North Sea
FLOW
Measurement Workshop
1998

PAPER 15 ~ 4·3

OPERATIONAL EXPERIENCE OF A MULTIPHASE METER ON HYDRO'S BRAGE PLATFORM

H Moestue, Norsk Hydro ASA
A Wee, Multi-Fluid International ASA

OPERATIONAL EXPERIENCE OF A MULTIPHASE METER ON NORSK HYDRO'S BRAGE PLATFORM

Mr. H. Moestue, Norsk Hydro ASA
Mr. A. Wee, Multi-Fluid ASA

1 SUMMARY

A multiphase flowmeter (MPFM) has been installed at Norsk Hydro's Brage platform, for allocation metering of a well in the Sognefjord formation. Due to limited, and uncertain, hydrocarbon production potential, an inlet separator with conventional metering could not be justified for economical reasons. Amongst several options available for a metering system, one multiphase meter upstream of the test and production manifolds was selected. The multiphase meter is verified/calibrated periodically against the test separator. The test separator measurements had to be upgraded, in order to provide useful references.

The multiphase meter has been in operation since 31.10.97, with some periods of well shut-down. In this period the meter has failed twice: once for software reasons, the other for hardware reasons. Otherwice, the meter has operated normally.

Approximately 95 calibrations against the test separator have been carried out. The adjustment factors obtained show more scatter, and more deviation away from the ideal factor 1, than what is considered comfortable. In particular this applies to the adjustment factors for oil. However, oil production is lower than predicted, while water production is significantly higher. It is quite possible that meter performance is within what can be expected.

Upgrade of test separator meters has improved the quality of measurement significantly, even if the gas meter is not yet up to 100% performance.

2 INTRODUCTION AND BACKGROUND

In 1997 a well from the Sognefjord formation was tied in to the Brage platform in the Norwegian sector of the North Sea.

The Sognefjord formation is close to the Brage field, and wells can be drilled from the Brage platform. The ownership of Sognefjord is different from Brage Unit. The production of hydrocarbons from Sognefjord must be allocated to the owners. Hence, there is need for allocation metering. The NPD regulations for fiscal metering are applicable to allocation metering.

For the following reasons it was rather obvious that "full fiscal metering" could not be justified economically:

- The hydrocarbon reserves are limited - and uncertain. The first Sognefjord well was completed for test production and formation evaluation.
- The ownership of Sognefjord is very similar to Brage Unit. There are minor differences in the respective shares, in Brage Unit and in Sognefjord.

A simplified metering system was proposed for Sognefjord, and accepted by the Norwegian Petroleum Directorate (NPD).

3 METERING CONCEPT

3.1 Options for allocation metering

Several options are available for allocation metering:

- Inlet separator, and metering of separated phases oil, gas and water,
- Well stream metering by multiphase meter,
- Upstream choke pressure (UCP)/Choke differential pressure measurement,
- Model/calculation, eg. IDUN,
- Well testing.

The frames, within which to work, are given by:

- The NPD regulations for fiscal measurement of oil and gas,
- Cost/benefit of metering

3.2 Cost/benefit analysis

Simplified allocation may be used if there is an apparent disproportion between the cost of a metering installation and the benefit which will be achieved from it (NPD regulation § 23, § 9, with Guidelines). If simplified metering is proposed, the Operator must submit a cost/benefit analysis for justification.

In case of Sognefjord, a cost/benefit analysis was carried out, with the following input:

- Oil and gas production predicted profiles,
- Oil and gas prices,
- CapEx risk factor of 0.25, ie. we are willing to spend 0.25 NOK in order to potentially save 1 NOK,
- Ownership (share) of Brage Unit and Sognefjord,
- Uncertainty in quantity determination is reduced by 15 % by introduction of a multiphase flowmeter on the well stream.

On this basis, the value - after allocation - of a possible measurement error is calculated. For Sognefjord, this value was found to be approx. 4.5 MNOK.

3.3 Well stream flow metering

The conclusion was that this first Sognefjord well A-37 was to be equipped with a multiphase meter for allocation metering. The multiphase meter would be verified periodically against the Brage test separator.

3.4 Test separator measurements

Existing test separator measurements were:

- Oil: Single line, orifice meter, 3 exchangeable plates, γ-density meter, pressure and temperature from separator vessel,
- Gas: Single line, orifice meter, 3 exchangeable plates, 7812 density meter, temperature, pressure from separator vessel,
- Water: Single line, electromagnetic meter

It was found necessary to upgrade test separator flow measurement, including secondary instrumentation and signal handling, in order to provide useful reference measurements for the A-37 multiphase flowmeter.

4 EQUIPMENT AND FUNCTIONALITY

4.1 Multiphase flowmeter

After evaluation a multiphase meter from Multi-Fluid was selected for this application.
Based on predicted production profiles, a DN100 FR meter was selected. Velocity measurement is cross correlation only. No venturi section is included.
The meter is installed downstream of the well valve tree and upstream of the choke valve.

The installation is according to the manufacturer's instructions, in a vertical line, between horizontal inlet and outlet DN200 piping. Fluid flow is vertically upward. The meter installation is shown in Figure 1. A more comprehensive description of the multiphase meter is given in Section 8: Appendix 1: Multiphase flowmeter description

Wellstream phase densities of oil, gas and water phases are calculated from initial simulated PVT data, using gradients around an assumed/nominal operating point. For variations in temperature and pressure around this operating point, coefficients are used to calculate phase densities.

<u>On-line</u> PVT calculations are not implemented in this system.
A PVT package could be used for several purposes:

- Calculation of phase densities at multiphase meter operating conditions,
- Calculation of mass transfer from liquid phase to gas phase when the well fluid pressure is decreased across the choke valve (ref. Section 4.3),
- Calculation of phase densities at Standard conditions (and further calculation of Standard volumes.)

4.2 Reference flow measurements/Test separator instrumentation

The test separator measurements were significantly upgraded, to the following standard:

- <u>Oil</u>
  Two-beam ultrasonic meter, density meter 7835 Advanced (Hart, digital mode) in pumped loop, temperature and pressure (Hart, digital mode), full profile water-cut meter.
  The oil from the test separator is close to its bubble point. The liquid head from the gas/oil interface in the separator to ultrasonic meter level is 1.5 - 2 meters. Some of the pressure difference is lost due to fluid flow fictional losses. The static pressure is further reduced by an amount $\frac{1}{2}\rho v^2$. A DN100 meter has a flow range which is more optimal, considering expected oil flowrates. However, linear velocity in the meter would be too high and potentially reduce the static pressure below the bubble point. A DN150 meter was selected,

- <u>Gas</u>
  Three-beam DN200 ultrasonic meter, density meter 7812 in a separate heated box, temperature and pressure (Hart, digital mode),

- <u>Water</u>
  Existing DN100 electromagnetic meter in continued use (after repair), piping modified to safeguard meter always running full,

- <u>Signal handling</u>
  A single flowcomputer handles all measurements: flowmeters for oil, gas and water, as well as all secondary measurements of densities, water-in-oil, temperatures and pressures. The flowcomputer is communicating with the process control system (DISCOS) to provide flow data and batch (well test) functions.

While this upgrade was initiated by the allocation metering for well A-37, it is also useful for testing of all other wells in Brage Unit, providing more accurate well test data. The advantage of not having to change orifice plates, is recognized by the Platform Operations.

4.3 Calibration of multiphase flowmeter against references (test separator)

"Calibration" of the multiphase meter against the test separator is an integral part of the metering system for well A-37. Periodically the well is routed through the test separator. Flow for each phase oil, gas and water, as measured by the multiphase meter, is compared with test separator measurement. "Adjustment factors" for oil, gas and water phase flow are calculated and may be implemented.

Manual recording of data and manual calculation of adjustment factors was considered not practical. A semi-automatic function is implemented, using the platform process control system DISCOS. Flow measurements from the multiphase meter electronic unit and from the test separator flowcomputer are transmitted to DISCOS on serial communication. A comparison of multiphase meter and test separator measured flowrates is carried out by DISCOS. Once the comparison/calibration process is started by the control room operator, it will continue to run until it is terminated by the operator. New adjustment factors are calculated by DISCOS and presented to the operator, who can elect to accept the new factors or not. Any combination of 0 (!), 1, 2 or 3 (oil, gas, water) may be accepted. It is possible to apply manually entered adjustment factors.

It should be noted that phase flowrates, measured by the multiphase meter and the test separator, are compared on <u>mass basis</u>. Some of the fluid, which is measured as liquid oil at the multiphase meter, will evaporate when the pressure is reduced across the choke valve. Hence the test separator will measure a lower oil mass flowrate and a higher gas flowrate, compared to multiphase meter readings. This mass transfer from the liquid oil phase to the gas phase is calculated and accounted for in the automatic comparison. The calculation is rather simplistic: $\Delta_{mass} = B_1 + B_2\Delta_{pressure}$. Coefficients B_1 and B_2 are based on initial process simulation.

5 EXPERIENCE

In this Section we shall discuss some of the experience from commissioning and operation of the multiphase meter. Since the upgraded test separator measurements are important for the evaluation, experience with the test separator measurements will be discussed briefly.

5.1 Multiphase flowmeter

A multiphase meter may be evaluated in two aspects:

- Function: Whether or not the meter works, most of the time or all of the time,
- Accuracy: How accurate are the measurements ?

5.1.1 Commissioning

The multiphase meter was commissioned in October 1997. The gamma density meter was calibrated in air, and the meter was configured with the process fluid densities. The measurements from the multiphase meter were checked against the test separator. With the present instrumentation of the test separator, the measurements of the multiphase meter was within its specification. Initially the water-cut of the well was approx. 30%. However, within a few weeks the water-cut was increasing to 50%, and the well liquid phase was changing from oil continuous to water continuous, together with an increase in the total production from the well.

5.1.2 Function

Well A-37 was started up 31.10.97, at 2200 - 2300 hrs.
The multiphase meter started up normally.
(The test separator measurements for oil and water failed completely for the first few hours, when well A-37 was started. Most likely, oil and water formed a stable emulsion, which did not separate in the test separator. Neither the ultrasonic oil meter nor the electromagnetic water

meter would work with this emulsion. Oil and water separated only after emulsion breaker was added.)

Well A-37 has been closed in periods:

1. Operational reasons: 02.-08.11.97, 15.-18.11.97, 08.-10.12.97, 14.12.97-01.01.98
2. Problems with "neighbor" well: 17.02. - 04.03.98
3. Problems with the MPFM (amp. board): 05.05. - 17.05.98
4. Piping & MPFM inspected for scaling: 16.05. - 17.05.98
5. Operational reasons: 13.06. - 27.07.98

During period Item 2 above, drilling mud from a different well came with the well stream for A-37. It took some time before the problem was solved. It is reported that the multiphase meter for well A-37 re-started measuring without the need for any action, like cleaning, maintenance etc.

Increased scaling may result from high water production. During period Item 4 above, the pipework was inspected for scaling. While significant scaling was observed downstream of the choke, it is reported that the multiphase meter was clean, with no deposits whatsoever.

During period Item 5 well A-37 was closed due to its high water production. Water treatment capacity at Brage was limited, until new hydrocyclones were put in operation.

The multiphase meter has been operative since start-up, except for two periods:

- 08.11. - 11.11.98
  Shortly after (2^{nd}) start-up in November the meter started to show occasional drop-outs. 10.11.98 the meter failed completely, when a regular well test of A-37 was to be carried out. Vendor assistance was called. Even if the cross-correlation was 90%+, meter reading was zero. It transpired that the software was unable to handle the high flowrate through the meter at the time: probably 30 - 35 m/s. A software modification was downloaded (11.11.98), and the meter readings came back immediately. The meter was previously never tested to such high flowrates during qualification tests.

- 28.04.98 and 02.05.-17.05.98
  In April '98 the multiphase meter failed occasionally, and then completely 02.05.98. The meter again started working 18.05.98, but a faulty electronic card was identified during an Vendor service visit 20.-21.05.98. The card was replaced, and a new software version was installed. The meter has been working normally since.

Two examples of readings from "a working meter" is shown in Figure 2 and Figure 3: when well A-37 is shut in and later re-started.

5.1.3 Accuracy

Accuracy is evaluated by considering the adjustment factors that have been obtained since meter start-up. Initially many calibrations were carried out to gain experience with the meter. Approximately 95 calibrations have been carried out since meter start-up late October '97.

It has been considered a problem that adjustment factors have been less stable than we would like to see. In particular this is true for the oil phase measurement, ref. Figure 5. The reason(s) for this scatter of data is not really established, but the following points could be noted:

- The well stream was oil continuous only for a few days. The meter has been working in the water continuous regime almost since start-up,
- Oil phase volume fraction was initially ≈ 20 - 25%. Current oil volume fraction is 5 - 7%,
- It is important that well produces with stable flow, pressure and temperature, during the calibration operation,
- A faulty electronic board was replaced 20.05.98. Even if the fault was classified as "not critical", it is possible that meter performance - and adjustment factors - were affected.
- Reference measurements (ie. test separator measurements) must be fully operative and accurate to within, say, ± 2%.

A verification of the multiphase meter and the test separator measurements were carried out 24. - 26.08.98, looking at :

- Multiphase meter functionality and setup,
- Multiphase meter calibration,
- Test separator measurements,
- DISCOS and OPIS functions.

Well A-37 was routed via the test separator 23. - 25.08.98. For well A-37 bottom hole pressure is available, and the control room technicians are able to evaluate well flow stability, from this pressure. Data were recorded directly from the test separator flowcomputer and from the multiphase meter Graphical User Interface (GUI), independent of any DISCOS or OPIS functions. Several calibrations were carried out 24. - 25.08.98, ref. Table 1 below.

Table 1 - Multiphase meter calibrations 24. - 25.08.98

Cal No	Date & time	Base operating conditions & densities				Adjustment factors		
		Press. barg	Temp. °C	Density kg/m³				
				Oil	Gas	Oil	Gas	Water
1	24.08.98 05:53-06.54	46.078	79.090	762.094	35.627	1.05444	1.03662	0.92761
2	24.08.98 15:34-18:12	- " -	- " -	- " -	- " -	0.946777	1.013672	0.988953
3	24.08.98 21:09-22:57	- " -	- " -	- " -	- " -	0.972046	1.015808	0.982849
4	24.08.98 08:40-14:25	- " -	- " -	- " -	- " -	0.969971	1.010071	0.975464
5	25.08.98 15:04-17:33	46.078	79.090	762.094	35.627	0.913147	1.013123	1.003235
6	25.08.98. 17:54-20:18	*24.500*	*80.699*	*793.781*	*20.699*	1.131226	0.943176	1.010132
7	25.08.98 20:32-22:32	46.066	79.090	762.094	35.627	1.10382	0.98914	1.01874

Cal No	Date & time	Actual conditions MPFM		Flowrates, tonnes/h					
		Press. barg	Temp. °C	Multiphase meter			Test separator (MPFM c.)		
				Oil	Gas	Water	Oil	Gas	Water
1	24.08.98 05:53-06.54	26.536	80.910	28.51	9.238	144.4	30.05	9.580	134.0
2	24.08.98 15:34-18:12	26.039	81.019	30.13	7.997	130.6	28.52	8.108	129.1
3	24.08.98 21:09-22:57	26.109	81.041	29.21	8.040	130.9	28.40	8.169	128.6
4	24.08.98 08:40-14:25	26.275	80.992	29.38	8.015	131.3	28.50	8.098	128.1
5	25.08.98 15:04-17:33	27.394	80.952	29.39	7.481	122.6	26.83	7.581	123.0
6	25.08.98. 17:54-20:18	27.291	80.948	23.66	8.016	121.7	26.78	7.562	123.0
7	25.08.98 20:32-22:32	27.377	80.953	24.26	7.653	120.6	26.77	7.570	122.9

We have tried to compare multiphase meter readings with test separator measurements with one-minute time resolution, to see if flow variations at the multiphase meter can be seen at the test separator, ref. Figure 4. It would appear that for such low oil flowrates the test separator tends to have a smoothening effect on small flow variations.

During this verification no malfunction or errors were identified. The multiphase meter is working, and so are the test separator measurements, even if the gas meter is working off one path only.

It is concluded:

1. System operation, as observed 24. - 26.08.98, reflects the performance that can be achieved with the current system, except that work continues to determine if other phase densities should be used,

2. In practical operation, it has been found that the initial requirements for reproducibility and repeatability - as described in Section 5.3 - were somewhat tight. In September '98 the calibration procedure was changed, and the reproducibility/repeatability requirements were somewhat relaxed, ref. Table 5. (It should be noted that "% reproducibility" and "% repeatability" is calculated on actual phase flow for each phase, not on total flow.),
3. We believe that the requirement for ± 5% reproducibility/repeatability is difficult to achieve when the oil volume fraction is down to 5 - 7%.

5.1.4 Sizing of multiphase meter

The prediction of the production flowrates and MPFM operating conditions was not very accurate. The well was producing at a higher total phase flowrate than expected (lower oil phase flowrate, but significantly higher water phase flowrate). After a few weeks, the well was producing outside the recommended operating envelope for the multiphase meter. After the software modification mentioned in Section 5.1.2, the meter is capable of measuring up to 40 m/s.

This point also illustrates one of the advantages of the cross-correlation meter. If the multiphase meter had been designed based on the predicted flow rates using a venturi velocity meter, there would have been a significant pressure drop across the multiphase meter. However, since the cross-correlation velocity meter is non-intrusive and has a turndown in terms of velocity, the multiphase meter was working even though it was operating outside the recommended velocity envelope.

5.2 Reference measurements (test separator)

It should be noted that there are no references against which the test separator measurements can be compared, once the meters are installed. Initially, all meters were flow calibrated by the manufacturers, and we have to assume that these calibrations are maintained, and valid, once the meters are installed and put in operation.

The experience can summarized as follows:

- Oil flow
  The meter failed occasionally on well A-37 and some other wells: ultrasonic beam failure. This was eventually attributed to solid particles in the liquid, not gas bubbles. The meter is now working better, but there are still some occasional errors, even at less than 5% water-in-oil. Above 10 – 15% water-in-oil, the meter readings become more unstable, until the meter fails severely above 20% water content.

- Oil density
  Very satisfactory performance. An oil sample was drawn from the test separator and analyzed for density (at density meter operating conditions) by an independent laboratory: Results are shown in Table 2 below.

Table 2 - Verification of test separator oil density meter

Description	12.11.97	Comment
Measurement/read-out Density meter, kg/m^3	803.36	
Lab. analysis, (independent on-shore lab.) kg/m^3	803.3	Recalculated to 1 vol-% water content
Difference %	-0.01	

Recently the density meter has been out of operation. The meter was due for periodic calibration, and the Hart interface card (inside the 7835 electronic unit) was damaged when the Hart circuit was opened/closed while with supply voltage still connected.

- Oil pressure and temperature
  Very satisfactory.

- Water-in-oil
  Very satisfactory. Water content is measured up to meter maximum, which is 20 vol-%. The meter has been working reliably since start-up. In-line calibration has been carried out three times. The results are shown in Table 3 below:

  Table 3 - In-line calibration of water-cut meter

All table values are vol-% water-in-oil	08.11.97	11.11.97	03.02.98
Measurement/read-out Water-Cut meter	2.2	0.77	0.190 - 0.187
Brage Lab. analysis, re-calc. to line conditions	2.3	0.22	0.181
Difference	-0.1	+ 0.55	ca. + 0.1
"Current correction" Water-Cut meter	+ 0.20	-0.34	-0.32

  It should be noted that in-line calibration of a water-cut meter on test separator oil is not easy. The water content has to be stable, which in most cases means low. It cannot be assumed that manual sampling and laboratory analysis gives error-free results. Results for absolute errors, as given in Table 3 above, is considered satisfactory for well testing purposes. It is considered satisfactory also for multiphase meter calibration.

- Gas flow
  When the ultrasonic meter was chosen for test separator gas, it was realized that the gas potentially contains some liquid, and that any such liquid might affect the ultrasonic flowmeter. However, the ultrasonic meter has several advantages over the orifice meter, and Brage decided to install the ultrasonic meter. There are six transducer ports for three beams. One of these ports is located such that liquid may accumulate in the port, while the other five other ports will drain any liquid back to the pipe.
  Most of the time one path is failing due to liquid build-up in one of the transducer ports. Since the failing path is one of the double-reflecting paths, the other double-reflecting path is disabled. Effectively the ultrasonic meter is working as a single beam/single reflection meter. The single-reflecting beam is operating with close to 100% performance all the time.
  It has been observed that when the gas flowrate increases, the "failing beam" comes back, probably because the liquid is sucked out of the port. When the flowrate decreases, the beam will again fail.
  (Note. The manufacturer has now changed the design of meters for this application, such that all ports drain liquid back to the pipe. An upgrade is planned also for Brage.)

- Gas density
  The density meter has been working satisfactory since start-up.
  Direct measurement of gas density, when the gas is close to its hydrocarbon - and water - dewpoint is recognized as difficult. As soon as liquid is condensed or collected in the measurement chamber, the density meter fails completely. Disassembly, cleaning, drying and re-calibration is then required.
  In case of Brage, great care was taken to avoid liquid drop-out in the measurement chamber. The density meter is installed 0.5 m above the process pipe, with maximum sloping sample lines. The density meter is heated and thermally insulated. The temperature is 90°C, approximately.
  A manual spot sample of test separator gas was analyzed for composition, except that water content was not analyzed. Assuming that the gas is saturated with water vapor, the mole-% were recalculated. Gas density at operating conditions were calculated for dry gas as well as wet gas, ref. Table 4 below.

Table 4 - Verification of test separator gas density meter

Description	12.12.97	
	without water vapor	with water vapor
Measurement/read-out Density meter, kg/m^3	8.05	8.05
Laboratory analysis (Brage) kg/m^3	8.035	8.115
Difference %	0.19	-0.80

- <u>Gas temperature and pressure</u>
  Very satisfactory.

- <u>Water flow</u>
  The water meter now seems to be working satisfactory.

- <u>Signal handling</u>
  Flowcomputer handling of flow and secondary measurements provides much improvement in functionality and accuracy over previous handling carried out by DISCOS. Improved measurement provides more accurate well test data, which is of importance mainly for reservoir management.
  For the test separator measurement data are generated by the flowcomputer, while DISCOS provides data transport functions and operator interface. DISCOS functionality is considered adequate for these purposes.

  Production data are transmitted to the Oseberg Production Information System (OPIS), for reporting and filing purposes. OPIS is not always stable, and sometimes reports are not generated correctly. On one occasion the OPIS computer stopped completely for a couple of days. When OPIS is down, no reports are written to file, and quantities are "lost".

  The multiphase meter electronics act as a flow transmitter. There is no handling or filing of daily totals. For allocation metering purposes supervisory computer functions are required. For applications where the hydrocarbon production is large, production data should be gathered in metering-type supervisory computers.

5.3 Control room functions

The multiphase meter is verified - or calibrated - on a (quasi-) periodic basis. The calibration is initiated - and accepted - by the control room technicians. A "Work description", which describes calibration of the multiphase meter, has been prepared.

The multiphase meter is calibrated whenever:
- The choke position is changed,
- Well A-37 is again opened after shutdown,
- Operating conditions are changed by more than 20% (pressure, temperature, flowrates),
- 1 month has elapsed since the last calibration,
- New configuration data are downloaded to the multiphase meter, or the multiphase meter is restarted after shutdown.

Certain conditions must be met, for a calibration to be carried out and new adjustment factors accepted:

Table 5 - Procedure and acceptance criteria for multiphase meter calibration

Description	**February 1998**	**September 1998**
Choke position	No change last 12 hrs	Stable
Well stream, and well stream temperature		Stable
Test separator trend curves	Test separator measurements working OK	Test separator measurements working OK
Stabilization time test separator	2 hrs	4 hrs
Calibration duration time	2 hrs	4 hrs
Reproducibility all phases oil, gas and water (Difference from calibration "previous month")	5%	10%
Repeatability all phases oil, gas and water (Difference from calibration "the same day")	5%	10%

If the adjustment factors do not repeat within required tolerance from the calibration "the previous month", a new calibration may be attempted. The second set of adjustment factors must agree with the ones from the first set ("the same day") within required tolerance. Otherwise the Senior Instrument Technician is called to investigate the matter, and a non-conformance report is filed.

It appears that the calibration process is operated comfortably by the control room technicians.

5.4 Physical properties of single phases oil, gas and water

With no on-line PVT calculations, phase densities are calculated for operating conditions in temperature and pressure, using a 2nd order polynomial. Phase densities are needed at the time when well production is started and hence must be calculated from previous well test fluid data. This data may be verified or recalculated once fluid samples are available after start-up. Also mass transfer coefficients have to be calculated from initial well test data and later verified.

The first problem was that actual operating conditions were not very close to what was predicted (ref. Section 5.5). In particular pressure was significantly lower at multiphase meter conditions. The "coefficient method" for calculation of densities away from the nominal operating point is probably not very accurate. It was therefore necessary to recalculate phase density to actual operating conditions. However, when flowrate varies, the fluid pressure in the multiphase meter varies, and measurement uncertainty increases due to the inaccurate correction method.

It proved more difficult than expected to obtain density data after start-up. Oil, gas and water was sampled at the test separator 1.5 months after well start-up. The samples were kept pressurized and sent to an on-shore independent laboratory for a rather comprehensive set of analyses, PVT analysis included. It was several months before complete analysis data - and recalculated phase densities - were available.

It is possible to calculate the effect of using wrong densities (sensitivity analysis). On 25.08.98 base densities were changed, to see the effect on the adjustment factors - in practice. Subsequently, the base densities were changed back to original values: The results are shown in Table 1, in Section 5.1, Calibration nos. 5 - 7. (Selected results are shown below, also.)

Cal No	Date & time	Base operating conditions & densities				Adjustment factors		
		Press. barg	Temp. °C	Density kg/m³				
				Oil	Gas	Oil	Gas	Water
5	25.08.98 15:04-17:33	46.078	79.090	762.094	35.627	0.913147	1.013123	1.003235
6	25.08.98. 17:54-20:18	*24.500*	*80.699*	*793.781*	*20.699*	1.131226	0.943176	1.010132
7	25.08.98 20:32-22:32	46.066	79.090	762.094	35.627	1.10382	0.98914	1.01874

Cal No	Date & time	Actual conditions MPFM		Flowrates, tonnes/h					
		Press. barg	Temp. °C	Multiphase meter			Test separator (MPFM c.)		
				Oil	Gas	Water	Oil	Gas	Water
5	25.08.98 15:04-17:33	27.394	80.952	29.39	7.481	122.6	26.83	7.581	123.0
6	25.08.98. 17:54-20:18	27.291	80.948	23.66	8.016	121.7	26.78	7.562	123.0
7	25.08.98 20:32-22:32	27.377	80.953	24.26	7.653	120.6	26.77	7.570	122.9

As can be seen from the table, operating conditions at the multiphase meter are similar for all Calibration nos. 5 - 7. Flowrates at the test separator are also similar. Even if a rather large change in the adjustment factor for oil is observed between Cal. nos. 5 and 6, a similar change in the opposite direction is not apparent between Cal. nos. 6 and 7, when the base densities from Cal. no. 5 was re-established. We have no explanation, except that the oil volume fraction was rather low: 6 -7%, "magnifying" any sort of real measurement scatter. The gas adjustment factor seem to show more "consistent" behavior. The water adjustment factor is little affected.

If we consider Calibration no. 5, the mass transfer from the hydrocarbon liquid phase to the gas phase - when fluid pressure is reduced across the choke - is calculated as 3.3% of total hydrocarbon mass (4.4% and 13% of hydrocarbon liquid and gas, respectively). Hence, this mass transfer is not small, and model errors will affect apparent performance of the multiphase meter.

5.5 Predictions of production flowrates and MPFM operating conditions

Before start-up, production profiles and wellhead pressure and temperature profiles were predicted from simulation/model calculations.

In the first place, multiphase meter sizing is based on predicted production profiles. Next, multiphase meter operating pressure and temperature - and hence phase densities - are determined. The operating pressure depends on flowrate and well fluid density. With a high water fraction, pressure loss is increased.

Actual production proves to be significantly different from predicted profiles. Water production is much higher, while oil production is rather low. Actual multiphase meter operating pressure is 20 – 30 barg, vs. predicted close to 90 barg.

Current fluid velocity through the DN100 meter is 20 m/s, which is quite high. Pipework upstream and downstream of the meter is DN200.

6 OVERALL EVALUATION

The overall evaluation is that the multiphase meter is working. Two failures have occurred, one software and one hardware. Adjustment factors show more scatter and more deviation from the ideal factor 1. This particular this is true for the oil phase. But the oil volume fraction is low: initially 20% and now down to 5 - 7%. It is quite possible that current performance is as good as can be expected.

Handling of phase densities at multiphase meter conditions was more difficult than expected. Use of on-line PVT calculation could possibly have improved the situation. However, an additional computer would have been required, adding to system complexity and cost.

Predicted production profiles were not very accurate. Inaccurate profile prediction may lead to incorrect meter sizing. It is fairly obvious that well A-37 produces significantly less oil than expected.

The upgrade of test separator measurement is considered a significant improvement, for accuracy as well as for operations. Work continues to make the gas meter work as intended.

The multiphase meter installation, with all associated functions, turned out to be quite expensive. Also upgrade of test separator measurements was expensive, but this effort is useful for all Brage wells.

7 ACKNOWLEDGEMENT

Many persons have spent a considerable effort with this project, during the project planning/engineering, installation, commissioning and operation phases.

Two years ago, very few multiphase meters were installed for allocation metering. Even today the number of applications is very limited. By selecting a multiphase meter for allocation metering of the Sognefjord well A-37, tied in to the Brage platform, it is felt that Brage Operations Group has contributed significantly to increase the experience base within Norsk Hydro. This experience has been utilized in two projects that followed.

The verification 24.-26.08.98, of the metering system for Sognefjord well A-37, was carried out by H. Tunheim and H. Moestue of Norsk Hydro.

8 APPENDIX 1: MULTIPHASE FLOWMETER DESCRIPTION

8.1 Introduction

The MFI Multiphase Meter culminates twelve years of R&D, much of it sponsored by seven international oil companies: Statoil, British Petroleum, Phillips Petroleum, Elf Aquitaine, Total, Saga Petroleum and Shell.

The MFI Multiphase Meter uses a unique, patented microwave technology. However, the fundamental physical principals involved are simple. Multi-Fluid's technological platform is based on the ability to adopt and apply these fundamental principals to the challenging technological task of measuring fractions and flow rates of different components flowing simultaneously in a pipe, without any prior separation of the phases.

8.2 Development of the MFI Meter

1986	In 1986 Statoil makes a technological and market survey with the purpose of developing continuous measurements of oil, water and gas flowing from wells and in pipes.
1987	Statoil and SRI International begins the initial research program at SRI International in Menlo Park, California in 1987. The initial research based on an idea of utilising microwave electronics is promising and Statoil continues to fund further development.
1989	In 1989 Multi-Fluid Inc. is founded in California in anticipation of future commercialisation of the technology. Hitec becomes part owner of Multi-Fluid Inc. later in the year and takes responsibility for the further development of the company. Hitec builds the first test loop in Norway in 1989. The first multiphase meter project started and the product is called MFI Multiphase Meter. Multi-Fluid invites other oil companies to participate in the project. BP, Elf, Phillips, Saga and Total join to fund and support the program.
1991	In 1991 the owners of Multi-Fluid Inc. establish Multi-Fluid International AS.
1992	The MFI WaterCut Meter was commercialised in 1992.
1993	In 1993 Multi-Fluid Inc. begins its commercial activities in the US. The company relocates all activities to Denver, Colorado.
1995	In 1995 Statoil, Norsk Hydro and Saga undertake an extensive qualification test of competing multiphase meters. The MFI Multiphase Meter showed very favourable results.
1996	Hitec becomes the majority owner of the Group. The Multiphase Meter project was completed and the subsea version launched. The MFI Multiphase Meter passed qualification tests in Porsgrunn (Hydro), at Shell Gannet and at Gullfaks B. The MFI SubSea Multiphase Meter qualified for use at Gullfaks Satellites and Åsgard. The Company has its commercial break-through as it wins several new contracts.
1997	Multi-Fluid International AS changes its name to Multi-Fluid ASA. Multi-Fluid ASA purchases Multi-Fluid Inc. and becomes the parent company of the Group. Multi-Fluid ASA is listed at Oslo Stock Exchange. Multi-Fluid Inc is moved to Houston. Multi-Fluid Subsea is established to take care of subsea activities.

8.3 System Description

8.3.1 The Sensor

The sensor is a compact, straight spool piece with no moving parts. A four inch, 1500 lb. sensor with ANSI flanges is less than 700 mm (28 inches) long.

The MFI sensors can accommodate high pressure requirements. They are machined from a solid bolt of steel. Pressure containment is achieved using standard methods. The sensor body is metal pipe and needs no special seals, while the microwave probes use traditional metal and/or O-ring seals.

8.3.2 System Architecture

MFI Multiphase Meters perform all measurements and calculations in the field electronics. Consequently, only final results are transmitted from the field using simple analogue or digital outputs. With this architecture, Multi-Fluid's meters can be used as stand-alone, remotely operated devices without the need for support facilities. This can dramatically reduce the cost of installing and using multiphase meters in remote or unmanned facilities.

8.3.3 Multiphase Composition Meter

Instantaneous oil, water and gas fractions are measured using 1) a patented microwave measurement device for measuring mixture dielectric properties (dielectric constant and conductivity) and 2) a commercial Cs 137 gamma density meter for measuring mixture density. Multi-Fluid's composition meter offers a unique combination of features.

It functions over the full 0 - 100% water cut range. Separate sensors are not required for low and high water cut measurements.

The microwave measurement system has unparalleled sensitivity. The microwave sensor works by measuring a characteristic microwave frequency that is inversely proportional to the square root of the mixture dielectric constant. A change from 100% gas to 100% water can result in a change in the measured microwave frequency of over 100 to 1. This sensitivity is many times greater than is possible with other techniques such as dual energy gamma technology. As a result, the meter can measure the water cut, oil flow rate, and water flow rate of multiphase mixtures with superior accuracy, particularly at high GVF.

The composition meter accurately measures component volume fractions several times per second. Thus, it is possible for it to function with any flow regime in the line, even intermittent plug flow. Another benefit of 'real-time' measurement is that the meter can be used to determine which flow regime is present in the line. Many other multiphase technologies integrate raw data over tens of seconds to get meaningful results, thereby losing useful real-time information.

8.3.4 Cross-correlation Meter

The primary element for measuring multiphase flow velocity is Multi-Fluid's Cross-correlation Meter. This device uses two identical microwave sensors (such as used in the composition sensor) separated by a known distance in the pipe to measure velocity. By statistically comparing measurements from the upstream sensor with those of the downstream sensor using cross-correlation methods, one can determine the mean transit time for the mixture to move between the sensors. The sensor spacing and the measured transit time give velocity. Multi-Fluid has developed a slip flow model to determine respectively the gas and liquid velocities from the measured velocity using, among other inputs, the statistical data from the composition meter to characterise the flow regime. These two velocities are combined with the readings from the composition meter to obtain the actual oil, water and gas flow rates. The Cross-correlation Meter has a number of advantages compared to other multiphase velocity meters (including Venturis) Turn-down ratio of up to 35:1

No moving parts

High sensitivity. It functions with zero water cut and fine bubble flow such as might be present during early production.

No differential pressure taps that can foul or dP transmitters that can drift

Easily used in high pressure systems without sacrificing accuracy

8.3.5 Venturi Meter

An optional element for measuring multiphase flow velocity is a Venturi meter. The suitability of a Venturi is assessed on a case-by-case basis. The beta ratio for the Venturi meter is tailored for each application to maximise the turn-down ratio and thus improve accuracy. It is possible to achieve a turndown ratio of 10 : 1 in mass flow terms.
Combining the Cross-correlation Meter with a Venturi gives some redundancy. The MFI Meter can continue functioning even if the Venturi Meter or the Cross-correlation Meter should fail. Either velocity meter can be used to measure liquid and gas velocities, when used in conjunction with Multi-Fluid's slip flow model. In some applications the Venturi meter is used to obtain condition dependent maintenance. Hence, by adding a venturi in addition to the cross-correlation meter, it is possible to detect a failure in both the gamma density meter, venturi meter and cross-correlation meter.

8.4 Installation Requirement

The sensor must be mounted vertically with flow directed upwards. In order to enhance mixing a blind T is installed upstream of the meter. Meter sizing will be evaluated on a case by case basis to optimise performance.

8.5 Field Configuration

Once the sensor and electronics have been installed and all field wiring is completed, the meter must be configured for specific field conditions. This is done in 15 minutes in a two step process. Step 1 - Measure the 'zero' density calibration point of the density meter. Step 2 - Enter the data necessary to characterise the oil, gas and water respectively using the User Interface Software.
Oil density at mean process pressure and temperature to an accuracy of ± 2%
Two factors describing the change in oil density with temperature and pressure
Gas density at mean process pressure and temperature to an accuracy of ± 10 %
Two factors describing the change in gas density with temperature and pressure
Water density at standard conditions to an accuracy of ± 1 %
Water conductivity to an accuracy of ± 10 % for oil continuous and ± 1 % for water continuous applications.
The oil and gas data can be calculated from a standard process analyser. The water data can be measured from a sample of production water. The only critical calibration data is the water conductivity, and even then only for high water cut applications.
No measurements of pure oil, water and gas are required in the field in order to calibrate MFI's Multiphase Meters.

9 FIGURES

Figure 1 - Multiphase meter installation for Sognefjord/Brage well A-37

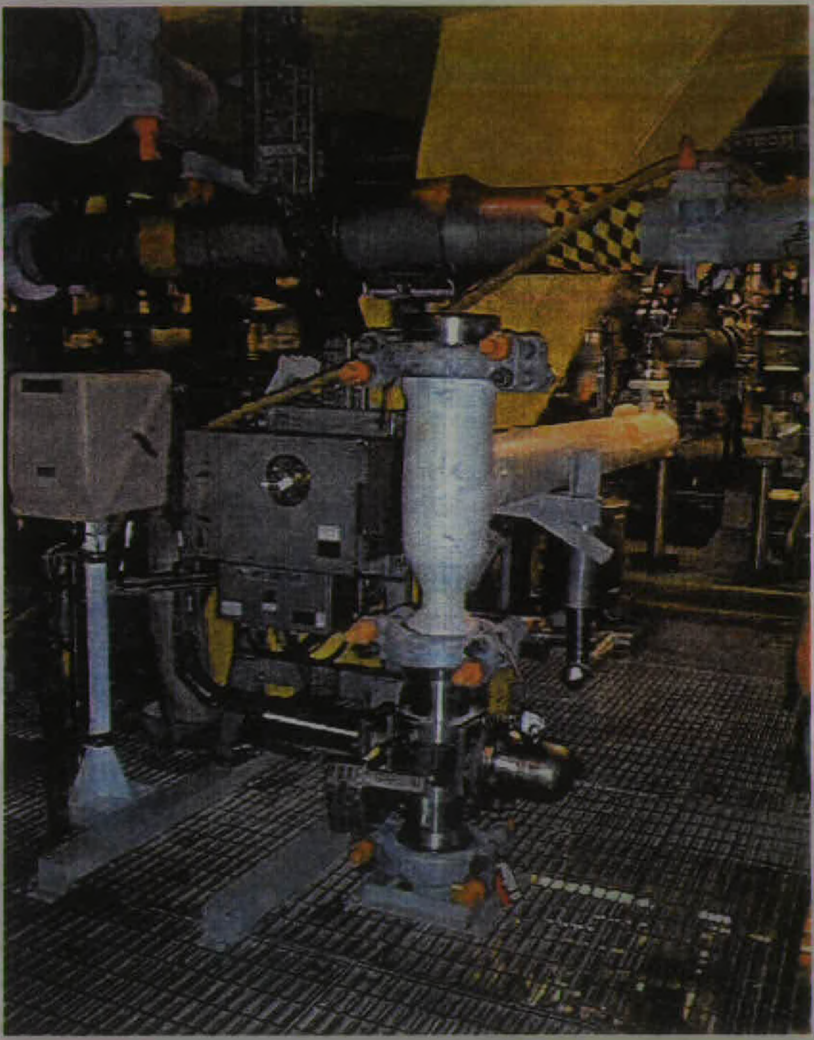


Figure 2 - Multiphase meter response at close-in of Brage well A-37

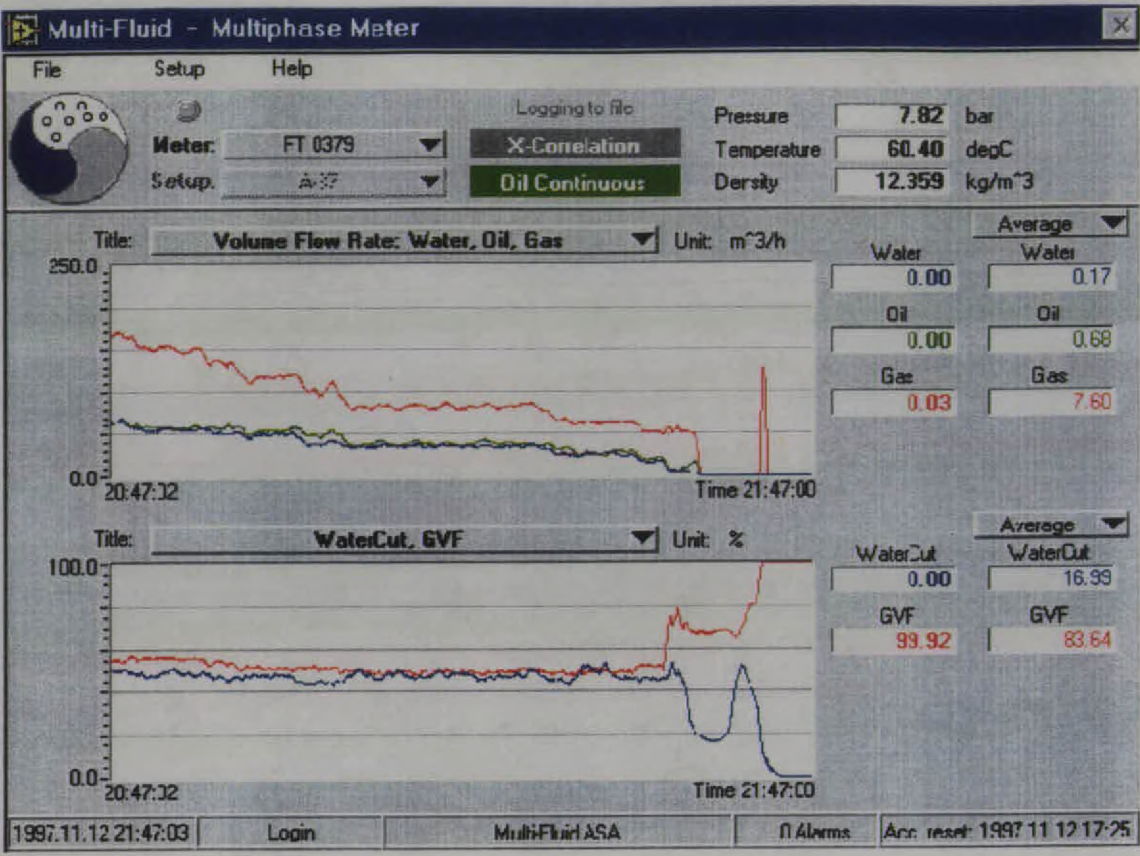


Figure 3 - Multiphase meter response for re-start of Brage well A-37

Figure 4 - Comparison multiphase meter and test separator

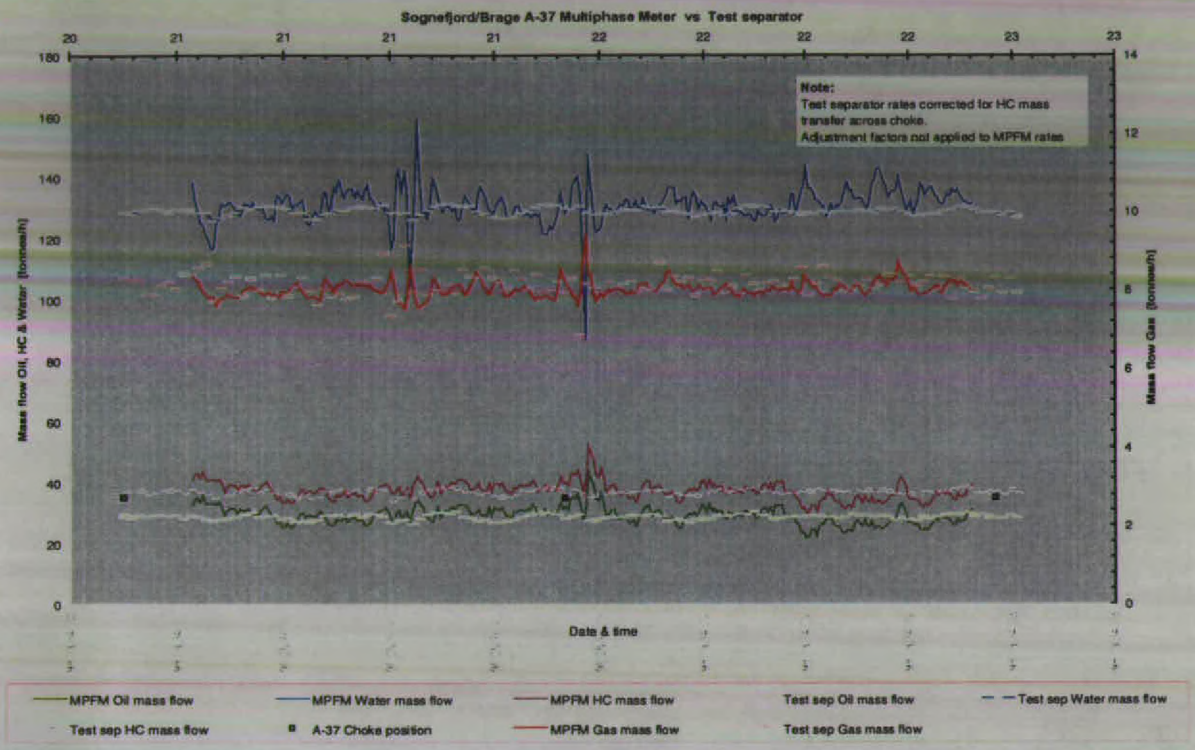
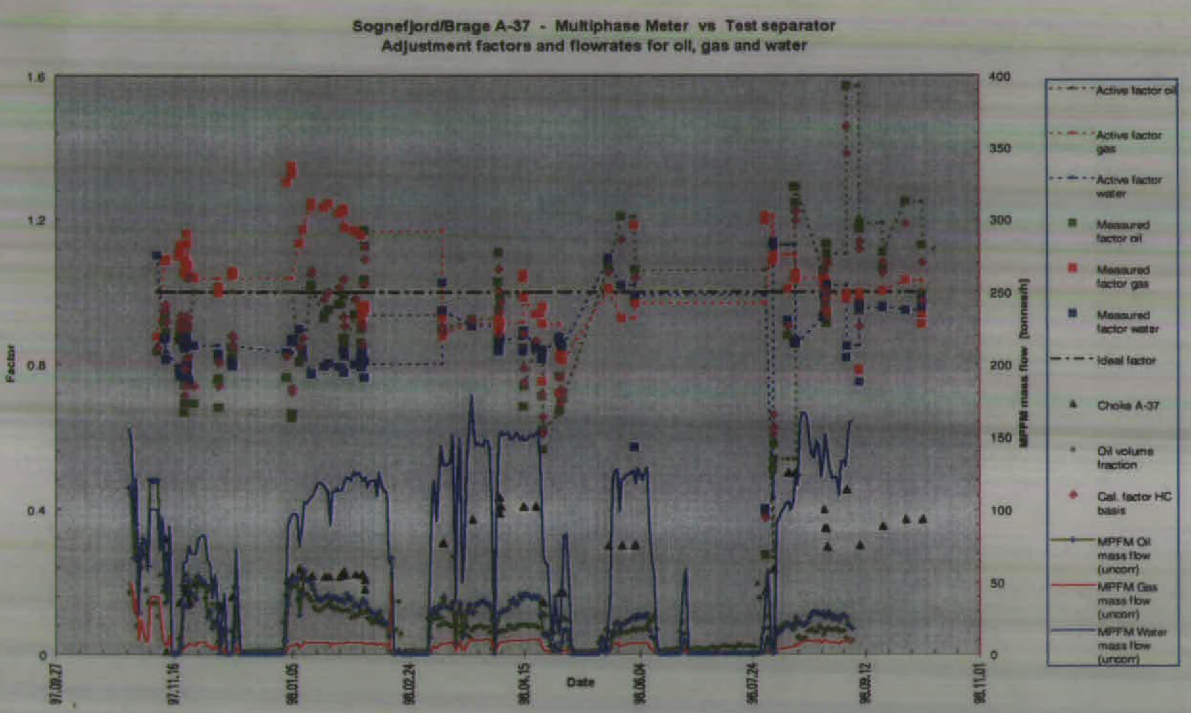


Figure 5 - Adjustment factors for multiphase meter



References

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

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