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Blind testing of a Dual Mode Multiphase/Wet Gas Meter at the Alaska Alpine Oil Field and the CEESI Wet Gas Test Facility

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1 ABSTRACT

This paper describes two blind tests of a multiphase flow meter performed by ConocoPhillips and BP during 2010. The first test was at the Alpine oil field in Alaska, and the second was at the Colorado Engineering Experiment Station Inc. (CEESI) wet gas flow facility in Colorado. The same 74 mm MPM multiphase flow meter was used for both tests.

The Alpine tests consisted of production from 16 wells, with a total of 88 tests, and 880 hours of flow during March and April 2010. The total production from these wells was about 4800 m^3 (30,000 bbl) liquids with an average 65% water cut, plus 2400 kSm^3 (85 MMscf) gas at an average GVF of 96% during the test period. Individual wells had gross liquid rates ranging from 2.0 to 46 m^3/h (300 to 7000 bbl/d); gas rates from 940 to 3900 Sm^3/h (0.8 to 3.3 MMscf/d); and water cuts from 10 to 99%. The instantaneous values varied substantially during individual tests, with dynamic variations in gas and liquid rates and water cut. The operating pressure was in the range 10 to 14 barg. During the field trial there were small salinity changes in the produced water whose conductivity varied from 3.7 to 4.2 S/m as measured by the multiphase meter.

Subsequently, the meter was installed at the CEESI wet gas facility for a wet gas flow test in September 2010. This test program was performed by BP and ConocoPhillips. The purpose of the test was to evaluate the performance of the meter in wet gas flow conditions. A total of 178 test points were performed at an operating pressure of 68 barg with GVFs in the range 94 to 100% and water cuts in the range 0 to 100%, with fresh water used due to material limitations in the flow facility. A total PVT fluid composition was provided at the beginning of the test and was used to generate look-up tables for fluid properties such as gas and condensate density, viscosity, etc. The meter was also configured to use *in situ* measurement of water and gas PVT properties.

In both cases the measurements from the multiphase/wet gas meter were compared to liquid and gas rates determined in single phase flow conditions downstream of a separator. This paper presents the test results of the MPM meter which is based on 3D Broadband technology. The tests were performed as blind tests where the vendor was not given any flow data prior to or during the tests.

2 TEST OF MULTIPHASE METERS AT THE NORTH SLOPE (ALASKA) AND CEESI

A multiphase metering study was conducted by ConocoPhillips in 2009 to investigate the feasibility of using MPFMs in place of a test separator or in place of the entire test system at new drill sites. The study was performed as a follow-up to an Onshore Arctic Infrastructure Study that identified multiphase metering as a technology to reduce the capital cost of standardised drill site designs.

The results of the study were promising, in part because multiphase meter technology has significantly improved over the past decade. Historically, flowing conditions of high GVFs and high water cuts in combination with the dynamics associated with slugging flows have presented the greatest challenges for multiphase flow metering [1]. Some meter designs are also sensitive to changes in produced water salinity and/or fluid composition. Recent advances in metering technology have created meters that are claimed to handle broader GVF & WC ranges, are less sensitive to slugging flows, changes in produced water quantities, salinity and changes in fluid compositions [2], [3], [4], [5], [6], [7], [8], [15], [16], [17].

Two MPFMs were considered for testing at ConocoPhillips Alaska facilities. This paper presents the test results of one, the MPM meter, which is based on 3D Broadband technology.

Since the results of the feasibility study indicated that MPFMs at new drill sites may reduce drill site facility cost and accelerate production, further work was considered necessary to progress this opportunity. In order to gain ConocoPhillips Alaska, working interest/royalty interest owners, and Alaskan regulatory (AOGCC/DNR) approval, a field test was deemed necessary to demonstrate the accuracy and robustness of the multiphase meters under consideration. This test was conducted with assistance of BP, who are one of ConocoPhillips Alaska field working interest owners.

Following the field test in March/April 2010, the same 74 mm meter was tested in wet gas conditions at the CEESI test facility in Colorado in September 2010 in a JIP between BP and ConocoPhillips. The meter used for the two installations was identical, but with a few minor modifications to the installation:

- The Alpine installation was downstream of another MPFM in a space-constrained location within the Alpine test building;
- During 2010, MPM built a transport and test skid for the meter which was used for the CEESI installation;
- The CEESI installation was downstream of a long length of straight pipe. The design of the skid included a double bend upstream of the meter, recommended by MPM to improve swirl through the meter to promote an axisymmetric flow pattern, and also ensured a requirement of matching of the pipe diameter through the immediate upstream pipework;

- Fluid properties used to generate the look-up tables for density, viscosity, etc. were different;
- A 1% reduction of the GVF switching limit between multiphase and wet gas mode of operation was implemented prior to the CEESI test;
- The Venturi pressure transmitter was re-ranged to a higher range based on the expected range of the CEESI test.

3 MPM TECHNOLOGY

3.1 3D Broadband™

The MPM meter measures multiphase flowrates with no separation or mixing device. A combination of a Venturi flow meter, a gamma-ray densitometer, a multi-dimensional, multi-frequency dielectric measurement system and advanced flow models are used. These are combined to form a multi-modal parametric measurement system [10], [11], [12], [13], [14].

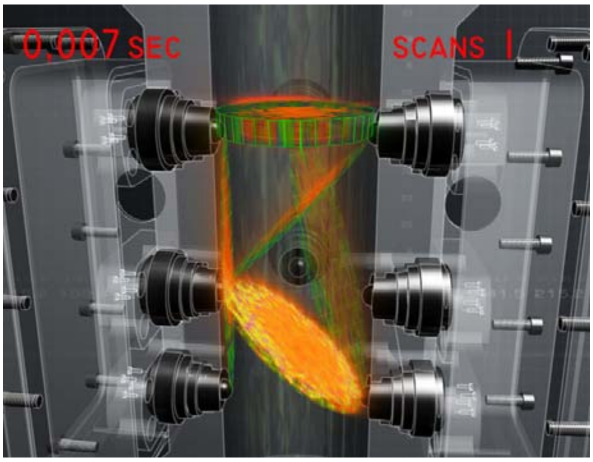

Figure 1: 3D Broadband multi-planar measurement

The 3D Broadband system is a high-speed electro-magnetic (EM) wave based technique for measuring the water/liquid ratio, the water salinity and the liquid/gas distribution within the pipe cross section, as illustrated in Figure 1. By combining this information with the measurements from the Venturi, the flowrates of oil, water and gas can be determined. The measurement is based on permittivity measurements performed at many frequencies in many planes within the sensor simultaneously. The measurement frequencies cover a range of 20 to 3700 MHz. The MPM meter has a dual mode functionality, which means that the meter it is a combined multiphase and a wet gas meter [16].

At ultra-high GVFs (typically > 99% GVF), when the liquid volume is extremely small compared to the gas volume, the Droplet Count® functionality is claimed to significantly improve the measurement resolution of the liquid fraction and to be highly tolerant towards changes in fluid PVT properties, such as the oil and gas densities and water properties. This is achieved through a patented (pending) methodology with a significantly higher resolution on mixture density compared to gamma based density measurements, and for which the liquid metering uncertainty reduces with increasing GVF [17].

3.2 *In situ* measurement of fluid properties

The MPM meter has three methods for *in situ* measurement of fluid properties that represent further increased robustness against uncertainties of the PVT properties for the MPM technology [4], [7], [15].

- Measurement of water salinity of the water phase. This is an in-line continuous measurement which is performed while the well is flowing. Separate methods are used for multiphase and wet gas flow conditions. The method used in multiphase flow conditions covers water-continuous flow conditions only (typically WLR > 50%) and the method used in wet gas flow conditions covers both oil- and water-continuous liquid emulsions.

- Measurement of gas density and permittivity by utilising the DropletCount method [17] to detect periods with pure gas within the pipe. During these periods, the permittivity and density measurement is used to measure, verify and correct the PVT calculated values for permittivity and density. The method can also be used to measure the permittivity and density of oil.

- Multi Mode Analysis. In wet gas, the MPM meter incorporates three different methods for measurement of the fractions and flowrates of the wet gas which can be used to determine PVT properties. This is an in-line continuous measurement which is performed while the well is flowing based on recalculation of the following measurement modes:

    a. three-phase mode with Droplet Count
    b. three-phase mode without Droplet Count
    c. two-phase mode with GOR Input

These three methods behave differently when errors are introduced in the PVT configuration data which can be used to derive an estimate of the PVT configuration data.

The methods used for *in situ* measurements of fluid properties are further described in [3], [4], [6], [7], [15].

3.3 Simplified field configuration

The robustness of the MPM meter towards errors in the PVT data and the ability to perform in-line measurement of the water and gas properties have enabled MPM to implement a simplified procedure for field configuration of multiphase and wet gas meters.

The simplified field configuration means that the meter can be field configured with a generalised (or average) fluid composition covering a wide range of wells and conditions using a common fluid configuration.

When the water salinity measurement and *in situ* gas measurement options are enabled, the meter is configured to use the measured water salinity to calculate the water conductivity, water density and water viscosity, based on the measured water conductivity.

Similarly, the meter can also be configured to use the *in situ* measured gas PVT to correct the PVT calculated values for gas density. Alternatively, the PVT calculated and *in situ* measured values may be logged in the database and used to correct the PVT configuration data manually when the meter has been in operation for a period such that sufficient in-situ verification data has been logged by the meter (typically a few hours to a few weeks depending on the field installation).

4 TEST SETUP IN ALASKA

The test site selected by ConocoPhillips was the Alpine Field, well pad CD1. The Alpine Field is located in the Colville River Unit, to the west of the Kuparuk and Prudhoe Bay oil fields on the North Slope of Alaska. Figure 2 shows the Alpine field location. The test objective was to determine MPFM suitability on existing well pads to supplement existing test separators and to determine the suitability of MPFMs to be used in place of test separators in new field developments. The Alpine oil field was chosen for the field trial by ConocoPhillips as similar flow properties are expected in a future development in the area.

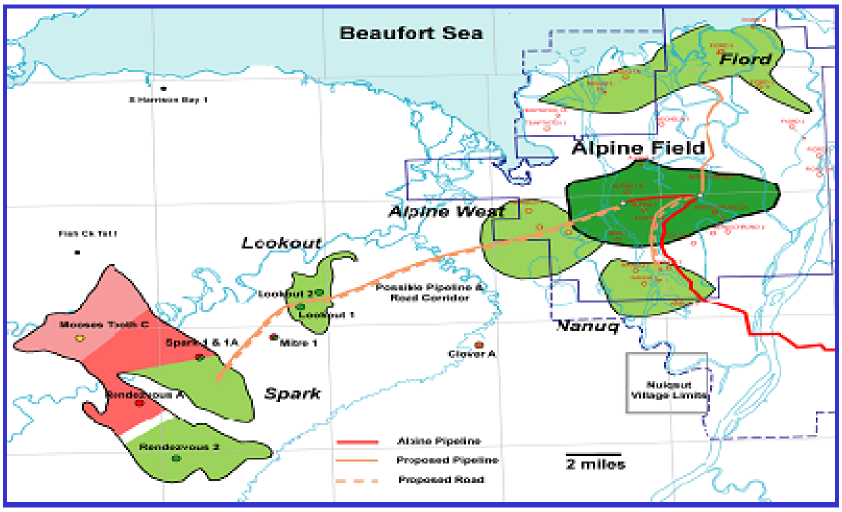

Figure 2: Overview of the Alpine area

The test was performed as a blind test where the vendor was not given any flow comparison data prior or during the test. The tests consisted of flowing from 16 wells, through a total of 88 well tests, and about 880 hours of flow.

The total production from these wells was about 4800 m^3 (30,000 bbl) liquids with an average 65% water cut, plus 2400 kSm^3 (85 MMscf) gas at an average GVF of 96% during the test period.

Individual wells had gross liquid rates ranging from 2.0 to 46 m^3/h (300 to 7000 bbl/d); gas rates from 940 to 3900 Sm^3/h (0.8 to 3.3 MMscf/d); and water cuts from 10 to 99%. However, these values varied substantially during individual tests, with dynamic variations in gas and liquid rates and water cuts. The operating pressure at the location of the multiphase meter was in the range 10 to 14 barg.

One of the problems recognised in testing multiphase meters in the field with a test separator is ensuring the quality of measurements made by the test separator and its measurement systems. Two elements need to be recognised by the readers of this paper:

- The test separator which the MPM measurements were compared against does not meter the target product (oil), directly. Oil is derived from the measurement of produced liquids and water cut. As a result water cut is one of the prime, but least determinate measurements.

- Water cut is derived from either a microwave water cut monitor installed on the liquid leg of the separator or from a density-based net oil computation. There are known water detection variabilities of the test separator unit. The uncertainty of the microwave water cut meter varies with water cut and with salinity/conductivity and the net oil calculations (for water quantities) using the Coriolis meter depends on oil and water densities, and may also be sensitive to gas carry-under in the liquid leg.

The CD1 well pad has the following flows: liquid flows from about 2.0 to 80 m^3/h (300 to 12,000 bbl/day) at operating pressure up to about 15 barg, with GVF from about 50% to 100% and water cuts of 0% to 100% from 24 wells.

The vendors reviewed a summary of the expected well flows and they premised that two sizes of meter would be required to cover the complete flow range. The well count was reduced to 16 wells in order to reduce the flow envelope to about 2.0 to 46 m^3/h (300 to 7,000 bbl/day) with a similar range of GVFs and water cuts in order to ensure that the vendors would only need to provide a single meter each.

This exercise indicated the care required to size multiphase meters in a well test scenario. There are both upper and lower flow limits beyond which their performance will be limited. It is common for well rates to decline over time and the probable need for smaller meters at a future point in time needs to be taken into account whenever multiphase meters are being considered for well rate determination.

5 TEST SEPARATOR AND WELL METERING

The Alpine CD1 test separator is a compact (small volume) two phase test separator, which is 5.3 m tan to tan by 1.7 m diameter, with a total volume of about 6.6 m^3.

The separator is provided with a 75 mm Coriolis meter for gas and a 50 mm Coriolis meter for liquid flow measurement. A microwave water cut monitor is installed in the liquid leg to provide water cut determination (and hence the derived oil rates).

The two test (multiphase) meters were installed in series upstream of the test separator as denoted in Figure 3 below.

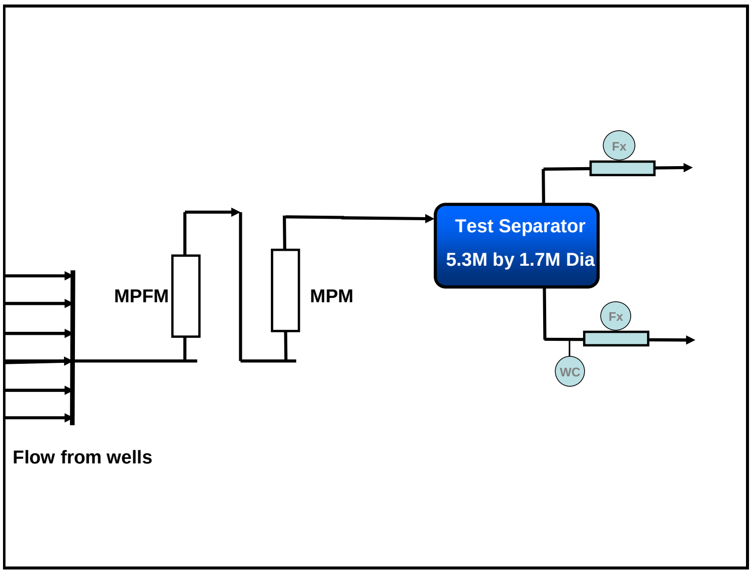

Figure 3: Multiphase meters and test separator in series

5.1 Gas Coriolis meter

The 75 mm Coriolis (gas) meter has a nominal flow range up to 11 kSm^3/h with a 0.7 bar dP. Uncertainty of the meter is quoted as ± 0.35% for a dry mass flow basis; however this meter is used as a volumetric meter on saturated gas with possible liquid carryover and its uncertainty must be considered to be somewhat greater.

There are two elements with respect to uncertainty:

- Conversion from mass to standard volume flow with an unknown (and possibly variable) gas density (or molecular weight), and
- How well (or otherwise) a Coriolis meter handles wet gas flows

The meter appeared to work well with drive gains in the 1 to 2.5V DC range with a few short excursions above this, indicating reasonable flow for most flow periods. Flow measurement uncertainty is a complex subject and has some unknowns embedded within it and so an assumption has been made that the uncertainty for a Coriolis meter in wet gas is uniformly distributed (and not a bias). The overall gas measurement uncertainty was considered to be ±4%.

The behaviour of this Coriolis meter in controlled wet gas flow conditions was verified by including a similar sized meter in a similar installation configuration in the wet gas flow test at CEESI in September 2010.

5.2 Liquid Coriolis meter

The 50 mm Coriolis (liquid) meter turndown depends on the dP deemed acceptable by the user. For live liquids it is essential that the dP be limited to restrict the risk of gas breakout or flashing (cavitation), and a dP less than 14 mbar was selected. On a 20:1 turndown the meter range is 4.3 to 87 m^3/h and the average flowrates experienced in the test were in the range 2.0 to 46 m^3/h.

Uncertainty is quoted as ± 0.1% of rate. However this does not account for gas carry-under, microbubbles and gas breakout during slug flow. There were 6 short durations when the meter drive gains peaked above 4V (of 14V). As a result a meter uncertainty of ±2.5% has been assumed, except on low flowrates where uncertainties were possibly higher.

An independent analysis of the Coriolis meter drive gains by the vendor indicated that they were ‘working well in these flows’.

5.3 Water cut monitor & net oil water cut calculations

The Alpine water cut monitor is a microwave unit, with a quoted uncertainty of ±1.0%, although in water-continuous flows (nominally water cut > 60%) with low gas volumes fractions (2 to 5%), this uncertainty may increase to ±2.0 to ±5.0%.

The uncertainty is undoubtedly adversely affected by slugging flows, and the mixing of the oil and water. Over time ConocoPhillips has recognised that the water cut monitor has limitations in performance at high water cuts, and when the salinity changes. In high water cut cases the Coriolis meter and a density based net oil calculation is used to compute the net oil and water flows; however this assumes:

- A good knowledge of the oil and water densities (assumed as 780 and 1020 kg/m^3 respectively);
- Stable flow conditions;
- No free gas in the liquid leg.

5.3.1 Water cut measurement and water salinity

In order to make an electrical measurement of water cut, the salinity must be considered. Uncertainty may be compromised without salinity compensation. If the fluids are oil-continuous where oil surrounds the water droplets at water cuts typically below 60%, salinity has little affect on the water cut measurement. However the inversion between oil- and water-continuous is not fixed and can be seen anywhere from as low as 40% to as high as 80% depending on the flow regime. Water cut is an ever changing parameter during a flow test and the oil-water continuous effect may be considered to be a multi-parameter state.

Salinity is an issue at the Alpine field where water injection is part of the tertiary recovery system and water is sourced from a variety of locations. The MPM meter highlighted that during the 6 week period of the field trial there were small salinity changes in the produced water whose conductivity varied from 3.7 to 4.2 S/m.

5.3.2 Water cut measurement and free gas

Water cut determination has a dependence on free gas, which may be present in liquids at pressure. Inadequate control of the separator during slug flow conditions may introduce periods with some free gas in the liquid leg. Typical examples of the effect on the measured water cut in the liquid leg for 1% free gas in the liquid leg for the test conditions is shown in Table 1 below:

	Microwave	**Density based**
Oil-continuous flow	+0.03% abs	-4.0 % abs
Water-continuous flow	-1.0 % abs	-4.0 % abs

Table 1: Water cut dependence on 1% free gas and measurement technique

Using a density based water cut measurement, 1% free gas will cause an under-reading of approximately 4% on the measured water cut. The microwave water cut meter is less influenced by free gas. For the microwave water cut meter, the effect of free gas has been calculated based on the permittivity impact of free gas in the liquid leg. In an oil-continuous flow, the permittivity effect of 1% of free gas causes an over reading of approximately 0.03%abs and in water-continuous flow causes an under reading of approximately 1%abs.

During well testing, water cuts can be unstable and can vary continuously during a test. This makes water cut determination a difficult measurement to make. Figure 4 below demonstrates the changing water cut whilst flowing over a few hours with the fluid density oscillating between 1020 kg/m^3 (water) and 780 kg/m^3 (oil) which equates to a water cut across the full range of 0 to 100%.

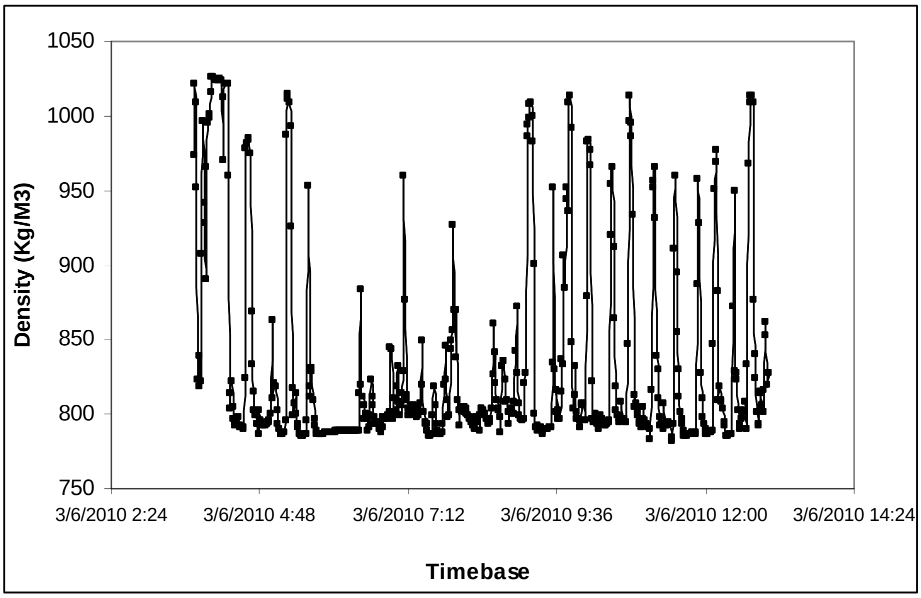

Figure 4: Coriolis liquid density indicating water cut changes in time

5.3.3 Net oil (density-based) calculations

Density-based net oil calculations make use of a combination of measurements and assumptions to determine the average mixture water cut.

For a homogeneous liquid/liquid flow (with no free gas), the density can be determined from

$$\rho_{mix} = (1 - wc)\rho_o + wc\rho_w$$

where ρ_{mix} is the measured density, ρ_o and ρ_w are the known (or assumed) densities of oil and water. Hence by rearrangement,

$$wc = \frac{\rho_{mix} - \rho_o}{\rho_w - \rho_o}$$

As an example, for a measured density of 900 kg/m^3, with oil density of 800 kg/m^3 and water density of 1000 kg/m^3, the calculated water cut would be 50%.

This computation method is considered to be good for water cuts in the 25% to 75% range but has sensitivity limitations when the water cut is very low or very high. This method is used at CD1 for water cut > 80% because of the previously observed limitations to the performance of the microwave monitor at high water cuts. Thus water cut determination at CD1 at high water cuts must be considered as having increased uncertainty.

6 MPM METER INSTALLATION AND COMMISSIONING

The MPM meter used in this test was a 74 mm dual multiphase/wet gas meter with a dual set of dP cells. The meter was also equipped with functionality for *in situ* measurement of water and gas PVT properties. The MPM meter as installed at Alpine CD1 is as shown in Figure 5.

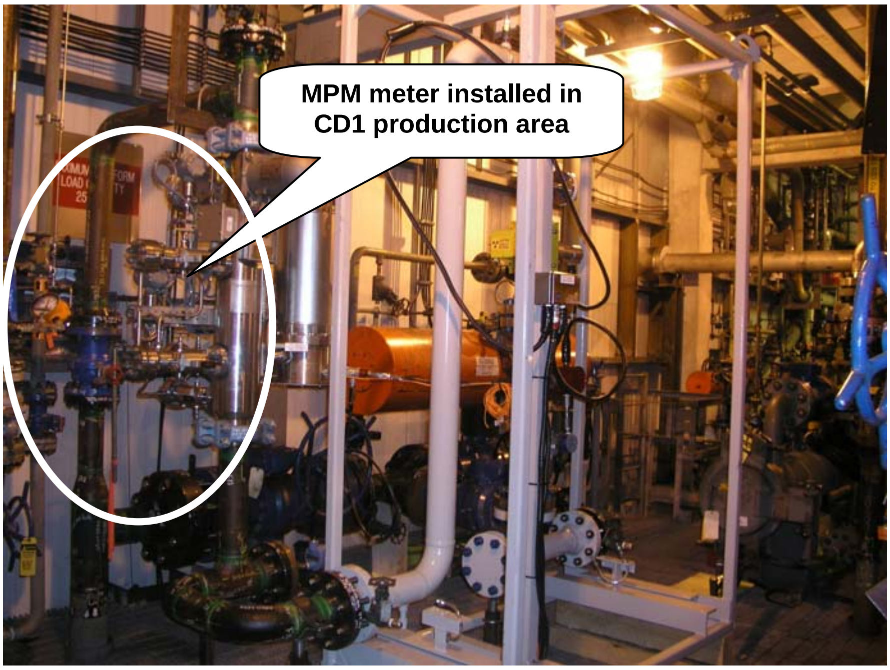

Figure 5: MPM meter installed at Alpine

A more detailed description of the MPM meter can be found in [3], [4], [6], [7], [14], [15], [16], [17].

The MPM meter was delivered as the basic meter and a separate gamma source. The meter and gamma source were assembled on site by the MPM technician and a licensed nuclear service provider. PVT configuration data was acquired from ConocoPhillips Operations (oil and gas density, viscosity and surface tension) and entered into the flow computer as a look-up table. The look-up tables were generated using Calsep PVTsim based on a typical (single average) composition for all the wells at the site.

The meter was also configured to configure the water properties automatically. In automatic water configuration mode, the MPM meter uses the measured water conductivity [15] and temperature to calculate the water salinity which is used to determine water density and viscosity.

The MPM meter was also set up to perform *in situ* measurements of the gas density and permittivity [7]. However since the pressure of the test was fairly low (10 to 15 barg) and the measured gas mass rate was used to compare the results to the test separator, the meter was not configured to automatically use the *in situ* measured gas density and permittivity. Instead, the *in situ* measured gas properties served as a validation measurement of the PVT calculated gas properties.

More information about the functionality for *in situ* measurements of fluid properties deployed by the MPM meter can be found in [3], [4], [6], [7], [15].

The meter was function tested prior to the flow tests and the technician departed. This was a conscious decision by MPM who wanted this to be a blind test (i.e. ‘plug and play’).

Two problems arose after MPM’s departure:

- The double block and bleed valve for the high dP cell (0 to 5000 mbar) had been left open and the initial flow test which exceeded the low dP cell range (0 to 2500 mbar) failed to record the high dP readings. This was quickly rectified.
- There were two gas output readings: actual gas flow and a total gas flowrate (actual gas plus solution gas). MPM needed to identify the respective data files. The actual gas (without the solution gas) was used in the comparison since the test separator did not account for solution gas.

Other than these points the meter was fitted, hooked up and commissioned without any problems.

7 COMPARISON OF MEASUREMENT DATA

Since the test separator was located immediately downstream of the MPM meter, the comparison between the test separator and MPM meter could be performed without accounting for phase transfer between oil and gas from the location of the MPM meter to the location of the test separator.

It was decided to compare the measurements based on the measured mass flowrates from the MPM meter and the test separator. By performing the comparison based on mass, the temperature and pressure at the location of the measurement did not have to be accounted for since it was assumed that there is no phase transfer between oil and gas from the MPM meter to the test separator. For the test separator, the flow measurements of gas and liquid are measured using Coriolis meters, and hence the primary reference measurement is mass flow.

For the MPM meter, the primary measurement is a combination of mass and volume. Since the density used in the Venturi model is based on a measured “multiphase density”, the measured total volume and mass flowrate from the Venturi is quite insensitive to any errors (bias) in the PVT configuration data (e.g. densities) for oil and gas.

The composition measurement is mainly a volumetric measurement. As an example, consider a homogeneous flow case at a GVF of 90% and pressure of 14 barg similar to the flow conditions at the Alpine field. A typical liquid density at actual conditions may then be 1000 kg/m^3 and gas density of 10 kg/m^3.

At a GVF of 90%, the homogeneous multiphase mixture then becomes:

$$0.1 \text{ x } 1000 \text{ kg/m}^3 + 0.9 \text{ x } 10 \text{ kg/m}^3 = 109 \text{ kg/m}^3$$

Since the comparison is based on mass, the PVT calculated densities may then introduce a bias in the comparison between the MPM meter and test separator. The effect on the measurement may be demonstrated by a simple example based on the above calculations.

Consider a flow case with a 90% GVF and a homogeneous mixture density of 109 kg/m^3. For simplicity the flow is assumed to be homogeneous such that the distribution between liquid film and droplet can be ignored and the difference in liquid droplet, film and gas velocity also can be ignored. In homogeneous flow, it is assumed that the liquid is dispersed as droplets and travels at the same velocity as the gas.

Since the primary measurement of density and permittivity in the case of the MPM meter is virtually unaffected by the composition of the oil and gas phase [4], any error in the PVT calculated gas density will have virtually no impact on the measured mixture density of 109 kg/m^3. Hence the measured mass and volume flowrate calculated based on the Venturi equation will be (virtually) unaffected by errors in the PVT calculated gas density.

What would then be the effect of a 5% bias in the PVT calculated gas density? At the conditions at the Alpine field, a 5% error in the PVT calculated gas density equals a 0.5 kg/m^3 error in the equation of state based calculation of gas density, and is not unlikely, based on the uncertainties involved in EOS calculations and characterization of the gas composition.

A 0.5 kg/m^3 error in the gas density would cause the meter to measure a GVF of 90.05% instead of 90.0%. Hence, the composition measurement introduces a bias (error) of 0.05% in the measured gas volume rate and a bias of 0.45% on the measured liquid flowrate. As mentioned above, the effect of the measured total volume flowrate from the Venturi can be ignored since a 5% error in the gas density have no impact on the measured density used in the Venturi equation . However, since the PVT calculated gas density is used to convert the measured volume rates to mass flowrates, a bias in the PVT calculated gas density at low pressure (e.g. 14 barg) will introduce almost the same amount of bias in the measured mass flowrate. Hence, if volume flowrates had been used instead of mass flowrate as the basis for the comparison, the result would have been less influenced by errors (bias) in the PVT calculated fluid properties for oil and gas.

To summarise, using mass flow measurement as a basis for comparison is most convenient when there is no mass transfer between the phases from the location of the

MPM meter and test separator. When mass flowrates are compared based on this assumption, any difference in operating temperature and pressure does not have to be accounted for.

However, at low pressure any relative error (bias) in the PVT calculated gas density is conveyed almost proportionally to the measured mass flowrate of gas since the measured volume flowrate is almost unaffected by errors in the PVT calculated densities.

8 TEST RESULTS FROM ALPINE

The meter test results are summarised in the following section.

Note that for the results presented, the average for the wells tested is presented. Of the 88 well tests, there were 16 wells; the 16 average well test results are shown in Figures 8 to 15 with the individual test results shown in the background. The number of tests per well varied between 2 and 12, and wells were tested for different durations. The data presented is for liquid, oil and water volume flowrates, gas mass flowrates and water cut.

The meter performed without problems or intervention during the test.

- Data from the MPM meter, without using the *in situ* measured gas density, resulted in average liquid, oil and water deviation of <-5% from the test separator, whilst gas was +7%.
- By using the *in situ* measured gas density (instead of the PVT calculated gas density), the difference of the gas density reduced the gas flow discrepancy from +7% to +2%.

There was no verification or tuning to the test separator during commissioning and test phases, and this data represents a true blind test.

About half of the wells exhibited slugging with large dynamic variations in gas and liquid rates and water cuts. Two tests exceeded the 5000 mbar limit of the dP cell, which saturated. On these wells the dP was clipped at 5000 mbar and the flows were probably under-metered for all phases. (See Figure 6, dP chart).

Figure 6 is a screenshot of the one of the wells where the dP was truncated. This clearly shows:

- The slugging nature of the flows as presented to the multiphase meters.
- Even though the average dP is around 750 mbar, the dP is clipped (saturated) at 5000 mbar. The dP varies from approx 3 mbar to greater than 5000 mbar for this well.
- High (> 95%) GVFs for extended periods (wet gas flows) in what was nominally an oil multiphase flow.

Whilst Figure 6 is not common for all well flows it is indicative of several of the wells and is not unusual for gas lifted wells where fluids are lifted using gas injected into the production tubing and the subsequent flows are cyclic.

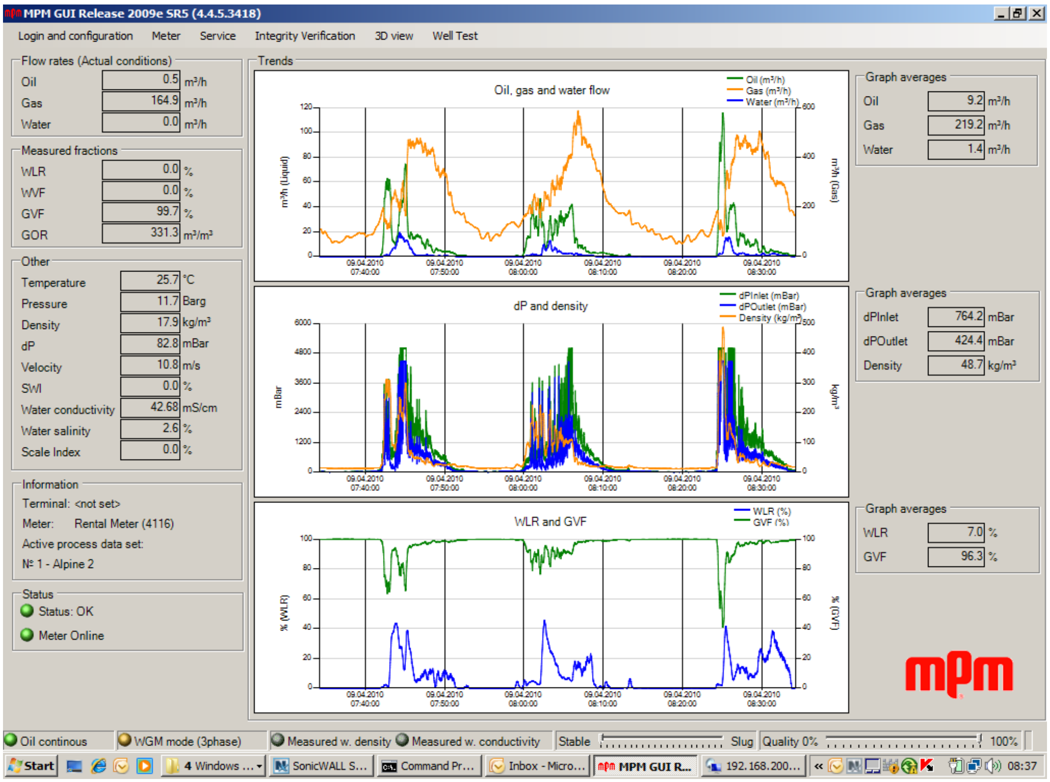

Figure 6: Screenshot of the MPM graphical user interface

Figure 7 shows the *in situ* measured gas density vs. the PVT calculated density for a 10 day period. The *in situ* measured gas density is measured by the MPM meter based on detection of pure gas in the meter as described in [4], [6], [7].

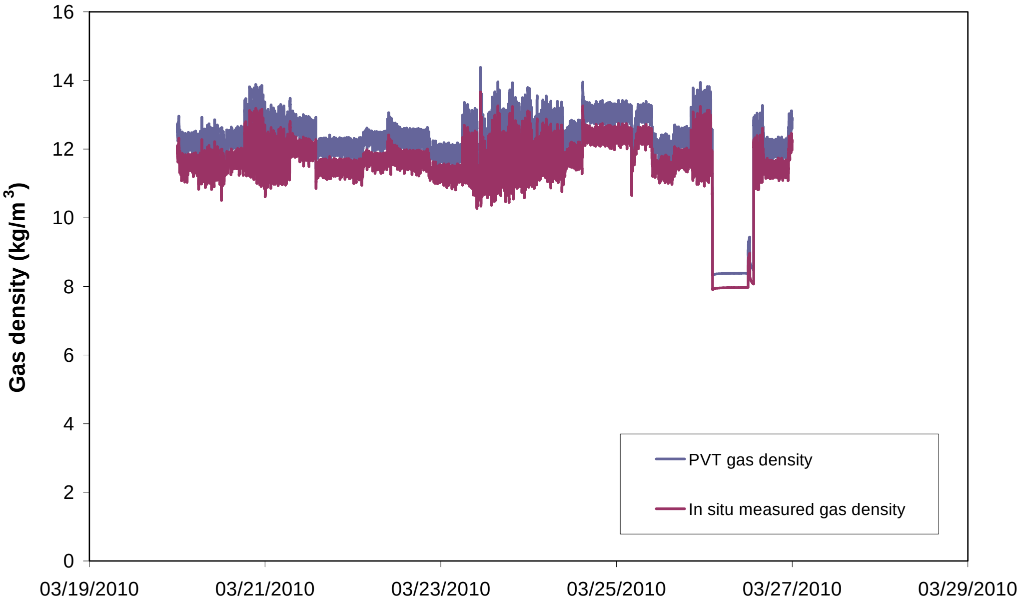

Figure 7: *In situ* measured gas density vs. PVT calculated gas density

Based on the gas density data from Figure 7, it was observed that there was a positive bias of approximately 5% (0.6 kg/m^3) between the PVT calculated gas density and *in situ* measured gas density. Since the mass flowrate was used as the basis for comparison between the test separator and the MPM meter, a positive bias of 5% on the PVT calculated gas density will give a corresponding positive bias in the comparison between the test separator and MPM meter as outlined in section 7 above.

In the following sections more detailed plots are provided of the MPM meter performance.

8.1 Liquid flowrate

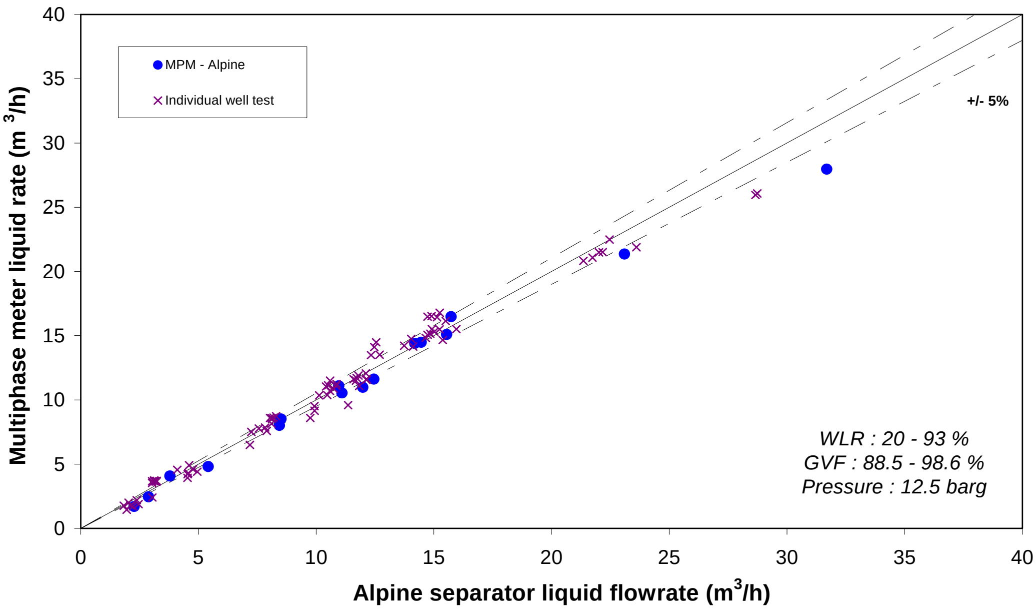

Figure 8: MPM liquid flowrate average for each of the 16 wells

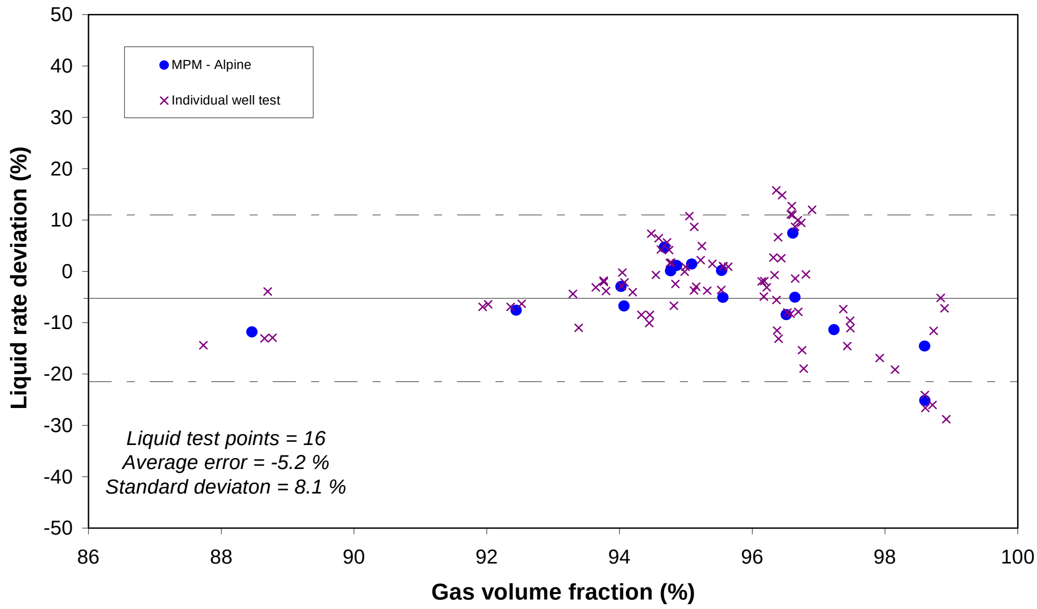

Figure 9: MPM liquid flowrate average deviation vs. average GVF

The liquid flowrate is generally within 10% with the exception of the two wells at the highest GVFs (lowest liquid flowrate) and one well where the dP was saturated during periods of the test (two largest liquid flowrates per Figure 8) with a dP exceeding 5000 mbar.

8.2 Oil flowrate

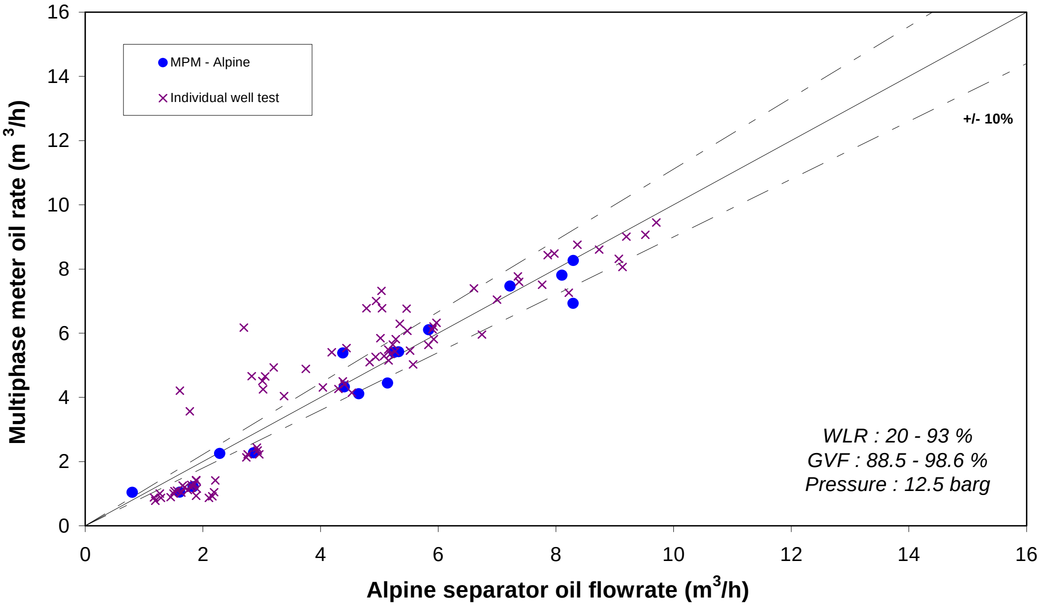

Figure 10: MPM oil flowrate average for each of the 16 wells

The average discrepancy for all well tests (88 total) was -4.5% versus the test separator for the oil rates.

8.3 Water flowrate

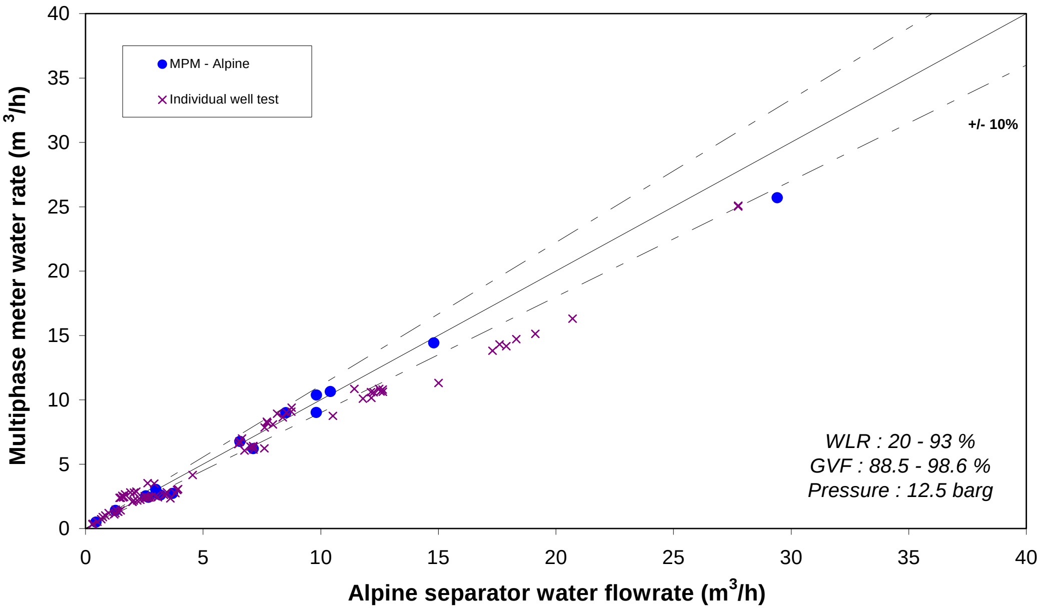

Figure 11: MPM water flowrate average for each of the 16 wells

The average discrepancy for all well tests was -3.8% versus the test separator for the water rates.

8.4 Gas flowrate

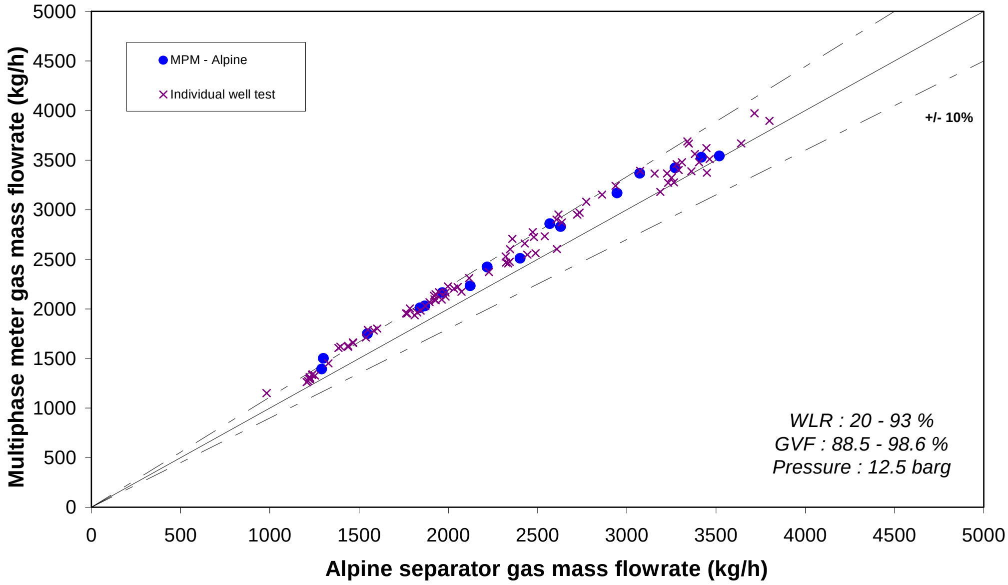

Figure 12: MPM gas mass flowrate average for each of the 16 wells

Per Figure 12, all readings were positive such that there was a suspicion of a systematic bias in the MPM gas readings. MPM checked the live gas density using their in house In Situ Verification®, and determined that there was a +5% discrepancy between the PVT calculated gas density used in the calculations and the measured gas density at the meter. The PVT density was based on data provided by the Alpine site during set up of the meter. Figure 13 shows that using the *in situ* measured gas density, the average gas discrepancy was +2.6% with a variation of -4.4% to +9.7%.

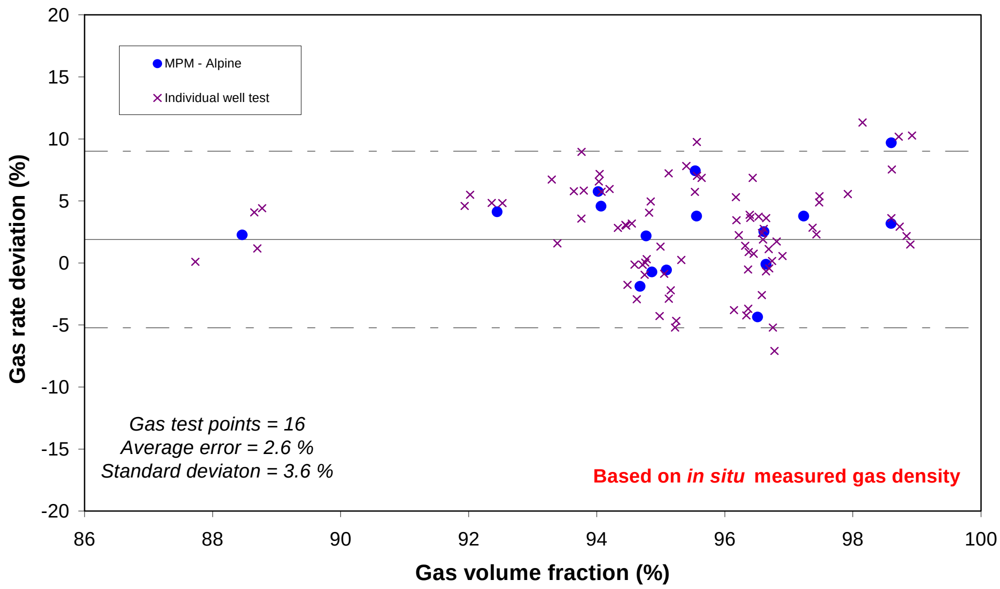

Figure 13: MPM gas flowrate deviation vs. GVF for each of 16 wells

Figure 14 shows that prior to the gas *in situ* density review, the average discrepancy for all well tests was +8.0% for gas flows. The variations ranged from +0.7% to +15.5%.

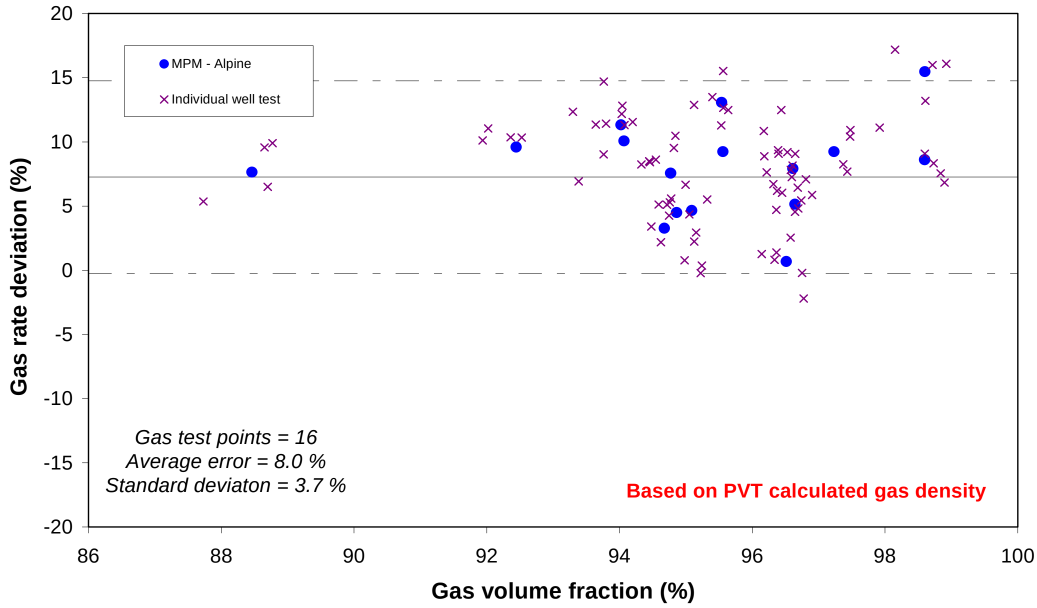

Figure 14: MPM gas flowrate deviation vs. GVF for each of 16 wells

8.5 Water cut (water/liquid ratio)

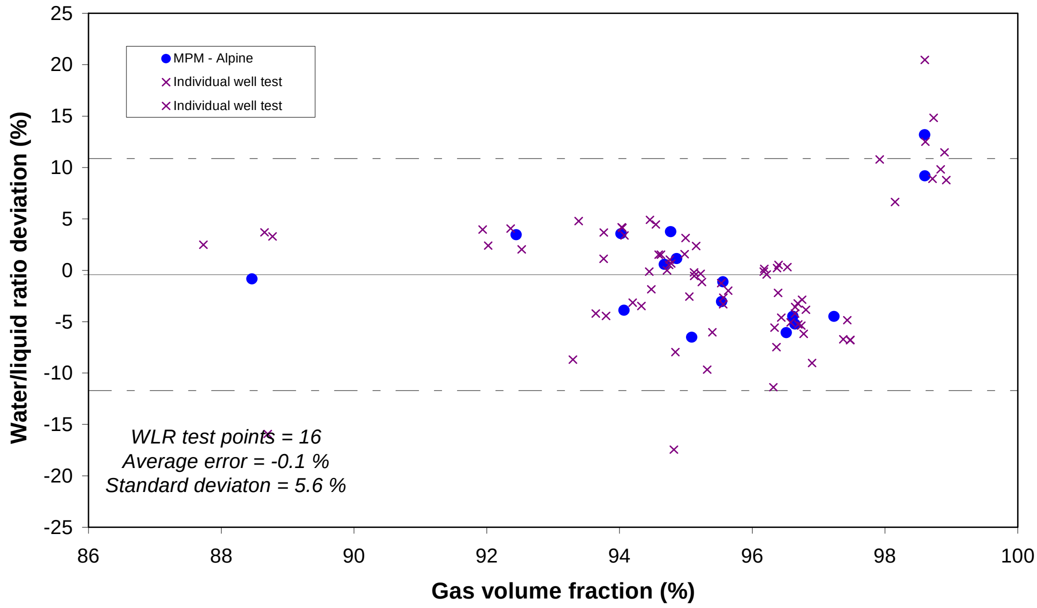

Figure 15: MPM water cut deviation vs. GVF for each of 16 wells

The average water cut discrepancy was -0.1%. The variations ranged from -6.5% to +13.2% for all the wells.

As explained in section 5.3, water cut determination from the Alpine test separator was known historically to have had some issues. Reference water cut was determined by two methods during the trial: the in-line microwave water cut meter and a net oil method based on the Coriolis meter density. For five of the wells the water cut measurement from the Coriolis meter method was determined to be more credible; for one well there was a significant discrepancy in the two reference methods; for the rest of the wells the microwave water cut meter was used as the reference.

9 TEST SETUP AT CEESI

After completion of the test in Alaska in April 2010, the same 74 mm meter was used for wet gas testing at the CEESI wet gas test facility in Colorado during September 2010.

Below is a block diagram (Figure 16) showing the major components of the CEESI test facility. The loop can be pressurized to the desired level using an outside source of natural gas and a charging compressor. Once the loop is pressurized, the natural gas is circulated around the test loop by circulation compressors. The only heat source in the test facility is the heat of compression produced by the compressors. This heat is sufficient to warm all the piping to a temperature which can be well above ambient. Heat exchangers are used to maintain a constant and stable temperature at the meter test section. Tests for this project were maintained at temperatures between 27° and 34°C, with the variation during an individual test less than 1°C.

Once the flowing temperature is stable, the mass flowrate of the natural gas is determined by the “gas flow measurement” package. The package consists of a turbine meter, a check meter, and a gas chromatograph. These items are described in more detail below.

A basic assumption for the test facility is that the mass flowrate of the natural gas remains constant throughout the loop for any data point. The pressure, temperature, and pipe diameter can change at any location within the loop, which will affect the actual velocity/volumetric flow at that location; but the gas mass flowrate remains constant.

The phase behaviour of the fluids in this system is believed to be much simpler and more easily predicted than for produced hydrocarbon fluids. There is no overlap in the composition of the gas (dominated by C1 with some C2, C3, CO_2 and traces of higher chain molecules up to C6) and the liquid (C9 to C14). At operating pressure, gas will be absorbed into the liquid, reducing the density of the liquid, but this fluid system is essentially very stable; the pressure was maintained between 67 and 71 barg throughout the tests. Changing the relative fractions of gas and liquid in the test system is unlikely to lead to any significant mass transfer.

The liquids are injected into the pipeline downstream of the reference gas flow measurement equipment. The liquids are then carried along with the natural gas through the test sections. After passing through the test section, the liquid mixture is separated from the natural gas at the gas/liquid separator. The gas returns to the compressor inlet and is then recompressed and re-circulated. The liquids (hydrocarbon liquid and/or water) falls to the bottom of the separator and is collected in a vessel underneath. From the collection vessel, the liquid flows into the liquid/liquid separator where by gravity forces and residence time the two liquids are separated.

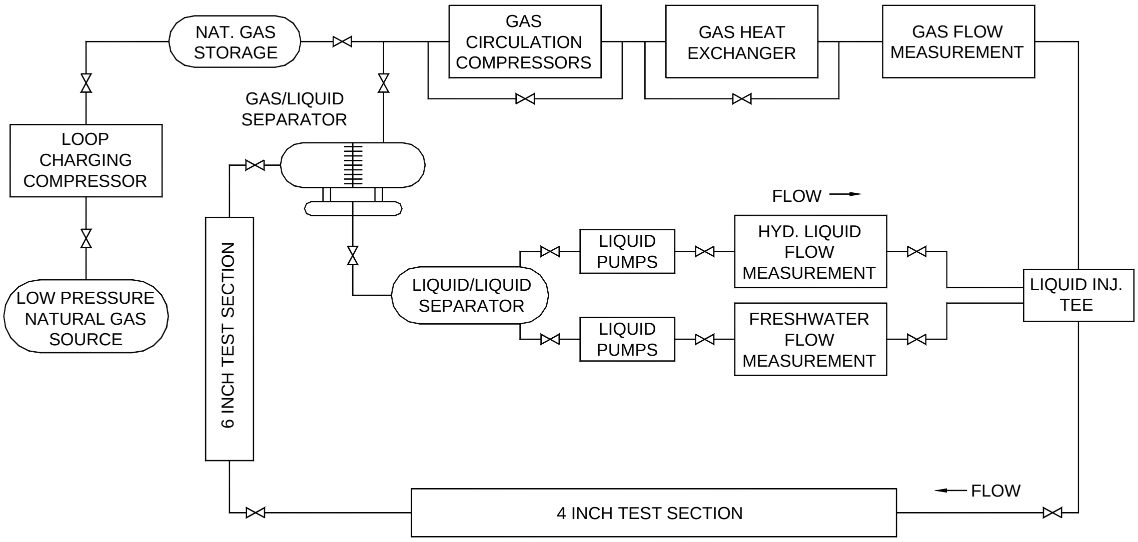

Figure 16: Block diagram of CEESI test facility

Liquid pumps then draw the two fluids from the liquid/liquid separator and the mass flowrate and density of each liquid is then measured. After the liquid flowrates are measured they are injected into the natural gas stream. Either the hydrocarbon liquid or water or both can be injected. With this arrangement, the water cut value can range from 0% to 100%.

Not shown in the above block diagram is a gas-fired liquid heat exchanger that heats the water and the hydrocarbon liquid to pipeline temperature before injecting them into the gas stream. The heating of the liquids is required during the winter months when the night-time temperature can be quite low and the stored liquid becomes cold. Both the gas/liquid separator and liquid/liquid separator are installed in a temperature-controlled building.

The test was performed as a blind test and was managed by BP and ConocoPhillips at the site. MPM handed over data to BP and ConocoPhillips on a daily basis. No reference data was provided to MPM until the entire test was completed and all data from the MPM meter was handed over to BP and ConocoPhillips. The test fluids used were Exxsol™ D80, gas from the supply network (mainly Methane) and fresh water.

The test matrix comprised 178 test points with a GVF range of 94 to 100% and water cut range from 0 to 100%, water volume fraction from 0 to 5.8%. The composition map of the test is shown in Figure 17 below.

The majority of the test points were with GVFs above 98% with an average GVF of 98.6% and an average water cut of 42% and average water fraction of 0.7%.

This was the first time the MPM meter was tested in water-continuous flow and fresh water. However, since the test facility at CEESI could only accommodate fresh water due to corrosion issues, it was not practically feasible to perform the test with salt water. The MPM meter is performing a dedicated measurement to classify whatever the liquid emulsion is oil- or water-continuous. In the event of a water-continuous emulsion and no salt in the water, this classification measurement could fail and introduce a systematic bias in the measurement. This was known to ConocoPhillips and BP prior to the test, however the cost of modifying the system to allow testing with salt water would have been substantial, and it was decided to use fresh water.

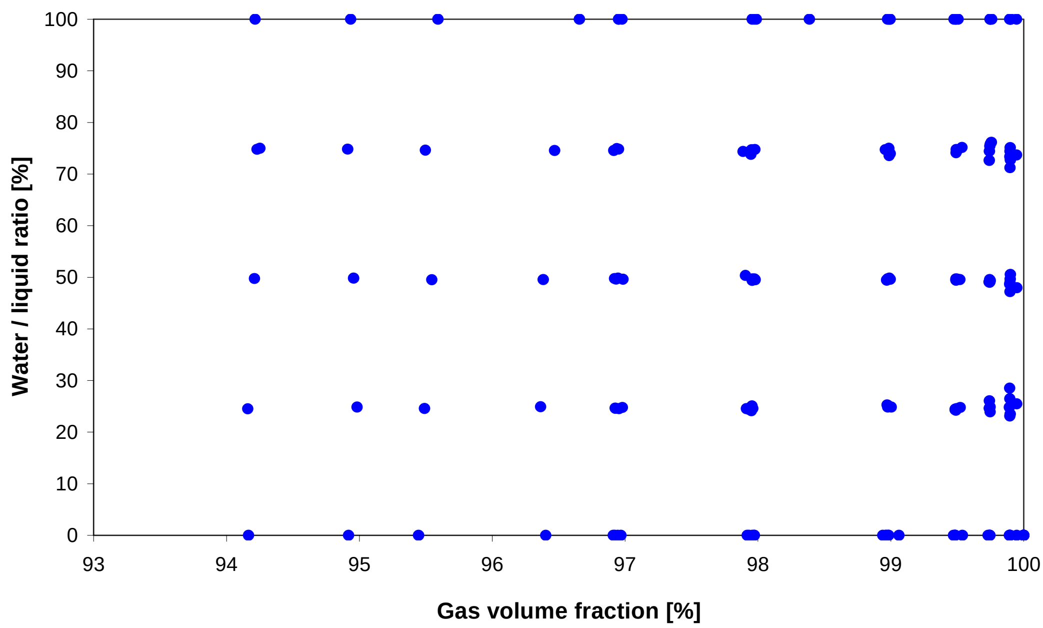

Figure 17: CEESI wet gas test matrix composition map

Prior to the test, the MPM meter was configured with the fluid data for the test rig. A characterised fluid composition was developed in Calsep PVTsim using a compositional analysis provided by CEESI from an Exxsol D80 sample taken from the separator and a gas chromatograph analysis of the gas. This was used to generate a typical fluid composition which was used to calculate look-up tables for oil and gas density, viscosity and surface tension. The same tables was used during the entire test. The meter was also configured to use the *in situ* measured gas fluid properties and measured water properties.

The meter was equipped with dual dP transmitters at the inlet of the Venturi and a single dP transmitter at the outlet. The inlet dP transmitter was ranged from 0 - 7000 mbar and the outlet dP transmitter was ranged from 0 - 2500 mbar.

Figure 18 shows pictures of the 74 mm MPM meter installed in the flow rig at CEESI. Comparison with Figure 5 shows some differences in the installation configuration, mostly due to the space constraints in the Alpine test building. Both installations have a horizontal bend prior to a blind tee leading vertically up through the meter, with a similar straight length between the blind tee and the meter.

Figure 18 : Pictures of MPM meter at CEESI

10 TEST RESULTS FROM CEESI

10.1 Gas flowrate

Figure 19 shows the measured gas flowrate vs. the CEESI gas flowrate in three-phase mode operation and Figure 20 shows the relative difference between the MPM meter and CEESI.

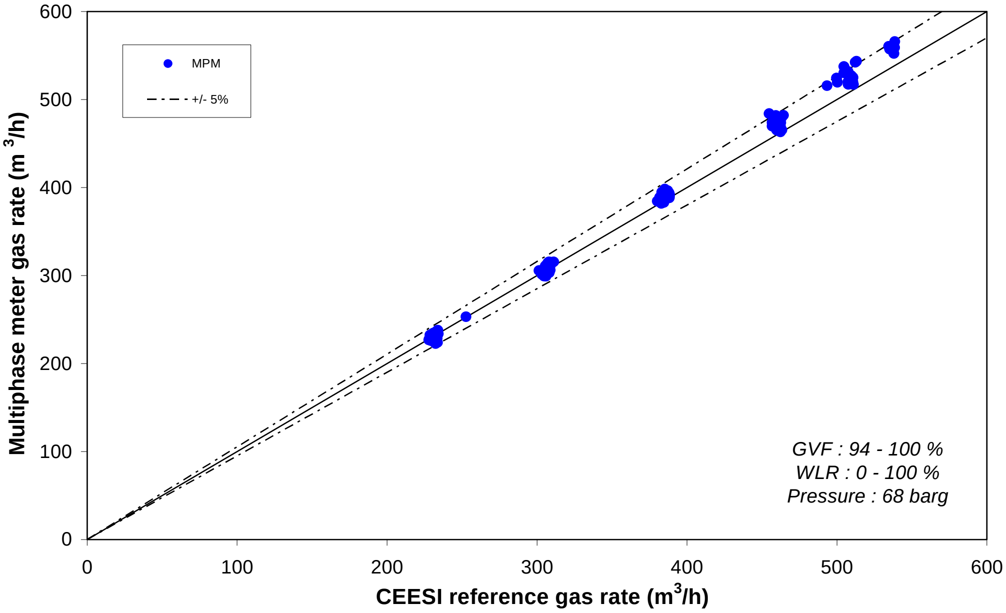

Figure 19 : MPM gas flowrate vs. CEESI gas flowrate

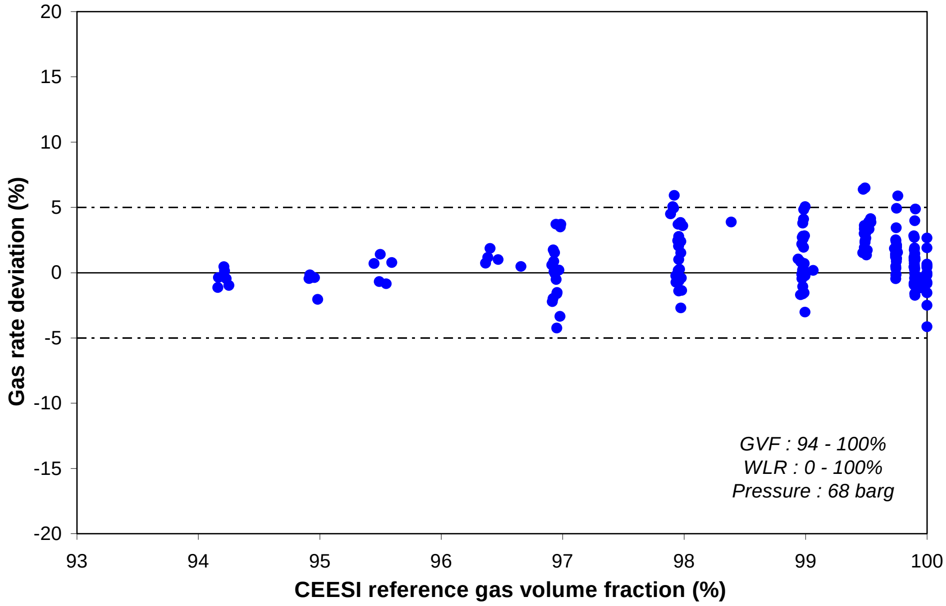

Figure 20 : Gas flowrate deviation vs. GVF

From Figure 21 it can be seen that the gas flowrate of the meter is within ± 3% of the CEESI reference when the Venturi dP is below 2700 mbar. For dPs above 2700 mbar there is a positive bias in the gas flowrate. The reason for this is that the dP transmitter at the outlet of the Venturi was ranged to 0 to 2500 mbar. For dPs above 2700 mbar on the inlet of the Venturi, the outlet dP is saturated, which introduces a larger uncertainty (and bias) in the gas measurement. A larger ranged dP transmitter at the outlet of the Venturi would have been more appropriate for this test.

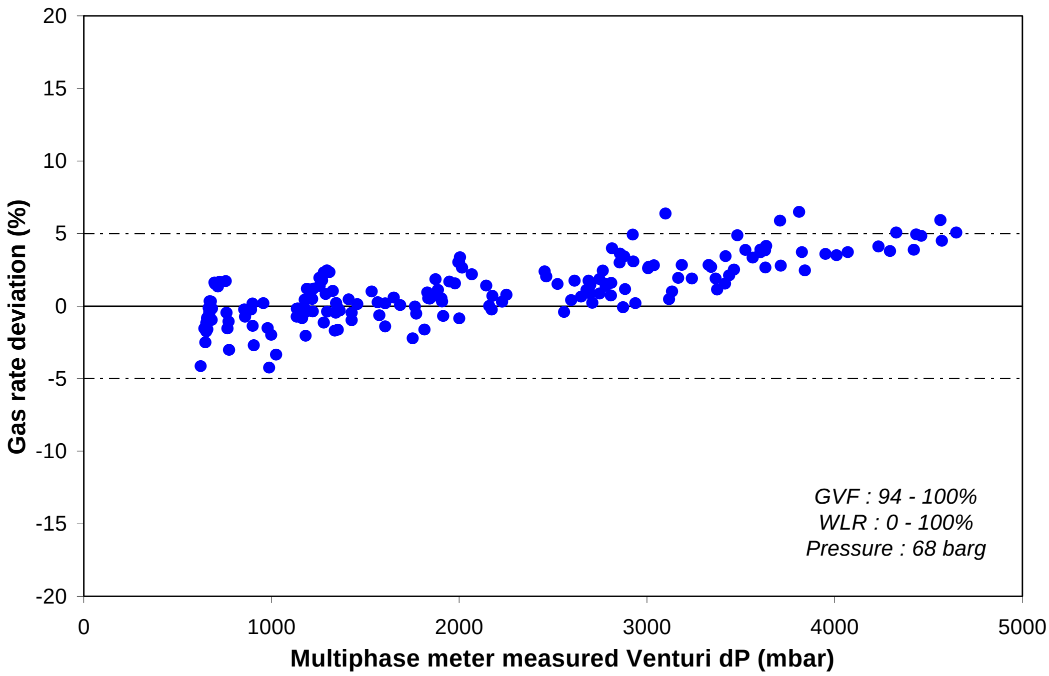

Figure 21 : Gas flowrate deviation vs. Venturi dP

10.2 Liquid flowrate

Figure 22 shows the measured liquid flowrate in three-phase mode operation. All the test points are within the greater of ±1m^3/h or ±10%.

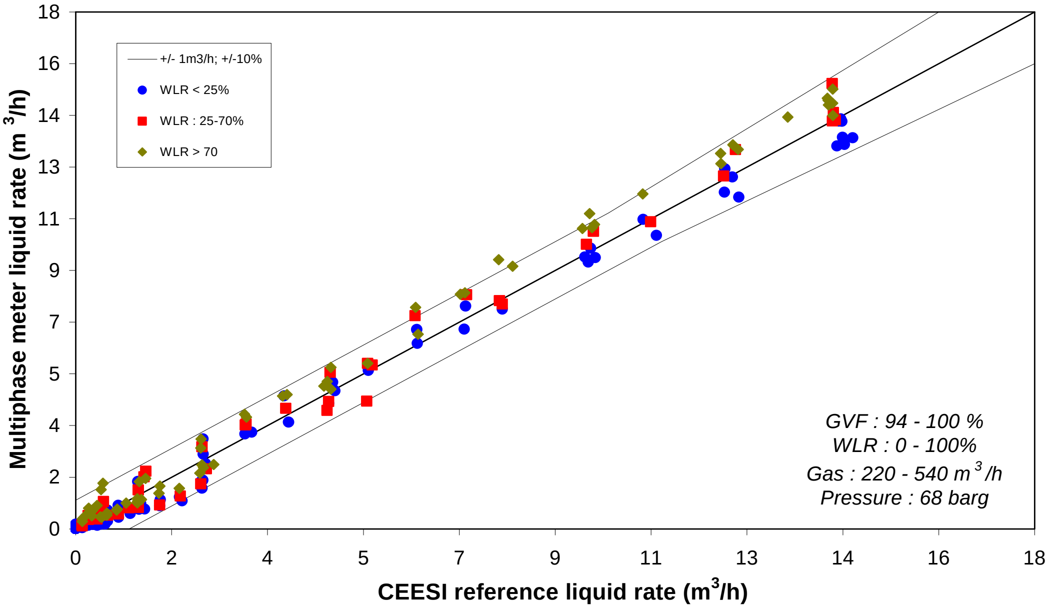

Figure 22 : MPM liquid flowrate vs. CEESI liquid rate

From Figure 23 it can be seen that the liquid flowrate is within ±1 m^3/h for most of the test points. The corresponding range of the gas flowrate is 220 to 540 m^3/h. For the test points with water cut greater than 70% (i.e. 75% water cut and 100% water cut), there is a small bias in the liquid flowrate of approximately 0.5 m^3/h. This bias is due to fresh water which causes misclassification of the emulsion type with a corresponding small positive bias in the measured liquid fraction of the wet gas.

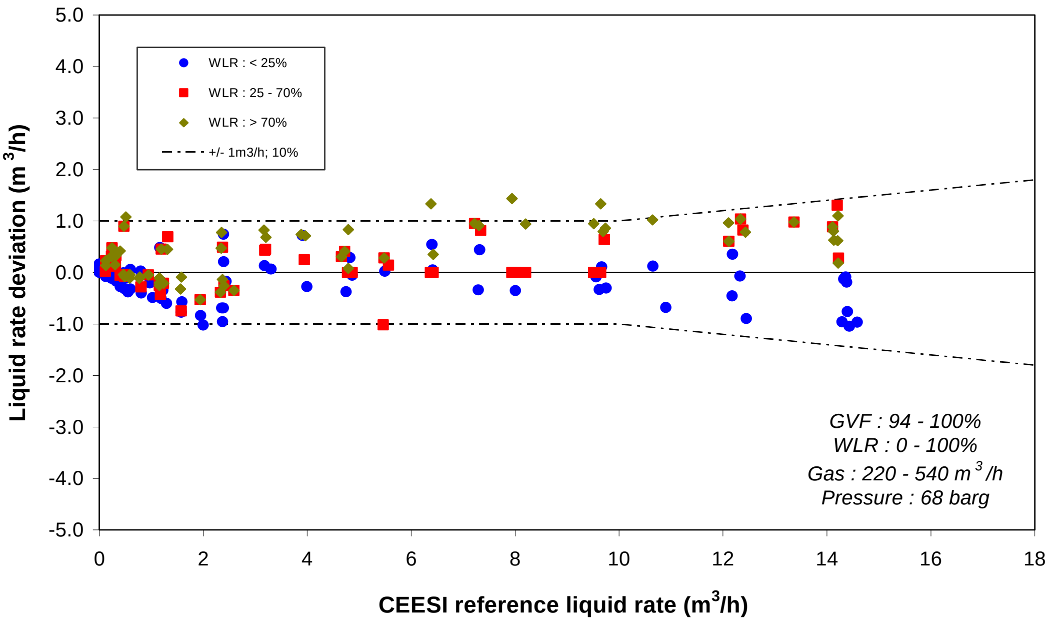

Figure 23 : Liquid flowrate deviation vs. liquid rate

10.3 Water flowrate

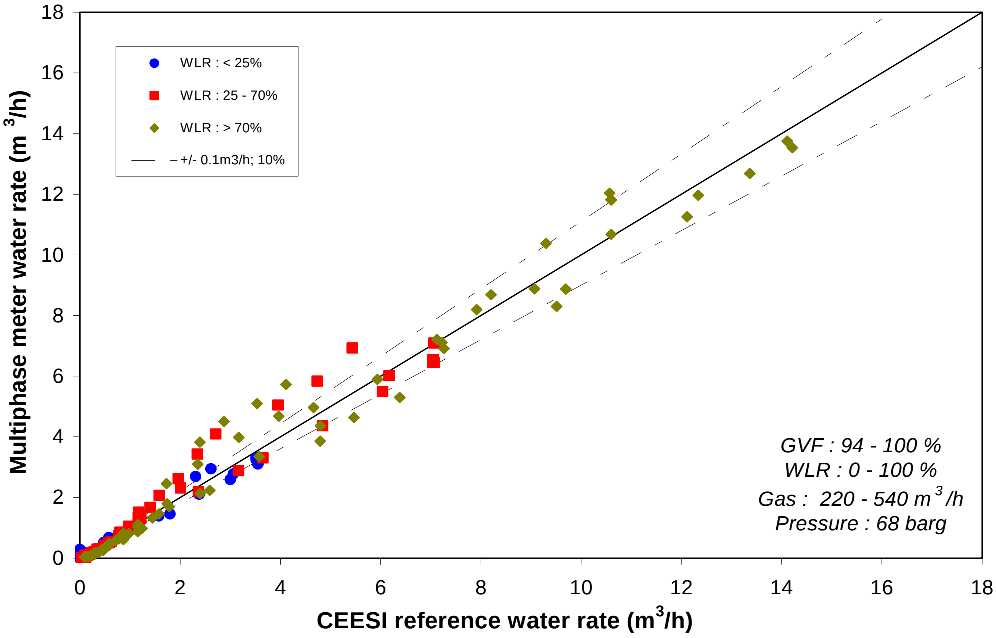

Figure 24 : MPM water flowrate vs. CEESI water rate (all flows)

Figure 24 shows the measured flowrate of the water for all the test points in three-phase mode operation and Figure 25 shows the measured flowrates of water for the lowest flowrates (below 2 m^3/h) in three-phase mode operation. The range for the water cut is 0 to 100% in the GVF range 94 to 100%, corresponding to a water fraction in the range 0 to 6%.

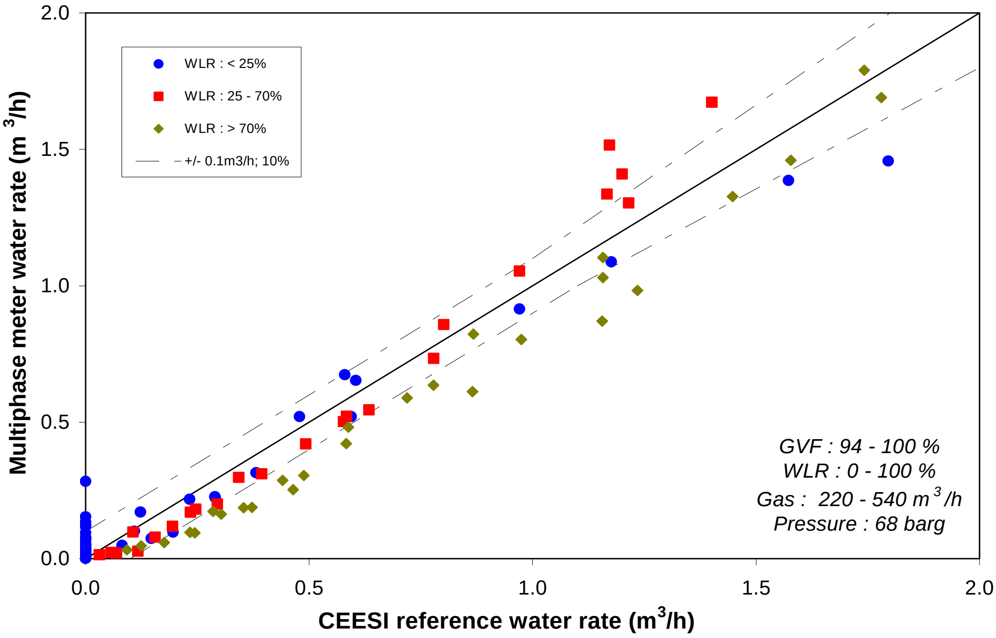

Figure 25 : MPM water flowrate vs. CEESI water rate (low range)

In general, the measured water flowrate is within the greater of ±0.1 m^3/h or ±10% for a gas rate in the range 220 to 540 m^3/h. There is a small bias in the water flowrate measurement for some of the high water cut test points. This bias is due to fresh water which causes misclassification of the emulsion type with a corresponding small positive bias in the measured liquid fraction of the wet gas.

There is also a small positive bias for some of the test points with zero water. One reason for this may have been that, although the reference flow measurements are zero, some water was still "trapped" in the test section upstream the meter and was slowly "cleaned out" through the meter.

At the lowest gas flowrates and highest liquid loadings (e.g. GVF of 94% and gas flowrate of 220 m^3/h) the meter indicated some instability in the flow which introduced a small positive bias in the water fraction measurement. However, as soon as more water was added to the flow, the water measurement increased instantaneously proportional to the amount of water injected into the test line.

Figure 26 below shows the difference (in m^3/h) between the measured water and the CEESI water flowrate vs. the water rate. Apart from a positive bias for some of the high water cut points and the points with no water (as mentioned above), there is a good linearity in the water flowrate measurement with a low spread. As seen from Figure 25 and 26, the spread and linearity in the water measurement is particularly low for low flowrates (below 2 m^3/h), which is valuable for early detection and measurement of formation water breakthrough.

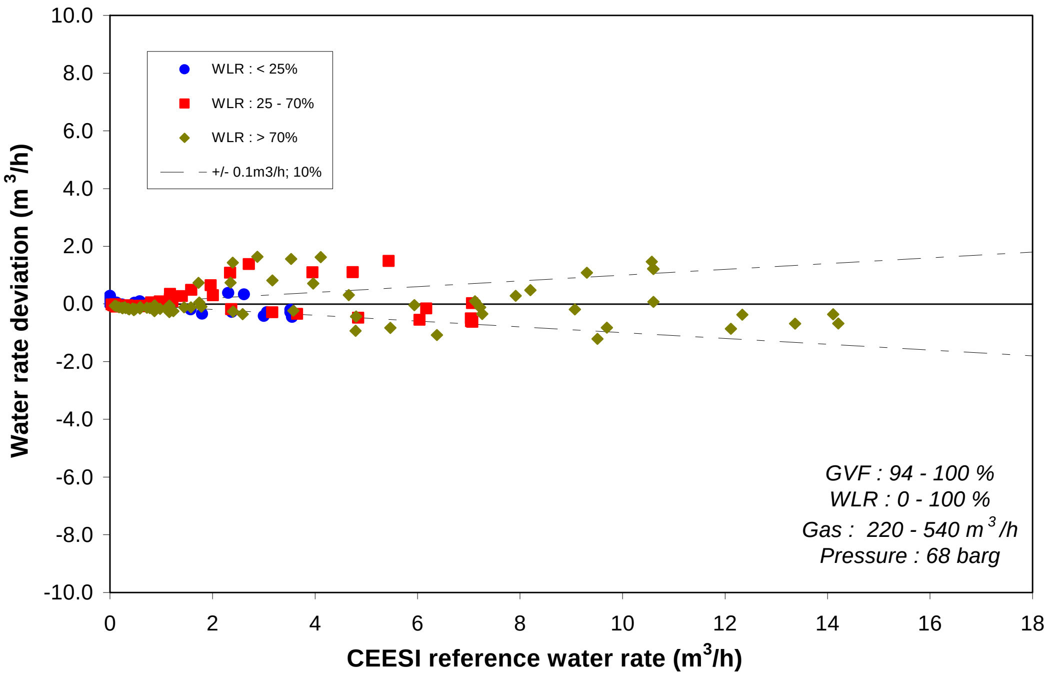

Figure 26 : MPM water flowrate deviation vs. condensate rate

10.4 Oil flowrate

Figure 27 shows the measured oil flowrate in three-phase mode operation. Apart from some of the cases with high water cut (water cut greater than 70%), the measured oil rate is within ±1 m^3/h or ±10% for a gas rate in the range 220 to 540 m^3/h. For the highest oil flowrates (more than 8 m^3/h), the condensate flowrate is within ± 5% of the CEESI measurement.

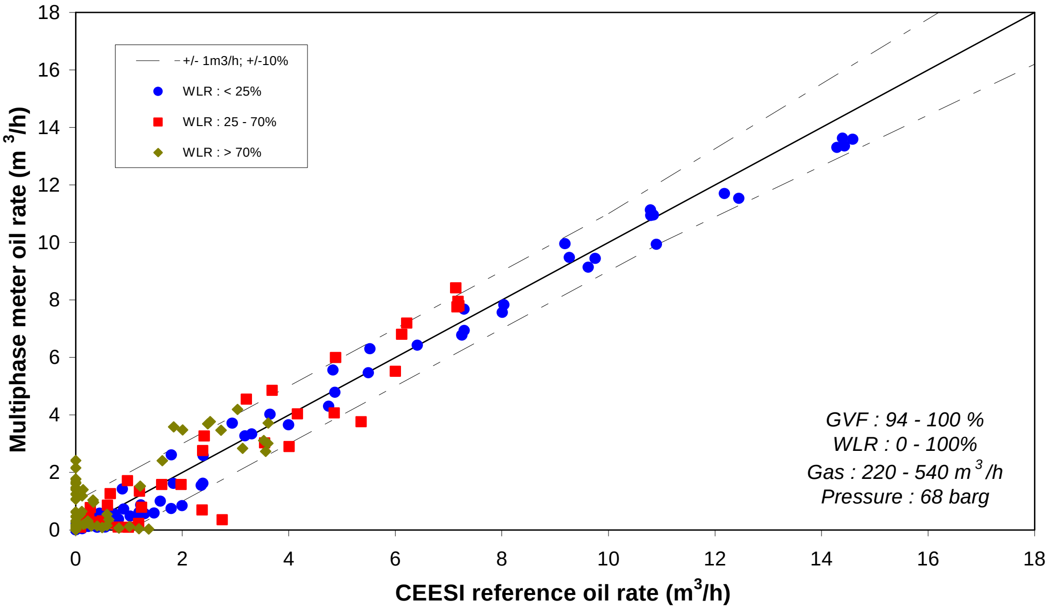

Figure 27 : MPM oil flowrate vs. CEESI oil rate

11 SUMMARY AND CONCLUSIONS

A multiphase flow field test of a 74 mm MPM meter was carried out at the Alpine CD1 well pad in Alaska followed by a wet gas laboratory test at the CEESI wet gas test facility in Colorado. The tests were performed as blind tests.

The MPM meter was a dual-mode multiphase and wet gas meter and was configured for automatic switching between multiphase and wet gas mode. The meter was also configured with a set of look-up tables, one for each test location (Alpine and CEESI). The meter was equipped with functionality for *in situ* measurement of fluid properties and proved to be tolerant towards errors in the fluid properties. No specific fluid sampling was performed or required prior to or during the tests, other than the composition data supplied for generation of look-up tables.

Table 2 below summarises the operating conditions at the two locations. It may be seen that the operating pressure, instantaneous GVF and fluid properties were very different for the two field locations, whereas the average GVF and average WLR was quite comparable.

Parameter	Unit	Alpine	CEESI
Operating pressure	Barg	10 - 14	68
Hydrocarbon liquid	-	Crude oil	Exxsol D80
Water salinity	% NaCl	2.1 to 2.7	Fresh water
Gas	-	Natural gas (formation gas and lift gas)	Gas supply network (mainly methane)
Average GVF	%	95.2	98.7
Instantaneous GVF	%	20 - 100	93 - 100
Average WLR	%	53.1	44.1
Instantaneous WLR	%	0 - 100	0 - 100
Flow conditions	-	Unsteady - slugging	Stable - annular / mist and stratified-wavy

Table 2: Summary table from test at Alpine and CEESI

Summarising the experience from the test at Alpine, Alaska:

- The multiphase meter was installed upstream and in series with the test separator at the Alpine field.
- The test comprised 88 well tests on 16 wells and 880 hours of flow.
- The average GVF range was 88 to 99% with an average water cut range from 20 to 93% at an average operating pressure of 12.5 barg.
- Several wells were considered stable, about half were unstable and exhibited severe slugging and several were highly unstable. Slugging and unstable wells showed short periods of multiphase flows and longer periods of wet gas flows (GVFs greater than 90%).
- The CD1 test separator appeared to work well. Metering of liquid and gas using Coriolis meters was good, and diagnostics from the Coriolis meter indicated good gas/liquid separation efficiency. Water cut monitoring using a microwave water cut detector was less satisfactory and was supplemented using density based Net Oil computing.
- The MPM meter performed without problems or intervention during the test.
- Using the *in situ* measured gas density (instead of the PVT calculated value), removed a 5% bias in the observed gas mass flowrate measurements.
- The largest liquid flowrate errors were observed at the extremes of the dP cell range including both low and high flowrates. In two wells, during slug flow, the dP cell exceeded the 5000 mbar limit, which saturated. On these wells the dP was clipped at 5000 mbar and the flows under-metered. This highlights the importance of correct meter sizing for the dynamic range of the flow conditions, and it is noted that the initial review of the application suggested that two sizes of meter would be required to cover the full range of well rates at Alpine CD1.

The test experience at CEESI, Colorado is summarised as:

- The same meter was then tested at CEESI.
- 178 test points were performed in wet gas flow conditions .
- The GVF range was 94 to 100% and the water cut range from 0 to 100% at an operating pressure of 68 barg.
- Flow regimes upstream of the meter were predominantly annular or annular-mist flow, with some stratified-wavy flow at the lowest gas flowrates and higher liquid loadings
- Gas rate was within ±5% over the entire tested flow range. For flowrates within the designed operating range (less than 2500 mbar), the gas rate was within ±3%. A larger range for the Venturi recovery dP transmitter would be required to reduce the uncertainty of the gas rate for Venturi dPs above 2500 mbar.
- The liquid flowrate was generally within ±1m^3/h or ±10%, although in some high water cut tests, testing with fresh water is considered to have caused over reading of the liquid flowrate.
- The water flowrate was generally within ±0.1m^3/h or ±10% for the entire gas rate range (220 to 540 m^3/h).

Based on the tests at both field locations, the following conclusions can be made:

- There was no verification or tuning to the test separator during commissioning and the test. This data represents a true blind test of the meter.
- The same meter hardware and software was used in both tests. The only difference was the fluid property look-up tables and the range of the Venturi dP transmitter.
- The impact of correct differential pressure transmitter sizing on the operating envelope of the meter was demonstrated.
- The wet gas testing at CEESI was limited to testing with fresh water; further testing with more representative water chemistry would be of value.

Data from the Alpine field test was used by ConocoPhillips to support a request for authorisation to use the MPM multiphase meter for well testing and production allocation at the ConocoPhillips operated Colville River and Kuparuk River Units, which was approved by the Alaska Oil and Gas Conservation Commission (AOGCC) in June 2010.

ACKNOWLEDGEMENTS

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