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A New Approach to Measuring the Gas and Formation Water Flow Rates in Wet Gas

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1 INTRODUCTION

Many gas wells are producing very little liquid. For these wells it is not uncommon to use a simple differential pressure flow meter to measure production. Many correlations and correction factors are available to correct over-reading caused by the presence of liquids. These require the liquid fraction, or some derivative of the liquid fraction like the Lockhart-Martinelli parameter to be known. As long as a gas well is not producing any reservoir water, it may be possible to calculate the liquid fraction from the water saturation pressure and PVT calculations. This allows the liquid fraction to be estimated and the gas rate to be corrected.

Formation water production cannot be derived from the gas rate directly. First, it is necessary to know whether formation water is being produced or not. Second, when formation water is present, it needs to be quantified by other means than just measuring the gas rate. This usually means that a wet gas or multiphase flowmeter is needed if gas production is to continue after the onset of formation water production. The rate of formation water may be much higher than the rate of condensed water and hydrocarbons, but may still constitute only a small fraction of the total flow. As a result, the formation water rate measurement may have a large relative uncertainty. This uncertainty will propagate through the correction of the gas rate and make the estimates of gas rate and total water rate uncertain as well.

In this paper we present how a measurement of the conductivity of the water phase may be used to detect the presence of formation water and to estimate the fraction of formation water as a function of the condensed water. The fraction of liquid hydrocarbons may be added to obtain a total liquid fraction at metering conditions. This liquid fraction is used to correct the over-reading of the gas rate. In this way a differential pressure measurement and a measurement of the conductivity of the water phase are combined into a full 3-phase wet gas flowmeter. The applicability of this approach to different gas reservoirs is also discussed.

2 GAS AND WET GAS RESERVOIRS

Oil and gas reservoirs can in very general terms be classified according to Figure 1. Gas reservoirs have reservoir temperatures higher than the cricondentherm and stay in single phase even when the pressure is reduced as a result of production. The PT trajectory from reservoir to standard conditions, represented by the curve *A-A′* in the figure, will usually cross the dew line, meaning that some liquid hydrocarbon will condense out of the gas as it travels through the wellbore and flow line, and ultimately through the process system. Whether a gas reservoir is considered "wet" or "dry" depends on how much liquid is being produced, but there is no clear boundary between the two.

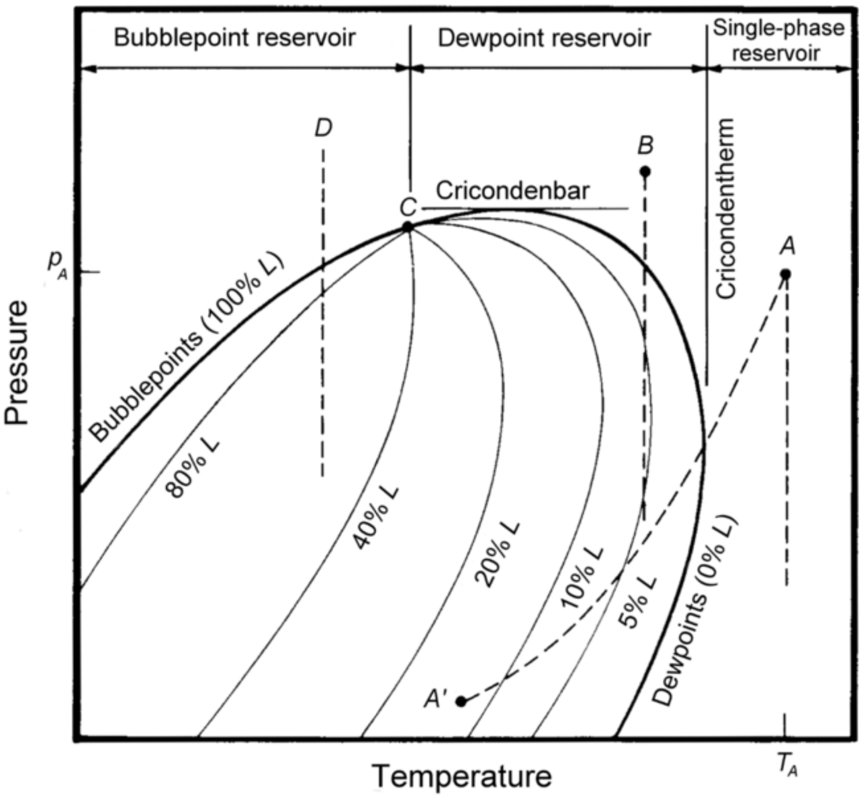

Figure 1 Oil and gas reservoir types relative to a phase envelope

Most gas reservoirs also contain water vapour in equilibrium with condensed water in the source rock. Some of this water will condense out of the gas phase and the volume of water in the liquid phase typically increases as the temperature and pressure is reduced. This is of particular concern in subsea gas production because of the risk of hydrate formation in subsea flow lines.

The reservoir rock will contain liquid water in addition to the gas; formation water. This water will normally contain some salt and other dissolved solids. This water may or may not be produced, depending on the properties of the rock, the reservoir, and the production. Onset of formation water, or formation water break through, is a key decision point in the production of gas wells. In some cases it is not seen as economical to continue production when formation water breaks through, while it in other cases will be desirable to continue production with formation water. The presence of salt water in the process stream causes new flow assurance risks like corrosion and scaling in addition to hydrates, and the mitigation of these is key in order to continue production.

Gas reservoirs may also be in contact with aquifers. Gas wells will normally be shut in if an aquifer breaks through into a producing well. The main risk in this case is the rapid increase in water production. It may be important to identify this at an early stage in order to avoid flooding the production system with water.

3 CONDENSED WATER IN PRODUCED GAS

An important objective of subsea wet gas flowmetering is often to provide data for flow assurance purposes, in particular hydrate risk mitigation. Flow assurance issues in gas production are often caused by produced water. Water comes out of the reservoir in vapour phase in association with the gas because the gas in the reservoir contains water vapour in equilibrium with condensed water. The water fraction in the gas can in this case be calculated from the saturation pressure.

For simplicity we assume ideal gases in the following. The fraction of water vapour in the gas in the reservoir is

$$\boldsymbol{F_{w,vap,r} = \frac{q_{w,vap,r}}{q_{g,r}} = \frac{P_w(T_r)}{P_r}} \tag{1}$$

The water vapour is considered a component of the gas in $q_{g,r}$.

The partial pressure of water vapour in the gas at reservoir temperature, $P_w(T_r)$ may be calculated from [4][6]

$$\boldsymbol{P_W(T_r) = P_c\, e^{\left(a_1\vartheta + a_2\vartheta^{1.5} + a_3\vartheta^3 + a_4\vartheta^{3.5} + a_5\vartheta^4 + a_6\vartheta^{7.5}\right)\frac{T_c}{T}}} \tag{2}$$

with:

$\vartheta = \left(1 - \frac{T}{T_C}\right)$, T_C =647.096 K, P_C = 22.064 MPa, a_1 = -7.85951783, a_2 = 1.84408259, a_3 = -11.7866497, a_4 = 22.6807411, a_5 = -15.9618719, and a_6 = 1.80122502.

The fraction of water vapour in the gas increases with reservoir temperature and decreases with reservoir pressure. Figure 2 shows the vapour pressure of water as a function of temperature. The vapour pressure is 1bar at a temperature of 100°C and the water content declines rapidly at lower temperatures.

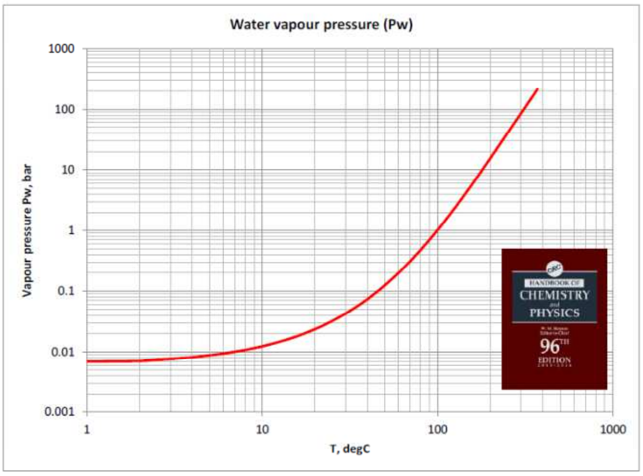

Figure 2 Vapour pressure of water as a function of temperature. From the Handbook of Chemistry and Physics, 96th Edition.

The volumetric rate of water vapour being produced can be expressed as a function of the total volumetric gas rate, which includes the water vapour.

$$q_{w,vap,r} = F_{w,vap,r} q_{g,r} = \frac{P_w(T_r)}{P_r} q_{g,r} \qquad (3)$$

We now convert the measured volumetric gas rate $q_{g,m}$ to reservoir conditions and express the produced water vapour in terms of mass flow.

$$Q_{w,vap,r} = \rho_{w,vap}(P_r, T_r) q_{w,vap,r} = \rho_{w,vap}(P_r, T_r) \frac{P_w(T_r)}{P_r} \frac{P_m T_r}{P_r T_m} q_{g,m} \qquad (4)$$

If hydrocarbons also condense out of the gas phase between reservoir and measurement conditions the relationship becomes a bit more complicated. In this case it will usually be necessary to create an Equation of State model to describe the PVT behaviour and find the gas rate at reservoir conditions. We will not discuss this further in this paper.

In the absence of formation water and with the qualifiers already mention, equation (4) gives the total quantity of water coming out of the well and that needs to be handled with respect to flow assurance.

The temperature of the gas will decrease as the gas enters the wellbore and travels upwards to the well head. The pressure will also decrease. As a result, some of the water vapour will usually condense into liquid water. Knowing the measured volumetric gas rate $q_{g,m}$, we can now calculate the mass rate of water still in vapour phase at measurement conditions (still ignoring any condensed hydrocarbons)

$$Q_{w,vap,m} = \rho_{w,vap}(P_m, T_m) \frac{P_{w,vap}(T_m)}{P_m} q_{g,m} \qquad (5)$$

The mass and volumetric rates of the water that is condensed to the liquid phase at measurement conditions are then

$$Q_{w,cond,m} = Q_{w,vap,r} - Q_{w,vap,m}$$

$$= \left(\rho_{w,vap}(P_r, T_r)\frac{P_w(T_r)}{P_r}\frac{P_m T_r}{P_r T_m} - \rho_{w,vap}(P_m, T_m)\frac{P_w(T_m)}{P_m}\right) q_{g,m} \qquad (6)$$

$$q_{w,cond,m} = \frac{Q_{w,cond,m}}{\rho_{w,vap}(P_m, T_m)} \qquad (7)$$

This condensed water is in itself free of ions and is non-conductive. There may be constituents in the gas, such as CO_2 or organic acids that will dissolve in the water and cause it to become slightly conductive. This needs to be assessed for each individual reservoir, and we will not discuss this further here.

If the well now starts producing formation water, it is no longer possible to estimate the total water production from a measurement of the gas rate alone. Additional measurements are needed.

4 FINDING THE RATE OF FORMATION WATER FROM MEASURING THE WATER CONDUCTIVITY

The rate of formation water may be calculated from a measurement of the conductivity of the liquid water if the salinity of the formation water and the rate of condensed water are known. We assume that the mass transfer of water from the liquid formation water to the gas phase between the reservoir and measurement conditions is negligible.

Let S_f be the salinity of the formation water and S_m be the salinity of the liquid water at measurement conditions. The latter is the formation water diluted by condensed water, so $S_m < S_f$. The salinity of the combined liquid water is the quantity of salt being produced with the formation water divided by the sum of formation water and condensed water.

$$S_m = \frac{S_f Q_{w,f}}{Q_{w,f} + Q_{w,cond,m}} \qquad (8)$$

The mass rate of formation water is then

$$Q_{w,f} = \frac{S_m}{S_f - S_m} Q_{w,cond,m} \qquad (9)$$

We see immediately that this method depends on the rate of produced formation water versus the rate of condensed water at measurement conditions. If the rate of condensed water is small, the measured salinity S_m will be very close to the salinity of the formation water S_f, and the calculated water rate will be very uncertain. It is necessary to analyse each case separately to determine the accuracy that can be achieved and the range of flow rates where it is applicable.

To give an idea about conditions where this method is applicable, we have calculated the measurement temperature T_m at which the rate of condensed water at measurement conditions is $q_{w,cond,m} = 0.2$ bbl/MMscf as a function of reservoir temperature T_r at different measurement pressures. The value of 0.2 bbl/MMscf is somewhat arbitrary, but with this rate of condensed water it will in most cases be possible to achieve estimates of the formation water rate with good accuracy over a wide range of formation water salinities and rates. The reservoir pressure is $P_r = 250$bar in this example.

Measurement pressures above 200 bar represent cases where the measurement is made upstream the production choke valve, while the lower pressures represent measurement locations downstream the choke valve.

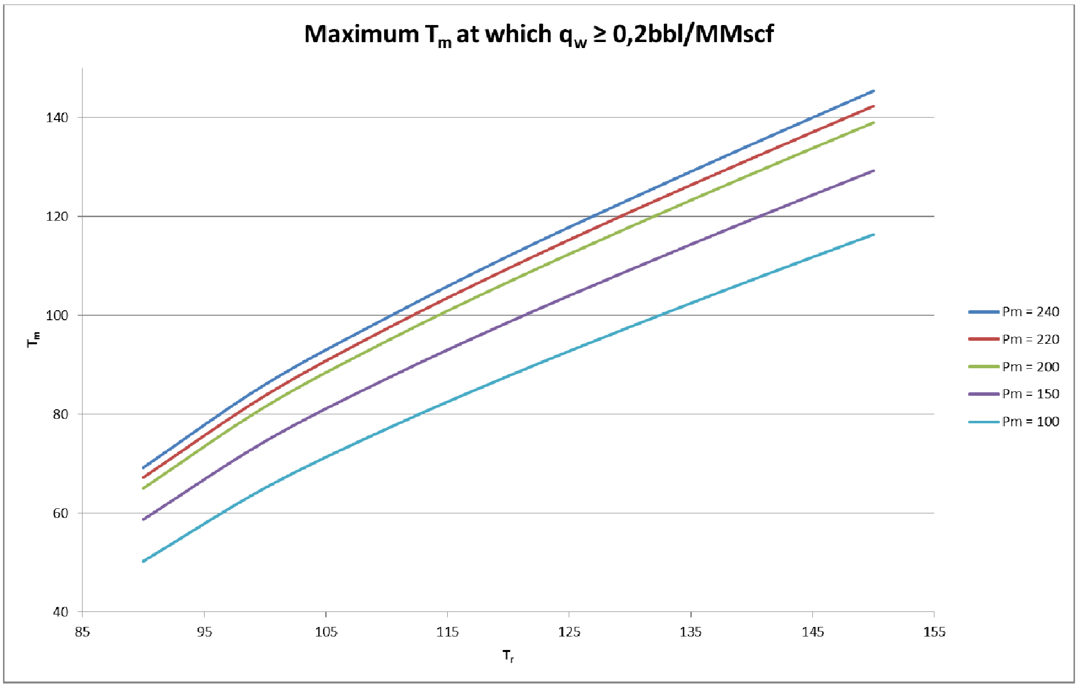

Figure 3 The measurement temperature T_m for which the rate of condensed water is $q_{w,cond,m} = 0.2$bbl/MMscf as a function of reservoir temperature T_r at different measurement pressures P_m. The reservoir pressure is 250 bar.

Let us now look at a simple example. Assume a gas well with the parameters shown in

Table 1. The measurement is made at the wellhead upstream the choke.

Table 1 Gas well parameters

Parameter	Symbol	Unit	Value
Reservoir Temperature	T_r	°C	140
Reservoir Pressure	P_r	bar	250
Gas rate	q_{gas}	MMscf/d	50
Measurement Temperature	T_m	°C	115
Measurement Pressure	P_m	bar	220
Formation water salinity	S_f	g/l	70

The resulting mass rate of water coming out of the reservoir in the gas phase is according to (4) 627 kg/h. This is equivalent to ~94 bbl/d at standard conditions. In normal operations and in the absence of formation water, an operator would decide the injection of hydrate inhibitors based on the lowest expected flowline temperature and this value including a healthy safety margin.

At measurement conditions the rate of condensed water is 295 kg/h equivalent to ~44.6 bbl/d. This represents a Water Volume Fraction of 833 ppm or 0.08 %. In the absence of condensed hydrocarbons and formation water, the Gas Volume Fraction would be 99.92 %.

First we determine the smallest formation water rate that may be detected. The conductivity of the water may be measured with an uncertainty of less than 0.2 S/m at low conductivities [5]. This is equivalent to a salinity of a bit less than 0.5 g/l at these measurement conditions. If the formation water has the salinity of seawater, which is 35g/l, it would require a formation water flow rate of less than 0.5 bbl/d to increase the salinity of the water at measurement conditions by this amount. Formation water with a salinity of 70 g/l would be detectable at a flow rate of less than 0.25 bbl/d.

We now calculate the formation water flow rate from the measured conductivity according to (9) and using the parameters in Table 1. Figure 4 shows the formation water flow rate as a function of measured conductivity.

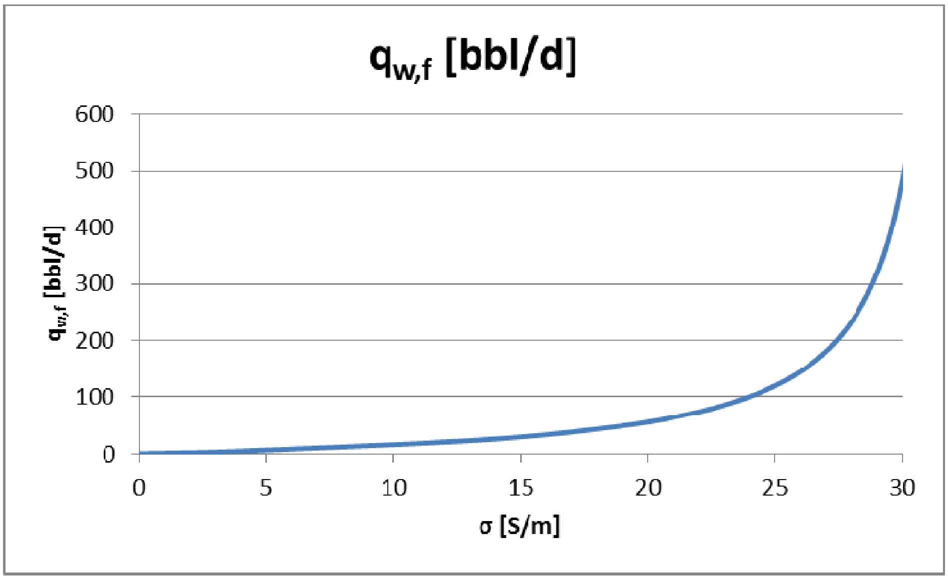

Figure 4 Formation water flow rate as a function of measured water conductivity.

When the formation water flow rate in this example exceeds 500 bbl/d, the measured salinity S_m starts approaching the formation water salinity S_f and uncertainties increase rapidly. The maximum formation water rate that can be reliably estimated in this way needs to be assessed for each individual case.

5 MEASURING THE GAS RATE

Differential pressure devices like Venturi tubes and V-Cones are widely used to measure gas and wet gas flow. The presence of liquid in the gas causes additional differential pressure and will cause the gas rate to be overestimated. This is known as over-reading.

There is a very rich literature on the topic of correcting the gas flow rate based on knowing the liquid rate, including *ISO/TR 11583:2012(en) Measurement of wet gas flow by means of pressure differential devices inserted in circular cross-section conduits*, and *ISO/DTR 12748:2014 Wet gas flow measurement in natural gas operations*. We do not intend to discuss the validity or accuracy of the various correction factors and correlations in this paper. The methods we describe do not depend on this, and the user may choose his or her favourite correlation.

The liquid rates at metering conditions are often very small and may constitute much less than 1% of the total volume. This makes it very difficult to measure them accurately. The liquid fraction may be calculated from PVT models and water saturation if the composition and the reservoir conditions are well known, but this is only applicable if there is no formation water. The ability to estimate the gas rate accurately then depends on whether formation water is present or not.

If there is no formation water it is sufficient to measure the differential pressure. Everything else can be calculated. In this case it is very important to detect the first formation water. We have already shown that the presence of formation water can be detected at very low levels by measuring the conductivity of the water, and in most cases we can assume that the uncertainties in the estimates of condensed water and hydrocarbon are much larger.

The most widely used correlations for correcting the gas flow rate measurement include the Lockhart-Martinelli parameter:

$$X = \frac{Q_{l,m}}{Q_{g,m}}\sqrt{\frac{\rho_{g,m}}{\rho_{l,m}}} \qquad (10)$$

In the absence of formation water, and still ignoring condensation of hydrocarbons from reservoir to measurement conditions, we get

$$Q_{l,m} = Q_{w,cond,m}$$

$$= \left(\rho_{w,vap}(P_r,T_r)\frac{P_w(T_r)}{P_r}\frac{P_mT_r}{P_rT_m} - \rho_{w,vap}(P_m,T_m)\frac{P_w(T_m)}{P_m}\right)q_{g,m} \qquad (11)$$

and

$$Q_{g,m} = \rho_{g,m}q_{g,m} \qquad (12)$$

hence

$$X = \frac{Q_{l,m}}{Q_{g,m}}\sqrt{\frac{\rho_{g,m}}{\rho_{l,m}}}$$

$$= \frac{\rho_{w,vap}(P_r,T_r)\frac{P_w(T_r)P_mT_r}{P_r\quad P_rT_m} - \rho_{w,vap}(P_m,T_m)\frac{P_{w,vap}(T_m)}{P_m}}{\rho_{g,m}}\sqrt{\frac{\rho_{g,m}}{\rho_{l,m}}} \qquad (13)$$

The Lockhart-Martinelli parameter does not depend on the liquid rate but solely on densities and fractions that can all be calculated from the fluid properties and pressure and temperature in the reservoir and at metering conditions. This is true also if hydrocarbons condense out of the gas, but as already mentioned we will not discuss this complication in this paper.

The liquid density is the density of the condensed water (ignoring condensed hydrocarbons).

A commonly used correlation for horizontal Venturi tubes is that of *de Leeuw*. The corrected gas mass flow rate is given as

$$Q_{g,m}^{corr.} = \frac{Q_{g,m}^{meas.}}{\phi} \qquad (14)$$

where ϕ is a correction factor based on *Chisholm's* correlation [1],[2]

$$\boldsymbol{\phi = \sqrt{1 + C_{Ch}X + X^2}} \qquad (15)$$

with

$$C_{Ch} = \left(\frac{\rho_{l,m}}{\rho_{g,m}}\right)^n + \left(\frac{\rho_{g,m}}{\rho_{l,m}}\right)^n \qquad (16)$$

Chisholm originally used *n = 0,25*, but *de Leeuw* introduced a modification of *n* based on the gas densimetric Froude number [3]

$$Fr_{gas} = \frac{v_{g,m}}{\sqrt{gD}}\sqrt{\frac{\rho_{g,m}}{\rho_{l,m}-\rho_{g,m}}} \qquad (17)$$

with

$$\begin{aligned} n &= 0.41 \quad \textbf{for} \quad 0,5 \le Fr_{gas} < 1.5 \\ n &= 0.606\left(1 - e^{-0,746 Fr_{gas}}\right) \quad \textbf{for} \quad Fr_{gas} \ge 1.5 \end{aligned} \qquad (18)$$

The densimetric Froude number does include the superficial gas velocity, but the error introduced by calculating this from the uncorrected gas rate is insignificant. All the other parameters depend on fluid properties, reservoir conditions, and measurement conditions.

If formation water is being produced, it is necessary to quantify the rate of formation water. We showed that this can be calculated from the rate of condensed water, which again can be calculated from the measured gas rate and the salinity. The salinity is found from the measured conductivity. The Lockhart-Martinelli parameter is then modified to

$$X = \frac{\left(1 + \frac{S_m}{S_f - S_m}\right)\left(\rho_{w,vap}(P_r, T_r)\frac{P_w(T_r)}{P_r}\frac{P_m T_r}{P_r T_m} - \rho_{w,vap}(P_m, T_m)\frac{P_{w,vap}(T_m)}{P_m}\right)}{\rho_{g,m}}\sqrt{\frac{\rho_{g,m}}{\rho_{l,m}}}$$

$$= \left(1 + \frac{S_m}{S_f - S_m}\right)\frac{f(P_r, T_r, P_m, T_m)}{\rho_{g,m}}\sqrt{\frac{\rho_{g,m}}{\rho_{l,m}}} \qquad (19)$$

This does not depend on rates either. The liquid density depends on the salinity and fraction of formation water. Again ignoring condensed hydrocarbons, we find that

$$\rho_{l,m} = \frac{Q_{w,cond,m} + Q_{w,f}}{q_{w,cond,m} + q_{w,f}} = \frac{Q_{w,cond,m} + Q_{w,f}}{\frac{Q_{w,cond,m}}{\rho_{w,cond,m}} + \frac{Q_{w,f}}{\rho_{w,f}}} =$$

$$= \frac{1 + \frac{S_m}{S_f - S_m}}{\frac{\rho_{w,f}}{\rho_{w,cond,m}} + \frac{S_m}{S_f - S_m}} \rho_{w,f} \qquad (20)$$

Determining the liquid density depends only on knowing the formation water salinity and the salinity of the water at measurement conditions.

The Froude number and the Chisholm parameter are also updated with the new liquid density.

6 A NEW TYPE OF THREE-PHASE WET GAS FLOWMETER

We have so far shown that we, in wet gas flow, can measure the gas rate with a differential pressure meter and correct the over-reading. The correction can be made without additional measurements if we can verify that the well is not producing any formation water.

If formation water is being produced, we have shown that it is sufficient to measure the conductivity of the liquid water at the measurement conditions in order to determine the total liquid rate and correct the gas rate, at least when there is sufficient condensed water. This requires, however, that the reservoir conditions and fluid properties are known.

The workflow can be summarized as follows:

- Characterize fluid behaviour, if needed by building Equation of State models covering reservoir and well measurement conditions.
- Measure pressure, temperature, and differential pressure at measurement conditions
- Calculate the fluid densities at measurement conditions
- Measure reservoir pressure and temperature
- Calculate the liquid fractions at measurement conditions
- Measure the conductivity of the liquid water
- If formation water is present, estimate the fraction of formation water and update the liquid fraction and liquid density
- Calculate a corrected gas rate
- Calculate the liquid rates from the corrected gas rate

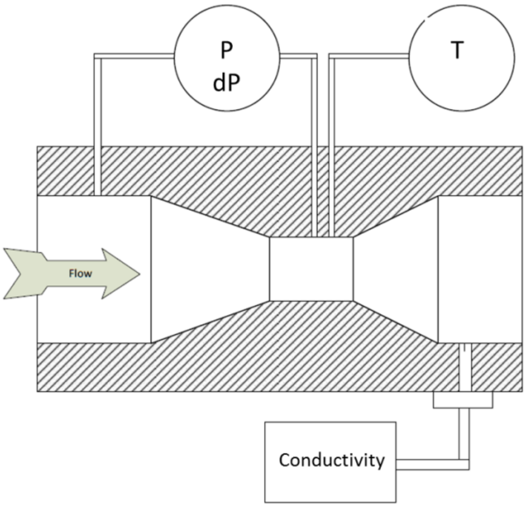

Figure 5 Wet gas flowmeter combining a differential pressure flowmeter and a water conductivity measurement.

7 EXAMPLE

Let us now return to the example from section 5 and look at the effect of increasing formation water rates. We have calculated the over-reading in the gas rate and the salinity and conductivity of the water that is liquid at measurement conditions, that is – the mixture of formation water and condensed water. We have then applied the workflow from section 7 starting with the gas rate and the water conductivity as they would be measured.

The condensed water rate of 44,6 bbl/d will cause an over-reading in the gas rate of 0.5%. As the formation water rate increases from 0 to 550 bbl/d the Lockhart-Martinelli parameter increases to 0,0342, and the over-reading increases to 7%.

Figure 6 shows the measured gas rate as a function of formation water rate. The true gas rate is 50 MMscf/d. The line labelled "Corrected, ignoring form. w." shows the gas rate corrected for the condensed water only, and the line labelled "Corrected" shows the gas rate corrected for both the condensed water and the formation water based on the measured water conductivity. The deviation between the corrected gas rate and the reference is caused by cumulative errors through the forward and inverse modelling and amounts to ~0.25% at 550 bbl/d of formation water.

The corrected gas rate is a function of many parameters, and many uncertainties are involved, but we will now focus on the sensitivity to the uncertainty associated with the measurement of the water conductivity. We have assumed a maximum measurement error of 0.5 S/m. This is conservative, in particular at low water salinities. In Figure 6 the resulting gas rate estimates are labelled "Corrected, S +0.5" and "Corrected, S -0.5" respectively. Note that if the measured water conductivity is higher than the true water conductivity the water rate will be over-estimated and the correction will be too large. The corrected gas rate will in this case be too small.

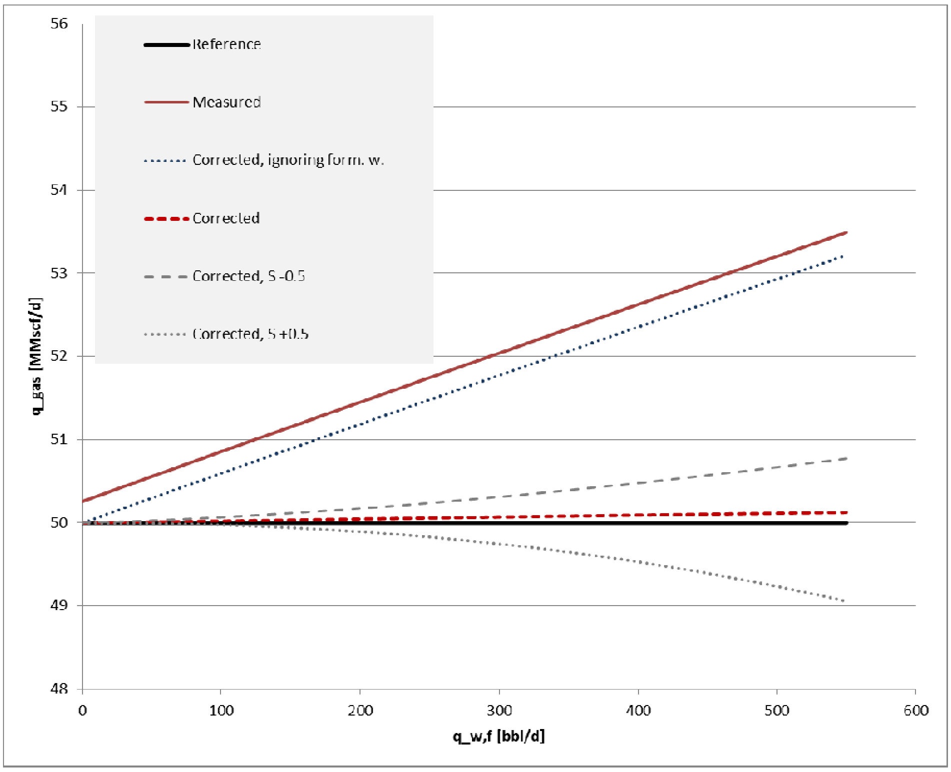

Figure 6 Estimated gas rate as a function of the formation water rate.

We also note that the sensitivity is higher when the measured conductivity is too high than when it is too low. This is caused by the increasing slope of the formation water as a function of water conductivity, as seen in Figure 4.

8 CONCLUSIONS

Gas and wet gas wells are producing from formations where all the produced fluids initially are in the gas phase, with the exception of possible formation water. If no formation water is being produced, it is possible to calculate all liquid fractions from composition and knowledge about reservoir conditions and measurement conditions. These liquid fractions may be used to correct a differential pressure gas rate measurement.

Additional measurements are required when formation water is being produced. In this paper we have shown that it is sufficient to measure the conductivity of the water. We have described a workflow for estimating the formation water fraction, and then using this to correct a differential pressure gas rate measurement and the liquid rates derived from the gas rate.

9 NOTATION

The following notation is used for variables and parameters being measured or calculated:

C_{Ch}	Chisholm's parameter
D	diameter
F	volume fraction
Fr	densimetric Froude number
P	pressure
P_w	vapour pressure of water
q	volumetric flow rate
Q	mass flow rate
ρ	mass density
S	salinity of water
T	temperature
v	velocity
X	Lockhart-Martinelli parameter
ϕ	gas mass rate correction factor

The following subscripts are used to indicate which fluid is being measured or calculated:

g	gas
l	liquid
w	water
f	formation water

The following subscripts are used to indicate the conditions where a variable is measured or: calculated

r	reservoir condition
m	metering conditions, normally at or near the well head
C	conditions of the critical point of water

The following subscripts indicate the phase of the liquid being measured or calculated:

$cond$	liquid water that was in vapour phase in the reservoir but is now condensed
vap	water in vapour phase

10 REFERENCES

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