North Sea FLOW Measurement Workshop

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Main Index

INFLUENCE ON THE VELOCITY OF SOUND ON THE ACCURACY OF GAS DENSITY TRANSDUCERS

by

H TUNHEIM and E CARLSEN

ELF AQUITAINE NORGE

PAPER 1.1

NORTH SEA FLOW METERING WORKSHOP 1984

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INFLUENCE OF THE VELOCITY OF SOUND ON THE ACCURACY OF GAS DENSITY TRANSDUCERS.

E. Carlsen and H. Tunheim, Elf Aquitaine Norge A/S.

Much dissusion about the accuracy of Solartron equipment. Stansfeld of Solartron defended the

INTRODUCTION

Although the title on the paper implies that gas density transducers in general will be included in this presentation, the paper has been prepared to examine in some detail only the models from Solartron Transducer Group, namely 7810 and 7811 which appears to be in most frequent use in all North Sea metering applications. In addition a description of the experimental work carried out by Dantest on behalf of TOM and EAN is included.

Finally it is assumed that the basic operation/calculation of the density-meter is familiar to the audience and only those aspects related to the velocity of sound correction will be discussed.

VIBRATING ELEMENT TRANSDUCERS, 78 SERIES.

The basic principle of the gas density meter is based on the fact that th surrounding gas is brought into oscillation by the vibrating cylinder and contributes to the mass term in equation 1. This means that the natural frequency, Wo, decreases with increasing gas density, but unfortunately this is not always the case.

Any physical quantity which contributes to undesireable changes in the mass, M, or spring stiffness K, of the vibrating system will cause an undesirable change in the maintained oscillation frequency and systematic errors will occur. Below is a summary of the most important factors.

- Vibrating cylinder stiffness

  Changes in the spring rate may be caused by changes in the stress of the vibrating element. A stress effect on the sensing element can arise if there is a pressure difference between the inside and the outside of the cylinder wall. However, the gas is passed, both inside and outside of the cylinder eliminating any stress effects due to the pressure of the gas.

  Changes in the spring rate can also arise, caused by variations in the elasticity of the vibrating element for different temperatures. In most cases materials can be chosen to give a very low thermoelastic coefficient. A nickel/iron alloy called Ni-Spanc has this property, and if the material is cold worked out and then carefully heat treated, changes in elasticity with temperature will be very small.(1)

- Maintaining circuit

  Regarding the closed loop magnetic maintaining circuit it must be emphasised that this in no way will affect natural frequency, but only cancells the viscous damping and other damping mechanisms.

However, because of the power supply to the coils a self-heat generation is possible, but a high mechanical Q minimises the energy required to maintain system oscillations which reduce heat generation and any attendant errors.

Another aspect is that the vibrating element must be manufactured from magnetic material and as mentioned above, must be as stable as possible, exhibiting the same basic characteristic under differing environmental conditions. Ni-Span C has both these properties, but it loses its magnetic properties above 160°C.(1) This means that it cannot be used at temperatures higher than 100°C to 125°C dependent upon the shape, size and general characteristics of the vibrating element. At higher temperatures materials such as FV 520 can be used but there is a considerable loss of stability and some form of temperature correction becomes more necessary.

- Relation of sound waves

Sound waves are generated by the vibration of the solid body in contact with the fluid medium. When sound waves are produced in a region completely enclosed by walls, rigid or otherwise, all wave motion is standing-wave motion and the acoustic pattern is determined by the nature of its geometry. For our case the acoustic picture will be very complicated, due to the shape and vibrating mode of the cylinder, but some general aspects will be discussed.

A cavity filled with fluid which is brought into oscillation will have many resonance frequencies. Those resonances depend on the geometry of the cavity and velocity of sound of the fluid.

In the frequency range before resonance, outgoing and reflected sound waves will be in the same phase. This means that the pressure will be increased both by outgoing and reflected sound waves. Sound waves will be reflected in a different manner and give a different acoustic picture outside and inside the cylinder wall due to the different shape of the reflecting walls and different distances. Thus a pressure difference will arise which will affect the cylinder stiffness and turn the vibrating system into a stiffness loading system. The natural frequency will increase instead of decrease with increasing fluid density due to the increased stiffness.

When a resonance is passed, outgoing and reflecting sound waves are not in phase and in the frequency range well above a resonance frequency, pressure difference is not dominating. The vibrating system becomes a mass loading system. Thus, the basic principle which the gas density-meter is based on exists.

The first three resonance frequencies of this system arise when:

1. The distance between the cylinder wall and the reflecting wall is a half wavelength.

2. The cylinder circumference is one wavelength.

3. The cylinder length is one wavelength.

A combination of the three mentioned, will give a number of other resonances and the vibrating system will have a very complex acoustic picture. What must be remembered is that the vibrating system can be both a mass loading or a stiffness loading system dependent on the frequency range. In the frequency range before resonance it will always be a stiffness loading system, then it will turn into a mass loading system every time a resonance is passed. For this particular system the three first resonances will not represent a great problem, due to the mode of cylinder vibrations. The cylinder vibrates in a radial mode (see Fig.1) and the volume inside and outside is not changed. This makes the system less sensitive to stiffness loading.

- Effective oscillating mass

When the frequency and the geometry is adapted in a way which make the vibrating system a mass loading system, the fundamental principle of the vibrating cylinder densitymeter exists. However, the gas mass which is brought into oscillation, the effective oscillating mass, is not only dependent on the gas density, but will be affected by the transport characteristic of the gas too.

The vibration of the cylinder is shown greatly exagerated in Fig. 1. When the cylinder vibrates in its simplest radial hoop mode. The shaded areas represent the amount of gas which moves in a oscillatory manner over a distance l. Of course not all the gas in the shaded areas moves directly around the circumference, there must be a circumferential fluid movement outside the cylinder as well as an axial and radial fluid movement both inside and outside the cylinder.

However, in order to develope a mathematical equation describing the motion of the gas, a simplified model is needed. Solartron describes in their technical data sheet IDS-105 [2] a simplified model shown in figure 1 which is considered to be an reasonable approximation for the actual movement of the gas along the cylinder wall. Fig. 3 shows the cylinder, spoolbody and liner "opened out" to a linear situation. On this drawing it is perhaps easier to see the analogy to a piston movement used by Solartron to develope their mathematical equation.

Refering back to figure 2, a tube filled with gas has a piston at each end moving, in synchronism, with displacement acoswt, and a distance, l, apart. An element of gas next to each piston will move substantially with the piston and with displacement, acoswt, but for elements away from a piston face, the elementary thin cross section, δx , will move with less amplitude. The displacement, δ , is a function of distance and time, t, and velocity of sound, C, and is given by the wave equation.

$$\frac{\partial^2 \delta}{\partial x^2} = \frac{1}{C} \frac{\partial^2 \delta}{\partial t^2}$$

In the technical note Solartron uses the concept of energy change to find a solution to the wave equation. The kinetic energy at the point of maximum velocity is transferred to potential energy at the point of maximum deflection. Hence the maximum value for kinetic energy occurs when : $\left(\frac{\partial \delta}{\partial t}\right)_{Max}$

Equation 4 describes the general expression for the kinetic energy of a standing wave. Following the mathematical manipulation suggested in Solartrons technical note, one will hopefully agree with the expression in equation 5. This shows that any system which measures the kinetic energy of a vibrating gas column as a means of deducting its density will arrive at a value described by equation 6.

Refering back to the simplified drawing in Fig. 1 it is seen that the value of l is equal to a quarter of the circumference. However, since the movement of gas in the real situation is more comprehensive the actual value of l to be used in the correction will be different.

Finally the quality of the simplified theoretical model and the resulting equation can only be judged when compared to experimental data.

The accuracy of the correction has of course been investigated by Solartron and also by the Dutch company, Gasunie. And for the low range model 7810 (0 - 16 Kg/M^3) sufficient data are available to form the accuracy of the correction. A recent report published by the Danish national center for testing and verification, Dantest, also supports the Solartron velocity of sound correction. However, the "magnitude of the accuracy" if such an expression can be used, is still very much discussed. But again refering to the Dantest report an uncertainty in the order to $\pm$ 0,1% is indicated.

For the high pressure model 7811 (0 - 400 Kg) experimental data on natural gas mixtures is not available in the high pressure range and Solartron "proves" the relevance of the correction using the ethylene IUPAC tables, i.e. comparing the error between published ethylene data and measurements (argon calibration) to the curves for velocity of sound for ethylene.It can be shown that the minimum error occurs when ethylene has the same velocity of sound as the argon used for the calibration i.e. about 320 metres/sec. This supports the theory of the velocity of sound correction in an elegant way, but the accuracy over the entire density range has not been demonstrated.

The issue of velocity of sound correction is further complicated by Solartron Transducer Ltd. by issuing two different calibration certificates for example, the high pressure model 7811 is issued with two calibration certificates, commonly refered to as:

1. User Gas certificate (ref. equation 7)

2. Calibration gas certificate using the "user gas offset" equation (ref. equation 8).

Finally if a Solartron flow computer is purchased and connected to the densitymeter the velocity of sound correction will automatically be calculated for you. The three approaches will as you may have guessed give rise to the three different answers, so it is hard to speak of accuracy in the correction unless experimental data is available to justify the selected approach.

It can be shown that equation 8 is a simplification of equation 7.

For an argon gas calibration Solartron Transducer Group calculate the term Gc/Tc+273 equal to 0,00282. This assumes the velocity of sound for argon is constant over the entire pressure and temperature range. Further G is defined as gas specific gravity/ratio of specific heat.

Now the specific heat of a gas is as you know dependent upon both composition, pressure and temperature. But since most flow computers do not calculate this value for you, the densitymeter user will probably program a constant value in flow computations.

With the above statements we hope to have succeded in pointing out our view that one cannot talk about accuracy of correction without having accurate experimental data as reference. The most favourable of the available methods to minimize metering errors can then be selected.

For this reason Total Oil Marine Ltd. and Elf Aquitaine Norge initiated a cooperation with Dantest to carry out experiments using natural and synthethic gas, and the objective was to show the absolute accuracy of the various equations so far discussed.

DANTEST EXPERIMENT

The density meters were calibrated by determining true density using the real gas law:

$$\rho = \frac{P}{Z \times R \times T}$$

Having obtained true density a regression curve between the period of the density meters and true density was established. The parameters were measured as follows:

P : The pressure was stabilized and measured with a Desgranges and Hout deadweight tester 5201S with a relative accuracy of 0,01%.

T : The temperature was held constant within 0,1°C by placing the density meters in series in a thermal cabinet. A resistance thermometer (PT100) was attached to each density meter. The stated accuracies was 0,05°C.

Z : The compressibility factor was measured using a Desgranges and Hout Z meter type 60000. This instrument had been previously calibrated using the NBS-tables. It is possible to establish Z with an accuracy of 0,1%.

R : The gas constant is determined from chromatographic analysis of the gas and is equal to the universal gas constant divided by molecular weight.

A sample of Frigg gas was analysed by Dantest while the premixed synthetic Frigg gas had previously been certified by the Department of Energy in Leicester.

TEST PROCEDURE

Two 7811 and two 7810 density meters were placed in the thermal cabinet and connected in series. A PT100 temperature element was placed in each position of the densitymeter.

The set up was leak tested with vacuum and with nitrogen at 20 bar.

With the thermal cabinet at approx. 35°C the density meters were calibrated with nitrogen, natural gas and the synthetic gas. During calibration, the density meters were filled with gas and stabilized during measurement. Due to equipment limitation data points were limited to the range 0 to 80 bar. From the data points, calibration certificates were calculated which enabled comparison to be made between original certificates issued by Solartron. The experiment was repeated at 3°C which is similar to the operating temperature at St. Fergus Plant.

RESULTS

One of the main objectives for EAN was to try and illustrate the accuracy of the argon calibration including the data calculated on user gas certificate using equation 7. Table I shows the results obtained. In August this year Dantest informed us that they had discovered a small leak in the hydraulic system of the dead weight tester which could have affected the measurements carried out in January this year. Dantest further indicated that this could at the most have affected the measurements by 0,2%. As such one should not put too much emphasize on the value of the discrepancy but a closer matching had been expected.

In St. Fergus the complete equation 8 is programmed into the flow computers and the similarity in densities obtained using the equation compared to Dantest results was naturally the subject of detailed examination. As mentioned previously the errors will be very much dependent upon how the specific heat is calculated. However, Total Oil Marine Ltd. uses a constant value of Cp/Cv calculated by using average parameters and properties of the Frigg gas. The results showed that this approach gave satisfactory matching to the experimental results over the relevant operating range.

Finally in order to indicate the integrity and accuracy table II is included. This table compares the Solartron nitrogen calibration with the nitrogen calibration carried out by Dantest. As seen the difference is less than the uncertainty of the data points.

Refering back to table I it should be mentioned that the composition of the synthetic gas is not exactly the same as the Frigg gas composition used by Solartron when computing the user gas certificate. However, the inadequacy of the argon calibration is further illustrated in table III.

In this table, Dantest's nitrogen calibration is compared to the density calculated with Solartron constants obtained with argon calibration and corrected to nitrogen by velocity of sound correction. The error is larger than the claimed accuracy of the density cell.

SUMMARY

Although one cannot draw any decisive conclusion from the information presented in this paper, some trends are nevertheless illustrated:

These are:

1. Argon calibration of the density cell should be avoided. Both because uncertainty in the velocity of sound data for argon and that the resulting correction for velocity of sound is rather large in natural gas application. For Frigg gas in the order of 0,8%.

2. If equation 8 is used in low pressure application (densiters 0 - 60 Kg/M^3) it is probably more accurate to use a constant value for Cp/Cp than calculating the true on line valve.

3. For densities in the range 0 - 60 Kg/M^3 calibrated with nitrogen, Solartron velocity of sound correction introduces an additional uncertainty in the density measurement of about $\pm$ 0,1%, which have to be added to basic calibration error of the instrument.

4. The basic theory of the velocity of sound and the overall accuracy is well documented in the low density range.

IMPROVEMENT IN DENSITY METER CALIBRATION

Due to equipment limitations maximum working pressure at the Dantest laboratory was 80 bar when the experiments were conducted. At the time of writing this paper the equipment is being redesigned to be able to operate in the pressure range 0 - 150 bar.

Elf Aquitaine Norge and Total Oil Marine will then be able to repeat the previous experiments over a wider range of pressures. Some of the experiments carried out during Phase I will be repeated in order to confirm the trends already reported in this paper.

The goal to obtain better accuracy in calibration of density meter can be obtained by either of the following two paths:

1. When reliable experimental data is available, it is a simple task to modify the relevant parameters in equation 7 or 8 to minimise error in density measurement.

2. The densitymeter constant can be established on a synthetic gas with similar properties to the relevant natural gas, thus eliminating the need for any velocity of sound correction.

When the Dantest Phase II experiments have been completed EAN and TOM in cooperation with British and Norwegian authorities will make the necessary adjustments to the exisitng calibration procedures used in the Frigg natural gas transportation system.

TABLE I

Deviation between density as determined by Dantest and user gas certificate.

User Gas Certificate	Dantest	Deviation 1 - 2 / 1
59,09	59,38	0,49%
51,00	51,24	0,47%
43,08	43,28	0,45%
35,36	35,51	0,42%
27,85	27,96	0,4 %
20,55	20,63	0,39%
13,47	13,53	0,45%
6,60	6,65	0,75%

TABLE II

Solartron nitrogen calibration compared with Dantest nitrogen calibration for 7810 density meters.

Density meter	Nominal pressure bar, abs.	Period micro sec.	1 Density Dantest N_2 3 °C kg/m^3	2 Density Solartron N_2 20 °C kg/m^3	3 Density Solartron N_2 3 °C kg/m^3	Error
A	10	224.1815	12.260	12.271	12.250	-0.08
	50	263.3800	61.95	62.02	62.00	-0.08
B	10	222.7444	12.257	12.278	12.260	-0.02
	50	260.9917	61.93	61.99	61.98	-0.08

TABLE III

Comparison between density calculated with Solartron constants obtained with argon calibration and corrected to nitrogen by sound of velocity correction and Dantest's nitrogen calibration at 35°C.

Density meter	Nominal pressure bar, abs.	Period micro sec.	1 Density Dantest N_2 35°C kg/m^3	2 Density Solartron Ar_2 20 °C kg/m^3	3 Density Solartron N_2 35°C kg/m^3	Error
C	10	485.2711	10.979	10.888	10.950	-0.26
	80	623.9000	76.48	75.98	76.21	-0.35
D	10	485.9037	10.979	10.867	10.928	-0.46
	80	621.8700	76.46	76.00	76.232	-0.30

References:

1. Green, D.R. "Resonant Frequency, Measurement tool of the Seventies". Control & Instrumentation, 7. 40-43. 1975.

2. Solartron Technical Data Sheet TDS 105: Sound velocity effect on the vibrating cylinder density Transducers.

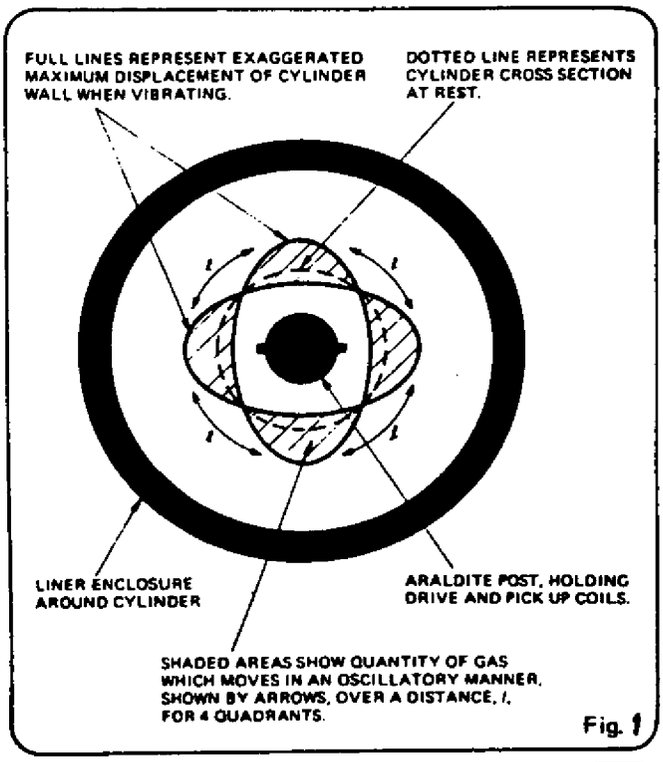

Fig. 1

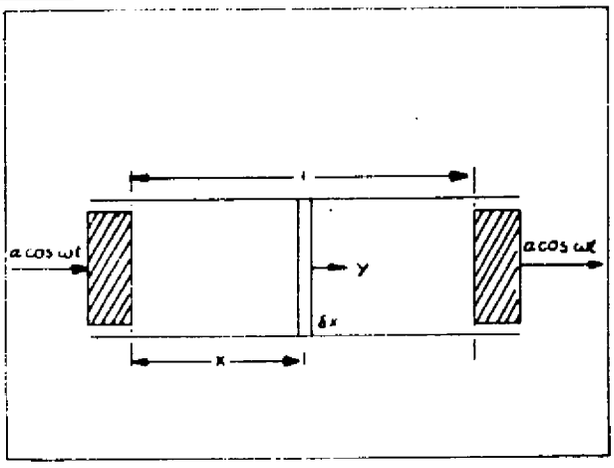

Fig. 2 A tube filled with gas and piston at each end

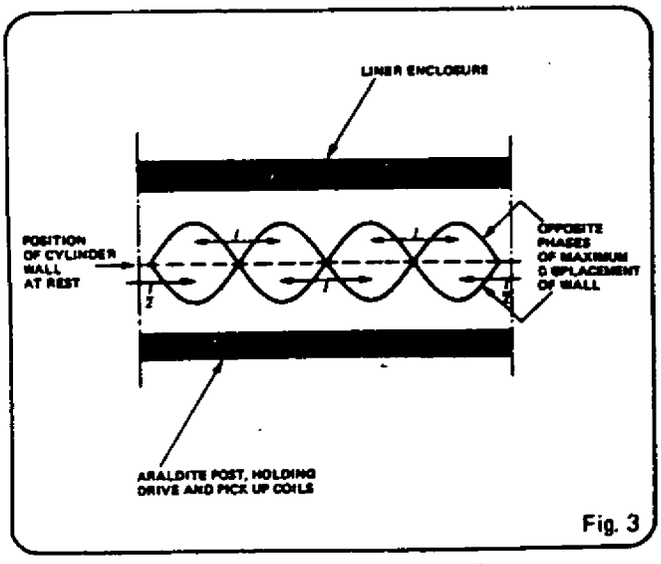

Fig. 3

$$\omega = \frac{1}{2}\,\pi\,\sqrt{\frac{K}{M}} \qquad \text{EQ.1}$$

WHERE ω = RESONANT FREQUENCY

K = STIFFNESS OF THE CYLINDER

M = MASS OF THE SYSTEM

$$\rho G = K_0 + K_1 \frac{1}{f} + K_2 \frac{1}{f^2} \qquad \text{EQ.2}$$

WHERE ρG = GAS DENSITY

f = OSCILLATION FREQUENCY

K_0, K_1 AND K_2 = CALIBRATION CONSTANTS

SOUND WAVE EQUATION:

$$\frac{\partial^2 \gamma}{\partial X^2} = \frac{1}{C}\,\frac{\partial^2 \gamma}{\partial t^2} \qquad \text{EQ. 3}$$

WHERE ∂X = ELEMENTARY CROSS SECTION

γ = DISPLACEMENT

X = DISTANCE

t = TIME

C = VELOCITY OF SOUND

$$1/2\, m v^2 = 1/2 \rho\, l\, (\omega \cdot a)^2 \qquad \text{EQ. 4}$$

Where $1/2mv^2$ = general kinetec energy

ρ = gas density

l = half wavelenght of the cylinder motion

ω = frequency

a = constant

$$K.E = 1/2\, \rho\, l\, (\omega \cdot a)^2 \cdot 1 + 1/6 \left(\frac{\omega l}{2c}\right)^2 \qquad \text{EQ. 5}$$

Where C = velocity of sound

$$\rho = \rho_i \left(1 + \tfrac{1}{6}\left(\frac{\omega l}{2c}\right)^2\right) \qquad \text{EQ. 6}$$

Where ρ_i = Indicated density

ρ = Actual density

$$\rho = \rho_i \frac{\left(1 + \tfrac{1}{6}\left(\frac{\omega l}{2c_c}\right)^2\right)}{\left(1 + \tfrac{1}{6}\left(\frac{\omega l}{2c_a}\right)^2\right)} \qquad \text{EQ. 7}$$

$$\rho = \rho_i \left(1 + \frac{k_3}{\rho_i + k_4}\left(\frac{G_c}{T_c + 273} + \frac{G_a}{T_a + 273}\right)\right) \qquad \text{EQ. 8}$$

Where ρ_i = Indicated density

ρ = Actual density

K_3, K_4 = Constants

G = $\frac{\text{Gas specific gravity}}{\text{Ratio of specific heats}}$

T = Temperature in °C

Main Index

CALIBRATION OF GAS DENSITY TRANSDUCERS USING NATURAL GAS

by

L ROSENKILDE

DANTEST

PAPER 1.2

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

CALIBRATION OF DENSITY METERS WITH NATURAL GAS

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1. BACKGROUND FOR THE WORK WITH GAS DENSITY

1.1. The Danish Natural Gas System

During the last ten years Denmark has built a system for distribution of natural gas coming foremost from the North Sea Thyra Field.

The main pipelines are distributed as seen on fig. 1. Along these pipelines 28 major stations are situated for quantity measurement of gas with turbine meters and density meters. The gas is measured in mass as follows (mass = Volume × density).

$$m = V \times \rho$$

Every station has two measuring sections each with a turbine meter and a density meter. Density will be measured at 16-40 bar and at 5 °C. The total number of density meters in Denmark is expected to be around 70, and these meters require a relevant calibration, which is the main subject of this paper.

1.2. Dantest involvement in natural gas metering

Dantest was formed as an independent institute the 1 January, 1980 merging together the National Institute for Testing Materials and the main part of of the National Bureau of Weights and Measures. Dantest has carried on to take care of mass and volume measurement in Denmark.

The density measurement of gas was therefore a natural continuation of this work, and over the past 4 years we have worked with several projects for the Technology Board/Agency of Technology (Government Organisation) concerning gas measurement.

To meet the need for calibration, Dantest has built a laboratory for calibration of density meters and for examination of the influence of the gas composition and calibration conditions on calibration results.

Dantest has furthermore laboratories for gas-chromatography and for calibration of smaller gas meters (diaphragm meters) with or without temperature compensation.

1.3. Traditional calibration methods

Traditionally gas density meters are calibrated introducing a known pure gas such as N_2 in the meter at controlled temperature and pressure conditions. The gas density is found from international accepted tables.

Then correlating the signal from the meter and the density of the gas a calibration point is achieved. Having several points, it is possible to evaluate an approximation for the density as a function of the vibration period, τ, of the density meter: $\rho = f(\tau)$. Where f usually is a 2. order polynomium in τ.

$$\rho = A\tau^2 + B\tau + C$$

As the calibration is made with a pure gas the question rises, how the density meter reacts on other gases such as natural gas containing many heavy hydrocarbons.

As an approach to this problem Solartron has as a manufacturer introduced their "velocity of sound correction" to be used for other gases than the calibration gas. The problem here is the lack of published documentation, and therefore it is difficult for the authorities to accept.

1.4. Calibration method with natural gas

Documentation for the necessary correction using a density meter calibrated with a pure gas to measure density of any natural gas is achieved by establishing

$$\rho_{cal.gas} = f_1(\tau) \qquad \rho_{nat.gas} = f_2(\tau)$$

This implies, that it is more direct to use a natural gas or a corresponding synthetic gas for calibration, instead of producing numerous corrections.

This was the main reason for Dantest in 1981 to build the already mentioned density laboratory.

In our laboratory we have established calibration curves for nitrogen-ethane mixtures, multi-component synthetic gas mixtures, and natural gas.

2. MEASUREMENT OF GAS DENSITY AND THE LABORATORY FACILITIES

The laboratory is primarily equipped for measuring density of gas with the object of calibrating density meters. In this process it was also necessary to create facilities for determination of the compressibility factor of any gas. In this way it is possible to examine, if existing tables such as AGA NX 19 are suitable for North Sea gas.

2.1. Determination of gas density

Density of gas can be determined in two ways. Fig. 2.

I By direct mass and volume determination

$$\rho_g = m/V$$

II By using the gas law

$$\rho_g = \frac{p}{Z \times R \times T}$$

ρ_g : density

p : pressure

Z : compressibility factor

R : gas constant (universal gas constant divided by mole mass)

T : temperature (in K)

m : mass

V : volume

In our laboratory density can be determined by both methods.

2.2. The layout of the laboratory

Fig. 3 shows a sketch of the laboratory.

The laboratory is divided into four sections.

a) Gas supply section

b) Compressibility factor measurement

c) Density measurement $\rho_g = m/v$ (method I)

d) Density measurement $\rho_g = \frac{p}{Z \times R \times T}$ (method II)

Item a)

The gas supply comprises a gas reservoir (gas bottles + regulator 300/150) plus a Desgranges & Huot deadweight-tester ① .

The deadweight-tester is used to stabilise and determine the working pressure for the other three sections. It has been calibrated by LNE*, and has a measurement range of 0.4 bar to 200 bar with a relative tolerance of 0.01 %. With the aid of a quick connection at Ⓐ , the "gas supply" can be connected to the three sections in turn.

Item b)

Comprises a Desgranges & Huot compressibility factor meter ④ (referred to as a Z-meter) and a Heto thermal bath which stabilises the temperature in the Z-meter. The Z-meter is calibrated with the aid of a known gas and the measurement range and accuracy are determined by the calibration. Dantest uses nitrogen with a purity of 99.9992 % and NBS tables for

* Laboratoire National d'Essais

nitrogen. The Z-meter is actually calibrated in the range 3 to 80 bar, and the use is limited to 90 bar.

Item c)

The section for determining the density according to method I comprises a pressure vessel ② , specially designed to calibrate density meters. This vessel can be used in the range 0 to 80 bar and can be used for most types of gas. The accuracy when determining density is between 0.05 % and 0.1 % depending on the pressure level and the type of gas. The vessel is equipped with measuring devices for pressure and temperature. The nominal volume is 12 litres.

Item d)

The section for determining the density according to method II comprises a thermal cabinet in which it is possible to place density meters. Each density meter is individually fitted with a Pt 100 resistance so that the temperature can be measured with an accuracy of ± 0.1 ^{o}C. The thermal cabinet ③ can be adjusted from 0 to 40 ^{o}C.

3. ACTUAL CALIBRATION PROCEDURES

This section describes briefly how the two methods for determining density are used for calibration of density meters. Fig. 4.

3.1. Determining density according to method I:

$$\rho_g = \frac{m}{V}$$

Calibration

Knowing the volume of the system (vessel + density meter) as a function of pressure and temperature, a calibration point (ρ, τ) can be found by weighing.

The mass of the gas is determined performing 3 steps:

1) Weighing the total system while it is empty.
2) Filling the system with gas. (After each filling/ emptying, the vessel is stabilized for at least 3 hours).
3) The vessel is weighed.

Temperature, pressure and the density meter signal are noted before and after weighing.

System volume

The total volume of the system (pressure vessel + density meter) is calibrated by a gravimetrical method. The measurement is a combination of nitrogen and water weighing. The volume of the vessel is determined by weighing the content of water. Experiments showed that it was necessary to determine

the volume at 60 bar since air bubbles disturb measurement at lower pressures. Further the volumetric pressure expansion coefficient for the vessel was found weighing the nitrogen content at three different pressures.

The volume of the density meter was determined by nitrogen weighing since the instrument could not tolerate water. It can be shown that the effect of the pressure expansion of the density meter is insignificant compared to the level of system accuracy.

3.2. Determining density according to method II:

$$\rho_g = \frac{p}{Z \times R \times T}$$

Calibration

The density meters are placed in a thermal cabinet and connected in series to the gas supply system. The temperature regulation is set to the required value and after stabilisation the calibration can begin.

The density meters are purged and filled with the calibration gas to the required pressure. Because of compression, a further stabilizing period of approximately 20 minutes is required.

Pressure, temperature and density meter signals are recorded continuously during stabilization and during the final read off.

The density meters are then filled/emptied for the next pressure stage until the required pressure is completed.

Compressibility, Z, and gas constant, R

Z can be determined according to tables, such as NBS tables for nitrogen and methane, or for other gases with the aid of the Z meter.

The gas constant, R, can be determined by calculation or by experiment. By calculation the known composition of the gas is used. The gas usually needs to be mixed gravimetrically in order to achieve sufficient accuracy, if the number of the components exceeds 2-3.

R can also be determined by measuring the density according to method I, and measuring the compressibility factor with the Z meter. Then R is calculated according to

$$R = \frac{p}{\rho \times Z \times T}$$

The Z meter

A sketch of the meter is shown in fig. 5. Since knowledge of the Z-value is a necessary basis for the use of natural gas or multicomponent gas mixtures for calibration of density meters, a more

detailed description is given of the measurement procedure.

The Z meter comprises two chambers with a pressure transducer placed in the largest chamber, three pneumatic valves A, B, and C, and two resistance thermometers.

Measurement procedure

Two valve positions are possible:

Valve position	Valve A	Valve B	Valve C
1	open	closed	open
2	closed	open	closed

In valve position 1 gas is filled in V1 to the required pressure and stabilised by the deadweight-tester. After a period of stabilisation the pressure transducer signal and temperature are noted.

In valve position 2, after the gas is distributed in the two chambers, the pressure transducer signal and temperature are noted again.

Determination of Z

The basis for calculating the compressibility factor Z is the real gas equation : $pV = ZnRT$.

Position 1

$p_1V_1 = Z_1n_1RM$

$p_2V_2 = Z_2n_2RM$

Position 2

$p_3(V_1 + V_2) = Z_3(n_1 + n_2)RM$

p_1, p_2 : Pressure in V_1 and V_2 respectively

p_3 : Pressure in $V_3 = V_1 + V_2$

T : Temperature (held constant)

Z_1, Z_2 : Compressibility factor for the two states (V_1, p_1, T) and (V_2, p_2, T).

Z_3 : Compressibility factor for state ($V_1 + V_2$, p_3, T)

n_1, n_2 : Number of moles af gas in V_1 and V_2 respectively

With these three equations we get an expression for the compressibility factor for the unknown gas, Z_1:

$$Z_1 = \frac{p_1}{\frac{p_3 \times (1 + A)}{Z_3} - \frac{p_2 \times A}{Z_2}}$$

A is the volume ratio V_2/V_1, measured by the manufacturer.

p_2 is the barometric pressure.

p_1 is the sum of the barometric pressure and pressure from the deadweight-tester.

p_3 can be determined after calibrating the pressure transducer. For this purpose a gas which properties are known from internationally recognised tables, e.g. nitrogen, is used.

Since Z_2 and Z_3 are unknown, the linear relationship between Z and p is used:

$$Z = 1 - k \times p$$

This applies to gases at pressures below 20 bar.

The gas constant, k, is determined, e.g. by iteration between the following two expressions:

1. $$Z_1 = \frac{p_1}{\frac{p_3 \times (A + 1)}{1 - k \times p_3} - \frac{p_2 \times A}{1 - k \times p_2}}$$

2. $$k = (1 - Z_1)/p_1$$

4. PRESENT STATE AND FURTHER DEVELOPMENT

4.1. Present state

Gas composition

It is important to have a good knowledge of the expected average composition of the gas to be measured.

From this composition a calibration gas is chosen. It can be either a sample of natural gas or a good synthetic reference gas.

Compressibility, Z, and gas constant, R

Z is measured at the temperatures and pressures (T, p) which are going to be used for calibration.

R is found with the highest accuracy by weighing, and Z determination. Another possibility is to calculate R from the gas composition found by gas-chromatography if the achieved accuracy is acceptable. If the gas composition is known with sufficient accuracy from the mixing process, this composition might be used, but we have had some problems using this way, in getting an officiel certificate of the composition.

Calibration

For each bottle of gas Z and R must be determined as described above. But as the gas consumption for calibration of density meters is small, the same bottle can be used again and again without new determinations of Z and R.

4.2 Development

At the moment the pressure is limited to 90 bar

in the Dantest laboratory because of the Z meter.

In order to meet the off-shore demands a new Z-meter is under construction.

It should be able to operate up to 150 bars. This Z meter which is shown in fig. 6. consists of two pressure vessels of 0.3 ℓ and 3 ℓ. Here we have the advantage, that we can calibrate the volume of the two vessels individually with airfree destilled water, and thus the Z-values will be independent of any existing gas tables. These tables will then be used for control of the Z meter.

With the new instrument it will be possible to calibrate density meters using natural gas in the off-shore pressure range too.

5. RESULTS

In this paper we are publishing some of our results for pure gases and synthetic gas mixtures representing expected natural gas compositions. Later we hope to publish results for natural gas too.

5.1. Measurements with nitrogen

To establish reliability of the laboratory and to estimate the accuracy level, nitrogen results were compared to NBS tables in the following way.

- Comparison of density measured by method I, $\rho = m/V$, with NBS tables showed a correspondance within 0.05 %.
- Comparison between method I and II using nitrogen showed deviations less than 0.06 %. The density meter signals (period) obtained in method I were introduced in the calibration curve obtained by method II, and the densities thus calculated were compared to the measured density $\rho = m/V$.

5.2 Measurements with methane and synthetic gas mixtures

The gases which have been used in the laboratory can be divided into 4 groups:

- methane
- two component methane/ethane mixtures
- synthetic gas mixtures (reference gases for natural gas)
- natural gas (not included here)

We have focused on the expected Danish gas composition and in the following typical results are given. Further results are given in the Dantest report for TR-project 133/360-81.368, "Calibration and examination of gas density meters".

Fig. 7 shows results obtained with a Solartron 7810 density meter for two gas mixtures. These two gas mixtures were chosen as reference gases for the

expected Danish gas composition. The figure shows the relative difference between the "true density" of the gas and the density determined from the density meter signal using the calibration constants obtained with nitrogen. "True density" is here achieved from $\rho = p/R \times Z \times T$. Abscissa is the above mentioned density obtained from the density meter using the calibration constants obtained with nitrogen. This is the resulting error, when a density meter calibrated using nitrogen is used for measurements on another gas.

The deviations up to 1 % show, that a correction is needed.

Table 1.

	Fraction of volume	
	"Natural" Gas 1	"Natural" Gas 2
CH_4	0.8956	0.9079
C_2H_6	0.0573	0.0491
C_3H_8	0.0223	0.0164
C_4H_{10}, i	0.0076	0.0074
C_4H_{10}, n	0.0059	0.0055
CO_2	0.0059	0.0059
N_2	0.0054	0.0078

Fig. 8 shows furthermore corresponding results for methane and methane/ethane mixtures. The results indicate, that a mixture with 6 % or 8 % ethane in methane might be used as a calibration gas instead of mixture 1 or 2.

The result for pure methane shows, that using methane as calibration gas, a correction is needed.

Fig. 9 corresponds to fig. 8, and it shows the similarity of two density meters of the same type Solartron 7810. As seen they agree within 0.05 %, which is under their calibration accuracy of 0.1 %.

We have very few data concerning temperature influence but in fig. 10 some results are compared to the Solartron temperature correction. The deviation is within the stated accuracy of the results. $\rho_{20\,^oC}$ is calculated from the calibration constants established at 20 ^oC and the signal given metering on the same gas at 5 ^oC. $\rho_{5\,^oC}$ is the gas density at 5 ^oC determined from p, Z, R and T.

6. ACCURACY AND TRACEABILITY

6.1 Accuracy

Z-measurement

Comparing the Dantest Z-results for methane with the corresponding values from the NBS tables gives an estimate of 0.05 % for the systematic uncertainty of Z. Having a random uncertainty of 0.024 %, we get an estimate for the uncertainty of Z of

$$100 \times \frac{e_Z}{Z} = \sqrt{0.05^2 + 0.025^2}\ \% = \underline{0.06\ \%}$$

This gives a reasonable basis to estimate 0.1 % as our general Z-uncertainty.

Density measurement

For the pressure the uncertainty is 0.01 % and for temperature 0.024 % based on certificates for the equipment. For R measured 0.06 %.

The estimate for the systematic uncertainty for ρ is then

$$\sqrt{0.06^2 + 0.01^2 + 0.024^2 + 0.06^2}\ \% = 0.09\ \%$$

The random uncertainty is 0.014 % and then the estimate for the total uncertainty of ρ is $\cong$ 0.1 %.

This gives the basis to estimate 0.15 % as the general uncertainty of the density calculated from the calibration curve because we normally only see deviations around 0.02 % between the value of ρ calculated from the calibration curve and ρ measured.

6.2 Traceability

It is important, that all equipment is calibrated in a proper way. At Dantest we have used the following institutes, which all are traceable to international accepted standards.

Instrument	Institute	Intervals
Deadweight-tester	LNE	2 years
Pt 100	RISØ	1 year
Barometer	SAS	1 year
Z-meter	Dantest, NBS tables	1 year
Electronic scale	Dantest	1 year
Weights	Dantest	1 year

6.3 Control procedures

The Z-meter is calibrated using the NBS-tables for nitrogen. The Z-meter is then used to measure Z-values for methane, and these values are compared with the NBS methane tables. Typical deviations are in the range of 0.03 - 0.08 %.

When calibrating density meters one or two known Dantest reference meters are inserted in series with the meters to be calibrated. The signal from the reference density meters are compared with their calibration curves before calibration of the unknown density meters.

Readings of all instruments are performed according to stabilization criterias, developed from experience and the desired accuracy of the measurements.

7. CONCLUSION

Our conclusion is, that the most direct way for calibrating density meters, is to use a representative gas mixture for the gas to be measured.

It is better to use such a gas for calibration of density meters, than to use it to find a correction for another calibration gas. The same measurements have to be done.

This procedure gives the highest probability for a good measurement, and it is possible in this way to obtain an uncertainty of the density as small as 0.15 % or even smaller.

It presents of course some safety problems, but they are reasonable to handle.

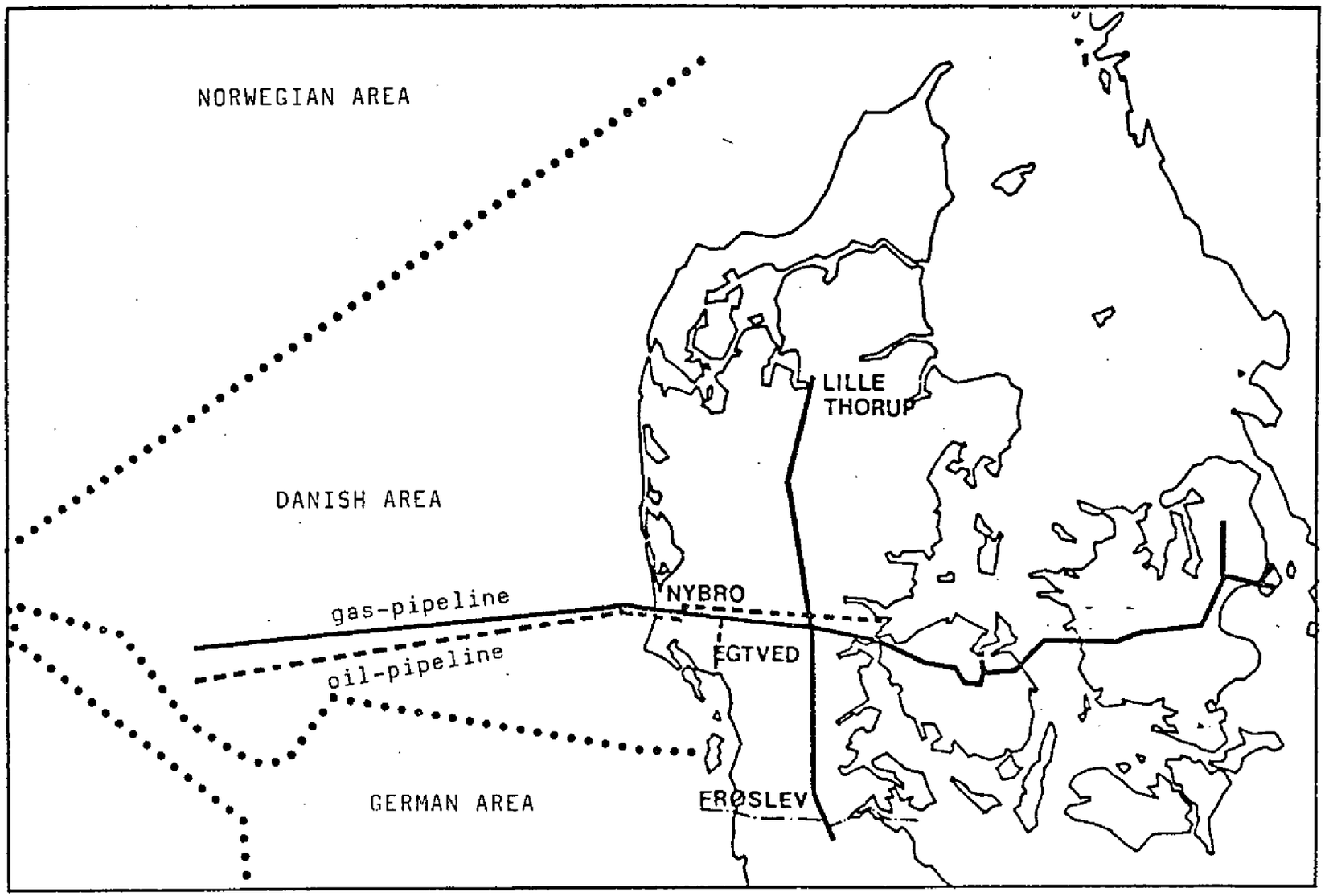


Fig. 1 The danish natural gas system

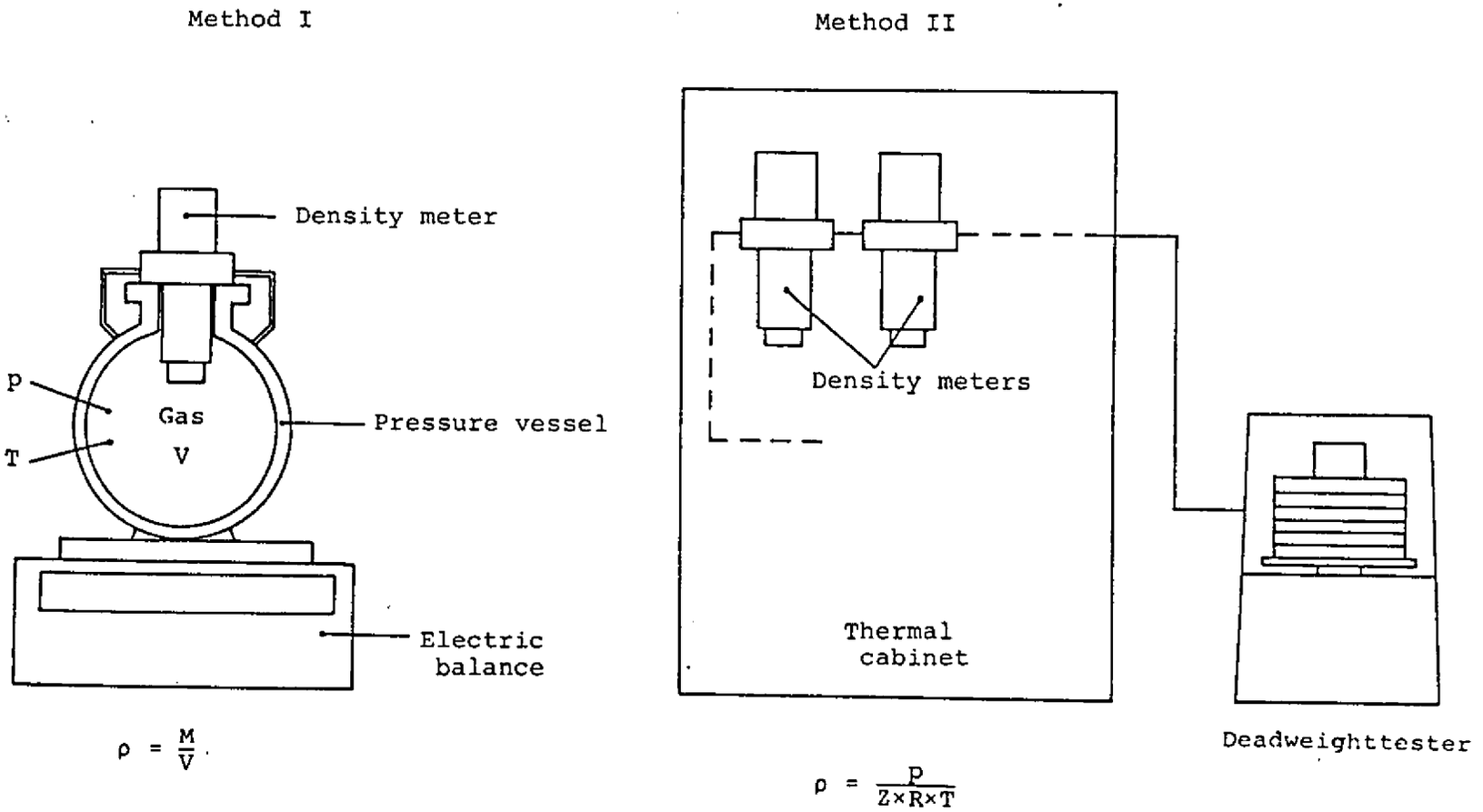


Fig. 2 Schematic figure of the two methods for measuring gas density in the laboratory of Dantest.

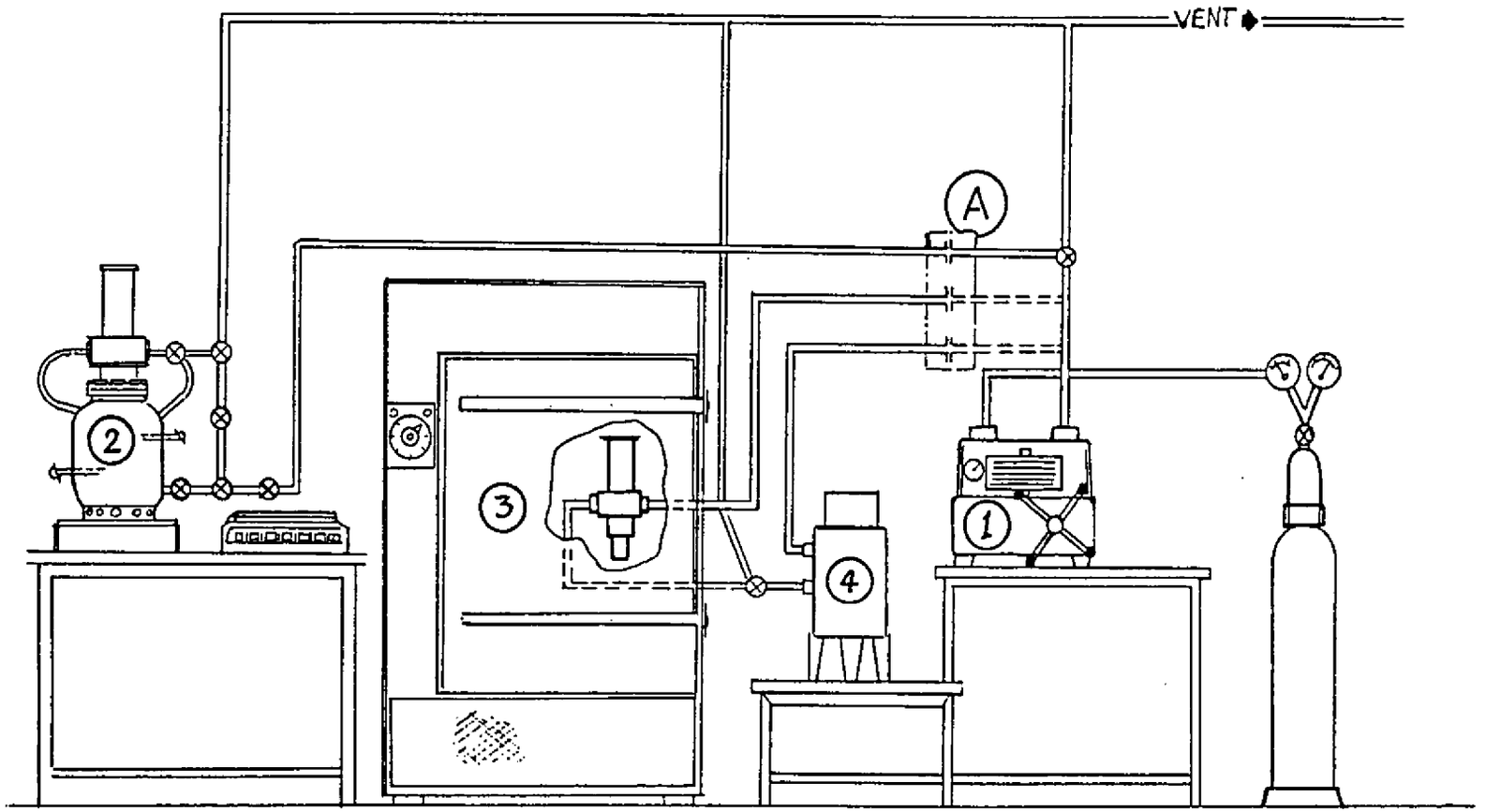
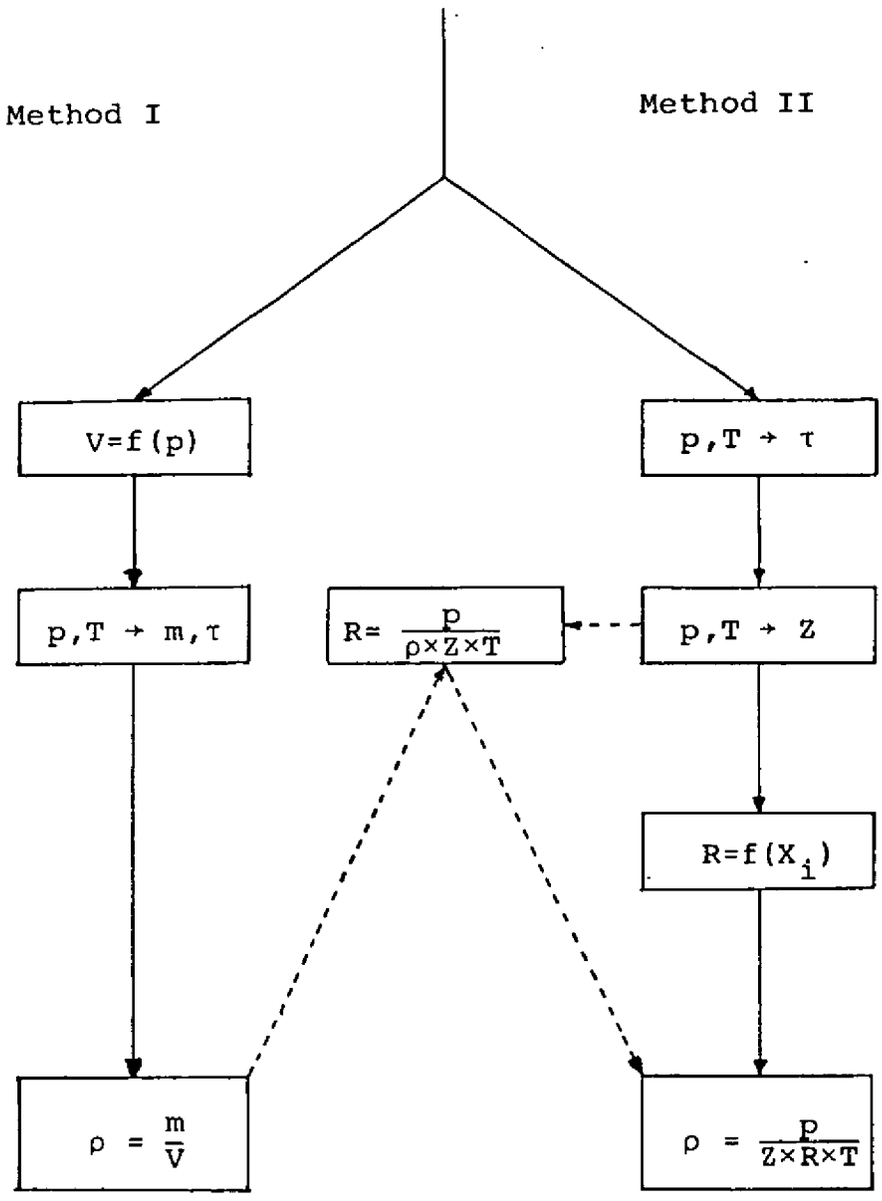


Fig. 3 Scetch of the laboratory.

Fig. 4 Measuring the density of gas



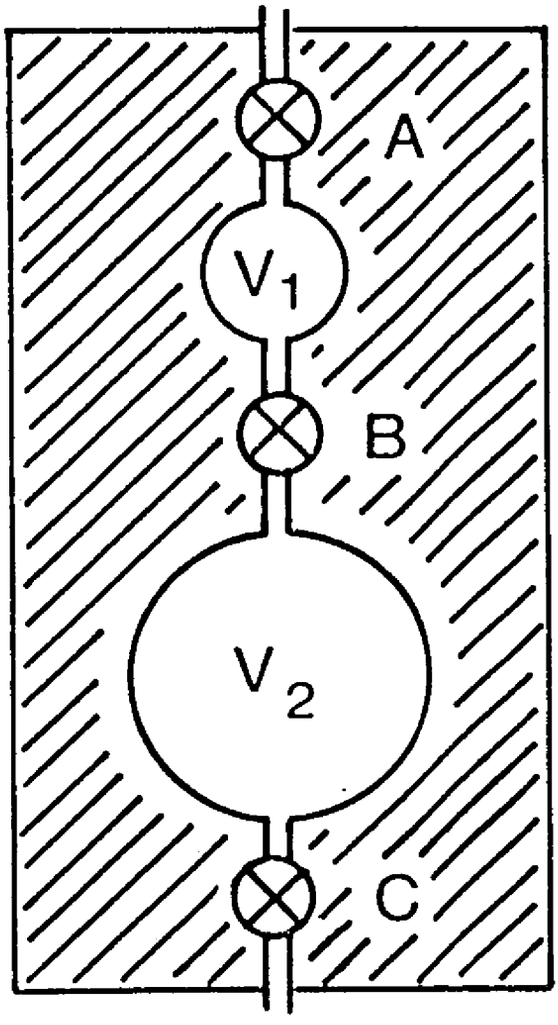


Fig. 5 Schematic drawing of a Desgranges and Huot Z-meter. Pressure range: up to 90 bar.

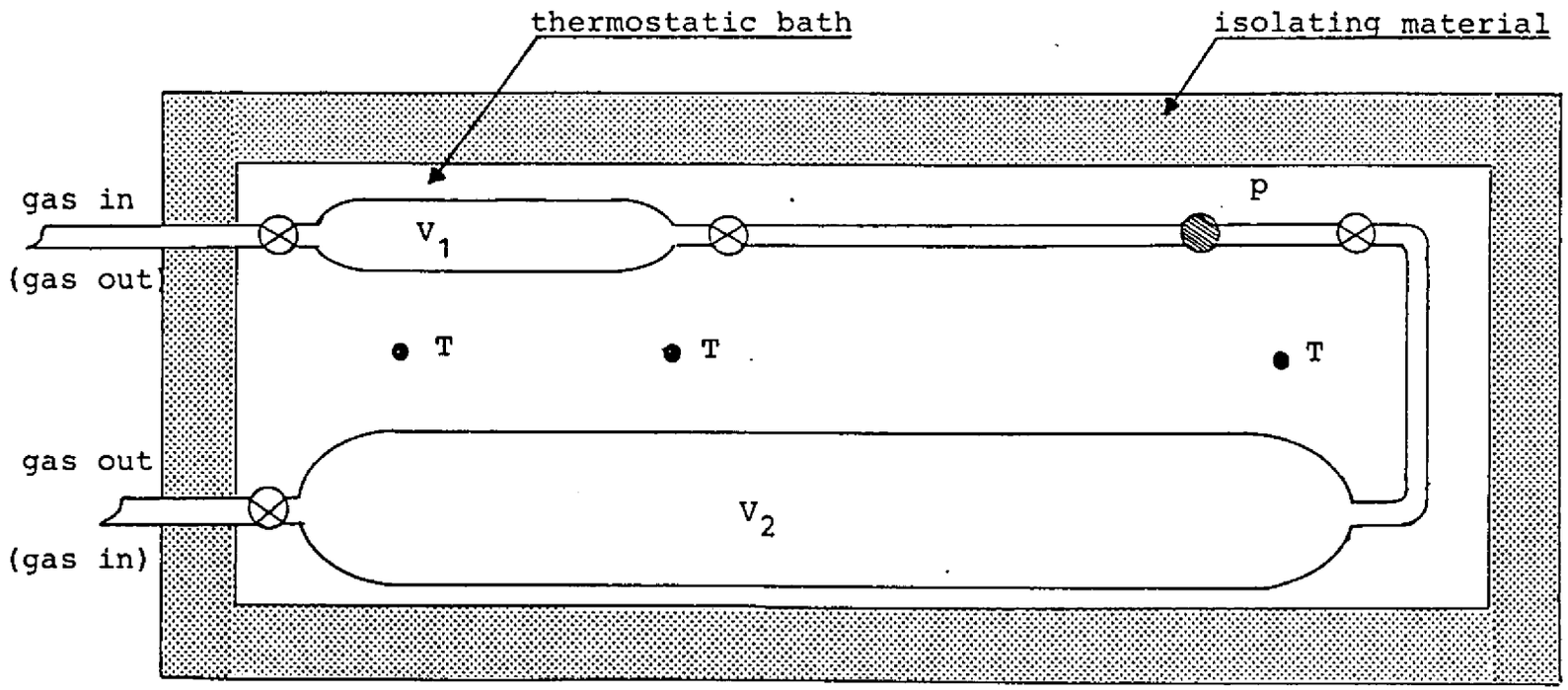


Fig. 6 Schematic drawing of the Z-meter Dantest has built. Pressure range: 50-150 bar

Fig. 7 THE RELATIVE DEVIATION BETWEEN "TRUE DENSITY" (DETERMINED FROM p, T, Z AND R) AND DENSITY CALCULATED USING CONSTANTS DETERMINED BY THE NITROGEN CALIBRATION.

DENSITY METER TYPE : SOLARTRON 7810 no. 6343

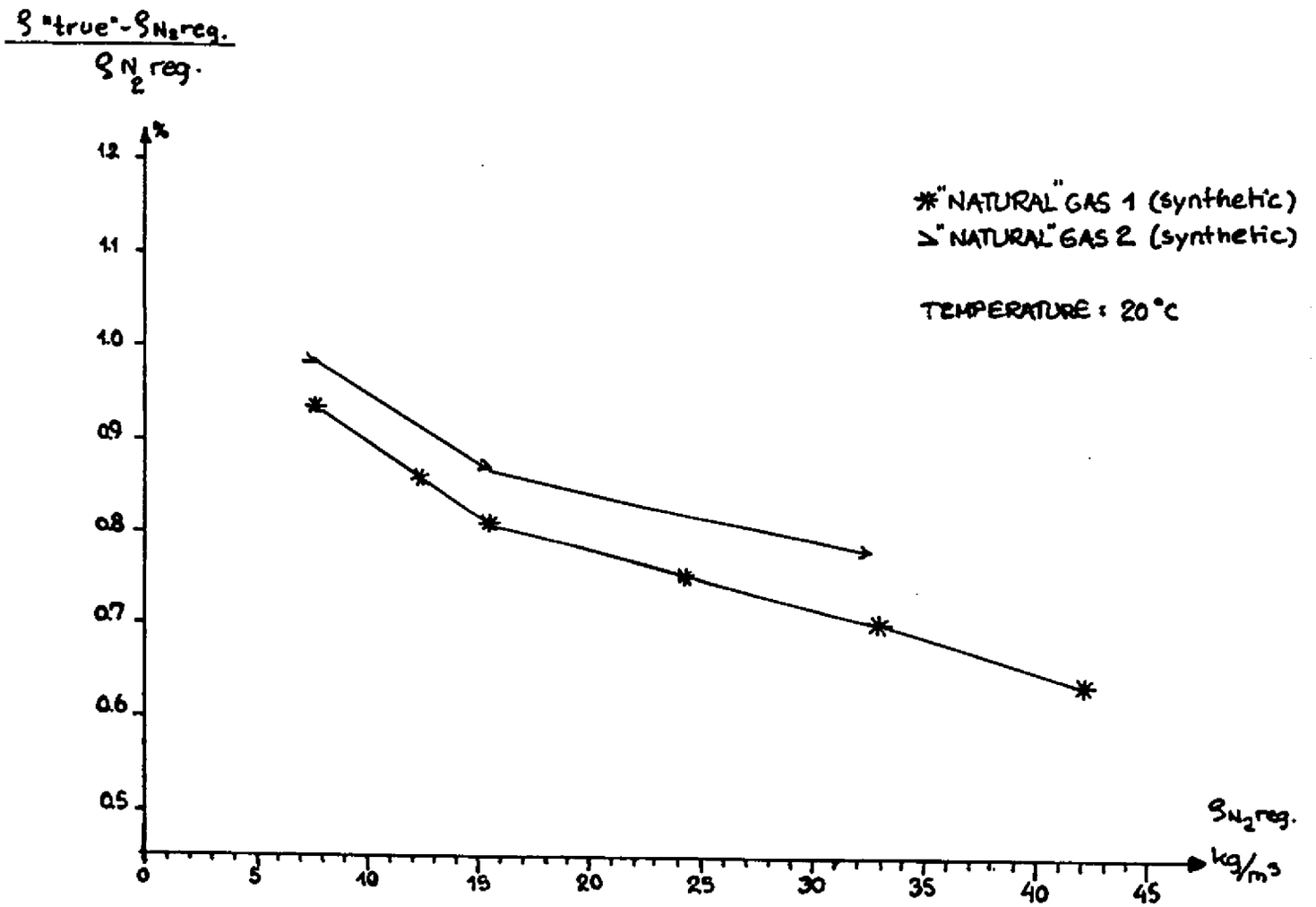


Fig. 8 THE RELATIVE DEVIATION BETWEEN "TRUE DENSITY" (DETERMINED FROM p, T, Z AND R) AND DENSITY CALCULATED USING CONSTANTS DETERMINED BY THE NITROGEN CALIBRATION.

DENSITY METER TYPE : SOLARTRON 7810 no. 6343

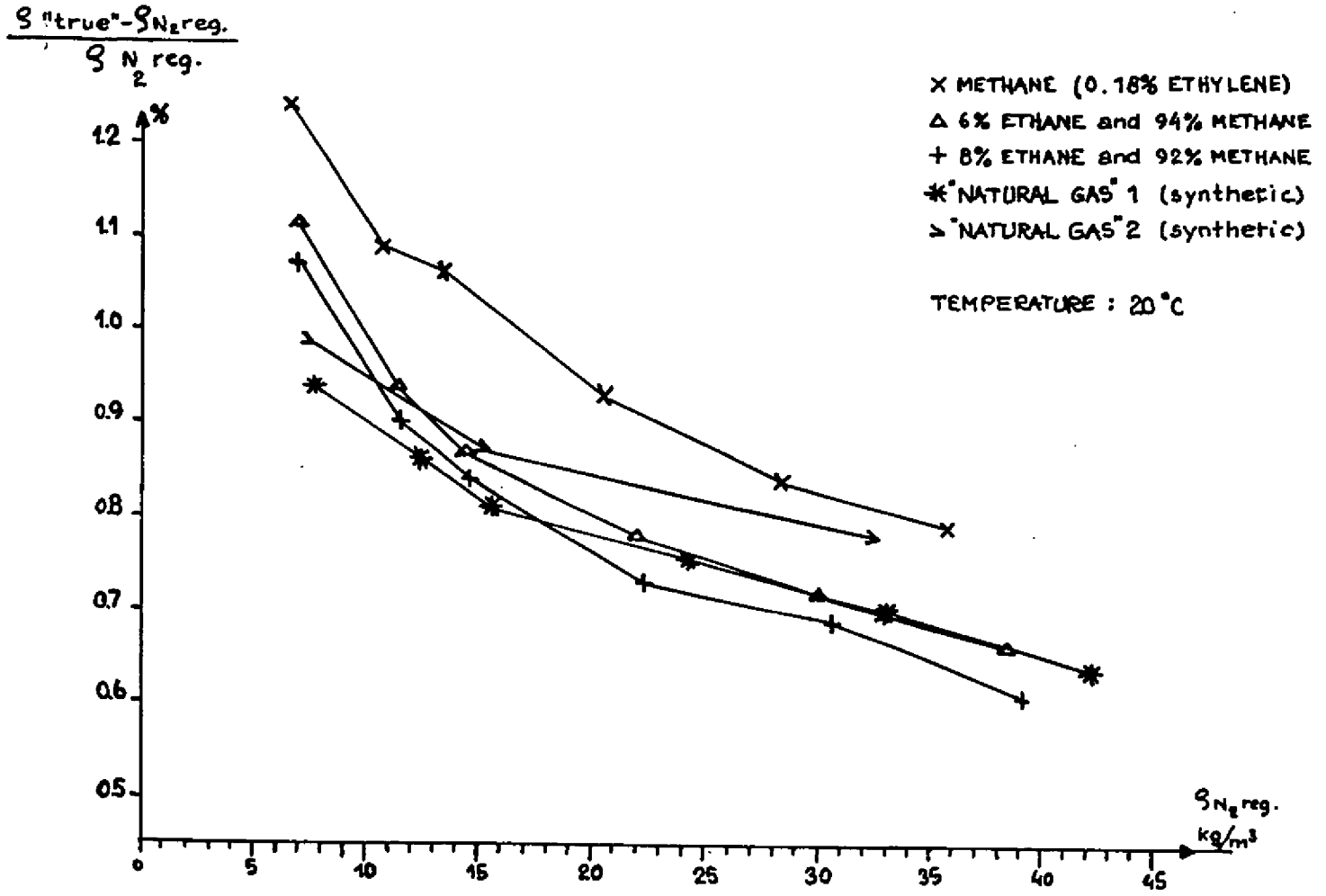


Fig. 9 COMPARISON BETWEEN TWO DENSITY METERS SHOWING THE RELATIVE DEVIATION BETWEEN "TRUE DENSITY" (DETERMINED FROM p, T, Z AND R) AND DENSITY CALCULATED USING CONSTANTS DETERMINED BY THE NITROGEN CALIBRATION.

DENSITY METER TYPE : SOLARTRON 7810 no. 6343 AND no. 6357

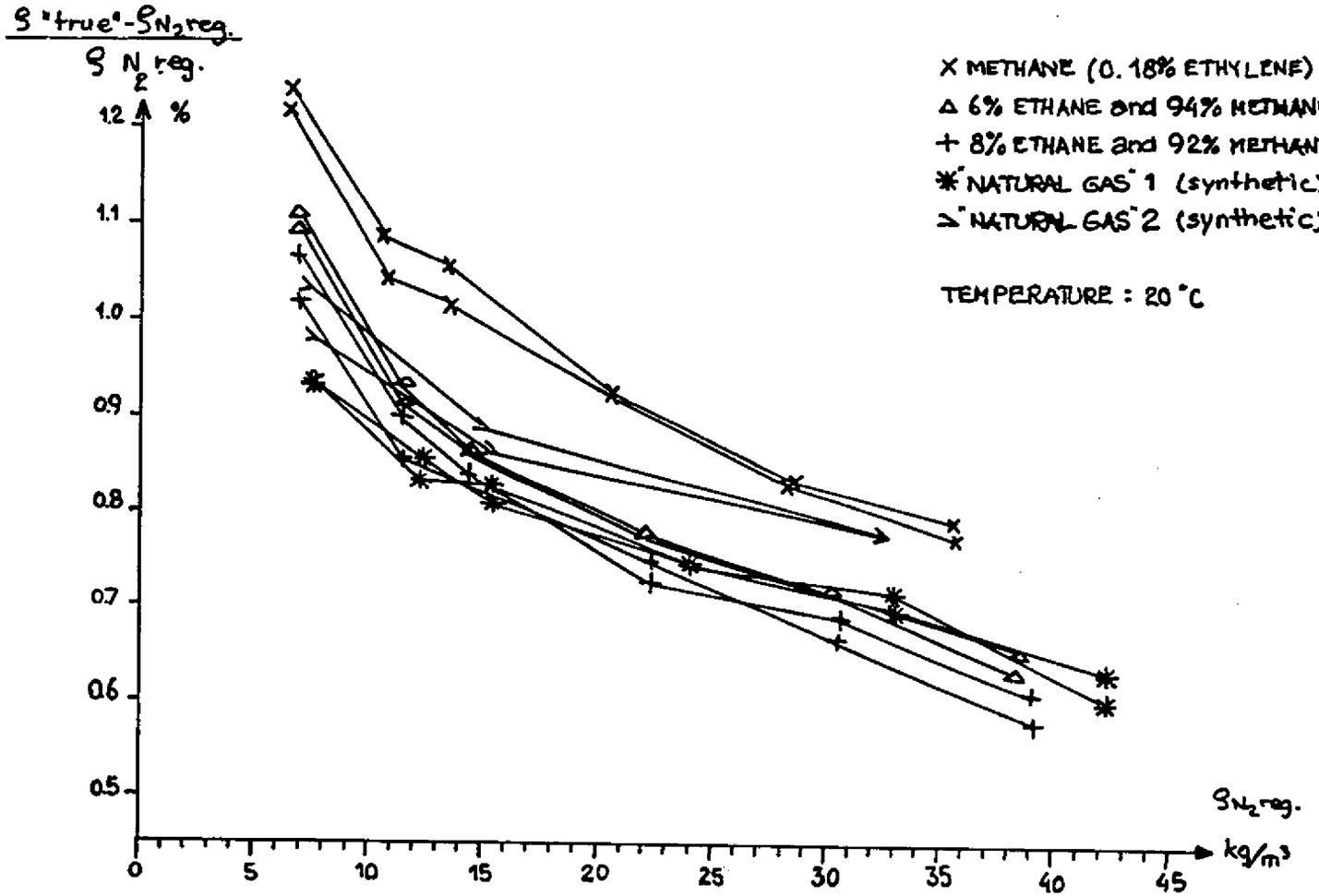
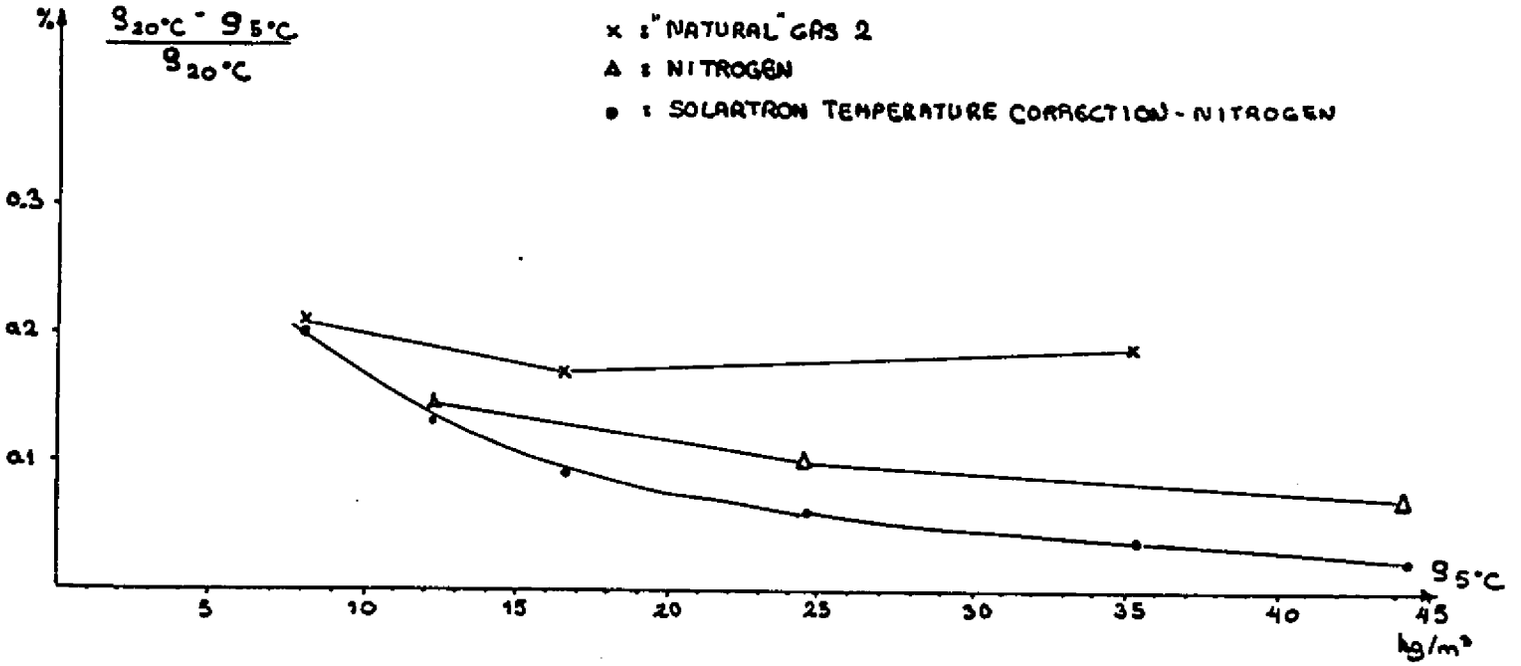


Fig. 10 TEMPERATURE CORRECTION FOR NATURAL GAS 2(SYNTH.) AND NITROGEN, BASE TEMPERATURE: 20°C.
EXPERIMENTAL TEMPERATURE: 5°C. DENSITY METER TYPE : SOLARTRON 7810 no. 6357



Main Index

EXPERIENCE WITH OPERATION AND CALIBRATION OF LIQUID DENSITOMETERS OFFSHORE

by

B LAWSON

ICE PETROCHEMICAL ENGINEERING LTD

PAPER 1.3

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

EXPERIENCE WITH OPERATION AND CALIBRATION OF LIQUID DENSITOMETERS OFFSHORE

Bruce W Lawson

INTRODUCTION

Accurate density measurement is of prime importance today because of its use in the determination of mass flow within multi user pipeline systems and their associated allocation agreements. The measurement of gas and liquid flow depends upon the measurement of density. In the case of gas, usually by orifice plate, mass flow is proportioned to square root of the line density. The error in the mass flow measurement resulting from error in density measurement is therefore approximately half the error in the density measurement. With liquid flow measurement however, generally by means of turbine meters, mass flow is calculated as the product of the volume flow at line conditions and the line density. Error in mass flow due to densitometer error will therefore be directly proportional to the densitometer error. Errors in liquid density measurement can therefore be said to have twice the significance of gas density measurement when considering the overall uncertainty in flow measurement.

Before a system can be operated successfully, it must first of all have been installed properly. We would therefore, firstly like to talk about some of the points that should be considered when designing a densitometer installation.

PROCESS LOCATION AND DENSITOMETER LOOP DESIGN

Carefully choose the location of the densitometer in relation to other items of process plant. It may be possible, as in figure one, to utilize the differential across an existing piece of process equipment. This simple installation is however, only of use where there are no wax problems, as there is no facility for flushing the loop with a solvent. In difficult conditions it is more advisable to utilize a design along the lines of Figure Two, which has facilities for solvent cleaning. This second design does not require a process differential pressure to operate as the integral pump circulates the oil through the loop.

As with any type of sample loop, before a representative sample can be obtained, great care must be taken in positioning the input to the loop. Ideally, this should be about 4 - 5 pipe diameters downstream of a point in the process where mixing is occurring (eg pump discharge, restriction orifice, control valve, turbine meter etc). An elbow may not be acceptable as a mixing device as water separation may occur due to certrifugal effects.

For best results under most conditions, the probe should be mounted horizontally with the pipework falling away from the probe. This arrangement helps to ensure any entrained water that is collected by the probe passes through the loop. With a vertical probe, under certain conditions the water may build up at the probe and fall back out of the loop. This can, however, usually be avoided by flow in excess of isokinetic velocity.

The length of pipework between the sample probe and the densitometers should be kept to an absolute minimum. This requirement is to eliminate, as far as possible, any problems regarding pressure and temperature equalisation. Temperature and/or pressure differences between the volumetric meter and the density meter should not cause a mass metering error in excess of 0.03%. In addition, if pyknometry is to be accomplished successfully, the length of pipework between the densitometer outlet and the pyknometer inlet must be the absolute minimum.

Any valves fitted between the probe and the outlet of the densitometers and/or pyknometers should be of the full bore type. If any other type of valve is used flashing may occur which will result in the loss of density measurement. In line with the above, any flow regulation for the loop should take place at the point of return to the process.

Very often in densitometer fast loop installations other analytical instruments are fitted to the loop (eg water in oil monitors and samplers) these instruments should be fitted after the densitometers. The reason again being that the flow path within these instruments may result in flashing and/or changes in temperature and pressure.

In use, various problems associated with the nature of the process medium may occur. These problems can generally be grouped as follows:

1. DEPOSITION OF FOREIGN MATERIAL ON THE DENSITOMETER INTERNALS

The two substances which are most commonly deposited on the densitometer tubes are wax and scale.

The first of these two substances, wax, is the most commonly experienced and is thankfully relatively easy to remove. The wax is best removed by either flushing with a solvent or by mechanical cleaning. If it is suspected wax deposition is going to be a problem, it is worth considering a system along the lines of Figure Two, which includes integral solvent flushing facilities. The amount of wax deposition may be reduced by careful design of the pipework and flow path in relation to the densitometers.

The second substance, and more serious of the two is scale. However, experience has shown that the level of scale formation in metering systems, including the densitometers, can be reduced and in some cases eliminated by the injection of a scale inhibitor. Once scale has formed on the densitometer internals it results in an erroneously high density reading and is extremely difficult, if at all possible, to remove on site. As scale formation takes place on all process steelwork, including the turbine meter, on which a relatively small amount of scale can shift the turbine meter factor dramatically. This shift, if it occurs can be used as a warning that scale formation is taking place.

If there is suspicion that either of the above problems has occurred, a relatively simple check can be made on the operation of the densitometer. This check is accomplished by isolating the densitometer from the process and after it has been thoroughly flushed and cleaned, allow dry ambient air to enter the tubes. Then, by measuring barometric pressure and ambient temperature, together with relative humidity if necessary, the reading of the densitometer can be compared to published tables.

2. CORROSION

On systems where the level of water in the crude is significant crevice corrosion of the tubes has been shown to be a problem. This corrosion occurs most when the densitometer is out of service as the water and oil separates. There is very little that can be done to prevent this corrosion, due to the limited choice of densitometer materials available. Therefore, the metering engineer should be aware of the possibility of corrosive produced waters.

3. FLASHING OF THE CRUDE WITHIN THE DENSITOMETER

When the phenomenon of flashing occurs, the gas bubbles that are created within the densitometer result in a loss of density measurement. The flashing off of gas from the oil occurs because the pressure of the oil has fallen below the vapour pressure. As previously discussed, this situation can be created by a poor design of system. However, flashing can also occur on live crude systems during a plant trip, as the pressure of the oil in the densitometer falls close to, or below, the pressure of the oil in the separators. In this event, great care should be taken to ensure this gas is fully flushed from the densitometers immediately on start-up otherwise a significant metering error will occur.

ROUTINE CHECKING OF DENSITOMETERS IN THE FIELD

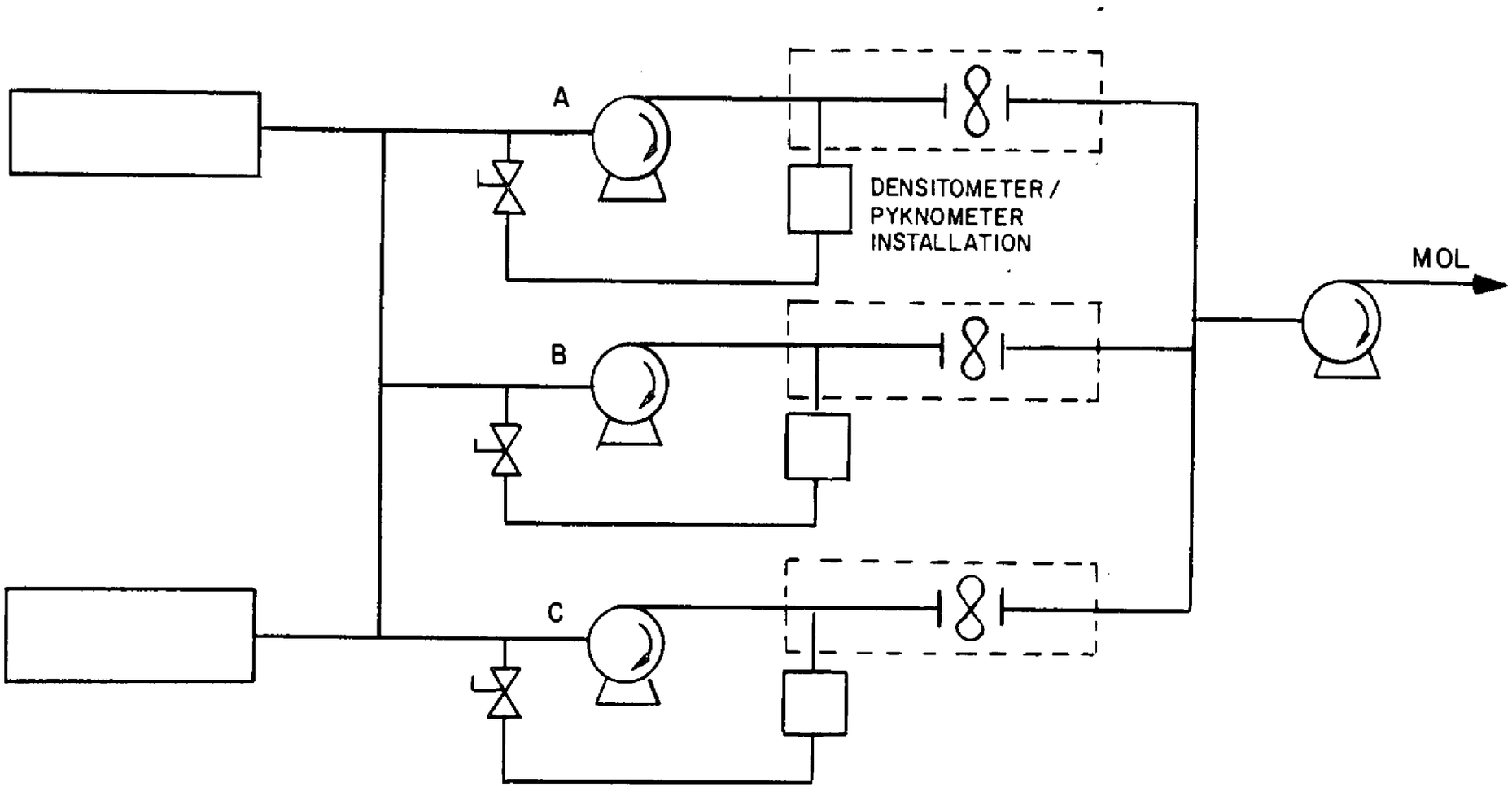
The types of densitometers used almost universally in offshore applications (ie vibrating tube type) are factory calibrated and sealed, allowing no real ability to adjust on site. Each unit comes with its unique calibration certificate upon which the appropriate coefficients are given to allow the conversion from frequency to density to be made. The calibration method employed by the manufacturer is a sophisticated process involving extreme pressure and temperature stability combined with the use of pure calibration liquids. This means that successful verification of density transducers in the offshore environment is extremely difficult to achieve.

Although some very highly commendable work has been reported in the field of offshore pyknometry[1], the fact remains, that it is a difficult practical operation to achieve with any degree of success, and should therefore, not be entered into lightly. In addition to any pyknometry carried out, if the densitometers are to perform correctly, it is important to monitor and, if possible, cross compare their output density readings. This can be achieved by carrying out air density checks, the regularity of which being decided by experience, and also cross comparing the output from parallel meter runs. If it is not possible to compare meter runs in parallel, then during periods of stable flow conditions it may be possible to change tubes and compare density readings. This practice of comparing density readings on a frequent basis is invaluable, particularly where scale is a problem, as both densitometers on the one stream may drift high to the same degree. On installations where pyknometry is not carried out, the practice of returning densitometers to the manufacturers for routine (typically annual) recalibration may be a solution.

Perhaps, as a final note on the verification of densitometers, the specialist metering companies who already carry out annual recalibration of the platform provers may consider offering the additional service of a pyknometry calibration for densitometers.

REFERENCES

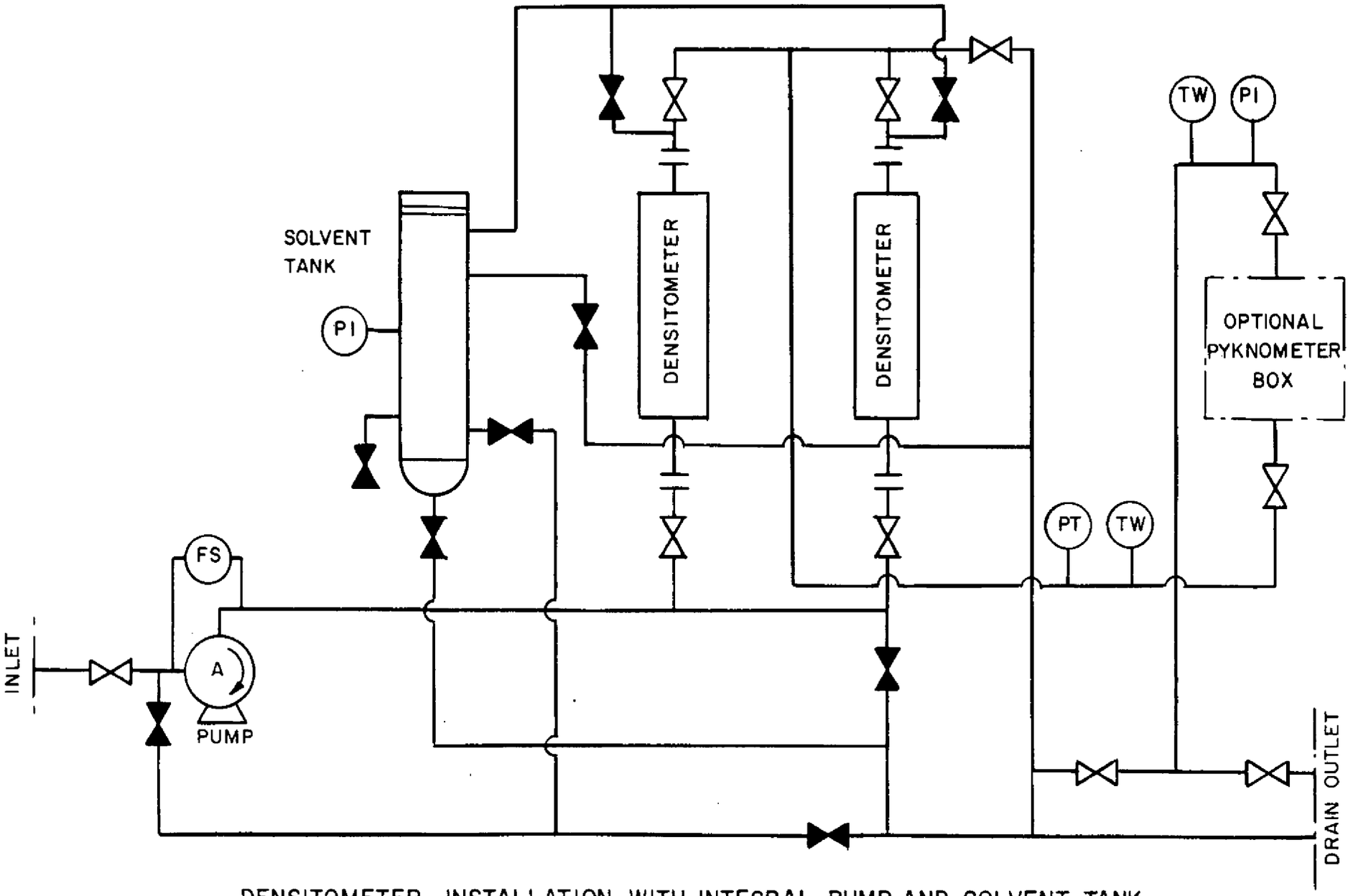
1 INSTITUTE OF MEASUREMENT CONTROL, May 1983, Boulter and Greig. "Validation of inline density meters by high pressure liquid service pyknometers".



SIMPLE DENSITOMETER INSTALLATION

(SUITABLE ONLY FOR LIGHT CRUDES WITH NO SUSPENDED SOLIDS)

FIG. 1



DENSITOMETER INSTALLATION WITH INTEGRAL PUMP AND SOLVENT TANK

FIG. 2

Main Index

FIELD EXPERIENCE WITH LIQUID DENSITOMETERS

by

S KRUPA

SARASOTA AUTOMATION LTD

PAPER 1.4

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
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FIELD EXPERIENCE WITH LIQUID DENSITOMETERS

STEPHEN KRUPA

INTRODUCTION

This paper discusses the problems encountered with the measurement of two different types of liquid hydrocarbons. Crude oil is probably metered more than other petroleum products but causes difficulties due to the presence of waxes, sand, sulphur and water.

Liquified hydrocarbons such as LNG, LPG, ethylene or condensate are generally much "cleaner" when metered but tend to be at much more extreme conditions of pressure and temperature. Consequently different techniques are employed to satisfy these differing requirements.

BACKGROUND

There are two main reasons for using liquid densitometers in the North Sea. The measurement of liquid quantities for fiscal purposes is normally calculated in mass units. Hence as there are very few accurate mass flow devices currently available and none of them widely accepted by Government Authorities this means that the flow rate is usually calculated in volume units and the conversion to mass flow with the use of a densitometer.

ie $M = V \times \rho$

The main requirement is to ensure that the density measurement is made at conditions which are as close as possible to those at the metering device, which is usually a turbine.

Current technology does not allow the design of a densitometer within the turbine, so this means that the meter must be placed close to the turbine and corrections made in the computing system to compensate for any differences.

Alternatively densitometers may be used to measure the quality of a product. The meter can be used on the product at any process condition and with a knowledge of the effect of variations of pressure and temperature on the fluid, a calculation can be made of the density at some base conditions, this being a measure of the purity. Sometimes the result can be compared with water at the same conditions and is expressed as relative density or Specific Gravity.

By far the largest use for meters offshore is with the measurement of mass flow.

METHODS OF DENSITY MEASUREMENT

There are several techniques employed in the measurement of density. Because the density of the fluid can constantly change at the metering point, on-line measurement is the only practical solution. Methods include weighing a tube or vessel through which the fluid is passing; measuring the buoyancy of a float totally immersed in the fluid and measuring the absorption of gamma rays from a radioactive source, through the fluid.

The most important class of density measuring devices is the vibrating element type, widely accepted as the most accurate form of on-line electronic density meter. In particular, the vibrating tube and vibrating spool density meters have been used widely, the former for liquids and the latter for liquids, liquid gases and gases.

The vibrating tube density meter maintains one or more tubes, in transverse oscillation by magnetic drive and pick-up coils, together with an electronic amplifier. The ends of each tube are clamped and the magnetic drive is to the centre, the frequency of oscillation being a function of the density of the fluid in the tube.

The vibrating spool density meter uses a shorter magnetic spool that is clamped at one end only. A drive coil causes the spool to oscillate and the movement is detected by a pickup coil, amplified, and the resulting signal applied to the drive coil as in the vibrating tube instrument. The oscillation is circumferential rather than transverse. The frequency of oscillation is again a function of the density of the fluid in the meter.

A development of the mechanical construction of the vibrating spool density meter enables the whole measuring element to be immersed in the process fluid. This is particularly successful in liquid/gas density measurement where it avoids the problems of temperature or pressure gradients that can occur with bypass systems. The meter can be installed through a blank flange or made retractable so that it may be removed without shutting down the process line.

VIBRATING ELEMENT DENSITOMETERS

The two types of vibrating element densitometers lend themselves to two separate applications.

A densitometer that can be inserted directly into the pipeline close to the turbine minimises the effects of any pressure and temperature gradients. If the meter itself has no pressure coefficient and a small temperature coefficient then the unit is best suited for liquified gases LNG, LPG, or condensates where the fluids are generally clean but small changes of pressure or temperature have a large effect on density.

Where the liquid to be measured is perhaps non-homogeneous, contains particles, sand and other impurities then a smooth bore tube is more suitable. The meter has no small clearances for the build-up of deposits on the measuring element. The vibrating tube meter gives a reading of the mass of the tube at any time regardless of its contents provided this is primarily liquid which will oscillate with the tube. Consequently it

is less prone to problems with small amounts of bubbles, particules, slurry or mixtures such as oil with water. Crude oil is therefore a natural application for this type of meter.

FISCAL METERING SYSTEMS

When designing a density metering system several problem areas must considered

temperature effects
pressure effects
response time
maintenance
proving
gassing off

Let us consider all these problems on the metering of two completely different products

(a) crude oil
(b) LPG

CRUDE OIL METERING

(a) The vibrating tube densitometer is not currently available in a form which can be inserted in the line and so a suitable bypass loop must be designed. Figures 5, 6 and 7 show simple bypass systems which can be employed. The main difference between them is the method of generation of differential pressure. The greater this pressure the faster will be the response to any changes and so any temperature changes can also be slightly reduced.

A high integrity fiscal metering system often requires redundancy and/or comparison of two densitometers and so the skid may be required to accomodate two complete systems as per Figure 8. It may be necessary to go one stage further and supply a complete package including solvent tank for flushing either of the meters and a pyknometer to prove the meters. See figure 9.

Any difference between the turbine pressure and densitometer pressure is usually very small and hence causes a negligible change in density. However the same is not true for temperature and this should be considered more carefully. The temperature should be monitored at the densitometer to allow for corrections of the temperature effect on the meter itself. This gives accurate calculation of density at the densitometer temperature. If there is a different temperature at the turbine then volume correction factors may have to be applied to correct for this. It may also be a useful feature to generate an alarm on deviation of these two temperatures.

Another useful feature is a flow alarm to indicate if the pumps are running dry and increase their operational life.

Different manufacturers of vibrating tube densitometers suggest different operational positions depending on design. The single tube and double tube device is mounted vertically to allow any bubbles to pass straight

through. A three tube system with 'S' shaped flow path is generally mounted horizontally to prevent air locking in any of the 180 degree curves.

LPG METERING

(b) The designer of the LPG measuring system has a much simpler task. As previously mentioned the temperature and pressure gradients between the turbine and the densitometer are kept to a minimum by use of a direct insertion meter close to the outlet of the turbine.

The response time of the meter is related to the flow rate and the type of filter used. The NBS Technical Notes 697 of October 1977 and 1055 of June 1982 evaluated different densitometers on liquid methane and liquid methane mixtures with ethane, propane, butane and nitrogen under cryogenic conditions. The conclusions are that vibrating element insertion densitometers are most suited to these applications and that a faster response is achievable without filters in the meter, bearing in mind that a more frequent maintenance schedule for cleaning would be required.

Removal of the insertion type of meter is available using a retraction device which means that the individual metering lines do not need to be isolated as each meter is fitted with a ball or gate valve.

ETHYLENE MEASUREMENT

The requirements for ethylene measurement are very similar to that of LPG and are best achieved with an insertion densitometer. Several evaluations have been carried out by various companies and institutions. One such evaluation, the "Industry Ethylene Measurement Project - Final Report to the Steering Committee", compared the performance of densitometers with the calculated density using pressure and temperature and the API table 2565. This shows that densitometers can perform accurately over a wide range of densities. Once again consideration is required for positioning of the densitometer as ethylene close to the critical condition has a very large temperature and pressure coefficient.

PROVING OF DENSITOMETERS

At the moment there are very few, proven, accurate and repeatable methods of proving of this 'type' of densitometers although improvements have been made recently in the design of pyknometers. If the product is pure then tables can be used as a first order check.

A paper was given at the Norflow 83 symposium in Aberdeen detailing the problems a North Sea operator has using a pyknometer. Once the problems were identified and an operational procedure laid down then a pyknometer when used in this way is a satisfactory method.

Other options are being investigated at the moment by another North Sea operator. This involves a Transfer Standard Densitometer. For it to be suitable for Offshore use the unit that has been supplied by Sarasota is mounted in a purpose-built insulated carrying case with handles. This allows transportation between platforms. For simple coupling up to existing pipework the unit is fitted with quick fit connectors. As a result of these tests on the Sarasota unit (and other manufacturers' also) a decision will be made as to whether the concept is feasible and practical. It is then likely that a procedure will be written and then adopted as an alternative to pyknometers for the proving of densitometers on fiscal metering systems.

FACTORY CALIBRATION OF DENSITOMETERS

An alternative to on-line checking of densitometers is to return the units to the manufacturing factory for re-certification. Consequently the calibration facility must be equipped with certified equipment traceable to the various standards. This subject in itself is worthy of a separate paper.

The normal method is to measure the upthrust on a silica (low temperature coefficient) body totally immersed in the fluid which is flowing through the meter. This means that the temperature must be monitored at both the meter and the measurement tank to ensure no variation. Temperature must be measured to an accuracy of 0.01 degrees C if the density is to be determined to 0.1 kg/m^3. It is desirable to calibrate each densitometer against the silica body so as to avoid any cumulative errors if another densitometer is used as a transfer standard. Mixtures of hydrocarbon fluids are used and a full calibration using a 15 point calibration including hysterois takes nearly three days. This also includes the calculation of the temperature and pressure coefficients of the meter. Consequently the system has to be computer controlled and automatic. Up to six meters can be calibrated at the same time and a temperature controller ensures equalisation and stable conditions. A hydraulic ram allows data to be taken at elevated pressure.

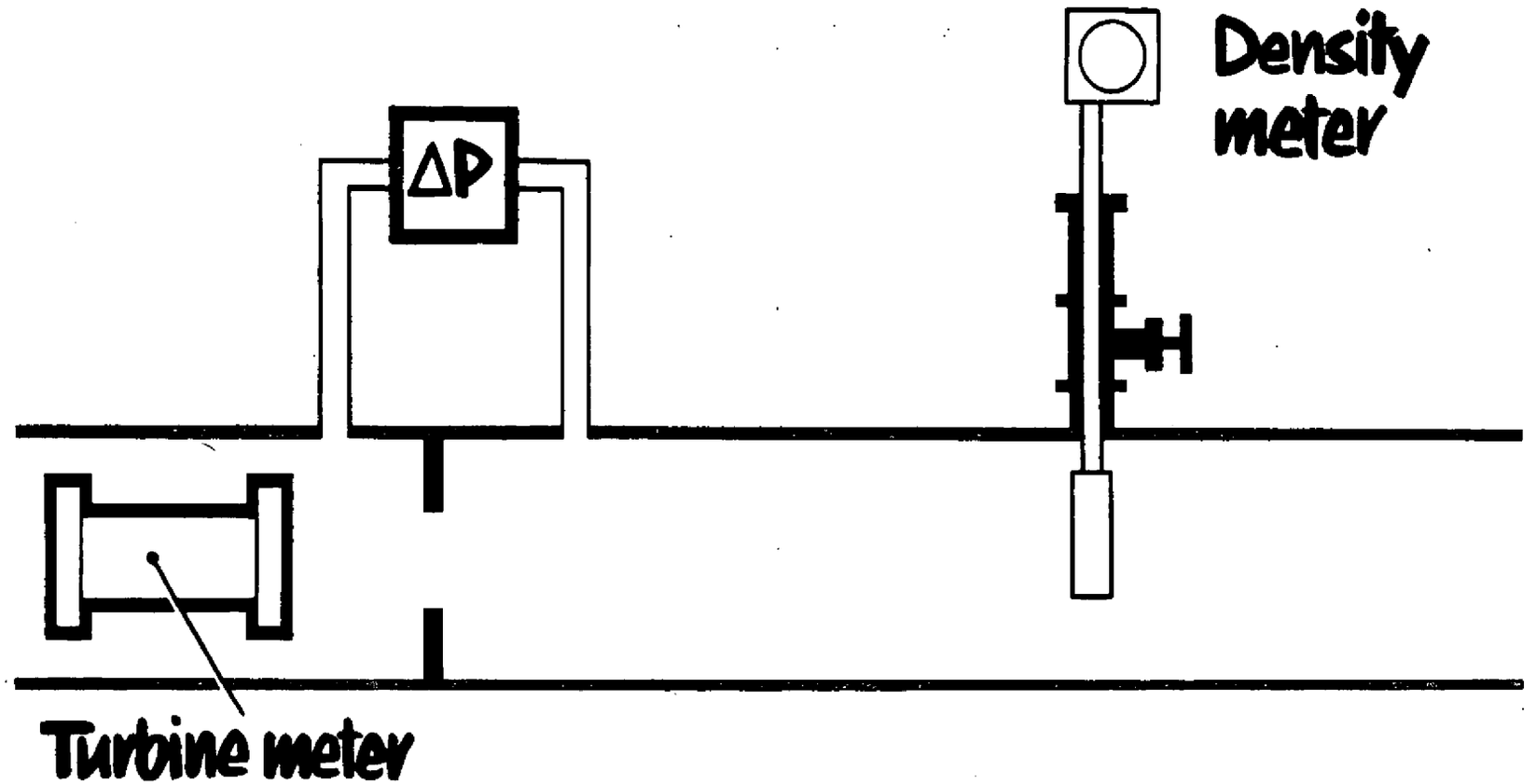
At the end of these tests calibration certificates are produced indicating the calibration data and whether it falls in the specified accuracy.

CONCLUSION

Vibrating element densitometers are an essential part of mass flow metering systems. The system designer must observe the procedures currently adopted by operators which have been developed as a result of many years' experience.

The proving of densitometers in situ is not easy to achieve with a high degree of accuracy. This is borne out by the fact that manufacturers have found it involves a large capital outlay on a suitable laboratory and system to produce accurate calibration.

Quantity Measurement



$$M = K\sqrt{\Delta P \times \rho}$$

or $$M = V \times \rho$$

FIG. 1

Principle of operation

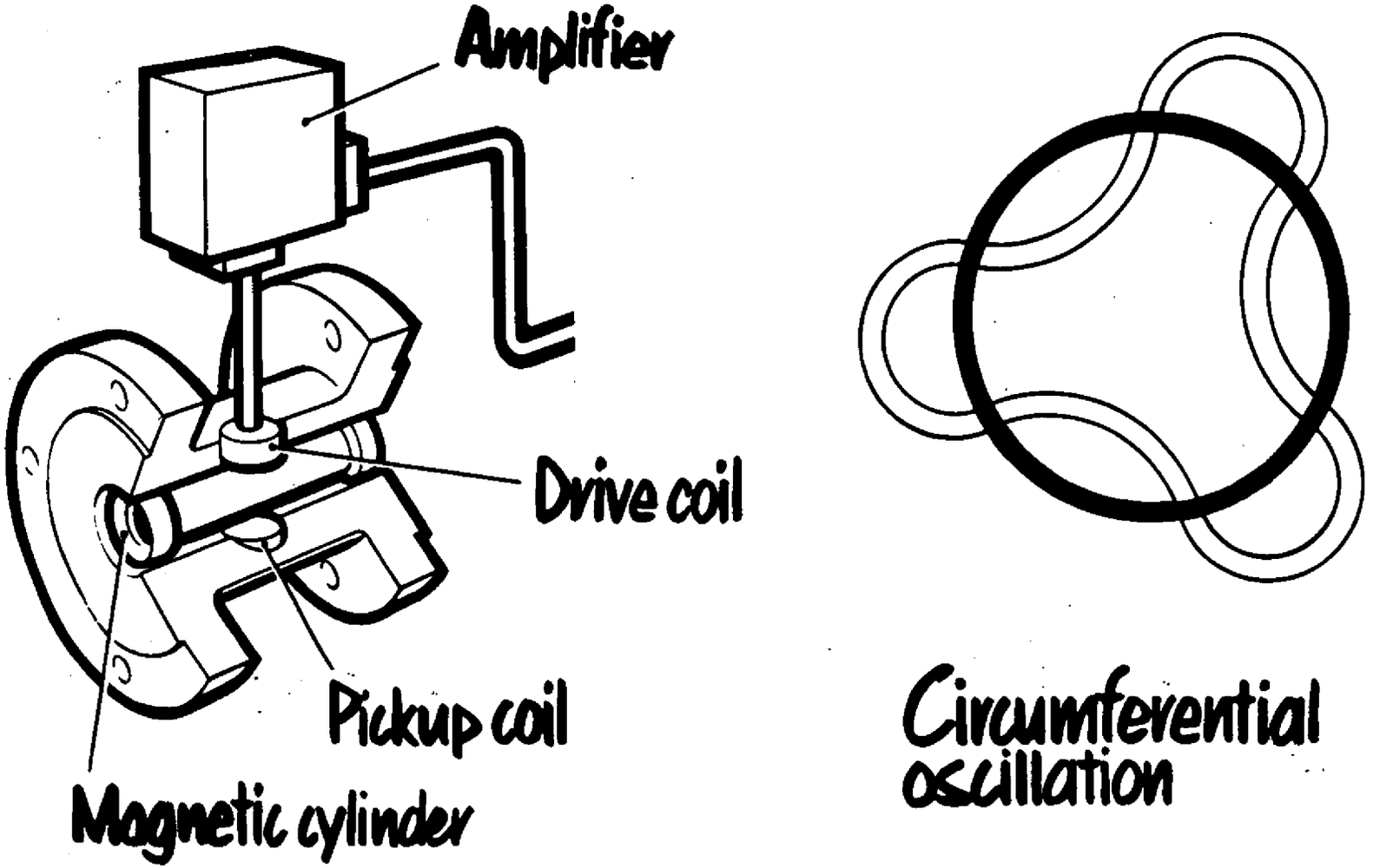


FIG. 2

FD 800 SCHEMATIC

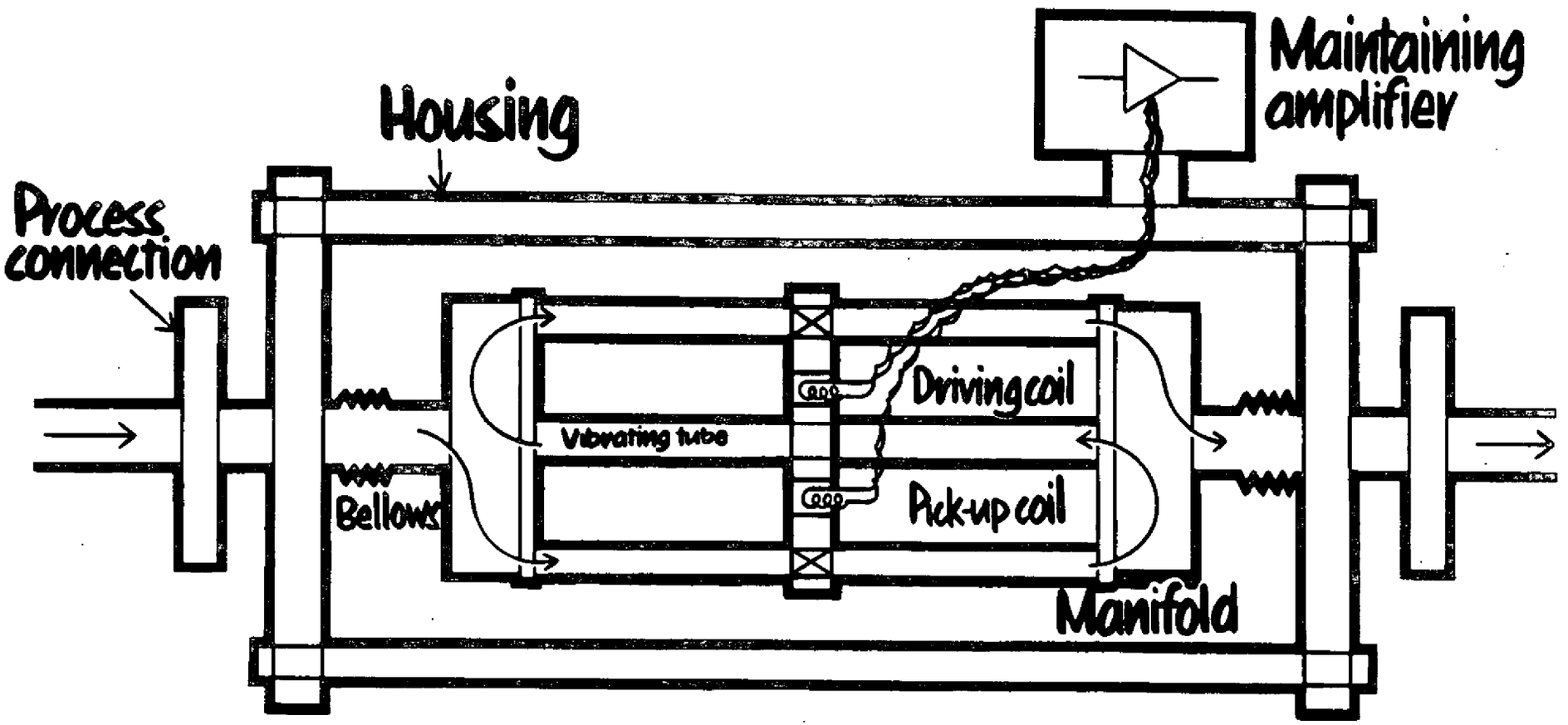
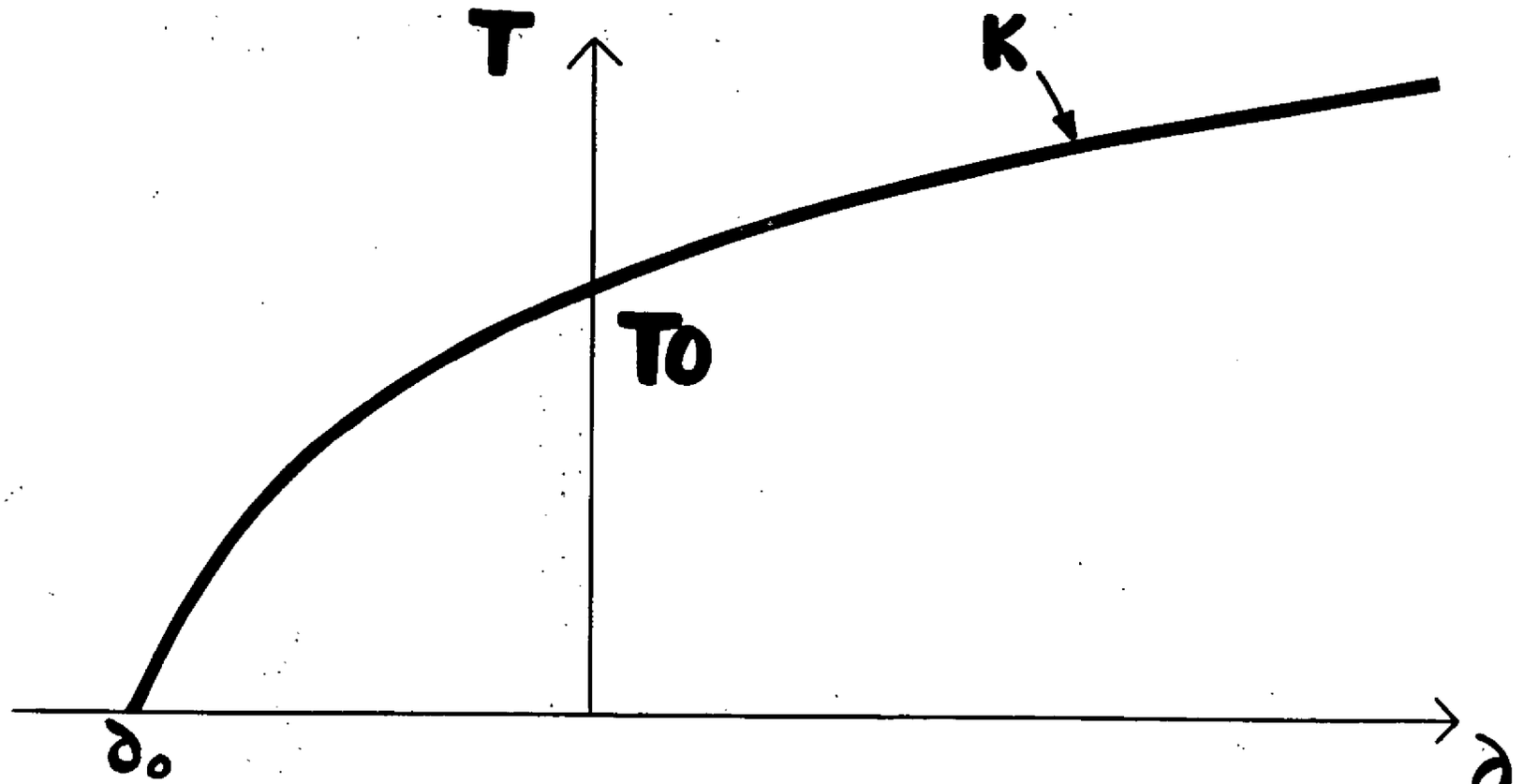


FIG. 3

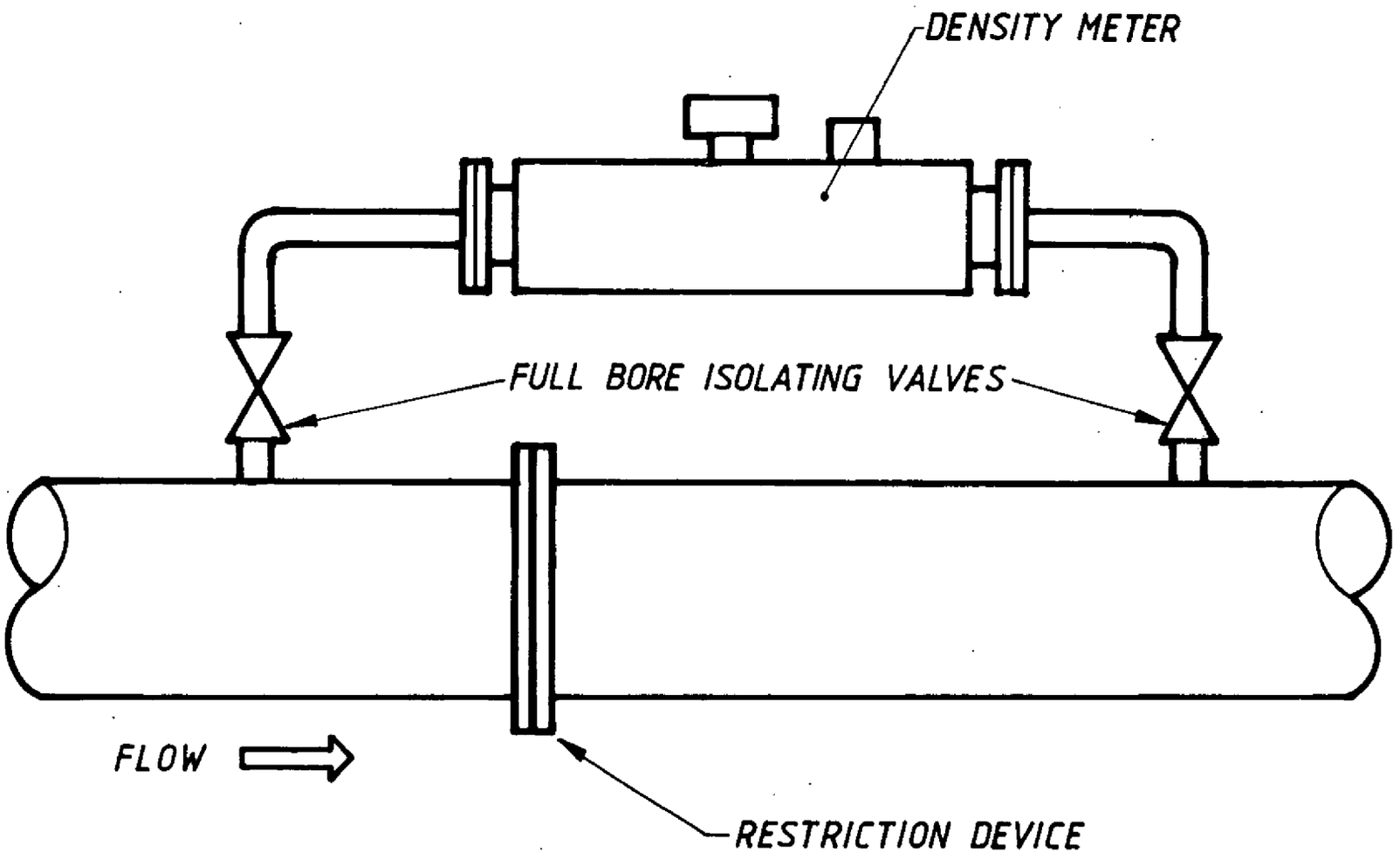
Transducer law



$$\partial - 2\partial_o \frac{(T-T_o)}{T_o}\left[1+\frac{k}{2}\frac{(T-T_o)}{T_o}\right]$$

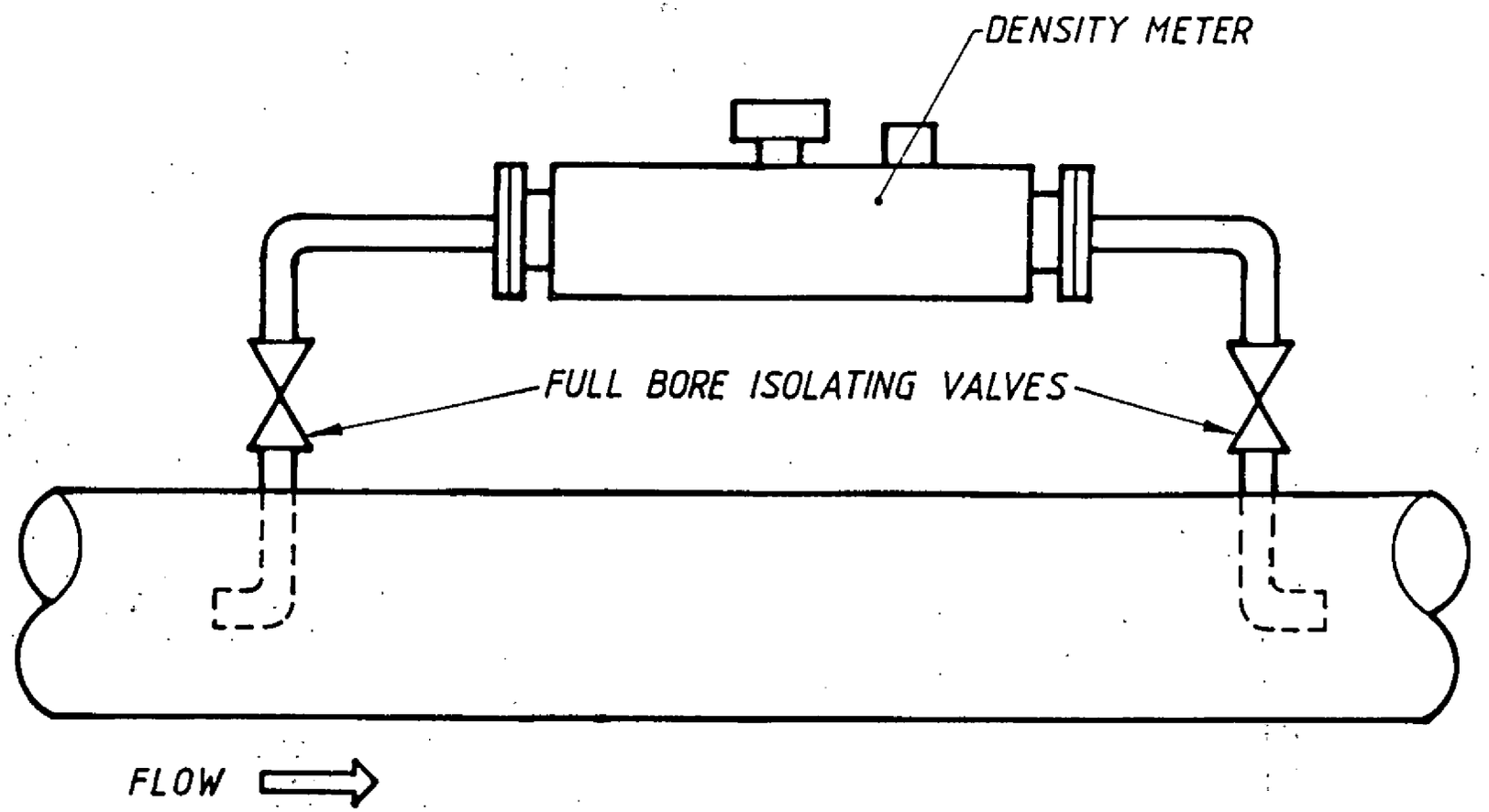
$$\Rightarrow \partial = A + BT + CT^2$$

FIG. 4



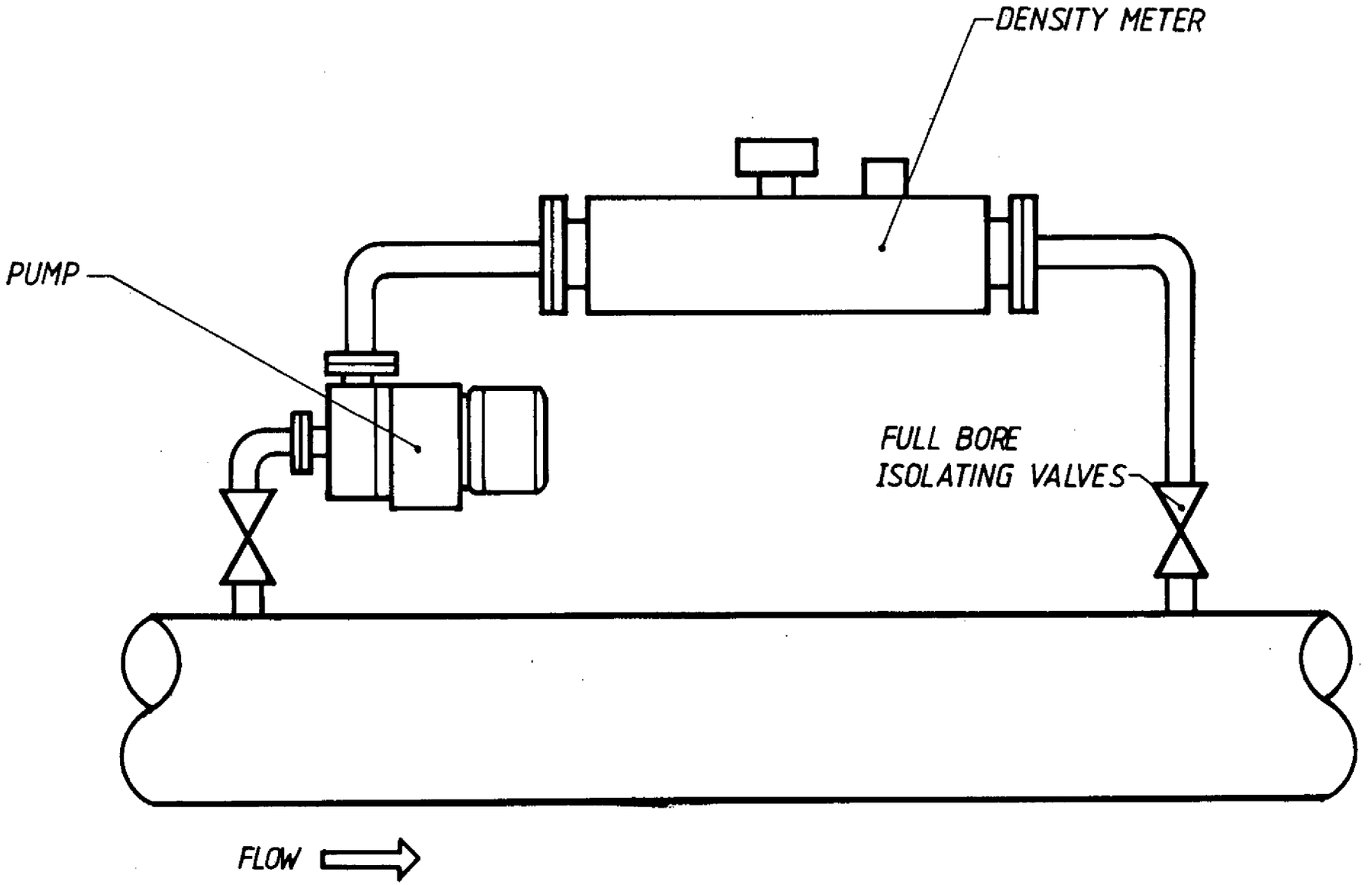
A RESTRICTION DEVICE TO CREATE A PRESSURE DIFFERENTIAL

FIG . 5



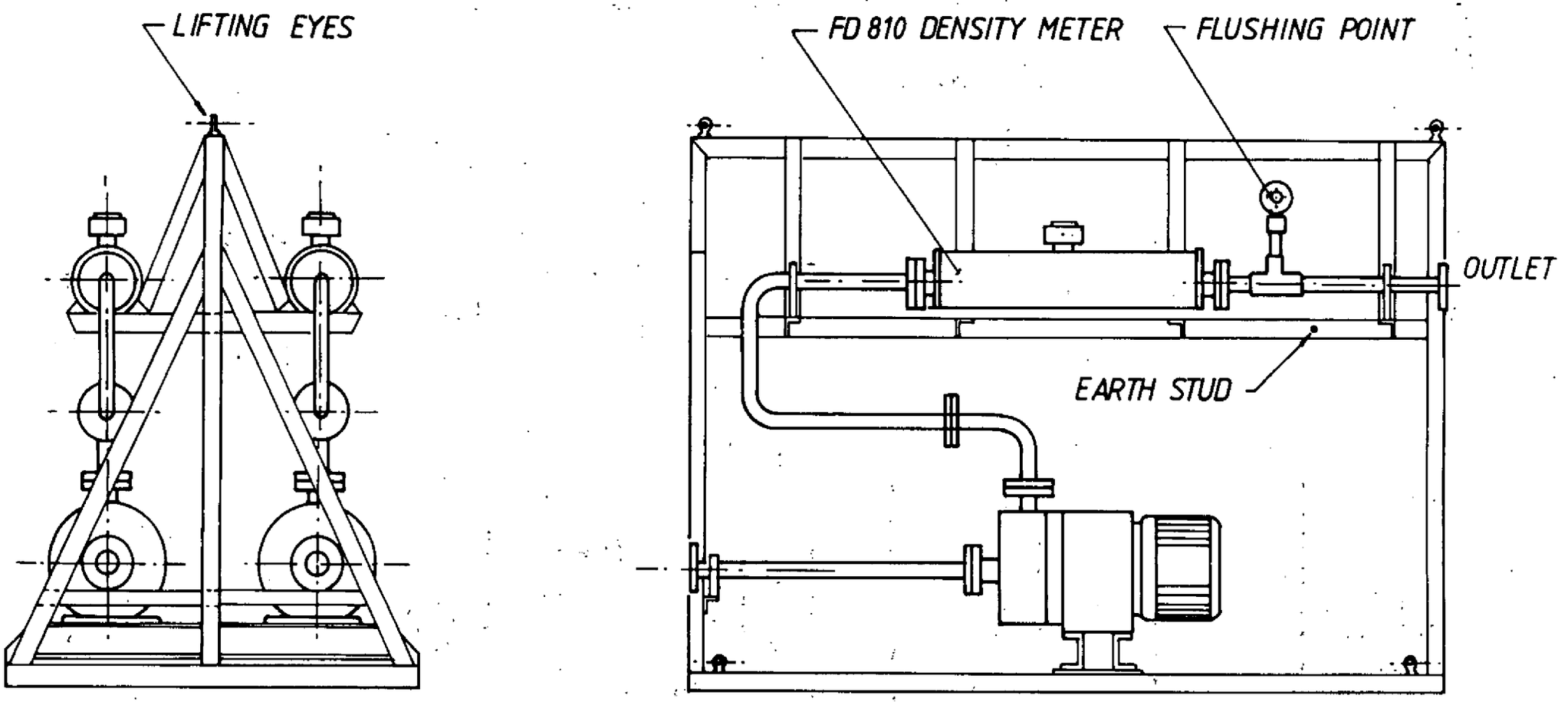
INSTALLATION WITH PITOT TUBE SCOOPS

FIG . 6

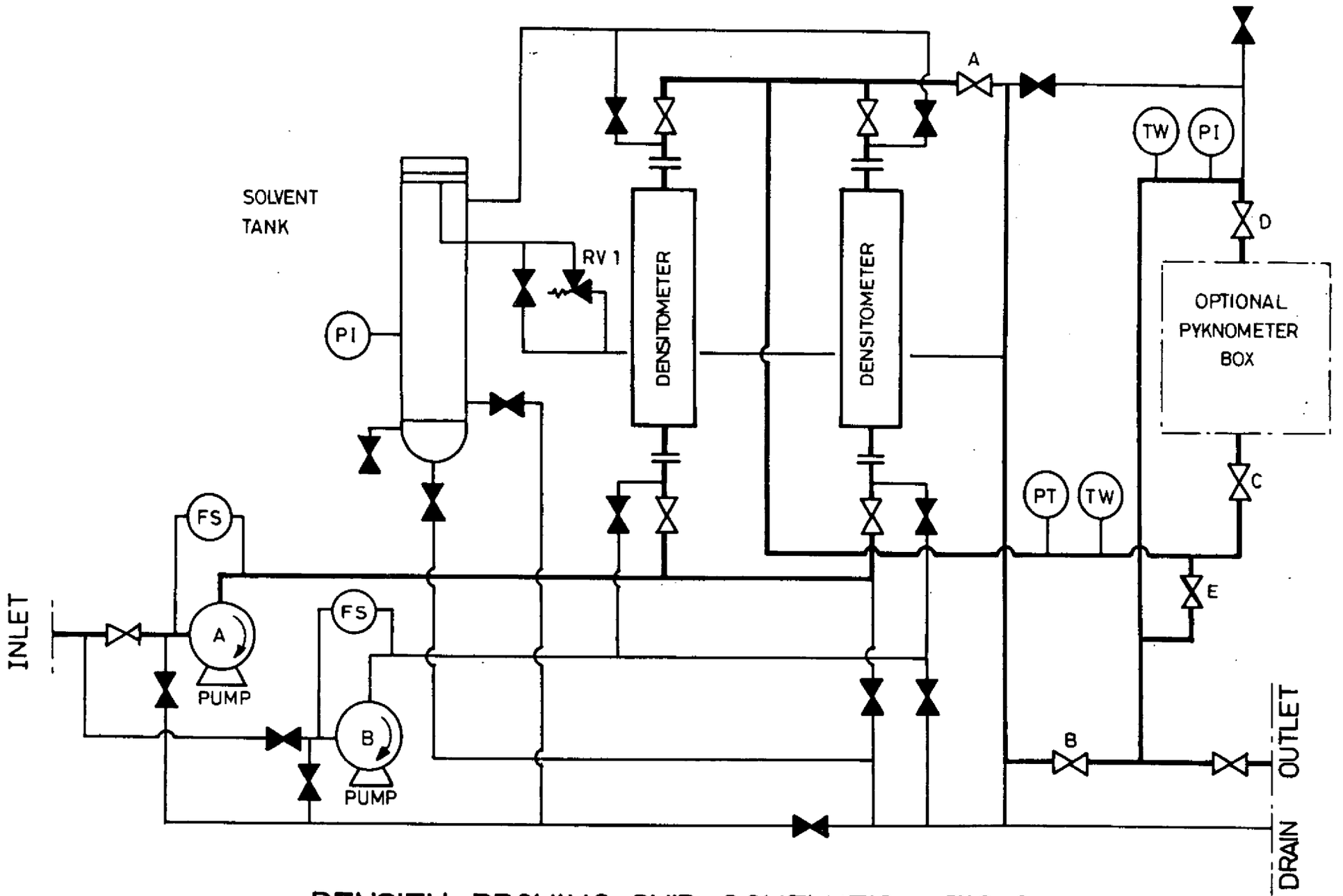


INSTALLATION WITH PUMP

FIG . 7



DUAL SYSTEM SKID FIG. 8



DENSITY PROVING SKID SCHEMATIC FIG. 9

Insertion meter

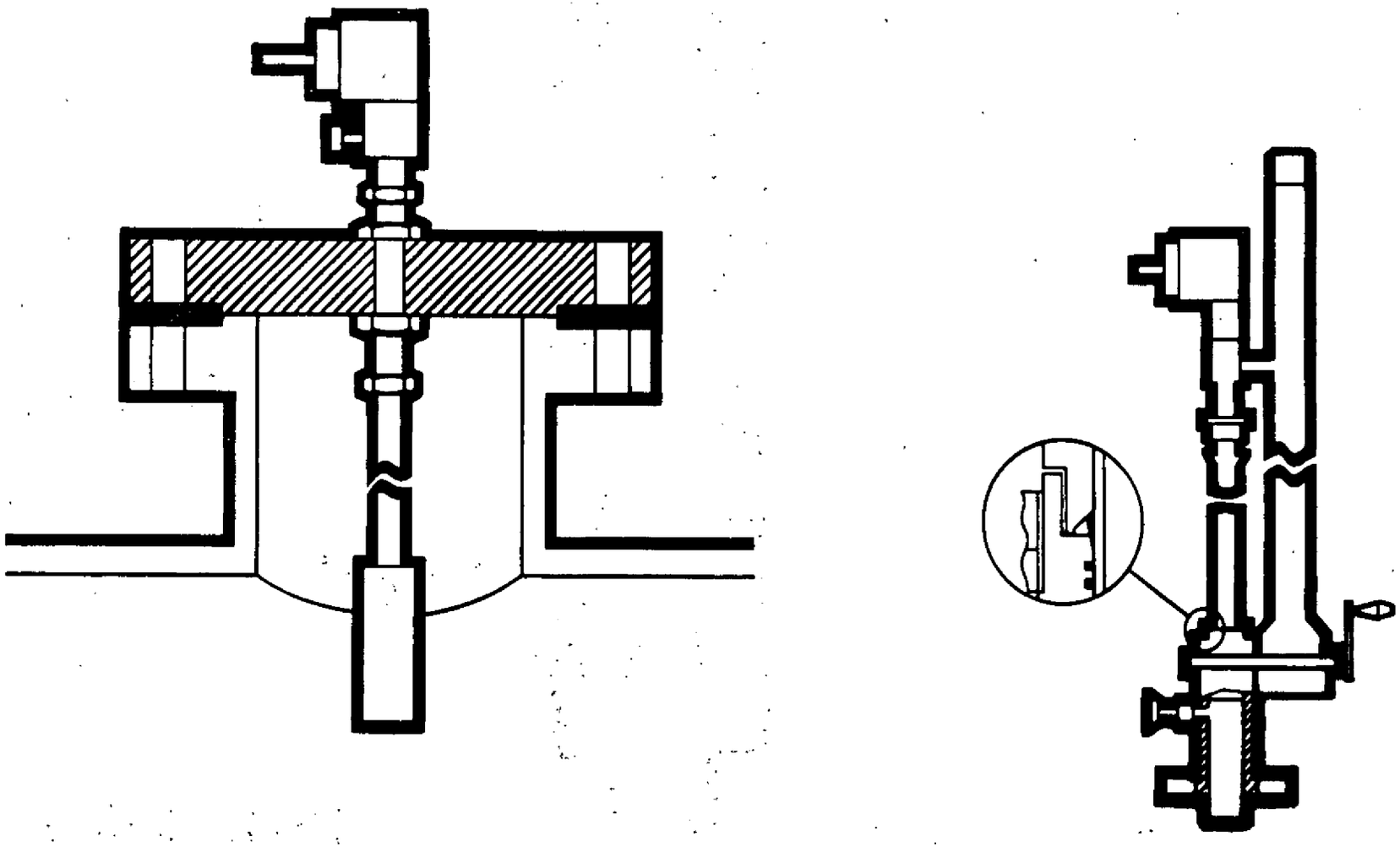
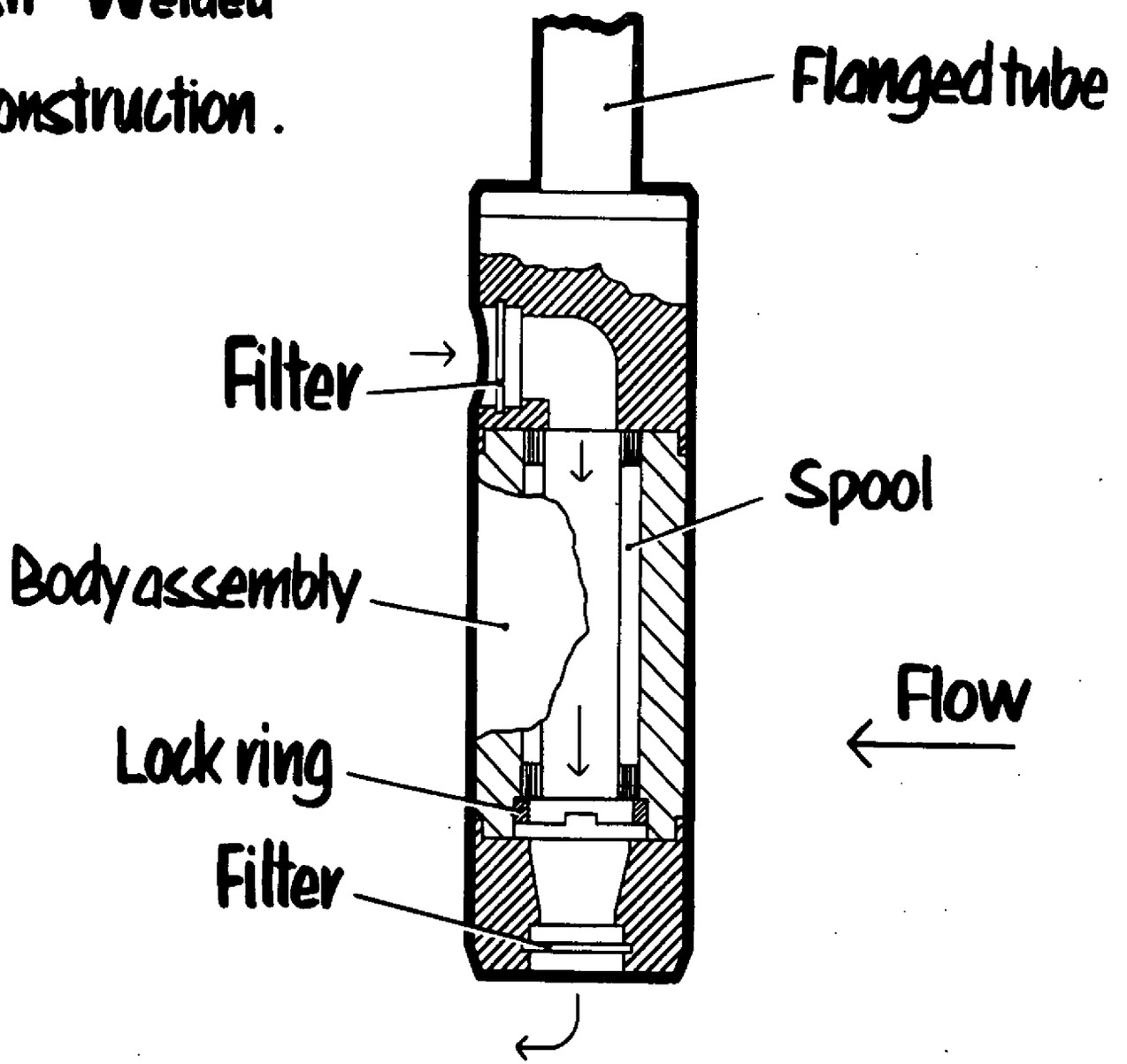
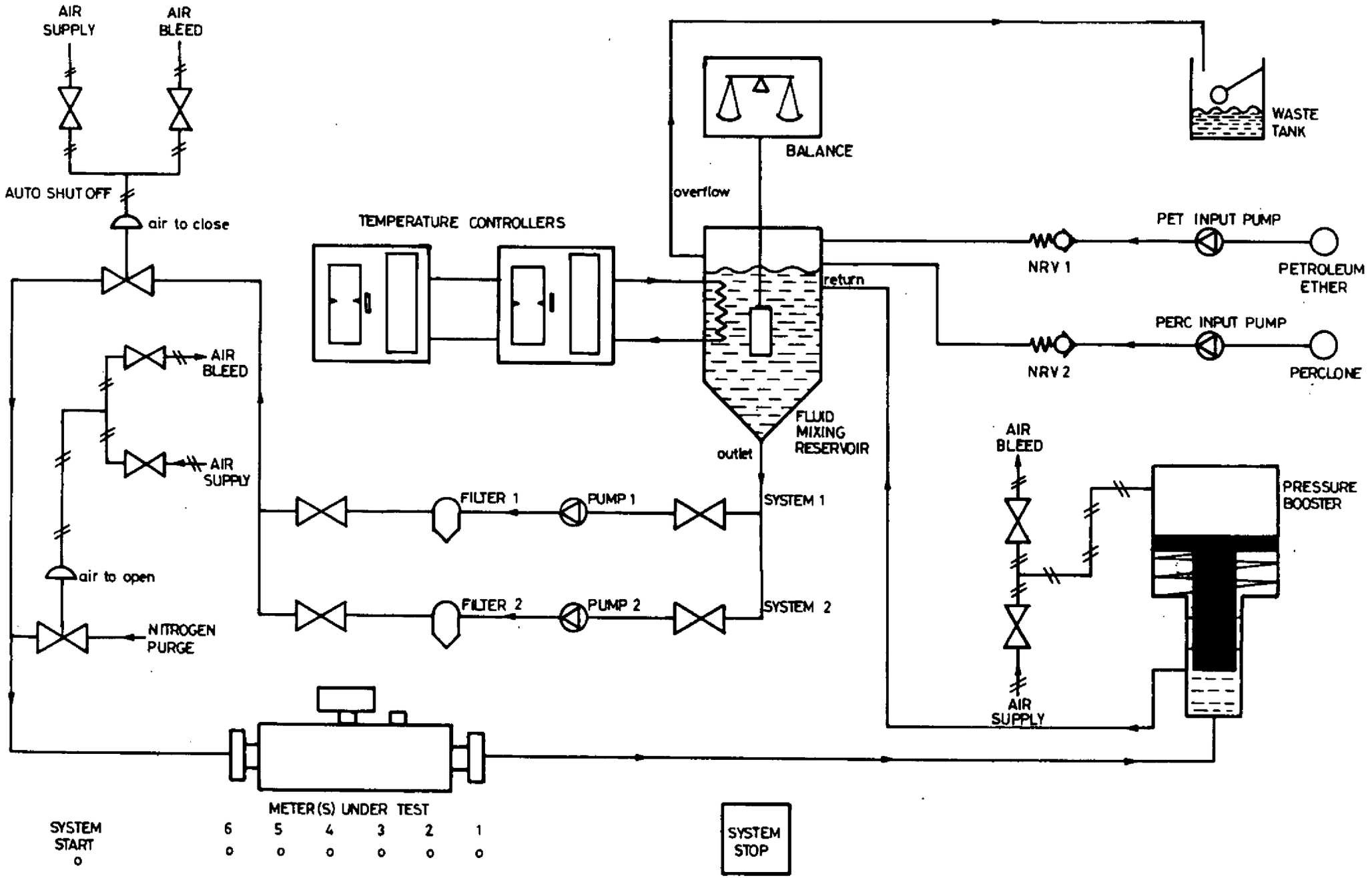


FIG . 10

All Welded Construction.



INSERTION DENSITY METER SCHEMATIC FIG. 11



AUTOMATIC DENSITY METER CALIBRATION UNIT FIG . 12

THE NEW NPD REGULATIONS

by

T OEGLAND

NORWEGIAN DIRECTORATE

PAPER 2.1

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

THE NEW NPD REGULATIONS

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Norwegian Petroleum Directorate (NPD)

I have been asked to present the most important and contentious points and highlight areas in the new NPD metering regulations. It is rather hard or almost impossible to include all the important points within the time allocated for this presentation. From our point of view all sections in the regulations are important. When I add that the regulation for fiscal measurement of gas includes 69 sections and the regulation for fiscal measurement of oil 63 sections, one can imagine quite some time would be needed to cover all aspects of the various sections.

I have, however, made a selection of points from the two regulations. Before I go into some of these points I would like to give a brief summary of the work preceding the issuance of the regulations. The drafting of the regulations started in 1981 and was sent out for hearing in December 1982. The drafts were sent to different oil companies, departments, directorates, consultants, vendors etc. The comments received were thoroughly examined by the NPD and the final regulations were put into force the 2 April 1984.

The purpose of the regulations is to ensure that accurate measurements provide the basis for royalty and tax stipulations by stating technical requirements and to set approval procedures for the measurement system (see section 2 oil and gas). In addition the regulation would minimize the meetings, correspondance and documents needed in the design,testing and operation phases. As a background I will first show an overhead of average figures for production of petroleum in the Norwegian part of the North Sea for 1983. From this figure one understand the importance of accurate measurement of oil and gas.

The regulations are based upon the Royal Decree of 8 December 1972, section 28 and below is an extract of this law.

> "The licensee shall, as further provided by the Ministry, in confirmity with methods customarily used in the petroleum industry, measure, weigh and analyze petroleum produced. Such methods must be approved by the Ministry."

This lecture includes the following:

Section 4 Internal Control

Chapter IV - Design of the computer part

Chapter V - Design approval

Chapter VI - Testing, calibration and control

Gas section 13 - Design of the metering system

" 15 - Maximum diameter ratio

" 16 - Maximum Reynolds number

" 17 - Maximum differential pressure

" 18 - Thickness of orifice plate

" 19 - Length of meter tube upstream and downstream of orifice plate

" 20 - Possibility for disassembling and inspection of meter tube

" 30 - Density Circuit

Oil Section 10 - By-passing the metering system

" 13 - Design of the metering system

" 14 - Requirements to meterprover and turbine meter

" 41 - Calibration of meter prover (before start up)

" 55 - Calibration of meter prover (after start up

This paper includes first some important sections and chapters which are common for both gas and oil regulations. Then some sections in the gas regulation and at the end some sections in the oil regulation.

The following sections are common in both regulations;

SECTION 4: INTERNAL CONTROL (SECTION 4 OIL AND GAS)

This section and sections 5 and 6 were not included in the draft regulation. The establishment of an internal control system is included as a requirement in all NPD regulations conserning safety. This is now also the case in the gas and oil regulations. This implies that the lisencee has to establish an internal control system to ensure that the requirements stipulated in the regulations are complied with. It is a requirement that the internal control system shall be documented.

DESIGN OF THE COMPUTER PART OF THE METERING SYSTEM (CHAPTER IV GAS AND OIL)

The requirements in this chapter includes the following:

- Security against errors and loss of data.
- Printouts and automatic logging.
- Routines for fiscal measurement calculation.
- Powersupply to the metering system.

It is too comprehensive to discuss the detail requirements in this chapter, but they are all important to secure an accurate and reliable measurement.

DESIGN APPROVAL OF THE METERING SYSTEM (CHAPTER V AND VI GAS AND OIL)

The draft version included approval arrangement for the design of the metering system. The requirement of submitting a complete documentation for approval of the design of the metering system, was commented upon from some companies. They suggested to submit the necessary documentation to the NPD in line with project progress. The NPD is aware of this problem but has, however, decided not to change this requirement. The lisencee is therefore requested to submit the necessary documentation to the NPD for approval. Some parts in the draft have been deleted and the approval arrangement has been split in the following 3 phases:

1. Design of the metering system including a complete technical description (Section 41 Gas, Section 31 Oil).

2. At the building site (Section 49 Gas, Section 39 Oil).

3. In the area of application (Section 49 Gas, Section 39 Oil).

I will underline that the requirements in no. 2 and 3 do not require that the NPD has to witness all these tests. The licensee has full responsibility to ensure that the metering systems are designed, tested and controlled according to the requirements (see section 4 internal control).

REGULATIONS FOR FISCAL MEASUREMENT OF GAS

SECTION 13: DESIGN OF THE METERING SYSTEM

DRAFT: 1. The metering system shall comprise orifice plates designed in accordance with requirements given in this regulation.

2. Other metering systems can be approved by the NPD if it can be documented that a metering system with the same as or a better degree of accuracy than that mentioned above can be designed.

Some companies commented upon that this section should state that the metering system should be designed in accordance with ISO 5167. As the requirements given in other sections in the draft regulation refer to ISO 5167, we agreed to this and the section has been modified (see section 13).

Among the contentious points were the additional requirements or restrictions to the ISO 5167, specially for the -ratio, Reynolds number and orifice plates thickness. To the latter comes also the restriction of the differential pressure transmitter. The reason for these additional requirements is to keep the uncertainty as low as possible.

SECTION 15: MAXIMUM DIAMETER RATIO

DRAFT: Diameter ratio shall not exceed 0,6.

The uncertainty of the discharge coefficient is given to be + 0,6% for β -ratio $\leq$ 0,6. For β -ratio above 0,6 the uncertainty of the discharge coefficient is equal to β. The NPD has choosen 0,6 as upper limit for the discharge coefficient for fiscal measurement. In the DRAFT "Code of Practise" for ISO 5167 it is recommended to remain below a β of 0,7 for reliable measurement. Consequently this sections has not been changed.

Example: Frigg and Ekofisk produces gas for a value of about 100 Mill NOK/day ($\sim$ 9 Mill £). An addition uncertainty in the mass flow of 0,1% is equivalent to 100 000 NOK/day ($\sim$ 90 000 £) or $\sim$36 Mill NOK/year ($\sim$ 3,2 Mill £/year).

SECTION 16: MAXIMUM REYNOLDS NUMBER

DRAFT: Reynolds number shall not exceed $3,3 \times 10^7$.

The ISO 5167 gives a maximum Reynolds number of 10^8.

The NPD does not know of any experimental investigation of Reynolds number higher than $3,3 \times 10^7$ without giving increase of the ISO tolerance. An investigation in -73 showed that the change in flow coefficient between 10^7 and $3,3 \times 10^7$ was less than $\pm$ 0,05%.

The NPD requirements given for β -ratio and the Reynolds number are in agreement with the guidelines in the "Metering Standards for Gaseous Petroleum Measurement" by the British Department of Energy.

SECTION 17: MAXIMUM DIFFERENTIAL PRESSURE

DRAFT: The differential pressure shall not exceed 500 millibars.

This limit is set for the following reasons:

a) To prevent possibilities of elastic deformation of plate(bend plates)

b) Accuracy of dp-transmitter. Most commonly used dp-transmitter has the accuracy given of full scale ( ): the uncertainty is very high at low range). The NPD has set a limit of the relative uncertainty of dp to 1%. (see § 34). If the dp is extended to higher values this will course to the necessary use of more LR/HR dp-transmitters.

c) Effects of the seals of the orifice plates at high dp has not been investigated.

50kPa (500 millibar) is normal practice in the industry and consequently in accordance with Royal Decree of 8 December 1972, section 28. This value is also preferred by Dapartment of Energy (Metering Standards for Gaseous Petroleum Measurement).

To minimize the elastic deformation one needs thick plates. Then I have come to the next important section.

SECTION 18: THICKNESS OF ORIFICE PLATE

DRAFT: The orifice plate shall have the maximum thickness as determined in ISO 5167.

If the plate has to be changed with a plate of different diameter ratio, the plate thickness shall be such that the tolerance in ISO 5167 for the pressure tappings are not exceeded.

This means that the maximum thickness of 0,05D in ISO 5167 p 7.1.4.3 should be used.

Some companies commented upon the practical difficulty with this design of the orifice carrier. If the requirement remains unchanged this might cause that non standard orifice carrier and orifice plate thickness has to be used. The section has been modified according to the received comments (see section 18).

The NPD may, however, require information showing that the elastic deflection is below acceptable limits.

SECTION 19: LENGTH OF METER TUBE UPSTREAM AND DOWNSTREAM OF ORIFICE PLATE

DRAFT: Table 3 in ISO 5167 shall be used to determine the minimum length of the meter tube. Upstream and downstream parts from the orifice plate shall have the length as specified in "Zero additional uncertainty".

This is an important requirement and means that the unbrached value in table 3 in ISO 5167 shall be used. The NPD is in agreement with the comments that the ISO 5167 p 6.2.8 footnote 5 is difficult to interpret (several fittings other than 90^{o} bends). We hope that the draft "Code of Practise" for ISO 5167 can give practical informations of how to use the ISO 5167.

SECTION 20: POSSIBILITY FOR DISASSAMLING AND INSPECTION OF METER TUBE

DRAFT: The meter tubes shall be made up and mounted at the area of application so that a part of the tube can be disassembled for inspection of the inner wall of the tube both upstream and downstream of the orifice plate.

This is an important requirement and the lisencee must take this into consideration when designing the metering system. There were only minor comments to this section, consequently we assume that the operators are in agreement with the reqiurement.

SECTION 30: DENSITY CIRCUIT

The draft contained the following requirements:

1. On-line calibration

2. Evaluation of calibration and installation effects.

3. Evaluation of effects of the use of filters in the by pass line.

4. Measuring errors.

From the received comments we concluded that it is very difficult to issue regulation of how to install and calibrate densitometers which can be applied to all fields in the North Sea or to terminals.

This section has been deleted in the regulation and the requirements of densitometers are covered in section 32 and 42, last sentence.

REGULATION FOR FISCAL MEASUREMENT OF OIL

SECTION 10: BY-PASSING THE METERING SYSTEM

DRAFT: By-passing the metering system is not allowed. Arrangements for recycling the crude downstream of the metering system are not allowed.

According to the received comments this requirement would cause some practical problems if not modified. This section presents problems with automatic sampling and other quality control equipment. This requirement would also cause problems during commissioning time.

Due to the above comments this section has been modified. See section 10.

SECTION 13: DESIGN OF THE METERING SYSTEM

DRAFT: 1. The metering system shall comprise turbinemeters with permanent connected meterprover. The system shall be designed in accordance with guidelines given in API Standard 2531, 2534 and 1101 or corresponding chapter in "API Manual of Petroleum Measurement Standards" and in accordance with the additional requirements given in this regulation.

2. Other metering systems can be approved by the NPD if it can be documented that a metering system with the same as or a better degree of accuracy than the above mentioned can be designed.

Some of the companies commented upon that this section assumed that all metering stations is for large volume flow, and that some less requirements should be given for small volume flow. Some companies proposed also to set a lower limit to define small volume flow. The NPD find it very difficult to set a fixed limit to define what is small and what is large volume flow. The requirement will in general be valid for all volume flows, but the NPD will, from case to case, decide whether the exemption in section 61 can be used or not.

The use of turbine meters with conventional prover is a design that is most customarily used in the North Sea today and in accordance with the Royal Decree of 8.12.72 section 28. The wording has, however, been changed. It is no longer a stringent requirement to use turbinemeters with conventional provers, but if this design is choosen, then it has to be designed accordning to the requirements given in this section. The NPD has opened the possibility to use other design than the above as the second part of this section shows. This section has been modified, see section 13.

SECTION 14: REQUIREMENTS TO METERPROVER AND TURBINMETERS

The draft version contained 5 spesific requirements. These requirements have not been changed but the wording has been changed, see section 14. In the draft it was stated that;

> "The meterprover shall be of the bi-directional type with an elastic sphere as displacer".

One should, however, notice that the requirement given in this section is only valid for a design according to the first part of the new section 13.

The regulations were, as I mentioned in the beginning of this lecture, put into force the 2 April this year and apply to all new metering installations. The regulations do not apply fully to existing metering installations which are approved by the NPD. The NPD may, however, determine that some sections also shall apply fully or partly to existing metering systems. These sections are mentioned in the last section in the gas and oil regulations and are as follows:

- Internal control	section	4 oil/4 gas
- Documentation	section	6 oil/6 gas
- Calibration	section	7 oil/7 gas
- Arrangement for control and calibration	section	11 oil/11 gas
- Working place for the metering inspector	section	11 oil/12 gas
- Design of the computer part of the metering system	section	36-30 oil/36-40 gas
- Procedures and personell	section	50 oil/56 gas

Forskrift for fiskal kvantumsmåling av olje som produseres fra indre norske farvann, norsk sjøterritorium og den del av kontinentalsokkelen som er undergitt norsk statshøyhet.

Regulation for fiscal measurement of oil produced in internal waters, in Norwegian territorial waters and in the part of the Norwegian Continental Shelf which is subject to Norwegian sovereignty.

(Unofficial translation)

OLJEDIREKTORATET

NORWEGIAN PETROLEUM DIRECTORATE

1984

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OLJEDIREKTORATET

THE NORWEGIAN PETROLEUM DIRECTORATE

Forskrift for fiskal kvantumsmåling av olje som produseres fra indre norske farvann, norsk sjøterritorium og en del av kontinentalsokkelen som er undergitt norsk statshøyhet, fastsatt av Oljedirektoratet den 2.4.84 i medhold av kgl res av 8.12.72, § 58, jf § 28, jf industridepartementets delegasjonsvedtak av 12.7.76, jf lov nr 12 av 21.6.63 om utforskning og utnyttelse av undersjøiske naturforekomster.

Regulation for fiscal measurement of oil produced in internal waters, in Norwegian territorial waters and in the part of the Norwegian Continental Shelf which is subject to Norwegian sovereignty, issued by the Norwegian Petroleum Directorate 2. April 1984 pursuant to Royal Decree of 8. Desember 1972, section 58, cf. section 28 in accordance with the letter of delegation of 12. July 1976 from The Royal Ministry of Industry cf Act of 21. Juni 1963 no 12 relating to submarine natural resources, section 3.

(Unofficial translation)

INNHOLD

CONTENT

Kap I INNLEDENDE BESTEMMELSER

§ 1
Anvendelse

Denne forskrift kommer til anvendelse på de kvantumsmålinger som må utføres for å beregne statens avgifter og rettighetshaveres inntekter av utvunnet olje. Forskriften omfatter kun de måletekniske sider av systemene.
Forskriften kommer til anvendelse på utnyttelse av petroleumsforekomster på havbunnen eller i dens undergrunn, i indre norske farvann, norsk sjøterritorium og den del av kontinentalsokkelen som er undergitt norsk statshøyhet, bortsett fra områder undergitt privat eiendomsrett.
Forskriften kommer også til anvendelse ved virksomhet som nevnt i annet ledd i området utenfor den norske del av kontinentalsokkelen dersom dette følger av særskilt avtale med fremmed stat eller av folkeretten forøvrig.

§ 2
Målsetting

Forskriften har som målsetting å sikre at nøyaktige målinger ligger til grunn for beregning av avgifter og skatter ved å sette tekniske krav til måleutstyret og fastlegge godkjennelsesprosedyrer.

§ 3
Definisjoner

I denne forskrift betyr:
Bruksstedet:
Plattform, plattformkompleks eller terminal der målesystemet er i bruk.

Datamaskindelen:
Den del av målesystemet som består av digitale datamaskiner og som mottar digitale målesignaler fra analog til digital omformer eller fra digitale målesløyfer.

Fiskale kvanta:
Målte kvanta som benyttes ved salg eller beregning av produksjonsavgift og skatt for petroleum.

Instrumentdelen:
Den delen av målesystemet som inngår mellom den mekaniske delen og datamaskindelen, dvs fra og med føler til digital inngang til datamaskindelen.

Kalibreringsdrift:
Endring av kalibreringskurve over tid.

Linearitetsfeil:
Det samme som: «Non-linearity error» i BS 5233:1975.

Mekanisk del:
Målerør, turbinmåler, rørnormal og alle de mekaniske innretninger som inngår i et turbinmålesystem med permanent rørnormal.

Ch I INTRODUCTORY PROVISIONS

Section 1
Application

This regulation applies to the quantity measurement which should be executed determining the Governmental Royalties and the Lisencee's income from exploited oil. This regulation covers only the technical aspects of the measuring systems.
This regulation shall apply to exploitation of petroleum in the seabed and the sub-strata of the Norwegian inner coastal waters, in Norwegian sea territorial waters and in that part of the Continental Shelf which is subject to Norwegian sovereignty, except areas subject to private ownership.
This regulation shall also apply to activities as mentioned in the second paragraph in areas outside the Norwegian part of the Continental Shelf if such application follows from specific agreement with a foreign state or from international law.

Section 2
Purpose

The purpose of this regulation is to ensure that accurate measurements provide the basis for royalty- and tax stipulations by stating technical requirements and to setting approval procedures.

Section 3
Definitions

In this regulation the meanings of the terms are as follows:
Area of application:
Platform, platform-complex or terminal where the metering system is in operation.

Computer part:
The part of the metering system which consists of digital computers and receives digital metering signals from A/D-converters or from digital instrument loops.

Fiscal quantity:
Measured quantity used for sale or calculation of royalty for petroleum.

Instrument part:
The part of the metering system which is located between the mechanical part and the computer part, i.e. from sensor to digital input of the computer part inclusive.

Calibration drift:
Variation of calibration curve as a function of time.

Linearity error:
The same as «Non-linearity error» in BS 5233:1975.

Mechanical part:
Meter tube, turbine meter, meter prover and all mechanical devices that form part of a turbine meter system with permanent meter prover.

Målerør:
Rett rørstrekning der turbinmåler er installert.

Målesløyfe:
Omfatter alle elementer som inngår i målingen av den enkelte størrelse fra føler til inngang på analog til digital omformer (analog målesløyfer) eller inngang av digitalt signal til datamaskindelen (digitale målesløyfer.).

Målesystem:
Består av mekanisk del, instrumentdel og datamaskindel.

Olje:
Stabilisert olje eller kondensat, omfatter også olje som inneholder større mengder lette hydrokarboner enn vanlig stabilisert olje, forutsatt at temperatur og de fysikalske egenskaper som viskositet og smørende evne ikke avviker vesentlig fra det som er vanlig for stabilisert olje.

Rettighetshaver:
Selskap eller annen sammenslutning som innehar tillatelse gitt i medhold av lov av 21. juni 1963 om utforskning og utnyttelse av undersjøiske naturforekomster, jf kgl resolusjon av 9. april 1965 om utforskning og utnyttelse av undersjøiske petroleumsforekomster og kgl resolusjon av 8. desember 1972 om undersøkelse etter og utnyttelse av undersjøiske petroleumsforekomster.

Rørnormal:
Innretning for kalibrering av dynamisk volummåler, basert på forskyvning av et legeme gjennom et kalibrert rør.

Termometerlomme:
Monteringslomme for temperaturføler.

Turbinmålers kalibreringsfaktor:
Benevnt eller ubenevnt tall som angir forholdet mellom turbinmålers registrering og gjennomstrømmet volum. Uttrykket er ment å dekke både det som internasjonalt kalles «meterfactor» og «K-factor».

Det er referert til følgende standarder i denne forskrift:
API 1101:
«Measurement of petroleum liquid by positive displacement meter». 1. utg. 1960.

API 2531:
«Mechanical displacement meter provers». 2. utg. 1963.

API 2534:
«Measurement of liquid hydrocarbons of turbine meter systems». 1. utg. 1970.

BS 5233:1975:
«Glossary of Terms used in metrology». 1. utg. 1975.

Meter tube:
Straight pipe section where turbine meter is installed.

Instrument loop:
Includes all elements that form part of the measurement of each individual quantity from sensor to input of the A/D-converter (analog instrument loops) or input of digital signal to the computer part (digital instrument loops).

Metering system:
Includes mechanical part, instrument part and computer part.

Oil:
Stabilized crude oil or condensate, includes also crude oil that contains larger amounts of lighter hydrocarbons than normal stabilized crude oil, provided that temperature and the physical properties such as viscosity and lubricating ability do no differ essentially from what is typical for stabilized crude oil.

Licensee:
A company, foundation or group that holds a licence issued pursuant to Act no 12 of 21 June 1963 relating to exploration for and exploitation of submarine natural resources, cf Royal Decree of 9 April 1965 relating to exploration for and exploitation of submarine petroleum resources and Royal Decree of 8 December 1972 relating to exploration for and exploitation of Petroleum in the seabed and substrate of the Norwegian Continental Shelf.

Meter prover:
Device for calibration of dynamic volume meter, based on displacement of a body through a calibrated tube.

Thermowell:
Well in meter tube for installation of thermometer.

Calibration factor for turbine meter:
A number that indicates the ratio between the readings of the turbine meter and the volume throughput. The term is meant to cover both the international «meterfactor» and the «K-factor».

In this regulation, referances are made to the following standards:
API 1101:
«Measurement of petroleum liquid by positive displacement meter». 1st edition 1960.

API 2531:
«Mechanical displacement meter provers». 2nd edition 1963.

API 2534:
«Measurement of liquid hydrocarbons of turbine meter systems». 1st edition 1970.

BS 5233:1975:
«Glossary of Terms used in Metrology», 1st edition 1975.

IEC 751 (1983):
«Industrial platinum resistance thermometer sensors». 1. utg. 1983.

ISO 1000–1981:
«SI units and recommendations for the use of their multiples and of certain other units». 2. utg. 1981.

ISO 3171–1975:
«Petroleum products – Liquid hydrocarbons – Automatic pipeline sampling». 1. utg. 1975.

ISO 6551–1982:
«Petroleum liquids and gases – Fidelity and security of dynamic measurement – Cabled transmission of electric and/or electronic pulsed data». 1. utg. 1982.

IP Petroleum Measurement Manual, part VI, Sect 2:
«Automatic Sampling of Liquid from Pipelines». Foreløpig utgave mars 1980.

NS 4900–ISO 5024:
«Petroleum, flytende og i gassform. Måling. Standard Referansebetingelser». 1. utg. 1979.

Forkortelsene ovenfor betyr:
API:
American Petroleum Institute.
BS:
Britisch Standards Institution.
IEC:
International Electrotechnical Commission.
IP:
The Institute of Petroleum.
ISO:
International Organization of Standardization.
NS:
Norsk Standard.

§ 4
Internkontroll

Enhver som driver eller deltar i petroleumsvirksomheten som omfattes av denne forskrift og enkeltvedtak i medhold herav, plikter å påse at disse overholdes. Rettighetshaver er videre ansvarlig for å påse at enhver som måtte utføre arbeid for ham, enten personlig, ved ansatte eller ved entreprenører eller underentreprenører, overholder bestemmelsene gitt i og i medhold av denne forskrift. Det samme gjelder enkeltvedtak truffet i medhold herav.
Rettighetshaver skal sørge for at det etableres et internkontrollsystem for å sikre at de krav som framgår av denne forskrift blir oppfylt.
Overordnet ansvar for og tilsyn med internkontrollsystemet bør legges til den enhet som allerede er etablert for virksomhetens øvrige internkontroll.

IEC 751 (1983):
«Industrial platinum resistance thermometer sensors». 1st edition 1983.

ISO 1000-1981:
«SI units and recommendations of the use of their multiples and of certain other units». 2nd edition 1981.

ISO 3171–1975:
«Petroleum products – Liquid hydrocarbons – Automatic pipeline sampling». 1st edition 1975.

ISO 6551–1982:
«Petroleum liquids and gases – Fidelity and security of dynamic measurement – Cabled transmission of electric and/or electronic pulsed data». 1st edition 1982.

IP Petroleum Measurement Manual, part VI, Sect 2:
«Automatic Sampling of Liquid from Pipelines». Tentative Mars 1980.

NS 4900–ISO 5024:
«Petroleum, flytende og i gassform. Måling. Standard referansebetingelser». 1st edition 1979.

The abbreviations above mean:
API:
American Petroleum Institute
BS:
British Standards Institution.
IEC:
International Electrotechnical Commission
IP:
The Institute of Petroleum.
ISO:
International Organization of Standardization.
NS:
Norsk Standard.

Section 4
Internal control

Any person executing or participating in the petroleum activity, which is included in this regulation or injunction issued pursuant thereto, is obliged to ensure that these provisions are complied with. Further, the licensee is responsible for ensuring that anyone performing work for him, whether personal, or employees, or contractors, or subcontractors, complies with the provisions stipulated in this regulation and provisions stipulated pursuant thereto. The same applies to injunctions issued pursuant thereto.
The licensee shall see to that an internal control system is established to ensure that the requirements stipulated in this regulation are complied with.
Superior responsibility for and supervision of the internal control system should be assigned to that unit which is already established for the other internal control of the activity.

§ 5
Kontroll av dokumentasjon
Før rettighetshaver innhenter Oljedirektoratets godkjennelse etter kapitlene V, VI og VII, skal denne sørge for at den dokumentasjon som Oljedirektoratet skal ha tilsendt er i samsvar med de krav som er fastsatt i denne forskrift.

§ 6
Dokumentasjon
Rettighetshaver skal etablere og opprettholde et ajourført arkiv som skal inneholde alle spesifikasjoner, beregninger og tegninger. Arkivet skal også inneholde rapporter om verifikasjon og kvalitetsrevisjoner, design-, fabrikasjons- og installasjonsresymé, samt inspeksjonsprogrammer og operasjonshåndbok for alle permanente og midlertidige faser, og annen relevant dokumentasjon.
Rettighetshaver skal utarbeide ajourførte lister over ferdig dokumentasjon og dokumentasjon under utarbeidelse.
Rettighetshaver skal oppbevare all dokumentasjon som er nødvendig for vurdering av eventuelle skader, reparasjoner og ombygginger. Dokumentasjonen skal oppbevares i Norge i hele innretningens levetid.

§ 7
Kalibrering
De målesystem som benyttes for bestemmelse av de fiskale kvanta skal være kalibrert med sporbarhet til internasjonale eller nasjonale normaler.
Innretninger som benyttes ved kalibrering av relevante deler av målesystemet skal være kalibrert og sertifisert ved et laboratorium som kan dokumentere slik sporbarhet.

§ 8
Målenheter
Målesystemene skal gi avlesning i SI-enheter i følge anbefalingene i ISO 1000-1981.

§ 9
Referansebetingelser
Standard referansebetingelser for trykk og temperatur skal være 101.325 kPa og 15°C. Dersom damptrykket er større enn det atmosfæriske ved 15°C, skal standardtrykket være likevektstrykket ved 15°C (jf NS 4900–ISO 5024).

§ 10
Føring av oljestrømmen utenom målesystemet
Oljestrømmen som skal måles, skal ikke kunne ledes utenom målesystemet. Resirkulering av oljestrømmen kan tillates dersom dette er nødvendig av operasjonsmessige grunner.

§ 11
Tilrettelegging for kontroll og kalibrering på bruksstedet
Alle deler av målesystemet på bruksstedet, inkludert avstengningsventiler for oljestrømmen til systemet, skal være lett tilgjengelig slik at

Section 5
Control and documentation
Before the licensee obtains an approval in accordance with chapters V, VI, VII, the former should see to that the documentation required by the Norwegian Petroleum Directorate is in accordance with the requirements stipulated in this regulation.

Section 6
Documentation
The licensee should establish and maintain an up to date file which should contain all specifications, calculations and drawings. The file should also contain reports concerning verification and quality revisions, design,- fabrication – and installation resume, including inspection-programs and operation manual for all fixed and temporary phases, and other relevant documentation.
The licensee should maintain up to date lists of current documentation and documentation under preparation.
The licensee should keep all documentation necessary for the estimation of possible damages, reparations and rebuildings. The documentation should be kept in Norway as long as the installation is in use.

Section 7
Calibration
The metering system used for determining the fiscal measurements shall be calibrated with traceability to international or national standards.
Secondary standards or instruments used for calibration of all relevant parts of the metering system shall be calibrated and certified at a laboratory which can prove such traceability.

Section 8
Units of measurements
The metering system shall give readings in SI-units in accordance with the standards in ISO 1000–1981.

Section 9
Reference conditions
Standard reference conditions for pressure and temperature should be 101 325 KPa and 15°C. If the vapour pressure at 15°C is higher than the atmospheric, the standard pressure should be the equlibrium pressure at 15°C (cf NS 4900–ISO 5024).

Section 10
By-passing the metering system
By-passing the metering system is not allowed. Recirculation of the oil stream may be permitted if it is essential for operational reasons.

Section 11
Arrangements for control and calibration
All parts of the metering system, including shut-off valves for the hydrocarbon flow to the system, shall be located so that inspection and calibration can be carried out without difficul-

kontroll og kalibrering skal kunne foretas uten vanskeligheter. Steder der kalibreringer og kontroller foretas skal være beskyttet mot uteklima og rystelser slik at kalibreringer kan utføres med den nøyaktighet som er fastsatt i denne forskrift.

§ 12
Arbeidssted for måleteknisk inspektør
På bruksstedet skal rom eller avlukke med nødvendig kontorinnredning være tilgjengelig i perioden for måleteknisk inspeksjon, slik at inspektøren uforstyrret kan utføre eventuelle kontrollberegninger og studere målesystemets loggbøker.

ties. Locations where calibration and maintenance take place shall be protected against bad weather and vibrations in such a way that the carrying out of the calibrations are as accurate as stated in this regulation.

Section 12
Working place for the metering inspector
In the area of use a room or a room that is partitioned off, furnished with the necessary office furniture shall be available during the metering inspection in such a way that the inspector undisturbed can carry out possible control calculations and study the logbooks for the metering systems.

KAPITTEL II
UTFØRELSE AV MÅLESYSTEMETS MEKANISKE DEL

CHAPTER II

§ 13
Utførelse av målesystemet
Målesystemets mekaniske del bestående av turbinmålere med permanent tilkoplet rørnormal skal utføres i henhold til retningslinjer gitt i API Standard 2531, 2534 og 1101 eller tilsvarende kapitler i API Manual of Petroleum Measurement Standards og i henhold til bestemmelser fastsatt i denne forskrift.
Annen utførelse av målesystemets mekaniske del kan benyttes dersom det kan dokumenteres og demonstreres tilsvarende eller bedre nøyaktighet enn ovennevnte utførelse.

Section 13
Design of the metering system
The mechanical part of a metering system consisting of turbine meters with a permanently connected meterprover shall be designed in accordance with guidelines given in API Standards 2531, 2534 and 1101 or corresponding chapters in «API Manual of Petroleum Measurement Standards» and in accordance with requirements given in this regulation.
Other designs of the mechanical part of the metering system may be used if it can be documented and demonstrated they are of equivalent or better accuracy than the above mentioned design.

§ 14
Krav til rørnormal og turbinmålere
Rørnormal av to-veis type skal ha to detektorbrytere i hver ende av den kalibrerte rørseksjon. Rørnormalen skal kalibreres med 4 separate volum. Rørnormalen skal ha en repeterbarhet som er slik at den kan kalibreres i en sekvens av 5 etterfølgende enkeltkalibreringer der differanse mellom høyeste og laveste volum ikke overstiger 0.02% av enkeltkalibreringenes gjennomsnittlige volum.
Rørnormal skal ha tilkoblingsflenser for kalibrering på bruksstedet.
Turbinmålerne skal ha en repeterbarhet som er slik at de kan kalibreres mot den permanente rørnormal i en sekvens av 5 etterfølgende enkeltkalibreringer der avvik mellom høyeste og laveste kalibreringsfaktor ikke overstiger 0.05% av gjennomsnittlig kalibreringsfaktor.
Turbinmålernes linearitetsfeil skal ikke overstige ± 0.25% i arbeidsområdet.
Bruk av utstyr for interpolasjon av pulssignal fra turbinmåler kan benyttes dersom det kan demonstreres at målesystemets nøyaktighet tilfredsstiller kravene i denne paragraf og tilfredsstillende dokumentasjon av driftssikkerhet kan framlegges.

Section 14
Requirements to meterprover and turbine meters
Meterprover of the bi-directional type shall have two detectorswitches at each end of the calibrated prover volume. The meterprover shall be calibrated with 4 separate volumes. The meterprover shall have a repeatability so it can be calibrated in a sequence of 5 consecutive runs where the difference between the highest and the lowest volume do not exceed 0.02% of the mean value of each calibration.
The meterprover shall have connecting flanges for re-calibration at the site of operation.
The turbine meters shall have a repeatability such that they can be calibrated against the permanent meterprover in a sequence of 5 consecutive runs where the difference between the highest and the lowest calibration factor do not exceed 0.05% of the mean calibration factor.
The linearity error for the turbine meters shall not exceed ± 0.25% over the working range.
The use of pulse interpolation for the pulse signals from the turbine meters may be used if it can be proved that the accuracy of the metering system satisfies the requirements in his article and satisfactory documentation of the reliability for the interpolation is produced.

§ 15
Målesystemets arbeidsområde
Målesystemet skal kunne måle alle oljestrømmer fra minimum til maksimum uten at noen turbinmåler kommer utenfor sitt arbeidsområde. Antall målerør i parallell skal være slik at maksimal oljestrøm skal kunne måles med minst ett målerør ute av drift og med de øvrige turbinmålere innenfor sitt arbeidsområde.

Section 15
Operating range of the metering system
The metering system shall be capable of measuring all flow rates from minimum to maximum without any of the turbine meters operating outside their operating limits. The number of parallel meter runs shall be such that maximum oil rate can be measured with one meter run out of service and the remaining turbine meters still operating within their working range.

KAPITTEL III
UTFØRELSE AV MÅLESYSTEMETS INSTRUMENTDEL

§ 16
Plassering av følere
Temperatur og trykk skal måles i hvert av målerørene og ved både innløp og utløp av rørnormal.

§ 17
Montering av kontrollinstrumenter
Det skal monteres termometerlommer nær alle temperaturfølere som inngår i målesystemet.
Det skal være tilkoblingsmuligheter for kontrollinstrumenter i parallell med samtlige av målesystemets trykkfølere.

§ 18
Generelt om målesløyfene
Signal fra føler skal overføres slik at målefeil blir minst mulig og ikke i noen tilfelle større enn de grenser som er fastsatt i denne forskrift. Overføring skal skje via færrest mulig signalomformere som kan bidra med målefeil.
Målesløyfene skal holdes adskilt fra øvrige instrumenteringer på bruksstedet. Signalkabler, omformere eller koblingsbokser skal ikke deles med instrumentsløyfer som ikke inngår i målesystemet.
Signalkabler og andre deler av målesløyfene skal utføres og monteres slik at de ikke påvirkes av elektromagnetiske felt.

§ 19
Overføring av pulssignal fra turbinmåler
Opplegg for overføring og behandling av pulssignaler fra turbinmåler skal utføres i henhold til retningslinjer i ISO 6551-1982, Section 3, Level A.

§ 20
Miljøkontrollerte rom
Instrumenter som er ømfintlige overfor temperatur eller andre miljøfaktorer skal innebygges i rom eller avlukke der disse faktorer reguleres.

§ 21
Målesløyfe for temperatur
I målesløyfe for temperatur skal platina motstandselement som er laget i henhold til IEC 751

CHAPTER III
DESIGN OF THE INSTRUMENT PART OF THE METERING SYSTEM

Section 16
Location of sensors
Temperature and pressure shall be measured in each of the meter tubes and at both the inlet and the outlet of the meterprover.

Section 17
Installation of control instruments
A thermowell shall be installed close to all temperature sensors included in the metering system.
It shall be possible to connect control instruments in parallel with all pressure sensors in the metering system.

Section 18
General about the instrument loops
Signal from sensor shall be transmitted so that errors are minimized and under no circumstances are greater than the limits determined in this regulation. Transmission shall run through the fewest possible number of signal converters that can contribute to metering errors.
The instrument loops shall be kept separate from other types of instrumentation in the area of use. Cables, converters or junction boxes shall not be shared with instrument loops that are not part of the metering system.
Cables and other parts of the instrument loops shall be designed and installed so they will not be affected by electromagnetic fields.

Section 19
Transmission of pulse signals from turbinemeter
Wiring for transmission and treatment of the pulse-signals from turbinemeter shall be designed in accordance with guidelines in ISO 6551–1982, Section 3, Level A.

Section 20
Environmental controlled rooms
Instruments which are sensitive to temperature or other environmental factors shall be installed in a room or a room that is partitioned off where these factors can be controlled.

Section 21
Temperature circuit
The temperature measuring element shall be a platinum resistance element in accordance with

(1983) toleranseklasse A eller tilsvarende standard benyttes. Målefeil for hele sløyfen, inkludert kalibreringsdrift pr måned, skal være mindre enn ± 0.3°C i det temperaturområdet målingene skal foretas i.

§ 22
Målesløyfe for densitet

I målesløyfe for densitet skal målefeil for hele sløyfen, inkludert kalibreringsdrift pr. måned, være mindre enn ± 0.3% av målt verdi.

§ 23
Målesløyfe for trykk

I målesløyfe for trykk skal målefeil for hele sløyfen, inkludert kalibreringsdrift pr måned, være mindre enn ± 0.3% av maksimalt kalibreringstrykk.

§ 24
Omforming av signaler fra analog til digital form

Målesystemet skal være innrettet slik at det skal kunne måle maksimal oljestrøm selv om det oppstår feil i en enkel analog til digital omformer.
Analog til digital omformer skal være slik at den ikke vil bidra med systematiske feil i målingene. Oppløsning skal være bedre enn ± 0.01% av full skala. Total feil i analog til digital omformingen, inkludert oppløsning, linearitet, repeterbarhet og andre tilfeldige feil, skal være maksimalt ± 0.02% av full skala.

§ 25
Prøvetakingsutstyr

Prøvetakingsutstyret skal være av automatisk type og utføres etter retningslinjene gitt i ISO 3171–1975 eller IP Petroleum Measurement Manual Part VI, Section 2. I tillegg skal det være utstyr for manuell prøvetaking.

IEC 751 (1983) "Tolerance class A" or equivalent. The accuracy for the complete circuit including any drift over a period of one month shall be better than ± 0.3°C in the temperature range of measurements.

Section 22
Density circuit

The accuracy for the complete density circuit including any drift over a period of one month shall be better than ± 0.3% of measured value.

Section 23
Pressure circuit

The accuracy for the complete pressure circuit including any drift over a period of one month shall be better than ± 0.3% of the maximum calibrated pressure.

Section 24
Conversion of signals from analog to digital form

The metering system shall be able to measure maximum flow rate even when failure in one single A/D converter occurs.
The A/D converter shall not contribute systematic errors to the measurements. The resolution shall be better than ± 0.01% of full scale. Total inaccuracy in the analog to digital conversion, including resolution, linearity, repeatability and other random errors shall be less than ± 0.02% of full scale.

Section 25
Sampling equipment

The sampling equipment shall be of an automatic type and be designed in accordance with guidelines in ISO 3171–1975 or IP Petroleum Measurement Manual Part VI, Section 2. In addition, equipment for manual sampling shall be available.

KAPITTEL IV
UTFØRELSE AV MÅLESYSTEMETS DATAMASKINDEL

§ 26
Generelt om utførelse av datamaskindelen

Datamaskindelen skal ikke ha andre funksjoner enn de som er knyttet til målesystemet. Målesystemet skal bygges opp slik at maksimal oljestrøm skal kunne måles selv om det oppstår svikt innenfor ethvert nivå i datamaskindelen.
Datamaskindelen skal bestå av digitale datamaskiner. Alle analoge signaler fra målesløyfene, som har betydning for målesystemets nøyaktighet, skal overføres til digital form ved analog til digital omformere som tilfredsstiller kravene i § 24. Data som rutinemessig mates inn i eller gis ut av datamskindelen skal være på desimal form. Det skal være mulig å avlese det binære signal fra analog til digital omformeren direkte. Ved utprøving av systemet for pulsoverføring for

CHAPTER IV
DESIGN OF THE COMPUTER PART OF THE METERING SYSTEM

Section 26
General about the computer part

The computer part in the metering system shall have no other functions other than those involved in the metering. The metering system shall be designed in such a way that the maximum oil flow will be measured even if a failure occurs within any level of the computer part.
The computer part shall consist of digital computers. All analog signals from the field circuits having influence on the accuracy of the metering system shall be converted to digital form by means of A/D converters according to the requirements in section 24. Informations that are fed into or given by the computer part shall be of desimal form. It shall be possible when testing the A/D converters to read the binary signal

turbinmålere skal det være mulig å lese antall pulser som mottas av datamaskindelen.
Tall for akkumulerte fiskale kvanta, både for det enkelte målerør og målesystemet totalt, skal lagres i minst to uavhengige registre. Disse registrene skal ikke kunne nullstilles eller endres ved operatørinngrep eller ved feil som strømbrudd og liknende.
Datamaskindelen skal kunne styre automatisk kalibrering av turbinmålerne.
Datamaskindelen skal ha automatisk overvåking av differanser mellom avlesing av måleverdier for parallelle målerør.

§ 27
Sikkerhet mot feil og tap av data

Datamaskindelen skal innrettes med størst mulig grad av automatiske, interne kontrollfunksjoner. Slike kontrollfunksjoner skal overvåke at programsløyfene gjennomløpes med korrekte intervaller. De deler av datamaskindelens lager der innholdet er fast i lengre perioder, skal overvåkes ved periodisk summering og sammenligning mot en kontrollsum.
De av datamaskindelens beregningsalgoritmer og faste parametere som har betydning for korrekt beregning av fiskale kvanta, skal være lagret i en lagerenhet som en bare kan lese fra.
Manuell innsetting av data i datamaskindelen skal sikres med nøkkelbryter eller tilsvarende sikring.

§ 28
Utskrifter og automatisk logging

For målesystemer benyttet til tankbåtlasting skal rettighetshaver legge fram et forslag til utskrift og automatisk logging.
For de øvrige målesystemer gjelder:
Følgende informasjon skal være tilgjengelig fra skriver:

a) Alarmer om de feil i systemet som datamaskindelen er i stand til å detektere.
b) Innsatte parametere i datamaskindelen, både de som er faste og de som kan forandres ved operatørinngrep.
c) Kvantumsrapporter.
d) Rapport for kalibrering av turbinmåler mot permanent rørnormal. Alle data som behøves for manuell kontroll av datamaskindelens beregnede kalibreringsfaktor skal inngå i rapporten.
e) Momentan verdi på oljestrøm og på alle innsignaler fra målesløyfene.

Datamaskindelen skal daglig eller oftere gi ut en rapport som minst skal inneholde følgende:

a) Alarmer som nevnt ovenfor.
b) Innsetting av parametere.
c) Aktivering av nøkkelbryter nevnt i § 27.
d) Periodisk målte kvanta og momentanverdier av oljestrøm og innsignaler.

Datamaskindelen skal for hvert målerør automatisk logge og lagre i minst en måned følgende:

directly. When testing the system for pulse transmission for the turbine meters it shall be possible to read the pulses received by the computer part.

The computer shall include at least two independent data files for storing accumulated fiscal quantities for each meter run and the total metering system. It shall not be possible to delete or change these data files by operator encroachment, power failure and similar.

The computer part shall control the calibration of turbine meters in an automatic mode of operation.
The computer part shall have automatic watch over for differences between readings of measured values for parallel meter runs.

Section 27
Security against errors and loss of data

The computer part shall be equipped with internal control functions as "watchdog timer". The "watchdog timer" shall monitor that the programme loops are executed at the correct intervals. The parts of the memory that contain data which is permanent in a longer period of time shall have a periodical control by "check-sum"
The algorithms and the fixed parameters important for accurate computation of fiscal quantities shall be stored in a read only memory (ROM).
Manual insertion of data in the computer part shall be secured with key operated switch or similar secure arrangement.

Section 28
Printouts and automatic logging

For metering systems used for tanker loading the licensee shall put forward a proposal for printouts and automatic logging.
For other metering systems:
The following information shall be available via printer:

a) Alarms for faults detected by the computer part.
b) Inserted parameters, both fixed and changeable.
c) Quantity reports.
d) Reports for meterprovings. All data needed for manually control of the calculated correction factor shall be included in the reports.
e) Instantaneous values of flow rate and all signals from the instrument loops.

The computer part shall at least once a day print a report containing:

a) Alarms as stated above.
b) Insertion of parameters.
c) Activation of key operated switch, ref. section 27.
d) Periodic measured quantities and instantaneous values of oil flow and input signals.

The computer shall for each meter run automatic log and store for at least one month the following data:

I 2 timers og 24 timers intervaller:
Kumulative kvanta og gjennomsnittsverdier av trykk, temperatur og densitet.
Denne informasjon skal i et oversiktlig format være tilgjengelig for utskrift på standard datapapir.
Inngrep i loggene skal ikke være mulig uten bruk av nøkkel.

§ 29
Datamaskindelens opplegg for beregning av fiskale kvanta
Datamaskindelens opplegg for beregning av fiskale kvanta skal tilfredsstille følgende:
a) Tidsintervall mellom datamaskindelens lesninger av målesystemets innsignaler skal ikke være større enn 1 sekund. Intervall mellom hver syklus for beregning av momentan væskestrøm skal være mindre enn 10 sekunder.
b) Datamaskindelens beregningsalgoritmer for turbinmålers kalibreringsfaktor og for volum ved referansebetingelser skal inneholde alle de korreksjonsledd som tilsvarer Ctlp, Ctlm, Cplp, Cplm, Ctsp, Cpsp, Ctsm og Cpsm i API 2534 eller tilsvarende kapitler i API Manual of Petroleum Measurement Standards.
c) Algoritme- og avrundingsfeil ved beregning av fiskale kvanta i datamaskindelen skal være mindre enn ± 0,001% av beregnet verdi.

§ 30
Strømforsyning til målesystemet
Målesystemet skal ha et strømforsyningssystem som sørger for uavbrutt strømtilførsel med stabil spenning selv om normal strømtilførsel faller bort.

At intervals of 2 and 24 hours:
Cumulative quantities and average values of pressure, temperature and density.
This information shall be accesible on a print out in a clearly set out format using standard computer print out paper.
Access to the logs for changing any data shall not be possible without the use of a key operated switch.

Section 29
The computer part routines for fiscal measurement calculation
The computer part routines for fiscal measurement calculation shall satisfy the following:
a) The time interval between the computer reading of the metering system's input signals shall not be greater than 1 second. The interval between each cycle for computation of instantaneous flow rate shall be less than 10 seconds.
b) The algorithms for calibration factor and volume at reference conditions shall contain all correction factors as per Ctlp, Ctlm, Cplp, Cplm, Ctsp, Cpsp, Ctsm and Cpsm in API 2534 or corresponding chapters in API Manual of Petroleum Measurement Standards.
c) Algorithm and rounding off errors for computation of fiscal quantities in the computer part shall be less than ± 0.001 % of the computed value.

Section 30
Powersupply to the metering system
The metering system shall have a power supply system giving no-break supply at stable voltage even in the case where the normal power supply is lost.

KAPITTEL V
GODKJENNELSE AV MÅLESYSTEMETS UTFØRELSE

§ 31
Godkjennelse
Målesystemets utførelse skal godkjennes av Oljedirektoratet.
Søknad om godkjennelse av målesystemets utførelse skal omfatte en samlet dokumentasjon med en fullstendig teknisk beskrivelse av systemet. Søknaden skal inneholde den dokumentasjon som er spesifisert i dette kapittel. Oljedirektoratet kan kreve tilleggsopplysninger.

§ 32
Dokumentasjon av de grunnleggende data for målesystemets utførelse
Det skal vises ved tegninger hvor målesystemet er plassert i det aktuelle produksjons- og transportsystem. Tegninger skal være slik at det gis en full oversikt over hydrokarbonstrømmene

CHAPTER V
DESIGN APPROVAL OF THE METERING SYSTEM

Section 31
Approval
The design of the metering sysem shall be approved by the Norwegian Petroleum Directorate.
Application for approval of the design of the metering system shall be submitted in a set of documents containing a complete technical description of the system. These documents shall contain the documents specified in this chapter. However, the Norwegian Petroleum Directorate may ask for supplementary informations.

Section 32
Documentation of the basic data for design of the metering system
Drawings shall show the location of the metering system relative to the actual production and transportation system. Drawings shall show a complete and general view over the hydrocarbon

innenfor produksjons- og transportsystemet. Fysisk plassering av målesystemet og data om miljøfaktorer, herunder temperatur, fuktighet og vibrasjoner i underlag, skal angis.
Maksimal og minimal oljestrøm gjennom målesystemet skal angis og hvilke forhold som er bestemmende for oljestrømmen og variasjoner i denne. Maksimum- og minimumsverdier for trykk og temperatur i målerøret skal angis.
Gjennomsnitts-, maksimal- og minimal verdi for oljens densitet ved standard referansebetingelser, Reids damptrykk, bunnsediment og vann, trykk og temperatur i målerøret skal angis.
Rettighetshaver skal legge frem et forslag til installasjon og drift av utstyr for prøvetaking og analyse av oljen, jf § 25.
Rettighetshaver skal legge fram et forslag til installasjon og måling av oljens densitet.

§ 33
Dokumentasjon av målesystemets mekaniske del

Det kreves tegninger som viser følgende:
a) Oversikt over det generelle arrangement av rør, ventiler, turbinmålere og rørnormal, samt dimensjoner.
b) Plassering av luftekraner, kalibreringstilkoblinger, detektorbrytere, givere og følere, termometerlommer og arrangement for uttak av rørnormalens kule.

Antall turbinmålere, dimensjon, arbeidsområde, repeterbarhet og linearitet innenfor arbeidsområdet skal oppgis. Antall pulser pr volumenhet og kalibreringskurver skal oppgis.
Det skal gis en teknisk beskrivelse av rørnormalen. Beregninger og vurderinger som er gjort for å sikre at rørnormalens repeterbarhet tilfredsstiller denne forskrift, skal være inkludert.
4-veis ventil eller annet utstyr og «block & bleed» ventiler skal beskrives ved tekst og tegninger. Lekkasjedeteksjonssystemet på ventilene skal forklares.
En nøyaktighetsanalyse av kvantumsmålingen skal gis på grunnlag av nøyaktigheten i de parameterne som inngår i beregning av oljestrømmen.

§ 34
Oversiktstegning over instrument- og datamaskindelene

Instrument- og datamaskindelene skal illustreres samlet ved en oversiktstegning. Tegningen skal vise signalruter fra givere til analog til digital omformere og datamaskindelene, og mellom datamaskindelene. De enkelte datamaskindelenes hovedfunksjoner skal indikeres på tegningen.

streams within the production and transportation systems. Physical location of the metering system and data for environmental parameters including temperature, humidity and vibrations in the foundations shall be stated.
Maximum and minimum oil flow through the metering system and conditions influencing the flow rate and its variations shall be stated. Maximum- and minimum values for pressure and temperature in the meter tube shall be stated.
Mean-, maximum- and minimum values for the density at reference conditions, Reid Vapour Pressure, Bottom Sediment & Water for the oil and also pressure and temperature in the meter tube shall be submitted.
The licensee shall present a proposal for installation and operation of equipment for sampling and analysis of the oil, ref. section 25.
The licensee shall present a proposal for installation and operation of density meters.

Section 33
Documentation of the mechanical part of the metering system

It is required that drawings be submitted showing:
a) A survey of the general arrangement, including dimensions of pipes, valves, turbine meters and meterprover.
b) Locations of vent valves, connection flanges for calibration, detector switches, transducers and sensors, thermowells and the arrangment for lifting/removing the prover sphere at the meterprover.

Number of turbine meters, dimensions, operating limit, repeatability and linearity within the operating limits shall be submitted. Number of pulses per unit volume and calibration curves shall also be submitted.
A technical description of the meterprover shall be submitted. Further, calculations and evaluations to ensure that the repeatability of the meterprover falls within this regulation shall be included.
Description and drawings of the 4-way valve or other flowreversing system and the "block & bleed" valves shall be submitted. Description of the leak detection system for these valves shall be included.
An analysis of the accuracy of the measured quantity on the basis of the accuracy of the parameters included in the computation of the oil flow shall be submitted.

Section 34
General drawing of instrument- and computer parts

The instrument- and computer parts shall be illustrated together in a general drawing. The drawing shall show the signal path from sensors to A/D-converters and computer parts and also the signal path between the computers. The main functions of each single computer part shall be indicated on the drawing.

§ 35
Beskrivelse av målesløyfene
For hver type instrumentsløyfe kreves tegning som viser alle signalomforminger, elektriske barrierer og andre deler av sløyfene. Spenningsnivå, verdi på ohmske motstander og impedanser og eventuelle frekvensområder skal angis i den utstrekning dette er nødvendig for å vurdere hensiktsmessige tilkoblingspunkter ved senere kalibrering og kontroller som omtalt i kapitlene VI og VII. Det kreves tekniske spesifikasjoner fra leverandør for samtlige deler i instrumentsløyfen. Det skal dokumenteres at nøyaktighetskravene i denne forskrift oppfylles.

§ 36
Beskrivelse av analog til digital omformere
Funksjonsmåte av analog til digital omformer skal beskrives og det skal vises at bestemmelsene i § 24 tilfredsstilles.

§ 37
Beskrivelse av datamaskindelen
Det kreves dokumentasjon som omfatter:
a) En beskrivelse av datamaskindelen som viser at bestemmelsene i kapittel IV er fulgt.
b) En operasjonshåndbok for datamaskindelen.
c) En vurdering av hvilke feil som kan forekomme i datamaskindelen, og hvordan en i hvert enkelt tilfelle vil oppdage slike feil.

Oljedirektoratet kan kreve at dokumentasjonen skal inkludere et blokksjema som viser hvordan datamaskindelens programsløyfer er oppbygd og en utskrift av programmene.

Section 35
Description of the instrument loops
For every type of instrument loop, a drawing showing all signal conversions, electrical barriers and other parts of the loop shall be submitted. Voltage levels, values of resistances and impedances and any frequency ranges shall be given if needed for assessing convenient connection points for later calibration and control as described in chapter VI and chapter VII. Technical specifications from supplier for all components in the instrument loop shall be submitted. A description shall be submitted to prove that the accuracy requirements in this regulation have been followed.

Section 36
Description of the A/D-Converters
The functions for the A/D-converters shall be described together with proofs that the provisions in section 24 have been followed.

Section 37
Description of the computer part
Following documentation is required:
a) A description of the computer part showing that this complies with the provisions of chapter IV.
b) Operational manual for the computer part.
c) An evaluation of possible faults occuring in the computer part and how each fault can be detected.

The Norwegian Petroleum Directorate may require that the documentation shall include a block diagram showing how the computer program loops are designed, furthermore a print out of the program.

KAPITTEL VI
PRØVING, KALIBRERING OG KONTROLL FØR MÅLESYSTEMET TAS I BRUK

§ 38
Generelt
Før målesystemet tas i bruk skal det prøves, kalibreres og kontrolleres etter bestemmelsene i dette kapittel.

§ 39
Opplegg og prosedyrer
Dersom ikke annet er fastsatt i den enkelte paragraf, skal kontrollene som beskrives i dette kapittel, utføres på følgende stadier:
a) Før målesystemet forlater byggeplassen.
b) Etter montering på bruksstedet, umiddelbart før målesystemet tas i bruk.

Rettighetshaver skal utarbeide og innsende til Oljedirektoratet detaljprosedyrer for kontrollene etter de bestemmelser som er gitt i dette kapittel. Oljedirektoratet skal ha anledning til å være til stede og bevitne kontrollene helt eller delvis. Varsel om tidspunkt skal gis Oljedirektoratet minst 3 uker før kontrollene finner sted.

CHAPTER VI
TESTING, CALIBRATION AND CONTROL OF THE METERING SYSTEM BEFORE START-UP

Section 38
General
Before the metering system is put in operation, it shall be tested, calibrated and controlled after the requirements in this chapter.

Section 39
Arrangements and procedures
Unless specified in each paragraph, the controls as described in this chapter shall be carried out in the following order:
a) Before the metering system leaves the building site.
b) After installation at the place to be used immediately before start-up.

The licensee shall work out and forward to the Norwegian Petroleum Directorate detailed control procedures according to the requirements given in this chapter. The Norwegian Petroleum Directorate shall have the opportunity to be present and witness the controls either completely

Målesystemet skal være godkjent av Oljedirektoratet før det forlater byggeplassen og før det tas i bruk på bruksstedet.

§ 40
Instrumentprøving
Oljedirektoratet kan kreve at en eller flere av de deler som inngår i målesystemet, og som anses kritiske for systemets nøyaktighet, skal evalueres ved prøving under kontrollerte betingelser ved et laboratorium.

§ 41
Kalibrering av rørnormal
Rørnormalens volum skal kalibreres før prøving og kontroll av målesystemet på byggeplass. Umiddelbart før målesystemet tas i bruk på bruksstedet skal rørnormalen rekalibreres.

§ 42
Kontroll av at målesystemet er bygget i henhold til tegninger og spesifikasjoner
Rettighetshaver skal utarbeide en punktvis liste for Oljedirektoratet som viser at målesystemet er bygget i henhold til tegninger og spesifikasjoner.

§ 43
Kontrollmåling av målesløyfene
Målesløyfene skal kontrollmåles av rettighetshaver. Alle relevante deler av målesløyfene skal være kalibrert før kontrollmålingene. Kalibreringsskjema i utfylt stand skal være tilgjengelig for inspeksjon av Oljedirektoratet. Hver målesløyfe skal utprøves ved at følerne settes til å måle et antall målestørrelser innenfor sitt arbeidsområde. Målestørrelsene skal frembringes ved det kalibreringsutstyr som normalt brukes for kalibrering av følerne på bruksstedet eller ved spesielt testutstyr. Avlesning for kontroll av målesløyfens nøyaktighet skal foregå ved inngang til datamaskindel eller, for analoge sløyfer, ved inngang på analog til digital omformer. Kontrollmåling av turbinmålernes pulsoverføringssystem skal utføres etter retningslinjer gitt i ISO 6551–1982, kap 7.3. Avlesning av pulser skal foretas på datamaskindelen og eventuelle eksterne telleverk.
Dersom spesielle forhold tilsier det, kan giver eller føler utelates og erstattes av en signalgenerator ved den utprøving som foretas før målesystemet forlater byggeplass.
Det skal simuleres 100 000 pulser. Dersom det signal som mottas av tellerne avviker fra simulert signal med mer enn 1 puls, og det er sannsynlig at avviket skyldes ufullkomne pulser ved start og stopp av signalgenerator, tillates et avvik på 2 pulser av 100 000 hvis det kan vises at avvik på 2 pulser ikke overskrides ved dobling av pulsantallet til 200 000.

or partly. Notice about the point of time for the controls shall be given the Norwegian Petroleum Directorate at least 3 weeks in advance.
The metering system shall be approved by the Norwegian Petroleum Directorate before it leaves the building site and before it is put in operation in the area of application.

Section 40
Instrument testing
The Norwegian Petroleum Directorate may require that one or more parts of the metering system, which are considered to be critical for the accuracy of the system, shall be evaluated by testing under controlled conditions in a laboratory.

Sections 41
Calibration of the meterprover
The volumes of the meterprover shall be calibrated before the test of the metering system that has to be carried out at the building site. The meterprover shall be recalibrated immediately before the metering system comes into use at the place where it is installed.

Section 42
Inspection that the metering system is built in accordance with drawings and specifications
The licensee shall prepare a point by point list for the Norwegian Petroleum Directorate showing that the metering system is built in accordance with drawings and specifications.

Section 43
Chech of the instrument loops
The licensee shall check the instrument loops. All relevant parts of the instrument loops shall be calibrated before the checks. Completed calibration sheets shall be available for inspection by the Norwegian Petroleum Directorate. Each instrument loop shall be tested by setting the sensors to measure a number of measurements within its working range. The measurements shall be produced by the calibration equipment normally used for on site calibration of sensors or by special test equipment. Readings for verification of the accuracy of the instrument loops shall take place at the input to the computer part or, for analog loops, at the input to the A/D converter.
The pulse transmission system from the turbine meters shall be checked in accordance to guidelines in ISO 6551–1982, chapter 7.3. Reading of pulses shall be made at the computer part and any external counters.
If special circumstances occur, the transducer or sensor may be left out and replaced with a signal generator in the test to be made before the metering system leaves the building site.
100 000 pulses shall be simulated. If the signals received at the counters differ from the simulated signals with more than 1 pulse and it is probable that the difference is due to imperfect pulses at start and stop of the signal generator, a difference of 2 pulses out of 100 000 will be permitted if it can be shown that the difference of 2

I tillegg til å kontrollere at overføring og telling av pulser skjer korrekt, skal feil som tilsvarer at en av transmisjonskanalene svikter eller forstyrres, simuleres for å teste systemets alarmopplegg.

§ 44
Kontrollmåling av analog til digital omformer
Analog til digital omformer skal kontrollmåles. Kontrollmålingene skal utføres ved simulering av analogsignaler inn på omformeren. Minst 10 ulike verdier, jevnt fordelt over arbeidsområdet, skal kontrolleres. Avlesning av digital verdi skal foretas på datamaskindelen. Det skal kontrolleres at kravene til nøyaktighet i § 24 tilfredsstilles.
Kontrollmålingen skal videre omfatte en kontroll av at samtlige binærsiffer fungerer.

§ 45
Prøving med væskestrøm gjennom målesystemet på byggestedet
Det ferdigmonterte målesystem skal på byggestedet prøves med væskestrøm.

§ 46
Kontroll av målesystemets opplegg for kalibrering av turbinmålerne på byggestedet
Målesystemets opplegg for automatisk kalibrering av turbinmålerne skal utprøves på brukstedet. Minst en kalibrering skal gjennomføres ved manuell betjening av ventiler.

§ 47
Kontroll av automatisk beregning av kalibreringsfaktor
Et antall, fastsatt av Oljedirektoratets inspektør, av de kalibreringsfaktorer som beregnes under utprøvingene som kreves i § 46, skal kontrollberegnes manuelt. Dette gjelder både meterfaktorer for den enkelte prøving og den gjennomsnittsverdi som beregnes automatisk av de 5 etterfølgende enkeltkalibreringer innenfor det tillatte variasjonsområde.

§ 48
Kontroll av datamaskindelen
For hvert enkelt målerør skal det utføres kontroll av datamaskindelen for å verifisere at de ulike funksjoner er operative, samt at alle beregninger utføres med lik eller bedre nøyaktighet enn den som er fastsatt i § 29.
Utprøving av datamaskindelens ulike funksjoner skal bl a omfatte manuell innmating av data, utskrifter, alarmer og eventuell dataoverføring mellom datamaskiner.
Kontroll av beregning av oljestrøm skal utføres ved at verdier for alle innsignaler legges inn i datamaskindelen manuelt. Enhver slik størrelse skal ha minst tre ulike verdier. Disse tre verdiene skal representere maksimum- og minimumnivå for det aktuelle signal, samt en verdi i arbeidsområdet. Manuelt innsatte størrelser skal

pulses will not be exceeded when doubling the pulses to 200 000.
In addition to verifying that transmission and counting of pulses occur correctly, errors corresponding to failure or trouble in one of the transmission channels, shall be simulated to test the alarm arrangement for the system.

Section 44
Checking of the A/D-converter
The A/D-converter shall be checked. The check shall be performed by simulation of analog signals into the converter. At least 10 different values equally spread over the working range, shall be tested. Reading of the digital value shall be made at the computer part. It shall be verified that the requirements of accuracy in section 24 are satisfied.
Further, the check shall include a verification that all binary bits are functioning.

Section 45
Testing at the building site with liquid through the metering system
The assembled metering system shall at the building site be tested with liquid flow.

Section 46
Control at the building site of the metering system's arrangement for calibration of the turbine meters
The arrangement for the metering system for automatic calibration of the turbine meters shall be tested at the building site. At least one calibration shall be carried out by manual operation of the valves.

Section 47
Control of the automatic calculation of calibration factor
A number, determined by the inspector from the Norwegian Petroleum Directorate, of the calibration factors which arise during the testing as required in section 46, shall be manually checked. This applies to both the meterfactor for the trial proof and the mean value, automatically calculated, of the 5 consecutive proving runs within the permissible variation span.

Section 48
Testing of the computer part
For each meter run testing of the computer part shall be made to verify that the different functions are operational and also that all calculations are performed with the same as or a better degree of accuracy as stated in section 29.
Testing the different functions of the computer part shall among other things include manual input of data, print outs, alarms and any data transmission between computers.
Control of computation of the oil flow shall be performed by manually entering into the computer the values for input data. Any such parameter shall at least have three different values. These three values shall represent maximum and minimum level of the considered signal, plus a value in the working range. Manually entered

være slik at en oppnår maksimal og minimal oljestrøm.
Kontroll av at datamaskindelen foretar korrekt integrasjon av de fiskale kvanta skal utføres. Integrasjonen skal kontrolleres ved maksimal og minimal verdi.

§ 49
Kontroll av datamaskindel og instrumentdel
Kontroll av datamaskindel og instrumentdel for beregning av oljestrøm skal inneholde et antall kontrollpunkter og utføres for hvert målerør under følgende betingelser:
a) Innsignalene skal påtrykkes med sertifiserte signalgeneratorer som koples inn i stedet for giver.
b) Et hvert innsignal skal simuleres med minst tre verdier. Disse tre verdiene skal representere maksimum- og minimumnivå for det aktuelle signalet, samt en verdi i arbeidsområdet.
c) Innsignalene skal være slik at en oppnår maksimal og minimal oljestrøm.

parameters shall be such as to obtain minimum and maxiumum oil flow rate.
A check that the computer part makes correct integration of the fiscal quantities shall be made. The integration shall be checked at maximum and minimum values.

Section 49
Control of computer -and instrument parts
Control of computer -and instrument parts shall include a number of check points and be performed for each meter tube under the following conditions:
a) Input signals shall be produced by replacing the transducers with a certified signal generator.
b) Any input signal shall be simulated with at least three values. These three values shall represent maximum and minimum levels for the considered signal plus a value in the working range.
c) The input signals shall be such that maximum and minimum oil flow is obtained.

KAPITTEL VII
MÅLESYSTEMET I BRUK

§ 50
Prosedyrer og personell
Før målesystemet tas i bruk skal rettighetshaver utarbeide og innsende til Oljedirektoratet prosedyrer for betjening og kalibrering av målesystemet. Disse prosedyrene skal tilfredsstille bestemmelsene i dette kapittel og være godkjent av Oljedirektoratet.
Rettighetshaver skal sørge for at betjening, kalibrering og kontroll utføres av kvalifisert personell. Det skal utpekes ansvarshavende for målesystemet. Ansvarshavende for målesystemet kan ha andre arbeidsoppgaver på bruksstedet i tillegg til tilsyn med målesystemet. En av de ansvarshavende skal være til stede på bruksstedet og ha ansvaret for at ovennevnte prosedyrer for betjening, kalibrering og kontroll følges. Ansvarshavende skal ha utdannelse og opplæring som gir tilstrekkelig innsikt i det eller de målesystem vedkommende har ansvaret for.

§ 51
Manuell logging
Prosedyrene skal foreskrive at en loggbok føres over alle aktiviteter og hendelser som angår målesystemet. Denne loggboken skal som et minimum inneholde følgende registreringer:
a) Automatiske alarmer som varsler feilmåling av oljestrømmen. Det skal oppgis årsak til og hva som ble gjort for å fjerne årsaken til alarmen.
b) Feil og uregelmessigheter, og hva som ble gjort for å rette på feilen.
c) Korrigerte akkumulerte kvanta pga feil nevnt

CHAPTER VII
THE METERING SYSTEM IN OPERATION

Section 50
Procedures and personnel
The licensee shall develop and send to the Norwegian Petroleum Directorate procedures for operation and calibration of the metering system before the metering system is put into use. These procedures shall satisfy the requirements in this chapter and be approved by the Norwegian Petroleum Directorate.
The licensee shall see that operation, calibration and control are executed by qualified personnel. Supervisors for the metering system shall be appointed. The supervisors may have additional responsibilities on the area of application besides having supervision with the metering system. One of the supervisors shall be present on the area of application and be responsible for the above stated procedures for operation, calibration and control. The supervisor shall have education and training giving sufficient insight into the system(s) for which the person concerned is responsible.

Section 51
Manual logging
The procedures shall prescribe that a logbook is kept over all activities and occurences concerning the metering system. This logbook shall as a minimum embody the following items of information:
a) All automatic alarms announcing errors in the oil measurement. The cause for the alarm and action taken to rectify this shall be entered.
b) Errors and irregularities and action taken to amend the error.

i pkt a) og b). Det skal angis hvordan feilmålingen er korrigert.
d) Forandringer av data til datamaskindelen.
e) Tidspunkt for kalibreringer og reparasjoner.
f) Den enkelte ansvarshavendes signatur og angivelse av tidspunkt for når han overtar og gir fra seg ansvaret for målesystemet.

§ 52
Kalibreringsdokumenter
Prosedyrene skal inneholde anvisninger og skjema for utfylling ved kalibrering. Alle slike skjema skal være innrettet slik at feil før og etter eventuell justering fremgår. Alle kalibreringsrapporter skal være tilgjengelige for inspeksjon i ett år fra kalibreringstidspunktet. Oljedirektoratet kan kreve kopier av kalibreringsrapportene tilsendt.

§ 53
Overvåking av parallelle målerør
Prosedyrene skal foreskrive en overvåking av parallelle målerør i målesystemet. De tilstander som ikke gir automatiske alarmer må kunne oppdages. Det skal brukes kontrollgrenser for kalibreringsfaktorer for turbinmålere tilsvarende appendiks B i API 2534.

§ 54
Kontroll og kalibrering
Prosedyrene skal foreskrive kontroll, og om nødvendig kalibrering hvis feil varsles ved alarmer fra datamaskindelen eller oppdages på annen måte. I tillegg skal målesystemet underkastes periodiske kontroller og kalibreringer som fastsatt i denne forskrift.

§ 55
Kalibrering av rørnormal
Når systemet er tatt i bruk, skal rørnormalen kalibreres dersom en systematisk endring av kalibreringsfaktor for alle systemets turbinmålere inntrer, og dersom det ikke kan påvises at denne endringen skyldes andre forhold enn endring av rørnormalens volum. Rørnormalen skal også kalibreres dersom andre forhold gir grunn til å anta at en endring av volumet har funnet sted.
Dersom rekalibrering av rørnormalen viser en volumendring større enn 0,02%, skal den nye volumverdien benyttes. For øvrig skal rørnormal kalibreres hvert år. Lengre kalibreringsintervall kan godkjennes av Oljedirektoratet for mindre viktige rørnormaler dersom det målte volum for de 2 siste kalibreringene etter at målesystemet er tatt i bruk, ikke avviker mer enn 0,02% ifra det benyttede volum. Kalibreringsprosedyrer skal i hvert tilfelle forelegges Oljedirektoratet.

c) Correction of accumulated quantities due to errors stated in sub-sections a) and b). It shall be shown how the false measurement is corrected.
d) Changes of input data to the computer.
e) Point of time for calibrations and repairs.
f) The individual supervisor's signature and point of time at which he accepts and relinquishes the responsibility for the metering system.

Section 52
Calibration documents
The procedures shall contain directions and forms for completion when calibration is carried out. All these forms shall be arranged so that errors before and after any adjustment are evident. All calibration reports shall be available for inspection for one year after the point of time for calibration. The Norwegian Petroleum Directorate may require copies of the calibration documents.

Section 53
General monitoring of parallel meter runs
The procedures shall prescribe a general monitoring of parallel meter runs in the metering system. The conditions not giving an automatic alarm must be detectable. Control limits for calibration factors for turbine meters according to appendix B in API 2534 shall be used.

Section 54
Control and calibration
The procedures shall prescribe control and if necessary calibration if errors are noticed by alarms from the computer part or are discovered in another way. In addition the metering system shall be subjected to periodic controls and calibrations as determined in this regulation.

Section 55
Calibration of the meter prover
When the system is in operation, the meter prover shall be recalibrated if a systematic change in the calibration factor for all the turbine meters occur, and it cannot be shown that this change is due to other conditions than an alteration in the prover volume. The meter prover shall also be recalibrated if other conditions give grounds for presuming a change in volume has occured. If recalibration of the meter prover shows a volume change greater than 0.02%, the new volume shall be used. Incidentally the meter prover shall be recalibrated each year. Longer calibration intervals may be approved by the Norwegian Petroleum Directorate for less important meter provers if the measured volumes for the two last calibrations after the metering system is put in operation do not differ by more than 0.02% from the volume used. Calibration procedures shall in every case be submitted to the Norwegian Petroleum Directorate.

§ 56
Kalibrering av turbinmålere

Snarest mulig etter at målesystemet er tatt i bruk skal et større antall kalibreringer av turbinmålerne utføres for å fastslå om og eventuelt i hvilken grad kalibreringsfaktoren påvirkes av oljestrøm, temperatur og sammensetning av olje når disse størrelsene endrer seg innenfor sitt variasjonsområde. Forøvrig skal opplegget for kalibrering av turbinmålerne tilfredsstille følgende:

a) Dersom det ut fra ovennevnte kalibreringer finnes en vesentlig sammenheng mellom kalibreringsfaktor og oljestrøm, trykk, temperatur, densitet, viskositet eller sammensetning, skal det etableres grenser for disse parameteres endring fra verdiene de hadde ved foregående kalibrering. Ved overskridelse av grensene skal ny kalibrering foretas.
b) Tidsintervall mellom kalibrering av de turbinmålere som er i bruk skal ikke overskride 4 dager. Hvor tankbåtlasting benyttes skal minst en kalibreringsfaktor for hvert turbinmeter etableres i hver lasteperiode.

§ 57
Kalibrering av givere

Kalibrering av alle givere skal foretas minst en gang pr måned. Kalibreringen skal omfatte flere punkter innenfor giverens arbeidsområde.
Kalibreringsmetodene skal være slik at systematiske målefeil som følge av forskjell mellom kalibrerings- og driftsforhold unngås eller kompenseres.

§ 58
Kontroll av signaloverføring fra givere til datamaskindelen

Overføring av signal fra givere til datamaskindel skal kontrolleres. Kontrollen kan utføres parallelt med kalibrering av givere ved samtidig å registrere signal fra giver og signal til datamaskindelen.
Dersom en giver av tekniske årsaker må demonteres og bringes bort fra målerøret ved kalibrering, kontrolleres signaloverføring ved å erstatte giver med signalgenerator.
Kontroll av signaloverføring skal utføres minst en gang pr måned.

§ 59
Kontroll av analog til digital omformere

Kontroll av analog til digital omformere som beskrevet i § 44, skal utføres minst hver 3. måned.

§ 60
Kontroll av datamaskindelen

Rettighetshaver skal utarbeide en vurdering av hvilke feil som kan oppstå i datamaskindelen under bruk. Prosedyrer som inneholder et opplegg for periodisk kontroll med basis i denne vurderingen, skal innsendes til Oljedirektoratet.

Section 56
Calibration of turbine meters

As soon as possible after the meter system is put in operation, a greater number of calibrations of the turbine meters shall be executed to determine if and to what possible extent the calibration factor is affected by flow rate, temperature and composition of crude when these alter within their variation range. In addition the general arrangement for calibration of turbine meters shall satisfy the following:

a) If, from the above mentioned, there is an essential correlation between calibration factor, flow rate, pressure, temperature, density, viscosity or composition, it shall be established what are the limits for these parameter changes from the values they had at the preceding calibration. When exceeding these limits, a new calibration shall be made.
b) The time interval between calibrations of the turbine meters in use shall not exceed 4 days. Where tankerloading is used at least one calibration factor for each turbine meter shall be established in each loading period.

Section 57
Calibration of transducers

Calibration of all transducers shall be performed at least once per month. The calibration shall include several points within the transducer's working range.
The calibration procedures shall be such as to avoid or to compensate for systematic measurement errors resulting from a dissimilarity in calibration and operational conditions.

Section 58
Control of signal transmission from transducer to computer

Signal transmission from transducers to computer part shall be controlled. The control may be carried out at the same time as the calibration of transducers by simultaneously recording signals from transducers and signals to the computer part. If, due to technical reasons, a transducer must be dismounted and carried away from the meter run for calibration, the signal transmission shall be controlled by replacing the transducer with a signal generator.
Control of the signal transmission shall be made at least once a month.

Section 59
Control of A/D-converters

Control of A/D-converters as desribed in section 44 shall be made at least every 3 months.

Section 60
Control of the computer part

The licensee shall prepare and evaluation of what errors may arise in the computer part during operation. Procedures that contain an arrangement for the periodical control based on this evaluation shall be sent to the Norwegian Petroleum Directorate.

KAPITTEL VIII
SLUTNINGSBESTEMMELSER

§ 61
Dispensasjon

Oljedirektoratet kan i særlige tilfeller fravike bestemmelsene fastsatt i denne forskrift.

§ 62
Straffebestemmelse

Overtredelse av bestemmelsene i denne forskrift straffes med bøter, jr straffelovens § 339 nr 2, såfremt ikke strengere straffebestemmelser kommer til anvendelse på forholdet.

§ 63
Ikrafttredelse

Denne forskrift trer ikraft straks.

Denne forskrift får ikke anvendelse på ferdigbygde målesystem som ved ikrafttredelse av denne forskrift er godkjent av Oljedirektoratet. Oljedirektoratet kan imidlertid bestemme at §§ 4, 6, 7, 11, 12, 26–30 og 50 i denne forskrift skal komme helt eller delvis til anvendelse også for de ovenfor nevnte ferdigbygde målesystem.

CHAPTER VIII
FINAL PROVISIONS

Section 61
Exemption

The Norwegian Petroleum Directorate may in special cases provide exemption from the requirements of this regulation.

Section 62
Penal provisions

Violation of provisions in this regulation are punishable by fines, according to the Penal Code Section 339 no 2, unless more severe penal sanctions are applicable.

Section 63
Entry into force

This regulation enters immediately into force.

This regulation does not apply to existing installations which are approved by the Norwegian Petroleum Directorate when this regulation enters into force. However, the Norwegian Petroleum Directorate may determine that sections 4, 6, 7, 11, 12, 26–30 and 50 in this regulation shall apply fully or partly for the above mentioned existing metering systems.

Main Index

UK STANDARDS AND REGULATIONS RELATING TO THE DESIGN AND OPERATION OF METERING STATIONS

by

J E MILLER

HUNTER TECHNICAL SERVICES

PAPER 2.2

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

UK STANDARDS AND REGULATIONS RELATING TO THE DESIGN AND OPERATION OF METERING STATIONS

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Hunter Technical Services

1. INTRODUCTION

The UK regulations for metering systems are firstly those which apply to crude oil and gas produced in the North Sea, and secondly those which apply to the products delivered from bonded hydrocarbon oil installations. These UK regulations, the UK standards they refer to, and the procedures by which UK standards are formulated, are discussed in this paper. Particular attention is given to the organisation and responsibilities of the Institute of Petroleum, and its working relationships with the British Standards Institution (BSI) and the International Organisation for Standardisation (ISO). The paper gives details of the latest position of the UK standards available in one form or another in the UK for dynamic measurements. Although, in order to give an overall view, gas measurement is mentioned more details of the standards are given in Paper 3 of this Session of the Workshop.

2. REGULATIONS FOR THE MEASUREMENT OF CRUDE OIL

The measurement of crude oil and gases in the North Sea is the concern of the Department of Energy (DoE), and all Petroleum production licenses granted by the Secretary of State incorporate a clause which requires a licensee to measure (or weigh) all petroleum liquids and gases won and saved, in accordance with good oil field practice. The current documents available from the Gas and Oil Measurement Branch of the DoE, which provide guidelines on the design, construction and operation of metering stations for liquids and gases, are as follows:-

2.1. Department of Energy Turbine Metering Standards for Liquid Petroleum Measurements - February 1979.
2.2. Department of Energy Operating Procedures for Approved Metering Stations - (Liquid Hydrocarbons) - October 1979.
2.3. Department of Energy Metering Standards for Gaseous Petroleum Measurements - March 1981.

It is understood that these guidelines are being revised and extended, but no details have yet been published.

The involvement of the DoE with measurement does not stop at issueing the guidelines, and a number of further steps are taken by the DoE, in conjunction with the licensee, to make sure the final installed system and its equipment is acceptable to them in terms of accuracy, reliability, fidelity etc.

Discussions are held with the licensee by the DoE on what methods of measurement for the project are being proposed since each application has its own

particular peculiarities, such as live or very viscous crude oils. Detailed examination then follows of the measurement proposals, including an analysis of the methods of calculations. When the measurement system has been built by the selected manufacturer, officers of the DoE witness the licensee's acceptance tests to ensure the system complies with the agreed design and operation criteria. Later on during the pre-commissioning phase, DoE officers again carry out on-site inspections to see that the whole system is being correctly assembled and checked out. Routine calibration procedures have to be agreed with the licensee, and field inspectors visit the site to witness these and carry out general operational checks. Finally any modifications or repairs have to be communicated to the DoE, and the inspector may wish to witness the changes that are being made.

As copies of the guidelines are available from the DoE to these who need them it is not necessary to go through them in detail. The requirements are straightforward, and represent good practice for metering and proving, and the associated measurements of temperature, pressure and density. It should be borne in mind that they are the minimum performance which is expected from the equipment. Considerable emphasis is placed on the pulse transmission system, and the design performance of the totalisers and compensators. It is also worth mentioning, particularly in view of the difficulties that are often encountered, that the other instrumentation specified as a requirement includes an automatic flow proportional sampling system, which is of course the underlying reason for Session 4 of this workshop.

If we now consider the extent to which these DoE guidelines refer to UK standards we find rather surprisingly that there are very few, since at the time they were written very little design criteria were available from UK standards. Thus the requirements and expectations for the acceptable meter factor variation over the operational flow range, the number of pulses generated in a prover run, and the resolution of totalisers are spelt out in the guidelines, rather than figures being quoted which occur in UK standards and codes of practice. It will be interesting to see if this aspect of the guidelines is still retained in any subsequent revision.

The reference standards that are listed in the DoE guidelines are these:

American Petroleum Institute

ANSI Z11-171 (API 2531) "Mechanical Displacement Meter Prover".

ANSI (API 2534) "Measurement of Liquid Hydrocarbons by Turbine Meter Systems".

Institute of Petroleum

IP252/76 "Code of Practice for the Security and Fidelity of Electronic Data Transmission Systems for the Metering of Fluids".

British Standards Institution

BS 1042 Pt 1: Sec 1.1	(ISO 5167)	"Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full".
BS 5844	(ISO 5168)	"Measurement of fluid flow: estimation of uncertainty of a flow rate measurement".
BS 4161		"Specification for Gas Meter Part 6. Rotary displacement and turbine meters for gas pressures up to 100 bar.

3. REGULATIONS FOR FLOWMETERS AT BONDED OIL INSTALLATIONS

The measurement for revenue accounting of products in UK land-based bonded oil installations is the concern of Her Majesty's Customs & Excise (HMCE), and the document which applies is:-

3.1 HMCE Notice 179M - Hydrocarbon Oils - Flow Meters at Bonded Oil Installations.

As this is for products rather than crude oil it is not of great concern to the subject of North Sea metering. In fact where crude oil is concerned HMCE rely on the DoE guidelines and state in Notice 179M that "For crude oil from the North Sea, meters approved for fiscal purposes by Department of Energy will be acceptable for Customs and Excise accounting purposes". There is a corresponding paragraph in the DoE Operating Procedures which states that "In addition to satisfying the relevant requirements of the Petroleum Engineering Division of the Department of Energy, the procedures where applicable meet the corresponding requirements of Her Majesty's Customs and Excise for measurement at land terminals".

In view of these cross-linked statements it is not intended to go further into the details of Notice 179M. Suffice it to say that because it presently directed towards the use of small metering systems for loading product into road and rail tankers, there is a marked difference in detail, but not in principle, from the DoE guidelines. However it is interesting that HMCE are proposing that in the long term, products should be measured in bulk as they leave the refinery. This may mean that the future requirements for product measurement will come more into line with those for crude oil measurements, and will include dedicated provers etc. Indeed this already tends to be the case for product pipelines and rail loading gantries.

The reference standards that are quoted by HMCE are:-

Institute of Petroleum

Part X Section 1. Pipe Provers

Section 2. Volumetric tank provers and reference meters.

Part XIII - as IP 252/76 (see 2.0)

4. DEVELOPMENT OF UK STANDARDS

Before examining the UK standards that are available, either completed and published, or in draft form, let us first review the structure of standards-making in the UK for petroleum measurement. The Institute of Petroleum (IP) through its Petroleum Measurement (PM) committee is the main body that produces standards and codes of practice in the first instance, for the UK oil industry. These form parts of the Petroleum Measurement Manual, which is a similar publication to that published in the USA by API. There are a number of sub-committees and panels of the PM committee (see Appendix 1), and these include in their membership, measurement experts from the oil companies, representatives from government departments and research laboratories, independent cargo surveyors and equipment manufacturers. Their first and foremost responsibility is revising and writing new sections of the Petroleum Measurement Manual. Later on in this paper those which are concerned with dynamic measurement will be discussed.

Parallel with the IP sub-committees and panels is a group of BSI committees (see Appendix 2) whose principal function is to provide the link between BSI and ISO. Membership of the BSI committees is nominated by UK organisations such as learned societies, trade associations, nationalised industries, and government departments. The IP is a major contributor to the BSI work, and its panels assist BSI in recommending UK comments on draft international standards.

The development of UK standards is usually along these lines:

- An IP code is written and published as part of the Petroleum Measurement Manual. It is likely to have considerable status in the UK and may be quoted as the reference standard in the official documents.

- If the subject forms a new field of activity in ISO then the IP code is submitted through BSI for consideration as the basis for the draft international standard. When it is accepted for this purpose then after a protracted period of comment, discussion and voting, it may emerge with many amendments as the draft international standard. (Of course similar treatment may be given to national codes from other countries).

- If the BSI committee decides to vote "yes" on the draft international standard the final version of the document is implemented as a dual-numbered BS without alteration .

The reason for going into detail in describing procedures in the UK is to make it clear that in effect UK standards are in these two forms:-

- Parts of the IP Petroleum Measurement Manual.
- ISO standards accepted by the BSI committees, and published as dual-numbered BS standards.

When there is an urgent and identified need for a new code in the IP, a group of experts with the necessary interest, time and dedication can produce it within a reasonable time span. (Appendix 3 shows those currently available for dynamic measurement) In contrast to obtain the international consensus necessary to produce an ISO standard takes a very long time and with limited resources and an involved procedure only a handful of ISO standards, and consequently BS standards, have been published over the last few years (see Appendix 4). There are several more international standards in draft form (see Appendix 5) .

5. CURRENT POSITION OF UK STANDARDS

It is now intended to look at the UK standards which relate to metering stations , and these are classified under the following headings:

5.1 Meters
5.2 Metering systems
5.3 Provers
5.4 Statistical aspects of measurement
5.5 Fidelity and security
5.6 Automatic sampling
5.7 Continuous density measurement
5.8 Calculation of oil quantities
5.9 The Petroleum Measurement Tables
5.10 Calculation terminology

5.1 Meters

Turbine meters are principally used for the measurement of crude oil in the North Sea, and these are the subject of BS 6169 Part 2 (ISO 2515). This covers design, installation, operation and maintenance, and includes Annexes on parts and characteristics of the meters and a trouble-shooting guide. A companion standard is BS 6169 Part 1 (ISO 2714) which is concerned with positive displacement meters, mostly of course used on road loading installations.

As these two documents are now available the IP has discontinued any further work and publications on meters except for Petroleum Measurement Paper No.1. This is a list of data required for a comprehensive evaluation of liquid flow meters. For the future it is worth noting that BSI is planning a comprehensive "Guide to the Selection and Application of Flow Meters" which will be in a number of parts covering the entire field of flow measurement. It will be written on a contractual basis, and is expected to be available in about 2/3 years time.

5.2 Metering systems

Within the last year the IP has set up two panels with the remit of drafting codes of practice on metering systems.

- Panel PM-D-2 is concerned with liquid measurement, and its document has

the title "A guide to the design of liquid metering systems for bulk transfer and pipeline services". The chapter headings are given in Appendix 6A.

- Panel PM-D-3 is concerned with gas measurement, and its document has the title "A guide to the design of custody transfer of gas measurement systems". The chapter headings are given in Appendix 6B.

There is no doubt that these two documents when they are complete will be extremely useful, and influential in respect of UK regulations.

As yet there is no ISO standard covering the same ground, although the API Manual of Petroleum Measurement Standards Chapter 6.6 Pipeline Metering Systems has been accepted by ISO/TC28/SC2 as the basis of a DP. It may be that the UK will have a preference for the IP code to be the UK standard but that is for the future.

5.3 Provers

There are two IP tentative codes of practice on provers. Part 10 Section 1 is intended as an instruction manual for the operators of pipe provers, and Part 10 Section 2 applies to loading road and rail tankers. Both are being updated, and revised editions are expected to be published in about a year. Part 10 Section 3 is a new comprehensive guide to provers now under development, and more details will be given in Paper 4 of this Session of the Workshop.

The ISO work on provers was initiated in 1978, and is making slow progress. Two parts on general principles and pulse interpolation techniques were issued as draft international standards in June 1984, but the part relating to pipe provers is still a draft proposal. There are some UK objections to it, which it is hoped to resolve at the next meeting of ISO/TC28/SC2 in November 1984.

The future position in the UK could be that the new IP code on provers is regarded as the accepted standard, rather than the ISO standard, but this has yet to be resolved.

5.4 Statistical aspects of measurement

In January 1979 the IP published a tentative code of practice Part XIV Section 1 on "Statistical Aspects of Measurement", which was concerned with uncertainties of measurement and statistical procedures. A very much more comprehensive and detailed treatment of the subject has now been prepared, which will be available towards the end of 1984. Strictly speaking perhaps this is not a standard but the section on estimating the uncertainties of meters and provers will be of considerable interest to those involved in metering systems.

The draft international standard DIS 4124 on meter control charts includes sections on central and on-line proving. In view of the forthcoming IP code, the UK position on this has not yet been established.

5.5 Fidelity and Security

The tentative version of Part XIII Section 1 published by the IP in 1976 on fidelity and security of data transmission systems had a very marked influence on the design of metering systems, for both crude oil and products. It established five levels of security protection to maintain the fidelity of the system and these, as has already been seen, are quoted in official regulations. Again the revision to this code, which is well underway and likely to be available in late 1984, is a much more comprehensive document. It includes chapters on system design principles, possible sources of measurement errors, power supplies, and commissioning, testing, inspection and maintenance.

The original IP document has been used as the basis for an ISO standard, and this was published in 1983 as BS 6439 - ISO 6551.

5.6 Automatic sampling

As has already been mentioned, the DoE standards for liquid petroleum measurements specify that "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". This has not been an easy requirement to meet, and there is intense activity on various fronts to develop reliable systems giving a fully representative sample. To assist in this the IP panel produced a tentative code Part VI Section 2 in 1980.

As other countries also had an urgent need for a standard on automatic sampling further action was taken internationally. An ISO working group was set up and after several meetings it has now produced a draft international standard DIS/ISO 3171. The main contributors to this have been USA, France and the UK. It is based on the IP and API codes, together with some theoretical work by France, and is very comprehensive covering all aspects. Regretfully because of the ISO procedures it is unlikely to be published as an ISO standard until 1986. A companion standard is DIS/ISO 3170 on manual sampling, which will be available as an ISO standard rather earlier.

Now that these draft ISO standards are ready the IP sampling panels are in the process of updating their codes. It has been decided that the future IP code on automatic sampling, although based on ISO 3171, will be rewritten as a practical users guide. For manual sampling the revised IP code will correspond closely to ISO 3170 but will include the manual sampling of high pressure crude oil from pipelines.

5.7 Continuous density measurement

When the need to have a continuous measurement of density for North Sea crude oil metering became apparent in 1976, the IP set up a panel to draft a code of practice. In view of the urgency a tentative version was published as Part VII Section 2. Based on experience obtained since that time this has now been thoroughly updated and the revision was published in June 1984.

Installations suitable for fiscal measurements and custody transfer operations are described in detail.

The tentative version was originally submitted through BSI as a proposed draft international standard, but this has now been superceded by the updated version. It is now being put into ISO format before circulation for balloting in accordance with the usual ISO procedure.

5.8 Calculation of oil quantities

The original IP code, Part 1, dates back to 1964 and revision is long overdue since it does not adequately cover the modern metering systems. Within the last year a new IP panel has convened and aims to complete work on a revision of Part 1 by the end of 1984. It will provide calculation procedures in a form which can readily be used in conjunction with on-line or off-line computers. These should be particularly valuable as the basis for fiscal transactions and inter-company transfers.

The panel, in its work, is referring to ISO/DP 4267/2 which is the ISO draft proposal for dynamic measurement - calculation of oil quantities. This is making some progress towards becoming a draft international standard, but not moving very fast.

5.9 The Petroleum Measurement Tables

Attention is drawn to the new API - ASTM - IP Petroleum Measurement Tables jointly developed in the USA and the UK. They are available as Volumes I to XIV, and form implementation procedures used to produce computer - sub-routines. Because of the length and complexity of the Tables, BSI has decided not to republish them in full so that BS 6441: 1983 only provides a schedule of the Tables available in ISO 91/1 - 1982.

Within the next few months the IP intends to publish Petroleum Measurement Paper No. 2 "Guidelines for Users of the Petroleum Measurement Tables", which will contain additional information on interpolation, corrections to API standard 2540, and a computer procedure for correcting the density of crude and condensate obtained at line conditions from an on-line densitometer to density at standard reference conditions. It will also have an Appendix giving the "API Guidelines on the use of the Petroleum Measurement Tables".

5.10 Calculation Terminology

The IP and BSI committees concerned with terminology have recently agreed on the UK preferred terms for measurement calculations, and these were published in Petroleum Review June 1984. They are now going through the process of being agreed by ISO for use in international calculation standards. Those for dynamic measurement are given in Appendix 7.

Attention is also drawn to the UK standard reference conditions of pressure and temperature specified in BS 5579 for measurements on crude petroleum and its products, both liquid and gaseous. These are 101.325 kPa

(1.01325 bar) and 15°C, with the exception of liquid hydrocarbons having a vapour pressure greater than atmosphere at 15°C, in which case the standard pressure is the equilibrium pressure at 15°C. Also specified in BS 5579, but not in ISO 5024, is that the standard reference conditions for the measurement of gases includes the humidity condition 'dry' i.e. free of water. This condition does not involve a requirement that the gas should in practice be free of water vapour when measured.

6. CONCLUSIONS

It must be apparent that the main thrust in UK standards-making for petroleum measurement comes from the IP. When the need for standards and regulations for metering North Sea crude oil was appreciated the IP responded by setting up panels to deal with specific problem areas, such as continuous density measurement, automatic sampling, and fidelity/security. Tentative codes were published on a rush basis, and now that field experience has been gained, these are being revised. Other new ones on various aspects of system design for both liquid and gas are being drafted. It is anticipated that within the next year or so the UK will have a very comprehensive collection of petroleum measurement standards.

These IP codes are widely used and referred to in the UK, and for all intents and purposes they are the de facto UK standards. The BSI policy commitment to international standards has meant that only a handful of BS standards are available, as can be seen from Appendix 4. The chance that these will substantially grow in numbers over the next few years is fairly remote, because of the long delays in getting ISO standards approved and published.

It is the personal opinion of the author that it would be better for BSI to recognise IP codes as the de jure UK standards, and to drop the dual-numbering system for ISO standards.

APPENDIX 1.

SUB COMMITTEES AND PANELS OF THE INSTITUTE OF PETROLEUM PETROLEUM MEASUREMENT COMMITTEE

Sub-committee	Panel	Title
PM-A		Static Measurement
	PM-A-1	Tank Calibration
	PM-A-2	Tank Gauging
PM-B		Physical Methods
	PM-B-1	Manual Sampling
	PM-B-2	Automatic Sampling
	PM-B-3	Water and Sediment
	PM-B-4	Density-Manual
	PM-B-5	On-Line Density
PM-C		Mathematical Methods
	PM-C-1	Tables-General
	PM-C-2	Tables Implementation
	PM-C-3	Calculations
	PM-C-4	Measurement Statistics
PM-D		Dynamic Measurement
	PM-D-1	Pipe Provers
	PM-D-2	Liquid Metering Systems
	PM-D-3	Gas Metering Systems
	PM-D-4	Commercial Metering of Products
PM-E		Electronic Security
PM-F		Light Hydrocarbon Liquids
	PM-F-1	Metering Systems
PM-G		Measurement Legislation
PM-H		Measurement Editorial

(reproduced from "Review of the activities of the Petroleum Measurement Committee" by J. E. Miller and J. R. Spencer - IP Petroleum Review November 1982)

APPENDIX 2.

BRITISH STANDARDS INSTITUTION COMMITTEES CONCERNED WITH PETROLEUM MEASUREMENT

PTC/-/1	- International work on petroleum products
PTC/12	- Petroleum measurement and sampling
PTC/12/1	- Static and dynamic petroleum measurement
PTC/12/2	- Measurement of light hydrocarbon fluids
PTC/12/3	- Bulk cargo transfer
PTC/12/4	- Measurement terminology

(reproduced from "Review of the activities of the Petroleum Measurement Committee" by J. E. Miller and J. R. Spencer - IP Petroleum Review November 1982)

APPENDIX 3.

CURRENT STATUS REPORT ON PARTS OF IP PETROLEUM MEASUREMENT MANUAL FOR DYNAMIC MEASUREMENT

Part I - Calculation of Oil Quantities.

Revision in progress. Expected completion end 1984.

Part VI Section 1 - Manual Methods of Sampling.

Revision to be based on DIS/ISO 3170. Expected completion end 1984.

Part VI Section 2 - Automatic Sampling of Liquids from Pipelines.

Guide to Automatic Sampling to be drafted, partly based on DIS/ISO 3171. Expected completion mid 1985.

Part VII Section 1 - Manual Methods for Density.

Revision in progress. Expected completion end 1984.

Part VII Section 2 - Continuous Density Measurement.

Revised edition now available.

Part IX Section 1 - Positive Displacement Meters.

Discontinued - refer to BS 6169 Part 1: ISO 2714.

Part IX Section 2 - Turbine Meters.

Refer to BS 6169 Part 2: ISO 2715.

Part X Section 1 - Field Guide to Proving Meters with a Pipe Prover.

Revision in progress, expected completion end 1984.

Part X Section 2 - Recommended UK Operational Practice for Proving Gantry Meters.

Revision in progress, expected completion end 1984.

Part X Section 3 - Prover Code (N.B. Title not finalised)

New draft in progress, expected completion mid 1985.

Part XIII Section 1 - Fidelity and security for data transmission from metering systems

Still published, but also available as BS 6439 (ISO 6551).

Part XIII Section 3 – Fidelity and security for data capture systems.

New draft in progress. Expected completion end 1984.

Part XIV – Statistical Aspects of Measurement and Sampling.

Revision with wider scope in progress. Expected completion end 1984.

Part XV Section 1 – Design of liquid metering systems.

New draft in progress. Expected completion end 1984.

Part XV Section 2 – Design of gas metering systems

New draft in progress. Expected completion end 1984.

APPENDIX 4.

BRITISH STANDARDS FOR DYNAMIC MEASUREMENT

BS 6169 Part 1	(ISO 2714)	Methods for volumetric measurement of liquid hydrocatbons. Part 1 Displacement meter systems (other than dispensing pumps).
BS 6169 Part 2	(ISO 2715)	Methods for volumetric measurement of liquid hydrocarbons. Part 2 Turbine meter systems.
BS 6439	(ISO 6551)	Fidelity and security of dynamic measurement of petroleum liquids and gases in cabled transmission as electric and/or electronic data.
BS 6441	(ISO 91/1)	Petroleum measurement tables.
BS 5579	(ISO 5024)	Standard reference conditions for measurement of petroleum liquids and gases.

APPENDIX 5.

DRAFT INTERNATIONAL STANDARDS FOR DYNAMIC MEASUREMENT

DIS/ISO 91/2.2	Petroleum measurement tables – Part 2: 20°C.
DIS/ISO/3170	Manual sampling
DIS/ISO/3171	Automatic pipeline sampling
DIS/ISO/4124	Measurement control charts and statistical methods.
DP/ISO/4267/2	Calculation of oil quantities – Dynamic measurement
DIS/ISO/7278/1	Liquid hydrocarbons – Dynamic measurement – Introduction to proving systems.
DP/ISO/7278/2	Liquid hydrocarbons – Dynamic measurements – Pipe provers.
DIS/ISO/7278/3	Liquid hydrocarbons – Dynamic measurements – Pulse interpolation techniques.
DP/ISO/ (N 222)	Liquid hydrocarbons – Dynamic measurements – Densitometers.
DP/ISO/ (N 224)	Pipeline measurement assemblies.

APPENDIX 6.

A. Proposed Chapter Headings for "A Guide to the Design of Liquid Metering Systems for Bulk Transfer and Pipeline Service".

1. Introduction
2. Scope
3. Glossary and Definitions
4. System Design Considerations
5. Meter System Design
6. Equipment for Primary Measurement
7. Equipment for Secondary Measurement
8. Equipment for Qualitative Measurement
9. Flow Computation and Display
10. Aspects of Operation and Maintenance

B. Proposed Chapter Headings for "A Guide to the Design of Custody Transfer of Gas Measurement Systems".

1. Introduction
2. Scope
3. Glossary and Definitions
4. Appl ications - General Requirements
5. System Design
6. Equipment
7. Equipment (for composition and quality measurement)
8. Flow Computers
9. Records and Control Charts
10. Commissioning, Operation and Calibration
11. Routine Inspection and Maintenance
12. Uncertainty Analysis - ISO 5168

APPENDIX 7.

TERMS FOR DYNAMIC MEASUREMENT CALCULATIONS

Meter factor	the ratio of the actual volume of liquid passed through a meter to the volume indicated by the meter.
Indicated volume	the change in meter reading that occurs during transfer through a meter.
Gross volume	the indicated volume multiplied by the appropriate meter factor for the liquid flow rate concerned, without correction for temperature and pressure. Note: This includes all water and sediment transferred through the meter.
Gross standard volume	the gross volume corrected to the standard temperature and standard pressure.
Net volume	the gross volume minus the volume of water and sediment transferred through the meter.
Net standard volume	The net volume corrected to the standard temperature and standard pressure.
Standard conditions	15°C and atmospheric pressure (101.325 kPa absolute). In the case of liquids having an equilibrium pressure above 0 gauge (101.325 kPa absolute) at 15°C, the standard conditions are 15°C and the equilibrium vapour pressure of the liquid at 15°C.

Main Index

CODE OF PRACTICE FOR ISO 5167

by

F C KINGHORN

NATIONAL ENGINEERING LABORATORY

PAPER 2.3

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

PREPARATION OF A CODE OF PRACTICE FOR ISO 5167

Dr F C Kinghorn

N O T A T I O N

a, b	Constants
C	Orifice-plate discharge coefficient
D	Pipe diameters
D′	Diameters at which orifice is supported
E	Elastic modules
h	Orifice plate thickness
N	Number of data points
p_1	Static pressure at upstream pressure tap
q_m	Mass flowrate
Re_D	Reynolds number based on pipe diameters
Y	Variable defined by equation (1)
Z	Compressibility factor
β	Orifice diameter ratio
Δp	Differential pressure across orifice
$(\Delta p)_y$	Differential pressure corresponding to yield stress of orifice
Δq_m	Error in flow measurement
ΔZ	Difference between computed and measured values of Z.
ϵ	Expansibility correction
κ	Isentropic exponent
ρ	Density
σ_y	Yield stress of orifice plate material

1 INTRODUCTION

The use of differential pressure meters has been common since the early 1900s and several national and international standards and recommendations have been published since then to provide guidance on how to manufacture and use them. The most recent International Standard on this subject, ISO 5167[1], was published in 1980. Although it was accepted by all countries except the USA as the best compromise between the various data and opinions proffered from numerous sources, it was also recognised that a number of its recommendations were based on experiments which were not entirely conclusive.

The Standard deals with orifice plates, nozzles and venturis, but it is the first of these which is by far the most frequently used, and one of the areas in which it is particularly dominant is in the metering of natural gas. In the USA alone the value of the gas consumed annually is 50 billion dollars, and in the UK it is 6 billion pounds and it has been calculated by two independent methods that the value of gas unaccounted for in the USA because of metering errors is about $700,000 per day. Again for the USA it has been estimated that over one million orifice plates are in use in industry, and the cost of replacing them would be $10,000 each on average. The widespread interest in orifice metering research and the strenuous efforts made to produce Standards which are universally agreed are therefore fully justified commercially.

2 BACKGROUND TO ISO 5167

The limited information on which the recommendations of ISO 5167 are based is nowhere demonstrated more clearly than in the values used for the discharge coefficients of orifice plates. The formulae from which they are calculated was developed by Stolz[2] in the mid-70s and used data from only two sources: Beitler[3] and Witte[4]. Beitler's tests were conducted in a manner well in advance of anything which had previously been done, and great care was taken to document every detail which was considered important. Nevertheless, of the 1000 or so test points, Stolz felt justified in using only 303 since others either lacked vital information or showed evidence of being invalid, eg in some cases the edge sharpness of the plate was recorded as questionable. It was possible to use approximately 300 test points from Witte's data, but confidence in them was diminished by the fact that all of the raw data, and even the derived coefficients themselves, had been lost by 1975. Their use was therefore based on graphs which appeared in publications and on a few points plotted by Ruppel[5].

Many requirements are given in ISO 5167 in connection with the use of orifice plates (the sharpness of the edge, concentricity of the orifice with the pipe, the flatness of the plate, the pipe roughness, the required straight lengths upstream and downstream, accuracy of location of the pressure taps etc) and there are varying degrees of confidence in them, but even where perfection can be clearly defined it is not always known how closely Beitler's or Witte's tests met this, eg Beitler merely stated that for his tests "as near as perfect concentricity was obtained".

Despite all of this there is great confidence in the validity of most of ISO 5167. This stems from a concerted world-wide effort to examine direct and indirect evidence and in many cases the resulting specifications have erred on the side of caution.

3 THE NEED FOR A CODE OF PRACTICE

From the foregoing it will be realised that in many cases it is not possible to identify a single unambiguous reason for the requirements laid down by ISO 5167. Indeed it has been said that many of the compromises arrived at "were built on judgement rather than evidence"[6]. One reason for deciding to produce a Code of Practice was therefore to give some explanation of the specifications in the Standard and an indication of the circumstances under which they apply.

Even before ISO 5167 was published it was realised that it contained some ambiguities and guidance which was not as clear as it might be. Rather than delay further the publication of a badly needed document which had already been many years in preparation, it was printed and note taken of sections which required further clarification. More queries quickly emerged as industry began to use the document, and omissions were also notified to be ISO Sub-committee of Technical Committee 30 through member countries. The most striking of these was that no mention whatsoever was made of how to measure the differential pressure generated between the orifice plate tappings.

A third purpose of the Code of Practice was to provide guidance on how some of the constraints of the Standard could be met, eg a limit is given for the extent to which an orifice may deviate from being perfectly flat, but no guidance was provided for how this could be checked under flowing conditions which is vital since the force of the flow can distort the orifice.

For these reasons Working Group 8 of ISO TC30/SC2, the Sub-committee responsible for the preparation of ISO 5167, was created and began work shortly after the SC2 meeting at Braunschweig, Germany in December 1981. Six meetings have been held and a draft which was considered by TC30/SC2 at its last meeting (Gaithersburg, Nov 1983) is now being revised in the light of comments received then and subsequently from member countries. It is expected that this revision will be completed by the end of 1984 and circulated to member countries for comment and discussion at the next meeting of TC30/SC 2, in the latter half of 1985.

The Code is therefore not finalised and so it is an appropriate time to consider at this Workshop the more important features in it in order that comments can be made and taken into account.

4 MAIN FEATURES OF DRAFT CODE OF PRACTICE

The Code concentrates very much on orifice plates; despite requests for contributions on nozzles and venturis virtually nothing has been submitted, reflecting the fact that orifice plates are the main concern in most countries.

Initially it was planned that the Code of Practice would be a separate document, and it was decided that the clause numbering would be the same as in ISO 5167 to enable easy cross-referencing. The wisdom of this is now being debated since comments are not required on every clause of ISO 5167, giving the code numbering a disjointed appearance. In addition some duplication of information already in ISO 5167 is unavoidable if the Code is to be an easily understood, self-contained document. Consideration is therefore being given to the options of including the code as an Appendix to ISO 5167 or inserting the clauses from the Code after the corresponding clauses in the Standard. The need for some form of index in ISO 5167 is recognised

and if included also in the code it would assist the user to locate quickly guidance on particular points.

The main technical features of the present draft are summarised here by grouping them into information omitted from ISO 5167, explanations of how to apply ISO 5167, and supplementary information needed to use the Standard.

4.1 Information Omitted From ISO 5167

The lack of any indication in the Standard of the uncertainty associated with flow measurements made in accordance with it was deliberate since there was no guidance on the choice or use of equipment for measuring differential pressure, but the code suggests that ±1 per cent is what could be achieved.

One requirement which had caused uneasiness among users of the Standard had been that any flow straightener used should be preceded and followed by 20D and 22D of straight pipe respectively; this appeared to nullify the whole point of using a straightener, which is to reduce the straight length of pipe required upstream of the flowmeter. The Code explains however that this general requirement is to cover the possibility of <u>any</u> disturbance preceding the flowmeter and goes on to provide fuller details than the Standard on the construction of straighteners. Their head losses are also given, but only for good flow conditions.

On the subject of uncertainty assessment, the relative importance of different sources of error is presented in tabular form, and there is guidance on how to estimate the uncertainty in total flowrate when a number of orifice plates are installed in parallel.

4.2 Explanations of How to Apply ISO 5167

An essential first step in using an orifice plate is to calculate the diameter ratio required since this is dependent on the acceptable pressure loss, the generation of a reasonable differential pressure, and must be such that it lies within the permissible range for the Reynolds numbers which are to be covered. It is necessary to use an iterative procedure to do this; several methods are possible, but some are unnecessarily complex. The Code presents a simple procedure as follows

put
$$Y = \frac{q_m}{\frac{\pi D^2}{4}\sqrt{(2\rho\Delta p)}} \qquad (1)$$

Then, substituting from equation (1) in

$$q_m = \frac{C\varepsilon\beta^2}{\sqrt{(1-\beta^4)}}\frac{\pi D^2}{4}\sqrt{(2\rho\Delta p)} \qquad (2)$$

and rearanging after squaring gives:

$$\beta^4 = \left\{1 + \left(\frac{C\varepsilon}{Y}\right)^2\right\}^{-1} \qquad (3)$$

The iterative procedure then becomes:

1 Calculate Y

2 Assume $\beta = 0.5$

3 Calculate $\varepsilon = 1 - (0.41 + 0.35\beta^4)\frac{\Delta p}{\kappa p_1}$

4 Assume $C = 0.6$

5 Calculate β from equation (3)

6 Calculate Re_D

7 Calculate C from the Stolz equation (using value of β found in step 5)

8 Recalculate ε (using value of β found in step 5)

9 Recalculate β from equation (3) (using C and ε from steps 7 and 8)

Steps 7, 8 and 9 can then be repeated as often as required until successive values of β differ by an acceptably small amount. Normally they will need to be repeated only once.

Similarly a procedure is presented for the calculation of flowrate when the Reynolds number is so low that the discharge coefficient is not independent of the flowrate.

The value used for the maximum permissible eccentricity of an orifice plate relative to the pipe axis, and the method of checking that this is not exceeded, have long been the subject of debate. A recent paper by Norman et al(/) has resolved the dispute about the requirements, and these are presented in the form of a graph which is reproduced here as Fig. 1. A number of diagrams in the Code describe alternative ways of ensuring the eccentricity is within permissible limits.

A further major problem has been the specification that the orifice plate shall be flat. According to the Standard the plate is flat if 'the slope of a straight line connecting any two points of its surface in relation to a plane perpindicular to the centre line is less than 1 per cent', but no guidance is given on how to check if this requirement is met under flowing conditions, and indeed it is only implied in the Standard that the limit applies in flowing conditions and not 'on the bench'. Norman(/) has shown that the relative error in flowrate measurement, $\Delta q_m/q_m$, is given by

$$\frac{\Delta q_m}{q_m} = -\frac{\Delta p}{E}\left(\frac{D'}{h}\right)^2\left(\frac{aD'}{h} - b\right) \qquad (4)$$

where h is the plate thickness,

E is the elastic modulus of the orifice plate material,

D' is the diameter at which the orifice plate is supported, and

a and b are constants given by the following table

β	0.2	0.3	0.4	0.5	0.6	0.7
a	0.021 77	0.027 52	0.029 46	0.028 00	0.024 60	0.018 70
b	1.102 3	0.974 5	0.849 9	0.729 9	0.615 8	0.508 2

He has also shown that if the 1 per cent slope limit applies to the orifice before installation, the resulting errors could range from 0.2 per cent for $\beta = 0.2$ to 0.12 per cent for $\beta = 0.7$. In order to keep errors due to this source under 0.1 per cent for all conditions, the maximum permissible slope on the orifice surface when measured on the bench would have to be about 0.5 per cent. To be safe the Code therefore recommends a limit of 0.1 per cent, and suggests that the plate material, thickness etc is chosen such that the maximum error predicted by equation (4) is 0.1 per cent.

These requirements refer to elastic deformation, but if there is a transient surge in flow it is important to be able to check if an orifice has undergone plastic deformation, since then all subsequent measurements would be in error, even for relatively low differential pressures. The Code provides the information that the differential pressure $(\Delta p)_y$ which will cause plastic deformation is given by

$$(\Delta p)_y = \frac{\sigma_y \left(\frac{h}{D'}\right)^2}{1.5(0.454 - 0.434\beta)} \qquad (5)$$

where σ_y is the yield stress of the orifice-plate material.

For further practical assistance, the materials most commonly used for manufacturing orifice plates are listed together with approximate values of their elastic modulus, yield stress and coefficient of thermal expansion.

4.3 Supplementary Information Required for Using ISO 5167

In addition to the information on orifice-plate materials referred to above, guidance is given on how to determine the physical properties of the fluid being metered. Because orifices are used in such a wide range of applications no attempt is made to provide these data, but instead a list of 21 references is given from which full details of most fluids can be obtained.

An Annex to the Code provides comprehensive advice on the relative merits of various methods of computing the compressibility factor of a gas. This is necessary for the calculation of the density of complex mixtures such as natural gas, and the information provided originates from a study carried out by the Groupe Européen de Recherches Gazières (GERG). The computational methods covered are:

- The method of corresponding states (CSP-BG)
- Methods using Redlich-Kwong equation of state (RKW-GDF, RKW-RG)
- Methods using Benedict-Webb-Rubin equation of state (BWR1, BWR2)
- Methods using AGA NX 19 (AGA NX 19 mod., Br. Korr. 3H).

No method was found to be satisfactory for all gas compositions, the 95 per cent confidence limits of the results obtained ranging from ±0.6 to ±72.8 per cent. Tables are therefore given to indicate which was found to be best for various types of gas. Fig. 2 illustrates the results obtained, which can be seen to be dependent on the calorific value and density of the gas. Acceptability of a method was defined in terms of the root mean square error (RMSE) obtained when the computational results were compared with experimental data, this being defined as

$$\text{RMSE} = \sqrt{\left\{\frac{\Sigma(\Delta Z)^2}{N}\right\}}$$

where ΔZ is the difference between the computed and experimental value of Z, N being the number of data points. The methods were grouped into those which gave an RMSE of less than 0.3 per cent for all the tests on a particular gas and those which could provide this value of RMSE when 50 per cent of the tests were considered.

As noted earlier, a major omission from ISO 5167 was information on the choice and use of auxiliary instrumentation. The Code devotes some 20 pages and 13 tables and figures to this subject, the main topics covered being:

- Pressure measurement. Reference is made to ISO 2186[8], and problems demanding special care are identified as ensuring no false back-pressure is generated, choosing isolating valves, and the use of condensation and gas collecting chambers. Descriptions are given of different types of tranducer.

- Temperature measurement. Purposes of the measurements, dealing with temperature fluctuations, corrections to be applied and precautions to be taken when making measurements.

- Density measurement. Methods of measurement are described and advantages and disadvantages of in-line, bypass and computational methods are given.

In addition there is a section on the general precautions to be followed when installing and using auxiliary instrumentation, with particular reference to difficulties associated with electrical supply and electrical installations. The whole section on instrumentation is supplemented by tables giving the characteristics and ranges of application of various types of different devices, and there are figures to illustrate preferred installation arrangements.

5 CONCLUSION

The Code of Practice is certain to provide valuable support for ISO 5167. Although it is not yet finalised the draft already contains the majority of the information necessary to make the Standard more easily used by those who are not expert in flow measurement using differential pressure meters, and to make it less ambiguous for those who are, or who wish to use it as the basis of a contractual agreement. It has been possible to describe only the main features here, but from them it can be seen that the Working Group has made good progress in a relatively short period of time. Even when it is published it is unlikely that the document will cover everything which a

potential user of ISO 5167 will wish to know, but as is always the case with new Standards the quickest way to make progress is to publish, receive comments and then produce a revision to take these into account.

REFERENCES

1 INTERNATIONAL STANDARDS ORGANIZATION. Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full. Geneva, ISO 5167, 1980.

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8 INTERNATIONAL STANDARDS ORGANIZATION. Fluid flow in closed conduits - connections for pressure signal transmissions between primary and secondary elements. Geneva, ISO 2186, 1973.

LIST OF FIGURES

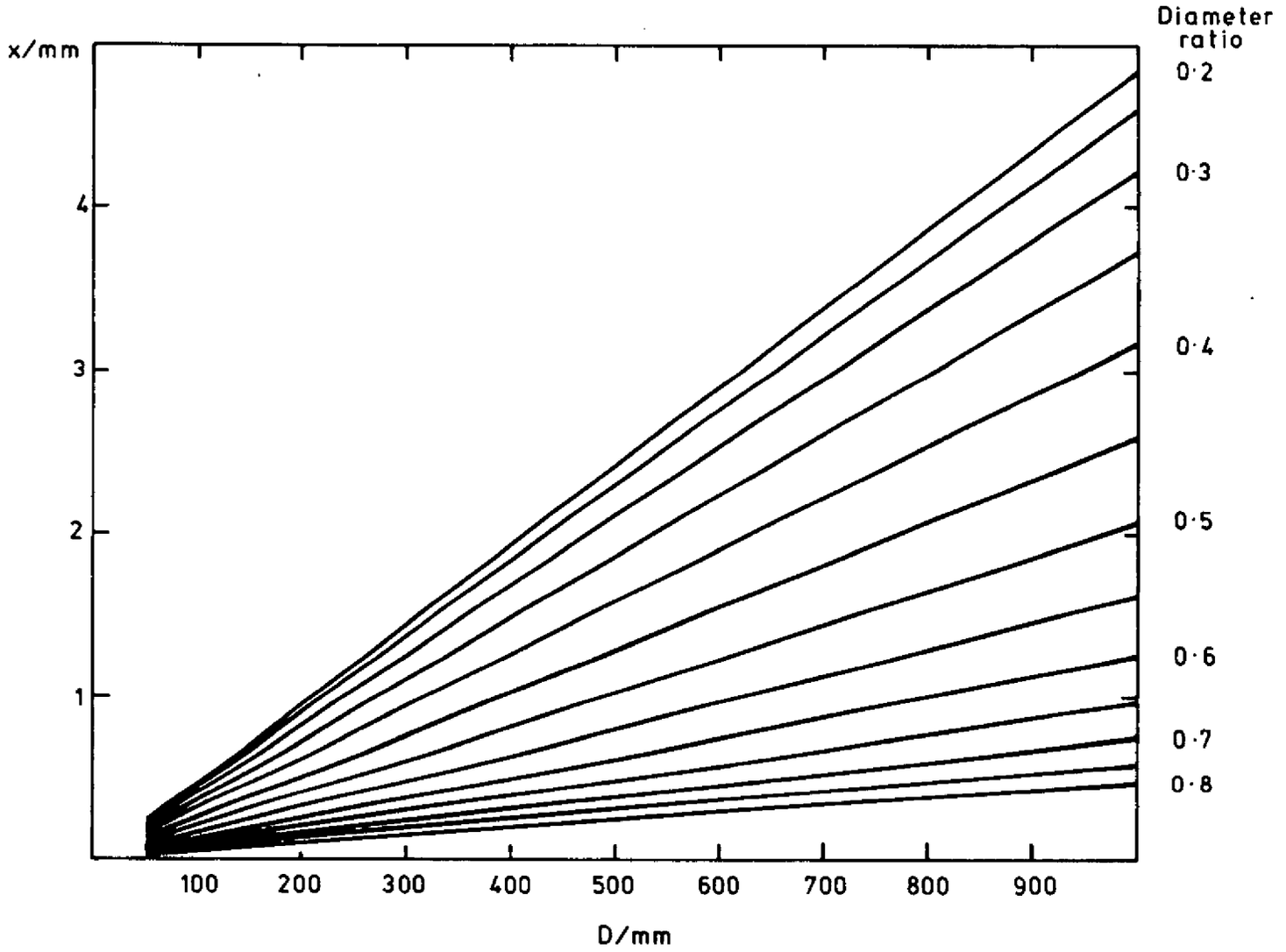

Fig 1 Permitted Distances Between Orifice and Pipe Centre Lines

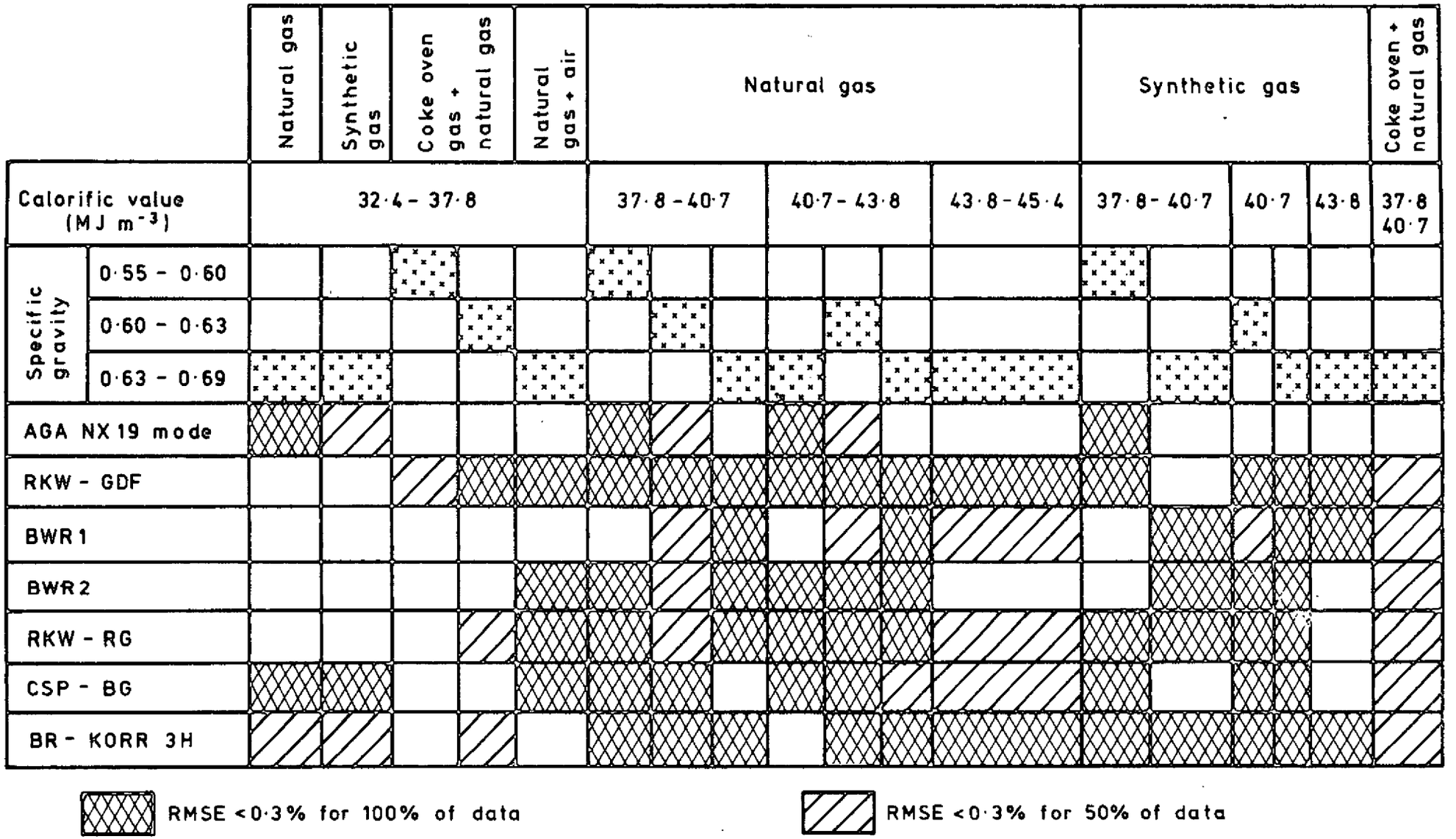

Fig 2 Applicability of Computational Methods for Compressibility

Main Index

IP CODE OF PRACTICE FOR PIPE PROVERS

by

R PETERS

DANIEL INDUSTRIES

PAPER 2.4

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

"THE NEW I.P. CODE OF PRACTICE FOR PIPE PROVERS"

Dr. R.J.W. Peters.

1. INTRODUCTION

1.1 On the 10th December, 1982, a Petroleum Measurement Committee called Working Group PMD 1 first met under the Chairmanship of Mr. J.M. Waring (I.C.I.) to prepare a Code of Practice for Pipe Provers. Initially it was envisaged that a separate Code for "Compact Provers" would be prepared but very quickly the conclusion was reached that a "Compact Prover" could not be treated in isolation since (a) the same Performance Criteria has to be met whatever prover is supplied and (b) with current developments when does a "conventional prover" become a "compact prover"? Convention has not reached such a decision.

2. PROVER STANDARDS

The existing standards used internationally for specifying meter provers are :

Institute of Petroleum	:	Petroleum Measurement Manual Part X - Meter Proving. Section 1 - Tentative 1979. "Field Guide to Proving Meters with a Pipe Prover",
American Petroleum Institute:		Manual of Petroleum Measurement Standards, Chapter 4 Proving Systems, including, 4.3 Small Volume Provers 4.6 Pulse Interpolation
ISO/DP. 7278/3	:	Liquid Hydrocarbons - Dynamic Measurement - Proving Systems. Part 3 : Pulse Interpolation Techniques.

Norwegian Petroleum Directorate 1984.

"Regulations for fiscal measurement of oil produced in internal waters, in Norwegian territorial waters and in the part of the Norwegian Continental Shelf which is subject to Norwegian sovereignty".

3. PROPOSED LAYOUT OF INSTITUTE OF PETROLEUM CODE.

The following are the Draft Chapter Headings and Synopsis used as the basis for preparing the Code.

3.1 Introduction and Scope
3.2 Classification of Pipe Provers
3.3 Performance Requirements
3.4 Sizing of Provers
3.5 Design Considerations

3.6 Equipment
3.7 Installation
3.8 Operation and Calculations
3.9 Calibration and Traceability
3.10 Analysis of Uncertainty.

The guidelines used to prepare these sections were as follows.

3.1 Introduction and Scope

Brief general description of a pipe prover and background to its use in the oil industry. Brief mention of conventional and more modern compact types. Highlight areas of difficulty e.g. checking of seals. Scope and purpose of I.P. Code.

3.2 Classification of Pipe Provers

A decision to be made as to how the classification should be made, i.e.

sphere/piston or
bi-directional/uni-directional or
conventional/compact

All three methods of classification should perhaps be mentioned, although constant reference to all three throughout the document will lead to confusion.

3.3 Performance Requirements

Repeatability, both short and long term. Base volume to remain constant over a stated flowrate range. Overall uncertainty requirements (refer to chapter 8 and 9).

3.4 Sizing of Provers

Guidance to the selection of diameter and base volume from given specification of maximum and minimum flowrate, pressure loss, displacer velocity and detector repeatability. Mention of pulse interpolation.

3.5 Design Considerations

Recommendations, for the design of the prover and associated equipment in order to achieve the performance requirements laid down in chapter 3. Particular areas which should be mentioned are end chamber design and run up lengths, displacer design, the elimination of pressure surges either during the run or when displacer is brought to rest, the need for block - and - bleed valves and for checking the performance of any seals in the displacer.

3.6 Equipment

Guidance for the selection of displacers, detectors, valves, thermometers and pressure measurement equipment. Pulse interpolation methods (reference to ISO Standard) and data collection systems.

3.7 Installation

Location of prover in relation to meters being proved, need for access for calibrating prover, location of thermometry and pressure measuring instruments, location of relief valves and filters. Use of four detectors. Avoidance of dead legs. Guidance on the installation of electrical equipment including instrumentation.

3.8 Operation and Calculations

This should contain procedures for proving meters and for subsequent calculations needed for pressure and temperature corrections etc. Mention should be made of the need for meter factor control charts, although this would be discussed in detail in the document on proving turbine and PD meters (field guide).

3.9 Calibration and Traceability

Procedures and calculations for calibration of provers by both water draw and master meter method. Recommendations as to what methods to use in particular circumstances. Calibration of both conventional and compact provers to be described.

Evidence of traceability of meters, tanks etc., used as references. Procedures for establishing traceability. Frequency of calibration and the use of control charts.

3.10 Analysis of Uncertainty

Consideration of all the sources of uncertainty, both systematic and random, in the proving of a meter by a pipe prover. Listing of all sources required together with recommended method of combining the uncertainties. Worked example to illustrate the technique.

4. PROGRESS IN PREPARING THE CODE

The committee subdivided into groups to prepare the separate sections which were then reviewed within the committee as a whole. The status in mid July 1984 (when this paper was prepared) is as follows.

4.1 Introduction and Scope

This section has been left until the bulk of the Code has been prepared but the scope will cover all types of provers.

4.2 Classification of Pipe Provers

Provers have been classified into four main types, namely:

(a) Uni-directional sphere prover (U/S)
(b) Bi-directional sphere prover (B/S)
(c) Uni-directional piston prover (U/P)
(d) Bi-directional piston prover (B/P)

The 'compact prover' does not necessarily fall into any of the above classifications but has the following characteristics:-

1) The calibrated volume would be no more than one-tenth the typical U/S or B/S provers for the same maximum flowrate.

2) A precision-bore cylinder containing a piston whose position is detected by normally a non-mechanical device.

3) A system to interpolate pulses between the primary pulses emitted by the meter being proved.

4.3 Performance Requirements.

Short-Term Repeatability

When a master-meter technique is used to calibrate the prover five successive proving runs shall be within a range of 0.02 per cent. Using the water draw technique three successive proving runs shall be within a range of 0.02 per cent.

The prover device must exhibit flowrate independence.

Estimated Total Uncertainty

The estimated total uncertainty in the mean of a batch of 5 proving runs shall not exceed $\pm$ 0.05 per cent.

4.4 Sizing of Provers

This section highlights points to be considered in sizing a prover taking care not be preclude future developments in prover design but making clear that whatever design is proposed it must meet the requirements of Chapter 3.

The chapter draws attention to the fact that the following factors must be taken into consideration when sizing a prover : Displacer velocity, prover pressure drop, detector repeatability, pulse discrimination technique, flowrate, the uncertainty of associated instrumentation and the computer or microprocessor (if used).

4.5 Design Considerations

A number of factors must be considered prior to deciding on the basic design. These are:-

1. Whether the prover is mobile or fixed
2. Number and size of meters to be proved.
3. Extent of automation
4. Flow rate range
5. Chemical and physical properties of liquid
6. Whether there is continuous flow through the prover
7. Hazardous area classification
8. Power supplies and utilities available at site.
9. Space and weight restrictions
10. Whether prover is insulated and above or below ground.

Having examined these parameters then the basic prover type as defined in Chapter 2 will be selected.

This Chapter then highlights more detailed parameters to be determined e.g. launch and receive details for displacer, displacer velocity, detection devices, connections to prover, valve integrity etc.

Valve integrity caused extensive discussion in the committee since we must now consider internal and external valves in the prover. Currently the proposed statement is as follows:-

"Prover valves must be leak tight. The method for demonstrating leak tightness will be agreed between the supplier and the customer and where applicable the relevant authority."

4.6 Equipment

This Chapter gives details of the following items of equipment.

1. Material Requirements
2. Temperature Measurement
3. Pressure Measurement
4. Valves
5. Displacer
6. Detectors
7. Internal Finish of Prover Barrel
8. Calibration Connections
9. System Control

4.7 Installation

This Chapter highlights the items which must be taken into account for Installation. This covers Mechanical Installation, Electrical Installation, Further General Installation Requirements and Commissioning and Testing.

Mechanical Installation includes such items as pressure codes, proximity of prover to meters, drainage, corrosion, access connections etc.

Electrical Installation highlights the need to abide by the relevant Electrical Safety Code in addition to the power and earthing requirements etc.

The General Installation Requirements include such items as safety interlocks to prevent unauthorised tampering, adequate lighting and access for operation and fire fighting etc.

Commissioning and Testing highlights the need to perform these functions to a well documented procedure preferably with the manufacturers personnel being in attendance.

4.8 Operations and Calculations

This Chapter has still to be written but should contain the procedures for proof runs with the calculations correcting for pressure and temperature etc.

4.9 Calibration and Traceability

In line with the importance of this topic for meter provers this Chapter looks like being the largest in the Code.

It will be subdivided into an Introduction and Scope followed by Prover Calibration by the, Water Draw, Gravimetric, Master Meter/Prover Tank, Master Meter/Master Pipe Prover and other Methods. A method of selection is then provided.

The Chapter provides the requirements for reference measures, traceability, correction factors and uncertainty.

This Chapter should be acceptable to the Department of Energy requirements and hopefully to the Norwegian Petroleum Directorate in order that the Code be acceptable for Fiscal Measurement.

4.10 Analysis of Uncertainty

This has still to be completed.

5. CONCLUSIONS

(i) The Code is nearing completion and hopefully will be completed early next year.

(ii) It has been decided that a separate Code for Compact Provers is not a meaningful proposition and that a Code on Provers should be all embracing.

(iii) The Code is written for an audience of engineers who have some appreciation of provers but require, a standard to work to, pitfalls to avoid and helpful guidelines to follow. It does not go into every last detail of prover manufacture and assembly on the assumption that this is better left to the experts.

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by

G PAUL-CLARK

DEPARTMENT OF ENERGY

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NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

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East Kilbride, Glasgow

ONLY A VERBAL PRESENTATION OF THIS PAPER WAS GIVEN

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by

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NATIONAL ENGINEERING LABORATORY

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NEL WORKSHOP PAPER

THE NEL SAMPLING PROJECT

Paper for Presentation at the NEL North Sea Flow Metering Workshop

16-18 October 1984

by

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INTRODUCTION

Water is present in crude oil flowing from most sub-sea wells and may account for up to 30 per cent of the volume produced. With oil now costing $30 a barrel both fiscal authorities and the operators need to know the exact composition of the crude oil they produce, sell and buy. An under- or over-estimation of 1 per cent, for example, in measuring the water content of a crude carrier's cargo represents a cash value approaching half a million pounds. It is impossible to separate the water in bulk for measurement purposes so reliance is placed on accurate analysis of small samples taken from the crude as it flows through a pipeline. As every part of the sample taken has to represent perhaps 5 million parts of the bulk cargo, it is obviously important that the sample taken be as representative of the cargo as possible.

To study the aspects of representative sampling and to improve present sampling methods, a consortium of 14 organisations concerned with fiscal custody and transfer of crude oil are sponsoring an on-going research programme at NEL. Using a unique two-component test facility, NEL has studied the performance of both proprietary and NEL-designed sampler systems under a variety of conditions. Quantitative measurements of the sampler's

performance and high-speed photographic techniques of their operation have identified certain areas where the samplers can be improved. The demand to perfect these samples is so great that a larger and more comprehensive test facility is being built at NEL to continue the work well into the late 80s.

A BRIEF HISTORY OF SAMPLING RESEARCH AT NEL

In the early 70s the price of crude oil was such that little attention was given to the accuracy of samplers. The rapid escalation in oil prices in the mid 70s changed this attitude however. At this time the newly formed Department of Energy became involved with the fiscal aspects of measurement in the North Sea and asked the NEL to evaluate a number of automatic samplers in current use in the North Sea. This work subsequently expanded into examinations of vertical sampling, mixing affects of bends and jet mixing.

A wealth of experience and the build-up of a comprehensive test facility at NEL resulted from this work. A closer liaison with the oil industry through IP and ISO committees was also established and at the conclusion of the Department of Energy's programme, an industrial consortium was formed to continue the work. This consortium, made up of the 14 members given in Table 1, has sponsored phases one and two of a continuing research project on automatic sampling. A third phase will soon be commencing for the period 1984/85.

BENEFITS OF A LABORATORY-BASED RESEARCH PROGRAMME

Rarely can a laboratory simulation be used to totally analyse a particular phenomenon; in most cases it is good practice to supplement laboratory data

with field data before drawing any conclusions. Several advantages are possible with laboratory simulations, however, and in the case of automatic sampling, these are described below.

a Reduced Costs

One method of studying the effect of pipe geometry or sampler operation on sampling accuracy is to measure the response of a sampler mounted in an actual on-stream pipeline and inject a known flowrate of water. This obviously involves a lot of expense in that normal operation of the pipeline is suspended and the injected water must be separated from the oil after the tests have been completed. Even for small refineries, ship discharges or production platforms, typical costs will run into thousands of pounds per hour of testing. The major advantage of such an expensive exercise is that the measurements are made on real crude oil in an actual field installation.

The use of a small-scale laboratory test facility as used at NEL is, by comparison, very cost effective. The cost of a new 200 mm diameter test facility being built at present, for instance, will cost about £40,000 and require a staff of only two to operate. Typical running costs for such a facility will be in the order of £1000-1500 per week.

b Better Control of Variables

If a field installation is to be used then the possibility of the background water content varying during a test run must be taken into account. The lack of precise measurement and control of both oil and injected water flow-rates brings a large degree of uncertainty into the exercise. Further,

control over tanker discharge flowrates is unlikely to be possible when refinery programmes, shipping schedules etc have to be taken into account.

In a laboratory environment, however, not only can the individual oil and injected water flowrates be controlled accurately, but the way in which the mixture is conditioned can also be controlled in a known and repeatable way. In the NEL test facility, for instance, the water droplet size and water concentration profile can be controlled and determined in a precise and repeatable way. Also, the water concentration, mainflow velocity and physical and chemical characteristics of the fluids can also be set to suit the particular requirements of the test.

For safety and convenience reasons, it is inadvisable to use a real crude oil in the laboratory but in order to reproduce Reynolds and Weber numbers found in practice, NEL have opted for an odourless kerosine with a viscosity of about 2 cSt at 20°C. Considering the wide range in physical and chemical characteristics of world crudes there is little to be gained by choosing any one crude in preference to another or the kerosine used in the laboratory work. In the North Sea alone the viscosities of the crude ranges from 2-30 cSt and with pipe diameters ranging from 0.3-1.0 m and flow velocities from 1-4 m/s this gives a range of Reynolds numbers of 11 000 to 500 000. The test facility being built at present at NEL can study flows with Reynolds numbers ranging from 50 000-250 000, and so covers the major part of the range experienced in the field. If a different range of Reynolds number, Weber number etc is required, then it is not excessively expensive to change the fluid used in the test facility, some 10 m^3 compared with millions of cubic metres in a field installation.

c Improved Quantitative Measurements

Even in the best of weather conditions there will be problems in installing and using flowmeters and instrumentation in a field installation. Is there a stable power supply available? What about earth loops and is that pump cavitating because someone else is using the process line? Then when you have everything set up, the fire main from which you were to draw water loses pressure.

It would be less than truthful to say that hitches do not occur in the laboratory, but in such a benign, purpose-built environment they are much easier to predict, identify and remove. Further, the life expectancy and calibration of the delicate instruments and data logging equipment will be maintained much longer in the laboratory than in the hostile world of the refinery or tanker discharge quay. A laboratory facility also has the advantage that all parts are readily accessible and in close proximity and in the case of the NEL facility the further advantage that flowmeters can be regularly checked against reference meters in the NEL flow measurement laboratory.

d Possibility of Qualitative Assessments

Many of the fluids suitable for use in a laboratory test facility are optically transparent and this lends itself to qualitative analysis of sampler performance by photographic techniques. In the case of the NEL test facility for instance, the kerosine has the same refractive index as the Perspex used in the construction of the test section and hence no optical distortion occurs no matter what the profile of the kerosine/Perspex interface. Microflash still photography and high-speed cine photography

have both been used in the NEL facility to determine the trajectories of water droplets about and through the samplers under test. This information has been invaluable in helping to explain some of the quantitative results obtained in the research programme.

THE NEL TEST FACILITY

For a laboratory test facility to provide a useful tool in sampling research it must meet several important specifications as described below.

a Mainline flowrate range. Sampler response is very dependent on the mainline flow velocity so any test facility must be capable of producing as wide a range of flowrates as possible.

b Water concentration. The water content of crude oils varies considerably so any research facility must be capable of producing a range of oil/water mixtures of known and controllable concentrations.

c Water conditioning. Some mixing device must be installed in the test facility to produce water droplets of various known and repeatable sizes.

d Water separation. Having injected water into the oil flow, some means of separating it must be employed if continuous operation of the facility is to be achieved, ie if the water takes time to settle and separate from the oil, then only a 'once through' mode of operation may be possible with 'before' and 'after' tanks required.

e Cooling. If continuous operation is envisaged then some form of heat exchanger may be required to cool the recirculating flow.

The facility used up to the present time for all the sampling research performed at NEL was based on a 100 mm diameter test loop with a maximum flow velocity of 1 m/s. A new larger and more up-to-date facility with a 200 mm diameter test section is presently being built to replace it and this will be capable of mainflow velocities up to 2.5 m/s. A schematic of the new facility is given in Fig. 1.

In normal operation oil is pumped around the circuit by pump 'A', a variable speed unit capable of 7–70 ℓ/s flowrates at a discharge pressure of 300 kN/m^2. After a long straight 100 mm section the flow passes through a calibrated turbine flowmeter before doubling back on itself at 'B' and entering a diffuser section into the 200 mm diamter test section. Fig. 2 is a schematic of one of several configurations of the test section which is basically a modular Perspex block construction incorporating various elements.

Water, from a calibrated metered supply, is injected into the test section immediately upstream of a mixing device. In the figure a special orifice mixer is shown which, by virtue of the various mixing velocities it produces through its choice of orifice sizes, can give known and repeatable water droplet sizes. Other proprietary devices could also be installed if required, or the mixing device could be removed entirely if the dynamic loop was to be used (see later).

The sampler to be examined can be installed in one of the Perspex blocks and positioned any distance downstream of the mixing section and in any orientation. A water micro-injector can be lowered into the flow immediately upstream of the sampler to study the trajectories of the individual water droplets by photographic means.

After passing through the test section, the water/kerosine mixture is constrained into a 100 mm pipe which in normal operation leads through valve 'C' to the diverter valve 'D'. The diverter is only used if a bulk sample is required as an absolute measure of the water content of the mixture flowing in the circuit. To do this the flow is momentarily diverted into the steel measuring cylinder tank where the water is allowed to settle out and the absolute water content of the bulk sample determined.

In normal operation, however, the mixture is conveyed via a flexible hose into an inlet ring 'E' at the bottom of the vertical cylindrical separation tank of 10 m^3 capacity. The whorls of small holes on the inlet ring ensure a uniform percolation of the flow into the tank where it rises slowly upwards, allowing water to settle downwards for collection and further separation via a coalescing filter. The water is passed into a holding tank for further settling before subsequent re-injection into the test section flow. The rising oil in the main separation tank, now without its water component, is collected by an outlet ring 'F' of similar geometry to the inlet ring and returned via a flexible hose to the main circuit and pump inlet through valve 'G'. The height of the inlet and outlet rings in the main separation tank can be adjusted to cater for different levels of fluid and also to achieve the best water separation characteristics. The geometry of the tank is such that screens and different inlets and outlets can be accommodated to achieve the best separation characteristics for any other oils that may be used.

At higher mainline flows and greater water concentrations it may not be possible to separate all the water from the oil as the flow rises in the separation tank. In these cases, to avoid recirculation of water into the test section, the facility can be run in a closed or 'dynamic loop' mode.

In this case valves 'C' and 'G' are closed and valve 'H' opened so that the separation tank is excluded and the flow recirculated only within the dynamic loop. As the volume of the dynamic loop is known, a water/oil mixture of known proportions can be used to fill it before sampling tests begin. The mixture is then circulated for a period to ensure uniformity around the loop before sampling starts. This method of operation requires no separation and can be used when sampling for long periods is required, the volume abstracted by the sampler being made up by a small feed tank and the small change in water concentration calculated accordingly.

EXPERIMENTAL PROCEDURES

All quantitative testing on the facility is based on the fact that a known water concentration is presented to the sampler under test and this can be compared with the water concentration in the resulting sample.

The percentage concentration of water in the test section is determined directly from the flowmeter readings for the incoming water and oil flowrates as below:

$$I = \frac{\text{volumetric flowrate of injected water}}{\text{volumetric flowrate of water and kerosine}} \times 100 = \frac{W_I}{W_I + K_I} \times 100.$$

This can usually be calculated to better than ±0.01 per cent.

The percentage of water in the sample is determined by gravimetric separation of the water and oil components and individual volume measurement in calibrated measuring cylinders or pipettes as below:

$$S = \frac{\text{volume of water in sample}}{\text{volume of water and kerosine in sample}} \times 100 = \frac{W_S}{W_S + K_S} \times 100.$$

The sampling error, E, was then determined from:

$$E = \frac{S - I}{I} \times 100 \text{ per cent.}$$

A positive error would therefore mean the sampler was collecting more water than it should, while a negative error would mean the sampler was collecting less water than it should. Note that whereas I and S express the water content as a percentage of the total water and kerosine volume, E is expressed as a percentage of the water volume only and the difference in magnitude of the two types of percentage must be remembered when comparing values.

The experimental uncertainty in measuring the sampling error, E, was calculated as better than ±5.0 per cent.

The normal practice in performing a test is to mount a given sampler in its desired position and orientation and set the oil flowrate by adjustment of the pump speed. After allowing time to purge all the sampling system with neat oil, the water injection is started and sufficient time allowed to establish stable conditions before samples are collected for analysis.

SOME RECENT FINDINGS IN THE NEL SAMPLING PROJECT

All data and results obtained from the sampling project are of course

available only to the sponsoring organisations of the research programme and only generalities can be discussed here.

The research programme of phases one and two over the last two years has concentrated on the study of fast loop and proprietary grab samplers using the original 100 mm diameter test facility. During the course of the sampler assessments, much effort has also been devoted to assessing the characteristics of the test facility. For instance, a photographic exercise performed to determine the actual sizes of water droplets obtained at the various mixing conditions found the large droplet setting produced droplets of 0.53 mm diameter with a 95 per cent scatter of ±0.47 mm. Tests were also performed to determine the vertical water concentration profile which confirmed that, but for the lowest mainline flow with large droplet size, the profile was acceptable on the axis of the test section where the samplers were positioned. Checks also confirmed that water was not retained in the kerosine used even after vigorous mixing over a sustained period. All samples were found to separate into their water and kerosine components by simple gravimetric separation within hours of issuing from the sampler.

In order to provide an absolute calibration check on the system, several bulk samples were obtained. In this exercise the total mainline flow was diverted into a holding tank at the same time as the output from the water and oil flowmeters were integrated. The water content of the bulk sample was compared with the water content derived from the flowmeters and found to agree within 2 per cent over several different conditions.

Having confirmed that the test facility produced the required conditions, the programme continued with an examination of samplers themselves. The sampler response in different orientations and as mainline flowrate, water

content, droplet size, grab rate, percentage isokinetic sampling rates etc, were varied, was studied quantitatively and qualitatively. Some salient points which came to light during the test programme are given briefly below:

a Probe Orientation

In general it was found that both the fast loop and grab samplers should be mounted horizontally from the side if the best representative samples were to be obtained.

b Sampling Rate

In general it was found better to sample isokinetically, ie with the same velocity within the sampler probe as in the main flow, when using a fast loop sampler. The high-speed photography indicated that even when the grab samplers were operated at 50 grab/min the flow distortion caused by the grab operation was swept away by the mainflow well before the start of the next operation.

c Water Droplet Size

The work indicated that water droplet diameters exceeding 0.5 mm could produce sampling errors. The use of high-speed photography identified several fluid dynamic phenomena to explain these findings.

d Mainflow Velocity

The results of the work and the high-speed photography identified several

fluid dynamic problems that were affected by the mainflow velocity. Although higher mainflow velocities are desirable as regards adequate mixing of the pipeline contents, the higher velocities can also introduce eddies and turbulence about the sampler probe.

e Design of Sampler

Several strengths and weaknesses of the various samplers were identified and some modifications made to improve their performance. The confidential nature of the research programme and the proprietary samplers means that no comments can be made on any particular design.

f Analysis of Sample

The research identified that, in certain circumstances, inaccuracies could occur in the centrifuge method of water determination. The reason for this was identified as the result of inaccurate graduation markings on certain batches of ASTM centrifuge flasks.

THE FUTURE - THE PHASE-THREE TEST PROGRAMME

The design, construction and commissioning of the new 200 mm test facility will occupy most of the staff effort on the project until January 1985. Only then will the test facility be available for full-time experimental work when the first task will be to check water droplet size, water concentration profiles etc.

The proposed subjects for study are described individually below.

a Statistical Analysis of Pertinent Data

This will include an examination of field sampling data as supplied by member companies to try to identify trends in sampling errors. A point of particular interest for study will be the problem of the 10 000 grab requirement for each tanker unloading.

b Grab Samplers

Further work will be done on proprietary grab samplers in both standard and modified forms. Higher mainline velocities will be used for the tests in the new facility. The effect of water concentration transients may also be studied.

c NEL Fast-loop Sampler Probe

After the promising results of the phase two work with this design of probe, further work will be done in the new facility to assess its peformance over a wider operating range and also when manufactured in different bore sizes. Again, the effect of water concentration transients could also be studied and compared with the grab sampler results of (b) above.

d Secondary Sampling

Using the NEL design of fast-loop probe as standard, studies would be made of the effect of secondary sampling. The effect of water concentration transients on such a secondary sampling system may be examined.

e Flow Conditioning

A brief examination of the effect of pipe bends, proprietary mixers, and a NEL type of jet mixer would be undertaken.

All the above work would be performed in a horizontal test section. The new facility will be capable of mounting the test section vertically, but such an option may have to wait until a later phase in the research project.

TABLE 1

MEMBERS OF THE NEL AUTOMATIC SAMPLING RESEARCH CONSORTIUM

Amoco (UK) Exploration Co
BP International Ltd
Britoil plc
Chevron Petroleum (UK) Ltd
Department of Energy
Department of Trade and Industry
ELF UK plc
Esso Engineering (Europe) Ltd
Marathon Oil UK Ltd
Mobil Oil Company Ltd
Norwegian Petroleum Directorate
Occidental Petroleum (Caledonia) Ltd
Shell UK Oil
Union Oil Company of Great Britain

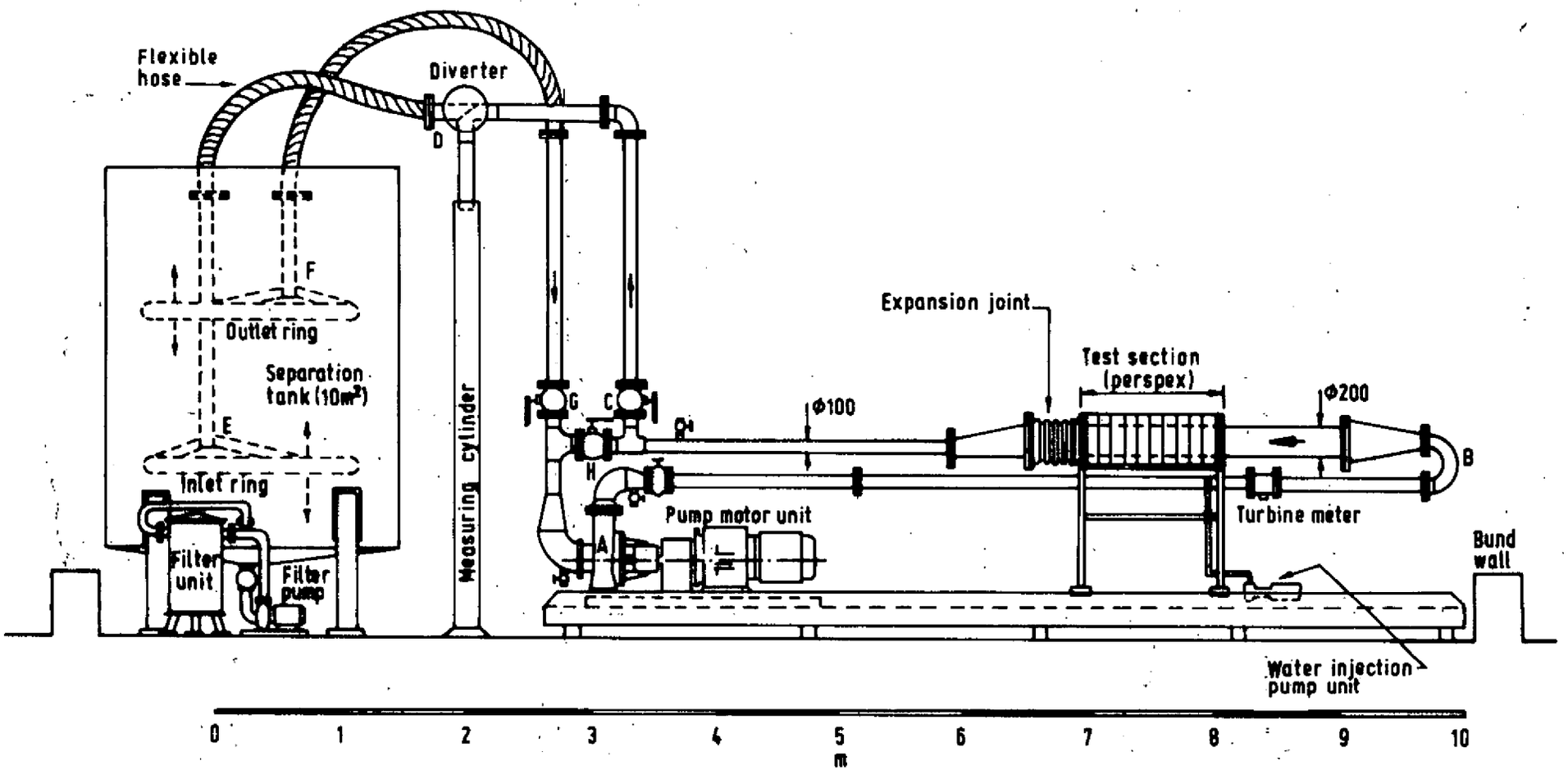
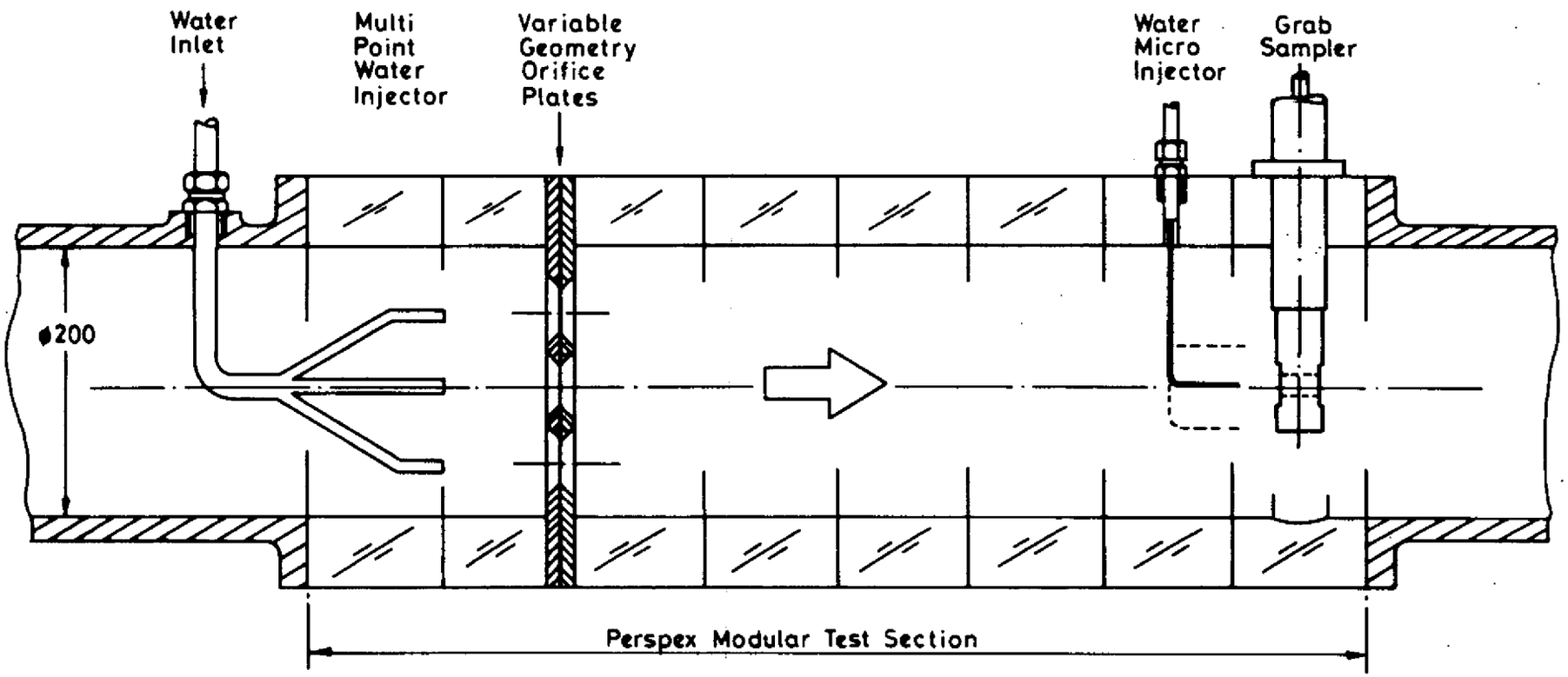


Fig 1 Schematic of 200mm Sampling Facility



Scale 5:1

Fig 2 Schematic of Test Section with Grab Sampler Installed

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MEASUREMENT ERRORS IN NORTH SEA EXPLORATION AND PRODUCTION SYSTEMS RESULTING FROM IGNORING THE PROPERTIES OF WATER

by

T J HOLLETT

BP PETROLEUM DEVELOPMENT

PAPER 3.2

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

MEASUREMENT ERRORS IN NORTH SEA EXPLORATION AND PRODUCTION SYSTEMS RESULTING FROM IGNORING THE PROPERTIES OF WATER

by Mr. T.J. Hollett

INTRODUCTION

Most of the recognised standards which govern metering and analysis of crude oil and water mixtures fail to deal adequately with the presence of water. When water forms a very small part of the total flowing fluid, these omissions will not produce significant errors. The standards have grown up in an environment dominated by the need to measure relatively dry crude from ships and overland pipelines. In the North Sea, situations can exist where circumstances give rise to the need to measure substantially wetter flows than previously encountered in the shipment and transportation of export grade crudes. It is probable that the future may see more North Sea locations where there will be a need to measure high water content streams. This paper attempts to quantify some of the errors and suggest ways of minimising their effect.

1. METERING WET CRUDE

Reporting metered quantities in terms of standard volumes at 15°C is still the practice in some North Sea production areas, even though, in many instances, density at line conditions is being continuously monitored by sophisticated instrumentation. It has long been recognised that this approach is subject to a small error introduced by the need to derive a volume correction factor to convert from volume at measured conditions to standard reference conditions. The question which must have been asked by many people is - "do I only consider the physical properties of the crude oil or should I also recognise the properties of the water present?"

Let us first consider a dry crude oil stream being metered at 60°C and 25 barg having a density at these conditions of 797.8 Kg/m^3 (measured by densitometer).

Using the standard formulae provided in the relevant Standards (see attachment) the following properties can be calculated:-

Compressibility factor b	=	12.10×10^{-5}/bar
Thermal expansion coefficient	=	0.0008919/deg C
Density at 15°C and 1.01325 bar	=	829.67 Kg/m^3
Volume correction factor	=	0.959420

The following sections consider the effect of the presence of water on the calculation of standard volumes.

1.1 COMPRESSIBILITY

Pure water is less compressible than crude oil having a compressibility coefficient of 4.4×10^{-5}/bar at 60°C. The presence of salts will further decreases the compressibility of water. The degree of this effect will depend on the properties of the salts present and the degree of saturation. If we restrict our attention to NaCl, then over the range of concentrations normally found in the North Sea the compressibility will only vary by approx. ± 10% about a mean of around 4×10^{-5}/bar.

If we calculate the compressibilities of crude/water mixtures assuming no effect of mixing we get:-

1% vol water b	=	12.02×10^{-5}/bar
10% vol water b	=	11.29×10^{-5}/bar

This gives pressure correction factors:-

Cpl (dry)	=	1.00303418
Cpl (1% water)	=	1.00301406
Cpl (10% water)	=	1.00283049

Even at 10% vol water the effect is very small and hence negligible as the error would only be around -0.02%. A negligible error can be shown for other salts commonly found in production water, at the pressures being considered here.

1.2 Thermal Expansion

Pure Water has a much lower thermal expansion coefficient than crude oil; ignoring this fact can lead to underestimating metered volumes at standard conditions. To demonstrate this, Volume Correction Factors (VCF's) have been calculated on three different bases and are shown in Table 1. The three different bases are:-

- VCF calculated from the thermal expansion coefficient derived from the dry crude oil density.

- VCF calculated from the thermal expansion coefficient derived from the wet crude oil density.

- VCF calculated from a total fluid thermal expansion coefficient derived from the individual thermal expansion coefficients of dry crude oil and production water. (It is assumed that this procedure generates the most accurate VCF.)

It is worth pointing out that the calculations used to derive "dry" crude thermal expansion coefficients are those specified in IP200/API2540. Strictly speaking this will not give absolutely accurate dry crude oil thermal expansion coefficients as the base data used to generate the equations (and Tables 53A and 54A) came from samples of "typical export quality" crudes i.e. they probably did contain small amounts of water. As the amount of water present is not reported, and probably varied from crude to crude, no estimate of the error involved in calculating dry thermal expansion coefficients can be made. In this paper it is assumed that this error is negligible when considering crudes containing more than 1% wt water.

The results, in Table 1, show that use of dry oil density to calculate VCF will cause significant errors at levels of water in excess of about 3% wt. (in this context it is assumed that a bias of -0.06% is significant in a modern turbine metering system designed to measure gross volumes to an accuracy of $\pm$0.1%). The errors will lead to an underestimate of the standard volume at 15°C.

It should be stressed that the errors being discussed are in addition to the potential errors already implicit in the VCF's derived by Standard IP200/API2540. The VCF precision (at the 95% confidence level) quoted in this Standard is:-

Temperature °C	40	65	90	120
Precision %	0.05	0.15	0.25	0.35

This arises because of the generalised correlation on which this Standard is based. The inherent precision of the VCF can be improved by using actual measured data for the thermal expansion coefficient of the substance being measured.

From the data in Table 1 it can be seen that the use of wet oil density, in the VCF calculation, produces much more acceptable results. At very high water concentrations (say $>$ 30% wt) the accuracy provided by this route may be judged to be inadequate, for the example choosen. If the production water is purer than the one used in the example (which was 2.68 molal NaCl) errors will increase because the thermal expansion

coefficient of pure water is less than that for salt water, at temperatures less than 60°C. Errors will obviously increase with operating temperature.

1.3 CONCLUSIONS

1. The relevant standards do not allow for use of the properties of water in metering calculations.

2. Ignoring the lower compressibility of production water, compared to crude, is unlikely to produce significant metering errors unless water concentrations are extremely high (e.g. 30% wt).

3. Use of dry oil density to calculate total wet fluid thermal expansion coefficients and hence Volume Correction Factors can generate significant underestimates of metered volumes at standard conditions if water contents are 3% wt.

4. Use of wet oil density to calculate total wet fluid thermal expansion coefficients, and hence Volume Correction Factors, does produce sufficiently accurate results over the range of water contents examined in Table 1 (1-10% wt)

1.4 RECOMMENDATION

1. Up to 10% wt water wet oil densities should be used to calculate metered volumes at standard conditions.

2. Above 10% wt water the need to include the thermal expansion coefficient of the produced water in the calculation of metered volumes at standard conditions, should be examined before a decision to use wet oil density alone is made.

The need for all of these calculations can of course be obviated by measuring and reporting platform dispatches in mass, calculated at line conditions. If this is done, a water measurement in terms of % mass is required to avoid the need to again introduce the uncertainties discussed above. The effect of salt content on the measurement of water concentrations is considered in the following section.

2. CALCULATING WATER QUANTITIES EXPORTED FROM NORTH SEA PLATFORMS

The most accurate method, available to the oil industry, of analysing for water is the Karl Fischer method. (IP 356/84). Unfortunately the chemists have provided an excellent way of determining pure water whereas the oil industry needs to know the level of produced water exported with the oil. A correction for water salinity therefore needs to be applied.

It can be shown that the mass of produced water exported in a given period can be calculated:-

$$\text{Mass of produced water} = \text{Total mass} \times \%\text{ wt pure water} \times \left(\frac{Dw}{Dw - TDS} \right)$$

where - % wt pure water is the Karl Fischer result
D_w = Density of produced water at 15°C in g/l
TDS = Total dissolved solids in produced water in g/l @ 15°C

$$\text{Salt correction factor} = \frac{Dw}{(Dw - TDS)}$$

This salt correction factor is plotted against water density in figure 1. This is only an approximate relationship, as the relationship between TDS concentration and water density obviously depends on the actual compounds present.

If gross quantities are measured to an accuracy of $\pm$ 0.1% one can see that the salt correction factor becomes significant at production water densities 1070 g/l at the 1% wt water level and at densities 1010 g/l at the 10% wt water level.

Hence, ignoring the salt correction factor can result in serious overestimates of the quantities of dry hydrocarbon exported from North Sea platforms.

It has already been suggested that measuring mass at line conditions eliminates several calculational uncertainties which would be reintroduced if water is measured as %volume. But what if the analytical technique used does give a volume answer, do corrections still need to be applied?

If the water concentration is determined by the centrifuge technique (IP 359/82) one does get an answer which relates in some way to the volume of produced water present. However, as the centrifuge technique uses equipment calibrated at 20°C and is actually done at 60°C the answer is not %volume water at 15°C as most people assume. The errors involved due to the confusing mixture of temperatures involved are not significant given the overall accuracy claimed for the test. It is the authors view that this method is not sufficiently accurate for modern mass metering installations.

If the water content is determined by the Dean and Stark Distillation technique (IP 358) the answer generated again relates to a concentration of pure water and therefore a salt correction factor must be applied.

In modern offshore metering installations volume temperature, pressure and density can be continuously monitored. Water measurement, however, still relies on collecting representative samples to be analysed off-line by laboratory techniques. It is not surprising, therefore that much

effort has been expended in recent years in attempts to develop instruments which will continuously monitor water concentrations in a flowing pipeline. From the comments made above it is apparent that the ideal continuous water measurement should generate a concentration in mass terms and allow for the salts present in the water.

2.1 CONCLUSIONS

1. To provide the best accuracy water should be analysed by the Karl Fischer technique which provides a concentration in mass terms.

2. Significant errors can be introduced in calculated dry oil quantities if the salt content of the produced water is ignored when the analytical test method is designed to measure pure water.

3. Any device developed to measure water content continuously would ideally need to allow for water salinity.

Aknowledgment

I would like to thank BP Petroleum Development (NW Europe) for permission to publish this paper. I would also like to express my gratitude to the many colleagues in BP who have helped me to prepare this presentation.

TABLE 1

	dry	wet 1% wt water	wet 10% water	Using α for water = 0.00035 deg/C	
				1% wt water	10% wt water
Density at 60°C, 25 bar g. Kg/m^3	797.8	800.00	820.34	800.00	820.34
Density at 15°C, 1.01325 bar Kg m^3	829.67	831.59	851.30	-	-
α	0.0008919	0.0008878	0.0008472	0.0008879	0.0008508
VCF	0.959420	0.959609	0.961475	0.959606	0.961310

$VCF = \exp[-\alpha \Delta t (1 + 0.8 \alpha \Delta T)]$

$\Delta T = 45°C$

Density of Water = 1100 kg/m^3 (at 60°C, 25 bar g)

Assume thermal expansion coefficient of water = 0.00035/deg C

1% wt water = 0.74% volume @ 15°C
10% wt water = 7.62% volume @ 15°C

Water Concentration	Error in VCF caused by using	
	dry oil density	wet oil density
1% wt	-0.019%	0.001%
10% wt	-0.197%	+0.017%

FORMULAE USED

Thermal expansion

$$VCF = \exp [- \alpha\Delta T (1 + 0.8 \alpha\Delta T)]$$

VCF = Volume correction factor

α = Thermal expansion coefficient = $\frac{613.9723}{\ell 15^2}$

ΔT = Operating temperature - 15°C

$\rho 15$ = density at 15°C, 1.01325 bar g in kg/m^3

Compressibility

$$b = \exp [1.38315 + 0.00343804T - (3.02909 + 0.0161654T) \ell n \rho_{15}]$$

T = Operating temperatures °C

e_{15} = density at 15°C, 1.01325 bar g in kg/ℓ

b = compressibility factor

$$Cpl = 1/(1-Pb \times 10^{-5})$$

Cpl = Correction for pressure

p = Operating pressure - bar gauge

b = Compressibility factor

Conversion of wet to dry oil density

$$Ddry = \frac{Dwet \times Dwater \times (100 - x)}{100\ Dwater - x\ Dwet}$$

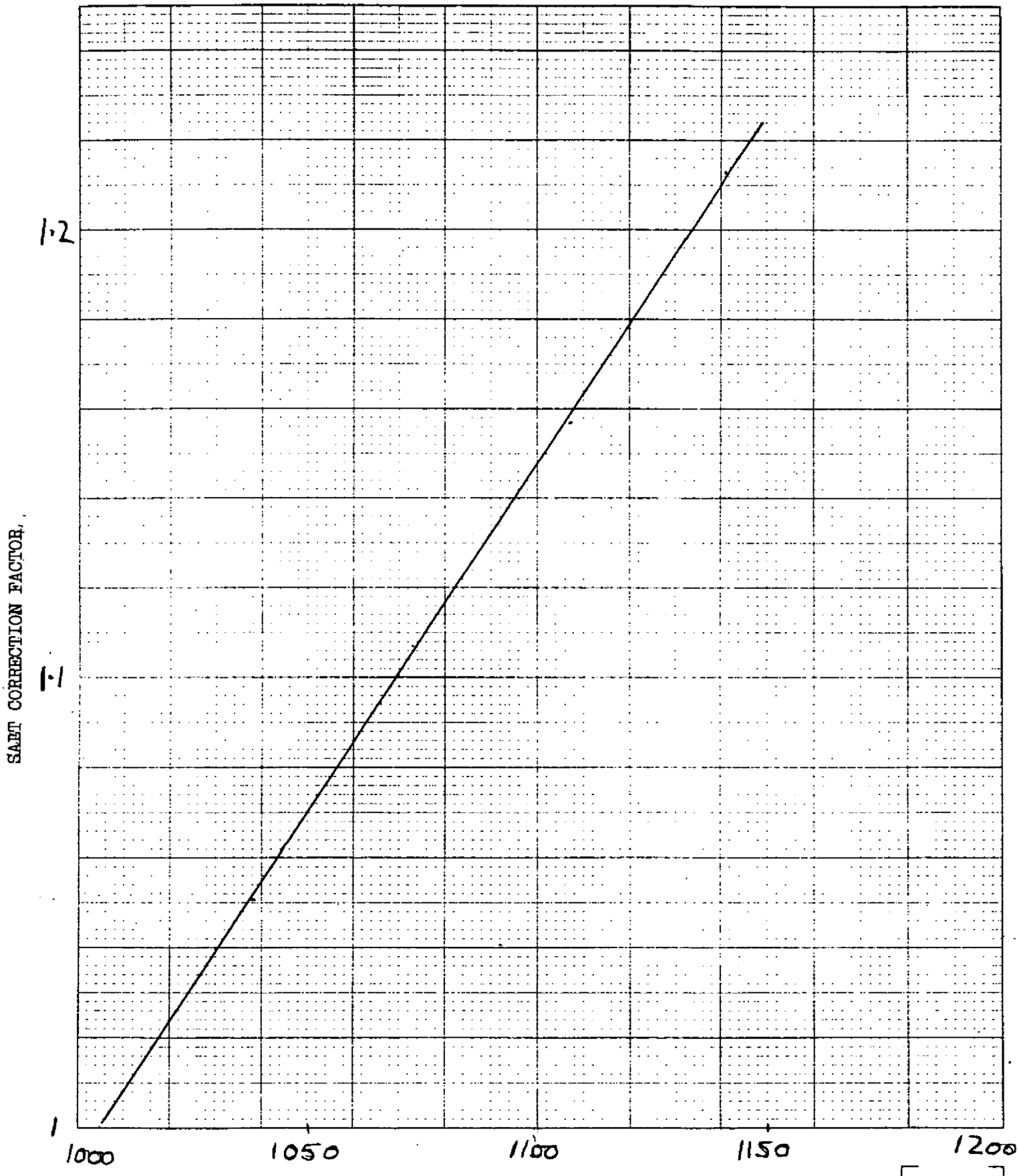
Ddry = density of dry oil

Dwet = density of wet oil

Dwater = density of produced water

x = percent wt/wt of production water present in wet oil

APPROXIMATE RELATIONSHIP BETWEEN PRODUCTION WATER DENSITY AND SALT CORRECTION FACTOR FOR KARL FISCHER TEST



BP. 1.(JAN.62) DENSITY OF PRODUCED WATER g/ℓ @ 15°C

Main Index

FIELD EXPERIENCE AND DEVELOPMENT WORK WITH HYDRIL BS AND W MEASUREMENT SYSTEM

by

C GRIFFITHS

AOT HYDRIL

PAPER 3.3

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

FIELD EXPERIENCE AND DEVELOPMENT WORK WITH THE HYDRIL BS & W MEASUREMENT SYSTEM

MR C GRIFFITHS HYDRIL-AOT LIMITED

1) INTRODUCTION

The measurement of crude oil water content in a continuous on-line fashion is extemely attractive in comparison with sampling techniques. The availability of real-time data provides the operator with a wealth of information relating to well performance, separator efficiency, etc.

However, to date the various methods employed have not been entirely successful and have not always demonstrated the levels of accuracy required.

Techniques currently employed are generally influenced by variations in temperature and composition or density of the crude oil as well as with water content variation.

This paper will look specifically at one such inferential technique based on the measurement of the dielectric constant of crude oil and water mixtures.

New development will be examined which promise to make such instruments independant of density, composition, pressure and temperature effects.

2) PRINCIPLE OF OPERATION

2.1 Theoretical Response

The Dielectric constant of a given fluid is a fundamental property such as for example, density.

Additionally, provided fluids can be mixed together in the form of an emulsion then the volume or mass ratio of the fluids concerned is directly related to the dielectric constant of the mixture.

It follows that if there are only 2 constituents in the mixture and that if the individual dielectric constants are known then the volume ratio of the mixture can be determined by measuring the mixture dielectric.

In order for this to be true for immiscible fluids one of the two constituents must be completely emulsified in the second.

In the case of oil and water the emulsion must be oil external and the water content should be less than 20% by volume as a guide. The onset of free-water breakout for a given emulsion will be determined by the properties of the crude oil and and the prevailing process conditions. In some instances it is possible to retain much higher percentages of water in an emulsion.

In order to measure the mixture dielectric and hence water content the Hydril BS & W Probe is constructed to measure the prevailing capacitance between a concentric electrode and the probe body as shown in figure 1. Provided the instrument is constructed in a rigid fashion such that no dimensional variation is possible, then the measured system capacitance is related directly to the fluid dielectric.

The probe capacitance may be expressed as follows:-

$$C = C_1 + \frac{2\pi \varepsilon_o L}{\frac{1}{K_1} \ln\left\{\frac{b}{a+2t}\right\} + \frac{1}{K_2} \ln\left\{\frac{a+2t}{a}\right\}}$$

Where: C_1 = Standing capacitance produced by the mounting arrangement for the electrode assembly (figure 2).

And:
- L = Inner element length.
- a = Electrode radius.
- b = Body Radius.
- t = Coating thickness.
- K_1 = Fluid dieletric.
- K_2 = Insulation dielectric.
- ε_o = Constant (permittivity)

The variable of interest is the fluid dieletric K_1 which is related to the individual dieletrics of the crude oil and water.

If the volume percentage of the oil and water constituents are expressed as V_o and V_w giving a total mixture volume of V_T, then the mixture dielectric may be expressed as follows:

$$K_1 = \frac{1}{\left\{ \frac{V_o}{K_o V_T} + \frac{V_w}{K_w V_T} \right\}}$$

From this it may be observed that since water dielectric constants are two orders of magnitude greater than those of hydrocarbons the total dielectric is very much dependant upon the value of the crude oil dielectric.

It follows that if the dry crude oil dielectric is unkown then significant errors may occur using an assumed figure. In addition, for a given water percentage in the emulsion, the total dielectric will be relatively insensitive to variations in formation water dielectric constant.

Reference to figures 3 and 4 will show how emulsion dielectrics and measured capacitances vary with water percentage changes and with different base water and crude oil dielectric valves.

From these tables the relative system sensitivity to base dielectric is graphically illustrated.

In addition it may be observed that the output is virtually independant of formation water properties. (Dielectric constant variation).

A graphical representation of this performance characteristic is shown in figure 5.

2.2 Base Oil Dielectric Variation

Following the foregoing analysis recent efforts have been made to define the effects of temperature, pressure and composition changes on the dielectric constant of crude oils.

A test facility was constructed (shown diagrammitically in figure 6) to measure the dielectric of a range of crude oils and investigate the dependance of dielectric constant on temperature, pressure and API gravity.

The results of the test programme to date are shown in figures 7 and 8.

It will be observed that where the crude composition (gravity) varies and where the temperature changes the response curves always exhibit the same shape but are displaced vertically. It is important to note that the response characteristic is thus fundamentally unaffected by base crude dielectric changes, which produce only a vertical shift in the response curve positions.

3) FIELD APPLICATIONS

3.1 Calibration

From the foregoing it follows that provided at a given measurement point the crude gravity and temperature are constant, gravity and temperature are constant, accurate measurements may be made. In addition if a dry sample of crude oil is not available for laboratory calibration and on calibration may be undertaken during flowing conditions irrespective of the prevailing water content within the span capability of the probe.

This is provided an accurate means of water determination is available to allow the probe output to be set. This method is illustrated in figure 9 which shows how a predicted response may be corrected by a single point field calibration. All Hydril BS & W Probes are equipped with series and parallel trimming capacitances to permit field calibration to be undertaken in this way.

3.2 Accuracy

In the North Sea, crude oil water content has up until recently been very small. Even with a 2% water content the change in capacitance to produce this is typically only 3-4% of the zero water or standing probe capacitance.

From the signal conditioning viewpoint this presents a major design challenge in producing de-modulation and amplification circuitry which is very stable.

Traditionally, such signal conditioning hardware has been based on the use of analogue techniques using the best specification components, etc.

More recently digital techniques have been used to improved stability and to

allow the effects of ambient temperature to be compensated for.

A new signal conditional technique has been recently developed and tested by Hydril which has built in temperature compensation. In addition, the capacitance measurement is based on microprocessor controlled charge/discharge cycles rather than a conventional AC bridge. It is anticipated that this method will enable smaller changes in capacitance to be resolved.

3.3 North Sea Applications

BS & W Probes are currently used on a number of North Sea Offshore platforms for water in crude oil and water in condensate measurement.

Normally the probes are fitted downstream of separators or de-hydrators to monitor performance. Where a calibration which has been carried out on an annual or 6 monthly basis long term results have been consistantly good.

Best results are achieved if the probe is mounted vertically and where the fluid velocity and turbulance is high enough to prevent deposition or free water drop out. For most practical applications these two installation requirements are essential.

Accuracies of $\pm$ 0.1% water have been consistently demonstrated on probes with a 3% or 5% water span.

4) NEW DEVELOPMENTS

4.1 Dry Sample Compensation

As previously stated the capacitance of an oil water mixture is dependant upon many variables apart from the water percentage.

An ideal measurement system should be insensitive to all physical variables with the exception of the measure quantity. (i.e. water percentage). In order to achieve this the concept of the Dry Reference System was developed, tested and is now in production.

This is shown diagrammatically in figure 10 which functions in the following manner:

The crude/water mixture is taken through a separator to remove free water. Retention time in the separator is arranged to ensure no free water remains in emulsion in a quasi-stable state. The emulsion is enhanced strengthened by an on-line mixer where a continuous sample is removed for measurement.

The sample capacitance is measured with the prevailing water content which is taken via a heat exchanger into a centrifuge. A small quantity is extracted from the centrifuge which is completely dry and passes via the same heat exchanger into a second capacitance probe.

These two capacitance probes are carefully matched and have the same characteristics. In this way the difference in capacitance is directly related to the water content alone.

Prototypes of this system have been under test and have produced encouraging results as illustrated in figure 11.

These test results come from comparisons with crude oil samples of a known water content as determined by laboratory analysis.

At present such a system in modified form is being supplied to the Alberta Gas and Oil Company for continuous BS & W monitoring on a pipeline where the crude oil characteristics vary.

5) CONCLUSIONS

Effort is now being devoted in developing a compact Dry Reference BS & W system which is completely self contained for use where crude oil properties and temperatures vary.

In addition, using new signal conditioning methods development work is continuing to improve the stability of the capacitance sensing circuitry to allow much smaller water content variations to be reliably determined.

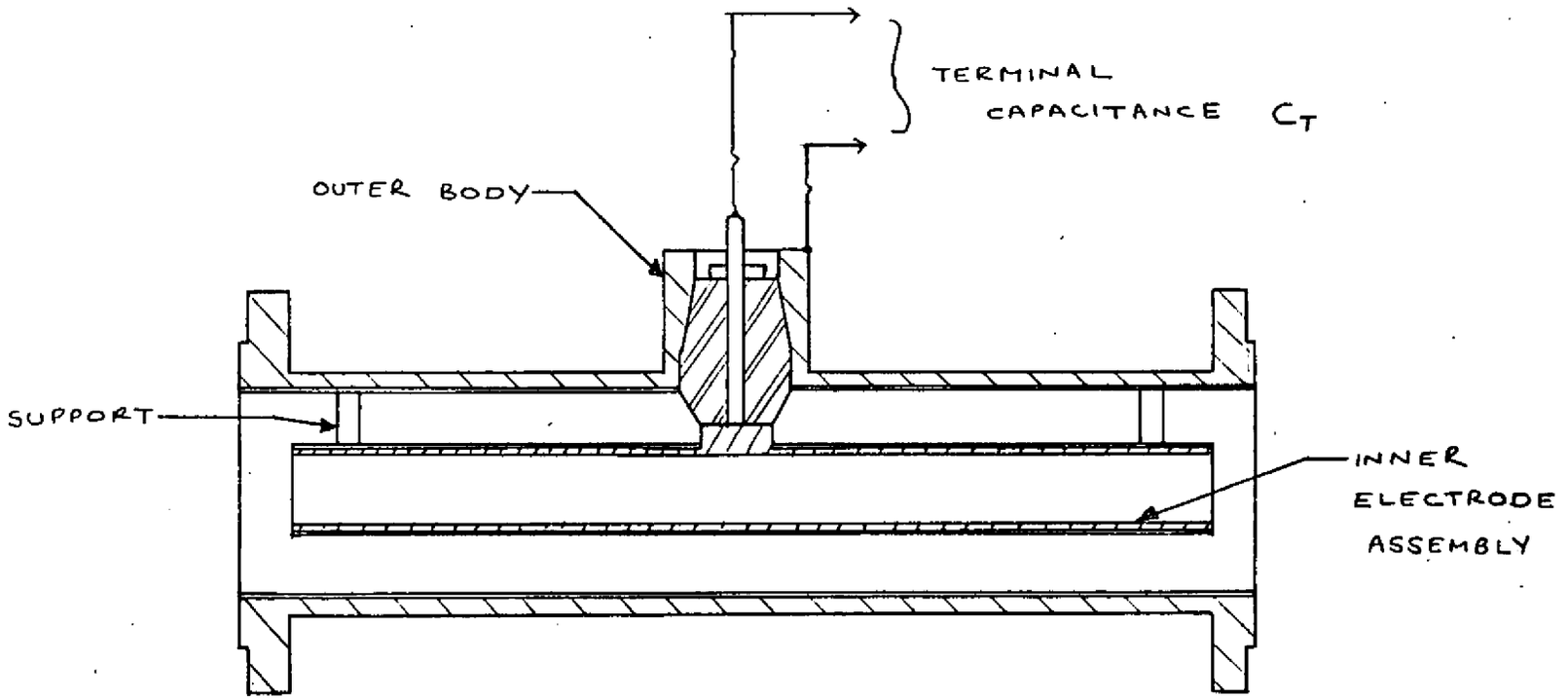


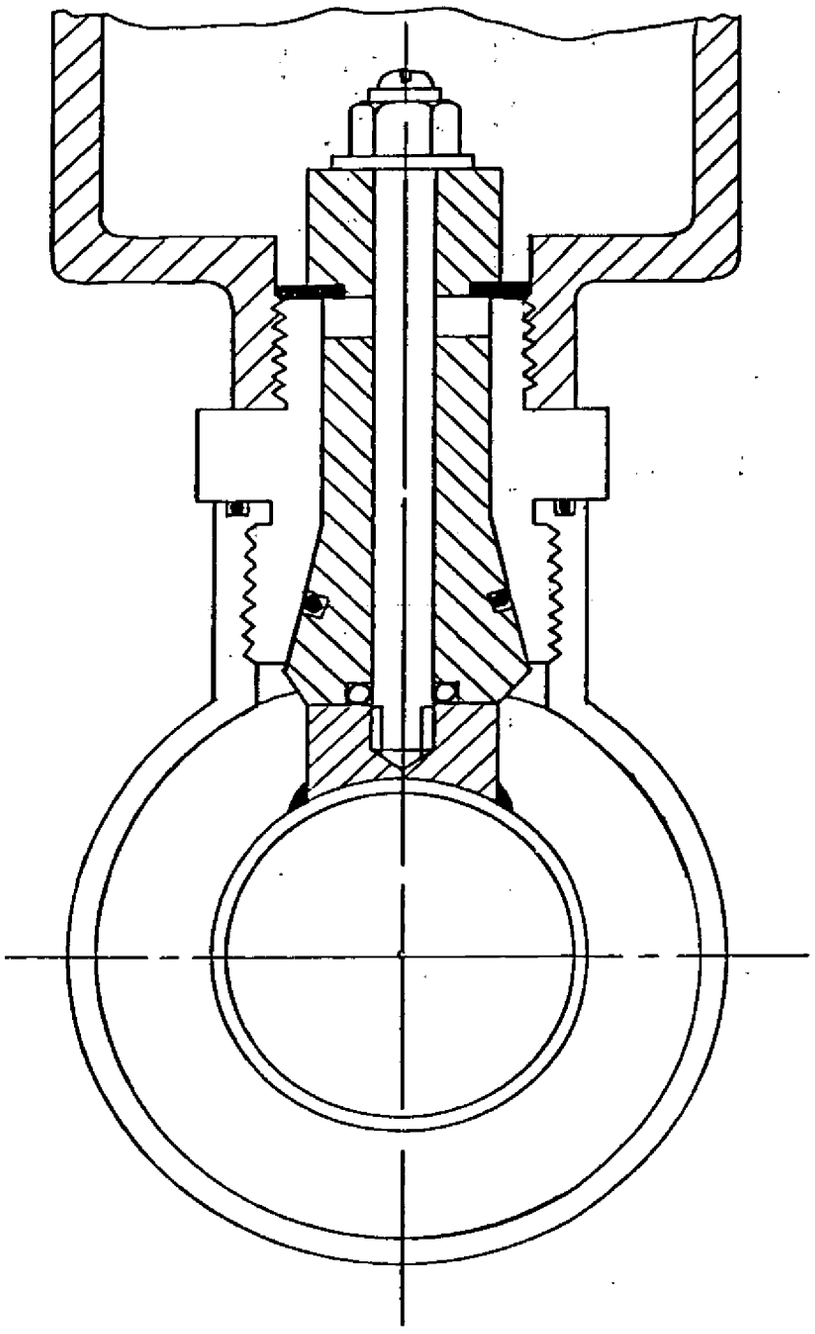
FIGURE 1

BS&W PROBE ARRANGEMENT.

FIGURE 2

OIL WATER PROBE

ELECTRODE MOUNTING



% Water	A K_o = 2.0 K_w = 300	B K_o = 2.0 K_w = 200	C K_o = 2.2 K_w = 200	D K_o = 2.2 K_w = 150	% Error A - B	% Error C - D
0%	2.0	2.0	2.2	2.2	0	0
5%	2.1045	2.1042	2.3144	2.3140	.29%	.35%
10%	2.2206	2.2198	2.4415	2.4405	.36%	.41%
20%	2.4958	2.4938	2.7425	2.7400	.40%	.46%
30%	2.8490	2.8450	3.1281	3.1232	.47%	.53%
40%	3.3186	3.113	3.6400	3.6312	.55%	.61%
50%	3.9735	3.9604	4.3521	4.3364	.66%	.73%
SPAN =	1.9735	1.9604	2.1521	2.1364		

FIGURE 3 OIL/WATER MIXTURE DIELECTRICS

% Water	K_o = 2.0 K_w = 300	K_o = 2.0 K_w = 200	K_o = 2.2 K_w = 200	K_o = 2.2 K_w = 150
0	31.76	31.76	34.02	34.02
5%	32.96	32.95	35.25	35.25
10%	34.24	34.23	36.58	36.57
20%	37.14	37.12	39.57	39.54
30%	40.57	40.53	43.08	43.04
40%	44.70	44.64	46.28	47.22
50%	49.77	49.68	52.39	52.29

FIGURE 4
ELECTRODE CAPACITANCE VARIATION
WITH WATER PERCENTAGE

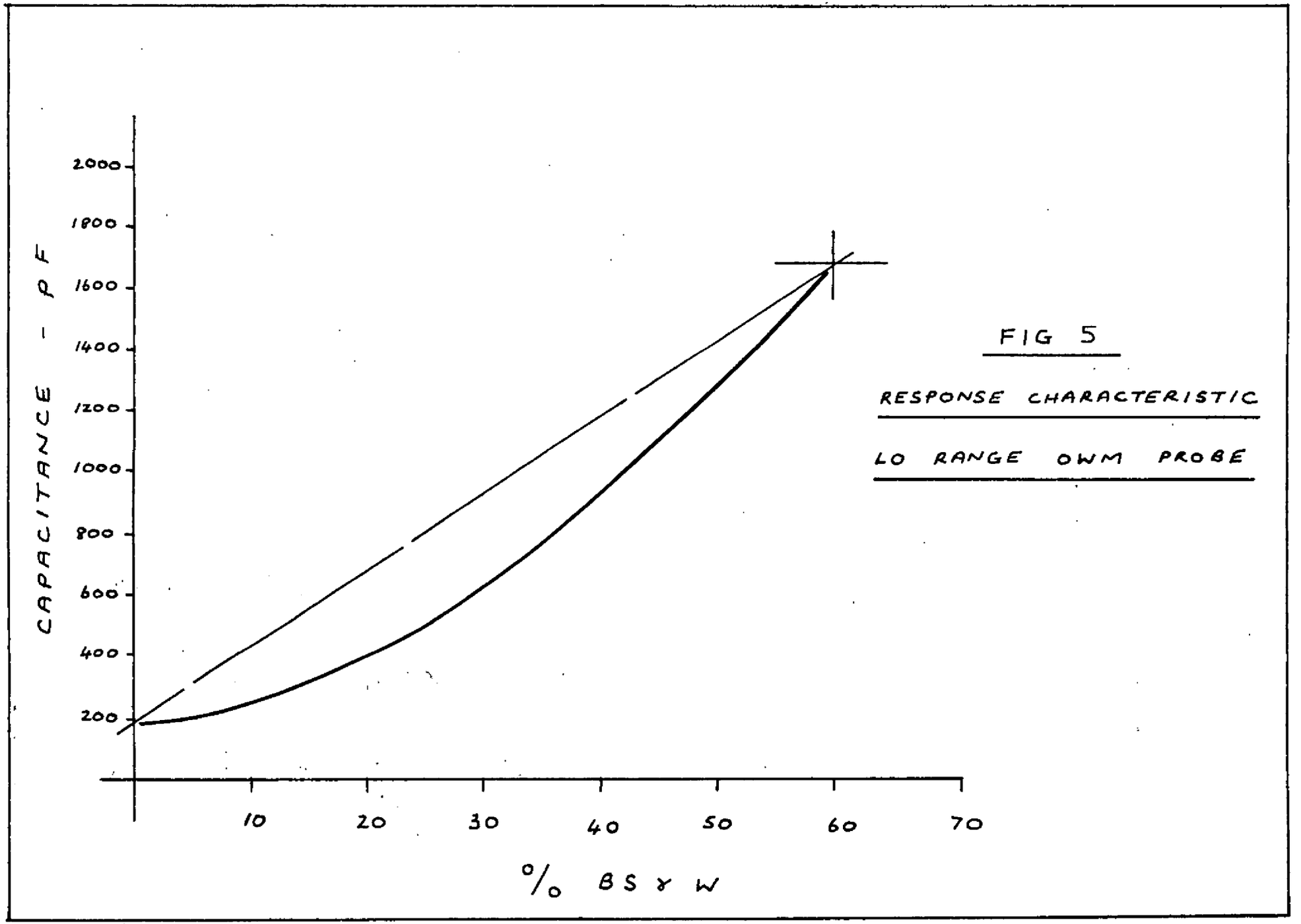
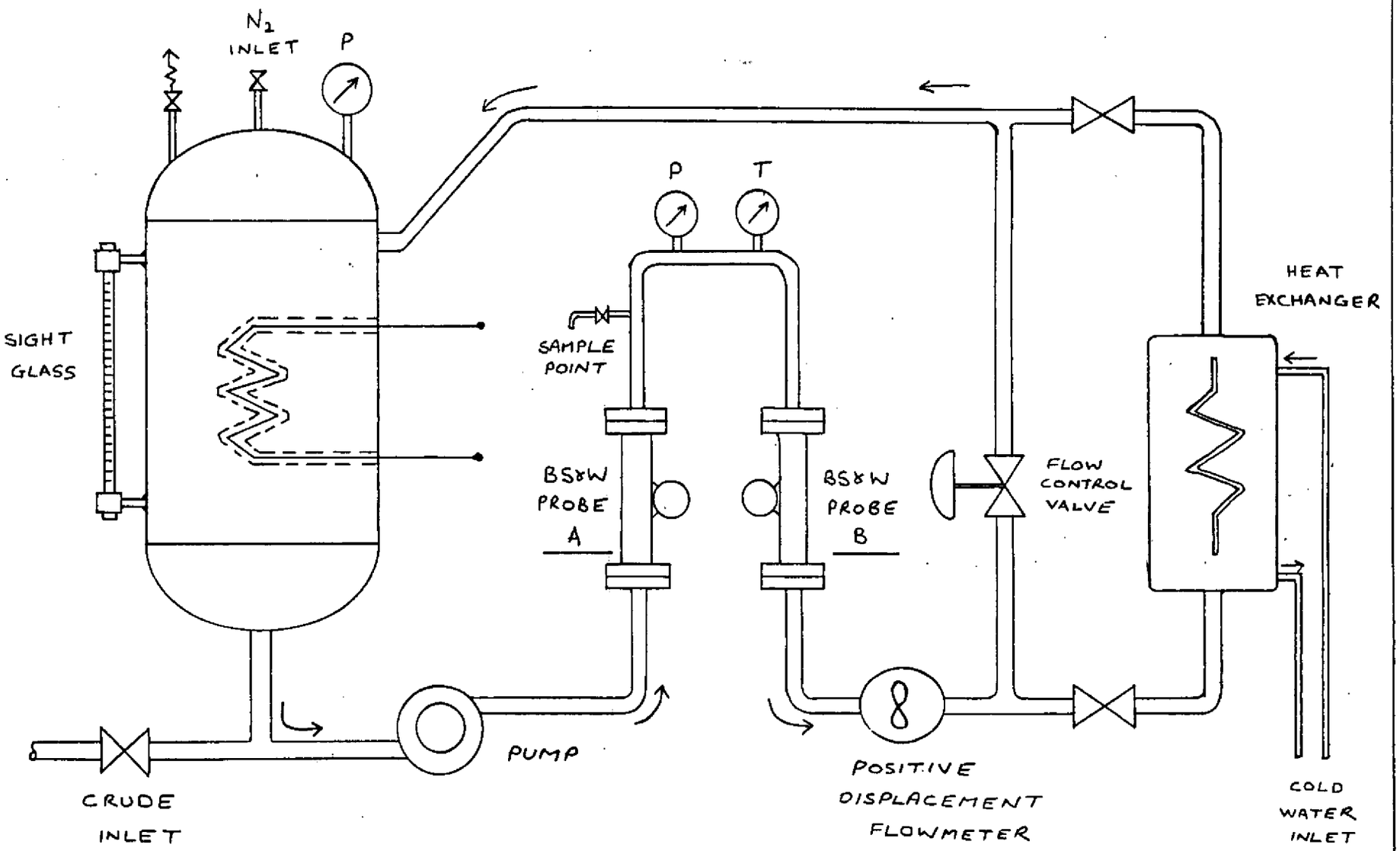


FIG 5

RESPONSE CHARACTERISTIC

LO RANGE OWM PROBE



BS&W PROBE TEST CALIBRATION LOOP

FIGURE 6.

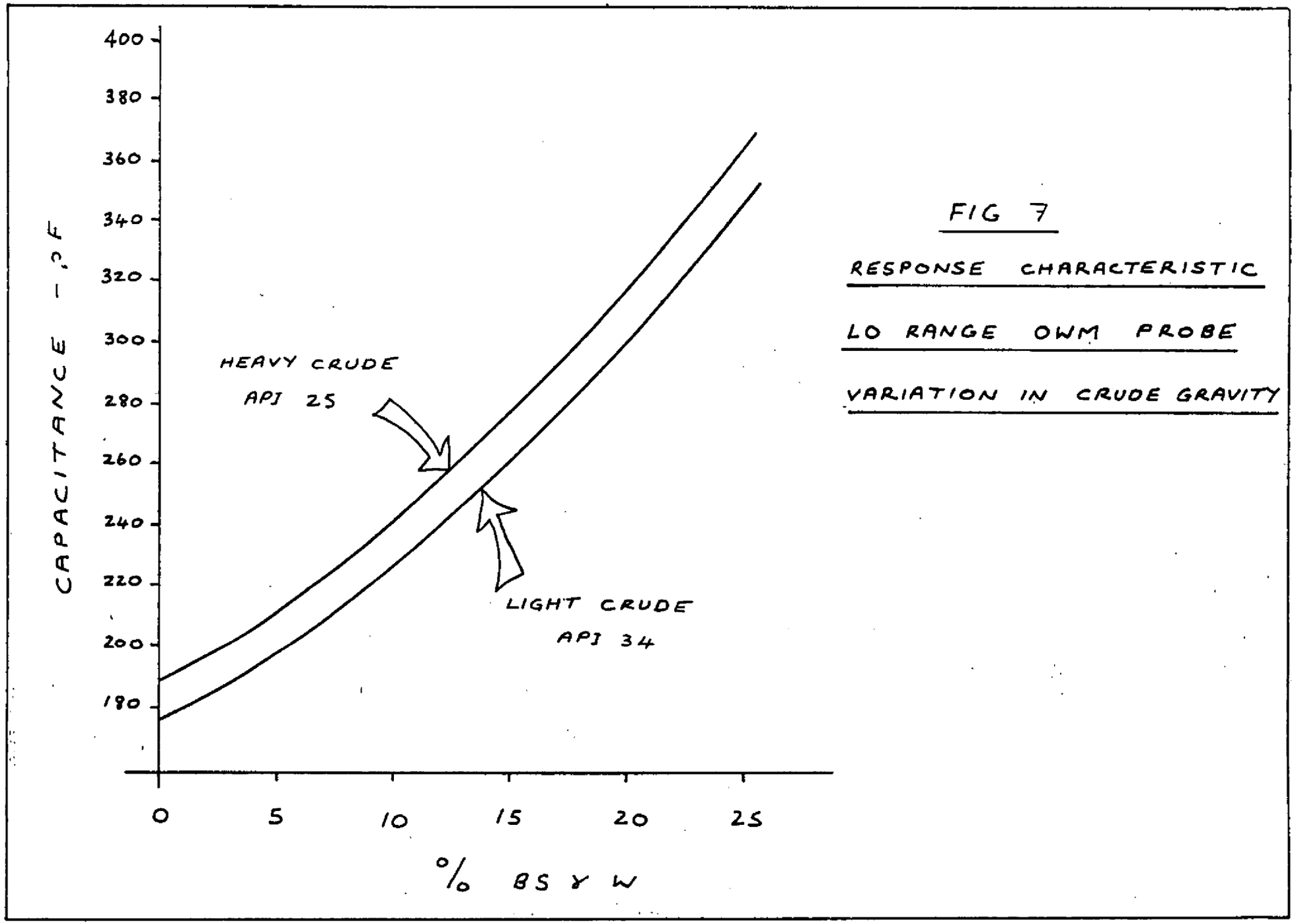


FIG 7

RESPONSE CHARACTERISTIC

LO RANGE OWM PROBE

VARIATION IN CRUDE GRAVITY

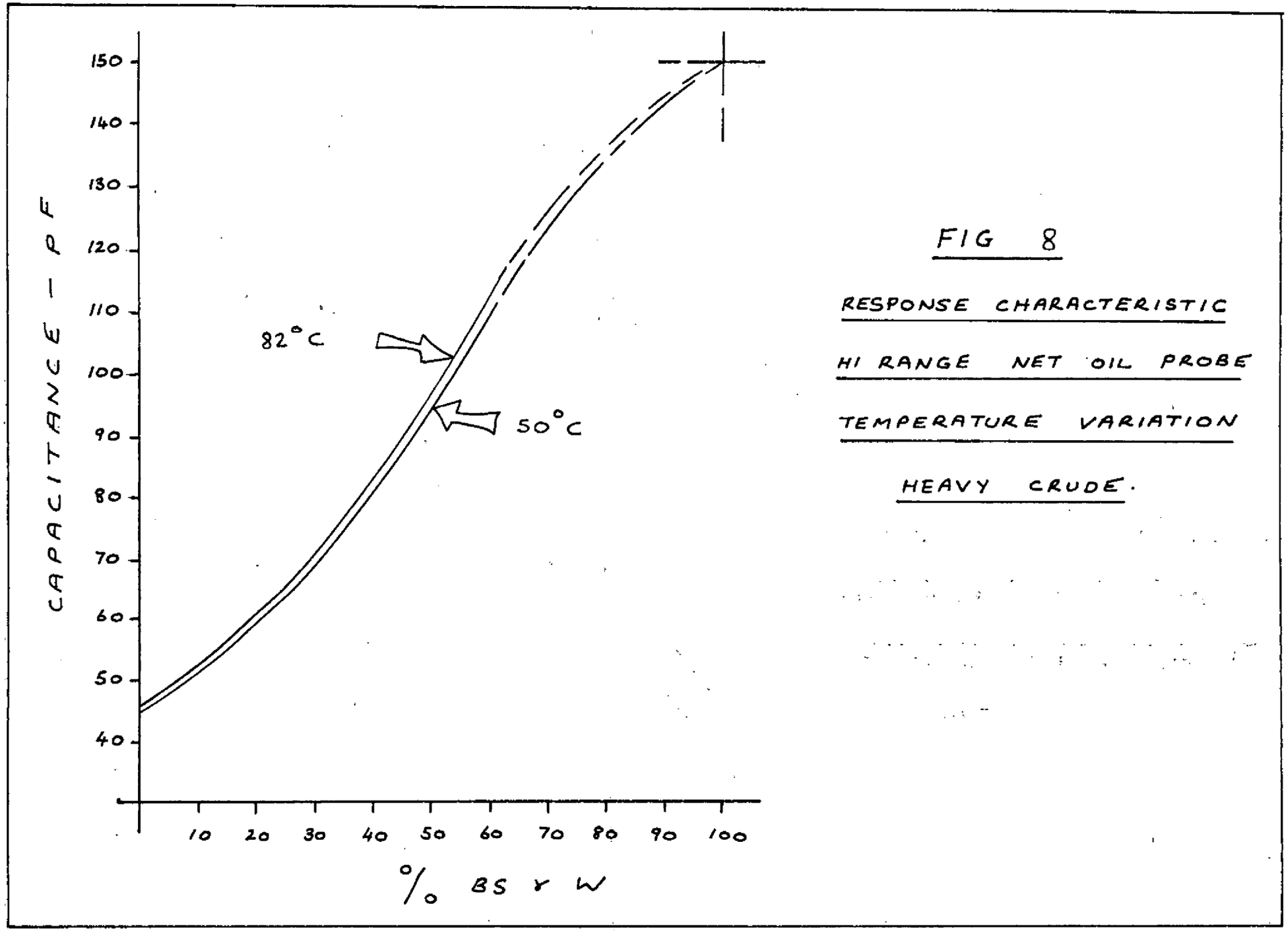


FIG 8

RESPONSE CHARACTERISTIC

HI RANGE NET OIL PROBE

TEMPERATURE VARIATION

HEAVY CRUDE.

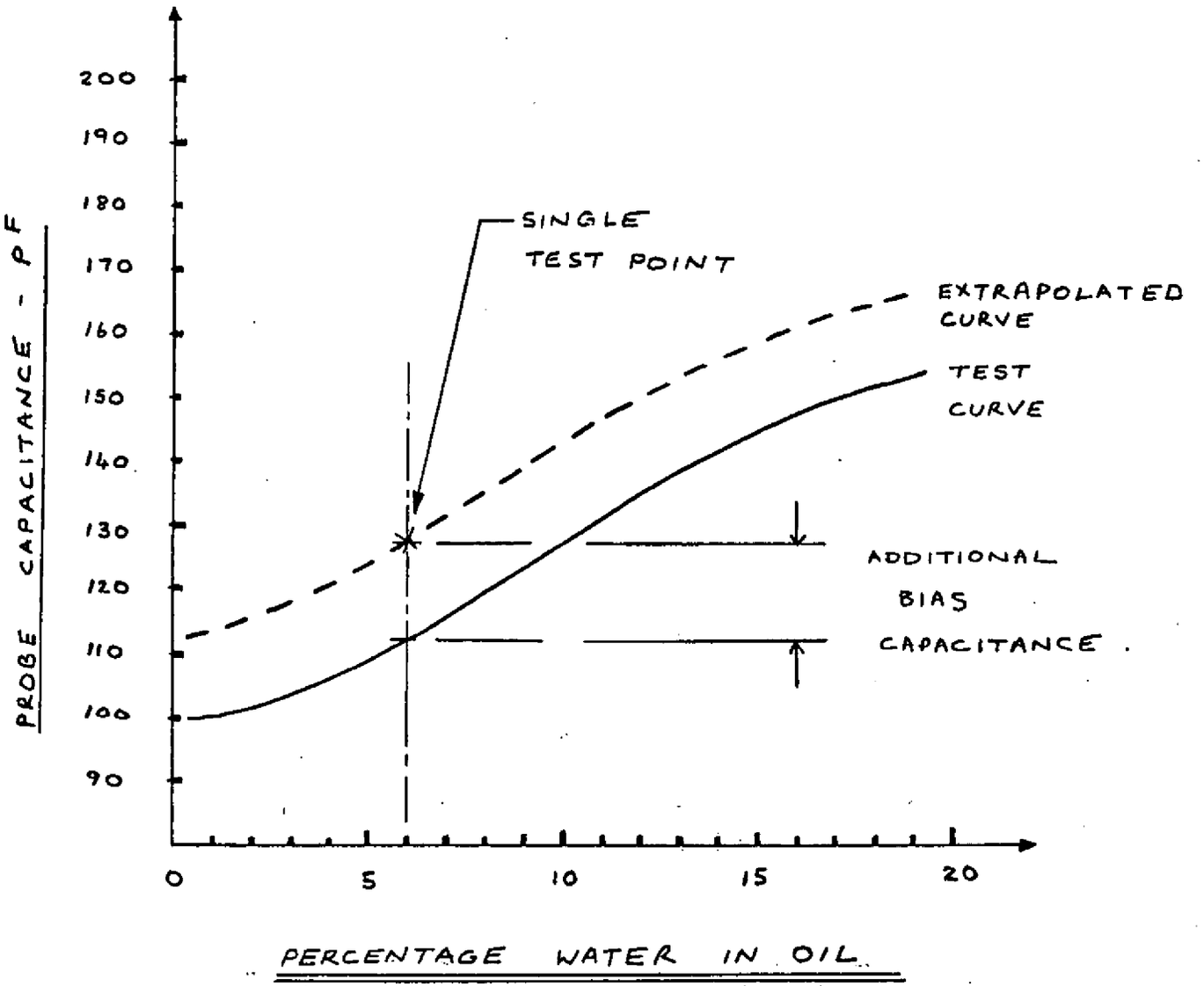
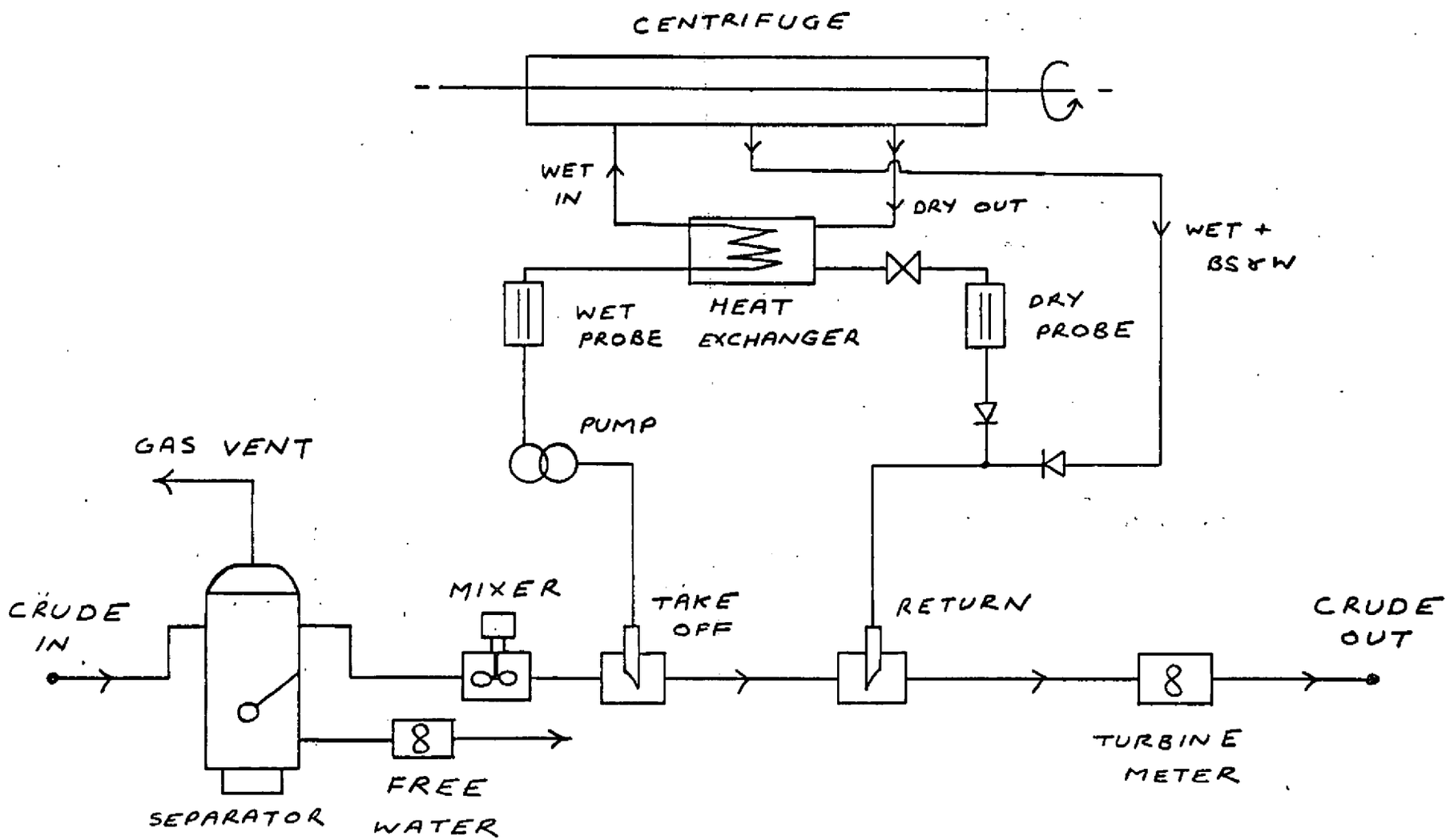


FIGURE 9 : FIELD CALIBRATION METHOD

FIGURE 10

DRY REFERENCE ON LINE BS&W SYSTEM



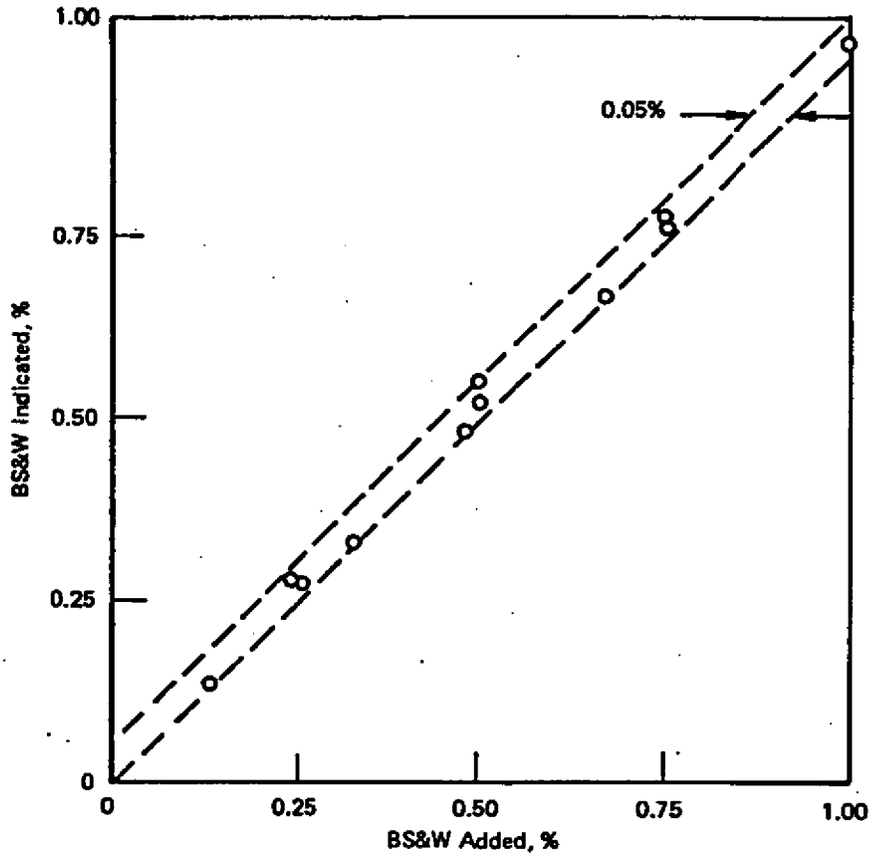


FIGURE 11

DRY REFERENCE SYSTEM

PERFORMANCE

Main Index

LABOATORY ANALYSIS TECHNIQUES

by

B ATKINSON

PETROFINA (UK) LTD

PAPER 3.4

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

LABORATORY ANALYSIS TECHNIQUES & WATER CONTENT OF CRUDE OILS.

C.B. Atkinson

The title of the paper being "Laboratory Analysis Techniques", begs the question that before receipt at the laboratory the sample is representative of the whole shipment or transfer.

The best method of ensuring this, is to have automatic sampling devices installed in order to produce a representative sample. As this is a subject in itself I intend to begin the chosen subject at the point where the sample is received at the laboratory.

In the first instance it could be that the laboratory is responsible for sampling direct from the automatic sample container which is commonly a can of the order of 11 litres.

The laboratory should then possess equipment suitable for the homogenisation of the sample, as outlined in papers given by Ken Underhill of Esso Research and Bob Mackison of B.P. Sunbury at Maidstone November 1981. The sample is then subjected to the homogenisation procedure which ensures representative subsampling.

Whilst it is realised that such massive disturbance of the sample reduces the representivity of the sample for such properties as light ends and density, it has been shown that the alteration in these properties once the sample has once more settled oil from water is relatively minor.

It is customary to obtain a 500 ml sample for testing for water by the laboratory.

Secondly the laboratory could receive a sample of oil for direct analysis. In this case it would have to be assumed that an approved procedure had been used to obtain the representative sample.

Finally, the sample could have been obtained manually, by a series of "Spot" samples.

The commonest of these are "T,M & B" samples out of shore tanks. It is here that representivity leaves much to be desired and that agreement is necessary to ascertain the suitability of such samples.

Thus the laboratory now has a sample which it has to check for water.

There are several ways this can be attempted, involving either physical or chemical meethods and we can now examine such methods individually from a critical viewpoint to determine which is the best technique for each laboratory's purpose.

One step however, which has to be carried out immediately before any testing of crude oil, is to re-homogenise the sample.

It has been found that in order to obtain reproducible results an homogenisation procedure such as that given in IP 356 has to be used. Mere shaking the can by mechanical shaking is not sufficient to obtain a representative sample.

After this procedure a sample may be taken with relative confidence of its representivity.

The long serving standards have been by physical means of separation of oil and water.

Firstly, centrifugation has been seemingly the test employed as long as the oil industry has been established. It has evolved from hand centrifuging in the field to heated laboratory centrifuges whirling round at a mathematically correct speed to apply a particular quantity of 'g' at the centrifuge tube tip.

This letter is the basis of the present day standard specifications. - See Fig 1.

It is commonly used world wide but has been proved to give low results. (At Esso Abingdon an exercise on a series of North Sea crudes outlined this problem some three years ago.)

Also it combines water at the bottom of the centrifuge tube with any other exraneous matter in the sample, particularly sand and possibly wax if the test is improperly carried out.

Thus erroneous results with this method are common.

In order to carry out such a test it is necessary to have a laboratory equipped with accurate balances and a heated centrifuge.

The centrifuge tubes although reasonably robust have a tendency to break during cleaning.

It is both time consuming and labour intensive but probably its main drawback is that with many crudes, provided the homogenisation procedure has been correctly followed, the centrifuge is not capable of breaking down the fine emulsion, consequently separate layers of water and oil do not form correctly.

Thus a critical examination of this method shows that it is costly to perform and yields obtained are generally below the true value. If transfers using this method for water are carried out it can result in large monetary losses along the way.

One should not however decry its value in the examination of particular products for water and it has its value in the laboratory but not in examination of crude oils.

Continuing attempts at improving the method for crude oils are being attempted but it is considered that effort on improvement would be more fruitfully directed elsewhere.

The alternative standard physical method of estimation of water in oil is by distillation, using a suitable solvent and this has been applied with modifications to crude oils and products ranging from gas oil fractions to bitumen. It is not so successful at water determination of the lighter fractions, but usually these contain so little water that this is a relatively unimportant property.

The standard methods given in Fig 1 are all technically equivalent and to date it is the only reliable method of determination of water which is internationally accepted.

The advantages of this method is that it is simple and reliable to operate. It is cheap and does not require many man hours of operation. Also this method may be carried out using a bank of apparatus with six or more determinations being carried out simultaneously.

Its principal drawback it that the determination takes approximately three to four hours minimum and care must be taken to ensure that water retained in the condensor and the trap is carried to the bottom of the trap by mechanical means.

A laboratory environment is more or less obligatory for this test as both electricity and running cold water are a necessity plus the apparatus and a balance.

With ASTM D4006/IP358 standard size 5ml and 10ml traps are quoted but it is common to use alternative sizes such as 2ml traps when examining product samples.

It is known that the results with this method has a low bias and seemingly there should be a fall off in precision when using the larger volume traps, although it is not shown in the repeatability and reproducibility figures for crude oils.

In the mid 1970's it was realised that alternative procedures must be examined for water determination in crude oils as the physical methods were no longer suited to large and rapid transfers both by VLCC and pipeline.

In this country and elswhere chemical methods of determination were considered and originally two were singled out as promising.

The French petroleum industry required a rapid evaluation of water in the field which was simple to operate and gave consistent, accurate results.

An apparatus designed originally for marine engine oil purposes was adapted for use with crude oil and it was shown that results better than those obtained by centrifuge could be obtained using the 'Fina Aquatest' apparatus.

It has been found simple to operate and is both cheap and rapid, but its biggest asset or "defect" is in its "take anywhere" value.

The apparatus is light, easy to carry and because it involves no electricity, can be taken into areas where other methods of test cannot be performed.

Its defect of course is that if used in a hazardous area, it is a near impossibility to obtain an homogeneous sample. The argument being that, as homogeneity is crucial to good water determinations it follows that a laboratory is required.

With the "field check" argument however, the use of a gas evolution method is probably the best method at present of obtaining a water determination.

It is a simple apparatus where a suitable quantity of crude oil is placed in a special receiver and a capsule of calcium hydride added. The gas evolved is measured in a cylinder, calibrated to read in percentage of water present.

The answer given is in a volume to volume manner which is useful in a field situation.

It use is generally restricted to stabilised crudes as it does not perform well with light or gassy type crudes. Similarly heavy crudes or crudes with above 2% water require dilution with a dry solvent in order to give results on the scale of the apparatus, with consequent alteration to the direct reading ability of the apparatus.

Only one result can be obtained at each operation and a fairly comprehensive cleaning is necessary to ensure gas-tightness for each successive test.

In the U.K. we took a close look at the Karl Fischer titration method for water in North Sea crude oils. The technique had always been seen as unsuitable for crude oils, but with a better designed apparatus, a "scaling down" of sample size and a fresh look at the solvents used we were eventually in a position to use the method in North Sea crudes. Whilst this development proceeded we also examined other crudes and concluded that the method could be seriously looked at with a view to becoming internationally accepted. Internationally, four difficult crudes were tested and statistically examined, the results, which were studied by both ASTM and IP in early 1984, has resulted in a draft for a joint method which we hope will be published in 1985.

For those not familiar with the Karl Fischer titration it is based on a complex chemical reaction between the water molecule and the reagent (A solution of iodine and sulphur dioxide in pyridine).

The water present being equivalent to the amount of iodine liberated. When excess Karl Fischer reagent is present a change in colour from violet to straw is noticed. The colour change is now however irrelevent as the end point is measured electrically.

The use of the Karl Fischer titration technique has led to an increase in accuracy of water determination. Together with its relatively simple operation and its speed, we feel it will become the prime laboratory method for water determination in crude oils.

The method is being examined internationally with the proposal that it will eventually become an ISO method.

Development using Karl Fischer technique as a basis for testing is continuing.

The original reagent had what can midly be described as a pungent odour. Non pyridine type reagents have now been marketed which in many cases are suitable for use with crude oils and are much more sociably acceptable.

Another development which has been in parallel with the development of our standard method is the use of coulometric apparatus using a modified reagent.

These are considerably more expensive than the normal Karl Fischer apparatus but however, are usually automated so that results are printed out in a matter of seconds.

Although only moderate skill is required to operate these pieces of equipment and the operation is simple, great care must be taken over the homogenisation step, the sample weighing and injection into the tester.

The sample is only of the order of 0.1 - 0.5g so one can see that any slight error will magnify or reduce the water result considerably.

Where a high throughput of samples is required on a permanent basis such a method can be highly commended, provided suitably accurate balances are available together with careful operators.

The high cost of the apparatus tends to disqualify their use for intermittant or varied work.

The coulometric method of Karl Fischer titration is at present being examined by a working group so that it may be included as a standard method for both ASTM and IP as soon as possible.

The necessity for sampling homogenisation, sub-sampling re-homogenisation and laboratory testing seems to be a cumbersome approach to water determination in crude oils. The obvious solution would be to measure the water "in situ" as oil passes down a pipeline.

Many approaches have been made to this such as density measurement, conductivity etc.

To date however no break through has occurred and it is still entrusted to the laboratory to obtain results on which millions pf pounds a year ha upon the accuracy of the determination.

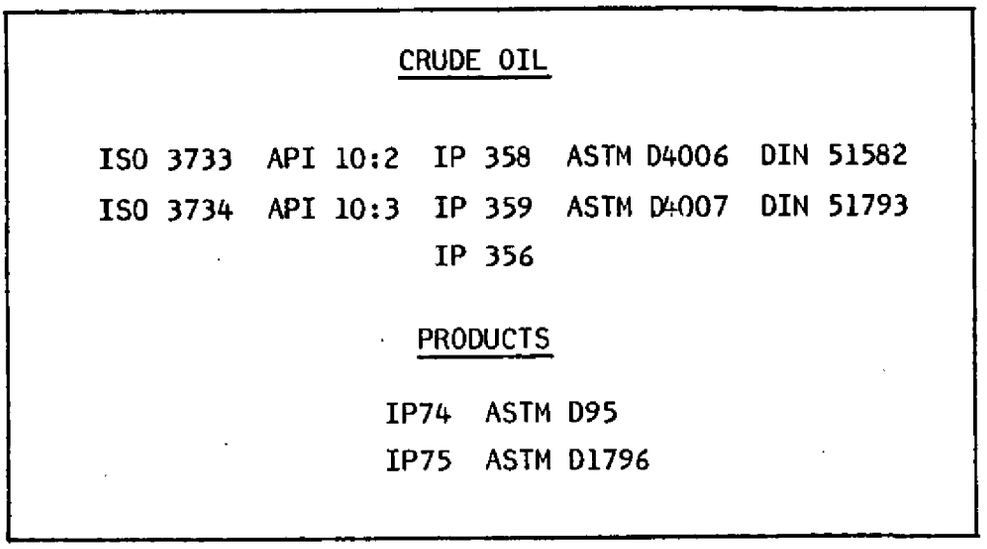

CRUDE OIL
ISO 3733 API 10:2 IP 358 ASTM D4006 DIN 51582
ISO 3734 API 10:3 IP 359 ASTM D4007 DIN 51793
IP 356
PRODUCTS
IP74 ASTM D95
IP75 ASTM D1796

FIG. 1.

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CONTINUOUS ON-LINE WATER MEASUREMENT

by

M WILSON and B RICHARDS

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CONTINUOUS MEASUREMENT OF THE WATER CONTENT OF CRUDE OIL USING ELECTRICAL CAPACITANCE TECHNIQUES - DEVELOPMENT AND APPLICATIONS

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SYNOPSIS

Accurate measurement of crude oil water content has become a very important fiscal measurement, for offshore platforms and terminals and for refineries. The established practice uses flow proportioned automatic samplers, but this approach poses some difficult problems especially for spiked crude and for high pressure pipelines. Another matter often debated is the incidence and significance of high water content transients and therefore the grab frequency required for an automatic sampler to ensure taking a representative composite sample.

The first part of this paper describes the development of a continuous monitor, using the well-known electrical capacitance technique, aiming to measure the water content of crude oil transfers to an accuracy comparable with established fiscal measurement practices. It is equally applicable to high pressure and spiked crudes and eliminates any concern for water transients.

The second part of the paper describes how a prototype capacitance monitor was used to study the water content profiles during discharge of VLCCs. The results indicate - inter alia - that despite large water transients being common, automatic sampling with a grab frequency of only one grab per minute or even lower would collect a representative sample. The importance of accurate flow proportioning is also highlighted. Another application for the capacitance technique which is described is for pipeline water profile studies, to give real time display of the profile and avoid tedious manual sampling and lab. testing.

1. DEVELOPMENT OF A CONTINUOUS ANALYSER

1.1 Introduction

Accurate measurement of water content has become a very important fiscal measurement for crude oils. The approach currently recognised internationally is to use an automatic sampler to derive a representative bulk sample of each transfer and test this sample in a laboratory.

This approach has many limitations, both in concept and in practice. The problems are particularly acute when applied to hot, high pressure and high vapour pressure crudes, as arise in production pipelines and offshore platforms. Results from sampling/testing are often too slow for operational benefit.

Clearly, there is a very strong incentive to provide the means to measure crude oil water content continuously on-line, i.e. in real time. Using the change in dielectric constant of an oil/water mixture to measure water content has been used for many years. However, it has generally been applied only in a simplistic manner and with little knowledge of the important parameters: consequently accuracy has been very poor and credibility low.

Since 1979, we have been studying the capacitance technique in the belief that it might offer the way to measure water in crude oils on-line, in the fiscal context. The technique has many practical advantages in that it is essentially very simple and is readily applicable to hot/high pressure/spiked crudes for which the existing sampler techniques are unattractive.

Our earlier work used some proprietary capacitance electrodes and conventional ac bridge electronics of the type supplied for level sensing. The overall system was rather elementary and lacked sensitivity, yet the results were highly satisfactory as a basis to progress the technique further.

About that time, Endress and Hauser Ltd who had provided the initial equipment for our tests, developed a new technique for measuring capacitance. It combined very high sensitivity with excellent stability and high immunity to resistive effects - characteristics all eminently suitable for the water content measurement.

Endress and Hauser became convinced that water content measurement by the capacitance technique could become a viable commercial prospect. Therefore they agreed to collaborate with us in its development.

1.2 Design Details

1.2.1 Flow Cell Design

The basis of the capacitance method for water content measurement is the flow cell, comprising an outer tube with connections for oil in and out and a central electrode. The tube and electrode form an electrical capacitor whose capacitance varies with the dielectric constant of the flowing oil/water mixture.

The capacitance between two plates is directly proportional to the plate area and inversely proportional to their distance apart. Thus the preferred design is to use a long large diameter tube with a concentric electrode whose diameter is just less than the tube ID.

In practice, the length and diameter of the flow cell tube are constrained by what can easily be handled and installed. The separation between the two cylinders must be large enough to cope with dirty crude/water mixtures, without risk of blockages. The cross sectional area of the flow annulus needs to be small enough to ensure that the fluid velocity for practical sampling rates is high enough to keep any water particles in suspension. Otherwise flow rate does not affect the measurement.

Our preliminary work had shown that temperature compensation would be essential for fiscal measurements. Therefore, a temperature sensor is required within the flow cell.

For low water contents, the oil/water mixture is non-conducting and therefore uninsulated electrodes would suffice. However, in practice, flow cells will experience short periods of high water contents (above say 40% volume water) and such mixtures would short circuit an uninsulated cell. A cell design with insulated electrodes is therefore preferred, but the insulator must be very thin to minimise its effect of reducing the active capacitance.

The flow cell tubing and the electrode connections must of course be designed to the pressure rating appropriate to the application. For refinery offsites service this is commonly Class 150, but for offshore/terminals/ pipelines, it may be as high as Class 1500 (i.e. working pressures up to 245 bar, 3600 psig).

For fiscal applications, one special design factor arises. An established practice for other fiscal measurements (e.g. turbine meters and densitometers) is to have a dual measurement with in-build discrepancy alarm, to enhance the system's integrity. We therefore conceived the novel arrangement to incorporate two capacitance measurements within the same flow cell, using an electrode in each end of a single flow tube.

Based on the above criteria and in collaboration with Endress and Hauser, dual measurement flow cells for Class 150 and Class 900 applications have been designed and manufactured. These are shown in Figs.1 and 2.

The low pressure cell, Fig.1, has an overall length of 1 metre. The outer tubular electrode has an internal diameter of 65 mm and the gap between the two electrodes is 6 mm. The effective length of each cell is approx. 200 mm. The central electrode is hollow to reduce its weight.

Both electrodes have an insulating coating to reduce the effect of conductivity at high water contents. This coating is an oven baked epoxy material approx. 0.004" thick (0.1 mm). To improve the adhesion of the coating the cell is manufactured from carbon steel.

In order to obtain high sensitivity and stability care must be taken to minimise the effect of stray capacitance at the cell ends where the central electrodes are mounted. This has been catered for by the shape of the central electrode, by the use of insulating materials and by the provision of a guard ring. The central electrode is a large diameter tube mounted by an insulator on a small diameter shaft, thus reducing the electrode surface area at the end of the cell. The end boss is further insulated. The guard ring provides a screen between the active electrode and earth, thereby reducing the standing capacitance at the boss. It is driven by a voltage of identical waveform to the measuring electrode but is not included in the measurement.

Each cell has an active capacitance ca 160 pF when full of dry crude oil. The change of capacitance between dry oil and 5% water/oil mixture is approx. 22 pF.

The high pressure cell, Fig.2, is of a similar design but built to Class 900 specification. The cell is made from 3" dia. Schedule 80 pipe requiring some changes in the dimensions of the electrode system.

As this cell is intended for high pressure production line application the specification is less demanding, in that only one 0-5% range is required. This together with the more difficult design of electrical connection seals has led to the ground ring being omitted. To compensate for this the insulated support rod of the central electrode has been extended giving increased separation between the active area and the end of the cell.

The central electrode is open to fluid, to eliminate any distortion due to pressure. The contents of this electrode have no influence on the measurement.

1.2.2 Electronics Design

The measuring technique used is the same for both the low and high pressure cells. It is a pulsed dc measurement whereby the capacitor that is the cell is charged to a fixed voltage simultaneously with a reference capacitor. These two capacitors are then switched such that their charges are integrated and compared to provide a difference signal.

The switching is accomplished with CMOS bilaterial switches at a maximum rate of 240 kHz. Varying this switching frequency provides a means of changing the span, increasing the frequency increases the sensitivity.

Various options are available or envisaged. The simplest option provides an output of instantaneous water content as a non linearised signal, together with temperature. As the water content signal is fairly linear over the limited range 0-5% it is possible to add a display to this verison to give a self contained single range unit. When more sophisticated facilities are required the above output and display circuit will need to be replaced by a micro computer package. Such a package is under development by Endress and Hauser Ltd. and is expected to be available by the end of this year.

1.2.3 Temperature Coefficient

Our results for temperature coefficients were very encouraging for the seven crude oils (and one lub. oil), as shown in Table 1.

Each coefficient was linear over the temperature range tested (15^{o} to $40^{o}C$) and all the crude oils had sensibly identical coefficients, at $-0.0020/^{o}C$.

Expressed in terms of equivalent water content, the coefficient is -0.027% volume water per degree C.

The significance of these findings is that, being linear, the temperature correction is easy to apply in practice: being the same for all crudes allows the correction to be factory set.

In the practical applications for the equipment, the crude oil temperature - either crude discharges or offshore pipelines - does not change greatly over a measurement period: probably by less than $5^{o}C$. In that case, appreciable difference in the temperature coefficient from the value we determined would have little effect upon the overall measurement. Note from Table 1 that the coefficient for lub oil was very close to that for the seven crude oils.

The temperature coefficients measured relate to dry crude only. Theoretical considerations would indicate that temperature would have no significant effect upon the sensitivity of the capacitance system to water content changes. However, in future studies, this assumption might be re-examined.

1.2.4 Dry Oil Dielectric Constants

From the outset of our work on capacitance techniques applied to measure crude oil water content, it has been recognised that the dry oil dielectric constand (ϵ) is a major factor. The ϵ value increases with density and aromaticity. Differences in ϵ values are small in absolute terms, but large in relation to the effects of small quantities of water.

Literature references sugges that the ϵ value for crudes ranges from 2.05 to 2.7.

The crudes tested were Forties, Ninian, Kuwait, Kirkuk, Arab Medium, Basrah and Zuluf. A lub oil basic grade (BG20S) was tested for comparison. The dry oil dielectric constants are shown in Table 1, referred to $20^{o}C$.

The spread is from 2.235 (Basrah) to 2.476 (Zuluf) much less than suggested by the literature but measured for only a few crudes of interest to BP. The ϵ values for the two North Sea crudes Forties and Ninian are very similar (2.301 and 2.280), as was expected for similar crudes.

1.2.5 Calibration for Water Content

The results from these tests are shown in Fig.3, but with the zero point for each crude shifted to a common value corresponding to a dry oil ϵ value of 2.2. Fig.3 shows that the calibration for all the oils tested was sensibly the same, excluding the shift in zero. For water contents below 40% v/v the calibration is independent of water salinity, for most practical applications.

From all our results, the relationship appears to have the form:

$$\mathrm{Ln}\epsilon_{\text{mixture}} = \mathrm{Ln}\epsilon_{\text{dry oil}} \times (1 - V) + \mathrm{Ln}\epsilon_{\text{water}} \times V$$

where Ln is the natural log

ϵ is the dielectric constant of the stated material and taking the empirical value for water in this closed emulsion situation as 55.

V is the volume fraction of water in the oil/water mixture, for values up to V = 0.4.

1.3 Accuracy Considerations

1.3.1 Target Accuracy

The equipment is intended to measure water in crude oil for fiscal applications. The aim therefore must be to attain the same or better accuracy (precision) as the alternative and presently accepted route using automatic samplers and laboratory testing of the composite sample.

The three standard IP/ASTM laboratory test procedures for water in crude oil are IP359/82 (= ASTM D.4007-81) Centrifuge method: IP358/82 (= ASTM D.4006-81) Dean & Stark Distillation method and IP356/82 Karl Fischer titration method (for North Sea crudes).

In view of the importance of this measurement, the laboratory test procedures have recently been reviewed (as indicated by the suffix dates) and their precision data revised. Now for both the centrifuge and distillation tests, the precision data cited applies only to water contents below 1% v/v. Repeatability and reproducibility are respectively 0.12%/0.28% v/v water for centrifuge and 0.08%/0.11% v/v water for distillation. The Karl Fischer precision is cited only up to the 1.5% water level, for which the figures are 0.02%/0.06% v/v water and better by a factor of two at the 0.5% water level. Internationally at this time, the centrifuge method is still very widely used, despite having the worst quoted precision of the three methods.

No data appears to be available for the overall accuracy of the measurement procedure involving automatic sampling/sample transfer/sample handling/sub-sampling/lab testing. Clearly, it cannot be better than the performance of the final lab test and all the qualitative evidence indicates that it is very much worse. Problems with sampling equipment and subsequent sample homogenisation have been widely reported. Spiked crudes present special problems.

Taking even the most optimistic view of the capabilities of existing sampling/lab testing systems, the **best** accuracy that is likely to be achieved is 0.05% v/v water. A more realistic figure, still with a good degree of optimism, is probably 0.1% v/v water, for relatively low water contents.

So, for the capacitance technique, our target was set initially at achieving 0.05% v/v accuracy at the 1% v/v water level for the bulk transfer, and being prepared to accept an accuracy of 0.1% v/v.

It is important to recognise and to emphasise that the capacitance technique is just as dependent as automatic samplers on drawing its primary sample from a fully representative location in the pipeline, and on the same equipment as samplers for flow proportioning the measurement.

An important and fundamental difference between samplers and the capacitance method is that the latter measures the instantaneous water content continuously and integrates the reading over the whole operational period. The capacitance equipment therefore has to be able to measure water contents from zero to 100% v/v (or more typically from zero to say 40% v/v) at any instant. These high water contents are of relatively short duration, since the overall parcel water content is generally less than 1% v/v. The accuracy required of the

capacitance system at high water contents needs to be the same in relative terms as aimed for in the bulk average figure, namely a target of 5 percent of the amount present and prepared to accept up to around 10 percent of the amount. Thus, at the 40% v/v water transient level, an error of ± 2% v/v could be considered good and we could accept ± 4% v/v error.

1.3.2 Estimated Accuracy

The accuracy of the capacitance system in service depends on several factors, viz:

a) the ability of the mechanical/electronic assembly to measure electrical capacitance, accurately and reliably:

b) establishing the relationship between the dielectric constant and the water content of the crude oil mixture in the cell:

c) any extraneous effects from gas bubbles, wax deposition or water particle size/shape; also flow proportioning errors.

From our evidence so far, the measurement capability of the primary cell assembly/electronics is excellent. The sensitivity corresponds to better than 0.01% v/v water, with linearity of the same order. The temperature coefficient is negligible. Long term stability is good, with no discernible drift over several days.

Therefore, excluding any extraneous effects (below), the accuracy will depend almost entirely upon knowing the relationship between the water content of the crude oil mixture in the cell and the measured electrical capacitance.

Our work on a limited range of crudes has shown (Fig.3) that the change in capacitance with change of water content is very similar for all crudes, with a spread of only a few percent relative about the mean sensitivity. Since our target accuracy (+0.05% v/v in 1% v/v) corresponds to five percent relative, this spread of sensitivity should not be too significant and it is only pertinent to multi-crude service. More work is in hand to establish precision data in this area.

The dominant factor is the dielectric constant of the dry oil, which dictates the zero setting for the measurement. As shown in Table 1, different types of crude have constants which differ by amounts which are large when expressed in terms of equivalent water content. Therefore, on any application, the accuracy of the capacitance technique will be determined largely by the constancy of the dry oil dielectric constant (= crude oil type) during the measurement period.

For production applications - e.g. Forties Field - the crude oil type is expected to remain sensibly constant. This may also apply to many pipeline applications. If applied to a line with multiple field inputs with fluctuating proportions of different crudes/condensates, then problems could arise. In practice, such changes may be self-evident from the instrument reading, since a change of oil type would produce an apparently large and unexpected change in 'water content' in either the positive or negative sense. On-line density monitors may give useful guidance. For refinery import

applications, the crude type is expected to change for each shipment and the calibration procedure proposed is described later. The assumption is made that each shipment is only one crude or a uniform mixture.

Any gas bubbles in the measured crude would depress the dielectric constant and produce an incorrect low reading. It may also produce a noisy signal and therefore its own diagnosis. Gas bubbles were not apparent during our prototype studies on VLCC discharges at a refinery.

Any wax deposition in the flow cell would reduce the active volume and thereby reduce the sensitivity to water and probably the zero point. We would expect the installation to be designed to avoid waxing: but if it occurs it is likely to affect each half of the dual cell assembly differently and therefore become evident by the discrepancy between the two independent channel measurements.

1.4 Potential Applications

1.4.1 Offshore and Production Pipelines

The capacitance technique is expected to be particularly attractive for offshore duties on spiked and high pressure crude, both because of the importance of the water content measurement and the severe problems experienced with the automatic sampling technique.

BP is in course of installing a Class 900 system on an offshore platform.

This package, in common with our general approach for offshore equipment, will be as simple as possible to maximise reliability Fig.4.

It will be a dual cell, with each cell having a single range of 0 to 5% v/v water. Each cell will have its own dedicated electronics unit/output signal which will be connected to the platform's central recording facility. The unit will not be flow proportioned. The system will provide just the instantaneous water content, without integration.

For 0 to 5% range, the calibration will be assumed linear. The zero will be set on the platform, to suit the oil and the relatively high operating temperature of ca 50-60^{o}C.

1.4.2 Refinery Import Lines

In many respects the refinery import duty is more demanding.

The equipment must cope with a wide variety of different crudes having different dielectric constants. The water content during the discharge can vary from zero to 100%. The oil flow rate also changes throughout the discharge, such that flow proportioning the water content measurement and continuously integrating the signal to give an overall cargo figure is essential.

Apart from the pressure rating of the cell, the primary equipment is the same as for the offshore duty, with the flow cell installed in a fast sample loop.

However, the electronics package associated with the flow cell would necessarily be more sophisticated, to perform the flow weighting and integration functions together with other facilities. Endress and Hauser are now producing such a package using microprocessor technology.

The refinery application poses two important questions, namely:

a) How to cope with the different crude oil types, each with a different base oil dielectric constant, hence instrument zero.

b) How to cope with water contents above the normal range for good capacitance measurements, i.e. above ca 40% v/v.

At this stage of the development, our approach to both these questions is dictated primarily by the need to retain simplicity, in order to ensure reliability and modest cost. Nevertheless, this approach may well be also the best in the longer term, though the possible alternative of using a differential (wet/dry) technique cannot be ignored.

To cope with different crudes, advantage is taken of the fact that the sensitivity to water is similar for all crudes: only the zero reading will be affected. Assuming that for each cargo the crude type is known and remains constant throughout the discharge, then the procedure would be as follows:

i) set the crude oil type into the controller: this data is or will be available. This sets the instrument zero at approximately the right point. (It need not be correct).

ii) During the main part of the discharge, when the water content is at its 'natural' low level (as indicated by the monitor itself), draw a spot sample and measure its water content by the standard test method, e.g. Karl Fischer. Compare the sample result with the monitor reading at the time the sample was drawn, to establish any zero error in the monitor.

iii) At the completion of discharge, apply the known zero error to the overall average reported by the monitor.

To cope with high water contents, above 40% v/v, our simple approach assumes that such high levels will be transitory and make little contribution to the average water content. This assumption is fully in line with our cargo studies described later.

Monitor readings above 40% v/v are greatly affected by the salinity of the water, which generally is an unknown factor. We therefore take the view that high readings will not be quantitative. Instead, we have proposed to E & H that the equipment be programmed in such a way that for all outputs beyond the normal range (40% v/v), a nominal value such as 60% v/v (selected by the user) would be applied automatically in calculating the overall average. We estimate from our studies that the error instroduced by this simple expedient will be negligible. In practice, water contents above 40% are far from common, even as transients.

1.5 Conclusions

The results to date are very encouraging and give clear indications of the potential capability of the capacitance technique to measure water in crude oils to the accuracy required for fiscal duties. Further on-line testing is now required to verify laboratory data and identify any operational problems.

A system is currently being installed for testing at a BP refinery - and its performance will be compared with the latest types of grab sampler.

2. PRACTICAL APPLICATIONS

2.1 Water Discharge Characteristics (Ship to Shore Transfers)

2.1.1 Introduction

When sampling crude oil for water content using automatic grab (discontinuous) samplers there is some doubt as to the overall representivity of the lab. sample if water has passed down the line in the form of transients (slugs). Computer simulations conducted in-house have demonstrated that transients could have significant effect if they formed the major contribution to the overall water content and their period of existence at the sampling point was equal to or less than the sampling grab interval. If such conditions existed then it would be essential to modify the sampling process to ensure that transients, as presented to the sampler were sampled representatively. The sampling process using conventional grab sampling techniques can be modified either by increasing grab frequency, or by modifying the transients with suitable sample conditioning (1 & 2).

Increasing the complexity of the sampling systems tends to result in reduced reliability. Unless it is known that transients affect results significantly extra sophistication is unnecessary and undesirable.

Consequently work was initiated on establishing the existence or non-existence of such transients and their importance to the overall sample representivity.

To do this we installed a continuous capacitance water in oil monitor in a fast loop of an existing Jiskoot Series 300 sampler on a 30 inch ship to shore crude import line.

Signals from the existing Detectronics Ultrasonic Doppler Flowmeter, which was used for the Jiskoot flow proportioning, were monitored together with the capacitance meter on a two pen recorder to give an overall picture of water content characteristics.

The initial intention of this work was to look solely at transient behaviour of the water content. However, the scope was extended to gain some experience on the continuous capacitance monitor as an alternative to discontinuous sampling.

2.1.2 Test Installation

The test installation is depicted in Fig.5. The sample probe and sample loop line sizing were chosen to present as large an area as possible to the main line whilst maintaining a good sample velocity. The probe was mounted vertically in the line with a minimum design velocity of 1.5 m/sec (i.e. using 10 mm ID tubing @ 7 litres/min.) to ensure no drop-out of water.

The probe was mounted in an area of high turbulence just downstream of a blanked Tee-section (Fig.6). The representivity of the sample at this point had previously been demonstrated by work done by others with manual sampling at this location and at the jetty head on the boom gantry.

The capacitance probe was mounted downstream of the sample extraction pump. The pump discharge pressure was around 30 psig above line pressure which reduces the probability of entrained gas affecting measurements. Also the pump was used to break-down any large water droplets and present a consistently mixed sample to the probe.

Signals from the capacitance meter and the flowmeter were fed to a two-pen flat bed recorder. The recorder traces were integrated manually to assess water contents, transient contributions and flowmeter performance. A PET computer was added at a later date to aid data integration.

The flowmeter signal was also being used to proportion the Jiskoot sampler. Thus any defect in the flow measurement affected the sampler and continuous measurements equally.

Nominal capacitance probe calibration is shown in Fig.7.

2.1.3 Water Profile Observations

Typical water content profiles associated with ship "free flow" discharge flow patterns are summarised in Fig.8 and relative quantities discharged for each stage are summarised in Tables 2 and 3.

Although the profiles are fairly predictable in appearance the relative quantities are by no means so. In two cases the initial line clearing operations accounted for 40 to 50% of the total water discharged and in one case 30% of the total water came over in the final strippings.

Line clearing (emptying of the lines of a previous cargo if of a different type) and stripping operations are generally carried out at lower flowrates than the main discharge. They represent less than 10% of the total quantity of cargo discharged but can contribute up to between 50 and 60% of the total water. This highlights the importance of good flowmeter performance over the operating range for consistent sample representivity. Also because such large quantities of water can be present during these periods good sample line mixing is essential. A water level of 100% was measured (manually sampled) and levels of around 20 to 40% were not uncommon.

Generally, our observations have shown that:

a) High water contents in the form of transients appear at the beginning of discharge and during tank stripping at the end of discharge.

b) Water transients will tend to occur when there is an abrupt change of flowrate due to pump failure/restart, suction changes, tank changes if not on common suction, etc.

c) During main discharges the water contents fall to values of 0.3% v/v and less as conditions stabilise and separated water is not picked up as in a) and b) above.

d) Normal practices of manual sampling at the jetty head and slumping of samples will invariably lead to erroneous estimations of water content due to the water discharge distributions and associated flow distributions.

e) For the range of ships observed flow meter readings varied between a minimum of 10% to a maximum of 90% range. A flowmeter with a turn-down of 10:1 is therefore necessary.

f) Because of the high water contents at low average flows and low water contents at the high average flows consistent accuracy of the flowmeter in terms of actual reading (not span) is necessary.

Typical water content traces against flow traces at different stages in the discharge are presented in Figs.9, 10, 11, 12.

2.1.4 Water Transient Characteristics

The Jiskoot sampler operates on an 86 second cycle (= 1000 cycles/24 hours). In order to arrive at a reasonable estimation of a water profile it is accepted that around 10 samples of each transient are required. For the purposes of this test we therefore looked at transients of 10 minutes or less as being capable of producing sampling errors.

Table 3 summarises these transient distributions and contributions during typical discharges. It is seen that in genral contributions are less than 0.04% v/v water which is insignificant in terms of other problems associated with sampling, sample handling and analysis. One example (not shown) of the contribution being 0.14% v/v water was recorded, however, consideration of 5 minute transients revealed the contribution was quartered to 0.04% v/v water. At the worst the Jiskoot could over estimate each transient by 1½ minutes which is approximately 30% (on a 5 minute basis) of 0.04% equal to 0.01% v/v water.

As contributions by 5 to 10 minute transients are of the above order it is difficult to justify:

a) transient time stretching techniques.

b) high frequency grab samplers with small grab volumes

Transients of less than 20 secs. were not observed and those of less than 1 minute were very infrequent, no more than 1 or 2 at most per discharge with negligible contribution to the cargo water content.

Statistically it is evident that the Jiskoot Series 300 type sampler only fails to catch representative samples in the presence of transients of less duration than the sample cycle time of 86 secs. and of such number/ magnitude to contribute a substantial proportion of the water content. These transient distributions are not evident.

2.1.5 Comparison of Continuous Monitor Results with the Grab Sampler

For this comparison it was not necessary to worry about representivity of sample from the line or accuracy of the flow proportioning flowmeter. This was because both "samplers" were on the same fast loop downstream of the pump and both used the same flowmeter signal.

However, the capacitance cell is known to be affected by the type of crude and temperature. It was therefore necessary to take manual samples at various times throughout each discharge to establish a calibration.

For the purposes of these tests, linear calibrations were considered sufficient and for each discharge zeros and sensitivities were established. Water contents were integrated with flow based on the nominal calibration (Fig.7) and then adjusted.

Where data was available in sufficient form to enable us to calibrate our probe against lab. samples (with due allowance for temperature effects) integrated mean water contents agreed fairly well with the Jiskoot results (see Table 2). These results were only obtained as an "aside" to the main objective of this work but serve to encourage us that continuous monitoring using capacitance techniques is a viable proposition.

It is interesting to note that on one occasion the grab sampler failed, but by this time we had sufficient confidence in the corrected continuous monitor result to use that for the refinery's official figures for water content received from the ship.

2.2 Water Profiling Tests

2.2.1 Introduction

At the end of 1981 it became apparent that in order to be able to specify economically and technically optimised solutions for the full range of BP's applications for automatic samplers, we would need to extend our knowledge and experience of the behaviour of water and crude oil mixtures in large pipelines. In particular we were interested to study the water/oil homogenising efficiency of in-pipe jet mixing systems.

2.2.2 Profiling Equipment

The aim of the test programme was to demonstrate that jet mixing could achieve homogeneity in the line and to measure the power required to do so. A key factor was to be able to simultaneously measure water contents of the mixture across the line profile at several locations beyond the jets. Based upon our separate development of the electrical capacitance technique for measuring water in crude, we decided to use this approach to monitor the water profiles at three positions. The alternative, of using manual sampling

and testing, would have been very slow and tedious for the number of tests required. Absolute accuracy was not deemed important at this stage of the study.

Three sets of profiling probes, each with six offtakes spaced equidistant across the pipe were made, generally according to draft ISO 3171.

The offtake inlets were designed to face the flow and minimise end effects. Connecting lines between the probes and the capacitance cells were selected to ensure fast flows and minimise tendency to separate the oil and water before entry to the cells. Flow rates at the probe entries were arranged to be nominally isokinetic.

2.2.3 Capacitance Cells and Water Profile Display Arrangements

The water contents of the samples were measured using eighteen capacitance cells. These were frame mounted, and piped and wired in groups of six.

Outputs from the capacitance cells were fed into a Commodore computer and presented as an instantaneous graphic display of the water profile (Fig.14). This is a unique feature of the test system. Facilities were provided to change the display range from 0-5% water to 0-30% water, and to print out the resultant bar chart. Note that water contents greater than 30% volume would appear on the computer readout as nominal 30%. The computer software also included the facility to zero all probe outputs.

2.3 Discussion of Applications

2.3.1 Water Discharge Characteristic Testing

The application of a continuous monitor allowed us to monitor the water content of 17 cargoes discharged to a Refinery over the period February to June 1982. Cargoes (the majority of which were the final parts of "part cargoes") ranged from 47,000 to 118,000 tons of Arab Light and Medium, Forties and Kirkuk crudes with 0.1 to 1.3% volume water.

We found that transients were less frequent and less severe than generally expected and are not a problem. Automatic samplers with grab intervals as long as two minutes would take a representative sample. There was no evidence to support the current international proposal for taking at least 10,000 sample grabs for each transfer.

No transient less than 20 sec. was observed. Only one or two transients less than 1 min. occurred during each discharge and their contribution to the total water content was negligible (less than 0.01% vol). Even the **total** contribution of **all** transients up to 10 min. duration was on average less than 0.04% volume water, for the cargoes studied.

Oil discharged during line clearing and stripping is typically only 10% of the cargo but may contain up to 60% of the total water. As these operations combine low flow rates with high water contents (sometimes up to 100% volume water), the importance of accurate flow proportioning and good line mixing for the water measurement system are very obvious.

We were also able to compare the overall water content calculated from the continuous monitor with that obtained from the Jiskoot Series 300 sampler (Table 2).

Where data was available in sufficient form to enable us to calibrate our probe against lab. samples (with due allowance for pressure effects and temperature effects) integrated mean water contents agreed fairly well with the sampler results (see Table 2). The average error between the two measurements was only 0.06% vol. water. This is a useful validation for both techniques.

Whilst the foregoing confirms that transient behaviour in ship to shore discharges does not merit grab frequencies greater than one per minute and/or transient stretching techniques it does not contradict the argument for continuous monitors.

The advantages of continuous monitoring were shown in its ability to observe discharge conditions and give an instantaneous integrated value of water discharged at any time during operations. Calibrations, if necessary, can be verified very quickly against spot lab. samples and above all any discrepancies argued and agreed whilst the ship is still alongside.

Only one problem with continuous monitors was noted. If flow in the line stops the monitor will continue to give a reading that can drift around depending on the settling and recirculation going on in the sampling section. This is easily accounted for in the integrated values because the flow is zero.

2.3.2 Water Profiling Tests

This application demonstrated admirably the superiority of continuous techniques over discontinuous techniques in the ability to obtain simultaneous real-time information on water contents (Fig.14).

The data obtained during the mixing trails far exceeded that which would have been possible within the time scale if manual methods of water determination were employed.

This application was purely on instantaneous comparison of readings from each capacitance cell to ascertain water profiles. Absolute calibration was not essential and provided each cell's calibration was stable effects of varying crudes and temperature were inconsequential.

The technique has since been applied at a major VLCC terminal in Europe and will be applied to our own further studies shortly at a refinery.

'Automatic' profiling, e.g. using this capacitance technique is recognised in draft ISO 3171

2.4 References

1. a) General Review of Automatic Pipeline Sampling and Continuous Measurement Techniques for Determining the Water Content of Crude Oils by W.H. Topham.

   b) Development of a New Definitive Automatic Sampler for Crude Oils by R.C. Gold and M.B. Wilson.

   Papers presented at IMC Symposium on 3/5th November, 1981 entitled:

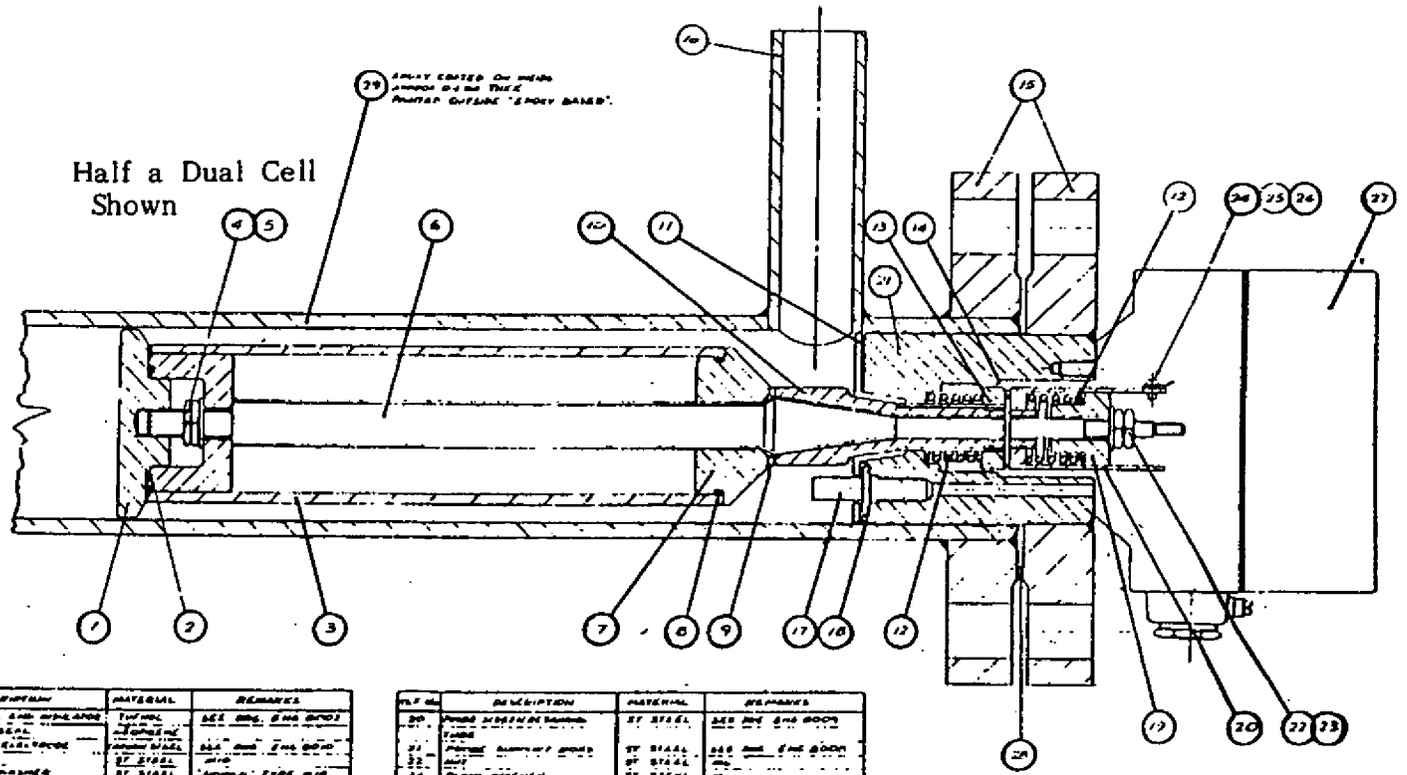
   "Automatic Sampling and Water Determination for Crude Oils".

2. UK Patent No. GB 2 106 408 Multi-Orifice Mixing Device

3. UK Patents Application No. 84 11147 Capacitance Cell for Measuring Water in Crude Oil

ACKNOWLEDGEMENT

Permission to publish this paper has been given by The British Petroleum Company p.l.c.



ITEM NO.	DESCRIPTION	MATERIAL	REMARKS
1			
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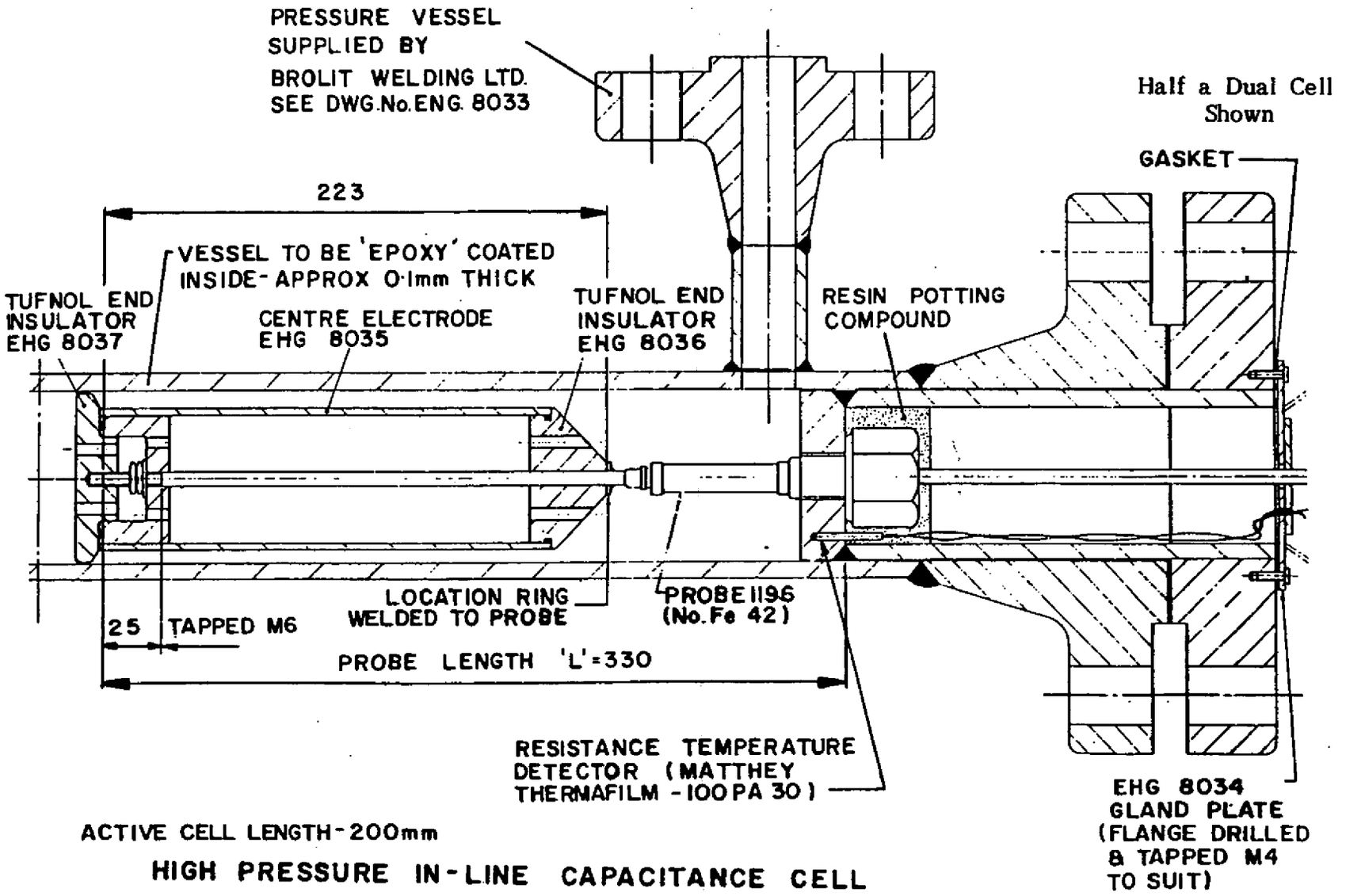
IN LINE CAPACITANCE CELL
GENERAL ARRANGEMENT

FIG.1



ACTIVE CELL LENGTH - 200mm

HIGH PRESSURE IN-LINE CAPACITANCE CELL

FIG.2

CALIBRATION DATA FOR E & H SYSTEM FOR WATER CONTENT IN SEVEN CRUDE OILS.

The points shown for each crude are measured values, corrected to have the same zero point. Measurements were made in a circulating loop test rig.

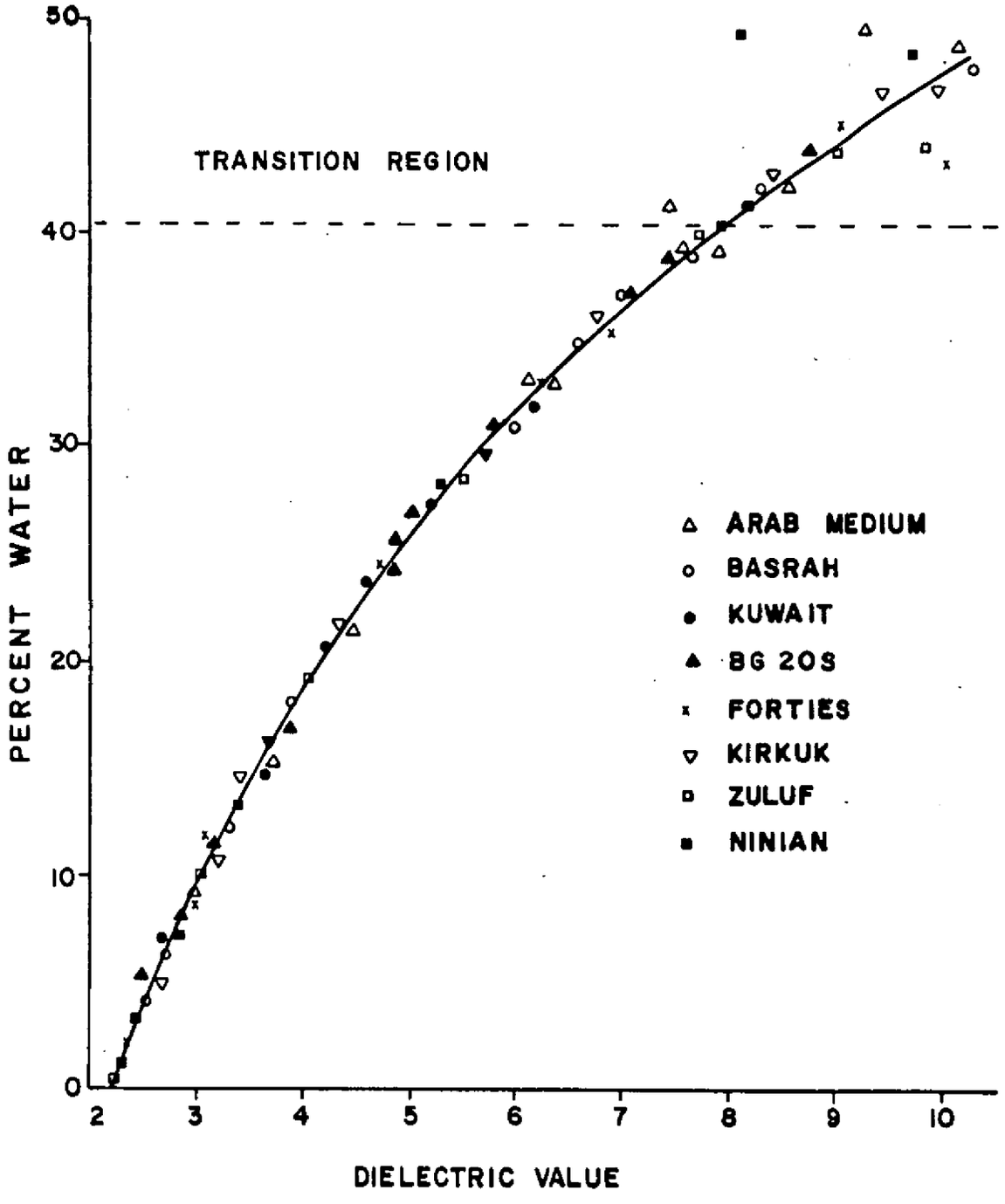
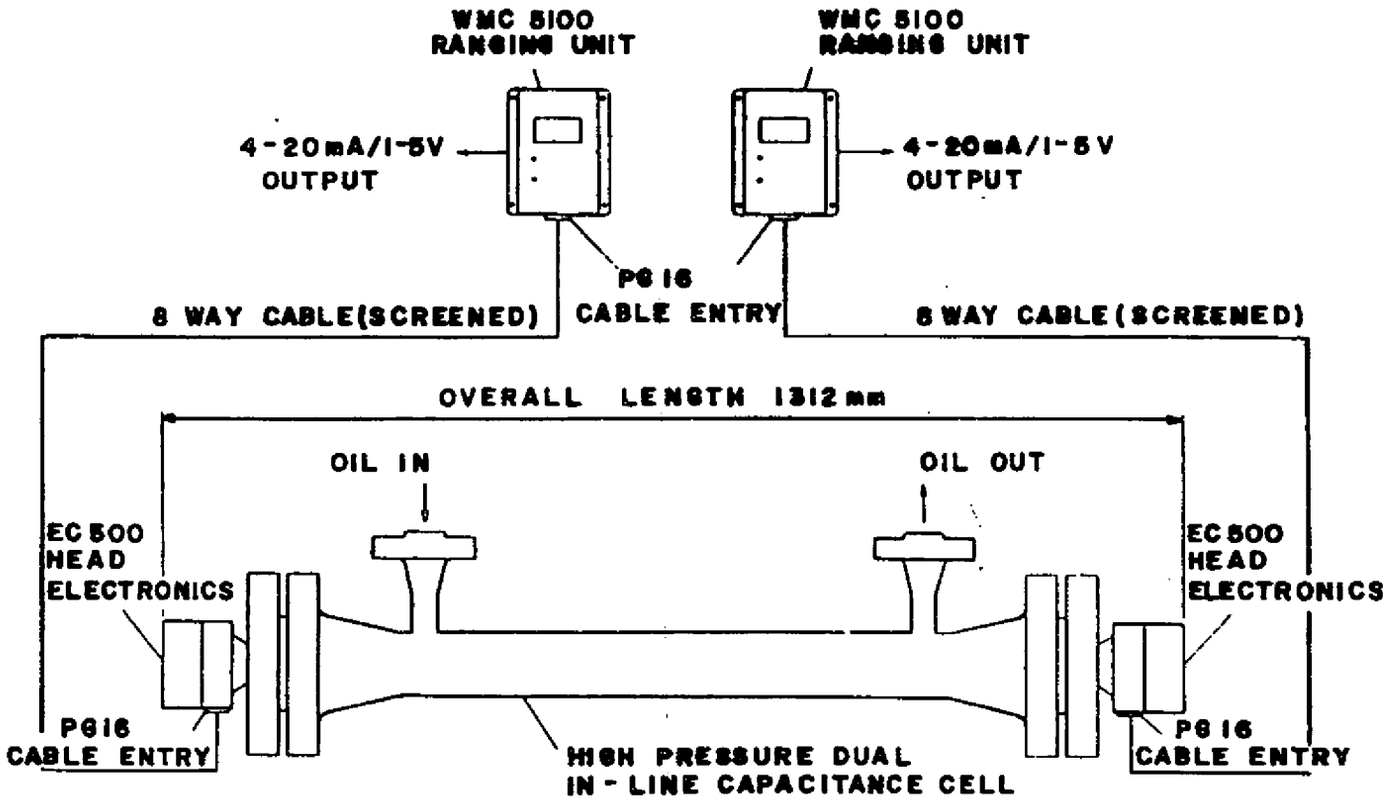
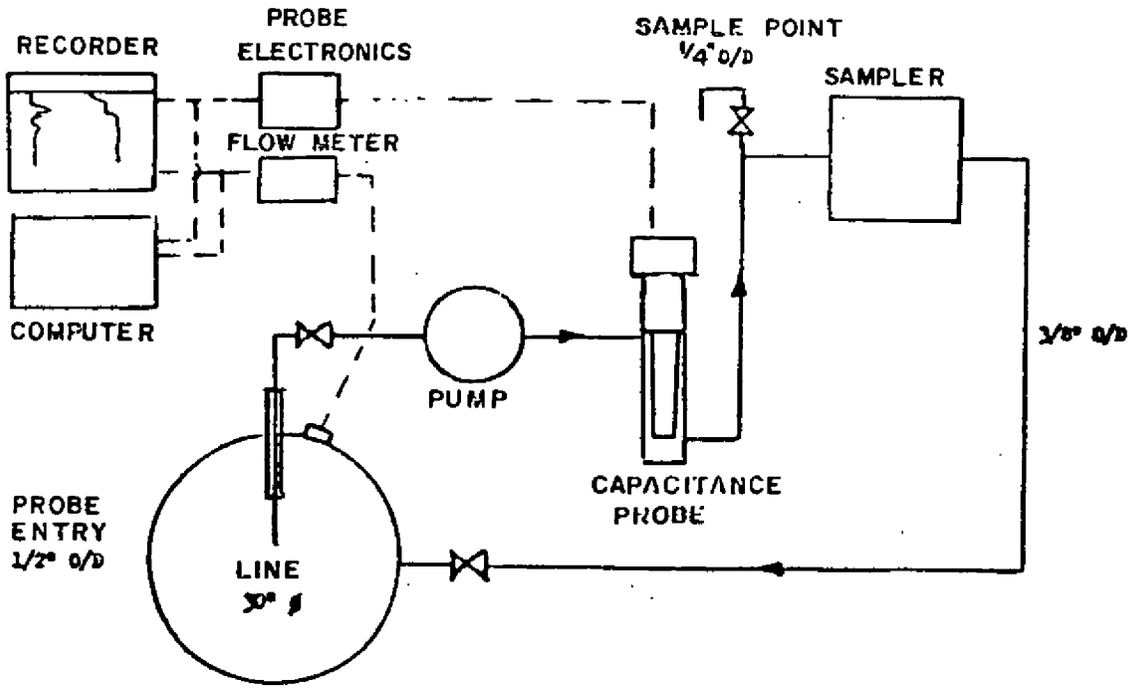


FIG.3



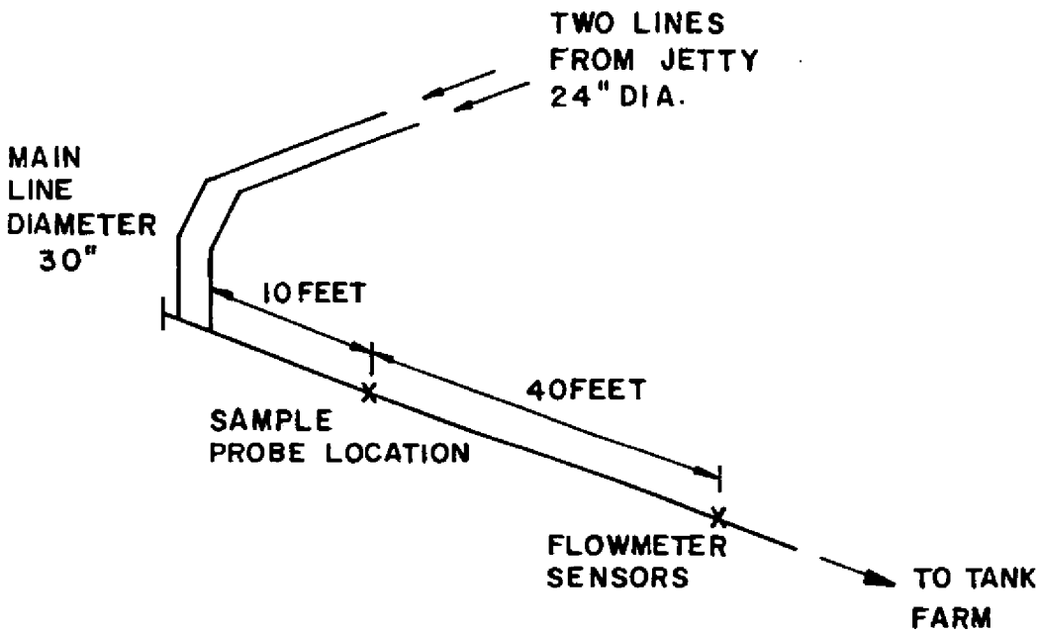
WATER IN OIL ANALYSIS SYSTEM

FIG.4



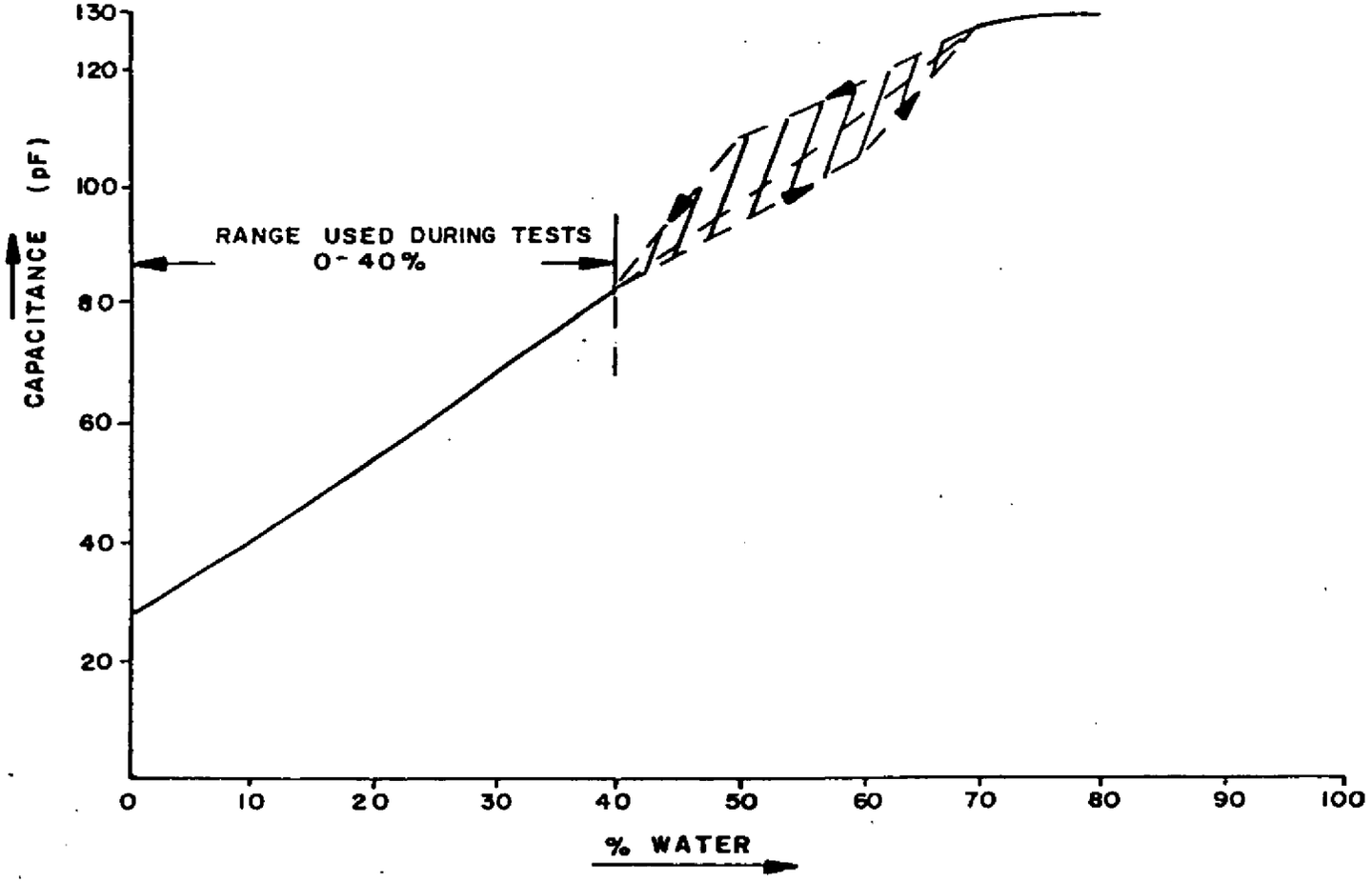
SAMPLE SYSTEM SCHEMATIC FOR A SINGLE CELL CAPACITANCE PROBE USED FOR WATER DISCHARGE CHARACTERISTIC STUDIES ON CRUDE IMPORT LINES

FIG. 5



SAMPLE SYSTEM AND FLOWMETER LOCATIONS

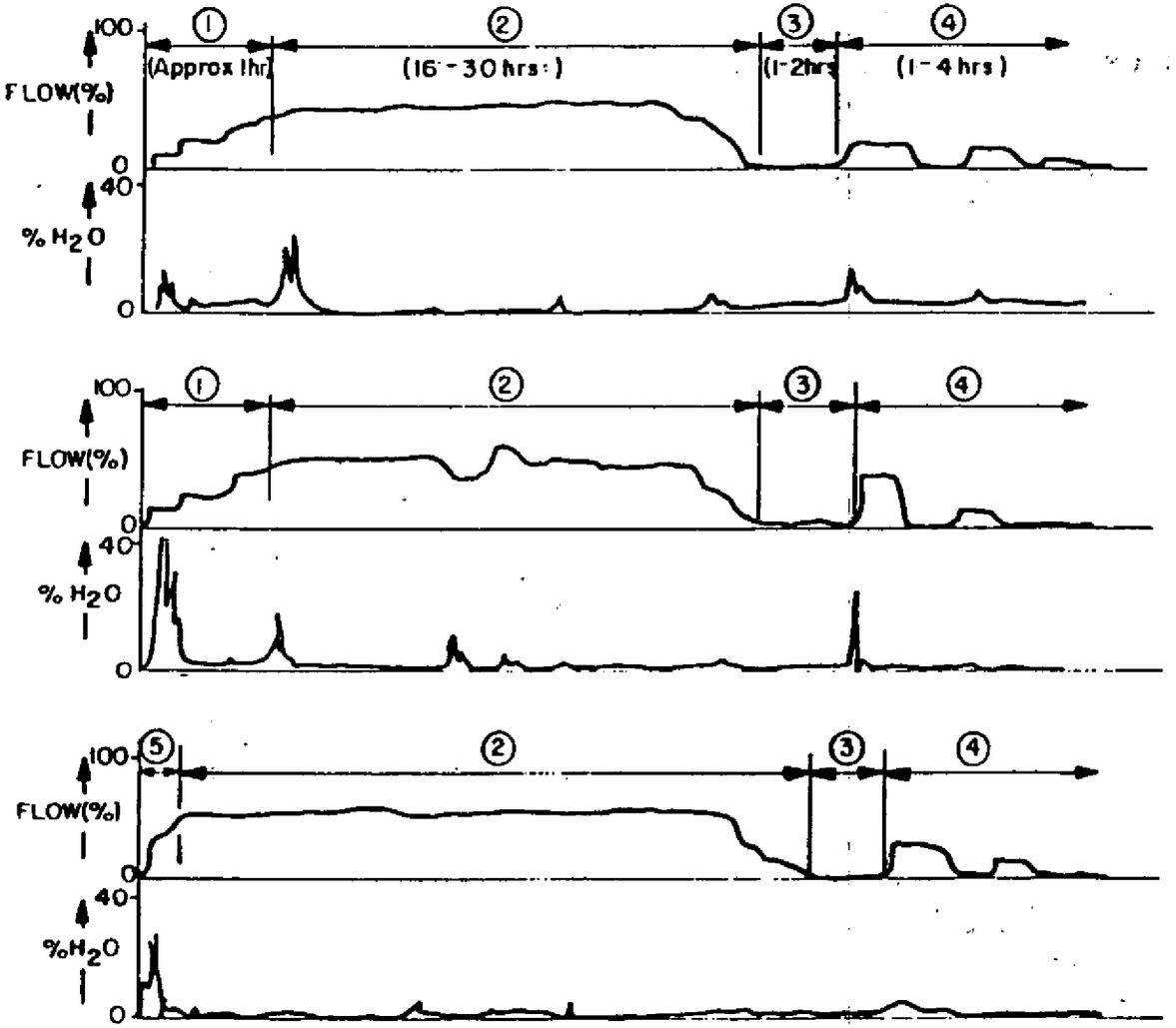
FIG. 6



CAPACITANCE PROBE NOMINAL CALIBRATION

FIG.7

TYPICAL CRUDE FLOW & WATER CONTENT PROFILES DURING SHIP DISCHARGES



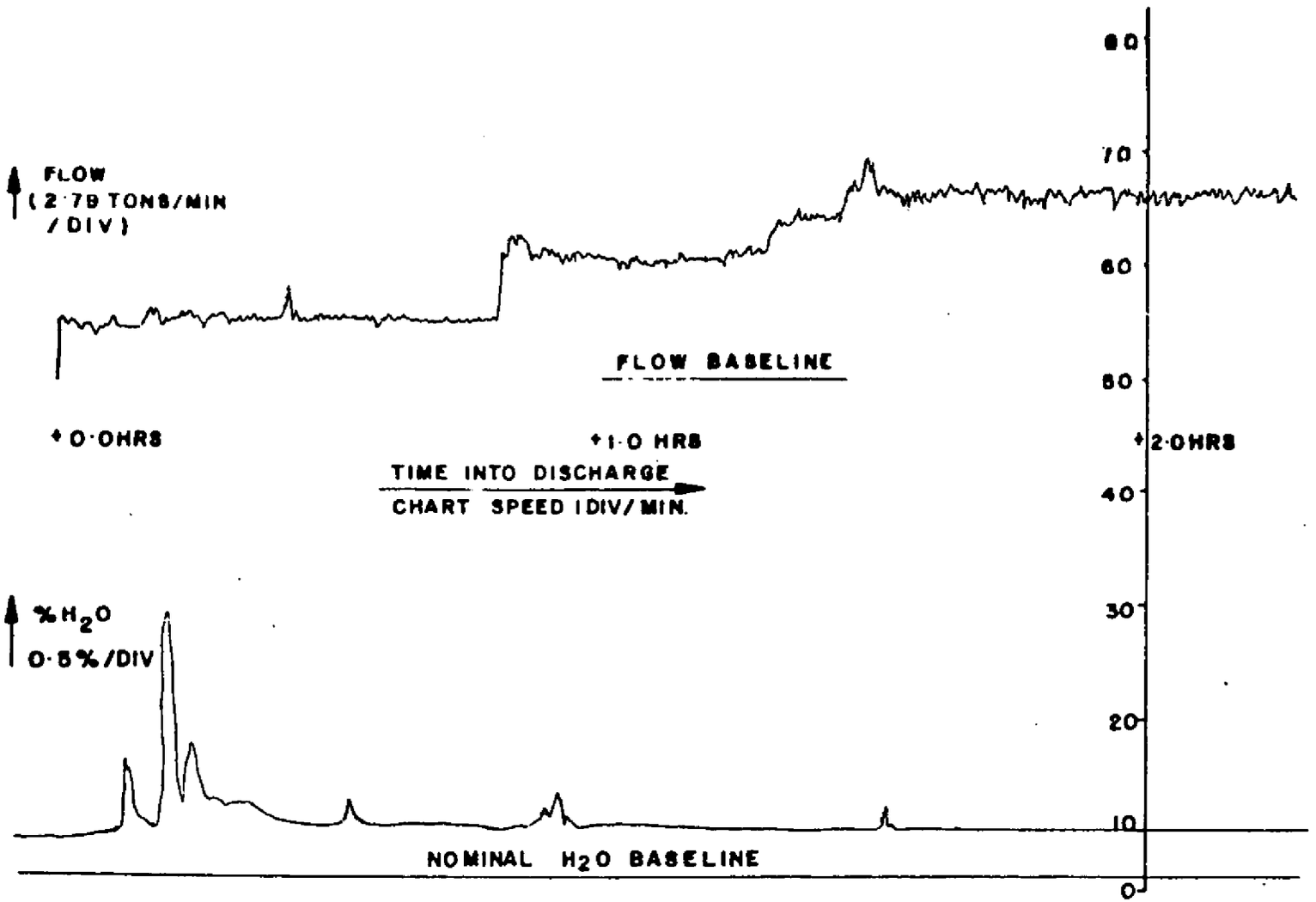
Ⓐ Line Clearing and Main Discharge Steady.

Ⓑ Line Clearing and Main Discharge Variable

Ⓒ No Line Clearing

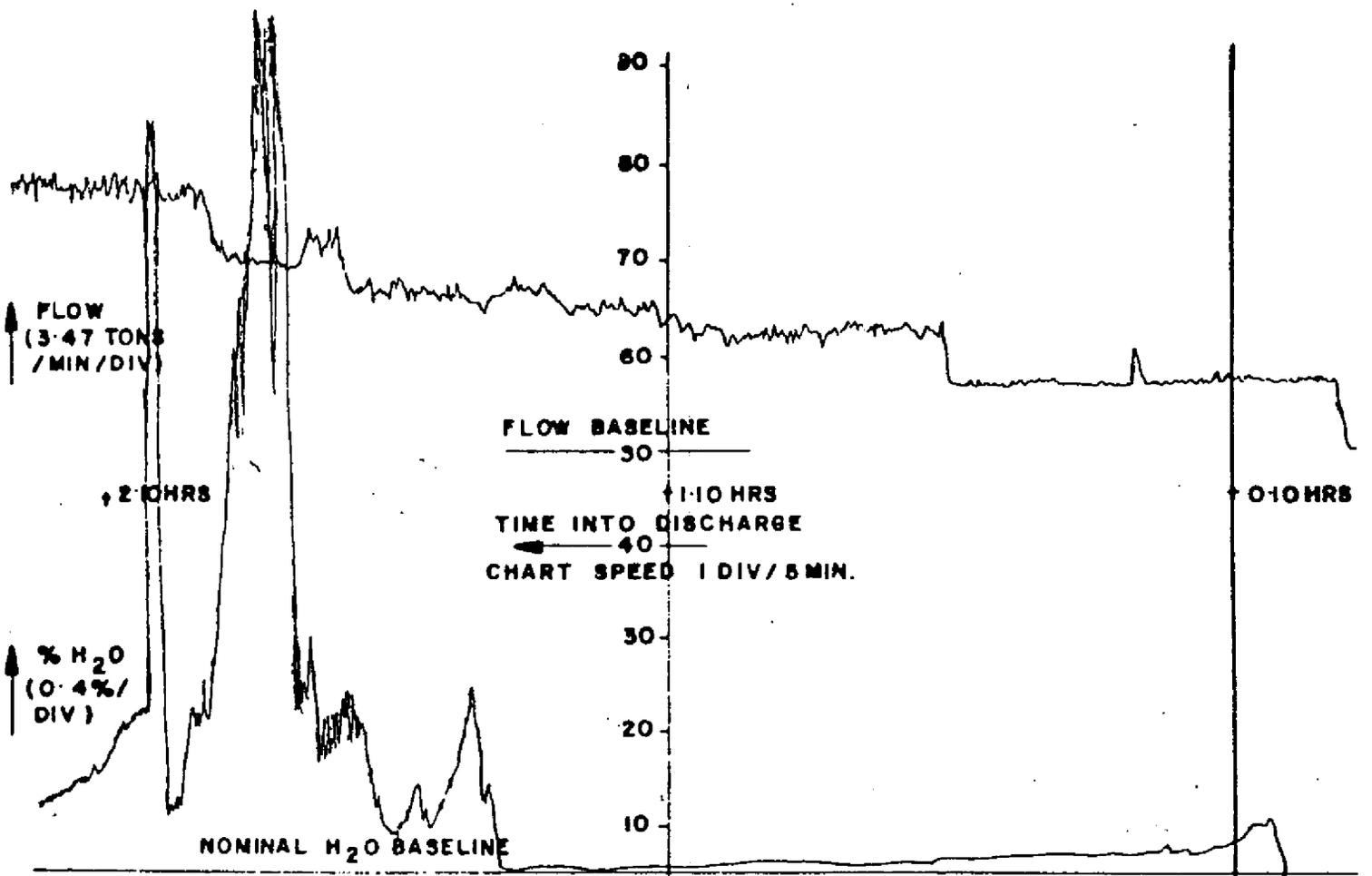
① Line Clearing
② Main Discharge
③ Discharge Suspended for Crude Washing
④ Tank Stripping + Discharge of Strippings
⑤ No Line Clearing, Flow Raised to Main Discharge Levels Within 5-10 mins

FIG. 8



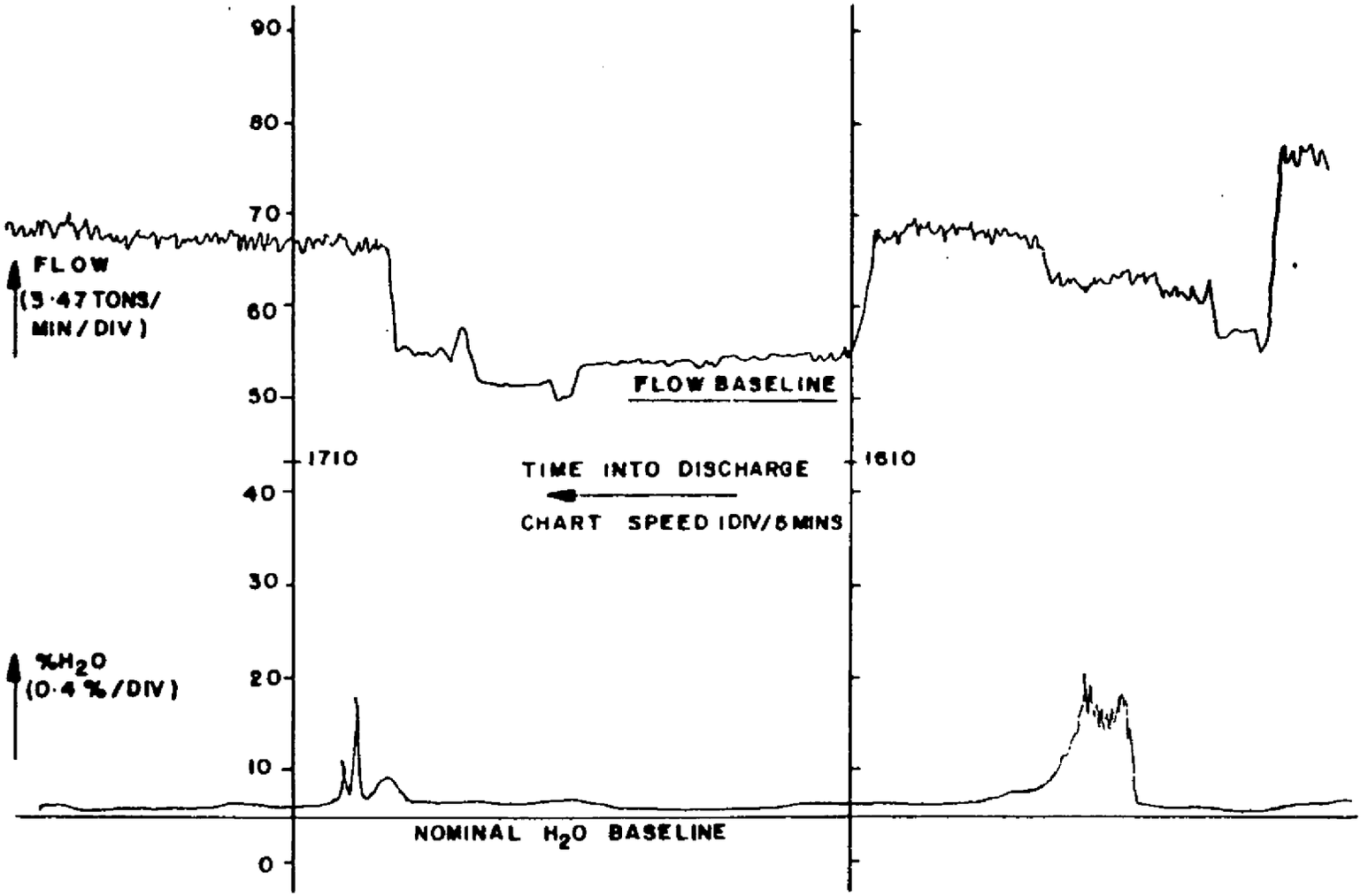
TYPICAL PROFILES FOR FLOW AND WATER AT BEGINNING OF A SHIP DISCHARGE

FIG.9



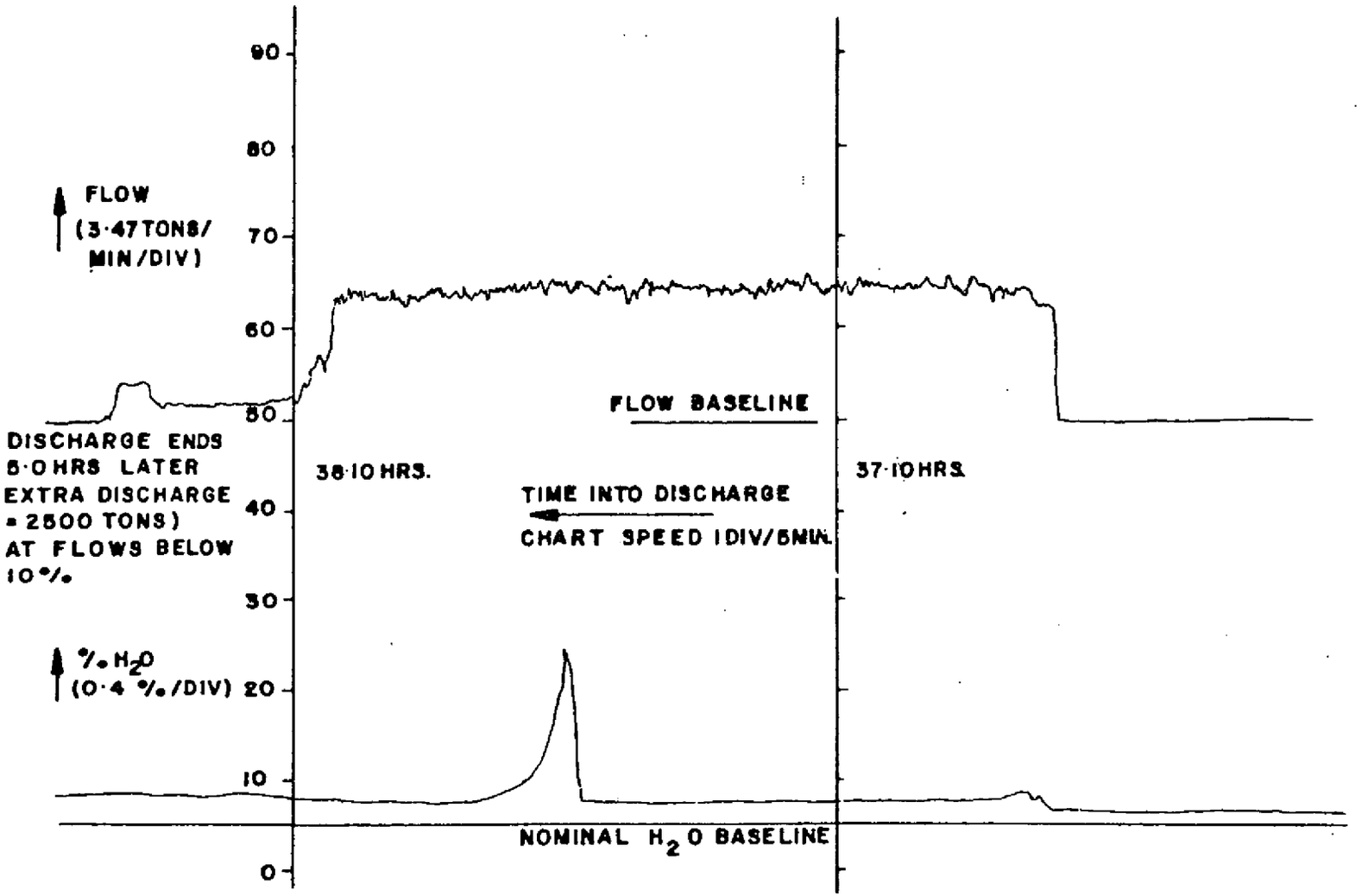
TYPICAL PROFILES FOR FLOW AND WATER AT BEGINNING OF A SHIP DISCHARGE

FIG.10



TYPICAL WATER PROFILE WITH CHANGES IN FLOW DURING A SHIP DISCHARGE

FIG.11



TYPICAL FLOW AND WATER PROFILES AT END OF A SHIP DISCHARGE

FIG.12

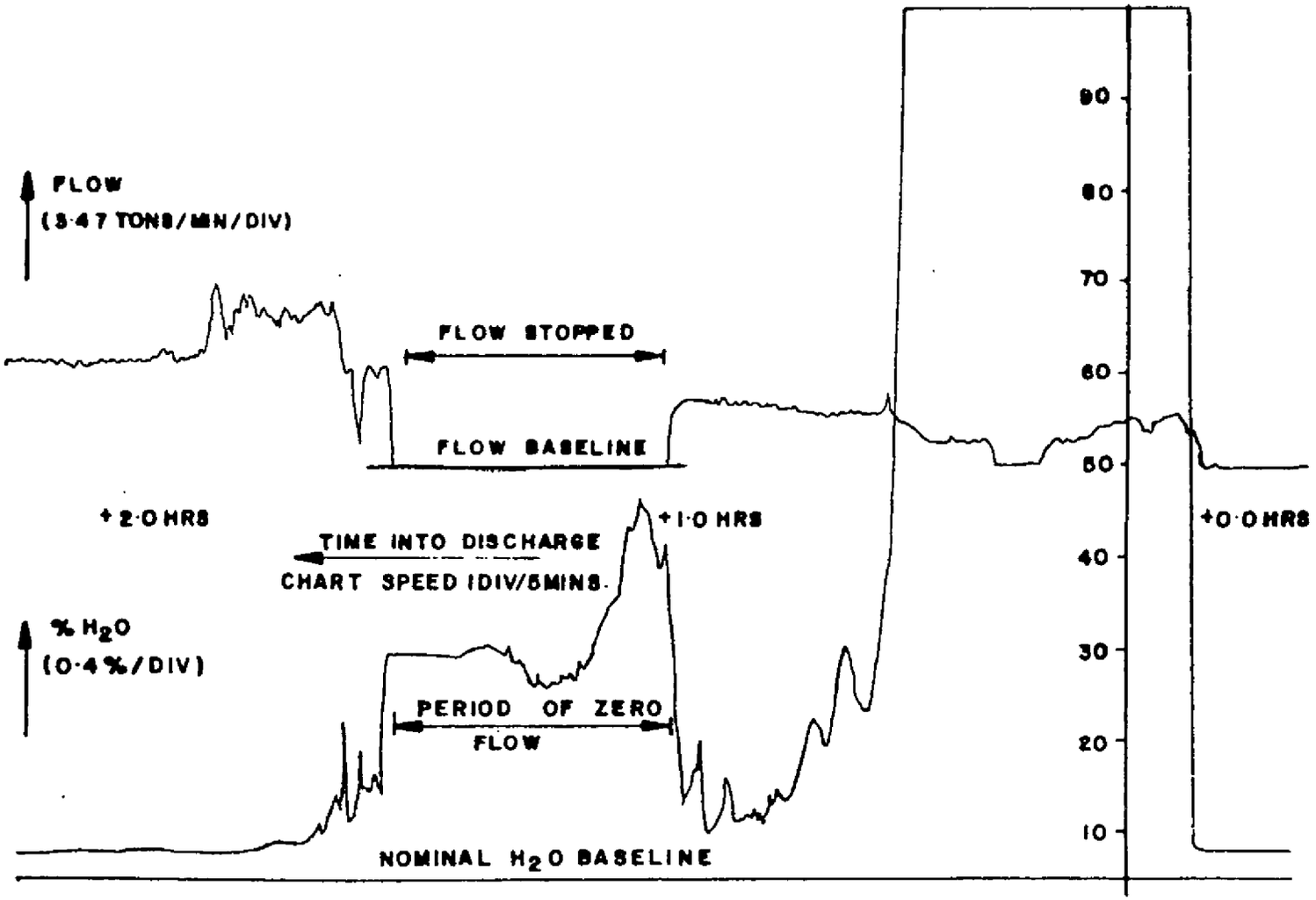


FIG.13

FLOW AND WATER PROFILE SHOWING RESPONSE OF CONTINUOUS MONITOR AT ZERO FLOW.

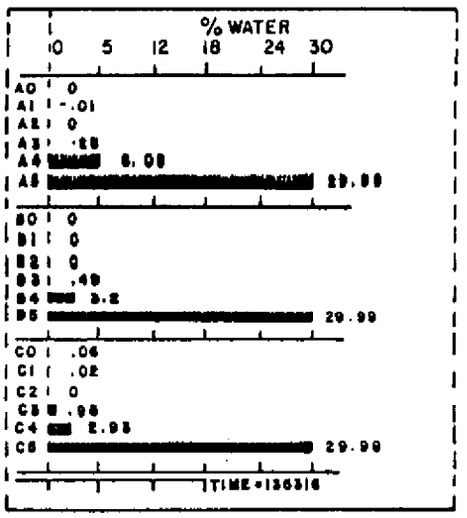
TYPICAL PROFILE PRINTOUTS FOR JET MIXING TRIALS

WATER - 9·6 %
FLOW - 1·6 m/s

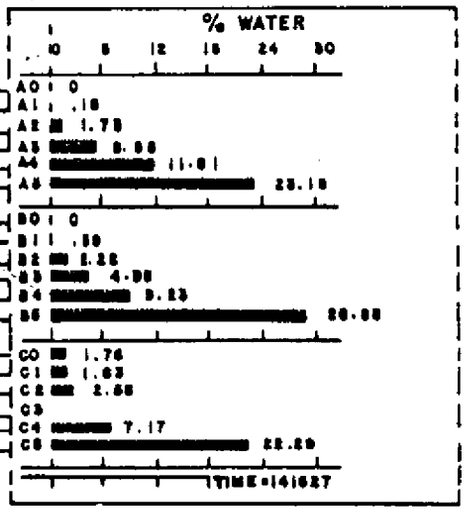
NOTES: 1. PROBE C3 FAILED MIDWAY THROUGH RUN.

2. MAXIMUM PROBE OUTPUT 29·99% ∴ READING OF 29·99% CAN REPRESENT WATER CONTENT TO 100%

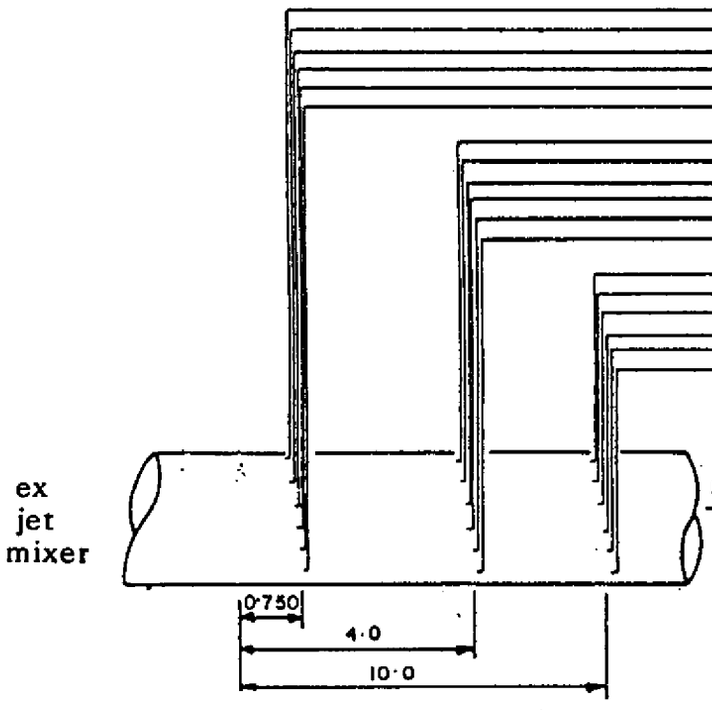
3. PROBE CALIBRATION IN ERROR READING OF 6% REPRESENTS WATER CONTENT OF APPROX. 10 %

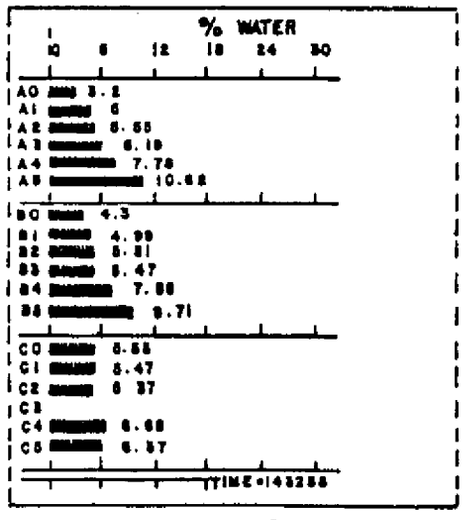


No mixing



Jet mixing at low power





Jet mixing - power increased

PRINTOUTS OF COMPUTER DISPLAY

FIG.14

CHARACTERISTICS OF VARIOUS TYPES OF CRUDE OILS

Crude type	Dry Oil Dielectric Constant (ε) @ 20°C	Temperature Coefficient of (ε) in absolute units	Temperature Coefficient in terms of % v/v water
BASRAH	2.235	-0.0020	-0.028
NINIAN	2.280	-0.0020	-0.027
KIRKUK	2.290	-0.0020	-0.027
FORTIES	2.301	-0.0020	-0.027
ARAB MEDIUM	2.341	-0.0021	-0.027
KUWAIT	2.441	-0.0021	-0.027
ZULUF (Arabian blend	2.476	-0.0020	-0.027
BG 20S LUB OIL	2.152	-0.0021	-0.030

TABLE 1

TABLE 2

COMPARISON OF THE CONTINUOUS CAPACITANCE MONITOR AGAINST THE JISKOOT SAMPLER ON MEAN WATER CONTENT

SHIP	DATE	CRUDE TYPE	TOTAL DISCHARGE (TONS)	TOTAL WATER (TONS)	MEAN % WATER	
					JISKOOT SAMPLER	CAPACITANCE MONITOR
A	3·2·82	KIRKUK	98,000	580	0·64	0·6
B	16·2·82	ARAB MEDIUM	67,000	132·5	0·18	0·20
C	22·2·82	FORTIES	100,000	1,210	1·3	1·21
D	25·2·82	ARAB LIGHT	65,000	269	0·35	0·41
E	16·4·82	ARAB LIGHT	64,000	67·2	0·12	0·10
F	26·4·82	FORTIES	47,000	96·4	0·35	0·20

WATER DISCHARGE DISTRIBUTIONS AND TRANSIENT CONTRIBUTIONS

SHIP	DATE	WATER DISTRIBUTIONS			TRANSIENT CONTRIBUTIONS (1)			% WATER CONTRIBUTED BY TRANSIENTS (1)
		LINE CLEAR (TONS)	MAIN (TONS)	STRIPPING (TONS)	LINE CLEAR (TONS)	MAIN (TONS)	STRIPPING (TONS)	
A	3·2·82	50·1	333	169·9	27	0	6	0·034
B	16·2·82	19·7	106·5	6·3	16	1·6	0·2	0·0266
C	22·2·82	530·3	646·8	32·9	7	14	0	0·021
D	25·2·82	18·4	242	8·6	5	5·5	2·0	0·0192
E	16·4·82	2·3	61·7	3·2	0·42	0·13	0·03	0·0009
F	26·4·82	8·7	86·5	1·2	2·7	6·7	1·0	0·022

NOTES: 1) TRANSIENT CONTRIBUTIONS BASED ON TRANSIENT PERIODS OF UP TO 10 MINS.
2) NO TRANSIENT OF LESS THAN 20 SECONDS DURATION WAS OBSERVED. (TIME CONSTANT OF SAMPLING SYSTEM WAS APPROXIMATELY 5 SECONDS.)
3) TRANSIENTS OF LESS THAN 1 MINUTE WERE OBSERVED BUT WERE INSIGNIFICANT IN NUMBER & CONTRIBUTION.

TABLE 3

Main Index

REVIEW OF COMPACT PROVERS

by

W C PURSLEY

NATIONAL ENGINEERING LABORATORY

PAPER 5.1

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

REVIEW OF COMPACT PROVERS

Dr W C Pursley

1 INTRODUCTION

The compact prover, or small volume prover as it is more properly known, is probably the most significant development in hydrocarbon flow measurement since the introduction of the ball prover more than thirty years ago. These conventional devices, while providing the necessary accuracy of proving, did this at the expense of vast size and weight; the cost of metering stations incorporating such proving devices can moreover represent a significant proportion of a production system whether it be on a platform or at a refinery unloading terminal.

The demand for savings in platform space and equipment weight, together with a growing need for some proving device which could be used as a transfer standard, has led in recent years to the development of several different techniques of pipe proving all of which may be classed under the general title of 'small volume provers'. Table 1 shows a comparison of two typical proving devices, a compact prover and a conventional ball-type prover. It can be seen that more than twice the flowrate can be achieved for only a fraction of the ground area or space occupied.

However bulky and expensive are the ball-type provers in terms of weight and space there can be no doubt about their repeatability, wide range, overall measurement accuracy and general reliability. In order to meet the performance criteria demanded by the various standards and codes, fiscal authorities etc, the small volume devices must therefore be shown to be at least the equal of the conventional provers they are expected to replace. That this is so has not yet been proved conclusively for most of the devices considered in this review.

Nevertheless much test work is in progress, both on site and in laboratories such as NEL where controlled conditions can be obtained and sophisticated measurement techniques can be employed.

The first, and so far the only one, of the small volume provers to be used in North Sea applications is the Brooks Compact Prover, manufactured in the USA, and two papers describing field experience with this device will be given later in the session. Other small volume provers however, both from the USA and the UK, are likely to be used in North Sea area in the near future, and it is the purpose of this paper to review the techniques employed by five of these devices, including the Brooks Prover.

The paper will describe briefly the physical principles of each of the designs of prover and compare and contrast their various features. A closer look will then be taken at one of the essential components in the measurement of volume using small volume provers - pulse interpolation. The paper will end with a discussion on some possible future developments in proving techniques.

2 PROVER DESIGNS

The range of small volume prover designs is growing rapidly. It has been estimated for example that up to a dozen varieties are either available or

are under development in the United States. For the purposes of this review, however, five designs of immediate interest to North Sea operators will be considered. These consist of three provers from the USA, the Brooks compact prover, which is the first device to be marketed and used in the North Sea environment, the Waugh Microprover which is well established in the USA but is still to be used off-shore, and the Smith Systems small volume prover which until recently was an in-house reference device but is now being marketed in the USA and in Europe. In addition to these American based provers, the review also considers two British devices, the Skeltonhall prover and the General Descaling prover which are beginning to come on to the UK market.

All five provers have the same basic components - a piston in a precision bore tube of relatively small pre-calibrated volume, together with some method of detecting the movement of the piston within this volume and a means of returning the piston to its starting point at the beginning of the proving cycle. Beyond this, however, there are many variations as can be seen when each design is considered in turn.

2.1 Brooks Compact Prover

This prover was originally developed and manufactured by Flow Technology Inc, Arizona, and sold under the trade name 'Ballistic Prover'. It is shown schematically in Fig. 1. The prover consists basically of a carbon steel nickel-plated measuring cylinder inside which a piston moves under the action of the flow. The piston is fitted with a co-axially mounted poppet valve which eliminates the need for a bypass valve circuit. The actuating rod for the poppet valve is brought out from the rear of the measuring tube to a hydraulic/pneumatic cylinder. The poppet valve is closed by applying pressurised gas (normally nitrogen) to one side of the actuating rod, thus enabling the piston to move down the cylinder under the action of the flow. During its passage down the cylinder the gas pressure on the upstream face of the actuator piston is sufficient to overcome piston inertia and seal bearing friction which might otherwise affect the flowrate through the meter being proved. At the end of the pass the poppet valve is opened and the piston returns, by means of hydraulic pressure applied to the actuating rod, to its starting point where the poppet valve is held open ready for the next pass.

No provision is available for dynamic checking of the critical piston seals, although these can be checked statically at the end of each operation if required.

Three detector switches, of the optical (infra-red) type are used, and are actuated by a flag mounted on the detector shaft which is rigidly connected to the piston. Two of these switches mark the beginning and end of the calibrated section of the prover while the third senses the position of the piston at the upstream end of the cylinder.

2.2 General Descaling Compact Prover

This prover is being manufactured by GD Engineering under licence from Moore, Barrett & Redwood Ltd, and is shown schematically in Fig. 2. The design is based on a free-travelling piston operating in the bi-directional mode in a double shell barrel. The double shell arrangement eliminates the need for any pressure correction and assists in the stabilisation of temperature. The direction of flow in the flow tube is changed by means of a spool-type 4-way valve mounted externally, and launch actuators at each end push the piston into the flow tube. The inner flow tube is fitted with integral detectors

and is completely removable via quick acting end closures, enabling the tube to be calibrated off-site. Two pairs of detector switches of the magnetic inductive type are used to ensure continuity in the event of failure. These switches are actuated by a magnet mounted on the free travelling piston, not shown in Fig. 2.

The piston embodies a seal-checking system which enables the seals to be checked dynamically during proving, while the integrity of the 4-way valve seals can also be monitored continuously. A static check of the piston seal can also be made whenever this is required.

2.3 The Skeltonhall Compact Prover

The device was developed by Maurer Instruments Ltd and is being manufactured, in the larger sizes, by Skeltonhall Ltd. The prover, shown schematically in Fig. 3, consists of a piston which is free to move along a calibrated measuring cylinder under the action of the flowing fluid. The measuring cylinder is contained within an outer cylinder, the space between being filled with flowing liquid. Thus pressure corrections are zero and the temperature stability is enhanced. Flow is directed into the prover chamber by the operation of a bypass valve, and at the end of a pass the piston enters a recessed portion of the tube, allowing the flow to bypass it. The bypass valve is then opened and a 'nudge' cylinder used to move the piston back into the main part of the cylinder. Thereafter circuit design ensures that the differential pressure across the piston is sufficient to move the piston back to its starting position ready for another pass. The 'nudge' cylinder also acts as a hydraulic damper, and helps to decelerate the piston at the end of the pass.

The piston seals can be monitored and the pressure in the pressurised space between them compared while the piston is in motion, with line pressure by a differential pressure transducer within the piston head. Static testing of the seal can be carried out using a bleed system in the chamber end closure.

The fundamental difference between this device and the others considered in this review is the method of measurement. Here the measuring system consists of a linear transducer mounted on the piston rod which detects pulses from a linear encoder mounted on a rigid 'INVAR' block. No detector switches are fitted although it can be used in a fixed volume mode by utilizing a fixed portion of the linear encoder.

2.4 Smith Systems Small Volume Prover

This consists of a barrel containing the measurement chamber and the piston which moves along it under the action of the flow. A bypass circuit round the barrel enables flow to be directed either through the bypass or through the barrel according to the position of a hydraulically operated bypass valve.

The operational sequence is shown in Fig. 4. The piston is first returned by the hydraulic system to its upstream configuration, with the bypass valve open. When the piston reaches the stop at the end of the barrel, the bypass is closed by the actuator and the piston begins its proving run. At the end of the proving pass the bypass valve opens and the proving cycle is ready to be repeated.

The detectors are of the optical (infra-red) type and are mounted on an INVAR bar in a special bracket which allows replacement without recalibration. A third switch is fitted on the INVAR rod to act as a positional sensor, while a further pressure switch monitors the pressure between the two piston seals

so that dynamic leak testing of the piston can be effected during a proving run. Dynamic leak testing of the bypass valve can also be carried out.

A unique feature of the Smith Systems prover is that either vertical or horizontal operation can be selected, using a hydraulic positioner to alter the mode of operation.

2.5 Waugh Controls Microprover

In this device the measuring cylinder is contained within an outer housing containing the fluid which therefore eliminates the need for pressure correction. The presence of the fluid surrounding the measuring cylinder also provides good thermal stability. Apart from this feature however, the layout is similar to the Smith Systems device described in Section 2.4.

The prover is shown schematically in Fig. 5. The fluid passes through the bypass valve or into the measuring cylinder (through a series of slotted parts), according to the position of the bypass valve. The piston moves down the cylinder under the action of the flow and is returned by means of a hydraulically operated return actuator. Two marks on the piston rod operate a single optical sensor at the beginning and end of each pass.

Dynamic checking can be carried out on the three critical seals in the system - the piston seal, the annular seal in the space between the inner and outer cylinders, and the bypass valve seal, which is of the block-and-bleed type.

3 A COMPARATIVE REVIEW

Table 2 shows a comparison of the five prover designs. A mid-range model, suitable for 8 inches (208 mm) main line operation, is chosen as the basis for the comparison.

It can be seen from the Table that the term 'compact' or 'small volume' has no precise definition. On the basis of floor area occupied the provers vary by a factor of more than 3 to 1, while on the basis of space occupied the factor by which the provers vary is more than 8 to 1.

Thus the 'bulkiest' prover (ie in terms of volume) is the General Descaling device while the most compact is the Skeltonhall prover. In terms of floor area the biggest is again the General Descaling prover and the smallest is the Skeltonhall device. It should be noted that comparison of the provers in simple terms of ground area or space occupied is not strictly fair to some of the models. For example the dimensions of the Waugh prover include the height to the top of the hydraulic actuator for the bypass valve. Presumably if height were critical the layout could be re-arranged. On the other hand the overall dimensions of the General Descaling prover conceal the fact that an extra 2.5 m at one end for tube replacement and 1.5 m at each end for normal maintenance are required.

The weight of the provers also show a large variation, by a factor of about 3 to 1, with the Skeltonhall prover being the lightest and the Brooks being the heaviest.

Table 3 gives a comparison of various features of the five provers.

All but the Brooks version employ some form of bypass valve. In the Brooks device the piston poppet valve serves the same purpose, that of providing a means of returning the piston to the other end of the cylinder. In most of

the other devices this bypass valve is a simple two-way device, but in the General Descaling version, since this is designed for bi-directional flow, a four-way valve (spool type) has to be used. Thus this device sacrifices the increased weight and cost of this valve for the ability to operate in the bi-directional mode.

The advantages of the double shell design, offered by the General Descaling, Skeltonhall and Waugh provers, are the elimination of any pressure correction factor and the increase in thermal stability which such an arrangement affords. The disadvantages are the increased construction cost and the increase in the overall weight. However when this feature is combined with the facility of replacing the flow tube in the event of damage or for pre-calibration off-site, as with the General Descaling prover, then the advantage of such a design would appear to outweigh any disadvantage of cost and weight. The replacement due to damage of a complete prover on an offshore platform, for example, must prove to be a very expensive operation in comparison with on-site replacement by a pre-calibrated tube carried as a spare.

The number of detectors varies from none in the Skeltonhall prover (since it utilizes a linear encoder) to four in the General Descaling prover. The General Descaling prover uses two pairs of switches as a guard against faulty operation, while the Brooks prover used three detectors - one to sense the presence of the retracted piston and two to measure the piston travel. The Waugh prover uses only one detector, of the optical type, which senses the passage past it of gate marks on the piston rod. Both the Waugh and Smith switches can be replaced without the need for recalibration of the prover barrel.

The assistance of subsidiary systems such as hydraulic and pneumatic circuits ranges from none in the case of the Skeltonhall and General Descaling devices, to both hydraulic and gas systems in the Brooks prover. No external assistance is required in the case of the Skeltonhall prover, which utilizes differential hydrodynamic forces to draw the piston back along the tube or in the General Descaling device which operates in the bi-directional mode. The Waugh and Smith provers utilize a hydraulic system to retract the piston while a combined pneumatic/hydraulic system in the Brooks prover serves two purposes: first to return the piston to the other end of the cylinder, and second to close the poppet valve and to assist the movement of the piston against the resistance offered by the inertia of the piston and the piston seals. The gas pressure behind the piston can be adjusted to minimise the differential pressure across it, thus minimising the effect of any leak at the piston or poppet valve seals.

The dynamic piston seal checking facility is available in all versions except the Brooks; however because of Brooks' unique facility for balancing the differential pressure across the piston the lack of dynamic seal checking is less important.

4 PULSE INTERPOLATION

Because of the small volumes utilized in compact provers, the number of meter pulses generated by the meter during a proving pass is almost always small enough to make errors of discrimination significant in relation to the required overall uncertainty of proving. A pulse count of 10 000 for example, is necessary to provide a discrimination error of $\pm$0.01 per cent. An 8-inch (204 mm) turbine meter, however, may only generate about 100 pulses between the detectors of a typical small volume prover. This would produce a discrimination error of $\pm$1 per cent and is clearly unacceptable; enhancement of

the pulse count by pulse interpolation must be carried out. Thus pulse interpolation is as much a part of a small volume prover as for example the piston or the detectors, and for this reason it is worth considering separately in this review.

At present there are three basic methods of pulse interpolation available to compact prover designers - the double timing or double chronometry method, the quadruple timing method, and the phase lock loop method. The ISO document (ISO 7278/3) on pulse interpolation which will form part of the ISO Standard on pipe provers describes these three basic techniques, although at present it does not consider refinements and variations incorporated for particular applications.

The choice of pulse interpolation method for use with a small volume prover must take into account the meter being proved and the proving conditions which will be experienced in the field. The most important factor which has to be considered is the reaction of the pulse interpolation system to changes in the frequency of the pulses emitted by the meter being proved. These frequency changes can arise either from external sources ie flowrate changes which are generally of lower frequency, or from sources within the meter such as bearing wear or intra-rotational non-linearity in turbine meters or inherent periodicity arising from hydrodynamic sources in devices such as vortex meters. These are of much higher frequency, and because of the relatively short transit times in small volume provers it is the behaviour of the pulse interpolation system with short pulse timescale variations which are the greatest potential source of error and which therefore are of most interest.

A systematic study of the behaviour of the various pulse interpolation techniques in the wide variety of flow conditions which might be experienced in the field has not yet been carried out. A programme of work at NEL, however, is under way and will be undertaken in conjunction with the present evaluation work on small volume provers.

At present, however, certain conclusions can be drawn on the existing methods. For example the original quadruple timing method of pulse interpolation, shown in Fig. 6, is very susceptible to errors arising from differences in the widths of adjacent pulses. The phase lock loop system, shown in Fig. 7, must be designed to ensure that its response to sudden changes in pulse frequency is sufficient to cope with such changes which might arise from, for example, the poor intra-rotational linearity of a turbine meter.

The pulse interpolation techniques employed in the five small volume provers considered in this review are shown in Fig. 8. Four designs use double timing, while the fifth uses quadruple timing. Brooks, Smith and Skeltonhall (in the fixed volume mode) use double timing, in which the time between the leading edge of the first pulse after the first detector signal and that of the first pulse after the second detector signal is measured, together with the time between the detector signals themselves.

The Skeltonhall prover provides a refinement of the double chronometry method in which successive pulse widths are measured and stored throughout the prover pass. If any pulse width falls outside certain prescribed limits, then an alarm signal is given.

The Waugh technique is similar, except that the first time is taken as that between the leading edge of the first pulse before the first detector signal

and that before the second detector signal.

The quadruple timing method employed by General Descaling is a distinct improvement over the original technique shown in Fig. 6. Here the interpolation is carried out on the actual pulses which are being generated while the detectors are being actuated. This means that the effects of intra-rotational non-linearity can be removed, although at the expense of the extra circuitry required to measure four periods instead of two.

Finally on the subject of pulse interpolation it should be stressed that the limitations to the various techniques have not yet been studied and reported in any detail. These limitations must also be considered in relation to the acceptable uncertainty and the tolerable variation in pulse frequency. Thus if a low level of interpolation was required, ie if a meter with a fairly high pulse density was being proved, then for a given uncertainty level a fairly wide variation of pulse frequency may be allowed. However if a meter with a very low pulse density was being proved, requiring a high degree of pulse interpolation, then very strict limits would have to be put on pulse frequency variations, otherwise a deterioration in the uncertainty level would be incurred. Quantification of these inter-related effects, however, awaits the outcome of further study.

5 FUTURE DEVELOPMENTS

This review of small volume provers has presented a survey of the characteristics of five provers from different manufacturers which are either established in the US or European market or are about to become available within the next year. It is believed that other designs both in the US and the UK are being considered for the North Sea market; however these designs are not sufficiently novel or different from those covered in this review, to be worth considering separately; nor are they likely to be in use in the next twelve months.

It is expected that the next few years will see the consolidation and acceptance of small volume provers in areas previously dominated by large conventional sphere type provers. It is extremely unlikely however that conventional provers will be completely superseded, certainly not before the end of the century. The shift of oil industry interest however, to deep sea wells, with the greatly increased production costs which this entails will mean that platform or vessel space will be even more critically allocated; it is unlikely in these high cost production systems therefore that off-shore proving would be carried out by conventional means. If off-shore metering was considered necessary this would almost certainly be done by a small volume prover.

The small size and low weight of these devices and their consequent transportability make them extremely attractive as transfer standards for locations where it is neither physically practicable nor economically desirable to install a dedicated proving system. Thus it may be that in future off-shore metering stations proving will be carried out by portable compact provers belonging perhaps to one of the calibration service companies who would be responsible for on-shore water draw calibrations against measures which are traceable to national standards. This arrangement would obviously involve the fiscal authorities and require considerable evidence of credibility.

With respect to the devices themselves all appear to show the promise of effectiveness in crude oil service. Apart from convincing the fiscal authorities of this fundamental design changes to the hardware is not envisaged. On the instrumentation and software side it is expected that as in other areas

of technology, substantial development will take place. Such developments are likely to include self checking facilities, more refined control chart analysis, and pulse interpolation systems which can be used with confidence under a wider range of conditions and with a wider range of meter types as these become more acceptable to the industry.

The lack of an in-line prover for natural gas is limiting the uncertainty levels achievable in gas flow measurement. There is in theory no reason why the small volume prover principle should not be applied to natural gas, and even with a slight reduction in the uncertainty level this would still be an attractive prospect.

It is to be hoped that future North Sea Flow Metering Workshops can report such developments and provide a forum for a critical discussion of their merits.

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LIST OF FIGURES

TABLE 1

COMPARISON OF A COMPACT AND CONVENTIONAL PROVER

	Compact	Conventional
Length (m)	3.0	14
Width (m)	1.2	1.5
Height (m)	0.76	2.4
Weight (kg)	1450	3000
Ground area occupied (m^2)	3.6	21.0
Space occupied (m^3)	2.74	50.4
Max. rated flowrate (m^3/h)	400	190

← dry weight

TABLE 2

COMPARISON OF FLOWRATE RANGE, PHYSICAL DIMENSIONS AND WEIGHT

	Brooks	General Descaling	Skeltonhall	Smith	Waugh
Inlet/outlet dia., in	8	8	8	8	8
Max. flowrate, m^3/h	795	600	720	795	681
O/A dimensions: length, m	4	4.2	2.9	4.6	3.7
O/A dimensions: width, m	1.2	2.15	0.6	1.5	1.3
O/A dimensions: height, m	1.2	1.8	0.6	1.2	1.8
Weight, kg	2722	2500 approx	900	2270	1451
Volume between switches, l	120	156	98*	159	87
Ground area occupied, m^2	4.8	9.03	1.74	5.9	4.81
Space occupied, m^3	5.76	16.25	1.04	7.08	8.66

*Prover swept volume

TABLE 3

COMPARISON OF FEATURES

Features	Brooks	General Descaling	Skeltonhall	Smith	Waugh
Mode of operation	UNI	BI	UNI	UNI	UNI
Bypass valve type	-	4-way spool	2-way ball	2-way plunger	2-way ball
Double barrel	No	Yes	Yes	No	Yes
Replaceable flow tube	No	Yes	No	No	No
Detector type	optical	inductive	-	optical	optical
Replaceable detector (without recalibration)	No	No	-	Yes	Yes
Pulse interpolation method	2-timing	4-timing	2-timing	2-timing	2-timing
Hydraulic system required	Yes	No	No	Yes	Yes
Gas supply required	Yes	No	No	No	No
Dynamic piston seal check	No	Yes	Yes	Yes	Yes
Turn-down	1000:1	1000:1	2000:1	1000:1	1000:1
Number of detectors	3	2 x 2	-	3	1

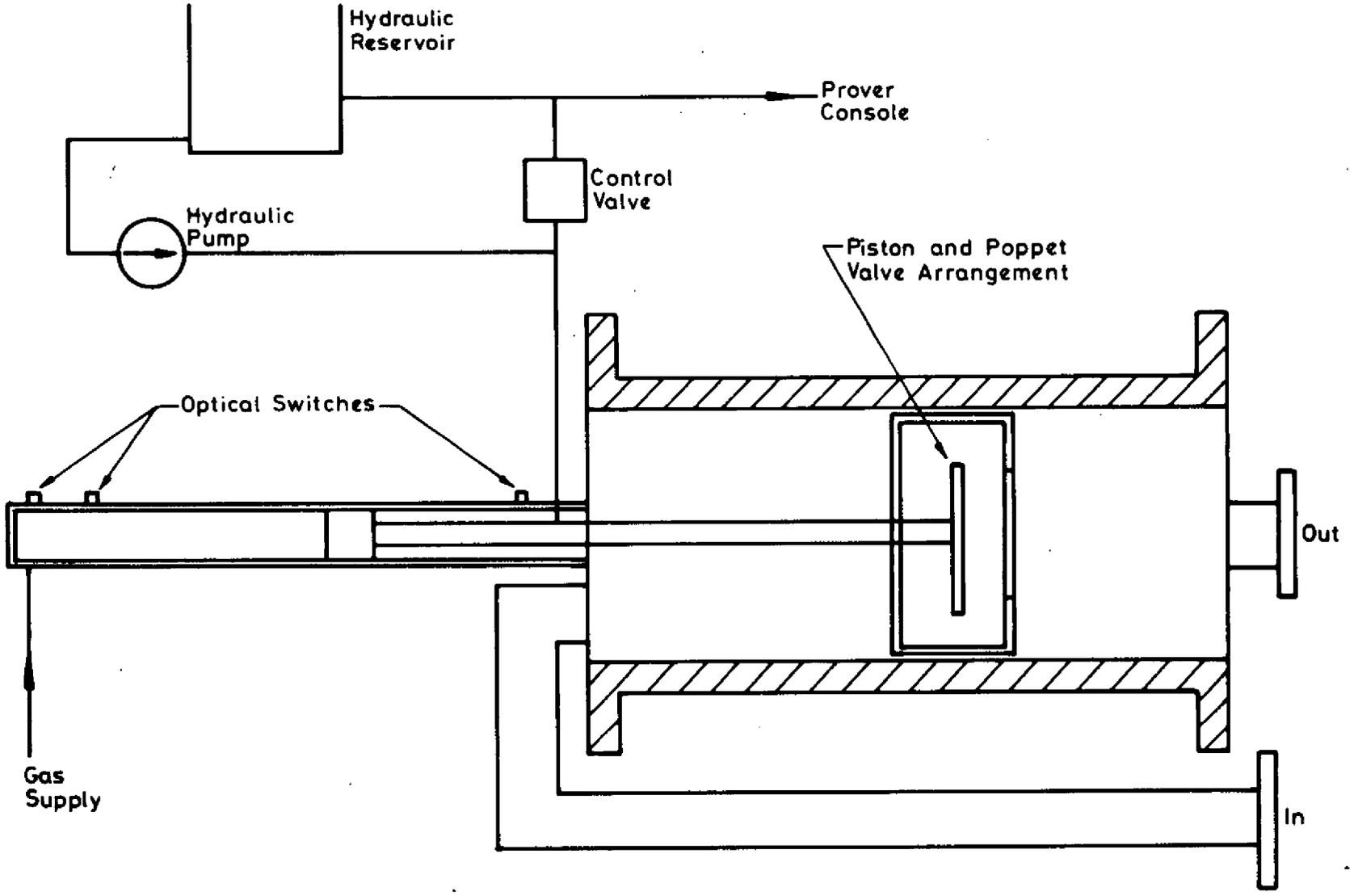


Fig 1 Schematic Diagram of Brooks Compact Prover

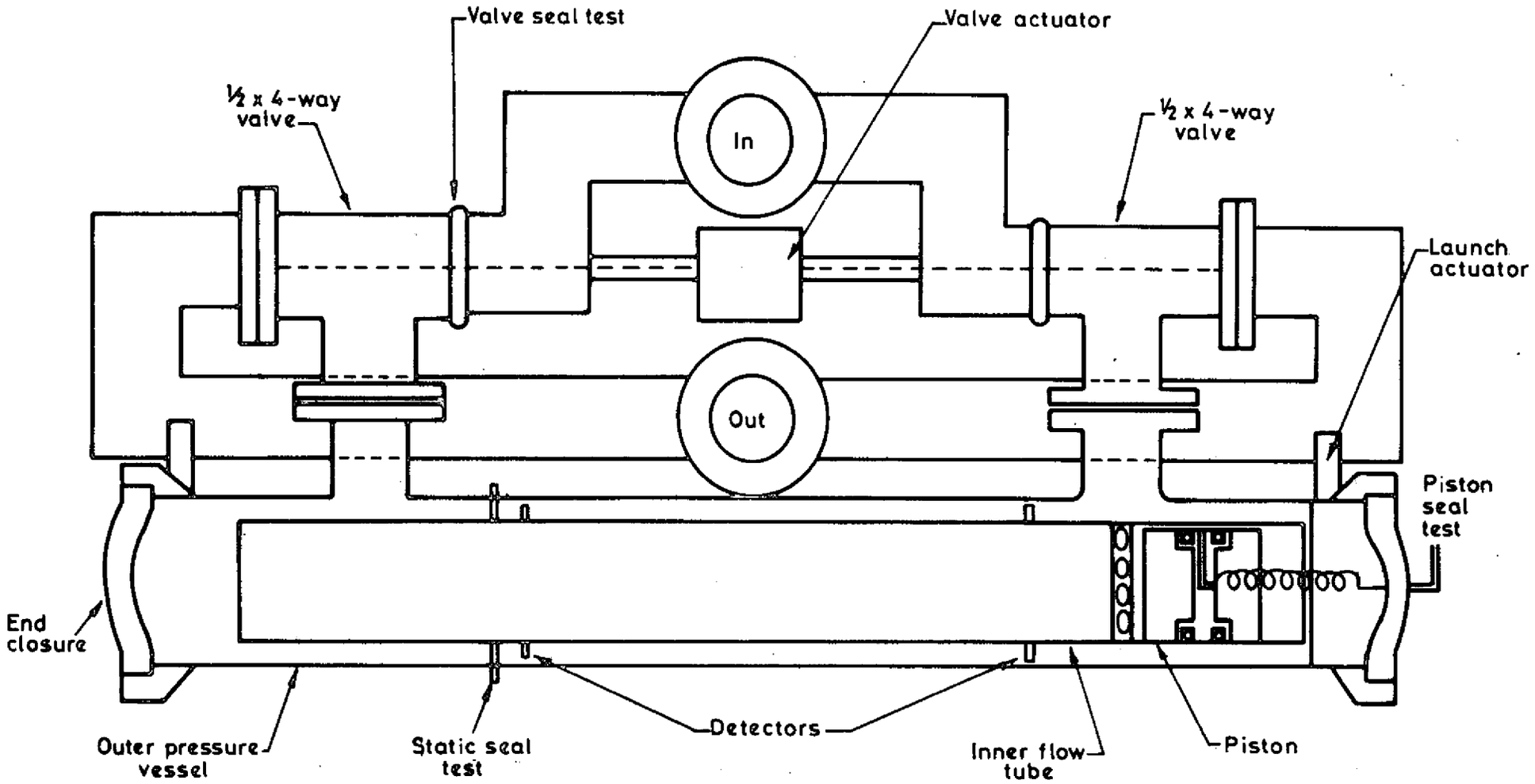


Fig 2 Schematic Diagram of General Descaling Prover

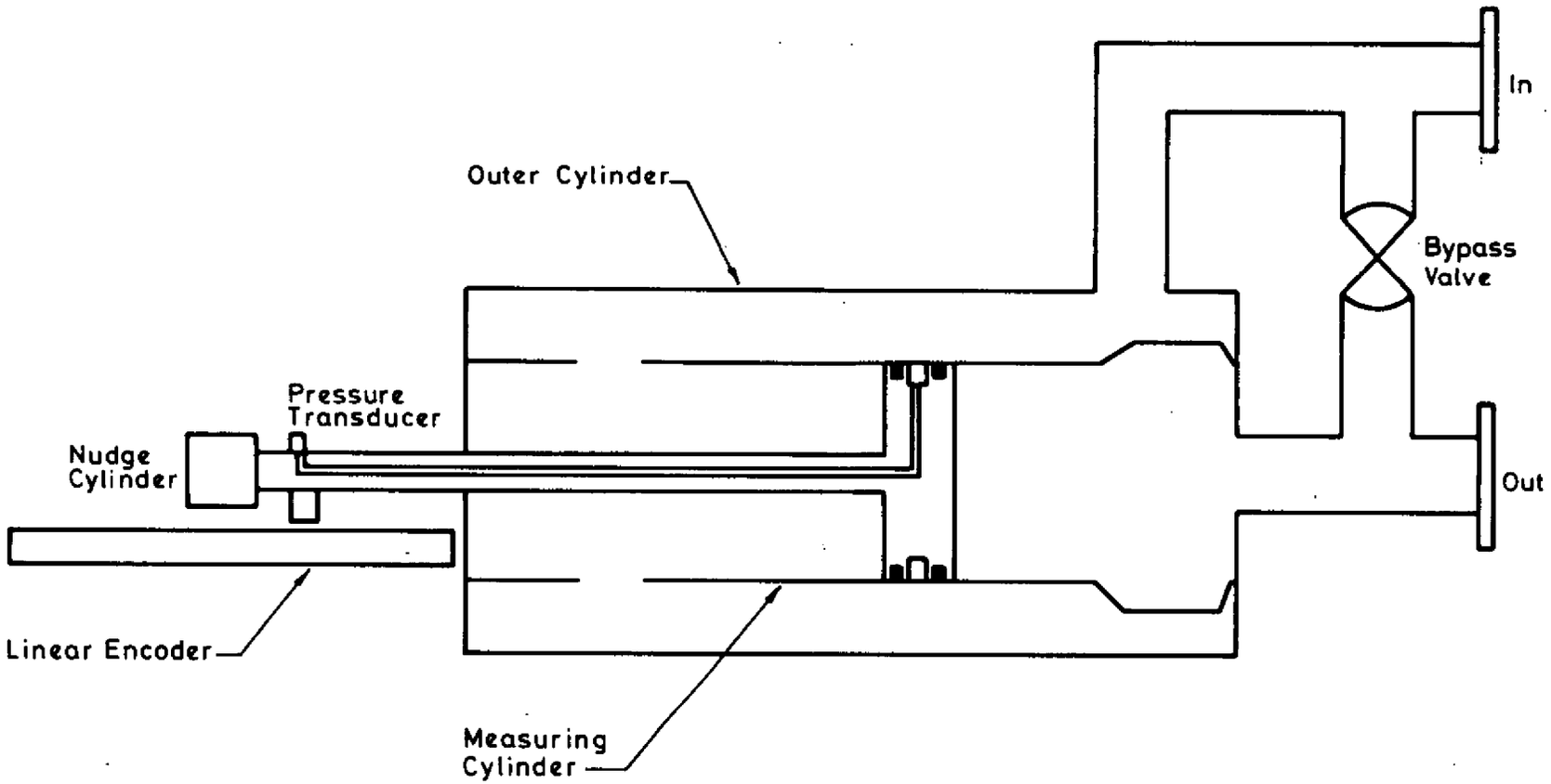


Fig 3 Schematic Diagram of Skeltonhall Prover

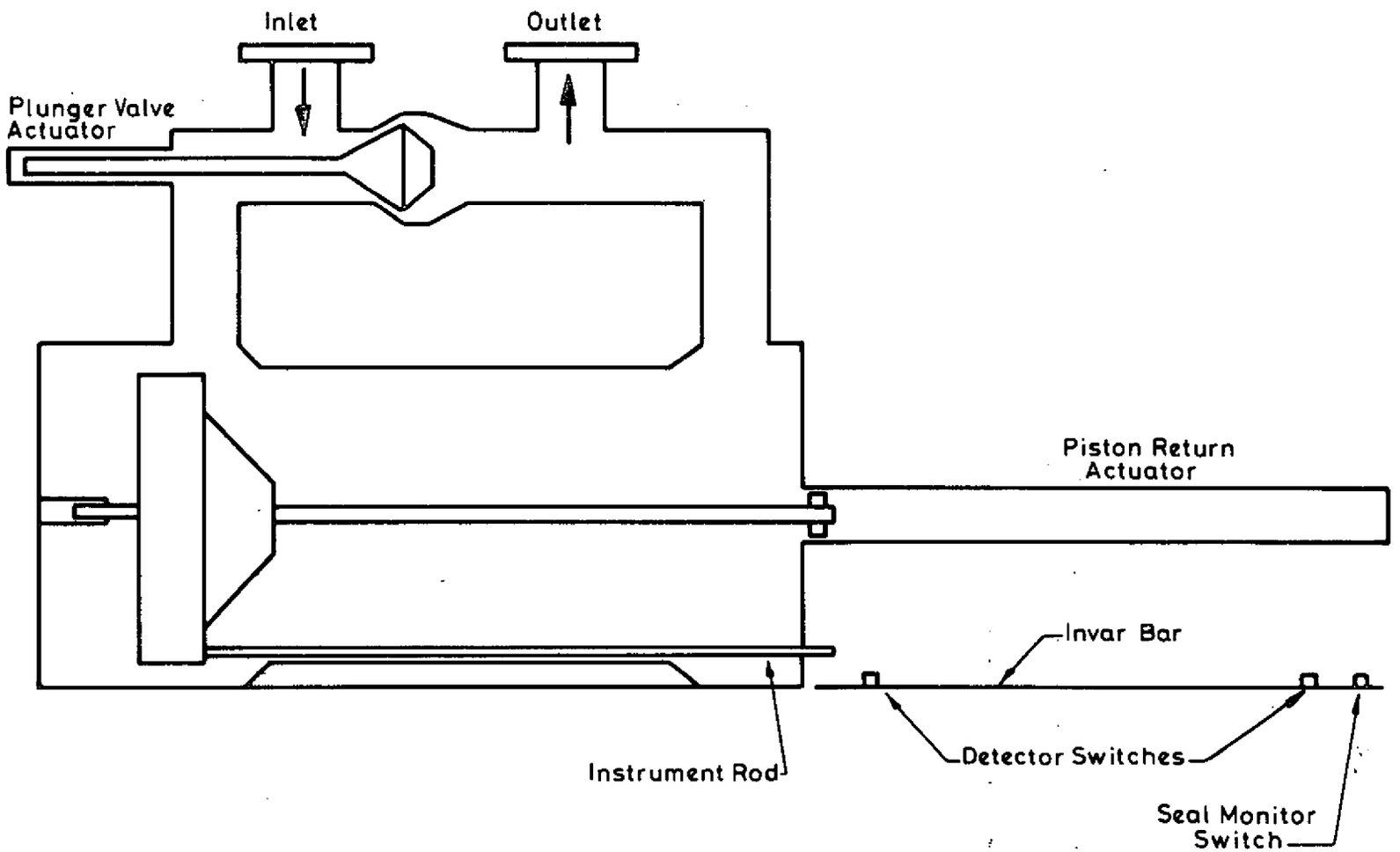


Fig 4 Schematic Diagram of Smith Systems Prover

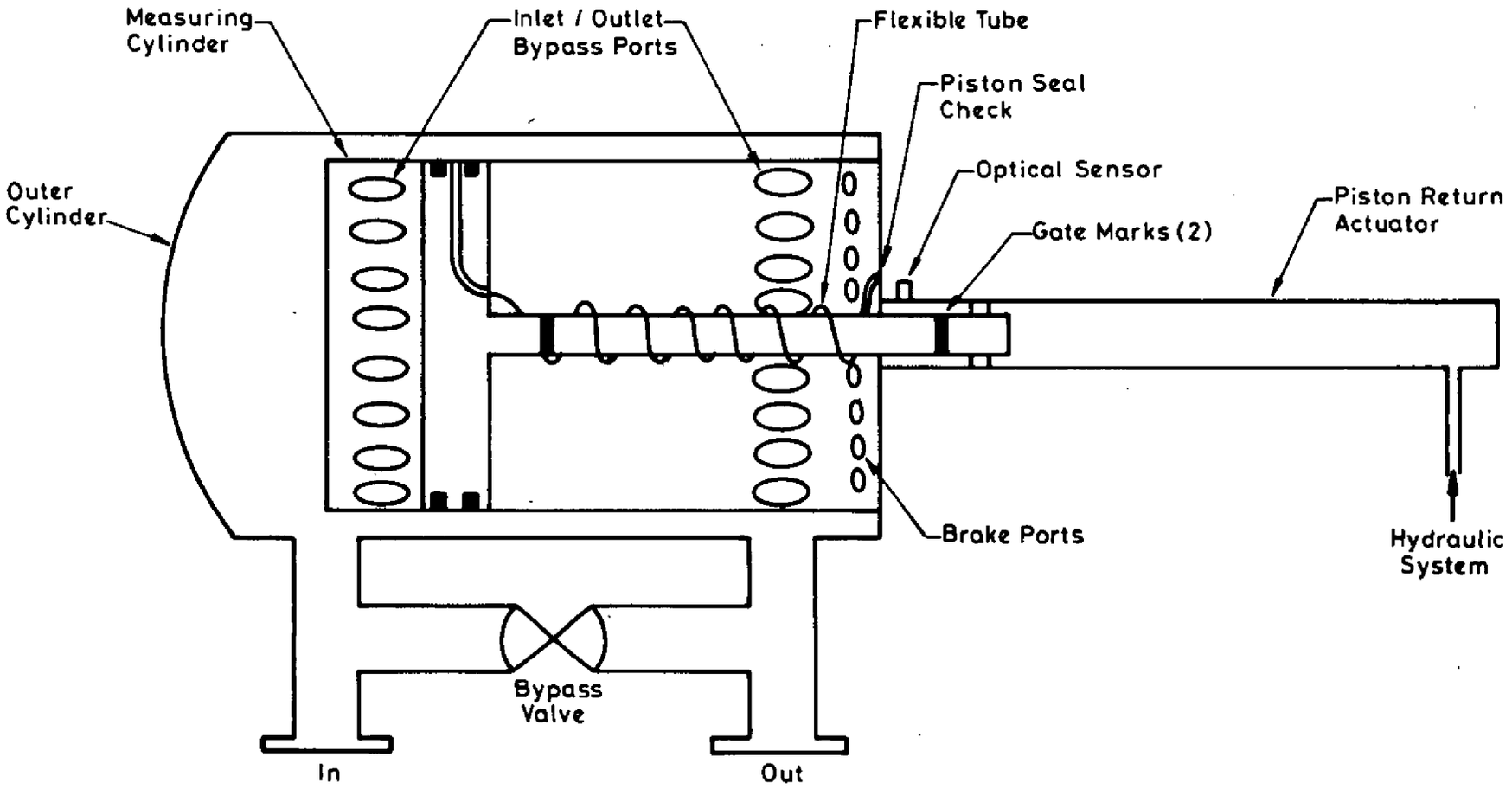
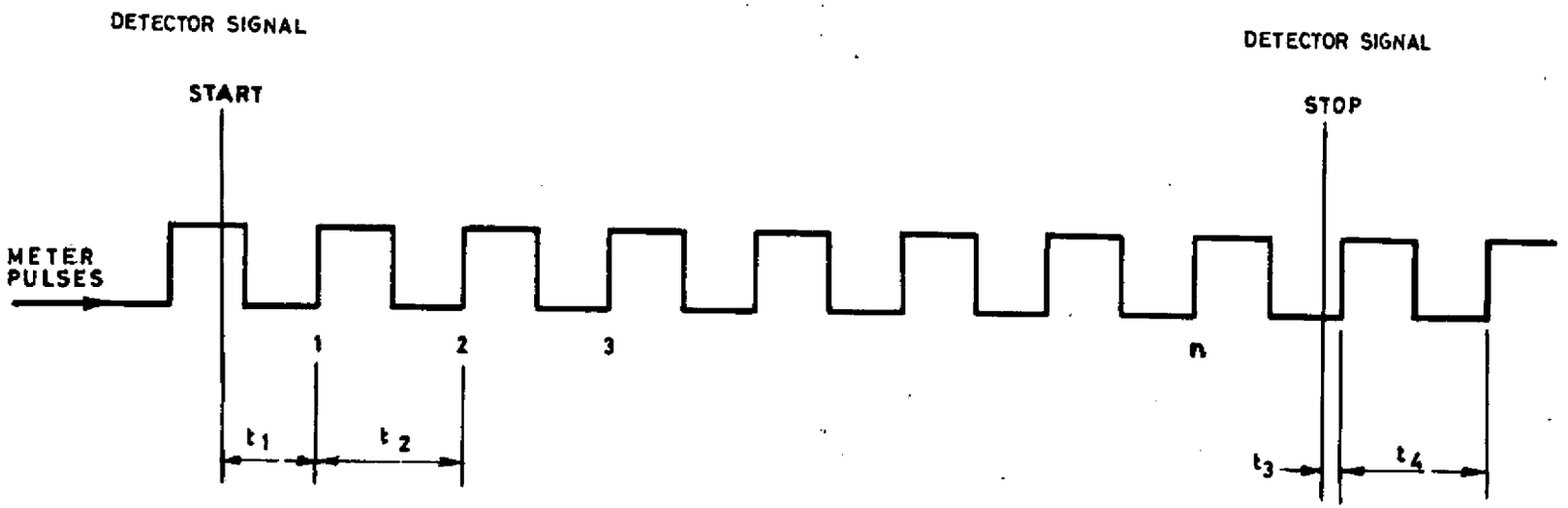


Fig 5 Schematic Diagram of Waugh Microprover



INTERPOLATED NUMBER OF PULSES $n' = n + \frac{t_1}{t_2} - \frac{t_3}{t_4}$

Fig 6 Original Quadruple Timing Method

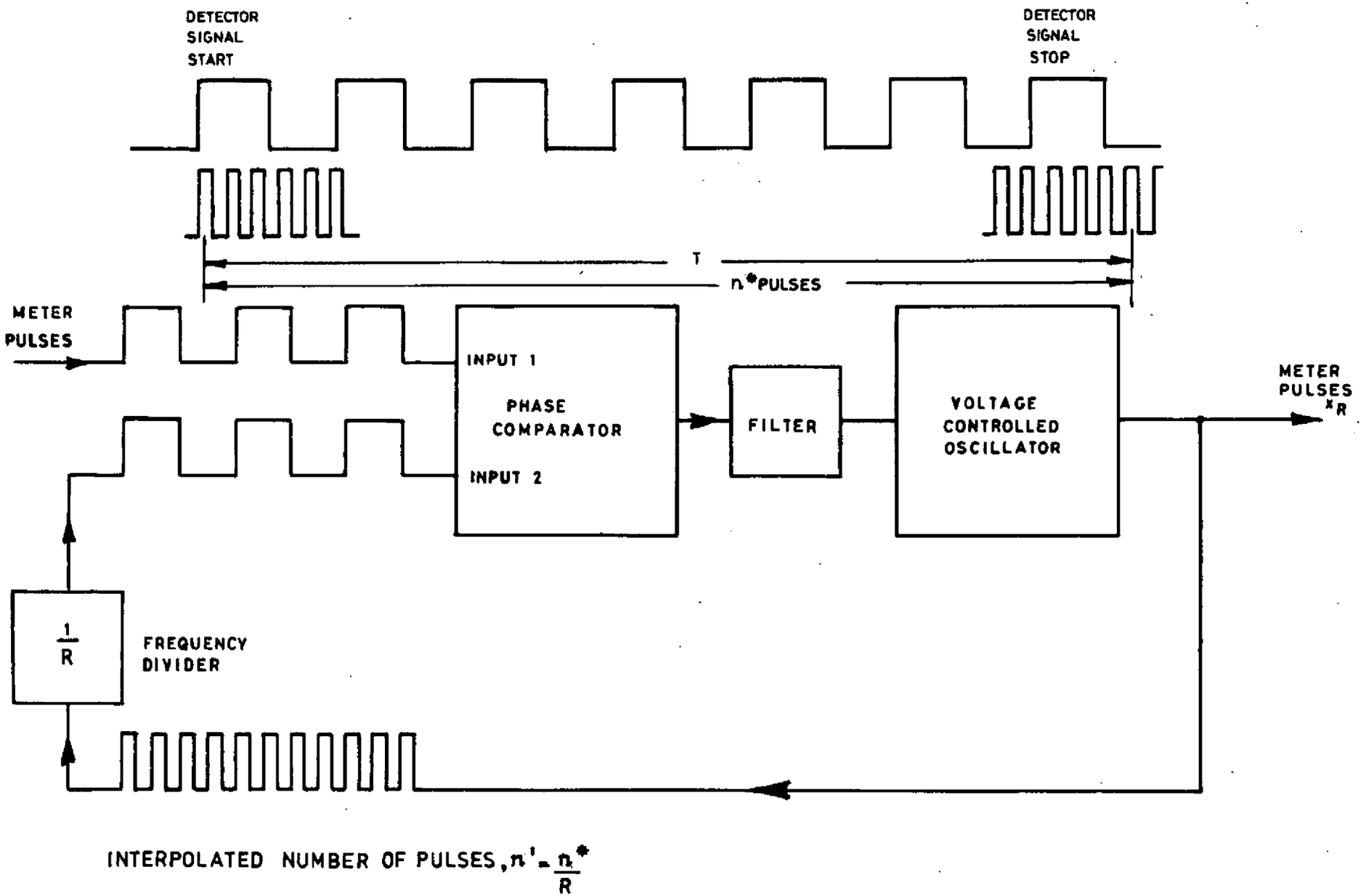
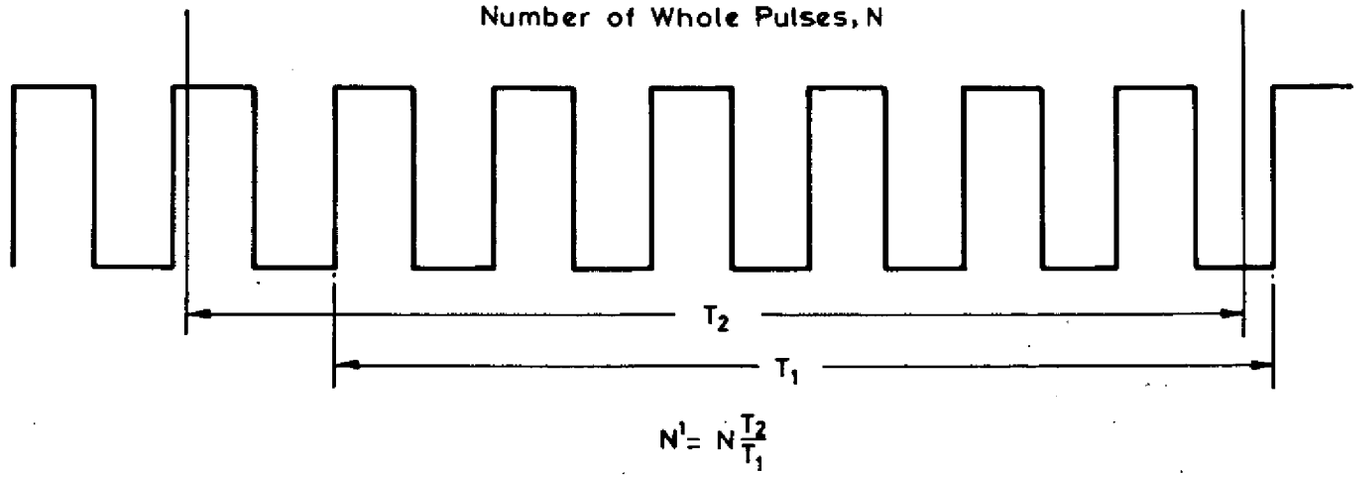
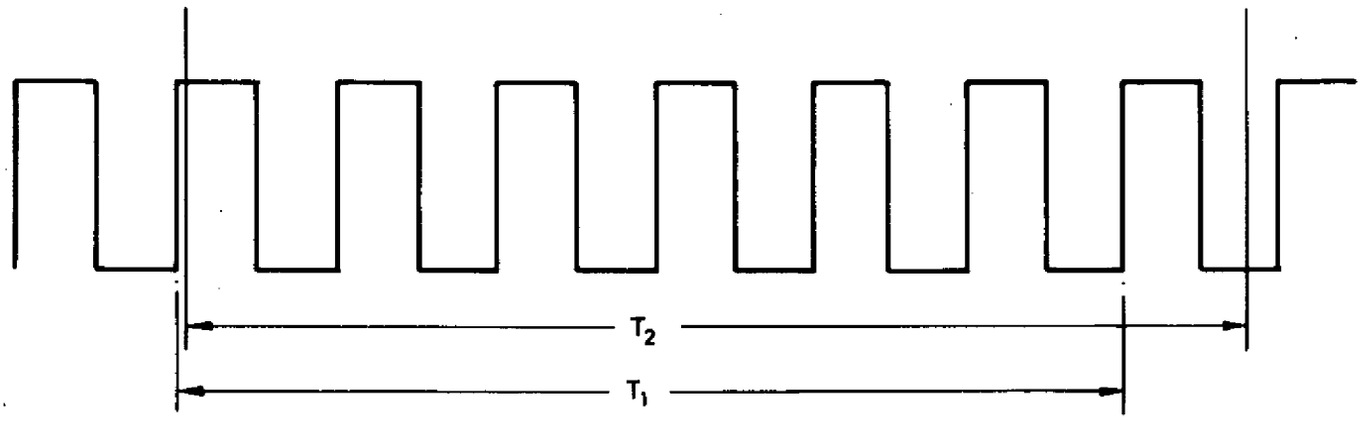


FIG. 7 PHASE-LOCKED-LOOP METHOD.



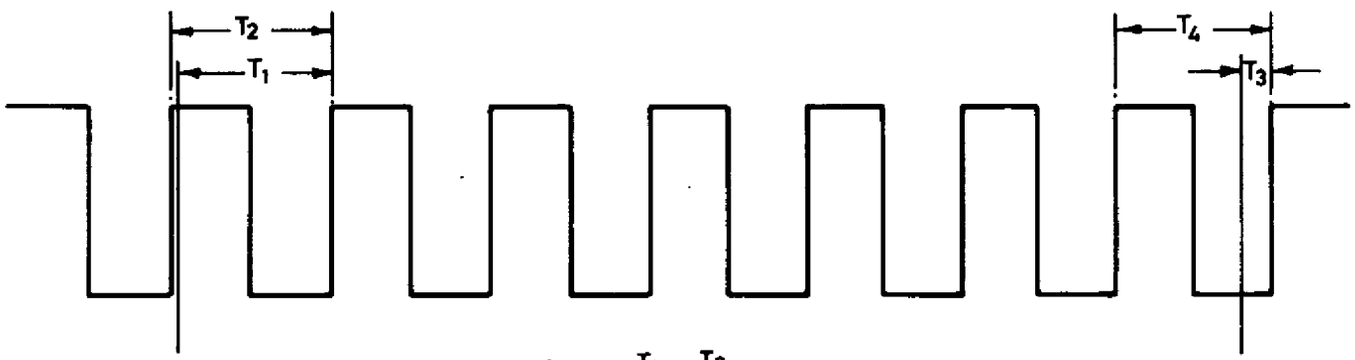
$$N^1 = N\frac{T_2}{T_1}$$

Smith, Brooks, Skeltonhall



$$N^1 = \frac{T_2}{T_1}$$

Waugh



$$N^1 = N + \frac{T_1}{T_2} - \frac{T_3}{T_4}$$

G D

Fig 8 Comparison of Pulse Interpolation Methods

Main Index

FIELD EXPERIENCE WITH COMPACT PROVERS

by

W GRANT

PHILLIPS PETROLEUM COMPANY

PAPER 5.2

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

FIELD EXPERIENCE WITH COMPACT PROVERS - PART I

B.G. Grant

PHILLIPS PETROLEUM COMPANY NORWAY

INTRODUCTION

The offshore oil industry has been continually faced with new challenges. Early in the history of the Ekofisk project, Phillips Petroleum Norway, as operator, had the problem of recalibration of liquid meter provers on nine platforms. An analysis of the various means of accomplishing the recalibration was studied and the following four general methods were evaluated:

1. The conventional water draw method

2. Master meter method utilizing the operating fluid

3. A conventional ball type pipe prover in conjunction with a transfer meter

4. A compact (ballistic) meter prover

Each of the first three methods had negative factors which were not easy to overcome on an offshore platform using crude oil with a very high vapor pressure. The fourth method had not been tried and proven offshore but it had the advantages of small size, weight and speed which was ideal for Phillips Norway's application. Our cost analysis showed that the compact prover could be adapted to our application for about the same cost as the other three conventional methods. An additional factor in favor of the compact prover recalibration system is that there would be less risk of lost production due to the time the platform prover must be out of service.

After consideration of the advantages and disadvantages of the compact prover, Phillips entered into a development contract to test and demonstrate the feasibility of this type system. We had to assure ourselves that there was no accuracy problem, then demonstrate the compact prover system to the Norwegian Authorities. The compact prover manufactured by Flow-Technology was selected and the Norwegian Authorities required that the unit must correlate with a conventional pipe prover to within $\pm$ 0.03 percent with repeatability of $\pm$ 0.02%.

BROOKS

The dimensions of the compact prover system were limited by the narrowest passageway available to move it from a lay down area to the platform prover skid on the platform with the most congestion. Due to a right angle turn through a doorway on two of the platforms the length was also limited. The weight of the unit was restricted so it could be lifted on board by any platform crane in weather up to the maximum swells allowed using the whip.

DEMONSTRATION

In August, 1980, a series of tests were performed in Tulsa, Oklahoma, with the compact prover system operating in conjunction with a conventional ball type pipe prover. The following procedures were carried out:

1. The certificates of calibration of the instruments were inspected.

2. All thermometers were recalibrated using a cold bath and a certified etched stem thermometer.

3. A leak detection test was performed on the compact prover seals and was verified by releasing 100 cc of fluid.

4. Calibration runs were made with one series at a faster flow rate (190 GPM) followed by a series at a slower flow rate (157 GPM).

5. A series of tests were performed to demonstrate the change, or lack of change, in the compact prover performance when the actuator piston pressure was varied between 30 and 45 pounds per square inch gauge.

The comparisons of the regular prover calibration with the compact prover were much better than our expectations. The compact prover was within 0.01% of the water draw base volume of the conventional prover using the faster flow rate and was 0.002% using the slower flow rate. The conventional prover was an 8 inch bi-directional ball type and the compact was 12 inch, 10 gallon model. Figure 1 is a schematic diagram of the demonstration test configuration.

The test results as shown in Figure 2, assured the Norwegian Authorities and Phillips that the compact prover provided the necessary accuracy for the recalibration of our offshore meter provers. Only the question of how often to perform a water draw calibration of the compact prover remained unanswered. It was agreed that a water draw would be made at Phillips Petroleum Company Norway, Shore Base, before the equipment was sent offshore by work boat. Diesel oil from the regular platform fuel system was to be the recalibration fluid. Phillips had earlier obtained a 10 gallon Seraphin can which was certified by the U.S. National Bureau Of Standards and recertified by Det Norske Justervesen upon it's arrival in Norway, Valving arrangements were installed on the compact prover so that a water draw calibration could be performed in only a few minutes. With this convenient arrangement, the waterdraw calibration was repeated many times during a day of testing. All the results were less than the uncertainty of the Seraphin can.

1980 RECALIBRATIONS

The calibration crew required one week to complete the first platform recalibration. Of course, the first two days of this time were spent waiting on the weather before the com-

pact prover could be hoisted onto the platform from the work boat, which is one of the risks we have in all our offshore operations. The first set of recalibrations on this platform showed a drift in the platform prover of 0.09% from the original factory water draw. We were disappointed to see this much drift so the ball was resized to 5% overfill and new calibrations were run. The drift was 0.056% but was in the opposite direction which did not boost our confidence. The drift of the next three platform provers was in the same direction, which suggested that there might be a bias in the system. We were satisfied when the fifth platform prover showed a drift in the other direction. The results from these recalibrations are shown in Figure 3. We considered offshore recalibration of the provers to be slightly less accurate than the factory calibration so only the one prover with a shift greater than 0.05% had the base volume changed in the computer. A water draw calibration of the compact prover was carried out periodically while it was being used offshore. Figure 4 shows the results of the onshore water draw and five additional water draws while offshore. The compact prover was relatively easy to flush out the diesel with fresh water, in order to perform the water draw calibrations.

The Norwegian Authorities were satisfied with the results of this series of recalibrations and they agreed that the next recalibration in two years, would include only the provers connected with the metering to the oil pipeline.

All the offshore provers would be recalibrated again in 1984.

1983 RECALIBRATIONS

The compact prover used for the 1980 recalibrations utilized micro-switch detectors. The compact prover selected for the next recalibration of the provers was a new model equipped with optical switches for even greater accuracy and has a 15 gallon capacity. A series of correlations were made at Bromborough, England, to establish the compact prover water draw volume with the same 10 gallon Seraphin can used during the 1980 recalibrations.

The compact prover unit was moved to the Seal Sands Teesside Plant for a demonstration and trial run of the equipment. Previous recalibrations of the inlet prover at this plant had utilized a conventional ball-type prover with a standard transfer meter.

We wanted to see what difference, if any, the use of the normal crude oil and the diesel oil system used with the compact prover might have on the results. The demonstration with the compact prover utilizing diesel compares with regular recalibrations as follows:

1. Ten months earlier -0.009%

2. Two months later +0.004%

3. Fourteen months later -0.003%

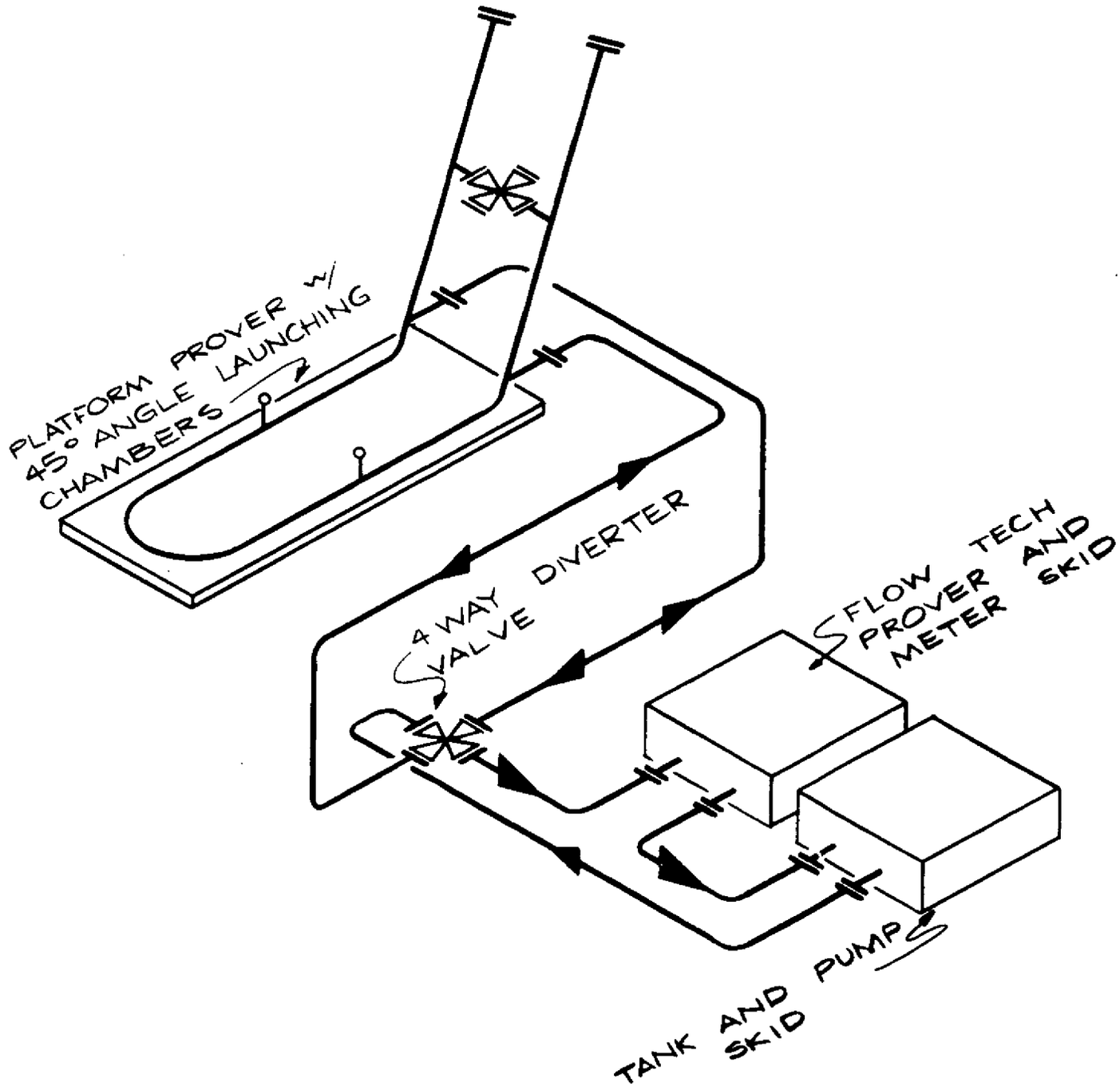
The regular recalibrations utilized the crude oil passing through the station.

The 15 gallon compact prover was used to recalibrate a 16 inch bi-directional prover on the Amoco 2/4G receiving platform and the 30 inch bi-directional prover on the 2/4T platform, both at Ekofisk Center and a 16 inch bi-directional prover on Albuskjell 2/4F platform. The results of these recalibrations are shown in Figure 5. A water-draw calibration of the compact was made before and after each of these recalibrations and the results are shown in Figure 6.

CONCLUSIONS

Phillips experience has proven the compact prover to be a very convenient method to perform the recalibration of offshore platform provers. Frequent water draw calibration of the compact prover gives added assurence that the certification of the offshore platform provers is as correct as possible. Our confidence in the compact prover has been assured and we are of the opinion that the recalibration of our offshore provers are as precise as the original factory calibrations.

The author wishes to thank T.L. Hillburn, Phillips Corporate Engineering, for permission to use excerpts from his internal report on the 1980 recalibrations.



DEMONSTRATION TEST CONFIGURATION

TULSA OK., AUGUST 1980

FIGURE 1

RESULTS OF DEMONSTRATION TESTS
TULSA, OKLAHOMA

Compact Prover	Pipe Prover	Master Meter
Base Volume 9.9240 Gal.	Base Volume 168.611 Gal	Size 2 inch
Flow Tech SN BFP-004	Signet SN 107/SFC 8413	Daniel CR SN 77-T-477

	Pass	MASTER METER K Gross Before	MASTER METER K Gross After		Pipe Prover Volume
Slower Rate	1	116.690	116.705	Using K=116.702	168.628
	2	116.701	116.698		168.644
	3	116.707	116.712		168.592
	4	116.703	116.697		168.608
	5	116.707	116.685		168.600
	Average	116.702	116.698		168.614
				Correlation	0.0018 %
Faster Rate	1	116.528	116.514	Using K=116.517	168.593
	2	116.516	116.499		168.627
	3	116.504	116.533		168.643
	4	116.511	116.512		168.617
	5	116.526	116.523		168.650
	Average	116.517	116.516		168.626
				Correlation	0.0089 %

33 passes were run while varying the actuator pressure from 27 psig to 45 psig.
The pulse count was 1158 for 26 passes and varied one count on the balance.

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Figure 2.

RE-CALIBRATION OF NINE BALL-TYPE PROVERS - 1980

Prover Size and Location	Original Calibration (U.S. BBL.)	Re-calibration (U.S. BBL.)	Percent Drift
30"/Ekofisk Center FTP	120.4699	120.4660	-0.003
30"/Ekofisk Center Tank	109.2977	109.2920	-0.005
18"/Tor 2/4E	42.3148	42.3118	-0.007
16"/Edda 2/7C	43.1290	43.1278	-0.003
16"/N. Eldfisk 2/7B	43.2425	43.2240	-0.043
16"/S. Eldfisk 2/7FTP	42.6939	42.6979	+0.010
16"/Albuskjell 2/4F	38.4219	38.4097	-0.032
16"/Albuskjell 1/6A	38.0480	38.0268	-0.056
10"/Cod 7/11A	10.1424	10.1433	+0.009

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Figure 3.

WATER DRAW CALIBRATION OF COMPACT PROVER (2309.63 IN ^{3} capacity)

Site	Pass	Net Volume ($In.^3$)	Correlation (Percent)
Tananger Base	1	2283.903	
	2	2284.078	
	3	2284.078	0.009
	4	2284.056	
	5	2283.873	
Albuskjell Alpha	1	2284.318	
	2	2284.227	
	3	2284.182	0.006
	4	2284.175	
	5	2284.189	
EDDA	1	2284.141	
	2	2284.239	
	3	2284.226	0.011
	4	2284.111	
	5	2284.363	
Eldfisk FTP	1	2284.408	
	2	2284.339	
	3	2284.403	0.005
	4	2284.421	
	5	2284.317	
Ekofisk (I)	1	2284.111	
	2	2284.159	
	3	2284.063	0.005
	4	2284.063	
	5	2284.182	
Ekofisk (II)	1	2284.275	
	2	2284.275	
	3	2284.427	0.009
	4	2284.313	
	5	2284.211	

Figure 4.

RECALIBRATION OF BALL - TYPE PROVERS - 1983

Prover Size and Location	Original calibration (U.S. BBL.)	1980 Recalibration (U.S. BBL.)	1980 Percent from original	1983 Recalibration (U.S. BBL.)	1983 Percent from Original	1983 Pecent from 1980
30" Tank	109.2977	109.2920	-0.005	109.2971	-0.001	+0.005
16" 2/4G						
Vol A	42.26089	New	---	42.2528	-0.021	---
Vol B	42.26855	New	---	42.2598	-0.021	---
16" Alb. 2/4F	38.4219	38.4097	-0.032	38.4096	-0.032	Nil

43B.1.BGG0705.8

Figure 5.

1983

WATER DRAW CALIBRATION OF COMPACT PROVER (3472.16 in^3 capacity)

Site	Pass	Average Volume Per Pour (in^3)	Correlation Percent
Before 2/4T	1 2 3	3471.9180 3472.1142 3471.9527	0.007
After 2/4T	1 2 3	3471.8490 3471.8337 3471.8990	0.002
Before 2/4G	1 2 3	3471.1692 3471.3386 3471.5241	0.010
After 2/4G	1 2 3	3471.9038 3471.8764 3471.9916	0.003
Before 2/4F	1 2 3	3472.2574 3472.3304 3472.3805	0.005
After 2/4F	1 2 3	3471.9532 3471.9838 3471.9685	0.006

43B.1.BGG0705.9

Figure 6.

Main Index

PRACTICAL FIELD OPERATION OF COMPACT PROVERS FOR MASTER PROVING

by

M BAYLISS

OCCIDENTAL PETROLEUM (CALEDONIA)

PAPER 5.3

NORTH SEA FLOW METERING WORKSHOP 1984

16-18 October 1984

National Engineering Laboratory
East Kilbride, Glasgow

PRACTICAL FIELD OPERATION OF COMPACT PROVERS FOR MASTER PROVING

M.D.H. Bayliss

Although compact provers have been commercially available in the USA for several years, their use in the UK has only recently been accepted by regulatory bodies. This acceptance has not been granted generally but permitted on an application-by-application basis only.

This paper describes the first permitted uses, as a special case, on live crude oils for annual master proof recalibration of UK offshore platform pipe provers. Techniques were developed to use the small volume and high speed of operation of a compact prover to its greatest advantage and improve upon the traditional API[1] methods of proving.

INTRODUCTION

Occidental Petroleum (Caledonia) Ltd. operates an oil pipeline on behalf of a consortium to their terminal on Flotta, Orkney. The live crudes feeding the line are exported from their Piper and Claymore platforms as well as Texaco's Tartan installation. Each platform has fiscal metering stations for crude oil using positive turbine meters and a bi-directional pipe prover.

Annual master proving calibration is required by the Department of Energy and until 1983 had been carried out using a portable pipe prover. This was normal practice in the UK sector of the North Sea and involved the use of one of two purpose built units which were both large and heavy. On Piper platform, the master proving exercise involved the temporary removal of a stairway each year and on both Piper and Claymore the access in the area was considerably reduced. Although physically large units, the portable pipe provers had very restricted flow capability which created difficulty in launching the sphere of the platform prover due to the sphere receiver design. It was thus with great interest that the availability of a compact prover in the UK was greeted.

One of the metering calibration companies was able to offer a 14" Brooks Compact Meter Prover in time for the 1983 master proving on Piper and Claymore. Details of the construction and principles of operation of this device have been described by Wolf[2] and are also available in manufacturer's literature[3]. On informal application to the Department of Energy there was naturally reluctance to permit the use of a device which had no local user history, particularly on live crude. Compact provers had been used in the Norwegian Sector of the North Sea but the only available data related to their use on diesel fuel circulated by a pump rather than using the process fluid.

Generally, there seemed to be a lack of confidence in a piece of equipment which had been produced in some quantity in the USA with good user experience. Doubts were expressed about leakage past the piston and poppet valve seals where dynamic checking of the leak rate was not possible, though static tests were demonstrably good. A number of trials were carried out but authorities remained sceptical about successful proofs on light hydrocarbon products being repeated on live crudes.

The advantages of using a compact prover offshore decided the writer to proceed independently with master proofs on a trial basis, since the authority's requested "double trial" using a portable pipe prover alongside the compact unit could not be readily accommodated offshore. It was agreed with the Department of Energy that the results obtained would not automatically be accepted but be reviewed along with other data from land-based proofs on petroleum products and water. Clearly, to gain the necessary experience with the unit on live crude, someone had to be first!

OFFSHORE MASTER PROVING PREPARATION

Both Piper and Claymore crude oil metering systems operate on a continuous basis, the flowrate being determined by the levels in the production separators, Fig. 1 q.v. Level Control Valves are placed, somewhat unconventionally, downstream of the meters but before the branch to the prover header, necessitating liquid compressibility corrections to the routine meter proofs. One meter is dedicated to each separator with a common spare. On Piper, flow to the master prover is achieved by pinching back the appropriate meter run valve with its associated prover diverter valve being fully opened. Claymore platform has the facility, schematically shown in Fig. 2, to feed crude from the test separator through the prover and return it to either of the production separators. This is ideal for master proving, since it enables one or two individual wells to be routed through the prover on their own. Claymore well characteristics vary considerably - wells featuring dry production, steady flow and low density being favoured for master proving.

The master prover connections on both platforms are the usual 3" 300 lb ANSI flanges, teed off the platform pipe prover discharge line. To ensure isolation of this line during master proving a line blind (spade) is fitted on Piper, a double block-and-bleed valve serving the same purpose on Claymore. For the initial trials, the compact prover was connected to its separate 3" turbine reference meter by means of flexible hoses, this being improved later to a fixed piggy-back mounting over the top of the prover barrel. The tie-in was thus similar to that used for a portable loop prover, though the improved access around the compact prover was immediately obvious with no walkways or stairs being significantly obscured.

Shipping the compact prover had been a simple task involving only a 1-1/2 ton lift into a standard container, the electronics and water-draw can being separately packed into the same container. Loaded forward on the supply boat to minimise seawater ingress, the container was handled normally onto the platform skid deck along

with other containerised cargo. The prover could then be rolled out on its large castors and lifted to the laydown area adjacent to the calibration connections, being finally moved by hand to the best position. Portable pipe provers had always been an awkward lift of 6-7 tons down to this area with the best position made inaccessible to the crane by an overhead walkway.

Normal preparations for the master proof, such as spading the platform prover drains where necessary and checking for leakage at appropriate valves, were carried out. The annual full maintenance programme had been carried out a few weeks before to change out the platform prover sphere and 4-way valve slips, check detector switches and calibrate all associated instrumentation. The platform prover was drained, flushed with water and the sphere removed for inspection and sizing. It has been found best to bed the sphere in by using it for a week or two prior to the master proof and allow it to assume the usual, slightly elipsoid, shape. The sizing should be about 2-3% over the bore of the prover for large provers such as Piper (24") and Claymore (18").

The most sensitive measurements required for determination of liquid coefficients are the various temperatures at the platform and compact provers. Observation errors in reading glass thermometers are a major source of measurement uncertainty so these were used initially to check the accuracy of the platform instrumentation whose direct digital readout was used thereafter. Intercomparison of the various standard glass thermometers to be used was also carefully carried out to minimise any small offsets to liquid characteristics measured at the different points. Pressure and temperature correction factors for the liquid in use cancel out in the calculations of prover volume when conditions are the same at the master prover, meter and platform prover. It should be noted that differences in conditions between the various points in the system are far more critical than the magnitude of their values. The actual values are however required for calculations of the steel correction factors back to standard (base) conditions. As a rough guide, the liquid temperature coefficients of cubical expansion are 25-30 times those of steel; ie: a 0.1°C temperature difference error between two liquid measurement points has the same effect as a 2.5°C error in the true temperature reading. Similarly, with pressure measurements, the ratio of coefficients is around 5:1 (liquid to steel) for the Piper and Claymore provers. Repeatability and readability are thus of great importance.

DEVELOPMENT OF THE NEW MASTER PROOF METHOD

For the initial proof trial on the Piper platform the procedure shown in Table 1 was to be adopted. The traceability advantages of this method have been fully described by Inglis[4].

This in line with the normal pipe master prover procedure except that the water draw data for obtaining the pipe prover pre-proof volume will have been determined onshore anything up to a year previously and no post-proof water draw would be carried out. It should also be noted that the commercial pipe-prover calibration

rigs employ positive displacement meters rather than turbines as the reference device. For master proving with the compact unit, the positive displacement meter is unsuitable due to its inadequate resolution, though its short-term repeatability is superior, particularly under varying flowrate conditions.

Five water draws were obtained within the necessary 0.02% spread, followed by five pre-proof turbine meter calibration runs (each consisting of the mean factor from five compact prover passes) using the same data spread criterion. Master proving then commenced and extreme difficulty was experienced in trying to achieve the five consecutive proof runs within 0.02% spread. 0.1% was being achieved with ease but the platform prover volume results jumped in steps within this band after a few readings. Whilst continuing to calibrate the platform prover, some compact prover runs were then made against the reference meter to track its meter factor and to confirm that the two provers would run in series without unwanted interactions. Similar order jumps in meter factor to those in platform prover pulse counts were noted. The reference meter was taken out of the line and stripped - only to discover that it spun freely on perfect bearings, was clean and that all was well with the pickups and associated electronics.

Pressures and temperatures had remained substantially steady over the course of the proving, so that the changes in meter factor could only be attributed to changes in flowrate and perhaps the float characteristics of the rotor on its liquid bearing. Small slugs of water were also suspected as possibly having settled out in the prover and, being of significantly different viscosity, temporarily altering the meter factor.

By taking the ratio of the meter factor during each platform prover half-trip run and the associated proof pulse count readings, a remarkably good repeatability emerged. Why not, then, discard previous practice and develop a new method? Indeed, there were some obvious advantages in carrying out as many compact prover runs as possible against the reference meter whilst the master proof of the platform prover was ongoing. On Piper, fifteen calibration runs were found possible for each half-trip of the platform prover, the dead time between runs being that taken for the compact prover piston to return. This resulted in a calibration run of approximately three seconds every sixteen seconds evenly spread over the four minute half-trip time. In addition, the meter liquid temperature and pressure corrections totally cancelled out in the calculations of platform prover volume, the recording of meter pressure and temperature readings being retained more by convention than necessity in order to arrive at a meter factor related to base conditions. Five consecutive round-trips within the necessary 0.02% spread were readily obtained using this technique.

The final water draw obtained, though it was observed that it had shifted somewhat and was only just within tolerance. The revised procedure had thus evolved as shown in Table 2.

CALCULATION PRINCIPLES

At an early stage, in considering the use of the compact prover, the need for quickly and accurately carrying out all the necessary prover pressure and temperature correction calculations had been appreciated. In addition, calculations for the water draw had to be completed rapidly in order to assess their validity. A suite of programs had been written for the Hewlett-Packard HP41CV hand-held calculator and printer so that the readings could be keyed in at the master prover location, all the necessary calculations performed, and a printed record retained. This facility proved invaluable in executing the revised procedure since it was useful to calculate the meter factor and the half-trip volume of the platform prover during the four minutes taken by the following run.

This made an immediate accurate judgement of the spread of corrected volumes possible which might otherwise have been difficult if a small (e.g. 0.2°C) temperature change between the provers occurred.

It is important to note that the published tables so often used for both liquid and steel corrections to and from base conditions do not really have adequate resolution for master proving. Thus all correction factors calculated by the program were stored and manipulated to full calculator (12 digit) accuracy and only rounded once the half-trip volume had been determined. Rounding at each stage of correction factor determination or using tables can readily introduce 0.01% glitches in the results - half the allowable result spread.

Since pressure and temperature characteristics of live crudes are not covered by published tables, samples of the platform oils were submitted to a laboratory for PVT analysis to determine their temperature coefficient of cubical expansion and compressibility. These data were used by the calculator program to calculate the liquid corrections. It is necessary to ensure that these coefficients are determined close to the expected proving conditions and that they are also subsequently used in making any liquid corrections required during the routine platform meter proofs.

FURTHER TRIALS

On completion of the Piper master proof the compact prover was shipped to Claymore. The large shift between pre and post water draw results had led to additional checks on piston seal leakage being made, though all appeared to be within the manufacturer's tolerances. Generally the history of this compact prover had always shown extremely repeatable water draw results, with changes in the prover swept volume of the order of 0.01% over a period of months. The reason for the shift on Piper became all too evident when, on Claymore, difficulty in obtaining repeatability on the compact unit prompted the calibration team to strip out the piston and examine the cylinder bore. What appeared to be a line of crevice corrosion had affected the honed bore along the bottom of the cylinder for a considerable length. The gap through which liquid could bypass the

piston was estimated to be about 1-2 mm^2 and the piston seals had suffered somewhat by contact with the resultant rough edge. The leak checks had been carried out, by chance, in an area of the bore virtually undamaged and had thus not revealed any problems.

In due course a new cylinder was obtained and seals replaced, with the lesson learnt to check for leakage at several points along the length of the swept volume and preferably also visually inspect the cylinder bore! Both these checks were simple to perform. It was noteworthy that the great sensitivity of the water draw procedure had highlighted the problem. In view of the doubts over the first trial proof which had been performed on Piper, it was repeated. The resulting platform prover volume came very close to the first and demonstrated that such calibration of the compact prover against water draws compensated even for such severe damage to the bore.

The calibration of the four volume combinations of Claymore's prover was achieved with better repeatability and speed than ever before. The greater flowrate capability of the compact unit also reduced the temperature drops between the platform and master provers by a factor of two compared with the previous portable pipe provers used, thus significantly improving one of the greatest sources of measurement uncertainty.

A year on - the Piper platform prover volume was again calibrated against the same compact prover. The difference between the 1983 and 1984 calibrations was 0.007%. Typical calibration sheets showing the calculations and results are appended. A number of improvements were made over the year to the compact prover to facilitate easier checking of piston leakage rates and protect against entry of foreign objects which might damage the cylinder bore or piston seals. Resolution and intra-rotational linearity of the reference turbine meter was improved by fitting a rimmed rotor in place of the blade type used in the first trials.

SUMMARY

The compact prover, despite early tribulations, has been demonstrated to perform an admirable job and the perserverance in developing new operating methods has resulted in improved performance as a master prover. The characteristics of the reference meter can largely be ignored and, by in situ water drawing, so can the long-term repeatability of the compact prover. The results using the revised operating procedure described have been accepted by the fiscal authorites.

The use of a compact prover as a permanent offshore calibration standard for routine meter proving will be considered by many as desirable for the lightweight jacket and floating production systems being proposed for marginal fields. Experience gained in use as a master prover has been invaluable in assessing the compact prover's suitability for such service.

ACKNOWLEDGEMENTS

The author wishes to thank the Piper and Claymore operations and maintenance staff, Mr. Gerry Inglis of Caleb Brett Technical Services and Mr. Bruce Lawson of ICE Petrochemical Engineering Ltd. for their cooperation and considerable assistance during the trials.

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2. Wolf, R.J. "Meter Proving with the compact piston prover". Proc. Inst. M.C. Conf. Aberdeen 1983 - Flow Metering and Proving Techniques in the Offshore Industry.

3. Brooks Instrument Div., Emerson Electric Co., Statesboro, Georgia. Technical Literature.

4. Inglis, G.E. "The Application and Operation of Compact Provers as used for the recalibration of in-service Mechanical Displacement Piper Provers Offshore" Proc. Inst. M.C. Conf, Aberdeen 1983 - Flow Metering and Proving Techniques in the Offshore Industry.

TABLE 1
CONVENTIONAL MASTER PROVING PROCEDURE

1. Water draw compact prover on site
2. Calculate pre-proof compact prover volume
3. Calibrate reference turbine
4. Obtain pre-proof turbine meter factor
5. Calibrate platform prover against reference meter
6. Calibrate reference turbine (post-proof)
7. Obtain post-proof meter factor
8. Water draw compact prover on site
9. Calculate post-proof compact prover volume
10. Calculate mean compact prover volume and recalculate steps 3/4, 6/7 and 5.

TABLE 2
REVISED MASTER PROVING PROCEDURE

1. Water draw compact prover
2. Calculate pre-proof compact prover volume
3. Calibrate platform prover against reference meter. Reference meter factor separately determined against compact prover for each half trip of platform prover.
4. Water draw compact prover
5. Calculate post-proof compact prover volume
6. Calculate mean compact prover volume and recalculate step 3

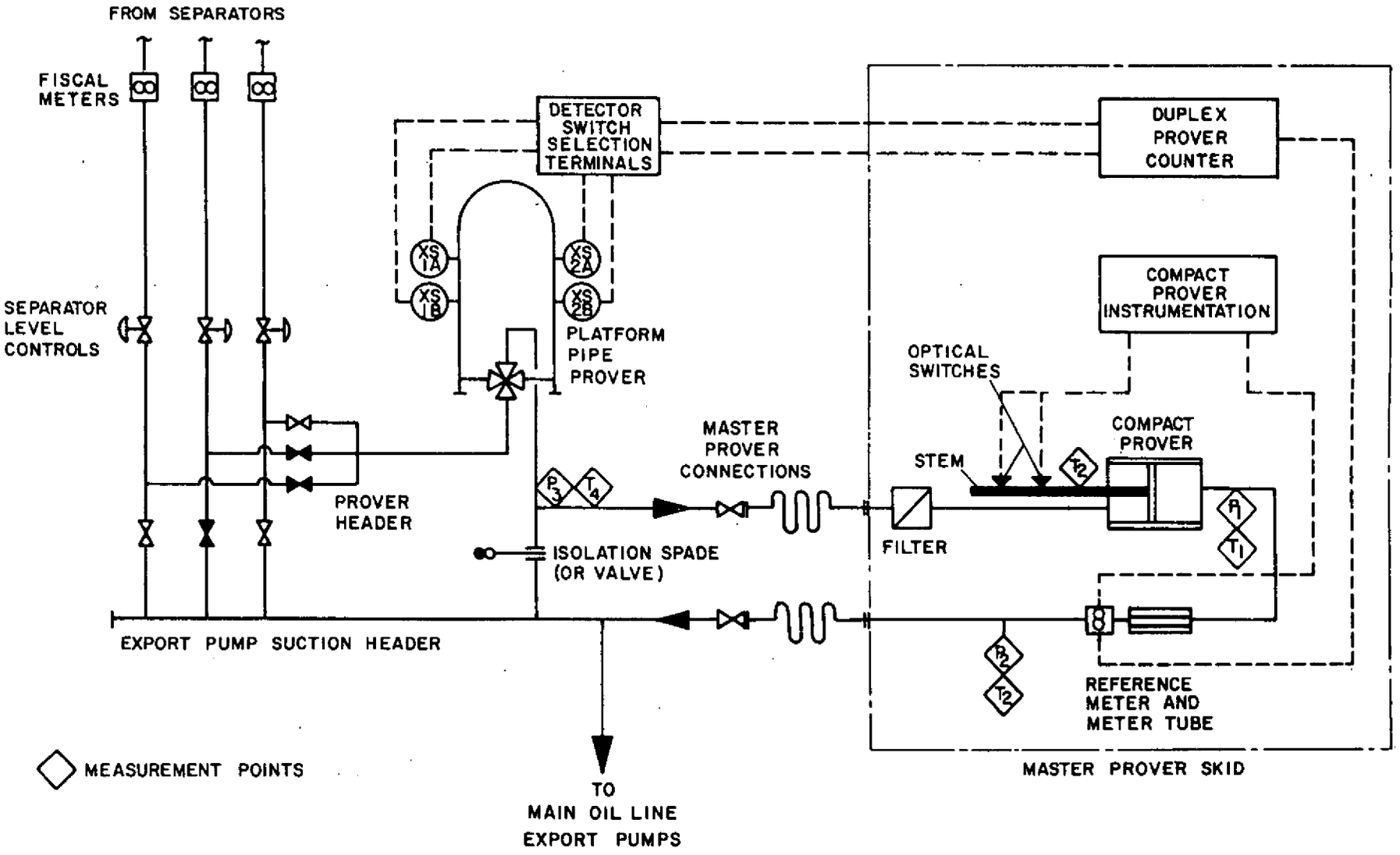

FIG.1. TYPICAL HOOK-UP SCHEMATIC FOR MASTER PROVING

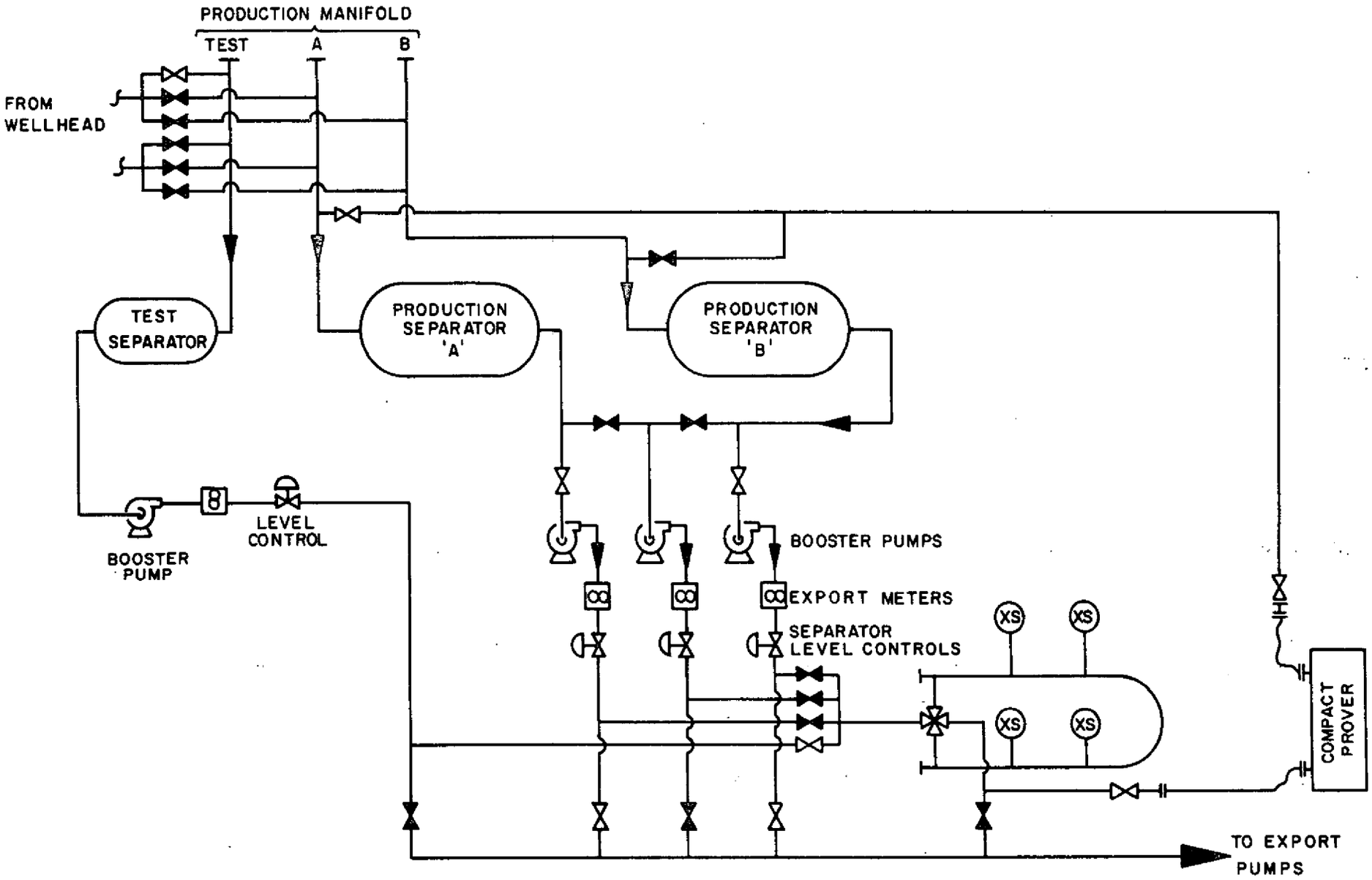

FIG. 2. CRUDE ROUTING FOR MASTER PROVING — CLAYMORE

Caleb Brett Technical Services

CALIBRATION REPORT for COMPACT METER PROVER (BY WATER DRAW)

PRE-CALIBRATION
WATER DRAW

CLIENT: OCCIDENTAL PETROLEUM

LOCATION: PIPER ALPHA PLATFORM

DATE: 29th AUGUST, 1984.

PROVER SERIAL No. 8202-08841
MANUFACTURER: BROOKS INSTRUMENT
NOMINAL INT. DIA. (D): 12.25"
WALL THICKNESS (t): 0.875"

PROVING TANK SERIAL No. 10031-3
CERTIFYING AUTHORITY: NATIONAL WEIGHTS & MEASURES LABORATORY
DATE OF CERTIFICATION: 20th JANUARY 1984
VOLUME: 56.7298 S.I. LITRES (3461.8648 IN^3) @ 15°C.

RUN No. (1)	MEASURE LITRES: BASE VOLUME (2)	SCALE RGD. IN^3 + (3)	SCALE RGD. IN^3 - (3)	READ VOLUME @ T_3 (4)	TEMPERATURE (°C.): CP T_1 (5)	ST T_2 (6)	MEAS. T_3 (7)	ΔT $T_3 - T_1$ (8)	PRESSURE PROVER (BAR G) P_1 (9)	TEMPERATURE CORRECTION: CTL (10)	CTSm (11)	CTSp (12)	PROVER VOLUME AT P, & REF.TEMP. (4)x(10)x(11)x(12) (13)
A2	56.7298	17.0		57.0084	18.2	15.7	18.0	0.2	3.3	1.00004	1.00014	0.99993	57.0147
A3	56.7298	17.0		57.0084	18.3	16.0	18.1	0.2	3.5	1.00004	1.00015	0.99992	57.0147
A4	56.7298	17.0		57.0084	18.4	16.2	18.2	0.2	3.4	1.00004	1.00015	0.99992	57.0147
A5	56.7298	16.5		57.0002	18.5	16.0	18.2	0.3	3.4	1.00005	1.00015	0.99992	57.0069
A6	56.7298	16.7		57.0035	18.4	15.9	18.1	0.3	3.4	1.00005	1.00015	0.99992	57.0103
											SPREAD	= 0.014%	

VOLUME: LITRES
REF.TEMP(T): 15°C.
REF.PRESSURE(P): 0 BAR G

AVERAGE DISPLACED VOLUME AT P, & REF.TEMPERATURE
= 57.0123 (14)

PRESSURE CORRECTION FACTORS
CPL: 0.99984 (15)
CPS: 0.99998 (16)

AVERAGE DISPLACED VOLUME AT REFERENCE TEMPERATURE & ATMOSPHERIC PRESSURE,
= (14) x (15) x (16)
= 57.0020 S.I. LITRES

ENGINEER
P. EVANS/P. BOYLE

ISSUED BY
G.E. INGLIS
For and on behalf of Caleb Brett Technical Services

NOTES ALL REFERENCES FROM MANUAL OF PETROLEUM MEASUREMENT STANDARDS/TABLES.
COLUMN (5)(6)(7) TEMPERATURES SHOWN ARE CORRECTED READINGS

(10)	THERMAL EXPANSION WATER	: CHAPTER 11.4.2.			
(11)	THERMAL EXPANSION STEEL (MEASURE)	: CHAPTER 12.2. PARA 12.2.5.1.	$1 + (T_3 - T)(\delta)$	WHERE δ =	0.0000477/°C.
(12)	THERMAL EXPANSION STEEL (PROVER)	: CHAPTER 12.2. PARA 12.2.5.1.	$1 - [(T_1 - T)(\delta_1) + (T_2 - T)(\delta_2)]$	WHERE δ_1 =	0.0000223/°C.
				δ_2 =	0.0000016/°C.
(15)	COMPRESSIBILITY OF WATER	: CHAPTER 12.2. PARA 12.2.5.4.	$1 + [(1 + (P_1 - P)(F)]$	WHERE F =	0.0000464/BAR
(16)	EXPANSION OF STEEL - PRESSURE	: CHAPTER 12.2. PARA 12.2.5.2.	$1 - (P_1 D/Et)$.	WHERE E =	2.0 x 10⁶

Caleb Brett Technical Services

CALIBRATION REPORT for
COMPACT METER PROVER (BY WATER DRAW)

POST CALIBRATION
WATER DRAW

CLIENT: OCCIDENTAL PETROLEUM

LOCATION: PIPER ALPHA PLATFORM

DATE: 2nd SEPTEMBER 1984.

PROVER SERIAL No. 8202-08841

MANUFACTURER: BROOKS INSTRUMENT

NOMINAL INT. DIA. (D): 12.25"

WALL THICKNESS (t): 0.875"

PROVING TANK SERIAL No. 10031-3

CERTIFYING AUTHORITY: NATIONAL WEIGHTS & MEASURES LABORATORY

DATE OF CERTIFICATION: 20th JANUARY 1984

VOLUME: 56.7298 S.I. LITRES (3461.8648 IN^3) @ 15°C.

RUN No.	MEASURE LITRES: BASE VOLUME	SCALE RGD. IN^3 +	SCALE RGD. IN^3 -	READ VOLUME @ T_3	TEMPERATURE (°C.): CP T_1	ST T_2	MEAS. T_3	ΔT $T_1 - T_3$	PRESSURE PROVER (BAR G) P_1	TEMPERATURE CORRECTION: CTL	CTSm	CTSp	PROVER VOLUME AT P_1 & REF. TEMP. (4)x(10)x(11)x(12)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
B1	56.7298	16.9		57.0067	20.5	24.4	20.8	-0.3	3.5	0.99993	1.00028	0.99986	57.0107
B2	56.7298	16.6		57.0018	20.7	25.2	20.7	NIL	3.5	1.00000	1.00027	0.99986	57.0092
B3	56.7298	17.0		57.0084	20.4	24.7	20.7	-0.3	3.5	0.99993	1.00027	0.99986	57.0118
B4	56.7298	17.0		57.0084	20.4	21.2	20.6	-0.2	3.5	0.99995	1.00027	0.99987	57.0135
B5	56.7298	16.7		57.0035	20.5	22.0	20.5	NIL	3.5	1.00000	1.00026	0.99987	57.0109
											SPREAD	= 0.008%	
										AVERAGE	(Pre-post)	VOLUME =	
												57.0015 LITRES	
										SPREAD	(Pre-post)	= 0.002%	

VOLUME: LITRES
REF. TEMP. (T): 15°C.
REF. PRESSURE (P): 0 BAR G.

AVERAGE DISPLACED VOLUME AT P_1 & REF. TEMPERATURE
= 57.0112 (14)

PRESSURE CORRECTION FACTORS
CPL: 0.99984 (15)
CPS: 0.99998 (16)

AVERAGE DISPLACED VOLUME AT REFERENCE TEMPERATURE & ATMOSPHERIC PRESSURE.
= (14) x (15) x (16)
= 57.0009 S.I. LITRES

ENGINEER: P. EVANS/P. BOYLE

ISSUED BY: G.E. INGLIS
For and on behalf of Caleb Brett Technical Services

NOTES
ALL REFERENCES FROM MANUAL OF PETROLEUM MEASUREMENT STANDARDS/TABLES.

COLUMN (5)(6)(7) TEMPERATURES SHOWN ARE CORRECTED READINGS

(10)	THERMAL EXPANSION WATER	: CHAPTER 11.4.2.		
(11)	THERMAL EXPANSION STEEL (MEASURE)	: CHAPTER 12.2. PARA 12.2.5.1.	$1 + (T_3 - T)(\gamma)$	WHERE γ = 0.0000477/°C.
(12)	THERMAL EXPANSION STEEL (PROVER)	: CHAPTER 12.2. PARA 12.2.5.1.	$1 - [(T_1 - T)(\gamma_1) + (T_2 - T)(\gamma_2)]$	WHERE γ_1 = 0.0000223/°C.
				γ_2 = 0.0000016/°C.
(15)	COMPRESSIBILITY OF WATER	: CHAPTER 12.2. PARA 12.2.5.4.	$1 - [(1 + (P_1 - P)(F)]$	WHERE F = 0.0000464/BAR
(16)	EXPANSION OF STEEL - PRESSURE	: CHAPTER 12.2. PARA 12.2.5.2.	$1 - (P_1 D/Et)$.	WHERE E = 2.0×10^6

Caleb Brett Technical Services

CALIBRATION REPORT for MECHANICAL DISPLACEMENT METER PROVER (BY REFERENCE METER/COMPACT PROVER)

CLIENT: OCCIDENTAL PETROLEUM
LOCATION: PIPER 'ALPHA' PLATFORM
DATE: 2nd SEPTEMBER 1984.

PROVER SERIAL No: PIPER 'ALPHA' PROVER
MANUFACTURER: A.O.T.
TYPE: 24" NB BI-DIRECTIONAL

RUN No (1)	CP VOLUME FACTOR or PULSE COUNTS (2)	K-FACTOR or K-GROSS (3)	TEMPERATURE °C. CP T_1 (4)	ST T_2 (5)	M T_3 (6)	PP T_4 (7)	PRESSURE BAR CP P_1 (8)	M P_2 (9)	PP P_3 (10)	CORRECTION FACTORS CP or PP CTSp (11)	CPSp (12)	CP or PP CTLp (13)	CPLp (14)	METER CTLm (15)	CPLm (16)	K-GROSS or PROVER VOLUME (17)	AVERAGE K-GROSS or TOTAL VOLUME (18)
30F	0.99997	13.3064	57.8	22.8	57.8		15.2	15.0		1.00097	1.00011	0.95574	1.00184	0.95574	1.00182	13.29138	
	59392	13.29138			57.8	58.1		15.0	18.3	1.00144	1.00042	0.95543	1.00221	0.95574	1.00182	4459.8724	
30R	0.99997	13.3040	57.8	22.8	57.8		15.2	15.0		1.00097	1.00011	0.95574	1.00184	0.95574	1.00182	13.28898	
	59327	13.28898			57.8	58.1		15.0	18.3	1.00144	1.00042	0.95543	1.00221	0.95574	1.00182	4455.7960	8915.6684
31F	0.99997	13.3135	57.6	21.2	57.6		15.0	14.7		1.00096	1.00011	0.95595	1.00182	0.95595	1.00178	13.29834	
	59407	13.29834			57.6	57.9		14.7	17.4	1.00144	1.00040	0.95564	1.00211	0.95595	1.00178	4459.0197	
31R	0.99997	13.3137	57.4	25.2	57.4		15.0	14.7		1.00096	1.00011	0.95616	1.00182	0.95616	1.00178	13.29854	
	59370	13.29854			57.4	57.7		14.7	17.4	1.00143	1.00040	0.95585	1.00211	0.95616	1.00178	4456.2197	8915.2394
32F	0.99997	13.3141	57.3	26.0	57.3		15.0	14.7		1.00096	1.00011	0.95626	1.00182	0.95626	1.00178	13.29894	
	59409	13.29894			57.3	57.6		14.7	17.4	1.00143	1.00040	0.95595	1.00211	0.95626	1.00178	4459.0127	
32R	0.99997	13.3082	57.2	25.8	57.2		15.0	14.7		1.00096	1.00011	0.95637	1.00182	0.95637	1.00178	13.29304	
	59352	13.29304			57.2	57.5		14.7	17.4	1.00142	1.00040	0.95606	1.00211	0.95637	1.00178	4456.7560	8915.7687
33F	0.99997	13.3083	57.2	23.8	57.2		15.0	14.7		1.00096	1.00011	0.95637	1.00182	0.95637	1.00178	13.29314	
	59400	13.29314			57.2	57.5		14.7	17.4	1.00142	1.00040	0.95606	1.00211	0.95637	1.00178	4460.3268	
33R	0.99997	13.3086	57.2	23.7	57.2		15.0	14.7		1.00096	1.00011	0.95637	1.00182	0.95637	1.00178	13.29344	
	59345	13.29344			57.2	57.5		14.7	17.4	1.00142	1.00040	0.95606	1.00211	0.95637	1.00178	4456.0963	8916.4231
34F	0.99997	13.3077	57.2	24.8	57.2		15.0	14.7		1.00096	1.00011	0.95637	1.00182	0.95637	1.00178	13.29254	
	59396	13.29254			57.2	57.5		14.7	17.4	1.00142	1.00040	0.95606	1.00211	0.95637	1.00178	4460.2278	
34R	0.99997	13.3135	57.2	24.8	57.2		15.0	14.7		1.00096	1.00011	0.95637	1.00182	0.95637	1.00178	13.29834	
	59357	13.29834			57.2	57.5		14.7	17.4	1.00142	1.00040	0.95606	1.00211	0.95637	1.00178	4455.3551	8915.5829
															SPREAD	= 0.014%	

UNIT VOL: LITRES
REF TEMP.(T): 15°C.
REF PRESSURE (P): 0 BAR G

FLOWRATE: 950/1125 LPM
PRODUCT: CRUDE OIL
TEMP.COEF.=1034×10^{-6}/°C.
PRES.COEF.=121×10^{-6}/BAR

PIPE PROVER NOM I.D (D): 23.000"
WALL THICKNESS (t): 0.500"
SPHERE DIA: 23.600"
SPHERE MATL: NEOPRENE

COMPACT PROVER NOM I.D (D): 12.25"
WALL THICKNESS (t): 0.875"
BASE VOLUME: 57.0015 LITRES
SET-IN VOLUME: 57.0000 LITRES

REFERENCE METER: DANIEL
SERIAL No: 82-00802
SIZE/TYPE: 3" TURBINE

CP – COMPACT PROVER
ST – SENSOR TUBE of CP
PP – PIPE PROVER
M – REFERENCE METER

NOTES: ALL REFERENCES FROM MANUAL OF PETROLEUM MEASUREMENT STANDARDS/TABLES.

COLUMN (2): CP VOLUME FACTOR = SET-IN VOLUME (COUNTER) ÷ BASE VOLUME (WATER DRAW)

(3): K-FACTOR OBTAINED FROM PRINT-OUT. K-GROSS OBTAINED FROM AVERAGE K-FACTORS

(4)(5)(6)(7): TEMPERATURES SHOWN ARE CORRECTED READINGS

(11): THERMAL EXPANSION OF STEEL : CHAPTER 12.2, PARA 12.2.5.1

$CP = 1 + (T_1 - T)\delta(8) + (T_2 - T)(\delta_2)$ WHERE δ_1 = 0.0000223/°C.
δ_2 = 0.0000016/°C.

$PP = 1 + (T_4 - T)(\delta)$ WHERE δ = 0.0000335/°C.

(12): EXPANSION OF STEEL - PRESSURE : CHAPTER 12.2, PARA 12.2.5.2

$CP = 1 + (P_1 D/Et)$ WHERE E = 2.0×10^6

$PP = 1 + (P_3 D/Et)$ WHERE E = 2.0×10^6

(13) (15): THERMAL EXPANSION OF PRODUCT ~~ASTM-1250-80~~

(14) (16): COMPRESSIBILITY OF PRODUCT ~~CHAPTER 11.2~~

$CPL_{cp} = 1 - [\overline{1 - (P_1 - P_2)F}]$ WHERE F = SEE TEMP.+ PRESS. COEFFICIENTS ABOVE.

$CPL_{pp} = 1 - [\overline{1 - (P_3 - P_2)F}]$ WHERE F = SEE TEMP.+ PRESS. COEFFICIENTS ABOVE.

$CPL_m = 1 - [\overline{1 - (P_2 - P_2)F}]$ WHERE F = SEE TEMP.+ PRESS. COEFFICIENTS ABOVE.

(17) K-GROSS AT REF.TEMP/ATMOS PRESSURE

$$= \frac{\text{K-FACTOR} \times CPVF \times CTLm \times CPLm}{CTSp \times CPSp \times CTLp \times CPLp}$$

$$= \frac{2 \times 3 \times 15 \times 16}{11 \times 12 \times 13 \times 14}$$

(18) PIPE PROVER VOLUME AT REF.TEMP/ATMOS PRESSURE

$$= \frac{\text{PULSE COUNTS} \times CTLm \times CPLm}{\text{K-GROSS} \times CTSp \times CPSp \times CTLp \times CPLp}$$

$$= \frac{2 \times 15 \times 16}{3 \times 11 \times 12 \times 13 \times 14}$$

AVERAGE DISPLACED ROUND TRIP VOLUME AT REFERENCE TEMPERATURE & ATMOSPHERIC PRESSURE
= 8915.7365 S.I. LITRES

ENGINEER: P. EVANS/P. BOYLE

ISSUED BY: G.E. INGLIS
For and on behalf of Caleb Brett Technical Services