Clamp-on Two Phase Measurement of Gas Condensate Wells Using Integrated Equation of State Compositional Models

Daniel L. Gysling, Expro Meters, Inc
Minfu Lu, Expro Meters, Inc
Ting Wen, Expro Meters, Inc

1 ABSTRACT

Production surveillance of gas condensate wells plays an important role in many production optimization and yield enhancement strategies. Unfortunately, production surveillance of gas condensate wells using conventional well testing methods is normally associated with high capital and operational costs. This paper describes an approach which provides cost-effective and convenient production surveillance of gas condensate wells using multiphase-tolerant, clamp-on sonar flow meters, integrated with an Equation of State (EoS) model for the Pressure, Temperature and Volumetric (PVT) properties of the produced fluids.

The approach utilizes an input compositional description of the well bore fluids, including water-cut. This composition is input to an EoS PVT model to calculate the gas and liquid properties of the produced fluids under the pressure and temperature conditions at the location where the sonar flow meter is clamped-on. The sonar flow meter provides a direct measurement of the mixture flow velocity within the flow line. This mixture flow velocity is interpreted in terms of actual gas flow rate using the gas and liquid properties of the mixture calculated with the EoS PVT model and an empirical correlation for the over-reading characteristics of the sonar meter operating in gas / liquid mixtures. Once the gas and liquid flow rates are determined at actual conditions, the mixture is flashed to standard conditions and oil, water, and gas flow rates are reported at standard conditions.

In addition to developing the measurement methodology, data are presented demonstrating this clamp-on production surveillance approach applied to three representative case studies selected to span a wide range of gas condensate production conditions. The first case demonstrates the system operating on a gas condensate mixture in the dense phase. Two other cases are presented for the system operating within the two-phase envelope with significantly different condensate-to-gas-ratios (CGR).

2 INTRODUCTION AND BACKGROUND

Accurate and timely information on the production rates of individual wells can play an important role in optimizing production and enhancing yields. Gas condensate wells represent a class of wells that is generally characterized by a significant amount of vapour / liquid phase exchange as the hydrocarbons are produced from the reservoir to the surface. Fig. 1 shows a representative phase trajectory of a gas condensate well mapped onto a phase diagram. As indicated, the hydrocarbons produced from gas condensate wells often exist as a dense phase fluid within the reservoir; but, as the hydrocarbons are produced, the pressure is reduced and the fluid encounters its dew point, either within the reservoir or within the production tubing. When a condensate fluid reaches its 'dew point', droplets of liquid condense within a gas-continuous mixture. Further reduction in pressure results in additional phase changes between hydrocarbon gas and liquid. This behaviour is contrasted to that of dry gas reservoirs, in which the hydrocarbon fluid remains outside the two-phase envelope in the dense phase conditions as it is produced from the reservoir to the surface.

In the example illustrated in Fig. 1, the contours of constant Liquid Volume Fraction (LVF) drawn within the two-phase envelope indicate that the gas condensate mixture reaches > 10% liquid by volume at a pressure slightly below 200 bar. The phase behaviour of any given gas condensate mixture is dependent on the pressure, temperature and composition of the mixture. Tracking and accounting for changes in the properties of gas condensate mixtures is

often critical for accurate production surveillance. The current system leverages an EoS-based description of the PVT behaviour of the gas condensate to perform this function.

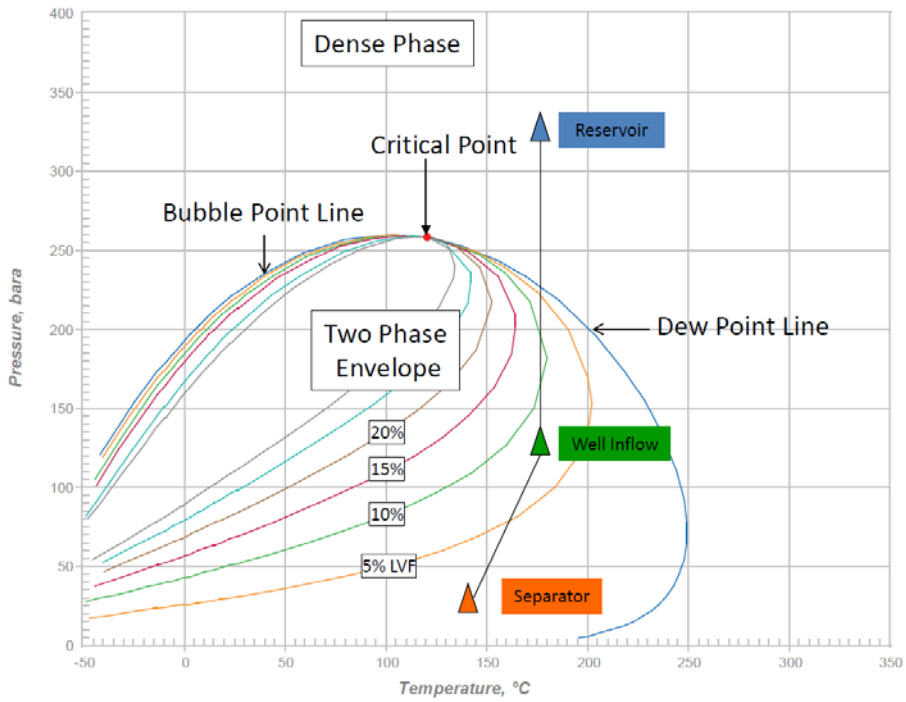


Fig. 1 - A representative phase trajectory of a gas condensate well on a phase diagram

Obtaining accurate and timely production data from gas condensate wells using conventional well test techniques can be capital intensive and operationally expensive. In efforts to achieve more cost-effective well-head surveillance, the industry continues to investigate, and in many cases, adopt, in-line multiphase flow meters for production surveillance.

While in-line multiphase flow meters do offer the potential to streamline the process of obtaining well head production surveillance, they are not ideally suited for gas condensate surveillance. Firstly, in-line multiphase flow meters often have difficulty accurately measuring oil and water components of wet gas flows [1], and often require extensive field calibration and/or a high level of user expertise to provide sufficiently accurate measurement of wet gas flows. Secondly, in-line multiphase flow meters are intrusive, typically requiring process shut-downs to install and maintain. These technical challenges, combined with high operational and capital costs, have limited the adoption of in-line multiphase flow meters for many gas condensate applications.

This paper describes a clamp-on approach designed to simplify the process of obtaining well head surveillance for gas condensate wells. This approach maintains functionality of the venturi-based gas condensate production system described in [1] and [11] with two significant enhancements intended to improve the convenience and usability of the system. Firstly, instead of relying on an intrusive in-line Differential Pressure (DP) flow meter, the current approach utilizes multiphase-tolerant clamp-on sonar flow meters as the primary flow measurement device. Secondly, instead of using PVT tables to calculate variations in fluid properties with pressure and temperature, the current approach utilizes an EoS based compositional model to facilitate the use of composition data in both 1) interpreting flow rates at actual conditions and 2) reporting measured and calculated flow rates at standard conditions.

The clamp-on production surveillance system described herein utilizes pulsed-array sonar flow meters described in [8] as the primary flow metering device. Sonar flow meters were originally developed to measure oil and gas production rates [12], [13]. They leverage sonar array processing technology to determine the speed at which coherent flow patterns convect

past an array of sensors attached to the pipe and are well suited to provide mixture flow rate of a wide range of single and multiphase flows [6].

Sonar flow meters are essentially volumetric-based flow meters, and as such, are relatively insensitive to the presence of liquids compared to momentum-based DP flow meters over a wide range of flow conditions [7]. However, despite reduced over-reading due to liquids, the accuracy of sonar flow measurement of a gas / liquid mixture will, in general, be improved if a model is used to account for any over-reading associated with the liquids. To this end, an empirical correlation for the over-reading of pulsed-array sonar flow meters was developed and implemented in the current approach. This over-reading correlation is based on extensive flow loop testing of sonar flow meters operating in wet gas conditions. It is analogous to over-reading correlations derived by others for other types of flow meters, such as orifice [2][3][14], venturi [5], and cone meters [16], operating in wet gas mixtures.

3 SCOPE

This paper describes a clamp-on approach to provide a direct measurement of gas flow rates and an inferred measurement of oil and water flow rates produced from gas condensate wells. Dry gas wells and dry gas wells with produced water can also be addressed with this approach.

In the approach described herein, produced oil and water rates are inferred from the measured gas rate using a user-defined well bore composition. Defining the well bore composition is functionally equivalent to specifying the produced condensate-to-gas-ratios (CGR) and the water-cut. Thus, while this system will measure variations of produced liquids due to variations in gas production, it will not measure variations in CGR and/or water-cut due to changes in wellbore composition. To account for these changes, an updated well-bore composition must be entered into the system. Updated well bore compositions can be obtained using a variety of existing methods, including PVT sampling, conventional well test separators, or tracer dilution methods.

4 PRINCIPLE OF OPERATION

The algorithm used in the current production surveillance system is shown schematically in Fig. 2. As shown, the system leverages three process measurements, pressure (P), temperature (T) and measured sonar flow velocity (V_{sonar}). Well bore composition is input by specifying molecular composition of the well bore fluid. The EoS PVT model calculates the properties of the well bore fluid at the location of the sonar meter using the measured pressure and temperature. In addition to the properties of the gas and liquid phases, the model also calculates mixture properties such as liquid volume fraction (LVF), liquid to gas mass ratio (LGMR), Lockhart Martinelli parameter (X_{LM}), etc. These fluid parameters are used in conjunction with an empirical correlation for the over-reading of the sonar meter due to wetness (developed below) to interpret the sonar flow velocity measured for the mixture in terms of actual gas flow rate. With the gas flow rate determined at actual conditions, the associated oil and water rates are then determined from the PVT model. The total mixture is flashed to standard conditions, and gas, oil (condensate) and water rates are reported at standard conditions.

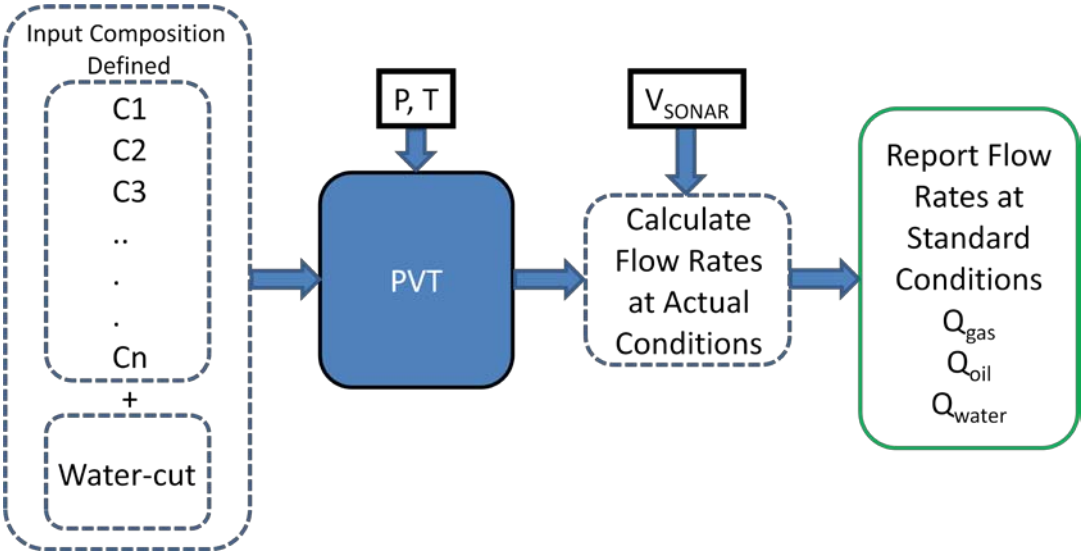


Fig. 2 - Schematic of real-time production surveillance calculation

Over-Reading of Sonar Meters in Gas / Liquid Mixtures

As indicated above, sonar flow meters measure a mixture velocity, and using the cross sectional area of the pipe, report volumetric flow rate at actual conditions. For gas / liquid mixtures, the presence of liquids will, in general, cause sonar meters to report a flow velocity exceeding the velocity that would be reported for the gas if the liquids were not present. The velocity that a given phase of a multiphase mixture would be flowing if the other phases were not present is defined as the superficial velocity for that phase. The over-reading of a sonar meter is defined herein as the ratio between the reported flow velocity and the gas superficial velocity:

$$OR_{sonar} = \frac{V_{sonar}}{V_{sg}} \tag{1}$$

where V_{sonar} is the flow velocity measured by the sonar meter; V_{sg} is the gas superficial velocity.

For a single phase gas, the volumetrically averaged flow velocity reported by a sonar meter is equivalent to the gas superficial velocity and the over-reading is defined as unity. The introduction of liquids serves to displace the gas within the cross section of the pipe, causing the actual gas velocity to increase above the gas superficial velocity. The liquid hold-up is defined as the fraction of the cross-sectional area in the two-phase pipe flow that is occupied by the liquid-phase, and is thus an important parameter that influences the over-reading of a sonar meter operating in a wet gas mixture.

For well-mixed gas / liquid mixtures, the liquid hold-up is simply equal to the ratio of the liquid volumetric flow rate to the total volumetric flow rate (i.e. Liquid Volume Fraction, or LVF), given below

$$LVF = \frac{Q_{liq}}{Q_{liq} + Q_{gas}} \tag{2}$$

Thus, for well-mixed flows, the over-reading of the sonar meter can be theoretically correlated to LVF by:

$$OR_{sonar} = \frac{1}{1 - LVF} \tag{3}$$

For gas / liquid mixtures in horizontal pipes operating in stratified or other flow regimes, the gas phase normally moves faster than the liquid phase. This results in the liquid accumulating, or 'holding-up', within the pipe. The more the liquid holds-up, the more the cross-sectional area of the gas phase is reduced, and the greater the gas velocity increases above that associated with the well-mixed flows [15].

For wet gas flows, the degree to which the flow stratifies, or "holds-up", is strongly correlated with the gas densimetric Froude number, defined as

$$Fr = \sqrt{\frac{\rho_g V_{sg}^2}{(\rho_l - \rho_g) g D}} \tag{4}$$

Following the reasoning developed above, an empirical correlation, based on wet gas flow loop data, was developed to characterize the over-reading of the pulsed-array sonar flow meters operating in wet gas flows, which is expressed as a function of the liquid volume fraction (LVF) and the gas densimetric Froude number (Fr):

$$OR_{sonar} = 1 + \beta \cdot \left(\frac{LVF^{0.5}}{1 + Fr}\right) + \varphi \cdot \left(\frac{LVF^{0.5}}{1 + Fr}\right)^2 \tag{5}$$

where β = 2.5249 and φ = - 3.9043.

Fig. 3 shows the measured and corrected experimental data used to develop the correlation. The operating conditions of the test data cover the following ranges: 300 psia < P < 800 psia; 0.4 < Fr < 5.8; 0 < LVF < 0.065; which, in terms of other commonly used wet gas parameters, corresponds to the following ranges: 0 < X_{LM} < 0.5 and 0 < LGMR < 3.7. All data were recorded in the horizontal pipeline with pipe sizes of 4-inch schedule 40 and 4-inch schedule 80. Gas flow rates corrected by Eq.(5) report corrected flow rates within +/- 3% of reference with a 95% confidence level (defined as 2X the standard deviation of the error). While the data used in this correlation span a representative range of wetness, pressure, and flow regimes for gas condensate well application, the confidence in applying the correlation over the broader range of parameters encountered in the field, such as various pipe sizes and schedules, would be improved by incorporating additional test data.

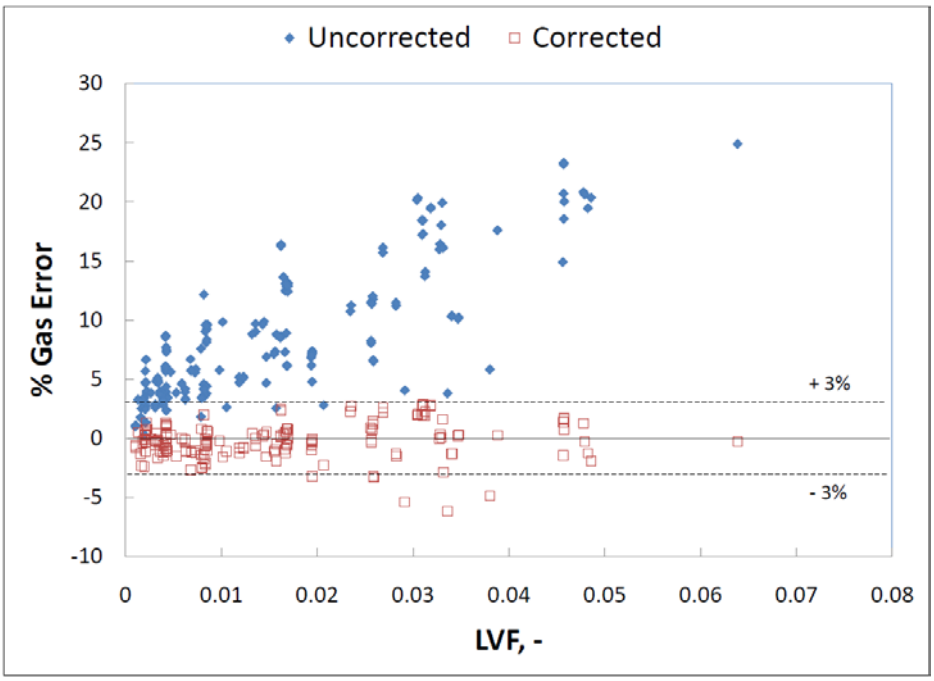


Fig. 3 - Wet gas data from pulsed-array sonar flow meter corrected with Eq. (5)

Note that the formulation for the over-reading correlation of pulsed-array sonar flow meters developed herein is similar in format to those developed for various types of DP flow meters. A primary difference is that, as volumetric-based metering devices, the over-reading characteristics of pulsed-array sonar flow meters are better captured by the LVF, whereas the over-reading characteristics of momentum-based DP flow meters tend to scale better with the Lockhart-Martinelli parameter for stratified conditions [14] and the Liquid to Gas Mass Ratio (LGMR) for well mixed conditions [7].

5 FIELD DATA DEMONSTRATIONS

Production surveillance data from three gas condensate wells, spanning a wide range of operating conditions, are presented. For the first case, the pulsed-array sonar meter is operating on a gas condensate mixture in its dense phase, where, with the exception of a small amount of water, the sonar measurement is essentially single phase. The second example is for a well producing at moderate CGR during the well clean-up phase, with the third example addressing a high CGR well.

5.1 Case 1: Gas Condensate Well with Sonar Meter Operating in Dense Phase

The goal of this trial was to evaluate the suitability of the clamp-on production surveillance system to measure the production rates of high pressure gas condensate wells. The availability of a permanently installed test separator at the facility made it particularly well suited for this evaluation**.** Fig. 4 shows a pulsed-array sonar flow meter clamped-on to an 8-inch, schedule 100 pipe (0.59 inch wall thickness) positioned upstream of the production choke on a gas condensate well producing gas condensate with a condensate-to-gas-ratio of 37 bbl/mmscfd and a water-cut of 1.8%. .

A sonar-based k-w plot [8] recorded during the testing is also shown in Fig. 4, reporting a mixture velocity of ~10 ft/sec. The diagnostic plot from the sonar meter indicates that the pulsed-array sonar meter was performing well under these dense phase conditions..

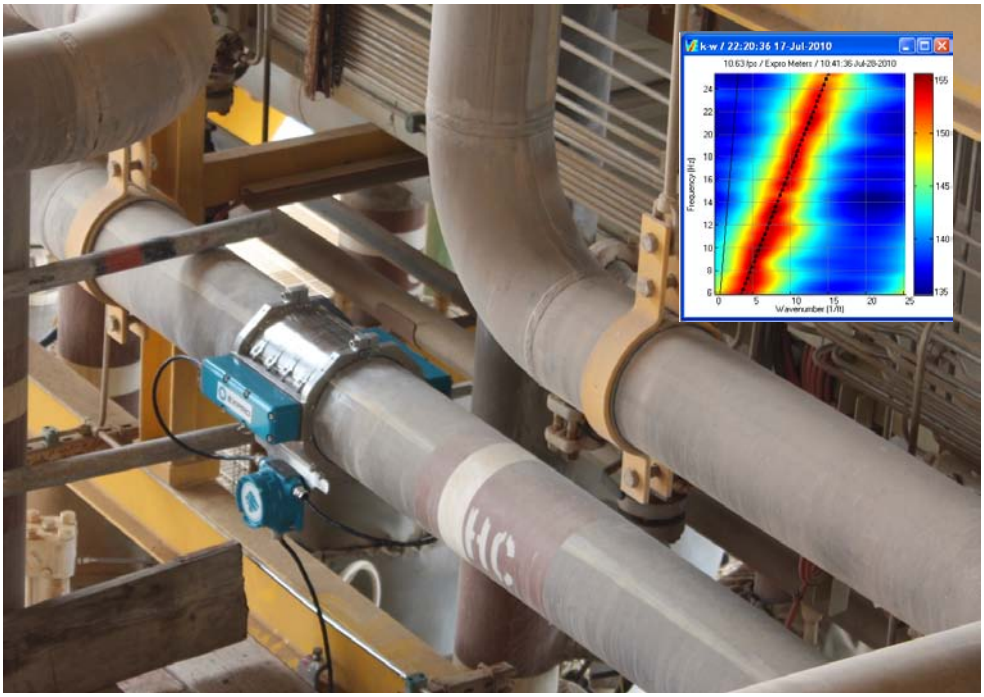


Fig. 4 - A pulsed-array sonar flow meter clamped-on to an 8-inch, schedule 100 pipe upstream of the production choke on a gas condensate well and its recorded k-w plot

The phase envelope of the hydrocarbon fluid, generated from a customer supplied well bore composition and tuned to match the producing CGR, is given in Fig. 5. The line pressure at the location of the pulsed-array sonar meter was between 3000~3500 psia and the line temperature was around 190 DegF. Mapping these conditions onto the phase envelope, it shows that the pulsed-array sonar meter was mainly operating in the dense phase region.

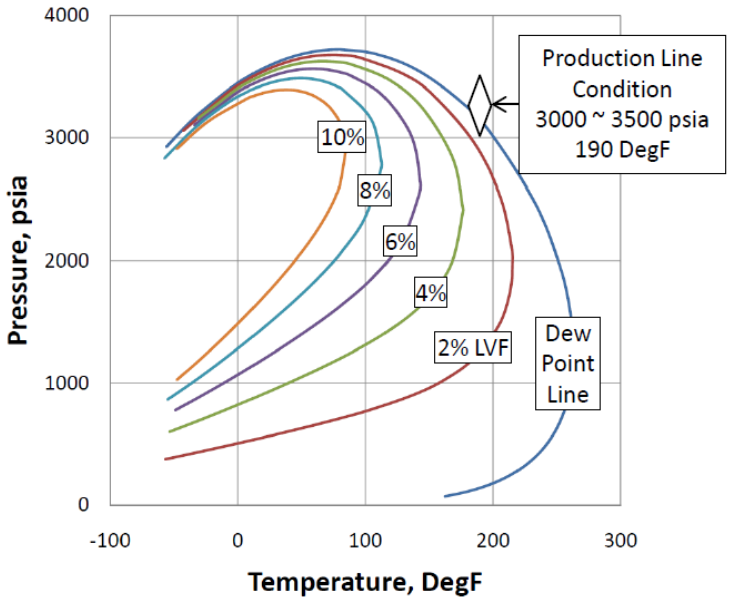


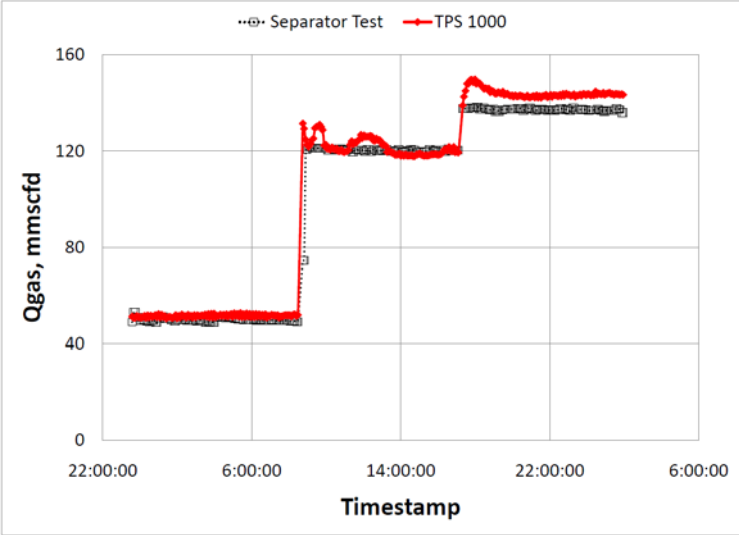
Fig. 5 - Hydrocarbon fluid phase envelope

Production Surveillance Results

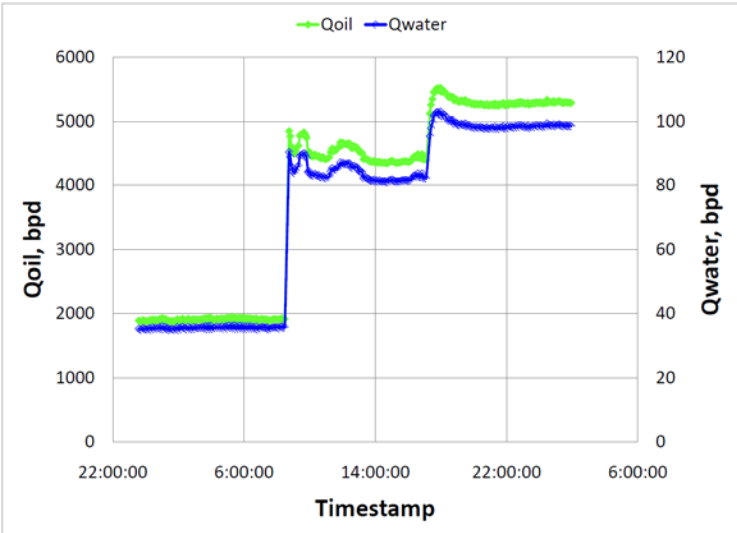
Fig. 6 gives production surveillance results for gas / oil / water flow rates. In Fig. 6 (a), the gas flow rates predicted by the clamp-on production surveillance system (TPS 1000) are compared with those measured from the gas leg of the well test separator. The gas flow rates reported by the surveillance system are in good agreement with the reference values. Fig. 6 (b) shows the associated oil (condensate) and water rates for the same period reported by the clamp-on production surveillance system. Unfortunately, no field reference data were available for either oil or water rates. Table 1 gives the average gas / oil / water flow rates in three distinct periods. The average gas flow rates measured by the production surveillance system are within 5% of those measured by the well test separator.

Table 1 - Production surveillance results vs. test separator reference values

Flow Period	Qgas @ STP, Separator	Qgas @ STP, TPS 1000	Error in Qgas @ STP	Qoil @ STP, TPS 1000	Qwater @ STP, TPS 1000
	MMSCFD	MMSCFD	-	BPD	BPD
1	50	51.5	3.00%	1899	35.4
2	120	121.7	1.42%	4487	83.6
3	138.0	143.8	4.20%	5300.0	99.0



(a)



(b)

Fig. 6 - Production surveillance results (a) gas flow rate; (b) oil / water flow rate

5.2 Case 2: Gas Condensate Well During Clean-Up

The goal of this trial was to evaluate the utility of the clamp-on production surveillance system during the clean-up phase of a well. Specifically, the clamp-on production surveillance system is capable of providing well production measurement when the test separator or other intrusive in-line multiphase metering systems are either 1) off-line due to instrumentation reconfiguration (i.e. changing out orifice plates) or 2) on by-pass due to, for example, heavy solids production.

Fig. 7 shows a pulsed-array sonar flow meter clamped-on to 3-inch, schedule 160 (0.437 inch wall thickness) temporary piping on a well test package, downstream of the production choke and upstream of the test separator.

The gas condensate had a CGR of 77 bbl/mmscf with 4.2% water-cut. The phase envelope, constructed based on compositional information supplied by the customer, is given in Fig. 8. The line conditions where the sonar meter was clamped-on were 657 psia and 97 DegF. Referencing these conditions on the phase envelope indicates that the meter was operating with both gas and liquid hydrocarbons present. At the production line conditions, the PVT

model indicated that the liquid volume fraction was ~3% and the Lockhart-Martinelli parameter value was ~0.10. A sonar-based k-w plot [8] recorded during the testing under similar conditions is also shown in Fig. 7 indicating a mixture velocity of ~23 ft/sec. As with the other example, the diagnostic plot from the sonar meter indicates that the pulsed-array sonar meter was performing well for this type II wet gas conditions [17].

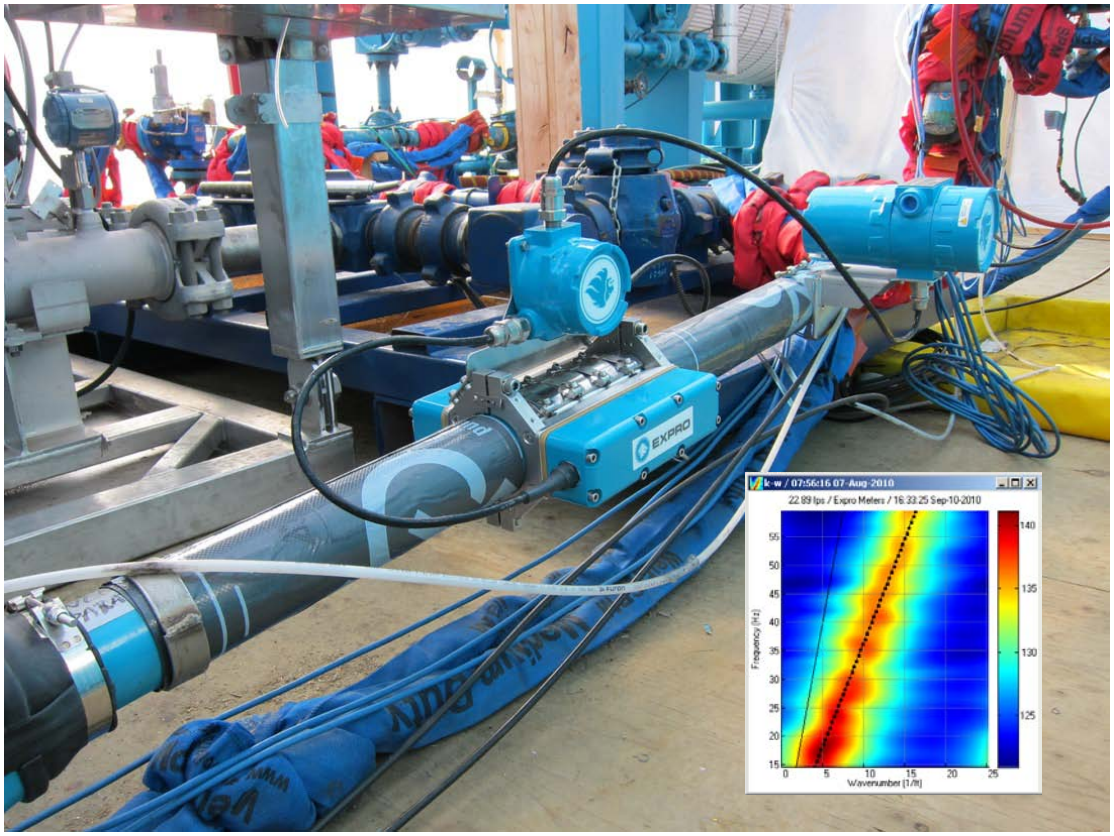


Fig. 7 - A pulsed-array sonar flow meter clamped-on to a 3-inch, schedule 160 temporary piping on a well test package, downstream of the production choke and upstream of the test separator

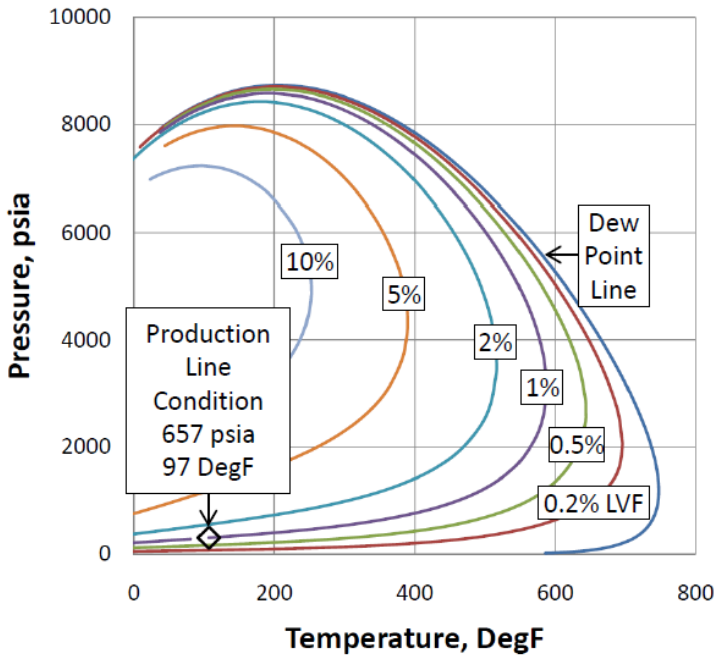


Fig. 8 - Hydrocarbon fluid phase envelope

Production Surveillance Results

Fig. 9 (a) - (c) give the real-time gas / oil / water flow rates predicted by the production surveillance system and compare them with those measured by the test separator. Overall, the predictions of both gas and oil flow rates follow a similar trend to the test separator results.

Fig. 9 (a) shows the gas rates reported by the clamp-on surveillance system operating upstream of the production choke at > 3000 psia, compared to the gas rates measured by the orifice plate on the gas leg of the test separator operating at < 1500 psia. The two results are in good agreement, capturing absolute flow rate and transient characteristics. Note that between 11:46 and 11:50 during the test period, reference gas rates were not available due to temporary removal of the orifice plate from service to resize the orifice plate. As shown in Fig. 9 (a), the clamp-on production surveillance system continued to provide gas rate measurements during this period.

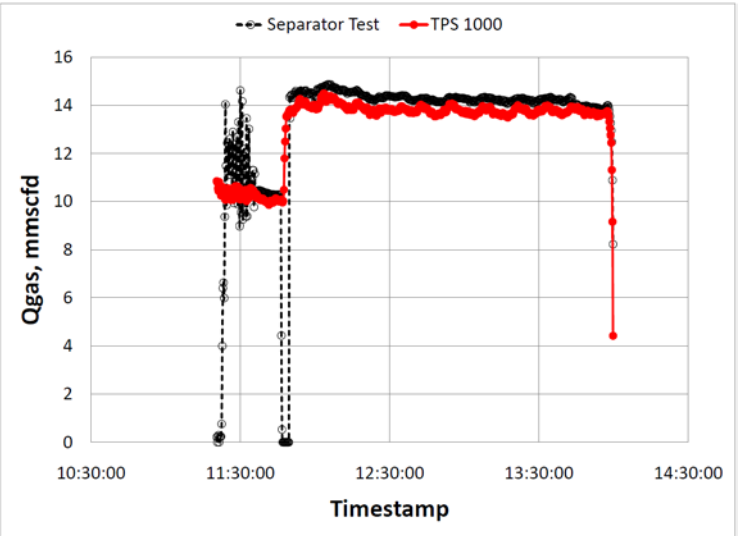
Fig. 9 (b) shows the oil rates reported by the clamp-on production surveillance system, compared with those measured by the turbine meter on the oil leg of the test separator. The results are in good agreement, with the clamp-on production surveillance system capturing the change in oil rates associated with the change in total production rates.

Fig. 9 (c) shows that the clamp-on production surveillance system did not track the relatively low water rates reported by the turbine meter on the water leg of the separator. This discrepancy could be attributed to several potential causes including: 1) time scale mismatch between the long residence time for the water leg of the test separator and the well transients; 2) offset in the water-cut contained in the well bore composition; or 3) the well producing variable water-cuts not being consistent with the constant water-cut assumption inherent to the clamp-on production surveillance system.

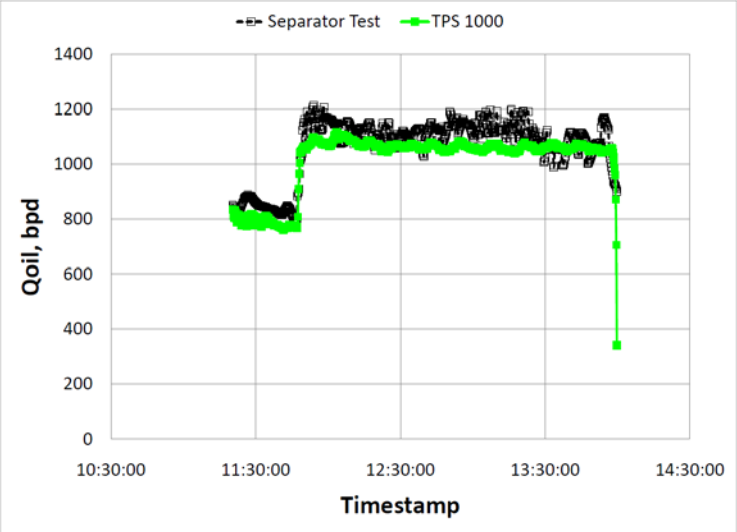
Table 2 compares the predicted gas / oil / water flow rates at standard conditions with those measured by the test separator during the time period from 12:30:00 to 13:30:00, where the gas / oil / water flow rates are stable. Over this period, the predicted average gas flow rate is -3.3% of that measured by the test separator; and the predicted oil / water flow rates reported are -6.4%.

Table 2 - Production surveillance results vs. test separator reference values

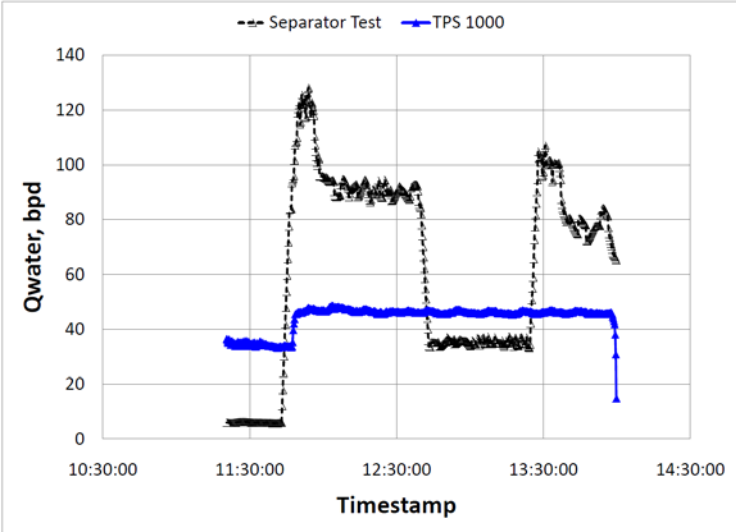
	Test Separator	TPS 1000	Error
Qgas, mmscfd	14.2	13.7	-3.3%
Qoil, bpd	1133	1060.	-6.4%
Qwater, bpd	35.2	32.9	-6.4%



(a)



(b)



(c)

Fig. 9 - Production surveillance results and comparisons with well test data

CFD Analysis

Based on the PVT model, the sonar meter was operating well within the two-phase envelope. To better visualize the flow regime in which the pulsed-array sonar meter was operating, a CFD analysis was performed to simulate the multiphase flow conditions within the pipe. The separator test data and the PVT model were used to generate the input conditions for the calculation, as given in Table 3.

Table 3 - Flow conditions in CFD analysis

Standard Conditions	
Average condensate flow rate, bpd	1130
Average water flow rate, bpd	35
Average gas flow rate, mmscfd	14.2
Pipeline Conditions	
Pipe ID, in	2.9
Pressure, psia	650
Temperature, DegF	97
Gas superficial velocity, m/s	23.5
Liquid superficial velocity, m/s	0.65
LGMR	0.57
X_{LM}	0.12
LVF	2.6%
Fr	6.2

Fig. 10 shows the gas / liquid distribution over a representative cross-sectional area of the pipe flow. As show, the flow is quite stratified, with a liquid hold-up of 8% versus a liquid volume fraction of 2.6% at these conditions.

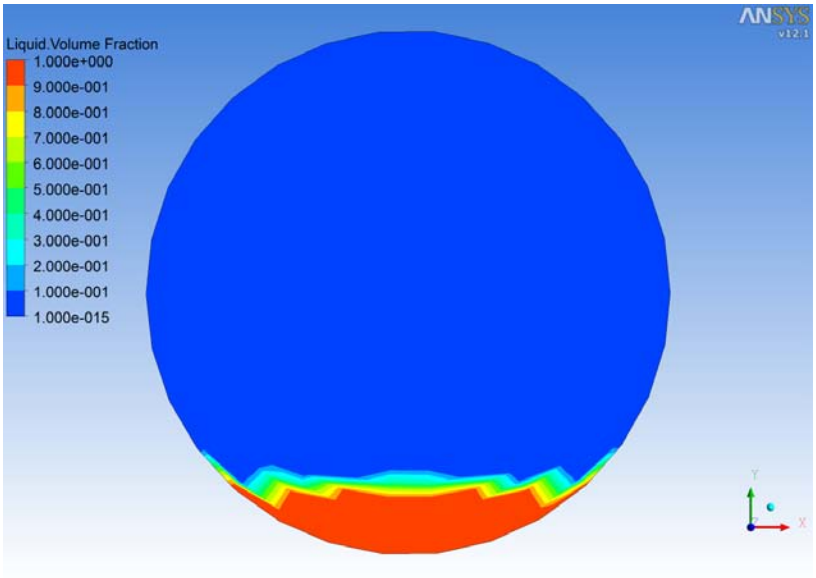


Fig. 10 - Gas / liquid distribution over the cross-sectional area for condensate well producing at 77 bbl/mmscfd

5.3 Case 3: Gas Condensate Well Producing at High CGR

This trial was conducted to assess the utility of the clamp-on production surveillance system on a well producing at a high CGR. Since the PVT analysis of this application indicates that the well is producing at a temperature below its critical temperature, from a reservoir engineering perspective, this well would be classified as a 'volatile oil' well [4].

Fig. 11 shows a pulsed-array sonar flow meter clamped-on to an 8-inch, schedule XXS+ (1.1 inch wall thickness) pipe operating at nominal conditions of 1508 psia and 176 DegF. The well was producing gas condensate at 182 bbl/mmscf with water-cut of 7.8%.

A diagnostic plot from the sonar meter recorded during the testing is also included in Fig. 11. The diagnostic plot indicates that, despite the high liquid loading, the sonar meter was operating well and reporting a mixture flow velocity of ~6 ft/sec.

The phase envelope of the hydrocarbon fluid in this application is given in Fig. 12. The PVT model indicates that the gas condensate mixture is heavily loaded with liquids at line conditions, with a liquid volume fraction of > 20% and a Lockhart-Martinelli parameter value is of 0.70. The liquid loading of this application exceeds the limit for wet gas flows, which are defined as gas and liquid mixtures with a Lockhart-Martinelli number of 0.01 < X_{LM} < 0.30 [9].

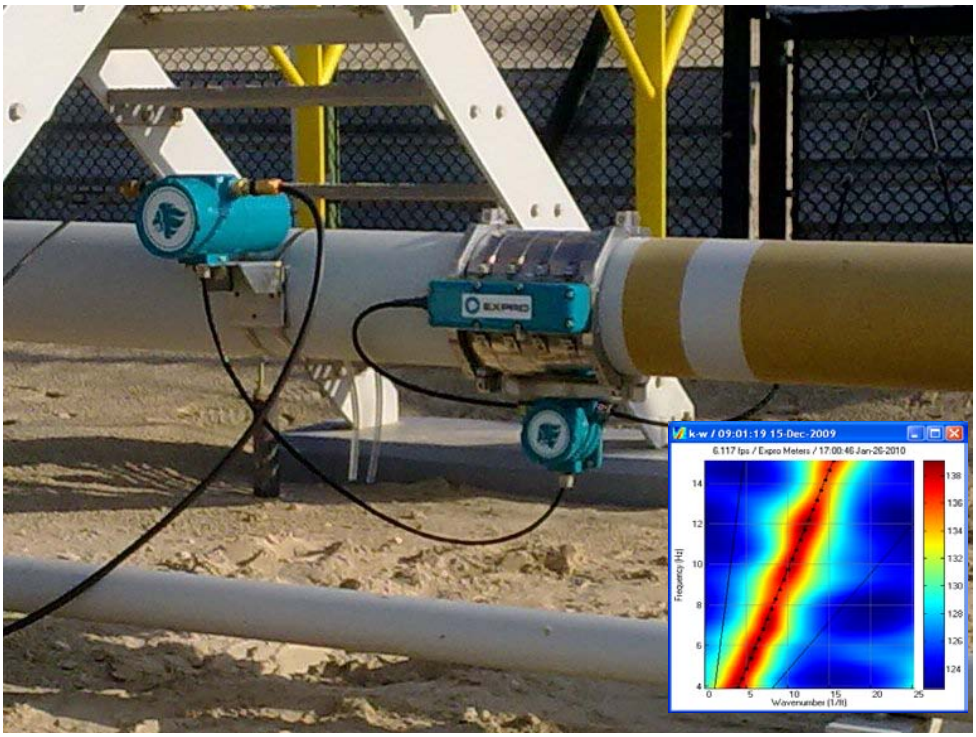


Fig. 11 - A pulsed-array sonar flow meter clamped-on to an 8-inch, schedule XXS+ (1.1 inch wall thickness) and its recorded k-w plot

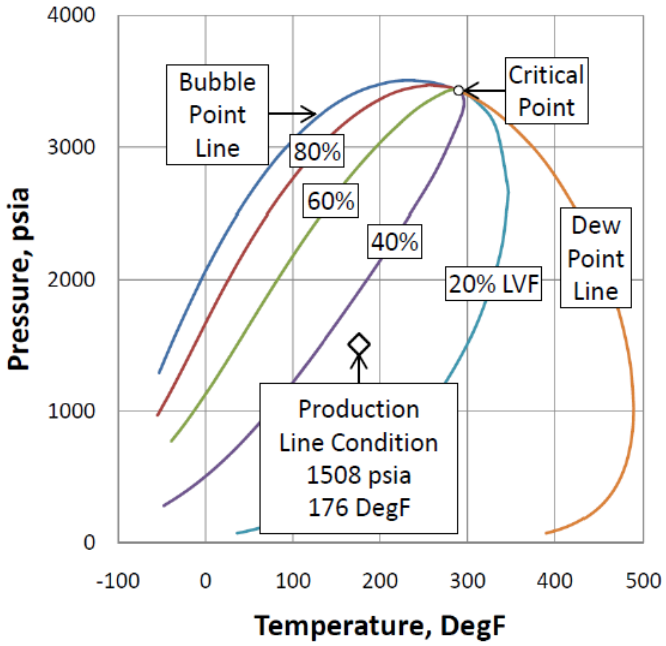


Fig. 12 - Hydrocarbon fluid phase envelope

Production Surveillance Results

The results from the production surveillance system on gas / oil flow rates at standard conditions are given in Fig. 13. The average values over this period are compared with those reported from the test separator over the same period in Table 4. The errors in gas and oil flow rates reported by the production surveillance system are ~12%. This relatively high error is attributed to the liquid loading exceeding the range of the test data from which the over-

reading correlation was developed, and as such, the over-reading correction was based on extrapolated data. It is anticipated that the accuracy of the production surveillance system in high liquid loading applications will improve as additional data points from such applications are incorporated into the over-reading correlation of the sonar meter.

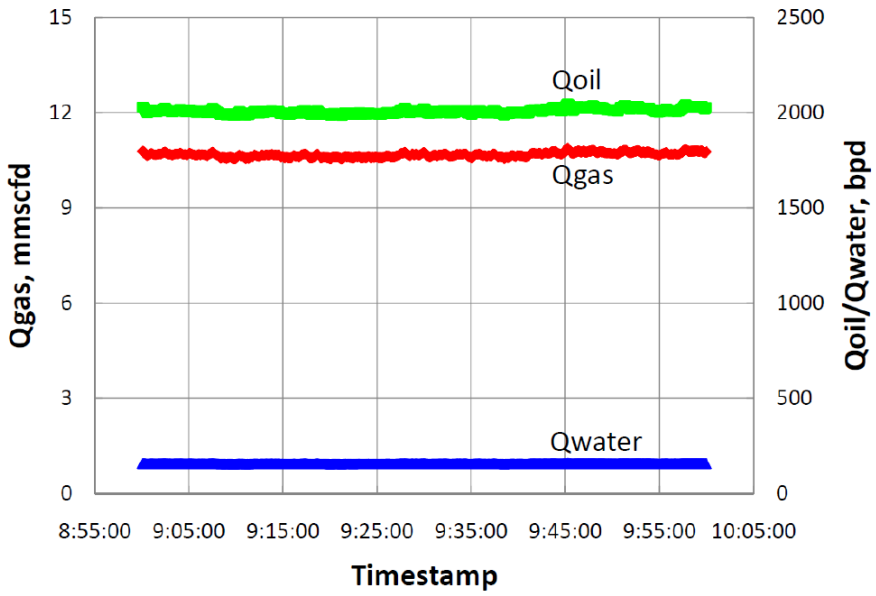


Fig. 13 - Gas / oil / water flow rates at standard condition predicted by production surveillance system

Table 4 - Production surveillance results .vs. test separator reference values

	Test separator	TPS 1000	Error
Qgas, mmscfd	9.6	10.7	10.7%
Qoil, bpd	1796	2007	11.8%

CFD Analysis

Similar to the previous case, CFD analysis was performed to simulate the multiphase flow conditions within the pipe at the location of the pulsed-array sonar meter. The flow conditions input to the CFD analysis are given in Table 5.

Table 5 - Flow conditions in CFD analysis

Standard Conditions	
Average gas flow rate, mmscfd	9.6
Average condensate flow rate, bpd	1800
Average water flow rate, bpd	140
Pipeline Conditions	
Pipe ID, in	6.435
Pressure, psia	1500
Temperature, DegF	176
Gas superficial velocity, m/s	1.14
Liquid superficial velocity, m/s	0.31
LGMR	1.7

X_{LM}	0.68
LVF	20.8%
Fr	0.40

Fig. 14 shows the gas / liquid distributions over a representative cross section of the flow. As shown, the flow is well stratified, with a liquid hold-up of 30.1% versus a liquid volume fraction of 20.8% at these conditions.

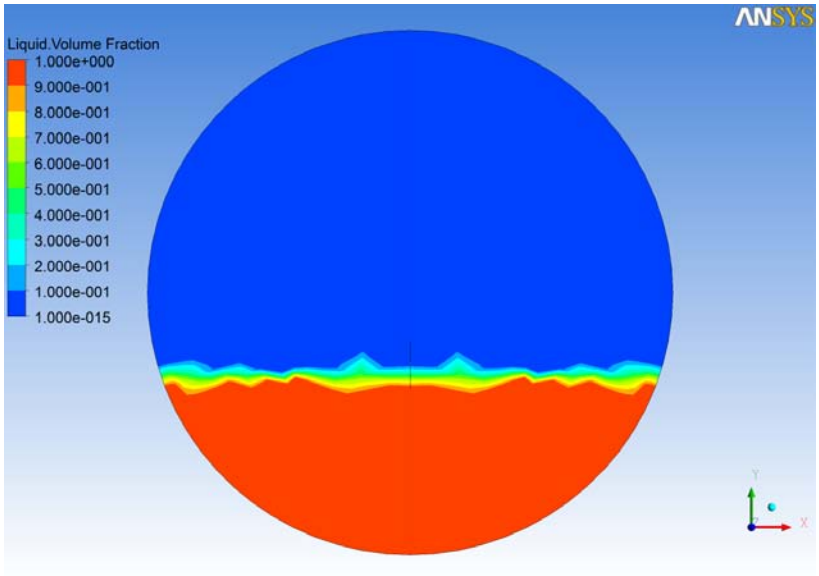


Fig. 14 - Gas / liquid distributions over the cross-sectional area for gas condensate producing at 182 bbl/mmscfd

6 CONCLUSIONS

A clamp-on production surveillance system designed to monitor gas condensate wells was presented. The system employs a multiphase-tolerant, pulsed-array, clamp-on sonar flow meter as the primary flow metering element. The output of the sonar meter is integrated with pressure, temperature, and well bore compositional information and interpreted in terms of gas, oil, and water rates using an integrated Equation of State PVT model and an empirical correlation for the over-reading of pulsed-array sonar meters.

When combined with accurate well bore composition data, the clamp-on production surveillance system provides practical, cost-effective, real-time surveillance of gas condensate wells. A variety of existing methods are available to determine well bore composition including PVT sampling, conventional well test separators, or tracer dilution methods.

Three example applications of the clamp-on production surveillance system applied to gas condensate wells, spanning a large range of operating conditions and with varying surveillance objectives, were presented. For each case, the clamp-on production surveillance system provided surveillance data that were consistent with available reference data.

7 ACKNOWLEDGEMENTS

The authors gratefully acknowledge Expro Meters, Inc. for permission to publish this work and acknowledge the efforts of numerous colleagues who have contributed to the development and evaluation of this technology. We also acknowledge the early-adopting operators who supported field trials of this approach.

8 REFERENCES

[1] Al-Taweel, et al., Wellsite Wet Gas Measurement System in Saudi Arabia, SPE 49162, presented at the 1998 Annual Technical Conference in New Orleans, LA, USA, Sept 1998

[2] Chisholm, D., Flow of Incompressible Two-Phase Mixtures through Sharp-Edged Orifices, Journal of Mechanical Engineering Science, Vol.9, No.1, pp.72-78, 1967

[3] Chisholm, D., Research Note: Two-Phase Flow Through Sharp-Edged Orifices, Journal of Mechanical Engineering Science, Vol.19, No.3, pp.128-130, 1977

[4] Danesh, A., PVT and Phase Behaviour of Petroleum Reservoir Fluids, Developments in Petroleum Science, Vol. 47, Elsevier Science B.V., ISBN: 0-444-82196-1, 1998

[5] de Leeuw, R., Liquid Correction of Venturi Meter Readings in Wet Gas Flow, North Sea Flow Measurement Workshop, Norway, 1997

[6] Gysling D.L., Loose, D.H., van der Spek, Clamp-on, SONAR-based, Volumetric Flow and Gas Volume Fraction Meter Industrial Applications, presented at the 13th International Flow Measurement Conference, organized by the National Engineering Laboratory, East Kilbride, Scotland, UK, June 2005

[7] Gysling, D.L., Loose, D.H., and Volz, R., Wet Gas Metering Using a Combination of Differential Pressure and SONAR Flow Meters, presented at the 24th International North Sea Flow Measurement Workshop, organized by the National Engineering Laboratory, East Kilbride, Scotland, UK, Oct 2006

[8] Gysling, D. and Morlino, N., “Pulsed-Array, Sonar-based Flow Measurement Technology for Clamp-on Wet Gas Metering, Presented at the 2009 Americas Flow Measurement Workshop, Houston, TX, USA February, 2009.

[9] Handbook of Multiphase Flow Metering, Revision 2, produced for The Norwegian Society for Oil and Gas Measurement (NFOGM) and The Norwegian Society of Chartered Technical and Scientific Professionals (Tekna), ISBN 82-91341-89-3, 2005

[10] Hasebe, B, et all, “ Field Qualification of Four Multiphase Flows Meters on North Slope, Alaska”, SPE 90037, presented at the 2004 Annual Technical Conference in Houston, TX, USA, October, 2004

[11] Konopczynski, M.R., Large-Scale Application of Wet-Gas Metering at the Oman Upstream LNG Project, SPE 63119, presented at the 2000 Annual Technical Conference in Dallas, TX, USA, October, 2000

[12] Kragas, T.K., et al., Downhole, Fiber Optic Multiphase Flow Meter: Field Installation, presented at the Society of Petroleum Engineers Annual Conference, SPE Paper #77654, September 2002

[13] Kragas, T.K., et al., Downhole Fiber-Optic Multiphase Flowmeter: Design, Operating Principle, and Testing, presented at Society of Petroleum Engineers Annual Conference, SPE Paper #77655, September 2002

[14] Murdock, J. W., “Two Phase Flow Measurement with Orifices”, Journal of Basic Engineering, Vol.84, pp.419-433, 1962

[15] Shoham, O., Mechanistic Modeling of Gas-liquid Two-Phase Flow in Pipes, Society of Petroleum Engineers, 2006, ISBN 978-1-55563-107-9

[16] Steven, R., Wet Gas Flow Metering with Gas Meter Technologies, Nunn, Colorado Engineering Experiment Station Inc., 9/1/2006, Ciateq 2006