Wet Gas Measurement in the Southern North Sea

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Abstract

ConocoPhillips has some 18 wet gas Venturi meters currently in use in the UK sector of the North Sea.

The paper covers:-

The experience gained in operating these meters:

- The importance of gas flow calibration. Flow calibration of these meters clearly shows that the discharge coefficient value given in ISO 5167 is clearly not applicable and the discharge coefficient can vary by > ±2%.
- The effect damage has had on the discharge coefficient of one meter arising from a broken choke impinging on the meter convergent section.
- Calibration repeatability over time
- The methods used to correct the over-reading (namely Murdock, Chisholm and de-Leeuw).
- Flow verification tests carried out on two meters installed in the Southern North Sea.
  - First, a sub sea meter located some 34km from the host platform. This not only demonstrated applicability of using a correct wet gas correlation but also gave valuable information on how gas, condensate and water flow along a pipeline
  - Second, a topside meter installed on an unmanned satellite, where verification was conducted over about a year. This showed very good agreement between the Venturi meter readings and high quality separator gas and condensate meters it was tested against.

A way forward: From the experience gained we propose a practical and cost-effective method of monitoring the liquid content of wells/satellite fields in a wet gas allocation system.

1. Introduction

ConocoPhillips uses Wet Gas Venturi meters extensively in its Southern North Sea operations. New gas fields are too small to justify full-scale separation and are tied back to host facilities using existing pipeline infrastructure and separation facilities.

The following are examples of the advantages of Wet Gas Venturi meters.

- They are robust instruments and are not damaged by high flow rates.
- They do not ‘dam’ the flow (unlike orifice plate meters).
- They use proven technology that has been widely accepted within the oil and gas industry, such as differential pressure, static pressure and temperature transmitters.
- They can operate at higher differential pressure than orifice plate meters without incurring permanent meter damage (differential pressure up to 4 bar can be used).
- When combined with smart differential pressure transmitters they have a relatively large turn down approaching 10:1.
- Provided sufficient care is taken in the manufacture and the selection of the secondary instrumentation they are very suitable for subsea use.
- Extensive work has been carried out to develop practical correlations for the over-reading of Venturi meters due to liquid entrained in the gas flow.

The design requirements for Venturi-type flow meters are contained within ISO 5167:2003, Parts 1 and 4. Note that this standard does not apply to wet gas. For example, piezometric rings are not suitable for wet gas applications as the rings will fill with liquid. Furthermore the Venturi section of ISO5167 was originally developed for single phase liquid applications. The 2003 edition acknowledges that Venturi meters are increasingly used for gas applications, and that they should be calibrated over the expected operating flow range. We present calibration data in this paper which highlights these issues.

In this paper we discuss three aspects of wet gas Venturi metering.

- Meter calibration issues including the effects of damage on a Venturi
- The most appropriate wet gas correction correlation
- Verification of operational Venturi meters.

Combining the findings from these aspects we suggest a practical and cost effective method for verification of wet gas Venturi meters that requires limited shutdown of associated facilities.

2. Venturi Meter Calibration Issues

2.1. Gas Discharge Coefficient

We present calibration data for the meters currently in use.

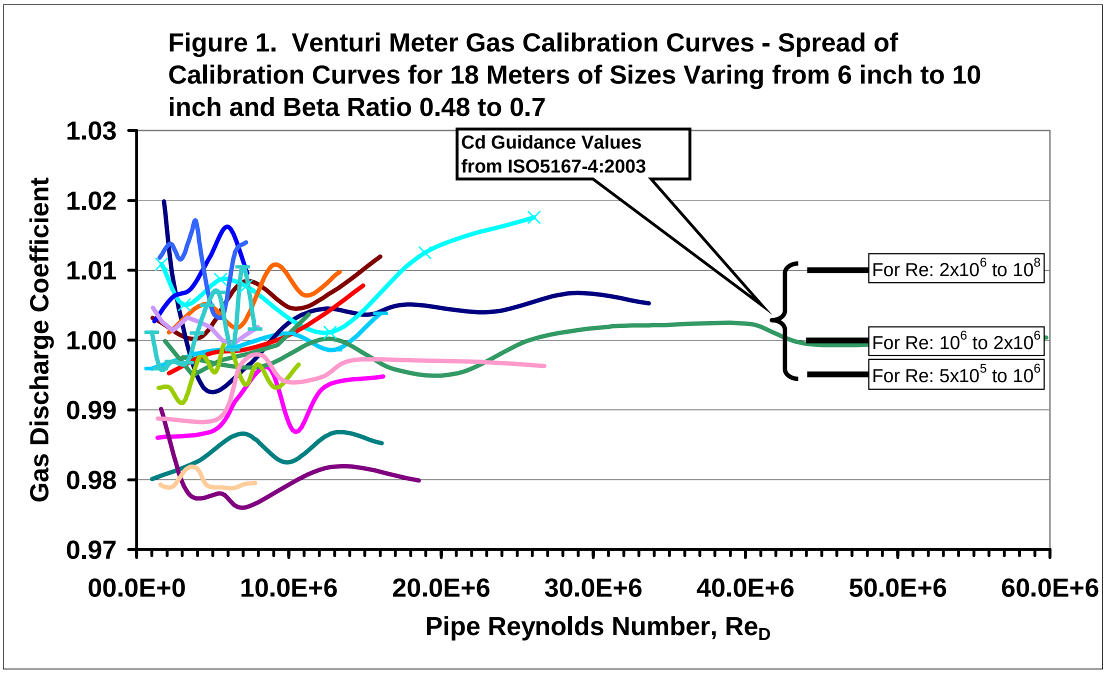


Figure 1 above shows similar gas calibration curves for 18 Venturi meters with diameters ranging from 6 to 10 inches and beta ratios ranging from 0.48 to 0.7. The meters were calibrated at the Advantica Flow Centre at Bishop Auckland on sales-quality natural gas. For the meters calibrated, the variation in discharge coefficients is about 4%. The curves themselves are evidently not linear, and many show sharp kinks. This confirms findings by Jamieson et al (Ref [1]).

These data confirm the statement in Note 1 of ISO5167-4:2003 that in many cases the discharge coefficients lie outside the range predicted by part 4 by 2% or more. However, the data are in conflict with Annex B, Table B.2, of the above standard, which is given for guidance when classical Venturis are used outside the scope of ISO5167-4. In particular this table gives a discharge coefficient of 1.01 for throat Reynolds Numbers between $2x10^6$ and 10^8. This would lead to an average bias of about -1.5% for the ConocoPhillips meters. On the right hand side of Figure 1 we have indicated the recommended values from Table B.2.

The important issue is that unless you can accept a meter calibration uncertainty of about 3%, potentially with a large bias, then you should follow the advice of ISO5167-4 and determine the value of the discharge coefficient from an actual calibration on gas. We consider that considerably more work must be done to clarify the guidance given by the standard on this issue.

We now split out these meters by manufacturer. Figure 2 and 3 below show the Discharge Coefficient calibration curves for meter Manufacturer A and Manufacturer

B. It is evident that the variations in calibration curves are similar and therefore cannot be attributed to the manufacturer.

Figure 2. Venturi Meter Gas Calibration Curves - Meter Manufacturer A - Spread of Calibration Curves

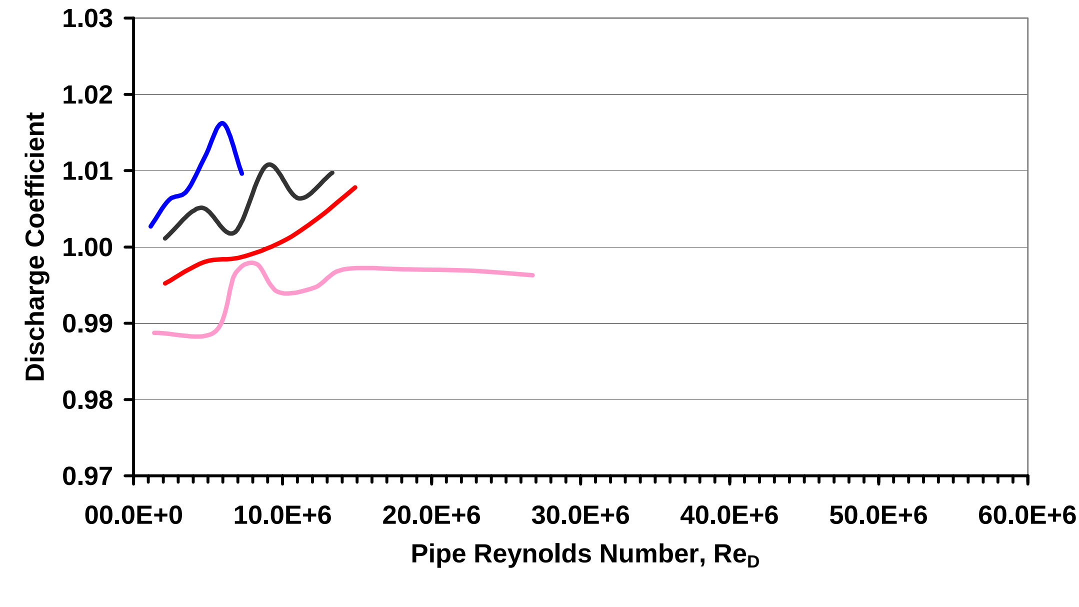
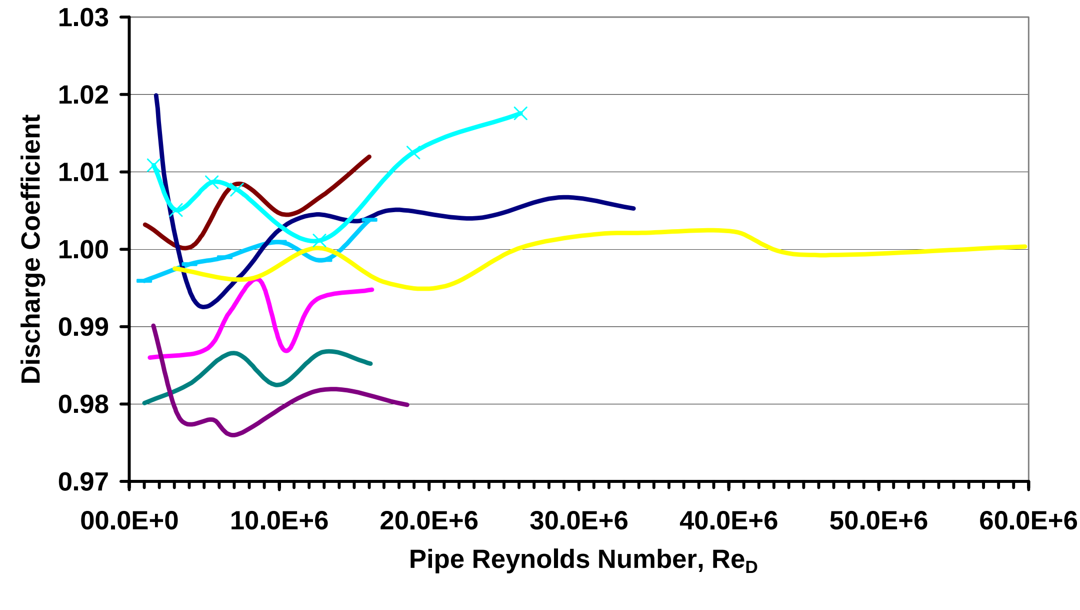


Figure 3. Venturi Meter Gas Calibration Curves - Meter Manufacturer B - Spread of Calibration Curves



Three of the meters supplied by Manufacturer B are nominally identical. Figure 4 below, shows the gas discharge coefficient curves for three 6 inch meters. These meters are identical within machining tolerances, being manufactured using the same computer numerical controlled (CNC) boring machine. The tapping holes were drilled using a vertical borer and deburred to remove any burrs. These calibration curves differ by as much as 2%, and the shape of the curves is markedly different.

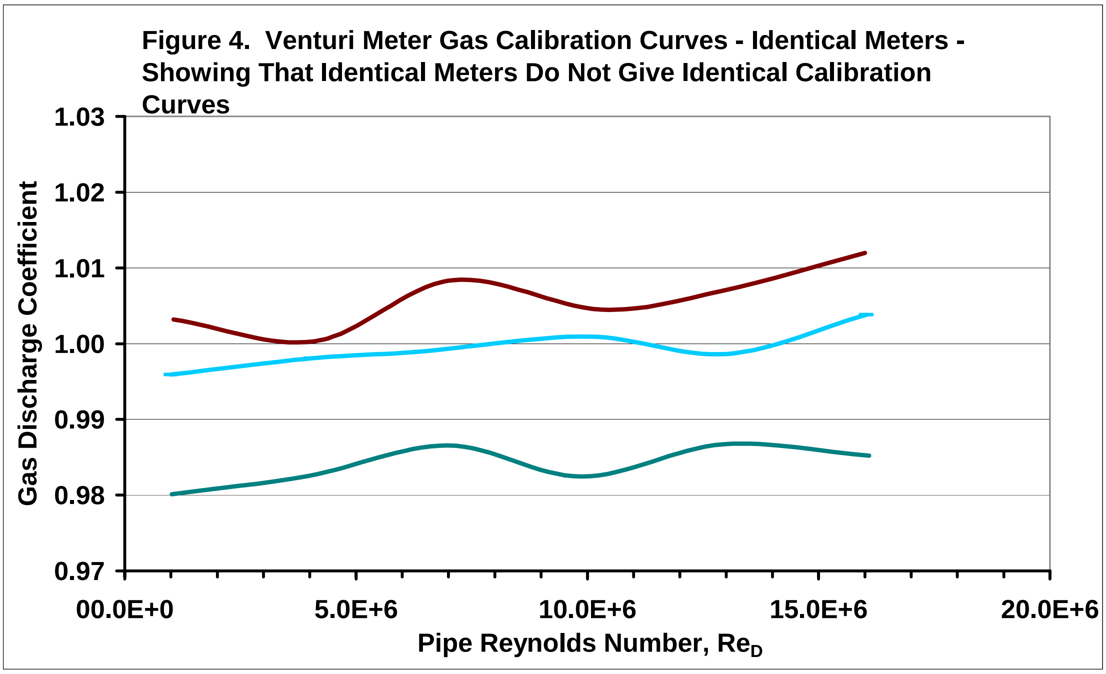


Figure 4. Venturi Meter Gas Calibration Curves - Identical Meters - Showing That Identical Meters Do Not Give Identical Calibration Curves

2.2. Liquid Discharge Coefficient

The correlations used to correct for liquid entrainment in wet gas require both the gas and liquid discharge coefficients which are usually not the same. Liquid discharge coefficients were determined on the water calibration facility at the E.ON Hams Hall Calibration Laboratory.

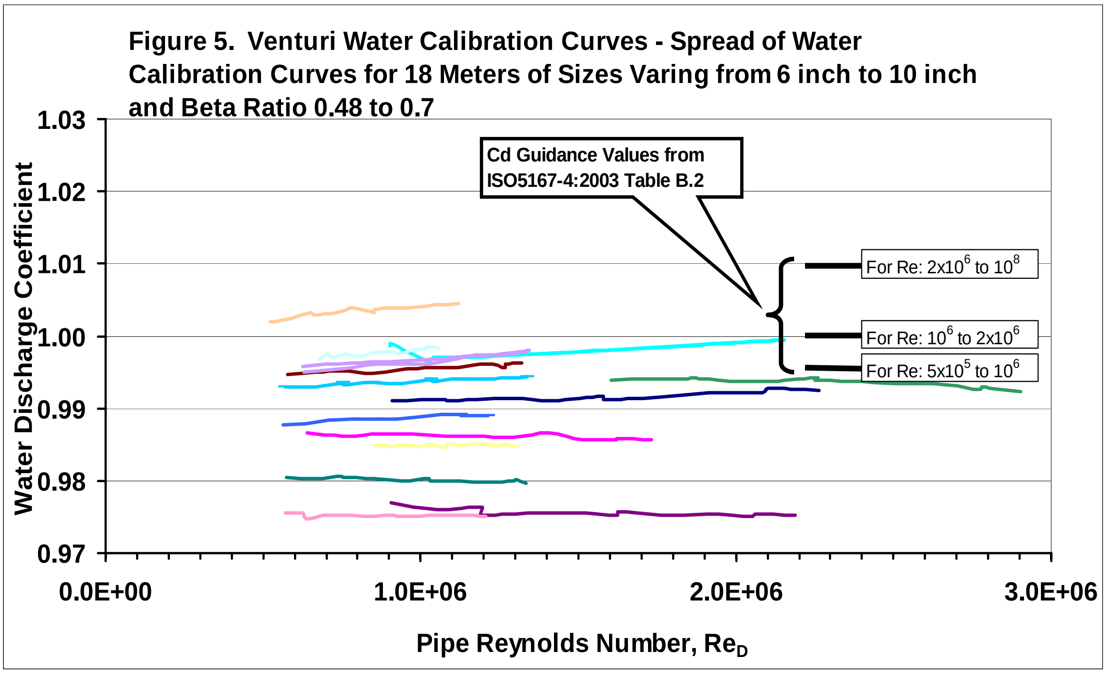


Figure 5. Venturi Water Calibration Curves - Spread of Water Calibration Curves for 18 Meters of Sizes Varing from 6 inch to 10 inch and Beta Ratio 0.48 to 0.7

Figure 5 above shows the water discharge coefficients for the same meters given in Figure 1. The water discharge coefficient curves are significantly more linear than the gas curves. The spread in water discharge coefficient, about 3%, however, is similar that that for the gas curves. ISO5167-4:2003 gives a value of 0.995 ±1% for throat Reynolds Number up to 10^6. Our calibrations are clearly in conflict. Note, however, that the liquid discharge coefficient has a second order effect in the wet gas calculations. We have not investigated this effect in detail at this stage.

We give below the calibration curves for both liquid and gas for the last six meters calibrated. These show that the water discharge coefficient curve lies below the gas curve. It may be practical, therefore, simply to take the lowest value of the gas discharge coefficient as the liquid discharge coefficient and dispense with the water calibration.

Figure 6. Meter A (6 Inch) Relationship Between Gas & Water Discharge Coefficient Calibration Curves

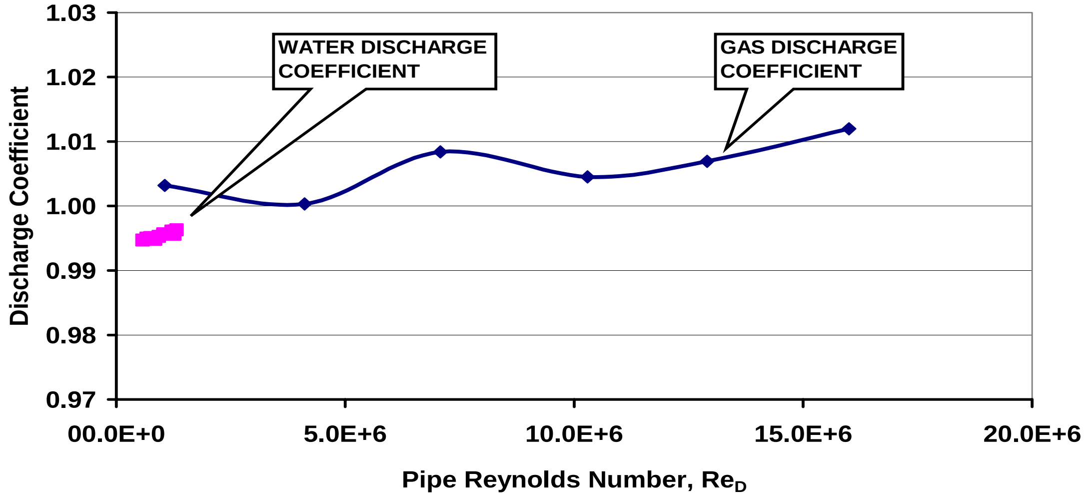


Figure 7. Meter B (6 Inch) Relationship Between Gas & Water Discharge Coefficient Calibration Curves

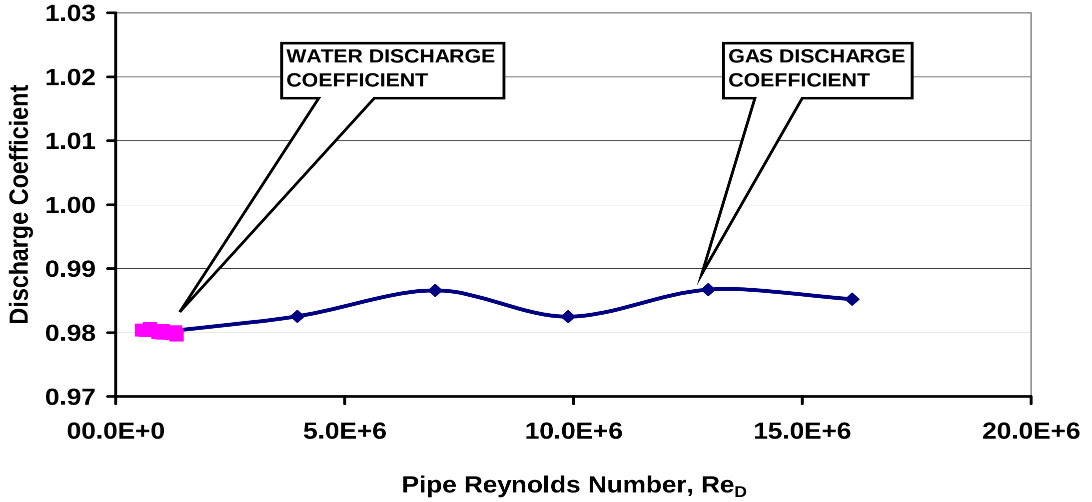


Figure 8. Meter C (6 Inch) Relationship Between Gas & Water Discharge Coefficient Calibration Curves

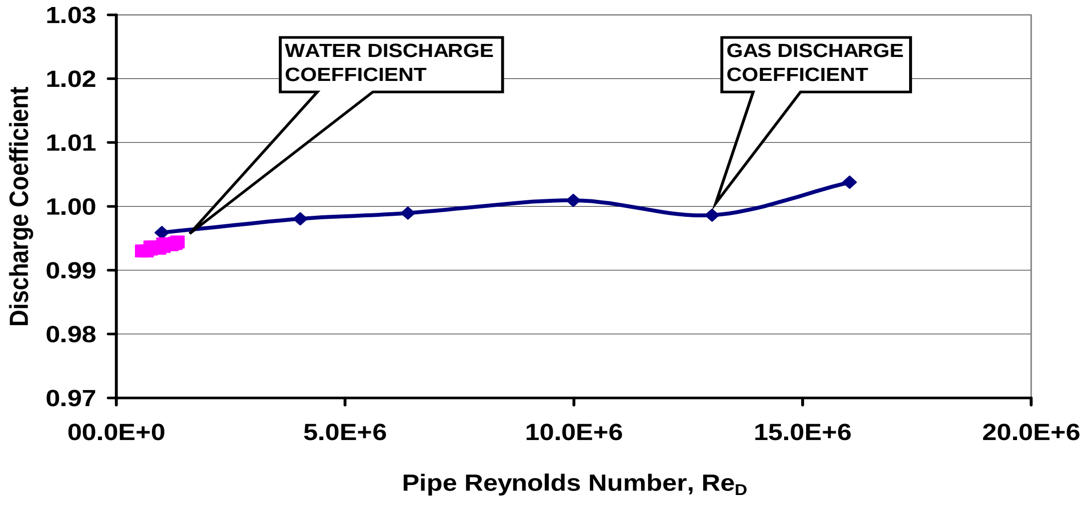


Figure 9. Meter D (8 Inch) Relationship Between Gas & Water Discharge Coefficient Calibration Curves

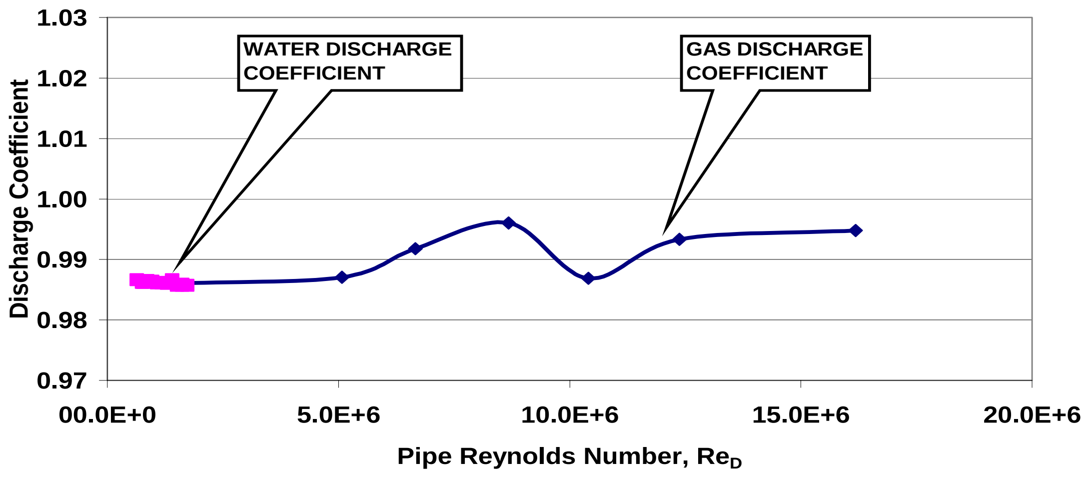


Figure 10. Meter E (8 Inch) Relationship Between Gas & Water Discharge Coefficient Calibration Curves

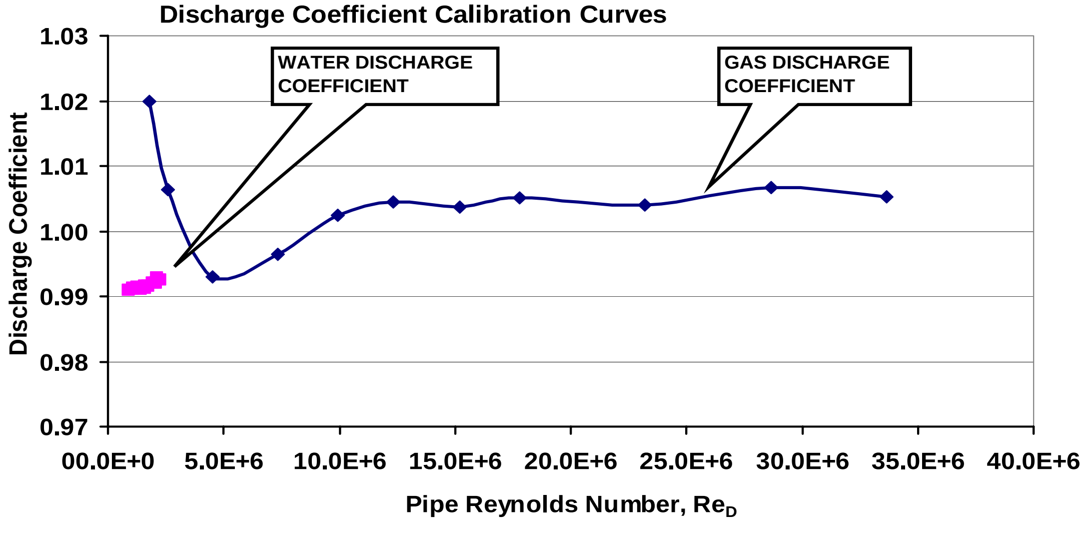
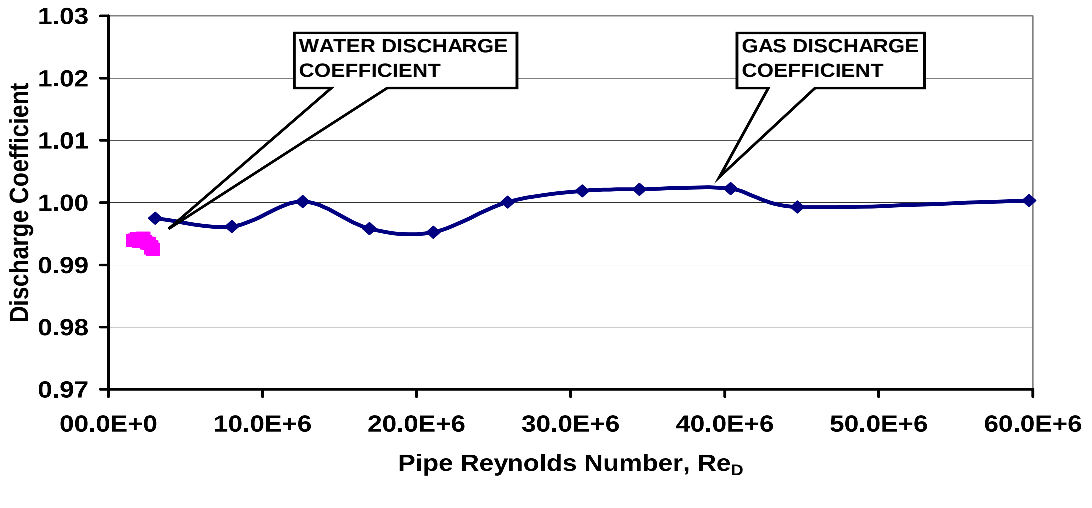


Figure 11. Meter F (10 Inch) Relationship Between Gas & Water Discharge Coefficient Calibration Curves



2.3. Effect of Damage to Meter on Discharge Coefficient

This section discusses the effect of damage from a broken choke on a Venturi meter.

The meter was installed immediately down-stream of a well head choke valve. The choke failed and part of the tungsten carbide flow control element was swept into the throat of the Venturi meter. The well was shut-in and the meter spool was removed from the line.

Figure 12 below shows the two recovered parts of the choke flow control element reassembled.

Figure 12. Recovered Flow Control Element

Figure 13 below shows the significant damage sustained by the upstream conical section. Note the deep scores. No damage was noted in the throat section or around the pressure tappings.

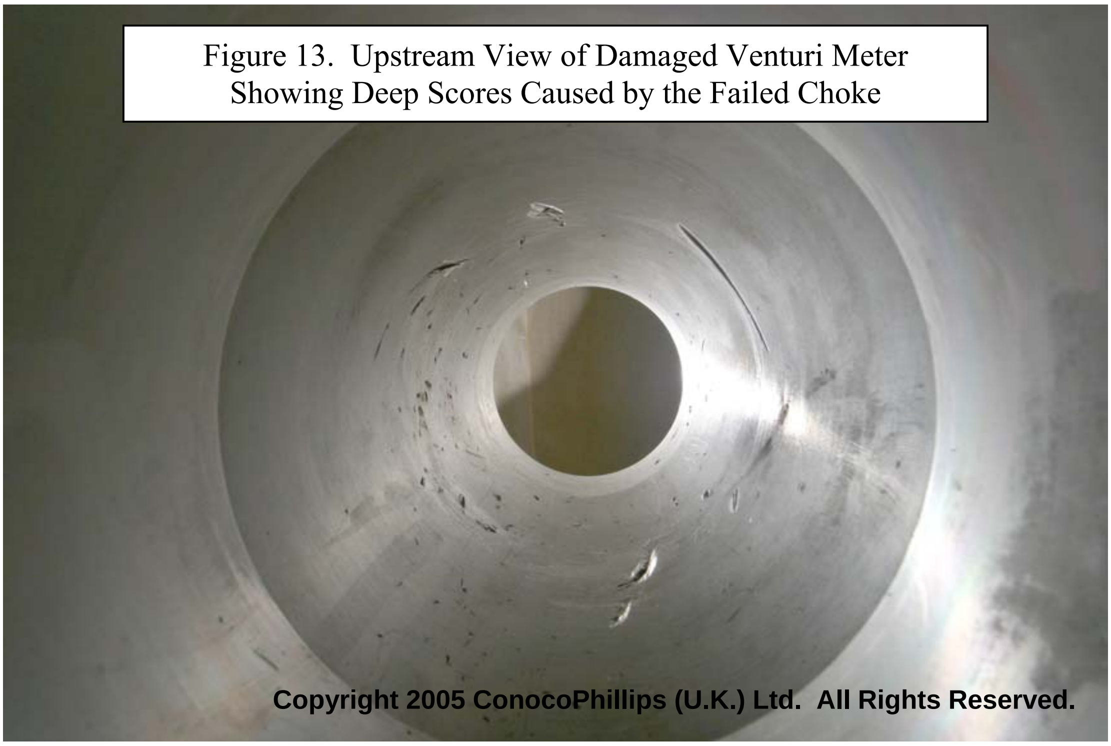


Figure 13. Upstream View of Damaged Venturi Meter Showing Deep Scores Caused by the Failed Choke

Figure 14 below shows the downstream conical section. Apart from slight pitting this section of the meter was not damaged.


Figure 14. Downstream View of Damaged Venturi Meter

Our original plan was to re-machine the damaged section of the meter, recalibrate it and return it to service. However, we decided to determine the effect that the damage would have had on the flow calibration. Accordingly the meter was recalibrated at Bishop Auckland where its original calibration had taken place.

Figure 15. Before and After Gas Discharge Coefficients Showing Effect of Damage on the Meter Performance

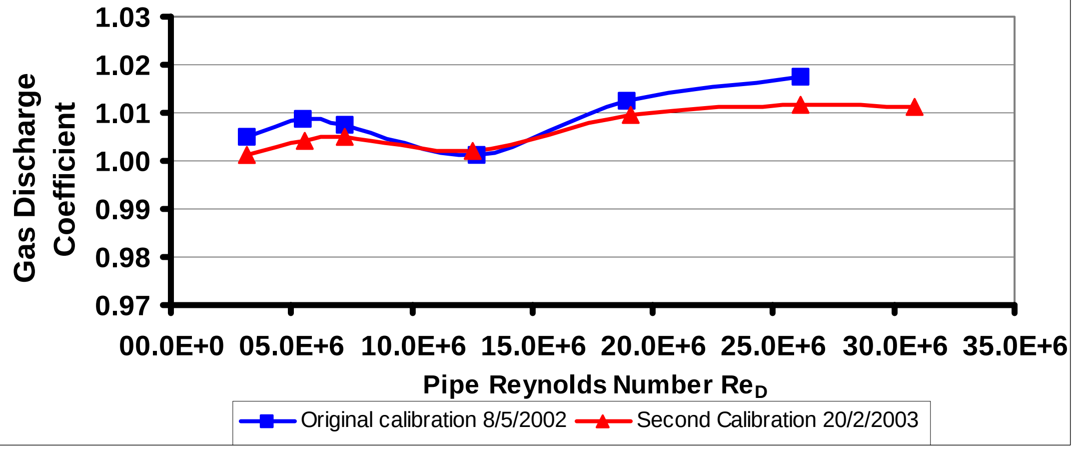


Figure 15 above shows the original calibration performed before the meter was installed prior to first production, and the calibration curve following the damage caused by the choke valve failure. It is evident that the damage had little effect on the meter discharge coefficient. We considered that the difference was as likely to be due to the uncertainty of the calibration as to a shift in calibration. Accordingly the meter was reinstalled without re-machining. We can offer no guidance as to the degree of damage that would result in a significant shift in discharge coefficient.

3. Wet Gas Correction

The equation for measuring dry gas flow using a Venturi meter is:

$$Q_g = \frac{Cd_g}{\sqrt{1-\beta^4}} * \varepsilon * \frac{\pi}{4} * \left(d'\right)^2 * \sqrt{2 * h * \rho_g}$$

Where:

Q_g	Mass flow rate
Cd_g	Discharge coefficient
d'	Venturi throat diameter at operating conditions (m)
ρ_g	Gas density at upstream tapping (kg/m^3)
β	Venturi Throat/Pipe Diameter ratio
h	Differential pressure (mbar)
ε	Expansibility factor

Liquids flowing through the meter in the gas flow will cause an increase in differential pressure over and above that would occur if there were no liquids present. This causes the meter to over-read in terms of dry gas, as follows.

$$Q_{g(ind)} = \frac{Cd_g}{\sqrt{1-\beta^4}} * \varepsilon * \frac{\pi}{4} * (d')^2 * \sqrt{2 * h_{(ind)} * \rho_g}$$

Where:

$Q_{g(ind)}$ Indicated mass flow rate

$h_{(ind)}$ Indicated differential pressure

It is therefore necessary to apply a correction to obtain a correct dry gas reading. This is applied in the form:

$$Q_{drygas} = \frac{Q_{g(ind)}}{Wet\ Gas\ Correction}$$

Where:

Q_{drygas} Venturi dry gas mass flow rate

The correlations currently used in wet gas metering were largely introduced by Shell Research. From field experiments at Coevorden in the Netherlands, Washington (Ref [2]) related the performance of Venturi meters to the earlier work carried out at NEL on orifice plate meters by Murdock and Chisholm. At low liquid fractions (less than 1%) and high pressures (around 100 bar) there is little to chose between the modified Murdock or Chisholm corrections.

Shell Research followed this work up by extensive testing at SINTEF in Norway covering a wide range of pressure and liquid content. The correlation from this work and the extent of the data, though not the detailed data set, has been published and is available in the public domain. Ref [3] is the most relevant. In this work de Leeuw showed that Murdock and Chisholm corrections are not suitable for general application particular at lower pressures and higher liquid fractions. Murdock takes no account of pressure; Chisholm does not take into account gas velocity. The de Leeuw correlation is much more appropriate for general application and the Murdock and Chisholm correlations should be retired.

Work carried out at NEL has revealed yet another dependence, this time on the β value of the Venturi meter, Ref [4]. The work at NEL can best be regarded as extending de Leeuw's work, and impacts at higher liquid content. De Leeuw's correlation is currently gradually being accepted as meter specialists realise the shortcomings of Murdock and Chisholm at higher liquid content and at lower pressure; the NEL work has not yet had the chance to be assimilated.

The following Figures 16 and 17 are taken from de Leeuw's paper cited above.

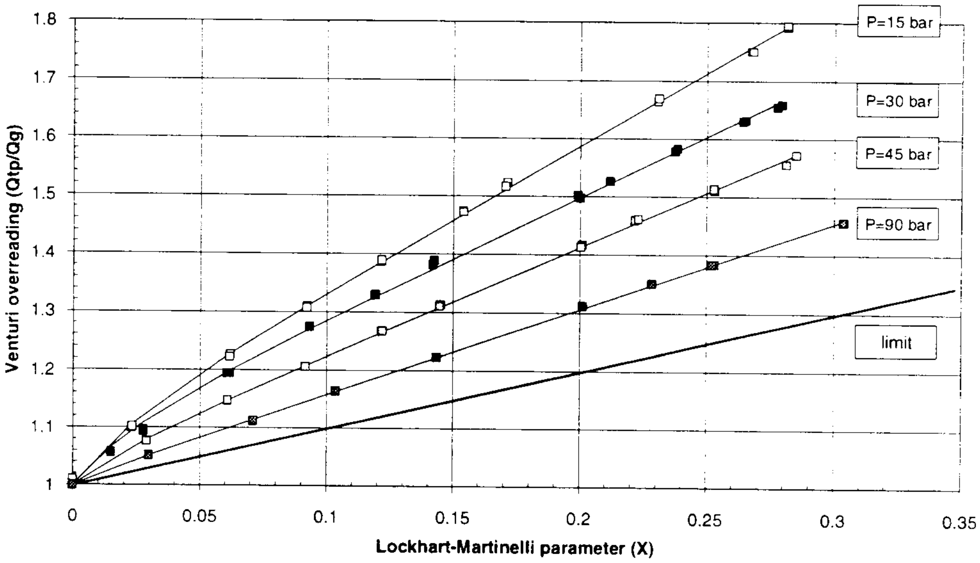


Figure 16. Trondheim Test Results Showing Venturi Overreading Against Liquid Fraction, Expressed as the Lockhart-Martinelli Parameter. Frg=3.2

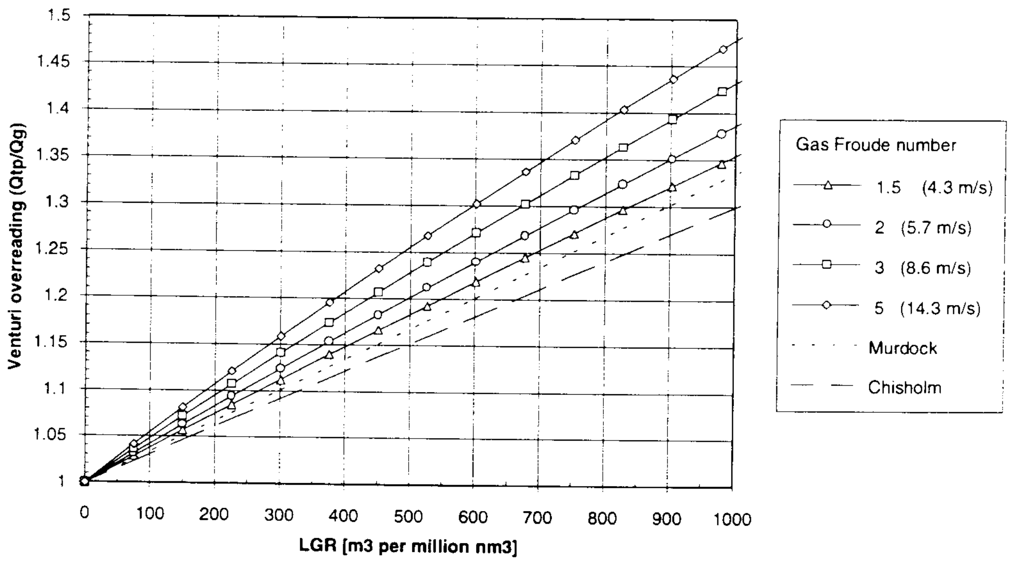


Figure 17. Illustrative Comparison Between the new Venturi Correlation and the Murdock and Chisholm Orifices relationships, for the Case ρ_l=700kg/m^3 and ρ_g=80kg/m^3

Figure 16 shows the test points measures at SINTEF, and gives the over-reading measured for the Venturi (4@ nominal diameter, β = 0.4) at pressures ranging from 15 to 90 bar, against the Lockhart-Martinelli parameter, a convenient parameter for expressing liquid fraction in multiphase flow studies. The SINTEF test loop uses diesel and nitrogen as working fluids. The lowest pressure was 15 bar, corresponding to a nitrogen density of 17 kg/m^3. Evidently this is the reason for de Leeuw restricting his correlation to gas densities above 17 kg/m^3. The NEL work was also based on nitrogen, and again the lowest test pressure was 15 bar.

Figure 17 illustrates the difference between de Leeuw correlation and the Chisholm and Murdock relationships. It shows the predicted Venturi over-reading for liquid and gas densities of 700 and 80 kg/m3 respectively plotted against the LGR (liquid to gas ration – m^3 liquid per million Sm3 gas) for different Froude Numbers. The gas Froude Number is often used as a convenient parameter relating to gas velocity in multiphase studies, as is the superficial gas velocity (v_{sg}), the velocity calculated assuming the gas is the only phase present. Figure 17 shows clearly the strong dependence of over-reading on gas velocity, and also that Chisholm and Murdock predict much lower over-readings.

4. SubSea Venturi Meter Verification

An opportunity was given in 2003 to verify a subsea Venturi meter measuring the wet gas production from a single well field in the Southern North Sea. The gas and liquids production was commingled in a subsea pipeline with the fluids from other fields and was transported a to central processing facility, where the combined gas and liquid production from the pipeline was metered at the outlets of a production separator.

4.1. Gas Measurement

The gas was metered by an orifice plate metering station designed and operated in accordance with ISO5167.

The meter verification was carried out by shutting-in the other fields producing into the 34km long pipeline and flowing only to the test field. Following a 24 hour stabilising time the test field meter readings were then compared with the gas, condensate and water readings from the production separator on the central processing facility.

It had been intended to carry out the meter verification at the same flow rate as when the test field produced normally into the pipeline. However, shortly before the verification started, the well annulus pressure was too high, and it was necessary to increase the well tubing pressure to ensure safe operation. This meant that the gas flow rate had to be reduced to about 90% of the then current normal production. This was considered acceptable. Production from the test field was steadily declining, and a verification at the reduced flow rate was considered to be more representative of average production conditions until the next planned verification.

However, there were further difficulties, with the consequence that the gas flow rate was reduced to 50% of the current normal production from the test field. Half way through the verification period, the difficulties were sufficiently resolved to allow the well flow rate to be increased back to 90% of the current normal flow.

During the stabilisation period, a preliminary comparison of the test field and central processing facility metering figures showed that the test field was indicating some 17% higher than the central processing facility.

It was clear that the verification was not proceeding in the straightforward way that had been intended. It was considered that it was essential to continue the test, not merely because it would take a long time to set up another one, but because it was evident that much more information would come from the test. It was agreed to continue for the full verification period and gather as much information as possible to allow ConocoPhillips to evaluate possible options thoroughly. The enforced need for two flow rates during the verification period meant that it was possible to look for a flow dependence in the difference between the test field and central processing facility metering figures.

Figure 18 below shows the gas data from the test field meter and central processing facility gas meters. The time scale is 4.5 days. The stabilisation and test periods are indicated. The average over-reading by the test field meter over the verification period was 16.7% (referred to the central processing facility metering readings) or 14.3% (referred to the test field meter reading).

Figure 18. Subsea Venturi Meter Verification - Gas Measurement

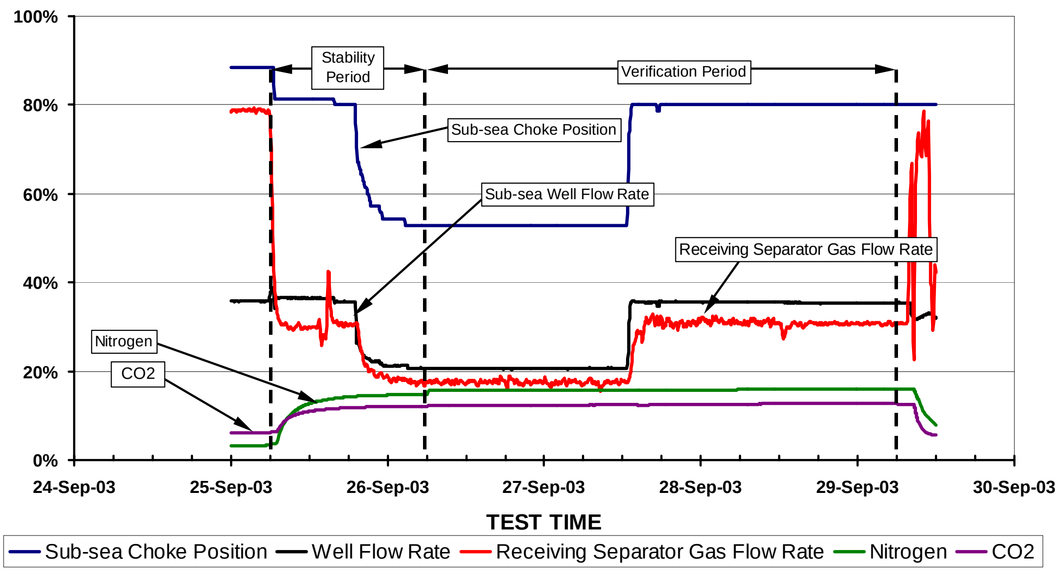


Figure 18 also shows the choke settings for the test field well. The field production follows these settings quite precisely, and the field flow rate was very stable.

Finally Figure 18 also shows the molar concentrations of nitrogen and carbon dioxide measured by the gas chromatograph on the central processing facilities. The concentration of these inert components are significantly different from the average composition of all of the fields producing into the pipeline, and so they provide an excellent indication of when test field gas filled the pipeline. The blips at 06:00 each morning are when the automatic calibration of the GC was performed. It is evident that by the end of the stabilisation period, the test field gas filled the pipeline.

In summary:

- During the verification period, the test field meter read higher than the central processing facility metering by 16.7%
- The difference between the test field and central processing facility metering figures appears to be flow related.
- Test field gas filled the pipeline in the stabilisation period.

4.2. Water Production

The produced water was measured by a 4" magflow process meter with no pressure or temperature corrections.

Figure 19. Subsea Venturi Meter Verification - Water Measurement

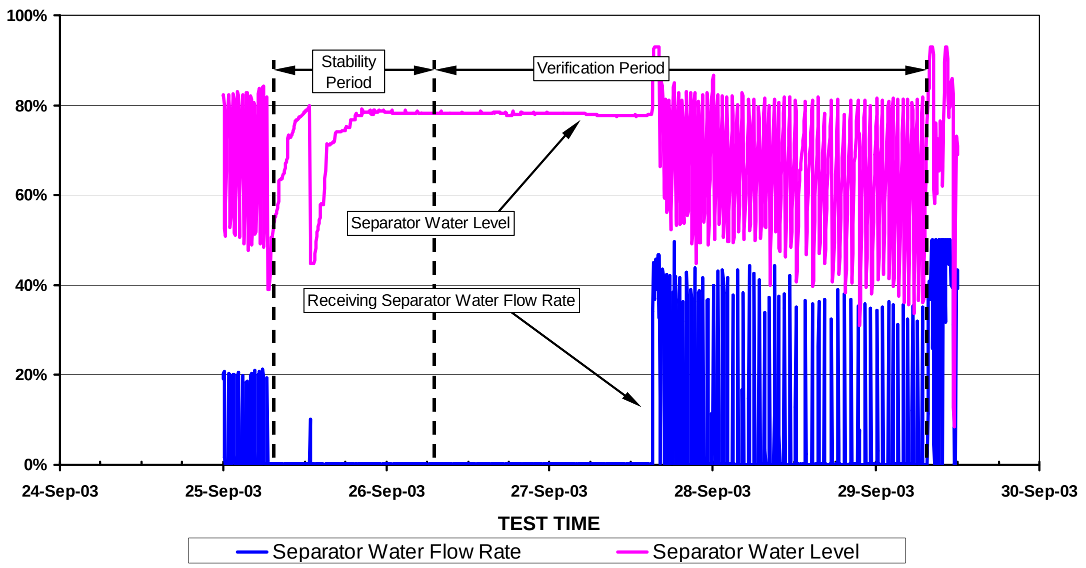


Figure 19 above shows the plot of the water production during the verification. The bottom trace shows the water flow rate; the upper the variations in separator interface level. The spike at about mid-day on 25 September corresponds to the water being drained prior to the test. The separator was operated in batch flow mode.

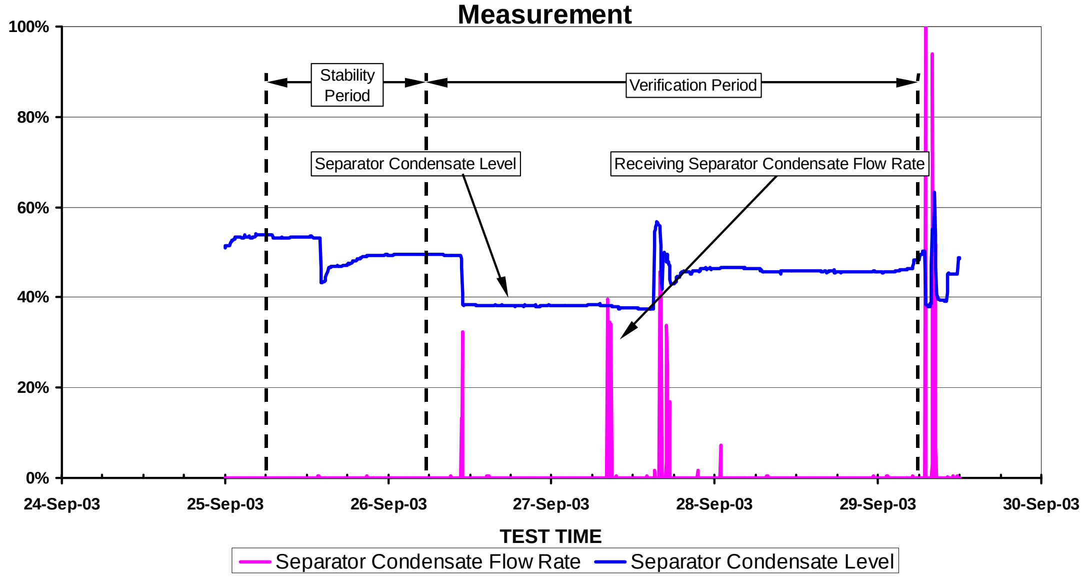
When only the test field was flowing into the pipeline the gas velocity would be reduced and liquid would accumulate in the low spots until a new equilibrium level was reached. Water would then be produced out of the pipeline onto the central processing facility and into the separator at about the same rate as it was being produced from the test field. Accordingly, to estimate the water production during the verification period it is appropriate to take the average water flow rate for the period when water was produced into the separator, applying that flow rate to the whole verification period, and calculate the corresponding volume of water.

4.3. Condensate Measurement

The condensate was measured downstream of the production separator by turbine meters maintained to fiscal standards. However, the uncertainties in determining condensate production from the well proved to be much greater than the uncertainties in these meters. The separator was operated in batch flow mode. Condensate was drained before the test was started and shortly after the end of the test.

Figure 20 below shows the plot of the condensate production during the verification period. Total condensate measured was 30.2m^3. Unlike the water, condensate appears to have been produced continuously into the separator throughout the verification. In the pipeline, condensate would have lain on top of the water and would have been swept through in preference to water. Accordingly, the assumption was made that the total condensate measured over the verification period was a high estimate of the condensate produced from the test field and there was a large uncertainty, say 50%, in its value. The measured condensate was 30.2m^3. Thus the estimate of the condensate produced during the test lay between 15 and 30m^3. There was no point in applying temperature and pressure corrections to these values.

Figure 20. Subsea Venturi Meter Verification - Condensate Measurement



4.4. Discussion of Findings

The 16.7% difference between the test field meter readings and the central processing facility meters was considerably larger than anticipated. The following issues were discussed as possible reasons for the over-reading of the test field meter.

Associated instruments of the test field meter

The possibility that the associated instrumentation, namely differential pressure transmitter, temperature sensor and pressure transmitter could have drifted or changed suddenly in calibration was reviewed.

The instruments had shown little drift from start of production and a previous verification of the test field meter where the agreement was 2.8%. The drift on the differential pressure and pressure transmitters would need to be about 28% to account for the over-reading. This was not considered possible with the equipment installed. The drift on the temperature sensor would need to be about 80°C to account for the over-reading. This was evidently not the case, as temperatures measured at the test field meter during the verification were about 44° and 51°C, both sensible values. It is even more unlikely that two or all of these sensors could have gone faulty at the same time to give the over-reading. Further more, in a recent shutdown the differential pressure transmitter (ranged 0 – 3000 mbar) gave a reading of -12 mbar and the other sensors responded as expected.

Errors in the test field subsea control system
The test field metering calculations are made in the subsea control system. By carrying out an offline calculation it was evident that the control system was working correctly.

Deposition on the inside of the Venturi meter
The velocities in the meter are high; often in excess of 25 m/s, and much higher in the throat of the venturi. It is most unlikely that deposits or scale could stick. If there was sand production, this would lead to erosion of the throat giving lower readings. Further if erosion was occurring in the venturi meter, it would be observed in other items of equipment where the consequences could be even more serious.

Blockage of impulse lines
There were no signs that there was a "locked-in" differential pressure due to blocked impulse lines to the differential pressure transmitter. When the test field well was shut in shortly before the test the differential pressure went down to -12 mbar, and during the test the differential pressure trend followed the choke settings closely.

Errors in central processing facility gas meters
If an orifice plate had been inserted the wrong way round in its carrier, the orifice meter would have under-read by about 20%, nearly explaining the over-reading. During the calibrations immediately before the test, the orientation of the orifice plates had been carefully checked to ensure they were correctly installed.

Choice of Venturi meter for service on test field
Venturi meters are chosen for subsea wet gas metering as they are robust, use proven components in the associated instrumentation, and there is little to go wrong.

Debris from well/broken choke
The possibility for debris lodged in the throat of the Venturi meter was seriously considered.

In September 2000, the choke trim had failed and had broken up into several pieces. When the choke was replaced it was not possible to recover all the parts. As the meter is downstream of a long sweeping elbow it was not possible to check if parts of the choke had stuck in the throat of the Venturi meter. Initially we considered this the most probable reason for the Venturi over-reading. However, during detailed discussions with the choke manufacturer it became evident that choke fragments could only lodge in the Venturi meter under very exceptional circumstances. As the exit diameter of the choke was smaller than the Venturi throat diameter, only a long, thin shard could have passed through the choke exit, turned sideways on, and then lodged in the throat. It would then have had to remain lodged in that position for two years.

Furthermore, there was no evidence in the production records of a sudden increase in differential pressure reading at the time that the choke failed. From the previous example given in this paper (section 2.3) of a choke failure, the fragment lodged in the Venturi meter only because it was bigger than the Venturi throat. It was therefore concluded that the over-reading by the test field meter was not due to well debris or a broken choke.

Appropriate wet gas correction

The predicted over-readings for the test field using the de Leeuw correlation were 1.227 at the high flow rate and pressure, and 1.203 at the low flow rate and pressure. This was based on a liquid to gas ratio of 258m^3 liquid per $10^6 Sm^3$ gas, corresponding to the liquid and gas measured during the verification period. The corresponding over-readings predicted using the Chisholm correlation were 1.065 and 1.058 and the over-readings using the Murdock correlation were 1.052 and 1.043. The observed over-reading was 1.167 on average, 1.155 at the high flow rate and pressure and 1.175 at the low flow rate and pressure.

Evidently both Chisholm and Murdock predict an over-reading that is too small. The de Leeuw and NEL work shows that the Chisholm and Murdock correlations should not be used for the conditions existing at the test field.

The over-readings predicted by the de Leeuw correlation appear to be somewhat higher than the observed over-reading, about 21% compared to about 16.5%. Furthermore the de Leeuw correlation predicts a higher over-reading at high pressure than at low pressure. The observed over-readings are the other way round. We calculated the liquid to gas ratios (LGRs) so that the de Leeuw over-readings match the observed over-readings. This resulted in a 20% lower LGR for the high pressure high flow rate gas (171m^3 per 106Sm^3) than for the lower pressure low flow rate gas (219m^3 per 106Sm^3). This probably corresponds to the situation where formation water is flowing at a more or less constant rate into the well bore, but the gas flow rate varies. However, the gas velocities are sufficiently high for all of the liquid to be removed.

Note that the pressures and densities of the gas at the test field meter (21bar, 14.4kg/m^3, and 15bar 10kg/m^3) are comparable with the SINTEF data set regarding pressure but not density. De Leeuw gives a minimum density of 17kg/m^3 based on the density of nitrogen at 15bar. There is no reason to believe that the de Leeuw correlation is invalid at our densities, but further work may be required to confirm this.

Water, the most of the liquid produced, was only produced at the host facility during the second half of the verification period, presumably because the pipeline was stabilising to a new liquid level. It was therefore very difficult to estimate the likely error in both water and condensate produced. It is probably more correct, and more useful, to turn things round and use the observed Venturi meter over-reading and the de Leeuw correlation to estimate the liquid throughput. These observations involve changes in accurate differential pressure readings, and a well founded correlation, in contrast to relatively poor water and condensate measurements at a separator at the end of a long pipeline.

5. Production Field Comparison

There is a similar installation to the test field described above, except that the Venturi meter is installed on a top-sides satellite and the de Leeuw correlation is implemented in the flow computer. The Venturi meter was calibrated on both gas and water before installation and is one of the meters shown in Figures 1 and 5. We consider that this installation follows best current practice. For this paper we shall call this field the "production field". Gas from the production field is routed through a subsea pipeline to a similar host facility as the test field. The major difference is that the production field has been producing on its own to the separation facilities for about a year. Therefore there has been a continuous verification of the production field Venturi for this period.

Figure 21 below shows the total hydrocarbon percentage difference between the host facility meters and the production field Venturi meter. The average difference for the 12 month period is 0.38%. We consider this very satisfactory. The scatter in the points is more a function of operating the pipeline and line packing and not the performance of either the host facility meters or the production field Venturi meter.

Figure 21. Production Field Venturi Meter Verification - Total Hydrocarbon Comparison

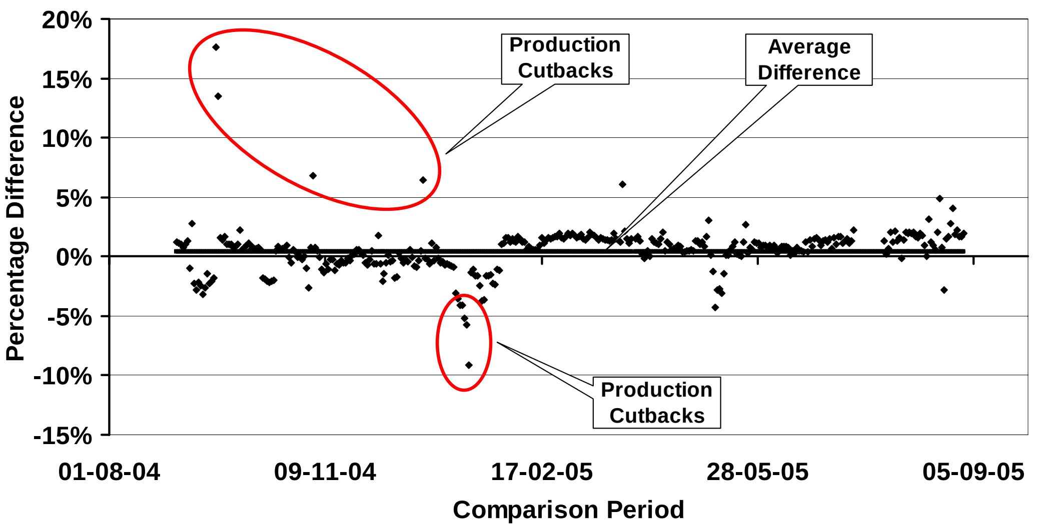
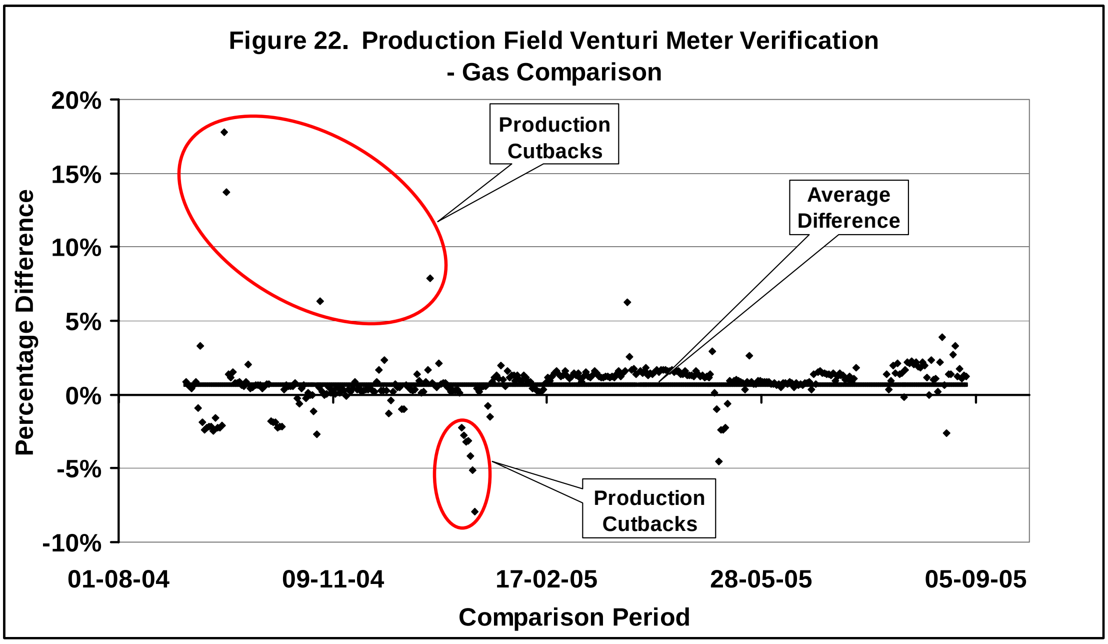


Figure 22 shows the difference for gas. Here the average difference was 0.67%.



6. Conclusions and Way Forward

- Venturi meters show such a wide spread in their discharge coefficients that for serious gas metering they must be calibrated before use.

- For wet gas applications they are commonly calibrated using both gas and water. It may be practical to use the lowest value of the gas discharge coefficient as the value for the liquid discharge coefficient, eliminating the need for a water calibration.

- In an example where significant damage was sustained in the convergent section of a Venturi meter there was a minimal shift in discharge coefficient saving costs of re-machining and further recalibration. It should be noted that no damage was seen in the throat section or around the pressure tappings.

- Verification of a subsea Venturi meter showed that the de Leeuw correlation was much more appropriate. The Chisholm and Murdock correlations were inaccurate and we consider they should no longer be used for Venturi wet gas metering.

- The gas was found to flow through the pipeline very quickly (hours rather than days) compared to the liquids. The arrival of the gas and stabilisation of the pipeline could be monitored easily by observing the change in gas composition.

- Water and condensate behaved differently. Water accumulated in the pipeline until a new equilibrium level was reached, whereas condensate flowed through more continuously. The errors in estimating both water and condensate quantities were large.

- Continuous verification of a topsides Venturi meter incorporating the de Leeuw correlation over a period of one year showed a difference of less than 1% for both hydrocarbon and gas comparisons.

Current practice is to try to estimate the liquid throughput and derive a wet gas correction factor using one of the available correlations. However in our case there was the large volume of the pipeline between the test field meter and the central processing facility meters. This meant that errors in estimating the liquid hold-up in the pipeline and hence the possible errors in estimating the liquid actually flowing through the test field meter were too large for this approach to be useful.

The above conclusions suggest strongly that it is probably more correct, and more useful, to turn things round and use the observed Venturi meter over-reading and the de Leeuw correlation to estimate the liquid flowing through the test field meter. These observations use accurate differential pressure readings, and a well-founded correlation, in contrast to relatively poor water and condensate measurements at a separator at the end of a long pipeline. The adjustment to make the test field gas figure agree with that of the central processing facility is made by the correction factor in the wet gas equation used to represent the over-reading due to liquid. By making observations at different flow rates it is possible to determine whether liquid is entering the well at a constant or varying rate and adjust the correction factor accordingly.

From our findings stabilisation took 12 hours, verification would take a less than a day. We had allowed four days' shutdown for our verification exercise. For a verification exercise of all fields in a multi field wet gas pipeline system the shutdown period could be minimised by good organisation.

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