitude of the shift in discharge coefficient from the baseline was less than 0.25 per cent.

References [18] and [19] describe the Venturi tubes and pipework used for this project and the measurements of installation effects obtained with them. All the experimental data were taken in water: over the complete database the throat Reynolds number, Re_d, was always in the range 1.9×10^5 - 2.0×10^6. Three classical Venturi tubes with a machined convergent section had been made by ISA Controls Ltd for Shell UK Exploration and Production to meet the requirements of ISO 5167-1. The pipe diameter was 154.0 mm. The divergent angle was 7½°. The pressure tappings were 4 mm in diameter and were connected in 'triple-tee' arrangements. Lengths of pipe upstream of the Venturi tubes were machined to ensure there were no significant steps near the Venturis. The lengths of pipe and the Venturi tubes were dowelled to ensure concentricity; O rings were used to ensure that there would not be recesses or protruding gaskets.

The three Venturi tubes were initially calibrated with 41*D* of straight pipe upstream of the upstream pressure tapping. Upstream of the straight pipe was a tube bundle flow conditioner. They were then calibrated immediately before the installation effects tests described here. At the end of all the calibrations (except for the calibration 17.8*D* downstream of a single bend which took place one week after the final baseline) all three Venturi tubes were recalibrated again. For each Venturi tube the slope of the calibration was positive for at least one calibration and negative for at least one calibration; so the mean value was used for each calibration. The mean value of discharge coefficient used as the baseline for each Venturi tube was the average of the mean values from the second and third calibrations, which preceded and followed the installation-effects calibrations.

The shift in discharge coefficient for a particular installation condition was determined by subtracting the mean discharge coefficient obtained with that installation from the baseline discharge coefficient. The measurement of length between a fitting and a Venturi tube is the distance between the downstream end of the fitting and the upstream tapping plane of the Venturi tube. The former has been taken to be the end of the curved portion of a bend or the tapered portion of a contraction or an expansion; the weld neck has been considered to be part of the straight length.

A contraction from 203 mm to 152 mm was installed upstream of each Venturi tube: the contraction was conical with a length of conical section of 350 mm, giving an included half-angle of about 4°. Upstream of the contraction there was 4.7 m of straight 203 mm pipe (23 diameters of 203 mm pipe) preceded by a tube bundle. The mean shifts are presented in Figure 3.

FIG. 3 CHANGE IN C FOR VENTURI TUBES DOWNSTREAM OF A 203 mm - 152 mm CONTRACTION

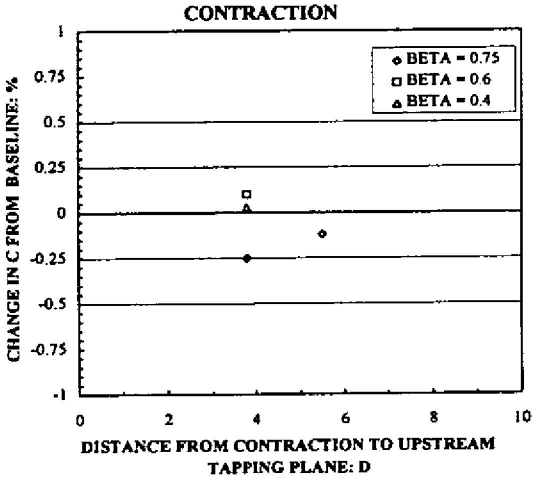
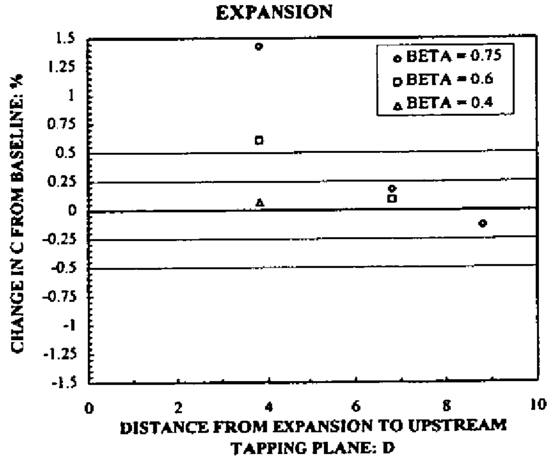


FIG. 4 CHANGE IN C FOR VENTURI TUBES DOWNSTREAM OF A 102 mm - 152 mm EXPANSION



An expansion from 102 mm to 152 mm was installed upstream of each Venturi tube: the expansion was conical with a length of conical section of 375 mm, giving an included half-angle of about 4°. Upstream of the expansion there was 4.9 m of straight 102 mm pipe (48 diameters of 102 mm pipe) preceded by a tube bundle. The mean shifts are presented in Figure. 4. The shifts are positive because the velocity profile is peaked.

Two bends in perpendicular planes were installed upstream of each Venturi tube. Upstream of the upstream bend there was 26*D* of straight pipe preceded by a Zanker flow conditioner. The mean shifts are presented in Figure 5. For all the calibrations downstream of bends the bends were of radius 1.5*D* and each had short weldnecks of approximately 50 mm so that the bends could be as closely coupled as possible.

FIG. 5 CHANGE IN C FOR VENTURI TUBES DOWNSTREAM OF TWO BENDS IN PERPENDICULAR PLANES

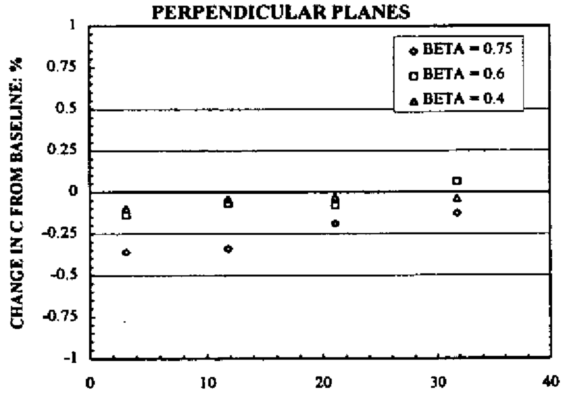
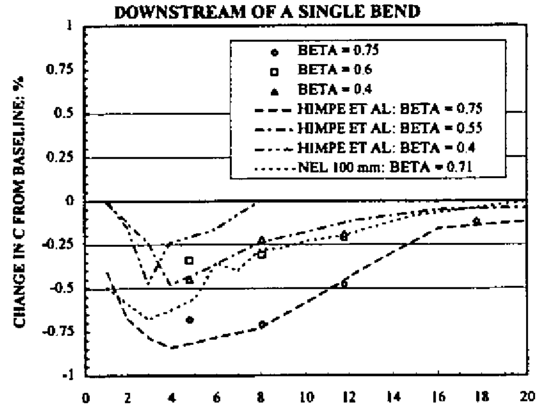


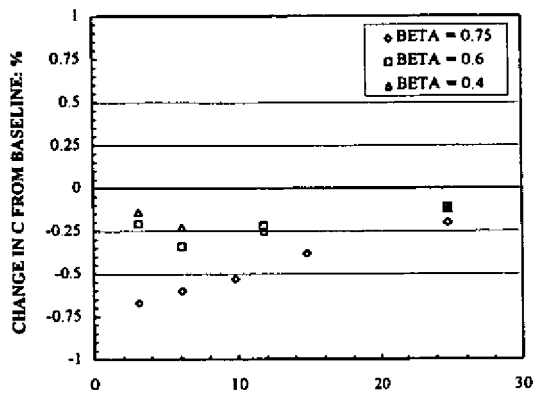
FIG. 6 CHANGE IN C FOR VENTURI TUBES DOWNSTREAM OF A SINGLE BEND



A single bend was installed upstream of each Venturi tube. Upstream of the bend there was the same 26*D* of straight pipe preceded by a Zanker flow conditioner as there was for the tests with two bends in perpendicular planes. The mean shifts are presented in Figure 6. These calibrations are in good agreement with the data of Himpe et al [20], particularly for the larger values of β, and those of NEL (1985) quoted by Kochen et al [21]. Both Himpe et al and NEL had a pipe diameter of 100 mm.

Two bends in the same plane were installed upstream of each Venturi tube. Upstream of the upstream bend there was 21*D* of straight pipe preceded by a tube bundle flow conditioner. The mean shifts are presented in Figure 7.

FIG. 7 CHANGE IN C FOR VENTURI TUBES DOWNSTREAM OF TWO BENDS IN THE SAME PLANE



Two conditioners, the Spearman (NEL) conditioner and the tube bundle, were tested downstream of two bends in perpendicular planes and the single bend and upstream of the Venturi tubes. The results are given in References [18] and [19]. The Spearman flow conditioner gave excellent results.

On the basis that straight lengths should be calculated so that shifts in discharge coefficient should be smaller in magnitude than 0.25 per cent or alternatively, for greater uncertainty, 0.5 per cent, the proposed revision of Table 2 of ISO 5167-1 was obtained. It is given as Table 5. The column relating to upstream valves has been left unchanged because of a lack of new data. To provide lengths for values of β other than those measured an appropriate dependence of shift on β based on both the general pattern of the data and the specific installation was assumed. Given the lack of multiple data sets for combinations of bends it was decided that the lengths from combinations of two bends should not be less than those from a single bend. It is known from the orifice installation effects data that a small change in bend separation can have a significant effect on the discharge coefficient shift. Moreover, it hardly seems sensible to encourage the installation of two bends in perpendicular planes upstream of a meter. The straight length is defined as it was for the tests; columns A and B are defined as in Table 1.

Table 5 - Required straight lengths for classical Venturi tubes

Values expressed as multiples of internal diameter D

Diameter Ratio β	Single 90° bend*)		Two or more 90° bends in the same plane or different planes*)		Reducer 1,33D to D over a length of 2,3D		Expander 0,67D to D over a length of 2,5D		Full bore ball or gate valve fully open	
1	2		3		4		5		6	
	A	B	A	B	A	B	A	B	A	B
0,30	8	3	8	3	4	4	4	4	2,5	2,5
0,40	8	3	8	3	4	4	4	4	2,5	2,5
0,50	9	3	10	3	4	4	5	4	3,5	2,5
0,60	10	5	10	5	4	4	6	5	4,5	2,5
0,70	14	10	19	10	4	4	7	6	5,5	3,5
0,75	16	12	22	12	4	4	7	6	5,5	3,5

It is encouraging that there is good agreement between the data sets shown in Fig. 6 of this paper. In addition to those data shown Bluschke et al [22] obtained data for β = 0.71 downstream of a single bend and two bends in perpendicular planes: they are very similar to those shown here, although with slightly larger shifts downstream of two bends in perpendicular planes. The existing lengths required by ISO 5167-1 are similar to those obtained by Pardoe [23]: he obtained positive shifts in C downstream of a single bend and stated that 6D was sufficient downstream of a single bend even for β = 0.8, whereas downstream of two bends in perpendicular planes even 30D would not be sufficient (at least for β > 0.55). An explanation for the difference between Pardoe's data and subsequent data is still required.

10 SURFACE ROUGHNESS OF VENTURI TUBES

According to ISO 5167-1 the surface roughness for the throat of a classical Venturi tube is that $R_a \leq 10^{-5}d$; so for a 50 mm β = 0.4 Venturi tube a surface roughness of $R_a \leq 0.2$ μm is required, which is very expensive to manufacture and unlikely to last long in service in the North Sea. Moreover, according to ISO 5167-1 subsonic nozzles only require $R_a \leq 10^{-4}d$; so Venturi tubes must be 10 times smoother than subsonic nozzles are required to be. NEL has recently purchased Venturi tubes from manufacturers who supply the North Sea and has found that Venturi tubes usually have roughnesses outside the existing standard but within $R_a \leq 10^{-4}d$. It has been agreed that the required surface finish of the throat of Venturi tubes should be such that $R_a \leq 10^{-4}d$. Modern data to verify the existing values of discharge coefficients and to extend the results to higher Reynolds numbers are being taken using Venturi tubes that are typical of current practice.

11 CONCLUSIONS

ISO 5167 is being revised to take into account the work on differential pressure flowmeters which has been done in recent years. This paper describes many of the planned changes: revised straight lengths upstream of orifice plates and Venturi tubes, a new expansibility equation for orifice plates, revised limits for eccentricity and flatness of orifice plates and for pipe roughness upstream of orifice plates. More accurate temperature correction, clarification on acceptable pulsations, and more practical throat thickness for nozzles and Venturi tube surface roughness are all included. As regards uncertainty, minor changes to give consistency with the Guide will be included. Other smaller changes will also be made.

ACKNOWLEDGMENTS

The work at NEL described in this paper was carried out as part of the Flow Programme, under the sponsorship of the DTI's National Measurement System Policy Unit.

Permission from Shell UK Exploration and Production to use their Venturi tubes is appreciated.

This paper is published by permission of the General Manager, NEL.

NOTATION

C	Discharge coefficient
c_p	Heat capacity at constant pressure (J/(mol.K))
D	Pipe internal diameter (m)
e_c	Eccentricity (m)
F	Throat thickness (of a nozzle) (m)
H	Enthalpy (J/mol)
k	Uniform equivalent roughness (m)
P	Percentage shift in C
p_1	Static pressure at upstream tapping (Pa)
p_2	Static pressure at downstream tapping (Pa)
Δp	Differential pressure (Pa)
R_a	Arithmetical mean deviation of the roughness profile (m)
R_g	Universal gas constant (J/(mol.K))
Re_D	Pipe Reynolds number
Re_d	Throat Reynolds number
S	Bend separation (m)
T	Absolute temperature (K)
U	Percentage relative uncertaintyZ Compressibility factor
β	Diameter ratio
ε_1	Expansiblity factor
κ	Isentropic exponent
λ	Friction factor
$\Delta\varpi$	Pressure loss (Pa)

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1998

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UNCERTAINTY OF COMPLEX SYSTEMS USING THE MONTE CARLO TECHNIQUES.

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16th NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

UNCERTAINTY OF COMPLEX SYSTEMS BY MONTE CARLO SIMULATION

Mr Martin Basil, FLOW Ltd
Mr Andrew W Jamieson, Shell UK Exploration and Production

ABSTRACT

Estimating the uncertainty of complex measurement systems by analytical methods is difficult and often the results do not inspire confidence.

Monte Carlo Simulation (MCS) is widely used in business by decision-makers to assess risk. Risk in this context is uncertainty and can equally apply to the uncertainty of a measurement system.

This approach has been used to assess the uncertainty of gas density, calorific value and Wobbe Index and fiscal allocation metering uncertainty. It has also been used to assess the uncertainty of test separators when regarded as multi-phase meters.

The MCS method of estimating uncertainty is fully compatible with the "Guide to the expression of uncertainty in measurement" [1], the uncertainty of a measurement result is usually evaluated using a mathematical model of the measurement and the law of propagation of uncertainty [1] (Para. 3.4.1). The advent of powerful desktop computers enables this technique to be applied to the propagation of uncertainties of most simple and complex measurement systems including many that cannot be found readily by conventional analytical means.

Results of these investigations will be presented to demonstrate the underlying simplicity and reliability of this approach to uncertainty assessment.

The authors consider the universal nature of MCS is well suited to computer implementation with potential to replace conventional methods for determining measurement uncertainty. We hope that the methods presented will be considered in the development of future uncertainty standards.

1 INTRODUCTION

This paper presents Monte Carlo Simulation methods in two worked examples. The first example is a simplified gas export metering system which is compared with conventional uncertainty methods from ISO 5168 [2], [3]. Whilst ISO 5168 [2] has been withdrawn by ISO because it does not comply with the "Guide to the expression of uncertainty in measurement" [1], it is nevertheless a practical document in the field of flow measurement. ISO 5168 [2] has been replaced by a technical report; ISO 5168TR: 1998 [3] until a fully compliant document is available. The second worked example is more complex and compares two empirical methods of finding gas density uncertainty discussed in a paper by Jim Watson of NEL [4] with the results obtained using MCS.

The examples used are based on actual projects by the authors, simplified for clarity. One of the authors (Martin Basil) has applied the technique on many client projects mainly concerned with fiscal allocation uncertainty including several meter stream uncertainties. In each case uncertainty was first found by conventional methods and verified using Monte Carlo methods with good agreement in all cases.

The application of the Monte Carlo methods to measurement uncertainty arose from fiscal allocation uncertainty projects in which confidence in the results was not high due to the many assumptions made using conventional analytical uncertainty methods. The availability of a method of assessing measurement uncertainties in relatively complex systems that is:

a) readily understood;
b) easily repeated; and
c) gives results in agreement with conventional analytical methods,

is the main reason for advancing this method.

2 MONTE CARLO SIMULATION AND ITS USES

How is Monte Carlo simulation used to find the propagation of uncertainties through a measurement system? The measurement system comprises a number of sensors whose outputs are fed into a computation unit that generates the measurement system output (or outputs). We suppose that a definite reference value is applied to the input of each sensor. If we look at the output of one of the sensors at any time, however, it can have one of a range of values that can correspond to the reference value, depending on how the sensor is made, and how well it works.

Using a desktop computer, we can readily generate a realistic distribution of output values for each sensor. We then select at random output values for each sensor and combine them according to the measurement system algorithms. We repeat this as many times as we want. The output of the measurement system will show a range of values for the set of sensor input reference values. We can then analyse that distribution of values using standard statistical techniques to generate the best estimate of the required measurement, and its uncertainty, corresponding to the set of sensor reference input values. We then repeat the process for sets of sensor input values, and generate estimates of uncertainty over the desired operational range of the measurement system.

In a short time (tens of minutes) we can simulate someone carrying out the same process with the real measurement system. However, it is usually quite impractical to carry out this process with a real measurement system.

Monte Carlo Simulation has a history going back to 1873 in which experiments were performed by dropping needles in a haphazard manner onto a board ruled with parallel straight lines to infer the value of π (= 3.1416 ...) from observations of the number of intersections between needle and lines. The first serious application was in 1908 by W. S. Gosset, (who went by the pseudonym of Student), to help him towards the discovery of the correlation coefficient, and in the same year the Student t-distribution. Monte Carlo Simulation methods were developed as a research tool during the Second World War on the atomic bomb to simulate probabilistic problems concerned with random neutron diffusion in fissile material. The theory was developed further from about 1970 to solve a class of problems where there was not sufficient time to find an exhaustive solution as the number of evaluations expanded exponentially.

Today Monte Carlo Simulation is widely used in all areas of activity including business risk analysis, weather forecasting, atomic physics, drilling, manufacturing etc. Metrology is an area in which this technique has not been applied to any great extent and this particularly applies to flow measurement uncertainty. This may be because neither of the two standards for this area, "Guide to the expression of uncertainty in measurement" [1] and IS05168 [2], provides any guidance in the use of simulation methods other than simple numerical methods used to find input/output sensitivity.

Monte Carlo Simulation offers significant advantages over conventional methods when evaluating the uncertainty of measurement systems with the following characteristics:

- Large number inputs and outputs
- Non-linear relationships requiring 2nd order partial derivatives to find sensitivity terms
- Large measurement uncertainties where linear interpolation assumptions fail
- Complex mathematical or empirical input/output relationships
- Input dependencies where the measurement system modifies the action of other inputs
- Untypical input and output distributions that cannot be described in conventional ways

The purpose of this paper is to explain the Monte Carlo Simulation uncertainty method for the benefit of a wider audience. We hope this will also lead to incorporation of these methods in future revisions of the, "Guide to the expression of uncertainty in measurement" [1] and ISO 5168 [2], [3] so that a common approach is used to apply Monte Carlo methods to measurement uncertainty.

3 EXAMPLE 1: GAS EXPORT METERING SYSTEM

A simplified gas export metering system is used to illustrate the calculation of uncertainty by MCS. Uncertainty is first calculated by conventional Root Sum Square (RSS) methods and then by MCS. The close agreement demonstrates the fundamental nature of MCS also showing that either method can be used to check the other.

The gas export metering system in Figure 1 comprises two identical streams fitted with orifice plate meters each with a measurement uncertainty of 1% of reading and a flow rate of 10 mmscfd. This example is only for illustration and considers uncertainties as random. .

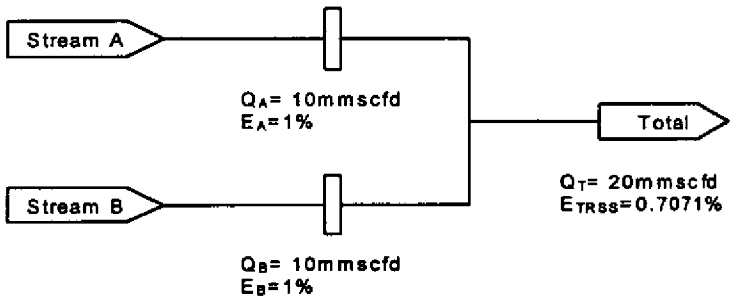

Figure 1 Gas Export Metering System

Uncertainty is found using conventional RSS methods in ISO 5168 [2] as follows:

To find uncertainty by MCS the flow rate measurement of each stream is simulated by generating random numbers with a normal distribution that are then applied to a mathematical model of the metering system. The model in this case is simply the sum of the two streams, Equation (1). The normal distribution is generated with a mean at the expected measured value of 10 mmscfd and a standard deviation of 0.05 mmscfd is obtained from the measurement uncertainty of 1% of reading with a 95% confidence level.

$$Q_T = Q_A + Q_B \qquad Q_T = 20 \text{ mmscfd} \qquad (1)$$

$$E_{TRSS} = \frac{\sqrt{(Q_A \cdot E_A)^2 + (Q_B \cdot E_B)^2}}{Q_T} \qquad E_{TRSS} = 0.7071 \; \% \qquad (2)$$

The simulated stream measurements are applied randomly to the model to give a set of flow rates with a normal distribution. The total flow rate is found from mean of the distribution and the uncertainty with a 95% confidence level is found from twice the standard deviation.

Figure 2 illustrates the simulation of the flow rate measurement of each meter stream input to the model and the resultant distribution. In this case 100,000 trial results were computed in less than 5 minutes. Generally fewer trials, in the region of 5,000 to 20,000, are sufficient for this application however the resulting distribution can appear ragged which may not be acceptable for presentation. The number of trials should be increased in proportion to the number of inputs to ensure most input combinations are properly covered.

In this example the MCS uncertainty of 0.7048% of reading is within 0.3% of the uncertainty of 0.7071% of reading found by RSS means.

Figure 2 shows simulated inputs with a normal distribution. Using MCS input distributions may be rectangular, triangular, skewed, discrete values or any other distribution that reflects the nature of the measurement. This can include actual measured data, which is then applied randomly to the model input. Systematic bias errors are particularly difficult to deal with using conventional methods but they can easily be propagated through a model with MCS.

In Figure 3 Stream B flow rate measurement has been given a rectangular distribution with upper and lower limits at 1% of reading. The results again show good agreement between the RSS and MCS uncertainty methods.

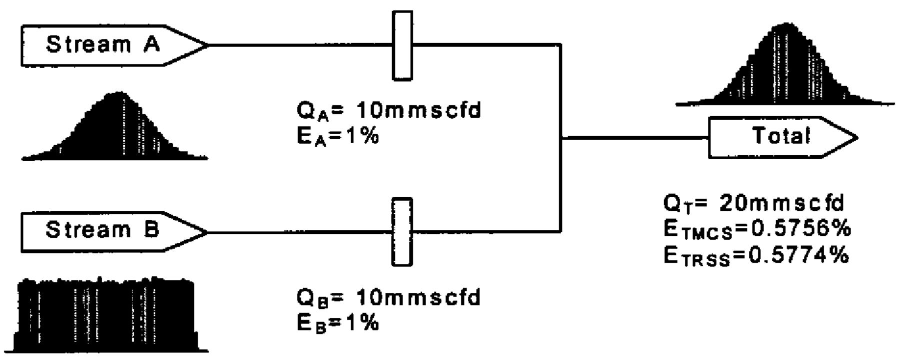

Figure 3 Gas Export Metering System Stream B Rectangular Distribution

To cater for the rectangular distribution the Stream B uncertainty is divided by √3, in accordance with the "Guide to the expression of uncertainty in measurement" [1], before finding the RSS uncertainty.

$$Q_T = Q_A + Q_B \qquad Q_T = 20 \text{ mmscfd} \qquad (3)$$

$$E_{TRSS} = \frac{\sqrt{(Q_A \cdot E_A)^2 + \left(Q_B \cdot \frac{E_B}{\sqrt{3}}\right)^2}}{Q_T} \qquad E_{TRSS} = 0.5774\ \% \qquad (4)$$

Results from the examples in Figures 1, 2 and 3 are summarised in Table 1.

Table 1 - Comparison of Gas Export Uncertainty Found by RSS and MCS

Stream	Measured Quantity (mmscfd)	Uncertainty (% reading)	A & B Normal Distribution (mmscfd)	A Normal, B Rectangular Distribution (mmscfd)
A	10	1%	9.9895	9.9895
B	10	1%	10.0235	10.0488
Total	20		20.0130	20.0384
MCS Mean			19.9994	20.0002
MCS uncertainty			0.7043%	0.5751%
Conventional uncertainty			0.7071%	0.5774%

4 EXAMPLE 2: AGA8 GAS DENSITY UNCERTAINTY

In this example MCS is used to find gas density uncertainty for two gas mixtures and compare them with the empirical methods discussed in a paper by Jim Watson of NEL [4]. Calorific Value and Wobbe Index uncertainty have also been found by MCS as a further demonstration of this technique.

Gas density can be found from a gas composition, pressure and temperature using the American Gas Association Report No 8 (AGA8) [5], Detail Characterisation Method. This is a complex calculation based on two equations of state and defined in a FORTRAN computer program for up to 21 gases over a wide pressure and temperature range.

AGA8 has a "Method" uncertainty, tabulated in Table 2, that is dependent on the pressure and temperature of the gas mixture. This uncertainty arises from the experimental data used to develop and verify the standard. These uncertainties apply to the "Normal" range of gas mixtures for all regions and have also been verified for the "Extended" range of mixtures in Region 1.

Table 2 - AGA8 Gas Compressibility Uncertainty

Region	Uncertainty (% reading)	Temperature Band (°C)	Pressure Band (Mpa)
1	0.1	-8 to 62	0 to 12
2	0.3	-60 to 120	0 to 17
3	0.5	-130 to 200	0 to 70
4	1.0	-130 to 200	70 to 140

Using AGA8, the density uncertainty of a natural gas arises from the following sources:

a) pressure measurement uncertainty;

b) temperature measurement uncertainty;

c) gas component uncertainty from:

CO_2, N_2, C1 to C7+	- online gas chromatograph;
H_2S	- analyser;
C8 to C12	- C7+ tail from periodic sample analysis

d) the uncertainty of the AGA8 calculation method.

Conventional analytical uncertainty calls for a calculation of the sensitivity of the gas density to each of the input terms. Sensitivity is found from the partial derivatives of each input with respect to the gas density. n practice this is not possible due to the large number of input terms and the internal complexity of the AGA8 calculation.

Sensitivity may also be found numerically by introducing a perturbation to each input of the AGA8 calculation to find the change in gas density. By combining the input sensitivity with the input uncertainty using RSS, the gas density uncertainty can be obtained, but this approach does not cater for interactions between inputs within the calculation.

Two alternative empirical gas density uncertainty methods that have been suggested in the NEL paper [4] are:

General method - each component uncertainty is weighted in proportion to the mole fraction of the component

1

$$E_{C_i} = E_i . X_i \qquad (5)$$

2

$$E_{C_i} = 0.1 \cdot \left[1 + \left(\log_{10} (X_i)^2 \right) \right] \qquad (6)$$

Rich Natural Gas (RNG) - a log rule is used that applies a greater uncertainty to components with a smaller mole fraction.

The component uncertainties are combined using RSS with the uncertainty of 0.15% due to pressure, 0.1% due to temperature and the AGA8 method uncertainty of 1.0% to find the overall gas density uncertainty:

1 Weighted Component Method

$$E_{\rho gas1} = \sqrt{\sum_i (E_i \cdot X_i)^2 + E_t^2 + E_p^2 + E_{AGA8}^2} \qquad (7)$$

2 RNG Log Rule Method

$$E_{\rho gas2} = \sqrt{\sum_i \left[0.1 \cdot \left[1 + \left(\log_{10} (X_i)^2 \right) \right] \right]^2 + E_t^2 + E_p^2 + E_{AGA8}^2} \qquad (8)$$

The gas density is found using MCS by treating the AGA8 calculation as a black box illustrated in Figure 4.

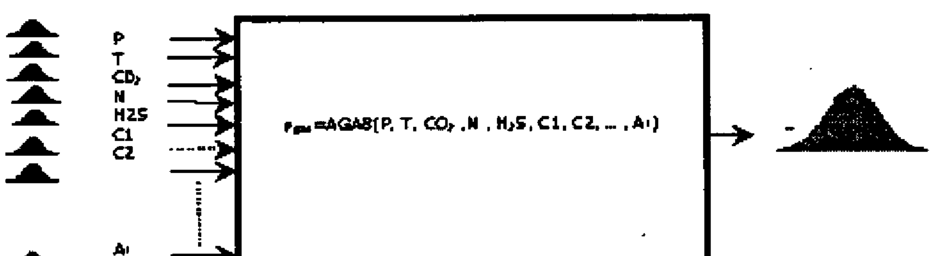

Figure 4

For each input to the black box a range of values is generated with a normal distribution whose mean corresponds to the input value and whose standard deviation corresponds to the uncertainty of the input value at the 95% confidence level. For each trial a value is selected at random for each input and applied to the AGA8 function within the black box and a value of gas density is calculated. Trials are repeated to generate a realistic distribution of gas densities corresponding to the uncertainties of the inputs.

Gas density is found from the mean of the output distribution, which in this case is a normal distribution. The gas density uncertainty at a 95% confidence level is found from standard deviation multiplied by 1.96. This uncertainty due to the input measurement uncertainty is combined with AGA8 method uncertainty using RSS to give the overall gas density uncertainty.

Gas density uncertainty, Calorific Value and Wobbe Index are found for two normalised gas mixtures. Firstly, a natural gas mixture and secondly, the Rich Natural Gas mixture RNG1 in the NEL paper [4]. The empirical methods are used to find the gas density uncertainty and then compared with the uncertainty found by MCS at 100 bar absolute and 45°C. Component uncertainty is 0.5% reading for the Weighted and MCS uncertainty method and does not apply to the Log Rule method.

The composition of each gas mixture is shown in Table 3. Gas properties and uncertainty for each gas is summarised in Table 4 for the three uncertainty methods.

Table 3 - Gas Mixture Composition

Gas (mol%)	N_2	CO_2	C1	C2	C3	nC4	IC4	NC5
Natural Gas	0.92	0.97	93.29	4.29	0.39	0.06	0.03	0.05
RNG 1	5.00	6.00	59.00	10.00	14.00	6.00	0.00	0.00

Table 4 - Gas Density Uncertainty Comparison 100% Mixture

Gas	Property	Value	AGA8 Method uncertainty	Uncertainty		
				Weighted	Log Rule	MCS
Natural Gas	Line Density (kg/m³)	74.603	1.0%	**1.118%**	**1.253%**	**1.163%**
	Standard Density (kg/Sm³)	0.7291	0.1%			0.450%
	CV 15/15 Real Sup (Mj/Sm³)	34.67				0.471%
	Wobbe Index (Mj/Sm³)	50.10				0.261%
RNG 1	Line Density (kg/m³)	148.967	1.0%	**1.063%**	**1.171%**	**1.150%**
	Standard Density (kg/Sm³)	1.112	0.1%			0.261%
	CV 15/15 Real Sup (Mj/Sm³)	49.56				0.299%
	Wobbe Index (Mj/Sm³)	52.02				0.195%

The comparison in Table 4 shows good agreement between the line density uncertainty for all three methods with marginally better agreement with natural gas between MCS and the Weighted method. Similarly there is marginally better agreement between MCS and the Log Rule method with the RNG for which the Log Rule was designed.

In the case of the two empirical methods the uncertainty due to pressure and temperature had to be estimated by other means whereas this was inherent in the MCS method. The dominant effect of the pressure uncertainty on the overall uncertainty requires particular attention.

The Log Rule method gas component uncertainty is calculated. Agreement between uncertainty results will not be as close for component uncertainties for values differing from the 0.5% used in this example.

In this example the AGA8 method uncertainty is 1.0% and is the main influence on the overall density uncertainty at line conditions. Where the method uncertainty is lower the influence of the other sources will have a greater impact on the final uncertainty.

In the course of this work it was noticed that when one gas is dominant, such as methane in natural gas, then normalisation of the gas composition leads to:

a) a reduction in the spread of results and consequently the uncertainty; and
b) an offset in the final density from the un-normalised result.

The reduction in the spread of results is due to the normalisation process in which all of the components become dependent on each other. Some uncertainties cancel reducing the overall uncertainty. This only becomes apparent when applying MCS and is masked by the simplifications in the other methods discussed, which do not take account of dependencies.

The offset in the final density is due to normalisation when one gas, methane, is dominant. Methane is redistributed over gases with a greater molecular weight without applying a correction for difference in molecular weight. In the following example it is shown that this effect may be significant and requires further investigation into the methods and the need for normalisation.

The initial gas composition of 99.5 mol% is based upon the natural gas described above with a 0.5% mol% reduction in methane. Table 5 on the next page shows the initial gas composition, the normalised composition with the normalised and un-normalised gas properties and uncertainties.

Gas	Property	Value	AGA8 Method uncertainty	Uncertainty		
				Weighted	Log Rule	MCS
Natural Gas	Line Density (kg/m^3)	74.603	0.1%	0.52%	0.77%	0.60%
	Standard Density (kg/Sm^3)	0.7291	0.1%			0.45%
	CV 15/15 Real Sup (Mj/Sm^3)	34.67				0.47%
	Wobbe Index (Mj/Sm^3)	50.10				0.26%
RNG 1	Line Density (kg/m^3)	148.967	0.1%	0.39%	0.63%	0.58%
	Standard Density (kg/Sm^3)	1.112	0.1%			0.26%
	CV 15/15 Real Sup (Mj/Sm^3)	49.56				0.30%
	Wobbe Index (Mj/Sm^3)	52.02				0.20%

Table 4 Gas Density Uncertainty Comparison 100% Mixture

The comparison in Table 4 shows agreement for line density uncertainty between the Weighted method and MCS for Natural Gas. Similarly there is good agreement between MCS and the Log Rule method with the RNG for which the Log Rule was designed.

In the case of the two empirical methods the uncertainty due to pressure and temperature had to be estimated by other means whereas this was inherent in the MCS method. The dominant effect of the pressure uncertainty on the overall uncertainty requires particular attention.

The Log Rule method gas component uncertainty is calculated. Agreement between uncertainty results will not be as close for component uncertainties for values differing from the 0.5% used in this example.

In this example the AGA8 method uncertainty is 0.1% and is not a major influence on the overall density uncertainty at line conditions. Where the method uncertainty is higher the influence on the final uncertainty is greater and can be the main source of uncertainty at extreme temperatures and pressures.

In the course of this work it was noticed that when one gas is dominant, such as methane in natural gas, then normalisation of the gas composition leads to:

a) a reduction in the spread of results and consequently the uncertainty;

b) an offset in the final density from the un-normalised result.

The reduction in the spread of results is due to the normalisation process in which all of the components become dependent on each other. Some uncertainties cancel reducing the overall uncertainty. This only becomes apparent when applying MCS and is masked by the simplifications in the other methods discussed, which do not take account of dependencies.

The offset in the final density is due to normalisation when one gas, methane, is dominant. Methane is redistributed over gases with a greater molecular weight without applying a correction for difference in molecular weight. In the following example it is shown that this effect may be significant and requires further investigation into the methods and the need for normalisation.

The initial gas composition of 99.5 mol% is based upon the natural gas described above with a 0.5% mol% reduction in methane. Table 5 on the next page shows the initial gas composition, and the normalised composition with the normalised and un-normalised gas properties and uncertainties.

AMENDMENT - UNCERTAINTY OF COMPLEX SYSTEMS BY MONTE CARLO SIMULATION

Input	Temperature deg C	Pressure bar a	Nitrogen mol%	Carbon Dioxide mol%	Methane mol%	Ethane mol%	Propane mol%	n-Butane mol%	i-Butane mol%	n-Pentane mol%	Total Composition mol%	Line Density Kg/m3	Standard Density Kg/Sm3	Calorific Value 15/15 Sup Real MJ/Sm3	Wobbe Index Real(AGA8) MJ/Sm3
Input (Mean)	45.000	100.00000	0.920	0.970	92.790	4.290	0.390	0.060	0.030	0.050	99.500	74.161	0.726	38.458	49.975
Uncertainty (% Input)		0.150%	0.500%	0.500%	0.500%	0.500%	0.500%	0.500%	0.500%	0.500%					
Uncertainty (Units)	0.25000	0.15000	0.00460	0.00485	0.46395	0.02145	0.00195	0.00030	0.00015	0.00025					
Normalised mol%	45.000	100.00000	0.925	0.975	93.256	4.312	0.392	0.060	0.030	0.050	100.000	74.636	0.729	38.652	50.101
											Method Uncertainty % Reading	0.100%	0.100%	0.100%	0.100%
											Monte Carlo Uncertainty %Reading	0.596%	0.441%	0.462%	0.242%
											Monte Carlo inc Method Uncertainty %Reading	0.604%	0.452%	0.473%	0.261%
											Normalised Monte Carlo Uncertainty %Reading	0.215%	0.037%	0.020%	0.014%
											Normalised Monte Carlo inc Method Uncertainty %Reading	0.238%	0.107%	0.102%	0.101%
Log Rule Uncertainty %Reading	0.1000%	0.1500%	0.1001%	0.1000%	0.4871%	0.1400%	0.1167%	0.2493%	0.3319%	0.2693%	Log Rule Uncertainty inc Method Uncertainty %Reading	0.760%			
Weighted Uncertainty %Reading	0.1000%	0.1500%	0.0046%	0.0049%	0.4640%	0.0215%	0.0020%	0.0003%	0.0002%	0.0003%	Weighted Uncertainty inc Method Uncertainty %Reading	0.508%			

Table 5 Natural Gas Mixture 99.5% Un-normalised and Normalised Results with 0.5% Component Uncertainty

Table 5 - Natural Gas Mixture 99.5% Un-normalised/ Normalised 0.5% Component Uncertainty

Input	Temperature °C	Pressure bar a	Nitrogen mol%	Carbon Dioxide mol%	Methane mol%	Ethane mol%	Propane mol%	n-Butane mol%	i-Butane mol%	n-Pentane mol%	Total Composition mol%	Line Density Kg/m3	Standard Density Kg/Sm3	Calorific Value 15/15 Sup Real Mj/Sm3	Wobbe Index Real(AGA8) Mj/Sm3
Input (Mean)	45.000	100.00000	0.920	0.970	92.790	4.290	0.390	0.060	0.030	0.050	99.500	74.160850	0.725692	38.457864	49.974627
Uncertainty (% Input)		0.150%	0.500%	0.500%	0.500%	0.500%	0.500%	0.500%	0.500%	0.500%					
Uncertainty (Units)	0.25000	0.15000	0.00460	0.00485	0.46395	0.02145	0.00195	0.00030	0.00015	0.00025					
Normalised (mol%)	45.000	100.00000	0.925	0.975	93.256	4.312	0.392	0.060	0.030	0.050	100.000	74.635648	0.729355	38.651987	50.100601
											Method Uncertainty % Reading	1.0000%	0.1000%	0.1000%	0.1000%
											Monte Carlo Uncertainty %Reading	0.5939%	0.4391[illegible]4%	0.459989%	0.240652%
											Monte Carlo inc Method Uncertainty %Reading	1.1631%	0.4504%	0.4707%	0.2606%
											Normalised Monte Carlo Uncertainty %Reading	0.216241%	0.036619%	0.020065%	0.014052%
											Normalised Monte Carlo inc Method Uncertainty %Reading	1.0231%	0.1065%	0.1020%	0.1010%
Log Rule Uncertainty (%Reading)	0.1000%	0.1500%	0.1001%	0.1000%	0.4871%	0.1400%	0.1167%	0.2493%	0.3319%	0.2693%	Log Rule Uncertainty inc Method Uncertainty %Reading	1.2521%			
Weighted Uncertainty (%Reading)	0.1000%	0.1500%	0.0046%	0.0049%	0.4640%	0.0215%	0.0020%	0.0003%	0.0002%	0.0003%	Weighted Uncertainty inc Method Uncertainty %Reading	1.1173%			

Line density distribution for un-normalised and normalised results in Figure 5 clearly shows a decrease in uncertainty from 0.59% to 0.22%, before applying the AGA8 method uncertainty, due to normalisation. Figure 5 also shows an increase of 0.48 kg/m^3 (0.65%) in line density from 74.16 kg/m^3 to 74.64 kg/m^3, again due to normalisation.

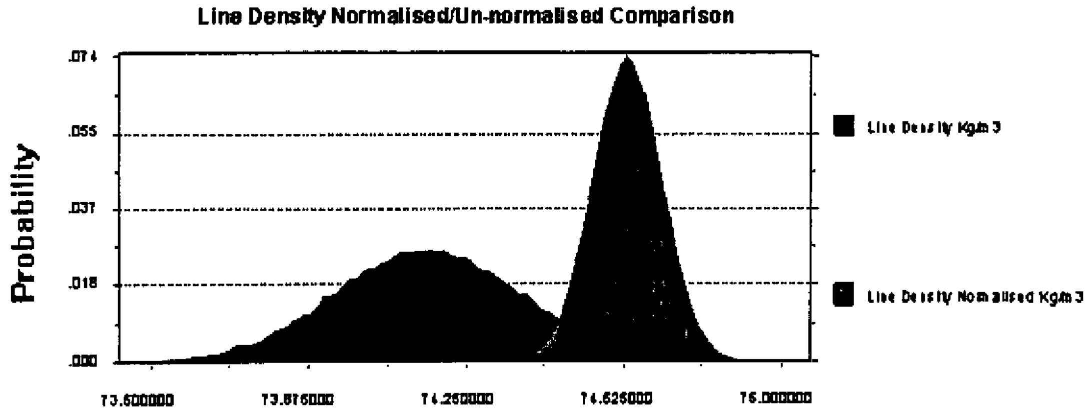

Figure 5 - Effect of Normalisation on Line Density

Figure 6 shows the same for standard density with a more pronounced reduction in uncertainty from 0.44% to 0.04% and with an increase in standard density of 0.5%.

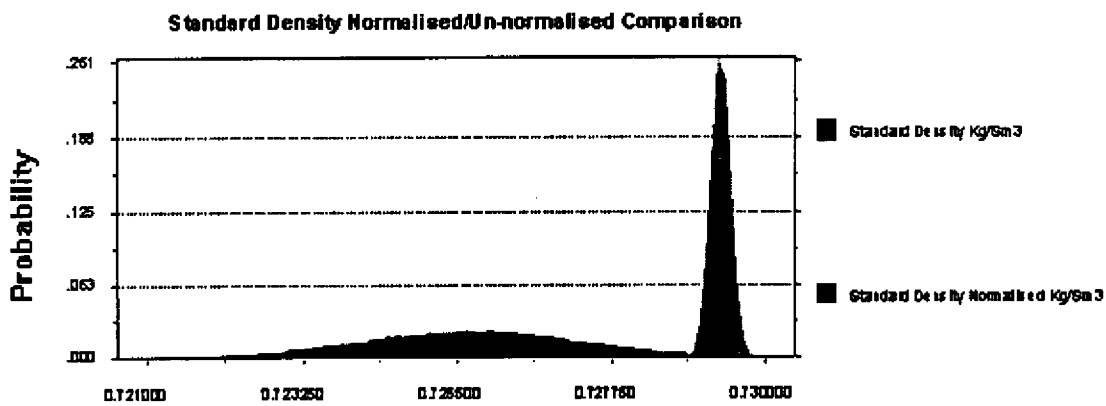

Figure 6 - Effect of Normalisation on Standard Density

5 CONCLUSIONS

Monte Carlo Simulation is a suitable method for determining the uncertainty of simple and complex measurement systems. MCS can be readily applied to verify uncertainties found by conventional analytical methods and to serve as a means of detecting errors to ensure confidence in the results.

When estimating the uncertainties of complex measurement systems particular care must be taken in identifying all uncertainty sources and how they propagate through the measurement process. Monte Carlo simulation is a fundamental approach that simulates the true characteristics of a measurement system, and implicitly the propagation of uncertainties through the system.

In the second example MCS allowed the impact of normalisation to be observed highlighting the change in the spread of results and the offset of the mean value. Conventional analytical methods do not provide this degree of insight.

The availability of powerful desktop computers means that engineers can readily apply MCS methods to finding the uncertainty of measurement systems.

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[2] ISO 5168 (1978): Measurement of fluid flow – Estimation of uncertainty of flow rate measurement, International Organization for Standardization (ISO), 1978.

[3] ISO 5168TR (1998): Measurement of fluid flow – Evaluation of uncertainties, International Organization for Standardization (ISO), 1998.

[4] Watson, J, The Density of Natural Gas Mixtures, National Engineering Laboratory (NEL), Gas Chromatograph Symposium, AMOCO, Aberdeen, 15 September 1997.

[5] Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases, American Gas Association Report No. 8 (AGA8), Second Edition, November 1992, Errata 1993, Reprinted with corrections 1994.

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FOCUS DISCUSSION GROUP A

YEAR 2000

I Smailes, Total.

NORTH SEA FLOW MEASUREMENT WORKSHOP

YEAR2000

Focus Discussion Group

YEAR2000 - WHY METERING ENGINEERS SHOULD BE CONCERNED!!

Of all the systems used in the upstream industry, reports from operators of Y2K problems with metering systems are common place.
What are these problems and what are the operators and metering equipment vendors doing about it ?
Also, what are the vendors doing about continuity of their own business to ensure they will still be able to service your needs?

This workshop will be an opportunity for you to find out.

This workshop will be chaired by Ian Smailes who is a member of the core Y2K team of Total Oil Marine and is Chairman of the UKOOA Y2K Task Force.

To set the scene, Ian will describe how the UK upstream industry is managing the Y2K issue as a whole , committing expenditure of more than £1/2 Billion in the process , before leading to the typical problems discovered and , more specifically , those affecting metering.

Ian Bates , Senior Metering Engineer at Total Oil Marine , will elaborate on the problems he has discovered.

Karen Rigby of Daniel Industries and William Miller of NEL will give a typical insight into what vendors are doing and how they are assisting upstream operators.

There will then be ample time to share experiences and discuss whether we have further cause for concern!

Biography

Ian Smailes career has covered the application of computers in industrial automation, metering, telephony , technical and office systems.
At times, he has actually coded embedded chips but does not admit to ever referring to the year in a date with only 2 digits!
He has worked for Total Oil Marine since 1986. Experience with Total has included the refurbishment of SCADA and Telemetry Systems , evolving the IT infrastructure, and refurbishing the networks supporting the exploration and petroleum engineering departments.

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FOCUS DISCUSSION GROUP B

MULTIPHASE 1 - TESTING & STANDARDS FOR MULTIPHASE METERS

A Hall, National Engineering Laboratory

Discussion of issues in multiphase flow metering - laboratory experience and practice

Andrew Hall
National Engineering Laboratory, UK

1. Introduction

There are a number of issues relating to the acceptance and use of multiphase flow meters - this short document sets out some of these as a basis for discussion in the multiphase metering discussion group at the North Sea Flow Measurement Workshop under the following general titles:

- Analysis of meter accuracy
- Standards for multiphase metering
- Relationship of laboratory testing to field practice
- Further technical challenges

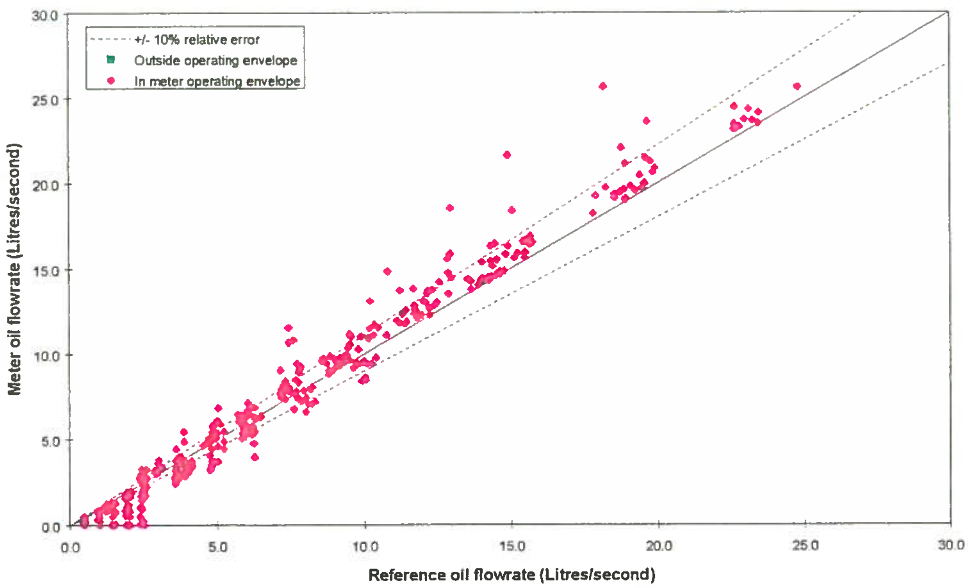
2. Analysis of meter accuracy

2.1 Graphical presentation

By way of example, a set of meter performance data has been constructed which does not relate to any real multiphase meter. The discussion below is based on the oil flowrate from this example meter.

One method to present data is to plot the meter flowrate against the reference flowrate:

Figure 1: Meter oil flowrate vs. reference oil flowrate



This figure shows that there are a large number of conditions where the meter flowrate lies within ±10% of the reference value, and that there are two areas where the meter errors are significantly worse: at low values of oil flowrate and a number of points at high flowrates. However, there is little further useful information which can be obtained from this graph.

More instructive is to look at the meter error, and it is useful to plot this against either the reference gas volume fraction (GVF) or water cut:

Figure 2: Meter oil flowrate error vs. reference GVF

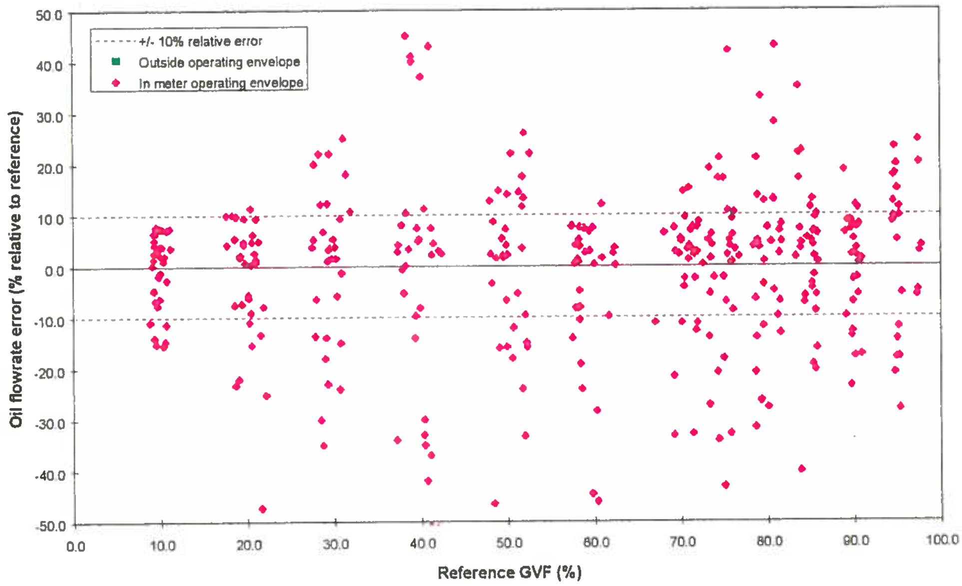
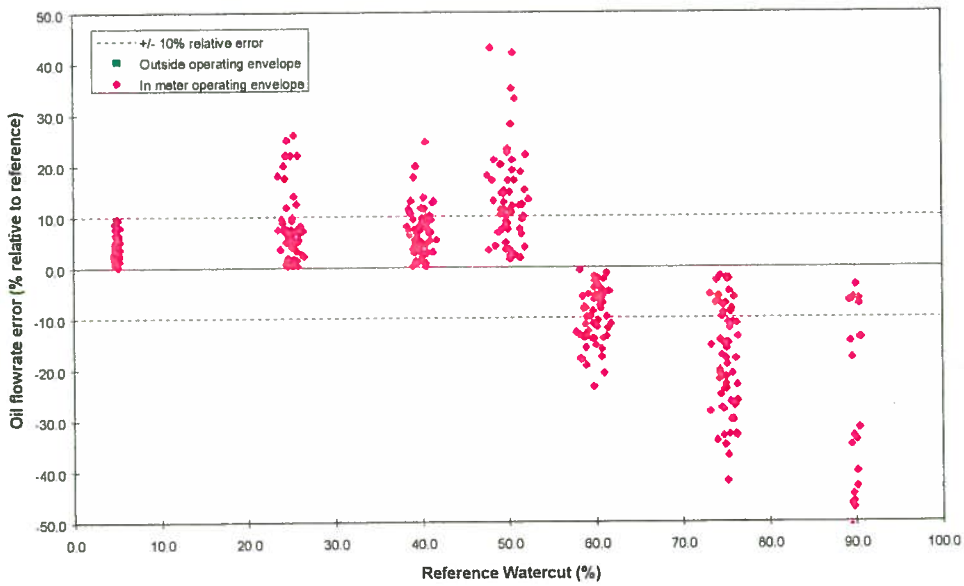
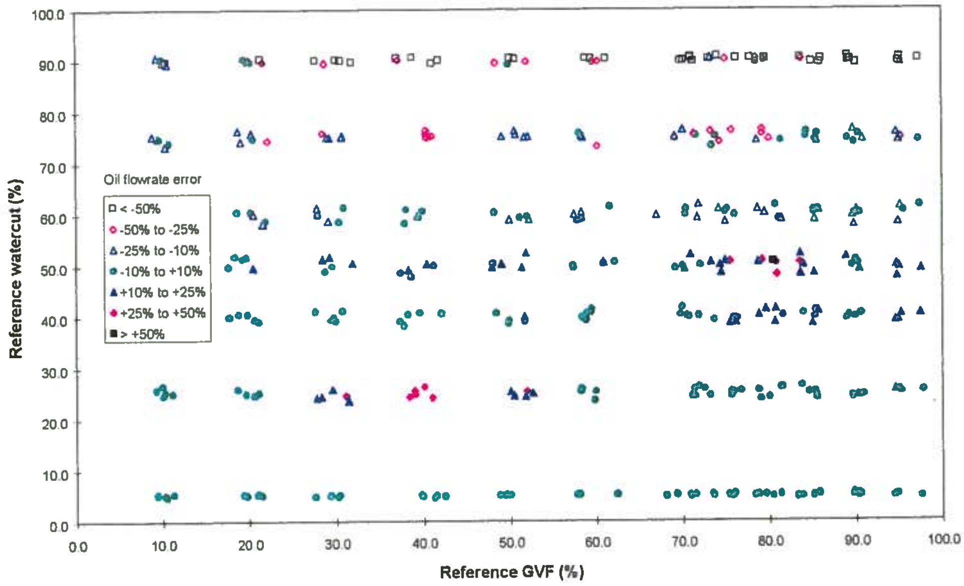


Figure 3: Meter oil flowrate error vs. reference water cut



Of these figures, it is clear that the plot of errors against water cut is beginning to show the strengths and weaknesses of the performance of this meter. The behaviour changes markedly between 50% and 60% water cut. It may be surmised that the spread in errors at each water cut is influenced by the gas fraction and therefore a plot which shows performance in terms of both water cut and gas fraction would be useful. One way to do this is to plot points on a GVF vs. water cut graph where the colour or symbol used for the points indicates the error, as shown in Figure 4.

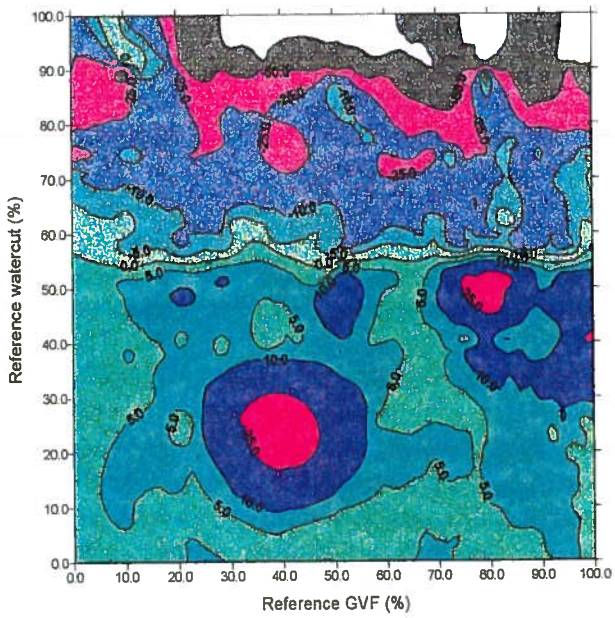
Figure 4: Meter oil flowrate error vs. reference GVF and water cut



This graph now shows the major regions where the performance of this meter is best and worst. For low water cuts (< 50%) the oil flowrate is within ±10% across all of the gas fraction range, apart from a significant region at approximately 25% water cut and 40% GVF. A similar 'hole' in performance occurs at 50% water cut and 80% GVF. For high water cuts (> 50%) the oil flowrate error is much worse.

The usefulness of Figure 4 is improved when converted to a contour graph, as shown in Figure 5.

Figure 5: Contour map of meter oil flowrate errors



While the underlying algorithm of the contour mapping may over-accentuate the problem regions, this graph is a quick visual means to observe the performance weaknesses of this meter.

Without exploring all these additional presentations of the data, the true performance of the meter may have been displayed.

2.2 Average accuracy calculations

Another meter accuracy issue is to find a suitable 'average' indication of the meter performance. All the calculations below have been seen in use.

The first is to compare the total reference volume of oil from all the tests with the total metered volume of oil. In this case the total reference volume of oil was $913m^3$ and the total metered volume was $935m^3$, giving an error on this measure of 2.4%. It may be surprising that the same set of data can be used to give the contour graph shown in Figure 5, yet indicate an overall error of 2.4%.

The second is to calculate the (arithmetic) average of oil flowrate errors of all the individual data points; this gives -7.4%. This measure gives an indication of bias in the measurements, but still disguises the scatter; calculating the standard deviation of the error values, 27.5% indicates the scatter.

A more useful average is the root mean square; in this case it is 28.5% - this seems much more consistent with the graphical presentation shown of the data.

A further method is to calculate the number of points which meet a particular level of accuracy. For example 30% of the data points have an accuracy within ±5%, 55% of the points lie within ±10% and 68% within ±15%. This calculation could give a quick method to compare the performance of different meters.

3. Standards for multiphase metering

It is hoped the preceding section serves to illustrate that standardisation of the analysis of multiphase meter performance is required in order to allow direct comparison of different meters and to display the full performance behaviour of the meters. At present, methods used to present data may be selected to give the best display of meter performance rather than meet the meter requirements of the end users.

A number of standardisation initiatives are currently underway, including revision of the Handbook of Multiphase Metering (Norwegian Society of Oil and Gas Measurement), and setting up of API and BSI/ISO committees on multiphase measurement standards.

4. Relationship of laboratory testing to field practice

A very important aspect of multiphase metering development has been the testing of multiphase meters in simulated conditions in laboratories. Those that have seen the greatest variety of meters have been the test facilities at NEL, Porsgrunn and Humble. Several other laboratories around the world also test multiphase meters. All of these test facilities have different strengths and weaknesses, such as operating pressures, test fluids, flexibility, independence, etc.

One of the major strengths of most laboratory testing is the quality of the reference information: the individual flowrates can be accurately and traceably metered and the properties of the fluids can be accurately measured; the meters under test can be calibrated using steady flows of the single phases to verify parameters such as conductivity, dielectric constants and gamma attenuation coefficients. Poor performance of a meter under evaluation in such a system will be a sure sign that further development is required, but is good performance a guarantee that equally good performance will be attained in a live application?

When applied in the field, it may not be possible to calibrate the meter using pure single phases; indeed it is usually the case that the fluid properties must be obtained from samples and corrections made to the meter software. This will inevitably introduce additional uncertainty into the overall measurement, particularly in applications where the properties of the fluids may vary. Changes in salinity of the water or in the composition of the hydrocarbon phase may significantly affect the accuracy. Where these properties change gradually it may not be apparent when a change to calibration constants may be required. Perhaps the most severe effect on all meters is that of changing salinity, where the salt content in some applications could change from a few ppm to several percent.

Where comparisons can be made between multiphase meters and field reference instrumentation such as test separators, the quality of the reference information may be significantly less accurate than references available in laboratory tests. The anecdotal evidence of examples where trials of multiphase meters against test separators has allowed debugging of test separator measurement problems illustrates this point. A comparison of a ±10% accuracy multiphase meter against a laboratory reference of ±1% is quite different to a comparison between a ±10% accuracy multiphase meter and a field reference of ±10%.

In-situ calibration and the validation of multiphase meters in service remain largely unanswered questions.

5. Further technical challenges

In addition to questions of accuracy calculation, standardisation and field practice, a number of technical issues also remain. These largely arise from the development of multiphase metering over recent years to a level where it is worth examining further issues, such as:

- unfavourable conditions: heavy oils
high temperatures
aggressive fluids (e.g. sand)

- metering at high gas fractions
- metering at high water cut
- long-term performance
- compensation for effect of salinity changes
- compensation for effect of other fluid property changes

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FOCUS DISCUSSION GROUP C

MULTIPHASE 2 - FIELD EXPERIENCE / INSTRUMENTATION

A Wee, MultiFluid International Ltd

MULTI-FLU

NORTH SEA FLOW MEASUREMENT WORKSHOP 1998

DISCUSSION GROUP ON MULTIPHASE TECHNOLOGY

Title

Operational Experience of the MFI MultiPhase Meter

Written By

Arnstein Wee

Operational Experiences – 1998

BRIEF INFORMATION ON RECENT INSTALLATIONS - MFI MULTIPHASE METER

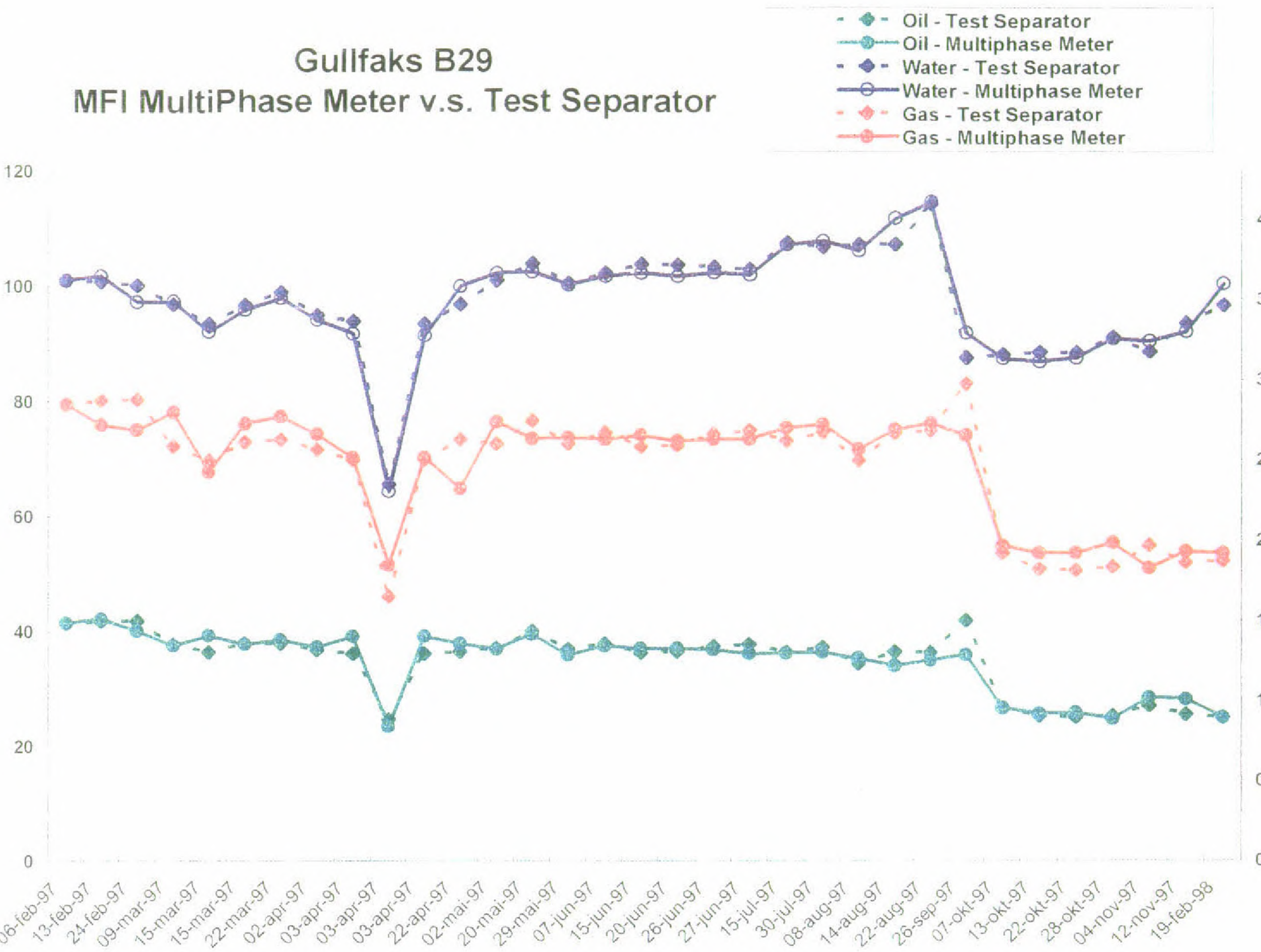
Enclosed are some plots of recent field experiences of MFI Meters in different applications. Some brief explanations are provided in the following.

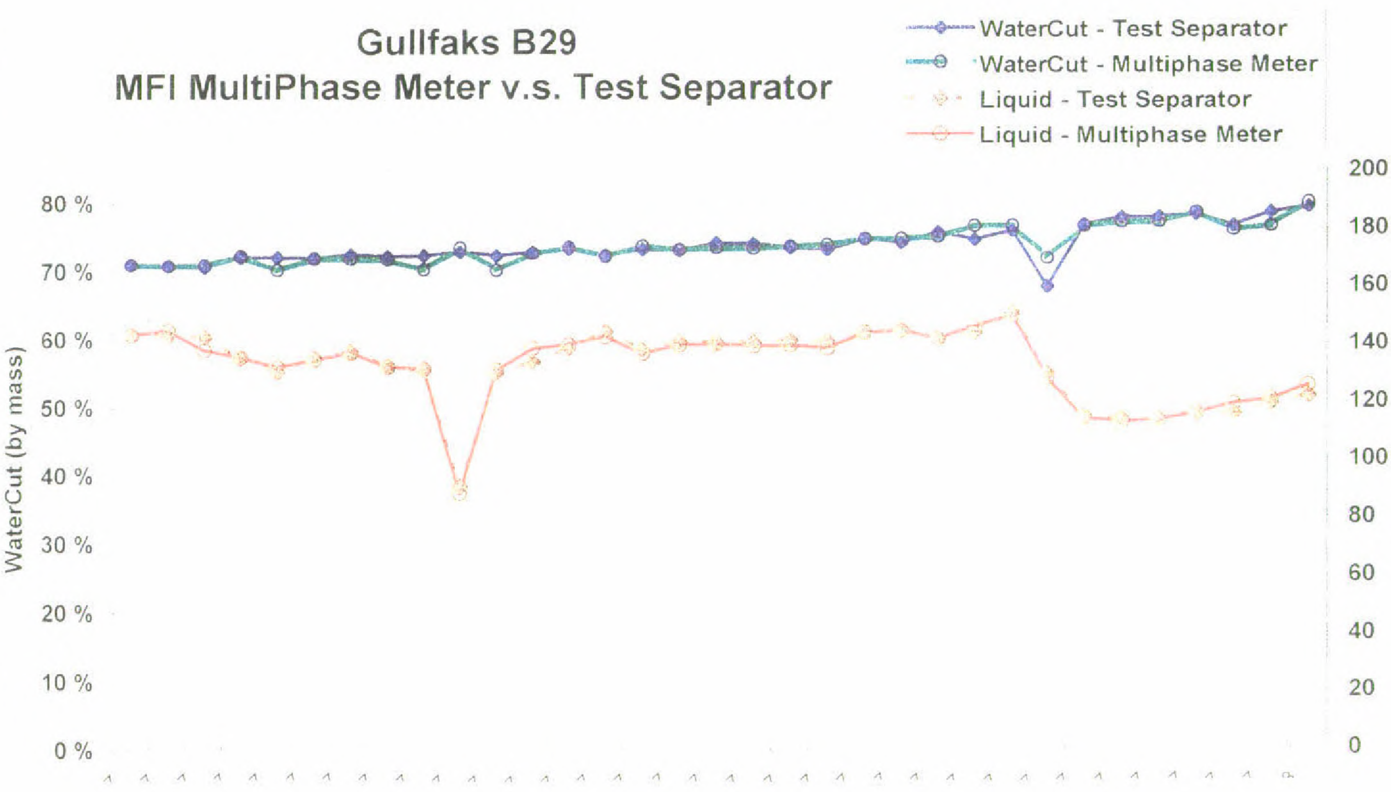
The first plot is made by Statoil, showing results from a 1 year test (Feb 97 – Feb 98) at the Gullfaks platform in the North Sea. The purpose of this test was to verify the operational stability of the MFI meter and to test its repeatability. The meter readings were adjusted to the test separator readings at the start-up in Feb 97, and the meter and its calibration was never touched after that point. As can be seen from the plot, the repeatability is extremely good, with no drift at all observed after one year of operation. The Meter did not suffer from any problems, and the readings from the different well tests are generally within 5%. On an accumulated basis, the oil, water and gas rates are found by Statoil to be within 1% during the whole one year period.

The second plots show start-up (2,5 hr period) of a well in Africa. As can be seen from the charts, a heavy emulsion during the first hour changed into steady flow with GVF at 70% and watercut around 10%. Later on (not showed in the charts) the watercut decreased to the expected level around 1-2 %. The second chart shows a comparative test of the measurements from the MFI Meter towards a test separator for a period of two weeks. As seen from the graph, the measurements from the MFI Meter were within ± 1.2 % of the flow rates from the test separator during whole this period.

A third example is taken from the Middle East, where different wells have been tested. This MFI meter is installed in a very hostile environment (ambient temperature during the day of 55 to 60 degC), and heavy slugging. The slug intervals and lengths can easily be found looking at the plots. Another interesting finding is that the temperature has a big impact on the flow conditions in the pipe, as can be seen in the *14 h test* plot. As you can see, the slugging becomes more severe as the ambient temperature decreases and the corresponding viscosity increases . Another result of the same is that some of the gas goes into the liquid phase. These things have been known by the operators, but unnecessary to say they were impressed by the MFI Meter performance which shows it real-time.

The final example is from Gullfaks A where 8 MFI MultiPhase Meters have been installed. Six of the MFI Meters are used for allocation of subsea tie-in fields and two MFI Meters are used to increase the welltest capacity of the test separator. The following two charts show a comparative test of 9 wells towards the Gullfaks A test separator. The wells have a GVF range of 25-75% and a watercut range of 10-90%. As seen from the graphs, both the oil and gas flowrates are well within ± 5%.

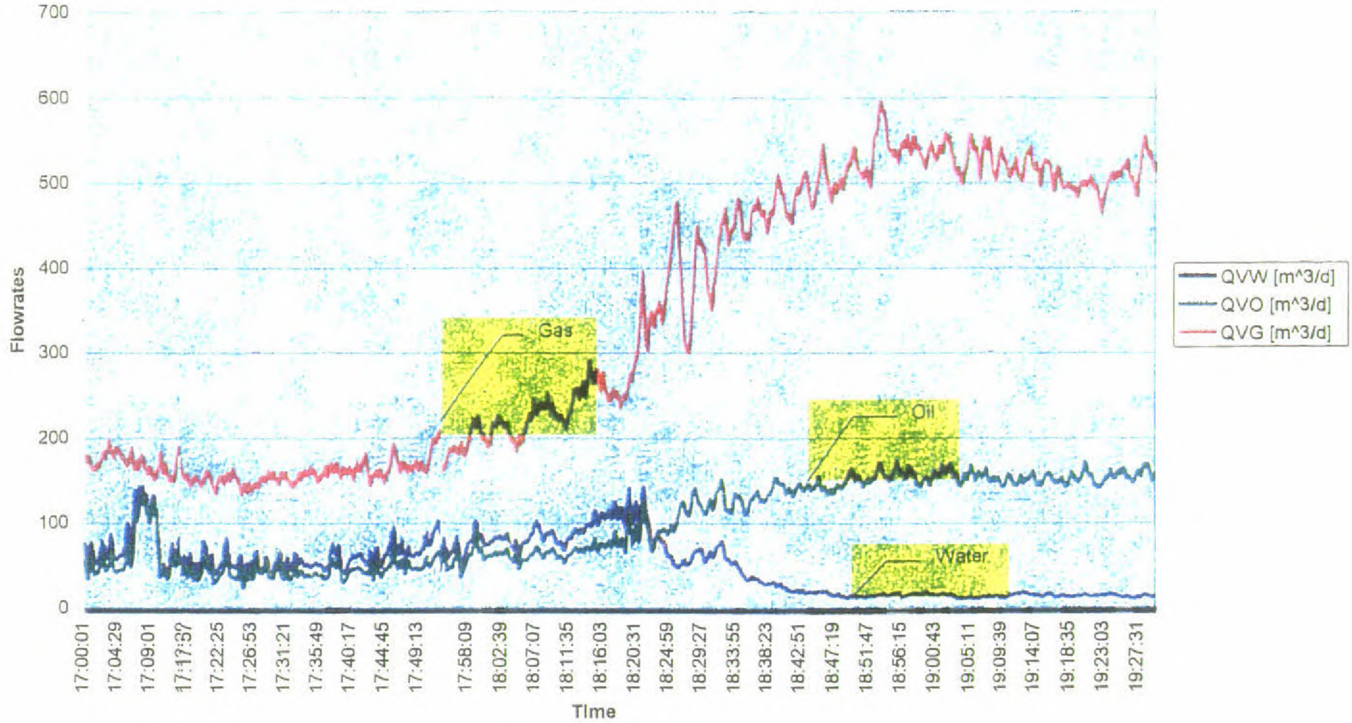

Gullfaks B29
MFI MultiPhase Meter v.s. Test Separator
Oil - Test Separator
Oil - Multiphase Meter
Water - Test Separator
Water - Multiphase Meter
Gas - Test Separator
Gas - Multiphase Meter
120
100
80
60
40
20
0
06-feb-97
13-feb-97
24-feb-97
09-mar-97
15-mar-97
15-mar-97
22-mar-97
02-apr-97
03-apr-97
03-apr-97
03-apr-97
22-apr-97
02-mai-97
20-mai-97
29-mai-97
07-jun-97
15-jun-97
20-jun-97
26-jun-97
27-jun-97
15-jul-97
30-jul-97
08-aug-97
14-aug-97
22-aug-97
26-sep-97
07-okt-97
13-okt-97
22-okt-97
28-okt-97
04-nov-97
12-nov-97
19-feb-98

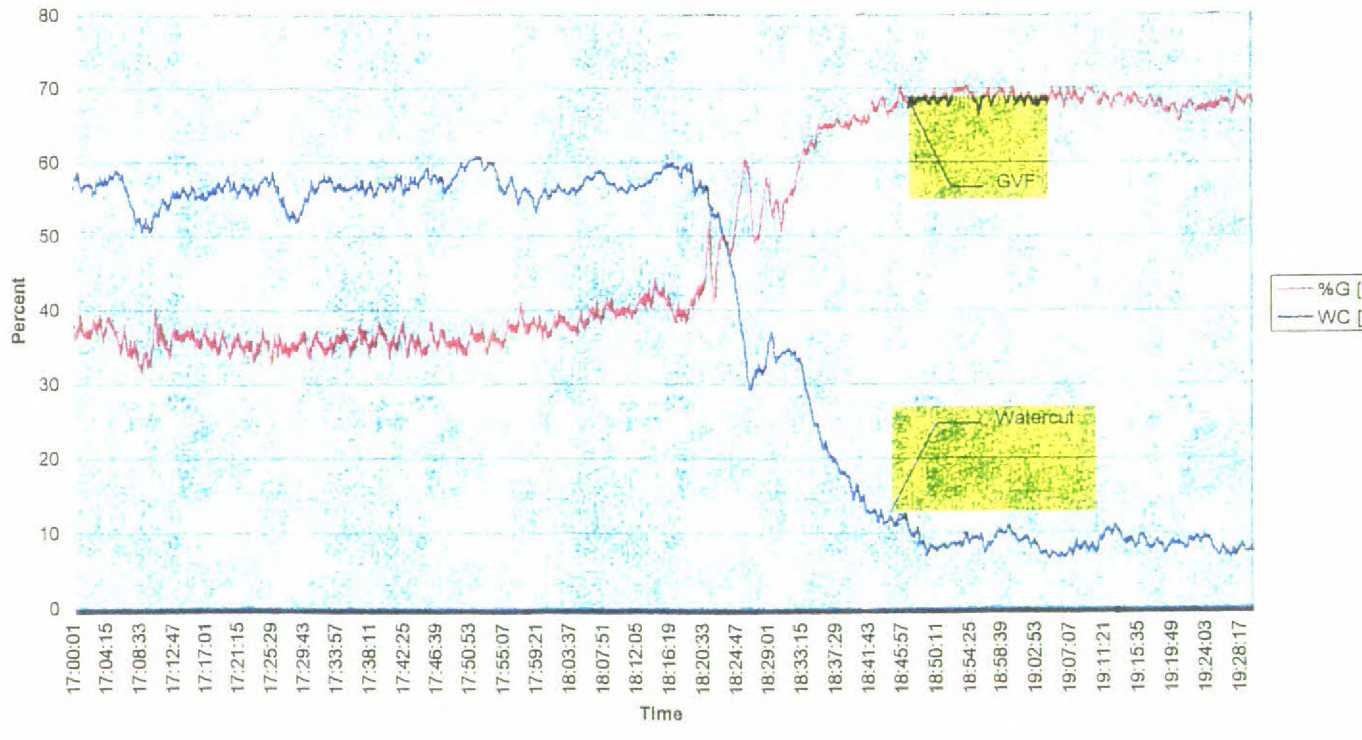

Gullfaks B29
MFI MultiPhase Meter v.s. Test Separator
WaterCut - Test Separator
WaterCut - Multiphase Meter
Liquid - Test Separator
Liquid - Multiphase Meter
WaterCut (by mass)
80 %
70 %
60 %
50 %
40 %
30 %
20 %
10 %
0 %
200
180
160
140
120
100
80
60
40
20
0

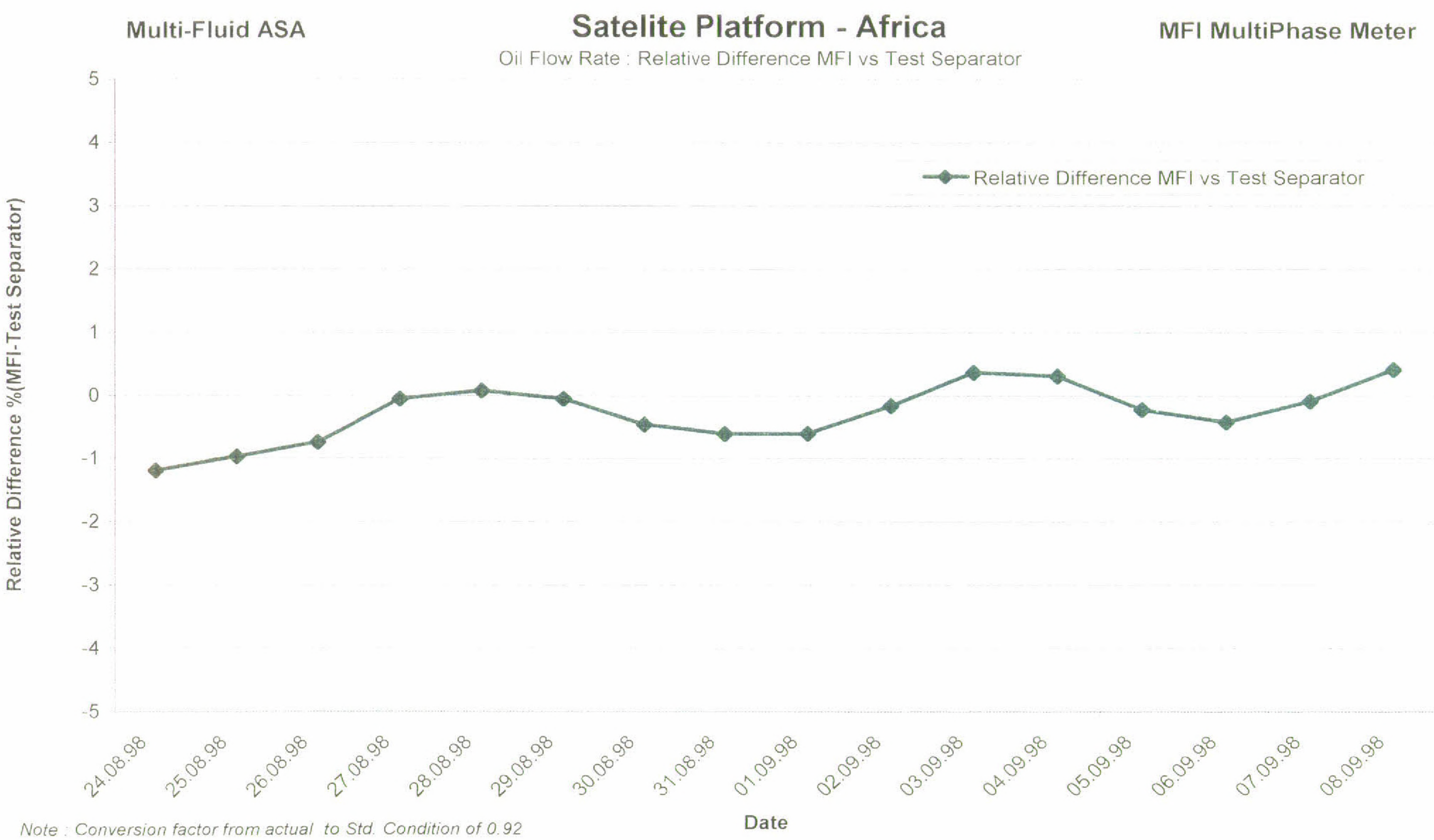
Multi-Fluid ASA **MFI MultiPhase Meter**

Satellite Platform - Africa

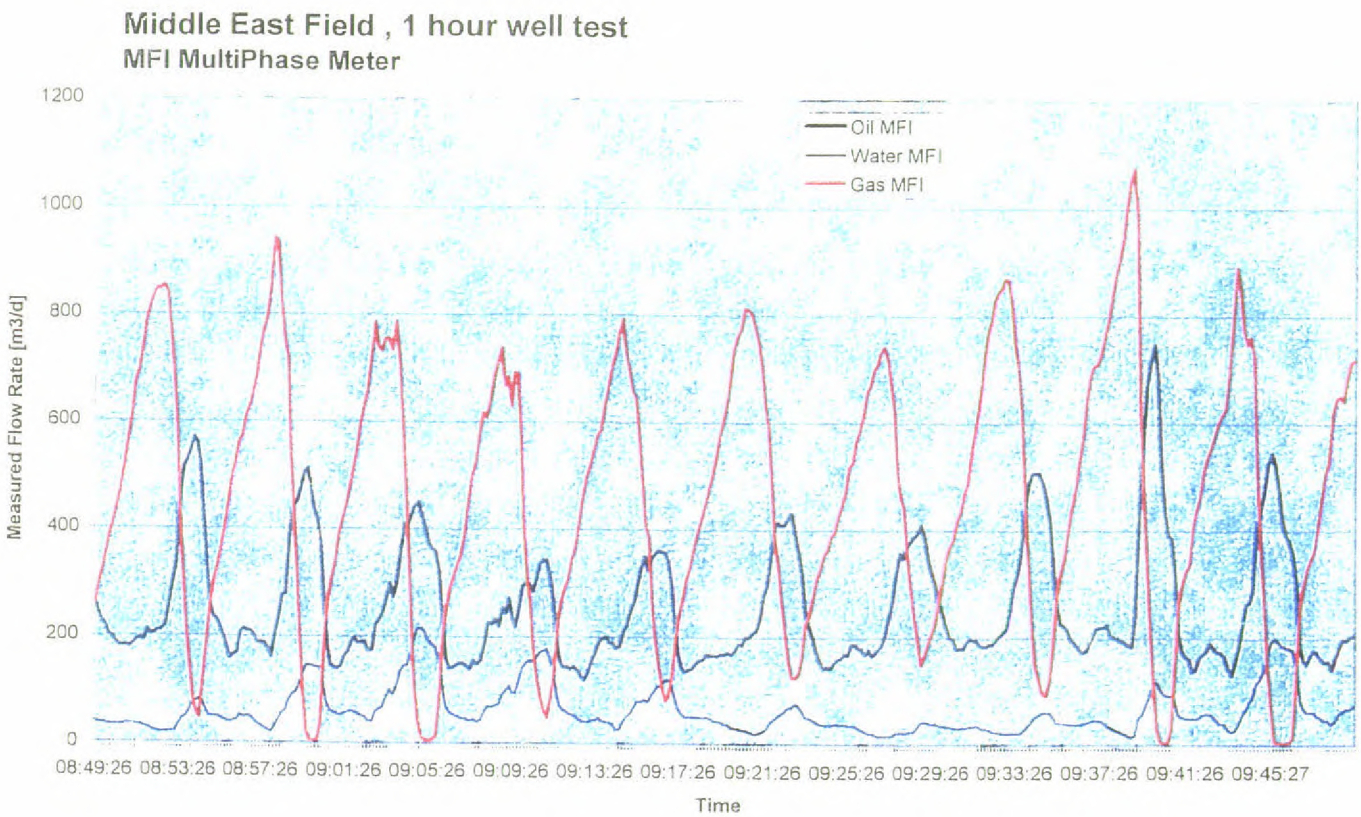
FlowRates during Start-Up, 2,5 hr period

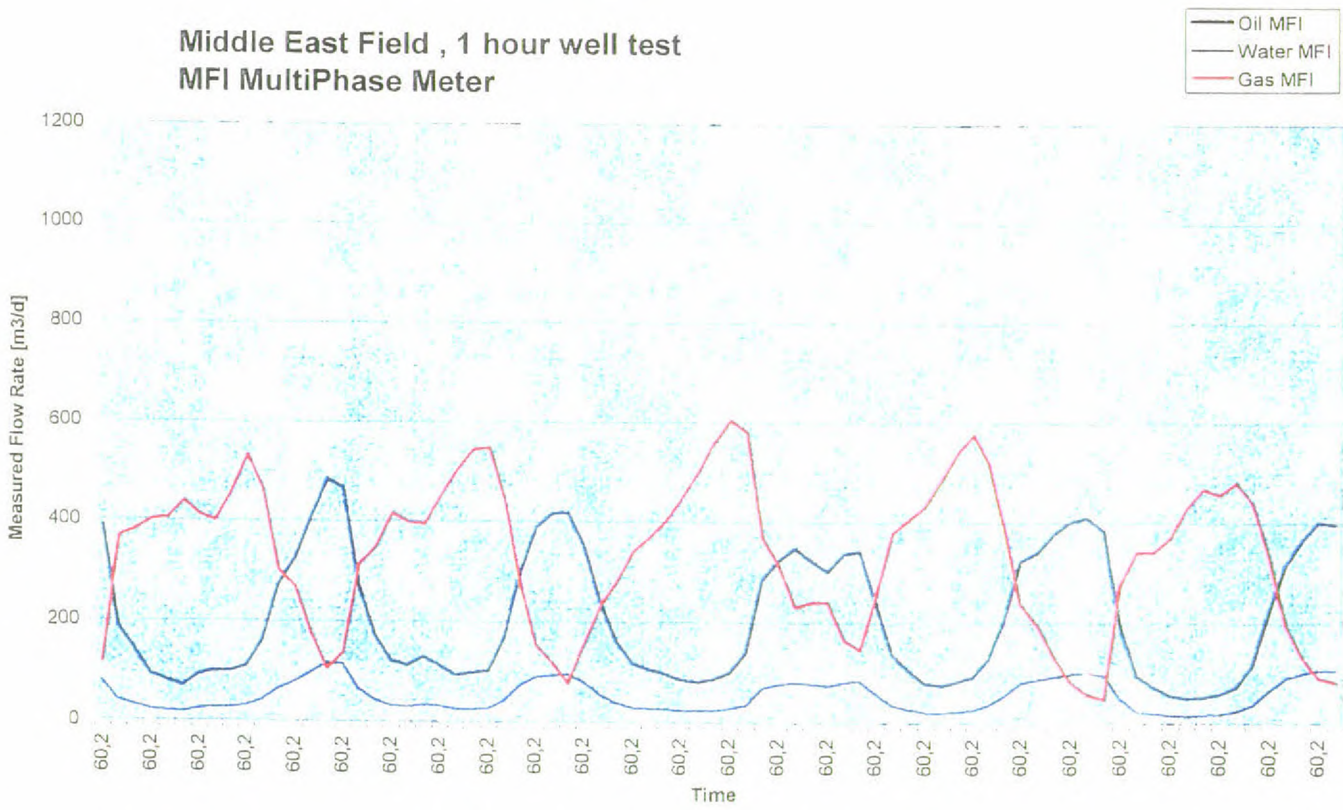




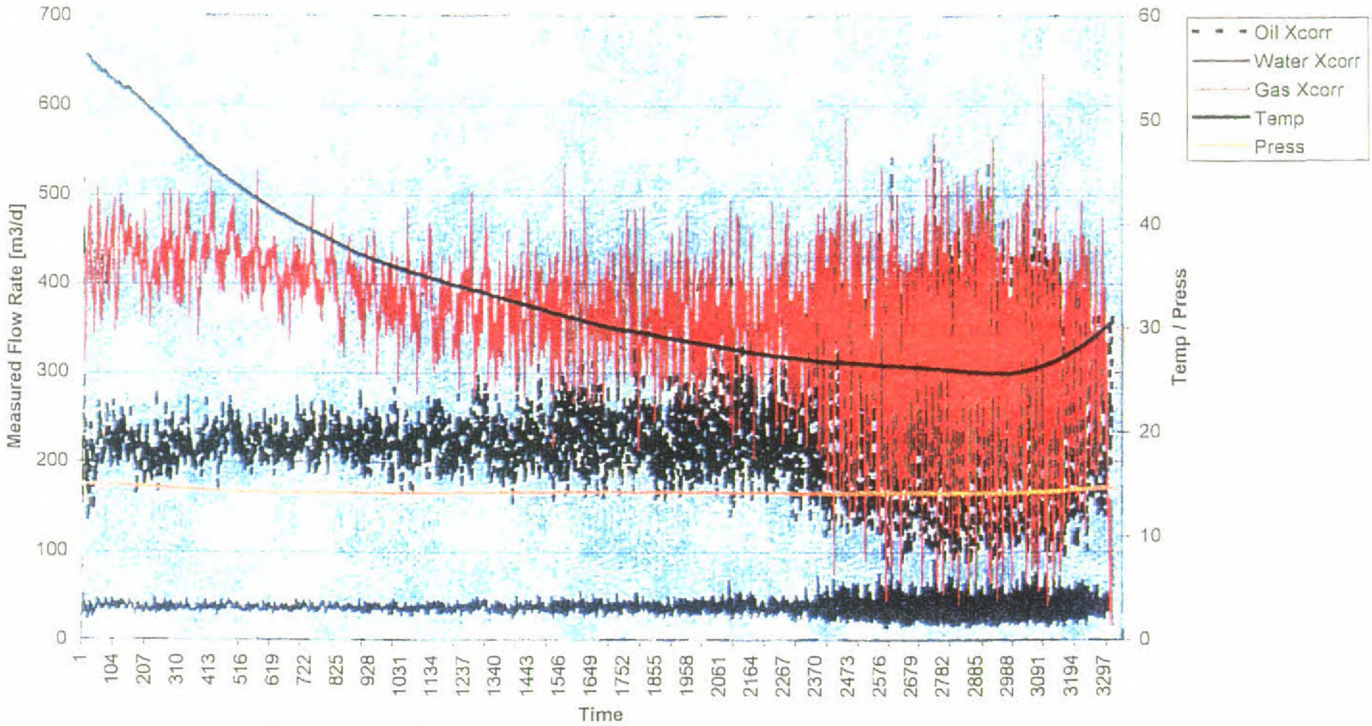


Multi-Fluid ASA
Satelite Platform - Africa
MFI MultiPhase Meter
Oil Flow Rate : Relative Difference MFI vs Test Separator
Relative Difference MFI vs Test Separator
Relative Difference %(MFI-Test Separator)
5
4
3
2
1
0
-1
-2
-3
-4
-5
24.08.98
25.08.98
26.08.98
27.08.98
28.08.98
29.08.98
30.08.98
31.08.98
01.09.98
02.09.98
03.09.98
04.09.98
05.09.98
06.09.98
07.09.98
08.09.98
Date
Note : Conversion factor from actual to Std. Condition of 0.92

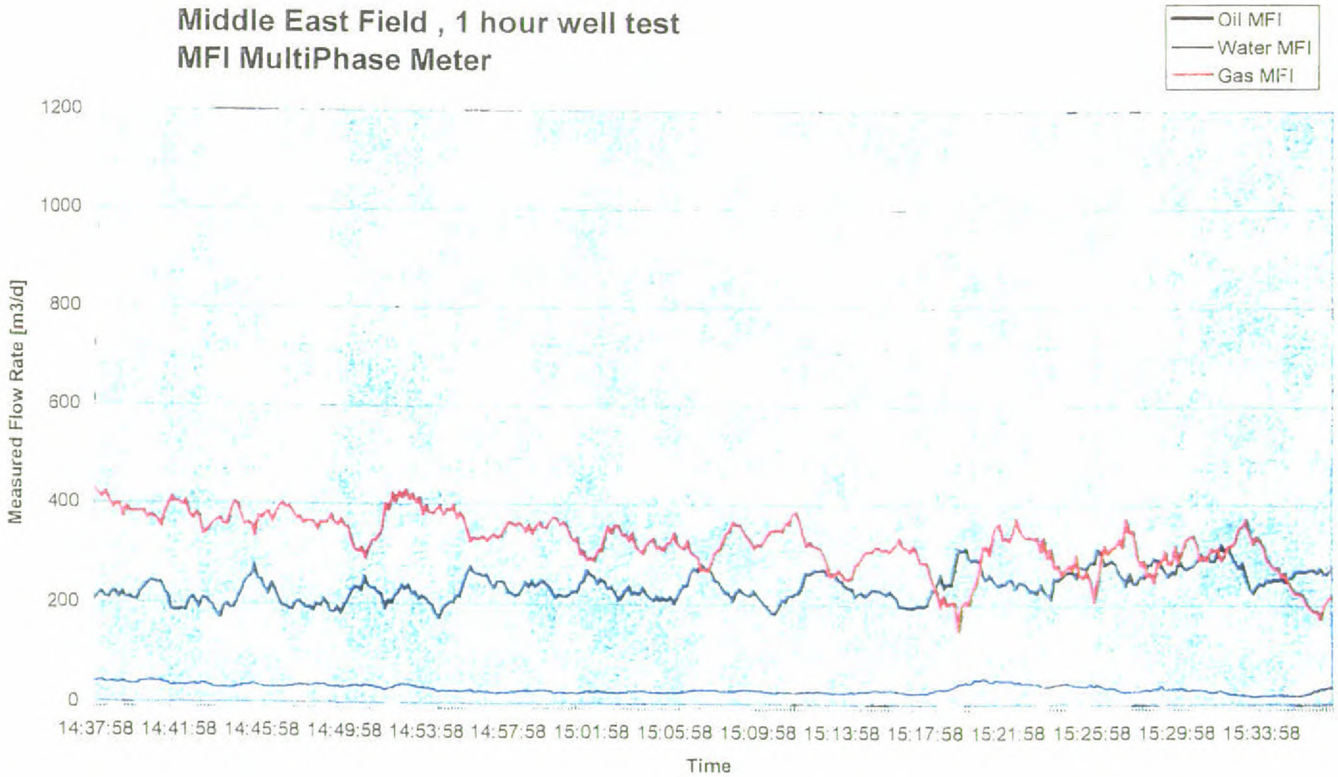

Middle East Field , 1 hour well test
MFI MultiPhase Meter
Oil MFI
Water MFI
Gas MFI
Measured Flow Rate [m3/d]
0
200
400
600
800
1000
1200
08:49:26 08:53:26 08:57:26 09:01:26 09:05:26 09:09:26 09:13:26 09:17:26 09:21:26 09:25:26 09:29:26 09:33:26 09:37:26 09:41:26 09:45:27
Time


Middle East Field , 1 hour well test
MFI MultiPhase Meter
Oil MFI
Water MFI
Gas MFI
Measured Flow Rate [m3/d]
0
200
400
600
800
1000
1200
60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2 60,2
Time

Middle East Field, 14 h Test over night
MFI MultiPhase Meter



Middle East Field , 1 hour well test
MFI MultiPhase Meter

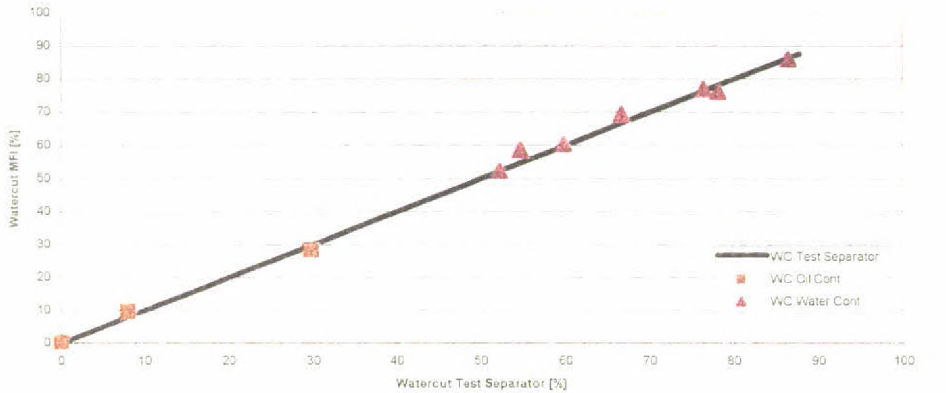


Gullfaks A Satellites

Increased Well Test Capacity utilising MFI MultiPhase Meters

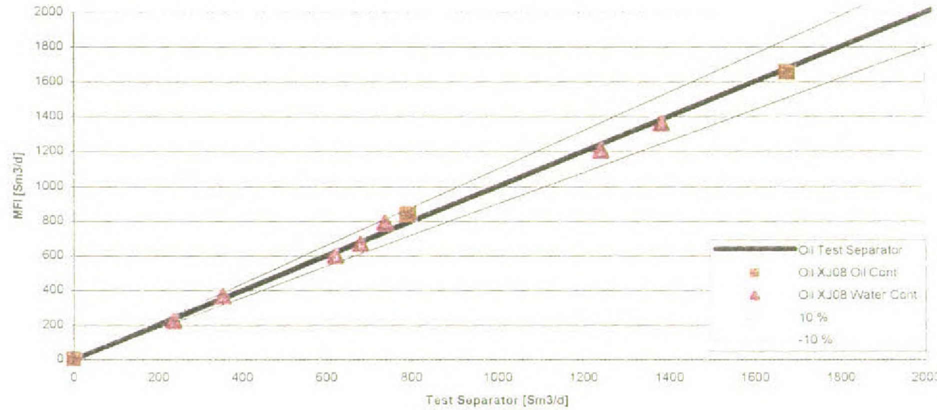
Watercut

Note: Calseb PVT on both Test Separator & MultiPhase Meter GVF = 25-75% Wate



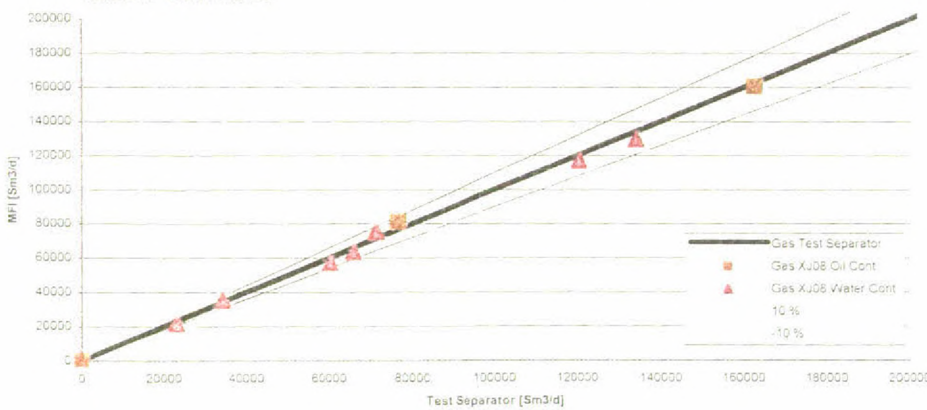
Oil Flowrate

Note: Calseb PVT on both Test Separator & MultiPhase Meter GVF = 25-75% Watercut = 10-90%



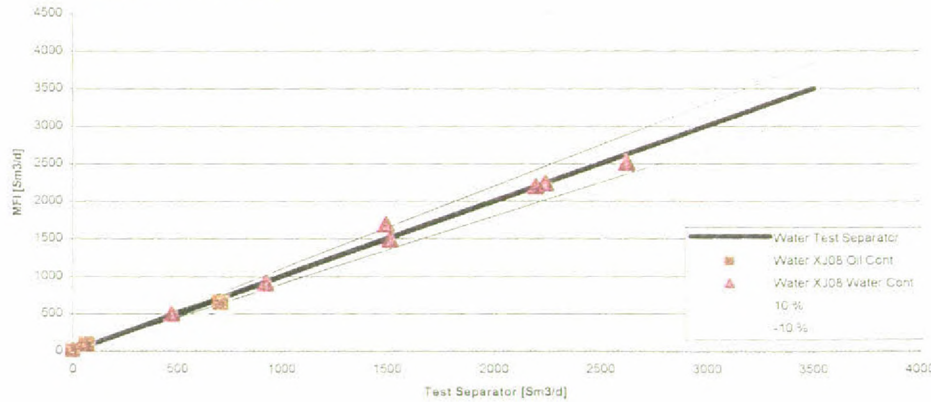
Gas Flowrate

Note: Calseb PVT on both Test Separator & MultiPhase Meter GVF = 25-75% Watercut = 10-90%



Water Flowrate

Note: Calseb PVT on both Test Separator & MultiPhase Meter GVF = 25-75% Watercut = 10-90%



Operational Experience 1998

MFI MultiPhase Meter

- MFI MultiPhase Meters in faultless operation for 2 years.

Examples :

	Location	*Start Up*
	Allocation Gullfaks B (SubSea system)	Nov. 96
	SubSea Meter Gullfaks B	Dec. 96
	Shell Gannet x 2	May 97
	Agip Trecate	Sept. 97

- Proven drift-free operation for more than one year at Gullfaks B
- Field experience covering all flow regimes.
- Accuracy reported by users to be better than ± 5-7%

MULTI-FLUID

Main Index

North Sea FLOW Measurement Workshop 1998

PAPER 27

FOCUS DISCUSSION GROUP D

GAS ULTRASONICS

Karen van Bloemendaal, Gasunie

ULTRASONIC METERS AND NOISE
A TASK OF THE '98 GERG PROJECT ON ULTRASONIC GAS FLOW METERS

K. van Bloemendaal, N.V. Nederlandse Gasunie, Groningen, The Netherlands.
G.H. Sloet, N.V. Nederlandse Gasunie, Groningen, The Netherlands.

1 INTRODUCTION

1.1 Background

In 1995, the status of multi-path ultrasonic gas flow metering was investigated by a GERG project group. This study not only established the state-of-the-art at that moment, but also identified gaps in the knowledge of such meters, which could be identified as topics for future research. The results were published in GERG Technical Monograph nr. 8 [1].

The most relevant of these "knowledge-gaps" were taken up in a second GERG project on ultrasonic gas flow meters (USM's). One of these items, the effects of (ultrasonic) noise on USM's, was investigated experimentally by Gasunie, and some results are presented in this paper. The other subjects of the GERG project, the effects of non-ideal flow, the development of a general uncertainty model, the development of procedures to evaluate transducers, and attenuation and propagation of noise in pipelines were or will be reported elsewhere [2, 3, 4, 5]. This GERG project ran in 1997 and 1998, and the project group involved 9 European gas companies: BG Technology, UK; Distrigaz, Belgium; ENAGAS, Spain; Gasunie, the Netherlands; Gaz de France, France; NAM, the Netherlands; Ruhrgas, Germany; SNAM, Italy, and Statoil, Norway.

1.2 Previous Work on USM's and Noise

The research of (ultrasonic) noise and the effects of it on USM's is induced by problems with USM's in the neighbourhood of valves and regulators encountered by users of these meters. A few times these problems in field locations were published [for example 6, 7, 8], but more often the problems are tackled in a practical way. Solutions to the problems are often sought in replacing the (silent) regulator with one of a different type, usually a non-silent one, or by increasing the distance between the regulator and the USM. The 1996 AGA Technical Note on USM's [9] also advises not to install USM's in close proximity to throttling devices, and suggests manufacturers to improve signal handling by techniques as for example stacking, and to increase the transducer power in order to increase the signal to noise ratio. In [8] it was possible to increase the transmission output to the sensors, but this is not usually the case. [10] presents a noise suppression algorithm for a USM.
In field situations, varying of flow and pressure difference is often difficult, and noise, if measured at all, can only be measured at one or two locations. In some publications [11, 12] an attempt is made to investigate the effect of noise on a given meter more systematically. However, the scheduled tests in these cases were curtailed, because the USM's would not operate correctly with substantial pressure reduction, and no noise measurements were performed. In [13] many sound spectra were recorded and compared with the signal level of a USM, but this investigation was performed at low pressures. [14] presents sound measurements of one regulator and signal to noise ratios of a USM .

1.3 Aim of the Present Work

The aim of the present work is to investigate whether it is, in principle, possible to measure gas flows with USM's in the vicinity of ultrasonic noise sources such as regulators, and if so, how reliable the USM output is. This is done by observation of the performance of as much as possible USM's of different makes in the vicinity of a pressure reducer and simultaneous registration of the noise disturbance in a more systematic way than has been done up till now. It has not been the intention to perform a competitive test, in other words to identify "the best meter".

2 EXPERIMENTAL SET-UP

2.1 Test Facility

The experiments described in this paper were performed in a test section at the Gasunie laboratory in Groningen. The gas flows first through the test section and then through the reference meters, before it is delivered into the distribution network of Groningen city. Pressure is reduced near the inlet from the supply pressure of 40 bar(a) to the desired test pressure and in case the test pressure is higher than 9 bar(a), between the test section and the reference meters, who always operate at the outlet pressure of 9 bar(a). Flow rate is controlled at the outlet of the facility, and it is limited by the gas demand of the city.

2.2 Pipe Configurations

The test section was about 18 m long. A large part of this section was of 200 mm diameter pipe. The inlet and the outlet of the test section are defined by 150 mm plug valves, which are a fixed part of the test facility. In the following figures, gas flow is from left to right.

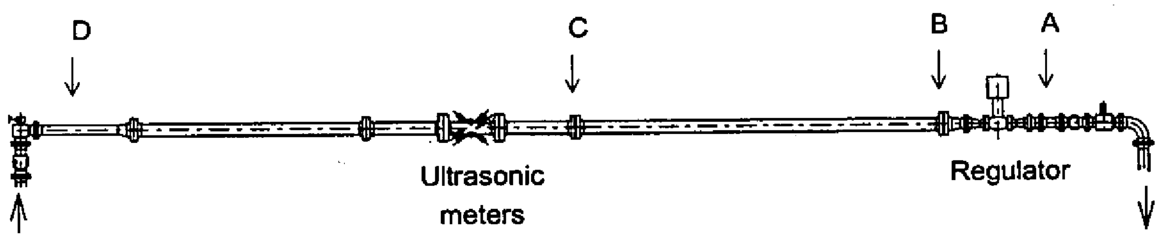


Figure 1: Test Set-up With Regulator Downstream (DN)

Figure 1 shows the set-up with the regulator (see 2.3) close to the downstream end of the test section (DN). Downstream of the 150 mm angular plug valve, the piping expands to 200 mm. Ca. 1.5 m upstream of the end of the test section, the pipe diameter is reduced back to 150 mm. The 100 mm regulator is mounted between two 100-150 mm reducers and is located about 1 m upstream of the outlet valve. The USM's spool piece (see 2.5) is located about 6 m downstream of the inlet valve; the distance between the USM's and the regulator is about 9 m. Sound measurement sensors (see 2.4) are located upstream (D), close to the middle of the test section (C), further downstream (B) and downstream of the regulator (A).

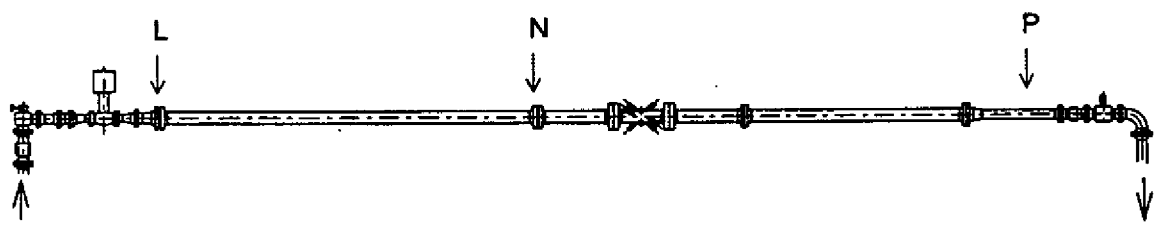


Figure 2: Test Set-up With Regulator Upstream and USM's in Middle of Test Section (UP-M)

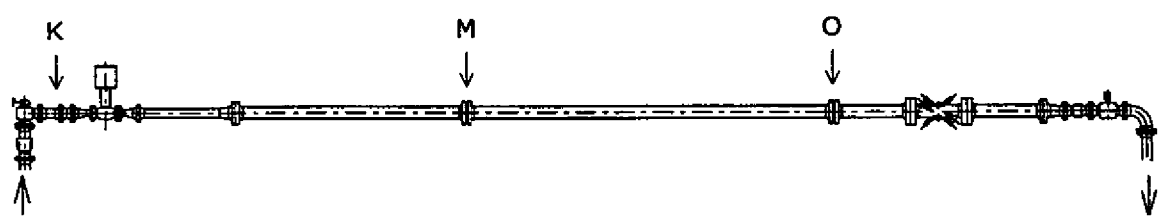


Figure 3: Test Set-up With Regulator Upstream and USM's at Long Distance (UP-L)

Figures 2 and 3 show the set-up with the regulator close to the upstream end of the test section, and the USM's spool piece located respectively near the middle of the test section (UP-M), or at longer distance, about 13 m, from the regulator (UP-L). In the UP-M case, the distance between regulator and USM's was about 9 m, the same as in the DN case. Sound measurement sensors were located at 3 positions downstream of the regulator: close to the regulator (L), near the middle of the test section (N) and near the end of the test section (P). In the UP-L case sound measurement sensors were located upstream of the regulator (K), between locations L and N (M), and between locations N and P (O).

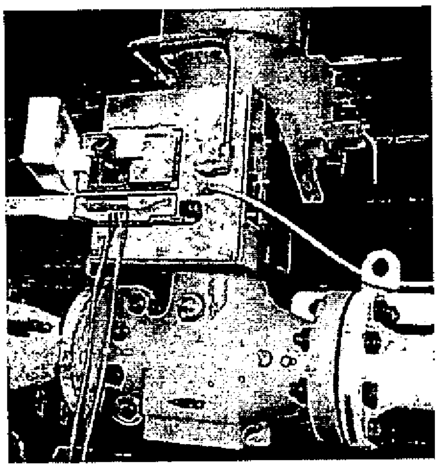


Figure 4: Mokveld Regulator.

2.3 Regulator

The regulator, a 4" axial flow valve see figure 4, is a product of and made available to the project by Mokveld Valves [15]. Bodies of such regulators are standard, the internal cages, the parts where actual pressure reduction takes place, are sized on specification. For this project the maximum pressure difference was set at 27 bar, and maximum flow rate at 30000 m3/h(s). The regulator was equipped with a pneumatic actuator so that it could be moved into position from the control room. Its position output could be read by the data acquisition system. The regulator was mounted both on the downstream and upstream ends of the test section.

Two cage designs were selected in order to investigate the influence of these constructions on the spectrum, see figure 5. The RVX cage is a "standard" cage with 7 slots, which produces a lot of audible noise. Noise levels of more than 100 dB(A) were recorded in the test room. The RQX cage is a low noise design with 228 holes, producing considerably less audible noise.

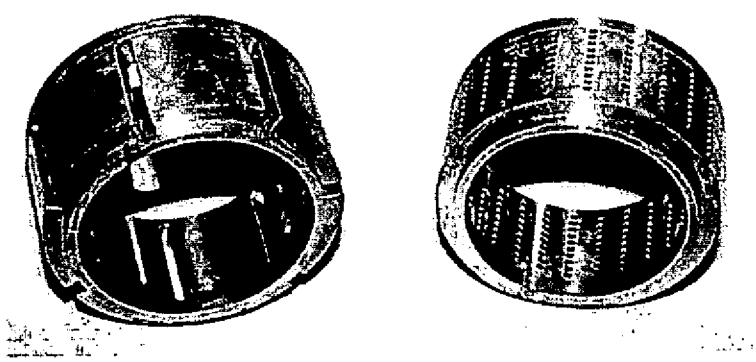


Figure 5: RVX (left) and RQX Cages.

2.4 Sound Measurements

Under all test conditions, the noise levels and spectra were measured inside the pipe at several locations, both upstream and downstream of the regulator (see figures 1 to 3 in section 2.2). For the sound measurements, PCB sensors type 132 A 41 [16] were selected. These piezoelectric sensors are very small, 3 mm diameter, and may be used in high pressure surroundings. Response is claimed to be accurate within ½ dB in the range up to 500 kHz. Calibration results of the sensitivity, in the order of 3000 mV/psi, are supplied with each sensor.

The signal of the sensor was recorded on a digital storage oscilloscope. Every sound measurement consists of 60000 data points, sampled at 1 μs, which were stored on file and processed off-line in a Matlab-environment. Every measurement was transformed into a spectrum by a FFT procedure, from which sound pressures in 1/3 -octave frequency bands were calculated. Mean sound pressure values over the frequency range of 50-500 kHz were calculated from these.

2.5 Ultrasonic Meters

Six major ultrasonic gas flow meter manufacturers were all willing to make available their equipment for the measurements. These were: Daniel; Instromet Ultrasonics; Kongsberg Offshore; Krohne Altometer; Panametrics and Ultraflux. Each manufacturer supplied one set of transducers and the necessary cabling, electronics and flow computers, to complete a 1-path meter. A pulse output frequency could be read by the data acquisition system of the installation for the calibrations (see chapter 4).

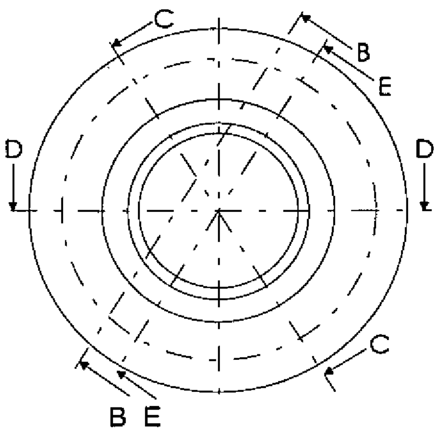


Figure 6 Spool Piece Cross Section

These 6 USM's were all to be exposed to the same test conditions and disturbances such as gas pressure, gas velocity, noise levels and distance to the source of the noise. For this purpose, a special spool piece was designed in which each manufacturer could install one pair of transducers. This spool piece basically consists of a 200 mm ANSI 1500 pipe of 1 m length (see figures 6 and 7). Each meter is (part of) a commercially available product of the manufacturer, each with its own transducer holder design.

The transducer holders are located in the planes B-B, C-C, D-D and E-E. The planes B-B and E-E each contain one straight path (i.e. no reflection on the pipe wall). The path in B-B makes an angle of 55° to the centre line, and is located at half- radius; the path in E-E crosses the centre line at an angle of 60°.Plane C-C contains two straight paths, both through the centre line at an angle of 45°. Plane D-D contains two reflection paths (both transducers of one path are located at the same side of the pipe, and the ultrasonic beam reflects on the opposite pipe wall). Both paths have angles of 60°.

Using this spool piece, and operating the ultrasonic meters one by one, the results of the meters and the effects of the noise could be compared

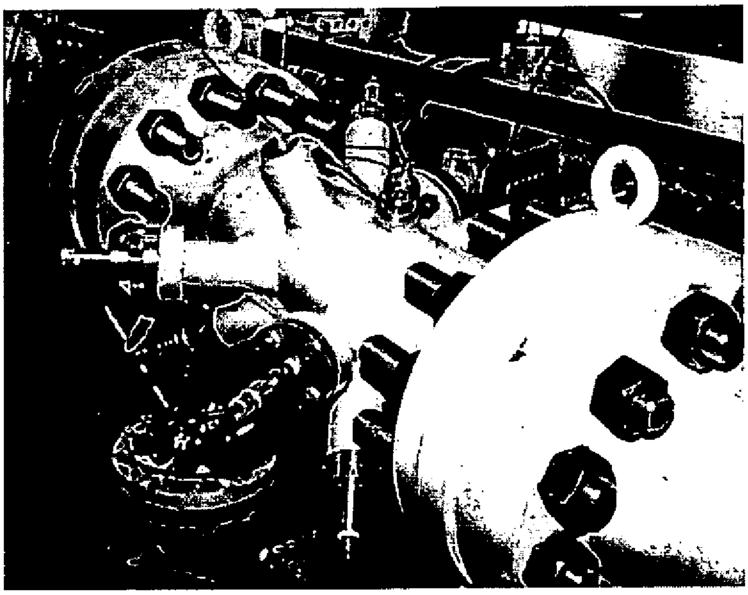


Figure 7: USM's Spool Piece

2.6 Test Procedure

For each test set-up at three fixed upstream pressures, 15, 24 and 36 bar(a), the flow rate was varied; and at two fixed flow rates, 6800 and 17000 m3/h(s), the pressure difference was varied. At every test condition sound measurements were performed and all USM's calibrated. During the sound measurements all USM's were switched OFF. The USM's were tested one by one, i.e. when one meter is switched ON, all other meters are switched OFF. This way, the meters are never influenced by (reflections of) signals from other meters.
As flow rates are given in standard cubic meters per hour, the actual gas velocity at the USM's is dependent on the local pressure, which is different when the meter is upstream or downstream of the regulator. Appendix A gives an indication of gas velocities at each flow rate.

3 RESULTS SOUND MEASUREMENTS

The sound measurements consist of sampling the signals from the piezoelectric sensors (see 2.4). The calculated mean sound pressures in 1/3-octave frequency bands are plotted against the central frequencies in every band in the range of 30 to 500 kHz. The y-axis is given in the sound pressure unit Pa, on a logarithmical scale, ranging from 1.e-1 to 1.e+4 Pa [1].
In every situation the mean sound pressure in the frequency range 50-500 kHz was calculated also, and plotted against three main variables: the valve position in percentage of maximum valve opening, the product of flow rate and pressure difference and the distance to the regulator.

3.1 Non-silent regulator RVX

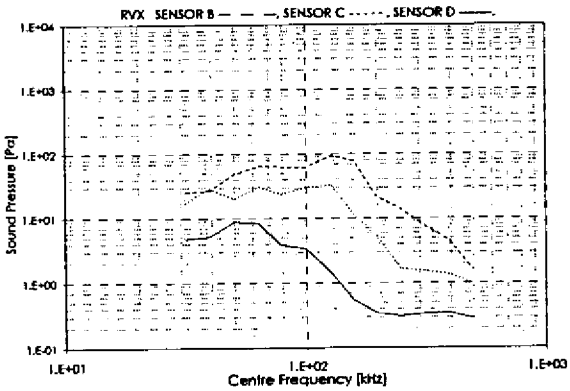


Figure 8: Results Sound Measurements Upstream of Non-Silent Regulator RVX

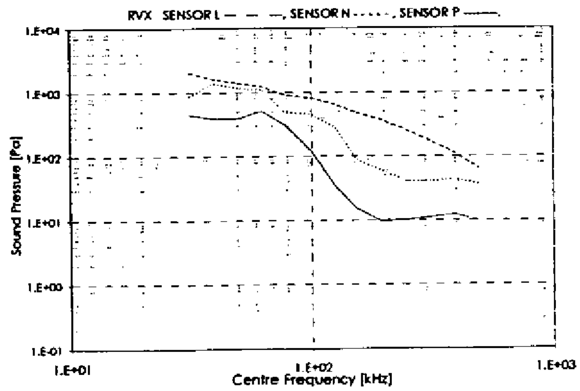


Figure 9: Results Sound Measurements Downstream of Non-Silent Regulator RVX

Figure 8 shows some results with the non-silent regulator RVX. The regulator was mounted at the downstream end of the test section, and the sensors (B, C and D) were located upstream of the regulator. The pressure upstream of the regulator was 36 bar(a), downstream 9 bar(a), the flow rate was 12000 m3/h(s). The valve position was 41% open. Figure 9 shows similar results, obtained in similar conditions, from sensor L, N and P, located downstream of the RVX regulator which was mounted at the upstream end of the test section.
These figures show clearly more noise downstream of the regulator than upstream, and also relatively more low frequency noise. With distance the noise decays, and this decay is stronger for higher frequencies.

3.2 Silent Regulator RQX

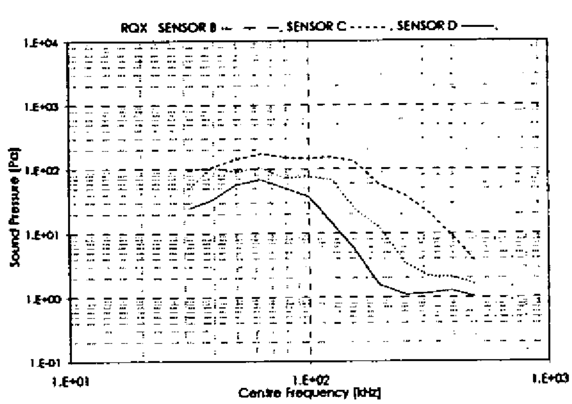


Figure 10: Results Sound Measurements Upstream of Silent Regulator RQX

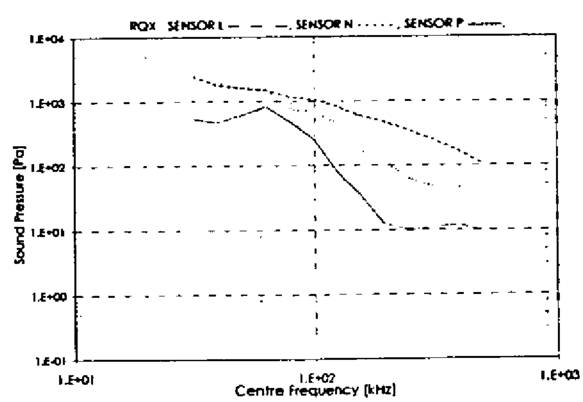


Figure 11: Results Sound Measurements Downstream of Silent Regulator RQX

[1] For readers who prefer decibel scales: this scale is equivalent to a linear scale ranging from 74 to 174 dB, relative to the internationally accepted value for reference pressure of 20 μPa [17].

Figures 10 and 11 show results of the silent regulator RQX, under test conditions corresponding to those of figures 8 and 9. Although this regulator is a low-noise one, designed for low noise in the audible range and outside the pipe, this regulator produces more noise inside the pipe in the frequency range of interest 30-500 kHz.

3.3 Mean Sound Pressure in Relation to Q*dP, Valve Position and Distance

Analysis of all (more than 500) obtained spectra revealed that the spectrum depends on regulator type, pressure difference across the regulator and flow rate, valve position, and distance to the regulator. In order to show these dependencies, the mean sound pressure (MSP) in the frequency range from 50 to 500 kHz is calculated for every test condition. Similar calculations were performed with two or more smaller ranges, to see the effect of frequency range.
Presented here is MSP(50-500 kHz) as a function of the valve position V, as a function of the product of flow and pressure difference Q*dP which are important parameters in the generation of noise inside the regulator, and as a function of distance to the regulator x as noise is known to decay with distance. Because of the large similarity, only results of non-silent regulator RVX are presented graphically.

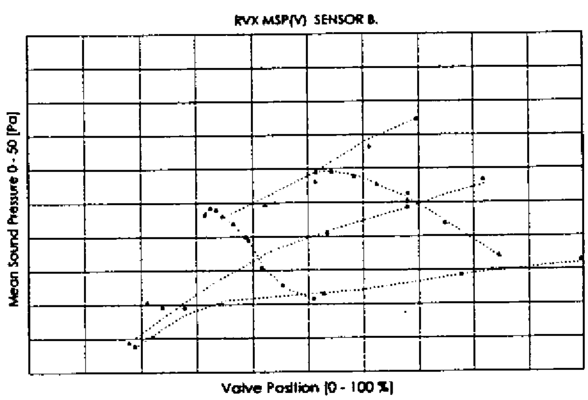


Figure 12: MSP as function of Valve Position Upstream of Non-Silent Regulator RVX

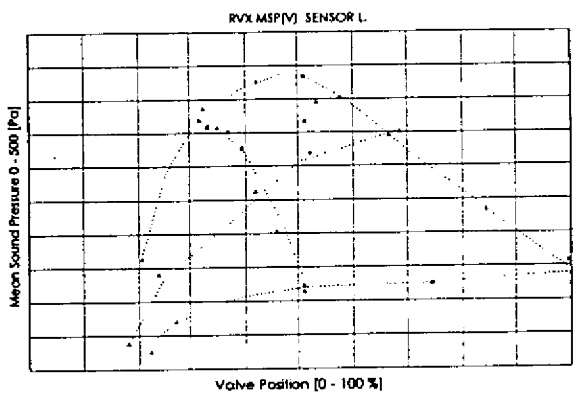


Figure 13: MSP as function of Valve Position Downstream of Non-Silent Regulator RVX

Figures 12 and 13 show mean sound pressures MSP for regulator RVX, upstream and downstream of the regulator, as a function of the valve position. Only data points from the sensors closest to the regulator, B and L respectively, are given in the figures. The other sensors show similar patterns, but at lower values.
The 5 different experiment series are clearly recognisable: three lines with fixed pressures and variable flow rates, and two lines with fixed flow rate and variable pressures. At a given flow rate, increasing valve opening means decreasing pressure difference, and accordingly decreasing sound pressure. At a given pressure difference, with increasing valve opening, flow rate and sound pressure increase.
With regulator RQX similar results were obtained.

Figures 14 and 15 show mean sound pressures for regulator RVX, upstream and downstream of the regulator. With some scatter, the mean sound pressure fits logarithmically with the product of flow rate and pressure difference Q*dP. Curve fits in the form MSP = A * ln(Q*dP) - B are drawn in the figures. Factor A decreases with increasing distance to the regulator.
A has larger values with silent regulator RQX than with non-silent regulator RVX. The difference between RQX and RVX increases with increasing distance, and is larger upstream than downstream of the regulator.

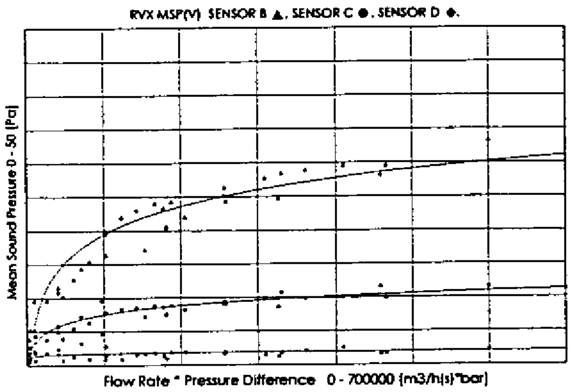


Figure 14: MSP as function of Q*dP Upstream of Non-Silent Regulator RVX

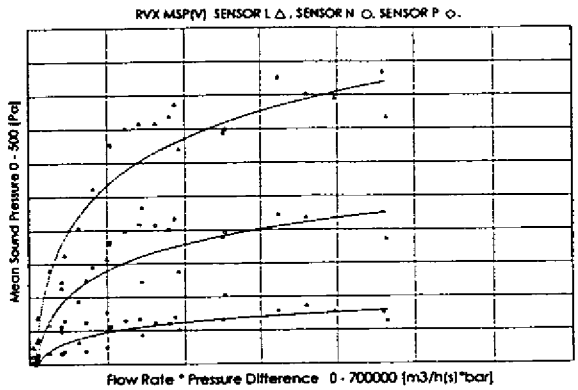


Figure 15: MSP as function of Q*dP Downstream of Non-Silent Regulator RVX

Figure 16 gives MSP as a function of distance to the regulator. All results of regulator RVX (in the different set-ups, see 2.2) are drawn in the same figure. The sensors A and K are located in the short part of the test section, that is between the regulator outlet flange and the nearby downstream valve (sensor A, RVX-DN) or between the regulator inlet flange and the nearby upstream valve (sensor K, RVX-UP). The results of these sensors are given in open markers, in contrast to the results of all other sensors, given in black markers.

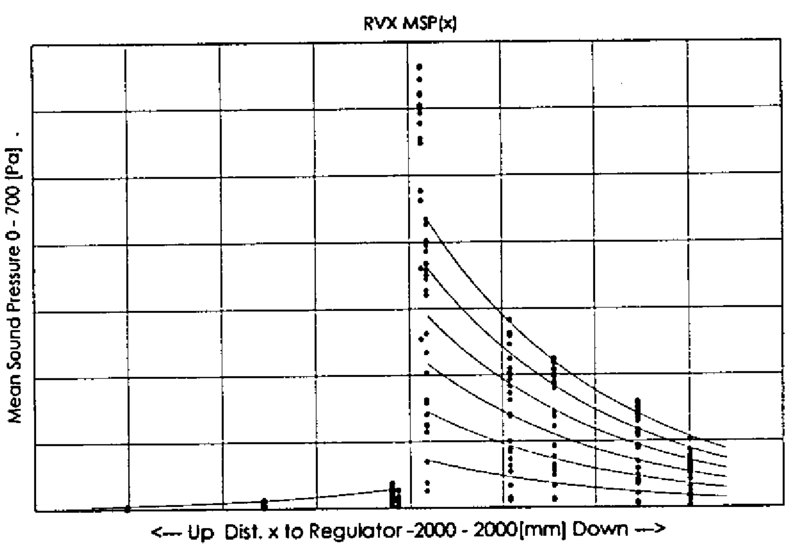


Figure 16: Mean Sound Power in the Range 50-500 kHz as a Function of Distance x for Non-Silent Regulator RVX

The results of sensors A and K are clearly very different from all other results. This shows that not only the source of the noise, the regulator is important, but also the up- and downstream pipe work and fittings. In this case, the up- and downstream valves may act as reflectors for the sound inside the pipe. When disregarding these results, the results of sensors B-D and L-P show an exponential decay with distance.
For illustration, a grid of exponential lines in the form $MSP(x) = MSP_0 * e^{-C'x}$ is drawn in the figure. The value x = 0 represents the middle of the regulator; the values of C and (maximum) MSP_0 are given in table 1.

Table 1 - Exponential Decay of Mean Sound Pressure with Distance

	Upstream of regulator		Downstream of regulator	
	RVX (non-silent)	RQX (silent)	RVX (non-silent)	RQX (silent)
C	-0.00012		-0.00010	
MSP_0 (max)	32	70	480	540

The exponent C gives the decay rate. In the frequency range 50-500 kHz, the upstream noise decays faster (C = -0.00012) than downstream noise (C = -0.00010). From the calculations with divided frequency ranges it follows that exponent C is larger for higher frequencies than for lower frequencies: the decay goes faster for higher frequencies

The base MSP_0, both upstream and downstream, is larger for the silent regulator RQX than for the non-silent regulator RVX. The "silent" regulator is producing more noise inside the pipe in the range of 50-500 kHz, than the "noisy" one. The ratio of noise for the two regulators RVX and RQX is not the same at the different sides of the regulator: upstream it is 0.5, downstream 0.9. These ratios change slightly with frequency.
Also, the base MSP_0 is much larger downstream than upstream for both regulators. This means that more noise is measured downstream of the regulator than upstream. The ratio downstream-upstream noise is not the same for these two regulators: 15 for regulator RVX and 7.7 for regulator RQX. These values are lower for higher frequencies, and higher for lower frequencies. Noise at lower frequencies is thus better "separated" by the regulator than noise at higher frequencies.

4 RESULTS ULTRASONIC METERS

4.1 Presentation of calibration results

The USM's are calibrated against the Gasunie reference flow meters during 3 times 100 s. For confidentiality reasons, the results of the calibrations of each USM in test situations with regulator are only presented as error shifts compared to the mean error of the same meter in "ideal flow": the calibration of the meter at the same pressure, when no regulator is mounted in the line. The results of these "ideal" calibrations are not presented in this paper.
A calibration of a USM under noise disturbed conditions is only sensible if the meter is functioning continuously. If one or more USM's are partially failing, one should assess its performance in another way, for example with a performance comparison method as described below.

4.2 A Performance Comparison Method

As ultrasonic meters are based on a measuring principle using a beam of sound, it is likely to expect that they may be disturbed by sound in the right frequency range and/or of sufficient power. Field experience learns that this is indeed the case. When both the ultrasonic beam and noise reach the receiving sensor of the USM, it will be more difficult or even impossible to detect the right signal out of it and from that, calculate a correct gas flow velocity. The output that is shown to the user, in this case the frequency of the pulse output, depends on signal strength, signal detection, analysis techniques and often also on user-set parameters.
The following four types of behaviour and the effect on the error curves of the meter, were observed in the experiments. In brackets the number of meters that showed this behaviour is given; one meter may be in different categories.

1 The meter fails, and the pulse output frequency is set to zero Hz. If the failure is complete, a meter error E of -100% will be found. If the meter only part of the time is failing, the error will be smaller. (4 meters).
2 The meter fails, and the pulse output frequency is set to a user specified "error-frequency", usually a frequency much higher than the maximum flow rate frequency. If the failure is complete, a high error E will be found. The value of E is dependent of the error-frequency, the frequency factor and the actual flow rate. If the meter is only partially failing, then the more it fails, the higher the meter error is. (1 meter).
3 The meter continues working but with a larger output variation. In the error curve more scatter will be observed. If the variation is on a relatively small time base, it is filtered out during the measurement time of in this case 100 s. (2 meters).
4 The meter continues working but with erroneous output. The resulting error shift is usually of several percents. The wrong output may be steady or switching between distinct values (2 meters).

For every test condition, each USM is given a "performance number" according to the scheme below. From all these performance numbers for each test set-up (USM's upstream or downstream of the regulator, the latter at two distances), a mean performance number P_i is calculated for each individual USM and P_m for all USM's together[2].

100 %	IF	USM functions correctly all the time	AND meter error E is smaller than 1 %
90 %	IF	USM functions correctly all the time	AND E lies between 1 and 5 %,
	OR	USM functions but shows some alarms	AND E is smaller than 1 %
75%	IF	USM functions all the time	AND E lies between 5 and 20 %,
	OR	USM functions but gives regular alarms	AND E lies between 1 and 5 %
	OR	USM fails sometimes	AND E is smaller than 1 %
50 %	IF	USM fails sometimes	AND E lies between 1 and 5 %
	OR	USM functions only half of the time	AND E is smaller than 1 %
25 %	IF	USM functions only sometimes	AND E is smaller than 1 %
	OR	USM functions half of the time	AND E lies between 1 and 5 %
	OR	USM functions (almost) all the time	AND E is larger than 20 %
10 %	IF	USM functions only a few times shortly	
0 %	IF	USM is not functioning at all	

4.3 Results with USM's Upstream of the Regulator

Figure 17 and 18 show meter error shift curves for all six USM's located near the middle of the test section, upstream of the regulator which is mounted at the downstream end of the test section (RVX-DN and RQX-DN). These are the results of the experiments with fixed upstream pressure, 15, 24 or 36 bar(a), and varying flow rate. The curves are given as error shifts relative to the meter error $E_{mean, Base}$ from the calibration of the same USM at the same pressure but in absence of the regulator (see 2.6 and 4.1).

Except for the lowest flow rates, almost all error shifts are well within ±2 %. Although the noise is at relatively low level in these situations, at the lowest flow rates of less than 1.5 m/s, the shifts of some USM's are much larger: within ±15%. As almost all USM's kept on functioning almost all the time, the mean performance numbers P_m are 94% with the non-silent RVX regulator, and 93% with the silent RQX regulator. All meters were in one way or another affected by the noise, the maximum P_i was not 100% but 98%. For some USM's the noise from silent regulator RQX was more severe than the noise from non-silent regulator RVX: the lowest individual performance numbers P_i were 81% (RQX) vs. 91% (RVX).

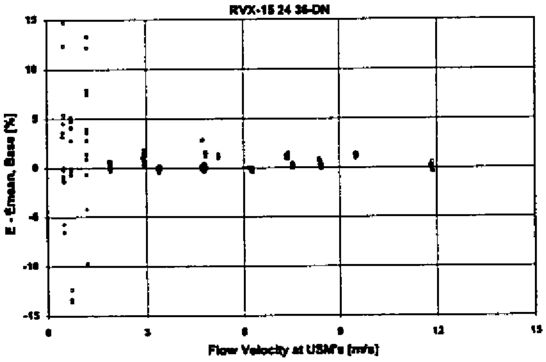


Figure 17: USM's Meter Error Shifts Upstream of Non-Silent Regulator RVX

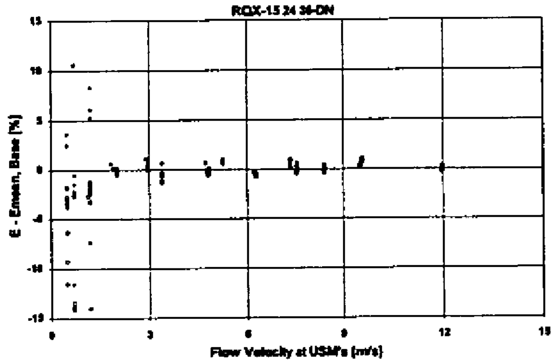


Figure 18: USM's Meter Error Shifts Upstream of Silent Regulator RQX

[2] Note that this is a selection scheme, in which error deviation and failing time are rated as good as equal. If one would appoint more value to the reliability of the answer or to the amount of time it is failing, this scheme and the mean performance numbers P_i and P_m could be quite different.

4.4 Results with USM's Downstream of the Regulator

Figures 19 and 20 show meter error shifts for all six USM's located at the end of the test section, as far as possible downstream of the at the upstream end mounted regulator (RVX-UP-L and RQX-UP-L). These situations are in two ways worse than with the USM's upstream of the regulator: downstream of the regulator the noise is considerably more than upstream, and the USM's operate at a lower pressure. The performance of the USM's is in these cases clearly much less than described above.

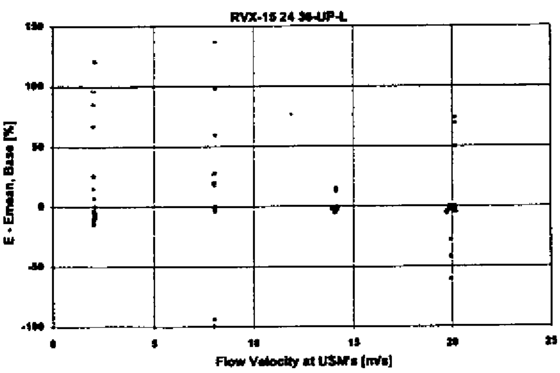


Figure 19: USM's Meter Error Shifts Downstream of Non-Silent Regulator RVX

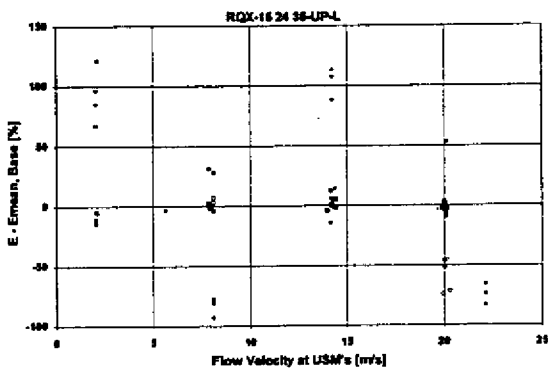


Figure 20: USM's Meter Error Shifts Downstream of Silent Regulator RQX

The figures show the 4 different meter behaviours, see 4.2:

1. USM's partially failing and, when failing, giving zero Hz output: error shifts of -50 to -100 %
2. USM's partially failing and, when failing, giving a (high) error frequency: error shifts of more than +50% (these may also be even more than +100%)
3. USM's that continue working, but output shows more fluctuation: the variation in data points around the x-axis is about twice as much as in figures 17 and 18.
4. USM's that "jump" between modes: mean error shift gives more variation, and may become very high (open circles).

With the non-silent RVX regulator the individual performance number P_i ranges from 34 to 87, and mean performance number P_m is 64 with a standard deviation of 22, and with the silent RQX regulator P_i ranges from 25 to 83; P_m is 58 with a standard deviation of 24.

When the USM's are located near the middle of the test section, which is closer to the regulator, more meters stop functioning, or are functioning less. Mean performance numbers P_m in these cases are: 53 with the non-silent RVX regulator and 49 with the silent regulator.

5 DISCUSSION

Before drawing conclusions, one should bear in mind the following:

- The situations tested here will always differ from field situations, and not only by the type and size of the regulator. For example the pipe work near the regulator (bends, valves, reducers etc.) has great influence on the noise that is measured in a certain position, due to reflection and/or absorption of noise. The pressure and flow control in the test installation (see 2.1) may influence the measured noise too. This work bears no illusion of being complete, but is more intended to make a step forward towards understanding USM's in noisy conditions.
- Immunity from noise is a subject for new developments for many meter manufacturers. In the past years, a great deal of work has been spent on this. Although this target has not been attained yet, many improvements have already been made.
- All experiments were performed with single path meters. For observing meter behaviour in noisy conditions only this is sufficient. However, for example when meter failure is not complete, the performance of a multi-path USM may be better than described in this paper.

- There is no "best meter". All meter characteristics, such as performance in pulsating flow, response times, maximum flows, error handling, and not to forget immunity from noise are a result of the specific combination of mechanical construction, path dimensions, techniques of sending and detecting of signals, signal analysis, filtering, etc. Many of these characteristics may also be influenced by a number of user-set parameters. For example: during the experiments, one meter kept on operating in almost all test conditions, albeit at the expense of large output variations; another meter was clearly indicating when it was failing, but if it was operating the output was highly reliable (no significant error shift nor variations). This makes it difficult to compare USM's, and select a "best one". A user should identify his specific conditions and needs, and select a meter accordingly.

6 CONCLUSIONS

- In-duct sound measurements near a Mokveld regulator were performed in which a "non-silent" RVX and a "silent" RQX internal cage were used. The regulator with RQX cage produces indeed considerable less audible noise outside the pipe, but more ultrasonic noise inside the pipe than with the RVX cage.
- The measured mean sound pressures of the noise fit logarithmically with the product of flow rate through and pressure difference across the regulator.
- Downstream of the regulator more noise was measured than upstream, and also relatively more low frequency noise.
- With distance the noise decays exponentially, and this decay is stronger for higher frequencies. The exponent C is larger upstream than downstream, which is a result of the frequency distribution: upstream relatively more higher frequency noise was registered.
- USM's may behave differently when subjected to noise: 4 different categories of behaviour were described. Many factors, including user-set parameters, influence the type of behaviour a meter adopts in a given situation.
- In general, a USM functions better when it is mounted upstream from the regulator, where the sound pressure is considerably less, and the operational pressure is higher. Furthermore because of the frequency distribution, the noise decays a bit faster than downstream, thus the effect of shifting the meter away from the regulator is larger.
- The mean performance of all USM's with the non-silent regulator cage RVX is better than with the silent cage RQX.
- The worst case (USM's at close distance to RQX regulator) still resulted in a mean performance number of 49%. The best case resulted in a mean performance number of 94%. This indicates that it is indeed possible to measure gas flows with USM's in the vicinity of a regulator. However, at this moment not with all meters and not under all circumstances.
- The work described in this paper is far from complete. In order to get a full picture of noise generated by regulators, future research could perform similar experiments under different circumstances: other pressure reducing devices, different flow and pressure regimes, varying distances to the regulator, and studying the effect of other devices such as bends and diffusers in the flow.
- Manufacturers of USM's have done a great deal of work on immunity from noise, and have already reached a number of successes. Although several meters have shown very good performances, no meter is perfect under every condition. Further development will be necessary. From the users point of view, more co-operation between the manufacturers could be a good idea.

7 ACKNOWLEDGEMENTS

The authors wish to express their gratitude to all who contributed to this part of the GERG project, which are to many to be named here: colleagues from the gas companies participating in the project, representatives from the manufacturers who made available equipment and expertise to the project, and several colleagues from within Gasunie.

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9 NOTATION

dP	Pressure difference across regulator	[bar]
E	Meter Error $(Q_{meter} - Q_{reference})/Q_{reference}$ * 100 %	[%]
$E_{mean, Base}$	Mean Meter Error in baseline calibration at the same pressure	[%]
MSP	Mean Sound Pressure	[Pa]
P_i	Performance number for individual USM, based on all test conditions	[%]
P_m	Mean performance number for all USM's, based on all test conditions	[%]
USM	UltraSonic (gas flow) Meter	[-]
Q	Flow rate	[m^3/h (s)]
V	Valve position in percentage of maximum (=open)	[%]
x	Distance to regulator	[mm]

Tests are indicated with codes in the form RRR-FF-PP-N, or parts of these., which stands for:

RRR =	RVX or RQX	Regulator with standard "non-silent" cage RVX or with "silent" cage RQX
FF =	9, 15, 24 or 36	Test pressure of 9, 15, 24 or 36 bar(a), and variable flow rate
FF =	LO or HI	Flow rate is LOw or High, 6800 or 17000 m3/h (s), pressure variable
PP =	UP or DN	Regulator at UPstream or DowNstream end of the test section
N =	M, L	USM's spool piece at Medium or Long distance from regulator

APPENDIX A

Table A1: Indication of local gas velocities in m/s at USM's for each flow rate as a function of pressure at USM's.

Flow rate in m3/h(s)	USM's donwstream of regulator 9 bar(a)	USM's upstream of regulator 15 bar(a)	USM's upstream of regulator 24 bar(a)	USM's upstream of regulator 26 bar(a)
27000	32	19	12	8
22000	26	15	10	6
17000	20	12	7	5
12000	14	8	5	3
6800	8	5	3	2
1700	2	1	1	1

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FOCUS DISCUSSION GROUP E

LIQUID ULTRASONICS

G Brown, National Engineering Laboratory

ULTRASONIC METERING OF LIQUID HYDROCARBON FLOWS

Gregor J Brown, National Engineering Laboratory, UK

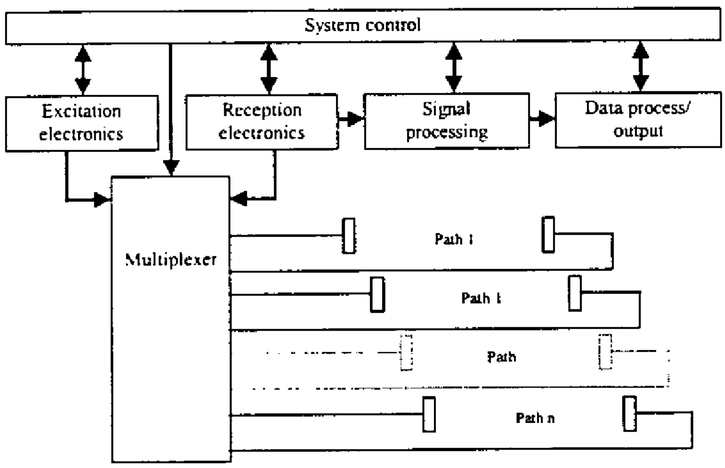
1 INTRODUCTION

Use of transit time ultrasonic meters for high accuracy demand applications in the North Sea is on the increase. This is obviously due to the economic and operational benefits related to the technology. It is however a relatively complex technology area and one in which there is great scope for variation in meter design and manufacturing quality. This paper is intended to promote discussion of the developments required to enable successful deployment of ultrasonic meters for liquid metering duties.

2 METER SELECTION

Meter selection would appear to be a good place to start discussion but it is not a trivial matter. As anyone who has looked through the manufacturers product literature knows, there is no such thing as a standard ultrasonic meter. Variations that influence performance and behaviour can exist in all the elements that make up the flowmeter as illustrated schematically in Figure 1. The function and behaviour of each of these elements is by no means transparent.

FIGURE 1
A schematic diagram of a transit time ultrasonic flowmeter system



In addition to the excitation, reception and signal processing elements of Figure 1, there are variations in the way that the transducers can be configured. These configurations (single path, multiple paths, crossed paths, bounced paths etc.) are at least apparent, if somewhat confusing at times. Although the transducer configuration constrains the information available to the data processing stage it does not dictate how the data is processed.

Selection of an appropriate meter requires that all the important requirements and considerations for a given application are identified. These can then be ranked in order of significance and a score given for each selection option in turn. For this approach to be successful, detailed information is required. Such information can generally be classified as one of three types.

- Vendor information
- User experience
- Independent information

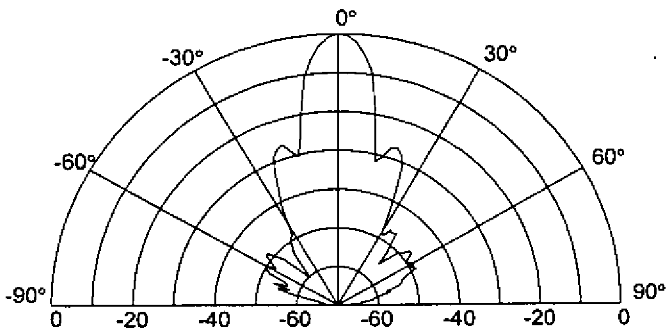
Each of these types of information has its uses and limitations. On balance at present it would appear that independent data is particularly scarce.

3 PRODUCTION CONTROL

Testing of specific designs and models, manufacturing quality control and factory calibration are factors which determine the potential performance of individual units that are delivered to the end user.

Type testing should be undertaken for all new designs and any significant alterations to components or systems. Both a representative sample and range of units should be tested over the full range of acceptable operating conditions. Extrapolation of test results to other configurations or application conditions must have a sound basis to be acceptable.

FIGURE 2
The directional response (in dB) of an ultrasonic transducer



Manufacturing quality control is important in order that the performance of units sold conforms to the results of type testing. An area of quality control that is critical is transducer manufacture, from production of the piezoelectric element to final assembly. Variability in characteristics of assembled transducers is well known (if not yet fully understood) and can affect the ultrasonic waveform and the radiation pattern significantly.

In turn this can influence meter behaviour. If, for example, variations in the radiation pattern are apparent, the effective path of the ultrasound through the fluid could be affected. It is likely that transducer characterisation will be an integral part of production and quality control for high accuracy meters.

4 CALIBRATION

Calibration is normally undertaken in the factory prior to delivery. 'Dry calibration' involves measurement of the meter body and path geometry in order to determine a theoretical calibration factor. The dry calibration process may also involve determination of offsets in transit time measurements by filling the meter body with static fluid (usually of known acoustic properties.

'Wet calibration' involves a comparison with results from a test rig in the factory or an independent laboratory. Normally the results are then used to adjust the factor determined by dry calibration. Wet calibration is preferable until improvements in the accuracy of dry calibration can be achieved and confidence in the approach can be established. The uncertainty and traceability of measurements made in a calibration facility are of utmost importance if the results are to be used in computation of the volume passed through the meter.

In the case of clamp-on meters, the results of wet calibration are only truly applicable if the transducers and pipe are treated as a complete assembly and installed as such. Even when the pipe in the field is the same as that used in the calibration facility, removal and replacement of the transducers will contribute to the uncertainty of measurement once the meter is installed.

FIGURE 3
Recalibration of a clamp-on meter following removal and replacement of transducers

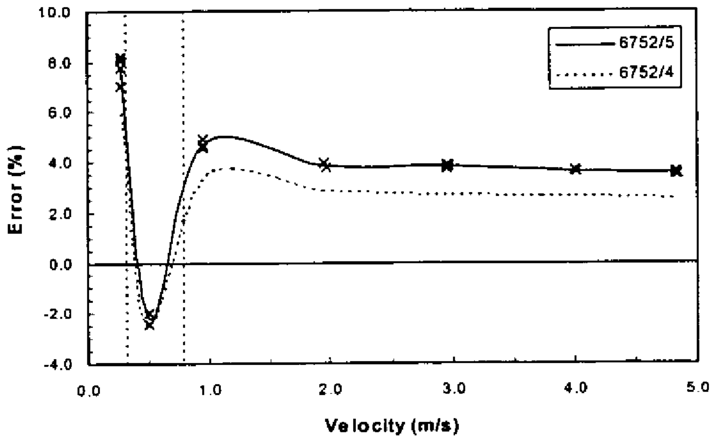
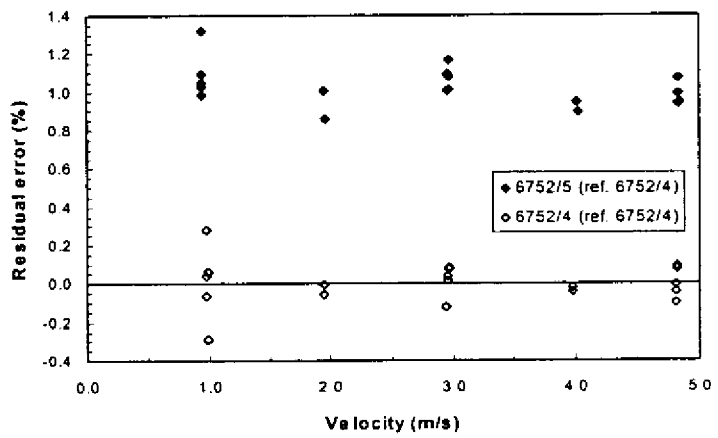


FIGURE 4
A plot showing residual errors with respect to the baseline calibration



This is illustrated in Figure 3 which shows the results of laboratory calibration of a clamp-on meter on 6-inch carbon steel pipe. Between the initial calibration (shown by the dotted line) and the repeat calibration (shown by the solid line) the transducers and mounting fixtures were removed from the pipe and replaced. Figure 4 shows the residual errors with respect to a second order polynomial curve fit to the initial calibration points above 1 m/s.

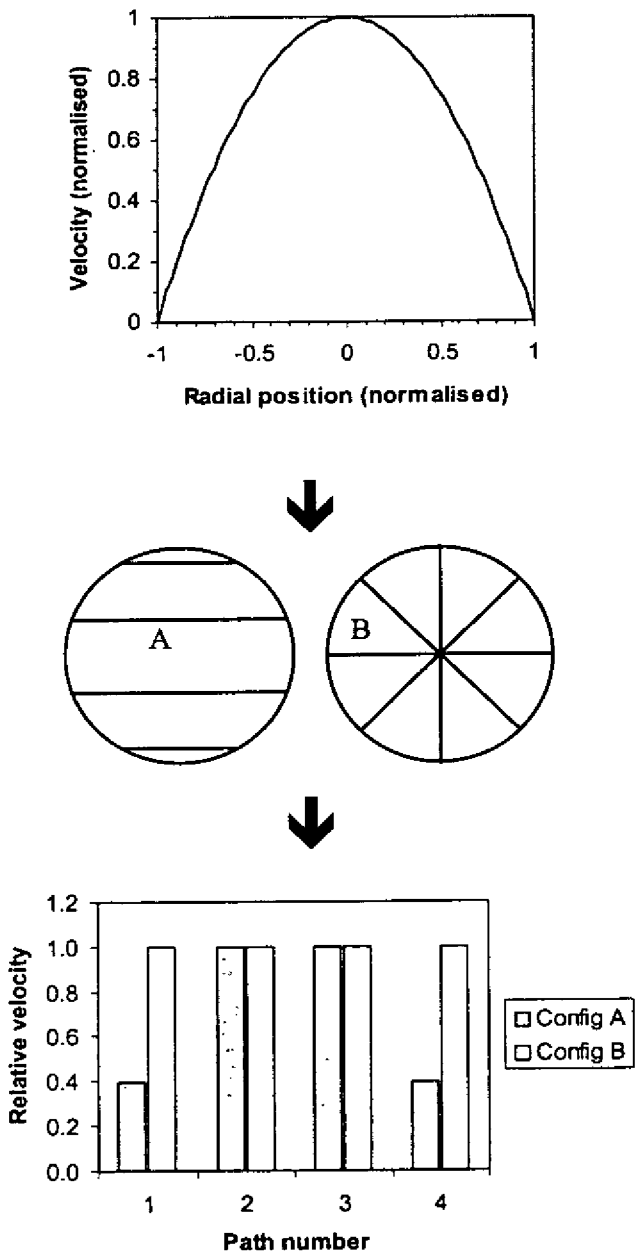
For high accuracy demand applications calibration conditions should match application conditions as closely as possible. In terms of flow conditions this is normally taken to mean that either velocity or Reynolds number should be matched. In some cases (e.g. low velocity and low Reynolds number) it may be necessary to match both, as either may have a significant influence on performance.

Wet calibration of large meters can present a problem when attempting to match both Reynolds number and velocity ranges as few facilities have high capacity, the ability to vary viscosity, and an accurate and traceable reference. In this situation it may be that use of a water calibration facility is an option, in which case it is more appropriate to match the velocity range. Dry calibration may also be an option as relative uncertainty in dimensional measurement is reduced. In ether case the applicability of the approach should be demonstrated by experimental results which demonstrate the accuracy of the alternative calibration procedure in practice under similar conditions.

5 INSTALLATION

Installation requirements will vary from meter to meter and with application conditions and performance requirements. In this discussion the term 'installation effect' is taken to mean the error in reading due to the presence of transverse velocity components (cross-flow and swirl) and distortions of the axial velocity profile. In general, the greater the number of paths, the less sensitive to the meter will be to velocity distribution. However, this being said, it is important to realise that the arrangement of the paths and the scheme employed to combine the measurements is generally more important than the number of paths employed.

FIGURE 5
An illustration of the relationship between velocity distribution and transducer configuration



To illustrate the importance of path configuration, consider two different flowmeter configurations applied to the same flow which has an axisymmetric velocity distribution. In configuration B all paths exhibit symmetry with rotation about the axis and therefore all measure the same value of velocity. Configuration B has paths on two chords with respect to the symmetry of the profile and therefore provides additional information that can be utilised in estimating the mean velocity.

Quantification of installation effects is a difficult area to address properly due to the wide variation in configurations and orientations. Sweeping statements on the subject should not be accepted as credible. For example, it has been suggested that ultrasonic meters are insensitive to small steps in bore upstream and downstream. This may be the case for configurations which are inherently less sensitive to variations in velocity profile (such as configuration A) but is almost certainly untrue for the likes of configuration B as the meter would have no ability to sense an axisymmteric distortion of the flow.

Installation effects are also likely to vary with meter size. As meter size increases, the disturbing effects of the transducer recesses and effects due to the finite size of the transducers will reduce. This does not necessarily mean that larger meters will perform better, these effects may increase or decrease the magnitude of an installation effect, depending on the pipework and transducer configuration.

In the short-term experimental testing is the preferred method of determining installation effects on ultrasonic flowmeters. However, with further development it is likely that computational fluid dynamics will provide a useful means of assessing potential installation effects.

6 OPERATION AND VERIFICATION

Once a meter has been selected, properly calibrated and installed, some means of verifying that the meter continues to operate properly is required. Ultrasonic meters have an advantage here in that being non-intrusive and having no moving parts they are not so susceptible to wear and tear as turbine meters for example. It could be presumed that if you install one of these meters and continue to get a credible output then there is nothing more that need be done. Unfortunately in real world things can go wrong with the meter and process conditions can change.

Generally ultrasonic meters have self-checking and fault diagnosis capabilities within electronics modules and processors. In more sophisticated models the capability extends to signal analysis in the transit time electronics and analysis of data time series. This can be very useful in indicating a problem due to, for example, entrained gas attenuating the ultrasonic signals.

There are some fairly common approaches to measurement and reporting of signal parameters. For example, most modern meters will report the automatic gain control (AGC) level being used to amplify the input to reception electronics. What is lacking however, is adequate description of how these parameters are used to actuate fault conditions. More important than this even, is the lack of information or data that demonstrates a correlation between the measured parameters and meter performance.

Some parameters measured in a given meter, such as the computed velocity of sound (VOS), obviously have no direct relationship with performance. This being said velocity of sound is used to determine changes in the fluid and can be cross-checked with VOS determined from external information. Others, such as a measure of signal-to-noise ratio, may have a more direct relationship to performance. This is demonstrated by the results of a series of oil/gas tests on a clamp-on meter installed on 4-inch pipework. As shown in Table 1, for all flowrates greater than 10 l/s repeatability is seriously degraded when the meters signal strength parameter falls below 5 % at conditions of increased gas volume fraction (%).

TABLE 1
Minimum observed signal strength at each flow condition

Nominal flowrate	GVF	Signal strength (%)	Repeatability (%)
10 l/s	2.5 %	100	5.12
	7.5 %	100	8.91
	22.5 %	4.8	8.15
30 l/s	0.75 %	80	3.53
	1.5 %	26	3.51
	4 %	3.4	22.19
50 l/s	0.35 %	17	2.02
	0.7 %	6	5.46
	1.5 %	1.9	101.14
70 l/s	0.4 %	15	4.46
	0.8 %	1	23.26

What an ultrasonic meter can not do at present is monitor the condition of the meter body and adjoining pipework. If degradation is serious enough, it may be possible to detect a change via velocity profile by analysis of relative velocities in multipath meters. It is also likely that deposits on transducers can be detected. However, it is less likely that a thin deposit on the interior of the meter body could be detected.

Changes to the internal bore are of great importance as any reduction in cross section will produce an equivalent error in volumetric flowrate. It would appear then, that until more progress is made it will be necessary to perform routine checks, either by inspection or by periodic calibration. Alternatively, appropriate material selection or regular cleaning may minimise the potential problem.

7 REDUNDANCY AND FAILURE

Failure of components or systems can occur for a variety of reasons. For example, it could be that a transducer cable is inadvertently damaged during work on an adjacent item of equipment or that an electronic component on a board fails. In any case, reasonable allowance for these sort of 'random' failures should be made within any metering system. With respect to ultrasonic meters, where multiple transducers and modular designs are common, it is possible to incorporate redundancy into a single meter design. Where in-built redundancy involves a change to the system function (e.g. computing flowrate based on a three-path rather than a four-path scheme) the effect of the (potential) failure on performance should be properly evaluated.

Some modes of failure (such as 'fatal' signal attenuation due to entrained gas) may render the meter inoperable in the short-term but permit unassisted recovery after the event. This type of failure may be inconsequential if it is of relatively short duration or may have significant consequences. If the later is the case, it may be that an alternative technology is required to guarantee continuous measurement.

8 MAINTENANCE, REPAIR AND UPGRADE

FIGURE 6
Recalibration of an ultrasonic meter following exchange of the electronics

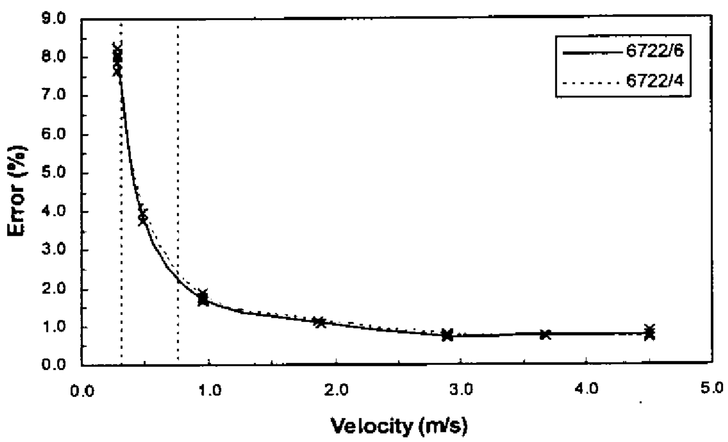
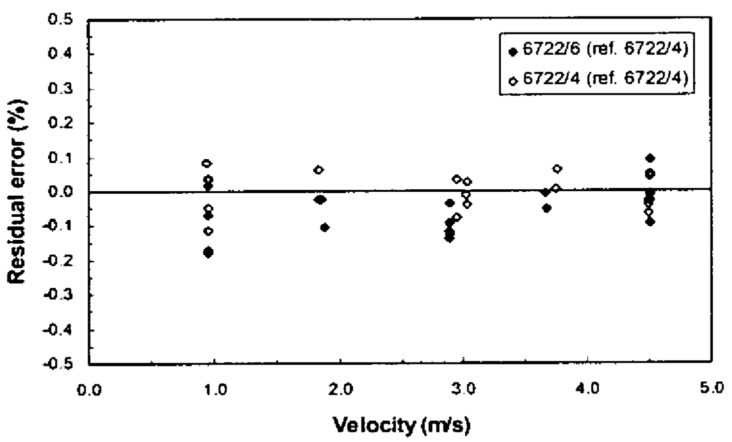


FIGURE 8
A plot showing residual errors with respect to the baseline calibration



As mentioned earlier, in an ideal world the ultrasonic meter should not require user intervention once properly installed and set-up. However, it may be necessary in the long run to perform some maintenance or repairs, or it may be beneficial to upgrade hardware or software. In any case caution should be exercised to ensure that calibration is not compromised.

Recent tests at NEL have shown the exchange of the electronics to have minimal effect on the calibration of a selection of 6-inch ultrasonic meters. One such result is shown in Figures 6 and 7. Figure 6 shows the baseline calibration as a dotted line and the calibration following the exchange as a solid line. Figure 7 shows the residual errors with respect to a second order polynomial curve fit to the initial calibration points above 1 m/s. Following the exchange of the electronics, the residual errors are less than ± 0.2 % and have a mean value of -0.072 %.

These results indicate that electronics can be exchanged without significantly affecting calibration. However, it should be noted that both sets of electronics were supplied at the same time by the manufacturers. As such it is advised that spare electronics be obtained at the time of purchase, otherwise good practice would dictated that the meters be recalibrated.

9 CONCLUSIONS

Ultrasonic meters based on the transit time principle can appear to be both deceptively simple and confusingly complex. For example, the theory of operation presented in most technical papers makes little reference to assumptions that have been made. At the same time, a higher degree of 'intelligence' than is generally feasible is often implied (especially with respect to signal detection and sensitivity to velocity distribution). At present the only rigorous way to determine the validity of manufacturers claims is by undertaking experimental evaluation. This will normally necessitate laboratory tests as performance evaluation in the field tends to be limited in terms of the range of conditions that can be obtained and the availability of an accurate and traceable reference. As such field trials very often do little more than demonstrate the reproducibility and reliability of a device rather than producing data to allow quantification of uncertainty in measurement.

In order to employ the technology more effectively and with greater confidence, operators will require a detailed knowledge of ultrasonic meter performance in relation to high accuracy demand applications. To meet this need NEL are initiating a Joint Industry Project (JIP) *The Evaluation of Ultrasonic Meters for Oil Flow Duties*. The mainstay of the JIP will be laboratory evaluation of the most commercially advanced devices across a range of flow conditions. For example, temperature, viscosity and two-phase flow effects will be determined. It is envisaged that this project will focus development in the technology area and lead to the development of testing and certification guidelines for custody transfer and fiscal applications.

ACKNOLEDGEMENT

Aspects of this paper are based on work carried out as part of the Flow Programme, under the sponsorship of the DTI's National Measurement System Policy Unit.

Main Index

North Sea

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1998

PAPER 29

FOCUS DISCUSSION GROUP F

MEASUREMENT UNCERTAINTY

M Basil, Flow Ltd

The Application of Monte Carlo Simulation to Measurement Uncertainty

Martin Basil

of

FLOW Ltd

16th North Sea Flow Measurement Workshop 1998

Gleneagles, 26-29 October 1998

Overview

- Background
- Explanation
- Example
- Applications

Background

- Wide use for risk analysis in business and industry
- First used in 1908 to confirm Student t-distribution
- First applied on the "Manhattan Project"
- Only method to solve some classes of problem
- Use limited by need for fast computers

3

•Widely used in business and on large projects for risk assessment and decision making

•First practical application in 1908 by William Sealy Gosset (Student) in the discovery of the correlation coefficient and later the same year to confirm his Student t-distribution findings

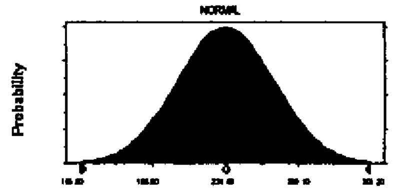
•First real application stems from development of the atomic bomb "Manhattan Project" during the second world war

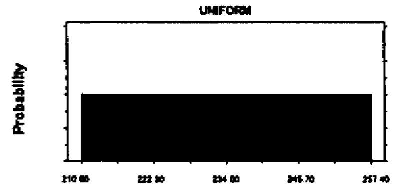
•Until recently the need for fast computers has prevented wider application in areas such as uncertainty assessment

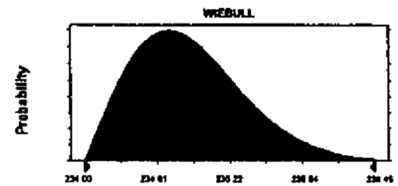
•

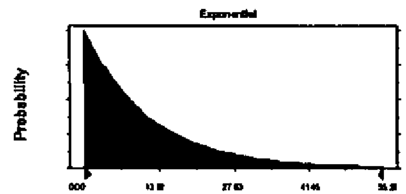
Explanation 1 Input Sensors

- Simulate measurement sensors
- Inputs may have any distribution
- Typically a "normal" distribution...
- ...with a "mean"
- ...and "standard deviation" based on the measurement uncertainty at a 95% confidence level i.e. 2 std. dev.









Explanation 2 Model

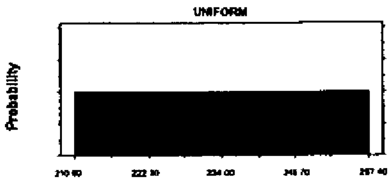
- **Simulated input sensor values are applied to a mathematical model of the measurement system**

$$x = a + b^2$$

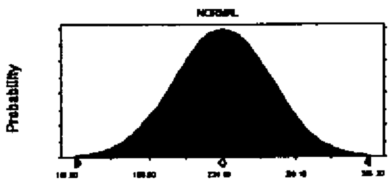
- **Repeated until sufficient trials representing most combinations of sensor values**

Explanation 3 System Output

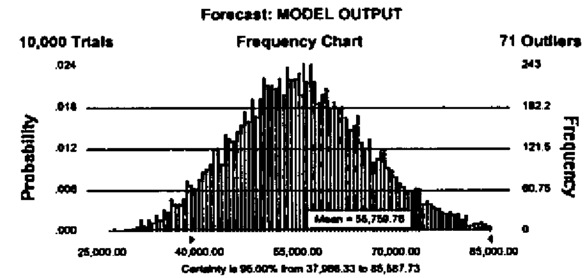
a



b



$$X = a + b^2$$



X

Measurement System Output Uncertainty is found from the "mean" and "standard deviation" of the distribution X

i.e. Uncertainty at 95% confidence level = 2 std. dev.

Example Analytical Uncertainty

Stream 1

Gas orifice plate flow meter

Q_1 = 10mmscfd

E_1=1%

Stream 2

Gas orifice plate flow meter

Q_2 = 10mmscfd

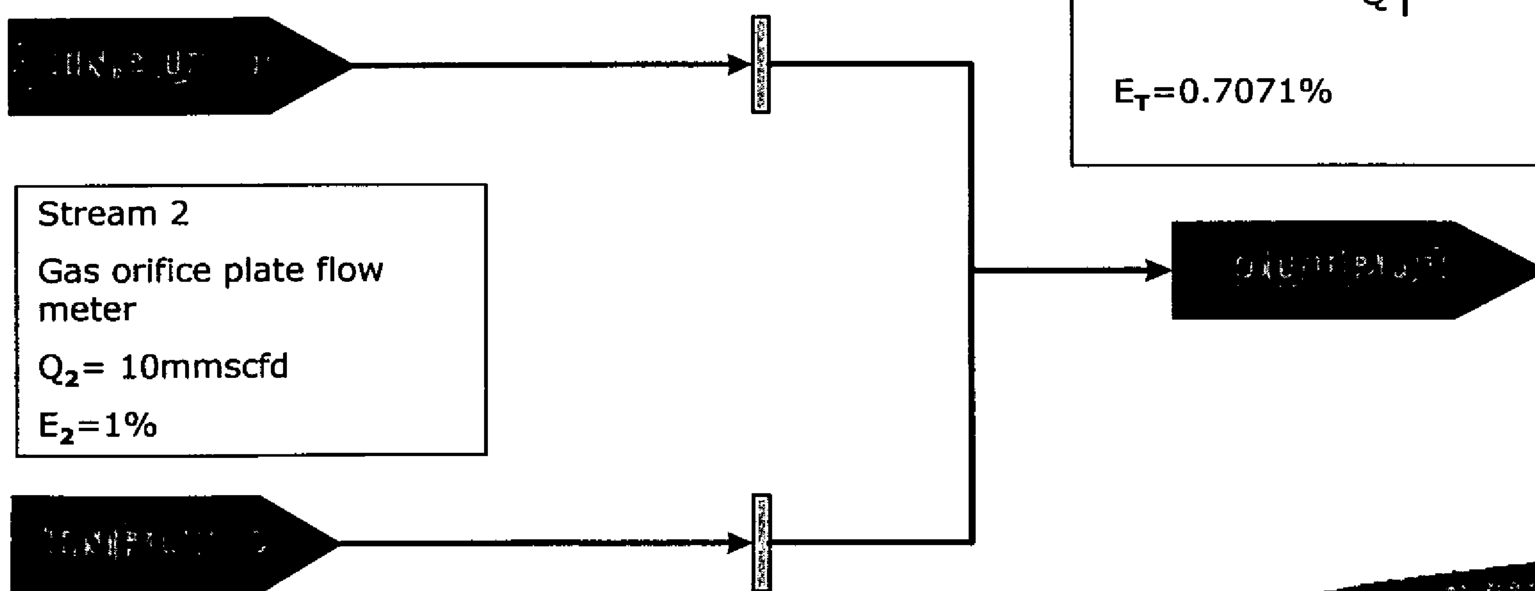
E_2=1%

Total Gas

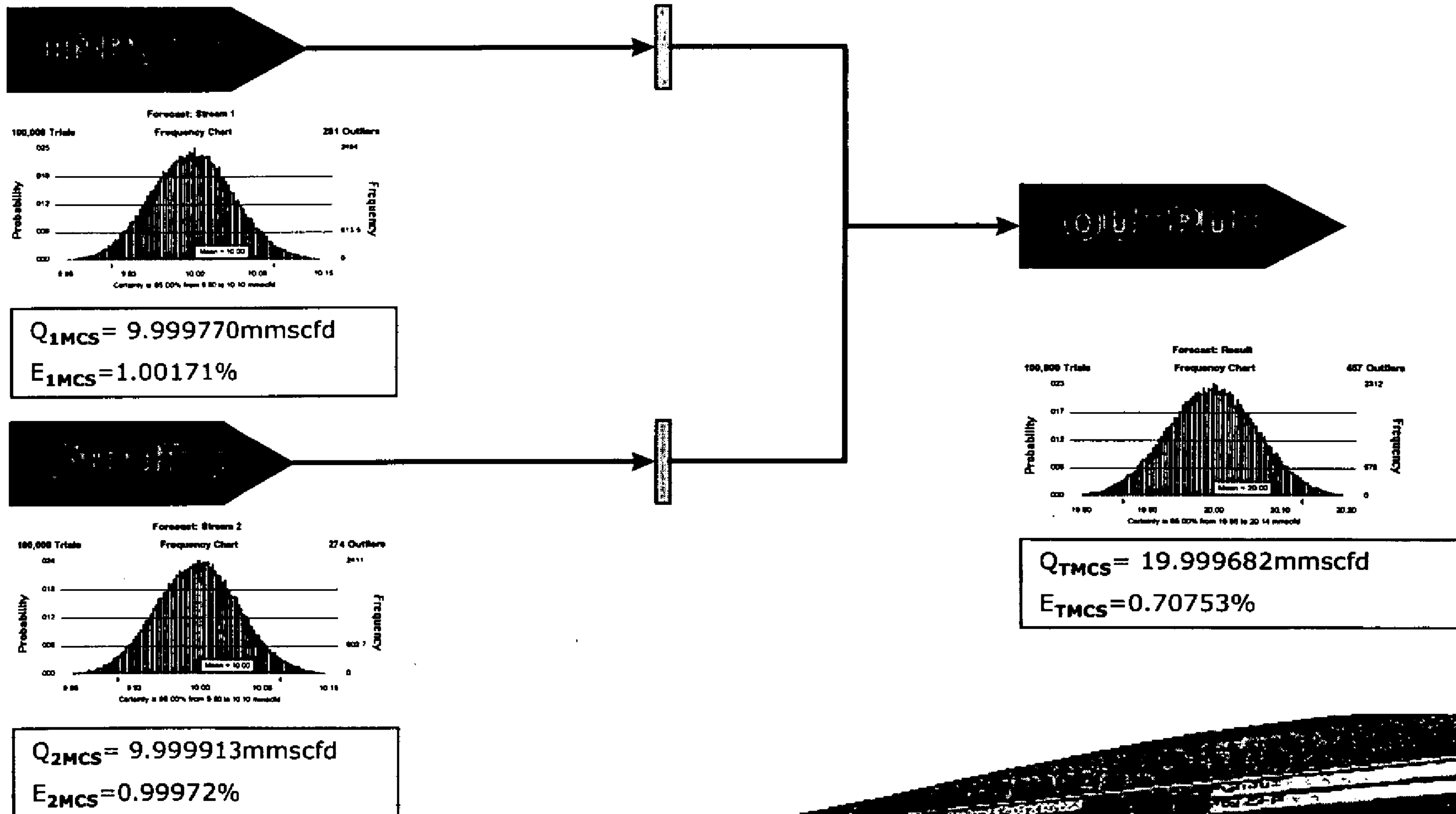
$Q_T = Q_1 + Q_2 = 20$mmscfd

$$E_T = \frac{\sqrt{(E_1 \cdot Q_1)^2 + (E_2 \cdot Q_2)^2}}{Q_T} \%$$

E_T=0.7071%



Example Monte Carlo Uncertainty



Applications

- Verification of analytical methods
- Large number of inputs or outputs
- Complex calculations and Non-linear relationships
- Large measurement uncertainty i.e. MPM
- Dependant inputs
- Unconventional input or output distributions

North Sea

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1998

PAPER 30

FOCUS DISCUSSION GROUP G

QUALITY CONTROL & FISCAL METERING

T Folkestad, Norsk Hydro ASA

DESIGN PHILOSOPHY AND EXPERIENCE WITH QUALITY CONTROL SYSTEMS FOR FISCAL METERING STATIONS

Trond Folkestad, Norsk Hydro ASA

1 INTRODUCTION

The long-term aim of Norsk Hydro is to be able to purchase a self contained fiscal metering station, with a fully automated quality control system requiring a minimum of manual preventive maintenance, supervision and routines to operate reliably over long periods of time.

Norsk Hydro has for a number of years worked on improving the design of quality control systems for Fiscal Metering Stations both on existing and new oil installations in the North Sea.

This paper gives a review of the design philosophy and experience with Quality Control Systems for Fiscal Metering Stations, operated by Norsk Hydro. This paper will cover both a manual system for use on existing oil installations, and a fully automated system for new oil installations.

This paper also introduces a new design philosophy for a self-contained Fiscal Metering System not requiring external computer facilities and dedicated interface designs to be operable and maintainable.

The implementation of some of these concepts in the revised NORSOK standards for Fiscal Metering will also be covered.

The paper will conclude with recommendations for implementation of quality control systems for Fiscal Metering Stations.

2 BACKGROUND

Why do we need a better quality control system?

The author started working for Norsk Hydro in December 1992. During 1993 - 94 the following problem areas / challenges were identified within Norsk Hydro:

- Written operations and maintenance procedures were incomplete and difficult to follow.
- Preventive maintenance work descriptions were incomplete or lacking.
- Mix of experienced / inexperienced maintenance technicians on new and old installations.
- Each shift performed preventive maintenance differently on the same equipment, on all installations.
- A wide span of opinions and misconceptions on how to operate and maintain a fiscal metering station on all levels in the operational organisation.
- A very high percentage of measurement errors were due to preventive maintenance, see Table 1.
- Reduction in manning on installations with respect to operation and maintenance of fiscal metering stations. Multi disciplinary functions in stead of dedicated personnel.
- Constant manning onshore but an increase in number of installations over the next few years.

Table 1 - Cause of measurement errors in fiscal metering stations from September 1993 - September 1995.

Platform	Number of measurement errors	Errors due to equipment failure	Errors due to preventive maintenance	Average duration of measurement errors
A	40	25,00%	75,00%	39,54 days
B	19	36,84%	63,16%	79,03 days
C	33	66,67%	33,33%	28,87 days

Based on this it was concluded that a common basis for rational operation and maintenance of all fiscal metering stations operated by Norsk Hydro must be developed. This effort started in May 1993.

A common set of procedures was developed by August 1993 containing templates for check/calibration forms and templates for writing maintenance work descriptions. The maintenance work descriptions have an Actions-Details Format [1] see Fig 1, so both experienced and inexperienced technicians can use them.

Calibration check of temperature element {installation} WORK DESCRIPTION See check form in annex x.y		
GENERAL Calibration check of the temperature element is performed at operating temperature as a single point check. The temperature reference must comply with the criteria for a reference normal for temperature measurement, given in chapter z.x.		
	ACTIONS	DETAILS
_ [1]	Connect the normal for temperature measurement.	If you use a thermometer, it must stabilize for at least 4 minutes, after connection.
_ [2]	Write into form all data for equipment. Write down the temperatures, in °C, and calculate deviation.	Read value from flow computer and normal for temperature simultaneously.
_ [3]	If deviation is greater than ± 0,20 °C, change the temperature element and repeat the calibration check for the new element.	First check for faults and try to get deviation within acceptance limits.
_ [4]	Write in "Performed calibration check for temperature" in the logbook.	Write tag no., line/ position and sign.

Fig 1 Template for writing maintenance work descriptions.

The basic idea was to improve the quality of maintenance of fiscal metering stations by moving the effort from periodic maintenance of all equipment, 1 month interval is the requirement from the Norwegian Petroleum Directorate (NPD), to frequent maintenance of problem equipment and more infrequent maintenance of good equipment.

The study of the cause of measurement errors had revealed that the equipment failed, was damaged or was operated in the wrong way during preventive maintenance. Focus was put on developing a non-intervention maintenance philosophy leaving alone fully functioning equipment. **If it works don't fix it!**

The aim was to be both more effective and efficient, see Fig 2. To achieve that we had to completely rethink our approach on how to do maintenance. Unfortunately the words effective and efficient translates to the same word in Norwegian "effektiv" which despite the way it's written normally is perceived as "being more efficient". So we do the same as always only faster. Our conclusion is given in Fig 2. Better maintenance — less work. Turn from interval based to condition based preventive maintenance for fiscal metering stations.

2.1 Start at Oseberg C

At the same time, in November 1993, the maintenance technicians on the Oseberg C platform had started an improvement program. They were looking at test methods and procedures to increase / maintain the quality and at the same time reduce the use of resources on maintaining the fiscal measurement equipment (do the same as always only faster).

	Norwegian translation	
EFFECTIVE	= Effektiv	(Useful)
and		
EFFICIENT	= Effektiv	(Skill level)

$\Downarrow$

Do the right thing in a better and more rational way,

and not

Do the same as always only faster

$\Downarrow$

For fiscal metering stations this imply :

From
Interval based preventive maintenance

$\Downarrow$

To
Quality control using
CONDITION BASED
PREVENTIVE
MAINTENANCE

Fig 2 Quality control through condition based preventive maintenance.

Why not adopt the new ideas on this platform?

The Oseberg C platform agreed that they should serve as a pilot installation for developing the idea of quality control through condition based preventive maintenance. During the spring of 1994 we together defined the basis for a manual quality control system, improved the content of the preventive maintenance work descriptions and improved test methods.

In the summer of 1994 our EDP department started developing a database application for use in condition based preventive maintenance. This application enables the maintenance technician to verify the condition of the measurement equipment over time and to determine its condition against predefined quality criteria using long-term trend curves, see Fig 3.

Norsk Hydro's plan for implementation of an improved quality control system through condition based preventive maintenance was presented to NPD in a meeting 19.08.1994. Based on feedback from NPD the implementation on the Oseberg C platform started in September 1994.

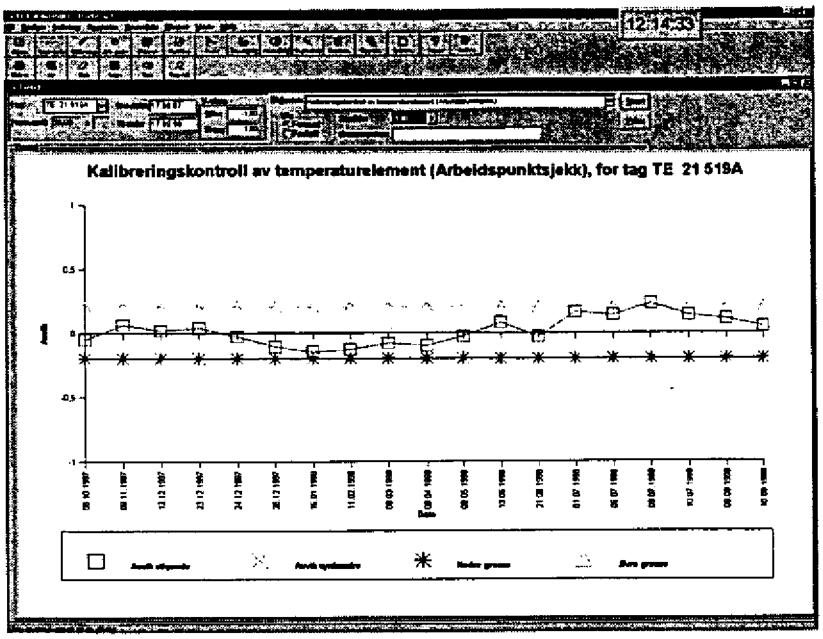
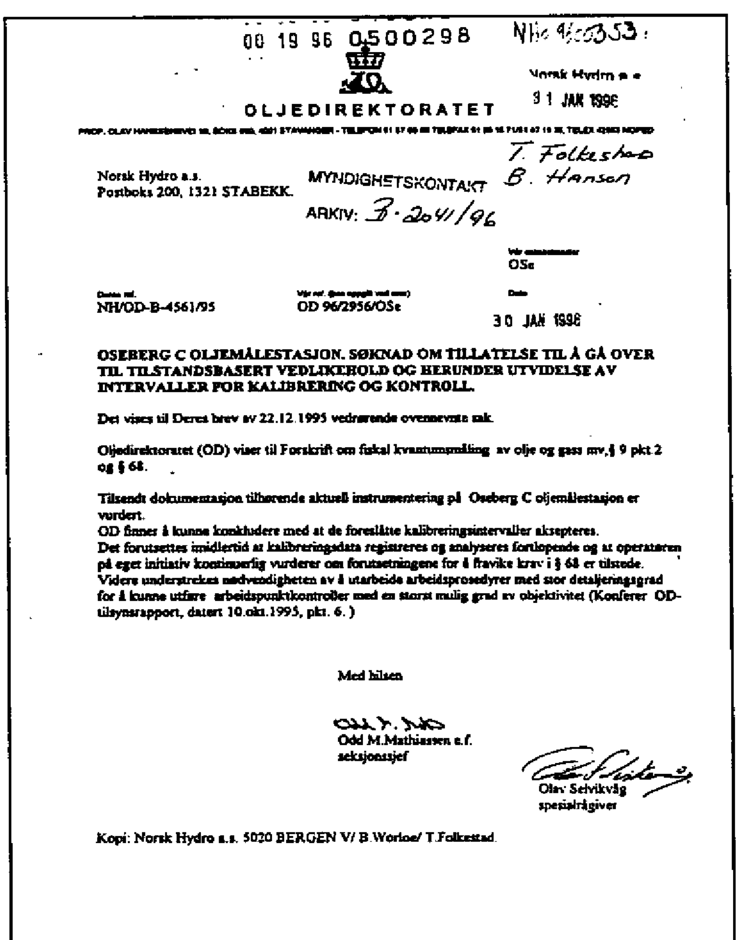


Fig 3 Screen shot showing trend curve function in database application.



00 19 96 0500298 NH 96/00353

OLJEDIREKTORATET

Norsk Hydro a.s.
31 JAN 1996

T. Folkestad
B. Hanson

Norsk Hydro a.s.
Postboks 200, 1321 STABEKK.

MYNDIGHETSKONTAKT
ARKIV: B-2041/96

OSe

NH/OD-B-4561/95

OD 96/2956/OSe

30 JAN 1996

OSEBERG C OLJEMÅLESTASJON. SØKNAD OM TILLATELSE TIL Å GÅ OVER TIL TILSTANDSBASERT VEDLIKEHOLD OG HERUNDER UTVIDELSE AV INTERVALLER FOR KALIBRERING OG KONTROLL.

Det vises til Deres brev av 22.12.1995 vedrørende ovennevnte sak.

Oljedirektoratet (OD) viser til Forskrift om fiskal kvantumsmåling av olje og gass mv,§ 9 pkt.2 og § 68.

Tilsendt dokumentasjon tilhørende aktuell instrumentering på Oseberg C oljemålestasjon er vurdert.
OD finner å kunne konkludere med at de foreslåtte kalibreringsintervaller aksepteres.
Det forutsettes imidlertid at kalibreringsdata registreres og analyseres fortløpende og at operatøren på eget initiativ kontinuerlig vurderer om forutsetningene for å fravike krav i § 68 er tilstede.
Videre understrekes nødvendigheten av å utarbeide arbeidsprosedyrer med stor detaljeringsgrad for å kunne utføre arbeidspunktkontroller med en størst mulig grad av objektivitet (Konferer OD-tilsynsrapport, datert 10.okt.1995, pkt. 6.)

Med hilsen

Odd M.Mathiassen e.f.
seksjonssjef

Olav Selvikvåg
spesialrågiver

Kopi: Norsk Hydro a.s. 5020 BERGEN V/ B.Worloe/ T.Folkestad.

Fig 4 Letter of approval from NPD for quality control through condition based preventive maintenance.

An application for approval was sent to NPD 22.12.1995 and approval was given 30.01.1996. As the first oil company in the Norwegian sector of the North Sea, Norsk Hydro had gained approval from the NPD for use of a quality control system through condition based preventive maintenance on fiscal metering stations, see Fig 4.

3 QUALITY CONTROL SYSTEM

The instrumentation in a fiscal metering station consists of a number of different types of sensors including flow sensors that transmit measured values to a flow computer via instrument loops. All these elements of the metering station must be calibrated and checked in a systematic way to ensure that given quality criteria / uncertainty limits are met.

Maintaining quality through condition based preventive maintenance and not using fixed intervals (1-month interval is the requirement from NPD), requires the identification of suitable conditions to verify and the definition of quality criteria for these conditions. Ideally if a condition always remains within acceptable quality limits, no maintenance is ever required for that equipment.

Condition monitoring can be divided into 3 practices:

1 *Automatic monitoring.* Fiscal metering stations with a minimum of 2 parallel meter runs in operation can be automatically monitored by comparing the same measured values on all meter runs in operation. The quality of this check is limited by the similarity in operating conditions that exists between meter runs in operation. Double instrumentation for the same measured value can be automatically compared and will give high quality condition monitoring.

2 *Daily quality check.* Manual check to compare across parallel meter runs and from day to day using trend curves. Gives lower quality condition monitoring.

3 *Single point check at operating conditions.* The operating conditions on our platforms are very stable and the operating range very small, for most measured values. A single point check at operating conditions is therefor a very god indication of the overall condition of the measurement sensor and will give a very high quality condition monitoring. This is the recommended practice and can be combined with practice no. 1 to give a fully automated quality control system.

Since the operating range is very small, for most measured values, sensors can be calibrated within a range just encompassing the operating range, giving increased measurement accuracy.

Single point check at operating conditions can be performed using several methods depending on the type of sensor and accessibility. Common to all these methods is the use of a measurement reference connected in parallel to the measurement sensor. The difference between the two single point measurements reveals the condition of the sensor. Slowly emerging errors can be detected as well using long-term trend curves.

Several methods for single point check at operating conditions, were evaluated for the Oseberg C platform:

a) Temperature measurement — 3 possible methods:

i) Reference temperature instrument in separate thermowell in close proximity to the temperature sensor to be checked. This will give a check of the temperature sensor as well as the instrument loop. This is a very accurate method.

ii) Double instrumentation using a double Pt-100 element mounted in the same thermowell as the temperature sensor to be checked. This will give a check of the temperature sensor as well as the instrument loop. This is the most accurate method because exactly the same operating condition applies to both measurements, and it can be automated by using a temperature transmitter for both elements.

iii) Comparison across 2 parallel meter runs in operation. This is the least accurate method because of the uncertainty in similarity in operating conditions for both measurements *b) Pressure measurement — 2 possible methods:*

i) Reference pressure instrument temporarily connected to the same pressure tapping point as pressure sensor to be checked. This will give a check of the pressure sensor as well as the instrument loop.

ii) Double instrumentation using a permanently mounted extra pressure sensor connected to the same pressure tapping point. This will give a check of the pressure sensor as well as the instrument loop. This can be automated.

c) Density measurement — 2 possible methods:

i) Manual spot sampling and simultaneous reading of measured value from density sensor. This can be a fairly accurate method for stabilised crude oil but difficult to use for gas and unstabilised crude oil. Not a very accurate method.

ii) Double instrumentation using two density sensors mounted in parallel or series. This is the most accurate method because almost exactly the same operating condition applies to both measurements, and it can be automated.

d) Differential pressure measurement:

i) No acceptable manual method was found so dp-transmitters must be calibrated periodically in a calibration laboratory.

ii) Double instrumentation using two dp-transmitters mounted in parallel. This is the most accurate method because almost exactly the same operating condition applies to both measurements, and it can be automated. This method requires averaging.

4 MANUAL QUALITY CONTROL THROUGH CONDITION BASED MAINTENANCE

A manual Quality Control System for Fiscal Metering Stations on existing installations in the North Sea operated by Norsk Hydro, was first developed at the Oseberg C platform. The design utilises manual Condition Based Maintenance to ensure the quality of measured fiscal quantities.

A comprehensive database application was developed along with detailed procedures to accomplish a high quality control system for Fiscal Metering Stations. The reduction in man-hours spent on preventive maintenance has been significant, at least 25%. Also a significant reduction has been achieved in measurement errors introduced during preventive maintenance along with the reduction in the work involved in correcting these errors. The overall result is a more reliable metering station.

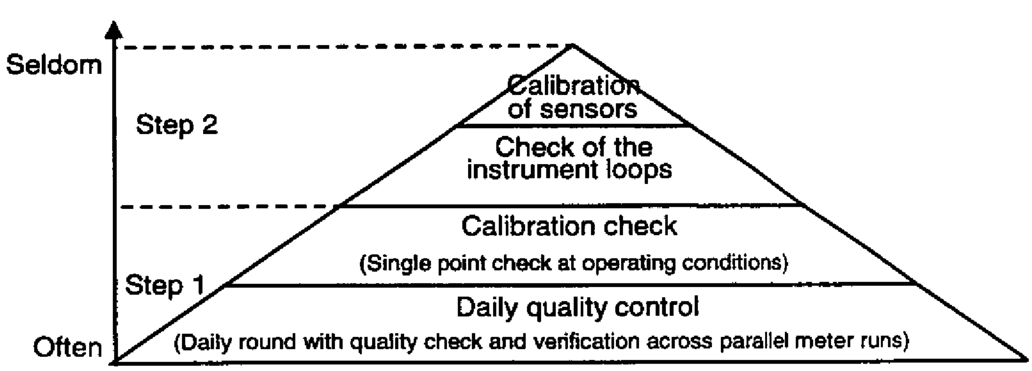


Fig 5 Quality control using manual condition based preventive maintenance. A two-step process.

Manual Condition Based Maintenance is a two-step process consisting of preventive and corrective maintenance see Fig 5 and 6.

Step 1, preventive maintenance, consists of daily quality control and calibration check.
Step 2, corrective maintenance, consists of check of the instrument loops and calibration of sensors.

Step 1 is performed regularly. Only on indication of error will step 2 be performed. NPD requires still that step 2 shall be performed at fixed intervals, but now with much longer intervals (at least 1 year).

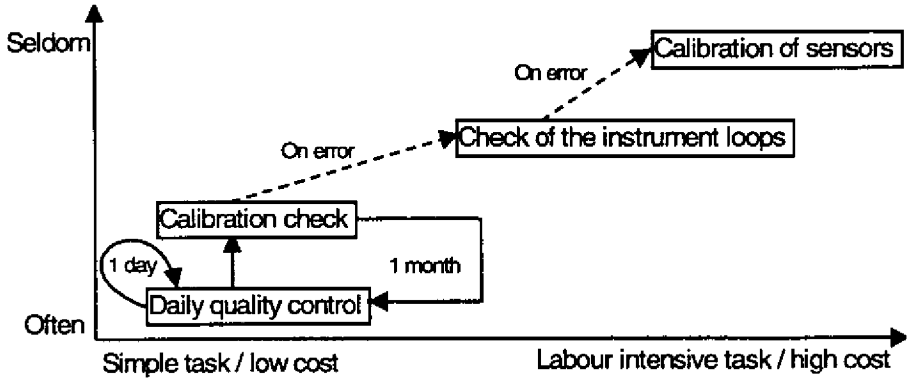


Fig 6 Quality control using manual condition based preventive maintenance. Part of preventive maintenance redefined as corrective maintenance.

All activities relating to condition based preventive maintenance, are registered in the database application, see Fig 3. This database application calculates deviations and enables the maintenance technician to graphically trend the condition of the measurement sensor. This is important in order to follow the development in condition over time and to be able to reveal tendencies of drift or failure in the sensors, as early as possible.

5 AUTOMATED QUALITY CONTROL THROUGH CONDITION BASED MAINTENANCE

A fully automated Quality Control System for Fiscal Metering Stations on new installations in the North Sea operated by Norsk Hydro, was first developed for the Visund platform, to be put in operation in the autumn 1998. The design utilises fully automated Condition Based Maintenance to ensure the quality of measured fiscal quantities.

A comprehensive functional design specification for design of both novel and conventional metering stations has been developed since 1996 to accomplish a high performance fully automated quality control system for Fiscal Metering Stations. The functional design specification has been developed in co-operation with Kongsberg Offshore (KOS) the frame agreement supplier of fiscal metering stations for Norsk Hydro. The key design features are to use double instrumentation in each measurement point wherever applicable as well as utilising the computer resources to perform automatic monitoring of critical functions and automatic verification and calibration of flow elements. The man-hours spent on operation and preventive maintenance will be reduced by at least 80% and the measurement errors introduced during preventive maintenance will be almost eliminated. A significant reduction in Life-cycle-cost for a metering station will be achieved. The overall result will be a considerably more reliable metering station.

The payback period will be less than 1 year after start of operation, for the investment in a fully automated quality Control System for the Fiscal Metering Stations on the Visund platform.

Fully automated Condition Based Maintenance is like the manual version also a two-step process consisting of preventive and corrective maintenance.

Step 1, preventive maintenance, consists of quality control and calibration check and is performed automatically by the Metering station database computer.
Step 2, corrective maintenance, consists of check of the instrument loops and calibration of sensors.

Step 1 is performed automatically. Only on indication of error will step 2 be performed. NPD requires (letter to all operators dated 18.11.1997) that step 2 shall be performed at fixed intervals, but now with much longer intervals (tentatively set to 3 years). Since all instrument loops are digital communication (HART) loops, loop checks are performed only on indication of error.

The fiscal metering stations are prepared through design for fully automated condition based maintenance. This includes the possibility to automatically verify the condition of every measured parameter in the metering station, like pressure, temperature, density, flow values (flow rate, K-factors, "health check" in ultrasonic meters) measured level in sample container (compared to predicted level and accumulated production in the sampling period) and so on. Verification of current condition is done using double instrumentation and without intervention in mounted equipment.

The Metering station database computer can store and trend any measured parameter or condition. A quality report can be generated automatically, or on request. Each condition in the quality report is verified against predefined quality criteria and has an alarm function. See Fig 7a-c for an example of a quality report from the KOS database computer for the oil metering station on the Visund platform. The alarm function is active on a continuous basis (every 10 seconds all conditions are verified) and gives an alarm to the process operator.

1998/06/15 00:01 Visund Oil Metering Station KOS FCM 212
QUALITY REPORT Page 1 of 3

LINE STATUS :

Line No	Status
1	CLOSED
2	OPEN
3	OPEN

CURRENT PRESSURE :

Line No	Pressure A Measured bar g	Pressure B Measured bar g	Pressure Deviation bar	Alarm Status	Mode
1	8.00	8.01	0.01		MEASURED A
2	8.00	8.01	0.01		MEASURED A
3	8.00	8.01	0.01		MEASURED A

Pressure deviation between open lines : 0.00 OFF

CURRENT TEMPERATURE :

Line No	Temp. A Measured Deg C	Temp. B Measured Deg C	Temperature Deviation Deg C	Alarm Status	Mode
1	50.00	49.99	0.01		MEASURED A
2	50.00	49.99	0.01		MEASURED A
3	50.00	49.99	0.01		MEASURED A

Temp. deviation between open lines : 0.00 OFF

CURRENT DENSITY :

Line No	Dens. A Measured kg/m3	Dens. B Measured kg/m3	Density Deviation kg/m3	Alarm Status	Mode
1	807.45	821.45	14.00	HIGH	DENSITOM.A
2	807.45	821.45	14.00	HIGH	DENSITOM.A
3	807.45	821.45	14.00	HIGH	DENSITOM.A

Density deviation between open lines : 0.00 OFF

Fig 7a Quality control report, page 1.

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QUALITY REPORT Page 2 of 3

CURRENT DENSITY PRESSURE :

Line No	Pressure A Measured bar g	Pressure B Measured bar g	Pressure Deviation bar	Alarm Status	Mode
1 !					MEASURED A
2 !					MEASURED A
3 !					MEASURED A
Common !	8.01	8.02	0.01		

CURRENT DENSITY TEMPERATURE :

Line No	Temp. A Measured Deg C	Temp. B Measured Deg C	Temperature Deviation Deg C	Alarm Status	Mode
1 !				HIGH	MEASURED A
2 !				HIGH	MEASURED A
3 !				HIGH	MEASURED A
Common !	50.01	49.89	0.12		

CURRENT PROVER PRESSURE :

	Pressure A Measured bar g	Pressure B Measured bar g	Pressure Deviation bar	Alarm Status	Mode
Inlet !	8.00	8.01	0.01		MEASURED A
Outlet !	8.10	8.09	0.01		MEASURED A

CURRENT PROVER TEMPERATURE :

	Temp. A Measured Deg C	Temp. B Measured Deg C	Temperature Deviation Deg C	Alarm Status	Mode
Inlet !	49.89	49.87	0.02		MEASURED A
Outlet !	49.80	49.81	0.01		MEASURED A

Fig 7b Quality control report, page 2.

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PROVER :

Line No	Previous Calibration	Hours since Previous Calibration
1 !	1998/06/14 21:05	3
2 !	1998/06/14 21:15	3
3 !	1998/06/14 21:35	3

CURRENT FLOW RATES :

Line No	Mass Flow tonne/h	ActVolume Flow m3/h	Std. Volume Flow Sm3/h
1 !	0.000	0.000	0.000
2 !	414.914	515.103	499.317
3 !	423.021	516.351	500.396
Station !	837.935	1031.454	999.713

SAMPLER :

	Production since start of sampling Sm3	Calculated level %	Actual level %	Deviation %
(A) Daily !	999.7	76	72	-4
(B) Monthly !	13926.3	37	35	-3

STANDARD DENSITY :

Line No	Density Measured kg/Sm3	Density from Lab kg/Sm3	Density Deviation kg/Sm3
1 !	830.96	845.01	14.05
2 !	830.96	845.01	14.05
3 !	830.96	845.01	14.05

Fig 7c Quality control report, page 3.

There is also a function for automatic proving of turbine meters with long term statistical check of K-factor. New K-factors will be automatically accepted after comparison with a standard K-factor (average of earlier accepted K-factors or fixed) and predefined acceptance limits of variation. The process operator will only be involved if the K-factor is outside the acceptance limits.

The critical valves in the fiscal metering station have automatic leakage detection.

The following figure illustrates how a fiscal oil metering station can be instrumented for fully automated quality control, see Fig 8.

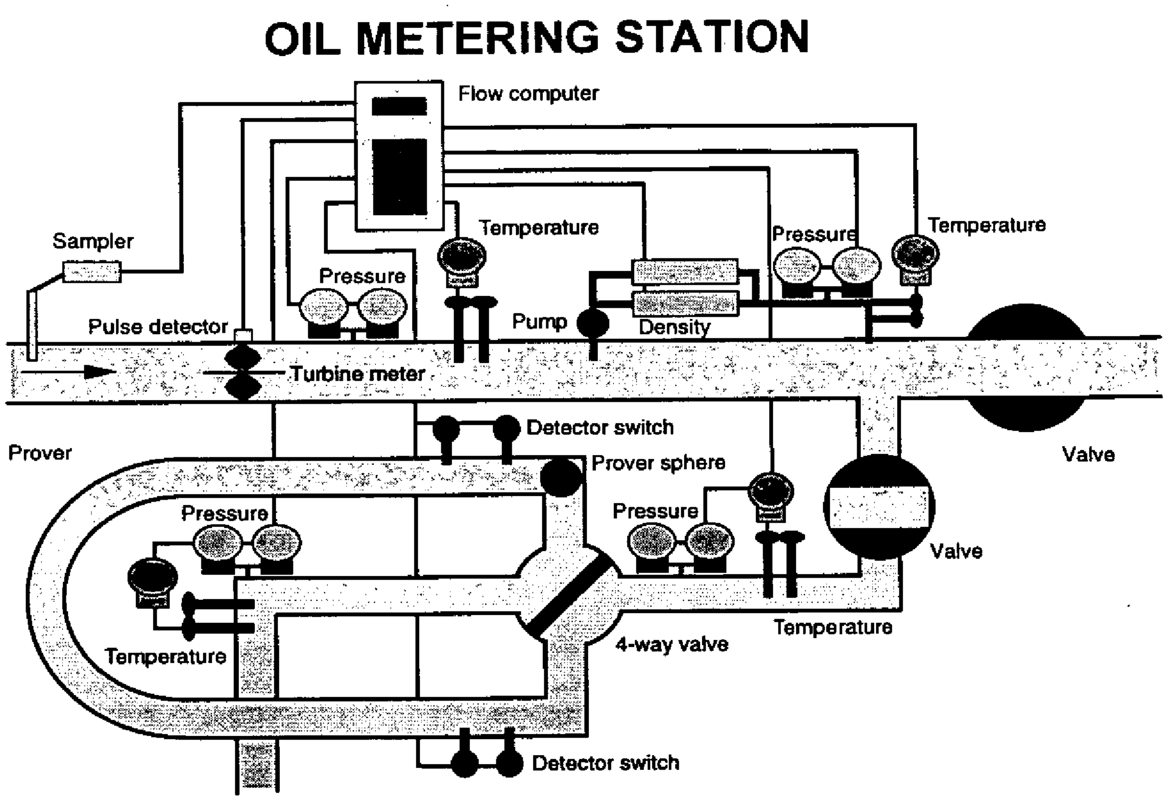

Fig 8 Typical oil metering station with instrumentation for fully automated quality control.

6 SELF CONTAINED FISCAL METERING STATION

Norsk Hydro would like to introduce a design philosophy for a self contained fiscal metering station not requiring external computer facilities and dedicated interface designs. Within this concept the Metering station database computer will communicate with the overall control system and other external computer systems via standard interfaces e.g. X-windows, see Fig 9 and 10.

A lot of effort is normally put into defining, designing and checking these various interfaces between computers. Dedicated programs need to be written to handle the data and commands transmitted over these interfaces as well, and identical screen pages have to be built on separate computers displaying the data and commands. We suggest a future solution were all these interfaces are practically obsolete, see Fig 10, where all other systems log onto the metering station database computer as a server. DISCOS is the Distributed Supervisory Control and Safety system while OPIS is the Oil Production Information System in Fig 9 and 10.

In order to achieve this the Metering station database computer will need increased storage capacity and functionality currently found in add-on programs on external computers.

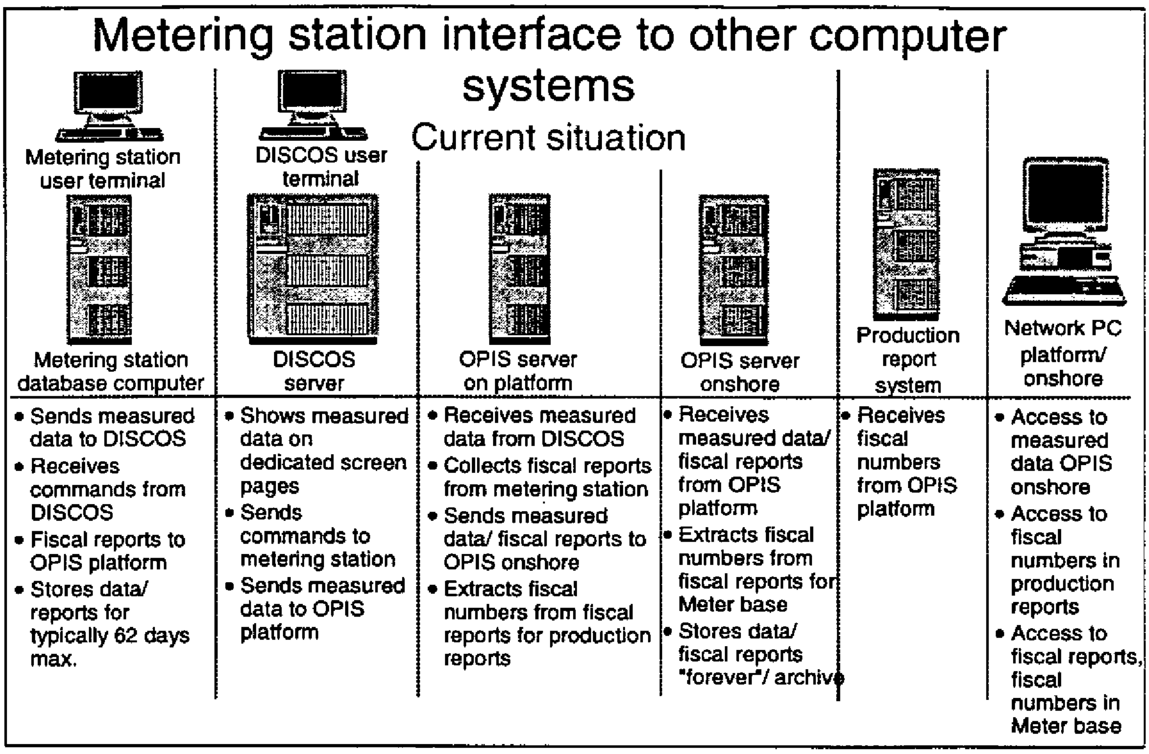

Fig 9 Current situation. A fiscal metering station dependant on external computer facilities to be operated and maintained.

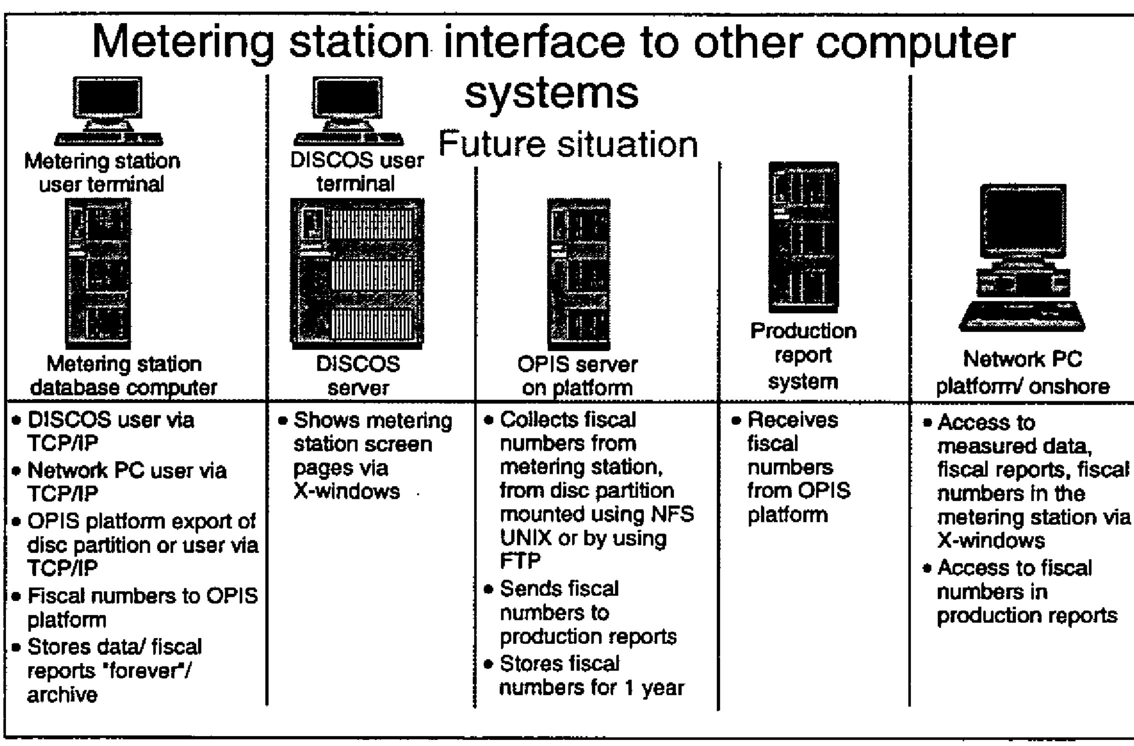

Fig 10 Future situation. A self contained fiscal metering station.

7 NORSOK STANDARDS

Some of the concepts mentioned in this paper have been included in the revised NORSOK standards for fiscal metering, see Fig 11.

NORSOK STANDARD

FISCAL MEASUREMENT SYSTEMS FOR HYDROCARBON GAS

I-104
Rev. 2, June 1998

NORSOK STANDARD

FISCAL MEASUREMENT SYSTEMS FOR HYDROCARBON LIQUID

I-105
Rev. 2, June 1998

Fig 11 Titles of the revised Norsok standards.

The requirements for an automated quality control system are given in Chapter 4 and 5 of the revised NORSOK standards, see Fig 12, while the detailed requirements are given in Annex A, see Fig 13.

4 GENERAL REQUIREMENTS

4.1 General

The measurement system which fulfils the functional and technical requirements and has the lowest life cycle cost shall be selected.

5.1.7 Maintenance Requirements

5.1.7.1 General

The field instrumentation should be chosen to ensure long maintenance and calibration intervals.

The maintenance requirements for automated condition based maintenance in Annex A shall apply. In addition, it should be easy to retrofit the instruments and flow elements for maintenance.

Fig 12 Text sections from the revised Norsok standards requiring an automated quality control system.

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ANNEX A REQUIREMENTS FOR AUTOMATED CONDITION BASED MAINTENANCE (NORMATIVE)

A.1 General

The fiscal measurement station shall be designed for fully automated condition based maintenance. This includes the ability to automatically verify the current condition of all measured field tags that are of importance to the integrity of the fiscal measurement station. These field tags are typically pressure, temperature, density, differential pressure, flow values (turbine meter k-factor, ultrasonic meter values), level in sampling container (compared to calculated level) etc.

This verification of current condition shall preferably be carried out using calibrated reference meters. The condition based monitoring may however also be carried out using duplicated equipment or by any other relevant method.

Where possible comparative monitoring of parallel meter runs shall be carried out, i.e. when two or more meter runs are operating concurrently.

A.2 Software requirements

The software shall be prepared for easy and reliable verification of the accuracy of each independent program routine and totalization. The computer under test must measure the duration of the accuracy tests, when the duration of the accuracy tests is influencing the estimated values.

The measured field tags and parameters indicating the condition of each field tag i.e. deviations from reference values, shall be stored and trended graphically. Additionally, a current condition report shall be generated at predefined times or on demand. The current condition report shall include comparisons against predefined limits of deviation for each parameter, and a written alarm shall be given in the report, if any limit is exceeded. Generally, a verification of current condition shall not include any manual interference with the measurement equipment or computers. The current condition report may be combined with the report of the daily status of the measurement system. The fiscal measurement reports shall not be combined with the current condition report.

In a turbine meter station with prover, a function for automatic turbine meter calibration combined with statistical evaluation of previous K-factors, shall be implemented: It shall be possible for a new K-factor to be automatically accepted by comparison with the statistical K-factor (e.g. average of the last 30 accepted K-factors) and predefined limits for acceptance. Manual acceptance shall be invoked if the new K-factor exceed acceptance limits. It shall be possible to select a mode where a fixed K-factor is used in stead of the statistical K-factor.

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Fig 13 Annex from the revised Norsok standards defining an automated quality control system.

8 CONCLUSION

New installations must be prepared for fully automated quality control through proper design choices. To implement this after start of operation or use a manual quality control system is not cost effective and very time consuming.

On existing installations a manual quality control system will often be the only option due to limitations in installed equipment. However, it can be a good investment to upgrade to a fully automated quality control system, but the payback period will be several years.

Norsk Hydro's current policy is that all new or modified metering stations shall be prepared for fully automated quality control and that all existing metering stations shall be prepared for manual quality control through condition based preventive maintenance.

As pointed out in the introduction Norsk Hydro wishes to be able to purchase a self contained fiscal metering station, with a fully automated quality control system requiring a minimum of manual preventive maintenance, supervision and routines to operate reliably. You the designers think of designing them to send into orbit if you like, but remember we don't have a NASA budget. We need a cost effective solution utilising currently available technology to its fullest potential.

9 REFERENCES

[1] Douglas Wieringa et al., "Procedure Writing. Principles and Practices," IEEE Press 1993.