Accuracy and long-term stability of ultrasonic gas meters at varying operating pressures and different liquid loadings – field experience.

Alexander Jakschik, SICK AG

Jörg Wenzel, SICK AG

Theo Warmenhoven, GDF SUEZ E&P Nederland B.V.

Dr. Volker Herrmann, SICK AG

1. Introduction

The gas industry again underwent growth of almost 2 % in 2012 (world gas production see Figure 1). The environmental advantages of gas and rising energy demands worldwide in recent years will keep this trend ongoing. This will also result in an increase in the onshore and offshore exploration of gas fields around the world.

The offshore ambient environment and technological economic circumstances, in particular, places high demands on metering technologies. Liquids occurring in the pipeline and pressure reduction require a meter technology which offers high accuracy and long-term stability in these harsh circumstances. Well proven in typical transmission and storage custody applications, ultrasonic meters are emerging in the gas production segment. Advantages like high turn-down ratio, no pressure drop, low-maintenance, self-diagnostic capabilities and proven long-term stability cause this trend.

This paper will discuss design criteria for optimized meter operation and also two practical challenges to measurement:

- Liquids in the gas flow - even after separators
- Pressure change due to depletion of gas sources

The paper follows a discussion on the use of USMs along with practical examples, including experience GDF SUEZ E&P Nederland B.V., which is one of the largest operators in the Dutch sector of the North Sea, with an annual gas production of around 6 billion Nm^3 at more than thirty production platforms.

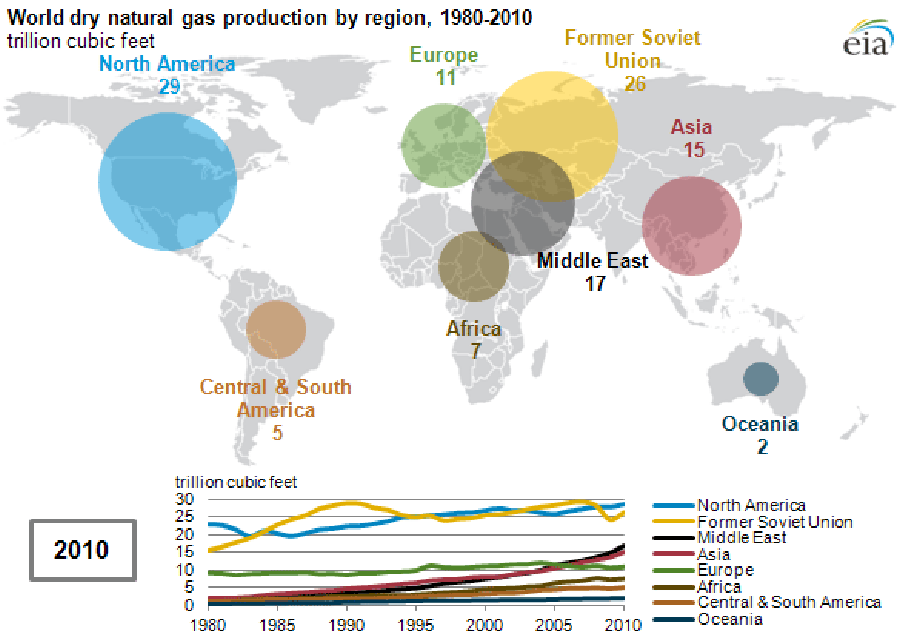

Figure 1: World dry natural gas production by region, 1980-2010 [5]

2. Offshore gas production

Unlike onshore drilling, offshore production is typically realized by a small number of large rigs (offshore platforms).

In the offshore oil & gas production process a distinction is generally made between three types of production platforms: the so-called "main production platform," the "manned platform" and the "unmanned satellite platform."

At the time this paper was written, GDF SUEZ E&P Nederland B.V. had 34 production platforms, of which four were main production platforms, nine were manned platforms and 21 were unmanned satellite platforms. Via a complex system of underwater pipelines, most of these platforms are connected to the gas transportation systems operated by Noordgastransport B.V. and NOGAT B.V., which have their own gas treatment plant onshore. Figure 2 provides an overview of the GDF SUEZ E&P Nederland B.V. production platform network, while Figure 3 shows the gas production platform L10-A as an example.

The main production platform is where the streams arrive from different satellite platforms. The gas is produced by separating the gas, dehydrating it and compressing it to the respective pipeline pressure. The different gas streams are combined to one stream before transport from the platform to the treatment plant. A satellite platform is a small, in most cases unmanned, platform where liquid is separated from the natural gas before the gas is transported. The gas is then transported to the main production platform. These platforms are designed to be operated remotely under normal conditions.

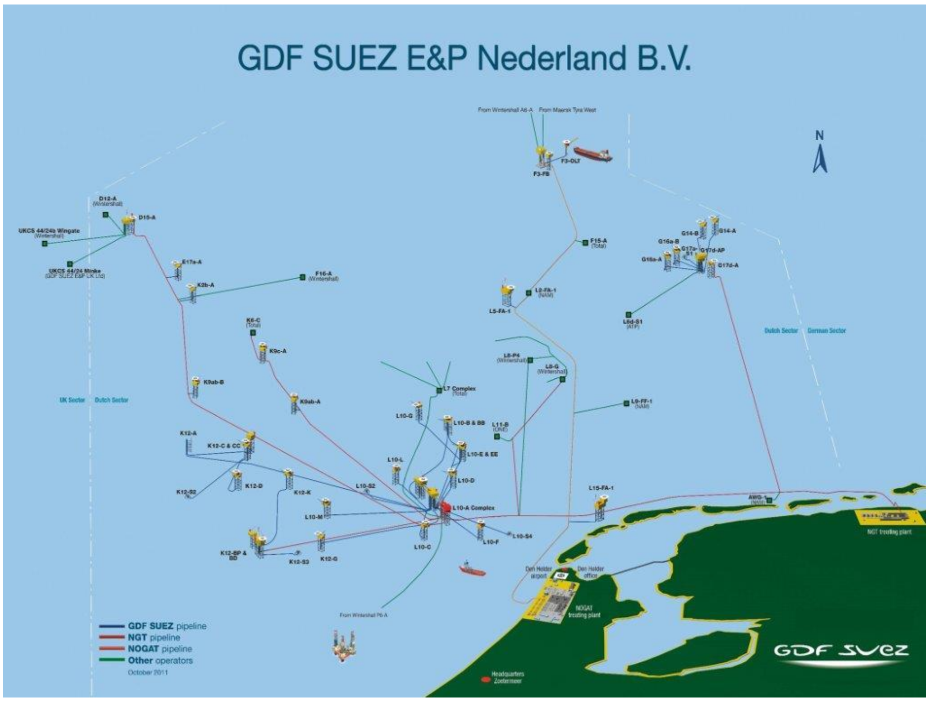

Figure 2: Map of GDF SUEZ E&P Nederland B.V. production platforms

Figure 3: Gas production platform L10-A run by GDF SUEZ E&P Nederland B.V.

Figure 4 depicts a typical gas process scheme at a main GDF SUEZ E&P Nederland B.V. production platform. Gas from several wells arrives at the platform: This can either include wells directly connected to the platform or gas coming from a satellite platform.

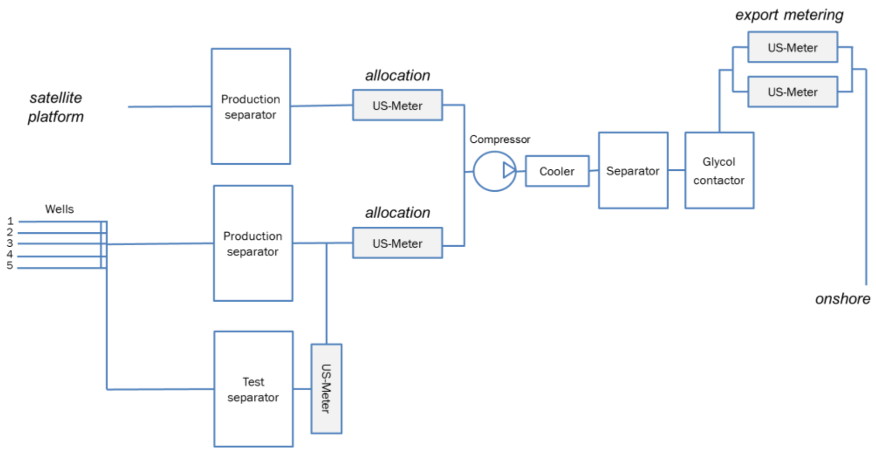

Figure 4: Schematic process - main production platform

The gas is metered after the respective separators for process control (allocation measurement) and reservoir management. The different gas streams are then gathered into one stream. Compression takes place if the flowing wellhead pressure is close to or lower than the pipeline pressure. The gas is cooled down to ensure that the separator runs at maximum efficiency before the gas enters the glycol contactor. The gas is then measured to an extremely high level of accuracy for transportation onshore.

Figure 5 shows a typical gas processing schema at a satellite platform run by GDF SUEZ E&P Nederland B.V. There is also a production separator and a test separator for allocation measurement and to quantify the amount of gas coming from the individual well for reservoir management. The gas is transported to the main platform for further processing.

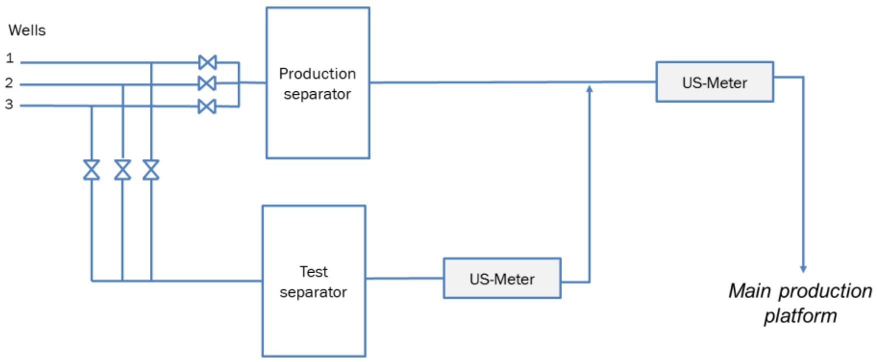

Figure 5: Schematic process - satellite platform

3. Gas flow measurement during offshore gas production

3.1. General design considerations for ultrasonic meters

The meter is the "cash machine" of the oil & gas producing company. The accuracy, reliability and long-term stability of the metering equipment are crucial: Low performance, or in the worst case down-time, can lead to substantial losses. In addition, remote unmanned production platforms require a measurement device with extremely high availability and very low maintenance.

The offshore environment itself places high demands on the metering equipment. This already has to be taken into account by the meter manufacturer at the design phase. The meter must be able to tolerate gas compositions outside standard specifications or recover quickly when the operating conditions returned to "normal". In addition the meter has to indicate in its diagnosis whether it has been operating outside the specifications.

Main challenges for metering equipment in offshore production:

a) Harsh environment
b) Liquid in the gas flow even after separator
c) Pressure change due to depletion of gas source

To achieve maximum reliability under such conditions it is necessary to analyze and eliminate potential issues such as:

- Outside corrosion, mechanical damage
- Vibration
- Inside corrosion and fouling resulting in
  - diameter change
  - profile change
  - symmetry change
- Transducer failure
- Loss of signal due to
  - high attenuation in the gas
  - reduction of transducer power, e.g. due to coating
  - body noise due to water bridges
- Reduction of path length due to coating
- Electronic failure

The above factors require several engineering measures. Further, three criteria are highlighted which are related to transducer design, because they are of special importance for offshore applications: transducer encapsulation, pressure resistance and pressure range.

3.1.1 Transducer encapsulation

The transducer's active elements need to be protected from any damage resulting from chemicals entering its internal structure. This is realized by encapsulating the active elements from the operation fluid, though this encapsulation is rather difficult to achieve in detail.

The transducer housing is made from corrosion-resistant titanium alloy. This material is sufficient for general corrosion protection. On the other hand, the assembly requires some threads, gaps or crevices within the housing to ensure that the optimum acoustic performance is produced. These connecting elements operate like springs to energize the transducer and increase the acoustic power of the resonant vibration. The remaining gaps have to be closed for protection. Glues cannot ensure sufficient resistivity to the gases and liquids in the oil and gas industry. Therefore welding is the only available technology to achieve real hermetic encapsulation.

Welding the gaps is a difficult topic, as the inner transducer parts should not be subjected to extensive thermal stress. The titanium alloy used typically melts above 1600 °C while the piezo-ceramic elements must be kept well below 300 °C. In addition, the welding technology options are limited, due to titanium's affinity to atmospheric gases such as oxygen or hydrogen. Technologies such as electron beam welding or laser welding can be used, but have to be optimized with respect to the welding parameters, while operation during welding needs to be very stable because of the very tight parameter range.

Figure 6 shows a cut-away view of an electron beam weld under a light microscope. The strongly localized influence of the heat during welding is a result of a well-defined, precisely adjusted welding procedure. Not even the thread connecting the two welded parts is influenced, and the ceramic is fully protected from the heat necessary to weld the two titanium parts. The localized welding seam also indicates that there is not too much heat introduced into the neighboring material. Tensions following uncontrolled heat introduction into the titanium would act as additional electromechanical actors. As a consequence the transducer would have parasitic resonance frequencies. Figure 7 shows the completed transducer part with the weld on the top.

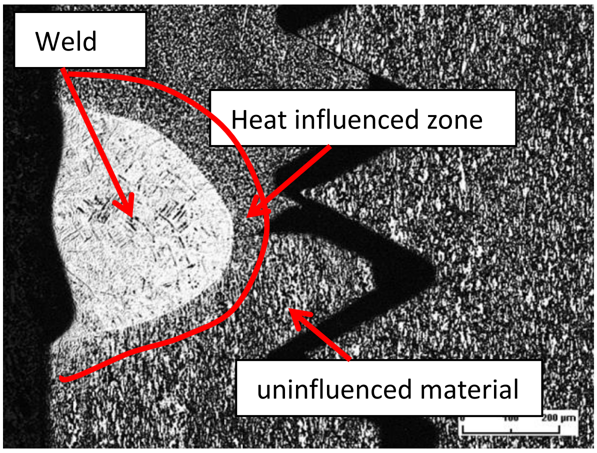

Figure 6: Weld on titanium transducer

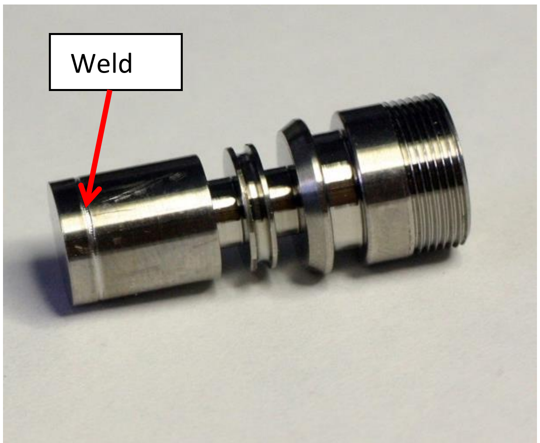

Figure 7: Transducer dummy with weld

3.1.2 Pressure resistance

Another aspect is that: the transducer is a part of within the pressure boundary of the meter and must withstand the pressure within the meter. This requires larger thicknesses of all the pressure pressure-bearing parts to be thicker.

To ensure sufficient that safety margins are efficient, the elements are designed to withstand much higher pressures than the design pressure, in this case up to 450 barg. It has have to pass much higher test pressures depending on the actual dimensions and material characteristics. An example for of such this kind of experimental design verification is shown below (Figure 8). A transducer was tested with increasing pressure, measuring the reaction (or non-reaction) of the structure to the pressure. The transducer was designed to withstand a 450 bar design pressure and from based on the actual wall thickness, actual strength values and tolerance consideration; a final test pressure of 450 barg was calculated.

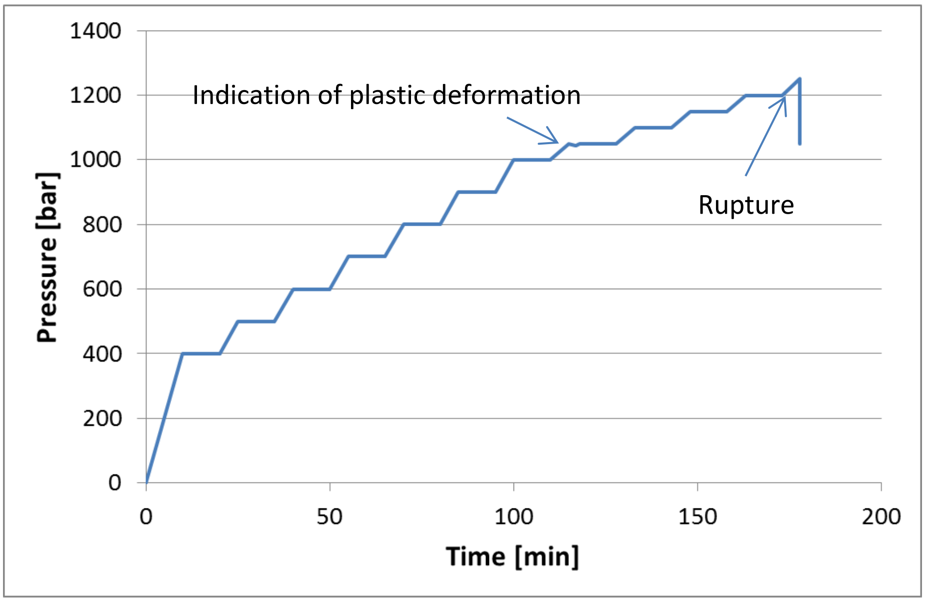

Figure 8: Transducer strength test – 450 barg design pressure

Looking at the test results, it can be concluded, that up to 1050 bar the transducer is free of any damage. The transducer failed no earlier than 1250 bar (damaged transducer shown in Figure 9).

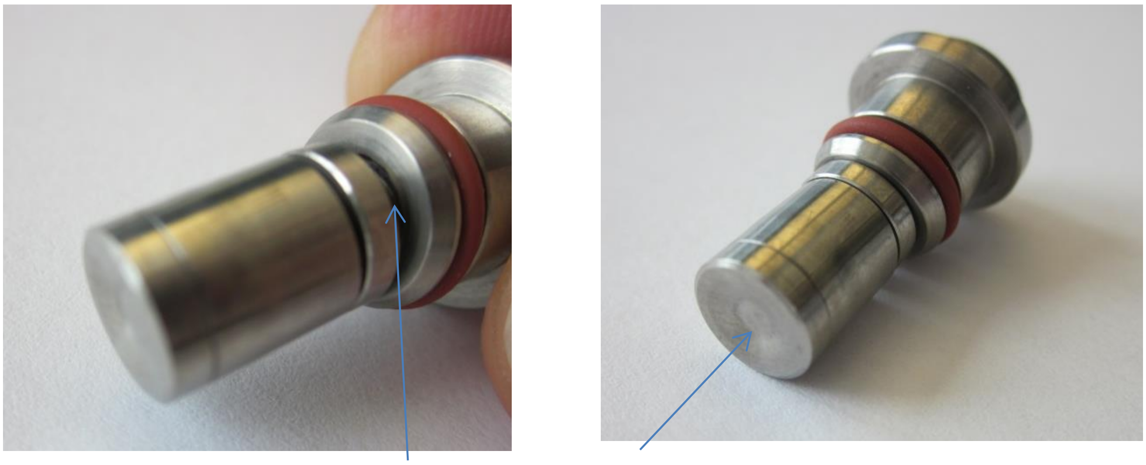

Figure 9: Burst and deformed transducer at 1250 bar

3.1.3 Increased pressure range

Transducers that can withstand the extremely high pressures need to be extremely robust. This includes having a relatively thick membrane. Having a thick membrane makes the transducer somehow "deaf".

An example for 2 different frequencies is given in Figure 10. This graph shows the normalized sound pressure level [dB] over the membrane thickness [µm]. As higher the frequency as higher the damping effect of thick membranes.

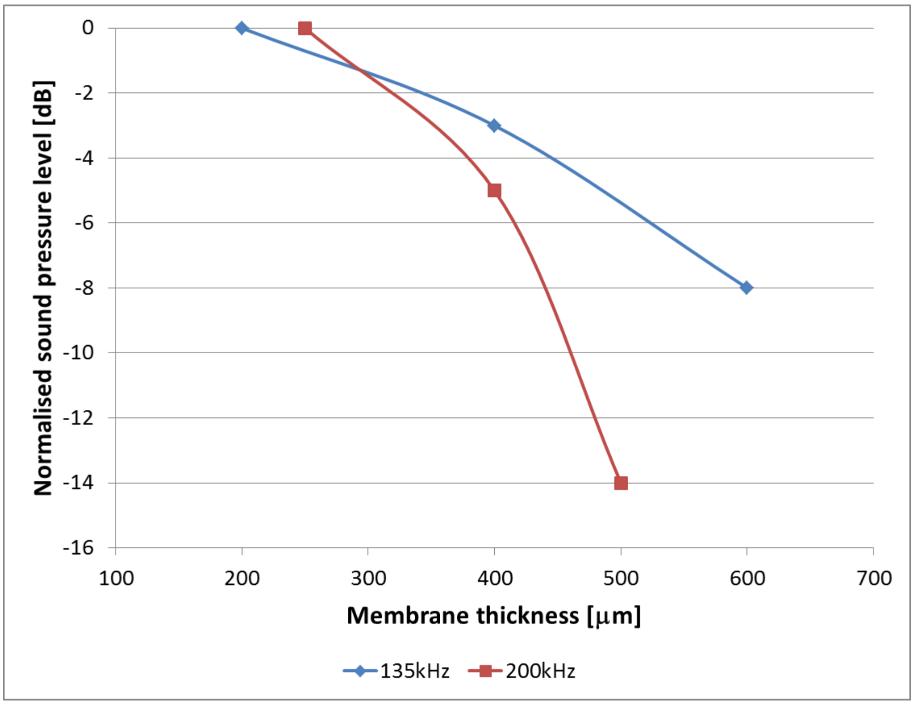

Figure 10: Relationship between normalized sound pressure level and membrane thickness [2]

At high pressures this is not a problem, since the sound transmission is very good. But as soon as pressure drops each dB sound pressure remaining can decide whether a meter can measure or not.

Figure 11 displays the relationship between the sound pressure level [dB] and gas pressure [bar]. One can see, that a pressure decrease from 10 to 1 bar means the sound pressure level is 20 dB lower. A decrease from 100 to 10 bar also leads to a decrease of 20 dB.

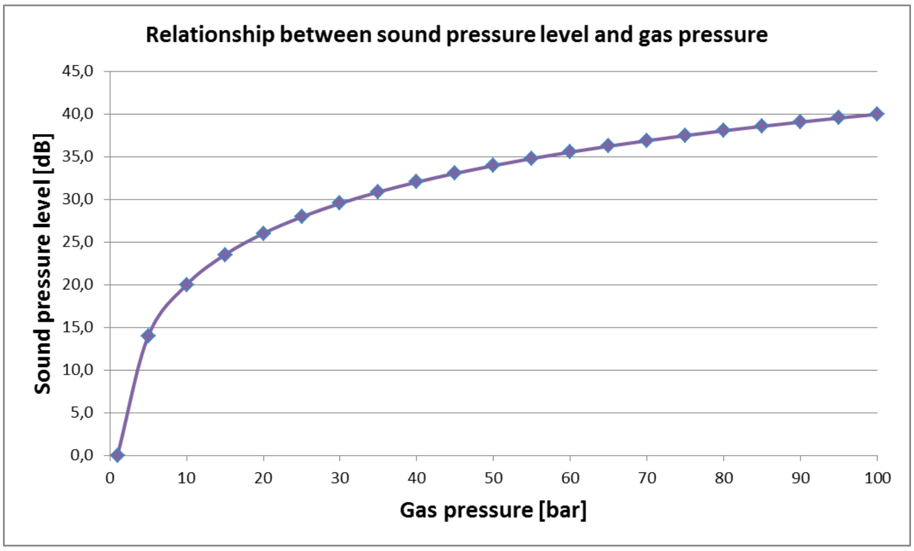

Figure 11: Relationship between sound pressure level and gas pressure

The challenge here is at lower pressures: The “deaf” transducer still has to receive enough signal strength to measure in custody transfer quality.

To realize this extreme pressure range with one meter it is necessary to transmit as much sound energy as possible into the gas and to make the dampening as low as possible.

For the transmission of a maximum acoustic energy into the gas an acoustic impedance matching is mandatory. Since a hermetic sealing, as discussed in chapter 3.1.1., is necessary, there is only a transformation or matching inside the encapsulation possible. Between the transmitted energy and the received energy there is the attenuation: A logarithmic measure along the path. A direct path layout positively supports signal quality in low pressure application. Therefor it seems to be given by the physical principle, that at a given transducer power a direct path layout will have a much wider pressure application range.

The overall concept allows the use of a direct path ultrasonic meter in the pressure range from 0 to 250 barg.

3.2 Challenge: Liquid in the gas flow

3.2.1 Application

During production and in test separators, liquids are separated from the gas. After separation, the respective components are measured and transported away or disposed of. Here, measurement plays an important role, for process control and/or to quantify the components of the respective wells (allocation metering). Typically the gas flow temperature at the separators ranges between 10°C and 90°C. The gas pressure is in a range from 120 down to 4 barg. Figure 12 shows a typical meter run after the test separator.

E17-A is a gas production platform without satellite platforms in the north west of the Dutch sector with a daily production rate around 3.200.000 Nm³/day (Figure 13). The 4-inch class 900 meter is installed behind the test separator in a 20D/USM/10D setup without flow conditioner. Each well is sequentially connected to the test separator. The flow range of the single wells is currently between 630.000 - 1.430.000 Nm3/day.

Figure 12: Meter run downstream of test separator

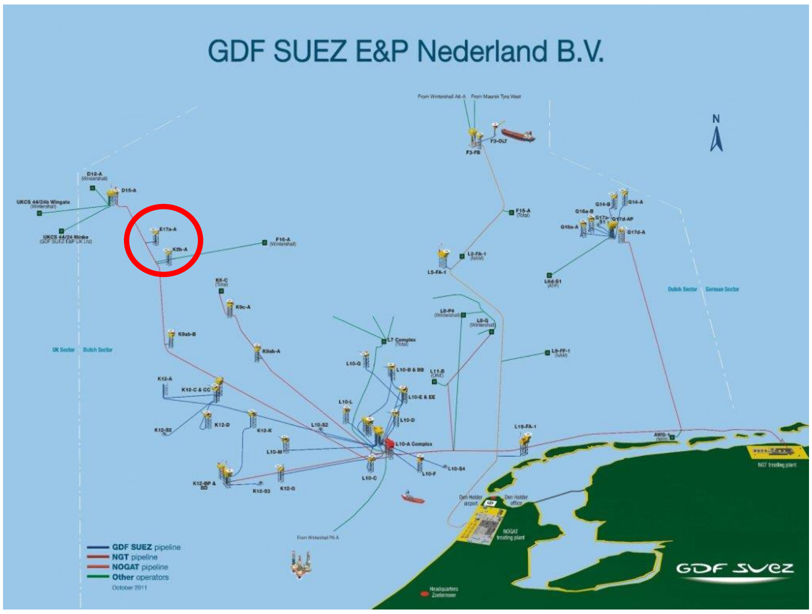

Figure 13: Platform E17-A, red marked

3.2.2. Theory of Liquid formation in Natural Gas

While separators are meant to extract all liquids from the gas stream, that target cannot be realized in every case. Changes in the separator operating regime can result in the device overflowing and the liquid accidentally being transferred into the gas meter. Another reason for liquids within the gas flow is based on the thermodynamics of the gas mixture itself: When a given composition of the gas stream is considered, the hydrocarbon dew point (HCDP) and the water dew point (WDP) depend on the pressure and temperature and can be calculated. The hydrocarbon dew points can be visualized with the help of the envelope graph shown in Figure 14 [3].

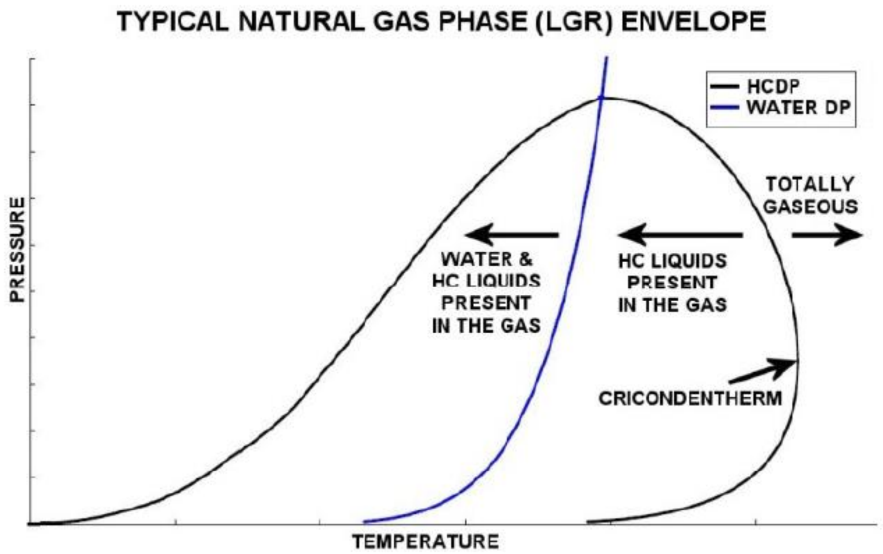

Figure 14: Example of hydrocarbon dew point envelope [3]

Reducing the temperature from right to left at constant pressure, for operating conditions above the hydrocarbon dew point envelope, the entire transported medium is gaseous. Between the water dew point borderline and the HC dew point envelope, hydrocarbons may be precipitated as liquids. Further lowering of the temperature at constant pressure leads to the condensation of water and more hydrocarbons.

But not only hydrocarbon liquids may appear in the gas phase. Sweet natural gas also contains water which has the potential to drop out if process conditions change. Figure 15 shows the calculation chart of water content in sweet natural gas.

An exemplary calculation from platform E17-A should demonstrate these dependencies. Temperature during production separation process is at around 86 °C at a pressure of around 112 barg. Due to low ambient temperatures, for example in winter time the gas pipeline temperature is lowered as well. The pipeline in between separator and gas meter causes a temperature drop of 4 K to 82°C. Knowing the pressure and the respective temperature drop, one can conclude, that ~800 kg water per 1.000.000 Nm3/d gas drop out into the pipeline only due to temperature drop of 4 K. At 82°C and 112 bar this results in a liquid volume fraction of 0,18%.

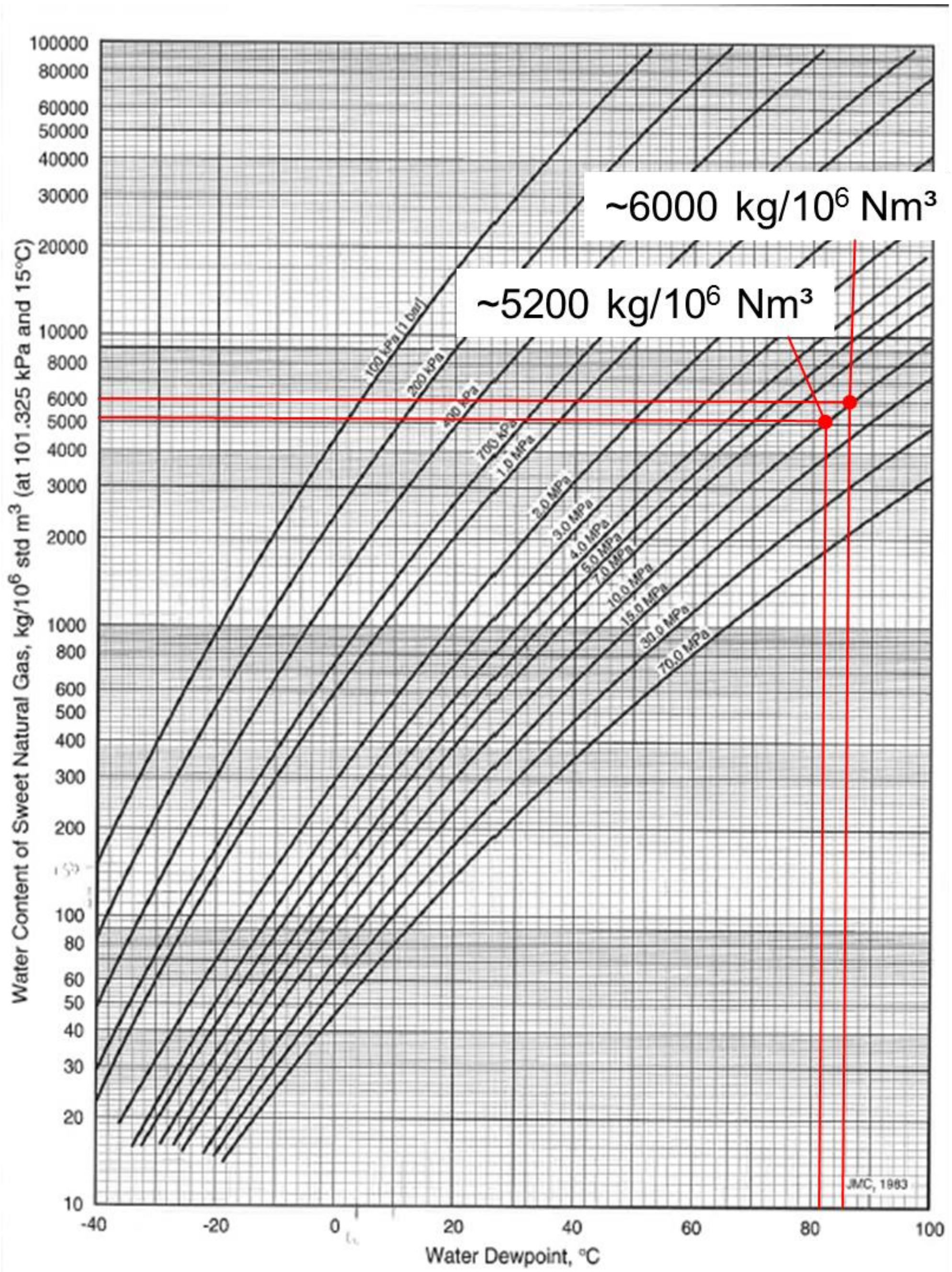

Figure 15: Calculation chart of water content in sweet natural gas [1]

Figure 16 displays the hydrocarbon envelope of the respective gas mixture produced. By this one can conclude, that there is no hydrocarbon liquefied at these process conditions if the temperature decreases from 86 to 82°C.

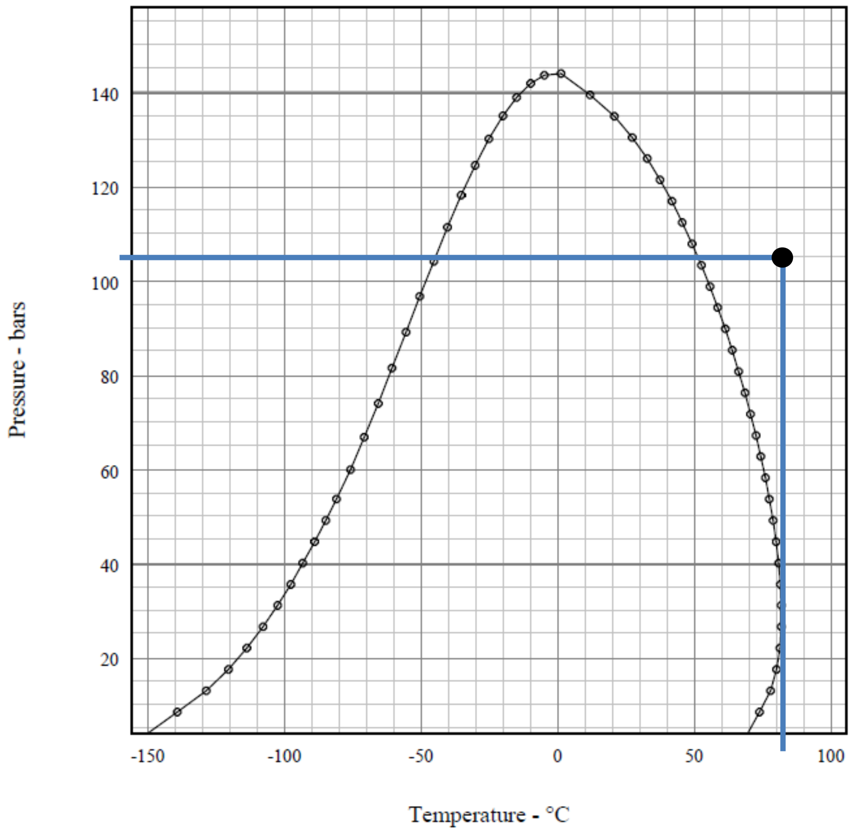

Figure 16: Hydrocarbon dew point envelope for gas composition at platform E17-A

Finally liquids also may occur if the test separator has been out of operation for some time and cooled down. In that case water may condensate on the separator outlet which will be blown away after restart of stream.

In conclusion the meter in operation will be affected by water but not condensates entrained to the gas phase if the ambient temperature causes a significant temperature drop of the gas.

3.2.3. Meter behavior – tests conducted on the wet gas loop at CEESI

Tests at the CEESI test stand have proven that even if the transducer is totally flooded, the path recovers after the liquid disappears. A 3-inch and 4-inch 2-path USM was tested up to a liquid volume fraction (LVF) of 5% at 13 and 55 barg and from 5 to 13 m/s [4]. The following table gives the test sequence, the gas volume fraction, the meter performance for the lower acoustic path as well as diagnostic values such as AGC, SOS and turbulence ratios For the meter under test at 55 bar and 8,2 m/s. Table 1 shows results from the CEESI test.

Time	GVF	Performance	SOS ratio	Turbulence ratio
10:45	1,000	100%	1,00	1,11
11:01	0,9550	0%	1,05	20,01
11:11	0,9771	68%	1,01	6,06
11:32	0,9951	100%	1,00	1,28

Table 1: Meter performance at different gas volume factions [4]

The meter remained in operation throughout the test, as the upper path didn't fail at the maximum LVF of nearly 5 %. At this maximum LVF level the lower path is flooded completely. Reduction of the amount of liquid to less 2,3 % brings the lower path back to operation. For lower liquid loadings, the measurement recovers completely and the performance index reaches 100 %. The results and diagnostic capabilities of the 2-path system from this particular test can also be transferred to a 4-path meter considering the different path locations.

3.2.4 Test Data for platform E17-A

Ideally a simulated test for entrained liquids under real operating conditions would require minimum ambient temperature, best performed during winter times.

The following test on the platform E17-A has been performed in July 2013 where the ambient temperature was not very low. Therefore it was not expected to see a lot of liquids in the gas phase right after the test separator.

Nevertheless, to increase the amount of liquid the separator was shut off for some hours and cooled down. In that manner liquids had the chance to drop out and form on the outlet of the separator. It was expected that after re-connecting a well to the test separator the increasing gas flow will blow the liquids downstream. Further the expectation has been that the installed 4-inch, 4path ultrasonic meter shall detect the small amount of liquid by giving some diagnostic indications.

The following process data have been measured after shut-down the test separator run:

Pressure	115 barg
Temperature	26°C
Speed-of-Sound	408 m/s
Flow velocity	0 m/s

In the next step gas stream has been routed through test separator. Velocity of gas is increased and diagnostic values are recorded. Under these conditions liquid carry over into the meter section was expected.

After the setup had been run under these conditions for 5 minutes the process went back to the following parameters.

Pressure	116 barg
Temperature	66°C
Speed-of-Sound	418 m/s
Flow velocity	7,94 m/s

These are considered normal operating conditions.

In figure 17 an installed 8-inch 4-path ultrasonic meter is shown, removed from the meter run, showing exemplarily the expected water droplets at the inner pipe wall.

Figure 17: Condensation on inner meter body wall due to temperature decrease below dew point

Normally, the limits for different parameters and values are set in the meter itself. Once one of the limits exceeds an alarm is generated. Following this alarm, the user can analyze the diagnostic data using the parameterization software to get a detailed look into the operation conditions. As it will be shown in the following example - the amount of liquid was too little to cause alarms. Nevertheless the meter diagnostic indicates the changes in process conditions very precisely.

The change in application conditions and especially the presence of liquids are visualized by five main indicators:

- Speed of Sound ratio
- Turbulence
- Performance
- Profile factor
- Symmetry

Figure 18 shows an example diagnostics screenshot, while the separator is being started up. The flow range raised from 0 m^3/h to $3m^3/h$.

Figure 18: Diagnostic data during start-up of separator, @ 14:09:39

The screenshot is made from the user software of the meter. Green indicates everything is OK. Yellow indicates alarm, but measurement is still valid. Red would be an alarm where measurement is invalid and the meter counts into the error counter. To help evaluate the diagnostics more easily, the speed of sound deviation is displayed relative to the mean value calculated from all four measurement path.

The flow profile is asymmetrical as the lower path indicates a lower VOG. The turbulence of path no. 4 is found to be higher compared to all other paths. In addition, the speed of sound measured on path 4 is lower compared to all other path values and the performance dropped to 90%.

Profile factor displayed versus symmetry give also a very good indication about the liquid loading. The graph in Figure 19 shows the so called profile indication (symmetry over profile factor), where the profile indication is out of its limits. A valid value would be within the dotted red box.

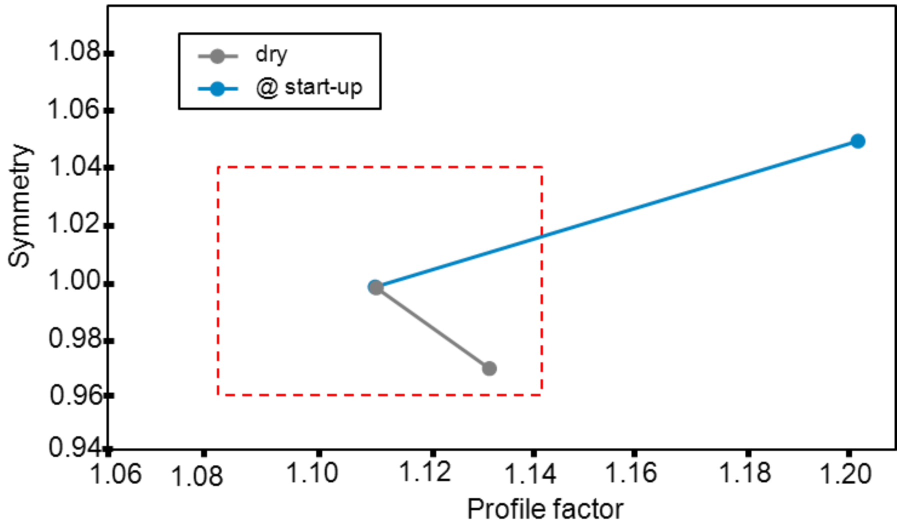

Figure 19: Profile factor vs. Symmetry at start-up and dry conditions

All parameters together clearly indicate that liquid has entered the metering section.

Another sensitive indicator of the ultrasonic meter is the speed of sound ratio. All four acoustic paths should indicate the same speed of sound in normal operation. A significant reduction of the speed of sound on one path could indicate the presence of liquid. An estimation using the composition of the gas and the liquid at the measured conditions and using Wood's formula [6] gives the liquid volume fraction present. In the particular application the average speed of sound of all paths is 412,265 m/s in the moment of the highest liquid loading. The speed of sound of the lowest path at that time is 411.73 m/s. This results in a ratio factor of 0.998. Comparing this result with the estimation of Figure 20 one can conclude that the amount of liquid is very low. This shows how precisely the ultrasonic meter can detect liquids.

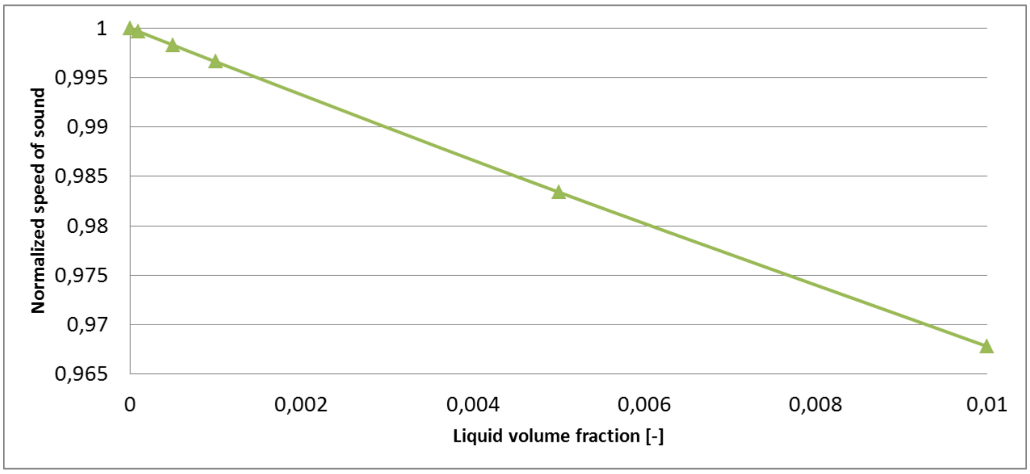

Figure 20: Normalized speed of sound calculated from Wood's expression for gas-liquid-mixtures

(In this figure all speed of sound data are normalized to the value of the pure gas phase at the reference conditions before shut-down of the separator.)

After approximately 2 minutes the metering section is cleared out and meter performance comes back to 100% on all paths. Figure 21 shows the same diagnostic values as before after maximum flow has been reached.

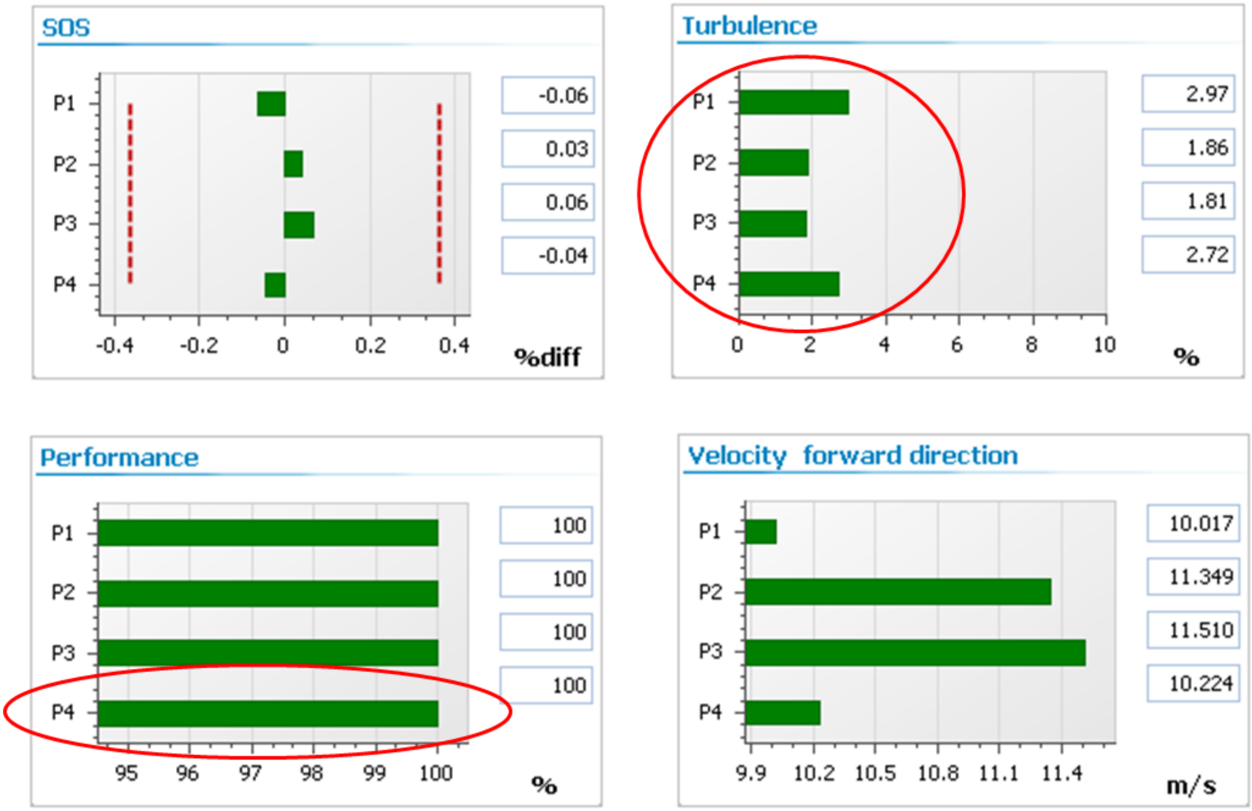

Figure 21: Diagnostic data after start-up at dry conditions, @ 14:11:05

The diagnostics and meter readings show, that the meter goes back to normal operation. Performance recovers to 100% and turbulence is in the normal range. It also indicates that there is no liquid in the gas anymore. The ability to recover after the presence of liquid is vital for the operation.

3.3. Challenge: Pressure change due to depletion of gas source

Typically flowing well head pressure takes place at pressure of 3 - 500 barg. For further gas processing pressure is reduced to 90 - 120 barg (“free flow”). However, natural gas sources deplete over time. Hence the pressure will drop.

Pipeline pressure in between offshore and onshore is defined to be at 85 – 110 barg. Therefore stream is connected to compression (Figure 4) in case of depletion, with the following steps: 6 - 10 barg, 12 - 20 barg and 35 - 50 barg, depending on the respective flow rate. Today the lowest operating pressure in offshore applications of GDF SUEZ E&P Nederland B.V. is around 7 barg. Nevertheless well pressure is expected to drop in the next coming years in some cases as low as 4 barg.

Therefore GDF SUEZ E&P Nederland B.V. does require an ultrasonic meter technology, which is able to cover a broad application pressure from ambient to 120 barg.

There are two major challenges for this extreme wide application range – Management of acoustic power by means of transducer design and path layout as discussed in chapter 3.1. and calibration discussed below.

The challenge regarding calibration is to provide a valid calibration over the full pressure range during lifetime. Normal calibration is valid between the half and doubled pressure during calibration. For example if a meter is calibrated at 60 bar it is approved for measurement between 30 and 120 bar.

So what can be done if the operating pressure in offshore applications drops below the calibrated thresholds? Here three possibilities shall be discussed.

1. *Standard re-calibration procedure*

In that case the meter needs to be dismounted and recalibrated on a dedicated calibration institute. This is done by GDF SUEZ E&P Nederland B.V today (re-calibration interval of 5 years). One re-calibration result from a 8-inch meter after five years in operation is shown in Figure 22. The maximum deviation to the initial calibration remains below 0.3% peek to peek and the FWME according OIML is 0.061% between Q_{min} and Q_{max}. Values are in the area of the uncertainty of the test stand.

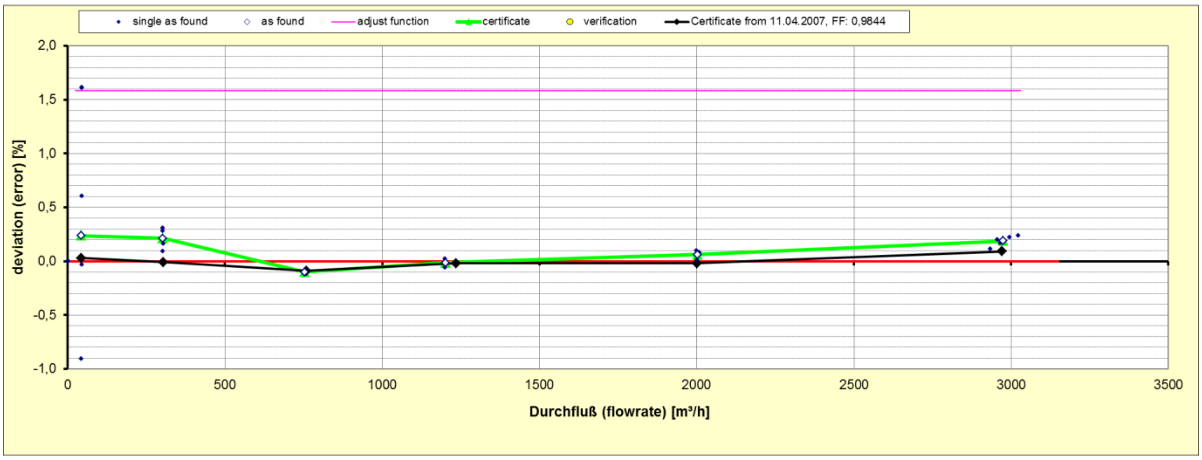

Figure 22: Re-calibration chart of an 8-inch meter

2. *Extended initial calibration*

Another possibility is to perform an extended initial calibration. If the pressure range of the application over lifetime is known the meter can be calibrated at different pressure levels initially. Data can be stored and in case pressure level drops the meter can easily be updated with the appropriate parameter setting. Or the individual calibration curves can be used by the flow computer to correct the meter values for pressure.

One example shall illustrate this procedure:

Pressure range over lifetime:	4 to 110 barg
Calibration 1:	@8 bar covering the range from 4…16 bar → Parameter set 1
Calibration 2:	@30 bar covering the range from 15 … 60 bar → Parameter set 2
Calibration 3:	@60 bar covering the range from 30 …120 bar → Parameter set 3

Performing all required calibrations before the meter is initially commissioned in the field saves time and money for the operators.

3. *Use of one set of coefficient of the whole range*

To allow the use of one set meter coefficients for the whole pressure range it is necessary to:
a) Develop and investage an internal Reynolds correction which is valid over the whole application range.
b) Approve and validate the correction by an independent authority like PTB or NMI
c) Continuously read the line pressure into the meters electronics

This procedure will be especially appropriate for high pressure applications above 120 barg, as calibration institutes have their limits.

4. Conclusion

This paper discussed the performance of ultrasonic meters in applications where liquid is present and significant pressure drop will happen over time. Beside theoretical examinations also practical experiences and advises have been gathered from GDF SUEZ E&P Nederland B.V., especially from an application on the E17-A gas production platform.

After what has been discussed one can conclude that USM's work reliably and stably over the long term in offshore natural gas production measurement, behind separators as e.g. at GDF SUEZ E&P Nederland B.V. Long-term stability in this application has been demonstrated also by showing re-calibration results from a meter which has been 5 years in operation.

If an increased liquid content is temporarily present the meter accuracy and performance is only temporarily affected and does recover. Diagnostics show not only potential changes in meter performance, but can raise the alarm when there is a change in a process operation.

The performed test has been done in summer 2013. Due to the high ambient temperature the amount of liquid drop out behind the separator was not as high as expected. But the meter still detected it. Therefore it is recommended to repeat the test during winter time, in worst case conditions to verify the diagnostic capability. During winter a LVF of 0.18% or higher should be present.

USM's are also an economical solution for allocation metering in offshore gas production (behind separators) under the conditions of varying pressures. The design of the transducers is vital for high metering performance and at a given transducer power a direct path layout will have a much wider pressure application range.

With a high turn-down of up to 1:130 a single meter can serve a large operation range. With a broad operating pressure range a single meter can be in use for the complete lifetime of a production well. Meters measure accurately under all circumstances.

With an extended calibration where two or three different pressures are calibrated initially the meter can be in use for fiscal operation until the well is depleted. The fact that ultrasonic meters require nearly no maintenance and do not cause additional pressure drop turn ultrasonic meters to be an economic device for use in onshore and offshore application already behind the first stage of separation.

Literature

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