FLOW MEASUREMENT USING ULTRASONIC METERS IN WET GAS APPLICATIONS

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Abstract
Increasing hydrocarbon product values and regulatory requirements have driven an increased emphasis on accurate midstream and upstream flow measurement. Multiphase flow, referred to as "wet gas", where the fluid is primarily gas but with some liquid present is often encountered in these measurements. Wet gas presents multiple measurement challenges that need to be properly understood and addressed.

This paper introduces wet gas concepts, outlines the challenges of wet gas measurement, and then examines the various advantages and disadvantages of meter technologies currently used in wet gas applications. This paper also focuses on utilizing ultrasonic meters for wet gas measurement and the advantages that the USM technology provides. Also discussed will be the diagnostic data provided by the USM in wet gas applications.

Why Is Wet Gas Important
Historically, the Oil & Gas Industry has neglected *Allocation* measurement and has focused on *Custody Transfer* measurement. Early multiphase and wet gas measurements were considered, at best, crude estimates. Advances in technology have changed that. Today, wet gas meters are replacing expensive separators and becoming an integral part of Oil & Gas production, measurement, and distribution.

The value of the oil and gas moving down a pipe is principally determined by flowmeters called *Custody Transfer meters*. These meters are calibrated against accurate reference meters. *Custody Transfer meters* only measure gas or oil, but not both at the same time. Called *comingling*, pipes carrying wet gas (gas, oil, and water) are fed into larger pipes, separators, and gathering stations, where the oil and gas are separated and measured. Unfortunately, operators lose the ability to know how much oil and how much gas came from a specific well or a specific group of wells when wet gas is *comingled*. Less accurate flowmeters are used to estimate the ratio of fluids feeding a comingled flow stream. These meters are called *Allocation Meters*. Multiple *Allocation Flowmeter* measurements are added together and compared to the output of the relevant oil-only or gas-only *Custody Transfer meter*. Flowrates from each *Allocation* meter are then adjusted so the total oil and gas *Allocation* flowrates equal the *Custody Transfer* flowrates.

Wet gas flow measurement is *Allocation* measurement. Well owners want to get paid their fair share of *comingled* oil and gas streams. Lessors and extracting, gathering, processing, and transporting stakeholders are increasingly demanding their fair share as well. Oil and gas supply and demand, price fluctuations, operating, production and transportation costs all dictate when a well should be shut in. *Allocation* measurement is a vital part of operational balancing and determining when to open or shut in a well or gathering station.

Figure 1. Gathering station where multiple oil and gas streams are combined and processed.

Separation, and The Birth of Multiphase Meters

Historically, it was considered impossible to measure wet gas. If you wanted to measure wet gas, Oil & Gas companies had to install large vessels called separators that segregated the gas and liquid into separate streams. The individual gas and liquid streams after the separator could then be measured independently by their respective liquid and gas flowmeters. Unfortunately, separators and the associated piping to create two separate oil and gas streams is an extremely expensive undertaking. Furthermore, separators are designed to operate efficiently over limited oil and gas flowrate ranges. As oil and gas flowrates change, as different comingled streams are added and subtracted, separators experience large and often rapid oil and gas flowrate swings. These large variations cause gas to flow into the exiting liquid stream and liquid to flow into the exiting gas stream. This is called *Gas Carry-Under* and *Liquid Carry-Over*. Separator efficiency is defined by *Gas Carry-Under* and *Liquid Carry-Over*. Gas flowmeters downstream of a separator experiencing *Liquid Carry-Over* often overread by 20% due to the entrained liquids in the gas stream. Liquid flowmeters downstream of a separator experiencing *Gas Carry-Under* often incorrectly read by 20% due to the entrained gases in the liquid stream. As a well produces less over its lifespan, the initial investment of a separator becomes increasingly difficult to justify. Separator costs, rangeability, and accuracy issues sparked the development of multiphase and wet gas meters.

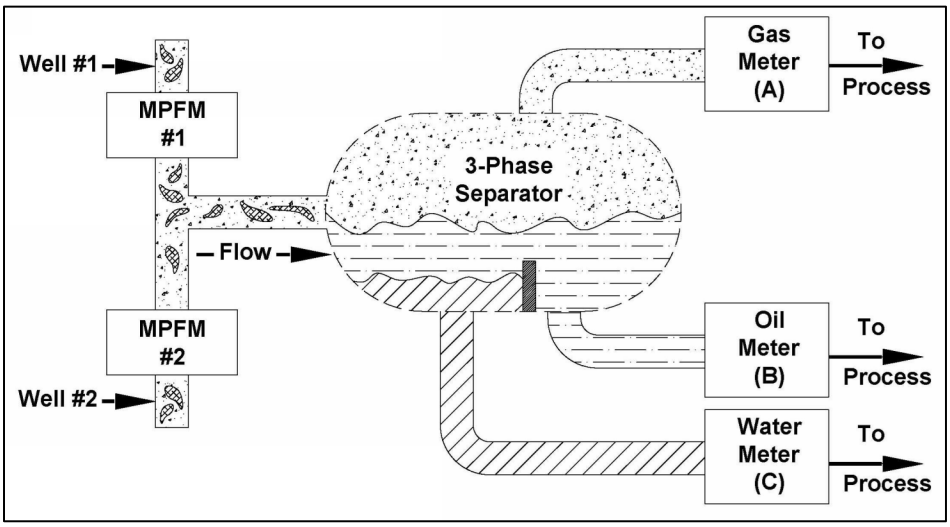

Figure 2. Schematic of two comingled flow streams and a gas-liquid separator. Two multiphase flowmeters (MPFM) measure the mixed gas-oil-water. In theory meters (A), (B), and (C) experience no Gas Carry-Under and no Liquid Carry-Over.

What Is Wet Gas and Why Is It Hard to Measure?

The definition of wet gas is quite simple. *Wet gas is simply defined as two phase flow where liquids are present. Wet gas is a subset of multiphase flow where the predominant fluid is gas.* While simple to define, wet gas is incredibly hard to measure, considering that the liquid density can be eight hundred times greater than the gas density. Furthermore, liquid velocities are much slower than gas velocities, and the liquid level in the pipe is constantly changing.

Wet Gas Terms and Definitions

Wet gas has its own unique language to describe the forces and parameters that influence its complex flowrates. Before we can discuss how wet gas meters work, we need to define several terms used to describe wet gas, and to understand some common wet gas misconceptions.

<u>Acronyms and Definitions</u>:

- DP Meter: Differential Pressure Meter (Venturi, orifice plate, cone meter).
- GAF: Gas Area Fraction (Gas cross-sectional area divided by total pipe area).
- GVF: Gas Volume Fraction (Gas volumetric flow divided by total volumetric flow).
- LAF: Liquid Area Fraction: (Liquid cross-sectional area divided by total pipe area).
- Liquid Holdup: Similar to LAF but does not include the liquid entrained mist.
- LVF: Liquid Volume Fraction (Liquid volumetric flow divided by total volumetric flow).
- MPFM: Multiphase Flow Meter.
- USM(s): Ultrasonic Meter(s).

Flow Regime: A term used to describe the theoretical distribution of gas and liquids in a pipe, and the manner in which the gas and the liquid travel down the pipe. Common wet gas flow regimes include *slug flow, wavy flow, stratified flow, annular mist flow, and homogenous mist flow*. Note, *homogenous mist flow* is a theoretical, perfectly mixed condition that is not achievable in real pipes.

Lockhart-Martinelli Number (X_{LM}): a dimensionless number used to express the liquid fraction in a wet gas flow stream and is the square-root of the liquid momentum divided by the gas momentum. Lockhart-Martinelli Numbers are used to correct DP meters for increasing liquid loadings. Unfortunately, Lockhart-Martinelli Numbers in a pipe are not easily obtainable, making it impracticable to correct DP meters without additional inputs.

$$X_{LM} = \sqrt{\frac{Liquid\ Momentum}{Gas\ Momentum}} = \frac{Q_l}{Q_g}\sqrt{\frac{\rho_l}{\rho_g}} \qquad \textbf{(Equation 1)}$$

Multiphase Flow: defined as any flow where gases and liquids are both present at any gas-liquid ratio.

Slip: used to describe how the faster moving gas travels or "slips past" the slower moving liquid.

Two-Phase and Three-Phase Flow: For convenience, the Oil & Gas Industry defines *two-phase flow as gas and liquid flowing at the same time, where the liquid composition is not explicitly defined as oil or water*. The Oil & Gas Industry defines *three-phase flow as gas, oil, and water flowing at the same time*. From a scientific perspective, matter exists in four defined phases: solid, liquid, gas, and plasma. In wet gas, oil and water exist in the same liquid phase. This paper utilizes the definition adopted by the Oil & Gas Industry.

Wet Gas Flow: defined as two-phase flow where liquids are present. The liquids can exist in mist form entrained in the flowing gas or as a liquid stream flowing like a river along the bottom of the pipe or any combination of the two. Wet gas is a subset of multiphase flow. *This paper defines wet gas as multiphase flow where the predominant volumetric flowrate is gas with smaller amounts of liquid.*

API Wet Gas Definition: In 2004, the American Petroleum Institute API issued a report entitled "*State of the Art of Multiphase Flow Metering*", API Publication 2565, 1st Ed, August 2004. In this report, API defined three distinct categories of wet gas in terms of the Lockhart-Martinelli Parameter (X_{LM}) specifically:

API Type I Wet Gas where $X_{LM} \leq 0.02$
API Type II Wet Gas where $0.02 \leq X_{LM} \leq 0.3$
API Type III Wet Gas where $X_{LM} > 0.3$

While the different API Wet Gas Types (Type I, Type II, and Type III) adequately characterize gas-liquid momentum ratios in a pipe using Lockhart-Martinelli Number (X_{LM}), these definitions are hard to incorporate in practice since Lockhart-Martinelli Numbers are typically not known prior to measurement and are a function of gas-liquid density ratios which are highly dependent on operating pressures.

Because the API Type I, Type II, and Type III definitions do not necessarily apply to meters that have discrete velocity-based technologies, they are not included in this paper. Furthermore, Type I, Type II and Type III are performance-based categories, initially defined by DP meter performance and not defined by typical liquid loadings in the field. Because liquid loadings can be extremely broad from well to well, from process to process, and from platform to platform any performance-based definition invites artificial subjectivity.

At the time of the API publication, differential pressure meters (DP meters) were the principle wet gas meter of interest with the Lockhart-Martinelli Number (X_{LM}) being the best parameter to correlate DP meter performance in wet gas. Utilizing discrete velocity measurements in the flow stream, Multipath USM technology is vastly different than DP meter technology. As such wet gas multipath USM performance is governed not by X_{LM} but rather by different fluid parameters, namely Gas Area Fraction (GAF) and Gas Volume Fraction (GVF).

Wet Gas/Multiphase Flow Common Misconceptions

Three common misconceptions about wet gas/multiphase flow need to be clarified before one delves into wet gas flow measurement. Wet gas/multiphase flow is one of the most complicated and least understood phenomena in flow measurement. With a wide range of pipe pressures, gas densities can vary by a factor of ten, gas-liquid density ratios can range from five to over eight hundred, and oil viscosity and gas viscosity ratios can exceed 50,000. While fluid forces can be adequately modeled in single-phase flow, immense complexities arise when slower moving viscous liquids are mixed with faster moving gases.

Normally predictable Reynolds Number-dependent, single-phase velocity profiles become highly non-linear and unpredictable in multiphase flow. Single phase fluid models simply do not work in the complicated world of two-phase and three-phase flow. Varying gas-to-liquid ratios and varying gas and liquid velocities can cause unstable flow patterns where stratified flow can become wavy flow which can produce liquid slugging in the pipe.

Misconception #1: Renderings and Homogenous Flow

Figure 3 shows renderings of what two-phase flow looks like with different liquid loadings at different velocities, at different gas-liquid density ratios. Compare the renderings in Figure 3 to actual, two-phase flow images shown in Figure 4. Theoretical boundaries between gas and liquid zones do not have ridged, well-defined borders. Unlike the illustrations in Figure 4, the borders between gas and liquid zones are constantly changing and exist as gradients and continuums, without sharp boundaries defining all-liquid flow, all mist flow, or all gas flow. Homogenous flow, or perfectly mixed flow, simply does not exist in two-phase pipe flow.

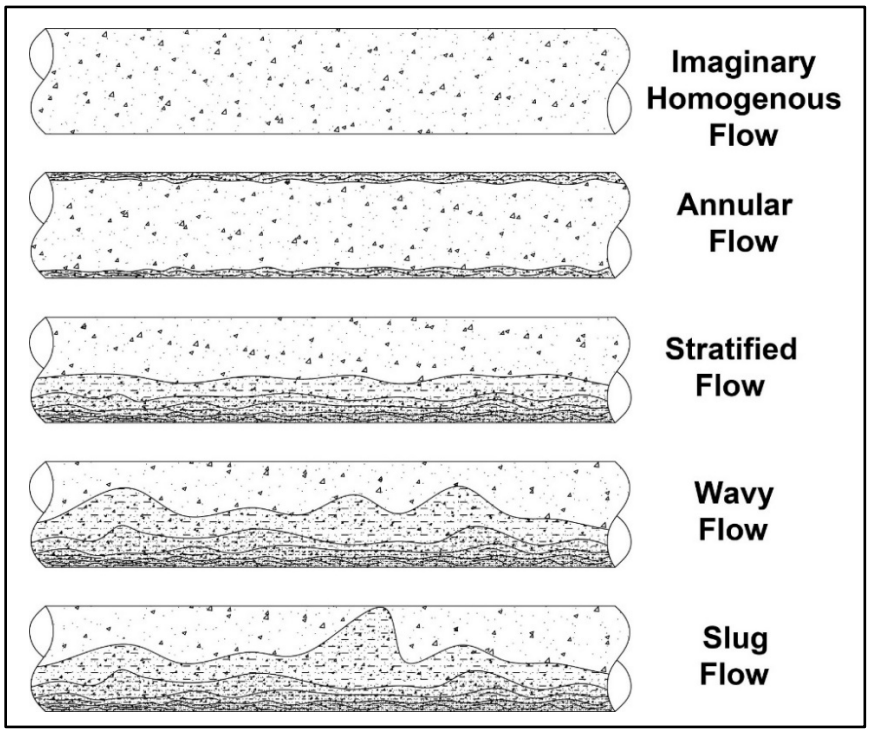

Figure 3. Artist rendering of various flow regimes.

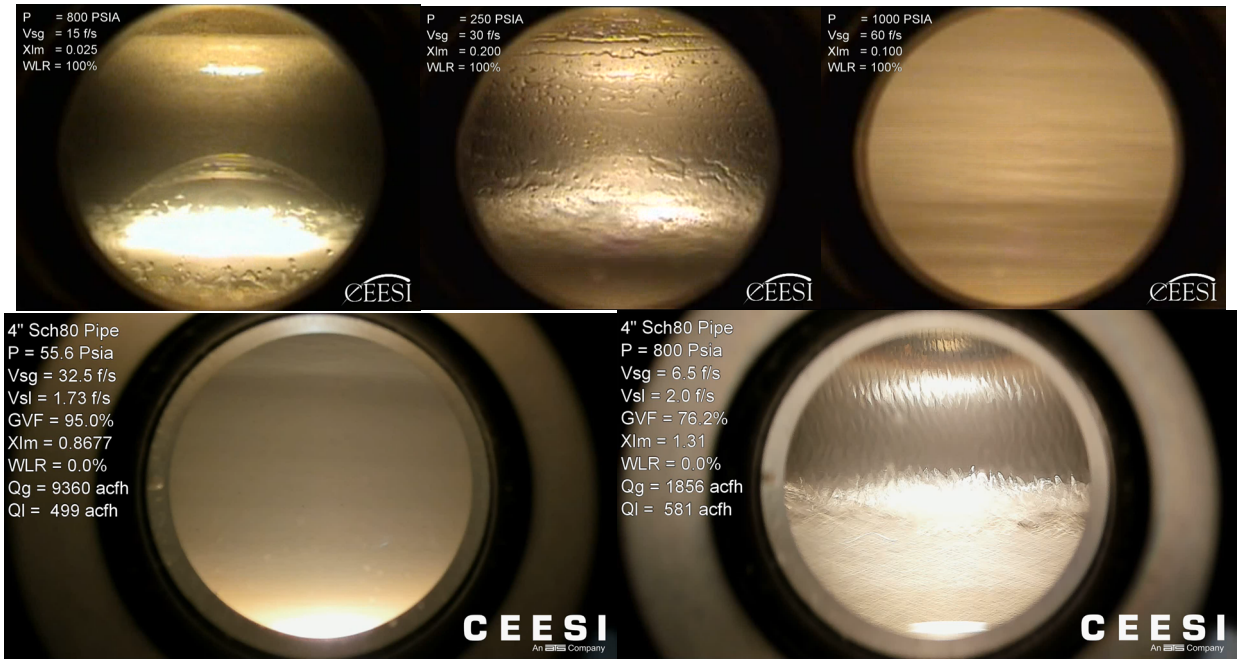

Figure 4. Actual images of various flow regimes in wet gas flow.
Images taken from a 360° fisheye viewport looking into a 4" sch 80 pipe.
Flow is from left to right (courtesy of CEESI)

Misconception #2: GVF is not GVF

Those unfamiliar with two-phase flow mistakenly think that if you could instantaneously slice a pipe in half, take a cross-section of the flow, measure the area occupied by the liquid, and compare it to the area occupied by the gas, you could determine the ratio of the flowing gas to the flowing liquid. Unfortunately, because the liquid is flowing at a different velocity than the gas, this simple cross-sectional area analogy is false. This theoretical cross-sectional area ratio between the gas and the liquid is called the *Gas-Void-Fraction* (or *Liquid-Void-Fraction*). We are not interested in how much area the gas and liquid occupy in a pipe, but rather are interested in the gas and liquid volumetric flow going down the pipe. Because the gas velocity is faster than the liquid velocity, the gas "slips" past the liquid making the *Gas-Void-Fraction* greatly different than the *Gas-Volume-Fraction*. In the field, the *Liquid-Void-Fraction* is often referred to as the *Liquid Holdup*.

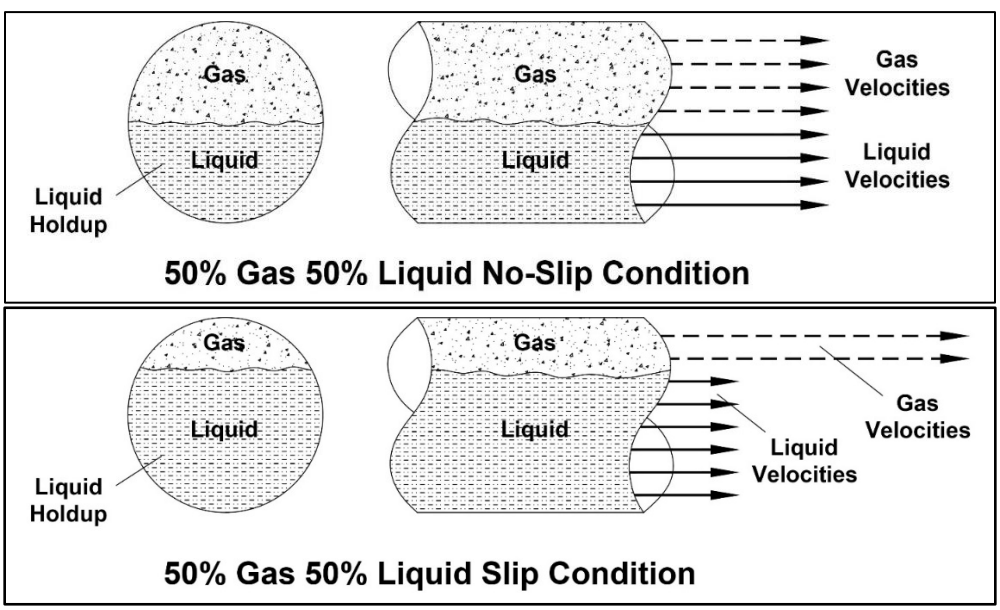

Figure 5. Shows the difference between Gas-Area-Fraction (GAF) and Gas-Volume-Fraction (GVF).
The liquid hold up is affected by the "slip" between the gas and the liquid.

Unfortunately, in the wet gas world, the abbreviation for *Gas-Vold-Fraction* and *Gas-Volume-Fraction* are the same, specifically (GVF). Using the same abbreviation for the two uniquely different parameters has been a source of confusion and misunderstanding. To avoid confusion, this paper uses the abbreviation (GAF) for the *Gas-Area-Fraction (*also called the *Gas-Void-Fraction),* and uses (GVF) to uniquely refer to the *Gas-Volume-Fraction*.

Misconception #3: Not All Flow Measurement Technologies React to Fluid Forces the Same Way

The principal forces in two phase flow that govern the performance of a differential pressure meter are very different than the forces that govern the performance of Coriolis Meter or a multipath ultrasonic meter. A Venturi or an orifice plate that measures pressure differences across a constriction is strongly influenced by the relative changes in the gas and liquid's momentum as the fluid accelerates through the constriction. A Coriolis meter that measures bulk angular momentum of the fluid is strongly influenced by localized superficial gas velocities, localized superficial liquid velocities, and the liquid holdup in the meter as the fluid changes directions in the sensing tubes. A multipath ultrasonic meter (USM) that transmits an acoustic sound wave at different elevations in the meter is influenced by differences in the localized superficial velocities at the different elevations. While each meter has unique advantages and disadvantages with varying degrees of success, they all share one thing in common. They utilize a technique called *Measurement-By-Difference* which is discussed in the next section.

The Physics and the Fluid Forces Behind Wet Gas/Multiphase Flow

In horizontal pipes, the force of gravity causes the heavier liquid to sink to the bottom of the pipe and flow like a slower moving river. Due to its lower density, the gas flows faster in the upper quadrant of the pipe. The more viscous, higher surface-tension liquid tends to adhere to the walls of the pipe. As the faster moving gas interacts with the liquid stream in the bottom quadrant of the pipe, liquid droplets are kicked up into the gas stream. Liquid droplets break into finer droplets and flow as a liquid mist in the gas, causing the gas to slow down. The liquid mist coalesces along the pipe walls and is pulled down into the slower moving "river" of liquid. The gas-liquid distribution in the pipe is dynamic and ever-changing.

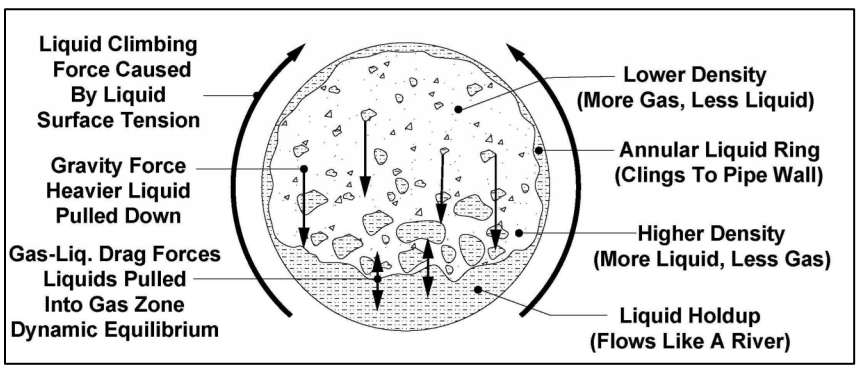

Figure 6. Rendering of the complex wet gas forces.
Dynamic equilibriums are governed by liquid holdup and complex fluid forces.

Measurement-By-Difference

Imagine a swim-run biathlete that finishes the race in seven hours. If you only know the biathlete's finish time you can never know how long it took him to complete the swim, how long it took to finish the run, or how long the swimming and running portions of the race were. If you knew how fast the runner could swim and how fast he could run, you still would not know how far the swimming and running portions of the race were. The solution to this problem is to measure the time of an additional athlete with a known swimming and running speed. This technique is called *Measurement-By-Difference*.

By measuring two athletes with known swimming and running speeds, you can determine their respective swimming and running times and the distance of the swim and the distance of the run. The equations in Figure 7 illustrate how by measuring the times of two athletes with known swimming and running speeds allow one to determine how long the swimming and running portions of the race were.

Contestant No.	Swimming Speed (mph)	Running Speed (mph)	Total Race Time (hours)
1	2	5	7
2	3	4	7

$$\frac{S}{2}+\frac{R}{5}=7 \; and \; \frac{S}{3}+\frac{R}{4}=7$$

$$\mathbf{S}=3\left[7-\frac{R}{4}\right]=21-0.75R$$

$$\mathbf{S}=6 \text{ miles}$$
$$\mathbf{R}=20 \text{ miles}$$

Figure 7. Two athletes competing in a biathlon.
Measurement-By-Difference using two equations with two unknowns.

In the same way one can measure the times of two athletes in a biathlon to determine the length of the swim and the length of the run, one can use two flow meters to determine the gas flowrate and the liquid flowrate in wet gas. For a Venturi meter or an orifice plate, by measuring the pressure recovery after the constriction, you are essentially creating a second flow meter. By measuring the velocity at two different elevations in a multipath USM, you are essentially creating two separate flow meters, each path having a different percentage of liquid and a different localized velocity.

Other Wet Gas/Multiphase Flow Meters (MPFM) utilize the *Measurement-By-Difference* technique with various technologies in different combinations. These include and are not limited to DP measurement, acoustic velocity, magnetic resonance absorption, conductivity, gamma-ray absorption, spectral absorption, and frequency response. Figure 8 illustrates how an additional pressure recovery measurement with an orifice plate can be used as a "second" meter to correct for the influence of liquids in wet gas. Figure 9 shows how an orifice plate flow measurement uncertainty can be reduced by two-thirds by utilizing pressure recovery as a "second" meter.

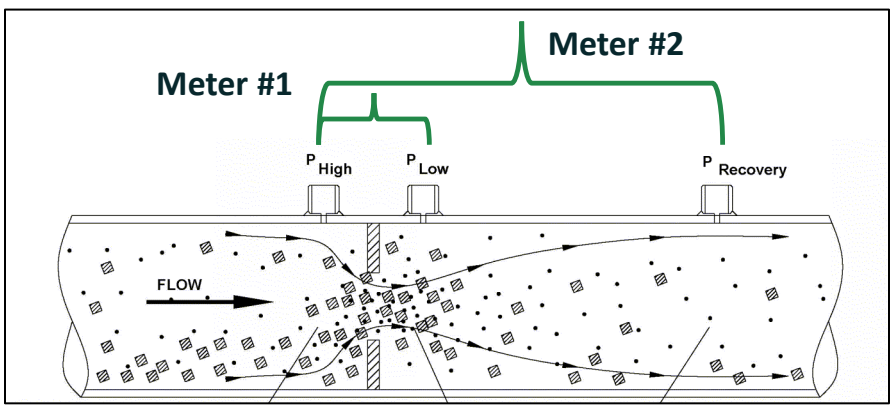

Figure 8. Orifice plate using pressure recovery as a "second" wet gas meter.

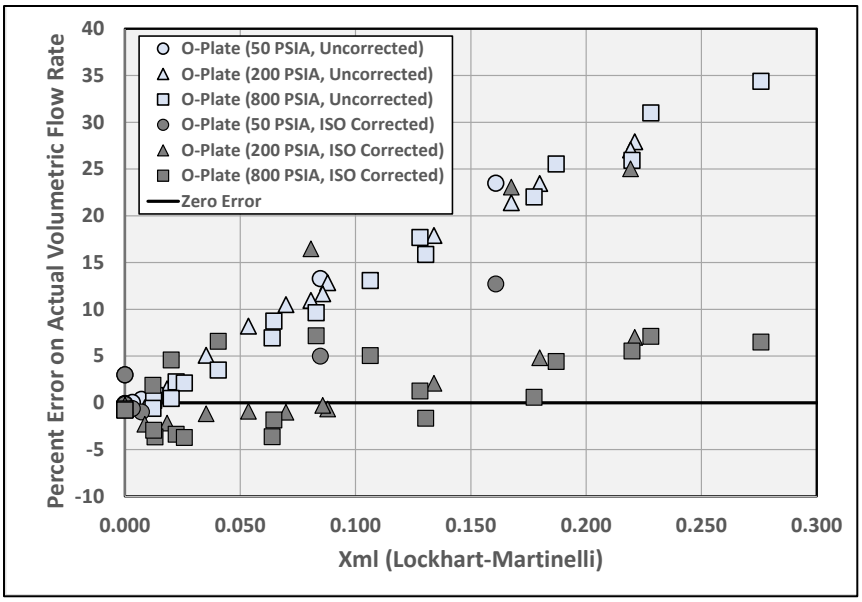

Figure 9. Orifice plate using pressure recovery to reduce flow measurement error by two-thirds. Flowrate percent error vs. Lockhart-Martinelli, graph taken from 4" orifice plate. Tested in natural gas and oil in CEESI's Wet Gas Test Facility, November 2022.

Figure 10 illustrates how a multipath USM can utilize two sound path velocities as two meters to correct for the influence of liquids in wet gas. The upper path experiences lower liquid loading than the lower path.

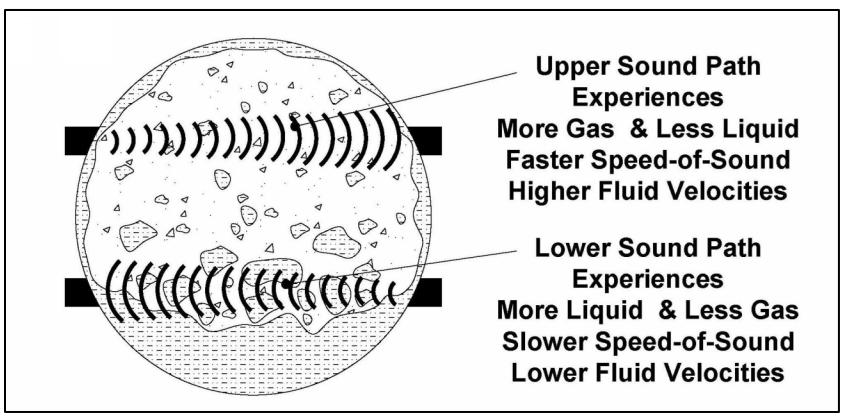

Figure 10. Multipath USM using two sound path velocities to correct for wet gas liquid loading. Measurement-By-Difference

As of 2024, nearly every major USM manufacturer had tested their multipath USM designs in a wet gas test facility. Newer USMs are better equipped to handle wet gas applications with improved transducer technology. Newer transducers have enhanced their ability to push acoustic sound waves across gas flows with entrained liquids and in pipes with significant liquid hold-up.

By taking advantage of the robust diagnostic capabilities inherent to ultrasonic meter technology (velocity ratios, speed-of-sound ratios, and turbulence ratios) multipath USMs provide added pathways to wet gas correction factors. While wet gas corrections to Venturi meters and orifice plates are principally based on Lockhart-Martinelli corrections and pressure recovery, evidence suggests USM corrections are better characterized by other wet gas parameters including GAF, GVF, LAF, GVF, gas-to-liquid density ratios, Froude Numbers, Weber Numbers, liquid hold-up correlations, or other, yet undiscovered parameters. While likely complicated, USM wet gas corrections, if successful, could provide significant improvements to wet gas measurement accuracy.

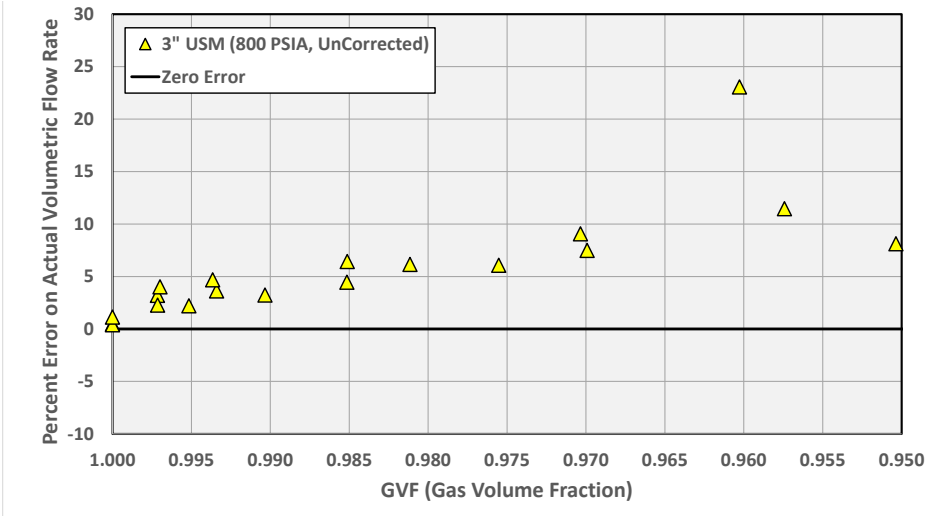

Figure 11. Two-path USM tested in natural gas and oil in CEESI's Wet Gas Test Facility, November 2022. Flowrate percent error based on USM output <u>not</u> corrected for wet gas.

The graph in Figure 11 shows a 3" USM tested in natural gas and oil at a wet gas test facility over a liquid loading range from 1.0 to 0.95 GVF. This is an impressive result considering no wet gas correction factors were applied to the data. With the added potential of improved accuracy with wet gas correction factors, USM technology will play a key role in future wet gas measurement.

Caution should be applied to USM wet gas correction factors based solely on two-phase, natural gas-oil testing. In the field, three-phase wet gas (gas-oil-water) conditions are common. Natural gas-oil-water mixtures behave differently than natural gas-oil mixtures as they flow down a pipe. Differences in densities, viscosities, and interfacial tension can produce different effects. USM wet gas correction factors should be based on wet gas testing in gas-oil-water combinations where differences in density, viscosity, and interfacial tension are carefully considered, and if necessary corrected for.

Summary

The accurate measurement of wet gas flow remains a significant challenge in the Oil and Gas Industry, largely due to the differences in density and velocity between the gas and liquids in the pipe. Wet gas measurement is crucial for correctly determining the distribution of oil and gas from a specific well or gathering station. Traditionally separators have been used to isolate the gas and liquid into separate streams. These are typically costly and inefficient over varying flow rates. Advances in wet gas and multiphase flow meter technologies now offer more practical solutions. Ultrasonic meters offer distinct advantages in wet gas applications with their robust diagnostic capabilities, and the potential for improved accuracies through the use of wet gas correction factors.

With an increased reliance on wet gas metering, the future of wet gas measurement will likely continue to see advancements in multiphase flow meters, and specifically USM technology in wet gas applications, driven by the need for higher accuracy and reliability in flow measurement. Continued research and testing in wet gas applications will be essential in improving these technologies and ensuring they meet the demands of industry.

References

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2. "*Handbook of Multiphase Flow Metering*", Revision 2, Norwegian Society for Oil and Gas Measurement (NFOGM), ISBN 82-91341-89-3, 2005

3. "*Wet Gas Flow Metering Guideline*", MFC-19G, American Society of Mechanical Engineers, Oct 2007 Draft