Custody transfer metering of unprocessed gas? Experience from testing a subsea ultrasonic flowmeter in a multiphase compressor test facility

Rolf Rustad, Emmanuel Lagrand, Harald Solheim, Magne Aanes, SLB OneSubsea
Gregor J Brown, Sensia

1 INTRODUCTION

Custody transfer metering of unprocessed, wet natural gas would enable large simplifications of many subsea gas production projects, for instance by enabling tie-in of new gas fields to existing subsea gas production infrastructure. Wet gas ultrasonic metering has been a topic of research for decades (see for example Beecroft et al. [1]), but the technology has never matured to the point of widespread practical implementation.

At the 41st Global Flow Measurement Workshop, we presented a subsea ultrasonic flowmeter (USM) and results from testing this with natural gas at an accredited calibration facility [2]. This test demonstrated the ability of the subsea ultrasonic flowmeter to meet the requirements for custody transfer metering of dry natural gas. In this paper we will discuss the feasibility of extending this technology to custody transfer metering of unprocessed gas subsea.

OneSubsea also manufactures wet gas compressors for subsea gas production. An 8-path 16-inch subsea ultrasonic flowmeter has been included in a wet gas compressor test loop where it has been exposed to wet gas flow over a wide range of flow rates and operating conditions. Experience from this testing will illustrate some opportunities and challenges of using a subsea ultrasonic flowmeter for custody transfer metering of unprocessed gas.

2 THE BUSINESS RATIONALE

Offshore gas fields are typically developed as tiebacks directly to shore or with floating processing facilities where the gas is processed for use or export. Both approaches typically involve capital investments amounting to several billion dollars. Large savings could be realized if new gas discoveries could be tied into existing infrastructure instead of building a new pipeline to shore or new floating processing facilities. This would require custody transfer metering of unprocessed gas on the seafloor unless the new field has the same ownership as the already developed field. Limitations in available metering technology for this purpose have so far prevented this approach.

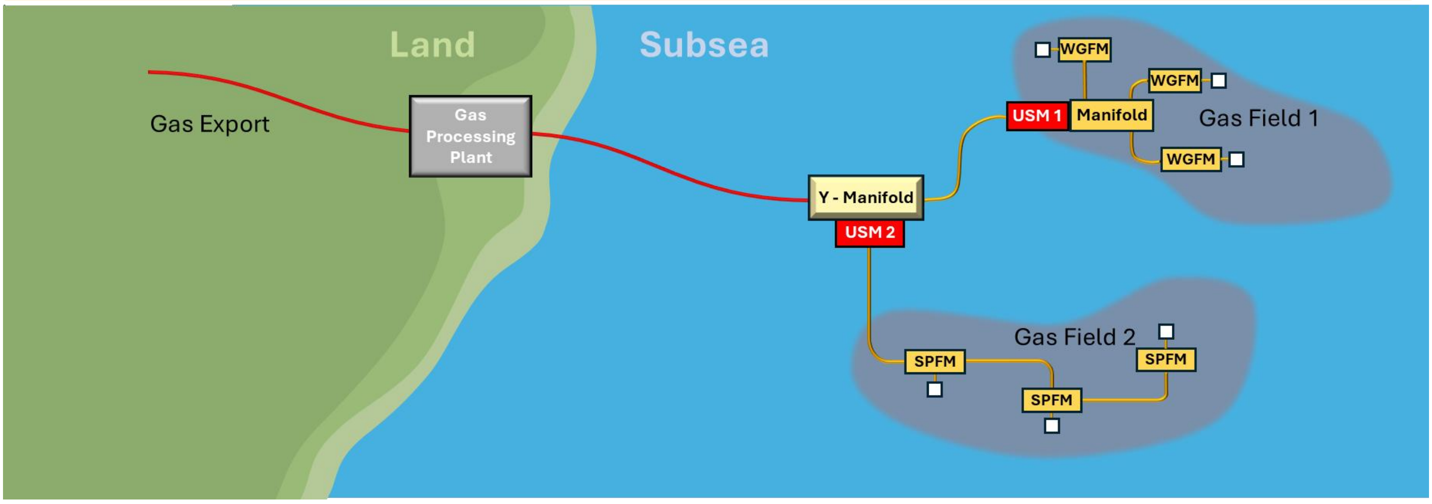

Figure 1 Two offshore gas fields sharing one flowline to shore.

3 THE SOLUTION

Ultrasonic flowmeters are widely used for custody transfer metering of processed gas. Using ultrasonic flowmeters for custody transfer metering of unprocessed, wet gas has been a topic of research for decades [1], but the technology has never matured to the point of widespread practical implementation. The introduction of a subsea ultrasonic flowmeter [2] is an opportunity to re-visit the feasibility of custody transfer metering of unprocessed gas driven by the large economic savings that could be enabled. Much of the earlier research in this area has focused on developing a two-phase ultrasonic flowmeter [3][4], with other studies focused on gaining a generalized understanding of meter over-reading behavior [5]. It has been attempted to determine the liquid fraction from the ultrasonic flowmeter's diagnostic data [3], or to measure it directly by measuring the position of the gas-liquid interface in stratified flow [4]. Both approaches have proven to be challenging. First, it is difficult to determine the fraction of liquid carried as dispersed droplets in the gas versus the fraction flowing at the bottom of the pipe or on the pipe wall. The liquid velocity is closer to the gas velocity in the case of dispersed droplets and substantially lower when the liquid is flowing on the pipe wall or in the bottom of the pipe. The over-reading of the gas velocity depends on how the liquid is distributed between the two. Second, the gas-liquid interface is rarely so well defined that it can be reliably identified by a pulse-echo measurement. This limits this approach to fully developed stratified flow at low velocities [4].

Figure 2 A 16-inch subsea ultrasonic flowmeter.

Our proposed solution to these challenges is threefold:

- Determine the liquid fraction from external data
- Control the flow conditions and validate performance at those conditions
- Limit the range of operating conditions with respect to liquid fractions and flow velocities

We believe the over-reading of the ultrasonic flowmeter is predictable and can be corrected under these circumstances. What remains, is to determine whether the residual measurement uncertainty is acceptable for custody transfer metering and the operating conditions at which the required measurement performance can be achieved.

3.1 Determining the Liquid Fraction

Ultrasonic gas meters over-read the gas rate when there is liquid in the gas. The mechanism is fundamentally different from the over-reading occurring in differential pressure-based meters, where the differential pressure is increased due to the increased effective mixture fluid density and additional elements of energy conversion [6]. The over-reading in an ultrasonic flowmeter relates to the reduction in flow area available to the gas because of the blockage caused by the liquid. The velocity difference, or slip, between the gas and the liquid can make the liquid hold-up much larger than the liquid volume fraction, so this blockage and the corresponding over-reading can be substantial even at low liquid volume fractions, though typically less than the over-reading in a differential pressure meter. The reduction in available flow area causes the gas to flow more quickly. Ultrasonic meters measure the increased gas velocity and normally multiply it with the assumed full flow cross-sectional area, causing an over-reading unless a correction is applied.

The first step of correcting the over-reading is to determine the liquid fraction. Liquid in unprocessed natural gas may have one of the following origins:

A. Hydrocarbons that are liquid in the gas bearing formation and that are produced with the natural gas
B. Water in the liquid state in the gas bearing formation and that is produced with the natural gas, also known as formation water
C. Hydrocarbons that are gaseous in the gas bearing formation and that condense into liquid hydrocarbons, also known as condensate
D. Water that is vapor in the gas bearing formation and that condenses into liquid water
E. Liquid chemicals that are injected into and mixed with the natural gas and other liquids present in the natural gas, for example Mono Ethylene Glycol (MEG) which is injected to prevent the formation of hydrates in the gas

It is not possible to calculate the volume of liquid that is liquid in the formation and that is produced with the gas, cases A and B in the list above, from the gas rate measured by a gas meter. This has to be measured individually, normally by well-head installed wet gas or multiphase flowmeters. The measured liquid rates may be sufficiently accurate to be used as input in a correction algorithm in an ultrasonic flowmeter, but this depends on several factors that require detailed analysis in each case. This scenario will not be discussed further in this paper.

The volume of liquid that is condensed from the gas phase, cases C and D, can normally be calculated quite precisely from the gas volume provided the gas composition is known. Downhole gauges that measure pressure and temperature at or near the sand face may improve the accuracy of these calculations.

Injected liquid chemicals, case E, can be metered accurately at the point of injection, for example by using Chemical Injection Metering Valves. The challenge in this case is to know when the injected liquid will reach the metering point. This uncertainty can be reduced by placing the injection point as close as possible to the metering point and avoiding slug-generating piping elements such as goose necks in the piping between the two points. These challenges are best managed during the system design phase and can be avoided altogether if the chemical injection can be placed downstream the metering point.

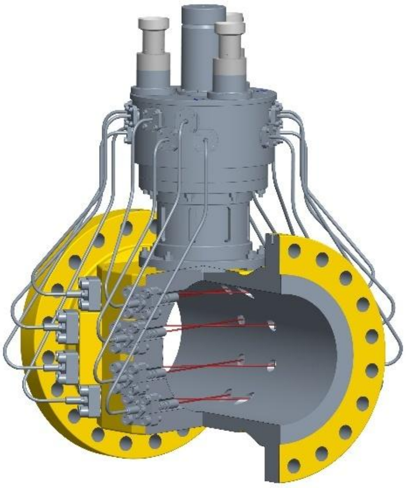

Figure 3 Subsea ultrasonic flowmeter with horizontal paths.

3.2 Flow Conditions and Flow Rates

The proposed solution utilizes a multi-path ultrasonic flowmeter installed horizontally with a horizontal straight pipe at the inlet. The multi-path ultrasonic flowmeter is oriented with the paths in vertically separated horizontal planes as shown in **Figure 3.**

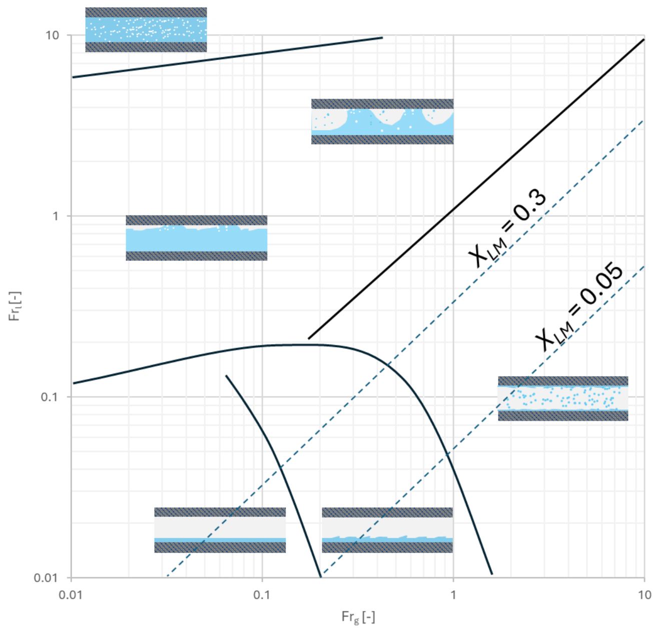

Figure 4 Flow regime map, adapted from Taitel and Dukler [6].

The flow regimes of wet gas flow in horizontal pipes can be mapped in different ways. shows a mapping versus densimetric liquid and gas Froude numbers as described by Taitel and Dukler [6]. In the area where the densimetric liquid Froude number is less than 0.1 and the densiometric gas Froude number is less than 1, a fully developed flow will be stratified or wavy stratified with very little liquid dispersed in the gas phase. In this case, calculating the over-reading is reduced to finding the liquid hold-up as a function of the Gas Volume Fraction. In many cases, it will be possible to condition the flow to this area of the flow regime map by sizing the flowmeter and the upstream flow line appropriately and allowing sufficient length of straight horizontal pipe to allow the flow to develop fully.

A second limitation is relating to the liquid loading, or 'wetness', which often is expressed in terms of the Lockhart-Matrinelli parameter X_{LM} [8]. An upward limit of $X_{LM} < 0.3$ is indicated in the figure above and is commonly used as a border between wet gas and multiphase flow. Further research and testing are required to determine whether this is a reasonable limit for custody transfer metering of unprocessed gas, but it should be noted that many offshore gas fields produce gas with much lower Lockhart-Martinellli numbers even after the addition of chemicals for flow assurance purposes. Values below 0.05 are not uncommon.

4 FLOW TESTING

OneSubsea is manufacturing wet gas compressors for subsea gas production. A test facility for these compressors is in operation at the OneSubsea plant at Horsøy outside Bergen. A series of compressor tests was carried out in December 2024 and January 2025. This presented an opportunity to test a subsea ultrasonic flowmeter at a wide range of flow rates, liquid loads, and pressures.

4.1 Test Meter

The test meter is the same 16” subsea ultrasonic flowmeter that was used in the test that was presented at the 41st Global Flow Measurement Workshop in 2023 [2]. This is the 8-path 16-inch meter shown in **Figure 2**. The calibrated range of this meter in gas flow is 0.3 to 30 m/s, corresponding to a range of flow rates from 112 m^3/h to 11,200 m^3/h.

The diameter of the flow path and the position of the acoustic paths are of particular interest to the present discussion. The flow path has a diameter of 363.58 mm. The acoustic paths are positioned above the bottom of the measurement cross-section as shown in **Figure 5**.

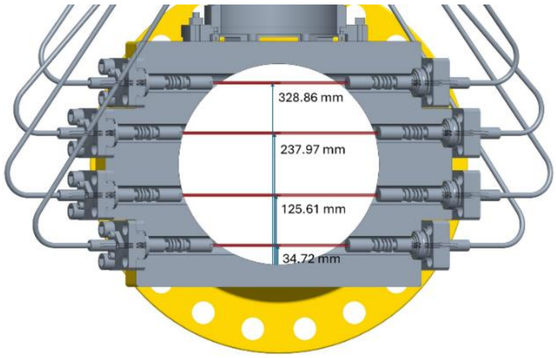

Figure 5 Cross section of the tested meter showing the position of each path.

The meter outputs a number of diagnostic parameters per path that can be used to infer additional information about the liquid loading, such as the Gain, the Signal to Noise Ratio (SNR), and the Performance, the latter being the percentage of transmissions that are successfully detected. Zanker and Brown [3], and Harman et al [7] provide examples of how these can be utilized in wet gas.

4.2 Test Facility

A simplified process flow diagram and a photo of the compressor performance test loop are shown in **Figure 7**. The test fluids are nitrogen and Exxsol D80. The test loop comprises a large gas scrubber that provides very good separation of the fluids downstream the location of the subsea ultrasonic flowmeter. Gas and liquid are then metered individually before they are mixed upstream the compressor. The primary reference meters are calibrated V-Cones. The subsea ultrasonic flowmeter is placed in the piping between the compressor outlet and a set of choke valves that control flow and backpressure. The flow is cooled in heat exchangers before being returned to the scrubber.

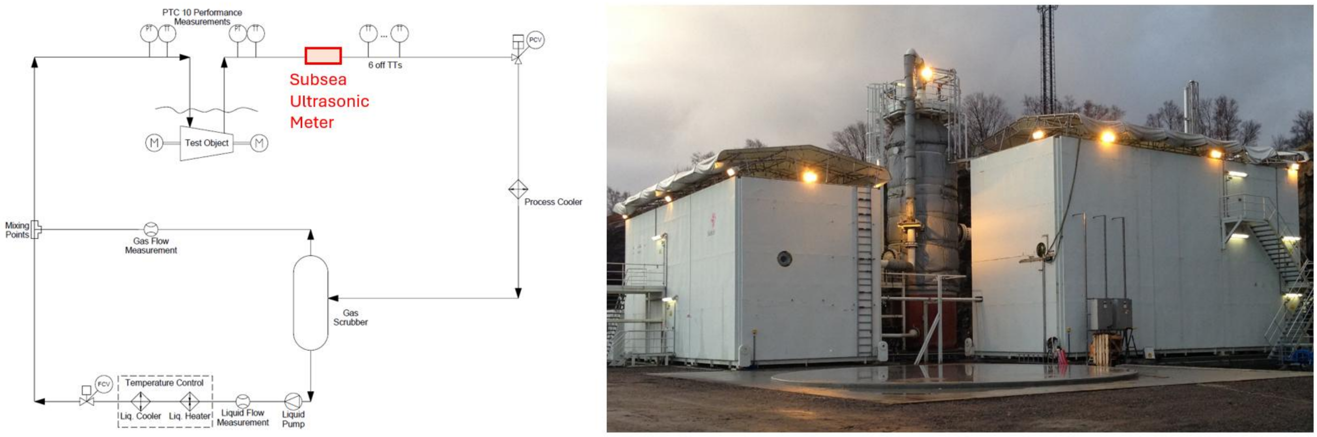

Figure 7 The compressor performance test loop. A simplified Process Flow Diagram indicating the position of the Subsea Ultrasonic Flowmeter to the left, and a photo to the right. The compressors are placed on the circular concrete slab in the front. This forms the bottom of a large water tank with a removable wall so that the compressors can be submerged during testing, see **Figure 8**.

The ultrasonic flowmeter was placed at the discharge side of the compressor outside the water tank. It is preceded by a long section of horizontal 10-inch pipe as shown in **Figure 8**. The connection is an excentric expander from the 10-inch pipe to the 16-inch meter body so that the bottom of the flow path through the subsea ultrasonic flowmeter is flat. It should be noted that the ultrasonic flowmeter is on the opposite side of the compressor from the reference meters, thus operating at very different conditions. The reference volumetric gas rates are calculated from the reference mass rates and the gas density at the location of the ultrasonic flowmeter. This test arrangement is not ideal from a measurement point of view, and the uncertainties of the reference rates are larger than in more conventional metering loops, but it was the best arrangement that could be achieved within the budget and time constraints of the project.

4.3 Test Conditions

The main purpose of including the Subsea Ultrasonic Flowmeter in this test campaign was to expose it to a wide range of flow rates and gas volume fractions at realistic pressures and temperatures. The main parameters of the test compressor test program are summarized in **Table 1**.

Table 1 Range of test parameters at the location of the ultrasonic flowmeter during compressor testing.

Variable	Units	Range
Pressure	bar	35 – 55
Temperature	ºC	10 – 110
Gas rate	m^3/h	2000 – 9000
Liquid rate	m^3/h	0 – 350
Flow velocity	m/s	5 - 20
Gas Volume Fraction	%	94 - 100

Three different compressors were tested in four different test campaigns producing a total of 72 flow points. We can map the range of test conditions onto the flow condition map as shown in **Figure *9***. We see that the majority of the test points lie outside the region of well-defined stratified flow and that the test conditions used in the analysis extend well into the area of annular-dispersed flow.

Figure 8 Location of the test meter outside the water tank where the compressors are submerged. Note the long horizontal pipe upstream the meter.

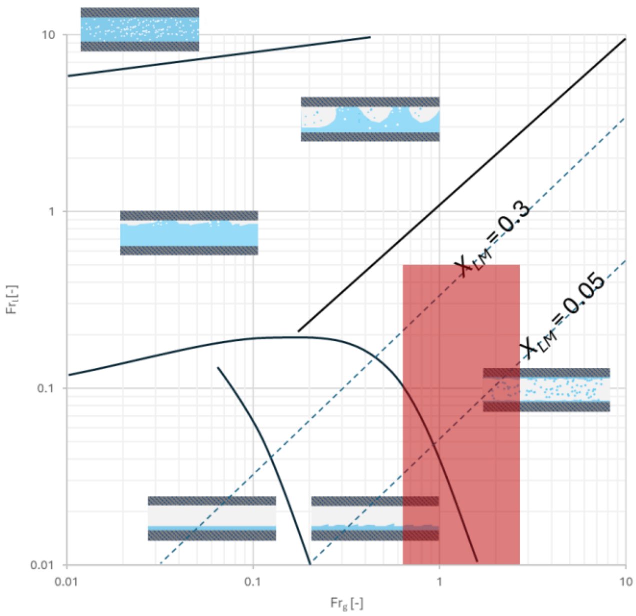

Figure 9 Flow condition map with the range of test conditions used in the analysis overlayed in red.

4.4 Test Results

The first result is purely qualitative: The subsea ultrasonic flowmeter produced flow rate results at all wet gas conditions, including the test points with very high liquid loading and corresponding low Gas Volume Fraction. An example is shown in **Figure 10**, which shows the USM (blue line) and reference flow (orange line) rates overlayed with the Liquid Volume Fraction LVF in % and the number of working acoustic paths. The definition of the latter is that at least 50% of attempted signal transmissions are successful. The data were acquired over an 8-hour period. The pressure is in the range 31 – 52 bar and the temperature 50 – 100ºC. The over-reading is stable and systematic even when more than half of the paths are non-functional.

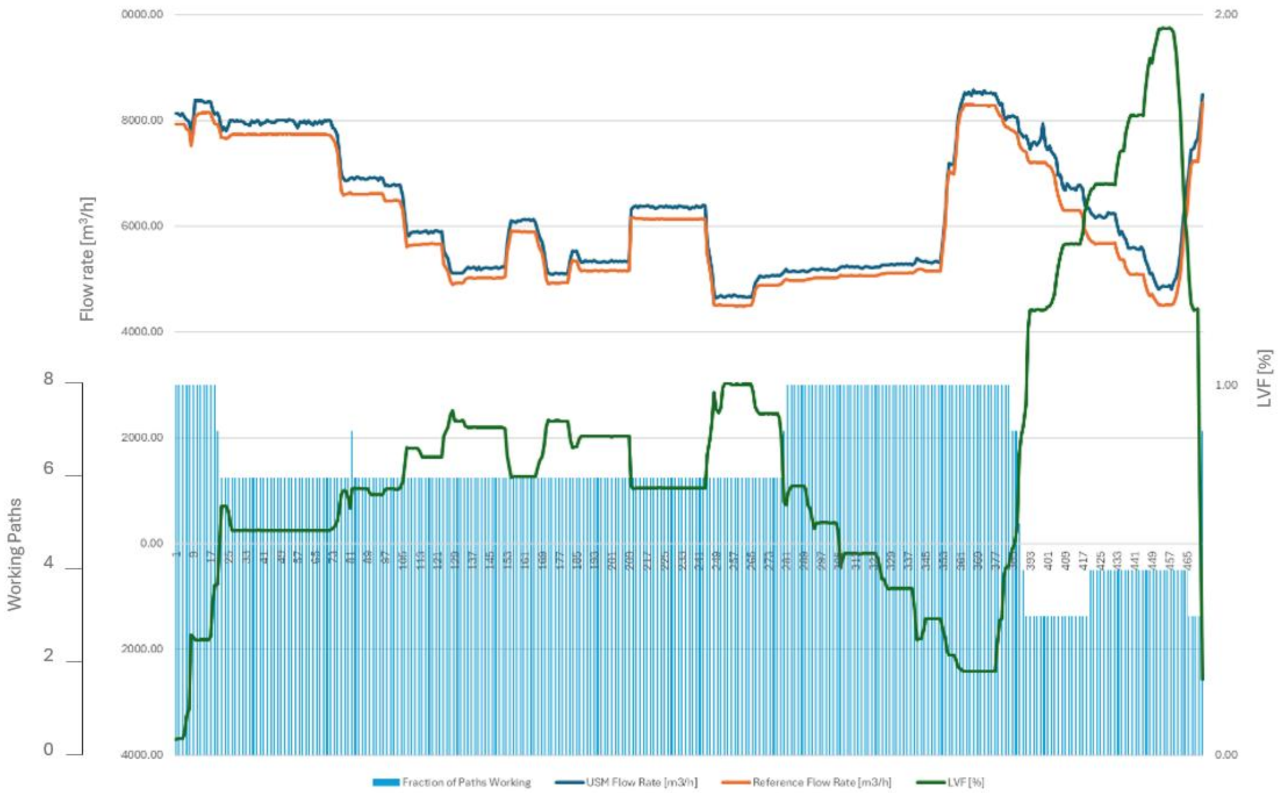

Figure 10 Example of wet gas flow periods showing the USM and Reference gas rates on the left-hand axis overlayed with the number of working paths on the second left-hand axis and the Liquid Volume Fraction (LVF) in % on the right-hand axis.

A more systematic analysis of the performance of each path reveals that as the liquid fraction increases, the 2 lower paths stop working first (paths 4 & 8) followed by the second-to-lowest (paths 3 & 7). The top paths showed robust performance at all liquid loads. The most likely reason for the lower paths not working, is that liquid is pushed upwards on the inner diameter of the flow path and into the transducer pockets. This can cause increased acoustic noise coupling between the transducer meter body, and in the extremes wetting of the transducer face will result in refraction of the signal path. The combination of these effects is to reduce the signal-to-noise ratio to a level below the rejection threshold set in the software. The 16-inch subsea ultrasonic flowmeter used for the test does not feature drain holes in the transducer pockets to prevent this, and it is likely that the addition of such drain holes would make the meter more tolerant to liquid loading.

Figure 11 shows the Error, meaning the difference between the gas rates reported by the USM and the reference gas rate, versus GVF and Densimetric Froude number for all 72 flow points that have been analyzed. The results should be seen in light of the uncertainty of the reference rates as explained above. As expected, the error increases with increasing liquid load and decreases as the Densimetric Froude increases past a certain threshold when more liquid is entrained in the gas. The magnitudes and trends of these errors largely agree with results from earlier wet gas testing with ultrasonic flowmeters, see for example Putten et al. [5].

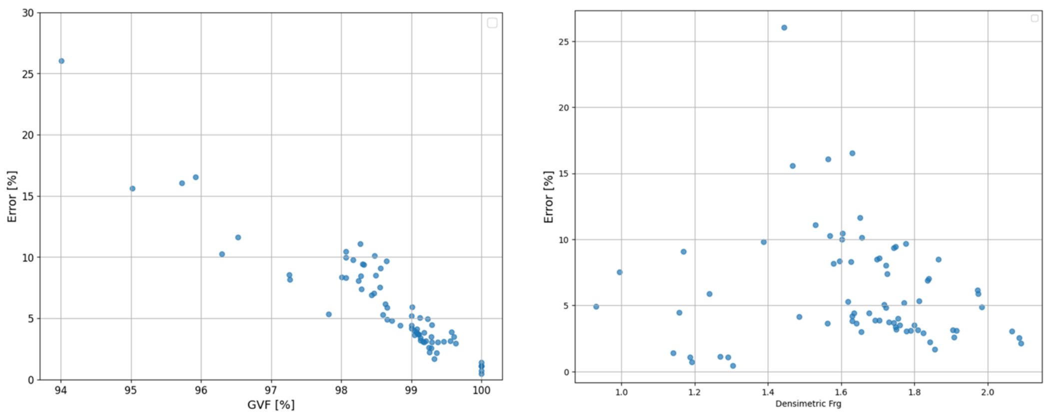

Figure 11 Error in % vs. GVF (left) and Densimetric Froude number (right) for all 72 flow points.

4.5 Correction Models

The authors are developing a proprietary model for the correction of the over-reading. This model is work in progress and will not be described in detail in this paper. We still think it is of interest to include some preliminary results produced by applying this model to the data acquired during the compressor testing, with the understanding that the model will be improved and developed further as more data become available from flow tests with more appropriate reference meters. For the time being, the model is limited to GVF > 98% and takes GVF and process pressure as inputs, as described in section 3.1 above.

The model contains several empirical parameters. The performance has been evaluated by deriving these parameters using data from testing of one compressor and then calculating the P95 value for the residual error for all the data points in one set of flow points, first when applying the model to the same data set, and second by applying it to the data sets acquired during testing of other compressors. An example of the former is shown in **Figure 12**. The P95 value for the residual errors in this data set is 1.7% after correction compared to 8.7% for the uncorrected data

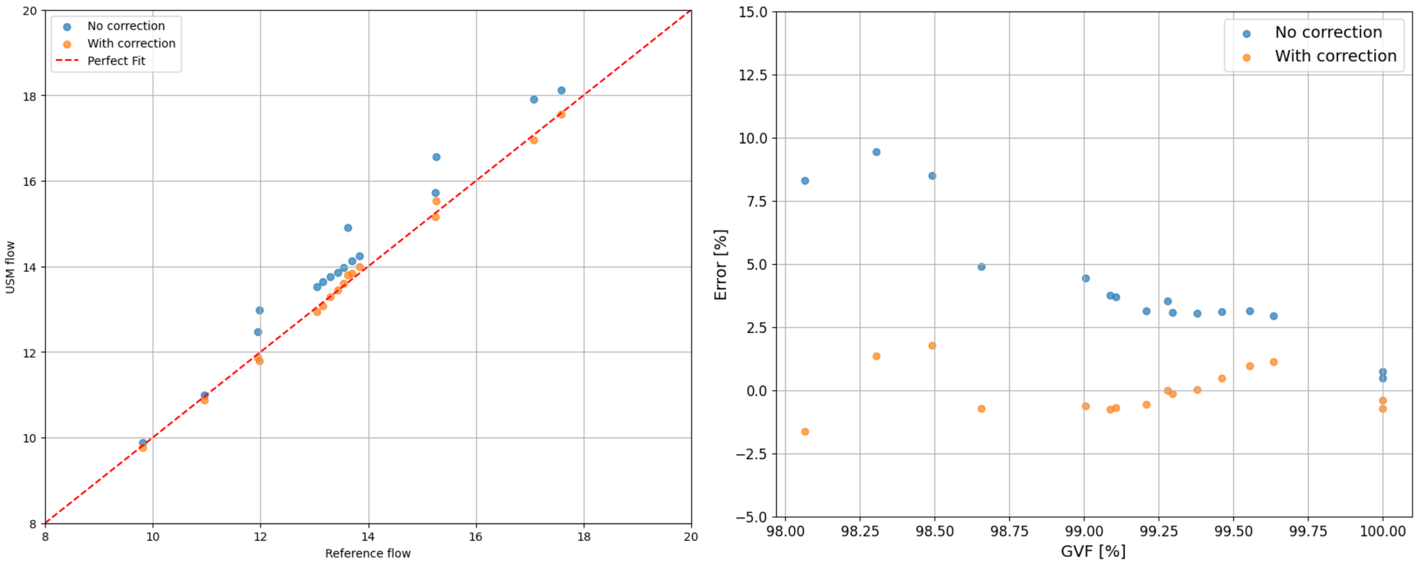

Figure 12 Performance of the correction model evaluated on the same data as it was derived from.

The residual errors increase marginally when the model is applied to data acquired while testing different compressors with P95 values of 1.7% (**Figure *13***) and 3.2% (**Figure *14***) respectively. A P95 value in the range 1.2 – 3.4% with different correction models is observed across all four test periods with the three different compressors.

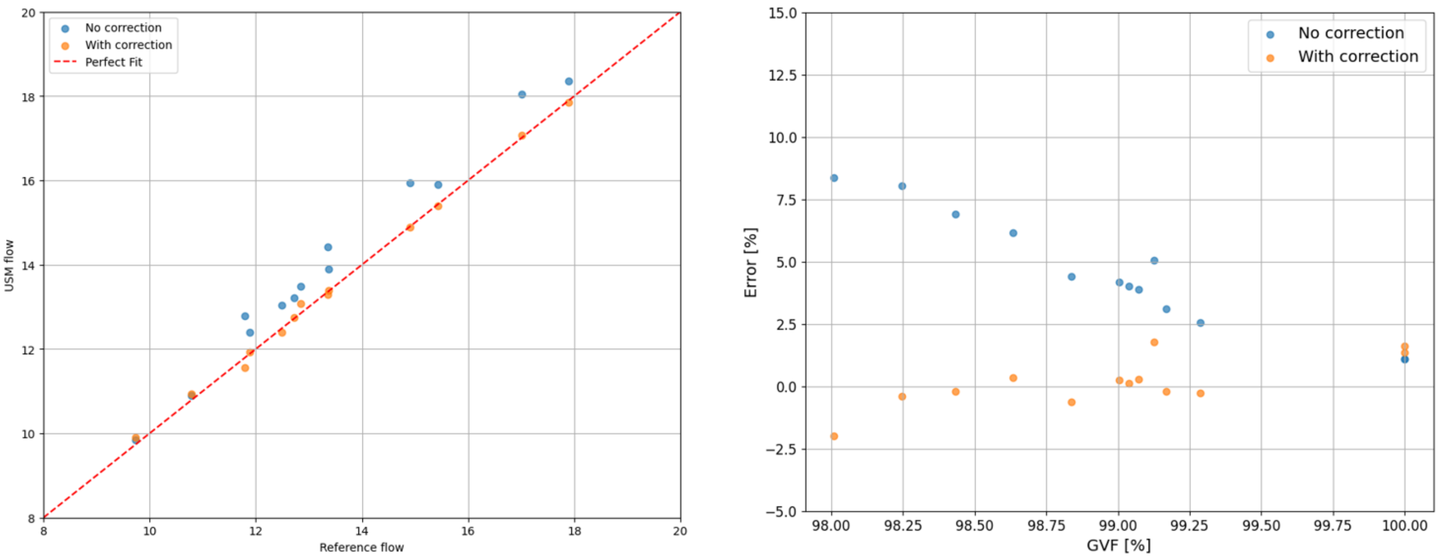

Figure 13 Performance of the correction model applied to data acquired during testing of a different compressor (1/2)

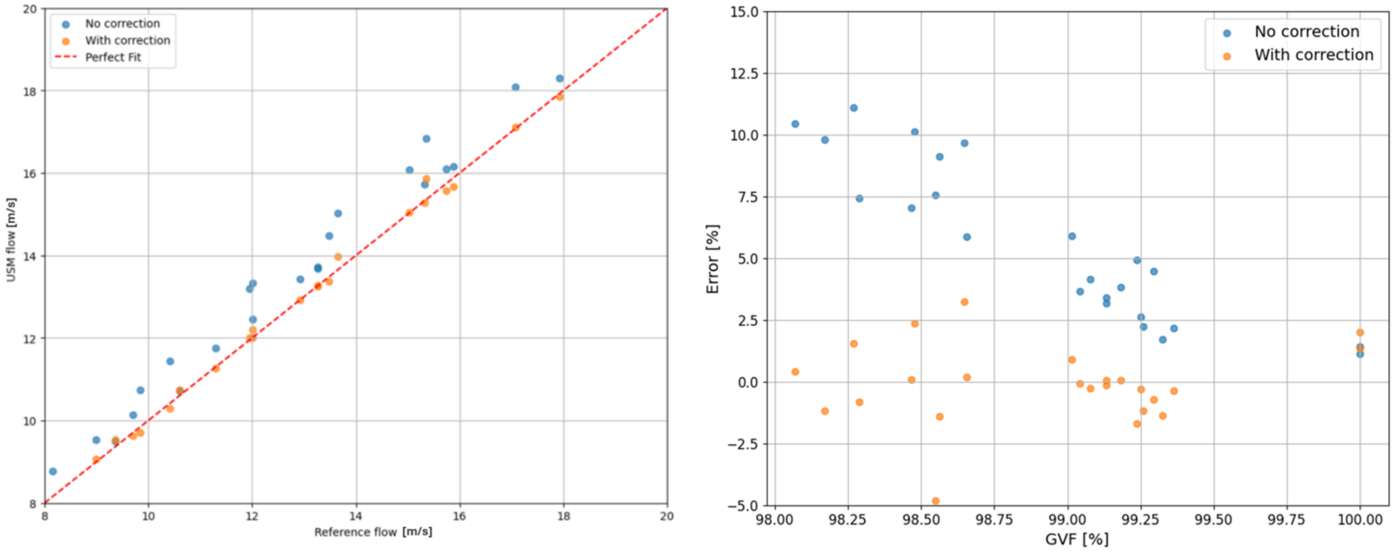

Figure 14 Performance of the correction model applied to data acquired during testing of a different compressor (2/2).

5 SUMMARY AND FURTHER WORK

Multi-path ultrasonic flowmeters are widely used in custody transfer applications in the oil and gas industry. Wet gas metering with ultrasonic flowmeters has been an area of research for decades but has not found widespread use in the industry. The introduction of a subsea ultrasonic flowmeter opens new opportunities where custody transfer metering of unprocessed gas would be of particular value. The first part of this paper discusses how the authors believe this can be achieved.

The second part of the paper presents results from testing an 8-path subsea ultrasonic flowmeter in a wet gas compressor performance test loop. This test made use of the available opportunity; however, since the test loop is not designed for metering and the installation is sub-optimal, the results should be interpreted with these limitations in mind. None the less they demonstrate that the ultrasonic flowmeter is capable of producing meaningful data over a wide range of operating conditions. A correction model is under development, and some examples of early results obtained by applying this model to the acquired test data have been presented.

The authors will continue to develop and refine the correction model as more data become available from other test campaigns in other test facilities with more precise reference measurements.

7 NOTATION AND ABBREVIATIONS

Fr_g	Densimetric gas Froude number
Fr_l	Densimetric liquid Froude number
GVF	Gas Volume Fraction
LVF	Liquid Volume Fraction
SNR	Signal to Noise Ratio
USM	Subsea Ultrasonic Flowmeter

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