Wet Gas Metering Using Sonar-based Flow Meters and Piping Pressure Loss Gradients

Daniel L. Gysling – CiDRA Corporation
Douglas H. Loose – CiDRA Corporation
Nicolas Morlino – BP America, EPTG
Alex van der Spek - Zdoor, BV

---

1. ABSTRACT

Convenient and accurate measurement of gas and liquid rates of wet gas mixtures represents a long standing challenge within the oil and gas industry. Recently, sonar-based flow meters have been demonstrated to provide accurate measurement of the mixture flow rate of wet gas mixtures on a clamp-on basis. This paper describes an approach which combines sonar-based flow meters with the measured pressure drop across a section of pipe to provide gas and liquid flow rates. The approach leverages recognition that variations in the pressure gradient along a given section of pipe containing a wet gas mixture are primarily determined by the flow rate and liquid content of the mixture. In this approach, a sonar-based flow meter provides the mixture flow rate, and the measured pressure drop across a section of fixed geometry piping provides a basis to determine the liquid loading. The interpretation of the measured quantities in terms of gas and liquid flow rates is performed using either empirical data-based model or with the assistance of a multiphase flow model. The approach is of particular interest in applications in which pressure gradient measurements either exist, or can be installed without requiring a process shutdown. Two data sets are provided demonstrating the utility of this approach: 1) a laboratory test with data spanning range of flow rates and pressures with wetness levels predominately in range of 0 to 2.0 Liquid Gas Mass Ratio, and 2) a field test in which the measured produced gas and liquid rates from a wet gas well are compared to test separator measurement over a range of flow rates and wetnesses ranging from 0.08 to 0.15 Liquid to Gas Mass Ratio.

2. INTRODUCTION

Measuring wet gas flows is important for a wide range of upstream oil and gas measurement applications. While measuring dry gas flow rate is a well-served application for a wide range of gas flow metering technologies, accurate and cost-effective measurement of wet gas flow remains a long-standing multiphase flow measurement challenge for the upstream oil and gas industry. The paper is targeted at Type I and Type II wet gas mixtures [1] and, broadly speaking, applies primarily to gas continuous mixture with a relatively small amount of liquid by volume (~< 10%). It should be noted that there are many parameters defined in the wet gas literature to quantify the liquid loading or wetness of a wet gas mixture. In this paper, the liquid to gas mass ratio is the predominate parameter used to quantify wetness. For a more in depth discussion of wet gas terminology, the reader is referred to a recent discussion paper on the subject [2].

Sonar-based flow measurement leverages sonar array processing technology to determine the speed at which coherent flow patterns convect past an array of strain-based sensors attached to the pipe. These naturally-generated, coherent flow patterns exist in virtually all types of industrial fluid flows, allowing sonar-based flow measurement to be broadly applicable to a wide range of single and multiphase flows. The sonar-based flow measurement technique was developed in 1998 for use in the upstream oil and gas industry and was the flow measurement principle used in the world's first downhole, fiber-optic flow meter on the Mars platform in 2000 [3]. Since then, sonar-based flow measurement has evolved to include clamp-on versions and has been applied to a wide range of single and multiphase flow applications [4].

Sonar-based flow measurement is well-suited to measure volumetric flow rate of wet gas mixtures. For well-mixed wet gas mixtures, Sonar-based flow meters have been shown to accurately measure the mixture flow rate, relatively independent of the liquid loading.

The relative insensitivity of sonar-based flow meters to liquid loading can be contrasted to the response of flow meters based on correlating the differential pressure (DP) created by flow through a cross-sectional area restriction, such as venturis, orifice plates and cone devices. An approach, termed DP plus SONAR is described in [5] in which and approach is developed which measures wet gas flows by leveraging this dissimilar response of sonar-based and differential pressure-based to liquid loading.

The approach developed in this paper is similar to the one described by [5], however, the differential pressure measurement is measured across an existing section of fixed geometry piping rather than a discrete flow restriction. Conceptually, the pressure losses through either a discrete flow constriction or a distributed section of piping will scale with the liquid loading of the wet gas mixture. Due to the complex nature of multiphase flows in piping networks, interpreting changes in pressure drop across a distributed section of piping in terms of liquid loading has the potential to be significantly more complicated than correlating increases in pressure loss with liquid loading through a discrete device. Thus, this paper presents two methodologies to perform this interpretation. The first employs a relatively simplistic empirical correlation between pressure drop and liquid loading, and the second employs an iterative process employing a mechanistic multiphase flow model.

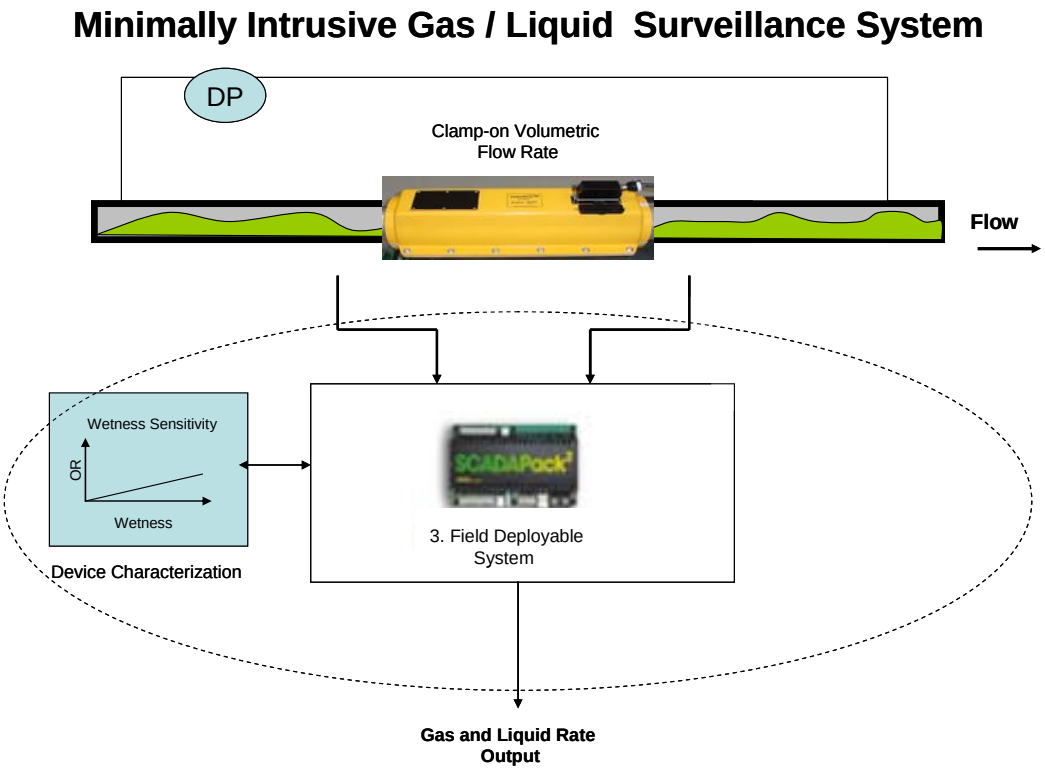

Figure 1: Schematic of DPDX plus SONAR approach for Wet Gas Measurement

2.1 Scope

The scope of this paper is limited to evaluating the practicality of measuring gas and liquid rates of wet gas flows by interpreting the measured flow rate from a sonar-based flow meter and a measure of the two-phase pressure gradient with a section of fixed geometry piping. It is

stipulated that the quantitative accuracy of this approach will, in general, be a function the specific application and the details of the empirical flow correlations and/or multiphase flow models used in defining the wetness sensitivity of both the pressure gradient measurement and the sonar-based flow measurement. It is beyond the scope of this paper to provide a critical evaluation of the various multiphase flow models that could be employed in this approach. Rather, the objective of this paper is to illustrate, using two approaches on two different data sets, the extent to which the output of such models can provide a means for measuring the gas and liquid rates of wet gas flow.

3.0 THEORETICAL DEVEOPLEMENT

The proposed approach, termed DPDX plus SONAR, determines the gas and liquid rate by measuring the mixture flow rate and the pressure drop across a given section of piping. The approach is shown schematically in Figure 1. The accuracy with which the measured quantities can be interpreted to determine gas and liquid flow rate will be a function of many multiphase flow parameters including the sophistication of the empirical correlations and / or multiphase models used in the interpretation.

3.1 Homogeneous Flow Model

Recognizing that a homogeneous multiphase flow model will likely be overly simplistic to provide the accuracy requirement for a majority of applications, it is present here since it does provide a useful first principles illustration of the DPDX plus SONAR concept for wet gas measurement.

One of the key aspects of the DPDX plus SONAR approach is that for well mixed flows sonar-based flow meters provide a flow rate that closely tracks the volumetrically averaged flow velocity of the wet gas mixture. Thus, the flow velocity reported by the sonar-based flow meter (VSONAR) can be related to the superficial gas velocity, the gas and liquid densities, and the liquid-to-gas mass ratio (LGMR) as follows.

$$V_{SONAR} = V_{mix} = V_{S_{liq}} + V_{S_{gas}} = V_{S_{gas}}(1+\frac{V_{S_{liq}}}{V_{S_{gas}}}) = V_{S_{gas}}(1+\frac{\rho_{gas}}{\rho_{liq}}\frac{\rho_{liq}V_{S_{liq}}}{\rho_{gas}V_{S_{gas}}}) = V_{S_{gas}}(1+\frac{\rho_{gas}}{\rho_{liq}}LGMR) \quad (1)$$

Where V_{mix} is the volumetrically averaged mixture flow velocity, Vs_{liq} and Vs_{gas} are the superficial velocities of liquid and gas phases and ρ_{gas} and ρ_{liq} are the gas and liquid densities. The superficial velocity of the phase of fluid (gas or liquid) is the volumetrically averaged flow that would exist if only that phase were present. The volumetric flow (Q) a given phase of fluid is given by the superficial velocity times the cross sectional area of the pipe.

Treating the well mixed flow as single phase flow, the pressure loss, ΔP, across a section of pipe of length(L) gradient can be related to the flow rate using the Darcy-Weisbach equation [6].

$$\Delta P = \left(\frac{dP}{dx}\right)L = f * \left(\frac{L}{D}\right) * \left(\frac{1}{2}\rho_{mix}V_{mix}^2\right) \quad (2)$$

Where f is the friction factor and D is the diameter.

For well mixed flows, we can define the following relationships:

$$\rho_{mix} = \rho_{gas} * GVF + \rho_{liq}(1-GVF) \quad (3)$$

$$V_{mix} = V_{S_{liq}} + V_{S_{gas}} \quad (4)$$

$$LGMR = \frac{\rho_{liq}V_{S_{liq}}}{\rho_{gas}V_{S_{gas}}} = \frac{\rho_{liq}}{\rho_{gas}}(\frac{1-GVF}{GVF}) = sqrt(\frac{\rho_{liq}}{\rho_{gas}})X \quad (5)$$

Where GVF is the gas volume fraction, Vs is the superficial velocity, and LGMR is the liquid to gas ratio, and X is the Lockhardt-Martinelli Number [2].

Using these relationships, the pressure drop across a section of pipe of length L can be expressed as follows

$$\Delta P_{1,2} = f\left(\frac{L}{D}\right)\left(\frac{1}{2}\rho_{gas}V_{gas}^2\right)\left(1+\left(1+\frac{\rho_{gas}}{\rho_{liq}}\right)LGMR+\frac{\rho_{gas}}{\rho_{liq}}LGMR^2\right) \qquad (6)$$

Generalizing for a fixed geometry piping without any elevation change and normalizing the pressure drop by the superficial dynamic head of the gas flow ($q_{gas}=\rho_{gas}V^2_{gas}/2$), the pressure drop can be expressed as follows:

$$\Delta\tilde{P} = \frac{\Delta P}{q_{gas}} = f\left(\frac{L}{D}\right)\left(1+\left(1+\frac{\rho_{gas}}{\rho_{liq}}\right)LGMR+\frac{\rho_{gas}}{\rho_{liq}}LGMR^2\right) \qquad (7)$$

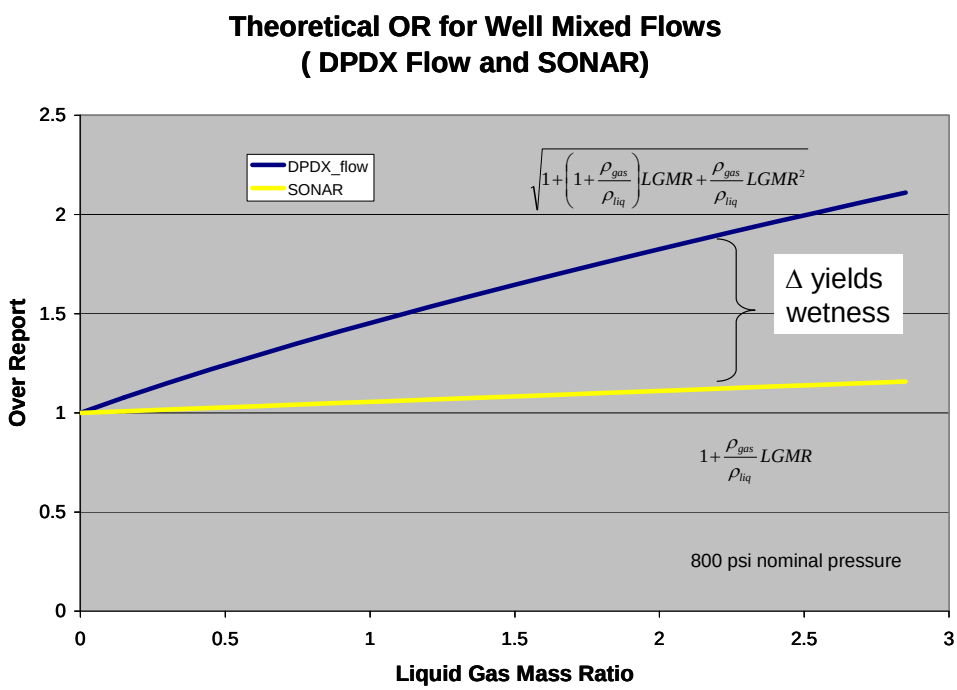

Figure 2: Theoretical Flow Rate Over Report as Function of Liquid to Gas Mass Ratio for Flow line differential pressure and sonar-based Flow meters in well mixed flows

The equation derived above for well mixed flow illustrates the impact that wetness, expressed as liquid to gas mass ratio, has on the normalized pressure drop between two locations. In this simplified model, a wet gas flow gas and liquid properties and fixed flow line geometry, the normalized pressure loss across a given section of piping provides a means to measure the liquid loading. Defining the over-report (OR)of a measuring device as the ratio of the flow rate reported in wet gas to the flow rate that would be reported with only the gas phase present, the wetness sensitivity of the two dissimilar measurements to the flow rate can be expressed as follows:

$$OR_{DPDX} = \sqrt{1 + \left(1 + \frac{\rho_{gas}}{\rho_{liq}}\right) LGMR + \frac{\rho_{gas}}{\rho_{liq}} LGMR^2} \qquad (8)$$

$$OR_{SONAR} = 1 + \frac{\rho_{gas}}{\rho_{liq}} LGMR \qquad (9)$$

The DPDX plus SONAR method for wet gas measurement is shown schematically in Figure 2 for a gas to liquid density ratio of 0.055. As depicted in Figure 2, DPDX plus SONAR is conceptually similar to DP plus SONAR described in [5].

4.0 FLOW LOOP TESTING

A flow loop test was conducted in February 2007 at the Colorado Engineering Experimental Station, Inc (Ceesi) designed to 1) evaluate the relationship between pressure loss and flow rate for wet gas mixtures in a straight, horizontal section of pipe and to 2) assess the practicality of using this approach for gas and liquid rate measurement. The differential pressure over an 86 foot and 8 inch (26.4 meters) section of 4 inch, schedule 80, pipe (273.5 L/D) was measured over a range of wet gas flow conditions as shown in Figure 3. The tests were conducted using natural gas (mostly methane) and Stoddard fluid (mostly decane) for the gas and liquid phases, respectively.

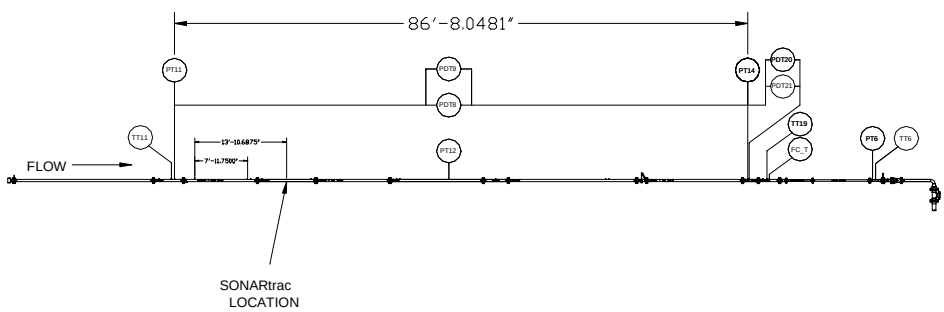

Figure 3: Piping Layout for Flow line Differential pressure and SONAR-based flow measurement test

4.1 RESULTS

The test results are summarized in Table 1. The tests were conducted predominately over a range of wetnesses from 0.0 to 2.0 LGMR, mixture velocities of 20 to 80 ft/sec and pressures of 300 psia and 800 psia.

Table 1: Results for DPDX plus SONAR Flow Loop testing

Test ID Number:	Pressure psia	Gas Superficial Velocity ft/sec	Liquid Superficial Velocity ft/sec	Gas density (kg/m^3)	Liquid Density (kg/m^3)	Froude Number (gas)	Lockhart-Martinelli Parameter	LGMR	SONAR trac Velocity (ft/sec)	SONAR OR	DP (psi)	DP/q	DP /q OR
18	299	51.73	0.00	14.7			0.00	0.00	51.91	1.00	1.032	3.902	1.000
11	308	50.52	1.66	15.1	756.3	2.26	0.23	1.64	53.48	1.04	3.505	13.532	3.468
12	306	51.18	1.26	14.9	755.7	2.27	0.18	1.24	53.34	1.03	3.104	11.784	3.020
13	303	51.56	0.80	14.8	755.6	2.28	0.11	0.79	53.15	1.02	2.516	9.492	2.432
14	300	50.88	0.39	14.7	755.3	2.24	0.06	0.40	42.55	0.83	1.941	7.581	1.943
15	299	51.60	0.25	14.6	755.3	2.27	0.03	0.25	53.37	1.03	1.809	6.896	1.767
16	298	50.94	0.16	14.6	755.3	2.24	0.02	0.17	49.20	0.96	1.692	6.631	1.699
17	297	50.97	0.08	14.5	756.1	2.24	0.01	0.08	52.22	1.02	1.629	6.391	1.638
17.5	296	51.12	0.04	14.5	756.6	2.24	0.01	0.04	52.22	1.02	1.544	6.043	1.549
18.5	300	23.43	0.00	14.9			0.00	0.00	23.50	1.00	0.212	3.867	1.000
19	304	23.64	1.67	15.2	760.7	1.06	0.50	3.59	30.33	1.28	1.531	26.774	6.924
20	300	23.36	1.22	15.0	760.1	1.04	0.37	2.68	26.55	1.13	0.913	16.524	4.273
21	299	23.48	0.80	14.9	759.9	1.04	0.24	1.76	10.04	0.43	0.664	11.983	3.099
22	297	22.94	0.42	14.8	760.1	1.01	0.13	0.96	22.84	0.99	0.444	8.465	2.189
23	296	22.98	0.25	14.7	760.6	1.01	0.08	0.56	22.40	0.97	0.377	7.202	1.863
24	295	23.11	0.16	14.6	761.2	1.01	0.05	0.37	22.20	0.96	0.344	6.525	1.687
25	294	23.17	0.08	14.6	761.7	1.01	0.03	0.19	22.40	0.97	0.310	5.886	1.522
26	293	23.32	0.04	14.5	762.6	1.02	0.01	0.10	22.60	0.97	0.288	5.410	1.399
27	291	23.28	0.00	14.4			0.00	0.00	23.00	0.99	0.204	3.875	1.002
40	808	77.90	0.00	41.6			0.00	0.00	78.95	1.00	6.647	3.907	1.000
48	823	78.29	1.69	42.1	739.7	6.03	0.09	0.38	80.17	1.01	8.481	4.874	1.248
47	821	78.18	1.24	42.0	738.0	6.02	0.07	0.28	80.31	1.02	8.308	4.801	1.229
46	820	78.78	0.82	41.9	737.8	6.06	0.04	0.18	80.40	1.01	8.166	4.658	1.192
45	818	78.39	0.61	41.8	737.9	6.02	0.03	0.14	79.88	1.01	8.034	4.635	1.186
44	816	78.76	0.40	41.8	738.5	6.04	0.02	0.09	80.24	1.01	8.045	4.607	1.179
43	816	78.92	0.32	41.7	738.6	6.05	0.02	0.07	80.38	1.01	8.048	4.593	1.176
42	815	78.30	0.25	41.7	738.8	6.00	0.01	0.06	79.65	1.01	7.901	4.585	1.174
41	813	78.39	0.17	41.6	739.2	6.00	0.01	0.04	79.63	1.00	7.844	4.548	1.164
48.5	808	77.97	0.00	41.5			0.00	0.00	79.04	1.00	6.812	4.005	1.025
49	811	40.79	0.00	42.2			0.00	0.00	40.94	1.00	1.873	3.957	1.000
57	817	40.16	1.73	42.7	738.4	3.11	0.18	0.75	40.31	1.00	3.725	8.031	2.029
56	817	40.52	1.42	42.6	737.4	3.14	0.15	0.61	40.65	1.00	3.499	7.430	1.878
55	816	40.72	1.24	42.6	737.2	3.16	0.13	0.53	41.18	1.01	3.405	7.157	1.809
54	814	41.11	0.82	42.5	737.1	3.18	0.08	0.35	42.47	1.03	3.092	6.394	1.616
53	811	40.21	0.43	42.4	737.6	3.11	0.04	0.19	41.09	1.02	2.626	5.686	1.437
52	809	40.39	0.25	42.3	738.3	3.12	0.03	0.11	41.01	1.01	2.500	5.374	1.358
51	808	40.41	0.17	42.3	738.8	3.12	0.02	0.07	41.15	1.01	2.471	5.314	1.343
50	808	40.56	0.08	42.2	739.5	3.13	0.01	0.04	41.11	1.01	2.381	5.087	1.286
49.5	805	40.51	0.00	42.1			0.00	0.00	40.60	1.00	1.844	3.961	1.001
58	796	20.33	0.00	41.4			0.00	0.00	20.03	0.98	0.457	3.961	1.000
59	797	19.89	1.68	42.0	738.6	1.53	0.35	1.49	13.52	0.68	1.452	12.973	3.275
60	791	20.43	0.82	41.7	738.5	1.57	0.17	0.71	22.30	1.09	1.027	8.742	2.207
61	788	20.64	0.39	41.6	739.2	1.58	0.08	0.34	21.76	1.05	0.796	6.657	1.681
62	787	20.26	0.21	41.4	739.9	1.55	0.04	0.18	20.68	1.02	0.652	5.686	1.436
63	786	20.37	0.12	41.3	739.9	1.55	0.03	0.11	20.48	1.00	0.607	5.255	1.327
64	786	20.38	0.08	41.3	740.0	1.55	0.02	0.07	20.25	0.99	0.583	5.047	1.274
65	784	20.45	0.04	41.3	742.6	1.55	0.01	0.04	20.03	0.98	0.554	4.766	1.203
66	782	20.17	0.00	41.1			0.00	0.00	19.97	0.99	0.442	3.925	0.991

4.1.1 Pressure Loss as Function of Wetness

Figure 5 shows the pressure loss data normalized by the dry gas pressure loss as a function of wetness (LGMR) for each data set. The pressure ratio over report as predicted by the homogeneous model developed above is also shown. For the range of pressures and velocities tested the dry gas pressure drop was shown to be largely independent of flow rate and pressure and measured 3.9 dynamic heads, translating into a Darcy friction factor of 0.014. As shown in Figure 4, the pressure drop increased with liquid to gas mass ratio, increasing sharply with the introduction of the initial liquids, and then building more gradually with wetness. For liquid loadings beyond the onset of wetness (LGMR < 0.05%), the pressure drop is shown to increase in a reasonably linear manner with wetness for each Froude number. The densimetric Froude number is defined as the square root of the ratio of the superficial gas dynamic head to the

gravitation head generated associated with a column of liquid with height equal to the diameter of the pipe corrected for the buoyancy of the gas.

$$Fr \equiv \sqrt{\frac{\rho_{gas} V_{S_{gas}}^2}{(\rho_{liq} - \rho_{gas}) g D}} \qquad (10)$$

Where g is the acceleration of gravity.

As shown, the data and the simplified model demonstrate similar behavior. Given the complexity of the two phase flows over the parameter space investigated, the data does exhibit an encouraging level of parametric simplicity. Since the Froude number is the first order parameter influencing the mixedness of gas/liquid flows, it is reasonable that the Froude number would influence the wetness sensitivity of the two phase pressure gradient. The data set with the lowest wetness sensitivity corresponds to the highest Froude number.

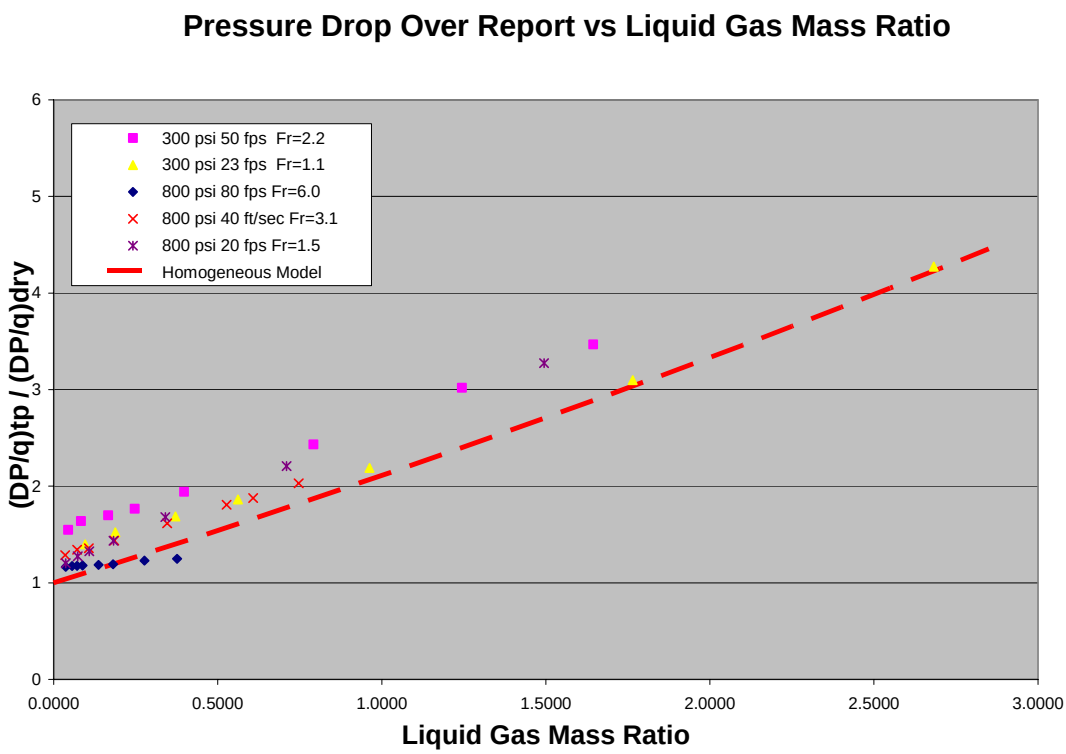

Figure 5: Over report of the Two Phase Pressure Loss over an 273.5 L/D section of pipe normalized by dry gas pressure loss as a function of wetness (LGMR) with Homogeneous Model

4.1.2 SONAR Flow Rate as Function of Wetness

For well mixed flows (i.e. wet gas flows with Fr >~2.0), the velocity reported by sonar-based flow meters have been shown to be relatively insensitive to wetness. Figure 5 shows the over-report, defined as the ratio between the reported flow velocity and the reference superficial gas velocity. The theoretical over report for well mixed flows, assuming that the SONAR meter reports the mixture velocity, is shown for reference for the two pressures. As shown, the data and theory are in relative good agreement for the higher Froude numbers. Specifically, the all the data points associated with Froude No. of 6.0 and 3.1 are within 5% of the well mixed model.

At lower Froude numbers, Fr<~2, gas / liquid flows tend to stratify and the interpretation of SONAR flow measurement is less well defined. Four data points for Froude numbers of 2.2 and lower exhibited anomalous behaviors associated with stratification and are shown as circled data points. These anomalies can often be "corrected" with advanced post-processing interpretation of SONAR meter diagnostic information, however, a detailed discussion of performance of the sonar- based flow meter for non-well-mixed flows is beyond the scope of this work.

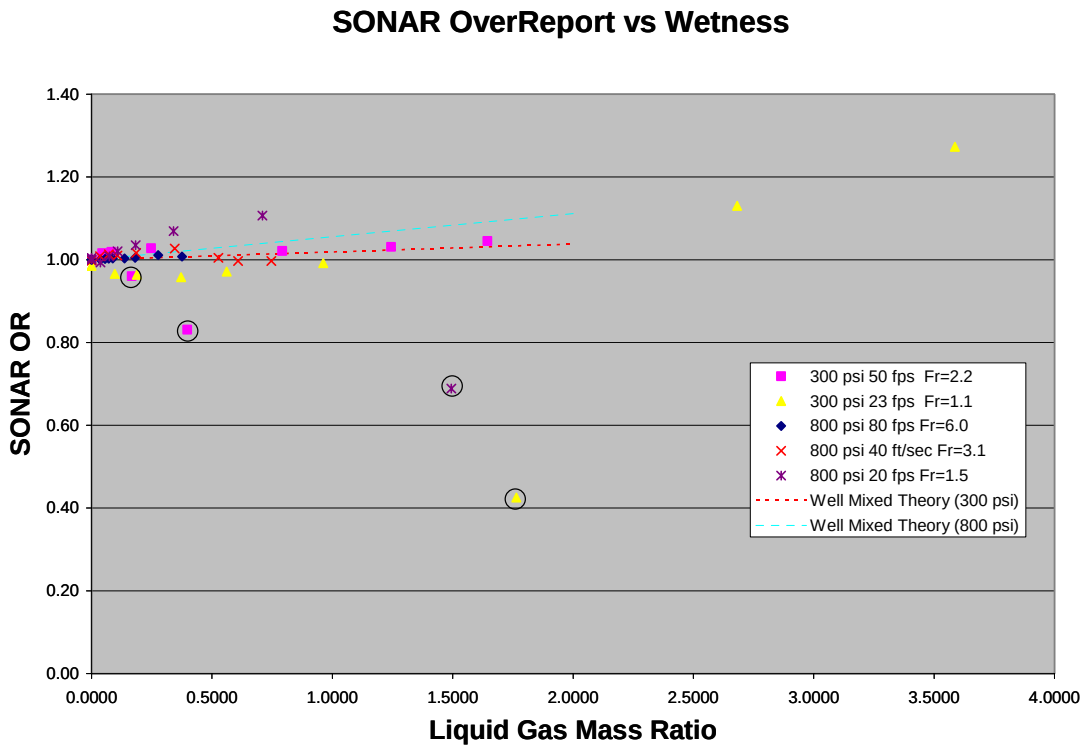

Figure 5: Over report of SONAR flow meter normalized by dry gas reading as a function of wetness (LGMR) with prediction from homogeneous flow model at two pressures

5.0 IMPLEMENTATION OF FLOW MEASURMENT METHODOLOGY

A goal of this work was to develop methods to measure the gas and liquid flow rates leveraging the dissimilar response of the SONAR meters and the axial pressure gradient to changes in liquid loading. In this paper we present two approaches to interpret the combined output of a sonar-based flow meter and the measured of the axial pressure gradient: 1) the first uses an empirical characterization of each device to measure wetness and, 2) the second uses an optimization algorithm in conjunction with a mechanistic multiphase flow model to provide a measure of the gas and liquid flow rates.

5.1 Empirical DPDX plus SONAR Methodology

As shown schematically in Figure 6, the wetness sensitivity of the differential pressure across the test section was fairly linear with increasing liquid to gas mass ratio, except for the initial onset of

wetness for LGMR < ~0.05. The wetness sensitivity of the pressure drop was parameterized assuming that the pressure loss increases linearly with liquid to gas mass ratio.

$$\frac{\Delta P}{\frac{1}{2}\rho_{gas} V_{S_{gas}}^2} = K^*_{DRY} + \beta * LGMR \qquad (11)$$

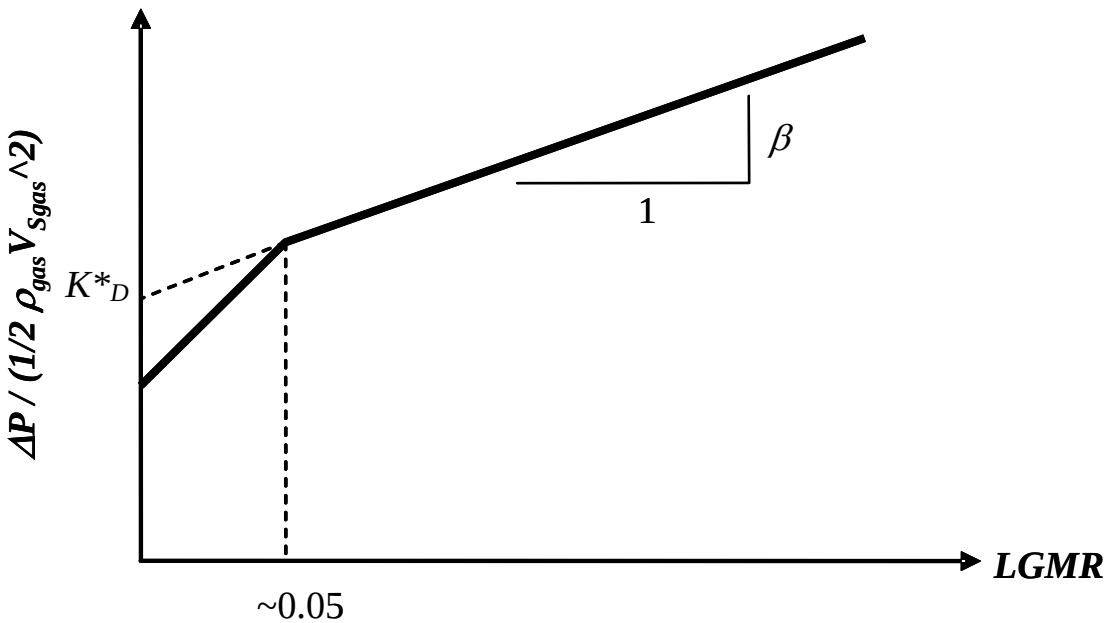

Figure 6: Schematic of the parametric model of the pressure loss as a function of wetness (LGMR) illustrating effective (psuedo) Dry Gas pressure drop

In this model, the wetness sensitivity is defined by a slope and offset, with the offset defining a pseudo dry gas pressure loss coefficient. These wetness sensitivity parameters were determined using a linear curve fit of the pressure loss data as a function of wetness for each data set of constant pressure and velocity (Froude number), excluding the dry gas pressure point. The wetness sensitivity parameters for the straight pipe test section determined in this manner are tabulated in Table 2.

Table 2 Wetness Sensitivity Parameters for 86 ft Section of 4 inch, Schedule 80 pipe

Pressure (psi)	Velocity (ft/sec)	Froude Number	Density Ratio	Kdry*	Beta
300	51	2.1	0.02	5.83	4.7
300	23	1.1	0.02	4.86	4.27
800	79	6	0.056	4.4	0.949
800	40	3.1	0.056	4.96	4.11
800	20	1.5	0.056	4.66	5.61

The wetness sensitivity of the sonar-based flow meter is parametrically assumed to increase with alpha times the liquid to gas mass ratio. For the well mixed model, alpha is equal to the ratio of gas and liquid densities as shown below.

$$\frac{V_{SONAR}}{V_{S_{gas}}} = 1 + \alpha LGMR = 1 + \frac{\rho_{gas}}{\rho_{liq}} LGMR \qquad (12)$$

The expressions for theoretical over-report for the SONAR meter and the empirical over-report of the pressure gradient can be solved to determine the LGMR consistent with a measured pressure loss and SONAR velocity and a given set of wetness sensitivity parameters (Kdry, and Beta, and Alpha). Identifying the LGMR enables the determination of the gas and liquid rates from the SONAR flow measurement.

$$V_{S_{gas}} = \frac{V_{SONAR}}{1 + \left(\frac{\rho_G}{\rho_L}\right) LGMR} \qquad (13)$$

$$Vs_{lig} = V_{S_{gas}} \left(\frac{\rho_G}{\rho_L}\right) LGMR \qquad (14)$$

The gas and liquid volumetric flow rates are then determined by multiplying the superficial flow velocities times the cross section area of the pipe. The interpreted gas and liquid flow rates are shown versus reference in Figures 7 and 8.

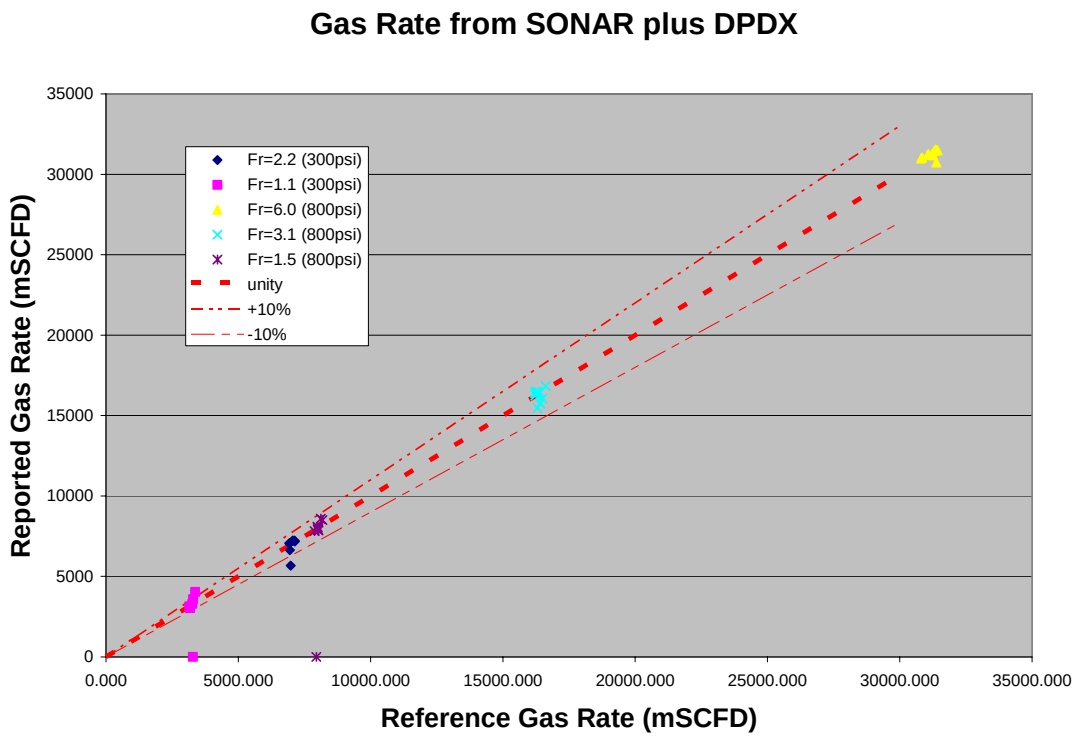

Figure 7: Gas Rate reported by DPDX plus SONAR System versus reference

As shown, the DPDX plus SONAR approach reported the majority of the gas flow rates within 5% of reference and the Majority of the Liquid Flow rates to within +/- 20% of reference.

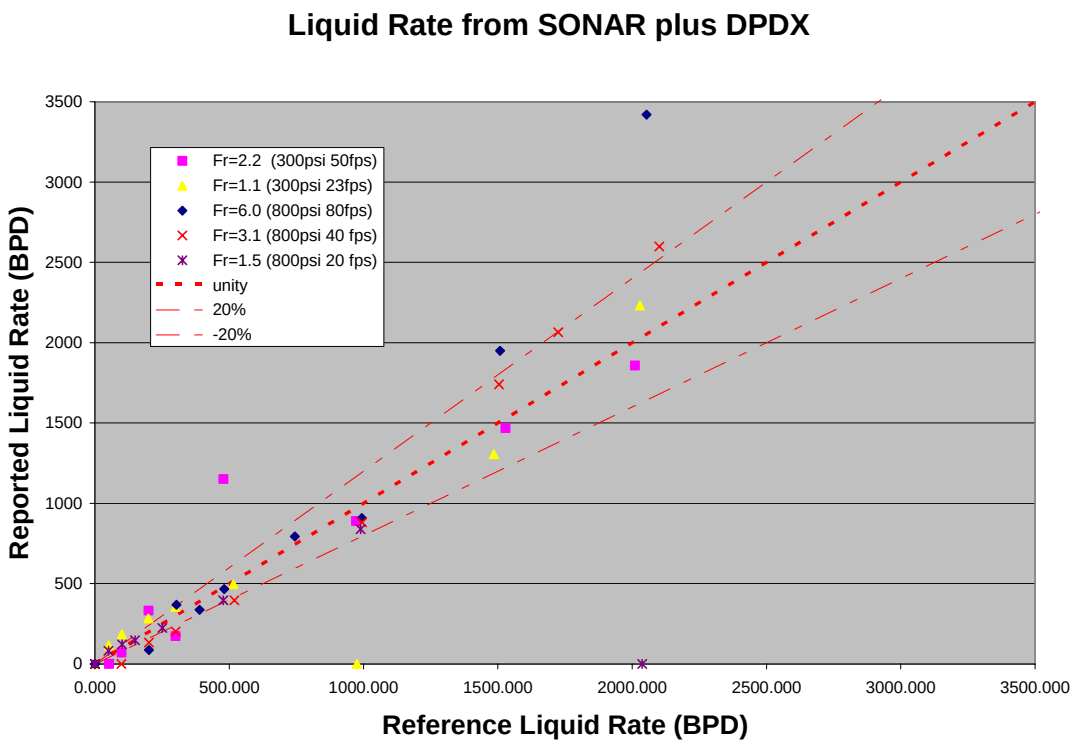

Figure 8: Liquid Rate reported by DPDX plus SONAR System versus Reference

5.2 Mechanistic DPDX plus SONAR

The empirical method described will in general require in-field calibration and will be applicable over a limited range of flow parameters. An alternative approach is to interpret the pressure loss across a section of pipe and the SONAR flow measurement using and optimization procedure and a mechanistic multiphase flow model. Most flow model operating in this forward fashion in which the input gas and liquid rates are specified and the model then computes the various flow parameters such as liquid hold-up, pressure drop and flow regime information. In this work, a mechanistic two fluid flow model described in [7] was used to compute two phase flow characteristics such as the liquid holdup and the pressure gradient associated with a specified input liquid and gas flow rates. For DPDX plus SONAR approach, the problem is inverted in that the flow rate and pressure gradient are measured and the input gas and liquid flow rates need to be determined. To accomplish this inversion, an optimization procedure was developed in which the input liquid and gas rates are determined by minimizing the error between measured and calculated flow parameters. A flow chart of the optimization procedure is shown in Figure 10.

In the mechanistic DPDX plus SONAR approach, the SONAR meter was assume to measure the actual gas velocity, whereas, in the empirical version, the SONAR meter was assumed to measure the mixture velocity of a well mixed flow. The importance of the distinction scales with the degree of stratification, a parameter that the empirical interpretation does not consider.

Flow Model Assisted Interpretation of DPX and SONAR

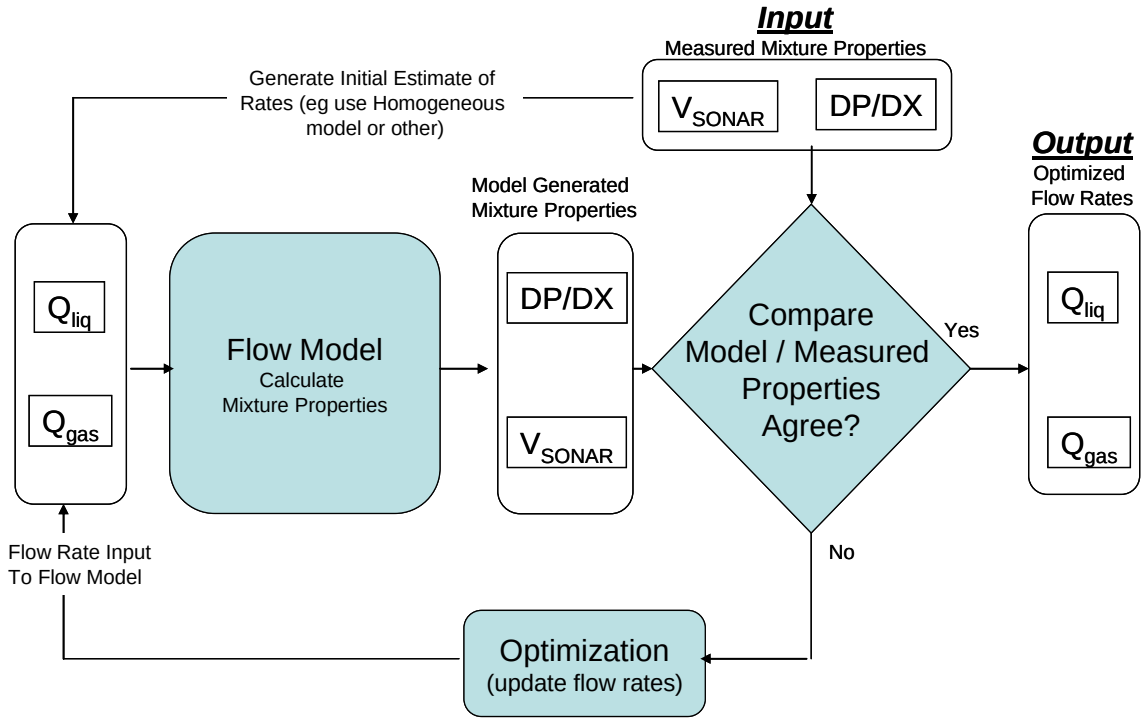

Figure 9: Flow Chart of the Multiphase Flow Model Assisted Interpretation Procedure

To assess the effectiveness of determining gas and liquid flow rates using the approach, the model was exercised to evaluate the characteristics of the optimization process used to determine the gas and liquid rates.

The optimization procedure is based on minimization of an error term that represents the difference between the calculated pressure gradient and gas velocity for a given gas and liquid flow rate and the measured values. This error function, termed chi-squared, is defined below. As defined, the chi-squared function is minimized at 0 when the measured flow rate and pressure gradient are equal to the calculated flow and pressure gradient, respectively.

$$\chi^2(Vs_{liq}, Vs_{gas}) = \left(\frac{V_{SONAR} - Vg_c}{V_{SONAR} + Vg_c}\right)^2 + \left(\frac{(dp/dx)_m - (dp/dx)_c}{(dp/dx)_m + (dp/dx)_c}\right)^2 \qquad (15)$$

Where m and c indicate measured and calculated values respectively.

Figure 10 shows contour plots of the chi-square error function for two representative cases, one with high liquid loading and another with low liquid loading. The right hand panel (TagID 03-2), is a 2-inch schedule 80 pipe at high Froude Number (Fr=8.3) and relatively high liquid loading. The actual gas rate is 260 m3/h (Vs_{gas} = 39.0 m/s) and liquid rate is 8 m3/h (Vs_{lig} = 1.20 m/s) corresponding to a liquid gas mass ratio of 1.5 and a Lockhardt-Martinelli No of 0.21. The left hand panel (TagID 02-2) is also in a 2-inch schedule 80 pipe with a slightly lower Froude Number (Fr=6.3) and a significantly lower liquid loading. The actual gas rate is 205 m3/h (Vs_{gas}= 30.9 m/s) and liquid rate is 0.5 m3/h (Vs_{liq}= 0.08 m/s) corresponding to a liquid gas mass ratio of 0.13 and a Lockhardt-Martinelli No of 0.02. As shown, the chi-squared function exhibits a well defined

minimum located at the bottom of a long extended valley that turns toward the Vs_{lig} axis as higher superficial liquid velocities. The overlaid reference, measurement and endpoint do not coincide with the minimum since the simulated pressure gradients do not exactly coincide with the measured gradients. The objective of this section is more to provide qualitative insight into the behavior of the chi-squared function of equation (15) rather than provide a quantitative comparison between the flow model and the flow loop data.

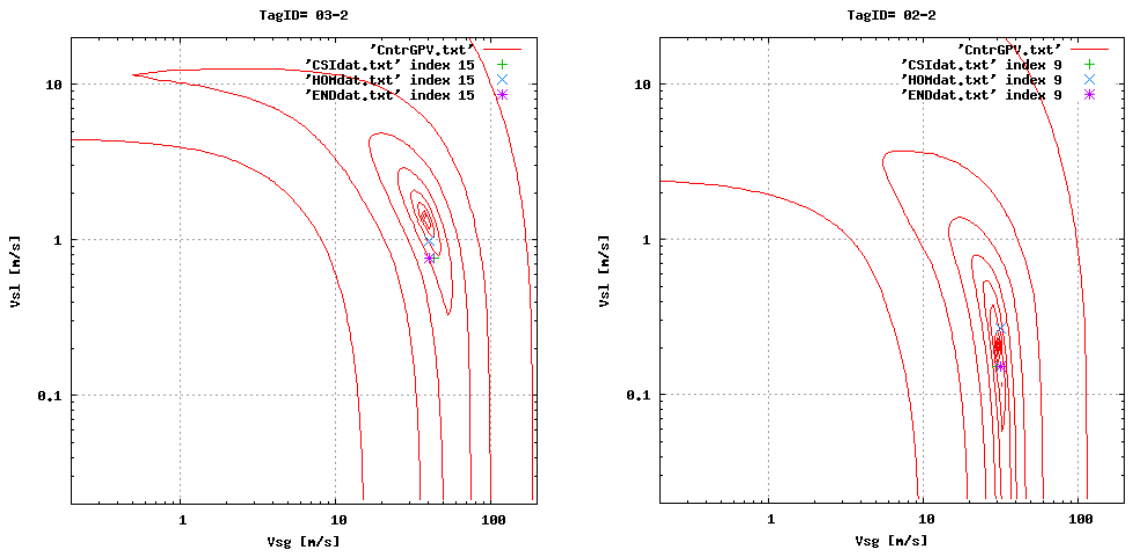

Figure 10: Contour plot for SONAR/DPDX type measurement.

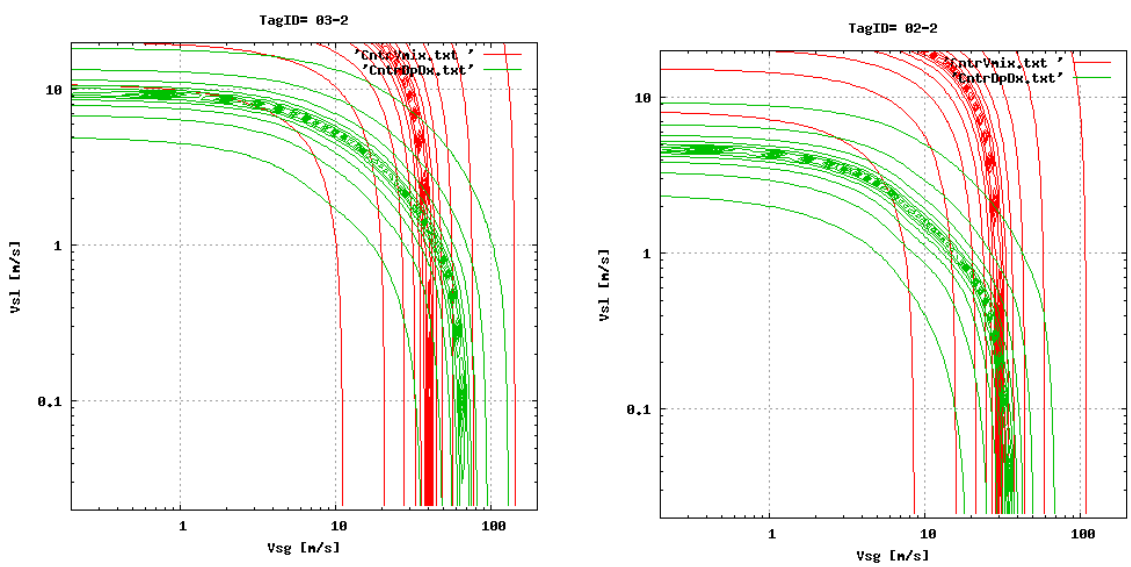

Figure 11: Component of chi square error function Separate contours for sonar (red) and dpdx (green)

The behavior of the chi-squared function of equation (15) can further be examined by considering the topology of its two error terms separately as shown in Figure 11. The right half applies to the relatively high liquid loading case and the left half applies to the lower liquid loading case. The red contours are associated to the velocity term; the green contours are associated with the pressure gradient term. As shown, the red and green contours are close to being parallel over a large part of the area of interest. This causes the long valley in the chi-squared function. The error term associated with measured velocity is relatively insensitivity to liquid loading for liquid volume fraction below roughly 10%. The error term associated with the pressure gradient is significantly

more influence by the liquid loading, with the intersection of the green and red minima combining to determine the gas and liquid rates.

Around a Vs_{lig} equal to 1 m/s the two sets of contours finally intersect which produces the sought for minimum It is to be expected that for conditions at lower values of Vs_{lig}, the point of intersection for the two contour sets will be less well defined. At lower values of Vs_{lig}, the red and green contours will be less "offset" from each other at the Vs_{gas} axis leading to a much more drawn out minimum. The right hand panels in Figure 11 demonstrate this for the case of test point with a Vs_{lig} = 0.08 m/s.

5.2.1 Interpretation of Flow Loop Data using Mechanistic DPDX plus SONAR

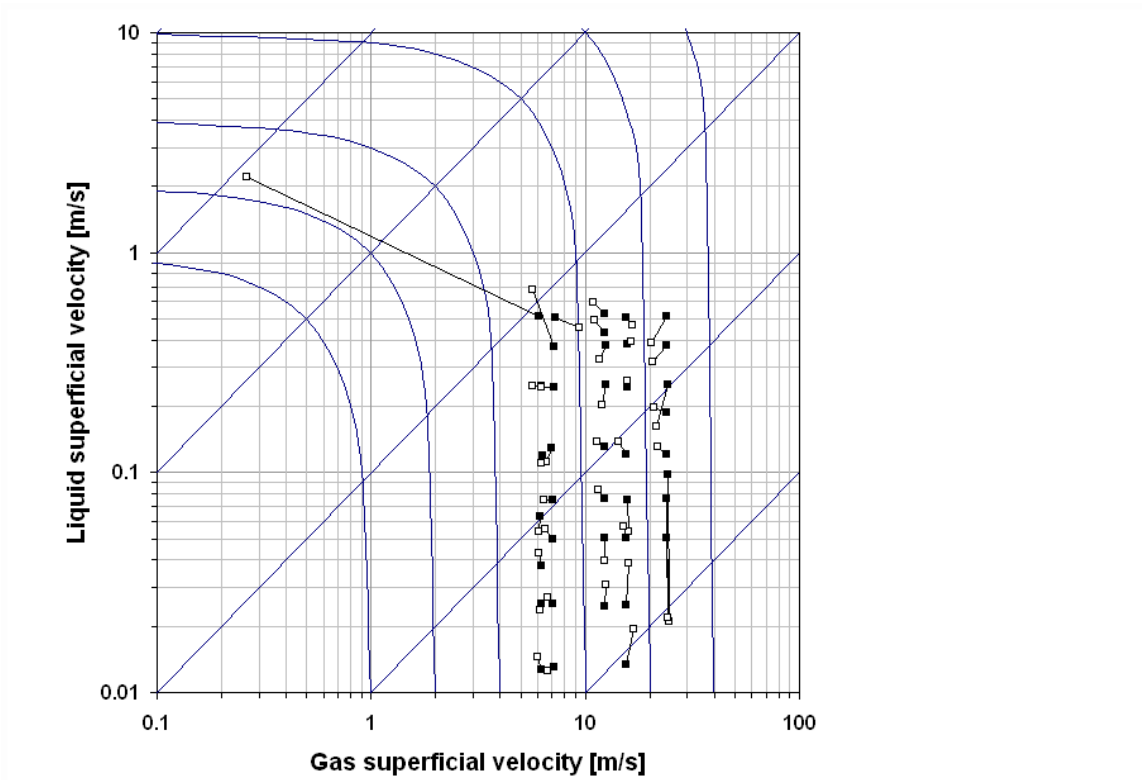

Figure 12: Two Phase flow map showing Reference data (closed symbols) and Measured Data (Open Symbols) Using the Mechanistic Flow Model Interpretation of the DPDX plus SONAR Flow Loop Data

The result of the flow model assisted interpretation of the SONAR plus DPDX data recorded in the flow loop test described above are shown in Figure 12. In calculating the results, the mechanistic flow model was run with the following assumptions.

- Entrainment factor [8] for the calculations was assumed to be zero. Calculations show that the entrainment is very low in virtually all conditions. This is consistent with the relatively low velocities in 4".
- Roughness, surface tension and gas/liquid viscosity set to give best match on pressure drop for the first 6 dry gas points.
- Flow patterns calculated. In total 3 of the two phase points are stratified. At such low superficial liquid/gas velocities, the stratified/annular transition is extremely sensitive to the pipe inclination. An exact value of 0° (horizontal) was used.

In the above flow map, the straight lines represent constant input phase fraction and the curved reference lines represent constant input mixture flow velocity. Each flow loop set point is plotted with a solid symbol, the open symbols of the interpreted results. The line connecting the reference point to the interpreted value is a measure of the error in the measurement, with each grid line representing a 10% relative error. As shown, the flow loop interpreted SONAR plus DPDX data is in reasonable agreement with the reference data. The largest errors in gas rate occur at the highest liquid loadings and the lowest superficial gas velocities. Relatively large errors in liquid rate are also exhibited at the high gas rate, low liquid loading. Errors in the region can likely be attributed in part to the zero entrainment assumption in the multiphase flow model.

6.0 Well Test Data

The empirical DPDX plus SONAR approach was evaluated through field testing on a wet gas well in November 2006. A 4-inch SONARtrac VF-100 meter manufactured by CiDRA Corporation was installed between the well-head and the test separator. The pressure drop used for the DPDX plus SONAR calculations was measured using a pressure gauge installed at the same location as the SONAR meter near the well head and a pressure gauge located near a well test separator, approximately 2000 ft away. The majority of the flow line between the two locations was 6-inch, horizontal flow lines, with short section of vertical pipe and the associated elbows.

In processing the data, it was assumed that the watercut was relatively constant so the liquid density was fixed. The gas density will vary with pressure, temperature and composition and therefore must be calculated for each point. To simplify the gas density calculation it was assumed that the gas composition was constant and that small changes in barometric pressure are insignificant so gas density changes only with line pressure and temperature.

Several well tests were conducted so that the DPDX plus SONAR results could be compared to the test separator reference. The operating condition of the well under test was changed by choking back the well. The change in flow rate caused a change in the produced gas to liquid ratio, with the liquid to gas mass ratio decreasing with decreasing flow rate.

Table 2: Well Test Data Using Empirical DPDX plus SONAR

Well Test Results	Test1	Test 2	Test 3	Test 4	Test 5
Well Test Ref Gas Rate (mmscfd)	31.2	19.9	27.5	39.3	36.3
Well Test Liquid Rate, calculated (bpd)	685	350	620	1015	873
Well Test LGMR	0.11	0.09	0.11	0.13	0.12
Densimetric Froude (4 in)	6.4	4.3	5.8	8.0	6.6
Average DP / Dynamic Pressure	33.8	32.4	34.0	35.1	34.0
Average Gas Density (kg/m3)	54.0	52.0	53.1	56.4	67.9
SONAR Gas Rate (mmscfd)	31.0	20.3	27.8	39.1	35.4
Deviation	-0.6%	2.4%	1.2%	-0.6%	-2.5%
SONAR Plus DP Liquid Rate (bpd)	684	360	631	1030	822
Deviation	-0.1%	3.1%	1.9%	1.5%	-5.8%

The constants K_D* and beta are defined as the offset and slope of the pressure drop versus LGMR relationship for LGMR greater then 0.05 (see Figure 6). Both of these constants were calculated from the data to provide a best-fit between the DPDX plus SONAR and the test separator results, resulting in 26.99 and 62.34, respectively. Note that effective Dry gas pressure loss through the pipe network in the field data of ~27 gas dynamic heads is approximately 7 times the dry gas dynamic pressure loss measured in the flow loop data, consistent with the longer and more complicated flow path associated with the well test pressure loss. It should also be noted that due to constraints in the amount of field data available, the pressure gradient as a function of LGMR was assumed to behave linearly with liquid to gas mass ratio even though the Froude number for each test point varied.

The results of the well testing are summarized in Table 2 below. Note that the gas rates are better than ±3% and the liquid rates better than ±6%.

The well E-06 testing demonstrated that the DPDX plus SONAR approach could accurately measure both the gas and liquid flow rates (and therefore gas-liquid ratio, GLR) for liquid-to-gas mass ratios greater than approximately 0.05.

The Froude Number indicated in Table 3 is the densimetric Froude Number in the 4 inch Schedule 80 line and is the relevant number for assessing the wetness sensitivity of the SONAR-based flow meter. However, since the majority of the flow line length was 6 inch, schedule 80, the relevant Froude number for characterizing the pressure gradient should based on the Froude Number in the 6-inch flow lines, which is approximately one half of the Froude number in the 4 inch lines.

The flow conditions in the well were varied by changing the choke position, resulting in the produced liquid to gas mass ratio varying with flow rate. As such the data represents Froude numbers in the 6 inch sections ranging from ~2 at the lowest LGMR to ~4 at the highest LGMR, reasonable consistent with the flow data discussed above.

Figure 13 shows the well test data flow over report (square root of the pseudo-dry gas normalized two phase pressure drop) plotted versus liquid to gas mass ratio. The theoretical over-report predicted by the simplified homogenous flow model for both pressure loss and the SONAR meters are also included. Data from the flow loop test at a pressure= 800 psi and Fr=3.1, normalized by the pseudo-dry gas pressure loss is also shown. As shown, the well test data and the flow loop data at similar conditions each follow the trend predicted by the simplistic model, providing a good first-principles confirmation DPDX plus SONAR measurement approach.

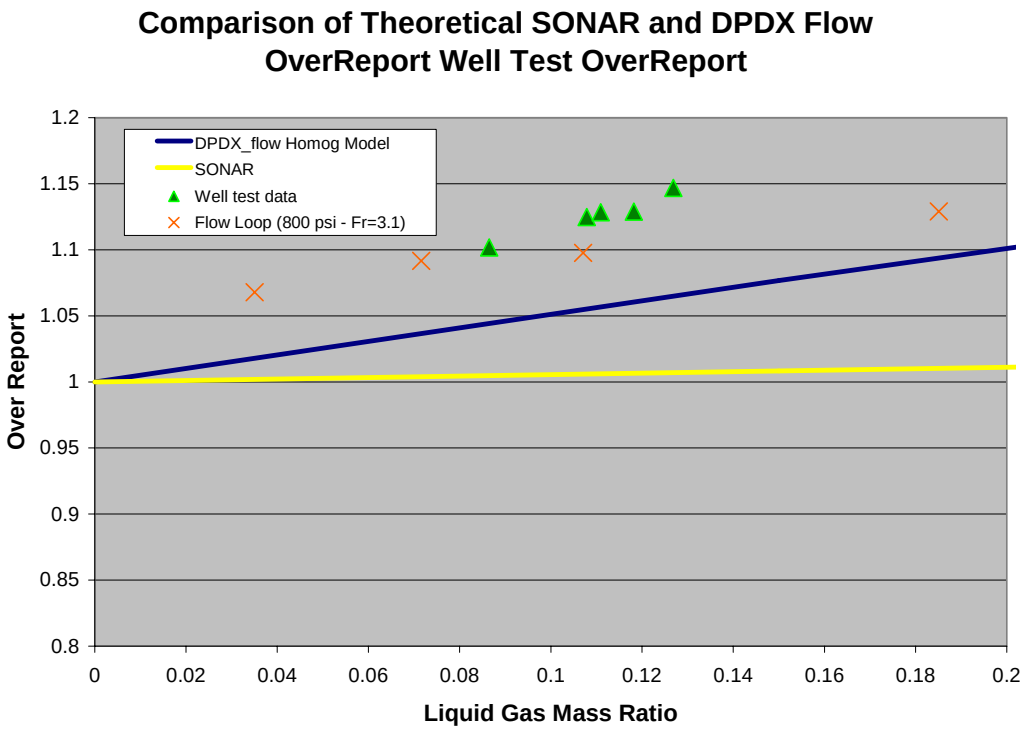

Figure 13: Flow rate Over Report as a Function of Wetness comparing the Flow Over report for the Homogenous flow model, SONAR flow meter, Flow Loop and Well test data

6.0 CONCLUSIONS

This paper demonstrates a minimally intrusive approach to measuring the gas and liquid rates of wet gas mixture using the combination of a clamp-on, sonar-based flow meter and a measurement of the pressure gradient over a given section of piping network. A key advantage of this approach is the ability to provide a gas and liquid measurement on a minimally intrusive basis.

Two approaches were demonstrated; one based on an empirical characterization of the wetness sensitivity a piping network with fixed geometry and another approach which used an optimization procedure in conjunction with a mechanistic two-phase flow model to interpret the measured pressure gradient and SONAR flow measurement in terms of gas and liquid rates of wet gases. Wet gas flow loop data was presented for the pressure loss over a straight section of pipe and the output of the SONAR meter over a range of flow conditions. The gas and liquid rates determine using both the empirical method and the Multiphase Flow model assisted interpretation were presented versus reference rate. The DPDX plus SONAR method was also applied to well test data using and empirical correlation of pressure loss versus wetness defined from test separator data. For the well test data, the piping network over which the pressure drop data was recorded was significantly longer and more complicated than the straight test section from the flow loop, yet demonstrated similar non-dimensional sensitivity to wetness.
The accuracy of either of these methods will be dependent on many application specific parameters, include the flow and fluid properties and the sophistication of the model used for interpretation. The densimetric Froude number of the wet gas flow through the sonar-based meter is an important parameter influencing measurement accuracy, with Froude Numbers greater than ~2 providing the best results.

7.0 ACKNOWLEDGEMENTS

The authors would like to acknowledge BP America and CiDRA Corporations for their support and permission to present this work, as well as the many colleagues who have contributed to this effort.

8.0 REFERENCES

[1] MEHDIZADEH, P., et al, "Wet Gas Metering: Trends in Application and Technical Developments", SPE Paper 77351, Presented at SPE Annual Technical Conference, San Antonio, September, 2002.

[2] A. HALL, D. GRIFFIN, R. STEVEN, " A Discussion on Wet Gas Flow Parameter Definitions", Presented at the 26th International North Sea Flow Meter Workshop, organized by the National Engineering Laboratory, East Kilbride, Scotland, UK, Oct 2007.

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

[4] GYSLING D.L., LOOSE, D.H., VAN DER SPEK, "Clamp-on, SONAR-based, Volumetric Flow and Gas Volume Fraction Meter Industrial Applications", presented at the 13th International Flow Measurement Conference, organized by the National Engineering Laboratory, East Kilbride, Scotland, UK, June 2005.

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

[6] J. P. BRILL AND H. MUKHERJEE, "Multiphase Flow in Wells", SPE Monograph Volume 17, 1999.

[7] R.V.A. OLIEMANS, "Multiphase science and technology for oil/gas production and transport", Lecture notes for course P2.24 on Multiphase flow in wells and pipelines, Shell Internationale Research Maatschappij B.V., 1994.

[8] S.W. CHURCHILL, "Friction factor equation spans all fluid flow regimes", Chem. Eng, **7**, November 1977, p 91.