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Paper 1.1

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

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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.

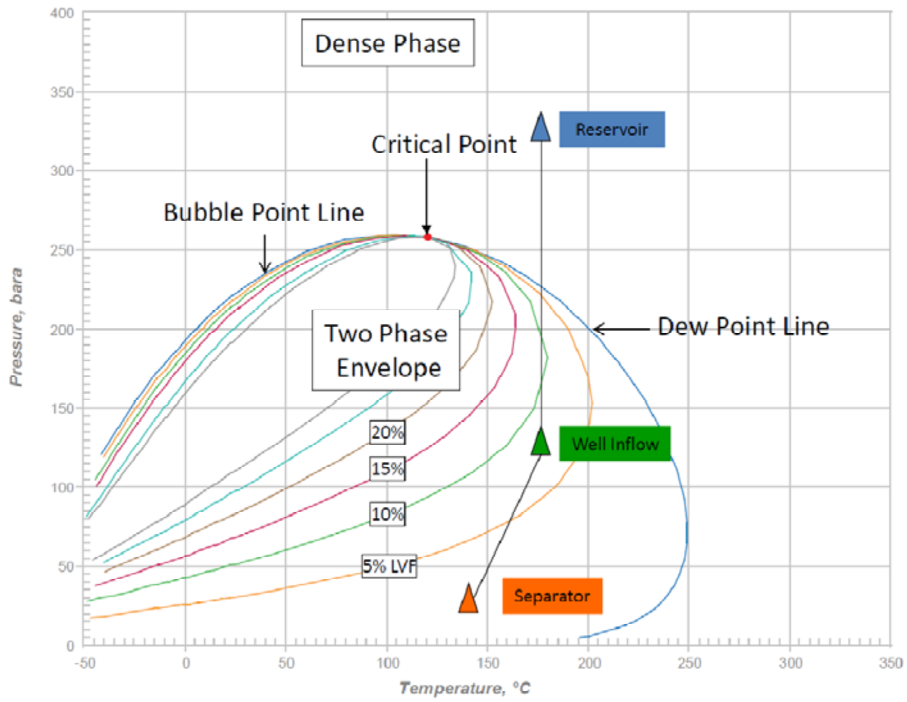


Fig. 1 - A representative phase trajectory of a gas condensate well on a phase diagram

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.

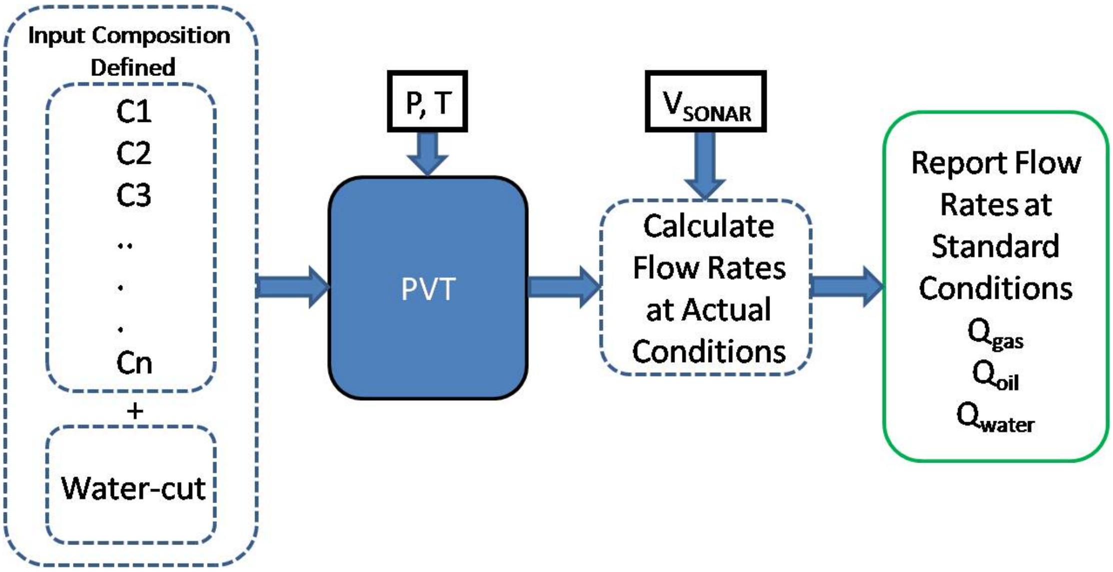


Fig. 2 - Schematic of real-time production surveillance calculation

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:

$$OR_{sonar} = \frac{V_{sonar}}{V_{sg}} \qquad (1)$$

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

$$LVF = \frac{Q_{liq}}{Q_{liq} + Q_{gas}} \qquad (2)$$

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

$$OR_{sonar} = \frac{1}{1 - LVF} \qquad (3)$$

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.

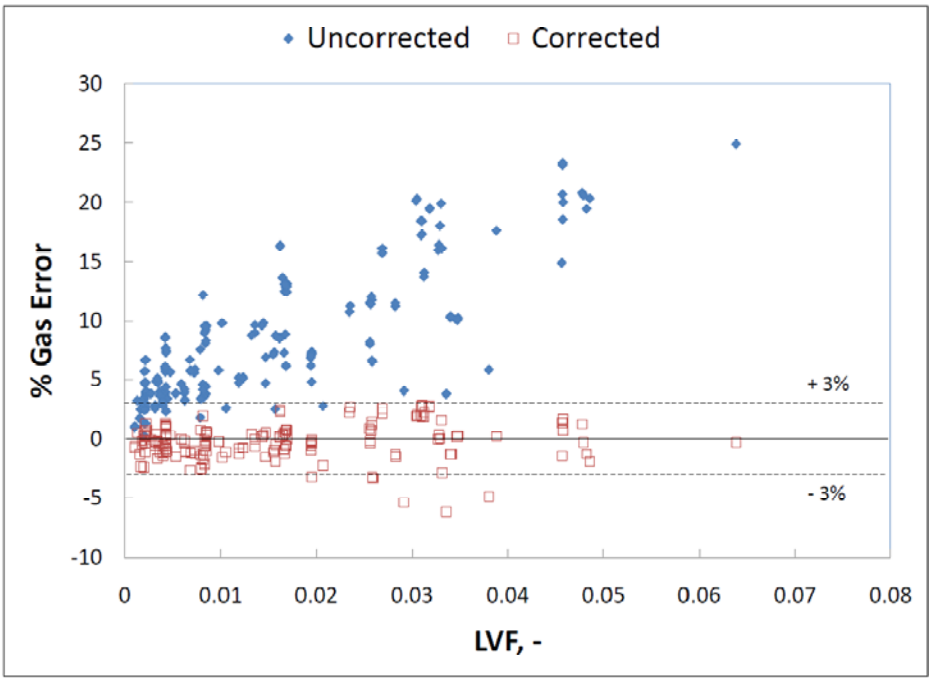


Fig. 3 - Wet gas data from pulsed-array sonar flow meter corrected with Eq. (5)

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..

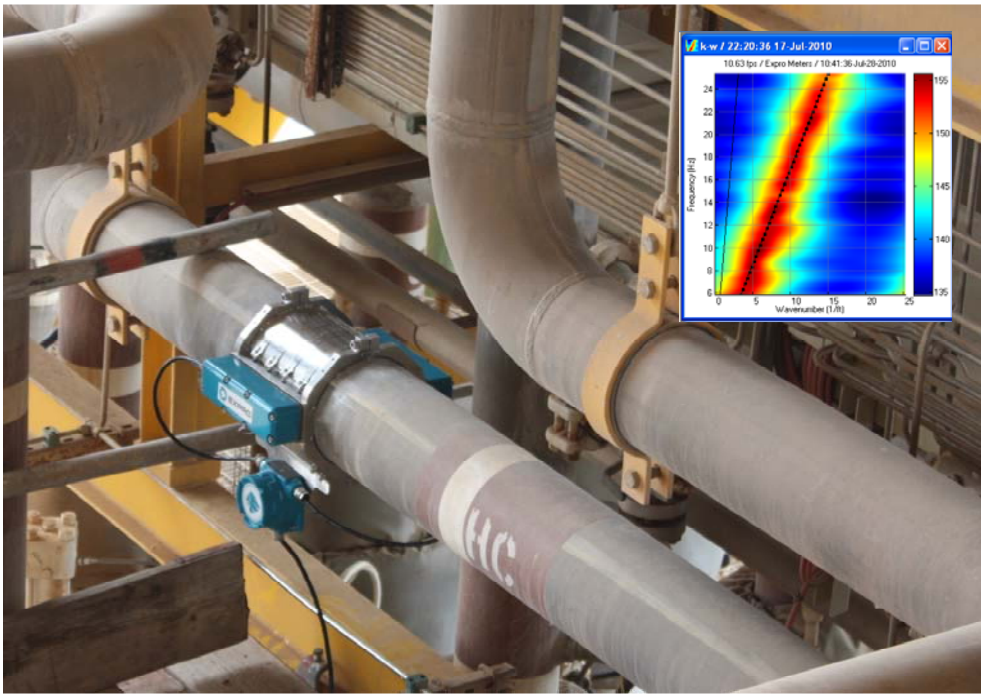


Fig. 4 - A pulsed-array sonar flow meter clamped-on to an 8-inch, schedule 100 pipe upstream of the production choke on a gas condensate well and its recorded k-w plot

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.

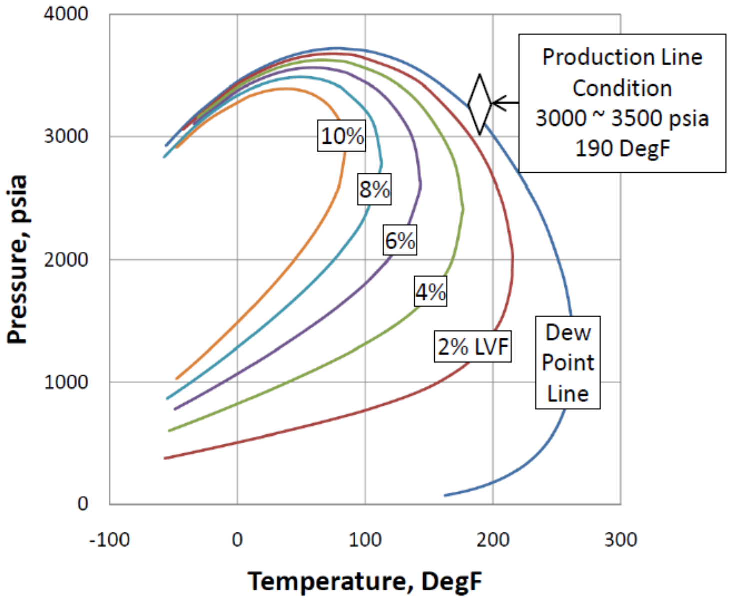


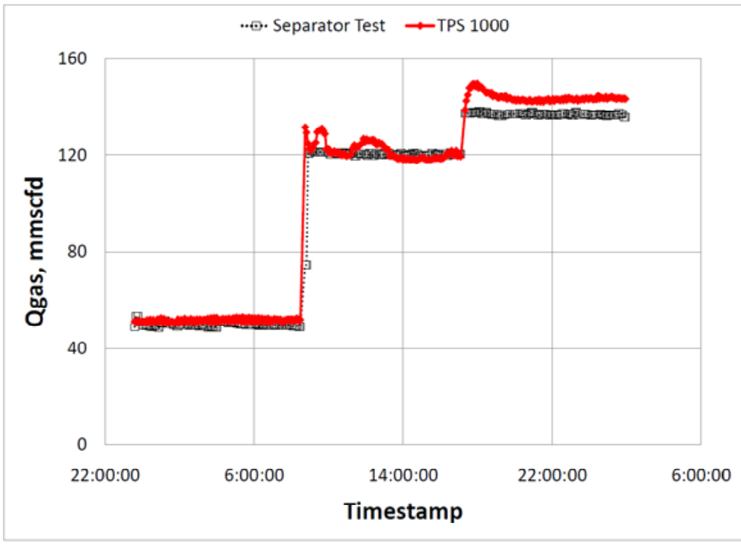
Fig. 5 - Hydrocarbon fluid phase envelope

Production Surveillance Results

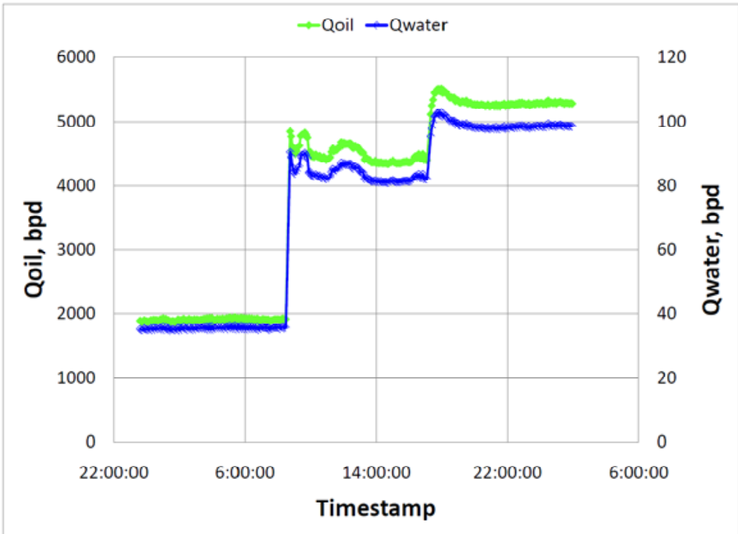
Fig. 6 gives production surveillance results for gas / oil / water flow rates. In Fig. 6 (a), the gas flow rates predicted by the clamp-on production surveillance system (TPS 1000) are compared with those measured from the gas leg of the well test separator. The gas flow rates reported by the surveillance 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].

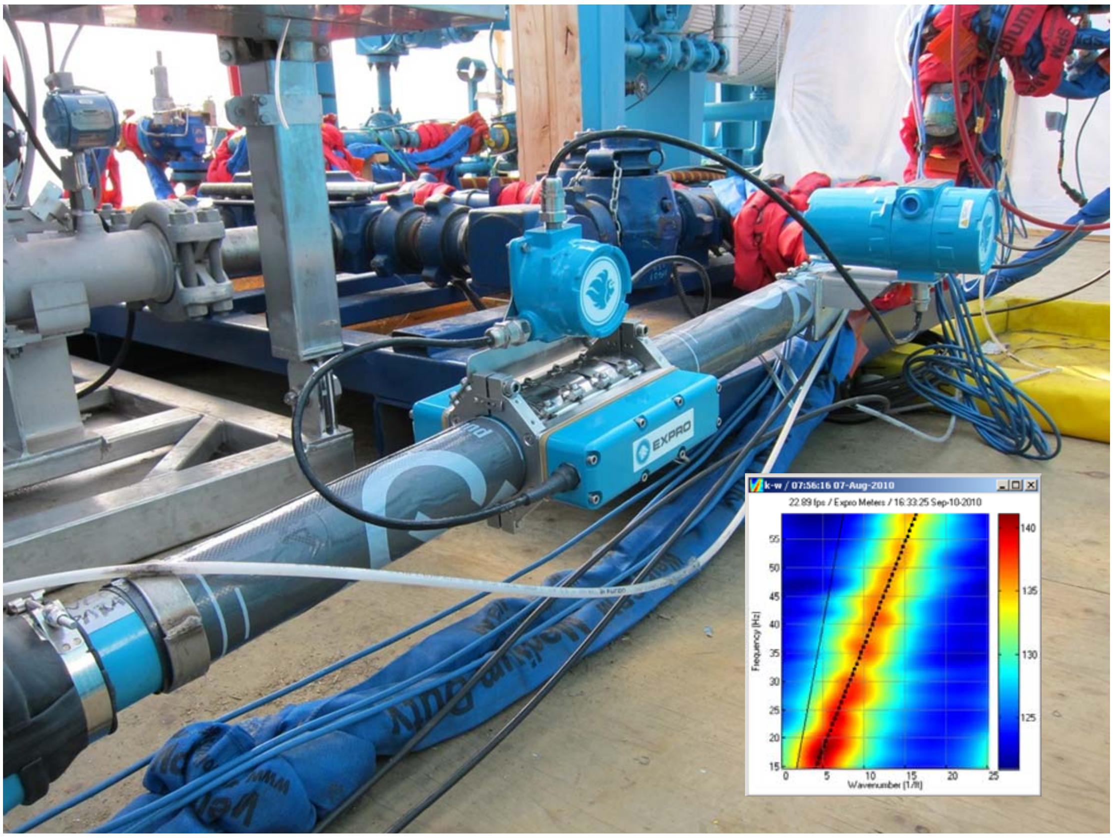


Fig. 7 - A pulsed-array sonar flow meter clamped-on to a 3-inch, schedule 160 temporary piping on a well test package, downstream of the production choke and upstream of the test separator

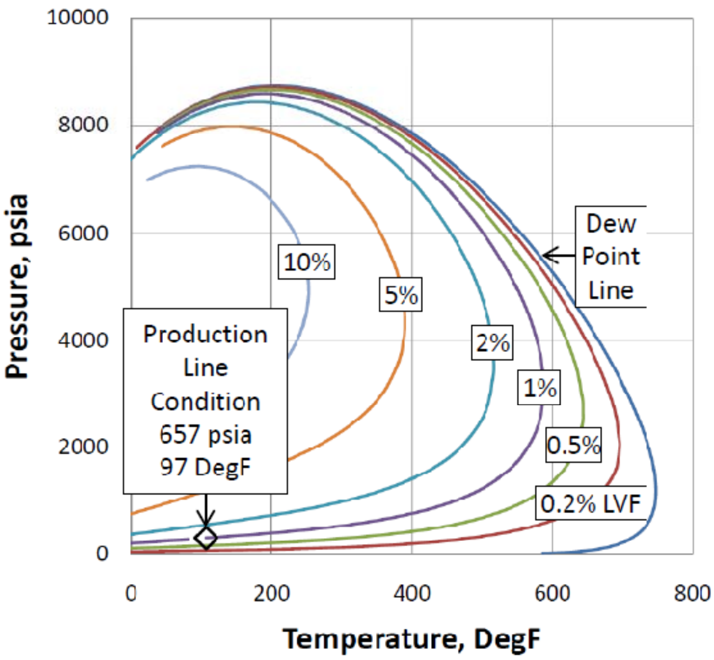


Fig. 8 - Hydrocarbon fluid phase envelope

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.

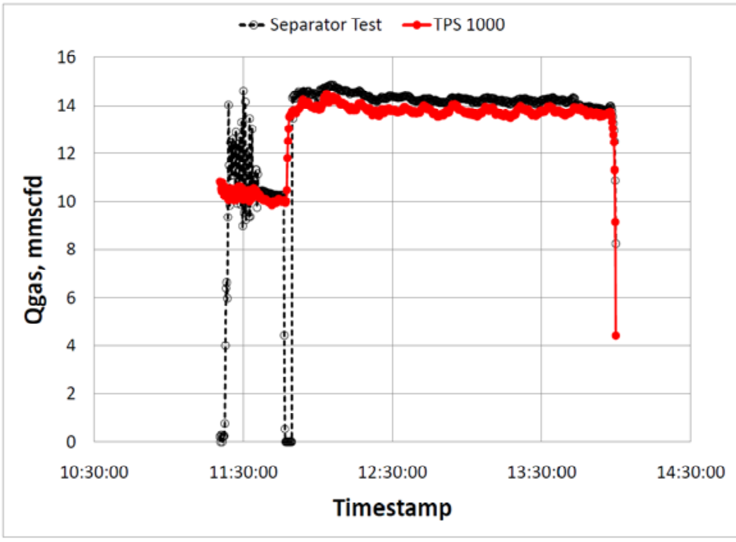
Fig. 9 (b) shows the oil rates reported by the clamp-on production surveillance system, compared with those measured by the turbine meter on the oil leg of the test separator. The results are in good agreement, with the clamp-on production surveillance system capturing the change in oil rates associated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

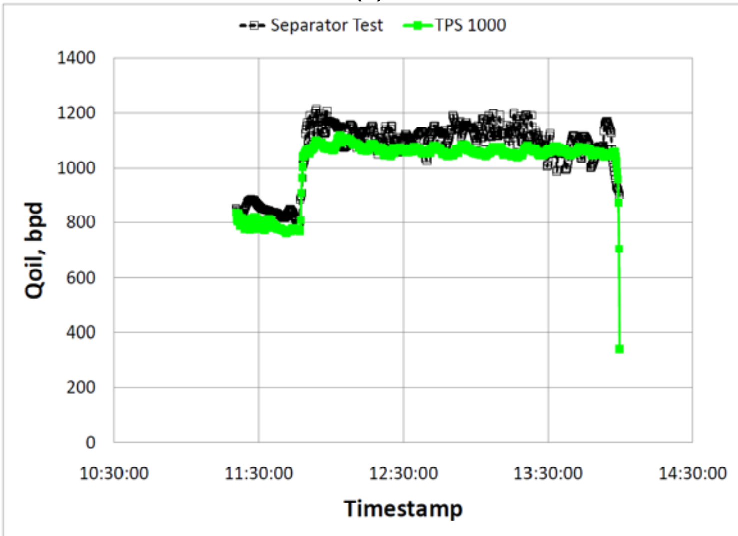
Table 2 compares the predicted gas / oil / water flow rates at standard conditions with those measured by the test separator during the time period from 12:30:00 to 13:30:00, where the gas / oil / water flow rates are stable. Over this period, the predicted average gas flow rate is -3.3% of that measured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

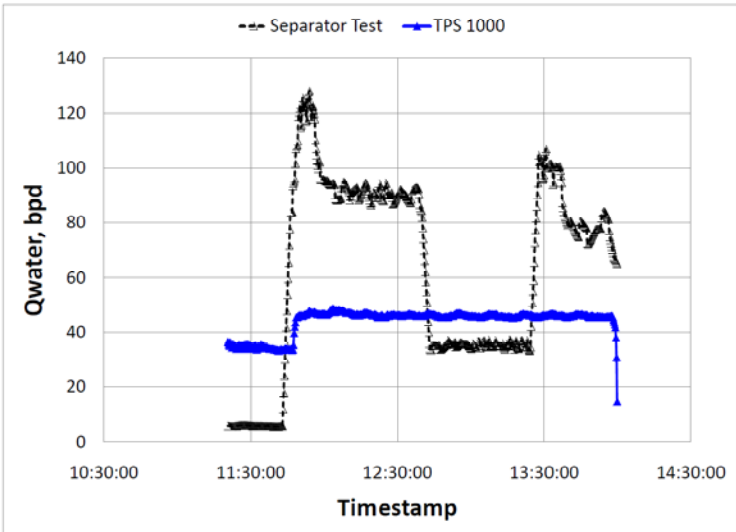
	Test Separator	TPS 1000	Error
Qgas, mmscfd	14.2	13.7	-3.3%
Qoil, bpd	1133	1060.	-6.4%
Qwater, bpd	35.2	32.9	-6.4%



(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.

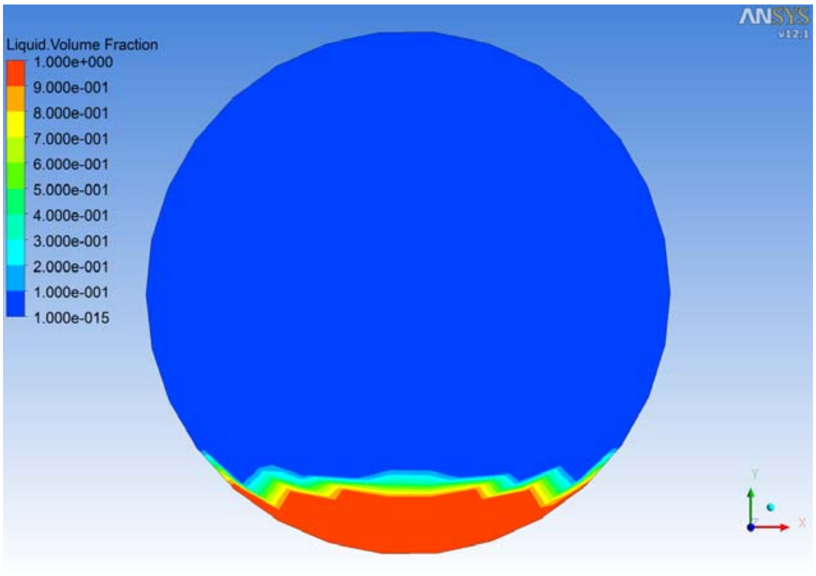


Fig. 10 - Gas / liquid distribution over the cross-sectional area for condensate well producing at 77 bbl/mmscfd

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].

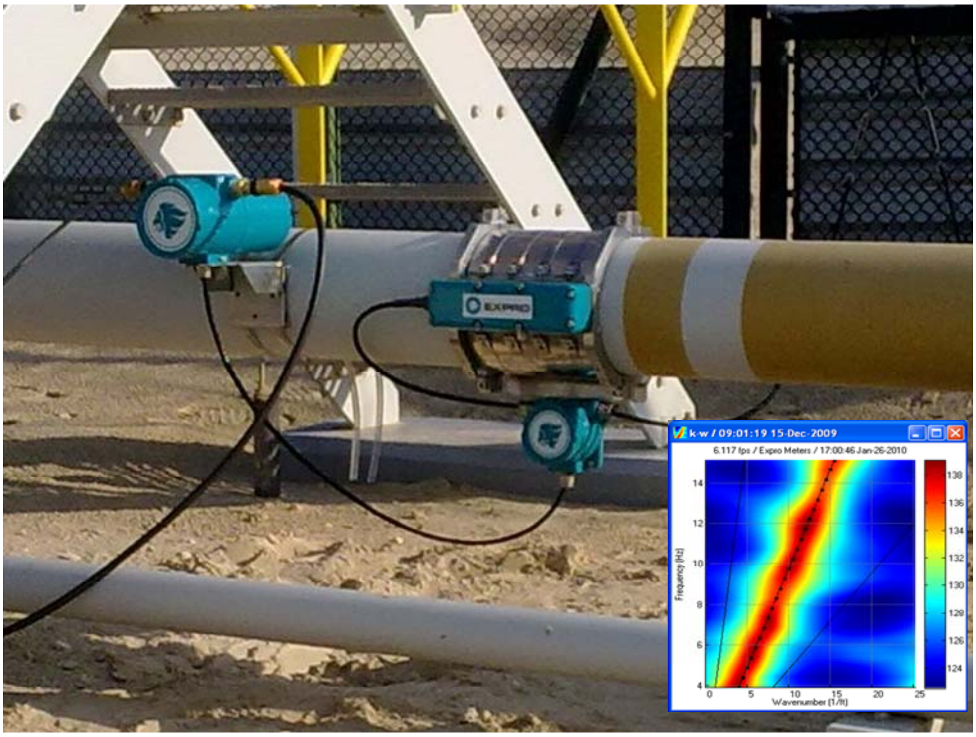


Fig. 11 - A pulsed-array sonar flow meter clamped-on to an 8-inch, schedule XXS+ (1.1 inch wall thickness) and its recorded k-w plot

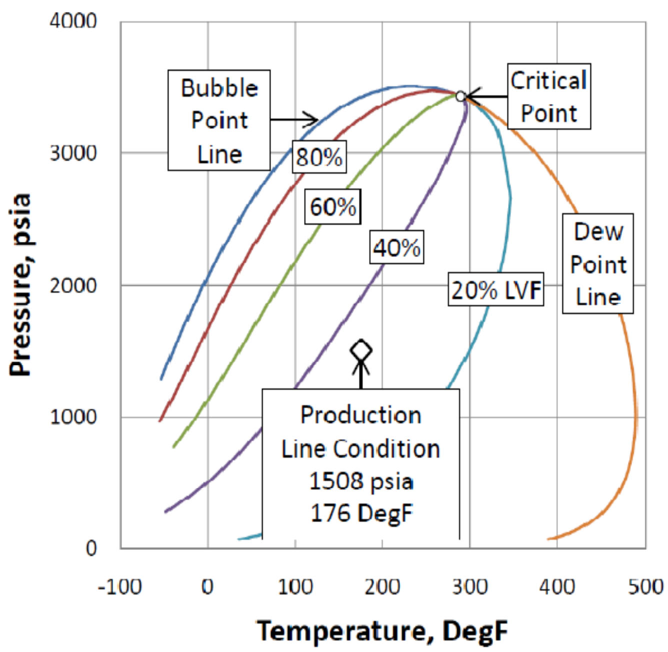


Fig. 12 - Hydrocarbon fluid phase envelope

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.

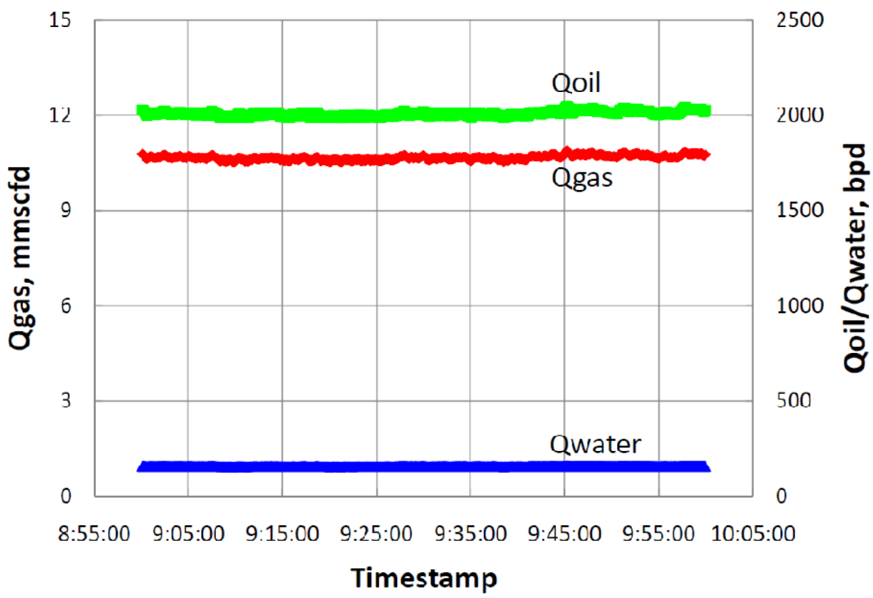


Fig. 13 - Gas / oil / water flow rates at standard condition predicted by production surveillance system

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.

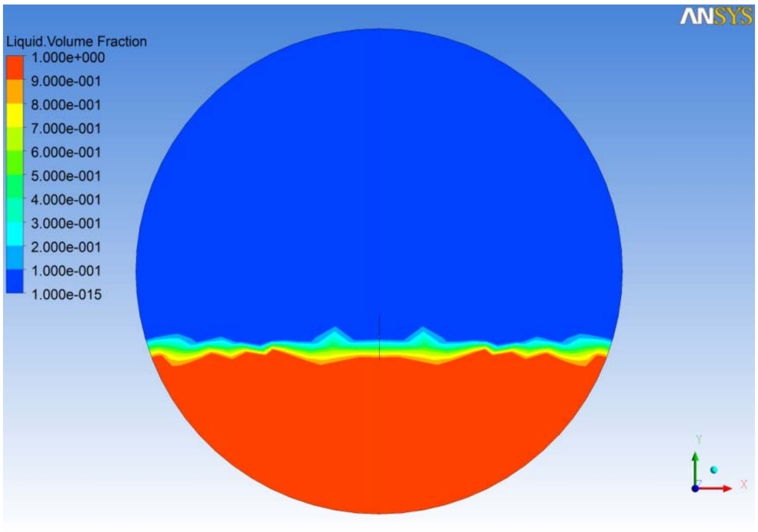


Fig. 14 - Gas / liquid distributions over the cross-sectional area for gas condensate producing at 182 bbl/mmscfd

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.

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North Sea FLOW Measurement Workshop

Paper 1.2

Wet Gas Test Comparison Results of Orifice Metering Relative to Gas Ultrasonic Metering

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1. ABSTRACT

Traditionally orifice meters have been used in wet gas applications rather than gas ultrasonic meters (USM). There are many reasons for this, but certainly one has been the question regarding reliability of a gas ultrasonic meter when subjected to liquid loading. The question is this: “How does the accuracy of the orifice compare to the gas USM when liquids exist?” Another question might be asked is: “Can the USM clearly identify when liquids are present, and give the operator an idea of what gas volume has passed through the meter during this time?”

To investigate these questions, two different meters were tested at the CEESI Nunn Wet Gas loop in Nunn, Colorado. The first test involved a 4-inch orifice and 4-inch USM in series (the USM was a 4 and 2-path meter all in one body). For the second test a 3-inch orifice and 3-inch, 2-path USM was tested. Both tests involved several flow rates, 2-3 different pressures, and up to 8 different levels of liquid loading. The fluid used in most of the tests was Exxsol, a kind of kerosene that is popular for this type of testing. For the 3-inch tests, a limited number of data sets were also taken using water.

This paper shows the results of these tests including transducer performance (the USM never failed even with a liquid loading of 95% gas volume fraction (or GVF)), and most importantly documents the errors seen by both types of technologies.

2. INTRODUCTION

The CEESI Nunn Wet Gas facility consists of a closed-loop test stand with up to 650 horsepower that permits flow rates from about 83 to 620 ACMH. This corresponds to 3 to 23 m/s in 4-inch Schedule 80 piping. Pressures can range from 1,380 kPa up to 7,500 kPa (13.8 Bar – 75 Bar). Gas flow is measured using a calibrated 6-inch turbine meter, and the injected liquid is measured using one of 2 different Coriolis meters (1/2” and 2” sizes). The liquid typically used is Exxsol D80, but water, or a mixture of both can also be used.

The first test involved a 4-inch dual-chamber orifice meter with the gas USM were installed in series. The second test incorporated a 3-inch dual-chamber orifice and 2-path USM, both in series. In both cases the USM was located upstream to minimize, if not totally eliminate, any affect on the orifice meter. In order to ensure that the flow profile is as realistic as possible to what would be seen in the field, the non-intrusive USM was located upstream of the orifice meter.

The 4 inch meter testing was conducted at 3 pressures (approximately 13, 33 and 55 Bar(a)), with 2 beta ratios (0.40 and 0.62), 3 differential pressures (from around 3.98 kPa to as much as about 60 kPa), and with GVFs including 100, 99.9, 99.5, 99.0, 98, 97, 96 and 95%. The 4-inch USM was a special meter built to obtain data on wet gas conditions. It includes a traditional Westinghouse® 4-path meter along with a conventional 2-path “mid-radius” meter, all within the same meter body. All testing included a Canadian Pipeline Accessories (CPA) 50E flow conditioner located at 10D upstream. Both the orifice and USM meters are Schedule 80, as well as most of the piping at the facility. Data was collected on both USMs and the orifice meter during the testing conducted in December 2009.

The 3-inch meter package tests were conducted at 2 pressures (approximately 13 and 55 Bar(a)), only one beta ratio (0.517), several differential pressures from 2.23 to 153 kPa, and GVFs including 100, 99.95, 99.90, 99.8, 99.5, 99, 98, and 95%. From testing done previously on orifice meters [Ref 1], it was decided 2 beta ratios weren’t needed, and that 2 pressures would suffice. This allowed more time to focus on added liquid loading, especially lower levels. A limited number of test points were also taken with water. These included GVFs of

99.90, 99.59 and 99.15%. The intent was to see if a different viscosity fluid would have any significant affect on the results.

3. INSTALLATION DETAILS FOR THE 4-INCH ORIFICE-USM PACKAGE

Figure 1 shows the facility during data collection in December. In the foreground part of the reference gas system and the Coriolis meter (used for the liquid measurement) can be seen. The meters under test are located after a 90 degree turn and more than 100 nominal diameters of straight pipe upstream of the USM. The orifice meter was located approximately 55 nominal diameters downstream of the USM. A standard CPA 50E flow conditioner was located upstream of the ultrasonic meter at 10D.

Figure 1 – CEESI Nunn West Gas Test Facility, 4-inch Testing, December, 2009

Figure 2 shows a picture of the ultrasonic meter (a 4-path and 2-path meter in one meter body). The 4-path and 2-path meters each have separate electronics.

Figure 3 shows the inside of this USM meter. Note that the 2-path meter has protruding transducers. Often times in wet gas applications this configuration has been show to be more “durable” and able to handle higher levels of liquid loading. At the right of the picture two of the four paths of the 4-path meter can be seen. The 4-path transducers are mounted in the traditional location and are the “typical” sensor used for dry gas applications. Since these sensors are totally sealed, there is no concern about failure due to liquid contamination within the sensor itself.

Figure 2 – Ultrasonic 4+2 Meter

Figure 3 – Transducers in the 4+2 Meter

Figure 2 also shows the flow conditioner mounted with differential pressure transducers. A CPA 50E was used for all testing regardless of pressure or liquid loading. Data was collected during the tests to document the differential pressure during all tests. This information will not be presented in this paper. A traditional 19-tube bundle was installed upstream of the dual-chamber orifice meter and was there for all testing.

4. INSTALLATION DETAILS FOR THE 3-INCH ORIFICE-USM PACKAGE

The second meter tested was a modified 2-path, 3-inch Schedule 80 meter located upstream of the 3-inch orifice fitting. Based on "lessons learned" from the 4-inch testing in December, 2009, it was decided to concentrate on two pressures (13 and 55 Bar(a)), and only one Beta ratio (0.517). Previous test results didn't indicate any significant issue at the intermediate pressure (33 Bar(a)), and the second Beta ratio (0.62) previously tested with the 4-inch didn't show any "surprises" either. Eliminating these from the test plan allowed more time to focus on lighter liquid loading as requested by some end users. Thus, for most of the tests on the 3-inch, liquid loadings included 100, 99.95, 99.90, 99.8, 99.5, 99, 98, and 95% percent GVF (approximate values). The highest level of GVF was not tested at 13 Bar(a) as the mass of the gas was too low compared to the liquid and this would cause slugging and very erratic results.

The testing at 55 Bar(a) was conducted both with and without a CPA 50E flow conditioner as many users incorporate flow conditioners at the higher pressures. At the lower pressures, users have to pay for compression. Thus there was little benefit in testing the package with a flow conditioner since few, if any, would install in this configuration. Some additional testing with water was also conducted at 55 Bar(a) (fewer liquid loadings) in lieu of the Exxsol D80 with the CPA 50E flow conditioner installed.

Figure 4 shows the installation of the ultrasonic meter (on the right) upstream of the orifice meter. Flow is from right to left. The CEESI piping consists of 4-inch, Schedule 80 piping. Upstream of the meter a 4x3 eccentric reducer was used. This eliminates "damming" at the reduction part. Approximately 39D of straight 3-inch, Schedule 80 pipe delivered flow to the upstream section of the USM meter package. The piping of the USM consisted of a 10D section of straight Schedule 80 pipe upstream of the CPA (when used) and then the 10D section upstream of the meter body (this part was welded to the measurement section). The USM was a straight through bore with no taper. After the USM there was approximately 16D of straight Schedule 80 piping prior to the orifice meter package. The orifice meter package included an upstream section that was 15D, a 19-tube bundle, and 13D of straight pipe in front of the dual-chamber fitting.

Figure 5 shows a close up of the meter and its associated, integrated upstream piping. The upstream section where the CPA flow conditioner is located for some of the tests is on the right. Figure 6 shows the CPA 50E flow conditioner. This was a modified flow conditioner with a tab welded to the unit to insure proper rotational alignment after installation. The two holes side by side are for two studs that bolt the flanges together. This makes orienting the CPA to top dead center very easy during installation, and simplifies future alignment.

Figure 4 – 3-inch Orifice and USM Installation, August 2010

Figure 5 – 3-inch USM and Piping

Figure 6 – 3-inch CPA 50E

5. 4–INCH METER TEST RESULTS

A week of testing was scheduled for collecting the 4-inch meter package data. Typically CEESI will run the meter with no liquid loading (GVF of 100%) to obtain a baseline, and then start the liquid loading with the highest first working to the lowest as the final test.

As discussed earlier, the 4-inch USM meter contained essentially two different meters. The 4-path version is a well tested and proven design with all the appropriate coefficients well known. The 2-path was a special meter, and as such there was no experience regarding the coefficients. Thus, the results of the dry testing (GVF of 100%) show the meter is on the order of 2% fast. This would, of course, normally be close to zero, and this offset should be subtracted from the various liquid loading tests to provide a more representative liquid loading result.

With so much data to present, and as there was little difference in the 33 Bar(a) and the 55 Bar(a) results, this paper will focus on 13 and 55 Bar(a). This will also be important when comparing the results of the 3-inch meter (tested at only 13 and 55 Bar(a)) to the 4-inch (both

USM and orifice). The flowing gas temperature varied from about 25 to 26 ºC for most tests with a couple being around 22 ºC.

In order to achieve the range of flows as shown in Figures 7 and 8, two beta ratios were used. For the lower flow rates, a beta of 0.4037 was used, and for the higher rates, 0.620 was used. Differential pressures varied from about 4 to a high of 57 kPa for the 0.4037 beta, and from 3.2 to 95 kPa for the 0.620 beta tests.

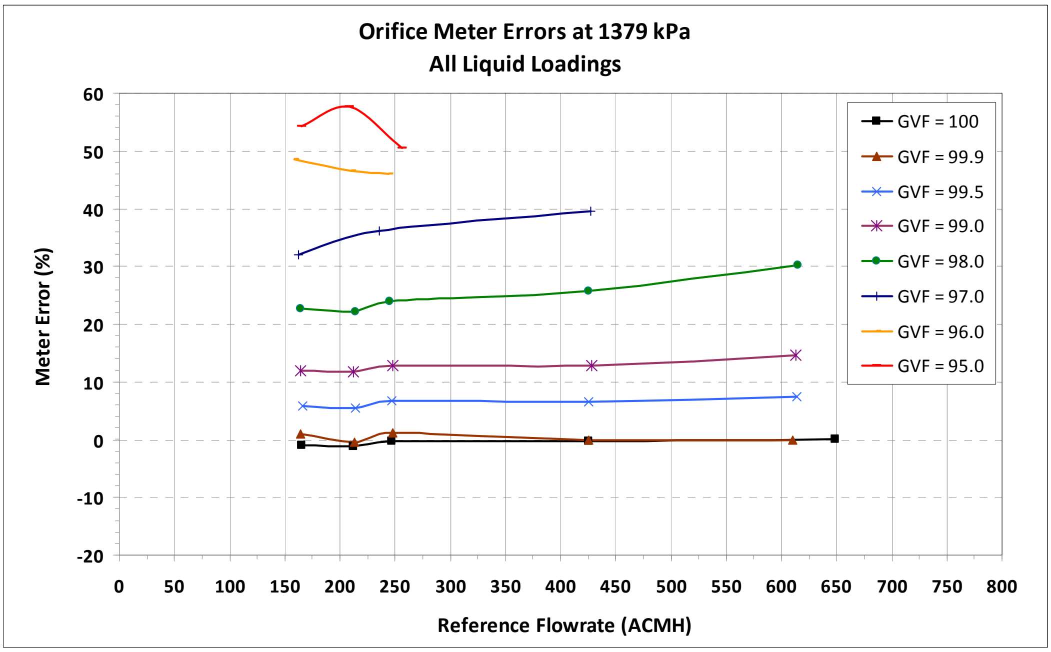

Figure 7 – 4-inch Orifice Meter Results – 13 Bar(a) – All GVF Values (ACMH)

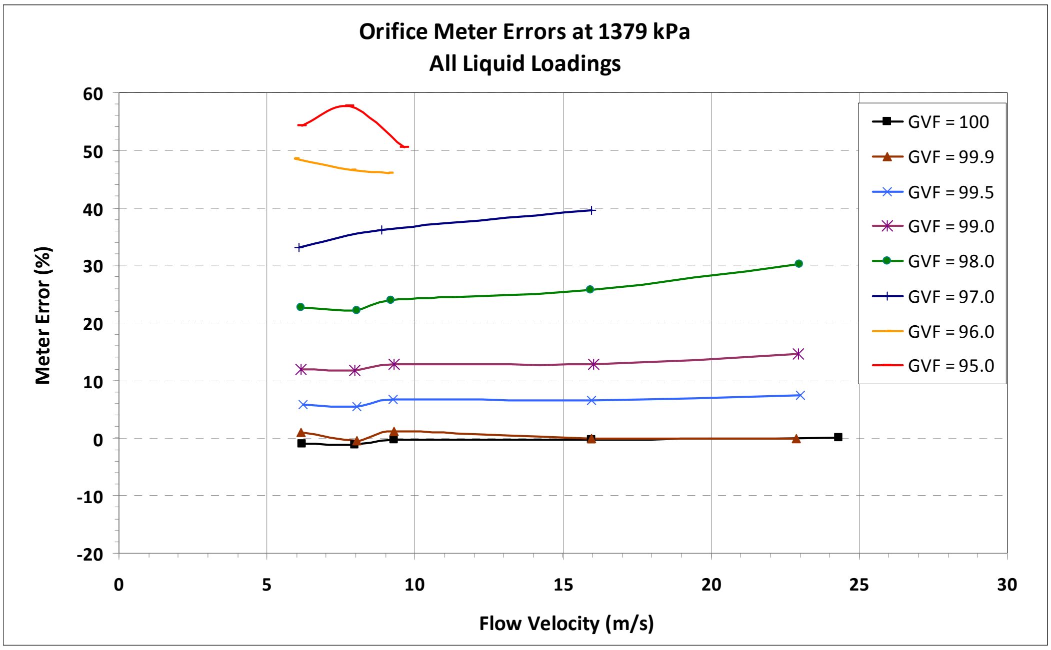

Figure 8 – 4-inch Orifice Meter Results – 13 Bar(a) – All GVF Values (Velocity)

Figure 8 is identical to Figure 7 but shows the flow in the X axis in velocity. Figure 7 uses the same axis as the USMs for simplicity, but of course we don't talk about flow in an orifice in ACMH. This Figure 8 provides the error as a function of gas velocity. It can be seen that as the liquid loading increases, the orifice meter has an increasing positive bias (usually called an "over-reading").

Figure 9 shows the results of the 2-path meter at about 13 Bar(a) (1379 kPa) with all test conditions. This includes GVF values starting at 100 and ending at 95.0%.

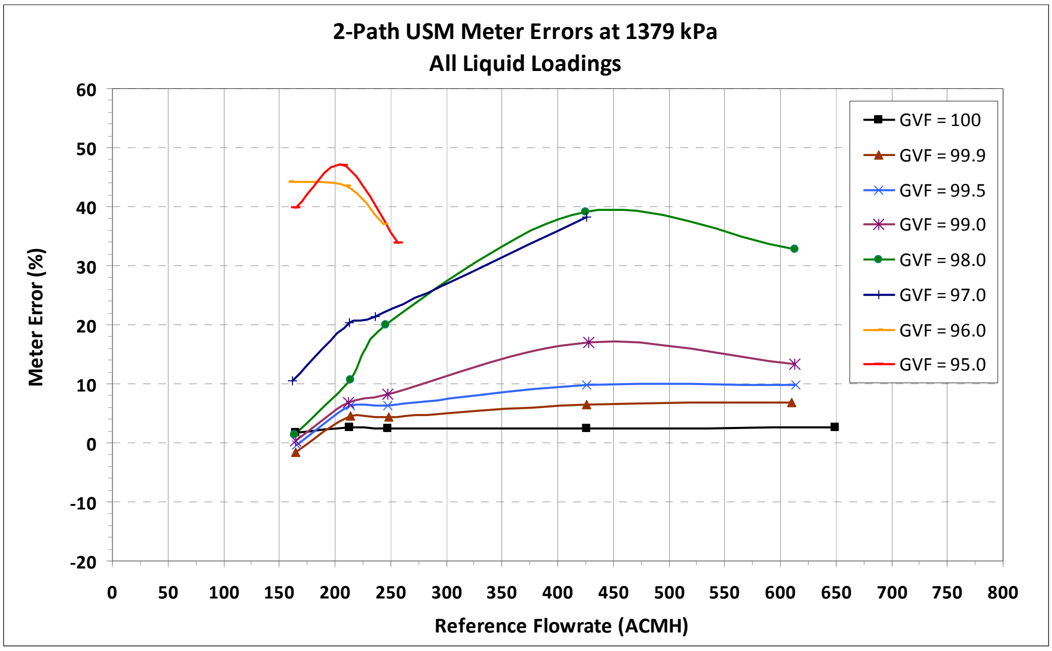

Figure 9 – 4-inch 2-Path Meter Results – 13 Bar(a) – All GVF Values

The 2-path meter was similar in accuracy to the orifice meter as can be seen by comparing the over-readings in Figure 7 with Figure 9.

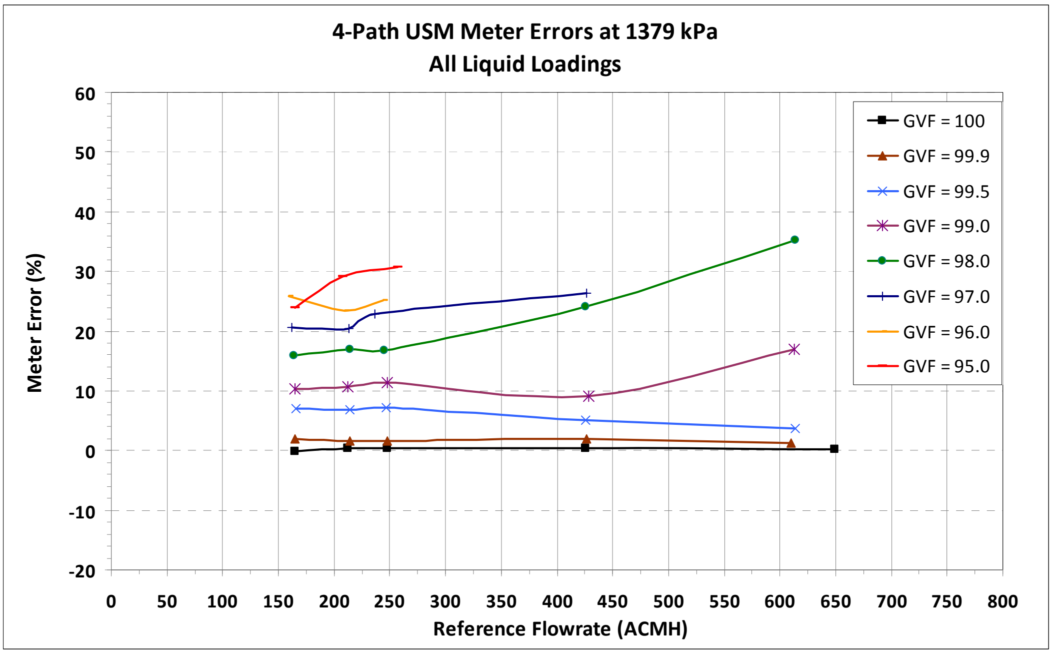

Figure 10 –4-inch 4-Path Meter Results – 13 Bar(a) – All GVF Values

Note that all graphs for the 13 Bar data contain the same scales for both the flow rate (X-axis) and the Meter Error (Y-axis). It is clear that liquid loading generally causes all meter errors to be positive (over-reading). At low liquid loadings on the 2-path, and at lower velocities, the errors are typically within less than 2%. However, once the liquid loading approaches a GVF of 98.0%, all meters begin experiencing significantly more errors. In all but the lowest flow rates, and lowest liquid loading, these 3 meters over registered. How much was mostly a function of GVF, but there is some correlation to meter error from flow rate. The following graphs are from the 55 Bar(a) testing for the same conditions.

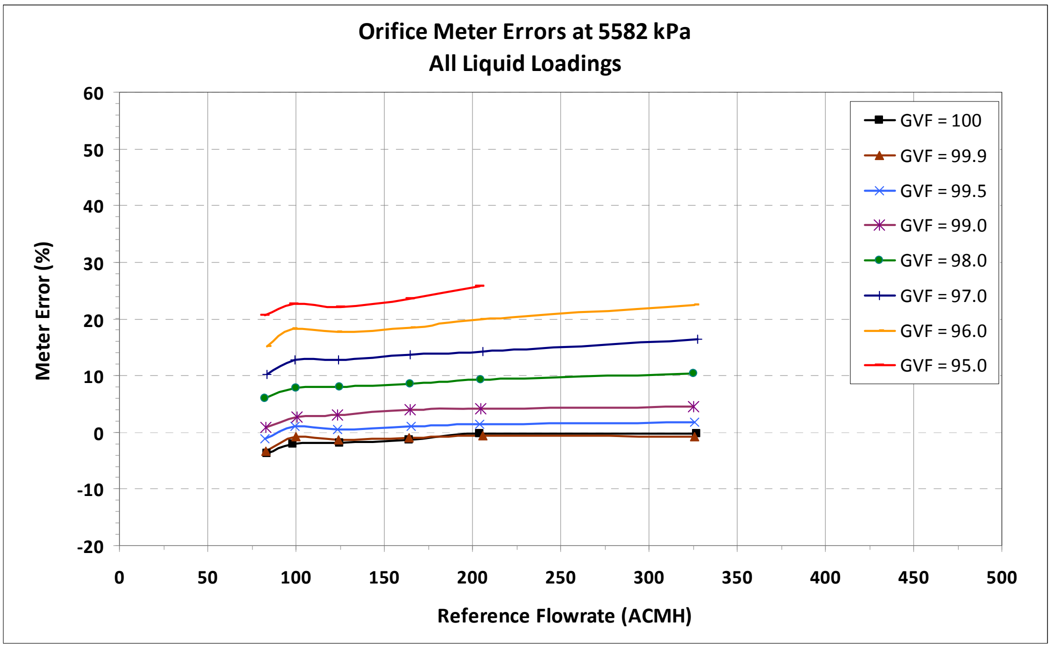

Figure 11 – 4-inch Orifice Meter Results – 55 Bar(a) – All GVF Values (ACMH)

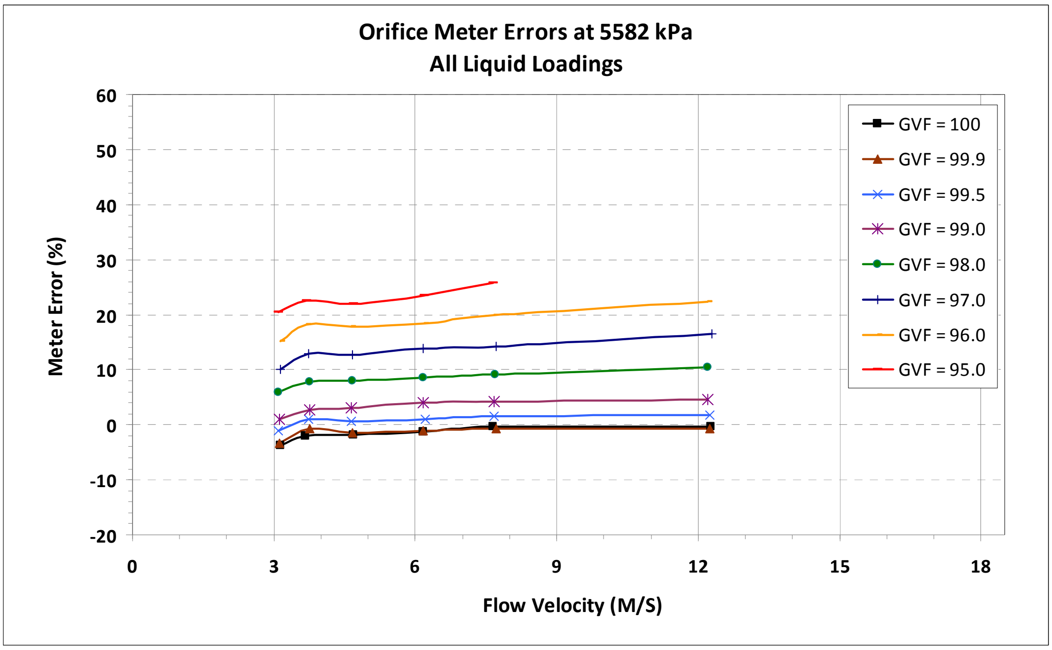

Figure 12 – 4-inch Orifice Meter Results – 55 Bar(a) – All GVF Values (Velocity)

As before, Figure 12 is identical to Figure 11, but it shows the flow in the X-axis in velocity and re-scaled to provide a similar X-axis result. Figure 11 uses the same axis as the USMs for simplicity.

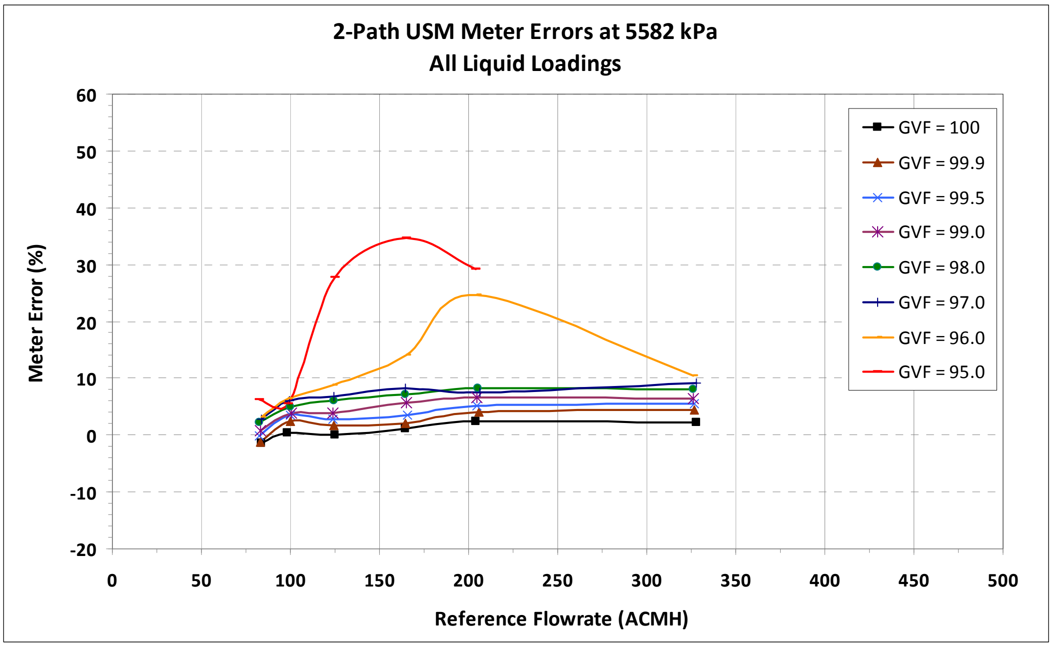

Figure 13 – 4-inch 2-Path Meter Results – 55 Bar(a) – All GVF Values

Figure 13 results indicate the 2-path meter performs better for liquid loading of 97% GVF and less, but at the higher loadings (96% and higher) the error begins to increase and at 95% its error is greater for the higher flow rates than the orifice. In Figure 14 the results show the 4-path meter to have similar errors to the orifice with no significant differences relative to the various GVFs tested.

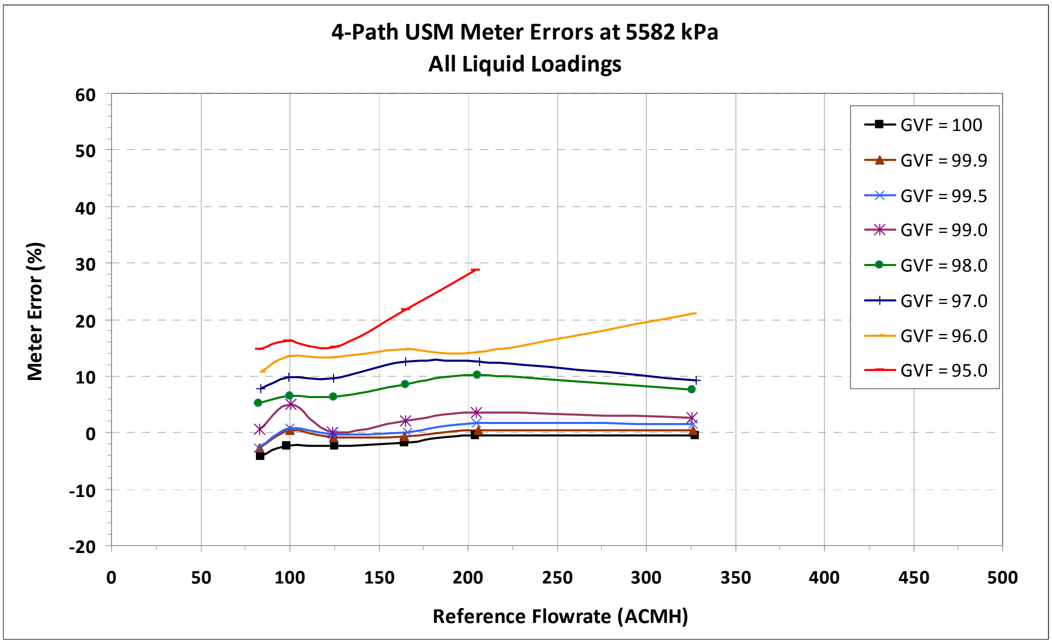

Figure 14 – 4-inch 4-Path Meter Results – 55 Bar(a) – All GVF Values

6. 4–INCH GAS ULTRASONIC METER DIAGNOSTICS

By reviewing the 4-path meter diagnostics, it is clear the meter is having no problems with GVF values of 100 and 99.9% GVF. As the liquid loading increases, so do the “Warnings” and eventually path failure (below 5% accepted) occurs at a GVF of 98.0%.

As the liquid loading increases beyond 99.9% (lower GVF), several diagnostic indicators are warning the user of potential issues. First the Turbulence on Path 4 exceeds normal conditions and it goes into a "Warning" condition at 99.5% GVF. As liquid loading continues to increase there are now "SOS" and "Performance" Warnings.

Finally at 98% GVF the lowest path fails. Beyond this level of liquid loading, additional "Warnings" are activated, but there are no additional path failures. The important thing to note is the meter continues operation while several "Warnings" are indicating problems to the user. Obviously if the measurement were an orifice meter, no one would know that liquid is present. Just one of the many benefits of using a meter with advanced diagnostics.

The following Health diagnostics were from 55 Bar(a) and a gas velocity of 7.6 m/s. These are representative of the other velocities. All of these tests included a CPA flow conditioner.

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	ok	Path Error	ok	ok	ok	ok
Warning Symmetry	ok	Warning Turbulence	ok	ok	ok	ok
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	ok	ok
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	ok
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	ok	ok
		Warning Performance	ok	ok	ok	ok

Figure 15 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 100 GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	ok	Path Error	ok	ok	ok	ok
Warning Symmetry	ok	Warning Turbulence	ok	ok	ok	ok
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	ok	ok
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	ok
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	ok	ok
		Warning Performance	ok	ok	ok	ok

Figure 16 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 99.9 GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	W	Path Error	ok	ok	ok	ok
Warning Symmetry	W	Warning Turbulence	ok	ok	ok	W
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	ok	ok
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	ok
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	ok	ok
		Warning Performance	ok	ok	ok	ok

Figure 17 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 99.5 GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	W	Path Error	ok	ok	ok	ok
Warning Symmetry	W	Warning Turbulence	ok	ok	ok	W
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	ok	ok
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	ok
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	ok	W
		Warning Performance	ok	ok	ok	W

Figure 18 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 99.0 GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	W	Path Error	ok	ok	ok	E
Warning Symmetry	W	Warning Turbulence	ok	ok	W	ok
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	ok	W
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	W
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	ok	W
		Warning Performance	ok	ok	ok	W

Figure 19 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 98.0 GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	W	Path Error	ok	ok	ok	E
Warning Symmetry	W	Warning Turbulence	ok	ok	W	ok
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	ok	W
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	W
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	ok	W
		Warning Performance	ok	ok	W	W

Figure 20 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 97.0 GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	W	Path Error	ok	ok	ok	E
Warning Symmetry	W	Warning Turbulence	ok	ok	W	ok
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	ok	W
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	W
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	W	W
		Warning Performance	ok	ok	W	W

Figure 21 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 96.0 GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	W	Path Error	ok	ok	E	E
Warning Symmetry	W	Warning Turbulence	ok	ok	W	ok
Warning High Gas Velocity	n.a.	Warning SNR Limit	ok	ok	W	W
Warning Low Input Voltage	n.a.	Warning AGC Dev	ok	ok	ok	ok
Warning logb. full of unackn. entries	n.a.	Warning AGC Limit	ok	ok	ok	W
Warning Diagnostic Difference	n.a.	Warning SOS dev	ok	ok	ok	W
		Warning Performance	ok	ok	W	W

Figure 22 – 4-inch, 4-Path Meter Health – 55 Bar(a) – 95.0 GVF

Figures 23 thru 27 summarize the various 4-inch, 4-path diagnostic data that supports the Health Warning data in Figures 15-22. This data is from the 7.6 m/s flow rate that provides examples of what the diagnostics do with liquid loading values varying from 100% GVF to the 95% values. They are representative of other flow rates.

The following graphs (Figures 23-26) represent various diagnostics from the meter from a GVF of 100% to 96.0%. Figure 23 shows total path failure occurred first on Path 4 at a GVF of 99% (also shown by the Figure 19 of the Meter Health graphs). Figure 22 show that Path 3 had failed (red with "E" in the box from Figure 22), but this only means the performance was below 5%. In actuality the performance was 1.5%, and explains why there is a Path Ratio even at 96% GVF. Figure 25 shows the SOS of each path (until it failed), and Figure 26 shows the Turbulence of each path. Path 4 Turbulence exceeded 100% at the 99.0 GVF value, but the graph scale was set at 25 so as not to compress all the other data.

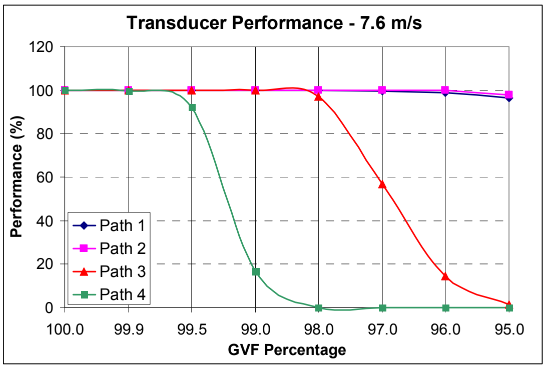

Figure 23 – Path Performance

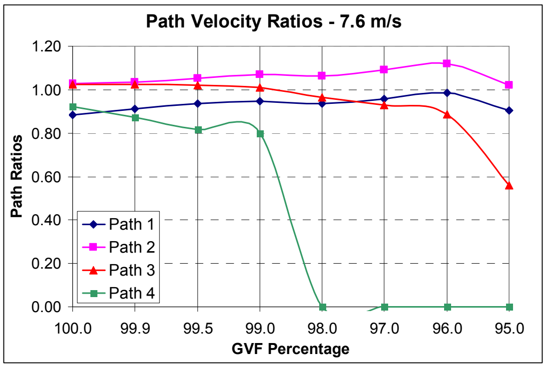

Figure 24 – Path Ratios

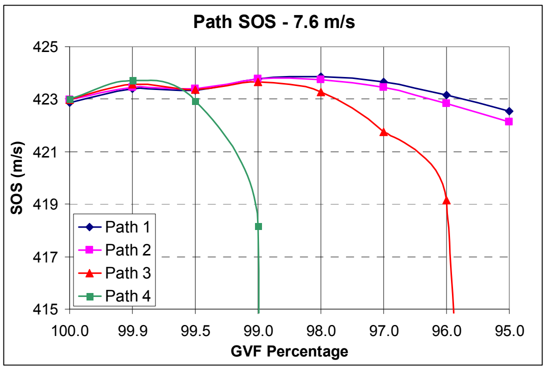

Figure 25 – Path SOS

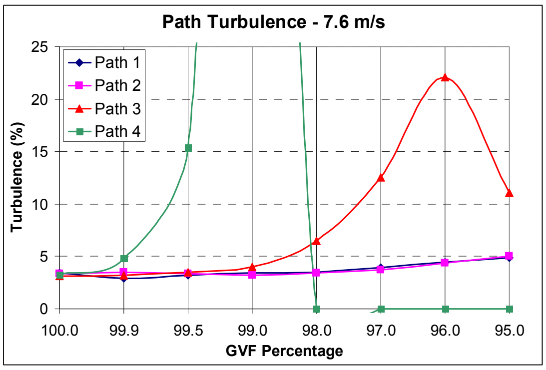

Figure 26 – Path Turbulence

Figure 27 shows the Profile Factor and Symmetry over the range of liquid loading. Note that the Profile Factor starts at 1.13 with a GVF of 100%, and the Symmetry is 0.981, both of which are normal for this meter and within expected tolerances. As the liquid loading increases (GVF value decreases), both Profile Factor and Symmetry gradually increase until the GVF exceeds 99%. At this liquid loading the gas velocity profile becomes much more distorted and there is significant step-change in both Profile Factor and Symmetry. This is also the level of GVF where the Turbulence becomes excessive on Path 4. Only when the GVF is less than 98% does Path 3's Turbulence increase significantly. Paths 1 and 2 increase some, but not to the same degree because the liquid is not affecting the profile as much at the top of the meter as it is at the bottom.

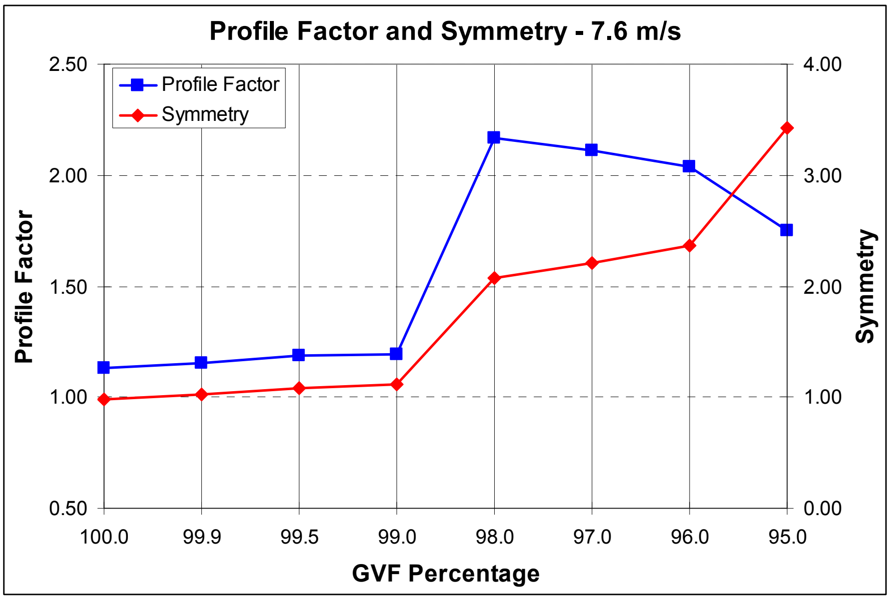

Figure 27 – Profile Factor and Symmetry

7. 3–INCH METER TEST RESULTS

From all data that was obtained in December, 2009 from the 4-inch USM and orifice package, and after analysis of the results, a modified 3-inch meter was developed. This meter had some minor changes to the design, and also incorporated the upstream meter tube (typically 10D) as part of the "package." Rather than have a separate 10D section bolted to the meter body, which is common for USMs, this upstream section was welded to the meter body.

The primary purpose of the integrated upstream section is to help reduce manufacturing costs, and ultimately the cost of ownership. One of the key considerations in using the orifice in lieu of the USM has been price. In order to be competitive (total cost of ownership), packaging the meter more cost effectively is very important. Thus welding the upstream section reduces the cost by 2 flanges and also insures alignment of the piping with the "measurement section", or meter body.

Most orifice meters used in "upstream" and "midstream" production markets range from 2-6 inches. Often the gas well is brought on line, produces at high rates for a period of time, and before long the output may decrease. The user is then often replacing the plate with a small beta in order to keep the differential within company guidelines. In many cases it isn't long before the orifice meter is at the lowest beta the company permits, and now the meter run must to be replaced with a smaller line size.

With the much greater rangeability of today's ultrasonic meter, many companies believe the 3-inch USM is the optimum size for these applications (equivalent rangeability to use in lieu of 2-4 inch orifice meters). As the gas well flow rates are generally higher upon commissioning, the USM can easily handle these. When the well production decreases, the USM is still well within its operational range. With the shorter tube lengths needed with the USM, the far lower maintenance (no orifice plate checks and replacements), and the added benefit of diagnostics, the 3-inch is the good choice for a majority of these applications.

The CEESI Wet Gas Facility was built primarily for testing 4-inch meters. All of the compressors and filter-separators are optimized for this size. With a 3-inch meter being tested, the lowest flow rates the lab can achieve with stability are higher than a typical low beta ratio 3-inch meter might be operated. For this reason the differential pressures (dP) on the 3-inch orifice, with a 0.517 beta, were no lower than about 6.2 kPa. In order to obtain the higher flow rates (rangeability), dPs (dry) were planned for as much as 153 kPa with dry gas, and of course much higher with liquid loading.

The testing for this meter was performed at two pressures: 1,344 kPa(a) (13.44 Bar(a)) and 5,500 kPa(a) (55 Bar(a)). From all the previous testing, there wasn't any significant difference between the 34 Bar(a) and 55 Bar(a) data. This permitted running more differential pressures and liquid loading tests during the same period of time. Also, from previous feedback from end users, there was more interest in lower levels of liquid loading, so additional points were taken. The goal was to obtain data on the following GVF values: 100, 99.95, 99.90, 99.8, 99.5, 99, 98, 97 and 95%. These were the targets with the 95% test only suitable for the higher pressure due to the increased gas density.

For the low pressure testing, no flow conditioner was used with the USM, but the traditional 19-tube bundle was used with the dual-chamber orifice meter. The purpose of testing at this low pressure is because many field applications operate around 700 kPa(a). Pressure drop in these measurement systems is critical as this gas must be compressed for transportation. Thus, having a USM with no pressure drop is a significant benefit. Therefore, it was decided to test the meter without the CPA at the 13 Bar(a), and also at the 55 Bar(a) level. For those users that prefer a flow conditioner, testing was also conducted at 55 Bar(a) with the CPA installed.

Figure 28 shows the results of the orifice meter with all the liquid loading tests at 13 Bar(a). All graphs relating to the 3-inch testing are shown comparing the various GVF errors relative to the baseline with a GVF of 100%. This makes it easier to relate what shift the meters have by comparing the results to clean, dry natural gas.

Figure 28 shows similar results to the 4-inch meter presented earlier. Errors were not significant until the liquid loading exceeded 99.8% GVF. Beyond this the errors became much more significant. In fact the highest liquid loading (GVF of 97.83%) showed results very similar to the 4-inch at a GVF of 98% shown in Section 3. Figure 29 shows the same results as Figure 28 but with the X-axis scaled in velocity (m/s).

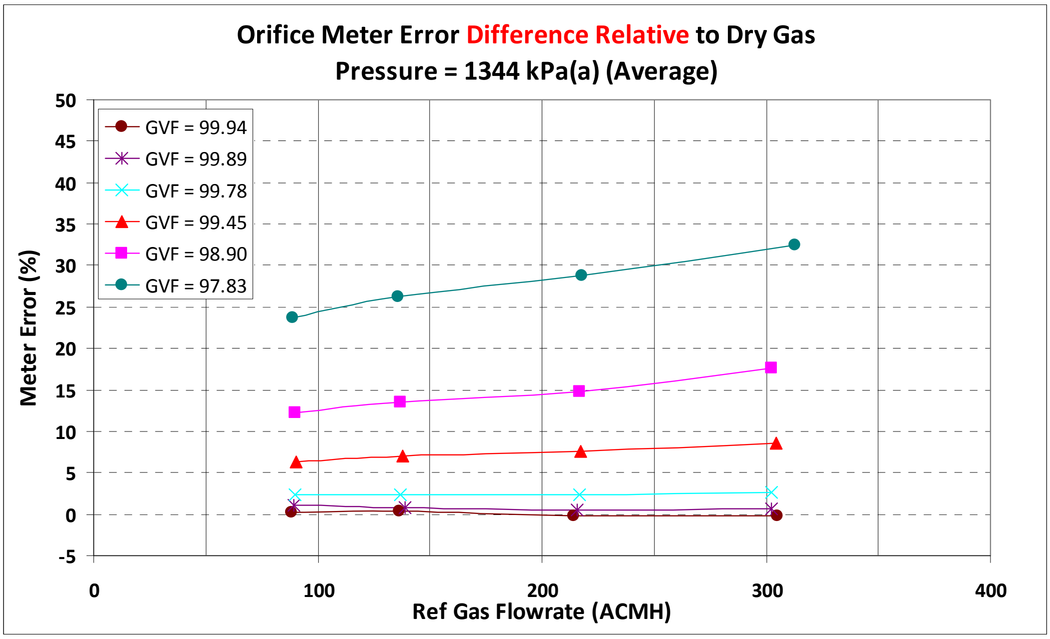

Figure 28 – 3-inch Orifice Results – 13 Bar(a) – Baseline Difference – All GVFs

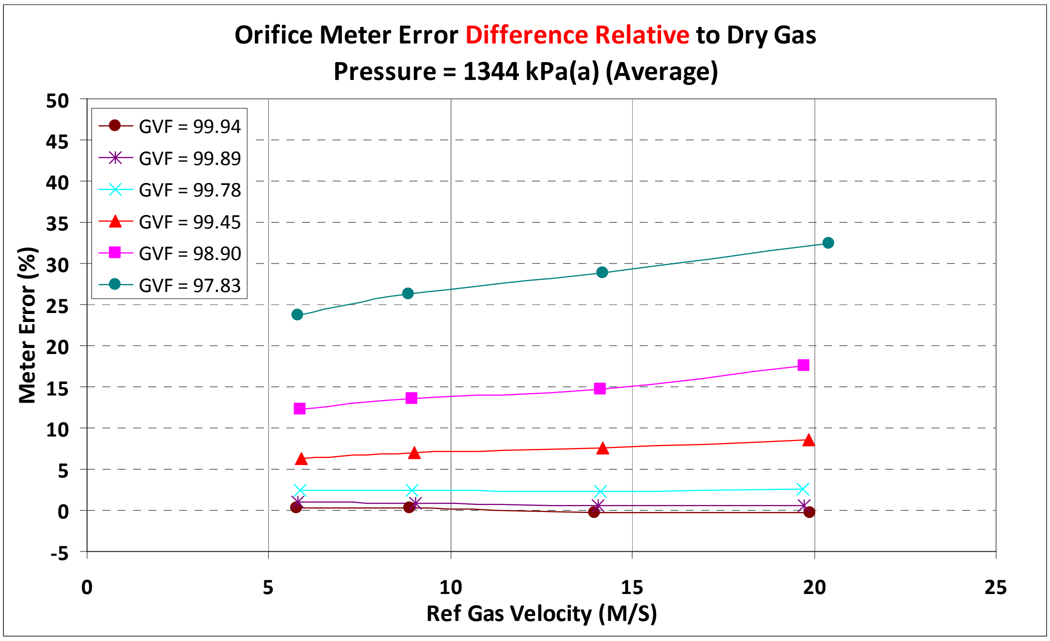

Figure 29 – 3-inch Orifice Results – 13 Bar(a) – Baseline Difference – All GVFs

Figure 30 shows the results of the 3-inch, 2-path USM with no CPA flow conditioner. It also represents the difference between the dry gas baseline and all of the liquid loading tests. Previous to this graph, all Meter Error axis ranges (Y-axis) were the same scale (0-50% error) to simplify understanding of the data. However, due to the significantly improved performance of this 3-inch meter, the Y-axis scale has been changed (-2.5% to +2.5% error) so the various results would be more legible.

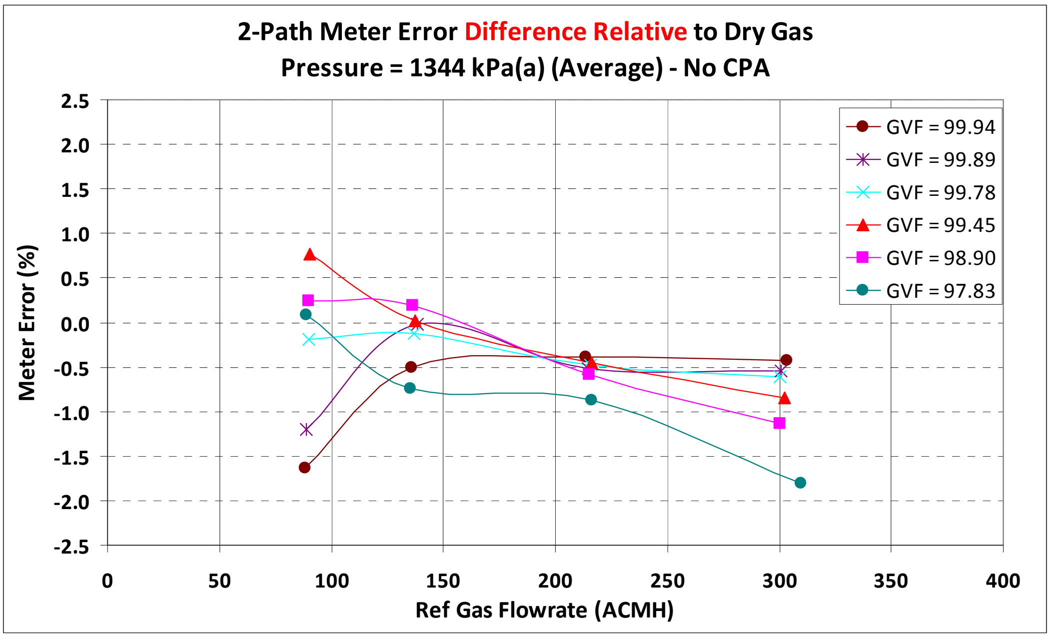

Figure 30 – 3-inch 2-Path USM Results – 13 Bar(a) – All GVFs – No CPA

These results show this meter is essentially within ±1% for GVF ≤99% or less than ±2% for virtually all tests, even the GVF of 97.83%. This prototype meter's initial test results indicate it is possible to use this USM design in these difficult applications.

The next series of tests were conducted at approximately 55 Bar(a). The same procedure was used as before. Figure 31 shows the results of the 3-inch orifice meter errors relative to the dry baseline. The USM was first tested without the CPA, flow conditioner and then the tests were repeated with the CPA.

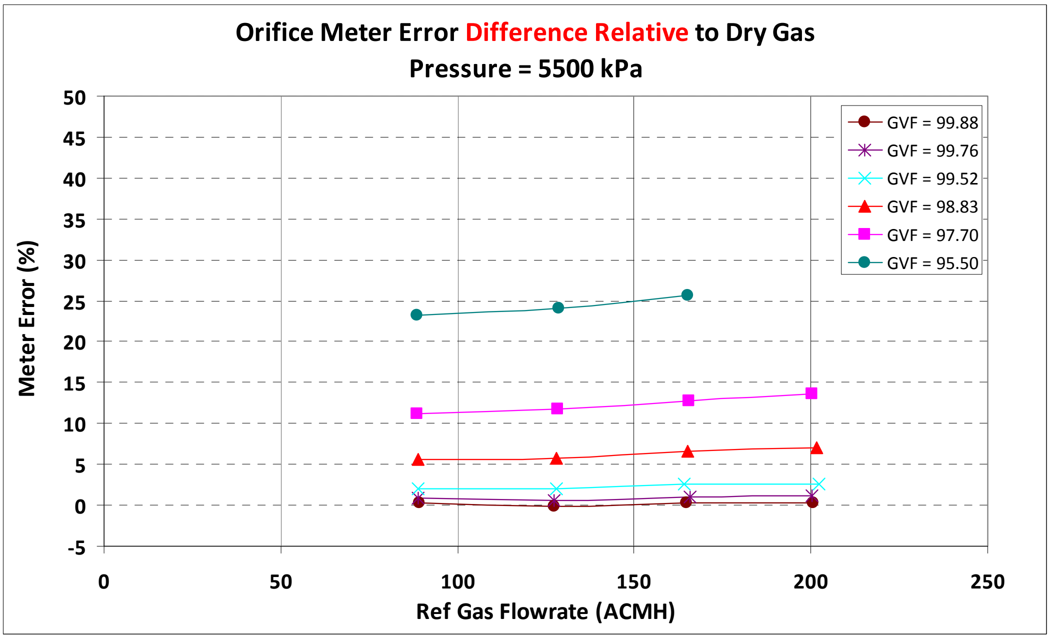

Figure 31 – 3-inch Orifice Results – 55 Bar(a) – Baseline Difference – All GVFs

The errors at 55 Bar(a), as shown in Figure 31, are very similar to those shown at 13 Bar(a) in Figure 28 (perhaps slightly less for most GVF levels). For the highest liquid loading, 95.5% GVF, there is no flow rate data due to the differential pressure exceeding the transmitter's upper limit (248 kPa). Figure 32 shows the same results but uses gas velocity in the 3-inch Schedule 80 piping for the X-axis.

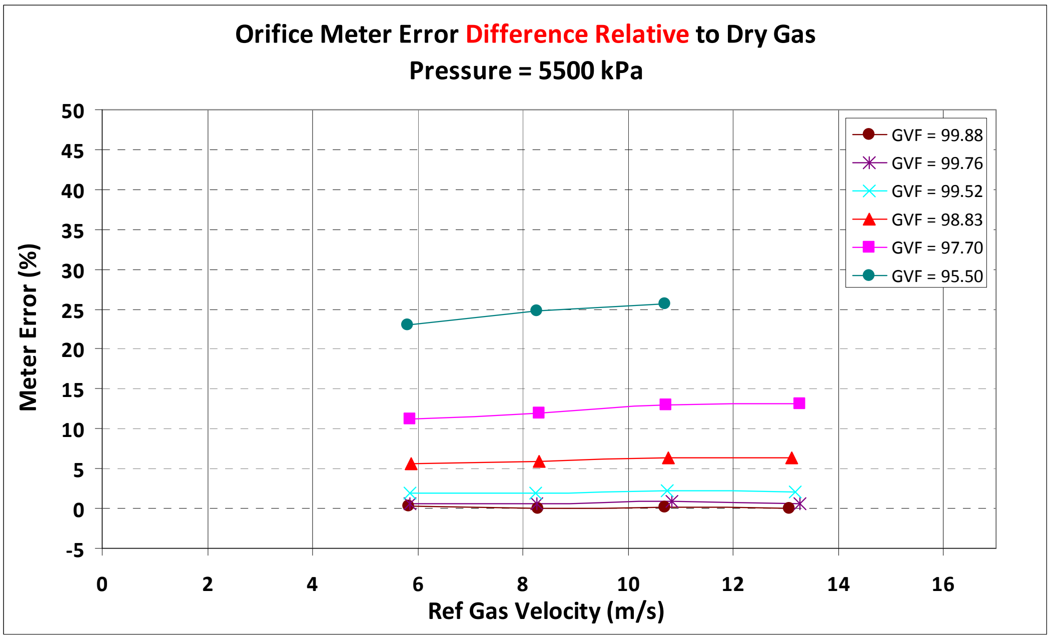

Figure 32 – 3-inch Orifice Results – 55 Bar(a) – Baseline Difference – All GVFs

Figure 33 shows the results of the 2-Path USM under the same conditions. These results were obtained with no CPA flow conditioner.

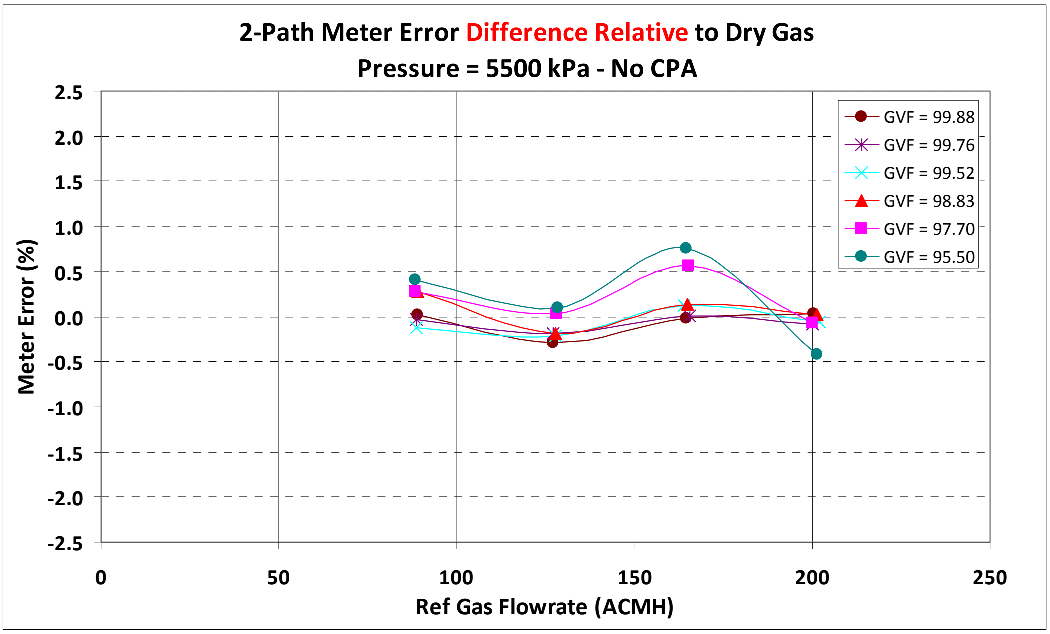

Figure 33 – 3-inch 2-Path USM Results – 55 Bar(a) – All GVFs – No CPA

The results of the 3-inch USM shows even less shift from baseline at 55 Bar(a) than at 13 Bar(a). The meter is now within ±0.75% for virtually all test conditions including the highest GVF of 95.5%. The meters were not tested at this high GVF at the lower pressures as gas density was too low. Figure 34 shows the results using the CPA.

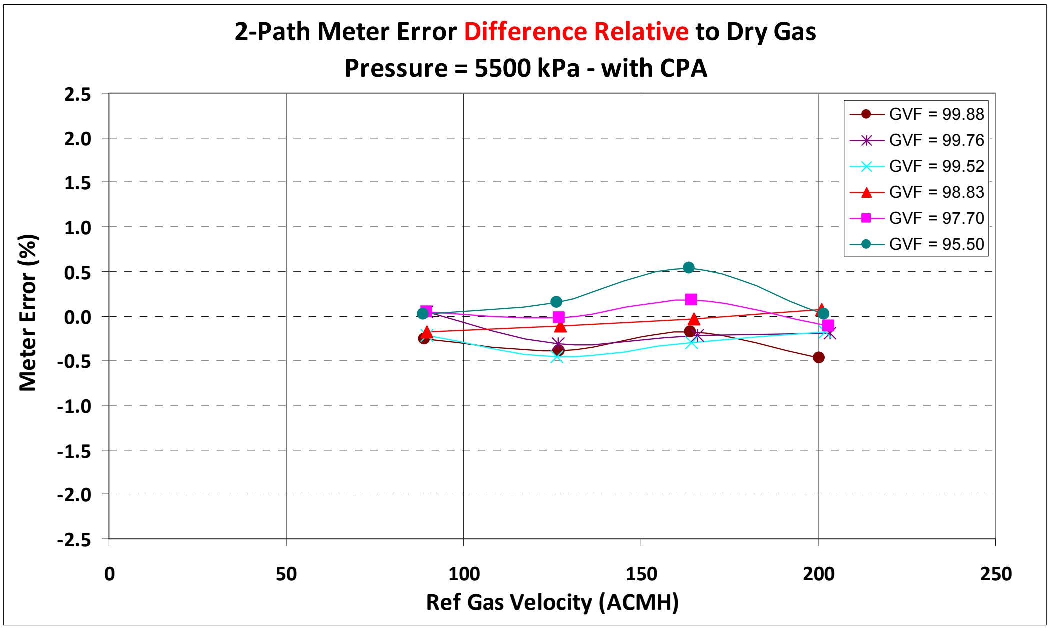

Figure 34 – 3-inch 2-Path USM Results – 55 Bar(a) – All GVFs – With CPA

The results in Figure 34 show the CPA flow conditioner produced almost identical results to those shown in Figure 33 when no flow conditioner was used. Once again test results were within ±0.5% relative to the dry gas baseline results.

The benefit of using a flow conditioner is to reduce the installation affects of upstream swirl and asymmetry flow that may be present when the meter is installed in the field. There is always concern the flow conditioner might influence the meter's accuracy during liquid loading tests, but these results show that is not true. Another concern with using a flow conditioner is the possible formation of hydrates under some conditions, but this didn't occur in these tests.

8. 3–INCH GAS ULTRASONIC METER DIAGNOSTICS

One benefit of using an ultrasonic meter is the diagnostics. This gives the user the ability to understand more about the operation of the meter. Problems such as blocked flow conditioners, dirty meters, pulsation and liquid in the pipeline are easily identified. This can be seen by either connecting to the meter, or if the meter incorporated automated diagnostics, obtaining it from the audit logs.

"Meter Health" summary information for the 3-inch, 2-path meter at all GVF levels is shown in Figures 35-41. Data was taken from the "Maintenance Report" that was collected during the testing. The following were obtained at 8.2 m/s to approximate the same flow velocity for the 4-inch, 4-path data that is shown in Figures 15 - 22. These tests used the CPA flow conditioner with pressure at about 55 Bar(a) (same condition as the 4-inch data). There was no difference in results when compared to no CPA. The yellow "W" in "Warning Diagnostic Difference" was not present for the 4-inch testing as show in Figures 15-22 as that firmware didn't yet have the "Fingerprint Function" (which is called Diagnostic Difference). This warning was caused by significant changes in the diagnostic parameters caused by the liquid loading tests.

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	n.a.	Path Error	ok	ok	n.a.	n.a.
Warning Symmetry	n.a.	Warning Turbulence	ok	ok	n.a.	n.a.
Warning High Gas Velocity	ok	Warning SNR Limit	ok	ok	n.a.	n.a.
Warning Low Input Voltage	ok	Warning AGC Dev	ok	ok	n.a.	n.a.
Warning logb. full of unackn. entries	ok	Warning AGC Limit	ok	ok	n.a.	n.a.
Warning Diagnostic Difference	W	Warning SOS dev	ok	ok	n.a.	n.a.
		Warning Performance	ok	ok	n.a.	n.a.

Figure 35 – 3-inch, 2-Path Meter Health – 55 Bar(a) – 100 GVF

Meter Health			P 1	P 2	P 3	P 4
Waming Profile Factor	n.a.	Path Error	ok	ok	n.a.	n.a.
Waming Symmetry	n.a.	Warning Turbulence	ok	ok	n.a.	n.a.
Waming High Gas Velocity	ok	Warning SNR Limit	ok	ok	n.a.	n.a.
Waming Low Input Voltage	ok	Warning AGC Dev	ok	ok	n.a.	n.a.
Waming logb. full of unackn. entries	ok	Warning AGC Limit	ok	ok	n.a.	n.a.
Waming Diagnostic Difference	W	Warning SOS dev	ok	ok	n.a.	n.a.
		Warning Performance	ok	ok	n.a.	n.a.

Figure 36 – 3-inch, 2-Path Meter Health – 55 Bar(a) – 99.88% GVF

Meter Health			P 1	P 2	P 3	P 4
Waming Profile Factor	n.a.	Path Error	ok	ok	n.a.	n.a.
Waming Symmetry	n.a.	Warning Turbulence	ok	ok	n.a.	n.a.
Waming High Gas Velocity	ok	Warning SNR Limit	ok	ok	n.a.	n.a.
Waming Low Input Voltage	ok	Warning AGC Dev	ok	ok	n.a.	n.a.
Waming logb. full of unackn. entries	ok	Warning AGC Limit	ok	ok	n.a.	n.a.
Waming Diagnostic Difference	W	Warning SOS dev	ok	ok	n.a.	n.a.
		Warning Performance	ok	ok	n.a.	n.a.

Figure 37 – 3-inch, 2-Path Meter Health – 55 Bar(a) – 99.76% GVF

Meter Health			P 1	P 2	P 3	P 4
Waming Profile Factor	n.a.	Path Error	ok	ok	n.a.	n.a.
Waming Symmetry	n.a.	Warning Turbulence	ok	ok	n.a.	n.a.
Waming High Gas Velocity	ok	Warning SNR Limit	ok	ok	n.a.	n.a.
Waming Low Input Voltage	ok	Warning AGC Dev	ok	ok	n.a.	n.a.
Waming logb. full of unackn. entries	ok	Warning AGC Limit	ok	ok	n.a.	n.a.
Waming Diagnostic Difference	W	Warning SOS dev	ok	ok	n.a.	n.a.
		Warning Performance	ok	ok	n.a.	n.a.

Figure 38 – 3-inch, 2-Path Meter Health – 55 Bar(a) – 99.52% GVF

Meter Health			P 1	P 2	P 3	P 4
Waming Profile Factor	n.a.	Path Error	ok	ok	n.a.	n.a.
Waming Symmetry	n.a.	Warning Turbulence	ok	W	n.a.	n.a.
Waming High Gas Velocity	ok	Warning SNR Limit	ok	ok	n.a.	n.a.
Waming Low Input Voltage	ok	Warning AGC Dev	ok	ok	n.a.	n.a.
Waming logb. full of unackn. entries	ok	Warning AGC Limit	ok	W	n.a.	n.a.
Waming Diagnostic Difference	W	Warning SOS dev	ok	ok	n.a.	n.a.
		Warning Performance	ok	ok	n.a.	n.a.

Figure 39 – 3-inch, 2-Path Meter Health – 55 Bar(a) – 98.84% GVF

Meter Health			P 1	P 2	P 3	P 4
Waming Profile Factor	n.a.	Path Error	ok	ok	n.a.	n.a.
Waming Symmetry	n.a.	Warning Turbulence	W	W	n.a.	n.a.
Waming High Gas Velocity	ok	Warning SNR Limit	ok	ok	n.a.	n.a.
Waming Low Input Voltage	ok	Warning AGC Dev	ok	ok	n.a.	n.a.
Waming logb. full of unackn. entries	ok	Warning AGC Limit	ok	W	n.a.	n.a.
Waming Diagnostic Difference	W	Warning SOS dev	W	W	n.a.	n.a.
		Warning Performance	ok	W	n.a.	n.a.

Figure 40 – 3-inch, 2-Path Meter Health – 55 Bar(a) – 97.71% GVF

Meter Health			P 1	P 2	P 3	P 4
Warning Profile Factor	n.a.	Path Error	ok	E	n.a.	n.a.
Warning Symmetry	n.a.	Warning Turbulence	W	ok	n.a.	n.a.
Warning High Gas Velocity	ok	Warning SNR Limit	ok	W	n.a.	n.a.
Warning Low Input Voltage	ok	Warning AGC Dev	ok	ok	n.a.	n.a.
Warning logb. full of unackn. entries	ok	Warning AGC Limit	ok	W	n.a.	n.a.
Warning Diagnostic Difference	W	Warning SOS dev	ok	W	n.a.	n.a.
		Warning Performance	ok	W	n.a.	n.a.

Figure 41 – 3-inch, 2-Path Meter Health – 55 Bar(a) – 95.51% GVF

From these "Meter Health" summaries it is clear the meter was performing normally until the GVF value was below 99.52%. Higher liquid loadings caused Warnings in Turbulence and AGC Limit (Turbulence exceeded 6% and the AGC limits exceeded normal value by 6 dB). As liquid loading increased, even more Warnings became present including SOS Deviation (greater than 0.25% SOS deviation from Path 1 to Path 2), and Transducer Performance (less than 80% accepted for the Performance Warning to be activated). Once the liquid loading was at the highest level (GVF of 95.51%), then Path 2 Performance fell below 5% accepted, and thus the meter reported it as failed ("E" in the box and it turned red).

The following graphs (Figures 42-45) represent various diagnostics from the meter from a GVF of 100% to 96.0%. Figure 42 shows the path performance was running 100% until the GVF reached 98.84%. As the liquid loading increased, performance fell and at 95.51 GVF, Path 2 had totally failed. Figure 43 shows per-path SOS. Note that the SOS on Path 2 was identical when the GVF was 100%, but was lower for all other liquid loadings until it finally failed. Turbulence is shown in Figure 44. As the liquid loading increased, all Turbulence values increased. Above a GVF of 99.52, the Turbulence on Path 2 started increasing significantly until the path failed at the lowest GVF value. Figure 45 shows the Symmetry. As the GVF value decreased from 100%, the Symmetry began to increase. This means the Path 2 velocity readings were becoming slower relative to Path 1.

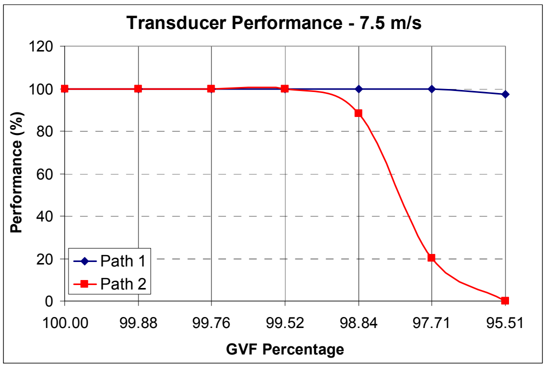

Figure 42 – Path Performance

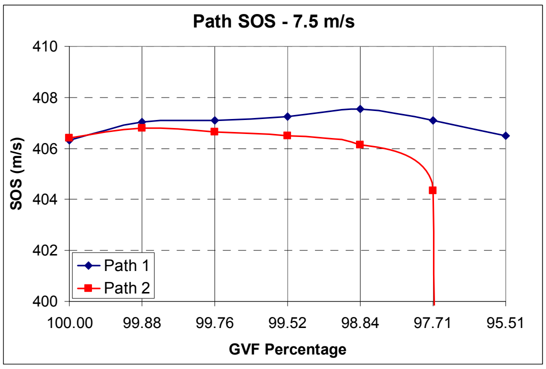

Figure 43 – Path SOS

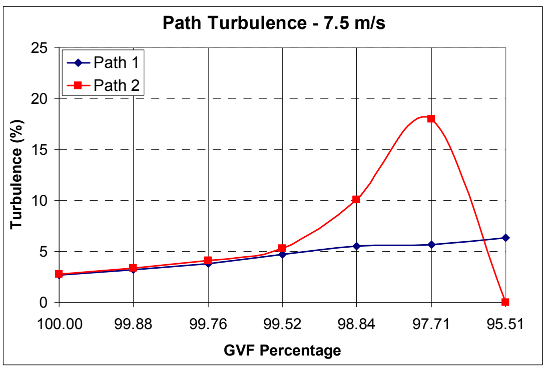

Figure 44 – Path Turbulence

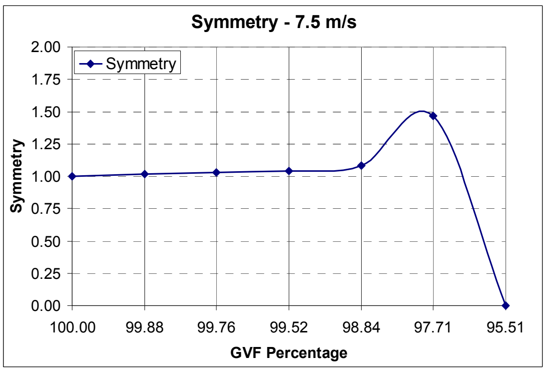

Figure 45 – Symmetry

One additional set of tests was conducted using water. All the previous data was taken with Exxsol D80 but there was interest in seeing if the results would be different using water. Thus

6 additional test points were included. Two flow rates of 8.2 and 13.1 m/s were run and three GVF approximate values of 99.88, 99.53 and 99.14% (there are some minor differences between the Exxsol and Water tests). The focus here was on the lighter liquid loading and whether the meters performed essentially the same with water as with the Exxsol D80. This testing also included the CPA flow conditioner since it was in line at the time the 55 Bar(a) data was taken with Exxsol D80.

Figure 45 shows the results of both the Exxsol D80 and the water for the orifice meter, and Figure 46 show the results for the 2-Path meter.

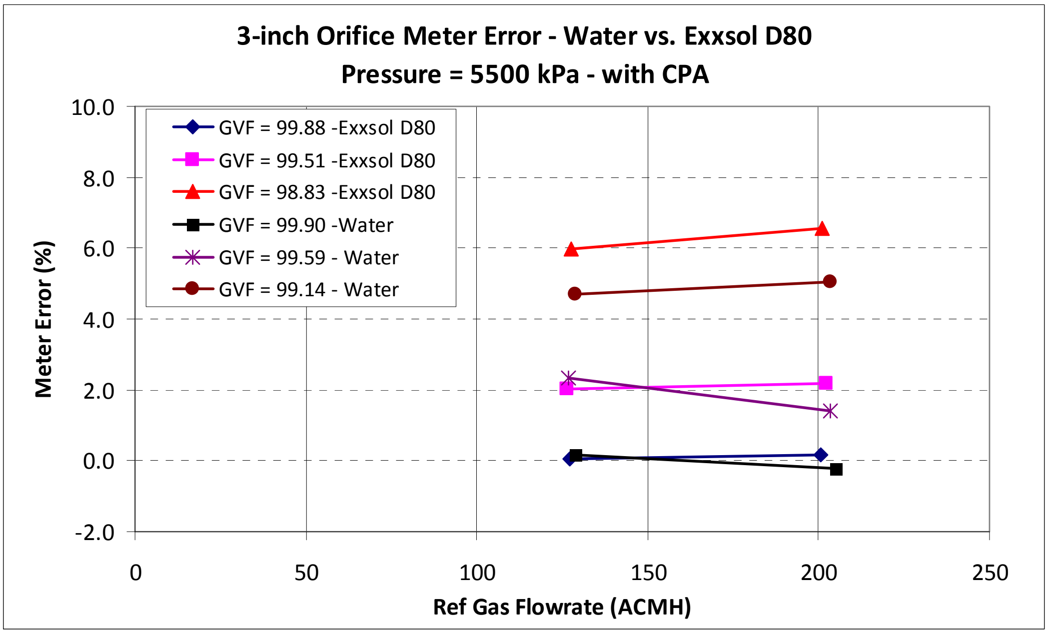

Figure 46 – 3-inch Orifice Meter Water and Exxsol D80 Errors– 55 Bar(a)

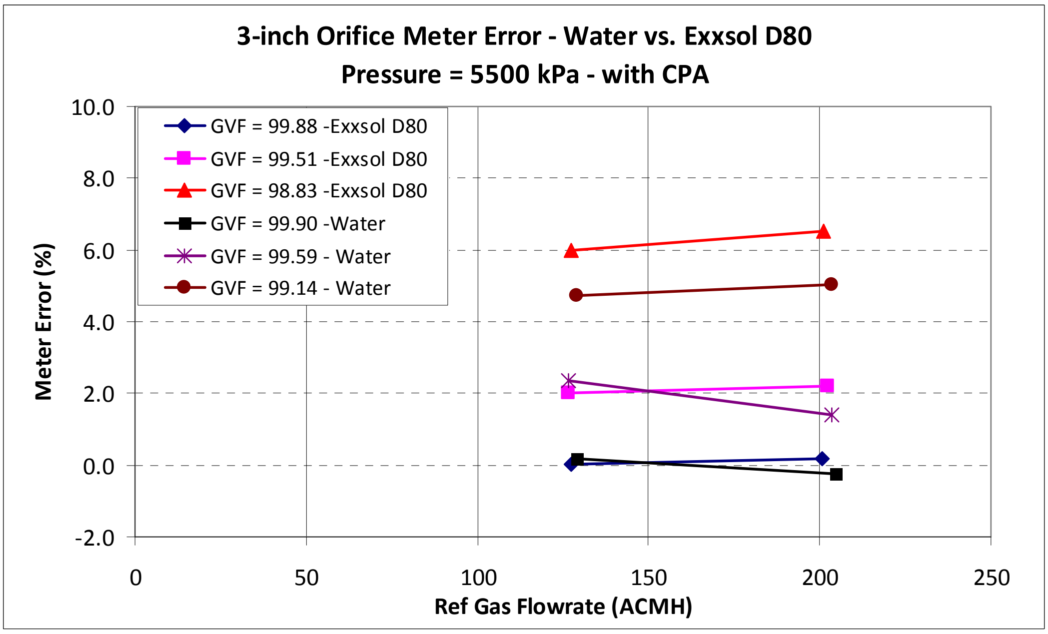

Figure 47 – 3-inch Orifice Meter Water and Exxsol D80 Errors– 55 Bar(a)

Figure 48 is a comparison between the Exxsol D80 and water for the orifice meter, and Figure 49 show the difference between Exxsol D80 and water for the 2-path meter. As these tests were conducted at the end of the program, they include the CPA flow conditioner.

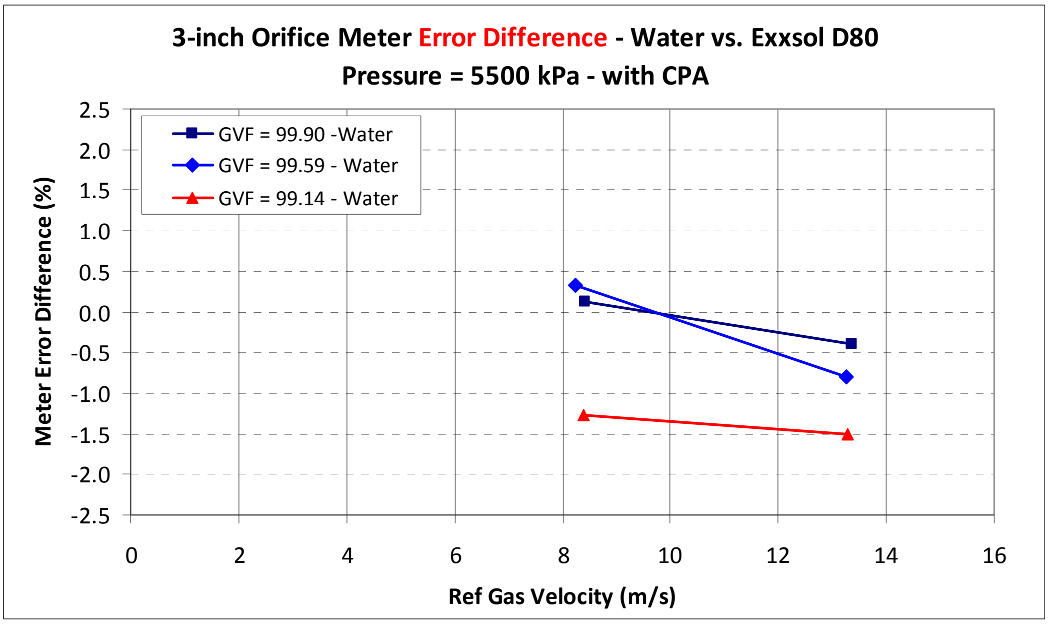

Figure 48 – 3-inch Orifice Meter Water and Exxsol D80 Difference – 55 Bar(a)

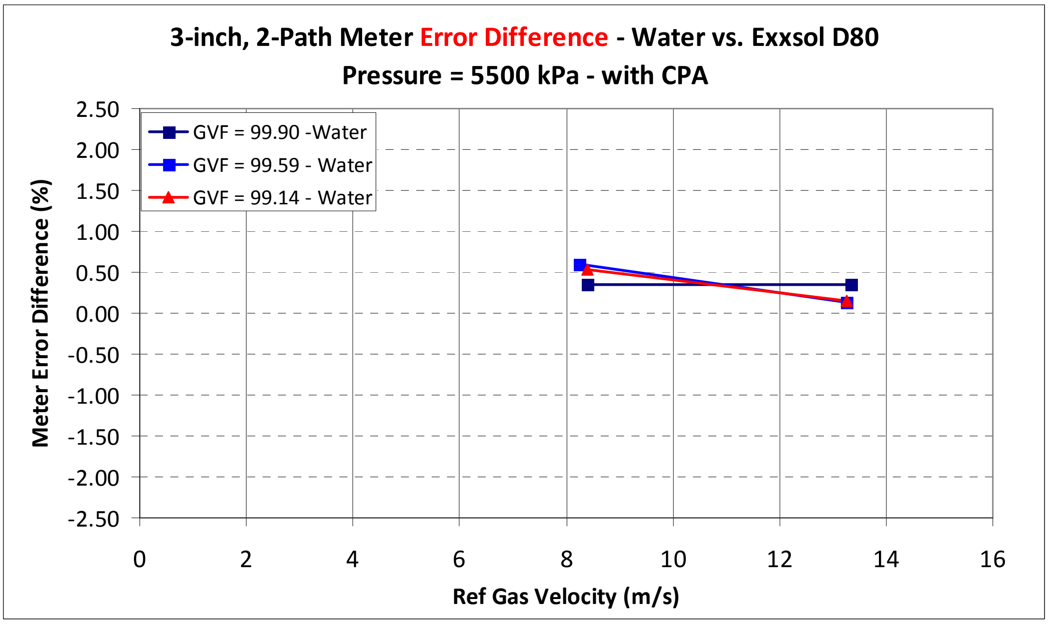

Figure 49 – 3-inch, 2-Path Meter Water and Exxsol D80 Difference– 55 Bar(a)

Figures 48 and 49 show there is no significant different between the Exxsol D80 and water although the higher level of liquid loading (GVF = 99.14) showed a difference of approximately -1.5% compared to the other levels of GVF. The difference in the 2-path USM was on the order of +0.25 to 0.5% and probably would be considered within the acceptable limits of repeatability for these tests.

Figure 50 is a graph of Gas Mass Flow Ratio (GMFR) vs. Lockhart Martinelli plotted at both 13 and 55 Bar(a).

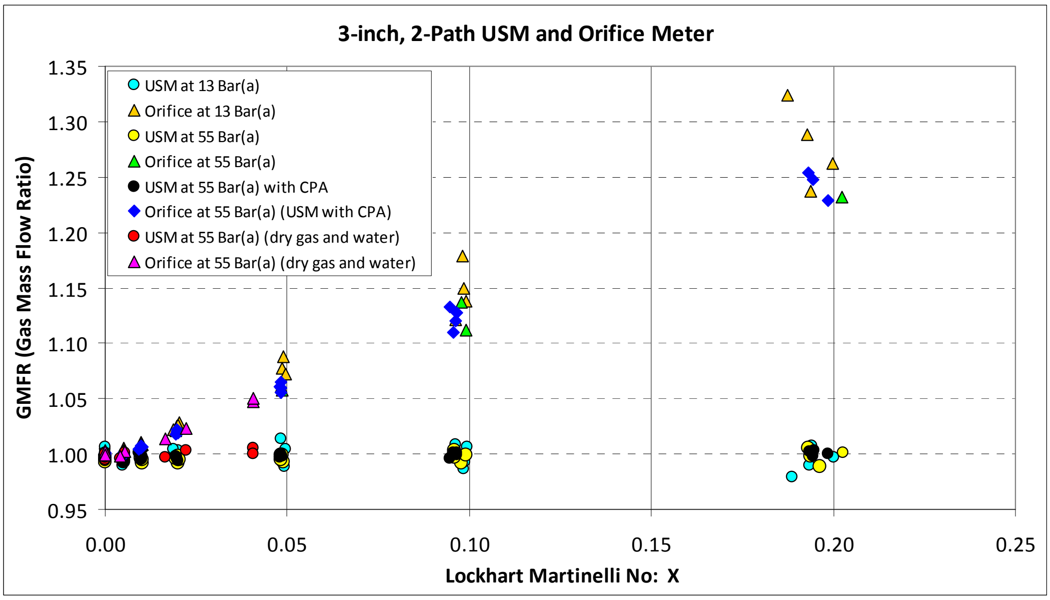

Figure 50 – Lockhart Martinelli for 3-inch Orifice and 2-Path USM

Figure 50 shows all the 2-path USM data remains very close to 1.00 GMFR as the Lockhart Martinelli Parameter increases to almost 0.2. The round circles represent the results of the USM and the diamonds and triangles represent the orifice meter. As expected the orifice meter trends in a fairly straight line with an increasing GMFR as the Lockhart Martinelli Parameter increases.

The integrity of the test data might be questioned since the results of the 3-inch USM were perhaps better than expected. The performance behavior of the orifice in wet gas applications has been documented several times. Most recently a paper was published at the Southeast Asia Conference in 2008 entitled "Further Evaluation of the Performance of Horizontally Installed Orifice Plate and Cone Differential Pressure Meters with Wet Gas Flows" [Ref 1]. In this paper an equation was developed to predict the over-reading of an orifice meter if the liquid content was known.

Figure 51 shows a graph of the Lockhart Martinelli vs. the 3-inch orifice meter over-reading, and also the predicted results using the equation that was developed and presented in this paper [Ref 1].

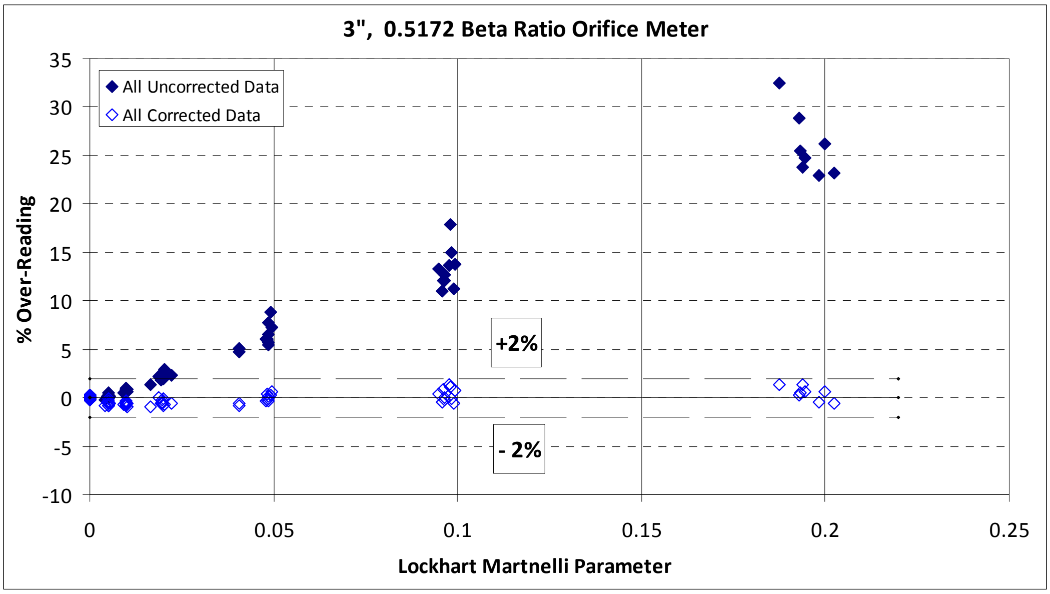

Figure 51 – Lockhart Martinelli for 3-inch Orifice with Predicted Correction

Results of the corrected data show all values to be within ±2.0% of baseline when the liquid flowrate is known. This graph agrees with the model very well and thus shows the results from the CEESI Wet Gas Loop are valid.

The data in Figure 52 represents the same data as Figure 51 with separate gas to liquid Density Ratios (DR).

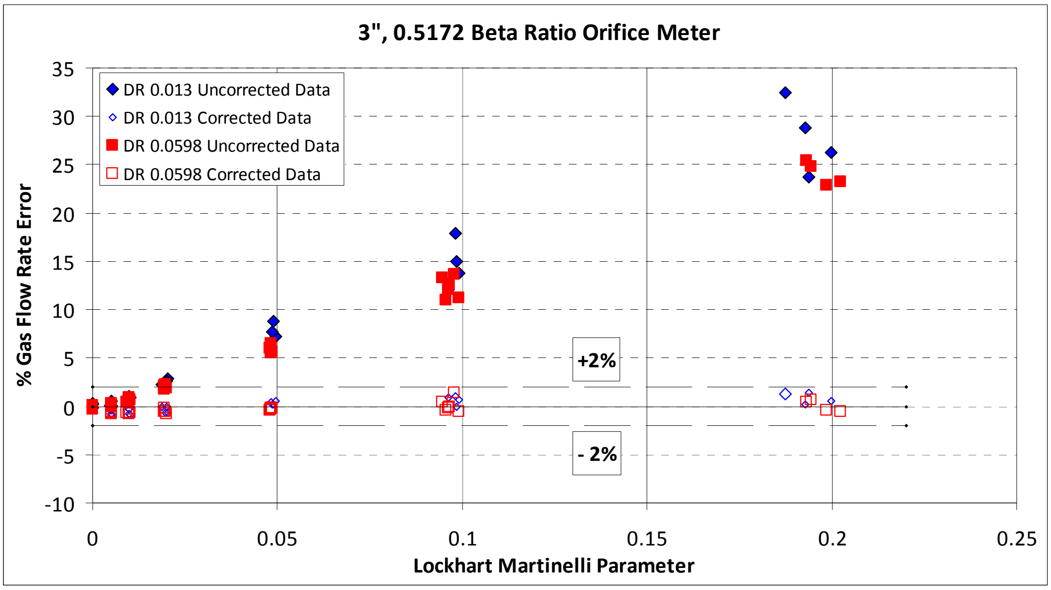

Figure 52 – Lockhart Martinelli for 3-inch Orifice with Predicted Correction – Both Pressures

The data in Figure 53 represents the low pressure (DR of 0.013) with separate gas densiometric Froude Numbers (Fr_g).

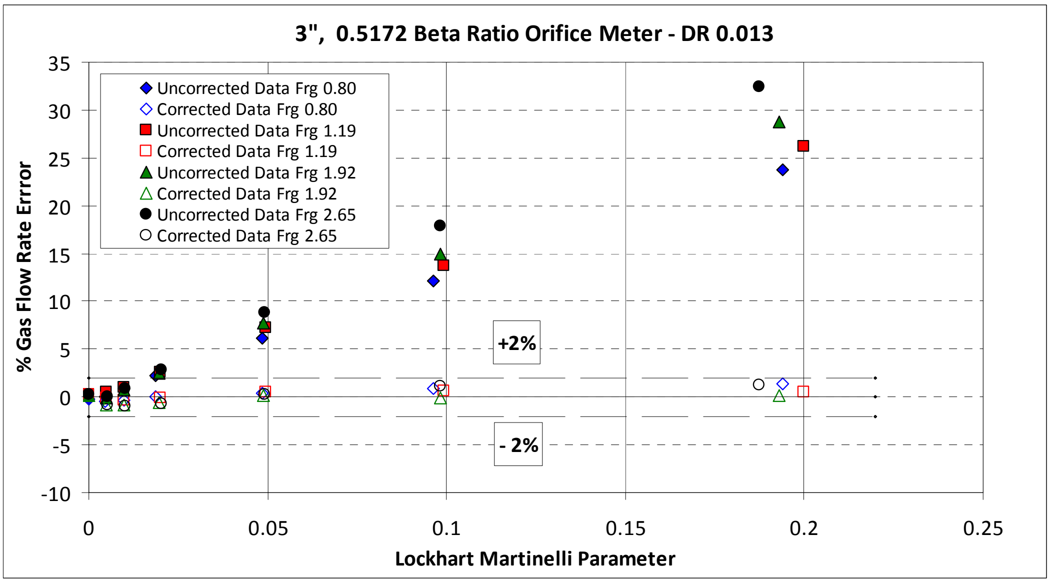

Figure 53 – Lockhart Martinelli for 3-inch Orifice for DR of 0.013

The data in Figure 54 represents the low pressure (DR of 0.06) with separate gas densiometric Froude Numbers (Fr_g).

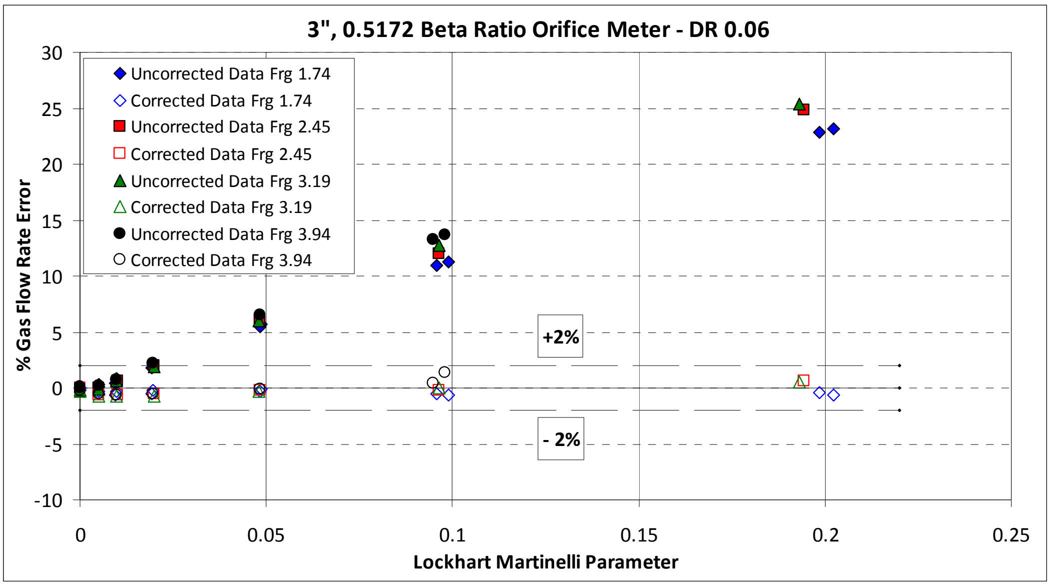

Figure 54 – Lockhart Martinelli for 3-inch Orifice for DR of 0.06

The point of these correction graphs, Figures 51-54, is to validate that the data collected for the orifice meter agrees very closely with the predicted results from this paper. Hence, the orifice meter has all the wet gas trends as previously published [Ref 1]. Thus it confirms the precise over-reading values as predicted by this independent reference [Ref 1]. It can be concluded that the test procedure and the facility reference meters are accurate and reliable.

9. CONCLUSIONS

Traditionally orifice meters have often been used in “wet gas” applications because they are “tolerant” of liquid in the gas stream. Being “tolerant” just means they aren’t generally damaged by the presence of liquids, as are turbine, rotary and other traditional measurement devices. The benefit of gas ultrasonic meters has been documented in many papers over the years. Certainly for small production applications the price of the primary element has to be considered, and once again the orifice meter has a significant advantage.

One of the wet gas problems is typically transducer damage due to the liquids penetrating the sensor. This has been solved in this prototype meter by using hermetically sealed, titanium transducers that can withstand hydrostat testing.

During December, 2009, the testing of a special 4-path and 2-path combination 4-inch meter at the CEESI Nunn, Colorado facility provided insight into what a traditional gas ultrasonic meter would do with a variety of liquid loadings. The values of GVF tested were based on some recommendations from production users. After reviewing the data, there was renewed interest in the results, and more data was requested with lighter liquid loading (higher values of GVF).

As expected, the first test results showed the gas ultrasonic meter over-registered as did the orifice meter. Both had significant errors with higher levels of liquid loading, with errors exceeding 30% as the GVF levels decreased below 98%. This was not unexpected. Both the 2-path and 4-path meters behaved similarly and thus there wasn’t really any significant benefit to using a 4-path meter in these difficult applications.

After analysis of the data, a modified version of a 2-path was constructed. As many users traditionally use 2-4 inch orifice meters, the 3-inch USM was identified as the best compromise to replace all three of these line sizes. Thus the second series of tests, conducted in late August 2010 was performed using only a 2-path meter constructed as it might be for the field applications.

This meter is a prototype designed with two goals in mind. First, reduce the cost of manufacturing in order to make the use of the ultrasonic meter more cost-attractive. This was part of the reason for incorporating the upstream 10D piping into the meter body. Reducing 2 flanges impacts the cost of manufacturing, and eliminates a leak path at the same time.

Second, attempt to improve the performance, and also use the diagnostics to help identify when liquids are present.

The accuracy results (shift from the 100% GVF baseline) for the new 2-path design were much better than expected. Once again the orifice meter shifted on the order of 30% at the highest liquid loading levels (both 3 and 4-inch meters), but the 3-inch modified ultrasonic meter was generally within ±1%.

Not only did this prototype gas ultrasonic meter, in this initial test, continue operating in these difficult conditions, it was more accurate under all levels of GVF when compared to the orifice meter. This data suggests that it is practical to use the USM in these applications.

9. REFERENCES

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