North Sea FLOW Measurement Workshop

Paper 1.1

The Importance of Proper Internal Surface and Alignment of Upstream Metering Tubes, When Metering Light Hydrocarbons with Turbine Meter

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1 INTRODUCTION

The Kollsnes process facility is located at an island 60 km north of Bergen. The gas terminal was ready for operation in autumn 1995, to serve the Troll field when that started up. In 2004 and 2005, gas from new fields as Kvitebjørn and Visund were tied into the Kollsnes Gasterminal. A brand new prosessing unit was intalled as a part of the Kvitebjørn tie in.

The present capacity on the export metering stations are 146 mill Sm3/day and 7500 m3/day of condensate mix.

The gas is measured through 2 orifice metering stations. Each consist of 6*20” tubes.

The condensate mix is measured trough 4*3” tubes. Each tube has one turbine with 2 pick ups, one density meter with temperature element, 2 temperature elements and 2 pressure elements. In addition a dedicated 6” prover is installed.

The condensate mix is exported across the fjord to Mongstad (Vestprosess) where it is splitted to propane, butane and naphta.

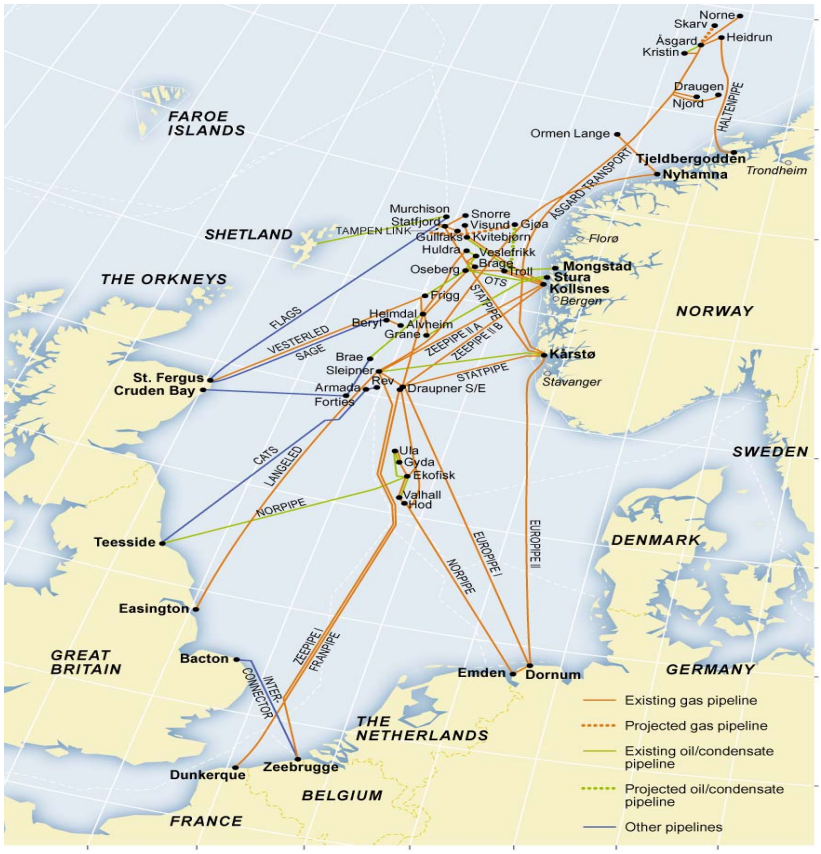


Figure 1

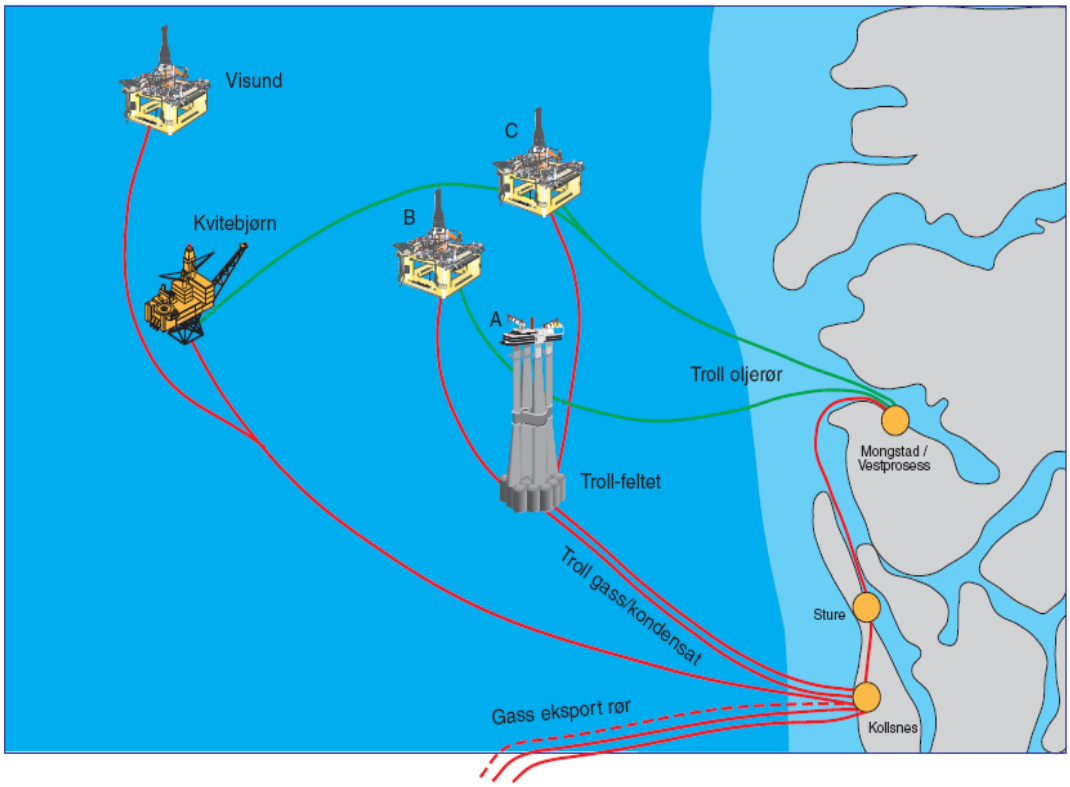


Figure 2

2 SWIRL AND NONAXISYMETRIC

Accuracy statements for flow meters are based on the steady flow of homogeneous, single-phase Newtonian fluid with an approach velocity profile that does not alter the coefficient obtained in long, straight runs of pipe.

Velocity profile is probably the most important influence quantity. The effects of swirl and nonaxisymmetric profiles on a meter performance are not only difficult to analyze, but they can not easily be duplicated in a laboratory.

The straight lengths of pipe required to eliminate swirl are different for gases and liquids. The higher viscosities of liquids dissipate both swirl and profile distortion sooner, so liquids require shorter pipe lengths than gas.

The standards in use for metering is reflecting this. The gas standards ISO 5167 (2003), ISO 17089 and AGA report no.9, is clearly addressing this aspect by setting requirements to the upstream pipe.

The similar standard used for liquid metering with turbines and prover is API Manual of Petroleum Measurement chapter 5.3, Measurement of Liquid Hydrocarbons by turbine meters. This standard also contain a number of recommendations for upstream piping, But they are formulated in a more vague form in the standard section 5.3.4. If a proper design job is not done, then we will suffer, when the end result is measured at
the start of proving operations.

This API standard is primarily an oil standard but also used for lighter hydrocarbons. We can achieve k-factor results within tolerances for oil with poorer quality pipe and centring of equipment. The challenges related to pipe surface and alignment are more exposed when you measure lighter hydrocarbons. And this was exactly what we experienced at the Kollsnes terminal.

3 MILESTONES FOR THE KOLLSNES CONDENSATE METERING STATION

a)
The metering station was built in 1994, installed in 1995 and put in regular operation in 1996.

b)
When delivered from factory, the metering station was calibrated with water and tested for repeatability and linearity (0,05% and 0,15%).

c)
When calibrated at the factory it was recognised that it was necessary to adjust some of the turbines to achieve the test requirements but this has been done on many projects so it should not be significant.

d)
The metering station was originally installed with 3 * 3” lines and pipe spec. BC21A CL300, with flow rate 15-150 m3/h.

e)
At start up in 1996, it was some difficulties to achieve the linearity and repeatability requirements. The linearity requirement was extended to 0,25%. The fluctuations in different process conditions was defined as the reason for the problems.

f)
In 2004 the condensate metering station was extended, by installing the forth metering tube. With this tube it was impossible to achieve the repeatability requirement of 0,05%. Even 0,1% was difficult to achieve.

g)
It was also identified that the situation for the 3 original turbine meters were getting worse when introducing more lighter components into the condensate. The repeatability requirement was more difficult to meet.

h)
The 4th tube was now opened and carefully examined. The following findings were done:

- Measured inner diameter in turbine meter 76,6 mm
- Measured inner diameter in the flange upstream/downstream turbine meter 77,9 mm/ 78,0 mm
- 0,7 mm edge upstream of turbine meter (pipe alignment)
- Welding protrusion 10 cm downstream of turbine meter
- Flange and metering tube are not polished on internal surface
- The flow straightening vane is of wrong model

i)
A new line 4 was installed and put in operation December 2005.

h)
The 3 original lines were replaced in September 2007.

4 AN EVALUATION OF THE LIQUID SPECIFICATIONS

It was quite clear that the liquid product was varying because of the downstream process. The density could be from 700 kg/m3 to 740 kg/m3, due to composition changes. The dynamic viscosity could similarly vary from 1 mPas to 2 mPas.

It was made up trends to establish the impact on the k-factor from these liquid changes. (Required according to NPD regulation section 25).

The conclusion was that the k-factor deviations could not be traced to these sources.

5 Upgrade of the 4th metering tube

A project was then raised to change out the 4th metering tube with a tube/flow straightening and turbine with higher quality, proper alignment and centring.

The specification for the project contained a number of detailed mechanical requirements:

- The vendor should calculate the flow profile and get this accepted by StatoilHydro.
- A 19 tube straightening vane bundle was specified. A 7 tube bundle was erroneously used in the first design.
- The straightening vane shall be centred in the pipe. It shall be no space between the pipe wall and the spacer lug. It shall fit as a piston in a combustion engine cylinder
- The turbine shall first be produced and measured. Then guiding vane holes (4) are drilled in the flange. Thereafter the metering tube is produced.
- A measurement certificate shall be produced for the metering tube and the requirements are equal to ISO 5167 part 2, except that the upstream distance to be measured is 10 D.
- Equally to the turbine. 4 holes for guiding vanes are drilled in the flanges, for centring of the turbine in the tube.
- Any welding protrusions downstream of the turbine shall be grinded.

This project was finalised in December 2005. The outcome is shown in Figures 3, 4 and 5.

Figures 3 and 4 shows pictures of line four, before and after the change out.

The improvement in quality from Figures 3 to 4 is easily seen.

Likewise the improvement in the k-factor plot can be seen in Figure 5.

Figure 3

Figure 4

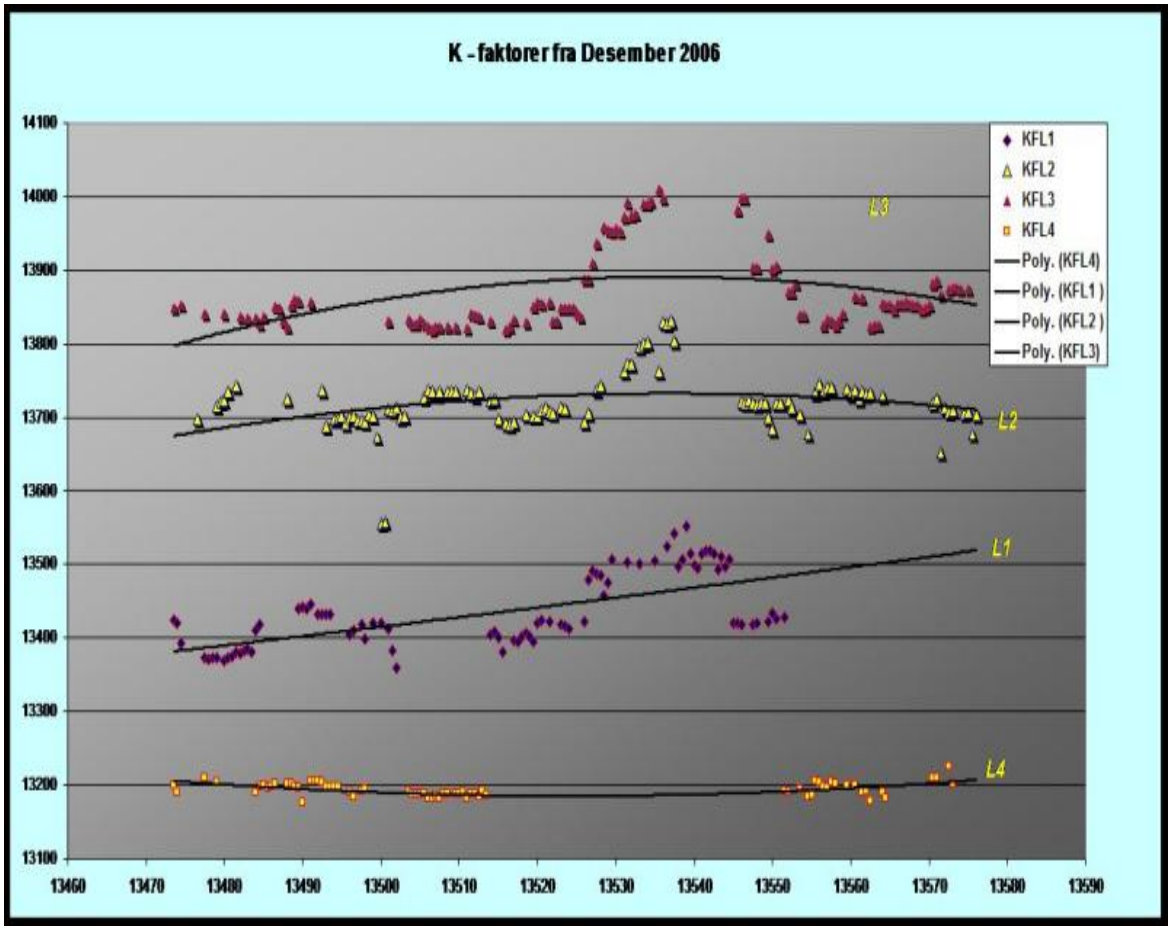


Figure 5

This figure shows the k-factor plots for the 4 lines shortly after that the new line 4 was put in service after being upgraded to fiscal quality.

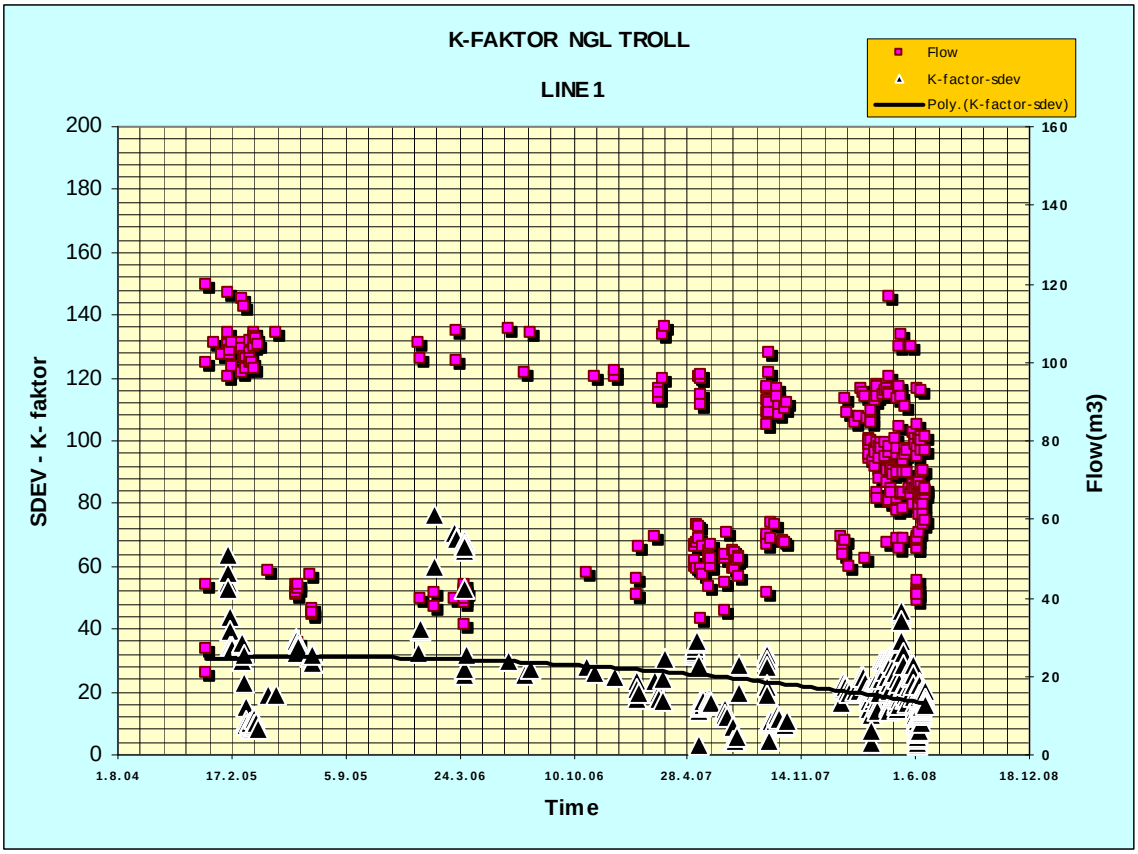
What we here see is that line number 4 has significantly better data then the three others.

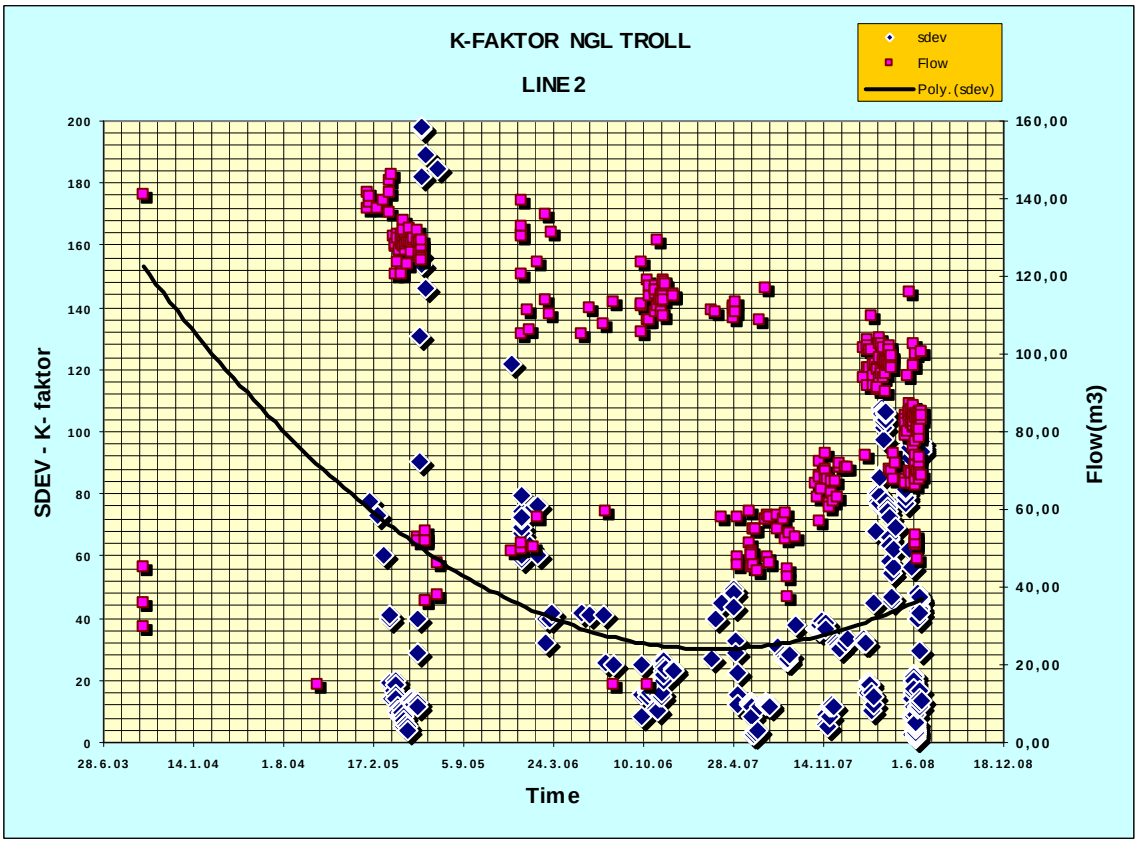
So our worries were not over with this.

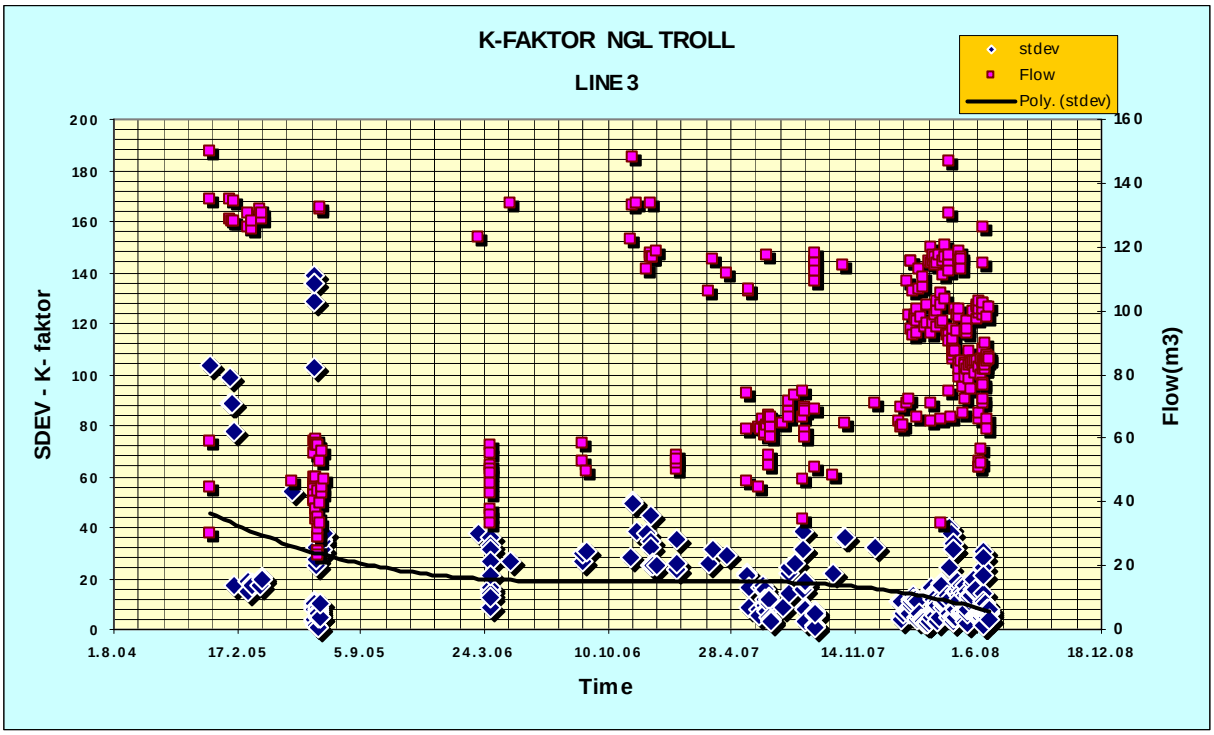
The 3 original tubes were also identified to have deviations from the new tube 4 specification related to centring, flow straightening and pipe internal surface. As the 3 existing lines were operating to some extent in conflict with internal and external requirements, it was decided to launch another pipe change out project also for these three lines. It was successfully done in 2007.

The only way to measure success here is by the evaluation of the k-factor plots.

The outcome is given the k-factor plots, Figures 6, 7 and 8.


K-FAKTOR NGL TROLL
LINE 1
Flow
K-factor-sdev
Poly.(K-factor-sdev)
SDEV - K- faktor
Flow(m3)
Time
200
180
160
140
120
100
80
60
40
20
0
160
140
120
100
80
60
40
20
0
1.8.04
17.2.05
5.9.05
24.3.06
10.10.06
28.4.07
14.11.07
1.6.08
18.12.08


K-FAKTOR NGL TROLL
LINE 2
sdev
Flow
Poly.(sdev)
SDEV - K- faktor
Flow(m3)
Time
200
180
160
140
120
100
80
60
40
20
0
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
28.6.03
14.1.04
1.8.04
17.2.05
5.9.05
24.3.06
10.10.06
28.4.07
14.11.07
1.6.08
18.12.08



We see from these plots a clear improvement in behaviour during proving. Especially for line 2 and 3 this tendency is very clear. For line number 1 the improvement is more moderate. SDiv for k-factor in each flow range is used, to make the curve easier to read. 10 consecutive k-factors in each flow rate.

6 CONCLUSIONS

When designing a liquid metering station we should be aware of the requirements for pipe roughness, and centring of flow straightening device and turbine meters.

If necessary we should specify these elements separately. This is of particular concern when we are metering light hydrocarbons.

The use of guiding vanes should be considered for being able to bring the turbines into the centre position.

Visual inspection of the flow straightening vane to ensure match with specifications and centring in pipe.

Visual inspection of the internal part of the tube to ensure that the pipe requirements have been followed.

We have to measure the tube in different positions to ensure that the requirements for the diameter and the roughness are fulfilled.

We have heard that some of the established metering vendors used experienced mechanical engineers, who without any written specification ensured that the pipe roughness, pipe specification and centring of equipment were ok. As manpower is changed and work now more often is contracted out to other companies, we need a written specification of how this shall be done. Otherwise we can end up with a bad end result as we did on Kollsnes.

The old slogan still remains valid: Always inspect, never expect.

7 REFERENCES

[1] Richard D. Miller. Flow measurement Engineering Handbook

[2] API, Manual of Petroleum measurement ch. 5.3. Measurement of Liquid Hydrocarbons by turbine meter

[3] ISO 17089. Measurement of fluid flow in closed conduits – Ultrasonic meters for gas

[4] AGA report no. 9. measurement of Gas by Multipath Ultrasonic Meters

[5] NPD . Regulations relating to measurement of petroleum for fiscal purposes and for calculation of CO_2 tax

[6] Information leaflets from StatoilHydro

[7] K-factor plots and project specifications from Bjørn Ullebust, StatoilHydro and Henning Ekerhovd, StatoilHydro

[8] Various Statoil/Bjørge project specifications

North Sea FLOW Measurement Workshop

Paper 1.2

API/IP Density Referral Constants – An Investigation into the Impact of Changing from K0 and K1 Values to API/IP Standard Values for the Flotta Pipeline System

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API/IP Density Referral Constants - An Investigation Into The Impact Of Changing From Custom K0 and K1 Values to API/IP Standard Values For The Flotta Pipeline System

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1 INTRODUCTION

The Flotta Pipeline System has used custom density referral constants, K_0 and K_1, for a number of years. This approach was introduced with the intention of making the density referral calculations more accurate by using coefficients that were more representative of the fluids actually being produced in each of the Flotta system fields, rather than those values given in API 11.1.

These custom constants have not been updated for several years now, due to costs and practicalities caused by constantly changing production profiles. Accordingly it has been proposed that the Flotta Pipeline System moves back to using the standard API constants in order to provide increased traceability.

KELTON were requested to undertake a study to assess the impact of this proposed change on the calculated production rates from each field in the Flotta allocation system. This paper summarises the findings of this study.

2 DENSITY REFERRAL CALCULATIONS

2.1 Purpose of Calculations

The density of oil varies with temperature and pressure, with the density increasing with decreasing temperature and increasing pressure. For a typical crude oil with a density of 800 kg/m^3, a 1°C temperature decrease will cause an increase in density of approximately 0.1%. The pressure effect is much smaller, with a 1 barg increase in pressure resulting in a density increase of approximately 0.01%. This is a “rule of thumb” and will vary with different oils and at different conditions. The relative change in density for a 1°C or 1 barg change is larger for lower density oils, and smaller for higher density oils.

In custody transfer oil measurement systems, the actual volume flowrate is commonly measured using a turbine meter, or some other form of volume flowmeter. This volume flowrate can then be converted to either a mass flowrate or a standard volume flowrate.

Mass flowrate is determined from:

$$q_m = q_v \times \rho_m \qquad [1]$$

where

q_m = mass flowrate (kg/s)
q_v = actual volume flowrate (m^3/s)
ρ = density at meter (kg/m^3)

whilst standard volume flowrate is determined from:

$$q_{v,std} = q_v \times C_{TPL} \qquad [2]$$

where

$q_{v,std}$ = standard volume flowrate (kg/s)
q_v = actual volume flowrate (m^3/s)
C_{TPL} = volume correction factor for temperature and pressure (-)

For the mass flowrate calculations the oil density at the meter is normally calculated from the measured density at the densitometer, corrected to account for the difference in oil temperature and pressure between the densitometer location and the meter itself. The densitometer is normally located in a bypass loop, although the temperature and pressure would be close to those at the meter.

For the standard volume flowrate calculations, the C_{TPL} term represents the volume correction factor from meter temperature and pressure to standard temperature and pressure.

In both cases it is clear that the change in density from one temperature and pressure to another must be accounted for in the flow calculations. The specific method for doing this can vary, however the vast majority of systems make use of the calculations given in Chapter 11.1 of the API Manual of Petroleum Measurement Standards (MPMS) [1].

2.2 API MPMS Chapter 11.1

The current version of API Chapter 11.1 standard includes the correction factor for the effects of both temperature and pressure on oil density. Previous version of API 11.1 (1952 and 1980) only covered the temperature effect, with Chapter 11.2 (previously API 1101 Standard) being used for pressure corrections.

The overall correction term is given as the product of the temperature correction and the pressure correction:

$$C_{TPL} = C_{TL} \cdot C_{PL} \qquad [3]$$

The temperature correction term is given as:

$$C_{TL} = \exp\left[-\alpha_{60}\Delta t\left(1 + 0.8\alpha_{60}\Delta t\right)\right] \qquad [4]$$

$$\alpha_{60} = \frac{K_0}{\rho_{60}^2} + \frac{K_1}{\rho_{60}} + K_2 \qquad [5]$$

where

α_{60} = thermal expansion coefficient at 60°F (/°F)
Δt = temperature difference between measured and base (t – 60°F) [°F]
ρ^*_{60} = base density at 60°F [kg/m^3]

The constants K_0, K_1 and K_2, are given in the standard for various commodity groups. For crude oils, K_0 = 341.0957, and K_1 = K_2 = 0, for a 60°F base temperature.

The current version of the Chapter 11.1 is given exclusively in terms of a 60°F reference temperature, with other reference temperatures (i.e. 15°C) requiring a second calculation to correct from 60°F[1]. However most commercial flow computers in current operation will still be using the 15°C base temperature calculations from the 1980 version of Chapter 11.1, where K_0 = 613.9723. It is this 15°C version that will feature later in this paper for comparison purposes.

[1] Older versions of Chapter 11.1 did contain metric conversions to 15°C, however these have not been included in the current version due to difficulties in maintaining consistent calculations with different base temperatures.

The pressure correction term is given as:

$$C_{PL} = \frac{1}{1 - F_P\left(P - P_e\right)} \qquad [6]$$

$$F_P = \exp\left[-1.9947 + 0.00013427t + \frac{793290 + 2326t}{\rho_{60}^2}\right] \qquad [7]$$

where

F_p	=	compressibility factor [/psi]
P	=	measured pressure (e.g. at meter) [psi]
P_e	=	equilibrium pressure at temperature t [psi]
T	=	measured temperature (e.g. at meter) [°F]

There are other small corrections used in the current Chapter 11.1 calculation to account for differences between the IPTS-90 and IPTS-68 temperature scales; however these are omitted from the above summary for simplicity.

2.2 Limitations of API Calculations

It has long been considered [2] that the constants given in Chapter 11.1 are not suitable for North Sea crude oils, as apparently only 2 out of the 124 oils used in the original research to develop the coefficients were from the North Sea (Forties and Auk fields).

Furthermore, the samples were allowed to stabilise in open containers prior to testing, thus allowing light ends to vaporise off. Water content was also restricted to very low levels, unlike current North Sea production.

Accordingly there have been calls for more representative volume correction factors for North Sea crudes [3] to avoid calculation errors and potential mis-allocation of field productions. Ref [3] claims that very significant errors will be introduced in North Sea allocation systems through the use of the standard API volume correction factors. However the basis for this claim appears to be mistaken as will be discussed later in this paper.

3 FLOTTA PIPELINE SYSTEM

The Flotta Pipeline System transports oil from a number of North Sea platforms to the Flotta terminal in Orkney. The fields producing through this system are AH001, Claymore, Duart, Galley, Highlander, MacCulloch, Piper, Saltire, Scapa, Tartan and Tweedsmuir.

The Flotta Pipeline System has used custom density referral constants, K_0 and K_1, for a number of years. The custom coefficients were calculated for each separate crude oil and NGL stream every three months. The values were based on coefficient of thermal expansion (CTE) analyses performed on periodic samples taken from each production stream. These custom values were then entered into the flow computers.

This approach was introduced with the intention of making the density referral calculations more accurate by using coefficients that were more representative of the fluids being produced, rather than those values given in API Chapter 11.1. However due to the constantly changing production levels from various fields, it became impractical to maintain representative custom coefficients for each field, and consequently these custom constants have not been updated for several years now.

Accordingly it has been proposed that the Flotta Pipeline System moves back to using the standard API K_0 constant in order to provide increased traceability compared with outdated custom values that are unlikely to represent current production fluids.

KELTON were requested to undertake a study to assess the impact of this proposed change on the calculated production rates from each field in the Flotta allocation system, to determine if any particular field(s) would be significantly affected. This paper summarises the findings of this study.

It is not proposed to modify the pressure correction method, therefore this study only addresses the impact of changing the K_0 value. The change in K_0 value will have a second order effect on C_{pl} calculations as the density at 60°F is an input into these.

4 STUDY OBJECTIVES

At the outset of the study it was agreed that production data for 12 months from 01/08/06 to 31/07/07 would be used as the basis for the study. Flow weighted average values for density, pressure and temperature were calculated over this period. This data would be used to assess the impact of moving from the custom K_0 values to the standard API values.

The areas identified for investigation were:

- the calculation of standard volume flowrates
- the impact on calculated meter K-factors

It was understood at the time that the effect on standard volume flowrate calculations would be the most significant as this would directly impact the Flotta allocation system and could lead to errors in the quantity of oil allocated to each field in the Flotta system.

During the course of the work, it became clear that the Flotta allocation system was not based on calculated standard volume flowrates, but was actually a mass based allocation system. Accordingly the impact on the mass values reported by each measurement system was assessed also.

5 STANDARD VOLUME CALCULATIONS

Flow weight averaged process variables were calculated for each stream, based on 12 months of PARS data, for the period 01/08/06 to 31/07/07. Tartan process conditions were calculated from 17/02/07 to 31/07/07 as Tartan and Highlander were commingled on this date. These average conditions are shown below in Table 1.

It can be seen that there is a large spread of operating temperatures, pressures and densities across the Flotta system streams.

These average process values were then used to calculate C_{TL} and C_{PL} values for each stream using both the existing custom K_0 values and the standard API coefficient. KELTON's FLOCALC® software was used for these calculations.

Table 1. Average process conditions.

Platform	Stream	FWA Density [kg/m^3]	FWA Pressure [barg]	FWA Temperature [ºC]
Claymore	**MOA**	864.54	16.89	57.77
	MOB	865.24	16.36	53.62
	Claymore Average[2]	**864.89**	**16.62**	**55.69**
	MOD	873.59	21.00	40.07
	MOE	892.76	20.83	40.16
	Scapa Average	**883.18**	**20.91**	**40.12**
Piper	**PPOA**	802.59	25.48	70.95
	PPOB	804.07	26.06	70.60
	Piper Average	**803.33**	**25.77**	**70.78**
	PTOA	828.14	32.47	62.50
	PTOB	offline	offline	Offline
	Tweedsmuir A[3]	795.07	30.09	25.85
	Tweedsmuir B[2]	822.39	27.55	24.45
	Tweedsmuir Average	**808.73**	**28.82**	**25.15**
	CML[4]	594.83	78.79	33.24
	NML[3]	520.56	84.09	40.11
MacCulloch	**MOM**	839.40	12.29	46.64
Galley	**MOG**	770.85	10.24	42.53
AH001	**MOA**	826.00	74.90	46.00
	MCA[3]	476.28	59.91	20.41
Tartan	**MOT & MOH**	873.92	12.74	45.11
	MCA	561.83	67.20	34.30

The results of this exercise are shown below in Table 2, which also shows the custom K_0 values currently in use for several systems. It can be seen that most systems would experience an increase in the calculated standard volume flowrate as a result of the change to the API K_0 coefficient.

The Tartan NGL stream (MCA) shows the most significant shift of +0.44%. This is not surprising as being an NGL stream the density is very low, and the custom K_0 value is significantly different from the API value. The density is in fact below the lower end of the current API Chapter 11.1. The correct standard for volume correction for this stream would be GPA TP-27 [4] (also published as API Chapter 11.2.4).

The next most significant shifts are for Claymore (+0.189%), Scapa (+0.180%) and Piper (+0.133%). All the remaining shifts are less than 0.1%, with the Piper test stream (PTOA) being the only stream to show a negative shift, albeit a very small one at -0.005%. The Tweedsmuir and Galley systems already use the API coefficient, therefore there is no impact on these two systems.

Table 3 shows the overall impact in terms of absolute differences as well as relative. From this viewpoint the Tartan NGL stream is not significantly affected as its production level is very low. The largest impact in absolute terms is the Claymore field, which would see standard volume production increase by 8.5 sm^3/day (53.5 bbl/day).

[2] Claymore C Stream not used in averaging as this is a spare stream and can be from either A or B Separator.
[3] Tweedsmuir & Galley Streams already uses K0=613.9723.
[4] CML, NML & AH001 MCA were not included in study due to their low production quantities.

Table 2. Calculated volume correction factors with custom and API K_0 values.

Platform	Stream	Calculated Values with Custom K0			Calculated Values using API K0			Overall effect on std volume flow
		K0	Ctl	Cpl	K0	Ctl	Cpl	%
Claymore	MOA	648.4273	0.96502	1.00128	613.9723	0.96678	1.00129	0.182
	MOB	654.4318	0.96801	1.00122	613.9723	0.96988	1.00123	0.194
	Claymore Avg	651.4295	0.96651	1.00125	613.9723	0.96833	1.00126	0.189
	MOD	672.2635	0.97866	1.00147	613.9723	0.98045	1.00148	0.183
	MOE	672.2635	0.97947	1.00135	613.9723	0.98119	1.00136	0.176
	Scapa Avg	672.2635	0.97906	1.00141	613.9723	0.98082	1.00142	0.180
Piper	PPOA	631.1146	0.94964	1.00265	613.9723	0.95089	1.00267	0.133
	PPOB	631.1146	0.95009	1.00269	613.9723	0.95133	1.00271	0.132
	Piper Avg	631.1146	0.94986	1.00267	613.9723	0.95111	1.00269	0.133
	PTOA	613.1146	0.96019	1.00296	613.9723	0.96014	1.00296	-0.005
	PTOB							
	Tweedsmuir A	613.9723	0.98959	1.00282				
	Tweedsmuir B	613.9723	0.99151	1.00229				
	Tweedsmuir Avg	613.9723	0.99058	1.00254				
	CML							
	NML							
MacCulloch	MOM	626.8444	0.97309	1.00101	613.9723	0.97362	1.00101	0.054
Galley	MOG	613.9723	0.97281	1.00113				
AH001	MOA	623.2288	0.97264	1.00669	613.9723	0.97303	1.00670	0.041
	MCA							
Tartan	MOT & MOH	637.2569	0.97587	1.00090	613.9723	0.97671	1.00091	0.087
	MCA	684.2582	0.95928	1.02273	613.9723	0.96318	1.02310	0.440

Table 3. Standard volume flowrate impact.

Stream	Old Standard Volume [Sm³]	New Standard Volume [Sm³]	Difference [%]	Difference [Sm³/day]
Claymore Average	4505.3	4513.8	0.19	8.5
Scapa Average	635.3	636.5	0.18	1.1
Piper Average	1979.7	1982.3	0.13	2.6
PTOA/B Average	107.8	107.8	-0.01	0.0
Tweedsmuir Average	2014.6	2014.6	0.00	0.0
MOM	2448.3	2449.6	0.05	1.3
MOG	816.8	816.8	0.00	0.0
AH001 MOA	440.6	440.8	0.04	0.2
Combined MOT & MOH	1687.7	1689.1	0.09	1.5
TARTAN MCA	150.4	151.1	0.44	0.7

6 K-FACTOR CALCULATIONS

When proving turbine meters against a volumetric prover, the meter K-factor is determined from the familiar calculation:

$$K = \frac{n}{V} \cdot \frac{C_{tlm} C_{plm}}{C_{tlp} C_{plp} C_{tsp} C_{psp}} \qquad [8]$$

where

n	=	number of pulses counted during prove [pulses]
V	=	prover volume passed [m3]
C_{tlm}	=	volume correction factor (temperature) from meter to standard conditions
C_{plm}	=	volume correction factor (pressure) from meter to standard conditions
C_{tlp}	=	volume correction factor (temperature) from prover to standard conditions
C_{plp}	=	volume correction factor (pressure) from prover to standard conditions
C_{tsp}	=	volume correction factor (temperature) for prover steel body
C_{psp}	=	volume correction factor (pressure) for prover steel body

The latter two corrections are not relevant to this study as they are not related to the proposed change from custom constants to API values.

The C_{tl} and C_{pl} factors for both meter and prover would be affected by the change. However as the prover corrections move from prover conditions down to standard conditions and the meter corrections then move from standard conditions back up to meter conditions, the impact of changing the coefficients used in the calculations is likely to be small as the prover and meter will be operating at a similar temperature and pressure.

Calculations were run using KELTON's FLOCALC® software for two systems, Claymore MOA and Piper MOA, to assess the impact of changing K_0 values. The relevant flow weighted average temperature, pressure and density shown in Table 1 were used in the calculations, together with a single pulse and the appropriate prover parameters. An average offset between meter and prover temperature and pressure was calculated and used to allow the prover temperature and pressure to be determined for these current calculations.

The full FLOCALC® outputs are shown in Appendix A for these calculations, however in summary the impact was found to be negligible as shown below in Table 4.

Table 4 below shows the results of the calculations, and it is clear that the impact of changing the K_0 values is negligible. This is due to the fact that the temperature difference between the meter and the prover is very small (approximately 0.3°C on Claymore and 0.6°C on Piper).

Table 4. Impact on K-factor calculations.

Meter Stream	K-Factor (Custom K0)	K-Factor (IP Paper 2 K0)	% Difference
Claymore MOA	0.146648	0.146650	+0.0014
Piper PPOA	0.262134	0.262130	-0.0015

7 MASS FLOWRATE CALCULATIONS

During the course of the study, from discussions with the allocation personnel at Talisman it became apparent that the Flotta allocation system was in fact a mass based system. The mass flowrates from each platform are input into the system and are combined with the analysis of the weekly samples to give component mass values. These are then reconciled with the total mass of each component leaving the Flotta terminal.

Accordingly, the important issue for the allocation system is the impact of changing K_0 values on the calculated mass values from each field. Eq. (1) shows that the mass flowrate is the product of the measured actual volume flowrate and the meter density. The meter density is calculated from the measured density at the densitometer, corrected from the temperature and pressure at the densitometer to those at the meter:

$$\rho_m = \rho_d \frac{C_{tlm} C_{plm}}{C_{tld} C_{pld}} \qquad [9]$$

where

ρ_m	=	meter density [kg/m^3]
ρ_d	=	measured density at densitometer [kg/m^3]
C_{tlm}	=	volume correction factor (temperature) from meter to standard conditions
C_{plm}	=	volume correction factor (pressure) from meter to standard conditions
C_{tld}	=	volume correction factor (temperature) from densitometer to standard conditions
C_{pld}	=	volume correction factor (pressure) from densitometer standard conditions

As for the prover calculations, there will be a large degree of cancelling out, as the meter and densitometer conditions will be very similar. Densitometers are normally installed in the fast loop bypass and are generally well lagged, such that the temperature should not change much between the fast loop and the meter stream.

Attempts were made to obtain data for meter vs. densitometer conditions, however KELTON were advised that many of the systems on the Flotta Pipeline System do not actually measure the temperature and pressure at the densitometer. The meter density is taken as being equal to the measured density.

It is not therefore possible to perform specific calculations on the actual measurement systems, however we can easily make an estimate of the effect based on assumed temperature and pressure differences. Table 5 below shows the results of some example calculations carried out using FLOCALC®.

Table 5. Assessment of impact on meter density calculations.

System	Calculation method	K0 constant	Measured Density (kg/m3)	Header temp (oC)	Header pressure (barg)	Standard density (kg/m3)	Meter temp (oC)	Meter pressure (barg)	Meter density (kg/m3)	Difference (%)
Claymore ave	IP Paper 2	613.9723	864.89	57.69	16.62	893.404	55.69	16.62	866.279	
	IP Paper 2	651.4295	864.89	57.69	16.62	895.172	55.69	16.62	866.36	-0.010
Scapa MCA	IP Paper 2	613.9723	883.18	42.12	20.91	900.52	40.12	20.91	884.55	
	IP Paper 2	672.2635	883.18	42.12	20.91	902.27	40.12	20.91	884.68	-0.015

Table 5 contains example calculations for two systems, Claymore average and Scapa average. In each case it has been assumed that the densitometer temperature is 2°C higher than the meter temperature. This would be considered a conservatively high temperature difference and in many cases the temperature difference would be lower than this.

It can be seen that the effect on meter density, and hence mass flowrate, of changing from custom constants to the API standard K_0 is very small indeed for the two cases shown above.

8 DISCUSSION OF STUDY FINDINGS

The study assessed the impact of changing from the current custom K_0 values to the standard API values.
It was found that the impact on gross volume flowrates, through K-factor calculations would be insignificant. This is due to the fact that the meter and prover will be operating at very similar temperatures and pressures, therefore the sensitivity to the actual K_0 values used is very low.

The impact on calculated standard volume flowrates was more significant, with shifts of up to 0.19% observed in crude oil streams, and 0.44% on an NGL stream[5]. However, the standard volume flowrates are not used in the Flotta allocation system therefore these shifts have no impact on allocation. It is believed that the pipeline tariffs are calculated on the basis of the standard volume flowrates, therefore there may be a very small financial impact here.

With regards to the impact on calculated mass flowrates, it was not possible to obtain exact data as the systems reviewed did not actually measure temperature and pressure at the densitometer. However assuming a 2°C difference between meter and densitometer, it was shown that the impact would be small, of the order 0.01% to 0.02%.

Overall it can be concluded that the impact of moving from the current custom K_0 values to the standard API value would not have a significant impact on the Flotta allocation system.

9 GENERAL SITUATION FOR UK PIPELINE SYSTEMS

During the course of this study KELTON contacted representatives of several of the other major oil pipelines (Forties, Brent & Ninian) in the North Sea to ascertain if their allocation systems operated in a similar manner to the Flotta system.

From these discussions it would appear that all of the allocation systems also operate on a component mass basis, and the influence of the K_0 values is limited only to the correction of density from densitometer conditions to meter conditions.

Obviously the impact of this would depend on the nature of the fluids involved and on the differences in temperature between the densitometers and meters[6]. As most systems will be fully lagged, it is this author's opinion that it is very unlikely that there will be temperature differences of more than 1°C or 2°C, and that consequently there would be little impact on calculated mass flowrates and hence product allocations.

It follows from this conclusion that there would seem little justification for any large scale research project to review the density referral coefficients for North Sea crude oils. However in order to further support this viewpoint it would be considered worthwhile to perform a desktop review of the measurement systems involved to ensure that there are no large differences in operating conditions between densitometers and stream meters.

10 REFERENCES

[1] API Manual of Petroleum Measurement Standards. Chapter 11 – Physical Properties Data. Section 1 – Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils. May 2004, Addendum 1, September 2007.

[2] R. THIRD and N. COYLER. Crude Oil Expansion Coefficients. 14th North Sea Flow Measurement Workshop, October 1996, Peebles, UK.

[5] The API Chapter 11.1 calculations should not be used on this NGL stream. Instead GPA TP-27 should be used which gives a very close agreement with the current custom K_0 value.
[6] The pressure differences are considered negligible, due to the lower impact of pressure on density.

[3] J. McNAUGHT et al. The Influence of Fluid Properties on Allocation Accuracy. 7th South East Asia Hydrocarbon Flow Measurement Workshop, March 2008, Kuala Lumpur, Malaysia.

[4] GPA Technical Publication TP-27. Temperature Correction for the Volume of NGL and LPG. Tables 23E, 24E, 53E, 54E, 59E and 60E. September 2007.

North Sea FLOW Measurement Workshop

Paper 1.3

Infrared Water Cut Meter for Cost Effective Individual Monitoring of Complex Wells

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Infrared Water Cut Meter for Cost Effective Individual Monitoring of Complex Wells

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1 INTRODUCTION

The success of field management depends on the accuracy and availability of well performance data. Continuous monitoring provides information so that corrective action can be taken in a timely manner to better manage expensive well assets by maintaining well potential, managing water conformance and increasing the well life. Accurate water-cut monitoring can significantly reduce the dead well number by providing the data to timely implement corrective action.

Methods for measuring water-cut values range from conventional hand sampling to cutting edge technology. Saudi Aramco's traditional well testing practices, utilizing a test trap at a GOSP, limit the information available, due to the infrequent test trap availability on a per well basis, usually exceeding one month or more. Test trap data also has inherent error built in, due to averaging and human error. What is needed is real-time, in-line and accurate water-cut monitoring.

When considering technologies for monitoring water-cut, factors such as accuracy, data transfer rate and cost play major roles. This paper presents how an infrared meter provides an accurate and cost effective means to monitor water-cut in complex wells. The infrared monitoring device is an in-line real-time monitoring system that provides accurate water-cut even, in very challenging flow conditions. A pilot test of the infrared water-cut meter was successfully conducted in a major oil field in Saudi Arabia. Results from this test will be included in the paper.

2 BACKGROUND

Near infra-red spectroscopy is a well-known technique for chemical analysis and has been successfully applied to measurement of small quantities of water in a variety of media such as paper, methanol, tobacco, etc. The technology was further developed to exploit the very characteristic attenuation of infra-red light by water as a means to measure the water-cut in mixtures of oil and water. Saudi Aramco initiated a trial test to evaluate the real-time water-cut monitoring using infrared water-cut meter. The test started in March 2006 and was successfully completed in January 2007. The trial test was conducted in two wells, referred to here as Well-408 and Well-458.

The infrared water-cut meter was used for the first time by Saudi Aramco for this specific application. The trial test was intended to verify the reliability of using infrared water-cut meters to provide cost effective means of monitoring expensive horizontal wells. This real-time water-cut monitoring should enable remedial actions to taken in a timely manner and, therefore, prevent potential loss on horizontal wells that is attributed to uncontrolled water-cut increase.

The trial test also intended to verify the practicality of using the infrared water-cut meter in areas that lack communication infrastructure. On the two wells tested, GSM technology was used to transmit well data to engineers' office computers.

Drilling wells with long horizontal section in many fields is a standard practice. Drilling complex wells with multi-laterals is at an increasing trend. The cost of these wells is very high opposed to conventional wells. The expenditure of such wells cannot be recovered if changes in water-cut go unnoticed, due to shortage of data, and eventually cause these wells to load up and die.

The only method that Saudi Aramco uses currently to acquire such data is through periodic well testing. This is a traditional well testing technique that utilises a test trap at the Gas Oil Separation Plant (GOSP). This technique limits the information availability as such tests are periodic on a per well basis. The interval between well tests normally exceeds one month. This has increased the feasibility of real-time water-cut monitoring systems should they provide data with the required frequency and precision. Choosing the right application for real-time water-cut monitoring depends on how much data is required and how accurate it needs to be. For the evaluation purposes, measurement accuracy, data transfer capabilities and cost effectiveness played a major role.

There are various methods to measure the water-cut in a producing well. Methods for measuring water-cut values range from conventional hand sampling to real-time high-end technology measurement. By facilitating means for continuous water-cut monitoring, we ensure that the required information is available to take corrective action in a timely manner to better manage expensive well assets by maintaining well potential, managing water-cut conformance and increasing the well life.

A real-time water-cut monitoring trial test was initiated in the Saudi Aramco Idea Management System. A multi-disciplined team was formed to evaluate and test the idea where applicable.

During the test, no major problems were encountered. The minimum water-cut measurement during the test was 5% and the maximum reached 42%. The meter was tested on oil wells with GOR of ±550 Scf/STB. The post test inspection of water-cut meters components indicated no corrosion at any of the water-cut meter components.

3 INFRARED WATER-CUT METER TRIAL TEST

3.1 Infrared Water-Cut Meter Description

The infrared water-cut measurement is based on near-infrared absorption spectroscopy. As shown in Figure 1, the dependence of absorption of near-infrared light on wavelength varies with the composition. At several key wavelengths, infrared light absorption is dependent on the behaviour of carbon-hydrogen and oxygen-hydrogen bonds in the molecules. Water contains O-H bonds and hydrocarbons do not, therefore, allowing infrared absorption to distinguish water from organic molecules. Furthermore, the characteristic wavelength associated with bending of the H-O-H bond in water is different from the wavelength associated with O-H bond stretch, so there exists the potential for water to be distinguished from other molecules, such as methanol, containing O-H bonds.

The infrared water-cut meter extends the performance of an older generation meter, which used a single wavelength, to allow more accurate measurements at lower water-cut, by simultaneously measuring multiple wavelengths that include both the water and oil absorbent peaks. Scattering effects caused by emulsions, sand or gas bubbles are expected to have the same effect at all wavelengths and as such can be eliminated.

Furthermore, changing salinity should have no effect on the measurement, since the water absorption is based on the water molecule itself, not what is dissolved in the water.

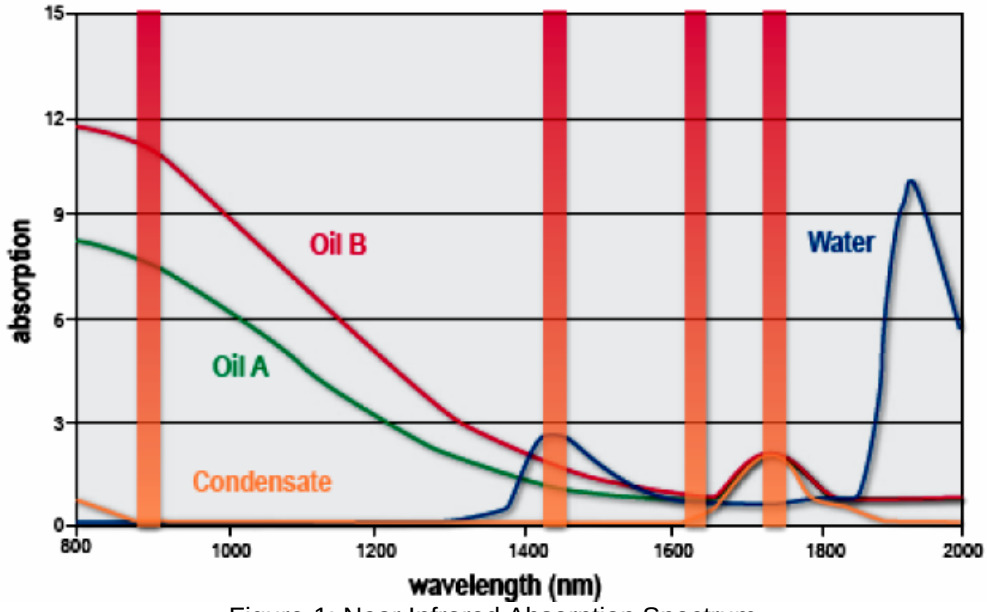

Figure-1: Near Infrared Absorption Spectrum

The internal design of the meter is shown in Figure 2. The meter consists of a probe which is inserted into the flow, either through a 1–inch NPT flowline tap or using a 1½–inch flanged connection and an electronics module mounted directly onto the probe. The only external connections required are for power (10 to 30 V DC @ 8 W) and output signal (4-20 mA analogue or RS-485 MODBUS outputs).

Figure-2: Infrared Meter Cross-Section

The main measurement section within the insertion probe has a small gap, with an infrared source on one side and detector consisting of a fibre optic bundle on the other. Between the optical source and detector and the process fluids are sapphire windows for their optical and mechanical properties, including abrasion resistance.

3.2 Well Selection

This trial test was conducted in a major oil field in the Eastern Province of Saudi Arabia. The field contains two oil bearing reservoirs. The produced crude is classified as Arabian Light Crude, 34° API. The selection of the two wells (408 & 458) was based on several factors. The GOR in the field plays a major role in the selection criteria. The selected area had a moderate GOR of ±550. The wells were selected as they have low to moderate water-cut ranging from 12% to 30%. Finally, the candidate wells were selected due to location with a GSM signal available. The field where the trial test was conducted did not have established communication infra-structure field wide. Using data enabled SIM cards and utilizing the existing GSM coverage allowed for data transfer from the well to the GOSP using this data transfer option for the first time in Saudi Arabia.

3.3 Trial Test Preparation

The infrared meter installed in Well-458 was calibrated by flowing single phase oil and single phase water through the meters prior to starting the test. Manual intervention was required during the test to double check the configuration. However, the meter installed on Well-408 was installed without the benefit of any reference water-cut readings. This was done to test the performance of the meter without using baseline test

Figure-3 and Figure-4 illustrate the site configuration for the infrared meter installation. The insertion style design (as illustrated in Figure-3) reduces the installation cost and saves time if performed correctly. The electronics are mounted directly to the measurement probe so the only field wiring required is for the power and output signal cables.

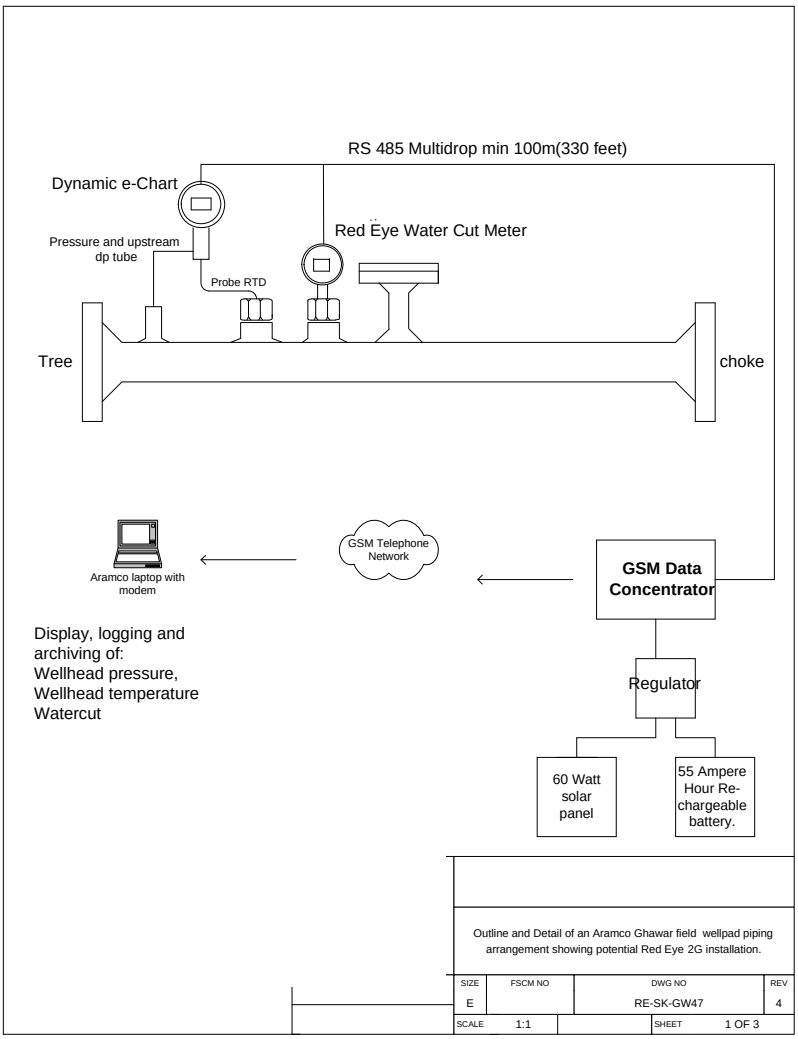

Figure-3: Infrared Site Installation

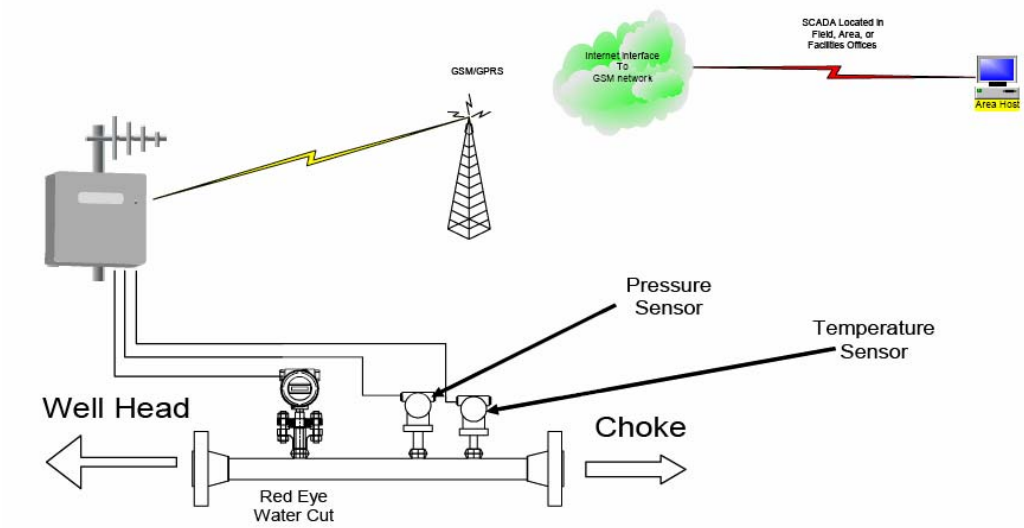

Figure-4: Infrared General Configuration

The data is gathered and collected in the RTU (Figure-5) before the system flushes itself and start saving the data for the next interval. The data can be downloaded manually every two to three months.

Figure-5: Infrared RTU

Moreover, the system has the capability to send the data as illustrated in the previous mentioned attachments. Data enabled GSM-SIM cards were used in this test to securely transmit the data from the well location sites to a receiving laptop in the engineering offices. Refer to Figure-6 and Figure-7 for the office interface.

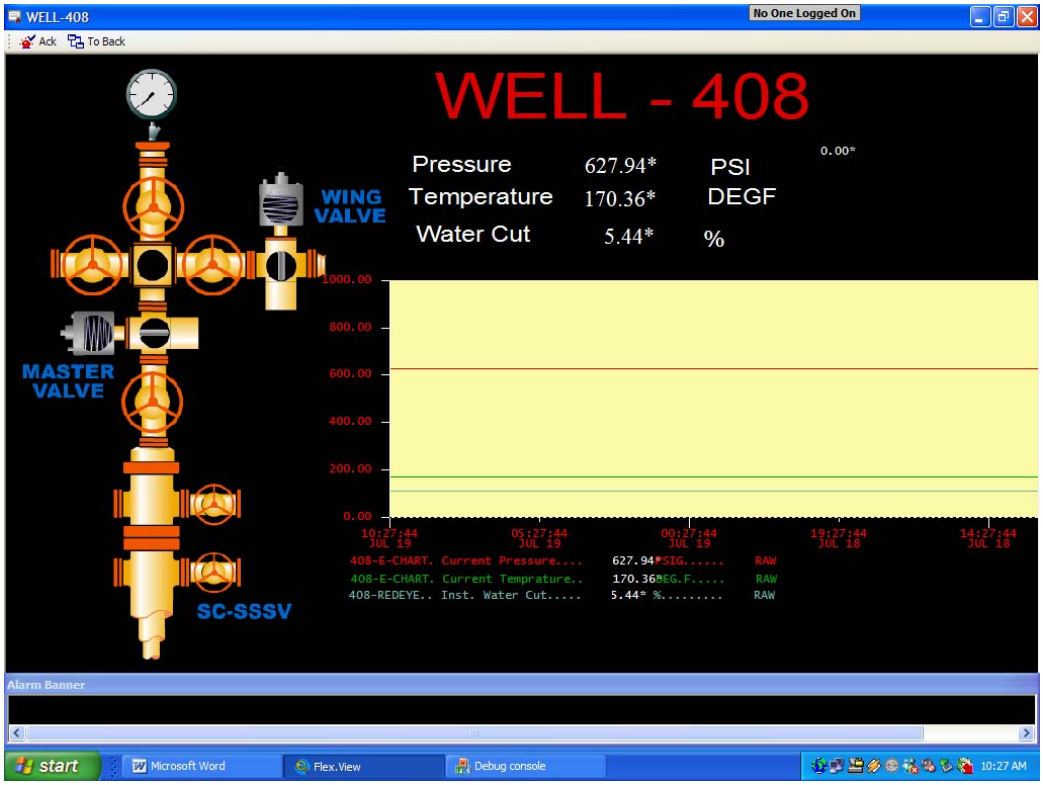

Figure-6: Well 408 Data Format Interface

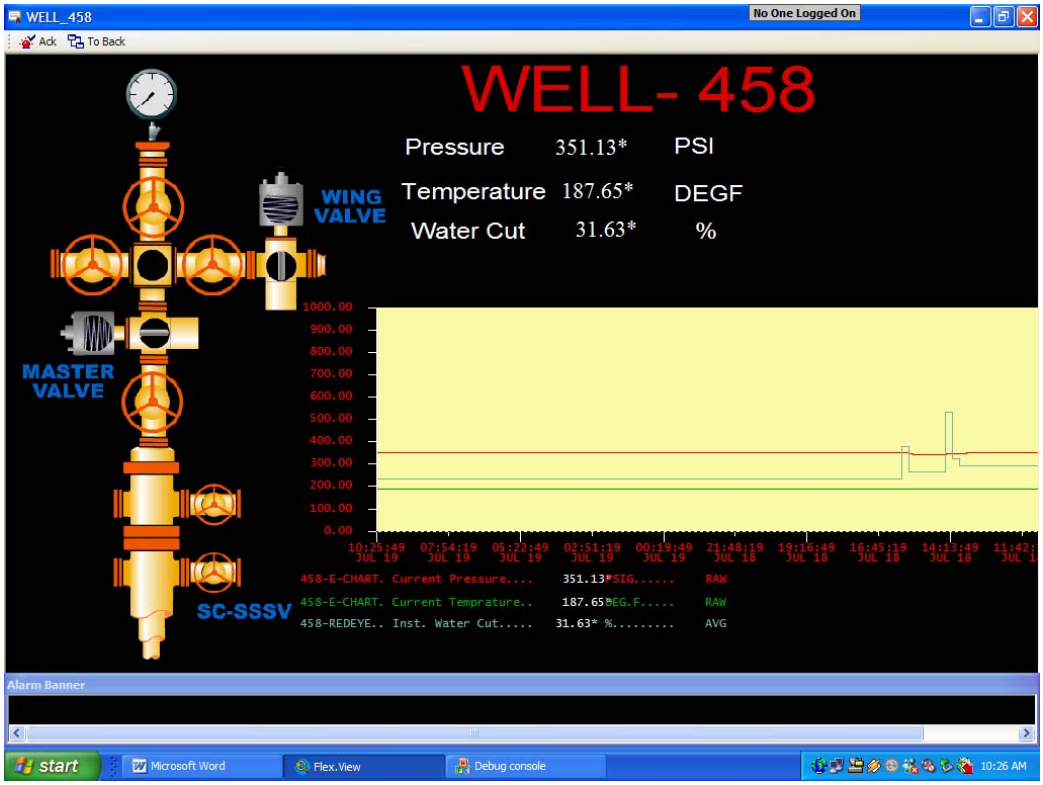

Figure-7: Well-458 Data Format Interface

3.4 Power & Communication

After the six month of trial test period, ending in November 2006, both infrared units experienced occasional loss of the water-cut signal. When the default configuration state is active, the actual readings and outputs from the meter unit are forced to zero even though the meter may be in an otherwise perfect working order. The internal data log showed the infrared units always dropped to 0% or came back to actual readings around 6 and 9AM in the morning.

If the battery runs low, the equipment will eventually shut off. Normally this is not a problem since once there is sufficient solar power the meter will start up and reload its configuration file then it will continue reading and reporting water-cut. However, if that start up is not “clean” as can happen with battery systems, the meter can experience an error with the configuration readings and go into the fault mode. This will stay active until another “clean” power cycle is experienced.

Starting in November, the days became shorter and the occasional rain resulted in the supplied solar power to drop below the minimum acceptable voltage. This would normally happen in the early morning, as can be seen in Figure-19. When the battery voltage climbs up to an acceptable level the system turns on. The added load on the battery typically results in a sag in voltage from the battery. This can trigger an on-off-on cycle as the solar power is coming back on line and this can, in some circumstances, cause the meter to experience the fault.

After consulting and studying the issue with the vendor, three remedies were brought forward to resolve the issue:

1. One option was to increase the solar panel/battery capacity and avoid the low power conditions.

2. The second option involved the use of a low voltage cut off with dead-band and this could be as a short term correction. With this approach, the unit will still turn off when

supply power drops below a set limit but the dead-band voltage between shut off and power up will eliminate the saggy/weak start up condition.

3. The third option was to provide electrical power to run system.

The meter also needed a modification for the firmware to check for valid configuration file at each start up. The vendor established the necessary modification and reconfigured the meters. In addition to the low cut off voltage modification, the vendor modified the system to track the input and output voltages provided to the system. Later, tracking the voltages shows that Well-408 battery is damaged due to excessive operation below 11.5V DC. The battery was changed and the performance is being tracked.

Although GSM has been used for the purpose of this trial test, it is recommended to use other communication alternatives in the future. The other possible options are summarized in the following table:

Table 1: Wireless Communications Options

Method	Advantages	Disadvantages
UHF Radio	– One time cost. – Easy to install. – Adequate bandwidth for application. – Long coverage.	– Authorization difficulty. – Not secure.
Spread Spectrum Radio (2.4GHZ Serial Data	– Easy to install – Adequate bandwidth – Possibility of storing and forwarding the data.	– Non licensed radio frequency may be difficult to import. – Remote diagnostics may not be possible. – Limited distance at restricted effective radiated power, typically 1 watt max. – Not secure.
Spread Spectrum Radio 2.4 GHZ Ethernet	– Easy to install. – Higher bandwidth. – Enable remote diagnostics. – Possibility of storing and forwarding the data. – Secure.	– Non licensed radio frequency may be difficult to import. – Limited distance at restricted effective radiated power.

Other alternatives include copper wire, fiber optics, satellite communication (V-Sat) and other types of Spread Spectrum Radio such as WiMAX. Copper wire communication is limited by the distance, and boosters may be required every four kilometres although boosters are not recommended. Although the fibber optics speed is unlimited, it requires huge construction and implementation cost. WiMAX is the best choice among these alternative, in terms of reliability and coverage. Out of the previous alternatives WiFi may be the quickest and cheapest alternative, if approved.

The recommendation is to work with the IT/Communication to determine other communication alternatives, to ensure reliable data communication for real-time water-cut and wellhead data monitoring in future.

4 TEST RESULTS

4.1 Infrared Water-Cut Meter and Test Trap Data Comparison

During the test, the choke setting was changed twice on both wells (408 & 458) to ensure that water-cut meter readings changed in conjunction with changes in choke settings. Additionally, the wells were scheduled to be tested through the test trap on a monthly basis to

check the water-cut readings. The first test was conducted in April 2006 and the second was conducted in September 2006. Figures- 8, -9 and -10 show the test conducted in April 2006 and Figures-11, -12 and -13 shows the test conducted in September, 2006 along with the comparison of the tests.

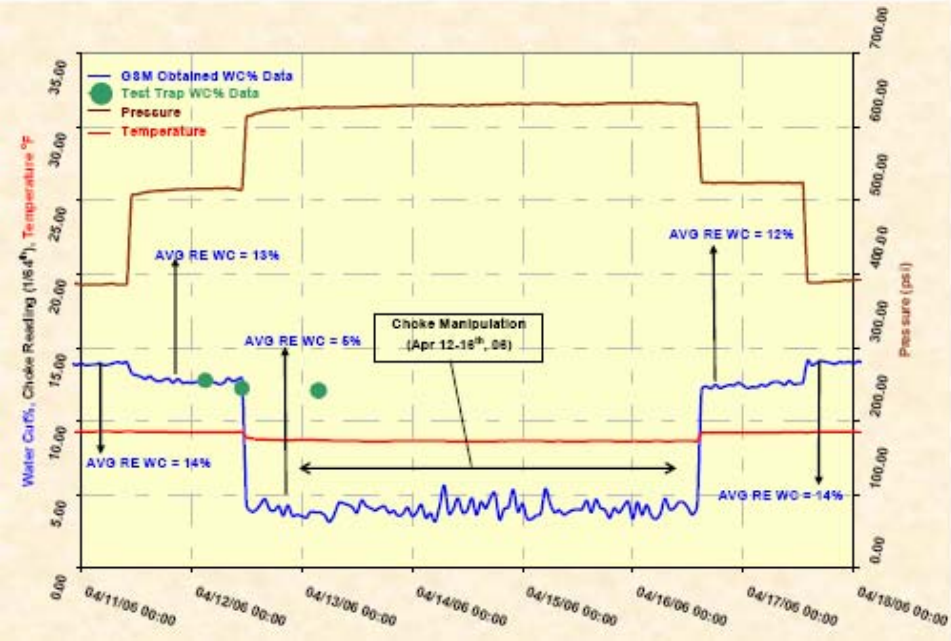

Figure-8: Well-408 April 2006 Test Data and Results

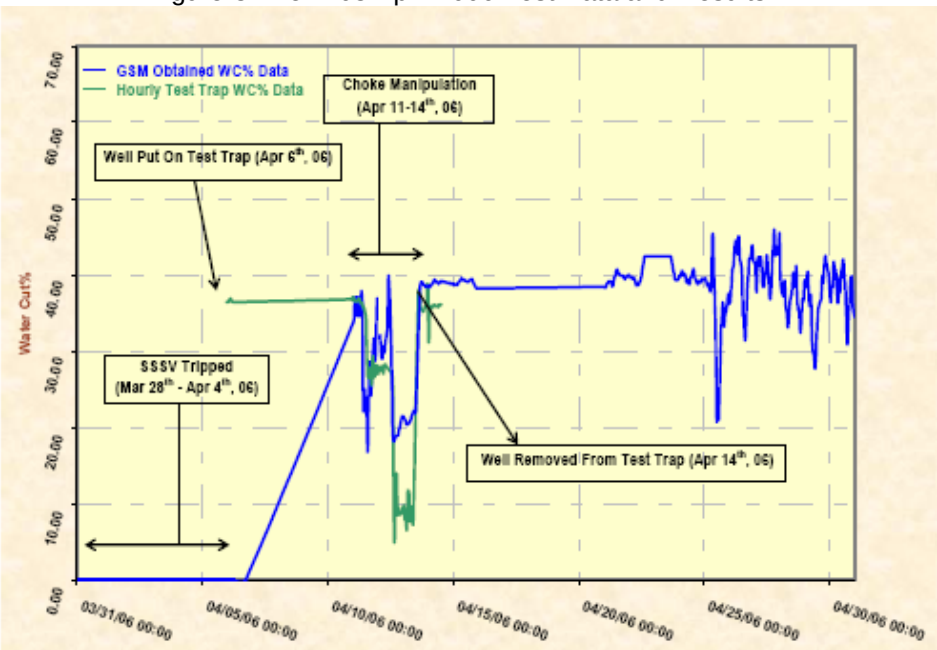

Figure-9: Well-458 April 2006 Test Data

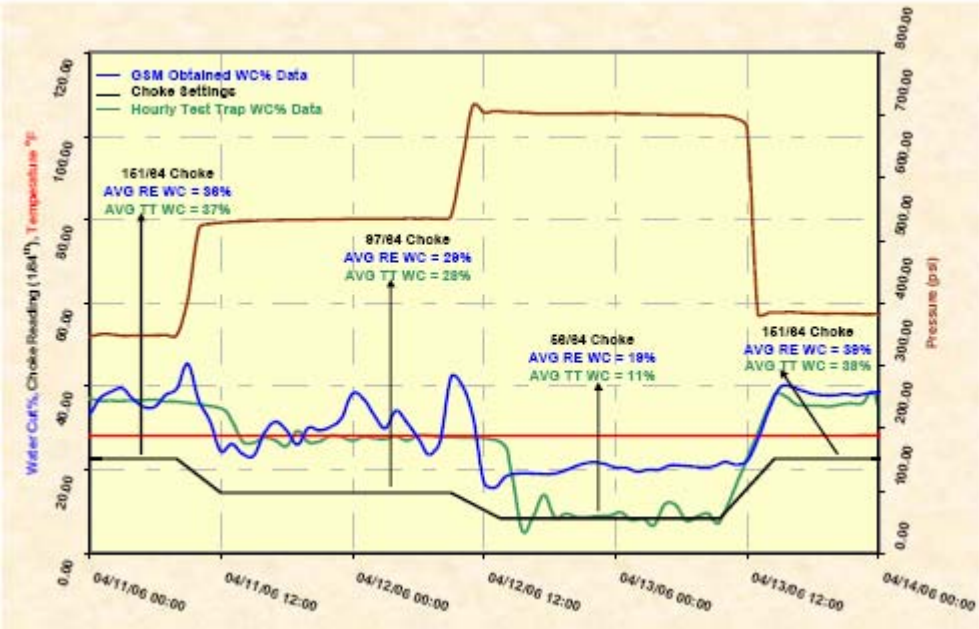

Figure-10: Well-458 April 2006 Test Results

Figure-11: Well-408 September 2006 Test Data & Results

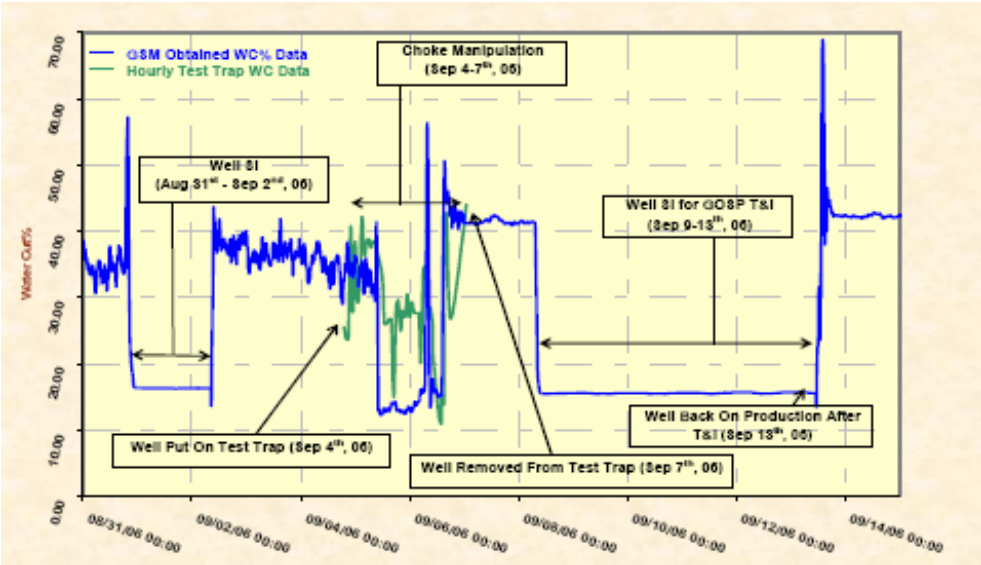

Figure-12: Well-458 September 2006 Test Data

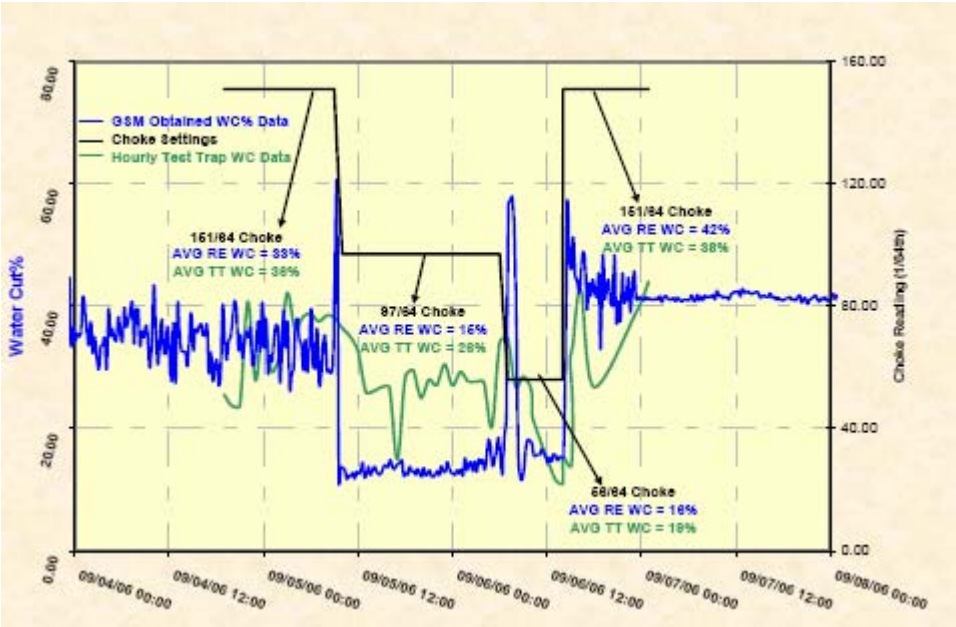

Figure-13: Well-458 September 2006 Test Results

Figure-11 illustrates the Red Eye 2G and the Pressure-Temperature transmitter. Well-408 has a water-cut of about 15-20% while Well-458 has a water-cut between 35-40%. Figures-15 and -16 show the data gathered through the test from Well-408 and Well-458. The figures show the quality of the data as well as the pressure and temperature behaviour. The figures also indicate that the meter is showing a reasonable qualitative data match for both wells.

Figure-14: Infrared Meter and P-T Transmitter

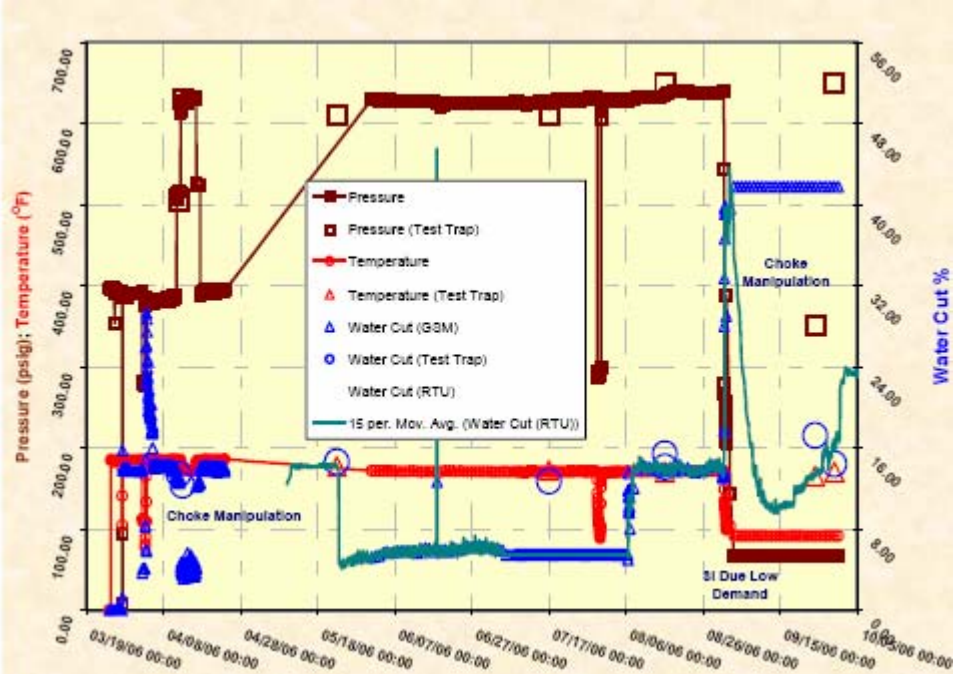

Figure-15: Well-408 General Test View Data

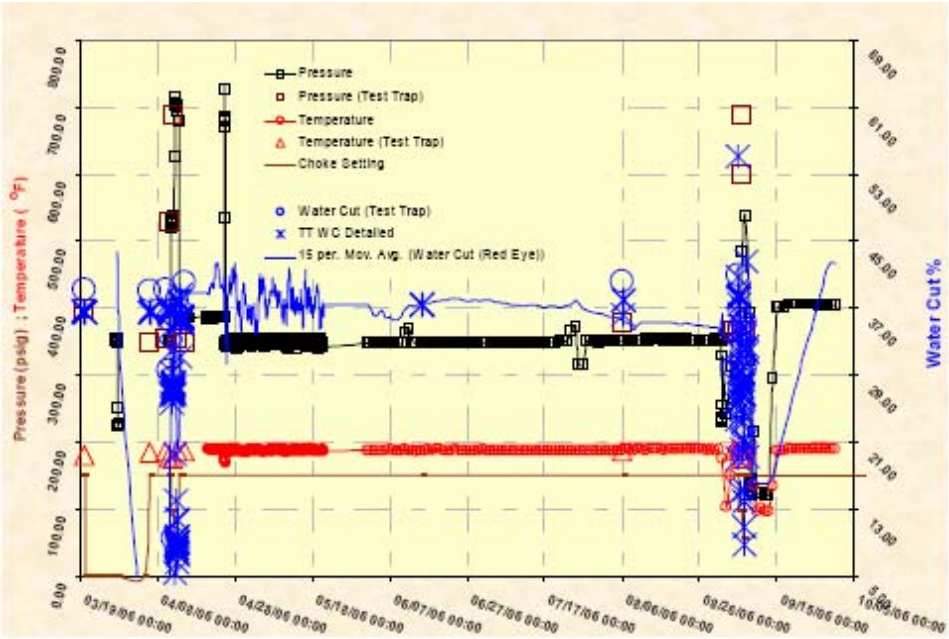

Figure-16: Well-458 General Test View Data

The data obtained from the RTU loggers shows acceptable water-cut tracking excluding the data lapses due to the problems encountered during the test. Initially, the meter was recording the instantaneous values for the water-cut but that was changed at a later stage and the meter was then reconfigured to show the average water-cut through a 10 second time interval. This was done in May of 2006 and the impact on the recorded water cut is clear. In the fourth quarter of 2006, the infrared meter began to experience power related problems as described in section 3.4.

In May 2007, the infrared meters on both wells were removed for corrosion inspection. No corrosion was observed on the meters. Figure-17 and -18 shows the internal probe of the meter installed in Well-408 and Well-458.

Figure-17: Probe (Inner Rod) For Well-408 Infrared Meter

Figure-18: Probe (Inner Rod) For Well-458 Infrared Meter

4.2 Results Validation and Verification

The trial test data was sent to Reservoir Engineering Department (RMD) to ensure the validity and the usability for better reservoir management. RMD validated the measurement quality of the meter, after cross checking it with the test trap data and advised on implementing the concept in the field where applicable. The meter will be useful to assist with the process of monitoring the water arrival on frontline wells and to take remedial action in a timely manner.

4.3 System Reliability and Technical Support

The overall test proved system reliability for qualitative measurement. As a new system, however, some issues were encountered during the test as shown in Figure-19. During the installation, the meter installed at Well-408 was found to have a faulty NIR source. A replacement meter was received and installed, configured and put into service. The meter was, however, installed and configured without the benefit of any reference water-cut readings for the previously mentioned reason.

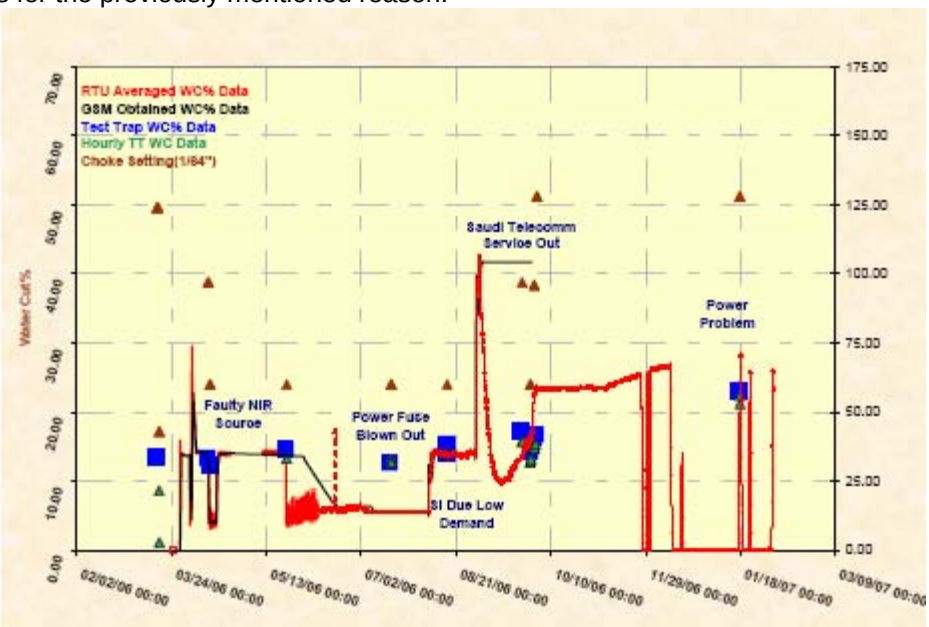

Figure-19: Problems Encountered In Well-408 Test

In June 2006, the reading in the office for Well-408 went flat again. This time the water-cut meter power fuse was blown. The vendor was consulted and the investigation revealed that the supply power from the solar panel system may have temporarily dropped below 9V DC, which would result in an increased current draw. A 12V to 24V converter was installed on both wells to resolve the problem.

In October 2006, the infrared meter data could no longer be gathered and obtained in the office. The data enabled GSM-SIM cards service was disconnected from the Saudi Telecomm Company after six months. Since then, data has been downloaded in the field.

A field visit was arranged in December 2006 and it was found that both meters were no longer displaying water-cut readings and reporting default-configuration errors. Troubleshooting the issue was started for further diagnoses and the vendor was consulted and confirmed that the meter will force a zero (0) water-cut reading if the default-configuration flag is active. The preliminary analysis was done under the assumption of possible firmware bug, but it was found after further diagnosis that the problem was caused due to a low power start-up issue.

4.4 Additional Findings

The infrared meter proved its qualitative measurement to detect the change in the well status. The previous mentioned figures demonstrate this issue clearly. Furthermore, Figure-12 shows an incident occurred in Well-458 when the SCSSSV tripped and the well was shut-in. If the well behaviour change had not been seen by the infrared data, the well would have remained shut in until field service arranged a visit to the well site. This would have resulted in production loss depending on the time of the visit.

5 CONCLUSIONS & RECOMMENDATIONS

The trial test showed that the increase and the decrease in water-cut trends measured by infrared water-cut meter were consistent with the choke changes and the test trap data. The infrared measurement provided accurate measurement on the selected wells with minimum water-cut measurement of 5% and a maximum of 42% during the test. The water-cut meter provided a qualitative means to monitor water-cut trends. Real-time monitoring provides continuous monitoring of well production behavior and status.

The test highlighted that water-cut meter installation is effective only with real-time monitoring capabilities. Without real-time monitoring, true benefits of decision making for remedial action can not be taken in a timely manner.

Communication wise, the first time use of the GSM-SIM card to transmit water-cut data, pressure, and temperature was successful and could be utilized in future as a temporary data transfer option. On the power side, no major problems were encountered, however, data interruption was noticed due to solar power dropping below minimum acceptable voltage during winter time (November-December).

Based on test results, it is recommended to use infrared water-cut meters to monitor water-cut trends on critical wells. The water-cut meter performed satisfactorily on wells with GOR of ± 550 Scf/STB. It is also recommended to consider usage of infrared water-cut meter downstream of 2-phase separator to aid in determining the water-cut in the liquid leg. Finally, it is recommended to liaise with IT/Communication to determine best communication alternatives to ensure reliable data communication for real-time monitoring on a field wide basis.

North Sea FLOW Measurement Workshop

Paper 1.4

An Investigation into the Performance of Coriolis and Ultrasonic Meters at Liquid Viscosities up to 300 cSt

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An Investigation into the Performance of Coriolis and Ultrasonic Meters at Liquid Viscosities up to 300 cSt

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1 INTRODUCTION

As worldwide reserves of light crude oil diminish rapidly and alternative sources of renewable energy remain in their infancy, attention is being turned to the world's vast deposits of heavy oils and tars[1]. Recovery of these viscous hydrocarbons – once regarded as being too difficult and costly to produce – is seen by many analysts as one of the only viable way of meeting the world's escalating energy requirements.

Extraction operations are now growing rapidly, supported by high oil prices and an increasing demand from national governments for security and diversity in their energy supplies. Innovative methods of retrieval (including new drilling and completion techniques), transport and measurement are considered essential to fully exploit the vast reserves in place; and the enormous monetary value of the product involved makes accurate flow measurement vital.

Unfortunately, the accuracy of many conventional flowmeters, at the higher viscosities encountered, remains poorly known; although there is anecdotal evidence to suggest that some technologies are more adversely affected than others. Among the technical challenges arising are the higher viscous friction of the fluid being metered, the increased pressure losses that occur across internal bends and restrictions, the possibility of extreme or varying velocity profiles, and the increased susceptibility of viscous liquids to entrain secondary components such as solids or gas.

To improve upon the current level of understanding, an NMS (National Measurement System) programme of research work was launched in the UK to investigate the responses of a selection of established flow metering technologies under elevated viscosity conditions.

This paper reports on an upgrade to the UK National Standards Oil Flow Facility, designed to provide the necessary test fluids (up to 300 cSt viscosity in the initial stage) along with accurate and traceable reference metering. Results are then presented on the performance of a selection of Coriolis and ultrasonic devices when operated at these elevated viscosities; and under the commonly-encountered situation where small quantities of gas become entrained within the viscous liquid flow.

2 MEASUREMENT CHALLENGES

As noted above, the additional technical challenges faced in the measurement of medium and heavy crude oils follow mainly from the higher viscous friction of the fluids involved (i.e. their tendency to resist flow), which can give rise to significantly different flow characteristics compared to low viscosity products.

The level of viscous friction presented by a fluid is characterised by its coefficient of viscosity. The "absolute" viscosity of a fluid is usually expressed in cP (centi-Poise) or in the SI units of Pa.s (where 1 cP ≡ 10^{-3} Pa.s). The higher the value of the absolute viscosity, the greater is the resistance of the fluid to flow. A related quantity is the kinematic viscosity, ν, the ratio of

[1] More than 5 trillion barrels of heavy crude oil and natural bitumen deposits are estimated to be in place around the world, with much of it in Canada, Venezuela and other Western Hemisphere locations. On the UK Continental Shelf alone, 19 heavy oil fields have been discovered to date, with around a third of these already actively producing. These reserves are estimated to total some 9 billion barrels, with the capacity to extend North Sea operating lifetimes by the order of several decades.

the fluid's dynamic viscosity to its density. This is generally quoted in cSt (centi-Stokes) or in m^2/s (where 1 cSt ≡ 10^{-6} m^2/s).

The viscosity of liquids tends to decrease with increasing temperature; unlike gases where the opposite is true. The rate-of-change of viscosity with temperature is also more significant in higher viscosity liquids (Figure 1). This can be problematic in very viscous fluids, where only small changes in temperature can have a significant effect upon the fluid viscosity and, in turn, any influence that the viscosity has on the accuracy or integrity of the flow measurement. It may, in fact, be difficult to make temperature measurements that are suitably representative of the *mean* fluid temperature; hence also increasing the uncertainty on any temperature-based corrections.

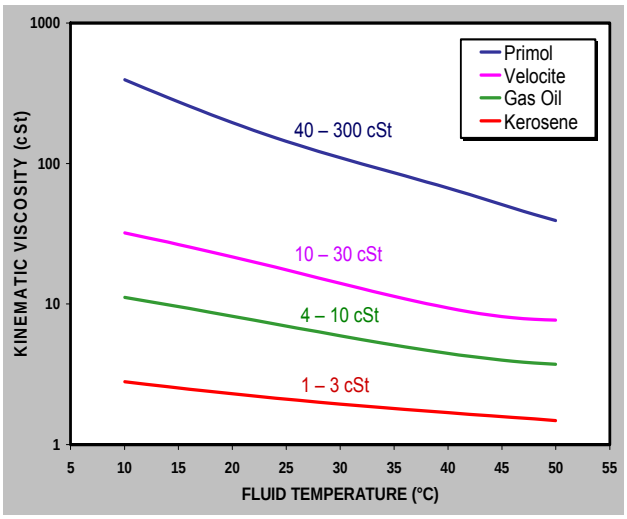

Fig 1. – Variation of viscosity with temperature for TUV NEL Oil Facility test fluids.

Such changes in viscosity can also have a significant effect upon the velocity profile of the flow, which in turn can affect metering devices that are sensitive to this quantity. The way in which the viscosity of a fluid influences its velocity profile is best described with reference to a dimensionless parameter known as "Reynolds number". Reynolds number (Re) describes the balance between the dynamic forces driving a fluid and the viscous (frictional) forces opposing its flow. For circular pipes, the Reynolds number, *Re*, can be written as:

$$Re = \frac{U \cdot D}{\nu} \tag{1}$$

Here, *U* represents the average flow velocity, *D* the diameter of the pipe and ν the kinematic viscosity. The Reynolds number serves to classify the flow into different "flow regimes". For example, if the Reynolds number is small (less than ~ 2000) then viscous forces dominate and the flow is described as "laminar". When the flow is laminar, it can be thought of as moving along in thin layers, with no mixing between the layers. If the Reynolds number is large (greater than ~ 5000), dynamic forces dominate and the flow is described as "turbulent". In turbulent flow, the general motion is parallel to the pipe axis, although mixing occurs between the different layers. In between laminar and turbulent flow, the flow is described as "transitional". In this regime, the flow switches back and forth between laminar and turbulent behaviour. The transitional regime is less predictable than either turbulent or laminar flow, and can present significant difficulties for flow measurement.

The nature of the flow regime has a direct impact on the "velocity profile" of the flow. Velocity profile is a term used to describe how fast the fluid is moving at different points over the cross-section of the containing pipe. For example, in a long straight pipe with completely frictionless walls, the fluid would move with the same velocity at all parts of the pipe cross-section i.e. as if it were a "solid plug". In such a case, the velocity profile would be described as "uniform". In reality, the pipe wall always creates some level of friction, meaning that a thin layer of fluid next to the pipe wall will, in principle, be stationary i.e. its velocity will be zero. Moving away from the wall, the drag exerted by the pipe becomes less and less, and the fluid moves at increasingly higher velocities. In a very long straight pipe, the highest fluid velocity therefore occurs in the centre of the pipe i.e. at the point furthest from the pipe wall. The precise way in which the velocity changes from the pipe wall to the pipe centre, depends on the nature of the flow regime, and hence also on the Reynolds number.

In laminar flow, the viscosity effect (or "internal friction") dominates the motion, and does an effective job of transferring the drag of the pipe wall to successive "layers" of the fluid. This

results in a profile where the fluid velocity changes fairly gradually from the pipe wall to the central axis (Figure 2a). In turbulent flow, the mixing action caused by the turbulence breaks up any gradual transfer of drag from the pipe wall, resulting in a "core flow" of high velocity and a narrow "boundary layer", near the pipe wall; where the velocity changes extremely rapidly (Figure 2b).

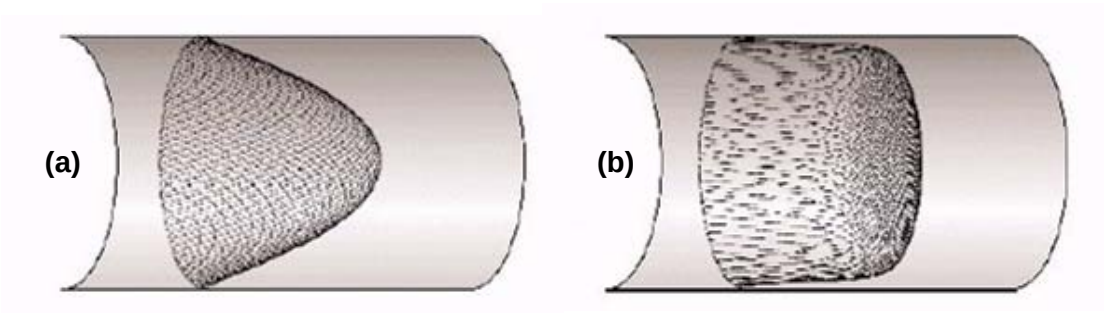

Fig. 2 – Velocity profile shapes in a circular pipe for (a) laminar and (b) turbulent flow.

Fully developed[2] laminar flow has a velocity profile that is parabolic in shape. The maximum fluid velocity (developed at the centre of the pipe) has a value equivalent to around twice the average velocity of the flow. Fully developed laminar flow exhibits this same velocity profile shape over all Reynolds numbers within the laminar region ($0 < Re < 2000$). Fully developed turbulent flow has a velocity profile that is flatter in the middle and varies sharply near the pipe wall (i.e. in the boundary layer). The maximum fluid velocity (at the pipe centre) has a value of around 1.1 to 1.3 times the average flow velocity. In fully developed turbulent flow, the profile shape varies slightly with Reynolds number; the central area becoming flatter as *Re* increases. There is also a dependence on the pipe roughness, with a smooth pipe producing a flatter velocity profile in turbulent flow than a rough pipe.

An additional consideration, when monitoring viscous flows, is the increased pressure drop developed across the flowmeter itself; particularly if introduces additional bends or restrictions into the fluid path. Ideally, the pressure drop across a flowmeter should be minimised wherever possible, as there is a cost associated with compensating for this loss. In some cases the differential pressure developed across a flowmeter can lead to internal (and unmeasured) leakage of fluid through the device. In extreme cases its mechanical integrity might even be compromised.

It is reasonable then to assume that the above characteristics of increasing fluid viscosity will influence – to varying degrees – the responses of different flowmeters.

In a **positive displacement** (PD) meter, for example, the primary source of measurement error is generally product slippage i.e. the unregistered leakage of fluid through the meter's internal clearances (between the gears, rotors, casing etc.). The level of slippage is closely related to the fluid viscosity. In fact, an often-quoted advantage of PD meters for heavy oil applications is that slippage is actually reduced as the fluid viscosity increases; although there is still the possibility for errors to be re-introduced if the fluid viscosity falls (e.g. as a result of commingling or a rise in temperature) – particularly if "high-viscosity" high-clearance rotors are employed [1]. Thermal expansion of the meter body can also lead to calibration shifts.

Another common means of metering hydrocarbon fluids is through the use of **differential pressure** (DP) devices, such as Venturi tubes or orifice plates. A DP meter computes the fluid flowrate by measuring the difference in pressure upstream and downstream of a restriction in the flow. A key parameter that requires accurate characterisation for DP devices

[2] A flow is said to be "fully developed" once its velocity profile no longer changes shape with distance down the flowline. This generally requires a minimum length of upstream straight pipe, with no disturbance from valves, bends, expansions etc.

(particularly at higher viscosities) is the discharge coefficient[3]. This is known to be a strong function of Reynolds number, but current industry standards – governing the design and operation of DP meters – apply primarily to high Re flows [2]. For such devices to be confidently applied in heavy oil applications, accurate characterisation of their discharge coefficients is required at low Reynolds numbers also; but, to date, this operating region remains relatively unexplored [3 – 6].

The tendency of viscous fluids to cling to contact surfaces can also be problematic to some measurement technologies. In **turbine** meters for example, changes in the fluid viscosity can alter the thickness of boundary layers on the walls of the metering tube and on the rotor blade surfaces. This affects the flow area and the lift forces that drive the turbine blades; and hence their rate of rotation. For this reason, conventional turbine meters – with multiple flat blades – are rarely employed at viscosities above 30 cP. "Helical" turbines [7] on the other hand – with fewer blades more closely aligned with the flow – have been employed in a variety of higher viscosity applications, although reliable information on the accuracies achievable and their upper viscosity limits is again relatively sparse.

Like many other technologies, **ultrasonic** meters are currently employed in a variety of custody transfer and allocation measurement systems for "light" oils; with meters regularly delivering measurement uncertainties of better than ± 0.25% over a significant fraction of their turndown range. However, one flow property that is known to strongly influence the performance of liquid ultrasonic meters [8] is the variation in velocity profile that occurs with changes in fluid viscosity (or more precisely changes in pipe Reynolds number). This follows from the fact that ultrasonic meters make measurements of the fluid velocity along only discrete narrow paths within the pipe cross section, which are then in some way combined according to the presumed (or deduced) flow profile. To maintain an accurate estimate of the volumetric flowrate, a liquid USM must therefore, in some way, account for any changes in the profile shape, particularly for Reynolds numbers close to the laminar-turbulent boundary. An additional issue for ultrasonic meters is that high viscosity liquids can also be severely attenuating at ultrasound signal frequencies. Potentially, the signal could deteriorate to such an extent that it is no longer detectable at the receiving transducer; resulting in path failure. This can be a particular problem where longer path lengths are involved, although most multi-path meters are able to interpolate for a failed path at the expense of increased uncertainty.

Coriolis meters provide a direct measurement of mass flow and product density with accuracies as high as ± 0.1% and ± 0.005 kg/m^3 respectively reported in light hydrocarbons. In higher viscosity fluids, independent and reliable data for Coriolis meters remains limited, although some preliminary investigations [9, 10] suggest that they may not be significantly affected by changes in fluid viscosity; with mass flow deviations limited to less than ± 0.25%, up to several hundred cP. Perhaps the main *perceived* drawback with Coriolis meters at present is the larger pressure drop presumed to be generated at elevated viscosities, compared to "straight-through" non-intrusive devices.

3 TEST PROGRAMME

3.1 Scope of Work

As highlighted above, there has been much speculation about the influence that rising viscosity has (or might have) on our current generation of liquid flowmeters, but so far little independent and verifiable data has appeared to define quantitatively the extent to which their accuracies are truly affected. This follows partly from a scarcity of suitable test facilities, capable of providing viscous calibration fluids in combination with accurate and traceable reference instrumentation. The first aim of the present test programme was therefore to extend the capabilities of the UK National Standards Oil Flow Facility at TUV NEL to offer test

[3] In principle, an ideal non-viscous fluid should obey Bernoulli's standard relation (equating fluid pressure and fluid velocity) in an exact manner. However, when real fluids pass through a restriction, some energy is converted to heat within viscous boundary layers. These frictional losses vary with viscosity and are accounted for through the discharge coefficient.

fluids up to 300 cSt in the initial case; and then to follow this with a preliminary investigation into the response of a selection of conventional flowmeters when operated at these higher viscosity conditions. The initial investigations reported here focus on Coriolis and ultrasonic type flowmeters; as these are often said to be two of the most promising "new" technologies for high viscosity flow measurement. The following sections describe the upgraded flow facility and the experimental test programme undertaken.

3.2 Upgraded Oil Flow Facility

The UK National Standards Oil Flow Facility, located at TUV NEL in East Kilbride, Scotland, consists of two separate flow circuits (A and B), each with a high capacity and a low capacity flow line. These can accommodate nominal pipe sizes from 0.5" to 8", and can operate at line pressures up to 10 bar. Test fluids can be delivered at flowrates up to 720 m^3/hr. Originally, only three test fluids were available in this facility – kerosene, gas oil and lubricant oil – covering liquid viscosities from 2 to 40 cSt. The addition of a fourth mineral oil, "Primol-352", extended this range to around 300 cSt (Figure 1). Other fluids, such as water, can also be employed to further expand the range of flow Reynolds number achievable.

Figure 3 shows a schematic diagram of one of the flow circuits. The oil for each circuit is drawn from a 30 m^3 supply tank into the suction stream of the main pumps, from where it is discharged to the test lines. A conditioning circuit, linked to each tank, maintains the oil temperature to within ± 1 ºC of a pre-selected value (itself set in the range 5 – 45 ºC). Each test line can accommodate up to 30 m of horizontal straight lengths or alternative configurations as required. At the outlet of each test section, a manifold directs the fluid back to the storage tank or to one of the calibrated weigh tanks. Line temperature and pressure are monitored both upstream and downstream of the test section. The flowlines share a common primary standard weighbridge system consisting of four separate weightanks of 150, 600, 1500 and 6000 kg capacity. The facility is fully traceable to National Standards and is accredited by the United Kingdom Accreditation Service (UKAS).

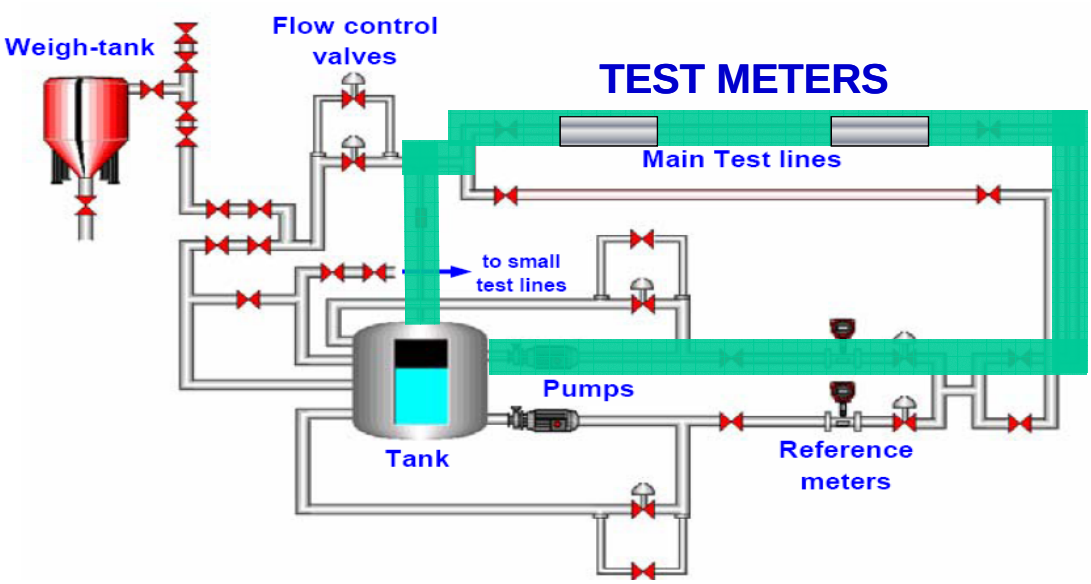

Fig. 3 – Schematic diagram of TUV NEL oil flow facility, with example of recirculation path.

For "primary" calibrations, a gravimetric "standing-start-and-finish" method is used to determine the quantity of fluid (volume or mass) which has passed through the flowmeter under test and into the selected weightank. The gravimetric weightanks constitute the primary reference standard of the TUV NEL oil flow facility. Using the above technique, the overall uncertainty in the reference flowrate, expressed at the 95% confidence limits is approximately ± 0.03 % (k = 2). For a "secondary" calibration, the quantity of oil passing through the test meter is measured using a pre-calibrated reference meter, installed in series. The reference meters used at TUV NEL have a history of previous calibrations and typical uncertainties of the order of ± 0.08 % (k = 2).

In order to test in higher viscosity fluids, several modifications were required to the test facility. To provide effective heating / cooling of fluids in the range 2 – 400 cSt, the facility's original plate-type heat exchangers were replaced with shell and tube units. Along with these, a new positive displacement delivery pump and motor set was also installed to cater for the wider range of fluid viscosities being fed through the heat exchangers.

Following the facility upgrade, the refined oils of Table 1 were available as test fluids. Nominal densities are given at 20 ºC, while their typical viscosity behaviour as a function of temperature is shown in Figure 1. As it is recognised that both the density and viscosity of these test fluids can change slightly over time – as a result of the small but finite cross-contamination of liquids that can potentially occur within the flow circuits – these quantities were re-measured offline on a periodic basis.

Table 1 – Facility Test Fluids.

Fluid	Density
Kerosene	797 kg/m^3
Gasoil	826 kg/m^3
Velocite	843 kg/m^3
Primol-352	865 kg/m^3

For test meter evaluation, the oil flow facility was operated in "re-circulation" mode (Figure 3) and the test meters compared against secondary reference standards; in this case 8-inch rotating vane PD meters (Smith Meters™). Prior to their use as secondary references, the PD meters were calibrated against the facility's primary gravimetric standard. The "K-factor" for this type of PD meter can be considered to be a function of three main parameters: the volumetric flowrate (Q), the liquid viscosity (ν) and the fluid temperature (T). For the present test programme, the PD meters were calibrated (as a function of flowrate only) for each possible combination of fluid temperature and fluid type in the test matrix. This provided the most accurate reference for testing, but required the measurement of 16 separate K-factor curves of the form:

$$K_{F,T} = f_{F,T}(Q) \tag{2}$$

where F and T denote the fluid type or test temperature respectively. The resultant uncertainty of the PD meters in service was of the order of ± 0.1% (95% confidence level).

3.3 Test Meters

Two models of Coriolis and two models of ultrasonic flowmeter were evaluated during the course of the test programme. Basic information on the meters tested is given below, although the meter manufacturers and model types can not be identified here under the terms of the research contract. This also necessarily restricts the amount of detail that can be given about the meter hardware or measurement methods.

Coriolis Meter # 1 was a standard, commercially-available 4-inch twin-tube Coriolis meter, with a nominal flowrate limit of approximately 150 kg/s.

Coriolis Meter # 2 was also a standard, commercially-available twin-tube Coriolis meter, but this time of 6-inch entry diameter and an upper flowrate limit of around 220 kg/s.

Ultrasonic Meter # 1 was a commercial 4-inch multi-path meter operating on the transit-time principle, with an approximate flow range of 5 to 100 l/s. Testing was conducted both with and without an artificial flow conditioner (tube bundle) installed upstream of the meter.

Ultrasonic Meter # 2 was also a commercial 4-inch multi-path liquid ultrasonic meter operating on the transit-time principle, but of a different design and chordal arrangement. The meter was installed for testing with the manufacturers recommended length of upstream and downstream straight pipe length. No artificial flow conditioning was employed in this case.

For evaluation purposes, the test meters were mounted in discrete skids or "packages" (Figure 4); based around straight pipe runs of 4-inch nominal bore.

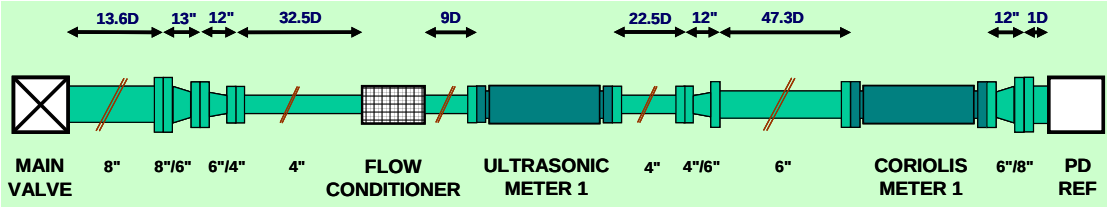

Fig. 4 – Example of a test package used to evaluate one Coriolis and one ultrasonic meter.

Each package consisted of two test meters in series, plus the manufacturer's recommended lengths of upstream and downstream straight pipe or flow conditioning elements as appropriate. In general, one "intrusive" (i.e. Coriolis) plus one non-intrusive (i.e. ultrasonic) meter was installed on each package, to minimise the overall pressure loss in the flow loop. The entire test packages were swapped between the relevant flow circuits, in order to gather data on each of the test fluids.

3.4 Test Matrix and Procedure

The test installation was based around a standard pipeline run of 4-inch nominal bore, with the test meters sized accordingly. Tests were conducted at flowrates ranging from 5 to 90 litres/second; using all four facility test fluids at set point temperatures of 10, 20, 30 and 40 ºC.

The resulting combinations of fluid viscosity and fluid velocity resulted in a test matrix covering a wide span of pipe Reynolds numbers, as depicted in Figure 5.

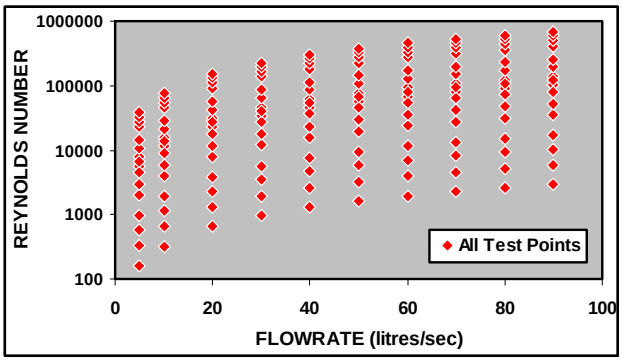

Fig. 5 – Range of pipe Reynolds numbers covered by nominal test matrix.

For the majority of the test programme, the oil flow facility was operated in "re-circulation" mode and the test meters compared directly with the pre-calibrated PD meter secondary reference standards. (Where time allowed, occasional spot-checks were also made against the primary gravimetric standard). For each fluid type, the meter-package housing the test meters of interest was firstly installed in the appropriate facility flowline. The test fluid was then circulated until a stable line temperature of the required value was achieved. The outputs from the test meters, PD reference meter and flowline pressure and temperature sensors were then logged over a pre-set data acquisition window of typically 4 minutes. The test meter and reference system results were then collated and compared offline. Where required – such as for direct comparison with the Coriolis meter outputs – the PD meter volumetric flowrates were converted to reference mass flowrates using measured or calculated values for the live fluid density. The measurement differences between the reference and test devices ("meter errors") were then assessed as a function of flowrate, temperature, viscosity, *Re* etc.

To investigate the sensitivity of the single-phase flowmeters to the presence of entrained gas, a short series of test were also made in which air was artificially injected, at a controlled and monitored rate, upstream of the test meter locations. The PD reference meter was installed upstream of the gas injection point for these tests, to ensure that it monitored the liquid flowrate only. The injection system consisted of a pressurised gas inlet stream and a series of pre-calibrated reference flowmeters – one small and one large Rotameter plus three gas turbine meters (½-inch, ¾-inch and 1-inch) – together with pressure and temperature sensors. The injection rates were such that gas volume fractions (GVFs) up to 10% could be set up in the main flowline. As before, one Coriolis and one ultrasonic meter were tested as a package. In this case, the Coriolis meter was installed closest to the gas injection point and, acting as a relatively good mixer, served to improve the distribution of the gas within the flowstream at the location of the ultrasonic meter downstream. Pressure transmitters were located in the vicinity of both test meters to allow offline calculation of the local gas volume fraction at each device.

4 TEST RESULTS

4.1 Coriolis Meter # 1

Coriolis Meter # 1 was tested horizontally (as per the sample installation of Figure 4) with the flow tubes in the "flag down" position; a standard arrangement for single-phase liquid flow.

4.1.1 Mass Flowrate Measurement

Figure 6 shows the mass flow error (i.e. the deviation of the test meter flowrate from the reference system flowrate) recorded for Coriolis Meter # 1 (4" device) for each of the four test fluids. The meter "zero" was set after each change of fluid according to the manufacturer's automated procedure, but was not reset for each change of temperature within a fluid group.

For the lower viscosity fluids, kerosene (1 – 3 cSt) and Gasoil (4 – 10 cSt), the mass flow error[4] is close to the manufacturer's specification (shown); allowing for the uncertainty of the reference system and the additional mass flow errors introduced through changes in temperature away from the "zero-setting" condition. (In this case a 10 ºC step is expected to add ~ 0.1% to the mass flow uncertainty at 10 kg/s).

However, in the higher viscosity fluids, Velocite (10 – 30 cSt) and Primol (40 – 300 cSt), a significant underreading is observed in the reported mass flow; most significantly at lower flow rates. The observations are characteristic of a "zero offset" error, although the same "zero settings" were repeatedly returned by the meter's automated algorithm. It is possible then that the "auto-zero" utility (common to most commercial meters) may not be as reliable or robust in high viscosity fluids as it is in low; an issue that is addressed further in Section 4.2.1. However, it is unlikely that an offset effect can fully explain the under-reading observed at the higher mass flowrates in Velocite and Primol, and it may be that some other effect of the increasing viscosity plays a role.

4.1.2 Density Measurement

The corresponding density measurement errors are reported in Figure 7. Within each fluid group, a small shift is observed for each change in temperature. Such shifts are correctable (usually within the meter software or flow computer) and in this case are in line with the manufacturer's stated sensitivity. The density response varies relatively little with fluid type, expect for a small but finite positive bias that appears to emerge at higher viscosities. However, allowing for the additional uncertainty of the reference system quantities, and the fact that no compensation has been made for the effects of temperature on the meter response, the density measurement is, in general, consistent with the meter specification.

4.1.3 Pressure Loss

As noted in Section 2, a vital consideration in the measurement of viscous fluids can be the pressure drop developed across the metering system. To compare the losses incurred by the different meter types, the pressure differential across each flow element was recorded at two viscosity values (65 and 200 cSt). Sample results for Coriolis Meter # 1 (4") are given below:

ΔP @ 90 l/s (65 cSt) ~ 600 mbar	ΔP @ 90 l/s (200 cSt) ~ 900 mbar

[4] The measurement uncertainty specified for a Coriolis meter is generally a function of both the measured mass flowrate and the meter's "zero stability" value. In essence, the zero stability value defines the maximum limits over which the meter zero is anticipated to vary during operation. To achieve the specified zero stability performance, Coriolis meters must be installed according to the manufacturer's prescription and zeroed at the actual operating conditions to be used in service. Certain process parameters (such as pressure and temperature) can affect the zero stability of Coriolis meters, and if these are significantly changed, re-zeroing of the meter may be required.

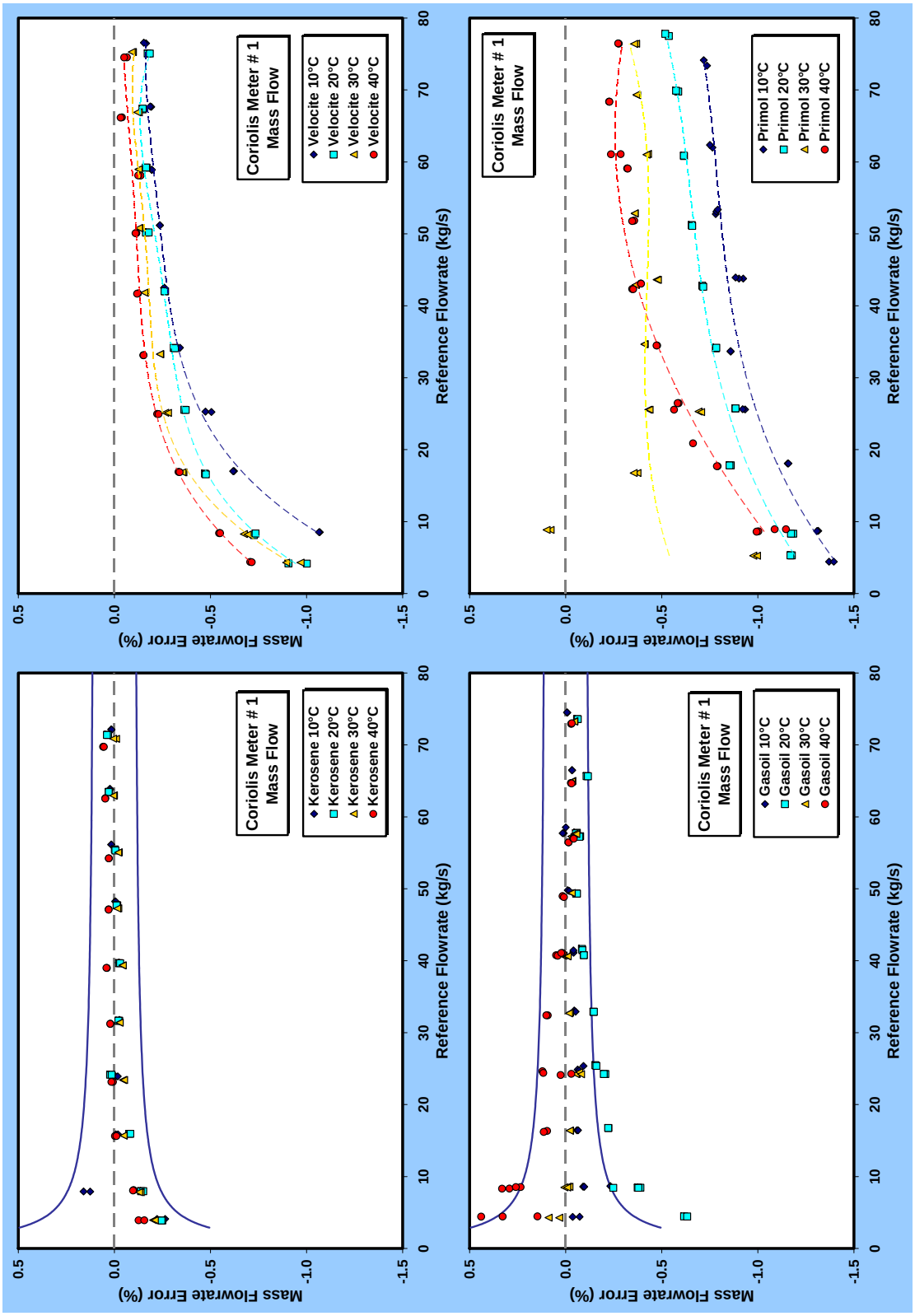

Fig. 6 – Coriolis Meter # 1: Mass flow error at temperatures between 10 and 40 ºC for each of the four test fluids: Kerosene (1 – 3 cSt), Gasoil (4 – 10 cSt), Velocite (10 – 30 cSt) and Primol (40 – 300 cSt). The meter "zero" was set after each change of fluid (as per the manufacturer's automated procedure), but was not reset for each change of temperature within a fluid group. For the first two fluids, the manufacturer's uncertainty specification has been overlaid for comparison.

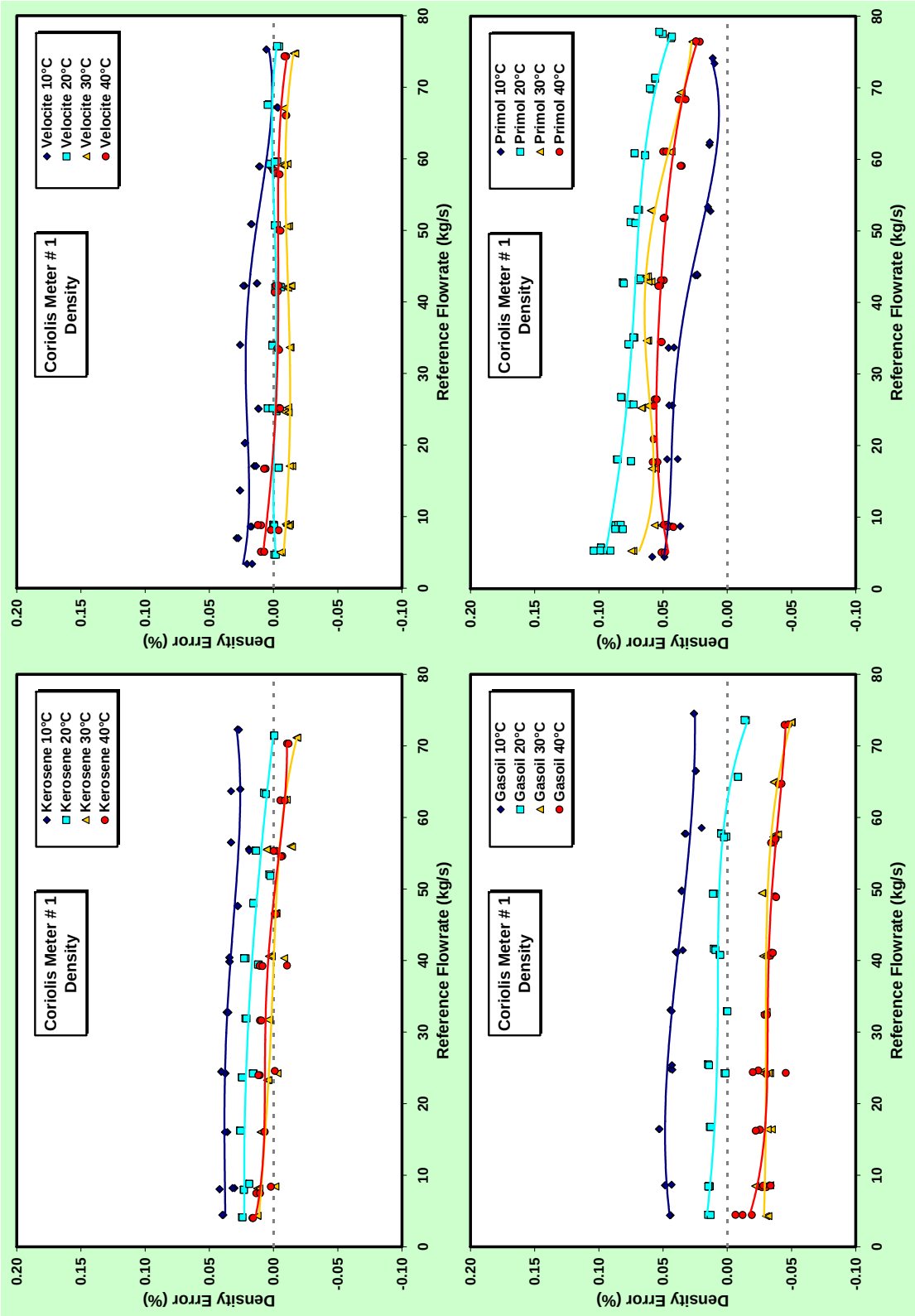

Fig. 7 – Coriolis Meter # 1: Density errors at temperatures between 10 and 40 ºC for each of the four test fluids: Kerosene (1 – 3 cSt), Gasoil (4 – 10 cSt), Velocite (10 – 30 cSt) and Primol (30 – 300 cSt). A small (correctable) shift is observed with temperature within each fluid group. The magnitude of the shift is in line with the manufacturer's published correction factor. The overall density deviations are also, in general, consistent with the meter manufacturer's specification.

4.1.4 Effect of Entrained Gas

The effects of the presence of entrained gas in a fluid of 200 cSt are shown in the graphs of Figure 8. Owing to pressure drop limitations, the liquid flowrates were limited to 70 l/s in these tests. The results are plotted as a function of GVF calculated at the meter inlet. The upper graph in Figure 8 shows the mass flowrate errors[5] induced by the injected gas. Anomalous and non-repeatable behaviour was observed at liquid flowrates below ~ 20 l/s and this data has been removed from the graphs for clarity. (It is possible that such flowrates are insufficiently high to drive the gas continuously through the meter's internal flowtubes – arranged in a vertical loop – and that the resulting gas hold-up or coalescence has a non-predictable effect on the meter's operation). At higher mass flowrates, a growing negative error is observed with increasing GVF. In fact, beyond ~ 1% GVF, these errors rise rapidly and in many cases the meter gave no reliable output.

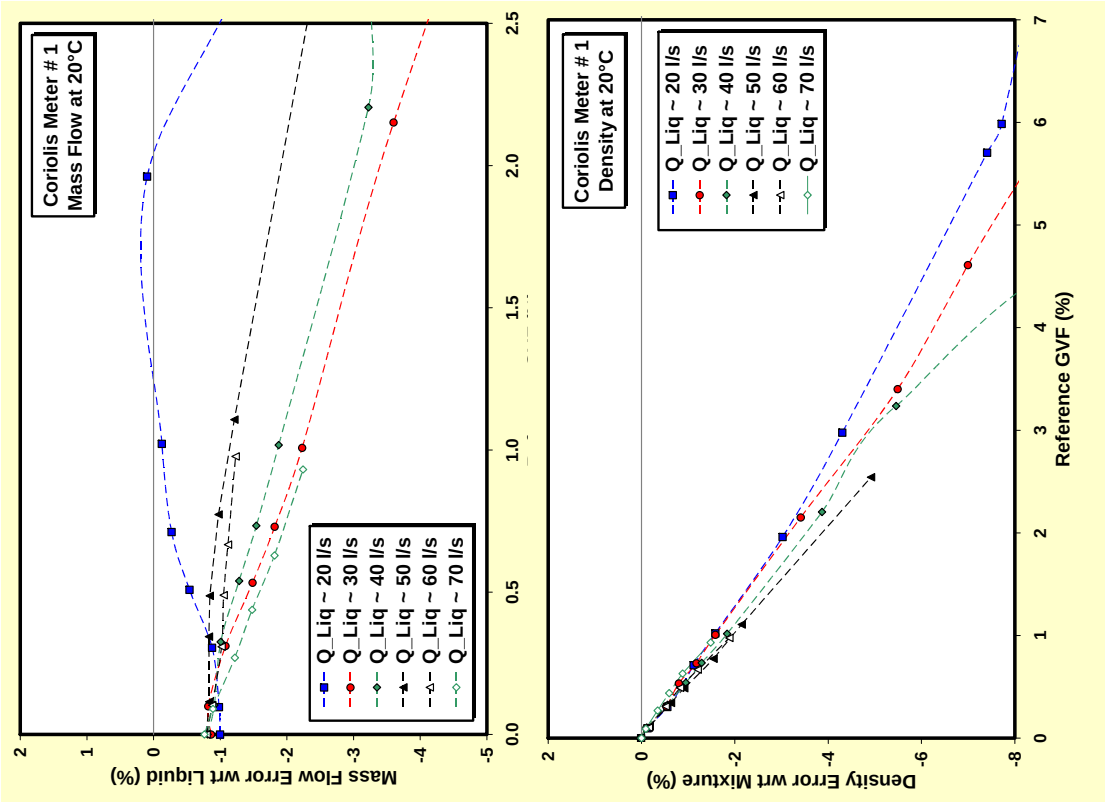

Fig. 8 – Coriolis Meter # 1: Mass flow errors calculated with respect to the reference liquid mass flow (upper figure) and density errors calculated with respect to the homogeneous mixture density (lower figure) in Primol at 20 ºC (200 cSt).

The lower graph in Figure 8 shows the corresponding density errors[6] for Coriolis Meter # 1. Above 20 l/s, the meter always under-reads with respect to the calculated (homogeneous) reference mixture density. At GVFs below 1%, the errors are less than ~ 2% (for all flowrates tested). Above 1% GVF, a reasonably linear relation persists between density error and GVF for the lower flowrates only. As the flowrate increases, the density errors rapidly diverge with increasing GVF, and the curves in Figure 8 are curtailed to reflect this.

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[5] The meter errors are calculated with respect to the reference liquid flowrate. The rate and density of the injected gas are such that its contribution to the total mass flowrate is negligible. No adjustment was made to the single-phase (i.e. liquid-only) response of the test meter prior to this evaluation i.e. its output was not tuned to match the reference system flowrates. The "zero-GVF" measurements should therefore be taken as the "baseline" response of the meter.

[6] While making little contribution to the mass flow of the two-phase stream, the injected gas does significantly alter its density. The meter errors, in this case, are therefore calculated with respect to the local mixture density (at the meter inlet) rather than the reference liquid density.

4.2 Coriolis Meter # 2

Coriolis Meter # 2 was installed and set up in a similar manner to Coriolis Meter # 1.

4.2.1 Flowrate Measurement

In a first set of tests, the meter was "auto-zeroed" after each change of fluid but not after each change of temperature (as per Meter # 1) and found to exhibit similar characteristics in its mass flowrate response (not shown). In a second set of tests, its performance was found to be slightly improved (Figure 9) by re-zeroing the meter after each temperature step as well as after each fluid changeover. Like the first meter, the mass flowrate deviations grow larger as the fluid viscosity increases; particularly at low flowrates. Again, this may be indicative of a poor zero-offset setting being returned by the automated zero-setting procedure.

The influence of the zero adjustment value on the reported flowrate could, in fact, be demonstrated with this particular device, which allowed a "forced" setting to be downloaded. Figure 10 shows the effect of varying this parameter. Over a small range of manually-set values, the linearity of the mass flow measurement is markedly improved; although a small constant under-reading is still evident. Again, this may be evidence that the automated zeroing process (or procedure followed) does not always return the optimum offset adjustment value in higher viscosity fluids.

As a conclusion to the mass flowrate evaluation, one final set of test data was gathered on the most viscous of the facility's test fluids at present (Primol at 10 ºC), with the zero-offset manually optimised and over-ridden. The results (Figure 11) show that a linear response can be obtained even at 300 cSt, provided that care is taken with the meter zeroing process. A small but constant under-read is, however, still evident[7], which may indicate some further influence of the elevated viscosity.

4.2.2 Density Measurement

The density response of the meter is shown in Figure 12. The behaviour is similar to that of Coriolis Meter # 1, and again in-line with the vendor's specifications for this larger 6" device.

4.2.3 Pressure Loss

Sample measurements of the pressure drops developed across Coriolis Meter # 2 (6") are:

ΔP @ 90 l/s (65 cSt) ~ 1000 mbar	ΔP @ 77 l/s (200 cSt) ~ 900 mbar

The pressure losses across this 6-inch meter are comparable (in fact slightly higher) than those of the 4-inch meter described in Section 4.1.3. This suggests that meter design, as well as just the internal bore, play a role in the pressure loss generated in viscous fluids.

4.2.4 Effect of Entrained Gas

Figure 13 shows the effect of entrained gas on Coriolis Meter # 2 (6-inch). Irregular behaviour was again observed at flowrates below 20 l/s (not shown). Above this value, the behaviour is similar to that of Coriolis Meter # 1; although the induced errors are significantly larger. At GVFs up to 1%, for example, mass flow errors as high as 12% are incurred. Above 1%GVF, the mass flowrate errors become impractically large for all flowrates tested.

The density errors remain below 3% for flowrates greater than 20 l/s and GVFs less than 1%, but grow rapidly at GVFs larger than 1%.

[7] Note: direct mass flow measurements made against the facility's primary standard showed a similar behaviour. For flowrates above 25 kg/s, an average deviation of -0.31% was observed against the gravimetric system, compared to -0.37% relative to the PD meters (Figure 11).

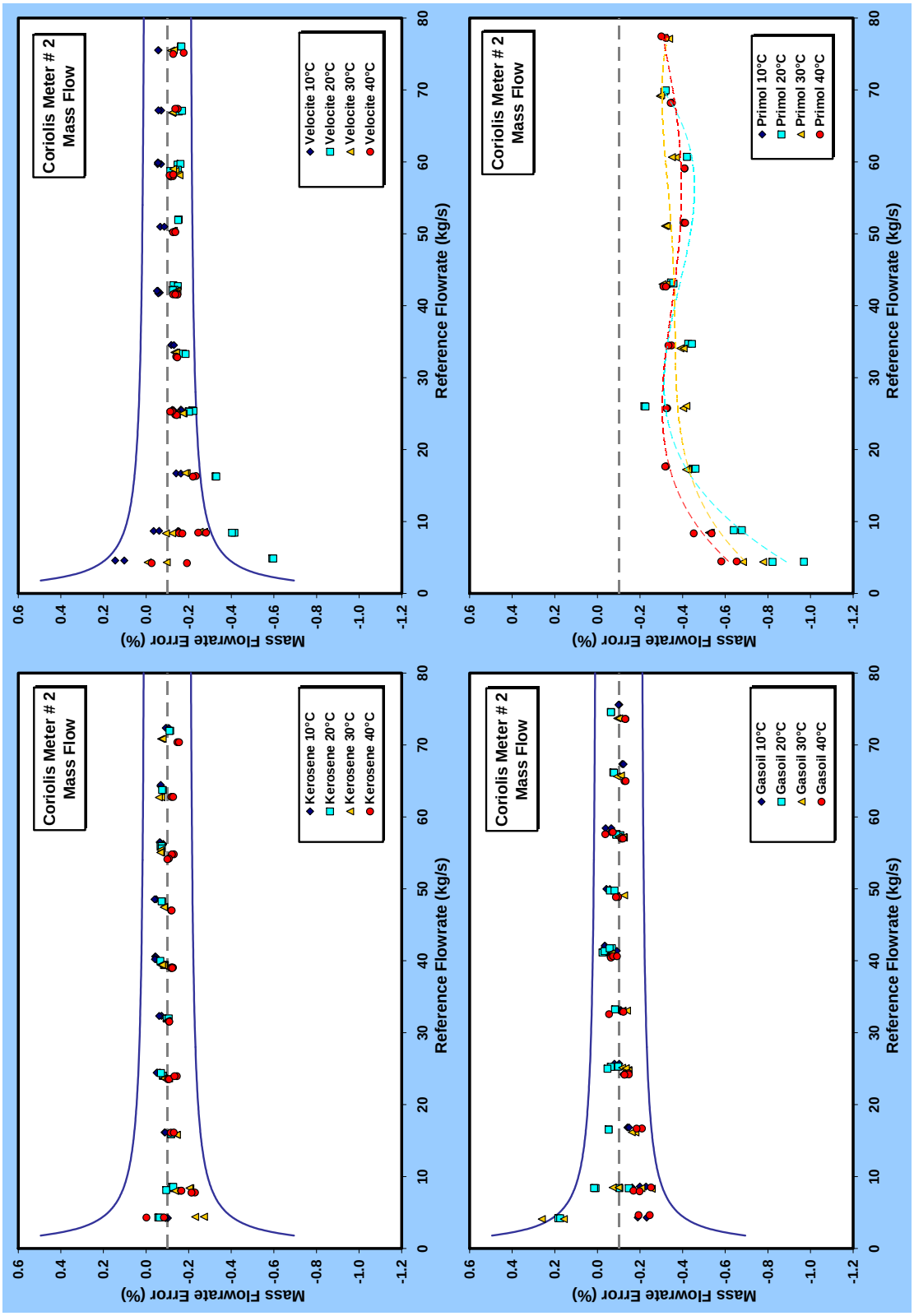

Fig. 9 – Coriolis Meter # 2: Mass flow error at temperatures between 10 and 40 ºC for each of the four test fluids: Kerosene (1 – 3 cSt), Gasoil (4 – 10 cSt), Velocite (10 – 30 cSt) and Primol (30 – 300 cSt). In this series of tests, the meter was zeroed after each change of fluid type and each change of fluid temperature. Where appropriate, the manufacturer's uncertainty specification has been overlaid for comparison. (This has been shifted by -0.1% to allow for a slight difference between the reference system and factory-supplied calibration).

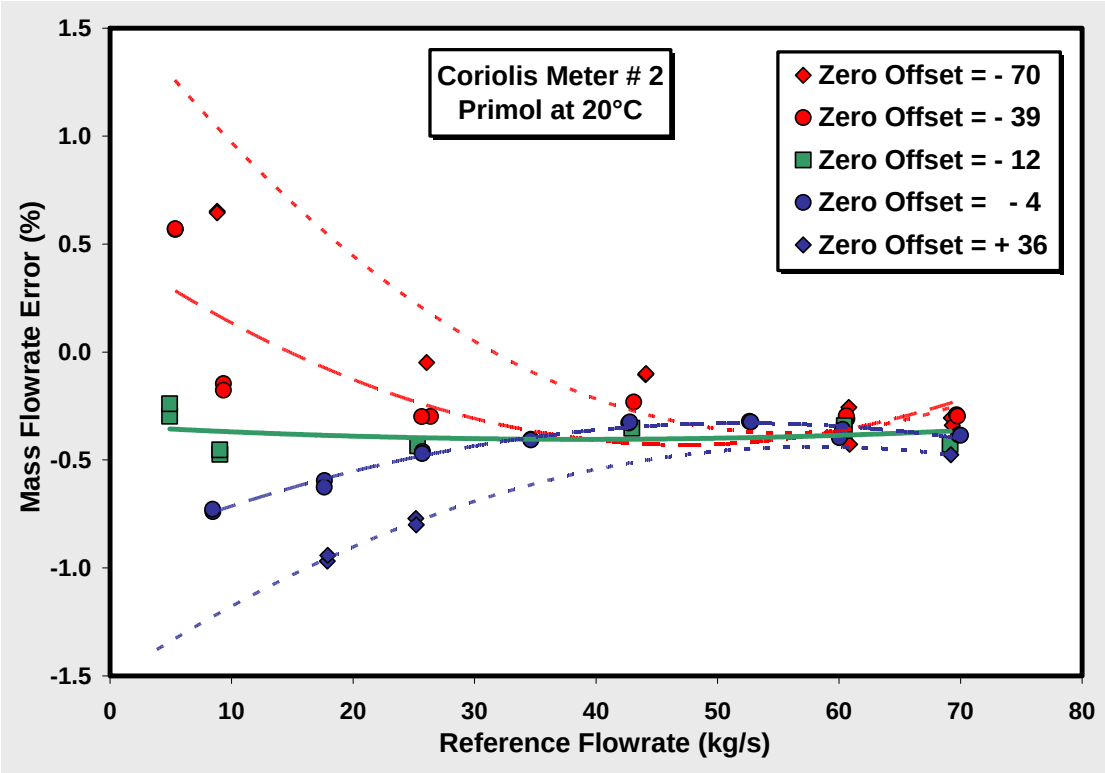

Fig. 10 – Coriolis Meter # 2: Mass flow error recorded at a fixed temperature of 20 ºC in Primol (fluid viscosity ~ 200 cSt). A linear response could be "forced" by manually optimising the meter's zero-offset parameter, although a systematic underreading of ~ 0.4% still remains.

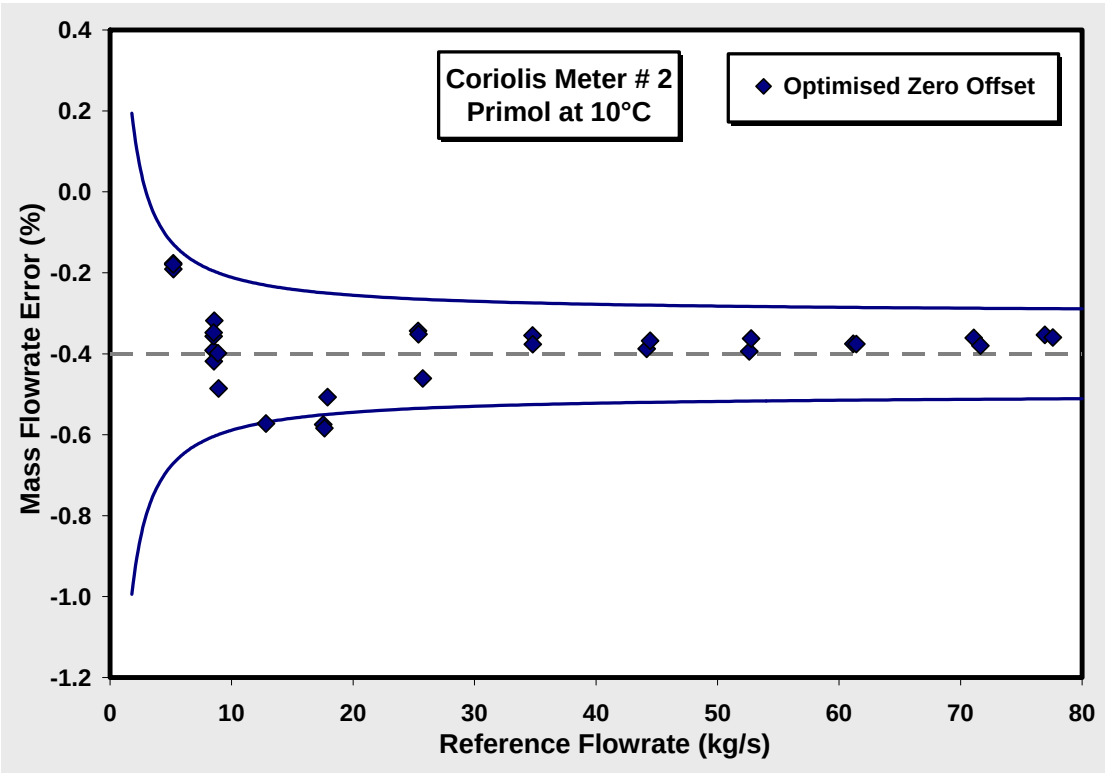

Fig. 11 – Coriolis Meter # 2: Mass flow error at the highest viscosity tested (300 cSt). In this case, the meter zero-offset parameter was manually adjusted to achieve a linear response as a function of flowrate; although a systematic underreading of ~ 0.4% still remains. The manufacturer's nominal uncertainty bands (also shifted by 0.4%) are overlaid for comparison.

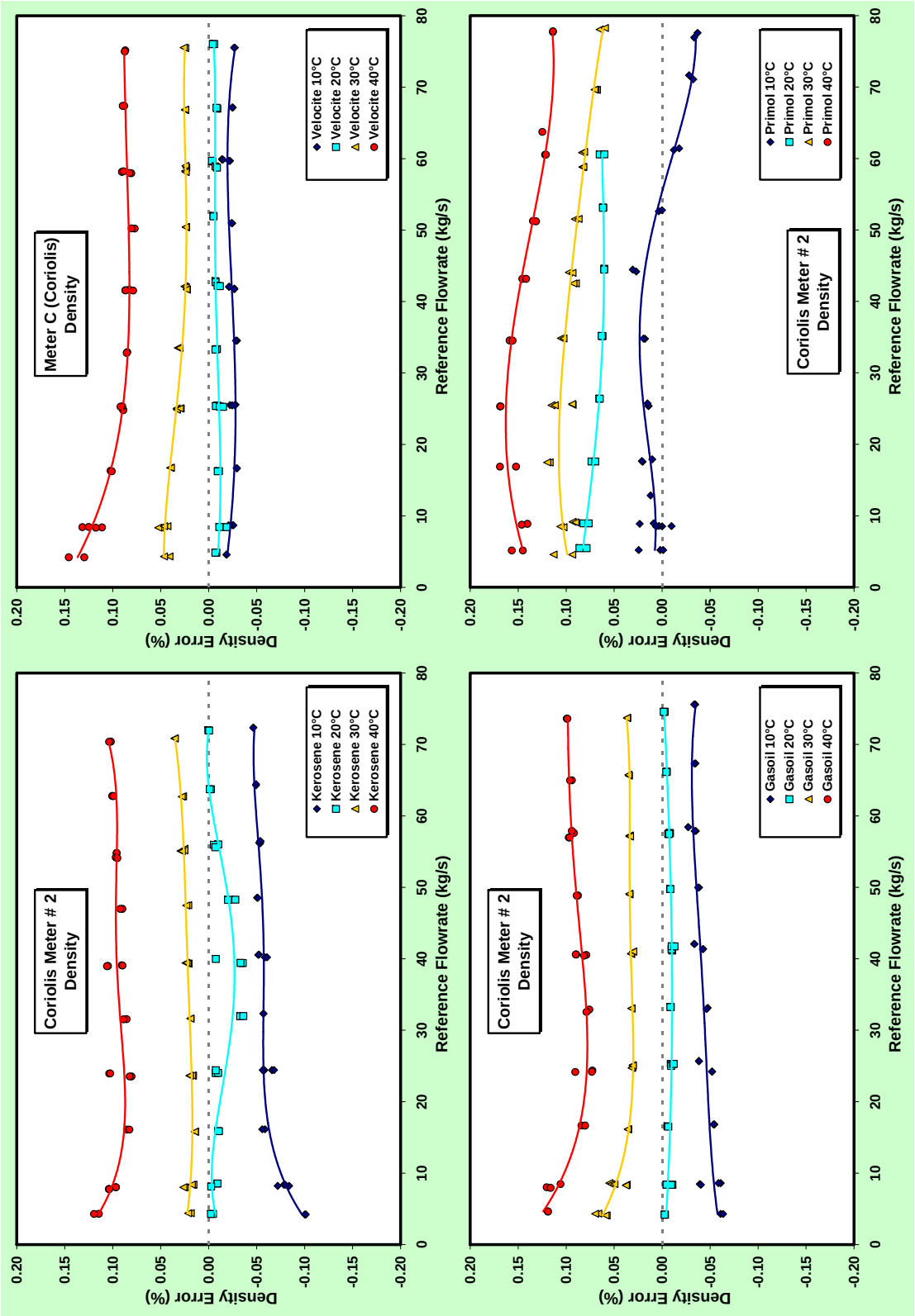

Fig. 12 – Coriolis Meter # 2: Density errors at temperatures between 10 and 40 ºC for each of the four test fluids: Kerosene (1 – 3 cSt), Gasoil (4 – 10 cSt), Velocite (10 – 30 cSt) and Primol (30 – 300 cSt). The results are from the same dataset as Figure 9, except for the 10 ºC Primol measurements, which were recorded some 9 months later. A small (correctable) shift is observed with temperature within each fluid group. The magnitude of the shift is in line with the manufacturer's published correction factor.

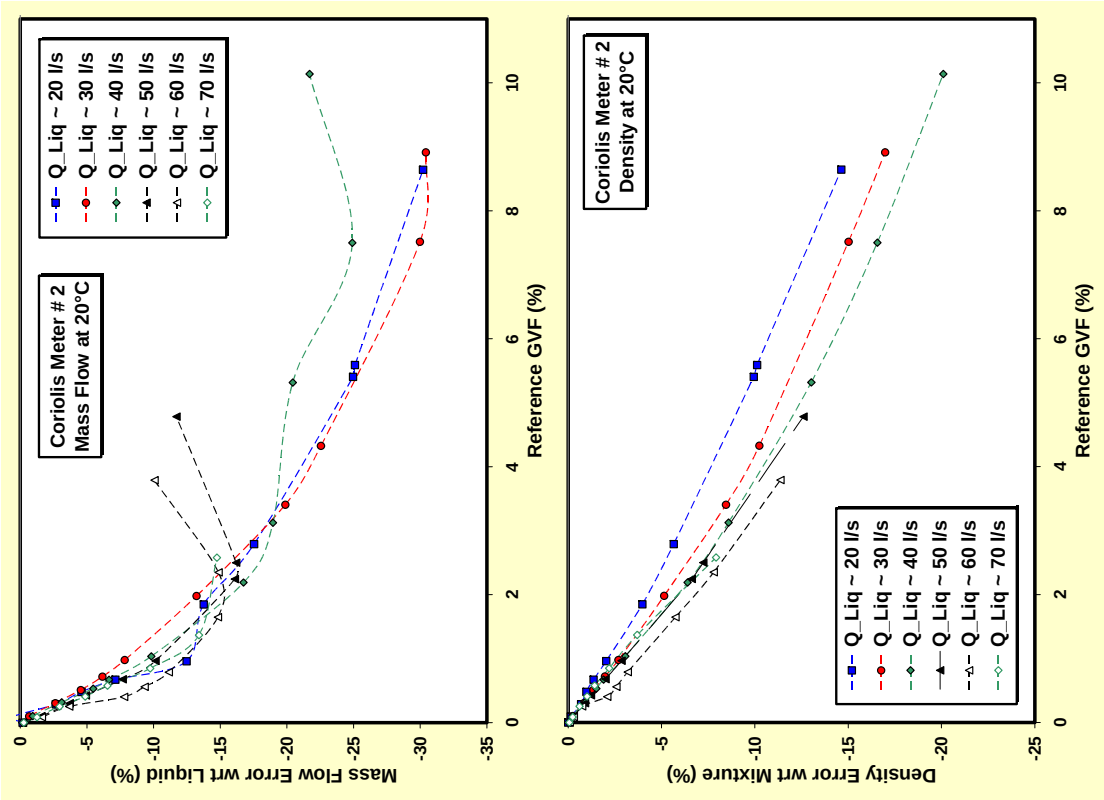

Fig. 13 – Coriolis Meter # 2: Mass flow errors calculated with respect to the reference liquid mass flow (upper figure) and density errors calculated with respect to the homogeneous mixture density (lower figure) in Primol at 20 ºC (200 cSt).

4.3 Ultrasonic Meter # 1

The core set of tests conducted on Ultrasonic Meter (USM) # 1 included no artificial flow conditioning within the test line; simply a basic installation set-up of (at least) 20D upstream and 5D downstream of straight pipe. Only the standard set of configuration parameters were loaded into the meter at this stage; that is to say the flowrate output was not additionally adjusted for any potential influences of high viscosity or low Reynolds number operation.

4.3.1 Flowrate Measurement

As Figure 14 highlights, the basic flowrate response of USM # 1 exhibits a strong dependence on the pipe Reynolds number, which is not unexpected for a “velocity-measuring” device. Also evident is a slight shift in the flowrate error with changing temperature. This is also partly expected (thermal expansion etc.), having not been specifically corrected for in the raw data.

However, most strikingly, there is a clear difference in the meter response between the laminar and turbulent flow regions. At high Reynolds numbers (greater than a few hundred thousand) the meter response is “reasonably” linear (i.e. the measured flowrate has a “relatively” constant offset from reference). However, as the Reynolds number is reduced, the measurement deviation increases markedly, peaking at *Re* values of around 6000 – 7000. There is then a very abrupt fall in the meter error between *Re* values of 6000 and 5000 before it rises again as the Reynolds number falls further.

Such behaviour has been previously observed [11, 12], albeit with a sparser set of data, and attributed to the integration and weighting methods used to combine the meter’s primary velocity measurements. Ultrasonic meters operate by transmitting ultrasound signals both with and against the fluid flow direction, between one or more pairs of “upstream” and “downstream” transducers. The difference in transit-time is directly related to the fluid’s velocity. While the measurement principle is fairly simple, derivation of the “true” average

flowrate of the stream can be complicated. Each transducer pair measures the average flow velocity, v_i, along only a single narrow acoustic path (or chord) at a fixed location in the pipe cross-section. To compensate for the shape of the velocity profile, multipath meters incorporate several sets of transducer pairs / chordal paths. The measurements from all paths (from $i = 1$ to N) are then combined with appropriate weighting factors, w_i , (which depend on the path location etc.) to compute the average axial flow velocity:

$$\bar{v} = \sum_{i=1}^{N} w_i \cdot v_i \tag{3}$$

The total volumetric flowrate is then obtained by multiplying by the pipe area. However, the number and location of the paths and the algorithms used to combine the individual path measurements all have a bearing on the final flowrate accuracy.

At high Reynolds numbers, particularly under the "ideal" installation conditions applicable here, the flow should be in a fully-developed turbulent regime, with a relatively flat and slowly changing velocity profile. However, as the Reynolds number is reduced, the velocity profile can be expected to change markedly; as the flow regime passes from turbulent through transitional into the laminar region. The authors of references [11] and [12] point out that any ultrasonic meters employing constant weighting factors in their path integration algorithms are susceptible to non-linearities of the type observed in Figure 14. In essence, the chord weighting factors suitable for one velocity profile are not necessarily appropriate for the range of profiles encountered over an extended Reynolds number range. Alternative or additional corrections must then be applied, according to the presumed or measured velocity profile.

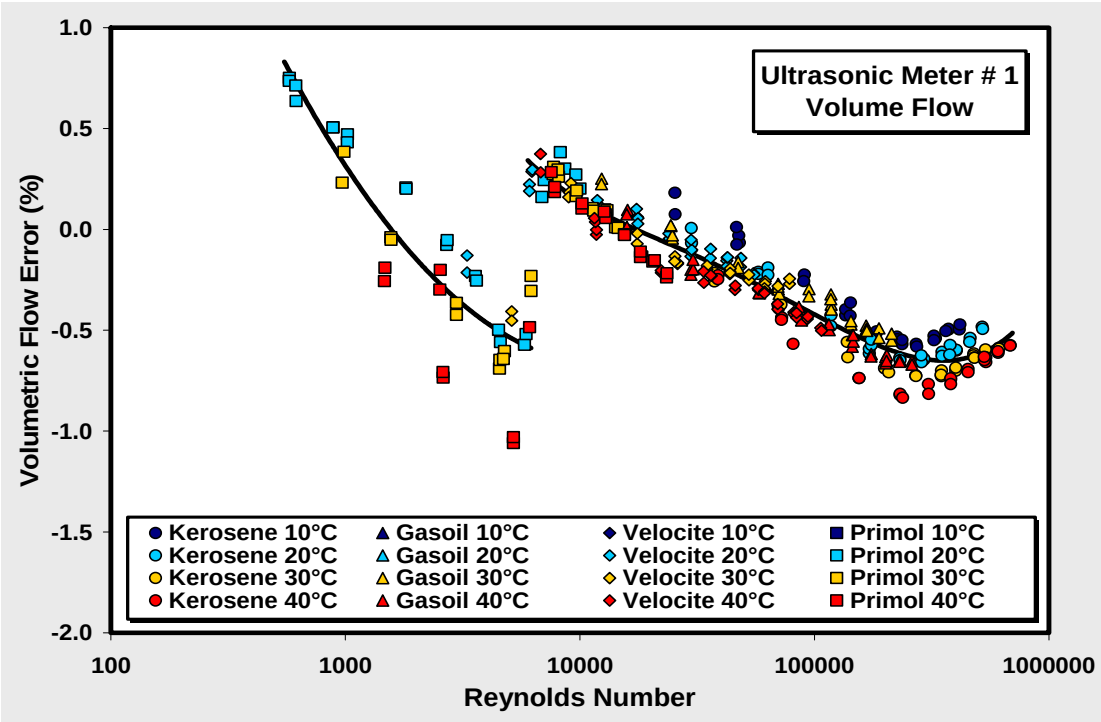

Fig. 14 – USM # 1: Volumetric flowrate error vs pipe Reynolds number with no artificial flow conditioner. The data are colour-coded according to fluid temperature. Two simple polynomial fits are made to the data, corresponding roughly to the laminar and turbulent flow regions.

As an example of the improvement that could *potentially* be obtained in the reconstructed flowrate – given the repeatability of the measurements – two simple polynomial fits are superimposed on the data of Figure 14. If used as "calibration curves" to adjust the raw meter response, only the residual errors of Figure 15 then remain. This approach does, however, assume advance knowledge of *Re* and, in practice, a more direct measurement of the velocity profile is likely to be preferred.

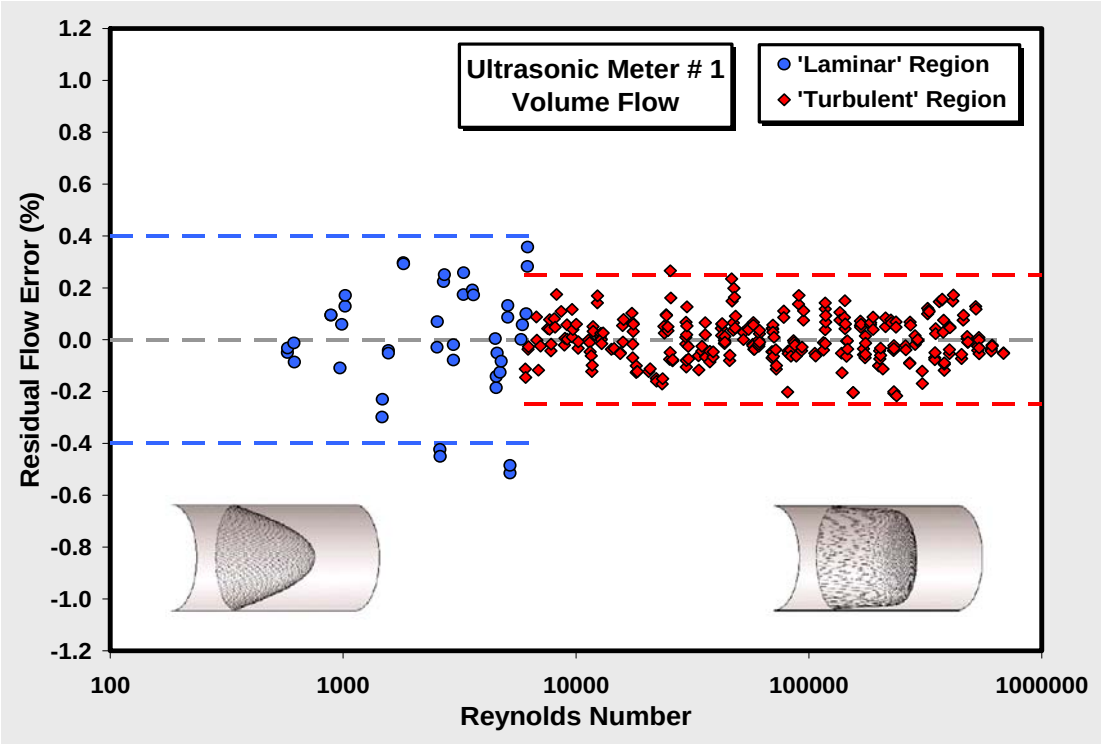

Fig. 15 – USM # 1: Residual flowrate errors following the application of a simple Reynolds-based adjustment factor (as suggested by Figure 14). This artificial offline correction demonstrates the potential improvement in accuracy that could be achieved. Error bands of ± 0.4% (laminar / transitional region) and ± 0.25% (turbulent region) are overlaid for guidance.

4.3.2 Pressure Loss

Ultrasonic Meter # 1 was a full-bore, non-intrusive device and as such contributed no more pressure drop per unit length than the supporting 4-inch pipework:

USM # 1 :	ΔP @ 90 l/s (65 cSt) ~ 44 mbar	ΔP @ 77 l/s (200 cSt) ~ 50 mbar
5D Plain Pipe :	ΔP @ 90 l/s (65 cSt) ~ 54 mbar	ΔP @ 77 l/s (200 cSt) ~ 62 mbar
Tube Bundle :	ΔP @ 90 l/s (65 cSt) ~ 922 mbar	ΔP @ 77 l/s (200 cSt) ~ 1167 mbar

When the test matrix was repeated with an upstream flow conditioner (tube bundle) installed, no significant improvement in the meter response was observed. However, the described tests were conducted under relatively ideal conditions (Figure 4) with close to fully-developed flow, and this does not rule out the potential requirement for artificial flow conditioning under other installation set-ups. Unfortunately, the additional pressure drop associated with the present flow conditioner (as noted above) tends to completely negate the pressure-loss advantage that ultrasonic meters otherwise offer in fluids of this viscosity.

4.3.3 Effect of Entrained Gas

Figure 16 shows the effect of entrained gas on USM # 1. The uncorrected (baseline) response of this meter in single-phase liquid has a complex dependence on liquid flowrate, being more closely coupled to Reynolds number (as shown in Section 4.3.1). While it was not yet optimised for high-viscosity (low *Re*) operation in the tests conducted here, some basic operating limits can be defined where, for example, the measurement errors are restricted to less then ± 3%. Figure 17 shows the maximum GVF tolerable to meet a 3% error criterion. It is clear that the maximum allowable GVF falls rapidly as the liquid flowrate increases.

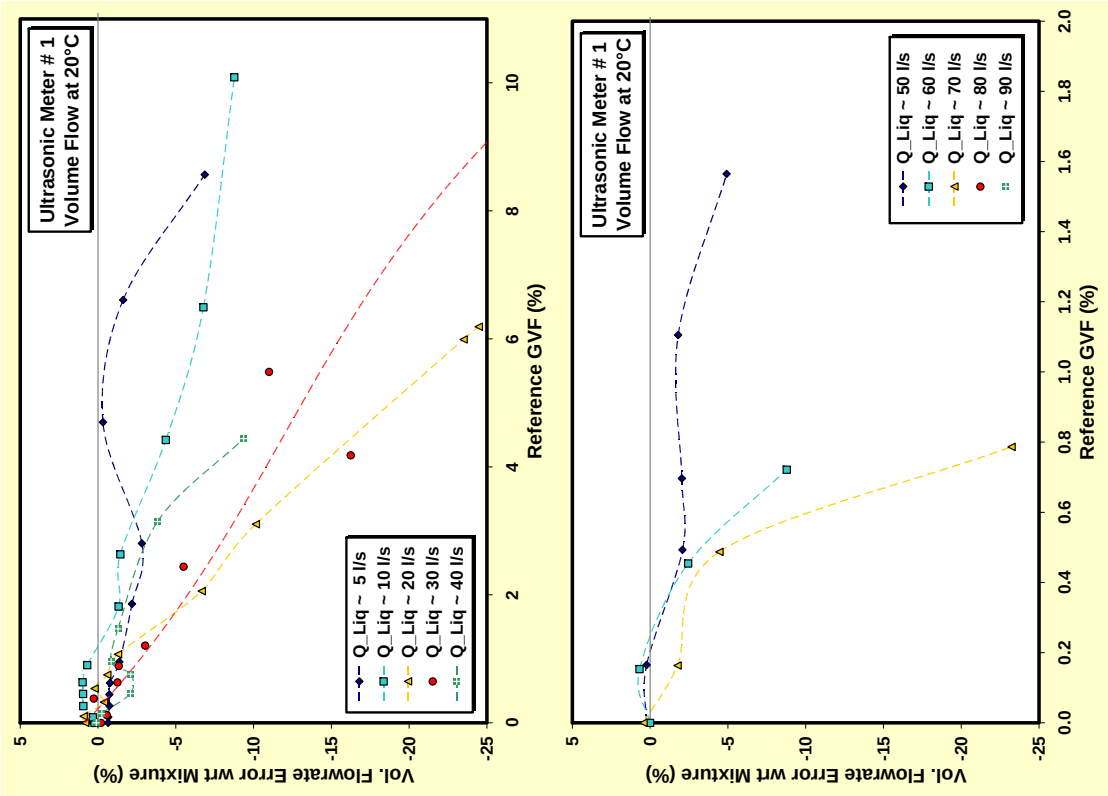

Fig. 16 – USM # 1: Volumetric flow errors recorded in Primol at 20 ºC (200 cSt) in the presence of entrained gas. The errors are calculated with respect to the total reference volumetric flowrate (oil + gas). For clarity the results are split into low flowrate data (upper graph) and high flowrate data (lower graph).

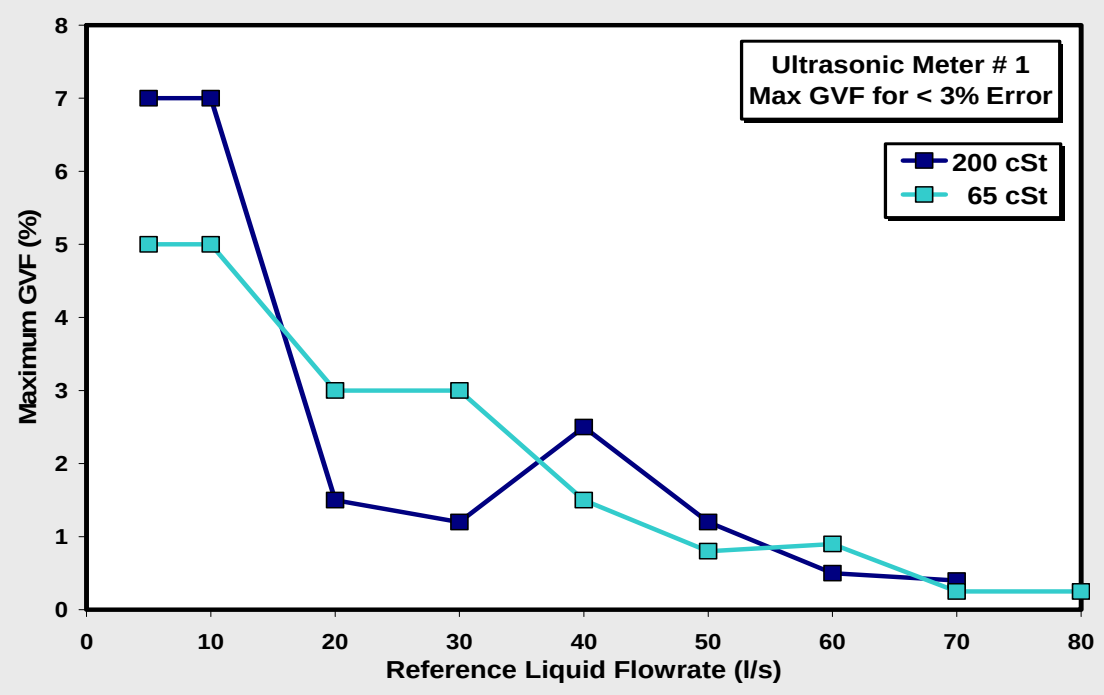

Fig. 17 – USM # 1: Upper limit on GVF for maintaining metering errors below ± 3%. The allowable GVF falls as the liquid flowrate increases, possibly because the distributed gas affects more and more chordal paths as the mixing effect increases. At low rates, stratified flow is more likely – a regime that most USMs can cope, even if one chordal path fails.

4.4 Ultrasonic Meter # 2

USM # 2 was installed with no artificial flow conditioner and initially configured with all internal correction factors[8] "switched off". A full data set (4 fluids x 4 temperatures) was acquired, and this "uncorrected" flowrate information, plus other internal diagnostic data, used to generate a series of calibration coefficients. These coefficients allowed the meter to output corrected flowrates[9] during subsequent service. A second independent set of test data was then gathered, to demonstrate the meter's "optimised" performance after the calibration process.

4.4.1 Flowrate Measurement

Figure 18 shows the "raw" flowrate output of USM # 2, gathered for calibration purposes, as a function of pipe Reynolds number. This "uncorrected" output has a different definition to that of USM # 1, but again shows a very systematic behaviour and correlation with *Re*.

While the deviation in flowrate is fairly flat at high Reynolds numbers (turbulent regime), this is far from true at lower Reynolds values (i.e. in the transitional and laminar flow regimes), where it may be surmised that the rapidly changing velocity profile is having a significant effect on the averaged "uncorrected" flowrate computed by the meter. The close correlation with Reynolds number and the high repeatability of the data does, however, offer significant scope for compensating this behaviour.

Of course, in practice, *Re* is not measured directly, and instead the flowrate error is mapped against other internal parameters, which *are* measured by the meter, to generate a meter factor / calibration curve. Once characterised over a suitably wide Reynolds number range, the calibrated meter can then, in principle, output "corrected" flowrate values without specific knowledge of the fluid properties or fluid viscosity.

Figure 19 shows the "corrected flowrate" response of USM # 2 after calibration. The results are from a second matrix of performance data, gathered independently of the calibration set. On the whole, the measured flowrates lie well within ± 0.25%, except for a small region of Reynolds number (20000 – 60000) where the internal calibration could clearly be improved, and at low Reynolds numbers where the calibration data (Figure 18) were relatively sparse. Nonetheless the meter response observed in these tests appears suitably repeatable and reproducible to offer significant promise for higher viscosity applications.

4.4.2 Pressure Loss

USM # 2 was again a full-bore device and as such introduced no more pressure drop per unit length than the surrounding 4-inch pipework.

4.4.3 Effect of Entrained Gas

The effects of entrained gas on USM # 2 are shown in Figure 20. Only the "uncorrected" flowrates are available for comparison, but it can be seen that significant deviations from the baseline (zero gas) response are avoidable over only a very limited combination of liquid flowrates and gas volume fractions. Again, gas entrainment at levels of greater than ~ 1% by volume can be seen to have a severe effect on the meter's performance.

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[8] The "raw" meter output consisted of an uncorrected total volume flowrate; calculated from individual ultrasonic path measurements, combined and averaged via proprietary algorithms.

[9] The corrections are based on the meter's primary and internal diagnostic measurements. Details are confidential to the manufacturer but require no additional information (such as *Re* or fluid properties) to be entered during operation.

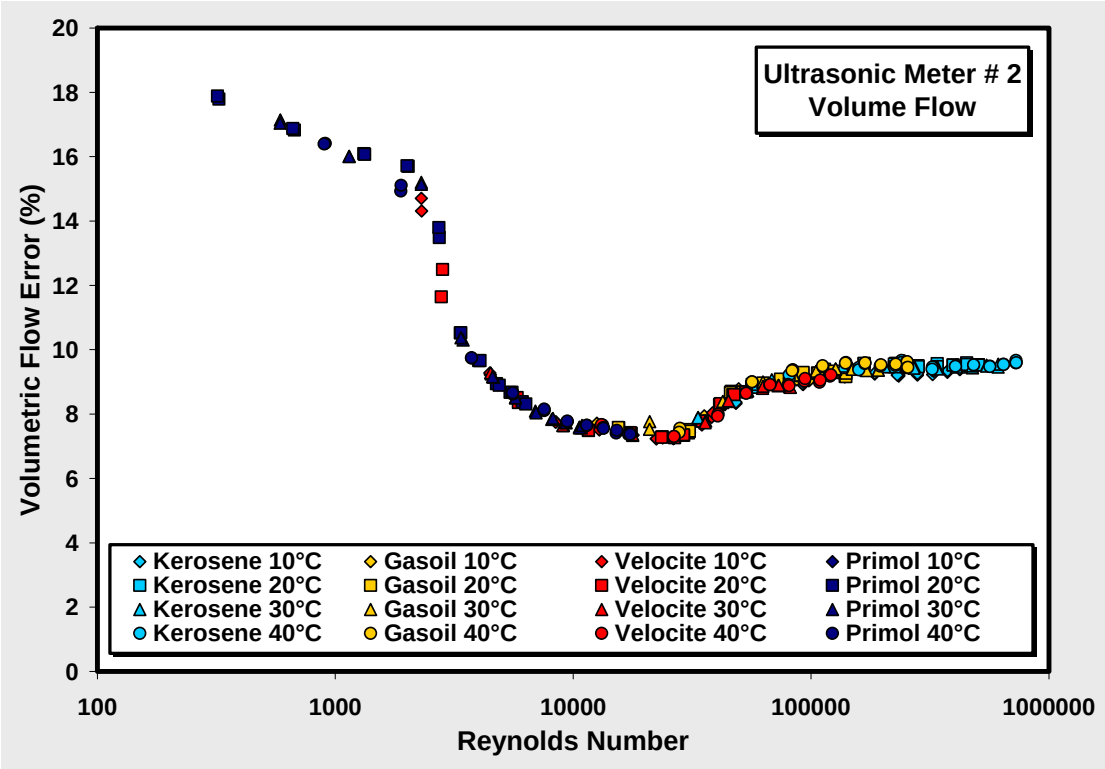

Fig. 18 – USM # 2: Error in "uncorrected" flowrate output, recorded during meter calibration.

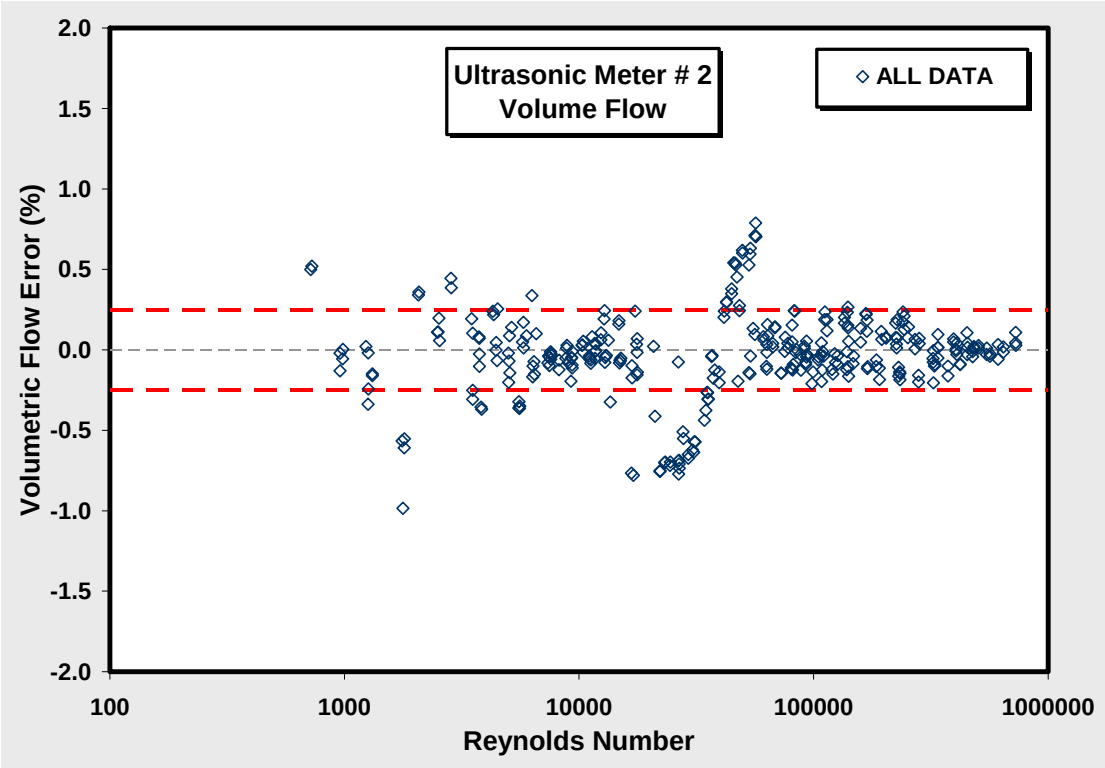

Fig. 19 – USM # 2: Corrected flowrate response, showing the uncertainty achievable after meter calibration. There are clearly some areas where the internal calibration could be improved or where additional calibration data would be of benefit. Error bands of ± 0.25% of reading are overlaid for guidance.

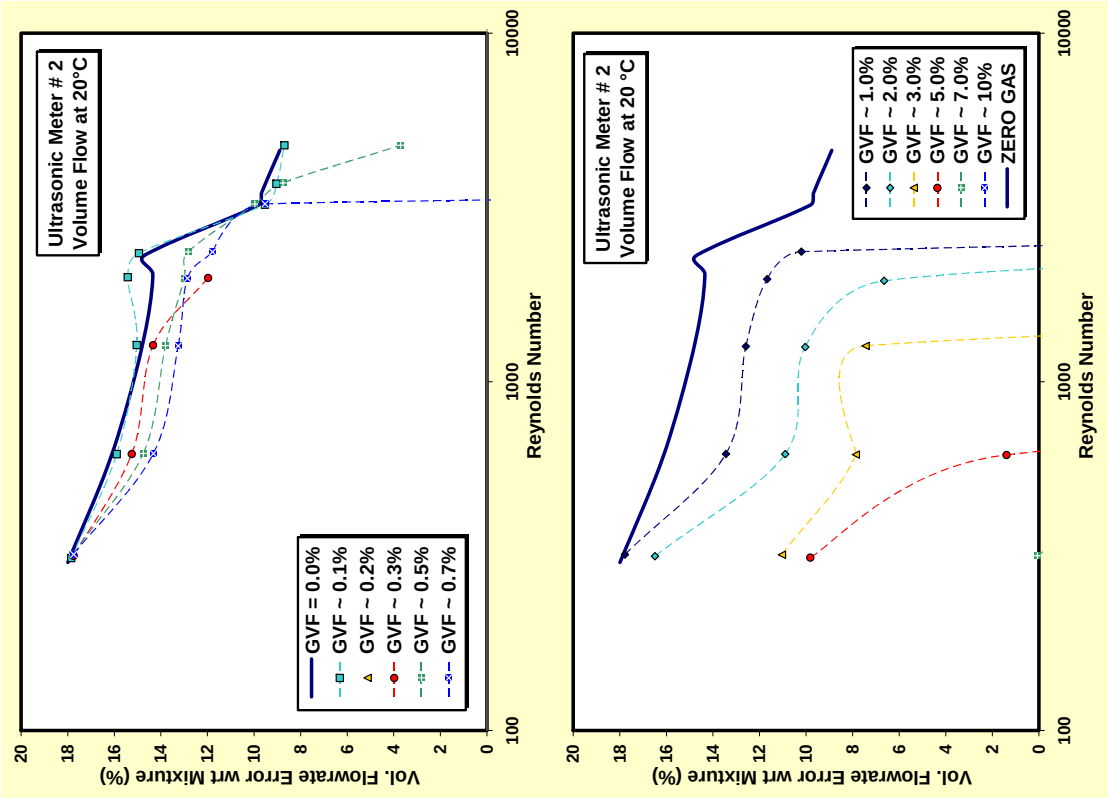

Fig. 20 – USM # 2: Volumetric flow errors (uncorrected) recorded in Primol at 20 ºC (200 cSt) in the presence of entrained gas. The errors are calculated with respect to the total reference volumetric flowrate (oil + gas). For clarity the results are split into low GVF data (upper graph) and higher GVF (lower graph). The zero-gas baseline is shown in each case for comparison.

5 SUMMARY AND CONCLUSIONS

An experimental investigation has been conducted into the performance of two conventional types of liquid flowmeter – Coriolis and ultrasonic – when operated in fluids of increasingly high viscosity (1 to 300 cSt). To facilitate this investigation, the National Standards Oil Flow Facility at TUV NEL was upgraded and a new viscous test fluid added to its previous suite of three lower viscosity oils. Testing was conducted on 2 x Coriolis and 2 x ultrasonic commercial devices, at flow-rates from 5 to 90 litres/second; using all four facility test fluids at set-point temperatures of 10, 20, 30 and 40 ºC. This allowed pipe Reynolds numbers from just a few hundred to almost one million to be explored over the course of the test programme.

In most industrial applications, the fluid transport conditions – velocity, viscosity and pipeline dimensions – are such that the flow is turbulent, but when dealing with viscous fluids there is a far greater likelihood that laminar or transitional flow regimes will be encountered. These regimes, which are strongly dependent on the Reynolds number of the flow, have significantly different velocity profiles.

The ultrasonic meters (USMs), in particular, exhibited a clear and significant dependence on the Reynolds number, which is itself a function of fluid velocity and viscosity. Such behaviour was not unexpected of course, since ultrasonic meters are velocity-measuring devices. However, the precise correlation between flowrate and *Re* differed significantly for the two devices tested, due to the dissimilar methods by which the average flowrate is reconstructed.

The first USM, for example, exhibited a very abrupt transition in its flow-rate response with *Re* in the vicinity of the laminar / turbulent boundary. This has been attributed to the use of constant weighting factors in its path integration algorithms [11, 12], which may generate accurate estimates of the mean flowrate where the velocity profile is slowly-changing and

turbulent, but which are less appropriate when the flow regime is laminar or transitional. A crude Reynolds-based calibration correction offers one method of compensating for the observed dependence (and the potential improvement in accuracy was demonstrated), but unfortunately neither *Re* nor the fluid viscosity is measured directly by most ultrasonic meters. Similar, although less abrupt, deviations in flowrate were observed in the "uncorrected" output of the second USM, but in this case it was shown how additional diagnostic measurements (more closely related to the flow profile itself) can be used to compensate for the changing meter response, without specific knowledge of the Reynolds number.

While it was noted in Section 2 that viscous products can block or attenuate ultrasound signals, this was not found to be a particular problem in the current test programme; although it could be an issue with different fluids, larger diameter devices or where longer (perhaps reflected) path lengths are involved. The inclusion of an artificial flow conditioner introduced a significant additional pressure loss at the higher viscosity conditions investigated here; suggesting that, if required, other means of mitigating installation effects (such as suitable straight pipe runs) may be preferable. Overall, however, the non-intrusive nature (low pressure loss) and onboard diagnostic capabilities of this type of meter appear to lend them significant promise for expansion into higher viscosity applications.

Coriolis meters have the recognised advantage of direct mass flow and density measurement. In addition, they are often claimed to be insensitive to viscosity and to the velocity profile of the flow [13], which can vary rapidly at low Reynolds numbers. Velocity profile effects *have*, however, been identified in previous studies [14] for certain meter designs and installation configurations.

Both of the Coriolis meters tested here performed within their mass flow specification for lower viscosity products, although their zero stability specification appeared difficult to achieve in more viscous fluids (at least when the meters were "zeroed" using the standard automated prescriptions). The experience gained here suggests that some operational or at least procedural improvements may be required to fully optimise this process, if the meters are to be confidently employed for heavier oils.

The present tests also demonstrated how, at higher viscosities, Coriolis meters are forced to operate lower in their standard flowrate range due to pressure loss considerations, where "zero stability" effects have their greatest influence. For extension to even higher viscosities (than those tested here), pressure loss minimisation is likely to be a key consideration in meter selection and design. While "over-sizing" a Coriolis meter for a given application may help minimise the pressure loss, this could have other consequences such as higher cost, increased installation space and reduced accuracy; due to the fact that metering is necessarily performed low in its turndown range. The density responses of both Coriolis devices tested were largely unaffected by increasing fluid viscosity, remaining generally consistent with the manufacturer's specifications. A slight over-reading of fluid density was suggested at the higher viscosities tested, but this requires more detailed investigation for clarification.

Some basic temperature dependencies were observed in several of the test meter responses (where not already compensated), but on the whole these were highly systematic in nature and in principle correctable within the flow computer or meter software. Gas entrainment at levels of greater than ~ 1% was shown to be severely debilitating to both types of meter (Coriolis and ultrasonic), although it must be emphasised that the specific models tested here incorporated no specific mitigation or correction methods[10].

Overall the results reported here reinforce the notion that conventional liquid flowmeters, cannot simply be relocated from low viscosity to high viscosity service without suitable characterisation, modification or care; nor can calibrations conducted in a low viscosity medium (such as light oil or water) necessarily be applied to heavier crudes without appropriate compensation.

[10] This is an ongoing issue that is currently being addressed by a number of manufacturers, universities and research bodies [15 – 19].

6 ACKNOWLEDGEMENTS

This project was not structured as an evaluation of any particular manufacturer or flowmeter model, but rather as a generic investigation of some of the effects of high viscosity on established measurement technologies. The vendors who provided test equipment for this purpose did so in good faith and on this understanding, and their confidentiality and valued cooperation is gratefully acknowledged.

7 FUTURE WORK

The experimental test work described in this paper was intended as a preliminary investigation into the effects of increased fluid viscosity on conventional flow measurement technologies. Awareness of the issues emerging is now growing among manufacturers and end-users alike, with new research being focused on their correction or mitigation. To assist with this process of innovation, a new Joint Industry Project (JIP) has been launched at TUV NEL, which aims to:

- Extend the range of meter types under test (to include, for example, Venturi devices etc.).
- Explore higher liquid viscosities (< 600 cSt) and even more demanding flow conditions.
- Explore in more detail the effects of gas entrainment on flowmeter measurement integrity.

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