North Sea FLOW Measurement Workshop

1988

North Sea FLOW Measurement Workshop

1988

Main Index

CALORIFIC VALUE MEASUREMENT WITH HONEYWELL HVT - 100

by

I Bates and T Davies
Total Oil Marine plc

Paper 1.1

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

CALORIFIC VALUE MEASUREMENT WITH THE HONEYWELL HVT-100

IAN P. BATES

TOTAL OIL MARINE PLC, ABERDEEN

JULY 1988

1. INTRODUCTION

This paper describes the requirement to replace the Continuous Recording Calorimeter with a more reliable and accurate instrument for the purposes of Fiscal Calorific Value measurement of Natural Gas.

The options considered are reviewed and particular attention is given to the instrument selected, detailing its evaluation and final installation.

The instrument selected was the 'Heating Value Transmitter' manufactured by Honeywell.

1.1 The Installation

Natural gas processed by the St. Fergus Terminal is transferred to the British Gas site for nationwide distribution. This transfer takes place through two parallel pipes, each metered by separate metering stations termed Phase I and Phase II.

Revenue from British Gas is based on energy, therefore the calorific value (CV) of the gas flowing through both pipes is required to be measured and transmitted to the flow computers for heat flow computation.

The measurement of the sales gas gross calorific value has been performed by 4 continuous recording calorimeters, two units installed on each Phase in a closely controlled and monitored air conditioned room. A sample line runs from the metering station pipe header to both calorimeters, allowing a continuous analysis of the same gas sample.

1.2 Existing Calorimeters

Since gas first flowed at St. Fergus calorific value has been measured by the industry accepted standard device - the continuous recording calorimeter, manufactured by Cutler Hammer.

As these units were designed in the 1930's their construction is almost entirely of moving mechanical parts, many operating in direct contact with water. The units display a sensitivity to ambient temperature and must therefore be operated in a closely controlled environment at all times. The moving parts are subject to wear which results in instrument drift.

As with any piece of analysis equipment, the manufacturers quote an expected accuracy. In the case of the Cutler Hammer calorimeter this is $\pm$ 0.5%, corresponding to $\pm$ 0.20 MJ/sm^3

Normal operation calls for close monitoring of instrument performance on a daily basis, this includes checks relating to the air conditioning systems. The accuracy of measurement is verified on a weekly basis by placing each unit on standby in turn and passing certified test gases through the device under test. A close examination of the unit is also required at this stage.

Planned maintenance is required on each calorimeter every three months by taking the units out of service in rotation. In addition to routine maintenance, the mechanical and electrical performance has to be rigorously tested. If unacceptable wear is found, the instrument is stripped and the area of wear located and remedied. This operation may take several days and large quantities of spares have to be stocked so that there are no unnecessary delays due to shortages.

During this maintenance period no standby unit is available. If a fault develops with the duty calorimeter, a preset CV may be required which usually calls for corrections to production totals to be made.

2.0 THE REQUIREMENT FOR A REPLACEMENT

2.1 The Continuous Recording Calorimeters gave rise to the following areas of concern.

a) Obsolescence

Cutler Hammer no longer manufacture complete calorimeters or spares. Although spares are available their quality is often poor. This has resulted in a programme of refurbishment being carried out, replacing critical items with specially manufactured items followed by accurate alignment.

b) Reliability

In addition to instrument drift detected by close monitoring, operational problems have been experienced due to a number of failures of the calorimeters. Occasionally, a calorimeter would trip while on-line, completely unexpectedly, rigorous examination revealing no apparent fault. These failures were subsequently traced to porous castings.

c) <u>Accuracy</u>

As gas revenue is directly proportional to measured calorific value, we are obliged to operate the calorimeters at the best accuracy level achievable. However, this level is limited by relative inadequacies in the design, materials used and manufacturing tolerances employed in these rather antiquated devices.

Although the calorimeters may be calibrated accurately at a single point it is rather difficult to maintain the accuracy at the various CVs encountered when in operation.

These units are sensitive to changes in ambient temperature, if faults develop with the air conditioning system, inaccurate measurement will result. To a lesser extent the calorimeters are affected by changes in atmospheric pressure, this results in misleading calibration results if attempted during periods of extreme barometic pressure.

The units are slow to respond to transients and may therefore not follow CV excursions correctly. The slow response time is a considerable problem when relighting following a shutdown. During this operation the calorimeters are extremely temperamental.

d) <u>Maintenance</u>

Due to the high level of manual monitoring and frequent intervention required in addition to the lengthy planned maintenance periods, the calorimeters are unreasonably dependent on skilled manpower. In view of the obligation to maintain accurate measurement at all times, little can be done to reduce this manpower requirement.

As the calorimeters become older and spares become rarer, the maintenance problems will increase with a corresponding deterioration in reliability and accuracy.

e) <u>New Technology</u>

It is now widely recognised that significant improvements in metering accuracy and reliability have been achieved through the widespread adoption of digital flow computers and largely solid state instrumentation, such as modern differential pressure transmitters and densitometers. Essentially moving parts have been either reduced to an absolute minimum or eliminated entirely in order to provide these advances.

Rather than continuing with obsolete equipment, it has been our policy to appraise devices which employ new technology.

3.0 REPLACEMENT OPTIONS

3.1 Several devices are available to measure the calorific value of natural gas. These devices may be categorised into three types.

a) Calorimetry methods which measure the heat released by the combustion of a metered volume of gas. The Cutler Hammer calorimeter was an example of this type.

b) Gas analysis methods which determine the calorific value by calculation from an analysis of the concentrations of individual components in the natural gas mixture. Instruments which may be included in this classification are: gas chromatographs, and spectrometers.

c) Inferred measurement methods which calculate the calorific value by measurement of a parameter which is related to the calorific value. Examples of this type are the Honeywell HVT-100 and the Therm-Titrator.

3.2 Each of these options was considered, but we required that items to be short listed should have already been proven in service as we could not evaluate all possibilities.

In the UK sector of the North Sea, Operators have considered the gas chromatograph as a suitable replacement to the continuous recording calorimeter and this device has gained acceptance as a point of sale instrument.

The Honeywell HVT-100 has received good reports and is widely used in the USA.

The gas chromatograph and HVT-100 are now discussed in detail.

3.3 Gas Chromatograph

3.3.1 Advantages

a) Already accepted for Point of sale measurement in UK.

b) A fundamental advantage of using gas chromatography is that additional parameters such as relative density and compressibility may be calculated and used in metering calculations, reducing the overall number of instruments required. Special air conditioned rooms are not required, further simplifying the installation.
However, as Operator of a large gas transportation system, we have considerable experience in the use of gas chromatographs, both in the laboratory environment and offshore on MCP01 where on-line GCs are used.

3.3.2 For on line use at St. Fergus the following disadvantages arise.

a) The nature of Frigg gas does not allow a simple analysis of light carbon components due to the long tail of heavy components.

In order to allow an accurate analysis and subsequent determination of calorific value a protracted cycle time would be required. In addition, the type of chromatograph to perform this analysis on-line has not yet been sufficiently developed.

b) Even if accuracy were to be compromised, a typical cycle time for the evaluation of an updated calorific value would take a minimum of 10 minutes and this would present problems in monitoring gas quality, as a continuous output will be required for control purposes if blending/nitrogen injection is to be performed efficiently.

c) The detection of unexpected components may result in large errors.

d) The chromatography columns are subject to contamination and associated inaccuracy.

3.4 Honeywell HVT-100

3.4.1 Advantages

The HVT-100 had good reports from other organisations and showed promise in the following areas:

a) The manufacturers specification offers good accuracy under our process conditions.

b) The unit is self calibrating and is designed to operate with minimal intervention.

c) The minimum amount of moving parts are used which promises good reliability. The design is microprocessor based with modern self diagnostic routines to aid rapid fault finding. A modular construction is employed which should allow quick exchange of faulty components.

d) The HVT provides a continuous output of measured calorific value and a fast response time is offered.

e) Unlike a conventional calorimeter the HVT is designed to tolerate variations in ambient temperature and would therefore maintain accurate measurement if the air conditioning system for the calorimetry room were to fail.

3.4.2 Disadvantages

a) Not accepted for point of sale measurement in UK at time of investigation.

b) A Specific Gravity analyser is required in addition to the HVT-100 for heat flow computation to Fiscal Standards.

3.5 Following a two week familiarisation period with a unit on site, the HVT-100 was selected as the device most likely to be able to demonstrate a worthwhile improvement in accuracy and large savings in maintenance costs over the existing calorimeters.

4.0 HVT-100

4.1 Principle of Operation for the HVT-100

The HVT-100 employs the well recognised principle, that for the gases in the paraffin (alkane) series, there is a direct relationship between the air to fuel ratio required to achieve stoichiometric combustion and the calorific value of the gas. This relationship also holds for a mixture of gases such as present in natural gas (Fig 1).

The air to fuel ratio is determined by a rotary mixing valve, where the rotational speed influences the ratio.

Mixed gas and air is then burnt in a combustion chamber where stoichiometric combustion is determined by monitoring the exhaust gas with a zirconium oxide sensor. This sensor detects the presence of oxygen in the exhaust gas and provides an output to the microprocessor controller which controls the rotational speed of the mixing valve. These components form a closed loop control system operating in the following manner to maintain stoichiometric combustion (Fig 2).

The zirconium probe develops its greatest output voltage when the oxygen content in the exhaust gas is at its lowest level. As the air to fuel ratio is adjusted towards a leaner mixture, the sensors output decreases until a point is reached where it drops sharply, in a stepped fashion, to a level at which any further increase in the air would cause the output to taper off into a nerstian region (Fig 3). The step response in the sensors output marks the period during which stoichiometric combustion occurs at the burner. The speed of rotation of the mixing valve is adjusted in accordance with the oxygen sensor output and the measured rate of rotation is related to the calorific value. The calorific value is in turn shown on a digital display on the front panel and also scaled for output as a 4-20 mA signal.

Self calibration is achieved by automatically switching from sample gas to a calibration gas such as methane. The HVT measures the CV of the calibration gas and then adjusts itself to measure the known value of the calibration gas input by the user. The auto-calibration interval is also preset by the user.

4.2 Installation

An HVT-100 was purchased for evaluation and installed in the Phase II calorimeter room and connected in parallel with the No. 2 calorimeter so that both the HVT and the calorimeter receive the same sample gas without affecting calorimeter operation.

5.0 EVALUATION TEST

5.1 Evaluation Test Programme

An evaluation test programme was drawn up to include tests which allowed an assessment of the HVT's suitability for accurate measurement of natural gas calorific value.

If favourable results were obtained then the test findings would be used as a basis for gaining approval for the HVT-100.

Test Criteria

The test unit, when compared to the existing calorimeters under the same operating conditions, should prove to be a worthwhile improvement in the following areas:

a) Accuracy and repeatability
b) Sensitivity to environmental conditions
c) Response time
d) Stability of output
e) Reliability
f) Maintenance requirement
g) Availability of spare parts.

5.2 Accuracy and Repeatability

5.2.1 Accuracy

In order to assess the accuracy of the HVT-100 under operating conditions, the unit was tested using a number of specially formulated gases which had been analysed and certified by the Gas & Oil Measurement Branch of Department of Energy, Wigston.

The test gas mixtures specified were chosen to represent the range of natural gas mixtures likely to be processed as St Fergus.

Gross calorific values for each test gas were calculated in accordance with ISO 6976 based on the certified gas analysis provided by Department of Energy.

5.2.2 Method

The tests were performed with the HVT-100 and the stand-by Cutler Hammer calorimeter piped in parallel, so that both instruments received the same gas test. This allowed a direct comparison to be made under normal operating conditions.

The Cutler Hammer CV was read from the on-line flow computer displays and the HVT CV was taken from the instruments digital display.

5.2.3 Results

HVT-100	Results within $\pm 0.05 MJ/sm^3$ for gases likely to be measured at St Fergus. The synthetic associated gas was within $0.10\ MJ/sm^3$
CH Calorimeter	Results within $\pm 0.05 MJ/sm^3$ except the synthetic associated gas: $\pm 0.15 MJ/sm^3$

5.3 Sensitivity to Environmental Conditions

This section may be split into two main areas: sensitivity to changes in ambient temperature and secondly, atmospheric pressure.

5.3.1 Ambient Temperature

The existing Cutler Hammer calorimeters are recognised as being sensitive to ambient temperature and for this reason are required to operate in an air conditioned room having a closely controlled air temperature.

As the HVT was installed in the same room it would only have been possible to alter the air temperature if the calorimeters had not been operating for some period during the evaluation test. Unfortunately Phase II was required to flow gas continually during this period and so ambient temperature effects could not be checked.

However, the HVT-100 was designed from the outset to operate in the open air and this would indicate a degree of insensitivity to ambient temperature.

This has been confirmed by other organisations carrying out similar evaluation tests.

5.3.2 Atmospheric Pressure

The Cutler Hammer calorimeters at St Fergus are known to display a certain degree of sensitivity to atmospheric pressure.

In order to assess any atmospheric pressure effect on the HVT-100,an analysis of the auto calibration results was made.
A sensitivity to atmospheric pressure changes should result in a deviation from the expected calibration results.

Barometric pressure readings were taken from continuous barograph charts (kindly loaned by British Gas St Fergus).

The effect of changing atmospheric pressure on the HVT is shown graphically in graphs A-E. These graphs analyse data for 5 days chosen to give a variety of barometric patterns. These included i) Steady barometric pressure. ii) Steadily falling barometric pressure. iii) Steadily rising barometric pressure. iv) A pressure peak and v) A pressure trough. The measured CV data is for certified high purity methane (37.77 MJ/sm3) using a 2 hour autocalibration period.

Each graph consists of three parts:

Top:	Tabulated calibration gas measured CV and corresponding barometric pressure at 2 hour intervals. Calculated values are CV error (assuming 37.77 MJ/sm3 is correct) and % change in barometric pressure since the last calibration.
Middle:	Plot of daily barometric pressure variation.
Bottom:	Plot of calculated values from table.

5.3.3 Findings

Graphs A and B show that there is a definite proportional linear relationship between CV error and change in barometric pressure. The relationship can be roughly defined as:

$$\frac{CV}{\Delta P} = 1.0 \quad \frac{MJ/sm^3}{in\ Hg}$$

If all drift is due to the barometric pressure change and fits the above relationship then:

$$\int_{t=T_o}^{t=T} d(CV) = \int_{t=T_o}^{t=T} K dP\, dt$$

If pressure variation is assumed to be linear between any two calibrations then due to the cyclical nature of barometric pressure it would be expected that:

$$\int_{t=T_o}^{t=T} d(CV) dt \rightarrow 0 \quad \text{as } (T - T_o) \rightarrow \infty$$

i.e. long term bias error due to atmospheric pressure should tend to zero over a long period if the above assumptions are correct.

Taking the complete test period for the 2 hour calibration data from 15 October 1987 to 7 January 1988 (spanning more than 600 calibrations); calculation gives average methane measured CV = 37.763.

Based on the assumption that pressure varies linearly with time and that measured CV error will be zero immediately following a calibration.

$$\text{Mean CV error} = \frac{37.763 - 37.77}{2} = -0.0035 \text{ MJ/sm3}$$

Since calibration gas CV is certified as 37.77 MJ/sm^3 an uncertainty of $\pm$ 0.005 MJ/sm^3 is implied.

Therefore long term bias error in CV is within the tolerance of the calibration gas. It can be confidentially stated that there was no detectable long term bias error introduced into CV measurement due to atmospheric pressure changes when using the HVT with a 2 hour calibration period.

SYMBOLS

T, t	=	Time
dP	=	Change in barometric pressure over time dt
K	=	Proportionality constant
d(CV)	=	Change in measured calibration gas CV over time dt.

AUTOMATIC CALIBRATION

5.3.4 The HVT is designed to operate using regular automatic calibration to compensate for any measurement drift. The calibration interval may be set by the user between 10 minutes and 4 hours.

In order to assess the effect of different intervals on the accuracy of CV measurement, the HVT was operated on normal sample gas with calibration intervals of 4 hours, 2 hours and 1 hour.

During each calibration cycle the HVT samples the calibration gas with normal sample gas isolated. The calibration gas is measured for a 30 second period and if stability criteria are passed, the result given on the printout is the mean value over the period.

Ideally, this result should be identical to the known calibration gas value, but if this is not the case the HVT will automatically realign itself to remove the measured error before returning to normal sample gas.

An analysis of these reported errors will allow an impression to be gained of the general accuracy of the HVT at different calibration intervals, allowing the optimum calibration interval to be set.

5.3.5 Findings

If the HVT-100 does not drift or display any error then the reported values at each auto-calibration test should always match the calibration gas value held in the HVT as a fixed parameter.

The calibration gas used throughout was high purity methane certified at 100% by Department of Energy, ISO 6976 gives a CV of 37.77 MJ/SM^3. Thus ideal results should be a straight line at this value with a standard deviation of 0.

4 Hour Interval

The overall average result over 45 days is 37.760 MJ/SM^3 with a mean std. deviation of 0.0300 MJ/SM^3. This would infer a slight under-registration of calorific value by 0.01 MJ/SM^3 over this period if constant CV gas had been sampled. Although the error encountered in measuring sample gas may be different to this value as one represents a pure gas and the other a mixture, the small magnitude of this error is very impressive.

2 Hour Interval

The overall average result for 94 days was 37.764 MJ/SM^3 with a mean standard deviation of 0.0308 MJ/SM^3. Thus this calibration interval gives slightly better results than a 4 hour interval.

This result is most impressive and shows that a 2 hour calibration interval maintains accurate measurement when operating on sample gas and is highly effective in reducing instrument drift.

1 Hour Interval

This test duration was limited to a period of one week due to the high calibration gas consumption rate.

The overall average obtained was 37.754 MJ/SM^3 with a mean standard deviation of 0.0226 MJ/SM^3.

Although this interval resulted in less scatter than the larger intervals, the overall average was slightly poorer. Thus the results from this brief test indicate that there is no benefit to be gained by using a 1 hour calibration interval.

5.4 Response Time

5.4.1 Method

The response time of the HVT-100 to changes in sample gas calorific value has been compared to an existing Cutler Hammer calorimeter using test gases.

The gas inlet pipework to the calorimeters allows gas to be instantaneously switched between normal sample gas and a test gas, or between two test gases. This operation is performed using manually operated valves.

5.4.2 Findings

The HVT was found to respond immediately to a step change in gas calorific value. The trend in all cases was near critical damping whether in response to an increase or decrease in CV. No sign of overshoot was noted, the initial response stopping just short of the final oscillating trend.

The results may be summarised as follows:

Time taken to reach 98.5% of step change in CV	:20 sec per MJ/SM^3
Additional time taken to attain final 1.5% of step change	:60 seconds

In contrast to the HVT-100 the C.H. calorimeter has a far poorer response time.

Switching between test gases which differ by $4MJ/SM^3$, first response does not occur for over 4 minutes.

In this case, HVT-100 would take 2 minutes 20 seconds.

Start-up

Following a shutdown the HVT-100 takes approximately 4 minutes before the output is restored. The start-up procedure is very simple: the sample gas supply is turned on and the HVT front panel ON/OFF button is pressed. No output is provided during the 4 minute stabilisation period, the output is restored as a step change.

Following a start-up the CH calorimeters are usually allowed to stabilise for a minimum of two hours before being considered for duty.

5.5 STABILITY OF OUTPUT

5.5.1 The Cutler-Hammer calorimeters tend to display a slightly oscillating output under steady input conditions. This trend is usually exaggerated by the length of service between rebuilds and is thought to be caused by wear resulting in small degrees of misalignment of the rotating parts. A limit has been set as to the maximum acceptable oscillation of 0.10 MJ/SM^3 peak to peak. Although an oscillation should not lead to poorer overall accuracy, as the mean result over the course of a day is the same for a constant output, the calorimeter instantaneous maximum and minimum values may not be acceptable. This is due to both duty standby calorimeters being constantly monitored for a difference in measured value, if one reads a maximum and the other reads a minimum the differential alarm may be raised although the measured mean values are correct.

The HVT-100 also displays an oscillating trend. Amplitude is ± 0.05 MJ/SM^3 with a time period of approximately 20 seconds.

The cause is the necessary variations is air/fuel rate in order to maintain stoichiometric combustion.

5.5.2 In order to check compatability with the flow computers, a spare flow micro-computer (869R) was linked to the HVT-100 via the analogue output.

A constant std volume flowrate was preset in the flow micro with CV as a measured variable. As energy and std volume flows are held for a 24 hour period, a daily average CV could be calculated and then compared with the HVT-100 internally generated daily average CV.

Very close agreement was found which indicates that the oscillation and the analogue converters do not degrade the daily energy totals.

Although not really necessary for our installation, we would prefer that the oscillations are reduced so that it is easier to interpret the measured CV at any instant.

It would seem that the most feasible way to reduce the amplitude of oscillation is to introduce a form of damping.

5.6 RELIABILITY

5.6.1 As the sample gas supplied to the HVT is essentially identical to both calorimeters on Phase II, a comparison may be made between reported daily average CVs.

5.6.2 Findings

An example of the results is shown in Graph F.

The HVT displayed daily averages are shown plotted against day number together with the Cutler-Hammer derived daily average taken from the flow computers.

The large swings in average CV are due to the effect of Piper/Tartan gas being injected into the pipeline in different quantities each day. This oil associated gas is much richer than the natural gas from the Frigg area.

The results from both instruments, essentially sampling the same gas, agree well, generally within $0.05MJ/SM^3$ and appear to follow similar trends.

Following initial commissioning the HVT-100 ran reliably for the duration of the six month evaluation period.

5.7 MAINTENANCE REQUIREMENT

No regular maintenance of the HVT-100 is specified by the manufacturers. However, it is apparent that certain parameters require regular monitoring to prevent unexpected loss of information. These parameters are listed below:

a) Calibration Gas Bottle Pressure

The gas pressure within the calibration gas cylinder must be checked regularly and the cylinder changed before calibration gas is exhausted as this would result in the shutdown of the HVT.

b) Digital Printer Paper

As a considerable amount of important information is reported by the digital printer connected to the HVT, the amount of reserve paper in the printer should be monitored regularly in order to prevent the loss of reported daily averages, alarm states and auto-calibration results.

c) Analogue Output

The accuracy of the analogue output to the flow computers should be verified regularly in order to correct any drift which may occur. This may be performed quickly by comparing the HVT displayed value to the flow computer displayed value or by comparing the HVT daily average to the inferred flow computer average CV.

d) On Line Diagnostics

The on-line diagnostics routine should be run on a regular basis in order to monitor the state of internal parameters which greatly affect the operation of the HVT. If any of the reported parameters exceed predetermined levels then further action should be taken to investigate the fault.

e) It is recommended that a certified test gas other than methane is sampled by the HVT-100 on a regular basis in order to verify linearity. A binary gas such as the currently used methane/8% ethane mix would be suitable.

f) The most critical moving part in the HVT-100 is the rotary mixing valve which determines the air/fuel ratio. As wear may affect the unit's performance, this component should be inspected or replaced at annual intervals.

5.8 EVALUATION TEST - SUMMARY

The results may be summarised as follows:

a) Accuracy and Repeatability

The HVT-100 has proven to be highly accurate over a wide range of calorific values and will be able to operate accurately when sampling the gases likely to be processed at the terminal for the foreseeable future.

Both accuracy and repeatability were found to be well within the manufacturers specification which offers a significant gain over the existing calorimeters.

Accuracy is claimed to be $\pm 0.10 MJ/SM^3$ over the range 33 to 41 MJ/SM^3.

The stated accuracy of the present CH calorimeters is $\pm 0.20 MJ/SM^3$.

b) <u>Sensitivity to Environmental Conditions</u>

The HVT-100 displays a sensitivity to atmospheric pressure variations, but this is overcome by the automatic calibration feature. Tests have shown that a setting of 2 hourly auto-calibration interval is effective in maintaining accurate measurement.

c) <u>Response</u>

The response time to step changes in gas CV was found to be very quick at around 20 seconds per MJ/SM^3. This is a magnitude faster than the existing calorimeters and will allow transients to be followed much closer and also allow testing to be carried out quicker. Start-up is completed within 5 minutes.

d) <u>Stability of Output</u>

The Cutler-Hammer calorimeters tend to display an oscillating output under steady input conditions of up to $0.10 MJ/SM^3$ peak to peak. The HVT-100 also displays an oscillating trend of the same level but with a much shorter time period of approximately 20 seconds.

Testing revealed that this oscillation does not degrade the output signal in operation.

e) <u>Reliability</u>

Reliability of the HVT-100 has proven to be excellent during the long term test. Following commissioning the unit has operated with complete reliability with only minor interruptions due to external circumstances.

f) <u>Maintenance Requirement</u>

The Cutler-Hammer calorimeters require regular intervention to maintain accurate operation and planned maintenance involving laborious adjustment. Often a complete rebuild is found to be required.

In contrast, the HVT-100 requires no planned maintenance other than regular monitoring. This work is simplified by self diagnostic routines.

g) Availability of Spare Parts

This is an area of major concern for the existing CH calorimeters both in terms of long term availability and quality.

6.0 INSTALLATION AND COMMISSIONING

6.1 A report on the evaluation test was submitted to the Fiscal authorities, a non-objection to the use of the HVT was subsequently granted. An order for three additional HVT units was placed with Honeywell allowing installation to commence in January 1988.

Each HVT was installed alongside its operational calorimeter and prepared for service.

With a calorimeter providing the used calorific value signal the HVT was connected to the flow computers and assumed the role of comparison unit. Prior to acceptance, for Fiscal metering duty, each HVT was tested for a seven day period to establish correct operation and presence of any systematic errors.

In the final installation the HVT digital data is internally converted to an analogue output using a DAC. The 4-20 mA signal then passes via a 2 channel plotter to each of the six flow computers where the signal is converted to 0.2 - 1.0 v using 50 ohm resistors. The voltage is then converted to a digital signal within the computer using an ADC.

During the acceptance period the accuracy of analogue conversion was monitored and calorimeter trends compared with those generated by the HVT. In addition to the 2 hourly methane autocalibration, daily span checks were performed using a certified methane-ethane mixture.

6.2 Results

An offset of 0.02 - 0.04 MJ/sm^3 was found between the HVT internally generated daily average and the flow computer calculated average. This offset originates at the HVT DAC and as it is not possible to adjust the DAC to eliminate this it was necessary to adjust the HVT output scaling to compensate.

Other calibration and test results were will within tolerance.

One unit was found not to restart after a shutdown. The HVT will not restart until it detects a flame in the main burner, the unit apparently detects a flame by monitoring capacitance changes between the igniter plug and main burner earth due to flame ionisation. The problem was rectified by repositioning the igniter plug in the main burner using spacers.

On recommissioning the original HVT unit, problems were encountered in making the unit run reliably, positive and negative spikes were observed on the analogue output at unpredictable time intervals.
Faults found:

The dehydrator unit was found to be defective and was replaced.
The main fault could be reproduced by open circuiting the zirconium probe output. This caused the main burner assembly including the sensor and igniter plug to be replaced .
The power supply board showed signs of overheating and was returned to Honeywell for investigation.

The rotary valve showed signs of wear and was replaced. Although Honeywell advised that the rotary valve assembly is supplied 'factory set', it has been found that the analogue output oscillations may be reduced significantly by adjusting the valve disc position on the motor drive shaft.

6.3 All four units have now been accepted and are operating well. The four Continuous Reading Calorimeters have been decommissioned.

7. AREAS FOR IMPROVEMENT

a) The automatic calibration interval could be increased and accuracy further improved if automatic atmospheric pressure compensation were to be performed. The linear effect means that the addition of a simple pressure transducer is enough.

b) The digital to analogue output converter calibration is factory set but small offsets could be removed by including an adjustment pot.

c) The user manual is rather superficial and could be improved. Two areas where more information is definitely required is in setting up the rotary valve and igniter sensor.

d) During the commissioning period Honeywell support for the HVT-100 in respect of fully trained personnel was only available in the USA where most units are in service.

In order to maximise the performance of the HVT-100 Honeywell should consider action on the above points.

8. CONCLUSIONS

A survey of alternative devices lead to the Honeywell HVT-100 being selected as the most suitable replacement device for the aging Continuous Recording Calorimeter.

An evaluation over six months under actual operating conditions showed that the HVT-100 met the manufacturers specification and indeed performed better than the existing calorimeters.

The performance and reliability of the HVT-100 could be further improved by Honeywell. Regular maintenance details are required in order to avoid unexpected failures.

The HVT-100 units installed have performed with greater reliability, better accuracy and less maintenance than the replaced Cutler Hammer calorimeters.

9. FIGURES AND GRAPHS

Figs

1) Relationship between air/fuel ratio and calorific value.

2) HVT-100 schematic diagram

3) Zirconium probe output characteristic.

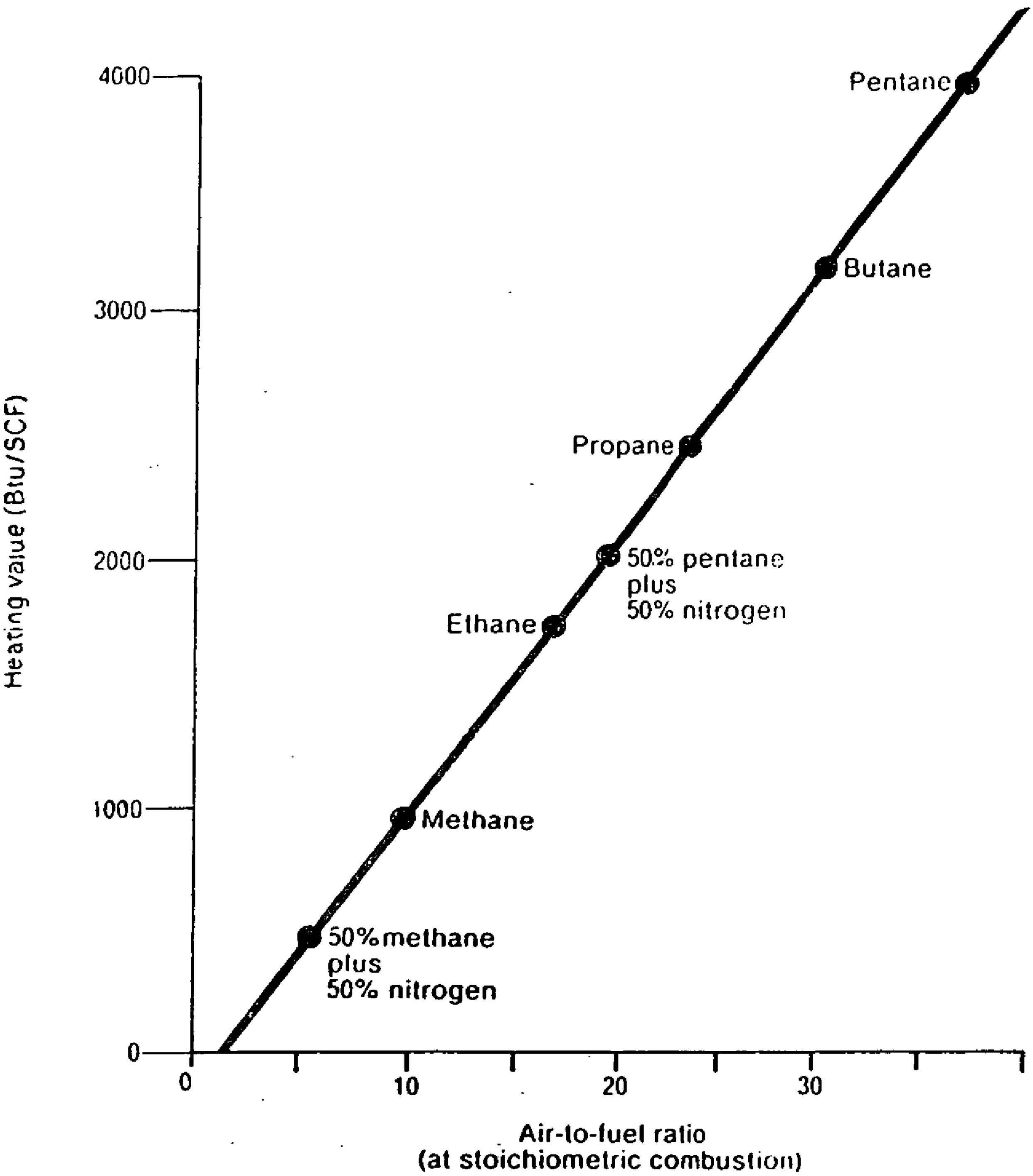
Graphs

a) Effect of steady barometric pressure
b) Effect of falling barometric pressure
c) Effect of rising barometric pressure
d) Effect of a barometric pressure peak
e) Effect of a barometric pressure trough
f) Comparison between HVT and calorimeter outputs

10. Acknowledgment

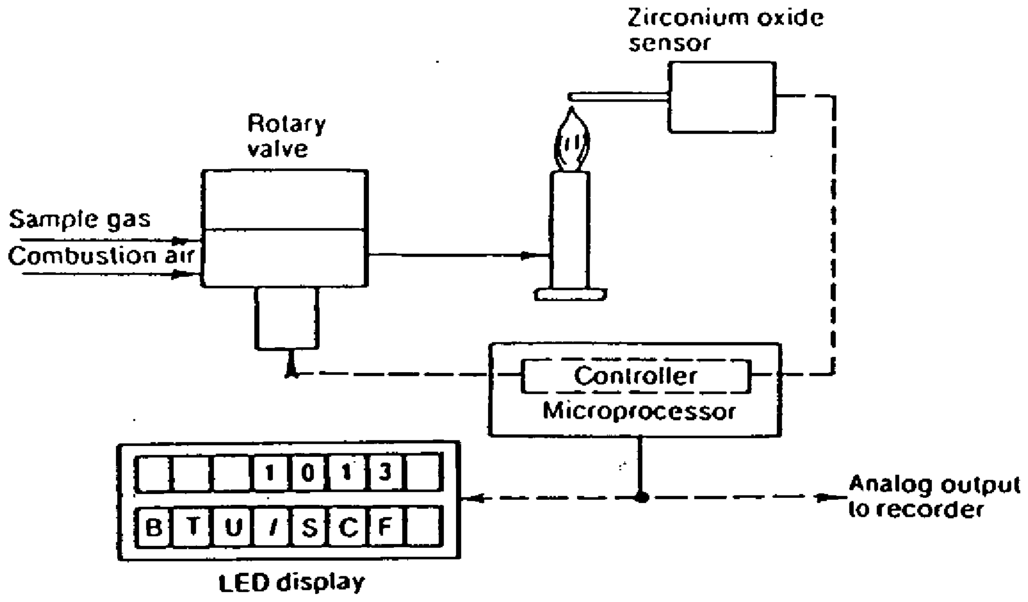
I would like to express my gratitude to Trevor Davis for his assistance in the preparation of this paper.

FIG 1.



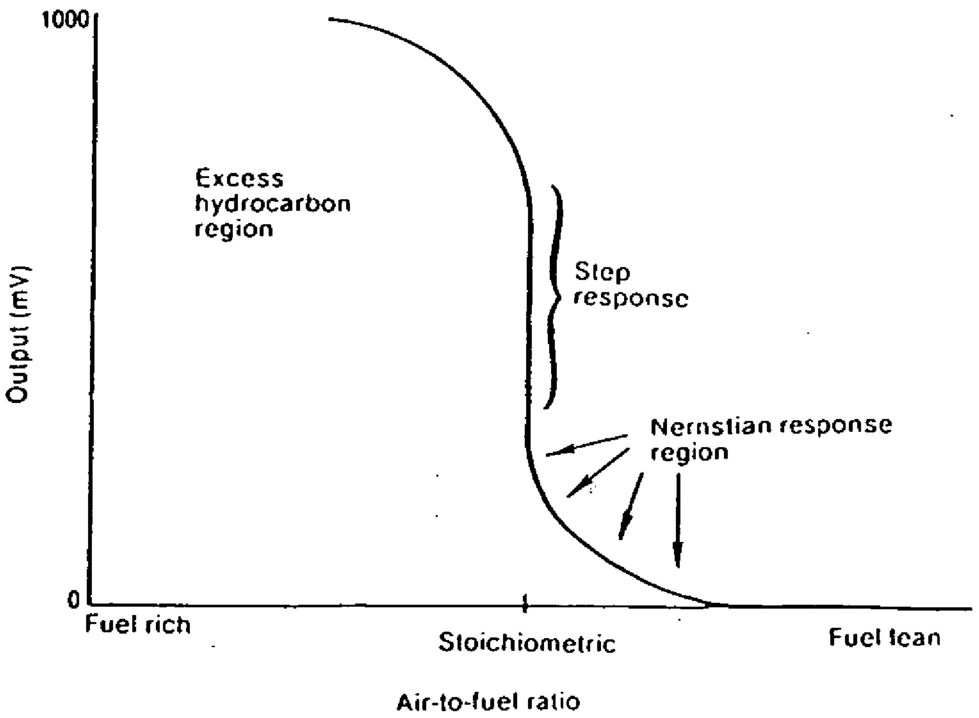
Heating value versus air-to-fuel ratios for paraffin series gases

FIG 2.



Basic operation of the HVT 100 Heating Value Transmitter

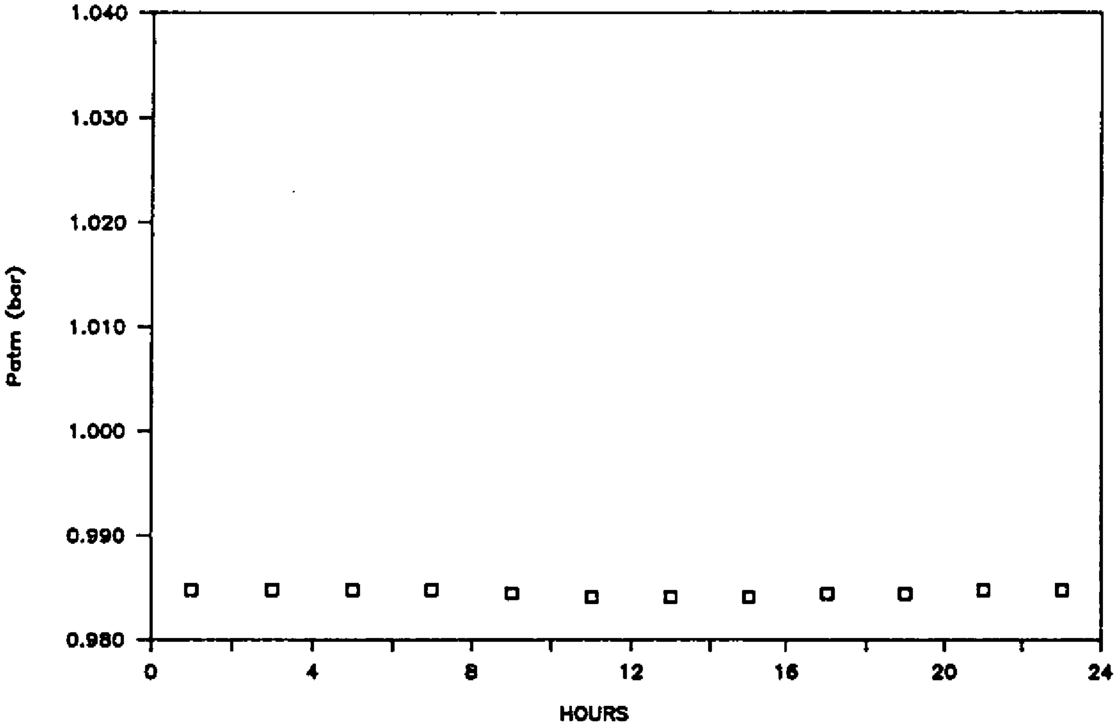
FIG 3.

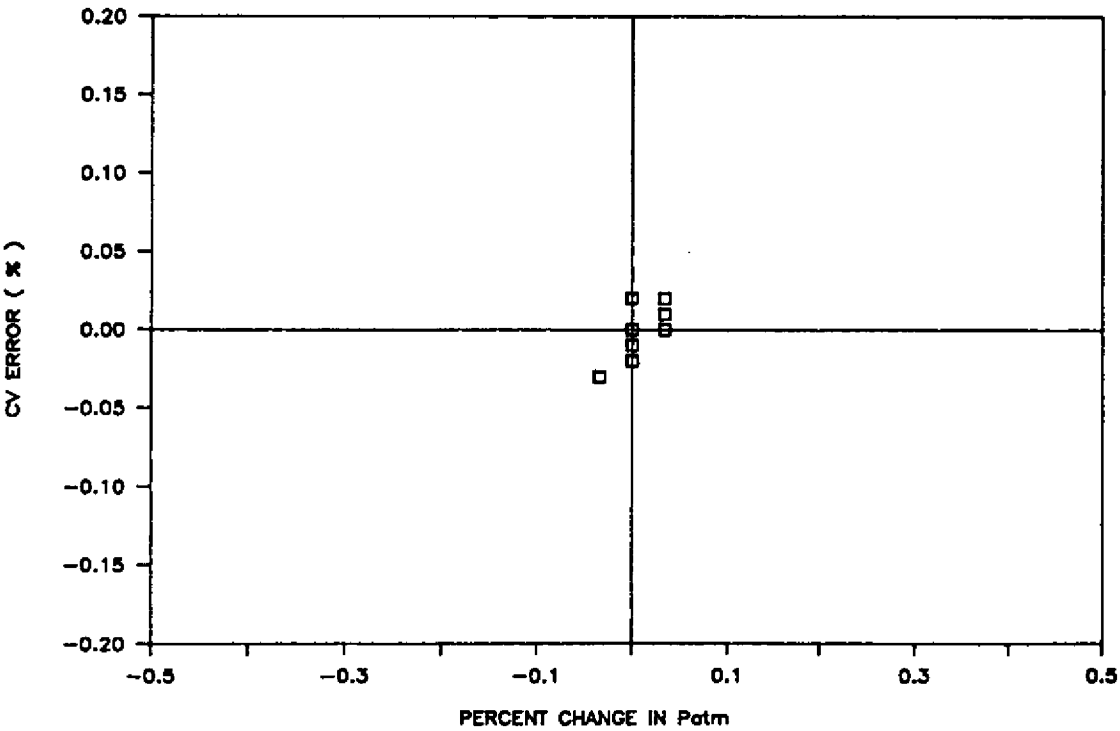


Performance of typical zirconium oxide sensor

DATE: SUN 19 DEC 1986 GRAPH A

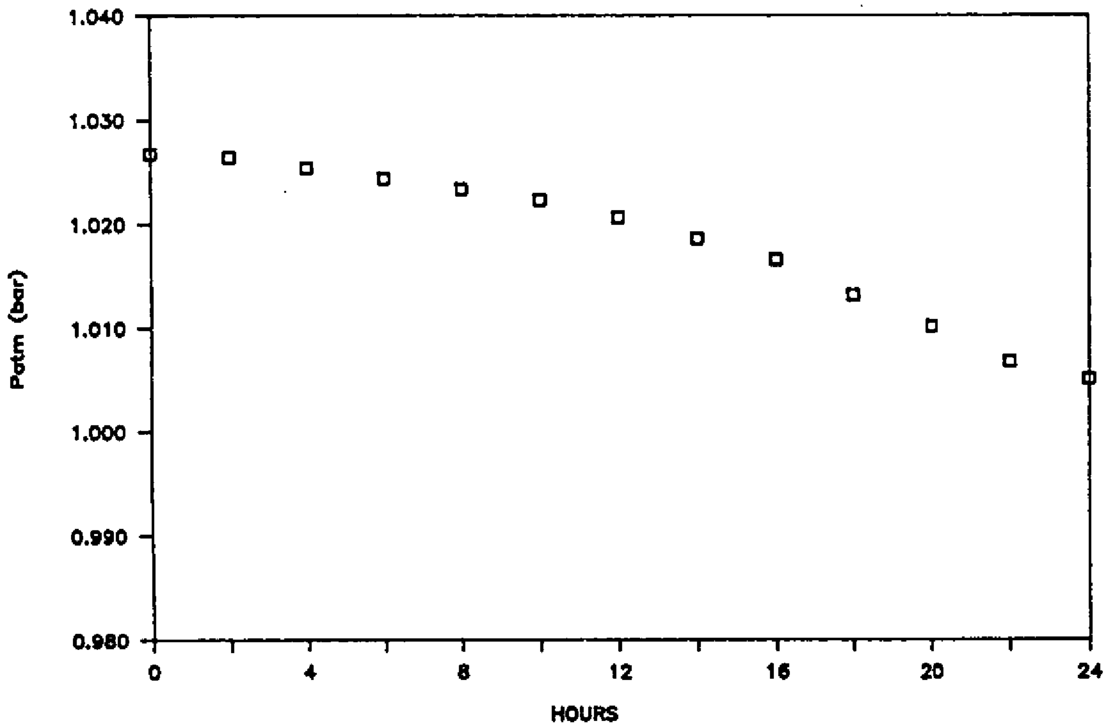
HOUR	BAROMETRIC PRESSURE Patm (bar)	CHANGE IN Patm (%)	MEASURED CALIBRATION GAS CV (MJ/sm3)	MEASURED CV ERROR (MJ/sm3)
-1	0.985			
1	0.985	0.000	37.75	-0.02
3	0.985	0.000	37.77	0.00
5	0.985	0.000	37.75	-0.02
7	0.985	0.000	37.79	0.02
9	0.984	-0.034	37.74	-0.03
11	0.984	-0.034	37.74	-0.03
13	0.984	0.000	37.79	0.02
15	0.984	0.000	37.76	-0.01
17	0.984	0.034	37.79	0.02
19	0.984	0.000	37.77	0.00
21	0.985	0.034	37.77	0.00
23	0.985	0.000	37.77	0.00
25	0.985	0.034	37.78	0.01

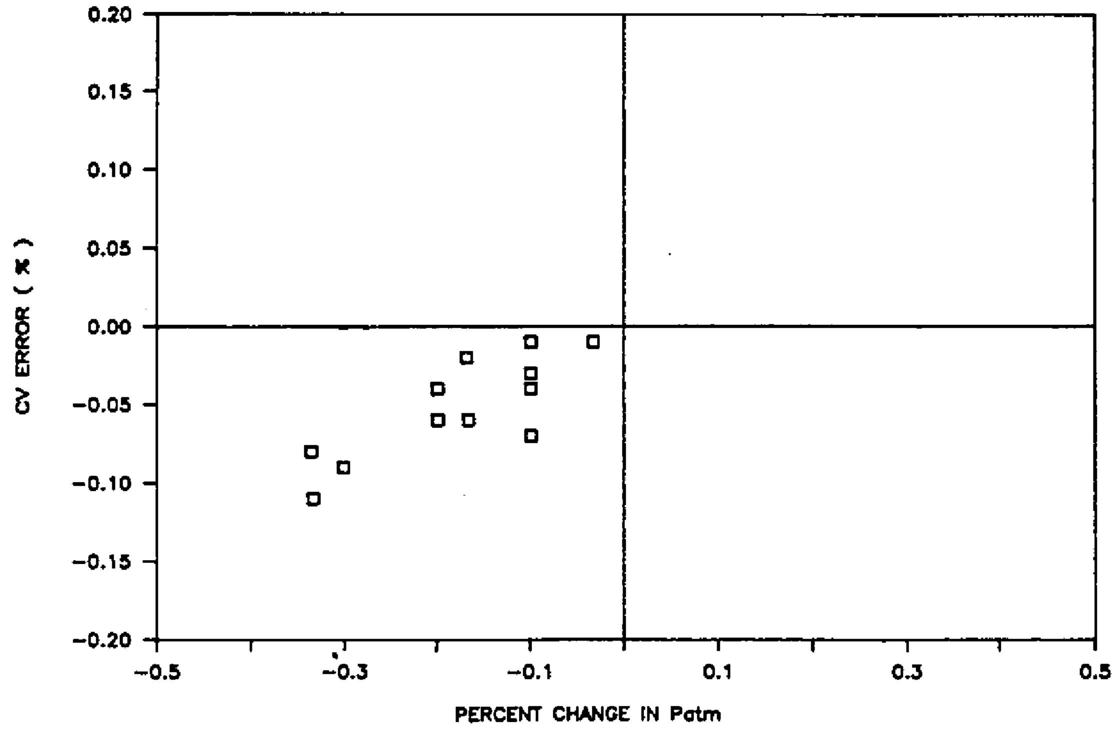




DATE: WED 24 DEC 1986 GRAPH B

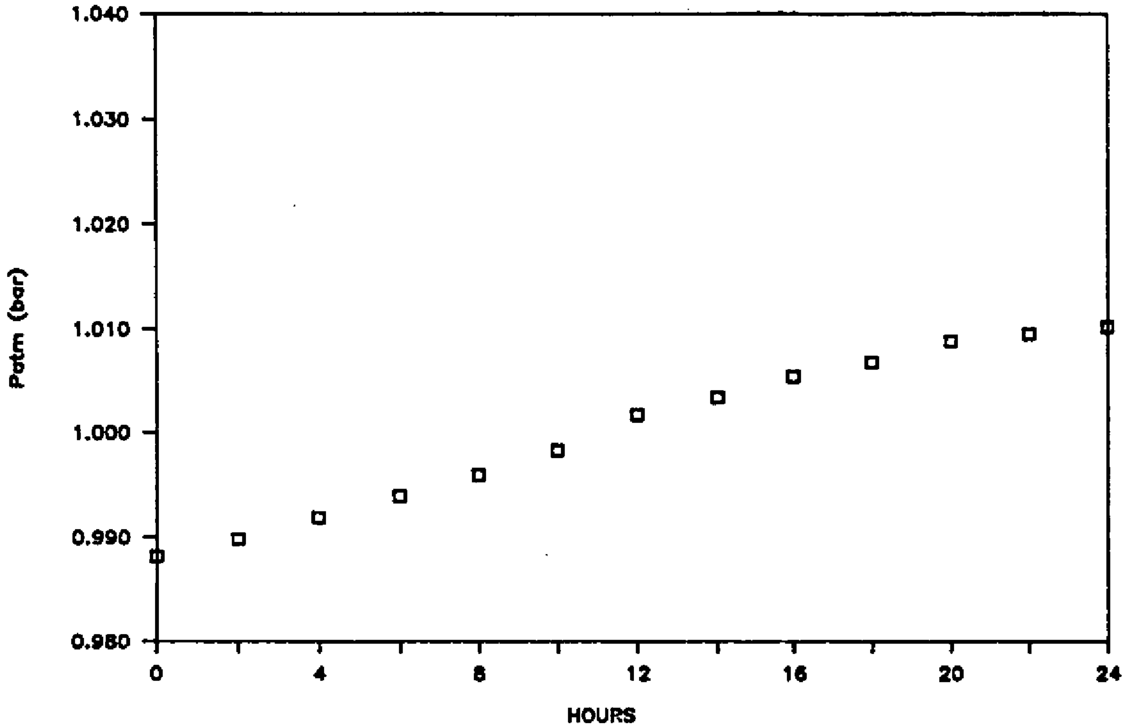
HOUR	BAROMETRIC PRESSURE Patm (bar)	CHANGE IN Patm (%)	MEASURED CALIBRATION GAS CV (MJ/sm3)	MEASURED CV ERROR (MJ/sm3)
-2	1.028			
0	1.027	-0.099	37.76	-0.01
2	1.026	-0.033	37.76	-0.01
4	1.025	-0.099	37.70	-0.07
6	1.024	-0.099	37.76	-0.01
8	1.023	-0.099	37.73	-0.04
10	1.022	-0.099	37.74	-0.03
12	1.021	-0.166	37.71	-0.06
14	1.019	-0.199	37.71	-0.06
16	1.017	-0.199	37.73	-0.04
18	1.013	-0.333	37.66	-0.11
20	1.010	-0.301	37.68	-0.09
22	1.007	-0.335	37.69	-0.08
24	1.005	-0.168	37.75	-0.02

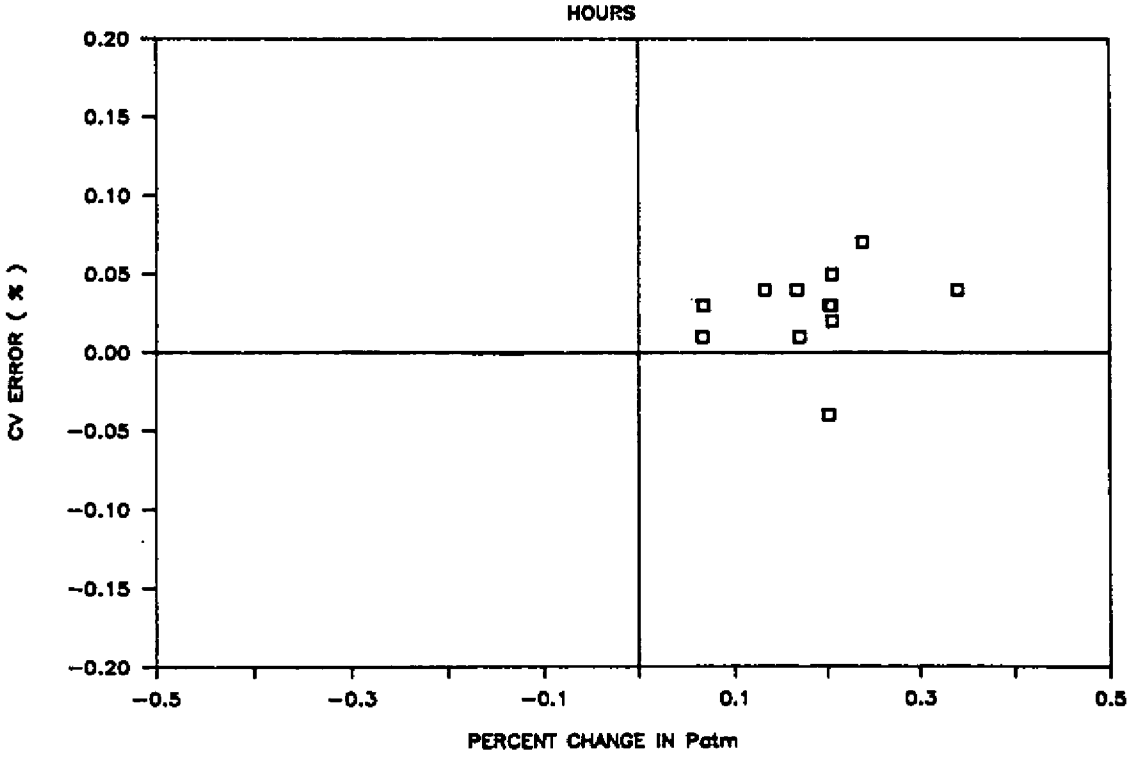




DATE: WED 31 DEC 1986 GRAPH C

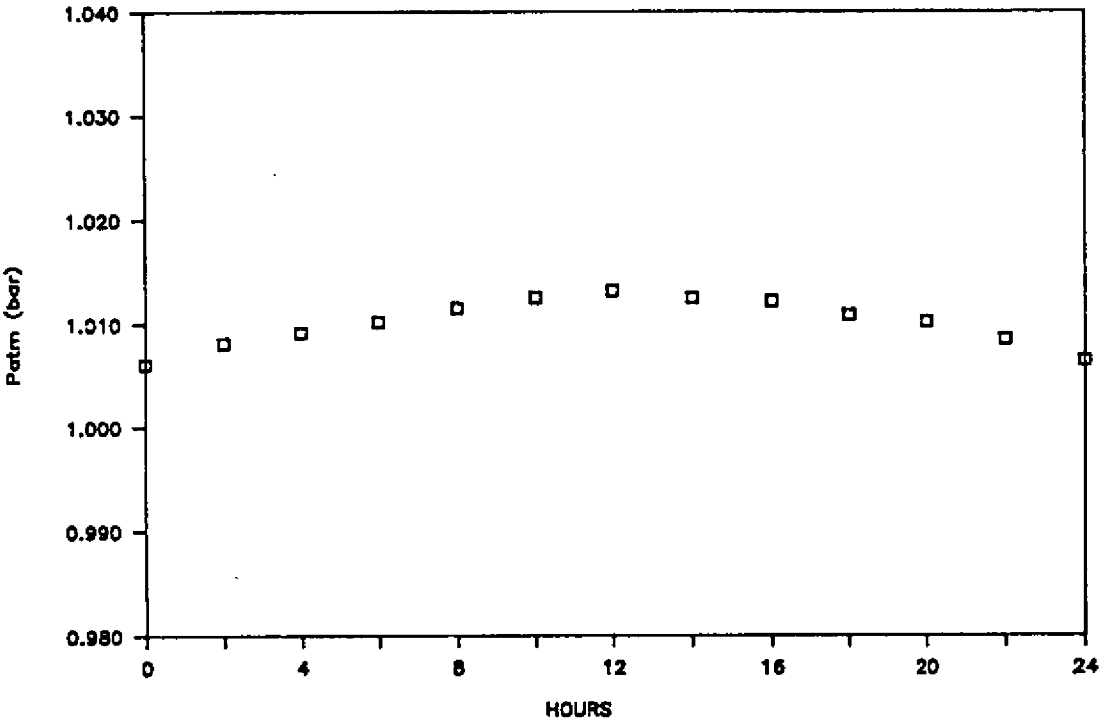
HOUR	BAROMETRIC PRESSURE Patm (bar)	CHANGE IN Patm (%)	MEASURED CALIBRATION GAS CV (MJ/sm3)	MEASURED CV ERROR (MJ/sm3)
-2	0.987			
0	0.988	0.069	37.80	0.03
2	0.990	0.171	37.78	0.01
4	0.992	0.205	37.79	0.02
6	0.994	0.205	37.82	0.05
8	0.996	0.204	37.80	0.03
10	0.998	0.238	37.84	0.07
12	1.002	0.339	37.81	0.04
14	1.003	0.169	37.81	0.04
16	1.005	0.202	37.80	0.03
18	1.007	0.135	37.81	0.04
20	1.009	0.202	37.73	-0.04
22	1.009	0.067	37.80	0.03
24	1.010	0.067	37.78	0.01

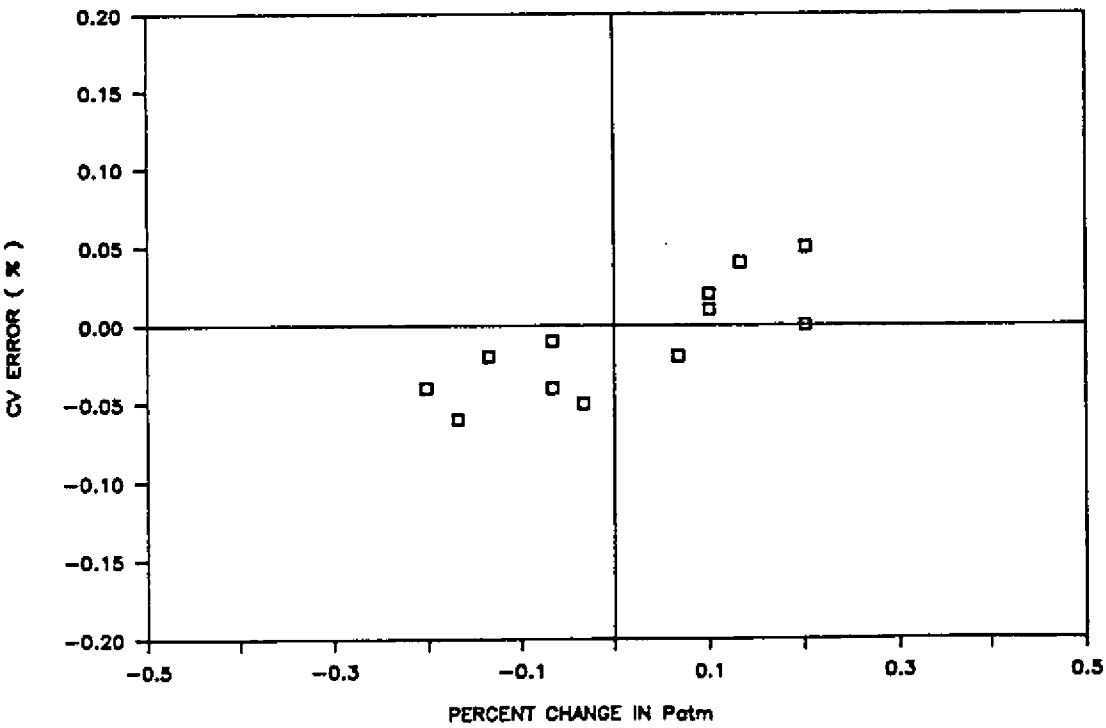




DATE: SAT 6 DEC 1986 GRAPH D

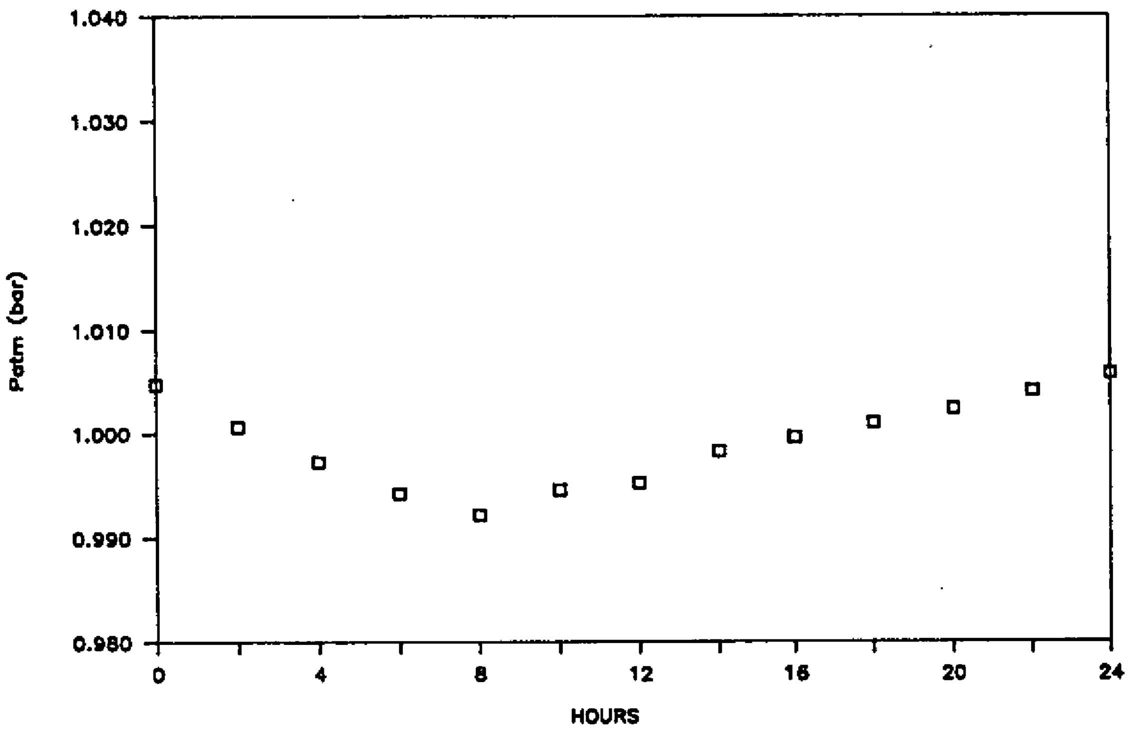
HOUR	BAROMETRIC PRESSURE Patm (bar)	CHANGE IN Patm (%)	MEASURED CALIBRATION GAS CV (MJ/sm3)	MEASURED CV ERROR (MJ/sm3)
-2	1.004			
0	1.006	0.202	37.82	0.05
2	1.008	0.202	37.77	0
4	1.009	0.101	37.79	0.02
6	1.010	0.101	37.78	0.01
8	1.012	0.134	37.81	0.04
10	1.013	0.100	37.79	0.02
12	1.013	0.067	37.75	-0.02
14	1.013	-0.067	37.76	-0.01
16	1.012	-0.033	37.72	-0.05
18	1.011	-0.134	37.75	-0.02
20	1.010	-0.067	37.73	-0.04
22	1.008	-0.168	37.71	-0.06
24	1.006	-0.201	37.73	-0.04

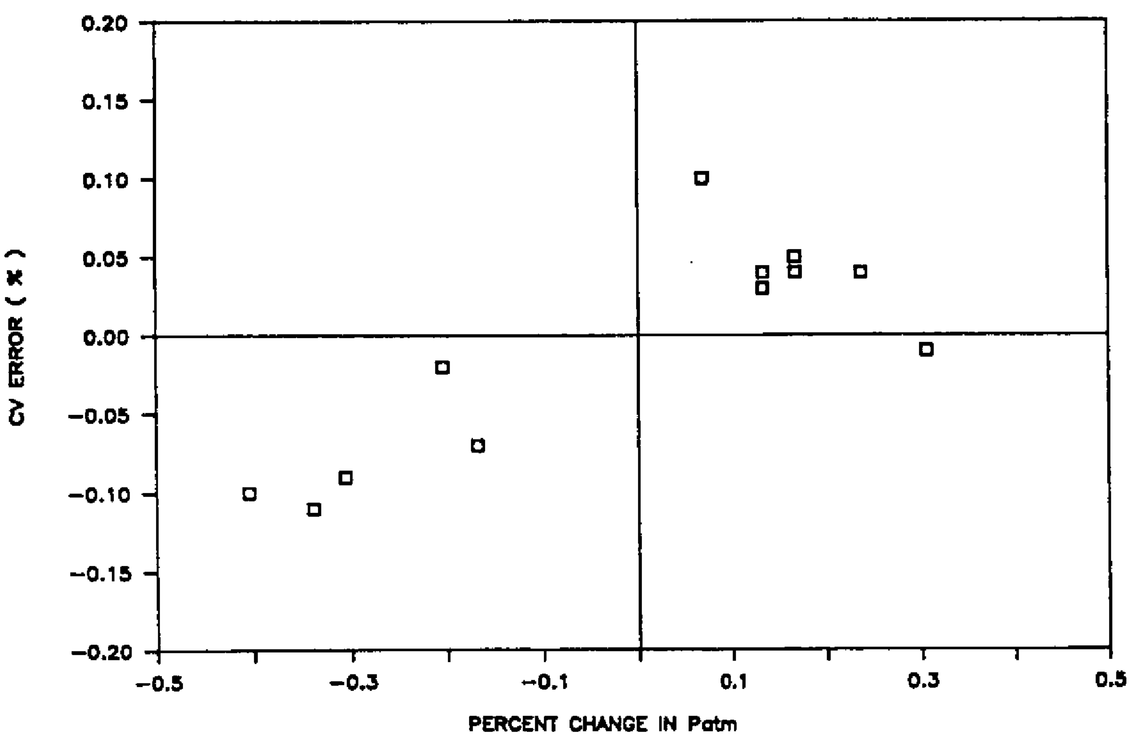


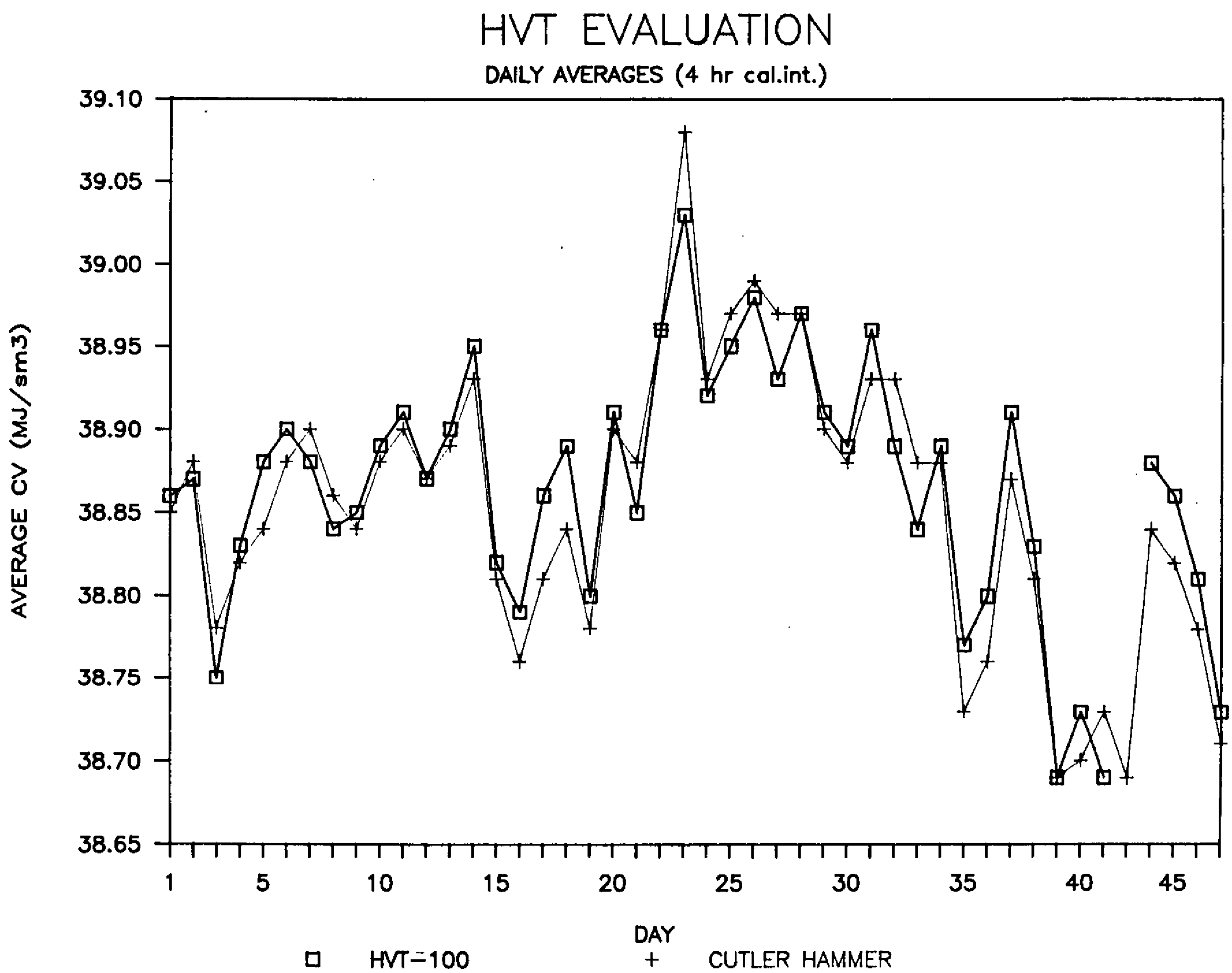


DATE: FRI 5 DEC 1986 GRAPH E

HOUR	BAROMETRIC PRESSURE Patm (bar)	CHANGE IN Patm (%)	MEASURED CALIBRATION GAS CV (MJ/sm3)	MEASURED CV ERROR (MJ/sm3)
-2	1.006			
0	1.005	-0.168	37.70	-0.07
2	1.001	-0.404	37.67	-0.10
4	0.997	-0.338	37.66	-0.11
6	0.994	-0.306	37.68	-0.09
8	0.992	-0.204	37.75	-0.02
10	0.995	0.239	37.81	0.04
12	0.995	0.068	37.87	0.10
14	0.998	0.306	37.76	-0.01
16	1.000	0.136	37.81	0.04
18	1.001	0.136	37.80	0.03
20	1.002	0.135	37.80	0.03
22	1.004	0.169	37.81	0.04
24	1.006	0.169	37.82	0.05






HVT EVALUATION
DAILY AVERAGES (4 hr cal.int.)
AVERAGE CV (MJ/sm3)
39.10
39.05
39.00
38.95
38.90
38.85
38.80
38.75
38.70
38.65
1
5
10
15
20
25
30
35
40
45
DAY
HVT-100
CUTLER HAMMER

Main Index

MAINTAINING MEASUREMENT ACCURACY ON A FISCAL METERING SYSTEM

by

B Lind-Nielson
Dantest

Paper 1.2

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

Dantest

NATIONAL INSTITUTE FOR
TESTING AND VERIFICATION

MAINTAINING MEASUREMENT ACCURACY ON A FISCAL METERING SYSTEM

Birger Lind-Nielsen

Dantest, National Institute for Testing and Verification, Copenhagen

SUMMARY

In order to satisfy customers, authorities, and other interested parties in a fiscal metering system, it is necessary not only to have an acceptable measurement accuracy on the metering system, but also to maintain this accuracy during the lifetime of the system.

The present paper will look into the evaluation and maintenance of the measurement accuracy of a metering system. After a brief survey of the basic concepts of uncertainty, the paper will discuss the ways of evaluating the uncertainty of a measuring system as supplied and the added uncertainty due to installation effects. The main part of the paper will concentrate on the quality system which is needed in order to maintain this uncertainty. The paper will describe the special demands the metering system will impose on the quality system, and the paper will refer in detail to the actual procedures which constitute the basis for the quality system.

1 INTRODUCTION

When a new project is underway a lot of work is expended in the early life of a fiscal metering system, from writing technical specifications to the commissioning of the system. The work involves many people within the oil/gas companies, the manufacturing companies, and the authorities [1], [2], [3]. When the work has been completed, the system is handed over to the operators who are expected to keep the system working in accordance with the policy of the company, especially to maintain the measurement accuracy within the agreed limits during the lifetime of the metering system.

By maintaining the measuring accuracy the operator ensures that:

- Production figures can be trusted.
- Production upsets can be recognized.
- All interested parties, i.e. customers, shippers, pipeline operators, authorities a.o. are satisfied that the measurements are correct.

The measurement accuracy of a metering system consists of the combined effects of the uncertainty of the metering system and the maintenance of this uncertainty, i.e. maintaining the metering system at a specific uncertainty level.

International standards contain information on evaluating the uncertainty but offer very little information about how to maintain the uncertainty.

The authorities in different countries have established different rules for maintaining the uncertainty. The Norwegian Petroleum Directorate (NPD), for example, requires the operators to have procedures for the operation and calibration of the metering system, and NPD sets up a detailed description of calibration requirements [4]. The Danish Energy Agency, on the other hand, relies on international standards and emphasizes the reliability of the system and the maintenance of the uncertainty.

The present paper will deal with the principles of measurement accuracy of a fiscal metering system. After a brief survey of the basic concepts of uncertainty, the paper will discuss the methods of evaluating the uncertainty of a metering system. The main part of the paper will concentrate on the quality system for maintaining the measurement uncertainty of such a system.

2 MEASUREMENT ACCURACY

The accuracy of a fiscal metering system consists of the combined effects of the installed uncertainty of the metering system and the maintenance level of the system.

The installed uncertainty consists of the combined effects of the supplied uncertainty and installation effects.

The maintenance level is the combined effects of the maintenance procedures and the control limits set up for each instrument.

2.1 Supplied uncertainty

The supplied uncertainty is the uncertainty of the metering system at the time of commissioning. It is the combined systematic and random uncertainty, and it depends on the uncertainty of each individual instrument and their calibration.

The basic concepts of uncertainty can be found in many standards and textbooks, e.g. ISO 5168 [5] describes the general theory of estimating uncertainty of a flow-rate measurement. The terminology used in this paper is based on ISO 5168.

ISO 5168 defines uncertainty as the interval within which the true value of a measured quantity can be expected to lie with a given probability. The key word here is probability. Every uncertainty should be associated with a stated confidence level. ISO 5168 recommends the use of 95% probability.

2.1.1 Systematic uncertainty

Systematic uncertainty is the component of the uncertainty, which in the course of a number of measurements of the same quantity remains constant [6]. The systematic uncertainty will never decrease or be eliminated by repetition of the measurements.

The systematic uncertainty can be estimated from the known characteristics of the instruments. In the evaluation of the systematic uncertainty, several contributions should be considered, for example:

- Linearity.
- Hysteresis.
- Repeatability.
- Ambient temperature effect.
- Long-term stability.

The systematic uncertainty is usually underestimated since it is easy to overlook parameters whose effect should have been included. For example, it is necessary to include the static pressure effect when considering differential pressure transducers.

The evaluation of the systematic uncertainty should be based on calibration of the instruments. The calibration should be traceable to International Standards.

2.1.2 Random uncertainty

Random uncertainty is the component of the uncertainty which, in the course of a number of measurements of the same quantity varies in an unpredictable way [6]. The random uncertainty of the average value of the measurements will decrease by repetition of the measurement.

The random uncertainty can be found by repeated experiments with the metering system. A measure for the random uncertainty is the standard deviation found for the experiment, multiplied by a weighting factor (Student's t distribution) which corrects for the number of degrees of freedom in the experiments. The ways in which the experiments can be performed can be divided into two groups: static and dynamic [7].

The static measurement can be exemplified by calibrating a pressure transducer using a dead-weight-tester. By keeping under control the influence parameters, such as laboratory temperature, vibrations etc., it is ensured that the random uncertainty of the dead-weight-tester is much smaller than the random uncertainty of the pressure transducer and repeated measurements will give an estimate of the random uncertainty of the pressure transducer.

When an instrument is used to perform a dynamic measurement, such as a flowrate measurement, the random uncertainty can be estimated by comparing two identical instruments in series on the same meter pipe. By taking pairs of simultaneous readings and evaluate the standard deviation of the difference in the readings, it is possible to estimate the random uncertainty of each individual instrument [7].

2.1.3 Combined uncertainty

It is generally recommended to list systematic and random uncertainties separately, as there is a great deal of controversy as to how to combine the two different uncertainties, when the distribution functions are unknown.

ISO 5168 [5] though, recognizes that there are many practical reasons for presenting a single combined value of the uncertainties and it provides guidelines for combining the uncertainties using the root-sum-square method. ISO 5168 does require though, that the random uncertainty is quoted separately.

Before the combination of the systematic and the random uncertainties, the standard requires that the random uncertainty is related to the recommended 95% confidence level.

2.2 Installation effects

The supplied uncertainty is the minimum uncertainty with the acquired instruments. When the instruments have been installed in the metering system, the uncertainty of the metering system increases due to installation effects. The added uncertainties not only depend on the mechanical and/or electrical effects but also on the flow itself and on environmental conditions.

As an example, flow disturbances in the upstream flow of a meter influence the uncertainty of the meter. This has been recognized in the international standards in the way the standards recommend minimum upstream lengths for the meter. If the actual lengths are larger than the minimum lengths, the standards states that there is no added uncertainty due to flow disturbances.

Another example is the effect of temperature on the measurement of density in the meter pipe using a densitymeter. If the densitymeter and the associated pipework is insufficiently lagged the sample flow to the densitymeter could acquire the temperature of the surroundings before entering the densitymeter causing a significant contribution to the uncertainty.

2.3 Influence of maintenance level on uncertainty

The maintenance level influences the uncertainty through the way the maintenance procedures are described, how often the procedures are performed, and which control limits are set up.

The maintenance procedure describes the actual steps for carrying out the maintenance work with reference to metering and the evaluation of the instruments. The procedures influence the level of maintenance by describing how detailed the maintenance checks should be carried out and how often.

The control limits are limits within which the values of an instrument's characteristic parameters should fall. If the values fall outside the limits, the operation of the instrument should be checked. Maintenance procedures used to maintain instruments at a specific uncertainty level can contain several control limits.

The maintenance procedures should be executed at regular intervals and the data from the tests should be evaluated and compared with the data from the previously performed tests. These test data together with the other information about each individual instrument (such as repairs, calibrations etc.) should be kept in the maintenance records. The development of the information in the maintenance records shows the history of the instrument, especially its long-term stability.

A special record in the maintenance records is the control chart. The control chart describes the variation with time of a specific parameter which is important for maintaining the accuracy of the metering system, e.g. the vacuum frequency of a densitymeter. Together with the actual data the control chart shows a mean value and the control limits for that particular parameter.

By analysis of the control chart an estimate of any added uncertainty due to the maintenance procedures can be made.

If the analysis shows, that the value of the instrument parameter never reaches the control limits, the control limits are too large and can confidently be reduced, thus reducing the uncertainty due to the maintenance procedures.

If, on the other hand, the value of the instrument parameter regularly reaches the control limits and nothing is done to correct this deficiency in the metering system, the uncertainty increases due to the maintenance procedures.

3 MAINTAINING MEASUREMENT ACCURACY

Maintaining measurement accuracy is a combination of maintaining installed uncertainty and carrying out external calibrations.

The primary requirement for maintaining the installed uncertainty is a quality system. The quality system should be so detailed that, for example, control limits, meter log, and personnel training are included. These items are often neglected and will therefore be mentioned in detail in the present paper. The quality system should also contain guidelines for external calibrations.

3.1 Quality system

The quality system should be organized according to the international standards ISO 9000 series [8] or similar standards and recommandations [9], [10]. According to these standards, the structure of the quality system should generally consists of three levels of quality documentation. The first level comprises the Quality Manual. This manual describes basic principles and policy statements.

The manual should include a section on the policy of metering, especially stating the uncertainty limits which are acceptable to the company. When it comes to fiscal metering though, the uncertainty limits will usually be defined by the authorities as the best obtainable. The quality manual should also define the line of responsibility for maintaining the measurement accuracy.

The next level in the quality system will be the general quality system procedures, which describe the interface controls between the departments. These procedures control the flow of information through the organization.

The lowest level in the quality system contains the maintenance procedures which can be divided into two parts, the general control procedures and the actual control procedures. The general control procedures control the flow of information through the department:

- Who receives the papers, in what order.
- What should be done to the papers.
- What should be done to the data.
- After processing, how and where should the papers be kept for the records.
- After processing, what action should be taken if the

evaluation of the data shows, that something has gone wrong.

The general control procedures should clearly state what should be done to the papers after they have been received in the department. Who should examine the papers, what sort of data evaluation should be performed.

The general control procedures should include enough information to ensure, that it is possible to build and maintain a history of the instruments. The general control procedures should also include instructions for evaluating the development in the history.

The actual control procedures should describe the checks which must be performed in order to evaluate whether the metering system fulfills the requirements that are set up so as to maintain the accuracy of the metering system. The procedures shall explain in sufficient detail how the checks should be executed so that the results obtained from the checks are independent of the operator.

The procedures must contain every step in the control process including preparations and possibly safety procedures. The procedures must be unambiguous, short and concise. The procedures must be adjusted to the actual metering system.

An actual control procedure can be divided into the following elements in the order stated:

- Description of purpose. Guidelines for the execution. Which department is responsible. Time schedule.
- Description of which equipment is to be checked and which equipment is to be used in the check.
- Description of the necessary preparations.
- A numbered, step-by-step and unambiguous explanation of every step in the check.
- A description of how the obtained results are forwarded in the quality system.
- A reference to the meter system log.
- Preprinted forms for recording data. The forms should have spaces for possible remarks and for all the data the operator is required to write down. The last two items are especially important for the revision of the procedures. These items also convey an insight into the operator's understanding of the procedures and help in locating errors in the metering system.

Although the procedure might be comprehensive, the procedure should not refer to subprocedures outside the procedure if the subprocedures are relevant to the control of the actual measurement process. If the procedure refers to a subprocedure, the procedure itself should contain adequate controls which show that the subprocedure has been performed at the right step in the procedure.

3.1.1 Control limits

In order to keep the metering system within agreed uncertainty limits, the deviation of each instrument from the reference value should be kept inside certain control limits. These limits should be established in such a way that it is possible to ascertain whether the metering equipment provides the desired uncertainty. The control limits should thus reveal if the metering equipment is working properly and stable.

The value of the control limit depends on:

- The agreed limit of the metering uncertainty.
- The uncertainty of the metering equipment.
- The installation effects on the metering uncertainty.
- The uncertainty of the check equipment.
- The applied control procedures.

The last item implies the interactive way control limits are set up. It is no good to use narrow control limits if the control procedures are poor. In that case, it is impossible to bring the instrument deviations within the control limits and the operators will discard the written procedures and execute the procedures in their own way. Thus loosing all possibilities for comparing the different check tests.

When the value of the control limits has been set it is necessary to determine through experiments that the limits are feasible in the actual measurement system before the control limits are used in the procedures.

For a large metering system it is difficult to establish control limits through experiments. So the limits will have to be set up á priori. This should be done with care. If the control limits are too small they will give rise to frequent unnecessary alarms which each have to be investigated. If the control limits are too large it might take too long time before an erring instrument is detected.

3.1.2 Meter system log with reference to measurement accuracy

There should exist a meter system log dedicated to the behaviour of the metering system with reference to measurement accuracy. It should not contain information about the general operation of the metering system such as when a meter pipe was closed or opened. This information should be kept in a separate log.

The meter system log should contain detailed information for each instrument about:

- Calibrations. When, where, and how.
- Name of operators executing control procedures.
- Possible repairs or adjustments of the instrument.
- Controls performed. Which, when, and by whom.
- Instrument operational disturbances.

The log should be kept next to the instruments in question thus ensuring that the log is used whenever it is necessary.

3.1.3 Personnel

Even the best quality system is of no avail if the personnel involved in maintaining the measurement accuracy are not trained for the job. The quality system should therefore include procedures for providing training for all personnel involved and particular attention should be given to training of newcomers to the system.

It is strongly recommended that the company use dedicated meter operators, i. e. technicians whose primary responsibility it is to maintain the metering system.

These operators should have a thorough knowledge of how the metering system works. They should know the requirements the quality system set up and they should have a basic knowledge of metering theory.

3.1.4 External calibrations

The check tests supply information about how well the metering equipment complies with the requirements. The check tests themselves do not usually provide enough data to evaluate instrument repeatability or the stability of the instrument.

As an estimate of the instrument repeatability is included in the measurement uncertainty it is necessary to subject each instrument to a periodic traceable calibration. That is, the instrument correction and the instrument repeatability is found by repeated comparisons of the instrument indication with one or several fixed reference values.

This external calibration should be performed by a recognized, preferably an accredited laboratory. The time interval between each external calibration depends on the development of the instrument history but should be performed after major reparations of the equipment.

3.2 Building confidence in the metering system

When the installed uncertainty has been evaluated and the quality system has been established, the metering accuracy has been provided. The next step is to establish confidence in the performance of the metering system. This is an interactive process.

The process starts with setting up á priori control limits and time intervals between each execution of the maintenance procedures. In the beginning the time intervals should be small so the instruments are followed closely until some confidence is obtained in the system. This confidence is based on evaluation of the measurement records with specific regard to the instrument history. From the evaluation of the instrument history it is possible to establish more reliable control limits and time intervals and thus increase the confidence in the metering system.

3.3 Independent audit

Even when the metering system operator has great confidence in the metering system it can be necessary to call in an independent audit if a disagreement should arise between the involved parties.

The independent audit can:

- Supervise the execution of the maintenance procedures and evaluate the usefulness of the maintenance procedures and their forms.
- Evaluate the control equipment, their use, and their calibration certificates. The evaluation will also include an inspection of the storage room for the check equipment and an assesment of how the check equipment is stored.
- Investigate the meter system log for events that might have affected the efficiency of the metering system.

The independent audit will evaluate whether the metering system performs within the agreed limits. If the evaluation turns out to be positive an independent audit will satisfy the authorities, possible partners and others that the metering system is acceptable. If the evalution is negative it will provide the management with the proper input to revise the quality system.

4 CONCLUSION

The measurement accuracy of a fiscal metering system is an important parameter in the approval of a metering system. When the desired value has been agreed upon, it is left to the combined efforts of the supplier and buyer to show that the meter system is supplied with an acceptable uncertainty, and that this uncertainty can be maintained during the lifetime of the metering system.

The evaluation of installed combined uncertainty is a cumbersome task which comprises estimation of systematic uncertainty from a detailed knowledge of the individual instruments, any installation effects, and experimental determination of random uncertainty. It is a one-time task. When it has been performed it does not have to be repeated, unless new instruments are introduced into the metering system.

Maintaining the uncertainty demands a quality system comprising:

- A quality manual with a statement of the metering policy and a definition of the line of responsibility for the metering system.
- General management procedures for the interdepartmental controls.
- General control procedures for handling the papers and data from the check tests of the metering system.
- Detailed actual control procedures for the execution of the periodic check tests.

When this quality system has been established it is a continuous process to maintain the uncertainty by executing the maintenance procedures on a regular basis. Otherwise, there is no guarantee that the uncertainty is kept within the agreed limits.

With well trained technicians and continually updated procedures, the quality system assures the operator of the metering system that it is possible to satisfy partners, pipeline operators and authorities that the measurements are correct and accurate.

5 ACKNOWLEDGEMENT

The author wishes to expres his thanks to his colleagues at Dantest for many fruitful discussions during the preparation of this paper.

6 REFERENCES

[1] Danielsen, H. B., Moestue, H. and Tunheim, H. - Fiscal Metering Systems for North Sea Oil & Gas. Experience from Purchasing to Start-Up. North Sea Flow Metering Workshop, Stavanger, 13-15 October 1987.

[2] Peters, R. J. W. - Purchasing a Fiscal Flow Metering Station. Suppliers Point of View. North Sea Flow Metering Workshop, Stavanger, 13-15 October 1987.

[3] Fosse, Steinar - Buying and Installing a Metering Station. North Sea Flow Metering Workshop, Stavanger, 13-15 October 1987.

[4] Øgland, T. - The Norwegian Petroleum Directorate (NPD) Regulations for Fiscal Measurement of Oil and Gas. The Metering af Petroleum and its Products. 7th and 8th March, 1985. London.

[5] International Standard ISO 5168. Measurement of fluid flow - Estimation of uncertainty of a flow-rate measurement. 1978 (E).

[6] International vocabulary of basic and general terms in metrology / Vocabulaire international des termes fondamentaux et généraux métrologie. Coedited by BIPM, IEC, ISO and OIML. Metrology, pp. 1-40, 1984.

[7] Hayward, Alan T. J. - Repeatability and Accuracy, Mechanical Engineering Publications Ltd., London and New York, 1977.

[8] International Standard ISO 9000. Quality management and quality assurance standards - Guidelines for selection and use. 1987.

International Standard ISO 9001. Quality systems - Model for quality assurance in design/development, production, installation, and servicing. 1987.

International Standard ISO 9002. Quality systems - Model for quality assurance in production and installation. 1987.

International Standard ISO 9003. Quality systems - Model for quality assurance in final inspection and test. 1987.

International Standard ISO 9004. Quality management and quality system elements - Guidelines. 1987.

[9] Nordtest Guidelines for Development of Quality Manuals for Testing Laboratories. NT TECHN. REPORT 082. Approved 1987-06.

[10] ISO/IEC GUIDE 49. Guidelines for development of a Quality Manual for a testing laboratory. 1986-11-01.

Main Index

TEST OF ON-LINE CHROMATOGRAPH ON THE GAS EXPORT METERING STATION, STATFJORD FIELD

by

E Jacobsen and O Furuseth
Statoil

Paper 1.3

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

TEST OF ON-LINE GAS CHROMATOGRAPH ON THE GAS EXPORT METERING STATION, STATFJORD FIELD.

Endre Jacobsen and Odd Furuseth

STATOIL Driftsdivisjon Stavanger.

S U M M A R Y

A three stage test program has been carried out, for proving the On-line Gas Chromatograph for fiscal accounting purposes. The following aspects have been studied:

- Mechanical Proving
- Availability
- Monitoring of Calibration and Operational Constants
- Analysing-accuracy
- Comparison against existing sampler/analysing system

Phase I:
The On-line GCs are found to be mechanically sound and they operate reliably. Changes to the calibration constants did not in some cases comply within the preset limits, mainly due to a weakness in some components.

Phase II:
Except for an overestimation of nitrogen content on two of the four On-line GC´s, all analysis were found to be within the ASTM 1945 reproducibility limits. The allocation laboratory reproduced all components within the given limits.

Phase III:
Two of the On-line GCs are compared against the existing system, and preliminary results have shown an underestimation of the C6+ fraction. All other components have been within the limits throughout the periods stated.

1. Introduction.

This paper describes the experience and preliminary results of an ongoing test program for the On-line GC on the Statfjord field. The test program was initiated in order to investigate the possibility of utilizing the On-line Gas Chromatographs for allocation purposes. Little experience was available by use of On-line Gas Chromatographs on offshore installations. It was therefore neccesary to go through an acceptance test for verifying the system.

Background:
To provide a real time analysis of the exported gas, it was decided to install an On-line GC for Statfjord A, Statfjord B, Statfjord C and UK-offtake metering stations, (later called system A, B, C and D in random order).

The reasons for choosing a continious analysis system were:

- to ensure that gas quality spec´s were met.
- to provide the pipeline operators with input for:
  1) pipeline leak detection system
  2) optimizing operations of the processing plant
  3) optimizing pipeline operations
- to furnish data to be used for calculating volume and energy flow.
- after a period of testing, include the On-line system in the allocation accounting procedure.

A three stage test program was initiated containing the following phases:

Phase I:
- Collecting of maintenance and reliability data. This has been compared against preset "limits".

Phase II:
- Compare the analysis results provided by the On-line GCs against certified gas samples, with respect to reproducibility and repeatability limits in the ASTM 1945.

Phase III:
- Compare composition analysis figures from the On-line GC against the existing sampling and analysing system.

2. Description of the On-line GC system

The On-line GC system is a part of the Gas Export Metering Station (shown in fig. 1). It consists of the following main component parts:

- Bendix 002 Gas Chromatograph, including three columns each dedicated for separating groups of components. The carrier gas is high purity Helium

- Sample/handling system, low and high pressure cabinets providing two-stage pressure reduction (ref. fig 2).

- Cosasco Probe, located in a commom flow point on the inlet header.

- Control unit, supervising the following tasks:

    - introduce the sample into the proper column
    - control column switching
    - convert raw data from the detector
    - check components for preset limits
    - perform all calculations and communication with master computer.
    - control the calibration sequence.

3. Phase I

3.1 Introduction

This phase involved the mechanical proving and the operational reliability of the entire On-line GC system. To monitor the performance of the system, three main test criteria have been established: Downtime, RRF and RRT, ref sect. 3.2 - 3.4.

3.2 Downtime

This mode is defined as "a period when the GC does not give a representative result of the gas sample composition". Downtime periods are normally caused by changes in the sample/handling system, analyser problems or hardware/software corruptions.
The objective was to keep the monthly mean downtime to less than 1 hour per day; i.e. availability = 95.8 %.

Fig. 3 shows the downtime results for GC system "A", "B", "C" and "D" versus maximum allowable downtime, 100 % is equal to 1 hour (4 cycles downtime) per day. An observation period of 17 months is included in fig. 3.

For all GCs, the actual downtimes were outside the objective at the beginning of the test period. This was mainly due to fact that the technicians working with the equipment were at the beginning of the learning curve. Later months have also shown downtime figures outside the objective, but they were mainly due to the following:

- periods of long response time during alarm conditions.

- hardware faults in a control unit.

- faults in the temperature control unit in one GC cabinet.

- weak design of a restrictor providing constant reference flow through one of the GCs.

The distribution of the downtime duration is presented in fig. 4. The plot is based on data from GC system "C" during a six months period. The peak of 4 downtime cycles (1 hour) was due to the calibration of the system. The GC is automatically set to be calibrated 4 times per month, and is then out of service for one hour.

Approx. 70 % of the downtime had a duration of 1 hour or less and approx 5 % of the downtimes´ exceeded 5 hours. The results shown in fig. 3 were typical for the remaining GCs.

3.3 Relative Response Factor (RRF)

Relative Response Factor (RRF) is a calibration constant, computed for each component during the calibration sequence. Calibration gas with known composition is then routed through the GC, and analyses are carried out.

When back in normal "analysing" mode, the sets of RRFs calculated during calibration, and the integrated peak areas are used to calculate gas composition.

Shift in the RRF-value indicates performance of the following GC components:

- columns
- pressure regulators
- detector (TDC, thermal conductivity detector)
- flow control
- temperature control

In addition, change of calibration gas can affect the RRF-values.

The objective of RRF stability was to be within +/- 3 % per 3 months.

Figs. 5 and 6 show the typical RRF development on GC system "B" and "C" over a period of 3 months for all components.

Some components were found to be outside the RRF objective, mainly due to the following:

- weak control of reference flow through a detector on system "B".
- weak temperature control in GC cabinet on system "B".

By proper maintenance and by corrrecting weak parts of the system, it is possible to achieve RRFs within the objective. Slight changes in the RRFs can be accepted as long as an optimal calibration interval is adopted

3.4 Relative Retention Time (RRT)

For each component, a fixed Relative Retention Time (RRT) through the columns, is established in the GC controller software. If no peaks are detected inside the preset "time-window", a "missing" alarm will be reported.

The objective is to keep the RRT for each component within +/- 4 secs for 3 months.
A six monthly test was carried out on GC system "B" and "C" and no significant shifts in the RRTs were observed. There was no need for changing the RRT-settings throughout the test period. If the "missing" alarm condition did occur, this was reflected in the downtime figures.

4. Phase II

4.1 Description

Phase II included comparison of the four On-line GCs on Statfjord against certified gas mixtures. For verifying and comparison, the onshore allocation GC has been included.

Analyses were carried out with the onshore GC, thereafter on the On-line GCs and finally back for verifying with the onshore GC.

The results have been checked for repeatability and reproducibility criteria in the current standard, ASTM 1945.

Two composition samples close to the typical gas export quality, have been investigated.

Typical Statfjord gas composition:

Methane	:	76.0 %
Ethane	:	11.0 %
Propane	:	8.0 %
I-Butane	:	0.5 %
N-Butane	:	2.0 %
I-Pentane	:	0.5 %
N-Pentane	:	0.5 %
C6+	:	0.5 %
Nitrogen	:	0.5 %
CO2	:	0.5 %

Certified gas bottles provided by Norsk Hydro were used as transfer samples between the On-line GCs and the onshore GC. Norsk Hydro is also used as the supplier of calibration mixtures to the onshore and offshore GCs.

The calibration gas is certified within the following accuracy:

- methane within a range : +/- 0.5 %
- all other components within a range : +/- 1.0 %

- Onshore Gas Chromatograph

The test gas cylinders were analysed according to the existing allocation analysis procedure, based on ASTM 1945.

The following calibration checks are performed prior to analysing:

- unnormalized sum to be within 100 +/- 1 %.
- two concecutive analyses to be within the limits in ASTM 1945.

If it is outside the limits, the GC is re-calibrated. A sample analysis is only accepted if results are within the above limits. The analysis with the unnormalized sum closest to 100 % is normalized and reported in sect. 4.2.

- Offshore On-line Gas Chromatographs

The On-line GCs were calibrated prior to the analysis of the transfer samples. Two concecutive analyses must repeat within the ASTM 1945 limits. Based on the last calibration analyses, new updated sets off RRF were utilized in the GC software.
The transfer samples were connected and prepared as done for calibration. Two concecutive analyses must then repeat within the given limits, and the latest ones have been reported in sect. 4.2.

4.2 Results

Results from two certified mixtures are presented. Each mixture has been analysed on two occasions on the onshore GC, plus once on each On-line GC. The results are separated for each of the involved GCs, see fig. 7, 8 and 9.

The bar height shows the fraction of maximum allowable reproducibility calculated for each component as follows:

bar height = (analysis-certificate)*100 / max reproducibility.

The certificate value is provided by Norsk Hydro. The plots show the distribution for every component in the mixture. Maximum allowable reproducibility and repeatability values according to ASTM 1945, for this calibration gas specification, are as follows:

Component	Reproducibility	Repeatability
N2, CO2, iC4, iC5 and nC5	0.06 %	0.03 %
nC4	0.10 %	0.05 %
C2H6 and C3H8	0.20 %	0.15 %
CH4	0.60 %	0.30 %
C6 and above	10 % of amount	5 % of amount

- Onshore Gas Chromatograph

The results are presented in fig. 7. Every component has reproduced against the certificate within the above reproducibility and repeatabilty limits.

- On-line Gas Chromatographs

The results from the 4 GCs on Statfjord, system "A", "B", "C" and "D" is shown in fig. 8 and fig. 9. The following main performance characteristic were observed:

- overestimation of the nitrogen content by 65% - 75% of maximum allowable on three of the GCs.

- all analyses were within the ASTM 1945 repeatability limits.

- all analyses except single nitrogen results were within the ASTM 1945 reproducibility limits.

4.3 Discussion

The main finding of the test comparison was the general overestimaton of nitrogen content on system "B", "C" and "D". This was not found to be of the same extent on system "A". Several explanations have been examined.
The main reason for nitrogen overestimation seems to be changes in the nitrogen RRF during the period of testing, due to process corruptions (liquid carry-over) on the metering stations.

A small shift was observed in the hexane (C6) result between the first and second analysis on the allocation GC. This can be explained by utilizing a new calibration bottle in the time between.

5. Phase III

5.1 Description

Phase III of the test program includes a comparison between the On-line GC figures and the analysed results from the existing sampler system.
The existing flow proportional sampler system collects small amounts (0.5 ml) of gas into the sample cylinder after fixed increments of exported gas. The sample piston cylinder uses argon as a back-pressure gas, keeping cylinder pressure slightly above line pressure. Maximum filling volume of the cylinder is 800 ml.

After a sampling period of 14 days, the cylinder is removed and transported to the onshore allocation laboratory for analysis.

The station master computer is provided with every analysis from the On-line GC. This information is combined with exported volumes since the last analysis, and printed on a chromatograph report.

During phase III, the chromatograph reports on GC systems "B" and "C" are continiously logged by a PC. The reports are created approximately 4 times per hour per GC system. During a 14 days period, 1100 - 1300 single analyses are logged.

In order to compare the GC data against the allocation analysis result, they must be weighted with respect to flowrate, and corrected if there are any obvious errors.

5.2 Preliminary results

During phase III, twelve sampling periods will be compared. The results presented in fig 10 - fig 13, cover the first eight of these.

The comparison of the results is based on the reproducibiliy limits in ASTM 1945 as done for phase II. The following main observations have been found in phase III.

- underestimation of the C6+ fraction particular for system "C", in the beginning of the test period.

- C1 - C5, N2 and CO2 have been within the reproducibility limits in ASTM 1945 for both systems.

- small variations in gas export composition.

- no systematic offset between On-line GC and Onshore GC, except for the C6+ fraction.

5.3 Discussion

Phase III was determined to be the most difficult part of the test program, and initially no test criteria or accuracy objective was established. For comparison against phase II, the same reproduciblity limits have been used in phase III. The distinct underestimation of the C6+ fraction on both systems during the first months, has gradually become less, particular for system "B". System "B" is today within the reproducibility limits in ASTM 1945.

The effect of a different sampling point for the GC and the existing sampler have been tested, and no significant difference was observed. Based on the phase-envelope of the gas, we are close to the two-phase region through the sample/handling system. If any condensation of heavy ends has occured, this may cause underestimation of the C6+ fraction, resulting in large variations within the C6+ analysis data; however this has not been observed.

The underestimation of nitrogen found in phase II, is not observed to any extent in phase III.

6. Conclusion

Phase I:
The mean availability for the test period is approx. 97 %, which is satisfactory. The relative response factor has in some cases not been within the preset limits, and the problem has been investigated. Satisfactory explanations have been concluded and overall the phase I testing shows that the GC operates reliably.

Phase II:
Results from three On-line systems shows an overestimation of nitrogen. All the analysed hydrocarbon components (C1 - C6+) and CO2 have reproduced on the On-line systems to within the ASTM 1945.

The Onshore and On-line GC have repeated within the ASTM 1945 limits and the Onshore GC has reproduced every component within the limits.

Phase II demonstrated that the GC analysing accuracy is sufficient to develop an accepted On-line GC for allocation purposes.

Phase III:
Preliminary results indicate for the last periods that the two independent sampling/analysing systems (On-line GC versus existing flow proportional system) agree within the reproducibility in ASTM 1945. A further study of the observed C6+ underestimation will be carried out.

Following aspects should to be taken into consideration when utilizing an On-line GC system for allocation purpose:

- optimize calibration interval based on experience ie. monitor the performance

- use high quality calibration gas

- operational and maintenance procedure to be established

- consider the education of personnell

The advantage of on-line available GC data can be included in the flow calculations for new gas metering systems. By continious updating of critical gas data (Tc, Pc, back-up density, viscosity, isentropic exponent, Zref, etc), improved measurement performance will be expected.

7. References

G. Brown - Use of inline gaschromatograph for gas sales from an offshore platform. North Sea Flow Metering Workshop, NEL 1986.

ASTM Designation 1945 - 81. Analysis of natural gas by gas chromatography.

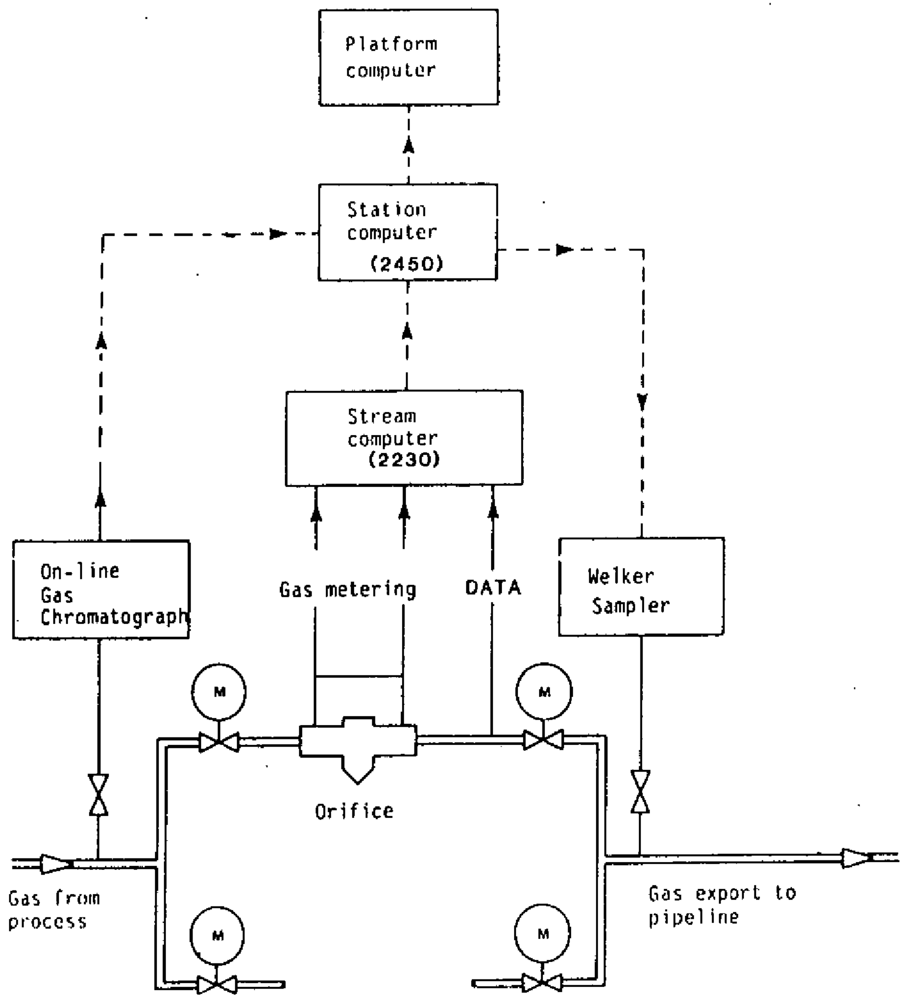
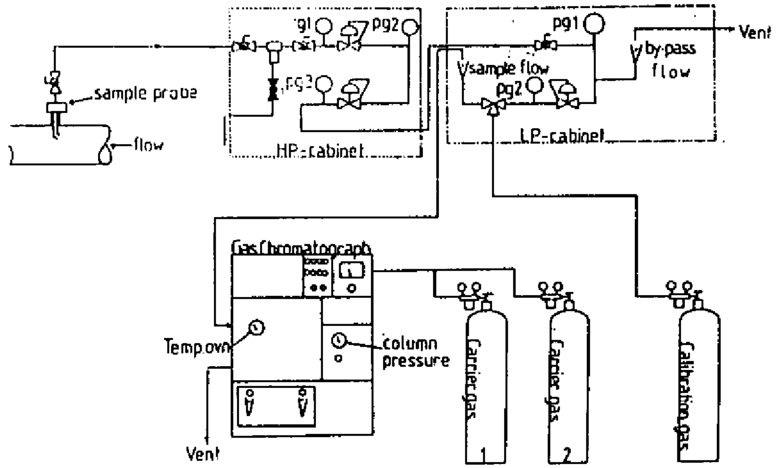


Fig. 1 STATFJORD FIELD GAS EXPORT METERING STATION



Schematic drawing of sample handling system
STATFJORD FIELD GAS CHROMATOGRAPH

Fig. 2

Fig. 3 Downtime on the Gas Chromatographs

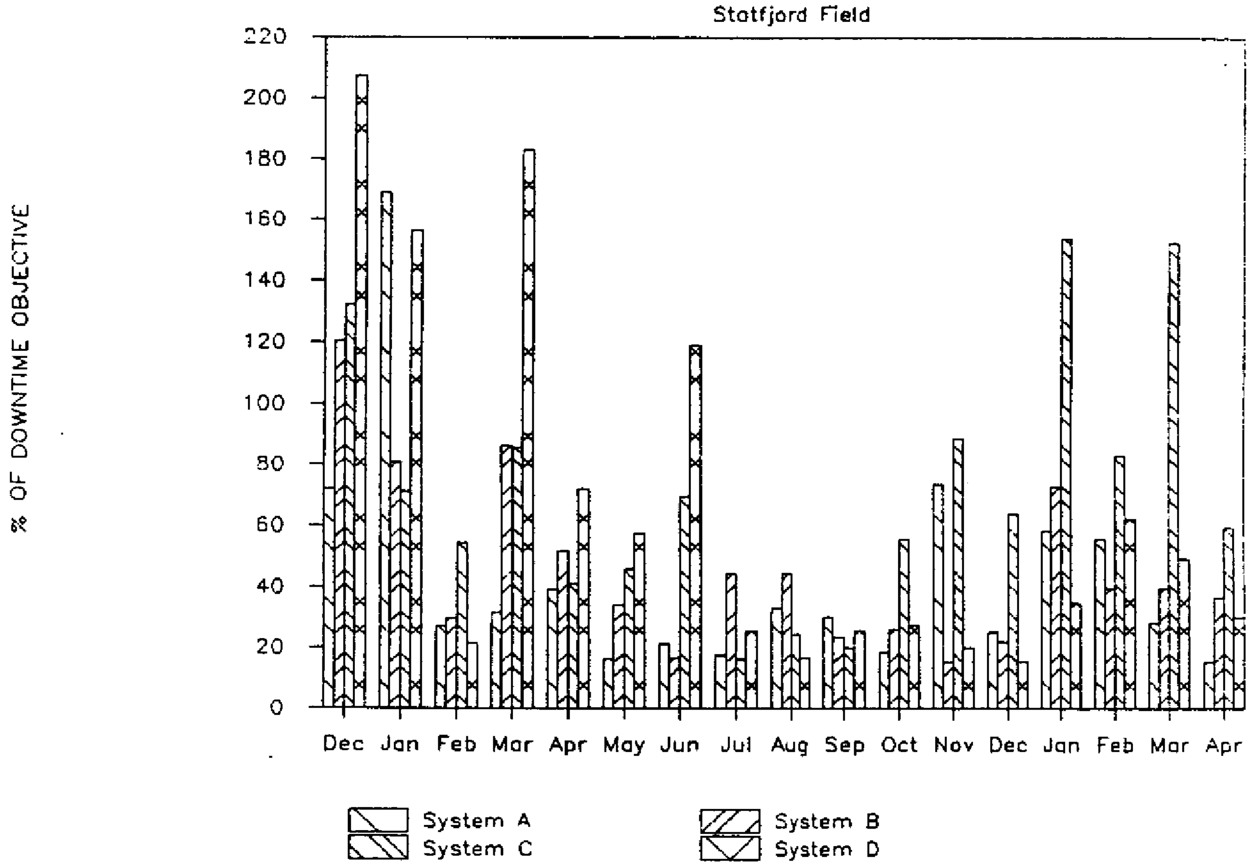
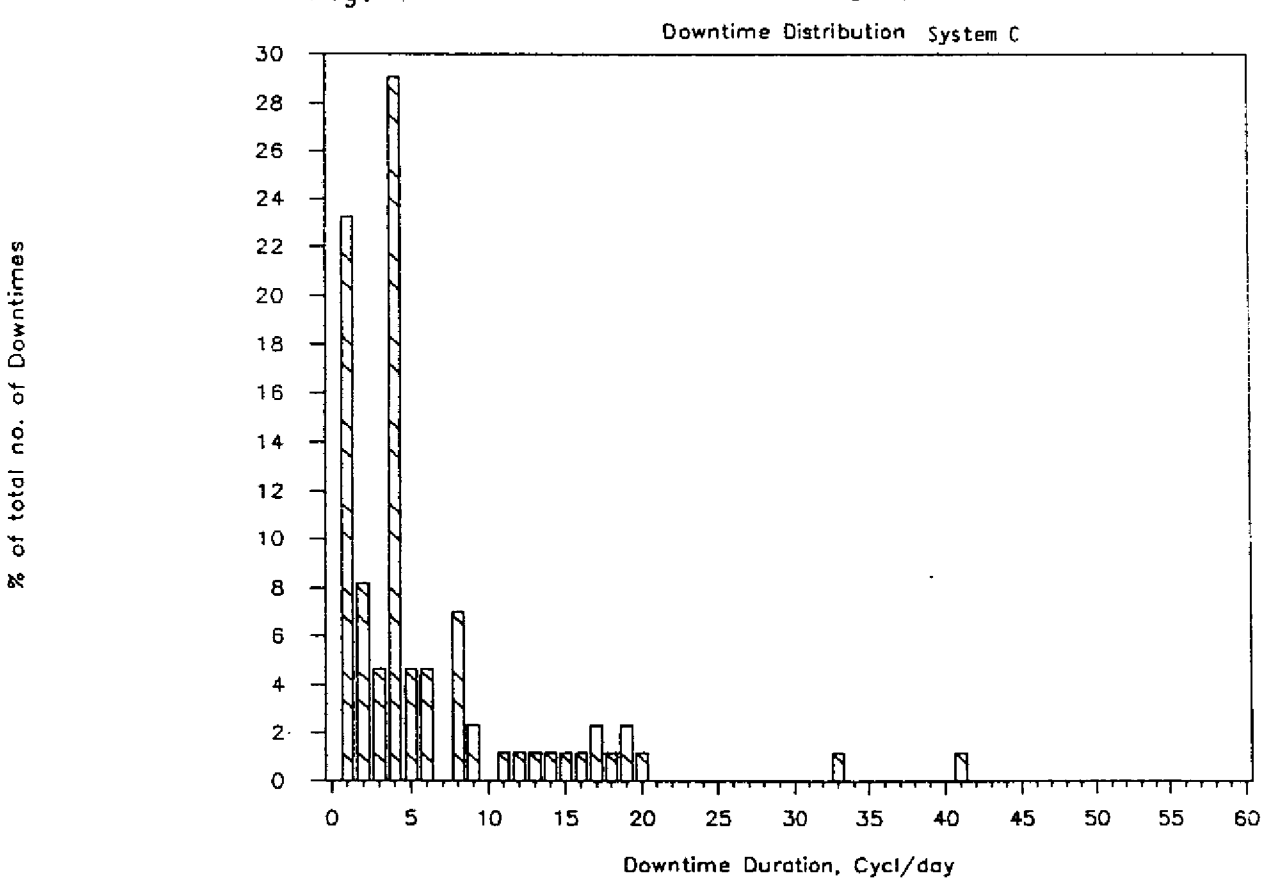


Fig. 4 Gas Chromatograph



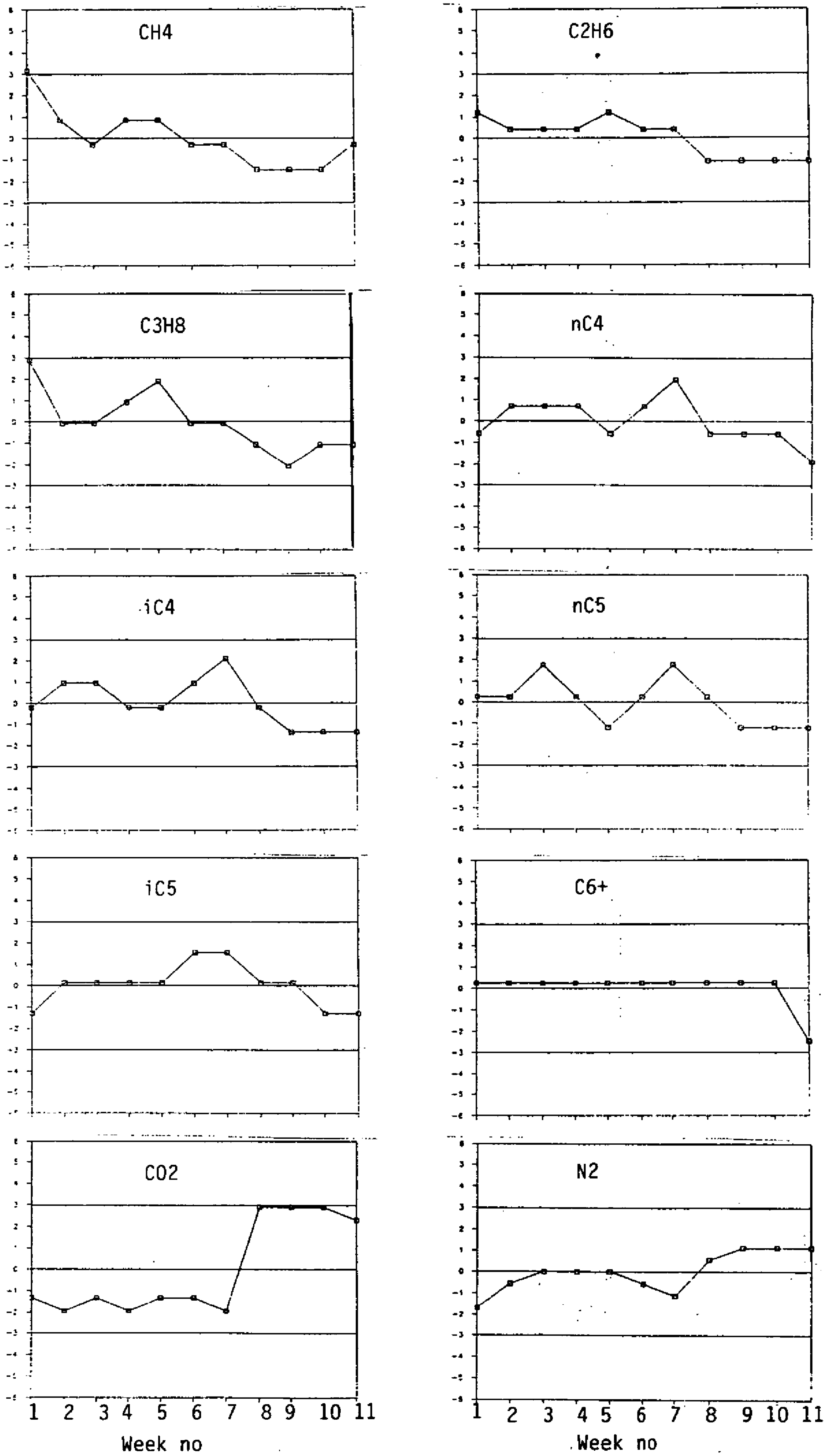


Fig. 5 RRF versus % of mean, System B

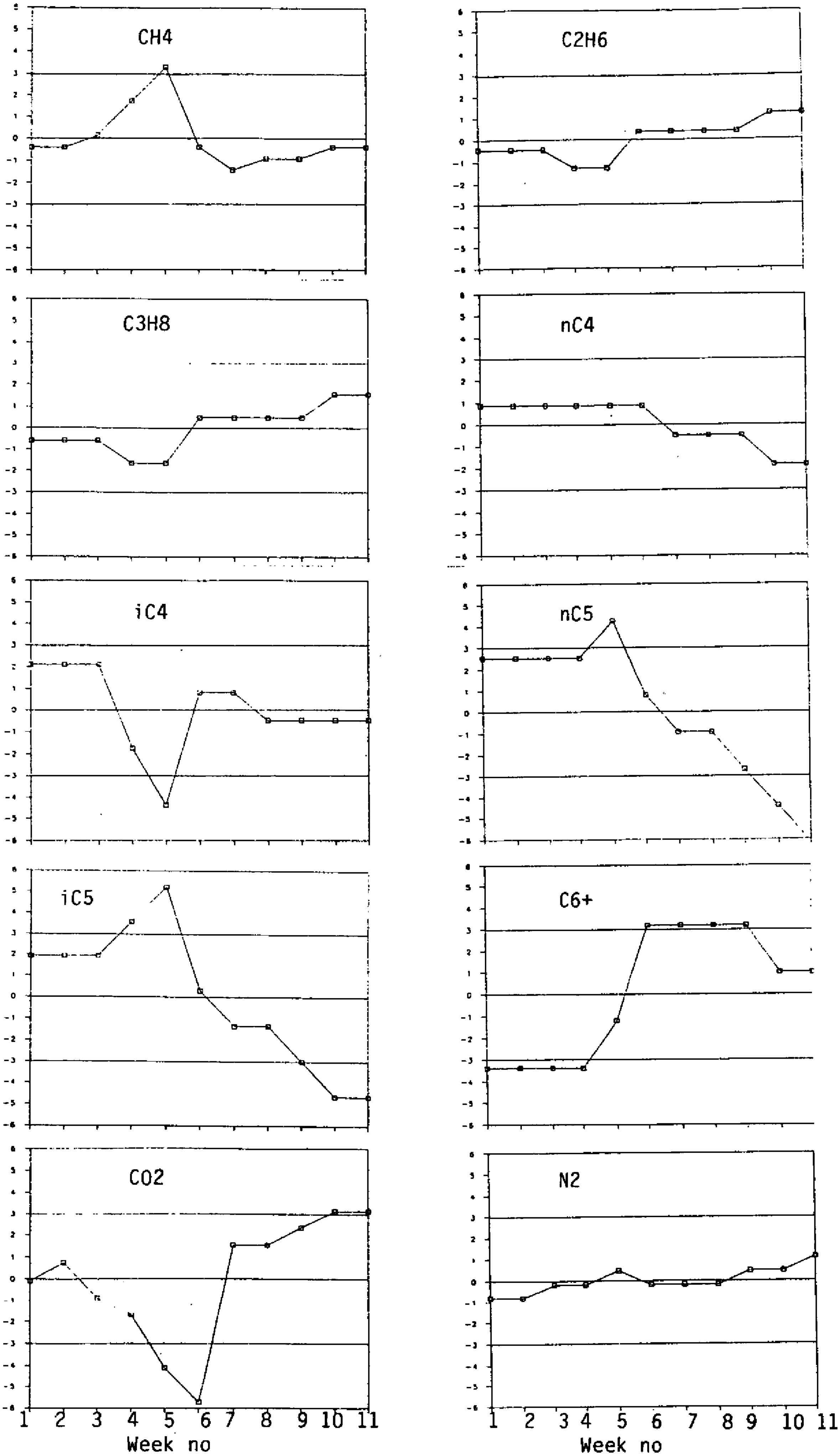
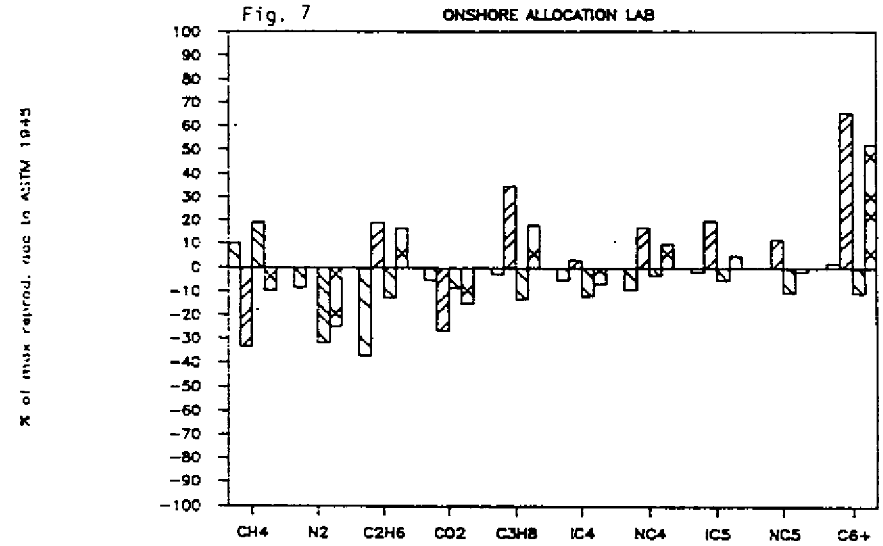


Fig. 6 RRF versus % of mean, System C

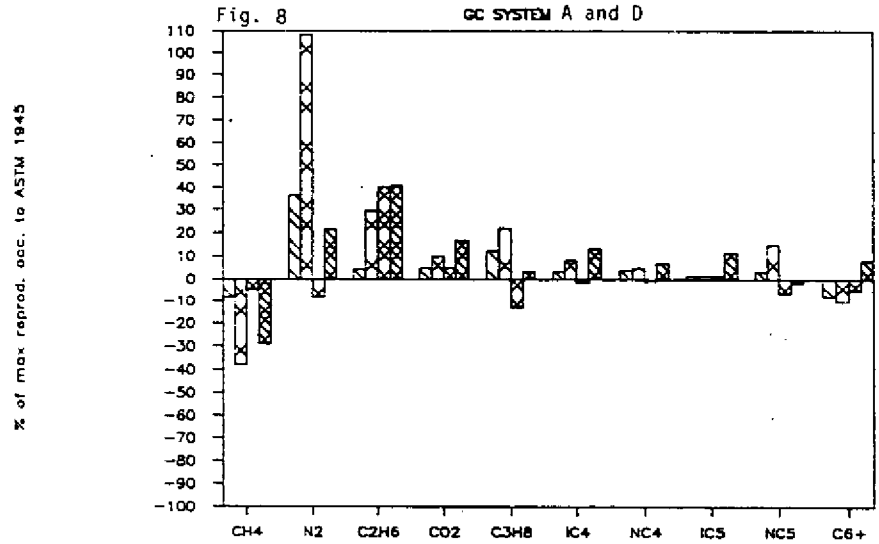
GAS CHROMATOGRAPH PHASE II

Fig. 7 ONSHORE ALLOCATION LAB



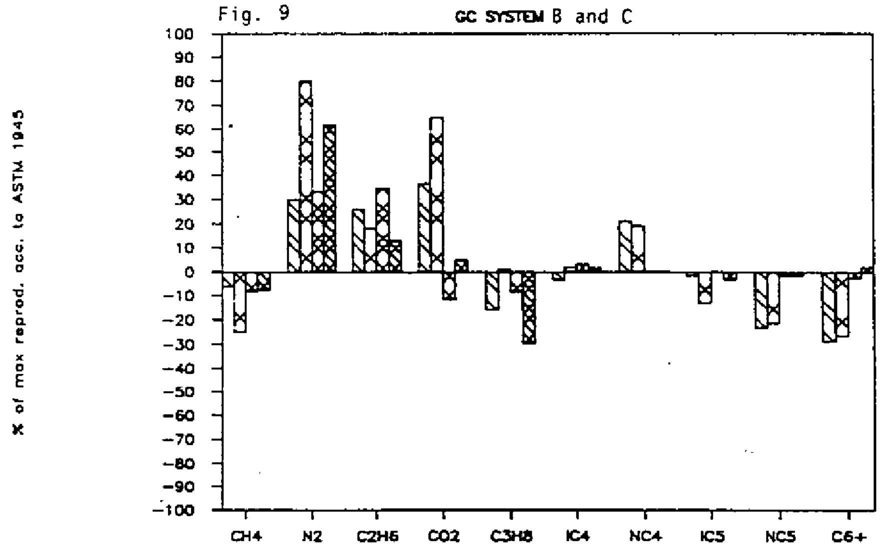
1. test, mix 1
1. test, mix 2
2. test, mix 1
2. test, mix 2

Fig. 8 GC SYSTEM A and D



System D, mix 2
System A, mix 2
System D, mix 1
System A, mix 1

Fig. 9 GC SYSTEM B and C



System C, mix 2
System B, mix 2
System C, mix 1
System B, mix 1

GAS CHROMATOGRAPH PHASE III

Fig. 10, System C

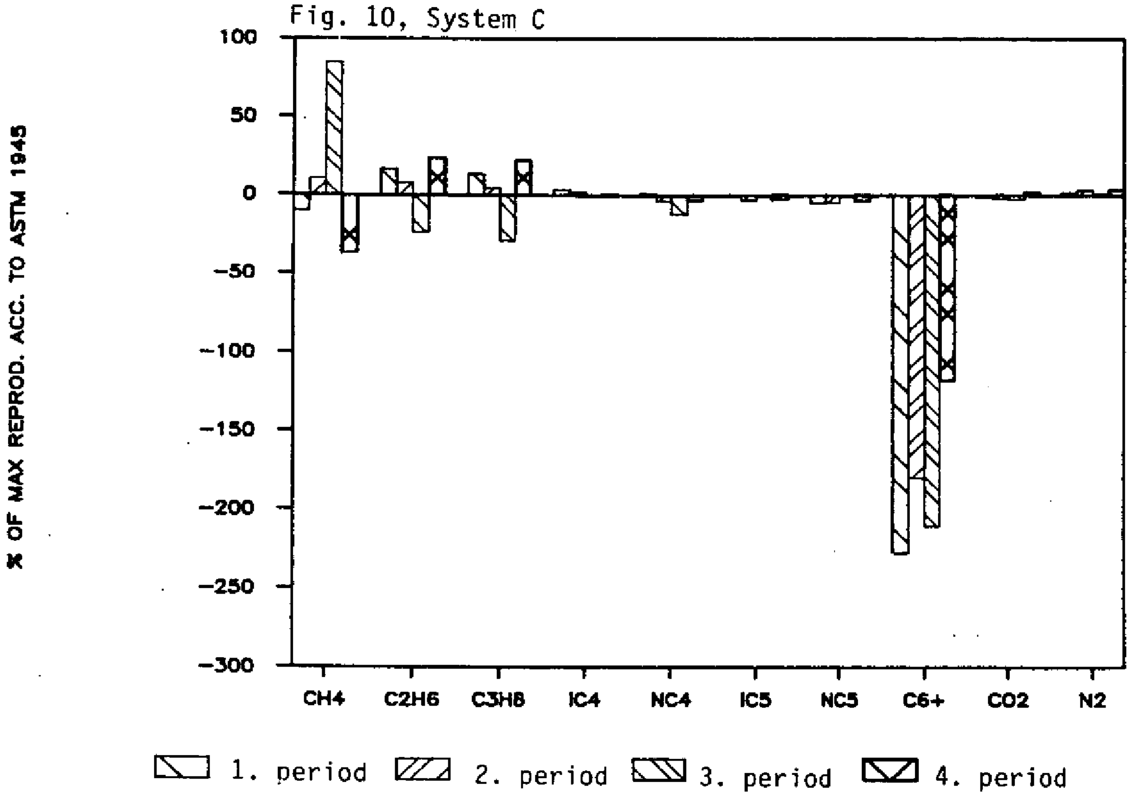
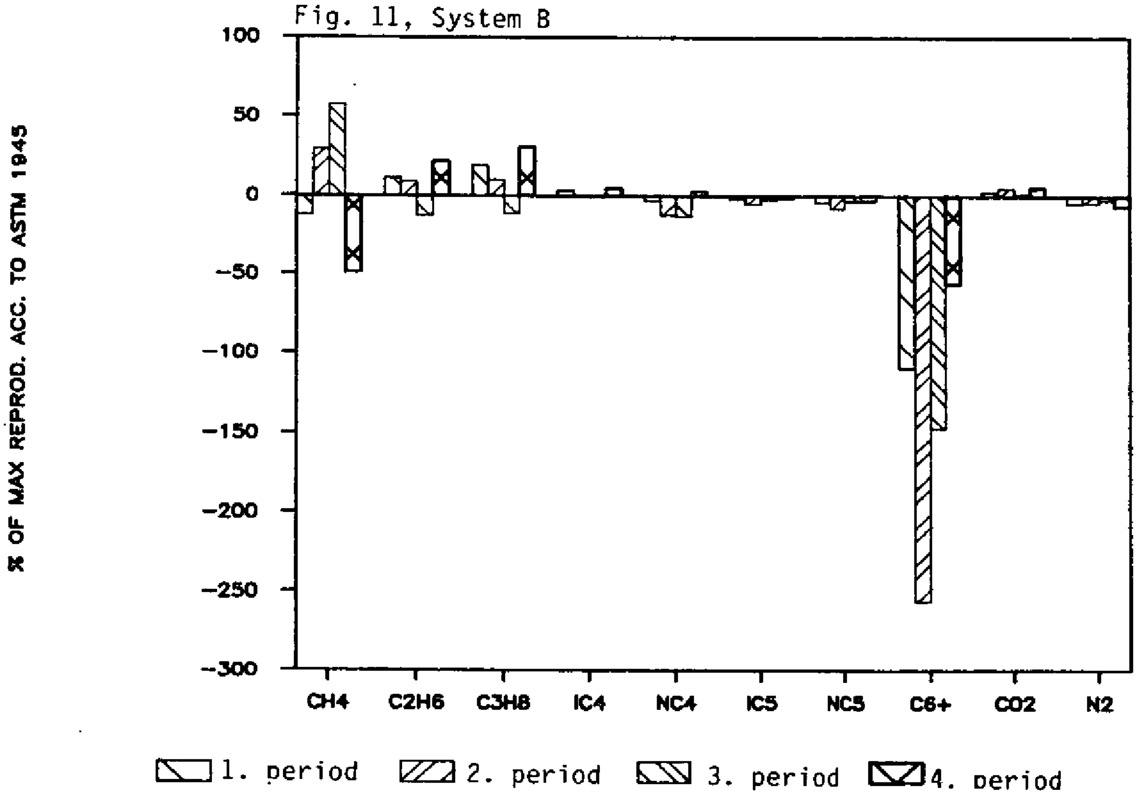


Fig. 11, System B



GAS CHROMATOGRAPH PHASE III

Fig. 12, System C

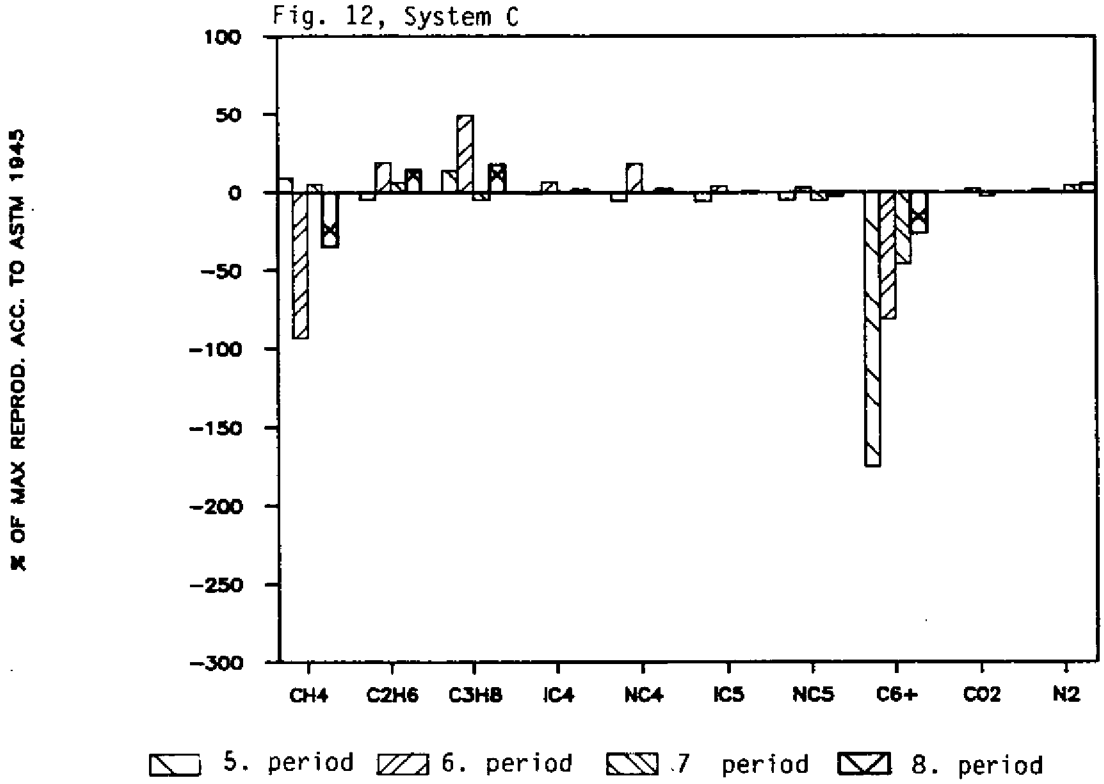
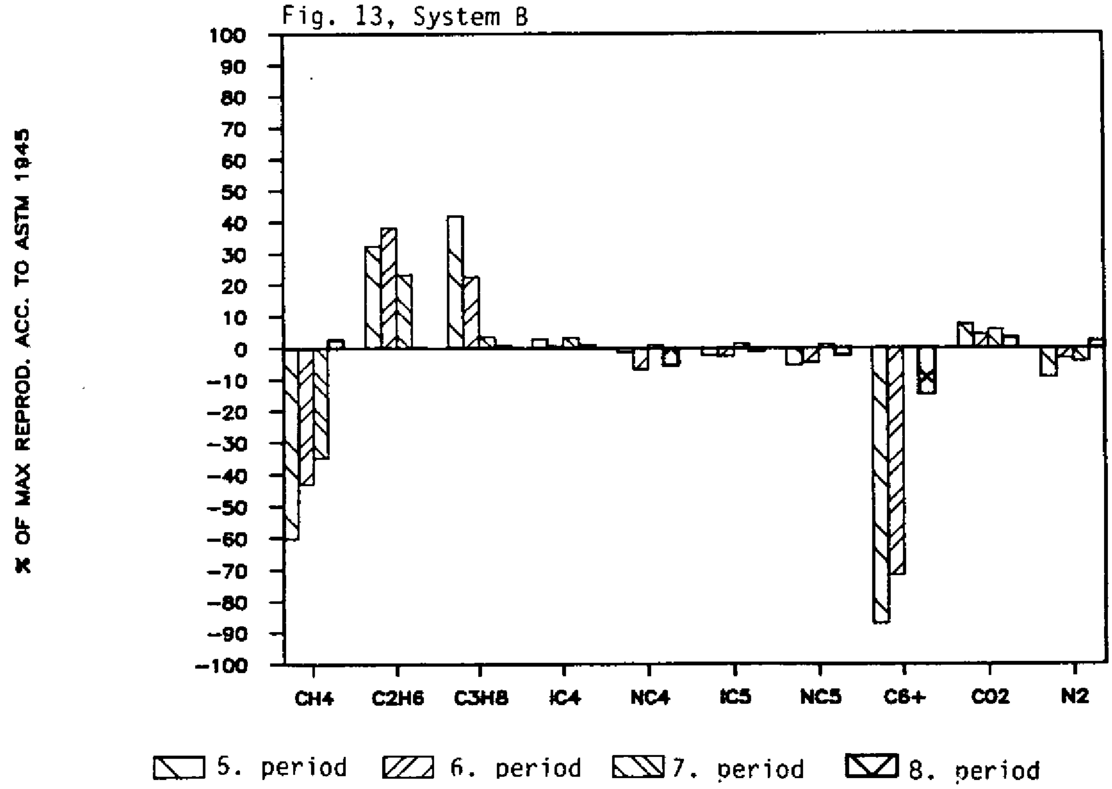


Fig. 13, System B



Main Index

THE CALCULATION OF THE ISENTROPIC EXPONENT FOR THE METERING OF NATURAL GAS

by

D W Gent
British Gas

Paper 1.4

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

THE CALCULATION OF THE ISENTROPIC EXPONENT FOR THE METERING OF NATURAL GAS

D.W. GENT
Communications and Instrumentation Department, British Gas HQ plc.

SUMMARY

The International Standard ISO 5167 requires the use of the isentropic exponent parameter in fluid flow calculations involving orifice plates, nozzles and venturi tubes in circular cross section conduits running full. In contrast, standard practice in the oil and gas industry is to substitute the isentropic exponent by the ratio of the specific heat capacities.

Starting with an introduction to British Gas plc, its involvement in fiscal metering and the motivation for this work, this paper describes how an algorithm for the isentropic exponent was developed for use with hydrocarbon gases. The algorithm is based on procedures written by the American Petroleum Institute and was developed in conjunction with University College, London.

The use of the isentropic exponent in preference to the ratio of specific heat capacities in gas metering computations is justified and the consequent increase in accuracy quantified.

NOTATION

α	Flow coefficient	dimensionless
d	Diameter of orifice or throat of primary device at operating conditions.	m
Δp	Differential static pressure	Pa
p_1	Upstream static pressure	Pa
γ_s	Isentropic exponent	dimensionless
ρ_1	Upstream gas density	kg/m^3
q_m	Mass rate of flow	kg/s
V	Volume	m^3
S	Specific entropy	kJ/K.kg
T	Thermodynamic temperature	K
ω	Acentric factor	dimensionless
Vm	Molar volume	m^3/kmole
Tc	Critical temperature	K
Pc	Critical pressure	kPa
Cp,m	Molar Isobaric Heat Capacity	kJ/K.mole
Cp	Isobaric specific heat capacity	kJ/K.kg
Cv	Isochoric specific heat capacity	kJ/K.kg
p	Pressure	kPa

The above terms are as defined in ISO 5167 where appropriate

1. THE BUSINESS AND STRUCTURE OF BRITISH GAS PLC

The primary business of British Gas is the purchase, transmission and sale of natural gas to domestic, industrial and commercial customers in Great Britain. The company also attaches great importance to the activities which support its gas marketing efforts, for example, appliance trading and customer service play a key role in supporting the domestic gas market. British Gas is also active in the exploration for and the production of hydrocarbons both offshore and onshore and is therefore an integrated company concerned with all aspects of the gas supply business. In addition expertise developed in the gas business is offered for sale overseas through the British Gas International Consultancy Service.

British Gas comprises a Headquarters and twelve Regions. The Headquarters is responsible for formulation of policies, for co-ordination and the direct management of centralised operations such as gas purchasing, exploration, bulk transmission of gas, negotiation of major industrial sales contracts and research and development. Regions are largely responsible for the important customer-related activities, including the distribution and sale of gas, the retailing, installation and servicing of gas appliances, meter reading and collection of accounts and the maintenance of emergency services.

1.2 SCALE OF OPERATION

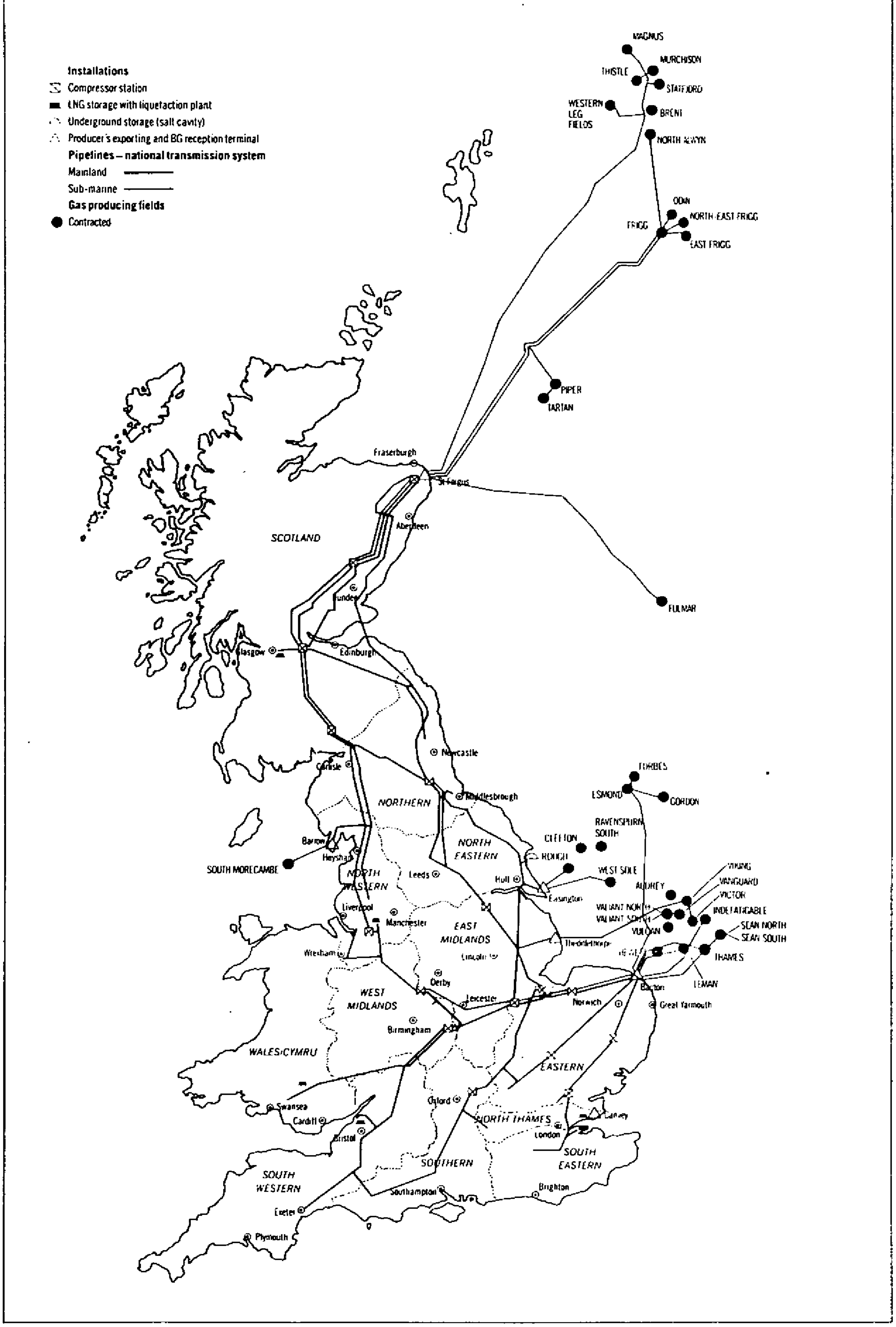
The turnover of British Gas for the year 1987/88 was £7364 million. British Gas supplies well over one half of the energy used in British homes and a third of the energy used by industry and commerce apart from fuel for transport.

To meet the annual demand of 1.97 million million Megajoules (18706 million therms) the cost of gas purchased was £3,186 million - a significant sum in the equation of British Gas' finances. The majority of the gas is purchased from oil companies, although an increasing proportion, currently ten percent during periods of peak demand, is produced by British Gas owned and operated fields, the Morecambe Bay field being the largest.

The gas is transmitted to the Regions from reception terminals by the National Transmission System, shown in figure 1.

The National Transmission System comprises a network of some 5300km of high pressure pipeline stretching from the North of Scotland to Kent in the South East, Exeter in the South West to Swansea in South Wales.

The system operates at a pressure between 38 bar and 75 bar and is supported by fifteen compressor stations with compressors driven by industrial derivatives of high powered aircraft gas turbines typically Rolls Royce Avons and RB211s.



* The above map is indicative only.

FIGURE 1

2.1 METERING

Despite recent developments, in Morecambe Bay for example, the majority of gas brought on shore in the UK is owned by oil companies. From the oil company's reception terminal the gas is sold to British Gas for onward transmission to British Gas customers.

Where two parties are involved in this matter, the gas is metered with duplicated instrumentation - one set owned and operated by each party. The supplier, bringing the gas onshore will meter the gas for two reasons:

a) To pay the duties owed to the Government on the gas.
b) To charge British Gas for each unit of gas supplied.

This metering is referred to as fiscal metering.

British Gas also meter the received gas using the duplicated instrumentation in order to validate independently the sums of money paid to the supplier. Such metering is called Check Metering.

Where offshore gas storage is used fiscal metering is also required by the Department of Energy to meter the gas pumped offshore and the gas brought back onshore for tax to be paid on any net gas brought onshore.

In all of these cases the volumes passing through metering installations are very large - for example 1.6 million m^3/hour - worth about £100,000/hr at the point of sale and therefore accurate metering is essential - an inaccuracy of a fraction of a percent can represent a considerable financial error between either the supplier and the purchaser or the supplier and the Department of Energy. Consequently the Gas and Oil Measurement Branch of the Department of Energy take an interest in, and lay down standards for, metering installations, actively pursuing compliance.

2.2 THE ORIFICE PLATE

All terminal gas metering installations are based on the orifice plate. The gas passes through the orifice plate causing a temporary differential pressure to occur across the plate due to the flow profile.

This differential pressure is proportional to the square of the flow and hence once all parameters are known, the flow rate of the gas can be computed from the differential pressure across the orifice plate.

To relate the actual flow through the installation to the differential pressure across the orifice plate caused by that flow it is necessary to know the pressure and temperature of the gas, its relative density, dynamic viscosity, molecular weight, density, isentropic exponent as well as the roughness of the pipe and the size of the orifice plate itself.

The differential pressure across the orifice plate, static pressure, relative density and temperature of the gas are constantly measured and the actual values are used in the calculation of flow. On line flow calculations are performed in a dedicated flow computer. The values of other parameters dependent on gas composition are placed in the computer for the calculation of the flow and only altered when a marked change of gas composition occurs.

The relationship between all these variables and the flow is given thus:

$$q_m = \alpha \epsilon \frac{\pi}{4} d^2 \sqrt{2 \Delta p . \rho_1}$$

Where $\epsilon = 1 - (0.41 + 0.35\beta^4)\Delta p/\gamma_S p_1$
and α = flow coefficient
d = diameter of orifice or throat
Δp = differential static pressure across orifice
ρ_1 = upstream gas density
β = ratio of orifice or throat diameter to pipe diameter
γ_S = isentropic exponent
p_1 = upstream gas pressure
q_m = mass rate of flow

The above terms are as defined in ISO 5167.

One of these variables, the subject of this paper, is the isentropic exponent. It can be seen that the flow through the orifice plate is dependent on the isentropic exponent through the expansibility factor.

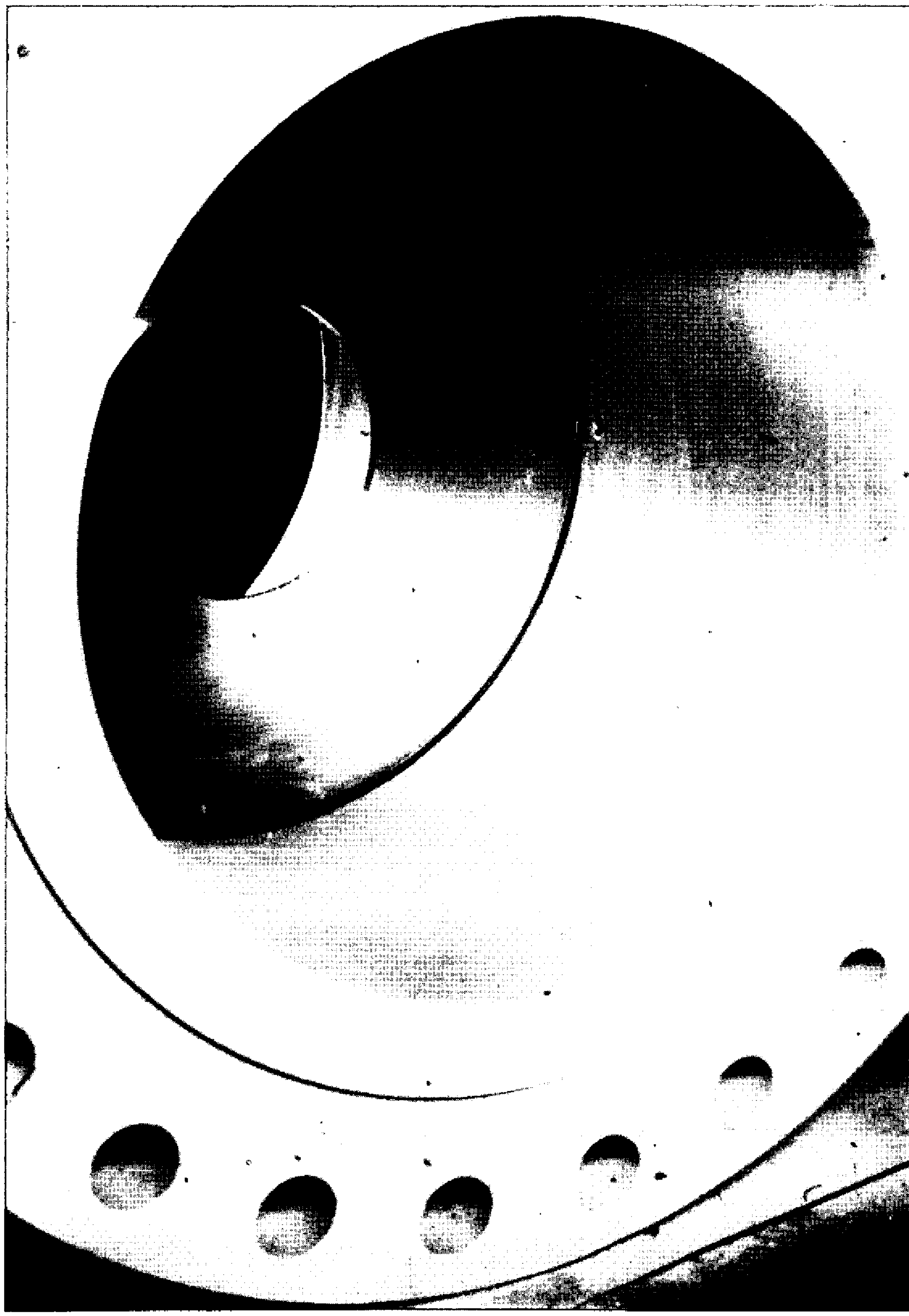


FIGURE 2

AN ORIFICE PLATE

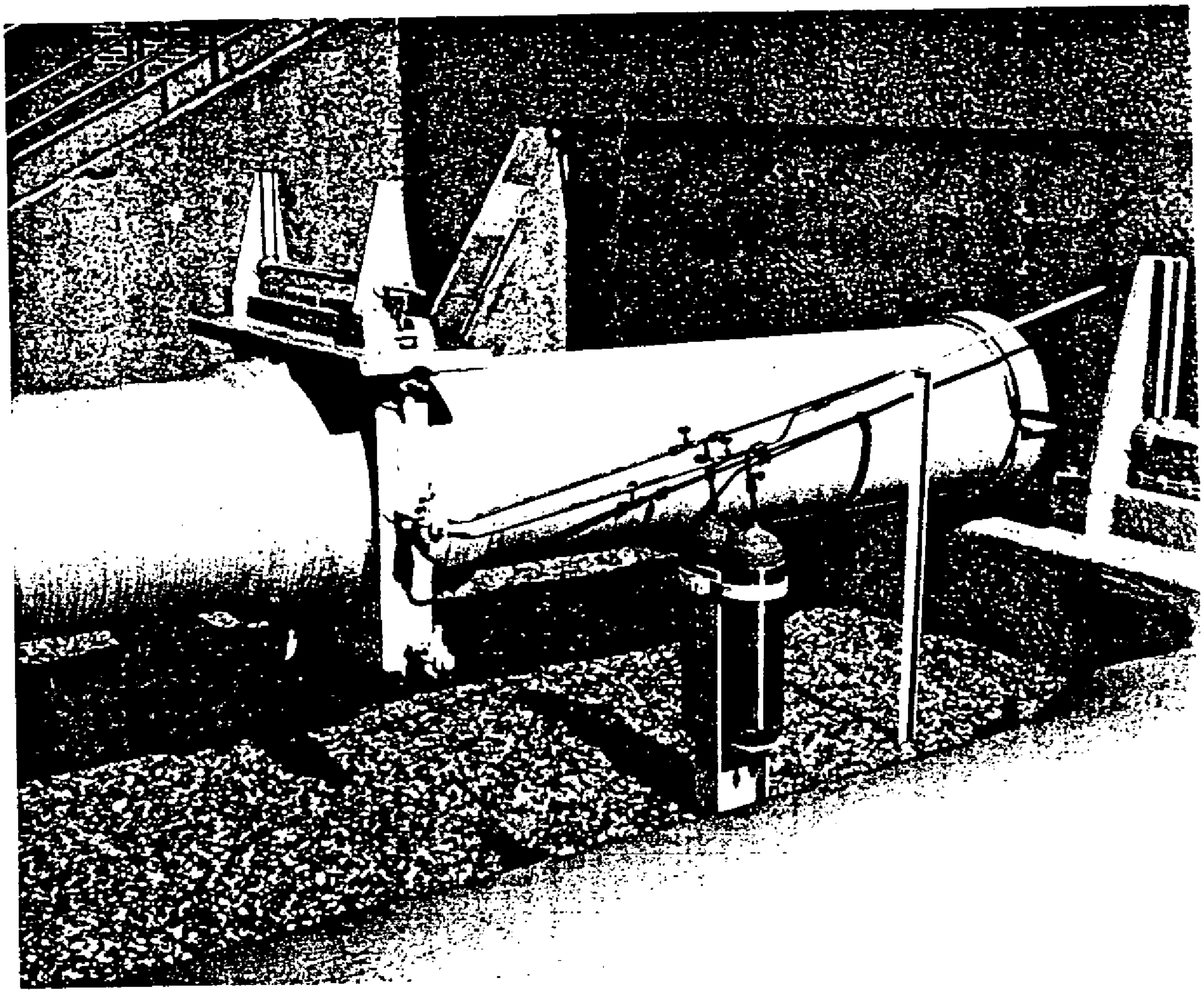


FIGURE 3

ORIFICE PLATE WITH DIFFERENTIAL TAPPINGS

3. THE MOTIVATION TO CALCULATE THE ISENTROPIC EXPONENT

BS 1042 and its International equivalent ISO 5167 state that although the isentropic exponent should be used in the above calculation of flow, it is recognised that there are many gases and vapours for which no values of the isentropic exponent are available. In such a case the standards state that the ratio of the specific heat capacities of the gas may be used in place of the isentropic exponent.

This use of the ratio of specific heat capacities rather than the isentropic exponent is widespread throughout the oil and gas industry. This follows because there is no Department of Energy approved method for the calculation of the isentropic exponent for many fluids and hence, in accordance with the standards, the industry reverts to the use of the ratio of the specific heat capacities. However preliminary calculations (Section 4) of the isentropic exponent for hydrocarbons have found that the exponent differs markedly - typically by 15% from the ratio of the specific heat capacities. This difference is typically equivalent to a 0.05% change in flow, and the financial effect can be very significant with a difference of £150,000 per annum for a typical metering installation.

There is therefore considerable motivation to determine accurately the isentropic exponent of natural gas mixtures within the oil and gas industry.

4. THE CALCULATION OF THE ISENTROPIC EXPONENT

Certain gases over a specific range of temperatures and pressures behave as ideal gases, where their compressibility factors are practically unity. The properties of ideal gases can be determined simply and as a result gases are often treated as if they were ideal gases, ie. their compressibility factors are taken as unity, the errors introduced being small and the advantages in simplifying calculations great. For an ideal gas, the isentropic exponent is simply the ratio of the isobaric specific heat capacity, (the specific heat capacity at constant pressure), Cp, to the isochoric specific heat capacity, (the specific heat capacity at constant volume), Cv. Both can be determined easily and hence the isentropic exponent for an ideal gas is found by a mere division. ISO 5167/BS 1042 allows gas mixtures to be treated as ideal gases if the real isentropic exponent cannot be determined and so the pseudo-isentropic exponent used in flow calculations is $^{Cp}/_{Cv}$, the ratio of specific heat capacities.

However, real gases - the gases met in the oil and gas industry - are not ideal gases, but gases with a non-constant value of compressibility. Therefore there are errors between the ratio of specific heat capacities, $^{Cp}/_{Cv}$, and the isentropic exponent.

To calculate accurately the isentropic exponent for natural gas it is first necessary to drop all assumptions that gas mixtures behave as ideal gases, and consider the mixture as a real gas whose compressibility will change with pressure and temperature.

Following discussions between the Department of Energy and British Gas it was agreed that the basis of all calculations should be the American Petroleum Institute (API) Technical Data Book. This data book contains a substantial selection of procedures for the calculation of a wide range of gas mixture parameters, but does not include a procedural method for determining the isentropic exponent.

British Gas ultimately required a computer program to calculate two parameters:

1) the ratio of specific heat capacities,
2) the isentropic exponent.

The values of the isochoric, Cv and isobaric, Cp, specific heat capacities required in (1) were thought to be necessary in the calculation of the isentropic exponent and thus were to be determined first. These heat capacities are calculated initially by treating the gas, whose properties are required, as an ideal gas and then correcting for pressure and temperature to determine the real gas specific heat capacities. The heat capacities are therefore a function of pressure and temperature for two reasons:

1. The ideal heat capacities are temperature dependent.

2. The density of the gas is a function of pressure and temperature. This affects the molar volume which influences the deviation between the ideal and real heat capacities, even though these properties are specific. ie in units of kJ/kg.K.

In order to obtain the ideal isobaric heat capacity for a mixture, the API Technical Data Book states that the individual component ideal heat capacities are weighted by their weight fractions and summed. The mixture isochoric heat capacity is found from the real mixture isobaric heat capacity.

The basic simplified steps to obtain the specific heat capacities to API procedures are shown in Figure 4.

The calculation of the specific heat capacities achieved the first stage towards the increased accuracy of flow metering as it gave British Gas a more accurate value of the ratio of the specific heat capacities by treating the gas as a real gas mixture and calculating to API procedures.

The next stage was to formulate an algorithm to calculate the isentropic exponent for a real gas mixture. The derivation of the algorithm was required since there is no explicit method for the calculation of the isentropic exponent in the API Technical Data Book. Nevertheless the mandate from the Department of Energy insisted that the final isentropic exponent algorithm should be to API procedures or in accordance with good oilfield practice and thus it was necessary that each term of the final algorithm should be sourced from these procedures. Further the Department of Energy required that the final algorithm should be certified by an independent authority recognised by the Oil and Gas Industry.

Early attempts by British Gas to formulate an algorithm were unsuccessful as literature researched on the subject did not provide a derivation for the isentropic exponent but conveniently skirted around the function merely stating that the exponent was a function of numerous variables. Therefore British Gas approached Professor M.L. McGlashan of University College, London who is a world authority in this field.

Professor McGlashan, in conjunction with British Gas, produced an exhaustive derivation of the isentropic exponent. This derivation forms the first part of Appendix A.

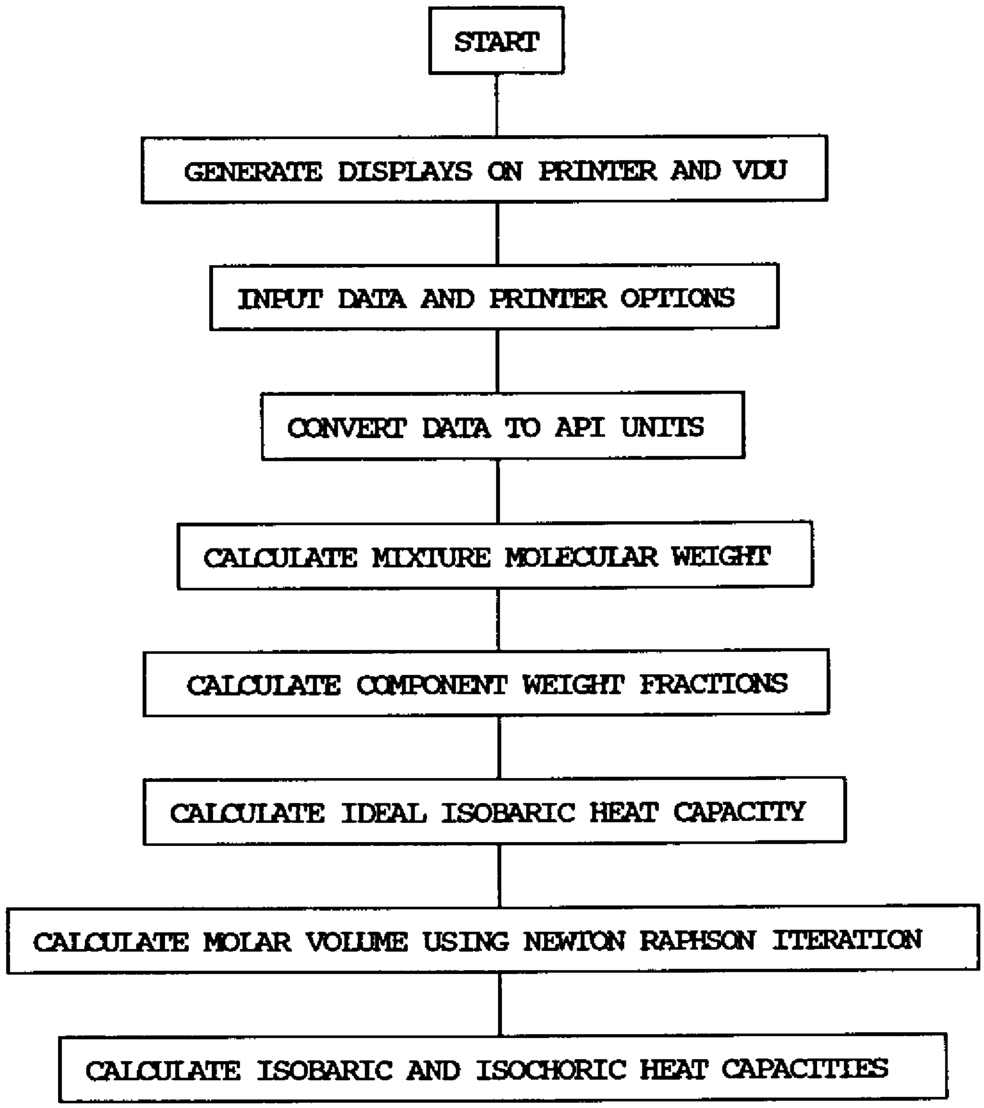


FIGURE 4

THE SIMPLIFIED STEPS TO OBTAIN THE SPECIFIC
HEAT CAPACITIES TO API PROCEDURES

The next aim was to link the terms in this equation to API procedures. Ideally each term in the isentropic exponent equation should be taken straight from an API procedure to satisfy the Department of Energy's requirements.

A further document was then produced linking each term of the isentropic exponent equation to an API procedure, although linking the partial differential terms to API procedures involved detailed analysis. The partial derivatives were available from the API procedures but these derivatives were not of the mixture under analysis but of a heavy reference fluid (octane) and a simple reference fluid. To determine properties of a mixture under analysis, the existing API procedures apply interpolation between the two reference fluid properties. The interpolation is based on the relative acentric factors.

Further work was therefore carried out on these interpolative procedures so that a partial derivative could be determined for the required mixture. As a result the API procedures were fully linked to the isentropic exponent algorithm. In all the analysis no approximations were made and therefore the final derivation of the isentropic exponent is exact.

British Gas are currently writing software titled 'VIPAN II' that will incorporate Professor McGlashan's algorithm, together with procedures employing the API interpolative techniques to determine the partial derivatives required from the API reference fluids. The final algorithm is derived in Appendix A and given in Figure 5.

$$\gamma_s = \frac{-V_m \, . \, C_{p,m}}{p.\left(\frac{\partial V_m}{\partial p}\right)_T . \, C_{p,m} + T.\left(\frac{\partial V_m}{\partial T}\right)_p^2 .p}$$

Where γ_s = Isentropic Exponent
V_m = Molar Volume
p = Pressure
$C_{p,m}$ = Molar Isobaric Heat Capacity
T = Thermodynamic Temperature (Temperature measured on an absolute scale).

Figure 5 - The Isentropic Exponent Algorithm

The accuracy of the final isentropic exponent value is dependent only on the accuracy of the API procedures. The API state that errors between the calculated and experimental specific heat ratios, on which the algorithm is based, rarely exceed two percent except in a critical region where errors in excess of ten percent can occur. This critical region is described within the API documentation and it is found that natural gas metering installation conditions are well outside this region. Strictly the final API procedure employed is only valid for pure hydrocarbon gases. The errors introduced by applying the procedure to Natural Gas Mixtures (which are predominantly methane) are thought to be small and this has been accepted by the Department of Energy.

Once finished, "VIPAN II" will be available for purchase together with the signed documentation prepared by Professor McGlashan. It is then intended that "VIPAN II" will be used to calculate the ratio of specific heat capacities and the isentropic exponent for fiscal metering installations.

5. CONCLUSION

British Gas, with assistance from University College, London, has developed a procedure for calculating the isentropic exponent to API procedures. It has been established that the isentropic exponent can differ markedly from the ratio of specific heat capacities that has hitherto dominated flow equations.

ISO 5167/BS 1042 states that the ratio of specific heat capacities is only to be used when the isentropic exponent is not available and hence the procedure developed has an important consequence for the oil and gas industry as it enables the isentropic exponent to be calculated for a much wider range of gas mixtures.

6. REFERENCES

1. MARRIS, J.H.S. - Matching Supply and Demand - The Operator's View, IGE Communication 1324.
2. BRITISH GAS PLC - Finance and Operating Statistics. Supplement to Annual Report and Accounts 1988.
3. ISO 5167 - Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.
4. BS 1042 Methods of Measurement of fluid flow enclosed conduits. Section 1.1 : 1981 Orifice plates, nozzles and venturi tubes.
5. AMERICAN PETROLEUM INSTITUTE - Technical Data Book - Petroleum Refining. Metric Edition.

7. ACKNOWLEDGMENTS

The author wishes to thank British Gas plc for permission to publish this paper. In particular he would like to thank Rosalind Rowe and other members of the Headquarters Communication and Instrumentation Department for their assistance in its presentation.

APPENDIX A

THE DERIVATION OF THE ISENTROPIC EXPONENT OF A REAL FLUID

Defining the isentropic exponent γ_S by

$$\gamma_S \overset{\text{def}}{=} -(\partial \ln p/\partial \ln V)_S = -(V/p)(\partial p/\partial V)_S, \tag{1}$$

where p denotes pressure, V volume and S entropy, we have, by use of "the rule for changing the variable held constant":

$$\begin{aligned}\gamma_S &= -(V/p)\{(\partial p/\partial V)_T + (\partial p/\partial T)_V(\partial T/\partial V)_S\} \\ &= -(\partial \ln p/\partial \ln V)_T\{1 + (\partial V/\partial p)_T(\partial p/\partial T)_V(\partial T/\partial V)_S\},\end{aligned} \tag{2}$$

where T denotes thermodynamic temperature: and thence by use of "the -1 rule":

$$\gamma_S = -(\partial \ln p/\partial \ln V)_T[1 - \{(\partial V/\partial T)_p/(\partial V/\partial T)_S\}], \tag{3}$$

and by use of "the -1 rule" again:

$$\gamma_S = -(\partial \ln p/\partial \ln V)_T\{1 + (\partial V/\partial T)_p(\partial S/\partial V)_T/(\partial S/\partial T)_V\}, \tag{4}$$

and thence, by use of the Maxwell relation: $(\partial S/\partial V)_T = (\partial p/\partial T)_V$:

$$\gamma_S = -(\partial \ln p/\partial \ln V)_T\{1 + (\partial V/\partial T)_p(\partial p/\partial T)_V/(\partial S/\partial T)_V\}, \tag{5}$$

and by use of "the -1 rule" for a third time:

$$\gamma_S = -(\partial \ln p/\partial \ln V)_T[1 - \{(\partial V/\partial T)_p\}^2/(\partial V/\partial p)_T(\partial S/\partial T)_V], \tag{6}$$

which, by use of the definitions: of the isobaric expansivity $\alpha \stackrel{\text{def}}{=} V^{-1}(\partial V/\partial T)_p$, of the isothermal compressibility $\kappa_T \stackrel{\text{def}}{=} -V^{-1}(\partial V/\partial p)_T$, and of the heat capacity at constant volume $C_V \stackrel{\text{def}}{=} T(\partial S/\partial T)_V$, becomes

$$\gamma_S = -(\partial \ln p/\partial \ln V)_T(1 + T\alpha^2V/\kappa_T C_V), \tag{7}$$

which, by virtue of the exact relation:

$$C_p = C_V + T\alpha^2V/\kappa_T,$$

where $C_p \stackrel{\text{def}}{=} T(\partial S/\partial T)_p$ denotes the heat capacity at constant pressure, can be written in the form;

$$\gamma_S = -(\partial \ln p/\partial \ln V)_T C_p/C_V, \tag{8}$$

$$\gamma_S = -(\partial \ln p/\partial \ln V)_T C_p/(C_p - T\alpha^2V/\kappa_T), \tag{9}$$

$$\gamma_S = C_p/(p\kappa_T C_p - T\alpha^2 pV). \tag{10}$$

Every equation above is exact. Every equation applies exactly to any homogeneous (one-phase) real fluid or fluid mixture. There are no approximations in any of the equations. In particular, none of them assumes that the fluid is a perfect gas, or that it is approximately a perfect gas. The concept of a "perfect gas" is nowhere used in the above derivation.

Substituting for α and κ_T in equation (10) and using equation (2), the isentropic exponent γ_s can be expressed in the exactly equivalent form:

$$\gamma_s = - V_m C_{p,m}/[p(\partial V_m/\partial p)_T C_{p,m} + T\{(\partial V_m/\partial T)_p\}^2 p], \tag{11}$$

where V_m denotes molar volume, T the thermodynamic temperature, p the pressure and $C_{p,m}$ molar heat capacity.

The independent variables are chosen throughout this analysis as T and p together with the (C - 1) independent mole fraction x_i, or the (C - 1) mass fractions w_i, of the C components of the gas mixture.

According to API Technical Data Book 6B1.8-1:

$$z = z^{(0)} + (\omega/\omega^{(h)})(z^{(h)} - z^{(0)}), \tag{12}$$

where

$$z \overset{\text{def}}{=} pV_m/RT, \tag{13}$$

so that

$$V_m = V_m^{(0)} + (\omega/\omega^{(h)})(V_m^{(h)} - V_m^{(0)}). \tag{14}$$

If we can calculate $V_m^{(0)}$ and $V_m^{(h)}$ then, given the recipe (equation API 2-0.2, p.2-1):

$$\omega = \Sigma_{i=1}^{i=C} x_i \omega_i^*, \tag{15}$$

where ω_i^* denotes the acentric factor of the pure substance i and the summation is over the C components of the mixture, and given that $\omega^{(h)} = 0.3978$, we can calculate V_m for any mixture.

It follows from equation (14) that

$$(\partial V_m/\partial p)_T = (\partial V_m^{(0)}/\partial p)_T + (\omega/\omega^{(h)})\{(\partial V_m^{(h)}/\partial p)_T - (\partial V_m^{(0)}/\partial p)_T\}, \quad (16)$$

and

$$(\partial V_m/\partial T)_p = (\partial V_m^{(0)}/\partial T)_p + (\omega/\omega^{(h)})\{(\partial V_m^{(h)}/\partial T)_p - (\partial V_m^{(0)}/\partial T)_p\}, \quad (17)$$

so that if we can calculate $(\partial V_m^{(0)}/\partial p)_T$, $(\partial V_m^{(h)}/\partial p)_T)_p$, $(\partial V_m^{(0)}/\partial T)_p$, and $(\partial V_m^{(h)}/\partial T)_p$ then we can calculate $(\partial V_m/\partial p)_T$ and $(\partial V_m/\partial T)_p$ for any mixture.

According to API 6B1.8-2

$$z^{(i)} = f(V_r^{(i)}, T_r) = f(p_c V_m^{(i)}/RT_c, T/T_c), \quad (18)$$

so that

$$p = (RT/V_m^{(i)}) f(p_c V_m^{(i)}/RT_c, T/T_c). \quad (19)$$

Writing the function f explicitly we then obtain

$$\begin{aligned} p = {} & RTV_m^{(i)-1} \\ & +(b_1T - b_2T_c - b_3T_c^2T^{-1} - b_4T_c^3T^{-2})(R^2T_cp_c^{-1}V_m^{(i)-2}) \\ & +(c_1T - c_2T_c + c_3T_c^3T^{-2})(R^3T_c^2p_c^{-2}V_m^{(i)-3}) \\ & +(d_1T + d_2T_c)(R^6T_c^5p_c^{-5}V_m^{(i)-6}) \\ & +c_4\beta(R^3T_c^5p_c^{-2}V_m^{(i)-3}T^{-2})\exp(-\gamma R^2T_c^2p_c^{-2}V_m^{(i)-2}) \\ & +c_4\gamma(R^5T_c^7p_c^{-4}V_m^{(i)-5}T^{-2})\exp(-\gamma R^2T_c^2p_c^{-2}V_m^{(i)-2}), \end{aligned} \quad (20)$$

where the parameters b_1, b_2, b_3, b_4, c_1, c_2, c_3, c_4, d_1, d_2, β, and γ are displayed on API p.6-75 for "the simple fluid" $i = 0$, and for "the heavy referenc

By differentiation of (20) with respect to $V_m^{(i)}$ at constant T it follows that

$$(\partial p/\partial V_m^{(i)})_T = -RTV_m^{(i)-2}$$
$$- 2(b_1T - b_2T_c - b_3T_c^2T^{-1} - b_4T_c^3T^{-2})(R^2T_cp_c^{-1}V_m^{(i)-3})$$
$$- 3(c_1T - c_2T_c + c_3T_c^3T^{-2})(R^3T_c^2p_c^{-2}V_m^{(i)-4})$$
$$- 6(d_1T + d_2T_c)(R^6T_c^5p_c^{-5}V_m^{(i)-7})$$
$$- 3c_4\beta(R^3T_c^5p_c^{-2}V_m^{(i)-4}T^{-2})\exp(-\gamma R^2T_c^2p_c^{-2}V_m^{(i)-2})$$
$$- 5c_4\gamma(R^5T_c^7p_c^{-4}V_m^{(i)-6}T^{-2})\exp(-\gamma R^2T_c^2p_c^{-2}V_m^{(i)-2})$$
$$+2c_4\gamma(R^5T_c^7p_c^{-4}V_m^{(i)-6}T^{-2})(\beta +$$
$$\gamma R^2T_c^2p_c^{-2}V_m^{(i)-2})\exp(-\gamma R^2T_c^2p_c^{-2}V_m^{(i)-2}) \qquad (21)$$

and by differentiation of (20) with respect to T at constant $V_m^{(i)}$ it follows that

$$(\partial p/\partial T)_{V_m^{(i)}} = RV_m^{(i)-1}$$
$$+ (b_1 + b_3T_c^2T^{-2} + 2b_4T_c^3T^{-3})(R^2T_cp_c^{-1}V_m^{(i)-2})$$
$$+ (c_1 - 2c_3T_c^3T^{-3})(R^3T_c^2p_c^{-2}V_m^{(i)-3})$$
$$+ d_1(R^6T_c^5p_c^{-5}V_m^{(i)-6})$$
$$- 2c_4(R^3T_c^5p_c^{-2}V_m^{(i)-3}T^{-3})(\beta +$$
$$\gamma R^2T_c^2p_c^{-2}V_m^{(i)-2})\exp(-\gamma R^2T_c^{(i)2}p_c^{(i)-2}V_m^{(i)-2}), \qquad (22)$$

from which $(\partial p/\partial V_m^{(i)})_T$ and $(\partial p/\partial T)_{V_m^{(i)}}$ can

be calculated for $i = 0$ and for $i = h$ given the same information as was used to calculate $V_m^{(0)}$ and $V_m^{(h)}$, and the values of $V_m^{(0)}$ and $V_m^{(h)}$.

Given that

$(\partial V_m^{(i)}/\partial T)_p = -(\partial p/\partial T)V_m^{(i)}/(\partial p/\partial V_m^{(i)})_T,$

and that

$(\partial V_m^{(i)}/\partial p)_T = \{(\partial p/\partial V_m^{(i)})_T\}^{-1},$

we can use (21) and (22) to calculate $(\partial V_m^{(0)}/\partial p)_T$, $(\partial V_m^{(h)}/\partial p)_T$, $(\partial V_m^{(0)}/\partial T)_p$, and $(\partial V_m^{(h)}/\partial T)_p$.

We can then use (16) and (17) to calculate $(\partial V_m/\partial p)_T$ and $(\partial V_m/\partial T)_p$ for our mixture.

Hence, using these and the existing API procedures, the isentropic exponent can be calculated using equation (11).

Main Index

A NEW MASS FLOWMETER AND ITS APPLICATION TO CRUDE OIL METERING

by

J Stansfeld and I Atkinson
Schlumberger Industries
and
G Washington
Shell International Petroleum Company

Paper 2.1

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

A NEW MASS FLOW METER AND ITS APPLICATION TO CRUDE OIL METERING

J. Stansfeld, I. Atkinson

Schlumberger Industries-Transducer Division, Farnborough.

G. Washington

Koninklijke/Shell Exploratie En Produktie Laboratorium,
The Netherlands.

S U M M A R Y

The paper describes a new mass flow meter development by Schlumberger in collaboration with Shell aimed at crude oil metering. The meter is based on the Coriolis principle and is unique in that the flow path is a single straight tube. This is particularly advantageous in the measurement of crude oils which contain erosive sand particles, scale or wax. The current meter is for liquid/liquid mixtures whether clean or not.

The accurate determination of density also means that the instrument can be used directly as a net-oil meter in liquid/liquid flow without additional mixing or the usual sampling problems.

1 INTRODUCTION

Today, in the oil industry, there are two trends that are promoting the development of accurate and robust mass flow meters: the reduction in field size and the trend towards accounting in mass terms. Both these factors increase the need for a flow meter capable of accurately metering the flows near the wellheads in an oil production station. Traditional flow measurements require fluids that are cleaner than those anticipated from the future production stations and few instruments have been engineered with this application in mind. The mass flow meter development by Schlumberger in collaboration with Shell is aimed ultimately at this environment. The meter is based on the Coriolis principle, and is unique in that the fluid flow path is a single straight tube. This is particularly advantageous in the measurement of crude oils which contain erosive sand particles, scale or wax.

The current meter is for liquid/liquid mixtures whether clean or not. It provides both accurate mass flow metering and density measurement making it uniquely suitable for the net-oil measurement of wet crudes.

2 THE APPLICATION

Traditionally mass flow has been measured by combining a density measurement with either a volume or a differential pressure measurement. With these methods, it is impossible to measure crude-oil flow accurately near the wellhead since they require clean, single phase fluids of well-known, or easily measurable properties. The future smaller production stations, will not have the facilities to produce clean single-phase fluids. Therefore, there is a need to develop a meter that does not require an accurate knowledge of the fluid properties and that tolerates both non-homogeneous mixtures of oil and water and small amounts of entrained solids.

An obvious contender is a Coriolis-based mass flow meter because, in principle, this measures true mass flow independently of fluid properties. A number of these instruments are now available each with different configurations which benefit particular applications. All are similar however, in that they either have split flow paths and/or bends that need relatively high fluid velocities. These characteristics coupled with the need to use thin-walled tubing are drawbacks for measuring the flow of wellhead crude-oil which will contain erosive particles.

The Schlumberger meter has no bends and is suitable for use with liquid/liquid phases whether homogeneously mixed or not. It is the first stage of a joint Shell/Schlumberger development programme aimed at the accurate measurement of flow near the wellhead.

The meter is particularly suitable for measuring net-oil because it also provides an accurate measurement of fluid density. This eliminates all the sampling problems normally associated with this measurement. The computation of net-oil flow from density and mass flow are included in the mass flow computer. Thus a single instrument can make the complete net-oil measurement.

3 GENERAL DESCRIPTION

The mass flow meter (7860) consists of a hermetically sealed housing containing the sensing element which is a straight tube approximately 50 mm in diameter and which vibrates in a lateral mode at its resonant frequency.

As fluid passes through the tube, Coriolis forces produce a phase difference between the vibration at one point in the tube with respect to another. This phase difference divided by the resonant frequency is directly related to the mass flow rate. In addition, a measurement of the resonant frequency provides an accurate determination of the fluid density.

The sensing element is manufactured from a highly stable steel (Ni Span C) which provides good instrument stability for both the mass flow and density measurements. In order to prevent external forces from influencing the vibration pattern, the sensing tube is coupled to the housing and process pipework via flexible couplings.

Sensitive electromagnetic detectors monitor the vibrations of the tube with their signals being fed to a special signal processor. For accurate measurements under noisy pipeline conditions, the dedicated flow computer (7960) subjects the input signals to comprehensive digital filtering techniques. In addition to mass flow rate, this electronic unit also generates values for density and flow totals in both mass and volume units.

4 THEORY OF OPERATION

The sensing element consists of a simple straight tube, vibrating in a lateral manner at its natural resonant frequency. Consider a tube A-B vibrating in the fundamental lateral mode as shown in Figure 1. Let the tube vibrate in an upwards direction; with no fluid flow the tube is displaced symmetrically about the line CD. Sensors (of displacement, velocity or acceleration) positioned at X and Y will monitor signals that are in phase.

Now consider fluid flowing through the tube with a velocity V, and let us examine the forces on the tube due to this flow. The Coriolis force, Fc, on a body of mass M, is defined as

$$Fc = 2M\omega V \qquad (1)$$

where ω = the angular rotation velocity and the force acts in a direction perpendicular to the plane containing the velocity vector V and the angular velocity vector ω .

Consider the forces on the tube due to a small element flowing at position X. This element rotates anti-clockwise about A, with an angular velocity ω , where

$$\omega = 2\Pi F \qquad (2)$$

where F = the resonant frequency of the tube.

Combining this angular velocity, ω , and the fluid velocity, V, results in a Coriolis force acting in an upwards direction. Now consider an element at position Y. The element now rotates clockwise about B; this results in a Coriolis force acting in a downwards direction. The net result of these additional forces due to the fluid velocity is that the tube displacement is no longer symmetrical about line CD but is asymmetric. This asymmetry manifests itself as a phase difference between the sensors at X and Y.

Furthermore, the phase difference, which is a measure of the asymmetry of the Coriolis force along the pipe is proportional to the mass flow rate (MV) multiplied by the angular velocity ($2 \pi F$).

In reality the situation is more complex than in this simplified model. Sophisticated mathematical models of the instrument have been developed which correlate very well with experimental results.

5 CONCLUSIONS

The Schlumberger mass flow meter development enables simple and accurate metering to be moved nearer the wellhead. The straight through configuration makes it particularly suitable for applications where the bends and thin wall tubing of most Coriolis meters are a drawback. The accurate determination of density also means that the instrument can be used directly as a net-oil meter in liquid/liquid flow without additional mixing or the usual sampling problems.

****APPENDIX****

SPECIFICATION

The specifications of the instrument are as follows:-

MASS FLOW SENSOR 7860

A sensor for liquid/liquid mixtures

Flow rate	100 metric tonnes/h
Pressure Drop	2 bar maximum
Turndown	10:1
Pressure	150 bar maximum
Temperature Range	0 - 100 Deg.C
Length	2100 mm
Weight	95 kg
Materials	Suitable for oil pipeline services
Wetted Parts	Ni Span C, 316 Stainless Steel
Safety	Zone 1, Gases IIB, Temp. T4

SIGNAL PROCESSOR 7960

Mounting	Panel Mount
Weight	4 kg

Surface Mount Technology

Maximum Distance from Meter	250 m
INPUTS	
Mass Flow	2
User Selectable (Analogue)	4 3 4-20 mA, 1 PRT
Status	4
OUTPUTS	
Analogue	3
Pulse (User Selectable)	4
Status/Alarms	4
COMMUNICATIONS	
Number of Lines	2
Port 1	RS 232C
Port 2	RS 232C or RS 485
Bi-directional	
INTERNAL TOTALISERS	4

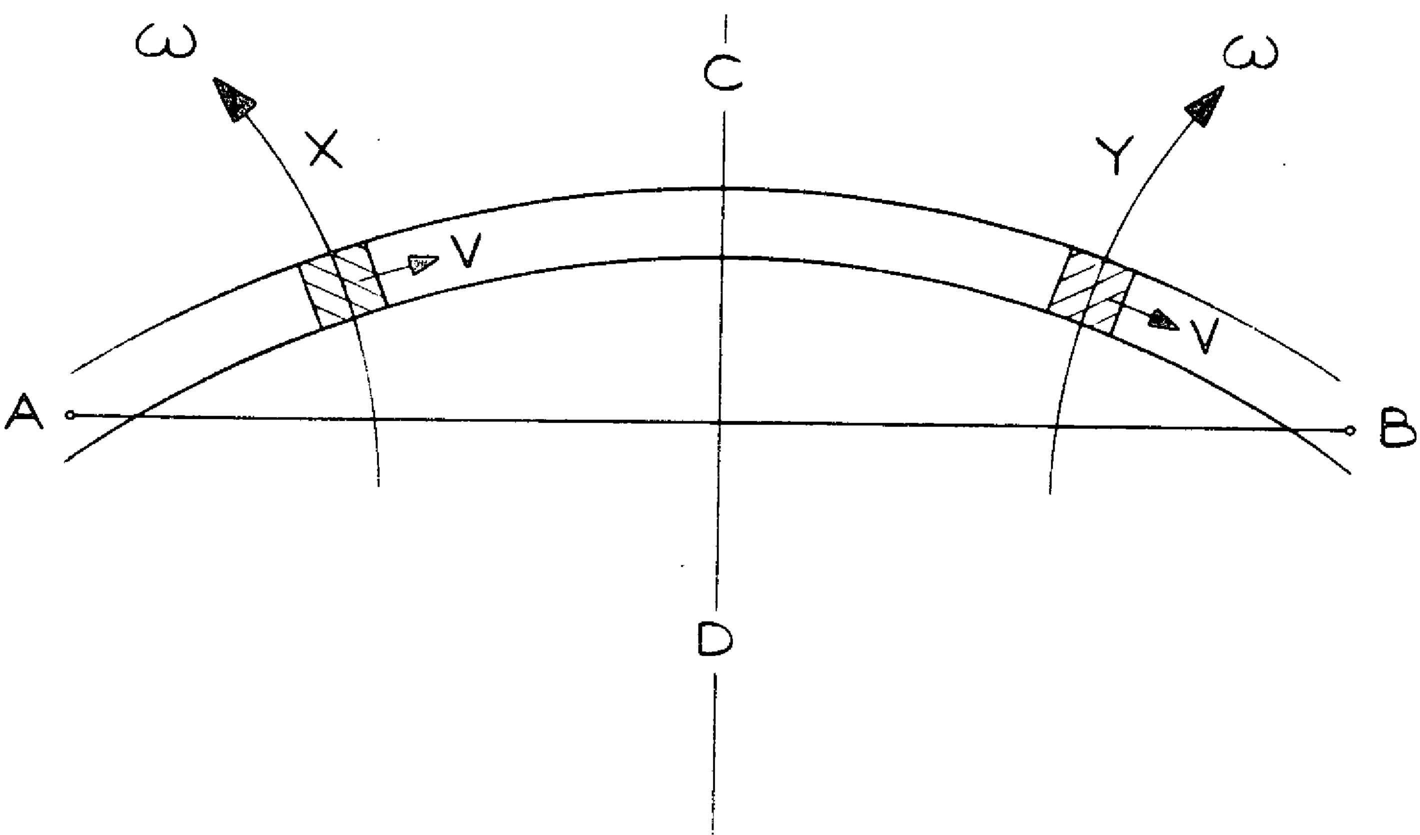


FIGURE 1: SCHEMATIC DIAGRAM OF VIBRATING TUBE

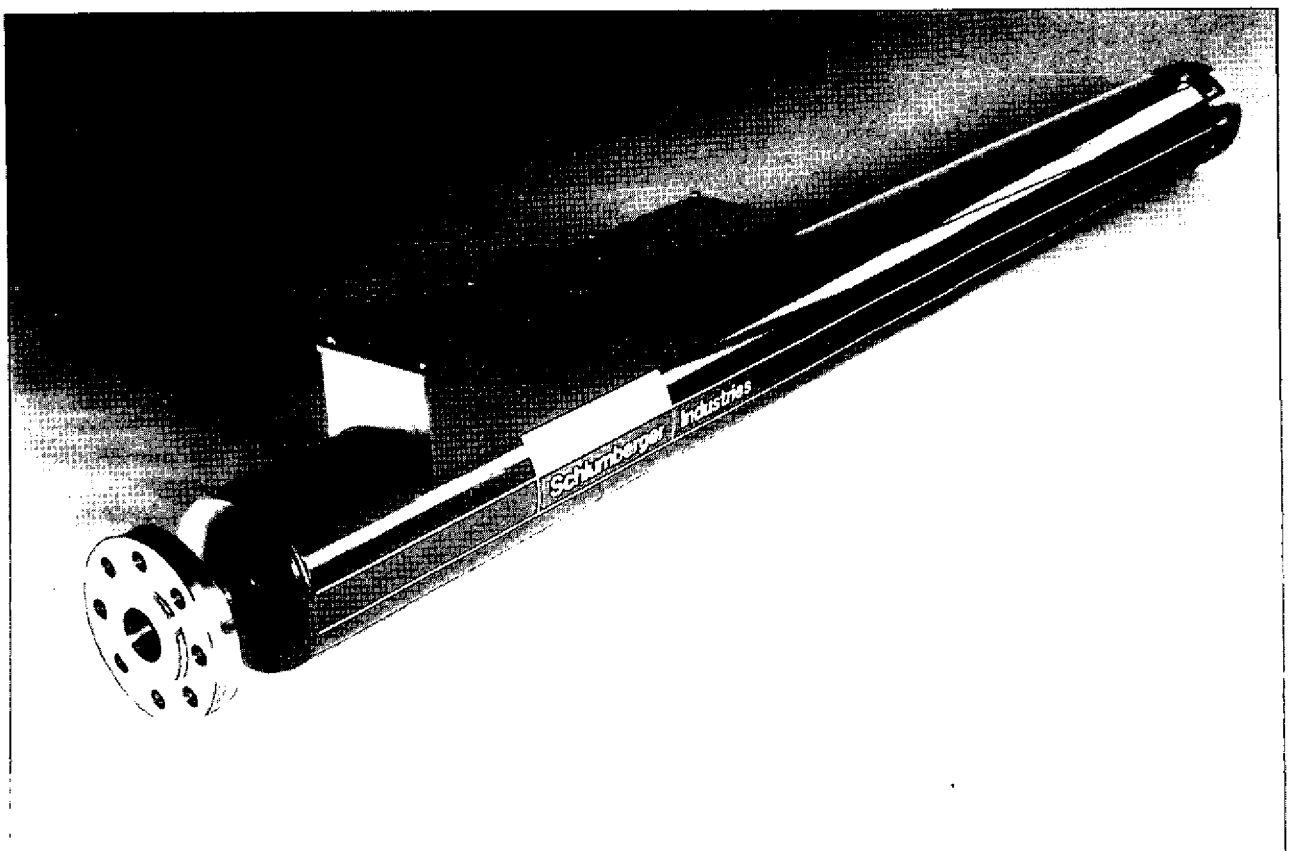


FIGURE 2: 7860 MASS FLOW METER

Main Index

ULTRASONIC FLOWMETERS FOR THE GAS INDUSTRY

by

M E Nolan and J G O'Hair
British Gas

Paper 2.2

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

ULTRASONIC FLOWMETERS FOR THE GAS INDUSTRY

M E Nolan and J G O'Hair

British Gas, London Research Station, London SW6 2AD.

R J W Peters

Daniel Industries Ltd., Larbert, Scotland.

S U M M A R Y

This paper describes the latest developments in the design, manufacture and operation of a multipath ultrasonic flowmeter. A number of meters have been in operational use on British Gas sites for several years now, and the experience gained during this time is reported.

Development has reached the stage where a commercial version of the meter is being manufactured. Performance tests of such a meter have been carried out on the British Gas Test Site, and the results of these tests are also reported. Plans for further developments of the meter are also described.

1 INTRODUCTION

A few years ago, British Gas reviewed all possible methods of metering large, high pressure, gas flows, such as occur in the National transmission system. It was apparent that, for a meter to have significant advantages over the widely used orifice plate meter, it should have similar (or better) accuracy, a higher turn-down ratio, simpler (and therefore cheaper) installation requirements and should have negligible pressure drop. An ultrasonic meter seemed the most likely type of meter to meet these requirements.

Evaluation of the established techniques, which had been developed primarily for liquid metering, indicated that a transit time technique would be the most suitable for accurate measurement. The theory of such meters has been included in previous papers(1,2), where the velocity of the gas (V) is shown to be given by the simple equation

$$V = L^2(T_2 - T_1)/ 2 X T_2 T_1 \quad \ldots\ldots (1)$$

where
T_2 is the transit time of the pulse travelling against the flow,
T_1 is the transit time of the pulse travelling with the flow,
and L and X are geometrical constants of the meter as shown in figure 1. This figure also shows, schematically, the positioning of the ultrasonic transducers, which act as both transmitters and receivers, with respect to the pipework or spoolpiece.

2 PRELIMINARY INVESTIGATIONS

2.1 Theoretical studies.

Though equation (1) is exact, and involves only measureable quantities, it gives only the mean velocity of gas in the section of pipe between the two transducers, not the mean velocity in the whole of the pipe. It is possible, in a fully developed turbulent flow, to relate a velocity measured across a diameter of the pipe to the required mean velocity. However, since one of the requirements was that the meter should have simple installation requirements i.e. no need for long straight lengths of pipe upstream of the meter, this option was discarded. It has since been our experience that, even in ideal metering installations, the expected, symmetrical flow distributions rarely exist, particularly so for low flows.

One method of obtaining a satisfactory value for the mean flow, even in disturbed distributions, is to make velocity measurements on several parallel chords spaced across the pipe. This enables a numerical integration technique to be used to compute the mean flow through the pipe. The accuracy of this integration is greatest if the chords are spaced as defined by the numerical technique used[3]. Also, the more chords the greater the accuracy.

Computer simulation of this integration technique was carried out using a number of mathematically defined flow distributions. Some of these were the standard symmetrical profiles, others were highly distorted. The conclusion was that, with four chords, the integration was unlikely to contribute errors which exceeded 0.5%. The use of five chords gave only a small improvement in accuracy whereas the use of only three chords gave a significant deterioration. We therefore decided to construct a four-path ultrasonic flowmeter and evaluate its performance.

2.2 Experimental Investigations.

The first meter to be thoroughly tested was 150 mm in diameter. The results of these tests have been reported in detail in earlier papers[1,2,4]. The conclusions were that the accuracy of the metering in fully developed flows was good and that, in highly disturbed flows, the integration technique performed with the predicted accuracy.

This same meter was later operated for 8 months in series with an orifice plate meter on an offtake station of the transmission system. There were no major problems, and the experience was used to guide the design of improved versions of the meter.

A number of meters, ranging in size from 100 mm to 1050 mm diameter, were manufactured and installed on British Gas sites. These sites were chosen to cover a wide range of operating conditions and our experiences are summarised in table 1 and described in the following section.

Where possible, each meter was tested on the British Gas test site at Bishop Auckland prior to installation on the operational site. The reference meters on the test site are turbine meters which have been calibrated against critical flow nozzles, themselves calibrated by NEL. The accuracy of the reference metering is within the range +0.5% to -0.7%. It is described further in reference (5).

Comparison against the reference meters is confined to primary metering i.e. to actual flows. Conversion to standard conditions can be by either of the commonly used methods, namely the measurement of density, or of pressure and temperature. The computations required to convert to standard conditions are carried out within the ultrasonic meter's microcomputer.

It is perhaps worth re-emphasing that the calibration of each ultrasonic meter is obtained from the measurements of the spool dimensions during manufacture. Comparisons with a reference meter serve to verify the principle of the meter and establish the accuracy of measurement. The data so gathered should assist in the writing of a recognised standard for the operation of ultrasonic meters.

3 OPERATIONAL EXPERIENCES

In general, all meters were designed to operate over the temperature range of -10 to +50 ^{o}C, and over the pressure range from 35 to 75 bars, though one meter has been designed to operate at pressures up to 240 bars. The meters are basically similar, except for the very high pressure meter, and except for the fact that meters of 300 mm diameter and above incorporate a ball valve for each transducer, enabling each one to be independently isolated from the high pressure gas and removed for inspection or replacement.

3.1 A Meter on an Offtake Station (Pressure Reduction Station).

The first meter to be installed on an operational site was 300 mm diameter and was used on an offtake station near Cambridge to replace an ageing orifice plate meter.

Prior to installation on site the meter was tested at the Bishop Auckland test site. The results are shown in figure 2, from which it can be seen that the measurement accuracy, over the range from 340 to 4000 acm/h, is well within the specification of ± 1% of actual flow.

After installation on site a further test of its accuracy was arranged as part of the meter validation procedure. A radio-tracer technique was used as a check of the primary metering accuracy, the results of which are shown in Table 2. The agreement is well within the combined uncertainty of the two methods.

The meter has been operational on this site since November 1984. It was initially set to measure flows up to 85,000 scm/h, but the computer has been reprogrammed to scale the analogue output for a maximum flow of 113,00 scm/h. Since installation, there have been very few problems with the meter, and all have been minor faults, namely a poor solder joint on the back-plane bus, an integrated circuit which failed, and a mechanical relay (used to provide voltage free contacts for a remote flow totaliser) which also failed.

3.2 A Meter Measuring Compressor Station Flow

There are special problems in selecting meters for use on compressor stations where accurate flow measurement is required to optimise efficient use of the compressors. British Gas has used elbow meters, which have low accuracy and limited turn-down ratio, or orifice plate meters which, because of the associated pressure drop, result in an increase in the fuel consumption of the compressors. The ultrasonic meter should provide a better alternative since it has no pressure loss and it has a high accuracy, the calibration being defined by the geometrical measurement of the meter section.

An ultrasonic flowmeter was installed, for the first time at a compressor station, in December 1984. This meter was too large (1050 mm diameter) for it to be tested on the test site prior to installation on the compressor site. However, as part of the compressor performance trials carried out in March 1985, some flows were measured using the radio-tracer technique and comparisons made with measurements using the ultrasonic meter.

The results of these comparisons are shown in table 3. The precision of the radio-tracer measurements was degraded slightly by the site conditions. The presence of a Tee-junction with a closed leg and the build-up of background radiation due to gas recirculation round the site, made the pulse of radiation more difficult to detect and time accurately. None-the-less, all the ultrasonic meter measurements agreed within the uncertainty of the radio-tracer measurements.

This performance evaluation showed that the meter measured over the normal operating range of the unit, but this particular compressor has not run very frequently, so it has been difficult to monitor the performance of the meter since then. There have been few problems with the equipment, but the signal processing has been improved and new, more sensitive, transducers have been fitted to improve performance at high flows. During recent visits to the site whilst the compressor was being tested, the meter was observed to be working properly with a flow of 2.34×10^6 scm/h (full scale is set at 2.5×10^6 scm/h) though this high flow could only be maintained for a short while following start-up of the compressor.

3.3 Meters Measuring Fuel Flow to a Compressor

Two 100 mm diameter meters were manufactured to measure the fuel flow to two compressor units. Both meters were tested at the Bishop Auckland test site prior to installation on the compressor station. The results of these tests are shown in figure 3 where it can be seen that agreement with the reference meters is always within the nominal ± 1% error band and for 23 of the 26 points, the difference is less than 0.5%.

The two meters are each ranged to measure flows up to 7595 scm/h. They were commissioned on site during November 1985, and have been operational virtually continuously since then. Transducers have had to be exchanged on two occasions since then, but the improvements to the transducer construction, described in the next section, are designed to obviate any further problems. The only other faults that have occurred have been the failure of an integrated circuit (an A to D converter in one of the analogue input circuits), a broken solder joint, and an electrical connector which was accidentally damaged. All these faults were very minor and were easily and quickly rectified.

3.4 Meter Measuring Flows to and from a Storage Facility.

A 150 mm diameter meter has been installed on a salt cavity storage site. The ultrasonic meter is particularly suited to such applications since it is bidirectional. This meter was designed for use at pressures from 90 bar up to 240 bar (class 2500) and to measure flows up to 3,500 scm/h. This particular application presented us with conditions we had not encountered before, and necessitated some mechanical modifications, described below.

Laboratory tests indicated that the performace of the existing transducers often deteriorated after pressure cycling tests up to the required operating pressure. The design was therefore improved, and all transducers are now manufactured to this new design. This means that their use at the more normal pressure of typically 70 bar is well within their design capability.

This meter was also tested at the Bishop Auckland test site, though only at a pressure of 70 bar, the maximum pressure available on the site. The results of these tests are shown in figure 4. It can be seen that, over the flow range tested, which was 1 to 32 m/sec, the difference between the ultrasonic meter and the reference meter was within ±0.4%.

The meter was installed on site in the summer of 1986. It was a while before the meter was used, and it was then very soon discovered that it was not operating properly. When the transducers were removed for inspection it was discovered that the acoustic interface between the crystal and the gas had been chemically attacked by something in the pipeline. Though we have not ascertained the cause of this trouble it is possible that liquid methanol was responsible. This required another change to the transducer design to incorporate a metal interface.

These new transducers were installed on site in the summer of 1987. Another problem was immediately apparent when gas began to flow out of the cavity. This was caused by a very heavy grease in the pipe, probably originating from the pipework at the head of the storage cavity, which quite quickly blocked the lower transducer ports, reducing the signal size considerably. This problem was solved by filling the associated pipework with methanol for a while to disolve the grease, and then flowing gas through to clear the grease from the system. The meter has since operated without any problems.

It is worth noting that, with many metering systems, the presence of this grease may have gone undetected and metering errors would have resulted. Also, the introduction of liquid methanol into the pipe section to clear out the grease served as a good test of the resistance of the new transducers to chemical attack.

4 RECENT DEVELOPMENTS

A modified design of the meter has recently been produced by the manufacturer. The transducers and drive circuits, though redesigned for ease of manufacter, are similar to those used in the batch of meters manufactured by British Gas for use on operational sites. The computer has undergone a more significant redesign, and now incorporates an integral display screen.

A 300 mm meter has been manufactured to this design and is being subjected to a rigorous program of testing. In particular, a series of tests were performed at the British Gas test site. The results of these are shown in figure 5. In developed flows the accuracy was well within the ±1% band throughout the range of flows from 76 acm/h to 6,500 acm/h.

Such performance in developed flows is not unexpected. Much more satisfying are the results obtained during measurements in the highly disturbed flows created when a partial blockage was mounted upstream of the meter. The blockages used, referred to as half-moon or quarter-moon plates, are shown in figure 6. They were installed 6 D and 10 D from the meter and with the orientations shown in the figure.

Figure 5 shows 57 comparisons between the reference metering and the ultrasonic meter reading with the disturbance plates installed. Of these, only one indicated a difference exceeding 1% and that, being the first of three readings at a new flowrate, may have been taken before the conditions had stabilised properly. The difference on all but three of the other readings was less than 0.8%.

The very high level of disturbance generated in the flow by these plates is shown in figure 6. The individual velocity measurements (V_i) made on each of the four chords ($i = 1$ to 4) have been represented schematically in this figure. They are shown as a ratio to the mean flow velocity ($\overline{V}$). Compared with the distribution in a fully developed flow, which can be seen to be virtually symmetrical, the distribution is highly distorted when the plates are installed either 6 or 10 diameters upstream.

In the cases where the plate, either quarter-moon or half-moon, was installed such that it blocked the top half of the pipe, the flow distribution, at both 6D and 10D distances, revealed that the flow was greatest in the top half of the pipe. This seems to suggest that the gas, having passed through the bottom half of the plate, tends to readjust so much that it over-compensates for the effect of the disturbance.

We also carried out tests in an extreme condition, with the half-moon plate located at the meter flange (1.5 D distant) blocking off the top half of the pipe (see figure 6). This gave a large negative flow in the top half of the meter, as the gas apparently swirled around behind the plate, and a very large flow through the bottom of the meter, almost three times the mean velocity on the bottom chord. Note the change of scale from previous figures for the figure representing this profile.

In this extreme condition the difference between the reference meter and the ultrasonic meter was still less than 2% for each of the three measurements at that flow, an amazingly good accuracy for such a distorted flow profile. Of course, with such large flows through the bottom half of the meter compared with the mean flowrate, the maximum measureable mean flow was much less than normal. We would not recommend the meter be installed and operated in conditions such as this, but the test serves to prove how well the meter can perform in the most extreme of conditions.

5 PROPOSED FUTURE ENHANCEMENTS

The most recent design, described in section 4, incorporates many improvements to the earlier British Gas design, though it is fundamentally similar. The present design requires a custom Flow Computer Unit which is discretely connected to a custom Transducer Drive Unit. Several disadvantages exist with this concept; a Flow Computer must always be provided, tailored to customer requirements; all flow measurements must be carried out by a single microprocessor in the Flow Computer while the same microprocessor is performing several other tasks; and the Drive Unit must be physically situated close to the Flow Computer due to the discrete connections between the two units.

Several enhancements have been identified to the present design which is seen as a two phase product development (see figure 7). The first phase would be to introduce intelligence into the Drive Unit and to comply with an industry standard form of communications protocol between the Flow Computer and the Drive Unit. The Drive Unit would still, as in the present design, require an intrinsically safe circuit to drive the transducers over an appropriate cable. The Drive Unit would be able to measure flow and carry out error checking on the measurements before communicating this information on the standard serial communications bus to any form of flow computer configured to accept this data.

The second phase of the development would be to remove all the intrinsically safe aspects of the circuits in the drive unit and place all the electronics in an explosion proof and/or sub-sea enclosure. This enclosure would then be mounted on the spool piece and would become, effectively, a "smart transducer". The same standard communications would be used to transfer up-to-the-minute flow data to a supervisory process control computer.

The first phase of the design would take into account any environmental conditions required for the second design phase. Therefore the two designs would be electrically similar; the main difference being in the more stringent mechanical and environmental requirements of the Explosion Proof version.

6 CONCLUSIONS

We have now obtained, after several years of development, a substantial body of operating experience for the four-path ultrasonic meter. We have established that the meter is very reliable, that it is accurate and that it maintains its accuracy well, even in very disturbed flow conditions. Most of our experience has been with the chords arranged in a "criss-cross" configuration, as described in our earlier papers[1,2]. This has been shown to give good cancellation of errors due to cross-flows or to swirl.

6.1 Information for the Operator

Like all other flowmetering techniques, the four-path ultrasonic meter is more suited to some applications than to others. Unlike most other techniques, an operator should always be able to tell when the primary flow measurements are not correct. This is possible because the operator can access a number of parameters and can compare values on each of the four measuring paths. Some examples of this are given below.

(a) Unreliable measurements on one or more paths due to weak signals or due to a high noise level, are easily recognised by the high percentage of rejected readings.

(b) Severely disturbed flow profiles are revealed by observing the measured velocities on each of the four chords. On the offtake station described in section 3.1 we found that a substantial amount of swirl was generated by the header arrangement and that the direction of swirl could be altered according to where the gas entered the header tube, i.e. according to which of the three filters were being used. The level of swirl present was not sufficient to affect the accuracy of the ultrasonic meter, but would have affected the accuracy of many other types of meter.

(c) Incorrect triggering, or variation in gas temperature across the pipe, can be observed as a change in the velocity of sound, which should be the same on all four chords when the meter is functioning correctly.

Other useful information can be obtained from the measurement of the velocity of sound. Variations in the velocity of sound at a constant, or known, temperature and pressure are related to the gas composition and may be used to monitor changes in composition or to control gas blending.

6.2 Installation Recommendations

Our experience also enables us to make some tentative recommendations concerning the use of such meters.

(a) We have established, through our extensive tests, that the existing design works well in high pressure (> 40 bars) natural gas. We have also done a limited amount of testing, with good results, in low pressure (5 bars) natural gas and have also operated the meter, for demonstration purposes, in the laboratory using air at atmospheric pressure.

(b) A conservative recommendation for the installation of such a four-path ultrasonic meter would be to have a minimum of 10 diameters of straight pipe upstream of the 1 diameter long metering section, and a minimum of 3 diameters downstream.

(c) For accurate measurement of low velocity flows in high pressure gas the meter should be lagged. This requirement is primarily necessary for accurate secondary metering measurement of temperature. Without lagging, the temperature of the gas at low flows can vary significantly across the pipe, so the measured temperature may not be the true mean temperature of the gas.

(d) The maximum mean gas velocity at which the meter works well is reduced if the transducers pick up a lot of acoustic noise in the gas or if the velocity distribution is extremely distorted. It is therefore best not to mount the meter too close to a compressor or very near a flow disturbance. Quantifying these effects can be difficult.

(e) The meter should be mounted with the measuring paths horizontal, primarily to avoid problems of dirt, or liquid, collecting in the transducer ports and blocking the passage of the sound pulse.

We have found the ultrasonic meter to have substantial advantages over alternative meters for the measurement of high pressure gas flows. Many of these advantages are particularly relevant to metering off-shore, where high reliability, easy servicing, low weight, and short installation lengths, are particularly beneficial.

7 ACKNOWLEDGEMENTS

The authors would like to acknowledge the assistance of all those at British Gas and at Daniel Industries who have helped in the preparation of this paper and also those who contributed to the work described. This expression of gratitude includes all those concerned on British Gas sites where the meters have been installed and/or tested.

We would also like to thank British Gas and Daniel Industries for permission to publish this paper.

8 REFERENCES

1 Nolan M.E. and O'Hair J.G., "An Ultrasonic Flowmeter for the accurate measurement of high pressure gas flows", Norflow '83, Institute of Measurement and Control. May 1983

2 Nolan M.E., O'Hair J.G. and Teyssandier R., "The measurement of high pressure natural gas flows using the four-path Ultrasonic flowmeter developed by British Gas", International Symposium on Fluid Flow Measurement, Washington D.C. Nov. 1986

3 British Patent No. 1503 852 - Filed April 1975. Published March 1978, Westinghouse Electric Corporation.

4 Nolan M.E., O'Hair J.G., Gaskell M.C., Cheung W.S., and Fellowes B., "Developments in the Ultrasonic flowmeter in British Gas", The Metering of Natural Gas and Liquid Hydrocarbon Gases, Oyez Scientific and Technical, London Feb 84

5 Norman R. and Drew W.A., "British Gas Test Facility at Bishop Auckland", International Conference on Flow Measurement in the Mid-'80s. National Engineering Laboratory. June 1986

TABLE 1 SUMMARY OF OPERATIONAL METERS

Meter Size	Site and Duty	Installed Commi'ned	Pressure bars	Flow scm/h
300 mm	Flow through an offtake station	Oct 84 Dec 84	35 - 75	0 - 113,000
1050 mm	Flow through a Compressor station	Sep 84 Mar 85	35 - 75	0 - 2.5×10^6
100 mm	Two meters, each measuring fuel flow to compressors	Nov 85	35	0 - 7,595
150 mm	Flows to and from Storage facility	Summer 86	90 - 240	+ 55,000 to - 125,000

TABLE 2 RADIO-TRACER TESTING OF 300mm METER

Station flow as % of full scale flow		56.5	39.1	25.0
Flow rate acm/h	Radio-tracer	783.1 ± 7.8	544.1 ± 9.9	349.0 ± 4.6
	Ultrasonic	791.7 ± 7.9	549.7 ± 5.5	350.7 ± 3.5
Combined uncertainty %		2.0	2.8	2.3
Difference % between methods		1.10	1.03	0.49

TABLE 3 RADIO-TRACER TESTING OF 1050mm METER

Flow rate by Radio-tracer Thousand acm/h		25.87	31.38	37.00	41.34
Radio-tracer uncertainty %	method 1	1.72	0.93	2.04	2.96
	method 2	0.97	0.93	2.37	2.23
Flow rate by Ultrasonic meter Thousand acm/h		25.99	31.67	37.22	40.97
Difference % betweeen methods		0.48	0.92	0.59	-0.84

Note: The flowrate shown for the radio-tracer technique is the mean of two methods used. The uncertainties of these two methods are shown individually.

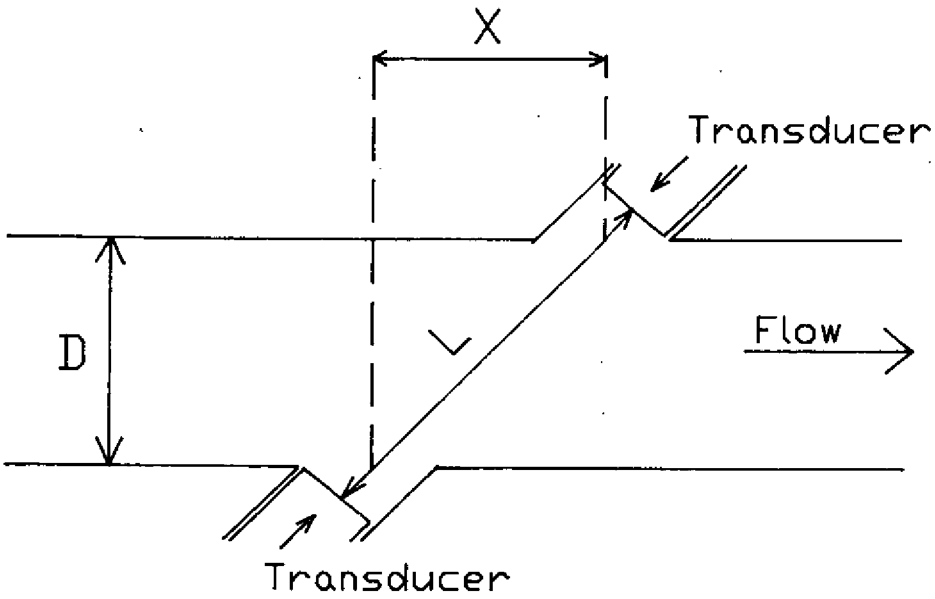


Fig.1. The schematic representation of the ultrasonic flowmeter

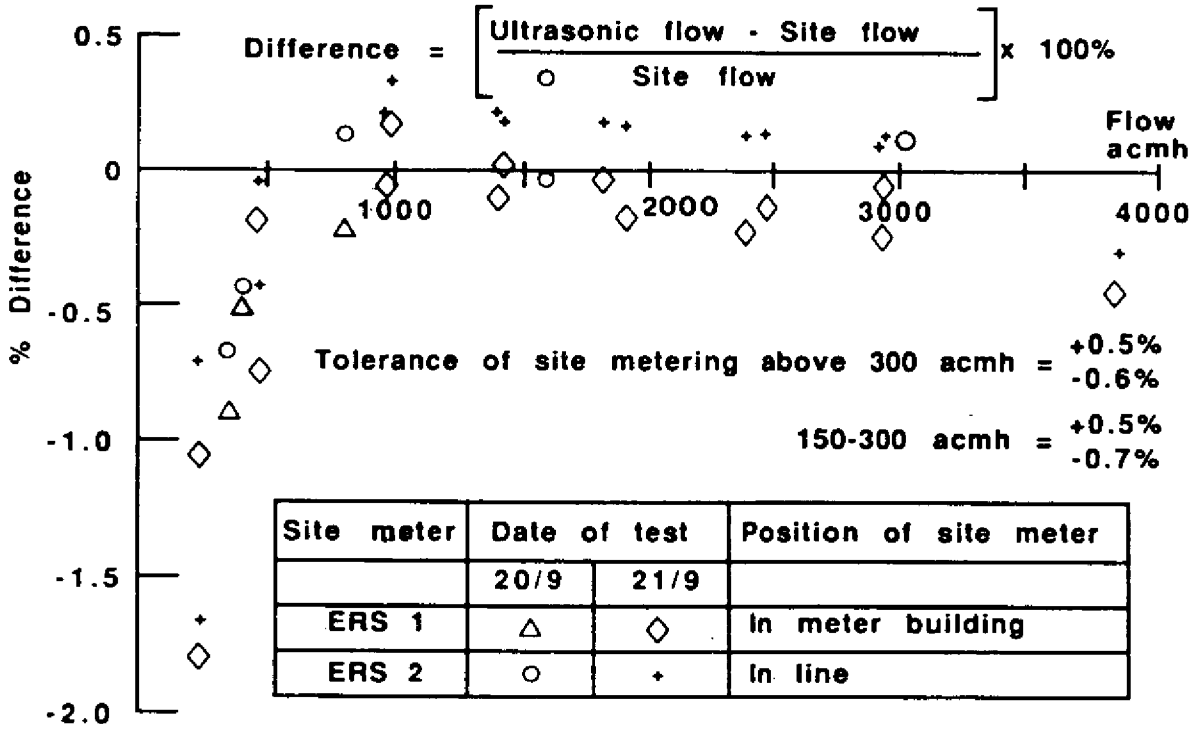


Fig. 2. Comparison between 300mm ultrasonic meter and test site metering

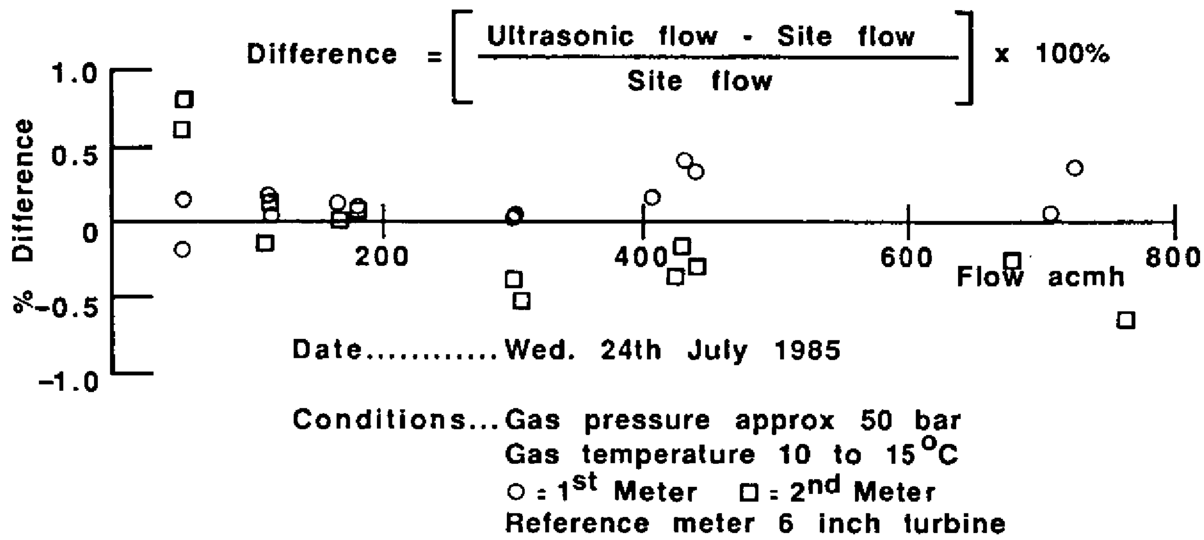


Fig. 3. Comparisons of 100mm ultrasonic flowmeters and Bishop Auckland test site meters

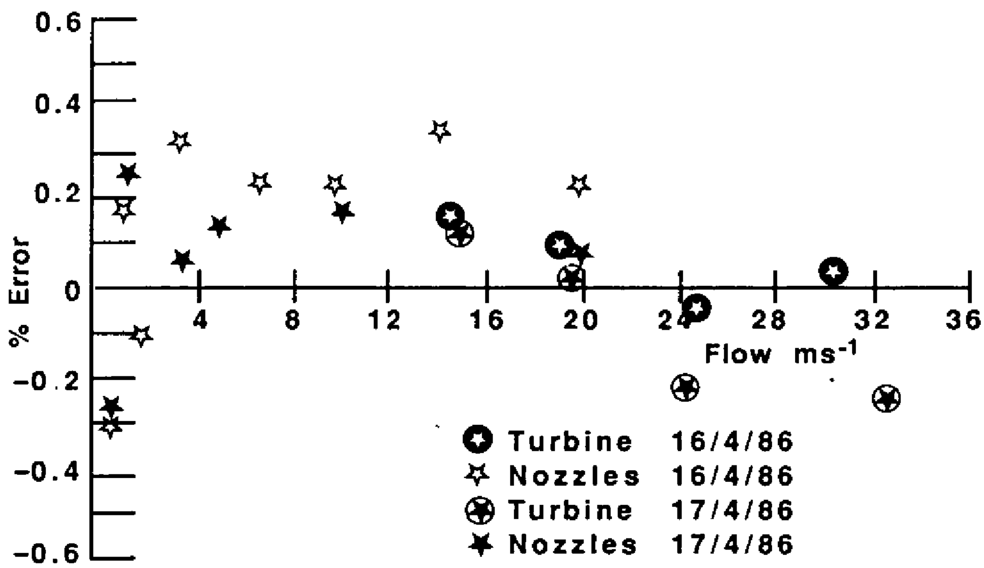


Fig. 4. Comparisons between 150mm ultrasonic meter and Bishop Auckland site metering

FIGURE 5

TEST RESULTS FOR A 300mm METER ON A BRITISH GAS TEST SITE.

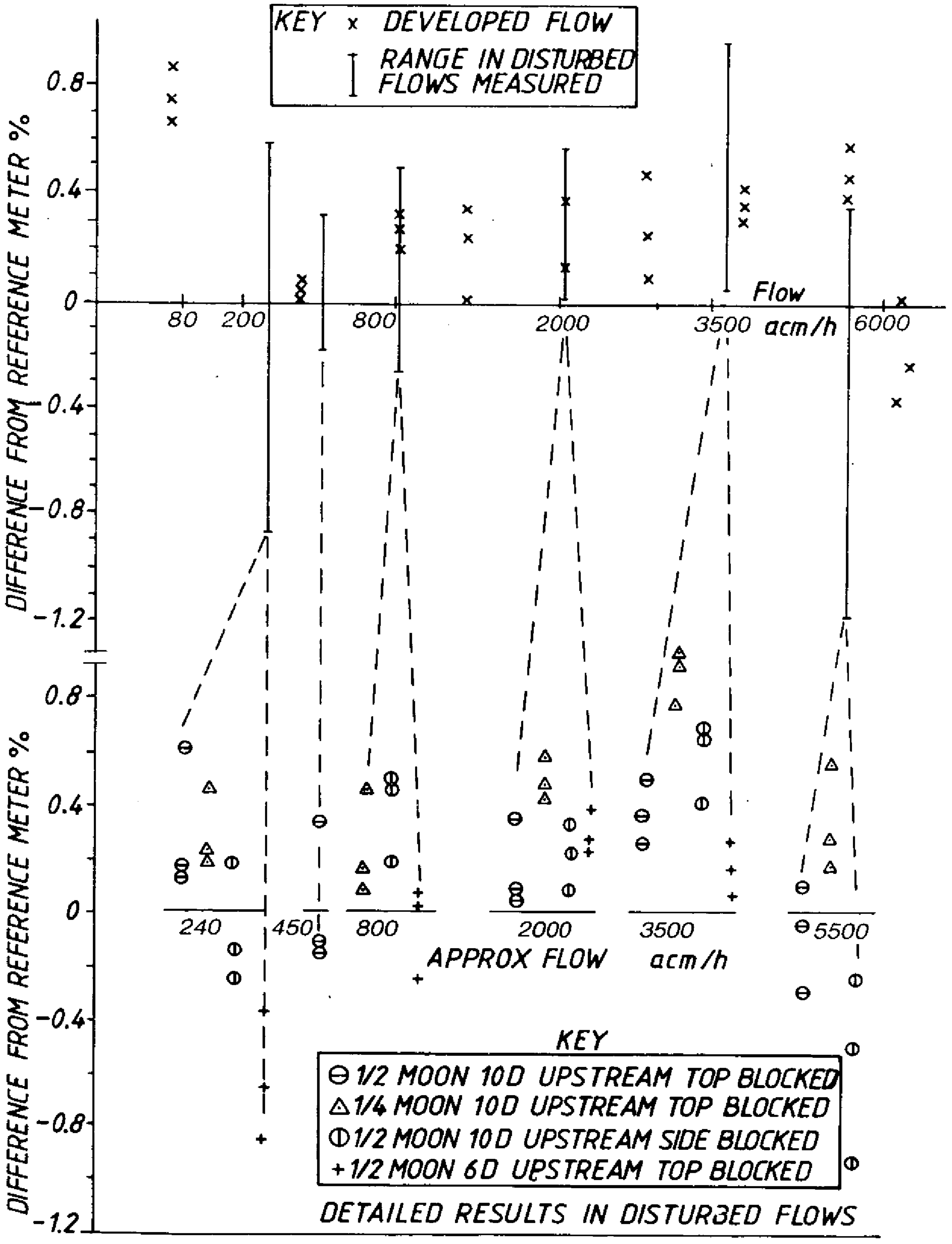


FIGURE 6

PLOTS OF MEASURED VELOCITY RATIOS

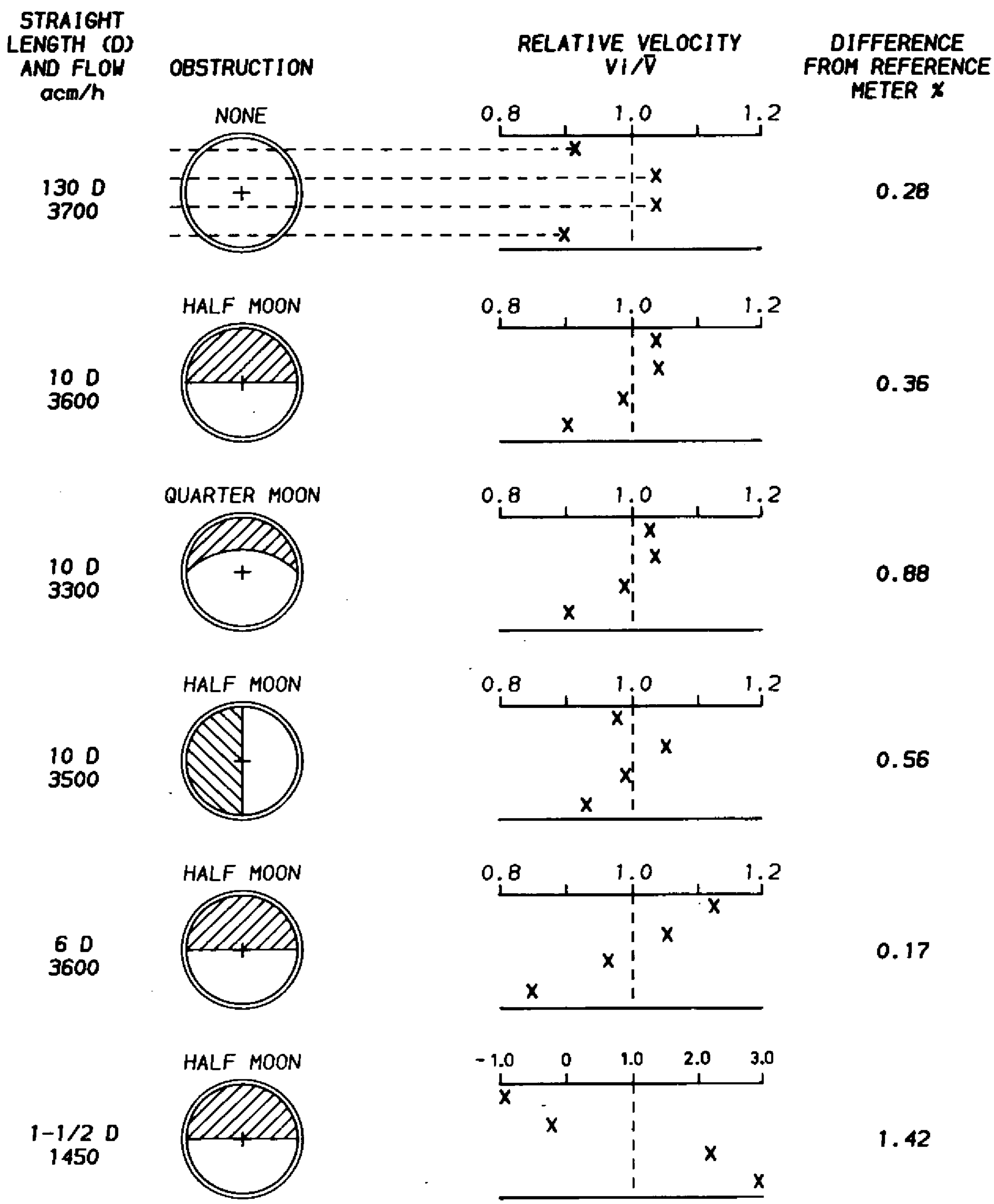
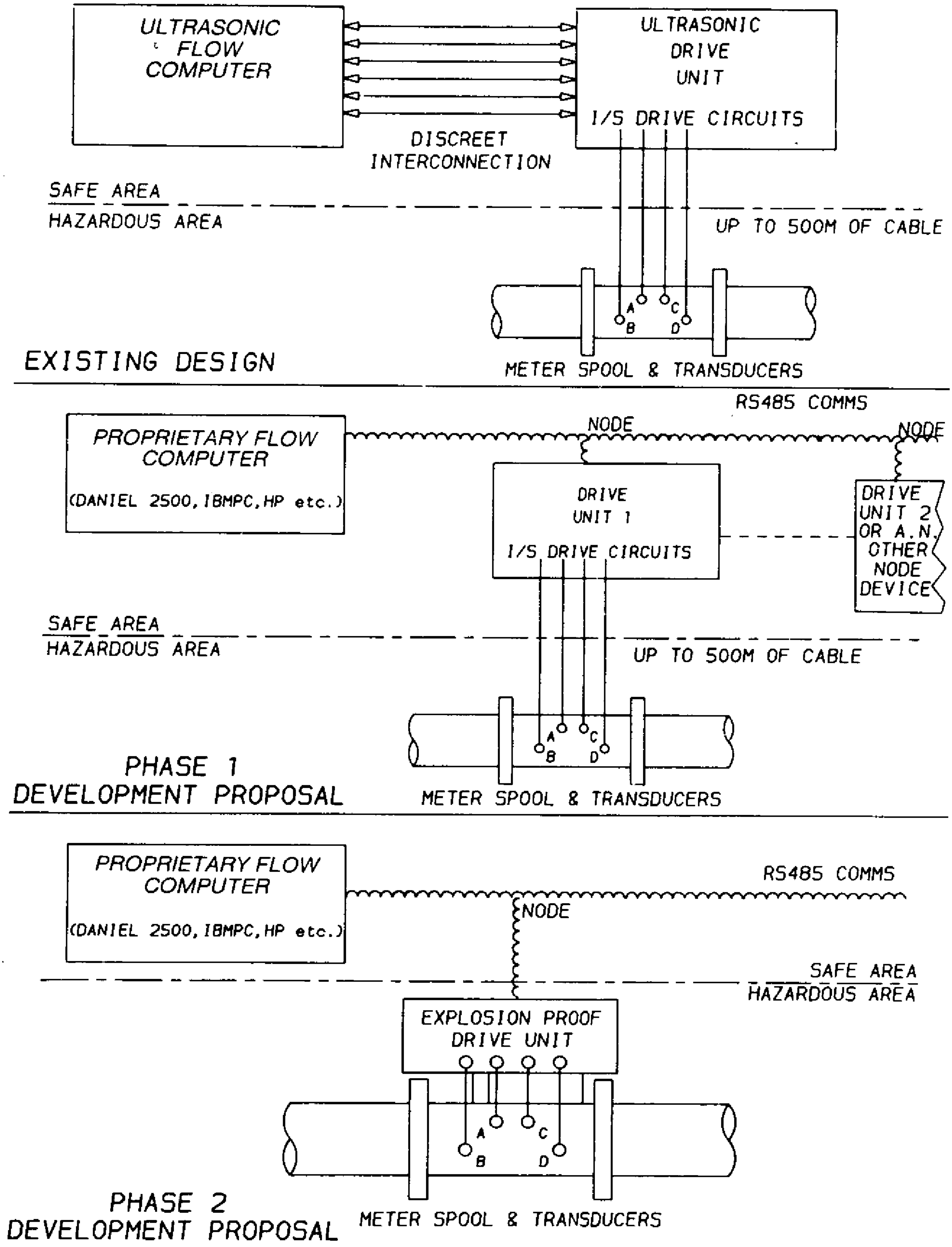


Figure 7 PROPOSED ELECTRONIC DEVELOPMENT



Main Index

FIELD EXPERIENCE OF TWO-PHASE FLOW MEASUREMENT

by

A Hall and C Shaw
Maersk Olie og Gas A/S

Paper 2.3

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

FIELD EXPERIENCE OF TWO-PHASE FLOW MEASUREMENT

A. Hall and C. Shaw

Production Engineering

Mærsk Olie og Gas A/S

SUMMARY

Field testing of a prototype two-phase meter revealed that with the existing configuration the unit was unable to measure phase volumes with the accuracy of a conventional test separator. An error analysis showed the fundamental measuring principle could be accurate to approximately ±5% if a more suitable volume measurement device were used. It is concluded that the possibility exists for obtaining greater accuracy by changing the method by which percent water is determined.

CONTENTS

NOTATION

		Units
K-factor		pulses/m^3
Γ_1	gas and liquid mixture density	kg/m^3
Γ_2	liquid density	kg/m^3
Γ_{gas}	pure gas density (calculated at T and P)	kg/m3
Γ_{oil}	pure oil density (calculated at T and P)	kg/m3
Γ_{water}	pure water density (calculated at T and P)	kg/m3
P	pressure	bar
T	temperature	^oC
OGF	offgas factor	Nm^3/m^3 of oil at T and P
SF	shrinkage factor	Nm^3/m^3 of oil and T and P
σ	standard deviation	%
σ^2	variance	$\%^2$

FIELD EXPERIENCE WITH THE TWO-PHASE FLOWMETER

1 INTRODUCTION

Mærsk Oil and Gas operate for the Danish Underground Consortium in the Danish sector of the North Sea. It has two major oil platform complexes plus two minor unmanned minimum facility, single production well platforms. Production from the unmanned platforms is processed at the Gorm complex (ref. Fig. 1). Daily production from the two unmanned fields is calculated from time in operation and well test data. Well testing of the unmanned fields is carried out on the parent platform by conventional means on average once per week.

The underlying reasons for testing a multiphase meter were three-fold. In the first place with the prospect of additional producing platforms in the offing, testing of them could only be carried out expensively, either by a subtraction method, or by installing a test separator. In the second place a multiphase meter might offer considerable savings over a conventional test separator and thirdly, greater overall accuracy was sought.

It was decided that the Rolf facilities would be used (ref Fig. 2), partly due to operational reasons and partly due to the start of water production from Rolf field and the possibility of gas-lift, thus giving the opportunity to extensively test the meter.

2 OBJECTIVES OF THE TEST

2.1 To ascertain that the measurement system functioned correctly according to its design under a variety of fluid conditions. Advantage was taken of the instigation of gaslift during the testing period.

2.2 To ascertain that the multiphase flow computer was calculating percentage phase and volume, in the line with the test separator located 17 km away on Gorm.

2.3 To determine the suitability of the unit for unmanned multiwell production platforms in terms of function.

3 PRINCIPLE OF OPERATION OF THE TWO-PHASE METER

The fundamental principle upon which the system relies is the linear relationship of mixture densities with changes in volume composition of the mixture. That is to say if one takes as an example a homogeneous two component mixture, the measured density of that mixture will be directly proportional to the volume concentration of each component. This means that provided you have the pure component densities it is possible to determine the volumetric ratio of the 2 components if you have measured the homogeneous mixture density.

Further, it is possible to extrapolate this concept and apply it to three component systems. In this case if the three component mixture density is known and it is then possible to entirely separate one of the components and remeasure the remaining two component mixture density, provided both the pure components densities are known, it is possible to determine the percent by volume that each component occupies. It is this principle the meter relies on and is able to work, essentially by making three fundamental dynamic measurements:

1) the total volumetric flow of the three component mixture

2) the gross mixture density (all three possible components)

3) the separated liquid density.
   Temperature and pressure are also measured and are used for conversion to standard conditions.

3.1 Operation of Hardware

With reference to Figure 3 it may be seen that the homogeneous fluid mixture enters the 4" section of the meter unit. Immediately downstream there is a side stream sampler which is situated in the middle of the pipe. It is assumed that a representative sample of fluid passes, by virture of the pressure drop across the flow straighteners and turbine meter, into the vertical pipe known as the separator. Good separation of liquid and gas in the separator is obtained by use of two inverted mesh cones inserted at the top of the separator. Separated gas is led from the top of the separator and reintroduced to the produced fluids downstream of the turbine meter.

The bulk of the fluid passes the sampler and then one of the two density measurement devices. Density is measured using a Berthold LB386 dual radiometric density meter. This uses a Caesium (CS) 137 gamma source and a scintillation counter for measuring the non-attenuated gamma radiation. In this way the bulk fluid density can be measured with reference to a calibration curve of counts versus density made with air and water.

The fluid passes further down the pipe where it encounters a set of flow straighteners. This comprises six 7/8" o.d. pipes welded in a circle and these are themselves welded to a central pipe which is used to centrally locate the bundle.

From the bundle the fluid flows through a 4" Euromatic turbine flowmeter with a five bladed rotor with ball race bearings and a single pick-up. Calibration of the flowmeter was conducted in situ in the meter system, so that the effect of the bypass was taken into account. The flowmeter was calibrated on water between approximately 200 and 2,000 m^3/d. The standard deviation was shown to be 0.15% (see Appendix I) over this range.

The second density measurement is made at the bottom of the separator pipe. This measurement is made by the second channel of the Berthold dual density meter also using a calibration curve of counts versus density for air and water. Each isotope scintillation counter combination must have its own calibration.

It has been seen how the unit is built up in order that gross mixture density, liquid density and total volume may be measured. The method by which the computer uses these three measured values is discussed in the next section 3.2 under "Operation of the Software".

3.2 Operation of Software

The computer pursues the following processing sequence:

3.2.1 Determination of gross volume per 10 s period

$$\text{Gross Volume (in 10 s)} = \frac{\text{No. of Pulses (in 10 s)}}{\text{K Factor}} \tag{1}$$

$$\text{K Factor} = \text{Pulse/Volume } (m^3)$$

3.2.2 Determination of percent gas volume

$$\%\ \text{Gas} = \frac{(\Gamma_2 - \Gamma_1)}{(\Gamma_2 - \Gamma_{gas})} \times 100 \tag{2}$$

Proof of the volume relationship of these parameters is presented in Appendix III.

Γ_{gas} = density of gas (at T and P) calculated by process simulation

Γ_1 = three component mixture density measured

Γ_2 = two component liquid density

3.3.3 Determination of percent liquid (oil and water) volume

$$\%\ \text{Liquid} = 100 - \%\ \text{gas} \tag{3}$$

3.2.4 Determination of percent oil volume in liquid

$$\%\ \text{Oil} = \frac{(\Gamma_{water} - \Gamma_2)}{(\Gamma_{water} - \Gamma_{oil})} \times (\%\ \text{liquid}) \tag{4}$$

Γ_{water} = density of produced water (at T and P) calculated

Γ_{oil} = density of oil (at T and P) calculated

3.2.5 Determination of percent water volume

$$\% \text{ Water} = 100 - (\% \text{ gas} + \% \text{ oil}) \quad (5)$$

The nitty gritty of the work has at this stage been completed. There only remains the conversion of these volume percents to standard conditions and additionally the reduction of raw oil volumes by the shrinkage factor and the consequent increase in gas volume by the related offgas factor. This is of course important as the numbers which the meter produces have to be compared to the test separator on the Gorm, in line with the objectives of the test.

The standard conditions which Mærsk Oil and Gas work to are

Gas	0^oC and 1 bara m^3 (normal) 60^oF and 14.73 psia ft^3 (standard)
Oil	15^oC and 1 bara m^3 60^oF and 14.69 psia bbls

The remaining part of the processing sequence to convert these actual volumes to standard was carried out as follows:

3.2.6 Actual volume of gas

$$\text{Act. gas} = \text{gross volume} \times \frac{\% \text{ gas}}{100} \quad m^3/10 \text{ s} \quad (6)$$

3.2.7 Standard volume of gas

$$\text{Normal gas vol.} = \frac{\text{Act. gas} \times P_{work} \times T_{norm}}{P_{norm} \times T_{work} \times Z} \quad N_m 3/10 \text{ s} \quad (7)$$

I) pressure was measured on site using a standard diaphragm silicone oil filled cell calibrated between 0-100 barg.

II) temperature was measured by use of PT 100 and transmitter was calibrated from $0\text{-}100^oC$.

III) normal temperature (T_{norm}) for gas volumes is 273.15^o.

IV) normal pressure(P_{norm}) is 1.0 bara.

V) Z factor is determined from process simulation by flashing reservoir composition at 80^oC and 19 barg and is entered as a constant, Z = 0.93.

3.2.8 Offgas volume

$$\text{Offgas} = \text{gross volume} \times \frac{(\% \text{ oil})}{100} \times \text{OGF} \quad Nm^3/10 \text{ s} \quad (8)$$

I) OGF is the offgas factor and is measured as normal cubic meter of gas per meter cubed of raw oil. Shrinkage is assumed to occur from operating conditions to final stage stabilisation conditions (1.8 bara and 40^{o}C). Values for OGF and SF are depicted in Table 1 overleaf.

3.2.9 Total gas volume can be obtained by combining equation (7) with equation (8)

$$\text{Total gas} = (\text{normal gas vol} + \text{offgas}) \times 360 \quad Nm^3/hr \tag{9}$$

3.2.10 Actual oil volume

$$\text{Act. oil} = \text{gross volume} \times \frac{\%\ \text{oil}}{100} \quad m^3/10\ s \tag{10}$$

3.2.11 Standard oil volume

$$\text{Std oil} = \frac{\text{act. oil}}{SF} \times 360 \quad m^3/hr \tag{11}$$

where SF is the shrinkage factor of the oil when flashed from operating conditions to final stage stabilisation conditions.

3.2.12 Volume of water

$$\text{Vol water} = \text{gross volume} \times \frac{\%\ \text{water}}{100} \times 360 \quad m^3/hr \tag{12}$$

3.2.13 Water in oil percent (BS&W %)

$$BS\&W = \frac{(\text{vol. water}) \times 100}{(\text{vol. water} + \text{std. oil})} \quad \%\ \text{water in oil} \tag{13}$$

3.2.14 Standard gas to oil ratio

$$GOR = \frac{\text{Total gas}}{\text{Std oil}} \quad Nm^3/m^3 \tag{14}$$

In this way it is possible to compare directly the results obtained from the flow meter with those obtained at the test separator 17 km away on Gorm.

The results presented are 10 s instantaneous flow rate values averaged over an hour and are compared to hourly readings taken at the test separator.

Table 1

Offgas and shrinkage factors used in converting raw oil and gas volumes to standard.

	Temperature ^{o}C	Pressure bar	OGF	SF
Rolf (Phases I & II)	80	19	96	1.149
Rolf (Phase III)	75	47	214	1.251
Test separator (LP)	32	8	25	1.045
Test separator (HP)	41	21	98	1.073

4 RESULTS

The results obtained over three test days are presented in tables 2-4 and graphically in Figs. 4-6. These results were obtained during three typical well test days where direct comparison was possible. There is no accounting for the time delay between measurements made on the Rolf and those made on the Gorm. As can be seen from Appendix II there is 2.6 hours time delay between the two platforms for the production rates at the time.

Examination of those results obtained prior to gaslift (tables I and II) indicates that production was stable and the measurements made by the test meter were equally stable. On average the test meter readings indicated approximately 35% more than the test separator.

In phase 3 it can be seen that results obtained during gaslift were highly unstable. Gas volumes were uncertain due to the loss of gaslift capacity during the test. It can also be seen from the percent water figures that the test separator meter readings which were almost 35% of the multiphase instrument suddenly fell to about 10%. It is thought that a water slug entered the sidestream and gave a much higher liquid mixture density than actual mainline conditions. The oil volumes as measured by the multiphase meter were therefore correspondingly lower.

The results though have an interesting feature and that is if one arbitrarily changes the turbine meter K factor it is possible to obtain the test meter and test separator volumes to within ± 5% of each other for all phases.

E.g. If the K factor is increased by 35% from 1255 to 1700 pulses per m^3 the following example:

Taken at 0800 during phase 2 would give:

	Multiphase Meter	Test Separator	Difference %
Oil (STBOPD)	9467	9566	-1.0
Gas (MMSCFD)	2.215	2.205	0.45
Water (BWPD)	985	972	1.3
GOR (SCF/SBBL)	234	230	1.7

In line with the figures for the first test an arbitrary increase in the turbine meter K factor (of 50%) gives Phase III test results which are much closer to values measured at the test separator.

It should also be noted that due to problems with the gaslift compressor on the day of testing production was not only rather unstable but conditions in the pipeline were causing slugging. Indeed a particularly big slug was measured at the end of the third phase.

TABLE 2

TEST RESULTS - PHASE 1 (13/06/87)

TIME	GAS MMscfd			OIL bopd			WATER bwpd		
	Meter	Test Sep	% error	Meter	Test Sep	% error	Meter	Test Sep	% error
1100-1200		2.291			9883			897	
1200-1300	2.898	2.302	26	12125	10303	18	1851	1042	78
1300-1400	2.974	2.283	30	12339	9567	29	1823	1011	80
1400-1500	2.933	2.302	27	12361	10463	18	1698	667	155
1500-1600	2.934	2.302	27	12436	10463	19	1601	667	140

TABLE 3

TEST RESULTS - PHASE 2 (02/07/87)

TIME	GAS MMscfd			OIL bopd			WATER bwpd		
	Meter	Test Sep	% error	Meter	Test Sep	% error	Meter	Test Sep	% error
0700-0800	3.003	2.206	36	12824	9598	34	1335	914	46
0800-0900	3.007	2.205	36	12831	9566	34	1264	972	30
0900-1000	3.051	2.207	38	13271	9656	37	1083	997	9
1000-1100	3.033	2.203	38	13036	9466	38	1191	956	25
1100-1200	3.051	2.206	38	13251	9589	38	1066	1020	5
1200-1300	3.048	2.201	38	13206	9399	41	1078	1027	5
1300-1400	2.857	2.194	30	11984	9136	31	950	965	-2
1400-1500	3.284	2.210	49	14588	9751	50	1162	971	20
1500-1600	2.924	2.210	32	12549	9177	37	1221	1018	20
1600-1700	2.968	2.209	34	12610	9711	30	1128	964	17
1700-1800	3.058	2.192	39	13094	9046	45	1243	1083	15
1800-1900	2.972	2.197	35	12614	9240	37	1228	976	26
1900-2000	2.978	2.197	36	12636	9245	37	1250	1043	20

TABLE 4

TEST RESULTS - PHASE 3 (14/07/87)

TIME	GAS MMscfd			OIL bopd			WATER bwpd		
	Meter	Test Sep	% error	Meter	Test Sep	% error	Meter	Test Sep	% error
1300–1400	8.537	5.650	51	15979	13420	19	2753	1082	154
1400–1500	8.958	5.697	57	16859	13532	25	2805	1008	178
1500–1600	8.568	5.697	50	16234	13532	20	2612	960	172
1600–1700	4.328	3.178	36	7593	12414	−39	6889	696	890
1700–1800	5.582	1.895	195	9690	7403	31	6788	869	681
1800–1900	6.269	3.270	92	10604	12772	−17	5123	1008	408
1900–2000	4.880	2.462	98	10901	10603	3	4663	N/A	
2000–2100	3.965	2.743	45	7836	9618	−19	6871	936	634
2100–2200		2.743			10714			960	
2200–2300		7.261			28362			960	

5 ASSESSMENT OF ACCURACY

In order to assess the accuracy of the multiphase meter it is important to know the expected accuracy of the instrument which it is intended to be checked against. Because of this an assessment of the test separator accuracy is presented prior to that of the multiphase meter. All accuracy calculations are made with reference to the ISO standard 5168.

5.1 Test Separator

As the multiphase meter presents three separate phase volumes, an analysis of each of the three measurement loops must be carried out separately i.e. there is no requirement to derive an overall system accuracy.

Gas volume measurement at the test separator is made by recording the pressure drop across an orifice plate installed in the gas outlet from the separator. The systematic error due the installation is estimated at 3% for any instantaneous measurement. Additionally a large random error is introduced when taking hourly average volumes. This is due to the large variations found over short time periods, and the subsequent difficulty in estimating an hourly average from the chart readings. This error is estimated at ± 5%. The total system standard deviation is calculated by adding the squares of the systematic and random standard deviation and taking the square root, so

$$\sigma_{gas\ vol\ test} = \sqrt{(\sigma_S^2 + \sigma_R^2)} \quad (15)$$

$$= \sqrt{(3^2 + 5^2)}$$

$$= 6\%$$

Oil and water volume measurements are made in the same way by use of a turbine meter with a factory determined K-factor. Systematic errors due to installation and calibration are estimated at 1.0% and 0.5%. respectively for oil and water. Further error of a random nature due to changes in flow profile, flow rate and fluid properties (e.g. viscosity) are estimated at 1.0% for each meter loop. This gives the following errors in measuring the oil and water:

$$\sigma_{oil} = \sqrt{(1.0^2 + 1.0^2)} \quad (16)$$

$$= 1.4\%$$

and

$$\sigma_{water} = \sqrt{(0.5^2 + 1.0^2)} \quad (17)$$

$$= 1.1\%$$

In order to be more rigorous the errors introduced due to correction for BS&W should be taken into account. These may be assumed to be 0.5% for systematic and 0.5% for random errors in the sampling and analysis. These are percent of oil measured in cubic meters.

from the formula

$$\text{corrected oil} = \text{oil} \times 1.0 - \frac{\%\text{water}}{100} \qquad n^3/\text{hr} \quad (18)$$

$$\sigma_{\text{cor oil}} = \sqrt{(\sigma^2\text{cor oilR} + \sigma^2\text{cor oilS})} \quad (19)$$

where $\sigma^2\text{cor oilR} = \left(1 - \frac{\%\text{water}}{100}\right)^2 \sigma^2\text{oilR} + (\text{oil})^2\ \sigma^2\%\text{waterR}$

$$= (0.9)^2\ (1.0)^2 + (0.9)^2\ (1.0)^2$$

$$= 1.6\%^2 \quad (20)$$

and $\sigma^2\text{cor oilS} = \left(1 - \frac{\%\text{water}}{100}\right)^2 \sigma^2\text{oilS} + (\text{oil})^2\ \sigma^2\%\text{waterS}$

$$= (0.9)^2\ (1.0)^2 + (0.9)^2\ (0.5)^2 \quad (21)$$

$$= 1.0\%^2$$

$$\sigma_{\text{cor oil}} = \sqrt{(1.6 + 1.0)} \quad (19)$$

$$= 1.6\%$$

Similarly for the percent deviation in the corrected water measurement from the formula

$$\text{corrected water} = \text{water} + \text{oil} \times \frac{\%\text{water}}{100} \quad (22)$$

$$\sigma_{\text{cor water}} = \sqrt{(\sigma^2\text{corwaterR} + \sigma^2\text{corwaterS})} \quad (23)$$

where

$\sigma^2\text{cor waterR} = \sigma^2\text{waterR} + \frac{\%\text{water}}{100}^2\ \sigma^2\text{oilR} + (\text{oil})^2\ \sigma^2\%\text{waterR}$

$$= (1.0)^2 + (0.1)^2\ (1.0)^2 + (0.9)^2(0.5)^2$$

$$= 1.2\%^2 \quad (24)$$

and $\sigma^2\text{cor waterS} = (0.5)^2 + (0.1)^2(1.0)^2 + (0.9)^2(0.5)^2$

$$= 0.45\%^2 \quad (25)$$

so $\sigma_{\text{cor water}} = \sqrt{(1.2 + 0.45)}$

$$= 1.3\% \quad (23)$$

Thus standard deviation for oil measurements is 1.6% and for the water measurements is 1.9%. Note, however, that this relates to one measurement by the test separator, if an average of n results are taken the random errors should be divided by n.

5.2 Two-Phase Meter System Accuracy

In order to estimate the overall system accurary it is first required to investigate the accuracy of the individual measurements made e.g. density, temperature, pressure, and volume. The accuracy is quantified in terms of systematic and random errors where possible.

5.2.1 Turbine Meter

The volume measurement of total fluid flow is critical to the operational accuracy of the whole meter system. From the data presented with the calibration sheet it may be calculated that the standard deviation of K-factors measured between 22 and 73 m^3/hr was 0.15% (see calculations in Appendix I). However, this type of accuracy was not anticipated for two phase mixture volume measurement. A figure of ±5% was assumed for the random error in measurement of homogeneous mixture containing <20% gas at actual conditions. It was further assumed that under high pressure the differences in density and viscosity between the gas and liquid become smaller and that this would further help to maintain the standard deviation to with ±5%. The deviation due to systematic error is estimated to ±1.0% due to non-standard installation. This gives a total turbine meter measurement ($\sigma_{turbine}$) deviation of 5.1%.

5.2.2 Density Measurement (Γ_1 and Γ_2)

The density meter is able to measure to 1.0 kg/m^3 or ±0.2%, however due to inadequacies in the calibration procedure the actual systematic error is estimated to be ±2.0%. Only two points using air and water were used to make up the calibration curve of scintillation counts versus their respective densities - a third point using a hydrocarbon liquid would increase the confidence in this calibration. Further error is likely considering that although the sources and counters were calibrated in situ they were dismounted and re-installed on the platform. Variations in pipe wall thickness along the pipe length will affect the counts versus density calibration. A random error of 0.5% is estimated due to variations in fluid homogeneity and hydrogen atom content (hydrogen has a different mass attennution coefficient so that a change in hydrogen content can show itself as a change in density even when there is not one).

This gives a total system deviation of $\sqrt{(2.0^2 + 0.5^2)}$ or 2.1%.

5.2.3 Process Simulation

As can be expected for any computer based theoretical calculation the accuracy is only as good as the input data which in this case was a compositional analysis obtained from a downhole sample. It is estimated that the calculated actual density values have a standard deviation of 2.0% and that the random error is considered to be 0% as the measurement relies on a mathematical calculation.

5.2.4 Combined Accuracy of Dynamic System

In order to determine the standard deviation of the values calculated for percent oil, gas and water it is necessary to add the variances of the measurements used to calculate these values.

I) for determination of the percent gas in the multiphase fluid the following equation is used:

$$\%\ gas = \frac{\Gamma_2 - \Gamma_1}{\Gamma_2 - \Gamma_{gas}} \times 100 \qquad (2)$$

the standard deviation of the value % gas ($\sigma_{\%gas}$) is then equal to the square root of the total of the variance due to random error ($\sigma^2_{\%gasR}$) and the variance due to systematic error ($\sigma^2_{\%gasS}$)

$$\sigma_{\%gas} = \sqrt{(\sigma^2_{\%gasR} + \sigma^2_{\%gasS})} \qquad (26)$$

where $$\sigma_{\%gasR} = \left(\frac{\delta\%gas}{\delta_{\Gamma2}}\right)^2 \sigma^2_{\Gamma 2R} + \left(\frac{\delta\%gas}{\delta_{\Gamma_1}}\right)^2 \sigma^2_{\Gamma 1R} + \left(\frac{\delta\%gas}{\delta_{\Gamma_{gas}}}\right)^2 \sigma^2_{\Gamma gasR} \qquad (27)$$

and $$\sigma^2_{\%gasS} = \left(\frac{\delta\%gas}{\delta\Gamma 2}\right)^2 \sigma^2_{\Gamma 2S} + \left(\frac{\delta\%gas}{\delta\Gamma 1}\right)^2 \sigma^2_{\Gamma 1S} + \left(\frac{\delta\%gas}{\delta Pgas}\right)^2 \sigma^2_{\Gamma gasS} \qquad (28)$$

the mathematics are presented in Appendix IV. The value for the standard deviation in the value % gas ($\sigma_{\%gas}$) is 1.9%.

II) for the determination of the percent oil phase the following equation is used:

$$\%\ oil = \frac{\Gamma_{water} - \Gamma_2}{\Gamma_{water} - \Gamma_{oil}} \times \%\ liquid \qquad (4)$$

As for the gas phase the standard deviation of the value of % oil ($\sigma_{\%oil}$) is equal to the square root of the sum of the variances for systematic and random errors.

$$\sigma_{\%oil} = \sqrt{(\sigma^2_{\%oilR} + \sigma^2_{\%oilS})} \qquad (29)$$

where

$$\sigma^2_{\%oilR} = \left(\frac{\delta\%oil}{\delta_{\Gamma water}}\right)^2 \sigma^2_{\Gamma waterR} + \left(\frac{\delta\%oil}{\delta_{\Gamma 2}}\right)^2 \sigma^2_{\Gamma 2R} + \left(\frac{\delta\%oil}{\delta_{\Gamma 2}}\right)^2 \sigma^2_{\Gamma oilR} + \left(\frac{\delta\%oil}{\delta_{\%liquid}}\right)^2 \sigma^2_{\%liquidR} \qquad (30)$$

and

$$\sigma^2\%oilS = \left(\frac{\delta\%oil}{\delta\Gamma water}^2\right) \sigma^2\Gamma water + \left(\frac{\delta oil}{\delta\Gamma 2}\right)^2 \sigma^2\Gamma 2S + \left(\frac{\delta oil}{\delta\Gamma oil}\right)^2 \sigma^2\Gamma oilS + \left(\frac{\delta oil}{\delta\%liquid}\right)^2 \sigma\%liquidS \quad (31)$$

the mathematics are presented in Appendix IV. The value for standard deviation of the value %oil ($\sigma_{\%oil}$) is 4.6%.

III) the following equation is used for determining the percentage water phase

$$\%\ water = 100 - (\%oil + \%gas) \quad (5)$$

As for the previous percentages it is possible to make an error analysis on this value for percentage water.

$$\sigma_{\%water} = \sqrt{(\sigma^2\%waterR + \sigma^2 waterS)} \quad (32)$$

where $$\sigma^2 waterR = \left(\frac{\delta\%water}{\delta\%oil}\right)^2 \sigma^2\%oilR + \left(\frac{\delta\%water}{\delta\%gas}\right)^2 \sigma^2\%gasR \quad (33)$$

and $$\sigma^2\%waterS = \left(\frac{\delta\%water}{\delta\%oilS}\right)^2 \sigma^2\%oilS + \left(\frac{\delta\%water}{\delta\%gas}\right)^2 \sigma^2\%gasS \quad (34)$$

The mathematics are presented in Appendix IV. The standard deviation of the value %water ($\sigma_{\%water}$) is equal to 4.9%.

The major reason for conducting such an error analysis is to estimate the suitability of the test separator as a tool for assessing the multiphase meter performance. It can be seen that for oil and water volume measurement the multiphase meter has considerably larger standard deviation than the test separator. For liquid assessment the test separator is therefore deemed suitable. However, the fundamental standard deviation for gas measurement of the multiphase meter is slightly less than the standard deviation of gas volume measurement at the test separator. Practically that means it is not possible to say which is the "true" value of the two.

The error analysis carried out indicates the fundamental accuracy of the multiphase meter only. No attempt has been made to include the accuracy of the turbine meter. This is partly because the results indicate this to be the weak link in terms of accuracy and that the standard deviation of the meter K factor changes from 0.15 to probably 40-50% depending on the actual GOR and flow rate.

6.0 CONCLUSIONS

6.1 Conclusions with Respect to the Test Objectives

As far as the objectives of the test are concerned it can be concluded that
1) the unit appeared to function satisfactorily inasmuch that continuous measurements of the three dynamic variables was possible and that good gas liquid separation seemed to occur in the side stream separator. However it must be said that facilities for varying the side stream flow rate, and measuring the approximate liquid and gas flow rates out of the separator would greatly help the function of the unit.

2) the fundamental principle by which gas percent by volume is determined appears sound and practical and further, it is envisaged that by better density measurement, the overall accuracy can approach that for conventional test separation if a suitable two phase volume meter can be found. By extension of this the percent liquid determined by the meter is also reasonable. It can be shown that a different method than the one employed for determining the percent oil phase could greatly improve accuracy. It should further be noted that despite the fact that the unit was installed off-shore it displayed a reasonable random error.

The turbine meter is shown to contribute a very large bias error by virtue of the fact that by simply, arbitrarily, changing the K-factor the three phase volume measurements for the most part changed to within ±5% of the test separator. It is concluded that the only way to continue with the use of a turbine meter would be to calibrate the unit at a number of flow rates for a number of various gas percentages. These curves may then be programmed into the computer and an interactive step applied to the programme which allows an initial estimate of gas percentage and flowrate, followed by a second step which checks that the correct K-factor has been used. Additionally, should the computer also have the ability to calculate gas and liquid densities at varying working conditions then accuracy could be further improved.

It should be notet that it is possible, by using the reciprocals of the density in the equation used for percent phase determination to, determine a percent by mass (instead of by volume) (refer to Appendix V where this is proved). In this case a mass measurement device may be used as the primary meter. It is anticipated that the mass for measurement of multiphase fluids will eventually be more reliable and that standard deviation in measurement could be much smaller than any volume based methods.

6.2 Further Conclusions

One of the biggest errors may lie in the fact that there is 17 km of pipeline between the two measurement devices. A significant difference is what goes in to that which comes out may occur, especially over short periods. Proof of this occurred when a large slug of liquid arrived at the Gorm test separator towards the end of the final stage of testing. It is the inability to quantify this error that makes drawing any conclusions from this test very difficult. The only way to avoid this error in the future might be to rent a test separator and install it just downstream of multiphase meter. In this way actual volumes could be measured and compared thus reducing the uncertainty due to conversion to standard conditions.

It may have been noted that little mention has been made in the potential inaccuracies due to converting actual values to standard. This is due to the fact that the results on Rolf were handled in much the same way as their conversion to standard as the results obtained from the test separator. This would tend to cancel any bias errors in the method used.

The results at the end of the third days trial indicate the unsatifactory way the unit was put together for control purposes. There existed no method for checking the flow through the unit, and thus no way to check that water build up in the separator pot was the cause of the higher water content readings.

It should be noted that the method for determining water quantity is highly unsatisfactory. The computer was not equipped with an interactive process simulation package that would allow updating of calculated pure oil, water and gas densities with changes in the working conditions. Furthermore the percent oil formula is far too sensitive to small changes in the measure liquid density (Γ_2). For example a 1% change in the measurement of Γ_2 gives a 3% change in the actual measured water volume. An improvement in water measurement could be made by installing a BS&W probe and additionally a sampling point for manual checking of this monitor's values by centrifuge laboratory method.

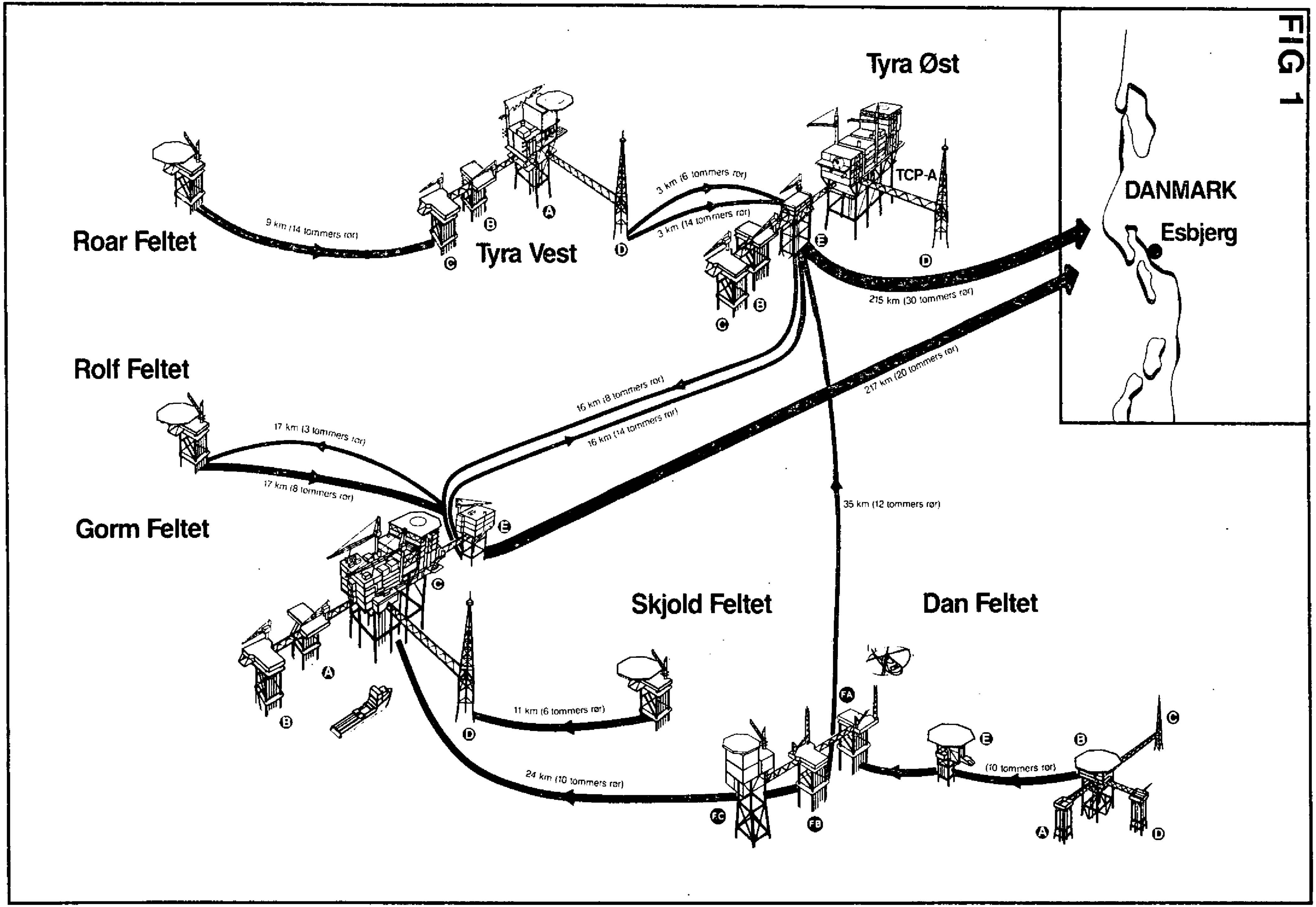
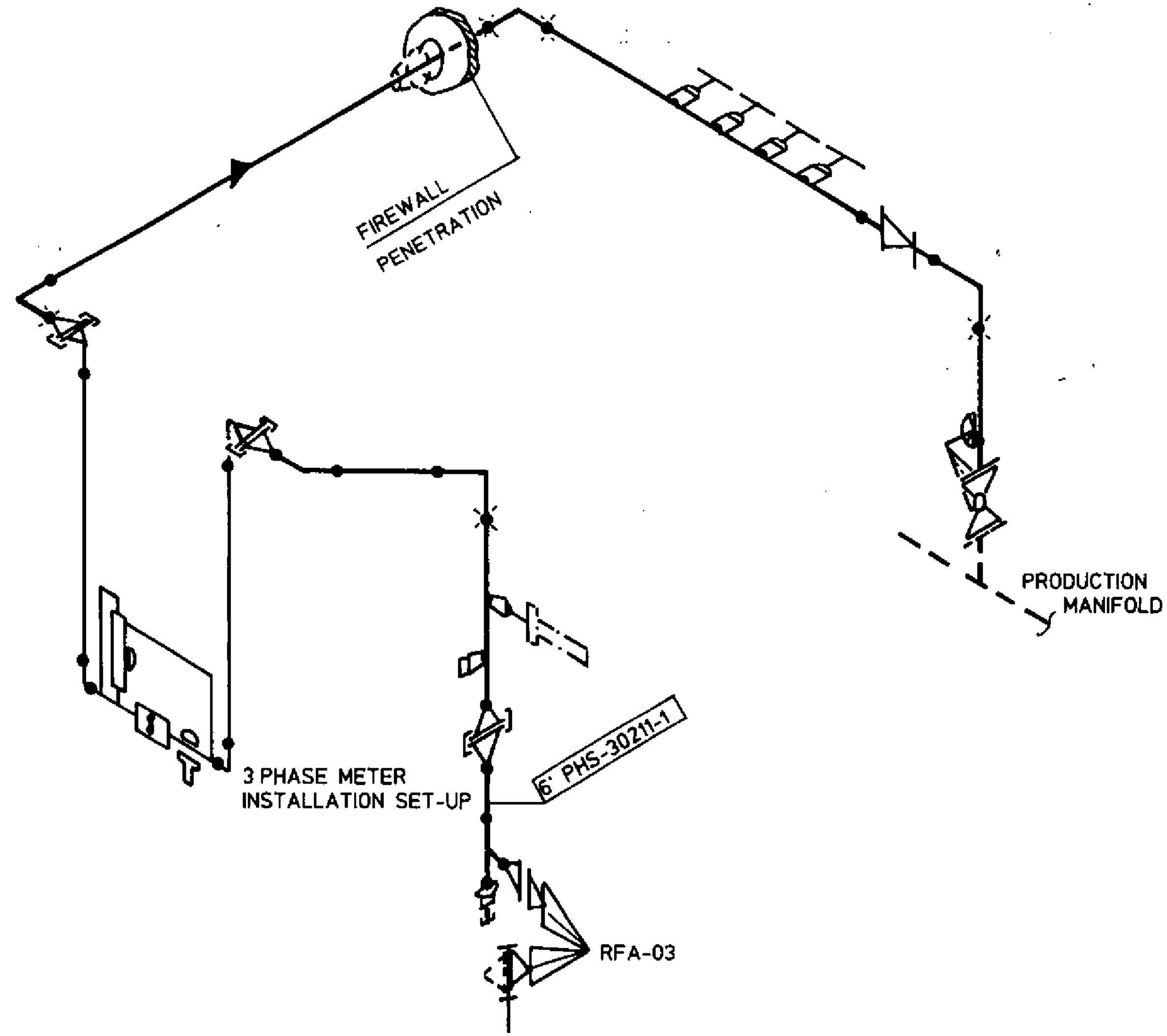

Tyra Øst
TCP-A
DANMARK
Esbjerg
Roar Feltet
Tyra Vest
9 km (14 tommers rør)
3 km (6 tommers rør)
3 km (14 tommers rør)
215 km (30 tommers rør)
Rolf Feltet
16 km (8 tommers rør)
16 km (14 tommers rør)
217 km (20 tommers rør)
17 km (3 tommers rør)
17 km (8 tommers rør)
35 km (12 tommers rør)
Gorm Feltet
Skjold Feltet
Dan Feltet
11 km (6 tommers rør)
24 km (10 tommers rør)
(10 tommers rør)

FIG 1

FIG 2



NOTE!
SPOOL PIECE FOR
FUTURE CONNECTION
OF 3 PHASE FLOW METER
P.L 19/9/86

Rev.		Date	Drawn	Chkd	Appr.	Date	Drawn	Chkd	Appr.	Description
		CONTRACTOR				COMPANY				

Approved	Date
Checked	Date
COMPANY	
Approved	Date
Checked	Date
Drawn SEMCO	Date 88050
CONTRACTOR	

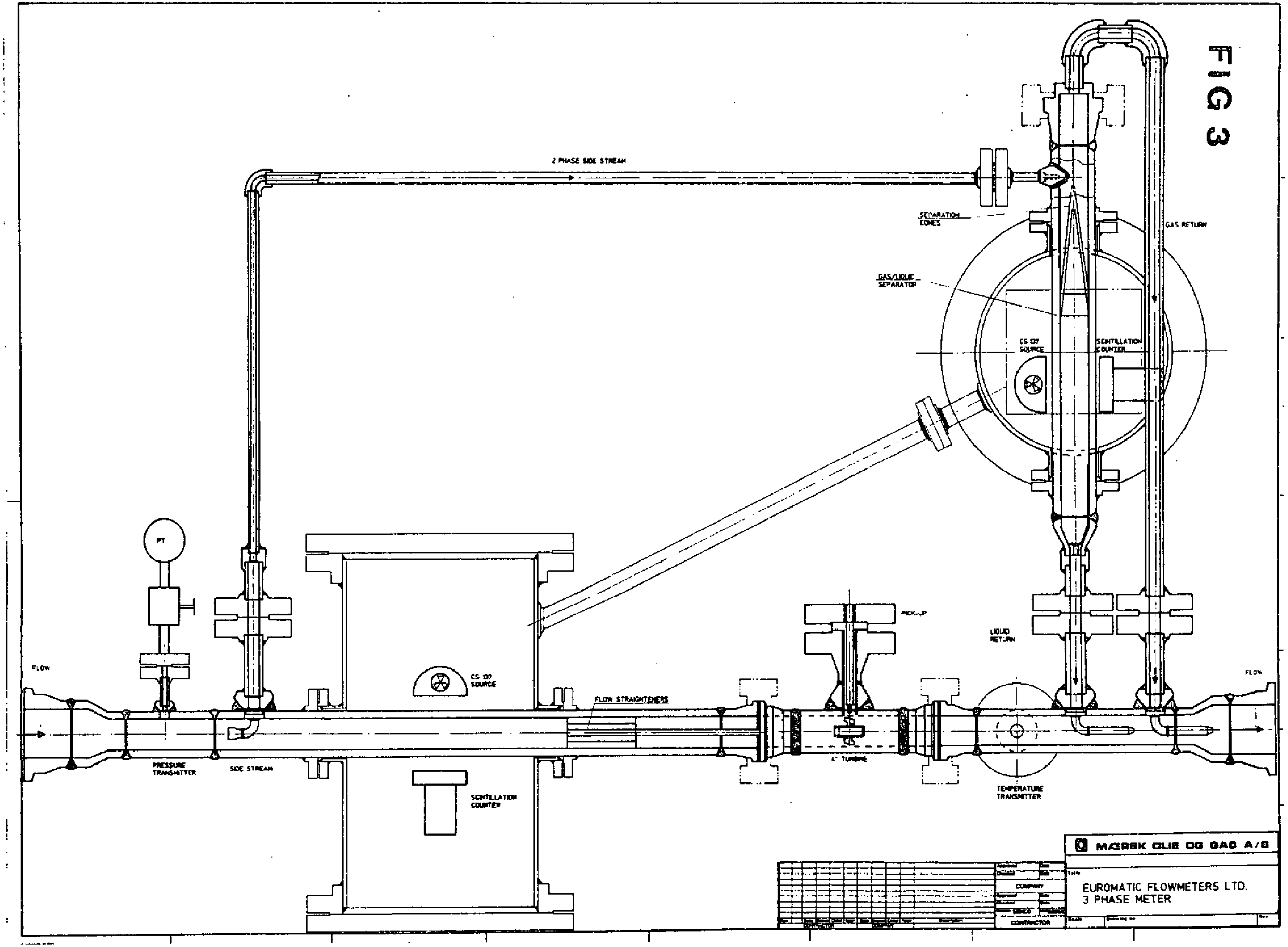
MÆRSK

MÆRSK OLIE OG GAS A/S

Title

PIPING ISOMETRIC ROLF-03

Scale	Drawing no.	Rev.



2 PHASE SIDE STREAM
SEPARATION CONES
GAS RETURN
GAS/LIQUID SEPARATOR
CS 137 SOURCE
SCINTILLATION COUNTER
PT
FLOW
PICK-UP
LIQUID RETURN
FLOW
CS 137 SOURCE
FLOW STRAIGHTENERS
PRESSURE TRANSMITTER
SIDE STREAM
4" TURBINE
TEMPERATURE TRANSMITTER
SCINTILLATION COUNTER
MÆRSK OLIE OG GAS A/S
COMPANY
CONTRACTOR
EUROMATIC FLOWMETERS LTD.
3 PHASE METER

FIG 3

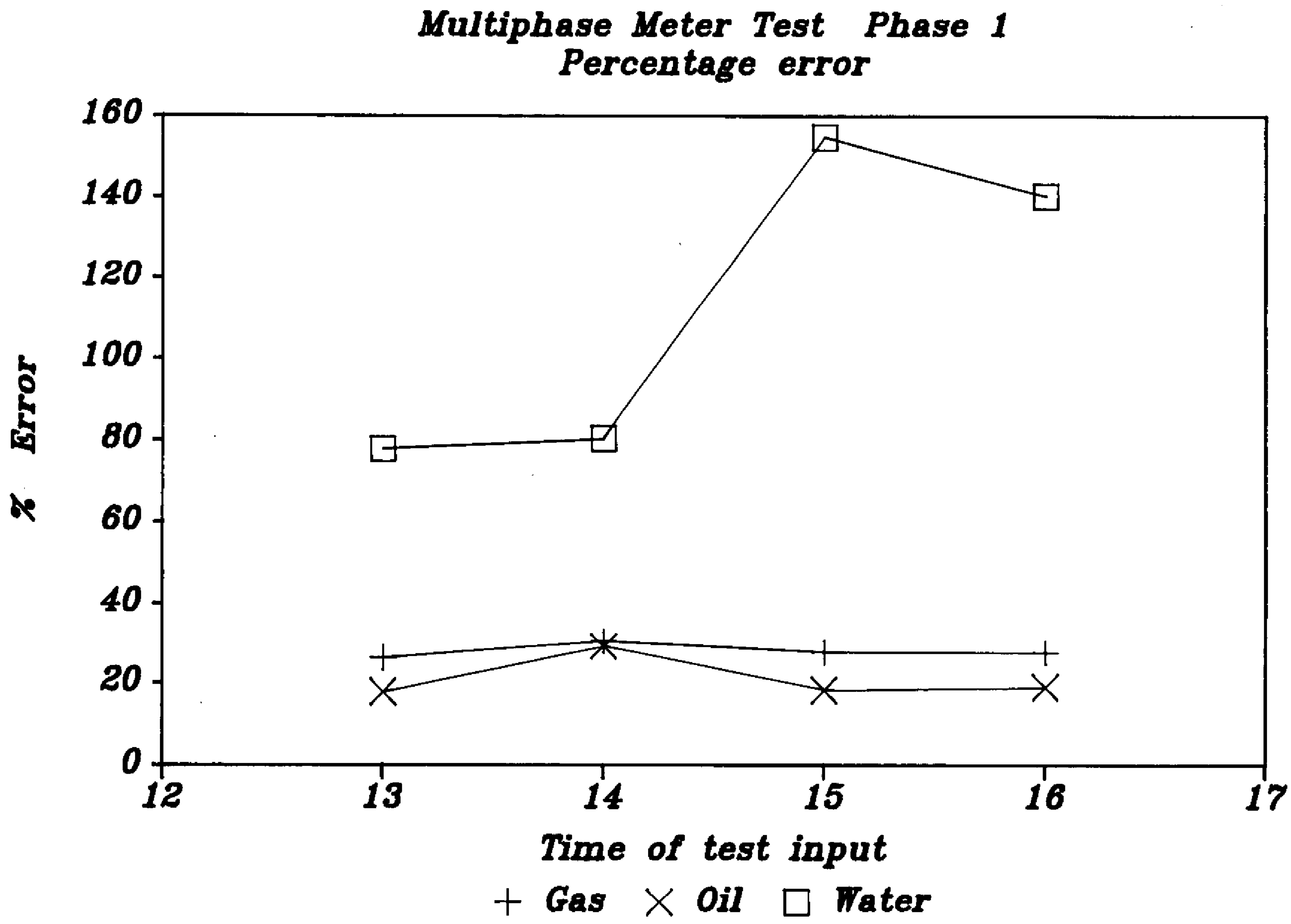

Multiphase Meter Test Phase 1
Percentage error
160
140
120
100
80
60
40
20
0
% Error
12
13
14
15
16
17
Time of test input
Gas
Oil
Water

FIG 4

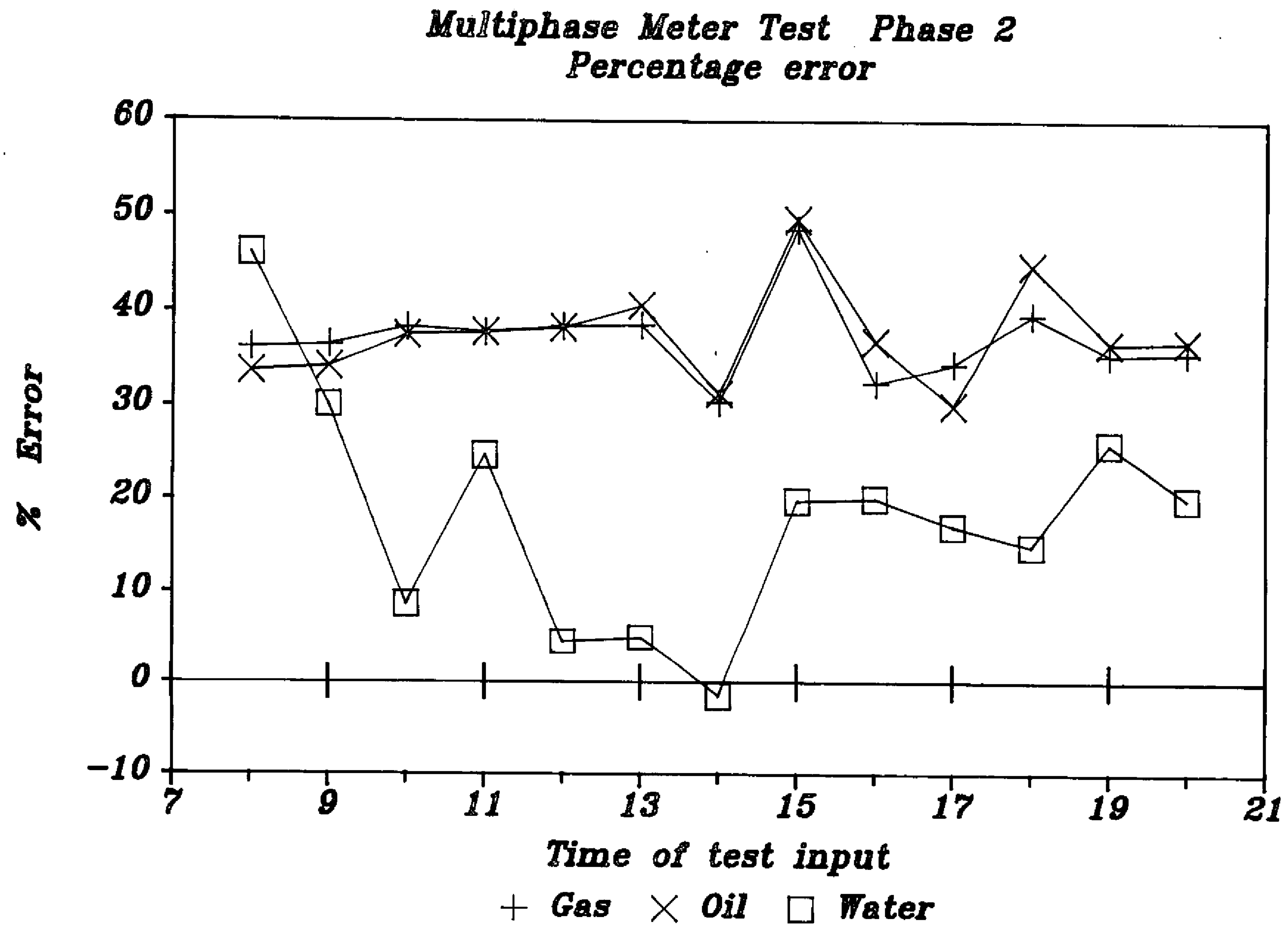

Multiphase Meter Test Phase 2
Percentage error
% Error
60
50
40
30
20
10
0
-10
7
9
11
13
15
17
19
21
Time of test input
Gas
Oil
Water

FIG 5

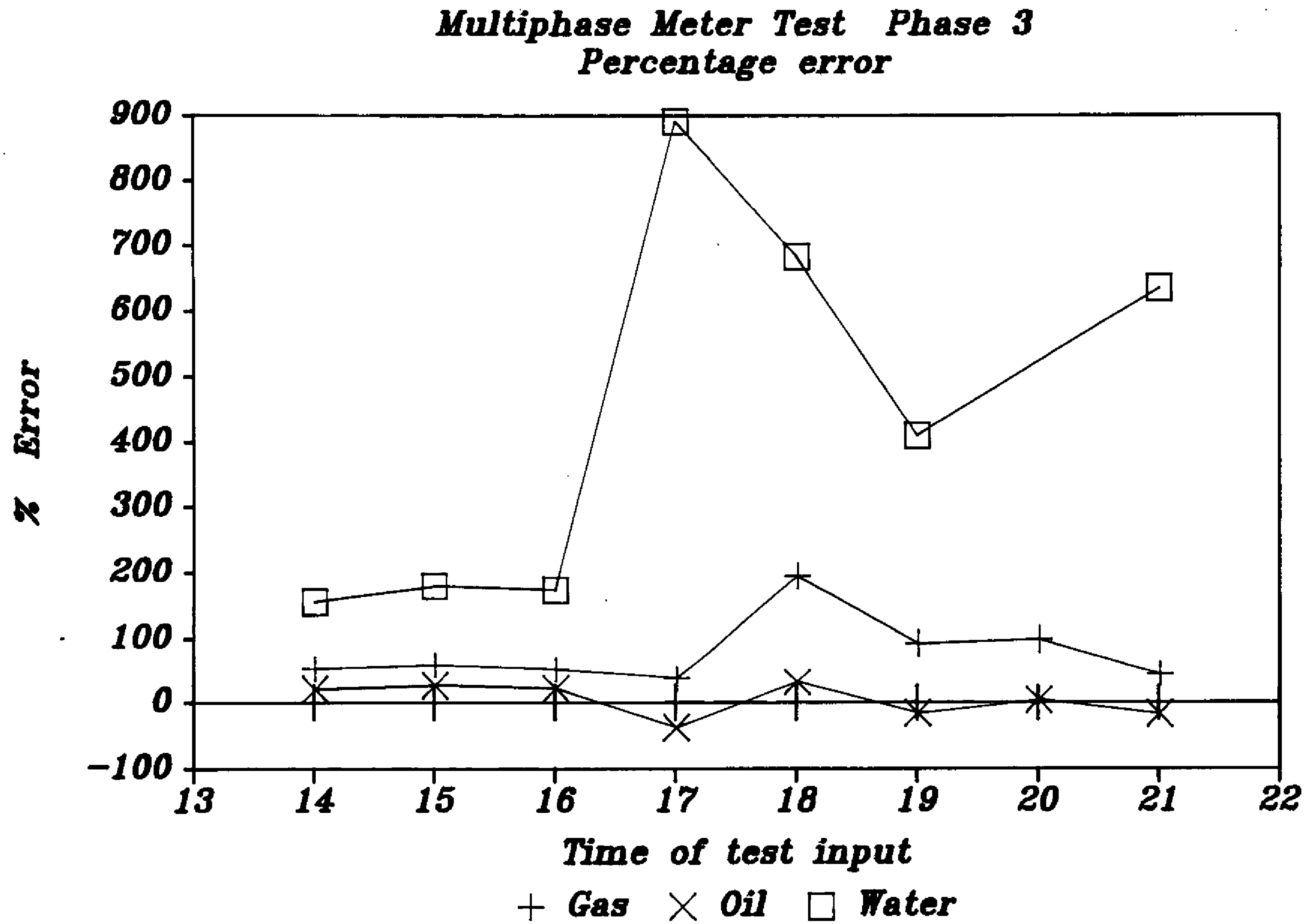

Multiphase Meter Test Phase 3
Percentage error
% Error
900
800
700
600
500
400
300
200
100
0
−100
13
14
15
16
17
18
19
20
21
22
Time of test input
+ Gas × Oil □ Water

FIG 6

APPENDIX I

Determination of the meter factor standard deviation (S) for the calibration data.

Flow rate bbls/d (UK)	K-factor x	$(x-\bar{x})$	$(x-\bar{x})^2$	x^2
11,678.8	1,043.02	2.06	4.244	1087891
9,930.7	1,044.02	1.06	1.124	1089978
8,267.6	1,045.02	0.06	0.0036	1092067
6,857.7	1,045.69	0.61	0.372	1093468
5,033.2	1,047.03	1.95	3.802	1096272
3,552.6	1,045.69	0,61	0.372	1093468
TOTAL	6,270.47			
	1,045.08		$\Sigma(x-\bar{x})^2 = 9.92$	$\Sigma(\bar{x}^2) = 6553144$

$(\Sigma x)^2 = 39318790$

$$S^2 = \frac{\Sigma(x^2) - \frac{(\Sigma x)^2}{n}}{n-1}$$

$$= \frac{11.66}{5}$$

$$= 2.33$$

$$S = 1.53$$

$$= 0.15\%$$

APPENDIX II

1. Calculation of Line Fill Times in 8" 17 km Rolf Pipeline

   a) Production rate 10,000 bopd with GOR of 250

Volume of oil	=	1590 m^3/d	
	=	66.25 m^3/hr	
Volume of gas	=	2.5 x 10^6 scf/d	
	=	67,000 m^3/d	
	=	2,790 m^3/hr	
actual gas	=	146	at 19 barg
Total volume (act.)	=	213.1 m^2/hr	
Pipeline Volume	=	$(0.2)^2 \, {}_{4} \times 17.000$	
	=	551 m^3	
Line Fill	=	$\frac{551}{213}$ hr	
	=	2.6 hr	

   b) Production rate 13.000 bopd and TGOR 450

Volume of oil	=	2067 m^2/d	
	=	86.1 m^2/hr	
Volume of gas	=	5.85 x 10^6 scf/d	
	=	243 x 10^3 scf/hr	
	=	6.54 x 10^3 m^3/hr	
actual	=	139.1 m^3/hr	
Total Volume	=	225 m^3/hr	at 47 barg
Line Fill	=	$\frac{551}{225}$ hr	
	=	2.15 hr	

APPENDIX III

PROOF OF VOLUME RELATIONSHIP FOR PERCENT PHASE CALCULATION

The percentage of gas:

$$\%gas = \frac{\Gamma_{liq} - \Gamma_{mix}}{\Gamma_{liq} - \Gamma_{gas}} \times 100\%$$

where $$\Gamma = \frac{Mass}{Volume} = \frac{M}{V}$$

$$\%gas = \frac{M_l/V_l - (M_l + M_g/V_l + V_g)}{M_l/V_l - M_g/V_g} \times 100\%$$

$$= \frac{\dfrac{(M_l \times (V_l + V_g) - V_l \times (M_l + M_g)}{V_l \times (V_l + V_g)}}{\dfrac{M_l \times V_g - M_g \times V_l}{V_l \times V_g}} \times 100\%$$

$$= \frac{\dfrac{(M_l \times V_g - M_g \times V_l}{V_l \times (V_l + V_g)}}{\dfrac{M_l \times V_g - M_g \times V_l}{V_l \times V_g}} \times 100\%$$

$$= \frac{V_l \times V_g}{V_l \times (V_l + V_g)} \times 100\%$$

$$= \frac{V_g}{V_l + V_g} \times 100\%$$

where

Γ_{liq} = density of liquid

Γ_{gas} = density of gas

Γ_{mix} = density of mixture

M_l = mass of liquid

V_l = volume of liquid

M_g = mass of gas

V_g = volume of gas

APPENDIX IV

a) Calculations of Error in Percent Gas Phase Determination ($\sigma_{\%gas}$) from the formula:

$$\%gas = \frac{\Gamma_2 - \Gamma_1}{\Gamma_2 - \Gamma_{gas}} \times 100 \qquad (1)$$

$$\sigma_{\%gas} = \sqrt{(\sigma^2\%gasR + \sigma^2\%gasS)} \qquad (2)$$

where R and S denote random and systematic errors.

$$\sigma^2\%gasR = \left(\frac{\delta\%gas}{\delta_{\Gamma 2}}\right)^2 \delta^2\Gamma 2R + \left(\frac{\delta\%gas}{\delta_{\Gamma 1}}\right)^2 \delta^2\Gamma 1R + \left(\frac{\delta\%gas}{\delta_{\Gamma gas}}\right)^2 \sigma^2\Gamma gasR \qquad (3)$$

and $$\sigma^2\%gasS = \left(\frac{\delta\%gas}{\delta_{\Gamma 2}}\right)^2 \sigma^2\Gamma 2S + \left(\frac{\delta\%gas}{\delta_{\Gamma 1}}\right)^2 \sigma^2\Gamma 1S + \left(\frac{\delta\%gas}{\delta_{\Gamma gas}}\right)^2 \sigma^2\Gamma gasS \qquad (4)$$

so $$\sigma^2\%gasR = \left(\frac{(\Gamma_1 - \Gamma_{gas})\ 100}{\Gamma^2{}_2+2(\Gamma_2\Gamma_{gas})+\Gamma^2{}_{gas}}\right)^2 \sigma^2\Gamma 2S + \left(\frac{100}{\Gamma_2 - \Gamma_{gas}}\right)^2 \sigma^2\Gamma 1R + \left(\frac{(\Gamma_2-\Gamma_1)\ 100}{\Gamma^2{}_2-2\ (\Gamma_2\Gamma_{gas})+\Gamma^2{}_{gas}}\right)^2 \sigma^2\Gamma gasR \qquad (5)$$

similarly

$$\sigma^2\%gasS = \left(\frac{(\Gamma_1 - \Gamma_{gas})\ 100}{\Gamma^2{}_2-2(\Gamma_2\Gamma_{gas})+\Gamma^2{}_{gas}}\right)^2 \sigma^2\Gamma 2S + \left(\frac{100}{\Gamma_2\ \Gamma_{gas}}\right)^2 \sigma^2\Gamma 1R + \left(\frac{(\Gamma_2-\Gamma_1)\ 100}{\Gamma_2-2(\Gamma_2\Gamma_{gas})+\Gamma^2{}_{gas}}\right)^2 \sigma^2\Gamma gas \qquad (6)$$

Typical values for the various parameters are as follows:

$$\sigma_{\Gamma 2S} = 0.02 \times 0.72 = 0.014 \ g/cm^3$$

$$\sigma_{\Gamma 2R} = 0.005 \times 0.72 = 0.0036 \ g/cm^3$$

$$\sigma_{\Gamma 1S} = 0.02 \times 0.46 = 0.009 \ g/cm^3$$

$$\sigma_{\Gamma 1R} = 0.005 \times 0.46 = 0.002 \ g/cm^3$$

$$\sigma_{\Gamma gasS} = 0.02 \times 0.02 = 0.0004 \ g/cm^3$$

where

$$\Gamma_1 = 0.460 \ g/cm^3$$

$$\Gamma_2 = 0.720 \ g/cm^3$$

$$\Gamma_{gas} = 0.020 \ g/cm^3$$

Inserting these values into equations (5) and (6) gives

$$\sigma^2_{\%gasR} = (89.8)^2(0.0036)^2+(143)^2(0.002)^2+(53.1)^2(0.0)^2$$

$$= 0.105 + 0.082 + 0.0$$

$$= 0.19\%^2$$

and similarly for the systematic errors

$$\sigma^2_{\%gasS} = (89,8)^2(0.014)^2+(143)^2(0.009)^2+(53.1)^2(0.004)^2$$

$$= 1.58 + 1.66 + 0.0004$$

$$= 3.24\%^2$$

finally from equation (2)

$$\sigma_{\%gas} = \sqrt{(0.19 + 3.24)}$$

$$= 1.19\%$$

b) Calculation of Error in Percent Oil Determination ($\sigma_{\%oil}$)

from the formula

$$\%oil = \frac{\Gamma_{water}-\Gamma_2}{\Gamma_{water}-\Gamma_{oil}} \times \%liquid \qquad (7)$$

$$\sigma^2_{\%oil} = \sqrt{(\sigma^2_{\%oilR} + \sigma^2_{\%oilS})} \qquad (8)$$

where

$$\sigma^2_{\%oilR} = \left(\frac{\delta_{\%oil}}{\delta_{\Gamma water}}\right)^2 \sigma^2_{\Gamma waterR} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma 2}}\right)^2 \sigma^2_{\Gamma 2R} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma oil}}\right)^2 \sigma^2_{\Gamma oilR}$$

$$+\left(\frac{\delta_{\%oil}}{\delta_{\%liquid}}\right)^2 \sigma^2_{\%liquidR} \qquad (9)$$

and

$$\sigma^2_{\%oilS} = \left(\frac{\delta_{\%oil}}{\delta_{\Gamma water}}\right)^2 \sigma^2_{\Gamma waterS} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma 2}}\right)^2 \sigma_2{}_{\Gamma 2S} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma oil}}\right)^2 \sigma^2_{\Gamma oilS}$$

$$+\left(\frac{\delta_{\%oil}}{\delta_{\%liquid}}\right)^2 \sigma^2_{\%liquidS} \qquad (10)$$

where

$$\delta^2_{\%oilR} = \left(\frac{1}{\Gamma_{water}-\Gamma_{oil}}\right) - \left(\frac{(\Gamma_{water}-\Gamma_2)(\%liquid)}{\Gamma^2{}_{water}-2(\Gamma_{water}\Gamma_{oil})+\Gamma^2{}_{oil}}\right)^2 \sigma^2_{\Gamma waterR}$$

$$+ \left(\frac{(\%liquid)}{\Gamma_{water}-\Gamma_{oil}}\right)^2 \sigma^2_{\Gamma 2R}$$

$$+ \left(\frac{\Gamma_{water}-\Gamma_2\ (\%liquid)}{\Gamma^2{}_{water}-2(\Gamma_{water}\Gamma_{oil})+(\Gamma^2{}_{oil})}\right)^2 \sigma^2_{\Gamma oilR}$$

$$+ \left(\frac{\Gamma_{water}-\Gamma_2}{\Gamma_{water}-\Gamma_{oil}}\right)^2 \sigma^2_{\%liquidR} \qquad (11)$$

and

$$\sigma^2_{\%oilS} = \left(\frac{1}{\Gamma_{water}-\Gamma_{oil}}\right) - \left(\frac{(\Gamma_{water}-\Gamma_2)(\%liquid)}{\Gamma^2{}_{water}-2(\Gamma_{water}\Gamma_{oil})+\Gamma^2{}_{oil}}\right)^2 \sigma^2_{\Gamma waterS}$$

$$+ \left(\frac{(\%liquid)}{\Gamma_{water}-\Gamma_{oil}}\right)^2 \sigma^2_{\Gamma 2S}$$

$$+ \left(\frac{\Gamma_{water}-\Gamma_2\ (\%liquid)}{\Gamma^2_{water}-2(\Gamma_{water}\Gamma_{oil})+(\Gamma^2_{oil})}\right)^2 \sigma^2_{\Gamma oilS}$$

$$+ \left(\frac{\Gamma_{water}-\Gamma_2}{\Gamma_{water}-\Gamma_{oil}}\right)^2 \sigma^2_{\%liquidS} \qquad (12)$$

Typical values are as follows

$\sigma_{\Gamma waterR}$ = 0.0 x 1.04 = 0.0 g/cm^3

$\sigma_{\Gamma waterS}$ = 0.02 x 1.04 = 0.021 g/cm^3

$\sigma_{\Gamma 2R}$ = 0.005 x 0.73 = 0.004 g/cm^3

$\sigma_{\Gamma 2S}$ = 0.02 x 0.73 = 0.015 g/cm^3

$\sigma_{\Gamma oilR}$ = 0.0 x 0.72 = 0.0 g/cm^3

$\sigma_{\Gamma oilS}$ = 0.02 x 0.72 = 0.014 g/cm^3

where

Γ_{oil} = 0.72 g/cm^3

Γ_2 = 0.73 g/cm^3

Γ_{water} = 1.04 g/cm^3

Inserting these values into equation (11) and (12)

$$\sigma^2_{\%oilR} = (6.4)^2(0.0)^2+(203)^2(0.004)^2+(197)^2(0.0)^2+(0.93)^2(0.44)^2$$

$$= 0.0 + 0.66 + 0.0 + 0.18$$

$$= 0.84\%^2$$

$$\sigma^2_{oilS} = (6.4)^2(0.021)^2+(203)^2(0.015)^2+(197)^2(0.014)^2+(0.97)^2(1.8)^2$$

$$= 0.018 + 9.3 + 7.6 + 3.05$$

$$= 20.0\%^2$$

finally from equation (8)

$$\sigma\%oil = \sqrt{(0.84+20.0)}$$

$$= 4.6\%$$

c) Calculation of Error in Percent Water Phase Determination ($\sigma_{\%water}$)

From the formula

$$\%water = 1.0 - \left(\frac{\%oil}{100} + \frac{\%gas}{100}\right)$$

$$\sigma^2\%water = \sqrt{(\sigma^2\%waterR + \sigma^2\%waterS}$$

where $$\sigma^2\%waterR = \left(\frac{\delta\%water}{\delta\%oilR}\right)^2 \sigma^2\%oilR + \left(\frac{\delta\%water}{\delta\%gasR}\right)^2 \sigma^2\%gasR \qquad (13)$$

$$= (1.0)^2(0.84) + (1.0)^2(0.19)$$

$$= 1.03\%^2$$

and $$\sigma^2\%waterS = (1.0)^2(20.0) + (1.0)^2(3.24)$$

$$= 23.24\%^2$$

$$\sigma^2\%water = \sqrt{(1.03 + 23.24)}$$

$$= 4.9\%$$

APPENDIX V

It can be readily shown that by taking the reciprocal of the measured densities a mass percentage relationship is obtained:

$$\%gas = \frac{\Gamma_l^{-1} - \Gamma_{mix}^{-1}}{\Gamma_l^{-1} - \Gamma_g^{-1}}$$

where Γ_l = liquid density
Γ_{mix} = mixture density

so that

$$\%\ gas = \frac{V_l/M_l - V_l+V_g/M_l+M_g}{V_l/M_l - V_g/M_g}$$

and V = volume
M = mass of the various constituents

$$= \frac{V_l(M_l + M_g) - M_l(V_l+V_g) \times Ml(M_l+M_g)}{V_lM_g - M_lV_g/M_lM_g}$$

$$= \frac{M_g}{M_l + M_g}$$

FIELD EXPERIENCE USING CORIOLIS MASS METERS - 1

by

B Lawson
Occidental Petroleum (Caledonia) Ltd

Paper 2.4a

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

FIELD EXPERIENCE USING CORIOLIS METERS

BRUCE LAWSON - INSTRUMENT METERING ENGINEER

OCCIDENTAL PETROLEUM (CALEDONIA) LTD

INTRODUCTION

During the autumn of 1985 Brooks Instruments held an exhibition at an hotel in Aberdeen to demonstrate the range of equipment they produce. On show at the exhibition was the Micromotion mass flow meter, which operates on the Coriolis principle. As an engineer who spends his life having to design orifice and turbine meters into difficult locations the virtual lack of flow conditioning prior to the meter seemed too good to be true. At the time we identified the following potential advantages of the meter over its more established rival types:

1 Relative ease of installation resulting from apparent lack of flow conditioning requirements.

2 Low maintenance costs and hence low "real" cost of ownership.

3 The potential for use on new developments , particularly offshore satellite developments, where additional savings are of obvious importance.

Following an initial appraisal of the meter it was decided to approach the Department of Energy to investigate their acceptance of the meter for Fiscal service. A D150 meter, rated at ANSI 1500, was procured for trial on the Claymore condensate system.

PRE-INSTALLATION WORK

In view of the declared intention to have a meter of this type adopted for Fiscal duty it was decided to check the manufacturers calibration at SIRA before the field test began. This calibration check was carried out during early May 1986.

The meter was tested in the SIRA No2 flow laboratory. The flowmeter was mounted in a straight, horizontal pipeline of 1.5 inch nominal bore, with an upstream straight length of 15D. The Mass was determined by weighing under static conditions, using a gyroscopic force measurement system. A mass of fluid was diverted into a weightank in a measured time. The mass of fluid was corrected for air buoyancy, following which the mass flowrate was calculated.

The flow meter was initially tested on kerosene at 30 ^{o}Celcius, the test was then repeated using a gas oil as the test fluid at 30 ^{o}Celcius. Throughout the test the temperature was maintained to within 0.2 ^{o}Celcius of setpoint.

The fluid densities were determined using a digital density meter operating on the vibrating tube principle. Fluid viscosities were measured using suspended level viscometers, in accordance with BS 188:1977.

All equipment used during the tests was traceable to UK national standards. The flow measurement uncertainty was estimated to be +/- 0.2% of the true conventional value(95% confidence level)

A schematic of the test loop is shown in figure 1.

SIRA Test results

The densities and viscosities of the two test fluids at 30^{o}Celcius were as follows:

KEROSENE	790.9 Kg/m^3	1.41 cSt
GAS OIL	837.9 Kg/m^3	4.81 cSt

The tabulated results of the tests on Kerosene an Gas Oil are given in figures 2 and 3 respectively. A plot of the results is given in figure 4.

The test results indicated that the meter performed within the manufacturers stated accuracy of +/- 0.4 percent.

INSTALLATION

Following the completion of the work at SIRA the meter was then shipped offshore to Claymore for installation on the condensate system, downstream of the existing Fiscal orifice meter run. The meter was installed in the line in June 1986 however, due to the extremely heavy workload with the Scapa development, the meter was not commissioned until early April 1987.

It was realised that the physical installation of the meter was far from perfect. However, this would test the ability of the meter to cope with a lack of flow conditioning. In an effort to eliminate any later criticism of the installation from the manufacturer, representatives of Brooks were invited to visit Claymore and approve the installation for themselves. No strong objections were received following the visit and the test belatedly began on the 1st May 1987. The meter is shown in figure 5 with the installation given in figure 6 and 7.

During the test, the meter was zeroed once and no further adjustments or replacements were made to either the meter or electronics.

FIELD TEST RESULTS

It was decided that the only way to test the meter was to record the daily total registered on both the orifice and the Coriolis meter totalisers. The totals on the orifice meter were taken automatically at midnight by the platform metering supervisory computer whilst the Coriolis meter total was recorded manually at midnight. This is not believed to have affected the results of the test by any significant amount.

Figures 9 and 10 show the variation in the Coriolis meter readings in relation to the orifice measurement. It is important to point out that the error, although depicted as being in the Coriolis meter, may just as likely be in the orifice meter. The comparative test was run at the conditions that prevailed on the platform at the time, no variation of the process conditions other than those required to operate the plant were possible. The relatively large negative peak which occurred in mid August was related to a period of unstable plant operation although, the actual cause of error has not been fully identified. It is very interesting to note that, when comparing the above plot with the plot of measured density the significant positive peaks coincide with positive changes in density. This may well be a function of the flow in the densitometer bypass loop associated with the orifice installation. A comparison of the mass and density plots is shown in figure 11.

Figures 12 and 13 indicate the process conditions throughout the test period.

The plant vibration was measured in the vicinity of the meter to see what vibration was present as the meter was located in the main compressor module. The results of these tests are shown in figure 8. The meter does not appear to be effected by the plant vibration, which was typical of an offshore installation with heavy rotating machinery in the close vicinity.

POST-INSTALLATION WORK

The meter was removed from the condensate system on 1st April 1988. It was then decided to close the evaluation test with a further calibration check, now almost two years since the original test at SIRA. The manufacturer offered to calibrate the meter at their plant in Holland. The tests were carried out at Veenendaal on the 9-10 June 1988, with representatives of the Department of Energy and Occidental in attendance.

The calibration was carried out on water using a load cell to measure the mass. Details of the calibration loop used at Veenendaal are shown on figure 15

On commencement of this calibration the short term repeatability of the meter was extremely poor. The test was halted and a detailed inspection was carried out during which it was discovered the earth connection to the sensor had been severed inside the flexible conduit connection. This damage had been suffered in transit due to the position of entry gland in relation to the lid of the box.

Once the above problem has been corrected the meter again performed within specification, as shown on figure 14.

CONCLUSIONS

The meter tested by Occidental has demonstrated its potential as an accurate, stable and reliable meter suitable for use on Fiscal applications in the future. However, one area which requires further development is the measurement of density within the meter. The accurate measurement of density, together with the mass flow, would allow calculation of volume. Even in a mass measurement multiuser pipeline system the volume of fluids is important as this will always be required for reservoir management and tariffing purposes.

Earlier this year Occidental had selected Coriolis meters to measure the flow of high pressure condensate from the Chanter field. However, due to recent events, this development is under reappraisal. A sketch of the proposed installation arrangement is shown for interest in figure 16. The verification of the meters calibration was to have been carried out off-line with only comparison checks being carried out in service.

ACKNOWLEDGEMENTS

The author would like to thank Union Texas, Texaco Britain, Thomson North Sea, Brooks Instruments and SIRA together with the operations and maintenance staff of Claymore for their assistance during the trials and in the preparation of this paper.

LIST OF FIGURES

SIRA 2500L/MIN HYDROCARBON FLOW FACILITY – SCHEMATIC DIAGRAM

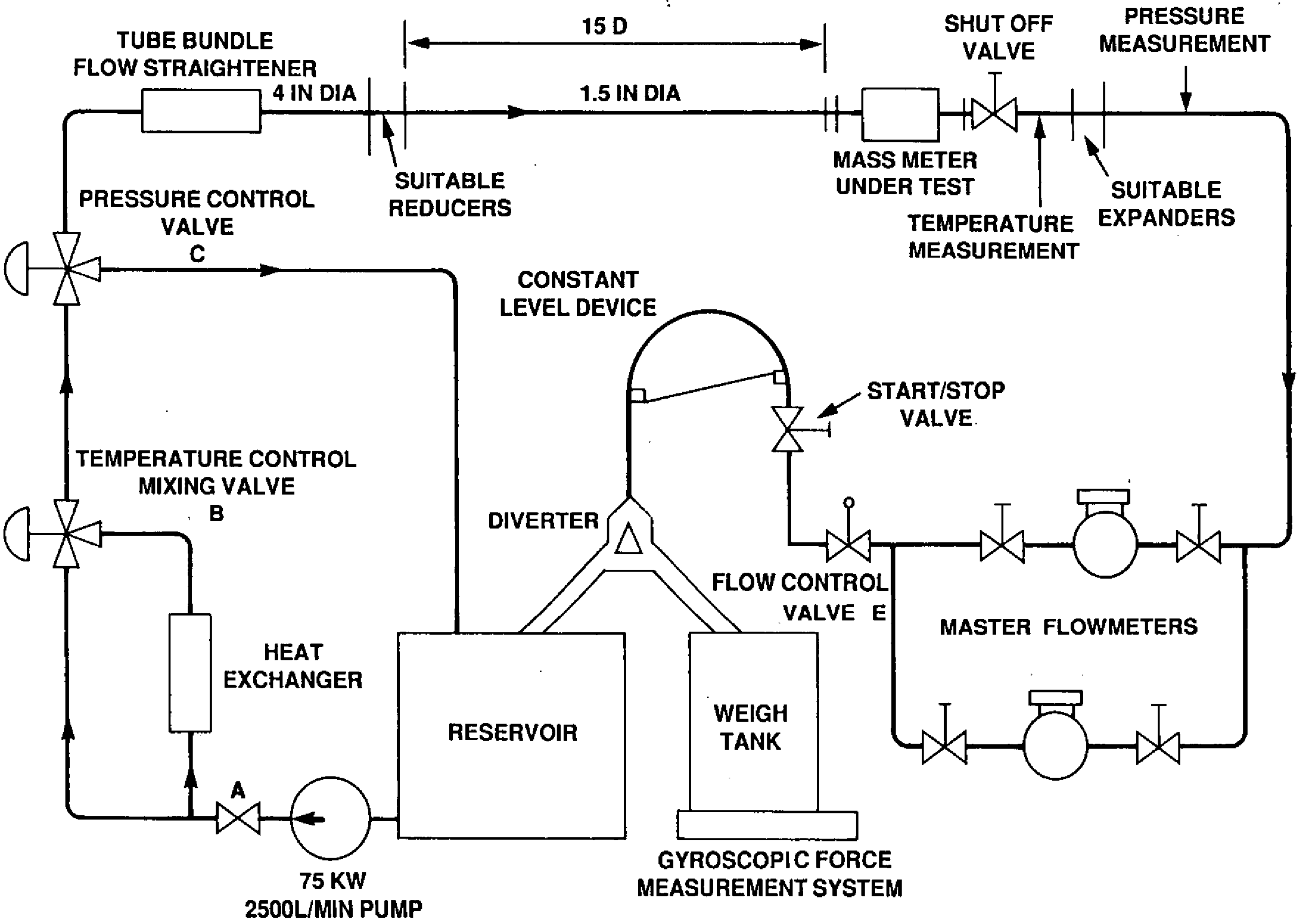


FIGURE 1

0424

TEST RESULTS
KEROSENE AT 30°C

FLOWRATE t/h	METER FACTOR pulses/t	OUTPUT FREQUENCY Hz
29.38	358999	2930
29.35	359182	2929
29.43	359025	2935
29.42	358756	2931
29.41	358755	2931
27.01	358726	2691
21.04	358087	2093
21.06	358222	2096
24.16	357975	2402
20.54	358176	2044
17.99	358333	1791
24.20	357952	2407
14.81	357764	1472
14.76	358280	1469
14.73	358136	1466
14.83	357980	1475
14.79	358102	1471
11.95	358280	1189
9.000	357561	894
6.003	357525	596
3.090	357867	307
3.083	357663	306
3.083	357997	307
3.079	358003	306
3.083	357488	306

FIGURE 2

0424

TEST RESULTS
GAS OIL AT 30°C

FLOWRATE t/h	METER FACTOR pulses/t	OUTPUT FREQUENCY Hz
30.51	358309	3037
30.41	357915	3024
30.45	358231	3030
30.00	358036	2983
30.11	357993	2994
27.39	357303	2718
24.13	357223	2394
21.14	356948	2096
11.97	358057	1190
9.071	357570	901
15.31	358083	1523
15.31	357952	1523
15.29	357740	1519
15.28	357263	1516
15.28	358403	1521
15.28	357950	1519
18.35	357144	1820
6.043	358007	601
2.987	357058	296
2.983	356929	296
2.979	357059	295
2.956	357315	295
2.972	356914	295
21.320	356735	2113

FIGURE 3
0424

MICRO MOTION D150 MASS FLOW METER

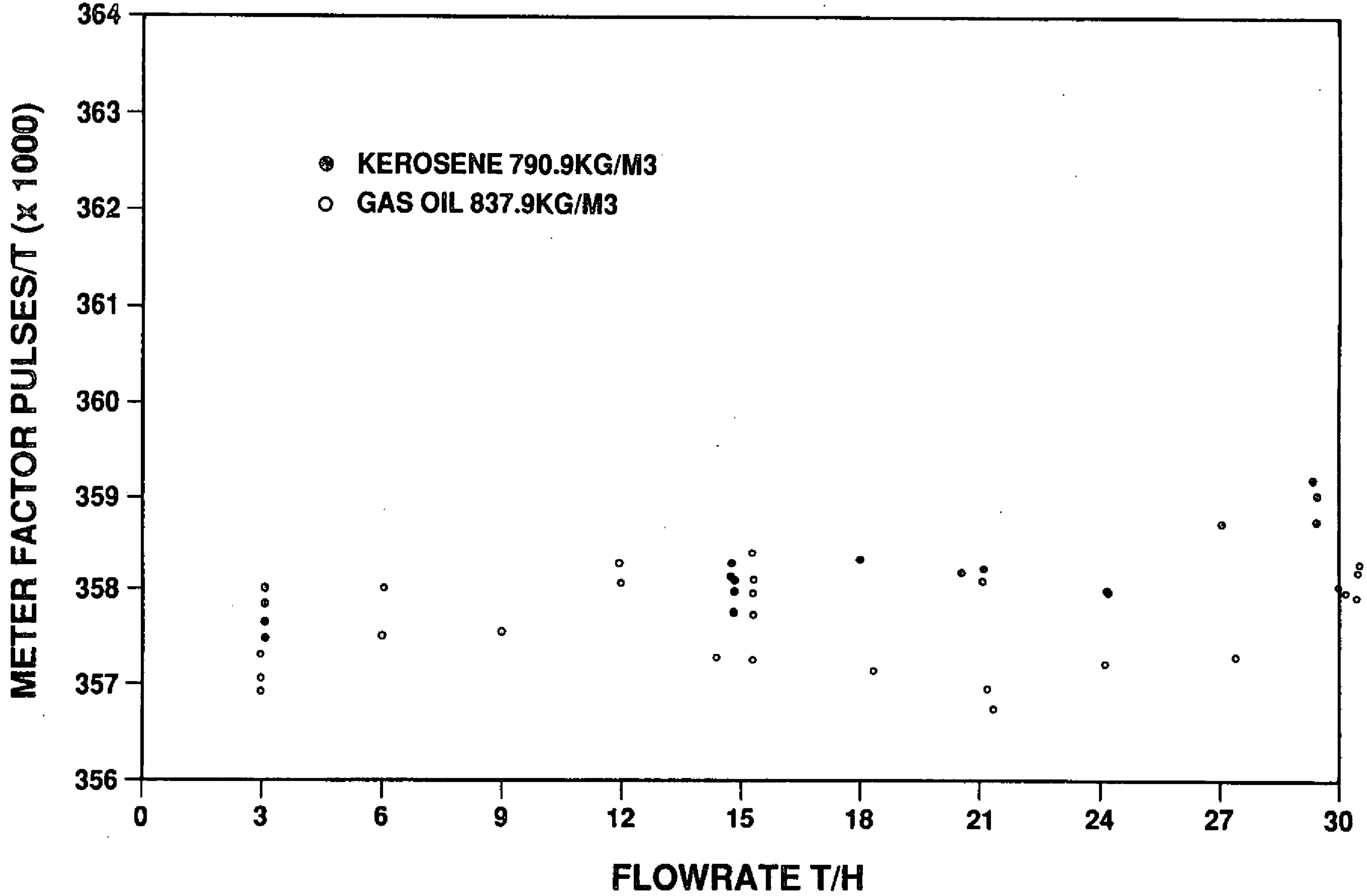
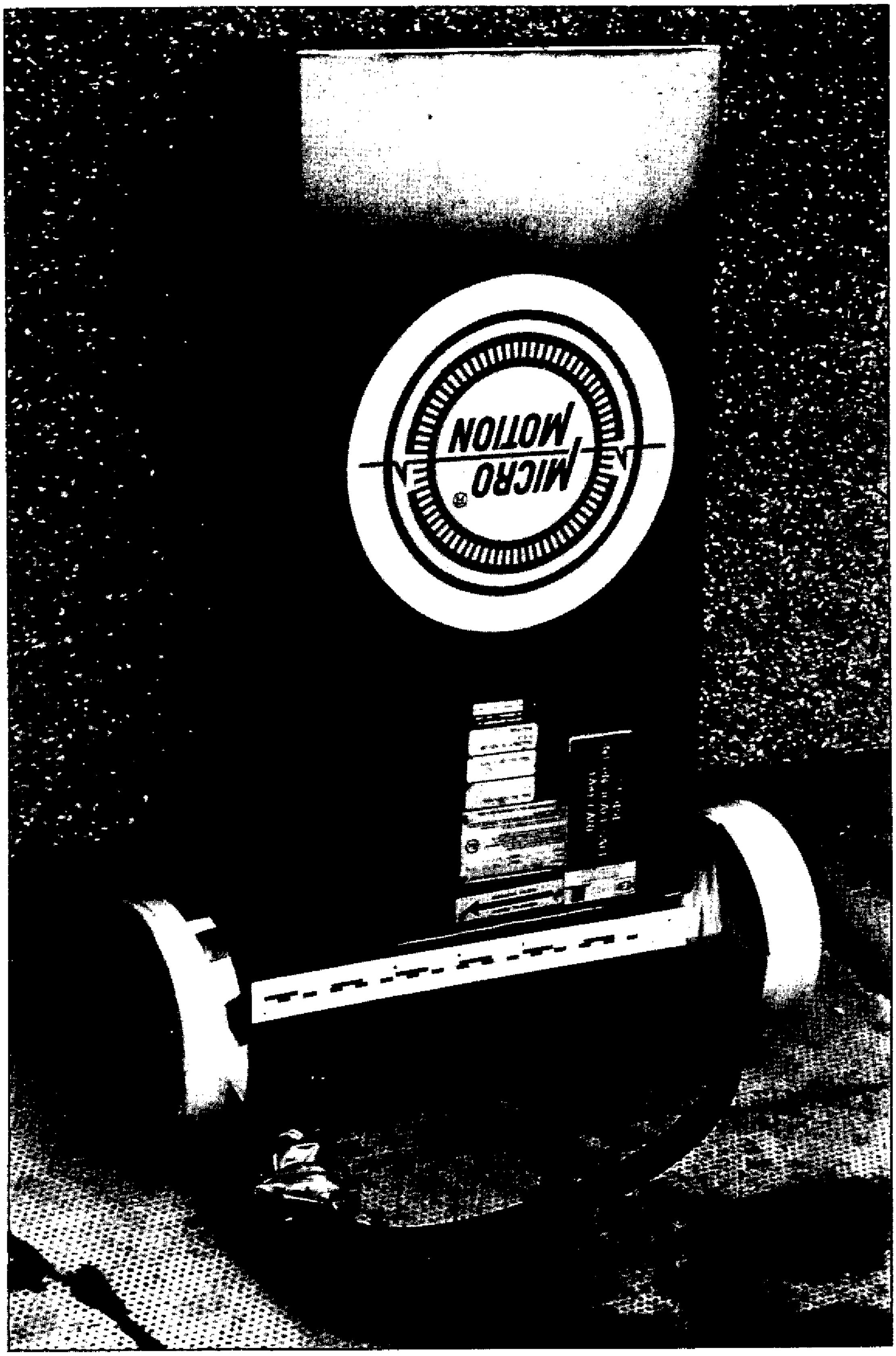


FIGURE 4

0424



D150 METER
ANSI 1500 PRESSURE RATED

FIGURE 5

CLAYMORE 'A'

PIPEWORK ISOMETRIC FOR CORIOLIS METER INSTALLATION

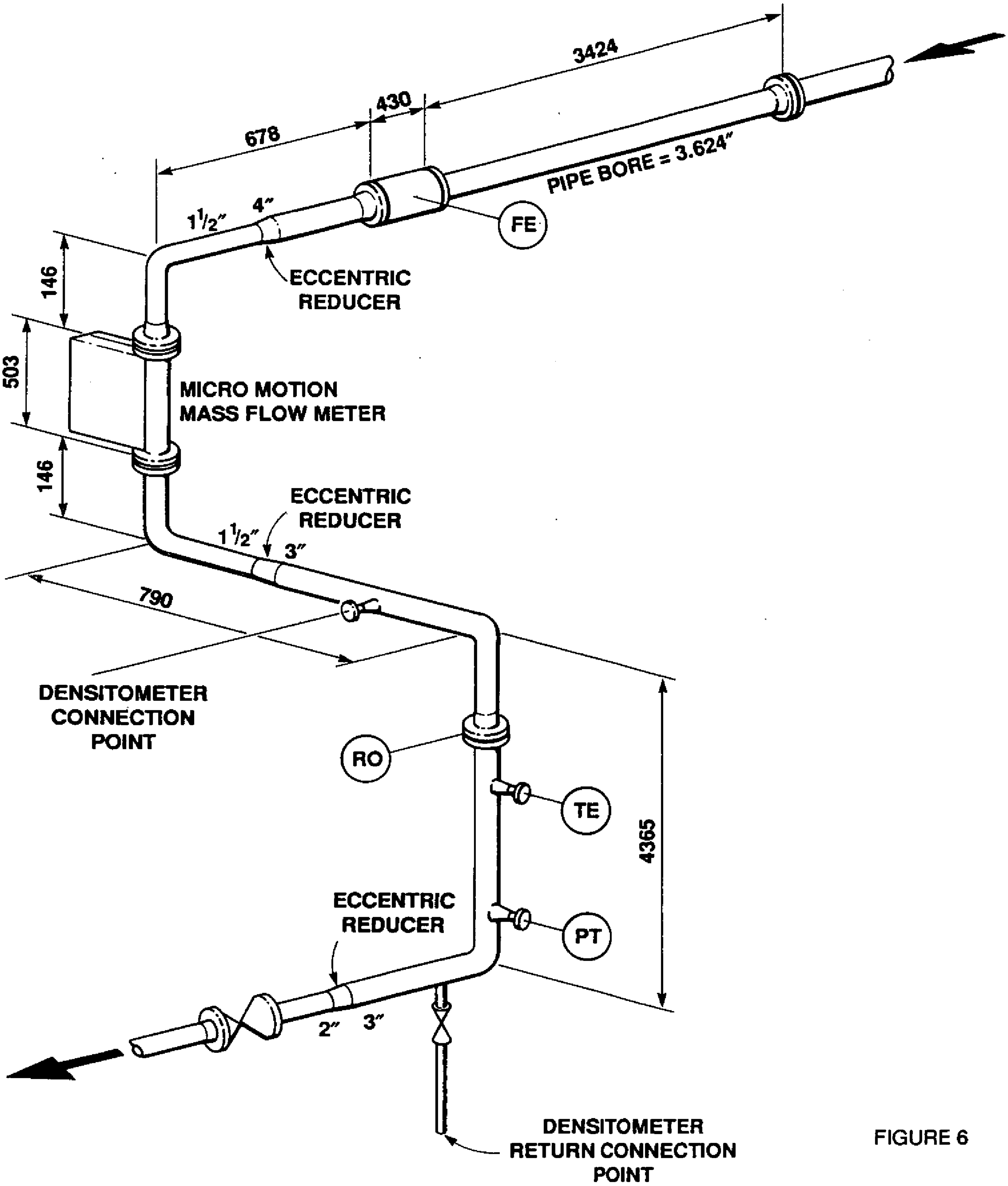
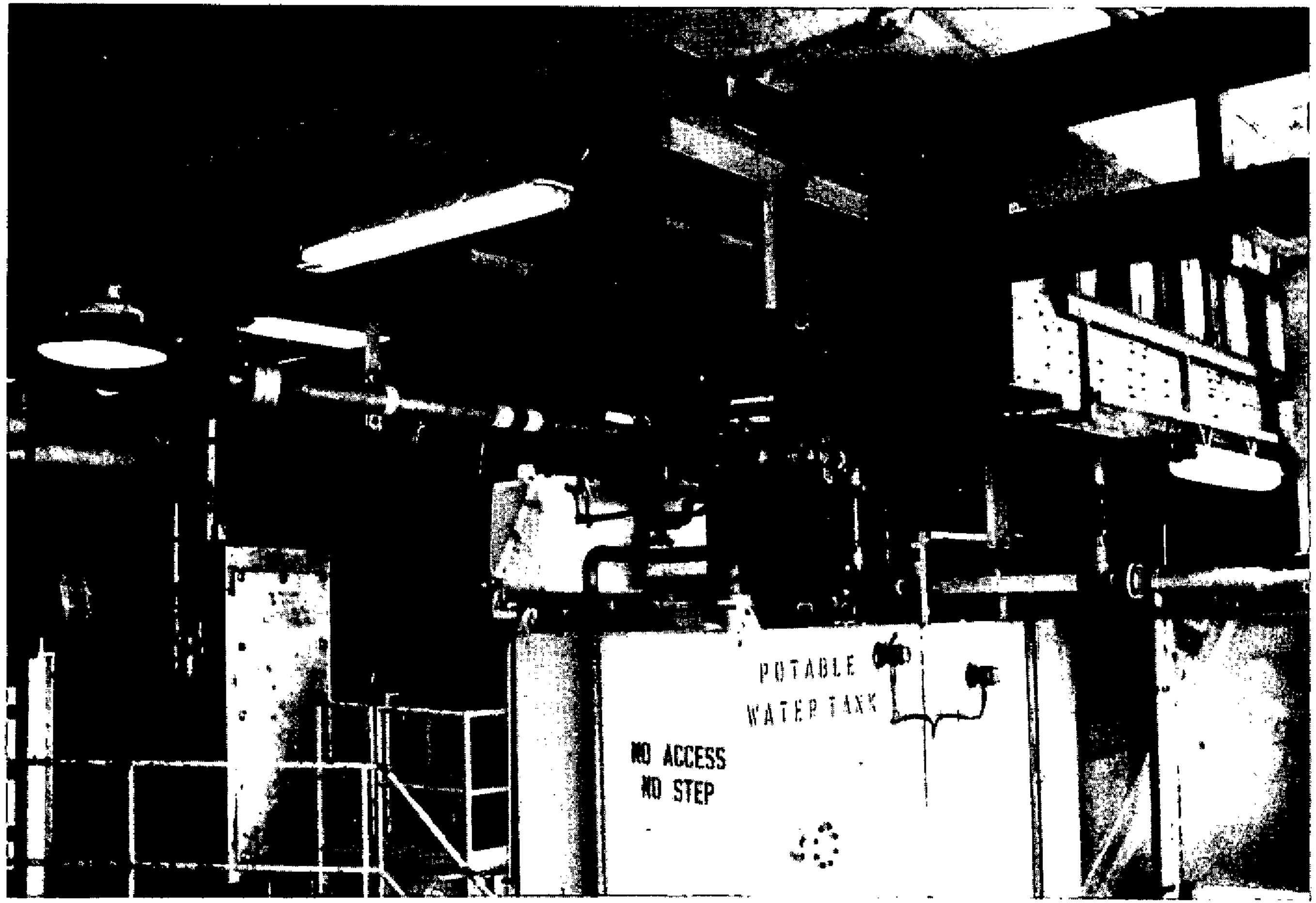
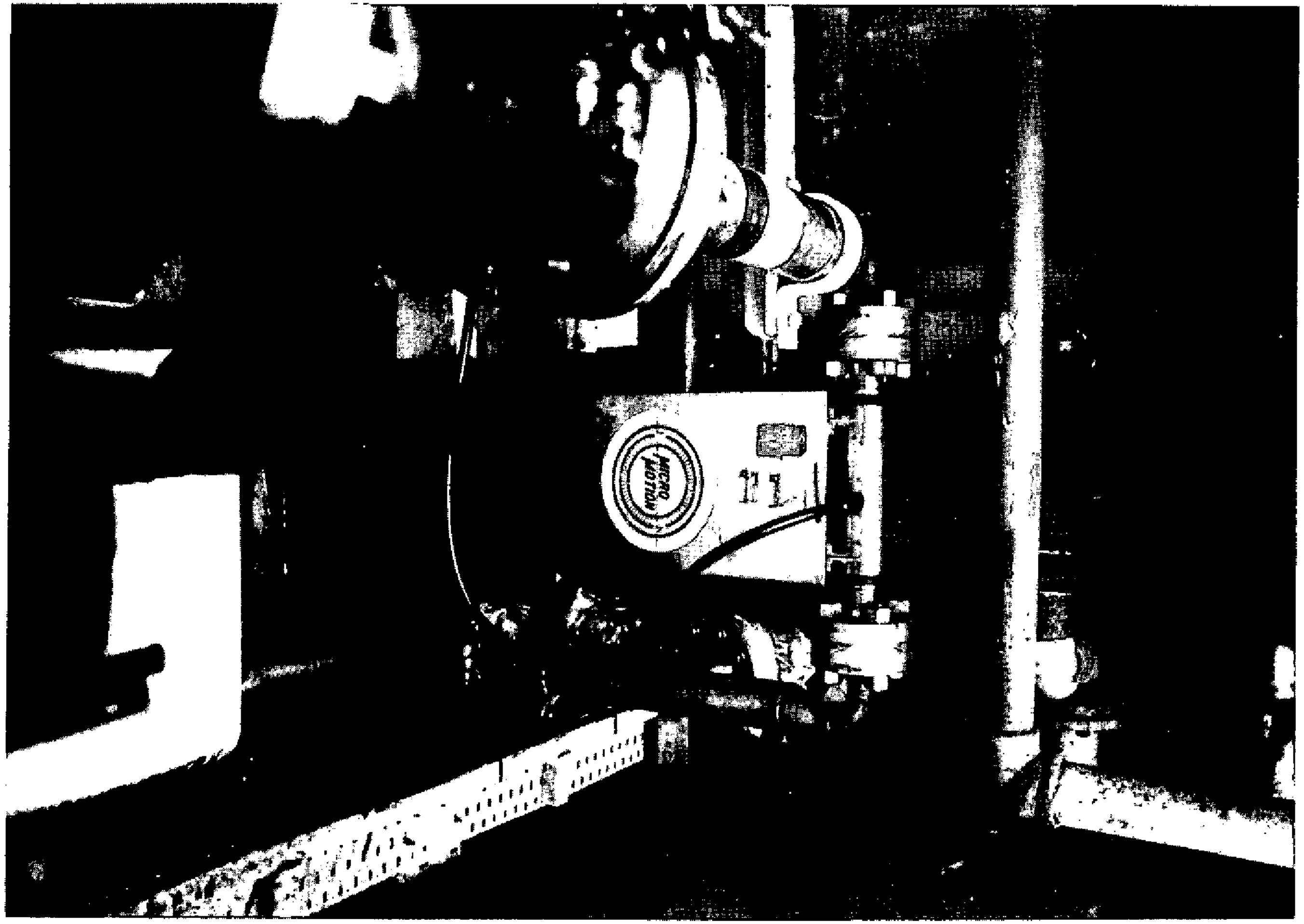


FIGURE 6



CORIOLIS METER INSTALLATION CLAYMORE

FIGURE 7a

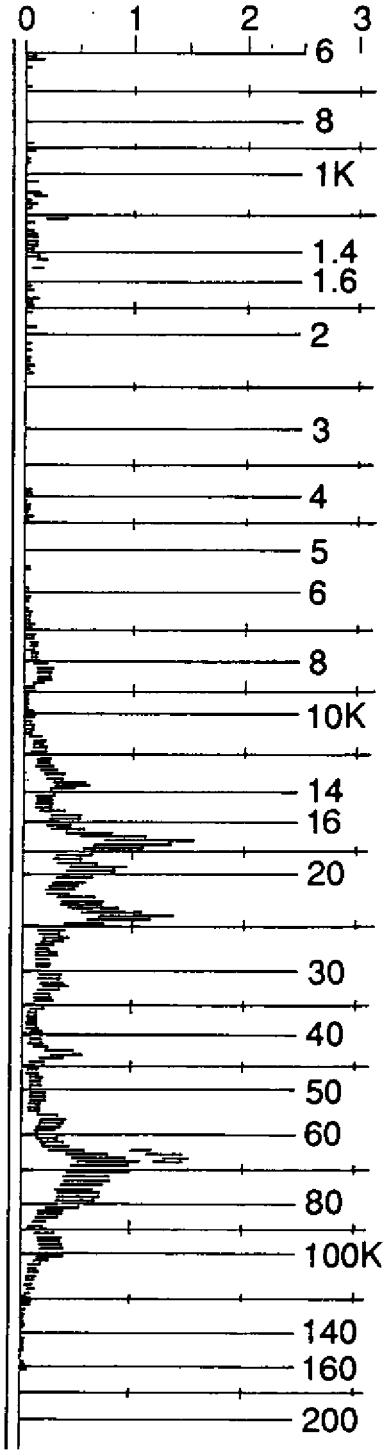


CORIOLIS METER INSTALLATION CLAYMORE

FIGURE 7b

BACKGROUND FREQUENCIES PRESENT ON CLAYMORE MEASURED 1 FOOT FROM OUTLET FLANGE OF CORIOLIS METER

IRD MECHANALYSIS
DATE 19/2/88 OA 4
MACH
POSIT A2 OUTLET IFT
COND
MM/SEC PK 5%BW



INSTRUMENT POWER OFF

IRD MECHANALYSIS
DATE 19/2/88 OA 4
MACH
POSIT A2 OUTLET IFT
COND
MM/SEC PK 5% BW

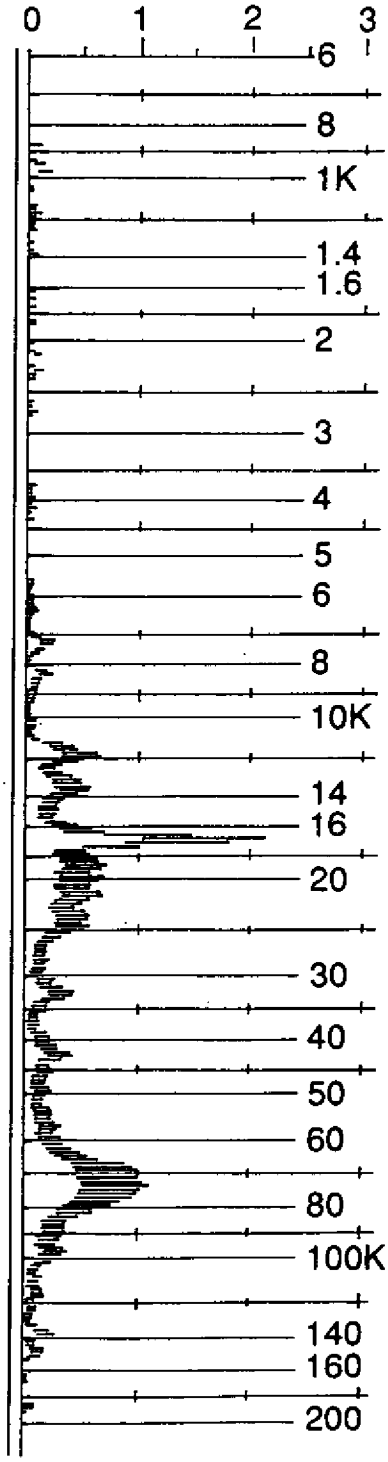


FIGURE 8

CLAYMORE CONDENSATE
COMPARISON OF CORIOLIS METER VS ORIFICE PLATE

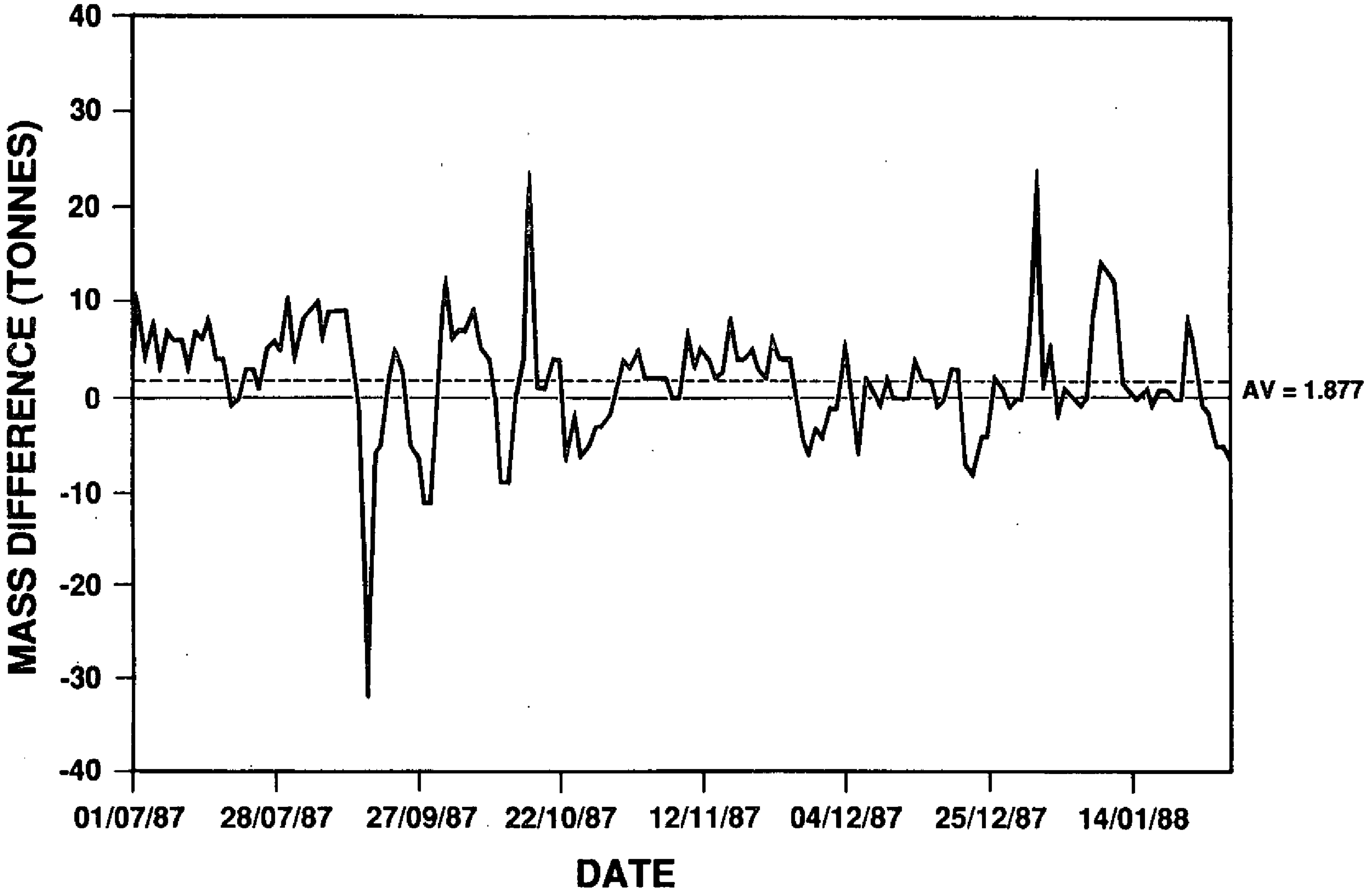


FIGURE 9
0424

CLAYMORE CONDENSATE
COMPARISON OF CORIOLIS METER VS ORIFICE PLATE

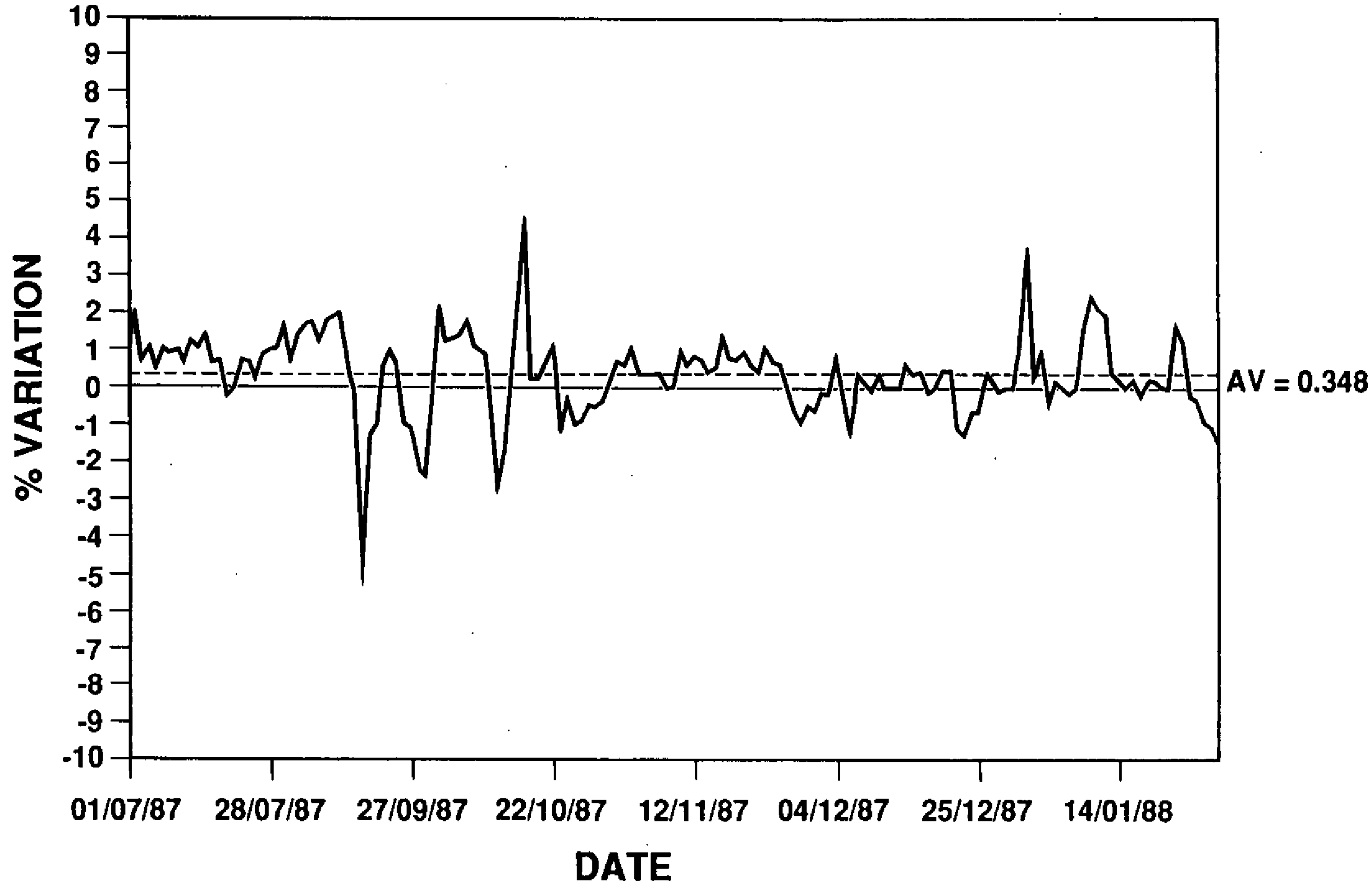


FIGURE 10

0424

CLAYMORE CONDENSATE
MASS DIFFERENCE Vs OBSERVED DENSITY

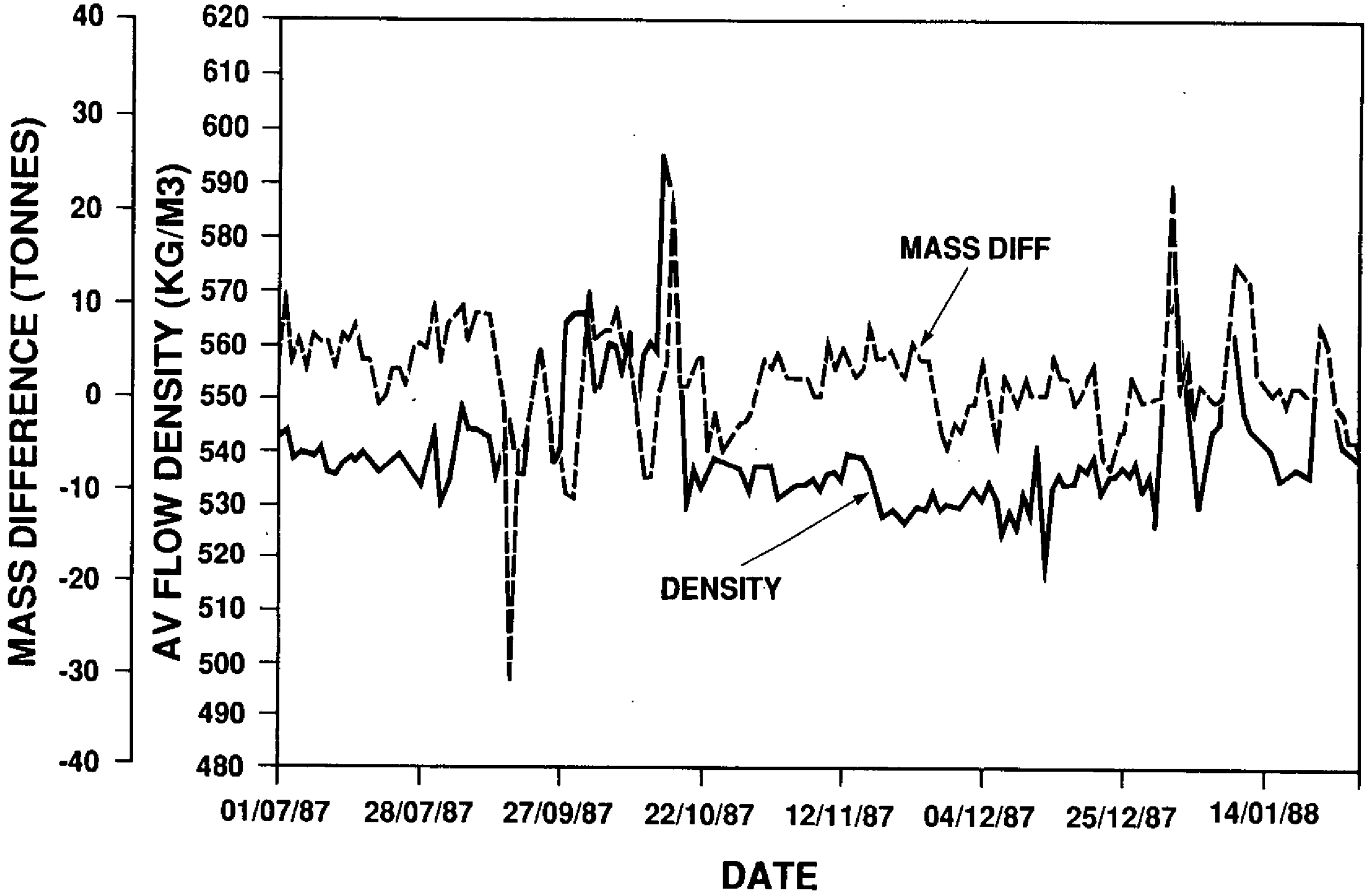


FIGURE 11

0424

CLAYMORE CONDENSATE
VARIATION OF AVERAGE FLOWING DENSITY

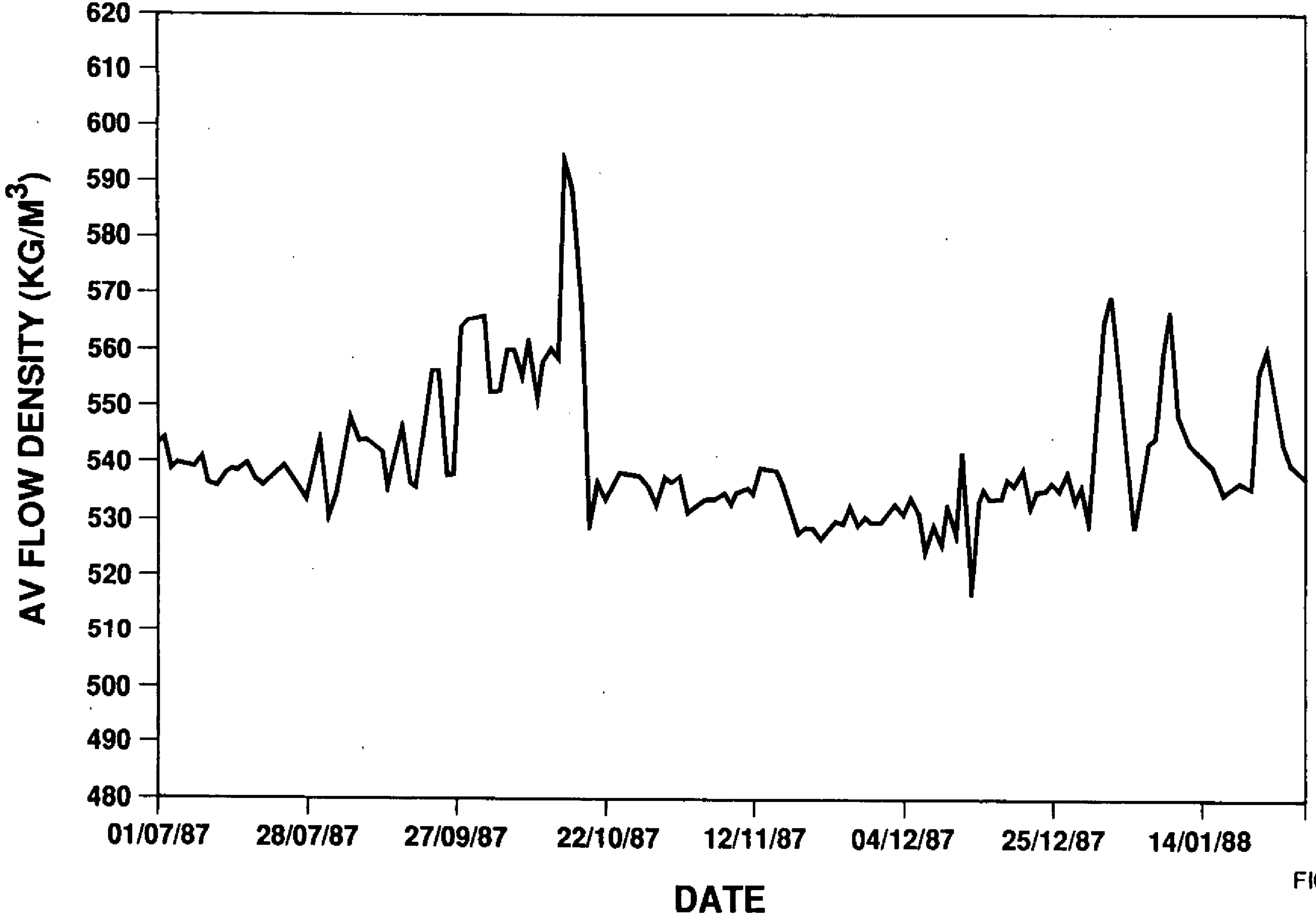


FIGURE 12

0424

CLAYMORE CONDENSATE
VARIATION OF DAILY FLOW, PRESSURE AND TEMPERATURE

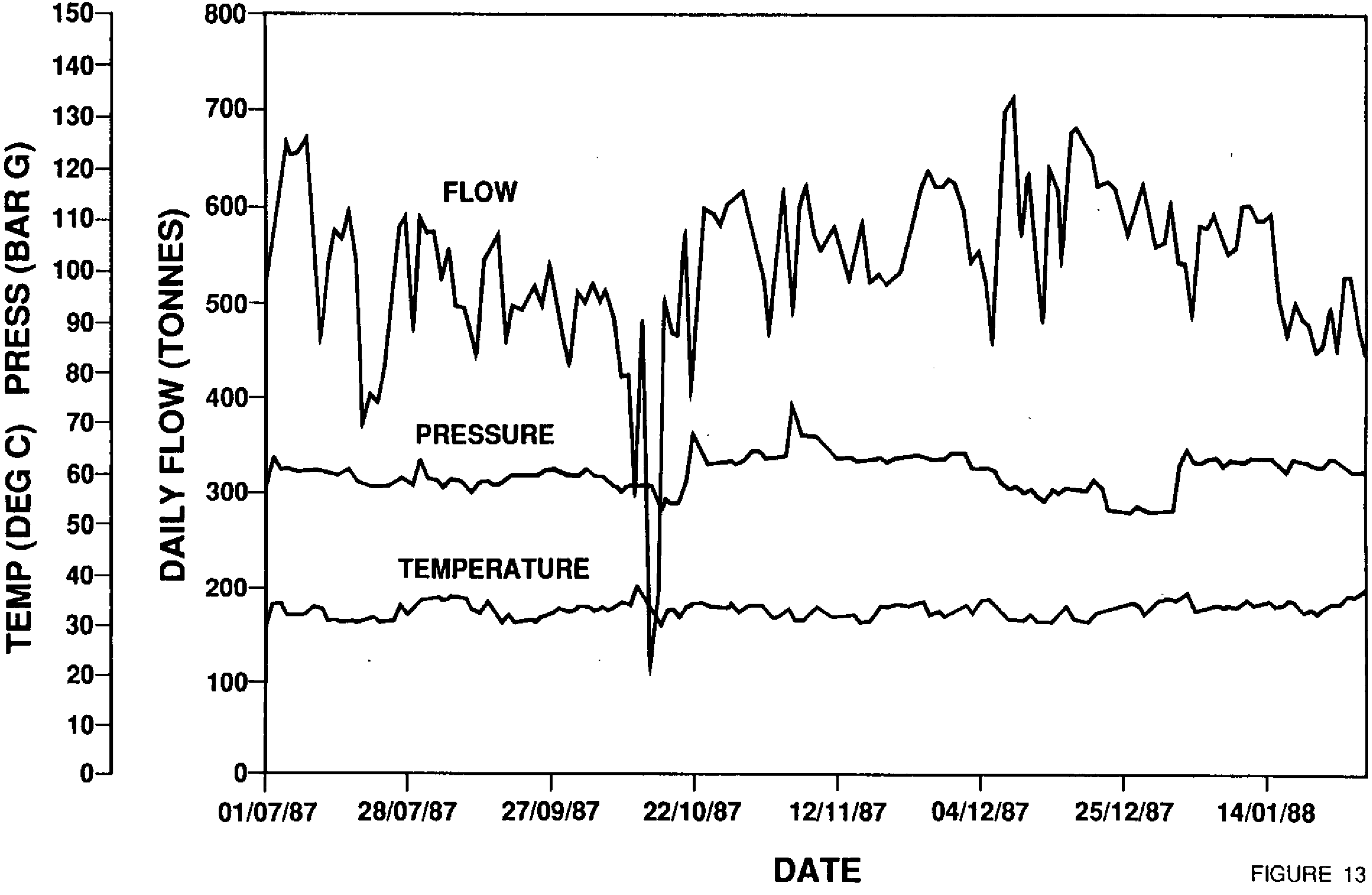


FIGURE 13

0424

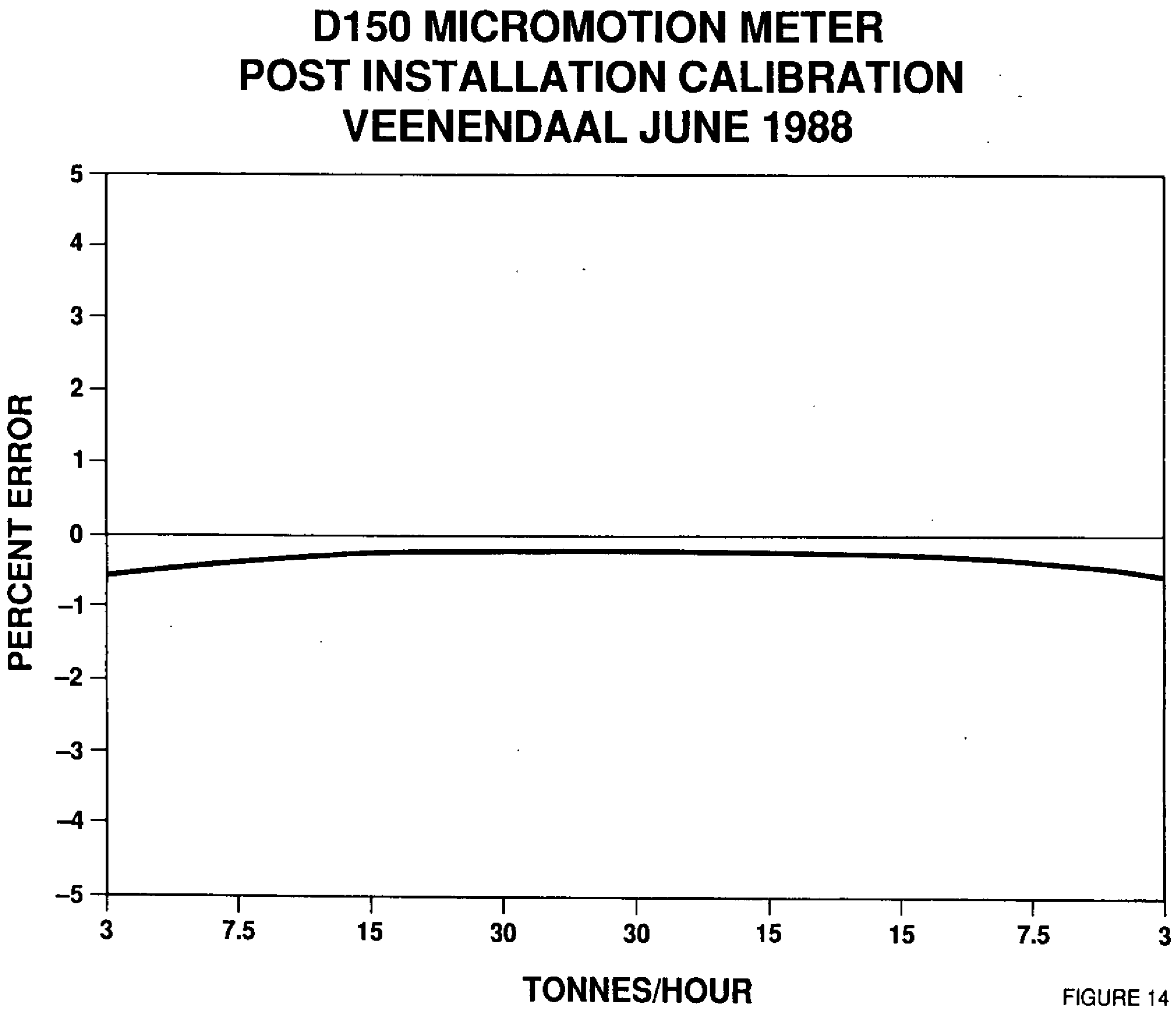


FIGURE 14

0424

DIAGRAM OF CALIBRATION FACILITY AT BROOKS INSTRUMENT PLANT VEENENDAAL HOLLAND

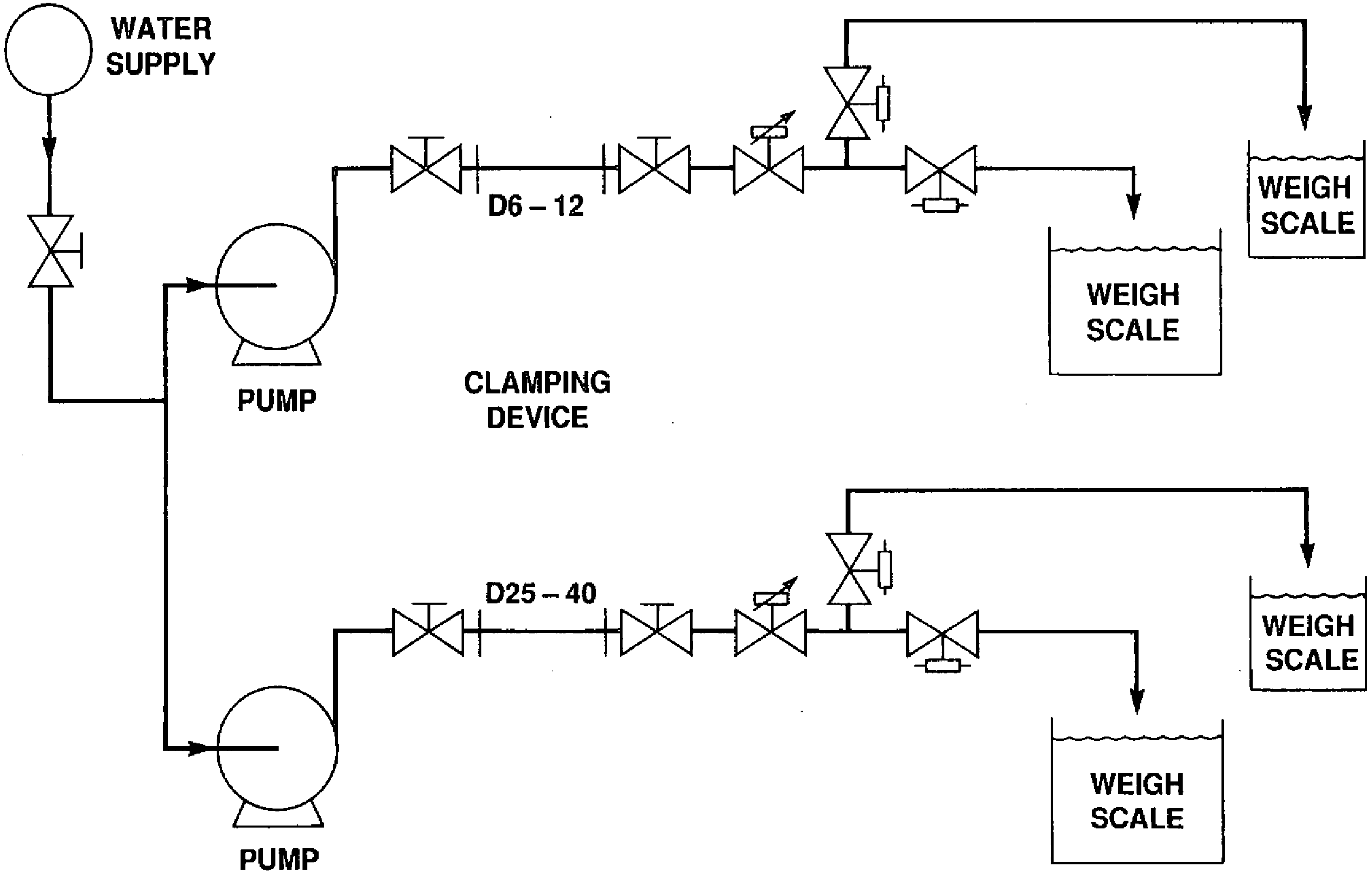


FIGURE 15

0424

PROPOSED CORIOLIS METER TYPICAL HOOK-UP

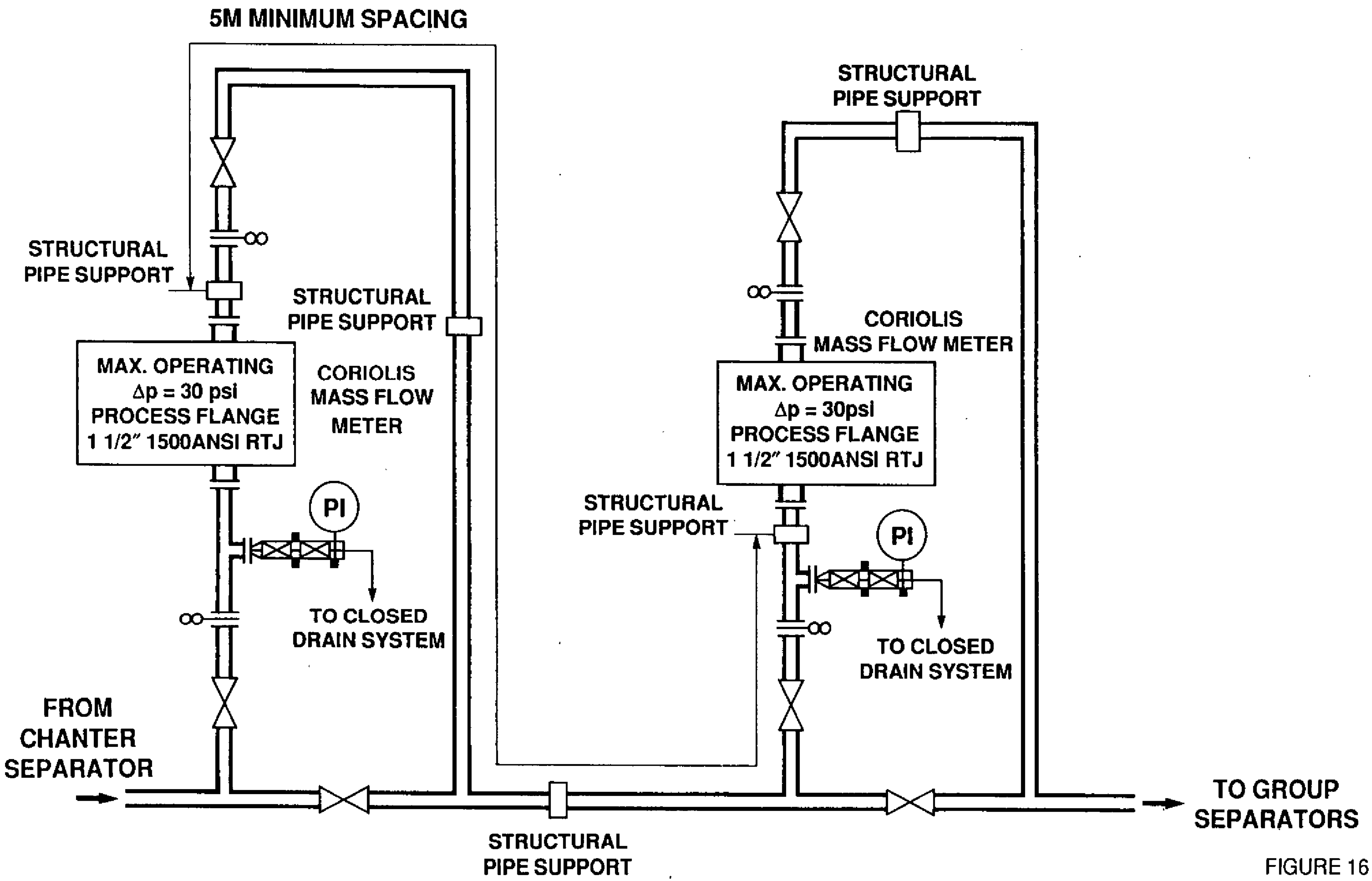


FIGURE 16
0424

Main Index

FIELD EXPERIENCE USING CORIOLIS MASS METERS - 11

by

R W Dean
Chevron Petroleum (UK) Ltd

Paper 2.4 b

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

FIELD EXPERIENCE USING CORIOLIS MASS METERS
PART II

R W Dean, Chevron Petroleum (UK) Limited, Aberdeen

I REASONS FOR INSTALLATION

On the Ninian Central Platform, operated by Chevron Petroleum (UK) Limited, part of the hydrocarbon production is available as liquified petroleum gas (L.P.G.) which is injected (i.e. spiked) into the main oil production after the fiscal metering system. This LPG stream can amount to about 800 tonnes per day which is up to 5% of the total production from the platform. The LPG production is gradually declining both as a flow rate and as a percentage of the whole.

As the platform was originally designed and built, the LPG was measured by means of an orifice plate with high and low range differential pressure transducers, an insertion type density meter and an analogue style flow computer-totaliser. When the platform changed from exporting 'dead' crude oil to the export of 'live' and 'spiked' crude oil, it was recognised that there was a need to upgrade the accuracy of the LPG measurement. A new system was installed for measuring LPG using 3" Kent type PMF turbine flow meters, high pressure Solartron type 7830 density meters with all these inputs combined together and integrated to measure mass flow by means of a Spectra-tek Model 869M flow computer.

As the quantity of LPG was small in proportion to the production of crude oil, and because the LPG had to be measured at high pressure (60 bar or possibly higher) the routine calibration of the turbine and density meters was performed by sending the turbine meters to the proving facilities at the Sullom Voe Terminal, and by sending the density meters back to the manufacturer or his agent. The flow meters were checked at approximately three monthly intervals and their repeatability has been very good. The only cause of any significant errors has been the deposition of a thin layer of sticky material usually thought to be mercaptans but these only occur very rarely and can be washed away quite easily with the appropriate solvent.

However, the LPG metering set-up has neither been provided with its own built-in proving system nor provided with duplicate densitometers to catch any short-term variations in performance. It was estimated that such a system would cost about £250,000 to install and could introduce additional safety problems. After discussion with the Gas and Oil Measurement Branch of the Department of Energy, it was agreed that some means of checking the short-term performance of the turbine meter and densitometer system was required, which would not be subject to any common-mode errors with the existing system.

It was found that a Coriolis style mass flow meter could be installed for about £40,000. By putting one of these new meters in series with the existing metering system it was considered that a completely independent cross-check could be made, because there was no fault condition that could be expected to cause equal errors in both meters (except co-incident power failure).

II CHOICE OF METER

At the time when the new Coriolis type of meter was needed there were only two different manufacturers offering suitable models on the market. We were assured that both manufacturers could comply with our specifications and certification requirements, and could also provide calibration documentation that was traceable to NBS standards. Chevron's choice was made on the basis of competitive price and compliance with specifications.

There were three minor reasons why we were pleased that the EXAC meter was financially more attractive than the Micro Motion Meter. Firstly we knew that another oil company operating in the North Sea would be trying out a Micro Motion meter on a similar duty, and we agreed to share and exchange experiences with them. Secondly, the EXAC meter seemed to have a more streamlined flow path and might be expected to have less pressure drop across it. Thirdly, the EXAC factory was not too far from the Chevron headquarters in California, which made progress chasing and quality assurance visiting a little easier.

III PURCHASE AND SUPPLY

The purchase order was for an EXAC Model EX1200 sensor with 2" Class 1500 ring type joint flanges working with a series 8100 flow transmitter. Materials in contact with the metered fluid were specified to be to NACE MR-01-75 specification for sour service. All pressure containing welds were to be radiographed and the assembly was required to be pressure tested to 225 bar g. Electrical circuits going to the sensor were required to be intrinsically safe to Cenelec design standards.

The fluid to be metered was defined as liquified petroleum gases at normal conditions of 60 bar g., and 15°C with a density of 500 Kg/m^3. The maximum flow rate was expected to be 800 Kg/min (i.e. 1200 TE/Day). The output required was a summation of mass flow in tonnes and an analogue output of fluid density.

During the progress of the order it became obvious that EXAC were not familiar with the requirements of our specifications, but with the assistance of Orca Corporation, Engineering and Inspection Services dealing with material matters and with technical guidance from SIRA Safety Services Ltd dealing with I.S. matters, we eventually obtained a meter to our requirements, albeit about two months later than we had originally expected. It must be recognised that the meter was going to be used for an arduous duty on an offshore platform and handling a hazardous flammable fluid, so that very high standards of quality assurance were required and obtained.

We also obtained a traceable calibration certificate which was of practical use during our accuracy investigations.

IV INSTALLATION AND COMMISSIONING

The new meter was installed in series with and immediately upstream of the existing metering system. Isolation and bypass valves were provided, and the meter was supported by pipe clamps that were the minimum recommended distances (i.e. equal to the meter length) upstream and downstream of the meter. There was a 90 degree bend immediately upstream of the meter. Since the surrounding pipework is to 4" Class 1500 specification great care was taken in making up the closing spoolpiece so that no major stresses were imposed on the new meter. It is possible to check that no adverse stresses have been introduced into the meter by measuring the drive voltage required to maintain its internal vibrations both before and after securing the pipe connections. There was no significant alteration, and this built-in diagnostic feature was considered to be of great value.

Once installed, the meter was commissioned according to the manufacturers instructions. It functioned immediately and has continued to operate as expected ever since with no failures.

The installation has been disturbed in several minor ways since the initial commissioning but none of these have caused a malfunction. Anti-vibration pads have been added to the pipe support clamps, the meter has been sent away for independent calibration, a bursting disc has been added to the meter case and a new micro-chip computer installed in the flow transmitter, but in all cases the meter performed as expected without any failures.

V PERFORMANCE AND ACCURACY

Since the meter is being used to measure hydrocarbons for fiscal purposes, we would have liked to achieve an accuracy of 0.1%. However, since this stream is only a small part of the total production from the platform, it was realistic to aim for 0.25%, which was the sort of performance claimed by the manufacturer. In this application the essential requirement, however, is to provide a short-term check on the existing turbine-meter and densitometer system, and for this function it is the meter's repeatability that is important.

Neither the accuracy nor the repeatability can be measured directly from our results, but estimates of the uncertainties can be deduced from a study of two sets of graphs.

The first set of graphs Fig. 1 is a daily plot of the difference of L.P.G. production as metered by the Coriolis meter and by the turbine-meter with densitometer system. The graphs show this difference in two ways, first as a simple difference in tonnes for the whole day but also as a percentage of the day's production (as indicated by the original metering system) which is itself also shown for reference purposes. This difference has been plotted for every day that the system has been in use with notes about any external influences or alterations added at the top of the sheet. These results are analysed in more detail later but the difference between the meters seems to indicate that the Coriolis meter reads low with a zero error rather than a span error.

The other graph Fig. 2 shows the results obtained when our meter was sent to the SIRA Institute Flow Calibration Laboratory at Chislehurst where it was calibrated against kerosene using their BCS certified weigh tanks. The results are plotted as percentage error against flow rate, but the sequence in which the tests were carried out is also shown by the numbers alongside each plot because this is important. The overall conclusion is again of a negative zero error.

VI EXAMINATION OF THE RESULTS

A) Both graphs show that the meter takes a long time to stabilise its zero calibration. Large errors in October 1986 and in the test points nos 3 to 10 of Fig. 2 were due to drift of zero calibration during the first 24 hours after switching on.

B) After the first 24 hours zero stability was much better, but some drifting does occur. The drift seldom produces an error of more than 2 tonnes per day.

C) Both the average difference from Fig. 1 and the general shape of points 1,2,11 to 15 in Fig. 2 indicate a small but persistent zero error which is not adjusted out when the meter's automatic zeroing procedure is activated. For reasons of security it is not possible to force the meter to register a flow when nothing is flowing through, but the overall performance over our working range would be better if a deliberate zero offset of about 1 TE/DAY could be introduced.

D) Because the percentage difference shown in Fig. 1 was consistently low and because the calibration of Fig. 2 also showed a small span error, the accuracy of the initial span calibration was rechecked. It was found that the test weights used were on average 0.1% light and that no compensation had been made for the bouyancy of air (about 0.12% for water tests). It was accepted that these facts would fully justify an adjustment of the meter's span calibration by 0.22%. The adjustment was made in November 1987 and performance during December 1987 was very good.

E) When the L.P.G. production rate is low, Fig. 1 shows that the difference between the two meters changes sign. Fig. 2 shows that the EXAC meter performs well at low flow rates. It is known from the characteristic curves of the turbine meters when checked against propane that their rangeability is limited with a well documented loss of performance at low flow rates. With this clear cut evidence that (for our application) the low flow rate performance of the Coriolis meter is better than the low flow rate performance of the turbine meter, the platform staff have been authorised to declare the EXAC meter result on the production report, if production is less than 300 TE/DAY.

F) At times of plant start-up, shut-down or operational disturbance the turbine meter system can be confused if there is liquid in the densitometer and gas in the turbine meter. In these circumstances the Coriolis meter does seem to work well and does not appear to give false results.

G) The Coriolis meter is installed in a platform module that also contains some reciprocating compressors. The vibration levels at the meter were measured and found to be quite low and particularly at its operating frequency of about 80 Hz. However, in an attempt to reduce the zero calibration problem, extra flexible pads were introduced as parts of the pipe supports. These did reduce the overall measured vibration but did not have any noticeable effect on the meter's performance.

H) Whenever a turbine meter was changed as part of its routine 3 monthly offsite proving programme, there was no significant or simultaneous step in the difference graphs. This gave reassurance that the turbine meter system was not subject to meter drift problems, which was one of the reasons for installing the Coriolis meter in the first place.

VII CONCLUSIONS

The Coriolis meter has performed the function for which it was purchased. It has given independent evidence that the turbine meter/densitometer system is accurate when working within its design limitations. The meter does not in its present state of development achieve 0.1% accuracy. The primary source of inaccuracy appears to be associated with zero stability, but apart from this the meter has performed well and has been very reliable.

NCP LPG EXAC vs SPECTRA-TEK MASS FLOW METERS

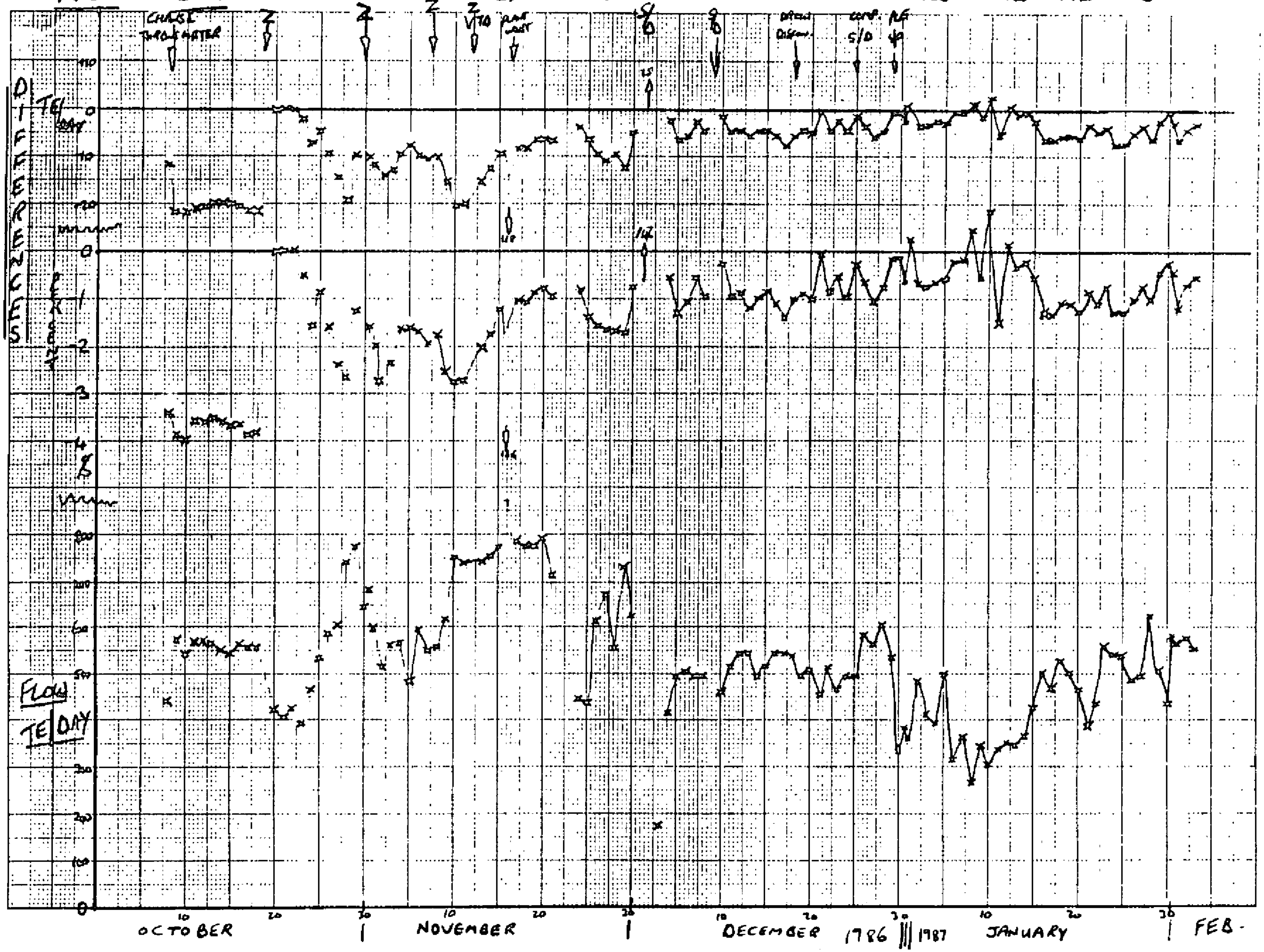
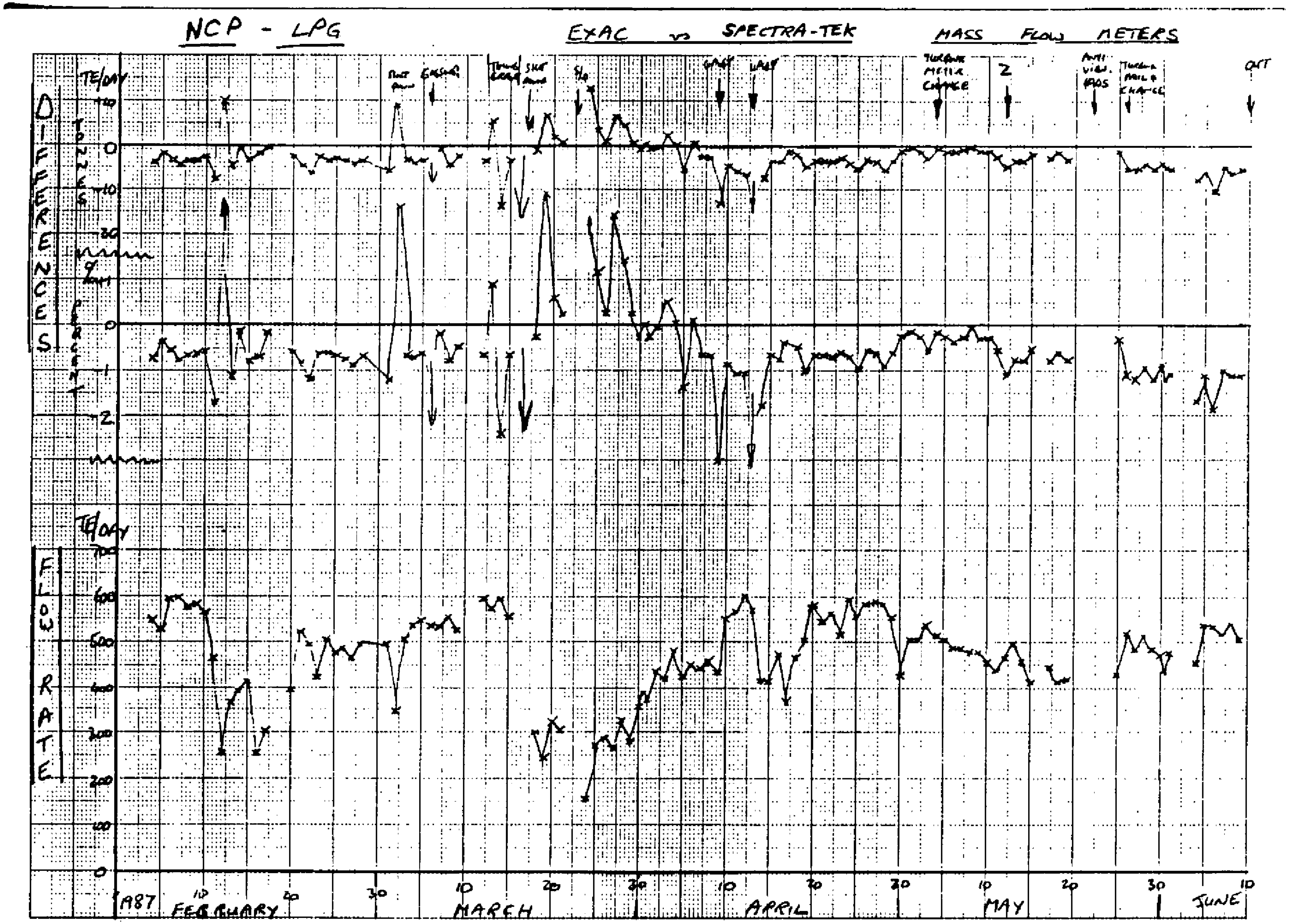
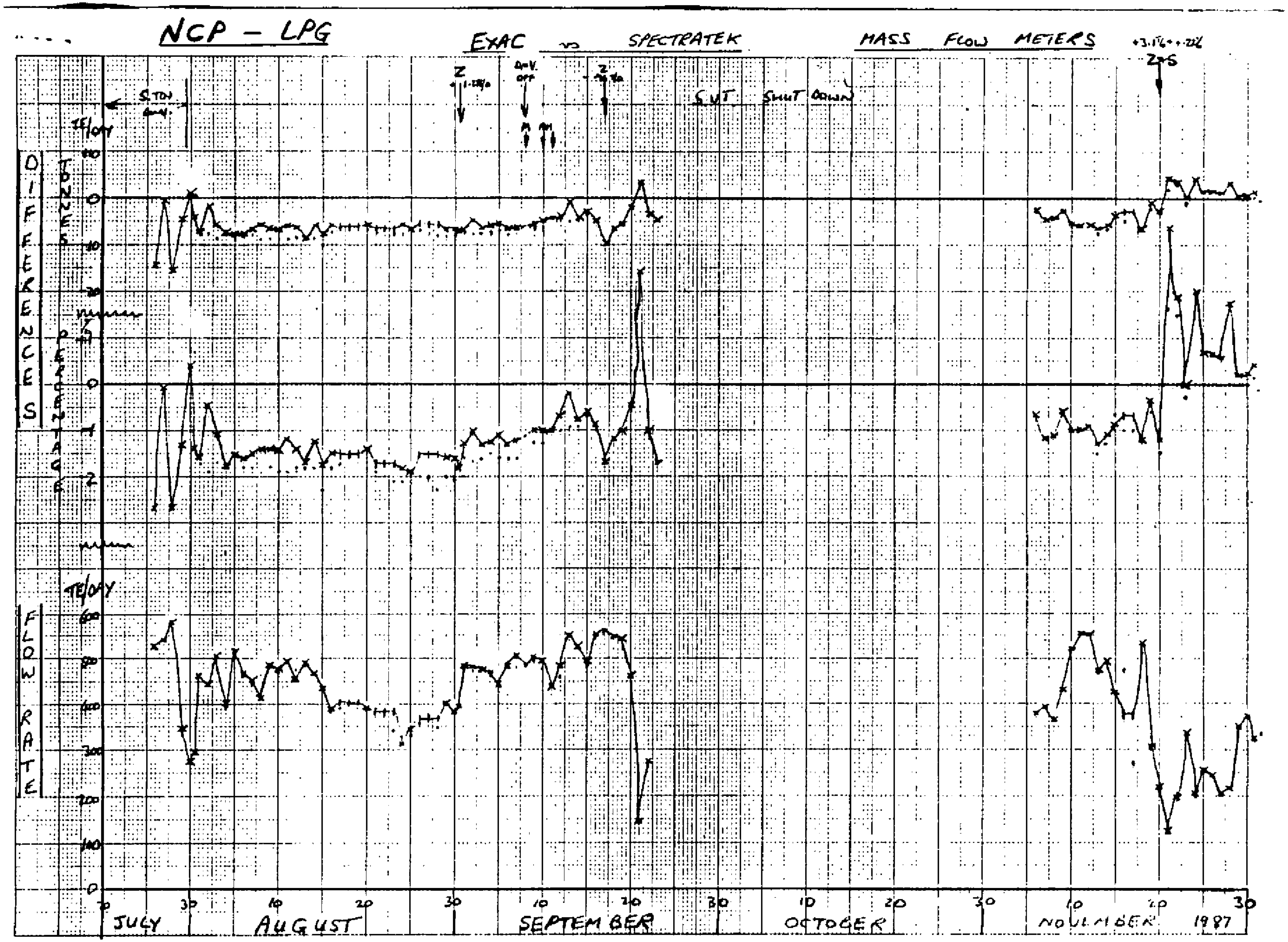


Fig 1 (g)



NCP - LPG
EXAC vs SPECTRA-TEK MASS FLOW METERS
DIFFERENCES
TE/DAY
TONNES
PERCENT
FLOW RATE
1987
FEBRUARY
MARCH
APRIL
MAY
JUNE

Fig 1 (b)



NCP – LPG
EXAC vs SPECTRATEK
MASS FLOW METERS
DIFFERENCES
TONNES
PERCENTAGE
FLOW RATE
TE/DAY
JULY
AUGUST
SEPTEMBER
OCTOBER
NOVEMBER
1987
SHUT DOWN

Fig 1 (c)


NCP - LPG
EXAC vs SPECTRATEK
MASS FLOW METERS
ONLY INTERMITTENT USE
DIFFERENCES
TONNES
PERCENTAGES
FLOW RATE
TE/DAY
DECEMBER
1987
1988
JANUARY
FEBRUARY
MARCH
APRIL

Fig 1 (d)

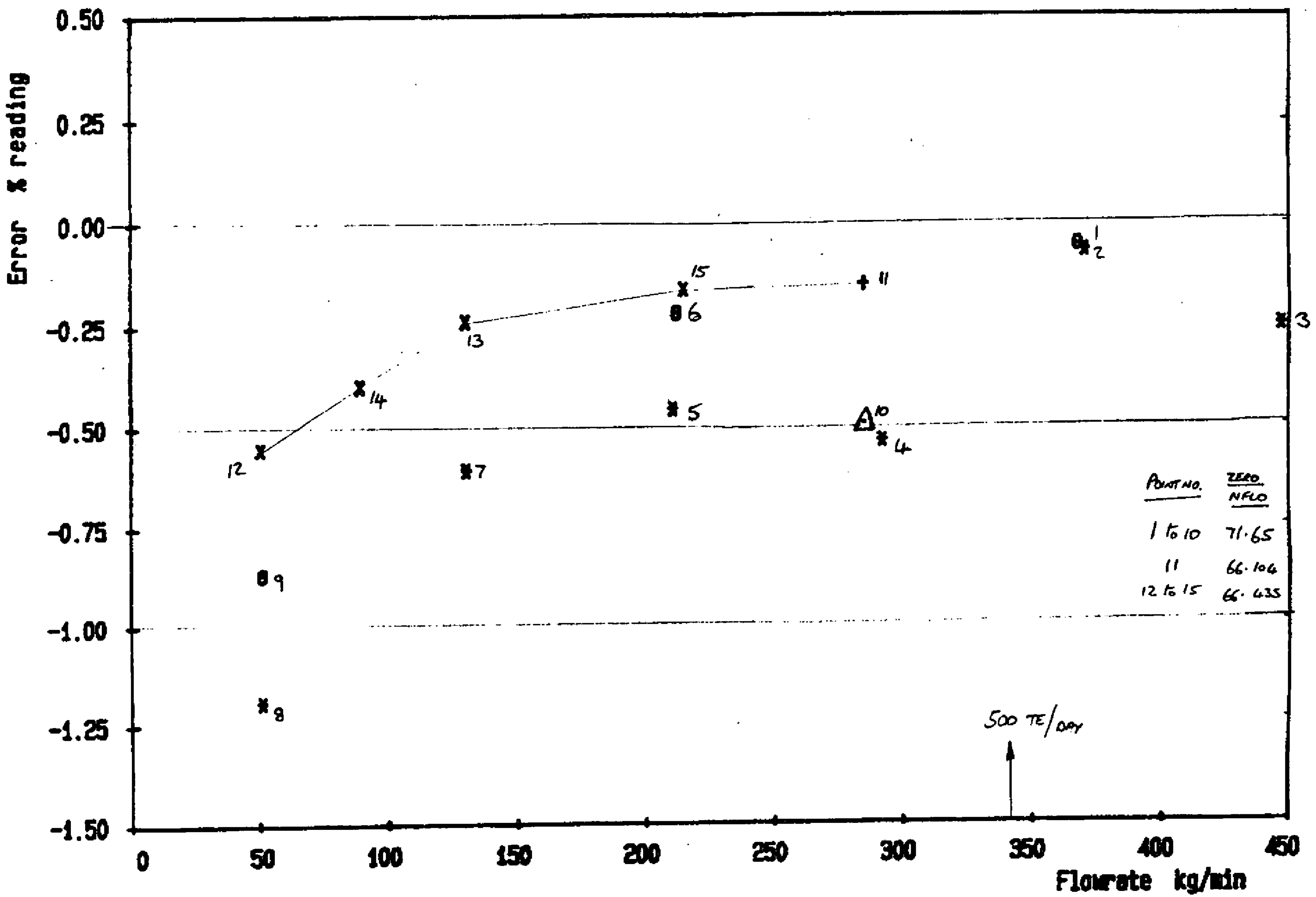


Fig2 Chevron Exac Mass Flowmeter

THE FIRST REVISION OF ISO 5167

by

J Stolz

Paper 3.1

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

THE FIRST REVISION OF ISO 5167

by

J Stolz
Electricite De France

S U M M A R Y

ISO 5167 is an international standard for the measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.

It was published in 1980. The sub-committee ISO/TC30/SC2 has decided a number of editorial and technical changes. The present paper lists, without comments, all the technical ones.

Each item will refer to the clause number of the existing document. The revised standard is entirely renumbered.

2 SYMBOLS AND DEFINITIONS

2.4.2 Reynolds number

The expression:

$$ReD = \frac{4q_m}{\pi\mu_1 D}$$

is added.

2.4.4 Acoustic ratio

The definition and the symbol are deleted.

2.4.5 Velocity of approach factor

The symbol is deleted. The definition is simply recalled in 2.4.6.

2.4.6 Flow and discharge coefficients

The concept of flow coefficient is no longer used in the standard. The symbol is deleted and the definition is simply recalled in a note of the clause. All references to 'α' are deleted in all places were it appeared and all texts deal now only with the discharge coefficient 'C'.

2.4.7 Expansion factor

Subscript 1 is added to the symbol ϵ when it is associated with ρ_1.

3.1 Principle of the Method of Measurement and Computation

The clause gives now the expression of q_m in terms of ϵ_1, ρ_1 as well as with ϵ_2, ρ_2 and the relationship between ϵ_1 and ϵ_2.

3.2 Method of Detemination of the Diameter Ratio of the Selected Standard Primary Device

The clause refers now to a new annex which deals with iterative computation.

3.4.2 (Fluid temperature)

For a gas, the thermometer well must be now at a distance of at most 15D downstream from the plate.

The clause no longer specifies isentropic expansion of gas, and suggests to assume no change in temperature between upstream and downstream conditions.

4 SELECTION OF THE PRIMARY DEVICE

This section is deleted from the body of the standard and assigned to the 'Code of Practice' (which is a companion document intended to facilitate the practical use of the standard).

5.3.2 (Flow conditions)

It is now suggested that increasing β might avoid a change of phase at the orifice.

6.1.6 (Installation requirements)

The clause now admits explicitly the use of seamed pipe, under some conditions.

6.3 Straightening Devices

Two other types of flow conditioners are added to the three previous ones. They are: the 'AMCA' which is a square mesh honeycomb, the 'etoile' which shows eight radial vanes.

6.3.2 (Pressure loss)

The newly accepted conditioners create a pressure loss considerably smaller than those obtained with the three other types.

6.5.3.3 (Eccentricity)

The maximum value of the offset of the orifice or throat axis of primary devices from the axes of upstream and downstream pipes is changed from: $0.0005D/(0.1 + 2.3\beta^4)$ to the less severe value $0.0025D/(0.1 + 2.3\beta^4)$.

7 ORIFICE PLATES

7.1.1.3 (Flatness of the plate)

A maximum slope of one per cent is required at operating conditions (such a one per cent limit was quoted in the next clause 7.1.2.1).

7.1.2.1 Upstream face

Flatness: A maximum slope of 0.5 per cent is now required under shop conditions, before on-site installation, provided that it can be shown that the method of mounting does not distort the plate.

7.1.2.2 Upstream face smoothness

The diameter for which a stated smoothness is required is now extended from 1.5d to 1D and, if not the case, the upstream face must be repolished or cleaned.

7.1.4.3 Thickness of the plate

A thickness of 3.2 mm is now permitted, even if exceeding the 0.05D limit.

7.1.5.2 Bevel angle

This angle is now specified as 45 ± 15°.

7.1.6.1 Edges

The downstream edges are now treated in a new clause, and do not require the high quality of the upstream edge.

7.1.6.2 Upstream edge sharpness

The cut-off value of D for the adequacy of visual inspection is now 25 mm, instead of 125 mm.

The text - finished by a very fine radial cut from the centre outwards - is deleted.

7.1.7.1 Orifice diameter

The β range is now the same for the three tapping systems, that is:

$$0.20 \leq \beta \leq 0.75.$$

7.1.7.3 Orifice cylindricity

A new requirement is that the roughness of the orifice bore cylindrical section shall not be such that it affects the edge sharpness measurement.

7.1.8.1 Symmetrical plates

Since the plate has to be especially thin, attention is now called to the value of the differential pressure, which may have to be limited, to prevent plate distortion.

7.2.1.4 Tap diameter

The maximum diameter of individual tappings is now specified as 0.13D or 13 mm (which is the lowest), instead of 0.08D or 12 mm. Note that the 13 mm limit is now compulsory, while the 12 mm limit was 'preferably'.

7.2.3.5 Flange tappings

The tolerances on the positions of tappings are now simple:

$$25.4 \pm 0.5 \text{ mm}$$

when simultaneously: $\beta > 0.6$ and $D < 150$ mm and 25.4 ± 1 mm in all other cases.

7.3.1 Limits of use

Those limits are now the same for all three tapping systems, except as regards ReD.

When d and D are in millimetres, they read as:

$$d \leq 12.5$$

$$50 \leq D \leq 1000$$

$$0.20 \leq \beta \leq 0.75$$

for corner taps:

$$5000 \leq ReD \text{ at } \beta \leq 0.45$$

$$10\ 000 \leq ReD \text{ at } \beta > 0.45$$

for flange and D, D/2:

$1260\beta^2 D \le ReD$

and the upper limit for ReD is deleted.

The maximum accepted pipe roughness is also now unified, keeping the most severe values of the criterion k/D (and the table of usual values of k is now shown in an Annex).

7.4 Pressure Loss $\Delta\bar{\omega}$

The text now precises that this loss is considered between sections situated approximately 1D upstream and 6D downstream of the primary device.

It also proposes another simpler expression of this loss:

$$\Delta\bar{\omega}/\Delta P = 1 - \beta^{1.9} \text{ (orifice plates only).}$$

8 NOZZLES

9 VENTURI TUBES

There are no technical changes in those texts, except that, since their individual pressure tappings are referred to the orifice plate ones, their diameter is now governed by the new 0.13D and 13 mm values.

ANNEX A

All tables quoting α are deleted.

Columns at ReD = 10^8 and ReD = ∞ are added in tabulation of C and values directly printed by a computer-connected printing machine are supplied to the ISO Print Office in Geneva.

ANNEX D

A new annex about iterative computation with fast convergence.

ANNEX E

Usual values of k.

A NEW TYPE OF FORMULA FOR THE ORIFICE-PLATE DISCHARGE COEFFICIENT

by

M J Reader-Harris
National Engineering Laboratory

Paper 3.2

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

A NEW TYPE OF FORMULA FOR THE ORIFICE-PLATE DISCHARGE COEFFICIENT

Dr M J Reader-Harris

National Engineering Laboratory, East Kilbride, Glasgow

S U M M A R Y

This paper describes a new concept, and hence form of equation, for fitting orifice plate discharge coefficients in which the physical basis of the different terms of the equation is clearer. As well as a term based on throat Reynolds number, a term based on friction factor is included. The latter makes clear the effect of pipe roughness.

The work described here is the first half of a project; further work is being performed.

N O T A T I O N

a, a_0, a_1, a_2	Coefficients at infinite Reynolds number
b, b_0, b_1	Coefficients of Reynolds number term
c, c_1	Coefficient of friction factor term
C	Discharge coefficient using corner tappings
D	Pipe diameter
k_m	Pipe roughness (as on Moody diagram)
k_s	Sand roughness
k, ℓ, m, n	Exponents
N	Number of data
Re_d	Throat Reynolds number
Re_D	Pipe Reynolds number
V	Variance
β	Diameter ratio
λ	Friction factor
σ	Standard deviation

SUBSCRIPTS

β	For a particular value of β

SUPERSCRIPTS

$'$	With throat Reynolds number term subtracted
$*$	Best fit value
#	Approximate valve
$-$	Mean value

1 INTRODUCTION

Both in the EEC and the USA there are current programmes of work to determine a new orifice plate discharge coefficient equation. The data have been collected and the analysis is being done. It is important to obtain an equation which truly describes the physics. The work presented in this paper demonstrates that the corner tap discharge coefficient depends on friction factor as well as on Reynolds number and that a simple equation can nevertheless be obtained.

2 A NEW TYPE OF FORMULA

Reader-Harris and Keegans[1] found that for a fixed pipe Reynolds number, Re_D, as the pipe roughness changed so the change in discharge coefficient was approximately proportional to $\beta^4\lambda$, where β is the diameter ratio and λ is the pipe friction factor. This led Reader-Harris to suppose that the form of the equation for the discharge coefficient, C, using corner tappings might be

$$C = a(\beta) + c_1\beta^m\lambda, \tag{1}$$

where m is approximately 4. Rapier[2] made experimental measurements in very smooth pipes and as a result of his work also proposed that C was best expressed as a function of friction factor. However, equations of the form of equation (1) do not give good agreement with experiment for small β, since they then give C almost constant.

Further computational work, solving the time-averaged Navier-Stokes equations with the k-ϵ turbulence model, was then undertaken at NEL to determine the effect of pipe roughness on an orifice plate of diameter ratio 0.7. Whereas in the initial work[1] the grids used had about 40 x 25 points, the new grids had about 80 x 60 points. Even with these more refined grids, which had small grid expansion ratios, and with careful attention to boundary conditions complete grid independence was not achieved except for Reynolds numbers of 3×10^6 and upwards. The computed discharge coefficients are shown in Fig. 1; multiple symbols at one Reynolds number give the calculated values for different grids (the higher values are for the more refined grids). The rough pipe values, though for different sand roughnesses, correspond approximately to a relative roughness of 0.0003 on the Moody diagram, which is within the ISO Standard[3]. It is interesting to note that the rough pipe values approximately follow the Stolz equation, although they are about 1 per cent high, whereas the smooth pipe values decrease much more rapidly than the Stolz equation for large Reynolds numbers. From the computations differences of more than 1 per cent can be caused by pipe roughness even when it lies within the ISO Standard; it is because of the magnitude of these differences that it is necessary to include a function of friction factor in the orifice plate discharge coefficient equation.

Replotting the computed points as a function of friction factor gives Fig. 2. The rough pipe points now lie approximately on the line of the smooth pipe ones. However, they fall just below the line, and this may not just be numerical error. The discrepency may be due to the need for an additional term in equation (1). To establish what that term is it is necessary to consider what type of equation would be appropriate for small β since it is for small β that equation (1) seems to be most inappropriate.

It seems reasonable that for low β the discharge coefficient should only depend on throat Reynolds number, Re_d:

$$C = a + f(Re_d). \quad (2)$$

To check this theory C was plotted against log Re_d (Fig. 3) for β less than or equal to 0.375 using all the EEC and American flange tap data available in summer 1987. So that all the data included in this analysis had been collected with the same type of tappings flange tap data from the EEC were used rather than corner tap data. In all cases the flange tap data were converted to corner tap data using the tap term formula of Reader-Harris and Cribbin[4]; it is much easier to fit corner tap data than flange tap data since optimisation of the tapping terms is then not required. The data in Fig. 3 approximately lie on a single curve (the data for $\beta = 0.375$ are slightly higher than those for $\beta = 0.2$ and the data for $\beta < 0.2$ are rather scattered). So for low β it appears that C only depends on Re_d. It then seems reasonable to suppose that for low β

$$C = a + b(10^6/Re_d)^n$$
$$= a + b(10^6\beta/Re_D)^n, \quad (3)$$

and this assumption was tested later.

Since we now have approximate equations for low and high β the most obvious general equation for C is given by

$$C = a(\beta) + b(10^6\beta/Re_D)^n + c_1\beta^m\lambda. \quad (4)$$

3 CONSTRUCTING THE EQUATION ITSELF

The first stage in constructing the equation was to attempt to determine n and thus b in equation (3). The value of n which gives the minimum standard deviation of the data about the best line fit of the form of equation (3) lies in the range 0.6-1.1 for each $\beta \le 0.375$; 0.75 was chosen. The data for $\beta \le 0.375$ and $Re_D > 4000$ have been plotted in Fig. 4 against $(10^6/Re_d)^{0.75}$. b is taken to be 0.0006, which is the approximate slope of the data in Fig. 4. Only the data for $Re_D > 4000$ were used in the subsequent fitting, in case the formula for C is different for laminar flow.

Then it is assumed that

$$C' = a'(\beta) + c'(\beta)(\lambda - 0.01), \quad (5)$$

where $C' = C - 0.0006(10^6\beta/Re_D)^{0.75}$.

$(\lambda - 0.01)$ is used rather than λ since when Re tends to infinity λ does not tend to 0 if the pipe is not hydraulically smooth (if the relative roughness on the Moody diagram, k_m/D, is 0.000 037, λ tends to 0.01 as Re_D tends to infinity).

λ can be calculated from measurements of pressure drop or estimated from measured values of roughness. For the EEC 100 mm pipe measurements are given in References 5-7 and for the 250 mm pipe the measurements are in References 8-11. Measured values of roughness for each of the American pipes were supplied by Wayne Fling[12].

k_m/D is in the range 0.000 01-0.0002. For the present work k_m/D was taken to be 0.000 02 for all pipe diameters, although for a given pipe finish k_m/D is a function of D. This value is probably too low and further work will be done in which the measured values of k_m/D are used for each pipe, where the measurements are available. Where values have not been measured approximate values based on measurements made elsewhere will be used.

Given k_m/D and Re_D, λ can be obtained from the Colebrook-White equation[13]:

$$\frac{1}{\sqrt{\lambda}} = 1.74 - 2\log\left[2\frac{k_m}{D} + \frac{18.7}{Re_D\sqrt{\lambda}}\right]. \qquad (6)$$

Using equation (6) C' can then be plotted against λ for each β and the results are approximately linear in each case; Figs 5 and 6 show the data for $\beta = 0.57$ and $\beta = 0.74$ (since the highest β at which EEC data were obtained was 0.7503 and the highest β at which American data were obtained varied with D but was about 0.73, $\beta = 0.74$ was taken as an approximate figure). Fitting straight lines of the form of equation (5) to the data then gives best fit values $a_\beta'^*$ for $a'(\beta)$ and $c_\beta'^*$ for $c(\beta)$ as follows:

β	$a_\beta'^*$	$c_\beta'^*$	σ_β^*
0.2	0.597 14	-0.044 91	0.001 8752
0.375	0.599 86	0.113 59	0.001 4982
0.5	0.603 79	0.220 58	0.001 1593
0.57	0.603 92	0.423 49	0.001 4060
0.66	0.602 00	0.884 74	0.001 4550
0.74	0.593 29	1.552 73	0.001 8598

The data for $\beta = 0.242$ and those for $\beta < 0.2$ were excluded. σ_β^* is the standard deviation of the data about the best line fit and is given by

$$\sigma_\beta^{*2} = \frac{1}{N_\beta - 2}\sum_{i=1}^{N_\beta}(C'_{\beta,i} - a_\beta'^* - c_\beta'^*\lambda_{\beta,i})^2, \qquad (7)$$

where, for each β, N_β is the number of data points and, for each i from 1 to N_β inclusive, $C'_{\beta,i}$ is a value of C for that β and $\lambda_{\beta,i}$ is the corresponding value of λ.

Equations for $a'(\beta)$ and $c'(\beta)$ are now required: the form for $c'(\beta)$ has already (equation (4)) been assumed:

$$c'(\beta) = c_1'\beta^m. \qquad (8)$$

The form of $a'(\beta)$ is initially assumed to be

$$a'(\beta) = a_0' + a_1'\beta^k + a_2'\beta^\ell. \qquad (9)$$

It is possible to find the best fit for each of $a'(\beta)$ and $c'(\beta)$ separately, but it is better to fit them simultaneously. Suppose $a_\beta'^*$ and $c_\beta'^*$ in the line fit are replaced by $a_\beta'^\#$ and $c_\beta'^\#$ (derived from equations (9) and (8) or similar). Then the standard deviation of the data about this line fit would be $\sigma_\beta^\#$, where

$$\sigma_\beta^{\#2} = \frac{1}{N_\beta - 2}\sum_{i=1}^{N_\beta}(C'_{\beta,i} - a_\beta'^\# - c_\beta'^\#\lambda_{\beta,i})^2. \qquad (10)$$

Now

$$\sigma_\beta^{\#2} = \sigma_\beta^{*2} + \frac{N_\beta}{N_\beta - 2}\{a_\beta'^{*} - a_\beta'^{\#} + (c_\beta'^{*} - c_\beta'^{\#})\bar{\lambda}_\beta\}^2 + \\ + \frac{(c_\beta'^{*} - c_\beta'^{\#})^2}{N_\beta - 2}\sum_{i=1}^{N_\beta}(\lambda_{\beta,i} - \bar{\lambda}_\beta)^2, \tag{11}$$

where

$$\bar{\lambda}_\beta = \frac{1}{N_\beta}\sum_{i=1}^{N_\beta}\lambda_{\beta,i}. \tag{12}$$

Suppose now that $a_\beta'^{\#}$ and $c_\beta'^{\#}$ are in fact of the form of equations (9) and (8). Then we could minimize ΔV, where

$$\Delta V = \frac{1}{6}\sum_{\beta=0.2}^{0.74}(\sigma_\beta^{\#2} - \sigma_\beta^{*2}). \tag{13}$$

A more immediately comprehensible measure of fit is $\Delta\sigma$, where

$$\Delta\sigma = \frac{1}{6}\sum_{\beta=0.2}^{0.74}(\sigma_\beta^{\#} - \sigma_\beta^{*}). \tag{14}$$

For any given m,l and k there is no problem in determining a_0', a_1', a_2' and c_1' to minimize ΔV. It is natural also to choose m,l, and k such that ΔV is at its minimum. For the data in the above table this gives m = 4.8, k = 1.4, l = 8.1, and $\Delta\sigma$ = 0.000 022. But a_0' = 0.593 56, which, from Fig. 4, appears to be too low. Inclusion of the data from $\beta \le 0.1$ would probably prevent this, but those data are very scattered. With only a small increase in standard deviation ($\Delta\sigma$ = 0.000 027) we can, for example, obtain a_0' = 0.595 38 with m = 4.8, k = 2.2, and l = 6.9. But such solutions are rather arbitrary: perhaps the best option is to require that when the velocity profile term (which is proportional to β^m) is small $a'(\beta)$ should reduce to a constant. One simple way of securing this is to put k = m and l > m. This also ensures that the same best fit is obtained whether the independent variable (λ - 0.01) or λ is used. Then the best solution has m = 4.3 and l very near to 4.3; moreover a_1' and a_2' are large in magnitude and a_1' is approximately equal to $-a_2'$. So equation (9) is replaced by

$$a'(\beta) = a_0' + \{a_1' + a_2' \log(\beta)\}\beta^m. \tag{15}$$

Then we have the best fit equation

$$C = 0.596\,31 + 0.0006(10^6\beta/Re_D)^{0.75} + \{5.465\,99(\lambda - 0.01) - \\ - 0.840\,15\log(\beta) - 0.119\,75\}\beta^{4.3}. \tag{16}$$

This has $\Delta\sigma$ = 0.000 058, which is still small compared to each σ_β^*.

Although λ may appear to be a rather inconvenient variable, it is possible to approximate it by a simple function of Re_D if a value of k_m/D is assumed. For instance if k_m/D = 0.000 02 (the assumed value for this work) λ is always within 0.0005 of $\lambda^\#$ for $Re_D > 4000$ if

$$\lambda^\# = 0.008\ 59 + 0.809\ 26/Re_D^{0.39}. \tag{17}$$

However, the significance of the new formula depends on the term in λ being a true pipe roughness term, not simply another Reynolds number term. It is necessary, therefore, to examine the rather limited quantity of data on the effect on the discharge coefficient of different pipe roughnesses at the same Reynolds number. The experiments included here are those of Clark and Stephens[14], Herning and Lugt[15], Spencer, Calame and Singer[16], Thibessard[17] and Witte[18]; the computations were done by Reader-Harris[1]. Values from both experiment and computation are plotted in Fig. 7, in which the product of ΔC, the change in C, and $\beta^{-4.3}$ is plotted against the change in λ. The experimental data are generally a little lower than the computed values. However, the data of Clark and Stephens are higher than the computed values. The line on the graph represents the prediction of equation (16) for constant Reynolds number. The agreement between the experimental and computed values and equation (16) is excellent and suggests that the term in λ in the equation is a true pipe roughness term.

In order to compare the fit of equation (16) with those of standard equations of the following form

$$C = a(\beta) + b(\beta)(10^6/Re_D)^n, \tag{18}$$

best fit values a_β^* and b_β^* for $a(\beta)$ and $b(\beta)$ in equation (18) were obtained for a series of values of n together with values of standard deviation σ_β^*. The values of σ_β^* for n = 0.5, 0.6 and 0.7 were as follows:

β	n = 0.4	n = 0.5	n = 0.6
0.2	0.001 854	0.001 844	0.001 853
0.375	0.001 762	0.001 627	0.001 537
0.5	0.001 182	0.001 109	0.001 138
0.57	0.001 519	0.001 409	0.001 475
0.66	0.001 947	0.001 519	0.001 518
0.74	0.002 091	0.001 916	0.002 216

The smallest values of σ_β^* were obtained for n = 0.5; for this value of n a_β^* and b_β^* were as follows:

β	a_β^*	b_β^*
0.2	0.595 89	0.000 6137
0.375	0.598 10	0.001 3501
0.5	0.602 25	0.001 7524
0.57	0.602 83	0.002 2131
0.66	0.600 81	0.003 4198
0.74	0.592 21	0.004 9383

Then it was assumed that $a(\beta)$ and $b(\beta)$ were of the following standard forms:

$$a(\beta) = a_0 + a_1\beta^k + a_2\beta^\ell \qquad (19)$$

$$b(\beta) = b_1\beta^m. \qquad (20)$$

Best fit values of the constants in equations (19) and (20) were obtained in the same manner as those for the friction factor fit and the best fit equation for C was as follows:

$$C = 0.597\ 11 + 0.015\ 47\beta^{1.8} - 0.289\ 87\beta^{10.3} +$$
$$+ 0.008\ 884\beta^{2.3}(10^6/Re_D)^{0.5}. \qquad (21)$$

Whereas the values of σ_β^* were very similar to those obtained with the friction factor fit, the values of $\sigma_\beta^{\#}$ were greatly increased by the poor fit obtainable for b_β^* ($\Delta\sigma$ = 0.000 287).

Because only a poor fit for b* is obtainable of the form of equation (20) it was decided to test also an alternative form for $b(\beta)$; so it was assumed that $a(\beta)$ was of the form of equation (19) and $b(\beta)$ was of the form:

$$b(\beta) = b_0 + b_1\beta^m. \qquad (22)$$

Best fit values of the constants were again obtained and the best fit equation for C was as follows:

$$C = 0.589\ 31 + 0.024\ 56\beta^{0.9} - 0.227\ 74\beta^{8.9} +$$
$$+ (0.000\ 7082 + 0.011\ 887\beta^{3.5})(10^6/Re_D)^{0.5} \qquad (23)$$

$\Delta\sigma$ = 0.000 072, which is small compared to each σ_β^*, but a_0 is too low.

The standard deviation of the data about the fits in equations (16), (21) and (23) (ie $\sigma_\beta^{\#}$) for each β were as follows:

β	Equation (16)	Equation (21)	Equation (23)
0.2	0.001 929	0.002 250	0.001 910
0.375	0.001 569	0.001 959	0.001 846
0.5	0.001 232	0.001 288	0.001 131
0.57	0.001 522	0.001 766	0.001 497
0.66	0.001 478	0.001 574	0.001 532
0.74	0.001 887	0.002 136	0.001 930

The best two equations (16) and (23) are plotted on a background of the data for 3 values of β for Re_D > 4000 in Figs 8-10. The good agreement between the EEC and the American data is visible as well.

4 CONCLUSIONS AND SUGGESTIONS FOR FURTHER WORK

Although the standard deviation of the data about the fit in equation (16) is not much lower than that about the fit in equation (23), the new form of equation suggested (equation (16)) makes clearer the physical cause for the different terms of the equation, one solely dependent on throat Reynolds number, the other on upstream velocity profile. It is, therefore, more suitable for extrapolation than formulae with less physical basis. It also makes clear the effect of pipe roughness.

A computer program is being written so that the best fit equation of a given form can be obtained by minimizing the standard deviation of all the data from that equation (including all the values of β simultaneously). It will be possible in this work to use the correct value of β (rather than an approximate one) for each set of data and to include the data for $\beta = 0.242$.

Although the data for $\beta < 0.2$ are more scattered than the other data and thus cannot be included as a whole in the simultaneous fitting it may be appropriate to follow a suggetion of Stolz and to include these data for which the orifice diameter is greater than 12.5 mm (0.5 in). It should be the case that equations of the form of equation (16) will automatically give a good fit to the data for very low β.

In the simultaneous fitting of the data the new tapping term formula which is being derived will be included. More accurate values of k_m/D will also be used in this work.

Further tests will be required to check that equations of the form of equation (16) are suitable for the data for $Re_D < 4000$. A suitable formula for λ in this range will be required; it may not matter that it will not be the true friction factor.

REFERENCES

1 READER-HARRIS, M. J. and KEEGANS, W. Comparison of computation and LDV measurement of flow through orifice and perforated plates, and computation of the effect of rough pipework on orifice plates. In Proc. of the Int. Symp. on Fluid Flow Measurement, Washington, D.C., Paper 12.1, November 1986.

2 RAPIER, A. C. The extrapolation of orifice calibrations to high Reynolds numbers. In Proc. of the Fluid Mechanics Silver Jubilee Conference, National Engineering Laboratory, East Kilbride, Glasgow, Paper 4.3, 1979.

3 INTERNATIONAL ORGANIZATION FOR STANDARDIZATION. Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full. ISO 5167, Geneva: International Organization for Standardization, 1980.

4 READER-HARRIS, M. J. and CRIBBIN, S. The tapping terms in the orifice plate discharge coefficient formula. Paper submitted to the EEC Orifice Plate Experts' Group, 1987.

5 Progress Report on EEC Orifice Plate Coefficients Project. Initial NEL Tests in Water on EEC 100 mm (4 in) Orifice Run for European Economic Community DGXII Research, Science and Education. Progress Report No PR2: EUEC/03. East Kilbride, Glasgow: National Engineering Laboratory, 1980.

6 Progress Report on EEC Orifice Plate Coefficients Project: 1982/83 NEL Tests in Air on Thin Orifice Plates for EEC 100 mm Assembly for European Economic Community DGXII Research, Science and Education. Progress Report No PR15: EUEC/10. East Kilbride, Glasgow: National Engineering Laboratory, 1984.

7 WILLEMSE, A. J. Dimensions of the EEC 100 mm orifice plate meter run. N. V. Nederlandse Gasunie, Department of Planning and Research, Report TP/I 83.R.203, 1983.

8 HARBRINK, B. EEC Orifice plate coefficient project: Progress Report No 1: Dimensional Measurements on the EEC 250 mm Orifice Meter run. Ruhrgas AG, Essen, 1983.

9 WILLEMSE, A. J. Second report on the dimensions of the EEC 250 mm meter run. N. V. Nederlandse Gasunie, Department of Planning and Research, Report TP/1 82.R.353, 1982.

10 NORMAN, R. and DREW, W. A. The EEC 250 mm orifice meter project. Part II Inspection of the meter run and orifice plates. British Gas Engineering Research Station, Report ERS R.3127, 1985.

11 EEC orifice plate coefficient project, final water tests on the EEC 250 mm orifice run. Delft Hydraulics Laboratory, M 1733-IV, 1986.

12 FLING, W. A. Jr. Private communication, 1988.

13 SCHLICHTING, H. Boundary layer theory. McGraw-Hill, New York, 1960.

14 CLARK, W. J. and STEPHENS, R. C. Flow measurement by square-edged orifice plates: pipe roughness effects, Proceedings of the I.Mech.E., 171, pp 895-910, 1957.

15 HERNING, Fr. and LUGT, H. Neue Versuche mit Segmentblenden und Normblenden, Brennst-Wärme-Kraft, 10, Part 5, pp 219-223, 1958.

16 SPENCER, E. A., CALAME, H. and SINGER, J. Edge sharpness and pipe roughness effects on orifice plate discharge coefficients. NEL Report No 427, East Kilbride, Glasgow: National Engineering Laboratory, 1969.

17 THIBESSARD, G. Le coefficient de débit des diaphragmes, la rugosité et le nombre de Reynolds. Chaleur et Industrie, No 415, pp 33-50, 1960.

18 WITTE, R. Neue Beiträge zur internationalen Normung auf dem Gebiete der Durchflußmessung, Brennst-Wärme-Kraft, 5, Part 6, pp 185-190, 1953.

LIST OF FIGURES

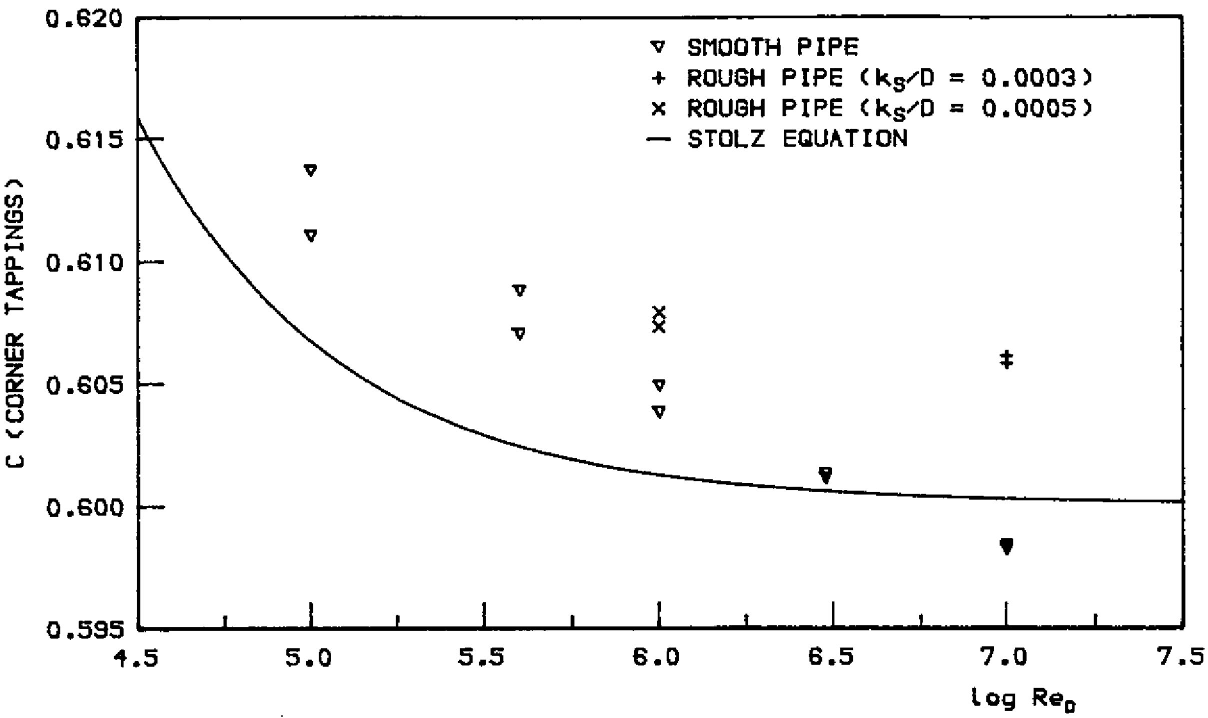


FIG 1 COMPUTED C v log Re_D FOR β = 0.7

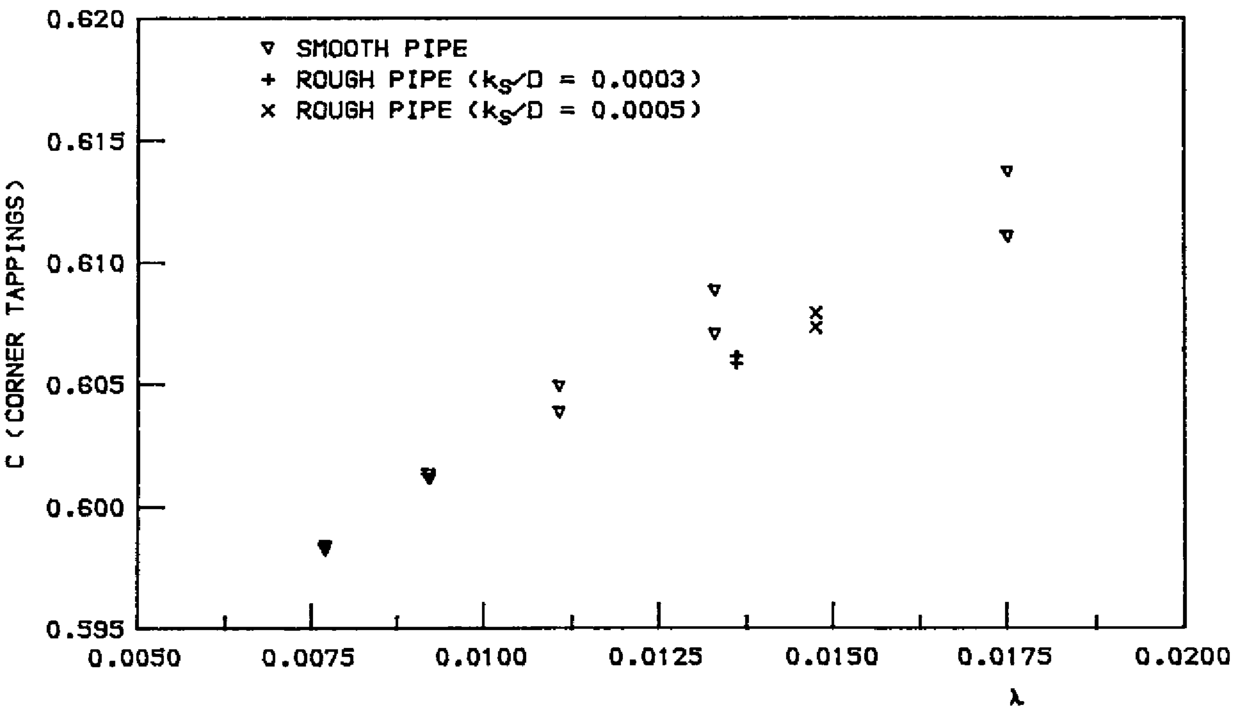


FIG 2 COMPUTED C v λ FOR β = 0.7

FIG 3 DISCHARGE COEFFICIENT V LOG(THROAT REYNOLDS NUMBER) FOR B<=0.375

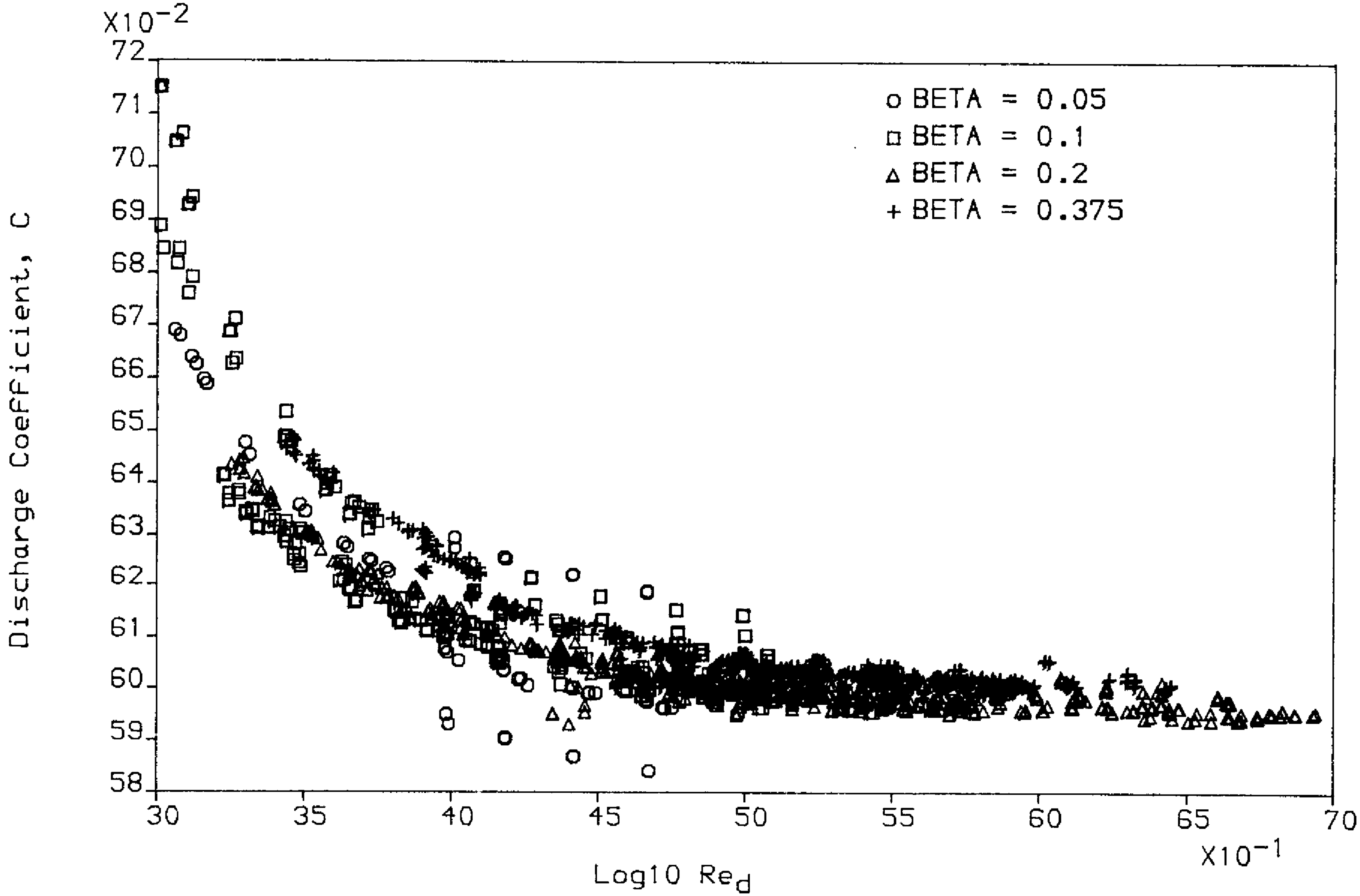


FIG 4 DISCHARGE COEFFICIENT V (10↑↑6/THROAT REYNOLDS NUMBER)↑↑0.75 FOR B<=0.375

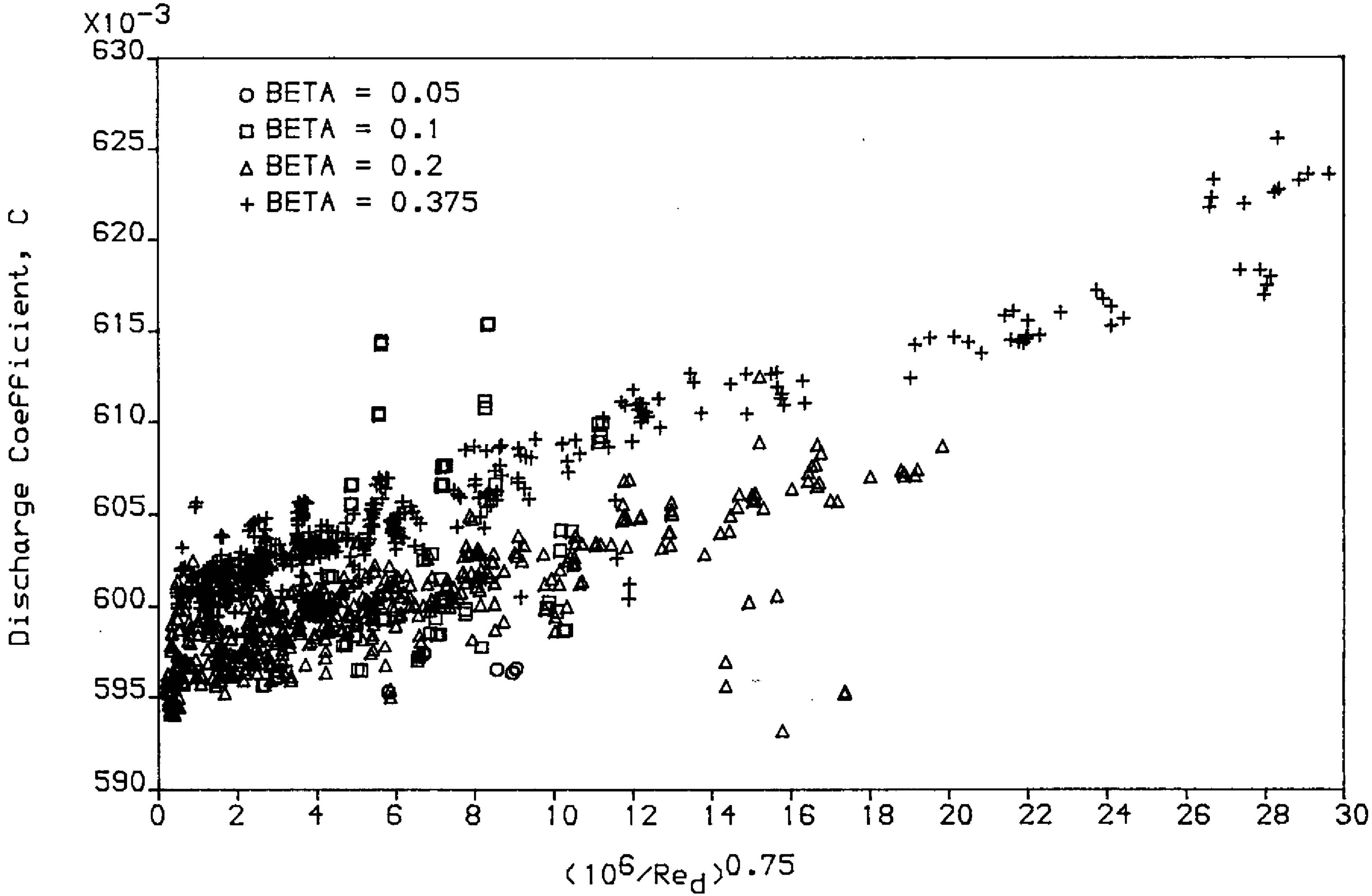


FIG 5 C' V (LAMBDA - 0.01) FOR BETA = 0.57

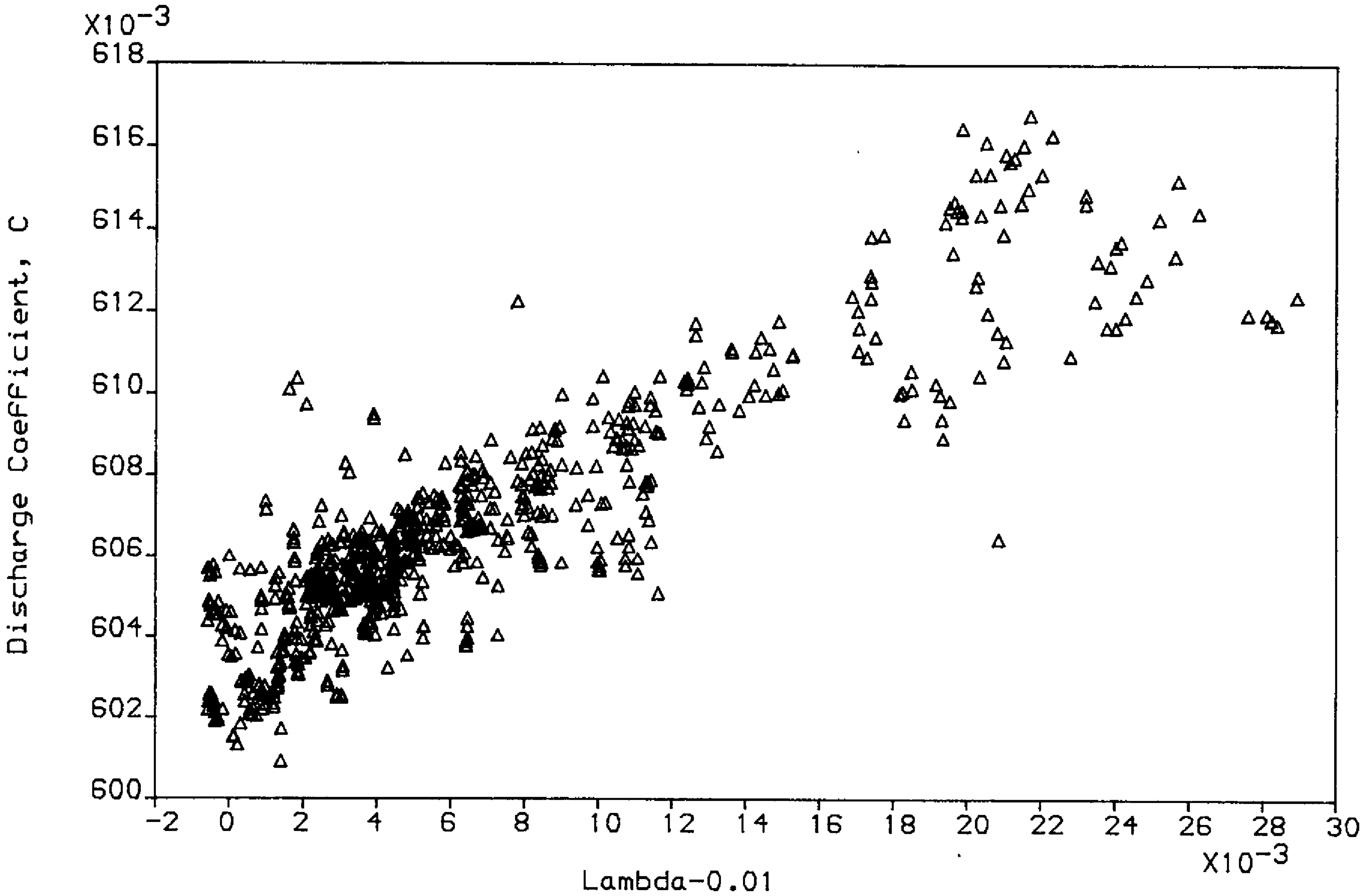
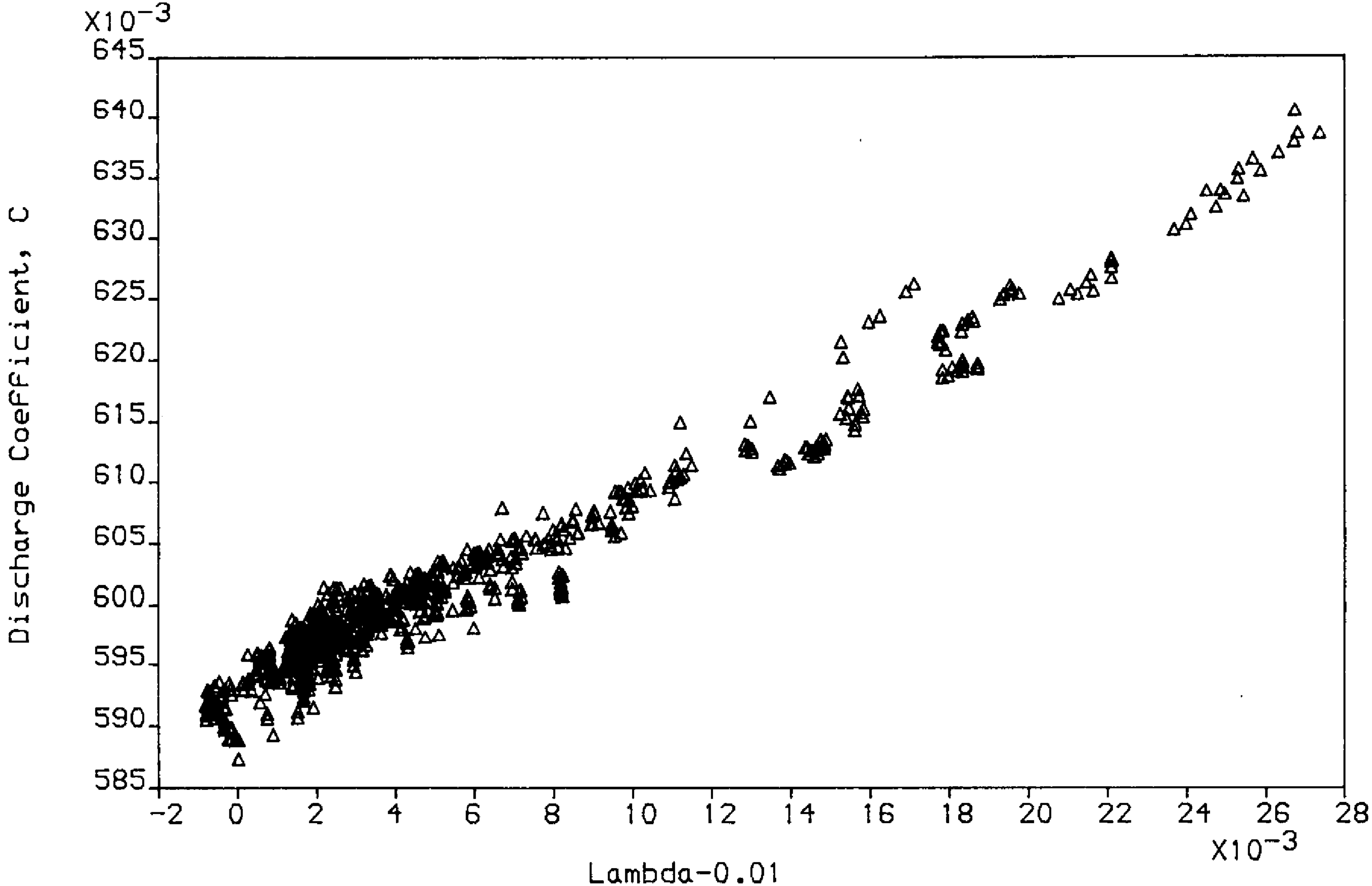


FIG 6 C′ V (LAMBDA − 0.01) FOR BETA = 0.74



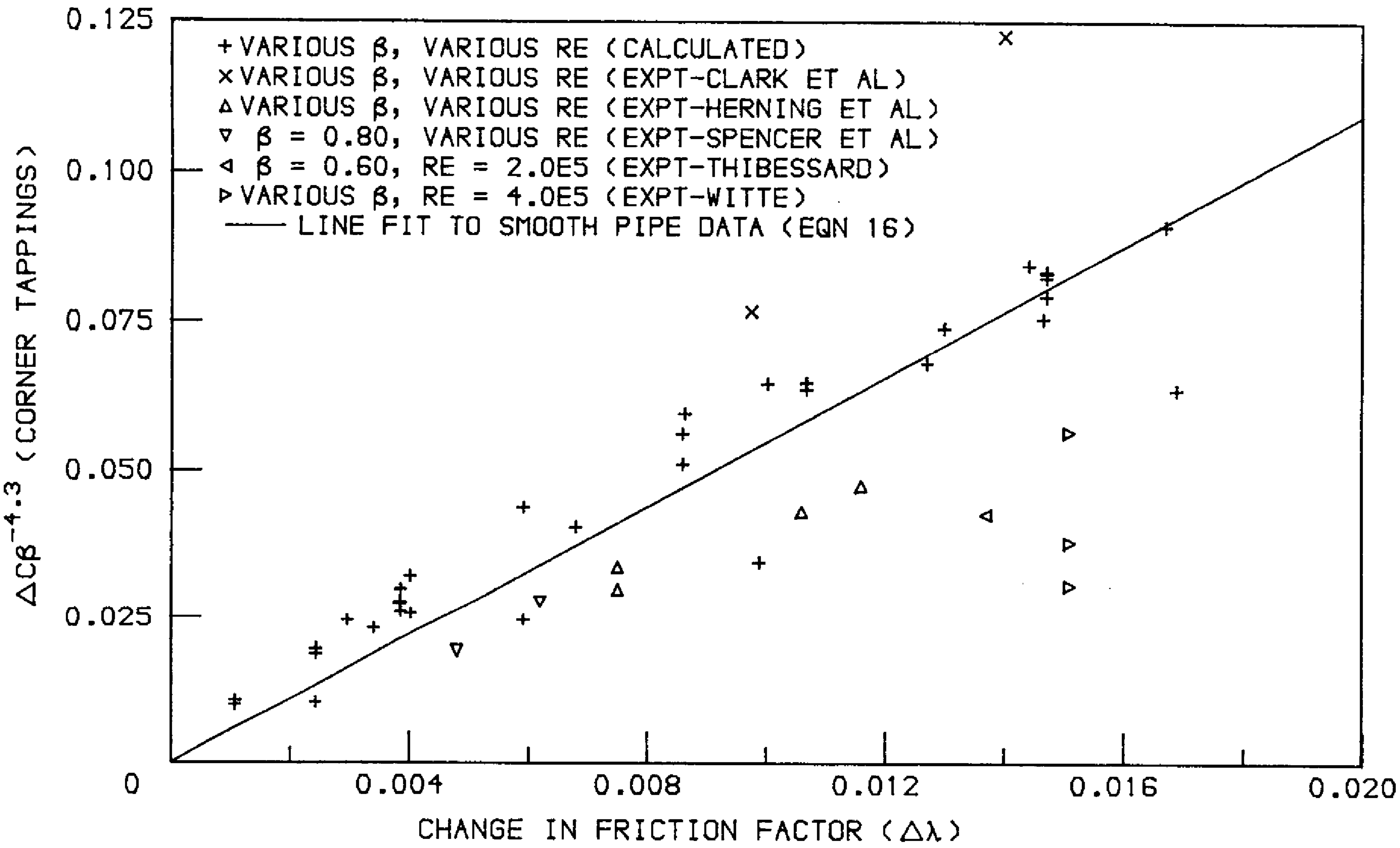


FIG 7 EFFECT OF ROUGH PIPE ON DISCHARGE COEFFICIENT (COMPUTATION AND EXPERIMENT, CORNER TAPPINGS)

FIG 8 DISCHARGE COEFFICIENT V LOG (REYNOLDS NUMBER) FOR BETA=0.2 (NOT 2 INCH)

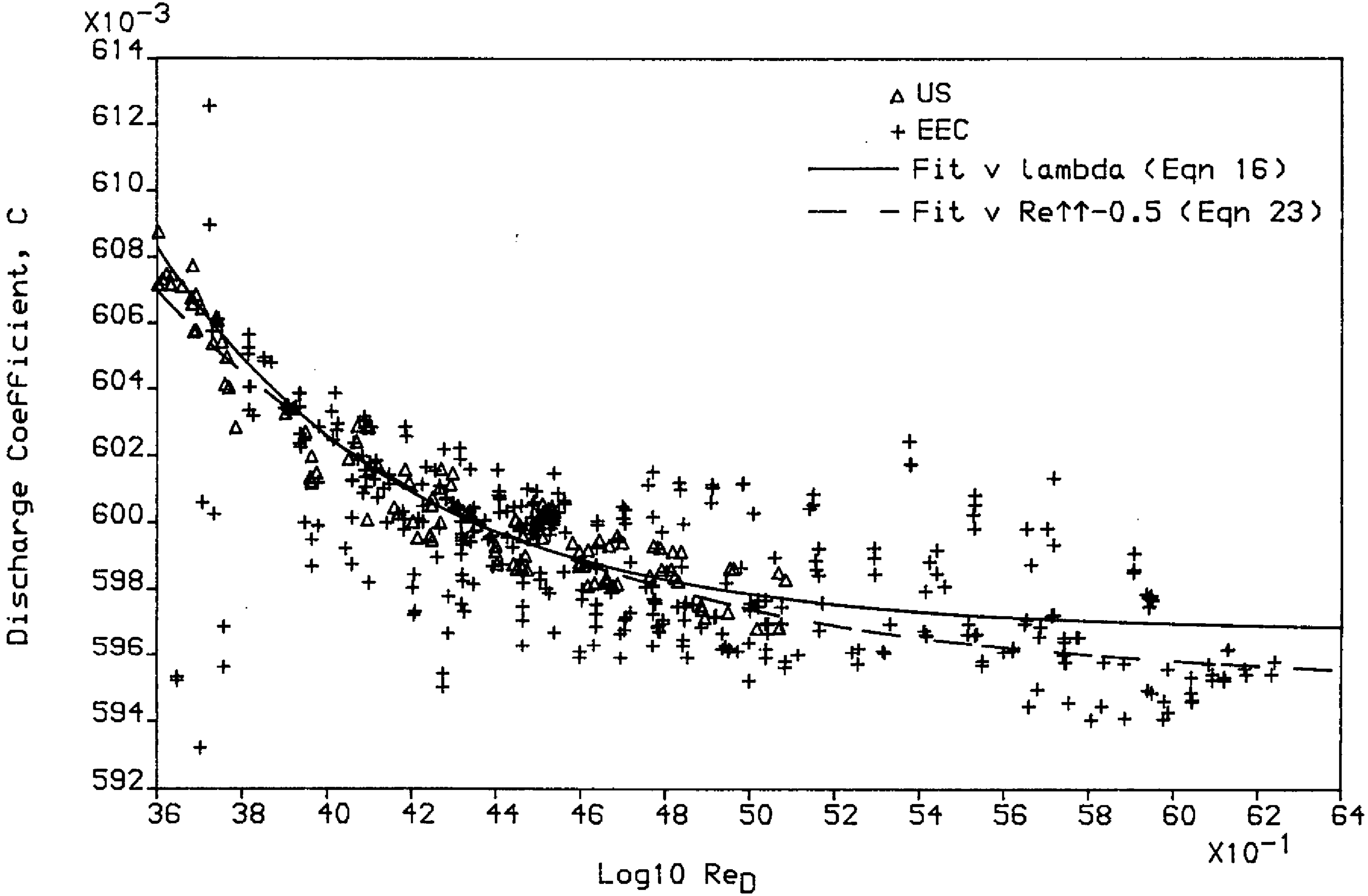


FIG 9 DISCHARGE COEFFICIENT V LOG (REYNOLDS NUMBER) FOR BETA=0.57

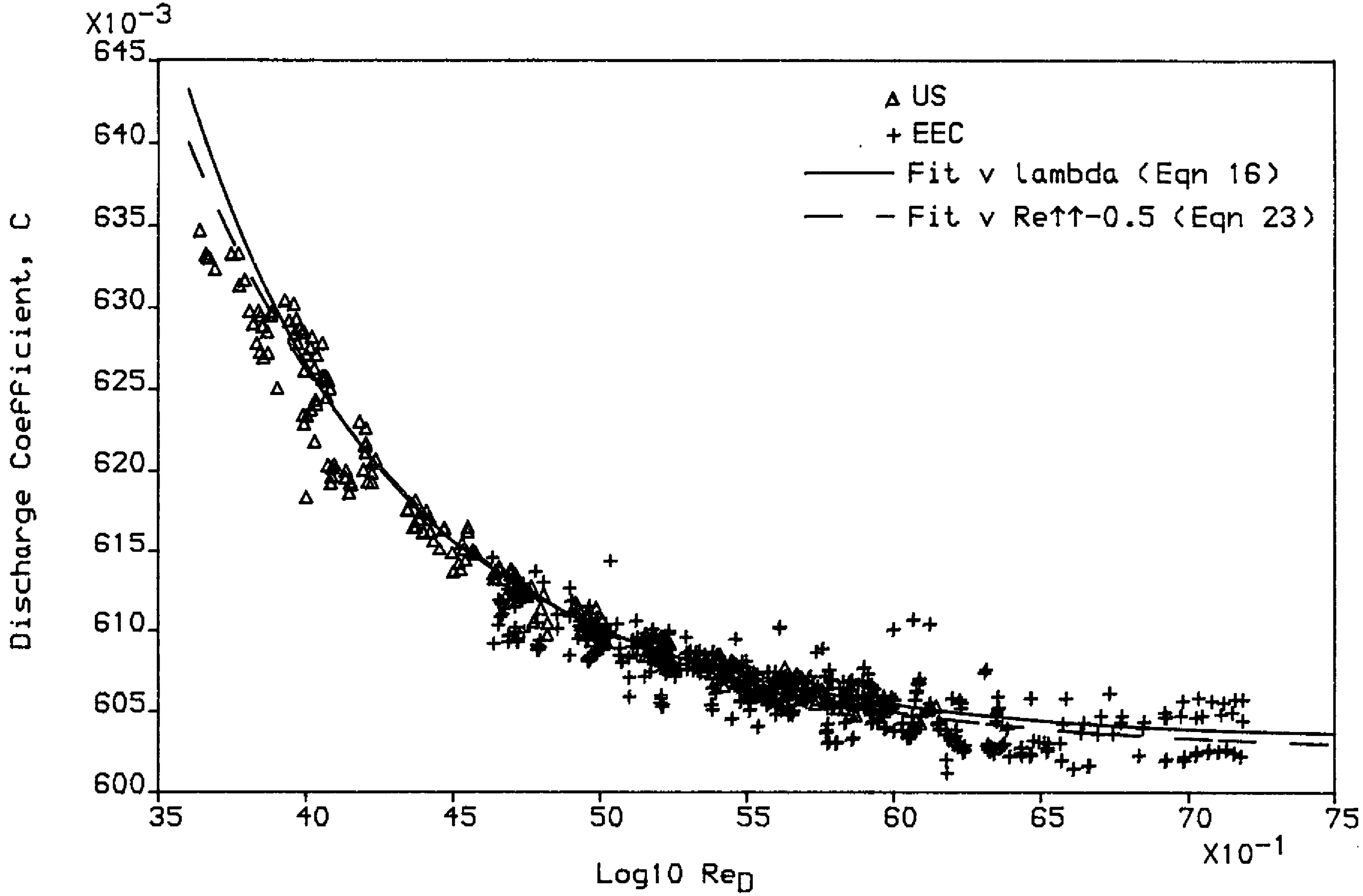
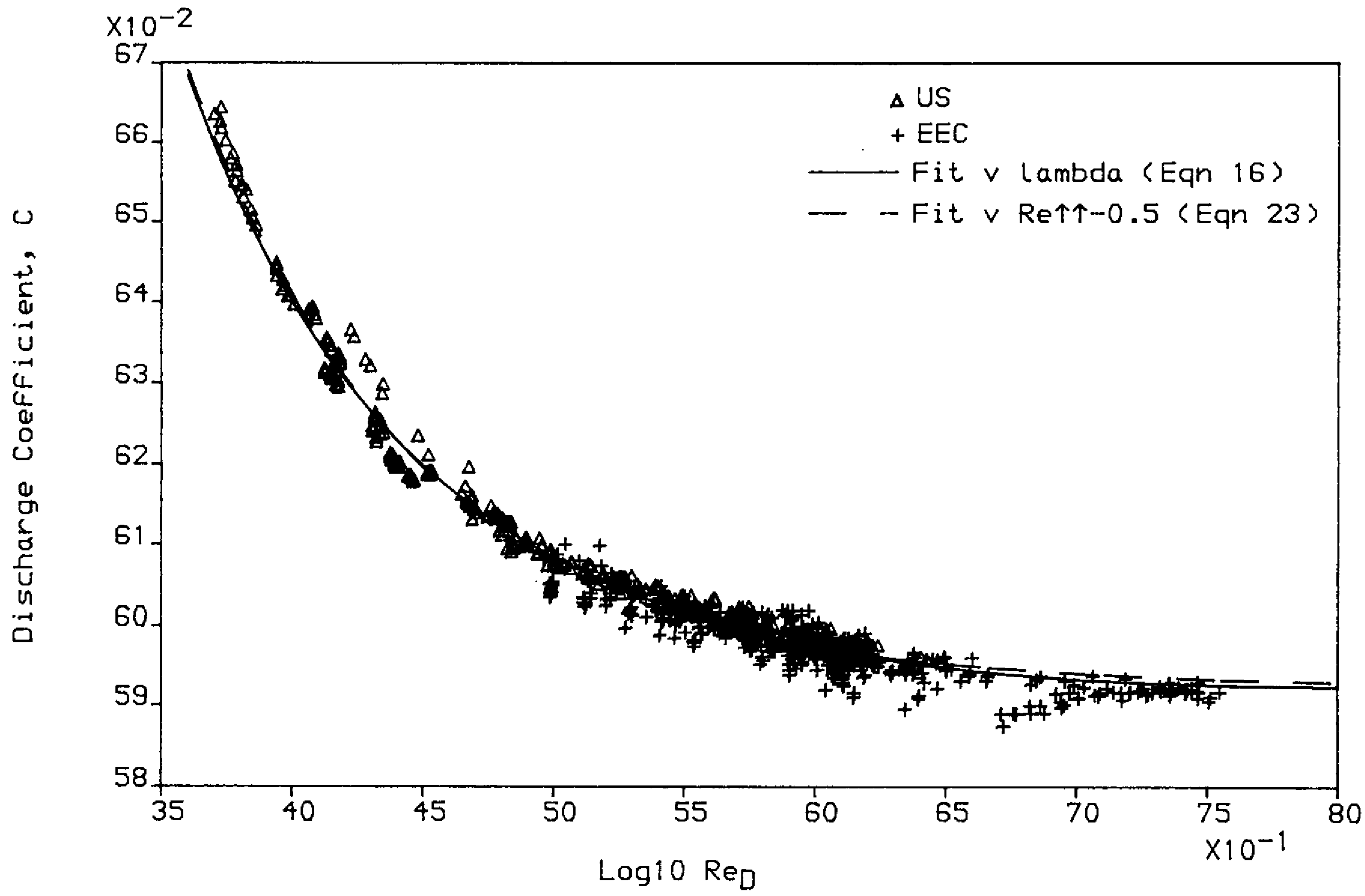


FIG 10 DISCHARGE COEFFICIENT V LOG (REYNOLDS NUMBER) FOR BETA=0.74



Main Index

DEPARTMENT OF ENERGY GUIDELINES ON PETROLEUM MEASUREMENT: CHANGING PRACTICES

by

L N Philp
Department of Energy

Paper 3.3

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

SC2/84

DEPARTMENT OF ENERGY GUIDELINES ON PETROLEUM MEASUREMENT: CHANGING PRACTICES

L N Philp
Department of Energy

Summary

The paper outlines the amendments to petroleum licences introduced by the 1987 Petroleum Act and describes the detailed changes in the Department's guidance documents for the method of measurement for compliance with the measurement model clauses incorporated in petroleum licenses.

1. INTRODUCTION

The timing of the issues of revised metering Guidelines is not connected with the timing of amendments to the measurement model clauses incorporated in petroleum production licences for exploration for and production of petroleum within the UK and its continental shelf. However, the various Acts, and Regulations made under them, do provide the basis for the Guidelines, which represent the outcome of discussions and consultations on "good oilfield practice" with which, as stipulated in regulations, metering systems must comply. The recently revised Guidelines were issued only after such consultation with the representative industry bodies.

The latest legislation, the Petroleum Act 1987, received Royal Assent on the 9 April 1987. Section 17 makes provision for the amendment of model clauses incorporated in existing licences, and Section 18 makes provision for the amendment of model clauses for incorporation in future licences.

Schedule 1 - amends existing licences

Schedule 2 - amends model clauses in the current Regulations

These provisions (ie sections 17 and 18and Schedules 1 and 2) came into force on 30 June 1987.

2. THE AMENDMENTS

The amendments cover several aspects of the measurement of Petroleum which were not previously covered, usual practices within the UK oil and gas industry being recognised.

Appendix 1 - lists the relevant legislation

Appendix 2 - summarises the effects of the amendments in Schedules 1 and 2 on the measurement model clauses.

Appendix 3 - reprints of Department of Energy guidelines.

The existing model clauses incorporated in petroleum licences require the licensee to measure or weigh all petroleum won and saved from the licensed area. For Petroleum Revenue Tax (PRT) purposes petroleum is valued by reference to amounts won and saved from the relevant oil field(s) within a licensed area, reflecting the fact that production and measurement facilities are installed by licensees to produce and measure petroleum from fields of which there are frequently a number wholly or partly within a licensed area. As different oil fields within a licensed area may attract different PRT and royalty regimes it is important that the petroleum produced from each field should be capable of being separately measured.

The amendments which insert new paragraphs (1A) and (1B) in the mesurement model clause and which are reproduced in full in Appendix 2 have the effect that if separate parts of the licensed area are oilfields for the purpose of the Oil Taxation Act 1975, there may be a need for separate compliance with para (1) of the relevant model clause (sub para (a) of new para (1A)) for each field in the licensed area. This would also be the case for a separate field extending beyond the boundary of the licensed area (sub para (b)of new para (1A)), although unit agreement would be taken into account.

The reference in sub para (c) of new para (1A) to "each well .... not within such an oil field" covers measurement of petroleum won and saved from, for example, an extended well test where it is not yet established that the well is producing from a separate field. There may be a requirement for production from such wells, pending determination of their ultimate fiscal status, to be measured in compliance with para (1) of the relevant measurement model clause.

The inclusion in para (1B) of a requirement, if, and to the extent that, the Secretary of State directs, to measure quality or composition in the main formalises current practice. Some quality and/or composition measurements are needed to determine quantities. In the case of multifield pipeline operations or in the case of single tanker loading fields, quality measurements are needed to calculate dry oil quantities in mass units or volumes at reference conditions of pressure and temperature. Quality measurement is needed additionally for the purpose of valuing petroleum.

3. APPLICATION

Having outlined the changes in the measurement model clauses introduced in the new Act, I should like to point out that although these new provisions apply to existing licences, they are not automatic requirements and apply only if, and to the extent that, a direction is given by the Secretary of State. In addition I should emphasise that it is intended that these provisions will only apply to new fields and in particular there is no intention of requiring licensees to alter agreed methods of measurement or measuring appliances, except where a licensee proposes to make use of the measurement facilities of an existing field in measuring the petroleum won and saved from a new field. These provisions are to be applied with full regard to economic considerations.

The provisions of the measurement model clauses are administered by the Petroleum Measurement Inspectorate of the Gas and Oil Measurement Branch. It is not intended that measurement requirements should be so onerous as to stop worthwhile development of petroleum resources going ahead. The agreed method of measurement for any field development whether major or marginal has therefore always been arrived at as a result of dialogue between the operator and the Inspectorate and full consideration is given by the Inspectorate as to what constitutes "good oilfield practice" in the specific context of each proposed development. While separate measurement to full "fiscal" standards would be ideal, such systems imply, with the limitations of present-day technology, separate treatment. There will be a number of small but nevertheless valuable prospects which could not be economically developed if the full infrastructure associated with separate treatment were required to satisfy a strict metering requirement. However, measurement proposals for each field, development, etc are reviewed by the Inspectorate, which takes fully into account the need for and economic justification of the method of measurement ultimately agreed: but now to detailed measurement aspects as covered by the Guidelines themselves.

4. DEPARTMENT OF ENERGY METERING GUIDELINES

In June 1987 the Gas and Oil Measurement Branch of the Department of Energy issued revised versions of the three guidance documents.

> "Department of Energy Metering Standards for Liquid Petroleum Measurements,
>
> Department of Energy Approved Metering Stations - Operating Procedures (Liquid Hydrocarbon Measurement)
>
> Department of Energy Metering Standards for Gaseous Petroleum Measurements"

Some of the changes are administrative and apply to all three documents. There is a change of name and address for the responsible Branch including an issuing office address and an address and contact point for operational matters.

Changes have also been made in the sections listing reference standards. Here we have sought to cite the up-to-date titles and reference numbers of the current issues from the main standards organisations ie, BSI, ISO, IP, API. However as each of these organisations is actively reviewing many of its standards in the field of petroleum measurement and from time to time issues amendments or revisions as well as completely new documents, no statement can hope to provide an up-to-date position for long in this rapidly advancing field.

The remaining changes are of a detailed nature and specific to each document.

5. DEPARTMENT OF ENERGY METERING STANDARDS - GASEOUS PETROLEUM MEASUREMENT

Apart from the administrative changes already mentioned, we have been more specific in requiring the avoidance of carry-over of liquids into the metering section, (4.6 refers). We now include a stipulation of the requirement to be given at least 14 days prior notice of Factory Acceptance Testing and Calibrations.

6. DEPARTMENT OF ENERGY METERING STANDARDS - LIQUID PETROLEUM MEASUREMENT

The changes in the document covering liquid metering standards are intended to reflect the changing approach to the metering of liquid petroleum. Specific reference to turbine meters has been deleted to widen the scope to include suitable meters operating on other principles. Where appropriate PD, vortex shedding, coriolis, and orifice plate metering systems have been considered and no doubt there may be scope for devices operating on other physical principles.

Section 3 - Mode of Measurement

This section now makes specific mention of Petroleum (Production) Regulations which are the legal basis for the metering requirements. A new reference to the possible need for pressure compensators is also included.

Section 4 - Prover Loops and Sphere Detectors

This section now includes a specific requirement for the continuity of the pipework within the calibrated volume. Here also we introduce the possibility, where approved, of the use of small volume provers and liquids other than the service liquid for the re-calibration of prover loops.

The repeatability criterion for prover loop calibrations has been re-stated as $\pm$ 0.01% of the mean volume of five consecutive round trips or statistically equivalent criterion may be used when using a small volume prover to calibrate a large pipe prover.

The note added to 4.4 referring to "other designs" is intended to permit the use of small volume provers for proving meters in service where their use can be agreed to conform to "good oilfield practice". My view is that there is still some way to go to establish these devices in offshore service particularly when used with partially processed crude.

Section 5 - Meters and Associated Pipework

Specific reference to turbine meters has been deleted as we recognise that in certain circumstances instruments operating on different physical principles may be more appropriate. A new statement has been included emphasising the need to exercise care in the selection of temperature and density measuring points to ensure the measurements are as representative of the conditions at the meter inlet as is reasonably practical.

Where we refer to the use of mercury-in-glass thermometers for temperature loop checks, we now state clearly that these should be certified thermometers.

Section 6 - Recirculation Facilities

Where re-circulation systems are fitted around the metering system, we have removed the requirement for automatic gating out of meters and replaced it with a requirement to log fully all recirculated and any non-export flows.

Section 7 - Pulse Transmission

Provision is now made to accept pulse error alarms generated by an error rate as well as the previous system based on cumulative error counts.

Section 8 - Totalisers and Compensators

An extra statement has been added requiring operators to give an outline on the procedures to be adopted to correct errors in flows caused by periods of mis-measurement.

Section 11 - Calibration Facilities

Here we now state that the calibrations of test equipment be traceable to National Standards of Measurement. This generally means UK National Standards but for imported equipment, initial traceability to the National Standards of the Country of origin would generally be accepted for the currency of the initial certification and subsequent re-calibrations should then be traceable to UK National Standards.

7. OPERATING PROCEDURES FOR LIQUID HYDROCARBON MEASUREMENT

Foreword

Reference is now made to types of meter other than turbine meters and the requirement where necessary to modify operating procedures to account for different characteristics particularly with "difficult" fluids such as viscous crudes or low lubricity fluids such as gas condensates.

We now require operators to submit their proposals for operation and calibration of their systems in duplicate to the Aberdeen office prior to commisioning and operation of the metering systems.

Section 1 - Prover Calibration

Apart from the name change the only new requirement is for two copies of prover loop calibration certificates.

Section 3 - Meter Proving in Service

This revised section gives more detailed advice on when to re-prove meters as a consequence of a change in flowrate.

Also included is a new paragraph dealing with proving requirements for meters other than turbine meters.

Section 4 - Meter Factors

The repeatability requirement for proving meters in service has been re-stated as $\pm$ 0.05% of the mean of five consecutive proof runs.

Section 6 - Documentation to be kept at the Meter Station

The log keeping requirements now includes density where this is measured continuously.

The minimum period for the retention of logs at the metering site has been increased from 3 to 4 months.

Section 7 - Direct Reporting

Specific reference to turbine meters has been deleted to account for systems where other types of flow meters may be employed.

Any reports required under this section should now be sent direct to Gas and Oil Measurement Branch. In the case of land terminals, the option to submit reports via Customs and Excise has been cancelled.

APPENDIX 1

Legislation pertaining to Petroleum Production Measurement

The Petroleum (Production) Act	1934
The Continental Shelf Act	1964
The Petroleum and Submarine Pipe-lines Act	1975
The Oil Taxation Act	1975
The Petroleum Act	1987

The various sets of Petroleum (Production) Regulations made by the Secretary of State in pursuance of powers conferred on him by Section 6 of the Petroleum (Production) Act 1934.

One of the provisions of the measurement model clause incorporated in petroleum production (and landward appraisal) licences is as follows:

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

APPENDIX 2

PETROLEUM ACT 1987 - MEASUREMENT MODEL CLAUSE AMENDMENTS

Section 17 and 18

Section 17 amends existing licences as provided by Schedule 1 to 1987 Act.

Schedule 1 amends existing licences in

1975 PETROLEUM SUBMARINE PIPELINE ACT

Part II Schedule 2 (Seaward Areas)	Measurement Model Clause 12
Part II Schedule 3 (Landward Areas)	Measurement Model Clause 12

1976 PETROLEUM (PRODUCTION) REGULATIONS

Schedule 4 (Landward Areas)	Measurement Model Clause 12
Schedule 5 (Seaward Areas)	Measurement Model Clause 12

1982 PETROLEUM (PRODUCTION) REGULATIONS

Schedule 4 (Landward Areas)	Measurement Model Clause 12
Schedule 5 (Seaward Areas)	Measurement Model Clause 11

1984 PETROLEUM (PRODUCTION) (LANDWARD AREAS) REGULATIONS

Schedule 4 (Landward Areas) (appraisal licences)	Measurement Model Clause 10

Schedule 2 amends Model Clauses (for incorporation in future licences)

1982 PETROLEUM (PRODUCTION) REGULATIONS

Schedule 5 (Seaward Areas)	Measurement Model Clause 11

1984 PETROLEUM (PRODUCTION) (LANDWARD AREAS) REGULATIONS

Schedule 4 (Landward Areas) (appraisal licences)	Measurement Model Clause 10
Schedule 5 (Landward Areas) (development licences)	Measurement Model Clause 11

These amendments insert after paragraph (1) of the relevant Measurement Model Clause the two following paragraphs:-

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

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

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

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

(1B) If and to the extent that the Minister so directs, the preceding provisions of this clause shall apply as if the duty to measure or weigh petroleum included a duty to ascertain its quality or composition or both; and where a direction under this paragraph is in force, the following provisions of this clause shall have effect as if reference to measuring or weighing included references to ascertaining quality or composition."

APPENDIX 3

JUNE 1987
ISSUE 3

DEPARTMENT OF ENERGY METERING STANDARDS FOR GASEOUS PETROLEUM MEASUREMENTS

1. INTRODUCTION

1.1 This document comprises a set of guidelines, issued to Licensees and Operators in the UK Continental Shelf and Landward Areas, for use in the design, construction and submission of gas metering systems that are to gain Department of Energy approval. It also covers the construction and operation of electronic computing and totalising systems.

1.2 It is intended that these specifications should be interpreted as general minimum requirements and that relaxed requirements will only be appropriate in special circumstances. Alternative specifications to those given in this document will be permitted provided that they can be shown to provide a similar or greater level of fidelity and accuracy. With this in mind Operators are required to submit metering proposals in duplicate to the Department of Energy, Gas and Oil Measurement Branch (GOMB) prior to the commencement of manufacture or, where practicable, at the design stage. The Branch address is:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
Aberdeen
AB9 2ZV

1.3 The metering requirements apply to:

1.3.1 Custody Transfer of gas covering sale, export or import. This includes the transfer of gas from one licensed area to another where both licences are held by the same licensee.

1.3.2 Allocated Utility and Fuel Gas. This category covers the measurement of gas used for process and power where the quantities of gas are used in allocating the production gas to more than one licensed area.

1.3.3 Continuous Flare Gas and Utility and Fuel Gas other than that covered by 1.3.2.

1.4 Gas Streams other than those indicated above, e.g. vent, reinjection or lift gas, should be accounted for. Special provisions will apply where gas is stored in conjunction with production.

2. REFERENCE STANDARDS

2.1 Gas metering systems should generally conform to the following standards where applicable.

a) BS 1042: Part 1: Section 1.1: 1981
Methods of measurement of fluid flow in closed conduits: Orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.
or its near equivalent
ISO 5167: 1980
Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.

b) BS 5844: 1980
Measurement of fluid flow - Estimation of uncertainty of flow-rate measurement.
or
ISO 5168: 1978
Measurement of fluid flow - Estimation of uncertainty of flow-rate measurement.

c) BS 4161: Part 6: 1979
Rotary displacement and turbine meters for gas pressures up to 100 bar.

d) Institute of Petroleum, Petroleum Measurement Manual:

i) Part VII Density: Section 2: 1983 Continuous Density Measurement.

ii) Part XIII Fidelity and Security of Measurement Data Systems Section 1: 1976 Electric and/or Electronic Pulsed Data Cabled Transmission for Fluid Metering Systems (IP 252/76).

iii) Part XIII Fidelity and Security of Measurement Data; Section 3: 1985 Electrical and/or Electronic Data Capture Systems for Flow Metering.

3. MODE OF MEASUREMENT

3.1 All measurements should be made on single phase gas streams.

3.2 Hydrocarbon measurements may be in either volumetric or mass units. The choice of measurement should however be discussed with the Department of Energy. Volumes should be measured in cubic metres and mass in tonnes.

3.3 Where volume is the approved measurement, it should be referred to the standard reference conditions of 15^{o}C temperature and 1.01325 bar absolute pressure (dry).

3.4 Where gas is subject to custody transfer, or used as a fuel where 1.3.2 applies, suitable sampling facilities shall be provided for the purpose of obtaining representative samples. This requirement may be influenced by the type of instrumentation incorporated in the measuring system.

3.5 The continuous measurement of gas density is preferred for custody transfer but the density of the gas being metered may, under certain circumstances, be computed from pressure and temperature measurements together with gas composition using a suitable equation of state and agreed computational techniques.

4. DESIGN -CRITERIA

4.1 Custody Transfer Gas

4.1.1 Where orifice meter systems are used, the design and operation should comply with BS 1042 : 1981 (ISO 5167) but with the additional specifications given below:-

a) Maximum beta ratio 0.6

b) Maximum Reynolds number 3.3×10^7

c) Maximum differential pressure 0.5 bar is preferred. Higher differential pressures may be used where it is demonstrated that the conditions of e), f) and g) are met.

d) The meter should be designed and constructed such that the minimum uncertainties specified in BS 1042 : 1981 are achieved.

e) The elastic deformation of the orifice plate at maximum differential pressure shall be less than 1%.

f) The uncertainty in flow caused by elastic deformation of the orifice plate shall be less than 0.1%.

g) The location of the differential pressure tappings with respect to the orifice plate shall remain within the tolerances given in BS 1042 : 1981 over the operating range of differential pressures.

h) Special considerations may be applicable where pulsations are unavoidable but normally the uncertainty due to any such effects should be kept below 0.1%.

4.1.2 Where metering systems other than orifice plate metering are to be used, the systems together with their flow compensating devices should be of the types agreed by the Department of Energy (see para 1.2) and should be calibrated over as much of the operating pressure, temperature and flow range as is reasonably practicable. Proposals for any extrapolation of such calibrations and correlations of the operating conditions should be presented.

4.1.3 Secondary instrumentation, line pressure and temperature, differential pressure, flowing density, density at base or reference conditions where appropriate and the flow computers should be specified and their positions in the system should be located such that representative measurement is ensured. In many applications the compositional analysis of the gas is required and it is necessary to provide for gas sampling or on-line analysis.

4.2 Allocated Utility and Fuel Gas

4.2.1 The total quantity of gas should be metered at one off-take if this is practicable. It is not necessary to meter gas streams to individual points of consumption (e.g. individual compressors) if the flow can be obtained from a single set of meters giving the total flow to the (compressor) station.

4.2.2 Where orifice plate meters are used the design and operation should comply with BS 1042 : 1981 (ISO 5167) The specifications given above in paragraph 4.1.1 a), b), c) and d) need not apply, but the design should meet the requirements of 4.1.1 e), f), g) and h).

4.2.3 Where meters other than orifice plate meters are used the requirements given in paragraph 4.1.2 shall apply.

4.3 Continuous Flare Gas and Utility and Fuel Gas other than that covered by 1.3.2

Proposals for determining these quantities (either directly or indirectly) should be presented. It is assumed that the venting of gas would be under abnormal or emergency conditions only. Provisions for estimates of such quantities should be made.

4.4 For custody transfer (1.3.1) and for allocated utility gas (1.3.2), sufficient meter runs should be provided to ensure that, at the nominal designed field production rate or utility rate, at least one stand-by meter is available. Due consideration should be given to the provision of adequate valves so that individual meters may be removed from service without shutting down the entire metering system.

4.5 Consideration should be given during design to the provision of back-up instrumentation to cover the failure of normal instrumentation, and to the on-site calibration of primary and secondary metering equipment.

4.6 Metering stations should be designed to be free from any carry over into the metering section, and from any condensation or separation, that would have a significant effect on measurement uncertainties.

4.7 An indication of the overall design accuracy and uncertainty in measurement of the metering system together with the sources of error should be given (paragraph 10.1 of BS 1042 : 1981) The assessment of uncertainties in gas measurement should preferably be calculated in accordance with BS5844 : 1980. (The Appendix contains guidance.)

4.8 Computers and Compensators

4.8.1 A flow computer should be dedicated to each meter run.

4.8.2 For custody gas (1.3.1) and utility gas (1.3.2) all computer and compensating functions, other than data input conversions, should preferably be made by digital methods. All calculation constants should be securely stored in the computer and should be easily available for inspection. Equipment should be designed so that constants can be adjusted, but only by authorised personnel. After initial agreement of stored constants subsequent changes in the computer should be made only with agreement of the Department. Where it is necessary to use manual inputs of data into the computer e.g., base density, the use of this data should be automatically logged.

4.8.3 Totalisers on individual and station summators should have sufficient digits to prevent roll-over more frequently than every two months. Totalisers should normally have a resolution of 1 tonne or 1000 standard cubic metres, or decimal submultiples thereof. Totalisers and summators should be non-resettable.

4.8.4 Where rotary positive displacement or turbine meters are used both compensated and uncompensated flow quantities should be recorded.

5. GENERAL

5.1 A comprehensive dossier containing the following information should be submitted as early as possible.

(a) Basic data.

(b) Design formulae and calculations.

(c) Secondary instrumentation specifications.

(d) Overall accuracy, or uncertainty in measurement.

(e) Relevant drawings.

(f) Outline of calibration and verification methods.

5.2 In a gas gathering system the operator responsible for the gathering should ensure that the basic metering data, flow formulae and computational techniques are compatible throughout all the fields connected to the gathering system.

5.3 The Petroleum Production Reporting System, agreed between the UKOOA and the Department of Energy calls for the average calorific value (energy per unit volume) of custody transfer gas to be reported to the Department monthly. Provision for the determination of the calorific value of custody transfer gas should therefore be considered.

5.4 The Department of Energy will require adequate notice (normally at least 14 days) of the factory inspection and calibration of primary and secondary equipment, including flow computers, in order that GOMB may witness these tests at their discretion.

5.5 Adequate verification or, where appropriate, calibration equipment should be provided to enable the performance of meters, computers, totalisers etc, to be assessed. Reference or transfer standards shall be certified by a laboratory with recognised traceability to National Standards (e.g. British Calibration Service).

Issued by:-
Department of Energy
Gas & Oil Measurement Branch
3 Tigers Road
South Wigston
Leicester
LE8 2US

Telephone 0533 785354
Telex 342457
June 1987

Contact point on operational matters:-
Telephone 0224 647961
Telex 739283

APPENDIX

The Calculation of Design Uncertainties in Flow Measurement using Orifice Plate Meters BS 1042 : 1981 (ISO 5167) ; BS 5844 : 1980 (ISO 5168)

1. The uncertainty in the measurement of a mass flow rate, q m, should be calculated using the simplified formula given in BS 1042 paragraph 10.2.2 (see list of equations, equation 1).

   The percentage uncertainty E of a variable can be substituted for the relative uncertainty throughout this equation (equation 2).

2. The uncertainties used should be those with a confidence level of 95%. At this confidence level uncertainty can be assumed to be equal to twice the standard deviation of measurements.

   If no information is available for the uncertainty of any particular variable an estimate should be made of the highest and lowest probable true values. The uncertainty should then be taken as half the difference between these values.

3. The uncertainty in should be taken as the uncertainty in C from BS 1042 paragraph 7.3.3.

   The uncertainty in the expansion factor should be taken from paragraph 7.3.3.2 of BS 1042

4. The uncertainties in D and d should be taken as those given in BS 1042 paragraph 10.2.2.3

5. The uncertainty in the differential pressure, E p, should include the uncertainties in signal conditioners or converters and any other transmission component. These uncertainties should be combined with the transducer uncertainty on a root-sum-square basis.

   This procedure also applies to the derivation of the uncertainty in the measurement of the operating density, E .

6. The uncertainty of the computer should be included by means of an additional term, (E_c) under the square root sign in equation 2, (equation 3).

7. Where volume flow qv is being computed, the uncertainty in the measured value of density at base conditions E b, should be derived, giving consideration to the principles of paragraph 5.

   The term (E b) should be included under the square root sign in equation 3, (equation 4).

8. If the operating density is calculated from measurements of pressure, temperature compressibility factor, and molecular weight then the term (E) should be deleted from equations 2, 3 and 4, and the following terms substituted (see annex equation 5), respectively,

where E is the percentage uncertainty in the measured operating pressure etc.

9. The uncertainty of a meter tube should be calculated at the design flow rate and one third of this flow rate.

10. In the statement of uncertainty of flow rate it is not necessary to distinguish between random and systematic components.

11. Where the gas flow is shared equally amongst a number of meters of identical design arranged in parallel the uncertainties in the factors alpha and epsilon should not be considered to be randomly distributed between the meters. The following procedure for calculating the uncertainty in the total flow, E , should be carried out.

Considering a single meter, the sum of the first two terms under the square root sign in equations 2-5 should be called (E) .

The uncertainty in the total flow, E , is then given by

equation 6

Where N is the number of meters in parallel, and (Ey) is the sum of the remaining terms in equations 2-5.

JUNE 1987
ISSUE 3

DEPARTMENT OF ENERGY METERING STANDARDS FOR LIQUID PETROLEUM MEASUREMENTS

1. INTRODUCTION

1.1 This document consists of a set of guidelines, issued to Licensees and Operators in the UK Continental Shelf and Landward Areas for use in the design and construction of metering systems that are to gain Department of Energy approval under the terms of the measurement model clauses included in the licensee's production licence. It covers the construction and operation of prover loops, metering systems and electronic totaliser systems.

1.2 It is intended that these standards should be interpreted as general minimum requirements, and that relaxed requirements will only be appropriate in special circumstances. Alternative specifications to those given in this document will be permitted provided they can be shown to provide a similar or greater level of fidelity and accuracy. With these considerations in mind, Operators are required to submit design proposals in duplicate to the Gas and Oil Measurement Branch (GOMB) prior to the commencement of manufacture.

The Branch address is:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
Aberdeen
AB9 2ZV

1.3 It is not mandatory that existing metering stations should be modified to comply with any new requirements given in this document.

2. REFERENCE STANDARDS

2.1 Metering systems should generally conform to the latest issues of the following standards:-

2.2 American Petroleum Institute:-

Manual of Petroleum Measurement Standards plus the following available separately:-

a) For crude:

Chapter 11.1, Volume VII, August 1980 (ANSI/ASTM D 1250) (IP200) (API Std 2540)
Table 53A - Generalised Crude Oils, Correction of Observed Density to Density at 15°C
Table 54A - Generalised Crude Oils, Correction of Volume to 15°C Against Density at 15°C

b) For computer programming:

Chapter 11.1, Volume X, August 1980 (ANSI/ASTM D 1250) (IP200) (API Std 2540)
Background, Development and Computer Documentation

2.3 Institute of Petroleum:-

a) Petroleum Measurement Manual:

i) Part VII Density: Section 2: 1983 Continuous Density Measurement.

ii) Part X Meter Proving: Section 1 (Tentative): 1979 Field Guide to Proving Meters with a Pipe Prover.

iii) Part XIII Fidelity and Security of Measurement Data Systems Section 1: 1976 Electric and/or Electronic Pulsed Data Cabled Transmission for Fluid Metering Systems (IP 252/76)

iv) Part XIII Fidelity and Security of Measurement Data; Section 3: 1985 Electrical and/or Electronic Data Capture Systems for Flow Metering.

b) Petroleum Measurement Paper No.2

Guidelines for Users of the Petroleum Measurement Tables (API Std 2540; IP200; ANSI/ASTM D 1250) - September 1984.

2.4 For condensate:

a) ASTM - IP - API Petroleum Measurement Tables for Light Hydrocarbon Liquids. London; John Wiley & Sons, 1986.

3. MODE OF MEASUREMENT

3.1 Hydrocarbon measurements for requirements under the Petroleum (Production) Regulations should be either in volumetric or mass units. The choice of measurement should be discussed with GOMB. Volumes should be measured in cubic metres and mass in tonnes (in vacuo).

3.2 Where the approved measurement is in volumes, these should be referred to standard reference conditions of 15 deg.C temperature and 1.01325 bar pressure. The metering system should compute referred volumes by means of individual meter temperature compensators and totalisers. Where appropriate, consideration should be given to the provision of pressure compensators. Alternative systems giving equivalent results can be considered.

3.3 Where the approved measurement is in mass units the metering system should feature dual or single density meters, (the former being normally required), together with automatic mass computation. Dual density meter systems should feature a density discrepancy alarm system - single density meter systems should feature high and low set point alarms. Suitable sampling facilities shall be provided in close proximity to the density meter(s) in all cases. The mass computers should compute total station mass throughput from volume and density at line conditions of pressure and temperature and should have facilities for manually over-riding the density input signal.

4. PROVER LOOPS AND SPHERE DETECTORS

4.1 Preferably prover loops should be of the bi-directional type with a suitable lining. The flanged joints within the calibrated volume should have metal to metal contact and there should be continuity within the bore. Connections should be provided on the prover loop to facilitate recalibration with a portable calibration prover loop and transfer meter or small volume type prover, where this is approved by GOMB for use in the particular application using the in-service liquid as the transfer medium, or other suitable liquid if approved by GOMB.

4.2 Provers should be constructed according to the following criteria:-

i. Number of meter pulses generated over swept volume to be 20,000 pulses. (This is equivalent to 10,000 pulses between detectors on bi-directional provers.)

ii. Resolution of detector/displacer system to be compatible with requirement (i).

iii. Displacer velocity not to exceed 3m/s.

Because the resolution of the detector/displacer system can only be gauged by the actual performance of the prover, the Department expects the manufacturer to demonstrate an acceptable repeatibility during calibration of the prover, such that on 5 consecutive round trips the range of volumes does not exceed +/- 0.01% of the mean volume. Alternatively, a statistically equivalent repeatability criterion for small volume provers or meter pulse gating systems may be used.

4.3 For offshore use, or in remote locations, prover loops should be fitted with dual sphere detectors and switches at each end of the swept volume. At least two volumes should be calibrated so that failure of a detector or switch does not invalidate the prover calibration. The detector should be designed such that the contacting head of the detector protrudes far enough into the prover pipe to ensure switching takes place at all flow rates met with during calibration and normal operation. Detectors and switches should be adequately waterproofed against a corrosive marine environment.

4.4 In the case of mechanical switches, each sphere detector should have a dedicated micro-switch. The actuation of each detector unit should be set during manufacture so that should it be necessary to replace a detector unit during service there will be a minimal change in prover calibrated volume.

NOTE: Other designs of prover may be considered subject to their being in accord with good oilfield practice.

5. METERS AND ASSOCIATED PIPEWORK

5.1 The meter should generate the electrical signal directly from the movement of the meter internals without any intermediate gearing or mechanical parts. Electrical interpolation systems may be accepted.

5.2 Enough meter runs should be provided to ensure that, at the nominal designed field production rate, at least one stand-by meter is available. Adequate valving should be provided such that individual meters may be removed from service without shutting down the entire metering system.

5.3 Metering stations should have a common inlet header and, if necessary, a common outlet header to ensure uniform measuring conditions at all metering streams, temperature transducers and density meters.

5.4 Temperature and density measuring points should be representative of conditions at the meter inlet and situated as follows:-

(a) In volumetric measurement systems: as close to the meter as possible without infringing the requirements of the API Measurement Manual.

(b) In mass measurement systems: as close to the densitometers as possible, which should also be located as near the meters as possible, without infringing the API Measurement Manual.

5.5 Metering systems should be provided with enough thermo-wells to facilitate temperature checks by means of certified mercury-in-glass thermometers.

5.6 Metering stations should be provided with correctly positioned sampling probes so that representative samples may be taken from the system. It is equally important to ensure that density meters are correctly located to ensure representative sampling.

6. RECIRCULATION FACILITIES

6.1 The Department does not normally permit the fitting of recirculation loops to metering systems except in production systems featuring rapid tanker-loadings. Where recirculation systems are fitted around the metering system, full logging of recirculation and any other non-export flows through the meters must be maintained.

6.2 Recirculation facilties intended for the use of pump testing etc. should be fitted upstream of the metering system.

7. PULSE TRANSMISSION

7.1 The metering signals (see also 5.1 above) should be generated by a dual meter head pick-up system in accordance with either Level A or Level B of the IP 252/76 Code of Practice.

7.2 A pulse comparator should be installed which signals an alarm when a pre-set number of error pulses occurs on either of the transmission lines in accordance with the above code. The pre-set alarm level should be adjustable, and when an alarm occurs it should be recorded on a non-resettable comparator register. Where the pulse error alarm is determined by an error rate, the error threshold shall be less than 1 count in 10^6. Pulse discrepancies that occur during the low flow rates experienced during meter starting and stopping should be inhibited.

7.3 The pulse transmission to the prover counter should be from one or both of the secured lines to the pulse comparator, and precautions should be taken to avoid any signal interference in the spur from the comparator line.

8. TOTALISERS AND COMPENSATORS

8.1 All totalising and compensating functions, other than data input conversions, should be by digital methods.

8.2 Each meter run should have an instrument computing uncorrected volumes at line conditions in which meter factors should be capable of being set to a resolution of at least 0.03%. In volumetric measuring systems, a liquid pressure correction may be included in the computation as this correction is usually small and of constant magnitude.

8.3 Totalisers on individual meter run instruments, and on station summators, should have sufficient digits to prevent roll-over more frequently than every 2 months and normally have a resolution of 1 unit of volume or mass. Totalisers should be non-resettable and, where they are of the non-mechanical type, should be provided with battery driven back-up memories.

The procedures to be used for correcting flow during any period of mis-measurement should be made available.

8.4 For the volumetric mode of measurement, automatic temperature compensation is required. Temperature compensation should be carried out on each individual meter-run. The liquid thermal expansion coefficient set into the compensator should be fully adjustable over the range likely to be encountered in practice and have a resolution of at least 2 significant digits.

8.5 Corrections to meter throughput for water and sediment content should be applied retrospectively based on the analysis of the flow-proportional sample.

9. OTHER INSTRUMENTATION

9.1 Temperature measurements that affect the overall accuracy of the metering system should be to an accuracy of at least 0.5 deg C, and the corresponding readout should have a resolution of at least 0.2 deg.C.

9.2 To provide a history of meter operation and flowing conditions and a record of meter malfunctions, each meter-run should be provided with a continuous chart recording of flow rate and metering temperature. Alternatively, electronic data recording will be accepted provided that the recording frequency is adequate and the system logs all metering alarms. Recording intervals no greater than 4 hours will normally be considered adequate.

9.3 In mass measurement systems, the density signals from the density meters should also be recorded continuously by a chart recorder or electronic data recorder at the same interval as in 9.2 above. A digital read-out is also required with a resolution of at least 4 significant figures.

9.4 Crude oil metering systems should be provided with automatic flow proportional sampling systems for the determination of average water content, average density and for analysis purposes.

9.5 In crude oil systems where slugs of water may be experienced, in-line water detection probes should be fitted to detect abnormal levels of water content. Continuous recordings of percentage water content and a high-level alarm system should be provided. Data from this source should not normally be used in determining dry oil quantities.

10. SECURITY

10.1 All meter factor settings and reset buttons, where allowed, should be secured with a seal or lock to prevent unauthorised adjustment. Prover loop sphere detectors and associated micro-switches should also be secured by locks or seals.

10.2 Valves on re-circulation lines provided for the purposes of off-line meter testing via re-circulation loops must be provided with approved type locks.

11. CALIBRATION FACILITIES

11.1 Adequate test facilities should be provided with metering systems to facilitate the checking and calibration of all computing and totalising systems. The calibration of test equipment shall be traceable to National Standards of measurement.

Issued by:-
Department of Energy
Gas & Oil Measurement Branch
3 Tigers Road
South Wigston
Leicester
LE8 2US

Telephone 0533 785354
Telex 342457

June 1987

Contact point on operational matters:-
Telephone 0224 647961
Telex 739283

JUNE 1987
ISSUE 3

DEPARTMENT OF ENERGY
APPROVED METERING STATIONS - OPERATING PROCEDURES
(LIQUID HYDROCARBON MEASUREMENT)

FOREWORD

To comply with the requirements of UK Licences for Petroleum Exploration and Production, all petroleum gases and liquids won and saved from both the UK Continental Shelf and Landward Areas have to be measured in accordance with good oil field practice. To define this requirement in respect of operational procedures for liquid measurement, the Department of Energy's Gas and Oil Measurement Branch has formulated these Operating Procedures, which were originally published by the Petroleum Engineering Division in September 1976. This third issue now supercedes the original publication. The organisation within the Department of Energy now responsible for metering is the Gas and Oil Measurement Branch (GOMB) whose address is:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
Aberdeen
AB9 2ZV

The procedures cover the metering of liquid mass and volume with particular emphasis on crude oil measurement, and are based on the operational characteristics to be expected of a typical metering station equipped with turbine meters. Where other types of meter have been approved a variant of these procedures may be appropriate. The performance of individual metering stations will depend on the particular characteristics of both the metering system and flow system and the type of hydrocarbon being metered: therefore deviations from these procedures may be necessary in special cases, for example measurements on very viscous crude oils, or low lubricity fluids such as gas condensate.

In addition to satisfying the relevant requirements of the Department of Energy (GOMB), the procedures where applicable meet the corresponding requirements of Her Majesty's Customs and Excise for measurement at land terminals.

Operators are required to submit their proposals for the operation and calibration of their metering systems in duplicate to the Aberdeen address prior to the commencement of commissioning and operation.

ISSUE 3 of these Operating Procedures has been revised and contains detail changes.

1. PROVER CALIBRATION

1.1 Prover loops should be calibrated at the manufacturers works as part of their systems checks, and after installation on site. Two copies of the calibration certificates for each of these and all subsequent calibrations should be sent to the GOMB Aberdeen Office. Such certificates should show the reference numbers of the sphere detectors used in the calibration.

1.2 While a metering station is in service, prover loops must be calibrated at a frequency of not less than once a year. Where this is not possible for operational or weather reasons a two month period of grace will be allowed. Inspection of the sphere, checking of sphere size, sphericity etc. should take place prior to calibration. After calibration the sphere detectors and switches should be sealed.

1.3 Any maintenance work on the prover that could affect the swept volume, eg changes of sphere detectors and switches, should not be undertaken without prior notice to GOMB who will advise if a recalibration is required.

1.4 GOMB must be given at least 14 days notice of all prover loop calibrations so that arrangements for witnessing can be made.

2. DETERMINATION OF METER CHARACTERISICS

2.1 For new or modified meters which are to be operated over a wide flow range covering flow rates below 50% of maximum, charac-teristic curves of meter factor versus flow rate should be determined for each meter. These curves should cover a range of approximately 20% to 100% of maximum flow rate, subject to any system restriction on flow rate. From these curves the permissable flow rate variations at a given meter factor setting will be determined.

2.2 Meters that are to be operated normally only at above 50% maximum flow rate, except during starting and stopping, will not be subject to the above requirement (Section 2.1) provided it can be shown that a meter factor variation of not greater than 0.1% occurs over the working flow rate range.

3. METER PROVING IN SERVICE

3.1 The requirements governing the intervals between turbine meter proving are:-

3.1.1 For a newly commissioned metering station in a continuous production system (as distinct from tanker loading), meters shall be proved three times a week at approximately equal intervals between proving. Provided the meter factor scatter is acceptable to GOMB, this frequency may be reduced to twice a week at the end of the first month, and once a week at the end of the second month.

3.1.2 For tanker loading systems, the frequency of proving will depend on the duration of the loading and the individual production system characteristics. The frequency of proving will therefore be subject to the approval of GOMB on an individual basis.

3.2 Meters must also be proved:-

(a) When the flow rate through the meter changes - this change in flow will depend on the gradient of the meter's flow characterisitics in any particular installation, (see Section 2.0), and would normally be such that a change in meter factor greater than 0.1% does not arise from the change in flow rate. If the change in flow rate is a

scheduled long term change then the meter(s) should be reproved at the first opportunity. If the flow rate change is unscheduled then the meters should be reproved if the estimated duration of the changed flow is 6 hours or more.

(b) When any significant change in temperature, pressure or density of the crude oil occurs for extended periods as for flow in (a) above that is likely to cause a change in meter factor of 0.1% or more. (In typical North Sea production systems practical values of these limits are of the order of $5^{o}C$ temperature, 10 bar pressure and 2% density).

3.3 Where meter types other than turbine meters are in use, the type and frequency of meter factor proving by the licensee will be determined on an individual basis by GOMB after consultation with the licensee. Account will be taken of the meter type, process fluid and operational load cycle. Where meters employing novel technology are to be used, extra evaluation periods and tests will usually be required before acceptance of a long term operational schedule can be determined.

4. METER FACTORS

4.1 Meter factors should be based on the average of at least five proof runs. All consecutive five proof runs must lie within ± 0.05% of the mean value. Full details of the proof runs, together with flow rates, pressures and temperatures should be entered in the Record of Meter Provings. (See 6.3).

4.2 On metering installations where the meter factor is set manually, the change in factor should be done in such a way as to prevent loss in the measured flow. Also, the new factor setting should be checked by a second person who should sign to this effect in the Record of Meter Provings.

5. GENERAL PROCEDURES

5.1 Metering stations should be operated and maintained in accordance with the manufacturers recommendations: particular attention should be paid to flow stabilization prior to meter proving, checking of block and bleed valves for leaks.

5.2 The temperature-compensated totalisers associated with the individual meters are to be used as the basis of the approved measurements at each metering station, except where the approved measurement is in mass units.

5.3 The operator should check the accuracy of the individual meter temperature compensation daily to detect the occurrence of possible errors. Correspondingly, in a mass measurement system a daily check of the mass computation should be done by comparing the totalised mass with that calculated from the individual metered volumes and density meter readings.

6. DOCUMENTATION TO BE KEPT AT THE METER STATION

6.1 The operator must maintain a log book for the prover detailing all calibrations, sphere detector serial numbers and any maintentance work done on the prover loop and its associated equipment.

6.2 A log must be kept for each meter showing details of:-

(i) type and identifying particulars including location and product measured;

(ii) totaliser reading(s) on commencement of metering;

(iii) all mechanical or electrical repairs or adjustments made to the meter or its read-out equipment;

(iv) metering errors due to equipment malfunction, incorrect operation etc., including date, time and totaliser readings both at the time or recognition of an error condition and when remedial action is completed;

(v) alarms, together with reasons;

(vi) any breakdown of meter or withdrawal from normal service, including time and totaliser readings;

(vii) replacement of security seals when broken.

6.3 The operator must also keep a Meter Proving Record for each meter giving the full details of each proof run. This record should include a running plot, or similar control chart, so that any undue change or fluctuation in meter factors may be easily detected.

6.4 A manual log or automatic recording should also be kept, at intervals of not more than 4 hours, of the following parameters:-

(i) all meter totaliser readings;

(ii) meter flow rates (also relevant meter factors), pressure and temperature, and (if measured continuously) density;

(iii) meter pulse comparator register readings.

One of these sets of readings should be recorded at 24.00 hours, or at the agreed time for taking daily closing figures if different.

Other parameters such as liquid density and percentage BS & W content should be recorded at agreed intervals, if not already included in the automatic log.

6.5 Records of parameters such as meter flow rate, liquid temperature and density should be kept at the metering station for at least 4 months.

6.6 All above records should be available at all reasonable times for inspection by GOMB.

7. DIRECT REPORTING TO THE GAS AND OIL MEASUREMENT BRANCH (GOMB)

7.1 For offshore tanker loading systems GOMB require for each tanker load a copy of the bills of lading, details of opening and closing totaliser readings and meter factors.

7.2 Operators should notify GOMB prior to any major maintenance or re-calibration work on the metering and proving system. GOMB should also be notified, preferably by telephone, when any abnormal situation or error occurs which could require significant adjustments to the totalised meter throughputs.

7.3 If a flow or density meter should require removal for maintainance work or replacement, a telex should be sent to GOMB detailing the serial numbers of the meters concerned and the reasons for the action taken.

7.4 When corrections to meter totalised figures are required due to known metering errors, a formal report should be submitted to GOMB detailing the times of the occurrence, totaliser readings at start and finish, required corrections to these readings, and reasons for the errors occurring.

7.5 The reports on the previous pages should be sent to:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
AB9 2ZV
Telephone: 0224 647961
Telex: 739283

Issued by:-
Department of Energy
Gas & Oil Measurement Branch
3 Tigers Road
South Wigston
Leicester
LE8 2US

Telephone 0533 785354
Telex 342457

June 1987

Contact point on operational matters:-
Telephone 0224 647961
Telex 739283

THE REVISION OF THE NPD REGULATION FOR THE FISCAL MEASUREMENT OF OIL AND GAS

by

S FOSSE
Norwegian Petroleum Directorate

Paper 3.4

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

THE REVISION OF THE NPD REGULATION FOR FISCAL MEASUREMENT OF OIL AND GAS

by

S Fosse
The Norwegian Petroleum Directorate, Stavanger

S U M M A R Y

This paper gives the status of the ongoing work to update the Norwegian Petroleum Directorate (NPD) regulation. It gives reasons, aims and ways to achieve the goal.

The paper also states two important areas within the mechanical and computer part where the NPD policy is undergoing a change from the recent regulation, (Compact prover and supervisory computers).

Our present regulation is based on the 'Royal Decree of 8 December 1972 relating to exploration for and exploitation of petroleum in the seabed and substrata of the Norwegian continental shelf'.

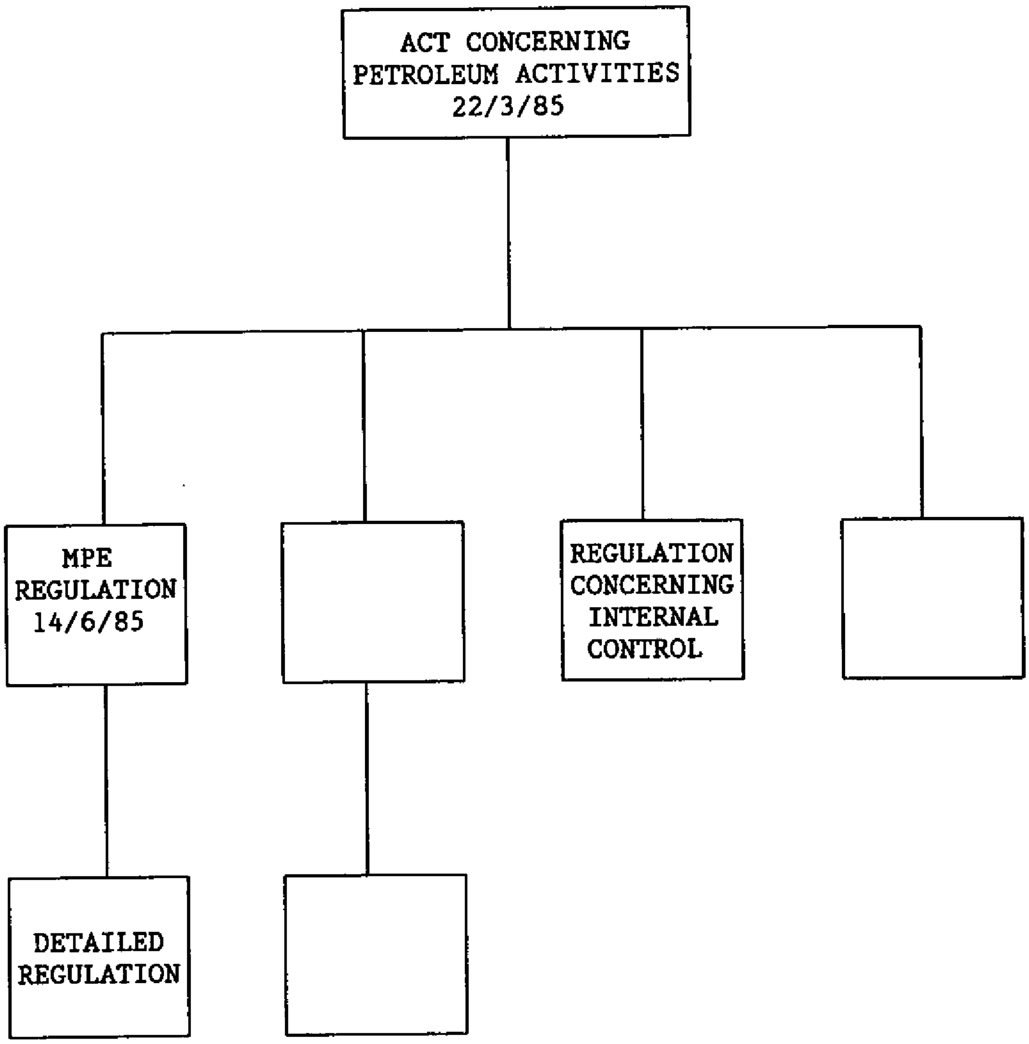


FIG 1 THE STRUCTURE OF THE PETROLEUM LEGISLATION

REASONS FOR A NEW REGULATION

AIM:

Requirements for the construction/operation of the system, in terms of uncertainty limits for various types of equipment.

INPUT:

1 Comments from users

2 Existing regulation

3 NPD metering experience

4 Legal adaption/economical consequences.

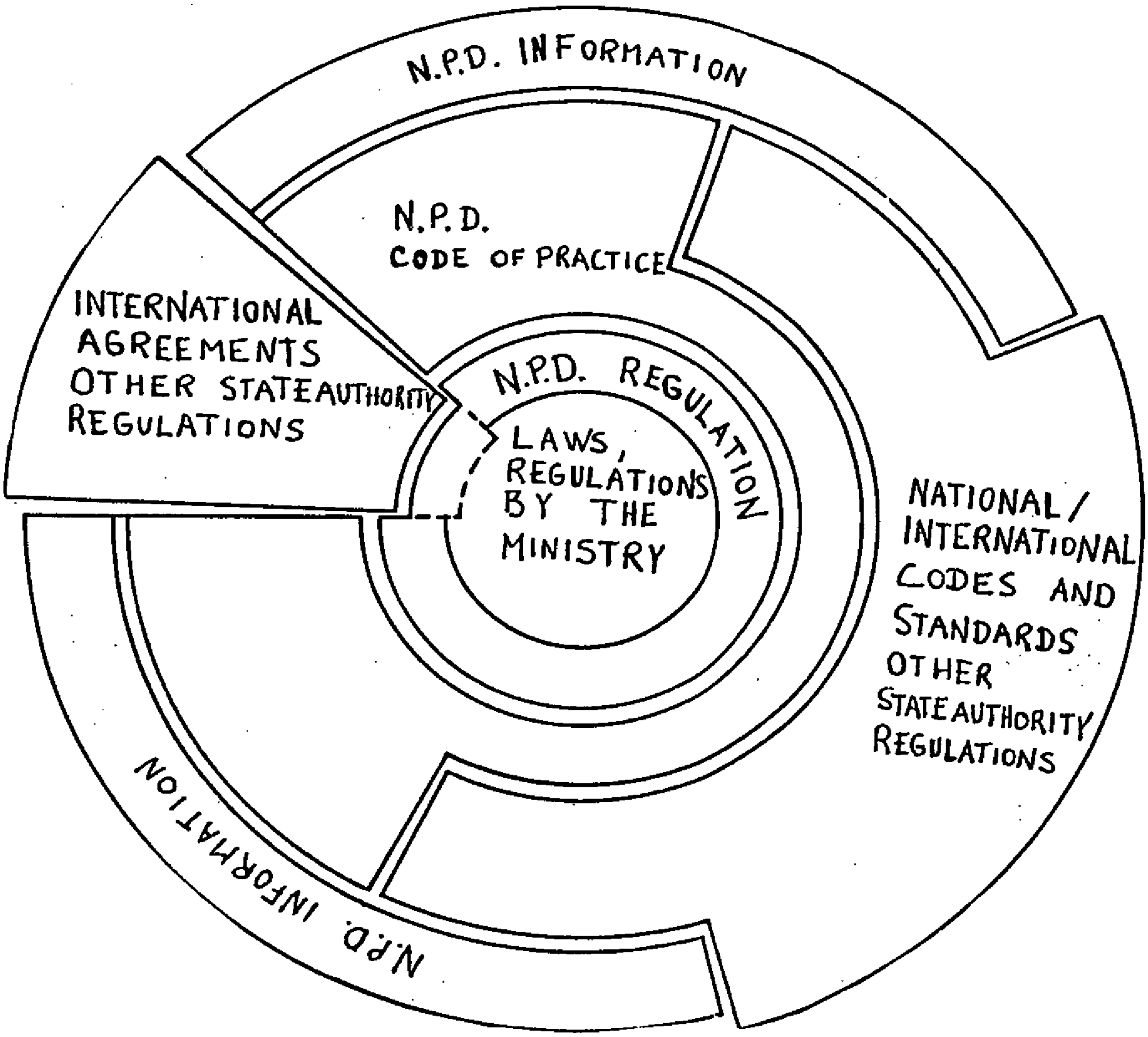


FIG 2 DEVELOPMENT OF A FISCAL REGULATION

REFERENCE GROUP

TASK

1 Each member must, within time limits of 3-4 weeks, comment on the various chapters

2 NPD can, within the same limits, ask the members in the Task Force to do special work within limited areas of the regulation.

For example:

a Propose wording for certain sections

b Evaluation of the content of specific selected standards.

The process of developing a new regulation is a rather slow process. It was initiated in Spring 1986. All parties concerned were invited to give in views/experience.

In Spring 1988 the process started to accelerate and the present time limits are:

Phase I Preparation 1 July 1988

Phase II Development 1 December 1988

Phase III Issuing for external comments 1 February 1989

Phase IV Entry into force 1 July 1989.

CONCLUSIONS

1 Oil/gas regulation has been marked into one regulation.

2 We collect the various sections within topic areas. It means that you now will find all requirements related to gas metering pipes under one section and one heading.

3 Regulation will still refer to turbinemeter/prover and orifice, as accepted equipment for fiscal metering. The code of practice will give advice in the use of other types of equipment.

- Repeatability and accuracy will be set for the various parts of the metering system and as a total. All types of equipment selected shall operate within these limits

- Various traceability requirements will be set.

MAIN CONSENTS FOR DEVELOPMENT AND OPERATION

1 Consent to detailed engineering (reference Section 11A, Safety Regulation)

2 Consent for fabrication of a metering package (reference Section 11B, Safety Regulation)

3 Consent to shipment from fabrication site (reference Section 11C, Safety Regulation)

4 Consent to operation of a metering package (reference Section 11D, Safety Regulation)

5 Consent for major rebuilding or major changes in operation of a metering package.

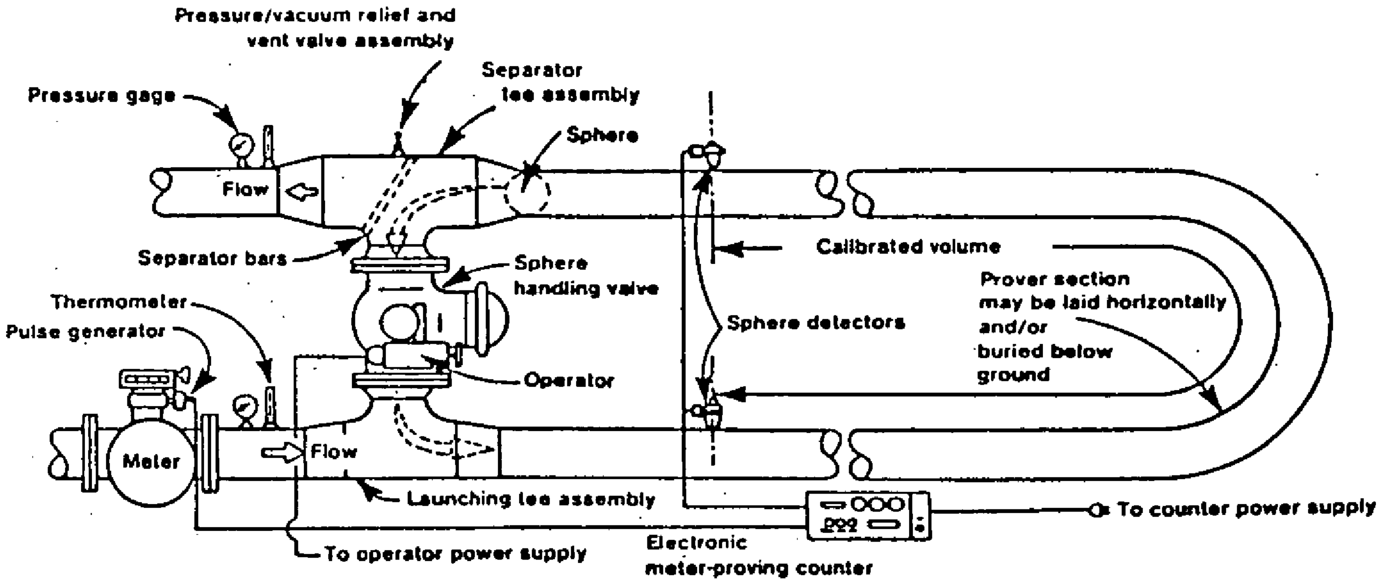


FIG 3 CONVENTIONAL BALL PROVER

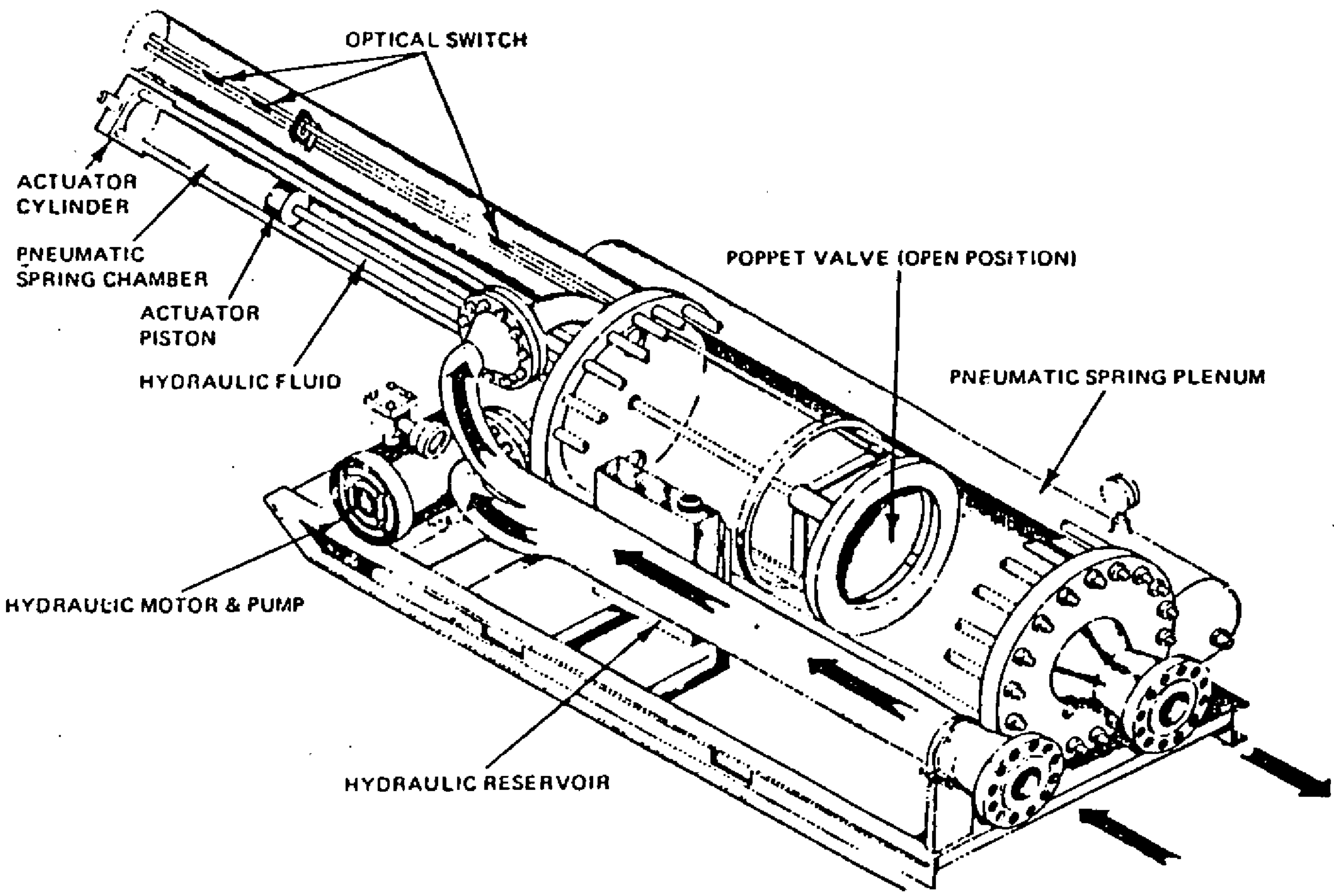


FIG 4 COMPACT PROVER

DESIGN OF THE MECHANICAL PART OF THE METERING SYSTEM

COMPACT PROVER

- NPD is now willing to accept compact provers in special cases if certain requirements are fulfilled.

1. The compact prover to be tested against a conventional prover within a limit of 0.020 per cent.

2. The licencee to present a list of all critical parts, to be available on the installation for immediate repair in case of a breakdown.

3. The compact prover to be equipped with a possibility for leak detection in the calibrated area.

4. Specific dedicated can to be available for recalibration on the installation.

5. Buffertanks/filters to be installed upstream.

6. The compact prover to be vertical mounted.

DESIGN OF THE COMPUTER PART OF THE METERING SYSTEM

- NPD's present regulation requires duplication of the supervisory computer and the supervisory computer dedicated for metering only.

- NPD will change this to a requirement for the reliability of the computer to be installed. That means that if the licensee can prove that the reliability of the supervisory computer they want to install is above a certain limit, NPD can accept one supervisory computer.

- If obvious reasons exist, NPD is willing to accept the supervisory computer to be shared with other, not fiscal activities.

Main Index

A STATUS REPORT ON K-LAB

by

P L Wilcox and J Bosio
K-Lab

Paper 4.1

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

"A STATUS REPORT ON K-LAB"

Authors: P. L. Wilcox - Scientific Manager
J. Bosio - General Manager

SUMMARY

First gas in to K-LAB was obtained on 8 December 1987. After a settling in period of 3 months, calibration of the reference sonic nozzles began on the smallest size sonic nozzles at 55 bars absolute in April 1988, and first calibrations on these nozzles at 156 bars absolute were obtained in July 1988. The results of all the calibrations obtained, the early problems that arose, and the proposed plan of future work are reported in this paper.

Presented at the North Sea Flow Metering Workshop 1988, National Engineering Laboratory, East Kilbride, Scotland, 18 - 20 October 1988.

Kårstø Metering and Technology Laboratory, Statoil,
P.O.box 308, N-5501 Haugesund, Norway.

1 INTRODUCTION

K-LAB, the Kårstø Metering and Technology Laboratory, is a natural gas metering laboratory in Norway. it is a joint venture between Statoil (66 2/3%) and Total (33 1/3%) with Statoil as operator. The purpose of K-LAB is to carry out testing, calibration, and research within the field of metering components and systems. In addition there are take off points around the flow loop for testing and research on activities related to production and transportation of hydrocarbons. The present scopes covers single phase (dry) gas metering.

The mode of operation of the laboratory is as a closed loop having an operating pressure range from 20 to 156 bars absolute with an accompanying temperature range of 20°C to 60°C above ambient.

Fig. 1 shows a schematic for the loop. At the present time only one compressor and associated cooling train has been built. This provides a maximum mass flowrate of 65 kg/s and corresponding volume flowrate of 6.5 Million sm^3/d. These flowrates will, of course, be doubled when the second compressor and cooling train is installed in 1990.

Sonic nozzles are used as reference flow meters and they are calibrated within the loop using a gravimetric primary calibration system. The project to build K-LAB commenced in January 1985 and first gas in to K-LAB was obtained on 8 December 1987.

2. DESIGN CONSIDERATIONS

K-LAB has been designed, engineered and built as a process installation, but with stringent requirements with respect to achievable performance since the main purpose of K-LAB is to carry out accurate calibration of gas flow meters. Some major concerns during the design of K-LAB were:

- the proper sizing of all volumes: to avoid introducing pressure fluctuations and other flow instabilities into the flow; to enable a reasonable number of primary calibrations to be made without refilling the loop.

- prediction of the thermodynamic behaviour at critical locations around the loop, and particularly the behaviour of the flow into the weigh tank during a primary calibration of a sonic nozzle.

- ensure that high precision on all relevant measurements (pressure, temperature, time, frequency, mass measurement, and sonic nozzle throat dimensions) is compatible with the design requirements of 180 bars in the test section.

During the first half year of serious operation, K-LAB has been found to operate as thermodynamically designed, and no adverse flow flucturations have been observed. Handling of the heavy pieces of equipment, moving of the sonic nozzle spool pieces between the reference nozzle section and the primary calibration location, are performed with no major difficulties.

In order to ensure complete traceability on all measurements relating to gas composition, an on-line gas chromatograph supplied by Combustion Engineering has been installed. This gas chromatograph is connected by an RS232 link to the Scientific Data Acquisition System.

3 PROTOTYPE EQUIPMENT

Due to the fact that the K-LAB is unique, there are several important items on the system which are prototypes. These are:

- Gyroscopic weighing system
- Scientific data acquisition system
- Diverter valves
- Disconnect system
- Sonic nozzles
- Mechanical dry seals for compressor
- Swirl sensor

3.1 Gyroscopic weighing system

The K-LAB requirement during a primary calibration test is to measure a mass of gas in the range 0kg to 600kg contained in a 9 tonne tank. The balance chosen which has been supplied by Wöhwa (FRG) operates on a gyroscopic principle and has the following stated uncertainties.

Range	Uncertainty
0 to 25kg	25g
25kg to 600kg	50g

On site calibration of the balance carried out in accordance with the requirements of the Norwegian Office of Legal Metrology has confirmed these uncertainties.

3.2 Scientific data acquisition system

A computerised system is needed to acquire the data from the scientific instruments around the loop during a test run. In addition this system produces test reports, calibration reports, keeps track of instruments calibrations, and has an archiving system to store safely all the results. The main supplier of the system is Fraser Nash Scientific Ltd (UK) who supplied the software.

The subcontractor supplying the hardware was Databasix (UK), and the hardware is built around a DEC. Microvax 2 computer. Again, this system is working well at the present time.

3.3 Diverter valve

In order to divert the flow from the test loop into the weigh tank and back again during a primary calibration of a sonic nozzle, a diverter system is required. The K-LAB diverter system is based on two 3 inch ball valves having a common actuator. The maximum design diversion time was set at 0.030 seconds.

BIFFI (I) is the supplier of the actuator. This system is working well.

3.4 Disconnect system

The mass of gas is obtained by taring out the mass from the tank containing natural gas at atmospheric pressure and then measuring the mass of the tank full of gas. To carry out this each time, the weigh tank must be disconnected from the pipework so that it is freely floating on the balance. The automatic disconnect system has been manufactured by Destec Engineering Ltd (UK) and at this present time is working well.

3.5 Sonic nozzles

The sonic nozzles are the reference flow meters for K-LAB and must be calibrated prior to carrying out tests in the metering sections. The sonic nozzles are the first of their kind as regards size and pressure rating, and have an integral silencer for noise reduction. The supplier of the sonic nozzles is Sofregaz (F) with sub-contractor Gas de France (F).

3.6 Mechanical dry seals for compressor

If the loop gas compressor were to use a conventional oil-lubricated seal system, it would be possible for oil to enter the gas loop. The effect of oil inside the loop would be disastrous, for it would probably alter the calibration of the sonic nozzles in an indeterminate manner, and gradually alter the composition of the gas in the loop as the test proceeds.

This problem has been overcome by installing dry mechanical seals in the loop gas compressor. The seals were manufactured by Crane (UK).

3.7 Swirl sensor

As is well known, the effect of swirl impinging on an orifice plate can noticeably change the value of the discharge coefficient. No set of measurements in a test section would therefore be complete without providing a measurement of the swirl angle in the test section.

At the present time (August 1988) no probe exists for measuring swirl covering the K-LAB pressure range, we are working on designing and manufacturing such a probe, and more details will be given at the workshop.

4 EARLY PROBLEMS ARISING DURING PRIMARY CALIBRATION

Before we can carry out tests in the test sections we need to have calibrated all the sonic nozzles which are used as reference flow meters. The sonic nozzles are characterised as follows:

Nozzle number	1	2	3	4	5	6	7	8	9	10	11	12	13
% max flow	1.25	1.25	2.5	5	10	10	10	10	10	10	10	10	10

At the present time as we have only one compressor giving 50% of the maximum flowrate, we have only installed the first eight nozzles.

Figure 2 shows a sketch of the layout of the primary calibration section. It is possible that over the life of the laboratory the composition of the gas in the loop can change. To overcome the effect of possible changes in gas composition from the time the sonic nozzle was calibrated to a later date when a test is to be carried out in the test section, we proceed as follows:

Primary calibrations are carried out in pairs. We calibrate each reference sonic nozzle against a standard nozzle. Let us denote any one of the reference sonic nozzles by subscript i, and let us denote the standard nozzle (which incidentally is a 1.25% nozzle) by the subscript s. We will compare the result of a calibration on the i'th nozzle with a calibration carried out on the standard nozzle at similar values of pressure and temperature.

The two calibrations are consecutive to ensure that the change in gas composition that takes place between the two calibrations is negligible.

Thus we have:

$$q_{mi} = (A_t C_D)_i \, C_{Ri} \sqrt{p_i \rho_i} \qquad (1)$$

$$q_{ms} = (A_t C_D)_s \, C_{RS} \sqrt{p_s \rho_s} \qquad (2)$$

Hence
$$\frac{(A_t C_D)_i}{(A_t C_D)_s} \cdot \frac{C_{Ri}}{C_{RS}} = \frac{\sqrt{p_s \rho_s}}{\sqrt{p_i \rho_i}} \cdot \frac{q_{mi}}{q_{ms}} \qquad (3)$$

Now since C_{R_i} and C_{R_s} are only dependent on p, T and gas composition we have:

$$C_{Ri} = C_{RS} \tag{4}$$

Hence

$$\frac{(A_t C_D)_i}{(A_t C_D)_s} = \frac{q_{mi}}{q_{ms}} \cdot \sqrt{\frac{p_s \rho_s}{p_i \rho_i}} \tag{5}$$

At some later date, prior to running a test in the test section, we carry out a run on the standard nozzle at conditions say po, and To which are close to the desired test section conditions p, T.

Then

$$q_{mso} = (A_t C_D)_{so} \; C_{Rso} \sqrt{p_o \rho_o} \tag{6}$$

where ρ_o is the measured density at po, To.
So if we now carry out a test with all i nozzles at a pressure and temperature p, T which are close to po, To respectively we have:

For the i'th nozzle:

$$q_{mi} = (A_t C_D)_i \; C_{Ri} \sqrt{p \rho} \tag{7}$$

Rearranging equation (7):

$$q_{mi} = (A_t C_D)_{so} \cdot \frac{(A_t C_D)_i}{(A_t C_D)_{so}} \cdot C_{Ri} \sqrt{p \rho} \qquad (8)$$

Now, since p, and T are close to po, To respectively and because the gas composition is similar between the primary calibration having subscript 0 and the gas composition during the run in the test section:

$$C_{Ri} = C_{Rso} \qquad (9)$$

It follows from equations (6), (8) and (9) that during the test run:

$$q_{mi} = \frac{q_{mso}}{\sqrt{p_o \rho_o}} \cdot \frac{(A_t C_D)_i}{(A_t C_D)_{so}} \cdot \sqrt{p \rho} \qquad (10)$$

Since every parameter on the right hand side of equation (10) has been measured, q_{mi} during a test run can be obtained.

The factor $(A_t C_D)_i / (A_t C_D)_{st}$ is, of course, a geometric factor which is determined from equation (5) as a function of throat Reynolds Number.

Amongst the early problems that arose during the calibrations of the sonic nozzles were the following items:

- Density measurement
- Water condensation on weigh tank.
- Effect of the "dead leg" in V3.

These problems will now be discussed in turn.

4.1 Density measurement

There are two alternative formulae available for calculation of mass flow rate through a sonic nozzle. The first form is used in equation (1) above, and is repeated in its general form here:

$$q_m = A_t C_D C_R \sqrt{p \rho} \tag{11}$$

The alternative form is:

$$q_m = A_t C_D C^* \frac{p}{\sqrt{RT}} \tag{12}$$

Prior to the commencement of project engineering it was decided to use the formula as given in equation (11) for calculating the flow through K-LAB sonic nozzles. This was because C_R is less dependent on variations in p and T than C* and at that time the accurate measurement of density was not considered a problem. To measure density in K-LAB we use Solartron 7810 or 7811 density meters in pockets in the inlet header to the primary calibration section. We then correct this measured density value using measured pressure, and temperature to obtain the value of density just upstream of the sonic nozzle being calibrated.

We have chosen an operating temperature of 37°C as the temperature we can achieve all the year round on K-LAB. Immediately we commenced carrying out primary calibrations we discovered that even though the density meter was enclosed in a lagged box, the pocket temperature was of the order of 1°C to 2°C lower than the free stream temperature.

Improvements to the insulation inside the lagged box followed, but the temperature difference between the freestream and the pocket could never be completely eliminated. This is probably due to the manner in which the loop is operated, commencing from cold every morning, and the actual volume of gas passing the pocket. On fiscal metering stations operating on a continuous basis with high flow rates, this effect would probably be negligible.

As of August 1988 we have just installed heaters inside the lagged inclosures with thermostats set at 37°C, and if this fails we are toying with setting the 7810's and 7811's directly into the gas flow. However this does have the considerable drawback that we must depressurise part of the loop to change out a density meter.

In addition, to keep our options open, we have obtained calibration curves based on equation 11 in two different forms:

$$q_m = A_t C_D C_R \sqrt{p \rho_{meas}} \qquad (13)$$

$$q_m = A_t C_D C_R \sqrt{p \rho_{CALC}} \qquad (14)$$

And we also have calibration curves using the equation (12). These 3 calibration curves are shown in Figures 3, 4 and 5 respectively. Note how the measured density calibration curve of Figure 3 is different, compared with Figures 4 and 5.

4.2 Water condensation on the weighing tank

As described previously in section 4, the calibrations are carried out in pairs in an attempt to have little variation in gas composition between a calibration pair. After carrying out one primary calibration the gas in the weigh tank can be flared off so that the weigh tank can be weighed "empty". Our first sequence of primary calibration was 55, 90, 120 and 156 bars absolute, and as the pressure increased the cooling effect from flaring became stronger and stronger leading to water vapour condensing on the outside of the weigh tank and associated pipework, which possibly affected the second run of the pair. To overcome this problem, much pipework was lagged with a non-absorbent foam and the rate of flaring was kept to a minimum.

4.3 Effect of the dead leg in V3

Referring again to Figure 2, prior to the insertion of the 3 way valve, the early primary calibration runs at fairly low pressure (55 bars absolute) were not affected by the "dead leg" - the volume containing the other sonic nozzle not undergoing calibration at that moment in time. However, as the calibration pressure was increased, the effect of this "dead leg" on the correlation became noticeable. Once the 3-way valve was installed, the problem disappeared. However, this meant that we had acquired a number of dubious calibrations on the first pair of nozzles.

5 FUTURE WORK

For the remainder of 1988 we are continuing the calibration of the remaining sonic nozzles. We are also installing a fully modular 6 ins diameter test section which will be completed in November 1988. In addition to this we are revamping the present 12 ins diameter test section so that from 1 April 1989 we will be in a position to calibrate turbine meters up to 156 bars absolute. In 1989 it is also planned to install a 24 ins test section in order to be able to accommodate the EEC 600 mm test run.

One of the first tests to be carried out in the modular 6 in test section will be investigating short length metering systems having (hopefully) the same accuracy as the present horrendously long fiscal gas metering systems using orifice plates.

In our view, 1988 sees the start of a change in emphasis in gas metering technology. The change began with the advent of ultrasonic meters. We now have non-intrusive multi-beam ultrasonic meters requiring only a small number of upstream pipe lengths to achieve comparable accuracy to that obtained using long upstream pipe lengths in conjunction with orifice plates.

It is our strong conviction that if the velocity profile is uniform, if the swirl angle is less than 1°, if the centre-line turbulence intensity value approaches that obtained in fully developed turbulent flow then the number of upstream pipe lengths needed to produce this condition is irrelevant. This is what we will be examining in 1989!

Flow diagram of the K-Lab test loop

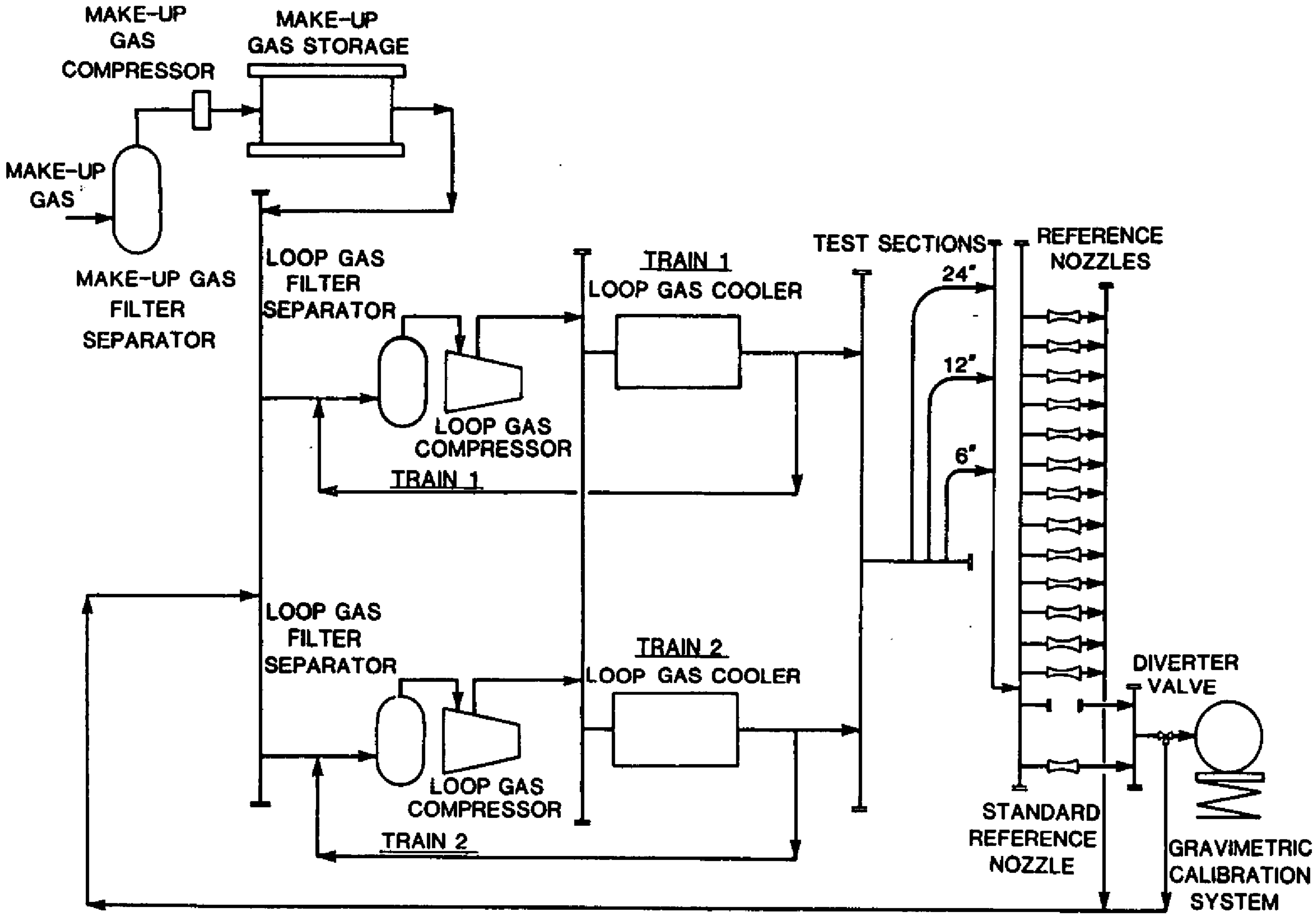


FIGURE 1.

PRIMARY CALIBRATION SECTION

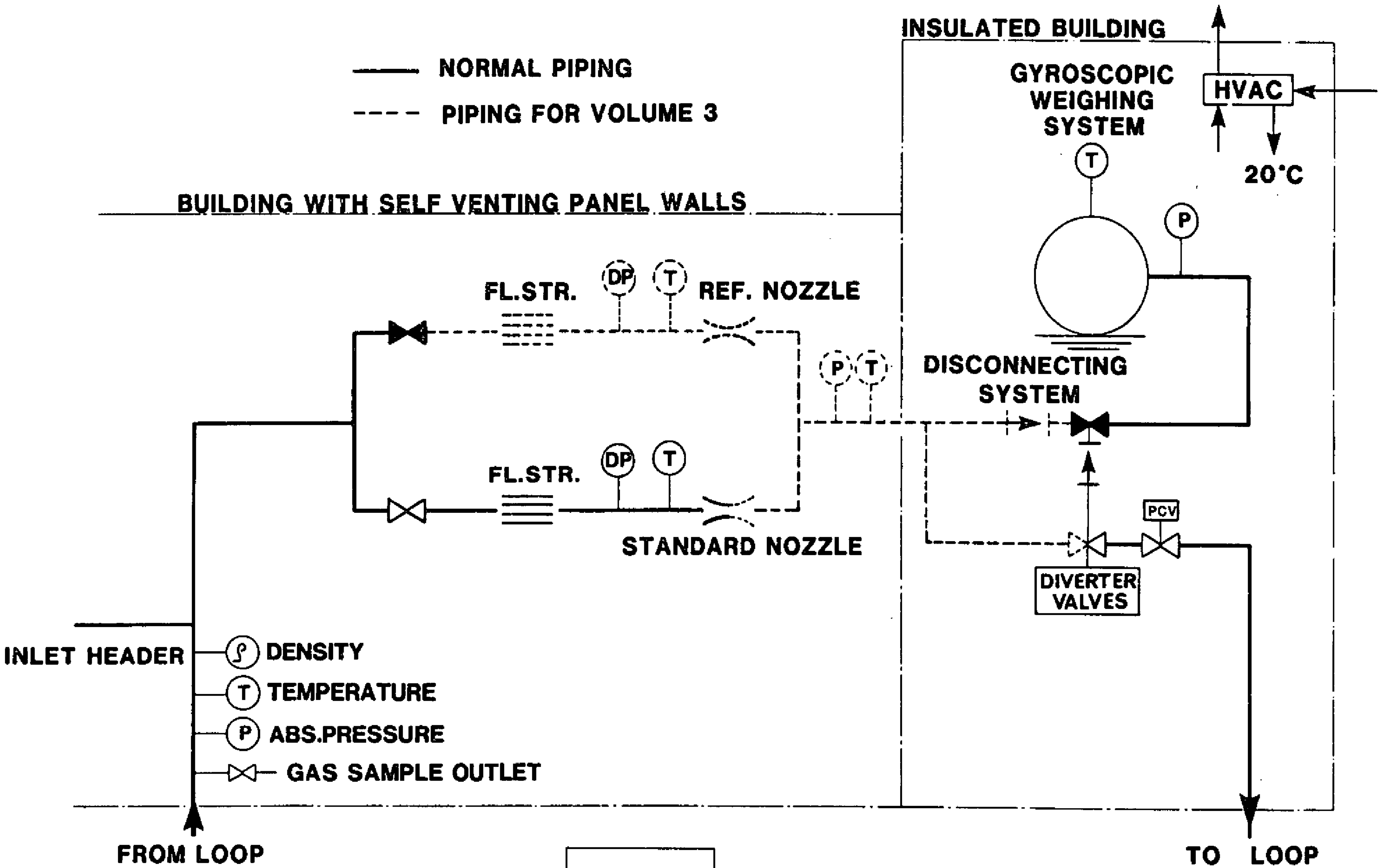


FIGURE 2.

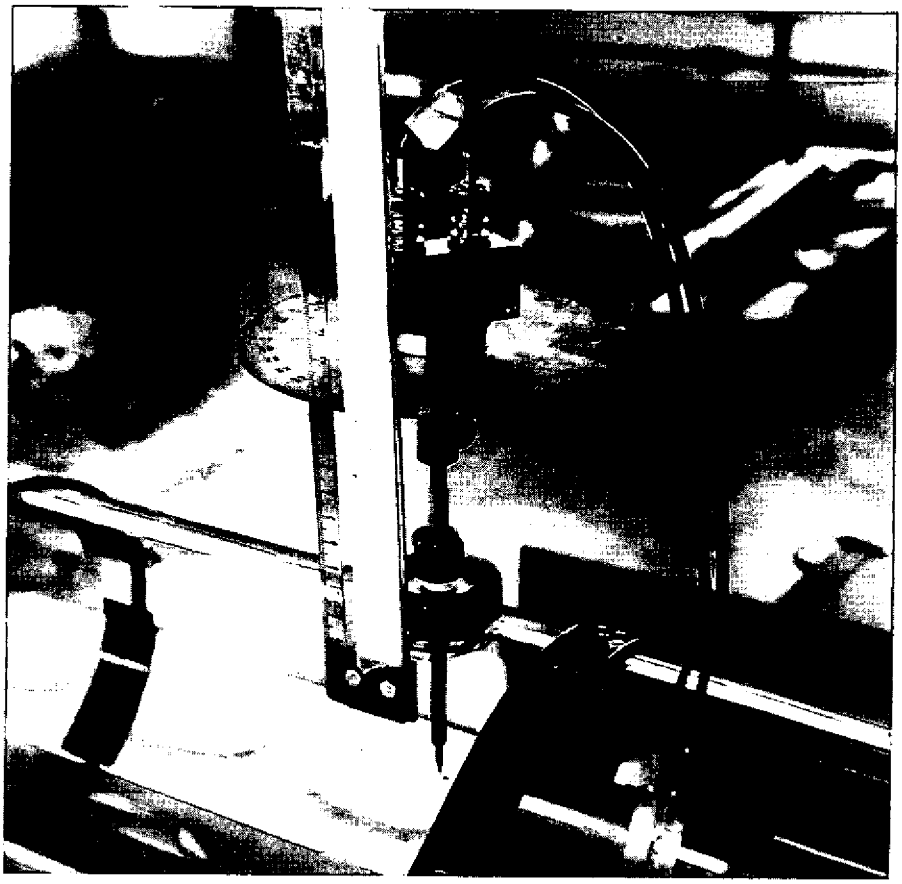


Figure 3. Detail of the probe support and the two rulers.

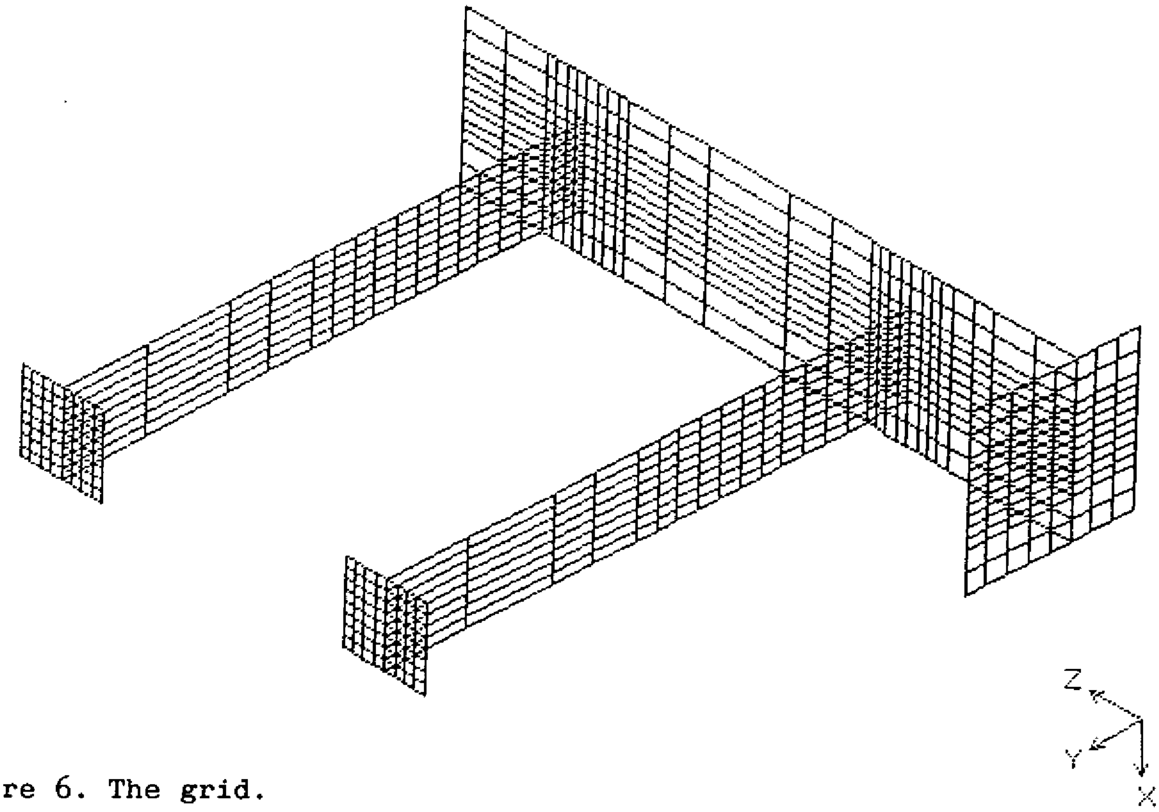


Figure 6. The grid.

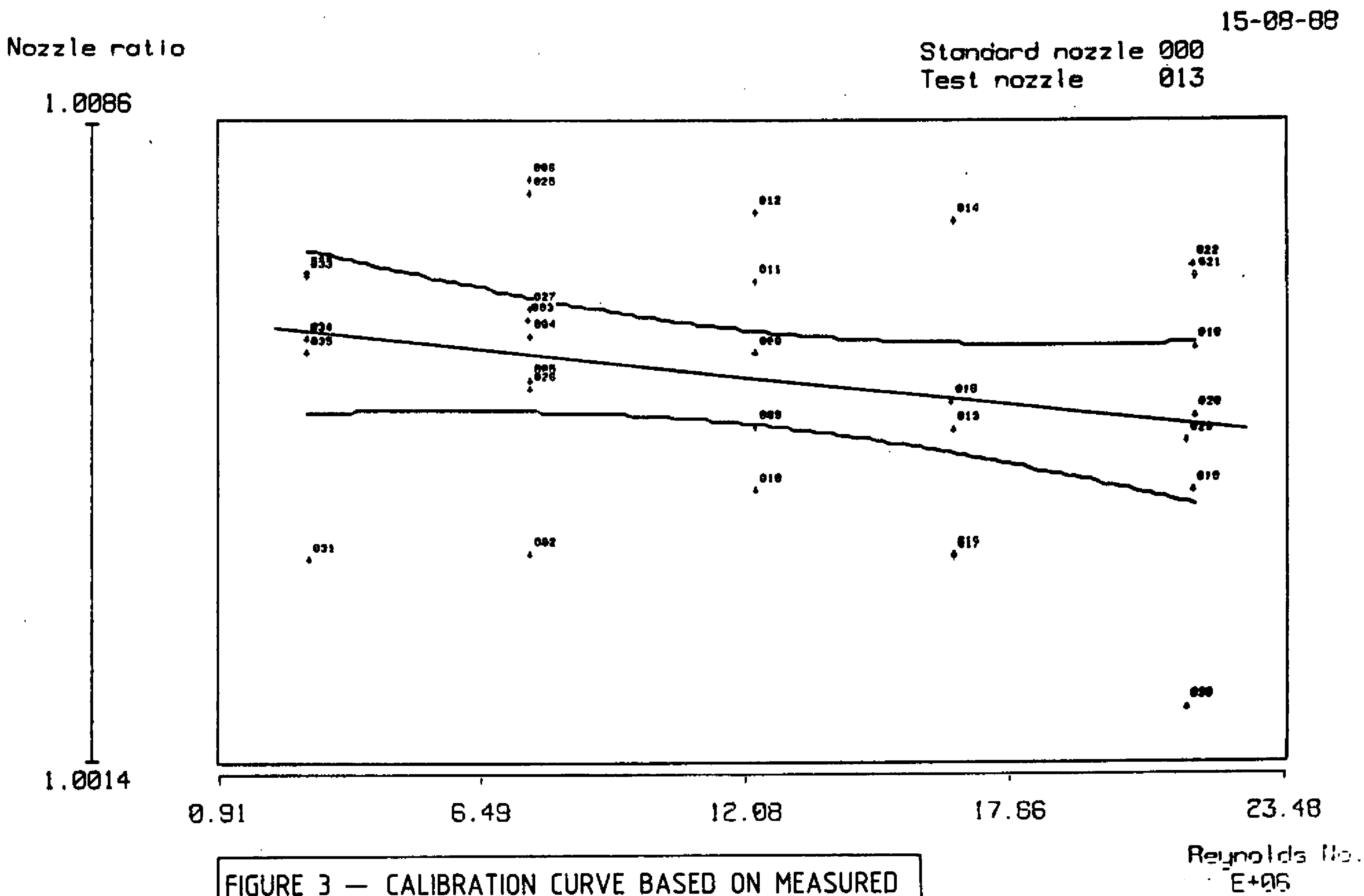


FIGURE 3 — CALIBRATION CURVE BASED ON MEASURED UPSTREAM DENSITY

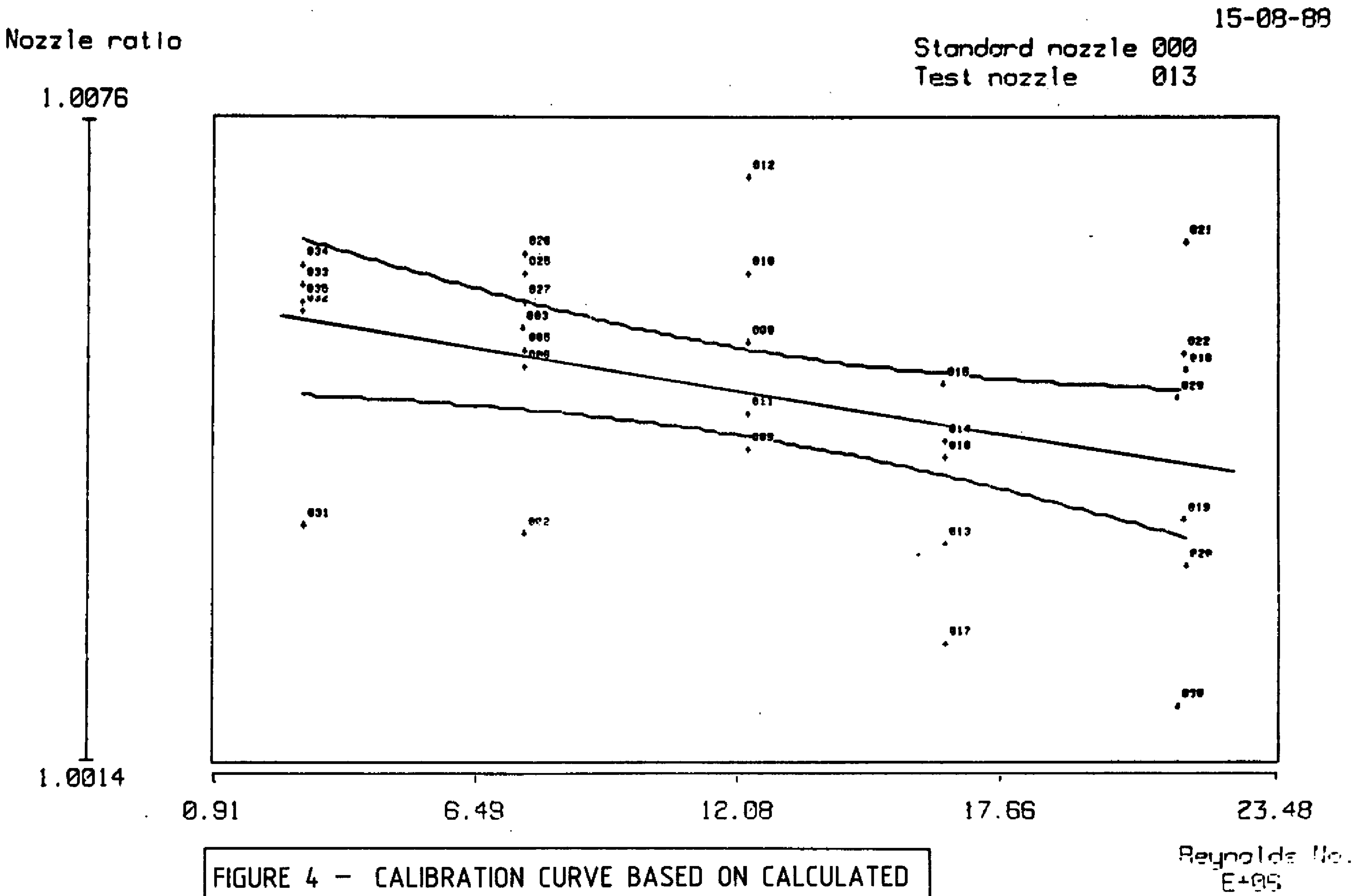


FIGURE 4 – CALIBRATION CURVE BASED ON CALCULATED UPSTREAM DENSITY

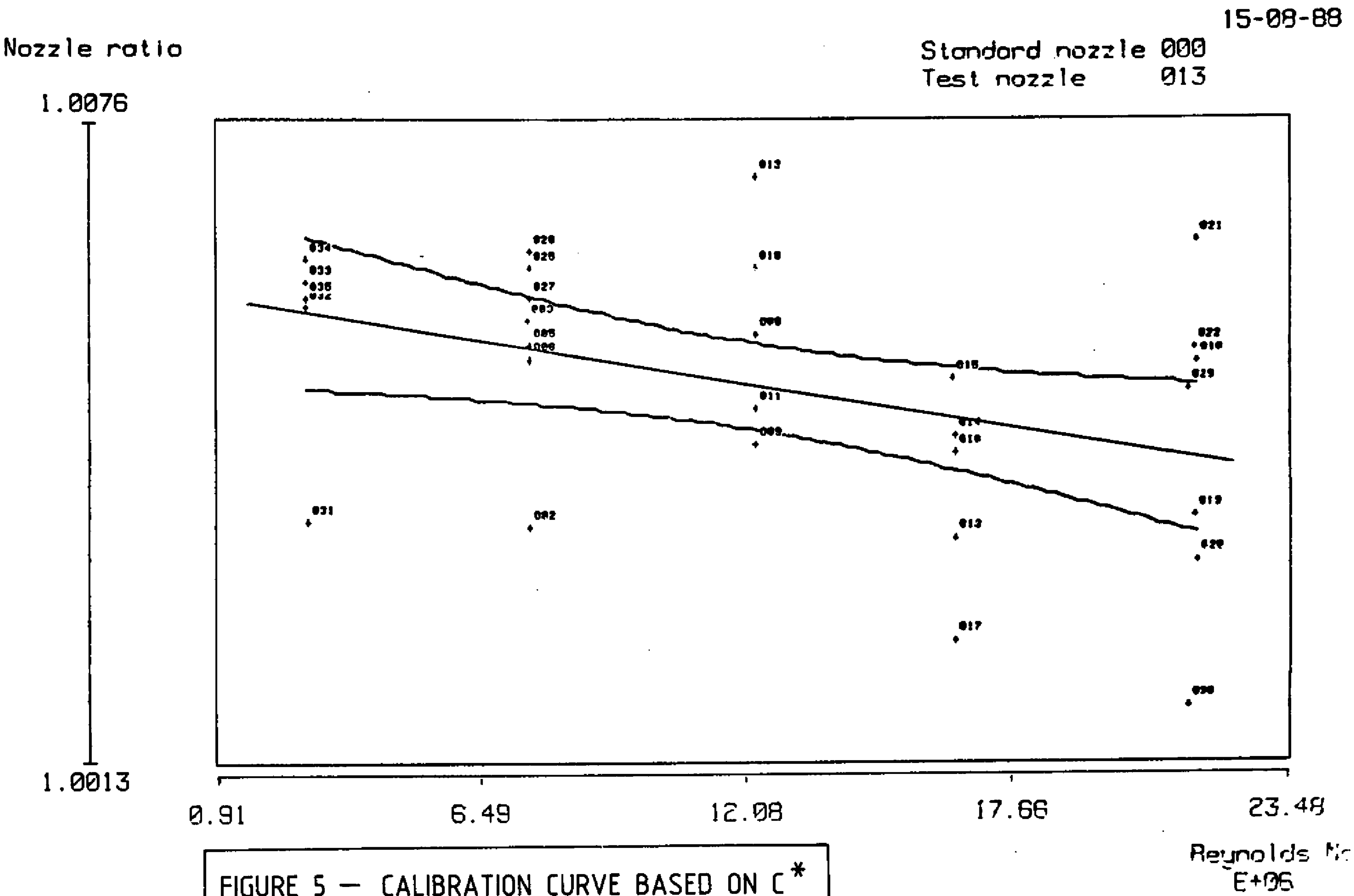


FIGURE 5 — CALIBRATION CURVE BASED ON C*

FLUID FLOW IN MANIFOLD GEOMETRIES - AN EXPERIMENTAL AND THEORETICAL STUDY

by

M Langsholt and D Thomassen
Institute for Energy Technology

Paper 4.2

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

FLUID FLOW IN MANIFOLD GEOMETRIES - AN EXPERIMENTAL AND THEORETICAL STUDY.

Morten Langsholt and Dag Thomassen

Institute for Energy Technology, Box 40, 2007 Kjeller, Norway

S U M M A R Y

A gas metering station based on orifice meters normally consists of a number of parallel meter-runs between headers. Some disturbances, e.g. swirl, decay slowly and since such disturbances may significantly change the orifice discharge coefficient, accurate measurements rely on properly designed upstream headers.

This paper presents results from measurements of mean velocities and turbulence intensities in a plexiglass model of a gas metering station. The flowing fluid was atmospheric air. Various pipe-configurations upstream of the inlet header have been examined and differences are highlighted. The results illustrate clearly the strong connection between metering station design and the flow conditions (swirl, skewness etc.) at the inlet of the meter-runs.

In addition to the measurements the paper also presents some results from numerical simulation of fluid flow in 3-D manifold geometries. These simulations have been performed using the program Phoenics.

NOTATION

D - header diameter
k - directional sensitivity coefficients in response equation
k - turbulent kinetic energy (defined by eq. 3)
Tu - turbulence intensity (eq.4)
U - velocity in x-direction in fixed coordinate system
u - fluctuating component of velocity in x-direction
$\overline{U}$ - average velocity in x-direction in fixed coordinate system
V - velocity in y-direction in fixed coordinate system
v - fluctuating component of velocity in y-direction
$\overline{V}$ - average velocity in y-direction in fixed coordinate system
W - velocity in w-direction in fixed coordinate system
w - fluctuating component of velocity in w-direction
$\overline{W}$ - average velocity in w-direction in fixed coordinate system
U_{eff} - effective cooling velocity
U_{ax} - typical axial velocity, see eq.4
V_N - velocity components in wire-oriented coordinate system
V_T - velocity components in wire-oriented coordinate system
V_B - velocity components in wire-oriented coordinate system

Subscripts:

B - axis normal to wire and normal to probe axis
N - axis normal to wire and normal to axis 'B'
T - axis parallel to wire

1. INTRODUCTION

A gas metering station will normally consist of at least two parallel meter tubes connected to a header. Accurate flow measurement depends on the meter being properly designed, manufactured, installed and operated. The geometry and its tolerances are regulated through the standard ISO-5167.

The standard requires fully developed turbulent profiles to exist at the inlet of the meter. The means to fulfill this requirement is to introduce a long straight pipe upstream of the meter. The required minimum straight lengths vary according to the nature of the nearest upstream fitting and with the diameter ratio of the orifice meter. The minimum straight lengths are given in the standard. However, questions have been raised to the validity and consistency of the given tables. There are also problems in interpreting the standard when components not included in the standard (e.g. headers) are used.

It might well be that the header design creates a flow disturbance which persist much longer than the disturbance traceable to a valve closer to the meter. This illustrates one important problem faced when designing a metering station, and it explains our interest in manifold flow.

Over the last few years we have at IFE been interested in the potential role of Computational Fluid Dynamics as a research and/or design tool for gas metering stations. So far promising results have been achieved for a numerical model for flow through an orifice plate. This model proved to be sensitive, and accurate, to even small alterations in inlet profile, plate geometry etc.

A long term goal is to be able to simulate numerically the flow field that will appear in the meter-runs for a given metering station design. In this way various alternative configurations can be compared and inappropriate ones avoided. A prerequisite is of course to be able to simulate the flow through a header.

The background for the experimental work presented in this paper was to establish experimental evidence so that proper evaluation of a numerical model for simulation of flow in a header geometry could be performed.We decided to limit the verification to a header design with two parallel meter runs, as illustrated in Figure 1.

A plexiglass model of a gas metering station with upstream header of this design was built and interfaced with an air flow rig. Detailed measurements of velocity and turbulence profiles at the inlet of the header and in the entrance section of the meter tubes have been performed by use of hot-wire techniques. Measurements were conducted for various pipe configurations upstream of the header inlet plane.

Subsequent to the experimental work identical cases were modelled in the numerical model and the results compared with the experimental data.

2. THE EXPERIMENTAL WORK

2.1 The flow rig

The IFE air flow rig is an atmospheric rig where a positive displacement pump sucks air through the test section. The static pressure in the loop is therefore slightly below the atmospheric pressure. The capacity of the pump is approximately 0.45 m^3/s.

In the experiments described here the test section was made up by the "metering station", including the immediate upstream geometry, connected to the pump as shown in Figure 2.

The test section

The fixed part of the test section consisted of the gas metering station with its two parallel meter runs. The inlet and outlet headers had an internal diameter of 190 mm (D), while the two meter runs had an internal diameter of 96 mm, see Fig.1. The pipes were made of transparent plexiglass with hydraulically smooth walls. No flow metering device was mounted in the meter runs. The Reynolds number in the meter-runs was $1.5*10^5$.

The exchangeable part of the test section, denoted the inlet geometry, was the piping immediately upstream of the inlet header. Three different inlet geometries were examined :

Designation:	Description of inlet geometry:
Inlet no. 1	straight pipe (20 D)
Inlet no. 2	single 90^0 bend + straight pipe (10 D)
Inlet no. 3	2 x 90^0 offset bend + straight pipe (10 D)

The sections of straight pipe of the inlet geometries were plexiglass pipes with 190 mm internal diameter. The bends had an internal diameter of 182 mm and a wall roughness exceeding that of the plexiglass pipes. The radius of curvature for the bends was 1.5 D.

2.2 Instrumentation

Hot-wire anemometry

The main instrument for measuring the mean flow velocity components and the turbulent kinetic energy was a tsi manufactured Constant Temperature Hot-wire Anemometer. The probe used was a single slanted (45^0) wire. The anemometer signal was digitized and reduced in an IBM PC AT compatible computer using a software package also delivered by tsi.

From the hot-wire instrument one obtains an effective cooling velocity, U_{eff}, which is a measure of the heat transport off the wire. By statistical analysis on a sample of readings of U_{eff}'s one find an average term and a fluctuating term. Through the sensor response equation, which defines the relation between the actual velocity and the effective cooling velocity, one can invert the problem to determine the mean velocities and the velocity fluctuations.

We did use the response equation :

$$U_{eff}^2 = k_N^2 V_N^2 + k_T^2 V_T^2 + k_B^2 V_B^2 \qquad \text{(eq.1)}$$

The instantaneous velocity components in the fixed XYZ-coordinate system can be written as the sum of a mean and a fluctuating part:

$$U = \overline{U} + u \; ; V = \overline{V} + v \; ; W = \overline{W} + w \qquad \text{(eq.2)}$$

The turbulent kinetic energy, k, is defined as :

$$k = \frac{1}{2} (u^2 + v^2 + w^2) \qquad \text{(eq.3)}$$

The response equation (eq.1) combined with the data reduction method of Acrivlellis (Ref./2,3/) gave us the mean velocity components and the turbulent kinetic energy in each point of measurement.

Pitot-static tube

As a reference velocity measurement for the calibration of the hot-wire anemometer we used a pitot static tube. The differential pressure was measured with a Type 5, Airflow testing set. For inlet geometry no.1 and no.2 the pitot static tube was also used to measure the axial velocity component along all 4 traverses.

2.3 Measurement procedure

The aim of the experiments was to measure the velocity field and the turbulent kinetic energy in a number of points in the inlet plane and in the two outlet planes of the header shown in Figure 1.

In the inlet plane the points of measurement were located along both the vertical and the horizontal diameter. Along each traverse measurements were performed in 8 positions. In the outlet planes measurements were made in 4 positions along the vertical diameter only.

As is also indicated in Figure 1, the vertical traverse in the inlet plane is denoted traverse "A", the horizontal one "B". The traverse in the outlet plane nearest to the inlet is called "C", and the remaining one "D". We also frequently refer to the outlets as outlet "C" and outlet "D", respectively.

At each of the four wall entry points a ruler was fixed against which the axial probe position was read. In addition an angular ruler was fixed to the probe support for angular positioning of the probe. This experimental set-up is shown in Figure 3. In each point of measurement along each traverse we operated the probe at typically 9 different rotational angles. This was done partly to close the set of equations (independent information), but also to reduce the effect of measurement uncertainty. The method of multipositioning the wire(s) to procure the required amount of information is based on the assumption of a "stationary" turbulent flow-field.

2.4 Results from the measurements

General

When we analyzed the measurement results it proved obvious that the measurements for inlet geometry no.3 was imperfect and had to be encumbered with additional measurement uncertainty. This inlet geometry typically generates strong swirl and high turbulence intensities, a situation which represent a challenge for the measurement system. Numerical experiments performed indicated that for variations in the inlet profile, within the limits of measurement uncertainty, the outlet flow regime could change significantly for example from twin vortices to a single vortex. The results for inlet geometry no.3 will therefore neither be the presented nor discussed.

The mean velocity vectors found have been decomposed into an axial component and a lateral one. The lateral component is represented by the vector-arrows in Figures 4 and 5. The point of attack for the vector is located on the mid-point of the arrow, and the vector-scale is given individually for each cross-section. The point of observation is on the downstream side. (For orientation of the fixed coordinate axes, see Fig. 1.) The axial velocity components are represented on the figures simply by their numerical values.

The turbulent kinetic energy will not be treated in detail for reasons that will become clear later in the paper.

The axial velocity profiles have been found both from the hot-wire measurements and from the pitot static tube measurements (i.e. two independt measurement techniques). The two sets of axial profiles compare well both in the inlet plane and in the two outlet planes.

Inlet plane

For inlet no.1 in Figure 4, the lateral velocities measured were in general smaller than the measurement uncertainty and are not included in the presentation. The axial velocities exhibit a typical parabolic profile. The skewness observed along traverse "B" are probably an effect of outlet "C" which is only 1 D downstream of the measurement section.

For inlet no.2 we clearly see in Figure 5 two secondary vortices superposed on a fairly skew axial profile.

The turbulence intensities, Tu, were relatively moderate, spanning from typically 6% for the straight pipe inlet geometry to values up to 20% for the inlet consisting of a single bend. The following definition of the turbulence intensity has been used :

$$Tu = \sqrt{2k} / U_{ax} \qquad \text{(eq.4)}$$

Outlet planes

In outlet "D" of Figure 4 there seems to exist two vortices symmetrically located about the horizontal mid-plane and for the same outlet in Figure 5 we can definitely identify a relatively strong single vortex. This vortex was also detected by a two-bladed turbine of zero pitch installed 1.5 D downstream of the metering plane. The turbine was never installed when hot-wire measurements were performed.

In outlet "C", for both inlets, the lateral velocity vector showed more or less identical behaviour. The vertical component was directed downwards (positive x-direction) and the horizontal component was directed to the right (the negative z-direction).

The measured axial velocity profiles in the outlet planes showed a parabolic shape with minimum velocity near the pipe centre-line.

The turbulence intensities found were for outlet "C" in the range 15-30% with the highest values near the centre-line. For outlet "D" the values were in the range 15-20 %. There was no significant difference between the intensities found for the various inlet geometries.

3. THE NUMERICAL SIMULATIONS

3.1 The Phoenics code

This is a general purpose fluid dynamic computer program based on a numerical solution algorithm developed at the Imperial College in London. The code is made commercially available through the company CHAM, ltd. For description of the program see refs./6,7/

3.2 Description of the numerical model

The grid

The manifold geometry is modeled in a cartesian coordinate system by "blocking" out cells from an initially rectangular bar. This leads to a manifold consisting of rectangular ducts. These rectangular ducts are approximated to circular pipes by the use of so-called porosity functions. These functions enable fractions of cell-volumes and cell-surfaces to be made unavailable for the fluid.

Polar coordinates, which appear to be a more natural choice when describing circular pipes, could not be used due to the coupling of pipes perpendicular to each other.

The computation domain was divided into a 12x20x27 grid (NXxNYxNZ) as illustrated in Figure 6. Of all these cells, approximately one half have been completely blocked out using the porosity functions.

The dependent variables

The equations were solved with respect to the following 5 dependent variables :

- 3 velocity components,
- the pressure and
- the density.

Boundary conditions

At the inlet plane profiles for all solved for variables, except for the pressure, were prescribed. Three different sets of profiles were established on the basis of the hot-wire measurements, one for each of the inlet geometries.

The outlet boundary was a fixed pressure boundary.

Due to the smoothing process of the rectangular ducts described above, wall-functions could not be activated for any of the dependent variables. One consequence of this is that the no-slip condition for velocities at the pipe-wall is neglected.

No turbulence model

In the present version of the numerical model we have no turbulence model and all viscous forces with origin in the turbulent velocity fluctuations are therefore neglected.

3.3 Results of the simulations

In this presentation we will focus on the solution found in the two outlet planes. The situation in the inlet plane does anyway only reflect the inlet conditions prescribed.

In Figure 7 and 8 we present the converged solution found in the two outlet planes for inlet geometries no.1 and 2. Also included in these figures are the measured velocity components.

There are two "windows" drawn for each outlet plane, one presenting the lateral velocities and the other one iso-lines for the axial velocities. The vector-plot (to the left), shows the velocity vectors projected into the outlet plane (lateral velocities). The vectors drawn in bold-face types represent the measured velocity vectors, while the remaining represent the simulations. The point of attack for the vectors is their mid-point and the vector scale is indicated below the figure.

The right hand "window" shows iso-lines for the axial velocities simulated, the numbers indicate the velocities for the iso-curves. The filled circles indicate the point of measurement with the hot-wire and the corresponding velocities found are given to the right at the same level as the circles.

The square shape of the drawn cross-sections, instead of a circle, is a result of the geometry modelling using blockages on square ducts.

4. Discussion

Effect of no turbulence model

We decided not to use a turbulence model since the use of standard turbulence model gave unrealistic outlet flow fields. This may be ascribed to the lack of proper boundary conditions the turbulence model variables.

No turbulence model in the computations means that the inertia forces dominates the flow. In our case this seems to be a realistic assumption due to our high Reynold numbers and since the fluid experiences large accelerations from inlet to outlet.

We also did numerical tests to examine the effect on the velocity field in the header when assuming no turbulence model. Only minor changes were observed and the assumption was accepted as valid.

The outlet planes for inlet geometry no.1 (Figure 7)

For outlet "C" we could, in the numerical solution, see the existence of a recirculation zone with point of reattachment close to the position of the defined outlet plane. Therefore we regard this case to be a difficult task for the hot-wire anemometer. As can be seen from Figure 7 a) the measured lateral velocities does not fit very well to the simulations. Concerning the axial profile, we can see that the simulations predict minimum velocities near the pipe-axis, although not as pronounced as for the measurements.

In outlet "D" the lateral velocities compare as well as could be expected. The axial velocities are too high, but show the desired typicality of minimum velocity near the center-line.

The outlet planes for inlet geometry no.2 (Figure 8)

The lateral velocities compare very well for outlet "D" and acceptable for outlet "C". One must keep in mind the measurement uncertainty, estimated to 1.0-1.5 m/s, for the lateral velocities.

For the axial profiles we can not explain the observed differences by measurement uncertainty. The numerical model, therefore, fails to predict the axial profiles in this case. Examination of the numerical solution 2D downstream of the point of measurement showed, however, much better agreement with the measurements. It appears as if typical features of the flow need longer distances to develop in the numerical model than what is found in the measurements. The absence of the effective viscosity of the turbulence in the numerical model may explain this effect.

5. CONCLUSIONS

1. It is possible to simulate numerically the flow in headers, however, to a considerable computer time cost.

2. The available calculational tool did not enable proper no-slip wall boundary conditions and turbulence treatment.

3. Tests did show that these simplifications to the numerical model were not critical to the results.

4. The best agreement is reached when the inlet profile is generated by a simple geometry generating the smallest turbulence level. This, of course, gives the best precision of the inlet profile measurement and consequently also for the inlet boundary condition for the numerical model.

5. We are convinced that the computational tool can be further developed and verified to become a valuable tool in design work.

Future work
This work is continued. The measurement system is improved and more traverses will be taken. The inlet boundary conditions to the header model will be generated by a separate straight pipe or bend simulation.

ACKNOWLEDGEMENTS

The work has been financially supported by Statoil a.s.We wish to thank Dr. Karl Sjøen at Statoil for his help and advice throughout the work.

6. REFERENCES

/1/ Jørgensen,F.E.: "Directional sensitivity of wire and Fiber-film probes." DISA Information No.11, 1971.

/2/ Acrivlellis,M.: "Hot-wire measurements in flows of low and high turbulence intensity." DISA Information no.22, 1977.

/3/ Acrivlellis,M.: "Finding the spatial flow field by means of hot-wire anemometry." DISA Information no.22, 1977.

/4/ Langsholt,M.:"3-D numerical simulation of fluid flow in manifold geometries using the Phoenics computer code", IFE/KR/F-87/069.

/5/ Langsholt,M. and Thomassen,D. :"Computer modelling of fluid flow through orifices", Flow Measurements in the Mid 80's, Conference held at NEL, 9-12 june 1986.

/6/ Spalding,D.B. et al. PHOENICS instruction manual. CHAM TR/100,1986.

/7/ Spalding D.B.:"A general purpose computer program for multi-dimensional one and two-phase flow." Mathematics and Computers in Simulation North Holland Press, vol XX11l, pp 267-276, (1981)

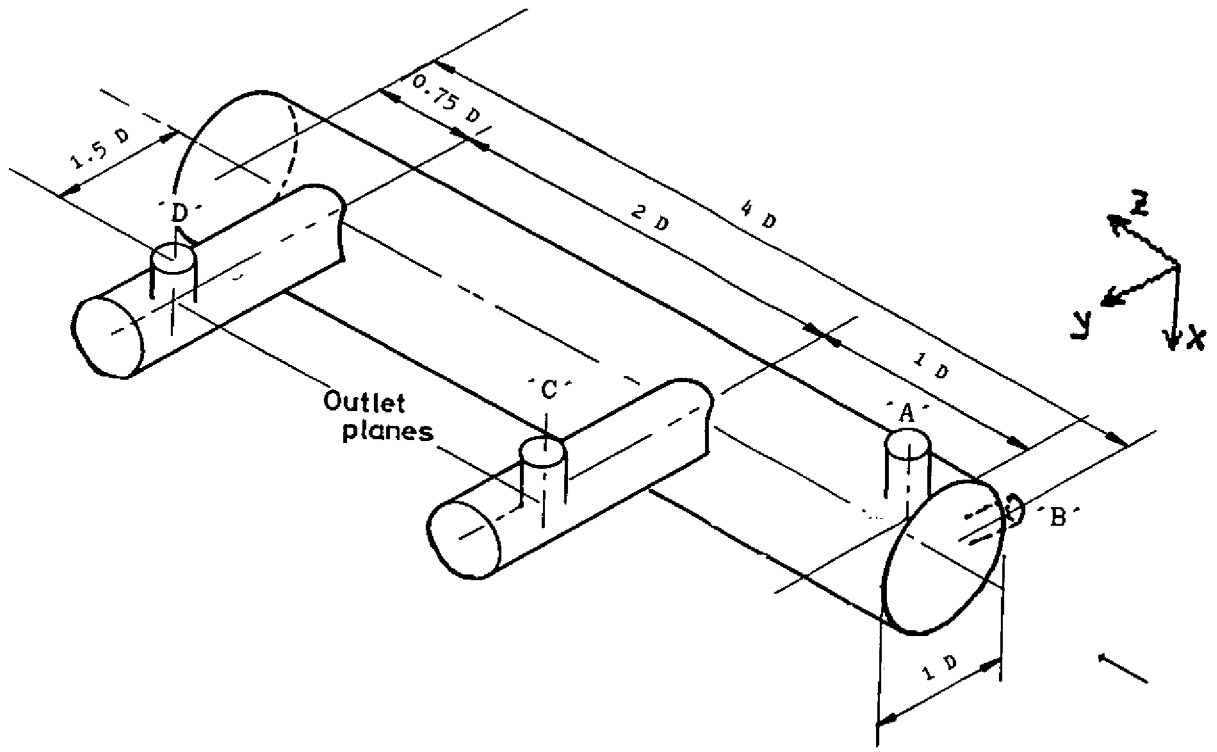


Figure 1. The header geometry.

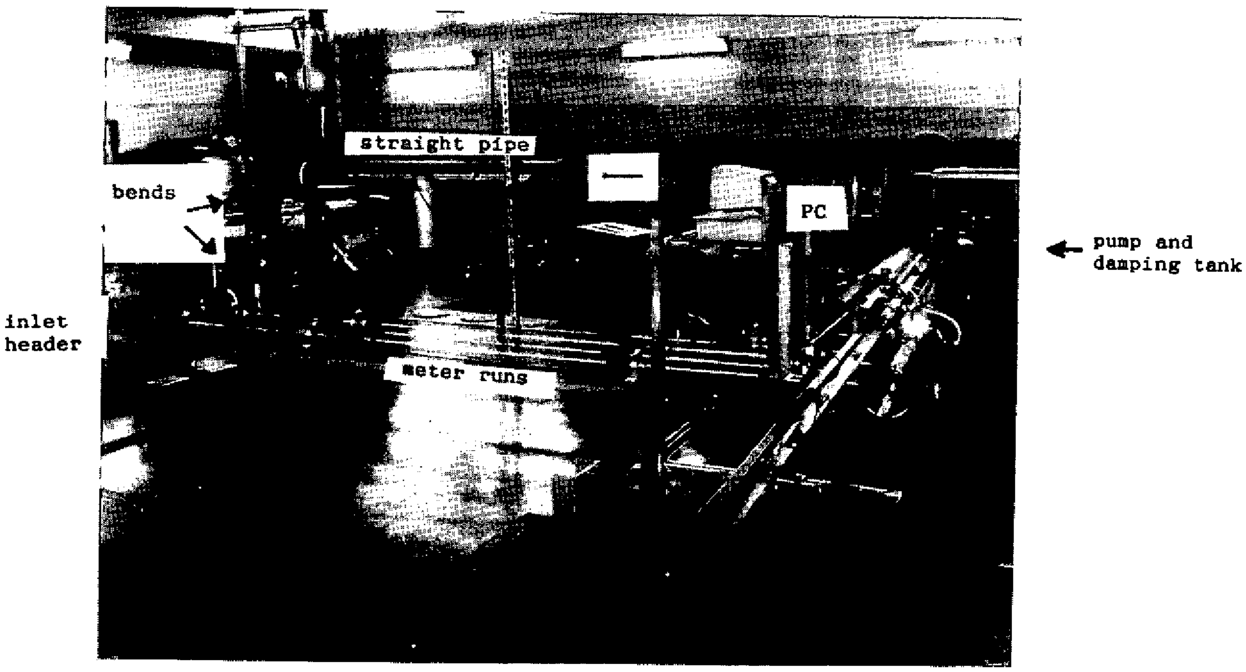


Figure 2. The experimental set up with inlet geometry no.3 mounted.

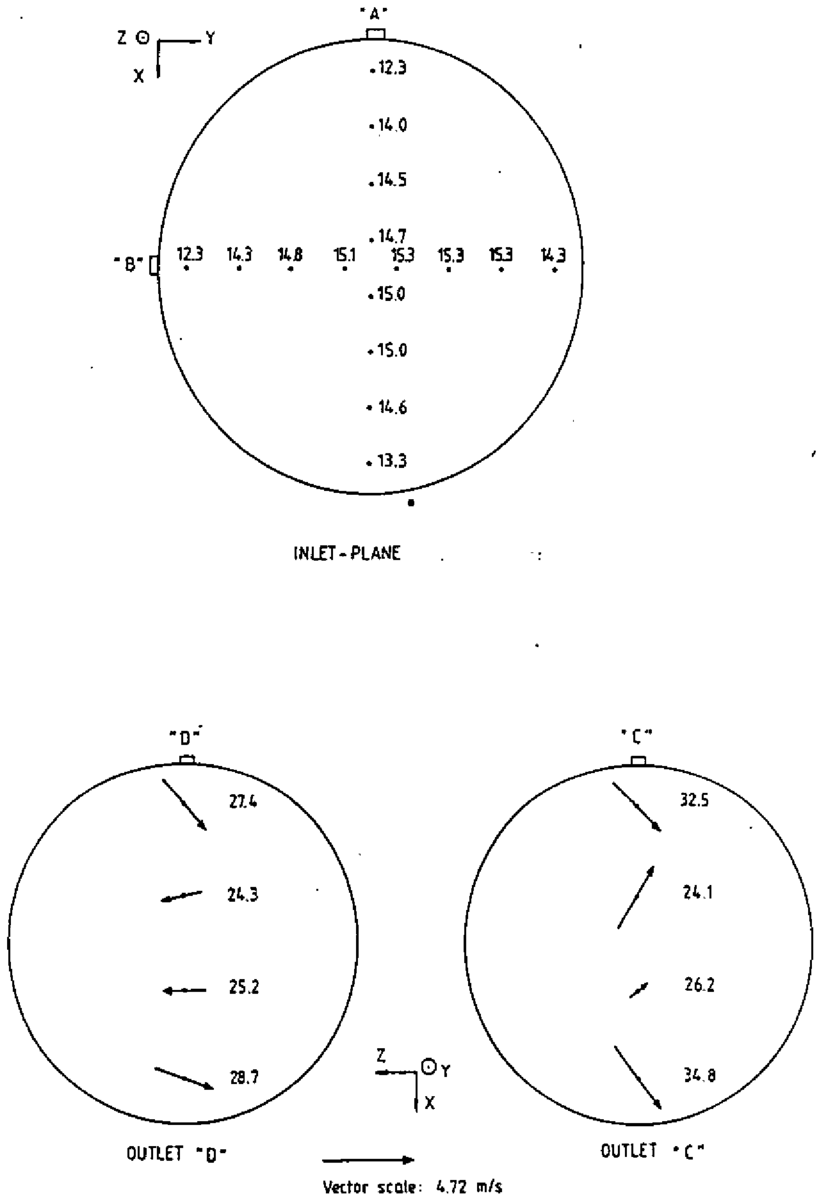


Figure 4. Vector plot presenting the lateral velocity vector measured in the inlet and outlet planes for inlet geometry no.1. The numerical values relate to the axial velocity component.

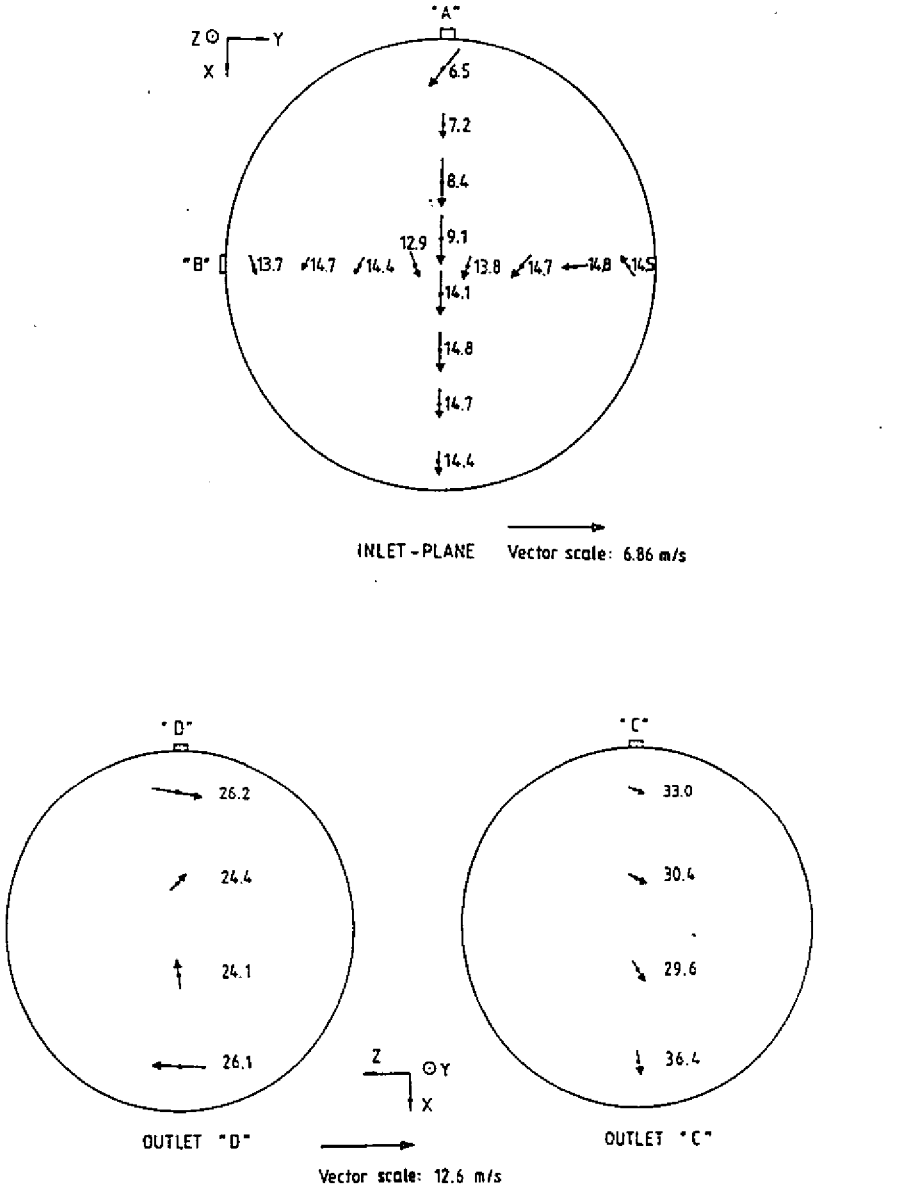
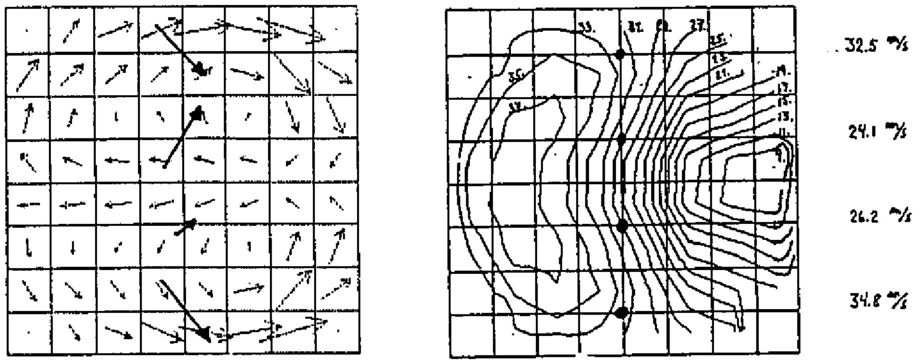
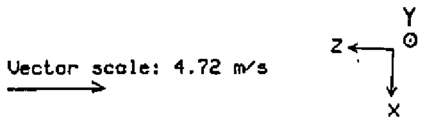
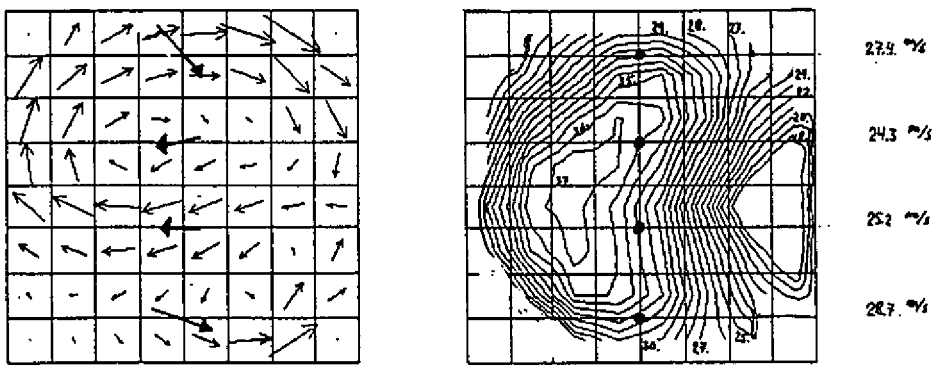


Figure 5. Vector plot presenting the lateral velocity vector measured in the inlet and outlet planes for inlet geometry no.2. The numerical values relate to the axial velocity component.



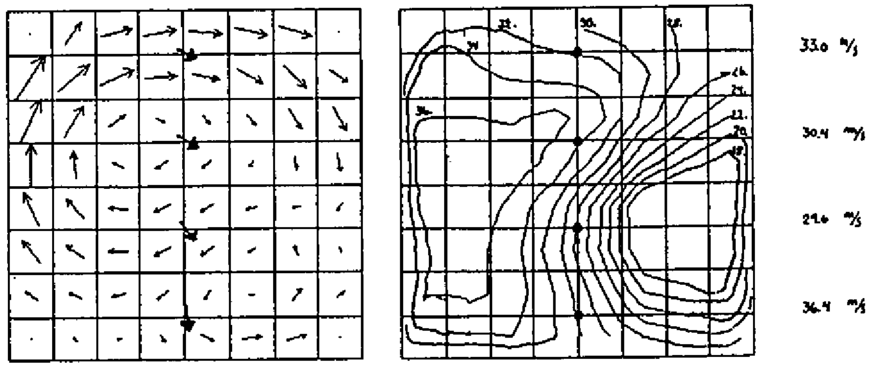
a) outlet "C"



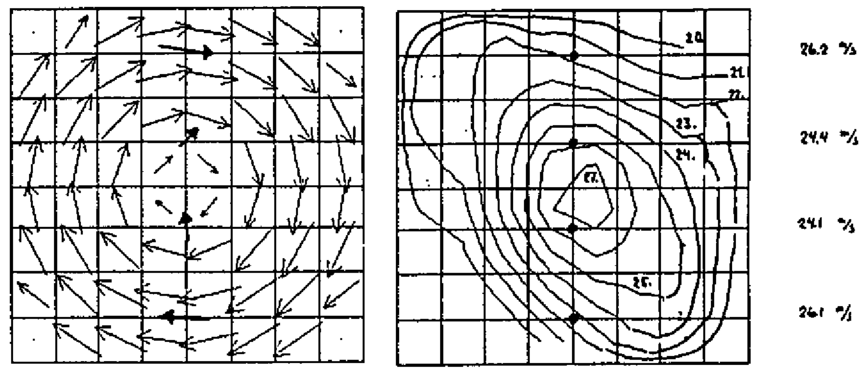


b) outlet "D"

Figure 7. Velocity fields in the two outlet planes for inlet geometry no.1. Both measurements and simulations.



a) outlet "C"



b) outlet "D"

Figure 8. Velocity fields in the two outlet planes for inlet geometry no.2. Both measurements and simulations.

THE NEL ORIFICE PLATE PROJECT

by

J M Hobbs and J S Humphries
National Engineering Laboratory

Paper 4.3

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

THE NEL ORIFICE PLATE PROJECT

J M Hobbs and J S Humphreys

National Engineering Laboratory, East Kilbride, Glasgow

SUMMARY

This paper reviews previous work to investigate the effect of upstream edge sharpness on the discharge coefficient of orifice plates. It traces the development of Standard requirements for edge sharpness and discusses the need for more guidance in the manufacture and inspection of orifice plates.

The NEL project to provide new experimental data on the effect of edge sharpness and other defects is described in detail. The main results indicate that the present criteria for edge sharpness are realistic, but the rejection of large orifice plates for very slight visible imperfections is perhaps unnecessarily stringent.

1 INTRODUCTION

An earlier version of this paper, presented at the 1986 Workshop, outlined the proposed project and gave relevant background information. The present paper records the outcome of the project and indicates the need to consider a revision of the tolerances required in some aspects of the current orifice plate standards. However, for completeness, a brief summary of the previous work, including the most recent, and the main requirements of the current standards are included in this sequel.

While the use of orifice plates to measure fluid flow is well defined in the current international Standard[1], there are some aspects of their manufacture and inspection which are not specified in sufficient detail.

One area which gives particular difficulty and, on occasions, grounds for debate is that of the edge sharpness requirement. Most people involved in the use of orifice plates are aware of the great importance of the square edge, but there is no convincing evidence to support the criteria for visual inspection given in various editions of the standards. For small pipe sizes (less than 125 mm bore) the limiting edge radius of 0.0004d is well nigh impossible to achieve and measure. For larger sizes, the edge sharpness requirement is easier to meet, but the rejection of plates showing 'any peculiarities visible to the naked eye' may be unnecessarily stringent and expensive.

Another deficiency in the current Standard is the quality of surface finish of the downstream face of an orifice plate. Again qualitative, but not quantitative, guidance is given.

The NEL orifice plate project was therefore undertaken to investigate three important topics:

a the effect of upstream edge sharpness to determine at what degree of rounding the orifice coefficient begins to change;

b the effect of local damage to the upstream edge or face of an orifice plate; and c the effect of the finish of the downstream bevel and the surface roughness of the downstream face.

An important part of this project was the survey of previous literature, covering earlier experimental work, and the evolution of the current standards. Equally important for the manufacture and testing of the orifice plates was the provision of measuring instruments of sufficiently good performance to resolve the small differences in the parameter being investigated and their effect on the orifice coefficient.

2 PREVIOUS WORK

Probably the first relevant reference to edge sharpness effects was in the early 1930s when Professor S R Beitler[2] examined microscopically the edges of plates which gave coefficients that were higher than expected. Although he considered them to be slightly rounded, it was not possible to measure the radius at that time without cutting up the plates.

It was not until the 1960s that a major experimental programme was attempted in which measurements of both edge sharpness and the discharge coefficient were made. Herning[3,4] and his colleagues carried out a programme of tests on a series of different diameter ratio orifice plates installed in meter runs of 50, 100 and later, 150 mm diameter. The edges of the orifice plates were progressively rounded with emery paper and a lead foil method was used to measure the edge radius before each successive calibration.

The results of their work were best summarised in Fig. 6 of Reference 4, which was reproduced as Fig. 1 in the 1986 NSFM Workshop paper. This showed that the effect of the edge depends only on the ratio of the radius of the edge to the orifice diameter.

More recently, Crocket and Upp[5] made further tests using 75 mm (3-in) dia. plates of 0.2, 0.4 and 0.6 dia. ratio and used the lead foil technique to determine the edge radius.

A little later Benedict[6] and his co-workers investigated the edge effect with 0.5 dia. ratio plates in a 101.6 mm (4-in) nominal bore test-line. Some of the plates were rounded to a radius of about 0.2 mm to represent an extreme case of edge roundness. Both optical and lead foil measurements were used to determine the edge radius.

All the above investigations were concerned with the effect of gross changes of the edge radius. Another series of tests were made by Spencer, Calame and Singer[7] in the 1960s on the production of orifice plates to the then current standard and the errors that could arise if care were not taken and the quality of finish required was not obtained.

Contemporary work on the effect of orifice plate condition has been carried out by Studzinski et al[8] who investigated the influence of surface roughness, solid and liquid deposits, and of nicks and burrs on the accuracy of flow measurement.

3 STANDARDS

The first international Standard on orifice plates[9] was published by the International Federation of the National Standardising Associations (ISA) in 1936. It included a graph showing the effects of 'dullness' of the edge. No qualitative description of this 'dullness' was given, but the graph is believed to have resulted from the work of Witte in the early 1930s.

Owing to the difficulty of measuring edge radius, most subsequent standards seem to have specified that the edge be sharp and left it to the user to satisfy himself that this has been achieved. Little guidance has also been given on how to machine a satisfactory sharp edge, quite a problem for some materials, especially for small orifice diameters.

In the ASME Power Test Code[10] PTC 19.5; 4-1959 it states:

> "e The inlet edge of the orifice shall be square and sharp, free from either burrs or rounding, so that when viewed without magnification a beam of light is not reflected visibly by the edge."

The German Standard DIN 1952 published in 1963 commented that a reflected ray of light from a rounding radius of 0.05 mm is just visible to the naked eye[11]. It was concluded that visual inspection could only be justified if the bore diameter were greater than 125 mm, at which value the edge radius would be 0.0004d, the criterion given for a sharp edge.

The revised British Standard BS 1042[12] published in 1964 included the same criterion for the sharp edge in the specification of the orifice plate. Clause 54 contained the following requirement:

> "d Upstream edge of orifice. The upstream edge of the orifice shall be square and free from burrs or wire edges. It may be regarded as square if its radius of curvature nowhere exceeds 0.0004d."

Elsewhere in the same standard some guidance was given on how to produce such an edge. Clause 40 included the statement:

> "A high quality of manufacture is necessary to meet the requirements detailed in Sections 7-14 especially for devices to be used in smaller sizes of pipe. The square edge of orifice plates may conveniently be produced by taking a fine cut, from the centre outwards, after the orifice has been bored; polishing or cleaning with emery cloth is not advisable. There must of course be no burrs or wire edges."

ISO 5167, 1980, which was adopted as BS 1042, 1981[13], incorporated basically the same message in clause 7.1.6.

> "7.1.6 Edges G, H and I
>
> 7.1.6.1 The upstream edge G and the downstream edges H and I shall have neither wire edges, nor burrs, nor, in general, any peculiarities visible to the naked eye.
>
> 7.1.6.2 The upstream edge G shall be sharp. It is considered so if the edge radius is not greater than 0.0004d.
>
> If $d \geq 125$ mm this condition may generally be considered as satisfied by mere visual inspection, checking that the edge does not seem to reflect a beam of light when viewed with the naked eye.
>
> If $d < 125$ mm visual inspection is not sufficient but this condition may generally be considered as satisfied when the upstream face of the orifice plate is finished by a very fine radial cut from the centre outwards.

However, if there is any doubt as to whether this condition is satisfied, the edge radius must be actually measured."

No guidance is given in the standard on how the edge radius should be measured, but a Code of Practice for ISO 5167 is being prepared and this will include brief notes on three suitable techniques, viz lead foil, casting and stylus methods.

4 NEL EQUIPMENT

4.1 Calibration Line

As all known previous work at the time of starting the project was limited to pipes of diameters of 150 mm or less, the present work was based on 300 mm (12-in) nominal bore pipe as being more representative of the sizes currently used in gas transmission. Accordingly, the calibration line shown in Fig. 1 was set up. Flow through the line was induced by a large centrifugal fan capable of developing a pressure difference of 9-13 kPa (36-53 inches water) over the range of flowrates required.

To facilitate repeated removal and replacement of the test orifice plates a metering tube incorporating a junior orifice fitting was chosen and this was provided with two pairs of flange tappings 180° apart. The upstream length of pipe was designed to satisfy ISO 5167, Table 3, for an expander 0.5D to D over a length of 1-2D, which for an 0.75 dia. ratio orifice plate (the largest likely to be used) was 38D. With the pipe sections that were available, 39D was in fact the length used.

In order to maintain sufficiently high Reynolds numbers to obtain near constant values of discharge coefficient over a small range of flowrate with the limited pressure difference developed by the fan, it was necessary to minimise the resistance caused by the reference flowmeter. Therefore, instead of using a second orifice plate for this, a set of three venturi nozzles for operation in free inlet condition were designed. Each nozzle was sized to correspond to one of the three orifice plate diameter ratios in order to give comparable ranges of differential pressure. The optimum size was rounded to the nearest standard pipe size to facilitate mounting on the diffuser section. Thus nominal bores of 100, 150 and 200 mm were aimed at. The nozzles were manufactured in GRP (glass reinforced plastic) and calibrated against secondary standard orifice plates.

4.2 Instrumentation

Differential pressures of the inlet flowmeter and the test orifice plate were measured using Betz projection micromanometers of range 0-800 mm water and a resolution of 0.1 mm. Static pressure (relative to atmospheric) at the orifice plate was measured using a similar projection micromanometer.

Barometric pressure was obtained from a precision quartz pressure gauge and air humidity with a whirling hygrometer. Temperatures were measured by standard platinum resistance thermometers with a digital readout or mercury-in-glass thermometers. Most of the above instruments were calibrated prior to use and all are traceable to national standards.

4.3 Orifice Plates

Orifice plates of three diameter ratios were chosen for this investigation, viz 0.4, 0.6 and 0.75, typical of those in regular use. Thus the nominal orifice bores were 120, 180 and 225 mm respectively. The plates were machined in the NEL workshop from blanks supplied by the manufacturers of the junior orifice fitting. Measurements of orifice bore, concentricity, thickness, flatness and surface roughness were made immediately after manufacture to ensure that the plates conformed fully to the requirements of ISO 5167.

4.4 Edge Sharpness Measurement

The radii of the sharp edges of the orifice plates were measured repeatedly during the course of the project. Two different and complementary methods were used.

4.4.1 Stylus method

This method is based on a development of the well known 'Talysurf' roughness measuring machine, or its equivalent, which is used to measure the surface finish of plates. By reducing the sensitivity of the machine in the vertical direction to that in the horizontal, a sufficient range can be obtained to examine the edge. As the roughness of the surface is not of prime interest, and the sensitivity is reduced, it is unnecessary to use a pointed stylus. A small spherical ball, which can be manufactured and measured to fine tolerances, is commonly used, being less likely to wear, but of course due allowance must be made for the radius of the ball itself. Magnifications of up to 500 times have been successfully used.

4.4.2 Casting method

This method was developed by Gallacher[14] of NEL and is based on the use of casting resins. A liquid cold-forming plastic was poured into a wax or plasticine mould surrounding the location on the orifice plate to be measured. When hardened, the casting can be removed, sliced and polished to a reference line, thus forming a perfect replica of the original edge. Results accurate to 0.005 mm have been obtained.

For each plate the edge radius was measured at eight positions, equally distributed around the bore, by both the stylus method and using plastic replicas.

5 TEST PROGRAMME

5.1 Datum Calibrations

Every test orifice plate was calibrated in the 'as received' condition to provide a datum or reference calibration against which any subsequent changes could be measured. In doing the first few of these it was necessary to establish the amount of random variation experienced in making the measurements and determine the number of test points to be taken in order to keep the uncertainty to within a fraction of the changes that were anticipated in subsequent tests. A typical calibration for an 0.6 dia. ratio plate is shown in Fig. 2. In this case the discharge coefficient after initially decreasing with increasing Reynolds number became virtually constant above a throat Reynolds number of 5×10^5. Subsequent calibrations were made for the range of Reynolds number over which the discharge coefficient was sensibly constant.

For a set of results the mean discharge coefficient and the standard deviation can be determined. It was established that, if about 25 test points are taken, the standard deviation of the mean discharge coefficient is about 0.03 per cent. As differences in discharge coefficient as small as 0.1 per cent were being sought, this figure was deemed to be acceptable. Any further significant reduction in the standard deviation of the mean would have necessitated unrealistically large numbers of test points.

The results of the initial calibrations of all the test plates available at the beginning of the project are summarised in Table 1. In most cases the agreement between different plates of the same diameter ratio was very good. The mean value of discharge coefficient over a specified Reynolds number range was used as a basis for comparison.

5.2 Upstream Edge Sharpness Tests

The major part of the project was to investigate the effect of the sharpness of the upstream edge of the orifice plate on the discharge coefficient. Initially three plates, each of a different diameter ratio, were selected for this work. For the first set of calibrations a target radius of 0.0001d was specified. This lay in the range 10-20 μm (0.0005-0.001 in) and was about one-quarter of the limiting value specified in ISO 5167.

After the initial calibrations the edges of the plates were successively rounded, measured and the plates recalibrated. Edge sharpness measurements were made using both the stylus method and by means of plastic replicas. This procedure of rounding, measurement and calibration was repeated until five complete sets of data were obtained for each plate evenly spaced over the range of edge radii covered.

The results, plotted as the change in discharge coefficient from the datum against the ratio of the edge radius to bore diameter, are shown in Fig. 3. Apart from two points, which appear to be exceptionally high, there is a clear trend of gradually increasing discharge coefficient as the radius of the sharp edge increased. Further tests made on two additional plates with a small degree of rounding confirmed this trend.

5.3 Local Damage to Upstream Edge

In contrast to the work described in the previous section, these tests were designed to simulate the effects of foreign objects, eg a bolt, passing along the pipe and striking the edge of the orifice plate. To achieve this kind of damage it was necessary to damage the plate by an impact method. By this means the metal is not simply removed, but is displaced and small raised areas are formed around the site of the indentation.

The method actually adopted used a cold chisel held at about 45° to the face of the plate and which was then struck sharply with a hammer. The resulting damage is shown in Fig. 4.

Two additional orifice plates were damaged in this way and then recalibrated. Their diameter ratios were 0.34 and 0.75. In the case of the former, calibrations were carried out with the indentation both adjacent to and at right angles to the pressure tappings; see Table 2.

As the differences were very small, further tests were made using both plates with the notches successively deepened by filing until greater changes became evident. These will be correlated with the dimensions of the notch once the measurements are completed.

5.4 Effect of Downstream Face

In the initial proposal for the project it was intended to investigate the effects of scores and scratches at various positions on and of increasing roughness of the downstream face of the orifice plate upon the discharge coefficient. As small imperfections on the downstream face were not expected to have much effect it was decided to begin with an investigation of the increasing roughness of the face which seemed likely to have the greater influence.

One plate of each diameter ratio therefore had its downstream face roughened by gluing on coarse sandpaper. No significant change in discharge coefficient was obtained, see Table 3. Further tests indicated that it did not matter whether the roughness was present over the whole of the downstream face or simply on the downstream level.

Because it was feared that the effective increase in thickness of the orifice plate might have an influence as well as the roughness, a further test was carried out with a sheet of smooth thin material (about 1.5 mm thick) glued to the entire downstream face of the plate, there being no hole in the annulus initially. In this test a small reduction in the discharge coefficient was observed, but this was not significant.

Following this, some further tests were made, this time to simulate localised roughness. In the first series of these tests a small disc of the sandpaper (25 mm dia.) was glued to the downstream face to simulate a patch of corrosion. Calibrations were made with this disc both adjacent to the pressure tappings and at 90° to them. A small increase in discharge coefficient was observed when the disc was adjacent to the pressure tappings, but when it was at right angles to them no significant difference could be detected, see Table 4.

For the second series of tests the arrangement was reversed. The sandpaper with a 25 mm disc removed was glued on smooth side out, leaving a depression to simulate the effect of corrosion pitting. Calibrations were again made with the hollow at right angles to the pressure tappings and adjacent to them. Very small increases in the discharge coefficient were observed, that with the depression adjacent to the pressure tappings being the greater, see Table 5.

6 CONCLUSIONS

Experimental investigations have confirmed that the radius of the sharp edge of orifice plates has a marked effect upon the discharge coefficient. On the other hand, local damage to the sharp edge needs to be particularly severe before a significant change in the discharge coefficient is detected. Thus the requirements of the current standards which call for the rejection of plates showing any visible defects may be unnecessarily stringent.

A general and gross increase in the roughness of the downstream face did not appear to have any significant effect, but local roughness patches gave a small change, especially when aligned with one of the pressure tappings.

7 ACKNOWLEDGEMENTS

This project has been sponsored by a consortium of 15 interested organisations and the authors are grateful for the advice and suggestions received from them.

Although the work was largely funded by the DTI, the contribution from the Community Bureau of Reference of the EEC is also acknowledged.

REFERENCES

1 INTERNATIONAL STANDARDS ORGANISATION. Measurement of fluid flow by means of orifice plates, flow nozzles and venturi tubes. Geneva: ISO 5167, 1980.

2 BEITLER, S. R. The flow of water through orifices. Ohio State University Engineering Experimental Station, Bulletin 89, 3 May 1935.

3 HERNING, VON FR. Untersuchungen zum Problem der Kantenunscharfe bei Normblenden und bie Segmentblenden. (Experiments on the problem of the edge sharpness of standard and segmental orifice plates.) Brenns-Warme-Kraft, 1962, 14(3), 119-126.

4 HERNING, VON FR. and WOLOWSKI, E. Die Kantenunscharfe von Normblenden und Segmentblenden und das Ahnlichkeitsgesetz. (The edge sharpness of standard and segmental orifices and the laws of similarity.) Brenns-Warme-Kraft, 1963, 15(1), 26-30.

5 CROCKET, K. A. and UPP, E. L. Measurement and effects of edge sharpness on the flow coefficients of standard orifices. Trans ASME, J. of Fluids Engng, June 1973, 271-275.

6 BENEDICT, R. P., WYLER, J. S. and BRANDT, G. B. The effect of edge sharpness on the discharge coefficient of an orifice plate. Trans ASME, J. Engng for Power, Paper No 74-WA/FM-4, 1974, 6 pp.

7 SPENCER, E. A., CALAME, H. and SINGER, J. Der Einfluss von Kantenunscharfe und Rohrrauhigkeit auf die Durchfluss von Normblenden. Brenns-Warme-Kraft, 1970, 22(2), 56-62. (Also published in English as: The influence of edge sharpness and pipe roughness on orifice plate coefficients. NEL Report No 427. East Kilbride, Scotland: National Engineering Laboratory, 1969.)

8 STUDZINSKI, W. et al. Effect of orifice surface conditions on accuracy of flowrate measurement. Second International Conference on Flow Measurement, London, 11-13 May 1988, Paper H1. BHRA The Fluid Engineering Centre, Cranfield, Bedford, UK, 1988.

9 INTERNATIONAL FEDERATION OF STANDARDISING ASSOCIATIONS. Rules for measuring the flow of fluids by means of nozzles and orifice plates. Geneva: ISO Bulletins Nos 9 and 12, 1935.

10 CHAPTER 4: FLOW MEASUREMENT. ASME POWER TEST CODES. Supplement No PTC 19.5: 4-1959. New York: Amer. Soc. Mech. Engrs, 1959.

11 DEUTSCHER NORMENAUSSCHUSS. Durchflussmessung mit genormten Dusen, Blenden und Verturidusen. Berlin: DIN 1952, 1963.

12 BRITISH STANDARDS INSTITUTION. Methods for the measurement of flow in pipes. Part 1 : Orifice plates, nozzles and venturi tubes. London: BS 1042 : Part 1 : 1964.

13 BRITISH STANDARDS INSTITUTION. Methods of measurement of fluid flow in closed conduits. Part 1 : Pressure differential devices.

Section 1.1 : Orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full. BS 1042 : Section 1.1 : 1981.

14 GALLACHER, G. R. Measuring edge sharpness of orifice plates. The Engineer, 17 May 1968, pp 783-785.

LIST OF TABLES

LIST OF FIGURES

TABLE 1

INITIAL CALIBRATIONS

Plate No	Diameter ratio (nominal)	Diameter m	Mean discharge coefficient
1	0.75	0.228 94	0.6032
2	0.75	0.228 57	0.6032
3	0.75	0.228 55	0.6021
4	0.75	0.228 52	0.6031
5	0.6	0.183 24	0.6073
6	0.6	0.184 82	0.6071
7	0.6	0.184 84	0.6066
8	0.6	0.182 79	0.6073
9	0.4	0.122 21	0.6062
10	0.4	0.121 87	0.6056
11	0.4	0.121 88	0.6053
12	0.4	0.121 83	0.6056

TABLE 2

CALIBRATIONS WITH LOCAL SEVERE DAMAGE TO UPSTREAM EDGE

Calibration	Discharge coefficient	Per cent change
Diameter ratio B = 0.34		
Datum calibration	0.6047	-
Damage at 90° to tappings	0.6049	0.03
Damage adjacent to tappings	0.6058	0.18
Diameter ratio B = 0.75		
Datum calibration	0.6056	-
Damage adjacent to tappings (Stage 1)	0.6057	0.02
Damage adjacent to tappings (Stage 2)	0.6067	0.18

T A B L E 3

CALIBRATIONS WITH ROUGH DOWNSTREAM FACE

Plate No	Diameter ratio	Initial C	Final C	Per cent change
1	0.75	0.6032	0.6040	0.133
7	0.6	0.6066	0.6068	0.033
9	0.4	0.6062	0.6067	0.083

T A B L E 4

CALIBRATIONS WITH DISC OF SANDPAPER GLUED TO DOWNSTREAM FACE

Calibration	Discharge coefficient	Per cent change
Datum calibration	0.6062	-
Disc at 90° to tappings	0.6061	-0.02
Disc adjacent to tappings	0.6076	0.23

T A B L E 5

CALIBRATIONS WITH A DEPRESSION ON DOWNSTREAM FACE

Calibration	Discharge coefficient	Per cent change
Datum calibration	0.6062	-
Hole at 90° to tappings	0.6069	0.12
Hole adjacent to tappings	0.6082	0.33

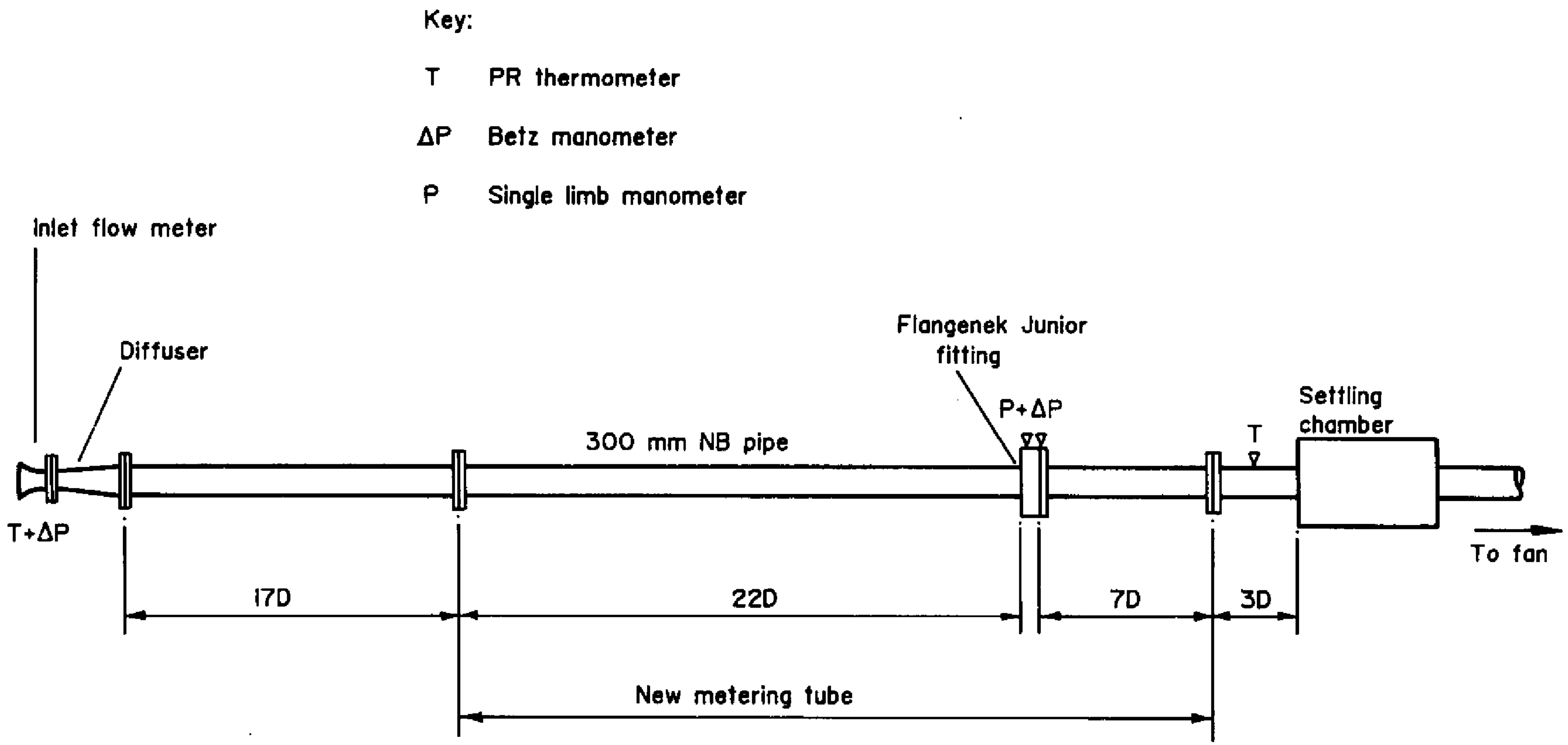


Fig 1 Layout of Calibration Line

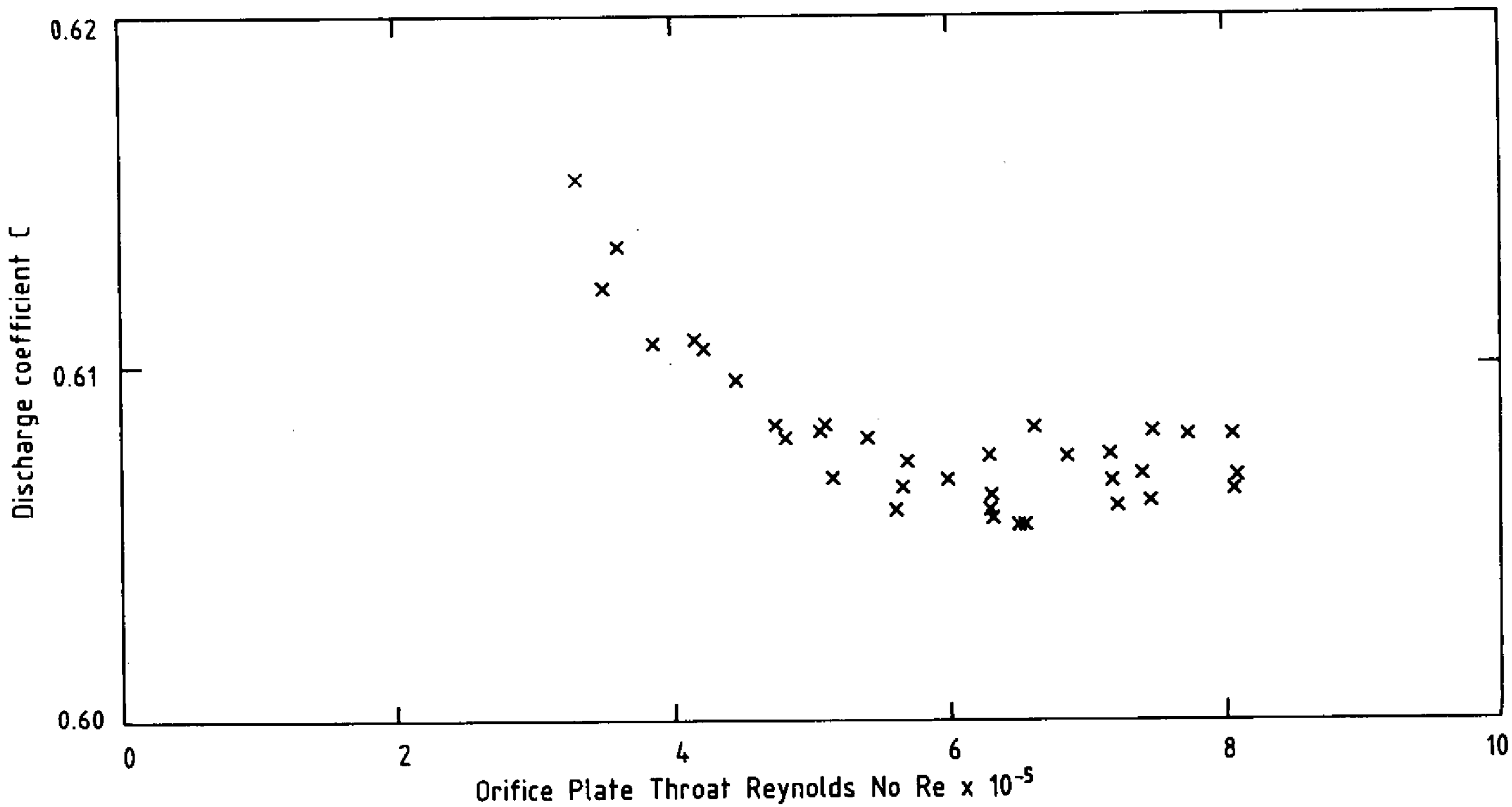


Fig 2 Typical Calibration of 0.6 Beta Plate

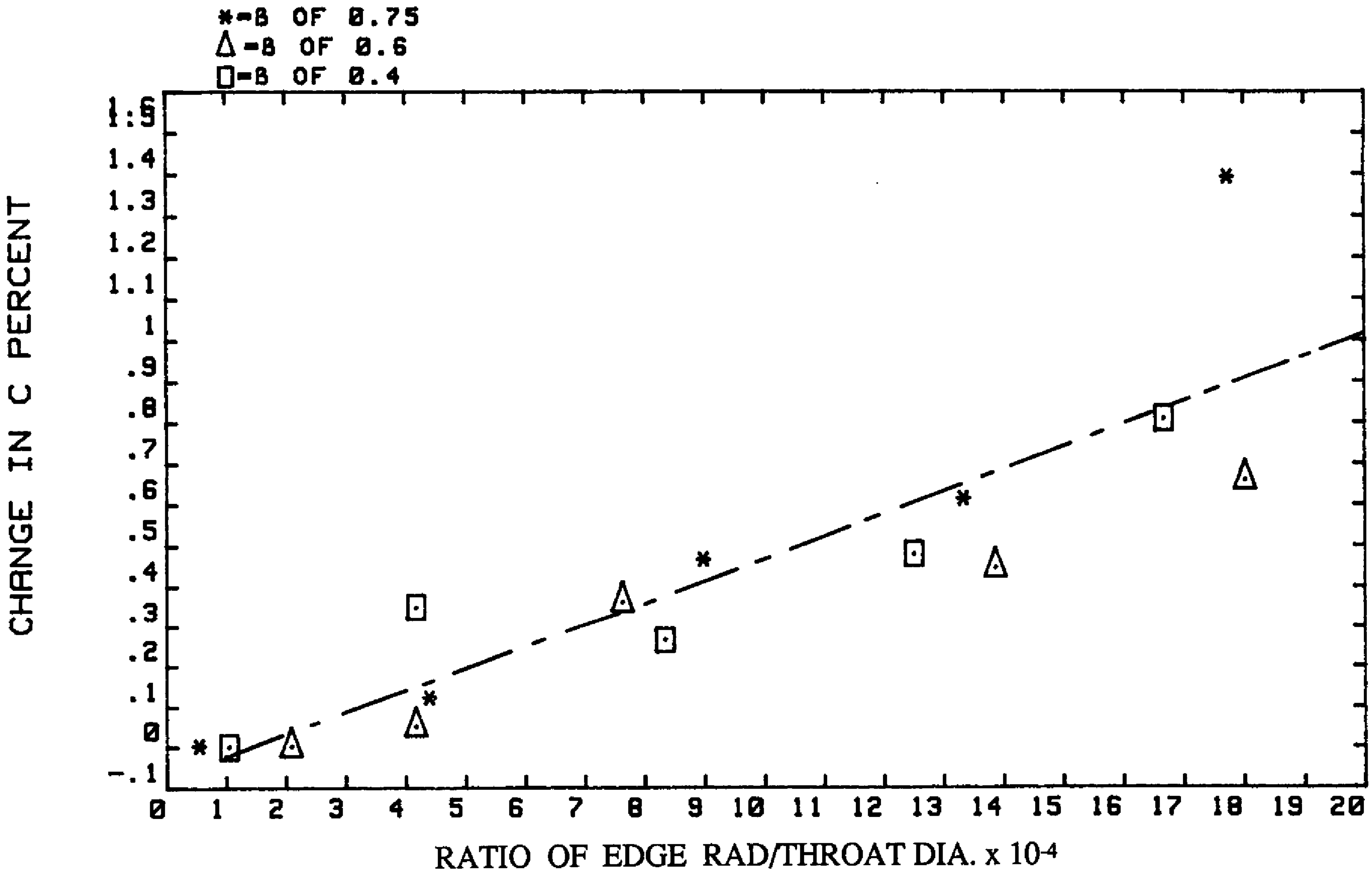
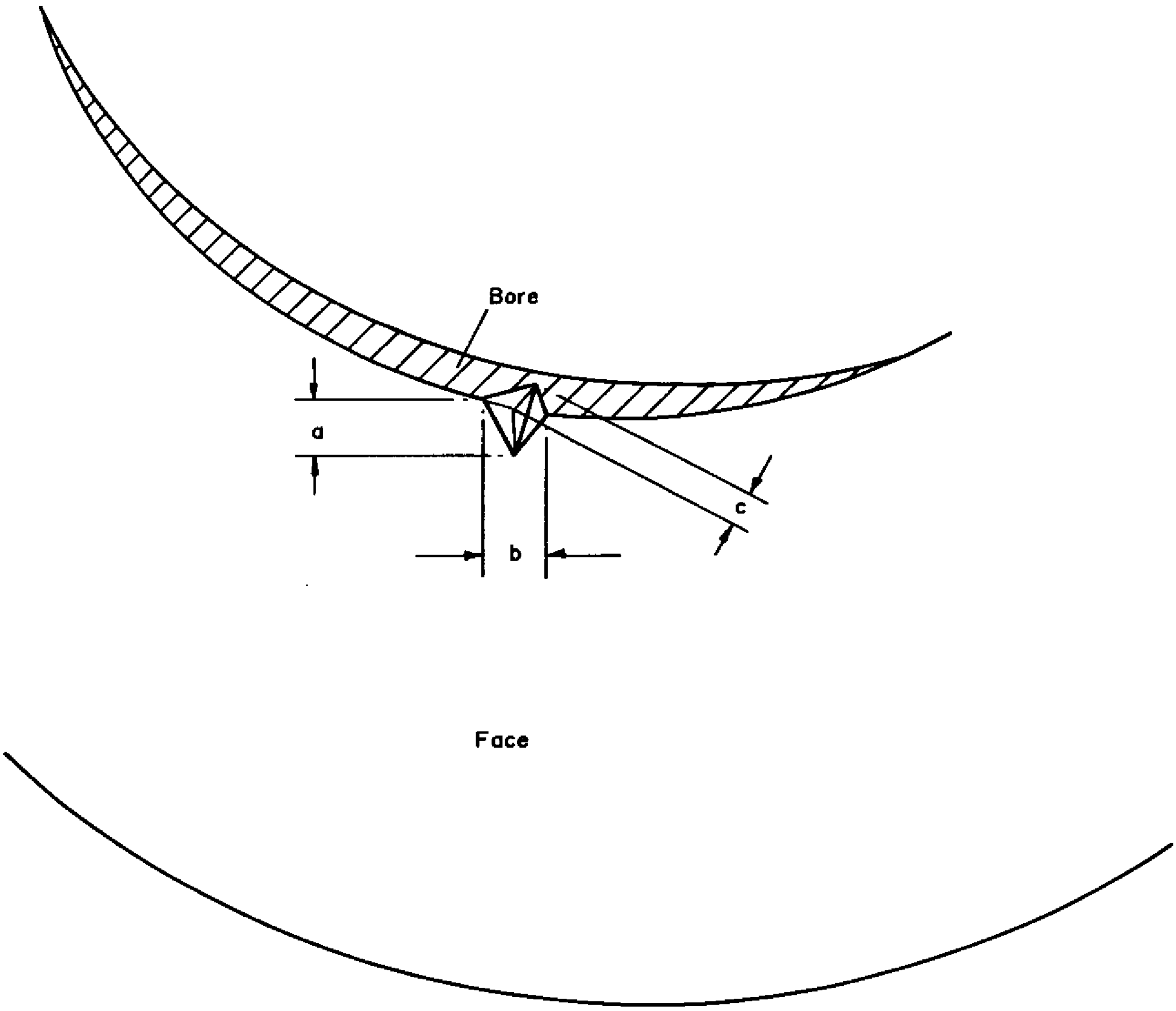


Fig 3 Effect of Edge Radius on Discharge Coefficient



Diameter ratio	Dimension (mm)		
	a	b	c
0.34	2.3	2.26	2.1
0.75	2.0	3.07	4.44

Fig 4 Geometry of Orifice Plate Damage

Main Index

ACCURACIES OF VORTEX AND TURBINE METERS IN NATURAL GAS

by

B Harbrink and O Brandt
Ruhrgas AG

Paper 4.4

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

ACCURACIES OF VORTEX AND TURBINE METERS IN NATURAL GAS

- Vortex Meter Tests at the Lintorf Test Rig and Field Intercomparison Tests Between Vortex Meters and Turbine Meters -

Dr. Bernd Harbrink, Head of the Applied Physics Section,
Ottokar Brandt, Head of the Gas Measurement Section,
Ruhrgas AG, Essen, Federal Republic of Germany

SUMMARY

Ruhrgas tested Bopp & Reuther vortex shedding meters at its Lintorf high-pressure flow metering test rig and RMG Meßtechnik vortex shedding meters at field stations where these were installed in series with turbine meters. This paper reviews the results of these tests.

The work has shown that vortex meters type-approved in the Federal Republic of Germany are not yet fit for custody transfer metering. At Ruhrgas metering stations, they are, for this reason, only utilized as check meters.

1. INTRODUCTION

Vortex flow meters may be installed at sales gas metering stations in lieu of turbine meters. Major advantages of vortex meters are

- no moving parts and therefore less maintenance,
- smaller diameters than turbine meters for the same rated flow rate,
- no hunting after sudden decreases in flow rates as is the case with turbine meters and
- better overload capabilities than turbine meters.

Manufacturers of vortex meters also mention the additional advantage of low head loss, which is certainly a benefit of the meter itself. However, since the type-approval certificate issued by Physikalisch-Technische Bundesanstalt (PTB), the West German national flow measurement laboratory, specifies

- 20 D straight upstream piping incorporating a 2.5 D tube bundle flow straightener and
- 5 D straight downstream piping,

the pressure drop across the vortex meter and the flow straightener is similar to that across the turbine meter.

Vortex meters manufactured by RMG Meßtechnik and by Bopp & Reuther have been type-approved for use at custody transfer metering stations in the Federal Republic of Germany.

As Ruhrgas customers have increasingly demanded the installation of vortex meters at sales gas metering stations in the Ruhrgas pipeline system, Ruhrgas decided to study the high-pressure behavior of the meters at its test rig and in the field.

The behavior of RMG vortex meters (in respect of long-term accuracy, failure rates, maintenance requirements) has only been field tested by Ruhrgas for some years at stations at which the vortex meters operate in series with turbine meters. Pilot Bopp & Reuther vortex meters were only laboratory-tested at the Ruhrgas high-pressure test rig, but the proposed field tests of these meters have been delayed, because of change in the research and development management of Bopp & Reuther.

This paper will discuss

- the laboratory tests of the pilot Bopp & Reuther vortex meter and
- the field tests of the RMG vortex meter.

The laboratory tests were carried out at the Ruhrgas high-pressure test rig in Lintorf, which is, among other things, used for test work for the EEC and the European Gas Research Group (GERG). However, the test rig has not been approved officially by the West German Office of Weights and Measures. The reference standards used at the Lintorf site are corner-tap orifice plates. The meter runs incorporating the orifice plates were calibrated at the water test facility operated by the Delft Hydraulics Laboratory. The rig in Lintorf consists of 5 parallel meter runs. The gas is tapped from a transmission line at a pressure of 47 bar and flows through the test rig incorporated in the bypass system of a governor station which reduces the transmission line pressure to the downstream distribution system pressure of 8 bar. Meters can, therefore, be tested at pressures between 8 and approx. 50 bar and at maximum flow rates of q_n = 120,000 m³/hr in winter and of q_n = 70,000 m³/hr in summer. The uncertainty of the Lintorf test rig for flow meter tests is approx. $\pm$ 0.3 %.

2. PILOT BOPP & REUTHER WZ 250 VORTEX METER LABORATORY TESTS

Ruhrgas tested a pilot DN 250, Bopp & Reuther vortex meter of a length of 2 D for a rated flow of q = 7,000 m³/h at its Lintorf high-pressure test rig.

The meter was calibrated using 61 D straight upstream piping length, including Bopp & Reuther's 20 D straight upstream spoolpiece containing the PTB-specified tube-bundle flow straightener and Bopp & Reuther's 6 D straight downstream piping length (see Fig. 1, Arrangement a).

For the calibration, the error of the vortex meter was determined at a pressure of 13 bar also used for all subsequent tests, but flow could only be increased to approx. 40 % of the meter's maximum flow rate as the flow from the transmission line to the distribution line was limited.

The calibration curve is a fairly horizontal line differing by approx. + 0.5 % from the reference flow, if downward-oriented peaks at 10 % and 14.7 % of the maximum flow rate are disregarded (see Fig. 2). The W-shaped peak is explained by resonance as the frequency of the test rig coincided with the frequency of vortex shedding. For such a resonance peak to occur in the calibration curve, the amplitude of the test rig pressure pulsations must be approximately the same as the amplitude of the vortex signal or substantially exceed half the amplitude of the vortex signal.

A second test of the Bopp & Reuther WZ 250 vortex meter using 61 D straight upstream piping, but not the tube-bundle flow straightener required by PTB (see Fig. 1, Arrangement b), was carried out to examine whether the flow straightener itself represents a flow disturbance. The error curve (see Fig. 2) shows again a peak due to resonance at the same flow rate, but the error is 0 % at more than 16 % of the maximum flow rate for which the vortex meter is designed.

These calibration tests have shown that the vortex meter and the straight upstream piping together with flow straightener must be treated as one package for calibration and field installation. The tube-bundle flow straightener 16 D upstream from the inlet of the vortex meter disturbs the flow profile. The disturbance is, of course, deliberate, but the profile should be reproducible. In the case on hand, the disturbance increased the error by + 0.5 %. Experience from the EEC orifice plate programme is similar, as a 4 D tube-bundle flow straightener 22 D upstream from the orifice plate (as required by ISO 5167) increased the coefficient of discharge due to a more laminar flow profile.

The tests also showed that the tube-bundle flow straightener does not eliminate resonance effects due to the test rig frequency.

Further tests not discussed in detail in this paper have demonstrated that

- the sensor taps should not be in the bottom part when measuring in a gas pipe (condensate problems),

- under non-resonance conditions, the error is not influenced by the relative length of the two instrument lines from the taps to the thermistor although the manufacturer had originally proposed to use lines of different length to make up for asymmetries in the tap configuration, and

- a gate valve 61 D upstream from the vortex meter is the source of major error (depending on the exact gate position), if the valve is not fully open.

As the dampening effect of the tube-bundle flow straightener on flow fluctuations was very limited, the manufacturer produced a perforated plate with 31 bores of a diameter equal to the plate thickness and 6 smaller bores (see Fig. 3) for additional tests. At atmospheric pressure, the flow straightening effect of the perforated plate fitted 10 D upstream from the vortex meter was at least as good as the effect produced by the tube-bundle flow straightener. Ruhrgas installed the perforated plate as shown by Fig. 3. The error of the perforated plate/vortex meter package and the error of the tube-bundle flow straightener/vortex meter package are compared in Fig. 4. Apparently, the slopes of the resonance peak are less steep for the perforated plate. The error for the package including the perforated plate was around 0 %.

The perforated plate tests have shown that

- the plate installed 10 D upstream from the vortex meter is not a flow disturbance itself and

- the error attributable to

  -- test rig resonance or
  -- flow irregularities caused, for instance, by a gate valve which is not fully opened,

  is not prevented by the perforated plate.

3 PILOT BOPP & REUTHER G 1600 VORTEX METER LABORATORY TESTS

As the resonance peaks of the q = 7,000 m^3/hr vortex meter always occurred at 10 % to 15 % of the maximum flow rate at which the frequency of vortex shedding is 15 to 21 Hz, it was decided that the frequency of vortex shedding should be moved to exclude, if possible, the test rig's frequency of 15 to 21 Hz from the meter's operating range. For this reason, a DN 150 Bopp & Reuther G 1600 vortex meter of a length of 2.3 D was tested.

The frequency of vortex shedding of the DN 150 meter is higher than that of the DN 250 meter, if the flow rate is the same. For this reason, Ruhrgas has assumed that resonance would not occur at the same flow rate as in the case of the DN 250 meter, but at a much smaller flow rate at which pulsation amplitudes are much lower.

To verify this assumption, pulsations were measured at the pressure tap of the meter, in the straight inlet piping and at a tee in the instrument line between the meter and the thermistor. The configuration is shown in Fig. 5 where Arrangement a shows the meter-plus-tube-bundle flow straightener package required by PTB and Arrangement c does not feature any disturbances. Measurements made at a flow rate of

9 % of the maximum flow rate	= approx. 220 m^3/hr = 19 Hz vortex shedding frequency (Bopp & Reuther 20 D straight inlet piping),
40 % of the maximum flow rate	= 1,000 m^3/hr = 87.5 Hz vortex shedding frequency (Bopp & Reuther 20 D straight inlet piping), and
40 % of the maximum flow rate	= 1,000 m^3/hr = 87.5 Hz vortex shedding frequency (using Bopp & Reuther 5 D outlet piping in front of the meter)

confirm the very low pulsation amplitudes at the test rig frequency and the elimination of resonance at a vortex shedding frequency of 87.5 Hz equivalent to the flow rate which caused resonance in the DN 250 meter case.

The meter was calibrated as delivered (PTB configuration) and also tested without any upstream flow disturbance using Bopp & Reuthers outlet piping in front of the meter.

The corresponding error curves a) and c) are shown in Fig. 6.

As had been anticipated, no resonance was found. The curve for the tube-bundle flow straightener/vortex meter package according to PTB specification was in the DN 150 case more than 1 % lower than the curve for the vortex meter without straightener. The apparent discrepancy between the DN 150 flow straightener/ vortex meter test data and the DN 250 flow straightener/vortex meter data is explained by the considerable flow restriction attributable to mating the ASA flanges of the test rig with the DIN flanges of the manufacturer's meter run (see Fig. 7).

To demonstrate that the flow restriction is the cause of a systematic error, configuration c was compared with a configuration in which the manufacturer's straight upstream and downstream piping was replaced by Ruhrgas piping not restricting flow (Arrangement d in Fig. 5).

The difference between curves c and d in Fig. 6 is more than 0.5 %, with curve d approaching curve a. The data confirm that the restriction of 4 mm at a point located 5 D upstream from the vortex meter (curve c) constitutes a considerable flow disturbance. On the other hand, the disturbance caused by the restriction in front of the tube bundle flow straightener in arrangement a is different from a disturbance exclusively attributable to a flow straightener. This difference may be the reason why curve a is still below curve d.

The tests of the DN 150 Bopp & Reuther vortex meter have shown that any recess upstream or downstream from the vortex meter must be avoided. Their effects may be eliminated by high-pressure calibration but they make an intercomparison between vortex meters difficult.

In a further test, Ruhrgas investigated the interaction between the radial position of the tube-bundle flow straightener and the position of the bluff body. In the case of the DN 250 vortex meter, the angle enclosed between the bluff body and the vertical plane through the center line of the flow straightener through the five tubes touching each other in this center line was nearly 0 °, while the same angle was approx. 30 ° in the case of the DN 150 vortex meter.

To study the effect of the angle on the error behavior of the meter, the tube-bundle straightener in configuration a depicted in Fig. 5 was turned by 90 °. In the new configuration b (60 ° angle between the bluff body and the 5-tube center line), the error increased, which is typical of an asymmetry effect (see Fig. 6).

All DN 150 tests have shown that

- the radial position of the tube-bundle flow straightener in the field must be the same as during the manufacturer's calibration tests,

- an intercomparison between the Bopp & Reuther DN 250 and DN 150 vortex meters is impossible because of the simultaneous changes of several parameters, including the fact that,

    -- in the case of the DN 250 vortex meter run, the vortex meter flanges are narrower than the flanges of the upstream and the downstream piping and the piping itself, while, in the case of the DN 150 vortex meter run, the vortex meter diameter is wider than the diameter of the downstream piping and the inlet flange of the upstream piping as well as the outlet flange of the downstream piping are narrower than the inlet and outlet pipes themselves, and

    -- the angle enclosed between the bluff body and the symmetrical axial plane of the tube-bundle flow-straightener is not the same for the two vortex meters.

  and

- asymmetry effects make an intercomparison difficult although the asymmetry effect is eliminated by high-pressure calibration.

4 EFFECTS OF A SINGLE 90 ° UPSTREAM BEND MEASURED BY LABORATORY TESTS

Using a Bopp & Reuther DN 250 vortex meter run, Ruhrgas also tested the effectiveness of

- the tube-bundle flow straightener incorporated in the 20 D straight upstream piping as specified by PTB,
- the perforated plate installed 10 D upstream from the vortex meter as proposed by the manufacturer.

As tests investigating the effect of installation conditions are relative in nature, the vortex meter assembly was first calibrated with 61 D upstream piping (Arrangement a, Fig. 8) before the vortex meter preceded by the tube-bundle flow straightener assembly (Arrangement b, Fig. 8) and the vortex meter preceded by the perforated plate assembly (Arrangement c, Fig. 8) were mounted directly downstream from a single 90 ° bend. The length of the straight piping upstream from the 90 ° bend was in excess of 10 D. The meter error was recorded at pressures of 13 and 20 bar. Since the test was carried out to study the effectiveness of flow straightening devices, Ruhrgas did not explore the reasons for the high positive error reflected by the base calibration curve (curve a in Fig. 9). It may be due to liquid adhesion on the thermistor.

The 90 ° bend immediately upstream from the tube-bundle flow straightener assembly increased the positive error by about 1 % (see curve b, Fig. 9). The performance of the perforated plate was not better than the straightening effect of the tube bundle arrangement (see curve c, Fig. 9). If it is assumed that the base calibration curve for the perforated plate/vortex meter package is below the curve for the tube bundle straightener/vortex meter package (as was the case for the tests discussed in Section 2, and the geometries were the same in the two cases), the systematic error due to the flow disturbance was even greater in the case of the perforated plate configuration.

Ruhrgas also measured the velocity profile at the outlet of the inlet piping specified by PTB when installed downstream from the single 90 ° bend. Fig. 10 shows the bend/flow straightener configuration and the location of the pitot tube measurement. The asymmetric velocity profiles depicted in Fig. 11 for $Re = 2.8 \times 10^6$ and in Fig. 12 for $Re = 5.5 \times 10^6$ were measured along two diameters in one plane. The profile does not satisfy the acceptable velocity profile conditions allowing a maximum deviation of ± 5 % from a swirl-free and fully developed flow profile as specified by ISO standard 5167.

The 90 ° bend test has shown that

- 20 D straight upstream piping incorporating a 2.5 D tube-bundle straightener does not warrant reproducible flow at the vortex meter inlet irrespective of upstream installation conditions,

- the systematic error produced by an upstream 90 ° bend is unacceptable, if compared with a turbine flow meter, and

- a perforated plate installed 10 D upstream from the vortex meter does not improve on the performance of the package incorporating the tube-bundle flow straightener.

As the high-pressure natural gas tests of Bopp & Reuther vortex meters were unsatisfactory, Ruhrgas intends to go ahead with a new research programme together with Gaz de France in order to define optimized general installation conditions for vortex meters. These tests will explore the potential of other types of flow straighteners as well as the effect of changing the distances between the upstream flow disturbance and the flow straightener as well as the distance between the flow straightener and the meter.

5. FIELD TESTS OF RMG MESSTECHNIK VORTEX METERS

At metering stations at which flow rates are in excess of q_n = 5,000 m³/hr, Ruhrgas checks its custody transfer turbine flow meters at monthly intervals by a series connection of the meter used for sales gas measurement and the standby turbine flow meter in order to identify drift of the custody transfer meter at an early date (see Fig. 13). These monthly checks help to detect meter wear or meter defects. As an intercomparison between two meters using the same measure principles or between two meters of the same design is not ideal, Ruhrgas installed vortex meters connected in series with turbine meters at some 20 metering stations for check measurement. At all but one stations, RMG Meßtechnik vortex meters are in operation because good high-pressure performance of these meters was demonstrated some time ago.

The check vortex meters do not only provide valuable field data for an evaluation of the vortex shedding technique, but also minimize metering station inspection requirements, as gas measurement engineers do not have to visit the stations at regular intervals, but only when a flow computer or a comparator generates an alarm (transmitted by cable system) because the difference between the flow measured by the turbine meter and the flow measured by the vortex meter exceeds a defined limit, or because a continuous drift is registered. This check measurement technique promises substantial cuts in metering station inspection man-hours.

Vortex meters are not used for custody transfer measurement in the Ruhrgas system for two main reasons:

- It still seems unclear what minimum straight upstream piping is required.

- If flow fluctuates, it is uncertain how often resonance will occur during one hour over which the sensor pulses are totallized. As the pipework frequencies are unknown, total quantities of gas delivered, for example, during one hour and, even more so, over the course of one month may and will reflect systematic errors.

Three different types of series connection have been used by Ruhrgas (see Fig. 14). Fig. 15 shows the layout at the Birlinghoven station which was the first station to be equipped with the vortex meter in October 1983. At this station, a U-type series connection configuration was used. For this type of connection, design requirements for the metering station are determined by the length of the vortex meter run. The turbine meter run is designed accordingly. The diameter of the vortex meter run is one size smaller because the meter has no moving parts. Fittings are stored at the station site to replace the meter in the case of a defect when the meter must be removed from service. During the short time required for installing the fitting, the station must be bypassed.

A comparator is installed to compare the output signals from the two meter runs. In addition, the registrations of the two meters have been compared at the Ruhrgas headquarters since October 1983. Fig. 16 plots the monthly outputs of the two volume correctors. No correction was made for the systematic error found during the high-pressure calibration of the vortex meter. Nevertheless, the maximum deviation of the flow measured by the vortex meter from the flow measured by the turbine meter of + 0.6 % is relatively small, considering that it reflects differences between two meters at a field station which do not even vary abruptly. The difference is approximately equivalent to the difference between the two high-pressure calibration curves at 30 % of rated flow. In fact, average flow through the Birlinghoven station was about 30 % of the rated flow of the two meters during the periods from October 1983 to summer 1985.

Malfunctions and failures occurred in August 1985 following an unexplained drift of the vortex meter starting in March 1985. The positions of the two meters were exchanged in November 1985. After the modification to the set-up, gas passed through the vortex meter first. Some further failures troubled operations in 1986 and were followed by a last defect in June 1987. Since the summer of 1987, the metering station has been out of service or operated at less than 5 % of rated flow.

To compare the field data and the laboratory data, the vortex meter field records must be corrected for the error which would have been eliminated by a high-pressure calibration. Further, it is essential to account for operating conditions before and after the exchange of the turbine meter and the vortex meter. Finally, it is important to note that flow through the Birlinghoven station was always relatively constant between the meter failures. The flow rate did not fluctuate and it is therefore unlikely that any resonance occurred if pulsation eigenfrequencies in the range of vortex shedding frequencies really exist. No piping vibrations have been observed at the station.

As Fig. 16 shows, differences between the vortex meter output and the turbine meter output seem to have hardly changed as a result of the change in the order in which the two meters were installed. The two meters did thus not interfere with each other. It even seemed as if the 20 D upstream piping configuration specified in the PTB type-approval certificate would be sufficient because two upstream U-configuration bends did not seem to shift the difference between the turbine flowmeter and the vortex meter flow data compared with the 90° single bend installation upstream of the flow straightener/vortex meter package since November 1985.

If the few data are analyzed, though, it becomes apparent that the meter run configuration at the Birlinghoven metering station did affect the vortex meter behaviour. Prior to the change in the order of the two meters, the systematic error of the vortex meter (by reference to the turbine meter) was between + 0.2 and + 0.4 % for an average flow of approx. 30 % of the rated meter flow rate. For this flow rate, the actual flow data of the vortex meter must be corrected by approx. - 0.7 % and the actual flow data of the turbine meter by - 0.25 % (see calibration curve, Fig. 17). If this correction is made, the systematic error of the vortex meter (again by reference to the turbine flowmeter) is between - 0.26 and - 0.05 %. Following the exchange of the two meters, flow was never above 23 % of the design flow rate. The systematic error of the vortex meter (by reference to the turbine meter) was in an interval around + 0.5 to + 0.55 %. If the actual flow data are again corrected in accordance with the calibration curve data for the low flow, the remaining systematic error of the vortex meter is between + 0.3 and approx. + 0.8 %. The vortex meter data are higher than those for the turbine meter; prior to the change, the relation was the opposite.

The field tests of the RMG Meßtechnik vortex meters have shown that an upstream single bend substantially increases the flow measured by a vortex meter as compared to the flow measured by a vortex meter installed downstream of a U-pipe two-bend configuration, if a turbine flow meter is taken as a reference.

It has also been shown that a Z-configuration upstream of a vortex meter is the cause of a substantial negative error often in excess of - 1 % (by reference to a turbine flowmeter).

These conclusions from the Ruhrgas field tests are very preliminary, though, because unknown pressure, temperature and volume corrector uncertainties, unknown flow fluctuations during the periods for which the comparisons were made and other parameters may be misleading with regard to the conclusions drawn for the interaction between installation conditions and vortex meter behaviour.

The tests seem to confirm, though, that the minimum 20 D straight upstream piping length specified in the type approval certificate is also insufficient for the RMG vortex meter.

The trial operation of the vortex meters has also indicated another potential source of error. Even if the station is out of service, the vortex meter occasionally generates flow pulses as if gas passed through the station. At stations which do not operate continuously or where flow is frequently less than 5 % of the design meter flow rate, these spurious pulses may be the cause of major differences between the monthly volumes measured by the two different meters. The intercomparison data uncertainty is increased by the automatic blockage of the meter dials at low flow rates which take place at different times. This uncertainty is caused in the stations by the considerable uncertainties associated with calibration curves for flows of less than 5 % of rated flow. The Ruhrgas field tests did not reveal whether the large volume differences at low flow rates are attributable to the vortex meter or to the turbine meter.

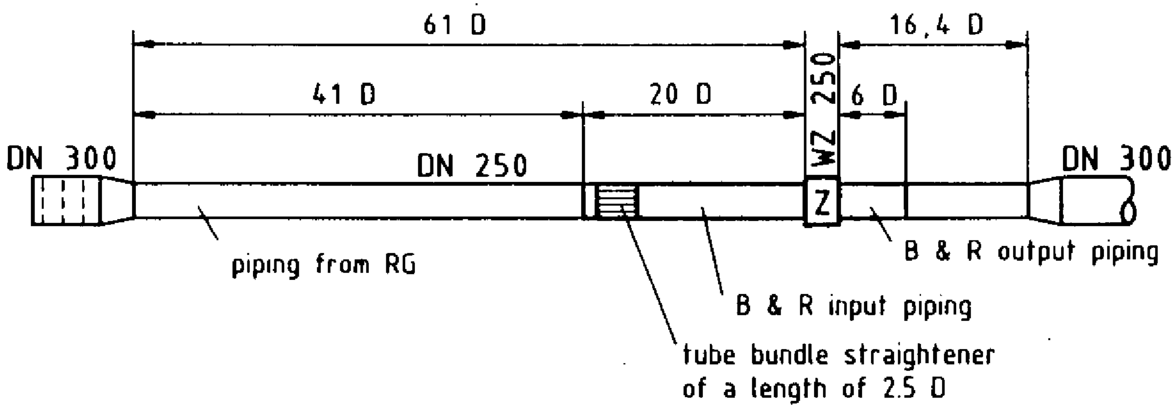
The Ruhrgas field trials have finally pinpointed the following weaknesses of the vortex meter system:

- The absence of a mechanical dial makes it difficult to determine flow in the event of a power failure.
- The pressure drop across the vortex meter package varies substantially as a function of flow.
- The 1 : 20 rangeability of the vortex meter is small by comparison with the 1 : 50 rangeability of the turbine flowmeter.
- Turbine flowmeters even measure reasonably accurately when flow drops to the minimum flow rate for the meter while the vortex meter behaviour is very erratic at low flow rates.

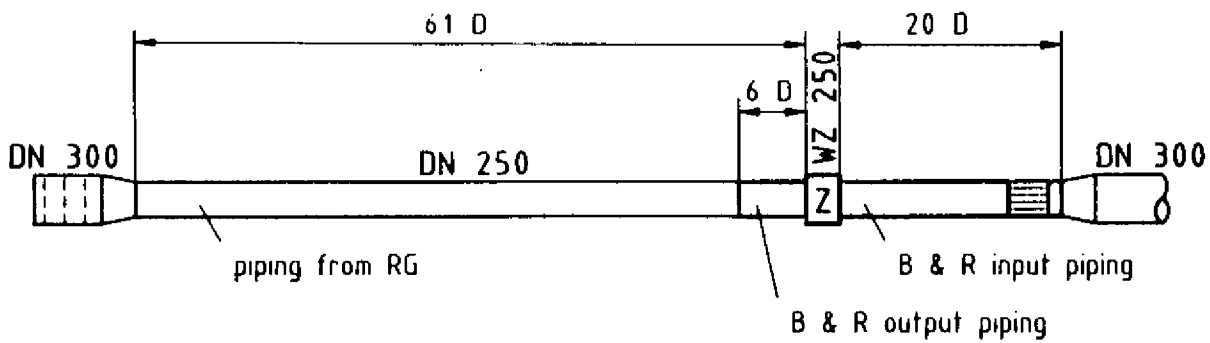
Both the laboratory test results and the evaluation of the field tests have not been sufficiently encouraging to justify the exclusive use of vortex meters at Ruhrgas custody transfer metering stations.

Installation Arrangement for Vortex Meter Testing
(Bopp & Reuther WZ 250)

a) with 20 D input piping according
to PTB requirements



b) without any disturbance

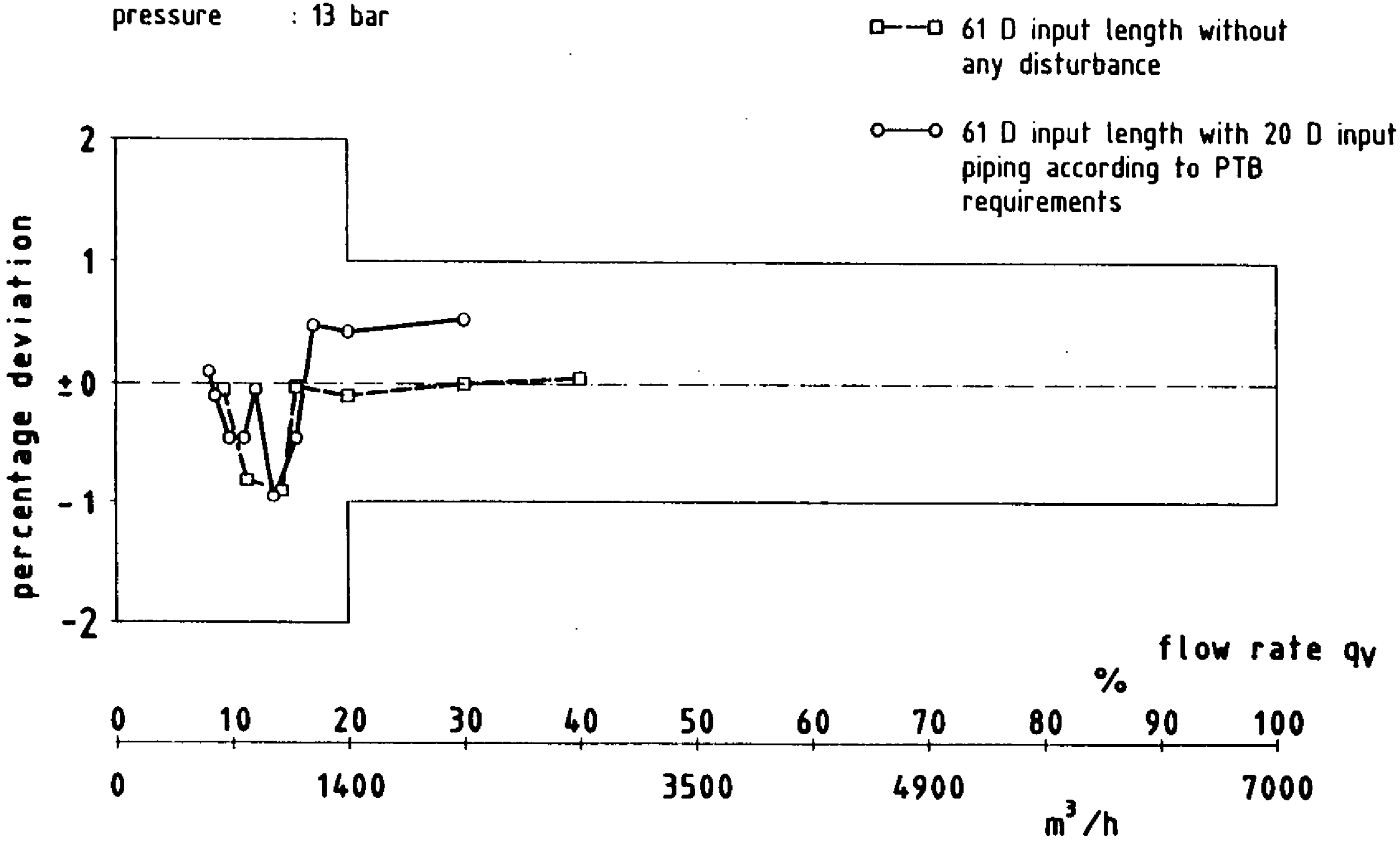


Meter to be tested

manufacturer : Bopp & Reuther
type : WZ 250
pressure : 13 bar

Reference orifice plates
(corner tapping)

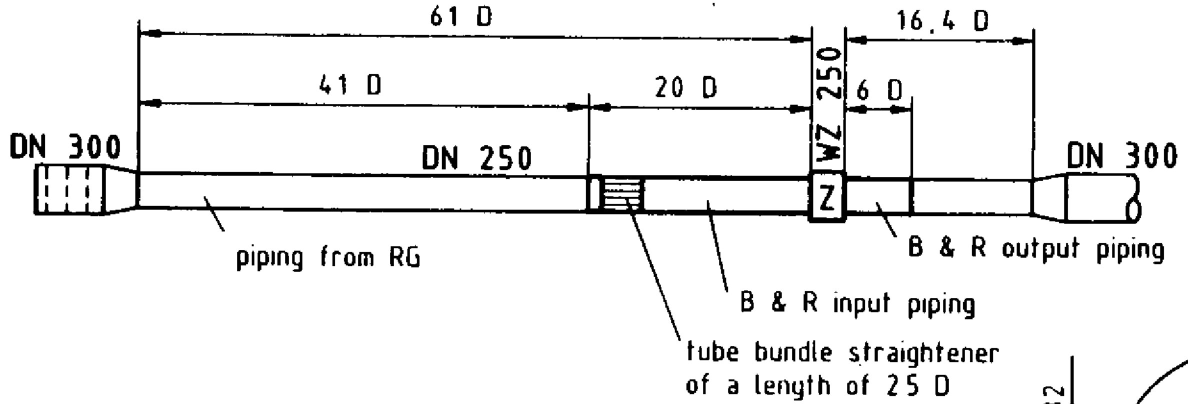
Nr. : 20.1 - 20.5
d(mm) : 132,02

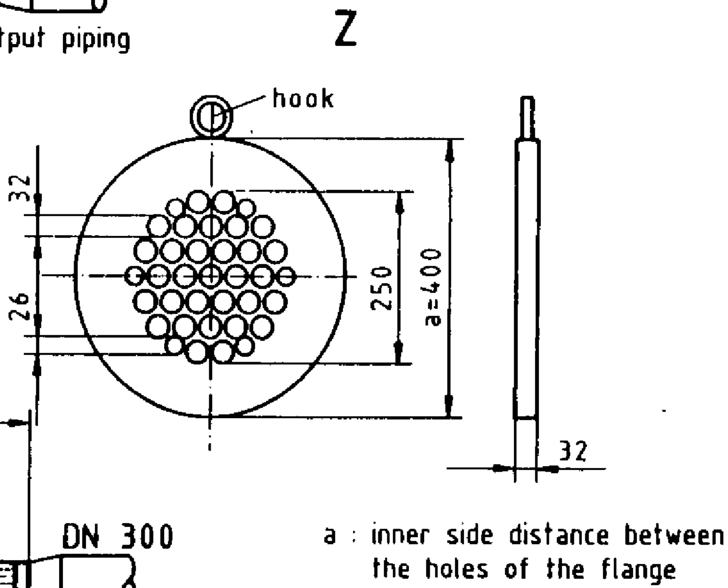


②

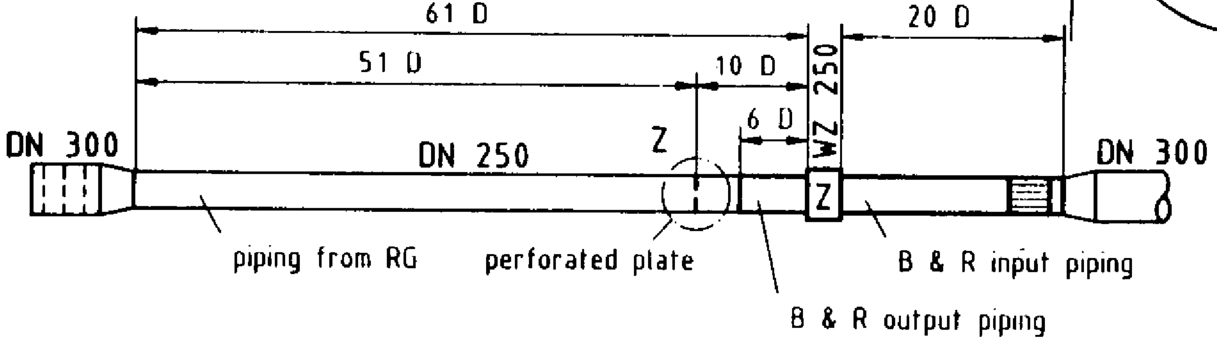
Installation Arrangement for Vortex Meter Testing
(Bopp & Reuther WZ 250)

a) with 20 D input piping according to PTB requirements





b) with perforated plate at a distance of 10 D

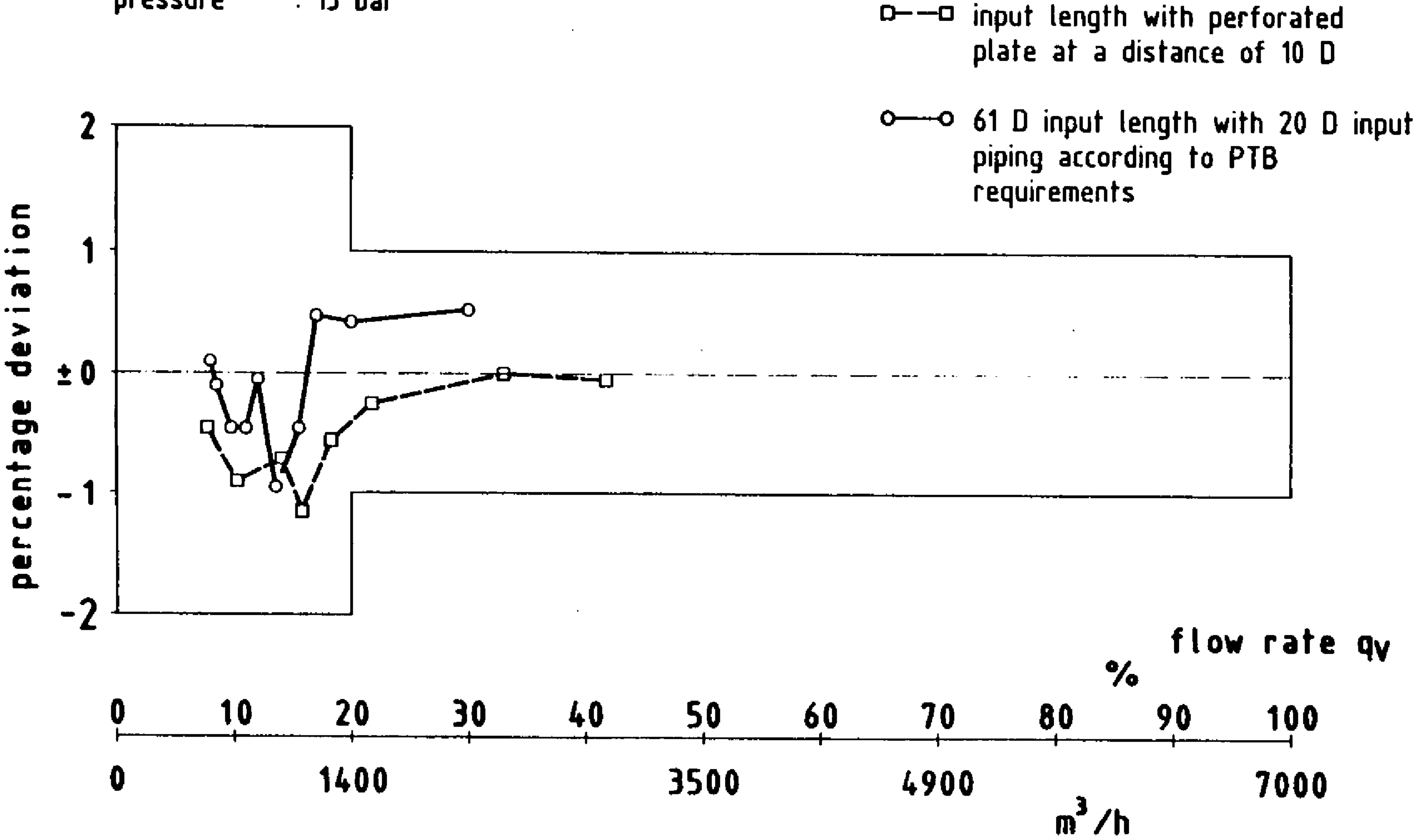


Meter to be tested

manufacturer : Bopp & Reuther
type : WZ 250
pressure : 13 bar

Reference orifice plates
(corner tapping)

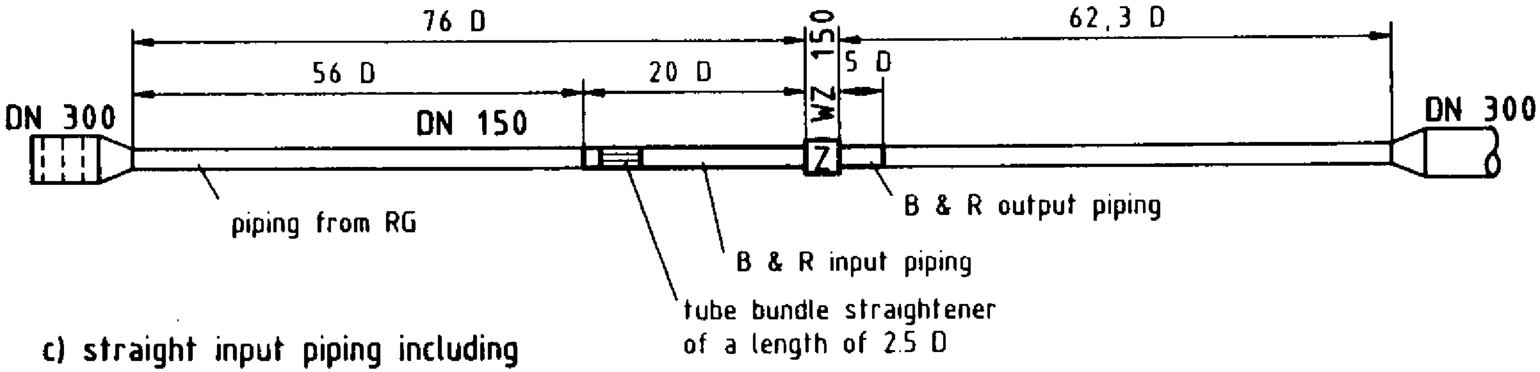
Nr. : 20.1 - 20.5
d(mm) : 132,02



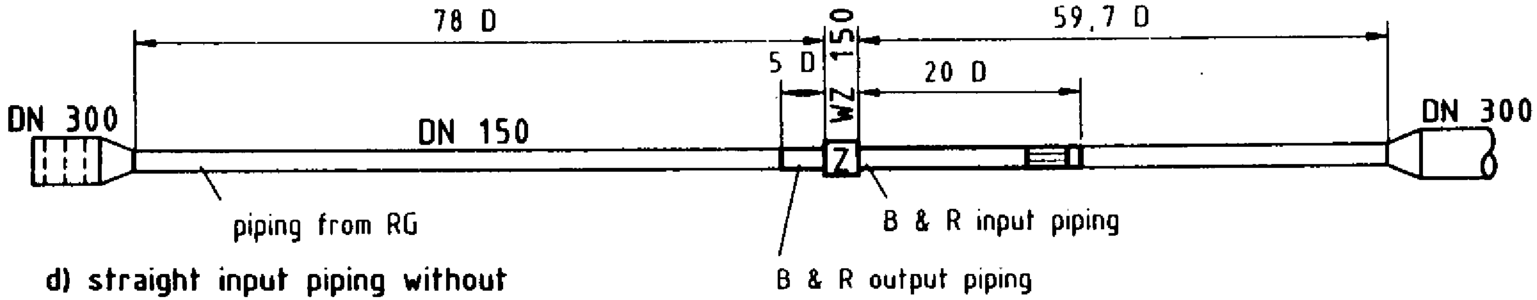
7

Installation Arrangement for Vortex Meter Testing (Bopp & Reuther WZ 150)

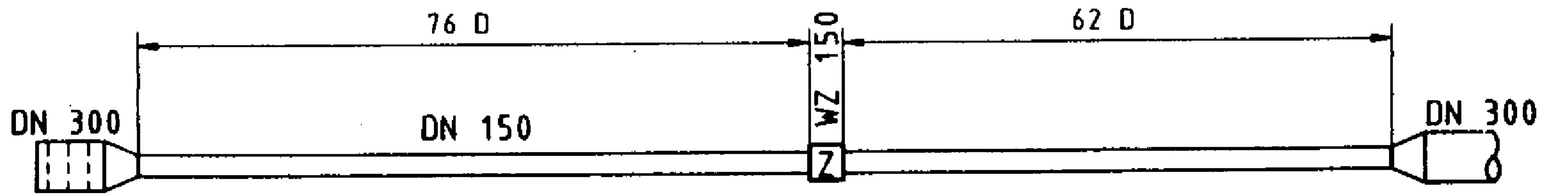
a) straight input piping including the B & R input spoolpiece



c) straight input piping including the B & R output spoolpiece



d) straight input piping without any B & R spoolpiece



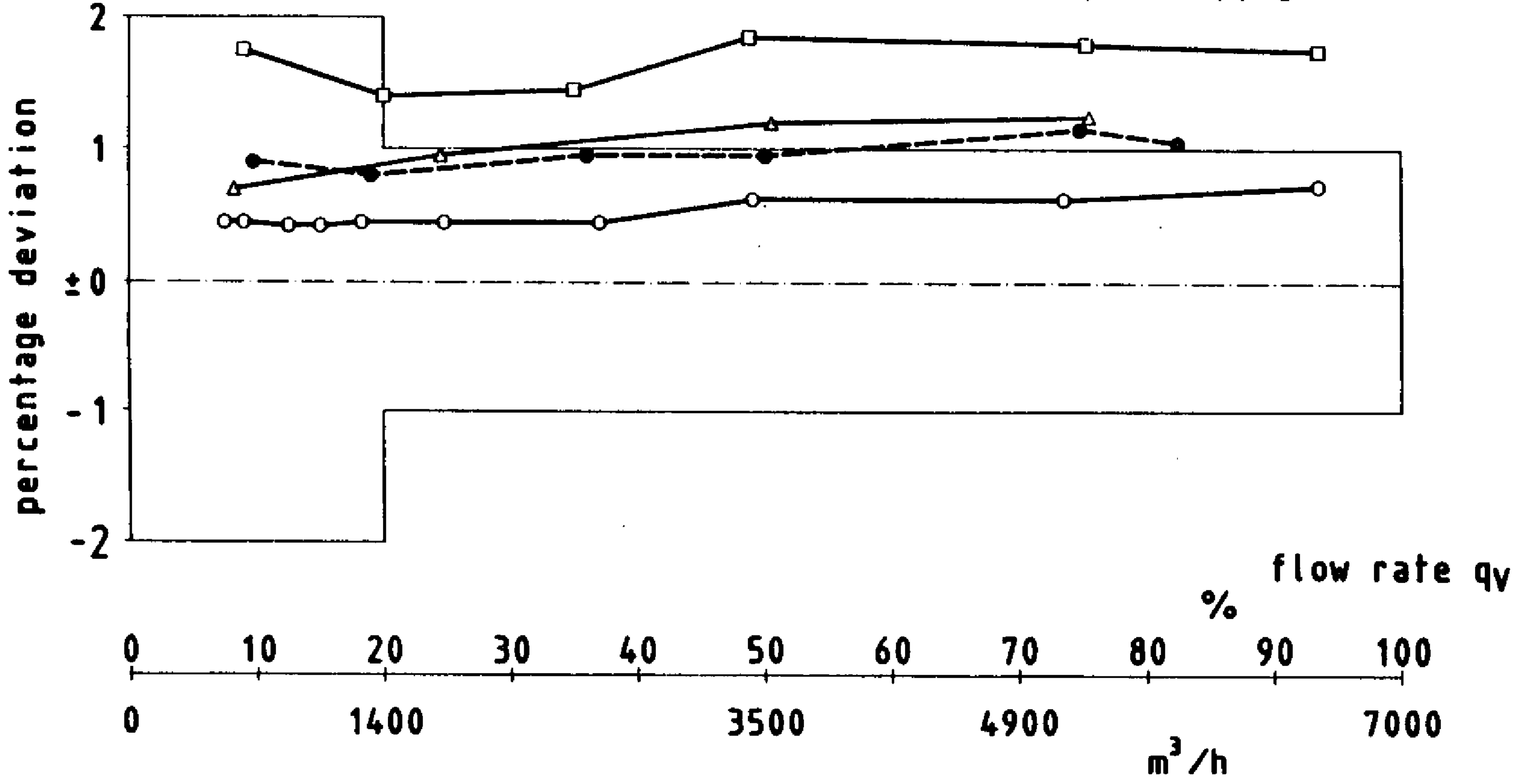
Meter to be tested

manufacturer : Bopp & Reuther
type : WZ 150
pressure : 13 bar

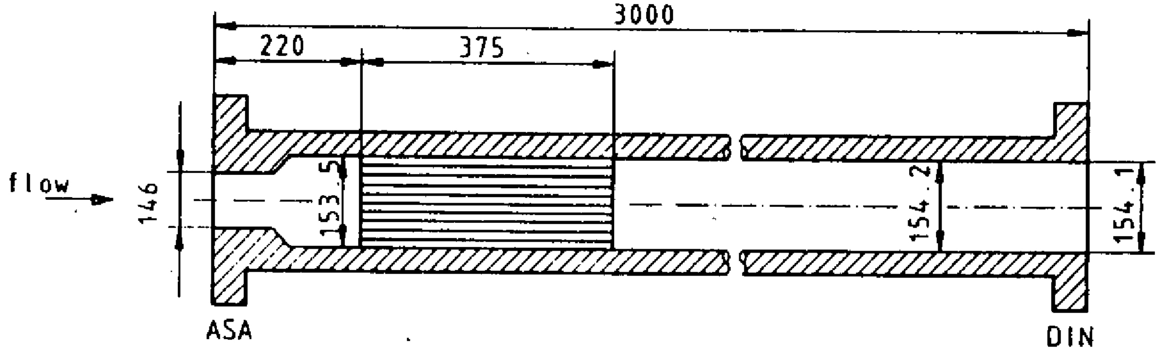
Reference orifice plates
(corner tapping)

Nr.:	d(mm)
14.1	87.41
20.2	132.02
20.3	132.02

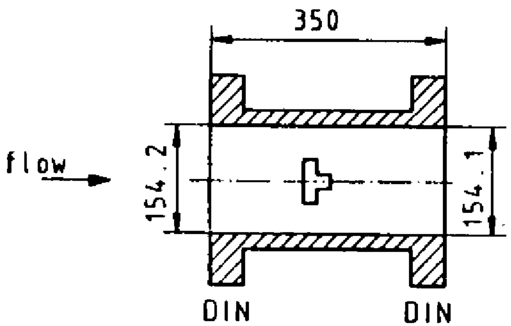
a) o—o including the 20 D input spoolpiece of B & R
b) Δ—Δ same arrangement, but the straightener turned by a 90° angle
c) □—□ the input piping including the B & R outlet spoolpiece
d) ●—● without any disturbance and without any B & R piping



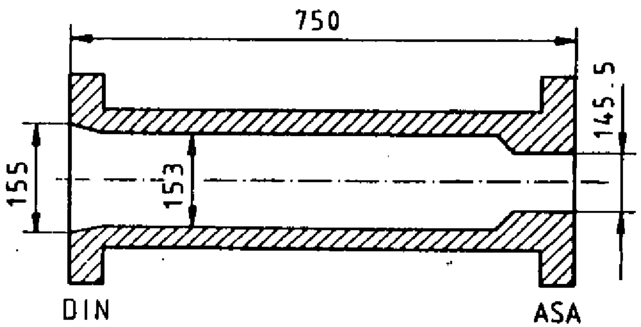
Dimensions of Bopp & Reuther piping WZ 150



input piping of a length of 20 D



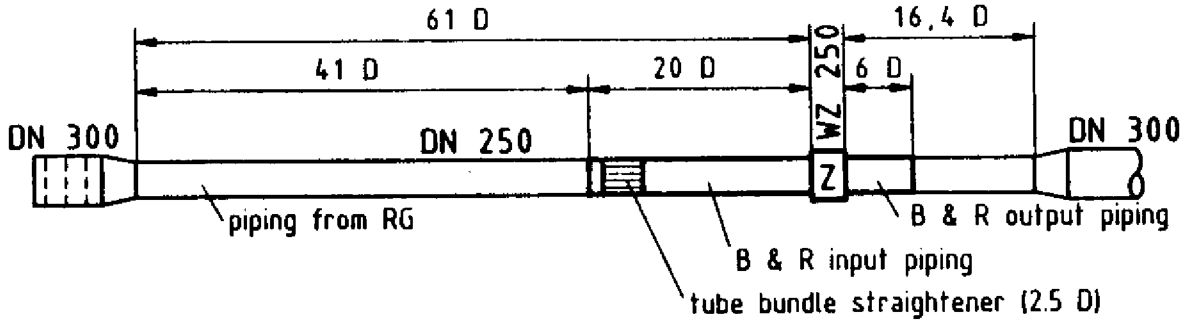
WZ 150



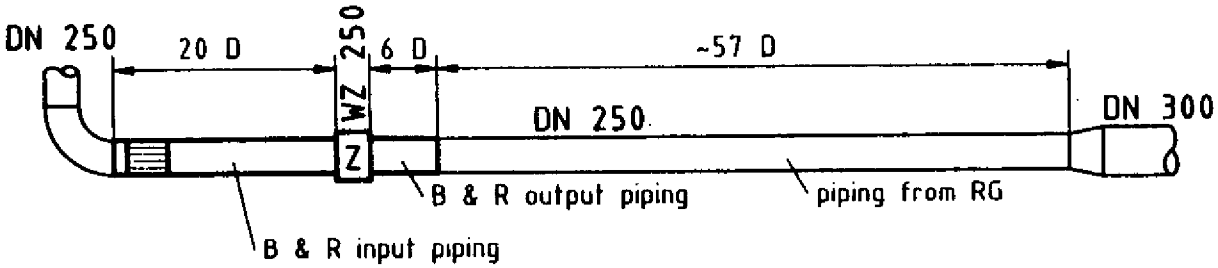
output piping of a length of 5 D

Installation Arrangement for Vortex Meter Testing
(Bopp & Reuther WZ 250)

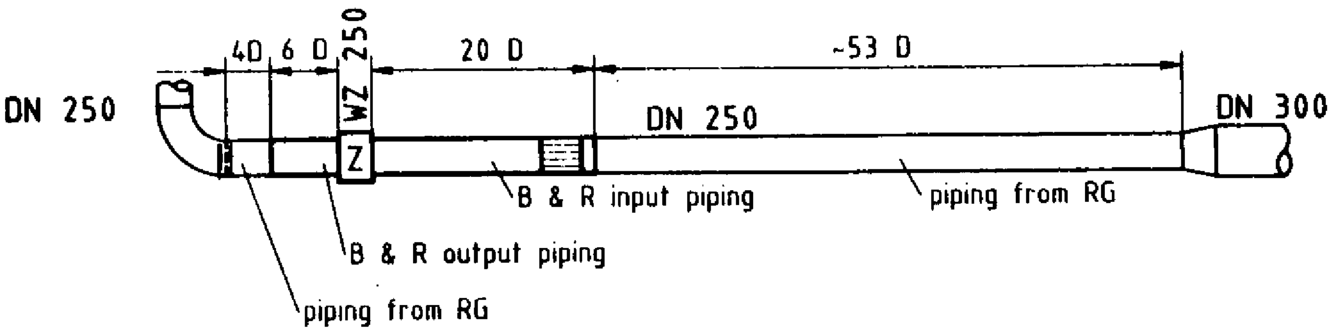
a) baric calibration with 20 D input piping according to PTB requirements



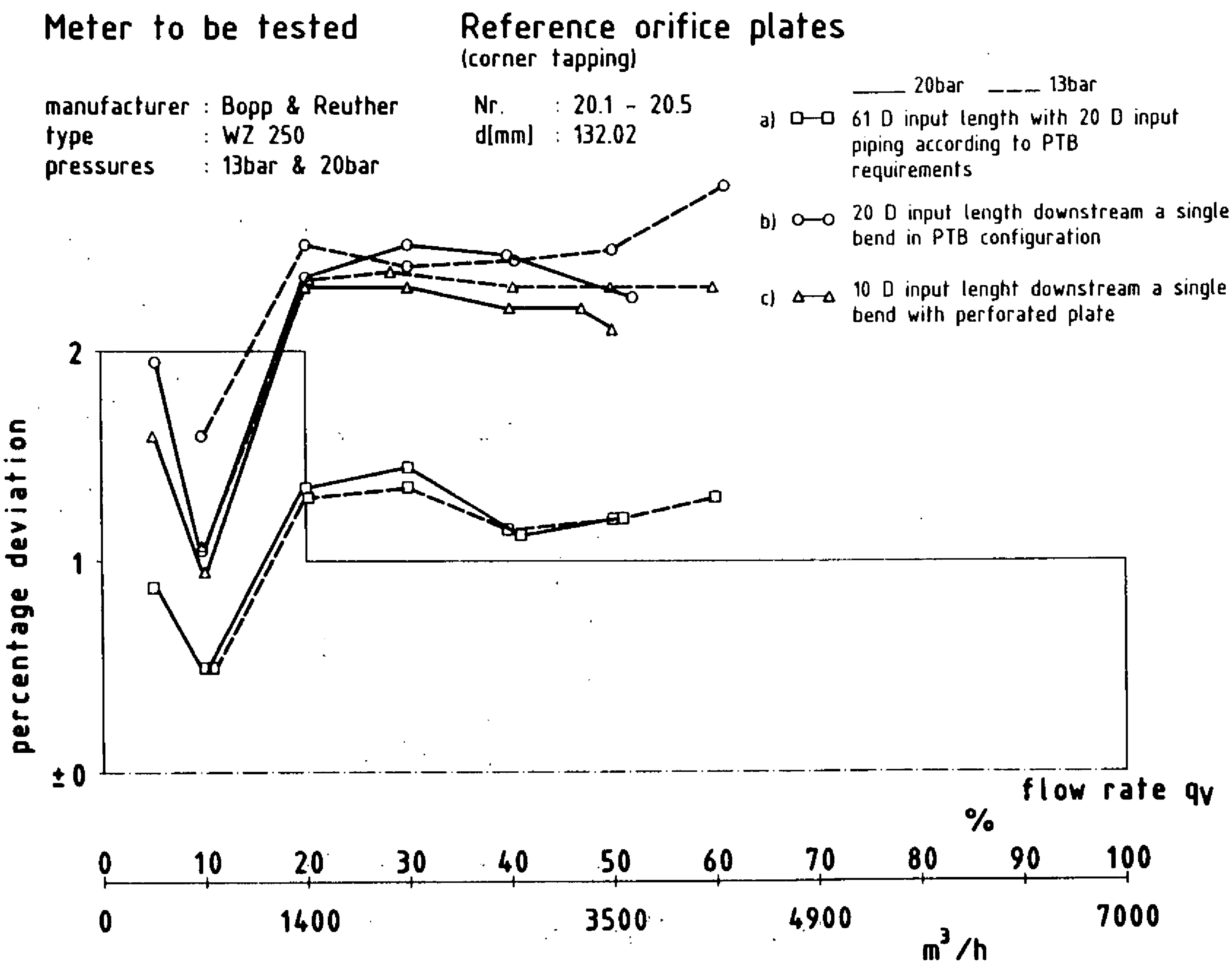
b) installation downstream of a single bend in PTB configuration



c) installation downstream of a single bend in a distance of 10 D with perforated plate



8

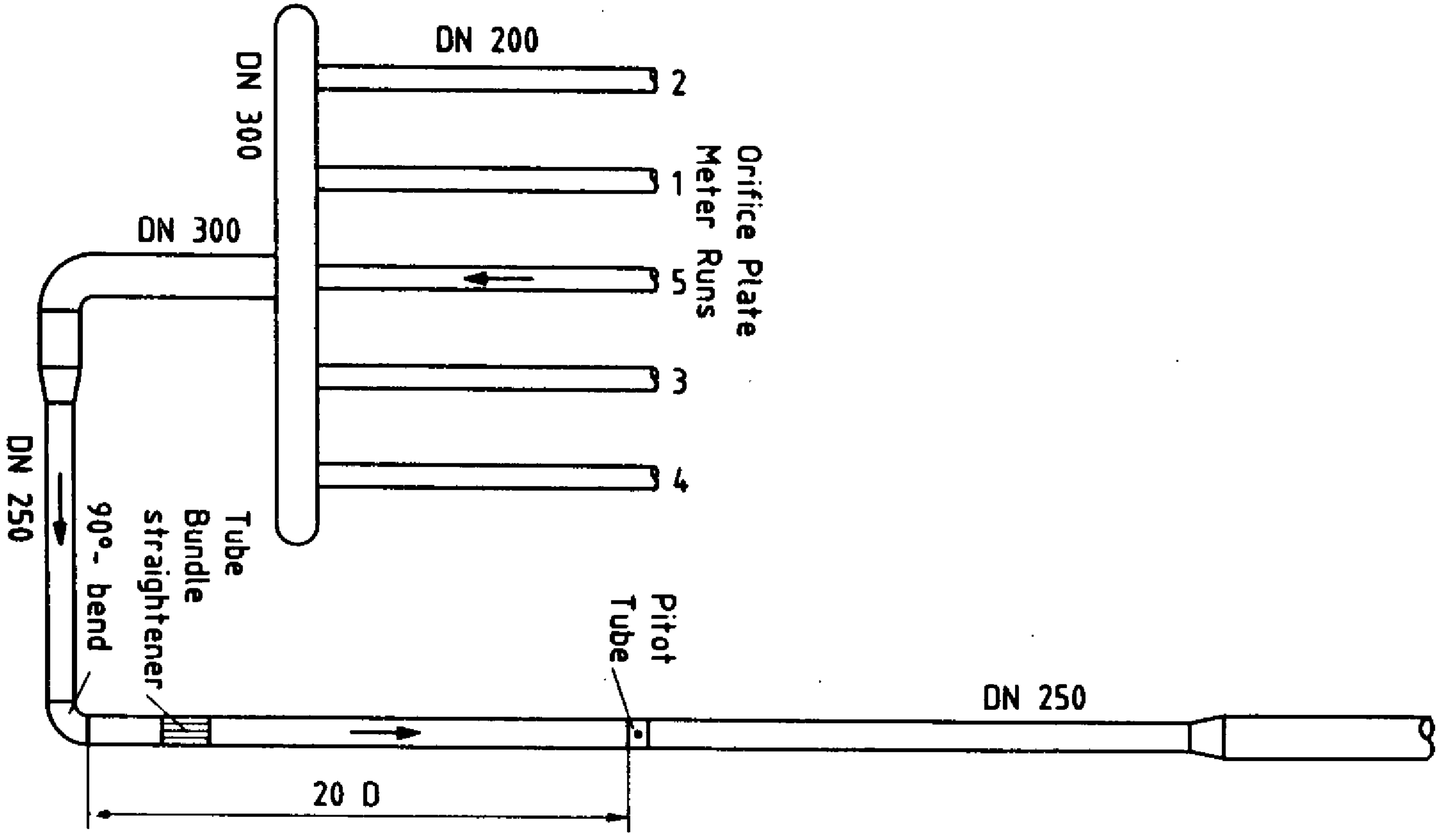


Meter to be tested
manufacturer : Bopp & Reuther
type : WZ 250
pressures : 13bar & 20bar
Reference orifice plates
(corner tapping)
Nr. : 20.1 - 20.5
d[mm] : 132.02
20bar 13bar
a) 61 D input length with 20 D input piping according to PTB requirements
b) 20 D input length downstream a single bend in PTB configuration
c) 10 D input lenght downstream a single bend with perforated plate
percentage deviation
2
1
±0
flow rate qv
%
0 10 20 30 40 50 60 70 80 90 100
0 1400 3500 4900 7000
m³/h

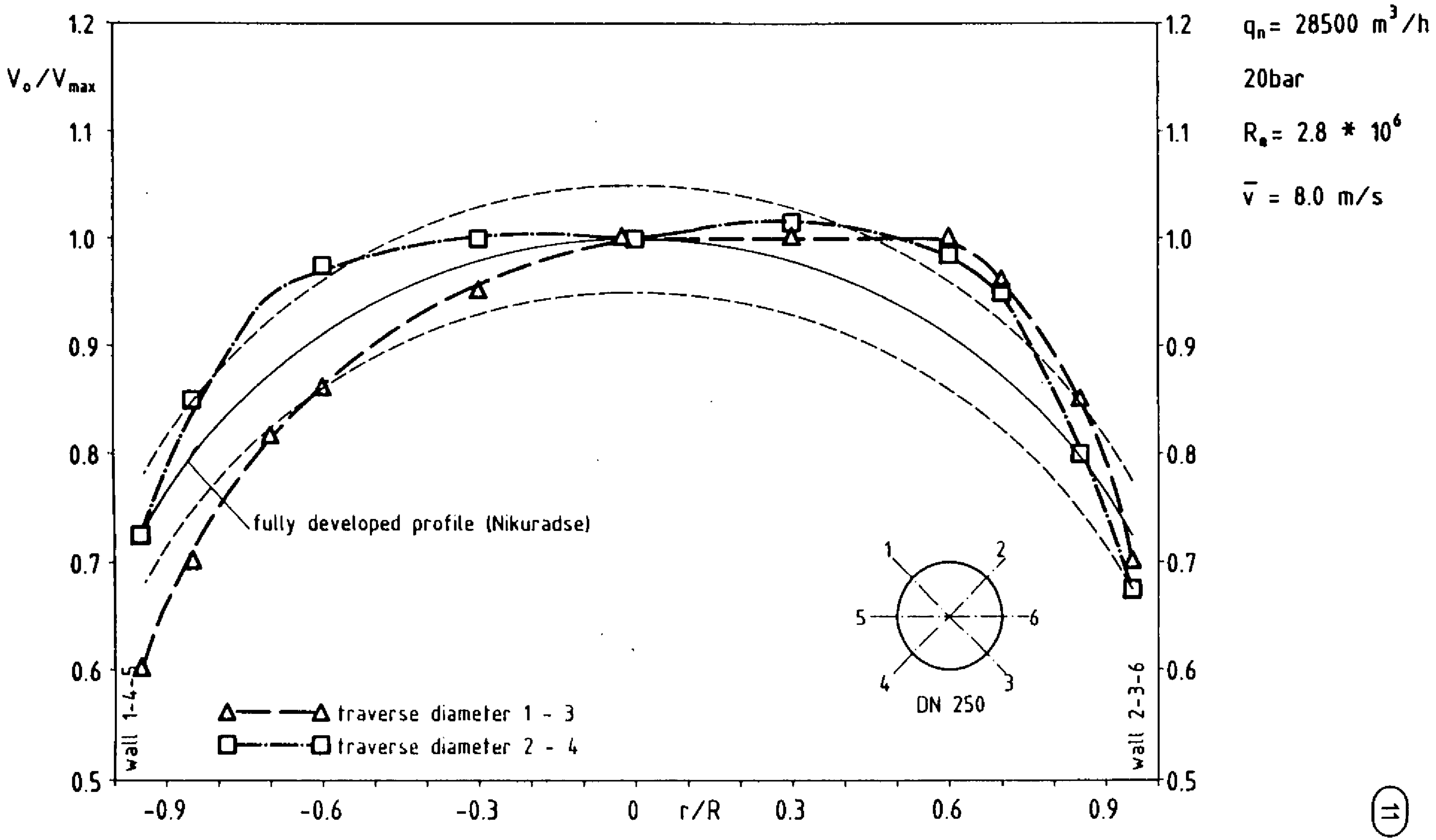
6

Installation Position of Pitot Tube

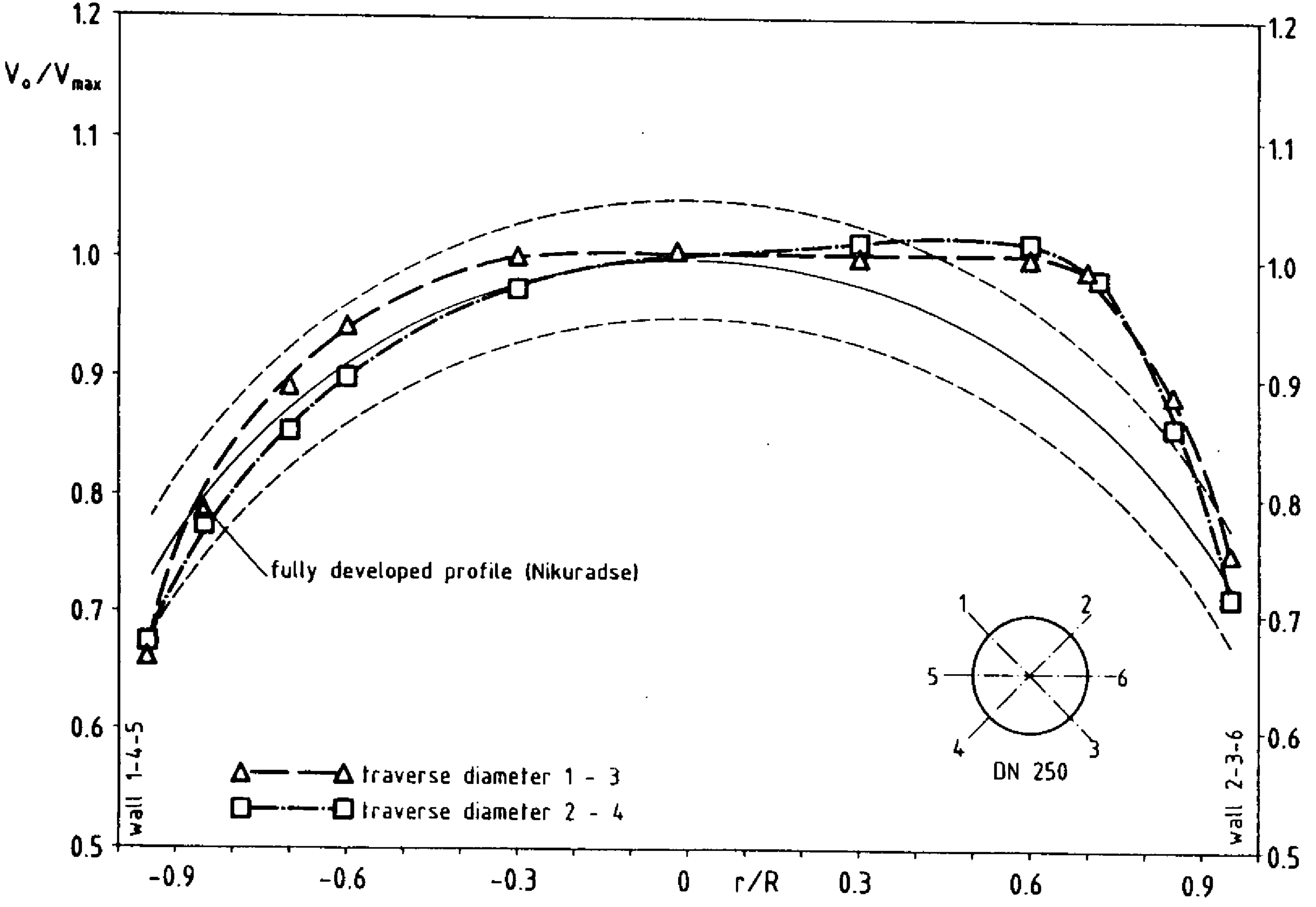
Measurement of Flow Profile at the Outlet of the Input Piping (length 20 D), when installed immediatly downstream a single bend



Axial Velocity Profile Downstream the Input Piping According to PTB, when installed downstream a single bend



Axial Velocity Profile Downstream the Input Piping According to PTB, when installed downstream a single bend



$q_n = 55000\ m^3/h$

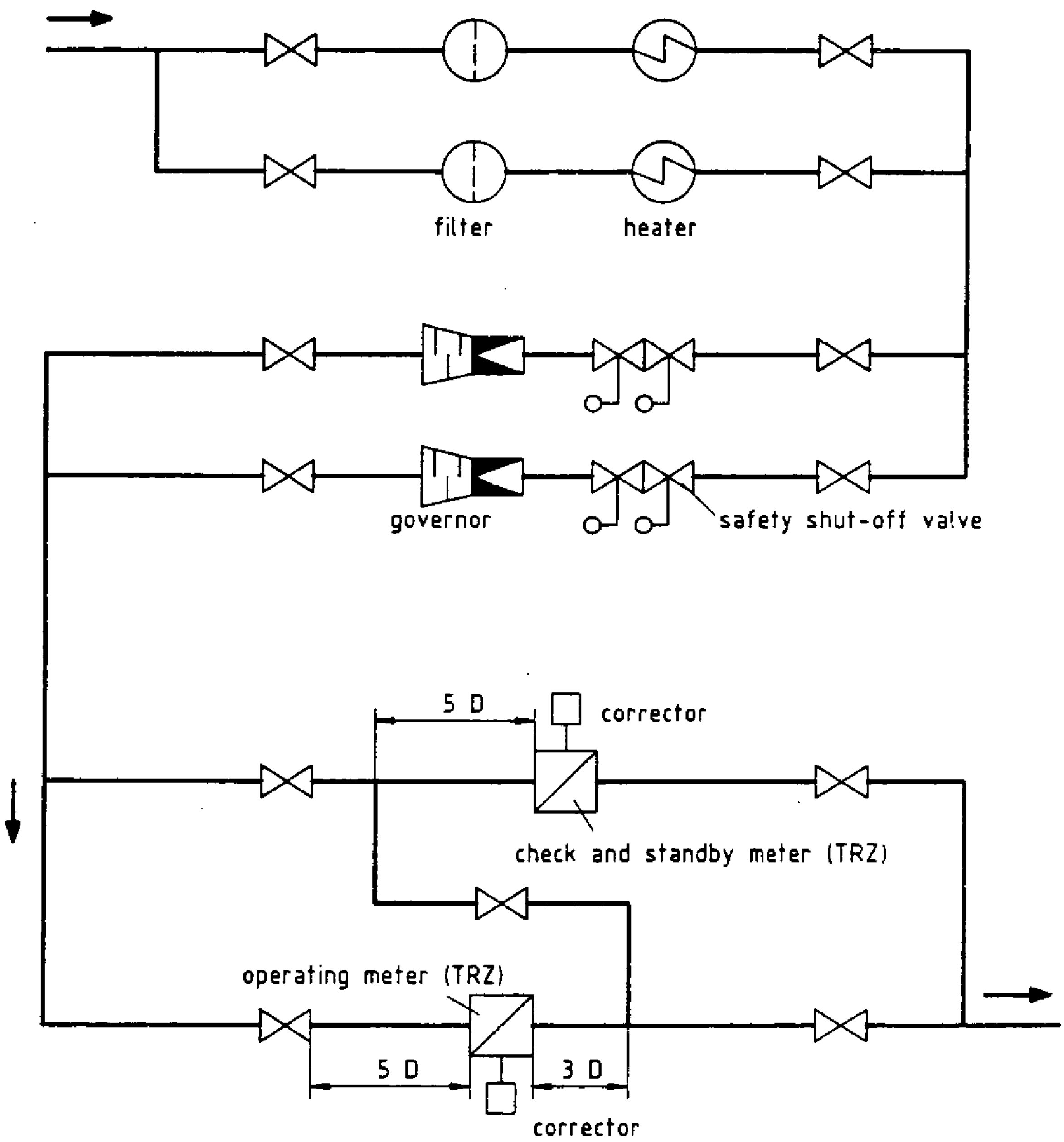
20bar

$R_e = 5.5 * 10^6$

$\bar{v} = 15.6\ m/s$

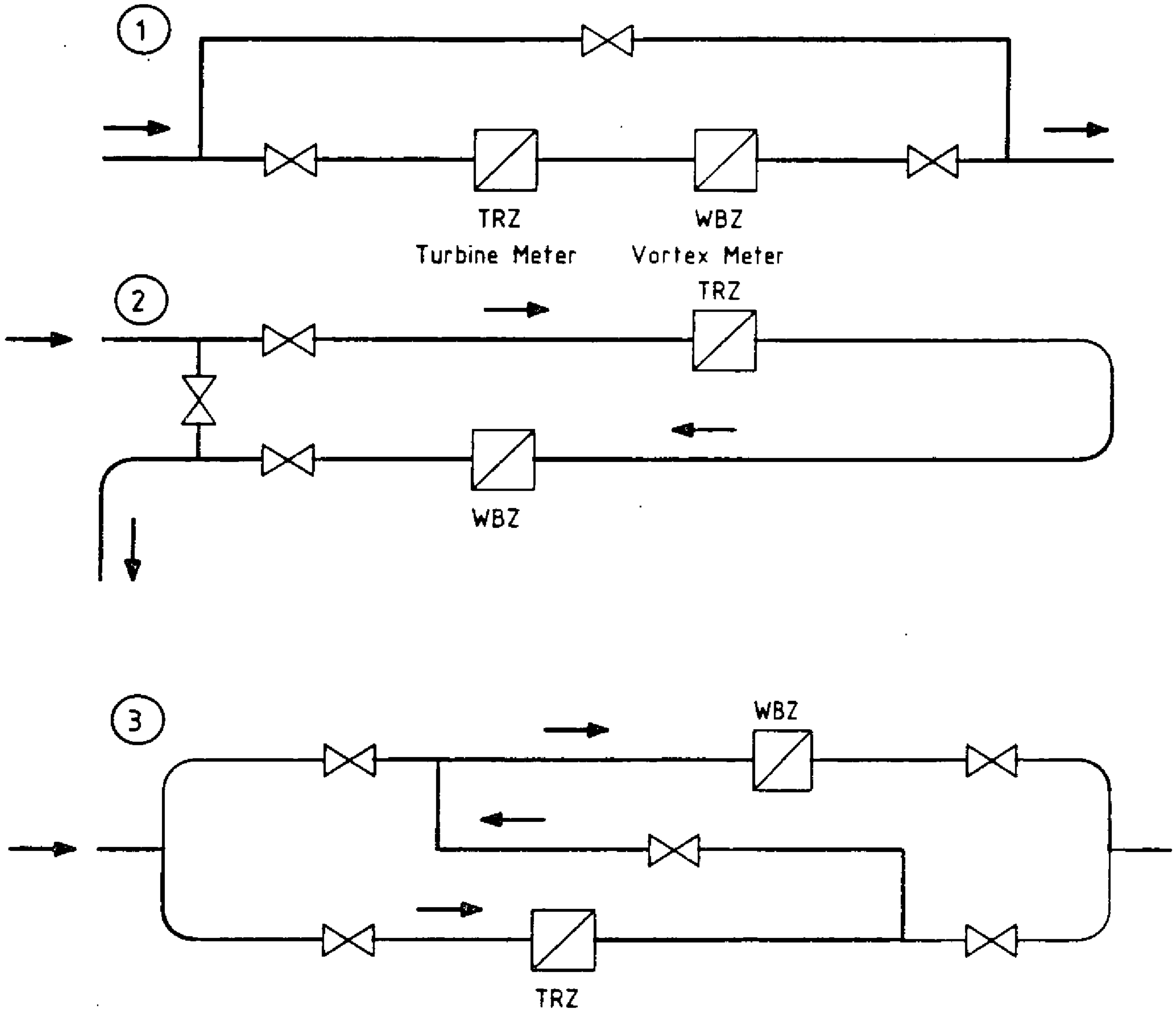
Measuring Station with a Check Meter

13

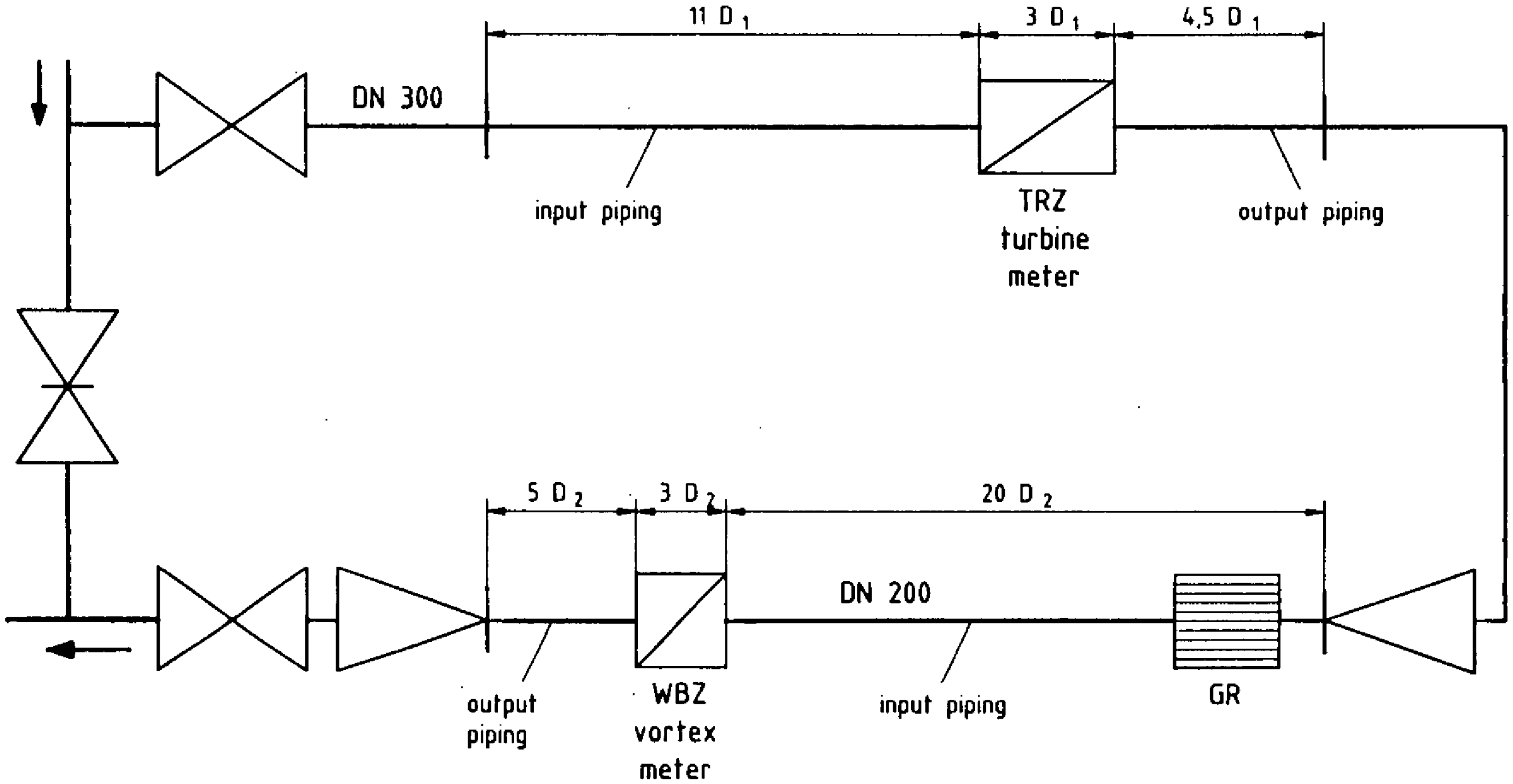


Measuring Stations with Turbine Meter and Vortex Meter in Series

Three Types of Arrangement:

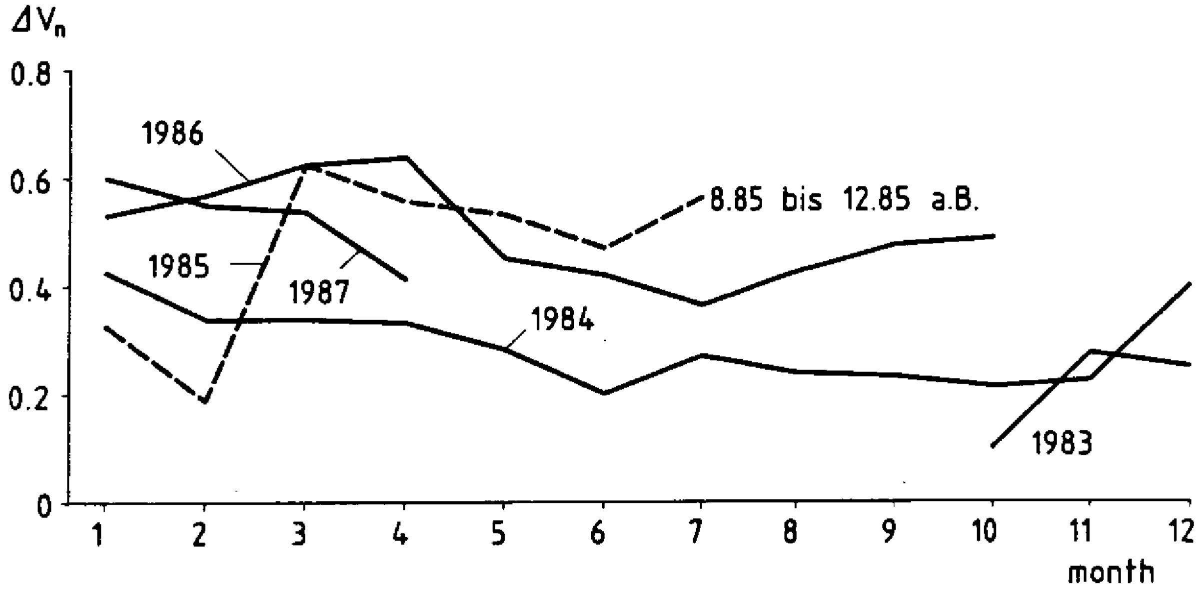


Measuring Station Birlinghoven with Turbine Meter and Vortex Meter in Series



Intercomparison between a Turbine Meter (100 %) and a Vortex Meter

Measuring Station : Birlinghoven



1.84 to 11.85 Flow through : 1.TRZ 2.WBZ
12.85 to 12.86 Flow through : 1.WBZ 2.TRZ

TRZ : Instroment, G 2500, DN 300, ANSI 600
WBZ : RMG, G 2500, DN 200, ANSI 600

Pressure : 45 bar to 65 bar
mean flow rate 20 % to 40 % 83/84
mean flow rate <20 % 86/87

OPERATING EXPERIENCE WITH A COMPACT PROVER - II

By G Groeneveld and P.A.M Jelffs

INTRODUCTION

Experience with Waugh compact provers over several years has permitted a detailed examination of the performance of the provers and of various types and sizes of turbine meters on products ranging from gas oil to LPG.

Also the methods for calibrating the compact prover have been investigated in terms of establishing reconciliation between base volumes determined by waterdraw and master meter/prover tank.

The methods employed in estimating the repeatability or "random" uncertainty of a single measurement in a series is the frequency distribution, "histogram". Although a series of provings comprising 5 successive runs have been carried out at different flowrates it is possible to remove the influences of the variations in the means of each set by plotting the difference between each K-factor and its respective set mean value. This technique is known statistically as the "pooled" standard deviation. Special graph paper is used to establish whether the frequency distribution is Normal or Gaussian and to test for skewness and outliers and to derive the uncertainty limits for 95 percent probability.

The "moving average" is another technique used to monitor the variation in the successive mean values of 5 proving or calibration runs and to detect any long-term variation or drift.

CALIBRATION AND TRACEABILITY

Upstream and Downstream Volumes

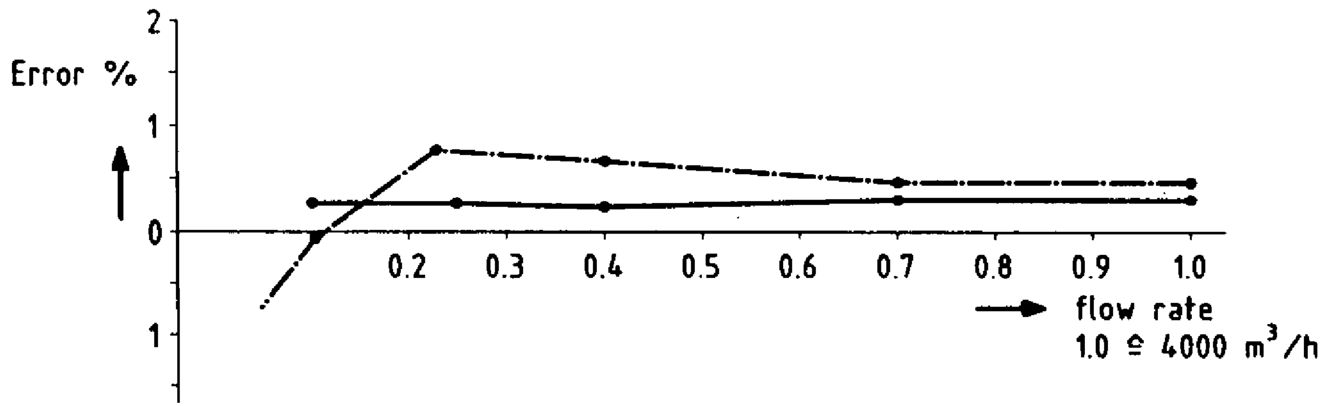
As the meter-under-test may be situated either "upstream" or "downstream" of the compact prover and the prover base volumes are not the same in both directions, it is necessary to determine the respective volumes by direct liquid calibration methods.

In the Waugh prover the displacement of the piston shaft and the leak detection tube are the main reasons for the difference between the upstream and downstream volumes.

Flowrate Independence

One of the requirements of the new Institute of Petroleum Part X Section 3 "Code of Practice for the Design, Construction and Calibration of Pipe Provers" is to demonstrate that for any new design of prover there is no significant variation in the base volume, from the lowest flowrate when the prover is calibrated to the maximum flowrate at which the prover is operated.

High Pressure Calibration of
G 2500 Turbine Flow Meter DN 300
G 2500 Vortex Meter DN 200
for Installation in Birlinghoven



Test Facility : Westerbork, Netherlands
tested at a pressure of 55 bar

Main Index

OPERATING EXPERIENCE WITH A COMPACT PROVER - 1

by

G Ross
Caleb Brett International Ltd

Paper 5.1

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

1. INTRODUCTION

This paper is based on a 12" Standard Brooks Instruments Compact Prover, owned and operated since September 1982 by Caleb Brett International Limited, and covers operational experiences, highlighting the problem areas, not at first recognised.

Those not acquainted with Compact Provers will, it is hoped, achieve an understanding of the operation of these units. Those familiar with these units will obtain an insight into operational problems that can arise.

2. HISTORY

Compacts were first manufactured during 1967 (over 20 years ago) by Flow Technology of Phoenix, Arizona, USA. They were known as the ballistrak or Balistic Flow Calibrator. Flow Technology still manufacture similar equipment called the Omnitrak, this normally being a static calibration system - not portable.

Ballistic Provers were developed to provide greater accuracy of measurement and used on exotic applications, such as metering payloads of rocket fuel for attitude control rocket Motors used by NASA.

Flow Technology sold the rights of the Ballistic Provers to Brooks Instruments on December 30, 1981 (Brooks being part of the Emerson Electric Company). Brooks manufacture these units to order, at their Statesboro, Georgia plant in the USA.

They build them to America/Canada area classification standards, however provers with a 60% UK content can be built to meet the European Zone 1 Area Classification standards by Brooks UK Stockport.

Their application for recalibration of in-service hydrocarbon pipe provers, as well as meter recalibration, was first recognised by Caleb Brett & Son's Metering Personnel, during the early 1980's.

The introduction of the first Caleb Brett unit into the UK, took place during late 1982. A Demonstration was arranged during December 1982, at Phillips Petroleum's Seal Sands Terminal. This was followed by work on the Ekofisk Field conducted during February 1983. Thanks to Occidental Petroleum's interest to conduct further trials, the units emergence on the UK sector of the North Sea was established.

A copy of this unit's full operational history can be obtained from Caleb Brett's Aberdeen Operation.

3. OPERATION

A Compact Prover is a Flow Measurement Calibration Instrument employed mainly on liquid service, the main components being a chromium plated 17.4 PH stainless steel barrel section finely honed and a uniquely designed operating piston with an integral poppet valve plate. The Brooks Prover is unique because the operational fluid flows through it, unrestricted at all times, without the use of bypass valving. This is made possible by the poppet valve incorporated via the actuator shaft to the piston of the actuator cylinder. Pressure (set in accordance with line pressure) in the pneumatic spring plenum, serves to assist the closing of the poppet valve and, in conjunction with the calibration fluid flow, operates the piston through a proving pass. (Nitrogen pressure is used to compensate for frictional forces within the barrel, thus ensuring that no energy is removed from the flowing stream. The Nitrogen system is a closed loop and not consumable.

The Hydraulic System returns the piston upstream, holding the poppet valve open in the upstream position thus allowing the normal flow of fluid to pass through the open valve. A failsafe stop is provided at the downstream flange which opens the poppet valve and prevents accidental blockage of the fluid.

The piston position in the cylinder is detected by optical switches. A signal is generated when a "Flag" which is attached to the optic shaft, (this shaft being secured to the main piston) moves in conjunction with the prover piston, and passes through slotted optic switches, blocking the passage of "light" across the gap between the emitter and sensor sections of the switches. Three switches are used, one for sensing the upstream or standby position of the piston assembly and two for defining the displaced volume of the prover barrel.

This displaced volume is passed through a series of pipes to a reference turbine meter. The AC signal produced by the meter is conditioned by a pre-amplifier to match the Brooks dedicated electronics requirements, in our case a 5 volt TTL square wave signal. When the flag passes through the first volume switch and a signal is generated. The action of the flag passing through the first volume switch starts clock one (time for displaced volume) and gates clock two (time for number of flow meter pulses). Clock two starts when the electronics receive the first positive going meter pulse. Clock one is stopped when the "flag" passes through the second volume switch and this also gates clock two. Clock two stops when the electronics receives the next positive going meter pulse. These clocks are referenced to an extremely accurate 1 MHz quartz controlled oscillator circuit. The electronics have thus collected;-

(a) time for displaced volume
(b) time for a number of meter pulses
(c) total number of whole meter pulses.

These data signals, along with the known volume of the compact's displacement (found by waterdraw calibration), are used by the electronics to compute the frequency of the input signal, the flow rate of the liquid through the meter, the K-Factor of the meter and other relevant parameters, required to allow calculation of prover volumes meter factors.

OPERATION (contd)

Having established the reference meter's K-Factor and the volume of the Compact, this instrument can then be employed as a volumetric transfer standard, to determine the volumes of other meters and/or mechanical displacement prover loops.

To comply with fiscal requirements Caleb Brett's system must be traceable to a national standard. In this case the certifing body being the National Weights and Measures Laboratory, who verify, gravimetrically, the volume of a field standard measure used by Caleb Brett to check the volume of their Compact Prover.

This vessel is used, as previously stated, to determine the volume of the compact barrel displacement, by the waterdraw method , whereby the volume of air-free, clean, fresh water is displaced from the barrel of the compact between the limits of the volume optics, into the field standard. This is repeated to prove the repeatability of displacement, until satisfactory results are obtained. After correction for temperature and pressure the volume delivered into the field standard will be the true volume displaced from the compact prover, to be used in future calculations.

4. PROBLEM AREAS

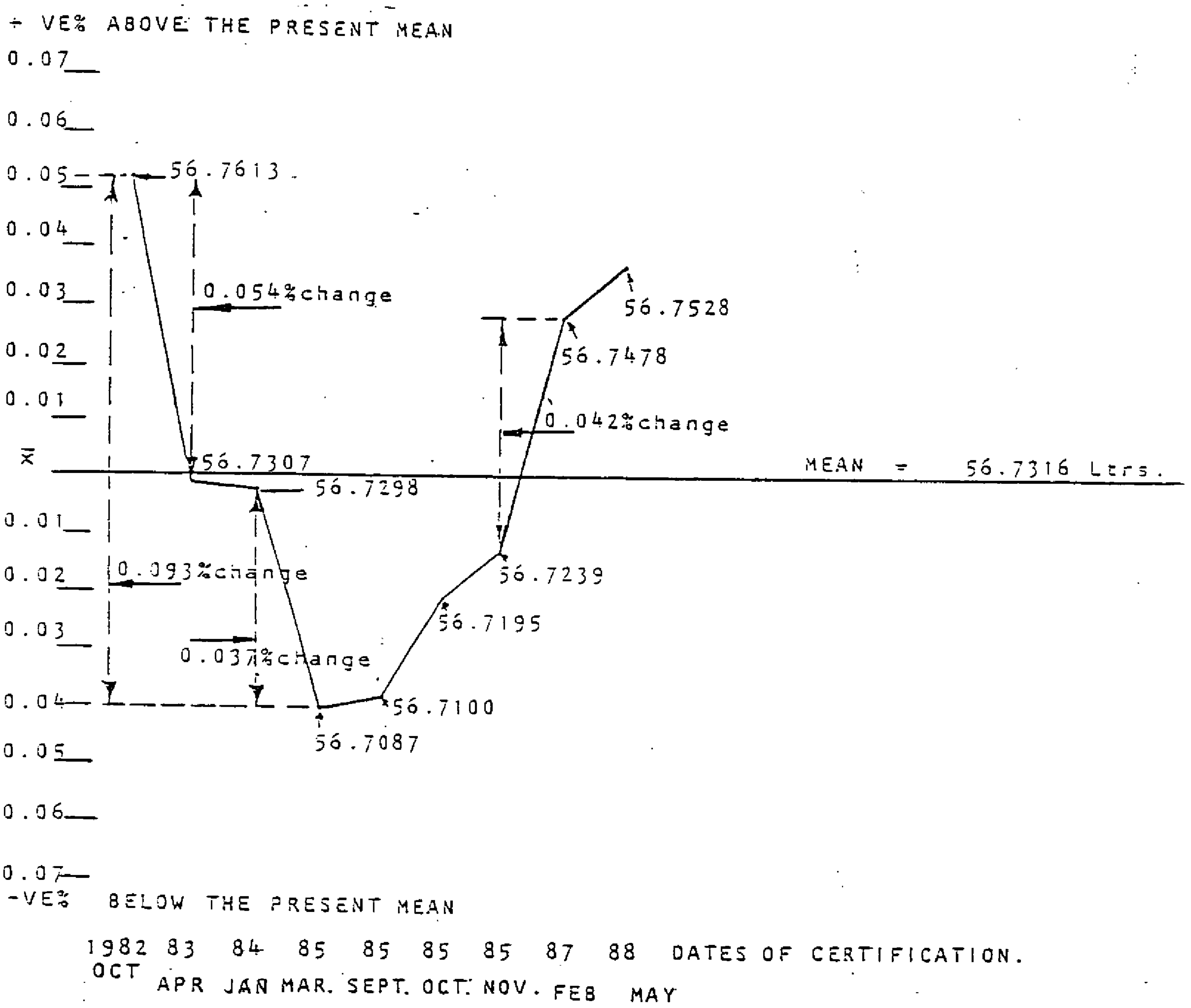
4.1 Measure

The measure is the first link in the volumetric accuracy required to certify the calibrated volumes of fiscal metering stations. Therefore it is of the utmost importance that this calibration be performed accurately, also that every effort is made to protect this measure from damage, which would affect the true volume of the measure. This traceable certification is performed annually or when the volume is suspect. The vessel used by Caleb Brett is a nominal 57 litre type made of stainless steel, and sealed after calibration at all points that could give rise to volumetric changes, i.e. the adjustable scale, the interface drain valve, the spirit levels used to level the vessel and so on. It is transported in its own foam blown packing case, which is carried inside the control cabin. Should any of the seals break, as with any certified device, then the vessel must be recalibrated and resealed. It can be seen that this vessel must be treated with great care. Should the vessel become dented or some materials become trapped inside, then it is obvious that the volume read on the scale would increase. The only way for the volume to decrease is if something is removed from the inside, i.e. if the vortex splitting weir was removed.

Since the original certification on 14th October 1982, we have seen the volume certified drop until a check calibration carried out during September 1985 showed the volume to be on the increase. This is illustrated on figure 1 attached. The actual changes between years are shown. It can be seen that some quite large changes in volume have occurred. Caleb Brett's standard procedure is to carry out waterdraws before and after each metering installation's calibration. The spread of the pre/post waterdraw results, must be within the 0.02% criteria. This procedure can give rise to a slight chance of contamination of the field measure, if the water delivered into the measure is not free from oil or suspended solids. Any residual hydrocarbons would adhere to the inner surface of the vessel, leading to a change in the drain down characteristics. So attention to cleaning of the vessel must be kept in mind, prior to recertification as well as during normal usage.

4.1 Measure (contd)

Shown below is a graphic plot of the certified volume of Caleb Brett's field measure since its first certification, all these tests have been conducted by the National Weights and Measures Laboratory.



DATE	CERT VOLUME	YEARLY % CHANGE	OVERALL % CHANGE
14 October 1982	56.7613		* Highest
18 April 1983	56.7307 Shift Down	-0.0539	
20 January 1984	56.7298 Shift Down	-0.0016	
26 March 1985	56.7087 Shift Down	-0.0372	* Lowest -0.0927
5 September 1985	Shift Up 56.7100	+0.0023	
23 October 1985	Shift Up 56.7195	+0.0167	
28 November 1985	Shift Up 56.7239	+0.0077	

DISPENSATION APPLIED BETWEEN NOVEMBER 1986 - FEBRUARY 1987 DUE TO WORK LOAD.

DATE	CERT VOLUME	YEARLY % CHANGE	OVERALL % CHANGE
3 February 1987	Shift Up 56.7478	+0.0421	
May 1988	Shift Up 56.7528	+0.0088	

EXTRACT FROM NATIONAL WEIGHTS AND MEASURES LABORATORY CALIBRATION REPORTS.

4.2 **Optics**

These slotted Optic switches are sensitive to changes in ambient light conditions if exposed under operating conditions. It should be stressed that the unit should not be operated with the optic switch cover off unless some sort of shade/cover can be arranged over the unit. Having said this, it is often necessary to remove the optic cover to allow visual access to the operating optic shaft, for inspection purposes.

If uncovered under high light i.e. sunlight conditions, the logic can become confused by the different signals it is receiving from the switches, i.e. if the piston is in the upstream optic position and the volume optics switch due to sun light, the logic flip flop can assume an indeterminate state and neither sets nor resets the logic circuitry.

The displaced volume of the compact has been noted to change by one or two cubic inches when the optic cover having been installed is removed and vice versa, under strong light conditions.

When an optic is broken or malfunctions and is replaced again the compacts volume can change, even though the movement of the optic horizontally is less than 1mm, vertical movement being between 4mm to 6mm, to allow for flag clearance and realignment upon replacement of an optic switch. Uncertainty of realignment of the emitter/sensor light path being the problem. Caleb Brett use a master rod of a fixed length made of invar to gauge between the volume optics to check alignment if optics are changed. This also shows up any distortion along the length of the optic assembly.

Another area of concern is the end volume optic which is mounted so that the expansion of the Invar rods accounts for and corrects the linear expansion of the barrel. This spring loaded mounting can lead to changes in volume if the mounting plate becomes displaced or is accidentally moved when the optic cover is replaced. A horizontal movement of as much as 1mm will lead to a 4.64 cubic inch change in the volume of the prover. Since the overall allowable volume change between displacements is +/-0.35 cubic inches, then it can be seen that 4.64 cubic inches is a large error.

Again, if the Invar rods become fouled in some way or dirt becomes trapped between the rod and the optic contact block then again problems will occur. The optic assembly must be in good condition, and no binding or dragging of the optic flag on the optic, or support rods, should occur as this will affect the functioning of the system.

4.3 Seals (Leak Check)

The seals on the compact piston could start to leak at any time during proving. It has been our experience that if a leak check is conducted as recommended by the Brooks Operating Procedure, that leaking seals will be detected prior to any proving and should leakage occur during proving, that this will show up as bad repeatability. Conducting the leak test is simplicity itself, all that is required is a good dial indicator and a good mounting point. This is normally conducted as part of the waterdraw procedure at one point of the piston's travel. The compact is filled with water and has all outlets closed off. Then the operating piston is launched and the dial test indicator applied to the flag rod to indicate any movement. Once again if the water pressure is fluctuating this will affect the leak test.This test can be conducted at any point along the length of the pistons displacement, to check for seal leakage. There is no doubt that a leak exists when one watches the pointer of the dial test indicator. Here again it takes only minor damage of the barrel/seals to cause a leak. This being the only draw back with these units, although the new stainless steel flow tubes with internal chrome plating exibit greater resistance to mechanical damage than the older carbon steel flow tubes.

4.4 Water Supplies

Water Supply problems appear from time to time. The problem is thought to be mainly due to loss of pressure on the rod end this results in the relaxation of the poppet valve and inaccurate deliveries of the displaced volume thereby accurate calibration will not be obtained, this phenomena again on new units, does not appear to our knowledge, as yet. This is in evidence when nitrogen pressure is set at, or below line pressure.

Air in the system will lead to reduced displacement as with any other system, here the air bleed sequence conducted between each withdrawal must be adhered to consistently to ensure no air entrapment in the high points of the compact. The water supply used should be clean, fresh, airfree and of constant pressure.

4.5 Power Supplies

Brooks recommend two separate supplies, one for the unit, and one for the electronics, both of which must be clean supplies, that have no sudden loading due to other machinery. We have in the past operated using the same power supply to power the unit and electronics, without any major problems.

Offshore we normally tie into a circuit which is on the Platform Shut Down System, so that if an alert status arises our equipment is automatically isolated.

4.6 Interface Connections

Cable connections that are repeatedly connected and disconnected are a source of problems. When we had the old electronics hardware we found most of the problems that manifested themselves were, when eventually tracked down, caused by bad connections, or broken wires. Intermittent contacts are difficult to trace and appear as all kinds of faults such as hydraulic lock out of the unit after a single pass, this being caused by a faulty connection between the scaler gate cable and the electronics console. We have eliminated this problem with the new system we are commissioning by using better quality connectors.

4.7 Suspended Solids

Damage to the barrel, or flow tube as it is called, has given us the largest headache. The unit has an inlet fluid filter and we have, in the past, encountered everything from sand, welding slag, prover lining, small rocks to chunks of prover sphere, trapped in the filter. The items that become trapped are not a problem, it's the smaller pieces that pass the filter and enter the flow tube that cause the damage or, in certain cases where the suspended solids are so numerous that the filter chokes and bursts, here again we have suffered flow tube damage. These solids, in many cases, were due to new installations or pipework modifications or because the meter prover calibration connections are normally dead legs on most metering stations and trap all manner of solids.

We use a 40 mesh filter element on the inlet line of the unit, which is removed and inspected after every job. This is conducted for two reasons: 1. It allows us to check the solids caught, and in the case of prover lining, we can inform the client of our findings and 2. Gives us peace of mind that nothing is wrong with the element of the filter.

4.8 Calibration Fluids

Although this unit has been mainly employed on crude oil service since late 1982, other calibration fluids have been employed. These include diesel, premium spirit, naphtha, white oils, black oil and various LPG cocktails of butane and propane.

Bunker fuel or black oils and LPG's give rise to problems. Due to the high viscosity and the glue like nature of black oil, we had a problem once where the piston seals were pulled off the piston. We suspect, but have no means by which to check our suspicions, that a degree of ovality was present in the barrel supplied, or that tolerance problems existed. i.e.if the piston meets the lowest tolerance on its diameter and the barrel meets the highest tolerance on its internal diameter then clearance/seal integrity is affected which can lead to premature failures. We hasten to add, that the time between finishing the proving on black oil and flushing with a lighter product, was sufficiently long to allow the black oil to set in the barrel, albeit that the unit was drained down. Had there been a lengthy flush of lighter fuel oil directly after using the black oil, to clean the internal parts of the compact, this would not have occurred. Unfortunately circumstances were such that it was not possible to conduct a flush immediately.

4.8 Calibration Fluids (contd)

Used on LPG's the unit must be clean to reduce contamination of the product from Black/Crude Oils. LPG's being cleaner fluids of lower viscosities and lower evaporation temperatures, show up slight seal leakage on atmospherically exposed seals straight away. Therefore the units seals must be in good condition before proving LPG's.

Brooks manufacture low temperature stainless steel units capable of operating at -40°C whereas the carbon steel units are limited to a minimum of -20°C. Below this exceeds the steels temperature parameters. Safety precautions when metering LPG's are of a higher level, due to the greater explosive nature and rapid expansion that occurs with gases. Purging with nitrogen before and after proving is one company's policy.

4.9 Corrosion

Corrosion of these units only becomes a problem on non stainless components as with any machinery when its internal parts are unprotected and where the machinery is likely to be idle for a period of more than a few days. The internal parts should always be inhibited as soon as it is anticipated that a period of shutdown or non-use will ensue. This is especially true where the last fluid in use was water or an LPG product. We have in the past during major overhauls found quite thick corrosion build up on the end flanges of the prover.

5.

5.1 Damage in Transit

Damage due to poor handling during shipping has caused considerable set backs. The unit is seen by most offshore personnel as just another lump of steel, although it's construction is fairly rigid, it is still a calibration instrument and should be treated as such.

We normally ship the unit and control cabin in a 20 foot long by 8 foot wide by 8 foot high open top container. We experience no damage under normal transit conditions as the unit and cabin are strapped into the container, but when forklifts are used to lift this container, containing a very unbalanced load, it is little wonder that the container ends up on it's side with the equipment inside damaged. Under these circumstances no amount of custom built container equipment would sustain a six foot roll and drop on to concrete.

Part of Caleb Brett's policy is to witness the loading and unloading of this equipment in person wherever possible, but sometimes we have to trust to our clients employees to pack the equipment away, and generally these are the times that the damage occurs. Refer to photocopy in appendix showing damage sustained due to poor packing practice.

5.2 Summary

Having spent some time covering the problem areas it is worth reflecting on just how many of these problems are of human origin. Owing to the nature of this work it is expected by clients that calibrations should be conducted from start to finish irrespective of interruptions. This leads in some cases to excessive periods of work which not only results in errors during calibration, due to tiredness but, to possible operational unsafe practices by cutting corners in an attempt to finish a calibration quickly. Therefore it must be stressed, this work is performed once a year and during this once yearly period that time should be taken to carry out the calibration correctly. Rushing to meet shipping or helicopters schedules only increases the error margin.

Measure

Considering the field measure, where any amount of errors can be directly attributed to human error.

(i) Lack of cleaning of the measure prior to calibration,
(ii) Possible ingress of foreign materials,
(iii) Calibration values that shift the volume,
(iv) Mechanical damage to the vessel, ie dents etc.

Optics

The optics, other than malfunction which has been the least of our problems, since they operate with success, time and time again unless they are disturbed. Generally only mechanical damage or physical misalignment give rise to problems when in use, this again depends on the operator.

Water

Water supplies, use of aerated supplies, or as previously stated dirty supplies will cause problems.

Connections

Interface connections, we have not encountered any problems in this area, since changing connectors, but the simple act of bad preparation of cable connections can lead to intermittent connection problems due to dry soldered joints.

Fluid Contamination

Suspended Solids, if adequate filtration is employed then this would no longer cause alarm. Generally good housekeeping and better engineering practices would see these units in more frequent useage, for either in-house or in-field work.

The present Caleb Brett Unit has worked harder than any other known unit of its kind and has proved itself over and over again as a small lightweight, reliable volumetric transfer standard.

5.3 Further Reading

Various documents have been written about these units: below are listed a few titles and authors who in the past have strengthened the case for use of compact provers.

Practical Field Operation Of Compact Provers For Master Proving.

By M.D.H. Bayliss of Occidental Petroleum.

The Application And Operation Of Compact Provers As Used For The Recalibration Of In-Service Mechanical Displacement Pipe Provers Offshore.

By G.E. Inglis of ICE.

Performance Of The Brooks Compact Prover On Air.

By J. Reid, National Engineering Laboratory.

Experiences With Compact Provers On Live Crude Oil (Extracted From North Sea Flow Metering Workshop, 5 - 7 November 1985).

By Mr John Stokes of Unitech.

Evaluation Report E2479 T 84 Published By WIB, Dated January 1985. Evaluation Of A Model BCP-PS-6623-LPM-12-6-600 Prover.

Reports On Tests Carried Out On A Brooks' Compact Prover By ICI Petrochemicals & Plastics Division Olefine Works, Wilton.

By D D Powell, 11/5/1983.

Mont Belvieu Prover Test (Mid-America Pipeline Co)

W A Latimer (Senior Measurement Engineer), 5th May 1982.

USER/STANDARDS LIST

1. REGULATORY AUTHORITIES (PROVERS ACTUALLY IN USE/ORDERED).

Sweden	Weights and Measures	Prime	Standard
Holland	Weights and Measures	Prime	Standard
UK	National Eng. Lab	Prime	Standard
Hungary	Government Standard Lab	Prime	Standard
Yugoslavia	Government Standard Lab	Prime	Standard

2. INDEPENDENT CALIBRATION COMPANIES.

Scotland	Caleb Brett	Meter Prover/Transfer	Standard
France	SGS	Meter Prover/Transfer	Standard
Australia	SGS	Meter Prover/Transfer	Standard
Norway	Contech	Meter Prover/Transfer	Standard

3. END USERS - EUROPE.

Norway	Norsk Hydro	Transfer Standard
Norway	Phillips	Meter Prover - Deisel
		Meter Prover - LPG
Holland	Shell	Meter Prover - Hydrocarbons + Crude Oil
Holland	Union Oil	Meter Prover - Crude
UK	ICI	Meter Prover - Ethylene
UK	Texaco	Meter Prover - White Oils
Italy	AGIP	Meter Prover - Gasoline

The above is a selection of our European Customer base.

Please also note that the Brooks Compact has now been approved by Weights and Measures in Norway for use as a Prime Calibration Standard.

CALEB BRETT COMPACT FLOW PROVER

ACCEPTED BY: United Kingdom Department of Energy
Norwegian Petroleum Directorate
Netherlands Weights and Measures

Witnessed and accepted by the authorities listed.

CUSTOMERS INCLUDE:-

British Pipeline Agency - Pipeline Provers	Crude Oil) Diesel Oil) Fuel Oils)	Customs and Excise
BP Petroleum Development - Forties (Kinneil) Pipeline	Crude Oil	Department of Energy
BP Refinery, Grangemouth -	Black & White Fuel Oils	Customs & Excise
BP Chemicals, Grangemouth	Naphtha, Ethylene	Customs & Excise
Shell UK - Brent, Dunlin, Fulmar Cormorant Platforms	Crude Oil	Department of Energy
Occidental Petroleum - Piper, Claymore Platforms	Crude Oil	Department of Energy
Texaco North Sea - Tartan Platform	Crude Oil	Department of Energy
Mobil North Sea - Beryl Alpha Platform	Crude Oil	Department of Energy
Phillips Petroleum UK Maureen Alpha Platform	Crude Oil	Department of Energy
Phillips Petroleum - Seal Sands, Ekofisk Platforms	Crude Oil	Norwegian Petroleum Directorate & Department of Energy
Phillips Petroleum Norway - Ekofisk Platforms	Crude Oil	Norwegian Petroleum Directorate
BP Petroleum Development - Buchan Alpha Platform	Crude Oil	Department of Energy

Main Index

OPERATING EXPERIENCE WITH A COMPACT PROVER - 11

by

G Groeneveld and P A M Jelffs
Moore Barrett & Redwood

Paper 5.2

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

Field Tests

In order to meet these requirements a number of tests were carried out using the following methods:-

a) Waterdraw Method

The volume of water displaced by the prover in each direction was measured in a 100 litre prover tank which was calibrated by a national Weights and Measures Authority. The assembly of equipment is shown in figure 1a. The calibration was carried out in the running mode by employing two solenoid valves. The flowrate was approximately 6 - 7 litres per minute.

b) Master Meter/Prover Tank Method

The master meter - (Avery - Hardoll BM500 positive displacement) was factorised by measuring water into a 2500 litre prover tank at two different flowrates viz 500 and 1300 litres per minute. The prover was then calibrated by the master meter at the same two flowrates as when proved and the appropriate meter factors applied to give the base volumes (corrected to standard conditions).The assembly of equipment is shown in figure 1b.

The results of these tests are given below: -

a) Waterdraw (into 100 litre proving tank) at approximately 7 litre per minute.

	UPSTREAM VOLUME (litre)	**DOWNSTREAM VOLUME** (litre)
	100.293	98.958
	100.296	98.953
	100.318	98.966
	100.302	98.970
	100.302	98.970
mean	100.302	98.963
sdev.	0.010	0.008
range	0.025 %	0.017 %

b) Master Meter/Proving Tank Method (2500 litre proving tank)

Master Meter Factors

The meter factors determined before and after each calibration, are:

OPERATING EXPERIENCE WITH A COMPACT PROVER - II

By G Groeneveld and P.A.M. Jelffs

SUMMARY

This paper discusses the results of recent tests carried out on a Waugh compact prover where the base volume in both the upstream and downstream directions was determined by waterdraw (running mode) and master meter/prover tank calibration methods.

An analysis of meter proving data showed that there was a larger random scatter when proving turbine meters with a compact than with a conventional sphere pipe prover and that this scatter varied considerably between individual meters of the same size and make.

In order to minimise the number of runs during a calibration (master meter/master prover) the master meter should be selected which has a random uncertainty of less than 0.02 % (95 % confidence limits).

BEFORE UPSTREAM calibration / **AFTER UPSTREAM calibration**

	BEFORE UPSTREAM 1300 l/min	BEFORE UPSTREAM 500 l/min	AFTER UPSTREAM 1300 l/min	AFTER UPSTREAM 500 l/min
	0.99629	0.99587	0.99614	0.99577
	0.99632	0.99576	0.99607	0.99600
	0.99620	0.99591	0.99595	0.99584
	0.99619	-	-	-
	0.99614	-	-	-
mean	0.99623	0.99585	0.99605	0.99587

BEFORE DOWNSTREAM calibration / **AFTER DOWNSTREAM calibration**

	BEFORE DOWNSTREAM 1300 l/min	BEFORE DOWNSTREAM 500 l/m	AFTER DOWNSTREAM 1300 l/min	AFTER DOWNSTREAM 500 l/min
	0.99595	0.99601	0.99606	0.99611
	0.99593	0.99580	0.99591	0.99610
	0.99585	0.99594	0.99605	0.99614
	0.99604	0.99580	0.99593	0.99603
	0.99589	0.99582	0.99596	0.99599
mean	0.99593	0.99587	0.99598	0.99607

Prover Calibration by Master Meter (with meter factors applied)

Single Trip Base Volume when meter is UPSTREAM / **Single Trip Base Volume when meter is DOWNSTREAM**

	UPSTREAM 1300 l/min		UPSTREAM 500 l/min		DOWNSTREAM 1300 l/min		DOWNSTREAM 500 l/min	
	100.356		100.347		98.989		99.004	
	100.335		100.317		99.009		98.985	
	100.333		100.340		99.004		99.006	
	100.339		100.350		98.992		99.015	
	100.342		100.356		98.991		99.014	
	100.334		100.347		99.014		98.998	
	100.327		100.344		98.988		98.998	
	100.323		100.354		98.987		99.012	
	100.340		100.326		98.987		99.014	
mean	100.337	1	100.342	1	98.996	1	99.005	1
sdev	0.010		0.013	1	0.010	1	0.010	1

Interpretation of Test Results

a) The waterdraw method results were within a range of 0.017 % and 0.025 % respectively, which is not as good as the range normally achieved with conventional provers.

b) The master meter proving results using the 2500 litre tank showed an uncertainty of the order of 0.026 % to 0.028 % (see fig 2). The difference between the before calibration and after calibration mean meter factors are given below:

Direction,	Flowrate	Mean(before)	Mean(after)	Difference % (between means)
Upstream	500	0.99585	0.99587	+ 0.002
Downstream	500	0.99587	0.99607	+ 0.020
Upstream	1300	0.99623	0.99605	- 0.018
Downstream	1300	0.99593	0.99598	+ 0.005

The difference between any two means will depend on the size of the sample. The smaller the sample size the larger will be the potential difference between the two means, assuming that the measurements were made with the same apparatus and under the same conditions.

For samples with number of measurements (n_1 and n_2) and the same standard deviations (S) the maximum variations in the means ($\bar{x}_1-\bar{x}_2$) is given by the following equation

$$\bar{x}_1 - \bar{x}_2 = t_{95,n-1} \; s\sqrt{\frac{1}{n_1} + \frac{1}{n_2}}$$

where $t_{95,n-1}$ is the students t value for $n-1$ degrees of freedom for a probability = 95 %

Substituting for values obtained in Master Meter Calibration

$$\bar{x}_1-\bar{x}_2 = 2.776 \times 0.014 \sqrt{\frac{1}{5} + \frac{1}{5}}$$

$$= 0.025 \ \%$$

The conclusion is that the differences between the means before and after the prover calibrations were not due to any change in flow conditions or meter factors but entirely due to the small sample size.

The prover calibration volumes obtained by multiplying the master meter readout by the appropriate meter factor and then correcting for the effects of steel and water expansion to bring the volumes to 20°C and 1.01325 bara show a normal distribution (see fig. 3 - histograms). The random uncertainty is of the order of 0.023 % to 0.030 %. This is surprising as the scatter should be larger than that experienced with the waterdraw method as the master meter method includes an extra stage of measurement: -

There is no indication of any drift in the base volume measurements as determined by the master meter/prover tank method.

Comparison between Mean Base Volumes

A comparison of the mean base volumes obtained by the different calibration methods is given below:

Directions	Waterdraw (7 l/minute)	Master Meter (500 l/minute)	Master Meter (1300 l/minute)	Difference % max (range)
Upstream	100.302	100.344	100.337	0.042
Downstream	98.963	99.004	98.996	0.041
	1.339(1.35%)	1.340(1.35%)	1.341(1.35%)	

The uncertainty due to sample size can be estimated by adding in quadrature the uncertainties of the means, $\bar{x}_1$ and $\bar{x}_2$ of the sample of 5 measurements (n=5) and standard deviations s_1 and s_2 respectively.

$$\bar{x}_1 - \bar{x}_2 = \left[\underbrace{\left(\frac{t_{95,4}S_1}{\sqrt{5}}\right)^2}_{\text{Waterdraw}} + \underbrace{\left(\frac{t_{95,4}S_2}{\sqrt{5}}\right)^2}_{\text{Master Meter}}\right]^{1/2}$$

$$= \left[\left(\frac{2.776 \times 0.010}{\sqrt{5}}\right)^2 + \left(\frac{2.776 \times 0.020}{\sqrt{5}}\right)^2\right]^{1/2}$$

$$= 0.02\%$$

However, when comparing the means of the base volume obtained by different methods and different tanks (and size) there will be an additional error which will be partially random and partially systematic.

The overall uncertainty (random and systematic) for the tank calibration quoted by the authorities is of the order 0.015 to 0.020 %. If this is added in quadrature to the uncertainty of the difference in the mean value due to sample size than the maximum variation in the determination of the base volume employing different methods could be:

$$= \sqrt{(0.02^2 + 0.02^2)}$$

$$= 0.03\%$$

This would suggest that there is no significant error incurred in the base volume by operating (1) the prover over a very wide range of flowrate, 7 to 1300 litre /minute, in the running mode and (2) when the piston is travelling in either direction. (The waterdraw calibration is carried out with the piston moving in the opposite direction as when calibrating by the master meter/prover tank method.)

There is no evidence that the base volume is flowrate dependent as the volume at 1300 litre/minute compares more closely to the waterdraw at 8 litre/minute than to the volume determined at 500 litre/minute.

Recent tests have shown that when calibrating a conventional sphere prover (20 metre between detectors) using the same 100 litre and 2500 litre proving tanks the difference between base volume was 0.04 %.

The only valid conclusion, therefore, would appear to be that the difference between the base volumes is mainly due to the traceability and uncertainty of the two proving tanks.

PERFORMANCE OF WAUGH PROVER WITH VARIOUS TYPES OF METER AND PRODUCT

1) Influence of Same Type of Meter

Several 6" turbine meters were proved with a compact prover (15" bore, 100 litre capacity) and the random uncertainty assessed. There is evidence that the uncertainty varies from 0.018 % to 0.030 % on a purely arbitrary basis; some meters with the worst scatter gave a a number of outliers whereas those with the best scatter gave no outliers at all. A 6" turbine meter of another make was tested and was found to have a similar range of uncertainty. The problem of not being able to predict the uncertainty of a turbine meter only becomes critical where it is employed as a transfer standard for a compact master prover.

2) Influence of Flow Rate

The frequency distribution of a 6" turbine meter for flow rates over 114 m^3/h and under 65 m^3/h showed the same order of uncertainty (see figure 4).

3) Influence of Density

There was again no significant difference in the random scatter when 6" turbine meters were proved on gas oil or propane (see figure 5).

4) Influence of Meter Size

The random scatter for 4" turbine meters was within the same range as the 6" meters (see figure 6). However, there was a significant increase in uncertainty as the meter size reduced to 2 1/2 " (i.e. 0.032 %).

5) Influence of Time on Variations of Mean K-Factor

The moving averages for a series of 50 proving runs carried out on a 4" turbine meter and compact prover (not a Waugh) on water exhibited a cyclic variation or wave pattern. The individual K-factors were plotted as a histogram which showed a normal distribution. In theory if the measurements were truly random then there would be no evidence of wave patterns (see figure 7). However, this phenomenon has been observed a number of times when analysing long-term K-factor variations. In practice there is evidently a number of small systematic errors which behave in the short-term as a bias but in the long-term as random errors.

The maximum variation in the moving average can be calculated from the equation:

$$x_1 - x_2 = 2\sigma\sqrt{\frac{1}{n_1} + \frac{1}{n_2}}$$

where

$\bar{x}_1$ and $\bar{x}_2$ are maximum and minimum averages

2σ is the uncertainty P = 95 % for $n > 30$
n_1 and n_2 are the number of runs

therefore $\bar{x}_1 - \bar{x}_2 = 0.025\sqrt{\frac{1}{5} + \frac{1}{5}}$

$$= 0.015\ \%$$

This value compares closely with the maximum variation of the moving average shown in figure 4. This short-term bias could create a problem where the average K-factors have to be compared and used for master meter factors in calibrating pipe provers.

The Compact Prover as a Master Prover

In theory the repeatability of a calibrating instrument should be equal to or better than the repeatability of the instrument to be calibrated. In the majority of cases the compact prover is used to calibrate conventional sphere provers. In order to achieve the same uncertainty of the mean calibration volume as the large conventional prover the number of runs can be estimated as follows.

	Conventional Prover		Compact Prover
Uncertainty of mean of 5 runs =	$\frac{2\sigma}{\sqrt{n_1}}$	=	$\frac{2\sigma}{\sqrt{n_2}}$

Substituting for $\sigma_1 = 0.015\ \%$
$\sigma_2 = 0.025\ \%$
$n_1 = 5$

$$n_2 = \frac{0.025^2}{0.015^2} \times 5 = 14 \text{ (rounded)}$$

It is evident therefore that 15 runs are required when using the Waugh Prover in order to achieve the same uncertainty of the means for 5 round trips as when employing a conventional prover (with a distance between detectors of 20 metres).

SUMMARY OF CONCLUSION

1) A comparison of the mean base volume obtained by the waterdraw and the master meter/proving tank method at two flowrates indicated an agreement to within 0.042 %. As these methods were based on two different sizes of proving tank they would involve both random and systematic uncertainties in the traceability chain. As the difference is less than 0.05 % which is the uncertainty quoted for conventional pipe provers there is evidence that the Waugh Prover meets the criteria generally laid down for custody transfer/royalty measurement standards.

2) The upstream and downstream base volumes can be calibrated directly by both the waterdraw and master meter methods.

3) The Compact prover requires a minimum of 15 passes or runs in order to achieve the same random uncertainty of the mean K-factor as the conventional prover achieves in 5 runs.

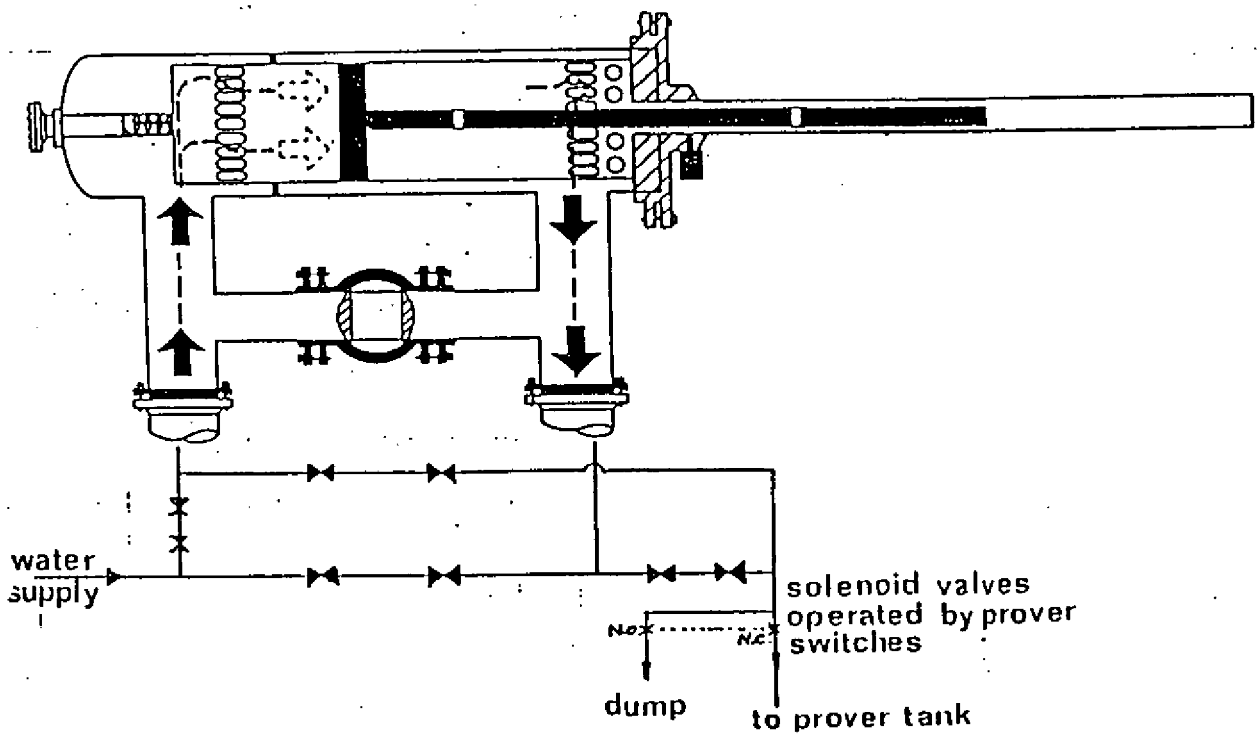
4) The random uncertainty experienced with a compact prover is mainly dependent on individual meter performance and is not unduly sensitive to flowrate or density but shows an increase with very small turbine meters. The performance of the Waugh Prover is similar to other compact provers.

References

Institute of Petroleum : Petroleum Measurement Manual, Part X, Section 3 " Code of Practice for the Design, Consruction and Calibration of Pipe Provers"(to be published shortly)

Fig 1 Assembly for Calibration of Compact Prover

a) Waterdraw [on the run]



b) Master Meter/Prover Tank

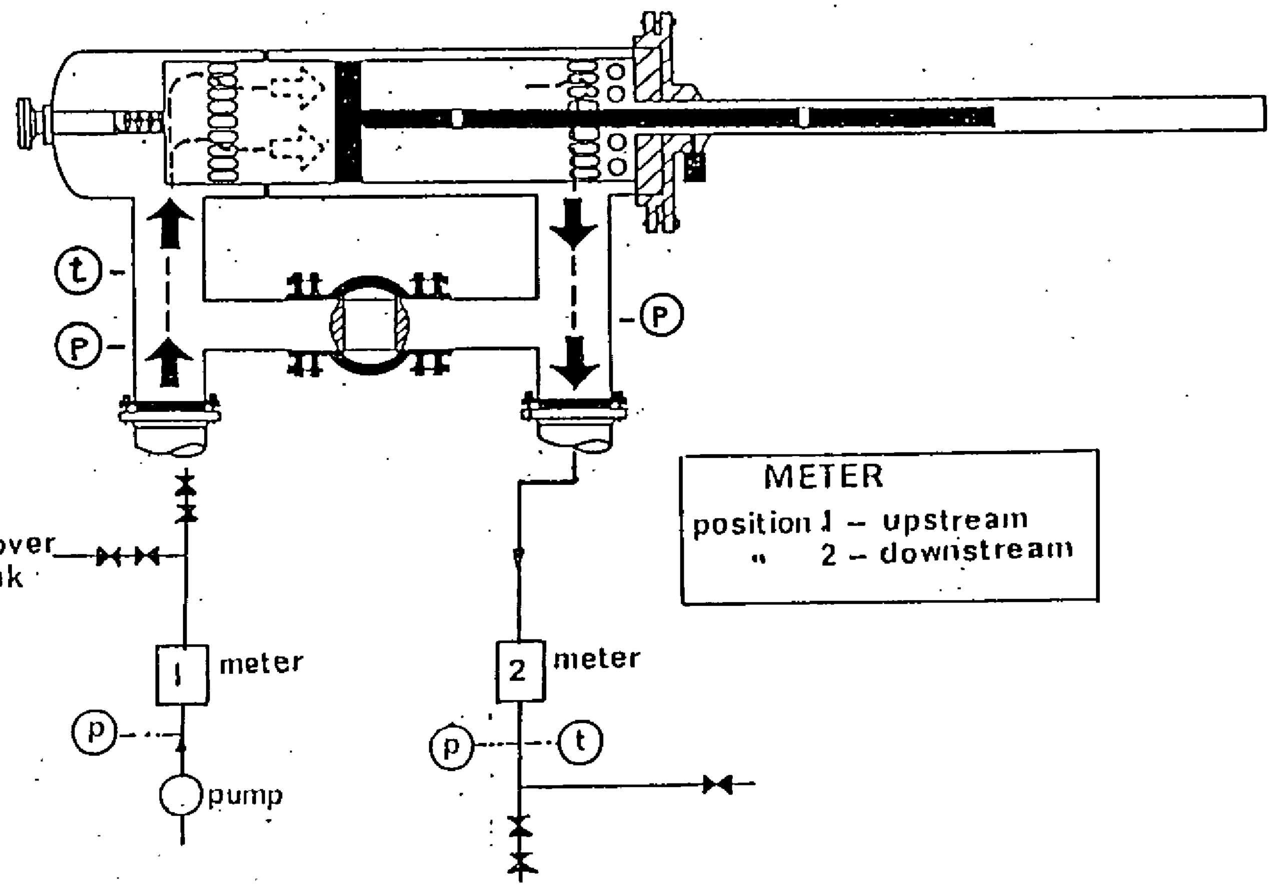
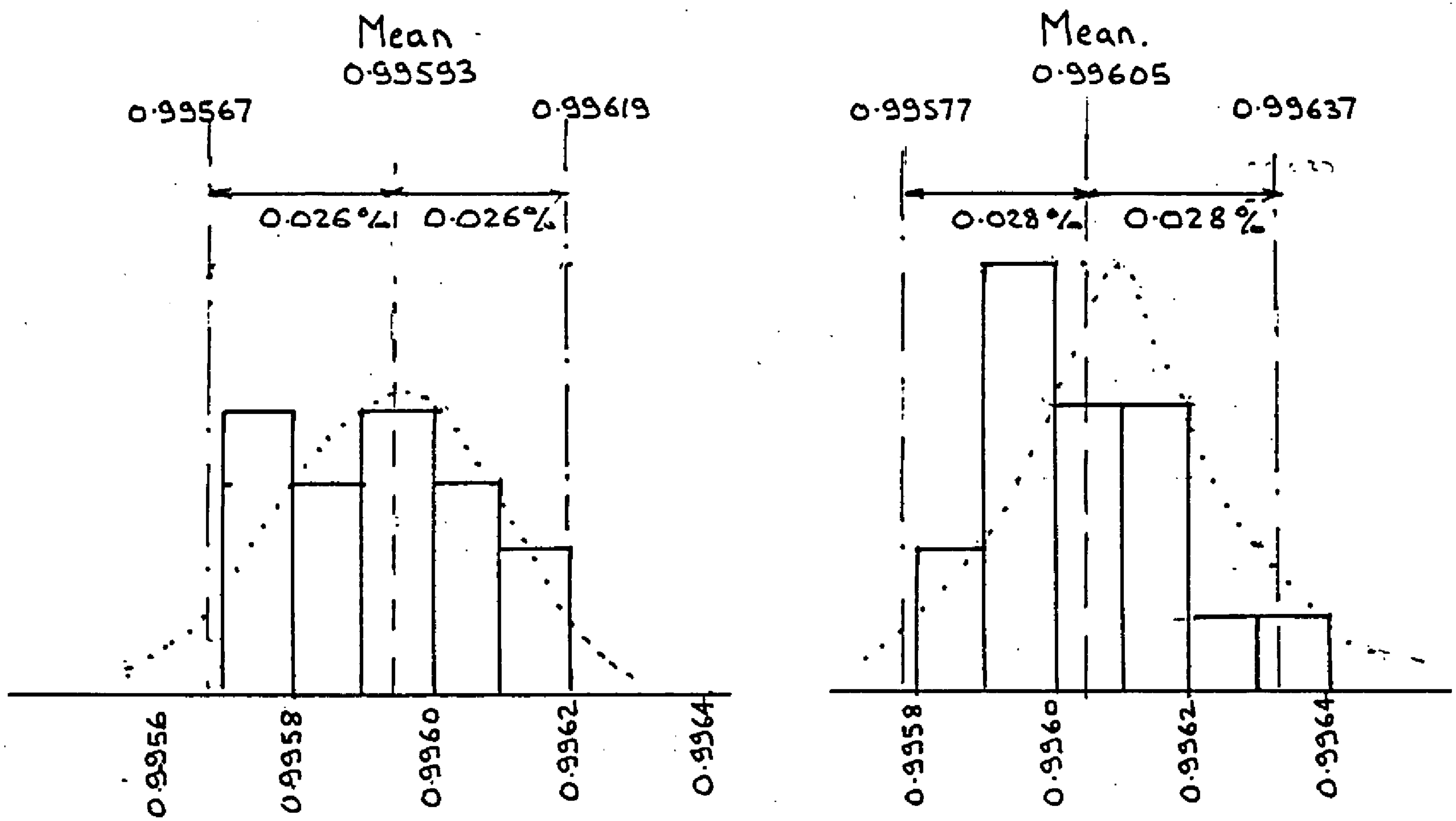


Fig 2 **Master Meter Calibration [factors]**

500 litre/min **1300 litre/min**



HISTOGRAMS

Fig 3 **Calibration by Master Meter**

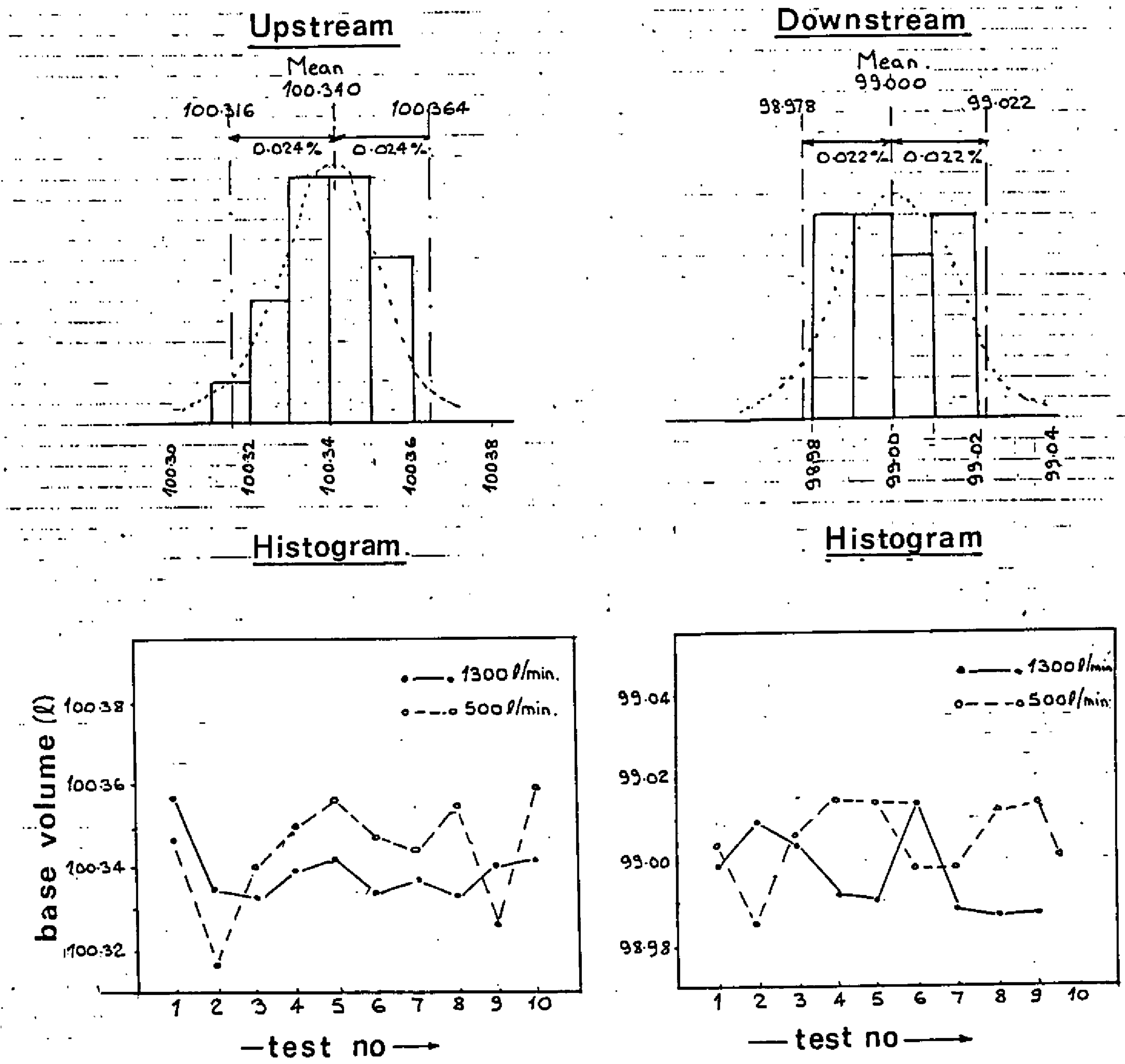


Fig 4 **Random Uncertainty**

(influence of flow rate)

6" Turbine Meters

$>114\ m^3/h$ $<65\ m^3/h$

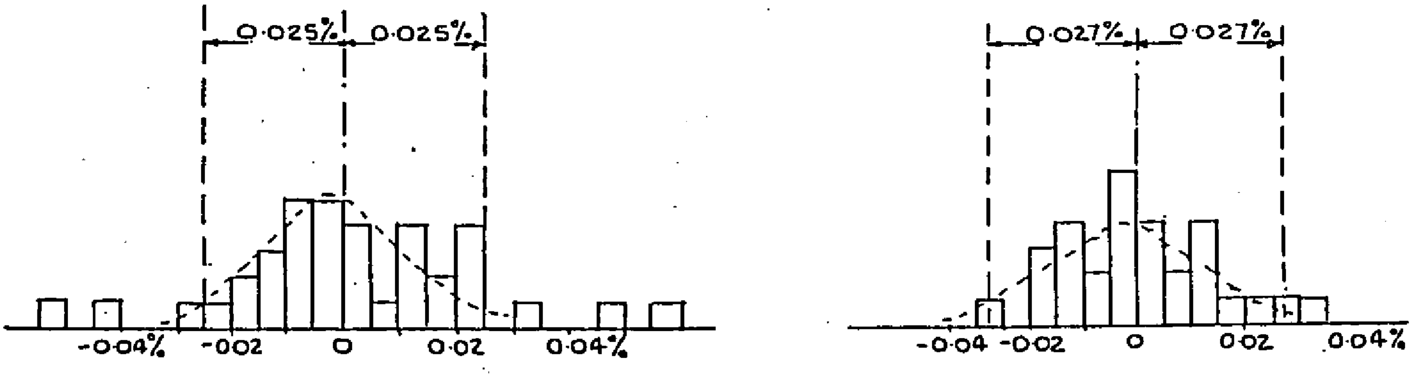


Fig 5 **Random Uncertainty**

(influence of density)

6" Turbine Meters

Density $> 814\ kg/m^3$ Density $< 672\ kg/m^3$

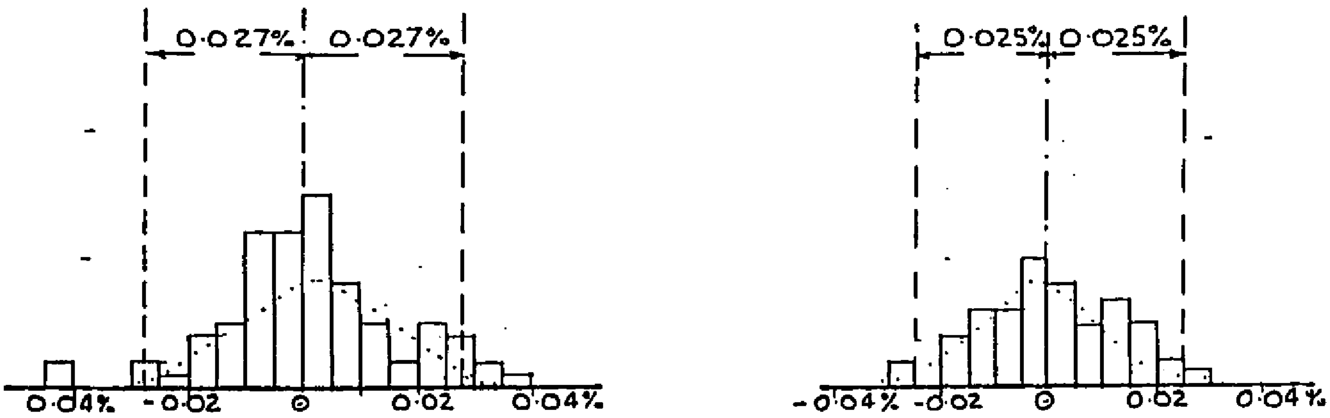
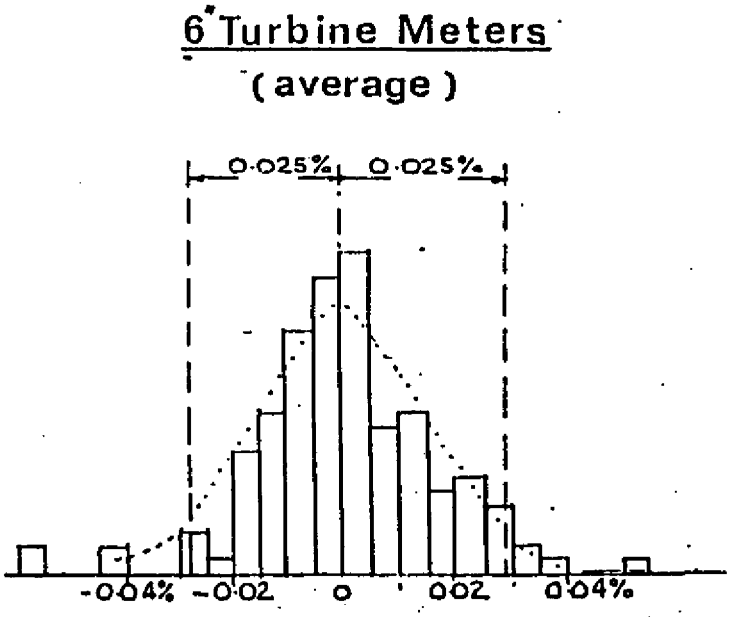


Fig 6 Random Uncertainty

(influence of size)



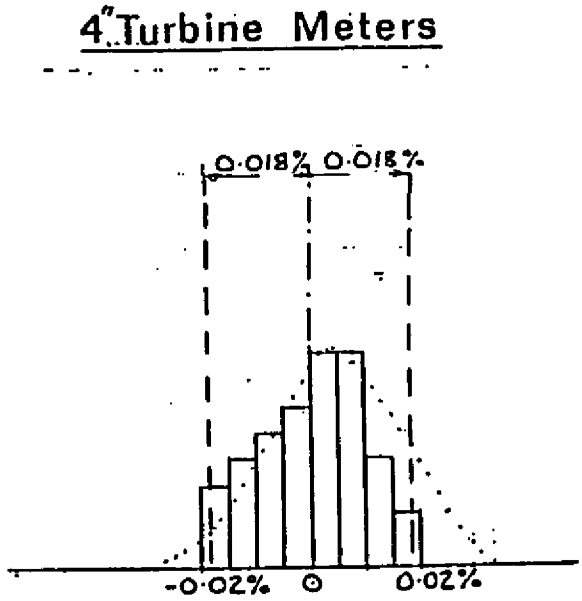
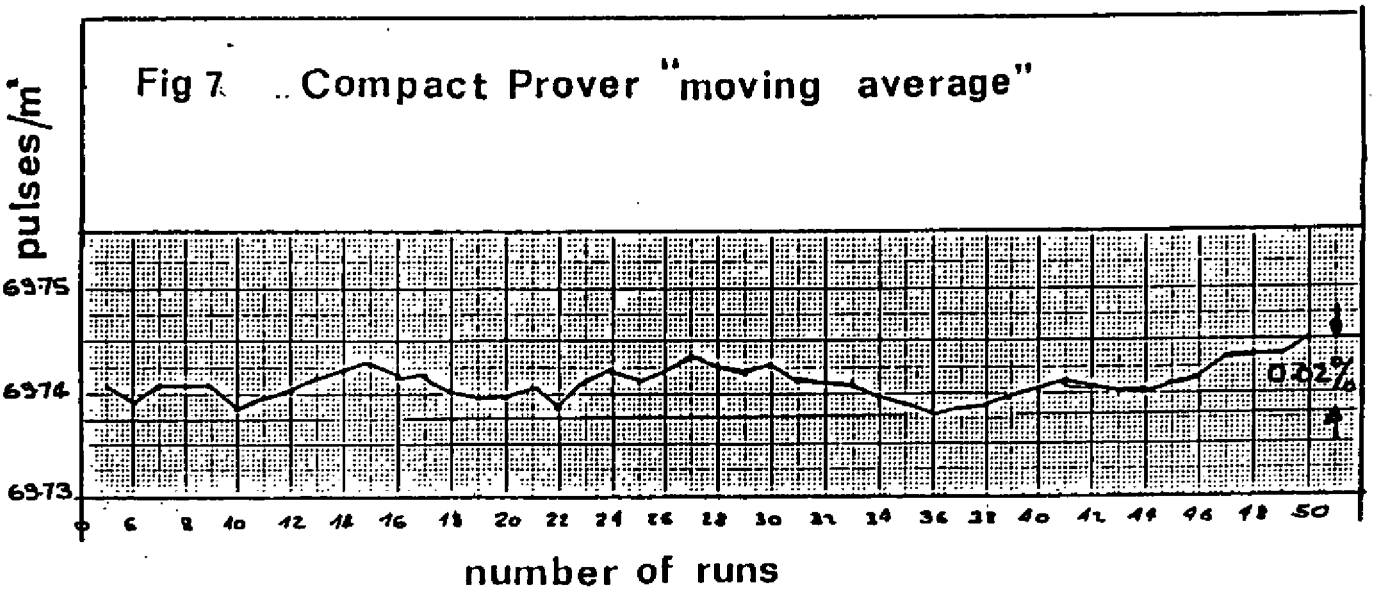


Fig 7 Compact Prover "moving average"



PULSE INTERPOLATION - REVISION OF ISO 7278/3

by

R Paton
National Engineering Laboratory

Paper 5.3

NORTH SEA FLOW METERING WORKSHOP 1988
18-20 October 1988

National Engineering Laboratory
East Kilbride, Glasgow

SUMMARY

ISO 7278/3 covers pulse interpolation for use in proving hydrocarbon flowmeters. The existing standard has been found to be inadequate in a number of respects, and requires revision. This paper describes the work done at NEL to provide data to allow an advisory table to be drawn up. The data has been produced by computer simulations of variable pulse intervals and a pulse interpolation system.

The results are compared with the present proposed revision of ISO 7278/3.

1 INTRODUCTION

ISO 7278 is the International Standard covering proving systems for volumetric meters used in the dynamic measurement of liquid hydrocarbons. Part 3, the section describing methods for pulse interpolation, was published in final form in 1987 and describes the methods and limitations of present pulse interpolation systems. These methods have been devised to increase the resolution of flowmeters, allowing them to be calibrated using relatively small volumes of liquids. A number of commercial pipe provers have been produced with small volumes, and it is the dependence of these devices on pulse interpolation that makes the need for a Standard extremely important. The original requirement arose from the desire to prove low resolution meters using conventional provers.

The Standard was produced using the data and experience available at the time, and has proved to be a useful document as far as describing the methods and their general limitations. A Table however was included in the Standard to advise on the minimum number of pulses required for different levels of variation in pulse time interval spacing. It is this variation in the time between incoming flowmeter pulses which is the limiting factor to achieving a repeatable calibration using pulse interpolation. Due to further work being carried out the number of pulses required to overcome the effect of this pulse variation has been underestimated in the Standard by a large amount.

A revision of ISO 7278/3 is at present proceeding with the main emphasis being on the development of a replacement for the existing advisory Table. It is extremely important that this revision is carried out as soon, and as thoroughly, as possible since other Codes and Standards are following the lead given by this Standard. To help provide more information on the relationship between the pulse variations, repeatability and the number of pulses collected, NEL has carried out computer simulations of prover systems along with the experimental work on small volume prover assessments. This has provided data which can, and will, be used in the revision of the Standard. This paper summarises this simulation work and describes the present proposed revision of the ISO document.

2 SUMMARY OF WORK ON COMPACT PROVERS AT NEL

A programme of tests was initiated at NEL some years ago to evaluate a number of compact provers in the laboratory. Three provers were tested and a summary was presented two years ago at the North Sea Flow Metering Workshop (Ref 1). All the provers showed that they operated well and could measure volume both accurately and repeatably. However they failed to calibrate some meters repeatably, but successfully calibrated others. The positive displacement meters fitted with gearboxes were the meters which did not calibrate well. Examination of the pulse intervals generated by several meters was carried out, and it was found that the spread of pulse interval variations was around 1 per cent for turbine meters and up to 30 per cent for positive displacement meters with gearbox drives (Ref 2, 3, 4).

Three other features were evident from the measurements of pulse time intervals. Firstly, it was seen that turbine meters, with eight blades, had a pattern of variation (Fig. 1) which repeated every revolution of the meter. This pattern, caused by irregularities in the blade spacing, did not follow any trend within a revolution. Secondly, the positive displacement meters also showed a repeating pattern (Fig. 2) due to revolutions of the meter. Because of the higher resolution of these meters, the pattern was a few hundreds of pulses long. This pattern, unlike the previous one, was characterized by a regular increase and decrease in pulse time across each revolution of the meter. The term given to describe these two phenomena is intra-rotational non-linearity (IRNL) and the two effects will be called irregular and regular IRNL respectively.

Thirdly, it was seen that there existed a completely random pulse variation superimposed on the patterns. When examined, this variation had an approximately normal distribution, although some examples showed broader or skewed distributions.

When testing the positive displacement meters with gearboxes using the three provers, it was observed that the calibration repeatability, although consistently poor, was different on each prover. No obvious explanation was found for this at the time of testing and the effect was thought to be either a faulty meter or electrical interference between the meter and the prover electronics.

3 COMPUTER SIMULATIONS OF PULSE VARIATIONS

To allow any guidance to be given in the Standard, it became clear that a relationship between the repeatability of calibrations, the pulse variation, and the number of pulses collected should be defined. It was even more obvious that the data for such a relationship could never be derived from flow testing since no control over either the number of pulses or the pulse intervals is possible.

To aid the revision of the ISO document, NEL produced a simulation program to investigate the various factors influencing pulse interpolation. The results of the simulations were presented (Ref 5) last year and have been used in the discussions of the Standard revision.

The program simulates the action of a meter prover with switches placed to enable the collection of any pre-determined number of evenly spaced pulses. The pulses are totalised to allow any one of the three pulse interpolation timing methods to be examined. Pulse intervals are modified within pre-set limits to simulate pulse variation. The first simulations were carried out with variations being chosen, between pre-selected limits, using a random number generator to give equal numbers of intervals spread between the limits (flat distribution). The program was later modified to give an approximate normal distribution between the limits.

For each pulse variation and chosen number of collected pulses, 20 passes of the prover were simulated, and the repeatability, R, calculated from the equation:

$$R = \sqrt{2}\,\sigma t \text{ per cent}$$

where σ is Standard deviation of interpolated pulses

and t is Students t at the 95 per cent confidence limit.

The mean of five repeatabilities was calculated to give the result.

The double chronometry method of pulse interpolation was used for all the simulations and the results are shown in Fig. 3.

From these results the following relationship was derived.

$$R = (0.08 + 0.52V)\frac{1}{\sqrt{P}}$$

where R is the repeatability (per cent)

V is the per cent spread of pulse intervals

and P is the number of pulses collected.

The number of pulses necessary to meet the oil industry requirement of ± 0.02 per cent repeatability could now be calculated for any level of pulse variation. This was done and the result is shown in Table 1 along with the values recommended in ISO 7278/3.

4 REVISION OF ISO 7278/3

From experience of compact provers in the field, the predicted number of pulses required to give acceptable repeatability was considered to be too high. This conclusion was based on the data presented from flow tests using small volume provers, but without much evidence of pulse interval variation levels. Where pulse intervals had been measured, only the range of intervals was given and no information on the distribution of intervals or the intra-rotational non-linearity. A revised Table showing the minimum recommended number of pulses has been drawn up as a first draft estimate for discussion. These show values which are a best compromise between the results of flow experience in the field and the simulations.

This information, Table 2, is designed to give guidance on the minimum number of pulses collected to avoid significant error. The level of repeatability expected from this condition is not stated nor is the definition of 'significant error'.

A further modification to the Table has been made to change the expression of the pulse variation from a spread to a standard deviation of pulse intervals. This change enables a more statistical approach to the measurement of pulse intervals to be made and allow, to some extent, for the distribution of the intervals. However, it does not account for intra-rotational non-linearity except in the most general way. This modification has allowed a statistical analysis of the relationship between pulses and repeatability to be carried out by Hayward (Ref 6), the results of which have been incorporated in Table 2

To compare these results with the NEL simulations, an assumption has to be made to convert range to standard deviation of pulse intervals. The range is assumed, for the large pulse numbers concerned, to be six times the standard deviation, which is an approximation which is thought to be acceptable. Again the results are given in Table 2.

For standard deviations up to 5 per cent, reasonable agreement is found between the predictions taken from simulation and statistical analysis. Above 5 per cent agreement is not as good, but since this corresponds to a variation in spread of 60 per cent, it is beyond the scope of the simulation.
One of the arguments for choosing a lower number of recommended pulses than are shown in either of the two theoretical approaches is that IRNL will allow the full range of the pulse variations to be ignored and only the random component of the variation need be counted. To examine this argument further, simulations were carried out with both regular and irregular IRNL.

5 SIMULATION OF IRREGULAR INTRA-ROTATIONAL NON-LINEARITY

Irregular intra-rotational non-linearity as would be produced by a seven bladed turbine meter was simulated. This was done by defining a pulse pattern and changing its spread to fall within set limits. This pattern was repeated every seven pulses, and the effect was superimposed on a random variation as described in Section 3.

The results of a simulation are shown in Fig. 4, where a 2 per cent random variation had a 10 per cent irregular IRNL superimposed on to it.

The repeatability is close to that expected from a 2 per cent random variation alone.

6 SIMULATION OF REGULAR INTRA-ROTATIONAL NON-LINEARITY

Regular IRNL, as might be produced by a high resolution positive displacement meter, was also simulated. In this case, the variation in pulse intervals was calculated using a sine function based on a selected cycle length. Again this effect was superimposed on a random variation.

The first simulation, Fig. 5 had a cycle length of 200 pulses with a pulse variation spread of 10 per cent. This was superimposed onto a 2 per cent random variation. It is observed that if the number of pulses collected is an exact multiple of the 200 pulse cycle, a very low repeatability is found. Between these numbers, however, the repeatabilities vary markedly.

A second simulation was carried out over a small range of pulses using a 100 pulse cycle. The cycle variation of 10 per cent was maintained along with the 2 per cent random variation.

The results are shown in Fig. 6. Across the range of pulses collected, the repeatability rises and falls regularly, with the lowest repeatability being found at exact multiples of one hundred pulses and the highest being mid-way between these points. The shape of graphed results is best described as a decaying fully rectified sine function. These findings indicate why the NEL calibrations of a positive displacement meter showed different repeatabilities when calibrated using different volumes of prover.

The repeatability will depend not only on how many pulses are collected, but on how many meter revolutions occur during a proving pass. More importantly, the magnitude of the fraction of a meter revolution, over and above whole revolutions, has a great effect on the repeatability of the calibration.

To investigate the effect further, a further simulation was carried out over a much larger range of collected pulses. In this case a cycle length of 200 pulses was chosen with the same levels of variation applied, ie 10 per cent cyclic, 2 per cent random. For each pass, the number of pulses collected was either a multiple of 200 pulses or the intermediate points. Fig. 7 shows the results. Two random variation curves have been drawn. The first curve is for a 2 per cent random variation alone from which it can be seen that when the pulses collected are a multiple of the cycle length, the cycle variation can be ignored. Between the multiples of the cycle length, the repeatability is poorer than would be expected from random pulse intervals of 10 per cent.

It appears that it would take many hundreds of meter revolutions to reduce the highest repeatabilities to the same level as a 10 per cent random variation, far less that expected of the underlying 2 per cent random component.

Two observations should be made at this time. Firstly, in simulating this regular intra-rotational non-linearity, each pass was started at a randomly chosen point in the cycle. Secondly, the standard deviation of the pulse intervals for a 2 per cent random and a 10 per cent regular variation was 3.5 per cent.

7 CONCLUSION

ISO 7278/3 is undergoing revision, and apart from a few minor changes, the most substantial modification lies in the guidance table. The original table, which recommends the minimum number of pulses required to be collected, is now clearly inadequate. The revised table being proposed increases these minimum recommendations substantially.

The work described in this paper indicates that, for pulse interval variations which are random, the revised figures are still perhaps a factor of ten too low to meet repeatabilities of $\pm$0.02 per cent. If irregular intra-rotational non-linearity is a large component of the variation measured, the estimates are perhaps reasonable, as the variation due to the meter rotations can be discounted. The position when regular intra-rotational non-linearity is present is much more complex. The repeatability varies greatly with the fractional part of the number of meter cycles in a proving pass. This explains why a lack of consistency has been found in the ability of compact provers to calibrate various types of meters, particularly positive displacement meters. If the prover volume and the meter revolution match or nearly match, good repeatability is found; if they do not extremely poor repeatabilities is obtained.

How this effect can be resolved within ISO will require much discussion. It is made especially difficult since the data on pulse variations, meter revolutions, and prover volumes from field tests are not available to verify the simulations.

REFERENCES

1 PATON, R. Experience with compact provers and pulse interpolation at NEL. Paper 5.1, North Sea Flow Metering Workshop 1986, October 1986. National Engineering Laboratory, East Kilbride.

2 PATON, R. An evaluation of Brooks compact prover. Flow Measurement Memo 376, April 1988, National Engineering Laboratory, East Kilbride.

3 PATON, R. An evaluation of Smiths systems small volume prover. Flow Measurement Memo 370, August 1987, National Engineering Laboratory, East Kilbride.

4 PATON, R. An evaluation of Daniel Industries small volume prover. Flow Measurement Memo 378, May 1988, National Engineering Laboratory, East Kilbride.

5 PATON, R. Predictions of flowmeter calibration repeatability using compact provers and pulse interpolation. Industrial Flow Measurement Onshore and Offshore, September 1987, IBC Technical Services.

6 HAYWARD, A. T. J. A simplified statistical analysis of the effect of pulse spacing variations on the repeatability of meter proving where pulse interpolation is employed. SGS Moore, Barrett and Redwood Ltd, RTN203, June 1988.

TABLE 1

COMPARISON OF PRESENT ISO RECOMMENDATION AND PREDICTION

Pulse interval variation %	Present ISO recommended minimum	Prediction for random variation R = 0.04%
1	50	225
2	100	280
5	250	4400
10	500	17000
20	1000	67000
30	1500	150000

TABLE 2

COMPARISON OF PROPOSED ISO RECOMMENDATION, PREDICTIONS AND STATISTICAL ANALYSIS

Irregularity of pulse spacing standard deviation %	Minimum number of pulses to be collected during a proving run		
	ISO	Statistical spread within 0.04%	Predictions *1 R = 0.04%
0.5	100	1300	1681
1.0	400	5000	6400
2.5	2500	30000	38800
5.0	10000	125000	153000
10.0	40000	280000	611000 *2
15.0	90000	500000	1373000 *2

*1 This assumes Standard deviation = 1/6 range.

*2 These points are beyond range of variations covered.

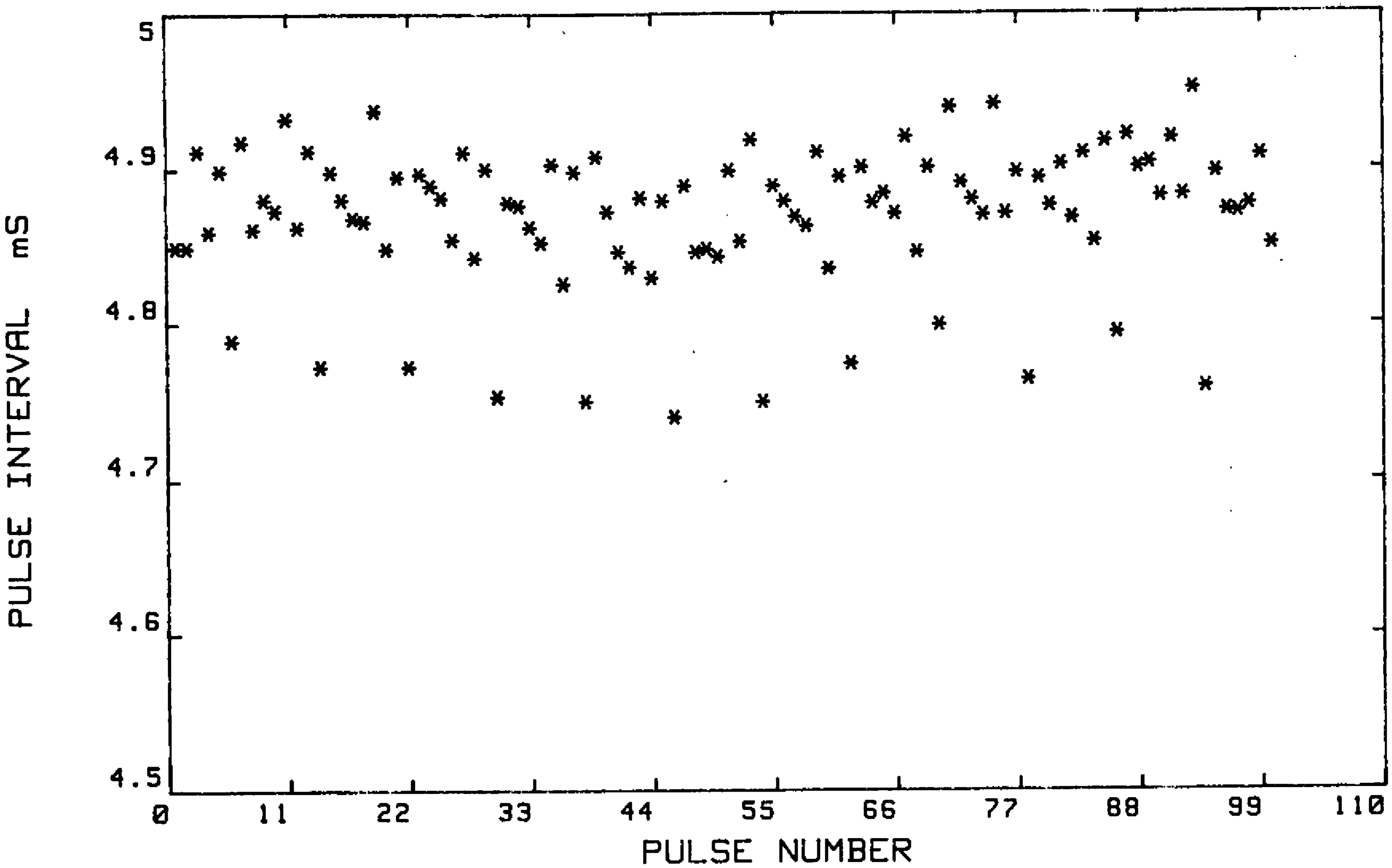


FIG I PULSE INTERVALS FROM TURBINE METER

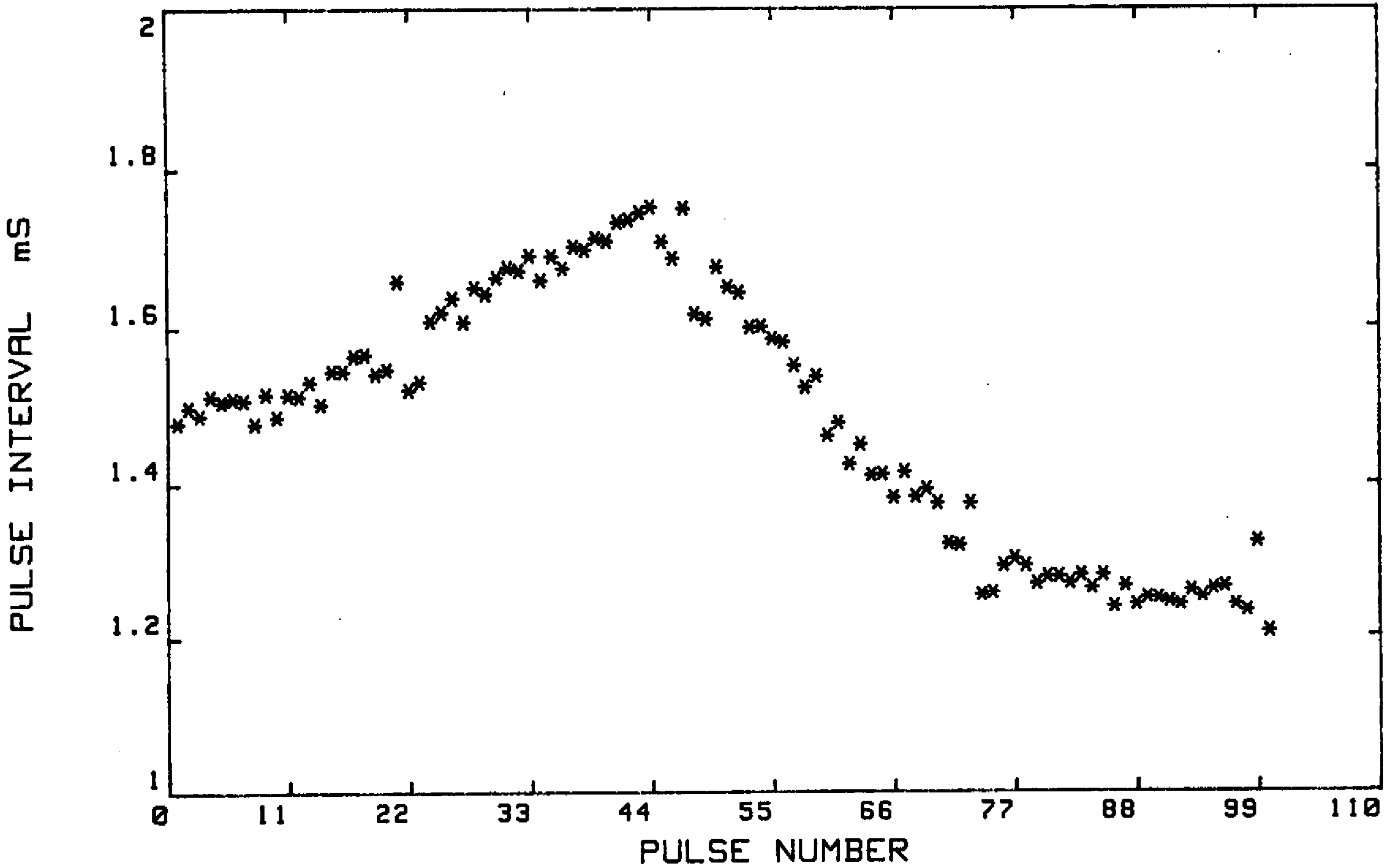


FIG 2 PULSE INTERVALS FROM METER

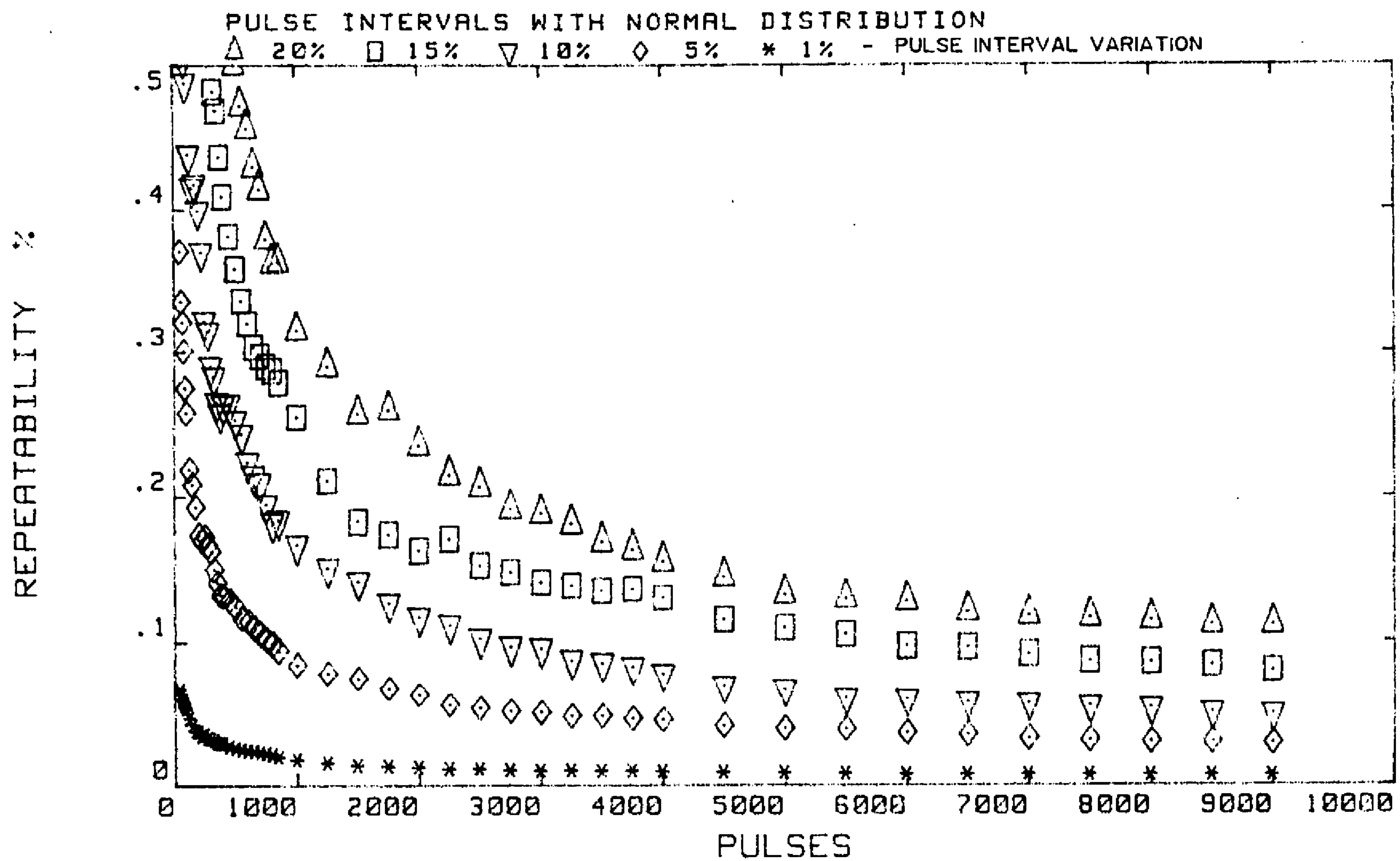


FIG 3 REPEATABILITY FOR DIFFERENT VARIATIONS

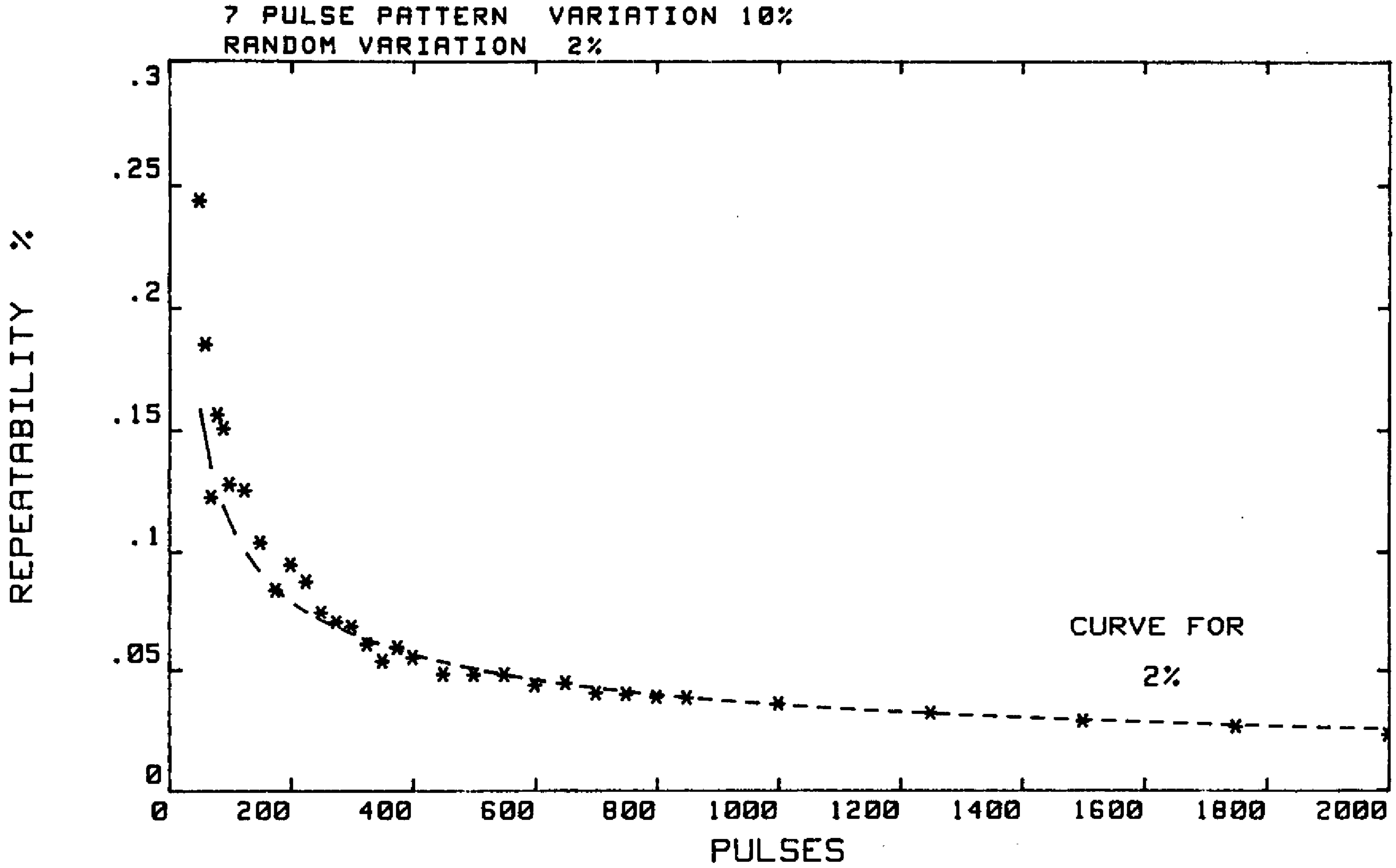


FIG 4 IRREGULAR INTRA ROTATIONAL NON LINEARITY

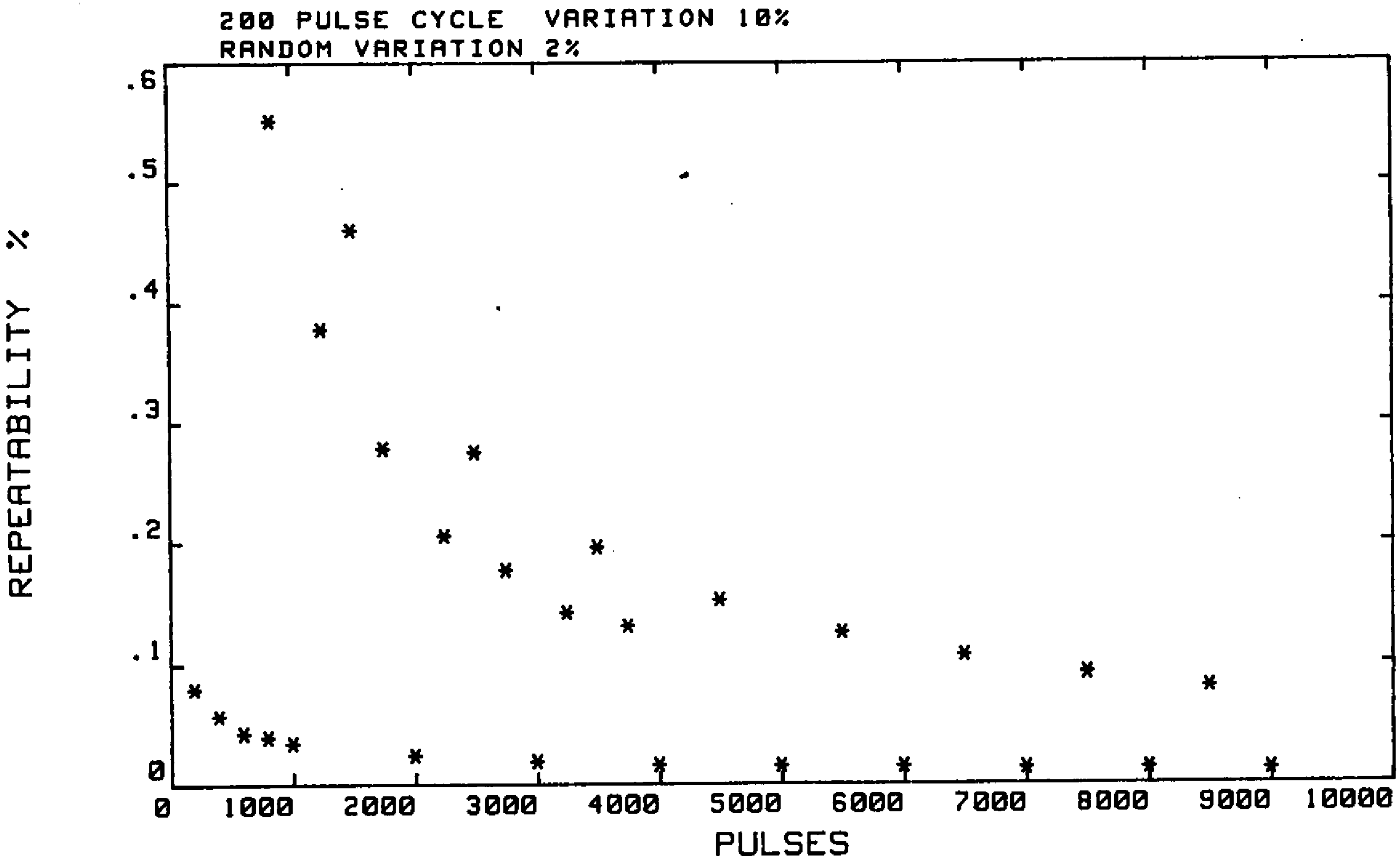


FIG 5 REGULAR INTRA ROTATIONAL NON LINEARITY

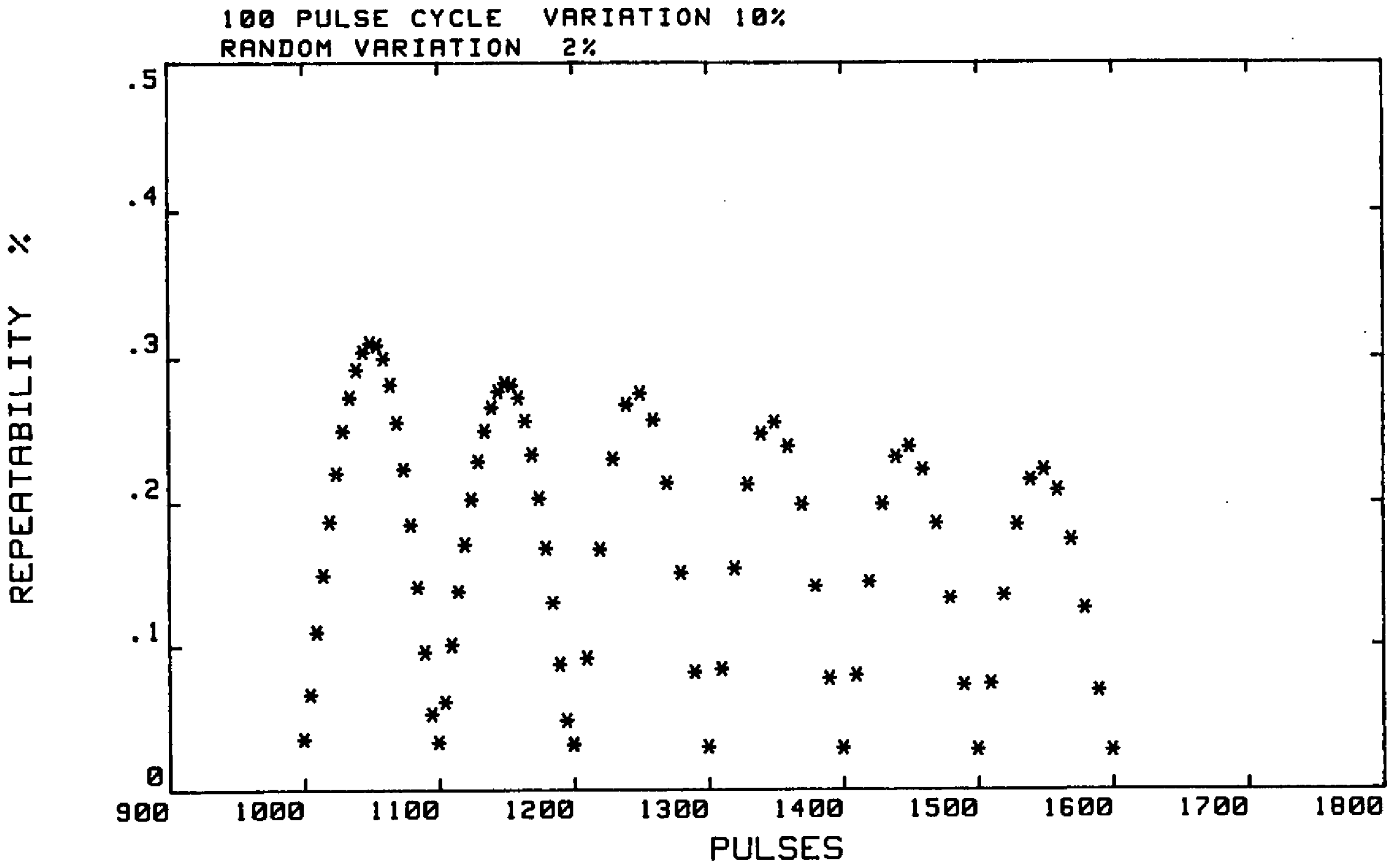


FIG 6 REGULAR INTRA ROTATIONAL NON LINEARITY

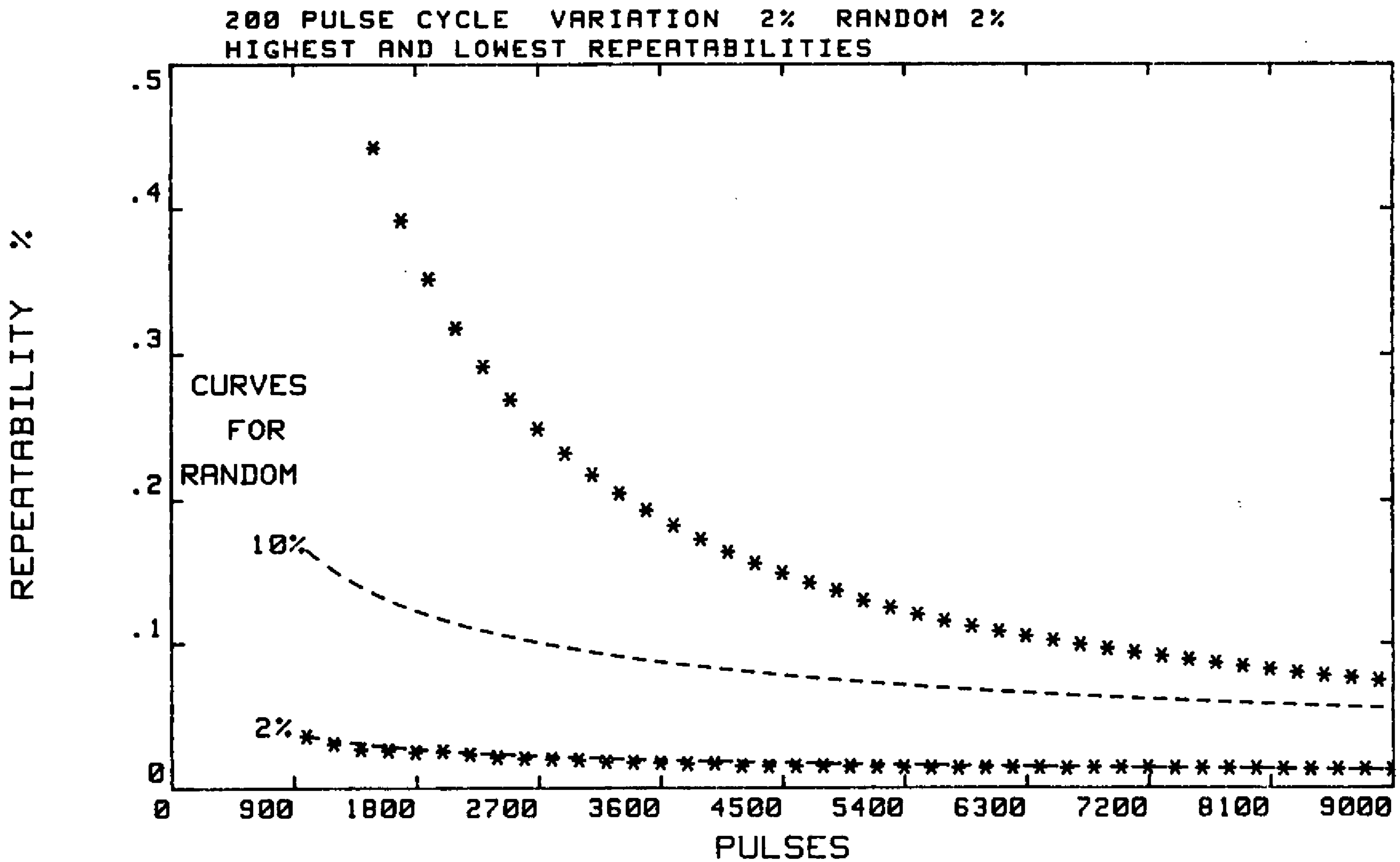


FIG 7 REGULAR INTRA ROTATIONAL NON LINEARITY