

Performance of subsea multiphase meters and topside test separator during well testing, after Skarv field start-up

Barbara M. Wrobel¹, Andrew Hall², Lukasz H. Wrobel¹
¹BP Norge AS, ²BP Exploration Operating Company Ltd.

1. Introduction

Since start-up of the Skarv field in December 2012, subsea multiphase flow meters (MPFMs), and a topside test separator have been routinely used for well testing of both oil and gas-condensate wells. There are five MPFMs installed on Skarv, with three installed on the oil-producing templates and two on the gas-condensate producing templates. There are two production headers on each template and one test header where the MPFM is located. Flow is directed either to the test or to the first stage separator through one of two risers. Figure 1 shows schematically the options for routing flow from the oil and gas-condensate wells, either through multiphase meters or directly to the test or first stage separators.

A number of wells share one MPFM on each of the production templates. Therefore for monitoring and historical tracking purposes, the positions of the diverter valves for each of wells are plotted against time, as shown in Figure 2.

The reasons why MPFMs are used for well testing in addition to the test separator include the following:

- To allow for metering of flowrates from oil and gas-condensate wells which have been drilled in different reservoir sections having different CGRs and GORs. This is especially important for a field with a large number of producing wells. There is also the possibility of testing of two or more wells with different GOR using the test separator and interpolating values for individual flowrates for each well from the total flowrate; however, this method would give increased uncertainty;
- Increased testing capacity by using the MPFM when occasionally the test separator is not available, for example due to cleaning or intervention;
- Surveillance of well performance during start-up using the MPFM, while the test and first stage separators are already in use.

According to [1], the main advantage of the MPFM over the test separator is reduction in time to perform measurement. Due to accumulation of liquid, the potential for slugging in the flowlines and risers, and the need to allow the separator to fill and stabilise when changing over wells for test, the response time for stable measurement using the MPFM is much shorter than for the test separator.

This paper consists of several examples, presenting performance of the subsea multiphase meters and the test separator on Skarv, as well as associated challenges.

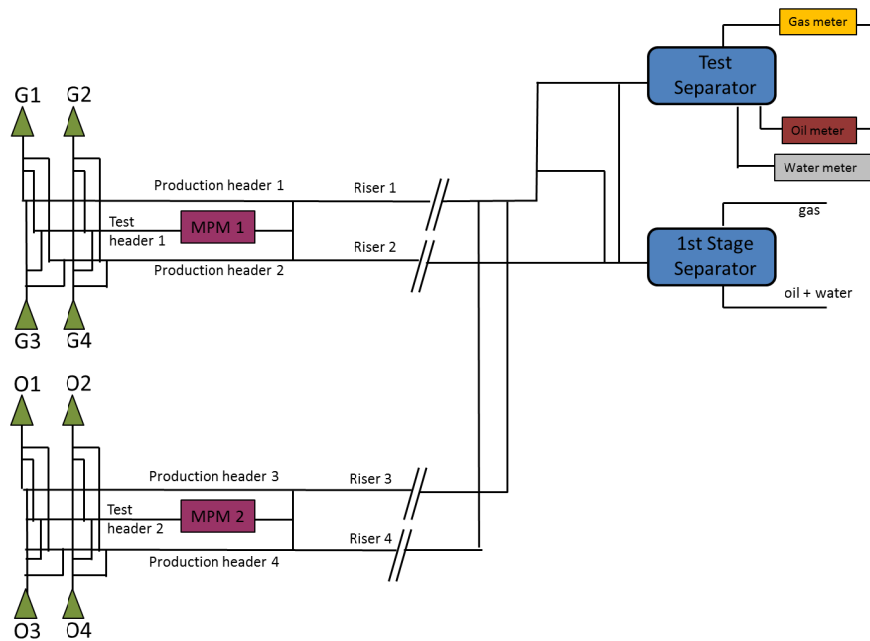


FIGURE 1 SKETCH OF FLOW ROUTING FROM WELLS, THROUGH MULTIPHASE METERS TO TEST SEPARATOR AND 1ST STAGE SEPARATOR [2].

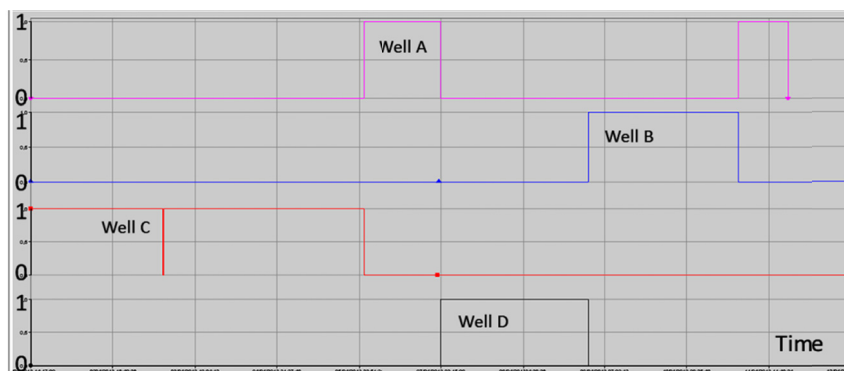


FIGURE 2 WELL DIVERTER VALVE IN OPEN (1) OR CLOSED (0) POSITIONS INDICATE IF A WELL CONNECTED TO MPFM [2].

2. Well conditions for production testing

Production testing of a well is based on a stable period, which is determined taking into account the following prerequisites:

- Bottom hole pressure and temperature must be constant,
- Well head pressure and temperature must be constant,
- Choke opening on a well must be constant,
- Flowrates at line conditions from multiphase meter must be stable (without noise, no fluctuations) - if a test is performed using the meter,
- Flowrates at line conditions from test separator must be stable (without noise, no fluctuations or slugging) - if a test is performed using the test separator,
- Ideally, well test period should last 24 hours.

3. Subsea multiphase meter (MPFM)

Measurement in the subsea meter is performed on a homogeneous mixture of gas, oil and water. A blind-tee is located immediately upstream of the meter with the intention of promoting flow homogeneity. The Skarv multiphase meters consist of a dual-energy gamma radiation source and a detector, Venturi throat, pressure, differential pressure and temperature transmitters, and a flow computer. Oil, gas and water mass rates are measured at line conditions and then converted to volume rates, which in turn are converted to standard conditions, using defined PVT tables. The PVT tables are created based on user input: reservoir fluid composition up to C36+ (which is especially important for oil fields), hydrocarbon properties (molar mass and density of C36+, saturation pressure, STO properties) and expected meter operating conditions. Tuning of the PVT model is performed against PVT data, from which the PVT tables are created. Other input into the meter is water composition, density and salinity. In the meter, there are also initial (reference) calibration constants, such as mass attenuation coefficients for air (empty pipe), oil, gas and water. The first coefficient is measured, while the last three may be calculated based on composition, or measured *in situ* in the meter [3].

Skarv multiphase meters operate at pressures in the range 90 to 130 bara and temperatures between 50 and 110°C, and therefore conversion of flowrates to standard conditions is a key consideration. The maximum design pressure of the meter is 310 bara and the design temperature range is from -10 to 130°C. For sizing purposes, the maximum differential pressure is taken as 4500 mbara, to allow for fluctuations which may take the DP to the range of 5000 mbar.

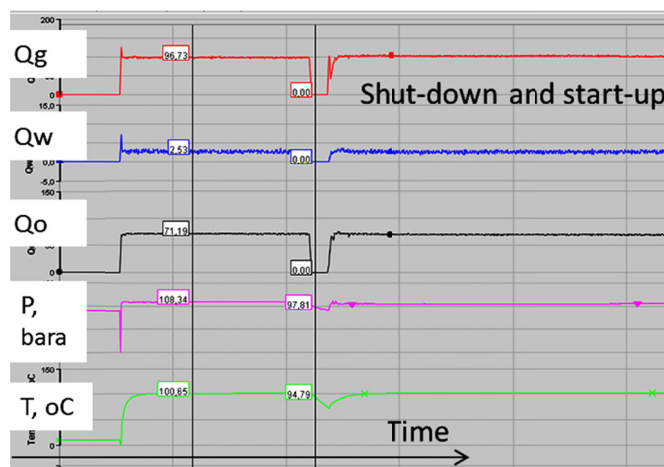


FIGURE 3 MEASUREMENTS FROM THE MPFM DURING WELL SHUT-DOWN AND START-UP [2].

In Figure 3, a smooth transition of flowrates, pressure and temperature in the multiphase meter can be seen during a well start-up and shut-down [2]. Figure 4 illustrates the solution triangle representing the MPFM operating range [3]. Vertices of the triangle represent 100% gas, 100% hydrocarbon liquid and 100% water, and the operating point lies in the middle of the triangle area (e.g. for gas fraction 50% and WLR 50%). If an operating point is shown outside the triangle, this would suggest a calibration issue.

Generally performance of multiphase meters has been satisfactory, with further evidence presented in section 6. Initially, the meter located on the gas-condensate template was showing a negative water reading (and water cut), driven by the fact that only a very small amount of condensed water was being produced from the gas-condensate wells.

The gas flowrate measurement error by comparison of the multiphase meter and the total gas production was within 2 to 3%. It was therefore decided to recalculate the mass attenuation coefficient for oil and for the “empty pipe” (as shown in Table 1). The first one was calculated by keeping the same GVF and CGR (CGR was believed to be correct), but only adjusting the oil mass attenuation coefficient to give a known value of water cut (see Figure 4 and in Table 1, 2nd segment). The required recalculated mass attenuation coefficient for oil turned out not to be physical, since the coefficient decreased and not increased, indicating that deviation was not a result of incorrect calibration of oil properties. This is due to the fact that regardless of any oil composition, the coefficient would not be so low, and even with the presence of unknown non-hydrocarbon components, the coefficient would increase, not decrease.

A shift in empty count rate could be a result of either the original test being incorrect - this may have happened for example if the meter had not been fully dry for the test, or the pressure was incorrectly measured, or a movement in the source during transit and installation (unlikely, but possible), so it is physically plausible.



TABLE 1 CALIBRATION OF THE MULTIPHASE METER FOR NEGATIVE WATER CUT

1) Current mass attenuation coefficients from diagnostic data:			
	LE	HE	
OIL	-0.0248837	-0.0172139	
WATER	-0.0348428	-0.0170521	
GAS	-0.0257691	-0.0180237	
Calculation of operating point for oil-gas-water mixture from diagnostic data:			
LE	-2.51319	GVF	97.51%
HE	-1.80647	WC	-28.89%
2) Keeping the same GVF, but adjusting OIL LE and HE to give known value of water cut:			
	LE	HE	
OIL	-0.0163627	-0.0144886	(not physically possible)
3) Calculation of operating point for empty pipe count rates, to give known, positive value of water cut and the same GVF:			
	March 2009	modified	
LE	30219	30580	
HE	17218	17283	

After this procedure was employed, the resulting water flowrate had a positive value ($\sim 1 \text{ m}^3/\text{h}$) and it was still possible to differentiate between the amounts of water from each of the gas-condensate wells, depending on which well was currently connected to the MPFM.

In case of the MPFM for the oil wells, the measured water cut was positive from the start of using the meter (water flowrate $> 3 \text{ m}^3/\text{h}$). Water cut measured by an MPFM employing a dual energy gamma source is sensitive to the amount of sulphur in oil; therefore it is recommended to test for sulphur and provide it together with the hydrocarbon composition for calculation of correct oil mass attenuation coefficient. The composition used for initial setup of the meter did not contain sulphur content. A recent PVT test of Skarv oil showed that it contains a small amount of sulphur. The PVT will be updated with this information and this will decrease the indicated water flowrate slightly.

In order to get confidence with using multiphase meters it is advisable to get to know deeply its working principles, to be aware of ways of calibration and to be acquainted with the multiphase meter standard maintenance procedure, such as updating composition of hydrocarbons and water (including water salinity) whenever they change or to perform *in situ* tests with oil or water samples [4].

4. Test Separator

The test separator operating pressure has been fairly constant, at around 80 bara, however the temperature fluctuates from 50 to 80°C with a difference of up to 10°C between the gas and oil legs. The gas flowrate out of the test separator is measured by a differential pressure Venturi meter; this meter is instrumented with two differential pressure transmitters, allowing for increased turndown, with a low flowrate range (0 to 7 mbar, 0 to 818 m^3/h) and a high flowrate range (0 to 500 mbar, 0 to 6 920 m^3/h). The oil flowrate out of the test separator is measured by one of two differential pressure orifice meters (designed for a low flowrate range with a maximum of 22 400 kg/h and a high flowrate range with a maximum of 256 600 kg/h). Water flowrate is measured by a magnetic meter with a measurement range from 6 700 to 67 000 kg/h [5].

The initial performance of the flowmeters installed on the test separator outlets was not as expected, leading to difficulty with matching flowrates from the individual tests using the multiphase meters and the total gas and oil production. Oil and water flowrate measurements were not converted to standard conditions, and gas flowrate, although given in standard conditions, still did not match. More recently, performance has been improved by correction of gas and oil flowrates offline (not real time), using a well testing spreadsheet which is described further in section 5.2. In addition, there was a negative water reading from the magnetic meter when gas-condensate wells were tested. This problem was solved by closing and re-opening the water control valve every few hours, in order to accumulate enough water and measure a slug of water flowing through the meter. An improvement in the system would be to add a meter with smaller meter size, as the requirement of a magnetic meter is to be completely filled by fluid, otherwise the measurement will be affected [6][7].

There is no doubt that a large test separator capacity is extremely beneficial for simultaneous testing of many wells having the same GORs. If necessary, it is possible to test two or more wells with different GOR through the test separator. Then, in order to get a well test of each well, the total flowrates of oil, gas and water are split, based on choke openings of each well (treated as fractions). The flowrates at line conditions and pressure and temperature of each stream must be taken into account when flow is converted to standard conditions. However, this method is likely to lead to increased uncertainties compared to testing an individual well via the multiphase flow meter.

Experience with using the test separator has shown that it is sensitive to slugging or other flow instabilities when well reaches high flowrates. This can be seen in Figure 5, where an oil well during start-up turned out to be challenging and quite unstable, which resulted in slugging in the test separator. However, such situation occurs rather infrequently and is handled quickly by operations.

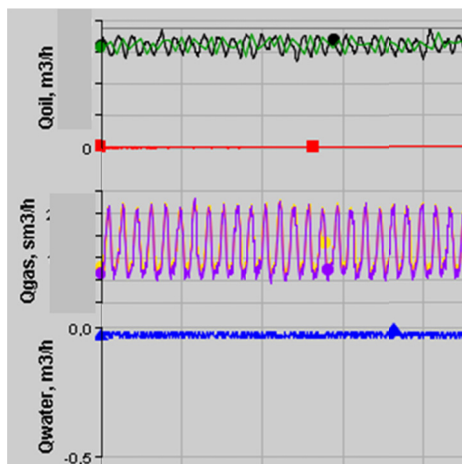


FIGURE 5 POSSIBILITY OF UNSTABLE FLOW IN TEST SEPARATOR [2].

5. Calculation of flowrates at standard conditions

A well testing calculation spreadsheet has been created for checking the validity of standard condition flowrates from the MPFM and for recalculation of test separator flowrates. In addition, it has enabled correction of test separator gas and oil flowrates from the Venturi and orifice meters which had been programmed with constant gas and oil densities and gas Z-factor.

The correction calculation consists of two parts: for multiphase meters and for the test separator. Petroleum Experts PVTp software has been used for calculation of gas and oil densities, vapour CGR, GOR, B_o and B_g , at any pressure and temperature conditions (within the MPFM and test separation ranges), based on PVT data for the oil and gas-condensate wells. Calculated parameters were used for conversion of flowrates from line conditions (multiphase meter or test separator) to standard conditions [8]. A single-stage flash from line to standard conditions was simulated using Constant Composition Expansion experiment. Although a real fluid separation is performed for three separation stages, a single-stage flash was performed, for consistency with the multiphase meter and test separator calculations. An equation of State (EOS) tuned for Skarv fluids was used in order to minimise uncertainty in the results [9]. In addition, Petroleum Experts PROSPER was used for calculation of water compressibility, B_w , within the operating pressure and temperature ranges. If hydrocarbon composition changes then new PVT properties will need to be calculated. This also applies for changes in water composition and salinity.

A well test is performed based on a long series of data (24h test, with test point every 2 minutes), which after conversion of rates to standard conditions is then averaged to single flowrate values, as a final well test result.

5.1 Flowrates at MPFM

Conversion of flowrates from multiphase meter line conditions to standard conditions was performed using equations (1) to (3). The total oil flowrate includes oil dissolved in gas, and the total gas flowrate includes gas dissolved in oil at meter conditions, which at standard conditions appear as free phase.

$$Q_{vo_sc} = Q_{vo_MPFM} / B_{o_MPFM} + CGR_{MPFM} * (Q_{g_MPFM} / B_{g_MPFM}) \quad (1)$$

$$Q_{vg_sc} = Q_{vg_MPFM} / B_{g_MPFM} + GOR * (Q_{o_MPFM} / B_{o_MPFM}) \quad (2)$$

$$Q_{vw_sc} = Q_{vw_MPFM} / B_{w_MPFM} \quad (3)$$

PVTp software produces a table with discrete values at pressure and temperature steps. Therefore, interpolated values at the exact pressure and temperature of the MPFM and test separator are calculated based on weighted average:

$$B_{o_av} = [(1/x_1) * B_{o1} + (1/x_2) * B_{o2} + (1/x_3) * B_{o3}] / (x_1 + x_2 + x_3) \quad (4)$$

Where:

- x_1 - is the first smallest distance between B_o @ line p,T and available B_o (at discrete p,T)
- x_2 - is the second smallest distance between B_o @ line p,T and available B_o (at discrete p,T)
- x_3 - is the third smallest distance between B_o @ line p,T and available B_o (at discrete p,T)

Comparison of MPFM flowrates at standard conditions to flowrates calculated from the spreadsheet is presented in Figure 6. Average relative errors for gas and oil flowrates are 2% and 3.7%, respectively, with maximum errors of 4% for gas and 10.5% for oil. This deviation is due to differences between the EOS used in the multiphase meter and in the PVTp software, with a higher impact at high operational pressure. Three out of four well tests with Q_o error of 9 to 10%, were performed for higher pressure at the MPFM (130 bar) than the average of 97 bara.

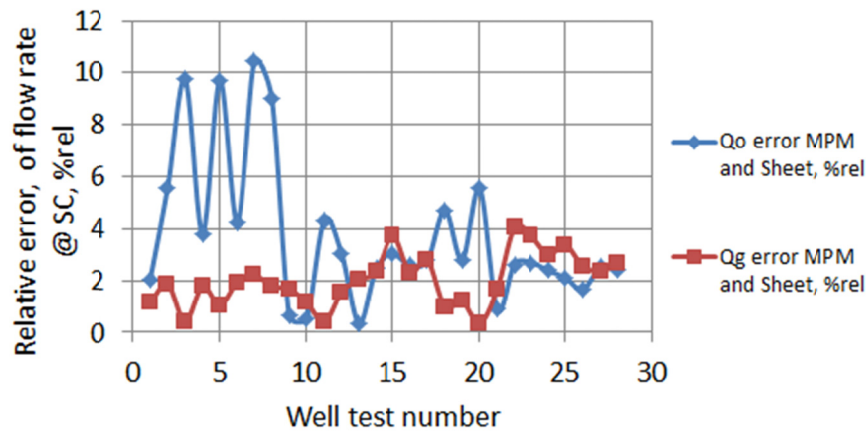


FIGURE 6 QUALITY CHECK OF CONVERSION OF LINE FLOWRATES FROM MULTIPHASE METER TO STANDARD CONDITIONS.

5.2 Flowrates at Test Separator

Test separator flowrates were corrected to standard conditions using equations (5) to (10). Total oil flowrate includes oil dissolved in gas, and total gas flowrate includes gas dissolved in oil at meter conditions, which at standard conditions appear as free phases. In addition, water cut is measured at standard conditions from the test separator oil outlet. This water is recalculated to separator conditions, extracted from oil and added to the water flowrate.

Equations for gas and water:

$$Q_{vg_sc} = Q_{vg_sep} / B_{g_sep} + GOR * Q_{vo_sc} \quad \text{gas} \quad (5)$$

$$Q_{vw_sc} = Q_{vw_sep} / B_{w_sep} \quad \text{free water} \quad (6)$$

Equations for oil Q_{vo_sc} (takes into account water in oil):

$$WC_{sep} = WC_{sc} * B_{w_sep} / (WC_{sc} * B_{w_sep} + (1 - WC_{sc}) * B_{w_sep}) \quad \text{water cut @ SC} \quad (7)$$

$$Q_{liq_sc} = Q_{liq_sep} / (WC_{sep} * B_{w_sep} + (1 - WC_{sep}) * B_{o_sep}) \quad \text{liq.=oil + water in oil} \quad (8)$$

$$Q_{vo_sc} = (1 - WC_{sc}) * Q_{liq_sc} + CGR_{sep} * Q_{g_sep} / B_{g_sep} \quad \text{oil without water} \quad (9)$$

$$Q_{w_sc} = WC_{sc} * Q_{liq_sc} \quad \text{water from oil} \quad (10)$$

Correction of flowrates from test separator gas and oil flow meters

In addition, gas flowrate at standard conditions from the Venturi meter had to be corrected. The programmed calculation used a fixed gas Z-factor and fixed gas density [5] ($Z = 0.9$ for $p > 51$ bara, $Z = 0.95$ for $p < 51$ bara, and default gas density of 82.4 kg/m^3). These numbers are replaced offline in the spreadsheet, with calculated gas Z-factor and gas density from PVTp software, which are dependent on gas composition, pressure and temperature conditions.

Oil flowrate from the orifice meter on the test separator oil leg reported at line conditions is converted to standard conditions in the spreadsheet. In addition, the default fixed oil density of 738 kg/m^3 used in the meter [5] is replaced with oil density calculated from PVTp

software. Such replacements resulted in changes of gas flowrate up to 33% and oil flowrate up to 18%, which is a significant difference that needed to be accounted for. Water flowrate converted to standard condition resulted in change by 1.5%.

Both Venturi and orifice meters are differential pressure flow meters, which are mass (density) dependent. Therefore without knowing correct density, these meters will not give accurate measurement. An improvement in the system would be installation of a densitometer, especially on the oil outlet of the test separator. However, the current offline correction is providing good results with substitution of densities of gas and oil from PVTp software. This calculation will have to be maintained as it requires update as composition changes.

6. Analysis of well testing results

Table 2 contains examples of calculated errors of oil and gas flowrates at standard conditions, based on well test results for a few months after field start-up. Flowrates obtained from the multiphase meter and test separator are compared along with the flowrates calculated by the well testing spreadsheet. As a rule of thumb, the aim is to obtain relative differences of up to ~5% for gas and ~10% for oil flowrates between the meter and separator. Cells highlighted in grey in the table represent measurements that are within the target, on average within 1.4% for gas rates and 5.5% for oil rates. This proves good agreement between the test separator and the multiphase flow meters. Measurements marked with * or **, have much bigger deviations. Comparing flowrate deviations between the MPFM and the spreadsheet (columns 5 and 8) for all well tests, it can be seen that errors in white cells are of the same size, as for “good” measurements in grey area. This indicates that conversion of meter rates to standard conditions is not a problem, and rather something else has impact on the deviations.

In order to explain these large deviations, consider Table 3. Here, gas and oil flow velocities are calculated at two locations: in the multiphase meter body and at the inlet into the test separator. Velocities were calculated from flowrates at MPFM and test separator conditions, taking into account local gas and liquid fractions. Tests were performed using the MPFM and test separator simultaneously. Comparing ratios of gas to oil velocities (columns 7 and 8), which represent how much faster gas flows in relation to liquid and ranking them for 1 being the highest and 4 being the lowest (columns 9 and 10), it can be seen that it is not necessarily always the case that the MPFM and test separator ranks are the same. For example, for gas well A, test no. 3, gas has the highest velocity compared to liquid in the MPFM and at the inlet to test separator. However, for gas well A, test no. 2, gas has 2nd highest velocity in the MPFM, but it is the lowest on test separator (see, also Figure 7). This can explain why sometimes there is a difference in GOR or CGR between the MPFM and the test separator, defined as gas to oil flowrates at standard conditions due to differences in gas and oil velocities. Such cases happened for well tests lasting 24h, while well conditions and flowrates were stable. The velocity difference is related to decreasing values of pressure and temperature from the MPFM (operating at 100 bara, 100 °C), through the flowline, up to the test separator (operating at 80 bara and 70°C). In addition, the geometry of flowlines may have influence on gas and oil velocity differences. Resulting errors may be even further enlarged, when oil and gas flowrates are converted to standard conditions.

TABLE 2 CALCULATED RELATIVE DEVIATIONS OF GAS AND OIL FLOWRATES BETWEEN MPFM, SPREADSHEET AND TEST SEPARATOR, FOR PERIOD OF A FEW MONTHS AFTER FIELD START-UP.

Type of well	Well test no.	Max. Q_g @ SC deviation, %			Max. Q_o @ SC deviation, %		
		MPFM and test separator	Sheet and test separator	MPFM and sheet	MPFM and test separator	Sheet and test separator	MPFM and sheet
Gas well A	1	0.12	1.27	1.15	24.43*	26.97*	2.04
Gas well A	2	8.14*	8.39*	0.23	1.77	2.44	0.66
Gas well A	3	0.29	2.14	1.85	2.35	3.12	5.55
Gas well B	1	0.74	2.51	1.76	3.17	0.63	3.82
Gas well C	1	2.87	0.52	2.33	9.32	12.04*,**	2.49
Oil well A	1	2.89	0.24	2.64	7.27	9.86	2.42
Oil well A	2	11.13*	8.57*	2.36	9.21	11.95*,**	2.51

*- Anomalies in calculated deviations may be related to differences in gas and oil velocities in multiphase meter and in test separator.

** - Deviations may be influenced by different PVT models used in the spreadsheet and MPFM for conversion of flowrates to standard conditions.

TABLE 3 CALCULATED REAL VELOCITIES (WITH INCLUDED SLIP) IN MPFM AND AT INLET TO TEST SEPARATOR, BASED ON OIL AND GAS FLOWRATES @ LINE CONDITIONS.

Type of well	Well test no.	MPF M U_g , m/s	Sep. U_g , m/s	MPFM U_o , m/s	Sep. U_o , m/s	MPFM U_g/U_o	Sep. U_g/U_o	MPFM Rank	Sep. Rank
Gas well A	1	11.95	2.64	0.37	0.47	32.22	5.58	4*	3
Gas well A	2	17.75	3.29	0.43	0.60	41.44	5.53	2	4*
Gas well A	3	19.02	4.04	0.44	0.62	42.75	6.49	1**	1**
Gas well B	1	18.81	4.00	0.48	0.65	39.00	6.17	3	2

*- The highest Q_g/Q_o @ LC on MPFM (for MPFM Rank) or test separator (for Sep. Rank)

** - The lowest Q_g/Q_o @ LC on MPFM (for MPFM Rank) or test separator (for Sep. Rank)

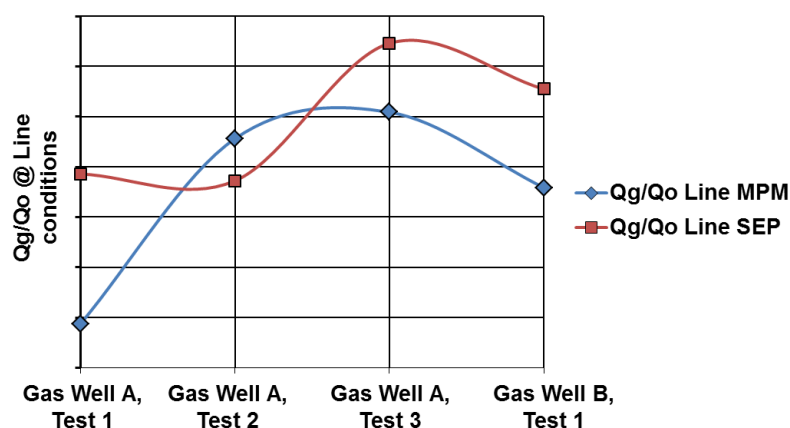


FIGURE 7 RATIOS OF GAS TO OIL FLOWRATES AT MPFM AND TEST SEPARATOR CONDITIONS FOR THREE WELLS TESTS FOR GAS WELL A AND ONE WELL TEST OF GAS WELL B.

Figures 8 and 9 present the quality of well testing of oil and gas-condensate wells using the MPFM and the test separator. In Figure 8, the first four tests were performed for the same gas-condensate well (gas well 1). The scale of gas and oil flowrates is similar for all four cases. The discrepancy between gas points from the MPFM and the test separator is very small, and for oil flowrate is satisfactory. However, for well tests 5-7 that have been performed for another gas-condensate well (gas well 2), it can be seen that only the MPFM provided flowrates of gas and oil of similar scale to well 1, while the test separator significantly overestimated them. Both wells are located in the same reservoir and have similar PVT composition. The behaviour of the test separator could be explained by instabilities of flow velocities due to reducing pressure and temperature in the flowline leading to the test separator. At the multiphase meter, the pressure and temperature are much higher, which means that gas has a higher density; there is more oil dissolved in gas, therefore gas velocity will be much lower than on the test separator. This may lead to lower velocity differences between gas and oil at the MPFM than at the test separator.

Figure 9 presents plotted GOR from four well tests of the same oil well. It can be seen that multiphase meter performance was much more stable, with values from all tests almost the same, compared to the test separator, which gave scattered flowrate values.

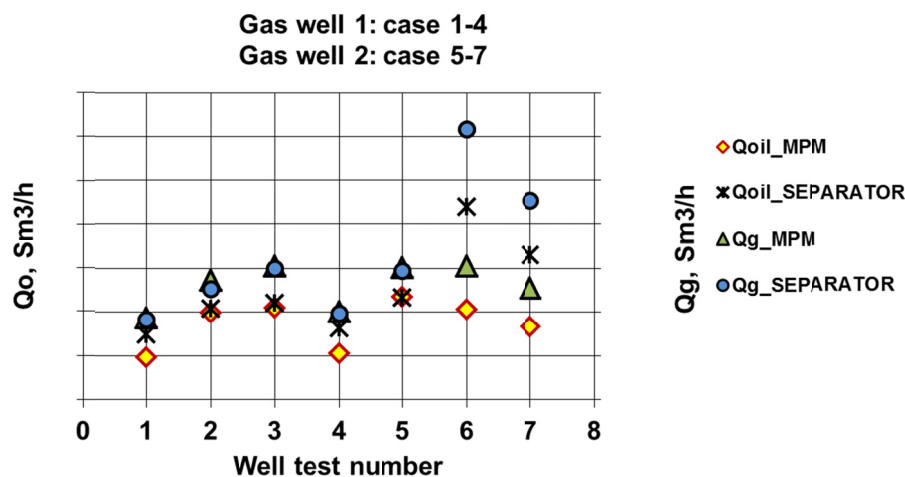


FIGURE 8 WELL TESTING OF TWO GAS WELLS PRODUCING FROM THE SAME RESERVOIR SECTION (WITH THE SAME CGR).

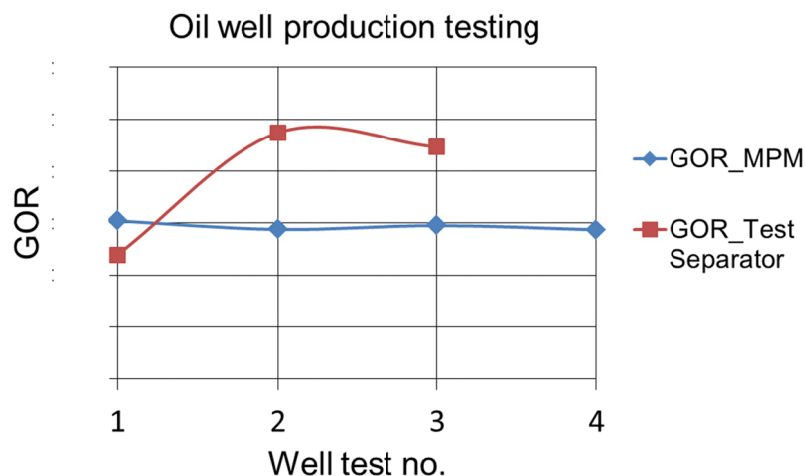


FIGURE 9 WELL TESTS OF THE SAME OIL WELL USING MPFM AND TEST SEPARATOR AT THE SAME TIME - STABLE FLOW CONDITIONS IN MPFM, BUT NOT IN TEST SEPARATOR.

Figure 10 shows CGR values from tests performed with the multiphase meter for gas-condensate wells plotted against time. Wells 1 to 3 have a similar range of CGR, compared to a slightly lower CGR for well 4 (by 7 to 8 stb/MMscf). This is in agreement with location of the wells - gas wells 1 to 3 are drilled in a different reservoir, than gas well 4. Reservoir fluid from wells 1 to 3 seems to be a richer gas-condensate, than from well 4. MPFM switches between these two compositions, depending on which well is currently connected to it.

Declining CGR with time, as well as with decreasing bottom hole flowing pressure (BHFP), see, in Figure 11, may be driven by two mechanisms. The first mechanism is related to the near-wellbore area falling below the dew point pressure. The dew point pressure is between 360 to 420 bara, depending on the reservoir segment. As evident from Figure 11, all tests are produced at BHFP below the dew point pressure. The condensate droplets start to form in the reservoir at the well location (lowest pressure) and into the formation with decreasing pressure. The condensate droplets are likely to stay largely below critical saturation, i.e. remain immobile. The second potential mechanism could be due to higher inflow of gas from upper parts of reservoir than from lower parts of reservoir. Due to compositional grading it is expected that the gas becomes dried when moving up the hydrocarbon column.

Declining CGR values indicate a change of composition of fluids entering the well. Any change in composition will have an influence on the multiphase meter measurement uncertainty; however a sensitivity study can show a significance of error, since in general PVT composition of reservoir fluid changes during field depletion.

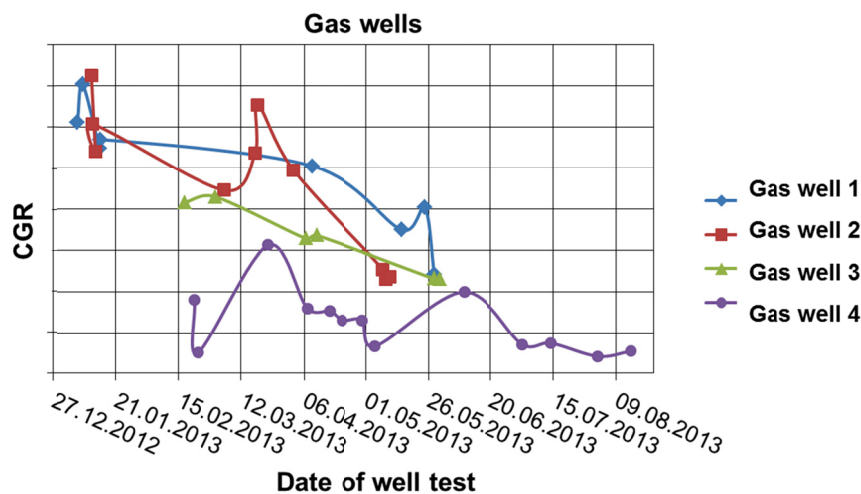


FIGURE 10 WELL TESTING TREND OF GAS WELLS SHARING ONE MULTIPHASE METER, WHERE GAS WELLS 1-3 ARE DRILLED IN DIFFERENT RESERVOIR SECTION TO GAS WELL 4.

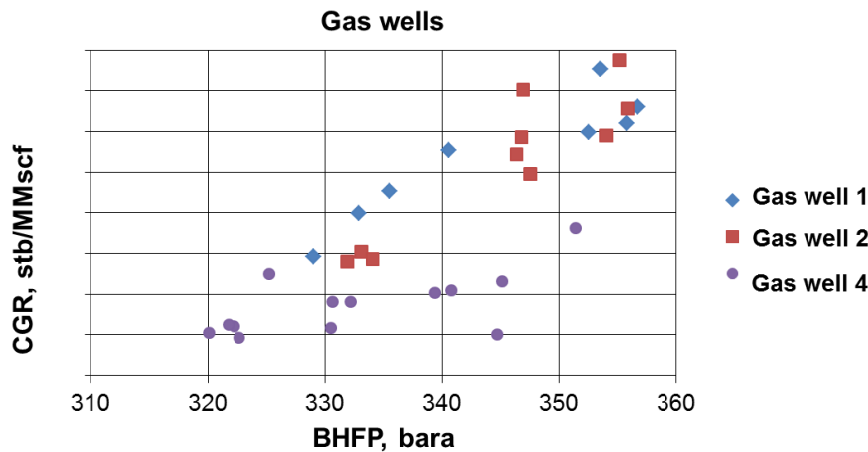


FIGURE 11 DEPENDENCE OF CONDENSATE-TO-GAS RATIO ON BOTTOM HOLE FLOWING PRESSURE - POINTS ARE BASED ON WELL TESTS SHOWN IN FIGURE 10.

Figure 12 presents GOR values from tests performed with the multiphase meter for four oil wells. Test points for all the wells are very consistent. Oil wells 1 and 4 are drilled in a different reservoir section than oil wells 2 and 3; however, composition of reservoir samples taken from exploration wells drilled in these two segments are very similar.

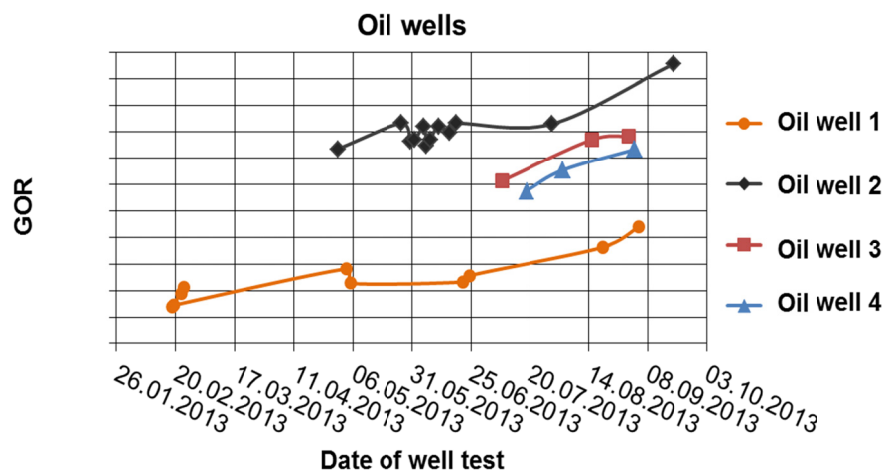


FIGURE 12 WELL TESTING TREND OF OIL WELLS SHARING ONE MULTIPHASE METER, WHERE OIL WELLS 1 AND 4 ARE DRILLED IN DIFFERENT RESERVOIR SECTION TO OIL WELLS 2 AND 3.

GOR points until mid-July are fairly constant for oil wells 1 and 2 and then they start to incline. Oil wells 3 and 4, which started production in July, also show inclining GOR points. This could be interpreted by reservoir pressure reaching bubble point in mid-July, which resulted in increased gas production. During recent production shut-down in September, reservoir pressure for all oil wells was higher than the bubble point, however bottom hole flowing pressure during testing of all wells was lower than the bubble point. This indicates that two-phase oil-gas mixture starts to appear in the vicinity of the well. Additionally, gas injection supporting oil wells started in May and June. Gas injection could be responsible for increase of GOR points after mid-July, as a delayed effect due to reservoir saturation with injected gas volumes or gas coning effects. This could result in an increased production of gas of lighter composition, when two-phase flow mixture flows into a well.

GOR values for oil well 1 are lower (by ~110 scf/stb), than for wells 2, 3 and 4. This may be related to a lower drawdown (32 bar) for oil well 1, than for the other three wells (52.7, 65.4

and 54 bar). Drawdown drives oil and gas velocities. With higher drawdown, more free gas is flowing from wells, which is reflected by higher GOR.

Based on data shown in Figures 10 to 12 the conclusion is that measured by MPFMs CGR values for gas-condensate wells and GOR values for oil wells are very consistent throughout the time observed. Multiphase meters have provided valuable information about the behaviour of Skarv wells during early field operation, which in addition to production surveillance and wells allocation purposes, are also used for constraining the dynamic model.

7. Summary

This paper presents several issues related to performance of subsea multiphase meters and a test separator after start-up of the Skarv oil and gas-condensate field:

- 1) routing possibilities for oil and gas-condensate wells through the multiphase meters and to the test separator,
- 2) an issue with negative water readings from multiphase and magnetic meters for very low water flowrate ($< 1 \text{ m}^3/\text{h}$), as well as calibration solutions for the multiphase meter,
- 3) correction of Venturi and orifice flow meters, due to programmed constant gas and oil densities and gas compressibility factor,
- 4) potential impact of flow instabilities on the test separator,
- 5) importance of correct calculation of oil, gas and water flowrates to standard conditions, together with presented equations,
- 6) presented examples of well test results for Skarv oil and gas-condensate wells, including:
 - study of short term effects that influence CGR and GOR ratios: individual oil and gas velocities in the multiphase meters and on the inlet to the test separator, PVT models for calculation of standard conditions flow rates,
 - description of mechanisms that may influence CGR and GOR ratios in long term perspective:
 - for the gas-condensate wells: immobile condensate droplets below critical saturation and compositional grading of reservoir fluid,
 - for the oil wells: gas injection support, which may affect produced fluid composition and the value of drawdown.

The use of subsea multiphase meter technology in combination with a topside test separator has been demonstrated to provide a robust way to determine well production rates in a system of subsea tiebacks, where wells are manifolded into flowlines and therefore otherwise difficult to test effectively.

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9. Abbreviations

MPFM - multiphase meter
GOR - gas to oil ratio [Sm^3/Sm^3]
CGR - condensate to gas ratio [Sm^3/Sm^3]
GVF - gas volumetric fraction [-]
CVF - condensate volumetric fraction [-]
WVF - water volumetric fraction [-]
PVT - pressure volume temperature
STO - stock tank oil
LC - line conditions
SC - standard conditions
 B_g - volume factor for gas [m^3/Sm^3]
 B_o - volume factor for oil [m^3/Sm^3]
 B_w - volume factor for water [m^3/Sm^3]
BHFP - bottom hole flowing pressure [bara]

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