

USE OF NON-CONTACT, PASSIVE SONAR-BASED VOLUMETRIC FLOW AND GAS VOLUME FRACTION METER FOR IMPROVED SOUR WATER REINJECTION MEASUREMENT

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1 ABSTRACT

Sonar flow and gas volume fraction technology employs an array of sensors that are wrapped around an existing process pipe, requiring no coupling gels or alignment. The sensor element is connected to a transmitter which consists of a powerful, digital signal processor that processes coherent pressure disturbances, naturally occurring in process pipes, to deliver real time measurements of volumetric flow and entrained gases in the process fluid (gas volume fraction).

Accurate measurement of produced sour water (water containing hydrogen sulfide) is a critical component of effective oil field management. An approach is presented which enables accurate measurement of sour water reinjected (disposed) into individual wells through the use of non-contact, sonar-based volumetric flow and gas volume fraction technology. Utilizing passive sonar, signal array processing to measure volumetric flow rate and gas volume fraction of the process fluid helps enable operators ensure efficient resource and asset utilization, accurate material balance reporting, and the health and safety of its employees.

Some of the benefits described in this paper will focus on the non-contact and entrained gas measurement features of the sonar technology. For example, because the sensor element is wrapped around the existing process pipe there is one less potential path for dangerous emissions to escape. In addition, the flow element can be installed or removed while the wells are flowing so there is no need to interrupt production, allowing for increased asset uptime and utilization. By providing a real time measurement of entrained gas in the process fluid, the sonar process flow monitoring system can be a leading indicator of decreasing back pressure so that the appropriate operator action can occur. Because an accurate real time measurement of gas volume fraction is maintained, a true liquid flow can be measured to produce more accurate measurements and material balances to the operating company and regulatory agencies. Finally a case study describing the practical application of the passive sonar technology by an Alberta oil and gas production company committed to employing innovative solutions to help improve health, safety and environment will be presented.

2 INTRODUCTION

Volumetric flow is a critical measurement for most industrial processes. The industrial flow meter market is often classified into two basic categories: old technology and new technology. Old technology flow meters include technologies that include turbine, orifice and variable area meters that have been in use for over 70 years. New technology flow meters, those that have evolved over the past 40 years or so include ultrasonic, electromagnetic, vortex and coriolis flow meters. Each type has evolved to serve various aspects of the diverse range of applications in process industries.

“Dirty” erosive/corrosive fluids and aggressive slurries present numerous operating, physical and measurement challenges to all of the aforementioned flow technologies to some degree. Often times, the operator might have to trade-off measurement reliability, lower maintenance and uptime when selecting a flow meter technology for these types of applications. In the case of in-line meters which come into contact with the fluid or slurry, safety risk increases as well due to potential leakages, meter change outs and so forth.

The need to make a non-contact, accurate and robust flow measurement on practically any type of fluid/slurry, pipe material, and lined-pipe has driven the creation of a new technology class of flow meter. This technology utilizes sonar-based processing algorithms and an array of passive sensors that wrap around a pipe to provide a full-bore measurement of flow and entrained gas or air. Passive sonar flow measurement technology represents a new class of industrial flow meters utilizing measurement principles distinct from existing technologies. Sonar flow meters were first introduced into the oil and gas industry in 1998 for use in downhole multiphase flow metering applicationsⁱ. Sonar flow measurement technology is currently being used in other industries such as oil and gas, mining and minerals, oil sands, pulp and paper, chemicals and power generation.

3 FLOW RATE MEASUREMENT

The overwhelming majority of industrial process flows involve turbulent flow. Turbulent fluctuations within the process flow govern many of the flow properties of practical interest including the pressure drop, heat transfer and mixing. For these reasons, turbulent pipe flows have been extensively studied over the years with roots back to Osbourne Reynolds and Lord Rayleigh in the late nineteenth centuryⁱⁱⁱ.

3.1 Turbulent pipe flow

For engineering applications, considering only the time-averaged properties of turbulent flows is often sufficient for design purposes. For sonar flow metering technology, understanding the time-averaged velocity profile in turbulent flow provides a means to interpret the relationship between speed at which coherent structures convect and the volumetrically averaged flow rate within a pipe. For turbulent flows, the time-averaged axial velocity varies with radial position, from zero at the wall to a maximum at the centerline of the pipe. The flow near the wall is characterized by steep velocity gradients and transitions to relatively uniform core flow near the center of the pipe. Figure 1 shows a representative schematic of a velocity profile and coherent vortical flow structures present in fully developed turbulent pipe flow.

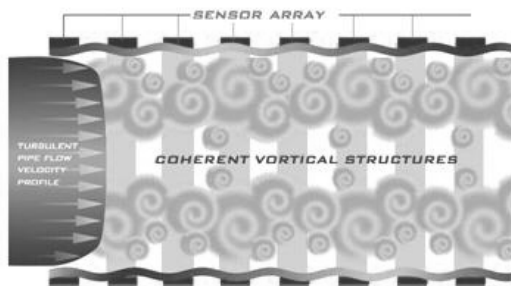


Figure 1: Coherent Structures in Turbulent Pipe Flows.

The vortical structures are superimposed over time averaged velocity profile within the pipe and contain temporally and spatially random fluctuations with magnitudes typically less than 10% percent of the mean flow velocity. The Reynolds number (Re), based on pipe diameter (D) characterizes many of the engineering properties of the flow. The Reynolds number is a non-dimensional ratio representing the relative importance of inertial forces to viscous forces within a flow. Pipe flows with Reynolds numbers exceeding a critical value, typically 2300, are turbulent. Those with Reynolds numbers below this value are laminar. The vast majority of flows in

industrial processes are turbulent with Reynolds numbers far in excess of the critical value.

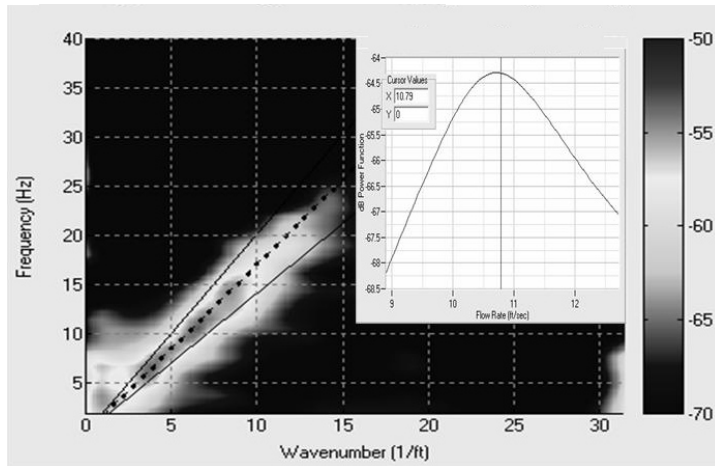
3.2 Coherent turbulent structures

Turbulent pipes flows are highly complex flows. Predicting the details of any turbulent flow is one of nature’s great-unsolved problems. However, much is known regarding the statistical properties of the flow. For instance, turbulent pipe flows contain self-generating, coherent vortical structures often termed “turbulent eddies”. The maximum length scale of these eddies scales with the diameter of the pipe. These structures remain coherent for several pipe diameters downstream, eventually breaking down into progressively smaller eddies until the energy is dissipated by viscous effects. Experimental investigations have established that eddies generated within turbulent boundary layers convect at roughly 80% of maximum flow velocity. For pipe flows, this implies that turbulent eddies will convect at approximately the volumetrically averaged flow velocity within the pipe. The precise relationship between the convective velocity of turbulent eddies and the flow rate for each class of meter can be calibrated empirically as described below.

3.3 Characterizing the unsteady pressure field

The sonar flow metering methodology uses the convection velocity of coherent structures within turbulent pipe flows to determine the volumetric flow rate. The convection velocity of these eddies is determined by applying sonar array processing techniques to determine the speed at which eddies convect past an axial array of dynamic strain measurements distributed along the pipe outer circumference. The sonar-based algorithms determine the speed of eddies by characterizing both the temporal and spatial frequency characteristics of the flow field. For a train of coherent eddies convecting past a fixed array of sensors, the temporal and spatial frequency content of pressure fluctuations are related through the following relationship:

$$u = \frac{\omega}{k} \quad (1)$$



Where u is the convective velocity of the unsteady pressure fluctuations (m/s), ω is the temporal frequency (rad/s) and k is the wave number (rad/m), defined as $k=2\pi/\lambda$ where λ is the wavelength (m). In sonar array processing, the spatial/temporal frequency content of time stationary sound fields are often displayed using “k-w plots”. k-w plots are essentially two dimensional power spectra in which the power of a pressure field is decomposed into bins

corresponding to specific spatial

Figure 2: k-w Plot Showing Convective Ridge

wave numbers and temporal frequencies. On a k-w plot, the power associated with a pressure field convecting with the flow is

distributed in regions which satisfy the dispersion relationship developed above. This region is termed the “convective” ridge^{iv} and the slope of this ridge on a k-w plot indicates the convective velocity of the pressure field. This suggests that the convective velocity of turbulent eddies, and hence flow rate within a pipe, can be determined by constructing a k-w plot from the output of a phased array of sensors and identifying the slope of the convective ridge. Figure 2 shows an example of a k-w plot generated from a phased array of transducers listening to a 16 inch pipe flowing water at approximately 350 l/s. The power contours show a well-defined convective ridge. A parametric optimization method was used to determine the “best” line representing the slope of the ridge. For this case, a slope of 3.2 m/s was determined. The

intermediate result of the optimization procedure is displayed in the insert, showing that the optimized value is unique and constitutes a well-defined maximum.

3.4 Sonar flow meter calibration

The k-w plot shown in Figure 3 illustrates the fundamental principle behind sonar based flow measurements, namely that an axial array of transducers can be used in conjunction with sonar processing techniques to determine the speed at which naturally occurring turbulent eddies convect within a pipe. The next issue is to quantify the relationship between the measured speed of the turbulent eddies and the volumetrically averaged flow rate within the pipe.

To quantitatively evaluate this relationship, a number of geometrically similar sonar flow meters with diameters between 2 and 30 inches were tested with water at a flow meter calibration facility for a wide range of flow rates. Using a low-order Reynolds number based calibration, spanning the operating range of flow meters of different physical sizes; the sonar meter measured the volumetric flow rate to within 0.5% accuracy. It is important to note that this flow metering approach has no fundamental size limitations and should be applicable to turbulent pipe flows of all diameters and Reynolds numbers. Furthermore, similarity laws suggest, and calibration data support, that the relationship between convection velocity and flow rate from geometrically similar meters of any size is governed by same Reynolds number based calibration.

4 MEASUREMENT OF GAS CONTENT

Using a similar hardware platform it is also possible to measure the speed of sound of acoustic waves propagating in the process fluid. The propagation of acoustic waves occurs at frequencies much above the frequency domain of vortical pressure fluctuations; therefore the same sonar processing can be applied to determine both the acoustical velocity and the vortical velocity at the same time. The relation between speed of sound in a two-phase mixture and the volumetric phase fraction is well known in the case when the wavelength of sound is larger than the pipe diameter and hence also significantly larger than any process inhomogeneities such as bubbles.

4.2 Speed of sound in liquid/gas mixtures

The mixing rule^v, known as Wood's equation^{vi}, expresses the fact that in a mixture the compressibility of the mixture equals the volumetrically averaged compressibility of the pure components. For the mixture density a similar rule holds: the mixture density equals the volumetric average of the pure component densities. Because the speed of sound in a fluid equals the square root of the compressibility over the density, the two mixing rules can be written as:

$$\frac{1}{\rho c^2} = \frac{\varphi}{\rho_g c_g^2} + \frac{1-\varphi}{\rho_l c_l^2} \quad (2).$$

$$\rho = \varphi \rho_g + (1-\varphi) \rho_l$$

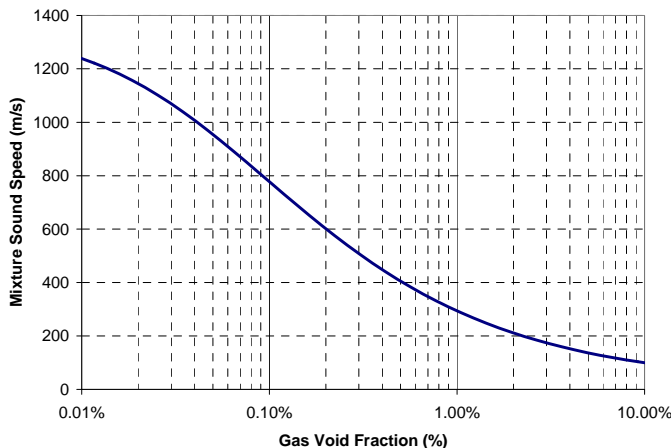


Figure 3: Mixture Sound Speed vs. Gas Void Fraction

Here, φ is the in-situ volume fraction of gas at line conditions, c is the speed of sound, ρ the density and the subscripts g and l refer to the gas and liquid phase respectively. Figure 3 illustrates the relation between mixture sound speed and gas content for a gas/water mixture. In most industrial processes, at moderate temperature and pressure line conditions, the compressibility of the gas phase is orders of magnitude larger than the compressibility of the liquid phase. Inversely, the density is dominated

by the liquid density. As such, it will be necessary to measure the process pressure (when varying) as both the gas density and the liquid density are significant when determining the gas void fraction from the mixture sound speed.

Conversely, neither the speed of sound in the liquid nor the speed of sound of the gas is a significant factor for mixtures where one phase is gaseous. In fact, the denominator of the first term in the Wood's equation equals the product of process pressure and polytropic exponent of the gas demonstrating that the gas content at line conditions can be determined using the speed of sound independent of the gas molecular weight or the gas temperature. Hence, the determination of the gas content using mixture speed of sound is independent of the gas type and will be accurate irrespective of the type of gas, which can be air, hydrocarbon, carbon-dioxide, hydrogen or any mixture thereof.

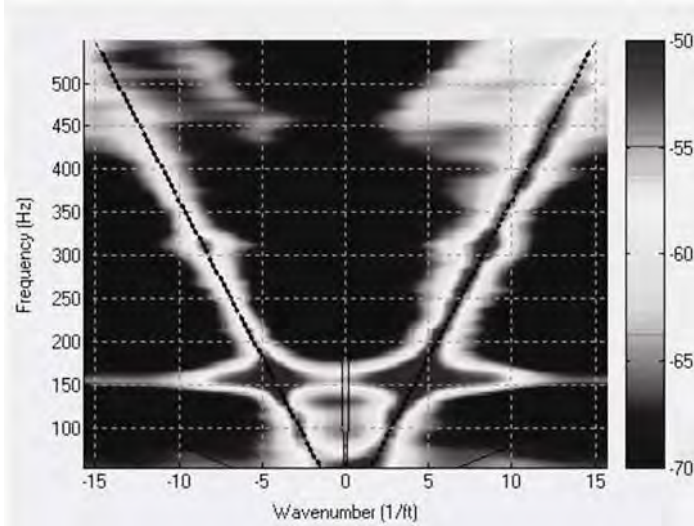


Figure 4: k-w Plot for 3% Entrained Air in Water.

Figure 4 shows a k-w plot generated for acoustic sound field recorded from still water containing ~3% entrained gas by volume in an 8 in, schedule 80, vertically oriented Plexiglas pipe. The k-w plot was constructed using data from an array of strain based sensors clamped to the outside of the pipe. Two acoustic ridges are clearly evident. Based on the slopes of the acoustic ridges, the measured sound speed for this for this mixture was 70 m/s, consistent with that predicted by the Wood equation. Note that adding 3% air by volume reduces the sound speed of the bubbly mixture to less than 10% of the sound speed of liquid only water.

4.3 Industrial applications

Entrained gas in liquid-continuous flows is often an unwanted but unavoidable phenomenon that negatively impacts safety, environmental emissions, product quality or the ability to accurately determine the flow rate. For instance, entrained gas in the brine flow at an underground natural gas or natural gas liquid (NGL) storage facility can indicate an upset condition in the process or in the facility infrastructure and has serious safety and environmental concerns. Likewise in sour (H₂S) water reinjection/disposal applications entrained gas can have similar effects on process, facility infrastructure and safety/environment. Following is a discussion of these effects.

5.0 SOUR WATER REINJECTION (Disposal): A CASE STUDY

Accurate and reliable measurement of produced sour water is a critical component of effective oil field management. We will next examine how sonar based technology is being used in sour water applications to provide a more reliable measurement, increase the efficiency of operations and the recovery of produced water while at the same time lend itself to improved health and safety conditions in the oil field.

5.1 Key Industry Characteristics and Challenges

The Pembina - Nisku play is roughly 30 km wide for roughly 140 km around the Brazeau Dam to Lake Wabamum. Successful wells are capable of producing over 750 boe/d with a reserve potential exceeding one MMboe per well. The play was described by energy analysts as “the source of the most significant series of light oil discoveries in the past five years.”^{vii} That said the sour nature of produced gas and produced water presents some very specific challenges for oil operators. A few key challenges are outlined as follows:

Environmental/Safety

One key challenge associated with the play is that the solution gas in these light oils is very “sour”, containing between 17% and 35% hydrogen sulfide or H₂S. Produced water, then, pumped through pipes and reinjected, or disposed into a well in order to fill the void left by the evacuated oil also contains high levels H₂S.

Mechanical Reliability

Maintaining back pressure within water reinjection pipelines is critical to the operator. At lower pressures, gas will break out of solution causing a “water hammer” which in itself can cause additional wear on mechanical equipment such as pumps, valves and conventional intrusive flow meters.

Downtime

Conventional flow meters used in sour water streams are typically turbine meters. Since turbines are installed in-line and are intrusive to the process flow they are subject to the corrosive and “dirty nature of the fluid as well as solid debris that occasionally are in the process flow. When a repair, replacement or proving of the turbine meter is required the line must be taken out of service thereby causing a stoppage of production.

Measurement Accuracy Issues

Loss of back pressure will also cause gas to break out of solution which in turn causing the conventional flow meters to over report the volumetric flow of the fluid stream. Gas break out and gas slugging passing through the turbine flow meter will cause the turbine blades to spin faster. This results in the over-reporting of volumetric flow and causes errors in mass balance calculations.

5.2 Deployment of Sonar-Based Flow Meters in Sour Water Applications

Sonar-based volumetric flow meter technology was first deployed in sour water applications in the Drayton Valley area approximately 3 years ago. Subsequently to the initial installation, multiple sonar-based flow meters were added, replacing the turbine meters that were in use at the time. All flow meters were upgraded to include the Gas Volume Fraction (GVF) measurement in order to enhance operating and process efficiencies. The accuracy of the sonar-based meter is $\pm 1.0\%$ of reading with a repeatability of $\pm 0.3\%$ of reading. Entrained gas accuracy of the sonar meter is $\pm 5.0\%$ of reading from 0.01% to 20% with repeatability of $\pm 1.0\%$ from 0.01% to 20.0%. By knowing the GVF percentage of the fluid mixture, the true liquid flow can be derived. This calculation can be performed in the DCS or in the transmitter. Flow velocity range of the sonar-based meter is typically 1 to 10m/s.

Following is a brief discussion of the benefits that operators have realized.

5.3 Benefits of the Sonar-Based Process Flow System: Improving Operating and Process Efficiencies

Environmental and Safety

The sonar-based sensor element uses an array of eight piezo-electric sensors that wrap around the process pipe. (Figure 5a and 5b) During installation and removal the operator does not need to breach the pipe and does not need to deal with flange, threaded connections, strainers, etc. at the metering point. By removing these mechanical connections, potential leak paths are eliminated, thereby reducing overall safety risk to the operator’s employees and contractors and eliminating leakage to the environment at the metering point.



Figures 5a and 5b: Sonar sensor bands without enclosure

Increased Mechanical Reliability

In addition to eliminating various mechanical connections and components at the metering point, other benefits were realized by the operator through the use of the Gas Volume Fraction (GVF) measurement feature of the sonar-based system. Since the sonar signal processing transmitter utilizes two 4-20ma outputs (or Foundation Fieldbus) where both measurements - volumetric flow and GVF – can be reported to the customer's DCS. As mentioned above, it is very important for the operator to maintain back pressure within the reinjection system to prevent water hammering and potential mechanical wear, damage and reliability issues.

The operator in this case study utilizes the GVF measurement as an “early warning” system that allows them to take corrective action when they begin to lose back pressure, thereby preventing process upsets, mechanical reliability issues and ultimately, downtime. (Figure 6)

Increased Asset Utilization and Process Uptime

As shown in Figures 5 and 7, because the sensor element can be wrapped around the pipe while the process is running there is never a need to interrupt or stop production during an installation or removal of the sensor head. Since the meter is based on *passive* sonar processing no coupling gels are required. The sensor installs quickly and easily as the sensor band is self aligning. Additionally since the sonar-based systems have no inherent drift mechanism and don't come



Figure 6: Passive sonar meter installation on water reinjection line

in contact with the process fluid, there is no need for the operator to perform meter proving thereby eliminating associated operating costs and disruption to production. Finally as stated above, the entrained gas feature of the sonar-based meter can be utilized as a leading indicator of decreasing back pressure, allowing the operator to take corrective measures. This capability contributes to reduced wear on pumps and other mechanical equipment – all leading to increased uptime benefits.

Increased Measurement Accuracy and Reliability

Accurate measurement of produced sour water is a critical component of effective oil field management. All installed sonar meters at the operator’s sites are equipped with the Gas Volume Fraction option. The sonar meters reports and measures the amount of entrained gas when present in the process fluid and typically caused by loss in back pressure. The volumetric flow measurement is then adjusted by subtracting the volume of gas from the total mixture volume thereby providing a measure of true liquid flow. This feature enables more accurate reporting and mass balance calculations.

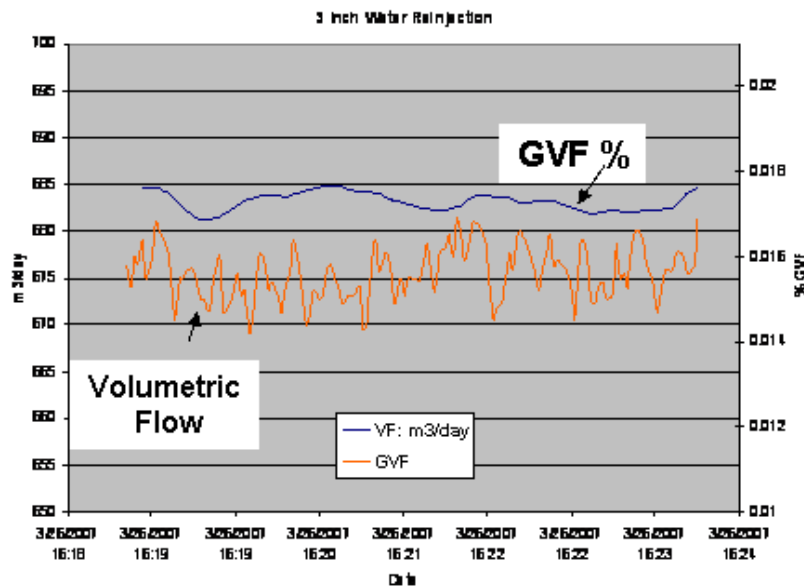


Figure 7: Passive sonar meter graph of volumetric flow and gas volume fraction on water reinjection line

6 SUMMARY

Utilizing passive sonar, signal array processing to measure volumetric flow rate and gas volume fraction in sour water applications helps enable operators ensure efficient resource and asset utilization, increased uptime, lower operating costs, enhanced mass balance reporting, and safeguards the health and safety of its employees.

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