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SONAR-based Wellhead Surveillance for Gas Condensate Fields

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Abstract

Production optimization and reservoir management rely in part on periodic surveillance of produced oil, gas and water flow rates of individual gas condensate wells. Flow measurement at the wellhead has proven to be challenging due to a number of factors. Conventional (gravity-based) Test Separators (CTS) and in-line Multi-Phase Flow Meters (MPFM) are intrusive and may be costly to mobilize, not to mention the associated HSE related risks. For fields where access and logistics pose a challenge, the deployment of either CTS or MPFM packages may require a significant amount of time. In some cases, the required well test frequency may not be reached with the available equipment or due to the increased number of wells in production.

This paper describes a convenient and cost-effective approach to production surveillance of gas condensate wells using the non-intrusive SONAR-based Surveillance system. The system integrates the clamp-on sonar flow meter (SONAR) with a PVT and multiphase flow engine to calculate the properties of the produced fluids, and the individual phase flow rates. The SONAR is a multiphase-tolerant volumetric flow device that provides the bulk flow rate of the fluid stream within the flow line. The PVT engine calculates the individual phase properties of the produced fluids, at the pressure and temperature conditions measured where the SONAR is clamped-on. The measured flow rate is then interpreted in terms of oil, gas and water rates at both the actual and standard conditions.

Examples of field performance of SONAR-based system for three-phase production surveillance of gas condensate wells are presented. The test results show that the SONAR-based system represents a reliable, safe and cost-effective solution for recurring production surveillance where reservoir conditions are relatively stable over time.

Introduction

Monitoring produced oil, gas, and water from individual wells plays an important role in reservoir management. Acquiring timely and accurate well head measurements can be challenging due to a range of factors. Using traditional well test separators provides only periodic measurements and may result in deferred production due to pressure drop.

While measuring dry gas flow measurement is well-served by a wide range of gas flow metering technologies, accurate and cost-effective measurement of wet gas flow remains a challenge for the upstream oil and gas industry. The paper provides a method to provide minimally intrusive, clamp-on production surveillance for wet gas flow measurement.

Expro developed a clamp-on non-intrusive production monitoring system, Total Production Surveillance (TPS), designed to provide rapid and cost-effective wellhead surveillance for a wide range of applications, such as gas and gas condensate wells. Expro's clamp-on SONAR-based (Sonar) flow meters, PassiveSONAR™ or ActiveSONAR™, operate effectively in multiphase conditions typical for most oil and gas applications. Therefore, they can be installed close to the wellhead, allowing accurate flow measurement on an individual well basis without installing an inline device or diverting production.

SONAR-based Flow Measurement Technology

History. Sonar flow measurement technology was introduced to the oil and gas industry in 2000, using SONAR-based passive-listening techniques to provide flow rate and compositional information for downhole applications (fiber-optic meter).

In 2004, a clamp-on version of a strain-based sonar meter (PassiveSONAR™) was introduced with piezo-strain sensors, providing similar functionality as the original fiber-optic-strain sonar technology with reduced cost and complexity. PassiveSONAR™ has been applied to a wide range of flow measurement applications, including single and multiphase mixtures, from gas / liquid mixtures to high solids content slurries.

In 2009, Expro Meters introduced the ActiveSONAR™, based on the pulsed-array sonar technology, using externally generated acoustic pulses to "illuminate" the vortical coherent structures. The pulsed-array sonar technology allows the measurement of lower flow rates than strain-based sonar flow meters. The ActiveSONAR™ meter is well suited for Gas and Gas Condensate wells in heavy schedule pipes. Expro Meters utilizes both types of Clamp-on SONAR flow measurement technologies to address a wide range of flow line conditions.

SONAR-based Flow Measurement. Sonar-based flow measurements utilize an array of sensors, aligned axially along the pipe, to characterize the speed at which naturally occurring, coherent flow structures convect past the sensor array using sonar processing techniques. Since both single and multiphase flows typically exhibit these coherent structures, the methodology is suitable for a wide range of applications.

Figure 1 shows the naturally occurring, self-generated, coherent structures characteristic for turbulent flow of Newtonian fluids. The turbulent eddies are superimposed over the time-averaged velocity profiles and are carried along with the mean flow. These eddies remain coherent for several pipe diameters and convect at, or near, the average flow rate in the pipe.

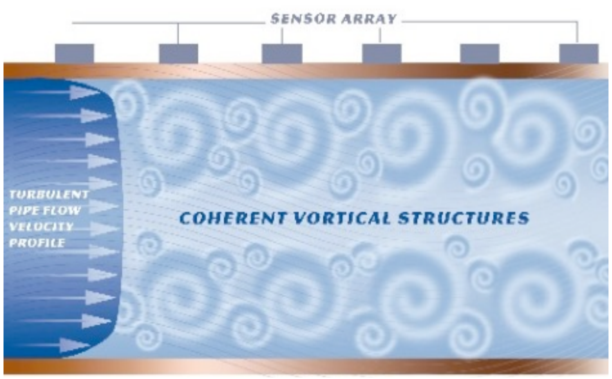

Figure 1: Sonar-based Flow Meters with Coherent Structures

Sonar flow meters use the convection velocity of coherent structures (eddies) to determine volumetric flow rate. The sonar-based algorithms determine the speed of these structures by characterizing both the temporal and spatial frequency characteristics of the flow field. For a series of coherent eddies convecting past a fixed array of sensors, the temporal and spatial frequency content of pressure fluctuations are related through a dispersion relationship, expressed as follows:

$$V_{convect} = \frac{\omega}{k} \qquad (1)$$

Where, $V_{convect}$ is the convection velocity of the disturbance, ω the temporal frequency (rad/sec), k is the wave number (defined as k=2π/λ) and λ is the spatial wavelength.

In sonar array processing, the spatial/temporal frequency content of sound fields are displayed using "k-ω" plots in which the power of the sound field is decomposed into bins corresponding to specific spatial wave numbers and temporal frequencies (Figure 2). On a k-ω plot, the power associated with coherent structures convecting with the flow is distributed along "the convective ridge". The slope of the convective ridge represents the speed of the turbulent eddies, which is then converted to volumetric flow.

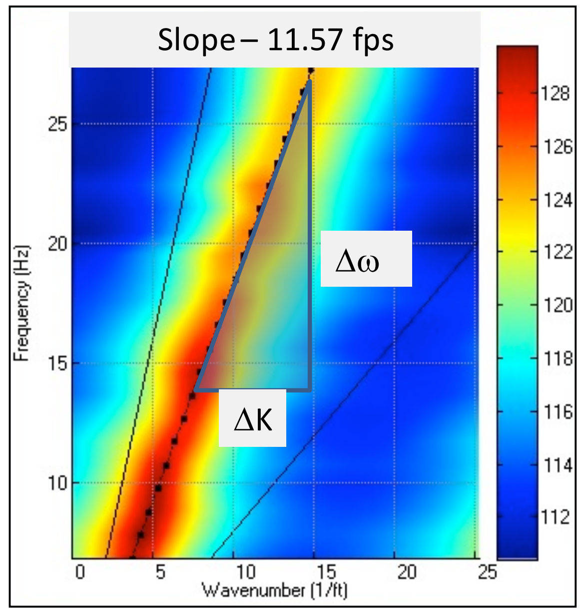

Figure 2: k-ω plot with convective ridge

Sonar Wet Gas Over-reading Correlation. When using the Sonar for wet gas flow measurement, the reported flow rate is higher than the actual flow rate of the gas phase of the mixture, similar to the dP-based flow meters (Venturi, orifice, etc.). The magnitude of the Sonar over-reaading is typically less than that of the dP-based meters.

The over-reading of a sonar meter is defined as the ratio between the reported flow velocity (V_{sonar}) and the gas superficial velocity (V_{sg}):

$$OR_{sonar} = \frac{V_{sonar}}{V_{sg}} \qquad (2)$$

The following empirical correlation was developed to characterize the over reading of pulsed-array sonar meters for wet gas streams flowing in fully developed, horizontal flow lines:

$$OR_{sonar} = 1 + \beta\left(\frac{\sqrt{LVF}}{1+Fr^{m}}\right) + \varphi\left(\frac{\sqrt{LVF}}{1+Fr^{m}}\right)^{2} \qquad (3)$$

Where, LVF is the liquid volume fraction (LVF) and Fr is the gas densimetric Froude number (Fr); β and φ are calibration constants and

$$m = \begin{cases} F_r - 0.5, & 0.5 < F_r < 1.5 \\ 1, & F_r \geq 1.5 \end{cases} \qquad (4)$$

Total Production Surveillance System (TPS). The system integrates the Sonar flow measurement with an Equation of State (EoS) model for the Pressure, Temperature and Volumetric (PVT) properties of the produced fluids in gas condensate wells as shown in Figure 3.

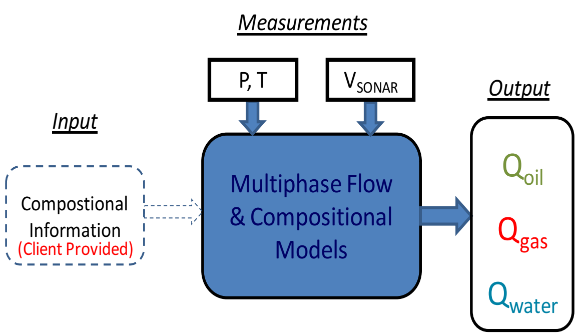

Figure 3: Schematic Total Production Surveillance Methodology

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. The model also calculates mixture properties such as liquid volume fraction (LVF) and gas Froude number (Fr). Those parameters are used in conjunction with the empirical correlation for the over-reading of the sonar meter to correct the sonar flow velocity of the mixture in terms of actual gas flow rate. Once the gas flow rate is determined at actual conditions, the 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.

A schematic of the the typical embodiment of the TPS system at the wellhead is shown in Figure 4:

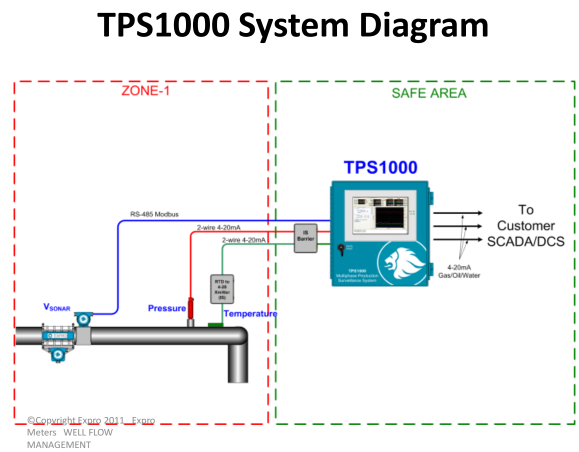

Figure 4: Schematic Total Production Surveillance Methodology

The over-reading correction enables the ActiveSONAR meter to report gas rates to within +/- 3% for 0<LVF<0.106 and 0.5<Fr<5.78. Figure 5 illustrates the results for a 4in Sonar tested in the wet gas loop at CEESI, CO.

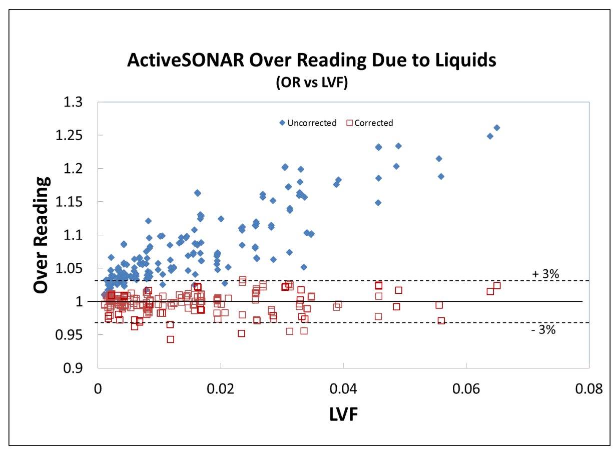

Figure 5: Wet gas over-reading correction (4in Sonar)

TPS Sensitivity with Compositional Parameters. Since defining the well bore composition is equivalent to specifying the CGR (condensate gas ratio) and WGR (water gas ratio) of the gas condensate stream, the accuracy of the compositional information would have a direct impact on the individual phase flow rates inferred by the TPS system.

Typically, the sonar-based surveillance relies on the knowledge of the well bore composition from either historical well tests or/and fluid sampling. Therefore, a brief sensitivity analysis would be beneficial to quantify the magnitude of flow errors due to errors in compositional parameters.

For simplicity, the flow conditions from one of the trials presented herein were used (Table 1). There are two CGR values used for the analysis, 30STB/mmscf and 70STB/mmscf, which are varied by ±20% each, while keeping the water cut (WC) constant, at 5%. The net effect of ±20% change in CGR is that both the oil and water flow rates shift by ±20%.

If the CGR is held constant (30STB/mmscf and 70STB/mmscf), and WC is varied by ±2% (absolute), the water flow rate changes by ±40%, which is similar to the relative change in WC.

	Sonar Wet Gas Sensitivity								
Well	CGR	Water Cut	WGR	Qgas	Qoil	Qwater	Qgas Error	Qoil Error	Qwater Error
	STB/MMscf		STB/MMscf	MMscfd	STB/D	STB/D	%	%	%
U	30	5%	1.58	79.00	2370.0	124.8			
	24	5%	1.26	78.79	1891.4	99.3	-0.27%	-20.19%	-20.43%
	36	5%	1.89	79.17	2850.0	149.6	0.22%	20.25%	19.87%
V	70	5%	3.68	80.11	5607.7	294.8			
	56	5%	2.94	79.73	4464.6	234.4	-0.47%	-20.38%	-20.49%
	84	5%	4.42	80.50	6762.1	354.2	0.49%	20.59%	20.15%
W	30	5%	1.58	79.00	2370.0	124.8			
	30	3%	0.92	79.02	2370.6	72.7	0.03%	0.03%	-41.75%
	30	7%	2.26	78.98	2369.4	178.5	-0.03%	-0.03%	43.03%
X	70	5%	3.68	80.11	5607.7	294.8			
	70	3%	2.16	80.15	5610.6	173.1	0.05%	0.05%	-41.28%
	70	7%	5.26	80.07	5604.7	421.1	-0.05%	-0.05%	42.84%
	Vsonar	75	ft/s						
	Pressure	1400	psig						
	Temperature	200	degF						
	Pipe Size	6in Sch 160							

Table 1: TPS sensitivity with well composition

The analysis shows the importance of having accurate compositional inputs in The TPS system in order for the inferred phase rates to be accurate. Therefore, the compositional information should be updated every time there is a significant change in the wet gas parameters.

Field performance

In many places around the world, the local regulatory body requires the wells to be tested at a certain frequency, but the existing infrastructure may not allow the operators to comply easily with those requirements. In most instances, it could lead to a significant increase of the operating costs, especially for the offshore and remote land fields where physical access poses challenges.

Often times, the field piping layout does not include the means (test separators) to test each individual well and the production allocation becomes a serious issue for both financial and technical reasons.

Production surveillance and monitoring of individual wells using the clamp-on SONAR-based TPS system, allows operators to measure the production of each well more frequently and without deferring production. Also, due to the clamp-on design, the well production is measured under normal operating conditions, helping to identify underperforming wells or the need for work over.

The test data from two gas condensate field trials is presented herein, one offshore and the other on land.

Offshore Trial. The offshore trial was conducted in a gas condensate field with two satellite platforms and one production platform. The satellite platforms are equipped with production separators, but no test separators.

The client was experiencing significant production losses when diverting wells through the test separator due to backpressure effects. Additionally, the client was looking to obtain production surveillance data at normal well flow conditions, unaffected by the limitations of the test separators. The client wanted to increase both the frequency and efficiency of production testing/surveillance.

Eleven wells were tested on platforms A and B: A1, A2, A3, A4, A5, B1, B2, B3, B4, B5 and B6, over a 7 day period.

Figure 6: Sonar flow meter (6in)

The flow data recorded by the flow meter was post processed using Expro Meters' proprietary TPS1000 software, along with well head pressure and temperature (provided by client), a well stream composition reconstructed with CGR and WGR (water gas ratio) values determined from the April 2014 well test report, to report gas, oil and water rates at standard conditions.

Well A5 was tested before and after a facility layout modification, as part of an optimization scheme. Review of the data for both tests (Pre- and Post- Modification) indicated that the flow measurement increased by 2.4 MMscfd in the post-test flow data.

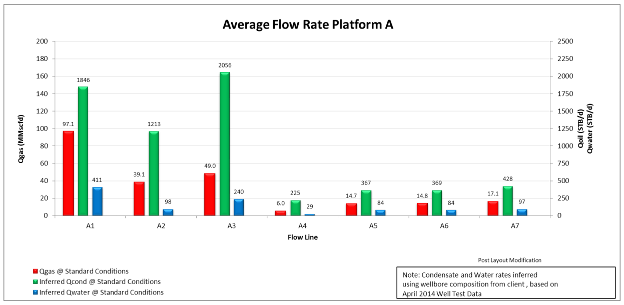

Figure 7: Sonar flow meter results Platform A

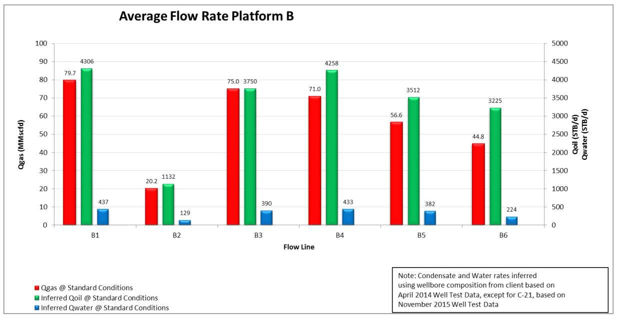

Figure 8: Sonar flow meter results Platform B.

The total 3-phase flow rates for the A and B wells, as reported by Expro Meters, have been compared to the production separator A (platform A), B1 and B2 (platform B) flow rates. Expro reported gas rates for the A wells were within 3% of the A platform production separator rates. The reported gas rates for the B wells were within - 3% of the B1 and B2 platform production separator rates. The condensate rates were within 4.5%, while the water rates within 12% for Separator B, which may be indicative of an incorrect WGR.

As a result of the trial, the client decided to employ Expro to perform the well surveillance on a quarterly basis and expand the scope to the entire field.

Land Trial. The land trial was conducted in a remote high pressure gas condensate field; the pressures recorded downstream of the choke were between 1700psig and 2150psig. The client was looking to increase well test frequency due to the local regulations and possibly reduce the cost.

At the request of the client, Expro Meters performed a wellhead surveillance trial on two wells: C1 and C2. The TPS1000 software was then used to provide single point volumetric flow rates (oil, gas and water) onsite, based on average velocity mesurements.

For well C1, the SONAR meter was installed on this well for six days. The flow data was post processed using line pressure and temperature readings along with a wellstream composition (CGR - 33.84 STB/MMSCF and WGR - 0.94 STB/MMSCF) provided by the client. The gas and condensate rates were within 4% of the separator rates, while the water within 10%.

The SONAR meter was installed on well C2 for three days. The flow data was post processed using line pressure and temperature readings along with a wellstream composition (CGR - 47.1 STB/MMSCF and WGR - 8.715 STB/MMSCF) provided by the client. The reported flow rates (gas, condensate water) were all within 3% of the reference.

Figure 9: Sonar flow meter (10in) well C1.

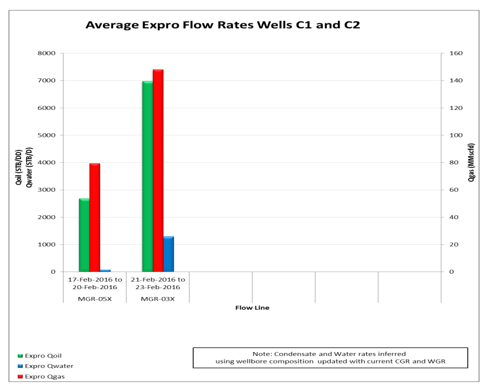

Figure 10: Sonar flow meter results wells C1 and C2.

The client is currently looking into what requirements need to be met in order to qualify the Sonar-based Surveillance for gas condensate well testing by the local regulatory body.

Conclusions

A clamp-on production surveillance system designed to monitor gas condensate wells was presented. The system employs a clamp-on sonar flow meter as the flow metering element, integrated with an Equation of State PVT model. In the approach described herein, produced oil and water rates are inferred from the measured gas rate using a user-defined well bore composition.

When combined with accurate well bore composition data, the clamp-on production surveillance system provides a practical, cost-effective, real-time surveillance of gas condensate wells.

Two field cases are presented illustrating the application of this system to gas condensate wells. The two cases utilized historical well bore compositional data to provide three-phase surveillance on a periodic or survey basis. The results for both trials proved that Sonar-based surveillance (TPS) is a viable alternative for gas condensate wellhead surveillance.

While the system measures variations of produced liquids due to variations in gas production, it will not measure variations in CGR and/or WC. To account for changes in CGR or/and WC, an updated well-bore composition must be entered into the system.

Traditional well testing approaches, such as CTS and MPFM may require a significant amount of time to be deployed in the field. The Sonar clamp-on approach requires a shorter amount of time (about 90min) for installation and commissioning which allows the possibility to perform multi-rate testing of the wells or multiple well testing in one day. Therefore, the sonar clamp-on methodology offers the opportunity to increase the well test frequency at a field-wide level thus allowing a better field/production management.

The Sonar-based Surveillance is not to replace traditional well testing methodologies, but to augment them by offering a quick, reliable and cost effective solution for applications requiring recurring production surveillance, especially where reservoir conditions are relatively stable over time.

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Nomenclature

CTS	=	*Conventional Test Separator*
MPFM	=	*Multiphase Flow Meter*
TPS	=	*Total Production Surveillance*
$V_{convect}$	=	*Convection velocity of turbulent eddies*
ω	=	*Temporal Frequency*
MPFM	=	*Multiphase Flow Meter*
TPS	=	*Total Production Surveillance*
$V_{convect}$	=	*Convection velocity of turbulent eddies*
ω	=	*Temporal Frequency*
k	=	*Wave Number*
λ	=	*Wave Length*
OR_{sonar}	=	*Sonar Wet Gas Over-reading*
V_{sonar}	=	*Sonar Velocity*
V_{sg}	=	*Superficial Gas Velocity*
LVF	=	*Liquid Volume Fraction*
Fr	=	*Gas Froude Number*
β	=	*Sonar Wet Gas Correction Constant*
φ	=	*Sonar Wet Gas Correction Constant*
m	=	*Sonar Wet GasCorrection Coefficient*
EoS	=	*Equation of State*
CGR	=	*Condensate Gas Ratio*
WGR	=	*Water Gas Ratio*
WC	=	*Water Cut*

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