

FIELD EXPERIENCE OF TWO-PHASE FLOW MEASUREMENT

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SUMMARY

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

CONTENTS

	Page
NOTATION	III
1. INTRODUCTION	1
2. OBJECTIVES	1
3. PRINCIPLE OF OPERATION OF THE TWO-PHASE METER	1
3.1 Operation of Hardware	2
3.2 Operaton of Software	3
4. RESULTS	7
5. ASSESSMENT OF ACCURACY	11
5.1 Test Separator	11
5.2 Two-Phase Meter System Accuracy	13
6. CONCLUSIONS	
6.1 Conslusions with Respect to the Test Objectives	16
6.2 Further Conclusions	16

NOTATION

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

FIELD EXPERIENCE WITH THE TWO-PHASE FLOWMETER

1 INTRODUCTION

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

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

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

2 OBJECTIVES OF THE TEST

- 2.1 To ascertain that the measurement system functioned correctly according to its design under a variety of fluid conditions. Advantage was taken of the instigation of gaslift during the testing period.
- 2.2 To ascertain that the multiphase flow computer was calculating percentage phase and volume, in the line with the test separator located 17 km away on Gorm.
- 2.3 To determine the suitability of the unit for unmanned multiwell production platforms in terms of function.

3 PRINCIPLE OF OPERATION OF THE TWO-PHASE METER

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

Further, it is possible to extrapolate this concept and apply it to three component systems. In this case if the three compo-

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

- 1) the total volumetric flow of the three component mixture
 - 2) the gross mixture density (all three possible components)
 - 3) the separated liquid density.
- Temperature and pressure are also measured and are used for conversion to standard conditions.

3.1 Operation of Hardware

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

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

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

From the bundle the fluid flows through a 4" Euromatic turbine flowmeter with a five bladed rotor with ball race bearings and a single pick-up. Calibration of the flowmeter was conducted in situ in the meter system, so that the effect of the bypass was taken into account. The flowmeter was calibrated on water between approximately 200 and 2,000 m³/d. The standard deviation was shown to be 0.15% (see Appendix I) over this range.

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

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

3.2 Operation of Software

The computer pursues the following processing sequence:

3.2.1 Determination of gross volume per 10 s period

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

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

3.2.2 Determination of percent gas volume

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

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

$$\Gamma_{\text{gas}} = \text{density of gas (at T and P)} \\ \text{calculated by process simulation}$$

$$\Gamma_1 = \text{three component mixture density measured}$$

$$\Gamma_2 = \text{two component liquid density}$$

3.3.3 Determination of percent liquid (oil and water) volume

$$\% \text{ Liquid} = 100 - \% \text{ gas} \quad (3)$$

3.2.4 Determination of percent oil volume in liquid

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

$$\Gamma_{\text{water}} = \text{density of produced water} \\ \text{(at T and P) calculated}$$

$$\Gamma_{\text{oil}} = \text{density of oil} \\ \text{(at T and P) calculated}$$

3.2.5 Determination of percent water volume

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

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

The standard conditions which Mærsk Oil and Gas work to are

Gas	0°C and 1 bara m ³ (normal)
	60°F and 14.73 psia ft ³ (standard)
Oil	15°C and 1 bara m ³
	60°F and 14.69 psia bbls

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

3.2.6 Actual volume of gas

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

3.2.7 Standard volume of gas

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

- I) pressure was measured on site using a standard diaphragm silicone oil filled cell calibrated between 0-100 barg.
- II) temperature was measured by use of PT 100 and transmitter was calibrated from 0-100°C.
- III) normal temperature (T_{norm}) for gas volumes is 273.15°.
- IV) normal pressure (P_{norm}) is 1.0 bara.
- V) Z factor is determined from process simulation by flashing reservoir composition at 80°C and 19 barg and is entered as a constant, $Z = 0.93$.

3.2.8 Offgas volume

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

- I) OGF is the offgas factor and is measured as normal

cubic meter of gas per meter cubed of raw oil. Shrinkage is assumed to occur from operating conditions to final stage stabilisation conditions (1.8 bara and 40°C). Values for OGF and SF are depicted in Table 1 overleaf.

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

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

3.2.10 Actual oil volume

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

3.2.11 Standard oil volume

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

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

3.2.12 Volume of water

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

3.2.13 Water in oil percent (BS&W %)

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

3.2.14 Standard gas to oil ratio

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

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

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

Table 1

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

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

4 RESULTS

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

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

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

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

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

Taken at 0800 during phase 2 would give:

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

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

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

TABLE 2

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

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

TABLE 3

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

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

TABLE 4

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

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

5 ASSESSMENT OF ACCURACY

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

5.1 Test Separator

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

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

$$\begin{aligned}\sigma_{\text{gas vol test}} &= \sqrt{(\sigma_S^2 + \sigma_R^2)} && (15) \\ &= \sqrt{(3^2 + 5^2)} \\ &= 6\%\end{aligned}$$

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

$$\begin{aligned}\sigma_{\text{oil}} &= \sqrt{(1.0^2 + 1.0^2)} && (16) \\ &= 1.4\%\end{aligned}$$

and

$$\begin{aligned}\sigma_{\text{water}} &= \sqrt{(0.5^2 + 1.0^2)} && (17) \\ &= 1.1\%\end{aligned}$$

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

from the formula

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

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

$$\begin{aligned} \text{where } \sigma^2_{\text{cor oilR}} &= \left(1 - \frac{\% \text{water}}{100}\right)^2 \sigma^2_{\text{oilR}} + (\text{oil})^2 \sigma^2_{\% \text{waterR}} \\ &= (0.9)^2 (1.0)^2 + (0.9)^2 (1.0)^2 \\ &= 1.6\% \end{aligned} \quad (20)$$

$$\begin{aligned} \text{and } \sigma^2_{\text{cor oilS}} &= \left(1 - \frac{\% \text{water}}{100}\right)^2 \sigma^2_{\text{oilS}} + (\text{oil})^2 \sigma^2_{\% \text{waterS}} \\ &= (0.9)^2 (1.0)^2 + (0.9)^2 (0.5)^2 \\ &= 1.0\% \end{aligned} \quad (21)$$

$$\begin{aligned} \sigma_{\text{cor oil}} &= \sqrt{(1.6 + 1.0)} \\ &= 1.6\% \end{aligned} \quad (19)$$

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

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

$$\sigma_{\text{cor water}} = \sqrt{(\sigma^2_{\text{cor waterR}} + \sigma^2_{\text{cor waterS}})} \quad (23)$$

where

$$\begin{aligned} \sigma^2_{\text{cor waterR}} &= \sigma^2_{\text{waterR}} + \frac{\% \text{water}}{100}^2 \sigma^2_{\text{oilR}} + (\text{oil})^2 \sigma^2_{\% \text{waterR}} \\ &= (1.0)^2 + (0.1)^2 (1.0)^2 + (0.9)^2 (0.5)^2 \\ &= 1.2\% \end{aligned} \quad (24)$$

$$\begin{aligned} \text{and } \sigma^2_{\text{cor waterS}} &= (0.5)^2 + (0.1)^2 (1.0)^2 + (0.9)^2 (0.5)^2 \\ &= 0.45\% \end{aligned} \quad (25)$$

$$\begin{aligned} \text{so } \sigma_{\text{cor water}} &= \sqrt{(1.2 + 0.45)} \\ &= 1.3\% \end{aligned} \quad (23)$$

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

5.2 Two-Phase Meter System Accuracy

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

5.2.1 Turbine Meter

The volume measurement of total fluid flow is critical to the operational accuracy of the whole meter system. From the data presented with the calibration sheet it may be calculated that the standard deviation of K-factors measured between 22 and 73 m³/hr was 0.15% (see calculations in Appendix I). However, this type of accuracy was not anticipated for two phase mixture volume measurement. A figure of ±5% was assumed for the random error in measurement of homogeneous mixture containing <20% gas at actual conditions. It was further assumed that under high pressure the differences in density and viscosity between the gas and liquid become smaller and that this would further help to maintain the standard deviation to within ±5%. The deviation due to systematic error is estimated to be ±1.0% due to non-standard installation. This gives a total turbine meter measurement (σ_{turbine}) deviation of 5.1%.

5.2.2 Density Measurement (Γ_1 and Γ_2)

The density meter is able to measure to 1.0 kg/m³ or ±0.2%, however due to inadequacies in the calibration procedure the actual systematic error is estimated to be ±2.0%. Only two points using air and water were used to make up the calibration curve of scintillation counts versus their respective densities - a third point using a hydrocarbon liquid would increase the confidence in this calibration. Further error is likely considering that although the sources and counters were calibrated in situ they were dismantled and re-installed on the platform. Variations in pipe wall thickness along the pipe length will affect the counts versus density calibration. A random error of 0.5% is estimated due to variations in fluid homogeneity and hydrogen atom content (hydrogen has a different mass attenuation coefficient so that a change in hydrogen content can show itself as a change in density even when there is not one).

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

5.2.3 Process Simulation

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

5.2.4 Combined Accuracy of Dynamic System

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

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

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

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

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

$$\text{where } \sigma^2_{\% \text{ gasR}} = \left(\frac{\delta_{\% \text{ gas}}}{\delta \Gamma_2}\right)^2 \sigma^2_{\Gamma_2R} + \left(\frac{\delta_{\% \text{ gas}}}{\delta \Gamma_1}\right)^2 \sigma^2_{\Gamma_1R} + \left(\frac{\delta_{\% \text{ gas}}}{\delta \Gamma_{\text{gas}}}\right)^2 \sigma^2_{\Gamma_{\text{gasR}}} \quad (27)$$

$$\text{and } \sigma^2_{\% \text{ gasS}} = \left(\frac{\delta_{\% \text{ gas}}}{\delta \Gamma_2}\right)^2 \sigma^2_{\Gamma_2S} + \left(\frac{\delta_{\% \text{ gas}}}{\delta \Gamma_1}\right)^2 \sigma^2_{\Gamma_1S} + \left(\frac{\delta_{\% \text{ gas}}}{\delta \Gamma_{\text{gas}}}\right)^2 \sigma^2_{\Gamma_{\text{gasS}}} \quad (28)$$

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

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

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

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

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

where

$$\sigma^2_{\% \text{ oilR}} = \left(\frac{\delta_{\% \text{ oil}}}{\delta \Gamma_{\text{water}}}\right)^2 \sigma^2_{\Gamma_{\text{waterR}}} + \left(\frac{\delta_{\% \text{ oil}}}{\delta \Gamma_2}\right)^2 \sigma^2_{\Gamma_2R} + \left(\frac{\delta_{\% \text{ oil}}}{\delta \Gamma^2}\right)^2 \sigma^2_{\Gamma_{\text{oilR}}} + \left(\frac{\delta_{\% \text{ oil}}}{\delta \% \text{ liquid}}\right)^2 \sigma^2_{\% \text{ liquidR}} \quad (30)$$

and

$$\begin{aligned} \sigma^2_{\%oilS} = & \left(\frac{\delta_{\%oil}}{\delta_{\Gamma water}} \right)^2 \sigma^2_{\Gamma water} + \left(\frac{\delta_{oil}}{\delta_{\Gamma 2}} \right)^2 \sigma^2_{\Gamma 2S} \\ & + \left(\frac{\delta_{oil}}{\delta_{\Gamma oil}} \right)^2 \sigma^2_{\Gamma oilS} + \left(\frac{\delta_{oil}}{\delta_{\%liquid}} \right)^2 \sigma^2_{\%liquidS} \end{aligned} \quad (31)$$

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

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

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

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

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

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

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

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

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

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

6.0 CONCLUSIONS

6.1 Conclusions with Respect to the Test Objectives

As far as the objectives of the test are concerned it can be concluded that

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

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

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

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

6.2 Further Conclusions

One of the biggest errors may lie in the fact that there is 17 km of pipeline between the two measurement devices. A significant difference is what goes in to that which comes out may occur, especially over short periods. Proof of this occurred when a large slug of liquid arrived at the Gorm test separator towards the end of the final stage of testing. It is the inability to quantify this error that makes drawing any conclusions from this test very difficult. The only way to avoid this error in the future

might be to rent a test separator and install it just downstream of multiphase meter. In this way actual volumes could be measured and compared thus reducing the uncertainty due to conversion to standard conditions.

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

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

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

FIG 1

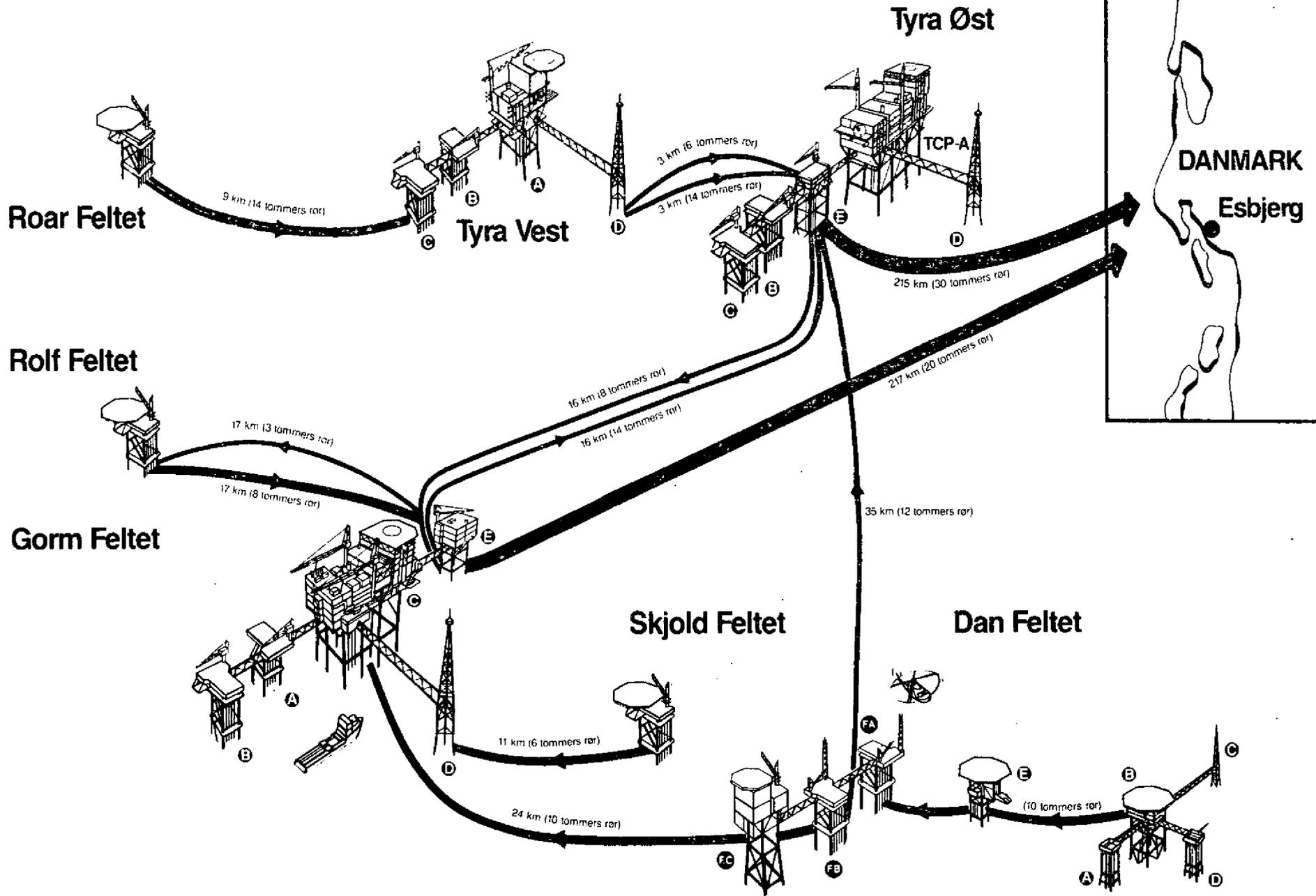
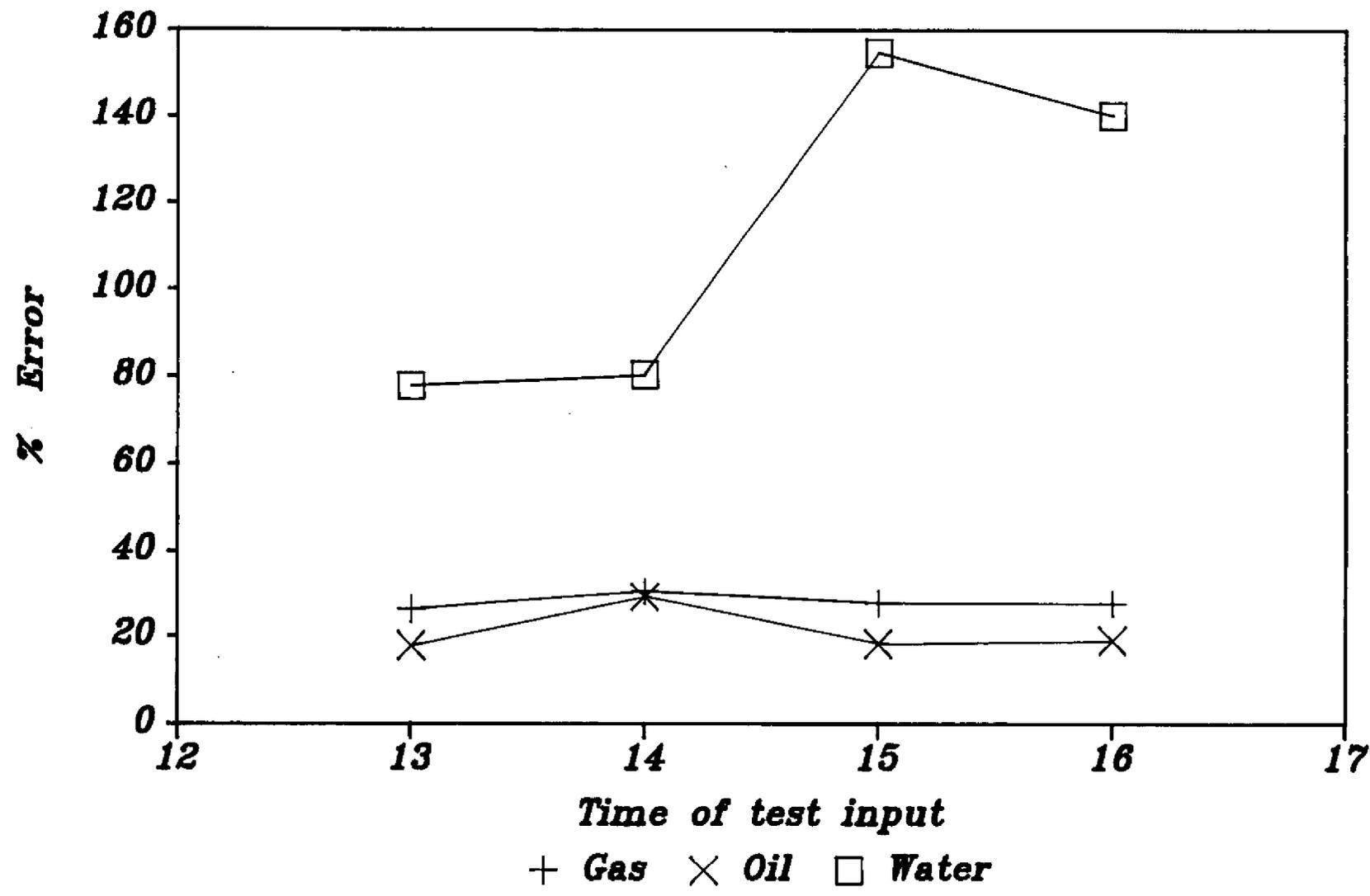


FIG 4

Multiphase Meter Test Phase 1
Percentage error



*Multiphase Meter Test Phase 2
Percentage error*

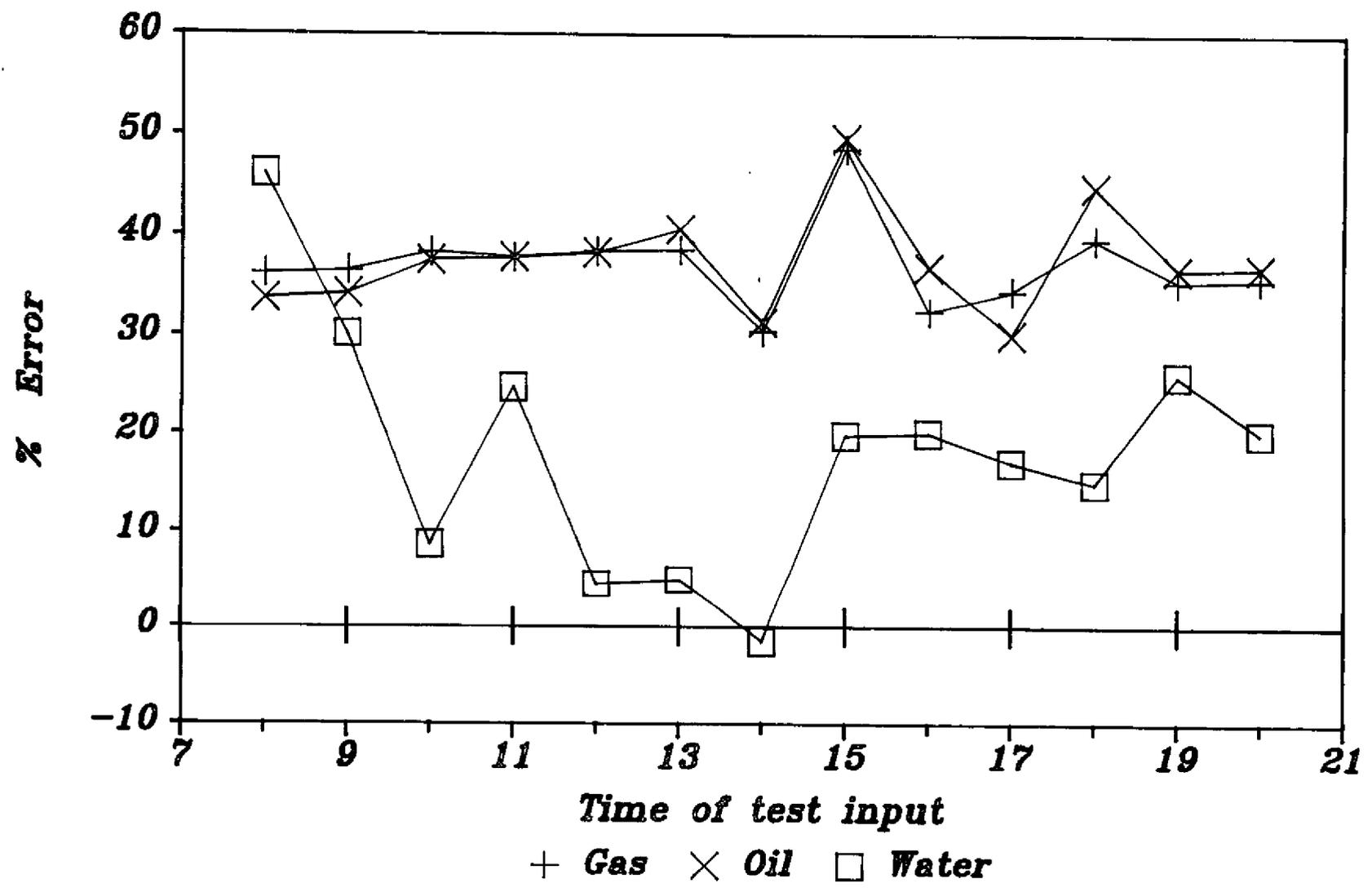
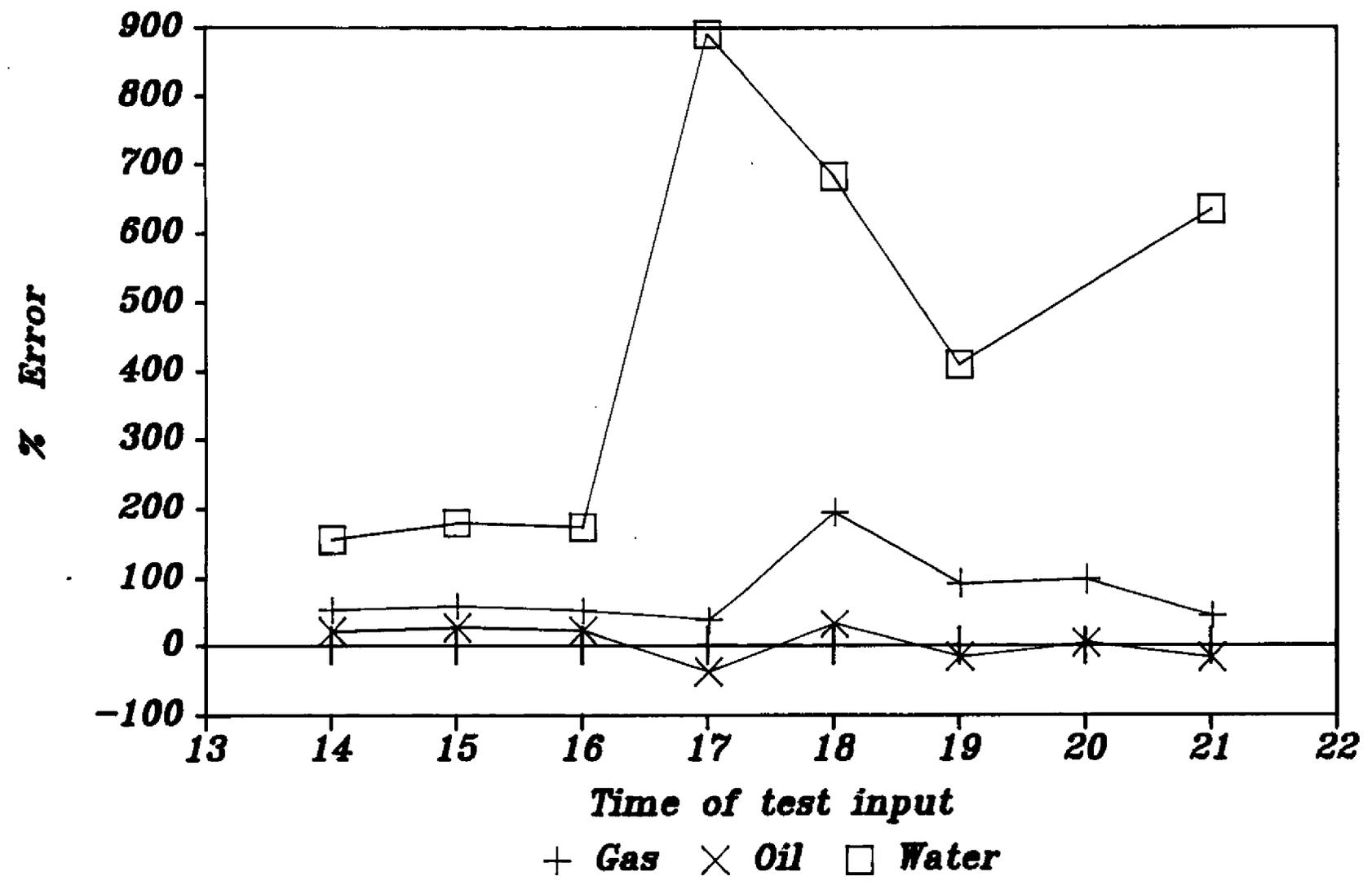


FIG 6

Multiphase Meter Test Phase 3
Percentage error



APPENDIX I

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

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

$$(\Sigma x)^2 = 39318790$$

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

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

$$= 2.33$$

$$S = 1.53$$

$$= 0.15\%$$

APPENDIX II

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

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

Volume of oil	=	1590	m ³ /d	
	=	66.25	m ³ /hr	
Volume of gas	=	2.5 x 10 ⁶	scf/d	
	=	67,000	m ³ /d	
	=	2,790	m ³ /hr	
actual gas	=	146		at 19 barg
Total volume (act.)	=	213.1	m ³ /hr	
Pipeline Volume	=	(0.2) ²	4 x 17.000	
	=	551	m ³	
Line Fill	=	<u>551</u>	hr	
		213		
	=	2.6	hr	

b) Production rate 13.000 bopd and TGOR 450

Volume of oil	=	2067	m ³ /d	
	=	86.1	m ³ /hr	
Volume of gas	=	5.85 x 10 ⁶	scf/d	
	=	243 x 10 ³	scf/hr	
	=	6.54 x 10 ³	m ³ /hr	
actual	=	139.1	m ³ /hr	
Total Volume	=	225	m ³ /hr	at 47 barg
Line Fill	=	<u>551</u>	hr	
		225		
	=	2.15	hr	

APPENDIX III

PROOF OF VOLUME RELATIONSHIP FOR PERCENT PHASE CALCULATION

The percentage of gas:

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

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

$$\begin{aligned} \% \text{gas} &= \frac{M_1/V_1 - (M_1 + M_g)/V_1 + V_g}{M_1/V_1 - M_g/V_g} \times 100\% \\ &= \frac{(M_1 \times (V_1 + V_g) - V_1 \times (M_1 + M_g))}{V_1 \times (V_1 + V_g)} \times 100\% \\ &\quad \frac{M_1 \times V_g - M_g \times V_1}{V_1 \times V_g} \\ &= \frac{(M_1 \times V_g - M_g \times V_1)}{V_1 \times (V_1 + V_g)} \times 100\% \\ &\quad \frac{M_1 \times V_g - M_g \times V_1}{V_1 \times V_g} \\ &= \frac{V_1 \times V_g}{V_1 \times (V_1 + V_g)} \times 100\% \\ &= \frac{V_g}{V_1 + V_g} \times 100\% \end{aligned}$$

where

- Γ_{liq} = density of liquid
- Γ_{gas} = density of gas
- Γ_{mix} = density of mixture
- M_1 = mass of liquid
- V_1 = volume of liquid
- M_g = mass of gas
- V_g = volume of gas

APPENDIX IV

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

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

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

where R and S denote random and systematic errors.

$$\sigma^2_{\%gasR} = \left(\frac{\delta_{\%gas}}{\delta_{\Gamma_2}}\right)^2 \delta^2_{\Gamma_2R} + \left(\frac{\delta_{\%gas}}{\delta_{\Gamma_1}}\right)^2 \delta^2_{\Gamma_1R} + \left(\frac{\delta_{\%gas}}{\delta_{\Gamma_{gas}}}\right)^2 \sigma^2_{\Gamma_{gasR}} \quad (3)$$

$$\text{and } \sigma^2_{\%gasS} = \left(\frac{\delta_{\%gas}}{\delta_{\Gamma_2}}\right)^2 \sigma^2_{\Gamma_2S} + \left(\frac{\delta_{\%gas}}{\delta_{\Gamma_1}}\right)^2 \sigma^2_{\Gamma_1S} + \left(\frac{\delta_{\%gas}}{\delta_{\Gamma_{gas}}}\right)^2 \sigma^2_{\Gamma_{gasS}} \quad (4)$$

$$\begin{aligned} \text{so } \sigma^2_{\%gasR} &= \left(\frac{(\Gamma_1 - \Gamma_{gas}) 100}{\Gamma^2_2 + 2(\Gamma_2\Gamma_{gas}) + \Gamma^2_{gas}}\right)^2 \sigma^2_{\Gamma_2S} \\ &+ \left(\frac{100}{\Gamma_2 - \Gamma_{gas}}\right)^2 \sigma^2_{\Gamma_1R} \\ &+ \left(\frac{(\Gamma_2 - \Gamma_1) 100}{\Gamma^2_2 - 2(\Gamma_2\Gamma_{gas}) + \Gamma^2_{gas}}\right)^2 \sigma^2_{\Gamma_{gasR}} \end{aligned} \quad (5)$$

similarly

$$\begin{aligned} \sigma^2_{\%gasS} &= \left(\frac{(\Gamma_1 - \Gamma_{gas}) 100}{\Gamma^2_2 - 2(\Gamma_2\Gamma_{gas}) + \Gamma^2_{gas}}\right)^2 \sigma^2_{\Gamma_2S} \\ &+ \left(\frac{100}{\Gamma_2 - \Gamma_{gas}}\right)^2 \sigma^2_{\Gamma_1R} \\ &+ \left(\frac{(\Gamma_2 - \Gamma_1) 100}{\Gamma^2_2 - 2(\Gamma_2\Gamma_{gas}) + \Gamma^2_{gas}}\right)^2 \sigma^2_{\Gamma_{gasS}} \end{aligned} \quad (6)$$

Typical values for the various parameters are as follows:

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

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

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

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

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

where

$$\Gamma_1 = 0.460 \text{ g/cm}^3$$

$$\Gamma_2 = 0.720 \text{ g/cm}^3$$

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

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

$$\begin{aligned} \sigma^2_{\% \text{gasR}} &= (89.8)^2(0.0036)^2 + (143)^2(0.002)^2 + (53.1)^2(0.0)^2 \\ &= 0.105 + 0.082 + 0.0 \\ &= 0.19\% \end{aligned}$$

and similarly for the systematic errors

$$\begin{aligned} \sigma^2_{\% \text{gasS}} &= (89.8)^2(0.014)^2 + (143)^2(0.009)^2 + (53.1)^2(0.004)^2 \\ &= 1.58 + 1.66 + 0.0004 \\ &= 3.24\% \end{aligned}$$

finally from equation (2)

$$\begin{aligned} \sigma_{\% \text{gas}} &= \sqrt{(0.19 + 3.24)} \\ &= 1.19\% \end{aligned}$$

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

from the formula

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

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

where

$$\begin{aligned} \sigma^2_{\%oilR} = & \left(\frac{\delta_{\%oil}}{\delta_{\Gamma_{water}}} \right)^2 \sigma^2_{\Gamma_{waterR}} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma_2}} \right)^2 \sigma^2_{\Gamma_2R} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma_{oil}}} \right)^2 \sigma^2_{\Gamma_{oilR}} \\ & + \left(\frac{\delta_{\%oil}}{\delta_{\%liquid}} \right)^2 \sigma^2_{\%liquidR} \end{aligned} \quad (9)$$

and

$$\begin{aligned} \sigma^2_{\%oilS} = & \left(\frac{\delta_{\%oil}}{\delta_{\Gamma_{water}}} \right)^2 \sigma^2_{\Gamma_{waterS}} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma_2}} \right)^2 \sigma^2_{\Gamma_2S} + \left(\frac{\delta_{\%oil}}{\delta_{\Gamma_{oil}}} \right)^2 \sigma^2_{\Gamma_{oilS}} \\ & + \left(\frac{\delta_{\%oil}}{\delta_{\%liquid}} \right)^2 \sigma^2_{\%liquidS} \end{aligned} \quad (10)$$

where

$$\begin{aligned} \delta^2_{\%oilR} = & \left(\frac{1}{\Gamma_{water} - \Gamma_{oil}} \right)^2 - \left(\frac{(\Gamma_{water} - \Gamma_2)(\%liquid)}{\Gamma^2_{water} - 2(\Gamma_{water}\Gamma_{oil}) + \Gamma^2_{oil}} \right)^2 \sigma^2_{\Gamma_{waterR}} \\ & + \left(\frac{(\%liquid)}{\Gamma_{water} - \Gamma_{oil}} \right)^2 \sigma^2_{\Gamma_2R} \\ & + \left(\frac{\Gamma_{water} - \Gamma_2}{\Gamma^2_{water} - 2(\Gamma_{water}\Gamma_{oil}) + \Gamma^2_{oil}} \right)^2 \sigma^2_{\Gamma_{oilR}} \\ & + \left(\frac{\Gamma_{water} - \Gamma_2}{\Gamma_{water} - \Gamma_{oil}} \right)^2 \sigma^2_{\%liquidR} \end{aligned} \quad (11)$$

and

$$\begin{aligned} \sigma^2_{\%oilS} = & \left(\frac{1}{\Gamma_{water} - \Gamma_{oil}} \right)^2 - \left(\frac{(\Gamma_{water} - \Gamma_2)(\%liquid)}{\Gamma^2_{water} - 2(\Gamma_{water}\Gamma_{oil}) + \Gamma^2_{oil}} \right)^2 \sigma^2_{\Gamma_{waterS}} \\ & + \left(\frac{(\%liquid)}{\Gamma_{water} - \Gamma_{oil}} \right)^2 \sigma^2_{\Gamma_2S} \end{aligned}$$

$$\begin{aligned}
& + \left(\frac{\Gamma_{\text{water}} - \Gamma_2 (\% \text{liquid})}{\Gamma_{\text{water}}^2 - 2(\Gamma_{\text{water}}\Gamma_{\text{oil}}) + (\Gamma_{\text{oil}}^2)} \right)^2 \sigma^2_{\Gamma_{\text{oilS}}} \\
& + \left(\frac{\Gamma_{\text{water}} - \Gamma_2}{\Gamma_{\text{water}} - \Gamma_{\text{oil}}} \right)^2 \sigma^2_{\% \text{liquids}}
\end{aligned} \tag{12}$$

Typical values are as follows

$$\begin{aligned}
\sigma_{\Gamma_{\text{waterR}}} &= 0.0 \times 1.04 = 0.0 \text{ g/cm}^3 \\
\sigma_{\Gamma_{\text{waterS}}} &= 0.02 \times 1.04 = 0.021 \text{ g/cm}^3 \\
\sigma_{\Gamma_2\text{R}} &= 0.005 \times 0.73 = 0.004 \text{ g/cm}^3 \\
\sigma_{\Gamma_2\text{S}} &= 0.02 \times 0.73 = 0.015 \text{ g/cm}^3 \\
\sigma_{\Gamma_{\text{oilR}}} &= 0.0 \times 0.72 = 0.0 \text{ g/cm}^3 \\
\sigma_{\Gamma_{\text{oilS}}} &= 0.02 \times 0.72 = 0.014 \text{ g/cm}^3
\end{aligned}$$

where

$$\begin{aligned}
\Gamma_{\text{oil}} &= 0.72 \text{ g/cm}^3 \\
\Gamma_2 &= 0.73 \text{ g/cm}^3 \\
\Gamma_{\text{water}} &= 1.04 \text{ g/cm}^3
\end{aligned}$$

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

$$\begin{aligned}
\sigma^2_{\% \text{oilR}} &= (6.4)^2(0.0)^2 + (203)^2(0.004)^2 + (197)^2(0.0)^2 + (0.93)^2(0.44)^2 \\
&= 0.0 + 0.66 + 0.0 + 0.18 \\
&= 0.84\%
\end{aligned}$$

$$\begin{aligned}
\sigma^2_{\text{oilS}} &= (6.4)^2(0.021)^2 + (203)^2(0.015)^2 + (197)^2(0.014)^2 + (0.97)^2(1.8)^2 \\
&= 0.018 + 9.3 + 7.6 + 3.05 \\
&= 20.0\%
\end{aligned}$$

finally from equation (8)

$$\begin{aligned}\sigma_{\%oil} &= \sqrt{(0.84+20.0)} \\ &= 4.6\%\end{aligned}$$

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

From the formula

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

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

$$\text{where } \sigma^2_{\%waterR} = \left(\frac{\delta_{\%water}}{\delta_{\%oilR}} \right)^2 \sigma^2_{\%oilR} + \left(\frac{\delta_{\%water}}{\delta_{\%gasR}} \right)^2 \sigma^2_{\%gasR} \quad (13)$$

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

$$= 1.03\%{}^2$$

$$\text{and } \sigma^2_{\%waterS} = (1.0)^2(20.0) + (1.0)^2(3.24)$$

$$= 23.24\%{}^2$$

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

$$= 4.9\%$$

APPENDIX V

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

$$\% \text{gas} = \frac{\Gamma_1^{-1} - \Gamma_{\text{mix}}^{-1}}{\Gamma_1^{-1} - \Gamma_g^{-1}} \quad \text{where } \Gamma_1 = \text{liquid density}$$

$$\Gamma_{\text{mix}} = \text{mixture density}$$

so that

$$\% \text{ gas} = \frac{V_1/M_1 - V_1+V_g/M_1+M_g}{V_1/M_1 - V_g/M_g} \quad \text{and } V = \text{volume}$$

$$M = \text{mass of the various constituents}$$

$$= \frac{V_1(M_1 + M_g) - M_1(V_1+V_g) \times M_1(M_1+M_g)}{V_1M_g - M_1V_g/M_1M_g}$$

$$= \frac{M_g}{M_1 + M_g}$$

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.