24th International North Sea Flow Measurement Workshop

24 – 27 October 2006

ACCEPTED ABSTRACTS FOR PRESENTATION

Provisional NEL ideas for abstracts.

A Novel Infrared Absorption Technique for Measuring Flare Gas Flow

Dr. Jeff Gibson[1] and Mr. John Hyde[2]

The measurement of hydrocarbon gas flowing to a refinery or production flare is critical in determining the annual emissions figures reported to regulatory bodies. However, flare gas flow measurement is not trivial, with a very wide velocity range (0.2 – 100 m/s), large line sizes and a requirement for a metering technology that is non-intrusive being just some of the issues that must be addressed.

This paper shall discuss the development of a unique infrared (IR) optical flow metering technique which operates on the time-of-flight principle. Unlike ultrasonic meters, the IR meter does not transmit energy through the gas stream in order to obtain a measurement and is therefore less prone to changes in gas composition and beam drift at high velocities. The results from tests undertaken in NEL's atmospheric flow facility, together with the applicability of the IR meter for flare gas measurement and any scope for future developments will be presented and discussed.

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24th International North Sea Flow Measurement Workshop 24th – 27th October 2006
Abstract for "Full Paper".

"A Discussion on Horizontally Installed Differential Pressure Meter Wet Gas Flow Performances"

Differential Pressure (DP) meters are currently being used to meter wet gas flows by either using wet gas correction factors on stand alone DP meters when the liquid content is predicted from an external source or as the primary meters at the core of wet gas or multiphase meters. In both applications it is critical that the reaction of the DP meter in question when exposed to wet gas flows is understood. However, the available DP meter wet gas data sets cover a small range of the industrial applications in terms of meter geometry and flow parameters. Industry is therefore often forced to extrapolate existing correlations. Few verification tests on existing DP meter correlations and few tests on the affect of extrapolating these correlations have been presented.

This paper presents CEESI wet gas data and analysis of the same 4" 0.4 beta ratio NAM Venturi meter that de Leeuw tested at Coeverden and Trondhiem. The CEESI test matrix was similar to that of Trondhiem. The performance of the de Leeuw correlation with the CEESI data is discussed. A rare wet gas 4" 0.6 beta ratio Venturi Nozzle Type DP meter data set is presented. This data sets gas densiometric Froude number limit is higher than has been previously presented. This allows investigation into the effects of the different geometry and the extrapolation of the gas densiometric Froude number parameter. The mathematical form of the de Leeuw equation is then discussed and new theory with regards to extrapolation is postulated. Finally, this theory is discussed with regards to the published NEL wet gas Venturi meter data (NEL report 2005/206) where different liquid component wet gas flows are tested.

By Richard Steven
CEESI

Abstract submission to: 24th International North Sea Flow Measurement Workshop
Oct 24-27th, 2006, St. Andrews, Scotland

Flow Data for Natural Gas with Water and Hydrates (Presentation)

Jeffrey L. Savidge, Ph.D.
CEESI

Hydrate masses, constrictions and blockages in flow lines and meters can cause severe capital and labor intensive challenges to operators. The problems include significant measurement errors, damage to measurement equipment, sensor malfunctions, flow shut-ins, and, in extreme cases, catastrophic failures. Safety is a paramount consideration when hydrates are present. As fluids and operating environments become more severe, hydrate control becomes an increasingly important component in risk assessment. Management of these risks mandates the need for advances in flow measurement. Although much is known about the equilibrium behavior of hydrates, little is known about their dynamic behavior. Full-scale flow data for natural gas with water and hydrates is critical for advancing measurement and hydrate control technologies. A consortium is sponsoring a multi-year program at CEESI to improve the understanding of hydrate flow behavior for hydrate monitoring, control, and flow assurance. The program is sponsored by the U.S. Dept of Energy, Pipeline Research Council, and the Gas Technology Institute. The goal of the program is to obtain data that identify the mechanism(s) of hydrate constriction and blockage formation. Other objectives include identifying pre-emptive methods for hydrate constriction and blockage remediation. Metering is an important element that is needed to achieve the goal. Field work is being carried out at two consortium member sites. Hydrate flow test data are being obtained at CEESI's full-scale Hydrate Flow Test Facility (HFTF) in Colorado. Hydrate flow measurements have been made at CEESI with orifice meters, clamp-on ultrasonic meters, and capacitance devices. Both the field and flow test data demonstrate the dynamic and diverse behavior of hydrates. The flow data collected at the HFTF include hydrate formation and flow tests with (1) water saturated natural gas, (2) natural gas with water and hydrate phases, and (3) natural gas with water, condensate, and hydrate phases. The test data include steady, unsteady, and transient flow data for isothermal and non-isothermal conditions. Data have been obtained under both normal and extreme operating pressure conditions. Test temperature conditions range from near wellhead fluid injection temperatures to flow line wall temperatures that are well below the ice point. The tests include full-scale horizontal, inclined, and vertical (simulated riser) flow line configurations. Efforts are in progress to extend the work to include hydrate flow behavior in the wellbore and valves. The paper will provide an overview of the hydrate flow measurement and testing program, highlight key findings from the field and lab, and identify research needs to advance gas measurement and monitoring when hydrates are in the flow line.

Critical review of wet gas definitions

G.Falcone (Texas A&M University), C.Alimonti (University “La Sapienza” of Rome)

Several definitions of wet gas have been proposed within the Oil and Gas industry and they are critically reviewed in this paper. Wet gas metering may apply to gas condensate fields, high GOR fields and wet gases. Accordingly to the definition given in the SPE monograph volume 20 (Whitson and Brule’, 2000), a reservoir fluid is classified as dry gas when the reservoir temperature is greater than the cricondertherm and surface/transport conditions are outside the two-phase envelope; as wet gas when the reservoir temperature is greater than the cricondertherm, but the surface conditions are in the two-phase region; as gas condensate when the reservoir temperature is less than the cricondertherm and greater than the critical temperature; and as an oil (volatile or black oil) when the reservoir temperature is less than the mixture critical temperature.

In 2002, the DTI issued guidelines where wet gas was defined as a two-phase flowing liquid with the LVF in the region of 5-10%. These guidelines were later modified to state that wet gas was a stream with LVF’s between 0 and 10% at metering conditions. Following this definition, wet gas metering can be regarded as the upper limit of multiphase flow metering (oils with high gas volume fractions) and the bottom boundary of gas metering (gases with high liquid volume fractions). This implies that, by pushing either multiphase flow metering or gas metering to their extremes, wet gas metering solutions could, in theory, be found. However, due to the complexity and peculiarity of wet gas flow, its metering may necessitate a dedicated effort.

The occurrence of slip between the liquid and the gas, the difficulties in predicting the transition between flow regimes in horizontal and in vertical currents, and the uncertainties related to the PVT characterization of gas condensate fields are among the problems still associated with wet gas metering. Also, the liquid phase of wet gas streams may be a combination of hydrocarbons and water, in which case wet gas metering becomes a three-phases problem. The oil/water inversion point may have a big impact on the multiphase flow correlations used to calculate pressure drops and boundaries between flow regimes. Finally, solids may be a fourth phase present in the stream.

The importance of working in mass fractions rather than volume fractions when characterising wet gas fields has been highlighted in the literature (Couput *et al.*, 2000; Jamieson, 2001). Wet gas streams are metered for a variety of reasons: economics and/or reservoir management, allocation issues, metering the produced gas only or metering both the liquid and the gas. Depending on the specific requirement (or requirements), different metering accuracies may be required and different wet gas metering solutions sought. For this reason, multiphase mass fraction triangles have been produced for different fluids densities, showing the possible percentages of gas, oil and water in a wet gas stream.

In order to account for the joint effects of flow regime, operating pressure and temperature, and liquid content of the gas, a revised classification for wet gas, based on the Lockhart-Martinelli parameter, has also been presented.

As a single definition of wet gas for Oil & Gas applications may never exist, a unique metering solution for all types of wet gas may be impossible to achieve. Hence, a critical approach must be taken in the selection of a wet gas meter for each specific application.

5 Years Offshore Operational Experience of 3-Path Gas Ultrasonic Flowmeters in Custody Transfer & Allocation Measurement Systems

This paper will present an overview of the practical metering issues experienced on the Custody Transfer and Allocation measurement systems onboard an FPSO in the North Sea.
Ultrasonic technology has been used by many operators in the North Sea for some years now and this paper will explore the advantages and disadvantages facing users of this technology.

Particular emphasis will be placed on

- online diagnostic monitoring & evaluation,
- recertification strategies and calibration shifts,
- transducer & electronics performance,
- redundancy strategy and exposure to meter failure
- upstream conditioning
- installation effects

The paper will be written and presented by an onshore metering engineer who has witnessed both the offshore tests, onshore recertifications and has also performed the online diagnostic monitoring to establish the health status of the offshore ultrasonic flowmeters.

Delivery method: ‘Full Paper’

Author: Mark Sinclair
METCO Services Ltd,

A Review of Pipeline Integrity Systems

Norman F Glen - TUV NEL Ltd
Jim Ryan, Ted Finlayson - Innovene

The visible evidence of a leak is often the first sign that the integrity of a pipeline has been breached. In an ideal world, one in which cost did not matter, pipelines would be designed to have guaranteed integrity, but in the real world it is inevitable that leaks will occur. Whether carrying water, gas or oil, there are financial, political, regulatory, safety and environmental issues which must be addressed when designing and operating pipelines. Pipeline integrity monitoring and leakage detection systems therefore have a key role to play in minimizing the occurrence of leaks and their impact.

The requirement to monitor the integrity of extensive and inaccessible pipelines is clearly widespread and there is a belief that some of these issues can be addressed by sharing experiences and practices across sectoral boundaries. As part of the 2002-2005 Flow Programme, NEL undertook a project to review the state of the art in monitoring systems for pipeline integrity across all relevant industrial sectors.

The overall review covered pipeline integrity in general, with a focus on documenting leakage detection methodologies. Although such techniques are used across a range of industries, the different operational and safety requirements have led to a variety of implementations.

It is clear that practices differ from sector to sector and the very different operational regimes of, and potential hazards from, oil, gas and water pipelines, mean that transferring best practice from one sector to another is not simply a matter of implementing an identical solution. The key recommendation with regard to the selection of any leak detection system therefore is that it must be made within the context of an overall pipeline integrity management plan. This paper provides a summary of the report, including an overview of the issues and a review of potential techniques. The project report and associated Guidance Note (available from the Flow Programme website) provide background information and a basic framework on which leakage-detection-based systems selection can be based.

North Sea Flow Measurement Workshop 2006

Steve Caldwell / CEESI
John Lansing, Volker Herrmann, Toralf Dietz / SICK MAIHAK

Investigations on an 8 path ultrasonic meter - what sensitivity to upstream disturbances remains?

During the past several years numerous improvements have been developed to enhance the performance of today's ultrasonic meter. As the cost of gas continues to increase, many users have elected to install flow conditioners to help reduce uncertainty. For many applications the additional pressure loss is not desirable. Thus the industry is still in need of a cost-effective solution for ultrasonic measurement applications where flow conditioners are not desirable, and accuracy is a high priority.

The response of an 8 path meter to common types of inlet disturbances is investigated at the CEESI high pressure, high volume calibration facility. Among the inlet disturbances tested are a combination of elbows and tees upstream. Results will be shown for these combinations with a flow conditioner between the disturbance and the meter, and with no flow conditioner. This data will be compared to baseline calibration performed at CEESI at approximately 70 bar and also with results obtained with ambient air calibration. This will provide additional information about any potential pressure effects between ambient air and high pressure operation.

Two-Phase (Gas/Liquid) Flow Metering of Viscous Oil Using a Coriolis Mass Flow Meter: a Case Study

By

Manus Henry, Michael Tombs, Mihaela Duta, Oxford University, Oxford, U.K.
Frank Kenyery, University Simon Bolivar, Caracas, Venezuela
Joseph Shen, Chevron Energy Technology Company, Houston, USA
Martin Morles, Chevron International E&P Company, Maracaibo, Venezuela
Carlos Garcia, Foxboro Company, Caracas, Venezuela

Submitted for presentation at
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St. Andrews, Scotland
24-27 October 2006

Abstract

The use of Coriolis mass flow metering for two-phase (gas/liquid) flow is an emerging theme of both academic research and industrial application [1, 2]. The key issues are to maintain flowtube operation during two-phase flow, while modelling and correcting for the errors induced in the mass flow and density measurements. While undoubtedly a universal two-phase flow correction model is the ultimate aim, this paper describes and demonstrates a methodology that has proven effective in developing good correction models for a specific flowtube and fluid.

Trials were carried out at the National Engineering Laboratory, Scotland on a 75mm flowmeter using a high viscosity oil (Primol: viscosity 300cSt at 15C and 200cSt at 20C), simulating the high viscosity oils extracted in Venezuela. Flowrates from 1kg/s to 10kg/s were examined – these are low for the meter size (nominal capacity 30kg/s), but match pressure drop requirements for the high viscosity fluid in Venezuelan applications.

Two-phase flow error models for mass flow and density were based on experimental data at a series of flowrates and gas void fraction (GVF) points up to 80%. The resulting model was tested on-line in a commercial Coriolis mass flow meter and demonstrated good performance for both steady and slugging two-phase flows, with both mass flow and density errors mostly less than 5% and typically about 2%.

The newly developed correction model has been implemented in a 75mm flowmeter for a field trial at an oil field in Venezuela. The Coriolis meter, located at the outlet of a test separator, measures the well production of extra heavy oil/water mixture entrained with gas micro-bubbles. Preliminary field data suggest reasonable measurements of liquid flow rate and GVF. Further evaluation of the Coriolis meter for this application is continuing.

While research continues into the development of a general two-phase correction, this case study demonstrates that good corrections can be obtained for economically important fluids.

Operating Gas Ultrasonic Meters After The Project Team Goes Home

This paper presents results and practical experiences from "in operation" measurement streams. It is not meter manufacturer specific and includes meters from leading manufacturers throughout Asia Pacific with data presented from at least 7 metering station installations.

The paper will provide blinded but actual field data from meters configured in a number of variations of what has become the standard two-meters in series, "Z" configuration. Pictures from Video Scope Inspections, USM diagnostics data and series check results will be presented. Additionally, how raw data can provide support information for the assessment of the secondary instrumentation.

The paper proposes an open discussion on "What should be considered as an acceptable tolerance for the "series check" on a "Z" configuration?"

Descriptions of some of the practical issues faced by operators and demonstrations of the impact of the corrective actions taken on these systems whilst in operation are presented.

As both AGA and ISO standards for Ultra Sonic meters for natural gas move towards making the decision for recommendation of the 10D rule for installation of flow conditioning plates, this paper will show "operational data" to provide a counter balance to the experimental data, (all data gathered from an operational perspective) and asks the question 10D OR NOT 10D, is this the answer?

It will also demonstrate the practical use of control charts to monitor operational performance and provide direction for targeted corrective actions.

Finally, the paper will also highlight some of the good news as well as concerns of this technology in operation.

Keith Roberts
Emerson Process Mgt Asset Optimization

Abstract for NSFM workshop 2006

Today the demand for leak detection and location systems is increasing. General knowledge about these systems is still limited and the general opinion is still these systems ‘will only detect catastrophic leaks’ or ‘give false alarms all the time’. In this presentation we will show how modern systems work, and based on field data, we will also show that these systems actually work.

The presentation will start with a brief introduction into KROHNE’s Extended – Real Time Transient Model (E-RTTM) based leak detection system. Focus will be given to the E-RTTM model where it will be explained how the model works and why it enables sensitive and false-alarm-free leak detection even during heavy transient flow conditions such as start-up and shutdown.

An actual application will be shown based on this technology. The application is an 11 km long pipeline with CO gas based at a chemical company in Germany. The system build-up will be shown (where are flow, pressure and temperature transmitters, how is data transmitted) and it will explained how the system was fine-tuned after data was recorded over several months of operation. Subsequently leak test results will be shown based on induced leaks of 2.5%, 1% and even only 0.5% of nominal flow.

Leak test results of a second application, a 10 km long pipeline transporting 7 different refined products will also be shown. These results demonstrate the minimum detectable leak rate under stationary, transient and heavy transient conditions.

Delivery preferred: Full paper

Authors:
Hilko den Hollander - KROHNE Oil & Gas
Prof. Dr. Gerhard Geiger - KROHNE Oil & Gas

Abstract

Flow measurement field calibrations by radioisotope tracers in off-shore, oil and gas industry

Risto Kuoppamäki
Indmeas Oy

Compared with prover and laboratory calibrations the field calibrations by radiotracer transit time method have a superior flexibility. It is due to the portability and easy installation on site, applicability to both liquid and gas flows, very large flow regime and the fact that the calibration procedure does not disturb the production process.

On the other hand the method has suffered from a larger measurement uncertainty. Appreciable progress in the measurement uncertainty has lately been achieved. Indmeas Oy has reached in the beginning of 2005 0,5 % as the best accredited calibration uncertainty with the transit time method in both liquid and gas flow field calibrations. This uncertainty level sets special requirements for the field conditions of the calibration, including a demand for a longer straight pipe section in the transit time measurement. The requirements are, however, most often fulfilled at the most important flow measurement positions of off-shore platforms, oil refiners and gas networks where the minimum measurement uncertainty is needed. The paper describes the first experiences from flare gas, natural gas and oil flow measurement calibrations carried out on the low uncertainty level.

Conclusion:
Field calibrations by radiotracer transit time method constitute today a competitive flow measurement quality maintenance method. It is a flexible, reasonably low cost method with the calibration uncertainty compatible with the requirements set by the rules of the CO2-emission trade and fiscal measurements. In custody transfer measurements of oil refineries and natural gas networks the method is a new promising alternative for traditional quality systems based on tank level measurements and laboratory calibrations.

Venturi-tube performance in wet gas using different test fluids

Dr Michael Reader-Harris, Dr David Hodges and Dr Jeff Gibson
NEL

Two standard Venturi tubes of diameter ratio 0.6 and 0.75, and one non-standard Venturi tube of diameter ratio 0.75 (10.5° convergent angle) were tested in the NEL wet-gas test facility at two gas-liquid density ratios using three gas-liquid combinations (nitrogen-kerosene, argon-kerosene and nitrogen-water). Changing the gas type had little measurable effect on the Venturi-tube performance with the largest deviations in over-reading relative to the nitrogen-kerosene data not exceeding a range of -0.023 to 0.02, with the majority of any deviations being comfortably inside this range. For the non-standard Venturi tube deviations in over-reading were generally much less than 0.01, suggesting no effect of argon compared with nitrogen. Changing the liquid type had a more significant impact on the Venturi-tube performance. With the exception of the minimum gas densimetric Froude number used, all Venturi tubes produced over-readings that were smaller for the nitrogen-water tests than for the nitrogen-kerosene tests. Deviations in over-reading varied from -0.012 to -0.095 at the maximum value of the Lockhart-Martinelli parameter value used. At the lowest gas densimetric Froude number of 1.5, the data show relatively small shifts between the three fluid combinations. However, at the mid–range Froude numbers a separation occurs between the argon-kerosene/nitrogen-kerosene and nitrogen-water data sets. At the larger Froude numbers tested (3.5 and above) it was found that the over-reading data sets for the three fluid combinations tended to converge once again, the most likely reason for this being that two-phase flow patterns produced upstream of the Venturi tubes are tending towards an annular-mist regime, where larger fractions of the liquid content of the flow become entrained with the gas flow as the Froude number increases.

Fig. 1 shows data for the standard convergent β = 0.75 Venturi tube at the higher gas-liquid density ratio (0.046).

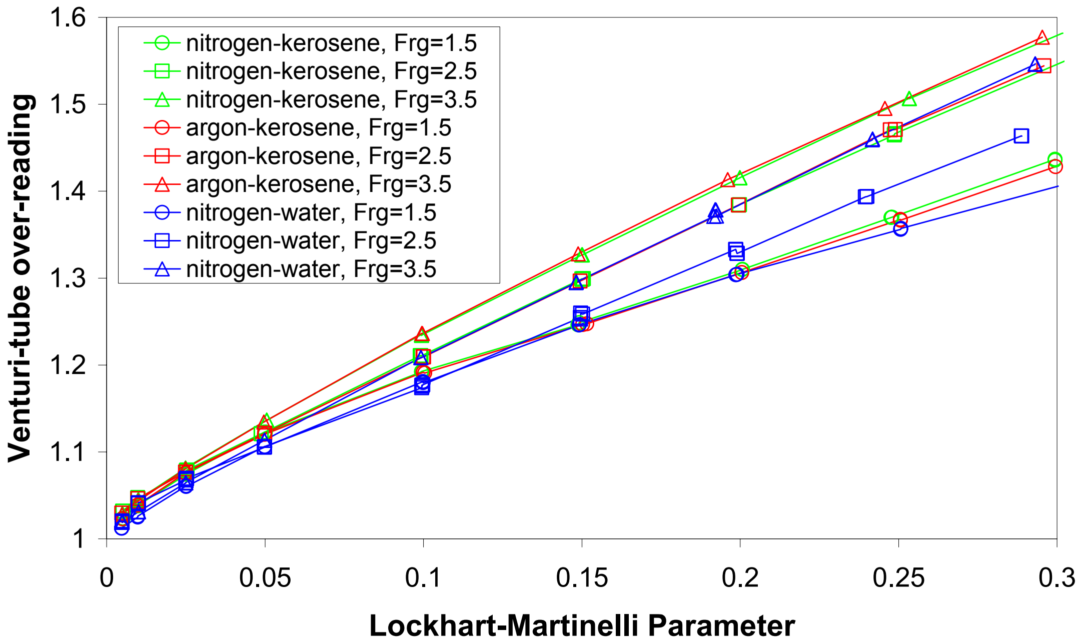

Fig. 1. Standard (β = 0.75) Venturi-tube over-reading

A CFD analysis of the flow through the Venturi tubes was undertaken. This indicated that it is possible to model wet-gas flow through Venturi tubes and provide trends that follow the experimentally obtained over-reading data moderately well, although limitations in the approach were evident at 60 bar. Fig. 2 compares the over-reading obtained in nitrogen-kerosene with that in nitrogen-water. Computed values are given for a β = 0.6 standard Venturi tube at a gas-liquid density ratio of 0.022 and gas densimetric Froude numbers of 1.5 and 3.0. The CFD predicts the same effect as found by experiment: the over-reading is lower in nitrogen-water than in nitrogen-kerosene, the difference increasing with increasing Lockhart-Martinelli parameter. However the magnitude of this effect was under-predicted by the CFD compared with the test results.

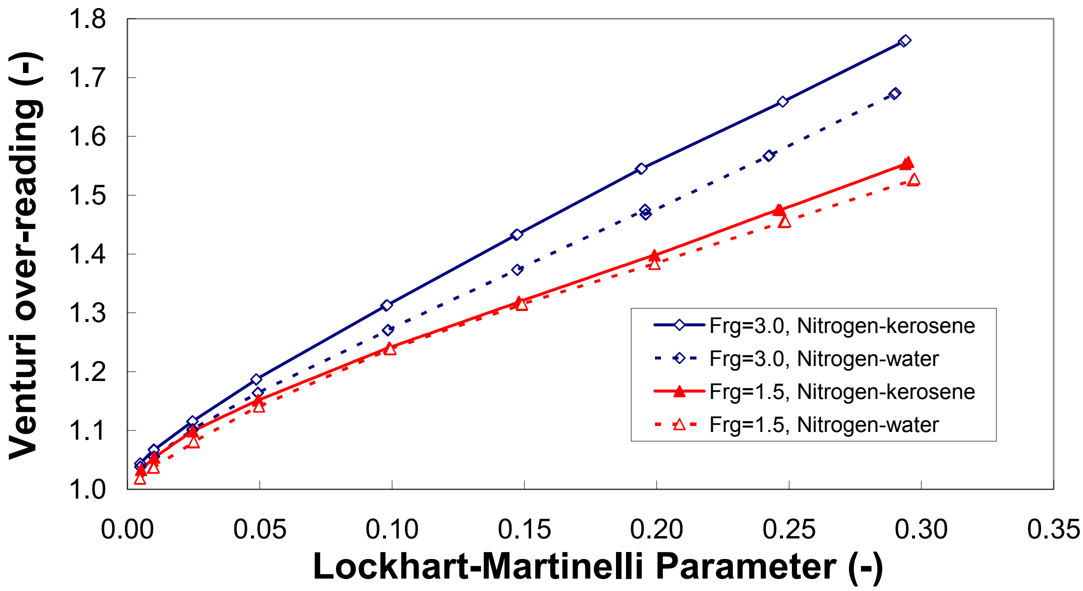

Fig. 2. Computed effect of changing liquid on over-reading

THE USE OF A MULTIPHASE SAMPLING KIT TO IMPROVE MULTIPHASE FLOW MEASUREMENT THROUGH ACCURATE PHASE-BEHAVIOUR CHARACTERISATION AT THE WELL SITE

Paul Guieze, Bruno Pinguet, John Nighswander, Graham Birkett *Schlumberger*

Representative reservoir fluid sampling & characterization has become increasingly important over the years. With exploration, appraisal and development activities moving into marginal fields and more challenging environments, accurate fluid characterization becomes more critical. This can be said for formation tester, DST and multiphase sampling and fluid characterization environments, with the most challenging area in recent years being the multiphase environment.

Multiphase flow meters have been accepted for several years now by the industry. The use in permanent or well testing applications has been growing rapidly. In many cases, multiphase flow meters have replaced the separator for flow rate evaluation, but some fundamental needs from the client were not addressed properly, such as the ability to collect representative samples for phase-behavior characterization. Moreover, metering accuracies at very high GVF or in Wet Gas Conditions has been questionable in many cases.

This paper will focus on a specific technology that is retrofitted to existing multiphase technology in a well testing application for the collection of representative samples to isolate each fluid phase, characterize the in-situ phase and data entry of the subsequent analysis to the meter for more accurate flow rates in a broad range fluid types.

This exciting development, combined with existing multiphase technology could possibly make test separators obsolete in the near future.

Density and calorific value measurement in natural gas using ultrasonic flow meters. Results from testing on various North Sea gas field data

Kjell-Eivind Frøysa,	Christian Michelsen Research AS (CMR), Norway
Per Lunde,	Christian Michelsen Research AS (CMR), Norway
Anfinn Paulsen,	Gassco AS, Norway
Endre Jacobsen,	Statoil ASA, Norway

Abstract:

Multipath ultrasonic transit time flow meters (USMs) are today extensively used in industry for volumetric flow metering of natural gas, for fiscal measurement, check metering, etc. As natural gas is typically sold on basis of mass or energy, the density and/or calorific value (GCV) of the gas is measured in addition. In current fiscal metering stations this is typically made using additional instrumentation like density meters or gas chromatographs.

In addition to the flow velocity and the volumetric flow rate, USMs give measurement of the velocity of sound (VOS) in the gas. The VOS is a quality parameter which contains valuable information about the gas. In last year's North Sea Flow Measurement Workshop a new method for calculation of density and GCV of natural gas from measurements of the pressure, temperature and VOS was presented. In this method no instrumentation is needed in addition to the USM itself and the pressure and temperature sensors. The method can be used on existing USM metering stations with only a software upgrade. Such a feature may be of interest for fiscal metering stations (e.g. for backup and redundancy) as well as simpler metering station (where density and GCV are not measured today, but where such information may be of interest e.g. for monitoring).

The present paper represents a follow-up of last year's NSFMW paper, and gives results using this method on data from several North Sea offshore gas field installations. The GCV and density is calculated from the VOS measured by USMs of various manufacturing types, installed on offshore metering stations. Additional instrumentation in the metering stations provides reference values for density and GCV. Time periods of several days are analyzed for each field, over varying pressure, temperature and gas composition. The results indicate that the method is of high interest for several applications, including natural gas quality check, allocation, redundancy and quality check of the metering station instrumentation, with accuracy close to or in some cases even within fiscal accuracy.

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Senior Scientist and Programme Manager
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Abstract for a Full Paper at the NSFMW 2006.

Author: Trond Folkestad, Norsk Hydro ASA

Title: Qualifying a Coriolis Condensate Export Metering station for fiscal use for Ormen Lange using 12" Coriolis meters.

Abstract:

The Ormen Lange field is Norway's largest gas field and will be developed with seabed installations at depths between 800 and 1100 metres, and will be linked through a 120 kilometres pipeline to a processing plant on land at Nyhamna on the west coast of Norway. The gas will be exported to Easington on the east coast of England trough a 1200 kilometre long export-pipeline. The condensate will be exported on tanker. Production will start in October 2007. A total of 24 subsea wells in four seabed templates will produce 6000 to 8500 Sm^3 per day of condensate and 70 million Sm^3 per day of gas.

For exporting the condensate a novel metering station design with 5 parallel 12" Coriolis meter runs was suggested with a design capacity of 6000 Sm^3/h. A master meter bank consisting of 3 parallel 8" Coriolis meters will be used, enabling a mass flow against mass flow proving. Onsite calibration of the master meter bank using a transportable reference is also part of the design.

To gain approval for the design from the Norwegian Petroleum Directorate (NPD) a lengthy qualifying activity was agreed. Starting with visits to the manufacturer and sites where similar meters were in use and witnessing calibration of a large 12" Coriolis meter on water, an acceptance to go ahead with the building of the metering station was obtained from the NPD.

The results from a total of 5 tests of the 8 Coriolis meters from Rheonik at TRAPIL will be covered together with the findings from these tests. A number of metering issues were uncovered during these tests and explains the number of tests required to qualify the meters. The resulting improvements made to the internal measurement and compensation algorithms in the Coriolis meters and in the flow computer will be presented. The various additional tests performed to characterise the performance of the Coriolis meters with respect to temperature, pressure and density will also be briefly covered.

Experience from the flow test of the metering station in Athens in November 2005 will be covered including the testing of the on-site calibration of the master meters using a transportable reference with turbine master meter, compact prover and water can.

During the final test at TRAPIL extraordinary results like a linearity of ± 0.013 % were achieved for one 8" Coriolis master meter. Repeatability was never a problem and has been excellent during all the tests and well within the requirement of 0.07%.

Hydro has qualified a novel export metering station design based on large Coriolis mass meters and master meter proving for fiscal use in Norway, with exceptionally good results. Hydro considers the compact simplified design to be a large improvement and we believe this is how liquid metering should be performed in the future. We also expect the design to significantly reduce operating costs of an export metering station.

Multiphase metering - An authority perspective

The development of the multiphase meters over the past 15 years I will use the variuous papers that has been given during the past 15 years as a reference for establishing the NSFMW history for the multiphase meters

- An overview of different lessons learnt I will use and summarize some practical experience learnt over the past years.

- The regulatory requirements as they stand today I will use NPD and international standards as reference for defining requirements to the multiphase meters.

- Some recommendations when installing multiphase meters in the future I will give some hints to what could be good installation practice.

- An estimate of the market for multiphase meters the next 5 years in Norway Based on the market assumptions for the Norwegian continental shelf, I will try to estimate the need for multiphase meters during the next 5 years.

Steinar Fosse (steinar.fosse@npd.no)
NPD
Norway

GE Sensing Proposed abstract for NSFMW 2006

The expanding use of LNG and thence Natural Gas to satisfy world energy demand requires technologically superior yet affordable flow measurement solutions in increasing numbers for cryogenic flow metering and custody transfer

Transit-time Ultrasonic Flowmeters are now firmly established as an acceptable technology for gas and liquid flow measurement in the global Oil & Gas Industry. The technology has not only proven to be extremely accurate, exceeding legal metrology requirements, but also able to yield considerable savings for operators due to the effective absence of both pressure drop and maintenance requirements.

This paper discusses how a unique design of thermal buffer, advanced transducer design and a radical change of direction in terms of custody transfer flowmeter design can financially offset the impact of the anticipated increase in flowmeter numbers within the industry.

A patented Bundle Waveguide Technology (BWT) enables ultrasonic transducers and hence flow meters to be employed for cryogenic LNG flow measurement, with possible removal without affecting line integrity or safety. The paper will cite numerous installations on cryogenic LNG and low temperature gas flow measurement applications that have been operating successfully for several years at LNG liquefaction and regasification facilities. Transit-time ultrasonic technology can accommodate the largest LNG pipeline encountered so far, significantly in excess of the largest pipe size accommodated by alternate technologies, without pressure loss and with lower capital outlay. BWT technology theory, design and case studies are discussed.

As the number of LNG terminals rises, and regasified natural gas of varying composition and quality flows into increasingly complex distribution grids, so the need for affordable custody transfer standard flowmeters will increase. Such flowmeters have evolved into complex multi-path designs configured to minimise or eliminate the impact of velocity profile distortion. However, the effectiveness of these designs remains a function of available upstream straight pipe length and the sources of disturbance present. In many situations (estimated to be as high as three quarters of all installations) a flow conditioner is still required despite the number and configuration of paths.

The paper describes the development, testing and deployment of a simplified natural gas flowmeter design employing only two diametric paths and an integral flow conditioning plate, to deliver custody transfer performance. Potentially, the meter can be calibrated on air with correlation to pressurised natural gas thus saving thousands of dollars when originally calibrated and again when periodic recalibration is performed after years of service. It can also be tested for functionality at the installation site prior to bolting in line.

In addition to an in depth discussion of the theory and implementation of the design, improved reliability over more complicated designs and functional test results at three well known calibration facilities are presented. The paper describes applications of the meter for gas allocation at liquefaction and regasigication facilities as well as custody transfer for gas transmission pipelines. Finally, a case study of the first commercial installation at a gas fired electric power generating station is presented.

North Sea Flow Measurement Workshop October 2006

Abstract

Neftemer – A versatile and cost effective multiphase meter

By
Vladimir Kratirov (Complex Resource), Andrew Jamieson (4C Measurement Ltd), Stephen Blaney and Hoi Yeung (both Cranfield University)

Neftemer (the name means "oil meter") is a multiphase meter which was conceived in the late 1970s, and whose development in the former Soviet Union and in the Russian Federation was in parallel but quite different to the development of multiphase meters in the West. There are no laboratory multiphase test loops in Russia, and assessing the performance and establishing the optimum design had to be done in the field using simple yet practical methods. Neftemer was developed to meter wells producing heavy oils with high watercuts at relatively low production rates, and consequently Neftemer had to be relatively inexpensive. The main objective of this paper is to bring the metering community up-to-date with this development. The paper will cover three main areas:

- The story of the development of Neftemer since the late 1970s (About 70% of the paper.)
    - the testing and verification in oilfields:
    - the use of Neftemer for improving the production from wells:
    - the different kinds of applications.
- The testing of Neftemer at Cranfield University to allow a comparison with western multiphase meters. (About 15% of the paper.)
- An overview of the current status of the multiphase metering market, showing how Neftemer fits in.

Innovene's Experience in Pipeline Leak Detection Using Flow and Pressure Measurements

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Abstract

Flow and pressure measurements are widely used for pipeline operation and control. This paper discusses the additional application of such measurements to pipeline leak detection and location. Five case studies will be presented to cover applications to crude oil, multi-product, ethane, ethylene and propylene pipelines. The flow meters used include turbine, ultrasonic and coriolis type. The performance of these meters will be discussed in the context of pipeline integrity management.

Oil/Water Tests on a 4-Path Ultrasonic Meter at Low Flow Velocities

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This paper describes the performance of a 4-path ultrasonic meter in oil/water flows at low velocities over a wide range of water-cut. These tests were performed as an acceptance test for the meter prior to deployment in the North Sea on an allocation duty measuring oil from a first stage separator.

The tests were performed on a 4-inch Caldon LEFM 240C ultrasonic flow meter in the multiphase flow laboratory at NEL. The tests covered low flow velocities in the range of 0.15 to 2.5 m/s. Tests were performed at 3, 5, 7, 10, 15, 20, 50 and 75% water-cut. Prior to the tests Caldon estimated the measurement uncertainty based on experience from previous oil/water laboratory tests at Ohio University. The meter performance was evaluated relative to the NEL reference meters and compared against the estimated uncertainty.

Transducer and flow diagnostics were logged at 5 second intervals during the tests. At low velocities and water-cut greater than 5 % the occurrence of an oil/water interface in the pipe at the level of one of the paths would cause rejection of the measurements on that path owing to poor signal quality. At the high end of the velocity range all paths would measure successfully, as the oil and water were well mixed. At a few conditions, a coarse, churned-up oil/water mixture would cause 2 out of 4 paths to be rejected, which would result in larger measurement errors.

This paper will present relevant diagnostic information as well as the measurement results in terms of the errors relative to the NEL reference meters. Time permitting, and with the appropriate approvals, it may also be possible to present some data from the meter in application.

The Use of Process Simulation Models in Hydrocarbon Allocation Systems

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Abstract

The main purpose of simulation models within hydrocarbon allocation systems is to provide information regarding how hydrocarbons are behaving in a process plant. The use of simulation models ranges from the prediction of physical properties and calculation of shrinkage factors, to full integration of the model, (using cloned components) within the allocation process itself.

The paper describes the appropriate construction of the simulation model for allocation purposes and incorporation of available measured plant data. The paper discusses the commonly available commercial simulation packages and talks about issues such as stability, reproducibility, licensing and maintenance associated with such models.

The paper presents a novel alternative approach to constructing process models (using chemical engineering calculations) outwith a commercial package. This alternative approach has been implemented in a number of North Sea allocation systems and provides the advantages of: direct integration into software, robustness and transparency.

The paper concludes with a discussion regarding the necessity of a process simulation model and whether the allocation results can be replicated without recourse to a model at all.

The Impact of SOX Compliance on Hydrocarbon Accounting

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Abstract

The 2002 Sarbanes-Oxley (SOX) Act - US Legislation enacted as a result of the Enron affair – is having a significant impact on the development and operation of Hydrocarbon Accounting Systems. The legislation is intended to improve the transparency with which any public Company registered with the US Securities and Exchange Commission conducts its business. It includes requirements detailing what financial documents companies need to keep and for how long. A direct result of this is the need for full auditability of all data with a financial bearing on the Company.

Fiscal allocation processes clearly fall into this category - across the full scope of data acquisition, through manipulation, to storage and reporting. The Act therefore impacts both the collection of data inputs to the calculations, and the development and implementation of the calculations themselves.

This paper discusses how compliance with SOX may affect the operation of Hydrocarbon Accounting processes. Topics discussed include Data acquisition; Verification of data and validation of allocation; Data storage integrity; and Documentation of rules and procedures.

This paper also looks to the future, discussing potential effects on the design of new systems and whether compliance with the Act will cause a shift towards bespoke Allocation Computer Systems rather than the use of off-the-shelf tools such as spreadsheets.

Field Code Changed