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The Effects of Symmetric Steps and Gaps on Orifice Measurement

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THE EFFECTS OF SYMMETRIC STEPS AND GAPS ON ORIFICE MEASUREMENT*

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INTRODUCTION

Recesses or protrusions within the near flow field of orifice meters can be found in a limited though significant number of installations. Recesses occur most commonly when the orifice and its associated piping are mounted with ring-type joints used in high pressure service. There are of course, other situations where recesses can occur such as a mismatch between a flange and a pipe, sealing rings on certain types of orifice fittings, etc. As a general rule, a recess is not considered to be a very significant condition. Protrusions, on the other hand, are another matter. Protrusions are always considered to be bad practice and are always thought to cause an error in measurement. Although protrusions are never designed into a system they do occur and are most commonly caused by the use of an undersized gasket.

Current standards supply limited guidance on either recesses or protrusions. Both U.S. (1) and international (2) standards restrict the use of gaskets to those which will be at most flush and generally below the pipe surface. The U.S. standards allows some recess in the vicinity of the plate for both flange and pipe taps (2 1/2 D upstream, 8D downstream). A recess of less than 6.4 mm (1/4 inch) is allowed for all β ratios. If the recess is greater (unspecified) than 6.4 mm (1/4 inch) this recess is allowed only for the following conditions: $\beta \leq 0.3$, D = 50mm; $\beta \leq 0.4$, D = 75mm; and $\beta \leq 0.5$, D = 100mm. The international standard addresses only corner tapped orifices and specifies an equation form which involves the depth and width of the recess. No information is given regarding flange taps.

The user of these standards will also note that these criteria address only the immediate vicinity of the plate. Other criteria (however unjustified) such as the pipe diameter tolerance are presumed to apply at other locations along the meter tube.

The published literature which forms the basis for the above specifications is somewhat limited in scope and number as will be discussed in the next section. The objective of this paper is to study systematically the effects of such recesses or protrusions at various locations for a small line size where effects would be. Four representative locations for the protrusions are considered. These are: in the vicinity of the plate on the upstream and on the downstream side, two diameters upstream of the plate and two diameters downstream of the plate.

*Sections of this paper have appeared as an ASME paper and as a Gas Processors Association Report.

PREVIOUS STUDIES

Beitler and Overbeck [3] investigated the effect of using a recessed flange before and after the plate. Recessed flanges are usually made with the pipe welded to the flange but without extending all the way to the face of the flange. This leaves a recess or a recess whose depth is typically equal to the pipe thickness. On the other hand, standard (non-recessed) flanges are made such that the pipe end is flush with the flange face. Combinations of both types of flanges were used by Beitler and Overbeck to determine whether the inlet or outlet recess was affecting the coefficient. The effect of the recess length was investigated. The flow rate through the test orifices was determined using a standard orifice (i.e. a comparison test). Both flange and pipe taps were used in these tests. The 51 mm (2-inch) line recessed flanges typically had a recess of 6 mm (0.25 inch) depth and 41 mm (1.625 inch) length. The results obtained using flange taps showed that C_d increases as a result of the recess. The deviation of C_d from the unrecessed flange case for $\beta \leq 0.4$ was less than 0.5%. The deviation increased generally with β, attaining a broad maximum of about 1.75% around $\beta = 0.63$ and dropped off to about 0.75% at $\beta = 0.75$. The authors were not surprised by these relatively substantial increases in C_d, since they expected the recess to increase the turbulence level ahead of the orifice and so decrease the contraction after the plate. However, the authors could not explain adequately why the deviation decreased for $\beta > 0.63$. The results for the pipe taps were generally similar but the deviation magnitude was slightly less at most values of β. The authors did similar experiments on 100 mm (4-inch) and 200 mm (8-inch) lines. For the 100 mm line, C_d increased monotonically with β starting at $\beta = 0.3$. The deviation amounted to 0.5% at $\beta = 0.5$, and rose to a maximum of 2.4% at $\beta = 0.75$. For this case the depth of the recess was kept at 6 mm and its length was 38 mm (1.5 inch) before the plate and 34 mm (1.34 inch) after the plate. The effect of using pipe taps instead of flange taps was similar to the 51 mm (2-inch) line case. For the 200 mm (8-inch) line, the trends were similar to those obtained in the 100 mm (4-inch) line. The deviatiation started at β = 05 and was less than 0.5% at $\beta = 0.6$ increasing to 2.5% at β = 08. The authors varied the length of the recess in the tests in the 100 mm (4-inch) line. They found that a recess of length equal to 6.4 mm (1/4 inch) or less had no effect on D_d. Beyond 6.4 mm (1/4 inch) the deviation increased with the recess length up to a value of 2% at 34 mm (1.34 inch). Experiments with a recess on one side of the plate showed that the downstream recess did not have any effect on C_d. Although the trends of the above tests are useful the fact that these were comparison tests (ie. to another reference orifice) tempers the conclusions drawn.

The second report found in the literature was by H. Bean [4]. He reported the results of some tests done by manufacturers of orifice meter equipment about 17 years earlier (in 1929). In most of these tests a reference orifice was used to determine C_d. Three β ratios: 0.31, 0.5 and 0.69 were investigated in a 100 mm (4-inch) line using flange, radius and pipe taps. The recess depth was 2.4 mm (0.094 inch) and its length was 39.6 mm (1.56 inch). For $\beta = 0.31$, no effect on C_d was observed. For $\beta = 0.5$, the deviations were: 0.6% for flange taps and 0.25% for both radius and pipe taps. For $\beta = 0.69$, the deviations were: 1.0% for flange taps, 0.5% for radius taps and 1.4% for pipe taps. Note again the use of a reference orifice.

McNulty and Spencer [5] investigated the effects of orifice plate carrier diameter (relative to the pipe diameter) in both rough and smooth pipes. A weigh tank system was used to determine the flow rate. The tests were done initially using a 100 mm (4-inch) line. Four orifice plates with β ratios of 0.45, 0.63, 0.74 and 0.84 were used in the study. The differential pressure was measured via corner taps of 4.8 mm (3/16 inch) diameter. The increase in the size of the carrier diameter relative to pipe diameter ranged from -2% to 14%, this corresponds to a protrusion or recess range of 1% and -7% of D (protrusions = 1 mm to -7.1 mm). Notice that a negative value indicates a recess. The results indicated that for $\beta < 0.63$, the pipe conditions and protrusions or recesses had no significant effect. For $\beta = 0.74$, C_d increased by 0.5% for recess of 5.5% of D (protrusion = -5.6 mm) and increased by 0.4% for recess of 2% of D (protrusion = -2 mm). For $\beta = 0.84$, the corresponding increase in C_d was about 1.5% for both recesses. For a protrusion of about 1.25% of D (protrusion = 1.3 mm), the increase in C_d was negligible for $\beta = 0.74$ and went up to 1.8% for $\beta = 0.84$. The authors gave curve fits for the deviation in C_d versus percentage change in carrier diameter. Due to the limited number of points (about 4), these fits should be viewed with caution. In a previous study McNulty and Spencer [6] presented some limited data for 51 mm (2 inch) and 150 mm (6 inch) pipes. This data obtained in the 152 mm line indicated that for an upstream ledge (with an effective protrusion of 4.67% of D), C_d increased by 0.5% for $\beta = 0.5$, 1.15% for $\beta = 0.6$, 2% for $\beta = 0.71$ and 6% for $\beta = 0.81$, while C_d did not change for the case with upstream recess of 2.5% D. The data obtained in the 51 mm (2-inch) line gave mixed results. The deviation of C_d with a protrusion of 1.85% D (0.94 mm) from C_d with the negligible recess of 0.375% D (0.2 mm) was -.16% for $\beta = 0.44$, -0.32% for $\beta = 0.39$, -1.125 for $\beta = 0.63$ and +3.7% for $\beta = 0.84$.

EXPERIMENTAL SET-UP AND TEST PROCEDURE

Three orifice plates with $\beta = 0.3$, 0.5 and 0.7 were tested in a 51 mm (2-inch) line using water as the working fluid. Figure 1 gives a diagrammatic sketch of the experimental set-up. Fully developed turbulent flow was insured by having a straight pipe run of 105 diameters upstream of the test section. The actual flow rate was determined by using a dynamic weigh tank and a timer (0.001 second resolution) triggered by the dynamic weight balance pointer. In the β = 0.5 and 0.7 tests reported here, 3000 pounds of water were collected while in the β =0.3 tests, 2000 pounds were used. The differential pressure across the orifice plate was measured via a pair of flange taps 9.5 mm (3/8 inch) in diameter. Three D-P cells were used to insure redundancy. Each of the D-P cells was calibrated versus a deadweight tester and also differential mercury manometer. Calibrations were conducted once every two weeks or whenever a discrepancy appeared between readings of the three D-P cells.

In a typical test, the D-P cell output is fed into the computer, digitized and averaged. A total of 3000 samples were averaged for the β = 0.5 and β = 0.7 tests and 7000 samples for the β = 0.3 tests. These averages together with appropriate calibration curve constants, were used to obtain the mean pressure measured by each D-P cell. Agreement was generally within 0.05% or between for the D-P cells at the critical

low end of the flow range. Whenever discrepancies were higher than that, the D-P cells were checked for air bubbles and/or recalibrated. The repeatability of the results for a number of representative configurations was checked and the data found to lie within a band of width equal to 0.15% of C_d. The test program lasted for about three months.

The test fixture is shown in Figure 2. Provisions were made for protrusions/recesses by using a number of rings. The width of each ring was 12.7 mm (0.5 inch). All the rings had the same outside diameter (to fit in provided locations in the fixture) while the inside diameter varied between different rings to provide different protrusions/recesses. The protrusions/recesses used in the study were 6.35, 5.3, 4.3, 3.2, 1.6, 0.15, 0, -0.15, -3.2 and -6.35 mm (0.25, 0.21, 0.17, 0.125, 0.0625, 0.006, 0, -0.006, -0.125 and -0.25 inches) respectively. A protrusion or recess of height equal to 0.15 mm represents the limit set by the ISO standard based on pipe diameter tolerance (a negative value indicates a recess). The test fixture was designed with a provision to change protrusions (rings) at the four locations. These locations were: 1) adjacent to the upstream face; 2) adjacent to the downstream face; 3) 2D upstream of the plate; and 4) 2D downstream of the plate. The fourth location was obtained by inverting the whole fixture. In this investigation, the height/depth of the proptrusion/recess was changed at one axial location while keeping the remaining locations in the flush configuration (zero protrusion). For each test the discharge coefficient was determined at 9-10 flow rates (Reynolds numbers) for $\beta = 0.7$ and 0.5 and at about 5 - 7 flow rates for $\beta = 0.3$.

RESULTS AND DISCUSSIONS

The results of this experimental program are displayed for each test in the form of a deviation of the measured discharge coefficient C_d from the corresponding base line coefficient C_{do}. This base line coefficient for each β ratio was obtained with no protrusions or recesses. These deviations are plotted versus $10^6/R_D$ where R_D is the pipe Reynolds number. The results will be presented in order from upstream to downstream results.

FAR UPSTREAM LOCATION

This region is located at 2 diameters upstream of the orifice plate. Figure 3a summarizes the test results for both the protrusions and recesses for $\beta = 0.3$. As shown by this figure all recesses at this location and β ratio had no noticable effect (defined by system repeatability) on the discharge coefficient. Protrusions into the flow stream, however, did show an effect. When the step was 3 mm into the flow stream an increase in discharge coefficient of about 0.2% was noted. The 6 mm step caused a 1% increase. As expected when the β ratio was increased to 0.5 the effect of the protrusion into the stream was magnified. (Figure 3b) For the same step (3 mm) as above the coefficient increased to about 1% and the maximum deviation for the 6 mm step was roughly four times (3.9% vs 1.0%) greater at this value of β. For the recesses, however, the changes were virtually not noticable with the maximum "apparent" change on the order of 0.15% at a 6 mm recess.

At the highest β tested (β = 0.7) the maximum step into the pipe (Figure 3c) caused about a 14% bias. The 3 mm step cited above resulted in about a 2.5% offset. A recess of 6 mm caused a positive bias of about 0.2%. This value being just outside of the overall repeatability figure might be subject to interpretation as to whether this was a true bias.

In all of the above cases the use of steps or gaps which fell within the 0.3% tolerance on diameter of the ISO standard resulted in deviations well within the repeatability of the experiments.

ZERO D UPSTREAM

In this configuration the protrusion or recess abuts the orifice plate itself forming a 13 mm (1/2 inch) perturbation in front of the plate. Figure 4a shows the deviations plotted for β = 0.3. The graph indicates that deviations are within a band of width = 0.10% C_d for protrusions = 1.6 mm (0.0625 inch) or less (well within laboratory repeatability). For protrusions equal to 3, 4 and 6 mm (0.125, 0.17 and 0.25 inch) the deviations are approximately 0.2, 0.6 and 1.6% above baseline. For recesses there was (as above) virtually no effect. For β = 0.5, the effects of protrusions became more pronounced while the recesses still had negligible effect as shown in Figure 4b. For a protrusion of 6 mm (0.25 in) deviations as high as 11.5% of C_d were measured. The deviation droped to 8% for a protrusion = 5 mm (0.21 inches), 5% for protrusion of 4 mm (0.17 inch) and continued with this trend down to 0.66% for protrusion of 1.6 mm (0.0625 inch). The deviation for a protrusion of 0.15 mm (0.006 inch) which is equal to the allowed pipe tolerance was negligible. Figure 4c shows similar results for β = 0.7. The protrusion effects even much more pronounced than those for β = 0.5. Deviations varied from 47.7% of C_d for a protrusion of 6 mm to 0.1% (or negligable) for protrusion of 0.15 mm. Recesses had some effect for this β; 0.9% for a value of -3 mm (-0.125 inch) and 0.77% for a value of -6 mm (-0.25 inch). It should be noted that neither the protrusion nor the recess effected the slope of the calibration curves.

The large increase in C_d at large upstream protrusions for large βs may be attributed to a nozzle type flow. For the extreme case of β = 0.7 and protrusion of 6 mm (0.25 inch), the flow stream in the pipe converges before arriving at the plate because of the relatively large annular protrusion. The length of the protrusion would also be expected to play an important part since it determines if the flow has a chance to reattach. If it does, it would affect the velocity profile in the vicinity of the plate. One can also consider this configuration to be a plate with a β = 0.9+ based on the diameter of the upstream ring (which may be considered as a very, very short upstream pipe). This definitely reduces the contraction of the jet and therefore it increases C_d. On the other hand, the reason for the increase of C_d due to large upstream recesses for the β = 0.7 case is not clear; however this behavior agrees with what was reported by Beitler and Overbeck [3] and by Bean [4] and with some of the results of McNulty and Spencer [6].

ZERO D DOWNSTREAM

The next location studied was that immediately downstream of the orifice plate. In contrast to the previous cases where it was possible

to note some effect for mid-range and smaller β ratios no effects were noted for either protrusions or recesses downstream of the orifice plate. That being the case, detailed deviation results plotted vs. $10^6/R_D$ are given for β = 0.7 only (Figure 5). The deviation is about 5.25% for a protrusion of 6 mm (0.25 inch), 0.8% for protrusion = 4 mm (0.17 in) and 0.4% for protrusion = 3 mm (0.125 in). For protrusions = 1.6 mm (0.0625 inch) and less as well as for recesses up to 3 mm (0.125 inch), the effect is negligible. A deviation of -0.25% has been found for a recess of 6.35 mm (0.25 in).

In this line size (50 mm) it is not surprising that this protrusion/β combination showed a significant effect. As noted above there is a "false β" on the downstream side of roughly β = 0.9+ which would surely be responsible for downstream streamline shape. Beitler and Overbeck [3] reported negligible effects for downstream recesses; however, they had no data on the effect of downstream protrusions.

TWO DIAMETER DOWNSTREAM LOCATION

By inverting the fixture, it was possible to test the effect of having a protrusion or recess at 2 pipe diameters downstream of the plate. Since the effects noted at the immediate downstream location were minimal it was decided to only test the extreme protrusion (6.35 mm) and the extreme recess (6.35 mm) for the three βs. The results showed negligible effect for either a protrusion or a recess at this location. Figure 6 shows the detailed deviation results for one β only (β = 0.7) for protrusions of +6 mm and -6mm. Results for the other two βs show less effect and therefore are not shown.

SUMMARY AND CONCLUSIONS

From the above experimental program the following conclusions may be drawn.

1. At three of the locations studied, the presence of a protrusion caused the coefficient of discharge to increase. This deviation increased with both the protrusion height and the β ratios investigated. The only exception to this was the far downstream case (2D) where there was no effect.

2. Protrusions at 2D upstream of the plate can have considerable effect on Cd. The error variation trends are similar to the case of a protrusion directly upstream of the plate (see below) however, the magnitudes are smaller. For example, it can be inferred from the present data (by interpolation) that a protrusion of 6.3% D or smaller results in an error within the repeatability of the data for β=0.3%; while for β = 0.5, the protrusion should be kept at or below 1.7% D; and for β=0.7, the protrusion should not exceed 0.9% D to achieve this accuracy.

3. As expected, the protrusions directly upstream of the plate caused the most substantial deviations in Cd depending on the size of the protrusion and the β ratio of the orifice plate. For β = 0.3, errors were negligible for protrusions less then 5.8% D but were as high as 1.6% for protrusion = 12.5% D. For β

= 0.5%, the effects were substantially higher beyond a protrusion of 1.0% D reaching a value of 11.5% at protrusion = 12.5%. For β = 0.7, the effects were even much higher, and protrusions should be avoided or kept below 0.38% D to keep the error within the uncertainty of the data. For β = 0.3 and 0.5 the protrusions should be kept below 5.8% D and 1% D, respectively, to have similar accuracy.

4. Protrusions at a location directly downstream of the plate had much less effect than the previous two upstream cases. In fact, for β = 0.3 and 0.5, the effect was negligible even at the highest protrusions. For β = 0.7, the error was less then 0.5% for a protrusion 6.25% D and less, but values as high as 5% were obtained with a protrusion of 12.5% D. Based on the data presented in the paper it may be inferred that the protrusion should be kept below 3% D to keep the deviation within the repeatability of the data for this β.

5. A 2D downstream the only test run indicated that the 12.5% step did not have a significant effect.

6. As expected recesses had a substantially lower effect than protrusions. At 2D upstream of the plate for β = 0.3 and 0.5, the deviations was negligible while deviations of 0.32 and 0.22% were obtained for β = 0.7 with recesses = 6.25% D and 12.5% D, respectively. Since there is no logical explanation for the higher deviation for the smaller recess that data point is very suspect.

7. Similar to the results at 2D upstream, the data for both β = 0.3 and β = 0.5 showed no effect on coefficient for recesses up to 12.5% of diameter. At β = 0.7, however, deviation of about 0.8 to 0.9% were measured for recesses larger than 6.25% of diameter.

8. On the downstream of the plate, recesses up to 6.25% seemed to have no effect on Cd for all plates, while a recess of 12.5% D gave a reduction in Cd (negative deviation) of 0.25% for β = 0.7.

9. Recesses two diameters downstream of the plate showed no effect for all βs.

10. The ISO-5167 pipe diameter specification of ±0.3% over the 2D upstream length shows no effect for a 13 mm wide perturbation placed at the extremes of the specified length.

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3. Beitler, S. R. and Overbeck, J.E., "Determination of the Effects of Certain Installation Conditions on the Coefficient of Sharp Edged Orifices," ASME Transactions, Vol. 59, No. 2, Feb. 1937, p. 115.

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5. McNulty, P. J. and Spencer, E. A., "Tests on Orifice Plates in a 4-inch Diameter Pipe; Effect of Pipe Roughness and Carrier Diameter," MERL Fluids Note No. 74, East Kilbride, Glasgow, Mechanical Engineering Research Laboratory, Jan. 1959.

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TEST RESULTS SUMMARY
$(C_D - C_{Do})/C_{Do}$ X 100%

2D Upstream

Step Size % of Diameter	β = 0.30	0.5	0.7
12.5%	0.995	3.65	14.26
10.5	-	2.58	8.9
8.5	0.471	1.64	4.54
6.25	0.196	0.94	2.32
3.125	-	0.372	0.73
0.3	-0.055	0.035	0.034
-0.3	0.006	0	0.054
-6.25	-0.056	0.157	0.32
-12.5	-0.077	0.164	0.22

0 D Upstream

12.5	1.63	11.5	47.7
10.5		8.0	45.6
8.5	0.63	5.04	27.8
6.25	0.21	2.8	13.0
3.125		0.66	3.66
0.3	0.93	0.035	0.1
-0.3	-0.001	-0.002	0.066
-6.25	0.038	0.17	0.9
-12.5	0.039	0.033	0.77

0 D Downstream

12.5	0.04	0.165	5.25
8.5			0.8
6.25	-0.07	-0.047	0.4
3.125			-0.006
0.3	0.003	-0.005	0.016
-0.3	-0.054		0.044
-6.25	-0.07	-0.017	-0.08
-12.5	-0.19	-0.101	-0.25

SYMBOLS FOR FIGURES 3 AND 4

Symbol	HEIGHT (mm)	% of Diameter
	6.35	12.5
	5.33	10.5
	4.32	8.5
	3.18	6.25
	1.59	3.125
	0.15	0.3
	-0.15	-0.3
	-3.18	-6.25
	-6.35	-12.5

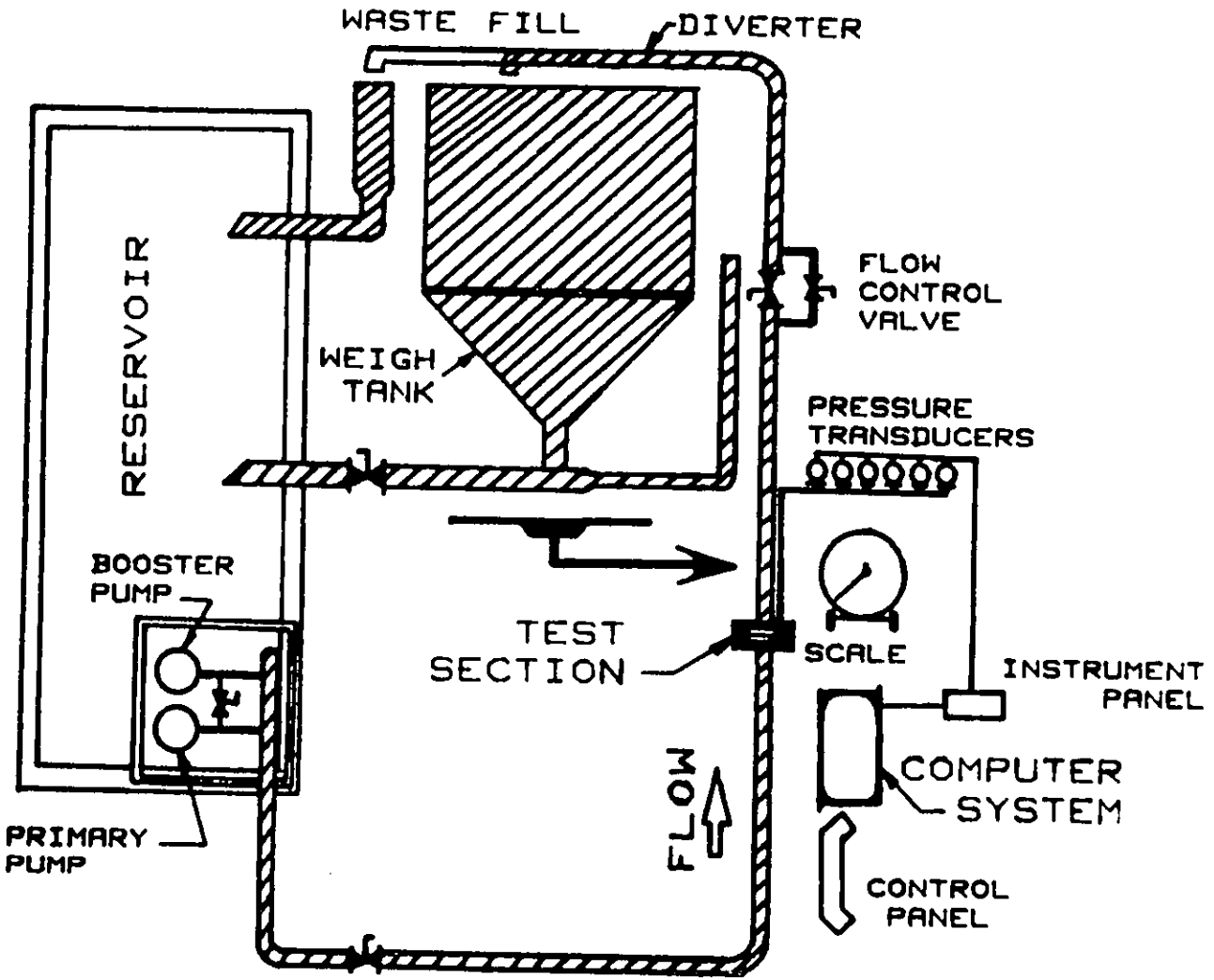

FIGURE 1 : SCHEMATIC OF EXPERIMENTAL FACILITY.

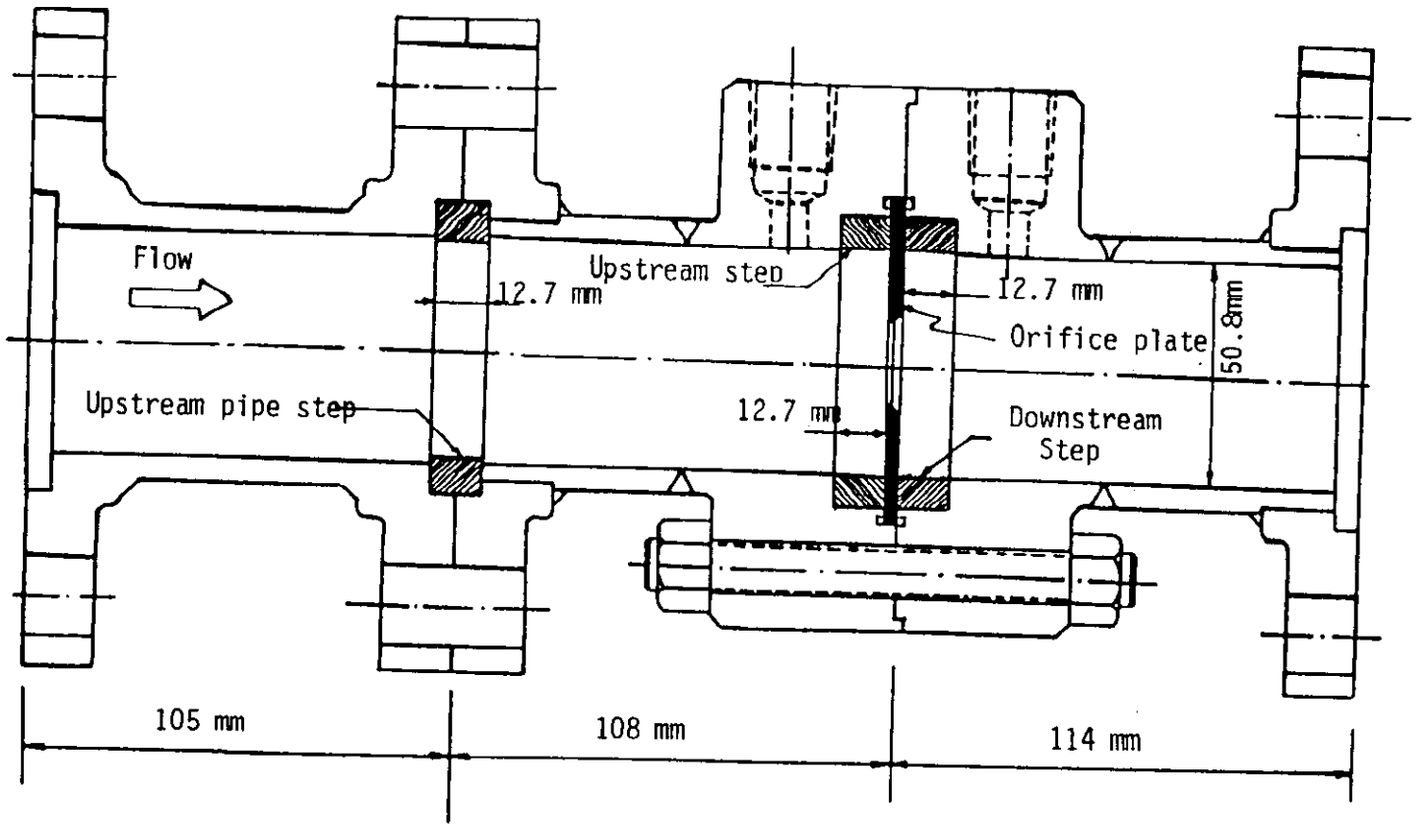

Figure 2: Test Fixture

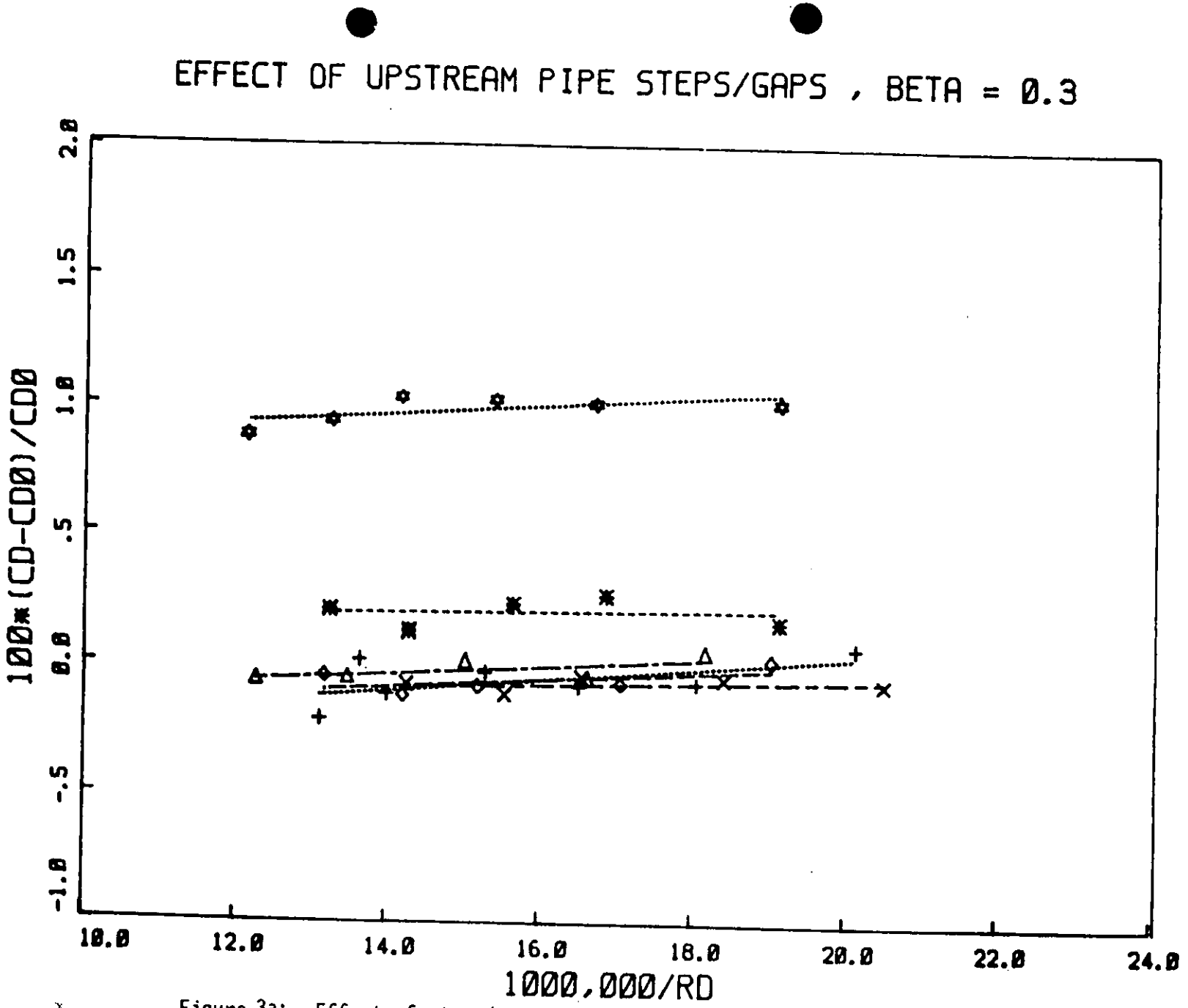

Figure 3a: Effect of steps/recesses at 2D upstream of the orifice plate for $\beta = 0.3$

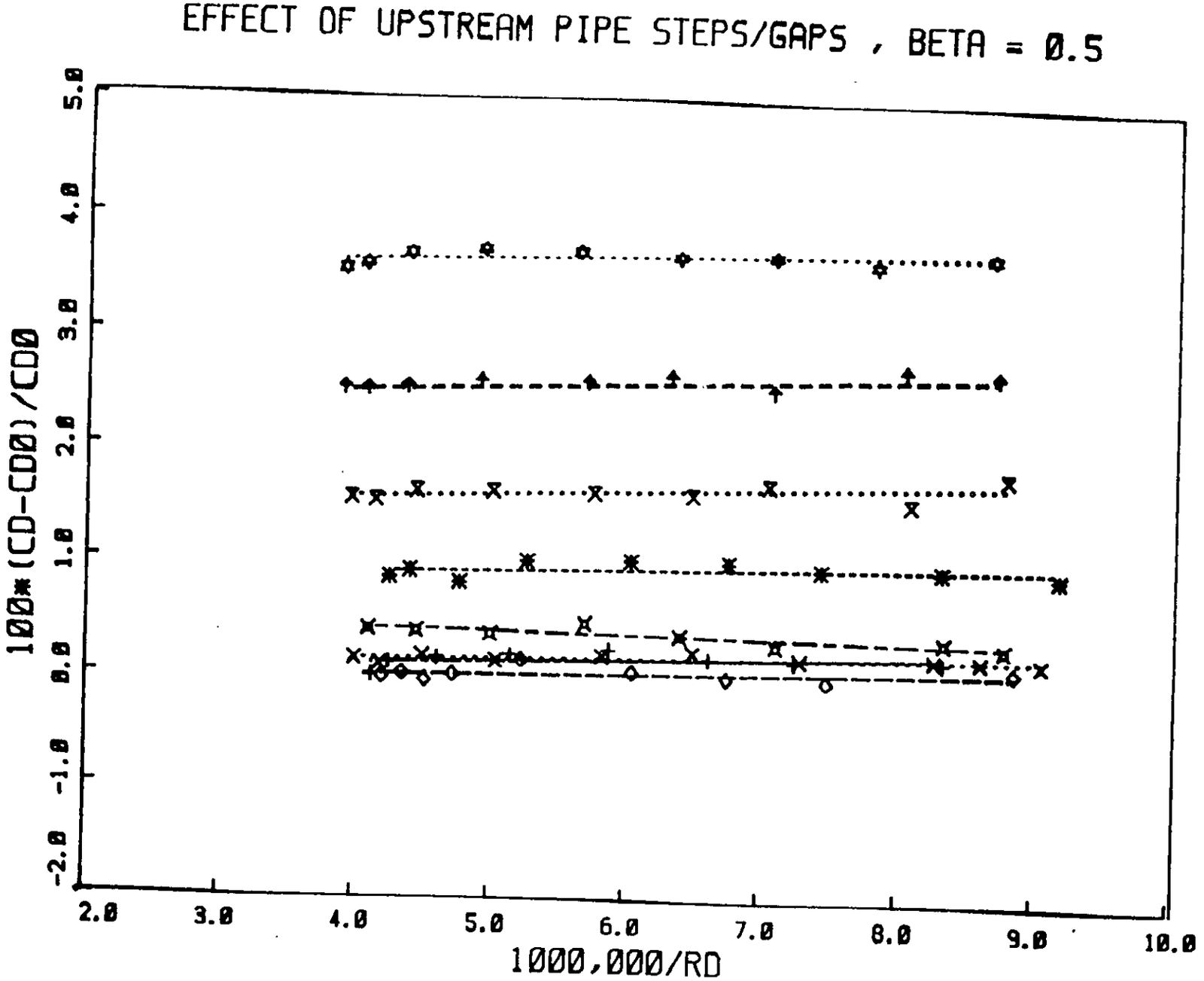

Figure 3b: Effect of steps/recesses at 2D upstream of the orifice plate for $\beta = 0.5$

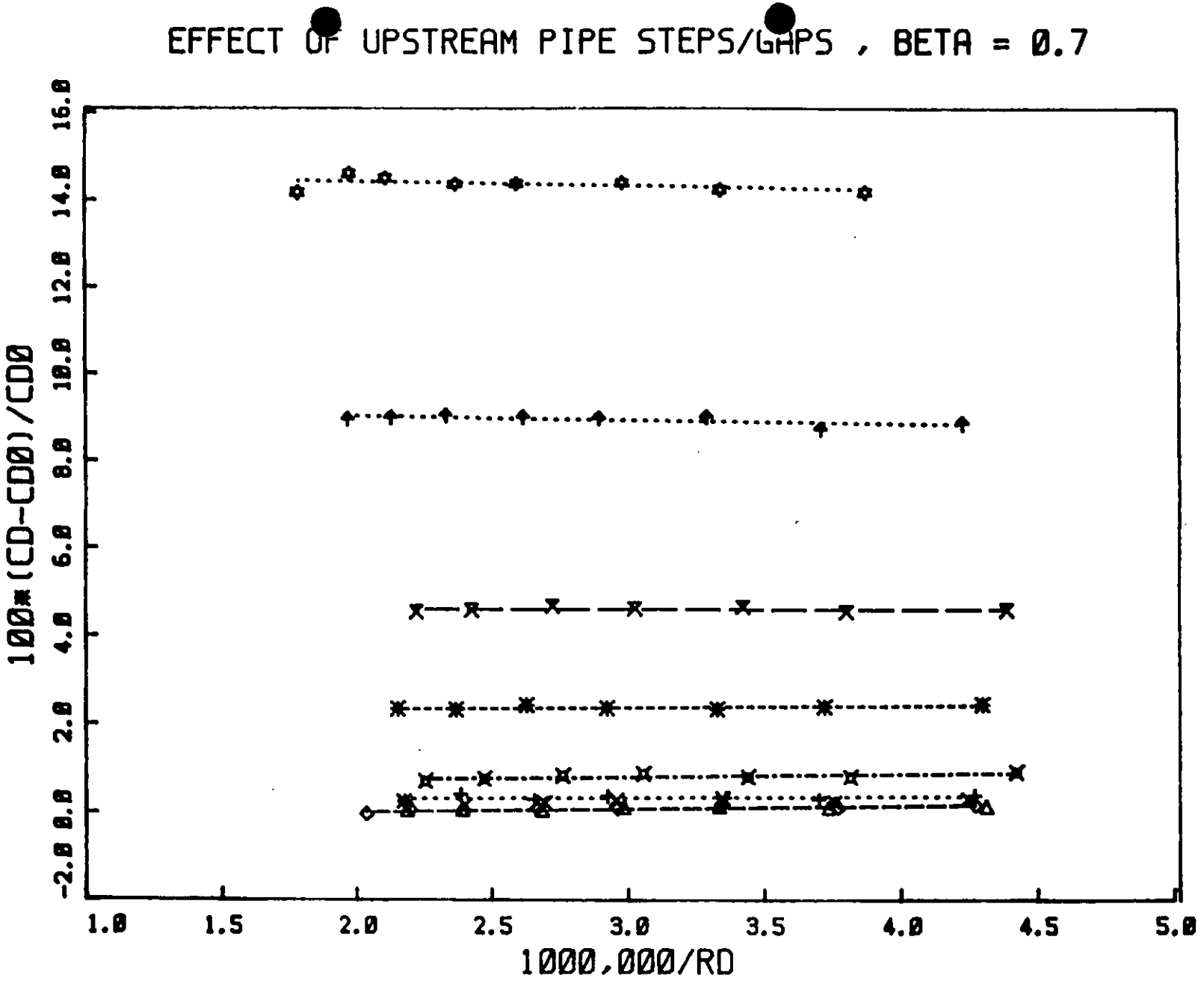

Figure 3c: Effect of steps/recesses at 2D upstream of the orifice plate for $\beta = 0.7$

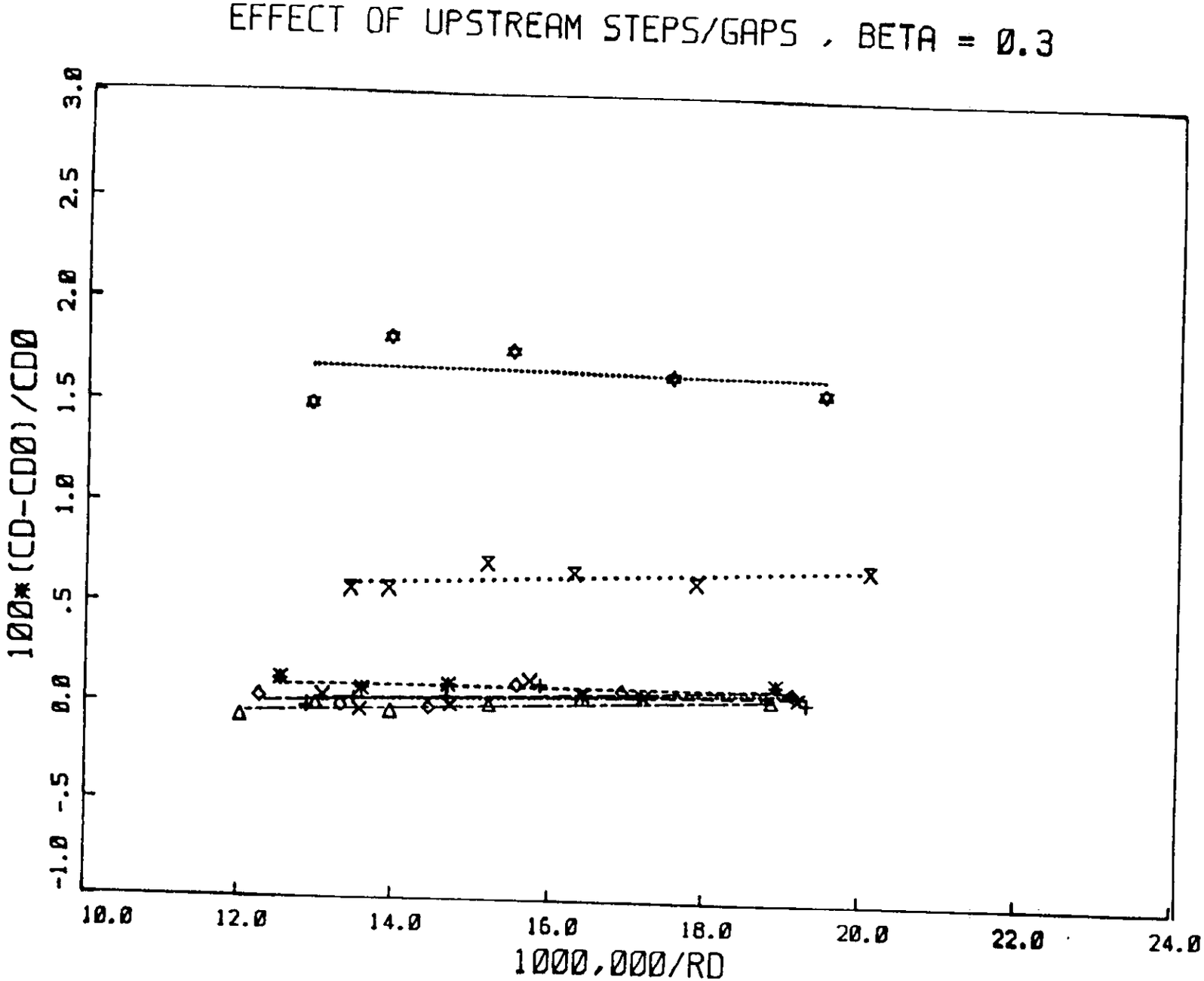

Figure 4a: Effect of Upstream Steps/Recesses at the Orifice for $\beta = 0.3$

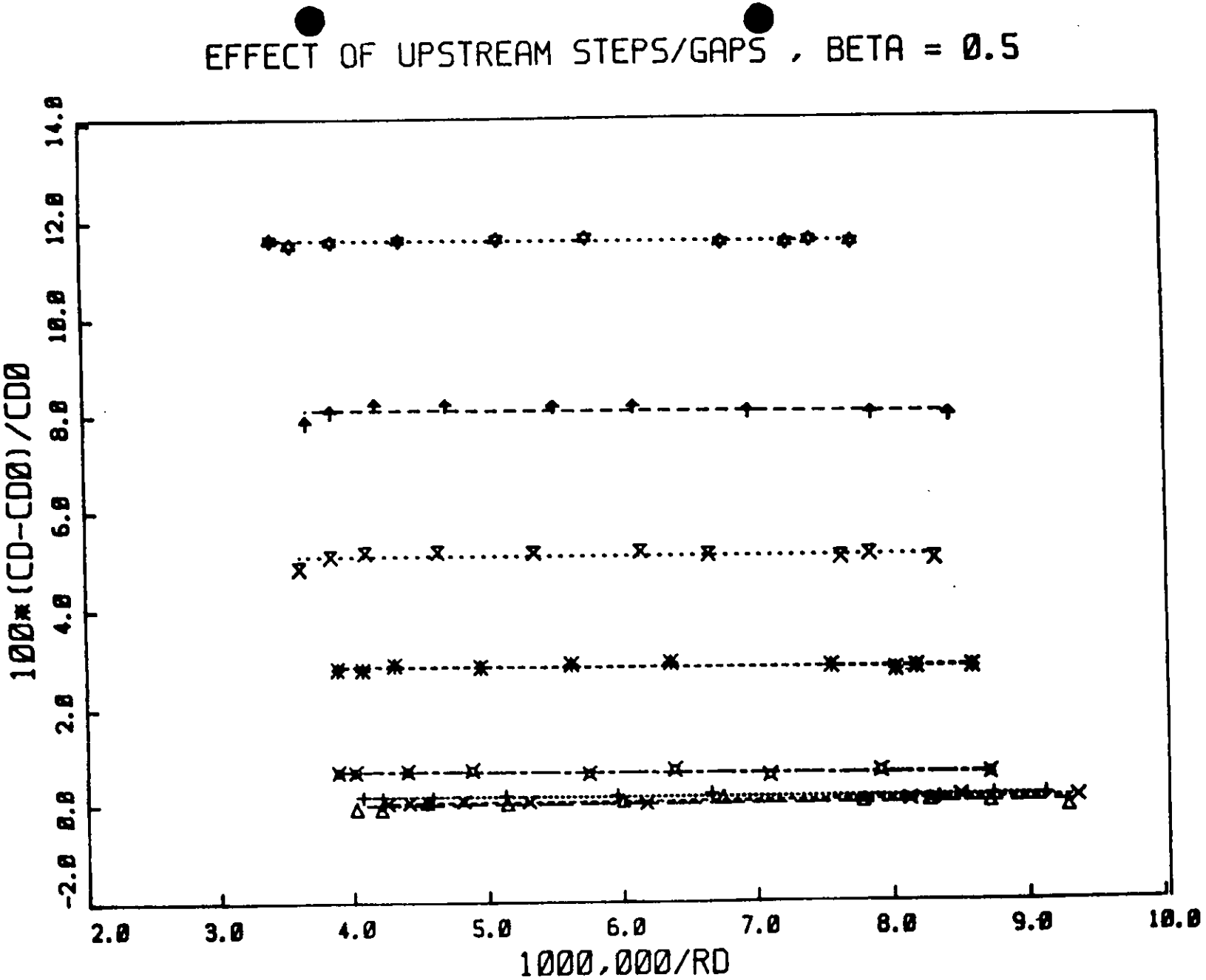

Figure 4b: Effect of Upstream Steps/Recesses at the Orifice for $\beta = 0.5$

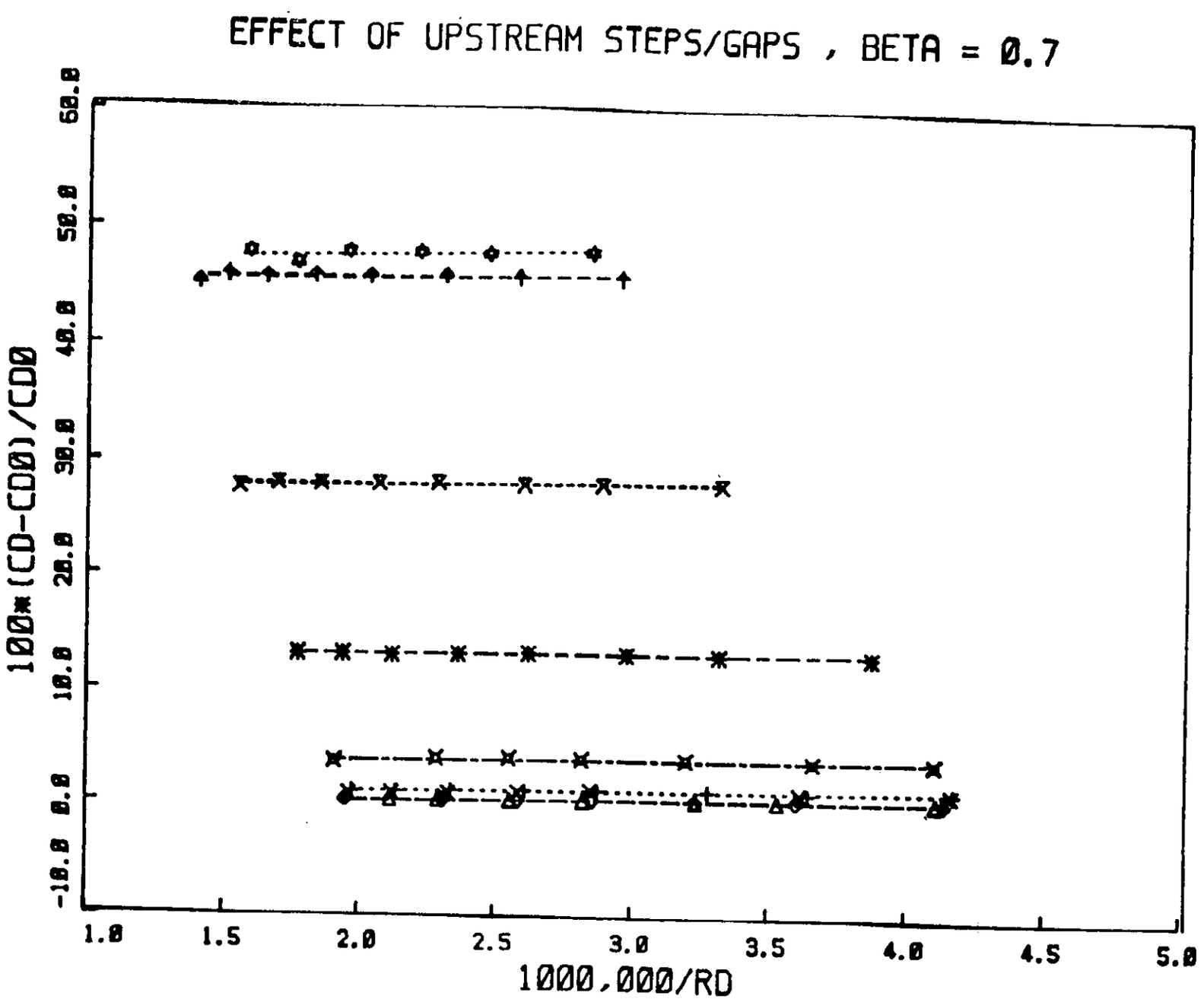

Figure 4c: Effect of Upstream Steps/Recesses at the Orifice for $\beta = 0.7$

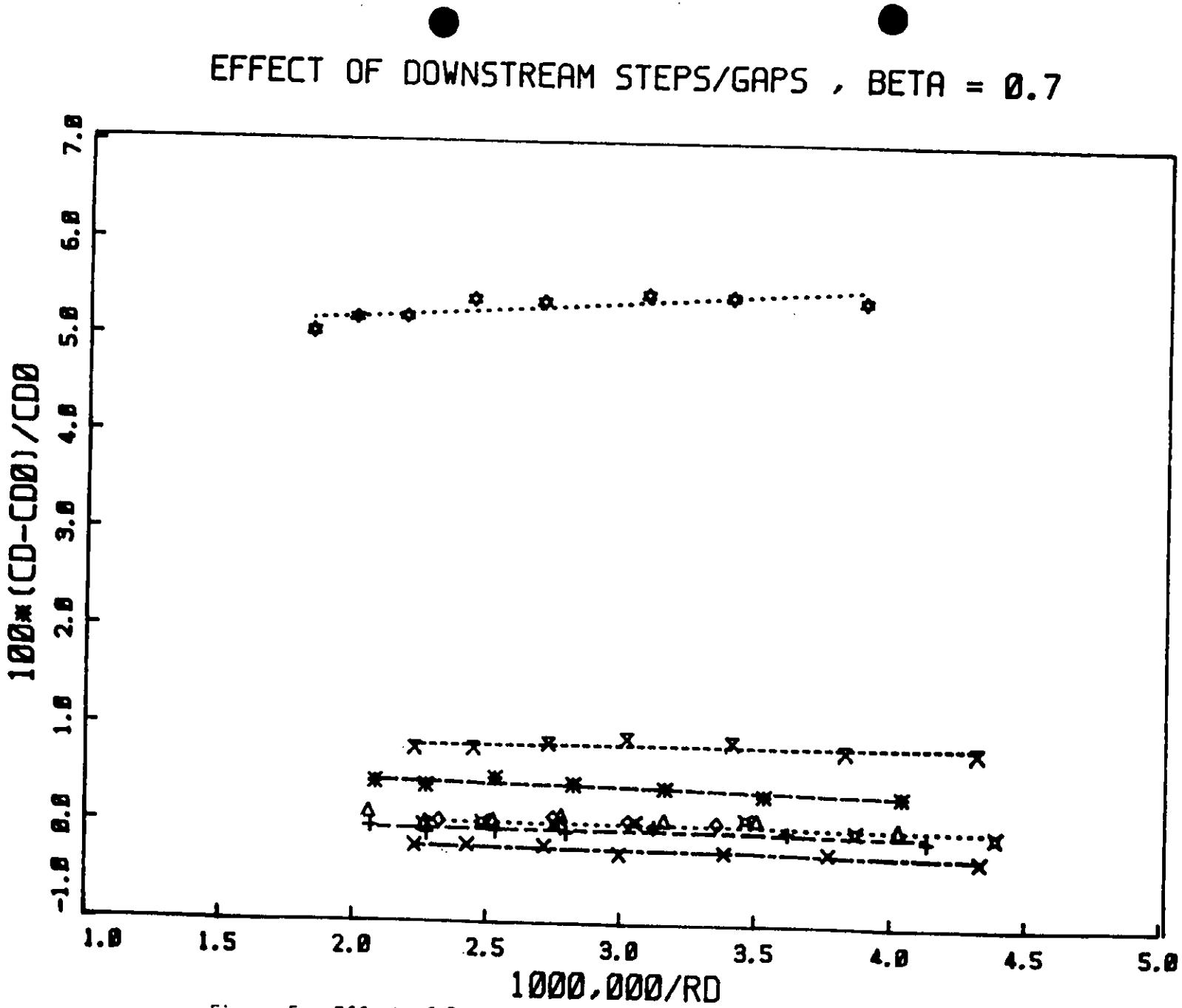

Figure 5: Effect of Downstream Steps/Recesses at the Orifice for $\beta = 0.7$

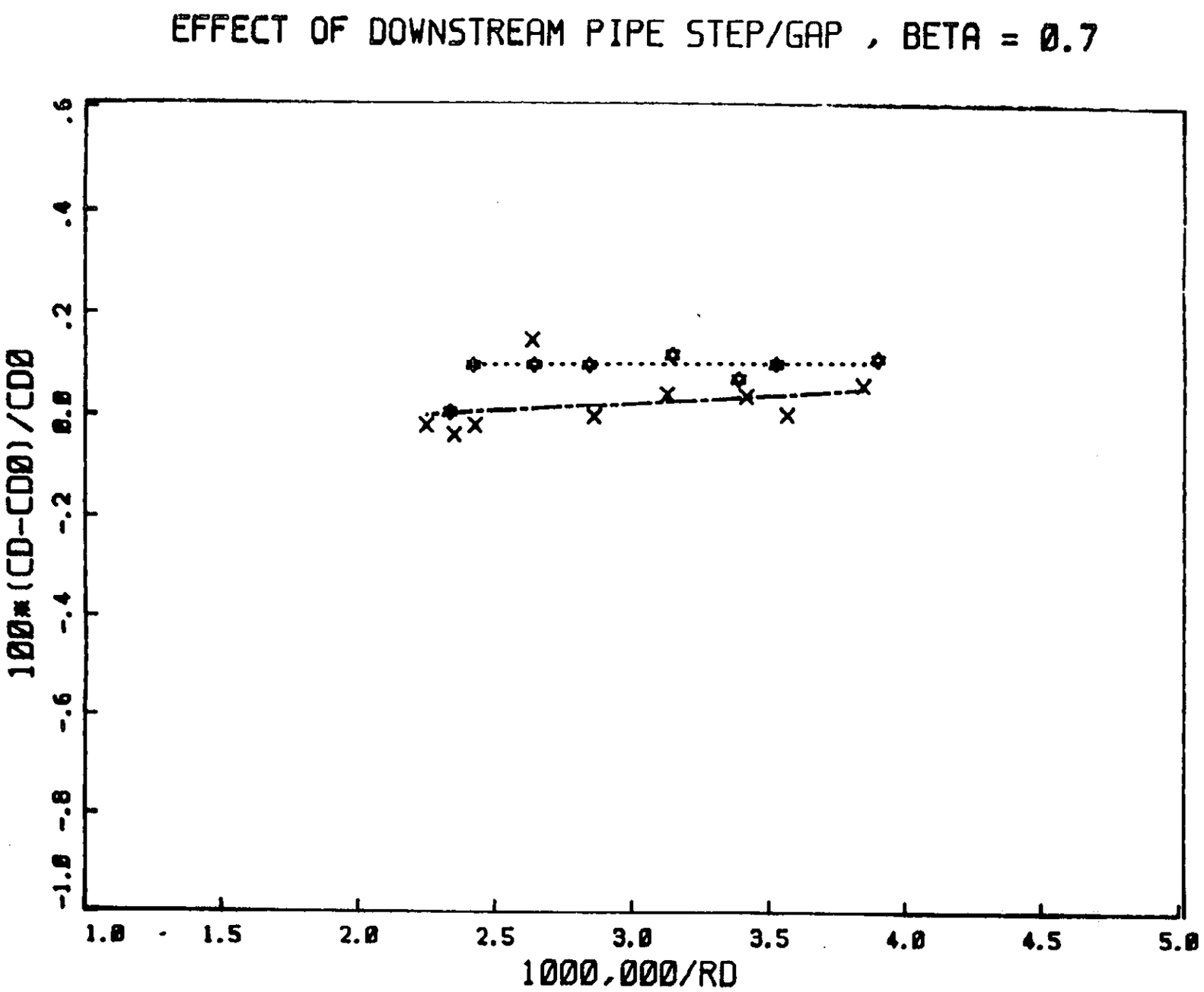

Figure 6: Effect of Steps/Recesses at 2D Downstream of the Plate for: $\beta = 0.7$; ✡, step = 0.25 in.; X, Step = -0.25 in.

Performance of the Brooks Compact prover on air

by

J Reid
National Engineering Laboratory

1.2

November 1985

1 INTRODUCTION

The Brooks Compact prover is the first of the small volume proving devices to be marketed in the UK and, as part of the research programme of the Metrology and Standards Requirements Board, an evaluation of this prover type was carried out using the NEL oil flow measurement facilities in the first half of 1984.

During these evaluation tests in oil, which are reported elsewhere, the use of the prover in air was discussed. It seemed that the principle of operation of the prover could, in theory, be applied to any fluid, since the proving by the positive displacement of a volume of fluid by a piston in a cylinder would depend basically on the maintenance of a seal between the moving piston and the cylinder wall, which would both prevent leakage and allow smooth travel of the piston during the proving run.

Brooks Instrument therefore decided to fund a pilot series of tests to examine the behaviour of the Compact prover in low pressure air (ie up to 7 bar) and these tests were carried out on completion of the prover evaluation on oil. The results of these low pressure air tests were encouraging and showed the prover to be capable of operation on gas. Consequently Brooks Instrument funded a second series of tests on the Compact prover to investigate its performance with air at pressures up to 60 bar and this test programme has recently begun at NEL.

This paper first considers the special problems associated with the use of the prover on air and then outlines the test programmes adopted and describes the test circuits used. The results to date are then presented and discussed and the papers ends with conclusions about the potential of the Compact prover for use on high pressure gas service.

2 BROOKS COMPACT PROVER IN AIR

The schematic diagram of the Brooks Compact prover given in Fig. 1 shows the prover in the return mode with the poppet valve open and the piston being drawn upstream by the hydraulic fluid which is pumped from a reservoir into the actuator cylinder. When the flag on the position detector rod triggers the standby switch, ie the switch furthest upstream, the piston is held at this position by the hydraulic pressure which also holds the poppet valve open allowing the flow to continue uninterrupted through the prover. When the prover is set to run the hydraulic vent valve is opened dumping the hydraulic oil to the reservoir, hence allowing pressurised nitrogen to close the poppet valve and assist the piston to move with the flowing fluid. As the flag on the piston detector rod passes through the switches defining the proving volume a timer in the prover controller/computer is started and stopped. The Compact prover uses the double chronometry method of pulse interpolation and therefore a second timer records the time interval between the detection of the first pulse from the meter under test following the triggering of the first prover volume switch and the detection of the first pulse from the meter under test after the second prover volume switch has been actuated. During this second time interval the pulse output from the meter under test is totalised. The proving pass is now completed and the hydraulic vent valve is closed allowing the hydraulic fluid to be pumped into the actuator cylinder to open the poppet valve and retract the piston to the standby position in readiness for the next pass. The required number of passes is fed into the prover computer which then automatically controls the running of the prover and calculates the results.

However, when the prover is to be used with air its data collection system is inadequate because air is a compressible fluid and consequently it is necessary to measure the pressure and temperature of the air in the prover and at the meter under test while the proving volume is being displaced so that the proving volume can be adjusted to the conditions at the meter under test.

The operation of a prover which was designed for liquid service on a gas such as air might well be adversely affected by for example the lack of lubrication between the piston seals and the cylinder wall causing erratic motion of the piston and/or by leakage across the piston and poppet valve seals. However, an advantage of the Compact prover is that it should be possible to solve the problem of any seal leakage by setting the pressure in the nitrogen plenum so that the differential pressure across the piston is close to zero while it displaces the proving volume.

3 TEST PROGRAMMES

3.1 Low Pressure Tests

Initial tests at low pressure highlighted the problem of juddering motion of the prover piston at low velocity and as a result the original test programme was revised to exclude static leak tests on the piston seals and piston velocity variation measurements using a laser interferometer. The revised test programme covered the assessment of the onset of piston judder at different line pressures, the variation in piston differential pressure with nitrogen pressure and the dynamic calibration of NEL secondary standard flowmeters against the prover at different line and nitrogen pressures.

3.2 High Pressure Tests

The programme for the high pressure tests was designed to investigate more fully those aspects of the prover's performance which were highlighted during the initial tests and to try to specify the limits within which the prover could be used with confidence on gas. Thus the determination of the minimum velocity at which smooth piston travel would occur was to be extended up to line pressures of 60 bar, the influences on the setting of the nitrogen plenum pressure to give zero piston differential pressure were to be studied and the uncertainty and repeatability associated with the calibration of a flowmeter against the Compact prover were to be assessed.

4 TEST CIRCUITS

4.1 Low Pressure Tests

This test circuit is shown diagrammatically in Fig. 2. The air supply to the test rig could supply 500 l/s free air at a maximum line pressure of 7 bar. The prover investigated was a standard 12-inch model with a maximum flowrate and turndown ratio of 110 l/s and 1000:1 respectively. Two rotary positive displacement meters were used as reference meters; one of 3-inch size with a flowrate range of 9-55 l/s and a nominal meter factor of 6 pulse/l and the other of 6-inch size with a flowrate range of 30-250 l/s and a nominal meter factor of 1.5 pulse/l.

The barometric pressure, the piston differential pressure and the air pressures in the prover and at the meter under test were measured using precalibrated transducers and the air temperatures in the prover and in the meter under test were measured using platinum resistance thermometers which were also calibrated prior to the commencement of the test programme.

The test data, including those from the prover controller/computer, were all logged by a data collection system based on a Hewlett-Packard HP85 computer which also calculated the test results.

4.2 High Pressure Tests

For the high pressure tests the prover was installed in the test line of the NEL high pressure primary flow facility, shown schematically in Fig. 3, upstream of the reference meter which is a 6-inch turbine meter with a flowrate range of 9 to 180 l/s and a nominal meter factor of 1.344 pulse/l. The turbine meter was calibrated before the start of these tests against critical flow venturi nozzles which have calibration characteristics directly traceable to the primary gravimetric system.

The data logging system used in these tests is the same one used for the low pressure tests and as before all the pressure transducers and platinum resistance thermometers were calibrated before the test programme was begun.

5 TEST RESULTS

5.1 Low Pressure Test Results

The results of the tests to investigate the onset of piston judder are presented in the plot of minimum judder-free prover flowrate against prover line pressure given in Fig. 4.

Fig. 5 gives the results of the tests where the nitrogen plenum pressure was varied in the form of plots of piston differential pressure against nitrogen pressure.

A great many tests were carried out where the prover was used as the calibrator and the results are too numerous to present in this paper. The tests of most interest and value were those carried out on the 6-inch N3 meter with the nitrogen plenum pressure set to give piston differential pressures close to zero and the results of these tests, at different prover line pressures, are presented in Fig. 6 as a plot of meter factor against volume flowrate.

5.2 High Pressure Test Results

Since these tests are still in progress the results presented and discussed here must clearly be considered to be of a provisional nature.

The results from the tests to determine the minimum judder-free piston velocity over a range of prover pressures are presented in Fig. 7 in the form of a plot of minimum judder-free prover flowrate against prover line pressure.

In these tests to determine the minimum judder-free piston velocity the nitrogen plenum pressure was set to give piston differential pressures close to zero and Fig. 8 plots the nitrogen pressure for zero piston differential against prover line pressure.

Testing the prover as the calibrator has just commenced and therefore it is not possible as yet to compare the NEL calibration for the turbine meter with results obtained against the prover. Nevertheless some interesting data have been obtained and these show that the nitrogen plenum pressure for zero piston differential varies with prover flowrate for a given prover line pressure. These data are shown plotted in Fig. 9.

6 DISCUSSION

The results of the initial tests on low pressure air highlighted a number of aspects of prover performance which were significantly affected by the change from liquid to gas service.

The juddering motion of the piston which became apparent early in the test programme seriously restricted the rangeability of the prover but as shown by Fig. 4 the minimum judder-free prover flowrate appeared to be dependent on line pressure. The results from the current tests, given in Fig. 7, confirm that the minimum judder-free prover flowrate is dependent on line pressure but more importantly show that at pressures of 20 bar or greater the minimum smooth flowrate attained can be close to the lower limit of 0.11 l/s specified for liquid service. Fig. 8 shows that, as well as being dependent on the prover line pressure, the minimum judder-free flowrate is affected by the nitrogen plenum pressure. It is therefore clear that on gas service the nitrogen plenum pressure is an extremely important variable and that further investigation of its effect on prover performance is vital.

The results from the tests on the prover at low pressure showed that leakage past the piston/poppet valve seals occurred when the piston differential pressure was much greater than zero. Tests were therefore carried out to determine how the piston differential varied with nitrogen plenum pressure and the results presented in Fig. 5 showed that the piston differential varied linearly with nitrogen pressure and that the nitrogen pressure for zero piston differential varied with line pressure but not as predicted in the manufacturer's literature. The latest results, given in Figs 8 and 9, also show that the nitrogen pressure for zero piston differential varies with line pressure but additionally, that the prover flowrate has an effect on the nitrogen pressure required to give zero piston differential. These results again stress the important part that the nitrogen plenum pressure plays in the behaviour of the prover on gas.

The results from the tests on the N3 meter, with prover line pressures in the range 1 to 7 bar and piston differential pressures close to zero, which are presented in Fig. 6 show that in general the calibration data obtained against the prover agree with the NEL calibration data to within 1 per cent. The agreement between the two calibrations is much better than 1 per cent at the prover pressures and flowrates at which the piston differentials were closest to zero.

The repeatability of the test data was very good on most occasions with spreads of less than or equal to 0.25 per cent within a single test run. This figure should be able to be improved if meters of higher resolution are used. When the prover piston was moving smoothly over the proving length the repeatability from test run to test run was also good.

Operation of the prover at higher speeds caused no major problems but the maximum flowrate with gas might be limited by the speed of data collection rather than by any limit on prover piston speed.

7 CONCLUSIONS

A Brooks Instrument 12-inch Compact prover has been tested on low pressure air and its performance is currently being investigated on high pressure air at NEL.

The results to date are most encouraging and show that the prover has considerable potential for operation on gas especially at higher pressures where indi-

cations are that its turndown ratio may well be in excess of 100:1. However the prover's behaviour on gas is much more complex than on liquids and this is particularly the case in the setting of the nitrogen plenum pressure because of the effect this pressure has been shown to have on both the rangeability of the prover and on leakage across the piston/poppet valve seals. If the Compact prover is to be used with confidence on gas with its existing seals it is most important to have a method of predicting the nitrogen pressure to give zero piston differential and also of determining how closely this pressure must be controlled to keep any seal leakage contribution to the prover uncertainty to a minimum.

Alternatively the piston differential pressure could be set to zero and controlled within defined limits by some automatic system or perhaps the piston seals could be replaced by seals specially designed for gas service.

The repeatability of the results of the tests is good and meter calibrations against the prover have shown reasonable agreement with calibrations obtained against recognised standards. These aspects of its performance are further evidence of the Compact prover's potential for gas service.

LIST OF FIGURES

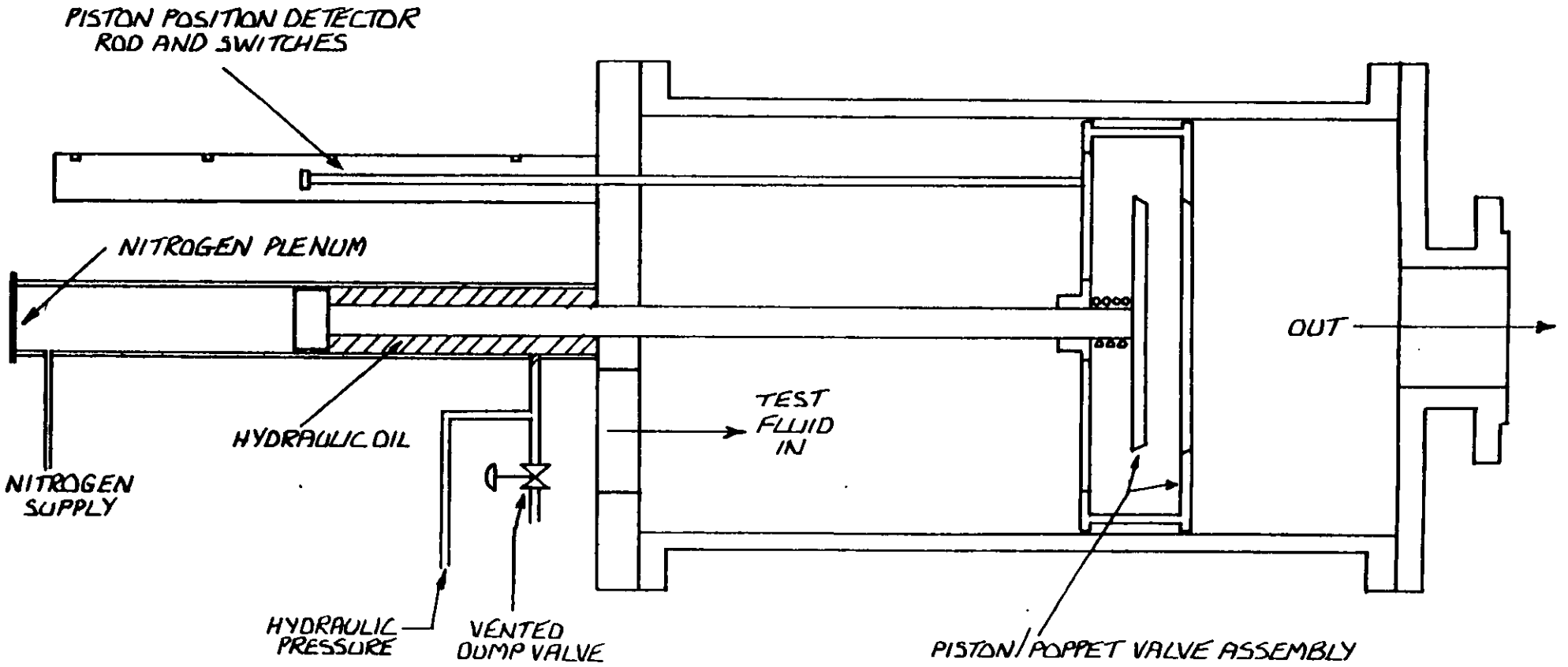

FIG. 1 SCHEMATIC ARRANGEMENT OF BROOK'S COMPACT PROVER.

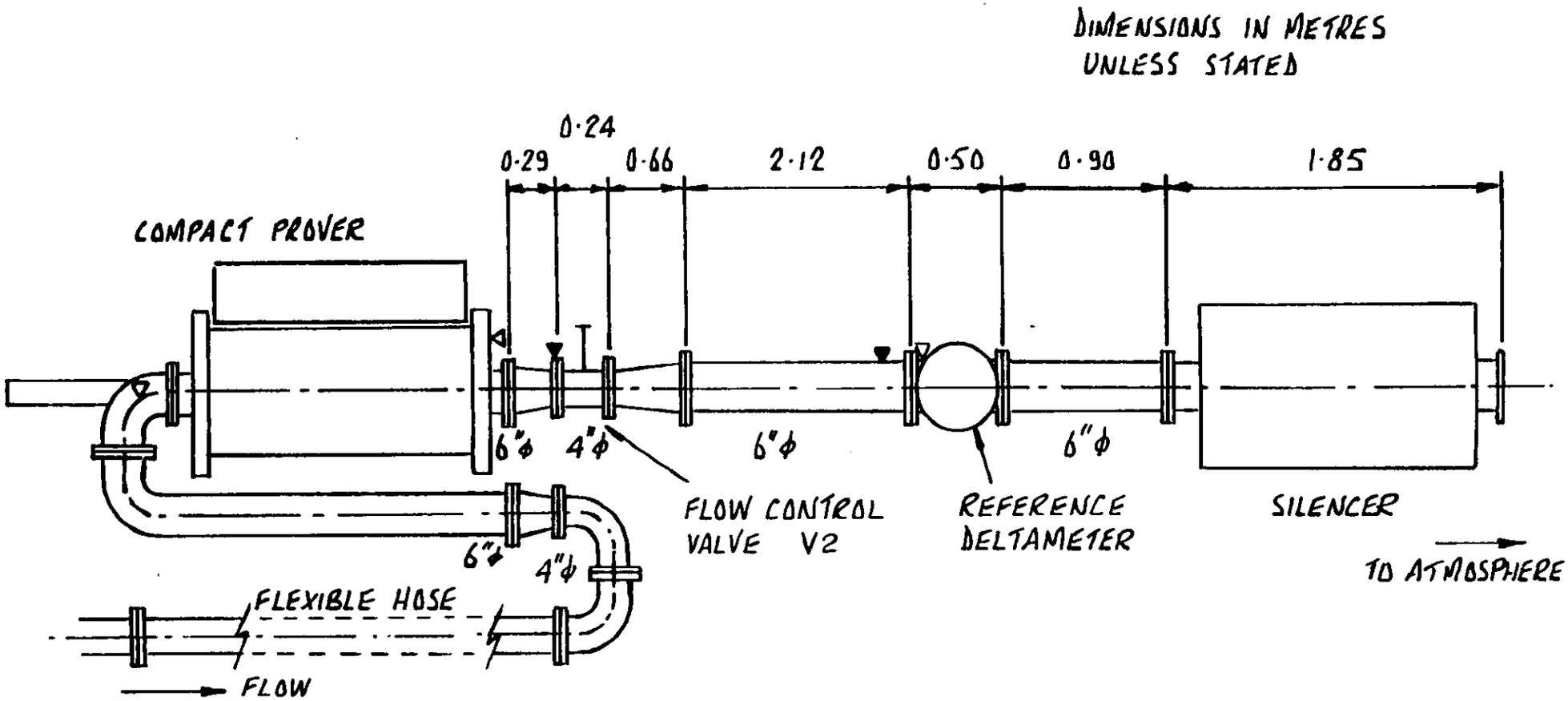

FIG. 2 DIAGRAMMATIC LAYOUT OF TEST RIG

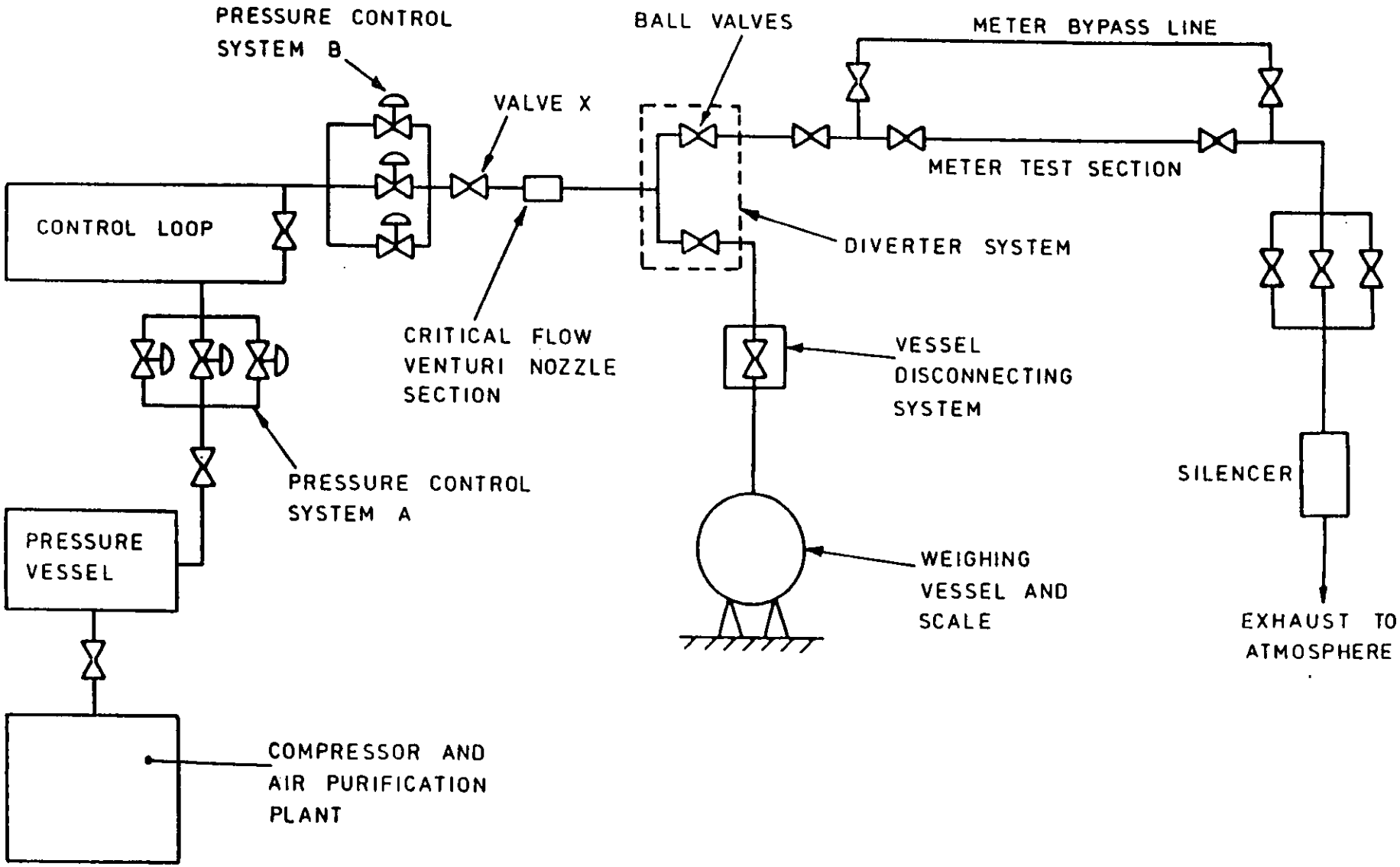

FIG 3 SIMPLIFIED DIAGRAM OF GRAVIMETRIC GAS FLOW SYSTEM

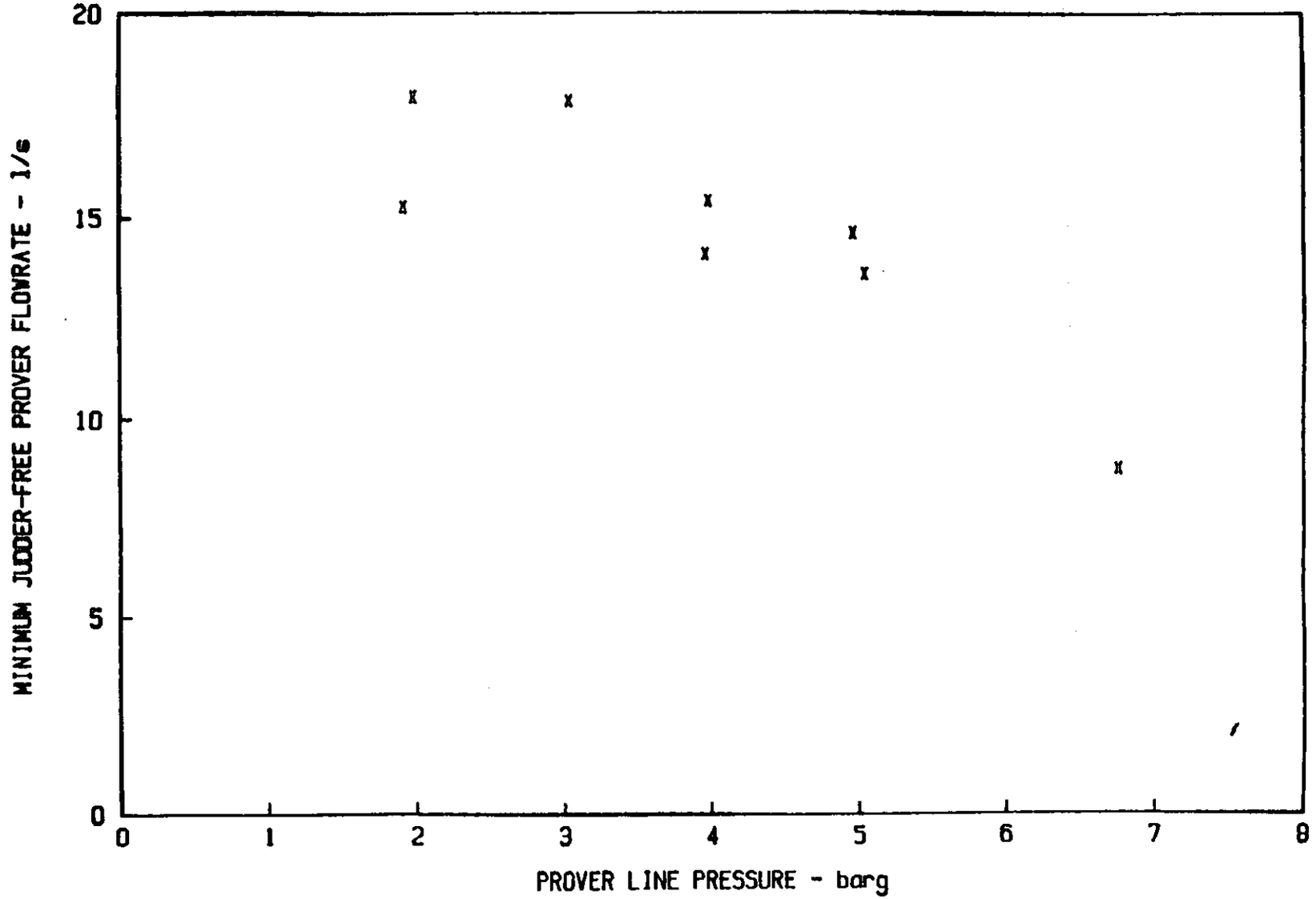

FIG. 4 MINIMUM JUDDER-FREE PROVER FLOWRATE AGAINST PROVER LINE PRESSURE

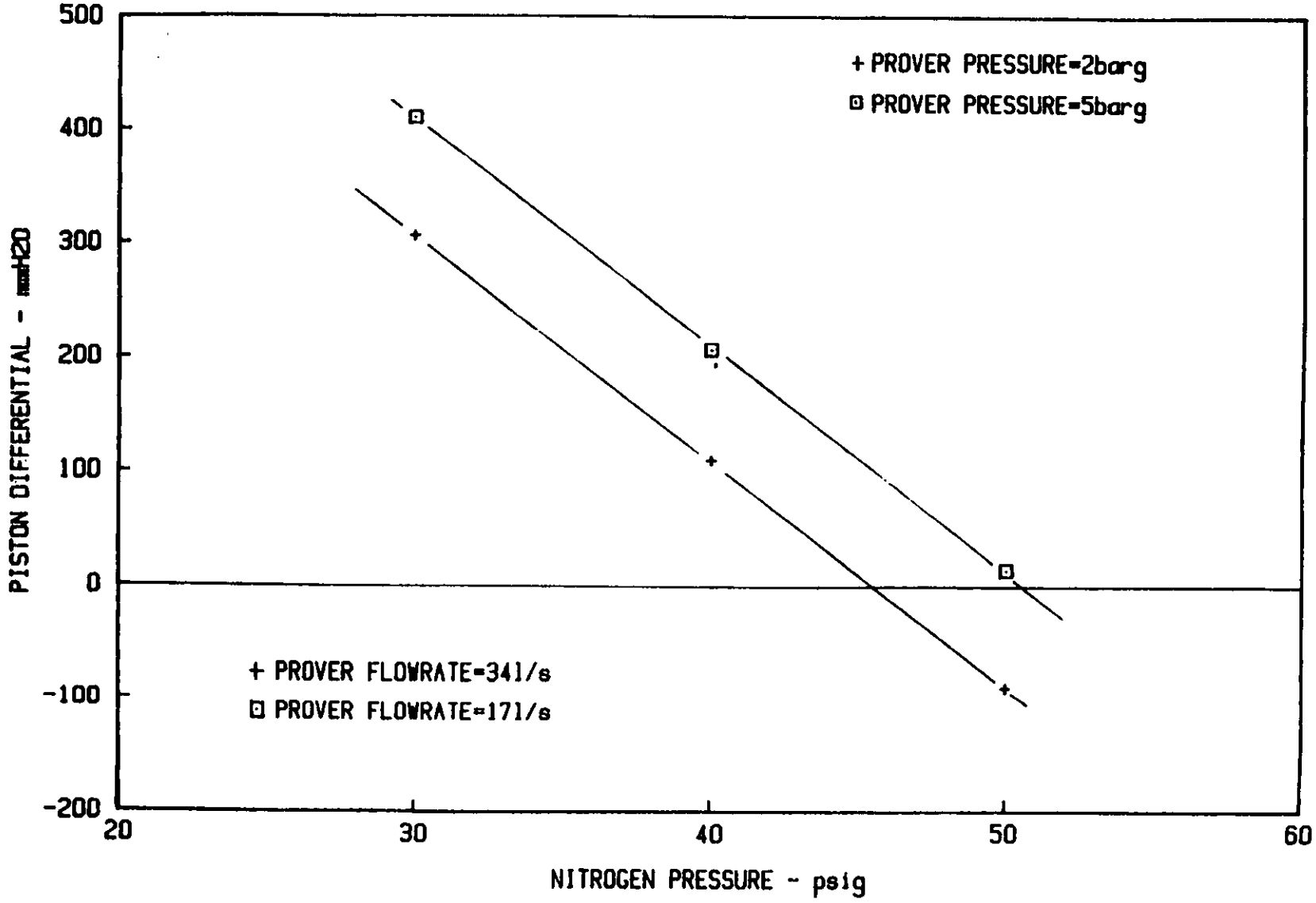

FIG. 5 PISTON DIFFERENTIAL AGAINST NITROGEN PLENUM PRESSURE

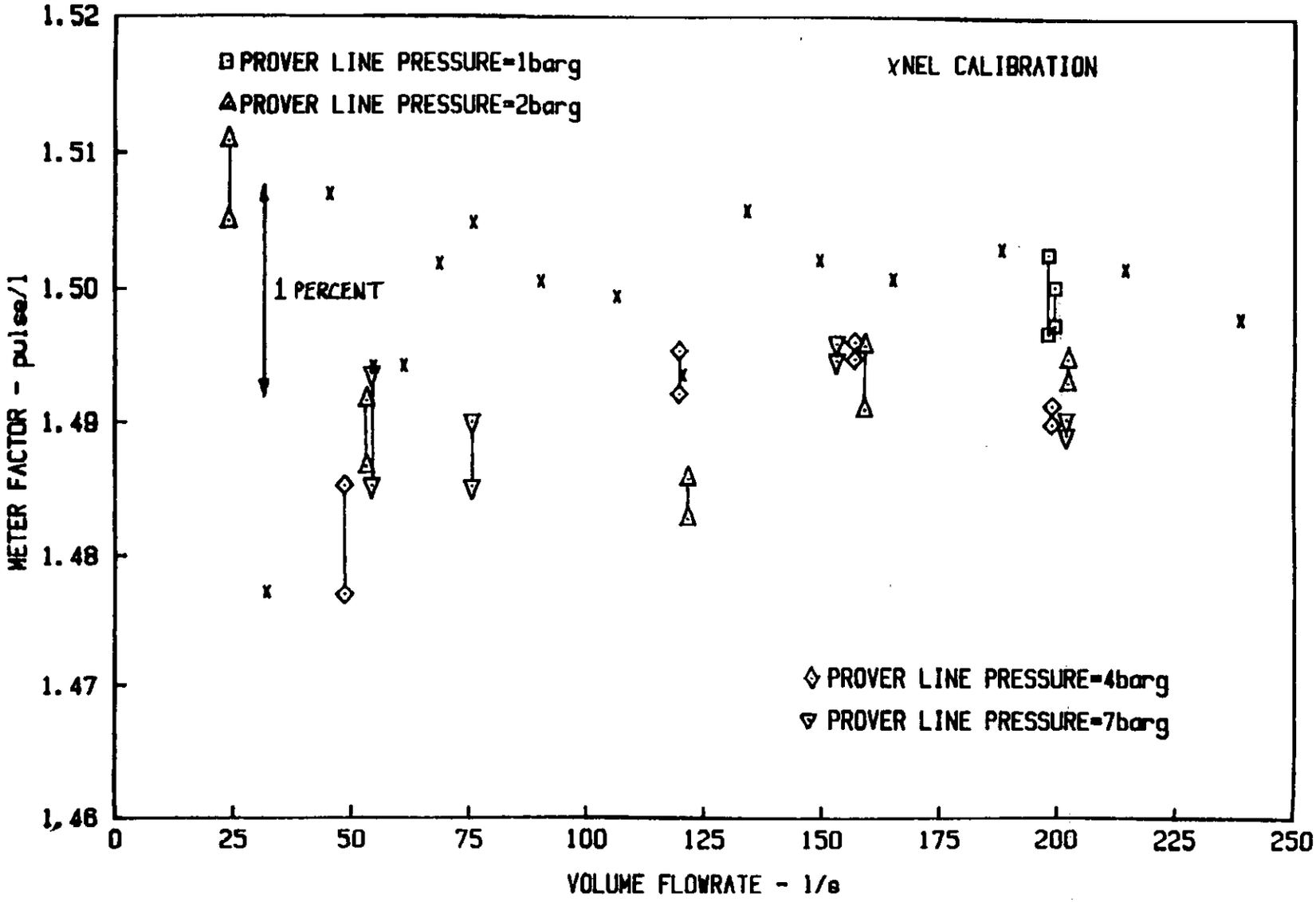

FIG.6 METER FACTOR AGAINST FLOWRATE FOR N3 METER : PROVER NITROGEN FOR ZERO DIFF

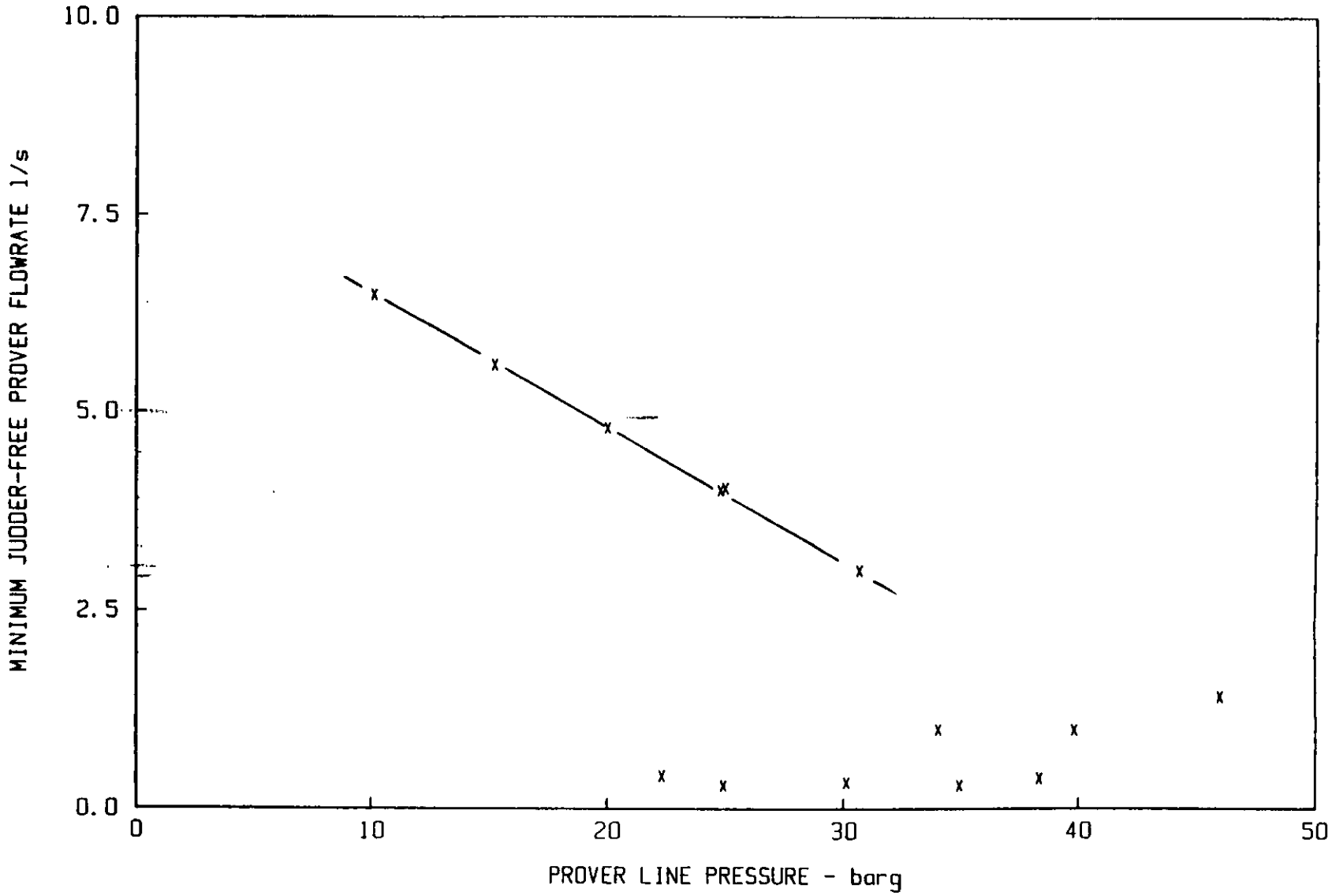

FIG.7 MINIMUM JUDDER-FREE PROVER FLOWRATE AGAINST PROVER LINE PRESSURE

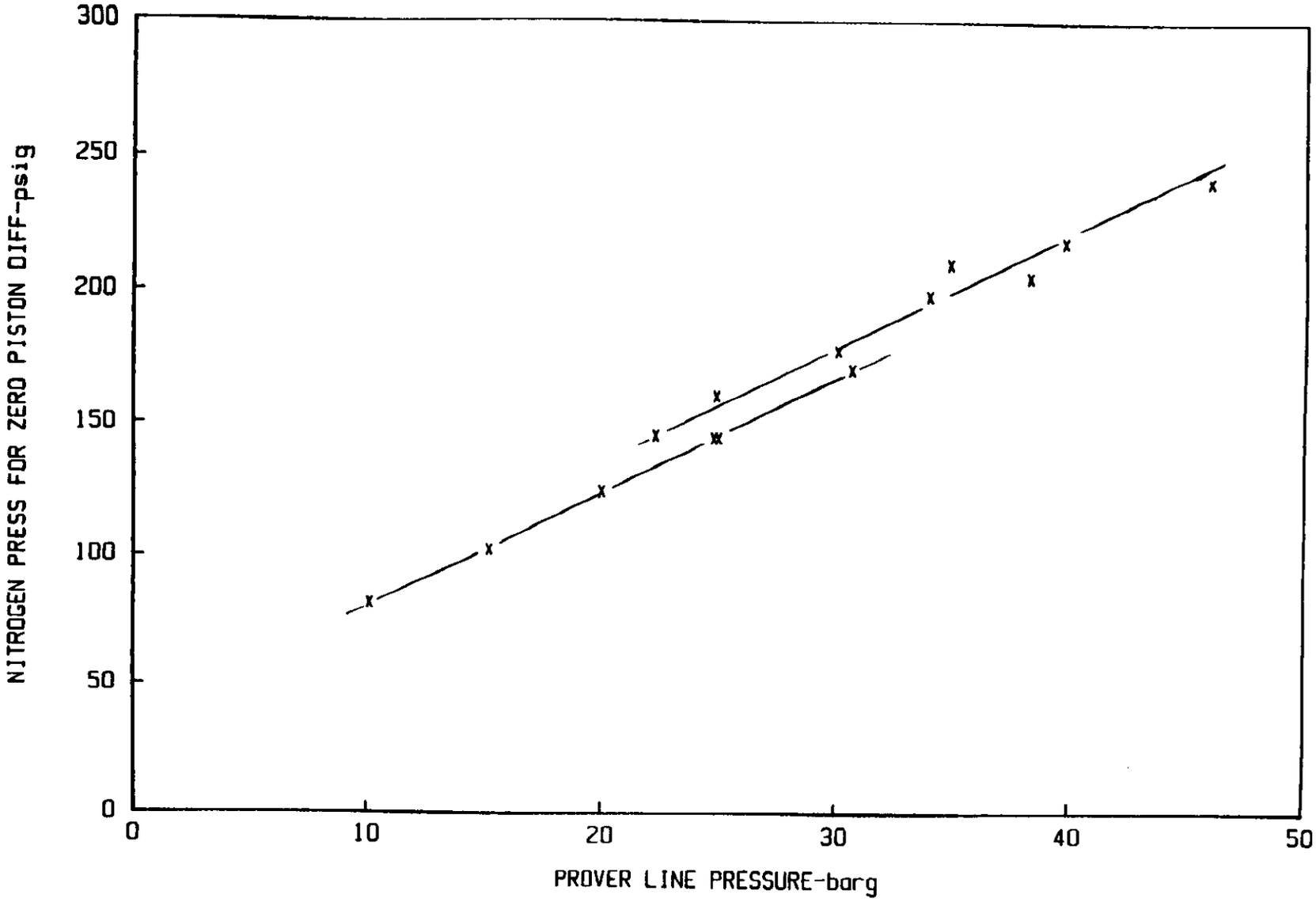

FIG. 8 NITROGEN PRESS FOR ZERO PISTON DIFF AGAINST PROVER LINE PRESSURE

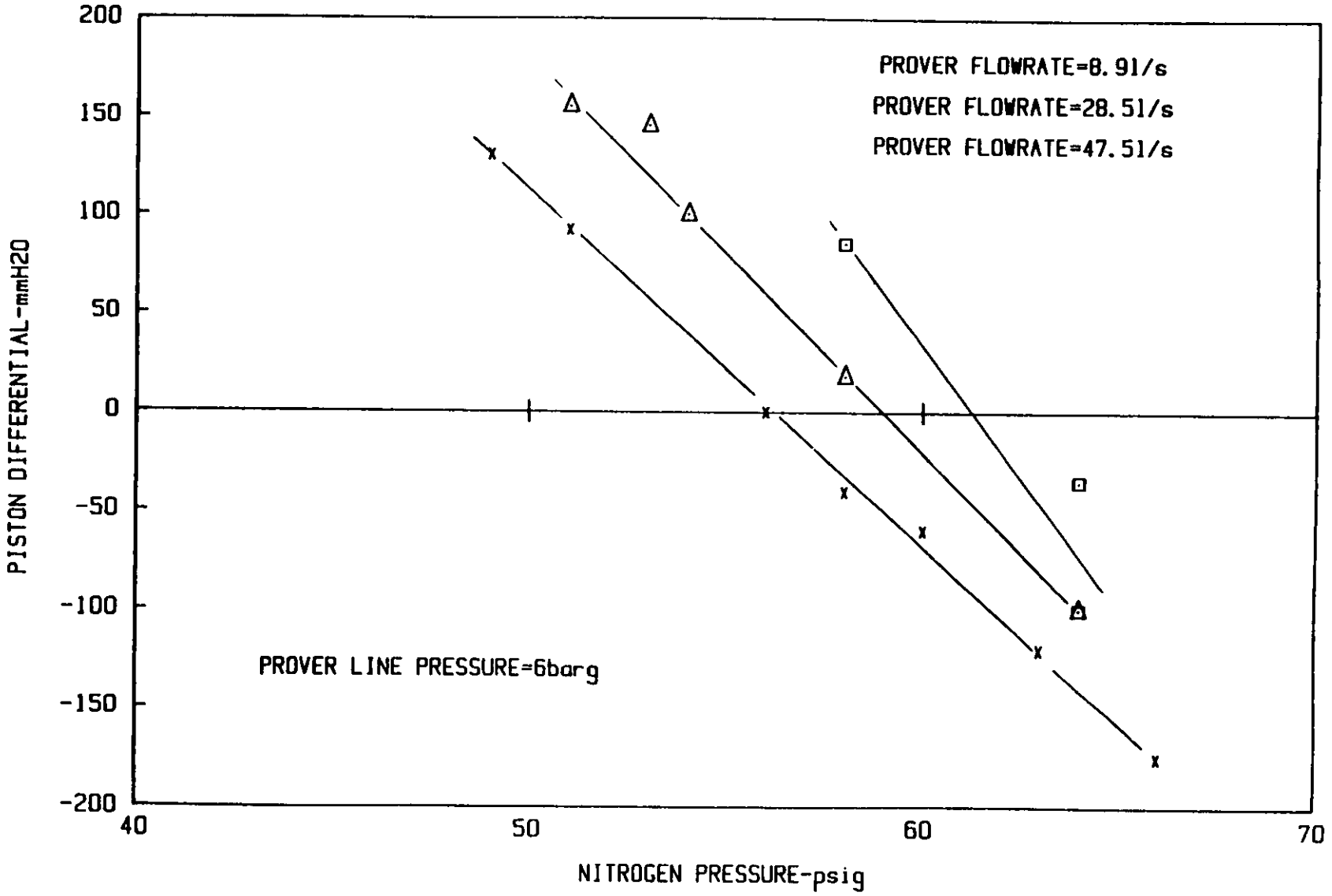

FIG.9 PISTON DIFFERENTIAL AGAINST NITROGEN PRESSURE

Norske Sivilingeniørers Forening
Norwegian Society of Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

5 - 7 November 1985, Stavanger Forum

Experiences with Compact Provers on Live Crude Oil

1.3.

Lecturer: Mr. John Stokes
Unitech

Introduction

The Dutch offshore oil industry was faced with a rather unique problem concerning the proving of their offshore metering systems in 1983.

Three offshore platforms which had been pumping crude oil into a common export pipeline required that their existing metering be upgraded to fiscal standards. The fiscal metering point was to be moved from the onshore terminal back to each separate entry into the pipeline offshore. In addition another operator would be using the same pipeline.

The platforms were built without the need to take account of the space requirements of a self contained fiscal metering and sampling system. Space for additional equipment was therefore at a premium. Indeed none was available in the immediate vicinity of the existing operational meters. The total head from the surge tank with additional top pressure used to circulate the oil through any additional metering equipment was limited. Extra weight also needed to be kept to a minimum. The choice of pipe prover, however, was limited by the constraints of space and weight on all three platforms.

During 1982/83 IJkwezen, the Dutch Weight and Measures Dept. were completing calibration trials on a compact prover. Government certification by IJkwezen was issued in Mid 1983.

The combination of these events set the scene for the beginning of the first known permanent compact prover installations offshore to perform all proving operations on crude oil p.d. meters.

Compact Prover Installation

Due to its small dimensions and relatively low weight, the 12 inch prover skid was installed offshore without any need for structural alterations to the platform in order to gain access to its final horizontal resting position.

The prover hydraulic system was drained temporarily to avoid spillage during the actual installation period.

A 90° elbow was fitted immediately downstream of the prover outlet flange to enable the flow tube assembly to be removed easily. Future inspection of the internal prover flow tube required that the rather heavy outlet flange be removed. A sliding overhead hoist was needed.

All the electrical control and safety barriers were removed from the prover skid and relocated in the control room, to enable the operators to prove meters from the control room, and control all water draw sequence testing.

Additional Control Meter for Monitoring Purposes

As there was no user experience for a compact prover operating offshore in continuous crude oil service there was a need to demonstrate that the prover base volume had not changed due to any malfunction.

By incorporating an additional meter in the proving line between the operational meters and the prover it was possible to monitor the base volume of the prover by comparing the respective K factors when proving both the operational and control meters simultaneously.

However, after gaining reasonable confidence in the compact prover results it was decided to discontinue these checks.

Regular water draw checks and seal leak checks are made to confirm if there is any shift in volume, or leakage across the seals.

Commissioning

All piping from the metering manifold to the prover was new and hence thorough flushing of the pipeline was essential to prevent any foreign matter entering the meter tube.

All optical sensors were inspected and found to be in excellent condition having survived a sea journey and several crane liftings.

Water draw calibration tests were carried out to verify the certified volumes established at IJkwezen's laboratories, and to ascertain that the vibrations caused by the shipping pumps situated directly under the prover did not effect the accuracy and repeatability of the prover.

A radio link between the control room and compact meter prover skid was found to be essential during water draw tests. This was certainly a disadvantage due to the high level of noise in the immediate area of the skid.

A local water draw control unit with optical switch status lights is envisaged in the future.

Water Draw

The cleaning and flushing of the provers have been completed extremely quickly and efficiently. "Down-time" of the provers have been kept to an absolute minimum. The stored water quantities required for a water draw are relatively small.

A calibrated measuring tank traceable back to the authorised standard is available on each platform. The water draw method is entirely self contained on the platform. There is no likelihood of delays to meter proving operations due to bad weather whilst waiting for a master meter/master prover skid unit delivery to the platform.

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Seal Leak Test

In order to make the seal leak check more efficient and easier a permanent installation consisting of micrometer feeler gauge and rods of different lengths were made available.

This avoided the protecting tube having to be removed and also lessened the chance of any accidental damage to the optical switches.

Calibration Trials

In order to achieve some operating experience before the fiscal metering point moved offshore, a series of calibration and meter proving trials were started.

As there were no internationally accepted rules for a minimum number of "runs" and passes, it was decided initially to prove all meters with 5 runs (equivalent to pipe prover requirements) and 6 passes (a minimum requirement by IJkwezen based on a minimum number of pulses per swept volume).

The number of runs and passes were varied with no effect on repeatability or "K" factors. 3 Runs and 6 passes have now been accepted by all interested parties as an acceptable standard.

The unanswered questions at the time during prover trials were:

- how reliable were the piston seals?
- was the poppet valve a good design?
- what should be the frequency of the seal leak test?
- would foreign matter enter the piston tube and damage the nickel plating
- how long would it take to repair a compact prover?
- what were the downtime periods?
- what were the practical problems to water draw offshore, especially when heavy crude oil was being metered?

Operational

Within several months from the start of commissioning trials one of the compact provers displayed difficulty in obtaining repeatability. A water draw and leak test confirmed that there was a problem.

This resulted in the prover being stripped to establish the cause. Extremely small score marks were observed in the barrel. It was discovered that the cause was due to a welding particle which had not been thoroughly flushed from the new upstream piping had entered the prover tube. One very small piece had lodged itself between the seal and barrel surface. Additional temporary filters were installed and the problem has not re-occured.

A spare tube was available and replacement time of the prover tube was completed in approximately 24 hours, which included isolating the prover from the process, unbolting the complete prover assembly, hoisting a new tube into place, re-assembly and preparations made for a water draw and leak test.

Interesting facts and figures

It will probably be of great interest to see some operating statistics of the three compact provers related to operational experiences over the last year.

Commissioning/start-up trials February - July 1984.

On-line - September 1984.

Approx. number of passes per prover - 26,000.
This is based on 5 runs 6 passes per meter proved.
This has now been reduced to 3 runs 6 passes with no effect to meter K-factors.

Total downtime - 4 days.

Failures - 1 poppet valve "O" ring.
Shift in volume after prover tube replacement + 0.004 cc.

Optical switches.
One switch located at "Launch Position" became unpredictable in operation and was replaced.

RECOMMENDATIONS

Installation Prover Tube

Compact provers can be sensitive to certain abrasives in the crude oil especially when they are wedged between the piston seal and tube. As already mentioned one of the prover tubes suffered this fate, the remaining two did not.

The question arose
"Was the horizontal mounting position a bad choice?"

It would seem that a vertical positioning of the prover may reduce the possibility of abrasive substances remaining in the tube and hence lessen the chance of severe wear. It is extremely important during pre-commissioning that all piping and prover tube do not have any abrasive particles inside before the system goes online.

Summary

The compact prover is certainly fulfilling its initial role as an acceptable alternative to crude oil flow meter proving.

The distinct advantages such as size and weight were in this particular case essential in making this metering upgrade project economically feasible.

The use of a compact prover as a permanent offshore calibration standard has now been established. The metering and proving facilities have been subjected to close scrutiny from the other parties in the oil transportation agreement and the Dutch Government Authorities.

Re-certification of the prover volumes by the authorities will now be on a 6 month basis until a learning curve has been established to determine how the flow tubes are wearing.

Compact Meter Provers have certainly a part to play in the development of international accepted standards for meter proving.

There is still room for improvement in many design areas of the compact meter provers, however, the experiences gained with actual proving operations on live crude oil, have now opened the door to allow a new generation of compact provers to be developed.

(0235p)

JS/ma

AN INVESTIGATION INTO THE VELOCITY OF SOUND CORRECTION APPLIED TO GAS DENSITY MEASUREMENT

1.4

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H DANIELSEN, Statoil, Norway

SUMMARY

This paper gives the results up to and including October 1985 of the joint experimental research effort into the velocity of sound correction associated with Solartron density meters. The whole of the experimental work has been carried out in the laboratory at Dantest.

The aim of the project is to measure the densities of various gases as accurately as possible, and then compare the results obtained with those measured using a Solartron density meter with various velocity of sound corrections applied to the results.

Gases tested were Methane, a synthetic natural gas, and Argon as a check on the original Solartron Argon calibration. The pressure range was varied from 50 bar abs up to 150 bar abs with the temperature at 35 °C. Results are reported on Solartron 7811 transducers.

1 INTRODUCTION

This paper gives the results up to October 1985 of our joint research effort into the Velocity of sound correction associated with Solartron density meters. The whole of the experimental work has been carried out at Dantest. The gases tested were Argon, Methane and a synthetic natural gas (93.7% Methane) over a range of pressures 50 bar to 150 bara and a temperature of 35 °C. Solartron 7811 transducers were used.

The aim of the project is to measure the density of a gas as accurately as possible using the real gas equation

$$\rho = \frac{p}{ZRT}$$

and compare the result obtained with that measured using a Solartron density meter with various corrections applied to the results.

Section 2 describes the equipment used in the Dantest laboratory, the procedures used for obtaining measurements of density using the Solartron density meter, the determination of the compressibility factor Z, and the gas constant R.

Sections 3, 4, and 5 give details of the results obtained using Argon, the synthetic natural gas and Methane.

Section 6 gives the conclusions and recommendations arising from the study, whilst section 7 gives the aims of the project for the next series of tests.

2 EQUIPMENT USED IN THE DANTEST LABORATORY

Dantest has 2 alternative methods for determining the "true" density of a gas, ie

I - By direct mass and volume determination:

$$\rho = \frac{\text{mass}}{\text{volume}}$$

II - By using the real gas equation:

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

where ρ - **gas density**

p - **absolute static pressure**

Z - **compressibility factor**

R - **gas constant for the gas in use**

T - **temperature K**

Figure 1 shows a sketch of the laboratory.

The laboratory can be divided into 5 sections:

a) Gas supply section.

b) Compressibility factor measurement.

c) Density measurement using method I.

d) Density meter calibration.

e) Deadweight tester.

The gas supply section comprises a gas bottle together with a pressure regulator and associated pipework. With the aid of a quick connection system at A, the gas supply can be directed to the three sections b, c and d as required.

In the compressibility factor section are two meters for determining Z, and these are items numbered 4 and 5 in Figure 1. Item 4 is a Desgranges and Huot Z-meter, Type 60000, with which a Heto thermal bath is used to stabilise the temperature. This Z-meter is calibrated using 99.9952% purity Nitrogen and the NBS nitrogen tables, and has a working range of 3 to 80 bars abs.

Item 5 is a Dantest designed Z-meter using the same principle of the Desgranges and Huot Z-meter but has a working range from 50 to 150 bars abs. The Dantest Z-meter enables us to determine Z without reference to the NBS tables. Results show agreement with NBS nitrogen and methane tables within 0.1%. The temperature in the Dantest Z meter is also stabilised by means of the Heto thermal bath.

The section for determining the density according to method I comprises a pressure vessel (item 2 in Figure 1) specially designed by Dantest. This vessel can be used over the range 10 to 80 bars abs, and can be used for most types of gases. The accuracy when determining density by this method is between 0.05% and 0.1% depending on the pressure and gas type. Pressure and temperature can be accurately measured in the vessel, which has a nominal volume of 12 litres. This method cannot be used to make a calibration curve for a density meter. The method is used to determine a single point of density at room temperature.

Density meters to be calibrated are enclosed in a thermal cabinet (item 3 in Figure 1). Each density meter in the cabinet has a PT100 thermometer attached near the measuring cylinder. The uncertainty of the temperature measurement is within 0.1°C. The temperature in the thermal cabinet is adjustable over the range 0 to 40 °C.

The deadweight tester is used to stabilise and set the working pressure in sections b, c and d. It is a Desgranges and Huot Type 5201S and has been previously calibrated by the Laboratoire National d'Essais, France. This instrument has a measurement range of 0.4 bar abs to 200 bar abs, and an uncertainty of 0.01%.

Having described the general layout for the Dantest laboratory, I shall now concentrate on the means of obtaining the results given in this paper. The "true" value of density for Methane was obtained by using NBS tables on the measured temperature and pressure. The "true" value of density for Argon was obtained from Solartron who, with Dantest measured temperature and pressure, computed the density values using multiple degree interpolation in the F. Din tables. The true value of density for the synthetic natural gas was obtained using the real gas equation (method II) :

$$\rho = \frac{p}{ZRT}$$

in which

1. R - the gas constant was determined by measuring ρ (p,T) using method I (ρ = m/v) then measuring Z (p,T) and hence R can be obtained from:

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

2. Z - the compressibility factor was measured using the Dantest Z - meter.

Three Solartron 7811 density meters were placed in series in the thermal cabinet and were stabilised at 35°C. After having purged the system with the gas under calibration the density meters were calibrated step wise with increasing pressure (and hence increasing density).

3. RESULTS USING ARGON

The aim of the Argon tests was to ensure that nothing peculiar had happened to the density meters since leaving Solartron and that both Dantest and Solartron were measuring without any significant systematic deviations. Figure 2 shows a comparison between the calibration obtained on Argon at Solartron and the corresponding calibration at Dantest over the range of pressures 40 to 150 bar abs at a nominal temperature of 20 °C. It can be seen that the overall differences are acceptable, but the Dantest results are consistently higher than Solartron's results over the range 40 to 150 bar abs.

4. RESULTS USING SYNTHETIC NATURAL GAS

Figs 3, 4 and 5 show the results obtained for calibrations on synthetic natural gas with 3 different corrections applied to the raw data. The details of the 3 methods of correction used are given in Appendix 1.

Fig 3. is Total Oil Marine's method of interpreting the velocity of sound correction using the Solartron user gas offset formula from the original certificate applied to Argon constants.

Fig 4. uses the Argon user gas calibration certificate at 20°C which has been supplied by Solartron from gas composition provided by the partners in the project. This user data at 20°C has been corrected to 35°C using the Solartron temperature correction formula supplied by Solartron.

Fig 5. uses the Argon user gas calibration certificate at 35°C which has been supplied by Solartron from gas composition provided by the partners in the project.

At offshore operating conditions with pressures approximately 120 bar abs. to 150 bar abs. it can be seen that the TOM velocity of sound correction is worse than the user data at 20°C which in turn is worse than the user data at 35°C.

It would thus appear that from these results, with the various corrections offered by Solartron, the Argon user data formula at the temperature corresponding to the field density measurements gives the best accuracy although still not within + 0.2%.

5. RESULTS USING METHANE

Fig 6 shows the results obtained in Methane with Total Oil Marine's method of interpreting the velocity of sound correction using the Solartron user gas offset formula applied to Argon constants. The detail of the correction is given in Appendix 1.

It can be seen that at no test pressure is the difference between true density and measured density better than 0.2%.

Fig 7. shows the effect of calibrating a density meter on Methane at 35°C and then attempting to use the constants obtained to measure the density of synthetic natural gas which contains 93.7% Methane. The deviation is within 0.2%.

6. CONCLUSIONS AND RECOMMENDATIONS

Before going into a discussion of these results it must be stressed that the measurements concerned are the first of their kind to be published. For this paper measurements have been made on two gases with a high methane content: pure methane and a synthetic natural gas with approximately 94% methane. This material basis is not large enough to draw general conclusions.

So the conclusions that follow should be treated with this in mind.

6.1 The argon calibration at Dantest shows that the density meters do not show a major drift from the Solartron calibration.

The results also prove that the two laboratories reproduce each others results within 0.15% (the British Calibration Service accuracy limits in Solartrons authorisation).

6.2 When regarding the results for the synthetic natural gas and methane they show poor agreement with the velocity of sound correction. The maximum deviations being about 0.4% to 0.5%. An explanation for part of this could be the tables used for the argon calibration. The FDIN tables show systematic differences from both NBS and IUPAC tables of approximately 0.2%. Using NBS or IUPAC and the same constants for the velocity of sound correction the deviation from 'true' density would fall to 0.2% - 0.3%. Further documentation is needed for further analysis of contributions to the deviation.

6.3 Comparison of the methane and the synthetic gas calibration, Fig. 7, shows that methane used as a calibration gas would bring deviations down to under 0.2% in the pressure range 50 to 150 bar.

Recommendations based on our limited results is that at offshore metering conditions the uncertainty in density measurement can be lessened if one of the following calibrations procedures is used:

1. Calibration with methane at the operating temperature providing the natural gas has a high methane content.

2. Calibration with argon using IUPAC tables and using the user gas calibration certificate derived at the operating temperature. This second recommendation requires more work doing to substantiate it.

A final conclusion is that more data is necessary in this high pressure range.

7. FUTURE WORK

The one obvious shortcoming of the foregoing tests is that the gas measured in the density meters is locked in, ie the measurement is "static". However, in the field it is, without exception, the case that density is measured "dynamically" with a small flow of gas always taking place through the density meter. It is our intention to investigate whether or not the difference between "static" or "dynamic" measurement is negligible. Our inclination from limited tests is to say that there is no difference, but it needs to be investigated thoroughly once and for all.

A second area to be explored is to compare the performance of density meters on various "dry" natural gases which are at conditions above their dewpoint.

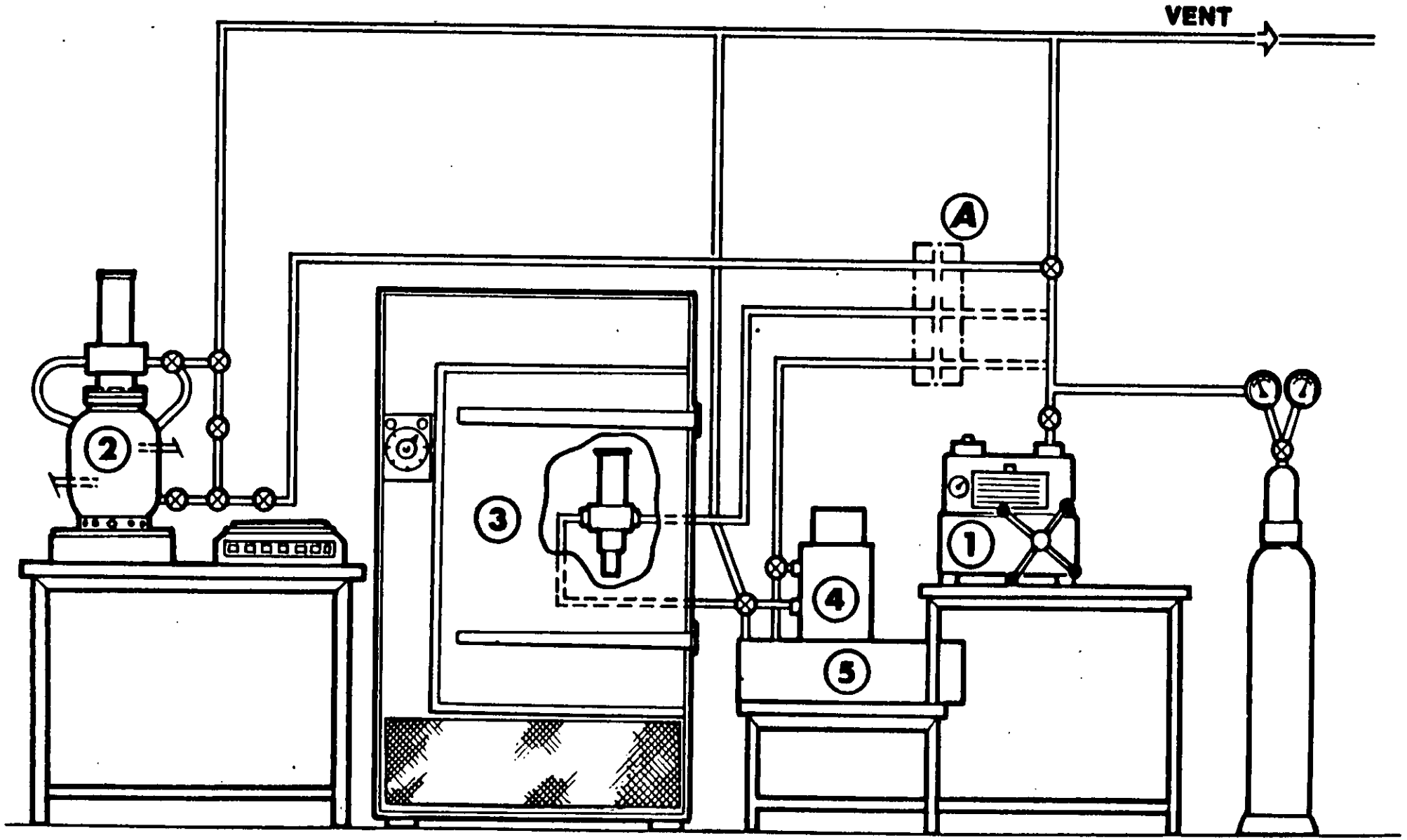

FIGURE 1 - SKETCH OF THE DANTEST LABORATORY

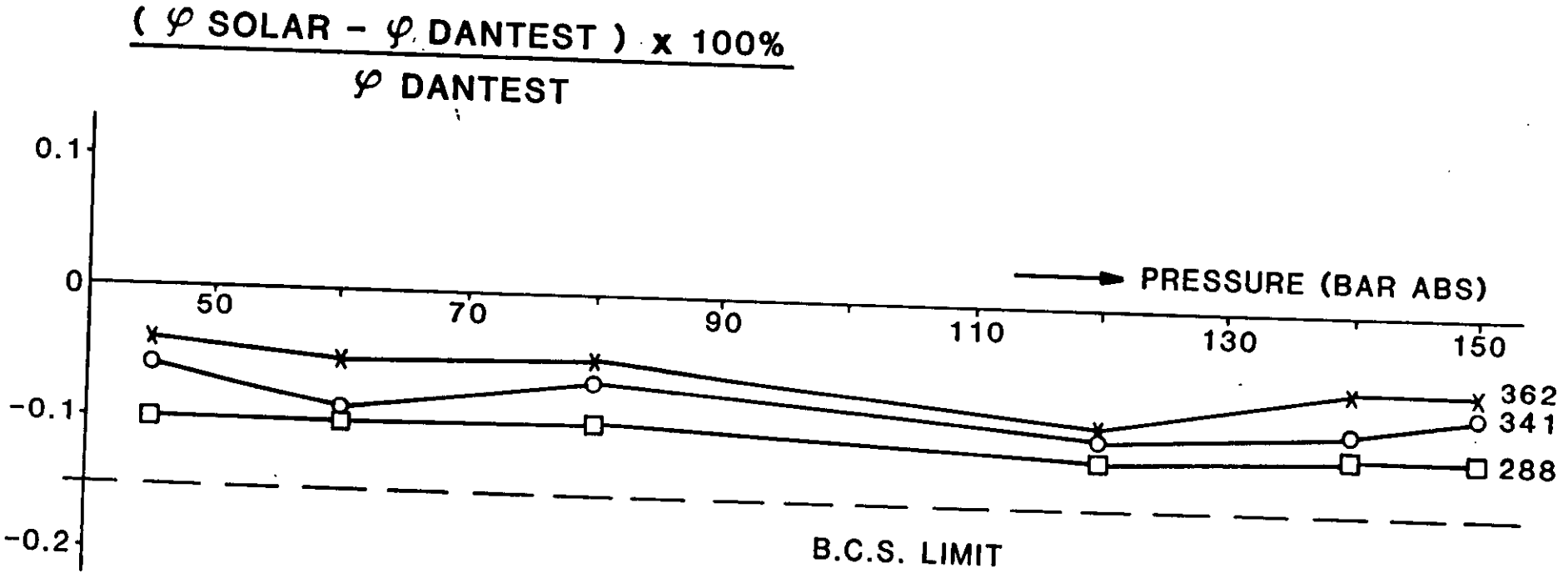

FIGURE 2 - COMPARISON BETWEEN DENSITYMETERS USING SOLARTRONS ARGON CONSTANTS AND DENSITY DETERMINED AT DANTEST

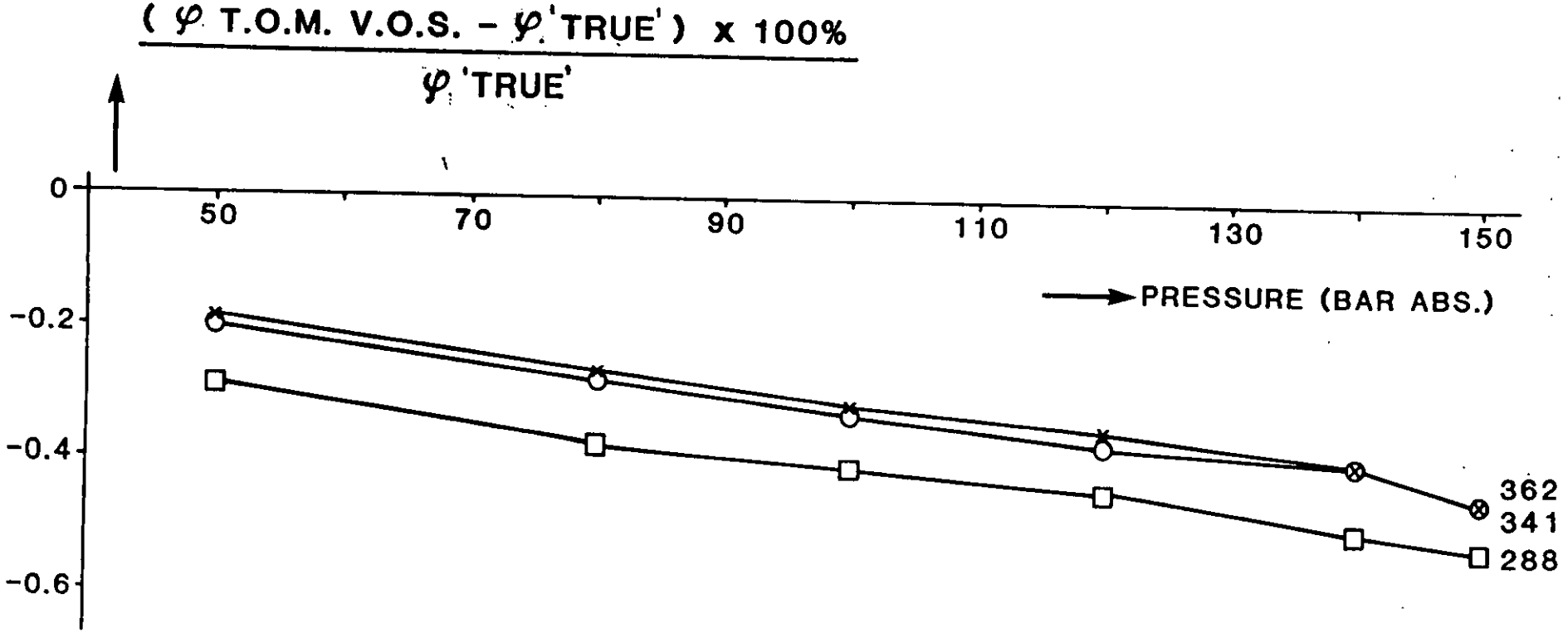

FIGURE 3 - COMPARISON BETWEEN SYNTHETIC NATURAL GAS WITH T.O.M. VELOCITY OF SOUND CORRECTION (USER GAS OFFSET DATA) AND 'TRUE' DENSITY OF THE SYNTHETIC NATURAL GAS

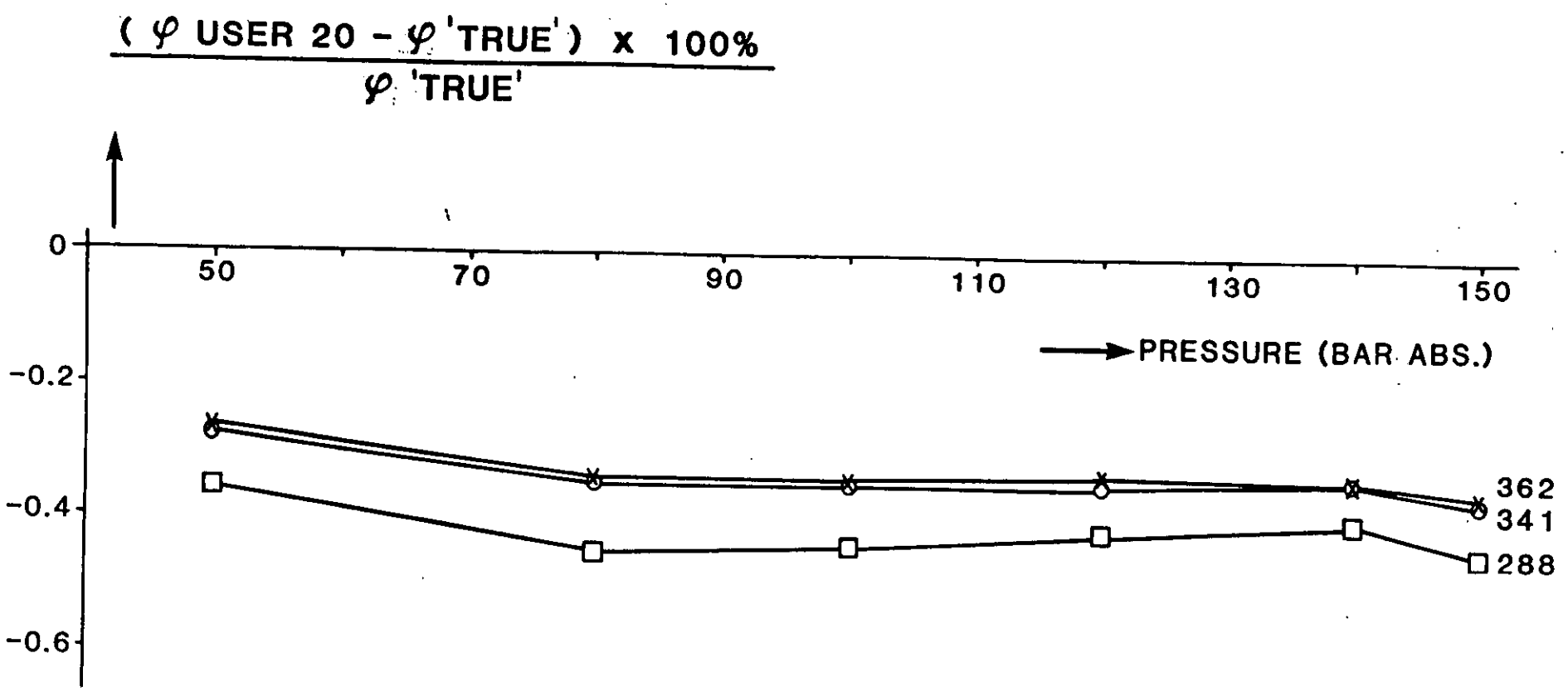

FIGURE 4 - COMPARISON BETWEEN SYNTHETIC NATURAL GAS USER DATA AT 20°C TEMPERATURE CORRECTED TO 35°C AND 'TRUE' DENSITY OF THE SYNTHETIC NATURAL GAS

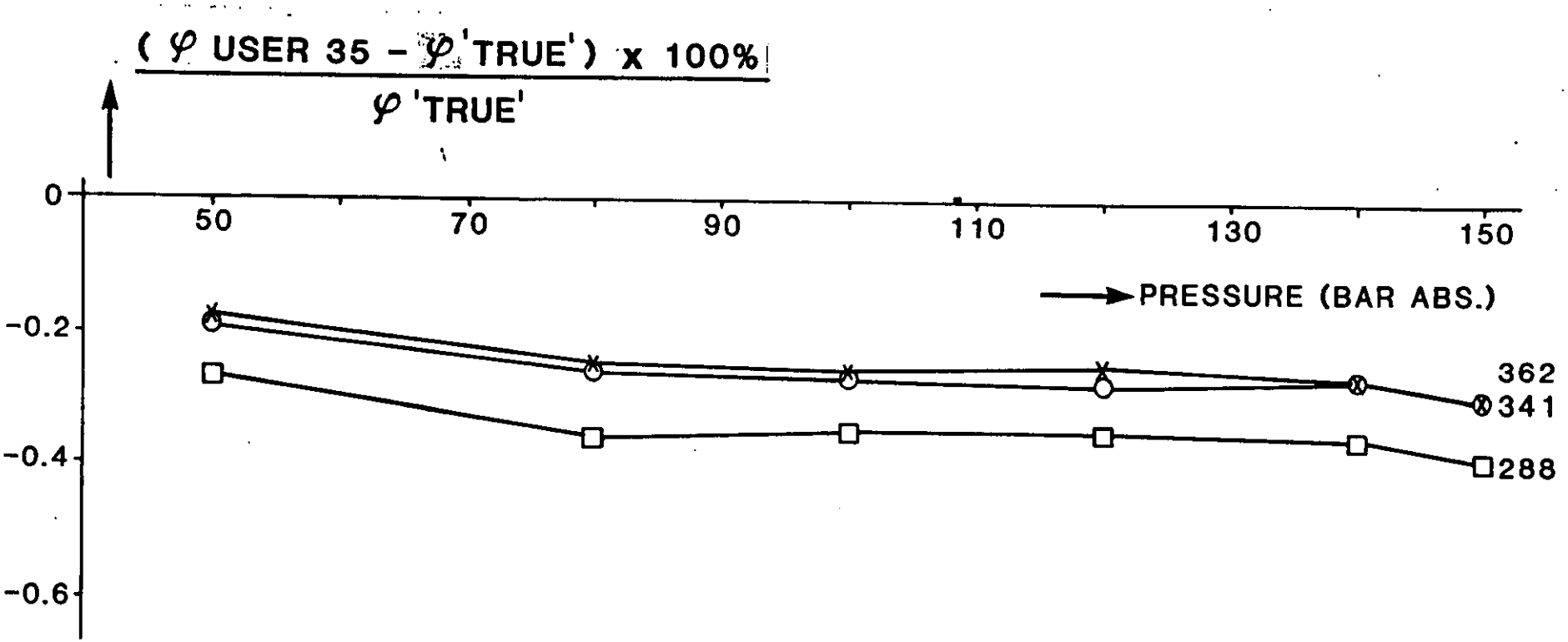

FIGURE 5 - COMPARISON BETWEEN SYNTHETIC NATURAL GAS USER DATA AT 35°C AND 'TRUE' DENSITY OF THE SYNTHETIC NATURAL GAS

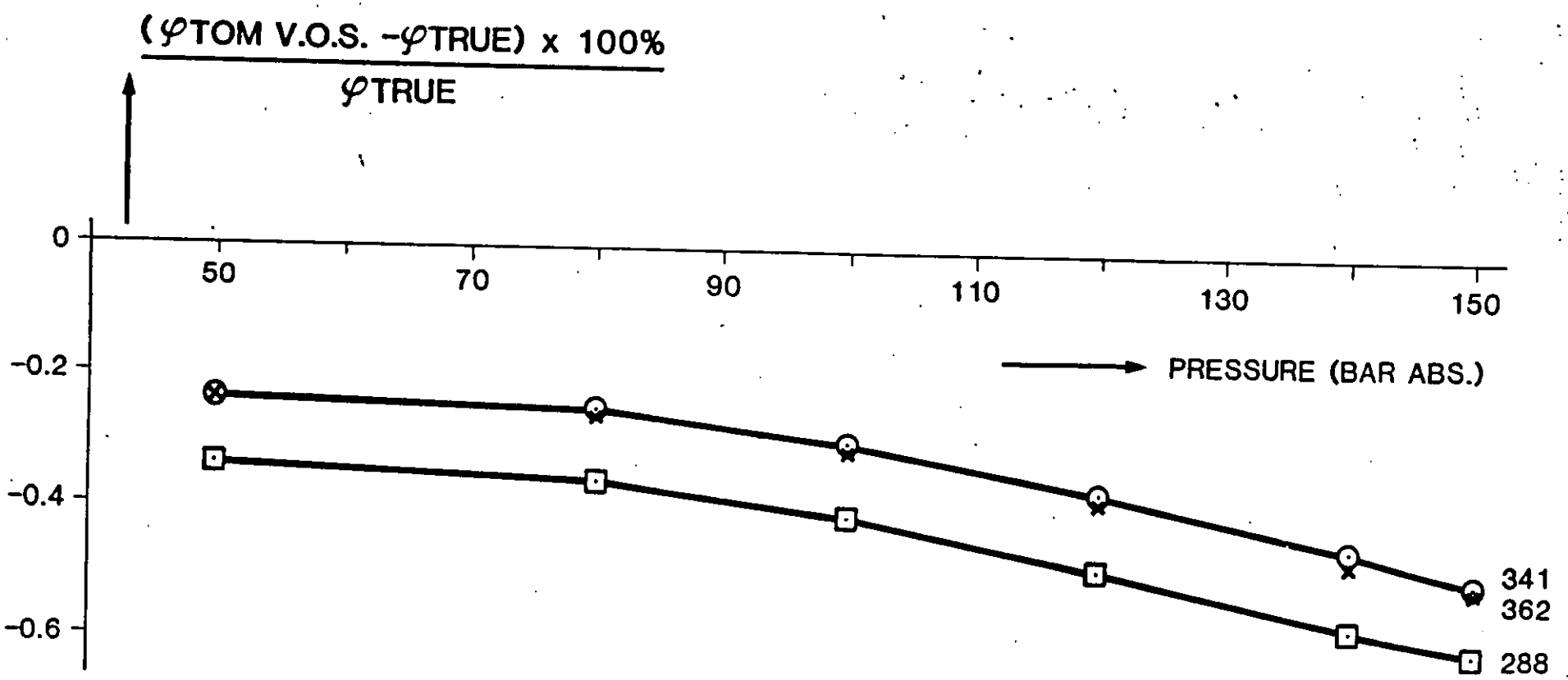

FIGURE 6 - COMPARISON BETWEEN METHANE WITH TOM VELOCITY OF SOUND CORRECTION (USING GAS OFFSET DATA) AND TRUE DENSITY OF METHANE

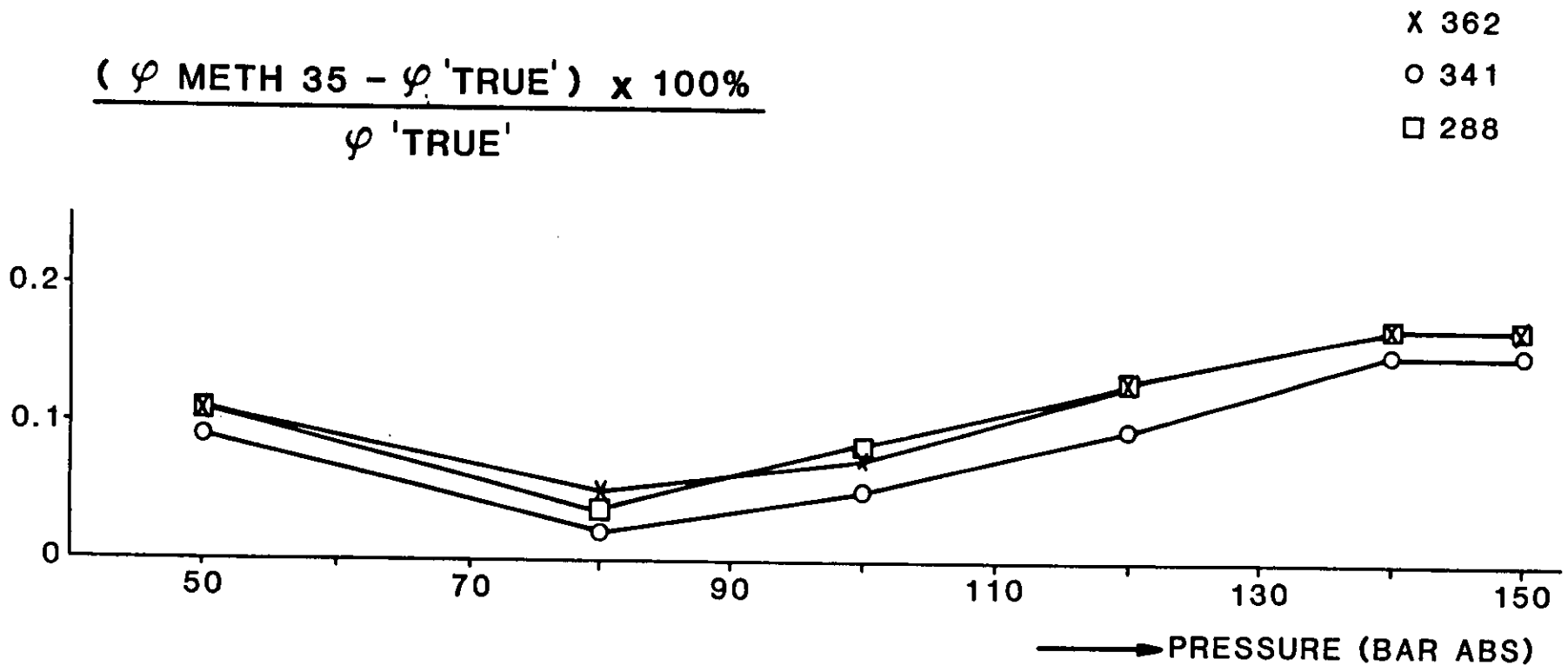

FIGURE 7 - COMPARISON BETWEEN DENSITYMETERS CALIBRATED ON METHANE AT 35°C AND THEN USED IN THE SYNTHETIC NATURAL GAS

APPENDIX 1

A1. TOM CONSTANTS FOR USER GAS OFFSET DATA ON THE SYNTHETIC NATURAL GAS

S.G. = 0.591, K = 1.3, hence G = 0.4546

$$D_A = D_T \left(1 + \frac{K3}{(DT+K4)}\right) 0.00282 - \frac{0.4546}{(T + 273)}$$

A2. TOM CONSTANTS FOR USER GAS OFFSET DATA ON METHANE

S.G. = 0.555, K = 1.3, hence G = 0.555/1.3 = 0.4269

$$D_A = D_T \left(1 + \frac{K3}{(DT+K4)}\right) 0.00282 - \frac{0.4269}{(T + 273)}$$

CALIBRATION CERTIFICATE

7811N GAS DENSITY METER SERIAL NO: 200288

CYLINDER NO: 200681 AMPLIFIER NO: 000621

UNIT PRESSURE TESTED TO 375 BARS (5440 PSI)

DENSITY CALIBRATION FOR ARGON AT 20 DEGREES C

DENSITY [KG/M3]	PERIODIC TIME [uS]
0	453.475
25	514.825
50	569.027
100	663.708
150	746.016
200	819.805
250	887.304
300	949.856
350	1008.411
400	1063.682

DENSITY=K0 + K1.T + K2.T**2 where K0=-80.9998
K1=-.025139
K2= 4.4876E-04

TEMPERATURE COEFFICIENT DATA

DT=DI(1+K18(T-20))+K19(T-20)

where DT=ACTUAL DENSITY (KG/M3) DI=INDICATED DENSITY (KG/M3)
T=TEMPERATURE (DEG.C) K18=-2E-05
K19= 1.14E-04

USER GAS OFFSET DATA

$$DA = DT\left(1 + \frac{K3}{(DT+K4)}\left(0.00282 - \frac{G}{T+273}\right)\right)$$

where DA=ACTUAL DENSITY (KG/M3) T=TEMPERATURE (DEG.C)
DT=TEMPERATURE-CORRECTED DENSITY (KG/M3)
K3= 741
K4= 63.5
G= GAS SPECIFIC GRAVITY / RATIO OF SPECIFIC HEATS

FINAL TEST

TESTER....66.....DATE.21 SEP 1994.....QC.....

S. E. G. 21 SEP 1994

SOLARTRON TRANSDUCERS

1GD7

SOLARTRON
Schlumberger

USER GAS CALIBRATION CERTIFICATE

7811N GAS DENSITY METER

SERIAL No:200288

Cyl No:200681

ARGON CALIBRATION DATA AT 20°C

K0 = -80.9998

K1 = -.025139

K2 = 4.4876E-04

K18 = -2E-05

K19 = 1.14E-04

USER GAS DATA AT 35°C

COMPOSITION BY % VOLUME :-

HYDROGEN	.0000
HELIUM	.1000
NITROGEN	.5600
CARBON MONOXIDE	.0000
CARBON DIOXIDE	.3100
OXYGEN	.0000
ARGON	.0000
METHANE	93.6900
ETHANE	4.3200
ETHYLENE	.1000
PROPANE	.4800
PROPYLENE	.0000
BUTANE	.2190
PENTANE	.2210
HEXANE +	.0000
TOTAL	100.0000

MAXIMUM TOTAL SENSOR ERRORS USING NEW COEFFICIENTS :-

DENSITY [kg/m³]	V.o.S. [m/s]	PERIODIC TIME [µs]	MAX. ERROR [%density]
40	430	547.218	0.199
60	432	588.292	0.185
80	441	626.556	0.175
100	456	662.517	0.171
120	476	696.548	0.166
140	502	728.930	0.167

FOR DENSITIES 40 TO 140 kg/m³:-

K0 = -81.338

K1 = -.024939

K2 = 4.5078E-04

N.B. SINGLE PHASE GAS IS ASSUMED

TESTED BY:-
FINAL TEST 87
6. /85

QUALITY CONTROL
8 AUG 1985
DLW
35

2005

SOLARTRON Transducers

SOLARTRON
Schlumberger

USER GAS CALIBRATION CERTIFICATE

7811N GAS DENSITY METER

SERIAL No:200362

Cyl No:200810

ARGON CALIBRATION DATA AT 20°C

K0 = -83.8641

K1 = -.026795

K2 = 4.8134E-04

K18 = -6.5E-06

K19 = 1.634E-03

USER GAS DATA AT 20°C

COMPOSITION BY % VOLUME :-

HYDROGEN	.0000
HELIUM	.1000
NITROGEN	.5600
CARBON MONOXIDE	.0000
CARBON DIOXIDE	.3100
OXYGEN	.0000
ARGON	.0000
METHANE	93.6900
ETHANE	4.3200
ETHYLENE	.1000
PROPANE	.4800
PROPYLENE	.0000
BUTANE	.2190
PENTANE	.2210
HEXANE +	.0000
TOTAL	100.0000

MAXIMUM TOTAL SENSOR ERRORS USING NEW COEFFICIENTS :-

DENSITY [kg/m³]	V.o.S. [m/s]	PERIODIC TIME [µs]	MAX. ERROR [%density]
40	414	535.127	0.197
60	415	574.366	0.184
80	422	610.961	0.173
100	435	645.383	0.171
120	454	677.978	0.166
140	478	709.011	0.169

FOR DENSITIES 40 TO 140 kg/m³:-

K0 = -83.4582

K1 = -.029219

K2 = 4.8573E-04

N.B. SINGLE PHASE GAS IS ASSUMED

TESTED BY:-

FINAL TEST 87

6/8/85

QUALITY CONTROL

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- 8 AUG 1985

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35

2005

SOLARTRON Transducers

Norske Sivilingeniørers Forening

NORTH SEA FLOW METERING WORKSHOP

Stavanger, 5 - 7 November 1985

High turndown orifice plate measurement using a single DP Cell

1·6

Lecturer: Mr. R. J. Frost
Spectra-tek UK Ltd.

SPECTRA-TEK

CONTENTS

1.0 SUMMARY

In this short paper we propose to put foreward a method of measuring flow through an orifice plate with high turndown using a single DP cell. Accuracy is at least as good as that obtained using the traditional 3DP cell approach.

By virtue of the equipment used, further advantages are obtained in problem solving.

The paper first briefly reviews the current method of dealing with high turndown flow conditions in an orifice plate.

It then goes on to describe the transmitter which can replace triple DP cells, the Honeywell ST3000.

Using the technology available in the Honeywell transmitter, Spectra-Tek have produced a device which will alow a computer to change ranges on the Honeywell ST3000, the QST.

Using their standard gas flow computer Spectra-Tek have developed special software to enable the computer to use the Honeywell ST3000 DP transmitter as if it were three DP cells with 3 ranges.

2.0 REVIEW OF THE CURRENT METHOD

2.1 Arrangement

A normal 3DP cell set up has 3 cells sitting on one manifold individually isolated.

Each cell signal goes through a pair of wires through barrier sets and the signal is read by the computer.

2.2 Operation

When reading the differential pressure the cells operate starting at the lowest range. As the range increases to say 95° of full scale value, the second cell is used for determining the differential pressure.

When on the second cell again, if the cell arrives at 95% of its full scale the third cell is used for determining the differential pressure.

When DP is falling, if the differential pressure say on cell number 3 reduces to the equivalent of 90% of full scale on cell 2, cell 2 is used in the determination of pressure.

Why use 3 cells?

Accuracy (See table 1)

It can be seen from table 1 that the accuracy of the cell considerably improves if 3 cells are used. I have taken, throughout this discussion, the error to be a percentage of the actual reading at each point.

For ease of comparison I have chosen ranges of 125, 250 and 400mbar and assumed switchover at 100%.

TABLE 1

ACCURACY CALCULATIONS FOR STANDARD CELL

ENTER ERROR PERCENT- .2

INPUT RANGES

RANGE 1(LOWEST)- 400

RANGE 2(MIDDLE)- 400

RANGE 3(UPPER)- 400

DP	%ERROR	RANGE	%FLOW ERROR
400	0.2	400	9E-2
300	0.266	400	0.13
251	0.318	400	0.15
250	0.32	400	0.15
201	0.398	400	0.19
200	0.4	400	0.19
126	0.634	400	0.31
125	0.64	400	0.31
100	0.8	400	0.39
63	1.269	400	0.63
62.5	1.28	400	0.63
50	1.6	400	0.79
20	4	400	1.98
10	8	400	3.92
5	16	400	7.7

INPUT RANGES

RANGE 1(LOWEST)- 125

RANGE 2(MIDDLE)- 250

RANGE 3(UPPER)- 400

DP	%ERROR	RANGE	%FLOW ERROR
400	0.2	400	9E-2
300	0.266	400	0.13
251	0.318	400	0.15
250	0.2	250	9E-2
201	0.248	250	0.12
200	0.25	250	0.12
126	0.396	250	0.19
125	0.2	125	9E-2
100	0.25	125	0.12
63	0.396	125	0.19
62.5	0.4	125	0.19
50	0.5	125	0.24
20	1.25	125	0.62
10	2.5	125	1.24
5	5	125	2.46

3.0 DESCRIPTION OF THE HONEYWELL ST3000

The ST300 is a so called "smart" DP transmitter (it is also available as an ordinary pressure cell).

The transmitter has on board a microprocessor which performs several functions.

It enables the device to be interrogated providing diagnostics and setting up facilities.

The transmitter is basically like any other transmitter with the process variable represented by a 4-20mA current.

Where it differs from other transmitters is in the communications. By using the hand held field communicator, it is possible to talk to the transmitter in the field. When this occurs the process variable signal is interrupted and is restored at the end of communications.

The hand held communicator has a host of facilities, including setting the cell to linear or square root action, setting 4mA and 20mA (LRV and URV), setting damping, calibration, zeroing, error checking and many more.

Communication is via the 4-20mA loop using the same wires. It involves a special protocol and special baud rate, together with a method of "waking up" the transmitter and putting it into communications mode.

The facilities were developed to enable the transmitter to be stocked as a standard item and configured to appropriate functions, range and tag number in the engineering department, before using in the field.

The key area that interests us in re-ranging. It is possible by downloading a command to set the LRV (lower range or 4mA value) and URV (upper range or 20mA value) from the hand held communicator.

So the Honeywell transmitters can be used to replace 3DP cells by taking three standard models, setting the ranges in the workshop and replacing the normal cells.

The next step is of course to consider whether one cell can be used to cover all three ranges in situ.

This question was first proposed to us by Shell. It might be possible to use one Honeywell ST3000 to replace the traditional 3 transmitters by using this re-ranging facility.

This involves waiting until the transmitter is near the top of its operating range and sending an instruction to it to change its LRV and URV to more suitable values. Similarly as flow reduced ranges could be manipulated to keep the current to a reasonable value.

What is needed?

1. To make a decision about when to change range.
2. Interact with the ST3000 to change range.
3. Interpret the results of change.
4. Cope with the loss of process variable signal during communication.
5. The ability to communicate.

This is best done with a dedicated computer.

There is a problem, however. The ST3000 transmitter will not accept 'normal' communication from a computer. This is because it has a special protocol and a special baud rate.

4.0 THE SPECTRA-TEK QST

The key to successful communication is to be able to convert a "standard" protocol with normal baud rates into one which can be used by the ST3000.

It was necessary to invent a piece of hardware to perform this trick and translate a normal RS232 type ASCII protocol into a suitable form. The transaction is required to be bi-directional.

So, Spectra-Tek developed a piece of hardware with an on board processor that could perform the task. Bearing in mind that we find it useful to provide maximum flexibility we built the QST.

So it has been developed with a multidrop capability talking to up to 4 ST3000, facilities which can be fully developed on a larger systems.

The QST has been designed to mount on standard top hat and asymmetric DIN rail. All connections are by screw terminals. The QST will operate an ST3000 either through a standard IS barrier or without any barrier and special links are provided to ensure that the hand held communicator will operate with no barrier present.

When used normally, the 4-20mA process variable signal is conditioned through 01.0% precision 50 ohm resistors. This provides a 0.2 to 1 volt signal to the host computer. When communication takes place this signal is corrupted and should not be read.

4.1 Communication

The communication with the QST involves the use of a special protocol.

The QST receives a pre-packaged message from the host computer via a standard communications link using 1200 baud transmission rate. The message is transmitted using standard ASCII characters.

The packaging of the message includes an address for the ST3000 on the QST board. Each QST board has links which can be set to provide an address. The QST will only repsond if the polling address is its own. A checksum system is used to validate the incoming message.

When a QST receives a poll it first checks if the message is for it. If so it then wakes up the Honeywell ST3000 that is addressed. At the same time the received message is changed to a format suitable for the ST3000 and passed on to the ST3000. During this time the process variable signal is disturbed and is no longer valid. Care must be taken to ensure that the reading of the process variable is suspended during communication. A typical communication time is 1.5 secs.

Having talked to the ST3000 the QST then waits for a reply. If a reply is received it is checked for transmission error, packaged to include the address of the ST3000 and that of the QST and returned to sender. If no reply is received an error message is returned to the sender.

5.0 IMPLEMENTATION OF RE-RANGING

We now have the ability to talk to an ST3000 from a computer. We can therefore use the computer to make decisions about when to change the range.

Once it has decided to action the range it sends the approriate information to the ST3000 to change the range and adjusts its own internal register appropriately.

This means that instead of listening to 3 cells the computer re-ranges the ST3000 to act as an appropriate cell.

When, say, on the lowest range the Honeywell cell reaches 95% of the full scale value, the computer, via the QST sends a message to the ST3000 to re-range to range 2.

Having done this it reads the PV as if it were from range 2.

Similarly at 95% of range 2 the Honeywell cell is re-ranged to to range 3. The same thing happens on the way down.

We can now cope with high turndown with only one set of wires, one set of barriers and one header.

6.0 ACCURACY

We have seen how the accuracy of a single cell deteriorates in comparison with a standard 3 cell system. Can the Honeywell ST3000 provide the accuracy required?

The answer is of course, YES. Indeed in comparison with a widely used cell the accuracy figures are better.

To demonstrate this I have produced calculated accuracy figures for a standard 3 PP cell system and compare them with the Honeywell ST3000.

I have taken published figures from a widely used transmitter. For the ST3000, I have used the formulae below.

Including combined effects of linearity, hysterisis and repeatability.

$\pm$ 0.1% of calibrated span or upper range value, whichever is the greater, terminal based, except below 125 millibar accuracy equals.

$$0.05 + \left(0.05 \times \frac{125 \text{ millibar}}{\text{span in millibar}}\right)$$

Combined Zero and Span Temperature Effect

Per $28^{\circ}C$ $\pm$ 0.25% of calibrated span between reference span and Upper Range Unit, except below 125 millibar accuracy equals.

$$0.2 + \left(0.05 \times \frac{125 \text{ millibar}}{\text{span in millibar}}\right)$$

Combined Zero and Span Static Pressure Effect

Per 69 bar $\pm$ 0.2% of calibrated span, between reference span and Upper Range Limit, except, below 250 millibar accuracy equals.

$$0.2 \left(\frac{250 \text{ millibar}}{\text{span in miilibar}}\right)$$

6.1 **Results**

I have chosen ranges of 0-125mbar, 0-250mbar and 0-400mbar with switching points 125mbar and 250mbar as explained above.

For a Standard Cell (Table 2)

The worst error of course occurs at switchover and you can see that at switchover values the worst errors are 0.32% and 0.4% with an error at 20mbar of 1.25%.

For Honeywell Cell including re-range error (Table 3)
(Assuming calibration at mid range).

0.21% and 0.2% with an error at 20mbar of 0.94%.

However, it is possible using the facilities for offset in Quantum and providing values at test to eliminate the re-range error. The figures then become ...

Honeywell Cell without re-range error (Table 4)

0.16% and 0.2% with error at 20mbar of 0.63%

It can be seen that the ST3000 performs substantially better than three standard cells.

TABLE 2

ACCURACY CALCULATIONS FOR STANDARD CELL

ENTER ERROR PERCENT- .2

INPUT RANGES

RANGE 1 (LOWEST)- 125

RANGE 2 (MIDDLE)- 250

RANGE 3 (UPPER)- 400

DP	%ERROR	RANGE	%FLOW ERROR
400	0.2	400	9E-2
300	0.266	400	0.13
251	0.318	400	0.15
250	0.2	250	9E-2
201	0.248	250	0.12
200	0.25	250	0.12
126	0.396	250	0.19
125	0.2	125	9E-2
100	0.25	125	0.12
63	0.396	125	0.19
62.5	0.4	125	0.19
50	0.5	125	0.24
20	1.25	125	0.62
10	2.5	125	1.24
5	5	125	2.46

TABLE 3

ACCURACY CALCULATIONS FOR HONEYWELL CELL WITH RERANGE ERROR

ENTER ERROR PERCENT- .1

INPUT RANGES

RANGE 1(LOWEST)- 125

RANGE 2(MIDDLE)- 250

RANGE 3(UPPER)- 400

CALIBRATED RANGE?(1-3)2

DP	%ERROR	RANGE	%FLOW ERROR
400	0.13	400	6E-2
300	0.173	400	8E-2
251	0.207	400	0.1
250	0.1	250	4E-2
201	0.124	250	6E-2
200	0.125	250	6E-2
126	0.198	250	9E-2
125	0.15	125	7E-2
100	0.187	125	9E-2
63	0.297	125	0.14
62.5	0.3	125	0.14
50	0.375	125	0.18
20	0.937	125	0.46
10	1.875	125	0.93
5	3.75	125	1.85

TABLE 4

ACCURACY CALCULATIONS FOR HONEYWELL CELL WITHOUT RERANGE ERROR

ENTER ERROR PERCENT- .1

INPUT RANGES

RANGE 1(LOWEST)- 125

RANGE 2(MIDDLE)- 250

RANGE 3(UPPER)- 400

CALIBRATED RANGE?(1-3)2

DP	%ERROR	RANGE	%FLOW ERROR
400	0.1	400	4E-2
300	0.133	400	6E-2
251	0.159	400	7E-2
250	0.1	250	4E-2
201	0.124	250	6E-2
200	0.125	250	6E-2
126	0.198	250	9E-2
125	0.1	125	4E-2
100	0.125	125	6E-2
63	0.198	125	9E-2
62.5	0.2	125	9E-2
50	0.25	125	0.12
20	0.625	125	0.31
10	1.25	125	0.62
5	2.5	125	1.24

7.0 A SPECIFIC APPLICATION
(Computer Operation with the St3000 using the QST)

The Spectra-Tek Quantum Gas flow computers have been programmed to operate with one Honeywell ST3000 using 1 QST. This combination will act as a 3DP cell system.

NOTE that, while ,for the other systems, it will possible to use the QST to talk to more cells, in Quantum only 1 cell is used with 1 QST for each Quantum.

Facilities Include:

- Setting upto 3 ranges.
- Automatic re-ranging.
- Setting of change up and change down points.
- 4mA and 20mA off sets.
- Initialisation routine.
- Error reporting.

The detailed operation is explained below indicating the displays, facilities and alarms available.

DETAILED DESCRIPTION

1. **Setting Ranges**

The ranges required are set on the displays for DP cell 1; DP cell 2 and DP cell 3. Each of these has a 4mA setting for DP (normally 0, but could be some other value) and a 20mA setting. These should be set, in order, to the scaling required.

For example:

Cell 1 could be set to 4mA Ombar, 20mA 125 mbar.
Cell 2 could be set to 4mA Ombar, 20mA 250 mbar.
Cell 3 could be set to 4mA Ombar, 20mA 400 mbar.

All readings are intepreted by cell 1 which indicates the actual DP being read at the time and the % of the full scale.

2. **Setting change up and change down**

These are set in the displays called DP used. They are normally in the region 90% for change down and 95% for change up. This makes maximum use of the cell and the same time provides some reasonable hysterises preventing "hunting".

The % of change up is applied to the current scale. On change down the % is applied to the cell that it is changing to.

e.g. Suppose we look at 2 cells 0-125mbar and 0-250mbar, change up at 95% will occur when cell 1 is at 95% of 0-125 = 118.75mbar. When on cell 2, 0-200mbar, change down will occur at 90% of cell 1, 112.5mbar.

3. **Using the correction**

Calibrating the Honeywell ST3000 can only be carried out at one range. When the cell is re-ranged some slight adjustments may be required to obtain maximum accuracy by eliminating the re-ranging error. The procedure to be adopted could be as follows:

First calibrate the ST3000 on range (the middle range would be best). Then, re-range the ST3000 to its other two ranges in turn. Using the testing facilities note the current (mA) required for zero and full range values of DP for each of the other two ranges. These 4mA and 20mA correction values can be entered into Quantum, which will then make the appropriate adjustments. Such values will be very close to 4mA and 20mA, e.g. 4.010mA and 19.023mA.

4. Calibration Error

This display is set so that an alarm will be caused if the reading before the change disagrees with the reading after the change by more that the % set. It is recommended for the ST3000 that it be set at a large number, e.g. 100%. However, it can be usefully used to indicate that there is a high rate of change at the change over points. In this case the scaling and/or changeover points can be changed to improve matters.

5. Initialisation

A display is available to initialise the ST3000 with the machine running. This allows the user to set up a new ST3000 in the system. It ensures that the transmitter is set to the correct range and it is linear. NOTE that if this is used or the mode switch is used to start an ST3000 that damping is set to zero. This may be changed by the hand held communicator after initialisation.

6. Checking

Every 10 minutes so the Quantum checks the ST3000 to ensure that it is set to a linear mode and its range is correct. This is to ensure that in the unlikely event of someone changing the cells characteristics, incorrect readings do not continue for any length of time.

7. Readings

During communication there is no process variable information from the 4-20mA loop. Quantum uses the last known reading during this period.

8. Alarms

A number of alarms are available to assist with diagnosis if problems occur.

ST3000 Telem Failure

This alarm is raised whenever there is a failure in communication between the Quantum and the ST3000. It will be cleared down on a subsequent successful communciation.

ST3000 Critical Status

If the ST3000 has a 'critical status', as defined by the ST3000 manual, then this alarm will be raised. It will be cleared down when the status reverts to normal.

ST3000 Non-Critical Status

If the ST3000 has a 'non-critical status', as defined by the ST3000 manual, then this alarm will be raised. It will be cleared down when the status reverts to normal.

ST3000 Xducer Anamaly

This alarm is raised for two specific instances from data obtained via the regular (every 10 minutes) data base poll. If the LRV and span at the transducer do not agree with the Quantum, or the conformity is not linear, then the alarm is raised.

ST3000 Can't Re-range

If we are at the highest ranges, but exceeding the change up pecentage then this alarm is raised. It is cleared when the current drops below the change up value.

ST3000 Invalid Database

If the transducer indicates that it has an invalid database then this alarm is raised.

9. Use of the hand held communicator

If a critical or non-critical alarm should arise, or any other circumstances, it is still possible to use the hand held communicator to provide a more detailed diagnosis. The flow measurement must, of course be stopped first.

This also makes available all the powerful other features in the smart DP cell; such as zeroing, checking of tags, changing damping, loop adjustment, loop validation and many more.

8.0 CONCLUSION

A traditional 3 DP cell system with 3 sets of wires, three manifold points and 3 barriers are used to provide accurate high turndown metering.

This can be replaced by a single Honeywell smart transmitter to measure the differential pressure.

To do this requires special software (provided in Spectra-Teks Quantum computers) and a special hardware interface also produced by Spectra-Tek (the QST).

Accuracy is improved and only one set of barriers and wires are required, together with a single manifold.

At the same time all the useful additional features provided by a 'smart' DP cell are available to the operator.

9.0 THE FUTURE .....

NORSKE SIVILINGENIØRERS FORENING

NORTH SEA FLOW METERING WORKSHOP
STAVANGER FORUM, STAVANGER
5. - 7. NOVEMBER 1985

CERTIFICATION OF ORIFICE PLATES

1.7

FORELESER:
JOHN EIDE
CON-TECH A.S

CERTIFICATION OF ORIFICE PLATES.

I have been requested to talk about Certification of Orifice Plates. First I will take the opportunity to do some free company marketing, then a short section on the development and research there have been within this paticular field, and finally I will get around to the main topics of this session.

Since the various words and expressions in this business is developed in English it is essential that you have a clear understanding of the meaning of the words. A dictionary does not always give you the correct answer. This leads me to a episode I came across when I was reviewing a metering procedure on behalf of a oil company. There I read a expression in Norwegian which puzzeled me, and what it said I will try to visualize with this drawing.
In the English original text it said "-- Custody Transfer of Crude Oil--".

Con-Tech a.s is a Norwegian independant company which has specialised within Custody Transfer Measurement and amongst other we offer services such as consultants, prover and meter calibrations and Orifice Plate Certification.
To my knowledge we are, as of today, the only Norwegian Company recognized by NPD and DoEn to do ISO certification of Orifice Plates.
I can not show you a offical paper confirming this but if you inform NPD that you intend to use us as Plate Certifiers they will tell you (hopefully) that they have no objections to such a arrangement.
This recognition is under constant evaluation and we have frequent visitors from NPD when doing certifications, checking our performance. If they are not satisfied I think you will be the first to know.
Another advantage it gives to have an independant company to do the certification of sales meter plates, is the integrety it gives the operating company versus its partners in the field.

HISTORY - RESEARCH

Within all companies that produces oil and gas there is a ongoing struggle to improve the systems and methods for operating and maintaining the sales meters. This struggle was intensified with the increasing prices for petroleum products, because the sales meters is one of the companys major cash register and should be treated accordingly.

Laboratories and institutions was assigned projects with the aim to improve the metering systems and reduce the uncertainties connected with the metering.

Brithis Gas did some research on the problems with orifice plate buckling and they experienced, on a 8 inch meter with a 0.7 beta and a half inch deflection, a flow under-registration of 14%. And with a quarter inch deflection, a error of 3%.

Foreign matter in the meter run, such as bolts, nuts, tools and welding rods, will also cause a metering error, but not of the magnitude of a buckled orifice plate. It is in the region of up to 1.5% under-registration. This particular problem decreases as a function of time from start-up and can be avoided with frequent meter run inspections after start-up.

Another and more serious type of meter run fouling is the presence of liquid. In the worst cases an over-registration of 50% can occur. However, in a properly designed meter run every effort are taken to avoid the presence of liquid, but mistakes can happen and they do happen. A example of that is a fuel gas metering run in the North Sea where the Orifice Fitting is the lowest item of the system and where it had become a operational procedure to drain the meter run at fixed intervals.

The last item to be mentioned in this section, that has a significant effect of the accuracy of flow measurement through orifice plates, is the sharpness of the upstream edge of the plate bore. Careful attention must be given to the condition of this edge or serious errors can result.

Some years ago, National Engineering Laboratory in Glasgow, did some research on the various methods available for assesment of the condition of the plate edge. The three methods they looked into was the reflection of a light beam, epoxy resin casting and lead impression. Their conclusion to the test was that the optical method at present was not suited for accurate measurements on small diameter plates,

but it could be used to examine large diameter orifices for burrs or excessive rounding. The NEL casting method takes the longest time (two days for the completion of a plate) but since each cast closely follows the edge profile, accurate results is obtained. This method is the best to determine the shape of re-entrant profiles. The lead foil impression is much more quickly to complete, and produces as accurate results as the NEL casting method. But it suffers from the disadvantage that it will not accurately define certain re-entrant profiles.

TRACEABILITY

Now I think it is about time to switch to the main topics for this session, namely Certification of Orifice Plates in accordance with ISO 5167.

When we decieded to set up a laboratory for certification of orifice plates, the most important issue to be dealt with was traceability. That is, how could I prove to a client that his 200 millimetre orifice bore really was 200 millimetre and not 201 or 199.5 millimetre? The answer to that was of course certified gauge blocks. Since we aimed against the sales gas orifice plates, we bought laboratory quality (ISO grade 00). We maintain the traceability by sending the gauge blocks to recertification on a annually basis, and any piece not meeting the specification are changed out with a new.

We of course purchased the necessary micrometers, instruments and tools, and was ready to start certifying.

But then we faced a new problem. NPD and our future clients asked what plans we had for demonstrating and convincing them that we knew what we were doing, and the accuracy of our work.

We had to arrange for a test by re-certifying some orifice plates and compare results. As some of you knows we passed the examination.

The first thing that happens when we recieve an order for certifying plates, is that we, by telex, informs the parties involved on which date the certification is going to take place.

Then we assign a job-number to the order and reserve the certificate numbers required.

After the plates are recieved and unpacked, they are given a visual inspection for damages and then placed in the lab for temperature

stabilization. The work sheets are filled in and the various limits calculated. The proper gauge blocks are assembled and the instrument for the orifice bore measurement are set up. The micrometers to be used are checked against gauge blocks in the actual ranges.

PLATE FLATNESS

I normally starts the certification by checking the plate flatness. the upstream face of the plate is placed towards our Diabas stone table and feeler gauges inserted between the plate and stone. The found values are noted on the work sheet. If the plate has a vulcanized seal, a straight edge ruler is placed across the upstream face instead. If the deflection is zero the plate will be checked along the outside for bukling against flow direction. In such cases notes will be made in the remarks colum. The average deflection is calculated and also the static's persentage of the total (static/dynamic) deflection. Discussions is still ongoing on how large percentage part to be allowed for static deflection.

PLATE ROUGHNESS

The next item to be checked is the plate roughness. The upstream face is checked for schratches or groves, and if nothing special is found, three spots is choosen at random.

The measurement is done with an electronic instruments which displays the R_a (Roughness average) in micrometers or microinches. In addition the trace is printed out as documentation for the findings.

The roughness meter is checked periodically for accuracy. This is accomplished by the use of a roughness standard, and the instrument adjusted if required.

I would like to point out that waviness is not considered roughness by the instrument, and therefore not reflected in the roughness average value displayed.

Full scale on the recording paper is normally 10 micrometers.

The maximum value found will be noted on the work sheet and a copy of the recordings will follow the certificate.

CONCENTRICITY

Another area where we can divide the allowed deviation into two sections is on orifice bore concentricity. A major part of the total deviation is put on the orifice plate carrier or fitting and a lesser part on the bore itself. No official decesion on the split between the two parts has been taken.

Our method of measurement for this section is by a digital vernier caliper, resolution 0.01 millimeter. The distance from the bore to the plate outside is measured at opposite positions and difference found. The average value is determined and calculated as percentage of the total allowed deviation. This percentage is also given on the certificate front page.

PLATE THICKNESS

The instrument used to measure the plate thickness is a micrometer caliper with a resolution of 0.002 millimeter. The thickness is measured about 20 millimeter from the bore at eight places and values noted on the work sheet. Four spots is choosen at random along the outside to check that the thickness and variations are within required limits. The micrometer caliper has a friction knob so that equal thightness is applied at all measurements.

EDGE THICKNESS

The method of measurement is by a depth micrometer with graduations in 0.01 millimeter.

The micrometer is placed against the upstream face of the plate and the stem aligned with the beginning of the beveled edge.

The alignment is by eyesight only and it is obvious that this is not a very accurate measurement. Variations less than 0.05 millimeter is difficult to detect, but with the good machining techniques we experiense, it is not often we register notable variations.

On plates not having a beveled edge or a vulcanized seal, precise measurements can be obtained taking into account any possible plate buckling.

ANGLE OF BEVEL

To measure the angle of bevel we use a bevel protractor with a resolution of 1/12 of a degree.

According to ISO 5167 the angle of bevel should be measured relative

to the orifice bore while the AGA-3 states that the angle should be measured relative to the upstream face of the plate. However, in practical certification we measure the "AGA-3" angle and then subtract from 90 degrees to get "ISO 5167" angle.
The angle is checked at four spots and average value noted on the woork sheet.

DOWNSTREAM FACE AND EDGES

The check here is visual only, and we do it when we recieve the plates. The reason for that is, if damages is discovered, we imediately can return the plate for further machining.

ORIFICE BORE

Our method of measurement of the orifice bore is by a electronic indicating instrument. Gauge blocks that equals the nominal bore of the orifice plate is assembled and the lenght of the indicating instrument is also assembled as close as possible to the same lenght. A note is made of the gauge blocks total lenght.
The indicating instrument is placed between the gauge blocks and the digital display on the electrinics is adjusted to zero, and so the pluss and minus sign shifts continously.
The display is normally set up to indicate one thousand of a millimetre, which is under our present conditions, the best accuracy we can claim.
The instrument is then placed in the plate bore, and by moving the handle, we search for the smallest number on the display. The value is taken down with special attention to either pluss or minus sign on the display. The displayed value is added or subtracted, depending on the sign, from the total length of the gauge blocks and the result noted on the work sheet.
This procedure is repeated three times through all the measurement stations.
Thereafter the indicating instrument is placed between the gauge blocks to get a verification of the zero reading on the digital display.
If a deviation occur, the instrument is re-zeroed and the whole procedure repeated.
However, if the deviation is a negative value it indicates that the instrument has been exposed to excessive heat from handling. Then the instrument has to be set aside for temperature stabilization.
When the instrument reads zero again, the metering procedure is repeated

and every effort is made to avoid excessive heat transfer.

EDGE SHARPNESS

The final item I will discuss is the measurement of upstream edge sharpness, and the method of measurement is by the lead impression method.
The instrument utilized for this measurement is of our design.
By a linear movement at an angle of 45^{o}, the lead foil is given an indentation about 15 to 20 hundreds of an millimeter deep. The depth is controlled by a micrometer head. A light alarm flashes when the lead foil gets in contact with the plate edge.
We have a set of lead foil clamps with numbering that corresponds with the measurement stations, so the above procedure is repeated seven times with different foil clamps.
Thereafter the foil clamp is placed under our microscope and a photograph taken with a polaroid camera.
The microscope and camera is so adjusted that the resulting magnification on the picture is 100 times. This can be verified by taking a picture of a object with known dimensions.
Information of certificate number, station number and job number is imediately noted on each picture.
After the pictures has developed, we compare the image of the orifice edge with a set of radius gauges, seeking for the best curve fit.
The size of the radius gauge is then divided by hundred and the result noted on the work sheet.
A copy of the pictures is a part of the certificate as documentation for the findings.
Due to the various edge profiles that occur it is not always easy and straight forward to determine the edge radius. In those instances we apply "the best curve fit" tecnique.
Viewing a picture of an impression you will always find the upstream face to the left and the orifice bore to the right.
Our experience so far, with respect to the quality of the norwegian machine shops, is that they do a exellent job. Out of about 150 certifications to date we have only rejected two plates with excessive edge roundness. Normally they are well within required limits.
That also applies for the other parameters we measure.

Finally we check through the various parameters measured to see if they are within ISO 5167 requirements. The findings are the noted on the certificate front page.

Con-Tech is continously looking for improvement of measurement methods and instruments in order to produce the best possible and reliable results.

Last month we completed the draft to our QA manual, and our various procedures are presently beeing adapted to the QA system.

Main Index

Norske Sivilingeniørers Forening

NORTH SEA FLOW METERING WORKSHOP

Stavanger, 5 - 7 November 1985

Static measurement of LPG

2.1

Lecturer: Mr. P. A. M. Jellfs
Moore, Barrett & Redwood Ltd

STATIC MEASUREMENT OF LPG

1. Introduction

This paper reviews the instrumentation and calculation procedures for loading and discharging ships carrying Light Hydrocarbon gas liquids.

2. Tank Design

Due to the pressure limitations for large storage containers the LPG is refrigerated in order to obtain a vapour pressure at near atmospheric conditions. Some LPG, however, is stored under pressure at ambient temperatures in horizontal cylinders or spheres both on shore and in ship's. Where gas liquids are refrigerated it is necessary to thermally insulate the tanks in order to reduce the boil-off of vapour from the liquid. These tanks will be equipped with both vapour input and output lines.

3. Safety Considerations

As the loading flow rate to the ship increases there can be a situation where the vaporisation rate is too slow to fill the space left in the tanks as the liquid level falls. This could lead to a tank's shell failure (implosion) and facilities for importing vapour from another tank are required. Alternatively the heat input through the insulation and from totally immersed pumps (for loading line circulation) can generate more vapour which must be exported.

4. Ship Loading Lines

The ship loading pipeline from the tank to the jetty is usually kept full of liquid and although insulated is usually continuously circulated to prevent formation of vapour. The circulation return line to the tank is also a further source of heat. In some cases there is a vapour return line from the ship into tank vapour space.

5. Static Measurement - (Based on Shore Tank)

The accurate measurement of quantities transferred from a vertical cylindrical storage tank is achieved by using a number of individual instruments which are described below:

5.1 Tank Level Measurement

Tank level gauges of the servo-operated displacer type are normally used for measuring the level of the liquid in the tanks. These gauges have no significant hysteresis and are able to determine the level to $\pm$ 2-3 mm.

As the vapour space will have a varying temperature profile with very cold gas liquids such as ethane it is necessary to make corrections for the contraction of the tape wire and tank shell height. The tape correction is:

$$\Delta h = \theta_g(t_v)\ (H-h) - \theta_c(t_v)\ (H-h) - \theta_c(t_\ell)h \qquad (1)$$

Where:

Δh = Correction to the gauge readout in mm.

H = Total height of the tank in mm at ambient temperature 15°C (from tank data).

h = Height of the liquid in the tank in mm (from gauge readout)

$\theta_g(t_v)$ = Change in length per unit length of the gauge wire or tape metal between 15°C and the average vapour temperature t_v.

$\theta_c(t_v)$ = Change in length per unit length of the tank metal between 15°C and the average vapour temperature t_v.

$\theta_c(t_\ell)$ = Change in length per unit length of the tank metal between 15°C and the liquid temperature t_ℓ.

NOTE In theory h is the corrected height. However, in practice the gauge readout is used in the equation without introducing significant errors.

Usually two gauges are recommended so that there is a redundancy factor in the event of a failure of one device also the mean of two gauges will give an improved precision in determining the level.

5.2 Temperature Measurement

As the thermal expansion of LPG is of the order of 0.3% by volume for 1°C it is necessary to measure the vertical temperature profile in both the gas and liquid space. A three or four wire platinum resistance multi-sensor system is normally used. The sensors spaced every 1 to 2 metres apart are often housed in a flexible stainless sheathed cable. For digital systems the uncertainty of n sensors (immersed in the liquid) is $0.4/\sqrt{n}$°C.

5.3 Pressure Measurement

The measurement of pressure in the vapour space is necessary in order to calculate the mass of the vapour above the liquid.

5.4 Vapour Measurement

Insertion type Vortex meters may be used for measuring the quantity of vapour entering into the tank from the compressor, adjacent tank or ships vapour return line during loading. Also vapour quantities discharged from the tank during loading at very low flow rates may be measured by Vortex meter.

5.5 Density Measurement

A density meter of the displacement or Archimedes type consisting of a float that is weighed by an electronic balance can be used for measuring liquid density in the tank. Alternatively a "vibration type" density meter can be installed in the shore tank which can be lowered through the liquid in order to obtain a density profile. Another method is to install a density meter in the loading line adjacent to the tank and to measure the average density of the liquid transferred to the ship. The device should be flow proportional.

A new single tube transducer has been recently developed which has a very low resonance frequency with a high Q value (a peaked resonance with large amplitude over a small range of frequency variation). This low resonance frequency is essential in order to minimise a systematic error which can occur when measuring densities of liquids such as LPG which have a low velocity of sound. (The low velocity of sound fails to disperse the pressure waves set up by the transducer vibration so that the density meter appears to see an apparently denser fluid.)

One method of eliminating this error is to calibrate the density meter on a liquid similar to the liquid in service. A special "Density Reference System" designed by NBS allows the density meter to be immersed in a refrigerated liquid in a vacuum insulated container. A silicon crystal suspended from the arm of an automatic balance allows the density to be measured to $\pm 0.02\%$.

5.6 Tank Calibration

The uncertainty of a vertical cylindrical shore tank is of the order $\pm 0.05\%$ expressed in terms of the cross sectional liquid area. It is necessary also to measure the total capacity of the tank in order to obtain the vapour volume.

Ships tanks which have been individually calibrated by physical measurement or water meter methods have an uncertainty of the order of ± 0.1 to $\pm 0.2\%$ (by volume).

Although accurate ship measurement is difficult due to the effects of liquid movement and trim/list, the overall uncertainty is usually better than the individual tank uncertainty due to the randomisation effect.

$$\text{Overall uncertainty} = \frac{\text{Tank uncertainty}}{\sqrt{\text{number of tanks}}}$$

5.7 Uncertainty of Static Measurement

The estimation of the uncertainty of the quantity loaded out of a tank is shown in the attached sheet. (Figure 1)

A number of assumptions are made which are detailed below:

i. The uncertainty of the calibration of the shore tank has been estimated as $\pm 0.05\%$ (area) including the effect of the liquid head expansion of the shell plates.

ii. The diameter of the tank does not vary by more than 1% from top to bottom.

iii. Most of the bottom floor movement takes place between 2-3 metres and the empty condition.

iv. The uncertainty of the vapour return quantity from the ship has not been included in the calculations.

5.8 Summary

The uncertainty improves as the Δh of the transfer quantity increases, which is the reason why long term contracts based on several transfers have until recently been acceptable. However, with the advent of the "spot cargo" market, single transfer quantities to small vessels (where the Δh is less than 10 m) can incur significant errors and is one of the reasons why meters are being installed (retrospectively in some cases).

6. Calculation Routines

6.1 To achieve a set of accurate calculation routines for certifying LPG cargoes which could be internationally standardised is now the main task of the Institute of Petroleum Liquid Gas Panel PM-F.

At present there are two main calculation routes as shown in the attached "Calculation Algorithm":-Fig 2

Mass (or weight) from volume and density at tank temperature

Mass (or weight) from volume and density at $15^{o}C$

These two calculation routes are partly covered by ISO Codes.

6.2 ISO DIS 6578 which covers density by calculation from composition is now being revised to accept the COSTALD density routine as an alternative to the Francis Routine. At present the code will only derive saturated densities (equilibrium conditions). A future revision would cover densities under pressure (which exceed the vapour pressure). Also there will be a need to include vapour density calculations for LPG under pressure by introducing a compressibility factor Z.

6.3 ISO 91/1 tables 53 and 54 below 650 k/m^3 will be re-published. These tables are based on "orthobaric" densities which are determined at their saturated or vapour pressure. In order to calculate densities at pressures in excess of the vapour pressure it will be necessary to have equations and/or tables which will give vapour pressure and compressibility factors corresponding to values of density at $15^{o}C$ respectively. The API have recently re-issued the original LPG compressibility tables in API Standard 1101 Table II and propose to supersede these with a new set in Chapter 11.2.2 covering the density range 350 to 636 k/m^3. However these tables require the vapour pressure of the LPG mixture in order to derive the compressibility factor.

At present, however, there is no official correlation of LPG vapour pressures with density at $15^{o}C$. It can be shown that in theory there is no unique relationship between these two parameters due to the fact that it is possible to have mixtures of varying composition with the same density but different vapour pressures. However in practice the uncertainty due to this problem would probably be insignificant.

Provisional correlations, therefore, for both compressibility factors and vapour pressure with density at $15^{o}C$ have been derived by my company.

6.4 Vapour Density Calculations

ISO DIS 6578 provides a density equation for vapour which uses the liquid molecular mass but does not include a correction for compressibility (Z). At refrigerated conditions for both commercial butane and propane the vapour pressure seldom exceeds 1 bar gauge. It is the intention therefore to recommend that where the pressures are less than say 2 bar gauge the Z factor will be taken as 1.0000.

For pressures above 2 bar gauge the Z factor will be calculated by using the Standing & Katz graph which is entered with Reduced Temperature T_R and Reduced Pressure P_R which can be calculated from composition ISO 91/1 has at present no vapour density routine but uses a "liquid equivalent of vapour". However as the latter makes no allowance for variations in composition or compressibility the I.P. are recommending the use of the same density routine as employed in ISO DIS 6578.

Graphs giving molecular weight, critical temperature and critical pressure for values of density at 15°C have been produced to enable the density calculation to be performed to the same order of accuracy as that derived from composition.

In theory the vapour composition and thus the molecular mass are not the same as the liquid for LPG mixtures. However where the main component in commercial butane and propane is greater than say 0.85% then the error incurred in calling the vapour molecular mass the same as the liquid is less than 0.1%.

6.5 Accuracy of the New Routines

It is evident that the original methods for calculating LPG under pressure employed density prediction equations which did not take into account the shrinkage - or negative volume of mixing which become significant at higher temperatures (i.e. ambient)[. ISO DP 4267/1.3 Calculation of Oil Quantities (Static)]. Also the mass of vapour should include a correction for compressibility which can be significant.

A table showing typical uncertainties illustrates the need for improved calculation techniques.(Fig 3)

6.6 Selection of Methods

The choice of the method is usually determined by the size and facilities of the installation.

Compositional analysis requires a fairly sophisticated laboratory with the analytical equipment and a competent technician.

In many situations the only apparatus for determining density is a pressure hydrometer which has a fairly low precision.

Even where there are facilities for obtaining the composition the density at 15°C is calculated using a Molar Volume Routine such as Francis or API Project 44 which does not allow for the negative volume of mixing.

7. Conclusion

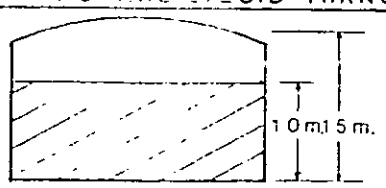
Improved instrumentation and standardised calculation procedures are now essential if voyage losses in LPG are to be accurately monitored between loading and discharge ports.

Note. An alternative routine is BS Redlich Soave Water equation

The mass of LPG at ambient temperatures and under pressure will be under-estimated when the calculation routines do not take into account the negative volume of mixing in the liquid phase and the compressibility in the vapour phase. Typically calculations utilizing Table 54 are under-estimated by 0.3% and utilizing composition by 0.5%.

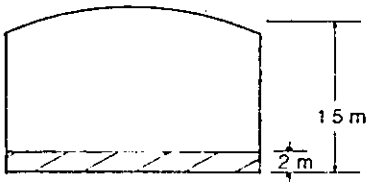
Fig 1 ESTIMATED UNCERTAINTY OF A PROPANE LIQUID TRANSFER

Assumptions
1mm depth = 1m³
Density at 15° C = 507.4kg/m³
at -43° C = 582.0kg/m³



LIQUID			
Level	± 2mm	2 x 1 mm	= 2.00m³
Temp. ° C	± 0.15° C	Plate shrinkage = 0.000022x0.15x10 000	= 0.03m³
Tank Calibration	± 0.05%	0.0005x10 000	= 5.00m³
		Vol.Uncertainty = $\sqrt{(2.00^2+0.03^2+5.00^2)}$	= 5.39m³
		Mass = 5.39x582/1 000	= 3.14 tonnes
Density	±0.22%	0.0022x582x10 000/1 000	= 12.80 tonnes
		Liq.Mass Uncertainty = $\sqrt{(3.14^2+12.80^2)}$	= 13.18 tonnes
VAPOUR			
Tank Calibration + Contraction.		Ignore	
Density: Temp. ± 1° C; Composition ±0.12%; Mol.Wt. ±0.10%; Press.5mb ±0.30%	± 1.0%	2.400x0.01x5 000/1 000	= 0.12 tonnes
LIQUID & VAPOUR		Uncertainty(Mass) = $\sqrt{(13.18^2+0.12^2)}$	= 13.18 tonnes
TOTAL MASS		= 582x10 000/1 000 + 2.4x5 000/1 000	= 5 832 tonnes

Assumptions
1mm depth = 1m³
Density at 15° C = 507.4kg/m³
at -43° C = 582.0kg/m³



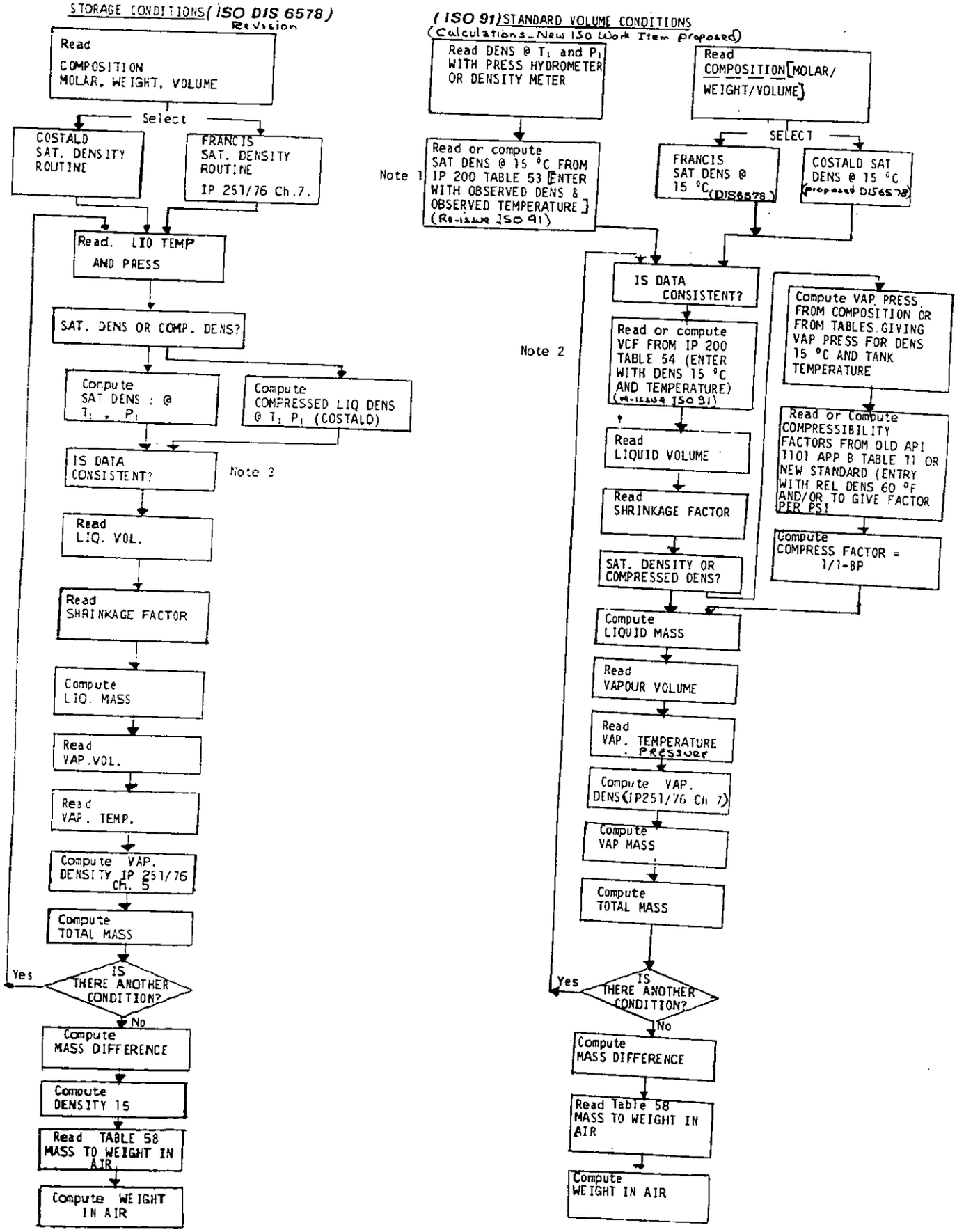
LIQUID			
Level	± 2mm	Same	= 2.00m³
Temp.° C	±0.15° C	Plate Shrinkage 0.000022x0.15x2 000	= 0.01m³
Tank Calibration	±0.05%	0.0005x2 000	= 1.00m³
		Vol.Uncertainty = $\sqrt{(2.0^2+1.0^2)}$	= 2.24m³
		Mass = 2.24x582/1 000	= 1.30 tonnes
Density	±0.22%	0.0022x582x2 000/1 000	= 2.56 tonnes
		Liq.Mass Uncertainty = $\sqrt{(1.30^2+2.56^2)}$	= 2.87 tonnes
VAPOUR			
Tank Calibration + Contraction		Ignore	
Density: Temp. ± 1° C; Composition ±0.12%; Mol.Wt. ±0.10%; Press.5mb ±0.30%	±1.0%		
LIQUID & VAPOUR		Uncertainty(mass) $\sqrt{(2.87^2+0.31^2)}$	= 2.89 tonnes
TOTAL MASS		= 582x2 000/1 000 + 2.4x13 000/1 000	= 1 195 tonnes

Uncertainty Before 13.18 x 100/5832 = 0.23%

Uncertainty After 2.89 x 100/1195 = 0.24%

SUMMARY Uncertainty of Mass Transfer = $\frac{100\sqrt{(13.18^2 + 2.89^2)}}{(5832 - 1195)}$ = ±0.29%

Fig 2 LIQUID PETROLEUM GAS CALCULATION ROUTINES



NOTES :

Note 1 Equation accepted by PM-C-2
Note 2 " " PM-C-2
Note 3 Equivalence between meas. density, meas. temp, and calculate pressure

P JELFFS Sept 1984

Fig 3

Instrumentation and Calculation Uncertainties

Density (By Composition and Calculation).

Composition 0.08%
Costald 0.20%
} Uncertainty = $\sqrt{(0.08^2 + 0.20^2)}$
$= \pm 0.22\%$

Francis [additional bias due to shrinkage] at $-43^\circ C + 0.20\%$
at $15^\circ C = +0.40\%$

Density (by direct reading)

	Pressure Hydrometer		
VCF	$\sqrt{(0.34^2 + 0.09^2)}$	=	± 0.35%
Density Meter	not known	=	±0.20% ?

Main Index

Norske Sivilingeniørers Forening

NORTH SEA FLOW METERING WORKSHOP

Stavanger, 5 - 7 November 1985

A reconciliation of turbine meter measurement with shipboard static measurement in the custody transfer of L. P. G.

2.2

Lecturer: Mr. J. B. Moralee
Phillips Petroleum Co. UK Ltd

RECONCILIATION OF TURBINE METER MEASUREMENT WITH SHIPBOARD STATIC MEASUREMENT IN THE CUSTODY TRANSFER OF L.P.G.

J.R. MORALEE
PHILLIPS PETROLEUM CO. U.K. LIMITED

SUMMARY

In the marine transportation of liquified gases, shipboard measurement is used extensively for the determination of Bill of Lading quantities. Shore measurement, which is used almost without exception for the fiscal measurement of heavier hydrocarbons such as crude oil, is now increasingly being used for Bill of Lading, Royalty and Custody Transfer purposes.

INTRODUCTION

This paper discusses the problems associated with the measurement of Liquified Gas at a Marine Loading Terminal. It reviews the uncertainties attached to two available methods, i.e. Shore Turbine Metering and Shipboard Static measurement and attempts to reconcile these by providing comparisons between the two systems.

It does not consider the use of Shore Static measurement nor the use of other types of flow meters. Neither is the content intended to be of a technical nature but merely observations based upon practical experience.

SOURCES OF ERROR

Turbine Metering

Meter

Due to the particular nature of the product: low temp, low density, low viscosity, poor lubricity and its desire to regain its natural state resulting in two phase flow, special problems have to be overcome by the Turbine Meter to achieve the same high performance as those in more viscous hydrocarbon service. Certain precautions are therefore required so as to provide the degree of reliability, repeatability and linearity necessary for fiscal or custody transfer measurement.

Two phase flow which can cause measurement errors and also possible damage to the meter due to high velocities overspinning the turbine must be avoided by ensuring that no vapours enter the loading system. An adequate back pressure must also be maintained to prevent errors due to flashing off across the meter. To prevent damage it may also be advisable to derate the meter to approximately 70% of its maximum rate on water.

The theoretical effect of low density fluids on a turbine meter is to cause a large shift in the K factor when operating at low rotational speeds. This effect, plus the derating of the meter, reduces the turn-down as can be seen in Figs 1,2,3,4 and 5, and therefore it is necessary to to operate the meter at a restricted range to maintain good linearity. Careful selection of the correct size of meter is essential so that for any given loading rate each meter is always operating within this reduced range.

Figs 1 and 2 show 4" meters on Butane service with a linearity of better than ±.25% between flow rates of 35 and 250 M3/hr. Fig 3 shows an 8" meter on Butane service with a linearity of ±.05% between 250 and 870 M3/hr and on Fig 4 ±.15% between 350 and 800 M3/hr for an 8" propane meter. The long term repeatability of these meters can be seen on the ship/shore comparison sheets.

Meter Proving

The accurate proving of the meters depends not only upon the repeatability of the meter itself, but upon the precision and performance of the Prover system.

Experience with proving 4" meters using a conventional bi-directional pipe prover has given excellent results down to temperatures of -11oC. All parts of the system have operated reliably, and five consecutive provings within a spread of ±.01% is easily achieved.

At temperatures down to -42oC (refrigerated Propane) some type of piston prover is required. The new generation of small volume compact piston provers appear ideal for this service but the type used in evaluating the performance of the 8" turbine meters in this paper has a larger degree of uncertainty than the conventional prover as the short term repeatability is not so good, i.e ±.05% spread in five consecutive provings. This reduced precision is possibly due to the distance between the detectors being less than 7 metres producing slightly over the minimum recommended 10,000 pulse counts, and the resolution of the detector switches which are of the magnetic proximity type.

Problems were experienced with obtaining a bubble-tight seal on the 4-way and twin seal valves but this was overcome by changing out the valve seat material. Other problems, such as freezing and leaking valves, switch failures, pre-amp failures, and valve leak detection malfunctions have all contributed to an unacceptable level of reliability, but nevertheless the system does function as a check on ships figures.

Cooldown

Liquified Gas Vessels often require a slow rate at the commencement of loading to enable the cargo tanks to be cooled down gradually. This may cause measurement errors if the rate required is outside the operating range of the meter, and therefore consideration may have to be given for the provision of a smaller cooldown meter specifically for this purpose.

Temperature

The accurate determination of temperature is a crucial factor in the measurement of Liquified Gas due to its large expansion coefficient. A one degree error will introduce a volumetric error of 0.3% for Propane and 0.2% for Butane. The platinum resistance thermometer is best suited for this service as calibration of these instruments has shown good long term stability. Positioning of the probe is important, for instances have occurred where the probe was determining the temperature of the lagging with the utmost precision.

Manual or automatic monitoring of each meter's dedicated temperature reading during the loading is advisable. A difference greater than 0.3 Degrees C should cause some concern and be investigated.

Vapour Return

Vapour returned to storage from the vessels cargo tanks must be accounted for and deducted from the metered volume. Any measurement errors introduced will contribute towards the total uncertainty of the loaded quantity. The accuracy requirement for this device is really dependent on the volume of vapours returned which in turn depends upon the ability of the ships equipment to contain any boil off. In most cases the volume returned to shore represents only a small percentage of the total cargo and therefore high accuracy is not required. The worst case experienced was 1% returned which when measured with a standard orifice of an accuracy of say ± 5% would account for .05% of total cargo loaded.

Line Contents

Another source of error in shore measurement is the quantity contained in the loading lines between the point of measurement and the receiving vessel. Ideally the distance should be kept to a minimum but if not then efforts must be made to ensure the same conditions before and after the transfer. A slack line at the beginning, and a packed line at the completion of a loading would result in a short delivery to the vessel.

SHIPBOARD STATIC MEASUREMENT

Tank Calibration

The design of cargo tanks in liquified gas tankers presents the tank calibrator with special problems in computing precise volumetric tables. These tanks vary in shape from the membrane type to free standing prismatic and pressure vessel type tanks. Large errors can be built into these tables, particularly if the gauge point is not situated in the exact geometric centre of the tank and allowances have to be made for the trim and list of the vessel. Some ship owners employ specialised companies to prepare these tables so that any errors are minimised. Nevertheless there are some vessels in service with calibration tables of doubtful accuracy and origin, probably prepared from Shipyard drawings without any physical check measurements being made.

Level Gauges

The most common method encountered on board ship of determining the liquid level is the float gauge type. This type appears to give the necessary reliability and accuracy when operating in a marine environment although other devices such as Slip Tubes, Capacitance and Ultrasonic gauges are also used. Each type have their own degree of uncertainty but large systematic errors can also be introduced if the equipment is not set up correctly so that zero reading corresponds to the datum point shown on the calibration tables.

Another source of error connected with level measurement is the condition of the liquid surface. Considerable agitation of the surface due to boiling can effect the readings at the end of the loading when conditions in the tanks have not yet reached equilibrium.

Temperature

The necessity for accurate determination of liquid temperature has already been mentioned due to the large expansion coefficiency of liquified gas. It is a fact that some wide variations in temperature accuracy is encountered in shipboard measurement. Thermometers are usually not of the same precision or calibrated as frequently as shore instruments but this is understandable as they have to operate in a much harsher environment and it is usually a compromise between accuracy and reliability. Nevertheless some vessels are able to determine the temperature with reasonable precision while others fail miserably. An example of the latter is a vessel which lowers a thermometer down a thermowell into fully refrigerated iso-butane and insists that the temperature is+5oC.

Sufficient temperature points should be mounted in the tank and positioned so that the liquid and vapour temperature can be determined accurately. There are some vessels in service with only one temperature point in each tank and therefore may have problems in obtaining a truly representative temperature.

Pressure

Pressure determination is not usually a critical factor in cargo measurement. Its use is confined to the calculation of vapour quantities, although theoretically there is argument for its use in the computation of a compressed liquid density rather than the Orthobaric density which is commonly used in the cargo calculation.

Part Cargoes

On examining ship/shore differences there is one fact which is particularly noticeable. This is the deviation away from the normal difference when part cargoes are loaded resulting in slack tanks (see comparison Vessel D). This may be due to using a reading in the averaging of the liquid temperature when it is actually in the vapour phase, but the most likely reason is an error in the calibration tables at that particular level. Differences of up to 5% have been noted.

On Board Quantity

The calculation of the quantity loaded on board a vessel is done in two stages. First, the amount of O.B.Q. consisting of vapour and liquid heel on board is calculated, and then on completion the total quantity of liquid and vapour on board. The difference being the quantity loaded. Measurement errors can occur at both stages, but the estimation of the quantity of liquid heel or any residue from previous cargo can be a large source of error. The calibration tables in the bottom section of the tank can be unreliable and also the wedge of liquid may even be outside the range of the level instrument, particularly if the vessel is well trimmed by the stern.

Venting Inerts

Vessels occasionally present themselves for loading with cargo tanks containing inerts, particularly after having arrived from dry-dock. The vessel may then require to dispose of these contaminants by venting off to atmosphere as the ships reliquification equipment cannot contain it on board. The quantities so vented are difficult to assess accurately and therefore contribute to the uncertainty of the final loaded quantities.

Calulation Methods

Different calculation methods of converting the observed volume of both liquid and vapour quantities to volume at standard conditions, and the method used to determine densities for weight conversion give slightly different results. This often leads to disputes as does the old problem of whether the final result is Mass or Weight in Air.

It is not intended to dwell upon this subject as the previous speaker will have covered this thoroughly, except to say for the purpose of the comparisons contained in this paper the COSTALD method, which was developed by Phillips Petroleum Company was used throughout.

Conclusions

The comparison sheets (Appendix 1-6 inclusive) show the Ship/Shore difference between four vessels (A,B,C, and D) and four different meter stations (2,4,6 and 8) each with its own dedicated prover.

These differences can be shown as follows:-

Station	Ship A	Ship B	Ship C	Ship D
2	-0.02%	-1.0%	+1.5%	+0.03%
4	+0.06%	-1.7%	-	-
6	-	-1.36%	+1.28%	+0.07%
8	-	-	+0.72%	-0.11%

The above results would indicate that:-

a) The meter stations are in close agreement with each other.

b) Vessels A and B are well calibrated with good instrumentation.

c) There is a possible problem with the measurement of Vessels B and C

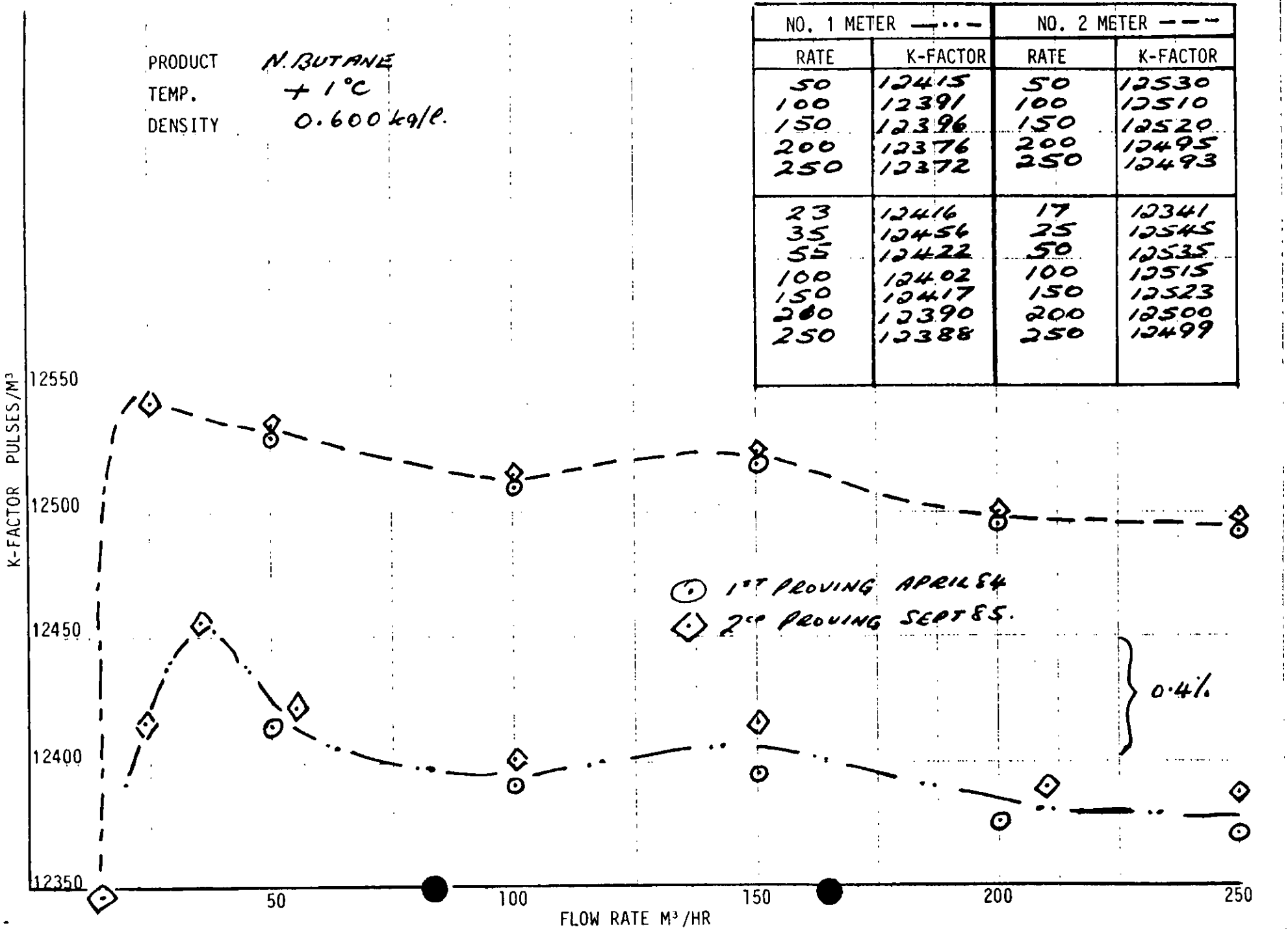
On comparison sheets (Appendix 1-8 incl) are shown the K-Factors of the meters which were proved on each loading. These K-Factors, and others which have been obtained over a number of years, show all turbine meters in Liquified Gas service to have a standard deviation of $\pm$0.1% which is comparable to the long term repeatability of those in other services.

STATION 5 (4" TURBINE WITH 10" BI-DIRECTIONAL PROVER)

FIGURE 1

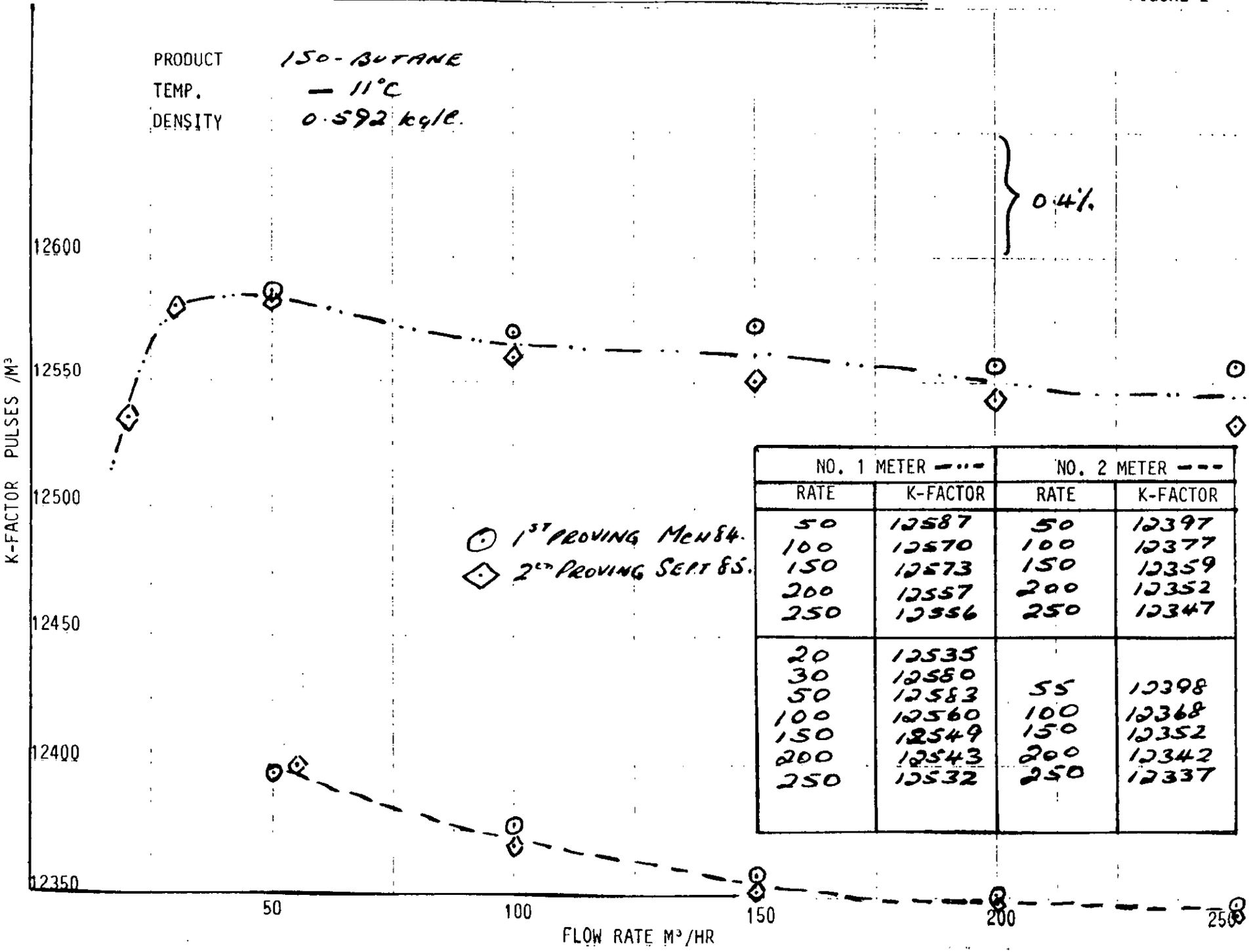
PRODUCT N. BUTANE
TEMP. + 1°C
DENSITY 0.600 kg/l.

NO. 1 METER —·—·		NO. 2 METER — — —	
RATE	K-FACTOR	RATE	K-FACTOR
50	12415	50	12530
100	12391	100	12510
150	12396	150	12520
200	12376	200	12495
250	12372	250	12493
23	12416	17	12341
35	12456	25	12545
55	12422	50	12535
100	12402	100	12515
150	12417	150	12523
200	12390	200	12500
250	12388	250	12499



STATION [redacted] (4" TURBINE METER WITH 10" BI-DIRECTIONAL PROVER)

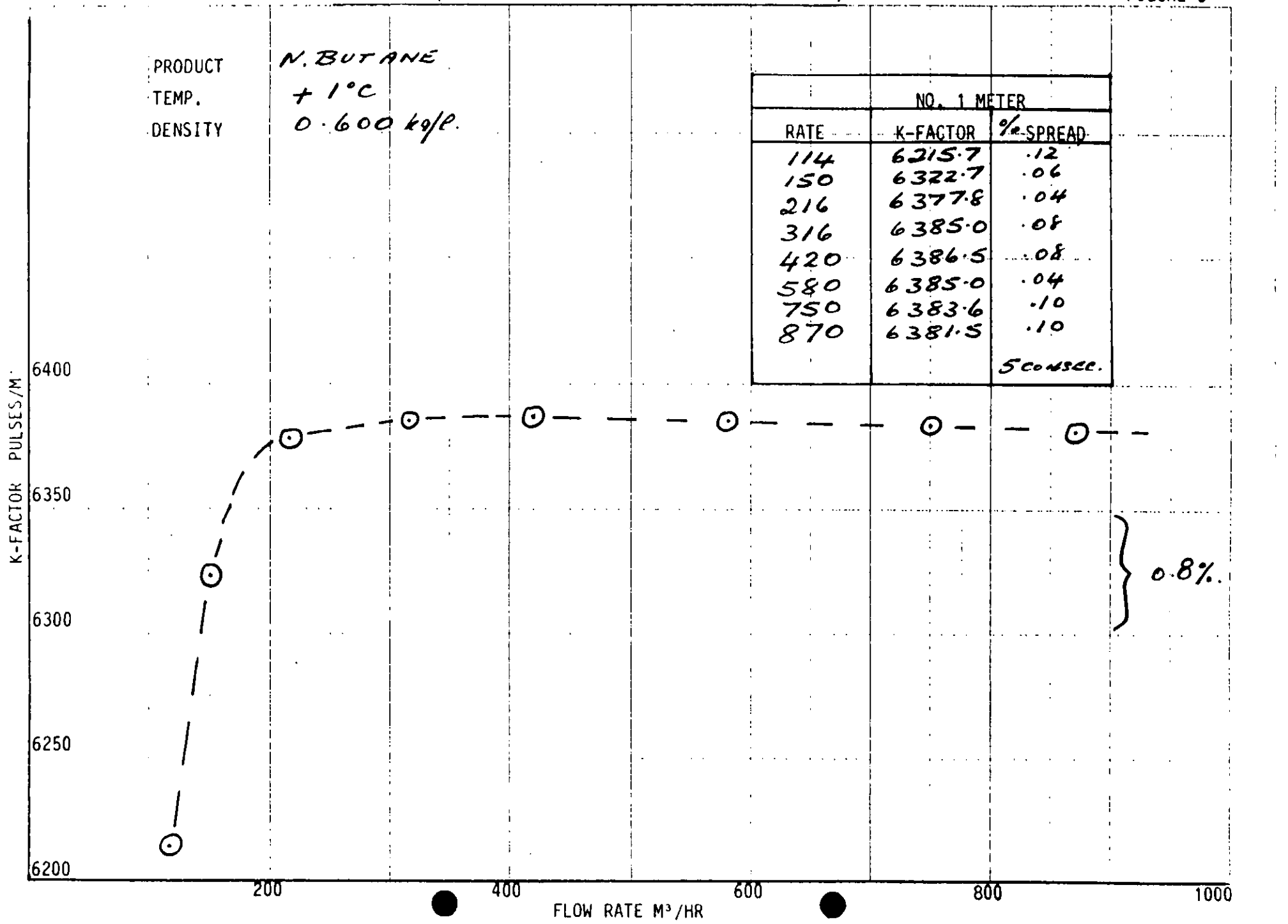
FIGURE 2



NO. 1 METER —·—		NO. 2 METER ---	
RATE	K-FACTOR	RATE	K-FACTOR
50	12587	50	12397
100	12570	100	12377
150	12573	150	12359
200	12557	200	12352
250	12556	250	12347
20	12535		
30	12580		
50	12583	55	12398
100	12560	100	12368
150	12549	150	12352
200	12543	200	12342
250	12532	250	12337

STATION 4 (8" TURBINE METER WITH 24" PISTON PROVER)

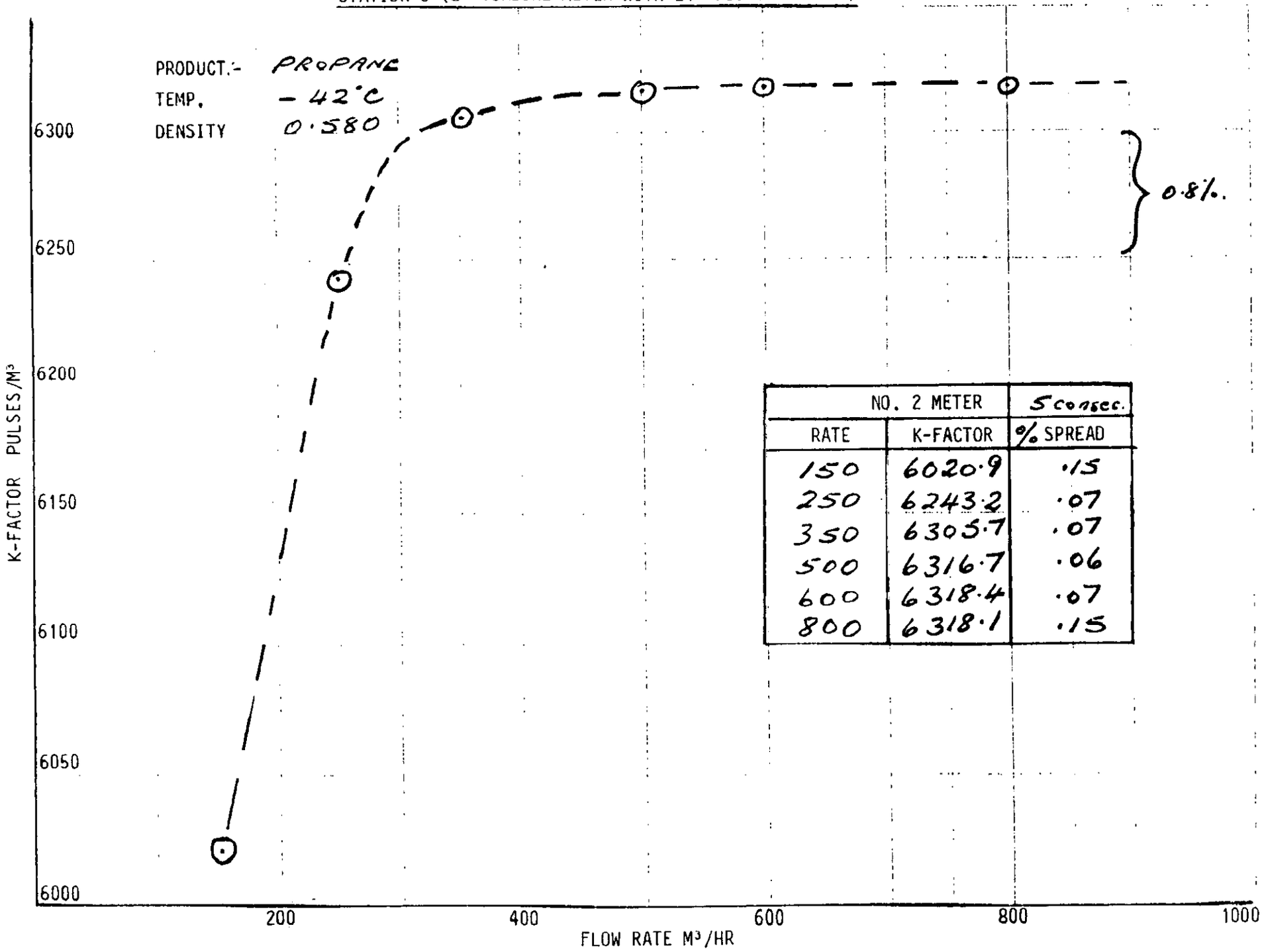
FIGURE 3



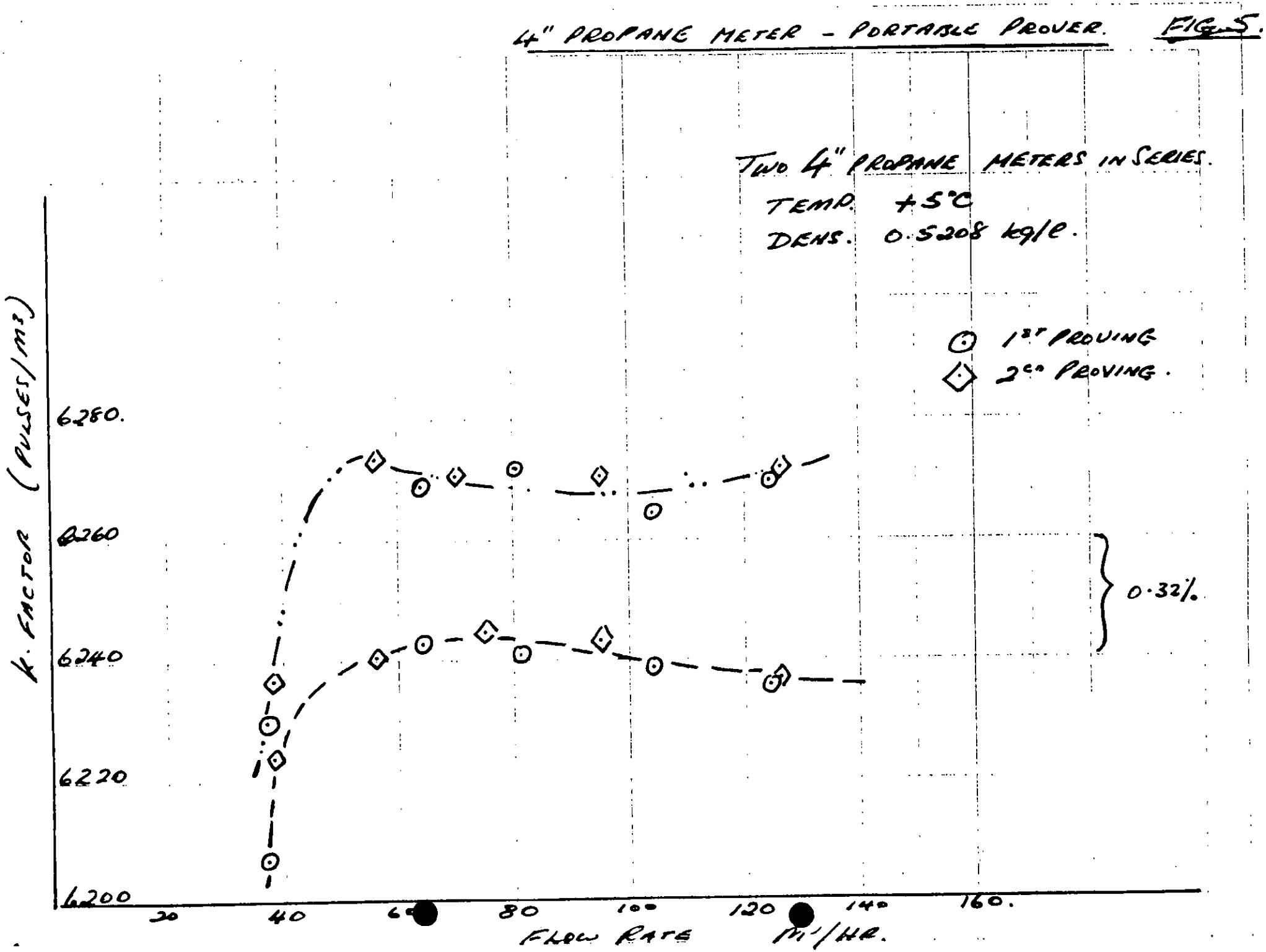
NO. 1 METER		
RATE	K-FACTOR	% SPREAD
114	6215·7	·12
150	6322·7	·06
216	6377·8	·04
316	6385·0	·08
420	6386·5	·08
580	6385·0	·04
750	6383·6	·10
870	6381·5	·10
		5 consec.

STATION 6 (8" TURBINE METER WITH 24" PISTON PROVER)

FIGURE 4



NO. 2 METER		5 consec.
RATE	K-FACTOR	% SPREAD
150	6020·9	·15
250	6243·2	·07
350	6305·7	·07
500	6316·7	·06
600	6318·4	·07
800	6318·1	·15


4" PROPANE METER - PORTABLE PROVER.
FIG. 5.
TWO 4" PROPANE METERS IN SERIES.
TEMP. +5°C
DENS. 0.5208 kg/l.
1ST PROVING
2ND PROVING.
0.32%
K. FACTOR (PULSES/M³)
6280.
6260
6240
6220
6200
30
40
60
80
100
120
140
160.
FLOW RATE M³/HR.

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 1

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	
"A"	6	2	iC4	1872.9	1872.1	+.04	12340	12467		
	"	"	"	12598	1259.2	+.05	12346	12482		VESSEL "A"
	"	"	"	1864.2	1864.1	Nil	12337	12473		STATION 2
	"	"	"	1858.2	1857.8	+.02	12336	12471		ISO BUTANE
	"	"	"	1864.2	1874.6	-.56	12345	12467		
	"	"	"	1868.0	1865.5	+.13	12338	12464		4" METER
	"	"	"	1864.1	1864.0	Nil	12347	12488		BI-DIR. PROVER
	"	"	"	1158.2	1159.4	-.10	12338	12484		
	"	"	"	1867.1	1868.9	-.10	12343	12488		
	"	"	"	1865.4	1865.6	-.01	12341	12475		
	"	"	"	1863.5	1867.8	-.23	12337	12464		
	"	"	"	1863.6	1866.2	-.14	12341	12471		
	"	"	"	1863.4	1864.1	-.07	12343	12471		
	"	"	"	1858.7	1861.5	-.15	12344	12466		
	"	"	"	1866.6	1862.7	+.21	12340	12475		
	"	"	"	1273.4	1271.5	+.15	12345	12478		
	"	"	"	1233.6	1228.9	+.38	12342	12476		
	"	"	"	1861.5	1858.6	+.16	12347	12476		
	"	"	"	1155.1	1156.9	-.16	12345	12486		
	"	"	"	1867.7	1866.7	+.05	12342	12481		
		MEAN:				-.02	12342	12475		

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 2

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	
"A"	8	4	iC4	1871.3	1871.9	-.03	12560	12362		
	"	"	"	1868.3	1869.2	-.05	12572	12358		VESSEL "A"
	"	"	"	1874.8	1874.7	Nil	12574	12362		STATION 4
	"	"	"	1873.5	1872.4	+.06	12566	12363		ISO BUTANE
	"	"	"	1863.8	1862.4	+.08	12563	12356		
	"	"	"	1863.9	1862.0	+.10	12564	12354		4" METER
	"	"	"	1870.1	1866.5	+.19	12564	12354		BI-DIR. PROVER
	"	"	"	1869.2	1868.1	+.06	12572	12356		
	"	"	"	1870.9	1869.1	+.09	12562	12365		
	"	"	"	1865.1	1863.4	+.09	12573	12360		
	"	"	"	1863.7	1864.6	-.05	12572	12358		
	"	"	"	1864.0	1864.5	-.03	12569	12360		
	"	"	"	1862.7	1863.6	-.05	12567	12357		
	"	"	"	1867.9	1861.7	+.33	-	12353		
	"	"	"	1863.4	1860.4	+.16	12579	12362		
		MEAN:				+.06	12568	12359		

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 3

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	
"B"	6	2	iC4	1375.8	1392.1	-1.18	12344	12464		
	"	"	"	1381.2	1393.2	-.94	12331	12453		VESSEL "B"
	"	"	"	1371.0	1369.0	+.14	12335	12449	12366	
	"	"	"	1371.2	1387.3	-1.17	12338	-	-	STATION 2
	"	"	"	1374.1	1391.9	-1.29	12337		12372	ISO BUTANE
	"	"	"	1371.6	1391.0	-1.41	12335		12371	
	"	"	"	1373.6	1391.5	-1.30	-	12457	12365	4" METER
	"	"	"	1376.8	1392.5	-1.14	12325		12365	BI-DIR PROVER
	"	"	"	1378.0	1390.5	-.93	12319	-	-	
	"	"	"	1095.0	1104.4	-.81	12329	-	-	
		MEAN:				-1.00	12333	12456	12368	
"B"	8	4	iC4	1371.8	1394.5	-1.65	-	12370	12461	STATION 4
	"	"	"	1386.4	1391.6	-.37	12569	-	-	ISO BUTANE
	"	"	"	1374.8	1392.0	-1.25	-	12346	12450	
	"	"	"	1376.5	1392.7	-1.17	12569	-	-	
		MEAN:				-1.11	12569	12358	12455	
"B"	6	6	nC4	1398.8	1417.9	-1.36	12387	12497	12386	STATION 6
										NORMAL BUTANE.

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 4

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	VESSEL "C"
"C"	6	2	iC4	1165.4	1152.0	+1.06	12333	12458	12365	STATION 2
	"	"	"	1163.1	1148.5	+1.25	12318	12450	12360	ISO BUTANE
		MEAN:				+1.15	12326	12454	12362	
										4" METER
										BI-DIR. PROVER
"C"	6	6	nC4	1380.5	1357.7	+1.65	-	12484		STATION 6
	"	"	"	1256.9	1249.2	+.61	12404	12516		NORMAL
	"	"	"	1469.9	1452.2	+1.20	12400	12520		BUTANE.
	"	"	"	1469.9	1445.3	+1.67	12400	12521		
		MEAN:				+1.28	12401	12510		
"C"	8	8	nC4	1468.9	1453.7	+1.03	12320	124/8		STATION 8
	"	"	"	1452.6	1446.6	+.41	12317	12464		NORMAL
		MEAN:				+.72	12318	12471		BUTANE.

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 5

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	
"D"	6	2	iC4	952.5	963.2	-1.12	12344	12487		VESSEL "D"
	"	"	"	1409.8	1410.8	-.07	12331	12457		STATION 2
	"	"	"	1364.9	1365.6	-.05	12336	12461		ISO BUTANE
	"	"	"	1399.9	1398.3	+.11	12326	12460		
	"	"	"	1365.0	1363.1	+.14	12346	12481		4" METER
		MEAN:				+.03	12337	12468		BI-DIR PROVER.
"D"	8	8	nC4	1429.4	1432.5	-.22	12308	12489		STATION 8
	"	"	"	1441.8	1442.1	-.02	12311	12468		NORMAL
	"	"	"	1434.7	1437.4	-.19	12303	12492		BUTANE.
	"	"	"	1436.7	1433.1	+.25	12285	12499		
	"	"	"	1259.8	1261.2	-.11	12313	12499		
	"	"	"	1154.2	1158.7	-.39	12312	12483		
		MEAN:				-.11	12305	12488		

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 6

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	
"D"		6	nC4	1446.9	1447.9	-.07	12391	12504	12382	VESSEL D.
	"	"	"	1441.9	1442.1	-.01	12408	12511	12373	
	"	"	"	1439.8	1439.6	+.01	12403	12510		STATION 6
	"	"	"	1432.2	1431.7	-.03		12495	12375	NORMAL
	"	"	"	1431.4	1430.5	+.06	12378	12516	12382	BUTANE
	"	"	"	1428.4	1430.5	-.13	12385	12504		
	"	"	"	1435.9	1430.5	+.38	12390	12516		4" METER
●	"	"	"	1434.3	1429.9	+.30	12386	12513		BI-DIR.
	"	"	"	1438.6	1440.5	-.13	12400	12522		PROVER.
	"	"	"	1433.6	1435.6	-.14	12403	12516		
	"	"	"	1436.9	1432.2	+.26	12383	12520		
	"	"	"	1435.6	1434.5	+.08	12402	12518		
	"	"	"	1441.1	1437.1	+.28	12402	12501		
	"	"	"	1432.8	1433.6	-.06	12419	12512		
	"	"	"	1428.3	1430.3	-.14	12400	12511		
	"	"	"	1430.5	1439.4	+.08	12404	12507		
●	"	"	"	1443.7	1441.8	+.13	12401	12515		
	"	"	"	1433.1	1428.2	+.34	12418	12505		
		MEAN:				+.07	12398	12511	12378	

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 7

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	
"X"	3	3	REFnC4	3380.4	3385.5	-.15	6380	6416	6343	
	"	"	"	3373.3	3376.5	-.09		6411	6332	
	"	"	"	3336.4	3336.9	Nil	6390	6410		NORMAL
	"	"	"	3351.2	3348.6	+.08	6389	6413		BUTANE
	"	"	"	3340.8	3345.2	-.13	6390	6415		
	"	"	"	3351.5	3360.2	-.26	6394	6416		8" METER
	"	"	"	3360.5	3366.4	-.17	6389	6414		PISTON
	"	"	"	3345.9	3350.7	-.14	6393	6411		PROVER
	"	"	"	3339.3	3350.4	-.33	6384	6411		
	"	"	"	3331.1	3340.5	-.28	6389	6416		
	"	"	"	3340.2	3351.5	-.34	6387	6412		
	"	"	"	3361.8	3369.8	-.24	6389	6420		
	"	"	"	3346.3	3361.3	-.44	6393	6419		
	"	"	"	3350.8	3353.3	-.07	6379	6424	6340	
	"	"	"	3349.8	3353.3	-.10	6382	6412	6340	
		MEAN:				-.16	6388	6415	6339	
"Y"	"	"	"	3350.6	3353.9	-.09	6378	6411		
	"	"	"	3354.8	3364.9	-.30	6393	6416		
	"	"	"	3344.3	3348.2	-.12	6385	6412		
	"	"	"	3346.5	3343.9	+.07	6385	6415		
		MEAN:				-.11	6385	6413		
"Z"	"	"	"	3474.1	3482.5	-.24	6381	6412	6338	
	"	"	"	3479.1	3481.5	-.07	6383	6416	6343	
		MEAN:				-.15	6382	6414	6340	

COMPARISON BETWEEN SHIPS FIGURES AND METER FIGURES FOR GAS VESSELS APPENDIX 8

VESSEL	JETTY NO.	METER STATN	PRODUCT	LOADED QUANTITY (TONNES)		METER DIFF. %	METER K-FACTOR			REMARKS
				METER	SHIP		1	2	3	
"X"	4	6	REF C3	6784.0	6786.0	-.03	6466	6312		
	"	"	"	5228.3	5225.5	+.05	6460	6316		
	"	"	"	6773.0	6775.0	-.03	6464	6312		PROPANE
	"	"	"	6800.3	6796.1	+.05		6313	6296	
	"	"	"	6771.2	6777.5	-.09		6320	6302	8" METER
	"	"	"	6809.3	6806.2	+.05		6316	6303	PISTON
	"	"	"	3573.9	3570.3	+.10		6318	6300	PROVER
	"	"	"	6802.6	6810.2	-.10	6463	6304		
	"	"	"	3564.2	3566.2	-.05			6305	
	"	"	"	3562.4	3569.2	-.20	6466	6315		
	"	"	"	6799.3	6823.6	-.36	6465	6323		
	"	"	"	6777.3	6797.9	-.30	6466		6298	
	"	"	"	6785.7	6814.3	-.40		6318	6300	
	"	"	"	3572.9	3582.0	-.25		6314	6301	
	"	"	"	3578.0	3594.2	-.45		6290	6314	
	"	"	"	6799.6	6831.6	-.47		6320	6305	
	"	"	"	6803.1	6836.6	-.52		6312	6304	
		MEAN:				-.20	6464	6314	6303	
"Y"	"	"	"	3551.9	3571.7	-.56		6316	6311	
	"	"	"	6762.0	6806.2	-.65		6318	6312	
		MEAN:				-.60		6317	6311	
"Z"	"	"	"	13542.3	13560.5	-.13		6307		

Leak detection for subsea oil pipelines with turbine metering

2.3.

Maron Dahlstrøm

PHILLIPS PETROLEUM COMPANY NORWAY

NORTH SEA FLOW METERING WORKSHOP

STAVANGER FORUM

5 - 7 November 85

EKOFISK - TEESSIDE OIL PIPELINE LEAK DETECTION

The approach to a leak detection system might be somewhat different from a metering system , in that shortcuts can be made where higher reliability can be acchieved when some of the metering accuracy is sacrificed . It is of high importance that false alarms is kept to a minimum , so that the user can have confidense in the system .

For the Ekofisk to Teesside oil pipeline the goal was a 1 % alarm detection limit over a one hour totalizing period . This might be hard to acchieve for a flow of 300 000 BPD when the linefill is 1.2 million barrels : A 1 psi change in average pipeline pressure will result in approx 9 barrels change in linepack , and a 1° F change in average pipeline temperature will result in approx 700 barrels change in linepack .

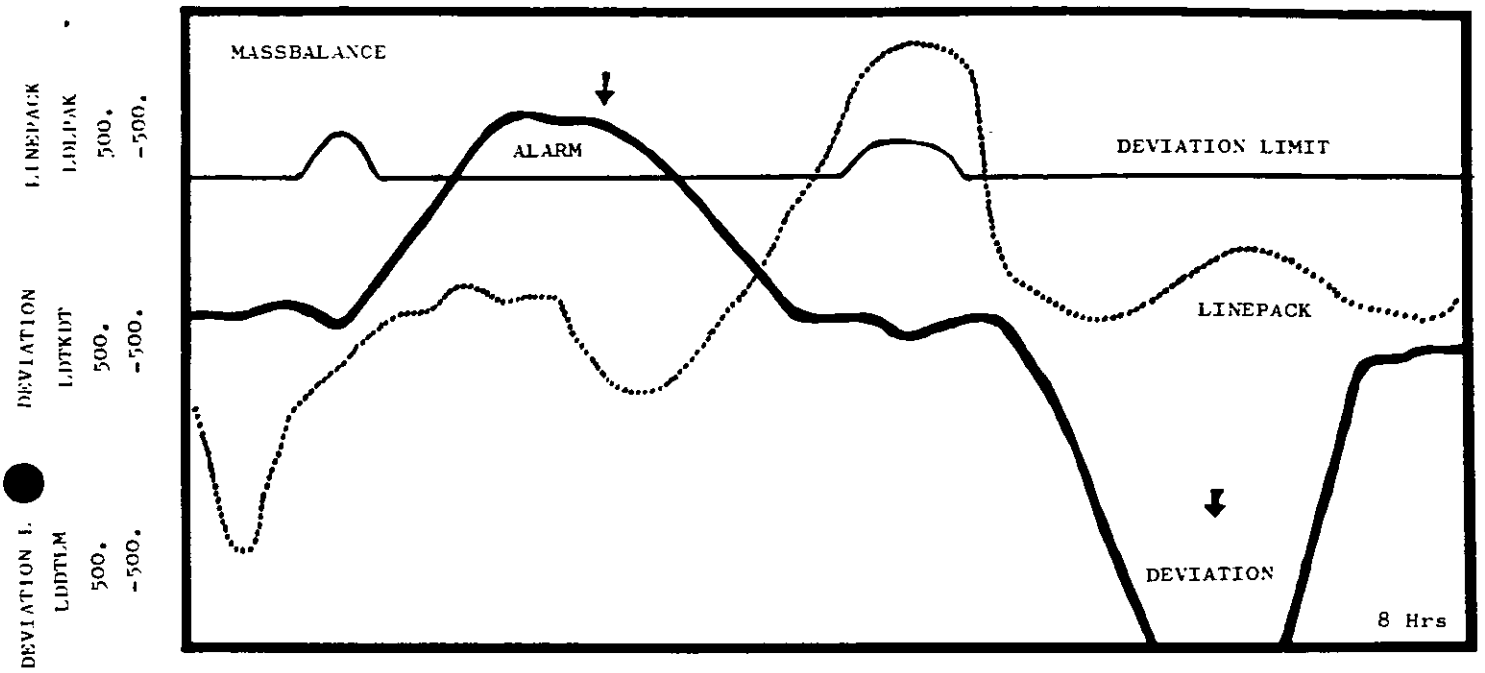
The first leakdetection system tried for the Ekofisk to Teesside oil pipeline was a pure balance of masses in and out totalized for one hour . In spite of the fact that the metering system was very advanced for the time : with online proved turbine meters and densitometers on frequent calibration cycles , the leak detection system very often showed up to 10 % imbalance .

The first attempt to improve the system was made in -82 . The one hour moving window was introduced with a correction for the change in pipeline pressure linepack . This resulted in a smoother trend for the pipeline balance deviation .

No correction was made for the change in linepack due to the change in temperatures . With a model depending on the repeatability in the temperature measurement , we would have a choise of either extending the moving window period or increase the alarm limit far beyond the 150 barrels that we were aiming for . Caracteristical for a subsea pipeline in stable temperature waters , however , the real average temperature change over a length of one hour can be disregarded . In any case the repeatability of the temperaturetransmitters alone would be far bigger than the deviation we are trying to detect . For an onshore pipeline this effect could be dramatic , with the day - night changes in ambient temperature.

The change in pipeline pressure linepack was estimated from the change in measured pipeline pressures at the inlet to the pipeline , at the suction for the booster pump platform , at the discharge for the booster pump platform , and upstream of the Teesside metering station . With a constant factor for each of these pressures , our goal was to estimate the linepack change within 5 % at stationary conditions . When the linepack change calculated exceeds approx 2 % of one hours totals , then 10 % of the additional linepack change is added on line to the alarm limit . The dynamic effects of pressure is taken care of thru checking the flow variations . An extra 50 000 BPD flow from 300 000 BPD would finally result in less than 500 barrels linepack change . But this is a slow process since it takes 5 minutes for a pressurewave from Ekofisk to reach Teesside . To eliminate the dynamic effect , half of the potential linepack change for flow variations in

excess of 25 000 BPD is added on line to the alarm limit .



But still there were imbalances of more than 10 % at times . This forced us to take a closer look at the massbalance theory :

$$\frac{\partial}{\partial t}\left(\rho A \, dx \right) + \frac{\partial}{\partial x}\left(\rho v A \right) dx = 0$$

The almost magical theory of looking at infinitesimal pieces of a pipeline had kept us all in the dark for a long time . But a pipeline does not have a massbalance unless it is carrying the very same homogenious fluid all the way thru . Dividing the pipeline into pieces does not make the massbalance more correct ; It just makes it more successful in hiding the real facts : The oil density is not even constant within this infinitesimal piece.

In lack of something better we have all tried to fit the mass-balance theory to the real life . The Ekofisk to Teesside pipe-

line had thoroughly revealed the weaknesses in this theory : Even though the fluid entering the pipeline is well mixed , a separating process takes place thru the pipeline . More so for a subsea pipeline which is far from horizontal , laying in the natural terrain at the bottom of the sea . Especially the water fallout plays an important part in this picture , as the water collects in the pipeline valleys . When a cleaning pig is sent thru , this water will be pushed in front of the pig . This is enough to create a 10 % imbalance in mass for a couple of hours before the pig reaches Teesside . Since the momentum balance :

$$A \frac{\partial P}{\partial x} dx + \frac{\partial}{\partial t}\left(\rho v A\right) dx + \frac{\partial}{\partial x}\left(\rho A \frac{v^2}{2}\right) dx = 0$$

is just as dependant of knowing the real density along the pipeline , complete modelling of the pipeline would only result in decreased reliability .

However , what goes in must come out . Even though it takes 4 days for the oil from Ekofisk to get to Teesside , the volume that goes in does push a volume out of the pipeline immediately . Disregarding the change in linepack caused by changes in temperature and pressure , the volume out should equal the volume in corrected to the conditions at the outlet . This correction must be based on the average fluid in the pipeline since the "reduction" of the volume in to the volume out is a momentary effect on the fluid that already is in the pipeline . The volume in at Ekofisk , which is found as turbine meter pulses divided by meter factor , should therefore be corrected

to the temperature and pressure at Teesside .

In the volumebalance leak detection system installed in -83 the temperaturecorrection used was :

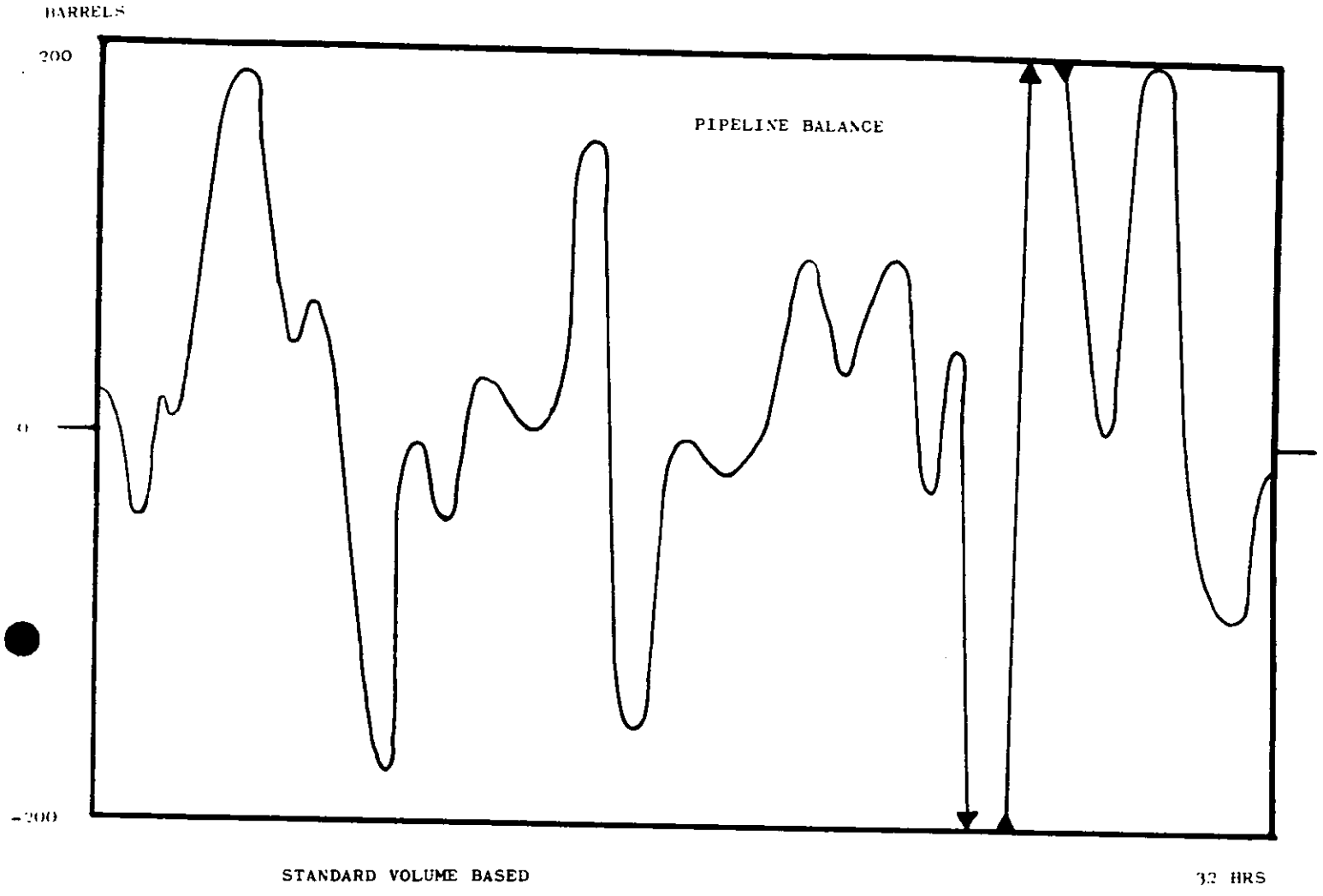
$$C_{tl} = e^{-(\tau + 0.8\tau^2)}$$

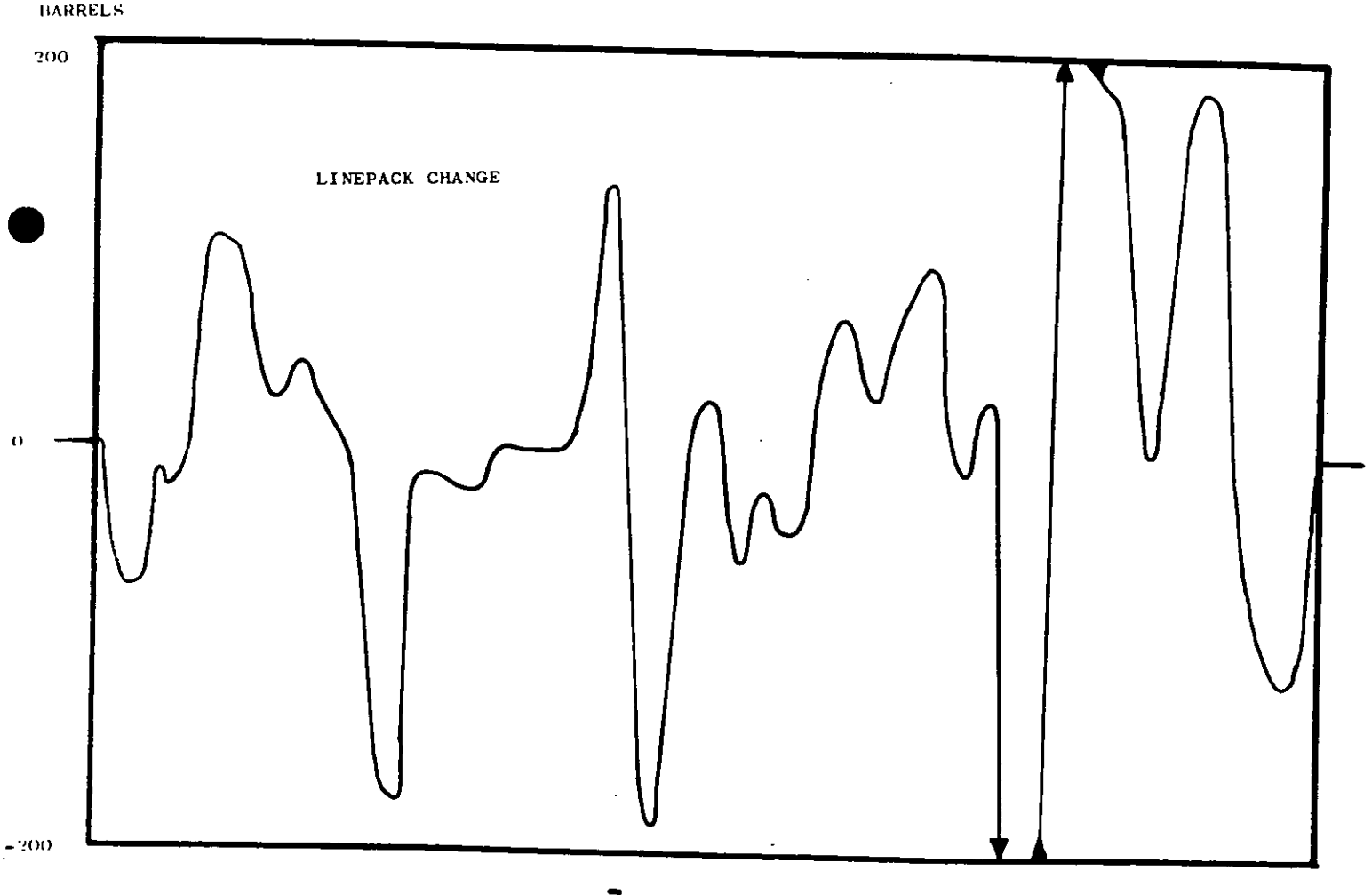
$$\tau = \frac{341.0957}{\overline{\rho}} (T_{in} - T_{out})$$

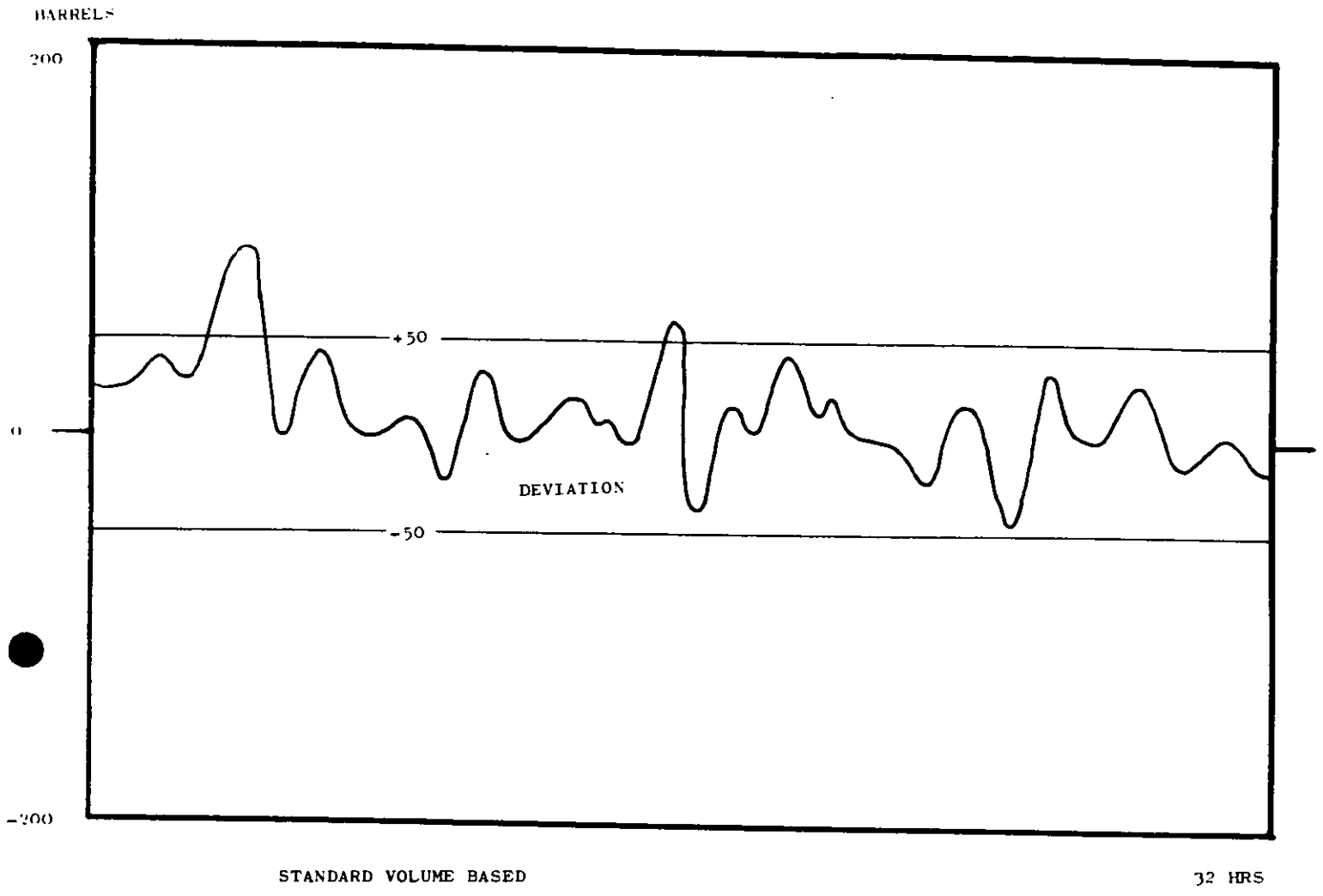
With a total temperaturecorrection of approx 4 % , the use of the 341.0957 crude oil constant rather than a constant for the higher vapour pressure Ekofisk "crude" gives an estimated error of less than 0.2 % at the worst . The use of a constant average density for the pipeline gives an estimated error of less than 0.1 % at the worst .

The pressurecorrection of approx 0.5 % is made using a constant compressibility factor . This gives an estimated error of less than 0.05 % . With these relatively small sacrifices we had made ourselves independent of the density measurement . The density might be measured at the metering stations with the same accuracy ; But the measured density could not have been used directly , since we are correcting for an effect on the entire pipeline content . So additional uncertainties would have been introduced . In addition : with the solution chosen , densitometer failures will not disturb the volume balance .

This volumebalance proved to be a success . The pipeline imbalance for the one hour moving window was normally without


BARRELS
200
PIPELINE BALANCE
0
-200
STANDARD VOLUME BASED
32 HRS


BARRELS
200
LINEPACK CHANGE
0
-200
32 HRS



any bias , and the linepack change corrected deviation came within a band of ± 50 barrels for approx 95 % of time . The availability acchieved was approx 99 % . A maximum of 43 days between false alarms has been experienced .

To acchive this reliability , efforts has been cosentrated on sycronizing the data . With critical data sent from up to 220 miles from RTUs thru a troposcatter system , we could not expect all of the data to reach Ekofisk undisturbed from the 30 second scanning . In reality the data available for the balance might be minutes in difference in origin . (This alone should be enough to discourage those who still belive that true time simulation requiring new measurement data in-

put every second might be a solution .) The time of data became an important figure in the data set , so that the volumes in and out could be compared on an equal basis . If no new data is available from one of the stations since the last 3 minute update of the one hour moving window , a balance would not be made for another 3 minutes .

With the leak detection system as it now is , we can thrust the long term balance enough to determine smaller system biases over a one day period .

For instance a 70 barrels (approx 0.5 %) bias per hour , as shown , can easily be determined from the trend picture . This can be used to give a warning that the meter factor for a turbine meter might be in error .

SINTEF

Main Index

2.4

NORTH SEA FLOW METERING WORKSHOP
Stavanger Forum, 5 - 7 November 1985

"Description of the Two-phase Flow laboratory in Trondheim"

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Background and present status

The erection of the laboratory was finished in the fall of 1982. The construction was overseen by SINTEF acting on behalf of Esso who was the main sponsor and owner of the laboratory the first year of operation (1983). Four other companies(Getty Oil, Mobil, Statoil and Texaco) sponsored the project with equal minority shares during the Esso period.

The reason for establishing the Two - Phase Flow Laboratory was basically the need for experimental data from a large scale two - phase flow line to develop and improve calculation tools and design criteria for two-phase flow field installations.

In 1983 SINTEF conducted about 1000 experiments under a research contract with Esso. Upon termination of this contract (January 1984) the laboratory was given to SINTEF for further utilization.

The investments covering the construction and the 1983 research program amounted to about NOK 100 millions.

A project called the The Two-Phase Flow Project 1984 - 86 commenced in January 1984 . This three year project is a continuation and supplement to the work executed in 1983 and includes about 3000 experiments and further refinement and development of a dynamic simulation program for two- phase flow named OLGA.

The project is jointly carried out by SINTEF and IFE (Institute for energy technology) and is presently sponsored by eight oil companies(Conoco, Esso, Mobil, Norsk Hydro, Petro Canada,Saga , Statoil and Texaco).
The sponsors pay equal shares .

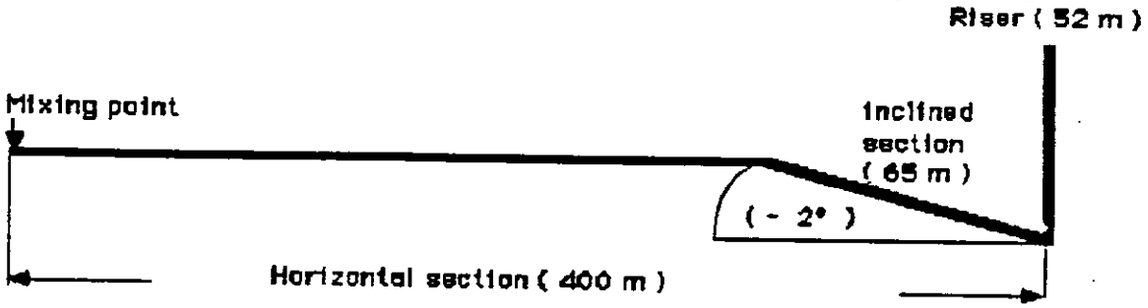
Experimental results and improved simulation tools are systematically released for the benefit of the sponsors.
New versions of of the OLGA simulation program are released with a one year cycle and the OLGA 84 is now in operation within the sponsoring companies.

The results of the Two - Phase Flow Project are already being used for field calculations and SINTEF and IFE have also executed quite a few studies for single clients.

MAIN FEATURES OF THE SINTEF , TWO - PHASE FLOW LABORATORY.

The test unit is arranged as a closed loop and consits of a 400 m horizontal section of 8 inch pipe , terminating in a vertical riser 52 meters high. The two -phase flow mixture coming out from the riser top is separated and oil and gas are taken to the circulating pumps and compressor respectively and discharged through separate pipelines to the starting point of the two-phase test pipe.

The present geometry allows for terrain effects . The last 65 meters of the horizontal pipe can be dipped prior to the riser entrance for investigating terrain effects on heavy slug formation. This feature is extremely important for the understanding of the onset and behaviour of very long, terrain induced liquid slugs.



In 1986 the horizontal section of the test pipe will be reconstructed to allow for small deviations from the horizontal (1° and 1/2° up and down) over the full pipe length (approximately 350 meters) .

The absolute pressure in the test section can be varied from 20 to 95 Bars.

The whole facility is fully insulated and heat traced and constant temperature is maintained by a temperature control system.

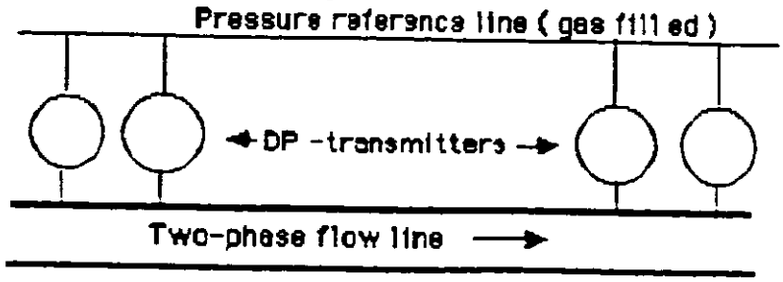
One of three hydrocarbon liquids may be applied ; naphtha, diesel or a lube oil base. The liquid viscosity is 0.2 , 2.0 and 20 cp respectively.
The liquid density varies from 660 kg/m3 to 860 kg/m3.

The gas phase is always nitrogen.

The single phase volumetric flowrate can be varied from 0.004 m3/s to 0.13 m3/s for the liquid phase and from 0.014 m3/s to 0.4m3/s (at the actual pressure) for the gas phase.

Flow pattern , liquid holdup and slug front velocities are established by means of eight single beam gamma-ray densitometers and by a socalled TEXACO -IFE Fast Volume Weight Meter , which also is based on gamma ray technology.

Absolute pressure and pressure drop are measured by means of differential pressure transmitters with the high pressure side linked to a pressure reference line and the low pressure side linked to the two-phase flow line.



Pressure taps and transmitters must lay in the same horizontal plane.

K-LAB: A LABORATORY FOR IMPROVING GAS FLOW METERING ACCURACY

PRESENTED AT

NORTH SEA FLOW METERING WORKSHOP

STAVANGER 5 - 7 NOVEMBER 1985

2.5

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CONTENTS

1. INTRODUCTION

K-LAB or Kårstø Metering and Technology Laboratory is a natural gas test facility being built close to the gas processing terminal at Kårstø which Statoil operates on behalf of the Statpipe group.

K-LAB is a Joint Venture project between Statoil and Total Marine Norsk whose main purpose is to provide a calibration and proving stand for gas flow meters and components where field conditions can be obtained.

The petroleum industry has a considerable economic interest in using accurate methods for measuring the large quantities of gas which are transported between producer and consumer.

The most commonly used method for metering large gas flows makes use of the orifice meter. In international trade this method is implemented according to an international standard, ISO-5167. Other orifice meter standards are the British standard BS 1042, the American standard AGA-3 and the German standard DIN 1952. Methods based on other metering equipment are currently being discussed.

There are strong indications for a systematic underprediction of the flow rates in commercial standard orifice gas flow meters and it is of primary importance to have full understanding and knowledge of the limitations in the systems which are currently used.

In order to influence the development of the gas metering technology it is necessary to operate an advanced experimental facility for testing, calibration and development of large scale gas meters.

The most obvious economic incentive for such a facility is the potential of reducing the anticipated systematic errors in the current orifice metering method, to test components and develop/calibrate new instruments.

2. BACKGROUND

2.1 The problem of accurate custody transfer metering

To calculate the mass flow rate through an orifice meter the following parameters must be known:

- the geometrical dimensions of the meter pipe and orifice,
- the differential pressure over a set of standard pressure tappings,
- the density of the fluid in the plane of the upstream pressure tapping,
- the meter discharge coefficient.

If the energy content of the gas is the basis for custody transfer one also needs to determine:

- the calorific value of the gas.

The uncertainties of all the above parameters must be controlled simultaneously to achieve the lowest possible overall uncertainty. Using the best of current technology the uncertainty of the discharge coefficient is the dominating one when mass flow is concerned. Parallel to the flow laboratory research, efforts in the field of calorimetry and densitometry must be emphasised to assure the best possible overall accuracy.

2.2 Current status on orifice gas metering

In February 1980 a new international standard for orifice plate metering, ISO-5167, was issued as a revision of the previous ISO-541. The ISO-5167 standard contains a new correlation formula for the discharge

coefficient. The standard gives the uncertainty of the discharge coefficient to be equal to ± 0,6% when the diameter ratio is less than 0,6 and equal to the numerical value of the diameter ratio when the diameter ratio is between 0,6 and 0,75. See ref./1/ for more details.

According to the plans of ISO/ TC30 (Technical Committee dealing with differential pressure devices) which are a change of the ISO-5167 revision, an updated version will be available within 2 to 4 years. The modifications which will be sent to hearings concern certain requirements on plate installation, some minor changes in the Stolz equation, and changes due to experience obtained since 1980. In addition a Code of Practice for ISO-5167 will be edited probably in 2 years. This is a handbook which will provide the users with practical information on how to use the standard. In the USA a similar revision of AGA-3 is nearly completed and will go public in the next two years.

2.3 Intercomparison between ISO-5167 and AGA-3

A comprehensive study comparing the standards with new experiments has been carried out by Miller in 1979, ref. /2/. In this report ISO-5167 and AGA equations with new flange tapped orifice meter calibration data from the Foxboro laboratory are compared.

2.3.1 Analysed data

The orifice meter runs were commercially available flange tapped meter runs fabricated to AGA specifications.

The data analysis were made on the full dataset (Group 1) and on two subsets (Group 2 and Group 3) defined as shown in table 1.

2.3.2 Results of Miller's analysis

Miller's analysis gave the results presented in table 2 as regards the systematic error and equation efficiency (the random error obtained if the systematic error had been corrected for) for both the AGA and the ISO-5167 equations and the three data groups.

It was observed that both the AGA equation and the ISO-5167 equation systematically underestimated the flow in the Foxboro laboratory. For the full dataset compared with the ISO-5167 the systematic error was estimated to +0,49%. Around this value the group 1 data were scattered within ±1,13% with 95% confidence.

The data of Miller also show two orifice meters of the same size having systematic errors differing with as much as 0,5%.

2.3.3 Conclusions

For all three data groups there is a positive systematic error for both equations. The systematic error for the ISO-5167 equation being less than the systematic error for the AGA equation.

Having in mind that the accuracy of the calibrations is equal to or better than ±0,15% there must be some design parameters not properly defined in the standard with the consequence that permitted variations of design parameters contribute to the wide scatter of the measurements. If this hypothesis is correct it should be possible to determine design parameter values which result in small systematic errors. Another possibility is that the calibrated meters for some reason did not comply with the standards.

These results do not add confidence to the stated accuracy of ISO-5167. It should, however, be mentioned that the Foxboro calibration tests do not conform to ISO-5167 regarding the installation of the flow straightener. Miller describes the distance between the flow straightener and the primary device to be a minimum of 20 diameters not 22 diameters as required by ISO-5167. Miller does not give information enough to judge whether the sections upstream of the flow straightener do conform to ISO-5167.

It must be a problem for the users of ISO-5167 that well known flow calibration laboratories obtain results as presented above when using commercially available orifice meter runs fabricated according to the existing standards. From the above data it seems to be room for significant improvements in the orifice meter standard. The efforts should primarily be directed towards reducing the systematic error component of the uncertainty.

2.4 Other views

In the open literature there is little information available for assessing the validity of the ISO-5167 standard. The referenced paper of Miller is the most comprehensive comparison between new experiments and the standard.

A meter calibration intercomparison campaign is going on between flow laboratories in the EC. Data have been produced and some of these were recently presented at a conference /3/. In the USA several laboratories are carrying out tests similar to the ones obtained in Europe. These results will serve as new data base for future revision of US standards. The main laboratories involved are National Bureau of Standards in

Gaithersburg and Boulder, Natural Gas Pipeline Company of America, Colorado Engineering and Experimental Station.

2.5 Degradation of standard installations

An orifice meter designed according to ISO-5167 has a precisely defined geometry. For various reasons the geometry of the meter may be modified during operation:

- Flow transients may buckle the orifice plate.
- Extraordinary operating conditions may result in accumulation of liquids in the pipe upstream of the orifice plate.
- Dirt may accumulate on the meter tube walls and on the orifice plate itself.
- The sharp upstream edge of the orifice plate may be rounded by erosion.

The surface roughness of both the meter tube and the orifice plate may be increased beyond the limits specified by the standard. The surface roughness may be increased by dirt in the gas attaching to the surfaces. Also erosion or corrosion may influence the surface roughness.

An important installation parameter is the eccentricity of the orifice bore relative to the meter tube bore. There are very strict limitations to the maximum allowed eccentricity. The eccentricity can be measured when the meter is installed for the first time. However, during normal maintenance it is difficult to measure the eccentricity, and in practice it is not measured at all.

The errors observed when standard metering installations are degraded have proved to almost always underpredict the actual flow, see ref. /4/. Errors due to non standard conditions will not cancel each other, they will all contribute to a measurement bias. Central to measurement accuracy is, therefore, assuring standard measurement conditions throughout the whole life of a metering station.

When discussing the measurement standard the principal question is: What were the conditions during the fundamental experiments generating the data base on which the current discharge coefficient equation is based. These conditions should be the basis of the standard conditions. The documentation of the original experiments shows an awareness of the problems, but the original installation parameters (e.g. edge sharpness, orifice eccentricity and surface roughness) were not quantified. One also regrets that the actual meter runs have been lost. The possibility therefor exist that todays standard does not cover the original conditions properly. This is an important argument for new experiments.

The tendency of creating a measurement bias emphasises the need of close inspection and control. A test of full scale meter runs will make it possible to identify necessary modifications to the existing maintenance procedures.

3. THE PURPOSE OF THE EXPERIMENTAL GAS TEST FACILITY

Generally the purpose of the Kårstø Metering and Technology Laboratory is to have the opportunity to create large gas flows, measure them very accurately and have the ability, in a flexible test section, to insert all kinds of test objects. With this facility it will be possible to check and ensure application of optimal equipment and methods for sales operations. With the large gas production in the North Sea small measurement errors have significant economic consequences.

3.1 Influence on new international standards

Research and development efforts in the field of gas flow measurements have increased considerably over the last years. A number of projects have been initiated by ISO and by institutions within EC. Still experiments are performed on a scale well below what is experienced in todays commercial gas metering stations.

K-LAB will give an important supplement to already existing experimental facilities and an active and constructive role in ISO and its committees dealing with metering standards is foreseen. Data obtained in K-LAB may be included in revisions of the relevant standards.

3.2 Influence on metering station design

There are two approaches to the improvement of metering station design. One is to improve the design of the existing meter and the other is to use another type of meter. Both ways have a considerable potential for metering improvement.

As discussed in section 2.3.3 there are reasons to believe that variation of design parameters within the orifice meter standard creates the relatively wide distribution of calibration points observed by Miller. With the test facility, as it is proposed it is possible to examine the influence of different design parameters on the orifice meter discharge coefficient. Such information will make it possible to avoid design requirements generating systematic losses. The experiments in such a program will have the objective to define those parameter ranges within the standard that do not generate a measuring bias.

The process of modifying an international standard lasts several years. If new experiments in the test facility confirm for instance the Miller results, a more rapid correction of the systematic error may be obtained if a meter requiring individual calibration is used instead of waiting for revision of the relevant international standard. It implies however that all parties involved agree on the type of meter to be used. Today the turbine gas flow meter, which is employed instead of the orifice meter in many installations, is a realistic alternative. An international standard of the turbine gas flow meter is in the process of being developed.

3.3 Examination of the effect of degrading standard conditions

During operation many parameters important to the metering accuracy will experience a shift due to new operating conditions, wearing effects or sudden changes due to measuring equipment parts. This problem is an extension of the one presented in the previous section and much of the information gathered for one task will also serve the other.

The phenomena that should be monitored closely during operation are:

- Non-standard orifice plate geometry (bending, erosion, corrosion, eccentricity, edge sharpness, dirt accumulation etc.)

- Liquid holdup in front of the orifice

- Flow pulsations

- Swirling flow generated by upstream pipe fittings (bends, tees, valves, manifolds etc.)

- Effects of flow straighteners

In addition a very careful maintenance of the secondary instrumentation must be ensured.

Even small disturbances of the above mentioned types create serious measurement errors. During acute operational situations the disturbances may create measurement bias. Situations like this must be detected rapidly.

3.4 Examination of installation effects

From study of the required straight pipe lengths to various upstream fittings for a given discharge coefficient accuracy poor agreement is found between the ISO-5167 and the AGA standard. From the technical debate within ISO it is evident that this is a real disagreement not only a matter of standard revision. These aspects of the standard are still developing.

It is also known that unexpected flow instabilities may arise in a metering system when the flow is varied through the various legs of a manifold. Experiments

should be aimed at testing the metering systems (and possibly also other systems) in advance in the test facility to ensure proper flow conditions.

3.5 Development and testing of new metering methods

The orifice meter is a robust and accepted standardised gas meter. However, compared to many other flow meters it also has inferior operating characteristics. Especially the orifice meter has a 3:1 rangeability while the turbine meter rangeability is between 30:1 and 40:1 depending on size and pressure. The vortex flowmeter rangeability is between 10:1 and 20:1. For all gas meters of differential pressure type the flow measurement uncertainty will increase with reduced differential pressure (reduced flow). In practice these problems may be partly circumvented. Interesting is also that the pressure loss of many new meters is much less than with orifice meters.

Important scientific and technical progress can be expected in the coming years in the field of developing new standardised gas flow meters. Improvements and extensions of methods based on the orifice-, turbine- and vortex principles as well as sonic nozzles represent important topics for research and development. In addition there is a considerable potential in less developed methods which do not disturb the flow field. Such methods include ultrasonic and laser based Doppler techniques and radioactive tracer techniques.

New, improved equipment will be accepted for commercial operation more rapidly if large scale tests in the K-LAB demonstrate the equipment performance without the risk of expensive production breaks.

4. REVIEW OF LARGE GAS TEST FACILITIES

All major gas consumer/producer countries operate gas flow test facilities either within national/university research centres or within gas companies (Gasunie, Gas de France, Ruhrgas, British Gas Corporation). A review of the major facilities in Europe is given in table 3 where also main characteristics are indicated.

When high flowrates are concerned the reference flowmeter is never calibrated directly against weight or volume. The reference meter is generally coupled in series with a set of parallel meters each one calibrated against fundamental quantities or against other meters. In this way a calibration chain is established making a high flowrate measurement traceable to fundamental standards of weight and measures. Central to the concept of accuracy is the traceability of the measurements to basic units by means of a chain of transfer standards. The concepts of traceability, calibration chain and accuracy are important for understanding the special features of K-LAB.

Increasing the number of transfer steps will increase the calibration uncertainty. Uncertainties are also introduced when theoretical extrapolations are made to adapt the calibrated meter for use with other gases and at higher pressures than calibrated for.

The reference flowmeter installed in the test facilities of table 3 are summarised in table 4.

At National Engineering Laboratory (NEL) sonic nozzles can be primary calibrated by a gravimetric method similar to the on described in section 5.1. The primary calibration uses air at a maximum pressure of 50 bar. The sonic nozzle can be used as a transfer standard and the process of calibrating another meter using the sonic

nozzle as transfer standard is called a secondary calibration. The flow medium of the secondary calibration may be different from the primary calibration flow medium and corrections for another flow medium must be included in the secondary calibration; corrections which introduce additional uncertainties. In addition to another flow medium the operating pressure may be different introducing other corrections. The chain of transfer standards is often longer than in the case above. In those cases the secondary standard is used to calibrate an other meter and so on.

In the test facility operated by British Gas Corporation at Bishop Auckland turbine meters is used as reference meters. These turbines are calibrated against sonic nozzles originally primary calibrated at NEL. Corrections for different flowmedia at NEL and Bishop Auckland must be introduced.

The largest test facility operated by Gaz de France (GdF) is equipped with a reference meter consisting of a battery of 7 sonic nozzles. Each of these are calibrated in a smaller test loop where the reference meter has been primary calibrated according to a volumetric method.

The reference flow meter at the Poitiers test facility consists of 12 sonic nozzles calibrated at the GdF test station. Some of the nozzles are primary calibrated and the largest are secondary calibrated.

The reference flow metre installed in the Lintorf facility, owned by Ruhrgas, consists of 5 orifice meters individually calibrated with water.

Gasunie uses turbine meters traceable via a series of transfer steps to a 3,5 m^3 bell prover at the Dutch Service of Weights and Measure.

For further details on the calibration methods see ref./5/.

Compared with the listed facilities the K-LAB will be unique regarding maximum operating pressure and the obtainable accuracy. Remarkable is that there is only one transfer standard between calibration at high pressure and large flow rates and basic weight measurements. In addition, the flow medium and pressure is the same in both the primary and the secondary calibration. This ensures the excellent accuracy of the facility.

5. DESCRIPTION OF THE KÅRSTØ METERING AND TECHNOLOGY LABORATORY

5.1 Test loop

A flow diagram and a general view of the K-LAB are shown in figure 1 and figure 2 respectively. The operating conditions and main specifications are given in table 5.

The gas which is supplied from the Statpipe terminal is circulated by means of a centrifugal compressor, Q1, through a heat exchanger, E1, into a reference flow meter consisting of 8 parallel sonic nozzles, where 6 have 15% of full flow capacity and 2 have 5% of full flow capacity, enabling the flow to be varied in steps of 5% of full flow. Thereafter the gas flows into one of the branches of the test section, then back to the compressor.

The test facility is equipped with a primary calibration system. This system guarantees traceability of the gas flow metering system with only one transfer standard step. The primary calibration system is operated in a line parallel to the reference flow meter, It consists of a diverter valve, V1, and a weighing tank, T1. The nozzle to be calibrated is mounted in the primary calibration system. The reference flow meter is shut off and the flow is directed through the primary calibration system. Maintaining critical conditions in the nozzle the flow is diverted by a high speed diverter valve into an empty weighing tank, T1. The diverter valve is operated back to bypass mode at an appropriate time. The time and increased mass of the weighing tank is measured giving the mass flow rate through the nozzle. The property of sonic nozzles that make them suitable for this type of application is that the mass flow only depends on the conditions upstream of the nozzle as long as sonic conditions prevail.

The test section comprises a 24" pipe, a 12" pipe, a 8" pipe and a 4" pipe which consist of flange connected pipe sections of standard lengths. The 24" pipe is designed to be both an on site gas backup tank and an installation where it is possible to examine the performance of large gas flow meters. The configuration can be modified when required, depending on the different experimental programs to be carried out.

Particles larger than 3 microns are removed from the gas in a filter, C1, just before the gas enters the main compressor and starts a new cycle in the loop.

The gas is supplied from the terminal at a maximum rate of 3kg/s. When the required loop pressure exceeds the terminal gas pressure, a booster compressor, Q2, is used to increase the pressure.

5.2 Obtainable flow conditions

The volume flow rate through critical flow venturi nozzles is almost constant for all operating pressures. The range of the volume flow rates of the reference flow meter (RFM) is between 0,05 m^3/s and 1,0 m^3/s in steps of 0,05 m^3/s (referred to conditions upstream of nozzles). The operating pressure in the test section may be varied continuously between 140 bar and 35 bar, thus enabling a continuous range of mass flow rates between 130 kg/s and 1,5 kg/s.

The obtainable pipe Reynolds number in the 12" test section is $3{,}2 \cdot 10^7$. It is determined by the maximum mass low rate and the pipe diameter and may in addition be limited by the flow conditions in the test section (e.g. pressure loss or test object limitations).

The obtainable Reynolds numbers are well above the Reynolds numbers of the tests forming the basis of the ISO.5167 standard or orifice meters. This is shown in figure 4. The basic tests were performed at Ohio State University in the 1930ies. The Gasunie tests that were used by the International Standardisation Organisation to verify extrapolation of the discharge coefficient correlation to Reynolds number as high as 10^{o} are also shown. These experiments were performed at normal transmission line pressure in the Netherlands and the reference meter consisted of three parallel orifice meters operated according to the standard.

5.3 Obtainable accuracies

The sonic venturi nozzle is a very reliable and accurate gas metering device. A reference metering system similar to the one used in the K-LAB is used by Gas de France in its test rig in Alfortville, by Bureau National de Metrologie in its installation in Poitiers and by British Gas Corporation in its Bishop Auckland facility.

The present calibration and reference meter system is designed to an accuracy better than $\pm$ 0,25%.

In the following an orifice meter discharge coefficient uncertainty calibration is used as an example for discussion. The discharge coefficient has been estimated for a RFM consisting of precalibrated nozzles or nozzles calibrated in the first loop. The result is shown i figure 4.

With precalibrated nozzles the estimated uncertainty of the orifice discharge coefficient shows a significant variation both with the volume flow rate and the pressure. The uncertainty varies between 0,7% and 0,49%. The reduction of the uncertainty due to flow

rate is mainly due to the increased number of independent measurements while the dependence on the pressure is due to corrections for the gas properties at elevated pressure. The curve for 140 bar in uncertain due to extrapolation of data for the sonic nozzle critical flow factor.

With nozzles calibrated in the K-LAB calibration rig the estimated uncertainty of the orifice discharge coefficient is considerably smaller than if precalibrated nozzles are used. This is because the primary calibration eliminates the need for determination of several uncertain parameters (dimension and gas properties). The variation of the orifice discharge coefficient calibration uncertainty with volume flow rate is due to the same effect as in the case with precalibrated nozzles. For illustration, the uncertainty of discharge coefficients of uncalibrated orifices according to ISO-5167 is also indicated in figure 4.

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/3/ Int. Conf. on The Metering of Natural Gas and Liquefied
Hydrocarbon Gases. 1.2. Febr. 1984 - LONDON.

/4/ Kemp J.,
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in course "Measurement of gas and liquids".

	Group 1	Group 2	Group 3
Min. diameter *)	2.067	3.853	3.853
Max. diameter *)	23.23	23.23	19.49
Min. dia. ratio	0.25	0.25	0.25
Max. dia. ratio	.7499	.7499	.7000
No. of orifices	28	26	18
No. of datapts.	422	395	288

*) Unit is inches.

TABLE 1. Grouping of Foxboro orifice data.

	Group 1	Group 2	Group 3
Systematic error AGA equation	+0.65%	+0.54%	+0.33%
Systematic error ISO-5167 equation	+0.49%	+0.36%	+0.25%
AGA equation efficiency	±1.18%	±0.87%	±0.55%
ISO-5167 equation efficiency	±1.13%	±0.62%	±0.49%

TABLE 2. Result of comparison between Foxboro calibrations and AGA and ISO-5167 equations.

Country/operator/location	Medium	Oper.pressure (bar)	Max. flow (m^3o/h)	Max. pipe Reynolds num.	Claimed accuracy (%)	Reference standards	Comments
FRANCE							
Gaz de France, Alfortville	Gas	5 - 50	$6 * 10^4$		± 0.3	Sonic nozzl.	In operation
Bureau National de Metrologie/ Ceat, Poitiers	Air	3 - 50 (70)	$1.5 * 10^5$	$1.5 * 10^7$	± 0.3	Sonic nozzl.	In operation mid. 1982 Blow down
W.GERMANY							
Ruhrgas, Lintorf	Gas	8 - 60	$1.2 * 10^5$	$1.5 * 10^7$	± 0.24	Orifice plate calibrated with water	In operation
THE NETHERLANDS							
Gasunie, Bergum	Gas	8 - 60	$1.4 * 10^5$		± 0.3	Turbine flowmeter	In operation
Westerbork	Gas	40 - 60	$2.5 * 10^6$	$>3 * 10^7$	± 0.2		In operation
NORWAY							
Kårstø	Gas	35 - 140	$5.5 * 10^5$	$3.2 * 10^7$	± 0.18 - 0.26	Sonic nozzl.	In operation mid. 1986
UNITED KINGDOM							
B.G.C. Low Thornley	Gas	11 - 56	$1.7 * 10^5$		± 0.5		In operation
Bishop Auckland	Gas	60	$1.4 * 10^6$			Sonic nozzl.	In operation mid. 1982
NEL, East Kilbride	Air	2 - 50	$1.5 * 10^4$	$1.5 * 10^6$	± 0.3	Sonic nozzl.	In operation Blow down

Table 3. Major european experimental gas test facilities

Test section	Reference flowmeter	Transfer standard	Primary Calibration
GDF. Alfortville	7 sonic nozzles 5 - 50 bar	Sonic nozzles (Gas)	Volumetry (Gas)
BNM, Poitiers	12 sonic nozzles 5 - 50 bar	Sonic nozzles GDF (Gas)	Volumetry (Gas)
RUHRGAS, Lintorf	5 orifice plates 8 - 60 bar		Gravimetry (Water)
GASUNIE, Westerbork	10 turbine flow-meters, 40-60 bar	Turbine flowmeter (Gas)	Gravimetry - (Water)
KARSTØ	8 sonic nozzles 40-140 bar	none	Gravimetry (Gas)
BGC, Bishop Auckland	Sonic nozzles 60 bar	Sonic nozzles	Gravimetry (NEL)
NEL	Sonic nozzles 2 - 50 bar		Gravimetry (Air)

GDF : Gaz de France
BNM : Bureau National de Métrologie
BGC : British Gas Corporation
NEL : National Engineering Laboratory

TABLE 4. REFERENCE FLOWMETERS AND TRANSFER STANDARDS WITH METHODS OF PRIMARY CALIBRATION FOR MAJOR FLOW FACILITIES.

MAIN SPECIFICATIONS

* Maximum operating pressure: 140 - 155 bar
* Maximum mass flow: 130 kg/s
* Maximum volume flow: 1 m^3/s
* Operating temperature: ApproX. 35^oC
* Diameter test section: 4" - 8" - 12" - 24"
* Straight pipe lengths: 500D - 250D - 170D - 110D
* Total gas volume: Aprox. 120 m^3

Table 5. Main operating conditions and specifications

Q1: Main compressor
4.8 MW ; 50 ton
1m /s

E1: Heat exchanger
5 MW ; 8ton

T1: Weighing tank
3.5m ; 10ton

C1/C2: Particle filters
C3: Oil filter
V1: Diverter valves

Q2: Booster compressor
70 KW ; 0.5ton

q_v = 1-0.05m /s
q_m = 130 kg/s-1.5kg/s

P des = 172bar
P max. test sect. = 156bar

F: Feed drum
P = 220bar

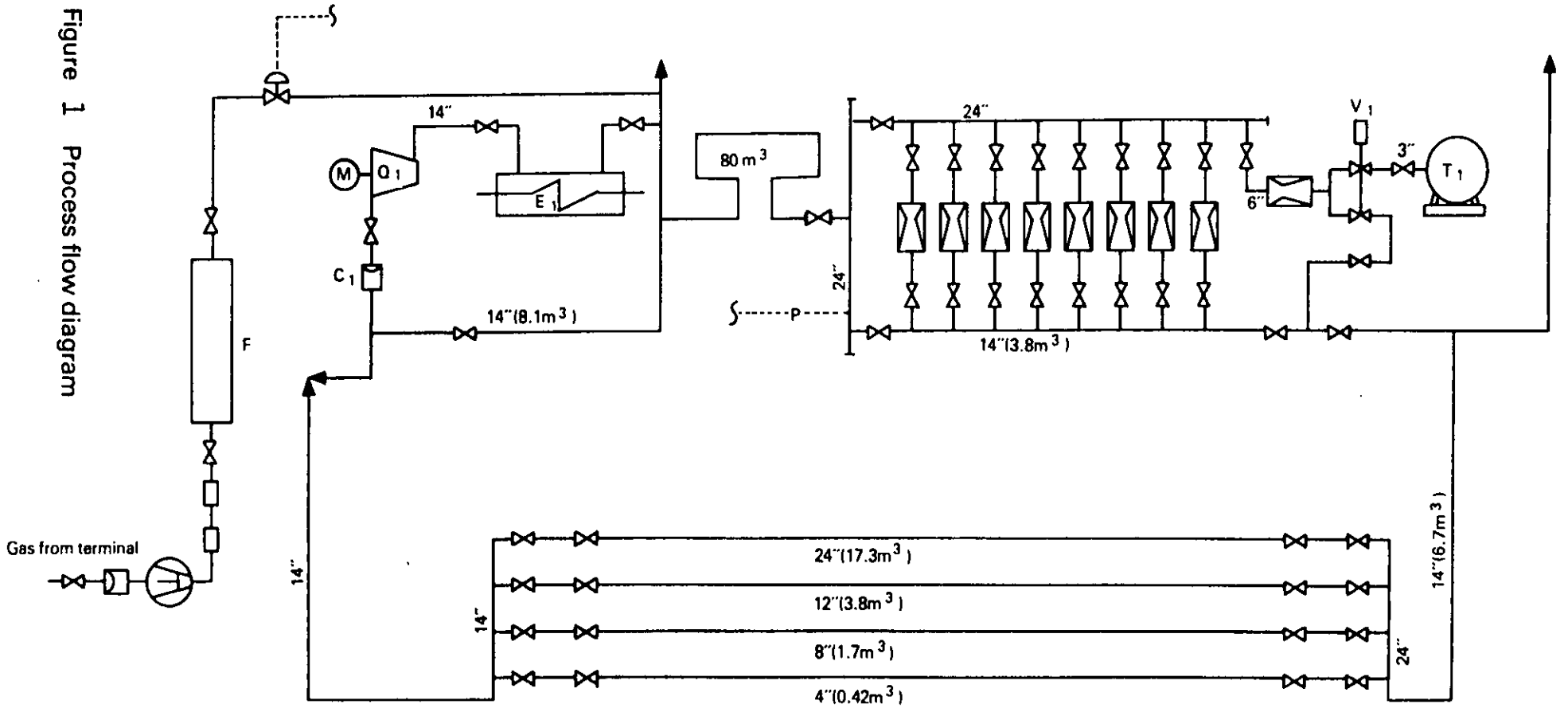

Figure 1 Process flow diagram

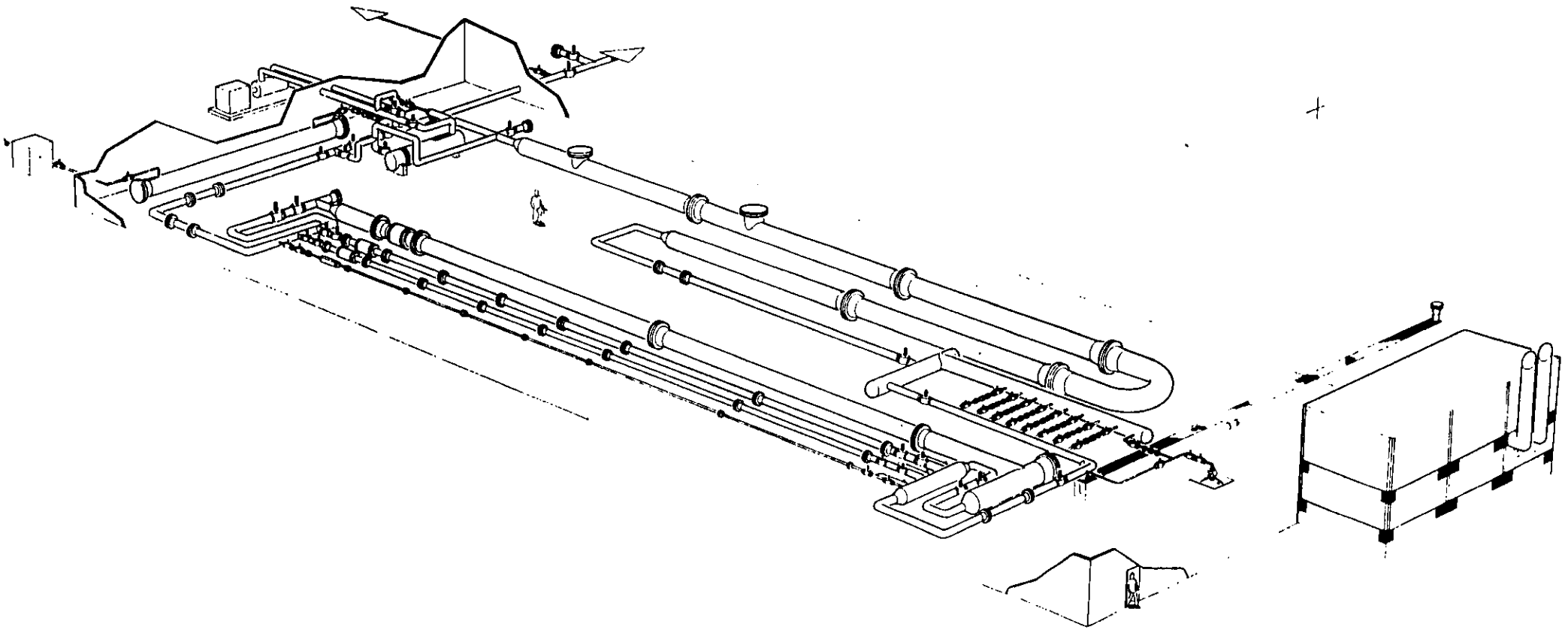

FIGURE 2. FLOW LOOP

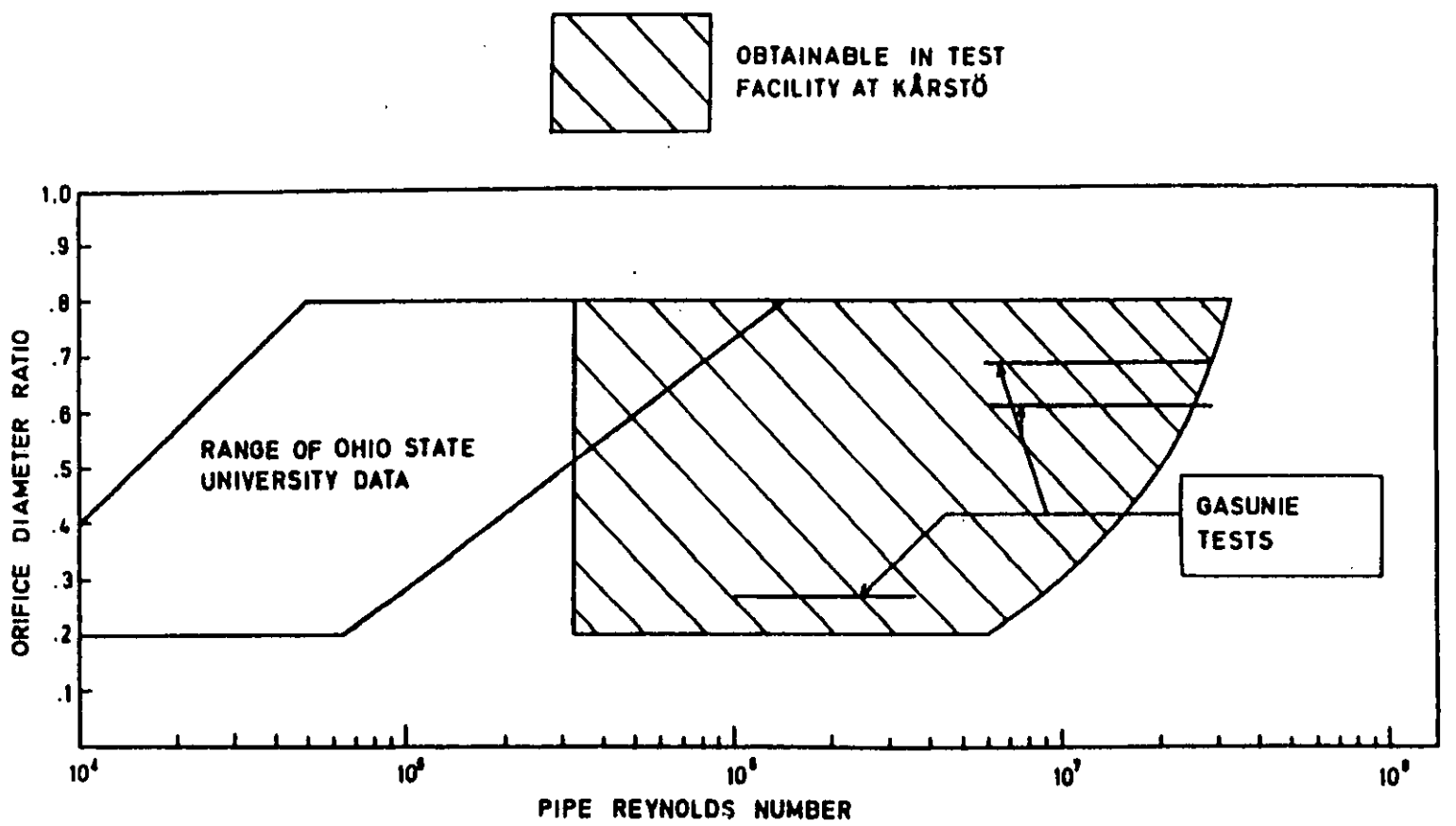

Figure 3. Obtainable Reynods numbers compared with ISO-5167 data base.

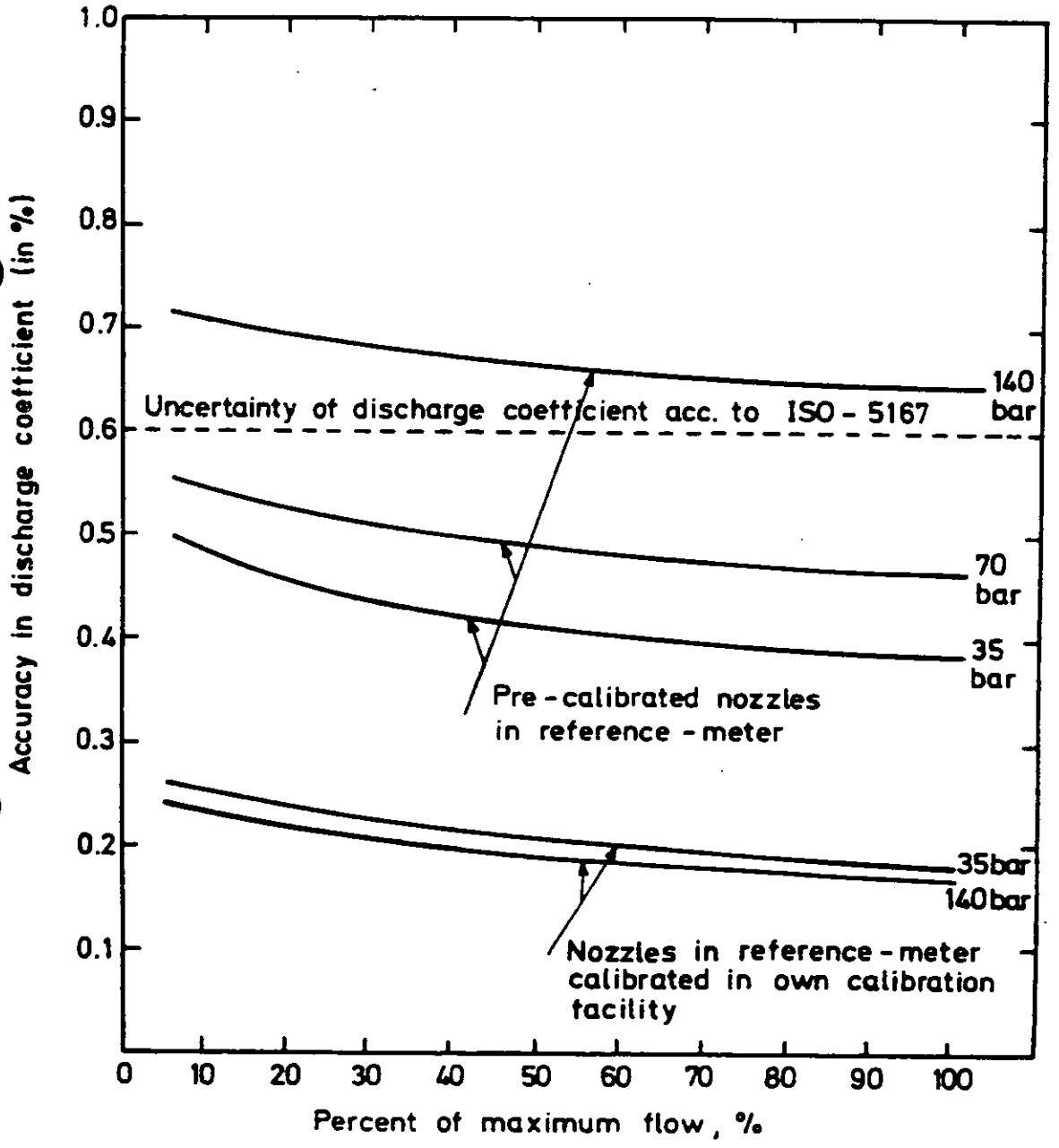

Figure 4. Obtainable accuracy in orifice discharge coefficient versus percent of maximum flow.

NORTH SEA FLOW METERING WORKSHOP
ARRANGED BY: NORWEGIAN SOCIETY OF CHARTERED ENGINEERS:

FIELD EXPERIENCE IN MEASURING WATER DEWPOINT OF NATURAL GAS

BY
Egil Carlsen
Elf Aquitaine Norge A/S

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~~2.7~~
2.6

INTRODUCTION

The determination of water wapor content in natural gas is of major importance to the natural gas transmission industry. If water condensation occurses in a transmission line, many operational problems can be expected. Free water can be sufficient to give;

* Hydrates - with partial or complete plugging of the pipeline, valves and regulators.

* Internal Corrosion - with metal loss of the pipewall, corrosion leak and breaks.

* Compressor faults.

The gas contract between the supplier and distributer usually specifies the maximums allowable water vapor content or water dewpoint. In order to determine if the gas meets the contract specification and to control the operation of the dehydration plant, a precise method of measuring the water content, therefore, is required. Several methods are available, but it has been found that special problems occur when measuring the dewpoint of the natural gas for the following reasons:

* Natural gas may contain hydrocarbones with a higher dewpoint than water.

* Natural gas may contain corrosive gases (CO_2, H_2S).

* Natural gas may contain alcohols such as glycol and methanol.

* Natural gas may contain deposites.

* Calibration on site is difficult.

The following discussion will cover typical methods used for determing the water vapour content of natural gas. Basic principals for a proper installation design will also be discussed and at last Elf Aquitaine NorgeA/Sexperienceon Frigg.

CURRENT METHODS

There are many methods for the determination of water vapour, but only a few are applicable for use in natural gas. Some of these are suitable for a continous monitoring of water vapour while some can be used only for spot checks. Some of the more important methods is based on one of the following methods.

1. DEWPOINT. Gas at known pressure is passed over a cooled mirror. The water dewpoint is recorded as the temperature at which water dropplets is first seen to appear on the mirror. If the hydrocarbone dewpoint is higher than the water dewpoint or the gas contains glycols or amines, a great deal of difficulty may arise in the interpretation of the water dewpoint.

2. ELECTROLYTIC. Absorption of water by phosphorous pentoxide and electrolycis of the water. The cell of the instrument is an insulating tube with a pair of wires wond in a spiral throughout the inside diameter. A thin film of phosphorous pentoxide is applied between the wires. As the sample passes through the cell the water is adsorbed by the phosphorous pentoxide. A voltage is applied across the two wires which causes the decomposition of water into hydrogen and oxygen. The resultant current that flows follows Faraday's law and is propotional to the number of water molecules electrolyzed. At a constant sample flow the current is a measure of the water vapour in the gas. Methanol and other lower alcohols cause high readings. This method is also flow dependent.

3. CAPACITANCE. The capacitance hygrometer is a method for determing the water vapour content of natural gas by using an aluminium strip which has an anodized surface of aluminium oxide. The aluminium oxide is coated with a thin layer of gold. The aluminium base and the gold layer form two electrodes of an aluminium oxide capacitor. Water vapour is adsorbed through the gold layer onto the aluminium oxide layer. The rate of absorption is directly proportional to the water vapour pressure of natural gas. The electrical capacitance of the sensing probe is then converted electronically into a correspondingdewpointtemperature.

This type of instruments are available both as continuous and as a portable instrument.
Solids particles and liquids i.e. glycols can block the sensor pores and reduce the sensitivity of the sensor or give faulse readings.

4. VIBRATING CRYSTAL. The vibrating crystal analyser measures the moisture in gas by monitoring the vibrational frequency change of a hygroscopically coated quartz crystal that is exposed alternately to wet and dry gas. Sample gas is divided into two streams, sample and reference gas, which are alternately passed through the measuring cell. Before reaching the crystal, the reference gas is passed through a molecular sieve dryer, which removes virtually all of its moisture. As the sample gas is passed over the measuring crystal, moisture is absorbed by the crystal's hygroscopic coating, therby causing a vibrational frequency change. The frequency difference between the sample gas and the reference gas is proportional to the amount of moisture absorbed from the sample gas. Glycol may interfere the measurement.

5. CONDUCTIVITY. This method utilize the increase in the electrical conductivity of glycerol according to the concentration of water. A pressure test chamber is equiped with a cell consisting of two thin horisontal layers of stainless steel separeted by an isolating ceramic material. The eight pocket holes of the cell are half filled with conductive glycerol and behave as independant electronic pairs. Water vapour is absorbed into the hygroscopic glycerol. This effect changes the conductivity of the cell. The cell temperature must be maintained at a constant level. This method responds to relative humidity and the probe is exposed to gas at operating pressure. Temperature variations of the fluid at the sensor can give false readings.

6. CHEMICAL TITRATION - Coulumetric titration. Natural gas is bubbled through a Karl Fisher reagent, an iodine based chemical, at controlled flow rate. The water vapour reacts with the reagent and neutralizes it. When the reagent has completely reacted, the time required to reach the end point is electronically transformed into an equivalent water vapour content.

Volumetric titration. Natural gas is bubbled through a methanol or glycol solution at a controlled flowrate. The water is absorbed by the hygroscopic solution. Karl Fisher reagent reacts mole per mole with water and an equivalent amount of water vapor content can be calculated.

The Karl Fisher titration method is both available in a portable and automatic version [1]. The portable version is not Ex-proof.

The Karl Fisher reagent undergoes a spesific reaction with water. The reagent is inert to hydrocarbons, carbondioxide, glycols and amines. Hydrogen sulfide and merceptans react with it and the method is not applicable to gas when the concentration of these components is above about five grams per 10^6cubic meter [1]. The method is flow dependent.

CALIBRATION OF HYGROMETERS

Calibration of hygrometers is normally done by one of the following procedures:

1. The water content of the gas as read by hygrometer is compared to the readings of another instrument or method known to be accurate (calibration instrument).

2. A stream of gas having a known water content (reference gas) is passed through the hygrometer.

For each procedure several methods are available.

Calibration Instruments

1. Gravimetric - The weight of water absorbed by a drying agent from a known volume of gas is determined. This is a primary laboratory method.

2. Titrimetric - The Karl Fischer procedure is a primary laboratory method.

3. Dewpoint - Measuring the water dewpoint with a manual mirror type analyser is a primary method.

Reference Gas

1. Hydrogen-Oxygen Mixture - A known concentration of hydrogen is combined with oxygen by a catalyst to produce a known consentration of water in a gas stream. A variation of this is to electrolyze water to form hydrogen at a known rate by Faraday's Law, then recombine the hydrogen with oxygen over a catalyst.

2. Permteation Tubes - Water vapour passes at a known rate through the wall of a plastic tube into a dry gas stream.

3. Dilution of Water Saturated Gas - A stream of gas saturated with water at a known temperature and pressure is diluted by a known proportion of dry gas.

4. Standard Moisture Mixture - Compressed gas containing a known concentration of water vapor is stored in a specially coated aluminium cylinder (1).

5. Temperature filter. A stream of gas is passed through a temperature filter. The temperature in the filter will represent the saturation temperature or water dewpoint at the existing pressure.

HYGROMETER INSTALLATION

In order to make a correct determination of water vapour content of natural gas it is important when designing a hygrometer installation to be aware of the effects which may give erroneous reading. The prime requisite for a correct reading is that no opportunity must be allowed for condensation, absorption or adsorption of water vapour. This requires keeping all parts of the sampling system well above the water dewpoint, selecting proper materials when designing the sampling system and very often maintain a constant purge flow. The temperature stability of the sampler system components is also very important. At a given equilibrium condition of temperature the system will absorb a special

amount of moisture. If glycol or another hygroscopic liquid is present in the gas and the sampling system is contaminated, the amount of moisture absorbed is increased dramatically. Any factor which upsets this equilibrium, wether it is a change in the sample concentration or a change in ambient temperatures, will require a new equilibrium condition to be established before a true humidity can be measured. Changes in sample line temperature should be avoided. It is also desireable to locate the sampling system and the hygrometrer sensor as close as possible to the pipeline. This is of special importance when glycol is present. Any glycol which is accumulated in the sampling system will increase the response time and may also give faulse readings. Installation of filters or coalescer upstream the hygrometer sensor in order to protect the sensor must be avoided because this will cause an accumulation of glycol giving the above mention effects. Removal of most of the liquid carried over into the sample stream may be obtained by use of a small separator 0,5 - 1 cm^3 (filter house with the filter removed) and with a contineous drain of liquid. Installation of a proper sample probe will also reduce the effect of liquid deposits. Outside turbulent area like tees and bends, the liquid contamination will travel along the pipewall and will not be pushed into the sample loop if a sample probe is installed (Fig.1). Further on, it is important to know that a pressure regulator which have to reduce the gas pressure by 150 BAR, will cause a Joule-Thomson cooling of the gas of about 35 - 40°C and therefor if used, the regulator should be heated.

Considering the above mentioned aspect the following design criteria should be followed.

* Use a material which not absorb water. Stainless steel are the best possible none-hygroscopic material.

* Reduce the sampling line to a minimum.

* Heat and insulate the sampling line.

* Install proper sampling probe.

* Avoid sampling from a turbulent area.

* Avoid a Joule - Thomson cooling effect upstream the hygrometer sensor.

FIELD EXPERIENCE MEASURING WATER DEWPOINT IN NATURAL GAS.

The water dewpoint monitoring system on Frigg which is a gas and condensate field, is based on both portable manual device and on-line automatic analysers. The philosophy is based on that the on-line automatic analyser shall monitor the water dewpoint continuously and the portable instrument which is a mirror type, is used as a "calibrating instrument" for the automatic analyser. The portable instrument is also used as a back up and spot check instrument. Figur 2 shows the location of the automatic dewpoint analyser and the location where the dewpoint most frequently is measured with the portable instrument.

Manual Dewpoint Techniques

The direct observation of dewpoint via a chilled mirrored surface using visual observation of the dew formation is a common and videly known method to measure the water dewpoint in natural gas. This method is also used for determining the hydrocarbon dewpoint. The hydrocarbon dewpoint is characterized by an rainbow coulored film which radiates from the center of the mirror. The temperature and pressure where the iridescence first appear is the hydrocarbon dewpoint. Normally, further cooling of the mirror the water dewpoint will appear as an opaque cloudy spot near the center of the mirror. The temperature and pressure at which the opaque film first appears should be taken as the water dewpoint.

The hydrocarbone dewpoint can occure either at a different temperature (higher or lower) or at det same temperature as the water dewpoint and it has been reported that when hydrocarbones condense above the water dewpoint, it will interfere with the water dewpoint[3]. Further on, if the gas contains a number of components aside from the hydrocarbones, a great deal of difficulty may araise in the interpretation of the water dew point. The other components may condense slightly before or along with the water vapour and cause a masking of the mirror.

On Frigg, both glycol and condensed hydrocarbones are present and represent a potensial problem. However, it has been possible to measure the water dewpoint with a satisfactory accuracy with the mirror type instrument. Sometimes the measurement has to be repeated and can take quite a long time to be performed. It can be very difficult to use under these conditions and requires an experienced, knowledgeable technician. If the hydrocarbon liquid makes it difficult or nearly impossible to measure the water dewpoint a small oil scrubber can be installed between the pipeline and the dewpoint tester.

Several referenses has discussed the above mentioned problems with condensate and glycol interfering the water dewpoint measurement [3,4,5]. Some are of the opinion that downstream glycol dehydrators and with hydrocarbon condensate present, measurement of the true water dewpoint will not be possible. In this discussion it is important to know under which conditions glycol is present and the quantity of glycol and hydrocarbone condensate present.

Triethylenglycol (TEG) does not normally interfere [3,4] when TEG exists as vapour due to the low vapor pressure in natural gas. However, at times glycol are present as an aerosol one would expect it to be an interference. This will normally happen if the amount of glycol carried over from the dehydration plant is high. Foaming in the glycol dehydration tower will normally give a high amount of glycol mist in the gas. This effect has been experienced on Frigg and during this period it was nearly impossible to get stable and repeatable water dewpoint readings.

Two different portable mirror types dewpoint analysers are tested on Frigg. The first one was a Bureau of Mines Type Dew Point Tester developed by W.M.Deaton and E.M. Frost and manufactured by Chandler Engineering Company (Fig.3).

Used by experienced technicians this instrument gave satisfactory results. The accuracy in claimed by the manufactor to be 0.1°C under normal conditions but used under the conditionson Frigg the accuracy is not better than 2°C. The Bureau of Mines Type Dew Point Tester is quite easy to operate, however it does not satisfy the electrical safety requirements for instalation in the North Sea.

Due to the problems with the Ex-certificate, a second portable dewpoint analyser were tested on Frigg, Optomat Ex from Hobre Instrumet b.v. This instrument is also using cooled mirror as measuring principle but it is easier to operate than the Bureau of Mines Type Dew Point Tester. The gas is cooled by a Beltier electric-element instead of cooling gas (CO_2,Propan).

This gives a much better control of the cooling process which is very critical when a mirror type instrument is used. Very often the mirror is cooled too fast and the water dewpoint will not get sufficient time to be built at the correct temperature and a lower reading will be the result. However, the mirror is very easily scratched and care must be taken when cleaning the mirror. Cleaning by means of aceton and instrument air is recommended.

Karl Fisher titration.

The Karl Fisher titration method has also been tested on Frigg. The experiences are that this method gives satisfactory results compared to the other methods. The Karl Fisher Titration which is tested on Frigg is based on the volumetric titration. This method is very time consuming and very flow dependent. If the Karl Fisher method is choosen, the coulometric titration principle should be used because this method is much faster than the volumetric method. As already mentioned, a portable version of this type is available but this does not have an Ex-certificate. The flow measurement is very critical for both methods and normally it is the largest source of error.

Automatic water dewpoint analyses.

The most difficult part of the water dewpoint monitoring has been to find an automatic water dewpoint analyser which can work under the Frigg process conditions. All of the automatic water dewpoint analysers available are more or less sensitive to glycol, deposits or hydrocarbon condensate poisoning, which are all present in the Frigg process.

Endress-Hauser WMY 370 automatic water dewpoint analyser was the first automatic analyser tested on Frigg. The Endress-Hauser utilizes the aluminium oxide sensor and measure the dewpoint under operating pressure. Fig.4 is a schematic recording of the installation. As can

been seen, the sample take off point is located just after the glycol dehydrator in a turbulent sone after a bend. A coalescer was installed to remove the liquids. The sampling line and the analyser cabinet was heated and insulated to avoid condensation of hydrocarbones and temperature variations. Although daily maintenance which included cleaning of sensor and the coalescer, the results never coincided with the manual readings over a longer period time. This system was also provided with a sample probe, but the location of it in a turbulent area after a bend, is not in accordance with good practice.

Next, a Shaw-SHA automatic water dewpoint analyser was tested. The Shaw-SHA analyser also utilizes the aluminium oxide sensor, but it is operated under atmosphere pressure. This means that the results has to be converted to operating pressure if the water dewpoint is wanted and that will increase the total uncertainty of the results due to the uncertainty of the converting methods which is available (6). The installation is shown schematically in Fig.5. The analyser did not give reliable results during the test. Similar to the Endress-Hauser, poisoning of the sensor by glycol and deposites gave faulse readings. The two Balston filters intalled upstream the sensor did not protect the sensor efficiently but acted instead as a increased storage for glycol, giving the known effects as increased response time and faulse readings.

In addition to the problems with the glycol and deposits, this installation had due to the pressure reduction of about 150 Bar upstream the sensor a severe condensation problem. The Baltston filter was filled with hydrocarbon condensate after a couple of hours.

The last automatic dewpoint analyser, Hygromat Modell 1100 from Hobre Instruments b.b., was installed a couple of months ago and is still beeing tested. The measuring principle is described in the chapter for Current Methods as the method utilizing the conductivity change in glycerol. The Hygromat Modell 1100 is operating at line pressure and there is no need of converting the water dewpoint. The cell temperature is manitained at 30° C by thermo-electric modules. The sensors are

identical and there is no need for recalibration when one cell is replaced by another. The sensor has normally to be replaced from two to four times a year. The reason for this is that the water which is absorbed into the glycerol normally will have a certain salt content and over a time periode the salt may be accumulated in the glycerol and cause a drift of the calibration curve.

A schematic recording of the installation is shown in Fig.6. The sample take off point is provided with a sample probe (Fig.1), located at the top of the pipeline. The sample line is made of non-hygroscopic stainless steel, heated by means of a self regulating heating tape and insulated. The water dewpoint analyser is located as close as possible and above the sampling probe without any U on the sampling line avoiding any accumulation of liquid. In order to reduce the effect of the Joule-Thomson cooling and reduce the hydrocarbon condensate build up in the flowmeter, the flow regulating valve is heated.

The analyser is located in a insulated stainless steel cabinet with an electric heater maintaining the temperature at 30°C.

The test during the first two months shows that the Hygromat Modell 1100 water dewpoint analyser is sensitive to glycol. However, foaming in the glycol towers with an increasing amount of glycol mist carried over in the gas has been a problem during these months. In spite of that, it has been possible to operate the analyser using a low flow through the sampling loope without any maintenance for a period up to three days. In addition the sensor can easily be cleaned by dry air. However, the results are not satisfactory, but without foaming this will most probably be better because the amount of glycol mist in the gas should decrease.

If it is not possible to increase the operating periode between the drying with instrument air, a liquid separator upstream the sensor will be tested. The two following methods described can be utilized without increasing the glycol accumulation too much. The first is a simple stainless steel Balston filter house (0,5cm^3) with a continuous drain of liquid at the bottom. The second method available is a temperature filter system. The gas is cooled by thermo-electric modules to a preset temperature and the liquid is continuously drained off.

Conclusion

* Optomat Ex which is a mirror type manual and portable water dewpoint analyser has been tested and found reliable for natural gas application. Glycol mist carried over from dehydration plaint and hydrocarbon condensate will cause problems if it is present in high consentration. Any manual mirror water dewpoint analyser must be operated by experienced technicians.

* The volumetric Karl Fisher method has also been tested and found useable for natural gas application. Glycol and liquid hydrocarbon do not interfere with the results. The volumetric Karl Fisher method is time consuming and if the Karl Fisher method shall be used the coulurmetric method is recommended. A portable version is available but this is not Ex-proof.

* Two automatic on-line water dewpoint analysers, Endress-Hauser WMY 370 and Hygromat Modell 1100, with an aluminium oxide sensor has been tested and found not useable in natural gas application downstream glycol dehydration towers. Filters and coalescers will not remove all glycol, hydrocarbon liquid and deposits present in the natural gas.

* A Hygromat Modell 1100 automatic on-line water dewpoint analyser has also been tested in natural gas under the same conditions. The analyser is found to be sensitive to glycol, but can be operated for a period of three days without maintenance even under a relatively high amount of glycol mist in the gas. The Hygromat Modell 1100 analyser can be cleaned by instrument air. The test is not completed, but the results so far are promising.

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FIG. 1 SAMPLING PROBE

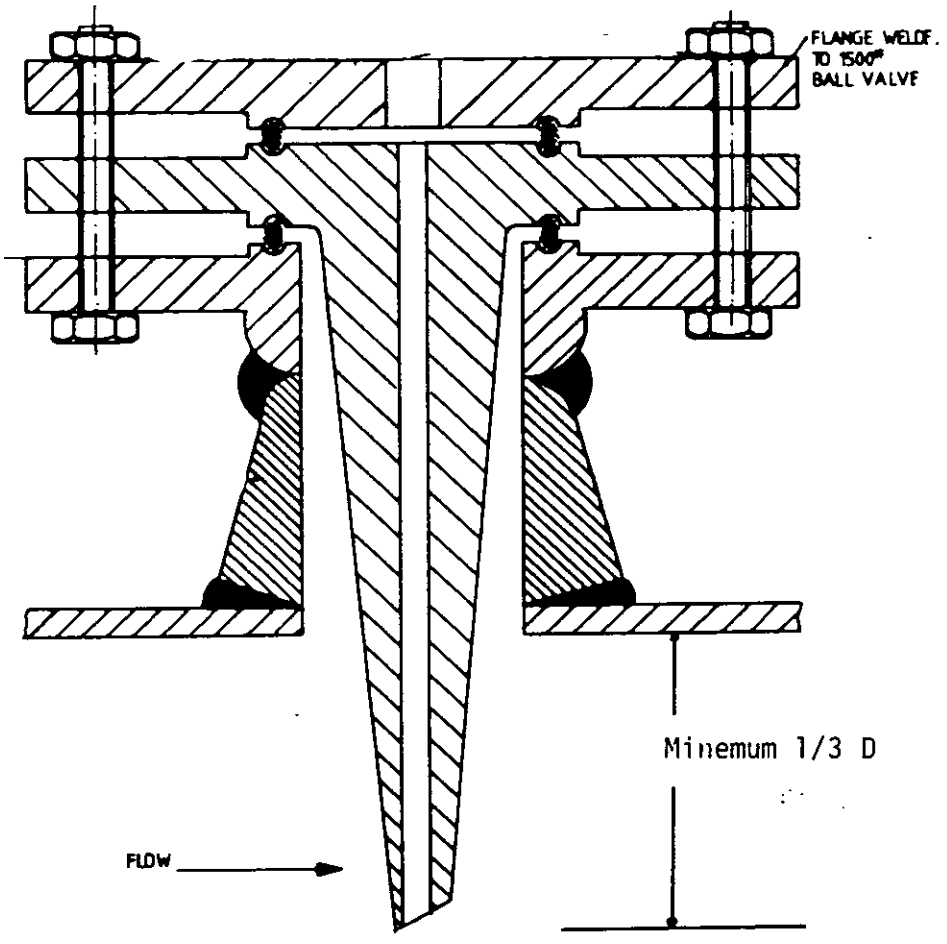
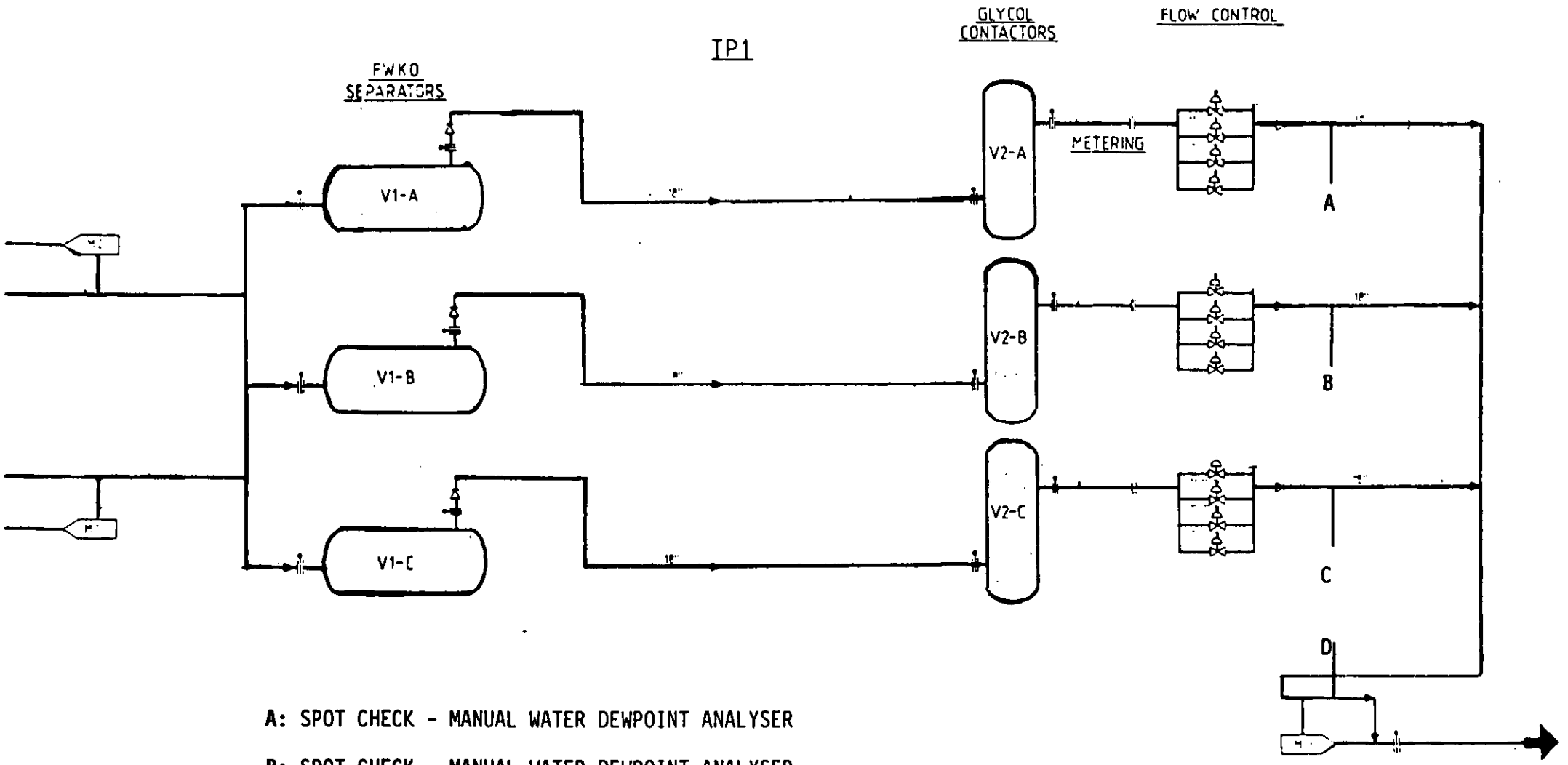


FIG. 2 FRIGG GAS PROCESS FLOW



A: SPOT CHECK - MANUAL WATER DEWPOINT ANALYSER

B: SPOT CHECK - MANUAL WATER DEWPOINT ANALYSER

C: SPOT CHECK - MANUAL WATER DEWPOINT ANALYSER

D: AUTOMATIC DEWPOINT ANALYSER

FIG. 3 BUREAU OF MINERS DEWPOINT TESTER CHANDLER ENGINEERING COMPANY

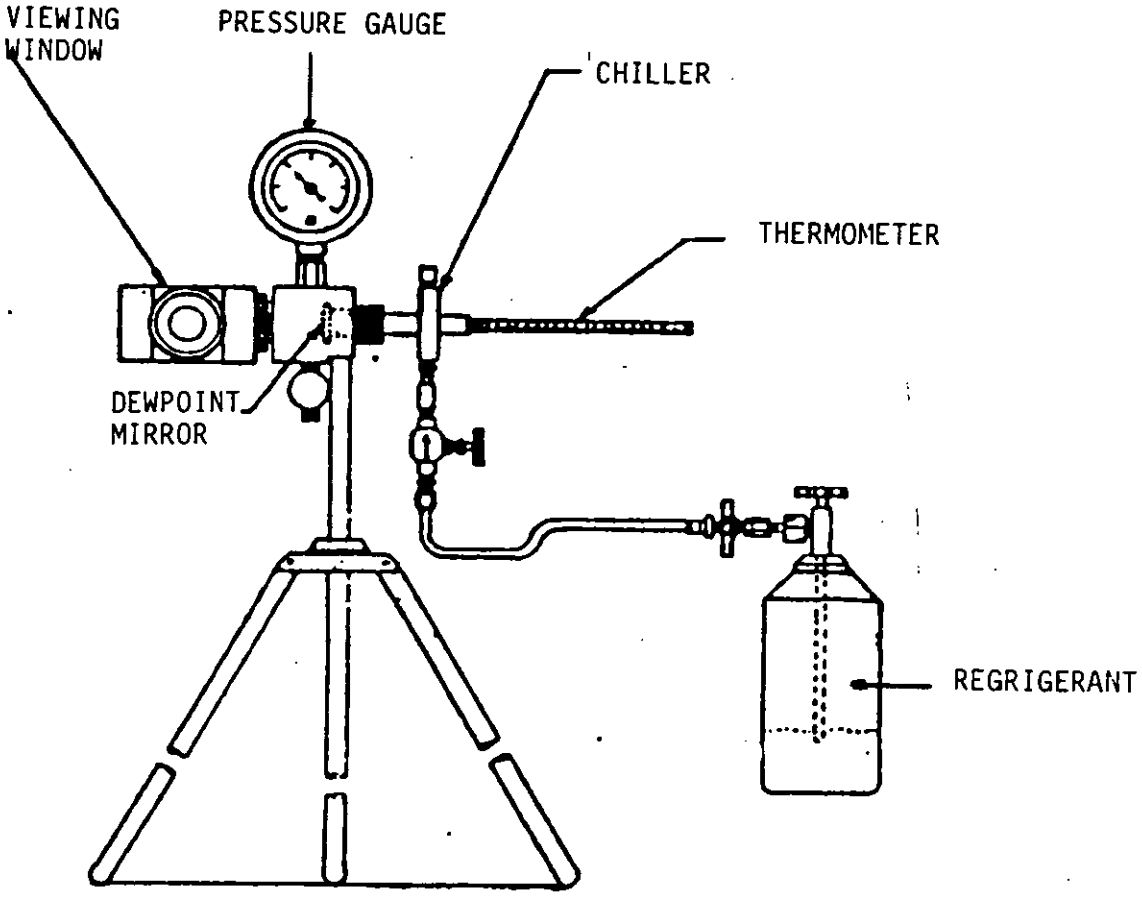
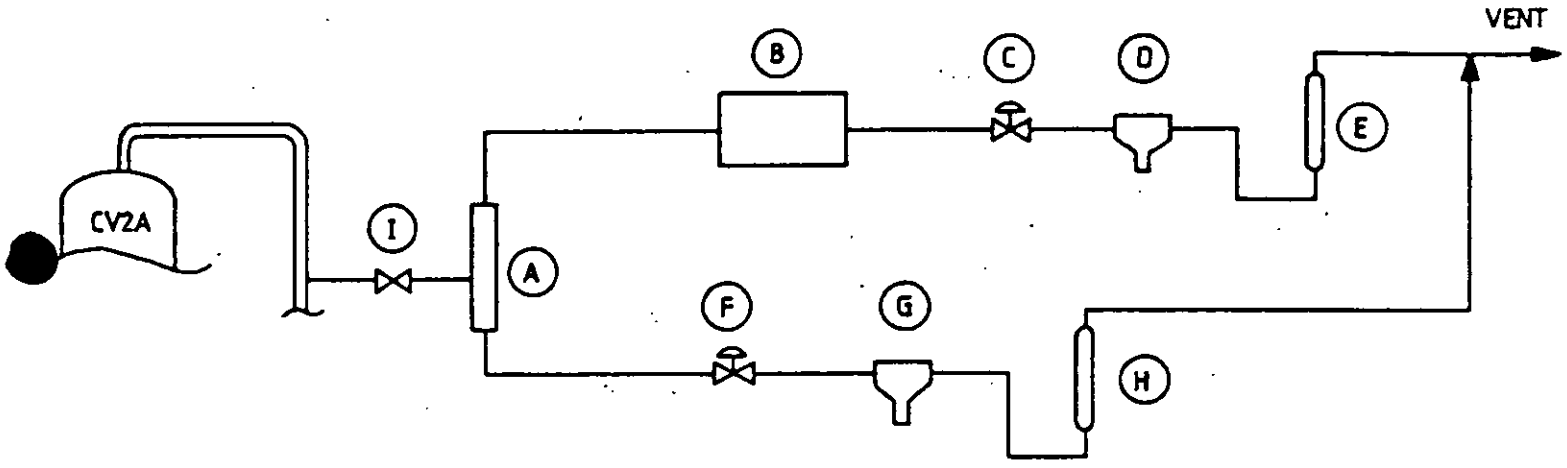


FIG. 4 ENDRESS-HAUSER WATER DEWPOINT ANALYSER INSTALLATION



(A) Coalescer

(B) Sensor

(C) Flow regulation valve

(D) Balston filter

(E) Flowmeter

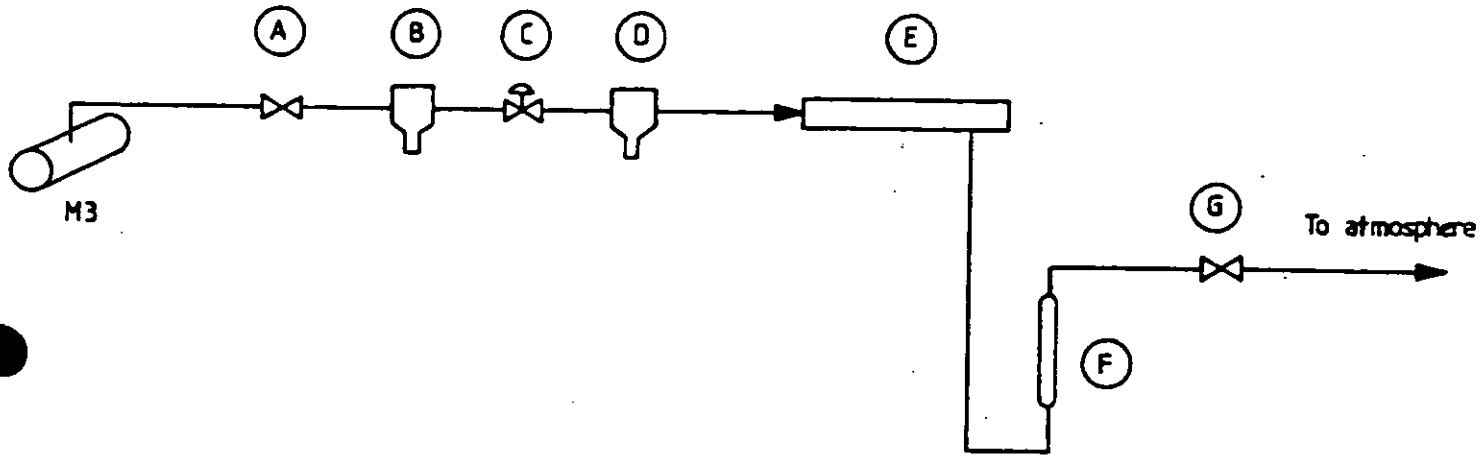
(F) Flow regulation valve

(G) Balston filter

(H) Flow meter

(I) Valve

FIG. 5 SHAW WATER DEWPOINT ANALYSER INSTALLATION



(A) Ball valve

(B) Balston filter

(C) Flow regulation valve

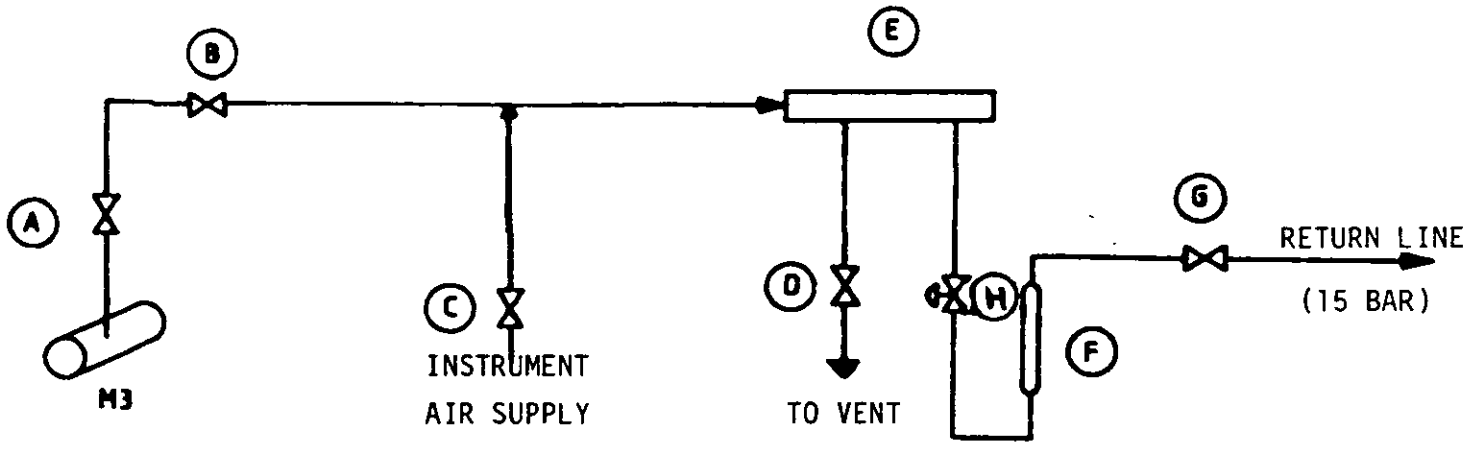
(D) Balston filter

(E) Sensor

(F) Flow meter

(G) Valve

FIG. 6. HYGRAMAT MODELL 1100 DEWPOINT ANALYSER INSTALLATION



(A) BALL VALVE

(B) BALL VALVE , INLET

(C) BALL VALVE

(D) BALL VALVE

(E) SENSOR

(F) FLOWMETER

(G) BALL VALVE, OUTLET

(H) FLOW REGULATION VALVE

Norske Sivilingeniørers Forening

NORTH SEA FLOW METERING WORKSHOP

Stavanger, 5 - 7 November 1985

On-line gas chromatograph

3. 7

Lecturer: Mr. Louis N. Cox
Daniel Industries Inc.

ON-LINE GAS CHROMATOGRAPH

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INTRODUCTION

Gas chromatography is a physical method of separation where the components to be separated are distributed between two phases - a stationary bed of large surface area, and a fluid that moves through the stationary bed. A gas or vaporized liquid mixture is physically separated into its individual components through this stationary bed.

HISTORY

Chromatography began in 1850 where F.F. Runge, a German chemist, demonstrated the Principle of Chromatography by observing the migration of inorganic cation through capillary porous material. Contributors through the years were recognized, D. T. Day 1900 (American) Tsweet 1903 (Russian), but modern chromatography began in 1952 by James and Martin (England) who developed gas-liquid partition chromatography.

KEY ELEMENTS IN A GAS CHROMATOGRAPH

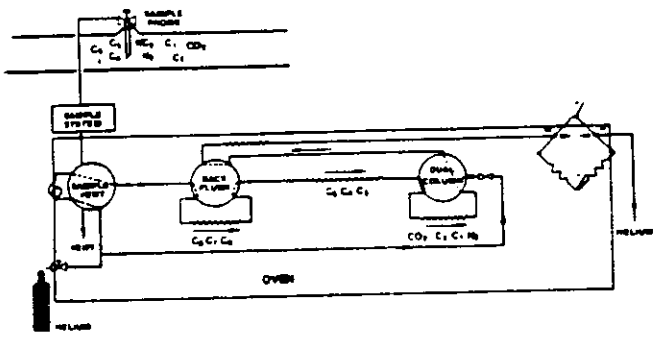

FIGURE #1

Sample Probe: To remove a representative sample from the process pipe. Usually 1/4" stainless steel tube extending into the pipe approximately one-third of the pipe diameter. A pressure regulator is used in conjunction with the probe to reduce line pressure to between 2 and 30 psi.

Sample Conditioning System for preparing the sample for injection into the chromatograph by filtering and regulating the sample.

Carrier Gas System to transport the sample through the columns and switching chromatograph valves.

Sample Valve for sizing and injecting the sample into the carrier gas ahead of the column.

Chromatographic Column - to separate the sample into individual componennts.

Chromatograph Oven - a temperature controlled chamber housing the sample valve, column and detector.

Detector - for detecting the eluted components in the carrier gas. The detectors are part of a Wheatstone bridge which provides an input into the controller.

Chromatograph Controller - for controlling the functions of the chromatograph and processing data.

Recorder and Printer - for recording the data.

HOW DOES THE CHROMATOGRAPH WORK?

The sample stream is continuously flowing from the sample probe through the sample conditioning system and to the sample valve. The sample loop is exhausted through the sample vent. The sample valve "fixes" the sample size for injection into the carrier gas for transport through the column across the detector and exits through the measured vent. The volume of the sample is determined by size and length of columns and volume of the detector assembly. Columns vary in size from 1/4" to 1/16" (micropacked, low volume). The speed of analysis is determined by the volume of sample and carrier velocity. As the sample is carried through the column by the carrier gas, the physical separation of the components occurs. Light molecular weight components will elute first, followed by heavier molecular components.

The components elute from the columns, pass across the measuring thermal conductivity detector where heat is removed in direct proportion to the thermal conductivity of the gas flowing across the element (Figure 2 T/C Detector). The thermal conductivity detector consists of two elements, typically a thermistor bead, two element bridge detector, measure and reference.

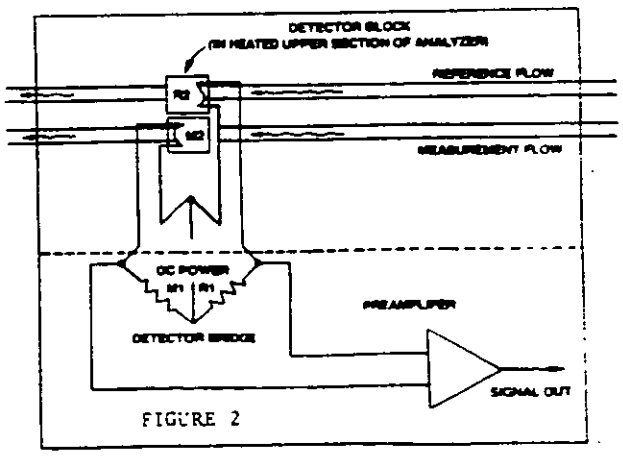

FIGURE 2

The reference detector typically measures zero grade helium. During the time no components are being measured, both detectors are measuring helium which results in a null signal or referred to as zero base line. As the components elute from the column, as mentioned, heat is removed causing an imbalance of current flowing through the detectors. This difference is amplified and used by the controller and recorder. The recorder produces a chromatogram which graphically displays each component. (Figure 3 Chromatograph)

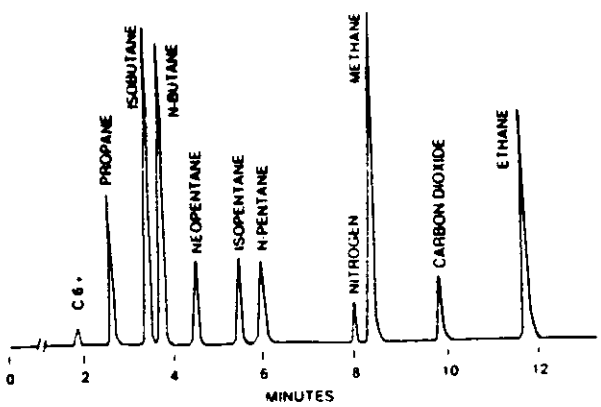

FIGURE 3

The microprocessor based controllers provide all control parameters for chromatograph, valve switching, stream selection, monitor oven temperatures and calculations. When natural gas is measured, the microprocessor calculates BTU, compressibility, specific gravity and Wobbe index if desired. Also, automatic calibration, analog and digital output to printer, recorder and host computer. Increased accuracy has been achieved in BTU measure, plus or minus 1/2 BTU in 1000.

The gas chromatograph, when properly applied, is rugged, reliable and accurate for a wide variety of applications for the gas and process industry.

Norske Sivilingeniørers Forening

NORTH SEA FLOW METERING WORKSHOP

Stavanger, 5 - 7 November 1985

Experience with gas chromatograph

3.2

Lecturer: Mr. Louis N. Cox
Daniel Industries Inc., USA

EXPERIENCE WITH GAS CHROMATOGRAPH

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METHODS AND PROBLEMS ASSOCIATED WITH ON-LINE CHROMATOGRAPHY

The on-line gas chromatographs available today are relatively maintenance free, due to a greater selection of separating column materials and advanced electronics - namely, the microprocessor based programmed controller. On-line chromatographs began with mechanical programmers which required continuous maintenance, but each generation of programmers has increased in reliability and accuracy, so that today's chromatographs can provide a BTU repeatability of ± .5 to 1 BTU/1000.

Installation of the chromatograph according to your manufacturer's recommendations is very essential.

A. Sample Probe

Should be installed one-third pipe diameter in the line. Pressure reduction, relief vent and sample line pressure gauge at the probe.

B. Sample Line

Sample line must not exceed 1/4", and should always be stainless steel tubing. If the sample line exceeds 50', reduce to 1/8" stainless steel tubing.

C. Installation

Install the chromatograph as near the sample point as possible. This will reduce transport problems. Some manufacturers state a temperature limit on their equipment, which may require some type of enclosure. If a temperature limit is not stated, install the chromatograph where morning or afternoon sun will not affect the chromatograph.

D. Calibration Gas

The calibration gas cylinder and gas are often not considered for ambient temperature limits. Special attention to the dew point of the gas must be given (low temperature). Consult your manufacturer for recommendations for calibration gas.

E. Liquid in Pipeline

If there is a possibility of liquid being carried through the pipeline (due to antifreeze operation, etc.), advise your manufacturer so filters or traps can be installed to collect this liquid.

F. Carrier Gas System

The carrier gas transports the sample through the chromatograph and, in some chromatographs, actuates the chromatograph valves. This eliminates the problems with compressed air.

Zero grade Helium (99.9999%) should be used for carrier gas. If zero grade is not available, chromatograph grade (99.95%) is acceptable.

The single most serious problem with the carrier gas system is changing the gas bottles. Dual gas bottle systems are available but most installations have one gas bottle with dual stage regulators. The objective is to keep air out of the system during bottle changes. Injection of air into the system plays havoc with the separation for several hours.

Install a tubing union and needle valve on outlet of dual state regulators. When changing bottles, close needle valve, trapping the Helium pressure in the chromatograph. Remove tubing union from regulator - remove regulator and install on full bottle, back off regulator pressure and place thumb over outlet, apply enough pressure so you can build up and release several times to "shake" the air from the regulator and gauges. Keep positive pressure on outlet, connect tubing union to regulator output, adjust to 100 Psi, open needle valve. The carrier gas bottle has been changed with no air entering the chromatograph.

If you do not know your supplier, as a safety precaution, installation of a carrier gas dryer might be advisable. These are available from your manufacturer.

G. Power Requirements

Power requirements vary with the manufacturer but are usually 120 VAC, 60 Hz, 150-200 watts. Areas that experience outages that cause nuisance shutdowns should consider uninterrupted power supply systems (UPS). Your manufacturer will have these available. If the microprocessor controller is mounted remote from the chromatograph, power must be on the same phase.

H. Chromatograph

The chromatograph contains the oven, separating columns, detector, valves, sample conditioning system and electronics, consisting of valve drivers, preamplifiers, decoder, temperature controller, etc.

Various manufacturers approach the component separation of C_1 - C_{6+} differently. Ideally, base line separation is desirable; i.e., each component returns to base line with no perpendicular drop or tangent skimming. The number of columns and chromatograph valves will determine the separation.

Figure 1 illustrates a one-column, one-valve separation for natural gas. The analysis time is extremely long (22 minutes). Also, due to diffusion in the column with time, the later eluting components will have very little detectability. Note: N_2, C_1, CO_2, C_2 not base line separated.

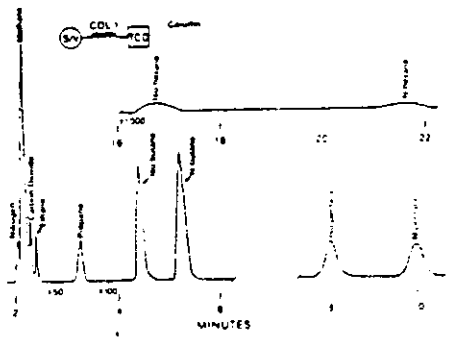

Figure 1

Figure 2 illustrates two-valve, two-column separation. The analysis time has been shortened; also, the sensitivity of the heavy components has been increased by grouping the C_{6+} components, the minimum detectable limit of the entire group becomes on the order of 20 parts per million.

Note: N_2, C_1, CO_2, C_2 are not base line separated.

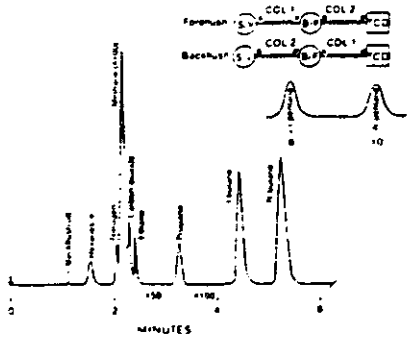

Figure 2

Figure 3 illustrates three-valve, three-column separation. The analysis time has been lengthened to twelve minutes but all components are base line separated for greater stability and accuracy.

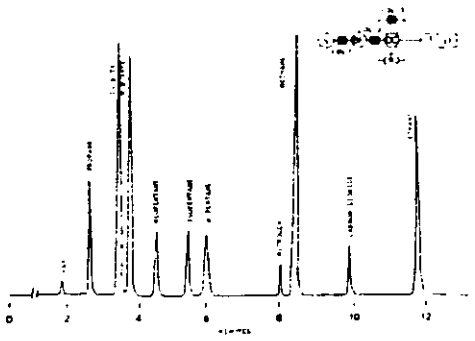

Figure 3

I. Detector

The thermal conducting detector is normally used for natural gas applications. Most manufacturers utilize the two element thermistor bead detector, which is rugged and long lasting. Loss of carrier gas does not destroy the detector.

J. Controller

The microprocessor-based controller controls the functions of the chromatograph: valve timing, peak identification, response factors, retention times, peak area or height measurement and computations. The microprocessor is an extremely reliable device and if left alone will operate for long periods of time.

There are various types of microprocessors available but all perform essentially the same functions. Most will self-check or troubleshoot all circuits and will alarm on a malfunction, indicating on a printer the the malfunction. Some features are:

1. Automatic calibration
2. 24-hour averages
3. Rolling averages
4. All component listing
5. BTU saturated or dry
6. Specific gracity
7. Compressibility
8. Long and short reports
9. RS-232 output
10. Analog outputs
11. Power failure - alarm - retain all data in memory via battery backup

K. Problems

Some problems can be readily identified with on-line chromatographs.

Sample conditioning system - A rotometer is installed on the inlet sample line with a needle valve. If the needle valve requires adjustment frequently to maintain the desired flow, indications are the in-line filter requires replacement.

Carrier gas regulator - If flow varies retention time will move, creating a retention time alarm.

Oven temperature varies - Increase in temperature decreases retention time about 5%/0° (temperature controller malfunction).

Sample size - A change in sample size will affect retention time. Check the sample valve for leaks, etc.

Prior to repairing a chromatograph, always run a chromatogram on the chart recorder. The chromatogram will indicate what is going on inside the chromatograph.

Conclusion

On-line chromatography is the most accurate, reliable device for component measurement on the market. Repeatability of BTU calculations are now as low as ± .5 BTU/1000 over a wide temperature span. You must be familiar with electronics and chromatography to fully understand the principle of measurement. The gas industry is rapidly becoming "high tech". Your manufacturers offer excellent training schools on their products. Take advantage of the opportunity to move into the "high tech" area of your company.

Norske Sivilingeniørers Forening
Norwegian Society of Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Stavanger, 5 - 7 November 1985

A comparison of the performance og in-line and bypass type sampling devices in the BP Rotterdam tests

3.3

Lecturers: Mr. R. C. Gold and
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BP International

1. SUMMARY

Trials have been carried out on a 48 inch crude oil transfer line at BP's Rotterdam Refinery to assess the performance of two versions of a new type of automatic grab sampler. One was mounted directly in the pipeline and the other in a pumped bypass loop. Also on trial were a new trash-resistant insertion flow meter and a continuous water content monitor.

Most of the tests were made on tank to tank transfers with injected sea water mixed by natural turbulence. Good water distribution was achieved but the water droplet size may have been larger than would be expected with a pipeline mixer.

Our principal finding was that the bypass sampler takes a representative sample for water content whereas the in-line sampler water content was low by about 5% relative. Our finding probably represents the worst case situation for operational installations: with more efficient mixing the difference could be less than 5% relative.

Both samplers proved reliable over the relatively short test period, operating on viscous crudes without tracing or lagging and below 0°C ambient. The Maurer 'Cruflo', turbine meter was trash resistant and is suitable for pacing samplers. Testing the need for isokinetic flow into the bypass loop gave pointers to the best method of loop operation but more work is needed before drawing firm conclusions.

The paper includes a description of a complete crude oil sampling package, which we have recommended for BP Group applications.

2. INTRODUCTION

The economic importance of accurately determining the water content of crude oil transfers is now well accepted, both for tanker discharges and for platform exports. Because there is as yet no proven accredited method for on-line continuous water determination, the present universally accepted procedure is to use automatic flow proportioned sampling, followed by a laboratory analytical test. In this procedure the representativity of the sample is obviously of critical importance.

Two aspects of automatic sampler performance have seriously concerned operators in recent years.

1) the ability of the sampler to take a properly representative sample
2) the reliability of the sampling equipment

Because of BP's widespread involvement in commercial crude oil transactions our Central Engineering Department have played a leading role in the development of sampling equipment over recent years.

The culmination of our work has been the development of the BP Grab Sampler, which is now made under licence and marketed by Jiskoot Autocontrol Limited and by Maurer Instruments Limited.

In 1984, the results of work in a small bore pipework test rig using kerosine and water by the National Engineering Laboratory, suggested that there could be differences between the water content of samples taken by an "in the line" grab sampler and by one installed in a bypass loop. Prompted by this, we designed a programme of field trials to try to determine which sampling installation gave the most representative results. Our intention was to establish the optimum crude oil sampling package, to be recommended for use by BP associate companies worldwide. So that the specification would be complete the trials were extended to include an evaluation of alternative flow metering devices suitable for crude oil sampler pacing. Also included in the trial installation was a continuous capacitance cell water content monitor. Although part of a separate evaluation project, information from this proved to be useful in evaluating sampler performance.

This paper presents the trial results.

3. MAIN OBJECTIVES

The main objectives of the field trials were:

1. To compare the representativity of samples taken by a grab sampler in a bypass loop, with those taken by a grab sampler in the main pipeline.

2. To monitor the mechanical reliability of the new Maurer grab sampler. The reliability of the Jiskoot Series 200 sampler had already been proven through use at other BP locations

3. To investigate the accuracy and reliability on crude oil of a trash resistant insertion turbine meter. (Reliable flow measurement is essential for the purpose of pacing a flow proportional automatic sampler.)

4. To investigate the performance under process conditions of a low pressure capacitance monitor and to assess its potential for continuous measurement of the water content of crude oil.

5. To compare the results from the alternative methods of water determination listed above i.e. automatic in-line and bypass loop samplers and continuous measurement using a capacitance cell.

6. To test the representativity of the system measurements using the water injection procedures recommended in ISO/DIS 3171.

7. In addition, profile testing was to be carried out at the chosen location to test for homogeneity of the line contents at the test conditions. These tests were also used to assist in verifying the theoretical prediction techniques being developed for determining homogeneity.

The basis for these objectives was as follows:

Objective 1 Because of the poor reliability record of so called fast loop type samplers, BP has in recent years favoured the use of automatic grab samplers.

Since the original BP patent for the grab sampler was filed in 1979, several different models have evolved. In most cases the difference has been only in the driving mechanism i.e. pneumatic/electric. However an important fundamental difference with later models is between the in-line and bypass or cell sampler. The original in-line sampler is installed directly into the process pipeline, whereas the cell or bypass sampler is installed in a pumped bypass loop, typically of 1" N.B.

The bypass loop sampler evolved mainly because of early problems associated with installing a sampler directly into a high pressure line. To resolve this, the recommendation within BP before these trials was to fit an in-line sampler for low pressure applications, and a bypass sampler for high pressure duty. Because the sampler in a bypass loop is sub-sampling a great deal of design effort was put into ensuring the representativity of this operation. To help ensure representativity the sampler is always placed after the bypass loop pump to ensure good water dispersion. In addition the sampler is fitted with a long upstream entry port to ensure that the severe bluff body effects of the capture tube have no influence on the sample entering the capture chamber. The in-line sampler also has an extended entry port, but because of the necessity for live line insertion through a valve its length has to be restricted. In practice it is only about 25% of the bypass sampler entry tube. Despite these significant changes in design concept no direct tests had ever been made to confirm the efficiency/representativity of either type of sampler. Comparative trials were therefore decided upon. For these it was imperative that both sampler mechanisms were identical as far as practicable, and that their primary sample offtakes should be from the same general area of the main pipeline (to negate any small differences in homogeneity). They should also be powered from the same controller.

Objective 2 Following an agreement with Maurer Instruments to manufacture grab samplers based on the BP patent, it was decided to use the opportunity presented by these trials to test the performance and reliability of their first production models.

Objective 3 The provision of a simple, cheap and reliable flow meter for sampler pacing has always been a problem, particularly for tanker discharges. The problems arise because of the comparatively large diameter lines, the presence of trash, and the need to retrofit. Work had previously been carried out within BP using a clamp-on type Doppler ultrasonic flowmeter with gas injection to provide the necessary phase discontinuities. Also we were aware that an American company were offering a large diameter insertion turbine meter for this duty. At first sight, this seemed to offer an equally attractive solution to the problem. However, on closer investigation we identified potential problems with the removal of the turbine blade from the pipeline in the event of its jamming. This possibility, coupled with a general feeling that a suitably designed conventional insertion type turbine meter could give satisfactory performance, led us to specify our own improved design of turbine meter. We felt that our design concept could have significant advantages over the two other possibilities.

Objective 4 The potential advantages of direct water in oil measurement are obvious and the proposed work constituted the first BP field trials of the Endress and Hauser on-line monitoring device known as the 'Aquasyst'. The capacitance monitor trials are not yet complete but the results to date, which have a direct bearing on the trials of the sampling equipment, are reported in this paper.

Objective 5 It was planned to compare the three methods of water determination; samplers, both in-line and in the bypass loop, and the capacitance system, against the actual water content calculated from the flows during tank to tank transfers.

Objective 6 and 7 The new draft ISO/DIS (Petroleum Liquids Automatic Pipeline Sampling) describes a water injection procedure for proving sampling systems without the need for profile testing. The objective was to test the method for its effectiveness, but also to use profile testing for added information.

Additional Objective In the course of the trials, evidence was obtained which indicated that the bypass loop sampler gave the most accurate results. It was then seen to be important to investigate the need for operating the bypass loop at isokinetic flow rates, as advocated in previously published literature. The advantage of not running at isokinetic flow rate are that the loop flow control system can be dispensed with and that, if a lower than maximum isokinetic flow rate can be tolerated, a smaller bypass loop pump can be used.

4. NEW DEVELOPMENTS

The equipment actually used in the Rotterdam trials was in all cases except one, the first production model. The exception was the Endress & Hauser continuous water monitor, and even for this, the trial was its first BP use in 'real' circumstances. Some background to the new developments may be of interest.

4.1 Samplers

Because of the importance of automatic sampling for accurate crude oil measurement BP have felt it necessary to have alternative manufacturing sources for the sampling equipment in order to protect our supply position.

To this end in early 1984 a specification was drawn up and detailed discussions conducted with Maurer Instruments Limited (the successful developer and manufacturer under BP licence of the PIM (Piston Internal Mixing) Sample Cylinder). This company agreed to produce an alternative grab sampler design, and to manufacture samplers to meet our immediate requirements. A particular advantage resulting from commissioning the design of a new grab sampler at this time, was that data obtained by the National Engineering Laboratory, in the course of their automatic sampler study project, could be incorporated into the new design.

4.2 Flowmeter

We felt an American design for a trash resistant flowmeter had good potential, but we later had serious reservations about the possibility of the single large rotor blade jamming across the entry tapping. In addition, the device on offer was not designed to conform to European electrical safety certification requirements.

Because of these potential problems it was decided to commission the design and supply of a special trash resistant insertion flowmeter for crude oil sampler pacing:-

The design criteria for this included:

a) As large a diameter rotor as possible
b) No shrouding
c) The rotor supported in such a way that trash could not collect on a support and impinge into the rotor
d) As wide a flow turn down as possible but to be capable of metering at 0.3 m/sec.

Maurer Instruments Limited agreed to develop and produce an instrument to meet this outline specification.

The meter resulting from the Maurer development is shown in Figure 1. The main points are that it will insert through a 6" hot tapping (live line insertion), has no shrouding, has large diameter bearings and the rotor is only supported from the rear.

4.3 Continuous Water in Oil Monitor

The potential advantages of accurate continuous water in oil measurement are obvious. Since 1979 BP has been studying the capacitance technique in the belief that it can be developed to measure water in crude oils on-line in the fiscal context. In collaboration with Endress & Hauser this work has progressed to the point where an instrument, the Aquasyst, is now commercially available. The Rotterdam trials provided the first opportunity to fit the new instrument into a real on-line monitoring system.

The full development of this instrument was described in last year's North Sea Flow Metering Workshop in Glasgow in a paper presented by Messrs. M.B. Wilson and B.O. Richards, our colleagues in BP Central Engineering Department.

5. SITE TRIALS

5.1 Site Equipment

The field equipment was installed as shown in Figure 2. The 48" No. 1 header can be used for imports from either No. 1 or No. 2 jetty to the Entrepôt. The selected position covered some 70% of the crude imports to our refinery at Rotterdam. The entry nozzle to the in-line sampler, and to the bypass loop scoop were within 2" to 3" of each other, on the same plane in the pipeline. This was so that, should the line contents not be completely homogeneous, the sample presented to each sampler was likely to be almost identical and the comparison between in-line sampler and the bypass sampler results would still be valid.

The multi-entry probe for testing the cross pipe water profile could not be fitted in the same plane as the samplers because of limited space. However its position was only 12" upstream of the sampler entries. All of the equipment, except the profile test probe, was designed so that it could be fitted into the pressurised line.

The sampler controller used for the trials was an available Jiskoot type HSC3 controller modified for grab sampler duty. Despite limitations in its range of parcel size settings it served its purpose well.

5.2 Test Modes

The testing was carried out in two basic modes.

a) Tanker Discharge - with both samplers and the flowmeter working normally.
N.B. Under these conditions we were unable to perform successful profile testing because the low line pressures were not adequate to overcome the pressure drop in the profiling test system.

b) Tank to Tank Transfers. In this mode the base water content of the crude could be measured and additional water injected. Sea water from the fire main was injected into the No. 3 header approximately 57 metres from the sampling location, equivalent to a volume of approx. 21 m^3 (Figure 2). Mixing was caused by the jetting action of the water entering the line, and subsequently enhanced by downstream turbulance created by four blind tees, two valves and four bends. The actual percentage water added to the oil was calculated from measurements derived from a 2½" Fisher turbine meter in the water injection system, and the change in tank dips over periods of steady flow. We estimated the overall uncertainty of this procedure to be ±0.5% of water content. Because there were no outside influences (i.e. from the ship) the flow rates could be held constant throughout each trial period.

The main drawback with measuring water in the tank to tank transfer mode was that the crude oil/water mixture downstream of the injection point did not pass through a pump before reaching the sampling point. Hence it could be postulated that the water droplet size might be larger than would normally be expected in tanker discharges when the oil and water will usually experience considerable mixing and break up due to the action of the ships pumps. Nevertheless, the majority of the test results reported here were obtained in tank to tank transfers because this allowed repeated small (300 ml) samples to be drawn by the samplers, all under steady state conditions.

In all, 6 tanker discharges were monitored and 4 tank to tank transfers. The 4 transfers covered 24 separate runs with main line flows varying from 0.3 m/s to 0.9 m/s and with water contents from 1.44% to 3.82%. However not all runs were under homogeneous conditions.

6. RESULTS AND FINDINGS

6.1 Water Concentration Profile Tests

Water profile tests were carried out at the sampling location for two purposes.

1) To confirm the uniformity of water distribution under the test conditions used during the sampler trials.

2) To test the practicability of the procedures recommended in ISO/DIS 3171. This work was the subject of another project and is not discussed in this paper.

In brief it was concluded that, with Iranian Heavy crude with a water content up to 3%, the contents of the 48" pipeline at the sampler location were homogeneous at line velocities above 0.6 m/s, and non-homogeneous at velocities below 0.3 m/s. Therefore, in later transfers when profiling was not performed, Iranian heavy crude was always moved at velocities above 0.6 m/s.

6.2 Samplers

Both samplers operated faultlessly throughout the trials. They needed no attention from the moment they left the factory in the UK until the trial work finished - not even requiring setting up on installation. In our opinion this was a very encouraging introduction for newly developed equipment.

The tests to compare the accuracy of the in-line sampler against the bypass sampler produced 24 sets of results from tank to tank transfers and 6 sets of results from tanker discharges. Of the transfer results 8 were taken under non-homogeneous conditions. The results are presented in Table 1. The graphs plotted from these results (Fig. 3 and Fig. 4) show quite clearly that the water content of the samples taken by the in-line sampler are lower than those taken by the bypass sampler by around 5% relative i.e. 0.15% water at the 3% level. The graphs also show how closely the bypass sampler results agreed with the actual water content calculated from the tank level change and the water flowmeter reading. The uncertainty limits of this procedure are also shown on the graph. In addition, from the table of results it can be seen that the bypass sampler water content also agrees very closely with the water content measured at the centre point of the profile probe. Statistical analysis shows no significant difference between the actual and bypass water contents. One standard deviation is equivalent to 0.025% water. This compares with the laboratory test (IP 356) repeatability and reproducibility, quoted as 0.03% and 0.09% water respectively at the mid range water content used in the tests.

The reason for the differences in water content between the two samplers may, in part, be due to the probability that, in the tank to tank transfers, the droplet size may be larger than normal because no pump is used. The entrance to the bypass sampler fast loop system is a 1½" diameter pipe placed within the 48" main line, whereas the in-line sampler probe presents an entry port of ¾" x 3/8" to the sample. The probe entry area ratio is thus 10:1. This large difference can be expected to be significant in terms of the probes' ability to receive large water droplets. Also, although the in-line sampler has an extended entry port in front of it, bluff body effects may still have some effect. Bluff body effects on the bypass sampler are likely to be significantly less because of the longer extended entry port; 6" compared with 1½" on the in-line sampler. Another important aspect of the bypass system is that the pump will significantly increase the dispersion of the water before the flow reaches the samplers' entry port.

However, in three of the six tanker discharges monitored, the in-line sampler gave the higher water content (Table 2). There is no obvious explanation for this, but the answer may be in the condition of the sample containers used. Some of these are known to have internal rust spots which may have prevented complete laboratory mixing of the water into the oil. During the tank to tank tests new 500 cc plastic containers were used.

It is appreciated that during tank to tank transfers the water breakup would have been limited so that the dispersion may represent worst case conditions. However it must be accepted that these conditions can occur in some real life tanker discharges. Therefore if there is any doubt about water dispersion, an automatic sampling system should be designed to suit this worst case.

Consequently our recommendation to BP companies is to use bypass samplers. This view is reinforced by the possibility that, because of the general trash known to be carried in crude oil imports, the entry port to an in-line sampler could block, without any obvious evidence of this occurrence outside the line. This is because the sampler would still operate, but with the sample drawn back through the exit port. In these circumstances the water content of the resultant sample would almost certainly be low. The danger of entry port blockage does not occur with bypass samplers because a coarse strainer can be fitted into the fast loop to prevent fouling, with an optional differential pressure measurement to give warning should the strainer start to clog.

6.3 Fast Loop Flow Rate

Having concluded that the bypass sampler gave the most representative water contents results, it was then considered important to determine the real need to run the bypass loop at isokinetic flow rates. Previous published work has emphasised the importance of isokineticism but the practical difficulties and cost of achieving this in real sampling applications made it important to examine whether it has any significant effect on sampling accuracy.

A major difficulty is in defining exactly what the isokinetic velocities are at the point of sample extraction. It is generally assumed for the purpose of isokinetic sampling that the average line velocity will be applicable at the sampling point, but at a typical sampling location a stable velocity profile may not have been established. Therefore the magnitude and direction of the flow at a particular point are uncertain, especially at the lower flow rates.

During our own work in commissioning the system at Rotterdam at flows equivalent to isokinentic and above, we had observed that changing the flow rate had no obvious effect on the on-line water monitor reading. This cast doubts on the need for flow control. Confirmation of this would yield obvious advantages i.e. there would be no need for the complication of flow control equipment, and, if sub-isokineticism were acceptable, a smaller bypass loop pump could be used. Tests were therefore performed to determine the effects of varying the bypass loop flow rate. (Table 3). Although the tests showed possible pointers to the best method of bypass loop operation, the results were not completely satisfying. Further work is necessary to be absolutely sure.

Figure 5 shows the results of three runs with Iranian Heavy Crude in which the main line flow conditions were held constant and the bypass loop flow rate varied from 25% isokinetic flow to 4 times isokinetic flow. Manual samples were taken from the bypass loop, and the bypass sampler operated for only two of the three runs. The graphs suggest that above a certain minimum flow rate, the resultant sample water content does not vary. In a preliminary test, the fast loop flow rate was raised to 9 times the isokinetic rate, and a similar result was obtained. The unsatisfying aspect of these tests is the way in which the capacitance cell readings differed from the manual samples. Even so, a constant signal output is still seen at above the same flow rate of approximately 1 m/s. How much these thresholds are affected by the crude oil type, the water content and the physical design of the fast loop has still to be determined.

However, we feel that eventually it will be possible to design fast loops to run at 50% of the isokinetic flow rate of the maximum flow expected in the main oil line. Assuming a 20:1 flow turn down, loop flow rates will then be about 10 times isokinetic at the minimum main line flow rate. In the short term however, because there is still contention about the case for isokinetic sampling, our recommended sampling package shown in Figure 7 does include flow control. We have recommended that the whole question of isokinetic sampling should be investigated further because of the obvious advantages of not having to flow control the bypass loop. This work is now in hand at Rotterdam.

6.4 Maurer Flowmeter

This flowmeter has been installed in the 48" line since October 1984, without fouling. The flowmeter has been removed from the line for inspection at regular intervals and the rotor has always been found to be completely clean and free spinning. On one occasion a strand of thread was seen on the support stem but, because of the special design of the flowmeter, this had no influence on its operation. There is positive evidence that trash has been present in the main line because it has been picked up by the bypass loop scoop and caused blockage problems in the bypass loop turbine flow meter. In several instances the debris has been reminiscent of the contents of a hay stack.

Because of electrical noise on the flowmeter signal this was averaged by the computer before being fed to the flow recorder. However the signal fed to the sampler controller was in the raw state.

The original flow rangeability specification for the flowmeter was 0.3 m/s to 5 m/s. This range was easily met. (Test certificate, Fig. 6). However, because the meter was installed on the 48" line, which is capable of accepting flow from two of the 30" jetty lines, there were periods when the main line flow was less than 0.3 m/s. Under these circumstances the output from the flowmeter decreased to zero. Tests with an oscilloscope showed that the rotor was still turning, but that its output was lost in signal noise. This evidence was presented to the flowmeter manufacturer who is now investigating the possibility of metering at a lower velocity while still retaining the trash resistant design.

6.5 Capacitance Water Monitor

The Endress and Hauser Aquasyst capacitance water monitor operated successfully in the fast loop for the duration of the trial. It was found to be very useful in setting up the test conditions and for observing the water peaks as they occurred. However, to ensure that all calibration data has the same basis, all trial results have been referred back to laboratory testing using the Karl Fischer technique.

7. RECOMMENDATIONS

7.1 Further Work

Although the results of the work to date indicated that flow rate control may be unnecessary, this conclusion has been based on limited tests. It was therefore considered to be advantageous to pursue the investigation further while the facilities are still available at our Rotterdam Refinery. Consequently additional tests have now been arranged with the assistance of the National Engineering Laboratory. The involvement of an independent body was thought to be necessary because the evidence we have at present is at variance with the literature and with the conclusions of the other major oil companies. It is important that BP's final sampling package has the broad acceptance of other oil companies so that eventually we can all have similar systems. This will hopefully help towards resolving disputes.

7.2 Sampling Package

The objective of all of BP's work on automatic sampling over the last few years has been to put us in a position to recommend a definitive total sampling package. We consider now that we are in a position to do this. Figure 7 shows diagrammatically our recommended scheme. It comprises the following components -

7.2.1 Pipeline Mixing

In any sampling system the first consideration must be to ensure that the water and oil are mixed homogeneously. While, at many sites this may occur naturally due to pipework configurations and/or pumps, there may be applications when the line contents are not always homogeneous, possibly due to low flow rates.

In applications where homogeneity is in doubt some form of artificial mixing is required. Previous work has shown that mixing by jet injection is highly efficient. Therefore a proprietary jet mixing system has been recommended.

The jet mix system now supplied by Jiskoot Autocontrol Limited uses the internal jet design recommended as a result of BP's work at Finnart. Several such systems have been purchased by companies outside of BP and are said to be in successful operation. For applications where mixing is only necessary at low flow rates the main line flowmeter can be used to control the jetting pump.

7.2.2 Bypass Loop System

The bypass loop system is shown with its entry through a Maurer scoop tube. This would be sized either with 1½" or 1" entry diameter, depending upon line and pump size. It can be supplied for live line entry. A coarse strainer should be fitted in the loop upstream of the pump to prevent trash being carried forward to the sampler and the fast loop flowmeter. The strainer may be a dual arrangement, or fitted with a differential pressure measurement to give early warning of fouling due to debris.

Because the theory that isokinetic flow control is unnecessary has not yet been fully proven, we are recommending a simple flow control system. The set point value will be cascaded from the main line flowmeter. To meet the requirement of isokinetic flow at all main line flow rates, the pump will be sized to ensure that the velocity at the inlet scoop tube is equal to the maximum expected main line velocity. If it can be shown eventually that fast loop flow control is not necessary, the size of the pump can be halved (para 6.3.).

7.2.3 Sampler

Grab samplers of the BP design are manufactured by Jiskoot Autocontrol Ltd. and Maurer Instruments Ltd. The instruments used in the trials reported here were made by Maurer and incorporate design changes arising from the latest results of the NEL Sampling Project.

The sample collection system is very much 'user's choice', and will depend on the application. However it is important that a relief valve is fitted after the sampler to protect it from the very high pressures which can be generated by it if it is operated against a shut off sample collection system.

7.2.4 Controller

At the moment there are at least four models of sampler controller available for safe area locations, all of which are in service with various users. It is expected SIRA will carry out an evaluation of these four models.

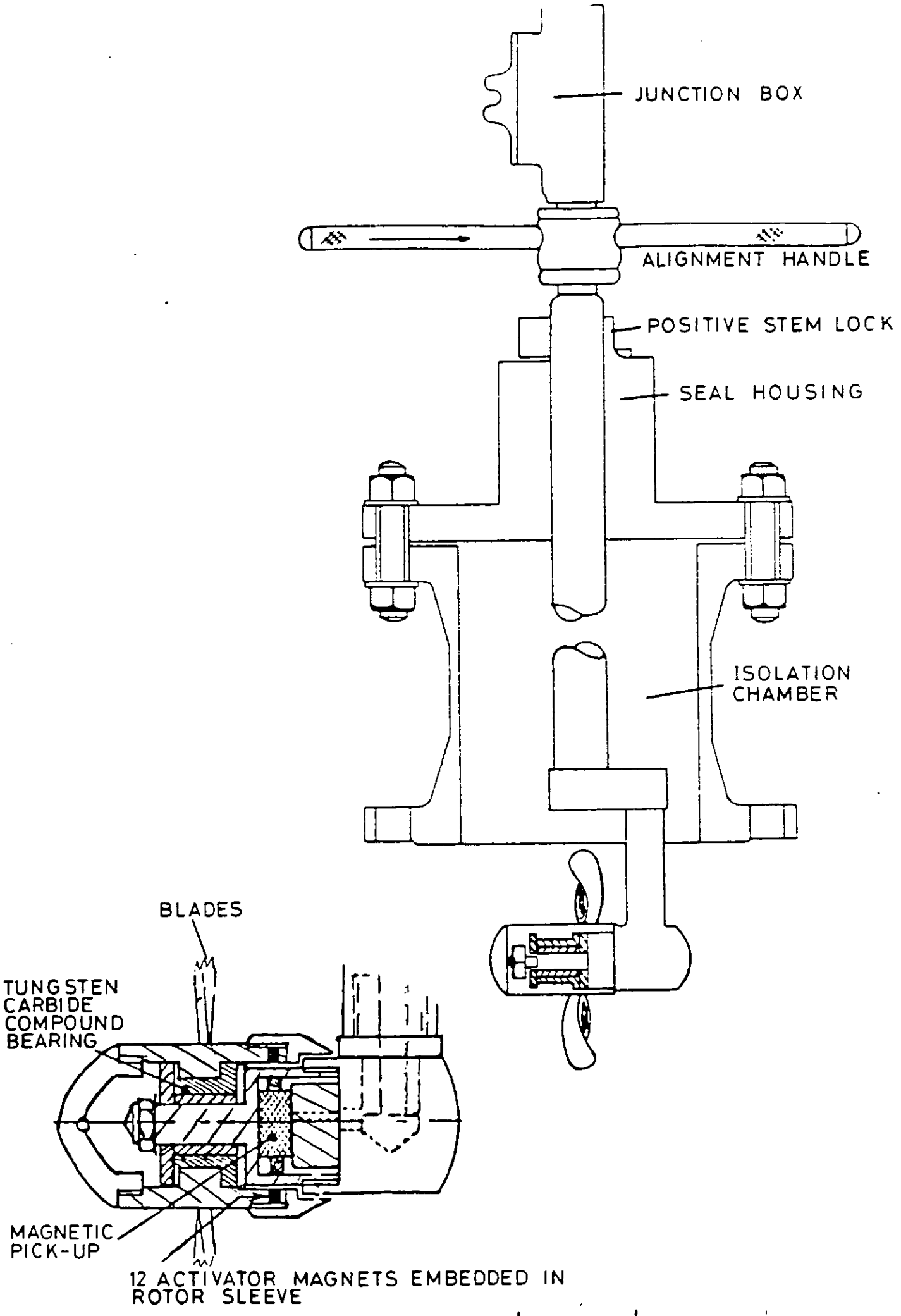
For applications requiring an explosion proof controller the choice is somewhat more limited.

7.2.5 Flowmeter

The main oil line flowmeter described in this paper and recommended for BP systems is the Maurer Cruflo. It can be live line fitted through a 6" hot tap. N.B. the trepanned hole must be at least 148 mm diameter.

8. ACKNOWLEDGEMENT

Permission to publish this paper has been given by The British Petroleum Company PLC.



MAURER FLOW METER 'CRUFLO'

FIG. 1

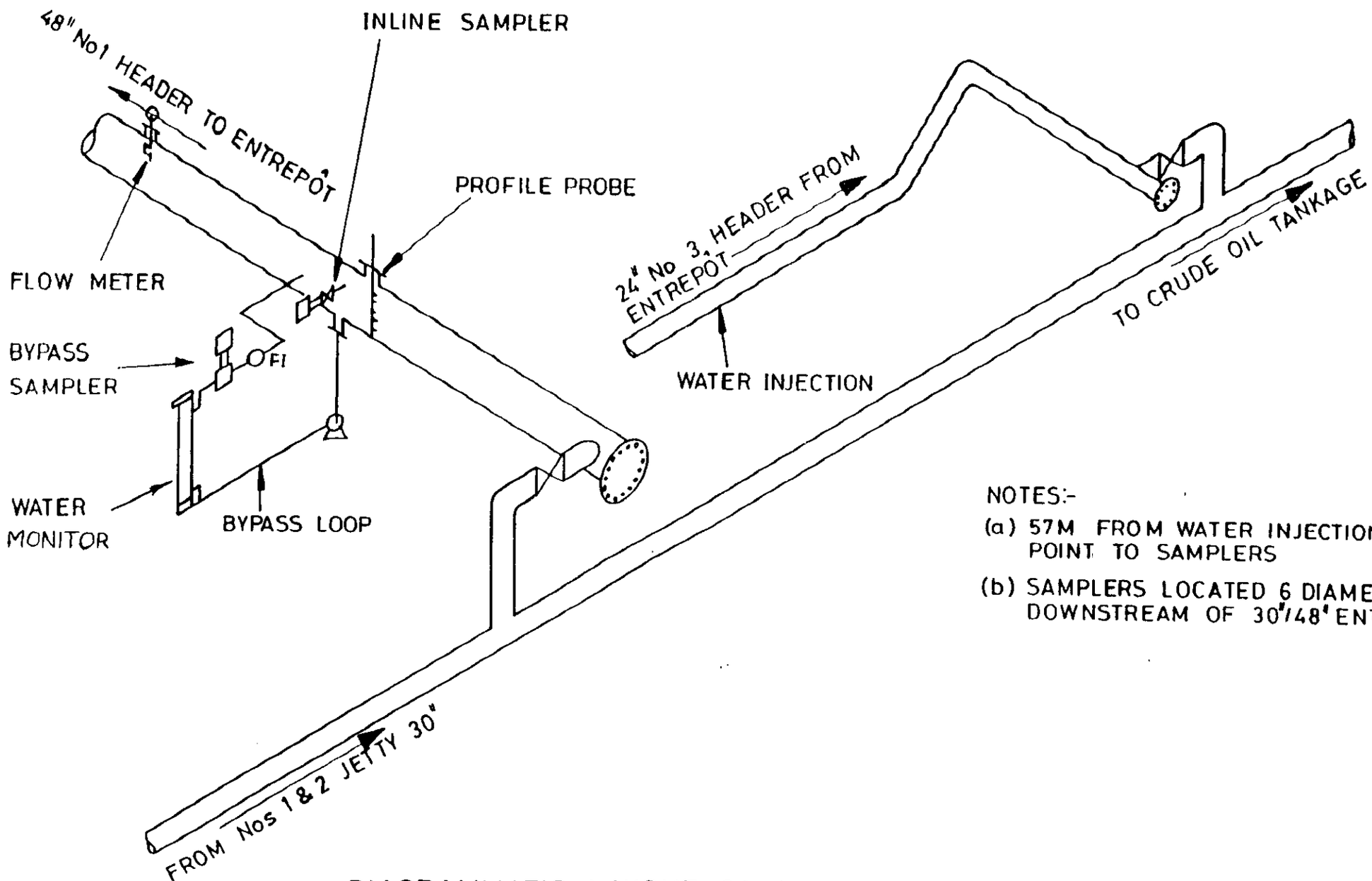


FIG. 2

DIAGRAMMATIC LAYOUT OF FIELD EQUIPMENT

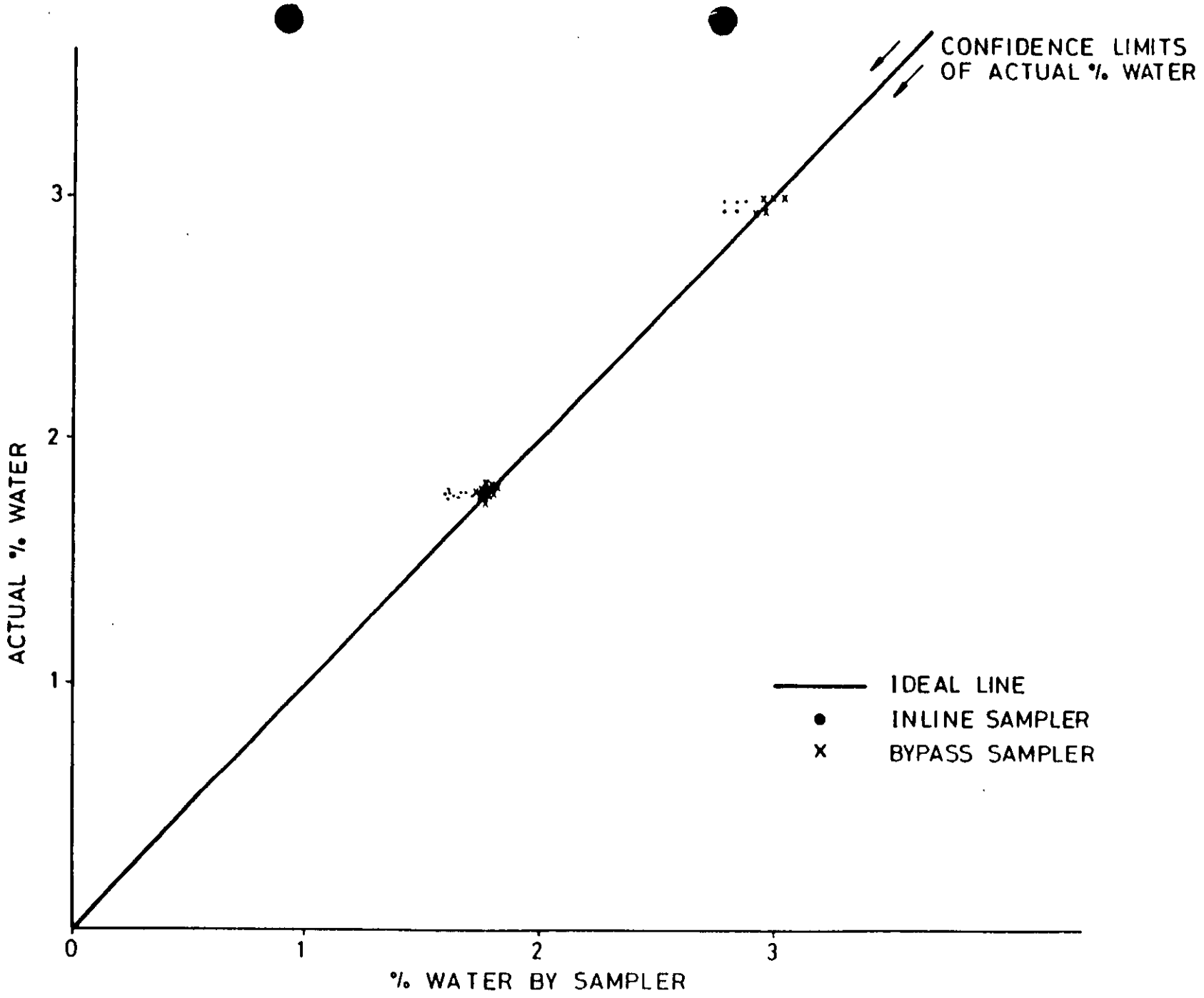


FIG. 3

ACTUAL % WATER –v– % WATER BY INLINE & BYPASS SAMPLERS
(HOMOGENEOUS CONDITIONS ONLY)

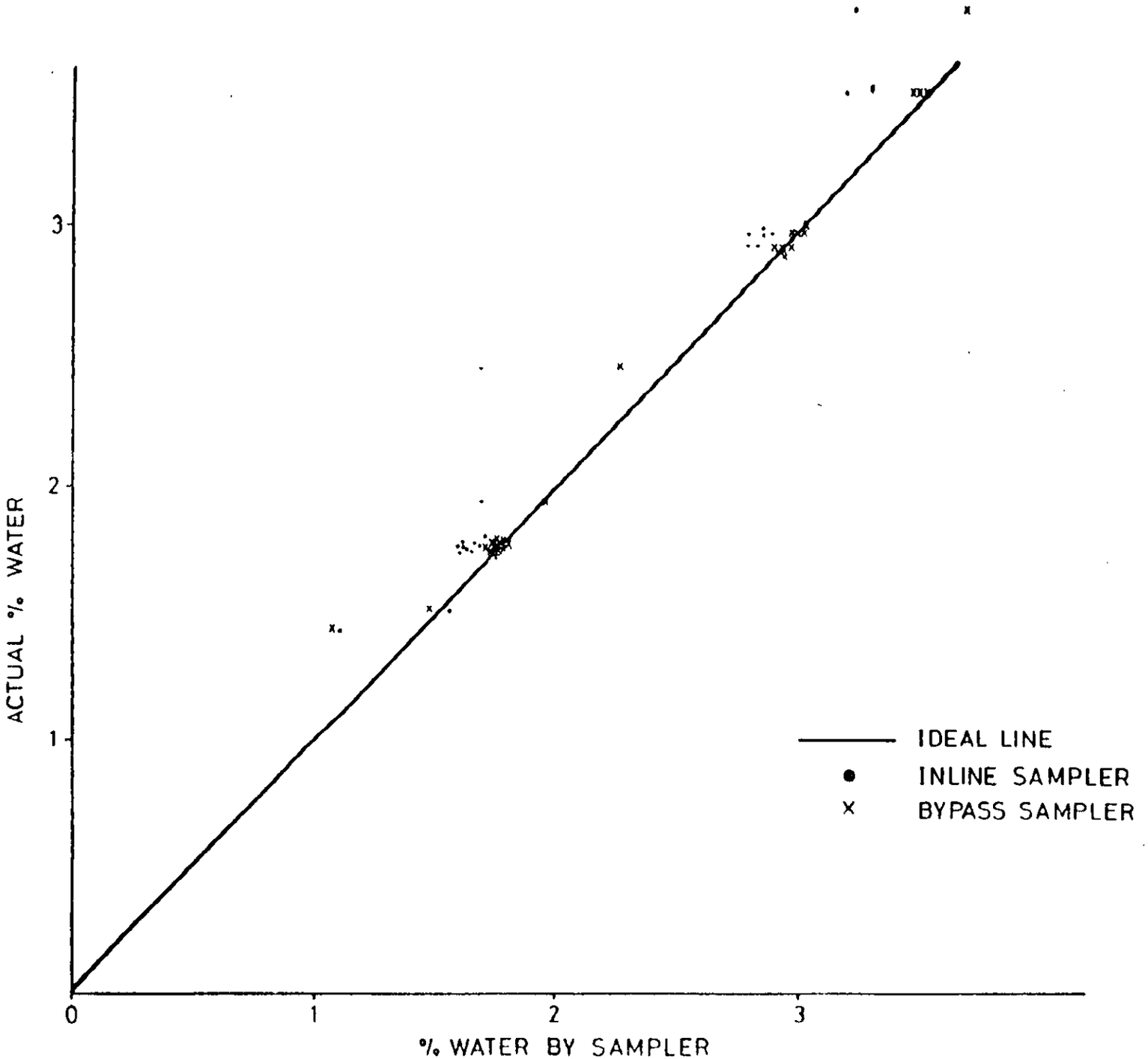
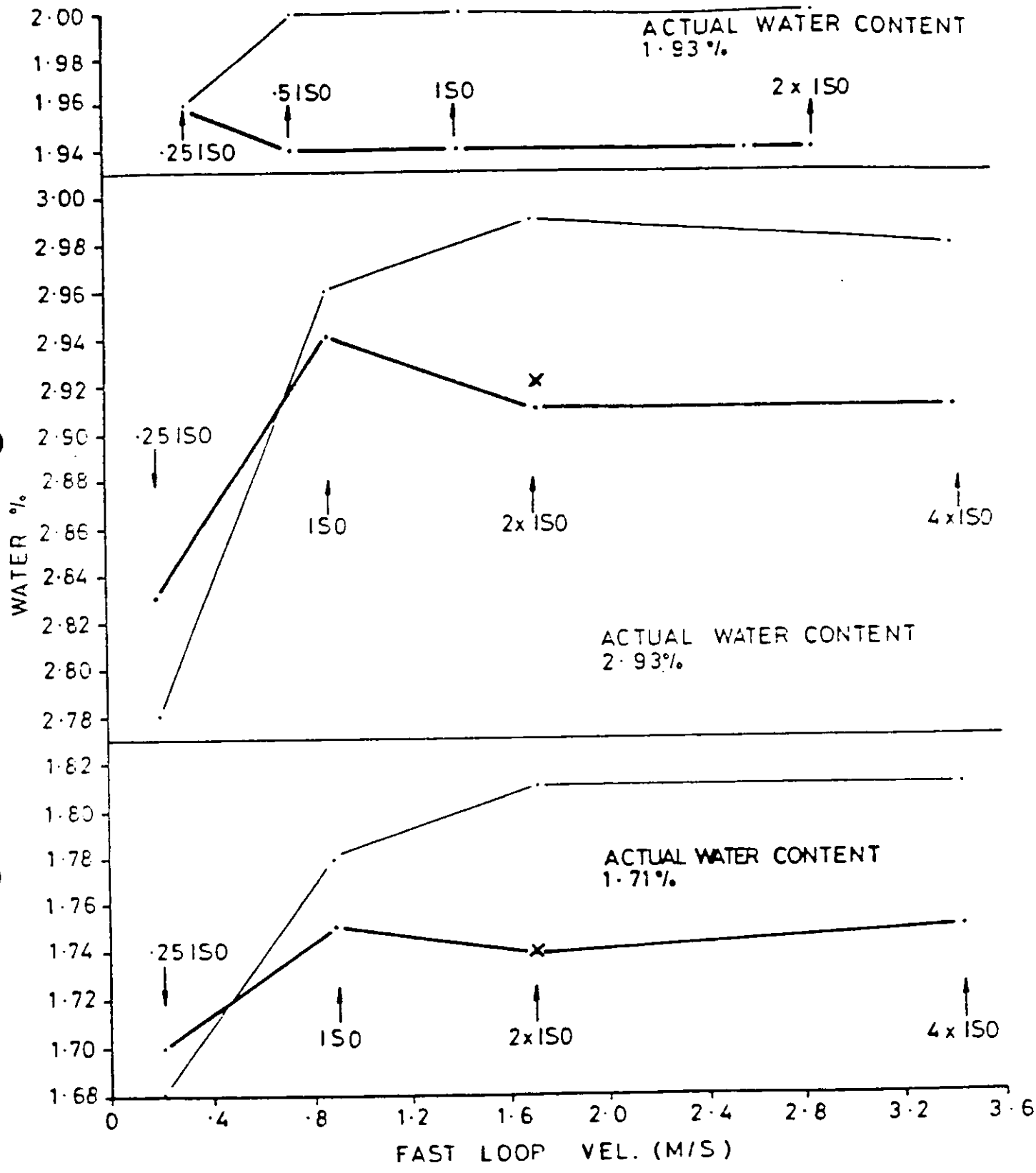


FIG. 4

ACTUAL % WATER —v— % WATER BY INLINE & BYPASS SAMPLERS
(HOMOGENEOUS & NON HOMOGENEOUS CONDITIONS)

FAST LOOP ISOKINETIC FLOW TESTS



WATER CONTENT FROM MANUAL SAMPLES

WATER CONTENT FROM CAPACITANCE CELL

× BYPASS SAMPLER

FIG. 5

FLOW METER TEST CERTIFICATE

CUSTOMER: BP-Harlow

ORDER NO: XED-700-86-1/EL25

METER SERIAL NO: 4070

WORKS ORDER NO: 8746

METER DATA

Meter Type: IP-6

Materials: 316 st/st

Nominal Flow Range:

Pickup: high output magnetic

TEST DATA

Insertion Meter Type IP-6 Serial No: 4070 was mounted in a 10" NB pipe spool piece and calibrated on the AOT-Andover meter prover. The AOT calibration data is attached herewith.

Base Annulus Area = 0.545 ft^2

Blockage Factor = 0.933

Nett Annulus Area = 0.508 ft^2 = 0.0472m^2

Fluid-Water Temperature 20°C

RUN DATA

time(seconds)	flow rate (m^3/min)	Axial Velocity (m/sec)	Total Pulses	Frequency	'K' factor metres/puls
37.72	20.925	7.388	10852	287.69	0.0257
46.66	16.916	5.973	10844	232.40	0.0257
60.80	12.982	4.582	10824	178.02	0.0257
89.65	8.804	3.109	10798	120.44	0.0258
161.31	4.893	1.728	10753	66.66	0.0259
Extrapolated Values	(2.832	1.0	-	38.58	0.0259
	(1.416	0.5	-	19.29	0.0259
857.06	0.920	0.325	9614	11.20	0.0290

NOTE:

To obtain flowrate in pipe size greater than 24" ID use equation:

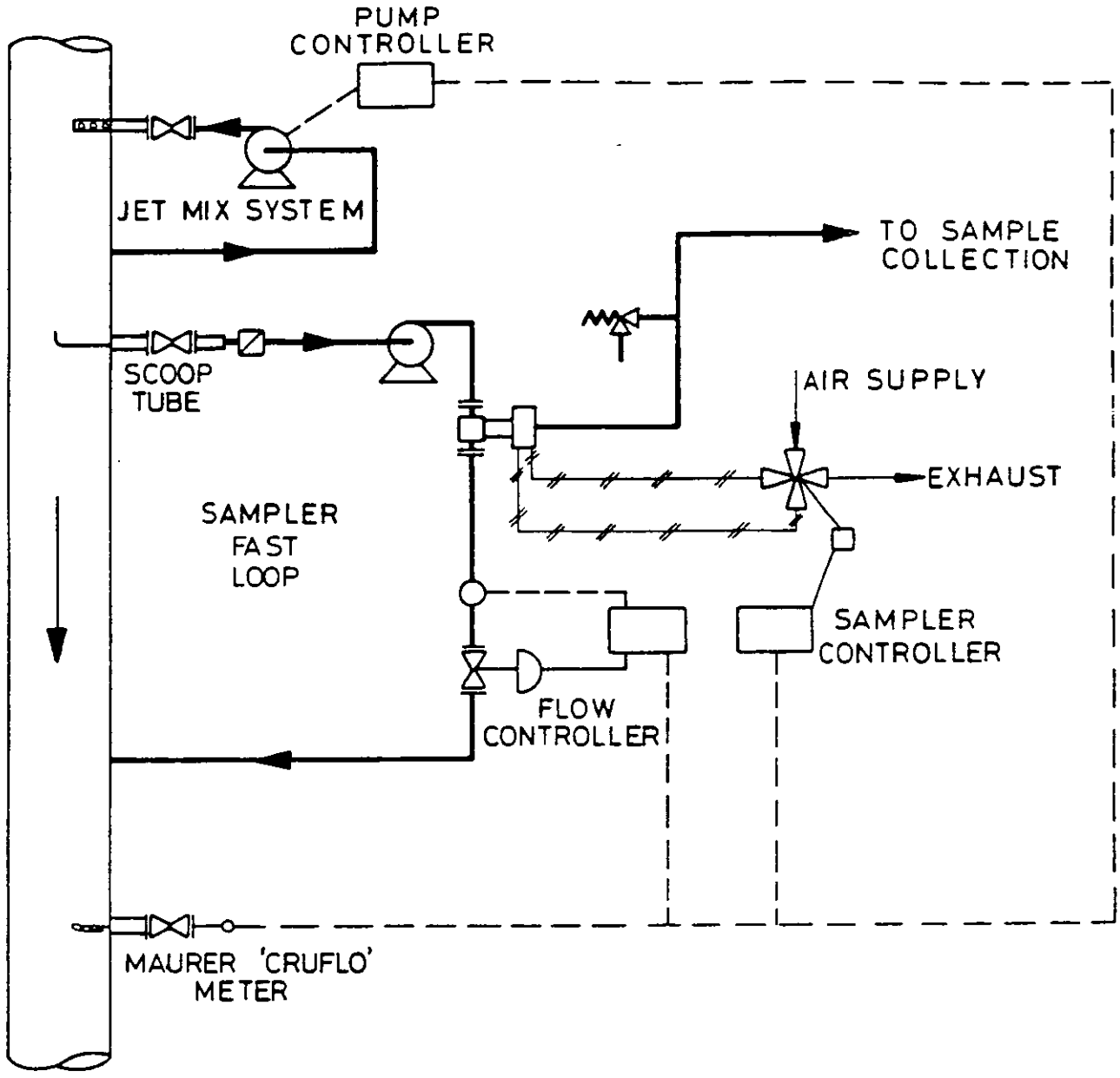
Q (m^3/sec) = 'K' factor x frequency x annulus area (M^2)

INSPECTOR:

DATE: 8.10.84

FIG 6

RECOMMENDED SAMPLING SYSTEM SCHEMATIC



MAIN COMPONENTS:-

JET MIX SYSTEM
- (a) JISKOOT JET
- (b) PUMP WITH STOP/START CONTROLLED FROM MAIN LINE FLOW.

SAMPLER FAST LOOP
- (a) SCOOP TUBE - EITHER 1" OR 1 1/2" DEPENDING ON LINE SIZE. LIVE LINE INSERTION POSSIBLE.
- (b) COURSE FILTER WITH OPTIONAL D.P. MEASUREMENT
- (c) PUMP SIZED TO GIVE ISOKINETIC ENTRY AT SCOOP TUBE FOR MAX. EXPECTED MAIN LINE FLOW.
- (d) CELL SAMPLER WITH CONTROLLER.
- (e) FLOW CONTROL SYSTEM WITH CASCADE FROM MAIN LINE FLOW.
- (f) SAMPLE COLLECTION SYSTEM WITH USER OPTIONS (eg CAN WEIGH & CAN CHANGEOVER)

MAIN LINE FLOW METER
- (a) MAURER 'CRUFLO' TRASH RESISTANT FLOW METER 6" ENTRY - LIVE LINE INSERTION

FIG. 7

TABLE 1

TANK-TO-TANK TRANSFER WITH WATER INJECTION

DATE	CRUDE	HOMOGENOUS	MAIN LINE VELOCITY M/S	ACTUAL % WATER	SAMPLER RESULT IN LINE % WATER	SAMPLER RESULT BYPASS % WATER	DIFFERENCE	AVE. CENTRE PROFILE PROBE % WATER	AVE. PAST LOOP % WATER	ACTUAL % WATER - % WATER BYPASS	ACTUAL % WATER - % WATER INLINE
20.3.85	FULMAR	no	0.27	2.46	1.68	2.25	-0.57	1.73	2.57		
		no	0.27	3.82	3.20	3.67	- 0.47	3.68	3.47		
		no	0.27	1.44	1.10	1.08	+ 0.02	1.14	2.89		
		no	0.52	1.94	1.68	1.95	- 0.27	1.95	1.95		
9.4.85	IRANIAN HEAVY	yes	0.67	1.76	1.61	1.74	- 0.13	1.74	1.73	0.02	0.15
		yes	0.67	1.76	1.61	1.75	- 0.14	1.73	1.73	0.01	0.15
		yes	0.67	1.76	1.61	1.75	- 0.14	1.74	1.73	0.01	0.15
10.4.85		yes	0.67	2.98	2.78	2.99	- 0.21	3.02	3.00	- 0.01	0.20
		yes	0.67	2.98	2.87	2.96	- 0.09	2.92	2.98	0.02	0.11
		yes	0.67	2.98	2.85	3.02	- 0.17	3.00	2.98	- 0.04	0.13
		yes	0.67	2.98	2.93	3.02	- 0.09	3.01	2.99	- 0.04	0.05
		no	0.29	1.52	1.56	1.48	+ 0.08	1.31	1.61		
		no	0.29	3.51	3.18	3.45	- 0.27	3.42	3.54		
		no	0.29	3.51	3.28	3.47	- 0.19	2.96	3.64		
		no	0.29	3.51	3.29	3.49	- 0.21	3.44	3.64		
8.5.85		yes	0.90	1.77	1.6	1.73	- 0.06		1.74	0.04	0.17
		yes	0.90	1.77	1.67	1.73	- 0.06		1.74	0.04	0.1
		yes	0.90	1.77	1.68	1.76	- 0.08		1.78	- 0.01	0.09
		yes	0.89	1.77	1.64	1.76	- 0.12		1.76	0.01	0.13
		yes	0.89	1.76	1.66	1.77	- 0.11		1.76	- 0.01	0.1
		yes	0.89	1.76	1.72	1.77	- 0.05		1.78	- 0.01	0.04
		yes	0.87	2.93	2.78	2.94	- 0.016		2.92	- 0.01	0.15
		yes	0.87	2.93	2.93	2.91	+ 0.02		2.93	0.02	0
		yes	0.87	2.93	2.82	2.91	- 0.09		2.95	0.02	0.11

TABLE 2

TANKER DISCHARGES

AUTOMATIC SAMPLER RESULTS

% WATER

DATE	VESSEL	CRUDE	INLINE	BYPASS	
7.2.85	FANNY	EKOFISK	0.38	0.39	
28.2.85	DON HUMBERTO	MAYA	0.61	0.55	Very low fast loop flow due to crude viscosity. Pump overloading.
29.2.85	DON HUMBERTO	ISTHMUS	0.07	0.10	
17.2.85	KABKAS	KIRKUK	0.05	0.06	
20.5.85	METCO CLYDE	BERYL	0.19 0.19	0.13 0.16	Repeat Laboratory Test.
21.5.85	IRANZU	RAS BUDRAN ZEIT BAY	0.59	0.41	Only front (wet) end of Zeit Bay sampled

TABLE 3

BYPASS LOOP - ISOKINETIC TESTS

Sample Number	% Water (Lab Test)	% Water Average	Flow Rate % Isokinetic	Capacitance Probe % Water	Bypass Loop Entry Velocity M/S	Actual % Water
			100	1.78	0.89	
3	1.68					
4	1.71	1.70	25	1.68	0.2	
5	1.72					
6	1.76					
7	1.76	1.75	100	1.78	0.89	
8	1.74					1.71
9	1.75					
10	1.75	1.75	400	1.81	3.44	
11	1.74					
12	1.74					
13	1.74	1.74	200	1.81	1.72	
14	1.75					
21	2.87					
22	2.79	2.83	25	2.78	0.2	
23	2.84					
24	2.93					
25	2.97	2.94	100	2.96	0.89	
26	2.93					2.93
27	2.92					
28	2.90	2.91	400	2.98	3.44	
29	2.92					
30	2.90					
31	2.93	2.91	200	2.99	1.79	
32	2.91					
36	1.97					
37	1.96	1.96	25	1.96	0.34	
38	1.94					
39	1.93					
40	1.94	1.94	50	2.00	0.76	
41	1.94					
42	1.95					1.93
43	1.94	1.94	100	2.00	1.44	
44	1.92					
45	1.94					
46	1.95	1.94	200	2.00	2.89	
47	1.93					

Norske Sivilingeniørers Forening
Norwegian Society of Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Stavanger, 5 - 7 November 1985

Composite sampling of natural gas

3.4

Lecturer: Mr. Thomas F. Welker
Welker Engineering Company

COMPOSITE SAMPLING OF NATURAL GAS

Thomas F. Welker
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The sampling of natural gas has been discussed and studied for many years. Serious testing on the proper sampling methods has been done in a number of locations in the recent past. From these tests, it has been determined that the sampling procedures must be carefully prepared and followed. For a person to collect a representative sample of natural gas, the procedures learned in spot sampling operations must be followed.

Continuous sampling is described as a method by which a representative portion of product is removed from a flowing stream and pumped into a sample container during a specific time or volume.

The object of the continuous sampler is to collect the sample in the sample container without changing the chemical composition, heating value, or physical characteristics of the products being sampled.

The continuous sampling system consists of a probe in the line, a sampling pump, a timing device, and a sample container. The continuous sampler is normally a mechanical device that is built to be a practical alternative to an on line analyzing mechanism, i.e., calorimeter, chromatograph, etc. The ease of installation, simple maintenance and reduced cost make the continuous sampler an attractive alternative to spot sampling and/or continuous recording devices.

The objective of any therm billing measurement program integrates accurate metering methods, including sampling, to accurately determine the heating value of the gas as delivered and sold to a customer. The heating value delivered is determined by multiplying the unit volume delivery by the heating value (BTU) of the sample extracted during the delivery period.

Since natural gas is commingled from various sources prior to the actual delivery to your customer, wide variations can occur in the components in the flowing gas stream. A repeatable, representative sample of the "as delivered" gas insures the accuracy of the billing.

An inaccurate method of sample heating value or the application of average figures can cost a gas company millions of dollars in lost revenue and/or contribute to the "lost and unaccounted for" volumes. Proper sampling philosophy can also lend accuracy to the sample analysis chemical composition in determining the correct supercompressibility factors in place of system averages.

The fact that the price of gas is high and the profit margin in your company is low dictates that present accepted measurement methods should be updated to present day metering technology. New equipment may be costly when viewed at its first cost, however, the new equipment may overcome inaccuracies that cost companies thousands of dollars per month per location. Corporate cash flow can be enhanced.

To collect a continuous or composite sample of gas, the following items must not be ignored:

1. Sample point
2. Sample probe
3. Hook-up and manifold of sampler and cylinder
4. Sampler
5. Purging of sampler and cylinder
6. Sample cylinder, cleaning, purging, valving
7. Cylinder transport
8. Leaks on sampler and cylinders and related piping
9. Preventative maintenance of the sampler

To ensure the continuous or composite sampler will give accurate and repeatable results, the above points will be covered briefly.

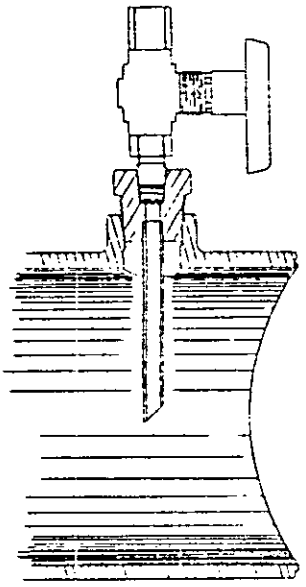
The Sample Point

A sampler is able to produce a sample no more accurate than the sample presented to it. The main consideration in the location of the sample probe is whether it sees the center one-third of the pipeline and whether it is in an area where there is good velocity with minimum turbulence. Turbulence is an aerosol generator and, therefore, liquids put into flight by the turbulence may affect the sample's result. This turbulence makes the liquids moving along the walls and bottom of the pipeline take flight and act as a gas. When aerosols are introduced into the sample container, condensation occurs. The sampler should be located in an area where the gas is moving. A sample should never be taken from a shut in or dead end line. Areas to be avoided are downstream of reduced port valves, control valves, check valves, obstructions and piping fittings. When installing the sampler downstream of an orifice plate, the probe should be as far away from the orifice as possible. Headers and blowdown stacks should be avoided as sample points. Samplers should never be connected to meter manifolds. Install the probe in a straight run of pipe as far away as possible from bends, tees, fittings or any type of obstruction in the line.

A sampler should not be installed without using a sample probe. A representative sample of any product cannot be taken without the use of a sample probe.

Sample Probes

The use of probes in the sampling operation is imperative. Without the use of a probe in the line, an accurate sample cannot be taken. A sample probe should be in the center one-third of the pipeline and equipped with a full open ball or gate valve. The placement of the sample probe is important in all sampling applications. Probes must be kept away from piping elbows, tees, manifolds, reduced port valves and orifice plates.



Design of the Probe

The probe may have a bevel or be cut flat across the end. The bevel on the probe may be faced upstream or downstream. Placement in the center one-third of the pipeline is the most important consideration.

If the probe is in the meter run, the placement should be away from the inlet elbow and as far downstream of the orifice plate as possible.

Headers and manifolds are poor locations for sample probes of any type. Turbulence generated by gas movement in headers and manifolds will not mix the gas uniformly. If gas comes into a header from multiple side taps, the gas moving through the header will not tend to mix readily with the gas moving in from the side.

Vertical headers are turbulence generators and liquid accumulators. Horizontal headers also have turbulence problems and should be avoided. Vertical headers having runs off of the side will encourage the heavies and liquids to move through the bottom run and the lighter, dryer gas will move through the upper meter run. In the weld cap of vertical headers, there is an impingement of the liquids. Therefore, the weld cap is not a proper location for probes for any use.

The actual location of a probe in the piping system is important. What is the objective? One rule is clear — the probe must be located directly in the flowing stream. Another more obscure consideration implies that the probe must be kept clear of free liquid and this includes aerosols which, in fact, are the real trouble makers. Since turbulence is the mechanism that generates aerosols, it is reasonable to make every attempt to stay away from the downstream end of turbulence producers such as reducers, elbows and measurement devices. How long a liquid remains in the aerosol state is a function of the gas velocity; however, in all likelihood, it will be a distance that exceeds 20 pipe diameters. This creates a problem when one considers that available straight and horizontal piping above ground rarely makes allowance for the ideal sampling location. For gas sampling, locate the probe in the top of a horizontal pipe.

Probe Construction

The probe should be constructed from a material that will not react with the product. 316 stainless steel is the most practical material for probe construction. Probes are normally constructed three different ways:

1. The stationary or permanent probe
2. The manually insertable probe
3. The automatic insertion probe

The stationary probe is installed as a permanent fixture in the piping system. A full open valve should be attached to the outlet of the probe.

The tube extending into the flow path should be made strong enough to resist bending.

The manual insertion probe is used in locations of medium pressure where a permanent fixture cannot be left in the pipe.

To insert the manual insertion probe, attach to a gate or ball valve and close the valve attached securely to the end of the probe. Open the pipeline valve and very carefully push the tube into the flow line. Tighten the fittings on the probe enough to hold the tubing in place and prevent leaks. Normally, the lower ferrule will be nylon (or PTFE) and the upper ferrule will be stainless steel. Once the stainless steel ferrule is "set," the insertion depth of the probe is fixed. This type of probe must be handled carefully with special attention given to locking the valve on the end of the probe and securing the probe into the insertion valve.

The Automatic Insertion Probe

The automatic insertion probe is used in locations that require frequent insertion and retraction of the probe from the pipeline.

The automatic insertion probe is built as a standard to screw into a 1-inch NPT ported valve. Other ends are available for attachment to the pipeline.

The use of the automatic insertion probe style allows easy access and removal of all types of probes into the line.

Probes in Wet Gas Systems

The wet gas pipeline system continuously exhibits the need for probes. In wet gas systems, liquid carryover in instrument supplies, valve operations, and chemical injectors is a continual problem.

Samplers, chromatographs, calorimeters and related on-line monitors should be hooked up to the line using a probe.

Sampler Hook-up and Manifold

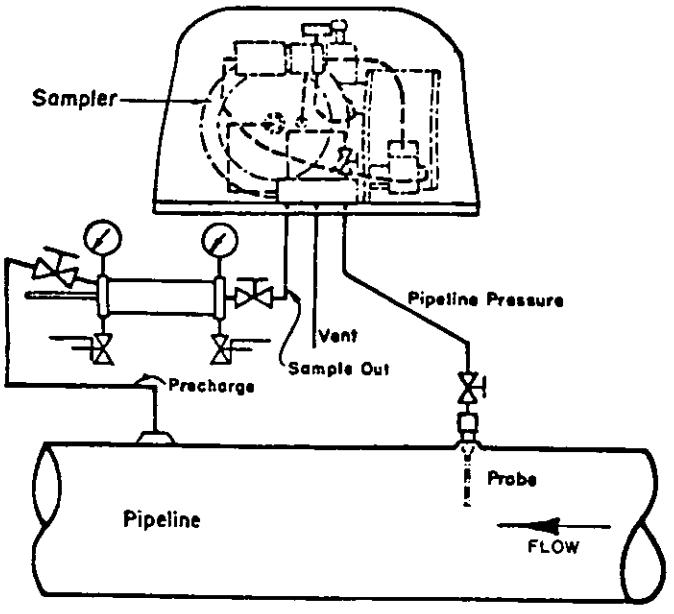
From the outlet of the probe, a ball valve or large ported valve should be installed. This valve should be opened completely. Downstream of the probe valve, a short length of small diameter line should be run upgrade to the inlet port of the manifold block on the sampler. The sampler should be mounted above the sample point on a pipe stand. The line to the sampler should always be sloped back toward the valve on the sample probe. This is to allow any free liquid to drain back into the pipeline. Free liquids should be discouraged from moving into the sample container. Two phase samplers in standard sample containers are difficult, if not impossible, to handle properly in the lab.

The installation of the sampler should be as close as practical to the sample point. Never sample a dead end line.

On the outlet of the sampler, the sample cylinder should be connected with a short length of small diameter tubing. This is to be pumped into the cylinder, not some excessive length of tubing. Mount the cylinder in some type of holder, not on the ground or deck.

The outlet tubing from the sampler to the cylinder must be carefully checked for leaks. Leaks allow the sample to dissipate nonuniformly. Gas will leak from a cylinder light ends first giving inaccurate results.

Care should be taken not to put filters, drips, or regulators between the probe and the sampler. This affects the gas and it is no longer representative of the pipeline product.



Sampler

The sampler is a mechanism that gives the operator an opportunity to have a composite sample in a cylinder. It is an alternative to a spot sample and/or an onstream monitoring device. The sampler should take its composite sample just as an operator would put a spot sample into his container. The sampler, however, does this continuously over a specific period of time.

The sampler may be a simple timed mechanism actuating the sampler periodically. It may be interfaced with measurement to cause the sample to be taken proportional to the flow electrically or pneumatically.

For stations or locations where the flow varies widely or the heating content swings up and down, the sampler should be actuated proportional to the flow.

For stations where the load is constant, a timer may be used without affecting the gas collected.

For stations or wells that have flow, no flow operations, the sampler should be turned off with a flow switch when the flow is off. Sampling should be stopped when there is no flow in every case. After a number of years and many test locations, it is recommended that in locations where gas has a heating value of 1025 BTU or above should be considered as prime locations for the use of a continuous sampler.

The sampler should be capable of pumping the sample into the sample container, regardless of ambient conditions.

The sampler should be able to purge itself prior to pumping a new "bite" into the sample container.

The sampler should sample the gas at pipeline conditions.

Purging the Sampler and the Cylinder

When the sampling device is put into service and a sample container is attached, the sampler and all its components including the cylinder should be properly purged.

The act of purging cleans the air from the sampler and associated components so they will not be present in the analysis. This purge also conditions the cylinder with the gas that is to be sampled. Note: If an evacuated cylinder is used, the associated tubing, fittings and valves still must be purged.

The Sample Cylinder

The sample cylinder is the carrier of the sample; therefore, it is an integral part of the system. It should be made of a material that will not react with the gas. It should be kept clean and well maintained. Valves and reliefs should be checked periodically for ease of operation and must be checked for leaks through the seat, bonnet and threads. No leaks may be tolerated. Soft seat valves should be used on sample cylinders.

The sample cylinder should be cleaned after each use with solvent and then air dried. Sample cylinders must be a proper working pressure to handle the source being sampled. Rising temperatures will increase the pressure in the cylinder so this should be considered when choosing a sample container.

Cylinder Transport

When the sample period is over, the sample container should be disconnected from the sampler and carefully checked for leaks. Plugs or caps should be installed on the valves. The sample information tag should be filled out fully. The cylinder should then be put into a proper case for transport. D.O.T. rules apply, even in your company trucks and autos. A cylinder should never be transported haphazardly.

Leaks

Leaks should not be tolerated in any portion of a sample system. Leaks will cause the sample to give incorrect results.

Maintenance on the Sampler

The continuous sampler is a mechanical device and should be checked each time the sample cylinder is changed. Simply remove the cover from the sampler. Check the supply, activate the sampler to check its stroke and supply regulator response. Open the vent valve on the filter (F-7) on the instrument supply to check if liquid is getting into your system. Close the outlet valve and activate the sampler to watch the pressure on the outlet gauge increase. Reopen the outlet valve.

Every three months, check the sample head for chemical attack or swelling.

Every year, change the o-rings and lubricate the shaft and three-way valve. Spare parts that should be kept on hand are:

1. Sampler head
2. -003 o-rings
3. O-ring kit
4. Batteries for timer (if required)

The Composite Sampler in Wet Gas Service

The composite sampler is effective in wet gas service. It is further recommended that a constant pressure sample cylinder be used in wet gas service. By using the composite sampler and the constant pressure cylinder in wet gas service, the sample can be maintained under pipeline pressure, thereby discouraging retrograde condensation in the cylinder. The sample in the constant pressure cylinder may be run in the lab under pipeline conditions, pressure and temperature to get a better result.

Measurement Effect of a One BTU Error (Expressed In Dollars Per Year)

Examples:

1. Daily Production Rate = 10,000 MCFD
   BTU from monthly spot sample = 1020 BTU
   BTU from composite-continuous sampling = 1019 BTU -- One BTU Variation
   Purchase Gas Cost = $3.50 per MMBTU (1000 BTU - Base)
   10,000 (1.020)($3.50) = $35,700 per day
   10,000 (1.019)($3.50) = $35,665 per day
   $ 35 per day
   $35 (25 days per month)(12 months) = $10,500

   One BTU Variation = $10,500 per year

2. Daily Purchase Rate = 200,000 MCFD
   BTU from spot sample = 1036 BTU
   BTU from continuous-composite sampling = 1035 BTU -- One BTU Variation
   Purchase Gas Cost = $3.50 per MMBTU (1000 BTU - Base)
   200,000 (1.036)($3.50) = $725,200 per day
   200,000 (1.035)($3.50) = $724,500 per day
   $ 700 per day
   $700 (30 days)(12 months) = $252,000

   One BTU Variation = $252,000 per year

DOLLARS PER YEAR DUE TO MEASUREMENT VARIATION IN SPOT BTU SAMPLE VS. COMPOSITE SAMPLE

(Dollars based on $3.50 per MMBTU - 1000 BTU Base)

Sample BTU Variation	MMCFD - Daily Purchase or Sale Rate					
	5	10	20	25	30	50
1	$ 6,387	$ 12,775	$ 25,550	$ 31,937	$ 38,325	$ 63,875
2	$ 12,775	$ 25,550	$ 51,100	$ 63,875	$ 76,650	$ 127,750
3	$ 19,162	$ 39,420	$ 76,650	$ 95,812	$ 114,975	$ 191,625
4	$ 25,550	$ 51,100	$ 102,200	$ 127,750	$ 153,300	$ 255,500
5	$ 31,937	$ 63,875	$ 127,750	$ 159,687	$ 191,625	$ 319,375
6	$ 38,325	$ 76,650	$ 153,300	$ 191,625	$ 229,950	$ 383,250
7	$ 44,712	$ 89,425	$ 178,850	$ 223,562	$ 268,275	$ 447,125
8	$ 51,100	$ 102,200	$ 204,400	$ 255,500	$ 306,600	$ 511,000
9	$ 57,487	$ 114,975	$ 229,950	$ 287,437	$ 344,925	$ 574,875
10	$ 63,875	$ 127,750	$ 255,500	$ 319,375	$ 383,250	$ 638,750

Basis for above information:

Daily Purchase = 5 MMCFD

BTU Sample Content = 1001

Purchase Gas Cost = $3.50 per MMBTU (1000 BTU - Base)

5,000 (1.001)($3.50) = $ 17,517.50 per day

5,000 (1,000)($3.50) = $ 17,500.00 per day

$ 17.50 per day

$17.50 per day (365 days) = $ 6,387.50 per year

COMPOSITE SAMPLING OF NATURAL GAS

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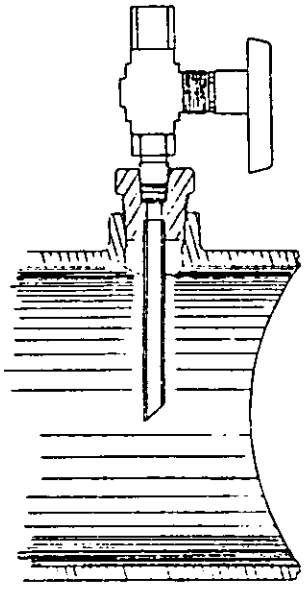

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If the probe is in the meter run, the placement should be away from the inlet elbow and as far downstream of the orifice plate as possible.

Headers and manifolds are poor locations for sample probes of any type. Turbulence generated by gas movement in headers and manifolds will not mix the gas uniformly. If gas comes into a header from multiple side taps, the gas moving through the header will not tend to mix readily with the gas moving in from the side.

Vertical headers are turbulence generators and liquid accumulators. Horizontal headers also have turbulence problems and should be avoided. Vertical headers having runs off of the side will encourage the heavies and liquids to move through the bottom run and the lighter, dryer gas will move through the upper meter run. In the weld cap of vertical headers, there is an impingement of the liquids. Therefore, the weld cap is not a proper location for probes for any use.

The actual location of a probe in the piping system is important. What is the objective? One rule is clear — the probe must be located directly in the flowing stream. Another more obscure consideration implies that the probe must be kept clear of free liquid and this includes aerosols which, in fact, are the real trouble makers. Since turbulence is the mechanism that generates aerosols, it is reasonable to make every attempt to stay away from the downstream end of turbulence producers such as reducers, elbows and measurement devices. How long a liquid remains in the aerosol state is a function of the gas velocity; however, in all likelihood, it will be a distance that exceeds 20 pipe diameters. This creates a problem when one considers that available straight and horizontal piping above ground rarely makes allowance for the ideal sampling location. For gas sampling, locate the probe in the top of a horizontal pipe.

Probe Construction

The probe should be constructed from a material that will not react with the product. 316 stainless steel is the most practical material for probe construction. Probes are normally constructed three different ways:

1. The stationary or permanent probe
2. The manually insertable probe
3. The automatic insertion probe

The stationary probe is installed as a permanent fixture in the piping system. A full open valve should be attached to the outlet of the probe.

The tube extending into the flow path should be made strong enough to resist bending.

The manual insertion probe is used in locations of medium pressure where a permanent fixture cannot be left in the pipe.

To insert the manual insertion probe, attach to a gate or ball valve and close the valve attached securely to the end of the probe. Open the pipeline valve and very carefully push the tube into the flow line. Tighten the fittings on the probe enough to hold the tubing in place and prevent leaks. Normally, the lower ferrule will be nylon (or PTFE) and the upper ferrule will be stainless steel. Once the stainless steel ferrule is "set," the insertion depth of the probe is fixed. This type of probe must be handled carefully with special attention given to locking the valve on the end of the probe and securing the probe into the insertion valve.

The Automatic Insertion Probe

The automatic insertion probe is used in locations that require frequent insertion and retraction of the probe from the pipeline.

The automatic insertion probe is built as a standard to screw into a 1-inch NPT ported valve. Other ends are available for attachment to the pipeline.

The use of the automatic insertion probe style allows easy access and removal of all types of probes into the line.

Probes in Wet Gas Systems

The wet gas pipeline system continuously exhibits the need for probes. In wet gas systems, liquid carryover in instrument supplies, valve operations, and chemical injectors is a continual problem.

Samplers, chromatographs, calorimeters and related on-line monitors should be hooked up to the line using a probe.

Sampler Hook-up and Manifold

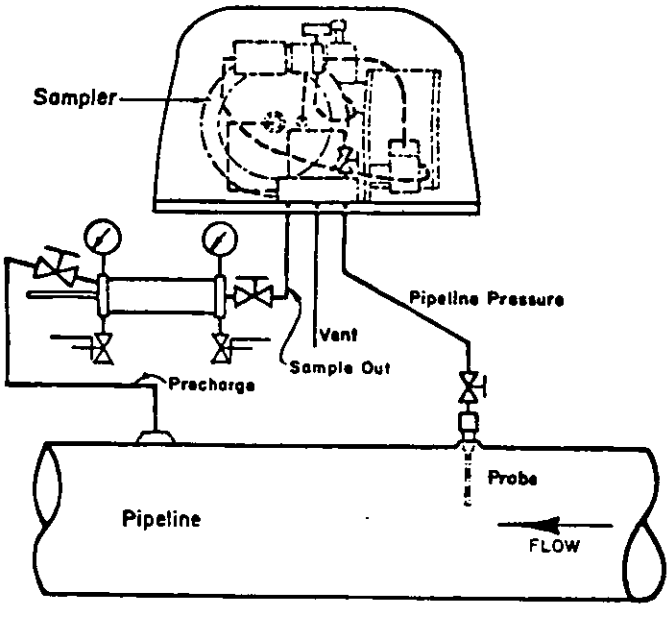
From the outlet of the probe, a ball valve or large ported valve should be installed. This valve should be opened completely. Downstream of the probe valve, a short length of small diameter line should be run upgrade to the inlet port of the manifold block on the sampler. The sampler should be mounted above the sample point on a pipe stand. The line to the sampler should always be sloped back toward the valve on the sample probe. This is to allow any free liquid to drain back into the pipeline. Free liquids should be discouraged from moving into the sample container. Two phase samplers in standard sample containers are difficult, if not impossible, to handle properly in the lab.

The installation of the sampler should be as close as practical to the sample point. Never sample a dead end line.

On the outlet of the sampler, the sample cylinder should be connected with a short length of small diameter tubing. This is to be pumped into the cylinder, not some excessive length of tubing. Mount the cylinder in some type of holder, not on the ground or deck.

The outlet tubing from the sampler to the cylinder must be carefully checked for leaks. Leaks allow the sample to dissipate nonuniformly. Gas will leak from a cylinder light ends first giving inaccurate results.

Care should be taken not to put filters, drips, or regulators between the probe and the sampler. This affects the gas and it is no longer representative of the pipeline product.



Sampler

The sampler is a mechanism that gives the operator an opportunity to have a composite sample in a cylinder. It is an alternative to a spot sample and/or an onstream monitoring device. The sampler should take its composite sample just as an operator would put a spot sample into his container. The sampler, however, does this continuously over a specific period of time.

The sampler may be a simple timed mechanism actuating the sampler periodically. It may be interfaced with measurement to cause the sample to be taken proportional to the flow electrically or pneumatically.

For stations or locations where the flow varies widely or the heating content swings up and down, the sampler should be actuated proportional to the flow.

For stations where the load is constant, a timer may be used without affecting the gas collected.

For stations or wells that have flow, no flow operations, the sampler should be turned off with a flow switch when the flow is off. Sampling should be stopped when there is no flow in every case. After a number of years and many test locations, it is recommended that in locations where gas has a heating value of 1025 BTU or above should be considered as prime locations for the use of a continuous sampler.

The sampler should be capable of pumping the sample into the sample container, regardless of ambient conditions.

The sampler should be able to purge itself prior to pumping a new "bite" into the sample container.

The sampler should sample the gas at pipeline conditions.

Purging the Sampler and the Cylinder

When the sampling device is put into service and a sample container is attached, the sampler and all its components including the cylinder should be properly purged.

The act of purging cleans the air from the sampler and associated components so they will not be present in the analysis. This purge also conditions the cylinder with the gas that is to be sampled. Note: If an evacuated cylinder is used, the associated tubing, fittings and valves still must be purged.

The Sample Cylinder

The sample cylinder is the carrier of the sample; therefore, it is an integral part of the system. It should be made of a material that will not react with the gas. It should be kept clean and well maintained. Valves and reliefs should be checked periodically for ease of operation and must be checked for leaks through the seat, bonnet and threads. No leaks may be tolerated. Soft seat valves should be used on sample cylinders.

The sample cylinder should be cleaned after each use with solvent and then air dried. Sample cylinders must be a proper working pressure to handle the source being sampled. Rising temperatures will increase the pressure in the cylinder so this should be considered when choosing a sample container.

Cylinder Transport

When the sample period is over, the sample container should be disconnected from the sampler and carefully checked for leaks. Plugs or caps should be installed on the valves. The sample information tag should be filled out fully. The cylinder should then be put into a proper case for transport. D.O.T. rules apply, even in your company trucks and autos. A cylinder should never be transported haphazardly.

Leaks

Leaks should not be tolerated in any portion of a sample system. Leaks will cause the sample to give incorrect results.

Maintenance on the Sampler

The continuous sampler is a mechanical device and should be checked each time the sample cylinder is changed. Simply remove the cover from the sampler. Check the supply, activate the sampler to check its stroke and supply regulator response. Open the vent valve on the filter (F-7) on the instrument supply to check if liquid is getting into your system. Close the outlet valve and activate the sampler to watch the pressure on the outlet gauge increase. Reopen the outlet valve.

Every three months, check the sample head for chemical attack or swelling.

Every year, change the o-rings and lubricate the shaft and three-way valve. Spare parts that should be kept on hand are:

1. Sampler head
2. -003 o-rings
3. O-ring kit
4. Batteries for timer (if required)

The Composite Sampler in Wet Gas Service

The composite sampler is effective in wet gas service. It is further recommended that a constant pressure sample cylinder be used in wet gas service. By using the composite sampler and the constant pressure cylinder in wet gas service, the sample can be maintained under pipeline pressure, thereby discouraging retrograde condensation in the cylinder. The sample in the constant pressure cylinder may be run in the lab under pipeline conditions, pressure and temperature to get a better result.

Measurement Effect of a One BTU Error (Expressed In Dollars Per Year)

Examples:

1. Daily Production Rate = 10,000 MCFD
   BTU from monthly spot sample = 1020 BTU
   BTU from composite-continuous sampling = 1019 BTU -- One BTU Variation
   Purchase Gas Cost = $3.50 per MMBTU (1000 BTU - Base)
   10,000 (1.020)($3.50) = $35,700 per day
   10,000 (1.019)($3.50) = $35,665 per day
   $ 35 per day
   $35 (25 days per month)(12 months) = $10,500

   One BTU Variation = $10,500 per year

2. Daily Purchase Rate = 200,000 MCFD
   BTU from spot sample = 1036 BTU
   BTU from continuous-composite sampling = 1035 BTU -- One BTU Variation
   Purchase Gas Cost = $3.50 per MMBTU (1000 BTU - Base)
   200,000 (1.036)($3.50) = $725,200 per day
   200,000 (1.035)($3.50) = $724,500 per day
   $ 700 per day
   $700 (30 days)(12 months) = $252,000

   One BTU Variation = $252,000 per year

DOLLARS PER YEAR DUE TO MEASUREMENT VARIATION IN SPOT BTU SAMPLE VS. COMPOSITE SAMPLE

(Dollars based on $3.50 per MMBTU - 1000 BTU Base)

Sample BTU Variation	MMCFD - Daily Purchase or Sale Rate					
	5	10	20	25	30	50
1	$ 6,387	$ 12,775	$ 25,550	$ 31,937	$ 38,325	$ 63,875
2	$ 12,775	$ 25,550	$ 51,100	$ 63,875	$ 76,650	$ 127,750
3	$ 19,162	$ 39,420	$ 76,650	$ 95,812	$ 114,975	$ 191,625
4	$ 25,550	$ 51,100	$ 102,200	$ 127,750	$ 153,300	$ 255,500
5	$ 31,937	$ 63,875	$ 127,750	$ 159,687	$ 191,625	$ 319,375
6	$ 38,325	$ 76,650	$ 153,300	$ 191,625	$ 229,950	$ 383,250
7	$ 44,712	$ 89,425	$ 178,850	$ 223,562	$ 268,275	$ 447,125
8	$ 51,100	$ 102,200	$ 204,400	$ 255,500	$ 306,600	$ 511,000
9	$ 57,487	$ 114,975	$ 229,950	$ 287,437	$ 344,925	$ 574,875
10	$ 63,875	$ 127,750	$ 255,500	$ 319,375	$ 383,250	$ 638,750

Basis for above information:

Daily Purchase = 5 MMCFD

BTU Sample Content = 1001

Purchase Gas Cost = $3.50 per MMBTU (1000 BTU - Base)

5,000 (1.001)($3.50) = $ 17,517.50 per day

5,000 (1,000)($3.50) = $ 17,500.00 per day

$ 17.50 per day

$17.50 per day (365 days) = $ 6,387.50 per year