North Sea FLOW Measurement Workshop

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Metering in the real world

by

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METERING IN THE REAL WORLD

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SUMMARY

This paper highlights some of the problems experienced by metering practioners once they step outside of the ivory towers and warm laboratories and enter the real world. The real world of course is not real at all, it vibrates, it rusts, it surges and gets hot and cold at all the wrong moments. But to many of us in the North Sea, its home and where we have to account for the products "won or saved" from our facilities. In addition the paper looks briefly at the cost of ownership of some simple metering stations.

The paper does discuss highly theoretical matters, these are left to more learned colleagues who will come later in the workshop.

INTRODUCTION

As an introduction to metering, we are all aware that there are certain golden rules which must apply to ensure consistent, reliable and even accurate metering. These are:

- Stable conditions with respect to
  - flow rate.
  - pressure.
  - temperature.
  - metered product composition.

- Cleanliness.

- Good metrology.

However, at times we experience changes in one or more of the above, and this has effects which may be of a greater or lesser degree. As 'flow metering' is not a discrete standard we sometimes ignore or don't even notice the offending parameter.

In addition we concentrate (naturally) on our cash registers - our fiscal metering systems..... ignoring our ancillary metering systems. Whilst not advocating that we should ignore our fiscal meters, we should perhaps pay a little more heed to those systems which might enable us to monitor and manage the one limited resource we have - our reservoirs. Lets look at these ancillary meters, which surpass in large quantities, the fiscal system meters.

If we consider that a fiscal skid for oil or gas will probably have 3 or 4 meters each and ancillary metering systems for a typical North Sea platform will have upwards of 50 meters then you will see that the opportunity for error in ancillery metering is large. The typical quantity of flow meters on a minimum facility are shown in Table 1.

So lets get back to our real world, and look at all those conditions, which are so important for consistent, reliable and even accurate metering.

TABLE 1 - TYPICAL NORTH SEA PLATFORM METERS

FISCAL			
GAS	3 off		
OIL	3 off		
ANCILLARY			
TEST SEPARATOR	1 oil	1 gas	1 water
1ST STAGE SEPARATOR	1 oil	1 gas	1 water
2ND STAGE SEPARATOR	1 oil	1 gas	1 water
GAS COMPRESSION		3 gas	
GAS TREATMENT	2 NGL		
GAS LIFT		15 gas	
WATER INJECTION			10 water
FUEL GAS		2 gas	
FLARE		2 gas	
FIRE WATER			2 water
SUB TOTAL	5 oil	25 gas	15 water

- IGNORES MISCELLANEOUS MINIMUM FLOW BYPASS LOOPS, AVIATION FUEL, DIESEL, CHEMICALS, ETC

STABLE CONDITIONS

An area of the process plant where we hope that stable conditions are designed in, is the test separator. Its purpose is of course to test the flow of individual wells and meter the constituents of the flowing products, in order to enable us to monitor and manage the performance of the reservoir. With the advent and discovery of smaller satellite fields, a secondary purpose has been allocated to some test separators - that is the allocation metering of the production from satellite fields in relation to the total (fiscally metered) output of the parent production facility.

So lets look at a typical test separator and its performance both perceived and real.

At the commencement of operations the field is assumed to produce under its own pressure in a relatively stable state with little or no water and in the initial stages, with no gas lift or ESP production enhancements. Under these conditions, the control of the separator is stable and metering poses few problems unless of course, the production rate is so high that the residence time is small. Later, once the reservoir pressure drops, enhanced oil recovery activities are undertaken, ie

- Water injection : to maintain reservoir pressure.

- Gas lift : to lift the products in the well tubing to the surface by reducing the specific gravity of the liquids.

- Submersible pumps.

These EOR activities certainly perform - they enhance the reservoir recovery. However, when we look into this, it also give us a myriad of problems in metering technology. We'll look at this again in a shortly.

WATER PRODUCTION

Water production is a natural byproduct of oil production, whether it be aquifer water driving the oil or injection water for reservoir pressure maintenance. Eventually water break through will occur, and increasing amounts of water will be produced. It is not unusual for mature fields to produce 2, 3, 4, 5 and 6 times more water than oil.

Separator performance at these levels of water production often falls and the water content in the "metered oil" may rise. Separator performance has been shown to be severely effected by the EOR facilities as these tend to break down and mix the fluids extremely efficiently.

If we look at Table 2 we can see a wide range of typical water cuts found at a typical test separator and at the inlet / outlet of first and second stage separators. These are dependant upon crude oil parameters, mixing regimes previously described, temperatures and the basic efficiency of the separators. Often this means that we are in fact trying to meter, not an oil with known pressure and temperature characteristics, but rather an oil / water mix.

Our traditional metering of flow, pressure and temperature and inputting this data into an efficient and complex flow computer provides us with a correct flow rate having carried out some complex calculations. Two of the computations carried out are :

- temperature compensation for crude oil volume changes between the operating temperature and 15°C.

- pressure compensation for crude oil volume changes between the operating pressure and 1.01325 bar g.

In a paper presented by T.J. Hollet of BP "Measurement errors in North Sea Exploration and Production Systems Resulting from ignoring the Properties of Water" to this workshop in 1984, the topic was rigorously explored. Some of the conclusions from this paper stated that the use of dry oil density to calculate total wet fluid thermal expansion coefficients and hence volume correction factors can generate significant underestimates of metered volumes at standard conditions if water contents are >3% wt and the use of

wet oil densities to calculate total wet fluid thermal expansion coefficients and hence volume correction factors does produce sufficiently accurate results over the range 1 - 10% water.

From the figures presented I have no doubt that this problem exists in many ancillary systems, and more than a few of the more mature production facilities, within their fiscal metering systems. However to my knowledge little further work has been done on this topic except for a few projects to look at water cut sampling, and the figures shown in Table 2 would indicate that the problem is still with us.

Further problems are present with water production and gas metering. One of the regular questions I am asked by my Production Engineers is "What have I done to the metering?". I now know what they mean - as I've now seen it happen a few times. With a new production well the gas oil ratio is steady at a level predetermined by the field GOR and then after a while the GOR begins to rise. The implication is that I or one of my colleagues has 'tweaked' the flow meters or the flow computer without saying anything. The reservoir gas oil ratio in a composite field is uniform - it does not change with time or production. However if you look at the change in GOR of a typical well over time, you may find it changes dramatically. Figure 1 shows a typical well GOR versus BS & W. The GOR hasn't actually changed but we are now metering gas plus water vapour carry over plus steam. The amount of steam depends upon the separator temperature and pressure and this can be investigated further via the steam tables.

This is an interesting problem, and will not disappear with the use of the more modern non-intrusive / mass flow meters. I'm sure Andy Jamieson in the next paper may say a few words on this topic under 'Wet Gas Metering' - however in its worst aspects this is not just wet gas - its almost multiphase.

TABLE 2 - SEPARATOR PERFORMANCES

WELL	FLOW RATE BOPD	BS & W AT METER	SEPARATOR TEMPERATURE	
1	2,557	2.6%	115°F	
2	1,447	0.8%	188°F	
3	4,796	7.8%	200°F	
4	5,186	1.3%	189°F	
5	1,371	0.6%	200°F	
6	3,874	0.3%	117°F	
7	3,860	51%	50°F	

FIRST STAGE SEPARATOR

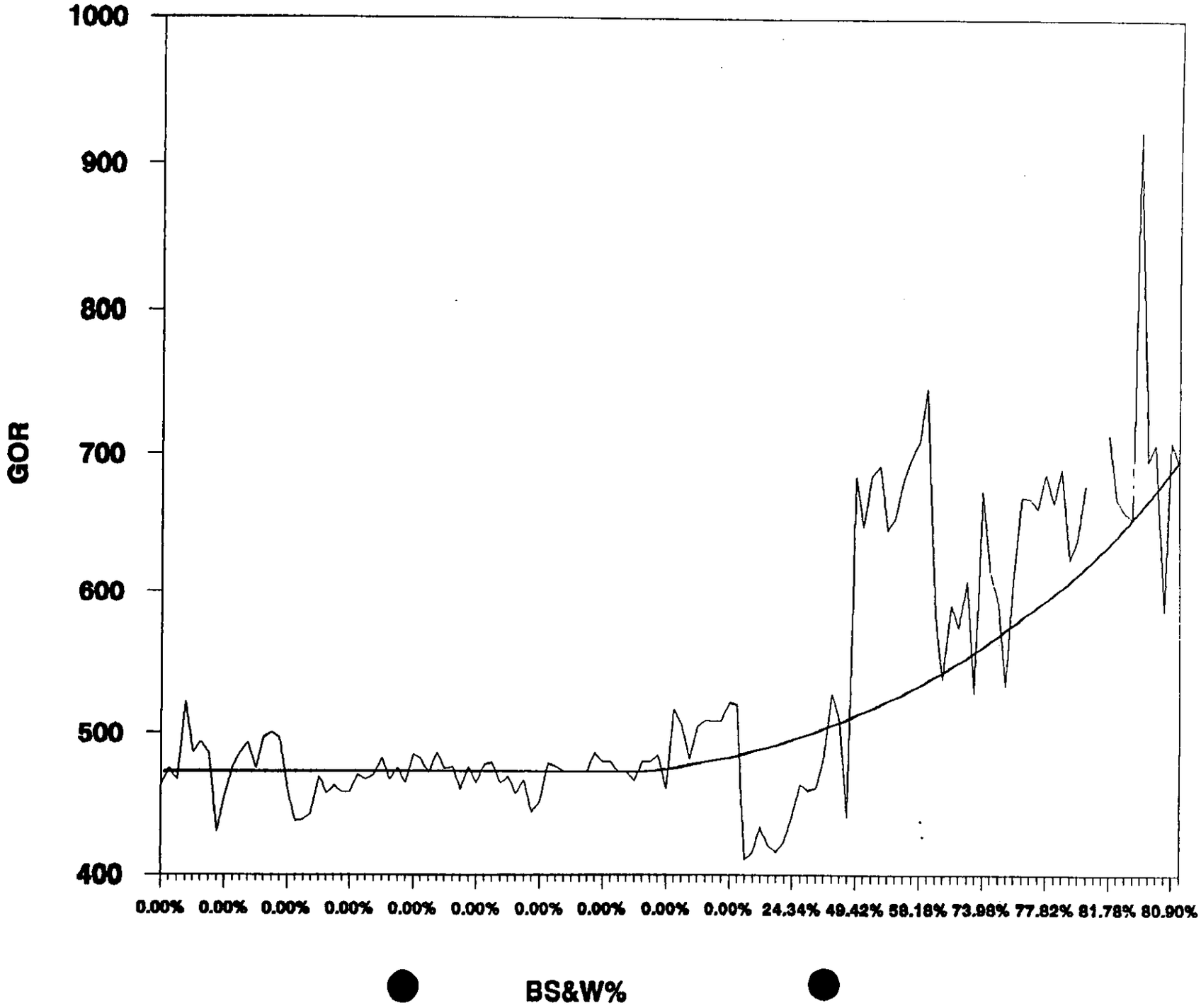
INLET BS & W = 67%

OUTLET BS & W = 47 %

SECOND STAGE SEPARATOR

OUTLET BS & W = 25 %

FIGURE 1: BS&W% Vs GOR



PROCESS CONTROL

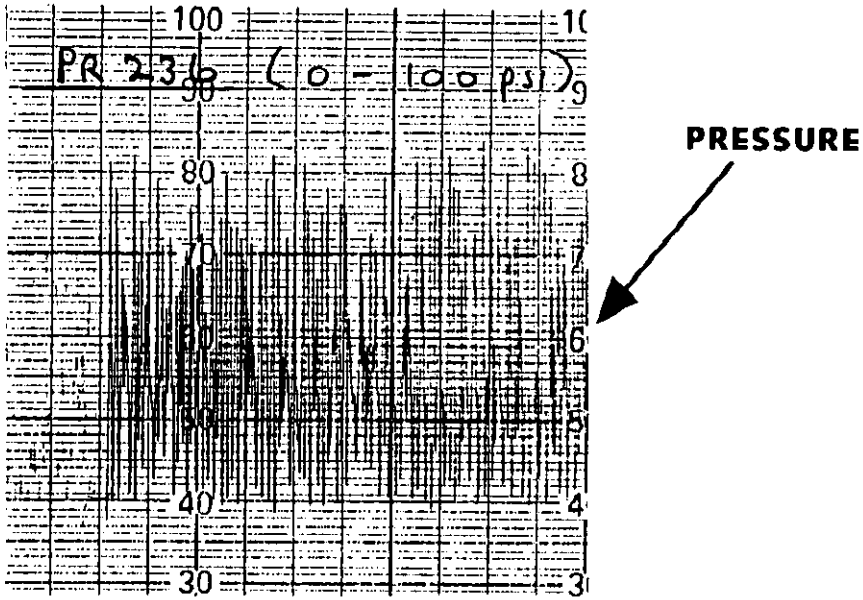
Poor control of the process can have severe effects on metering. A new field generally comes on stream under relatively stable conditions. Once water break through occurs and / or gas lift is used to maintain the production rates and remote satellite fields are brought on stream then test and first stage separators can be subject to large shifts in pressure due to slugging in production risers and production pipelines. These shifts under some conditions can be violent enough to trip the process or create excessive surges in flow which can induce severe metering swings at best or permanent damage to the associated meter. Turbine meters with scored and overheated bearings and orifice plates bowed beyond their elastic limit (plastic deformation) are often the result of such surges.

Figures 2 and 3 shows just what the pressure, temperature and flow rate fluctuations can be on a slugging well produced via a test separator with a comparatively 'slow' process control system. The flow rate fluctuations are, along with the pressure changes, large due to the relative slowness in the controls. These of course lead to significant shifts in metering accuracy when compared to more stable wells.

The flow surges are large and with turbine meters the effects of surge or overspeeding can be more damaging to bearings etc. Once the problem is identified then solutions can be put in place. Many of the older generation platforms are often pneumatic controlled (see Figure 5) and it is these that are now troubled by slugging wells and the features shown in Figures 2 and 3 are typical. Improvement in control may be brought about by installing electronic analogue or digital controllers, which of course speed up the control functions by eliminating the transmission lags especially if the controllers are mounted remote (in the control room) from the separator.

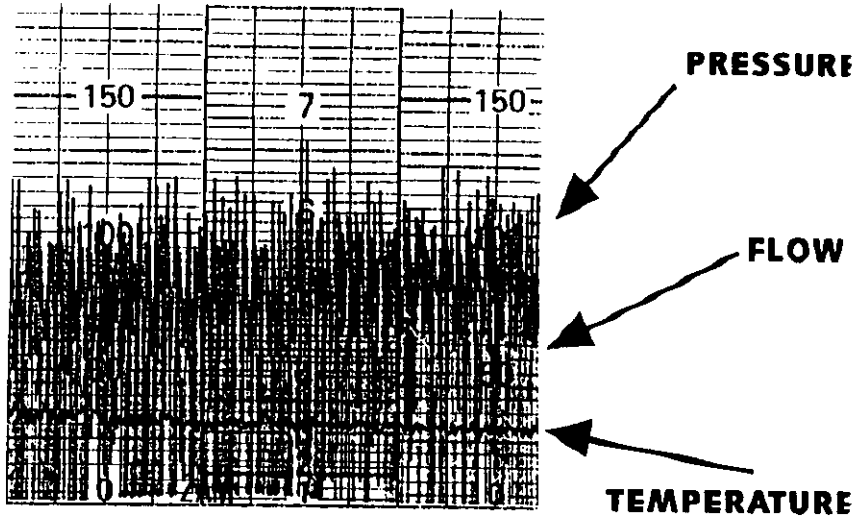
However the assessment of the improvement on metering is difficult to quantify and hence the justification to management for finance to carry out the modifications often has to be concluded as part of a safety or process improvement rather than a straight metering upgrade.

BEFORE



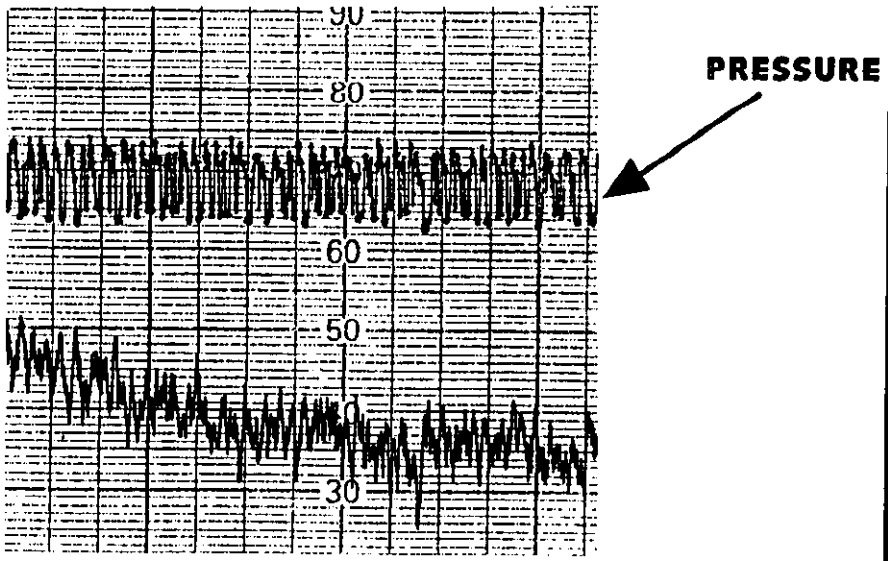
TEST SEPARATOR PRESSURE

BEFORE



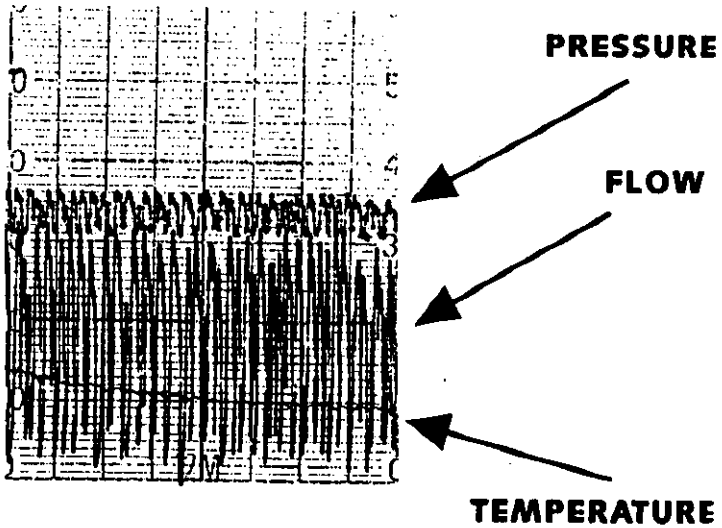
TEST SEPARATOR GAS METERING

AFTER



TEST SEPARATOR PRESSURE

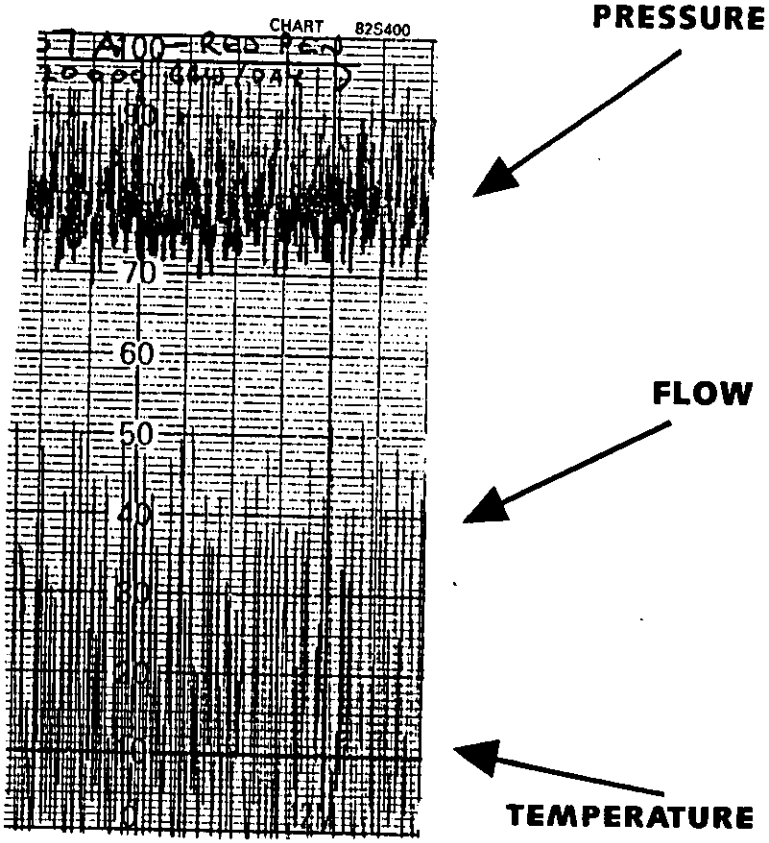
AFTER



TEST SEPARATOR GAS METERING

FIG. 2 SEPARATOR GAS PRESSURE & GAS METERING

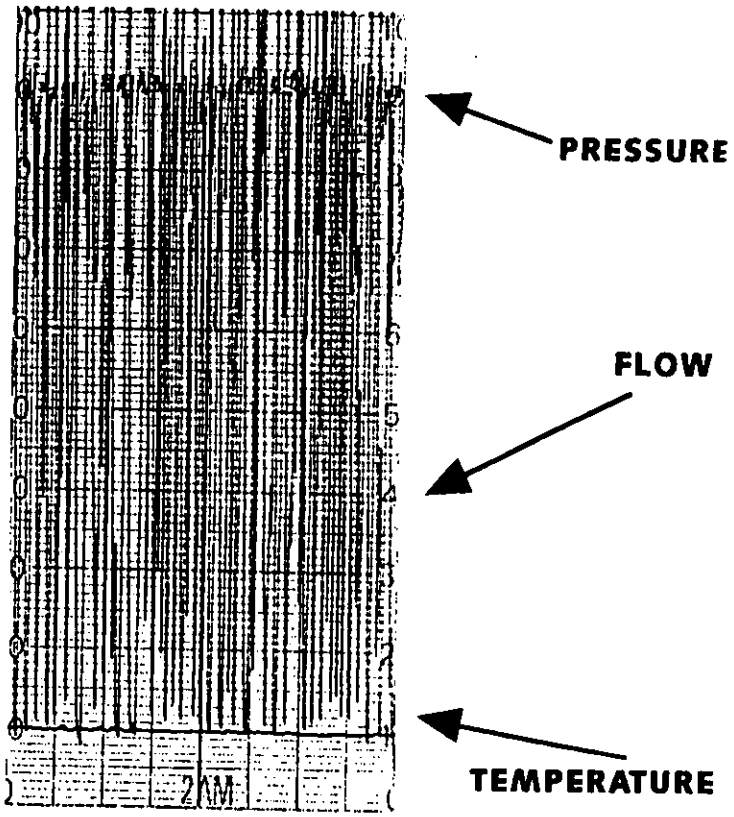
BEFORE



FLOW SCALE 0 - 20,000 BBL/DAY

TEST SEPARATOR OIL METERING

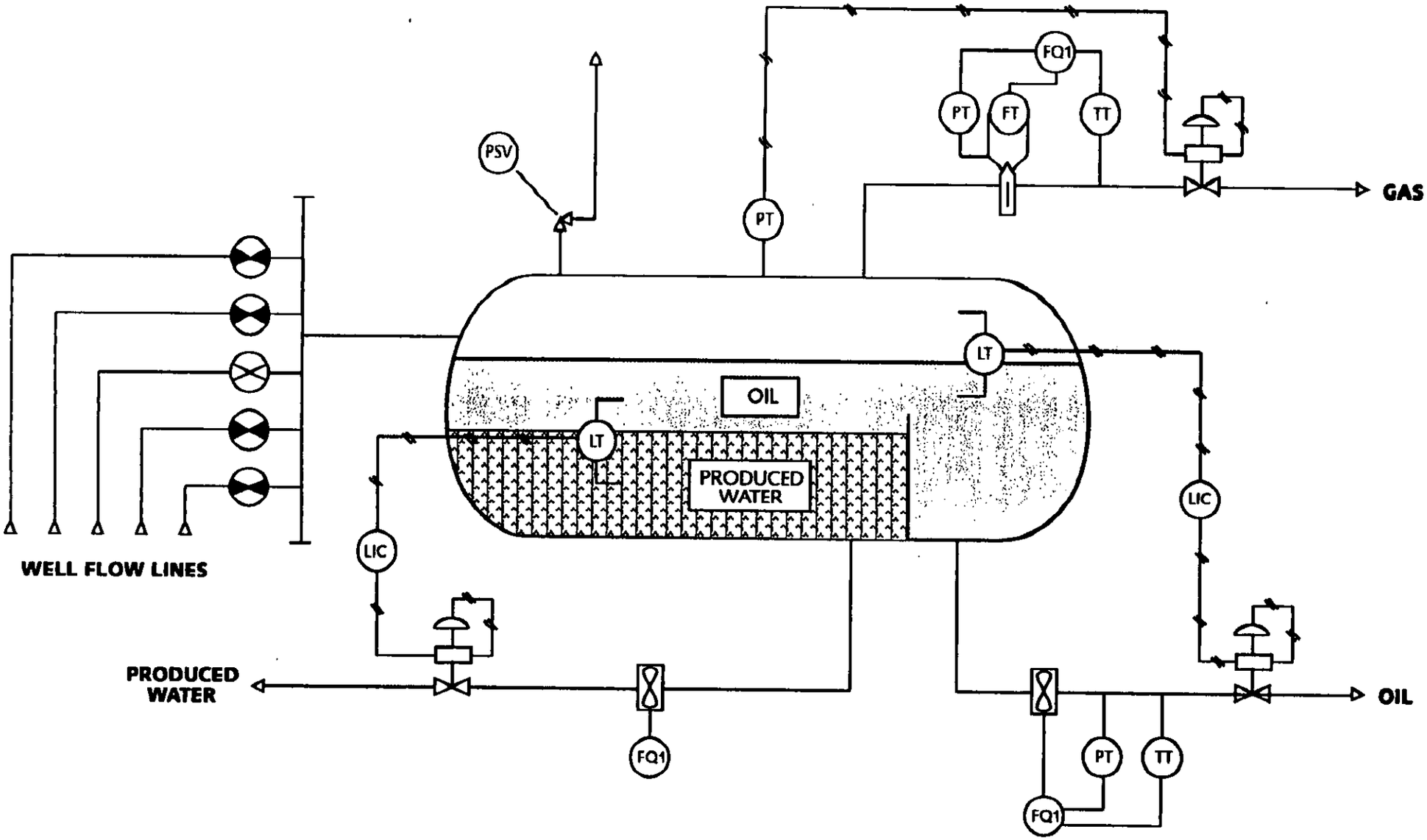
AFTER



FLOW SCALE 0 - 7500 BBL/DAY

TEST SEPARATOR OIL METERING

FIG. 3 SEPARATOR OIL METERING



TYPICAL TEST SEPARATOR - FIG. 5

METERING INTERFERENCE

So far in my career I've come across several cases of interference. These were from electrical sources. The first was from a thyristor powered gas heater. The interference was irregular and rose and fell with the e.m.f. imposed on the turbine cables for the heater supplies.

The second was less easy to spot. This case comprised of a compact metering skid complete with a booster pump, inlet and outlet headers, two parallel meters and a bypass line. During production commissioning it was found that wells flowing through this meter skid were producing flow rates in excess of what had been metered in the past. By accident it was noted that the isolated spare meter was giving a readout. We changed over the meters and again found the metered flow rates were high and the 'spare' meter too had a reading. The final check (days later) was to flow through the bypass line and check the meters. Yes you guessed it - they both gave a readout.

2" meter (MF11400 p/l)	-	18.947368 litres per hour.
3" meter (MF8900 p/l)	-	24.2694 litres per hour.

It took a while of course - but no doubt you can tell me what the frequency of my platform supply is.

The solution to both the above problems was to install a resistance / capacitive bridge across the turbine meter pick-up coils. This was done by trial and error until the interference was eliminated. In the latter case we quizzed the turbine meter vendor on the problem. There was unfortunately no help forthcoming from that source!

METERED PRODUCTS

In the UK our production licenses require us to meter all the products "won or saved". It is here that I must apologise to representatives of Her Majesties Government for not sticking closely to my license requirements. Two products we produce continuously one of which we don't meter with a great deal of certainty.

These are :-

- Sand
- Wax

Sand production from the reservoirs we produce varies enormously. The rate often depends on the reservoir geology and production flow rates. Removal of 2 tonnes of sand from a test separator over an 18 month period is not unusual. This of course doesn't take into account the sand flowed away via the water or oil or even the gas phases.

Sand of course flowing in a liquid not only introduces errors in metering (both volumetric or mass flow) and can introduce some interesting effects on the meters themselves. The effects of course will depend on the sand rate, velocity meter design etc.

Wax production in North Sea crude oil is not uncommon. It's rate varies from field to field, and whilst the crude is hot, and the wax is kept in solution it tends not to be a problem. When it comes out of solution, that's when we can experience problems. Pick up on a stationery turbine meter can increase the meter readout by 10 to 15%. The wax can of course be removed by high velocity flows and high temperature use, however those conditions are not always available and in the interim products will be over-metered.

SYSTEM DESIGN

Between us, the system designers, design contractors and the practioners we know all there is to know about the design of metering system. Right? Wrong!!

The mistakes we made 30 years ago in Texas are those we made 20 years ago in the early days of the North Sea, 10 years ago when the money was big in the North Sea and were making the same ones today when the barrel price is low and we can't afford the mistakes. Why are we making the mistakes?

Basically its because we can never know enough about the subject. So lets look at one or two typical problems we can see on a meter skid.

FOUR WAY VALVES

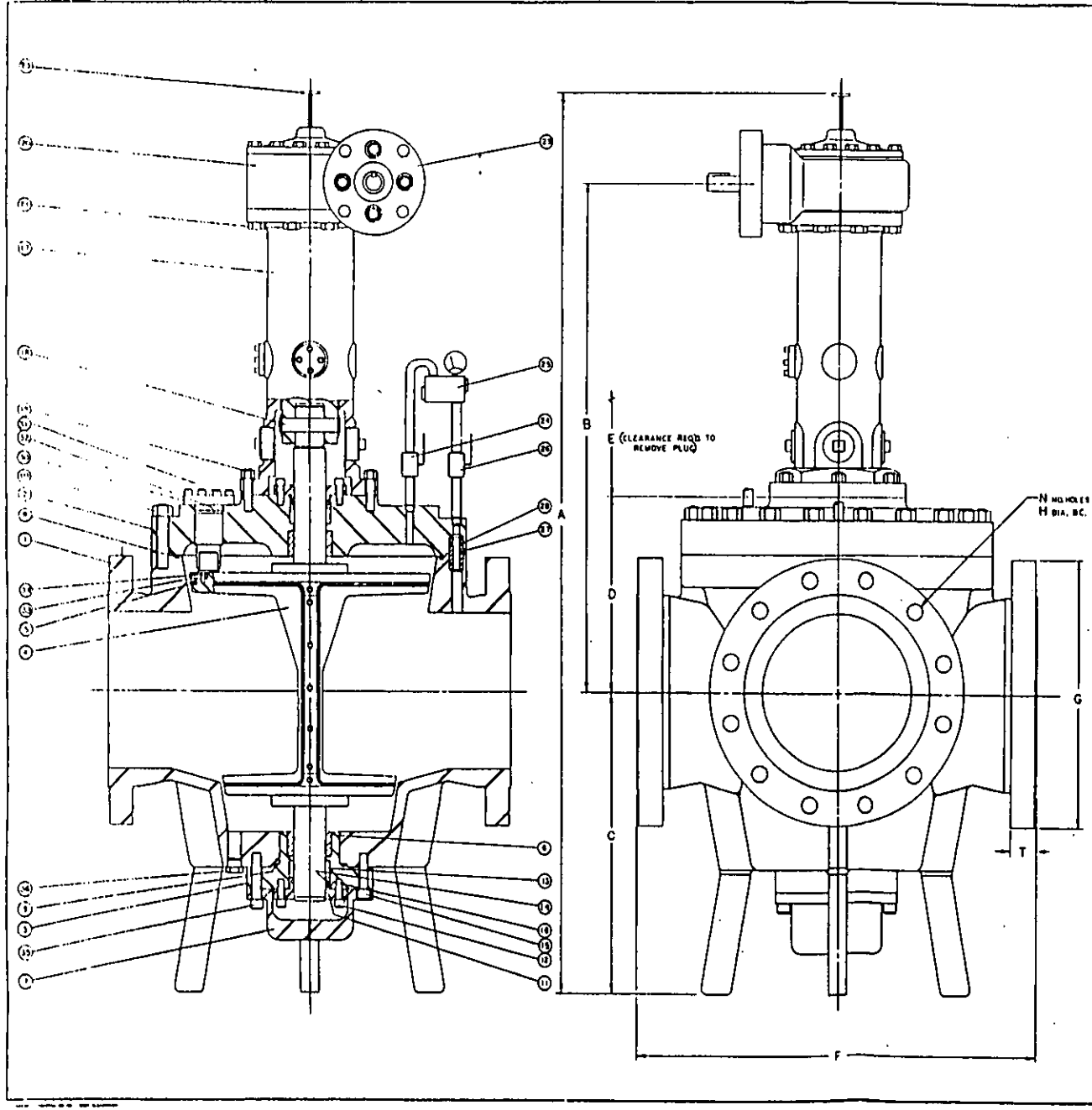
Traditional bi-directional prover loops utilise a 4 way valve to reverse the flow in the loop. These are relatively simple devices but require very tight dimensional tolerances to maintain a product seal. I've no doubt that some serious design work has been carried out over the years to calculate the stress levels in the pressure containing parts and the loadings on the flanges etc. I'm also equally confident that the system designers (and builders) prepare a competent design and carry out all the necessary pipe stress calculations to ensure no part of the design is working outwith its design limits. This is all well and good provided there is very tight dimensional control during fabrication. Without this control, additional stresses can be induced in the flange faces leading to ovality or distortion of the internal bore. This can result in early failure of at least one set of slips. The evidence for this is usually leakage through one flow path and sealing in the other flow path, or motor drive failure due to torque fluctuations.

If you're the system builder out there, I know you'll be saying that cannot possibly be your skid. But if you surveyed the offshore maintenance teams who have had reason to remove a 4 way valve and refit it - you'll find that a good proportion had to use a come-along lever to line up the pipework. I can't say I've observed it - but the valve always appears to be in place first thing in the morning! My Irish friends talk about the "little people", no doubt my Norwegian friends talk about the Trolls who have carried out the installation.

Figure 6 shows a typical 4 way diverter valve. If we review a 10 inch 600 lb raised face valve, the fixing bolt details are :- =

-	number of holes	-	16
-	pitched circle diameter	-	17 inch.
-	bolt diameter	-	1.25 inch.
-	bolt torque	-	560 ft / lb for stress of 40,000 psi (ok for ASTMA - A193-B7 bolts).

It is difficult enough to align a two way valve and a 4 way valve requires all four mating surfaces to be square and accurate. Any slight deviation in even one face during assembly could impose torque loadings on flange faces and valve bodies in the region of 45,000 ft / lb. No wonder we from time to time find the valve failing. It needs a lot of care in assembly.



ITEM	DESCRIPTION	MATERIAL
1	BODY	CAST STEEL
2	BONNET	CAST STEEL
3	TRUNNION HSG.	STEEL
4	PLUG	CAST STEEL
5	PLUG SEAL	VITON
6	TRUNNION BUSHING	TYPE 2 NI-RESIST
7	TRUNNION CAP	STEEL
8	O-RING	BUNA
9	O-RING	BUNA
10	STUD & NUT	STEEL
11	PACKING GLAND	STEEL
12	CAPSCREW	STEEL
13	PACKING SET	VITON & ASBESTOS
14	'T' SEAL	BUNA
15	CAPSCREW	STEEL
16	O-RING	BUNA
17	OPERATOR ASSEMBLY	
18	TRUNNION-OPERATOR PIN	STEEL
19	OPERATOR STUD & NUT	STEEL
20	GEAR HSG. ASSY	
21	GEAR HSG CAPSCREW	STEEL
22	HANDWHEEL (NOT SHOWN)	STEEL
23	INDICATOR FLAG	STAINLESS STEEL
24	BODY ISOLATION VALVE	STEEL
25	THERMAL & PRESSURE RELIEF MANIFOLD	STEEL
26	PORT ISOLATION VALVE	STEEL
27	BONNET ALIGNMENT PIN	STEEL
28	O-RING W/BACK-UP	BUNA
29	MOTOR ADAPTER FLANGE	STEEL
30	ADJUSTABLE ROTATIONAL STOP	STEEL
31	CAPSCREW	STEEL
32	O-RING	BUNA
33	SEAL RETAINER PLATES	STEEL
34	CAPSCREW	STEEL
35	CAPSCREW	STEEL
36	DRAIN PLUG	STEEL

SIZE	ANSI	WEIGHT	A	B	C	D	E	F	G	T	H	N	C_v
2	150				9	6 1/8	17 1/4	17	6	1/8	4	4 3/4	290
	300				9	6 1/8	17 1/4	17	6 1/2	1/8	8	8	290
	600				9	6 1/8	17 1/4	18	6 1/2	1	8	8	290
3	150				9	6 1/8	17 1/4	17	7 1/2	1 1/8	4	6	400
	300				9	6 1/8	17 1/4	17	8 1/2	1 1/8	8	8 3/4	400
	600				9	6 1/8	17 1/4	18	8 1/2	1 1/2	8	8 3/4	400
4	150				9	6 1/8	17 1/4	17	9	1 1/8	8	7 1/2	647
	300				9	6 1/8	17 1/4	17	10	1 1/8	8	7 1/2	647
	600				9	6 1/8	17 1/4	18	10 3/4	1 3/4	8	8 1/2	647
6	150				13 3/4	11 1/4	24 3/4	24	11	1 1/4	8	9 1/2	1960
	300				13 3/4	11 1/4	24 3/4	24	12 1/2	1 1/4	12	10 3/4	1960
	600				13 3/4	11 1/4	24 3/4	26	14	2 1/4	12	11 1/2	1890
8	150				13 3/4	11 1/4	24 3/4	24	13 1/2	1 1/4	8	11 3/4	2425
	300				13 3/4	11 1/4	24 3/4	24	15	1 1/4	12	13	2425
	600				13 3/4	11 1/4	24 3/4	26	16 1/2	2 1/4	12	13 3/4	2425
10	150	2250	67 1/2	39 1/4	21 1/2	15	32 3/4	32	16	1 1/4	12	14 1/4	4250
	300	2400	67 1/2	39 1/4	21 1/2	15	32 3/4	32	17 1/2	1 1/4	16	15 1/4	4250
	600	3250	67 1/2	39 1/4	21 1/2	15	32 3/4	36	20	2 3/4	16	17	4250
12	150	3175	67 1/2	39 1/4	21 1/2	15	32 3/4	32	19	2	12	17	5100
	300	3375	67 1/2	39 1/4	21 1/2	15	32 3/4	32	20 1/2	2	16	17 3/4	5100
	600	4450	67 1/2	39 1/4	21 1/2	15	32 3/4	36	22	2 1/4	20	19 1/4	5100
16	150	5875	74 1/2	42 3/4	25	18 1/2	35 1/2	40	23 1/2	2 1/4	16	21 1/4	8800
	300	6175	74 1/2	42 3/4	25	18 1/2	35 1/2	40	25 1/2	2 1/4	20	22 1/2	8800
	600	8100	75	42 3/4	25 1/2	18 1/2	35 1/2	40	27	3 1/4	20	23 3/4	8800

DANIEL 4-WAY DIVERTER VALVE 2" THRU 16
150 THRU 600 ANSI

SCALE: NONE
DATE: 05-18-78
PROPERTY OF DANIEL IND.
FIGURE NOS. 471G, 473G, 475G
SK-C-0069

FIGURE 6 TYPICAL FOUR WAY DIVENTER VALVE

SKID DESIGN

Too often we design meter skids wherein we are unable to remove individual meters without disassembling the majority of the skid.

In our rush to preserve straight lengths and the minimum of bends prior to and after the flow meter we build in considerable maintenance problems. Figure 7.1 is typical of our design. By the judicial use of flange elbows (see Figure 7.2) we are able to drop our individual meters easily, with a (hopefully) small cost in weight.

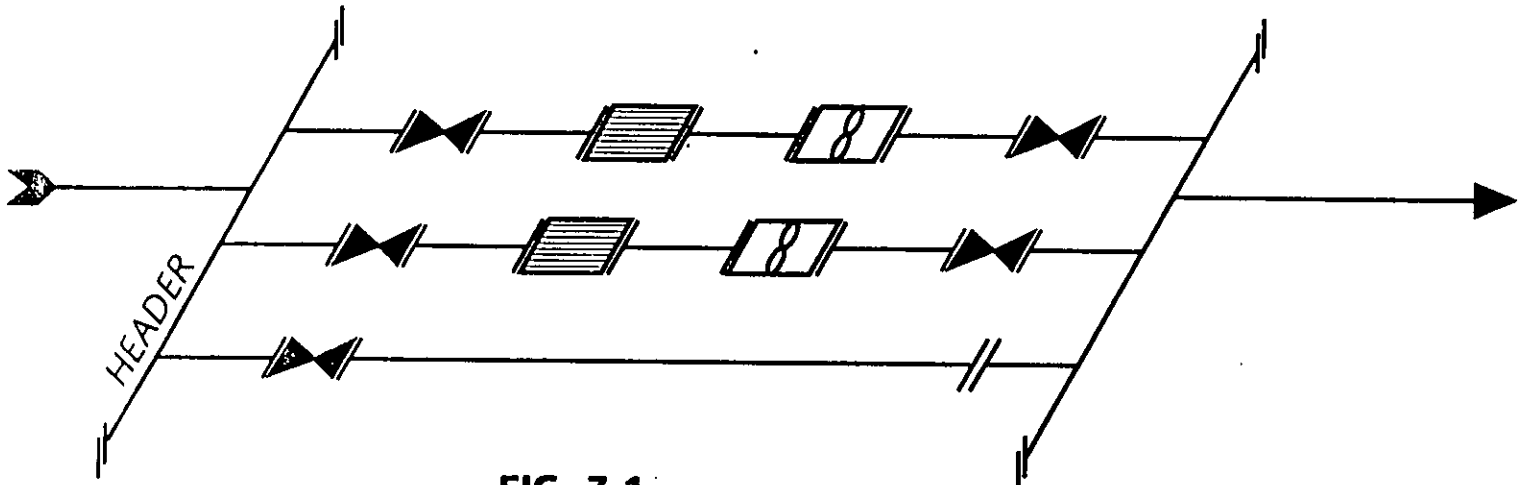


FIG. 7.1

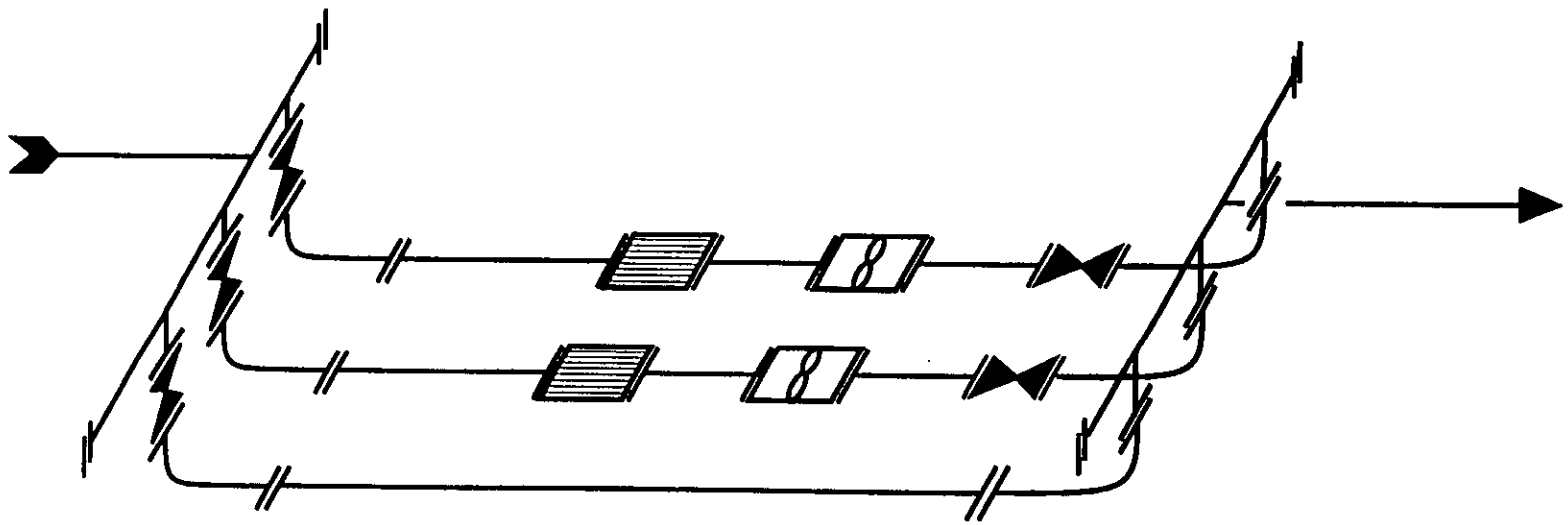


FIG. 7.2

FLOW METER SKID DESIGN FIG. 7

SIMPLE METERING PROBLEMS

Some of the simple metering errors which seriously affect our ability to meter accurately and repeatedly :

- Turbine meters which have been oversped during commissioning. During commissioning it has been known for plant equipment to be filled too quickly, displacing nitrogen which overspins the turbines.

- Meters installed back to front. If the meter is flow direction sensitive - get it marked with flow directions. I don't doubt we all know what way up a meter goes, but we as practioners don't install that many meters these days. The number of meters installed back to front is surprising. The problem is two way though... sometime we don't know which way the flow is going with a convoluted pipework set-up!.

- Self draining impulse lines. One major manufacturer of replaceable orifice fittings installs the orifice tappings on the horizontal. The only way to get vertical lines (for gas service) is to install the meter on the horizontal.

- Test equipment. From time to time test equipment has to be returned to the beach for calibration or maintenance. It is a relatively frequent occurrence for the test equipment to be returned with a certificate of conformity and a note saying the calibration certificate "will follow later". It does of course follow later - not a lot later, with the invoice! So guess where the certificate is when the external auditor is checking? Yes, in the invoice files! And no, you cannot have the original, you can only have a copy..... so says the invoice clerk, when you've back-checked the calibration laboratory, the buyer, the engineer, etc.

METER CALIBRATION

The calibration of meters on a live plant is always a problem. There are enough papers in the public domain on the use of meter provers, compact provers, etc. However even with the use of an (expensive) compact prover, it is difficult on a live plant to fully characterise a meter, because we are often unable to provide the full range of flow rates.

I have in the past calibrated turbine meters on test separators using a compact prover, but generally, due to cost and time constraints, its been a one or two point calibration. This does have limitations. So I discussed the problem with Nick King and Richard Paton at the National Engineering Laboratory.

I didn't want to calibrate using water - this could be done by one of several certified test houses - and I did want to use oil. I would have preferred dead crude, and still would prefer that product, but processed oil of the right density and viscosity, I am assured is just as good. So we thought we'd give it a try.

The real problem is to get a laboratory to simulate your real world conditions. In general they cannot meet your operating pressures, which in a test separator can range from 4 to 40 barg, or temperature ranges which as you will have seen earlier can range from 50°F (10°C) to 200°F (95°C). The results of the controlled test are shown in Figure 8, and the calibration data is shown in Table 2.

However as soon as the meter went offshore and was calibrated against a compact prover we came up with the real world problems.

We ran out of time, had a boat to catch and could only get one calibration run in - and of course we certainly couldn't attain the process figures for which the meter now had a certified calibration curve.

We ran at 90°C, 11.6 barg, 0.9913 kg/l and 8.7 litre / second. Our meter factor was close - but not close enough at 29.37012 p/l. Thus area needs much more work by both parties.

FIGURE 8. TURBINE CALIBRATION CURVE

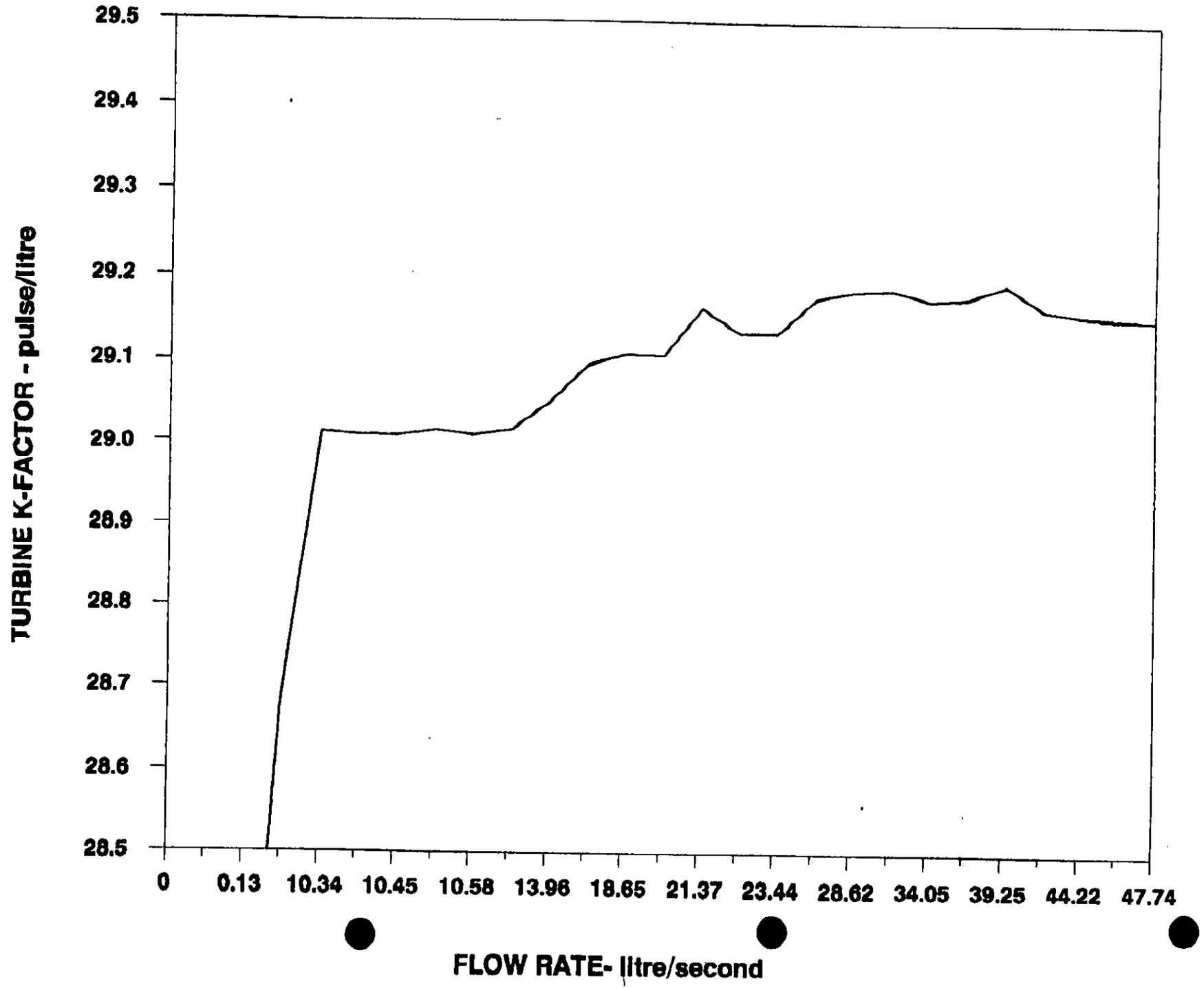


TABLE 2 - CALIBRATION DATA

TEST NUMBER: 6524/1	DATED: 23 Jul 93	TEST OPERATOR RB

CALIBRATION OF 3 INCH TURBINE METER

Fluid Density @ 20 C : 0.817032 kg/l	Exp. Factor : -0.0008482/deg C

Point No.	Time s	Temp. C	Corr/ Weight Kg	Volume l	Flow Rate l/s	Turbine Pulses P	K-Factor P/l
1	227.77	20.26	741.56	907.82	3.99	26037	28.681
2	114.23	20.42	757.50	927.46	0.12	28887	28.001
3	74.87	19.87	767.39	939.14	12.54	27250	29.016
4	79.14	21.27	1106.28	1355.45	17.13	37437	29.095
5	68.57	20.05	1119.29	1370.01	19.88	38877	29.107
6	75.79	20.73	1450.83	1776.83	23.44	51767	29.134
7	136.37	21.27	2840.76	3491.70	25.60	101871	29.175
8	103.97	20.59	2891.41	3540.69	34.05	103296	29.174
9	125.53	20.07	3961.22	4848.58	39.25	141547	29.193
10	87.44	20.93	2899.82	3552.02	40.62	103500	29.164
11	80.77	20.93	2922.95	3580.34	44.33	104381	29.154
12	74.55	20.89	2905.63	3559.02	47.74	103757	29.153
13	80.64	20.73	2911.84	3588.14	44.22	103977	29.157
14	99.44	20.36	2911.04	3564.02	35.84	103985	29.177
15	110.17	20.17	2887.00	3534.05	32.08	103143	29.186
16	128.35	20.60	2999.25	3672.79	28.62	107186	29.184
17	161.80	20.71	2823.12	3457.42	21.37	100829	29.163
18	79.58	20.57	1468.41	1788.13	22.80	52387	29.134
19	73.85	20.15	1125.22	1377.38	18.65	40094	29.109
20	67.70	20.40	771.88	945.05	13.96	27454	29.050
21	87.88	20.83	758.24	929.92	10.58	26975	29.008
22	89.70	20.77	767.51	940.00	10.48	27274	29.015
23	89.04	20.81	759.88	930.53	10.45	26992	29.007
24	89.80	20.45	762.18	933.23	10.39	27071	29.008
25	89.98	20.30	760.24	930.73	10.34	27003	29.013
26	148.45	20.24	743.06	908.85	8.13	28322	28.838

COST OF OWNERSHIP

The term 'cost of ownership' is now the vogue terminology with many oil companies. Our managements are seeking routes by which economies can be made, especially as fields mature, production (revenue) declines and overheads probably climb.

We as Metering Engineers may be looked at in one of two ways :

- an expensive overhead who constantly demands additional monies to 'improve' his black art / black box systems, with no perceived pay back.

or - the keeper of the cash register.

I fear, due to our own reticence, we fall into the first bracket, and unfortunately many of our managers fail to understand what we do or how we do it - or even in some cases why.

I have not spent a long time on this, but have wanted to explore the area of 'cost of ownership' for some time.

The problem is, to do it properly you need a large data base, and it is perhaps an area for a Joint Industry Project. I'll admit its not an exciting topic, but one in which we perhaps as Engineers should be looking at.

As an example I have selected a semi-fiscal 8 inch gas flowline and tried to compare an orifice fitting with say a ultrasonic meter. See Tables 3 and 4.

On a straight CAPEX and OPEX summation the orifice plate appears to be cheaper of the two units, until about year 6. However to carry out the study to its end conclusion we need to look at :

- replacement costs within this life time in terms of seals, lubricants, bolts, gaskets and primary and secondary instruments.
- theoretical and actual (real life) metering uncertainties,

and there is no doubt that this latter topic could swamp the calculation dramatically one way or the other should one meter be just 10 or 15% "better" with respect to overall metering uncertainty.

TABLE 3 - COST OF OWNERSHIP
8 INCH ORIFICE METER

CAPEX

8 INCH FLOWLINE, HP CHAMBER, STRAIGHTENER, AND ELEMENT	£	12,500
FLOW TRANSMITTER	£	1,200
PRESSURE TRANSMITTER	£	1,200
TEMPERATURE ELEMENT & THERMOWELL	£	1,000
FLOW STRAIGHTENER	£	1,500
FLOW COMPUTER	£	5,000
FLOW RECORDER	£	1,000
SUPPORT STEEL (1 TONNE)	£	8,000
CAPEX (Excl cabling)	£	31,400

OPEX

CHECK FE	12 TIMES / PA	48 man hours
CHECK FX	4 TIMES / PA	12 man hours
CHECK PX	4 TIMES / PA	6 man hours
CHECK TX	4 TIMES / PA	12 man hours
INSPECT BORE	1 TIMES / PA	24 man hours
CHECK FR	4 TIMES / PA	4 man hours
	OPEX	106 man hours per year

For £50 per hour -	The cost of ownership : Year 1	£	36,700
	The cost of ownership : Year 2	£	42,000
	The cost of ownership : Year 3	£	47,300

TABLE 4 - COST OF OWNERSHIP
8 INCH ULTRASONIC FLOWMETER

CAPEX

FLOW ELEMENT, TRANSMITTER, FLOW COMPUTER AND RECORDER	£	50,000
PRESSURE TRANSMITTER	£	1,200
TEMPERATURE ELEMENT AND THERMOWELL	£	1,200
8" FLOWLINE	£	4,000
SUPPORT STEEL (3/4 TONNE)	£	6,000
CAPEX (Excl cabling)	£	62,400

OPEX

CHECK PX	4 TIMES / PA	6 man hours
CHECK TX	4 TIMES / PA	12 man hours
CHECK - "No Flow" Conditions		2 man hours
	OPEX	20 man hours per year

For £50 per hour -	The cost of ownership : Year 1	£36,700
	The cost of ownership : Year 2	£42,000
	The cost of ownership : Year 3	£47,300

THE FUTURE

Nick King of the NEL at the 1991 North Sea Flow Metering Workshop asked us as a group, where we thought we ought to be in 10 years time. Its taken me 2 years to prepare a response to this.

Firstly we need to understand why we exist - and in this respect it is to protect the revenue due to our employers, and we do this by minimising possible losses. In order to do this we need flow meters that are :

- accurate.
- repeatable.
- process tolerant.
- reliable.
- economically viable.

and finally - easily verifiable,

and I hope that's why we're all here this week, to determine just what this elusive beast will look like.

ACKNOWLEDGEMENTS

I would like to thank the management of Phillips Petroleum Company (U.K.) Limited and its partners in the Maureen field, Agip (U.K.) Limited, British Gas E & P Limited, Fina Exploration Limited and Pentex - for permission to prepare and publish this paper.

My thanks are also expressed to the many colleagues and friends in Aberdeen, NEL East Kilbride, and in a variety of offshore locations who assisted me with ideas and encouragement in the preparation of this paper.

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Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

High Accuracy Wet Gas Metering

by

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Shell U.K. Exploration and Production

HIGH ACCURACY WET GAS METERING

Authors

P.F. Dickinson A.W. Jamieson

Shell U.K. Exploration and Production

Summary

For economic development of several small marginal gas fields in the Southern North Sea, evacuation routes may be shared with other parties. It is therefore necessary to apply high accuracy metering prior to commingling. Conventional orifice metering stations require the gas to be dry, necessitating the installation of expensive separation facilities whose cost may make development of these fields uneconomic. An alternative is to install venturi meters to measure the wet gas flowrate of each well stream. The readings can then be summed to give the total production with an overall uncertainty of about 1%. This is similar to a conventional fiscal metering station. For a typical field eliminating the bulk separation facilities can save up to £20 Million. The paper covers the design of the metering system, its practical implementation and quantification of the measurement uncertainty.

High Accuracy Wet Gas Metering

Introduction

Shell Expro has discovered a number of small gas fields in the Southern North Sea which are not economically viable unless costs can be significantly reduced. If unprocessed well stream fluids could be metered to sufficient accuracy to allow commercial custody transfer and to satisfy Department of Trade and Industry requirements it would then be possible to commingle fluids from a number of fields prior to separation. It is then no longer necessary to dedicate facilities for processing gas to each field, thus allowing the use shared processing and transportation facilities including ullage within existing infrastructure. Furthermore, metering the gas to high accuracy as it leaves the field allows much greater operational flexibility of both offshore and onshore facilities. All of the above lead to significant savings; the removal of the bulk processing facilities on a single development can alone realise savings of up to £20 million.

Extensive work on metering wet gas has been performed previously. Most notable is the work of Murdock[1] and Chisholm[2,3] dealing mostly with wet steam measurements. They developed semi-empirical equations that quantified the over-reading of orifice meters caused by entrained liquids.

Shell Research carried out extensive tests on behalf of NAM in the Netherlands during the late 1980s. These demonstrated that the over-reading of both orifice meters and venturi meters measuring natural gas at pressures around 80 bar and with liquid fractions up to 4% by volume followed Chisholm's and Murdock's predictions. This work was presented at the 1989 North Sea Flow Metering Workshop[4]. For liquid fractions up to about 4% the over-reading appeared to increase linearly as the liquid content increased. A measurement uncertainty additional to that experienced on dry gas was quantified to be about 1% per 100 m^3 liquid per 10^6 normal m^3 gas. This results in a total uncertainty of less than 2% for a well installed orifice or venturi meter for liquid fractions up to 1% by volume. Although there were differences between the field measurements and Murdock's and Chisholm's expressions, the errors involved were acceptable for NAM's applications. However, these differences are too large to be generally acceptable for fiscal and custody transfer purposes.

NAM have used wet gas meters to eliminate test separation facilities. For Shell Expro the immediate interest is in eliminating dedicated bulk processing facilities and permitting the use of shared transportation facilities. Figure 1 shows an overview of a typical simplified development indicating equipment which can be eliminated. The elimination of test separators is seen as an additional long term goal. For typical UK Southern Basin gas fields Shell Expro is satisfied that high accuracy, approaching 1% uncertainty, wet gas metering systems are now fully practicable and can be satisfactorily operated on unmanned off-shore installations.

Wet Gas Metering System

Overview

The measurement system (Figure 2) comprises a traditional venturi flow meter installed in each well flow line with pressure and temperature measurements providing on-line corrections for changes in operating conditions. A test separator, with an on-line gas chromatograph and conventional manual sampling facilities to permit on-shore analysis of the liquid samples, is used to establish the well stream composition and other parameters during periodic well testing. Flow calculations, including Murdock's compensation for the entrained liquids, are performed in by an on-line computer system. Murdock's equation (1) was selected as it appears to produce a lower uncertainty than Chisholm's equation.

$$Q_g = \frac{Q_u}{1 + 1.26 \frac{(1-X)}{X} \frac{C_g \varepsilon_g}{C_l} \sqrt{\frac{\rho_g}{\rho_l}}} \qquad (1)$$

Where:
Q_g is the corrected gas mass flowrate,
Q_u is the uncorrected gas mass flowrate,
X is the gas mass fraction,
C_g and C_l are the venturi gas and liquid discharge coefficients,
ε_g is the expansibility coefficient for the gas,
ρ_g and ρ_l are the gas and liquid densities.

Primary Measuring Element

A venturi meter, generally in accordance with ISO 5167, is installed in each well flow line, upstream of the choke to avoid the introduction of swirl. The Xmas trees are installed in such a manner that no out of plane bends are introduced upstream of the meter. Venturi meters are selected as the primary measuring elements. They are extremely robust and when combined with modern high precision differential pressure transmitters can achieve the required accuracies over a wide (ten to one) turndown. Pressure and temperature measurements are made at each meter. The differential pressure, pressure and temperature instruments are "smart" transmitters operating in digital mode. In addition to providing high accuracy and stability these instruments provide comprehensive fault diagnostics when integrated within a computer system.

The installation of custody transfer flow meters on a not normally manned installation could be expected to generate maintenance problems. However, the robustness of the venturi and the stability and reliability of modern transmitters are such that it is only necessary to check calibrations at intervals longer than six months to maintain the required accuracy.

The gas mass fraction, i.e. the gas mass divided by the total mass, and the compositions of the gas and liquid fractions must be measured at regular intervals. Currently it is only possible to measure these parameters with sufficient accuracy by using a test separator. A test separator is, however, significantly smaller and cheaper than a bulk production separator. More importantly for unmanned installations, it does not require immediate remedial maintenance when a malfunction occurs as production can continue uninterrupted until the next planned visit. Other applications of wet gas metering have stressed the elimination of the test separator. For us, elimination of the bulk separation equipment and commingling with other fields are the main benefits. Elimination of the test separator would be a further bonus for the future. Figure 3 shows the test separator arrangement. Bold lines indicate the fluid path when a well is being tested.

The gas flow from the test separator is measured using a venturi installation similar to the well flow line meters. The liquid from the test separator is measured using a Coriolis type mass flow meter which will give the liquid mass flowrate and density. The gas mass fraction is calculated from the integrated gas and liquid mass flow over the test period. Each well should only require to be assessed about once a year, as the composition of each well stream is not expected to vary rapidly. Initially it will be necessary to assess the wells at shorter intervals.

Sample facilities are provided on both the liquid and gas outlet streams. Manually taken liquid samples are analysed in an on-shore laboratory to determine the liquid composition. Note that the liquid samples do not need to be representative of the total flow, only a representative sample of the hydrocarbon liquids and a representative sample of the aqueous liquids are required. Onshore analysis of manually taken gas samples could also be used to obtain the gas composition, but we consider it preferable to use an on-line gas chromatograph. Gas density at test separator pressure and temperature can be calculated from the gas composition using AGA 8.

The liquid and gas composition data are combined with their respective flowrates to give the liquid and gas mass component flowrates, and hence the total well stream mass component flowrates (Figure 4). We have also determined the gas mass fraction, the gas density and the liquid density at the pressure and temperature prevailing during the well test. We now use all of these data as a basis to calculate the liquid and gas flow rates at other conditions of pressure and temperature.

Calculations

The calculation procedure is illustrated in Figure 5. The total well stream composition obtained from a well test is fed into a flash calculation. This calculates the changes in composition and the consequent changes in gas density, liquid density and gas mass fraction as line pressure and temperature vary.

The standard flow equation in ISO 5167 is used to calculate the uncorrected gas mass flowrate from the differential pressure across the venturi and the line gas density. Murdock's equation, modified as described below, is used to calculate the corrected gas mass flow. Finally, the liquid mass flow rate and the total mass flow rate are calculated from the gas mass fraction and the gas mass flowrate.

Modifications to Murdock equation

In the field measurements made for NAM[3] the slope of the graph of over-reading versus liquid content for venturi meters was some 5% higher than that predicted by Murdock's equation. The origin of this discrepancy is not clear, but it is too large to simply apply Murdock's equation directly and achieve high accuracies. As the total emphasis of our approach is to be able to apply wet gas metering now using existing equipment, it is important to be able to apply the most accurate correction to the metered wet gas. The value 1.26 in Murdock's equation was determined empirically. If this value is replaced by a variable M as in equation (2) we retain the form of Murdock's equation but can adjust it for wet hydrocarbon gas at the field operating conditions.

$$Q_g = \frac{Q_u}{1 + M\frac{(1-X)}{X}\frac{C_g \varepsilon_g}{C_l}\sqrt{\frac{\rho_g}{\rho_l}}} \qquad (2)$$

The value of M can be assigned from data gathered in laboratory or field tests. In laboratory tests measured amounts of liquid can be injected downstream of a reference meter but upstream of the wet gas venturi. The over-readings for different gas mass ratios, flowrates and pressures can be measured. In the field, at each well test the over-reading of the well venturi meter can be obtained directly by comparison with the test separator venturi and a value for M obtained for the conditions prevailing during the test. As the number of well tests increases the value for M can be refined, in principle for each well. However, we expect that in practice a single adjustment covering the platform will suffice. Eventually, as more data are obtained, it should be possible to refine the equation to provide a highly accurate equation specifically for natural gas at high pressure.

Uncertainties

Single meter

The overall uncertainty calculations were made in accordance with ISO 5168. The uncertainty for the venturi installation operating with dry gas was calculated in accordance with ISO 5167. The uncertainties associated with Murdock's equation were then calculated and the two combined to produce an overall uncertainty value for a single venturi meter measuring wet gas. Table 1 gives the relevant parameters and the values used in the analysis. Calculations have been performed for a typical development for high liquid loading. In this case the uncertainty in mass flow was shown to be 1.35%. Lower liquid loadings result in lower uncertainties; at design conditions the uncertainty is 1.25%.

The uncertainty of the gas mass ratio is calculated assuming that the gas and liquid flows are measured periodically using a test separator. The uncertainties for other parameters, given in Table 2, are taken from manufacturers' standard literature, from recommendations by NEL or from past practical experience.

A major source of uncertainty comes from the flash calculation and physical property generator used to calculate the gas mass fraction and gas and liquid densities over a wide range of operating conditions. Typical uncertainties are of the order of 3 - 5%. However, we have accurate direct measurements of liquid density from the well test, and application of AGA 8 gives the gas density from the gas composition with an uncertainty of 0.1% up to 120 bar and to 0.3 % up to 170 bar. To obtain the line gas and liquid densities we calculate the differences from the densities obtained at test separator conditions, effectively calibrating the flash calculation. By this combination of calibration and working in a differential mode the uncertainty in gas and liquid densities is reduced to about 2.0%.

Murdock's equation itself contributes significantly to the overall uncertainty. From the NAM test data we estimated an uncertainty of 0.76% for the highest liquid case. We anticipate that this uncertainty will be reduced as more data becomes available from laboratory tests and field experience.

Total export flow

For an installation where a number of nominally identical wet gas meters are summed the overall uncertainty in total mass flowrate is given by:

$$U_T = \sqrt{U_s^2 + \tfrac{1}{n} U_r^2} \qquad (3)$$

where U_S and U_T are the systematic and random uncertainties in the mass flowrate of a single wet gas meter and n is the number of wells. The uncertainty in total flow is therefore less than that of a single meter as the random errors present partially cancel.

A current Southern North Sea prospect which is expected to produce significant quantities of liquid has been selected as an illustration. It requires eight production wells. Table 3 gives the uncertainty in summed flowrate for up to eight wells, two liquid loadings, and two values of uncertainty in gas density. When all wells are producing at design flow rates the overall uncertainty in export flow rate measurement is about 1.15% at the highest liquid loading (about 0.9% by volume at line conditions). This is similar to a conventional sales gas export meter.

The above calculations assume that the gas and liquid densities and the gas mass fraction are calculated using a flash calculation and physical property generator which covers a wide range of pressure and temperature. It is possible to significantly reduce the uncertainties in these parameters if the operating envelope remains close to the test conditions. It is also possible to use the gas chromatograph to obtain the gas density of each well stream more frequently. Either of these allows the uncertainty in the gas density to be reduced to less than 1% which results in an uncertainty of about 1% for a single meter and 0.94% in the total export flow.

Either approach for reducing uncertainties can be implemented immediately. However, the first results in restricted operational flexibility while the second requires increased operating and maintenance involvement. We believe that it will be possible to achieve these lower uncertainties when we define the procedures for calibrating the flash calculation and physical property generator.

Practical points

To avoid complicating the measurement system, chemical injection points are only installed downstream of the metering system. Materials for all the piping and equipment upstream of the choke valves will be manufactured from corrosion resistant materials.

Installing a gas chromatograph on a not normally manned facility should not be treated lightly. We have successfully installed a gas chromatograph on a Southern North Sea platform for a trial period of some nine months, with virtuallly no intervention required. We are therefore confident that this is feasible. It is essential to ensure that no free liquid enter the columns of the gas chromatograph otherwise it may be out of action for days. We took the gas sample from the top of a horizontal run of pipe into a sample conditioning chamber. This was simply a short piece of vertical 2" pipe with a helical steel strip inside. This encouraged any liquid to gather on the walls and drain back into the pipeline. The sample should be heated sufficiently after leaving the sample conditioning chamber to ensure that no liquid can form in the pressure let down system for the gas chromatograph.

Valving will be included on the test separator to allow all the well fluids to pass through the gas venturi meter. This allows the over-reading due to liquids to be determined accurately. It also provides a check for the well flowline meters.

Further Work

Modifications to standards

Although ISO 5167 covers the use of Venturi meters, it does so only up to Reynolds number of 10^6. This does not cover the Reynolds numbers commonly met with in normal gas production operations. This is really a reflection of the lack of fully traceable data on which the standard is based.

The tappings given in ISO 5167 for a venturi are four for the upstream and throat pressure tappings, joined by a piezometer ring. This is impractical for wet gas metering as liquid will always gather in the lower parts of the piezometer ring. It would be preferable to have only two tapping points on the upper side of the venturi. However, tests will be required to show that the difference in discharge coefficient is negligible for multiple or single tappings.

The question of manufacturing tolerances must also be addressed. Currently, ISO 5167 gives an uncertainty of 1% in discharge coefficient for a venturi with a machined convergent for line internal diameters between 50 mm and 250 mm, and an uncertainty of 0.7% for venturis with a rough cast convergent for line internal diameters between 100 mm and 800 mm. These values are unacceptably large for high accuracy wet gas metering, but it is unlikely that they can be reduced to the value of 0.41% that can currently be achieved by calibration in a high quality laboratory installation.

If there is sufficient interest within the gas industry for wet gas metering a joint industry effort to extend the gas metering standards should be considered. A programme of work would be required to establish the reproducibility of manufactured venturis and the conditions under which they should be used. Further work is also required to quantify

the relation between the over-reading and the liquid content in more detail, particularly for higher pressures. In the long term it may be necessary to draw up a separate standard for wet gas meters.

Cheaper methods to determine the gas mass fraction

For many applications it is clearly desirable to eliminate the need for a test separator to determine the gas and liquid fractions, and the over-reading of the flowline venturi meters. Tracer techniques are being developed by Shell Research. Two tracers, one specific for the gas phase and one specific for the liquid phase are injected at known flow rates and at a point where good mixing can be obtained. The concentration of the tracers are measured downstream. The flowrates of the liquid and gas phases can be determined and hence the gas mass fraction.

Other applications

There is an obvious requirement for wet gas metering on subsea installations but there are significant practical difficulties in determining the liquid content in these circumstances. A subsea test separator is not an attractive option. Tracer injection into each well stream is straightforward but extraction of samples from each well stream to measure the tracer concentrations is very difficult. A more practical means of determining liquid content is clearly required.

Wet gas meters are special examples of multiphase meters. Multiphase meters in combination with a test separator could be used in a similar way to the wet gas meters to give higher accuracy metering of the multiphase flows from satellite wellhead platforms. The key is to reduce especially the systematic uncertainties. If the systematic and random uncertainties in a single meter could both be reduced to 4%, an overall uncertainty of 5% could be achieved with four wells.

Conclusions

High accuracy wet gas metering is a very attractive technique which is immediately available using proven equipment.

Unprocessed gas exported from typical Southern North Sea gas fields can be metered with an uncertainty of around 1% using venturi meters. This uncertainty is similar to that of a conventional sales gas meter.

Wet gas meters are suitable for installation on not normally manned platforms.

Bulk processing equipment is not required on the producing facility to allow metering. This reduces considerably the cost of a typical installation and allows new fields to utilise existing infrastructure at minimal cost. Savings in operational costs can also be achieved as wet gas metering installations are robust and require lower maintenance than conventional metering stations.

It is clearly possible to develop high accuracy wet gas metering further. Cheaper, more accurate methods of determining the gas mass fraction mean that a test separator will not be required. An extended and improved section on Venturi meters in the gas metering standards appears to be essential.

A similar approach can be used for metering unprocessed multiphase fluids from a satellite wellhead platform.

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3. D. Chisholm, Research Note: Two phase flow through sharp edge orifices, Journal of Mechanical Engineering Science, I.Mech.E 1977.

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Tables

Figures

Venturi Beta	0.6
Upstream Pressure	93 Bar.a
Gas Density	
- High liquid loading	86.34 kg/m^3
- Medium liquid loading	78.04 kg/m^3
Discharge Coefficient Gas	0.995
Discharge Coefficient Liquid	0.995
Expansibility Factor Gas	0.998141
Liquid Loading (per 10^6nm^3 of gas)	
- High liquid loading	91.5 m^3
- Medium liquid loading	73.4 m^3
Gas Mass Ratio (Gas mass/total mass)	
- High liquid loading	0.928
- Medium liquid loading	0.94
Liquid Density	
- High liquid loading	681.2 kg/m^3
- Medium liquid loading	708.1 kg/m^3

Table 1. Parameters and values used in analysis

	Random %	Systematic %	Total %
Uncertainty in Gas Discharge Coefficient	0.100	0.400	0.410
Uncertainty in Differential Pressure	0.141	0.141	0.200
Uncertainty in Expansibility Factor	0.000	0.015	0.015
Uncertainty in Gas Density			
- High Density Uncertainty	1.410	1.410	2.000
- Low Density Uncertainty	0.710	0.710	1.000
Uncertainty in Liquid Density	1.410	1.410	2.000
Uncertainty in Gas mass ratio from well test (Gas, liquid uncertainties 1% & 0.5% resp.)			
- High liquid loading	0.057	0.057	0.080
- Medium liquid loading	0.047	0.047	0.067
Uncertainty in Liquid Discharge Coefficient	0.100	0.40	0.410
Uncertainty in Murdock's equation (1% per 100m^3 liq. to 10^6 nm^3 gas)			
- High liquid loading	0.000	0.760	0.760
- Medium liquid loading	0.000	0.610	0.610

Table 2. Uncertainties in parameters

Number of wells summed	High D.U. High L.L.	High D.U. Medium L.L.	Low D.U. High L.L.	Low D.U. Medium L.L.
1	1.33	1.25	1.00	0.89
2	1.23	1.14	0.97	0.86
3	1.19	1.10	0.96	0.84
4	1.17	1.08	0.95	0.84
5	1.16	1.07	0.95	0.83
6	1.15	1.06	0.94	0.83
7	1.15	1.06	0.94	0.83
8	1.14	1.05	0.94	0.83

Table 3. Calculated uncertainties in summed flow rate for up to eight wells at high and medium Liquid Loading (L.L.) and at high and low gas Density Uncertainty (D.U.)

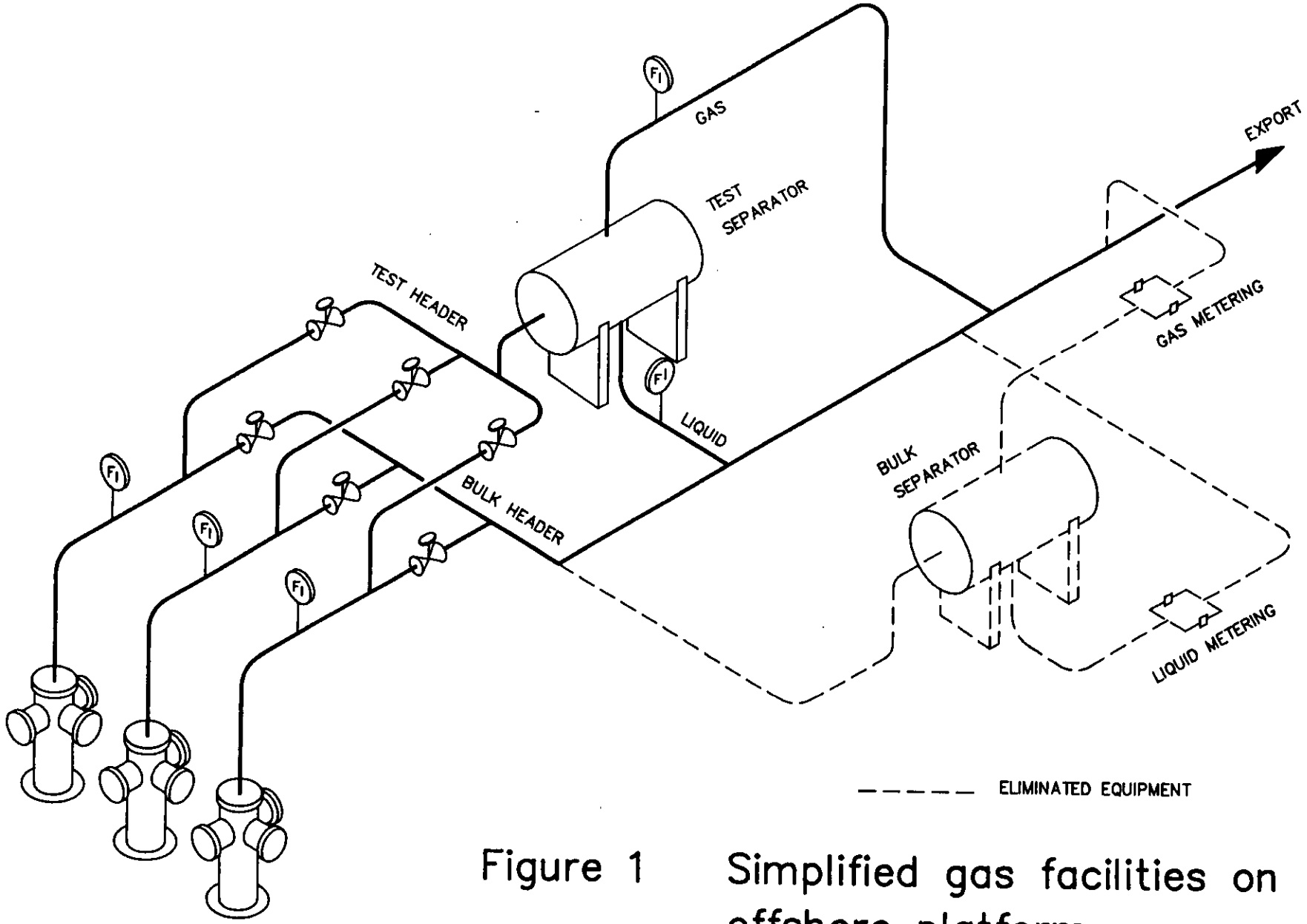

Figure 1 Simplified gas facilities on offshore platform

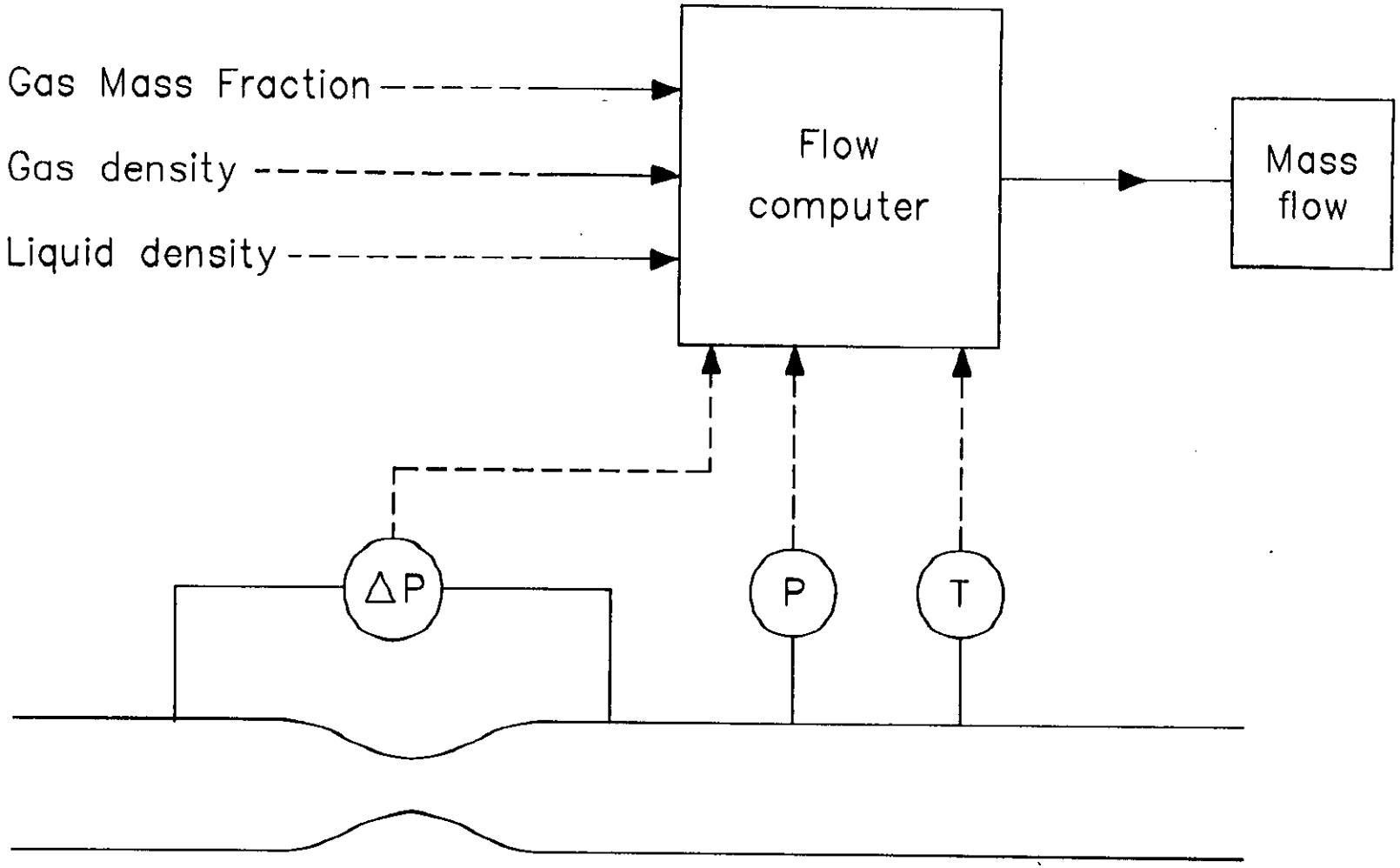

Figure 2 Wet gas measurement system

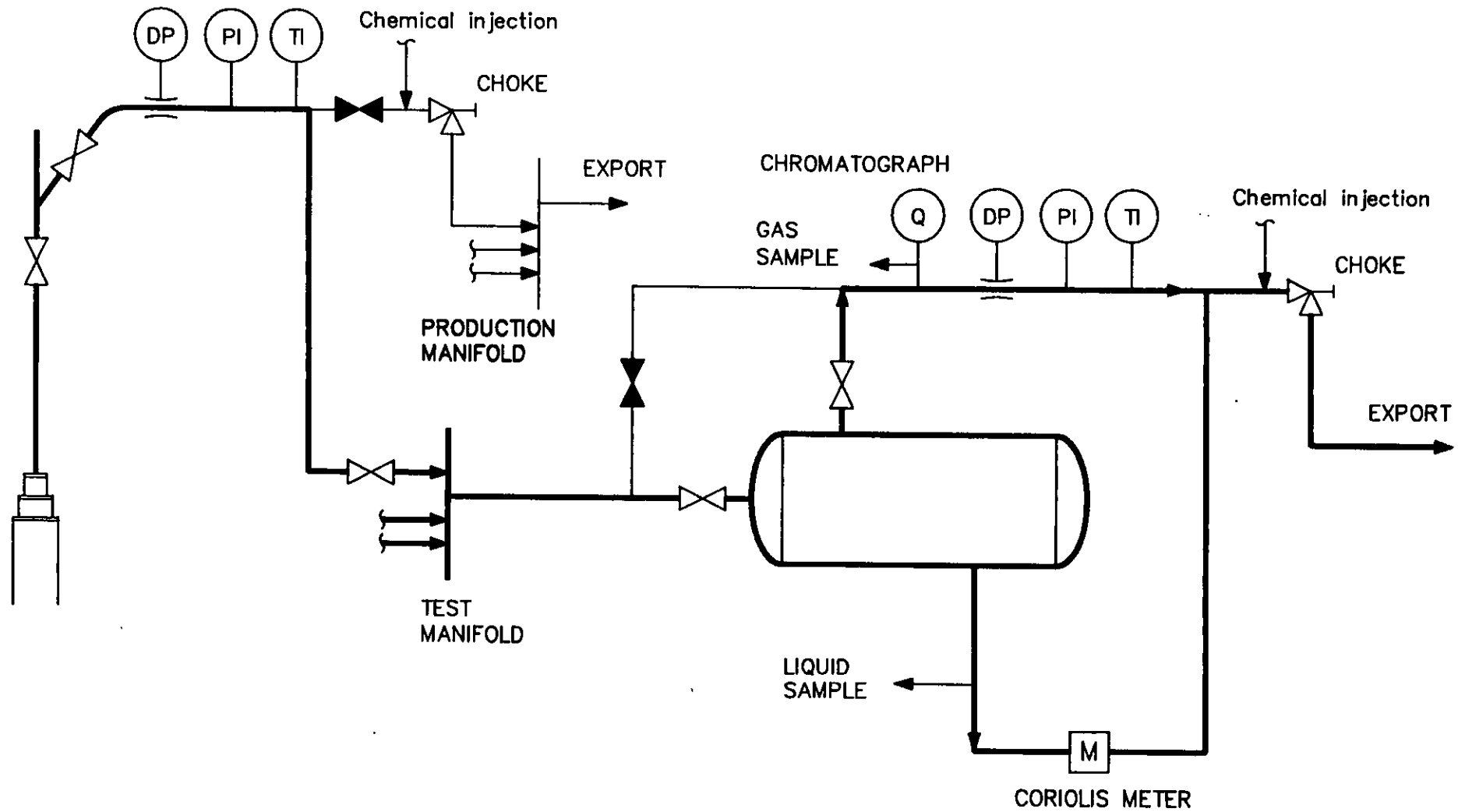

Figure 3 Test separator arrangement

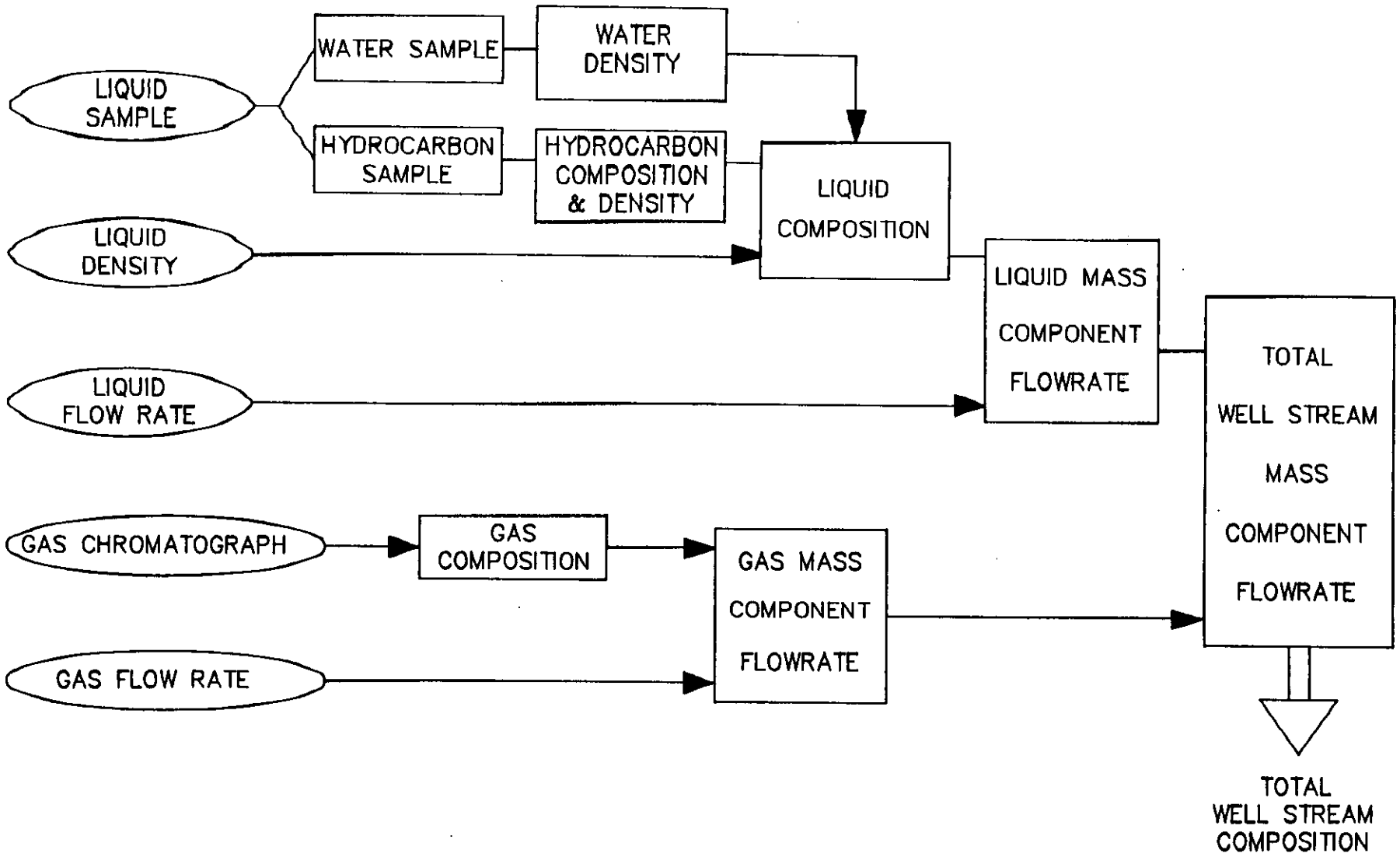

Figure 4 Determination of fluid composition

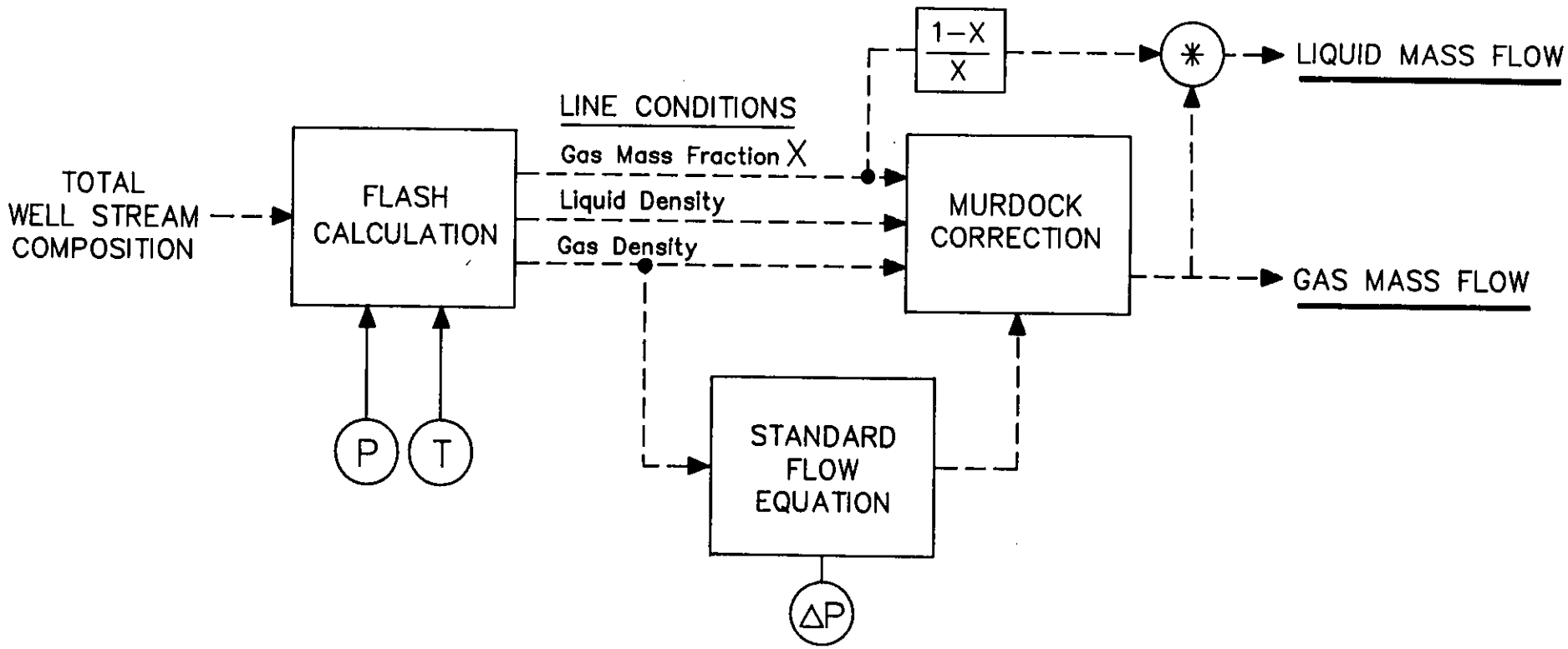

Figure 5 Wet gas computation

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NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

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NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Scaling problems in the oil metering system at the Veslefrikk Field

by

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Norway

SCALING PROBLEMS IN THE OIL METERING SYSTEM AT THE VESLEFRIKK FIELD.

Kåre Kleppe / Harald B. Danielsen STATOIL

Summary

The fiscal oil metering at the Veslefrikk platform was in operation without significant problems from start up in December 1989 until June 1992. At that time a new well was brought into operation and introduced a major problem in the metering system.

The new well's formation water turned out to contain significant amounts of barium and strontium ions. These ions reacted chemically with the sulphate ions of injection water from one of the other wells and formed bariumsulphate and strontiumsulphate. These sulphates have very low solubility in water.

Because of their low solubility, the sulphates will have a tendency to deposit on the inside of flowlines and process equipment. At Veslefrikk such a deposition formed a layer of scale on the internal parts of the metering system.

Other parts of the process plant at Veslefrikk have also been affected by deposition of scale but the oil metering system have given more problems than other equipment.

This paper describes the problems of scale deposition in the metering system and the attempts made to cope with the problem.

At the time when this paper is written, it seems that the problem may be very much reduced or even solved by adding a scale inhibitor to the well stream and in addition polishing the internals of the meter runs to a very high degree of surface smoothness.

1. The Veslefrikk oil metering system

The system is a conventional North Sea oil metering system. Figure 1 is an early P & I drawing. It is not accurate in all details, but gives a general overview of the design of the system.

The system has 3 meter lines, each with a 4" conventional turbine meter. The bi-directional prover has a nominal diameter of 10". Each meter line has an in-line density meter to enable direct reading of mass as well as standard volume.

The main data for the metered oil stream are as follows:

Oil type:	Stabilised crude oil, standard density 825 kg/Sm3, water content 0.1 - 0.3%.

Maximum flowrate: 285 m3/hr per meter line.

Operating temperature: 75 deg. C.

Operating pressure: 10 bar(g)

The system is a fiscal metering system, metering Veslefrikk's stream of oil into the pipeline of the Oseberg Transportation System.

2. Start of the scaling problem

In June 1992, a very rapid increase of the K- factors of the two turbine meters in use, started.

Up to this time the K-factors had been almost constant, but suddenly there was a daily increase of the order of 0.3-0.6 % per day. Figure 2 shows the K-factor of one of the meters during a period of 15 months before the start of the scaling problem.

As both meters in use were affected, the main suspects were the prover and the four way valve.

The third meter was brought into operation and behaved in the same manner as the two others. This meter was then shut down and taken out for inspection. The inspection revealed that the internals of the meter had a thick, hard deposit.

Analysis of the deposit and further investigations lead to the conclusion that the deposit was scale, the scale consisted mainly of bariumsulphate and that the source of the problem was a new well that had just been brought into operation.

3. Reason for scale formation

The new well's formation water contained significant amounts of barium ions (and smaller amounts of strontium ions). At the time when the well was completed, there had been injection water breakthrough into one of the other wells. The injection water is seawater and contains sulphate ions.

When the formation water of the new well mixed with the seawater coming from the other well, the barium and strontium ions reacted chemically with the sulphate and formed bariumsulphate and strontiumsulphate. Both of these compounds have very low solubility in water.

This mixing of formation water and seawater takes place in the wells' production header. From that point on the water of the produced oil, oversaturated by bariumsulphate and strontiumsulphate, tends to leave deposits inside the oil processing equipment.

In addition to the oil metering system, the seals of the pipeline pumps have been seriously affected.

A simplified flow diagram of the Veslefrikk oil processing plant is shown in fig. 3.

4. Details of the scaling problem in the oil metering system

In addition to the problem of drifting meter factors, the scale deposits also lead to excessive pressure loss in the metering system and to problems with the liquid density meters.

Pressure loss

The normal pressure loss over the metering system, with no scale deposits, is of the order of 2.0 bar.

When the scale problem started the pressure loss would increase up to 4 bar during a short period of time. At this pressure loss, the suction pressure of the pipeline pumps was very close to the trip-limit of the pipeline pumps.

The immediate remedy for this was to clean the meter runs' strainers with a frequency as high as once a day the worst periods. In addition, with a lower frequency, the meter runs' internals were cleaned by shotblasting. The flowstraightener was the element that probably gave the largest contribution to the pressure loss downstream of the strainer.

Fig. 4 shows scale deposits on a flowstraightener.

Density meters getting out of calibration

For reasons which are outside the scope of this lecture, two types of direct insertion density meters were in use at the time when the scaling started: Sarasota ID 781 and ITT-Barton model 668.

The Sarasota instrument has a small filter in the shield around the sensing element which is a vibrating cylinder. The scale was deposited on this filter but not on the sylinder itself. This resulted in errors in the density reading, alarmed by excessive differences of density of meter lines operating in parallel.

The ITT-Barton instrument has an unshielded vibrating vane as sensing element. It got a gradually increasing amount of scale on its vibrating vane, leading to an increase of the reading of the instrument.

Drift of the K-factors of the turbine meters

Drift of the K- factors became a serious problem.

A graph showing typical drift of the K- factor of one of the turbine meters during January 1993 is shown in fig. 8. There is an irregular increase of K-factor from day to day leading to a maximum value about 2% higher towards the end of the month than at the beginning of the month.

This graph shows less drift of the K-factor than at the time when the problem started. This is mainly due to that scale inhibitor is in use in the period shown on the graph.

Fig. 5 shows scale deposits on the impeller of one of the turbine meters.

5. Solutions

The immediate measures taken to keep the system going, like dismantling and shotblasting, proving the meters every day, recalibration of densitometers etc. were not very desirable as a long term solution to the scaling problem.

The following has been tried as long term solutions:

Injection of scale inhibitor

Injection of scale inhibitor into the production header was started ten days after the scale had been identified. Although not fully eliminating the problem, it has reduced it .

An additional problem that may have been caused by the scale inhibitor was that the prover ball was chemically attacked by the oil stream, see fig. 6. This problem was solved by using prover balls made from nitril instead of polyurethane.

Plating of internal parts of the meter runs

Because deposits will have less tendency to stick to the surface of a noble metal, silver plating of the flowstraighteners and the internal parts of a turbinemeter was tried.

Our experience from this was that there was no deposition of scale on the silver plated parts. On the other hand we could not get the plating to stay, it broke loose after less than a month of operation of the turbine meter. The flowstraightener kept its silver plating longer, but it also came off gradually.

As a consequence of this, silver plating has been abandoned.

Epoxy coating was tried on a flowstraightener, it worked in preventing scale deposition but developed blisters and was abandoned.

Polishing

Polishing the internal parts of the the meter run to a mirror surface is the remedy that is being tried at the time when this paper is written.

This one seems to work. A polished flowstraightener was installed in a meter run in december last year and was removed for inspection this summer. There was no scale deposit on it.

Also, a turbine meter with polished internals was installed on 15th august this year. Fig. 9 indicate very clearly why we think polishing will be the solution to the scaling problem in the meter runs.

Fig. 7 shows this turbine meter.

6. Status as per 1st. september 1993.

At this moment, injection of scale inhibitor and polishing the flowstraightener and the turbine meter to a mirror finish seem to be able to cure the metering problem that the scale deposits have given us.

Polishing of flowstraighteners, the inside surface of the meter line and of the turbine meters on all meter lines will be made within this year.

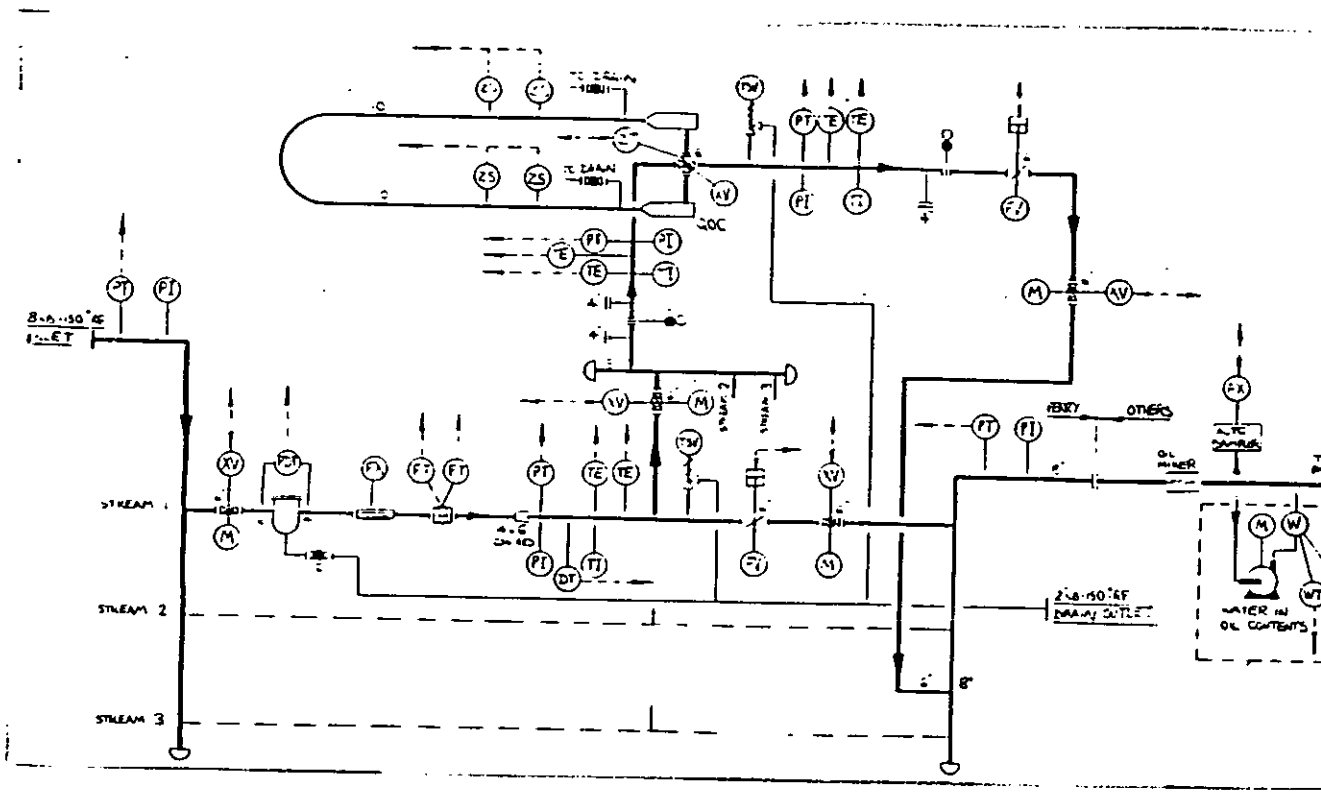

Fig. 1 P&I drawing for general overview of the Veslefrikk oil metering system
(Note: Not accurate in some details)

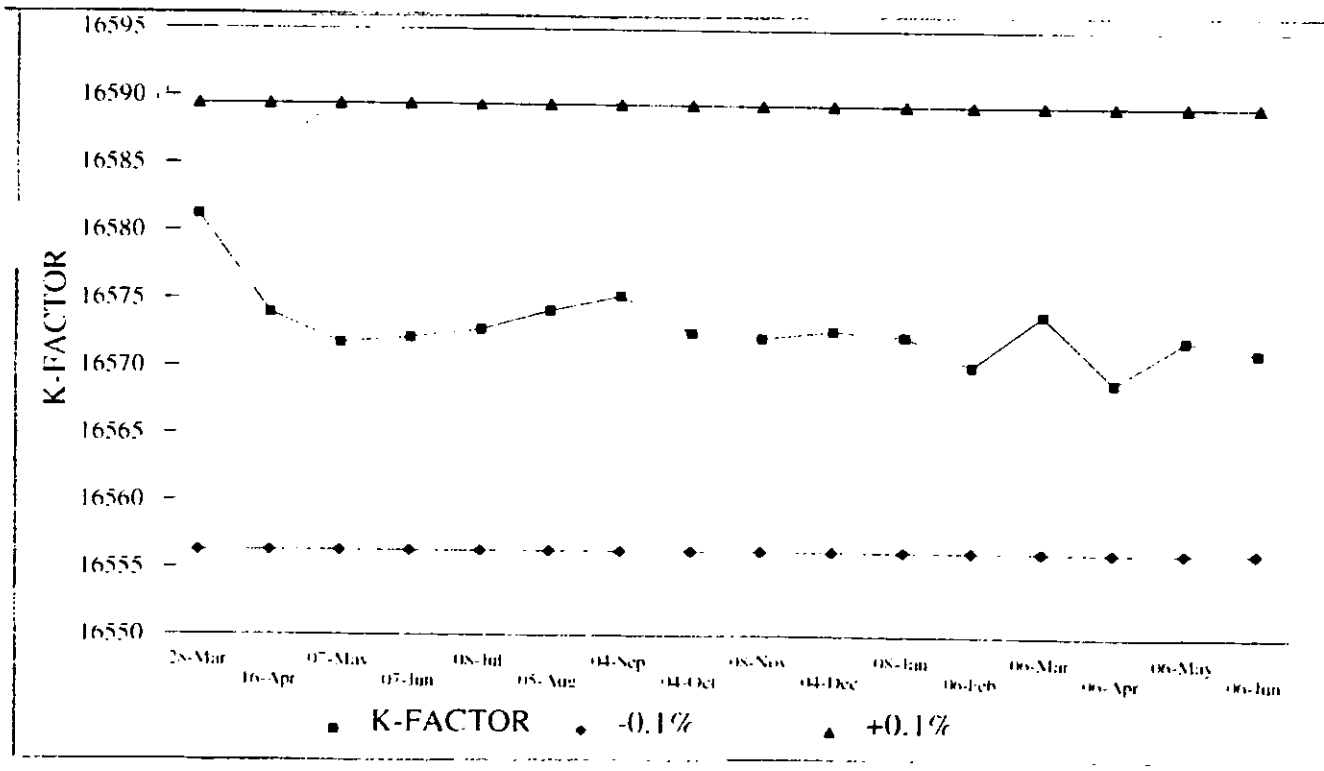

Fig. 2 Before the scaling problem, typical K-factor values as a function of time for one of the turbine meters.

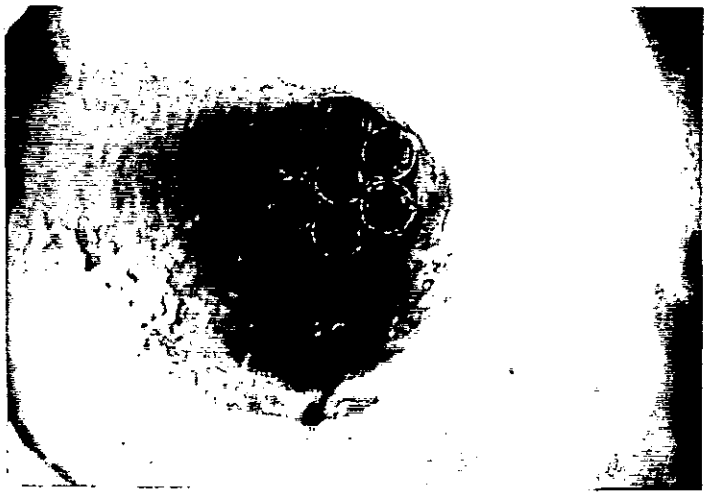

Fig. 4 Scale deposits on flowstraightener

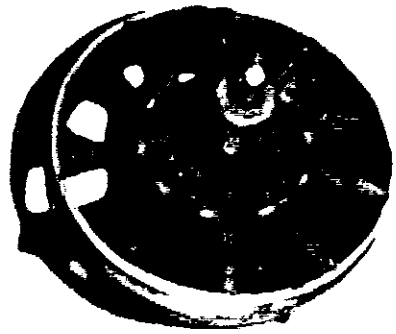

Fig. 5 Scale deposits on impeller of turbine meter.

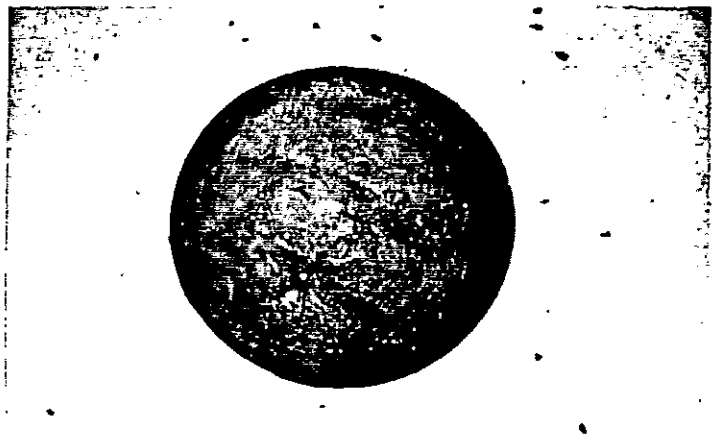

Fig. 6 Polyurethane sphere

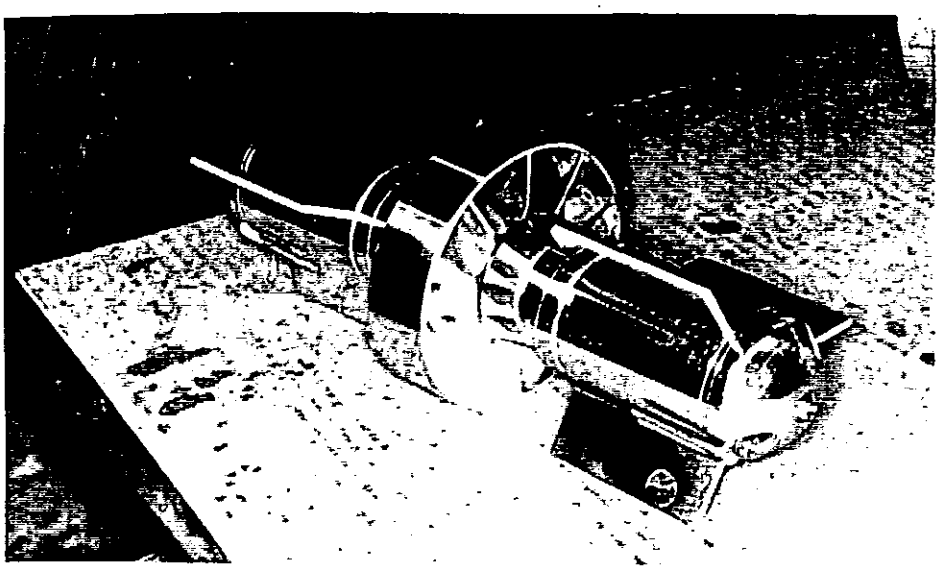

Fig. 7 Polished internals of turbine meter

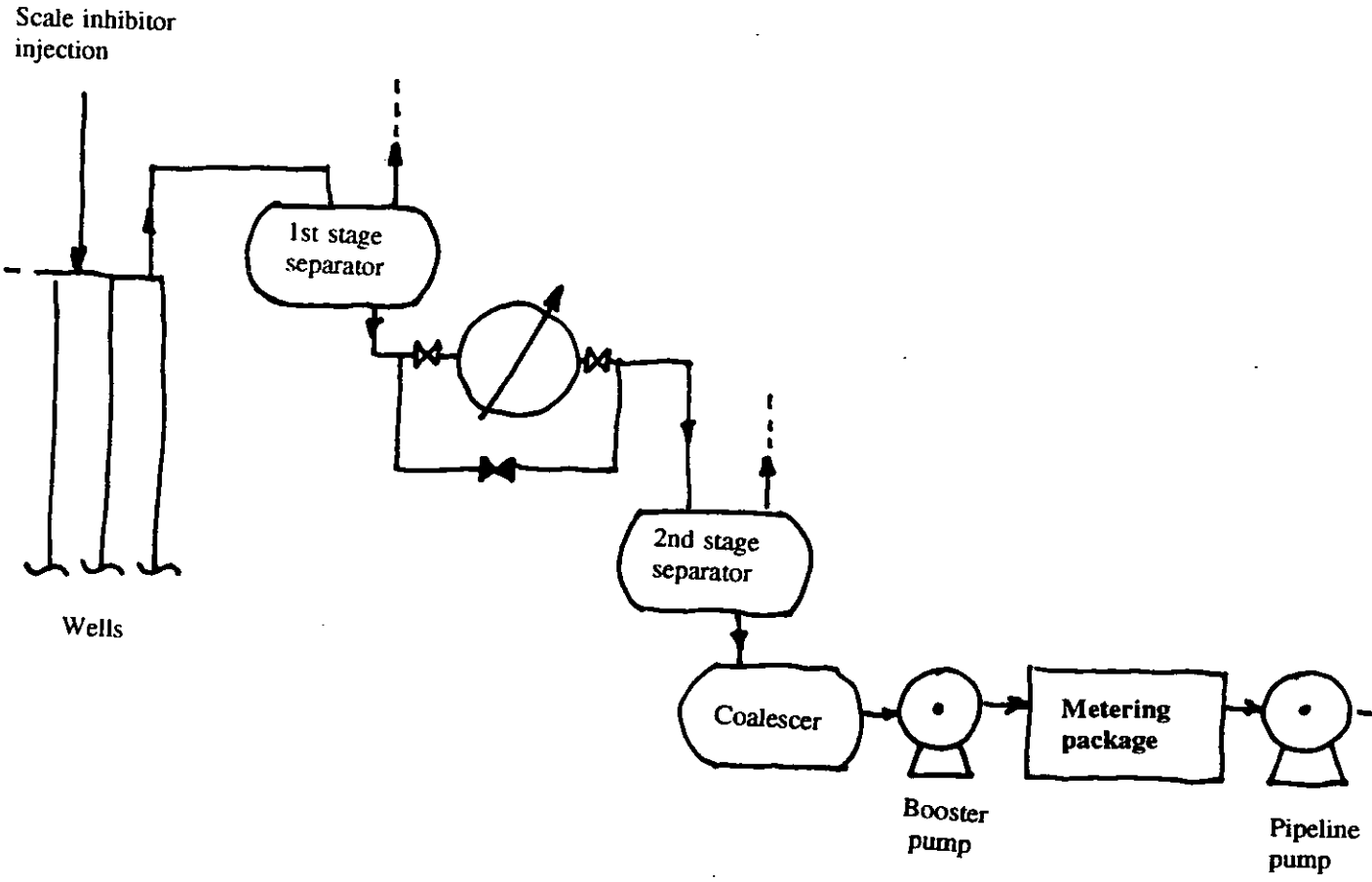

Fig. 3 Simplified flow diagram, Veslefrikk oil processing plant

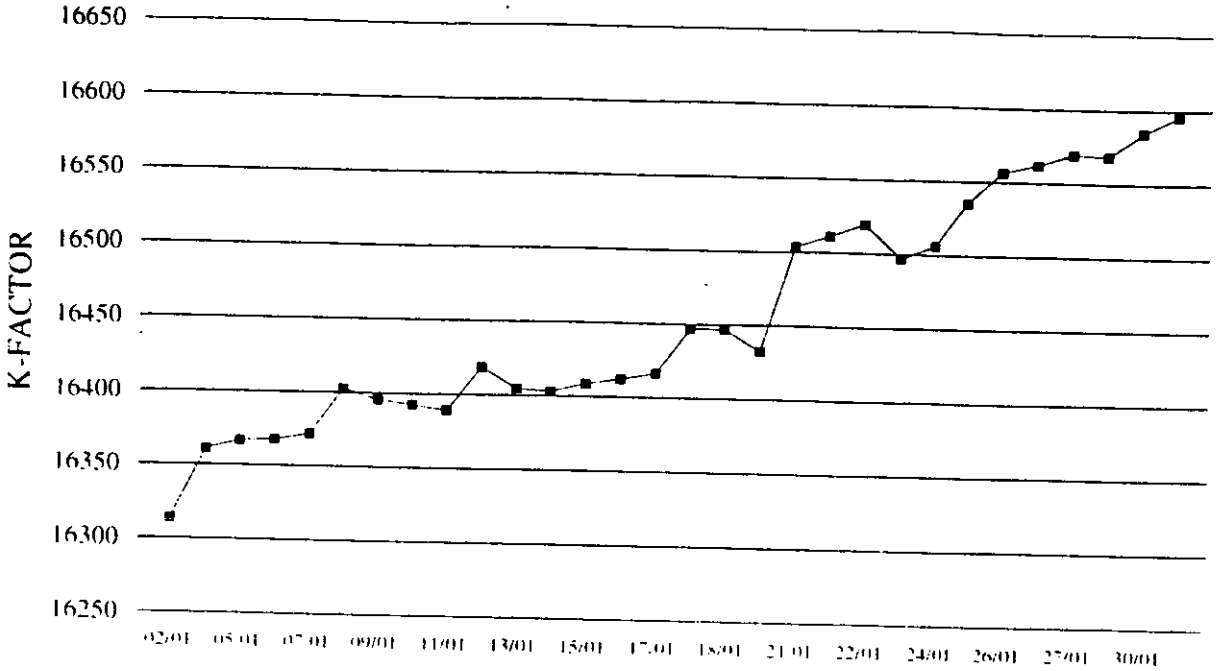

Fig. 8 Typical K-factor values as a function of time in a time period when scaling takes place and scale inhibitor is being used.

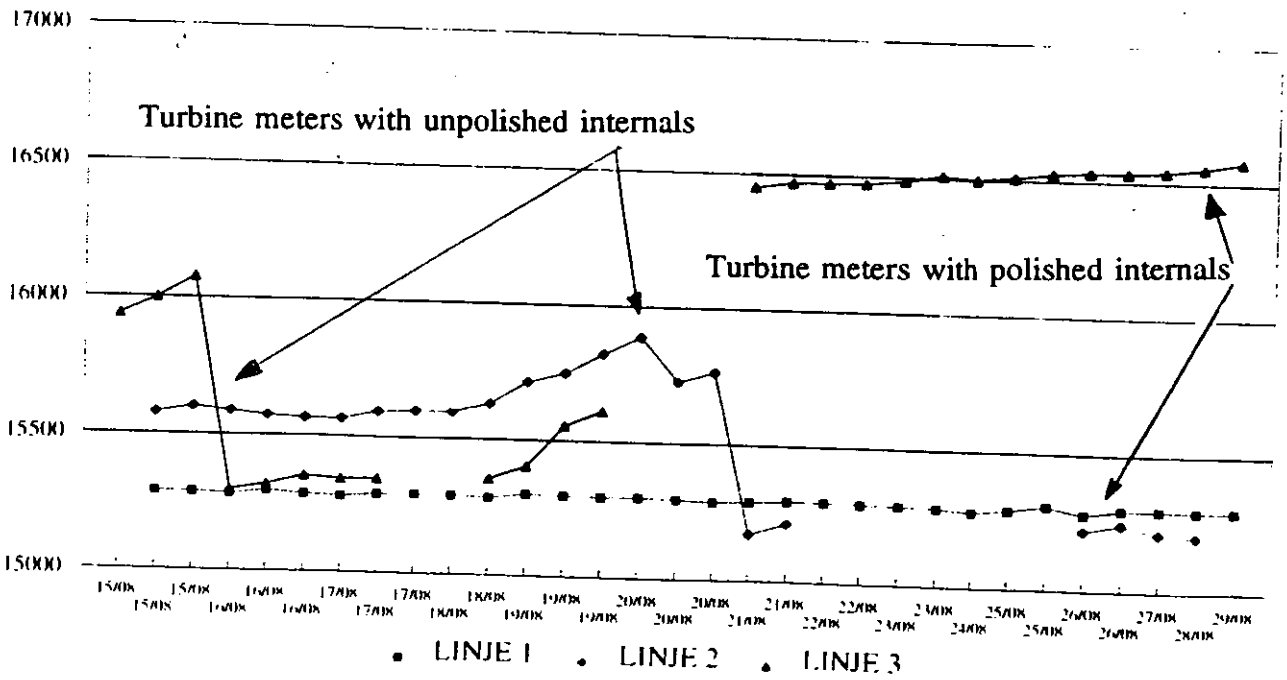

Fig. 9 K-factor values for turbine meters with and without polished internals.

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Scaling problems in the oil metering system at the Gyda Field

by

Mr. Finn Paulsen/Mr. Øistein Hansen,
BP Norway Ltd U.A.

Scaling problems in the oil metering system at the Gyda Field.

Paper by: Finn Paulsen and Øistein Hansen

BP Norway Limited U.A.

1. Introduction

The Gyda field is an oil field located in the south-westerly corner of the Norwegian Continental Shelf. Gyda is an integrated production, drilling and quarter platform .

The Gyda reservoir (Late Jurassic sandstone) is estimated to contain recoverable reserves of some 200 million barrels of light, low-sulphur crude oil. The reservoir depth is 3,600 meters and has a temperature of 156 ^{0}C, the hotest producing field in the Norwegian sector.

The current production rate is around 70,000 barrels a day. About 90,000 barrels of water are injected daily to maintain the reservoir pressure and improve sweep efficiency .

The reservoir fluid goes through a separator where oil, gas and water are separated in a 2 stage separator process. The crude oil is then cooled before passing through the metering station. The gas and oil is transported in pipelines to Emden and Teesside respectively through Ekofisk center.

The Gyda metering system is designed and manufactured by Jordan Kent Metering Systems, UK. The oil metering system comprises of three 4 inches Kent turbine meters, and a 14 inches bi-directional prover.
Maximum capacity is 560 m3/hr through two streams.

Densitometers: ITT Barton model 668 (in-line densitometer with vibrating vane). One densitometer in each line. No check densitometer installed.

Operating conditions:

Oil density :	750 kg/m3.
Operating pressure:	20 barg
Operating temperature:	80 ^{o}C.
Water cut, weight %:	0.5 to 1.5

2. Scaling in the oil metering system

Oil production on Gyda started in July 1990. During the first months of operation BPN had some problems with the prover ball due to high export temperature. This has been presented on this conference in 1991.

The scaling problem probably started very soon after first oil but due to the prover ball problem it is difficult to determine exactly when .

2.1 The Gyda Scale.

The scaling in the Gyda metering system is caused mainly by Zinc compounds in the produced water which again deposit in the platform facilities.

Chemical reaction: $Zn + H_2S = ZnS$

Chemical analysis of scale sampled from a turbine meter gave the following results:

Zinc sulphide , ZnS	~ 90 %
Organic materials (Asphaltens)	~ 10 %.

Conventional scale inhibitors do not seem to prevent formation of this type of scale.

Removal of scale by use of acid: $ZnS + 2\,HCl = ZnCl_2 + H_2S$

Formation of ZnS increases the potential for other types of scale to deposit, ie. $BaSO_4$ and $SrSO_4$ which adheres to particles.

(The H_2S level in export gas has been constant since start up. (Approx. 20 ppm))

2.2 Effect on turbine meters.

Early in 1991 BPN saw a steady increase in K-factors for all turbine meters. In March 1991 the K- factor increased on average for all streams of around 27 counts (equals 0.12 % - K-factors around 22 100 pls/m3) on each daily prove. In some cases the K-factor suddenly dropped before the increase started again. Inspection of turbine meters taken out of service revealed that the internals of the turbine meter waere covered with a layer of scale.

BPN believe that the reason for the sudden decreases is probably due to scale that has fallen off the impeller. We have seen evidence that some of the scale has flaked off. This will effect the turbine meter characteristics.

In extreme cases the K - factors have dropped dramatically, up to 1000 pulses/m3. Reason in all cases: bearing failure.

In spite of the unstable K-factors there has been few problems with repeatability during proving.

From time to time the turbine meters linearity have been checked after a shift in the K - factors. BPN have never seen any linearity problems due to the scale, only a shift in the linearity curves.

2.3 Injection water breakthrough.

In the first days of March 1992 we had injection water breakthrough in one of the wells on Gyda. The water cut through the metering station increased from about 2 to over 4 weight per cent in less than three weeks.
The K-factors were stable in the first part of the this period, but after a couple of weeks we experienced severe scaling problems in all the turbine meters. Six turbine meters were changed for inspection and cleaning. All meters were completely covered with scale.

One turbine meter had restart problems after shutdowns, most probably due to high friction in the bearing at low flow rates.

The produced water treatment system was commissioned in May 1993. After some weeks with optimising the operation of the system, in particular chemical usage, the water cut through the metering station was down to a more normal level again. We still had some scaling but not as severe as before.

This spring a well with very high water cut was shut in. The well produced more than 90 % of the total produced water . The produced water treatment system was shut-in at the same time due to the drop in the produced water rate. This resulted in a higher water cut in the oil and an increase in the K-factors variations until the produced water system was put back in operation.

2.4 Pressure loss.

Due to the scale problem the pressure loss over the metering system has increased. The pressure before the main oil pipeline pumps is very close to the trip-limit for these pumps (low suction pressure). In order to reduce the pressure drop, all three metering streams are used during normal operation.

2.5 Densitometers.

So far there is no clear indication that the scaling has any effect on the densitometers. BPN have seen a tendency of decrease in readings after a couple of weeks in service which may be due to scaling. More data is required before BPN can draw any conclusions or relate this to the scaling problem.

3 Measures taken to reduce the problems

3.1 Increased proving frequency.

According to the NPD regulations all turbine meters should be proved at least every fourth day. Due to the variations in the K- factors all turbine meters are proved on a daily basis to improve the measurement accuracy.

If the change in K-factor is more than 30 counts, which equals 0.14 %, the stream is reproved to verify this new K-factor and the next proving is carried out after another 12 hours.

If the change in K-factor is more than 100 pulses/m^3, the stream will be shut in, and the turbine meter removed for inspection and cleaning if necessary.

3.2 Frequent change out and cleaning of turbine meters.

The turbine meters are sent onshore for cleaning, removal of scale, and inspection. The first step in the cleaning process is to put the meter into an ultrasonic bath. If still scale on the turbine meter, it will be soaked in an acid solution (10 % sulphuric acid) for about one hour.
In some cases even acid is not dissolving the remaining scale. The scale is then removed mechanically by carefully using a small knife and a steel brush.

3.3 Test of helicon type turbine meter.

A helicon type turbine meter has been tested three times. It failed every time due to destroyed bearings. The meter performance was good with very stable K-factors before the bearing problems started.

3.4 Scale inhibitors - metering station.

In August this year trials with scale inhibitor injection were started. The scale inhibitor was injected in the crude oil stream just before the Low Pressure Separator. Four weeks later the injection point was moved to the Low Pressure Separator outlet.

The effect of this injection seems to be positive, but it is difficult to draw any conclusions at this stage. The trial is going to be continued for at least another month.

4. Modifications

4.1 Turbine meters.

The internals of a turbine meter was coated with Teflon, and the sleeve bearing was replaced with two sealed ball bearings to reduce the crude oil flow through the bearings . After only a few weeks in service the bearings broke down. Later BPN have tried with another type of sealed ball bearings. This meter also broke down after a short period.

The Teflon coating seems to be a step in the right direction as the amount of scale on the turbine meter was reduced. The flow straightners were also Teflon coated to reduce the pressure drop over the metering system. But it is very important to use the right type of coating. The coating company changed the coating specification on some of the flow-straightners and BPN ended up with blistering problems.

4.2 Filter baskets.

Two of the filter baskets were coated with Teflon summer 1991 after the fine start - up mesh had been removed.

After some weeks they where removed for inspection and very little scale was found on surface. Unfortunately, the filters where sandblasted to remove the small amount of scale. The coating was destroyed. No other trials has been carried out.
BPN do not have problems with high pressure drop over the filters.

5 Measurement accuracy

Due to the variations in the K-factors an uncertainty analysis of the whole oil metering system has been carried out. The K-factor's contribution to the total uncertainty is about 1/3.
The main conclusion of the study is that the Gyda oil metering accuracy is in compliance with the NPD regulations.

6 Cost impact of the scaling problem

The frequent proving has in periods led to continuos problems with the 4 - way valve and hundreds of extra man-hours for our mechanics. Together with the frequent change out and cleaning of turbine meters this has significantly increased the operating costs for the Gyda metering station.

7 Not affected by the scale problem.

BPN have not seen any impact on the:

- prover volumes
- samplers
- static mixer
- valves (leaks)

8 Future plans

Later this autumn or this winter BPN plan to Teflon coat another turbine meter, and put it in to service in parallel with a brand new standard turbine meter .

BPN are still thinking about bearing modifications, for instance to try roller bearings instead of ball bearings. No decision has been made yet.

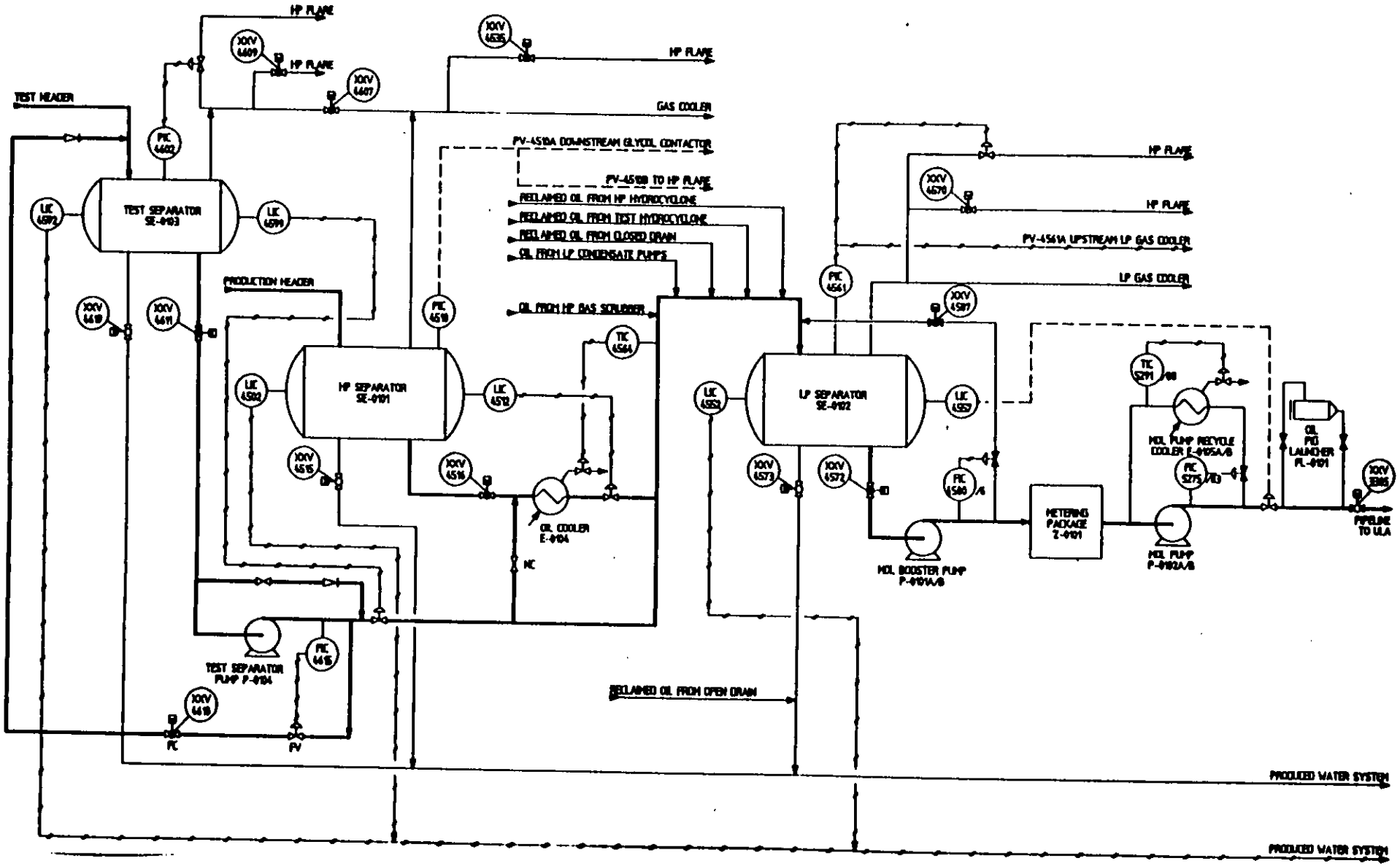


Figure 1 Gyda oil production system

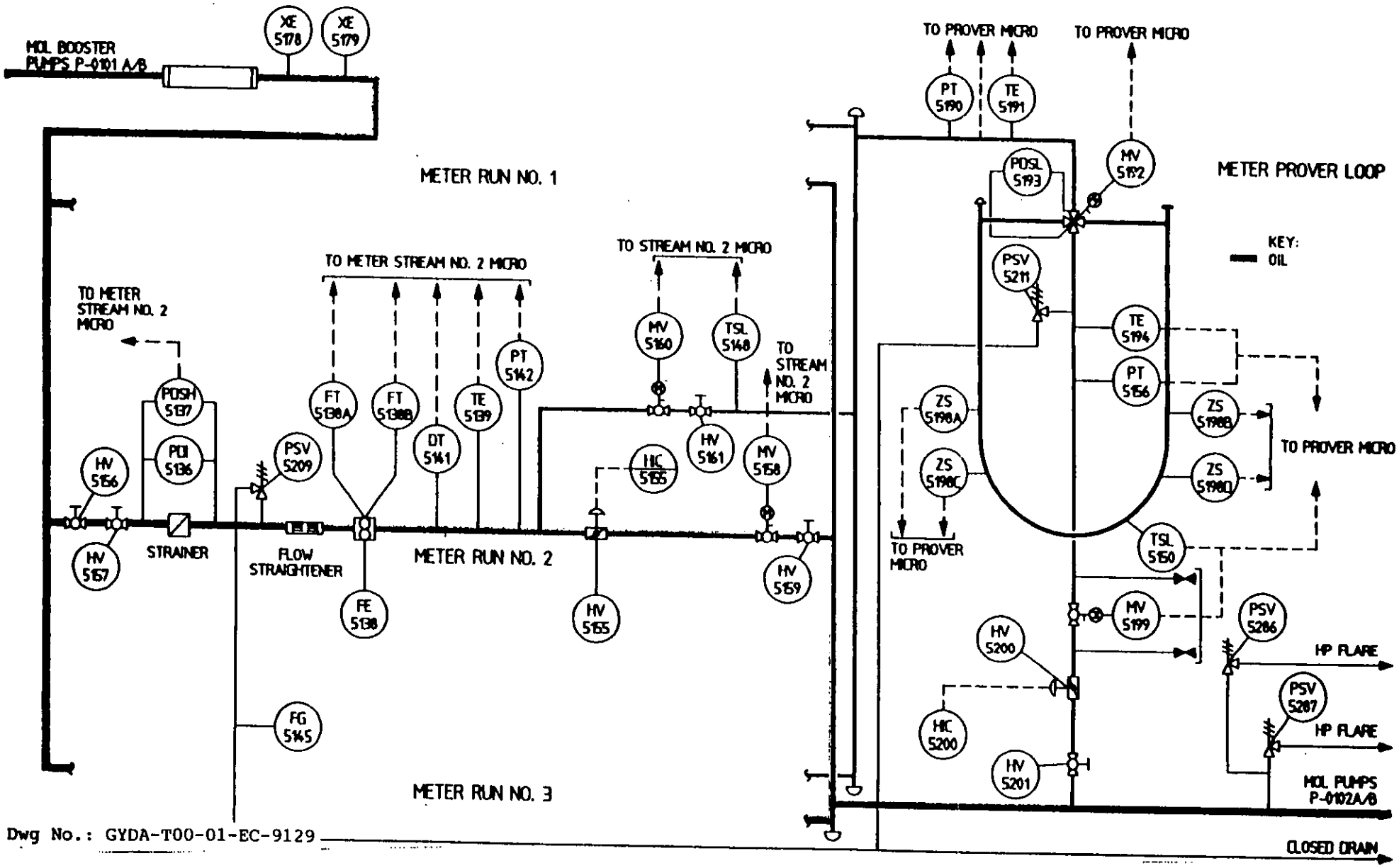
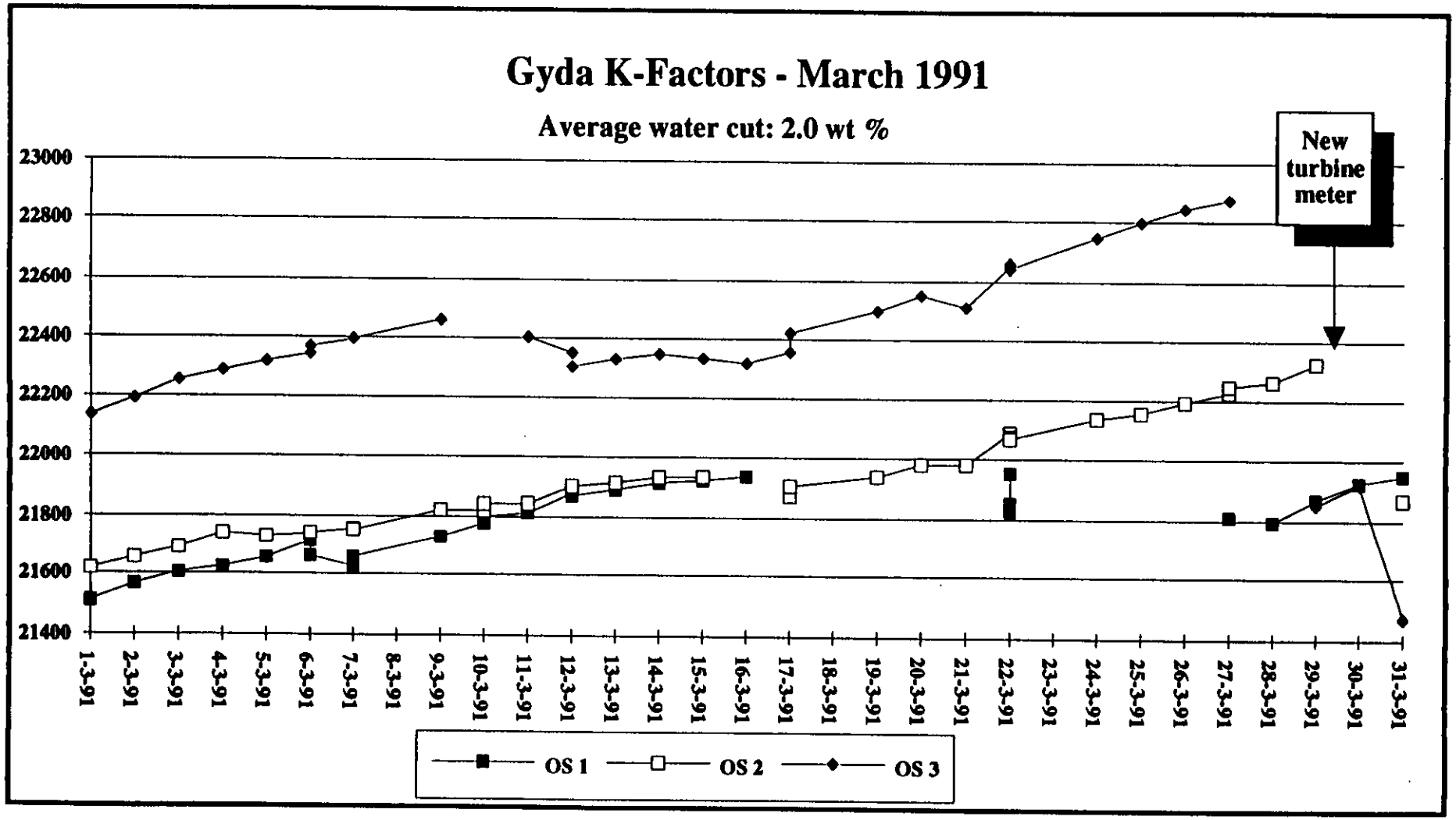


Figure 2. Gyda oil metering system


Gyda K-Factors - March 1991
Average water cut: 2.0 wt %
New turbine meter
23000
22800
22600
22400
22200
22000
21800
21600
21400
1-3-91
2-3-91
3-3-91
4-3-91
5-3-91
6-3-91
7-3-91
8-3-91
9-3-91
10-3-91
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24-3-91
25-3-91
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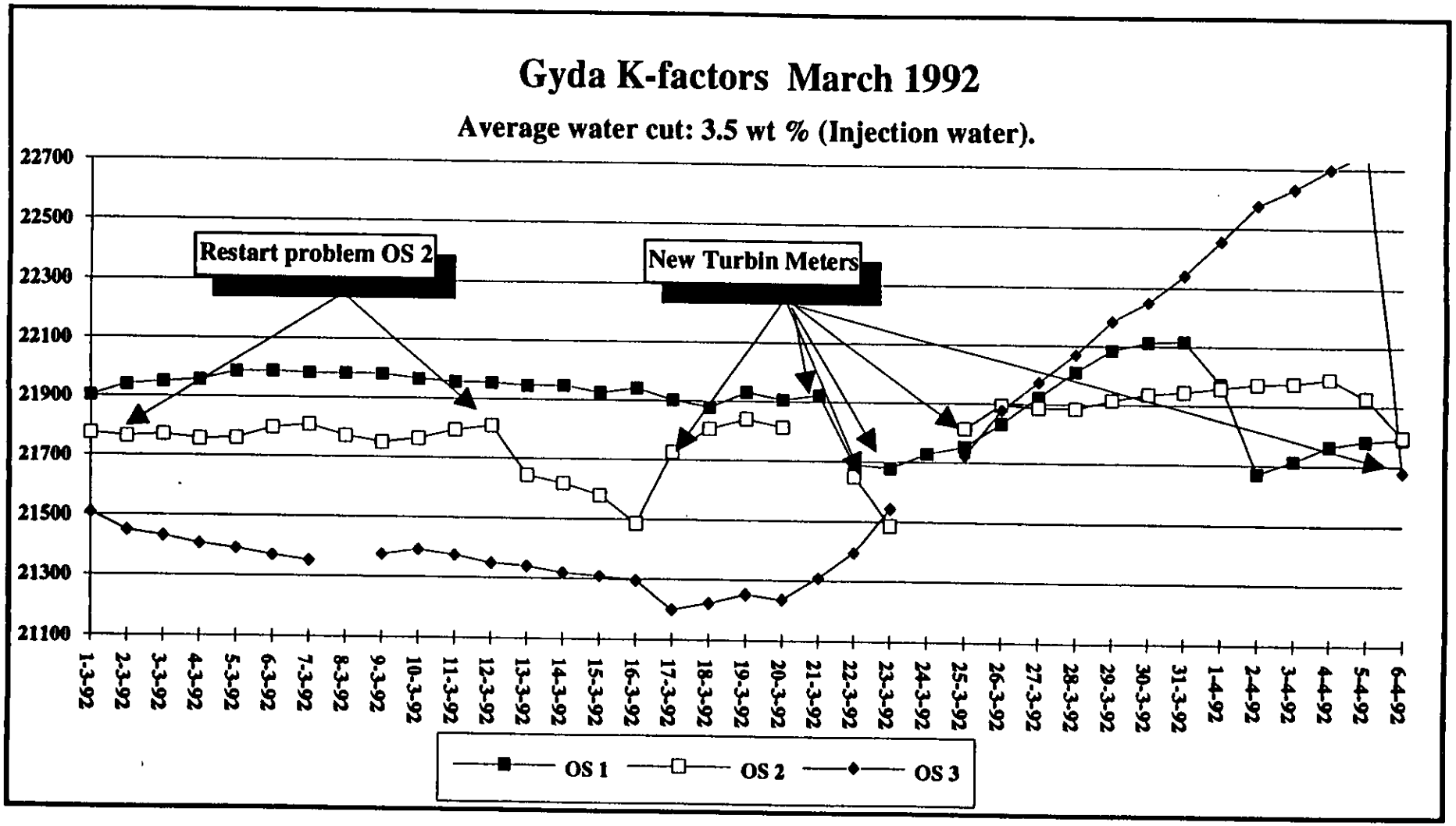
29-3-91
30-3-91
31-3-91
OS 1
OS 2
OS 3

Figure 3.


Gyda K-factors March 1992
Average water cut: 3.5 wt % (Injection water).
Restart problem OS 2
New Turbin Meters
22700
22500
22300
22100
21900
21700
21500
21300
21100
1-3-92
2-3-92
3-3-92
4-3-92
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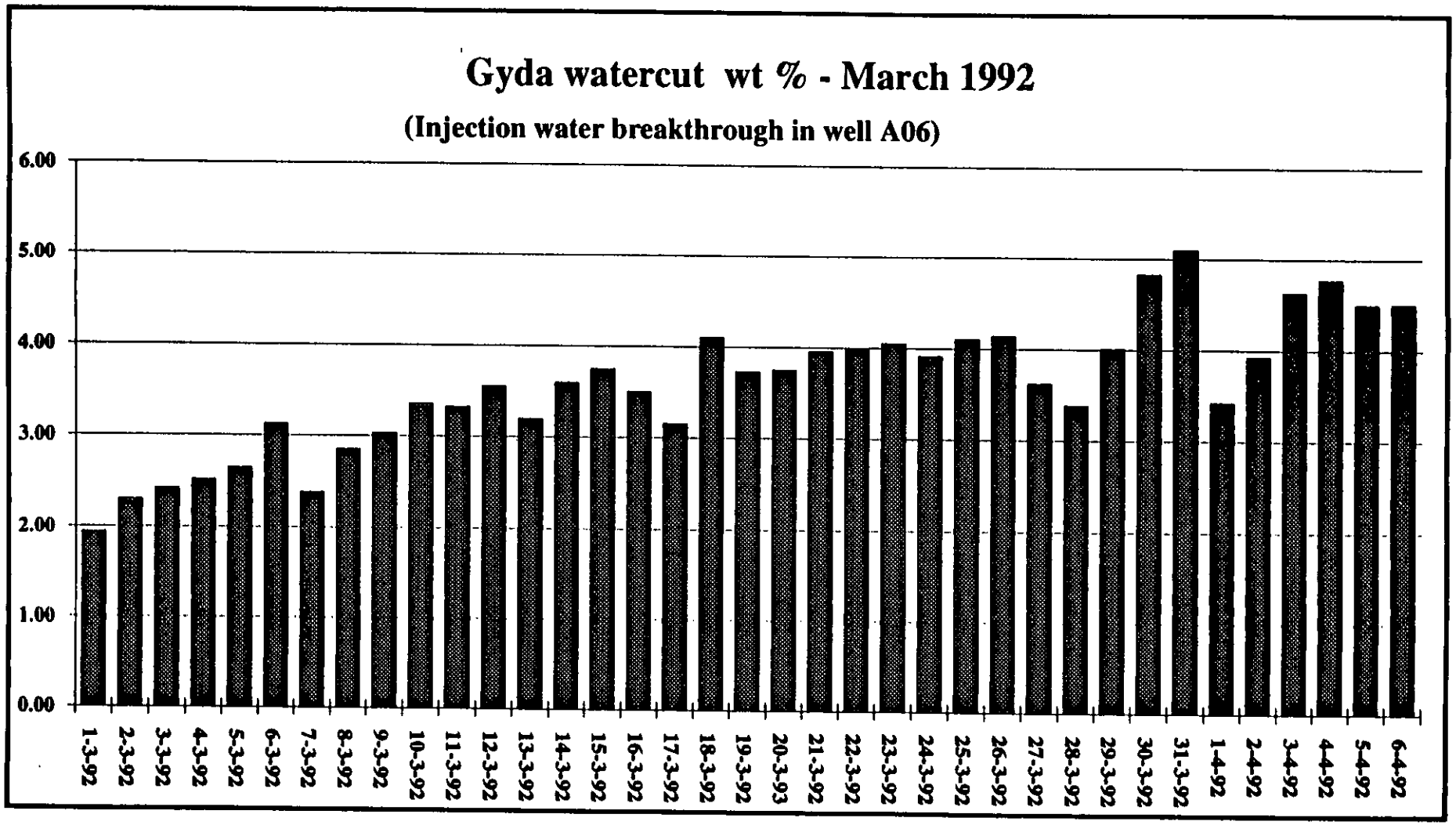
OS 1
OS 2
OS 3

Figure 4.


Gyda watercut wt % - March 1992
(Injection water breakthrough in well A06)
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1-3-92
2-3-92
3-3-92
4-3-92
5-3-92
6-3-92
7-3-92
8-3-92
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2-4-92
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4-4-92
5-4-92
6-4-92

Figure 5.

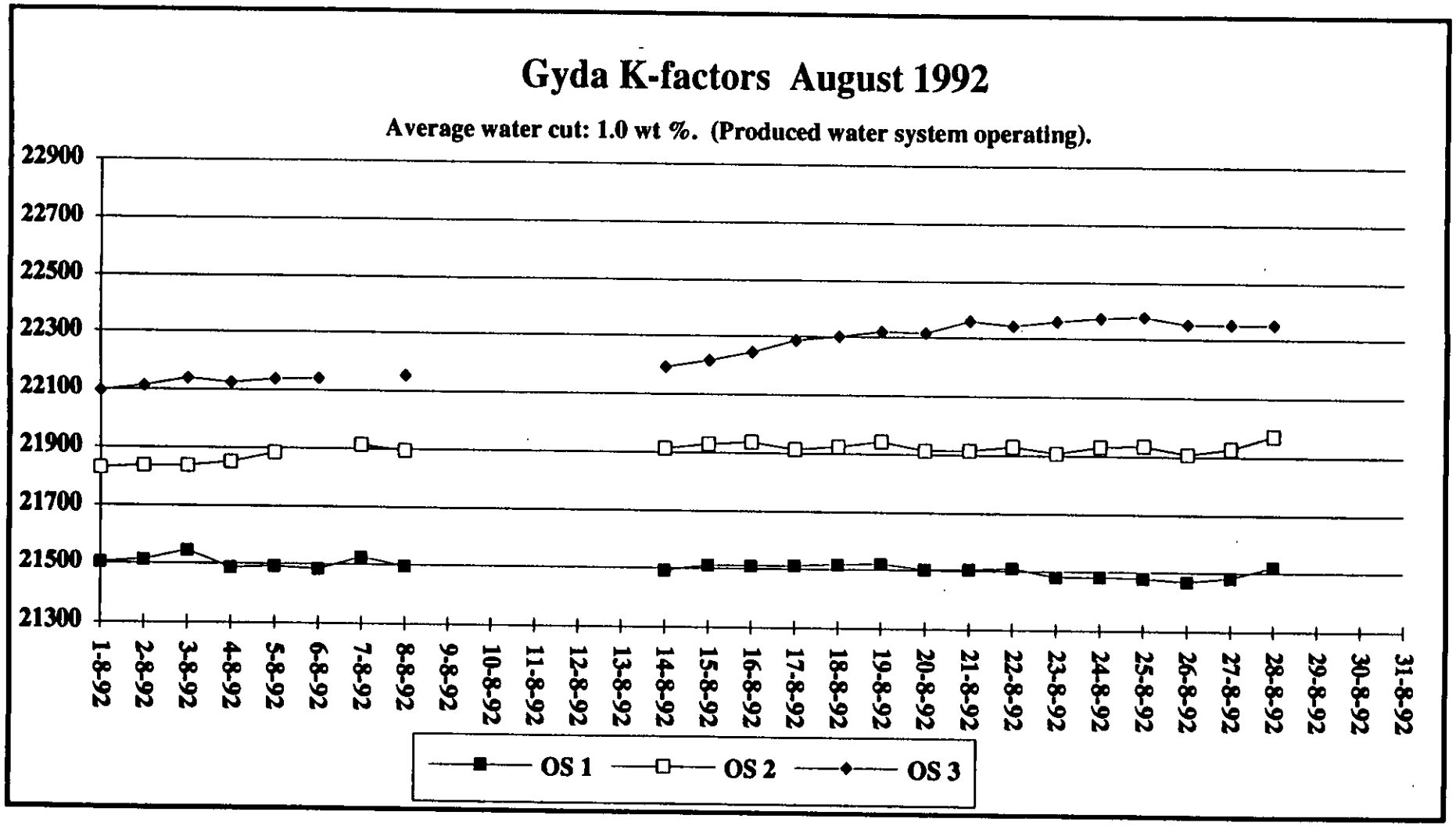
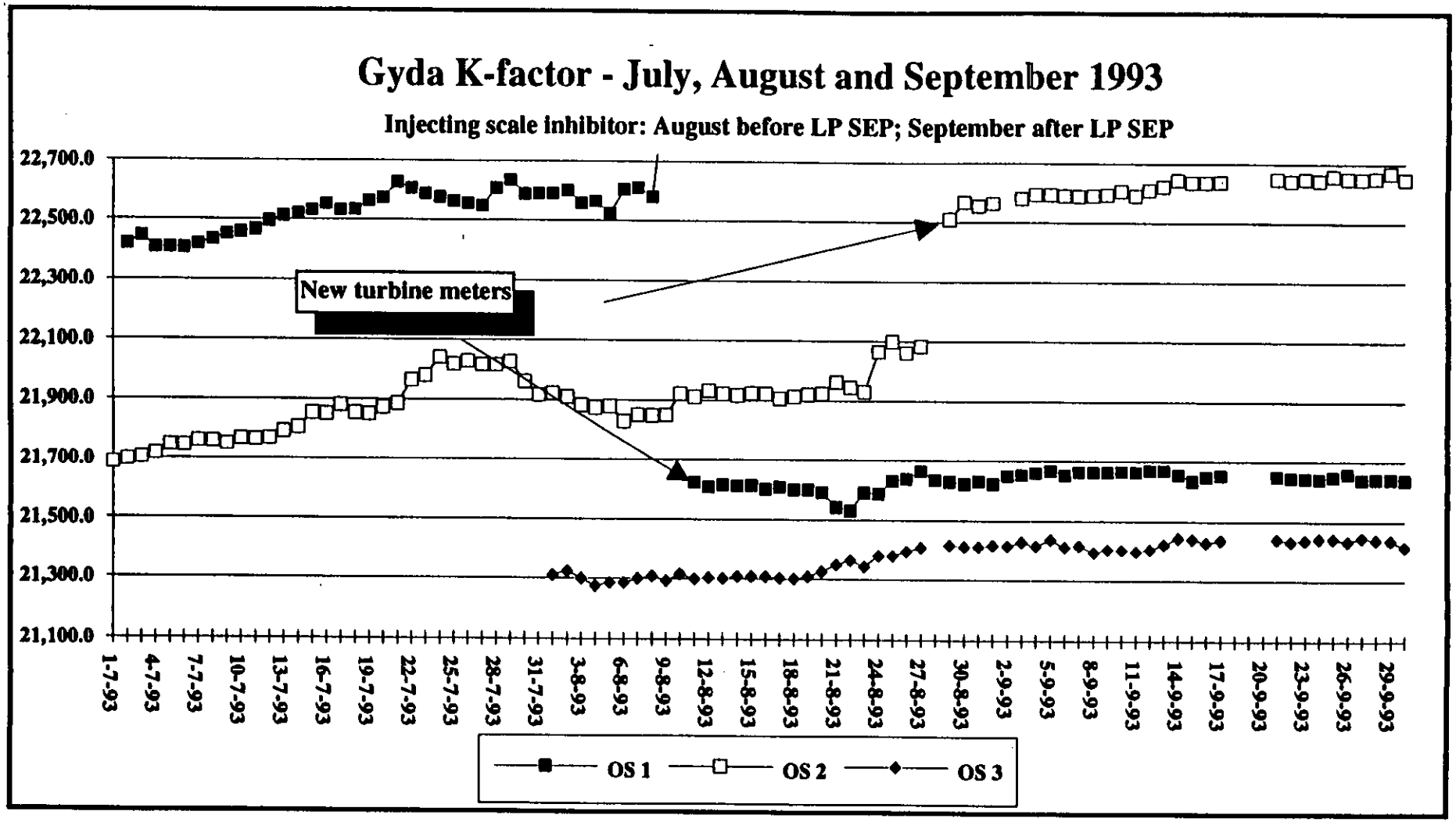

Gyda K-factors August 1992
Average water cut: 1.0 wt %. (Produced water system operating).
22900
22700
22500
22300
22100
21900
21700
21500
21300
1-8-92
2-8-92
3-8-92
4-8-92
5-8-92
6-8-92
7-8-92
8-8-92
9-8-92
10-8-92
11-8-92
12-8-92
13-8-92
14-8-92
15-8-92
16-8-92
17-8-92
18-8-92
19-8-92
20-8-92
21-8-92
22-8-92
23-8-92
24-8-92
25-8-92
26-8-92
27-8-92
28-8-92
29-8-92
30-8-92
31-8-92
OS 1
OS 2
OS 3

Figure 6.


Gyda K-factor - July, August and September 1993
Injecting scale inhibitor: August before LP SEP; September after LP SEP
New turbine meters
22,700.0
22,500.0
22,300.0
22,100.0
21,900.0
21,700.0
21,500.0
21,300.0
21,100.0
1-7-93
4-7-93
7-7-93
10-7-93
13-7-93
16-7-93
19-7-93
22-7-93
25-7-93
28-7-93
31-7-93
3-8-93
6-8-93
9-8-93
12-8-93
15-8-93
18-8-93
21-8-93
24-8-93
27-8-93
30-8-93
2-9-93
5-9-93
8-9-93
11-9-93
14-9-93
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20-9-93
23-9-93
26-9-93
29-9-93
OS 1
OS 2
OS 3

Figure 7.

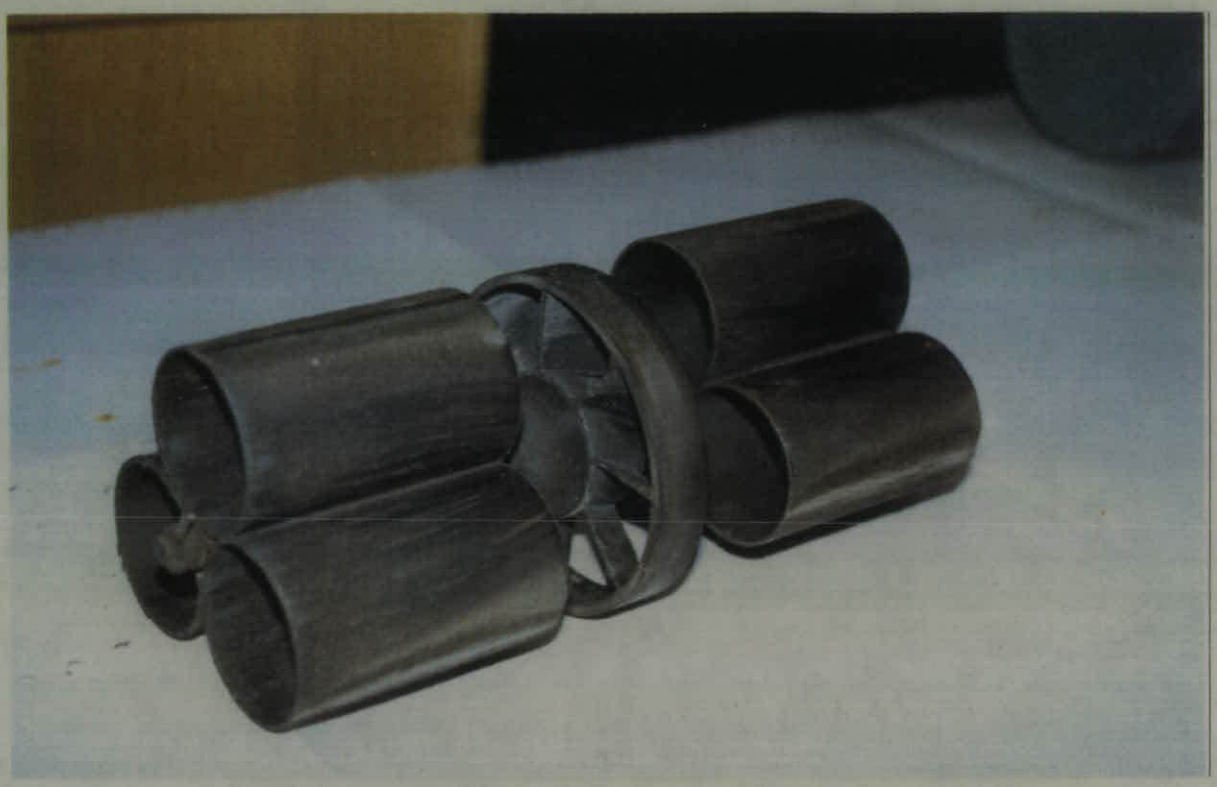

Figure 8. Scale deposits on internals of turbine meters.

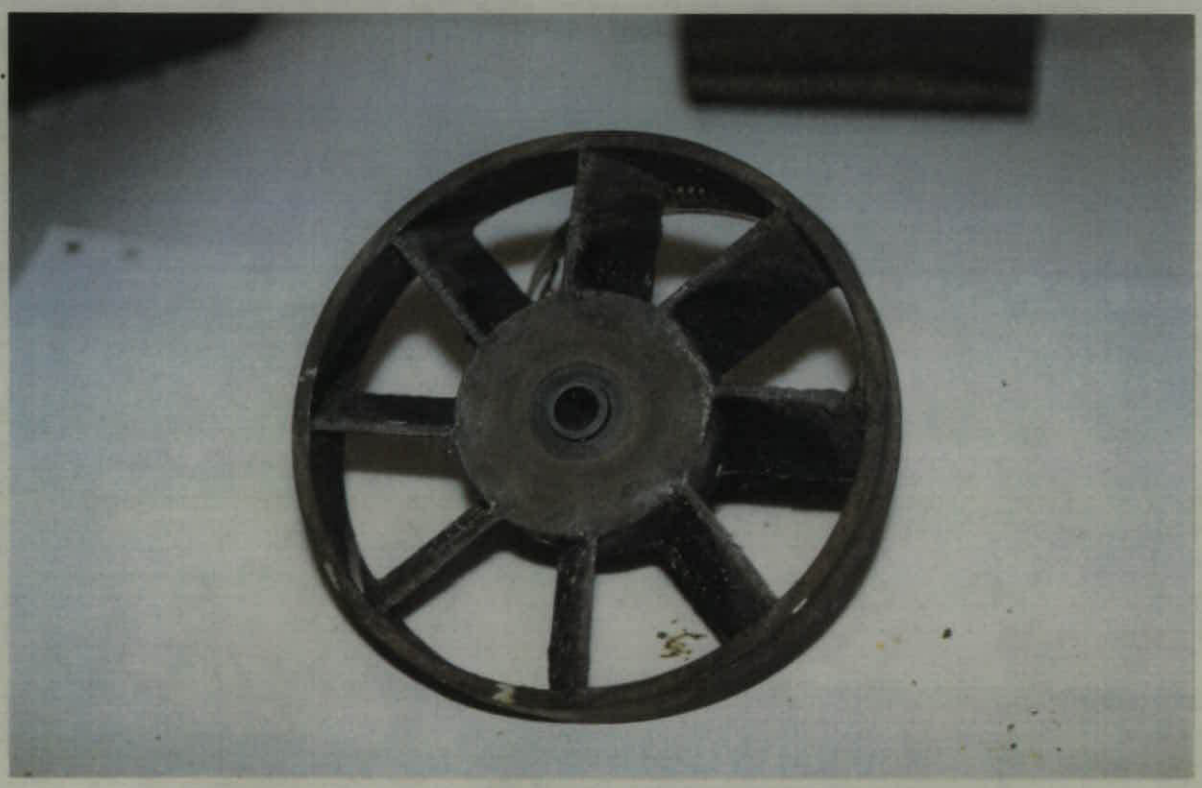

Figure 9. Scale deposits on impeller of turbine meter.

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NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Optimal Measurement Accuracy for Allocation Measurements

by
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Optimal Measurement Accuracy for Allocation Measurements

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ABSTRACT: Due to the fact that newly discovered oil field often are small compared to those discovered in mid 20, new and less expensive production solutions must be used. If the fields are in a reachable distance from an existing process platform, an economically production strategy could be to transport the production to existing process capacity. The different marginal oil fields (*i.e.* satellite fields) and the process platform will often have different constellation of owners, hence, there will be a need for allocation measurements. For obvious reasons it will be expensive to use standard fiscal metering stations for each satellite fields, so new and more cost effective measurement systems must be used. That is, the measurement accuracy will decrease, and hence not within the existing regulations. In this work there has been developed an economical model which calculates the net present value as a function of measurement accuracy, production etc. This model indicates that fiscal measurement standards is often not economically, neither for the owner of the satellite field, the owner of the process platform and the government.

1. Introduction

New satellite fields are coming into production in the Norwegian continental shelf. Existing infrastructure such as *Statfjord* and *Gullfaks* platforms are located in the vicinity of some of these new fields. Due to spare processing capacity the new fields are developed with subsea wells with pipelines routing the wellstream directly into the existing platforms. We also see a need for partially processing and dewatering of the wellstream at one platform, then further transporting of the crude to other platforms in the area for last stage separation, storage, fiscal metering and loading (see Figure 1).

Commingling of crudes demand a mass allocation system. The crudes are not stabilized so metered mass must be multiplied with component dependent shrinkage factors.

The crude coming from satellite fields must pay a processing tariff for each barrel of oil and gas delivered to the existing platforms. The crudes to be commingled are coming from different licenses and vary in quality. Calculating the technical value of the different crudes show a significant difference in value. Allocation measurement is therefore also needed for supplying data for tariff accounting and tanker scheduling purposes. Density and composition are needed for value adjustment between different streams and converting mass allocation to volume distribution between the participants.

Looking at Figure 1, showing a relevant future allocation scheme for oil, indicates an increasing need for new metering and sampling equipment for oil and gas. To secure single phase (due to unstabilized crude) through turbine meters and orifice plates, booster pumps and gas heaters are necessary equipment to obtain an accuracy within the existing regulations.

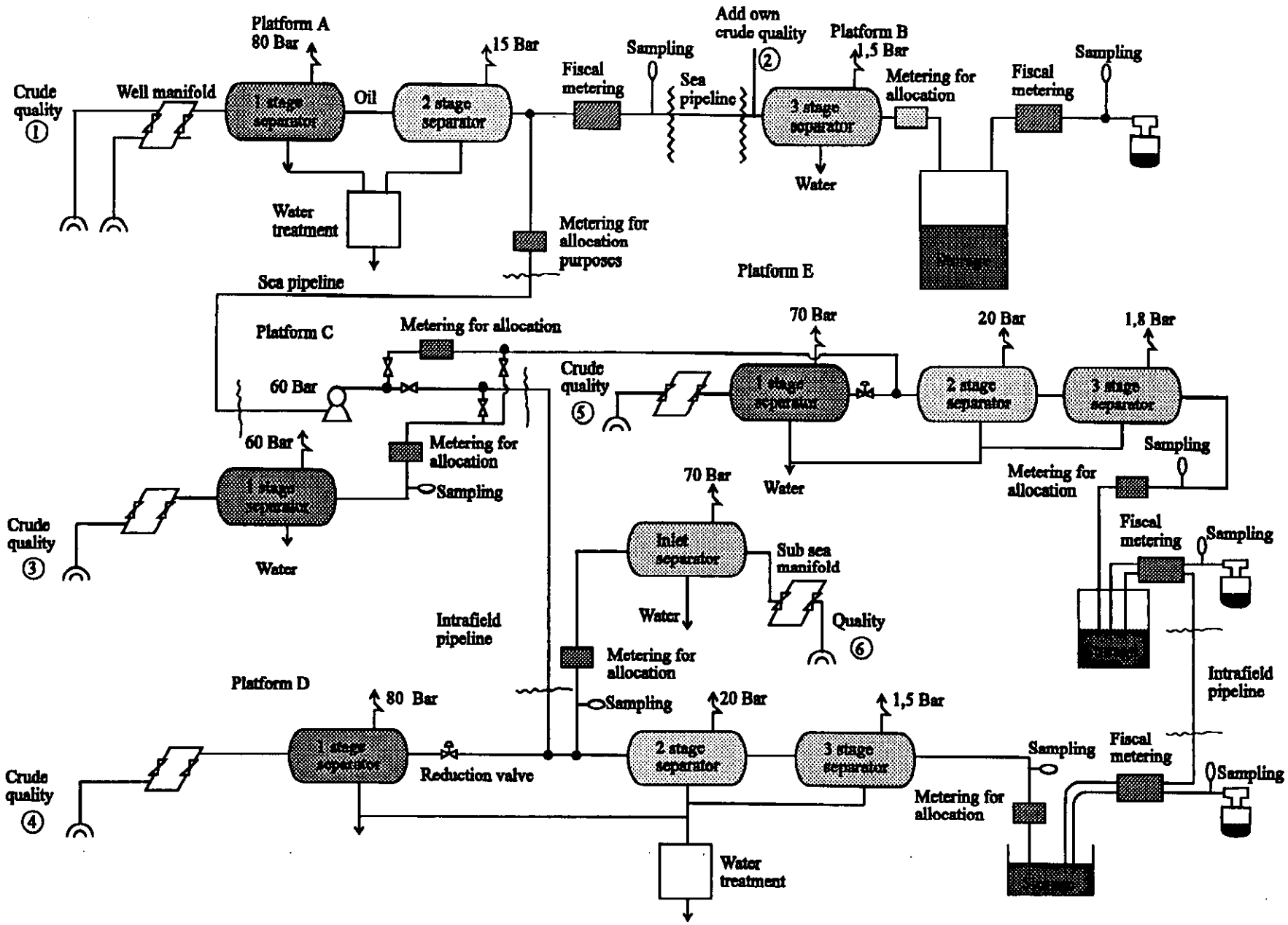


Figure 1. Future allocation scheme for oil.

Use of multiphase flow meters could in this case save place, but the obtained accuracy would often not be within regulations. Figure 1 also shows that crudes are commingled under varying pressure and temperature conditions (gas/oil ratios vary from *20* to *80*). To find allocated mass at standard conditions, we must introduce several shrinkage factors.

To calculate allocated mass, we often also have to accept measurement by difference. Figure 1 shows that crude oil from *platform A* (*quality 1*) can either be routed to *platform B* or *C*. All crude oil from *A* is metered. Crude oil from *platform A* to *platform E* is metered. Crude oil masses routed to *platform D* are found by subtracting metered mass to *platform C* from total input (*i.e.* measured by difference). This scheme indicates that no gas must be flashed of at *platform C*. *Quality 1* is then mixed with *platform C* and *platform D*'s own production (*quality 3* and *4*). *Platform D* and *E* do not have metering facilities after *1 stage* separator. Their mass entitlement are calculated as a difference between metering to storage and the result from metering by difference. To further complicate the picture a satellite field is also tied into *platform D* (*quality 6*). The resulting blend can if necessary be routed to *platform E* storage for lifting purposes.

All allocation of crude is done on dry (free of water) mass basis component for component up to C_{6+}.

$$M_{Allocated} = \sum m(C_i) \cdot ORF(C_i), \tag{1}$$

where $M_{Allocated}$ equals the total allocated mass, $ORF(C_i)$ equals the oil recovery factor for component C_i. $C_i = C_1, C_2, C_3, iC_4, nC_4, iC_5, nC_5, C_{6+}$ and $m(C_i)$ equals the mass per component.

Most of the commingling points are after *1-stage* separation where water content from 2-5% can be observed. A good on line water monitoring is therefore very important for calculating a correct dry crude oil production. Allocated gas to a satellite field is allocated as total mass minus allocated oil mass. A water measurement with low metering uncertainty is therefore necessary for a reliable total allocation uncertainty for the satellite field.

The crude oil qualities vary from light paraffinic crude oils to heavier naftenic/aromatic types of crude. The densities vary from approximately *0,81* to *0,88*. Due to different composition and market value, there must be some sort of value adjustment between the qualities blended together. To get input data for a value adjustment procedure all qualities must be sampled, analysed for composition, distillation yields, water and sediments.

During negotiation of processing agreements, involved companies develop empirical formula for mass allocation, tariff calculation and value adjustment. Those formula are a mixture of results from process simulators calculating shrinkage factors, measured shrinkage factors, distillation of crude oil yields and not to forget often pure commercial issues.

Remarks:

- When we are looking at all the metering points, metering by difference, water monitoring, shrinkage factors, crude oil value adjustment procedures, **we may wonder about total metering uncertainty.**
- Booster pumps, heaters (to secure single phase), metering equipment and mechani-

cal samplers are **costly and occupy much space** on the existing platforms. New technology (*e.g.* multiphase metering systems) and regulations can save space.

- At some metering points we are using **expensive measurement** equipment and at other metering points we relay on **metering by difference**.
- Measurement under high pressure and on line water monitoring of unstabilized crude **influence also** on the total allocation uncertainty.
- In the next *5-10* years, new fields (more than *10*) will come into operation. Most of them will be tied into existing platforms.
- To optimize processing capacity **intrafield pipelines** must be built.
- What sort of **metering methods** and **metering equipment** do we need in the North Sea for coping with this development?

2. Allocation Measurements and Sampling of Crude streams

Production from new fields in the North sea are likely to be routed to existing process platforms. Commingling of crudes demands allocation and technical value adjustment procedures as explained earlier.

Satellite field is developed by two or more sub sea wells. Unstabilized crude is routed to a existing processing platform. Tie-in is done by construction of new inlet crude heaters and new inlet separators (*1-stage* separation). Booster pumps, gas heaters, crude oil and gas metering packages, calibration equipment and sampling equipment must be installed before commingling of crudes in *2-stage* separator.

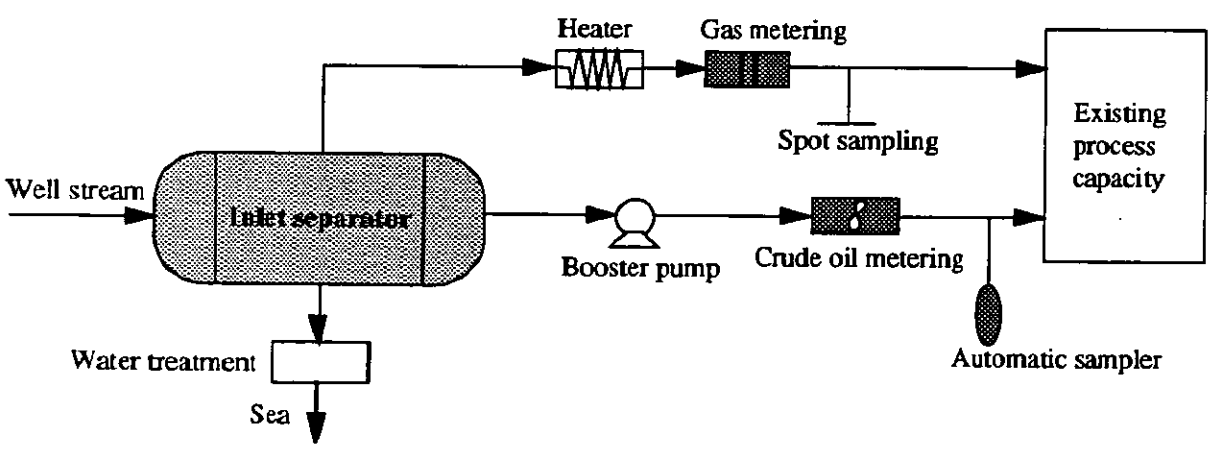


Figure 2. Satellite field tied into an existing platform. Gas and oil inlet metering is needed for allocation purposes. Fiscal standard single phase crude and gas metering is used to day.

Measurement and sampling of crude to storage is also needed for calculating oil recovery factors.

Experience from tie in of *Tordis* and the *Statfjord* satellites indicates that such modification work is time and cost consuming. Use of new technology could save space, but often lack of

accuracy compared to fiscal standards results, and hence, not within regulations.

2.1. Produced mass from a satellite field

The allocated mass to the satellite field M_{SAO} is found by following formulae:

$$M_{SAO} = \sum m_{SAO}(C_i) \tag{2}$$

$$m_{SAO}(C_i) = m_{STD}(C_i) \cdot ORF(C_i) \tag{3}$$

$$ORF(C_i) = \frac{m_{TPO}(C_i)}{m_{TPO}(C_i) + m_{TPG}(C_i) + m_{TFFL}(C_i)}, \tag{4}$$

where $C_i = C_1, C_2, C_3, iC_4, nC_4, iC_5, nC_5, C_{6+}$, $m(C_i)$ equals mass per component, ORF (Oil recovery factor) is the measured shrinkage factor for the processing platform, $TFFL$ = Total Fuel and Flare, SAO = Satellite Allocated Oil, TPO = Total Processed Oil and TPG = Total Processed Gas.

Satellite field part of fuel and flare is calculated by following formula:

$$M_{SSFF} = M_{TFFL} \cdot \frac{M_{SAO}}{M_{TPO}}, \tag{5}$$

where $SSFF$ = Satellite Share of Fuel and Flare.

The conversion of allocated masses to lifting volumes must be done after value adjustment.

$$V_{LIFTING} = \frac{M_{SAO} \pm \Delta M_{TVA}}{\rho_{STORAGE}}, \tag{6}$$

where TVA = Technical Value Adjustment.

Lifting volume is each owners part of the satellite fields allocated storage mass

The conversion of satellite allocated masses to volumes for tariff purposes must be done before value adjustment.

$$V_{SAO} = \frac{M_{SAO}}{\rho_{ALLOCATED}} \cdot 6,293 \tag{7}$$

The process tariff is a fee for using the platform facilities. The volume for tariff is found by using allocated mass before value adjustment divided by the satellite fields measured density. Allocated density is found by analysing the crude oil inlet stream before commingling. When using allocated density new fields coming into the platform at a later stage will not influence the existing and negotiated tariff level.

2.2. Technical value adjustment of crude

A technical value adjustment procedure is needed for the crude from the satellite field commingling with the platform crude oil blend. The procedure shall compensate for the difference

in value on mass basis between satellite crude oil and the existing crude oil to storage on the platform.
If the crude from the satellite field has similar composition to the platform blend, the value can be determined on the basis of refinery yields expressed in weight percent cuts as follows:

- Naphtha (20-165°C)
- Jet kerosene (165-250°C)
- Gasoil (250-375°C)
- Atmosph. resid. (375+°C)

The mass to be value adjusted can be whole crude or C_{5+} fraction. If using C_{5+} the originally allocated C_{4-} mass will be added unchanged to the allocated and value adjusted C_{5+} mass.

If the crudes to be commingled vary in composition and density there often arises a need for splitting the atmospheric residue cut into a vacuum gasoil cut and a vacuum residue cut (see Figure 3).

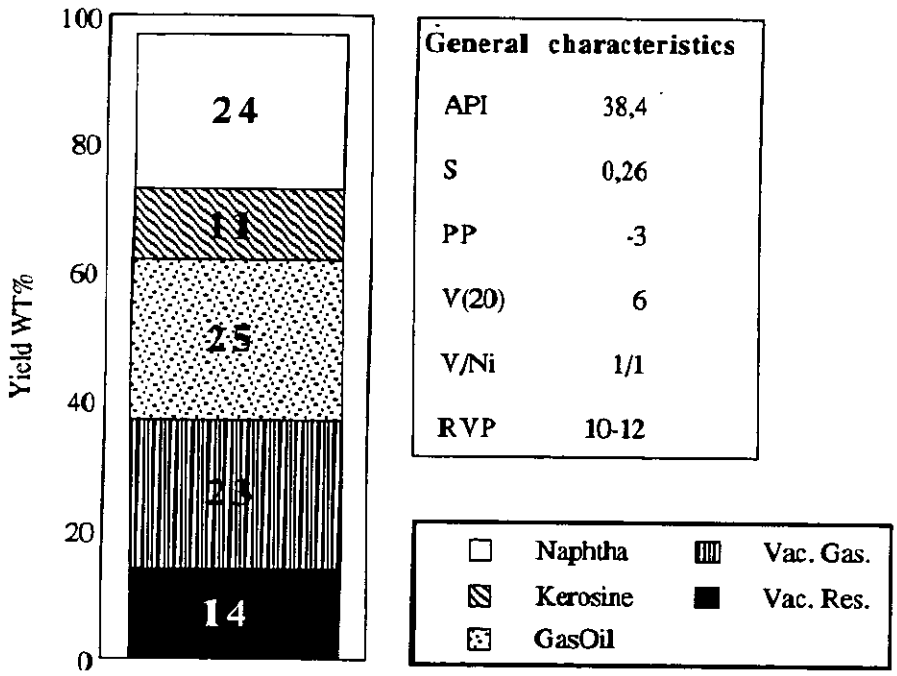


Figure 3. Crude composition.

A stream of *e.g.* condensate commingled with a heavier crude quite often needs a commercially orientated cap because the increased marked value of the common blend will not cover the value transfer caused by the procedure.

The following adjustments to the fractions will be implemented:

- Naphtha: no quality adjustment
- Jet kerosene: density adjustment
- Gasoil: density adjustment
- Atm. residue: sulphur and viscosity adjustment

The basis for determination of the commercial value of the yields, can be the prices quoted per

metric ton for naphtha, jet kerosene, gasoil and fuel oil, published as the *European Bulk* quotation for cargoes *CIF North West Europe* by *Platt's Marketscan* (Platt's quoted). The value adjustment will be settled monthly in kind, and on a mass basis.

2.3. Commingling of pressurised crude between existing platforms

Figure 1 shows commingling of pressurised crude. *Platform A* delivers crude with a gas oil ratio of about *20*. When arriving at *platform C* the crude is boosted up to *60* bar, routed and commingled with unstabilized platform crude (much higher gas/oil ratio) at *platform D* or *E*.

The crude from *platform A* must be metered and sampled. Crude routed to *platform E* is metered by a turbine meter and crude to *platform D* is estimated by difference (total mass delivered from *platform A* minus mass to *platform E*).

Formulae with measured shrinkage factors (*ORF*) cannot be used. The alternative will be to use shrinkage factors from a process simulator (*SORF*) where input data are, separator configuration, composition, temperature and pressure.

Allocation between platforms:

$$M_{APLA} = \sum m_{APLA}(C_i) \tag{8}$$

$$m_{APLA}(C_i) = m_{DPLA}(C_i) \cdot SORF(C_i), \tag{9}$$

where *APLA* equals allocated crude from *platform A*, *DPLA* is delivered crude from *platform A* and $SORF(C_i)$ is the Simulated Oil Recovery Factor as a function of the component C_i for *platform A*.

If the crude composition vary, a technical value adjustment procedure must also contain a cap and a vacuum gas oil cut.

3. Choosing the optimal measurement system

In this section, we describe a model for determining an acceptable level of metering uncertainty and calibration frequency in the case of allocation measurements [1]. We show in some detail how the stochastic process representing the *systematic* measurement errors are modelled. Furthermore, we present some typical results from numerical examples, and we show that choosing the optimal measurement system is closely related to risk attitude.

3.1. The model

The problem of choosing a metering system is likely to be viewed differently by the parties involved. We consider three parties who may have conflicting interests: The operator of the mother field (*M*), the operator of the satellite field (*S*) and the government (*G*). The roles played by each of these can be summarized as follows:

M: Produces from the mother field. Owns the process capacity, and collects process tar-

iffs from *S*.

S: Produces from the satellite field. Pays processing tariffs to *M*, which covers the investment and operating costs of the allocation metering system. These tariffs are defined such that, after tax, *M* gets back what it has paid for investment and operating costs assuming the flow measurements are *100%* correct.

G: Demands the payment of taxes from *M* and *S*. Since the taxes depend on total investments and operating costs, as well as *M*'s and *S*'s income, the government partly covers the expenditures of the metering system.

At this point we would like to stress the fact that income and costs not concerning the allocation measurements are omitted. The model is constructed to determine the net present values (*NPV*) of the net economic effect of the measurements, and some statistical results for all three parties involved, as shown in Figure 4.

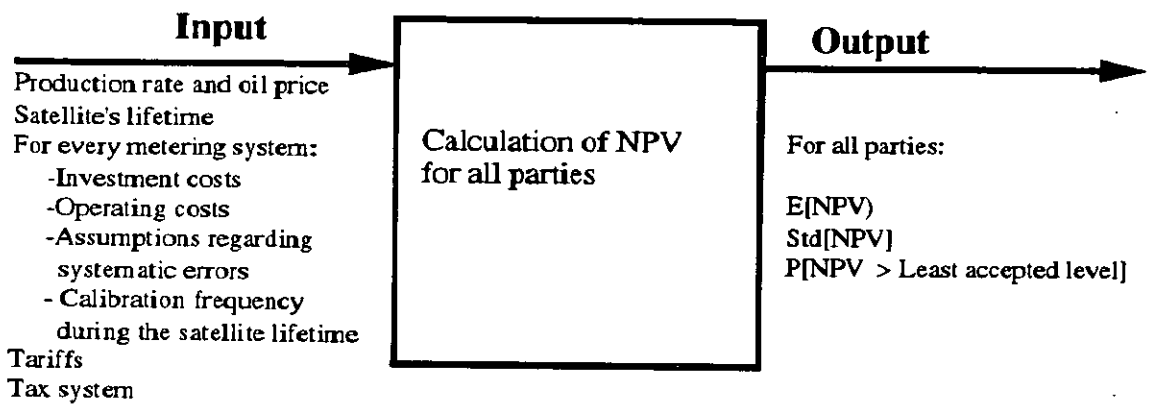


Figure 4. Block scheme of the model

The following input assumptions are made:

- Each metering system is uniquely defined by the measurement inaccuracy, the assumed initial slope of the error growth, and the investment and operating costs.
- Production rates, oil prices, interest rate, processing tariffs and marginal after-tax shares are all constants.
- The calibration costs increase with investment costs.
- The lifetime of the satellite field is *20* years.

In particular the assumption concerning constant oil prices and production rates etc., are obviously one of the weaknesses in our calculations. In addition *M* and *S* will undoubtedly have different positions for tax payment through a period of *20* years. However, the more complex the model is, the more difficult it is to interpret the results. The model, however, is constructed to handle variable oil prices, production rates and processing tariffs. We assume that the satellite field has a lifetime *T*, which is divided into *n* (not necessarily equally long) sub-periods. We also assume that the metering system is calibrated once in every sub-period. Calibration costs are a part of the total operating costs for the allocation measurements.

As output the model simulates mean and expected *NPV* (*E* [*NPV*]) for all parties. Also the

standard deviation of the *NPV* (*std* (*NPV*)) is estimated. To be able to determine an acceptable level of measurement uncertainty, the probability for the simulated mean *NPV* to exceed a least accepted *NPV* level ($P[NPV > NPV_{min}]$) for each party is calculated.

In Figure 5 below, we illustrate the problem under study. We consider the allocation meter to be encumbered with systematic measurement errors, whereas the flow of processed petroleum is measured precisely. The latter assumption is made for analytical simplicity; the model can easily be generalized to cover inaccurate measurement of processed products as well.

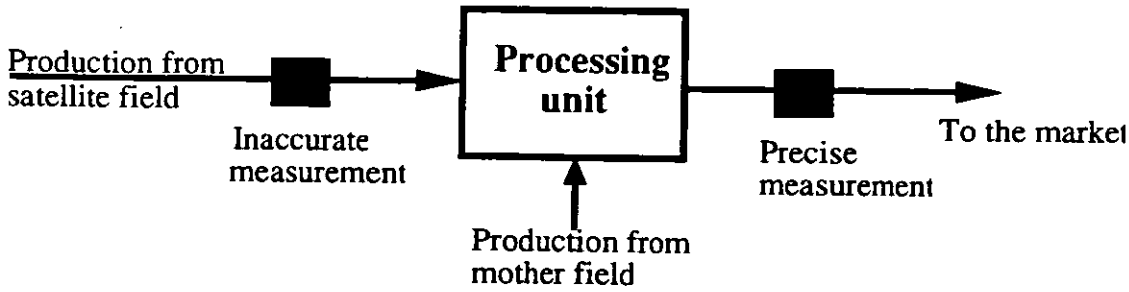


Figure 5. Allocation model.

We have included the government in our analysis because of the importance of taxes, and also because government legislation may in some cases be decisive in the choice of measurement technology. On the Norwegian Continental Shelf, rather detailed regulations concerning measurement accuracy apply. The model may therefore indicate whether or not such legislations are rational, even from the government's point of view.

3.2. Modelling of systematic errors

One of the most important parts of the model is the representation of systematic measurement errors. In this work, these are modelled as a special stochastic process. We assume that every metering system is characterized by an initial error. This error is modelled as random, and is assumed to be normally distributed with zero mean and technology dependent standard deviation. Table 1 shows the two descriptive parameters for the metering systems we have used in our calculations.

Table 1. Cost and maximum initial error for the metering systems. NOTE: 1 dollar is about 7 NOK.

Metering system	Cost [mill. NOK]	Max. init. error [%]
Meter 1	5	8
Meter 2	10	5
Meter 3	20	3
Meter 4	30	0,5
Meter 5	50	0,2

Furthermore, we assume that the metering system has a systematic error growth in each interval between two calibrations. Figure 6 is a simulation of an orbit for the total systematic error for *meter 1*, X_1, with calibration every month during one year.

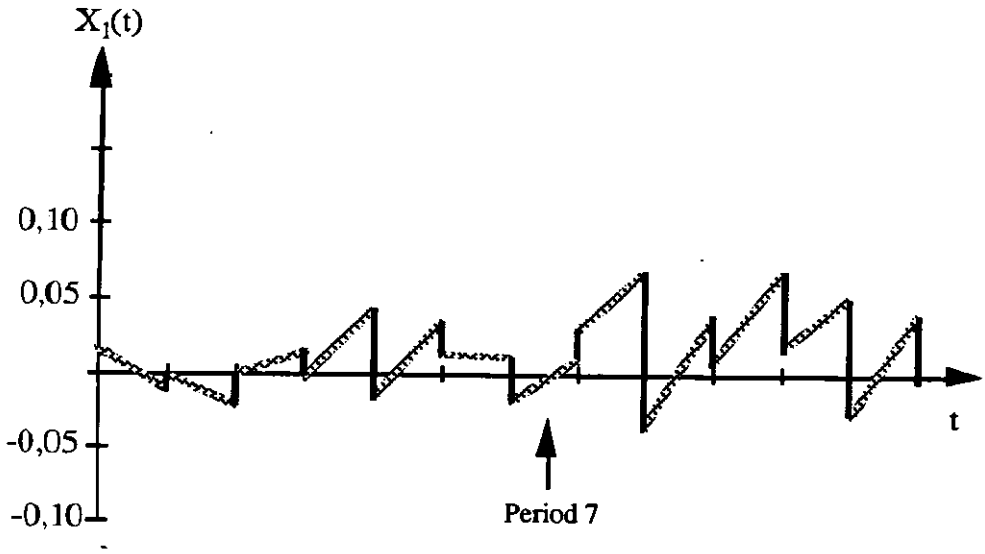


Figure 6. A simulated orbit for the total systematic error with initial error growth assumed to be zero. The meter is calibrated every month during one year. Note: $X_1(t) = 0{,}05$ means 5% overestimation at time t.

Briefly, the stochastic process for the total systematic errors can be described as follows: Before the first "off-shore calibration", the trend of the error growth, if there is any, is assumed to be known. After this calibration, we expect that the systematic error growth will continue as in the first period. More precisely, the slope of the expected error growth in period k equals the actual slope of the error growth in period $k - 1$. This is used to calculate the conditional mean of the measurement errors before calibration, which we assume to be normally distributed. The standard deviation of these errors are proportional to the time interval between two calibrations. The study is performed for two values of this proportional coefficient. To simplify, the sequence of initial meter errors after calibration is modelled to be independent of each other. The stochastic process for total systematic error is non-Markovian since what is expected to happen in the future is dependent of what has happened in the past. Figure 6 illustrates this phenomenon from *period 7* to *period 12*, where the error growth in one period is "approximately equal" to the error growth in the preceding period.

3.3. Simulations

In this work we have studied the *NPV*'s, using imaginary data, concerning only the allocation measurements for different metering system as a function of four variable quantities. These are the calibration frequency, the initial slope of the error growth, the calibration and the metering investment costs. In the model the systematic errors are described using Monte Carlo simulation for the stochastic process. An example of a possible orbit for the total systematic error is shown in Figure 6. These values are then used to calculate the parties' *NPV*'s and in addition their expectations and standard deviations. This process is repeated $N = 2000$ times.

Figure 7 to 9 show normalized simulated mean *NPV*'s as a function of calibration frequency for M, S and G, respectively. The slope of the initial error growth is zero for all cases. We

assume that *meter 1* (the cheapest and most inaccurate) and *meter 5* (the fiscal type) are used. Let n be the number of subdivisions of $T = 20$ years. Since there are *365* days and *52* weeks during one year, corresponds to calibrating once a day, $n = 7300$ corresponds to calibrating once every week, $n = 240$ means once every month while $n = 40$ means twice a year. The normalized *NPV* in Figure 8 and 9 (*i.e.* for *S* and *G*) are negative because we only consider the net economic effect of the costs. The more negative the normalized *NPV*, the more loss of money for the party and vice versa.

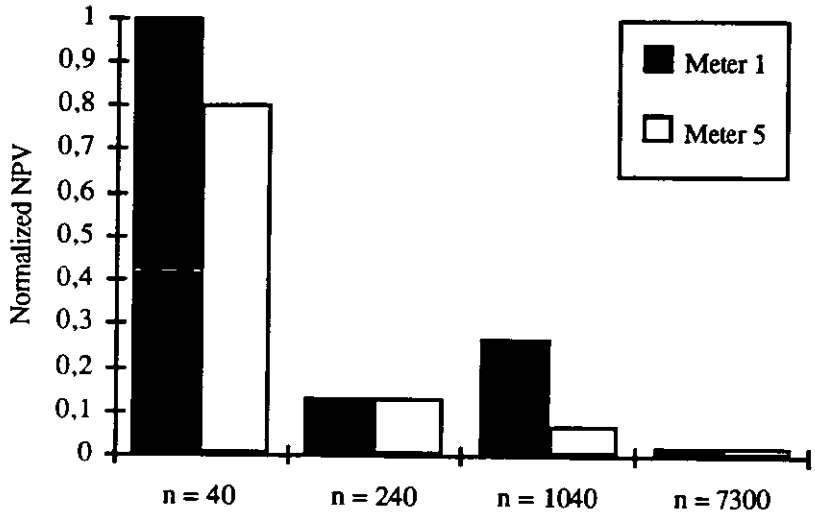


Figure 7. Normalized mean *NPV*'s for *M*, using *meter 1* and *5*, as a function of calibrations during *20* years (n).

The simulations shows (see Figure 7) that the mean *NPV* for the owner of the process capacity (*M*) is decreasing with increasing calibration frequency. In addition it can be observed that the *NPV* is at least as favourable for *meter 1* as for *meter 5*. In Figure 8, that is for the owner of the satellite field, there is obviously no economic agreement for a fiscal metering system with a high calibration frequency. We could also note that *meter 1* (the cheapest and most inaccurate) always implies a higher expected *NPV* compared to *meter 5* (the fiscal type). Figure 9 shows the most striking result in this paper. For the government, the losses are particularly high when the calibration frequency approaches once a day. This should perhaps indicate that it never pays to use a fiscal metering system.

However, there are always two sides to a coin. The other side is the degree of uncertainty we have when using an inaccurate metering system compared to a fiscal one. Using a fiscal metering system with a high calibration frequency implies accurate measurements. But as the total investment and operating costs increases, the expected *NPV* decreases. An inaccurate system with a low calibration frequency gives uncertain measurements, but in return the expected *NPV* is greater than in the first case since the costs are reduced. Without regard to the existing measurement regulations, choosing an optimal metering system is thus a trade-off between lower expected *NPV* and low risk on the one hand, and higher *NPV* and greater risk on the other. This argument confirms what we stated in the beginning: Choosing an optimal measurement system is a matter of risk attitude. To illustrate, consider Figure 10 which is an example of two probability distribution densities with different standard deviations and different expectations. The wider density would correspond to the more inaccurate meter and the narrower to the fiscal meter.

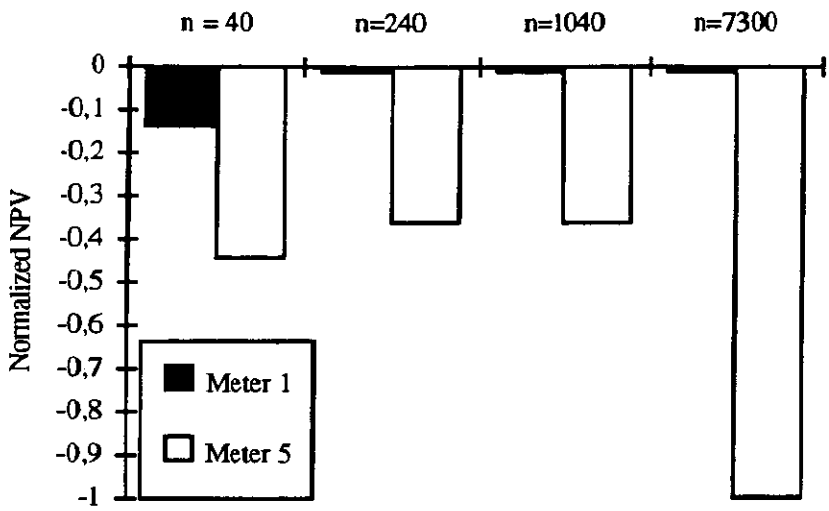


Figure 8. Normalized mean *NPV*'s for *S*, using *meter 1* and *5*, as a function of calibrations during *20* years (*n*).

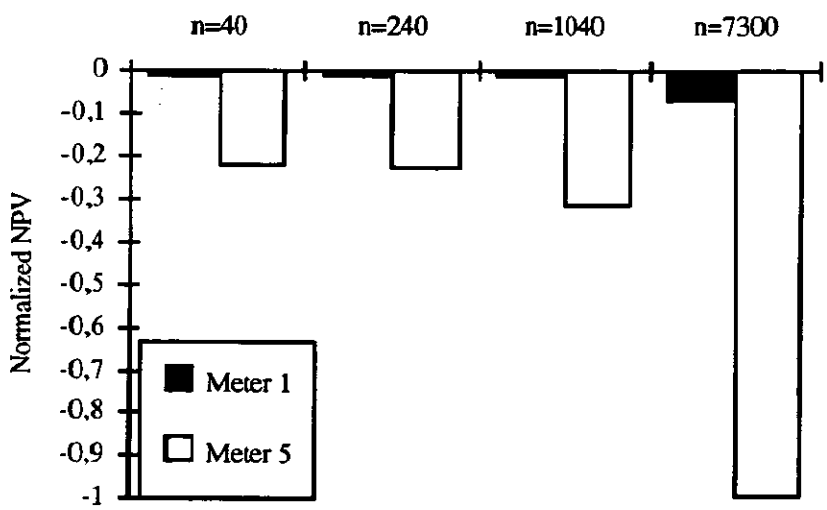


Figure 9. Normalized mean *NPV*'s for *G*, using *meter 1* and *5*, as a function of calibrations during *20* years (n).

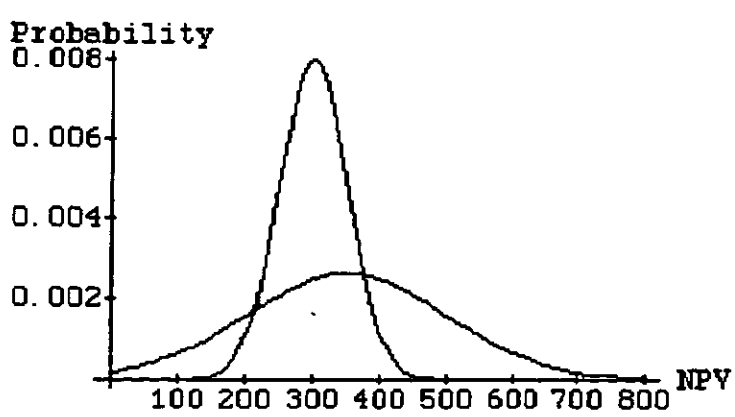


Figure 10. An example of two *NPV* distributions with the *NPV*'s measured in mill. NOK.

4. Conclusions

There is an increasing need for allocation measurements to obtain optimal use of existing process capacity. So far these measurements have been obtained by using turbine meter for the liquid phase and orifice plate for the gas phase. To ensure single phase through the turbine meter and the orifice plate, booster pumps and heaters are needed. Hence, space consuming and expensive installations results. However, the costs may be reduced by using new technology (*e.g.* multiphase flow meters), but this will often implies decreased accuracy and hence not within existing regulations.

There has been developed a model which calculates the net present value as a function of measurement accuracy, production etc. for all involved parties (S, M and G). On the basis of simulations it could be stated that it is never economically to use fiscal metering systems compared to less expensive system for the owner of the satellite field (S) and the government (G). The results also indicates that the NPV decreases with increasing calibration frequency.

There is no reason a priori to believe that a meter neither will consequently under- nor overestimate. Therefore, the results in the case of zero initial slope for the error growth are the most valid and therefore chosen to be presented in this paper. For this case the simulations indicates that fiscal measurement standards is not economically, neither for the owner of the satellite field (S), the owner of the process platform (M) and the government (G).

Today, the regulations for fiscal measurement of oil and gas in the petroleum industry in Norway does not allow the parties to consider the problem above as a decision problem. If there were no regulations, there is no unique answer to question of choosing an optimal measurement system, but it is rather a matter of risk attitude.

References

[1] Nyhus H, Haugland D og Isaksen Ø (1992) *Optimal målenøyaktighet* (*"Optimal measurement accuracy"*) CMR-92-F15019.

Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

New Networked Fiscal Metering System for the Phillips Ekofisk Complex

by

Mr. Flemming Sørensen,
Holta & Håland A/S, Norway

Holta & Hålan

CONTENTS :

0. INTRODUCTION

The paper describes the architecture and functionality of the metering system supplied by **Holta & Håland A/S** (H&H) to replace the existing measurement computer system on Ekofisk 2/4-T and 2/4-Golf. The replacement Measurement Computer System consist of **Daniel Industries** (DUK) Micro 5000 flow computers, performing data gathering and calculations, and the Supervisory Computer System supplied by **Eurotherm Process Automation** (EPA) performing reporting and logging functions.

The paper describes the fundamental requirements and the final system architecture and relates some of the unforeseen problems encountered in implementing a large and complex integrated metering system.

The system integrates field instrumentation such as smart transmitters and individual stream computers into a wide area networked supervisory system with distributed databases. Use of fault tolerant configurations throughout ensures high availability of functionality and data.

The need to maintain accuracy, data integrity and security, network access protection, and on-line maintenance of fiscal data are key features of the system.

H&H have delivered one system which is in operation at Statoil Kårstø (a simplified version of the Ekofisk system), and a system for the Ekofisk complex which now are undergoing final testing.

The following important requirements have been achieved in our system:

- High availability (99.996)
  By use of dual redundancy
- High accuracy
- Scalability
  Start small grow large
- Remote operation
  Unmanned platforms
- Real time applications in Supervisory system.
- Flow Computer with fast sample rate. All I/O within 1 second.
- Oil flow calculation cycle less than 2 seconds
- Gas flow calculation cycle less than 4 seconds.

1. CLIENT REQUIREMENTS

- Flow Measurement at Ekofisk 2/4-T and 2/4G.
- Available Requirements: Overall time availability of 99.996%
- Best available accuracy, using SMART transmitters where appropriate. (pressure, d/p, temp).
- State of the art technology, but using as much standard (proven) software as possible.
- Expandable system, capable of accommodating the total requirements of the Greater Ekofisk complex in the longer term, but maintaining speed performance as system expanded.
- Ability to perform remote monitoring, control and maintenance (from on-shore facilities, and other platforms)
- Act as slave for communication of measurement data to telemetry computer (TCS).
- Display of local oil and gas densitometer, pressure and temperature values..
- Maintain storage for two months of hourly reports for each meter and station.
- Printing of metering reports and system alarms.
- Provide VDU graphic trending display.

The following improvements to client requirements were achieved

- Flow Computers with fast sample rate. All I/O within 1 second.
- Oil flow calculations with cycle less than 2 seconds.
- Gas flow calculations with cycle less than 4 seconds.
- Fast real time response at the Supervisory System (typically 1 to 2 secs).

2 SYSTEM OVERVIEW

The system architecture and functionality has been developed and evolved to meet the latest NPD regulations, and the stringent operational, maintenance and integrity requirements of Phillips for the major Ekofisk refurbishment programme.

The Ekofisk 2/4T metering stations and the number of associated flow computers is as follows:

- Oil: 12 streams + 4 future
- Prover: 1 duty and 1 standby prover computer
- Gas: 28 streams + 8 future
- Flare Gas: 6 streams
- Test Separator: 2 streams

The Ekofisk 2/4G metering stations and the number of associated flow computers is as follows:

- Oil: 3 Streamers + 1 future)
- Prover: 1 flow computer.
- Gas: 4 Streams + 1 future.

A total of 72 flow computers serving 69 metering streams.

The total metering system integrates the specialist functions of Daniels Fiscal Metering Subsystems (Micro 5000) into an EPA Network 6000 Automation System (Maxi-Vis Supervisory system). The resultant system combines the advanced features of the Micro 5000 flow computers with the large system environment of Network 6000.

Maxi-Vis Supervisory system

Maxi-Vis IV Supervisory Systems are assembled from a base set of well proven hardware and software packages. The mix of base software packages defines the general functionality. To this is added special metering application package.

The system is based on a 'Metering Database' package, which is a standard industry package addressing the off-shore Oil and Gas Fiscal Metering Application. The mix of standard DEC hardware and a well proven base package for fiscal metering provided the user with a flexible and expandable system.

Data from the front end subsystems is regularly scanned into the central Maxi-Vis IV database system. The structure of the system is designed to provide a throughput of data into the database such as to achieve a currency of 1-2 seconds on each data value.

Access to this database can be achieved from different terminals either directly linked to the Maxi-Vis IV (e.g. Operator Workstation) or remotely (e.g. On-Shore Computing Workstation).

The system includes operator colour graphic workstations, allowing access via preformatted displays, mimics and spreadsheets to the real-time database. Trending and alarm features are also available as standard at this terminal. Alarm and event messages, database change messages and reports are stored on disk and printed on dedicated hard copy printers. The operator interface is simplified by the use of a dedicated operators keyboard in conjunction with a trackerball. The operators workstation is also used by the engineer (via key protected access) to configure the Maxi-Vis system on-line via standard EPA software packages.

Micro 5000 flow computer

The flow computers are Daniel Industries µ5000 flow computers. They each calculate stream totals, stream flow rates and press, temp, d/p density based on the data gathered from each stream input point. The flow computers each monitor the stream to which they are dedicated. A prover flow computer is provided to carry out proving functions for each of the oil streams.

The µ5000 flow computer is a microprocessor based instrument capable of measuring field signals representing flow and process conditions. The µ5000 flow computer can measure flow represented by signals from primary devices such as turbine meters, PD meters, differential pressure transmitters, and with inputs representing process conditions such as, pressure, temperature, and density, can perform corrected flow and totalisation in accordance with recognised standards such as AGA 3, (API 2530), ISO 5167, AGA 5, AGA 7, AGA 8, API 1101, API 2534, and API 2540.

All the electronics required to monitor and measure these signals are located on a single circuit card. Each µ5000 flow computer can therefore carry out full metering, alarming, control and reporting on single metering stream. Multiple stream metering is also possible only limited by the input and output capability of the instrument.

3. SYSTEM ARCHITECTURE

3.1 Supervisory System

Network 6000 is the generic term for an EPA Integrated Automation System. These systems have a number of characteristics incorporated in the fundamental system design, each of which is important to the successful implementation of a modern Automation System. These are:-

- Predictable real-time performance.
- Open Architecture
- High Availability Configurations

Use of a combination of Fault Tolerant (dual redundant) configurations and distribution of function at a low level.

A Network 6000 System consists of 4 primary logical elements:

- Maxi-Vis Database Servers
- Networked Operator Stations
- Primary Plant Subsystems
- Foreign Database Servers

The Maxi-Vis database server is responsible for updating its database with current data, servicing external database access requests using structured interface routines, and providing a computing platform to run other supervisory functions.

The server communicates with the Primary Plant Subsystems (fiscal flow computers, general process I/O, continuous control elements etc.), using optimised proprietary protocols. By partitioning the communications into a number of segments, each controlled by a dedicated communications processor resident in the server chassis, the server is able to maintain an update rate of 1 to 2 sec. for all primary dynamic data.

Larger systems may be accommodated by adding extra standalone Maxi-Vis Real-time Database Servers. In this case communication between data base computers is handled by an extensive set of Distributed Database interface routines that allow the user to define the types and speed of data exchange (this includes display and file data transfer).

Foreign Device Database Servers can communicate with Maxi-Vis Servers using the same Distributed Database interface routines, or can use an optional package (Distributed Database Network Interface) that imposes strict access protection mechanisms on the device accessing the Maxi-Vis Database. Either method can use DECNet, TCP/IP or other custom protocols.

Maxi-Vis functionality

A brief description of each function follows.

Stream Metering Operations
Operator and Engineer operations are provided for metering runs and stations using a combination of real-time spreadsheets and mimic displays. Extensive use is made of the display hierarchy configuration facilities to provide Operators and Engineers with access to information and facilities in a logical and efficient manner. Integrated into the Operator facilities is the production of hourly, daily and on demand reports.

Meter Proving Operations
Meter proving operations are integrated into the Oil station Operator and Engineer interface using a combination of real-time spreadsheets and mimic displays.

A tape streamer allows archiving of trend data for long term storage and is also used to backup the files on the system disk.

Oil/Gas Densitometer Surveillance
Oil and Gas density surveillance spreadsheets show for each run the density figure used in the flow calculations. An override spreadsheet allows the Operator to choose between measured, calculated or manually entered values.

Sampler
Pulsed digital outputs, proportional to station flow, are provided for sampler systems. Parameters are configured via a spreadsheet.

Real Input Overrides
Spreadsheets are provided to allow the Engineer to override values used by the flow computers.

Information Security
Security of information is ensured by providing:

- Four levels of Operator/Engineer access.
- Read only and read/write privileges to workstations.
- Restricted network access via account passwords.

Information Integrity
The integrity of information is maintained by:

- File/Program/Spreadsheet version numbers.
- Master/Standby Measurement Computer System.

- Duty/Standby flow computer interface.

Time Synchronisation

The system is designed to centralise all date and time stamping for Fiscal reports at the Supervisory Database Computer.

To satisfy the overall time Synchronisation (and data currency) requirements of ± 1 sec., the following system design criteria are observed:-

a) Each stream micro will recalculate the primary flow algorithms and update its local database at a frequency of approximately 1Hz.

All Primary Flow data are updated each second.

b) The Maxi-Vis will update all primary flow data into its real-time database at a frequency of 1Hz. Thus, primary flow data held within the Maxi-Vis real-time database will have a time currency of ± 1 sec.

c) Reports will be formed by taken a snap shot of the set of core data (within say 100 msec. of the specified time of day), and copying into a static scratchpad area of the database.

(Note:- the size and structure of this scratchpad area is user definable via the database configuration tools).

Once placed into scratchpad, the data (formed as a consistent set in time) is then available for the spreadsheet processes to operate on.

d) As a backup the Daniels flow computers will hold the latest value for each of the following stream flow totals - hourly total, daily total, weekly total.

e) The time of day clock within the master and standby Maxi-Vis systems will be maintained to within 1 sec. of the time received from the EPA system.

Alarm and Event Processing

The standard alarm and event processing system providing extensive functionality and flexibility.

Long Term Data Storage and Access

Historic trend data is transferred to tape for later recall.

Daniels Micro 5000 Flow Computer Interface

- Implemented via front end processors.
- All parameters down loaded from the MCS.
- All parameters read back after down load and compared with master files.
- Data down loaded to both duty and standby computers.
- Parameters scanned every one second.

Smart Transmitter Interface

Read only interface to smart transmitters for calibration purposes.

Telemetry System Interface

- Handles both send and receive requests.

3.2 Flow Computer system.

The system is configured with one μ 5000 flow computer dedicated to each metering line. The input signals are segregated into signal type. These are distributed to the appropriate flow computers. Signal conversion is carried out on each flow computer termination module.

The oil stations have a PLC monitoring the valve interlock for proving. This carries out interlocking functions.

Each metering run are supplied with one computer per line, each monitoring the following signals :

- Turbine meter:
  Dual Pulse Inputs : optically isolated.
  0 - 2.000 Hz, Integrity Monitoring to ISO 6551 Level A or B optional on each input channel

- Densitometer:
  Frequency Inputs : optically isolated.
  5 - 10,000 Hz, 650 nano-seconds resolution. Accuracy : Typically 0.0013% of reading.

- Flow Control valve:
  Analogue feedback signal
  4 - 20 mA, 16 bits resolution ± 0,02% of full scale accuracy.

- Control valve position:
  Status Inputs

- Prover Detector Switch Status Inputs

- RS485 link to the smart transmitter interface. Temperature, pressure, diff. pressure, process values

- Flow Control valve:
  Analogue Control Outputs :
  4 - 20mA, 12 bits resolution ± 0.1% accuracy, 100 msec update.

- RTD Inputs:
  4 Wire. 100 ohms PRT to IEC 751 Class A, ± 0.1% accuracy (of reading)

- Valve:
  Control Outputs

Each flow computer has the following communications links : -

- Link to dual supervisory computer system (Dual RS 422 Link)
- Link to prover flow computer (RS 422 Link)
- Link to the neighbouring flow computer providing standby metering (RS 422 Link)
- Link to the neighbouring flow computer that this flow computer is supplying standby metering for (RS 422 Link)
- Link to the smart transmitter interface for the standby process signals (RS 485 Link)

Each flow computer receives the signals as detailed above and uses the values measured from the transmitter outputs to calculate flow rates and flow totals. The calculated values and data gathered from each transmitter are available for the supervisory computer and can be accessed at each computer using the hand held keypad. In addition to the signals received and supplied, as detailed above, each flow computer provides monitoring and controlling for the neighbouring flow computer.

Proof Control

The system is configured with two micro 5000 flow computers providing common proof control for all oil stations. The two flow computers are arranged in a primary/standby arrangement, with proof control only possible from the primary flow computer. A switch is provided to enable selection of the primary and standby flow computers. The switch will enable the operator to select which flow computer is the primary. The standby flow computer will become the primary after a switch over and the primary flow computer shall control the valves. A single RS 422 communication link is provided between the stream flow computers and the prover flow computers. The primary prover flow computer acts as the master with the other flow computers on the communication link.

4. PROBLEMS ENCOUNTERED

Size and complexity of system caused some implementation problems. The system has proved to be more complex than any of the participating Companies originally envisaged.

Creating a secure multi-user environment with sufficient levels of protection, particularly in relation to remote network access and partitioning data access and executive access.

Failure mode detection and recovery.

Understanding and agreeing precise functional requirements, and translating these into an agreed implementation.

Time and complexity of integrated and FAT testing

e.g. large quantity of complex real time spreadsheets
failure mode testing
network testing.

5. FUTURE POTENTIAL

Experience gained has established the overall design principles for a Fiscal metering system integrated into a comprehensive network environment.

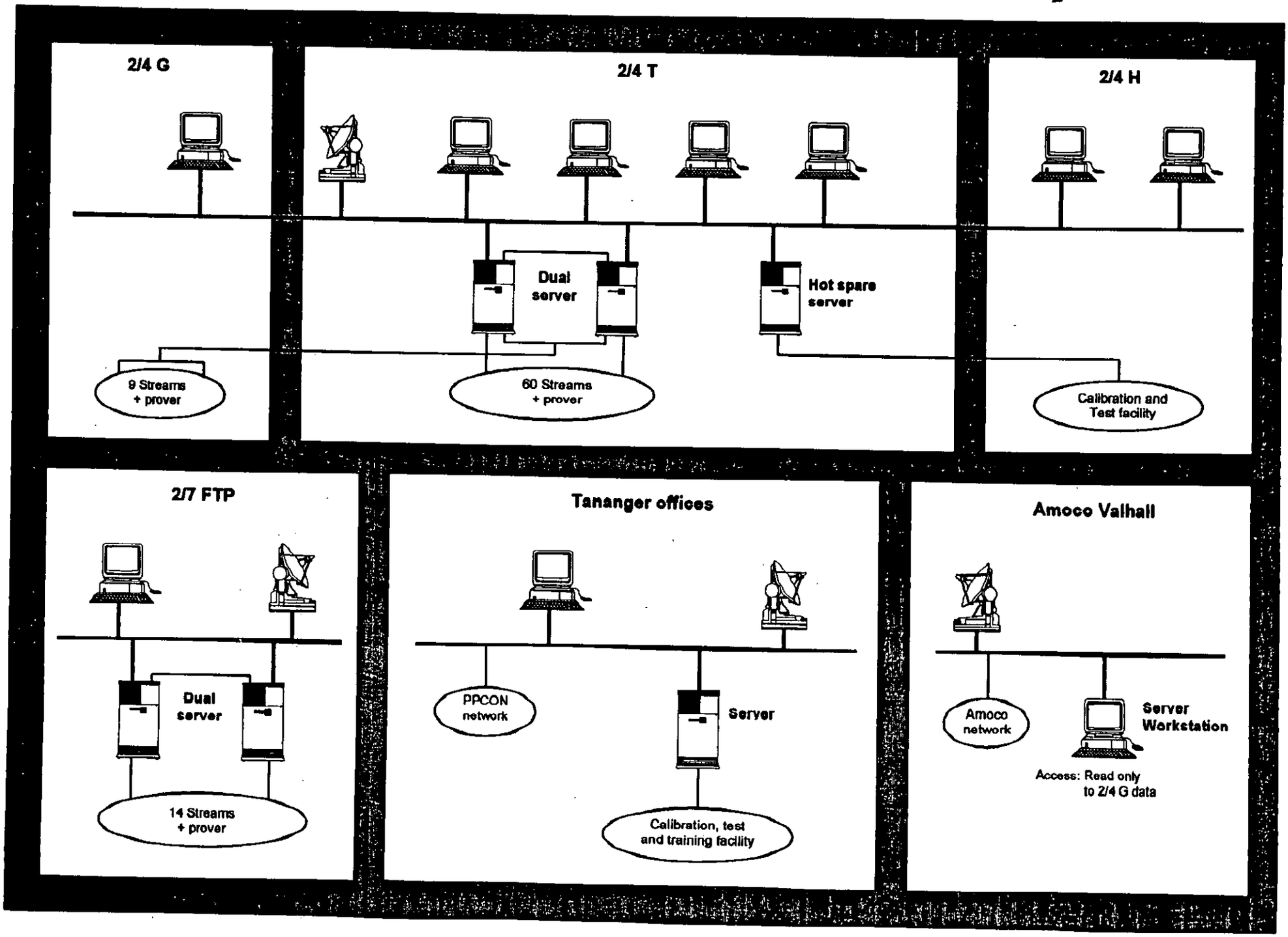
With current computing technology, these principles can be readily applied to small system applications, but ensuring that the system can be expanded as required in the future. For example, a single workstation combining the functions of database and user interface can be used to supervise a few fiscal stream computers in the knowledge that the basic architecture will support expansion into a larger integrated environment if required.

6. ILLUSTRATIONS

- PPCON Ekofisk System overviews
- Unique features
- Operator overviews

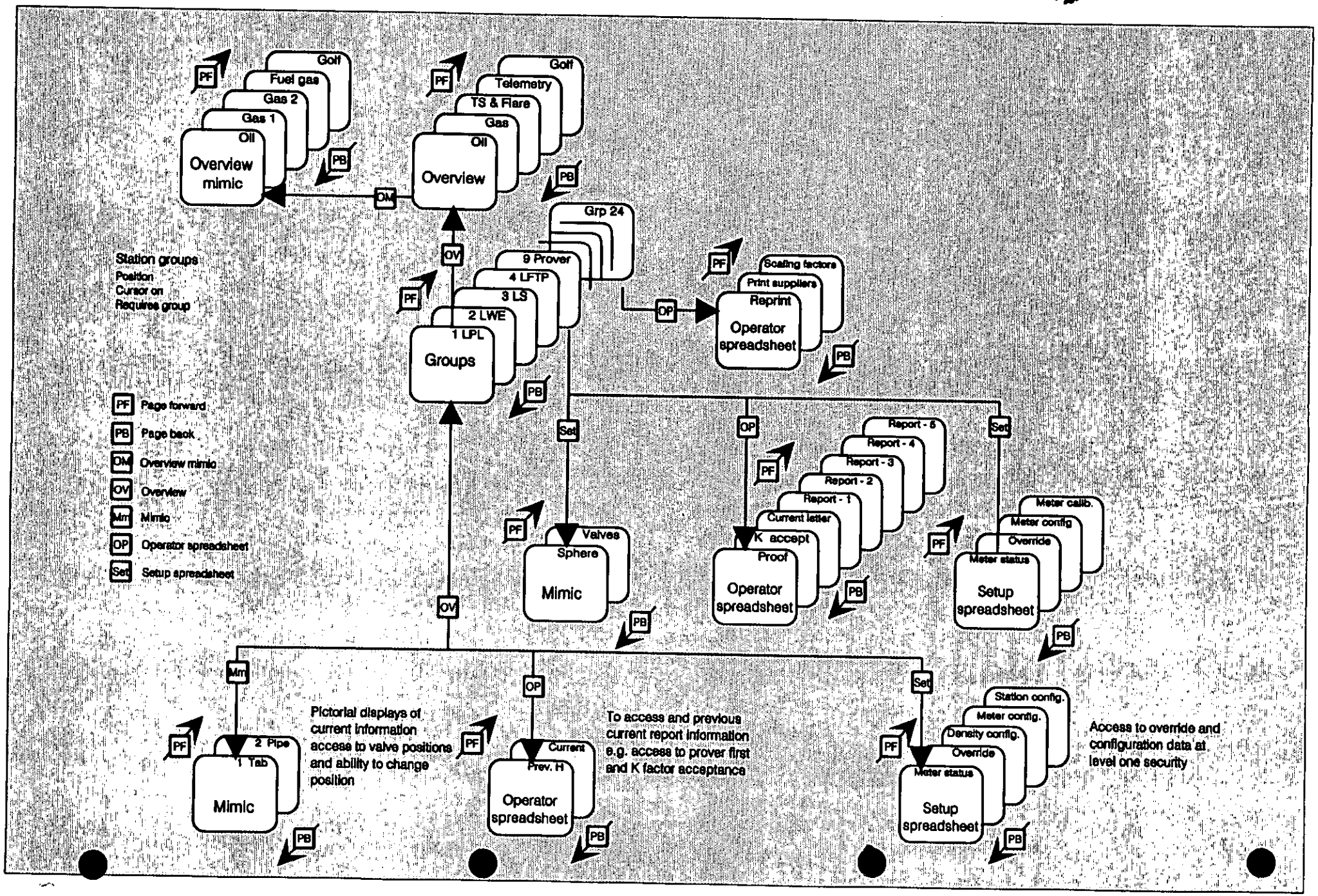
PPCON Ekofisk System overview

Holta & Haland



Operator overviews

Holta & Håland



Holta & Håland

Unique features

- High availability (99.996)
  - By use of dual redundancy
- High accuracy
- Scalability
  - Start small grow large
- Remote operation
  - Unmanned platforms
- Real time applications available in Supervisory system (SCADA, process control etc)
- Flow Computer with fast sample rate. All I/O within 1 seconds
- Oil flow calculation less than 2 seconds
- Gas flow calculation less than 4 seconds

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NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

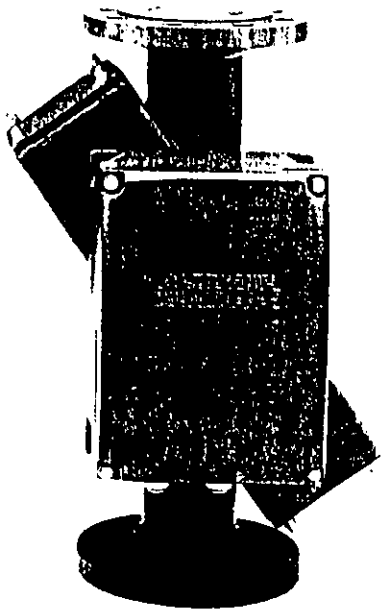
NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Mass Gasflow measurement using ultrasonic flowmeter

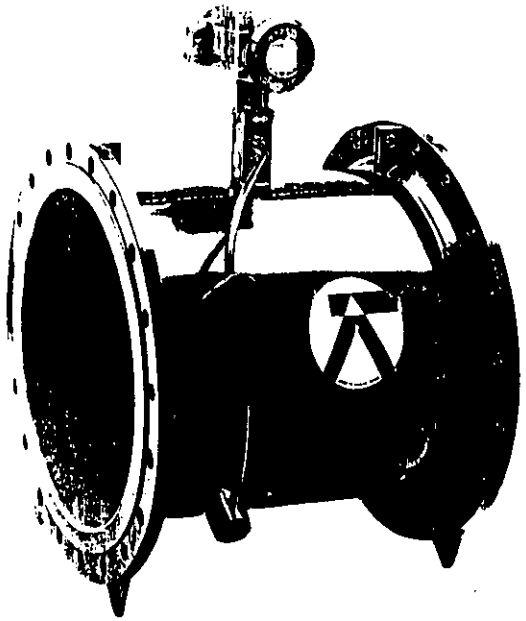
by

Mr. A.H. Boer,
Krohne
The Netherlands



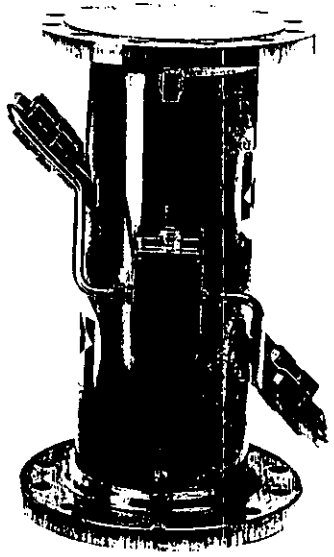
1978

For liquids

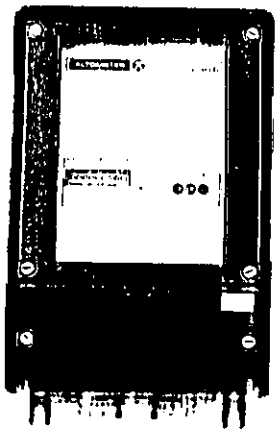


1990

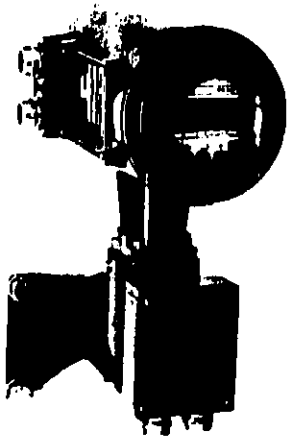
For gases



1988



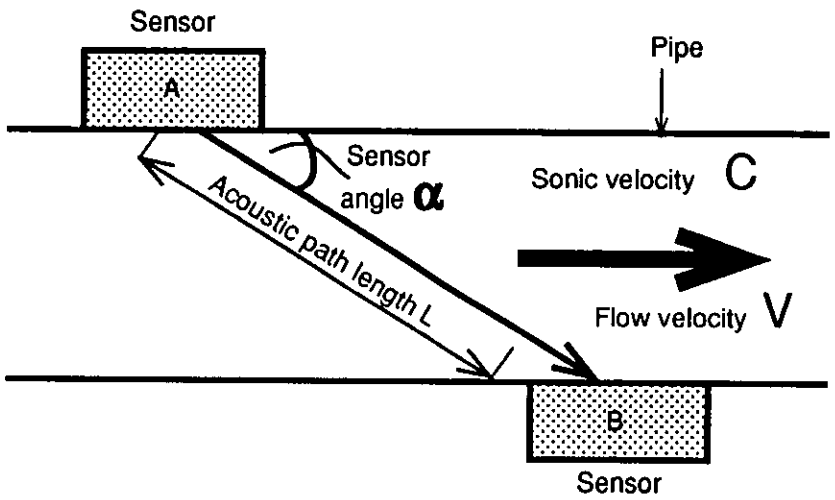
1988



1992

KROHNE
Ultrasonic

Measurement of Transit time T



$$T_{A \rightarrow B} = \frac{\text{Acoustic path length L}}{\text{Sound wave velocity}}$$

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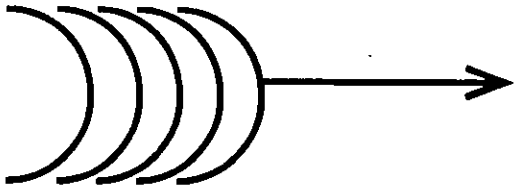
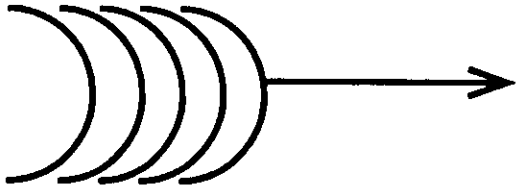
Ultrasonic

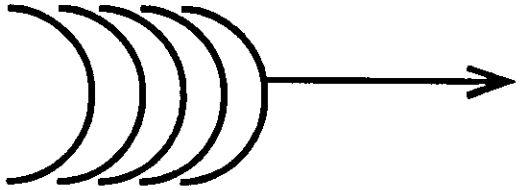
Sonic velocity



Gases	
Air	330 m/s
Chlorine	210 m/s
Methane	430 m/s
Hydrogen	1280 m/s



Liquids	
Water	1480 m/s
Methanol	1100 m/s
Kerosine	1320 m/s
Glycerol	1900 m/s



Solids		
Steel	5900 m/s	3200 m/s
Glass	5600 m/s	3300 m/s
Berylium	12900 m/s	8900 m/s

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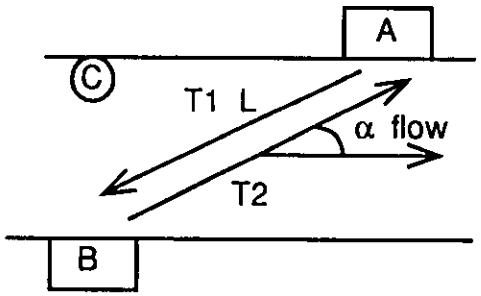
How to measure the sonic velocity ?

- Integration in transit time Ultrasonic gasflowmeter



$$V \approx \frac{T1 - T2}{2L \cos \alpha} C^2$$

$$C \approx \frac{2L}{T1 + T2}$$

C = Sonic velocity

T1 = Transit time A to B

T2 = Transit time B to A

L = Acoustic path length

V = flow velocity

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Ultrasonic

Molecular weight

Relation between sonic velocity of a gas and its molecular weight

$$c = \sqrt{\frac{Ks}{\rho}}$$

c = sonic velocity

Ks = Isentropic modulus of compression

ρ = density

for an ideal gas, this works out as:

$$\boxed{M = \frac{n * R * T * K}{c^2}}$$

M = molweight

R = universal gas constant

T = temperature

K = Cp / Cv

c = sonic velocity

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Ultrasonic

Limitations of model

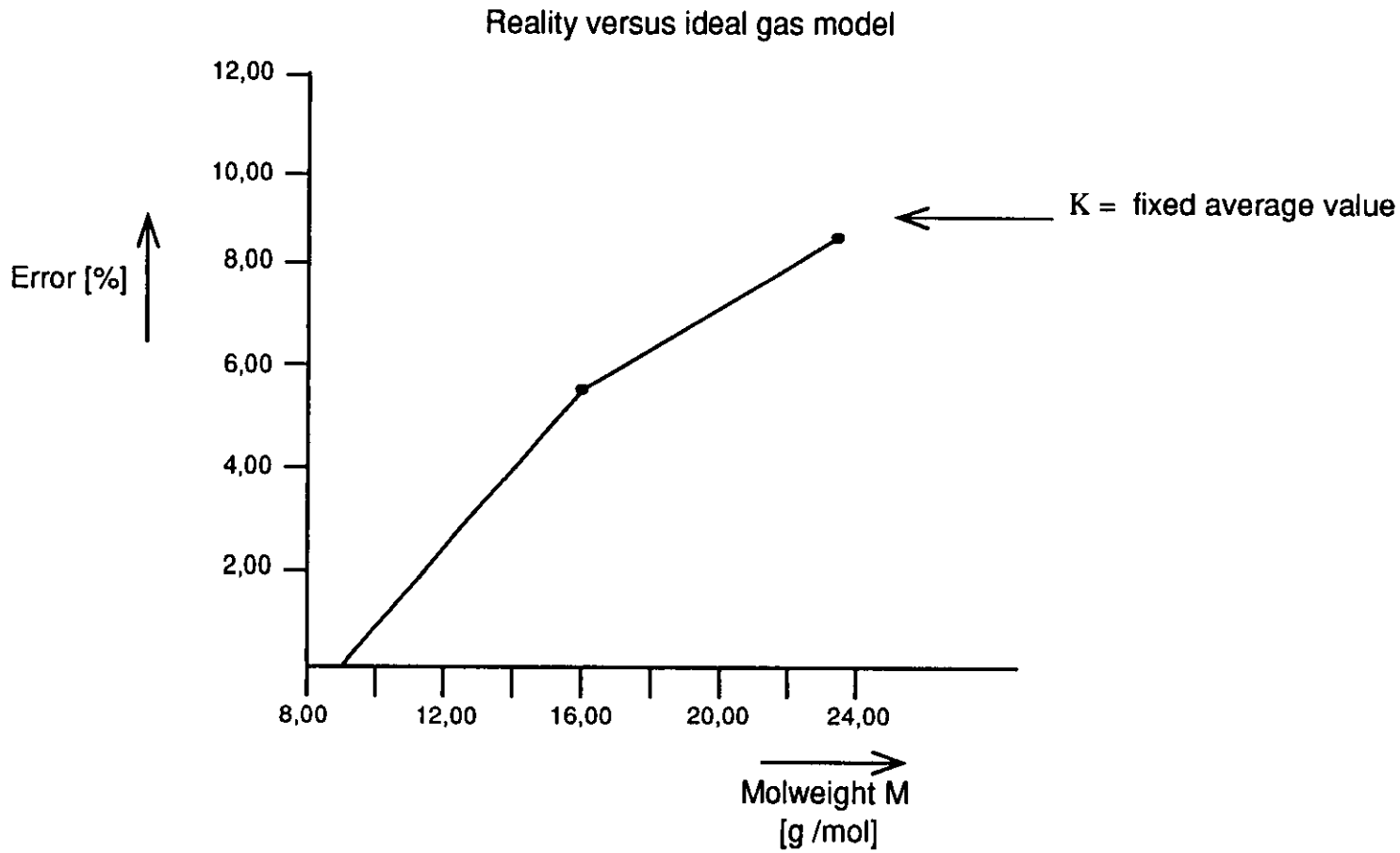
1. - Fuel gas doesn't behave as ideal gas

2. - K = Cp / Cv is not constant

Gas	K *
He	1,66
H2	1,41
CH4	1,31
C2H6	1,22
C3H8	1,13

* at 273 K

Limitations of model



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Enhancement of model

1. Realistic gas model, introduction of correction factor Z:

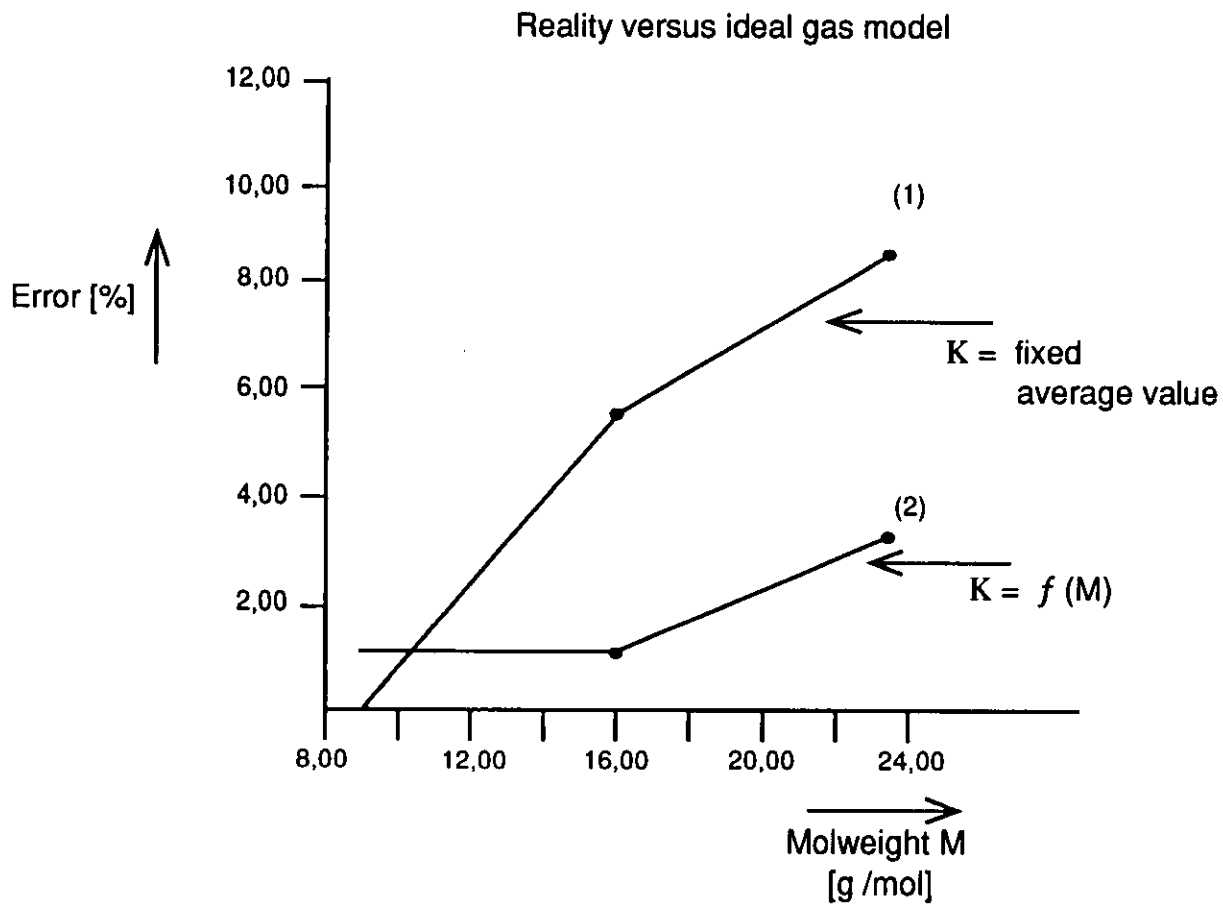
$$P * V = n\ R\ T * Z$$

To compensate for:

* Molecular volume
* Molecular interaction

2. Introduce : $K = f(M,T,P)$ and $Pc = f(M)$, $Tc = f(M)$

Results: 1st fase



(1) Ideal Gas Z=1
K = average value

(2) Ideal Gas Z=1
K = *f* (M)

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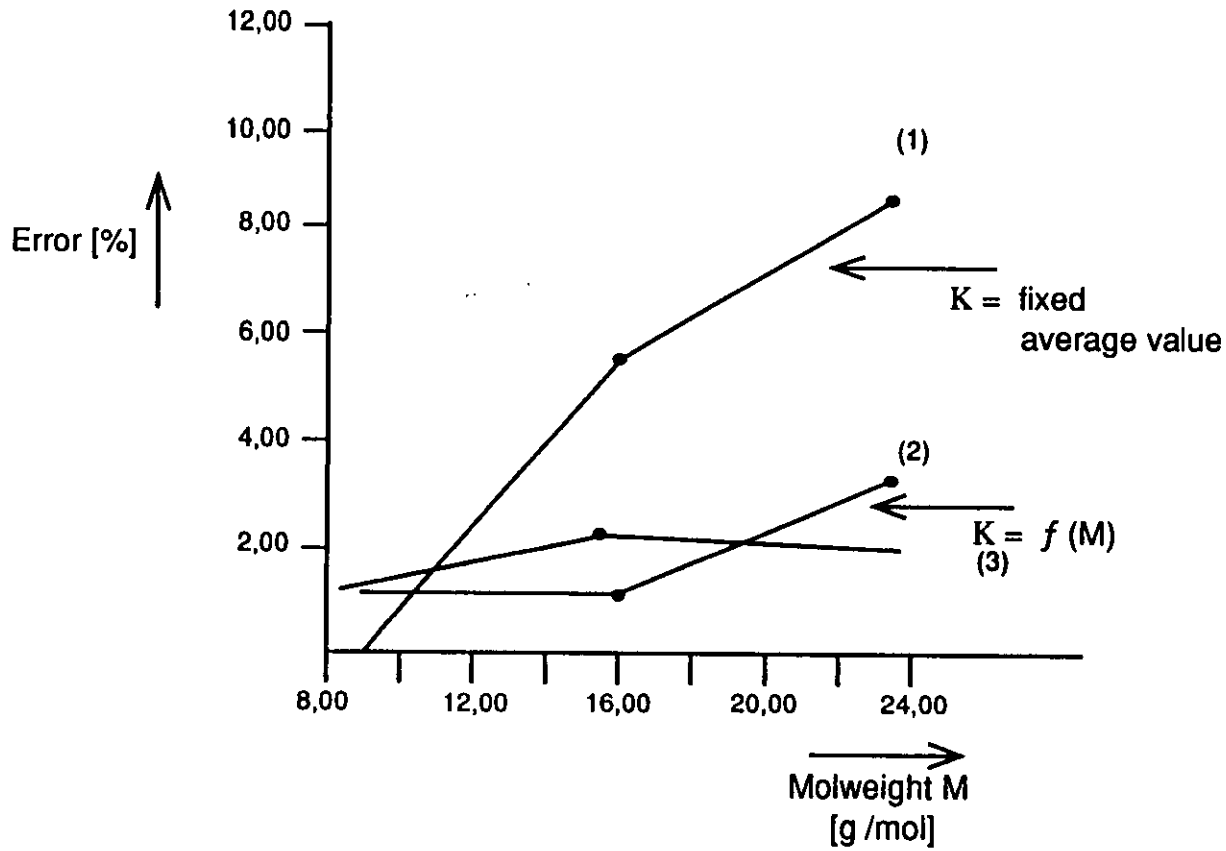
Results: 1st fase

2nd fase

Reality versus ideal gas model



(1) Ideal Gas Z=1
K = average value

(2) Ideal Gas Z=1
K = f (M)

(3) Non-Ideal gas
K = f(M, T, P) and Tc = f (M), Pc = f (M)

Actual fuel gas composition

component	min. vol.%	max. vol.%
H2	35,00	69,66
CH4	8,58	10,40
C2H6	6,03	17,10
C3H8	2,64	17,30
C4H10	10,73	11,70
C5H12	0,48	1,20
CO2	0,19	0,30
N2	1,45	4,10

M min 12,5
max 24,6

PM 9310.9AHB

PM 9310.10AHB

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Ultrasonic

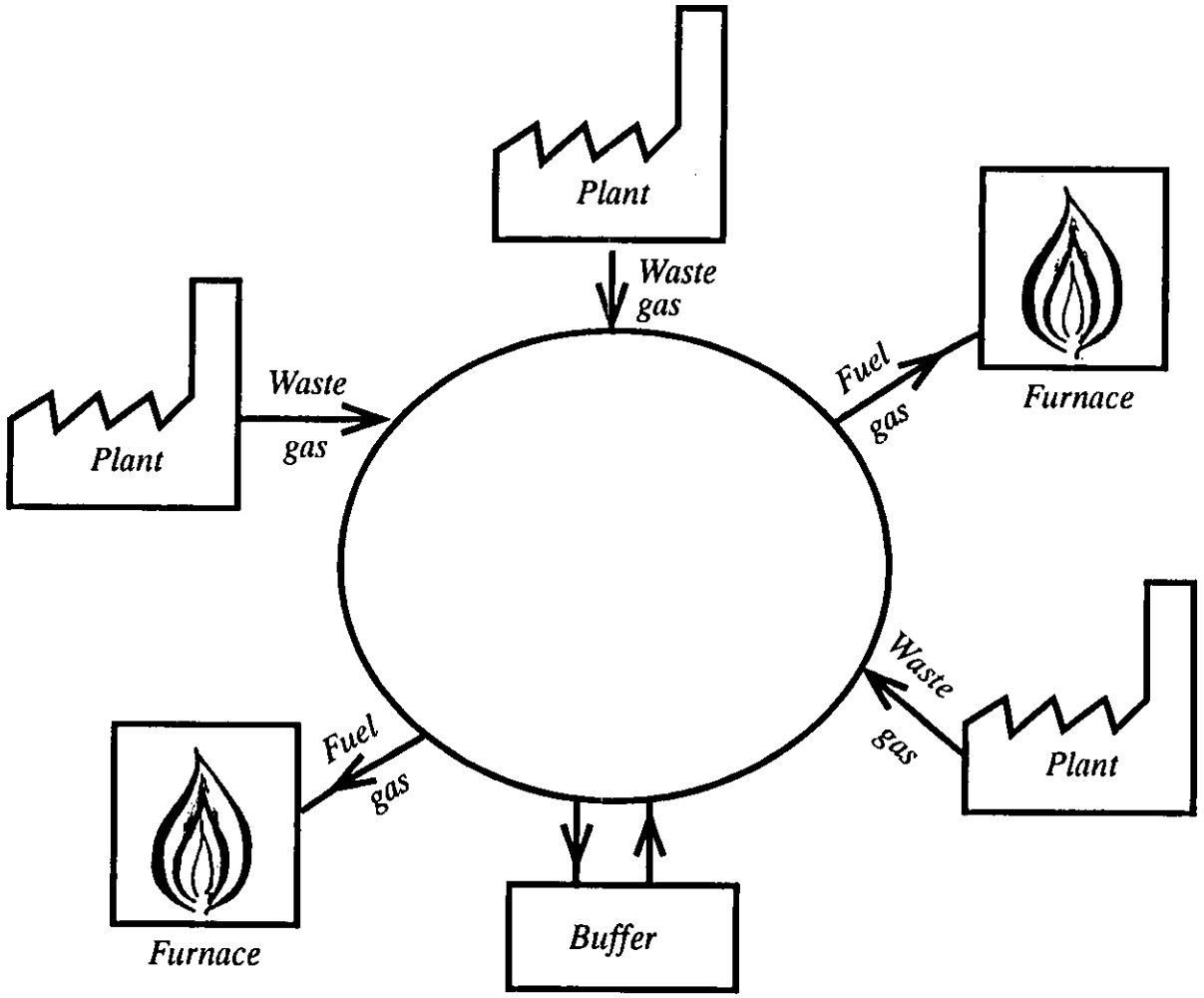
GFM 700

APPLICATION

Fuel gas ring pipeline

1. Waste gases from plants serve as fuel gas for furnaces

2. Composition of fuel gas dependant on production of waste gases



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Furnace Control System

PRESENT SITUATION

Oxygen measurement in Exhaust

* Point measurement (homogeneous ?)

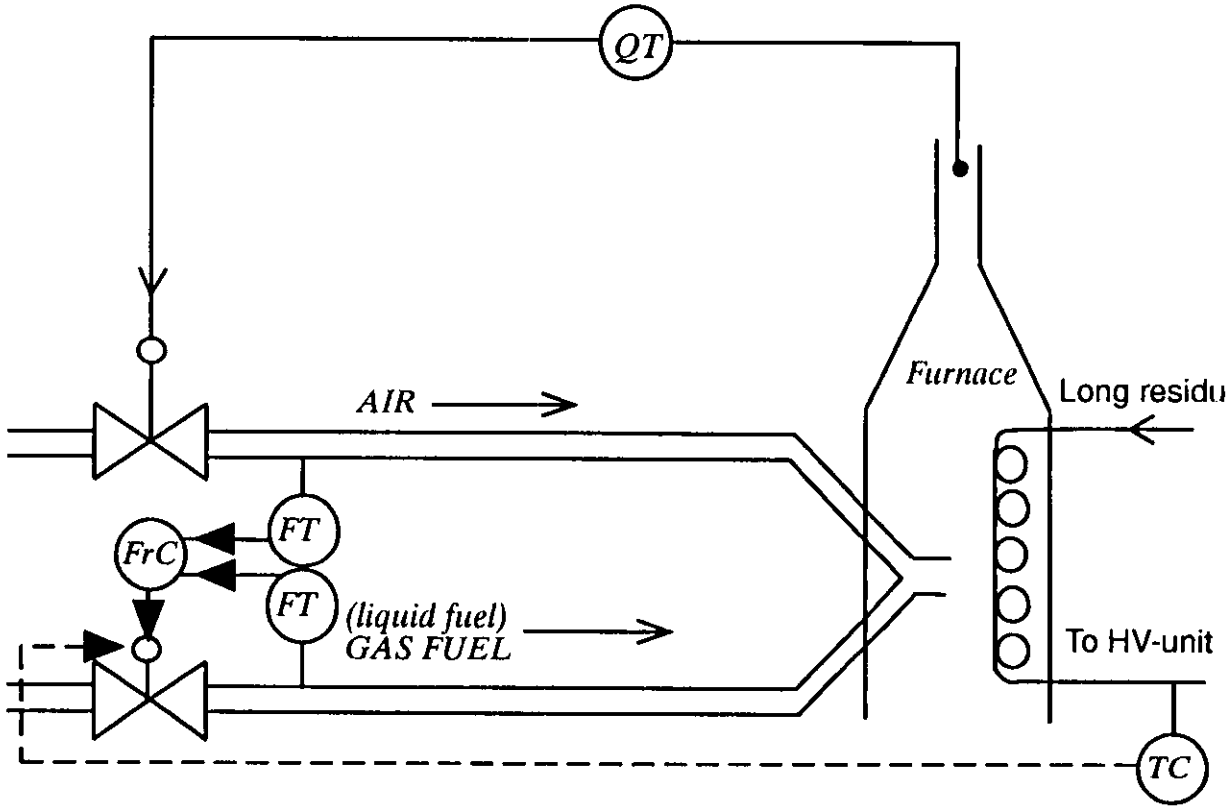
* Slow response (negative feedback)

Oxygen - Gas ratio

$\lambda = 1{,}20$

* High concentration of NO x

* Energy losses



Note: Liquid fuel
no longer allowed due
to high sulpher content

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Ultrasonic

Desired *improvements on present situation*

- Better control of Oxygen to Gas ratio

  $\lambda = 1{,}05$

* Lower concentration of NOx

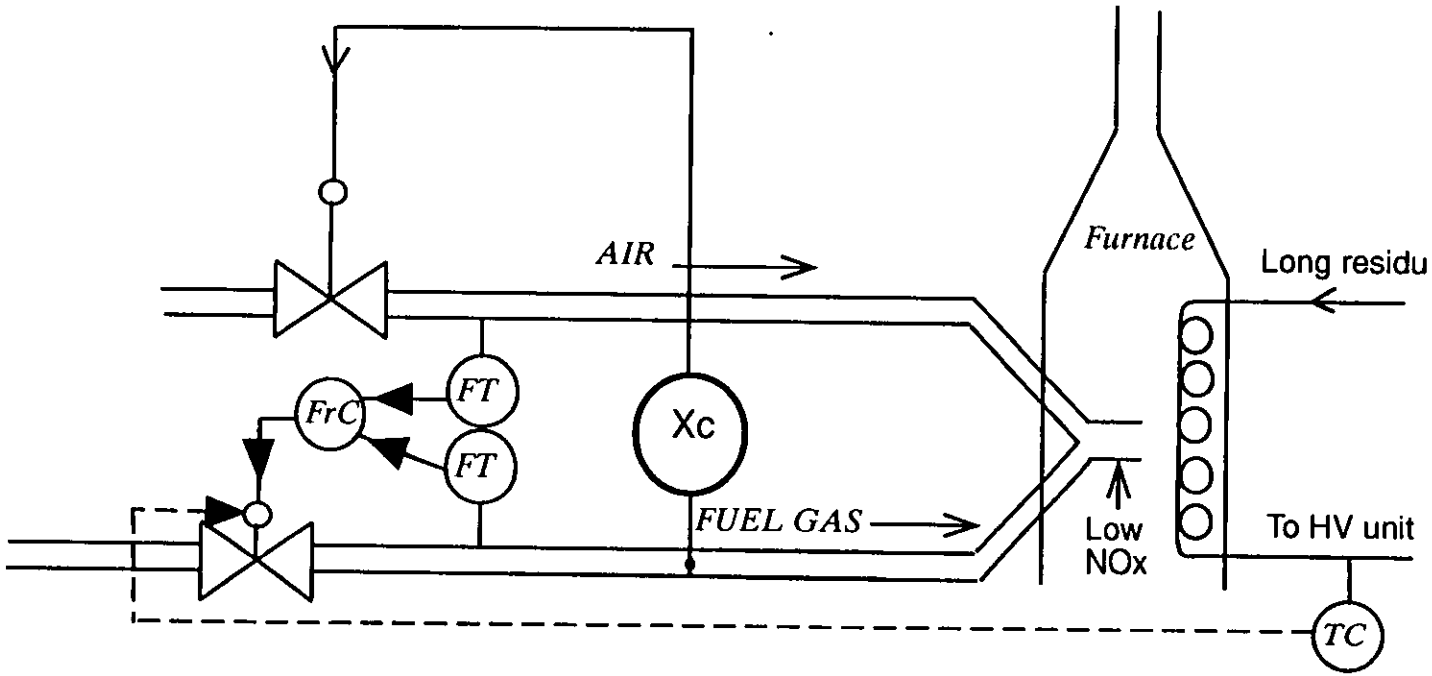
* Lower energy losses

* Lower CO2 production

- Positive feedback system

* Faster response on changing fuel gas composition

DESIRED SITUATION



Xc instrument that measures gascomposition in order to control the airsupply

(positive feedback)

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Ultrasonic

Finishing touch

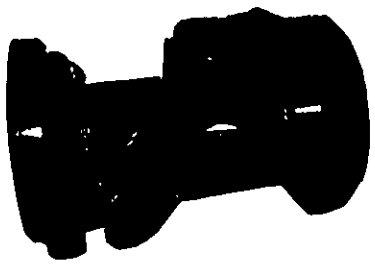
Based on range of gascompositions

- $\frac{\text{air flow}}{\text{fuel gas flow}} = f\,(M)$, airflow as output

When P, T are measured

- Gas density as output

- Massflow as output



GFS 700

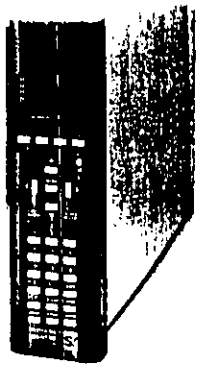
GFC 700

Flow in m3/h under Operating conditions

Sonic velocity

Pressure

Temperature



Spectratec

Sentinel 500

Molecular weight

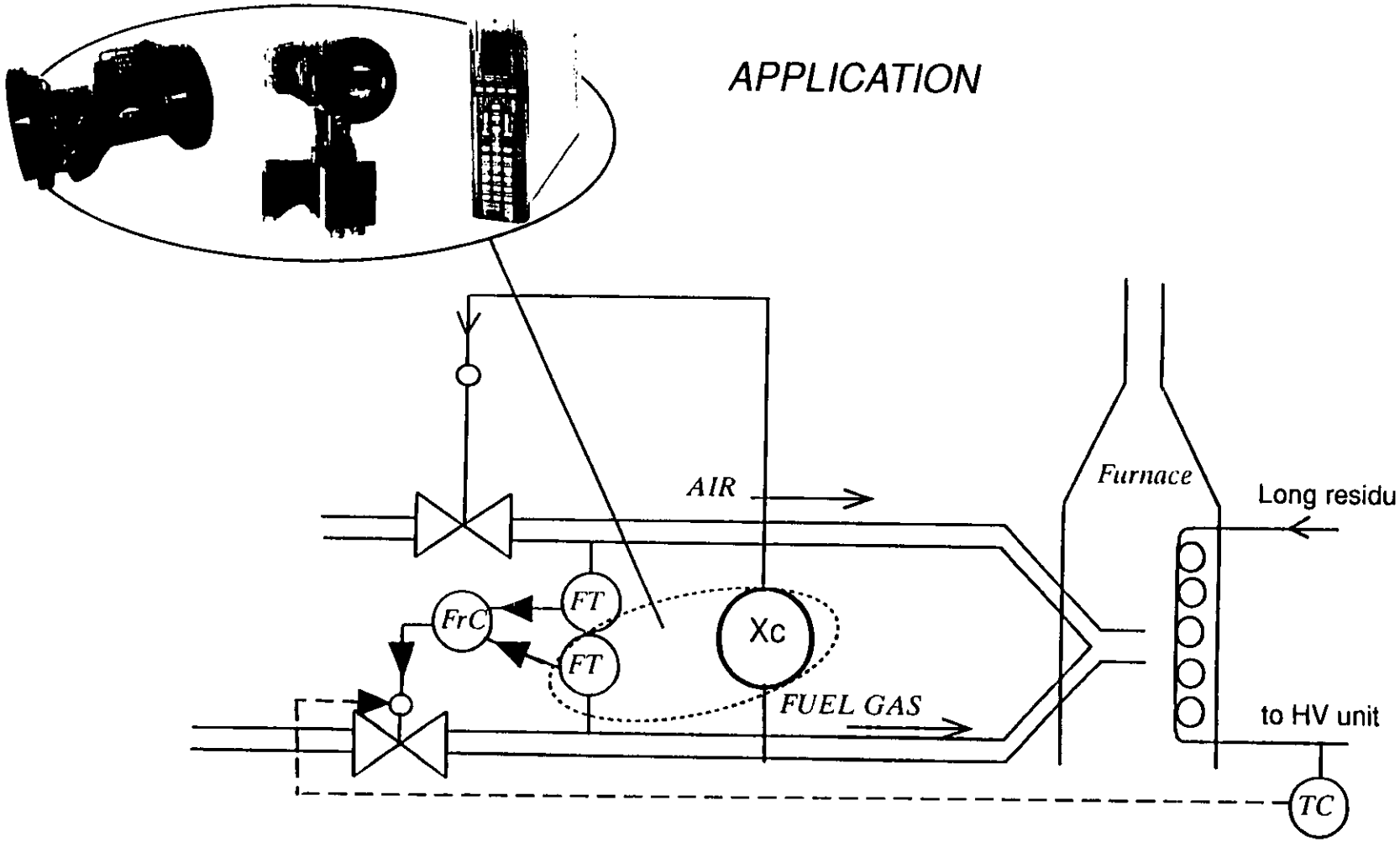
Density

Massflow

Required airflow

KROHNE
Ultrasonic

APPLICATION



- Both flow **and** molweight are measured, integrated in one instrument

KROHNE
Ultrasonic

Results:

- λ from 1,20 down to 1,05
- Lower NOx emission
- Lower energy consumption
- Well within environmental regulations

Main Index

STATOIL

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NFOGM

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993

26 - 28 October, Bergen

Comparison between three flare gas meters installed in a 36 inches process flare line

by
Ben Velde
Statoil center for Applied Gas Technology
Kårstø, Norway

1006 C

Table of content

1. Summary

A flare meter comparison test was conducted in the 36 in. process flare line at the Statpipe Gas Terminal at Kårstø, Norway. The hydrocarbons evacuated through the flare line range from methane to butane and nitrogen may also be present.

The main parameters of interest for the test were:

Velocity, Volume Flow Rate, Actual Density, Mass Flow Rate, Accumulated Volume, Accumulated Mass, Mole Weight, Velocity of Sound, Pressure and Temperature.

A Fluenta ultrasonic flare gas meter, FGM 100 MK II, a Panametrics ultrasonic flare gas meter, Model 7168, and a Dieterich Standard Diamond II Annubar were installed for the test. **The reader should be aware of the fact that there were no reference flow rate meter or reference densitometer available for the test. The meters can therefore only be compared to themselves.**

The Fluenta and Panametrics Ultra Sonic Meters, USM, have very similar performance.When a measured USM variable is compared to its corresponding variable of the other USM, there is in general little relative discrepancy, and the trend curves follow each other very well.

The Fluenta FGM 100 MK II measured higher than expected velocity (up to a factor 2) in some situations with large negative gas temperature gradients (rapidly decreasing temperature to a value well below zero °C). When the negative temperature gradient reversed, the Fluenta USM again showed expected values.

Before 29-06-93 the Fluenta had a time gate range unable to cover the range of velocity of sound for the heaviest hydrocarbons. This also influenced other parameters measured by this USM in such situations with high molecular weight gas present.

The Panametrics Model 7168 has also shown unexpected measurements in situations with large negative gas temperature gradients. The velocity dropped to zero on one such occurrence, and non-physical velocity of sound for gas (750 - 1000 m/s) has been logged in a few situations. This USM also showed values as expected when the negative temperature gradient reversed.

The Dieterich Standard Diamond II Annubar installed in a system with varying standard density fluids requires an additional densitometer to measure more accurately. At low densities, a velocity range below 5 m/s should be avoided.

Only velocities within the specified range of the meters were observed and logged during the test period.

Two gas samples were analyzed using a gas chromatograph, and the mole weights agreed very well with both USM measurements.

The pressure and temperature were common (analog) input for all meters. These variables were converted individually by each meter´s analog to digital converter. The pressure sensor was located about 270 m upstream of the Panametrics USM, and there was still more than 25 m downstream to the Fluenta USM and the Annubar.. Especially at high flow rates this caused a larger absolute pressure error for all meters and a small relative pressure error between the meters. The PT 100 temperature sensor had a rigid thermo well and was mounted downstream of all meters. This caused a time lag between pressure, velocity and temperature inputs which may have caused problems related to transient flow conditions such as the large negative temperature gradients referred to above.

2. Conclusion

The Fluenta and Panametrics ultra sonic meters compared in this test are both comparable in performance. When a measured USM variable is compared to its corresponding variable of the other USM, there is in general little absolute discrepancy, and the trend curves follow each other very well. Situations where some USM parameters show unexpected values have been recorded for both meters, but no absolute trustworthy explanations have been identified for these occurrences.

The Dieterich Standard Diamond II Annubar cannot measure accurately in a system with varying standard density fluids unless an additional densitometer is utilized. The accuracy can be improved using multiple differential pressure transmitters of different range, but at low densities a velocity range below 5-10 m/s should be avoided.

When the mole weight of the gas present was low and the velocity well above idle condition, the Annubar has presented measurements as expected and comparable to the ultra sonic meters' measurements. Gas properties such as density, mole weight and velocity of sound cannot be measured by the Annubar.

Because there were no reference flow meter or reference densitometer present for the test, and for several other reasons, great care should be taken when comparing the results. One parameter may influence another and discrepancies between the meters may be explained and not necessarily caused by bad performance of a meter.

3. Introduction

This flare meter comparison test was conducted in the 36 in. process flare line from train 100 and train 200 at the Statpipe Gas Terminal at Kårstø, Norway.

The hydrocarbons evacuated through the flare line range from methane to butane with mole weights in the range 16 to 58 g/mole. Nitrogen may also be present. Normally, dry sales gas of a mole weight of about 18-19 g/mole is continuously purged through the flare line at a low (idle) flow rate to keep oxygen out.

A Fluenta ultrasonic flare gas meter, FGM 100 MK II, a Panametrics ultrasonic flare gas meter, Model 7168, and a Dieterich Standard Diamond II Annubar were installed for the test. The Fluenta FGM 100 is Statoil property whereas the other meters were kindly lent for the test by Panametrics Ltd. - Ireland through Pemac A/S, Kristiansand - Norway, and the Annubar from Fagerberg, Moss - Norway.

The comparison period started in May `93, more than a year behind schedule. Panametrics and Fagerberg deserves credit for lending their meters for the test as well as for their patience throughout the project.

Fluenta also deserves credit for upgrading the FGM 100 MK I to MK II at their cost, and for the effort in trying to solve the problem related to the RS-232 communication between the Fluenta USM and the logger.

The Statpipe Partners should have credit for financing the project.

4. Test programme

The purpose of the test was to compare the results from the three meters over a period of six months. The test period was originally planned to start early in 1992, but for several reasons the test was delayed. The comparison period started in May 1993 and the logging was stopped in September with this conference in mind.

Due to lacking personnel resources during the hectic Statpipe Gas Terminal periodic maintenance period and the startup of the Sleipner Condensate System, only 3 months of successful measurements were recorded in total. Several situations in late August and early September with high flow rates were attempted logged, but sadly these attempts failed. There are however large amounts of data available even if the total test period logged was 3 months instead of 6.

The measured parameters were:

	A	B	C	D	E	F
1	Time	Pressure	Temperature	A-Velocity	A-MassRate	A-VolRate
2	hh:mm:ss	bara	°C	m/s	ton/h	kSm3/h
	G	H	I	J	K	L
1	A-TotMass	A-TotVol	A-ActDens	A-Selected DP	A-DP wide	A-DP mid
2	ton	kSm3	kg/m3	mmH2O	mmH2O	mmH2O
	M	N	O	P	Q	R
1	A-DP low	P-Velocity	P-MassRate	P-VolRate	P-TotMass	P-TotVol
2	mmH2O	m/s	ton/h	kSm3/h	ton	kSm2
	S	T	U	V	W	X
1	P-ActDens	P-MW	P-VOS	F-Velocity	F-MassRate	F-VolRate
2	kg/m2	g/mol	m/s	m/s	ton/h	kSm3/h
	Y	Z	AA	AB	AC	
1	F-TotMass	F-TotVol	F-ActDens	F-MW	F-VOS	
2	ton	kSm3	kg/m3	g/mol	m/s	

Fig. 4.1 Measured variables. A, F and P denotes Annubar, Fluenta and Panametrics respectively.

All variables were registered with a period of about 10 sec and logged as the average value every 5 minutes.

5. Installation

The installation in this flare line which is in continuous operation is not an everyday possibility. It has to be done during the periodic maintenance period when the Statpipe Gas Terminal is completely shut down, or hot tapping procedures must be followed. Hot tapping is expensive and makes inspection of the installation difficult. For these reasons the pressure sensor was located about 270 m upstream of the meters where a pressure tapping was available. Especially under high velocity conditions this introduces an absolute error, but since all meters read the same (too high) pressure, this makes no difference for comparison of the meters´ results. There is also a pressure drop over the

distance between the Panametrics USM and the other meters.The pressure drop increases with velocity, and is considered negligible at low velocities. However, at high velocities this may cause a relative error between the meters.

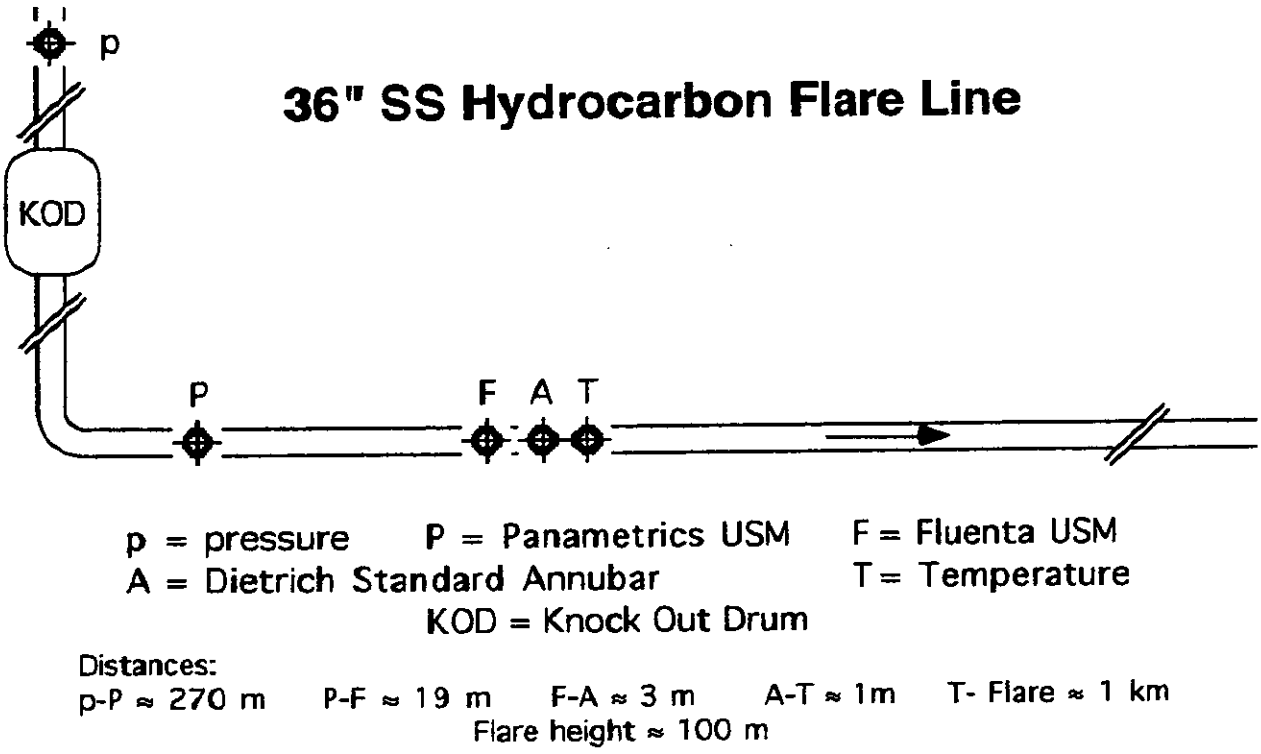


Fig. 5.1 Installation

The Diamond II Annubar has a square cross section, like a diamond (◊), with the pressure holes on one diagonal. The diagonal is 50.3 mm. The cross section area blocking ratio is 7 %. At the time of installation the blocking ratio was considered not to affect the Fluenta USM.

The differential pressure was measured using three Differential Pressure Transmitters, DPT, of 4-20 mA SMART type. The DPTs covered the ranges:

0 - 25, 0 - 333, and 0 - 5000 mm H_2O (2.5, 33 and 500 mbar)

The low range DPT was a Scope & Faeser APR 200 and the upper range DPTs were both Rosemount 1151.

The USM suppliers installed their respective meters for the test. The Annubar was installed by Statoil.

The pressure and temperature transmitters were also SMART type 4-20 mA transmitters covering the ranges 0.8 - 5 bara and ÷100 - +50 °C respectively. All meters read the same pressure and temperature signals using their own Analog to Digital Converters, ADC. The pressure and temperature readings of the different meters were checked against each other and showed small but acceptable discrepancies of typical 30 mbar and 1 °C. The USM ADCs were not checked by other methods by the test team.

The temperature probe was a PT 100 mounted in a rigid well intruding into the flare line. The mass of the thermo well caused a time lag in temperature relative to pressure and flow measurements. This time lag was enhanced by the downstream mounting position, but this position was chosen because

of a potential flow disturbance problem if mounted upstream.

The Panametrics USM has two probes intruding almost radially into the flow with the sensor surfaces angled towards each other, whereas the Fluenta USM's sensor surfaces are mounted flush with the pipe wall. The sensors can be removed when the flare line is in operation.

The Fluenta USM is designed for measuring velocities up to 100 m/s in temperatures down to ÷30 °C. The Panametrics velocity range is specified up to 85 m/s and temperature input can be down to ÷50 °C.

The USMs were both sending their data via a serial RS-232 line. Both meters has this feature as well as analog outputs. The serial output makes more parameters available than the option of analog output.

The communication was established with the Panametrics USM after some trial and error. Parameters in one of three preselected scanning tables can be polled by sending a single character to ask for a parameter. The USM will then send this parameter at its own updating frequency until a new parameter is called on.

The Fluenta USM has a similar concept although one must send a string of characters for each parameter that is called upon. This concept was never established 100 % and a communication problem caused the USM to warm start, breaking the communication string from the Macintosh logger. When the logger was disconnected, no warm starting of the Fluenta USM was registered. The phenomenon can be seen as a negative ripple on some of the trend curves, caused by one or more lost samples in an average value. The problem did not occur in every average so the true Fluenta USM output can be seen represented by the smoother top of the trend curve. In general, the problem can easily be identified and is more of cosmetic art when viewing the trend plots from this test.

When the Fluenta FGM was upgraded from MK I to MK II all parameters wanted could be sent in a single string at each USM update. This concept is very convenient. The polling string was reduced to one character only. Still, the warm start problem continued, and both Statoil and Fluenta made an effort in solving this problem. In late June Fluenta identified a handshaking disagreement with the logger which made us believe the problem was solved. However, some problem related to the communication continued for the rest of the test. Unfortunately, the Statoil test team did not discover this until after quite some time. Time and personnel resources at Statoil did not allow for more trial and error to solve the problem at this time. RS-232 communication is sometimes hard to establish, and it could just as well have been the Panametrics USM which had problems "understanding" the logger or visa versa.

6. Measurements

A Macintosh IIsi computer using LabVIEW 2.2 software and a National Instruments NB-MIO-16 Analog to Digital Converter, ADC, as well as the two serial RS-232 ports were used for the data acquisition.

The analog signals from the barriers of the pressure-, temperature- and DP-transmitters were converted in the ± 10 V, 12 bit ADC using 475 Ω resistances. The system was checked using a Solartron 7061 DMM.

The temperature sensor was a PT-100 resistance thermometer device, RTD, mounted in a thermo well. The temperature response is somewhat delayed relative to the pressure and velocity measurements because of the mass of the rigid well and because of the distance between the sensors.

All Annubar calculations were performed using LabVIEW on the Macintosh.

All USM parameters were calculated internally in the meters except for the Panametrics standard

density which was derived by dividing the mass flow rate by the volume flow rate. The total volume flow was derived by dividing the total mass by the standard density. The standard density was converted to actual density using the analog pressure and temperature. Unit conversion was also performed on some of the data from the USMs.

The Annubar had no density **measurement** input to its algorithm. It therefore had to rely on the standard density for the purge gas which was the most common quality in the line. This standard density of 0.78 kg/m^3 was corrected for pressure and temperature to derive the Annubar actual density. Thus variations in mole weight/standard density when other gases than sales gas were flared could not be taken into account by the Annubar. This would have required an additional densitometer.

7. Test data

The reader should be aware of the fact that there were no references available other than the the Kårstø Lab gas chromatograph used to analyze the two gas samples taken during the test. No reference flow rate meter or reference densitometer meter were available for the test. The meters can therefore only be compared to themselves.

Pressure:

The normal pressure is 0.94 bara during "idle" flow. This is due to a lower than air density for the gas used for idle flow and the friction loss in the 1.3 km flare line.

During high flow rates pressures above 1.5 bara have been experienced. A small pressure difference caused by friction loss over the distance between the meters was not accounted for. Also, the absolute error common to all meters, caused by the pressure transmitter being mounted about 270 m upstream of the meters should be noted. Both errors grow with increasing velocity.

The Annubar cross section area blocking ratio of 7 % should also be noted here although the effect on the USMs was assumed to be negligible.

Temperature:

The normal temperature fluctuates a lot due to daily variations of the surrounding conditions. At high flow rates, the temperature depends highly on which process vessel is vented. The composition, pressure and temperature of the vented fluid determine the gas temperature measured. Temperatures between ÷ 60 and + 40 °C have be seen. The lowest temperatures measured are below the lower temperature specification of both USMs. (Fluenta ÷ 30 °C, Panametrics ÷ 50 °C)

Velocity:

During flare idle, normal velocity is 0 - 0.3 m/s. Even negative velocities can be seen. This is possible due to batches of varying density gas flowing up the flare riser and flow fluctuations in the line. The Panametrics USM is capable of of measuring a maximum velocity of 85 m/s and the Fluenta USM 100 m/s maximum velocity. The flare line design allows for velocities twice as high, although such situations hardly ever occur.

At a limited high velocity range a loud noise was heard from the Annubar area, probably caused by resonance. If this could have had any influence on the USMs has not been identified.

Differential pressure:

This is the primary measurement for the Annubar velocity. Three different range transmitters cover the total velocity range of the Annubar. The low range transmitter drifted quite much causing large offsets when measuring low velocities. Assuming correct zero and correct standard density, the shift velocities should be at about 15 m/s and 55 m/s. The shift was determined by the upper range DPT.

Density:

The Annubar had no density measurement available. It relied on a fixed standard density corrected for pressure and temperature. This standard density represent light sales gas used for flare idle. When heavier gases was present, all parameters calculated by the Annubar algorithms are influenced.

Mole weight:

Hydrocarbon mole weight from methane to butane range from 16 - 58 g/mole. Nitrogen may also be present. Liquids should normally not be present, but traces may be caught in the knock out drums to slowly evaporate.

Velocity of sound:

The higher the mole weight, the lower is the VOS. It should be noted that the time gate of the Fluenta USM allowed 250 - 450 m/s before it was adjusted 29-06-93. This influenced other parameters of this USM when high mole weight gases were present before this date. The Fluenta USM range was set to 200 - 450 m/s. The Panametrics USM has a range of 150 - 1500 m/s.

Some of the test data is shown as trend plots in the appendix. **In general, there is little discrepancy between corresponding parameters of the two USMs. The trend curves follow each other very well. The Annubar shows a discrepancy to the USMs as expected in situations of low velocities and high mole weights.**

Below, some occurrences of special interest are reported.

20-05-93:

At about 20:30 a batch of 30-35 g/mole gas mix was vented. This was recorded by both USMs. The effect on density and mass flow measured by the Annubar is clearly seen as expected (since no densitometer was present in the Annubar system). The higher density from the high MW gas is hardly noticed in the Annubar density "measurement". The mass rate was somewhat less affected, but this was due to a positive offset in the Annubar velocity which was caused by a drifting low range DPT.

14-06-93:

At about 9:00 a sample was taken from the Annubar DPT pressure line and analyzed using the lab gas chromatograph. Both USMs showed a value of about 18.5 g/mole whereas the analysis showed 19.3 g/mole.

15-06-93:

In the periods 15:30-16:25, 16:50-19:03 and 19:30-20:10, the mole weight of the gas present was so high that the range of the Fluenta USM time gate was unable to cover the Velocity Of Sound, VOS, of this gas. This is believed to be the reason for the high velocity measurement of the Fluenta USM. The time gate range of the Fluenta USM was expanded on 29-06-93 to cover the VOS range 200-450 m/s.

Ca. 21:00 a batch of lower MW gas was released. The temperature dropped to ÷ 56 °C (below both

USMs' ranges). All meters responded to the increasing velocity. The Fluenta showed a velocity higher than the others. The Panametrics and the Annubar showed comparable velocities, and in this occurrence the standard density of the gas was close to the constant standard density used by the Annubar algorithm. The Annubar velocity could therefore be assumed correct in this situation.

In the middle of the high velocity period, the Panametrics velocity suddenly dropped. A non-physical VOS for gas of 750 m/s was measured simultaneously, and the density and MW also showed values that can not be correct. Once the temperature drop stopped, however, the Panametrics USM again showed values in a believable range.

24-06-93:

A new GC lab analysis after trip of a compressor. Panametrics showed 36-37 g/mole, Fluenta showed 33-34 g/mole, and the lab analysis said 35.6 g/mole which is quite in the middle of the two USM measurements.

08-07-93:

Here we have two situations of cold, low MW (17-22 g/mole) gas release. This is similar to the occurrence of 15-06-93. Again, the Fluenta showed higher velocity than the two other meters, and again, we could assume the Annubar density to be nearly correct and therefore also its velocity.

It seems that the higher velocity (a factor of 2 or more) of the Fluenta can be linked to a sudden large drop in temperature to well below zero. However, when the steep, negative temperature gradient stops, the Fluenta velocity again comes back to expected values.

8. Comments

All meters included in this test need additional pressure and temperature transmitters. The Annubar will need another additional densitometer to measure accurately in a system where the standard density varies as in the system of this test. It will also need an ADC and a processor which was not provided by the supplier for this test. The USMs have an inboard ADC for pressure and temperature connections as well as a processor for calculations and display.

The Annubar velocity measurement (and all other flow variables dependent on the velocity) is less accurate below 5-10 m/s when the (constant) standard density is as low as in the test system. The function given in the Dieterich Standard Annubar Flow Handbook is plotted in fig. 8.1 - 8.2. The function clearly shows the Annubar velocity's poor sensitivity to differential pressure in the low velocity regime. However, when the standard density increases, as seen in fig. 8.3, the Annubar velocity's sensitivity in the low velocity range also increases.

During the test the Annubar low range DPT often showed a drifting zero which greatly influenced the velocity and the daily accumulated mass. In addition, if the DPT drifted into the negative range, the Annubar flow parameters could not be calculated because of a negative root.

The Annubar is a suitable instrument for an application where the velocity and density ranges have been carefully evaluated to suit its characteristics. In the process flare line at the Statpipe Gas Terminal, it has clear disadvantages compared to the USMs.

Both USMs will measure properties such as density, mole weight and velocity of sound in addition to the flow parameters velocity, volumetric flow rate and mass flow rate measured by the Annubar.

USMs will especially cover the low idle velocity range much better than the Annubar. As in this test, the Annubar accuracy and range can be improved by using multiple DPTs of different range, but

this cannot overcome its characteristics at low velocities and low densities.

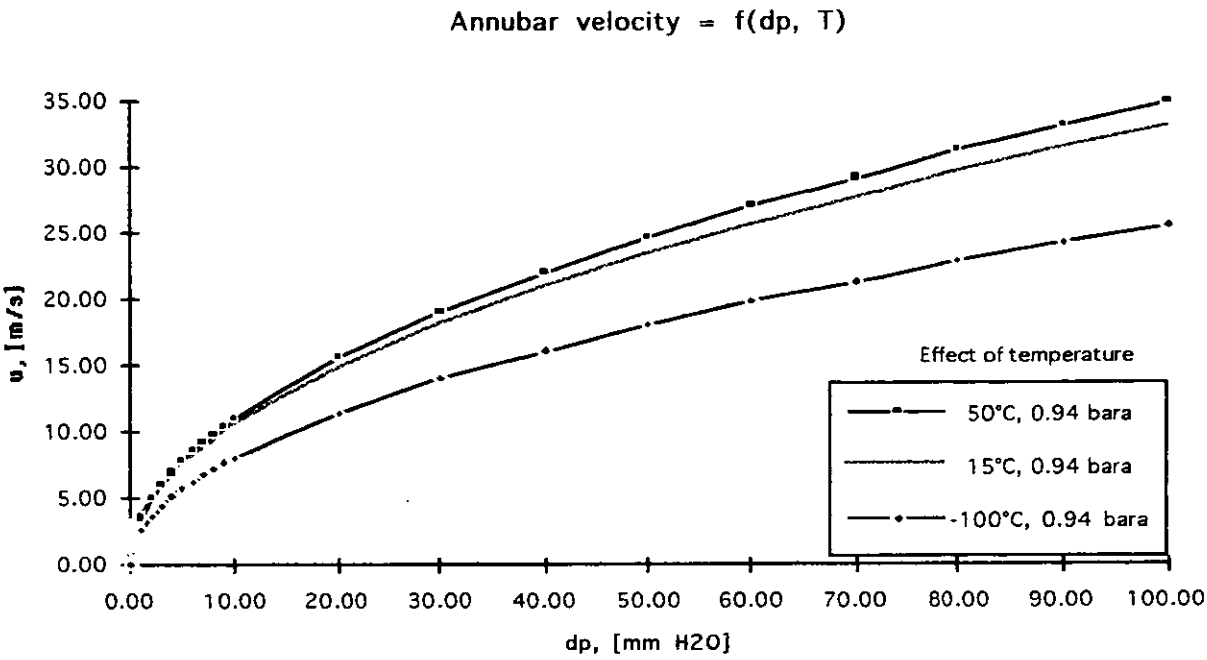


Fig. 8.1 Annubar velocity as function of differential pressure and temperature.

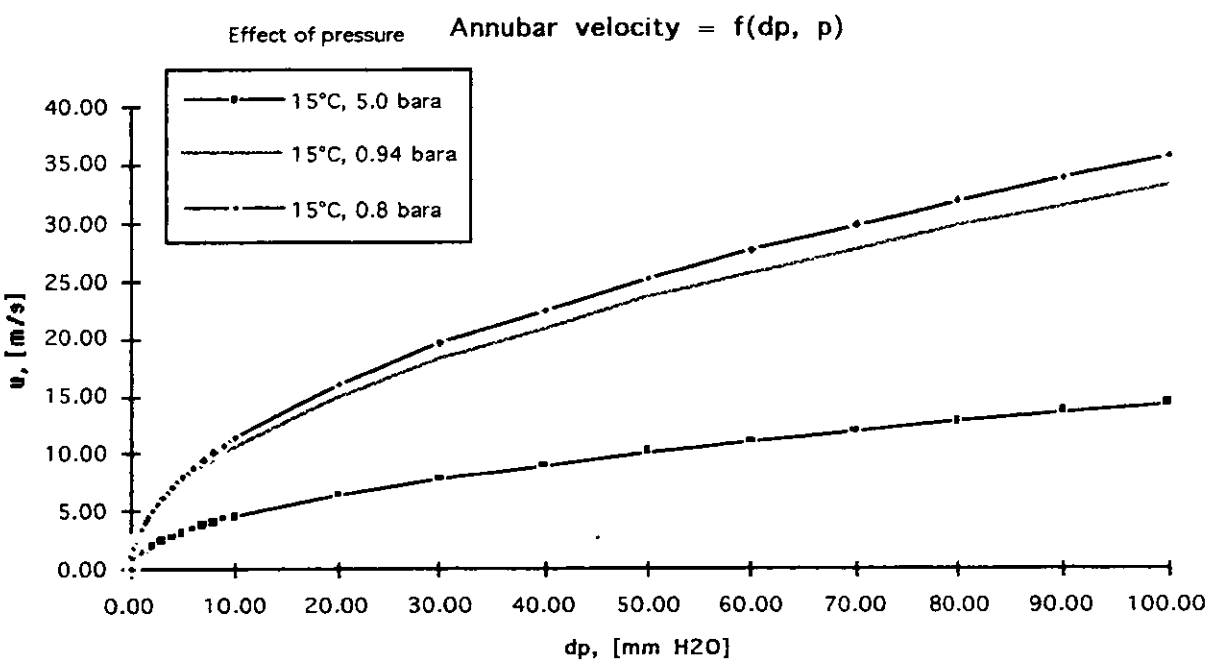


Fig. 8.2 Annubar velocity as function of differential pressure and absolute pressure.

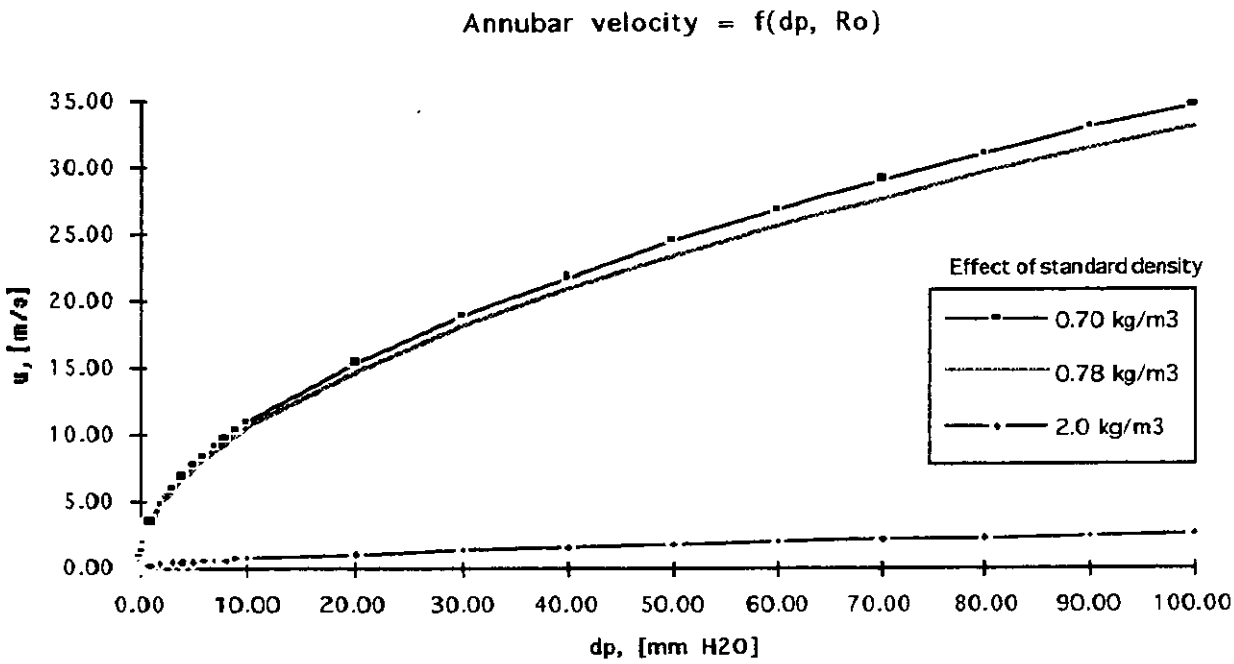


Fig. 8.3 Annubar velocity as function of differential pressure and standard density.

The negative ripples/spikes and complete dropouts seen on some of the trend curves is mostly due to communication problems between the USMs and the Macintosh logger. When the logger was connected to the Fluenta USM, the USM could sometimes warm start probably because of a handshaking problem of the RS-232 line. The warm start caused some data in the next averaging period to be lost, and this is seen as one or more fixed level negative spikes on the curves. The reason was one or more samples lost without being excluded from the averaging routine of the logger. The upper trend of the curves represent the true USM output.

Similar with the Panametrics' actual density. This parameter is calculated by the logger as mass flow rate divided by standard volume flow rate and corrected for pressure and temperature. If one of these variables were lost, the density was also lost. This can be seen as complete dropouts to zero. The upper trend of the curve represent the true USM output.

The Annubar's DPTs sometimes measured negative values probably because of DPT zero drift. Since differential pressure goes under a square root in the Annubar algorithms none of Annubar's parameters are calculated if this situation occurs for the selected (low range) DPT.

In general, the USMs followed each other remarkably well in all measurements. There always seemed to be a more or less constant offset. This was probably due to slightly inaccurate spacing between the two ultra sonic sensors of one or both USMs.

The Annubar follows the USMs well in high velocity conditions where the standard density of the gas is close to the constant standard density specified for the Annubar. When a high molecular weight gas is released, this effect on the actual density is detected by the USMs, but not by the Annubar. When the temperature or pressure influence the density, these effects are detected by all three meters.

A high volume noise has been heard from the test section of the flare line in a limited, high velocity range. This is believed to be resonance noise from the Annubar. If this disturbance could have had an

effect on the measurements, we have not been able to identify.

Situations where the temperature suddenly drops to well below zero have been observed to produce unexpected measurements by both USMs. However, when the temperature gradient flattens and start to increase, the measurements go back to expected values. Although both USMs have a fault indicator (LED), these signals have not been logged. It is therefore possible that the occurrences reported here were alerted by the USMs. Further, the time lag between pressure, USM measurements and temperature in this installation may be part of the reason for the USM problems when unexpected measurements have been recorded related to sudden, large drops in temperature.

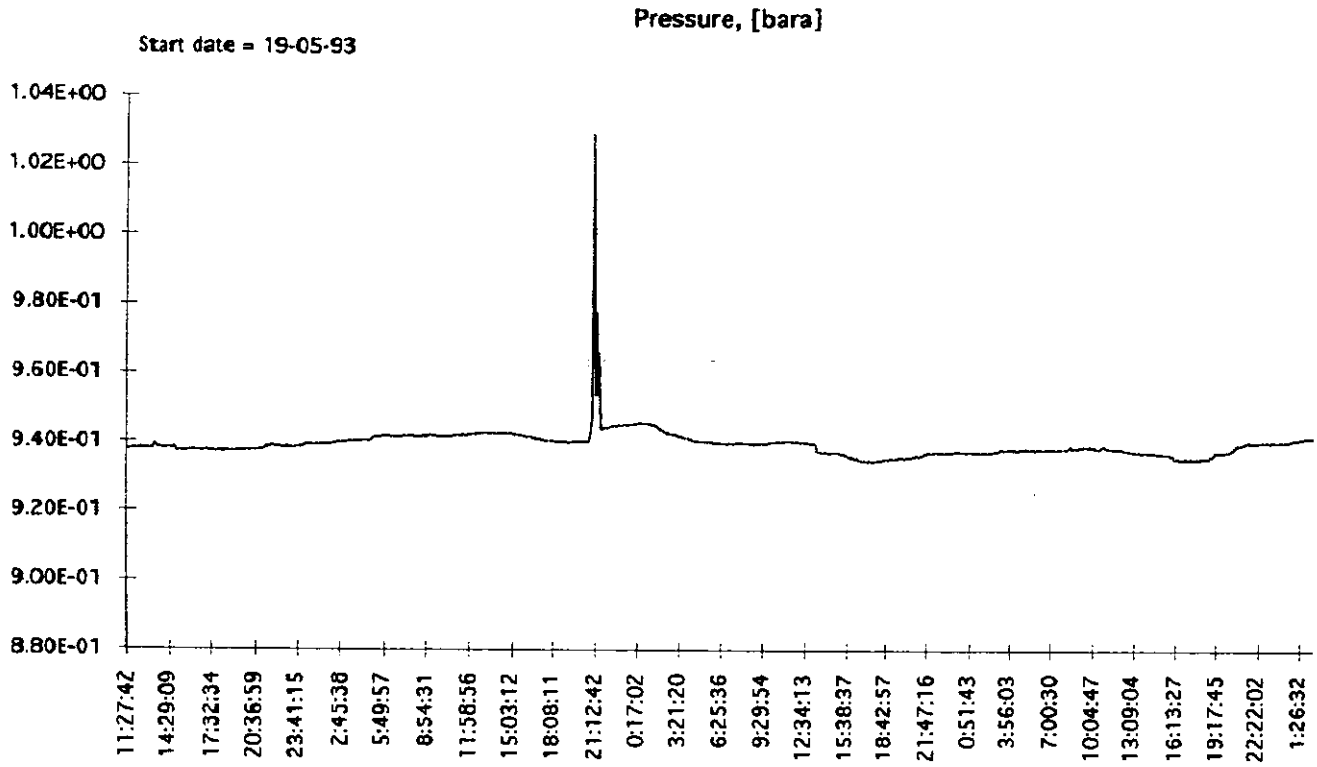
Both USM suppliers have been at Kårstø for service on their systems during the period the meters have been installed (1991-1993). The Fluenta USM has required more service than the Panametrics. This has been due to implementation of a new algorithm, and due to the communication (handshaking) problem. The Fluenta FGM 100 was upgraded from MK I to MK II before this comparison test started. Both USM suppliers have performed service on the sensors once. No service has been performed on the Annubar. However, the DPTs were calibrated and adjusted a few times by the Statoil test team.

Appendix 1

Test data trend plots

(On following pages)

STATOIL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9.40E-01
9.20E-01
9.00E-01
8.80E-01
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14:29:09
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20:36:59
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5:49:57
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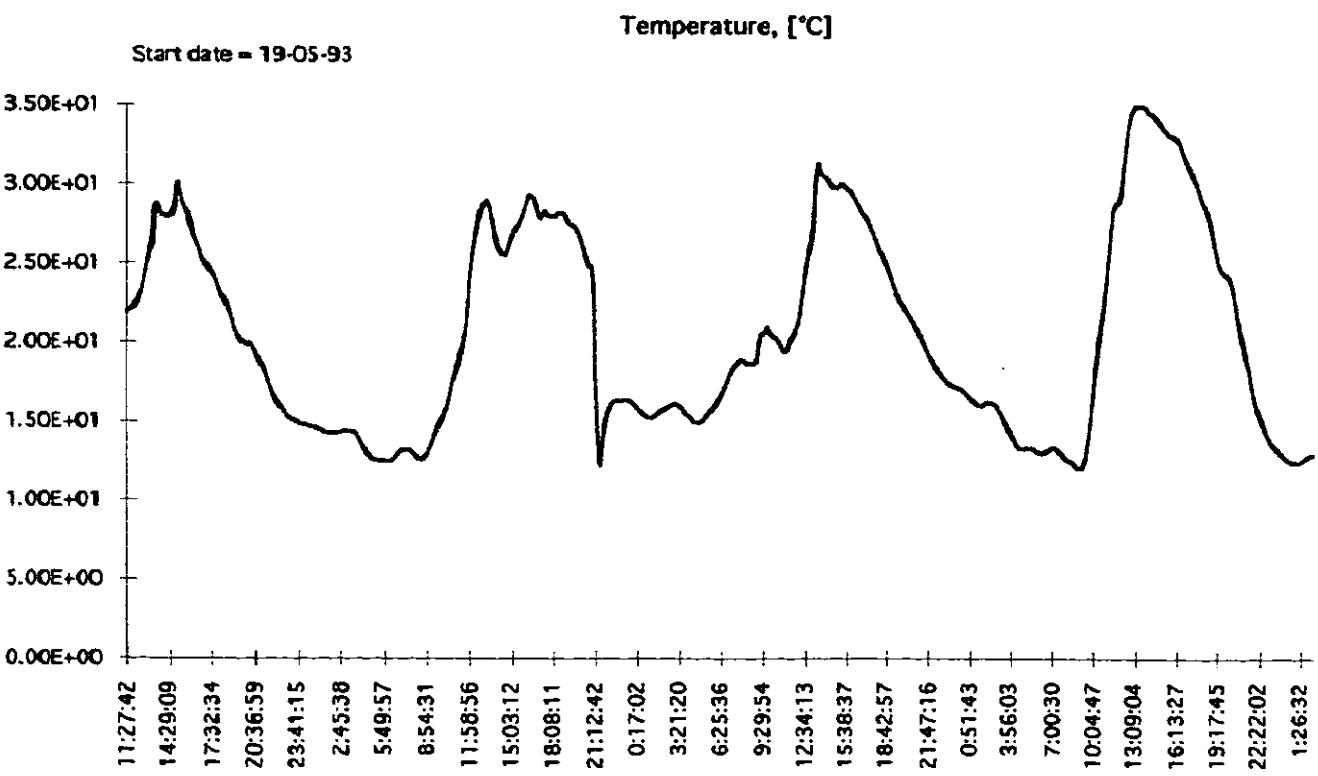
22:22:02
1:26:32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0.00E+00
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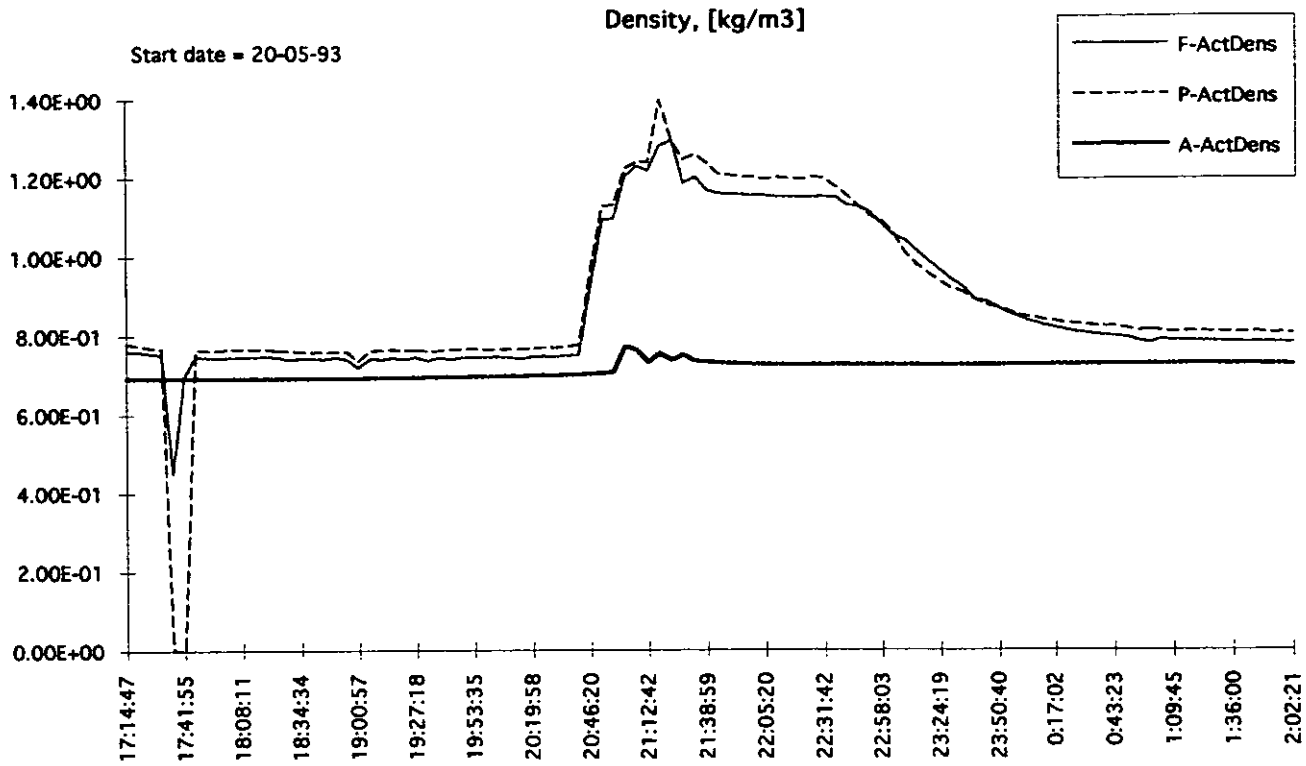
7:00:30
10:04:47
13:09:04
16:13:27
19:17:45
22:22:02
1:26:32

STATOIL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P-ActDens
A-ActDens
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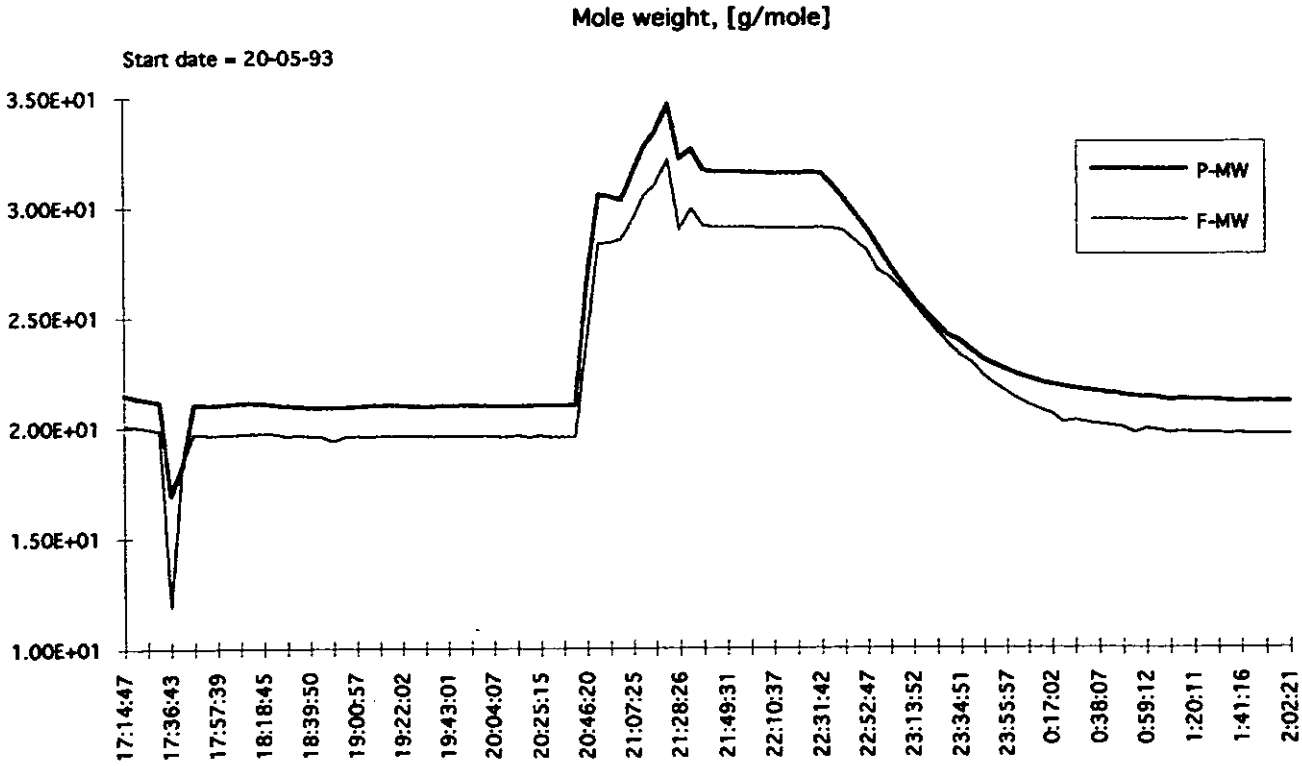
1.00E+00
8.00E-01
6.00E-01
4.00E-01
2.00E-01
0.00E+00
17:14:47
17:41:55
18:08:11
18:34:34
19:00:57
19:27:18
19:53:35
20:19:58
20:46:20
21:12:42
21:38:59
22:05:20
22:31:42
22:58:03
23:24:19
23:50:40
0:17:02
0:43:23
1:09:45
1:36:00
2:02:21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F-MW
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2.50E+01
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1.50E+01
1.00E+01
17:14:47
17:36:43
17:57:39
18:18:45
18:39:50
19:00:57
19:22:02
19:43:01
20:04:07
20:25:15
20:46:20
21:07:25
21:28:26
21:49:31
22:10:37
22:31:42
22:52:47
23:13:52
23:34:51
23:55:57
0:17:02
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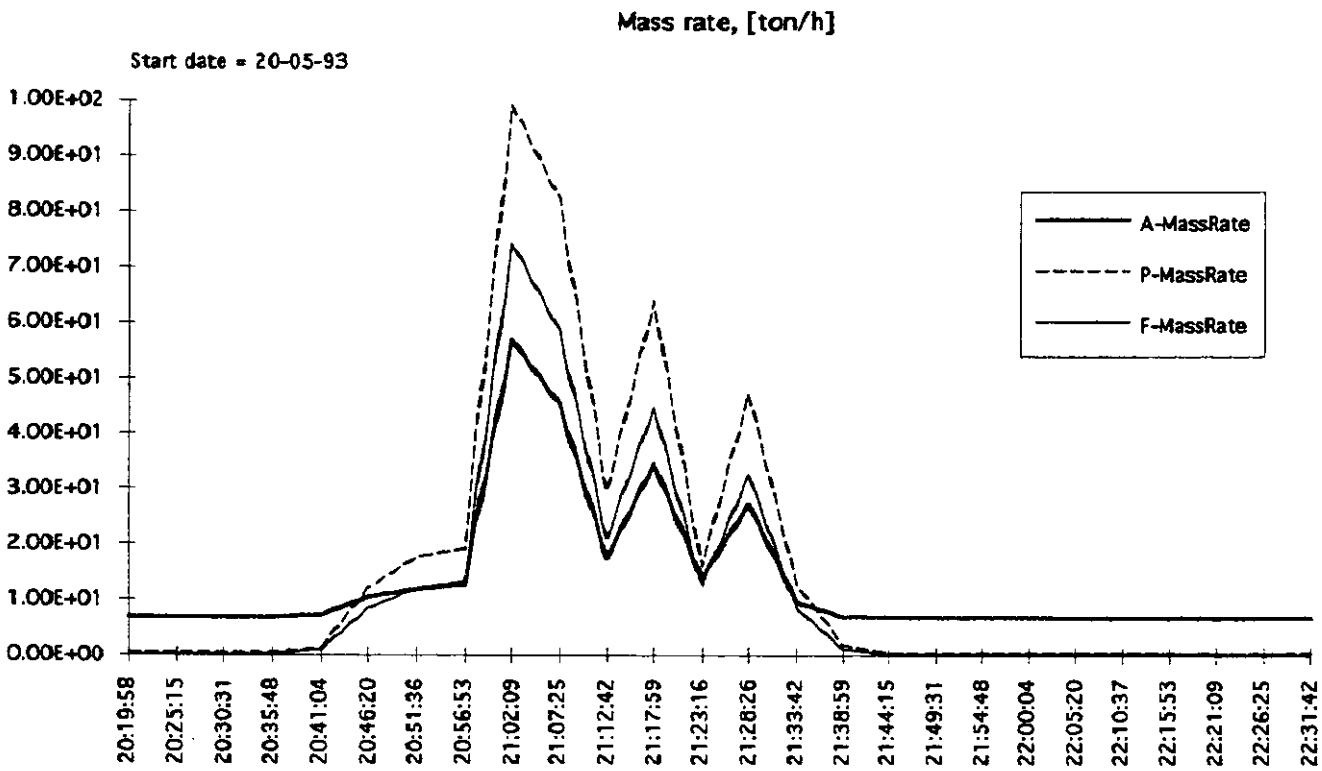
1:20:11
1:41:16
2:02:21

STATOIL


Mass rate, [ton/h]
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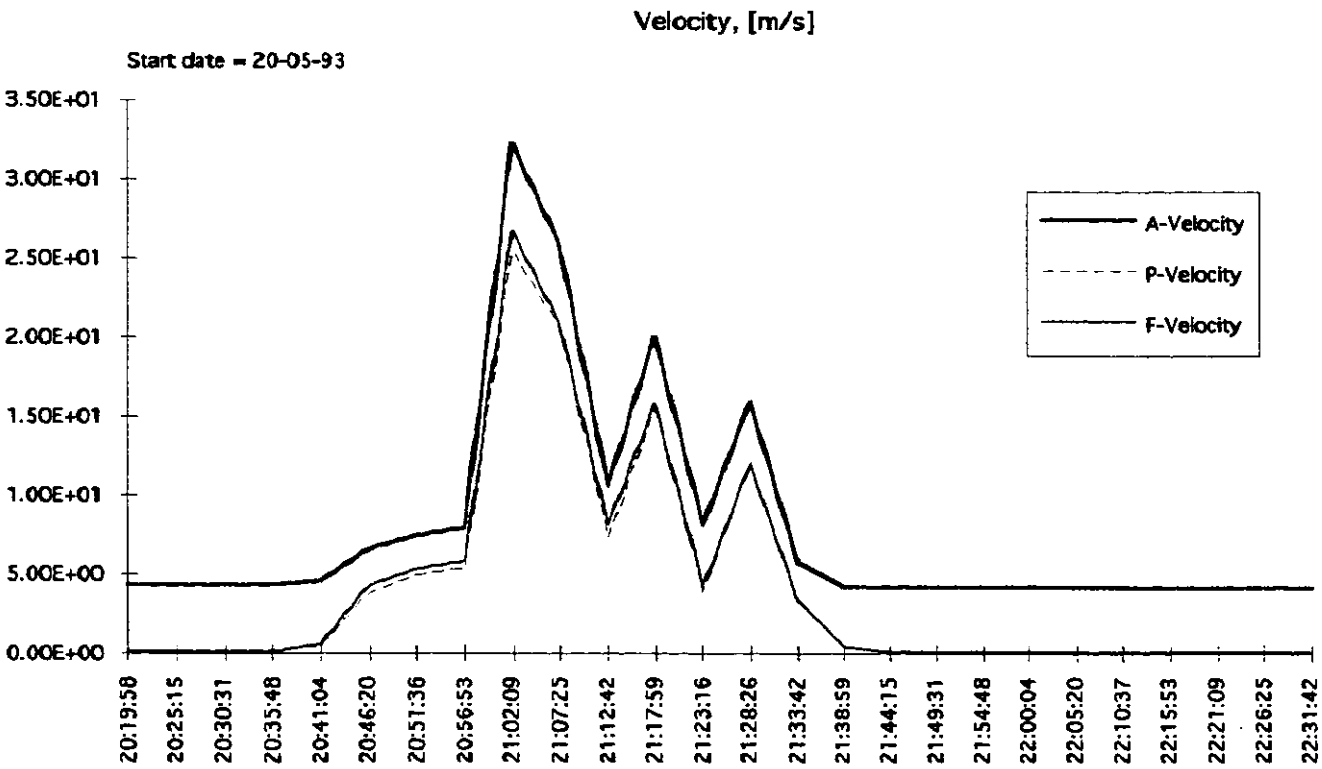
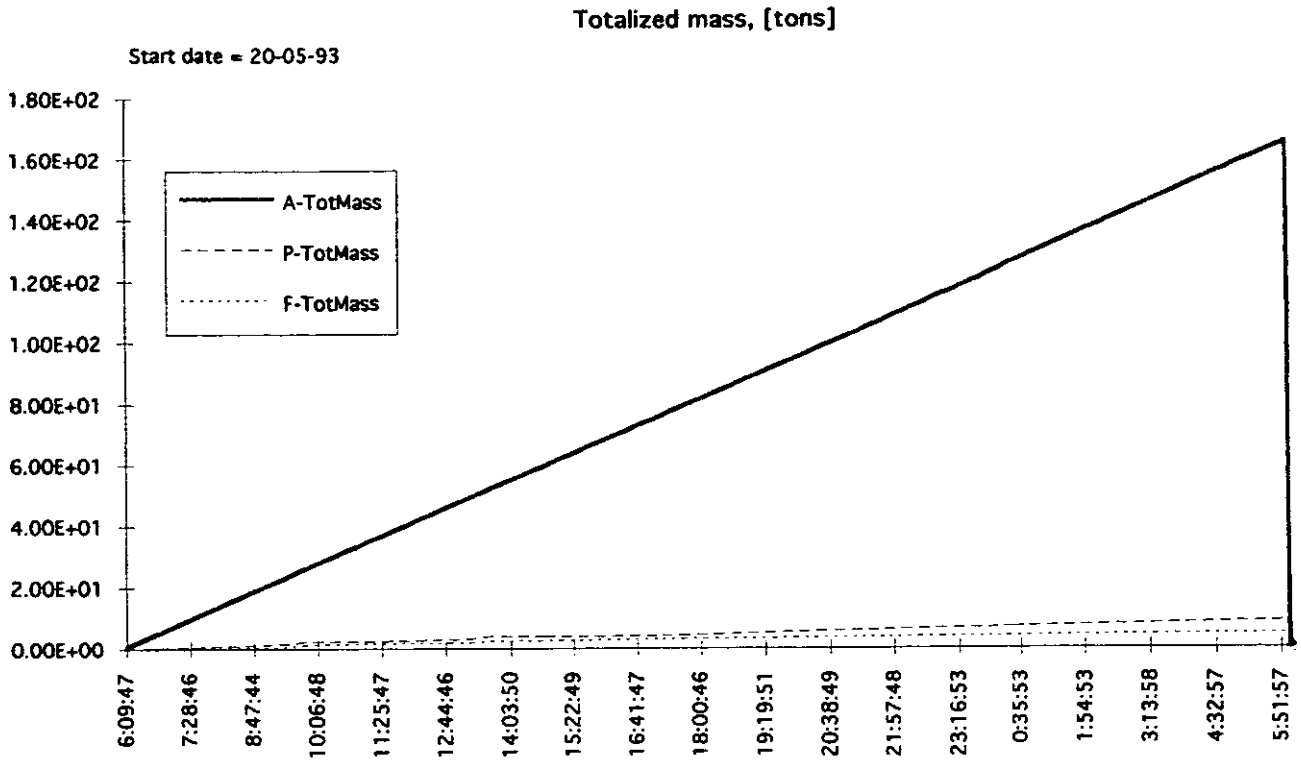
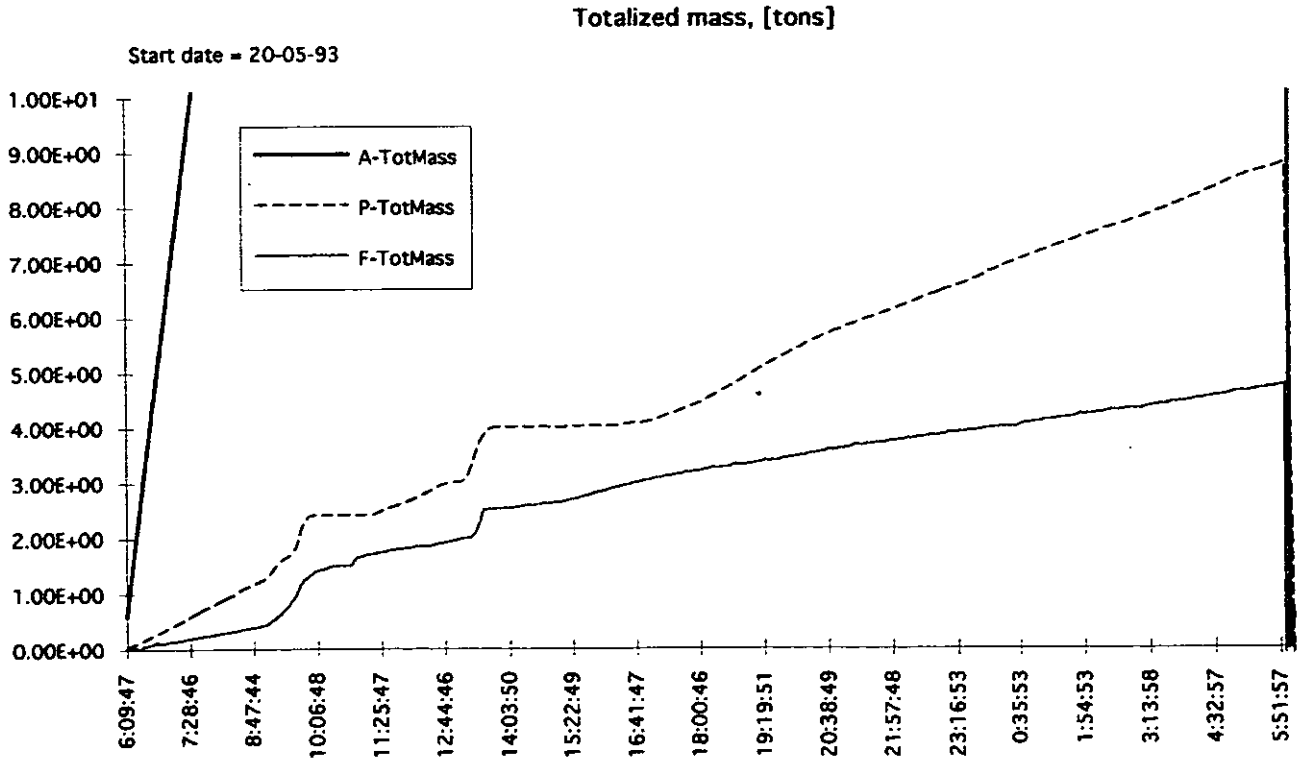
7.00E+01
6.00E+01
5.00E+01
4.00E+01
3.00E+01
2.00E+01
1.00E+01
0.00E+00
A-MassRate
P-MassRate
F-MassRate
20:19:58
20:25:15
20:30:31
20:35:48
20:41:04
20:46:20
20:51:36
20:56:53
21:02:09
21:07:25
21:12:42
21:17:59
21:23:16
21:28:26
21:33:42
21:38:59
21:44:15
21:49:31
21:54:48
22:00:04
22:05:20
22:10:37
22:15:53
22:21:09
22:26:25
22:31:42


Velocity, [m/s]
Start date = 20-05-93
3.50E+01
3.00E+01
2.50E+01
2.00E+01
1.50E+01
1.00E+01
5.00E+00
0.00E+00
A-Velocity
P-Velocity
F-Velocity
20:19:58
20:25:15
20:30:31
20:35:48
20:41:04
20:46:20
20:51:36
20:56:53
21:02:09
21:07:25
21:12:42
21:17:59
21:23:16
21:28:26
21:33:42
21:38:59
21:44:15
21:49:31
21:54:48
22:00:04
22:05:20
22:10:37
22:15:53
22:21:09
22:26:25
22:31:42

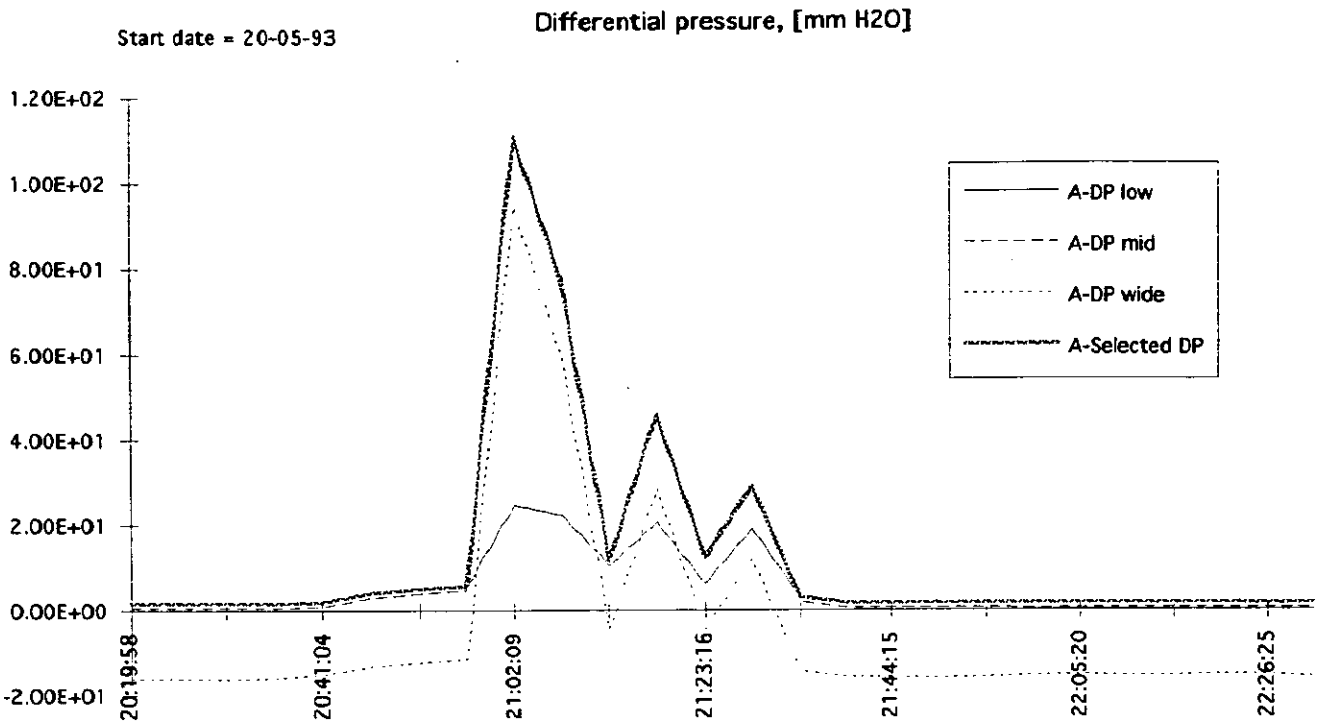
STATOIL



19-5-93.xls Chart 16



STATOIL


Differential pressure, [mm H2O]
Start date = 20-05-93
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1.00E+02
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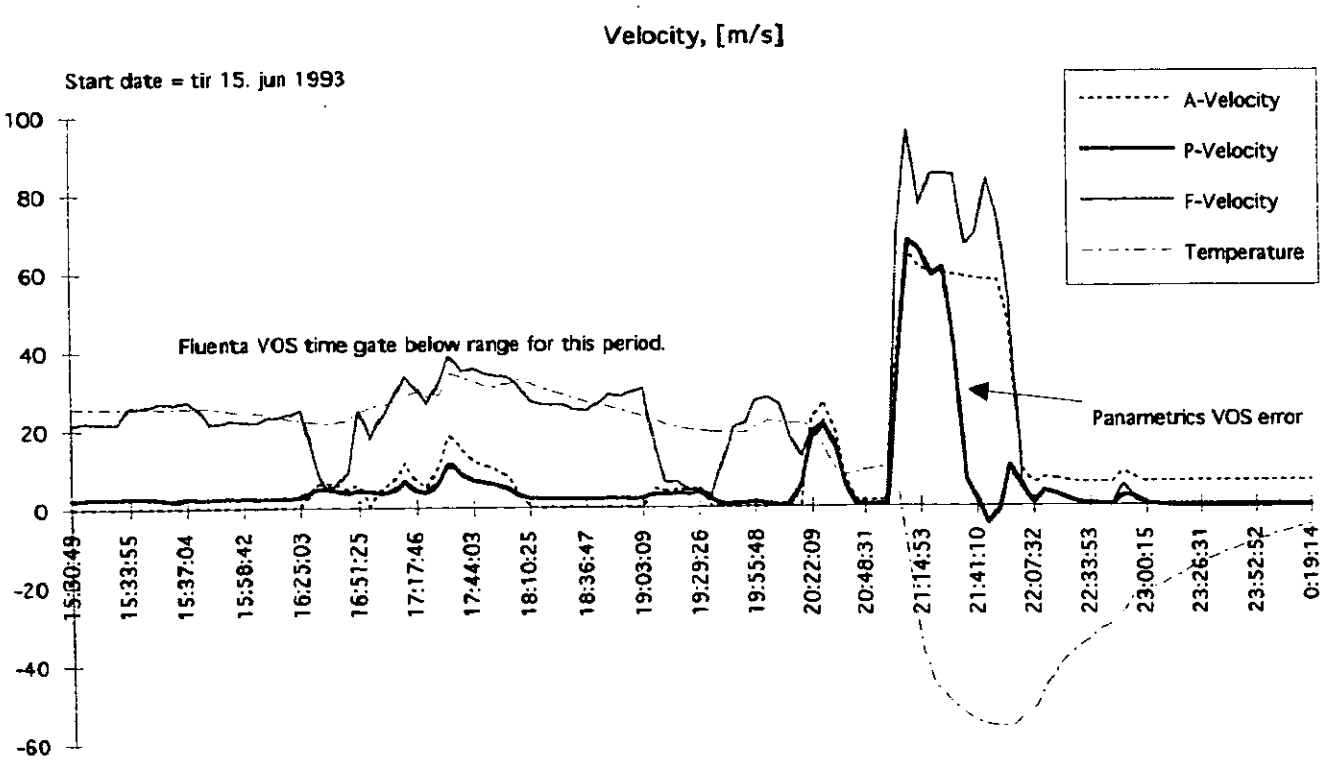
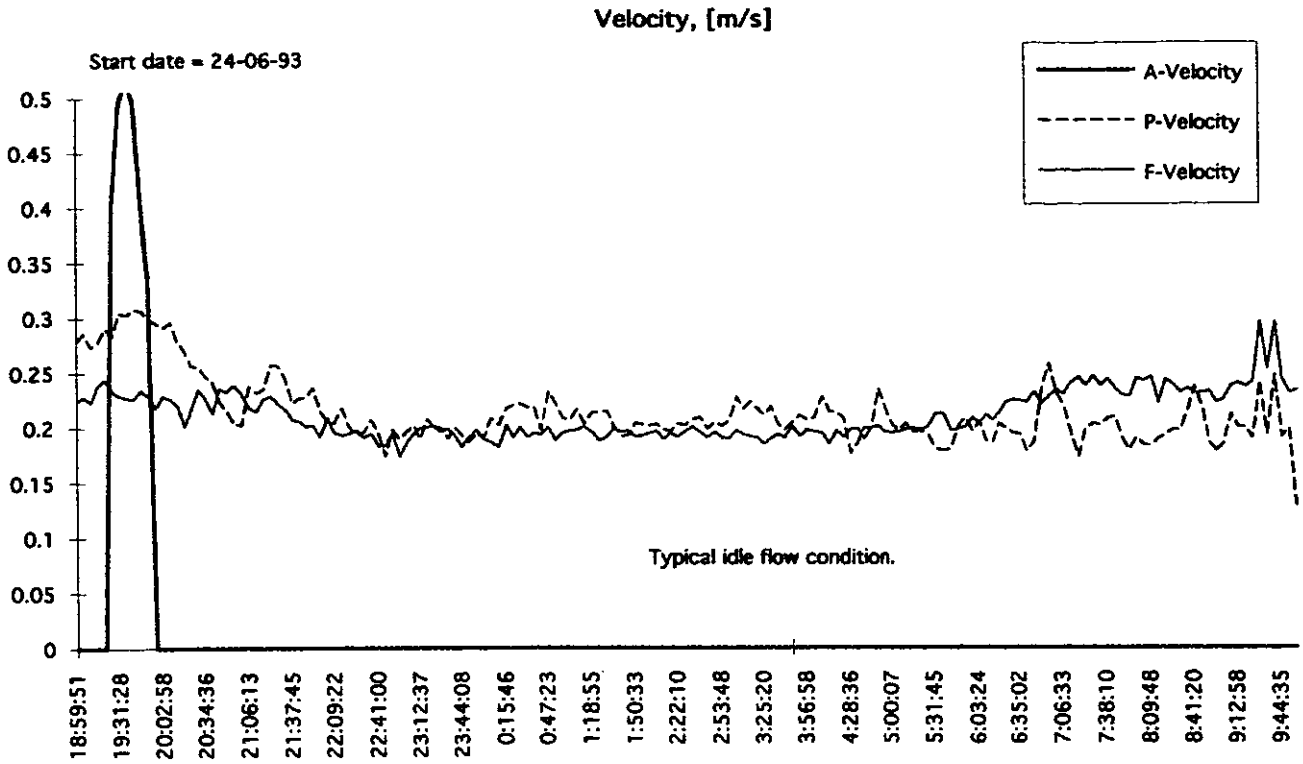
6.00E+01
4.00E+01
2.00E+01
0.00E+00
-2.00E+01
20:19:58
20:41:04
21:02:09
21:23:16
21:44:15
22:05:20
22:26:25
A-DP low
A-DP mid
A-DP wide
A-Selected DP

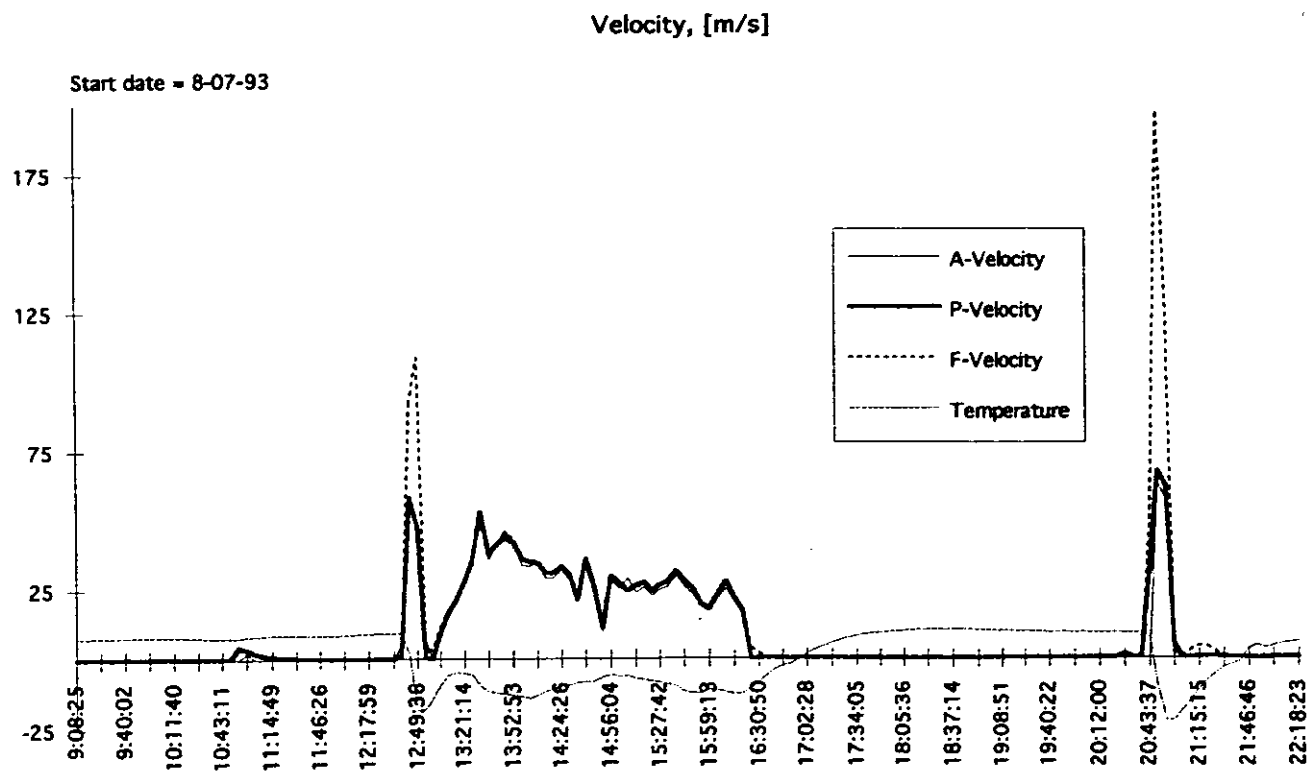

Velocity, [m/s]
Start date = tir 15. jun 1993
100
80
60
40
20
0
-20
-40
-60
15:30:49
15:33:55
15:37:04
15:58:42
16:25:03
16:51:25
17:17:46
17:44:03
18:10:25
18:36:47
19:03:09
19:29:26
19:55:48
20:22:09
20:48:31
21:14:53
21:41:10
22:07:32
22:33:53
23:00:15
23:26:31
23:52:52
0:19:14
A-Velocity
P-Velocity
F-Velocity
Temperature
Fluenta VOS time gate below range for this period.
Panametrics VOS error

18-6-93.xls Chart 13

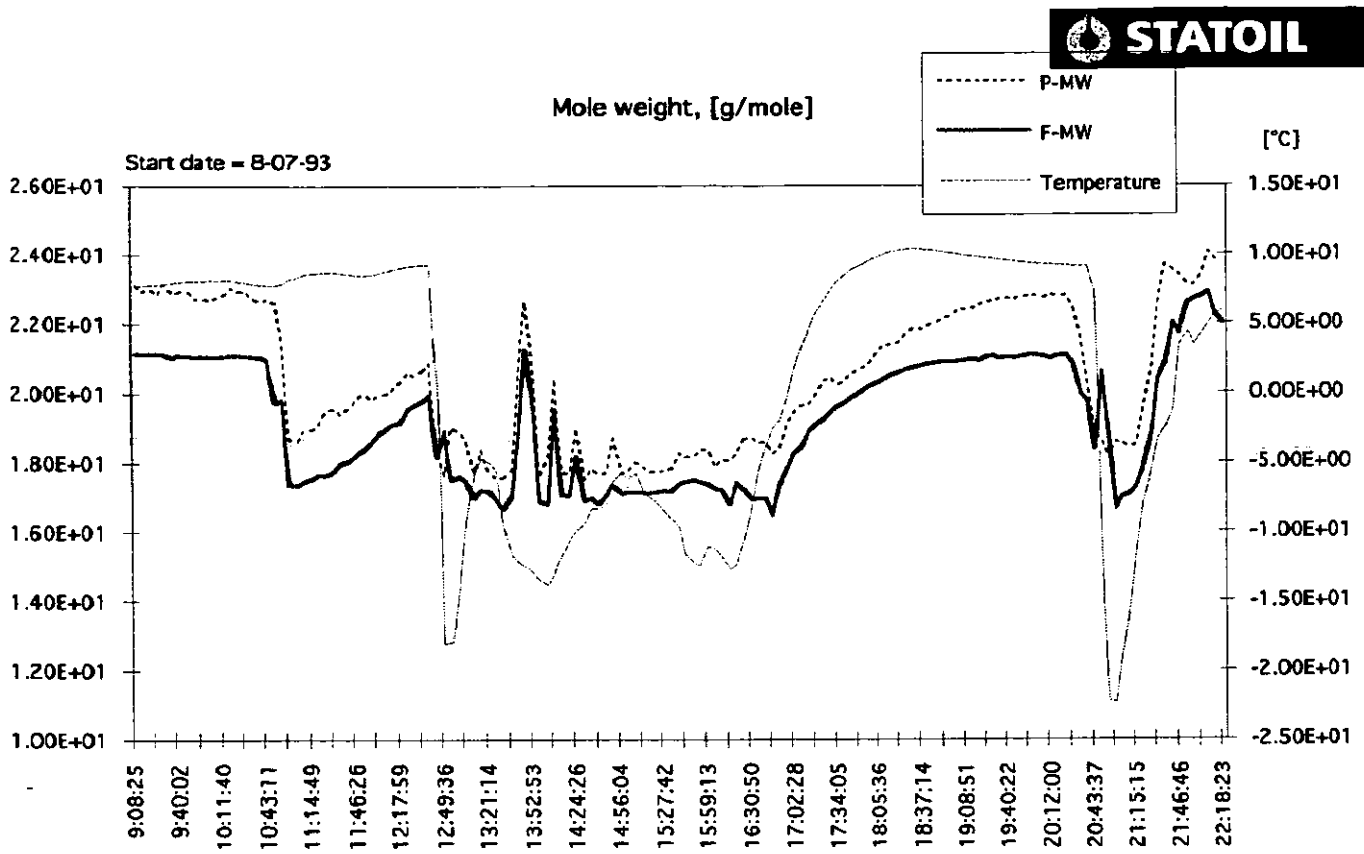
STATOIL



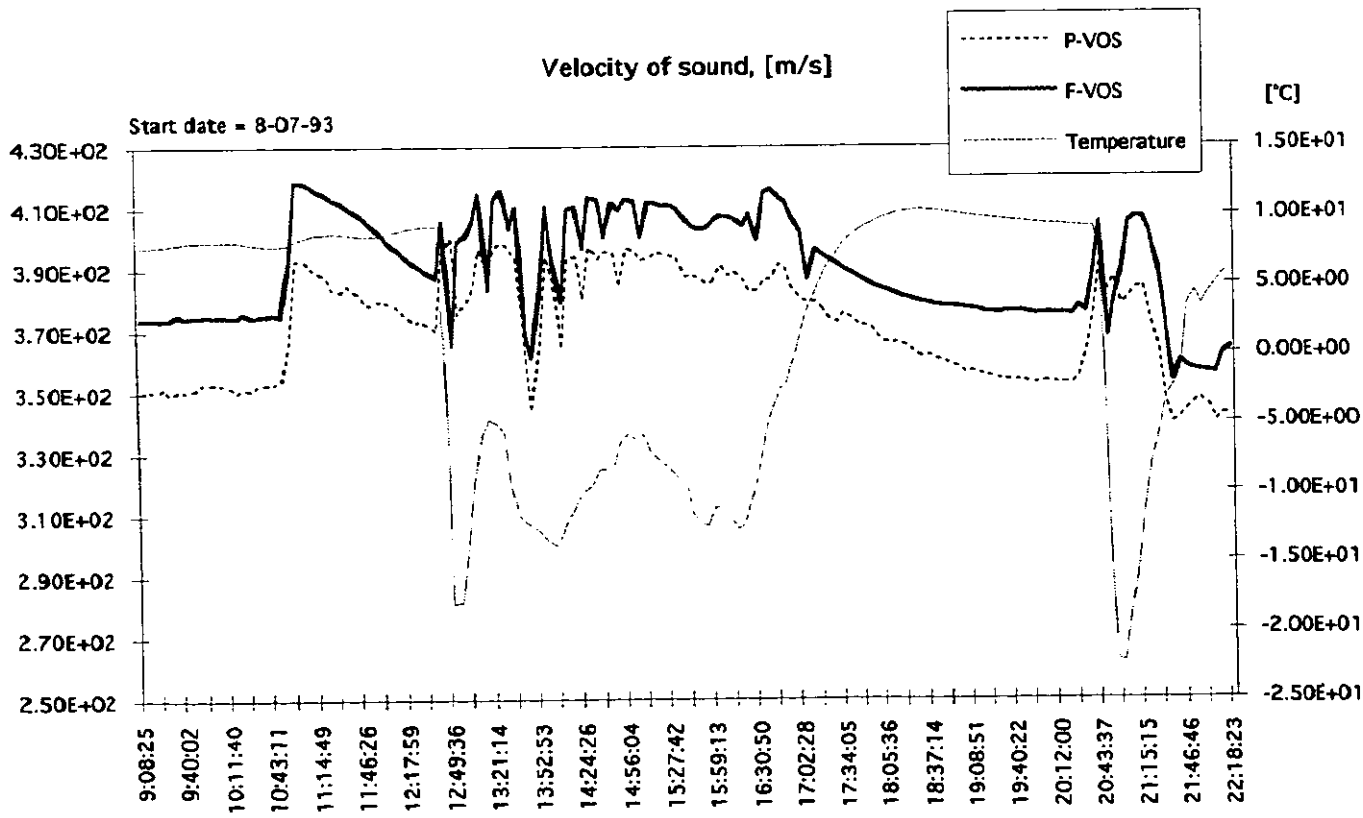
29-6-93.xls Chart 7



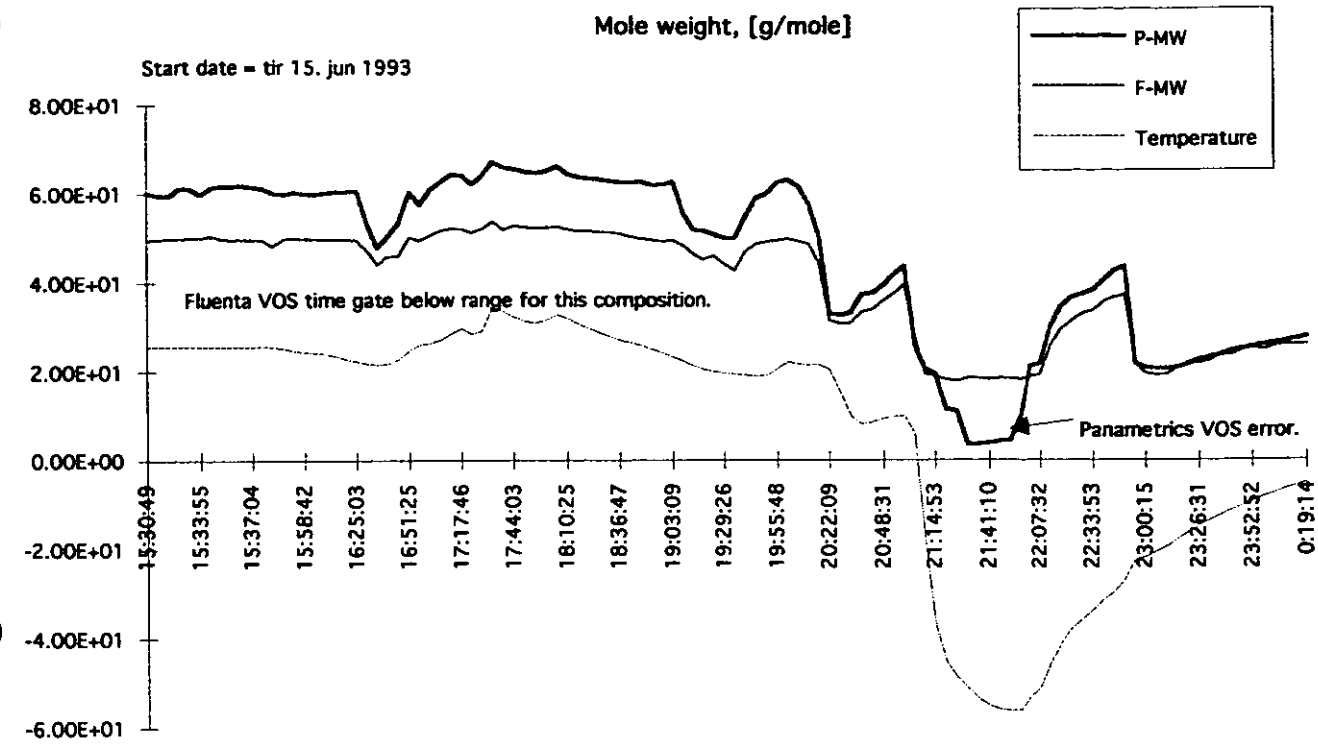
29-6-93.xls Chart 8



29-6-93.xls Chart 9



STATOIL


Mole weight, [g/mole]
Start date = tir 15. jun 1993
P-MW
F-MW
Temperature
Fluenta VOS time gate below range for this composition.
Panametrics VOS error.
8.00E+01
6.00E+01
4.00E+01
2.00E+01
0.00E+00
-2.00E+01
-4.00E+01
-6.00E+01
15:30:49
15:33:55
15:37:04
15:58:42
16:25:03
16:51:25
17:17:46
17:44:03
18:10:25
18:36:47
19:03:09
19:29:26
19:55:48
20:22:09
20:48:31
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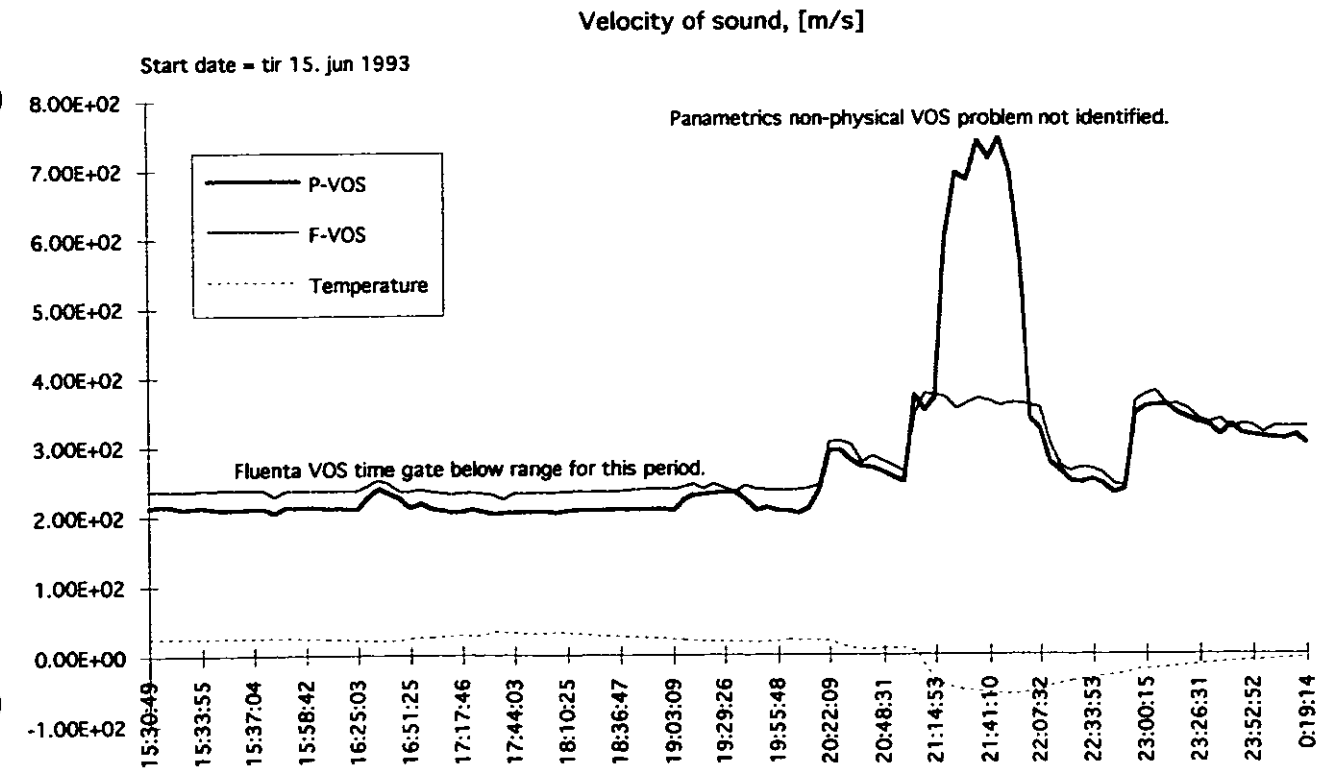
23:00:15
23:26:31
23:52:52
0:19:14


Velocity of sound, [m/s]
Start date = tir 15. jun 1993
Panametrics non-physical VOS problem not identified.
P-VOS
F-VOS
Temperature
Fluenta VOS time gate below range for this period.
8.00E+02
7.00E+02
6.00E+02
5.00E+02
4.00E+02
3.00E+02
2.00E+02
1.00E+02
0.00E+00
-1.00E+02
15:30:49
15:33:55
15:37:04
15:58:42
16:25:03
16:51:25
17:17:46
17:44:03
18:10:25
18:36:47
19:03:09
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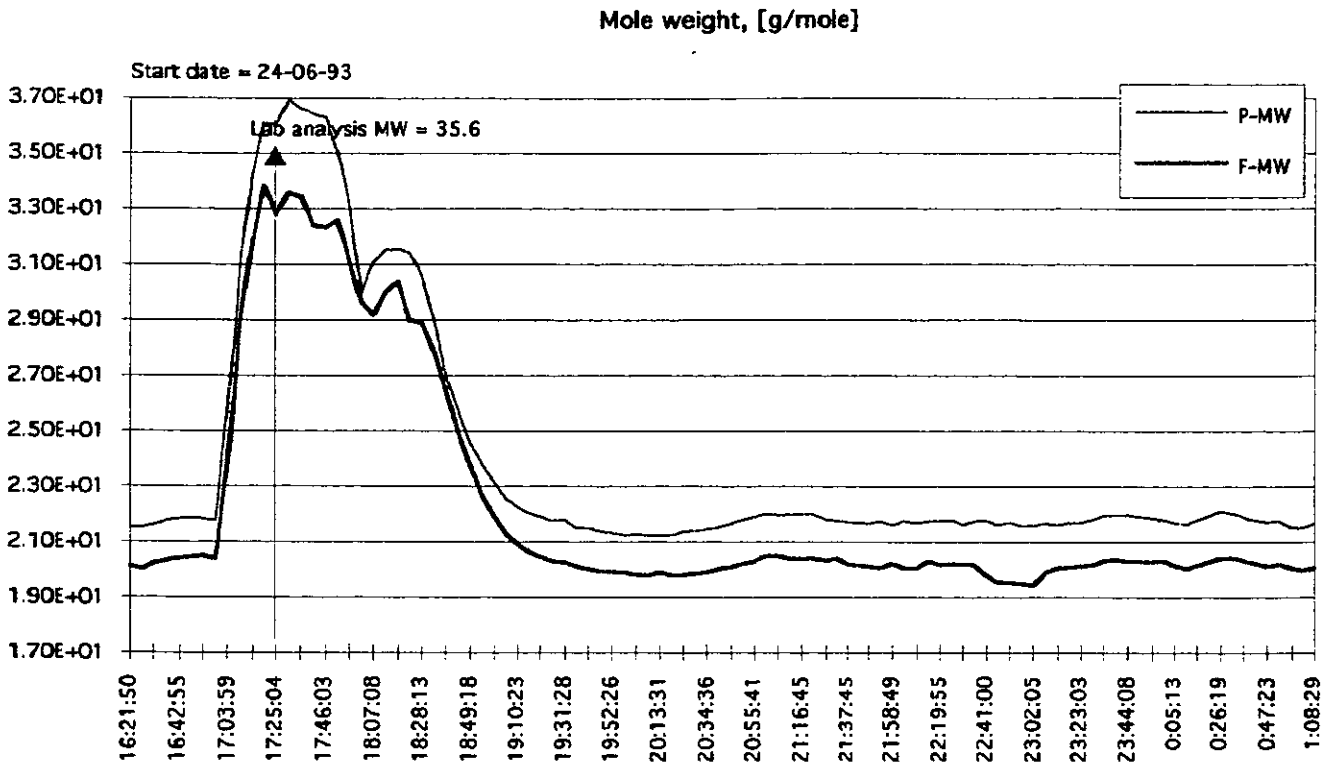
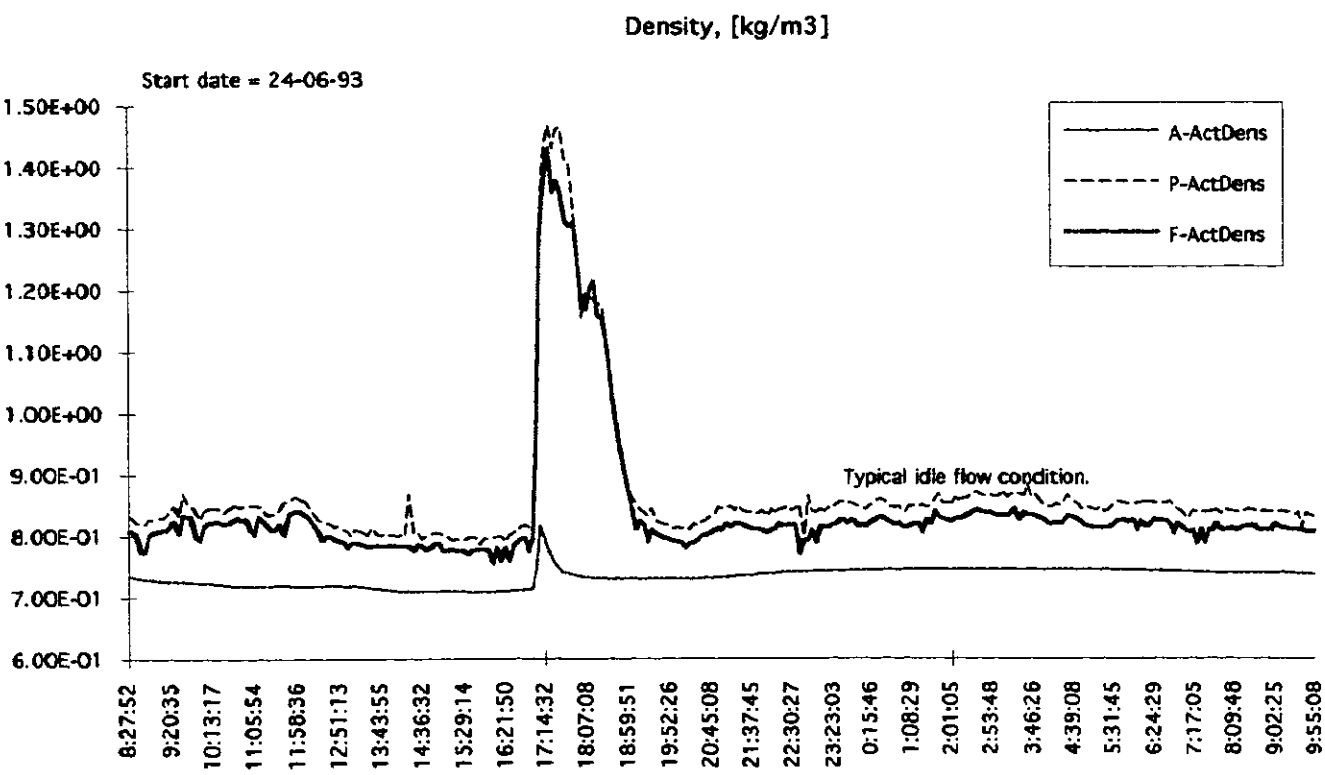
23:52:52
0:19:14

STATOIL



18-6-93.xls Chart 7



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NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Platform Trial of a Multiphase Flow Meter

by

Mr. J.S. Watt,
CSIRO Division of Mineral and Process Engineering,
Australia

PLATFORM TRIAL OF A MULTIPHASE FLOW METER

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PMB 5, Menai 2234, NSW, Australia

This paper describes a trial of a new multiphase flow meter (MFM) on the Vicksburg offshore production platform on Australia's North West Shelf. The flowmeter is based on two specialised gamma-ray transmission gauges mounted on a pipe carying the full flow of oil, water and gas.

Measurements were made on the full and reduced flows of oil/water/gas mixtures from each of nine single wells, and on five combined flows of different pairs of wells. These measurements were made by two MFMs, one mounted on a horizontal and the other on a vertical, section of a pipeline linking the test manifold and test separator. The flows measured ranged from 130 to 2900 BPD for oil, 230 to 5100 BPD for water, and 0.5 and 1.9 million cubic feet per day for gas. The water ranged from 17 to 95 %, with a mean of 73%.

The r.m.s. difference between the flow rates determined by the MFM and by the separator output meter was determined by least squares regression. The ratio of r.m.s. difference and mean flow rate was 8.9% for oil, 5.6% for water and 8.2 % for gas for flows in the vertical pipeline and slightly larger for flows in the horizontal pipeline. These ratios include not only the errors in the multiphase flow meter but also the combined errors of the separator and separator output meters.

1. INTRODUCTION

The extraction of fluid hydrocarbons from their geological reservoirs involves the piping of multiphase mixtures of crude oil, (salt) water and gas from each well. Knowledge of the flow rates of each component, in each well pipeline feeding to the production platform, is required to control production. Current practice is to feed sequentially the outputs from each well to a common test separator system, and to measure the flow rates of each (single phase) component after separation. The time to determine the flow rates for each well is many hours, and the determination can also be unrepresentative because the flow rate is sampled for only a small part of the total production time of a well.

The oil industry requires a multiphase flow meter (MFM) which is compact, measures the flow rates continuously, and can be mounted directly onto each well pipeline [1,2,3]. Use of such a meter should lead to

a) the replacement of the need for test separators, initially in non-critical applications and later, after the MFM technology has been proved to be dependable, in most new offshore platforms,

b) the reduction in the cost of subsea piping because the outputs of two or more wells can be commingled and flow through a single flowline from satellite platform to central facility,

c) the reduction in capital costs of new platforms because the heavy test separator can be replaced by the light MFM,

d) better reservoir management, production allocation, and optimisation of total oil production over the field lifetime.

Not only would new oil fields be exploited more economically, but it should make possible the production of oil from wells in greater depths of water and the development of off-shore oilfields which were previously marginal.

Various organisations are developing multiphase flow meters for oil, water and gas in pipelines. The most promising approaches are those based on nuclear [4,5,6,7], capacitance [8,9], and microwave [5,10] techniques. The target is to determine the mass flow rate of each component to about 5-10% relative (1σ). Most of these techniques have been tested on laboratory loops, but few tests have been undertaken on production pipelines. None of these prototype meters developed to date have been demonstrated to cover all the flow conditions occuring in pipelines from oil wells.

CSIRO is undertaking a three stage program to develop and prove techniques for the on-line determination of the mass flow rates of oil, water and gas in pipelines, and to license and transfer the technology to ensure that the multiphase flow meter (MFM) becomes commercially available to the oil industry. Both gamma-ray and microwave techniques are being developed.

This paper describes the use of gamma-ray transmission techniques to determine the mass flow rates of oil, water and gas, and the trial of the multiphase flow meter based on these techniques, on production pipelines on an offshore oil platform.

2. THE MULTIPHASE FLOW METER

The strategy adopted by CSIRO in developing the multiphase flow meter is to make measurements directly on the well pipelines. This approach has the advantage over MFMs used on sample bylines in that it avoids the errors caused by non-representative sampling from mainline pipe to sample byline. It does, however, make the analysis more complex since measurements must be made on the heterogeneous mixture of oil, water and gas in the pipeline.

The most common flow regimes for oil, water and gas in pipelines from oil wells are slug flow for horizontal pipes and plug flow for vertical pipes. In slug flow, slugs of liquids including some gas fill the whole cross-section of the pipe, and consecutive slugs are separated by a layer of liquid as a film beneath a gas pocket above. The velocities of the liquids and gas in the slug, the front of the slug, and the liquid in the film, are all different. Even for a two component mixture of a liquid and a gas, the translation of measurements made on the mixture in the pipeline into mass flow rates involves using models of the flow regime.

The CSIRO techniques developed for the determination of mass flow rates of oil, water and gas are based on

* single energy gamma-ray transmission measurements (Figure 1) to determine the mass per unit area of fluids in the gamma-ray beam as a function of time,

* cross-correlation of gamma-ray transmission measurements, with one gauge upstream of the other, to determine flow velocity,

* dual energy gamma-ray transmission (DUET) measurements to determine the approximate mass fraction of oil in the liquids,

* pressure and temperature measurements, and

* knowledge of the specific gravities of oil and (salt) water, and the solubility of the gas in the liquids, all as a function of pressure and temperature.

The measurements are first used to identify the flow regime. They are then combined in models of the identified flow regime to give the mass flow rates of each component. Computer programs process the measurements made on horizontal and on vertical pipelines to give the mass flow rates of oil, water and gas.

3. PLATFORM TRIAL

The most important aspect of tests of a multiphase flow meter on an oil platform is to test it over a wide range of flow rates, pressures, and volume fractions of oil, water and gas. Measurements made on only one well, even with variations in flow conditions, would provide an insufficient test of a multiphase flow meter. To ensure a wide range of flow conditions, one of our sponsors (Western Mining Corporation) suggested that measurements be made on a pipeline connecting the test manifold to the test separator on their Vicksburg offshore platform. A variety of flow conditions could be achieved by sequentially routing through this test pipeline the flows from each of the nine separate wells feeding the platform, and combinations of these well flows.

3.1 Vicksburg platform and oil wells

A full scale trial of the MFM was undertaken on the Vicksburg platform during February and March, 1992. This platform, on the Northwest Shelf off-shore from Onslow, West Australia, is a combined drilling and oil production platform operated by Western Mining Corporation. The wells intersect a thin layer of oil about 1500 metres below the sea bed. The platform stands in about 20 metres of water, and the main deck is about 20 metres above sea level. The oil wells mainly tap the South Pepper (SP) field; and some of the well pipelines are essentially horizontal at the depth of the oil accumulation. One well drains the North Herald field, and the multiphase mixture is piped first to a satellite (monopole) platform and thence 5.6 km along the sea bed to the Vicksburg platform. Eight South Pepper and one North Herald wells were operating at the time of the field trial. The densities of oil and water from these wells are respectively 0.81 and 1.03 g cm^{-3} at STP.

3.2 Gauges

In laboratory experiments, gamma-ray transmission techniques accurately determined the flow rates of water and air in both horizontal and vertical sections of a water/air loop [5]. We decided that gauges would be installed on both vertical and horizontal sections of the test pipeline during the entire platform trial. Although this required the use of four rather than two gauges, the simultaneous measurements made would give a much better assessment of the comparative advantages of installing gauges on horizontal or vertical production pipes.

Four gamma-ray transmission gauges were used during the trial. The two DUET gauges were based on measurement of the transmissions of ^{241}Am (energy 59.5 keV) and ^{133}Ba (about 356 keV) gamma-rays. The two density gauges were based on measurement of the transmission of ^{137}Cs gamma-rays (662 keV). Lead collimation in the radioisotope containers restricted the gamma-rays passing through the oil/water/gas mixture to a narrow beam. The intensities of detected gamma-rays at the two different gamma-ray energies in the DUET gauge were simultaneously measured using pulse height analysis. The mass per unit area (g cm^{-2}) of fluids in

the gamma-ray beam is determined from the detected intensities of the ^{133}Ba and ^{137}Cs gamma-rays. The detected intensity of ^{241}Am gamma-rays depends both on mass per unit area of fluids and on the effective atomic number of the fluids.

The four gauges were mounted about the test pipeline. A shielded radioisotope source holder was located on one arm of a C frame. The gamma-ray detector, high voltage supply and pre-amplifier were housed in a flameproof enclosure attached to the other arm of the C frame. The gamma-ray detector, a NaI crystal/photomultiplier combination, was surrounded by a heating element and thermostat to keep its temperature constant at about 40° C. The electrical pulses from the photomultiplier were routed via the preamplifier to an amplifier and signal processing unit whose output was in turn routed to an IBM compatible 386SX computer. Signals from the fluid pressure and temperature sensors were also routed to the same processing unit. Both the processing unit and computer were mounted in a control room on the platform.

3.3 Test pipeline

The test pipeline (Figure 2), set up by Western Mining Corporation for the platform trial, linked the test manifold to the test separator. The test pipeline was 73.7 mm nominal bore. The gauges were mounted external to the pipeline carrying the oil/water/gas mixture (Figure 1), no penetration of the pipeline being necessary other than for the pressure and temperature sensors through standard fittings. The DUET gauges were mounted on a 2 m length aluminium alloy section of the pipeline near the end of a long run of horizontal pipe (Figure 2). One was mounted directly about the pipeline, and the other with an extended path length of about 200 mm. The pressure sensor was mounted immediately upstream of the first DUET gauge, and a temperature sensor about 12 metres upstream. The density gauges were mounted near the top of a vertical section of pipe.

The pressure immediately prior to the test separator on the Vicksburg platform is normally low, about 600 kPa. A choke was installed immediately prior to the test separator, increasing the pressure in the test pipeline to close to well head pressure (WHP), and making it possible to make measurements on flows at different pressures.

3.4 Measurements

Measurements were made on oil/water/gas mixtures passing through the test pipeline. Most measurements were made with flows from only one well at a time in the test pipeline. In these cases, measurements were first made with the choke immediately prior to the separator set to about the same diameter as that of the choke near the Christmas tree. A second measurement was then made with the separator choke reduced in size, thus changing the flow conditions. Measurements were also made with the combined flows from pairs of wells. In these cases, the separator end choke had to be set wide open to maintain normal production, and thus the pressure in the test pipeline was much lower than well head pressure.

The range of flow parameters in the test pipeline during the MFM measurements was large (Table 1).

3.5 Results

Much of the results and discussion is based around two wells: SP4 and SP7. SP7 is typical of most wells coming directly to the platform, which exhibit regular and frequent slugging. SP4 is a typical "terrain slugging" well. The terrain slugs develop in the subsea flowline between

the well head and the Vicksburg platform, a distance of about 1.8 km for the SP4 well. The intermittent nature of terrain slugging gives rise to large variations of liquid and gas flow rates, as well as mass per unit area in the test pipeline, versus time.

a) Mass Per Unit Area of Fluids Versus Time

The detected intensities of gamma-rays from ^{133}Ba (horizontal pipe) or ^{137}Cs (vertical pipe) gauges give the total mass per unit area (g cm^{-2}) of liquids and gas in the gamma-ray beam. This is determined independently of the distribution of the liquids and gas in the gamma-ray beam, i.e., it gives no information of spatial distribution of liquids and gas in the pipeline. In practice, spatial distribution can often be inferred, e.g., during the passage of slugs, the oil/water/gas mixture is reasonably uniform across the whole cross-sectional area of the pipe.

Figure 3 shows the time variation of the mass per unit area of fluids in the gamma-ray beam in the vertical section of the test pipeline for the SP7 well at two different pressures, for the combined streams of SP5 and SP6 wells, and for the SP4 well. The counts were summed over 10 milliseconds periods, and the records in Figure 3 show the mass per unit area determined each 10 ms period over a total time of about 17 seconds. Superimposed on the obvious changes in mass per unit area in each record is "noise" due to the statistics of counting over the 10 ms periods.

The plots for the SP7 well (top left and right, Figure 3) both show the fairly regular slugging behaviour in the vertical pipeline, typical for flows from wells close to the platform. The frequency of slugging is different because of the different pressures in the pipeline. The velocities of the slugs are 10 and 5.5 m s^{-1}, and the slug lengths are about 5 metres (top left) and 8 metres (top right). The low mass per unit areas between the slugs corresponds to the film.

The plot for the combined flows of the wells SP5 and SP6 (bottom left, Figure 3) shows a much more frequent slugging. The velocity of the slugs, about 14 m s^{-1}, is much higher than the velocities for the SP7 well. The length of the slugs is about 2 metres.

The plot for the SP4 well, which is 1.8 km from the platform, is typical for terrain slugs; the record over the 17 second period is highly irregular. Records for consecutive 17 second periods do not show a regular repetition pattern. The flow rate of the liquids is highly irregular, varying very considerably with time over periods of tens of minutes.

b) Velocity Versus Time Over 40 Minute Periods

Figure 4 shows results of measurements of mass per unit area (in the gamma-ray beam) in the vertical section of the test pipe, for flow from the SP8 well. Both gauge outputs are shown. Cross-correlation of the gauge outputs gives a measure of time delay for the slugs to pass from one to the other gauge. There is a close correspondence between upstream and downstream gauge outputs with the slugs seen on the downstream gauge output being delayed by about 0.4 seconds compared with the same slug on the upstream gauge.

Figure 5 shows the velocities for flows from the SP4 and SP8 wells, the former corresponding to terrain slugging and the latter to frequent, regular slugging. The velocities were determined every 17 seconds by cross-correlation of the outputs of the gauges mounted on the horizontal pipe. The velocity for the flow of the SP8 well varies little with time over the whole 40 minute period recorded, the standard deviation being about 6% relative. The variation in velocities is

much greater for the SP4 well, with a standard deviation being 37% relative. The wider range of velocities shown for SP4 is a true measure of the large variations in flow which occur over the 40 minute period.

Velocities can be accurately determined by cross-correlation techniques in a time short compared with the response time of the separator and the time of passage of terrain slugs. The time necessary to determine the average velocity of the flow from a well depends more on the inherent nature of the flow, as for terrain slugs, than the response time of the mass flow meter.

c) Flow rates of liquids

Figure 6 shows the liquid flow rates for wells SP7 (left) and SP4 (right) determined from the mass per unit area measurements by gamma-ray transmission and the cross-correlation of the ^{137}Cs transmitted intensities to measure time delay and hence velocities. Well SP7 has frequent and regular slugging (Figure 3) and the flow varies little with time. Well SP4 has terrain slugging, and the flow varies by over a factor of five with time. This gross variation of flow with time was also observed in changes in flow rates as measured by the oil and water meters (at the separator outputs) which record little flow between the terrain slugs and very high flows during these slugs.

d) Gauge Versus Separator Output Flow Rates

The measurements of mass per unit area, pressure and temperature were combined using models of flow regime to determine the flow rates of the total liquids (i.e., oil + water) and of gas. The DUET measurements were used to determine the ratio of the mass fractions of oil and water. All the results were then combined to determine the volume flow rates of oil, water, liquids, and gas.

The results of determinations of the volume flow rates of oil, water, gas and total liquids in the vertical pipe are shown in Figure 7. Each point in this Figure corresponds to the flow rate averaged over a forty minute period. Each flow rate was measured twice, in consecutive forty minute periods, and results for both periods are shown as separate points on the graphs. For each of the eight wells, measurements were made corresponding to the flows at two choke settings. For the five combinations of two wells, measurements were made corresponding to only one choke setting. Results of one of the two SP7 well measurements has been left out of the final gas calculations because there was a significant decrease in gas lift during the measurement period.

R.m.s. differences were calculated by least squares regression of volume flow rates as determined by the gamma-ray transmission gauges and by the relevant separator output meter. The ratios of r.m.s. difference and mean flow rate, expressed in per cent, are given in Table 2. These relative errors include errors in the MFM determination and also errors in the determination by the separator/meter combination, not just of the MFM alone. The Table 2 results show that the volume flow rates of oil, water and gas have been determined to within the range of 5 and 9% relative for the vertical pipe, and 8 and 14% relative for the horizontal pipe.

4. DISCUSSION

4.1 Vicksburg platform trial

The accuracies of the determinations of the volume flow rates of oil, water and gas are particularly pleasing because of the wide range of flow rates and flow conditions in the pipe. Most of the

measurements were made on mixtures with high water cuts. The water cuts covered the wide range of 17 to 95%, with a mean of 72%. Three well streams had water cuts of about 95%. Many of these high water cut mixtures corresponded to oil in the water phase. The determination of flow rates of mixtures with high water cuts is a problem for capacitance techniques and, because of this, conductivity measurements are being developed to measure the flow rates of oil in the water phase. The present MFM results show the versatility of the CSIRO multiphase flow meter in its ability to determine flow rates covering the whole range of water cuts.

The equipment used for the Vicksburg trial performed reliably under typical oil field conditions and over a reasonable length of time. The equipment design met all offshore safety criteria, e.g., electrical zoning, etc.

The results for the measurements on the vertical pipe are better than those for the horizontal pipe. Hence, at least for the flow conditions in wells feeding to the Vicksburg platform, gauges mounted on vertical pipes would be preferred to those mounted on horizontal pipes.

The results of the platform trial are excellent considering that this was the first field trial of the MFM on production flows of oil, water and gas. The accuracies of flow determination obtained are sufficient for many applications on production pipelines.

4.2 Further work

The MFM is being trialled again, between August and November 1993, at oil processing facilities on Thevenard Island, West Australia. These facilities are operated by West Australian Petroleum Pty. Ltd. This trial will provide tests on flow conditions different to those encountered on the Vicksburg platform, and involve the use of both gamma-ray transmission and microwave techniques on a 137 mm bore pipeline.

Mineral Control Instrumentation Ltd [11] has been selected as licensee for the MFM. CSIRO and MCI will test the commercial prototype in a long-term trial starting in April, 1994, and the fully commercial version of the MFM will be available to the oil industry late in 1994.

5. CONCLUSION

The mass flow rates of oil, water and gas have been determined with an accuracy between 5 and 9% relative by gamma-ray transmission techniques. These measurements were made on the flows from eight wells, and five mixtures of two wells, on the Vicksburg offshore oil platform. The multiphase flow meter performed reliably under typical oil field conditions, and its design readily met offshore safety criteria of this platform.

A further field trial is being undertaken from August to November, 1993, on production pipelines. The commercial prototype MFM will be jointly tested by CSIRO and the commercial licensee, Mineral Control Instrumentation Ltd., in a long-term trial in 1994. The fully commercial version will be available late in 1994.

6. ACKNOWLEDGMENTS

The authors wish to thank both D. Nairn and D. Stribley of the Australian Mineral Industries Research Association (AMIRA) for their efforts in coordinating the project; and Western Mining Corporation staff, Mr N. Keron, for his suggestion that the MFM be tested on the Vicksburg Platform, and for his and other platform staff support during these platform trials. The work

described in this paper has been financially supported in part by the Energy Research and Development Corporation (ERDC) of the Australian Government, The Shell Company of Australia Ltd., West Australian Petroleum Pty. Ltd. (WAPET) and Western Mining Corporation.

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TABLE 1. RANGE AND MEAN OF TEST CONDITIONS DURING PLANT TRIAL.

	Range	Mean	Units
Oil	130 - 2900	1018	BPD
Water	230 - 5100	2731	BPD
Total liquids	1350 - 6370	3740	BPD
Water cut	17 - 95	72	%
Gas	0.5 - 1.9	0.89	MMSCFD*
Gas/oil ratio	390 - 3700	870	SCFD/Barrel
Pressure	640 - 2800	1350	kPa
Temperature	28 - 74	56	°C
Velocity	3.5 - 13.1	7.4	m/s

* million standard cubic feet per day at STP.

TABLE 2. RATIOS OF RMS DIFFERENCE (σ) AND MEAN FLOW RATE

Flow of	Vertical pipe		Horizontal pipe	
	σ/mean %	Correlation Coefficient	σ/mean %	Correlation Coefficient
Oil	8.9	0.994	9.0	0.995
Water	5.6	0.991	8.3	0.982
Gas	8.2	0.985	14.4	0.952
Liquids	5.2	0.991	8.4	0.978

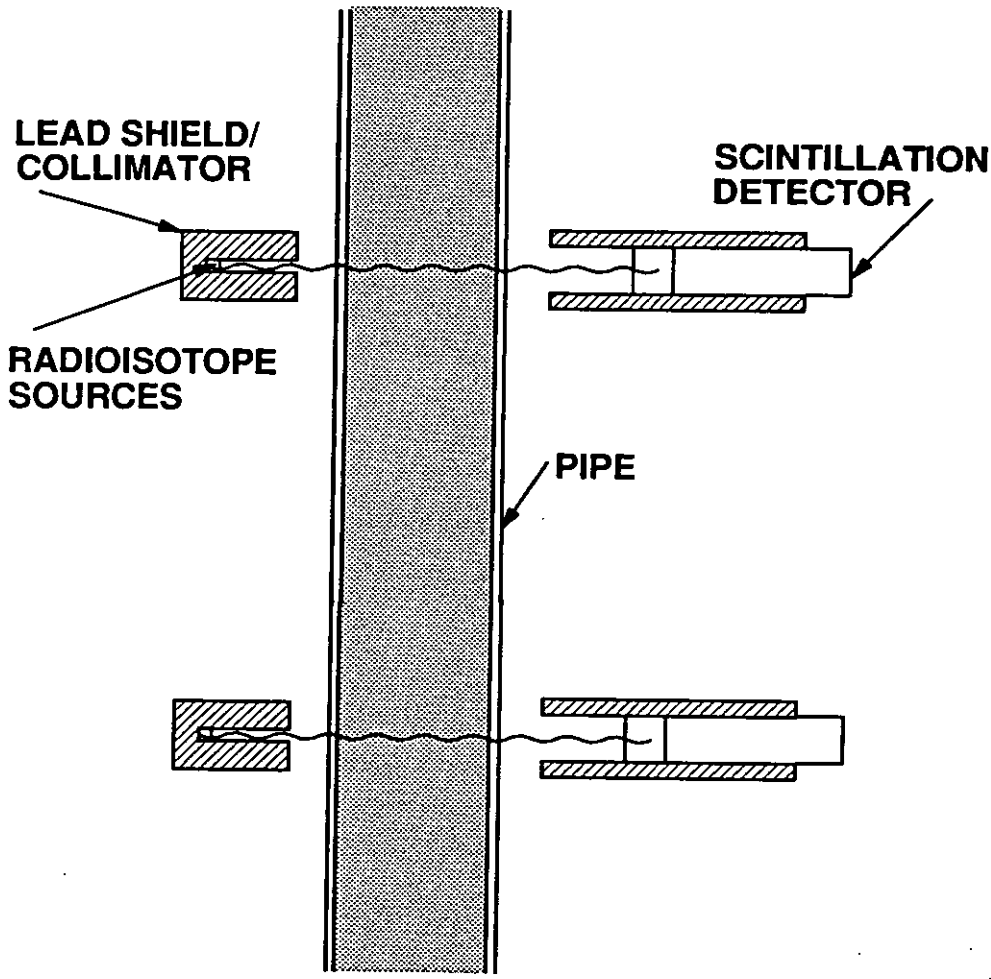

Figure 1. Gamma-ray transmission gauges mounted about pipeline.

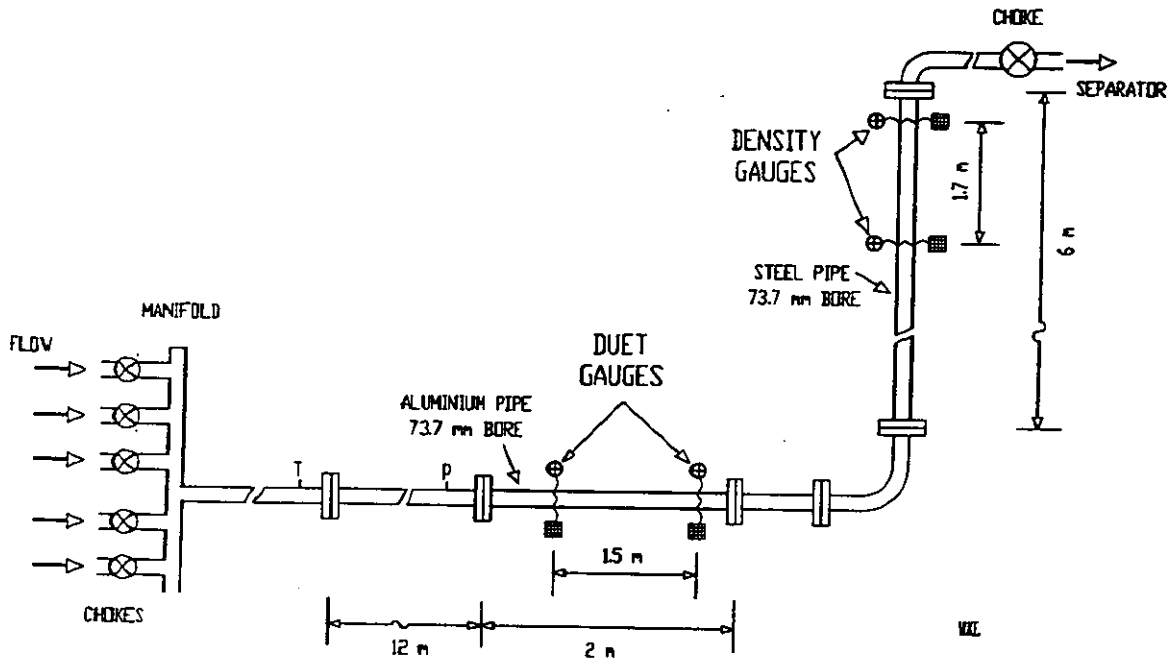

Figure 2. Schematic of the test pipeline joining the manifold and the test separator on the Vicksburg platform. P and T indicate pressure and temperature transducers.

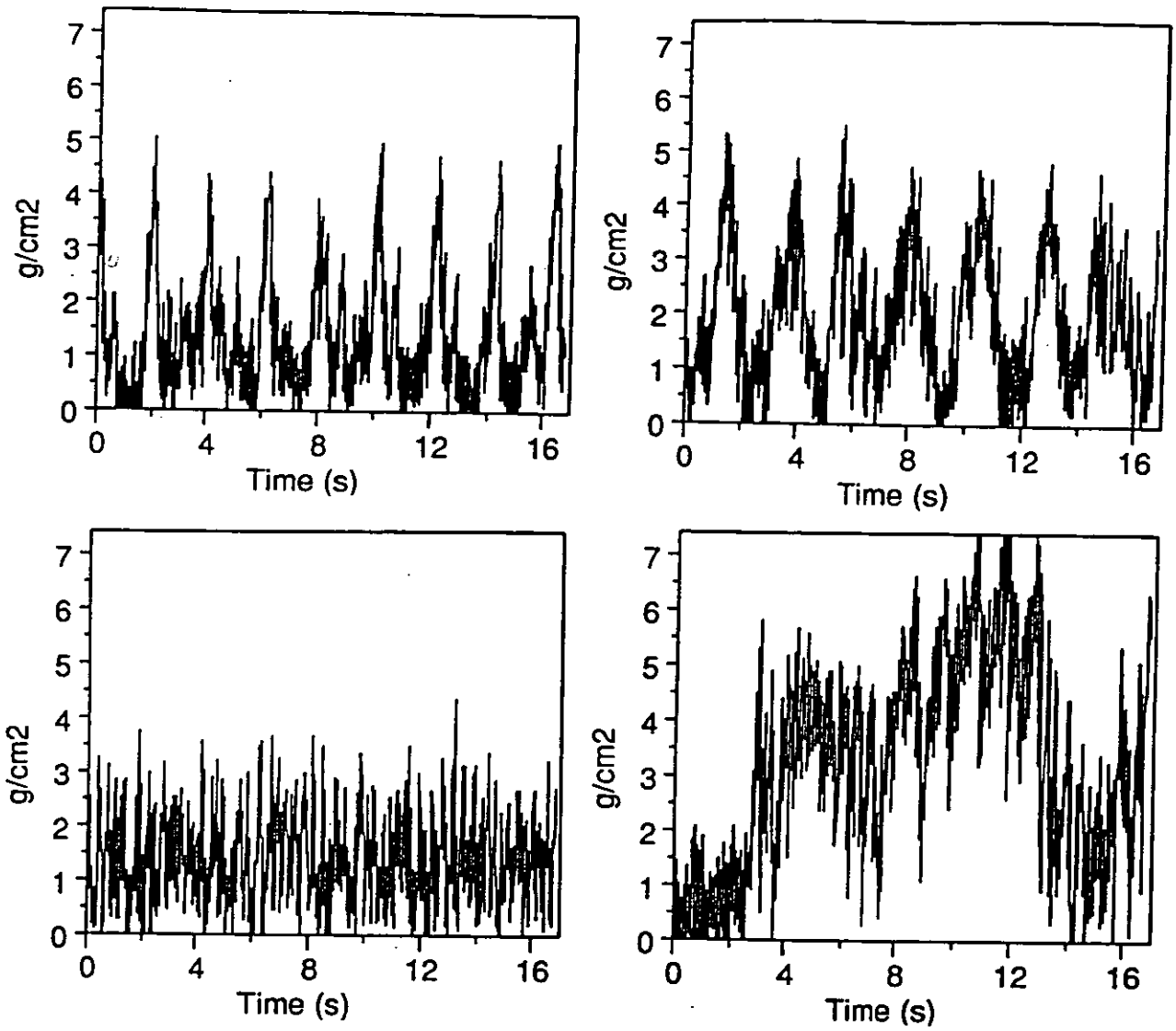

Figure 3. Variations of mass per unit area of liquids in the gamma-ray beam with time, for the flows for the SP7 well at two different pressures (top left and right), for the combined flows from the SP5 and SP6 wells (bottom left), and for the SP4 well (bottom right), in the vertical section of the test pipeline.

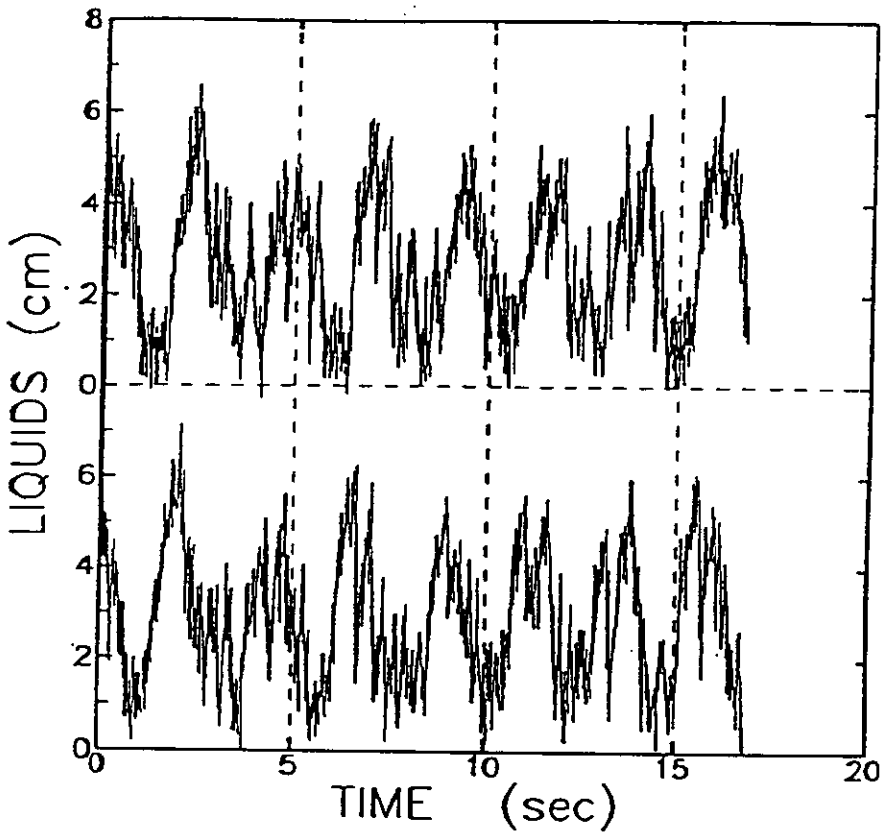

Figure 4. Variation in mass per unit area of liquids (in the gamma-ray beam) with time for the two gauges mounted on the vertical pipeline. The time delay between the upstream gauge (lower record) and upstream gauge is 0.4 seconds.

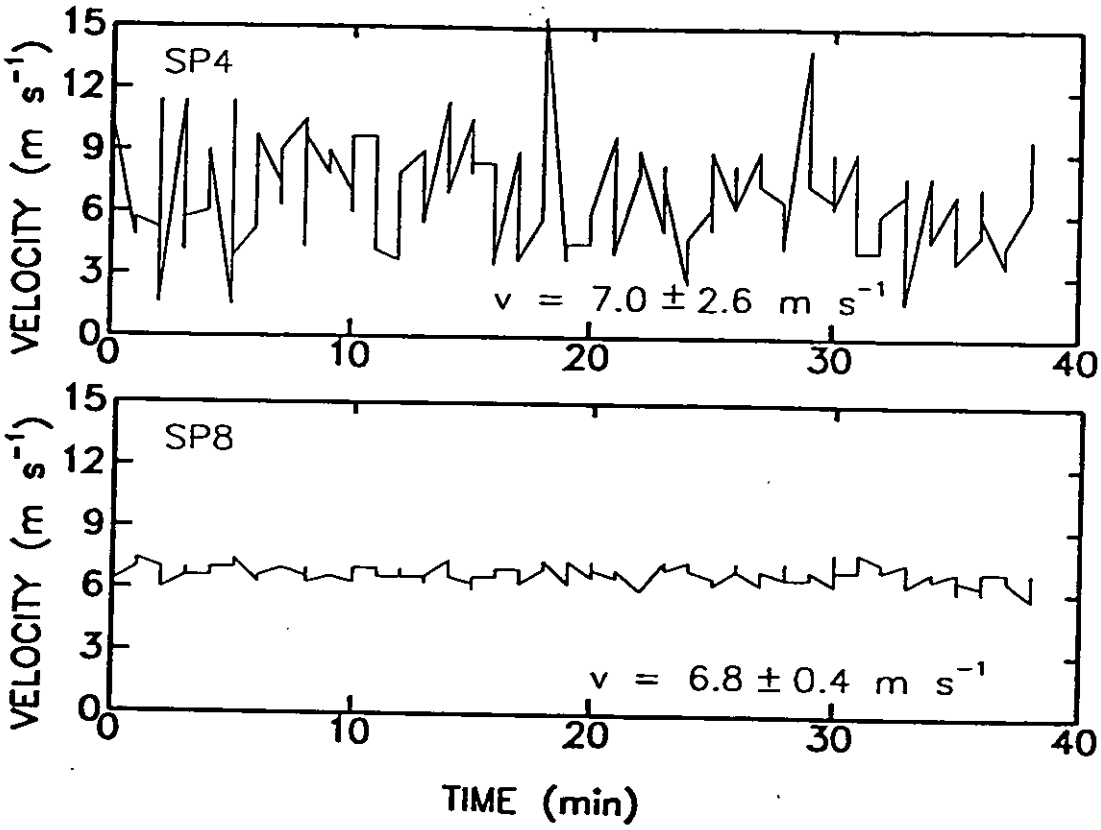

Figure 5. Velocity versus time for the flows from the SP4 and SP8 wells, determined by cross-correlation averaged over 17 second periods.

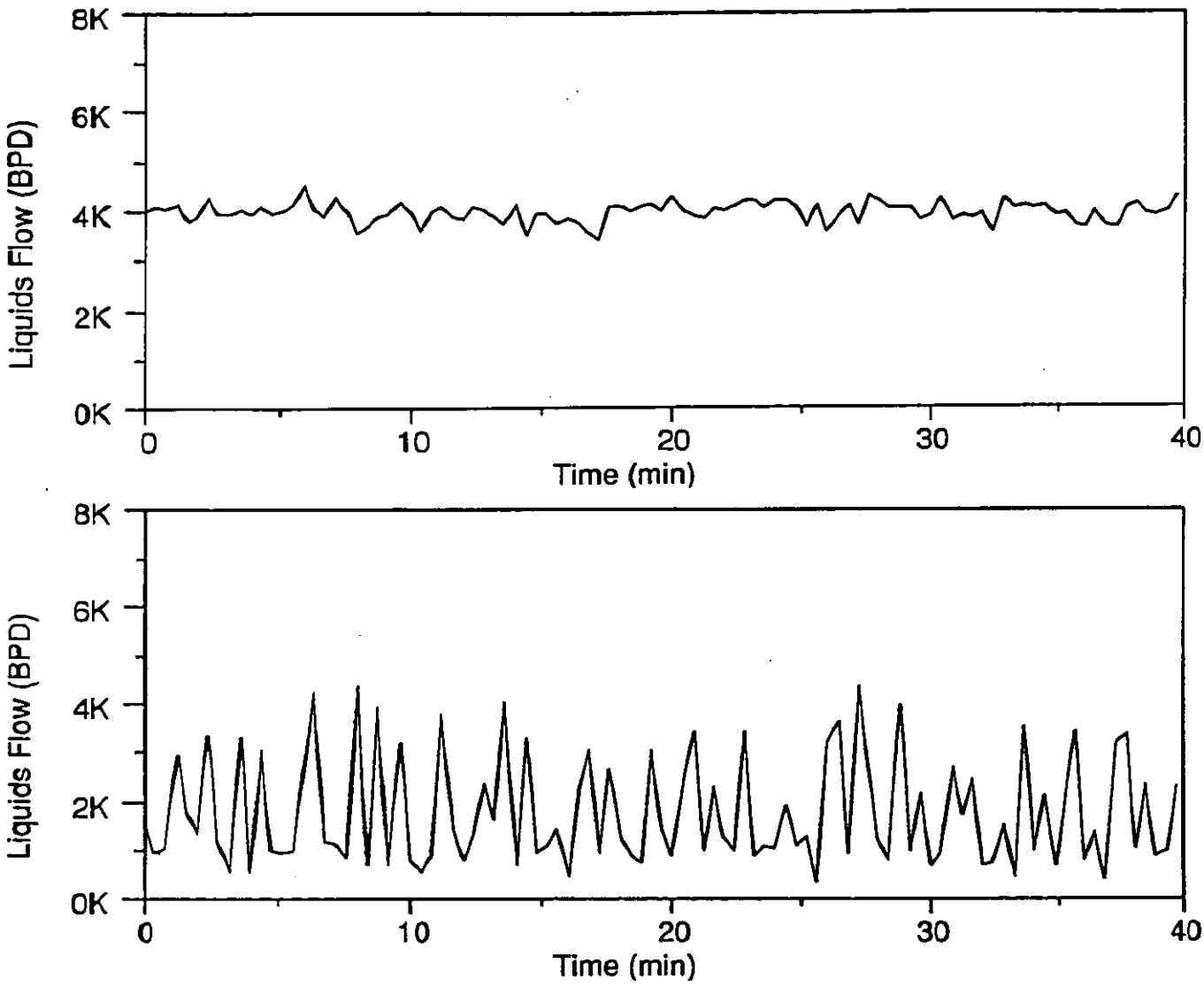

Figure 6. Variation of the volume flow rate of the liquids (oil + water) with time for the flow of SP7 and SP4 wells in the vertical section of the test pipeline.

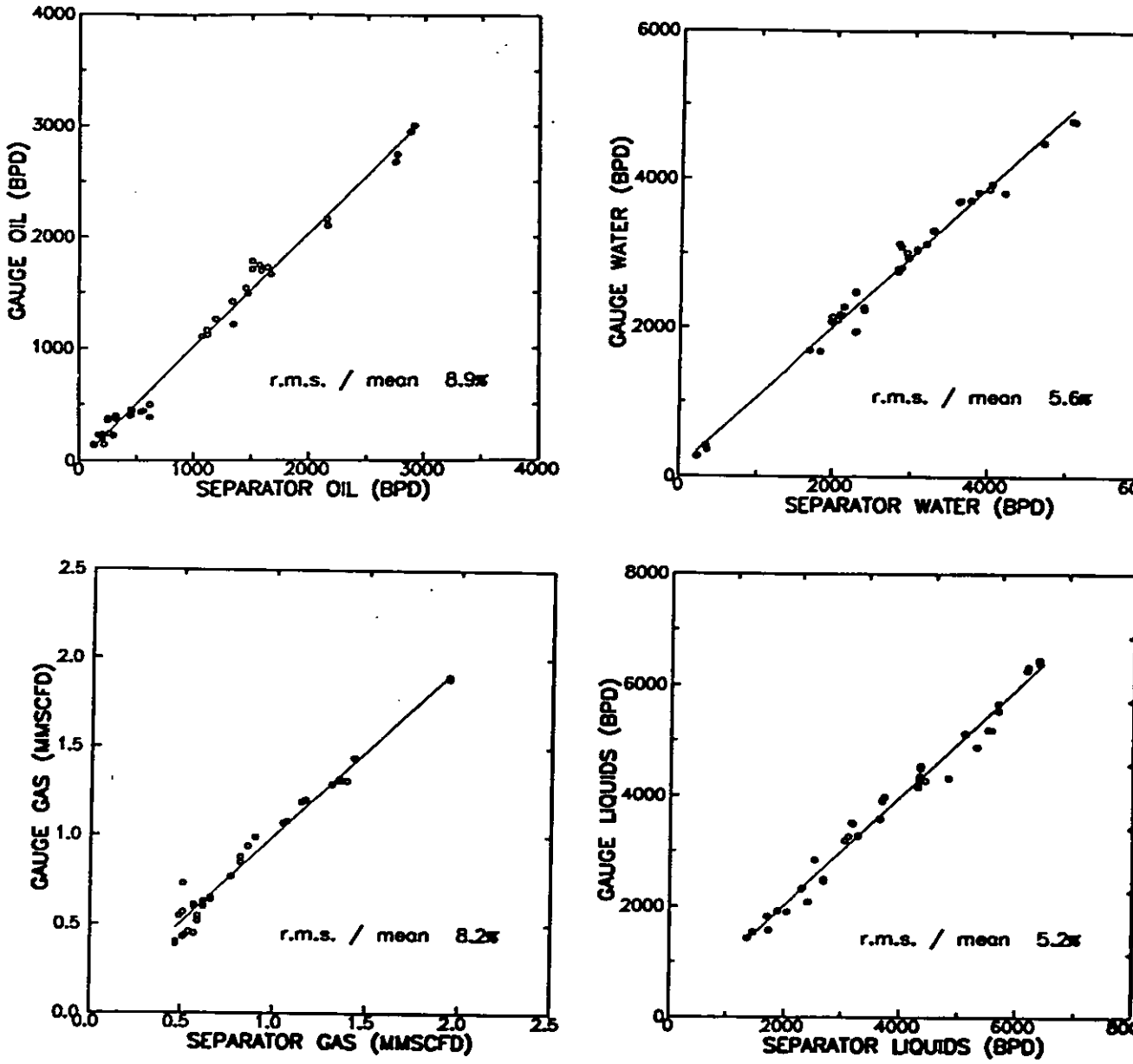

Figure 7. Gauge and separator output determinations of the volume flow rates of oil, water, gas and total liquids.

Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Field Testing of the Multi-Fluid LP Multiphase Meter

by

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and
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INTRODUCTION

This report describes the results of the first successful offshore field test of a complete multiphase meter for measuring the production rates of oil, water, and gas flowing from live oil wells. The test was sponsored by Saga Petroleum and carried out by Statoil on the Gullfaks B Platform in the Norwegian sector of the North Sea. The multiphase meter was developed and supplied by Multi-Fluid.

Many efforts are underway in the world to develop and prove multiphase meters. In Norway alone, there are four large independent efforts to develop a meter. In February of 1992, Saga Petroleum purchased the first prototype of a new multiphase meter from Multi-Fluid for testing on live wells in the North Sea. The meter was installed in November 1992 on the Gullfaks B platform by Statoil and the field tests of the meter started in December. The results so far are very promising.

THE MULTIPHASE METER

The meter being tested by Saga and Statoil is a 4 inch, ANSI Class 600 LP Meter supplied by Multi-Fluid. It is a full-bore instrument measuring 66.7 cm in length and has no moving parts. Unlike some 'multiphase' meters under development, this meter measures the complete production stream without using separation to partially or completely separate the gas from the liquid for measurement purposes. The meter spool piece was fabricated in 316L stainless steel and weighs approximately 100 kg.

The complete multiphase meter consists of two separate meters. It has a composition meter for measuring the instantaneous volume or mass fractions of oil, water, and gas in the sensor. The meter also contains a velocity meter for determining how fast the mixture is flowing through the sensor. Combining the outputs makes it possible to calculate the instantaneous volume or mass production rates of the separate components in the flow stream. Figure 1 is diagram of the LP Meter.

The measurement principle of the composition meter is to determine the composition of a well stream by measuring its density and its dielectric properties (permittivity and conductivity). Mixture density is measured using a conventional single source gamma-ray densitometer which mounted directly on the sensor spool piece. Mixture dielectric properties are quite sensitive to the water content while mixture density is most affected by the gas. The complimentary nature of these measurements is well known. Multi-Fluid is not the alone in using this combination as the basis of a multiphase composition meter. What sets the LP Meter apart, however, is the method used to measure the dielectric properties of the mixture.

The measurement method used in the LP Meter is the 'resonant cavity' method. It is one of the oldest methods of measuring dielectric properties of low conductivity materials at high frequency and it is still the most accurate. It is almost exclusively a laboratory method, however.

A resonant cavity is an electrically closed structure inside which electromagnetic waves will resonate at characteristic frequencies related to the geometry of the cavity and the dielectric constant of the medium in the cavity. Electromagnetic waves injected into a cavity reflect back and forth inside it, until the energy is dissipated. If the wavelength of the waves match the geometry of the box in a well defined manner, then the waves will reflect back and forth in phase with one another generating a high energy standing wave. Electrically the response of a resonant cavity is illustrated in Figure 2. The response is characterized by sharp easily identified output power peaks at characteristic frequencies. By analogy, a resonant cavity

works with electromagnetic waves in the same manner as violin strings work with mechanical waves. A violin string resonates, producing sound, at characteristic fixed pitches related to the length of the string.

To measure the dielectric constant of a material using the resonant cavity method, one simply takes a closed metal box, fills the box with the material, then measures the characteristic frequency or frequencies at which the box resonates. Comparing the characteristic frequencies of the box when filled with the material to the frequencies when the box is empty gives one a direct and unambiguous measure of the dielectric constant of the material. In addition, measuring the width of the frequency peaks determines the conductivity of the material. The advantages of the method are 1) no sensitivity to drift in electronics, 2) nearly complete isolation of the measurement electronics from the measurement system, 3) high sensitivity because frequency can be measured with high precision, and 4) direct measurement of the dielectric constant of the desired material in the measurement cell without the perturbing effects of other materials used to build the cell. The measurement is virtually digital in nature.

Multi-Fluid's contribution to the resonant cavity method is to devise a means of building a cavity which is physically open so that a continuous flow of material can pass through, yet is remains electrically closed so that it will resonate. In this manner, the method can be usefully applied in industrial applications such as multiphase metering. Custom microwave electronics and software have been designed to make the process of finding and tracking the resonant peak automatic and extremely fast. The LP Meter has all of the inherent measurement advantages of the resonant cavity method that are realized in the laboratory.

The velocity meter determines the flow rate using cross-correlation techniques. More specifically, the velocity meter makes very rapid microwave dielectric measurements in two separate resonant cavities separated by a known distance in the pipe. By statistically analyzing the signals from each of the measurement sections using cross-correlation techniques, it is possible to determine the average time it takes the material to flow from the first measurement section to the second. Given the transit time and the spacing between the measurement sections, one can determine the velocity. The LP Velocity Meter benefits from the natural amplification of signals in the resonant cavities. Even very slight fluctuations in composition can be correlated to measure velocity with the meter. This means the meter still be used in applications with little to no water and virtually no gas, unlike other meters which implement cross-correlation methods.

Some of the important meter specifications are listed in Table 1.

LIMITATIONS OF THE METER

The LP Multiphase Meter tested at Gullfaks has some limitations.

1) It is not able to measure production streams where the water is the continuous phase of the liquid. This is inherent to the resonant cavity method. When the conductivity of a material is too high, the cavity cannot resonate. In practice, this limits the usage of the meter to applications with water / oil ratios not much greater than 1. However, the meter is designed to function during water continuous slugs.

2) The first generation velocity meter is designed for bubble flow conditions only where the velocity exceeds about 2 meters per second. The first meter is specifically not designed for more difficult flow regimes such as plug, slug, or stratified flow. The complex slip flow conditions of these latter flow regimes pose greater difficulties for cross-correlation techniques. Multi-Fluid recommends that the meter be installed just after a static mixer with flow directed vertically upward. In this configuration, the mixer can break up most

annular or stratified flow conditions for the short distance necessary to perform the measurements. After more field experience is gained with the first generation LP Meter and specifically after cross-correlation techniques prove viable for bubble flow, Multi-Fluid will extend the measurement range of the velocity meter toward more difficult flow regimes.

3) The meter is intrusive, though it has virtually no pressure drop. It cannot be pigged. Another version of the meter, which has not been fully developed is non-intrusive. This version of the meter may be particularly suitable for subsea applications.

Multi-Fluid recognizes that this first meter is limited. Many applications for multiphase meters will require the capability of measuring higher water contents. Statoil and Saga together with British Petroleum Norway, Elf Aquitaine Norge, Phillips Petroleum Norway, and Total Norge have been sponsoring Multi-Fluid to develop a second multiphase meter capable of measuring 0 - 100% water. This second multiphase meter is based on very similar technical principles as used by the LP Meter. It will begin field trials later this year.

After years of effort and substantial research expenditures, the first generation of multiphase meters are moving toward implementation in the field. Nevertheless, it is becoming increasingly clear to those involved in the development of multiphase measurement devices that no single instrument will be capable of accurately measuring all possible multiphase flow streams with the accuracy and reliability required by users. Instead, different meters will serve different applications. The LP Multiphase Meter should be quite suitable for new fields where the water content is not high. It is also well suited for production logging of new wells.

THE TEST SET-UP

The meter is being tested on the Gullfaks B platform in the North Sea. It has been installed in a 4 inch bypass loop connected to the 8" test line running from the test manifold to the test separator. The meter is installed in a vertical line with flow directed upward. Twelve different wells are available for testing at the Gullfaks test site. The water/oil ratios vary from near zero to over 3. GOR's are typically 50 - 70 Sm^3/Sm^3. Eight different wells have been tested during the trials performed so far. The temperature and pressure at test conditions were about 65°C and 76 bar. The velocities on the tested wells varied from about 2 m/sec up to about 7.5 m/sec. The flow regime for these tests was uniformly bubble flow even though most wells produced between 30 and 50% gas by volume at test conditions.

The test separator itself is a very large three phase separator measuring some 15 meters in length and 3.5 meters in diameter. Because of its size, the separator is very efficient at separating the oil, water, and gas phases. Typically, the residual water content of the oil line is less that 0.5% and the oil in the water line is less than 0.1%. Consequently, the reference measurements made with the test separator are more accurate than would usually be expected with such a setup.

The instrumentation on the test separator consists of an orifice meter on the gas line and turbine meters on the oil and water lines. Figure 2 shows the test set-up. The accuracy of the liquid reference meters are estimated to be within ±2% of reading and the gas reference within ±5%. The test separator readings were totalized at 10 and 30 minute intervals to give volume production rates for oil, water, and gas. From the individual production rates, the average oil, water, and gas volume fractions and flow velocities were

calculated for each test period to compare to the meter readings. The velocity reference was calculated by taking the sum of the production rates for the three components and dividing by the cross sectional area of the meter - Velocity $= \Sigma Q_i$ / Area. **This calculation assumes no slip flow between the different phases.** The composition reference was calculated similarly - Volume Fraction$_i$ = $Q_i / \Sigma Q_i$, again assuming no slip flow.

The meter was calibrated for the Gullfaks B tests in about 10 minutes. First, the gamma densitometer was calibrated in air at atmospheric conditions prior to pressurizing the bypass loop. Second, the estimated oil and gas densities at process conditions were keyed into the instrument. The values used were 815 and 53 kg/m^3 respectively. Finally, the approximate density of the water (980 kg/m^3) and its conductivity (60 mS/cm) were keyed into the meter. This completed the calibration process. No specific on-site dielectric or density measurements of the constituent oil, water, and gas components were necessary. Moreover, no attempt was made to differentiate between the oil, water, and gas in the different wells tested. The same values were used throughout. The simple calibration process is one of the attractive features of the meter.

Results from the meter were logged every 10 seconds, though its actual data output rate was more than once a second. The values were integrated for 10 and 30 minute intervals timed to match the measurement intervals from the test separator. These data sets were compared to determine how the meter was performing.

THE RESULTS

The meter was tested at periodic intervals from December 1992 to July 1993. Between test periods, the bypass loop was closed off. Thus the meter has not been exposed to been in continuous service for the whole 10 months of the test period. Results from several different test periods will be discussed and compared. Composition and Velocity Meter results will be assessed separately to better focus attention on the strengths and weaknesses of the first generation meter.

Composition Meter Results - The composition meter has performed exceptionally well during the tests. Figure 4 shows the results of tests in December 1992 and in July 1993. The meter and the test separator data are presented in terms of percent by volume for each of the components at process conditions for representative periods. In addition to the oil, water, and gas percentages, volume percent hydrocarbon is also shown. This is equal to the sum of the oil and gas contributions. This value is considered to be more valuable by many field engineers when looking at data for high pressure and temperature fluids. The percent error represents the difference in absolute percentage terms between the meter readings and the readings from the test separator.

The results for the three wells tested in December were very good. Well B11 was water continuous, so the meter did not function as expected. For the other wells, B17, B20 and B21, the meter was within ±1.1% of the reference for all components. The test on well B21 was repeated on two separate days with equally good results.

The meter was tested again in March of 1993 and again in July 1993. The results for the five wells tested in July are summarized in Figure 4 as well. For three of the five wells, B2, B10, and B20, the meter was well within ±1% for all components. On the remaining two wells, B9 and B25, three of the six of the readings were between ±2 and ±3% off as compared to the reference; one excessive error each for oil, water, and gas. The %

hydrocarbon error only exceeded ±2% in one case. In all the results are very promising for a first test.

While Figure 4 illustrates the performance of the composition meter over long periods, it does not illustrate the relative quality of the meter's performance for real-time measurements when compared to the test separator. The test separator required about 30 minutes to stabilize after the test well was changed. The composition meter, on the other hand, reacted instantly to each new well. Moreover, the composition meter readings changed very little during the course of a well test cycle. They were generally stable to better than 1.5%. Figure 4a) shows the composition meter readings and the measured values from the test separator compared at 30 minute intervals for well B21. Note, that even with a 30 minute integration time, the results form the test separator are not nearly as stable as those of the meter. It became quite clear during the test that the composition meter gave very accurate, reliable and fast trend information about the production of individual wells. Figure 4b) shows a typical real-time data log from the meter over a 30 minute interval.

Velocity Meter Results - The results from the Velocity Meter are shown in Figure 6. The well tests shown are for the same set of wells as described for the Composition Meter. In general, they are not as good as with the composition meter, but still encouraging. As Figure 6 shows, the velocity meter is reading consistently high in all test. The velocity errors range from +4.5% and +7.4% on the low end and +11.3% and +13.2% at the high end. A simple reduction of the readings by 10% would put the velocity meter within its specified accuracy of ±5%. During the whole of the test period, the velocity meter has performed quite consistently, but biased to the high side.

Figure 7a) shows the measured velocities compared to to the corresponding results from the test separator on well B21 at 30 minute intervals. As with the Composition Meter, the Velocity Meter results trend nicely with the test separator, but are less erratic when looked at over this time scale. Figure 7b) shows a typical real-time output from the meter over a 30 minute interval. The spike in the results is caused by software imperfection in the first meter. When the meter measured erratic velocities for a long enough period of time, the zero velocity routine was be enabled improperly resulting in the spike in the reading to 0 m/sec. The logging software which would totalize the results from the velocity meter was programmed to override these spikes. Thus, they did not effect the results in most cases. It is hoped that this flaw has since been corrected in the meter.

MultiRate Test - In March of 1993 (and again in July) the meter was tested at several flow rates on a single well to determine the consistency of the Composition and Velocity Meters respectively under the different conditions. The test was performed on well B21. The flow velocities tested were 2.3, 3.4, and 5.3 m/sec respectively. Figure 8 shows the production rates for oil and gas as measured by the LP Meter and from the test separator respectively. The results are consistent with the others obtained with the meter. The Velocity Meter read consistently high. The flow rates measured by the meter were uniformly higher than measured with the separator. The Composition Meter tracked quite well during the test as is evidenced by the match in relative flow rate errors for the oil and the gas. In all, the multiflow rate tests have demonstrated that them meter does not perform oddly when the flow rates are varied.

DISCUSSION

Composition Meter - The LP Composition Meter has performed to everyone's satisfaction. This is not to

say that there is not room for improvement. Some of the results in July exceed the accuracy specifications of the meter. There are three likely sources of error. They will be investigated more carefully in future tests if possible.

- The oil and gas densities of the different wells are not likely to be equal. The variation was not taken into account when the meter was calibrated, however. Errors are likely to appear as a result. When the results are look at in mass terms instead of volume terms, however, the errors should be less. The instrumentation on the test separator at Gullfaks is being upgraded such that reference data will be available expressed in mass terms. Individual component masses will also be available at test conditions for calibration purposes.
- The first generation meter was not programmed to adjust the calibrated densities of oil and gas as the temperature and pressure conditions vary. During the many tests, temperature varied approximately between 49°C and 68°C. This is certainly enough variation to call into question the fixed density calibration used in the meter. A software update will address this problem in upcoming tests.
- The meter was calibrated with a constant water density and conductivity. As with the oil and gas density, it is not likely that the water was the same in each well. This too will be investigated more thoroughly in future tests.

Velocity Meter - The Velocity Meter results while consistent and encouraging. But, where is the offset in the results coming from? At the moment no satisfactory answer has been found. The meter at Gullfaks is one of only two LP Multiphase Meters that have been built. Neither of them is available to Multi-Fluid for additional testing to try to find the source of the error. It is hoped that the Gullfaks meter can be returned to Multi-Fluid at some point in the future for a thorough investigation.

- The most obvious explanation is slip flow - the gas is moving faster than the liquid. If this were the case, however, then it is difficult to explain the excellent composition meter results. If significant slip flow were present in the different wells, then the composition reference values calculated from the separator results would overestimate the gas significantly and underestimate the liquid components. This was not observed.
- The meter was not calibrated properly. This is a plausible explanation, but one which cannot be explored until the meter can be looked at again.
- The flow profile of live wells is flatter than it was for the low pressure fluids used to calibrated the meter. This would account for the offset in the velocity results, but it is difficult to test this possibility with multiphase flows.

CONCLUSIONS

This test represents the world's first successful offshore test of a complete multiphase meter on live wells. The meter did not perform perfectly - there is still an outstanding question about the offset in the velocity readings. The composition meter performed especially well, however. The specifications of ±2% accuracy for the composition meter seem supported by the results. When the results of the composition and velocity meters are combined to calculate production rates in terms of produced volume per unit time for each

component, the results were consistently high by about 10% ± 3%. The error is directly attributable to the high velocity readings. 10% is the target accuracy for the first generation of multiphase meters to be used for allocation purposes. The Multi-Fluid LP Meter appears capable of achieving this target when the velocity measurement is corrected.

Looking ahead to field implementation, certain important options appear readily achievable with this technology.

1) The meter is a compact self-contained unit. It has low power and communication requirements. It should, therefore, be readily implemented as a subsea device. Engineering a marinized version of the meter should be underway soon.

2) Another important possibility with this technology is pre-choke installation. Most difficulties with multiphase measurement are associated with high gas fractions and complex flow regimes. One can take advantage of the higher operating pressures before the choke to alleviate these problems somewhat. Higher pressure means lower gas fractions and more nearly equal liquid and gas densities. The LP Multiphase Meter can quite easily be designed for very high pressure. This will give engineers the option to install the meter before the choke to improve their measurements.

The Multi-Fluid LP Multiphase Meter

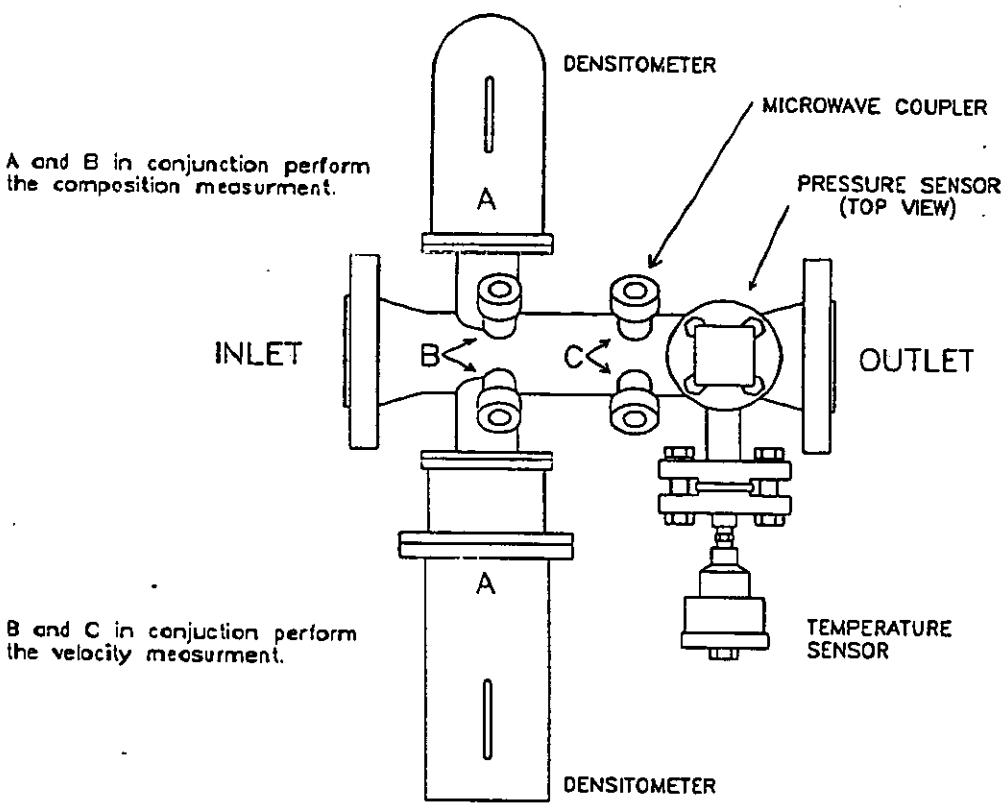


Figure 1

Typical Response of a Resonant Cavity

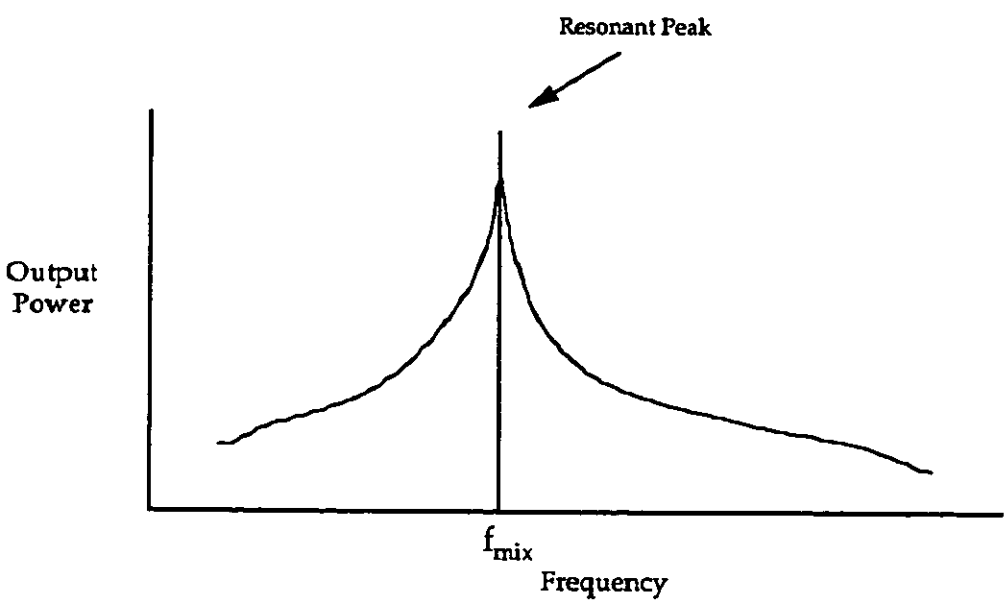


Figure 2

TEST FACILITIES

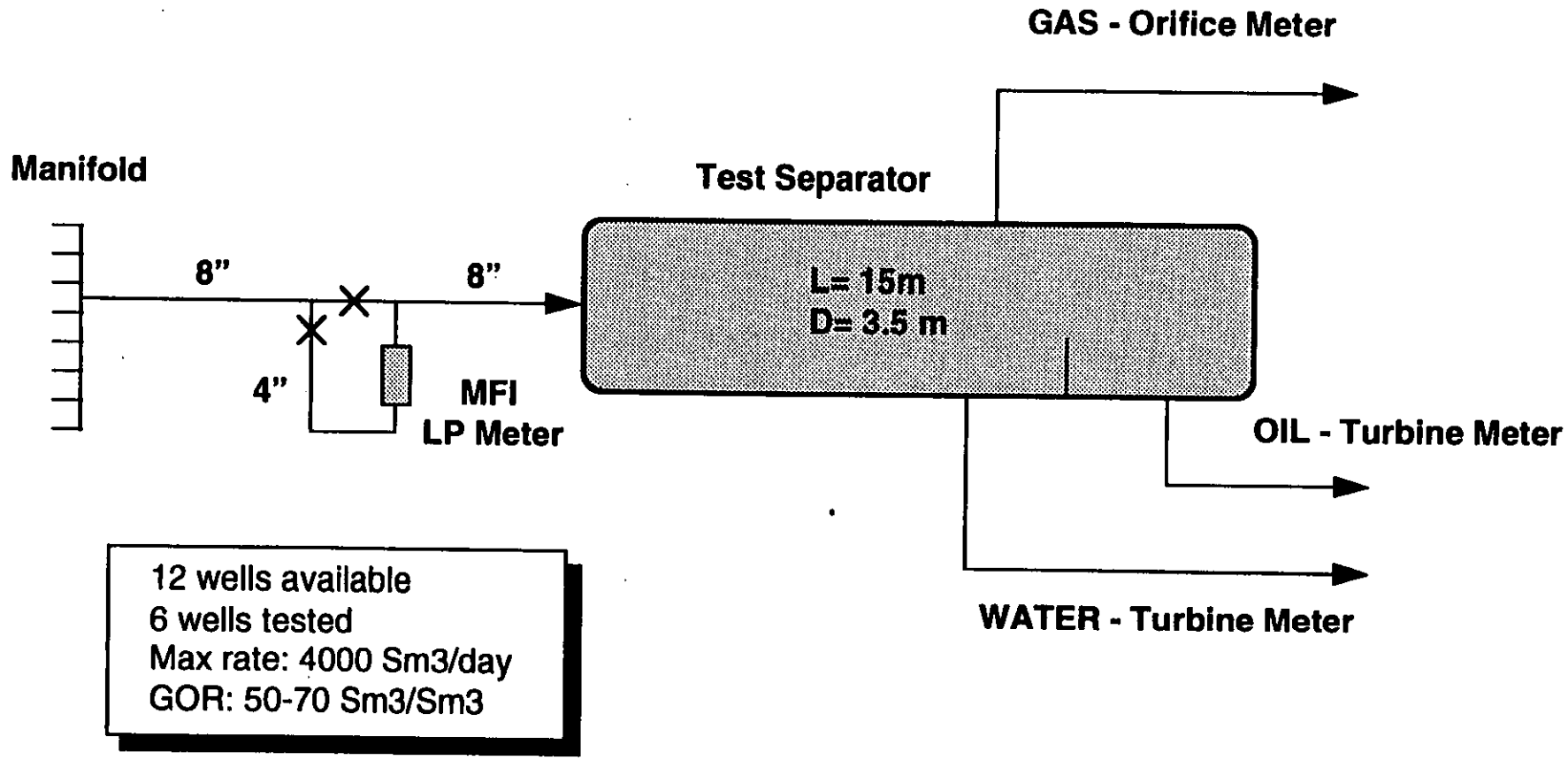


Figure 3

COMPOSITION METER TEST RESULTS

WELL NO.	DATE	TIME	TEST SEPARATOR				MULTIPHASE METER				PERCENT ERROR ABSOLUTE			
			Water %	Oil %	Gas %	HC %	Water %	Oil %	Gas %	HC %	Water %	Oil %	Gas %	HC %
December '92														
B11	18-Dec	11:00-15:00	65.2	22.4	12.4	34.8	No readings - Water continuous				-	-	-	-
B17	18-Dec	21:45-01:45	11.1	52.6	36.3	88.9	10.0	53.2	36.8	90.0	-1.1	0.6	0.5	1.1
B21	18-Dec	04:40-08:40	0.0	60.4	39.6	100.0	0.2	60.2	39.6	99.8	0.2	-0.2	0.0	-0.2
B20	19-Dec	12:30-13:30	0.0	61.0	39.0	100.0	0.6	60.2	39.2	99.4	0.6	-0.8	0.2	-0.6
B21	19-Dec	04:10-11:10	0.0	60.3	39.7	100.0	0.0	59.9	40.1	100.0	0.0	-0.4	0.4	0.0
July '93														
B2	29-Jul	18:30-22:30	0.0	61.2	38.8	100.0	0.1	61.5	38.4	99.9	0.1	0.3	-0.4	-0.1
B9	30-Jul	15:00-17:00	24.6	43.9	31.6	75.5	22.1	45.8	32.1	77.9	-2.5	1.9	0.5	2.4
B10	30-Jul	1:00-5:00	8.9	52.8	38.3	91.1	9.3	52.5	38.2	90.7	0.4	-0.3	-0.1	-0.4
B21	30-Jul	11:30-12:30	1.5	58.7	39.8	98.5	2.2	58.4	39.5	97.9	0.7	-0.3	-0.3	-0.7
B25	30-Jul	10:00-14:00	0.0	51.6	48.4	100.0	0.0	48.9	51.1	100.0	0.0	-2.7	2.7	0.0

Figure 4

A Comparison of the Meter Readings for %Oil
with Those of the Test Separator for Well B21

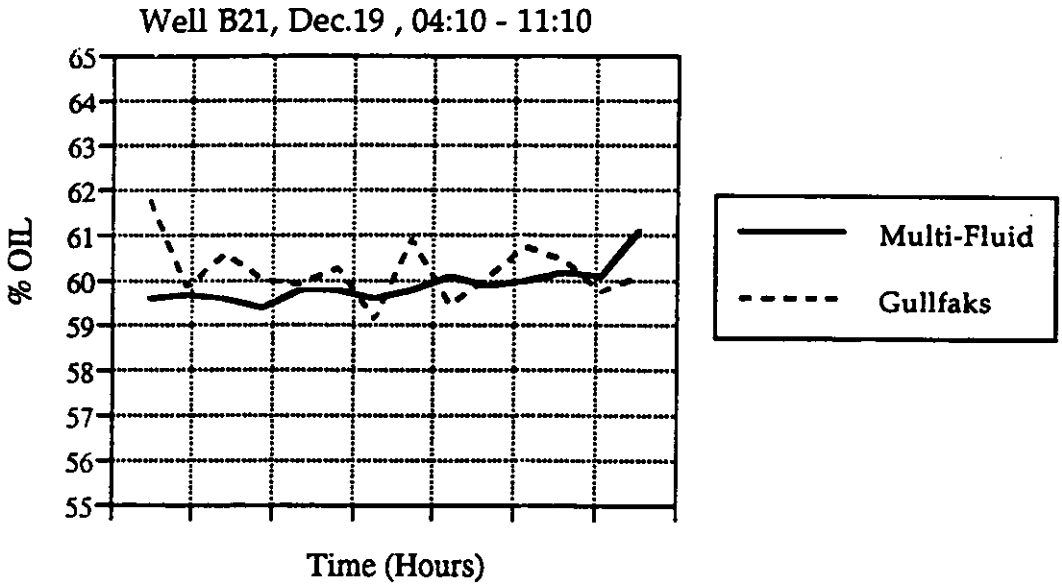


Figure 5a)

Real Time Composition Meter Output
for 30 minute interval on Well B10

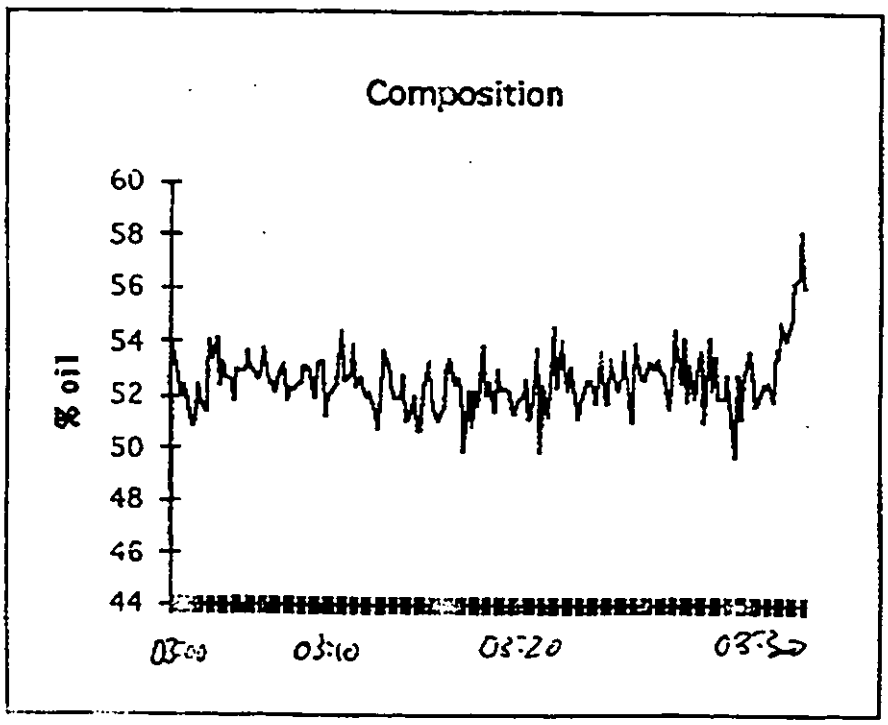


Figure 5b)

VELOCITY METER TEST RESULTS

WELL NO	DATE	TIME	TEST SEPARATOR (m/sec)	VELOCITY METER (m/sec)	PERCENT ERROR
December '92					
B11	18-Dec	11:00-15:00		No readings Water Continuous	
B17	18-Dec	21:45-01:45	8.75	9.14	4.5%
B21	18-Dec	04:40-08:40	no data	2.88	-
B20	19-Dec	12:30-13:30	7.13	7.94	11.4%
B21	19-Dec	04:10-11:10	3.16	3.59	13.6%
July '93					
B2	29-Jul	18:30-22:30	2.05	2.32	13.2%
B9	30-Jul	15:00-17:00	4.55	5.04	10.8%
B10	30-Jul	1:00-5:00	4.76	5.30	11.3%
B21	30-Jul	11:30-12:30	7.28	7.82	7.4%
B25	30-Jul	10:00-14:00	7.09	7.82	10.3%

Figure 6

A Comparison of the Meter Readings for Mixture Velocity with Those of the Test Separator for Well B21

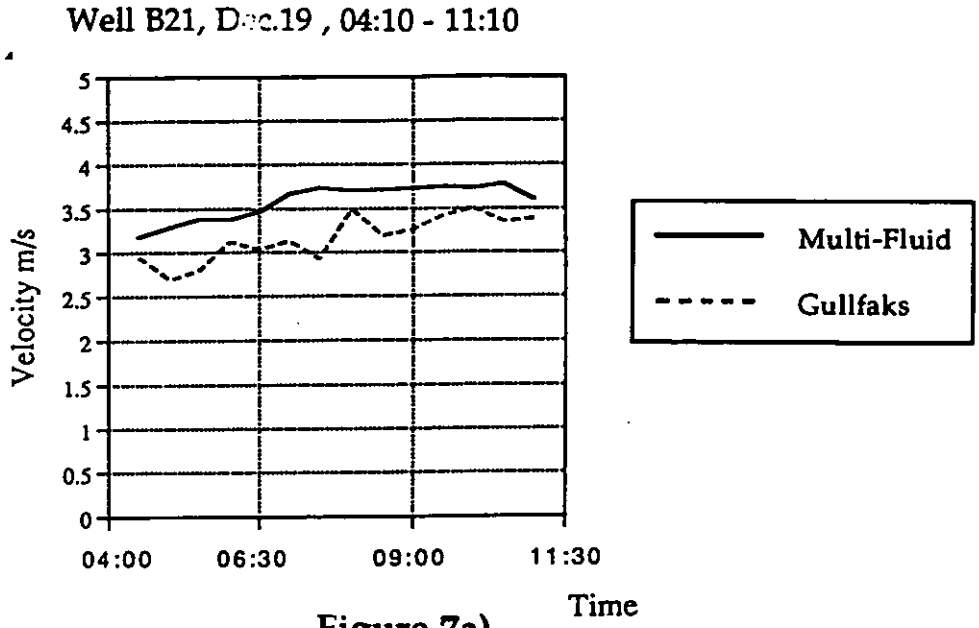


Figure 7a)

Real Time Velocity Meter Output for 30 minute interval on Well B10

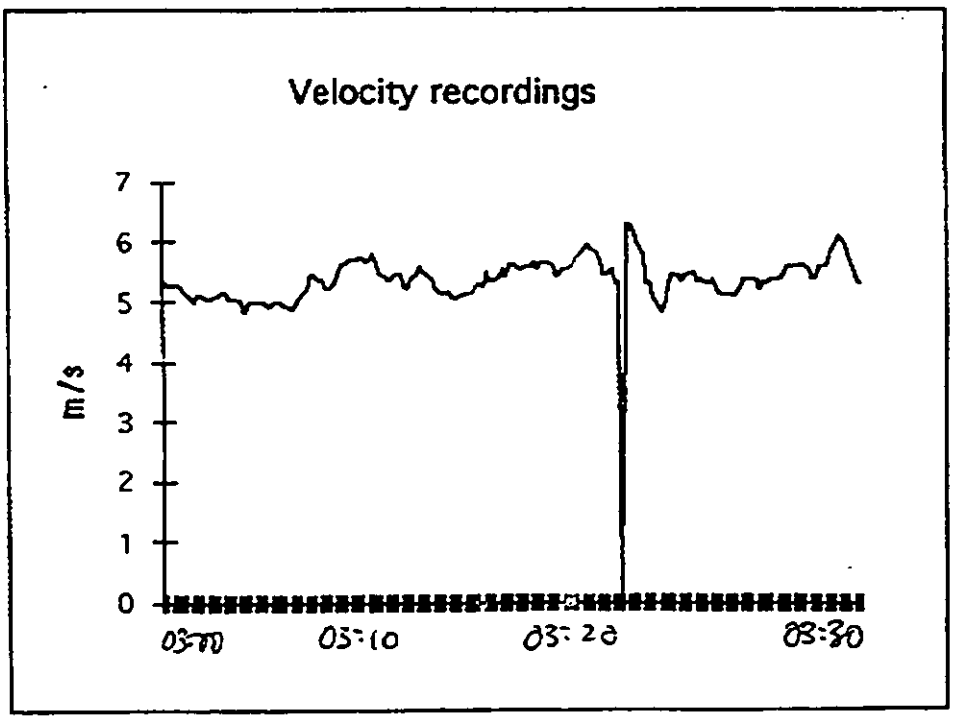
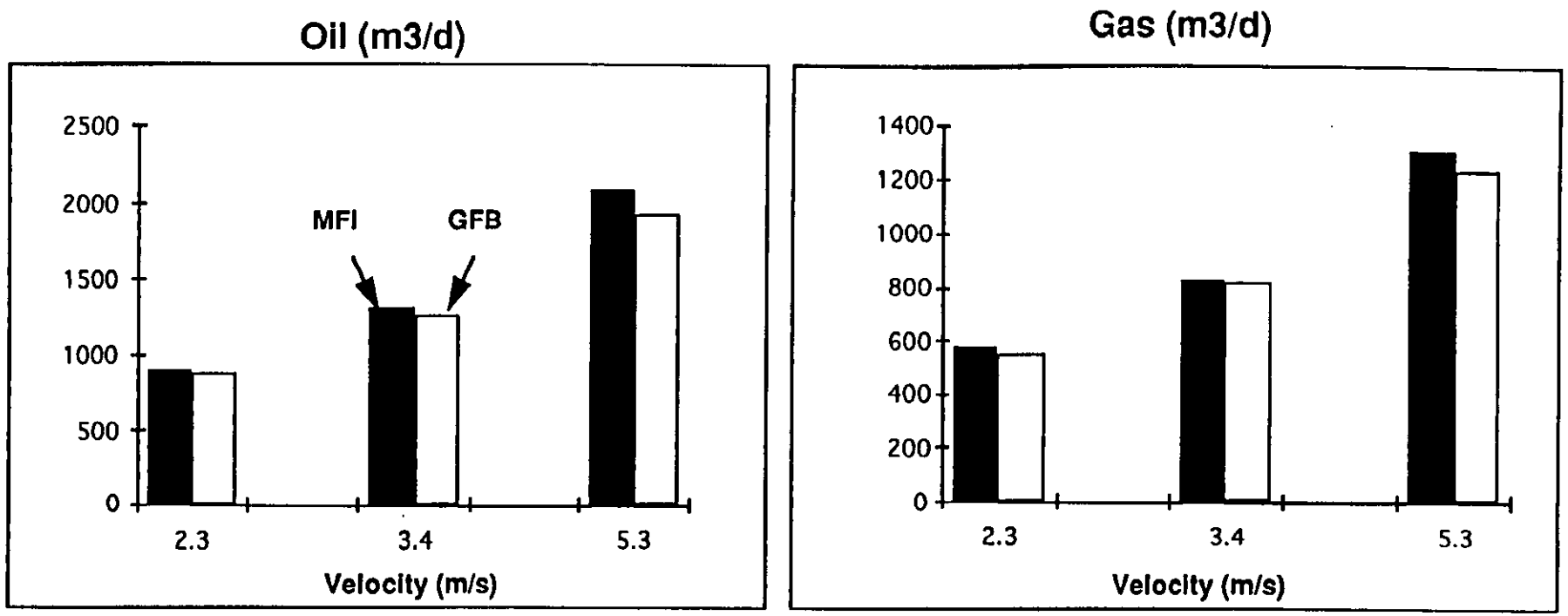


Figure 7b)

Gullfaks B - July 1993

Multirate test - Well B21



Oil fraction =61%
Gas fraction = 39%
Water fraction = 0

Pressure: 77 barg
Temperature: 64d egC

Figure 8

Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Field Experience with the Multi-capasitor Multiphase Flow Meter

by

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Field Experience with the Multi-capacitor Multiphase Flow Meter

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SUMMARY

The multi-capacitor multiphase flow meter (MCF) has been tested at three field locations covering a wide range of crude properties and process conditions. Results of the field tests show excellent repeatability, and good agreement between the MCF and reference measurements of liquid flow rates. An apparent systematic over-reading of 20% for gas flow rates in the field is currently being investigated. Calibration in the field is straightforward. Installation requirements, though not fully defined, have been shown not to be very severe, since slugging flow is stable even through complex pipework.

INTRODUCTION

The multi-capacitor flow meter, a device for measurement of flow rates in multiphase slugging flow, has been developed in a joint project between Shell Research in the Netherlands and the manufacturers (Kongsberg Offshore) in Norway, with Norske Shell as co-sponsor. The operating principle has been described elsewhere [1]. Briefly, flow rates are derived from the output of an array of capacitive sensors mounted on two plates in the flow line parallel to the flow direction. These sensors measure the cross-sectional areas of the pipe occupied by liquid and gas, the velocity of the liquid in the liquid-filled part of the pipe and the velocity of the slug passing down the pipe. On the assumption that the slugs travel at the same velocity as the gas, the flow rates are calculated from the product of the cross-sectional areas occupied by the liquid and gas and their respective velocities. The Mark 1 MCF operates with watercuts up to around 40%.

The meter has now been extensively tested in two laboratory flow loops and at three different field locations. It is the purpose of this article to describe the experience with the meter in the field, highlighting where necessary the differences encountered between laboratory and field environments.

Very little is known in detail about instantaneous flow conditions in well flow lines since production is usually measured using a test separator, which acts as a large buffer smoothing out any possible short-term fluctuations in flow rates. This complicates the selection of test sites for multiphase meters since these meters are designed for certain types of flow or ranges of steady conditions, and these requirements must then be matched to the available test-separator data, which are usually averaged over periods of 4 up to 24 hours.

One lesson drawn from the MCF field trials is that 24-hour test data can be misleading as a basis for assessing the suitability of a site as a test location – or of a meter for a given application – since the dynamics of well production are then excluded from the assessment [2].

FIELD DATA

The three field locations for the initial MCF trials were Marmul in south Oman, Ramlat Rawl in north Oman and Rabi in Gabon. These sites were selected as representing a wide range of crude characteristics and operating conditions. Marmul produces medium heavy, viscous crude, Ramlat Rawl lighter, thin crude and Rabi light, waxy crude. Table 1 summarises the oil properties and selected well test data for these fields. The operating ranges for the 3-inch and 4-inch Mark 1 MCF, based on laboratory data, are given in Appendix A. The 3-inch version was selected for the trials in Oman and the 4-inch version for Gabon.

It is generally accepted that gas-lifting can cause instabilities in well production, even at a constant gas injection rate. What is perhaps less well known is that steady beam pumping does not necessarily prevent large fluctuations in production. The wells available for testing at Marmul were all beam pumped and all showed cyclic variations in production with periods varying from well to well from 30 minutes to 2.5 hours and minimum flow rates for both oil and gas as low as zero. Figure 1 shows control-room chart recordings of gas flow rate and test separator liquid level for two typical wells under test. The cyclic nature of the production, at a frequency much higher than that of the separator's normal dump cycle, is clearly evident. At the other two locations the wells were either free-flowing or gas-lifted/assisted, and production rates were steady except for the usual day-and-night variations caused by changes in ambient temperature.

Table 1

Oil properties and typical well test data from MCF test sites

	Marmul*		Ramlat Rawl*		Rabi**		
WELL	M-23	M-50	RR-01	RR-04	RAB03	RAB76	RAB26
Gross liquid flow (m3/d)	98	106	118	232	279	460	525
Liq. superficial velocity (m/s)	0.25	0.26	0.29	0.58	0.35	0.58	0.66
Associated gas flow (st.m3/d)	1610	5073	16800	31900	16900	58300	21900
Line pressure (kPa)	200	200	900	900	600	690	700
Gas superficial velocity (m/s)	2.0	6.3	4.7	8.9	3.5	10.6	3.9
Gas volume fraction (%)	88.9	96.1	94.2	93.9	93.4	94.8	85.6
BS&W (%)	27	23	39	0	0	0	40
Dry oil density 15 °C (kg/m3)	918	922	870	870	854	854	854
Kin. viscosity 25 °C (mm^2/s)	480	610	15	15	25	25	25
Kin. viscosity 50 °C (mm^2/s)	110	150	4	4	8	8	8
Dyn. viscosity 50 °C (mPa.s)	101	138	3.5	3.5	7	7	7

* 3-inch MCF ** 4-inch MCF

REFERENCE MEASUREMENTS

A major difference between laboratory and field tests is the quality of the reference measurements. The Shell Group has considered field measurement requirements in the past and concluded that an uncertainty of ± 10% for each phase (oil, water and gas) is acceptable having regard to operational and reservoir-engineering requirements. Shell operating companies generally achieve this target, though less stringent standards can be accepted in practice for the accuracy of water and gas flow-rate metering in remote oil fields, since these phases are usually re-injected.

An analysis of field measurements using the guidelines for uncertainty calculation contained in the ISO 5167 recommendations for flow meter installations shows that a properly engineered and maintained test separator can limit the uncertainty in the flow rate to ± 5% for gross liquid flow, ± 10% for net-oil in the watercut range up to 40%, and ± 10% for gas flow, provided the orifice size is chosen to give a reading around mid-scale. These uncertainties are based on the usual practice of testing a number of different wells with different characteristics on a test separator, while using average fluid properties such as gas and liquid density and integrated values for pressures and temperature to calculate the flow rates for all wells.

The reference instruments used for the MCF field trials are given in Table 2. An orifice meter was initially used for the gas flow rates at Marmul. However, the large cyclic production fluctuations from any single well made it impossible to choose a single orifice diameter to cover the full range of gas flow rates encountered during a well test. A vortex meter with a specified rangeability of 30:1 was therefore installed instead. Even this meter could not cope with the full range of fluctuation, however. The small excursions down to zero flow beyond the lower end of the range do not, however, add substantially to the measurement uncertainty. The reference measurements for Ramlat Rawl were obtained from a gathering station connected to the remote manifold by 16 km of 8-inch diameter production flow line. In Gabon, local test-separator reference measurements and regular slugging flow - ideal for MCF evaluation - were present, but the waxy nature of the crude was also reflected in the quality of the production gas used for the pneumatic instrumentation, which caused occasional blockages and spurious measurements.

Table 2

Reference Instrumentation

Location	Liquid Gross	Watercut	Gas
Marmul	1-inch Micromotion Coriolis meter	Coriolis density measurement	1.5-inch Vortex
Ramlat Rawl*	pd meter	Hydril probe	Orifice
Rabi	2-inch OILGEAR PV meter	Manual sampling and analysis	Orifice (selected by operator)

* at gathering station 16 km away

TEST DURATION

It is another lesson of the MCF field trials that conclusions on meter accuracy cannot be based on only a limited series of measurements. Fluctuations in individual well production and uncertainties in the reference measurements both lead to the conclusion that a proper assessment of test-meter accuracy can only be obtained by testing and re-testing a large number of representative wells.

In Gabon, some 18 tests over 7 wells were required before a clear picture of the MCF performance emerged. Even this number does not allow a meaningful statistical analysis of the results that could have, for instance, revealed possible erroneous measurements. Wells producing outside the specification of the MCF were also tested to confirm the meter's operating range. The complete evaluation programme at Rabi covered almost four weeks of well testing. A total of five weeks was spent testing at Marmul. The one week spent testing the four wells at Ramlat Rawl was barely sufficient for a complete evaluation, since the lack of local reference measurements required more short- and long-term repeatability tests to be performed to demonstrate the consistency of the meter.

RESULTS

Marmul

When the Marmul 24-hour well test data are plotted on a flow map with the flow regimes superimposed (open circles in Figure 2), the flow rates appear in the slugging flow area and conditions appear very suitable for use of the MCF. However, the large flow fluctuations illustrated in Figure 1 cause the flow regime in the line to move continually in and out of slug flow. This is made worse by liquid accumulation and water separation in the low parts of the flow line during the no-flow periods, followed by violent flow of the accumulated liquid during the peak flow periods. Bubble, plug and stratified patterns have all been observed and problems with short-circuiting of the capacitive sensors by free water were also encountered during these peak flow periods.

The MCF measurements were repeatable in the absence of free water, even during operation in the bubble or stratified flow regime. In a limited number of wells, the discrepancy between MCF and test-separator measurements of both gas and liquid flow rates could be kept to within about ± 20%. However, the Mark 1 version of the MCF cannot be recommended for application under the particular process conditions found at Marmul.

Ramlat Rawl

The oil properties and steady flow conditions at Ramlat Rawl were well suited to the MCF (Figure 3). From the flow map, one of the four wells available for testing would appear to be in the annular flow regime. However, in practice all wells were found to be slugging. The flow regime at the MCF seems to be more determined by the long 6-inch flow lines than by the relatively short 3-inch metering loop.

Although a detailed comparison between MCF and reference data will not be presented here, the one-week trial of the MCF at the four Ramlat Rawl wells has shown:

- good agreement with previously known production data.
- excellent short- and long-term repeatability.
- ease of calibration on-site.
- robust hardware, which gave no problems during transport, installation or daily use exposed to the outside desert environment.
- no down time due to well testing.

The meter has remained installed at Ramlat Rawl as the only means of testing the wells there. (In addition to the four wells covered by the present study, a fifth well has since been added and a further well is due for completion some time in 1993.) A test procedure and test frequency have been agreed with local Operations to provide experience with the meter and to generate information on its long-term reliability. The Ramlat Rawl MCF was still producing good results six months after the initial installation. The meter diagnosed a rapid increase in watercut in one of the wells, which has subsequently been closed-in pending a workover.

Rabi gathering station A

In Gabon the meter was installed upstream and in series with the test separator at Rabi gathering station A. Seven wells within the range of the meter were available for testing. By listening to the flow noise in individual flow lines, one can judge whether a flow line is slugging or not. In this case, all flow lines appeared to be slugging – even the two wells shown by Figure 4 to be in the annular flow regime. This could be confirmed in one case using the MCF, but the largest producing well could not be tested because of test-separator throughput limitations.

The wells tested had a range of gross liquid flow from 120 to 740 m3/d, gas production ranged from around 5,000 to 60,000 n.m3/d (at 1 bar and 15 ºC) and watercuts from 0 to 40%. The results, illustrated in Figure 5 and listed completely in Table 3, show no systematic difference between the MCF and test-separator measurements of liquid flow rates, with an error band of ± 5% attributed to each. For gas, the MCF shows a systematic over-reading of 20% compared with the test-separator measurements, with an error band of ± 10% attributed to each. This error is thought to be caused by differences in slugging characteristics between the laboratory (short, regular slugs) and the field (long, less frequent slugs). This is being investigated further. If this difference is shown to be typical for other field installations, the error can be removed by a simple correction factor. Repeatability of the MCF measurements was at least as good as for the test separator. Wells with watercut higher than the specified 40% were also tested but, as expected, these proved to be outside the meter's operating range.

OPERATIONAL EXPERIENCE

Slugging flow

A major task during development of a flow meter based on slugging flow is determining how many flow lines actually operate in this flow regime. A short survey of selected representative well flow lines was carried out in north Oman, where the wells are either gas-lifted, gas-assisted or free-flowing. The objective was to obtain a good estimate of the percentage of flow lines likely to be slugging at the wellhead, and also at the manifold where the lower pressure gives higher gas volume fractions in the line.

Flow regimes were identified using a portable clamp-on system. Basically this system uses an accelerometer as a sensitive, selective microphone to listen to flow noise, in particular to the passage of liquid slugs.

At or near the wellhead, 10 out of the 11 flow lines visited (91 %) were found to be slugging.

A total of 30 well flow lines were surveyed at the manifold; of these, 26 (87 %) were found to be in slugging flow.

A number of other observations were made.

- Flow lines with gas volume fractions above 99%, where one would normally expect stratified or even annular mist flow, were slugging directly at the wellhead and maintained this slugging regime right up to the manifold. Either the well is functioning as a slug generator, or the slugging envelope in live crude is different from that reported for laboratory flow loops.
- Slugging appears to be stable. Once formed, slugs are maintained even on steeply descending flow lines where flow might be expected to become stratified.
- Care must be taken with acoustic survey equipment at or near manifolds. Some experience is required to distinguish flow noise from mechanical noise – and from flow noise generated in neighbouring flow lines and transmitted to the flow line under survey by mechanical coupling.

Meter calibration

The MCFs installed at Ramlat Rawl and Rabi were given the algorithms and constants determined for the laboratory flow loop. No fine tuning or adaptation to local conditions was required. Calibration requires signal levels from the individual sensor plates in both air and dry oil. The meter was calibrated at Ramlat Rawl using a purpose-built calibration rig in the shape of an inverted U-tube with the meter mounted at the bottom of the U. In this case dry oil was available from one of the wells, but this is not essential since this thin crude separates rapidly, allowing water to be tapped off until the MCF is completely filled with dry oil collecting at the bottom of the calibration rig. In Gabon, the meter was mounted at the lowest point in the flow loop. Dry oil was again available, so the meter could be calibrated simply by emptying and filling the loop while recording the MCF readings.

Wax fouling

A secondary aim of the MCF test in Gabon was to determine the effect of waxy crude on the meter. The MCF senses flow fluctuations using two vertical plates in the flow line parallel to the flow direction [1]. During the tests, these plates became coated with wax. This could be detected easily and quickly from the MCF trend signals. The standard wax-removal procedures used by Shell Gabon (heating, steam cleaning or chemical injection) were all successful in removing or preventing this build-up of wax without affecting the operation of the MCF.

Installation effects

At all three test sites the multiphase meter was mounted in a flow loop specially constructed for the test, with a straight upstream section ten metres long and a straight downstream section three metres long, each having the same diameter as the MCF. Conditions further upstream of the MCF were, of course, very different from in the laboratory. The fluids produced at each well flow through up to several kilometres of undulating 6-inch diameter flow line, then through the test header, a number of sharp bends and changes in height and (for some tests at Rabi) also through a heat exchanger before arriving at the MCF. This complex geometry might be expected to have a detrimental effect on the performance of the MCF by interfering with regular slugging flow, but no such effects were observed in practice.

The minimum installation requirements for the MCF still have to be determined, but they are clearly less severe than originally thought in view of the observed stability of the slugging flow regime.

DISCUSSION

The Mark 1 MCF tested at Ramlat Rawl will remain installed as the only means of testing the remote wells at this location. Operational experience is being fed back to both Shell Research and the manufacturers (Kongsberg Offshore) to help in the continuing development of these meters. A number of other applications are being considered for the Mark 1 MCF, mainly for installation at manifolds in order to remove test-separator-related bottlenecks. These applications will generate the experience and confidence needed for installation of the MCF in individual flow lines – the original target of multiphase meter development.

Another Shell Group operating company now considers the MCF as a real option for the development of a satellite field some 20 km from existing processing facilities. A decision on how to proceed will be taken this year. This company is also keen to evaluate the next version of the MCF, which will be designed to cope with higher watercuts. This Mark 2 meter is a candidate for application in the further development of an existing onshore field in 1995.

The development of the Mark 2 MCF is proceeding on schedule. This new version aims at metering gas and liquid flow rates across the full range of watercuts. The first prototypes were ready in August 1993 for testing and refining in the laboratory. A field test of this new MCF is planned in Nigeria when laboratory testing is complete. Continuing developments are targeted at adding watercut measurement in water-

external emulsions, extending the operating range to neighbouring flow regimes and producing a subsea version of the meter.

REFERENCES

[1] D. Brown, J.J. den Boer and G. Washington: "A multi-capacitor multiphase flow meter for slugging flow," The North Sea Flow Measurement Workshop, October 1992.

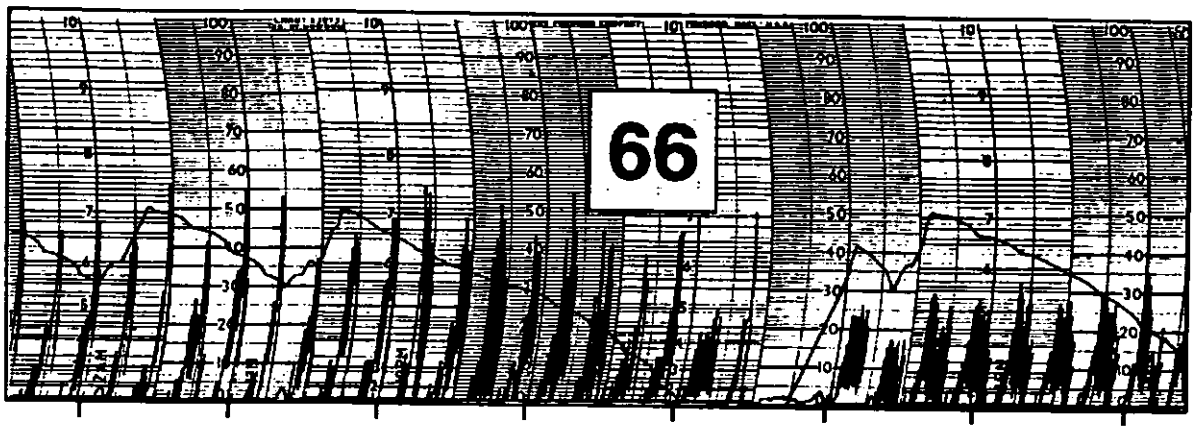
[2] C.J.M. Wolff: "The required operating envelope of multiphase flowmeters for oil production measurement," The North Sea Flow Measurement Workshop, October 1993.

APPENDIX A: The operating ranges for the Mark 1 MCF

The MCF depends on intermittent flow for its operation. On the basis of experience in the Shell Research multiphase test loop, the approximate operating ranges for the 3-inch and 4-inch Mark 1 versions are:

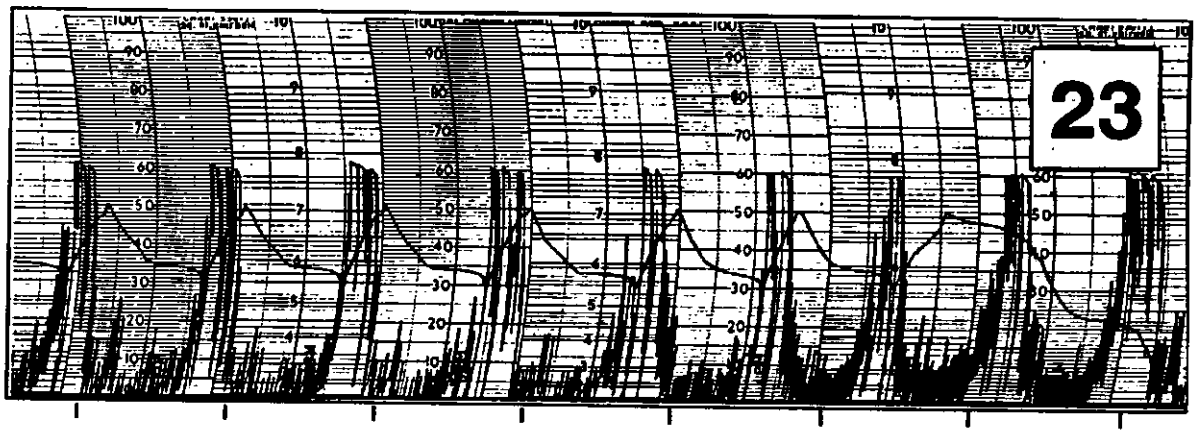
3 inch	LIQUID	60 - 800 m^3/day
	WATERCUT	0 - 40 %
	GAS	450 - 6500 actual m^3/day, (line conditions)
4 inch	LIQUID	120 - 1600 m^3/day
	WATERCUT	0 - 40 %
	GAS	800 - 12000 actual m^3/day, (line conditions)

(a)



Hours

(b)



Hours

Figure 1 Test-separator chart recordings for Marmul Wells MM66 (a) and MM23 (b). In each chart, the high-frequency trace represents the gas flow rate measured at the separator outlet, while the low-frequency trace shows the liquid level in the separator as a function of time. The separator works on a dump cycle between 50% and 30% full. The slope of the latter trace is roughly equal to the liquid flow rate, since the effect of tank rounding in the liquid-level range covered is slight. The apparent time shift between low liquid flow and low gas flow, seen most clearly in the chart for Well MM23, is an artefact due to displacement of the recording pens. The time between successive peaks for Well MM23 is approximately 1 hour. The chart for Well MM66 shows more frequent peaks, approximately four per hour, and also includes a test stop (full dump) and start sequence clearly seen on the liquid level trace. Actual flow rates could be estimated from these recordings, but are not required to illustrate the fluctuations in well production.

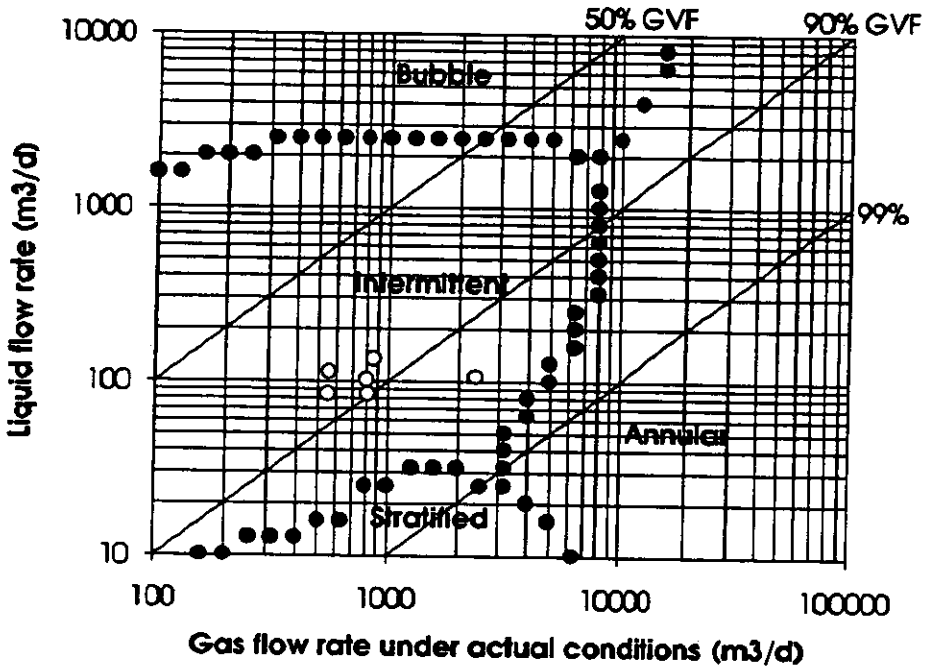


Figure 2 Flow regimes in Marmul 3-inch flow line

The boundaries between the different flow regimes are calculated with the aid of software developed at Shell Research Amsterdam, after input of the relevant operating parameters (in the present case: oil density=920 kg/m3, oil viscosity=200 mPa.s (40 C), line pressure=200 Kpa). Each open circle in this graph represents 24 hour average gas and liquid flow rates derived from routine production monitoring. **Intermittent** includes both slug and elongated bubble (plug) flow regimes.

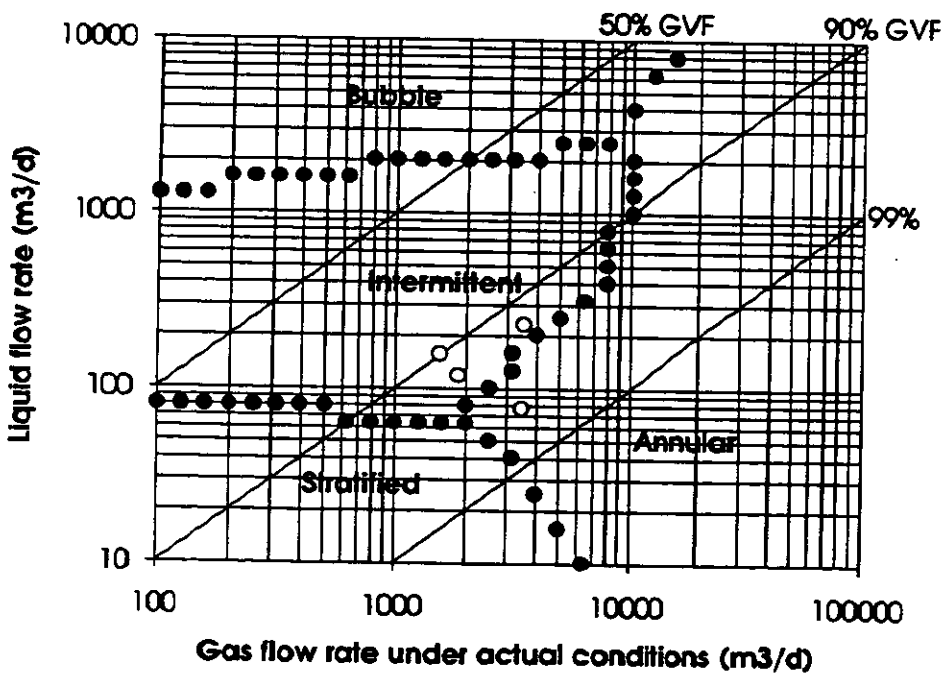


Figure 3 Flow regimes in Ramlat Rawl 3-inch flow line

Operating parameters: oil density=870 kg/m3, oil viscosity=6 mPa.s (40 C), line pressure=900 kPa. Other details as in Figure 2.

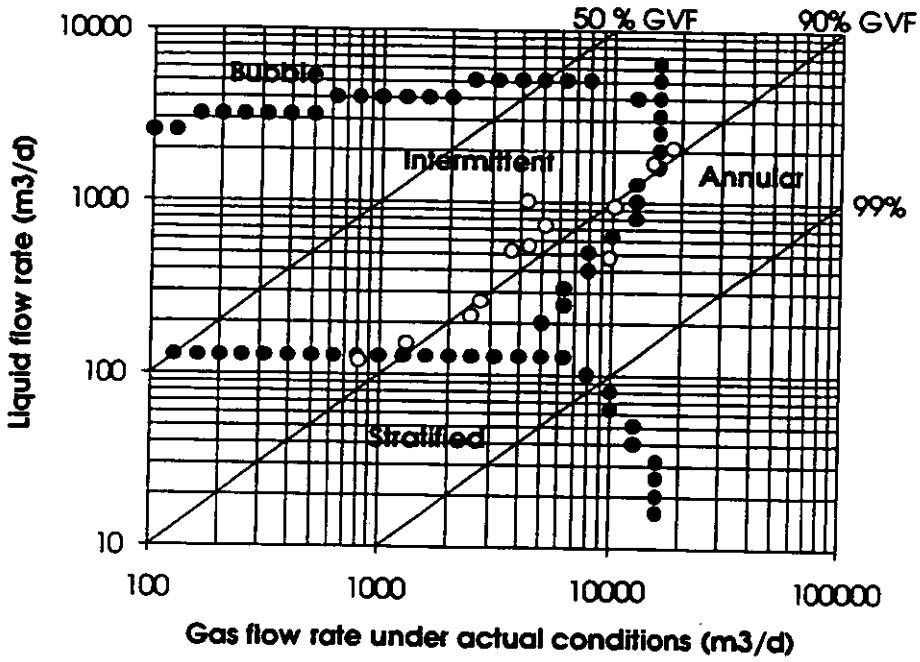


Figure 4 Flow regimes in Rabi 4-inch flow line

Operating parameters: oil density=854 kg/m3, oil viscosity=10 mPa.s (40 C), line pressure=600 kPa. Other details as in Figure 2.

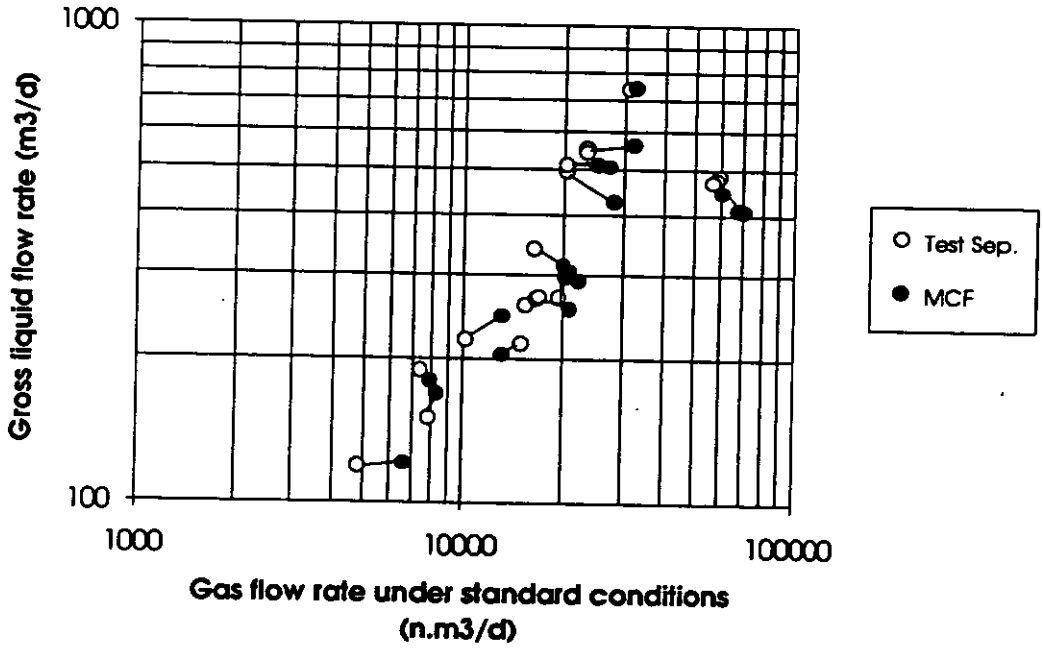


Figure 5 Results of MCF field trial in Rabi 4-inch flow line

Corresponding test-separator and MCF measurement points are joined by a tie-line.

The liquid flow-rate measurements show no systematic difference between MCF and test separator, and an error band of +/- 5% for both.The gas flow-rate measurements show a systematic difference between MCF and test separator of +20% (to be studied further), and an error band of +/- 10% for both.

Table 3

Results of MCF Field Trial in Gabon

	MCF readings				Test-separator readings				Difference	
Well ID	Liq. m3/d	Gas n.m3/d	W.C. %	GOR n.m3/m3	Liq. m3/d	Gas n.m3/d	W.C. %	GOR n.m3/m3	Liq %	Gas %
03-1	304	20870	0	69	268	19480	0	73	13	7
03-2	296	20360	0	69	259	15350	0	59	14	33
03-3	291	22340	0	77	266	16570	0	62	9	35
03-4	254	21040	0	83	269	16820	0	63	-6	25
03-5	313	20130	0	83	339	16310	0	48	-8	23
04-2	121	6680	0	55	119	4840	0	41	2	38
06-2	169	8330	0	49	151	7820	0	52	12	7
06-3	245	13080	0	53	219	10200	0	47	12	28
33-1	180	7930	2	44	189	7390	0	39	-5	7
33-2	740	32650	0	44	733	31150	0	43	1	5
62-1	204	13170	8	65	215	15000	6	70	-5	-12
76-1	445	60900	0	137	481	59800	0	129	-7	2
76-2	408	70600	0	173	474	58960	0	124	-14	20
76-3	410	67900	0	166	468	56700	0	121	-12	20
26-2	504	27360	40	90	553	23400	40	71	-9	17
26-3	562	32200	42	99	540	23600	40	73	4	36
26-4	426	28260	38	107	493	20300	40	69	-13	39
26-5	510	25200	43	87	509	20400	40	67	0	23
								Average	0	+20
								Standard deviation	± 8	±14

W.C. = watercut GOR = gas/oil ratio

Liquid flow-rate measurements show no systematic difference between MCF and test-separator results, and an error band of ± 5% for each.

Gas flow-rate measurements show a systematic difference between MCF and test-separator results of + 20% (to be further investigated), and an error band of ± 10% for each.

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NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

The performance of the Fluenta MPFM 900 phase fraction meter

by

Mr. B.C. Millington,
NEL-Scotland

THE PERFORMANCE OF THE FLUENTA MPFM 900 PHASE FRACTION METER

B C Millington (NEL), K Frantzen (Fluenta) and M Marshall (Amerada Hess)

ABSTRACT

The purpose of the evaluation performed by NEL was to give Amerada Hess an independent and critical evaluation of the performance of the MPFM 900 prior to further investment in the MPFM 1900 multiphase flowmeter.

Whilst some of the early findings were unfavourable for totally unexpected reasons, the laboratory trials eventually proved to be highly successful. The instrument met the claimed uncertainty figures of 3 per cent on phase fraction over the entire test envelope.

A similar evaluation of the MPFM 1900 is presently in progress at NEL, prior to an offshore trial and then marinisation. The results of the NEL work will be presented in 1994.

1 INTRODUCTION

As part of the development of a multiphase flowmeter system for Amerada Hess's North Sea operations, the Fluenta multiphase fraction meter was evaluated at NEL in 1992. Since the phase fraction measurement is the most challenging part of multiphase metering, this work was seen as a necessary prelude to evaluating the MPFM 1900 multiphase flowmeter.

The MPFM 900 is a full-bore, non-invasive instrument which uses two fundamental measurements associated with the fluid properties: a measurement of the capacitance of the liquid to determine the water cut and a measurement of gamma ray absorption across the pipe diameter. In combination, these two measurements allow the phase fractions of oil, water and gas to be determined.

The purpose of the evaluation was to critically examine the claimed performance figures over a range of flow compositions, flow velocities and installation conditions. It will be seen that some important conclusions resulted.

2 THE TEST FACILITY

The instrument was installed in one of the multiphase flow facilities at NEL, see Figs 1 and 2. The water cut was set by adding the desired amount of water to the oil held in the main tank, and as such the nominal water content was fixed until the next addition or subtraction of water. Since the mixing within the tank was to some degree a function of the bypass flowrate, the test section water content was actually determined by abstracting a continuous sample from the liquid entering the test section. The sample flow passed through a Schlumberger densitometer and from the density readings the true water cut was obtained. During the test runs the density readings for a particular condition were stable to within a 5 kgm^{-3} range.

The liquid flowrate was determined by a turbine meter calibrated over a range of viscosities to allow for the viscosity variation as the water content changed. The gaseous phase was air, which was metered with a turbine meter of appropriate size from a set of three. From these measurements the volumetric phase fractions were determined. In addition, because the MPFM 900 measured the area-based phase fraction due to the operational characteristics of the gamma densitometer, a second gamma meter was installed to provide a reference area-based phase fraction measurement.

The initial test runs were performed using a refined oil, similar to kerosine, but with a viscosity of 7 cSt at 20°C. However, for reasons explained in Section 3 the oil was changed during the evaluation.

3 INITIAL RESULTS

The instrument was installed and commissioned using low water content mixtures and gave no indications of the rather unusual performance that was to follow.

On increasing the water cut to just over 20 per cent, the phase fraction measurements, notably the water and oil fractions, became highly dependent upon the liquid flowrate. Figs 3 and 4 illustrate the variation in phase fraction readings for an identical flow composition and installation, the only change between the graphs being an increase in liquid flowrate from 10 l/s to 20 l/s.

This problem was examined extensively using varying water cuts and flowrates and, for all instances were this increase in phase fraction was noted, the following were concluded:

a Liquid flowrate was the dominant parameter;

b On reducing the liquid flowrate below the apparent threshold value, the change in the MPFM 900 readings was sudden, usually taking no more than 5 seconds to move from the previous stable value to the new stable value.

There was much debate about mixing and whether the water was separating prior to reaching the instrument, and some tests were performed using jet mixing immediately upstream of the MPFM 900. The mixing had limited effects, and in view of (b) this was perhaps not unexpected: it would have been virtually impossible for the characteristics of the water droplet distribution to change so radically in 5 seconds.

Attention was therefore focused on the MPFM 900's capacitance sensor in relation to the characteristics of the oil/water mixture. Clearly the capacitance sensor was shorting out, hence the high water readings, and in view of the flowrate dependency it seemed feasible that water might be building up on the sensor walls. It was further believed that as the liquid flowrate increased, the water build-up was reduced until, at a critical flowrate, the sensor was no longer being shorted out. Beyond this critical liquid flowrate the MPFM 900 operated correctly.

After much analysis of oil/water samples, a very clear conclusion was drawn by the extremely simple method of shaking mixtures in bottles made from glass and polythene. Unlike virtually all the other oil/water combinations tested, the NEL refined oil and water promoted the adherence of water droplets on a surface similar in nature to the ceramic liner in the MPFM 900.

After a change of oil the instrument performed well, but this episode had created major doubts about the application of the meter for production well monitoring where the oil/water mixes would be of relatively unknown characteristics. These doubts were reinforced when offshore trials of the MPFM 900 in the Norwegian sector gave very similar results to the NEL findings. Fluenta therefore spent considerable time and effort investigating this problem further, taking advice from Bergen University, and it was eventually concluded that under certain conditions the ceramic liner was hydrophilic.

The <u>liners are now made from borosilicate</u>, and it should be made very clear that no such problems are now experienced, but for all would-be manufacturers of multiphase flowmeters, this is a very important example of how even simple design features can seriously influence performance.

4 EVALUATION WITH NEW OIL

The oil was changed to Shell Vitrea 9 and no trace of the difficulties described in Section 3 were evident. The evaluation therefore proceeded and a selection of the graphs produced are shown in Figs 5-9. Note that the Y-axis is given in absolute terms because the fraction measurements themselves were in percentage format.

In terms of phase fractions, Fig 5 and Fig 6 show the instrument to have been within 3 per cent of the reference measurement system which provided area-based data. As expected, the instrument gave incorrect readings at water cuts above 38 per cent, so the graphs of Fig 5 and Fig 6 represent the lower and upper bands of water content. The change to water continuous mixtures has been addressed in the most recent MPFM 1900 instruments which use both capacitance and inductance to cover the entire water content range.

It is interesting to compare Figs 5 and 6 with Figs 7 and 8 which were taken at identical flow conditions, in fact during the same test runs. Figs 7 and 8 used the reference flowmeters to derive the phase fractions, ie volume-based reference measurements. Agreement was reasonable at low gas fractions, but as the gas fraction increased the area-based measurements of gas fraction were significantly lower than the equivalent volume-based measurements. Gas-liquid slippage was therefore occurring, with the gas flowing faster than the liquid, but over a smaller area of the pipe cross-section (ie to maintain continuity). This is to be expected in vertical upward gas/liquid flow, but it ought to be noted that with the MPFM 900 installed 10D downstream of the blind 'Tee' rather than 5D downstream, the same slippage effects were not as prevalent. Installation position did therefore influence the area-based phase fraction measurements from the MPFM 900.

Other tests to determine instrument stability and repeatability were performed and both showed the instrument to be within the claimed specification. A temperature dependency was observed on this particular instrument, see Fig 9, which Fluenta have since corrected.

5 CONCLUSIONS

There were two major findings from the work. Firstly, the performance of the MPFM 900 with a ceramic liner was dependent upon the chemical characteristics of the oil/water mixture. A conclusion confirmed by subsequent independent trials in Norway. The liner has since been changed to borosilicate to eliminate this problem.

Secondly, after changing the oil to one that did not promote the hydrophilic nature of the ceramic, the (percentage) phase fraction measurements were always within 3 per cent of the reference (percentage) phase fractions. This was for gas fractions up to 70 per cent by volume, water cuts in the range 0-40 per cent, and for liquid flowrates in the range 5-25 l/s.

The instrument was considered to have passed the first stage evaluation, and work is now in progress at NEL on the MPFM 1900 multiphase flowmeter. The results will be reported in 1994.

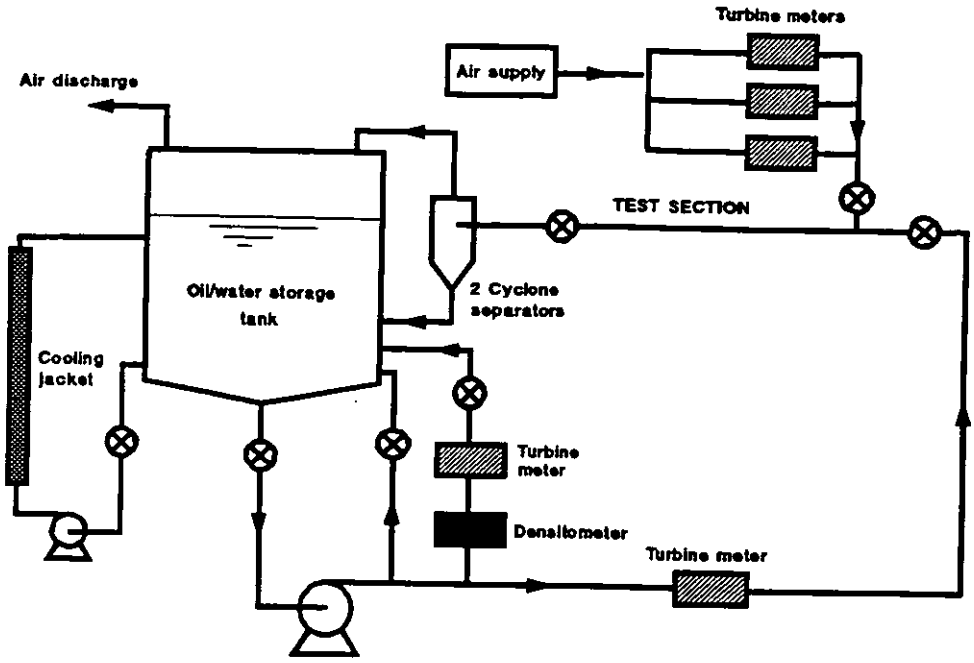

Fig 1 The test facility used for the evaluation

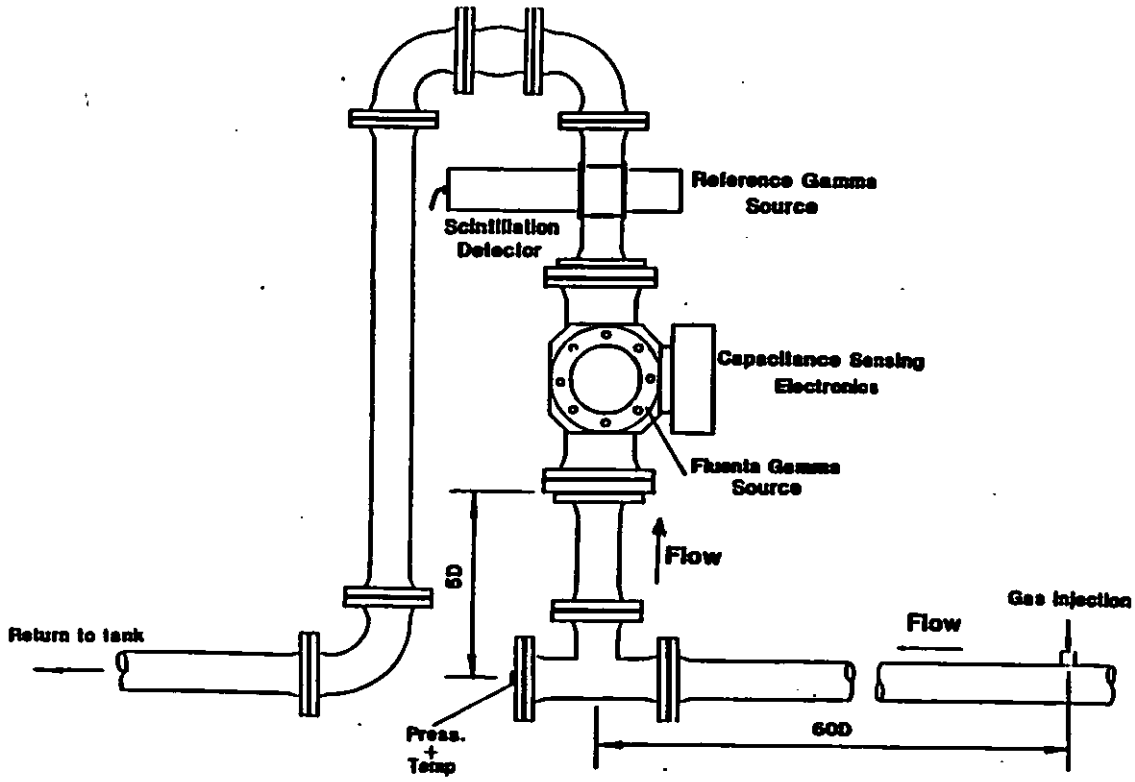

Fig 2 The test section configuration

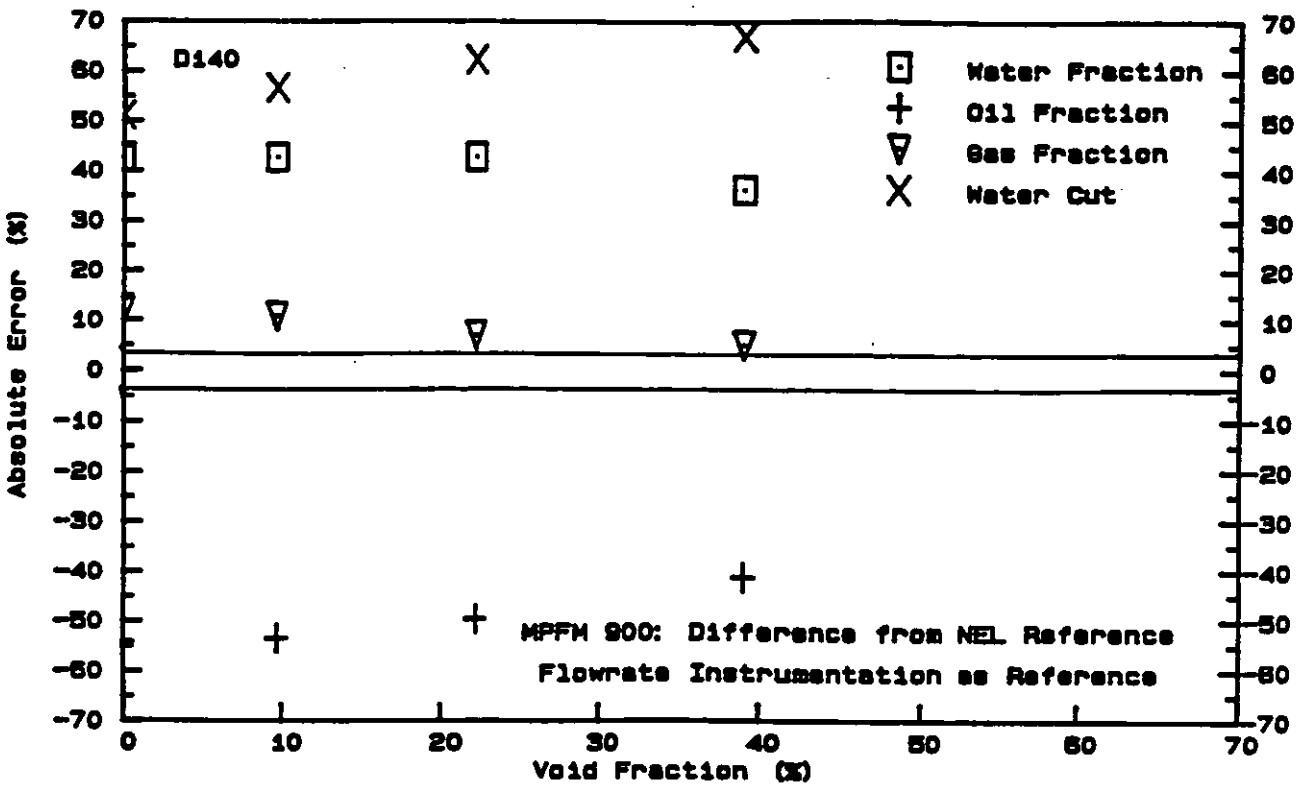

Fig 3 Initial testing with 23 per cent water at 10 l/s
(NB oil subsequently changed)

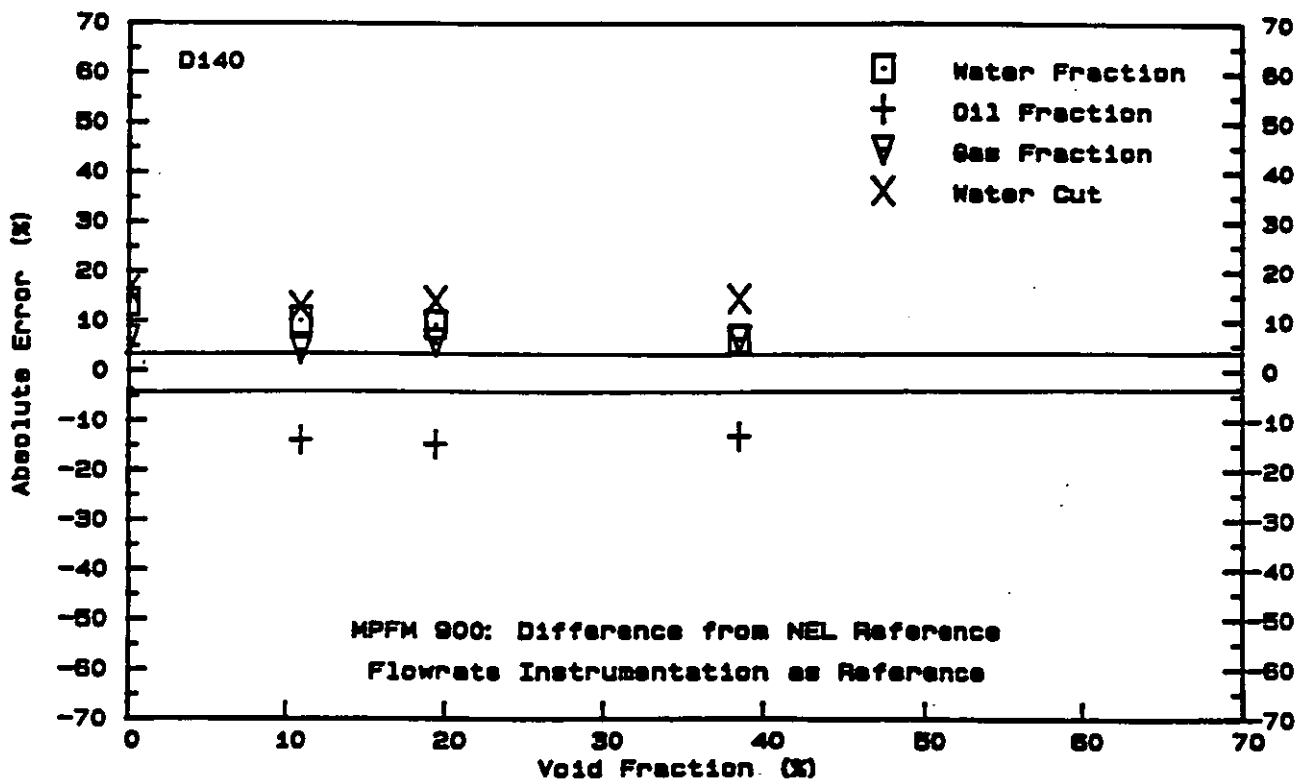

Fig 4 Initial testing at 23 per cent water at 20 l/s
(NB oil subsequently changed)

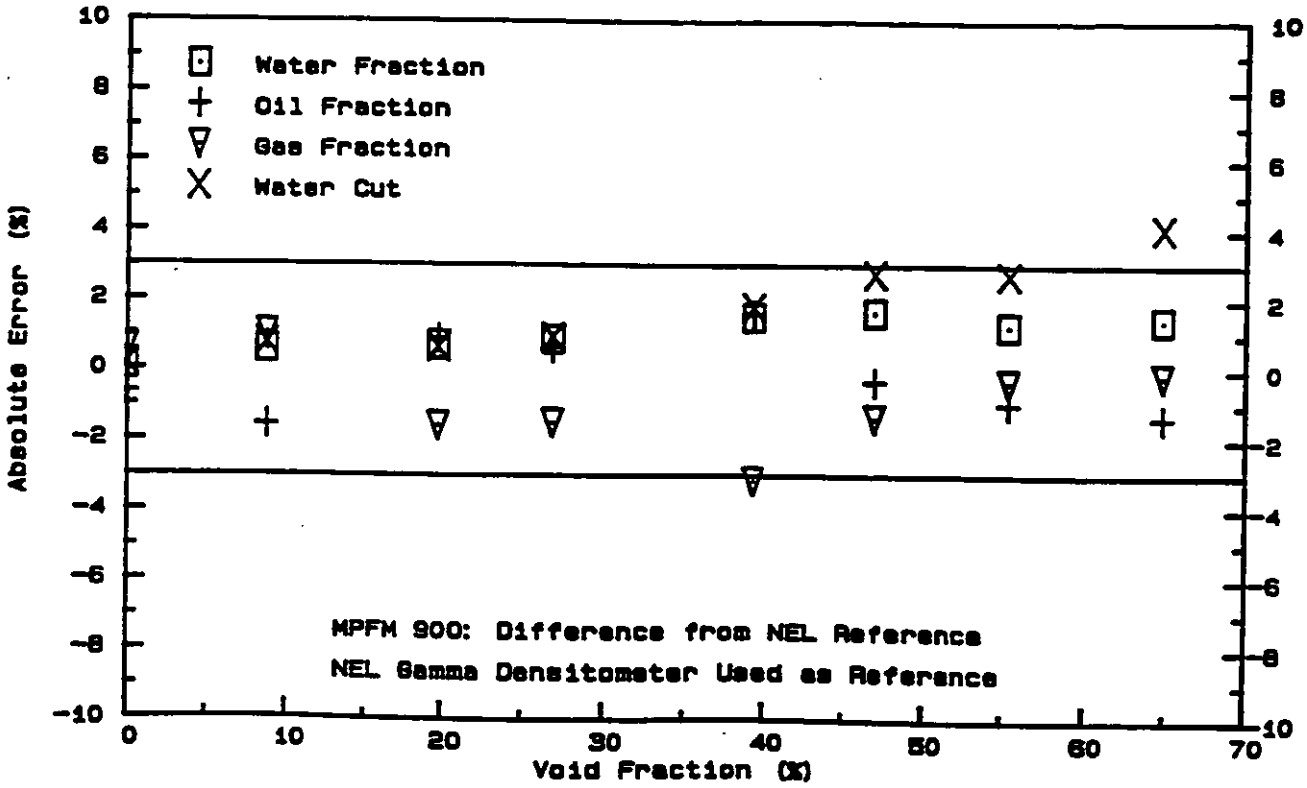

Fig 5 Performance with 10 per cent water at 10 l/s
(Area-based reference measurements)

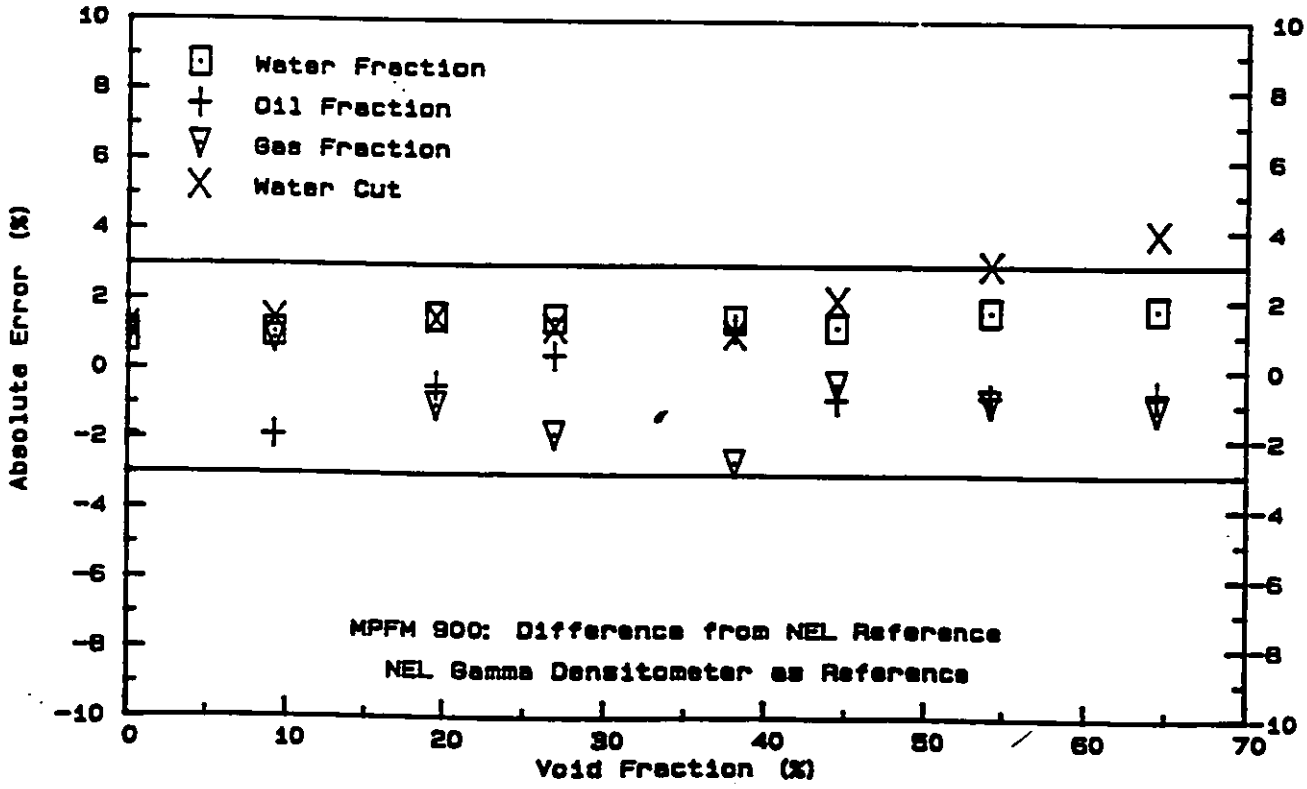

Fig 6 Performance with 30 per cent water at 10 l/s
(Area-based reference measurements)

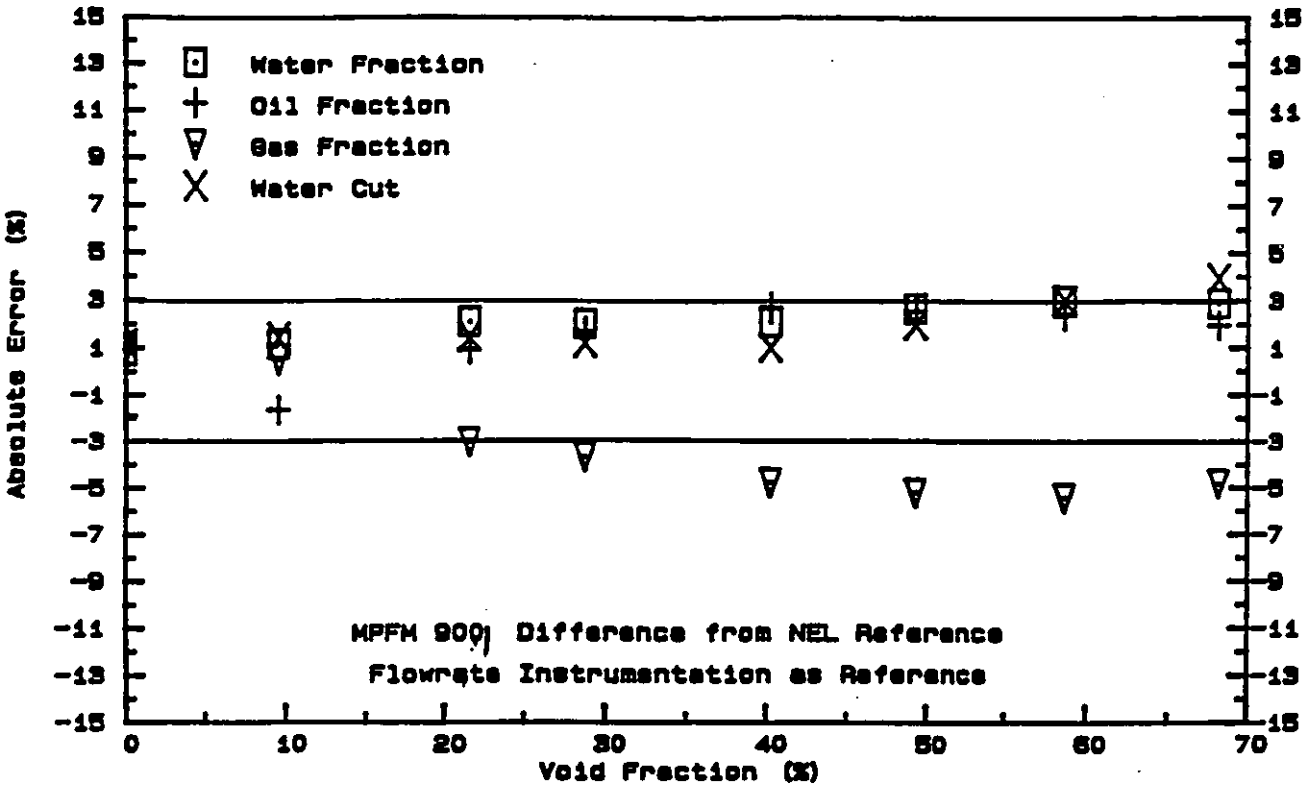

Fig 7 Performance with 10 per cent water at 10 l/s
(Volume-based reference measurements)

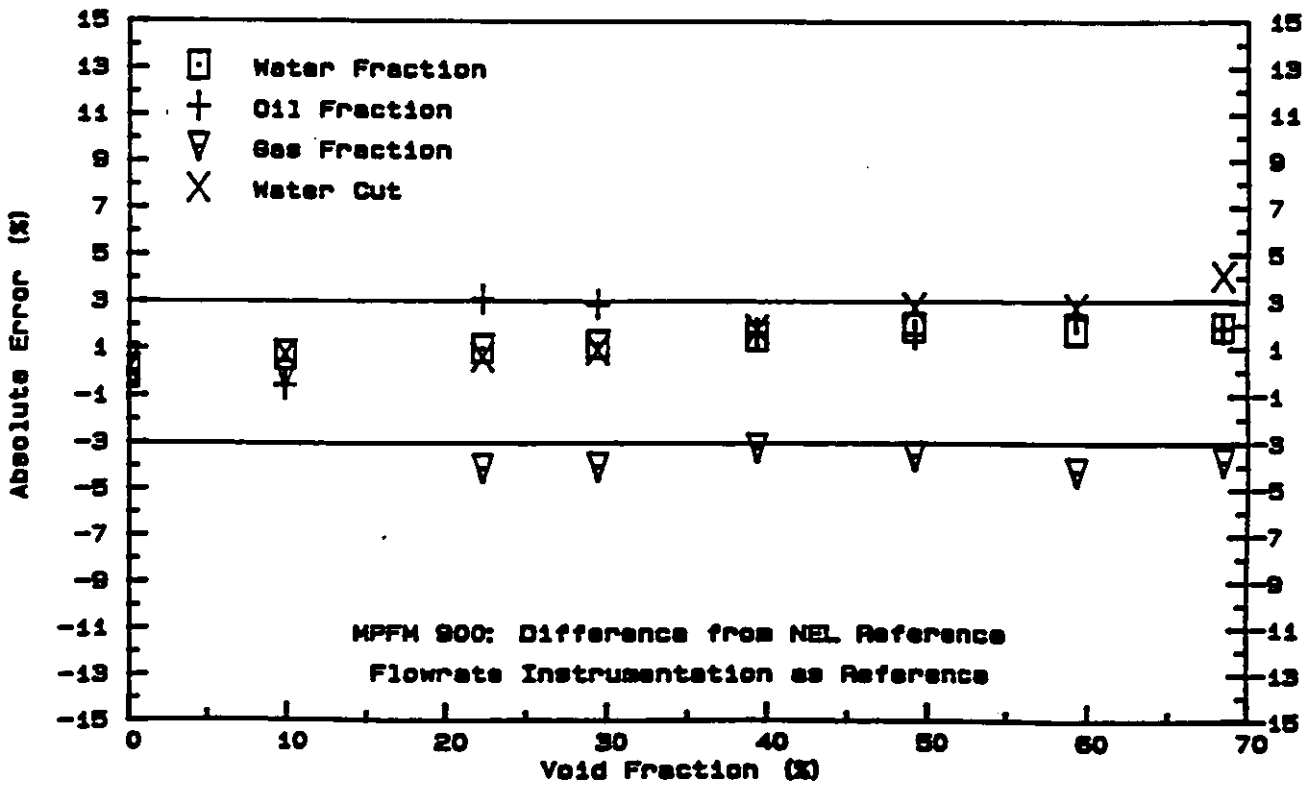

Fig 8 Performance with 10 per cent water at 10 l/s
(Volume-based reference measurements)

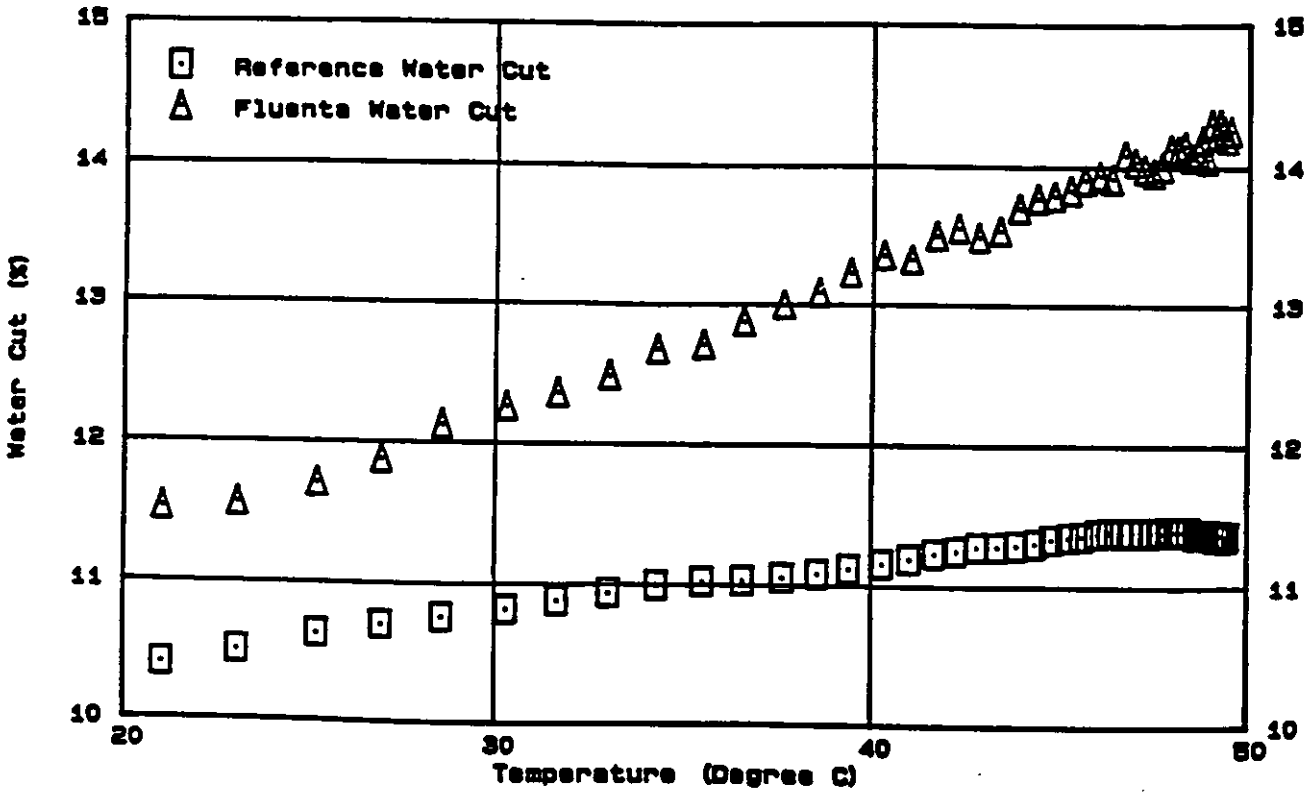

Fig 9 The effect of temperature on water cut measurements

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NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Meter Calibration under Simulated Process Conditions

by

Mr. Hans Berentsen, Statoil a.s, Norway
and
Mr. John M. Eide, Con-Tech A/S, Norway

Meter Calibration under Simulated Process Conditions

by

Hans Berentsen, Statoil a.s and John M. Eide, Con-Tech a/s

INTRODUCTION

Con-Tech a/s is an independent Norwegian company, established in 1985, which have specialised on services within fiscal flow measurement of oil and gas.
In 1991 we established a subsidiary company, Con-Tech UK Ltd, in Aberdeen. Both companies offer the same scope of services.

In 1991 Con-Tech a/s was accredited, by Norwegian Accreditation, for calibration of Pipe Provers over 500 litres with an best uncertainty of ± 0,030%. Equipment to be used for this accredited work is our Compact Prover and Master Meter.

In 1992 we was approached by Statoil with a request for our interest to participate in a evaluation test of Coriolis Meters and to set up a calibration laboratory for this purpose.
The design specification was agreed to be as follows:

- Hydrocarbons to be used as calibration liquids
- Multiple storage tanks for various qualities
- 0 - 400 m^3 / hour as range of flowrates
- 0 - 100 barg pressure range
- 20 - 85 °C temperature range
- Due to the use of hydrocarbons all electrical equipment must be Eex
- Real time data acquisition and computations

In January 1993, 6 months delayed, all equipment was installed and commissioned and the test programme started.

CALIBRATION SET-UP

The calibration loop consists of 3 parallel streams connected to a inlet and outlet header. One stream is 6" maximum and 2 streams is 4" maximum. Each stream have a double block and bleed inlet valve, space for installing a Coriolis Mass Meter (CMM), adjustable points for support, pressure taps before and after CMM, turbine meter with meter run, pressure and temperature transmitters, location for insertion densitometer and outlet flow control valve. Dual Schlumberger Oil Densitometers are located downstream of the outlet header with one pressure and two temperature transmitters. Further downstream is the takeoff to the heat exchangers with a bypass flow control valve. Next comes the variable speed circulation pump before the liquid enters the Compact Prover.
The tie-in for liquid filling and pressurisation is also upstream of the pump.

Signals from CMM's, turbine meters, densitometers, pressure and temperature transmitters are all connected to the Siemens Sicomp process machine. Temperature and pressure on the Compact Prover are logged manually.

The VDU presentation consists of, for every stream, temperature, pressure, volumetric flow rate, mass flow rate from CMM, calculated mass flow rate from reference, density and density temperature and pressure.

The process machine software also have a feature for data sampling and averaging, sampling time selectable by operator.

All data collected during a sampling period can be transferred to the PC for presentation in engineering units. This data file is transferred to a calculation program, developed by Con-Tech, and manually logged data is also entered here.

This calculation program converts Compact Prover volume, volume displaced during meter calibration and density to the conditions at the turbine meter. Hence the calculated accumulated mass or mass flowrate will be at turbine meter conditions and this data is compared to the accumulated mass or mass flowrate from the coriolis meter under test. The density output from the CMM is also compared to our reference densitometers.

As an extra verification of the density, a oil sample is drawn during a test and sent to a laboratory for density and viscosity determination.

Coefficients for oil thermal expansion and compressibility is determined by varying temperature and pressure and then calculate density changes per deg. C and barg. This is checked in the operating range.

CALIBRATION OF GULLFAKS "B" METER RIG.

The Gullfaks "B" Meter Rig is designed to meter unstabilized crude oil coming from the platforms test separator. The Meter Rig will also be used as reference for testing of Multiphase Meters which will be located upstream of the test separator.

The Gullfaks "B" meter rig comprises a 4" Daniel turbine meter with a 3" Micromotion Mass Meter in series. It then splits into two lines where one line have a 2" Schlumberger Mass Meter and the other a water cut meter. There is also provisions for installing an insertion densitometer.

Valve arrangement is such that the 2" Schlumberger Mass Meter or the water meter can be isolated from the oil flow.

The test set-up for these meters and calibration rig was that Gullfaks "B" crude oil entered the Compact Prover from the pump and through a 4" pipe to the GFB rig inlet. The two outlets were routed through a 6" pipe to our metering streams and heaters / coolers.

Temperature and pressure were recorded at GFB rig inlet and outlet. Mass Meter Density signals interfaced through their flow computers to our process machine. Turbine Meter signal interfaced to our Compact Prover Computer and process machine. Temperature and pressure on the Compact Prover were logged manually. Due to interface limitations mass flowrate was read of the instrument's flow computer.

The test programme was set up to be a 5 point calibration over the meters range, or the range achieved with a maximum of 2 bar differential pressure and with the following pressure and temperature conditions:

60 barg and 50 °C
60 barg and 60 °C
70 barg and 50 °C
70 barg and 60 °C

The mass meters was also calibrated on a very low rate of 4 tonnes / hour.
Calibration on every rate and condition should be repeated 3 times.
Zero flow to be monitored for every change in pressure/temperature, but not adjusted.
After completed calibration the CMM's calibration factor should be recalculated and a verification calibration done on one condition, at 3 flowrates.

This all added up to 75 calibration points for each of the CMM's and at least 500 single calibrations of the turbine meter.

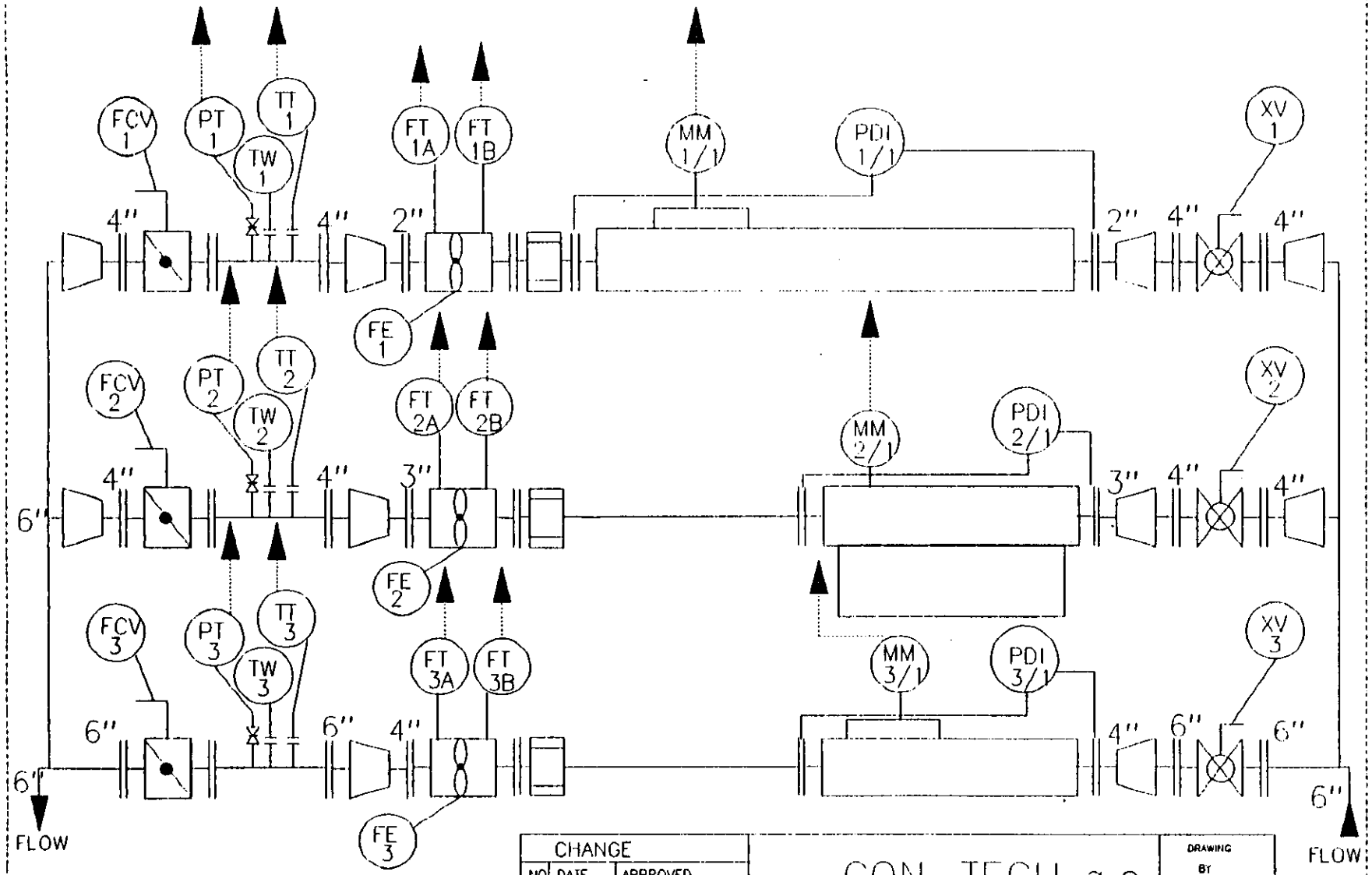
CALIBRATION RESULTS.

Daniel Industries 4" Turbine Meter. (Fig. 1)

The turbine meter is calibrated directly against our Compact Prover.
The curves are drawn with reference to the meter factor obtained in the factory water calibration.
Every point is the average of 25 single calibrations with a repeatability of < 0,025%.
The flowrate through the turbine was maximum 130 m^3/hr due to loop pressure drop.
The meter factor is 1,5% lower than the factory calibrated meter factor, when metering crude oil.
Temperature sensitive at 70 barg and at the lower flow rates.
Meter linearity at 50C/70bar is ± 0,6 %.
Not able to trace down reasons for change in meter factor on 50C/70bar, lower rates. The 2" Brooks Reference Meter gave similar results.

Micro Motion 3" Coriolis Mass Meter. (Fig. 2)

Maximum flowrate 112 tonne/hour with 2 bar pressure drop. Density 0,874 kg/l, viscosity 7,4 cSt/40C.
The curves are drawn with reference to calculated mass flowrate from our calibration equipment, rate averaged over 5 minutes.
Repeatability on 3 tests < 0,1%.
Our master meter, 4" or 2" Brooks Turbine Meter, was calibrated against the Compact Prover just prior to comparison test, repeatability better than 0,020%, minimum 25 single calibrations.
Displayed rate is 1,5% lower than factory calibration, when metering crude oil.
No obvious sensitivity to varying pressure or temperature.
All points within a range of ± 0,55%. Linearity at 60C/60barg ± 0,35%.
Verification test gave results within 0,05% of expected.



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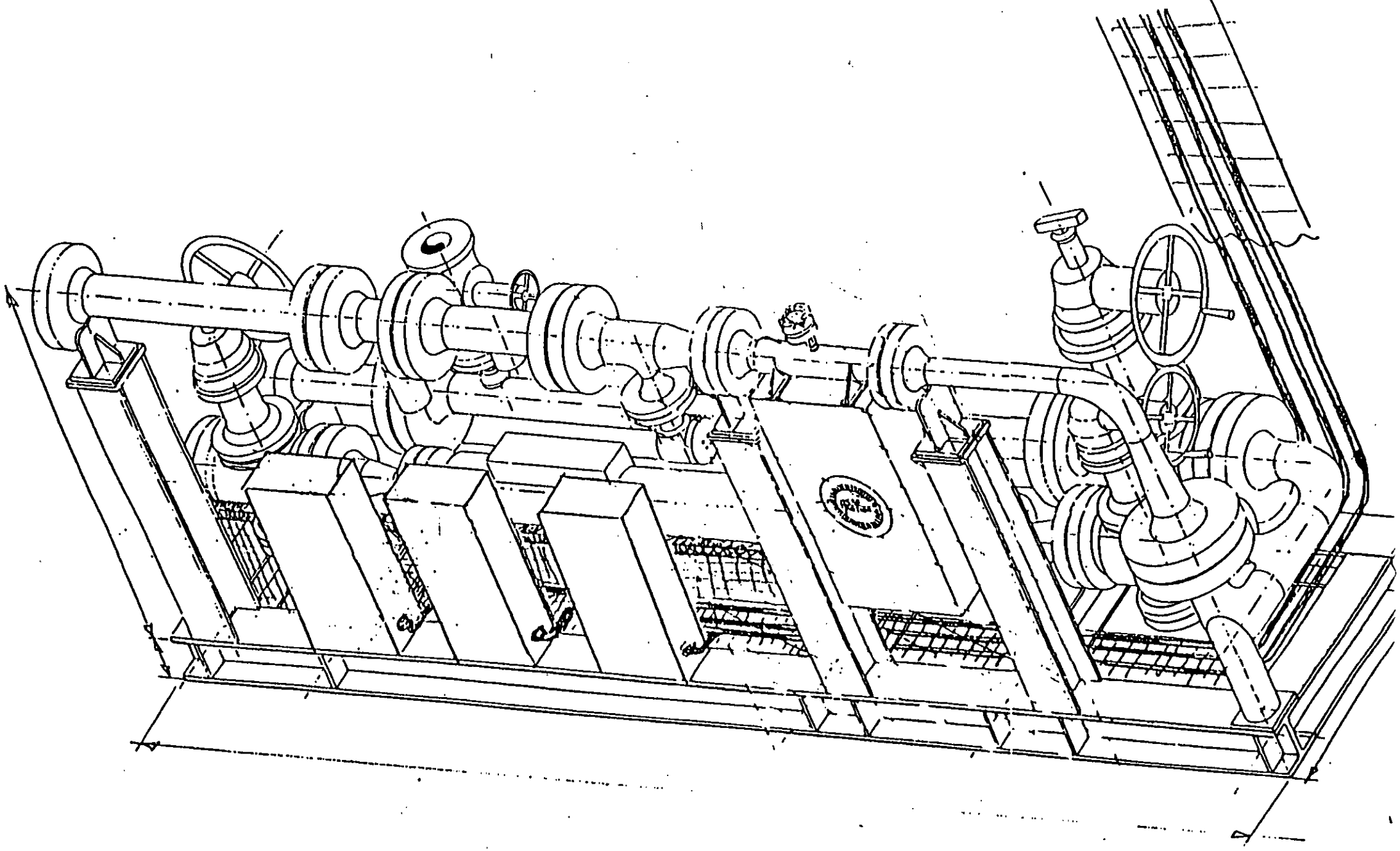

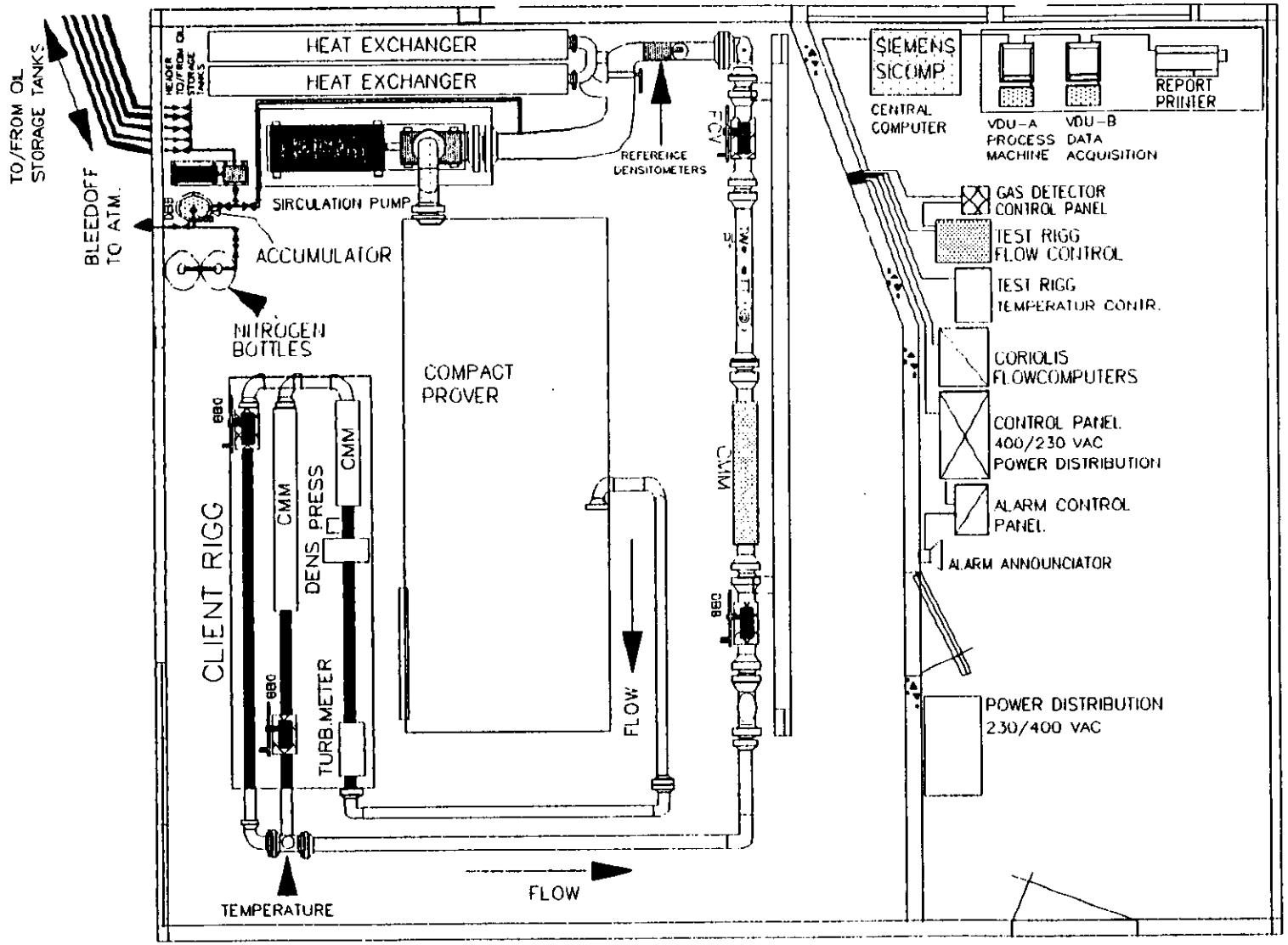

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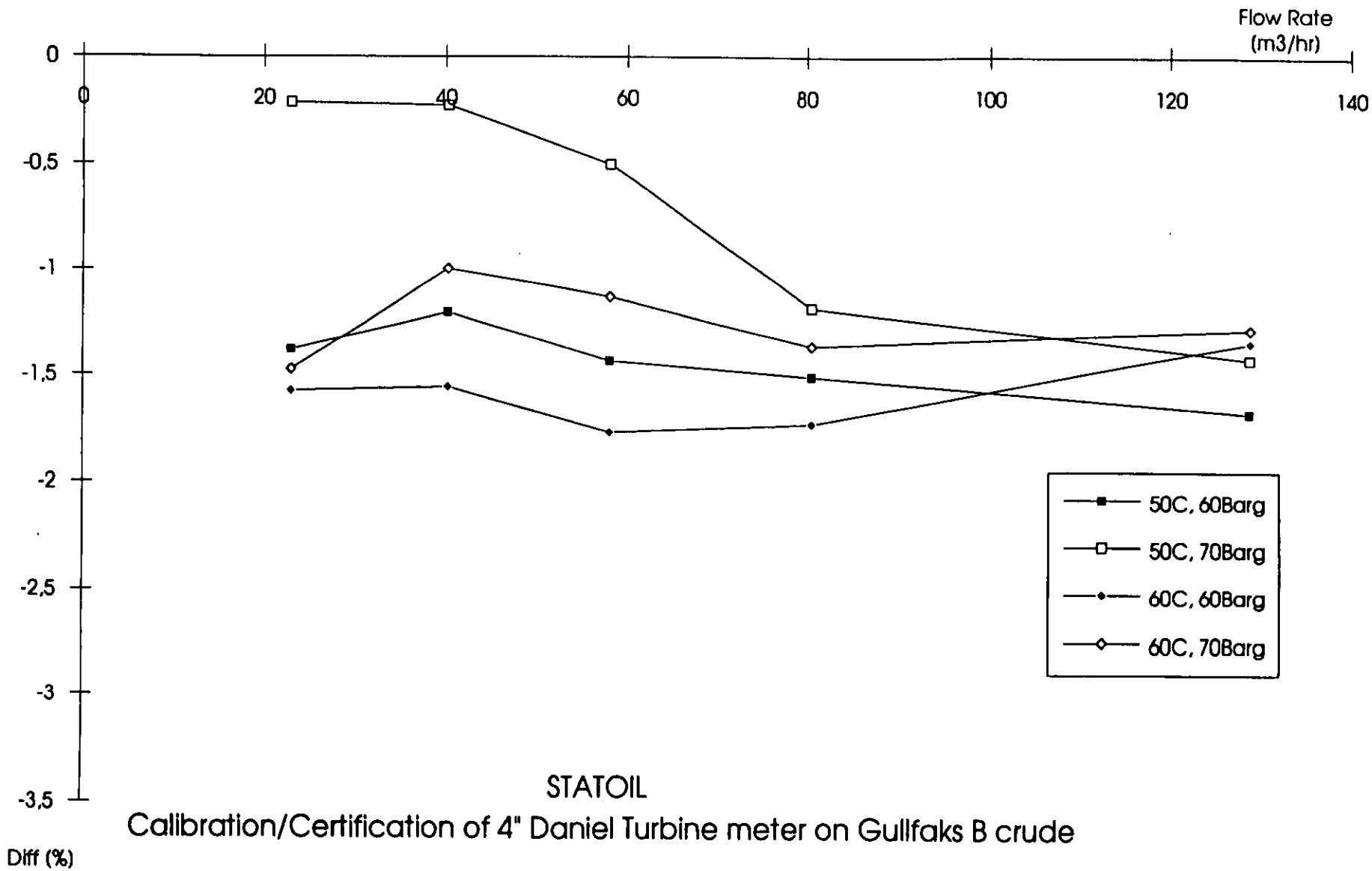
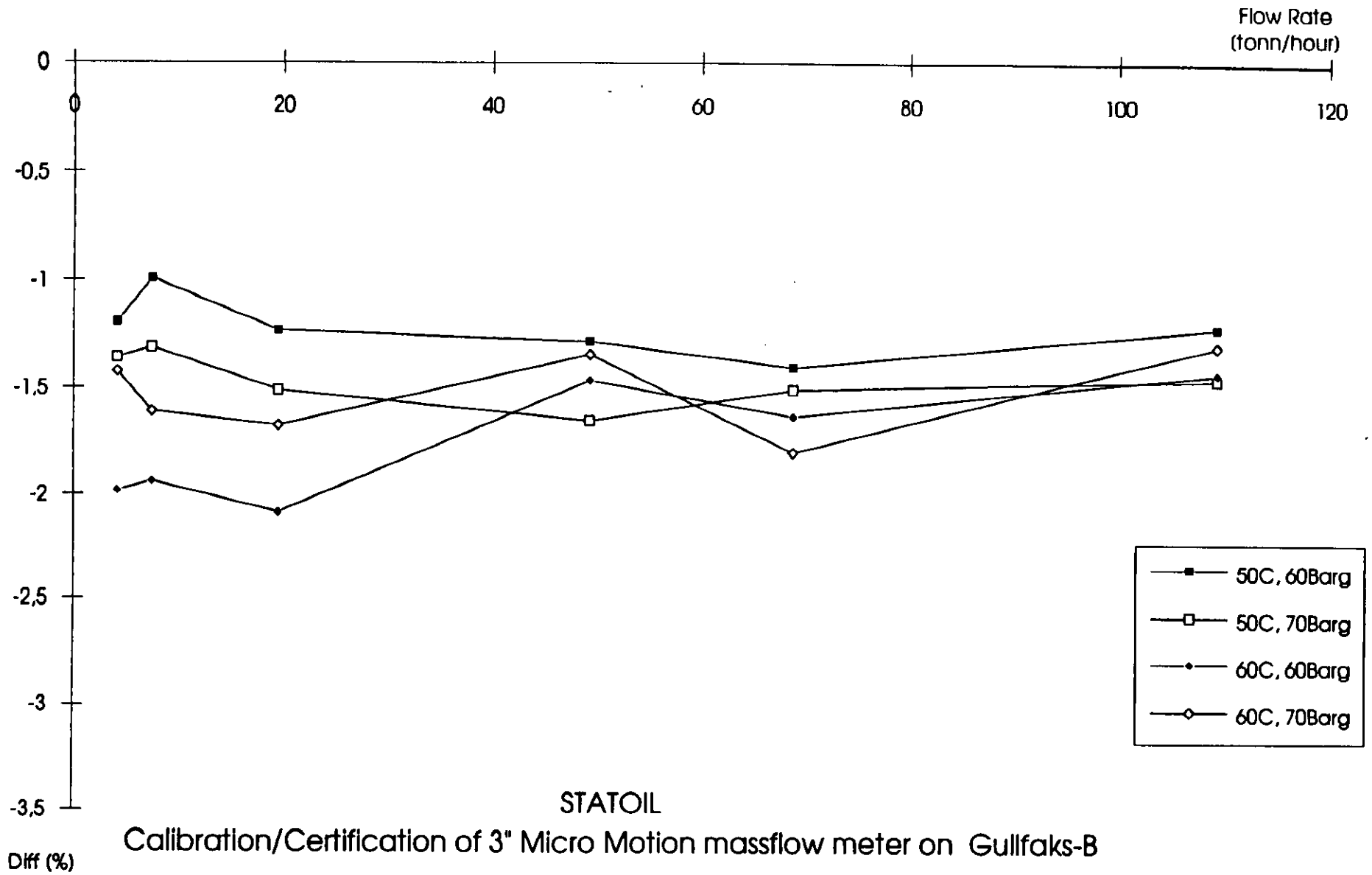


STATOIL

Calibration/Certification of 4" Daniel Turbine meter on Gullfaks B crude

FIG. 1



STATOIL

Calibration/Certification of 3" Micro Motion massflow meter on Gullfaks-B

FIG. 2

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NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Cariolis Mass Flow Measurement

by

Mr. Stewart Nicholson,
NEL, UK

CORIOLIS MASS FLOW MEASUREMENT

S Nicholson

NEL, East Kilbride, Glasgow

S U M M A R Y

This paper describes the work undertaken during a two year consortium funded project at NEL. The consortium consisted of nine members and was established to examine the generic behaviour of Coriolis Mass Flowmeters in practical applications.

To this end, eight manufacturers each supplied a one-inch nominal bore meter. The calibration results from tests on these meters are summarised. None of the results discussed are directly attributed to a particular manufacturer to preserve confidentiality arrangements.

The tests covered a range of liquid densities, viscosities and temperatures. Tests were also undertaken to quantify installation and air entrainment effects on the meters. NEL also undertook gas tests on six of the meters. LPG tests were undertaken by NMI in The Netherlands.

INTRODUCTION

Coriolis meters have been used in the market-place for some years, although it is fair to say that the market has been dominated by a few manufacturers.

Today there are many more Mass Flowmeter manufacturers and, to provide industry with comprehensive test data, meters from a range of manufacturers must be tested in any evaluation programme.

NEL* together with the consortium members decided that the project should support the testing of eight one-inch meters, which were supplied for the duration of the tests by the manufacturers listed below. This would provide a representative sample of the meters available at the time of the programme.

It was decided by NEL to form a consortium to fund test work on a range of coriolis meters and the nine member consortium comprised:

CONSORTIUM MEMBERS	MANUFACTURERS
Statoil	Endress and Hauser
Philips Petroleum (UK) Ltd	Schlumberger
Elf (UK) Ltd	Rheonik
Norwegian Petroleum Directorate	K-Flow
Total Oil Marine Ltd	Micromotion
Amoco (UK) Ltd	Exac
Amerada Hess Ltd	Smith
Kodak Ltd	Krohne
DTI	

LEAD LABORATORY: National Engineering Laboratory (NEL)
LPG TESTS: Netherlands Measurement Institute (NMI)

The UK Department of Trade and Industry was represented by The National Weights and Measurements Laboratory.

* The National Engineering Laboratory Executive Agency (NEL) is an industrial research establishment within the Department of Trade and Industry concerned with most areas of mechanical engineering research. Within NEL, the Flow Centre is the holder of the United Kingdom National Standards for flow measurement. Facilities exist for calibration and research into water, oil and gas flow meters. All the facilities are fully traceable to the primary standards of weight, time, etc, and most are accredited by The National Measurement and Accreditation Service (NAMAS).

INITIAL TESTS

Each meter manufacturer or agent was initially invited to NEL to ensure that their meter was installed to their satisfaction before the first test.

All testing was carried out on the NEL low flow test loop. This consists of a gravimetric system using a 300 kg weightank with a pneumatically operated inlet valve which was fitted with switches to enable it to trigger start/stop timers and pulse counters. The tank was weighed using a mechanical weighbridge and the temperature taken using platinum resistance thermometers placed at either end of the test section and averaged over the duration of each test point. The test rig is illustrated in Fig. 1.

To enable standardisation, in meter package length, amongst all eight meters, an overall gap of 1.5 m was designated for the meters to be fitted into the test line.

Individual pipe lengths were manufactured to suit each package. Pressure tappings were located at either end of the 1.5 m package.

In an effort to gain some 'hands-on' experience of the meters, they were all given an initial calibration in kerosine at 20°C. This gave manufacturers an opportunity to comment on these tests and to resolve any initial faults encountered during them.

To enable a coriolis meter to perform within its specification the meter has to go through a zeroing process before being put into operation. This is to enable the meter electronics to establish a datum with which to compare future readings. To perform this duty it is important that the meter is purged of all air which may be contained within the meter's tubes. The meter should also be protected to some degree from external vibration from pumps etc, as well as being clamped according to each manufacturer's guidelines. The flow must then be stopped before the zero adjustment is undertaken.

Fig. 2 displays calibration results from a meter with the zero adjustment carried out satisfactorily. If the zero adjustment is not satisfactory then a meter will produce a calibration characteristic similar to the one shown in Fig. 3.

All of the meters were calibrated using the pulse outputs. Zero setting took place with the downstream valve closed before a test was undertaken, with the exception of the temperature tests. During the first test it was discovered that some of the meters 'download' pulse counts into a buffer memory which is emptied of pulses some seconds later. This allows the generation of 'real' pulses some seconds after the flow has been stopped. Obviously if these pulses are not counted this can cause errors in the calibration curve similar to that of an incorrect zero.

FLUID VISCOSITY AND DENSITY TESTS.

Density was measured 'off-line' using a hydrostatic balance and a first degree equation of density as a function of temperature was derived. This equation was then used to calculate the density of the liquid at the test temperature.

Viscosity was measured by a falling ball viscometer. This was again done off-line with the viscometer connected to a hydrostatic bath. Water, kerosine, gas oil and glycol were used as test liquids, thus enabling significant ranges of density and viscosity to be covered. This gave a viscosity range of 1.0-29.5 cSt between water and glycol at 20°C and a density range of 0.78-1.11 kg/l for kerosine and glycol at 20°C. Results shown in Fig. 4 show a meter that was not affected by changes in viscosity or density, whereas Fig. 5 shows a meter that has a density effect and Fig. 6 a meter that suggests a viscosity effect.

Only one meter performed within the manufacturer's specification over the entire range of liquid tests. Two meters gave satisfactory results at high and medium flowrates but drifted outside the manufacturers specification towards true lower flowrates. The remaining meters showed large calibration shifts.

Density comparison readings ranged from the best meter giving results within 0.001 kg/l and the worst within 0.120 kg/l.

INSTALLATION EFFECTS

To simulate installation effects on the meters, tests were undertaken to investigate the effects of:

- Tensile loading
- Compressive loading
- Swirling velocity profile
- Vibration.

Tensile and compressive loadings were introduced using a hydraulically operated expansion piece upstream of the meter package. This was utilised to introduce compressive forces of up to 800 kgf and tensile forces of up to 350 kgf. None of the meters was affected by either of those tests.

Swirl was introduced by offsetting the meter package by means of a non-coplanar bend assembly followed by a further 90 degree bend. This arrangement was fitted immediately upstream and downstream of the meter package and is illustrated in Fig. 7. Pump vibration was isolated from the meter by utilising rubber bellows upstream of the offset pipework. Two of the eight meters showed signs of zero drift at low flowrates after swirl was introduced. This is illustrated in Figs 8 and 9. This effect may have been caused by the installation of this pipeline configuration rather than the fluid swirl as the high flow calibration was unaffected.

Finally, the meter package was vibrated in the vertical axis. This was done by installing an electromagnetic actuator to the upstream pipework of the meter package as illustrated in Fig. 10.

Acceleration forces of up to 10 m/s^2 were applied over a frequency range of 30-1000 Hz, although each test was concentrated over that particular meter's tube vibration frequency.

Only one meter showed an effect from these forces. This occurred at one particular frequency which was different from that meter's tube vibration frequency.

TEMPERATURE EFFECTS

The meters were tested at three temperatures between 5 and 40°C. The test liquid in this series of tests was water. Each meter was zeroed at the datum temperature, which could have been high or low temperature depending on the meter sequence in the test schedule. When the initial test was completed, the test temperature was then reset, the system allowed to settle and the next test completed. This was followed by the final test. During these tests, the meters were not rezeroed, switched off or drained of test liquid.

Fig. 11 illustrates a meter with poor temperature effect results, with an error of approximately 1.5 per cent at mid-flowrange. Fig. 12 shows a meter with a calibration which shows little or no temperature effect.

Of the eight meters, three showed no effects due to fluid temperature. Two meters showed calibration shifts in K-factor of 1.5 and 2 per cent. A further one had an increase in K-factor of 0.5 per cent and the remaining two had shifts of 1 and 1.5 per cent.

Temperature sensor location within the meter housing plays a significant part in how accurately the meter temperature readout reflects fluid temperature. If the sensor is attached to the outside of the tube then the sensor will be affected by the air temperature within the case as well as the tube material and fluid temperatures.

The variation in results from all the meter temperature read-outs is illustrated in Table 1.

DIFFERENTIAL PRESSURE

The differential pressure across each meter package was monitored throughout the tests using pressure tappings at either end of the package. These were connected to a calibrated Rosemount differential pressure transducer.

The pressure drop across the meter package was between 1.2 and 2.0 bar at a flowrate of 4.0 kg/s in kerosine.

Two of the meters tested gave audible signs of cavitation at 4 kg/s flowrate and their flowrate range was subsequently curtailed to prevent damage to those meters.

AIR ENTRAINMENT TESTS

The air entrainment test set-up is illustrated in Fig. 13. The air supply was taken from the NEL 7 bar supply and was controlled by a pressure regulator upstream of a critical flow nozzle package. This package contained a thermometer, a 0.508 mm diameter critical flow nozzle and an upstream pressure gauge. A non-return valve was fitted to prevent test fluid flowing back through the air supply line.

A critical flow nozzle was used to ensure that a constant mass flowrate of air within 0.3 per cent was supplied, provided the upstream pressure and temperature were maintained constant.

Air temperature and pressure were monitored using a platinum resistance thermometer and Texas Instruments pressure gauge respectively.

Each meter was thoroughly flushed and a mid-range flowrate set with no air injected. The meter was zeroed and an initial test point was undertaken. An air flowrate of approximately 2 per cent by volume was set using the air regulator and the air flow stopped. The meter was purged of air and the liquid flow stopped. The test point was started by simultaneously starting the liquid and pre-set air flowrate and stopped by closing both flows simultaneously when the weightank was full. This method was repeated with air percentages up to 4 per cent by volume.

None of the meters performed satisfactorily. Two of them ceased to operate on introduction of the two phase flow. One further meter gave a spread of results of 3 per cent but the density readings during the test points fluctuated by 10 per cent. The remaining meters gave calibration errors of up to 58 per cent.

No correlation could be found between volume of air and K-factor error.

GAS TESTS

These tests were carried out in the Gas Flow Measurement Laboratory at NEL using air.

This set of tests can be split into two distinct sections: low and high pressure. Three meters had been supplied with 18 bar max pressure flanges and were tested at pressures of 15 bar across a flowrange 0.1-1.0 kg/s. Three meters were supplied with flanges capable of withstanding high pressures. These were tested at 60 bar over a flowrange of 0.1-2.0 kg/s. Two meters were not tested in air at the manufacturers' requests.

Of the three meters tested at low pressure, one gave results having a repeatability of 15 per cent. The remaining two exhibited linearities of approximately 0.6 per cent greater than was achieved from liquid tests and repeatability of, in one case, 1 per cent greater than in liquid tests. In both these cases this related to a 10 per cent calibration shift in the K-factor results.

In the high pressure tests one meter failed to operate. The remaining two meters displayed linearities of 1.5 and 1.3 per cent and repeatability of ±0.3 per cent greater than their respective liquid tests.

Fig. 14 illustrates a low pressure test with zero set at 15 bar and zero set at ambient pressure. This shows a typical result in the difference in repeatability depending on the pressure at which the meter's zero is set.

Fig. 15 shows a high pressure test result where the meter was zeroed at both 60 bar and ambient pressure and the results are similar, in this case.

LPG TESTS

Six meters were sent to NMI in The Netherlands for testing at the Shell Pernis plant using LPG to give an extreme value of density.

The meters were all reconfigured to standardise the pulse outputs allowing calibration by a compact meter prover.

Fig. 16 illustrates a typical meter calibration where the LPG results have been re-calculated and superimposed onto a graph of the previous test liquids. There is a shift in K-factor of approximately 0.5 per cent. Overall the LPG results produced linearities of 0.05-1.0 per cent and repeatability of similar order to those of the respective meters in other liquid calibrations.

CONCLUSIONS

From the results found the meters can be separated into four groups.

- One meter performed within the manufacturer's specification in all test phases.

- Two meters performed to the manufacturers' specifications after initial teething problems had been overcome.

- A further two meters, although not meeting the manufacturers' specification, indicated that the specification could be obtained with further upgrading.

- The remaining three meters provided erratic test results throughout the test series.

It is obvious from the above that while a minority of manufacturers' meters perform satisfactorily, the majority showed significant room for improvement.

It is encouraging to note that since the inception of this project many manufacturers have come into the market with new products and most of the manufacturers whose meters were tested in this report have already developed new meters or upgraded the meter electronics.

TABLE 1.

Nominal temperature	13°C		20°C		45°C	
Meter Ref	NEL °C	Meter °C	NEL °C	Meter °C	NEL °C	Meter °C
1	12.18	10.60	19.95	19.00	45.29	44.50
2	12.24	11.22	19.86	18.96	46.14	45.24
3	12.75	N/A	19.94	N/A	45.34	N/A
4	12.29	12.70	19.96	20.10	45.10	43.90
5	12.34	13.30	19.93	21.00	44.69	N/A
6	12.74	12.60	20.16	20.00	45.74	45.00
7	12.39	15.00	20.04	23.00	44.91	47.00
8	12.85	14.10	20.40	21.20	46.28	44.50

Note: Meters 3 and 5 not tested at all 3 temperatures

TEST METER TEMPERATURE COMPARISO

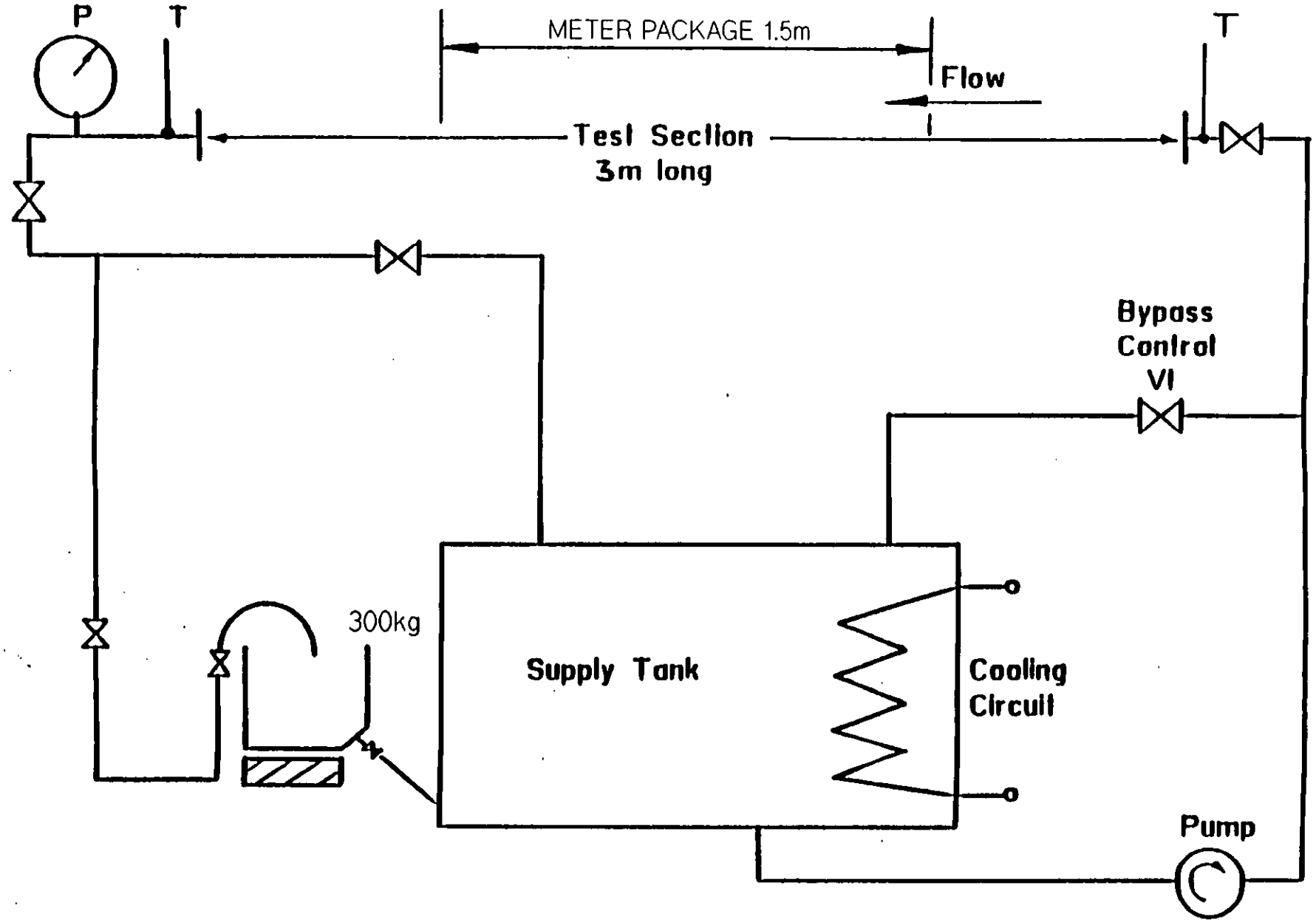

FIG.1. TEST RIG LAYOUT

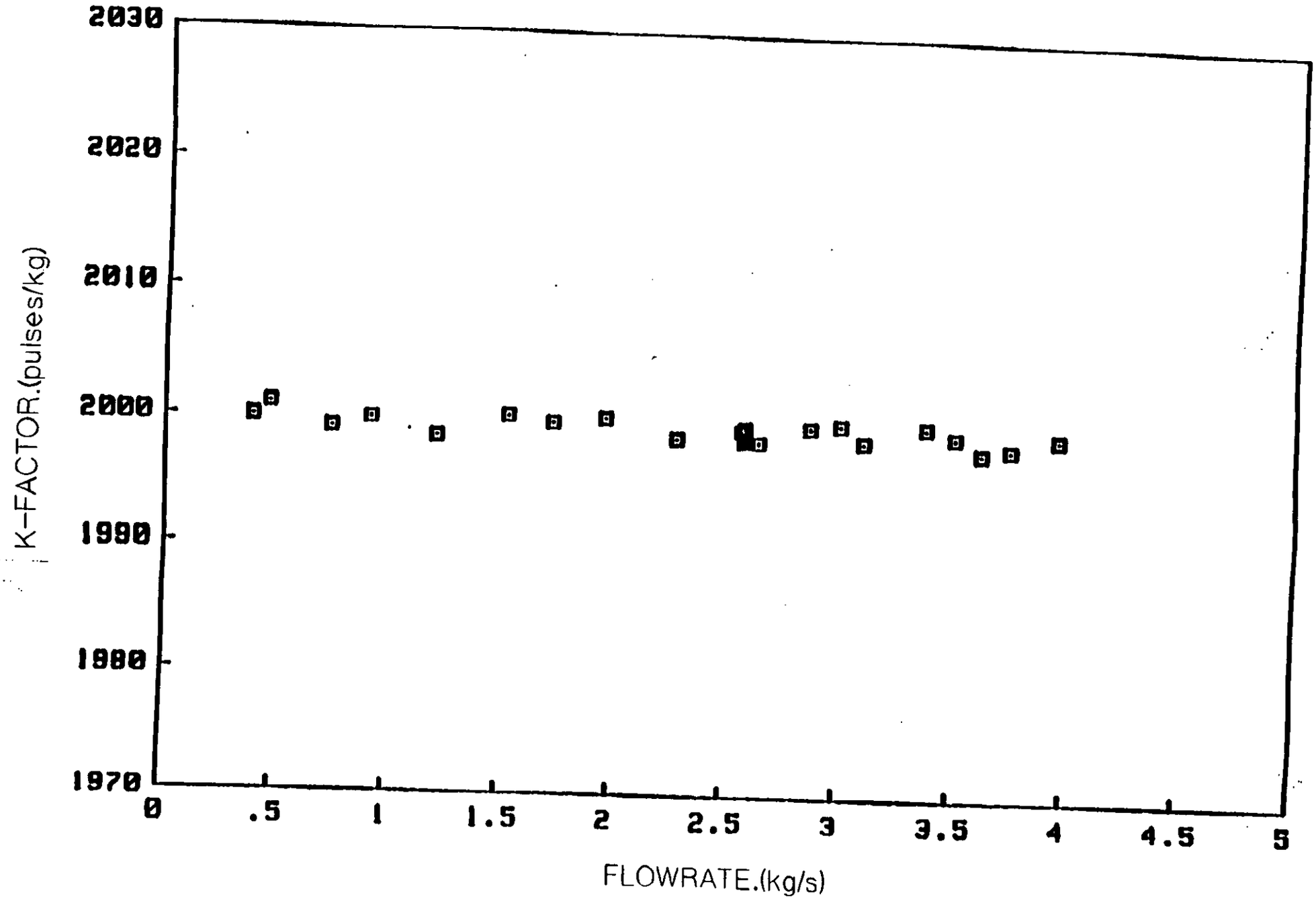

FIG.2. SATISFACTORY ZERO CALIBRATION

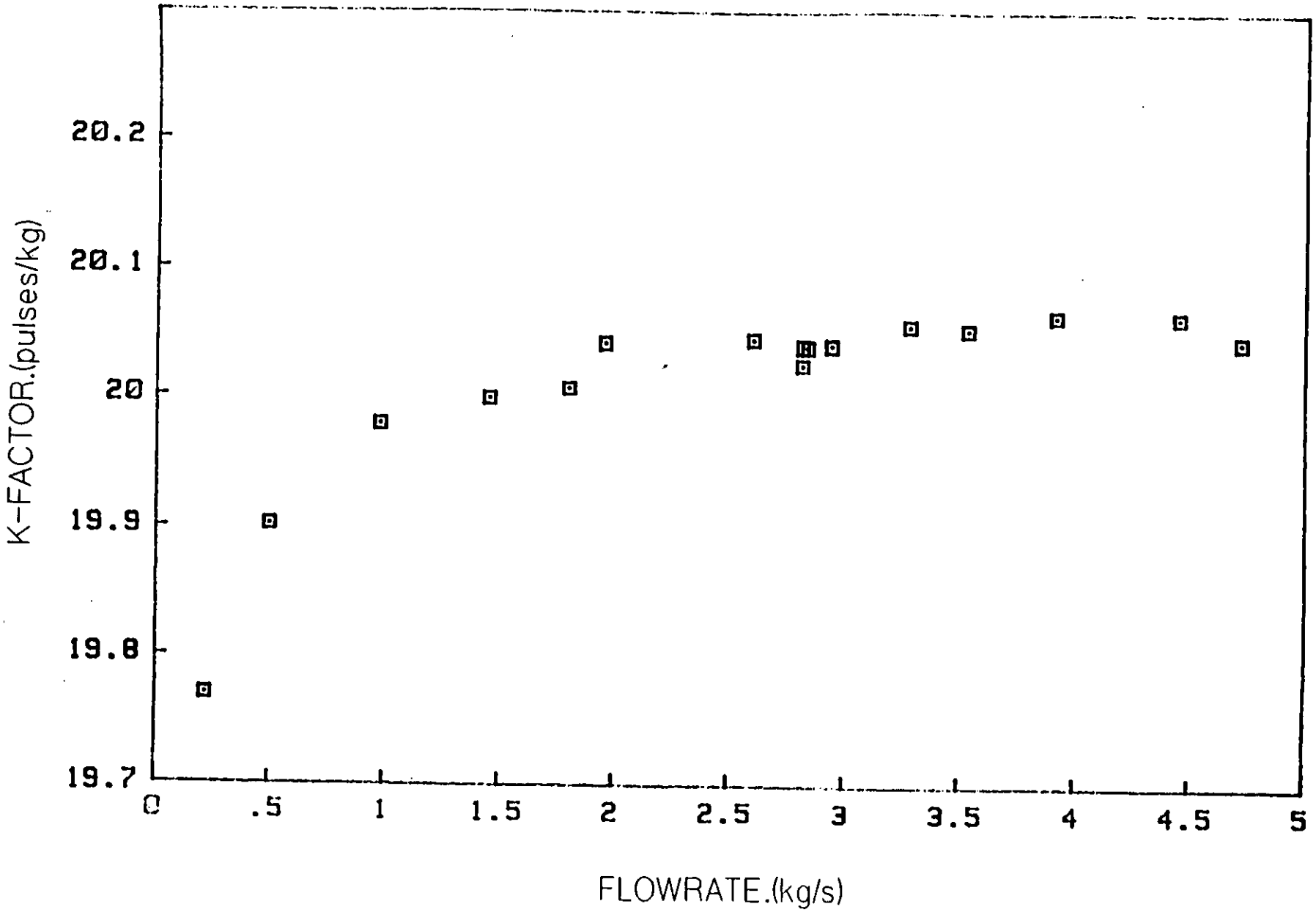

FIG.3. UNSATISFACTORY ZERO CALIBRATION

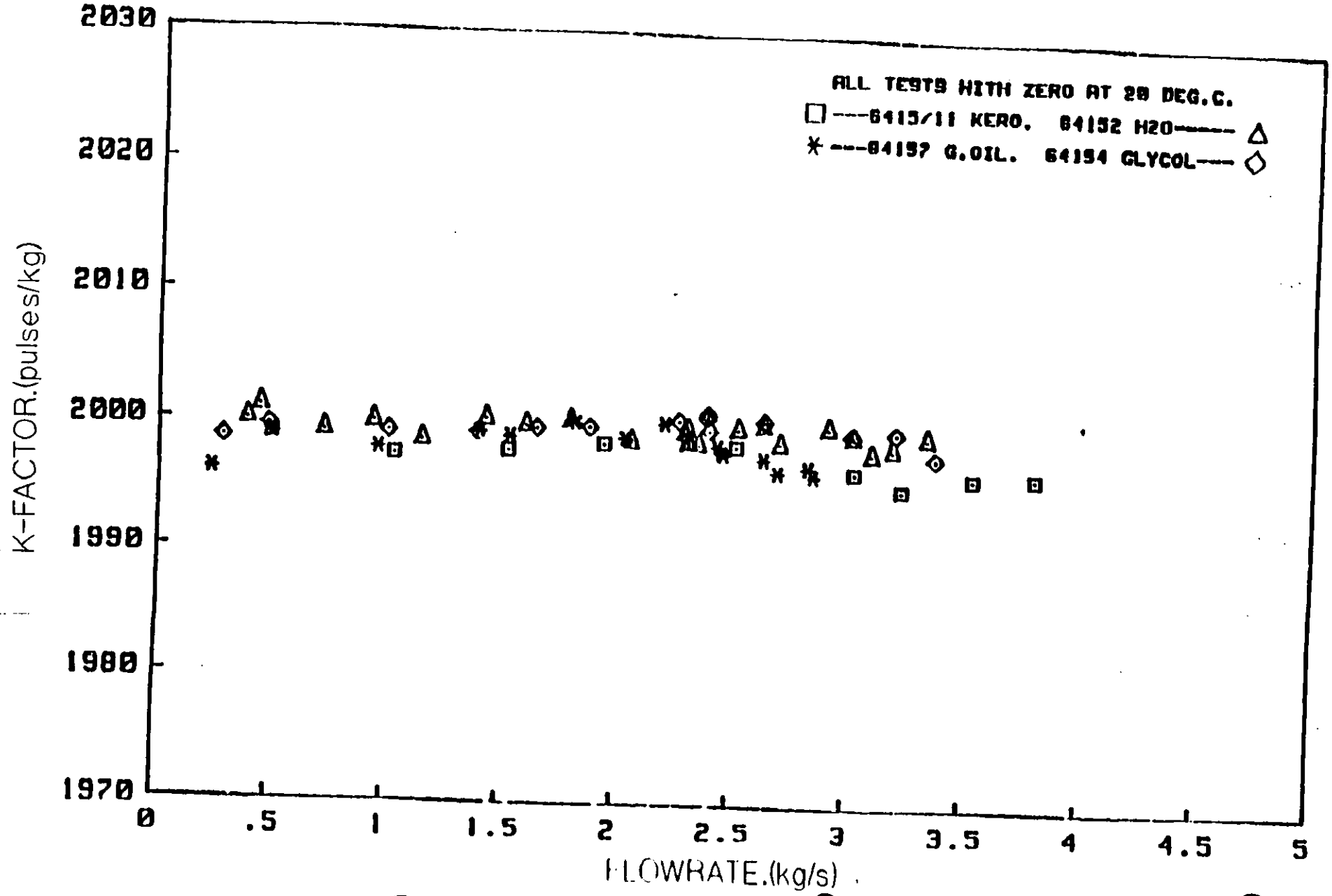

FIG.4. NO DENSITY OR VISCOSITY EFFECTS

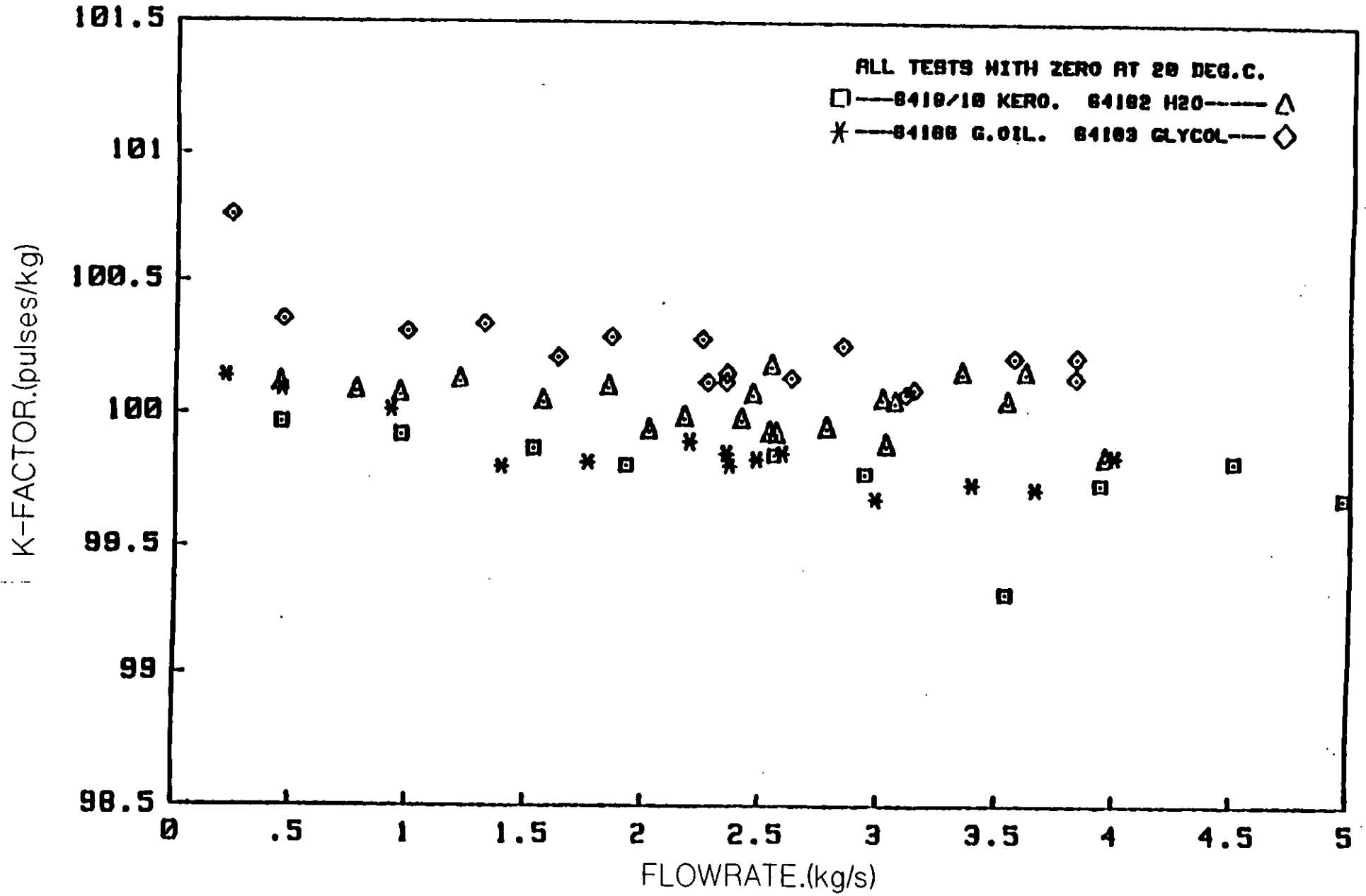

FIG.5. DENSITY EFFECT

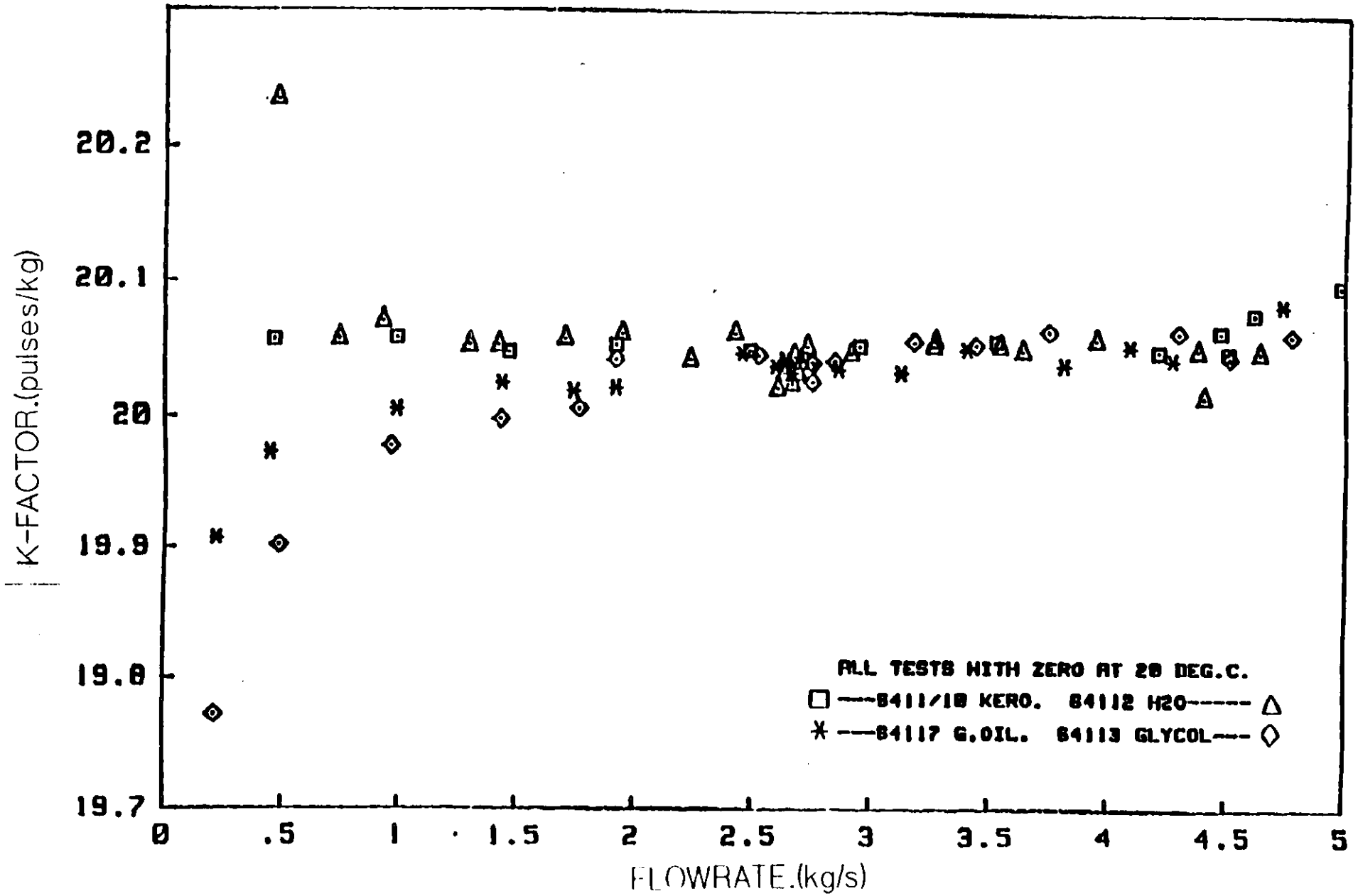

FIG.6. VISCOSITY EFFECT

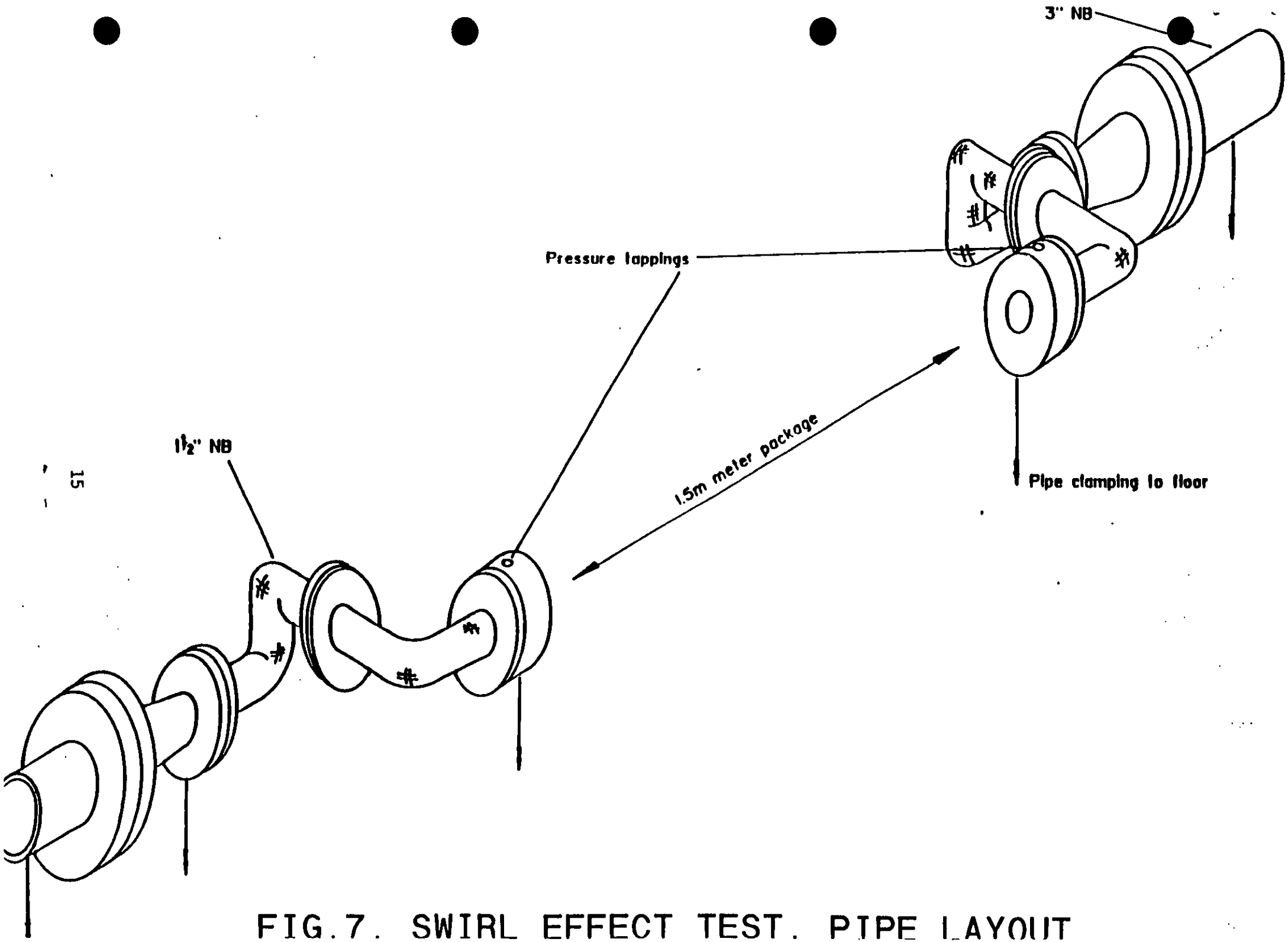

FIG.7. SWIRL EFFECT TEST. PIPE LAYOUT

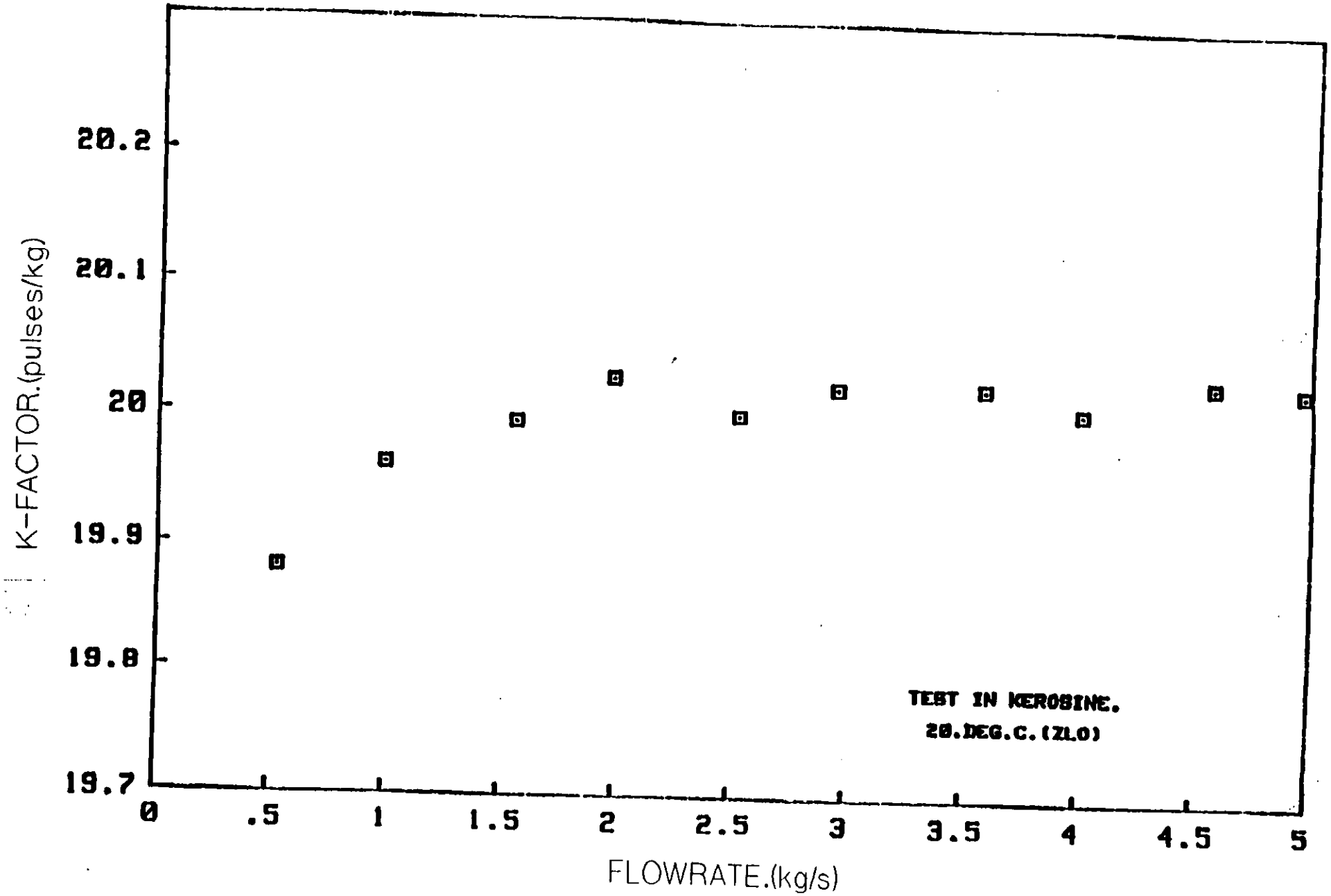

FIG.8. ZERO DRIFT DURING SWIRL TEST

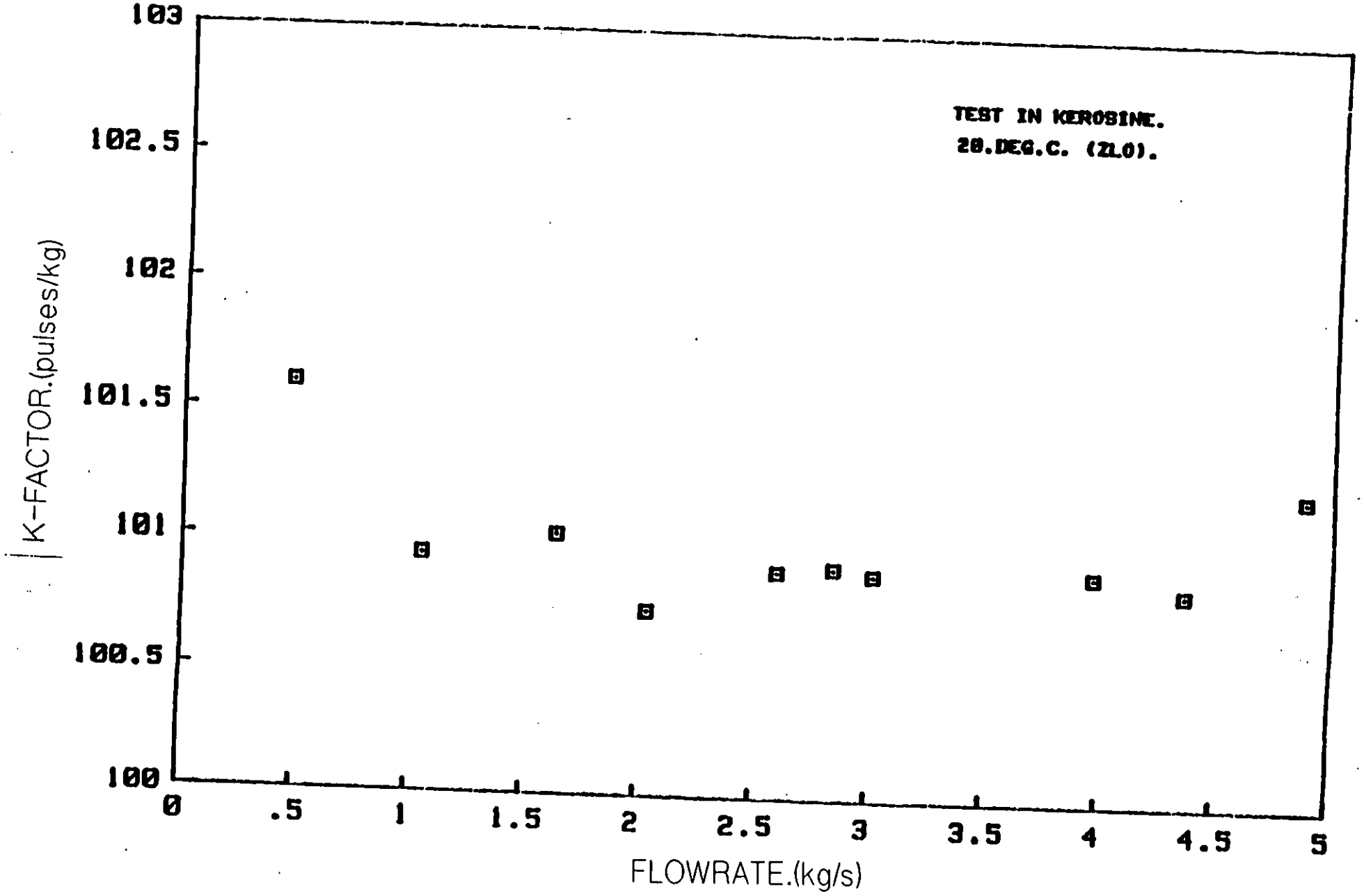

FIG.9. ZERO DRIFT DURING SWIRL TEST

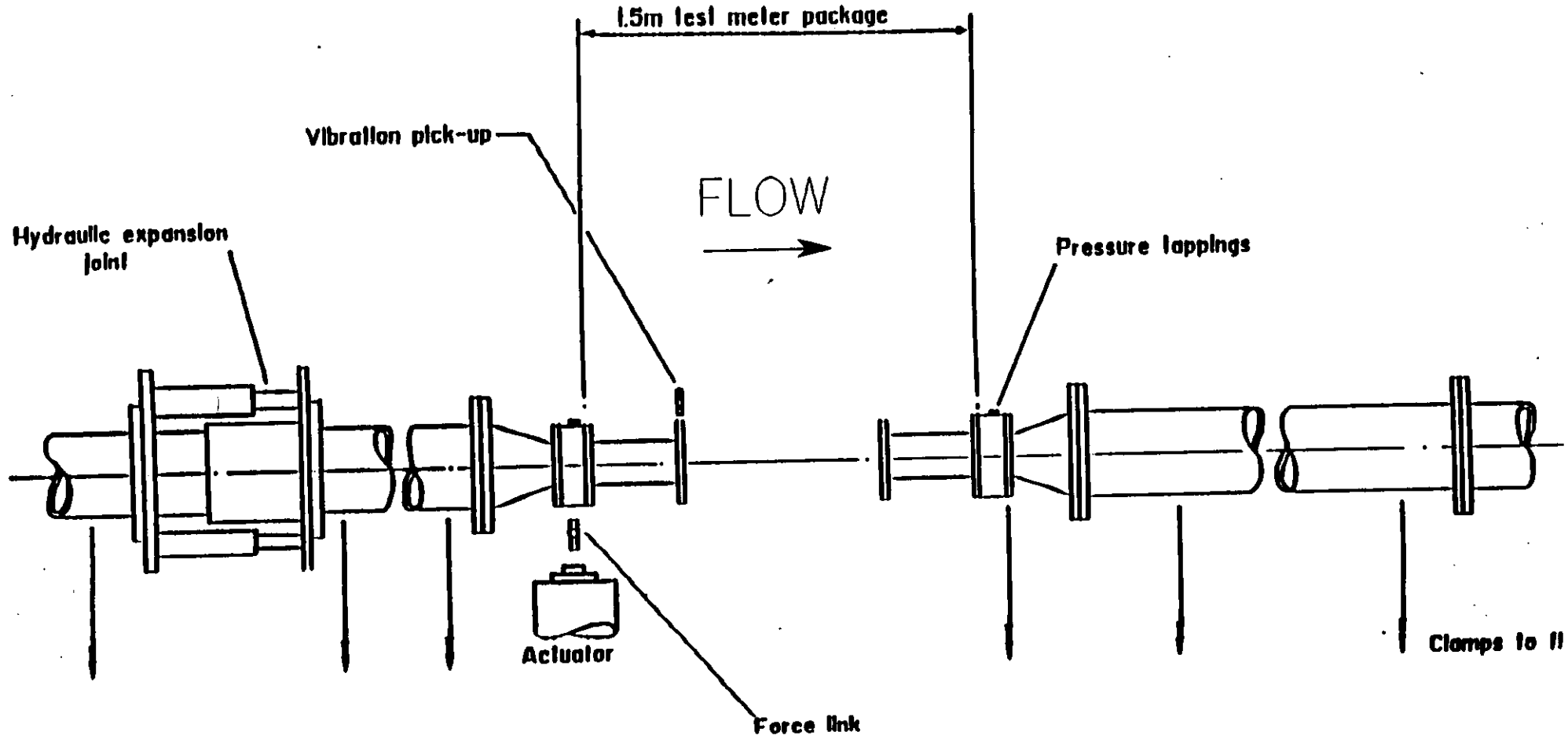

FIG 10 VIBRATION EFFECT TEST. PIPE LAYOUT

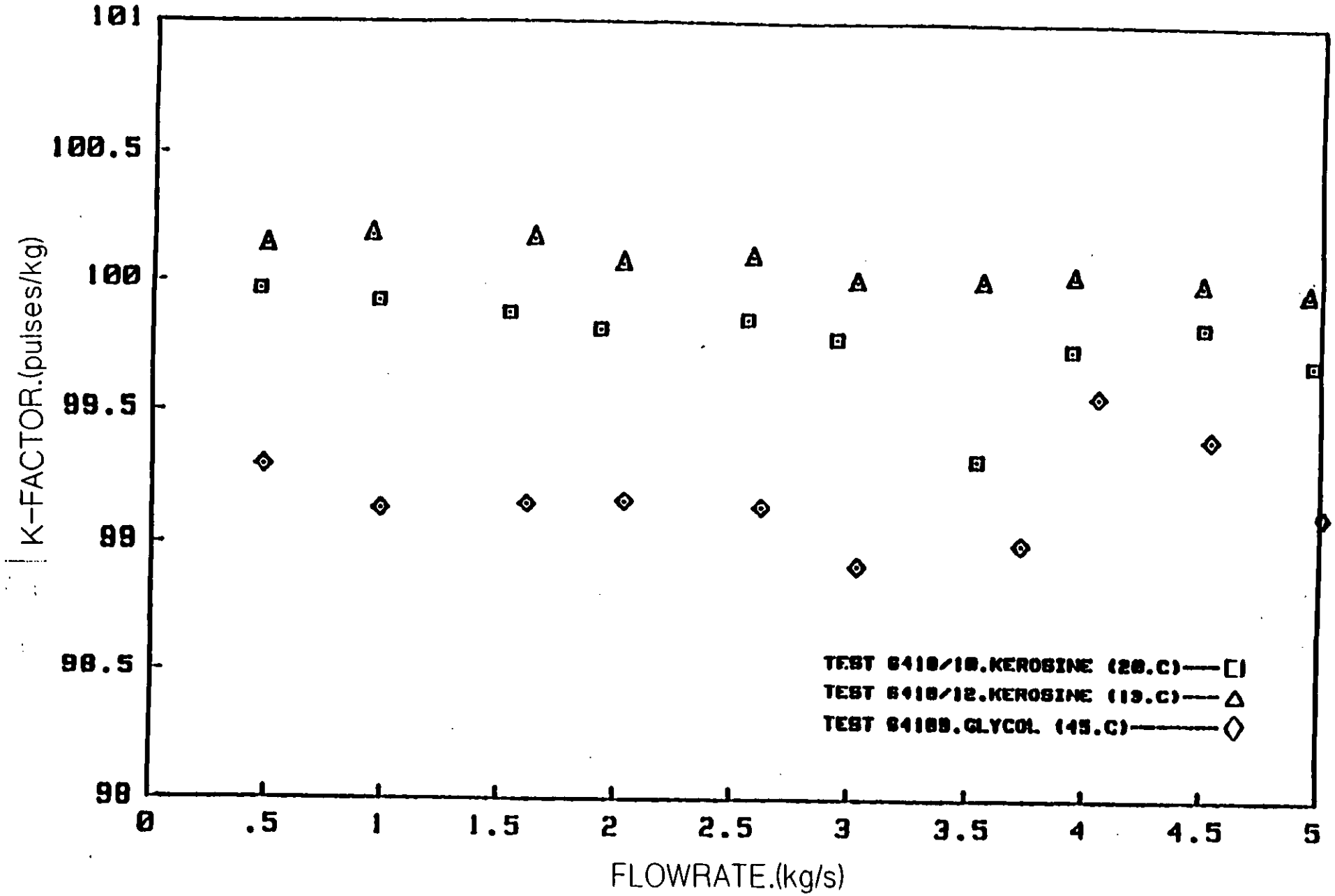

FIG.11. POOR TEMPERATURE EFFECT CALIBRATION

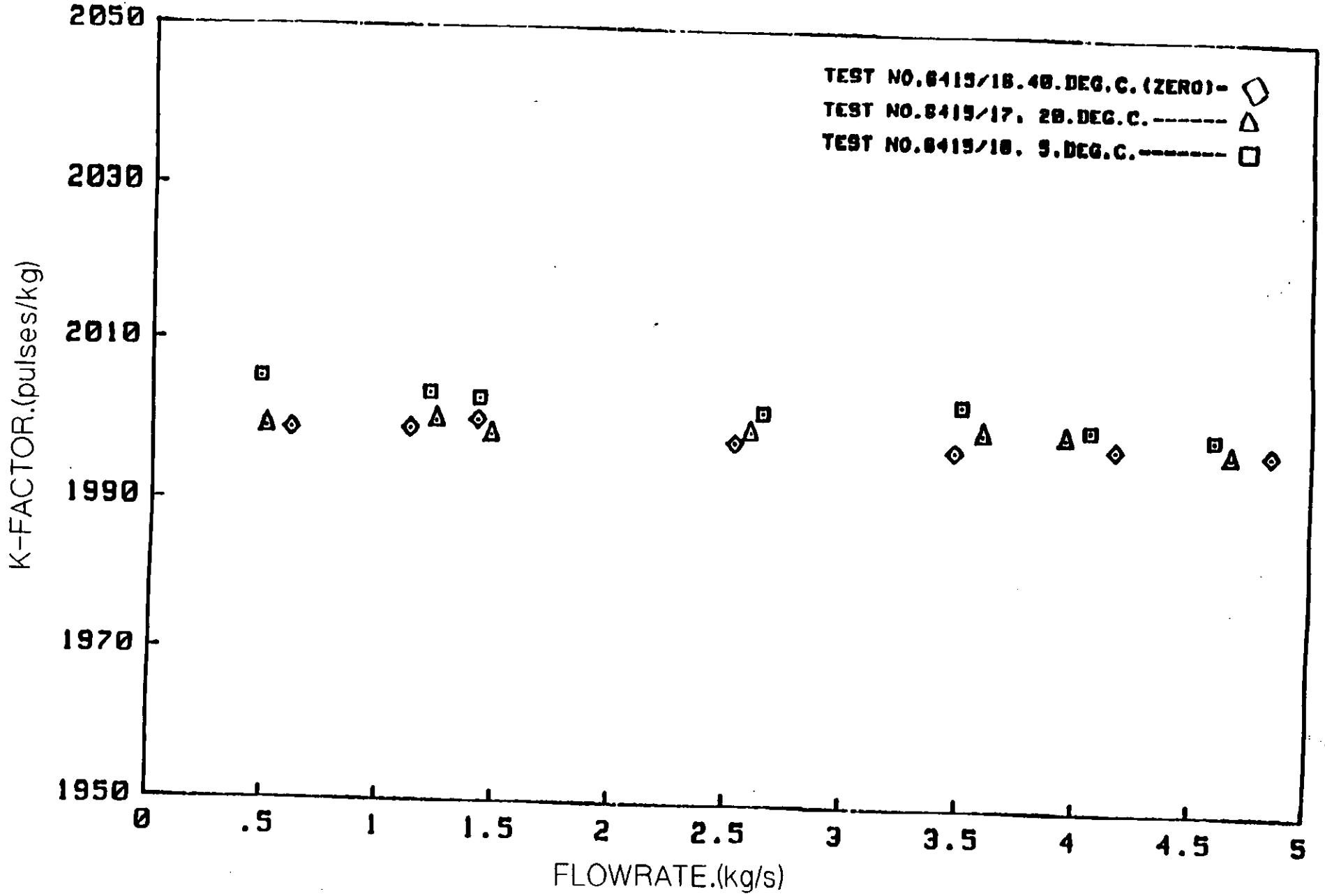

FIG.12. GOOD TEMPERATURE EFFECT CALIBRATION

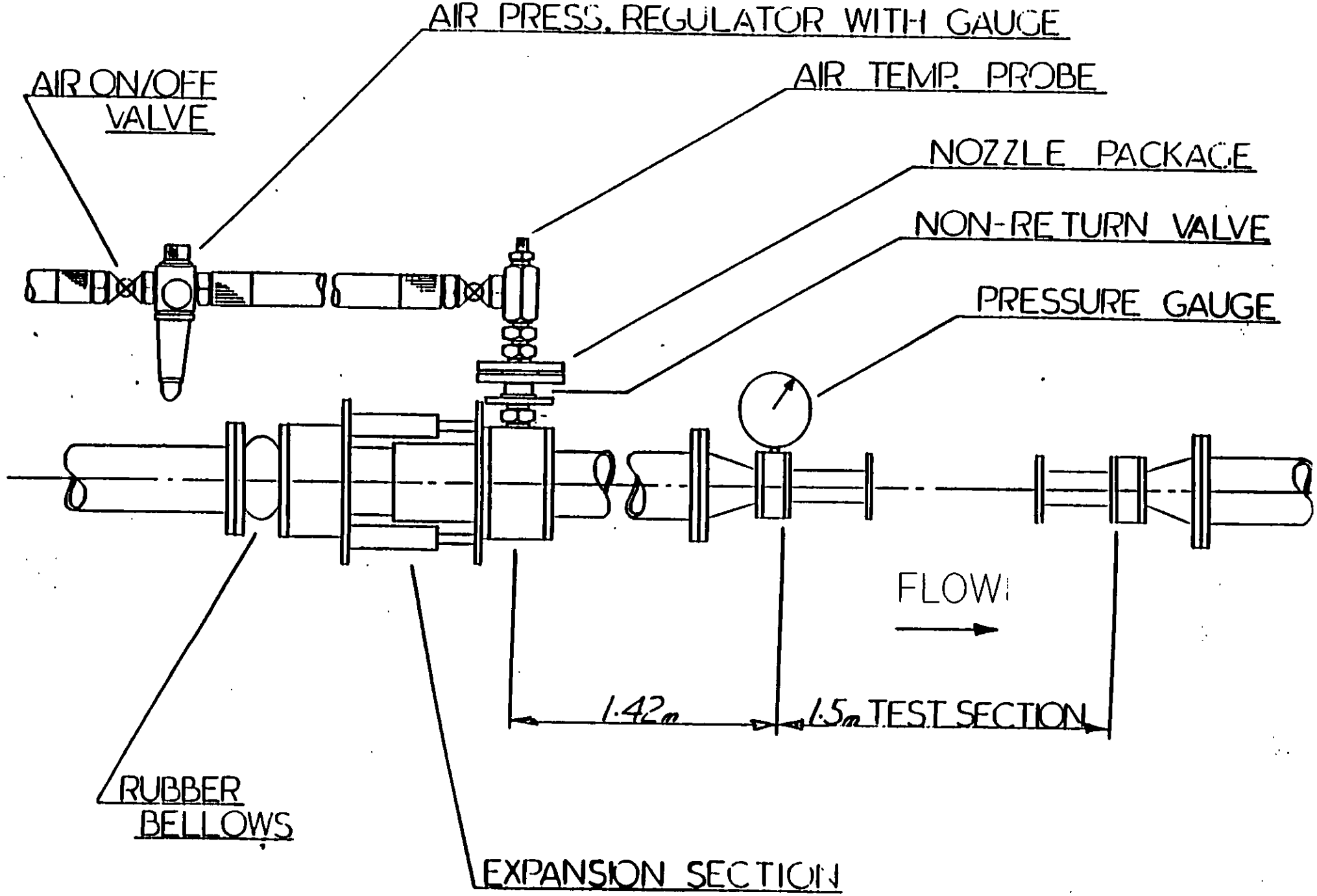

FIG.13. AIR ENTRAINMENT TEST. PIPE LAYOUT

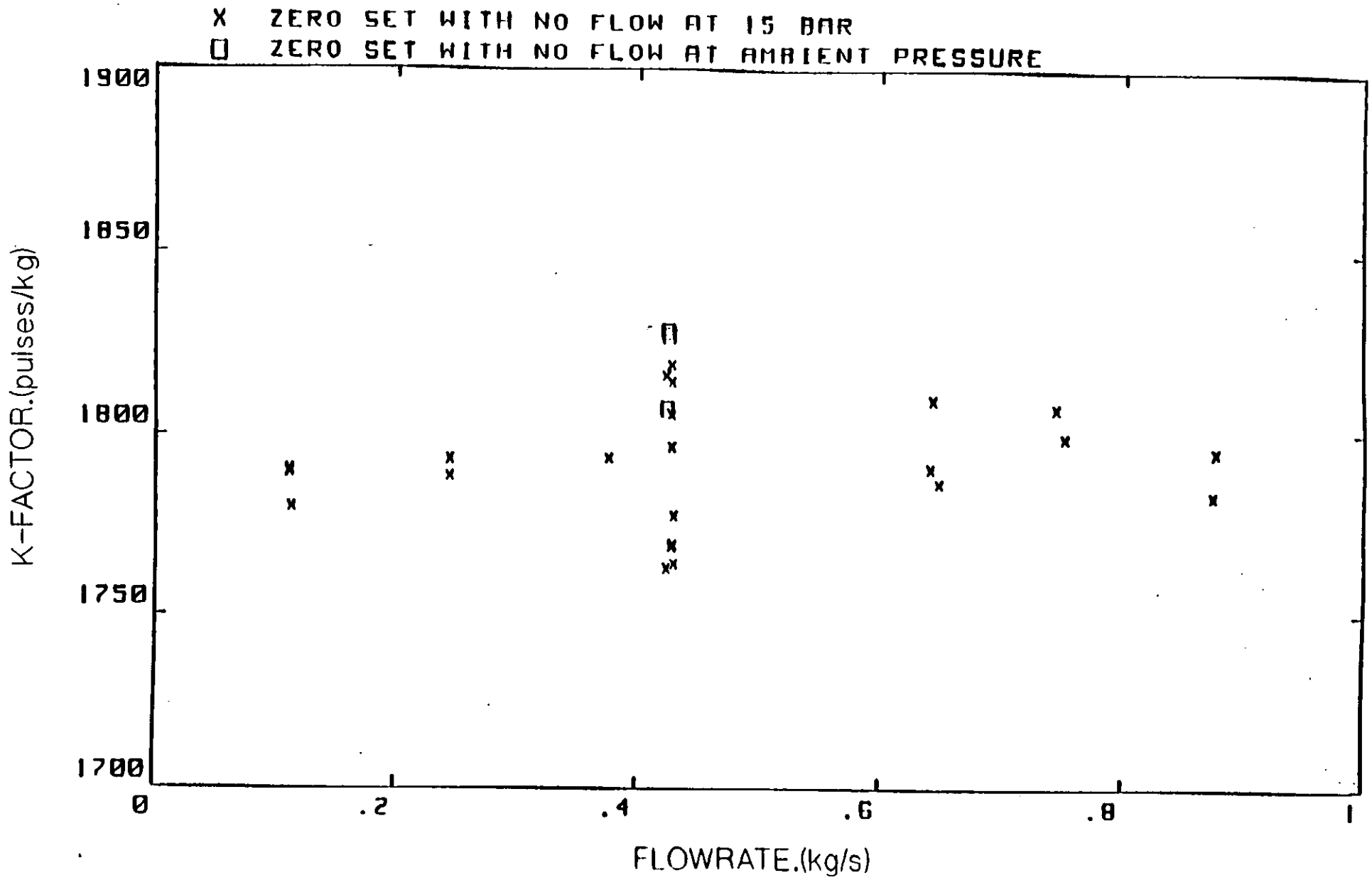

FIG.14. LOW PRESSURE GAS TEST RESULT

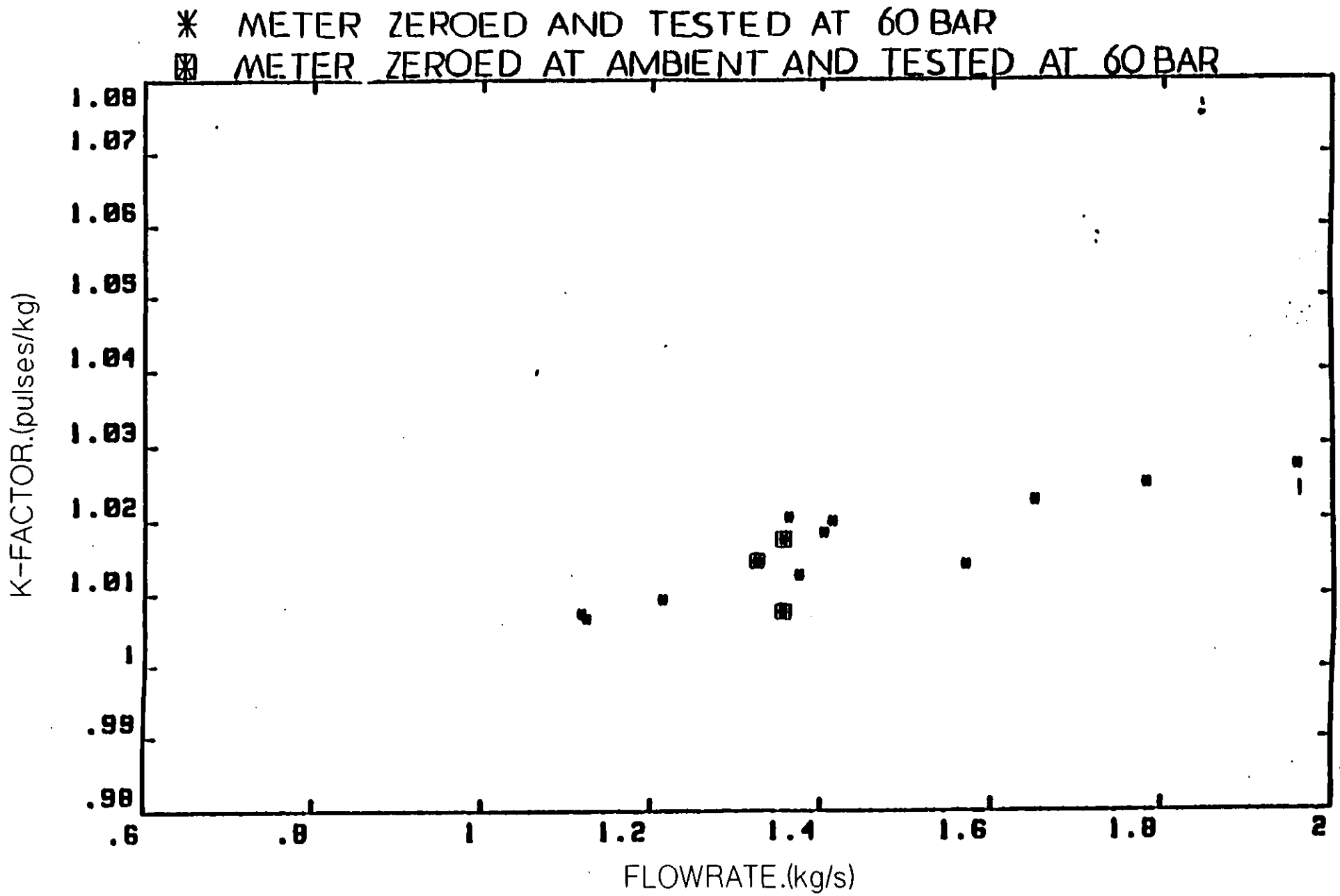

FIG.15. HIGH PRESSURE GAS TEST RESULT

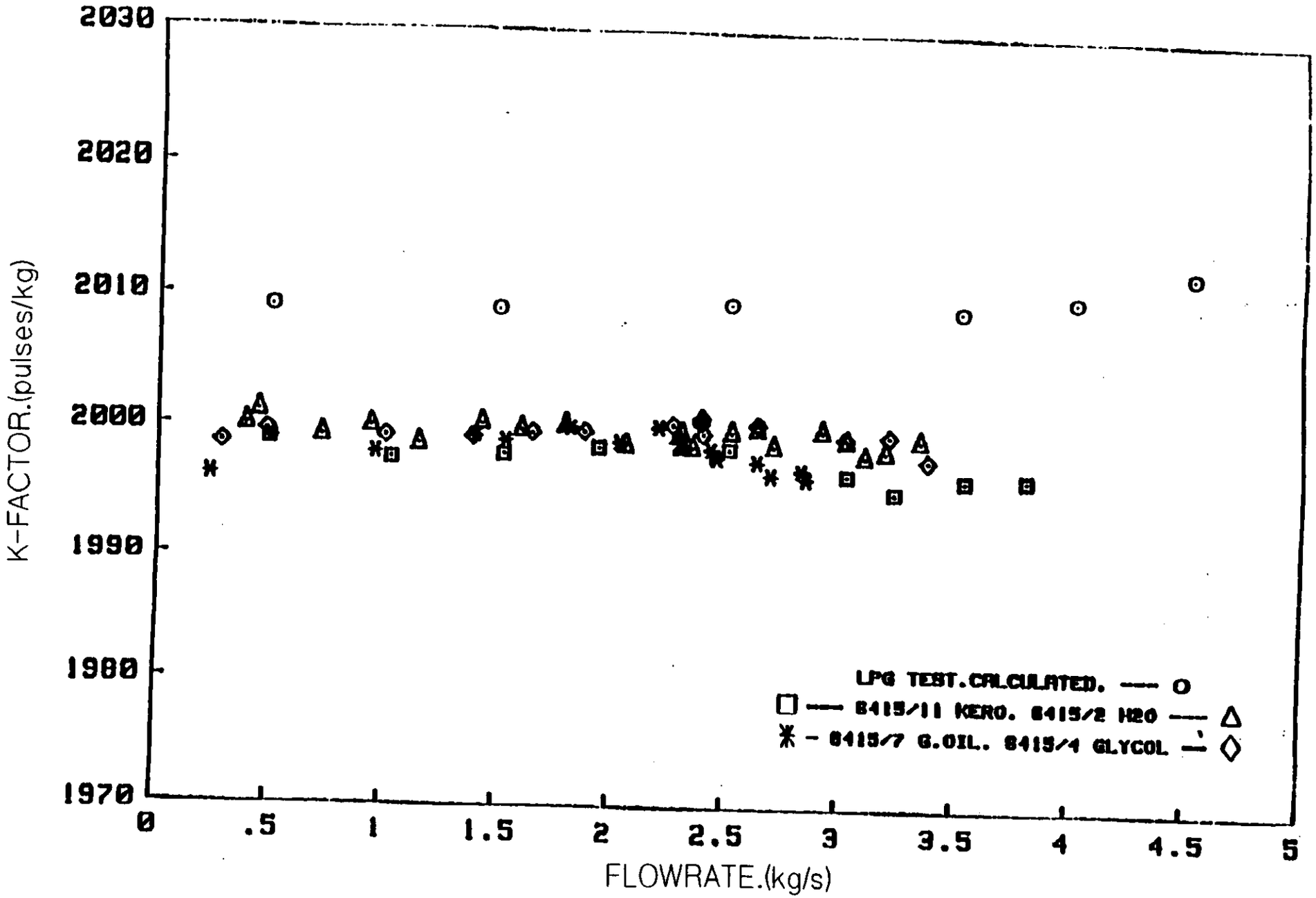

FIG.16. LPG AND LIQUID TEST RESULT

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Evaluation of ultrasonic liquid flowmeters

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ABSTRACT

In 1992, Christian Michelsen Research (CMR) carried out a project in order to evaluate ultrasonic liquid flowmeters. The aim of the project was to characterize a selection of commercially available multi beam liquid flowmeters, with emphasis on future applications on crude oil. The test program included a calibration test, which was carried out with water at a certified calibration laboratory, and a functional test on diesel oil. Through the calibration test, the flow meter uncertainty during ideal conditions was established, along with an investigation of the installation effect caused by a bend. The functional tests included test with single phase diesel oil, diesel oil that contained small fractions of water, and diesel oil that contained small fractions of gas.

1 INTRODUCTION

Future developments of oil and gas reserves off the coast of Norway will largely concern small fields, most of which will be linked up with existing platforms, although independent developments may also take place. If the development of these small fields is to be profitable, reductions in development and operating costs will usually be necessary. A fundamental method of reducing costs will be to utilize simpler, more compact process equipment. Especially in cases where the well-stream from a satellite well is led to an existing platform, space requirements alone make it necessary to evaluate alternative methods of product metering.

Today, the turbine meter is almost universally utilized for measuring crude oil product. Alternative technologies include coriolis mass measurement devices and multi beam ultrasonic volume flow meters based on the transit time principle. Before ultrasonic meters can be brought into service offshore, it is necessary to test out their technology under controlled conditions similar to the test programs that have been performed on coriolis meters.

Therefore a project was initiated to investigate the performance of commercially available ultrasonic liquid flow meters, in particular their suitability for oil product measurements. Participants in the project were Den Norske Stats Oljeselskap (Statoil), Norsk Hydro and Saga Petroleum. Furthermore, the Norwegian Petroleum Directorate (NPD) engaged themselves in the project in order to obtain knowledge and experience with multi beam ultrasonic volume flow meters. The project was managed by Christian Michelsen Research AS (CMR), and largely performed by personnel at CMR and Hydro Porsgrunn.

The aim of the project was to characterize the performance of a selection of commercially available multi beam ultrasonic liquid flow meters based on the transit time principle, in particular their suitability for volume flow measurements of crude oil.

Based on the knowledge of the leading multipath ultrasonic liquid flowmeters, three manufacturers of ultrasonic liquid flowmeters were invited to participate in the evaluation project. On request, all three manufacturers put their meters to disposal for the project free of charge. Among the three flowmeters were the Danfoss SONO 2000 and the Panametrics Model 6468. The project work carried out in the project, as well as the test results obtained, was classified as confidential, and one manufacturer used his right not to have the results published.

The work presented in this paper merely describes the test program that was carried out, and is not meant as a thorough study and discussion of the ultrasonic flow meter technology. The extent of the project did not allow for more than a brief description of the meters to be evaluated.

2 TECHNICAL DESCRIPTION OF TEST METERS

2.1 Description of Danfoss SONO 2000

The Danfoss SONO 2000 is a two-track ultrasonic flowmeter based upon the transit time measurement principle, with each transducer acting both as transmitter and receiver [1]. The distance between the two tracks is 0.45 diameter, with the transducers configured in two parallel traces. Danfoss SONO 2000 has a 1 MHz signal frequency, and a counter frequency of 128 MHz, thus giving a 7.2 ns resolution for the signal detection system. However, Danfoss has implemented a special averaging algorithm, claiming a resolution of less than 1 ns. The resolution of the detection system is most critical at low flow rates, setting the lowest possible detectable flow rate for the system. Additionally, the measurement uncertainty rely upon this parameter.

The signal detection system is based on a simple level and zero-crossing detector. The first zero-crossing after the level detector is triggered, is registered. If the measured zero-crossing is detected within a given time window, set by the signal frequency, the measurement is stored and further processed. Otherwise, the measurement is rejected, and an error indication is given. The measured transit time is corrected for time

delays in the electronics and the transducers. Furthermore, the transit time in the cavity in front of the transducers is compensated for.

20 measurements with the flow and against the flow form the basis for estimating the flow velocity for each track. The average value for the two tracks is the output value, representing the average flow velocity in the pipe. No comparison between the output values for the two tracks is carried out.

An Automatic Gain Control (AGC) is implemented in order for the SONO 2000 to adapt to different measurement conditions. The AGC assures constant peak-to-peak level at the received signal, thus enabling fixed trigger-level for the level detector.

2.2 Description of Panametrics Model 6468

The Panametrics Model 6468 is a two channel ultrasonic flowmeter based on the transit time principle [2]. The two channels operate as two separate channels, thus the operator can select between the average value or single channel values as output. The transducers are configured in such a manner that the two beams are crossing each other in the centre of the pipe. The two pairs form an angle of about 60°, with all transducers being oriented towards the centre of the pipe. All transducers act both as transmitter and receiver.

The signal frequency of the test meter was 1 MHz. Other signal frequencies are used dependent on the application. Various digital signal processing techniques, including cross-correlation, are used to determine the transit time and to calculate flow velocity. To assure correct transit time measurements, time delays in the electronics and in the transducers are corrected for.

The Panametrics Model 6468 has implemented an Automatic Gain Control (AGC) system. The AGC assures constant peak-to-peak level at the received signal, independent of different measurement conditions. Digital signal processing techniques used allow dynamic digital trigger level detection.

3 CALIBRATION TEST

3.1 Background

The central parameter in the evaluation of a flowmeter is the measurement uncertainty. It was therefore essential to perform a calibration test at a recognized laboratory whose reference measurements can be traced back to international standards. Accordingly, the meters were calibrated at Norsk Hydro's calibration laboratory for liquid meters in Porsgrunn.

3.2 Test conditions

The meters were calibrated at Norsk Hydro's calibration laboratory located in Porsgrunn. The calibration rig is primarily used for calibration of test meters, with water as the fluid medium. The calibration is based on a volumetric reference, which consists of several tanks with volume from 0.5 up to 12.0 m^3. The tank used depends on the meter size and flow rate. The volumetric tanks are calibrated against a calibrated weight every 3rd year. By using the volumetric tanks as the reference, a ± 0.05% reference uncertainty in the volume is claimed.

Each calibration test started at zero flow and ended at zero flow, implying a transient flow at the beginning and end of the test run. The accumulated volume of the meters under test was compared to the volume filled in the reference tanks. In order to minimize the effects of the transition periods caused by the opening and closing of the valves controlling the flow rate, a minimum test period of 1 minute is required. However, the duration of

the test runs for the calibration of the ultrasonic meters lasted from 2 minutes and 24 seconds, up to over 11 minutes, clearly assuring that the transition period effects were minimized.

3.3 Test with maximum straight pipe-length upstream

In order to obtain the meter performance, the meters were installed with as long upstream straight pipe length as possible. However, it should be noted that during this test the meters were installed in series, implying that the meters experienced different inlet lengths. As can be seen from Figure 1, the Danfoss SONO 2000 was installed 26D, and the Panametrics Model 6468 was installed 39D downstream of a 12" to 4" conical diffuser.

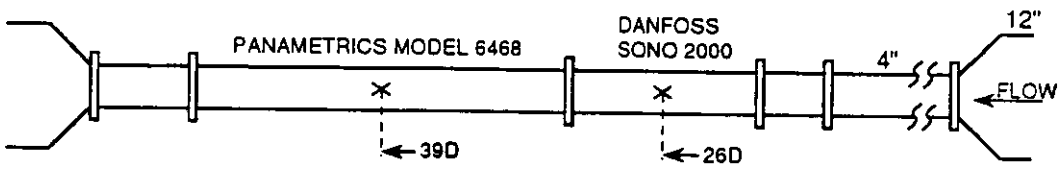

Figure 1 Layout of test section, maximum straight pipe-length upstream of flow meters.

3.4 Test with a 90° bend 10D upstream the flow meters

During this test the meters were tested one by one. The distance between the ultrasonic sensors and the 90° bend section was 10D for all meters. The meters were tested at 3 different flowrates, with 3 repetitive tests at each flowrate.

3.5 Test results for Danfoss SONO 2000

The Danfoss meter was calibrated at Danfoss calibration facility in Nordborg, Denmark, prior to the calibration test at Hydro Porsgrunn, see Table 1. Thus, the results from the calibration tests at Hydro Porsgrunn are compared with the pre-calibration results. Danfoss claims a ±(0.5% Reading + 0.5% FullScaleOutput) measurement uncertainty in the 10 - 100% flow range area for a 4" meter, see Table 3.

Reference volume flowrate	Deviation
34.3 m^3/hr	- 1.94 %
83.7 m^3/hr	- 0.86 %
83.7 m^3/hr	- 0.88 %
166.6 m^3/hr	- 0.30 %
228.5 m^3/hr	± 0.00 %
228.5 m^3/hr	- 0.05 %

Table 1 Danfoss SONO 2000 pre-calibration results. The meter was calibrated up to 70% of full scale flow, at 24.1 °C.

In Table 2, and Figures 2 and 3, the results from the calibration tests are shown.

Reference flow rate [m³/hr]	% deviation; Danfoss SONO 2000		% deviation; Panametrics Model 6468	
	26D Test	10D Test	39D Test	10D Test
300	- 1.01	- 1.85	- 2.38	- 2.29
300	- 1.22	- 1.50	- 0.64	- 3.05
300	- 0.94	- 1.78	- 0.80	- 3.13
260	- 0.80		- 1.22	
260	- 0.73		- 0.68	
260	- 1.27		- 1.34	
198	- 0.78	- 1.60	- 0.25	- 2.69
198	- 0.86	- 1.67	- 0.21	- 2.50
198	- 0.97	- 1.65	- 0.68	- 3.23
127	- 0.94		- 1.25	
127	- 0.98		- 0.94	
127	- 1.02		- 1.25	
127	- 0.88		- 1.31	
127	- 1.03		- 1.23	
65	- 2.26		- 1.49	
65	- 1.89		- 1.25	
65	- 1.99		- 1.02	
33	- 2.53	- 3.47	- 0.19	- 0.79
33	- 2.78	- 4.01	0.04	- 2.57
33	- 2.70	- 3.56	0.34	- 2.55

Table 2 Results from calibration tests at Hydro Porsgrunn. During the entire test period, the fluid temperature varied between 25.0 and 28.0 °C.

Volume flowrate	Uncertainty
28.3 m³/hr	± 1.56 m³/hr, or ± 5.5 %
56.6 m³/hr	± 1.70 m³/hr, or ± 3.0 %
113.2 m³/hr	± 1.98 m³/hr, or ± 1.75 %
169.8 m³/hr	± 2.26 m³/hr, or ± 1.33 %
226.4 m³/hr	± 2.55 m³/hr, or ± 1.125 %
283.0 m³/hr	± 2.83 m³/hr, or ± 1.0 %

Table 3 Danfoss SONO 2000 claimed measurement uncertainty for a 4" meter.

In principle, given that the calibration conditions were equal, one would expect the results from the two calibrations to be equal, within the repeatability of the meter.

However, it was not possible to repeat the results obtained during the pre-calibration of the meter. Since no information of the installation conditions for the pre-calibration of the meter is available, it is difficult to identify the reason for this deviation. If we compare the results in Table 2 with the specified meter uncertainty, see Table 3, the Danfoss SONO 2000 obtained results that were within the claimed measurement uncertainty of the meter for the 26D inlet length test.

It is well known that the flow profile has an influence on the performance of a single or multi beam ultrasonic meter. The effect of the 90° bend section on the Danfoss meter is shown in Figure 2, where the results for the maximum straight pipe-length tests and 10D tests are compared.

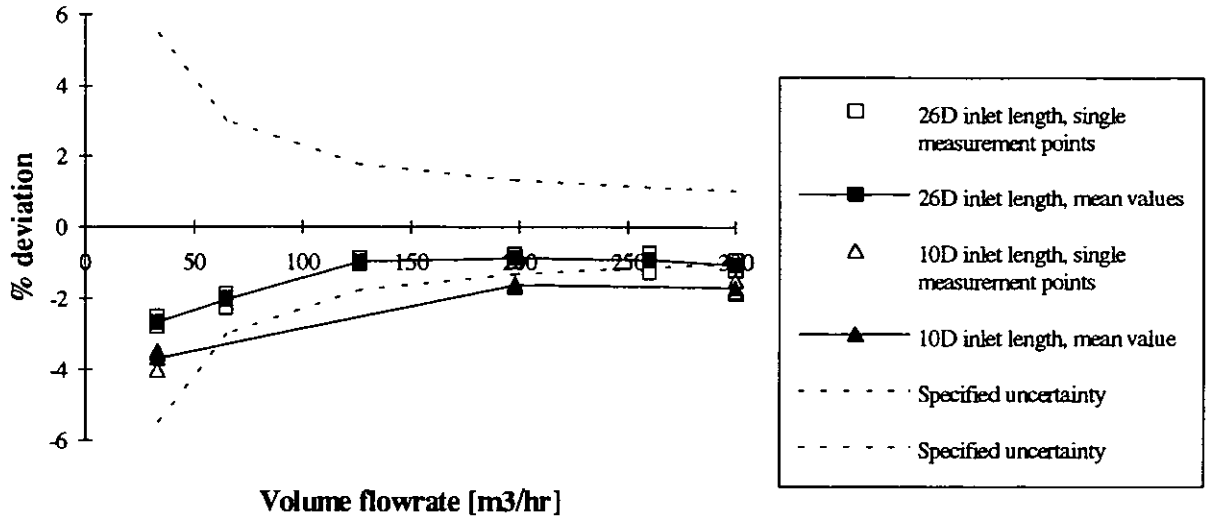

Figure 2 Danfoss SONO 2000, results from tests with 26D straight pipe-length upstream to a 12" to 4" conical diffuser, and 10D straight pipe-length upstream to a 90° bend. Temp = 25.0 - 28.0 °C.

3.6 Test results for Panametrics Model 6468

The Panametrics Model 6468 was not pre-calibrated prior to the calibration test. A zero-calibration was carried out on-site in the test rig at Hydro Porsgrunn. The zero-calibration procedure was based on the assumption that the speed of sound for the two ultrasonic paths were equal during the calibration period. Thus, this zero-calibration procedure requires steady state zero-flow conditions and a homogeneous temperature in the cross section. It is difficult to state that this was the case or not during the calibration period.

Panametrics claims a system accuracy of ± 1.0% of reading for velocities above 0.3 m/s. For a pre-calibrated system, a ± 0.5% of reading is claimed. The repeatability is claimed to be typically 0.2% of full scale, giving approximately 0.02 m/s for the 4" version with 330 m^3/hr full scale output.

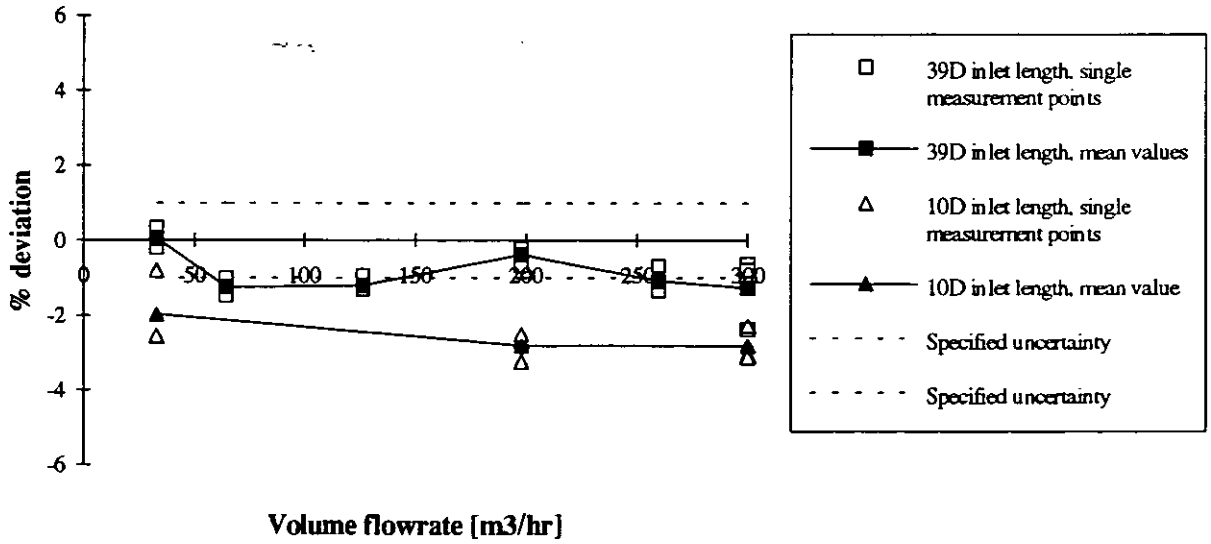

Figure 3 Panametrics Model 6468, results from tests with 39D straight pipe-length upstream to a 12" to 4" conical diffuser, and 10D straight pipe-length upstream to a 90° bend. Temp. = 25.0 - 27.7 °C.

Figure 3 shows the test results for the Panametrics Model 6468. The test results did not meet the specified ± 1.0% accuracy specifications for all flow rates, as indicated in Figure 3, although single measurement points were obtained within the ± 1.0% limit, see Table 2.

With reference to Figure 3, we can again observe the installation effect on the meter performance. As long as the flow profile is stable, the effect of a non symmetrical flow profile will result in an measurement curve offset.

4 FUNCTIONAL TEST ON OIL

4.1. Background

The main goal of the project was to determine the performance of the meters, particularly with regard to their ability to measure the volume flow of crude oil. In some applications, product flow must be measured before the oil has been completely separated, with the result that the oil may contain small quantities of water and gas. It was therefore desirable to determine how the meters performed under such conditions.

As it is a costly and comprehensive task to calibrate flowmeters in a crude oil flow-rig, they were calibrated with water at Norsk Hydro's calibration laboratory, and functional tested with oil at CMR.

The CMR multiphase flow rig used for the functionality test is shown in Figure 4. It is based around a 4" flow loop including a separator. The rig is equipped with a reference system for measurements of flow rate, temperature, pressure and density of the test media. Additionally, the water and gas fraction can be determined by an on-line water-in-oil monitor in conjunction with the density meter. By closing the valves at A and B, the separator can be disconnected, enabling closed loop test runs. For single phase test runs, this feature is advantageous.

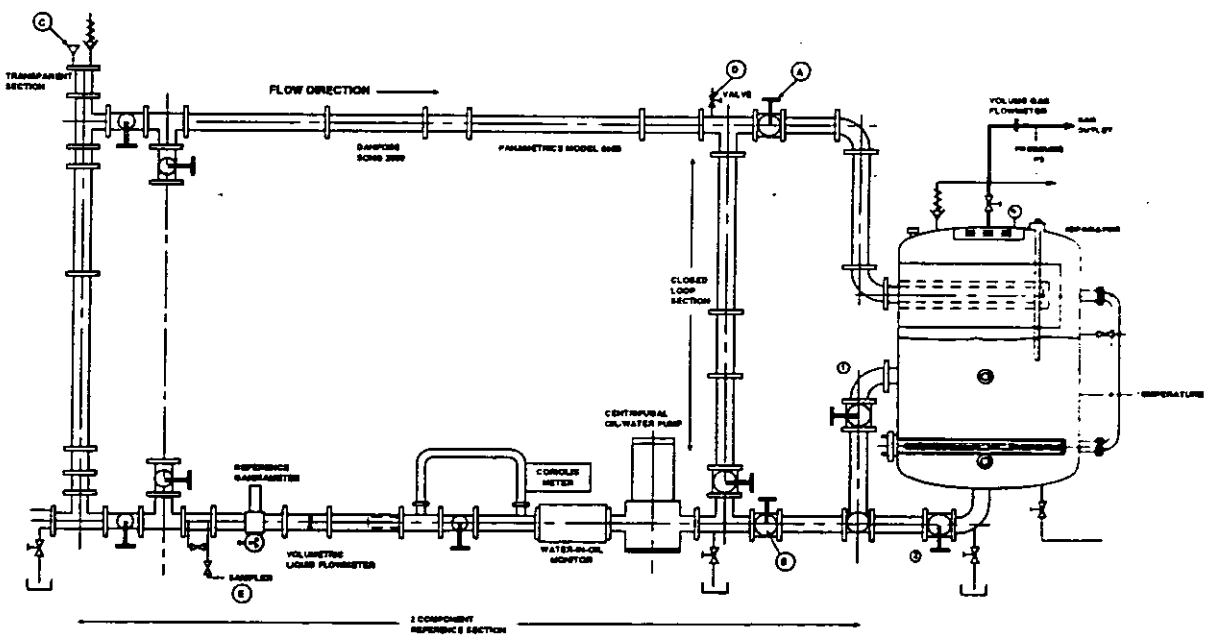

Figure 4 The CMR multiphase flow rig. The schematics shows the setup with the three ultrasonic flow meters installed in series.

4.2 Results from tests with low water fractions in the oil

The results from the low water fraction tests are shown in Figures 5 - 9.

During these tests, a 1.5" coriolis mass meter was used as the system reference. Thus, the maximum obtainable flowrate was approximately 27 m^3/hr. Thus, the tests had to be carried out at the lower end of the measuring range for the meters, increasing the measurement uncertainty. All measurements for the meters under test were carried out simultaneously, assuring identical reference conditions.

From Figure 5, we can observe the influence of water on the measurement performance for Danfoss SONO 2000. The % deviation for each of the 3 measurement points for each water fraction is shown. As can be seen, the deviation increases with increasing water fraction. However, it is not possible to state that the increase in deviation is solely due to an increase in measurement uncertainty of the ultrasonic meter. The influence on the coriolis meter must also be counted for.

The results for the Panametrics Model 6468 is shown in Figure 6. It should be noted that the Panametrics meter at this point probably was influenced by an internal error. This assumption was based on the observation that the volume flowrate output from one of the two channels seemed unstable with large variations at approximately steady flow. Accordingly, the total output from the meter was influenced by this instability. The cause of the error was not identified. The obtained measurements can not be said to be representative for the meter performance of the Panametrics Model 6468. Again, although the Panametrics Model 6468 most likely was influenced by an internal error, the measurement deviations must be viewed as a result of the water fraction influence on both the ultrasonic flow meter and the coriolis reference meter.

Figures 7 - 9 show of the test run measurement sequences for 0, 4.8 and 10 vol% water in the oil. These figures show the measurement instabilities of the Panametrics Model 6468. Compared to the performance of the Danfoss SONO 2000, it is very likely that the Panametrics Model 6468 did not operate properly during these tests.

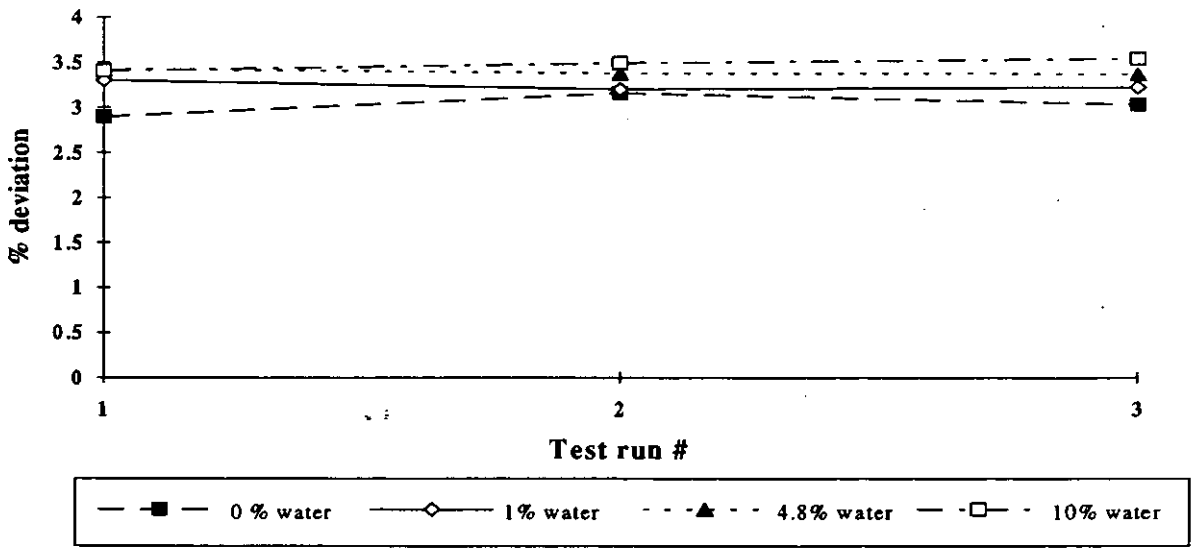

Figure 5 Results from functional test of Danfoss SONO 2000, with water fractions up to 10 vol%.

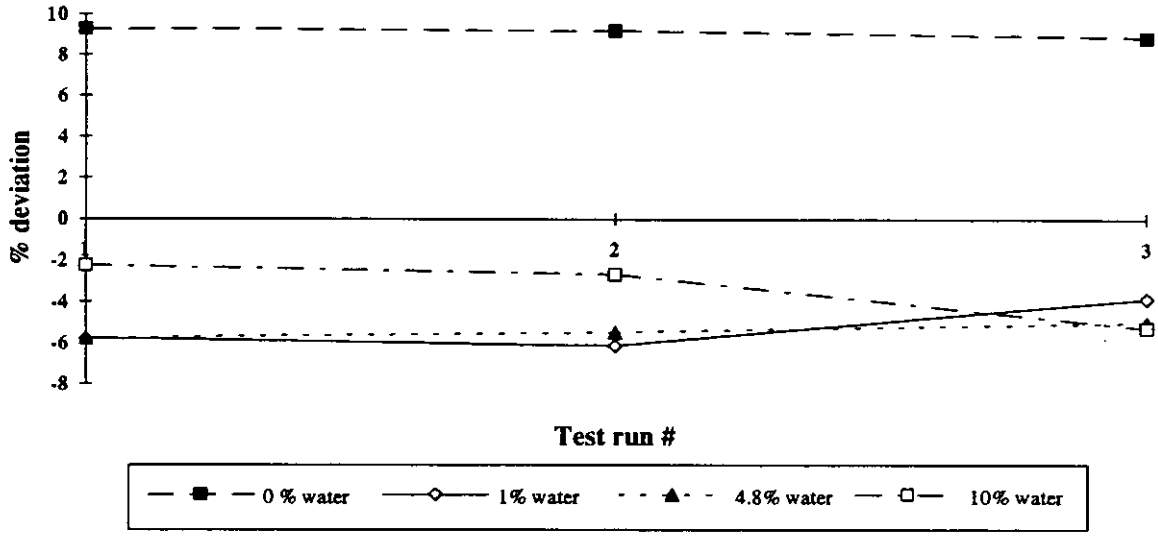

Figure 6 Results from functional test of Panametrics Model 6468, with water fractions up to 10 vol%.

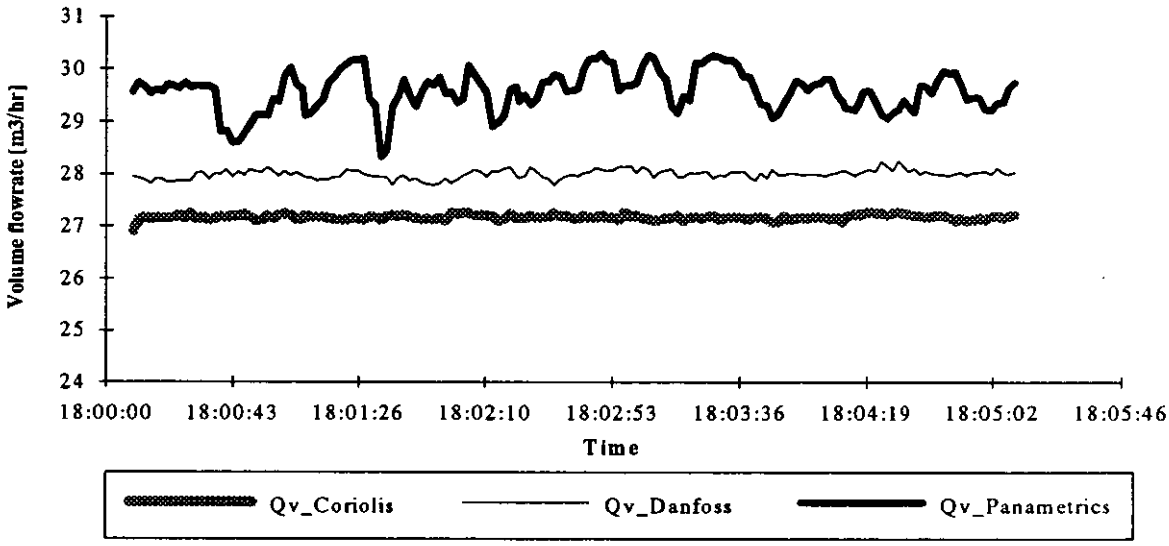

Figure 7 Functional test on diesel oil, 0 vol% water, test run # 3

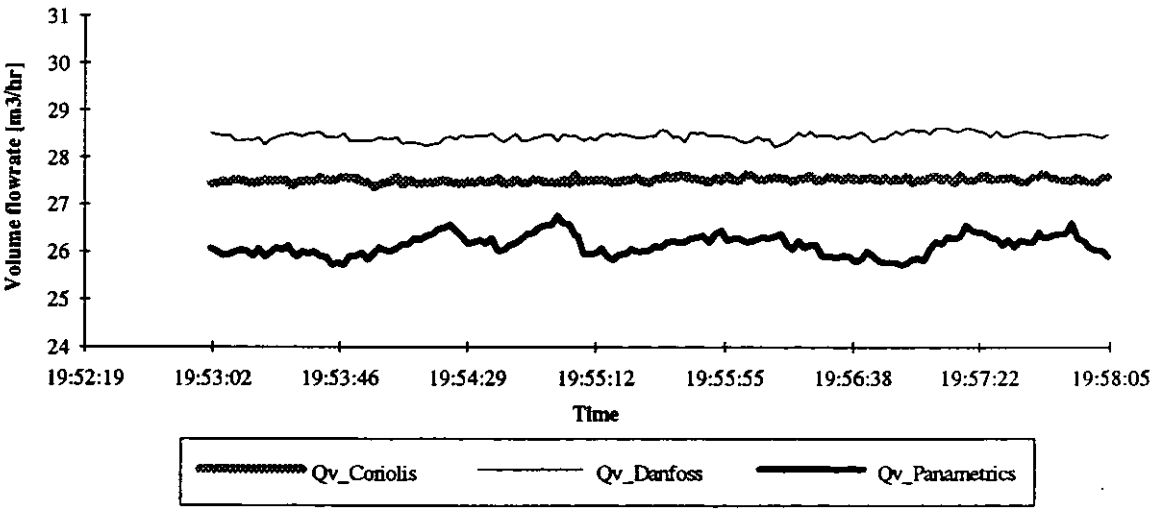

Figure 8 Functional test on diesel oil with 4.8 vol% water, test run # 3

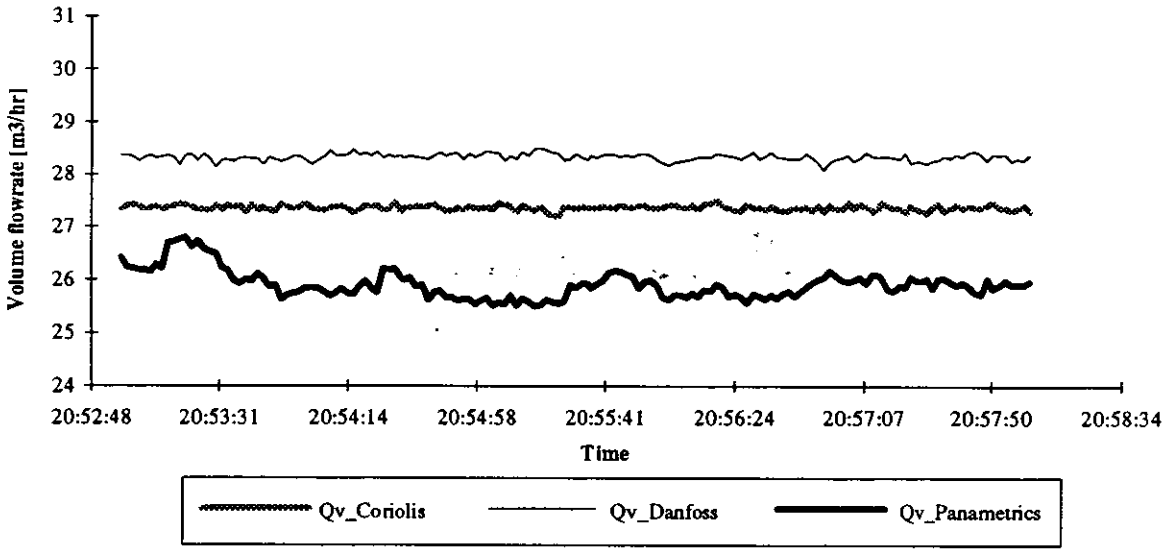

Figure 9 Functional test on diesel oil with 10 vol% water, test run # 3

4.4.3 Results from tests with low gas fractions in the oil

Initially, the test program was outlined in order to investigate how the meters performed with 1, 2 and 3 vol% of gas in the oil. However, at the initial gas fraction of 1 vol%, none of the meters operated properly. Thus, it was decided to revise the test program. By injecting 0.1 vol% of gas at a time, the aim was to determine the maximum gas fraction the flow meters could handle. With a total rig volume of 175 litres, the amount of gas to be injected at each step was 1.75 dl. The injection of gas was carried out by draining 1.75 dl of oil, and substitute that volume with air. The oil was drained from the sampling outlet, see Figure 5, E, and air injected through the valve at D. The measurement sequences were logged to files in the reference system computer, so that the test run sequences could be visualised through a spreadsheet. The results from the low gas fraction tests are shown in Figures 10 - 12.

In Figure 10, no air has been injected in the rig, i.e. the rig is completely filled with oil. Different flow rates are tested. In order to assure best mixing of oil and air, a highest possible flow rate was desirable. However, since the test was carried out as a closed loop test, a high flow rate would imply a temperature and pressure increase. To comply with these potential problems, a flowrate of approximately 40 m^3/hr was chosen as the test flow rate. At this flow rate, the increase in temperature and pressure was minimal.

In Figure 11, the measurement sequence during the period of which up to 0.4 vol% gas was injected in the rig is shown. The sequence shown in Figure 11 was started just after 1.75 dl of oil was drained from the rig. When the oil was drained, the valve at the top section of the rig, see Figure 15, D, was not opened. As can be seen from Figure 11, the injected air had little influence on the meter performances. At time A, another 1.75 dl of oil was drained from the sampling outlet. During this draining period, the valve D was opened, so that the drained oil was substituted with air. Now at least 0.1 vol% of gas was injected in the rig. The effect of the injected gas can easily be seen immediately after the pump was started. The Danfoss SONO 2000 did not perform correct measurements. However, the Panametrics Model 6468 is less influenced by the injected gas, although giving varying measurement output.

At time B, Figure 11, another 0.1 vol% of gas was injected. As can be seen, both meters are clearly affected by the increased gas fraction. The Danfoss SONO 2000 did not give any measurement output hereafter. Accordingly, 0.1 - 0.2 vol% was the maximum gas fraction at which the meter operated.

The influence of the injected gas on the Panametrics Model 6468 can be observed at time B and C, Figure 11, and further at time D and E in Figure 12. At time E, a total of 0.6 vol% of gas had been injected in the rig. An identical procedure was used each time the gas fraction was increased; the pump was stopped, the oil drained

from the sampling outlet E, Figure 15, and the valve D opened in order to inject gas. As can be seen from Figures 11 and 12, the Panametrics Model 6468 started operating a while after the pump was started each time the gas fraction was increased. The period of which the meter was not operating became longer as the gas fraction increased. Possible explanations for this behaviour may be:

1. An introduction of gas bubbles in a liquid will affect the transmission of sound in the fluid, [4]. The velocity of sound will change, and the acoustic absorption will increase. Both these parameters will influence the ability of an ultrasonic transit time flow meter to perform correct measurements. In order to investigate the effect of a possible change in the velocity of sound, a simple test was carried out. The receiver time gate of the Panametrics Model 6468 was varied, but with no apparent effect.

2. A decrease in the void fraction will reduce the acoustic absorption of the fluid. In similar tests with small gas fractions, (< 5 vol%) in a closed loop rig, the void fraction decreased towards zero with time if the liquid in the rig was circulated continuously, [5], because the gas is dissolved in the liquid. This is the most probable cause for the observed behaviour of the Panametrics Model 6468.

3. Also, we can not exclude the possibility that some of the injected gas was deposited in small cavities in the rig, e.g. in the coriolis mass flowmeter loop, reducing the amount of free gas in the circulating fluid.

From the figures, we can observe that the Panametrics Model 6468 gives a constant output value for limited periods of time, e.g. as in Figure 12, at time 14:09:36. This is due to a "hold last value" feature, i.e. if the meter does not carry out correct transit time measurements, the unit holds the last value until this is accomplished.

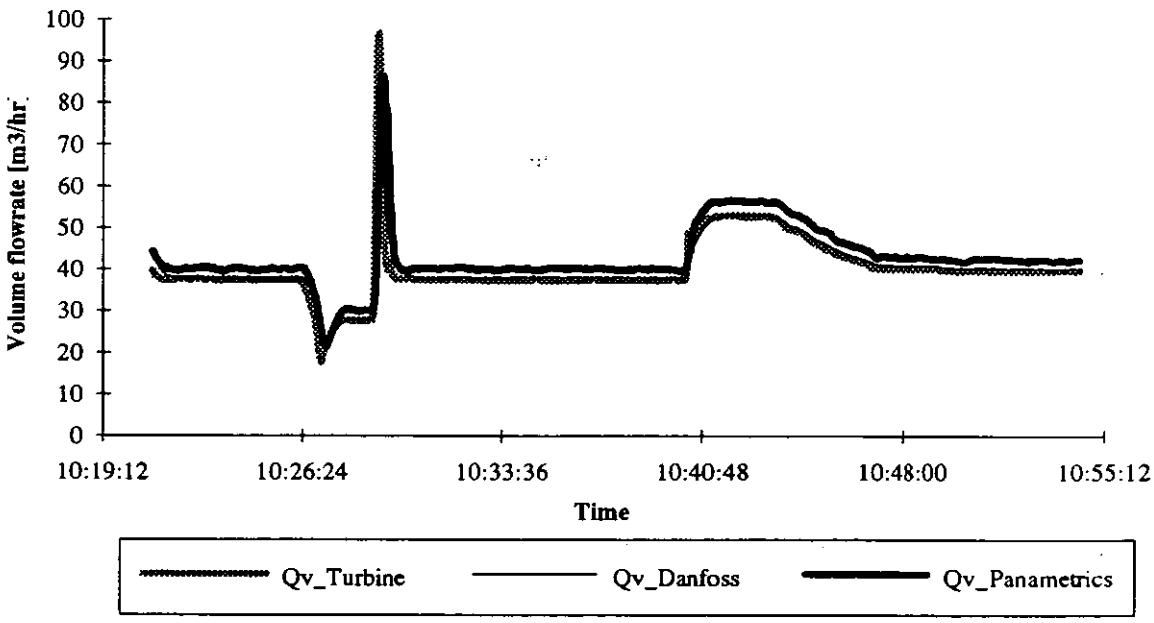

Figure 10 Functionality test on oil with small amounts of gas.
Measurement sequence with rig completely filled with oil.

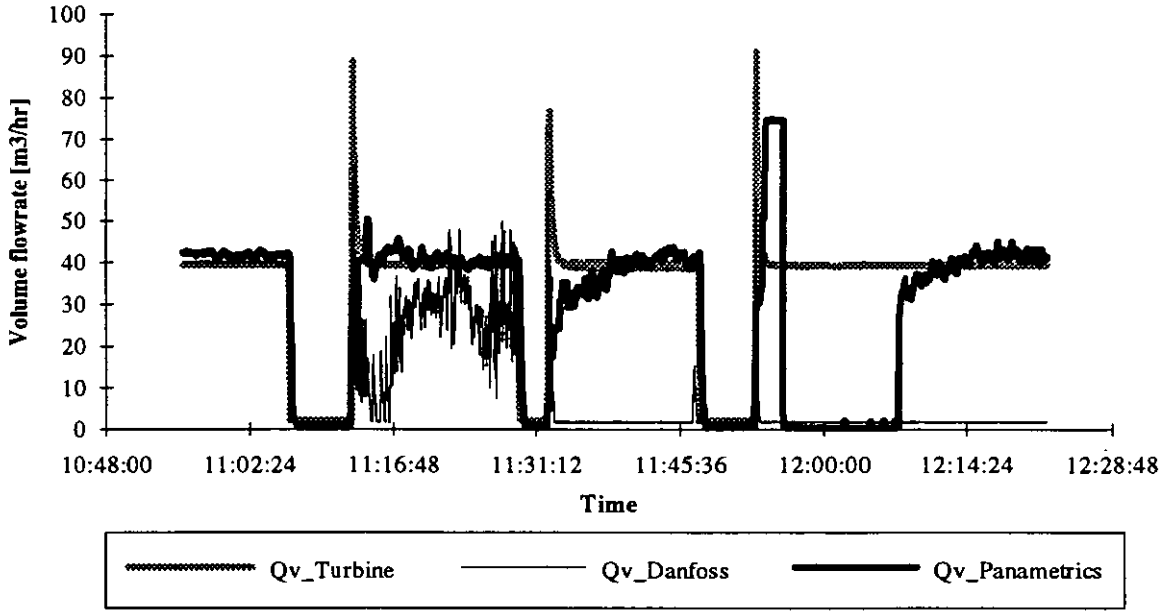

Figure 11 Functionality test on oil with small amounts of gas.
Injection of up to 0.4 vol% gas in the oil flow. Note that the Danfoss SONO 2000 does not give measurement outputs after 0.3 vol% gas have been injected in the oil, at approximately time 11:31:12. Also note the repeated measurement sequence for the Panametrics Model 6468 for each gas injection.

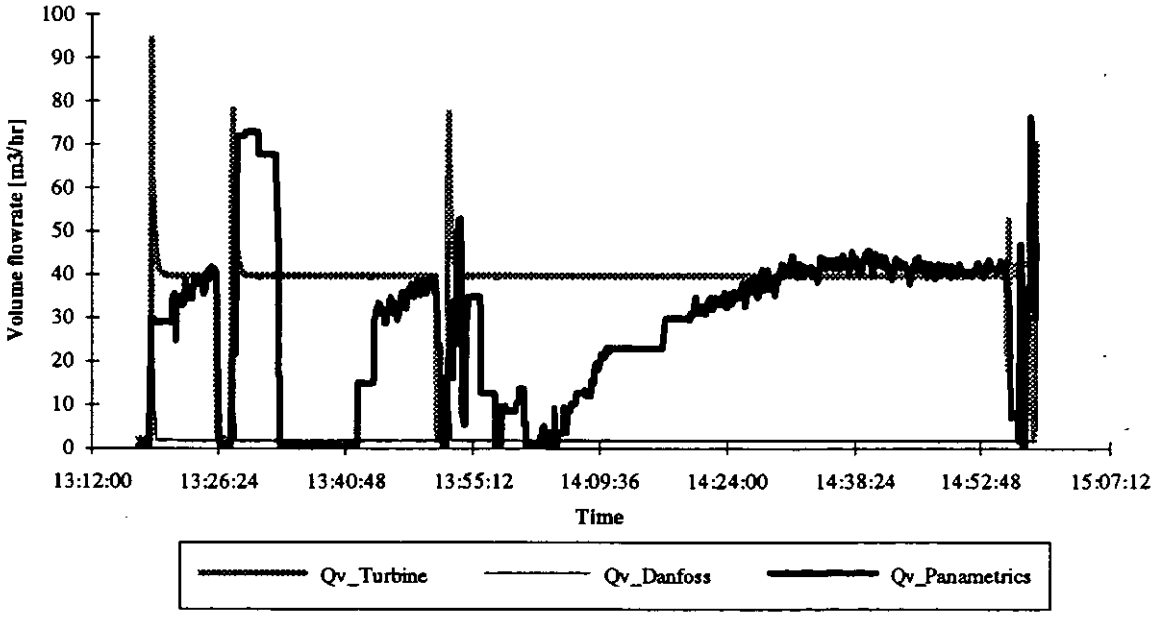

Figure 12 Functionality test on oil with small amounts of gas.
Injection of up to 0.6 vol% gas in the oil. Note that during this test sequence, the Danfoss SONO 2000 did not give measurement outputs, and the repeated measurement sequence for the Panametrics Model 6468 for each gas injection.

5 CONCLUSIONS

Calibration test
In order to obtain the meter performance for the ultrasonic meters, they were tested on water under ideal conditions. The aim of this test was to establish the measurement uncertainty. The calibration tests visualized the upstream pipe-length requirement for a two-beam ultrasonic meter. The results obtained with "maximum" and 10D inlet pipe showed that flow profile variations will affect the measurement uncertainty of the meters. Reducing the inlet pipe length from 26D to 10D resulted in an approximately 1% shift in measurement uncertainty. More than two beams are required in order to decrease the flow profile sensitivity, [3]. Furthermore, on-site calibration is required if the lowest possible measurement uncertainty is required. Comparing the results from the pre-calibrations and the calibration test at Hydro Porsgrunn supports this conclusion. The results from the tests deviate with approximately 1 %.

Functionality test with oil
The ultrasonic meters were tested on oil, at flow rates from 10 m^3/hr up to 90 m^3/hr. All three meters operated without any problems. The flow meters should operate equally well on stabilized crude oil.

Effect of water in oil
The meters were tested with up to 10 vol% water in oil, and operated without any difficulties. However, as the water fraction increased, the measurement deviations compared to the reference system increased. It is not possible to state that this is an effect solely due to an increase in the measurement uncertainty of the ultrasonic meters, since the reference meter also is influenced by the increased water in oil fraction.

Effect of gas in oil
The ultrasonic meters under test were designed for operation on liquids only, although Panametrics claims to handle "a small percentage of entrained gas", [2]. In [1], Danfoss states that the gas fraction should not exceed 1-2 vol%, in order for the meter to perform properly. The functionality test using oil with small amounts of gas injected, showed clearly that none of the meters on test managed to handle flow conditions with as little as 0.5 vol% of gas in the rig. It is though difficult to identify the exact void fraction, as we believe that some of the injected gas is dissolved in the oil with time, reducing the amount of free gas in the fluid.

However, the advantage of an ultrasonic meter is that it will either provide a "correct" measurement result, or give a warning to the operator. In the same measurement situation, most flowmeters will provide a seemingly normal reading without any error indication.

Future work
In order to be able to handle small percentages of entrained gas in the oil, ultrasonic meter design must be improved. Based on our experience with ultrasonic flowmeter technology, it is our opinion that the current designs can be improved to handle gas fractions which will make it possible to install an ultrasonic meter downstream of e.g. a 1st stage separator. It is not within the scope of this paper to state which technological improvements that are required. It is our impression that manufacturers of ultrasonic flowmeters are aware of the requirements of the oil industry, and are continuously making efforts to improve the performance of their flowmeters.

6 ACKNOWLEDGEMENTS

The author would like to express his thanks to Statoil, Norsk Hydro, Saga Petroleum and the Norwegian Petroleum Directorate for their support and cooperation throughout the project.

Also, the manufacturers should be acknowledged for putting the ultrasonic meters to disposal for the project free of charge, and a special thanks to Danfoss and Panametrics for the opportunity to publish the project results.

Finally, I appreciated the service and the enthusiasm shown by Bjørn M. Realfsen, Hans F. Drange and the rest of the staff at the calibration site during the test period at Hydro Porsgrunn.

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Main Index

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NORTH SEA FLOW MEASUREMENT WORKSHOP 1993

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Practical experiences with multipath ultrasonic gas flowmeters

by

Reidar Sakariassen
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Norway

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ABSTRACT

This paper will concentrate on experience gathered from laboratory tests and offshore field test of a 24" four-path ultrasonic gas flowmeter system. Experience with other dimensions and different marks will be mentioned when necessary to verify the general validity of the findings from the tests with the 24" system.

The paper will also describe basics of the measurement method, what could influence on the meter, how the meter behave, check possibilities and proposed check procedures.

Through the projects Statoil has learned a lot about this technology. Through this paper we wish to share our knowledge about a metering principle which we believe is a technique which will be widely used in the future.

CONTENTS

1 INTRODUCTION

Statoil is constantly searching for costeffective solutions offshore. This include also metering systems. Traditionally, metering systems based on orifice plates are bulky and heavy. Accordingly, the platform costs are considerable. The cost can be significantly reduced if the size of the metering systems is reduced [1,2].

Statoil has recently experienced that due to the increasing number of pipeline to come (Fig. 1), a large number of metering systems at one single riser platform could be required. The cost for large conventional metering systems with capacity up to 50 MSm^3/d installed at an existing riser platforms would be enormous.

In cross-overs between transportation systems bi-directional flow occurs and bi-directional measurement is required.

Those examples indicate Statoil's interest for compact metering systems. Statoil has seen the potential of compact metering stations based on ultrasonic gas flow meters. Fig. 2 indicates the difference in size between a convential metering station based on orifice plates and a system based on multipath ultrasonic flowmeter for bi-directional flow. The main reasons for the reduction in size is the increased flow capacity for a given dimension and reduced requirement for length of straight pipes.
For some more reflection concerning size,ref. is made to [3].

However, it is mandatory with high accuracy and reliability. To verify accuracy and reliability, Statoil has initiated and been actively involved in a number of projects aiming to verify the feasibility of ultrasonic flowmeters. Among those can be mentioned:

- tests at K-Lab of 6" meters of different marks and design
- development and tests at different laboratories of a 12" meter in cooperation with Fluenta/CMR [4]
- laboratory tests at K-Lab and six months field tests at riser platform 16/11-S (Statpipe) of a 24" system
- laboratory test at K-Lab and offshore installations of a 12" system

From these activities it has been possible for Statoil to learn how these meters behave, which precautions should be taken to obtain and maintain accuracy and which checks to be performed. Also, we have been aware of what could cause problems for such meters and what should be looked further into in the future. In close cooperation with the manufacturers, it has been possible to improve the equipment and propose modifications.

Through this paper it is our intention to share with other potential users of such technique the knowledge necessarry to improve the probality for successful use of ultrasonic gas flow meters.

2 BASICS OF THE MEASUREMENT METHOD

The description in this chapter is partly based on fundamental theory and partly on findings and observations during our projects.

2.1 Basic principles for the velocity measurement

The basic principle of the meters is based on the well established transit time difference. It utilize the fact that the propagation velocity of an acoustic pulse is modified by the flowing gas. An acoustic pulse will propagate faster with the flow than against the flow.
The basic principle is described in Fig. 3.
Ideally, the transit time is the time between the acoustic pulse is passing the imagary points where the intertransducer line is crossing the flush with the inner pipewall.
The formulas used in Fig. 3 is a practical formula which takes into the consideration the fact that in practice the transducers are set back a certain distance from the pipewall. Another practical solution is described in [4].
It must be underlined that with the practical solutions described above, it is the transit times between the transducers' outer fronts that is the transit time to consider.

Based on the transit times, the **velocity of sound** is measured as $(t_{AB} + t_{BA})/(2L)$. As will be seen later, the velocity of sound can be used as check parameter.

2.2 Volume flow measurement

To determine the the volume flow, the average velocity over the cross sectional area of the pipe, more pair of transducers is mounted. The principle is described in Fig. 4.

2.3 The ultrasonic transducers

Before proceeding to the various aspects of the ultrasonic meters, I think it is worthwile to describe and explain the functions of the ultrasonic transducers.

An example of a design of a transducer is shown in Fig. 5 [5]. The active part of a transducer is the piezoelectric crystal. By applying a voltage to the crystal at a certain frequency, the crystal itself will start to oscillate at the same frequency resulting in pressure wave (acoustic wave) radiations from the crystal. Also, a short voltage "kick" to the crystal start an oscillation of the crystal at a frequency given by the type, size and form of the crystal. The normal frequency range for high pressure gas meters is 100 - 200 kHz. The crystal works also opposite: Applying a pressure change results in the generation of a voltage change across the crystal picked up by the electrodes.

The tricky things with such transducers is to have radiation patterns (lobes) so the radiation hits the receiving transducer and enough acoustic energy is transferred into the gas from the generating transducer and from the gas into the receiving transducer. This latter requirement is

the difficult part. The combinatination of mechanical protection and matching of the acoustic impedances between gas and tranducer material is hard to achieve.

As can be seen from Fig. 5, there is a distance between the transducer front and the active crystal. The time of interest is from when the acoustic signal pass the front end of the emitting transducer till it pass thr front end of the receiving transmitter. The direct measured time is from the voltage is applied to the generating crystal till a voltage is generated by the receiving crystal. Therefor the measured transit time needs to be corrected to arrive at the time of interest. This time correction is often referred to as **the transducer's delay time**. Normally, the delay time, with the symbol τ, is in the order of 10 µs.
It is a fact that this delay time is not the same for a transducer when it is acting as a transmitter and as a receiver. For a pair of transducers the total delay time will therefor not be the same for both directions,
The time delay also differs slightly between transducers. For different pairs of transducers, the total delay time will therefor not be the same.

Determination of the transmitters' acoustical behaviour, the delay times and the length of the transmitters are the most important parameters the manufacturer should determine.

2.4 Detection of received acoustic signal

The acoustic pulse signal consist of a number of periods. The piezoelectric crystal in the reciever needs to "see" a certain signal amplitudes of the periods to correctly detect the exact point of time when the signal is received. Fig. 6 indicates ways of detecting the pulse: Either based on pulse amplitude or on priod pattern recognation.

It is necessary to always detect the received signal at the same period as when the delay times were determined or when the laboratory calibration of the meter took place. This needs to be regular checked by use of oscilloscope.

If the detection systems hits the wrong period, the result will be an error. To illustrate the magnitude of the error the following example is given for the 24 " meter investigated:

Missing detection by one period in both direction the resulting error is 0.5% of velocity.
Missing detection by one period in only one direction, the resulting error is $\sim$1.5 m/s.

Reason for not detecting the correct period is that either the acoustic signal is too weak because of:

- bad transducers (loose crystal)
- too much deposit on the transducers
- signal damping along the acoustic path because of temperature gradient

or there is too much noise because of

- too much noise from external sources compared to signal strength
- too much signal left from the previous acoustic "shot"
- electrical noise

2.5 Time delay in tranducers

As mentioned in 2.3, it is necessary to know the tranducers time delay.

For a pair of transducers this is determined by the manufacturer and given in certificate for the transducers. See example of a transducer certificate in Fig.7.

The delay times could however be influenced by the way the transducers are installed and possibly also by the temperature. It is therefore recommended to check the time delays after the meter is installed.

To understand the way the ultrasonic flowmeters could be checked, it is absolutely necessary to understand the importance of the delay times.
Based on measured "transit times" (which are not the true transit times as explained in 2.3) the expression for the gas velocity is as follows:

$$v = \frac{L^2}{2x} \frac{(t_2' - \tau_2) - (t_1' - \tau_1)}{(t_2' - \tau_1)(t_1' - \tau_1)} = \frac{L^2}{2x} \frac{(t_2' - t_1') - (\tau_2 - \tau_1)}{(t_2' - \tau_2)(t_1' - \tau_1)}$$

where

t' is measured "transit times"
τ is delay times
subscript 1 is for upstream direction
subscript 2 is for downstream direction

The delay times are entered into the flow computer.

Knowing that a transit time difference of 3 µs means approximately 1 m/s one can understand that the delay time difference (τ_2 - τ_1) needs to be determined by an accuracy of 0.03 µs to have an uncertainty of 0.01 m/s which means 1% at 1 m/s.

It is assumed that the absolute delay times are determined by an uncertainty of 0.5 µs. For the 24" meter investigated this means an uncertainty of approximately 0.05%.

To have a precise determination of the difference in the time delays, the meter is zero checked. When the flow is definitely zero, it is possible to **adjust the delay times** to obtain a reading of gas velocity on all pairs (or chords) to be exact zero. This is the socalled **zero flow check.**

This zero check should be done at a temperature close to normal operating temperature. From the testing of the 24" meter there are indications that there is a temperature effect on the zero reading of approximately +0.0003 m/s pr. °C. This corresponds to a temperature effect on the delay time difference of 0.001 µs.

2.6 Velocity of sound along the acoustic path

The description given in 2.1 and the formula in Fig. 3 is only correct if the velocity of sound in the cavity between the pipewall and the transducer front is the same as witin the cross section of the pipe.
If this cavity is deep, care should be taken to ensure that this is the case. For the four-path 24" meter extensivly investigated, the conditions can be illustrated as in Fig. 8. The main practical problem arises when the gas gas is much warmer than the ambient. This could cause a temperature gradient in the cavity and consequently also a gradient in the velocity of sound.

If the temperture gradient causes the average velocity of sound along the acoustic path to be changed by 1 m/s, the effect on measured velocity is affected by 0.5% for our 24" meter.

Velocity of sound decreases by approximately 1 m/s as temperature decreases with 1 °C at our normal conditions.

A way of checking the effect of the temperature gradient on the velocity of sound is to compare the measured velocity of sound with calculated velocity of sound. As mention in 2.1, velocity of sound is measured by an ultrasonic flowmeter. A program SONFLOW [6] makes it possible to calculate the velocity of sound very accurate.

The way to minimize this problem is to insulate the meter very carefully.

3 CONTENT OF THE TESTS

A complete 24" metering systems consisting of the ultrasonic flowmeter itself, inlet and outlet pipe sections, pressure transmitter, temperature sensors, density sensor and flowcomputers was tested at K-Lab before and after a test periode of 6 months at the riser platform 16/11-S in the Statpipe system.

At K-Lab it was very long straight pipe upstream the meter. At 16/11-S the meter was installed 10 D downstream a single horizontal bend.

The flow capacity of K-Lab limits the gas flow velocity tomaximum 2.2 m/s which is only approximately 10% of the meter's total range. The temperature was 37 °C.

At 16/11-S the gas flow velocity was normally between 2 and 5 m/s. Maximum velocity during the test was 12 m/s for a short while. The pressure varied between 72 and 100 bar and temperature 4 - 7 °C.

Fig. 9 shows the complete system. Its weight is about 15000 kg. It capacity with the conditions at 16/11-S is 45 MSm^3/day.

Fig. 10 shows its position in the transportation system.

The systems generates local reports at the platform. Data were also transferred to the Transportation Control Center, Bygnes. We were especially interested in how reliable the system would operate. Besides, it was also possible to check its measurement results against other orifice metering systems.

4 TEST RESULTS

4.1 K-Lab results

Fig. 11 shows the result from the K-Lab tests as deviation against K-Lab references before and after the test period at 16/11-S.

It seems to be a shift in calibration after the meter has been at 16/11-S. The shift can, however, be explained by the effect described in 2.6:
The first test was done in December -92 and the second was done in July -93. The difference in ambient temperature has affected the velocity of sound in the cavity. This is verified by an analysis of the velocity of sound logged during the tests. See Fig. 12. The conclusion is that the meter was not sufficient insulated in December resulting in an 0.5% error. The meter were adjusted by modifying the delay times corresponding to 0.5% as described in 2.5.

The conclusion from the K-Lab tests is that the meter was in reality adjusted to read 0.5% too high prior to the test at 16/11-S

4.2 Analysis of the velocity of sound

As mention in 4.1, an analysis of the speed of sound indicated a problem with the insulation.

A further analysis of the velocity of sound can be done by comparing velocity of sound in the individual chords. This is shown in Fig. 13 and 14. It can be seen that in December it was very large differences between the chords. It can also be compared with results from 16/11-S as shown in Fig. 15 where there is almost no difference among the chords.

To indicate that this problem is related to the deep transducer cavities, results from a five-path meters with almost no cavities at all, is shown in Fig. 16.

The conclusion is that comparison of measured velocity of sound against calculated is a good day-to-day check. So is also an intercomparison between the chords.

4.3 Results from 16/11-S

When adjusting for the wrong adjustment of the meter at K-Lab in December, the comparison between the ultrasonic meter and orifice meter system showed a steady deviation of 0.3-0.5 % through the whole test period from February till June 1993. No dependance of flowrate or pressure was observed.

One significant shut-down of the meter occurred: At one occasion the pressure drop across a control valve 10 m from the meter created noise estimated to more than 105 dBA. This generated too much noise for the meter. When the noise decreased below 105 dBA, the meter started functioning again. The shut-down lasted for 20 minutes.

The meter was exposed to foreign matters in the gas. When the transducers were taken out of the meter after the tests at 16/11-S, it was observed that the cavity had been almost filled up with oily liquid. It was however no indications that this had caused problem during the offshore tests.

Conclusion from this tests is: The meter had function satisfactory. If high pressure drop is expected across control valve near the meter, use valves that generate little noise.

4.4 Velocity profile

With multipath ultrasonic flowmeter one can also get information about the velocity profile in the pipe.

Fig. 17 shows normalized velocity profile at 16/11-S for different flowrates. These indicate normal situations.

Fig. 18 shows simular results at K-Lab. Results with 12", 24", five- and four-path are consistent and indicates assymetric profile at low flowrates.

The velocity profile should also be used as day-to-day check.

5 CONCLUSIONS FROM THE TESTS

Through this project - and other similar projects - it has been shown that ultrasonic flowmeters can be accurate and reliable also in offshore situations.
As for other methods, some precautions have to be taken, such as:

- good insulation of meter with deep transducer cavities
- avoid noise generated from control valves close to the meter above 105 dBA

Before the meters are installed at the site of application, a complete flowcalibration should be performed.

By controlling the acoustic signal level, checking gas velocity profiles, velocity of sound measuremets and on-line zero checks it is fully possible to avoid later recalibration in flow laboratories.

6 FURTHER INVESTIGATIONS

Like with all other types of flowmeters, it is interesting and useful to know more about the meters.

The items that Statoil would study further in the near future is

a) to quantify more precisely the amount and type of deposit on the transducer the meter can cope with

b) to quantify more precise what level of noise from control valves it can withstand and if the type of valve is of any importance

c) to study more the temperature effect on the transducers.

Statoil would like to cooperate with other companies in such studies.

7 ACKNOWLEDGEMENTS

The author would like to thank the Statpipe Joint Venture Partners for allowing the tests to be run at 16/11-S and the Zeepipe Joint Venture Partners for the use of their meters in the tests. Further, the personell at K-Lab and 16/11-S for their good cooperation, efforts and enthusiasm that made the tests possible.

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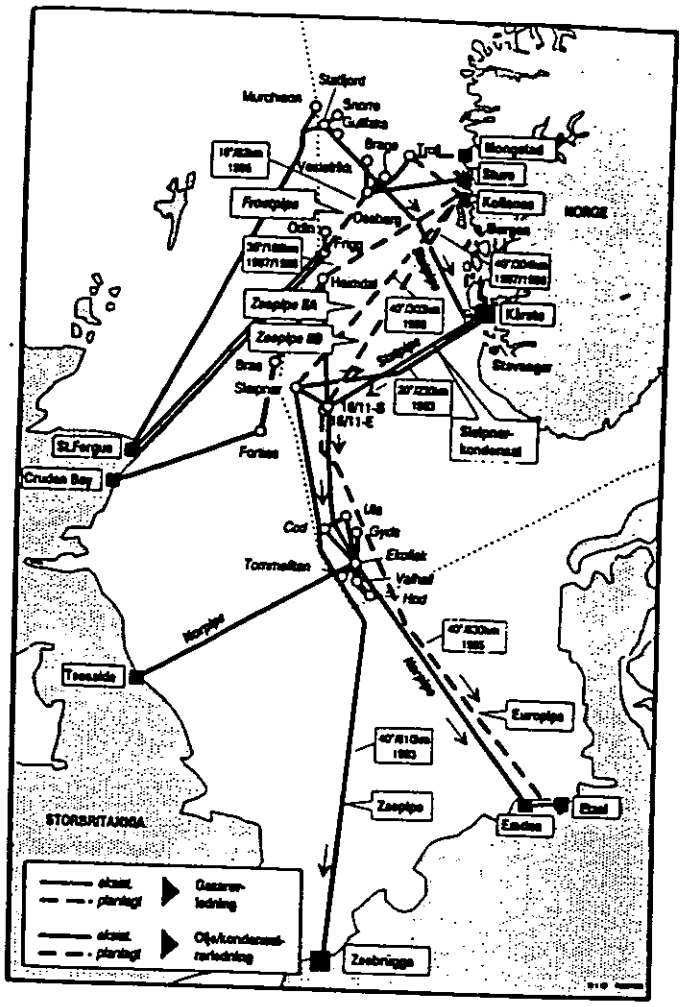


Fig.1 Existing and coming pipelines in the Norwegian sector

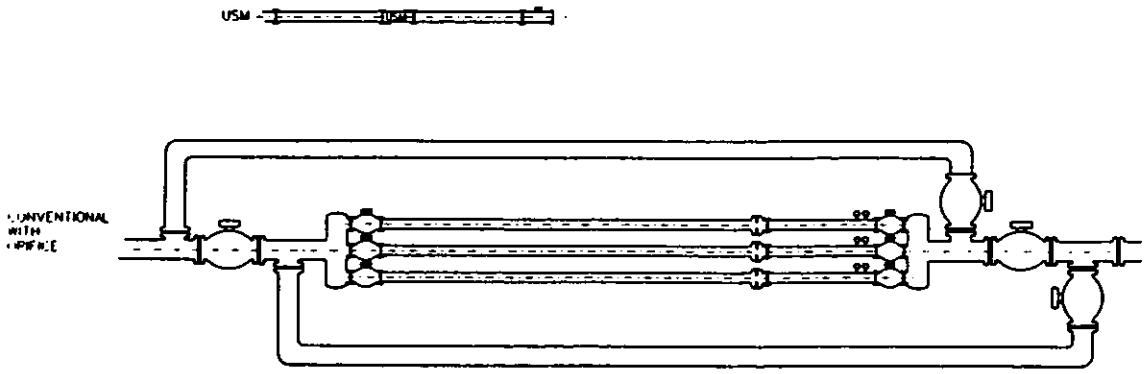
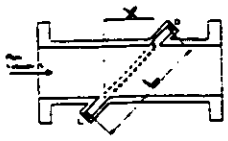


Fig.2 Possible difference in size between bidirectional meter based on ultrasonic flowmeter (USM) and orifice plates

Single-path meter



c = velocity of sound in the gas

$t_{AB} = L/(c + v \cdot (X/L))$; $t_{BA} = L/(c - v \cdot (X/L))$

Subtracting the reciprocals of these times and re-arranging gives:

$v = ((t_{BA} - t_{AB}) / (t_{AB} \cdot t_{BA})) \cdot L^2/(2 \cdot X)$

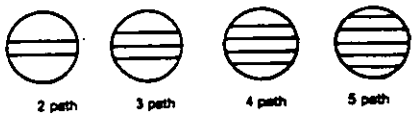
$q_v = A \cdot v$

A being the cross sectional area of meter spool piece

Fig.3 Basic principle for transit time difference flowmeters

Multi-path meter

By increasing the number of path improved performance is obtained.



Integration methods will combine the individual measured velocities to obtain the average velocity over the cross sectional area:

$$\bar{v} = \sum_{i=1} W_i \cdot v_i$$

where W is the weighing factor.

Fig. 4 Multi-path ultrasonic flowmeter

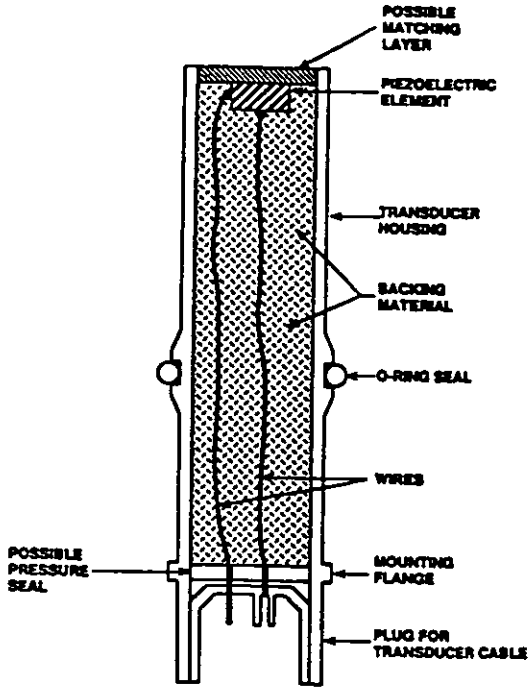
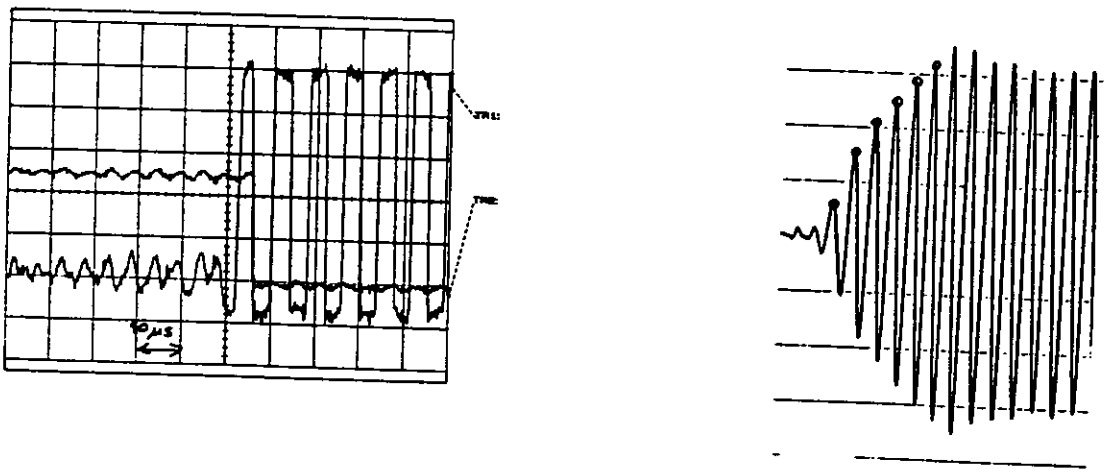


Fig.5 A possible design of a ultrasonic transducer



a b

Fig.6 Detected received pulses
a) Pulse amplitude detection
b) Pulse pattern recognisition

TITLE

ULTRASONIC TRANSDUCERS
TEST CERTIFICATE

Meter Serial No. N/A **Pipe Area** N/A ft^2

Chord No.	N/A	
Basic Transducer Distance L (inch)	N/A	
Transducer length Side 1 (inch)	1.9265"	
Transducer Length Side 2 (inch)	1.9305"	
Corrected Transducer Distance "L" (inch)	N/A	
Corrected Transducer Distance "L" (feet)	N/A	
Component Path In Flow X (feet)	N/A	

"L" (feet) = "L" (inch) / 12

Transducer Distance "L" = Basic Transducer Distance L + (Length Side 1 + Side 2)

Transducer Serial No. Side 1		
Transducer Serial No. Side 2	[illegible]	
Transducer Delay Side 1 (μsec)	25.66009562	
Transducer Delay Side 2 (μsec)	25.60176228	
Date	12.2.93	
Signature	[signature]	

Fig.7 Example of a transducer certificate

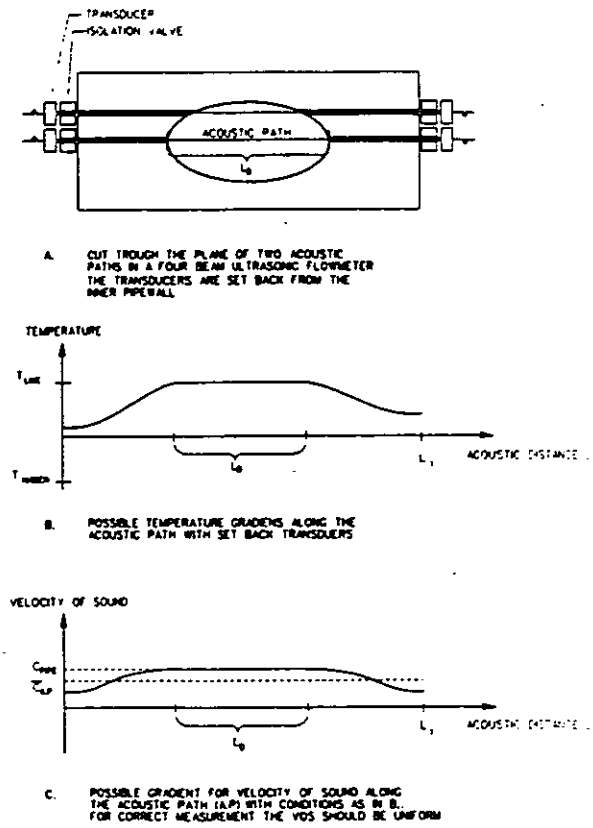


Fig. 8 Condition with deep transducer cavities

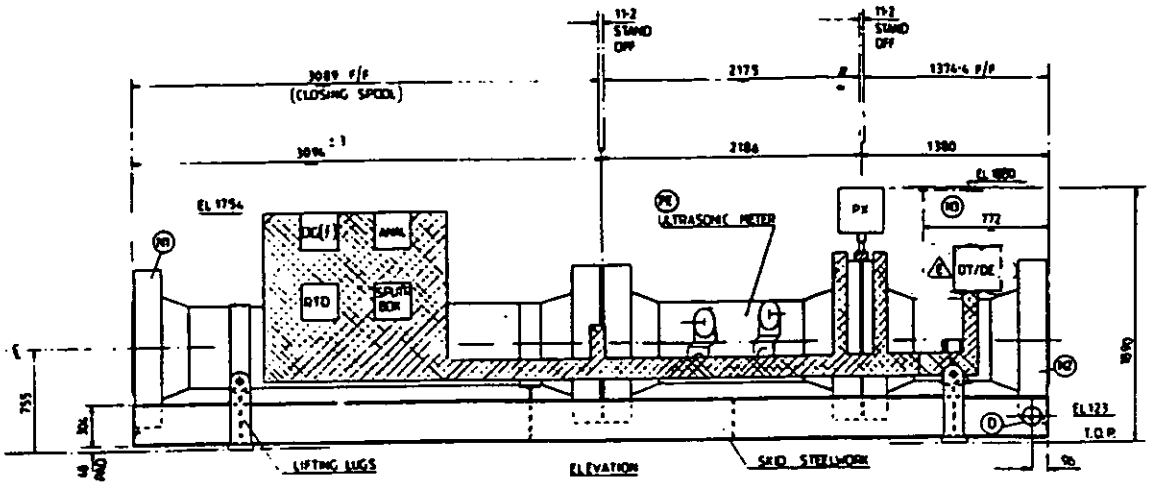


Fig. 9 The 24" ultrasonic metering skid

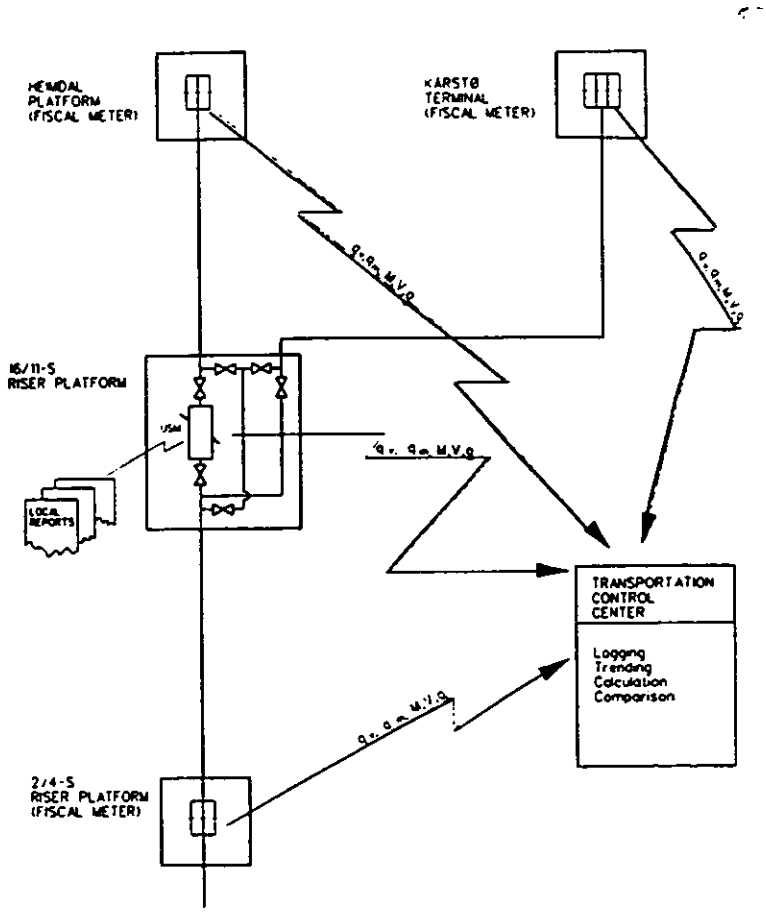


Fig. 10 Position of the meter's location in the transportation system

FIG. 11 24 " USM CALIBRATION TESTS AT K-LAB 100 BAR AND 37°C

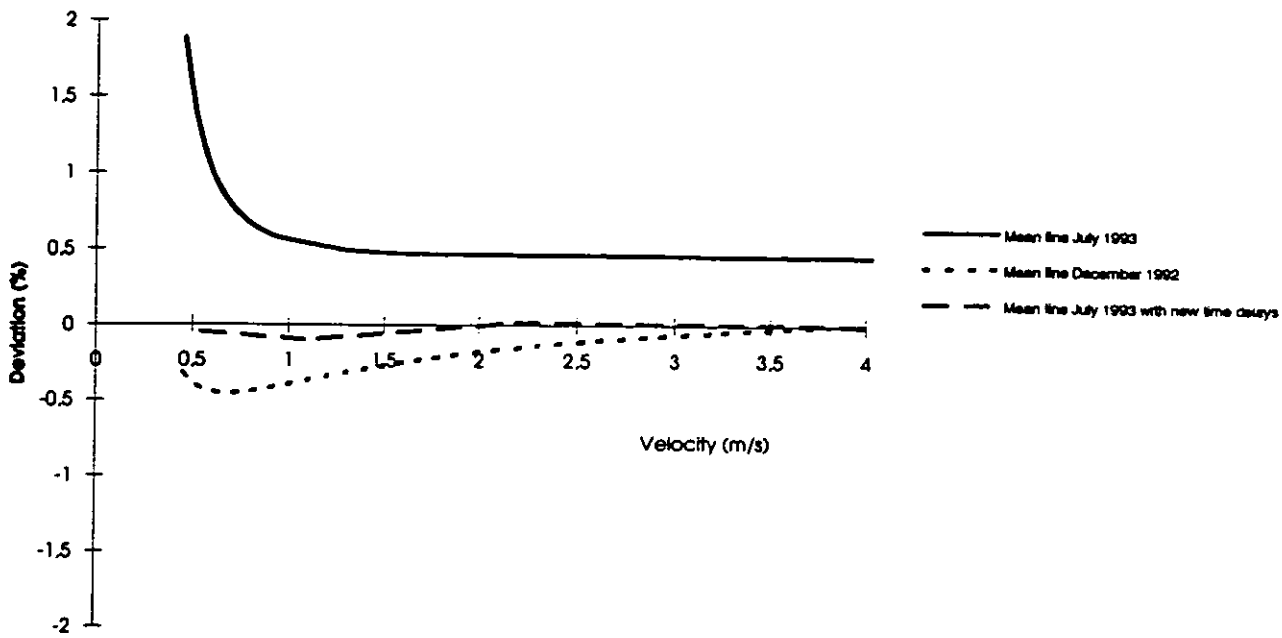


FIG. 12 24 " USM DEVIATION BETWEEN MEASURED AND CALCULATED VELOCITY OF SOUND AS FUNCTION OF GAS FLOW VELOCITY

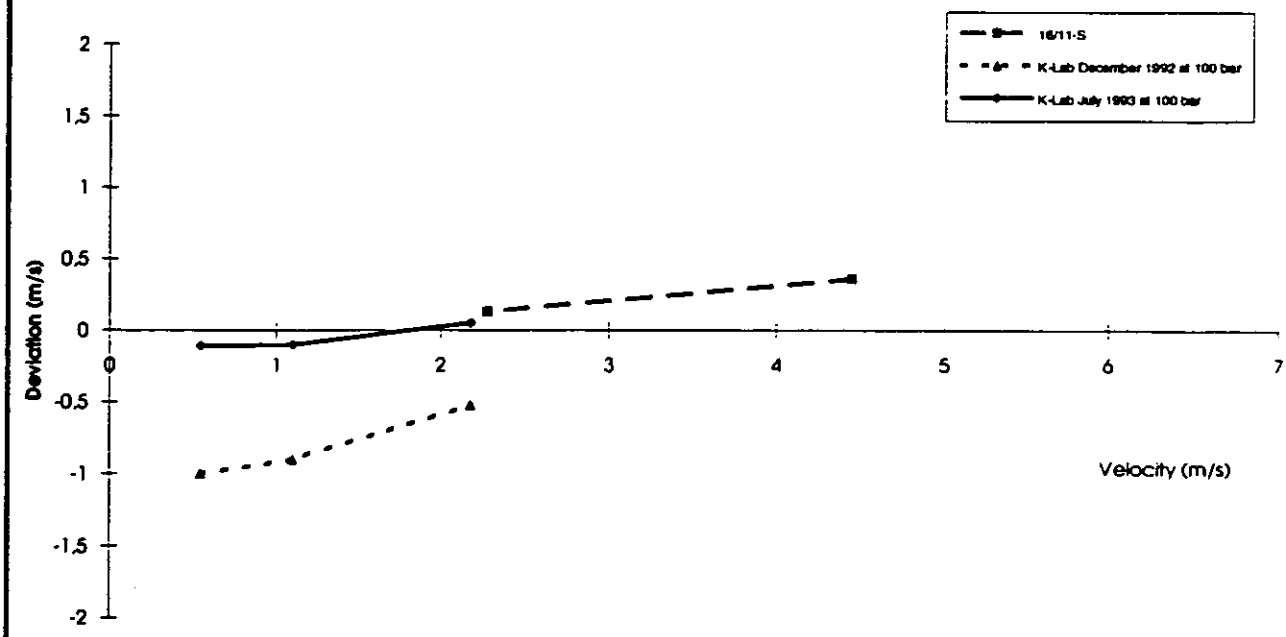


FIG.13 24" USM VELOCITY OF SOUND PROFILE AT K-LAB JULY 1993 FOR DIFFERENT GAS VELOCITIES

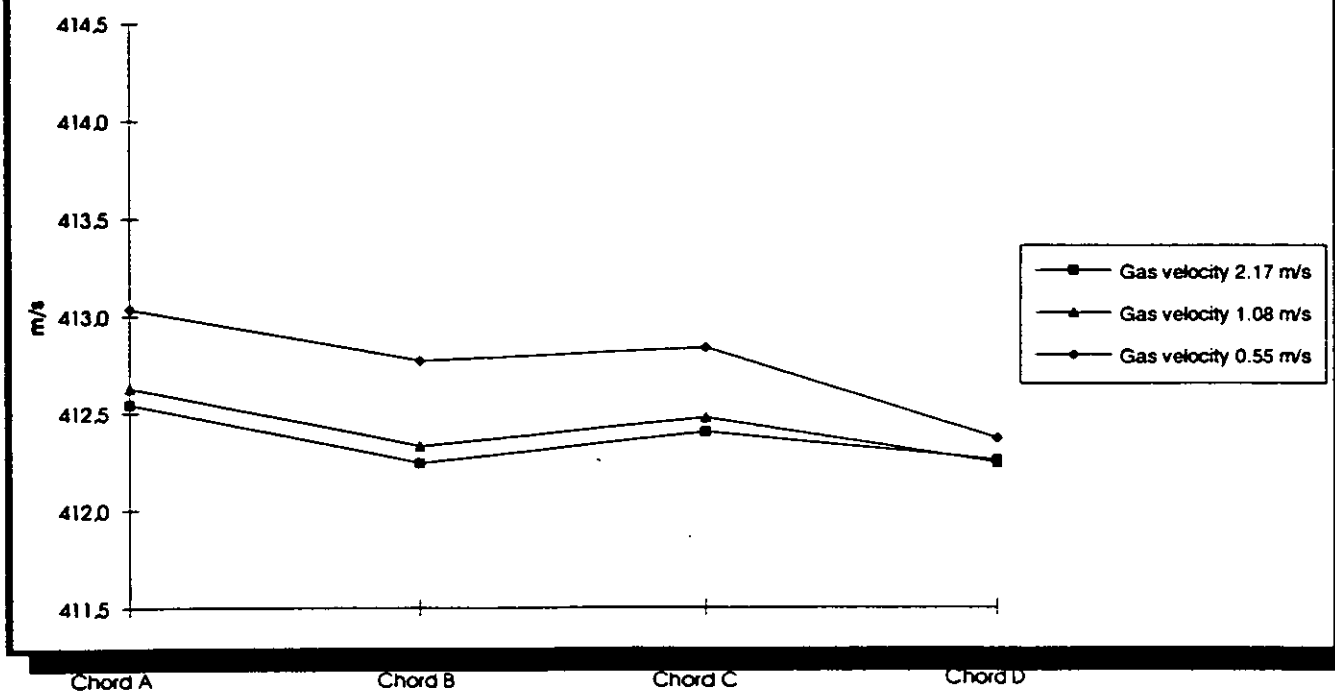


FIG. 14 24" USM VELOCITY OF SOUND PROFILE AT K-LAB DECEMBER 1992 FOR DIFFERENT GAS VELOCITIES

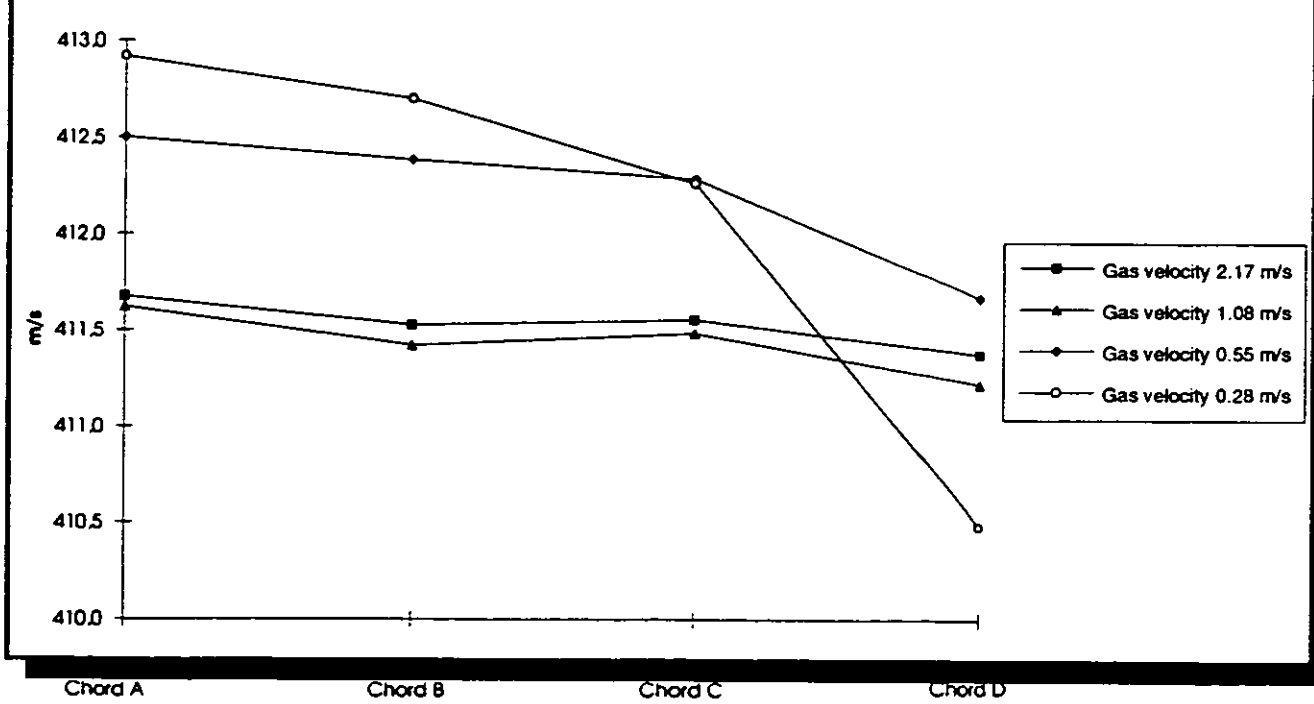


FIG 15 24" USM VELOCITY OF SOUND PROFILE AT 16/11-S FOR DIFFERENT AMBIENT TEMPERATURE

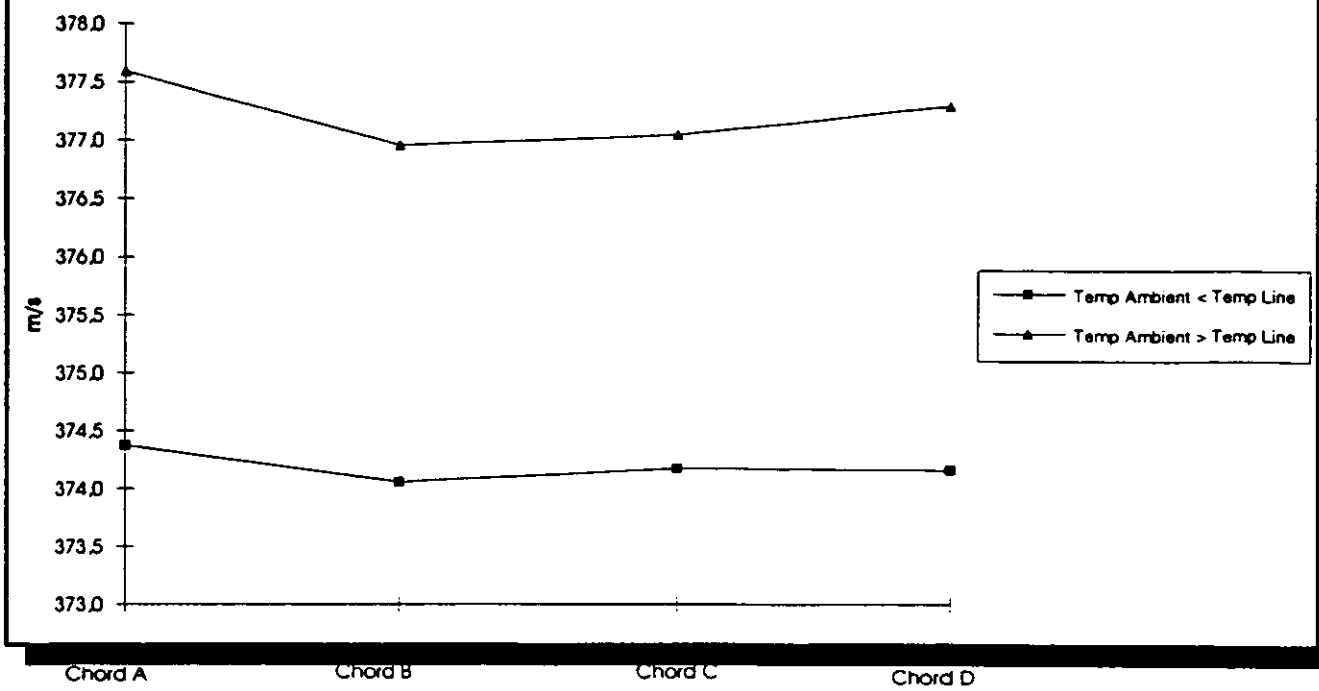
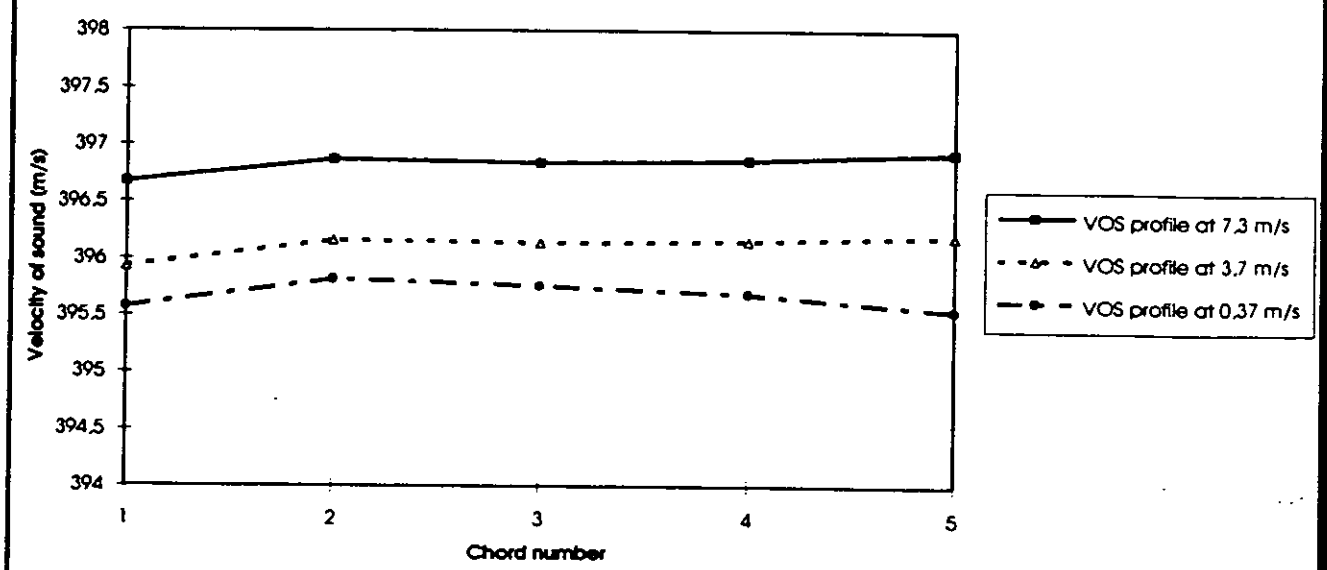


FIG. 16
12" USM FIVE PATH WITH TRANSDUCERS AT THE PIPEWALL. VELOCITY OF SOUND (VOS) AT K-LAB AT 20 DEGC



Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Review of multiphase flowmeter projects

by

Mr. B.C. Millington,
NEL-Scotland

REVIEW OF MULTIPHASE FLOWMETER PROJECTS

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ABSTRACT

Significant progress has been made in the development of multiphase flowmeters over the last 18 months, and a number of manufacturers now have prototypes in the final laboratory and field testing stage.

This paper examines the progress of these leading developments with comment on the available performance data. The flowmeters are grouped under three general descriptions: those using conventional technology such as the Texaco SMS and NEL/SGS meters, those using capacitance, microwave and cross-correlation techniques such as the Fluenta MPFM and the Kongsberg/Shell meter, and those which combine conventional technology with innovative techniques, such as the flowmeter manufactured by Framo.

From the review it is concluded that no particular flowmeter is capable of providing an accurate measurement of multiphase flows across the entire flow composition and flow velocity ranges. With this in mind the most suitable area of application for each approach is noted.

1 INTRODUCTION

The demand for multiphase metering technology is now well established and has been commented on in many articles and conferences over the last decade. However, to the authors' knowledge no multiphase flowmeters have been installed for operational purposes, either topside or subsea. A lot of experimental development and testing, both in the laboratory and in the field has been taking place, and a number of metering systems are now being promoted as direct replacements for test separators and for subsea reservoir management and control.

While much has been said in the past about the numerous independent multiphase flowmeter developments, it has unfortunately resulted in a rather incoherent strategy for the development of this technology. NEL has recently launched an industry funded Multiphase Flow Club with the specific aims (amongst others) of re-focusing that strategy and developing user-friendly standards relating to multiphase metering.

The purpose of this paper is to give an up-to-date appraisal of the technologies used for multiphase metering, which will aid in the re-focusing process. A full review of all the meters in a single paper is not possible, so the approach has been to select multiphase flowmeters from each of three "technology" categories and to comment on their respective strengths and weaknesses. It should be stressed that this is done from an independent stand point.

The advantages and limitations of the techniques used to derive multiphase measurements are discussed and their potential for further development is assessed. Comments are also made on the validity of the common approach taken by all the projects, wherein the phase flowrates are derived from several inter-dependent measurements. This latter point leads on to discussion of the

expectations of potential users of multiphase flowmeters, and these expectations are contrasted with the performance of current and foreseeable developments.

2 GENERIC MULTIPHASE FLOWMETER DESCRIPTIONS

There are three basic types of multiphase flowmeter systems that can be considered as generic types:

a A system of three sensors, one sensor to measure each of the individual phase flowrates (oil, water and gas). The measurements from each sensor are unaffected by the presence of the other two phases;

b A system that measures the cross sectional area of the pipe occupied by each phase, and measures the average velocity of the individual phases so that flowrates can be computed;

c A system that mixes the flow to provide a uniform flow velocity (no slip), and provides techniques for deriving the phase fractions.

The ultimate goal is to achieve a system such as that described in (a), but this is highly unlikely within the next 10-15 years. Present developments centre mainly around the generic system (c) and as such this puts current technology into perspective. There is considerable scope for future development.

3 DESCRIPTIONS OF THE REVIEWED FLOWMETERS

Within the generic range (c) referred to in Section 2, present multiphase flowmeters can be conveniently categorised in terms of their operating principles:

Type 1 Metering systems which comprise instruments which have a proven track record in single-phase flow, or oil/water flows;

Type 2 Instruments using fluid property characteristics - capacitance, inductance, microwave absorption - in combination with cross correlation flow metering. These instruments are much smaller than Type 1 multiphase meters;

Type 3 Instruments which utilise some of the features of Type 1 and some of the features of Type 2, and are often termed 'hybrid' multiphase flowmeters.

Type 1 multiphase flowmeters include those developed by Texaco and NEL/SGS. The Texaco SMS shown in Fig 1 is designed to operate in a subsea environment. The device consists of a subsea gravity separator, a vortex shedding meter on the gas outlet to provide the gas flow rates and a differential pressure flowmeter to measure the total liquid flowrate. The water content is determined from a StarCut microwave water monitor sited in a sampling loop which abstracts liquid from the separator. By combining these various readings with those of temperature and pressure, a measure of the oil, water and gas flowrates is achieved.

The NEL/SGS multiphase flowmeter, shown in Fig 2, utilised an upstream static mixer and venturimeter for total flowrate measurement. The mixture density was measured at the venturi throat using a gamma densitometer. To measure the water cut in the liquid a small sample of the oil/water/gas flow was extracted from the main flow and passed into a compact gas/liquid separator. The separated liquid phase returned to the main flow through an in-line density transducer, thereby allowing the water cut to be derived.

Type 2 meters include those developed by Fluenta and Kongsberg in conjunction with Shell. The Fluenta MPFM 1900 has been developed from an earlier multiphase fraction meter, the MPFM 900. In its present form the water content is derived from non-intrusive capacitance/inductive sensors, and the mixture density from a gamma densitometer. The phase fractions are calculated from these measurements. The phase flowrates are derived from velocity measurements based on cross-correlation between the signals from two axially spaced capacitance sensors. The velocities of large gas voids and small bubbles are measured independently and simultaneously, and it is assumed that the liquid velocity is equal to the small bubble velocity.

The Kongsberg multiphase flowmeter also uses capacitance sensors and is effectively a very sophisticated level measurement system. Two thin parallel plates are mounted in a vertical sense within the flow passage. An array of capacitance sensors is mounted on the surface of each plate. The measured capacitance allows the location of the gas/liquid interface, and therefore gas fraction, to be determined. The average water cut of the liquid is derived from the capacitance measurements from the sensor pairs which are immersed in liquid. The meter makes use of the slug flow pattern to cross-correlate between sensor signals to give the slug velocity. A slip correlation is then used to estimate the bulk gas and liquid velocities, with subsequent calculation of the volume flow rates.

An example of the Type 3 hybrid multiphase flowmeters is the meter developed by Framo. This uses a mixer which provides temporal mixing as well as spatial mixing to produce an approximately homogeneous flow with near-equal gas and liquid velocities. The mixture then passes through a venturimeter which measures the total flowrate. The gas fraction and water content are derived from a dual energy gamma densitometer system which is mounted across the throat of the venturimeter. The phase fractions and total flowrate are combined to give the phase volume flowrates.

4 PROGRESS OF PROJECTS

Extensive testing of the Texaco SMS has been conducted in both the laboratory and in field trials by Dowty et al[1]. The initial laboratory results were promising and the optimum configuration for the meter was finalised, but foaming problems were experienced at the meter inlet during the field trials in the North Sea. The foaming reduced the effectiveness of the gas/liquid separation, and the poor quality of separation caused problems in the single-phase metering runs on the separator outlets, resulting in a reduced performance when compared to the laboratory conditions. The SMS has since been modified to counter the foaming problems and is presently under further trials at Texaco's onshore facility at Humble near Houston. Recent results are favourable according to Texaco.

The NEL/SGS multiphase flowmeter underwent extensive laboratory trials over the full range of gas and water fractions. The final prototype measured the total volume flowrates to within 15 per cent of the reference flowrates at the majority of flow conditions, Fig 3. The individual phase flowrates were measured less accurately, with uncertainties of around 25 per cent at most test conditions. Higher uncertainties were found at low phase fractions. The reasons for this are discussed in more detail in Millington[2], but in short are due to the diminished presence of that particular phase. This is a mathematical reality common to all multiphase flowmeters which use multiple inter-related measurements to derive the phase flowrates.

The NEL/SGS development project was concluded - perhaps prematurely - after emulsions in the separator were found to reduce the effectiveness of gas/liquid separation, which caused incorrect water cut measurements. The problems experienced using a compact gravity separator were felt likely to be exacerbated under field conditions.

The Fluenta MPFM 1900 is presently being evaluated at NEL for Amerada Hess prior to field trials in the North Sea. Conoco (US) and Statoil are also evaluating the meter, the former in

condensate/gas flows and the latter at Gulfaks B. Published results are presently unavailable from these commercial evaluations, but early trials by Dykesteen and Midttveit[3] at CMR showed that the total volume flowrate can be measured to within 10 per cent, Fig 4. However, the measurement of the individual phase flow rates was less accurate for the reasons referred to above.

The Kongsberg MCF has been tested under laboratory conditions in oil/water/gas flows by Brown et al[4]. The meter was shown to perform well in slug flow under oil continuous flow conditions. (A further development programme is underway to extend the range of the meter to water external emulsions). The laboratory trials indicated that the flowrates can be predicted to within 10 per cent in slug flow and with a repeatability of approximately 5 per cent, Fig 5. Outside of the slug flow regime the results, as expected, were less accurate since the prime objective of this instrument is for application in slugging flows.

Torkildsen and Olsen[5] have evaluated the Framo multiphase flow meter under laboratory conditions over the full range of gas and water fractions expected under normal operation. The total mass flowrate was measured to within 10 per cent at the majority of the test conditions, but the meter was less accurate when predicting the individual phase flowrates, and gave uncertainties of typically 25 per cent. The phase flowrate uncertainties varied according to the phase fraction as described above. The laboratory trials were judged to have been sufficiently successful for the Framo meter to go for field trials in the North Sea during 1993. Results are awaited.

5 STATE-OF-THE-ART IN MULTIPHASE METERING

Multiphase flow measurement poses many challenging problems and it can be seen from the progress of some of the leading projects referred to in Section 4, that no complete solution has yet been found. All the projects referred to have contributed to the knowledge of the problems involved with multiphase flow metering and each has made some progress towards solving these problems.

Work using Type 1 multiphase flowmeters has demonstrated the limitations of established technology when confronted with non-standard fluid mixtures. Major difficulties exist in obtaining homogeneous mixtures, both spatially and in particular temporally. There is considerable doubt about the effectiveness of mixers, and in relation to the potential blockage effects that they may cause, it is difficult to argue a case for their general inclusion in all meters. Indeed some of the meters (eg Fluenta) rely on not mixing the flow for the cross correlation systems to be most effective.

The limitations of scaled down separation technology were clearly identified in the NEL/SGS project. This continuous method of sampling, separation and return to the main flow has been avoided in the meter recently developed by Paul Monroe. The batching system used in this meter may prove advantageous, although there are considerations of batch interval which need to be addressed.

The Type 2 multiphase flowmeters, which employ capacitance, inductance and microwave technology have found limitations imposed by the state of the oil emulsion, and by the flow regime. When certain required features within the flow are not present then accuracy suffers, often dramatically and the challenge here is to know when the readings are in error because of the flow conditions and not because of instrument malfunction; not an easy task if the meter is subsea. However, experience in the laboratory environment has shown the Type 2 multiphase flowmeters to generally be as accurate, if not more accurate, than the proven technology instruments.

In terms of commonality of approach, nearly all multiphase flowmeters use nucleonic techniques for either determining the gas fraction, or determining gas fraction and water content in the liquid. Considering the relatively modest performance of such instrumentation it is perhaps surprising that alternative gas measurement systems have not been proposed. It is certainly one area of the

technology were improvements in performance could be achieved. In dual energy systems, which offer gas and water fraction measurement non-invasively over the full composition range, particular care must be exercised as there are several fundamental problems. Firstly, the highest attenuator is the pipe wall, particularly at low photon energies, which results in large sources being required. Secondly, mass absorption coefficients may prove difficult to establish in practice and this can have serious consequences in terms of uncertainty. Dual energy techniques rely on the difference in mass absorption coefficient of water and oil to infer water cut, but this difference is only a few per cent at photon energy levels down to approximately 60 keV, therefore any uncertainty in the mass absorption coefficient, or for that matter measured count rates, can have serious effects on water content measurement.

In summary, all the techniques so far used for multiphase metering have their own advantages and disadvantages, but from available evidence the present state-of-the-art is measurement of phase flowrates to approximately 10 per cent over reasonably wide operating envelopes. This level of performance will not be achieved over the entire flow composition range until direct, and independent, measurements of phase flow rates can be made.

6 USER EXPECTATIONS AND THE FUTURE

Expectations of the performance of multiphase flowmeters vary considerably. Those perhaps less familiar with the subject often believe uncertainties normally associated with single-phase flowmeters can be achieved, while those with considerably more experience in this technology usually take a more pragmatic view and aim for uncertainties similar to those achieved using test separators. The latter view is perhaps the most sensible approach to adopt at present because it avoids stating hard percentage figures which at best are often mis-understood, and at worst totally mis-leading.

Irrespective of the technology used to determine the phase flowrates, the uncertainties are always a function of the phase fraction. Low phase fractions have a higher uncertainty, and vice-versa Simply stating an objective of say 5 per cent uncertainty is not good enough, the figure must be related to a phase fraction value, or envelope, over which it applies.

This leads on to the next difficulty in terms of user requirements, that is the operating range, or in single-phase metering terms, the turndown ratio. With a turbine meter for example, the user might expect a turndown of 10:1 on flowrate, but many potential users of multiphase flowmeters are expecting a system capable of metering flows with 0-100 per cent gas, 0-100 per cent oil and 0-100 per cent water as well as a total flowrate turndown of 10:1, or better. The perception of the capabilities of multiphase meters often does not match reality.

It is the flow composition measurements that are most crucial, Millington[2], and in view of the comments made above there is now a gradual change in attitude within the industry to the performance of multiphase flowmeters. It has been realised that the future will probably see a range of flowmeters which cover specific application areas, eg wells with high water will have different flowmeters from gas lifted wells. The belief that one manufacturer could dominate the market in the same way as Microsoft have done in the computer operating system market, has diminished over the last couple of years.

In response to this realisation, and because potential users will want to know which one of the current multiphase flowmeters best suits their requirements, NEL have launched a JIP called Multiflow to evaluate all the leading meters over a wide range of operating conditions. Using the same test facility throughout, this work will be the first definitive intercomparison of multiphase flowmeters from which firm conclusions can be drawn. All previous test work has been performed on different facilities, and with different oils and water. Effective comparison of the results is impossible.

Beyond this project, it appears unlikely that significant improvements in metering uncertainty can be made within the (b) and (c) generic classes of multiphase flowmeters, see Section 2. It is the authors' view that in the medium term the use of tomographic techniques to quantify flow composition, the development of an alternative to gamma densitometry for gas fraction measurement, and the application of neural networks, will bring about the most significant advances. Beyond the medium term the goal must be to develop sensors capable of directly metering the individual phases. The future is challenging, but holds considerable promise.

ACKNOWLEDGEMENTS

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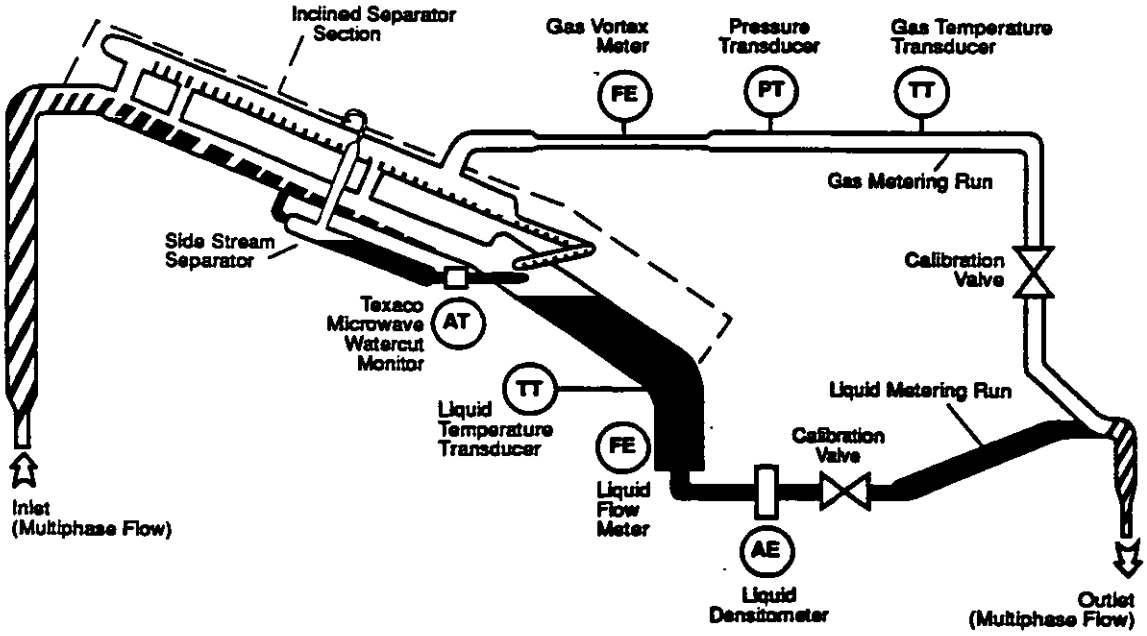

Fig 1 The Texaco SMS multiphase metering system

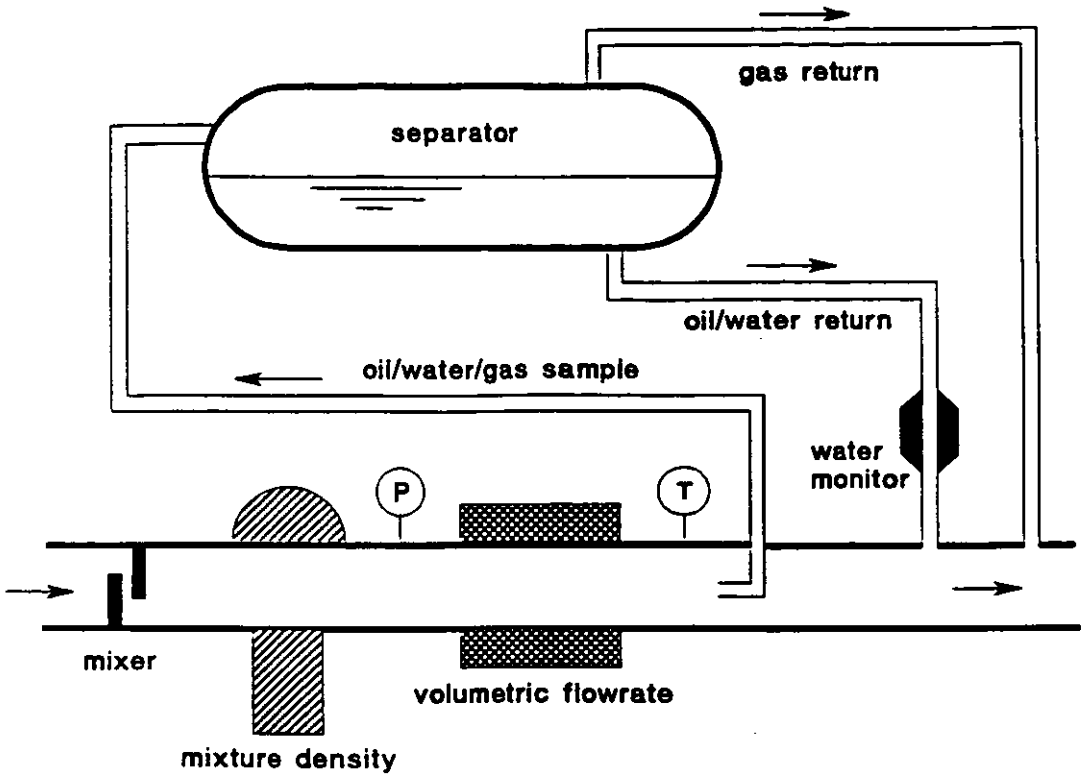

Fig 2 The NEL/SGS multiphase flowmeter

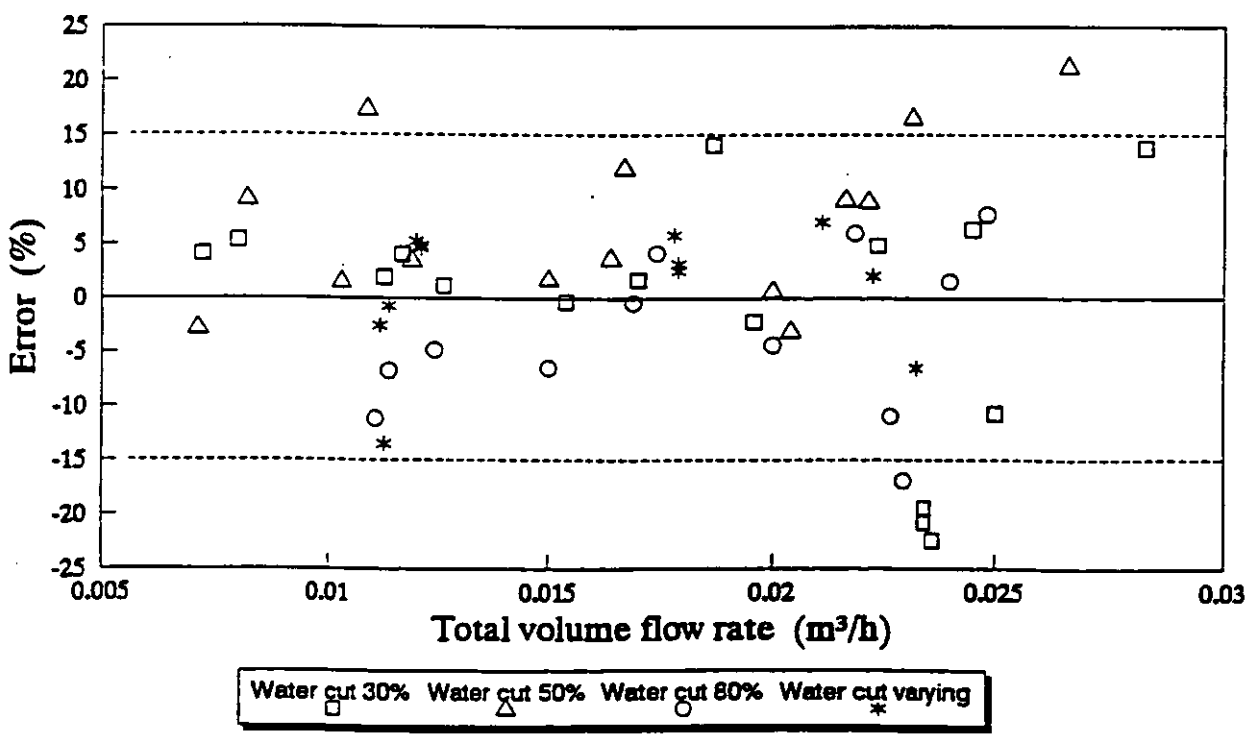

Fig 3 The performance of the NEL/SGS multiphase flowmeter

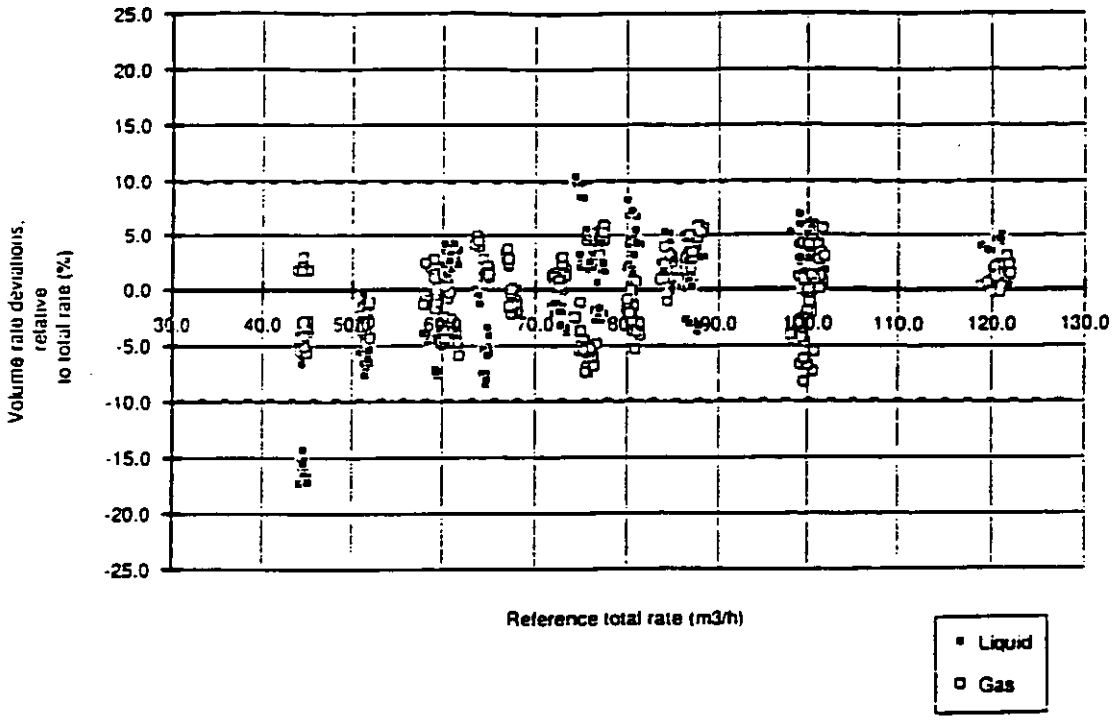

Fig 4 The performance of the Fluenta MPFM 1900 multiphase flowmeter (ref 3)

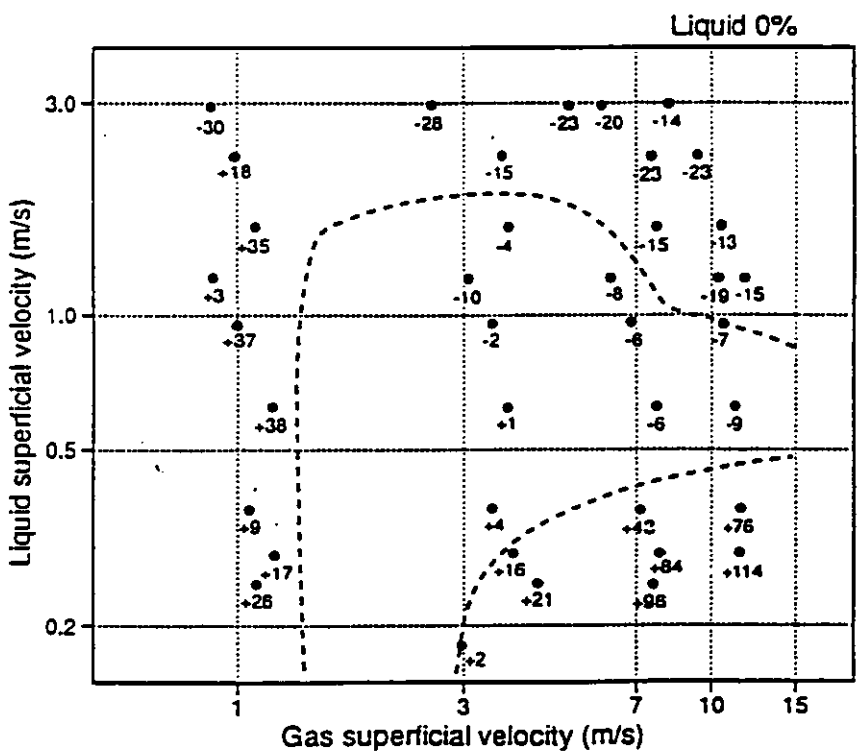

Fig 5 The performance of a 75mm diameter Kongsberg MCF (ref 4)

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

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NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Required Operating Envelope of Multiphase Flow Meters for Oil Well Production Measurement

by

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Paper for North Sea Flow Measurement Workshop,
Bergen, Norway, 26-28 Oct. 1993

REQUIRED OPERATING ENVELOPE OF MULTIPHASE FLOW METERS FOR OIL WELL PRODUCTION MEASUREMENT

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SUMMARY

This paper presents a method which is useful in specifying the performance of multiphase flow meters. The first topic often raised in a discussion on the performance of multiphase flow meters is "accuracy". We propose that the "operating envelope" of a meter, which can be defined as an area on the two-phase map of gas and liquid flow rates, should be considered. First the production rates of wells are presented on a two-phase map for a number of oil fields. It is shown that the majority of these wells produce with gas volume flow fractions at well head conditions around 90%, with a range between 50% and 99%. Subsequently, the operating envelopes of some known multiphase meters are estimated. Unfortunately, the performance results published do not always permit a complete assessment of the operating envelopes. In those cases the published data are complemented with theoretically derived characteristics.

It appears that the estimated operating envelopes of the meters leave a significant number of the studied wells uncovered. Lack of coverage is particularly prominent for gas volume flow fractions above 90%. It is feared that this may be more generally the case. How severely surging well production affects a meter's potential performance is another aspect which should be further investigated.

INTRODUCTION

During the past year a number of development projects on multiphase flow meters have reached the stage of prototyping, and laboratory and field trials, so that once again the old question has arisen of how to characterise their performance. Everyone working in this field must have participated more than once in discussions on whether the target accuracy of a multiphase meter should be 10%, 5% or even better. However, there are other equally important characteristics which are not usually addressed: for example, the *operating envelope*, which is the multiphase equivalent of the range of a single-phase flow meter, and the ability of a meter to cope with *fluctuating flow rates*. Whilst these features have a fairly simple definition for single-phase flow meters, the definition is not obvious for multiphase meters. This paper discusses how to characterise and specify the performance of multiphase meters and introduces a graphical representation of the operating envelope. Typical well

production characteristics and requirements are presented for a number of oil fields and the characteristics of a number of well-known multiphase meters are then evaluated against the fields. It thereby becomes apparent that it is much more difficult to develop an adequate multiphase meter for some field applications than for others.

TWO-PHASE MAP

There are a number of ways the production of an oil well, and hence the output of a multiphase meter, can be presented. The user of the measurement results usually wants to see:

Oil flow rate
Water flow rate
Gas flow rate

It is customary in the oil industry to express these quantities at standard conditions. However, from a measurement point of view this is pointless, since a meter will only see actual conditions. Therefore this paper will only consider actual conditions.

Other ways of presenting the measurement results are:

Gross liquid flow rate
Watercut (or BSW)
Gas Volume Flow fraction (GVF)

or

Gross liquid flow rate
Watercut
Gas flow rate

Obviously, the above quantities can simply be converted from one set to the other. However, the importance of the difference between the sets becomes apparent once uncertainty intervals are assigned to the quantities presented. It is our experience that the latter two sets have definite advantages over the first set. This is because they separate the specific problems of two-phase fluids (gas/liquid) from the liquid composition aspects (watercut). An even more important argument is that it allows graphical presentation of the flow rate data on a so-called two-phase map (Fig. 1). The map is similar to the well-known Mandhane map. Gas flow rate is along the horizontal axis, and liquid flow rate along the vertical one. Since the scale of the map is logarithmic, the diagonals of the map represent lines of constant gas–liquid ratio or gas volume flow fraction (GVF). This is a useful feature, since it will become clear from the field data that the gas volume flow fraction is probably the most critical parameter in multiphase metering. It appears that the majority of wells can be plotted on the map when the gas flow rate scale runs from 100 to 100 000 m^3/d (actual), and the liquid scale from 10 to 10 000 m^3/d. Note that the main diagonal of this square is the line of approximately 90% gas volume flow fraction.

WELLS AND FIELDS PLOTTED IN THE TWO-PHASE MAP

We have plotted the reported production of wells on the two-phase map for a number of fields. In some cases the reported data were at test separator conditions, in other cases they were at flowing tubing head conditions. The significant difference is that the lowest GVFs possible are found at flowing tubing head pressure, ahead of the choke. Further downstream the GVF only increases.

The data presented are for fields from different parts of the world. The selection was not systematic, but it is believed to be fairly representative (although this cannot be proven). The names of the fields have been replaced by codes, if the data are not in the public domain.

Fig. 1 shows a field in the UK sector of the North Sea, often considered typical for future (prolific) subsea wells. Data are at the test separator pressure of 3300 kPa.

Fig. 2 shows two new fields in the UK sector of the North Sea. It is not known whether data of #1 are at test separator or flowing tubing head pressure. The box for field #2 represents a general design well for another field. The lower gas volume flow fraction (76%) is at flowing tubing head pressure, whereas the higher GVF (92%) is at test separator pressure.

Fig. 3 is from Gullfaks B. The data are based on information taken from Refs. [1] and [2]. The well data are at a test separator pressure of 7600 kPa. Note that the GVF never exceeds 50%.

Fig. 4 shows some 45 wells in the Danish sector of the North Sea, taken at test separator conditions. The GVFs range between 80 and 98%.

Fig. 5 is an example of a field in South East Asia with gas lift: There are many wells with small production rates per well. Some wells do not need gas lift. They produce typically at a higher liquid rate than the gas lifted wells. All gas rates are given at flowing tubing head pressures, i.e. they are minimum values. The GVFs for the naturally flowing wells are less than for the gas lift wells. GVFs of 99% for both types of wells are not uncommon.

Fig. 6 shows data from Gabon at a test separator pressure of 600 kPa(a).

The following picture emerges from the data. For the North Sea the gas volume flow fractions are typically between 50 and 90%. The GVF of Gullfaks B of maximum 50% does not seem to be very representative for the other fields. The field in the Danish sector (Fig. 4) even has GVFs between 80 and 98%. The gas lifted wells observed seem to be operated typically at GVFs of 90% and above, so that GVFs of 99% are not exceptional. We also see that the gas lifted wells of the example in Fig. 5 have typically lower production rates than the naturally flowing wells. It should be noted that one would generally expect future subsea and offshore wells to be "prolific", i.e. producing at oil rates above 1000 m^3/d, since this will be required by the economics of new developments. It is concluded from the data that gas volume flow fractions of oil wells are typically in the range of 50% to 99%.

PRESSURE DROP

A very important characteristic of a multiphase meter is its pressure drop. Of course there are cases where the flowing tubing head pressure is very high and pressure is available to drive the fluids through the meter. But even in such cases it is probably not advisable to dissipate too much energy over the meter, as energy dissipation is tantamount to wear. Another, operational reason for limiting the pressure drop is in the envisaged application of the meters in satellite production stations. The available well head pressure will be required to transport the fluids from the well head to a gathering station or mother platform. Multiphase boosting is difficult and costly. The approach should therefore be to conserve the available pressure and not to waste it in a meter. A one bar (100 kPa) pressure drop is probably the maximum that can be tolerated, but even that could lead to a significant reduction of the production rate, and hence represent a high economic value. So the lower the pressure drop the better. In gas lift systems with flowing tubing head pressures of only 500 kPa, it is obvious that an extra loss of 100 kPa can be very important.

EXPECTED OPERATING ENVELOPES OF METERS

Four multiphase meters for which sufficient published data could be found were selected for analysis. These are (1) a combination of a positive displacement meter and a gamma ray absorption meter, (2) a combination of venturi flow meter and gamma ray absorption meter, (3) a meter of unknown principle but which explicitly gives its operating envelope, and (4) a flow meter based on slug flow.

1) Combination of PD-meter and Gamma ray. PD-meters typically have a maximum total volume flow rate, above which the friction in the internal moving parts becomes too high. One manufacturer of multiphase meters comprising a PD-meter indicates that the total pressure drop in gas will be lower than that in liquid, but more detailed information is not available [3]. So for simplicity's sake it will be assumed, that the maximum throughput of a PD-meter is given by a line of constant volume flow rate on the two-phase map. An example of such a line (at 2400 m^3/d) is shown in Fig. 7. The flow rate is selected from Ref. [3] as corresponding to one bar pressure drop over the 3"/4" version. A unit of this size was also used for the reported experiments [4]. Lines for larger or smaller sizes can simply be constructed by shifting the curve along the diagonal lines of constant GVF.

Many multiphase meters reported in the literature comprise a gamma ray composition meter. It is used to determine the average density of the mixture, and subsequently to split the total fluid flow into a gas and a liquid fraction. From basic principles we can expect that for very high gas volume fractions, the ability to determine the liquid flow rate will diminish [5]. Publications on the experimental performance of some multiphase meters confirm this [4, 6]. Results for gas volume fractions above 85% are not even reported. It should also be noted that it is virtually impossible to obtain a homogeneous mixture for GVFs higher than about 80%. This results in additional measurement uncertainties. Based on the above points, we selected a typical upper limit for such gamma ray densitometers of 85%. In Fig. 7 a line is drawn at 85% GVF, which together with the maximum throughput curve produces a theoretical operating envelope for the multiphase meter studied.

2) Combination of venturi flow meter and gamma ray. The maximum throughput of such meters is governed by the resultant pressure drop over the venturi. From our work with venturis we have learned that in multiphase flow, recovery of the differential pressure is insignificant. For practical purposes the pressure loss can be assumed to be equal to the differential pressure. If one further assumes that the fluid is homogeneous (this is not the case due to slip between the phases, but it does not invalidate this argument) then for a given throat diameter the maximum throughput of a venturi can be calculated. See Appendix A for details of the calculation. In Fig. 8 two lines of 100 kPa pressure loss over a 50 mm throat diameter are given for a combination of water and gas, one for a gas density of 5 kg/m^3, the other for 50 kg/m^3. Note that for GVFs smaller than 90% the difference between the two lines is small. We can also calculate that in order to cope with "prolific" wells, such as shown in Figs. 1 and 3, venturi throats of 70 or 100 mm diameter are required. This is a potential problem for dual energy gamma ray composition meters [6] that use very soft gamma rays, which can be strongly attenuated over such a long absorption path. The general argument about loss of accuracy with increasing GVF as presented under (1) is equally valid in this case. Therefore in Fig. 8 the theoretical operating envelope for this meter is completed with a similar line of maximum GVF = 85%. This is supported by the published data [6].

3) Agar multiphase meter. Recently a brochure was published by a manufacturer of multiphase meters [7], which does present the operating envelope of the products on offer as an area on the two-phase map. Unfortunately the operating principle of the meters is not disclosed, apart from the statement that they do not comprise a gamma ray absorption meter. To allow a fair comparison with other meters, the data from the brochure are represented in Fig. 9, but this time on the same scale as used throughout this paper. Note that although these meters have no gamma ray incorporated, the part of the operating envelope exceeding the 90% GVF line is also rather small.

4) Flow meter based on slug flow. One meter design makes use of and is therefore dependent on the occurrence of slug flow [8]. So to a first approximation the operating envelope of this meter will coincide with the slug flow area on the Mandhane map. In Fig. 10 the slug flow area ("intermittent flow") is depicted as calculated by a proprietary two-phase flow computer program for the example of a field in Gabon (Fig. 6). The slug flow area is seen to extend to or slightly beyond the 90% GVF diagonal. In reality the wells proved to be slugging indeed, and good measurements were made with the slug flow meter [9]. By selecting a different flow line diameter than the 4-inch line which was applicable, and a corresponding meter, the slug flow area can be shifted along the constant GVF diagonals.

FLUCTUATING FLOW RATES

The information usually reported from well tests contains only average values of liquid flow rate, BSW (base sediments and water) and gas flow rate. More detailed information about how the values fluctuate may be available but it is not reported. From a recent analysis of a limited number of detailed recordings of well tests, it became apparent that wells can exhibit strong surging behaviour. Surge periods of 15 minutes to one hour were observed. Obviously this has an impact on the requirements for multiphase meters. An example of a surging well is reported by

Brown [9] and also Cary et al. [10] report surging of production flows. The actual production occurs in peaks that are much higher than the average flow rate. The range of a multiphase meter has to be selected in order to cope with the peaks, but one does not know in advance how high the peaks will be. Obviously, if the meter range is too high, this will be at the expense of accuracy. From field measurements with multiphase flow meters and noise measurements made on a number of well heads, we already know that this kind of surging is not exceptional. Further investigation into the magnitude of this phenomenon seems necessary.

DISCUSSION

The usefulness of representing well production data and meter operating envelopes on a two-phase map has been shown. It allows an easy evaluation of the suitability of a specific meter for a certain well or field. It is also possible to plot observed accuracies in the map. This can be done either in the form of contour lines of constant error, or by plotting the reference value and the observed value for each observation on the same map. We have found both techniques useful. The main advantage of showing the data on the two-phase map is that full consideration is given to the conditions pertaining to the measurement, rather than primarily to the size of the measurement error.

Manufacturers of multiphase meters should be encouraged to present the operating envelopes of their meters graphically as an area on the two-phase map. This would allow users to assess quickly whether a meter would be useful for their application.

If we compare the operating envelopes of the multiphase meters discussed with the characteristics of the fields presented, then we see that many wells are not covered by the meters. Lack of coverage is particularly prominent for GVFs above 80 or 90%. It is feared that this applies to many more wells than those presented. It would seem that there is generally a need for multiphase meters that can cope with GVFs higher than 80%, where an upper limit of say 99% seems to be a good target.

One way of keeping the GVF as "seen" by a meter at a low value would be to install the meter as far upstream as possible, e.g. upstream of the choke. However, it should be realised that this would need a meter with a higher pressure rating. Whether or not this is attractive depends on the actual value of the pressure rating and the specific characteristics of the multiphase meter. Safety aspects also have to be taken into account.

CONCLUSIONS

(1) Typically oil wells produce with gas volume flow fractions between 50% and 99%.

(2) Reasoning from basic principles, many multiphase meters currently being developed are likely to have difficulty in achieving adequate performance for the higher gas volume flow fractions.

(3) A graphical presentation of the operating envelope of a multiphase meter allows easy evaluation of its suitability for a certain job.

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APPENDIX A Approximate pressure drop over a venturi in two-phase flow

Experience has shown that in two-phase flow, the pressure loss with a venturi flow meter is almost equal to the signal pressure. Hence the pressure recovery is negligible. The pressure drop can then be approximated by

$$dp = \frac{1}{2}\rho_t * v_t^2$$

where ρ_t is the mixture density and v_t is the mixture velocity in the venturi throat.

Assuming homogeneously mixed fluids gives

$$\rho_t = \alpha\rho_g + (1-\alpha)\rho_L$$

for the mixture density, where α is gas volume flow fraction, and ρ_g and ρ_L are the densities of gas and liquid, respectively.

Using $\alpha = Q_g/(Q_g+Q_L)$, and $v_t = Q_t/(\pi d^2/4)$ the pressure drop formula can easily be converted into

$$\rho_g*Q_g^2 + (\rho_g+\rho_L)*Q_g*Q_L + \rho_L*Q_L^2 = 2*dp*(\pi d^2/4)^2$$

where Q_L and Q_g are the liquid and gas volumetric flow rates and d is the diameter of the venturi throat.

As an example we shall take dp = 100 kPa, d = 50 mm and ρ_L = 1000 kg/m³ and ρ_g = 5 and 50 kg/m³, respectively. The formula then reduces to

$$Q_L^2 + (1+\rho_g/\rho_L)*Q_L*Q_g + (\rho_g/\rho_L)*Q_g^2 = 0.0278\ m^3/s)^2$$
$$= (2400\ m^3/d)^2$$

The graphs are symmetrical around the diagonals given by

$$Q_g/Q_L = (\rho_L/\rho_g)^{1/2}$$

It then follows that for ρ_g = 5 kg/m³ the graph is symmetrical around α = GVF = 93%, and for ρ_g = 50 kg/m³ this is around GVF = 82%.

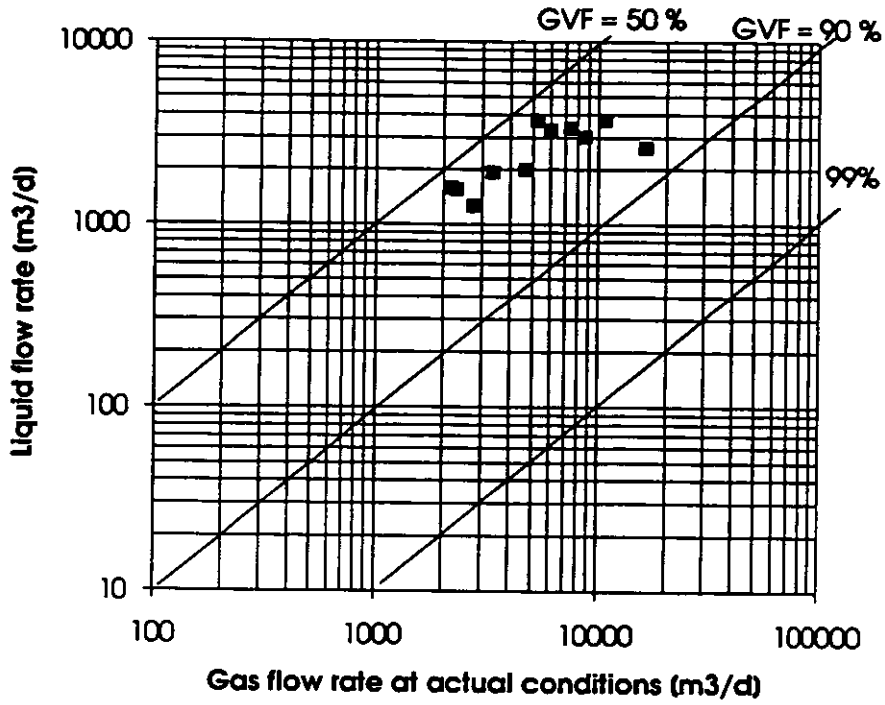

FIG.1 Two-phase map showing a typical field in the North Sea UK sector

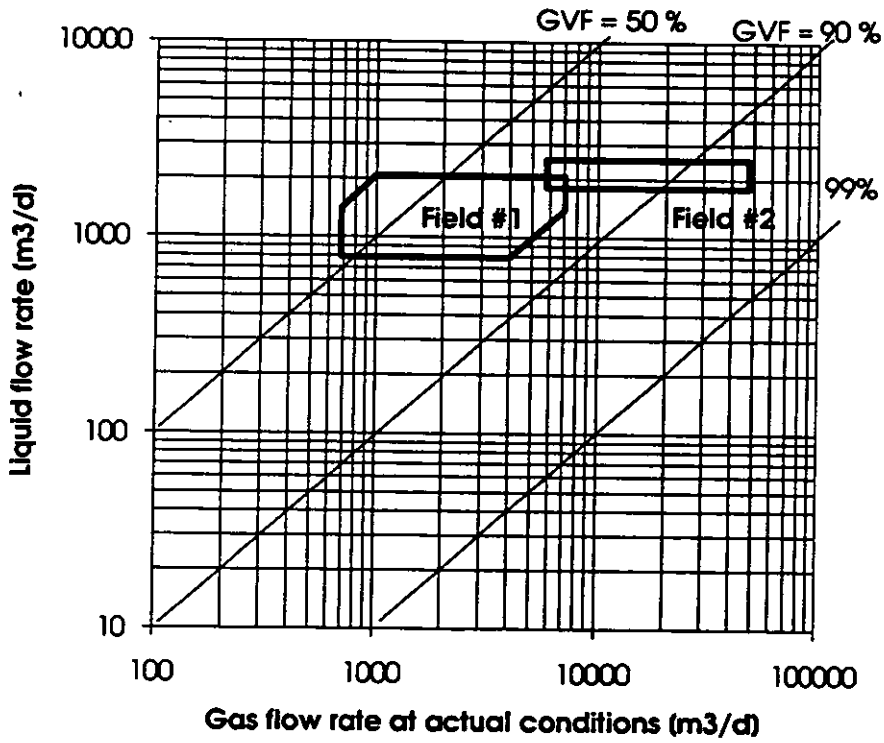

FIG.2 Two-phase flow map showing operating envelopes of two prospects in the North Sea UK sector

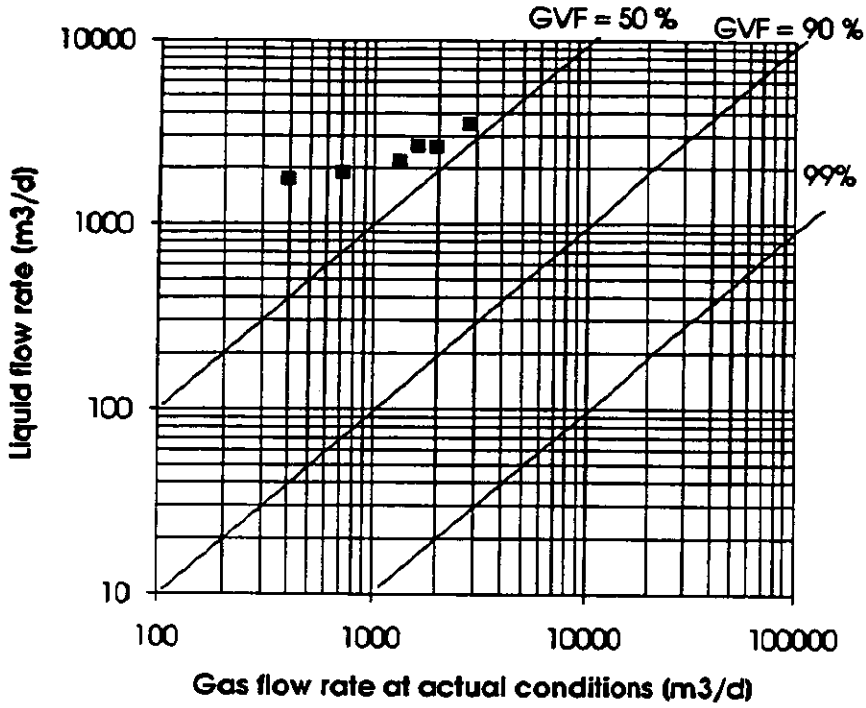

Fig.3 Gullfaks B wells in a two-phase map at test separator conditions (Interpretation from data published in (1) and (2))

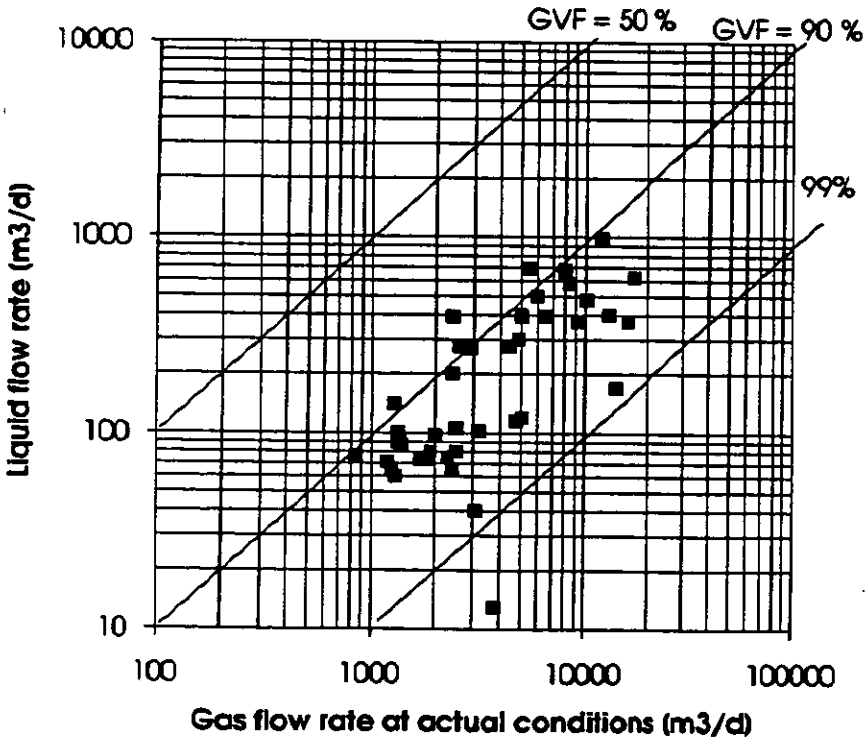

Fig.4 Two-phase map with wells from field in Danish sector

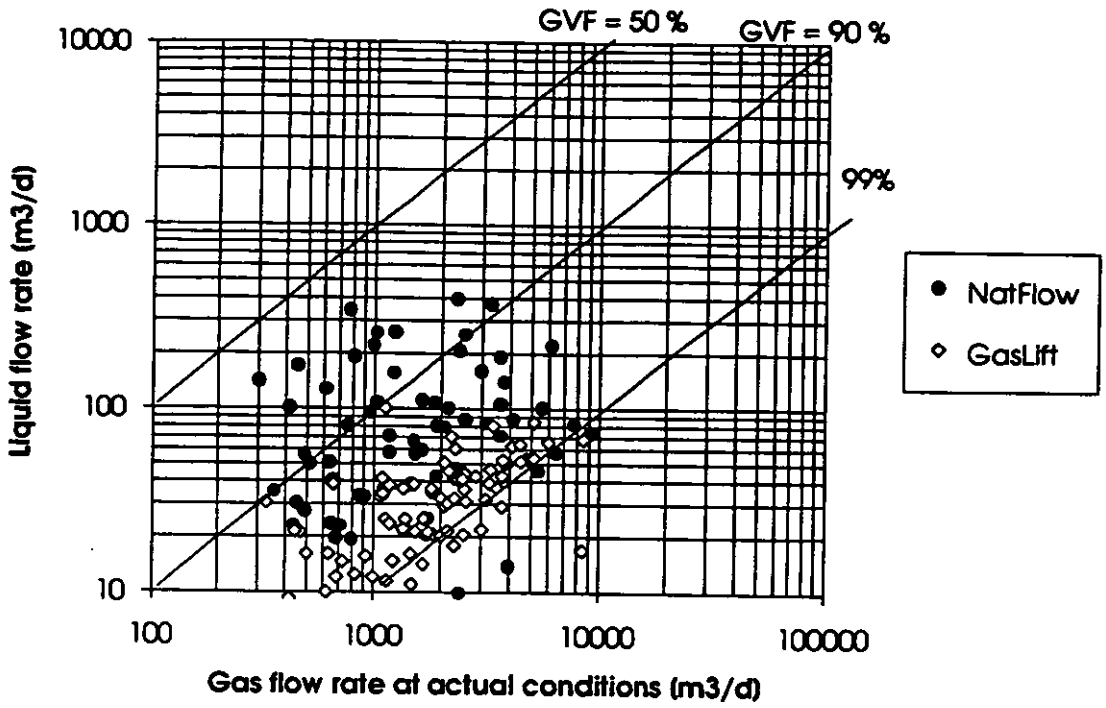

Fig.5 Two-phase map showing wells of a field (#1) in S.E.Asia at flowing tubing head pressures

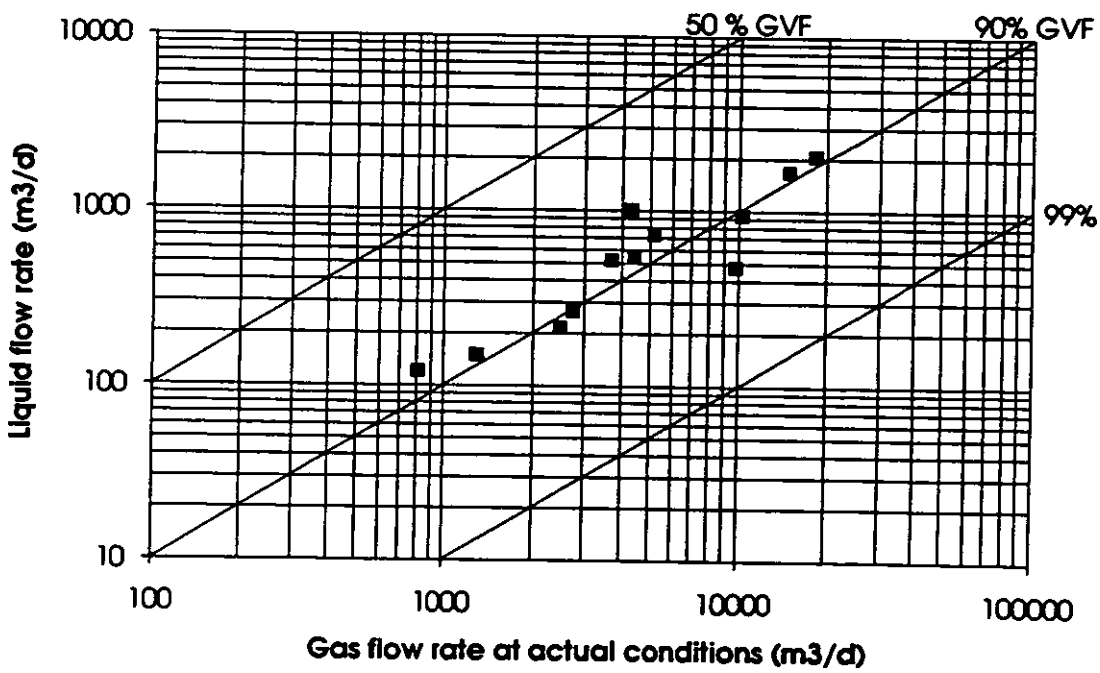

Fig.6 Two-phase map showing wells of field in Gabon at test separator conditions, 600 kPa(a)

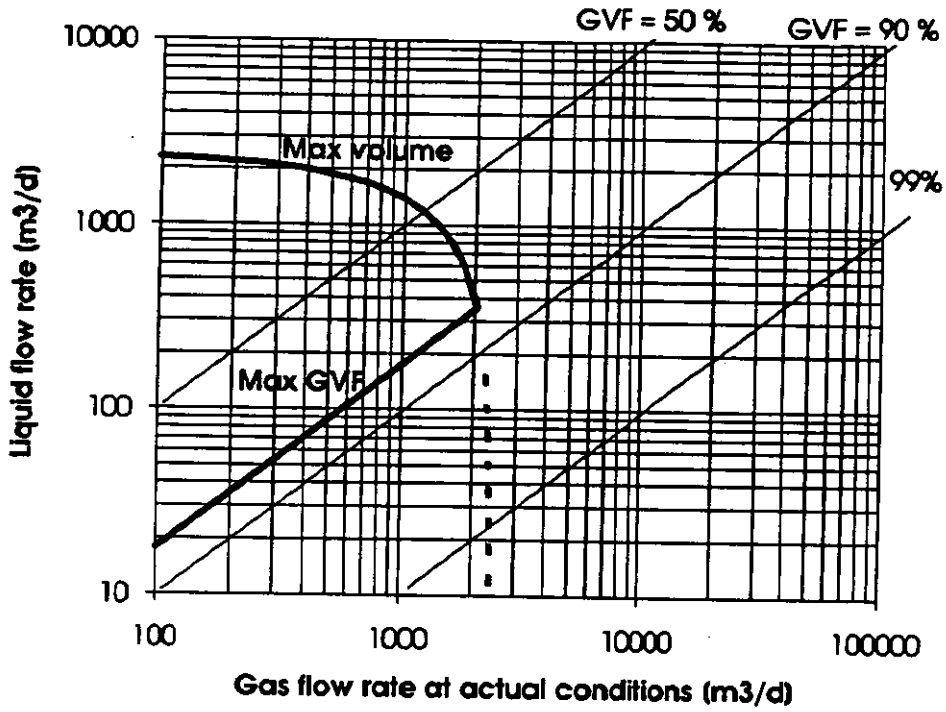

Fig.7 Theoretical shape of operating envelope of a PD-meter/gamma ray flow meter rated at 2400 m3/d

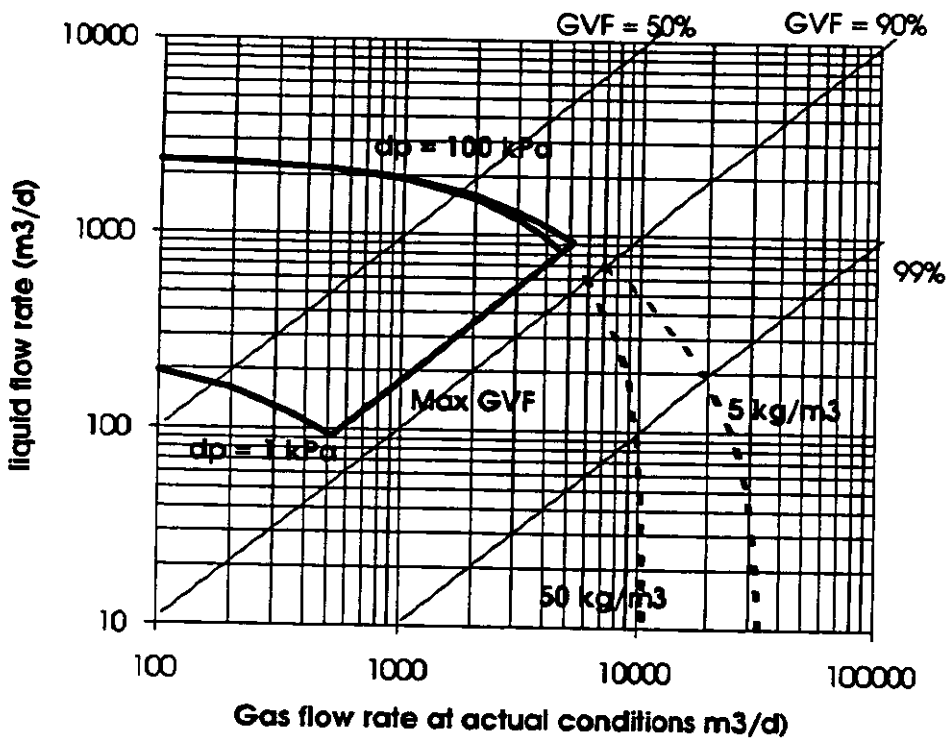

Fig.8 Theoretical operating envelope of a venturi/gamma ray meter with 50 mm diameter throat (Gas densities 5 and 50 kg/m3)

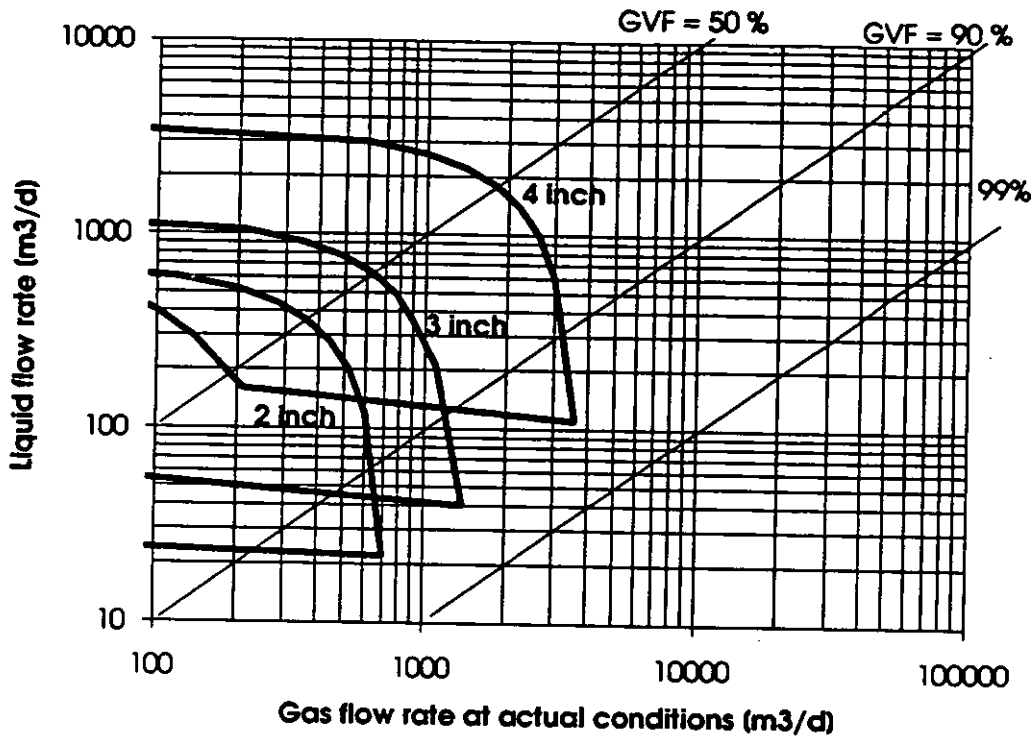

Fig.9 Operating envelopes of three Agar multiphase meters (Data taken from company brochure)

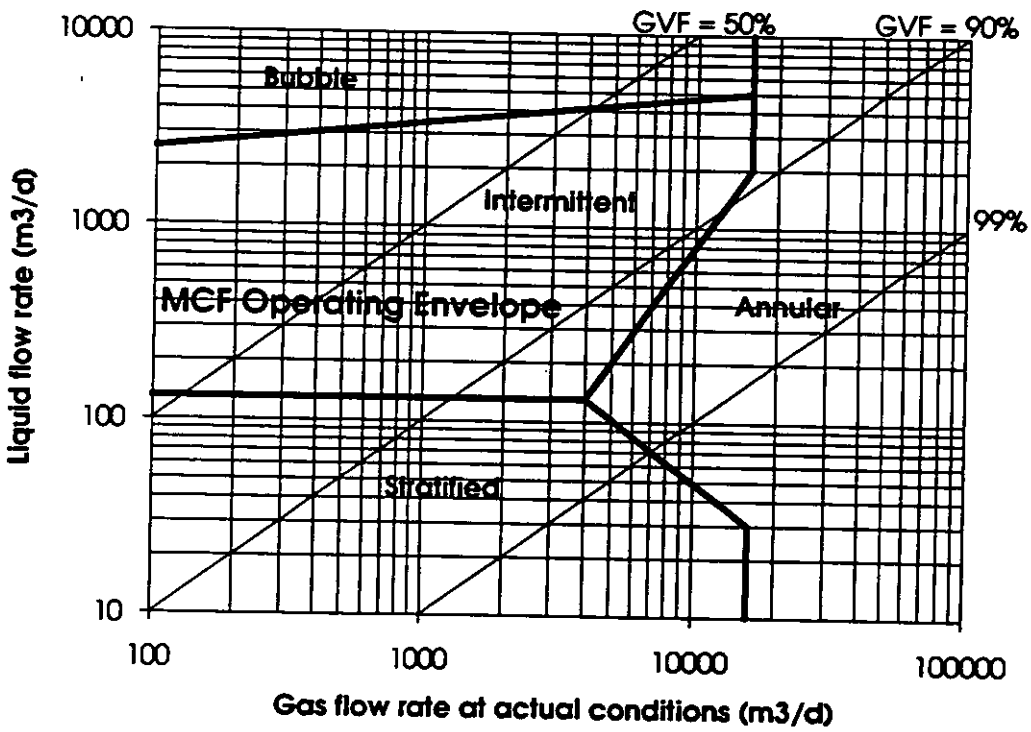

Fig.10 Expected operating envelope for 4" MCF slug (intermittent) flow meter for the field in Gabon shown in fig.6.

Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Standardisation of Multiphase Flow Measurements

by

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Norway

STANDARDISATION OF MULTIPHASE FLOW MEASUREMENTS.

By
Eivind Dykesteen
Christian Michelsen Research, Bergen, Norway.

An introduction to the Discussion Group "Standardisation and user requirements for multi phase flow meters"

1. MULTIPHASE FLOW MEASUREMENT TECHNOLOGY IS MATURING.

The development of multiphase metering technology for oil/gas/water flow started in the early eighties. Over these years there has been made several attempts to develop a suitable multiphase meter, and by now there are in the order of twenty active projects. Norway has been particularly active in this area. As a result of this massive effort we now begin to see the first multiphase meters for topsides installation becoming commercially available.

Together with a maturing technology, a requirement for standardisation also arise. This refers to definitions of terminology, standards for specification of instrument performance, calibration standards etc.

This short-paper, which serves as an introduction to the discussion group "Standardisation and user requirements for multi phase flow meters", will raise some of the questions which have to be answered in a work of standardisation. It will however not attempt to give any of the answers. The paper will also present the status and objectives of some ongoing work in the area of multiphase standardisation.

2. WHY DO WE NEED STANDARDISATION?

Several multiphase meters are becoming available to the oil industry, all with different performance specifications. The specifications are given by the manufacturer of the instruments, but without reference to any common standards. The different meters have all been tested on different, and in many cases proprietary, test facilities, and conventions for good practice for testing and specification of multiphase meter performance are lacking.

- On this background, how can the users make any comparative evaluation of the meters?
- And how can they decide which meter will best suit their particular application?

Metering for product allocation between companies is an other application where the lack of standards may be prohibitive for the use of multiphase meter. In this case both the involved companies, as well as governmental bodies, will have to agree measurement and calibration procedures.

- When no calibration standards exist, how can the overall measurement uncertainty be established, maintained and accepted?
- Which calibration routines should be undertaken?
- How do you prove a multiphase meter?
- How do you calculate the overall measurement uncertainty?

Resulting from the development of multiphase technology within the oil industry, a whole new world of "multiphase terminology" has been established. Unless there exist commonly agreed definitions for this terminology, confusion and misunderstandings will be unavoidable.

- Do we recognise the difference between gas fraction, gas hold-up, GOR, GLR and gas quality factor?
- What do we mean by a *multiphase meter*? Is it any meter that measures a multiphase parameter?
- And where do we find the definitions of these terms?

3. STATUS OF MULTIPHASE METER STANDARDISATION

The requirement for starting a work on standardisation within multiphase metering has been discussed at several previous venues, also at the previous North Sea Flow Measurement Workshop, and some work has been initiated both in Norway and in UK.

Norway:

A proposal for starting a work within multiphase standardisation was presented and discussed at the NFOGM (the Norwegian Society for Oil and Gas Measurement) seminar in Haugesund in March '93. Encouraged by the positive response received here, the NFOGM in May '93 initiated a working group consisting of representatives from R&D, oil companies and manufacturers of multiphase meters.

The objective for the work in this group is to develop a guide for users and manufacturers of multiphase meters. It is further the aim that the "handbook of multiphase measurement" resulting from this work should form the basis of an initiative to develop an international standard for multiphase measurement. The scope of work for this group includes multiphase terminology, requirements to multiphase meters, specifications of multiphase meters and procedures for calibration of multiphase meters.

UK:

The NEL in Scotland have recently built a completely new flow laboratory. As part of this flow laboratory a new multiphase meter calibration loop has been built, which NEL denotes as "the UK multiphase flow measurement standard". This facility will provide a possibility for independent testing of multiphase meters over a wide range of flowrates, compositions, and flow regimes. It will be possible to operate the facility on dead crude oil.

But it will of course be difficult to keep a "hard standard", i.e. a calibration loop, unless there is also a "soft standard" to reference it against. NEL therefore suggest to develop a calibration standard for multiphase meter, and propose this to be undertaken as part of a "multiphase club".

4. CONCLUSIONS.

Based on the status as described above, the following conclusions may be drawn:

There is a need for standardisation.
Standardisation will promote the use of multiphase meters, it will make it easier to choose the right meter for a given application, and it will provide a platform for agreement between the different involved parties in the case of production allocation metering based on multiphase meters.

The timing is correct.
Several different multiphase meters have passed their first pilot installations, and are becoming readily available. The market has already responded to this fact by seriously considering the use of multiphase meters in new satellite field developments. Governmental bodies will demand that the uncertainty involved with allocation based on multiphase meters is documented, and that acceptable procedures for maintaining the accuracy have been established.

Activities should be co-ordinated.
Duplication of work within standardisation of multiphase metering must be avoided. It would be preferable to all parties if only one multiphase metering standard document was developed, and that this was widely accepted among governmental bodies, oil companies and meter manufacturers. Steps to co-ordinate the ongoing work across borders must be taken at an early stage, i.e. now.

A fruitful discussion here at the North Sea Flow Measurement Workshop 1993, will be an important step towards a widely accepted international standard within multiphase metering.

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

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Testing water-in-oil monitors at the Mongstad terminal

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Testing water-in-oil monitors at the Mongstad terminal

1. Summary

This paper presents an installation developed by Statoil to test and qualify water-in-oil monitors at its Mongstad oil terminal near Bergen.

Results from extensive testing of three different water-in-oil monitors are described. These meters were tested with three different types of crude, which had a water content varying from 0.1 to 10 per cent. Extremely good results were achieved with two of the meters, supplied by Fluenta and Multi-Fluid International (MFI) respectively. These meters are now regarded as qualified for use as devices that give a higher level of accuracy and repeatability than the present method based on laboratory analysis of oil samples.

2. Introduction

Considerable efforts have been devoted by various research institutes and oil companies over the past 10 years to developing better equipment for volume metering of hydrocarbons before and after separation. "Better" in this context means greater accuracy, improved repeatability and a more robust construction. Other important factors when considering an installation include less time-consuming operation, continuous provision of data and a space-saving design.

A multiphase meter, which gives the user continuous flow information on a blend of oil, water and gas, is a good example of such new instruments. Similarly, water-in-oil monitors are devices which could advantageously replace time-consuming off-line analysis equipment such as the Karl Fisher method, and which also provide continuous information about the amount of water in oil at any time. A space-saving configuration would also be beneficial by replacing large and heavy process equipment/metering systems with smaller and more compact units. Examples of this could be the replacement of test separators with multiphase meters. In the longer term, it could also be appropriate to replace large prover stations for calibrating oil metering stations with smaller systems based on mass meters with enhanced long-term stability.

All new equipment entering the market must undergo an extensive qualification process to satisfy users about the functionality of the device and to permit optimisation/improvement by the supplier.

Constructive cooperation between user and supplier is important in this phase, which embraces intensive laboratory and field tests and which often takes longer than desirable. Such collaboration makes it possible to identify teething problems and gives the end-user confidence in the product.

To perform such qualification tests as effectively as possible, Statoil has developed facilities which permit field testing of working products. A flow loop has been constructed at the Mongstad terminal in order to test water-in-oil monitors. Similarly, a flow loop installed upstream of the test separator on Gullfaks B permits multiphase meters to be tested on the different wells. Work is also under way on facilities for testing level meters and for qualifying single-phase mass meters for both gas and oil.

It is gratifying to observe that Norway possesses several highly-qualified companies that have developed advanced metering instruments which hold a market lead in development terms. Over the past year, Statoil has enjoyed constructive cooperation with Fluenta of Bergen and Multi-Fluid International (MFI) in Stavanger. Water-in-oil and multiphase meters developed by both these companies have been thoroughly tested at Mongstad and on Gullfaks B respectively.

3. Test facilities

One question that always arises when assessing test results from new meters is whether process conditions during the tests are representative for later installations. To minimise this uncertainty, it is important to perform the testing under conditions which come as close as possible to those that will prevail in field applications of the equipment.

Examples of test facilities developed in recent years include:

* The K-Lab at Kårstø north of Stavanger: calibration/certification of fiscal gas flow meters

* Con-tech in Stavanger: flow loop for calibrating fiscal flow meters for different types of oil under high pressures and temperatures.

* Gullfaks B: Test facility for multiphase meters.

The test setup at Statoil Mongstad is presented below.

4. Water-in-oil monitors

When metering crude oil, water content is the most difficult parameter to measure with certainty. The actual sampling device is often faulty, and results from the analyses of water content on the ship and by the recipient generally differ fairly widely. This is particularly the case when a large volume of water (from one per cent and up) is accidentally introduced to the oil. A water content this high in oil can result in legal disputes between shipper and recipient that involve very large sums of money on occasion. More accurate and uniform measurement of water in oil could therefore eliminate a major source of uncertainty.

The oil outlet from the separator is another location where Statoil considers it appropriate to install water-in-oil monitors, permitting continuous monitoring of the separation process. This applies particularly to test separators during well testing, where corrections for the water content in the oil are important if the correct protection rate is to be recorded.

4.1 History

Several companies, including Fluenta and MFI in Norway, began to develop oil-in-water meters in the mid-1980s. Statoil has supported Fluenta during the initial development phases and MFI throughout the development of its device. The aim of this commitment has been to develop in-line instruments for fiscal metering of water in oil.

Until now, water content has been measured using the flow proportional sampler and Karl Fisher titration. The accuracy of this method depends largely on the operator. Whether the water content in a 10-litre oil sample corresponds to the actual water content in the crude passing through the pipeline is also highly uncertain.

4.2 Test objectives

The objective of the test programme was to establish whether any of the three selected meters could qualify to replace the conventional sampler for purchase/sale purposes. The Fluenta and MFI devices were supplemented by a third meter during the initial test phase, but the latter was removed from the programme after yielding unsatisfactory results.

Since all three meters could basically be described as prototypes, it was important to test the following parameters:

- accuracy with different water cuts and types of crude oil
- repeatability with the same water cut
- stability of the instruments in the long and short terms
- sensitivity to variables such as water conductivity, oil density and dielectric constant
- genuine variations in these parameters
- effect of varying air temperatures
- influence of varying temperature, pressure and flow speed
- weaknesses in the instrument, its electronics and its man-machine communication
- possible constraints on the instruments.

4.3 Choice of test facility

Mongstad is the site of a large terminal which takes delivery of crude oil loaded into shuttle tankers on several North Sea fields. Part of this crude is stored in large rock caverns for later export by tanker. Several considerations prompted the choice of this facility as the test site for the water-in-oil monitor:

- It allowed the water-in-oil monitor to be tested with all types of crude handled by Statoil. These oils vary in dielectric constant, density and water conductivity.

- Because the terminal is on land, costs are significantly lower when compared with an offshore test.

- Mongstad is interested in qualifying a water-in-oil monitor for its own use to achieve greater control of such measurements in connection with purchase/sale.

Figure 1 shows a diagram of the actual test rig with the three meters installed.

4.4 The Mongstad test facility for water-in-oil monitors

Crude oil metering station A at Mongstad

The test rig for water-in-oil monitors is linked to crude metering station A at the Mongstad terminal. This is one of two identical units - the other being station B - used when loading and discharging crude oil. During these operations, the crude is transferred between tankers and the terminal's storage facilities.

Both metering stations are equipped with eleven 12-inch lines, giving a theoretical metering capacity of 20 000 cubic metres per hour. In practice, the loading/discharging rate through each station is about 10 000 cubic metres per hour.

Oil from the Gullfaks A/B, Gullfaks C and Statfjord platforms in the Norwegian North Sea can also be circulated from the rock cavern stores, through the metering station and back into storage.

The test rig

The test rig for water-in-oil monitors is a two-inch bypass loop with its inlet and outlet located after the mixer and before the automatic flow sampler at metering station A. The mixer is a motor-driven propeller type installed in a 48-inch pipe after the metering station.

Constructed by Norwegian company Framo Engineering, the test rig is equipped with a frequency-controlled screw pump. A 3/4-inch fresh-water intake, with valve and back pressure valve, has been installed immediately behind the inlet to the test rig. Fresh water from the firewater system is used for injection. The frequency-controlled in-line screw pump is operated by a 4-20 mA signal proportional to the flow rate through metering station A, which means that oil flows through the test rig at the same speed as through the 48-inch line. This isokinetic measurement ensures that results obtained from the water-in-oil monitors during loading/discharging are comparable with those from the automatic sampler.

Static two-element mixers are installed upstream each meter and the sampler probe to ensure that the metered volumes are adequately homogenised.

Fresh-water injection

Initial measurements showed that oil from the Mongstad storage caverns normally contains very little water, about 0.1-0.2 per cent on loading into the tankers. During discharging, water separated

out at the bottom of the cargo tanks emerges immediately after the pumps start and can exceed 10 per cent of the flow for a few minutes.

The dielectric constant varied considerably between the three crudes tested. As a result, the MFI and Fluenta meters had to be recalibrated for each type of oil. This calibration must be performed when the water content is stable and below one per cent.

During discharging, the water content of the oil changes so quickly that it proved impossible to take a representative sample at the same time as the instruments were read. After an hour, the water content in the oil was constant and less than one per cent. This meant that the instruments could only be tested during discharging over the lower range - 0.1-0.5 per cent.

In order to test the meters with varying and high water contents, a connection to the firewater system was installed in the two-inch line ahead of the pump. This arrangement permitted the water content to be varied from 0-12 per cent by injection during loading, discharging and recirculation.

Data collection, trend monitoring

The water cuts reported by the three metering devices were logged once a minute by a Bailey process control system installed in the central control room. The values logged over the previous seven days can be presented as freely-scalable time curves in a freely-selected time window on the screen. The screen picture can be captured to a printer at any time.

In addition to a common time curve, separate time curves can be generated for each of the three meters. It is also possible to obtain the average water cut from the moment when loading commenced, in order to compare this with the result from the sampler. In addition, the total flow rate through the metering station can be presented as time curves on the screen.

Collection of spot samples

Oil samples of 0.9 litres at a time were taken from the two-inch line downstream of a dedicated mixer. The flask was then corked and labelled with the time, the sample number and the values read from the MFI meter while the sample was being taken. Local reading at the actual device was only possible with the MFI meter. Metered values for the other instruments were checked over a radio link with the control room, and recorded in order to be sure that all the meters were stable.

Procedure for Karl Fisher titration

After the oil had been mixed for at least 15 seconds in a dedicated mixer at 20 000 rpm, a sample was drawn into a syringe of a size determined by the water content.

To ensure that the operator was injecting the correct volume, the syringe was weighed before and after injection. Uncertainty in the injected volume was about ± 1.5 per cent. The contents of the syringe were then injected in the titrator. At least two samples were taken from each flask to check repeatability. In the event of

poor repeatability, or when titration took a long time, the titration fluid was replaced.

4.5 Requirements for water-in-oil monitors

The MFI water-in-oil monitor was developed by that company in cooperation with oil companies Phillips, BP and Statoil, with Hitec of Stavanger as project manager. During the development, the following standards were established for accuracy:

- ± 0.5 per cent absolute accuracy from zero-one per cent water in oil

- ± five per cent of measured values from 1-12 per cent water in oil.

This requirement was proposed by BP in the UK, which had the greatest experience from research projects relating to water-in-oil sampling and analysis. It has since been applied as a standard in efforts to qualify other water-in-oil monitors for fiscal metering. Reference will be made to this standard later in the paper.

4.6 Reference

The Karl Fisher method is the most widely-accepted current method for determining the water content of oil, and has been used as the reference method in all testing of the various water-in-oil monitors.

A test performed in 1991, in which known amounts of water were injected into a closed loop with a known volume, compared one of the water-in-oil monitors with the Karl Fisher instrument. This experiment showed that the meter gave more accurate results and better repeatability than the analysis-based method.

It is unrealistic to expect the accuracy of an instrument to be better than the reference used as a basis for comparison. The estimated accuracy of the Karl Fisher technique bears a non-linear relationship to changes in the water content of the oil. Setting the accuracy of the Karl Fisher method to equal the requirement for the water-in-oil monitor yields approximately the right result in the zero-five per cent range for water in oil.

The acceptable tolerance for the water-in-oil monitor using Karl Fisher as the reference can then be extended to $\sqrt{0.05^2+0.05^2} = 0.07\%$ absolute deviation for zero-one per cent water in oil, and $\sqrt{5^2+5^2} = 7\%$ of the measured values over one-five per cent water in oil.

4.5 Test procedure

The main test comprised three rounds of testing with crude from Gullfaks A/B, Gullfaks C and Statfjord respectively. After a few hours of loading/discharging or recirculating, the water content was down to about 0.1 per cent and completely stable. Only minimal changes (± 0.02 per cent) were registered from time to time. The pressure and temperature of the oil was also quite stable.

Once these conditions were established, the meters were calibrated and the tests performed by injecting the desired amount of water into the oil flowing through the test rig. In order to spread

different tests with the same water cut over time, the quantity of injected water was constantly varied.

Three samples were taken for each of the three oil types at the following water cuts: 0.1, 0.2, 0.4, 0.6, 0.8, 1.0, 1.5, 2.0, 3.0, 4.0, 5.0, 7.0 and 10 per cent.

During these main tests, all parameters other than water content were kept as constant as possible. In addition to the main test, seven other tests were performed to investigate the stability of the individual meters under different operating conditions. These tests were carried out with stable amounts of oil in the water.

4.8 Test results, Fluenta WIOM 300

Specification

Fluenta's water-in-oil monitor has the following features: a non-intrusive design, full-profile metering and no need for a mixer in normal use. It measures the range from zero to 40/80 per cent water (equalling the transition point for the oil) and comes in diameters from one to 12 inches.

Mongstad test

Before a test round started, the meter was calibrated for the correct type of crude by entering its dielectric constant. This can be done automatically by putting in the meter in a calibration mode and entering the exact volume of water, or manually be entering the constant.

A total of 98 tests were performed during the three rounds. The results from four of these were outside the adjusted requirement (0.07 per cent absolute accuracy for zero-one per cent water and seven per cent of the measured value for one-five per cent water, while results from 21 tests were outside the original standard of 0.05-5 per cent.

Figure 2 gives an example of a test round, where the measurements are shown in a deviation diagram. Table 1 presents the results of the test round with Gullfaks C crude. The upper part of the table shows the absolute deviation between meter and laboratory analysis for zero-one per cent water in oil, while the lower section presents deviation from the measured value when the water content exceeds one per cent. The lowest values are not official test results since the uncertainty associated with the Karl Fisher method becomes high for a water content exceeding five per cent. Each test is numbered in the order it was performed.

The Fluenta meter drifted a little between one oil cargo and another from the same field, and therefore had to be recalibrated for each cargo. Whether this drift was due to variations in ambient temperature or the sensor/electronics is not known.

Fluenta has developed a water-in-oil monitor which gave very good results in an extensive test. Replacing traditional BS&W metering methods with this device would be advantageous in environments with a reasonably stable ambient temperature.

Statoil has installed a Fluenta WIOM 300 on its Gullfaks A platform. Placed in a bypass line ahead of the oil metering station, this meter has performed very satisfactorily since it came on line in August 1992. The meter is compared at regular intervals with samples, and a good match has been found. But the tests performed so far with the meter have not been sufficiently detailed to permit any conclusions about its accuracy and long-term stability.

4.8 Test results with the MFI Watercut Monitor

Specification

The MFI device comes in two versions - one measuring water content from 0-12 per cent and the other covering the range from 0-40/70 per cent water, depending on the type of oil involved. The meter can be delivered in all diameters from two inches and up, and will provide full-profile measurement.

Testing

Before starting a test round, the meter was calibrated for the right type of oil by entering its dielectric constant. This can be done automatically by putting the meter in a calibration mode and entering the exact amount of water, or manually by entering the constant. In addition, water conductivity must be entered with an accuracy of ± 50 per cent.

A total of 98 tests were performed in the three rounds. All results from these tests are within the modified requirement (0.07 per cent absolute accuracy for zero-one per cent water and seven per cent of the measured values for one-five per cent water). Four of the tests yielded a result outside the strictest standard of 0.05 per cent-five per cent.

Figure 3 gives an example of a test round, where the measurements are shown as a deviation diagram. Table 2 presents results for the test round with Statfjord crude. The upper part of the table shows the absolute deviation between meter and laboratory analysis for zero-one per cent water in oil, while the middle section presents deviation from the measured value when the water content exceeds one per cent. The lowest values are not official test results since the uncertainty associated with the Karl Fisher method becomes high for a water content exceeding five per cent. Each test is numbered in the order it was performed.

The MFI meter is stable from cargo to cargo, and remains apparently unaffected by variations in its surroundings.

MFI has developed a water-in-oil monitor which gave extremely good results in an extensive test. Since these tests, MFI has improved the operator communication - the only weakness of the device exposed during testing. Replacing traditional BS&W metering methods with this meter would be advantageous.

Statoil intends to install an MFI meter on the Gullfaks B test separator. This device will be used to measure the exact water content in the crude after separation, and help to improve the accuracy of reference measurements on the test separator. This meter will then be tested for long-term stability. Statoil is also

planning to install meters for the export metering stations on both Statfjord A and the Veslefrikk field in the Norwegian North Sea.

4.9 Conclusion, water-in-oil monitors

The Mongstad test has demonstrated that both Fluenta and MFI have developed water-in-oil monitors which could advantageously replace existing methods based on sampling and subsequent laboratory analysis for purchase/sale metering. Both meters are accurate and are easy to operate. Reservations focus not so much on the meters as on the electrical characteristics of the medium in which they are to measure.

The dielectric constant varies from one type of crude to another. Measurements from Mongstad have also revealed that this constant can vary from one cargo to another supplied by the same field by a factor corresponding to as much as ± 0.05 per cent water in oil.

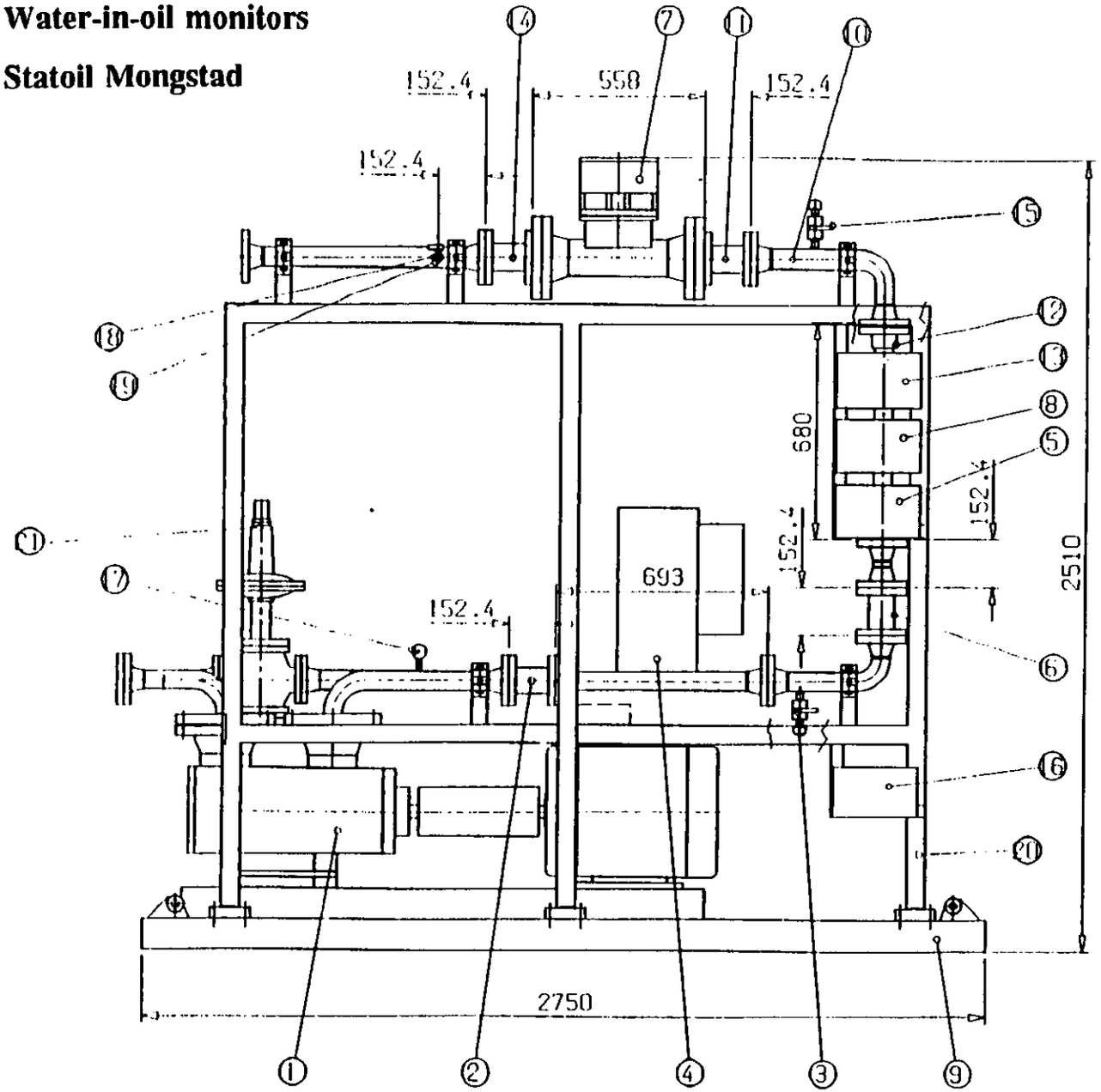
These water-in-oil monitors must be approved by the Norwegian Petroleum Directorate if they are to replace today's samplers for purchase/sale of oil. This approval can only be achieved by documenting good long-term stability and little day-to-day variation in the dielectric constant. Statoil is planning to install the MFI water-in-oil monitor at several of its installations.

The long-term stability of the meters has not been adequately tested or documented by the Mongstad tests.

Test Facility for

Water-in-oil monitors

Statoil Mongstad



1 - Pump
2 - Static mixer
3 - Ball valve
4 - MFI water-in-oil monitor
5 - Junction box
6 - Static mixer
7 - Fluenta water-in-oil monitor
8 - Junction box
9 - Frame
10 - Piping
11 - Static mixer
12 - Water-in-oil monitor
13 - Junction box
14 - Static mixer
15 - Ball valve
16 - Junction box
17 - Pressure gauge
18 - Sampler probe
19 - Ball valve
20 - Frame
21 - Safety valve

Fig. 1

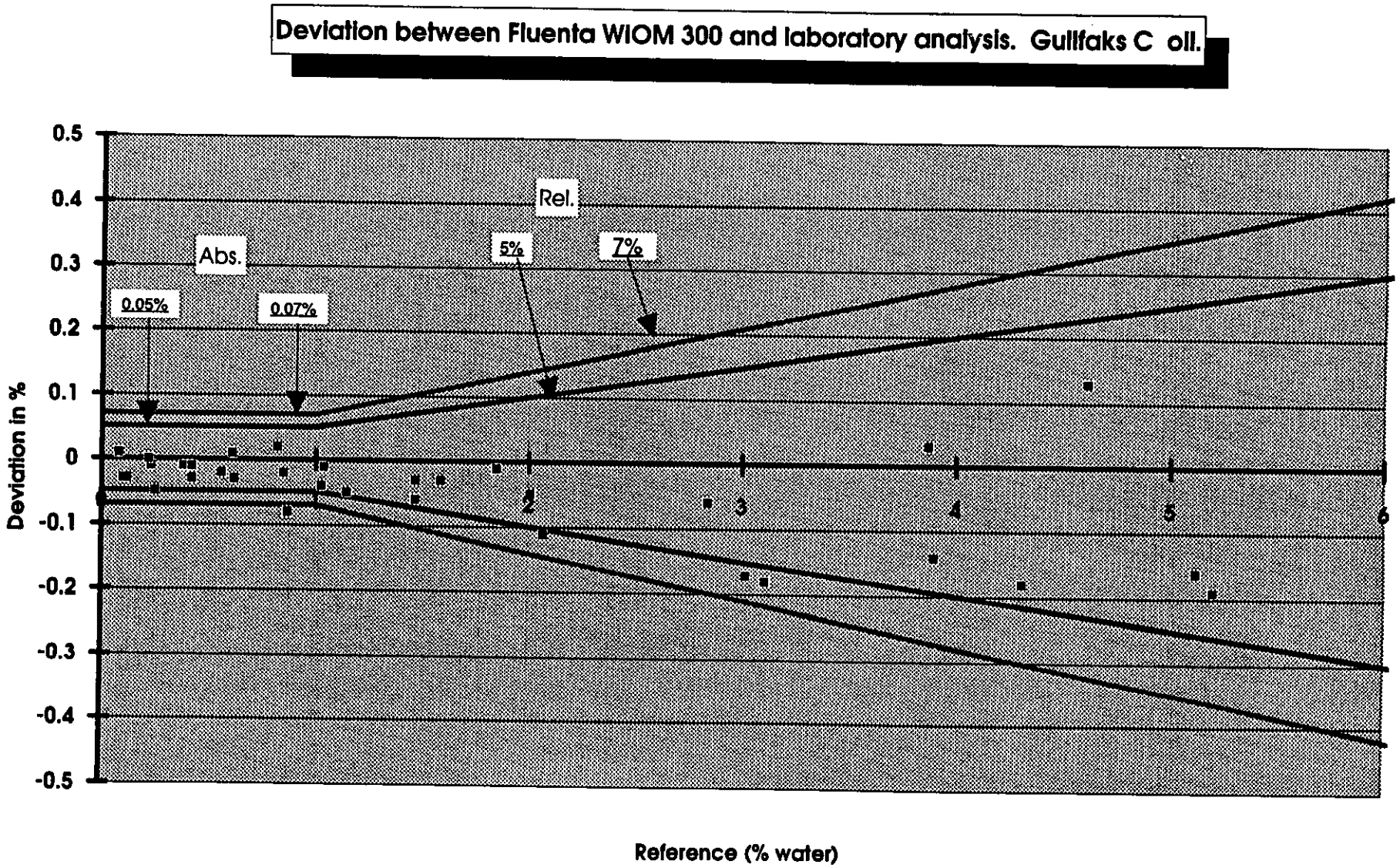

Deviation between Fluenta WIOM 300 and laboratory analysis. Gullfaks C oil.
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
-0.5
Deviation in %
Abs.
Rel.
0.05%
0.07%
5%
7%
2
3
4
5
6
Reference (% water)

Fig 2

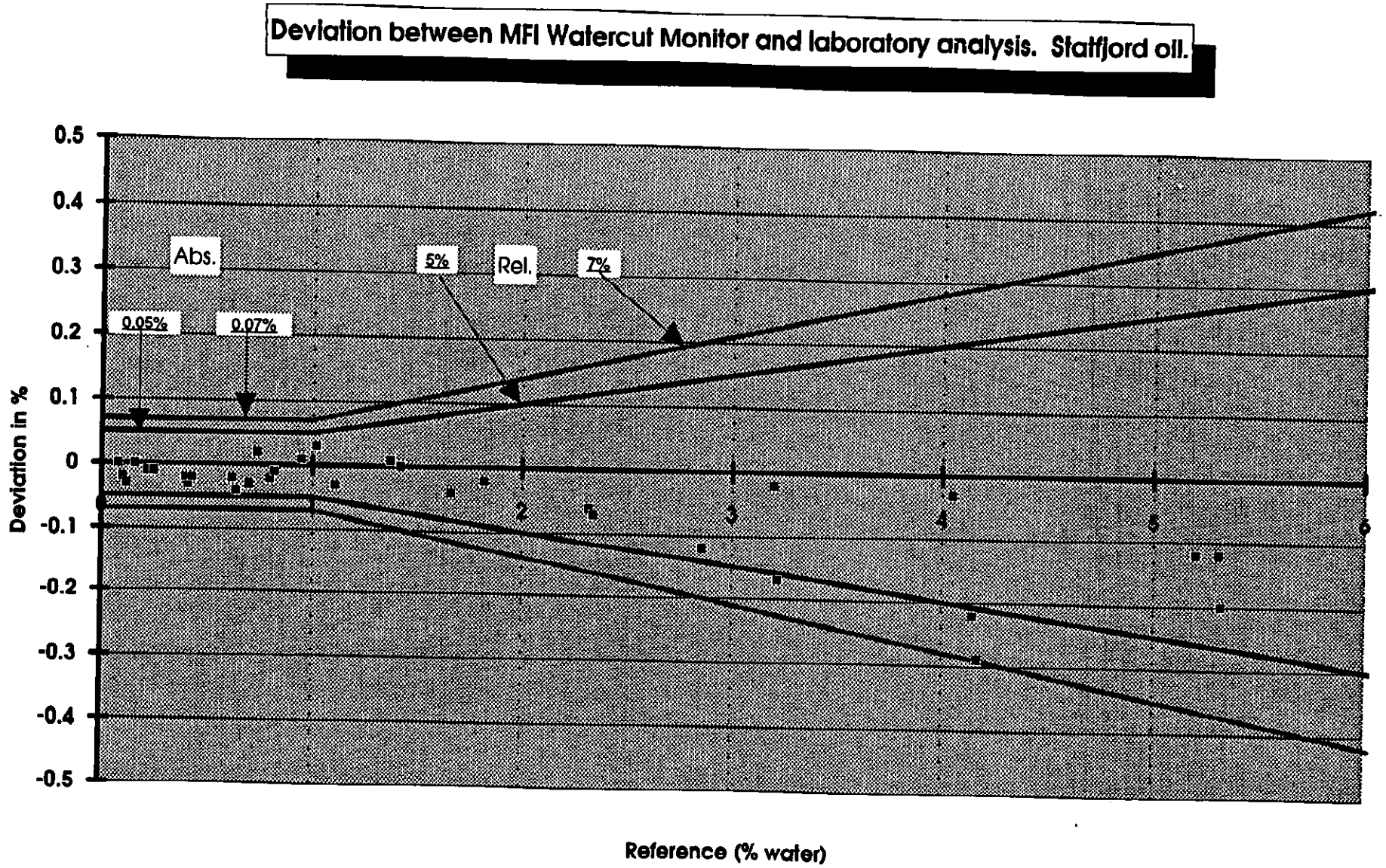

Deviation between MFI Watercut Monitor and laboratory analysis. Statfjord oil.
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
-0.5
Deviation in %
Abs.
Rel.
0.05%
0.07%
5%
7%
1
2
3
4
5
6
Reference (% water)

Fig. 3

TESTING WATER-IN-OIL MONITORS AT THE MONGSTAD TERMINAL

OIL TYPE: GULLFAKS C **DENSITY: 859.5 kg/m3** **DATE: 26.1.93**

INJECTION OF FRESH WATER **SIX HOURS OF RECIRCULATION BEFORE START OF TEST**

Test no.	Time	Fluenta % water	Lab. analysis % water	Deviation lab./ MFI	Oil temp. (oC)	Ambient temp. (oC)	Line pressure (barg)	
1	15:43	0.07%	0.10%	- 0.03%	23.4	-3	5.3	
26	19:17	0.08%	0.08%	0.00%				
39	19:57	0.09%	0.12%	-0.03%				
4	15:57	0.20%	0.25%	-0.05%	23.6	-3	5.3	
25	19:15	0.22%	0.23%	-0.01%				
28	19:24	0.22%	0.22%	0.00%				
5	16:00	0.37%	0.38%	-0.01%				
22	19:05	0.39%	0.42%	-0.03%				
27	19:20	0.41%	0.42%	-0.01%	23.8	-6	5.1	
3	15:55	0.59%	0.62%	-0.03%				
24	19:12	0.54%	0.56%	-0.02%	23.7	-6	5.1	**Absolute deviation**
31	19:31	0.62%	0.61%	-0.01%				
2	15:50	0.83%	0.85%	-0.02%				
23	19:08	0.79%	0.87%	-0.08%				
30	19:28	0.84%	0.82%	0.02%				
6	16:03	0.99%	1.03%	-0.04%				
20	18:56	1.10%	1.15%	-0.05%				
29	19:27	1.03%	1.04%	-0.01%	23.7	-6	5.2	
8	16:10	1.44%	1.47%	-2.04%				
21	19:00	1.41%	1.47%	-4.08%				
32	19:33	1.56%	1.59%	-1.89%	23.8	-6	5.2	
7	16:07	1.96%	2.01%	-2.49%				
19	18:53	1.96%	2.07%	-5.31%				
33	19:36	1.84%	1.85%	-0.54%				
9	16:14	2.93%	3.11%	-5.79%	23.7	-4	5.2	
18	18:50	2.85%	3.02%	-5.63%	23.8	-6	5.2	
34	19:40	2.78%	2.84%	-2.11%				
10	17:25	3.90%	3.87%	0.78%	23.7	-5	5.2	**Relative deviation**
16	18:05	3.76%	3.90%	-3.59%				
38	19:55	4.13%	4.31%	-4.18%				
11	17:34	4.74%	4.61%	-2.82%				
17	18:10	4.96%	5.12%	-3.13%				
37	19:53	5.01%	5.20%	-3.65%				
12	17:37	6.90%	6.89%	0.15%	23.6	-5	5.3	
15	17:59	6.68%	6.85%	-2.48%	23.6	-5	5.1	
36	19:50	6.76%	6.99%	-3.29%				
13	17:43	8.90%						
14	17:50	9.64%						
35	19:45	9.38%			23.8	-6	5.2	

Tab. 1

TESTING WATER-IN-OIL MONITORS AT THE MONGSTAD TERMINAL

OIL TYPE: STATFJORD **DENSITY: 832.9 kg/m3** **DATE: 27.1.93**

INJECTION OF FRESH WATER **THREE HOURS OF RECIRCULATION BEFORE START OF TEST**

Test no.	Time	MFI % water	Lab. analysis % water	Deviation lab./ MFI	Oil temp. (oC)	Ambient temp. (oC)	Line pressure (barg)	
2	14:40	0.9%	0.12%	- 0.03%	18.8	0	5.3	
18	15:24	0.08%	0.10%	-0.02%	18.4	-4	5.4	
35	16:28	0.08%	0.08%	0.00%	17.6	-4	5.4	
9	14:58	0.24%	0.25%	-0.01%				
17	15:22	0.21%	0.22%	-0.01%				
34	16:22	0.16%	0.16%	0.00%				
8	14:57	0.38%	0.41%	-0.03%				
16	15:17	0.38%	0.40%	-0.02%				
32	16:17	0.41%	0.43%	-0.02%				
6	14:52	0.67%	0.70%	-0.03%	17.9	0	5.3	**Absolute deviation**
15	15:15	0.60%	0.62%	-0.02%				
33	16:19	0.60%	0.64%	-0.04%				
7	14:55	0.76%	0.74%	0.02%				
13	15:10	0.78%	0.80%	-0.02%				
30	16:12	0.81%	0.82%	-0.01%	17.8	-3	5.3	
5	14:49	1.08%	1.11%	-0.03%	18.8	0	5.4	
14	15:12	0.96%	0.95%	0.01%				
31	16:14	1.05%	1.02%	0.03%				
4	14:47	1.62%	1.66%	-2.41%				
12	15:05	1.38%	1.37%	0.73%				
29	16:10	1.42%	1.42%	0.00%				
3	14:45	2.26%	2.32%	-2.59%				
11	15:03	2.27%	2.34%	-2.99%				
28	16:07	1.80%	1.82%	-1.10%				
1	14:35	3.05%	3.22%	-5.28%	18.6	0	5.4	
10	15:01	2.47%	2.86%	-4.20%	17.9	-3	5.4	
27	16:03	3.18%						
22	15:43	3.93%	4.15%	-5.30%				**Relative deviation**
26	15:57	3.88%	4.17%	-6.95%				
39	16:43	4.02%	4.05%	-0.74%	17.4	-4	5.3	
21	15:40	5.12%	5.32%	-3.76%				
25	15:55	5.08%	5.20%	-2.31%				
38	16:40	5.19%	5.31%	-2.26%				
20	15:36	7.38%	7.14%	3.36%				
24	15:50	6.77%	6.95%	-2.59%				
37	16:37	6.88%	6.61%	4.08%				
19	15:33	9.34%			18.2	-2	5.3	
23	15:45	9.03%						
36	16:32	9.25%						

Tab. 2

Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

Remote Sampling

by

Mr. Bjørn Åge Bjørnsen,
Phillips Petroleum Company Norway

BACKGROUND:

Embla is the last field development by Phillips Petroleum Company Norway in Norwegian sector of the North Sea. It is situated south of Ekofisk, near Eldfisk, on block 2/7. The reservoir is found appr. 5000 m below seabed in Jurassic sand. It is a high temperature, high pressure field. Production started April this year.

Embla is a relative small field. Consequently it was decided to use available facilities on nearby platforms, Eldfisk A/FTP, for separation and processing, with only one small unmanned and remote operated platform located on Embla. 8 producing wells were originally planned for in phase 1 of the development.

During normal operation, production from the wells are combined, and transported to Eldfisk A without any processing on Embla. For allocation and reservoir evaluation purposes, a test seperator is installed. Each well was intended to be tested at least once every month for allocation purposes. Samples of oil and gas should be collected manually during testing. Consequently it would be necessary for qualified sampling personnel to travel to the platform by helicopter 8 times every month to collect samples. In addition to sampling personnel, a minimum safety crew of 7 persons, also would have to go to the platform at the same time.

Based solely on economics, good reasons to look into some way of remote sampling were obvious.

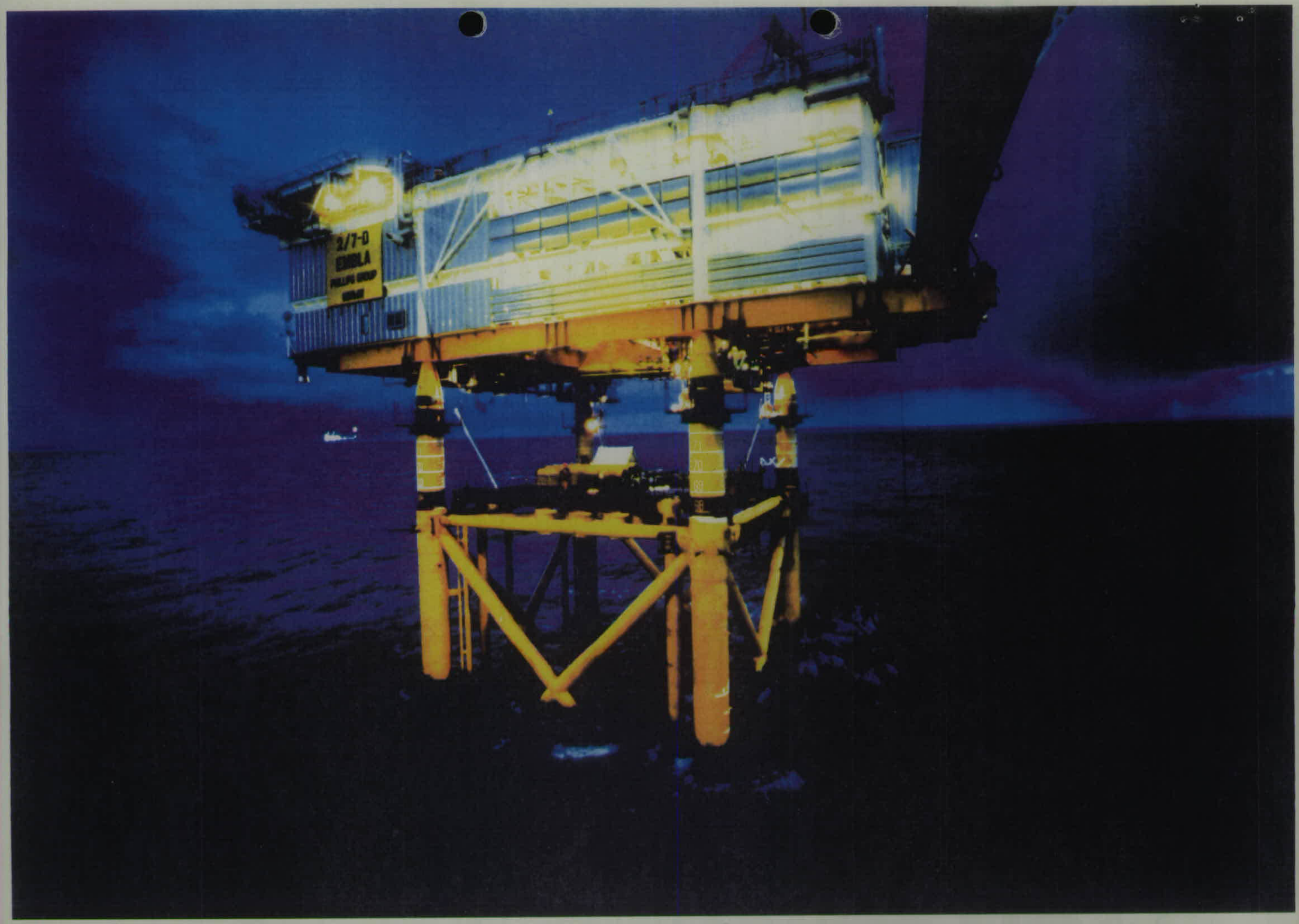
DEVELOPMENT OF "RAS":

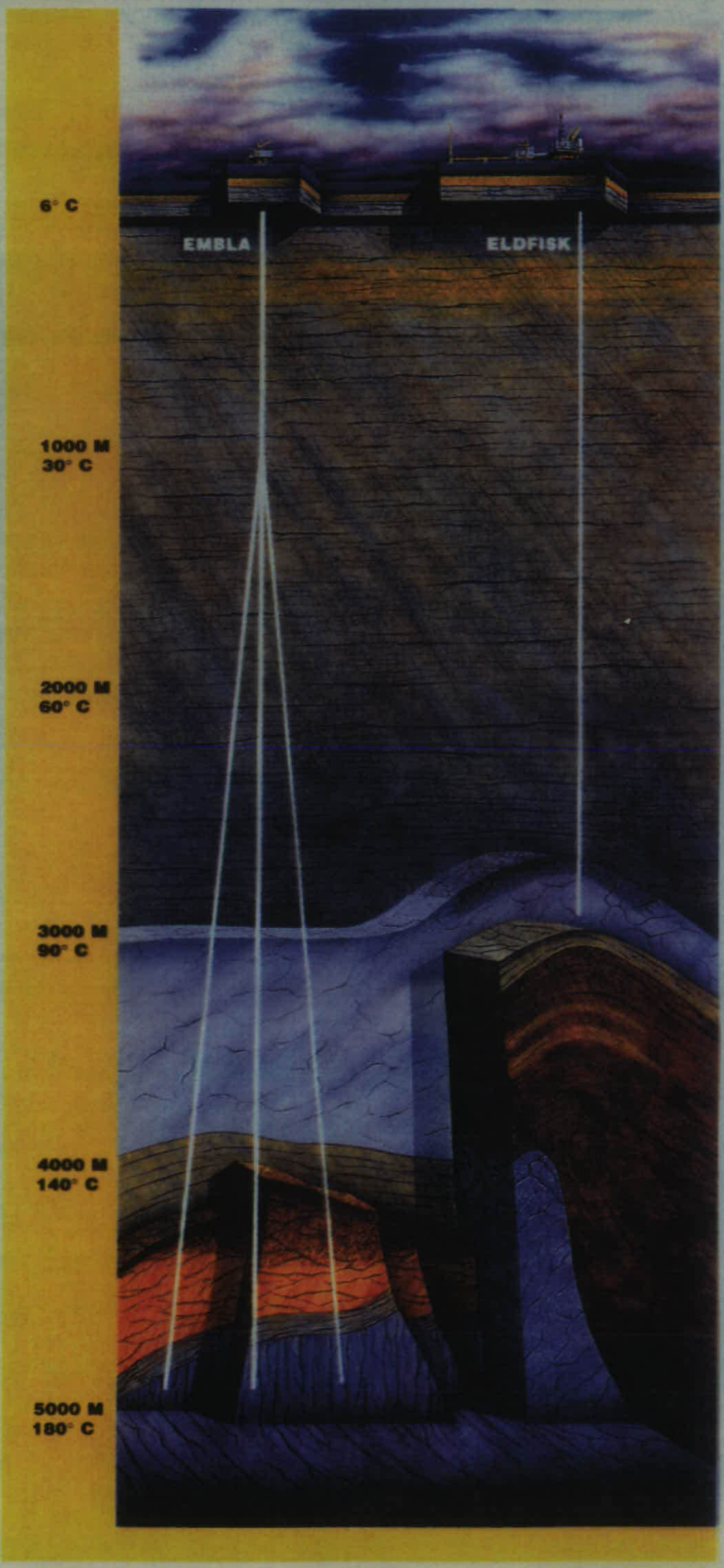
Mid 1990 personnel from PPCoN were invited to Proserv for a demo of their new sampling system, PRO-SAMP. It consisted of a Titanium sample cylinder with piston and mixing device. The piston position was detected from outside by means magnetic field action on a non contact lance position detector, MAGPOS. A LCD display showed the sampled volume at any time. Later the system was developed to show the piston location graphically on a monitor.

Late 1991 PPCoN decided to go for remote sampling on Embla. Potential vendors of equipment were contacted, but none were able to deliver "turn key" equipment to PPCoN specifications. In the mean time Proserv had further developed their PRO-SAMP system, and discussions initiated on even further development of this to a 10 cylinder remote operated sampling system. Fall 1992 a development contract was signed.

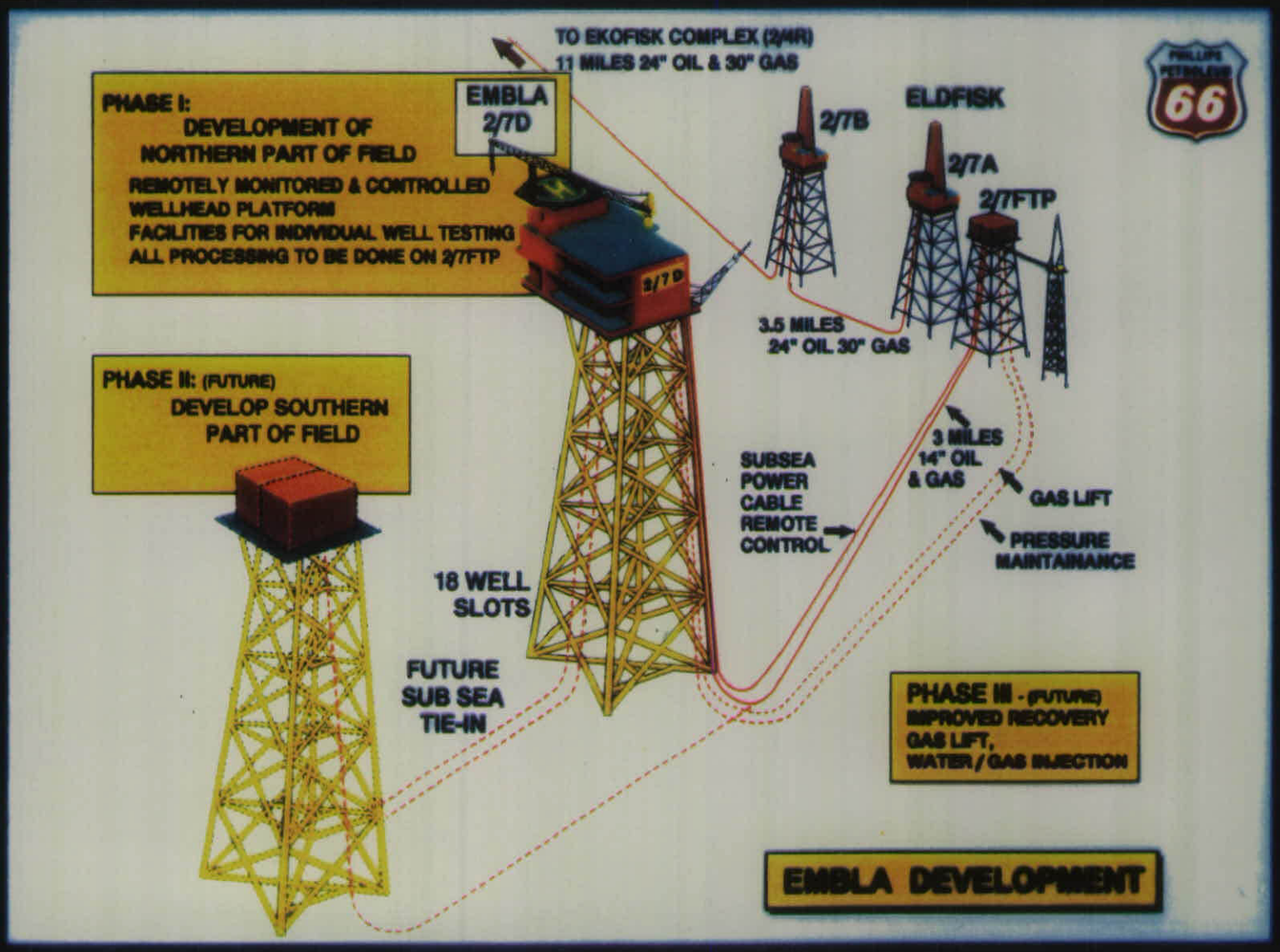
The original system was designed to fill each of 8 cylinders once, to a predetermined volume. Prior to this, the bypass loop should be flushed at a preset time and flow. No options for emptying and refilling was planned at this stage. The cylinders should be changed once every month.

PHILLIPS *The* PIONEER

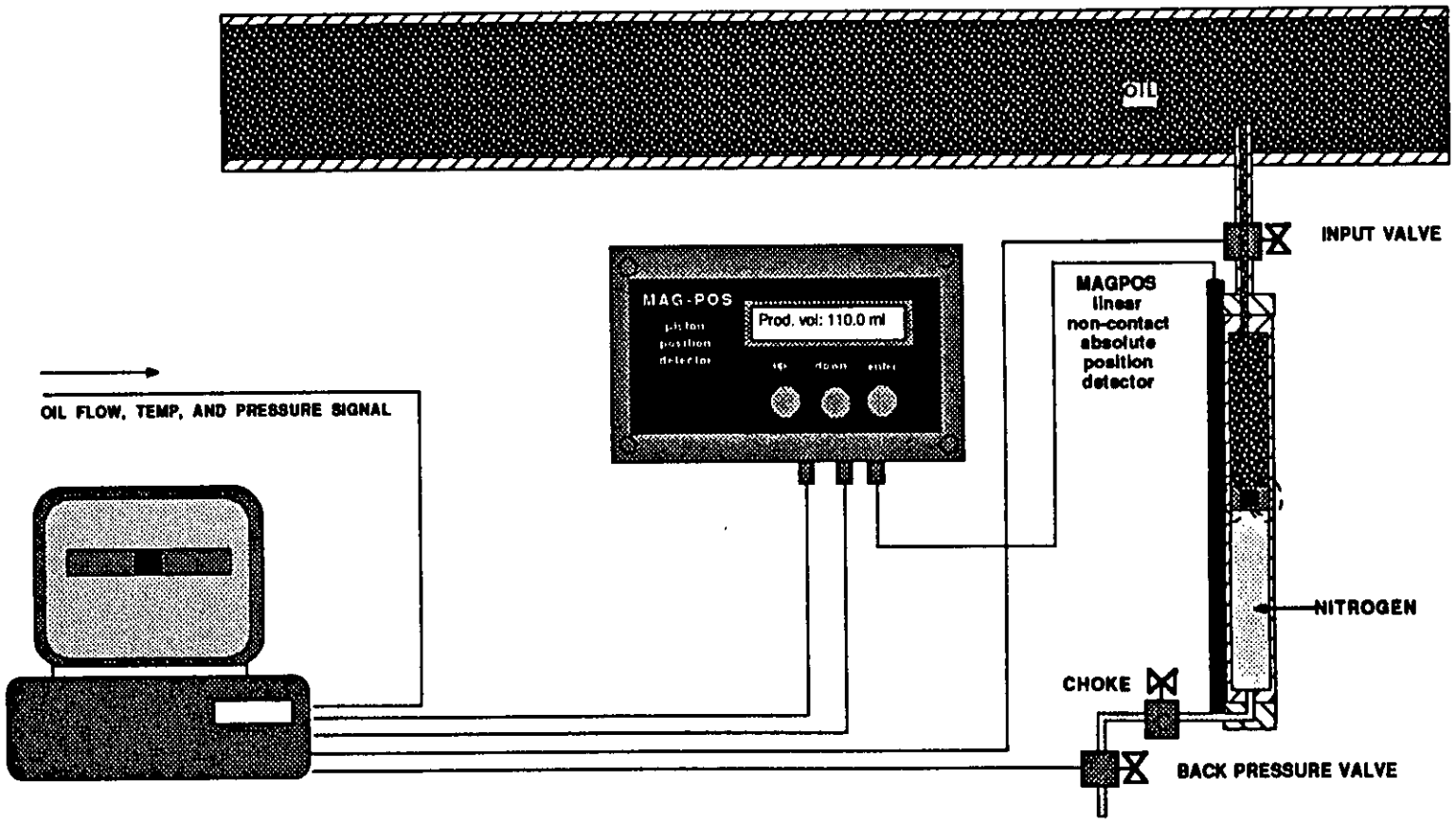

2/7-D
EDBELA


6° C
EMBLA
ELDFISK
1000 M
30° C
2000 M
60° C
3000 M
90° C
4000 M
140° C
5000 M
180° C

MEDIA▼TEAM Postboks 1125 4004 Stavanger, Norway Tlf.: (04) 58 10 80 Telefax: (04) 58 44 05



BASIC PRINCIPLE PROSERV / INFOTRONICS
REMOTE AUTOMATIC SAMPLING



The project progressed smoothly until April 1993. An unacceptable leak on the magnetic operated solenoid valves resulted in a "snow ball" effect on the design. The computer program, sampling and report options, have been modified and improved continiously. Future modifications can be performed from any place, also onshore, via modem.

A final functional test was performed June 24. Prior to this, the equipment was throughly tested, using pressurized crude oil and real flow data. Shipment to Embla was delayed to late August due to specification based hardware modifcations. Offshore equipment installation and computer communication was completed mid September.

First sampling from onshore via modem was performed Sept. 23.

ADVANTAGES USING "RAS":

Improved sample quality:
Good, and reproduceable quality is a requirement for samples used for allocation purposes. Through an automatic system, human errors and individual variations are eliminated.

Reduce operational costs:
Helicopter rental and labor time expences related to manual sampling are eliminated.

Safety improvement:
High pressure, high temperature sampling of this nature might involve safety hazards, especially when performed by personnel with limited experience. This is eliminated.

Helicopter shuttling to unmanned platforms is in general reduced to a minimum for safety reasons.

Tools and spare parts on an unmanned platforms are normally limited. Unforeseen problems might in certain cases lead to procedural hazardous short cuts in manual sampling.

Sampling time flexibility:
Sampling can be performed at any time, preset or manually initiated from remote location.

Reduce training costs:
A high number of personnel is involved in sampling on different platforms. To ensure proper sampling, training time has been a considerable "expense". The intention is to reduce number of people involved to a minimum.

SYSTEM DESCRIPTION:

1) Sampling Probe:
Standard probe, collecting sample from center of pipe. Sampling point is located on vertical pipe section upstream metering. Probe is fitted with shut off valve, and T-piece for manual spot sampling.

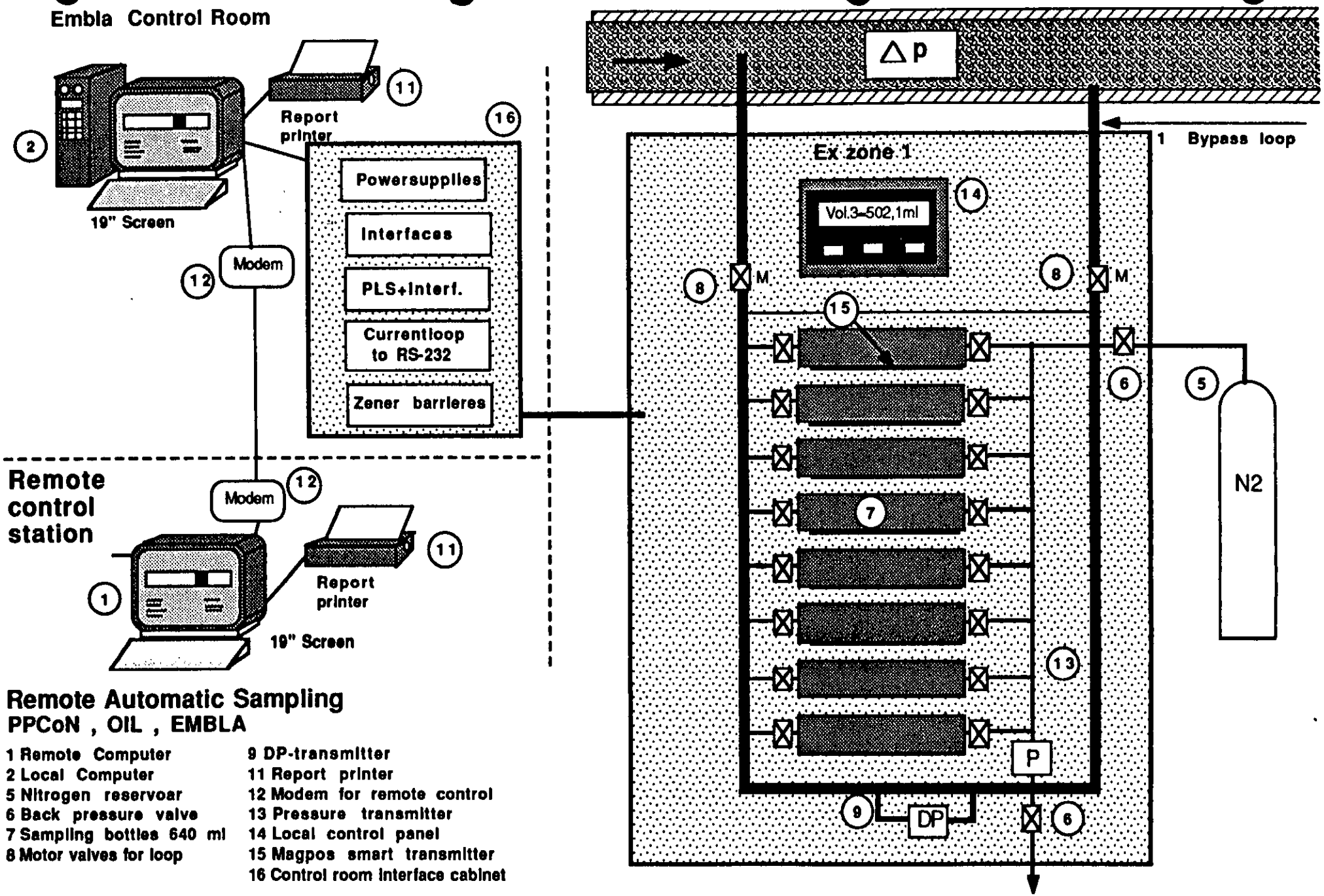
2) Bypass Loop:
A 3/8" Monel 400 tubing connected to the sampling probe. This tube transfer liquid through sampling cabinet, and terminates on low pressure side of production regulating valve. Choke valve is located at the outlet from the sampling cabinet. Shut off valve is in addition located on return point.

3) Sampling Cabinet:
A 316 SS cabinet sized 2250mm*1500*600mm (H*W*D) equipped with full open doors in front and removeable walls. The lower and largest part of the cabinet is occupied by sampling hardware. The seperated top section is reserved for signal processing units and connection boxes. The lower section contains:

Sample Cylinders:
In this version, eight 640 cc floating piston sample cylinders are located horisontally above each other. The cylinders are standard design PROSERV mod. S1-690-64 made of Titanium, with magnetic core pistons. Each cylinder is equipped with gauges, manual valves, rupture disc and quick connectors. On location the cylinders rest on a "tray", and are secured by a quick locking metal strap. The counterparts to the quick connectors on the sample side of the cylinders are permanently mounted. This ensures that the cylinders are installed in same position after change out, thus eliminating repositioning of piston indicator lances.

Piston Detectors:
For continious detection of piston, INFOTRONC MAGPOS Linear non-contact position detector mod. 444 has been used. These are mounted on the tray walls behind the cylinders. When calibrated, the volume on the sample side is determined with an accuracy of 0.1 cc. Small deviations in sample cylinder location (after change out) are easily corrected for.

Cylinder Valves:
Two magnetic operated solenoid valves with metal seats located downstream each end of all cylinders. The valve on the inlet side is located close to the cylinder, on a 1/4" SS tubing. The preload gas discharge valve is located downstream a h.p. flexible tubing. Magnetic operated valves were selected due to requirement of fast response.
Each cylinder is also equipped with manually operated valves. These are normally open when the cylinders are installed in the cabinet.



Remote Automatic Sampling
PPCoN , OIL , EMBLA

1 Remote Computer
2 Local Computer
5 Nitrogen reservoar
6 Back pressure valve
7 Sampling bottles 640 ml
8 Motor valves for loop
9 DP-transmitter
11 Report printer
12 Modem for remote control
13 Pressure transmitter
14 Local control panel
15 Magpos smart transmitter
16 Control room interface cabinet

PROSERV A/S
INFOTRONICS A/S

Bypass Loop Valves:
Two electrically motor actuated ball valves are installed on inlet and outlet of the bypass loop, inside the cabinet. These will open and close for flow through the bypass prior to and during sampling.

Differential Pressure Transmitter:
A DP-transmitter measures the pressure drop between inlet and otlet of the bypass loop in the cabinet. This is used as a indirect measure of the flow rate in the bypass loop.

Total Pressure Transmitter:
Purpose of this transmitter is to measure the the pressure on the nitrogen side of each cylinder, and monitor backpressure when sampling. A secondary function is to detect abnormal friction between piston and cylinder. (High dp sampling side vs. preload side.)

Sampling Valve:
This magnetic operated fast response valve is continiously operating during sampling. It bleeds off nitrogen in small portions, thus creating a smooth piston movement during sampling.

Local Control Panel:
From this push buttom box, all operations normally executed from the PCs can be performed locally. It is normally not used for sampling.

4) Nitrogen Reservoir:
Two 40 l cylinders with pressure reduction valves. Through a seperate magnetic operated valve, nitrogen at preset pressure is delivered to the sampling cylinders.

5) Interface Cabinet:
This is located on Embla, in the control room. It has connections to the sampling cabinet and the local computer. It contains power supplies, PLS, Zener barriers, relay switches, over voltage protection and communication interfaces.

6) Local Computer:
This is located in Embla control room, and is the main computer for the system. It contains a communication modem and the traditional three hardware parts, PC, screen and printer.

At power on, the system boots automatically. The PC executes the config.sys and autoexec.bat and starts up Window with Norton Desktop automatically. Norton Desktop has a program called "Automatic Start-up". The driver routines and sampling program is located in this window.

There are four programs which starts up automatically:

- Net-DDE - for remote communication by modem.
- Omrom Modbus Driver - for communication with PLS and MagPos.
- MC-Link - for receiving data from measurement computer.
- Sampling Program - Intouch (eye Icon)

The system is then ready to receive commands.

7) Remote Computer:

This will normally be located in Ekofisk Center Laboratory, but any location with modem connection to telephone lines is possible. The remote computer station consists of same hardware parts as the local computer.

The remote PC also starts automatically at Pover On. There are only two programs in the automatic start up program group, the Net - DDE and the Sampling Program. The Net - DDE program automatically calls up the sampling computer (local). If connection is not made, the program retries every minute to establish connection. Changing the telephone number and the settings is done by starting up this program seperately and enter the wanted numbers.

All parts of the system are constructed according to regulations for offshore application. In addition the strict specifications for installation on Embla have been followed.

OPERATION:

1) Changing Cylinders:

This has to be done manually. Any, or all cylinders can be removed, or changed out whenever convenient.

The position where a cylinder is not present will automatically be indicated on the PC screen by a missing cylinder symbol. At same time valves and other functions related to this position will be inactivated in safe positions, but sampling can still be performed in other cylinders.

Prior to removing a cylinder, the manual valves on the cylinder must be closed, and pressure in the quick connector bled off. The two quick connector parts are then easily disconnected, and the cylinder removed. The replacement cylinder is connected, and the manual cylinder valves opened. Replacement cylinders should be precharged with nitrogen, but this can also be checked and performed after installation in the cabinet.

2) Sampling Conditions:

Sampling parameters can be entered or changed at any time, from any of the work stations. The only limitation on changing conditions is the authority level of the operator. Lowest levels are not permitted to perform any changes. The values most frequently changed are shown at any time on the screen. Changes are made by pointing at relevant figure and enter new value. Sample volume may also be changed by moving the vertival line crossing the cylinders. Before any sampling is initiated, pistons should be in start position, and the MagPos set to zero (unless a special sampling procedure is wanted). Sampling conditions are printed on the report for documentation purposes.

3) Sampling:

The system permits use of three different sampling procedures:

- **Automatic Sampling initiated by operator.**
- **Automatic Sampling initiated by timer.**
- **Manual Sampling.**

Before any sampling is initiated, the valves on the bypass loop must be opened manually from the computer.

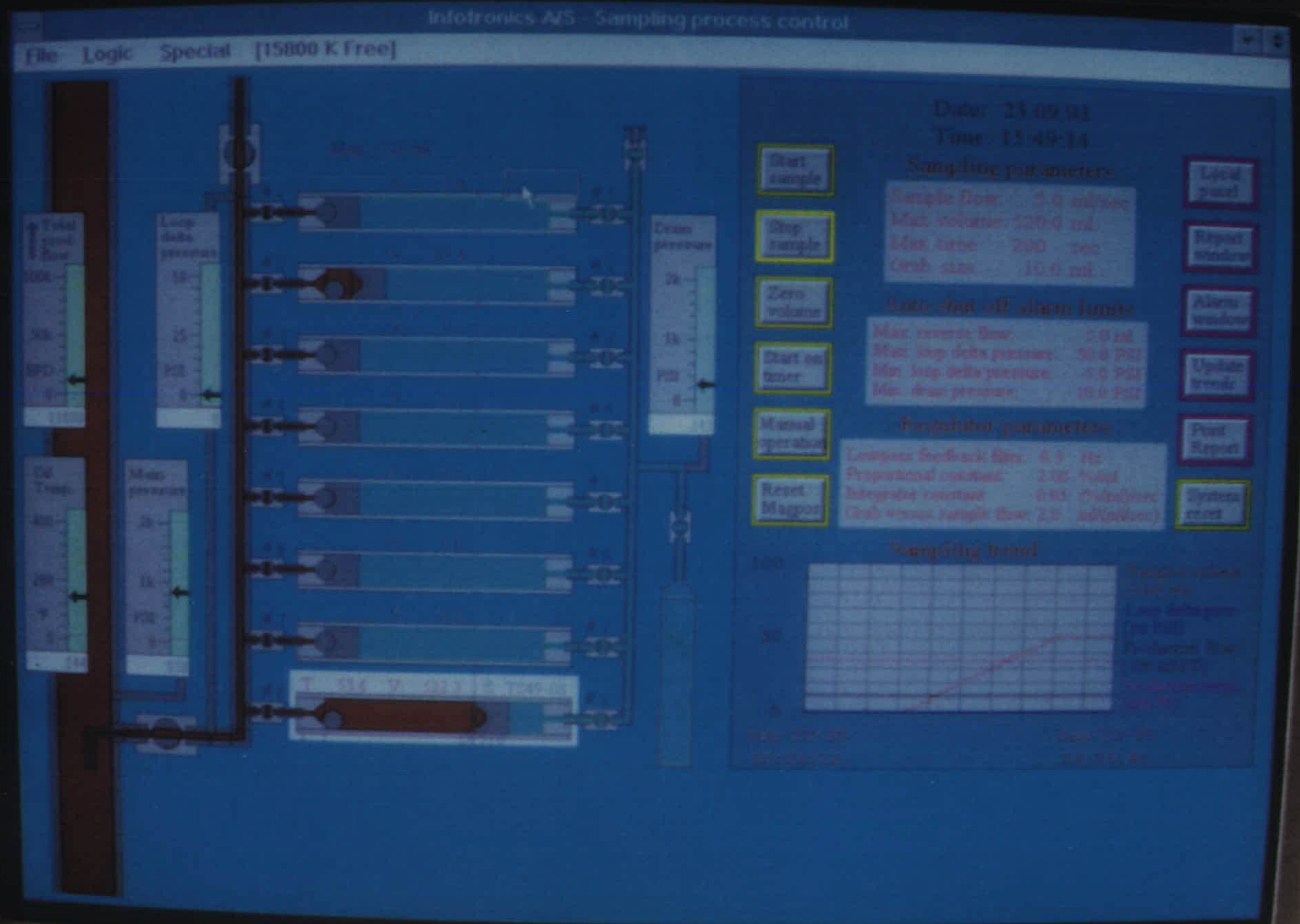
The cylinder which is to be filled, is marked by clicking in the bottle-symbol on the screen. This cylinder is then marked with a white frame. Only the chosen bottle is live and gets updated values on volume and temperature.

Sampling is initiated by a "click" on "Start Sample" button on the screen.
First back pressure is bled down to match inlet pressure. Then smooth sampling according to preset conditions is regulated by the sampling valve.
When selected sample volume is reached, sampling stops, and all valves close.

Sampling may be terminated any time during sampling. Sample volume may also be changed during sampling.

If "Sampling Initiated by Timer" is selected, the predefined time is set by double-clicking on the sample trend window and enter selected date and time. The function is activated by pressing the "Start on Timer" button in the command window.

If "Manual Sampling" is selected, the operator can manipulate all valves directly. The valves are operated by clicking on their symbols, which causes them to toggle on and off. The motor operated bypass loop valves must not be toggled more often than every 30 sec., as this is the time necessary to completely open and close the valves.


Infotronics A/S - Sampling process control
File Logic Special [15800 K Free]
Date: 23.09.93
Time: 15:49:14
Start sample
Stop sample
Zero volume
Start on timer
Manual operation
Reset Magnor
Sampling parameters
Sample flow: 5.0 ml/sec
Max. volume: 120.0 ml
Max. time: 200 sec
Grab size: 10.0 ml
Auto shut off alarm limits
Max. remote flow: 2.0 ml
Max. loop delta pressure: 50.0 PSI
Min. loop delta pressure: 5.0 PSI
Min. drum pressure: 10.0 PSI
Regulator parameters
Lowpass feedback filter: 0.5 Hz
Proportional constant: 2.00 %/mil
Integrator constant: 0.03 (%/mil/sec)
Grab versus sample flow: 2.5 (ml/ml/sec)
Sampling trend
Local panel
Report window
Alarm window
Update trends
Print Report
System reset

If for some reason a sample is rejected, and the cylinder wanted to be reused, the sample can be injected back into the production line. This is done manually from the PC by opening the bypass loop and cylinder valves, and apply nitrogen pressure from the reservoir. The pressure forces the piston to move towards zero position and dump the rejected sample back into the production line. The cylinder is now ready to collect another sample.

The Procedure Manual for Ekofisk Laboratory will be updated with a detailed sampling procedure. This will also include a subroutine for flushing of the transfer lines between the cylinders and the bypass loop.

4) Reports:

The sampling report can be shown on screen by pressing the report window button, and will be printed out on the attached printer.

The alarm messages during sampling may also be printed on this report.

The graph showing the progress of sampled volume, printed on remote location, will normally show a stepwise development. This is a result of communication between the local and remote PCs. In reality the sampling progress is smooth, as can be seen an a report printout from the local printer.

CONCLUSION:

A user friendly system for remote operated oil sampling has been constructed.

It can easily be modified for similar sampling of gas.

Sampling can be performed by personnel without any experience in manual sampling procedures.

The system can be installed on any location with access to telephone lines.

Remote sampling from any location, also onshore, is possible.

Software can be modified or expanded to include other or more options.

Several safety related properties are included in the system.

Oil sampling report

PPCON Embla

Date:	23.09.93
Time:	15:34:29

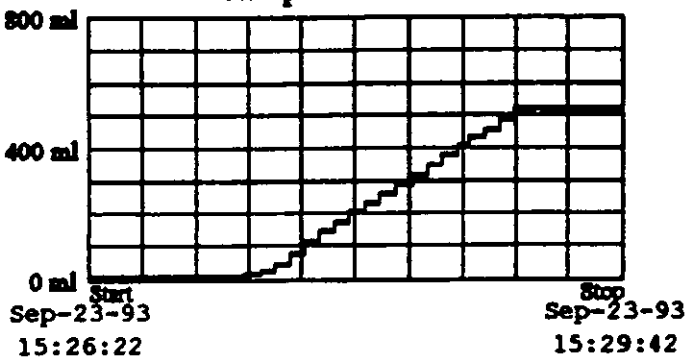
Bottle nr.	8
Serial nr.	TS49-08

Operator entries

Operator: B.Å. BJØRNSEN

Well number: D-20

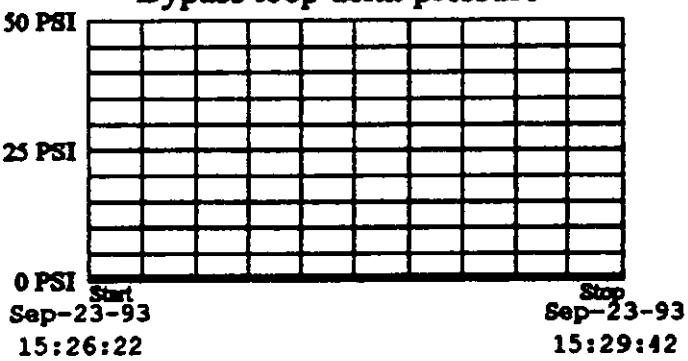
Sampled volume



Process status

Meter pressure:	830	PSI
Meter temperature:	144	°F
Production rate:	11.9	kBPD

Bypass loop delta pressure



Sampling parameters

Sample flow:	5.0	ml/sec
Max. volume:	520.0	ml
Max. time:	200	sec
Grab. size:	10.0	ml

Auto shut off alarm limits

Max. reverse flow:	5.0	ml
Max. loop delta pressure:	50.0	PSI
Min. loop delta pressure:	-5.0	PSI
Min. drain pressure:	10.0	PSI

NOTE: REMOTE SAMPLING FROM INFOTRONICS OFFICE IN SANDNES.

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

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NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

How to specify and design on line analyser systems

by

Mr. L. Bruland,
KOS A/S, Bergen
Norway

HOW TO SPECIFY AND DESIGN ON LINE ANALYSER SYSTEMS

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How to specify and design on-line analyser systems.

On-line analysers are found all through the oil and petrochemical industry. They usually perform well, but on many occasions this was not so from the start. A lot of unnecessary start-up problems are often found with analyser systems. And the result is that maintenance people have the attitude that "analysers never work".

The main source for these problems lies in the specification. This paper deals with a more structured way of writing a specification, what is necessary information and what decision criteria apply.

The best approach is to devide the specification into two phases. Phase 1 is the collection of necessary information, before we can even start to think of an analyser. Here we collect data such as stream compositions, hazardous area information and applicable law's. For this input from all disciplines is required Mechanical engineering should aid in sample tap locations and probe design, Process Engineering defines what analysis is required and whether it is for control or indication only. Instrument Engineering will define what interface-signal must be available. And all groups must review and approve the complete specification.

Only if phase 1 is complete, one can start with phase 2: the actual analyser system specification. If phase 1 is not finalised before phase 2 starts, a small change in basic specification might lead to an enormous change in the analyser system design, with all related costs.

In phase 2 the input from Maintenance is highly favoured. They are experienced in this field and therefor they have there preferences. They can give you the advise you need. And they are the ones that will operate the system you are specifying. So ask them to help you, they can make life very easy for you.

Phase 1: COLLECTION OF NECESSARY INFORMATION.

This is the most important phase in the writing of a specification. This because the information collected in this phase is the basis for all further actions.

What information is needed :

1. Where and what are we going to analyse.
2. What are the stream specifications at the sampling point.
3. What are the piping specifications at the sampling point.
4. What area classification is applicable. Where can an analyser system be located, and which degree of protection is required.
5. How are we going to subtract a sample from the process.
6. What do we do with the analyte. To the flare or back to process.
7. How and what to communicate with the process machines.
8. Which utilities are available.
9. Which regulations standards etc. apply. A system designed according to the Norwegian regulations is not the same as a system designed according to Russian standards !

If this is all known we can make a start with Phase 2 : the specification of the analyser.

Ad 1. Where and what are we going to analyse.

The choice of the sampling point is not always easy. Sometimes process control wants a location where construction has planned something else, or has great objections for financial reasons.

Let us use a fractionator as example. The best way to control the fractionator is to subtract the sample direct at the top of the fractionator and have the sample extracted and vaporised simultaneously, by use of a (steam-) heated sample probe. Construction normally does not like that because of the difficulties and the costs. This leads to the selection of the outlet as take-off position where the sample is subtracted as liquid and only is vaporised in a sample pre-conditioning system.

It is obvious that one needs to know what needs to be analysed. However, please also pay attention to the maximum lag-time that may lay between sample take-off and having the results ready for evaluation, and to the minimum analysis frequency. If you need it only once a day, and time is not important, it is more convenient to have the Laboratory perform the analysis. But a Claus desulphurisation plant performs best if the H_2S/SO_2 ratio is monitored at least each 5 seconds and reported within 30 seconds.

Ad 2. Stream specification.

Before an analyser can be chosen, it is of utmost importance that the stream, which needs to be analysed, is well defined.

This definition of the stream needs to give in depth information not only about the components that can be present in a normal situation but also in not-normal situations (the minimum and maximum concentrations of the components). Besides the concentrations, also physical data such as pressure, temperature, phase, viscosity (at given temperature and pressure), presence of solids etc. is vital.

Most analyser manufacturers do not fully understand the process in which their analysers are hooked-up. The result is that the manufacturer regards the normal stream specification and does not take precautions for process upsets. The upset may easily damage the analyser and the manufacturer hides behind the normal stream specifications with:"you never informed us that such could happen. This is not our problem". And any process engineer knows that upsets happen, and should be able to indicate what the analyser will have to withstand during upset.

Ad 3. What are the piping specifications at the sampling point.

These data are commonly available from the construction engineers.

The specifications are not only for the piping material itself but also for flanges (with their gaskets and stud-bolts), valves etc.

Most often an analyser system designer wants to get rid of piping specifications as soon as possible, and indicate all as being instrumentation.

It is for this reason that a sample line between process and an analyser is commonly 1/4" or 6 mm OD tubing, with compression type fittings. Most piping is welded together and is far thicker. Normally a sample probe is regarded as pipe-spec. and all other is instrumentation.

Ad 4. What area classification is applicable. Where can an analyser system be located, and which degree of protection is required.

The applicable area classification is an important selection criteria for an analyser. Ex or non-Ex, that is the question.
Since each analyser has a certain need for maintenance it is very convenient if the analyser can be located in an general purpose area. We do realise that such is normally not always possible, but still.

Where do we place the analyser, and how many space is available and how should the analyser be protected.
This calls for many variations. Indoors, outdoors under a shelter or out in the open. Please remember that the climate in the Gulf of Mexico is not the same as in the North sea.

It would be very convenient to locate all analysers in one place, the analyser shelter. This enables ease of maintenance, easy climate control for all analysers and if designed well it can create a safe zone inside a Ex-classified area. Nowadays most analyser shelters are fabricated as pre-packaged units which will be fully tested etc. with the supplier before it is installed. Such a transportable shelter can be made of Steel, Glass-Reinforced Polyester or Concrete. All have there own (dis-) advantages. Hardly anyone will use concrete for Off-Shore applications but On-Shore it is great material.

If analysers cannot be grouped together, each analyser (or group of analysers) many are

placed inside a cabinet. Normally an IP 54 cabinet will do but analyser systems which are to placed fully in the open mostly require IP 65 . For this the choice is normally between GRP and Steel.

Ad 5. How are we going to subtract a sample from the process.

The answers to the following questions in fact define the sample probe.

- Will it be a heated probe?
- Is there a requirement for mounting and dismounting the probe under full line-pressure.
- What kind and how many valves are required?
- Is pressure reduction necessary? Or is a Pitot-probe to help build up pre-pressure required.
- Which process connections will be available.

Ad 6. What do we do with the analyte.

In former days it was quite common that the analyte was vented or send down the drain. This was also true for fast-loops. However, if compared on a yearly basis a lot of money was send down the drain too. Furthermore, venting/draining mostly is bad for the environment and flare systems do cost money.

With above in mind it is clear common sense that good sample return location is found. It makes life of environmentalists easier and it saves money.

If the analyte can be returned to the process, the process conditions at the return point must be made available. There have been situations that the return point was badly specified and that after installation it was found that the return pressure was far higher than take-off pressure. Only the installation of an expensive pump could solve this problem.

Ad 7. How and what to communicate with the process machines.

Or rephrased : will a simple 4...20 mA signal do or is better communication called for.

First of all specify the process machines that will be used. Many analyser manufacturers, and especially the gaschromatograph manufacturers have added networking capabilities to their machines. This may even go up to full computer communications protocols like Modbus, completely tested with TDC 3000 machines or equal.

Also RS 485 communication is coming available rapidly.

The best approach is to specify several levels of communication. The question : does your thermo element need a local signal transmitter or is this part of control room instrumentation, can easily change an analyser system.

Ad 8. Which utilities are available.

The utilities are normally poorly specified.

Yes, there is 230 V +/- 10%, 50 (48...52) or 60 (57...63) Hz. For heavy analyser pumps 440 V or 660 V with the same frequency, can be used. And yes, instrument air and steam for heating purposed is available.

But the analyser manufacturer wants to know more.
Instrument air must be dust and oil-free with a moisture dewpoint of at least -20 degrees C. Hydrocarbon dew point at least -40 degrees C. Is there also unlimited supply?? There are certain gas-chromatographs which can consume up to 2,6 m^3 per hour!!!

For steam on likes to know whether it is low, medium or high pressure steam and what is the temperature.

Also for other available utilities (like Nitrogen or Hydrogen) data on purity, pressure, availability etc. are required.

And finally specify the available flare system, vent headers (atmospheric?), drain system (closed or open) and or open sewer header. What can go where and what connections, like relief valves, check valves etc., are required.

Sometimes it is good to have a sample recovery system. This can be used for both gas or liquid samples.

Phase 2: THE SPECIFICATION OF THE ANALYSER

The purpose of this phase is to describe the analyser in such a way that both engineering and manufacturer know exact what needs to be delivered (and also what needs not delivered). If this description is done right, it is easy for Procurement to select the right manufacturer. Also it will prohibit that during manufacturing there is a great need for changes or amendments to the system. And if a change is necessary, it is easily defined what is additional work and not.

First thing that needs to be done, is to organise all information as collected in Phase 1. There is data which will be applicable to all analysers, and there is analyser specific information.

If all the analyser specific information is brought together, one can get the idea of which type of analyser will be possible for this particulate application. It is normally easier to analyse oxygen in a range between 5 and 100 % with a thermomagnetic oxygen analyser than with a gaschromatograph.

As soon as a certain type of analyser has been chosen, one can start with the design of the sampling system.

The sampling system can be devided into 5 parts, all equally important, but sometimes not so clear to identify. If a analyser system can be located near the process pipe on might only find a sample probe, some tubing and a cabinet which holds both the sample conditioning system and the analyser, and the 5 individual parts are not easily recognised anymore. However, the are still valid.

Part 1 is the sample take-off and the sample return probe. The sample pre-conditioning (SPCS) system is the second part. This SPCS is to be located as close to the sample take off probe as possible. Its main purpose is to pre-treat the sample in such a way that a fast transport to the analyser is possible. Therefor a SPCS can consist of a filter and a pressure reducer or a pump. If the sample taken is in the liquid phase, one even might vaporise the sample in the SPCS.
The SPCS is followed by the sample transportation system (part 3) and the sample conditioning system (part 4). And last but not least we come to the analyser itself (part 5).

Part 1. The sample probe.

A sample probe serves only one goal: to subtract a representative sample from the process.

And the difficulties mostly arise from the question what is representative. The answer is different from take-off location to take-off location.

The design of the sample probe is mainly dictated by the analyser and the required lag-time. The probe for an oil density analyser is not the same as for gas density.

The design starts with the definition of where to subtract the sample. In a process pipe, from a vessel etc.

For process pipe which run horizontal, it is common that the sample is extracted from the top. The insertion length is chosen such that the probe extracts normally from the middle part between 1/3 and 2/3 of the pipe. If a multiphase medium is flowing through the pipe, the length may vary according to the required phase that needs to be analysed. With multiphase media one must consider the use of an in-line static mixer before sample take off. Modern static-mixers have already a side port available for sample take-off purposes.

If the medium is gas, showing full turbulent flow, the sample probe may be very short. One has only to cover for the flow effects near the wall of the pipe, in order to subtract a representative sample.

Subtraction from a vertical process pipe is mm. the same as for horizontal pipes. Please be aware that if high amounts of solids are combined with a vertical downgoing stream, special shields must be used to protect that high amounts of solids are sucked into the probe.

For vessels etc. the probe length is mainly defined by common sense.

A probe strength calculation is mandatory for the proper design of a probe. Many analyser system manufacturers can help you with this, but if you want to be independent, a good approach is to use the same equations as used for thermowells.

A special type of probe is the Pitot probe. This probe can be used to create the necessary differential pressure in order to feed the analyser with sample.
The Pitot probe is in fact a Pitot tube as used in former days for flow measurement, but now the static pressure is used for creating a positive pressure for the analyser. The Pitot-probe can be combined with a reverse Pitot return probe, in order to create an even greater differential pressure.

Special attention must be paid to probes which need to be retracted and installed under full line pressure. If such can be avoided by selecting a different take-off location, please do so. Retractable probes are always much more expensive that normal probes, and they can create great problems if there is a slight bend of the probe.

For special applications, very special types of probes have been developed. ISO kinetic probes, Pyrolisis probes and many others. These will not be discussed here.

Part 2. The sample pre-conditioning system (SPCS).

A sample pre-conditioning system is nothing more than a device that enables a safe fast and easy transport from the sample to the analyser.

For high pressure process lines, the SPCS reduces the pressure to a more moderate pressure, such enabling a short lag time. Consider a sample transport line 6 mmOD, 4mmID with a length of 10 meters. Its internal volume is 0,125 liter. If gas is transported with a pressure of 100 Bar or with 5 Bar the actual content differs 20-fold. Since the analyser analyses normally under almost atmospheric conditions the lag-time for the 100 Bar application is far higher.

Liquid sample transport is often time consuming if compared to gaseous samples. This for vary obvious reasons. Some analysers (gaschromatographs) vaporise the sample before it is analysed. Why not vaporise the sample near the take-off probe and enable short lag-times.

Other devices available for SPCS are sample pumps when pressure, filters etc. Attached you will find some schematic arrangements. Diagram 1 and 2.

Part 3. Sample transport.

Sample transport looks so simple but in reality there are many mistakes made.

The problem comes from the fact that sample as leaving the SPCS may not be influenced anymore. If a vaporised liquid is transported, a to low temperature in the transport system will have the high boiling components condensate again.

A sample transport line has a great influence on the lag-time. Therefor a lag-time calculation must be made in order to use the best possible transportation system. Many manufacturers calculate such with own developed Lotus macro's and can help you with this. The actual

expected distance between the SPCS and the analyser is needed for such. So please use Manhattan distances!!

Part 4. The sample conditioning system.

The sample conditioning system (SCS) is used for treatment of the sample in such a way that the analyser can handle it. This means that flow is regulated, relief valves are placed and that filters/coalescers can be present. Also it is there to enable easy calibration of the analyser.

Before a flow regulator is specified, one must be aware of the product and of the onsets that might happen, if anything fails. A good rule is to use metal tube flow regulators if the product is flammable or a pressure above 7 Barg might occur. In all other cases one may evaluate glass or equal materials.

If a coalescer filter is required, the condensate drain must be specified as well. Will it be an open sewer, a closed drain system or is a sample recovery system necessary.

Modern analysers have options available for stream selection, event steering etc. and so a completely automated system can be created. But is this always necessary? In diagram 3 you will see the set-up of a simple sample conditioning system, while diagram 4 show a far more complex type.

Whatever you specify, please keep it simple. Maintenance on complex systems is usually also complex. And it can create many mistakes. Furthermore, pay attention to the cabinet in which the system has to be placed. See to it that not to many items are stuffed in a too small cabinet.

Part 4. The sample conditioning system continued.

And what will happen if we open the cabinet door in winter-time? How long will it take to regain its normal operational temperature? So a heating system has not only to overcome the normal heat-loss but must also have some "spare" capacity.

Part 5. The analyser.

This is the core of the system. And the specification is very simple once we have come this far.

We now know what type of analyser we would like to have, and all related items are specified. Now we need to establish a preference list of make and model of analyser suitable for the Job. With this list and the specification one can ask several analyser manufacturers/suppliers to indicate a budget price for the complete system and to send a good analyser specification.

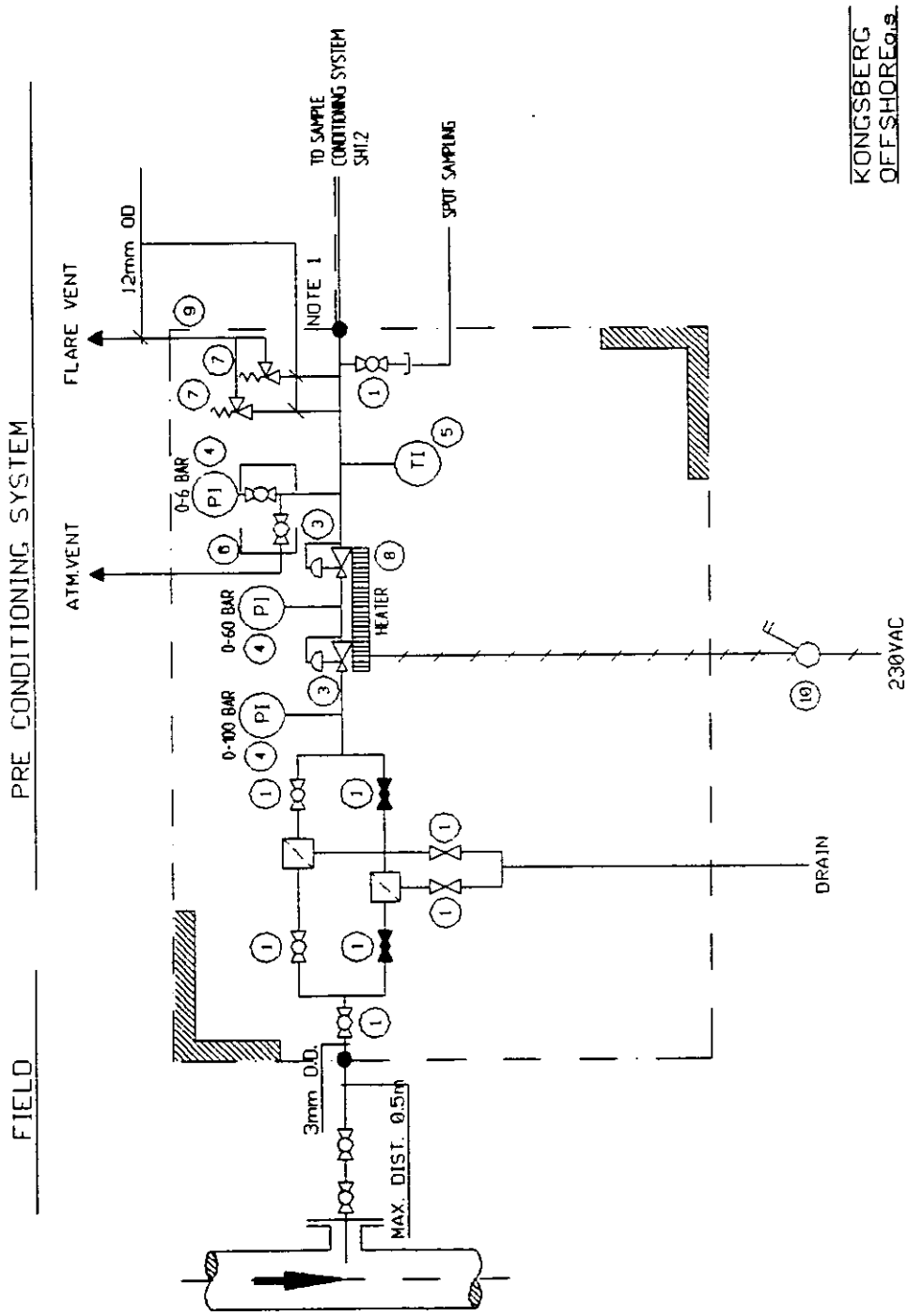
Many analyser manufacturers have what they call "Lock-out" specifications for their analysers. If you use these you make life more difficult for their competitors. So we use 2 or 3 Lock-out specs and we create one general spec, which give good coverage for the analyser and fulfils all of the project needs.

Now the specification is complete, the best we can do is to have it checked by someone not involved in the project. This person(s) can easily indicate whether all information is available, if it is understandable and if it is a realistic design. Let us hope it is, because that was what it was meant to be.

And second last step is having the complete specification approved by the different parties involved. These parties are Process, Mechanical, Instrumentation and Maintenance.

The specification itself is finalised when it is accepted by Procurement. They have to use your specification in their process of selecting the right manufacturer and bying the equipment for the right price. But your responsibility only ends after the analyser system is installed and is accepted by Maintenance as a "working" system.

Diagram 1. Schematic sample pre-conditioning system with dual filter system and dual heated pressure reducing system.



The dual filter system is often used if high amounts of solids are expected, or if the analyser system is of major importance.

Diagram 2. Schematic sample pre-conditioning system with fastloop and sample pump.

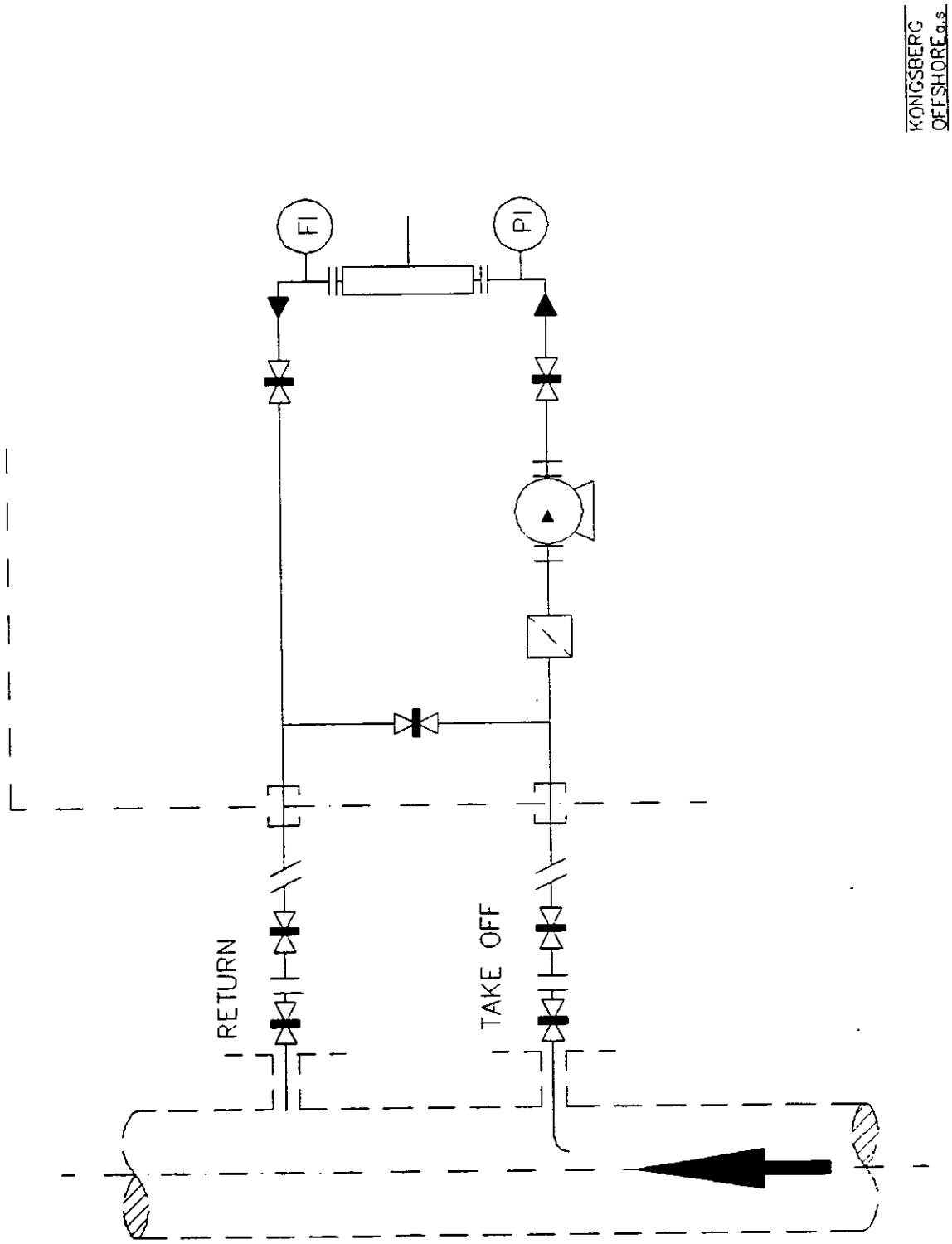


Diagram 3. Sample conditioning system simple.

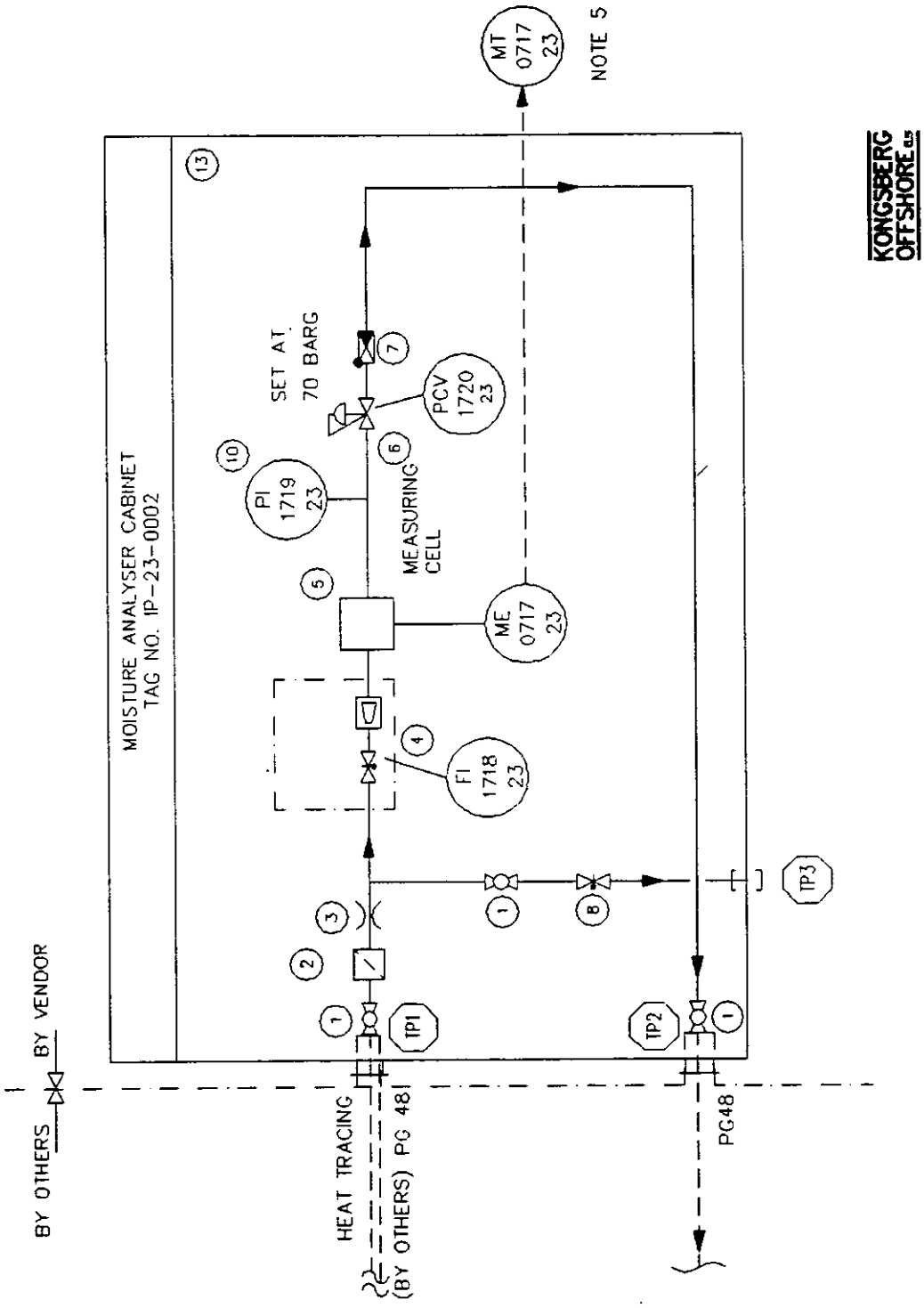


Diagram 4. A rather complex sample system