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Wet Gas Metering Using Combination of Differential Pressure and SONAR Flow Meters

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1. ABSTRACT

A method to measure the gas rates and liquid rates of Type I and Type II wet gas flows is presented. The approach combines a differential pressure-based (DP) gas flow meter with a SONAR-based flow meter to provide two independent measurements of the wet gas mixtures, each with distinct and repeatable over-report characteristics due to wetness. The outputs of the two devices are then interpreted to provide gas rate and liquid rate of wet gas flows.

Experiments were conducted to validate the ability of the combination of DP and SONAR meters to measure gas and liquid rates of wet gas flows. The over-report due to wetness of a 0.6 beta ratio venturi (DP meter) and a clamp-on SONAR-based flow meter were characterized over a wide range of flow conditions broadly representative of oil and gas production and processing conditions. The experimentally determined over-report due to wetness of each was shown to be in good agreement with theoretical models predicting the over-report associated with well-mixed gas / liquid mixtures for each device.

The ability of the combination of the DP and SONAR meters to determine gas and liquid flow rates was evaluated using experimentally determined wetness sensitivity coefficients to solve for the gas and liquid rates based on the outputs of the venturi and SONAR meters installed in series on a test loop. The combination was shown to accurately measure gas flow rates to within ~+/- 2% and liquid rates to within +/-10% over a wide range of wet gas flows with gas oil ratios ranging less than 4000 scft/bbl to greater than 100,000 scft/bbl.

The results of these experiments suggest that the combination of a clamp-on SONAR-based flow meter and a differential pressure-based device is a viable means to provide both liquid and gas flow rates of type I and II wet gas flows.

2. INTRODUCTION

Access to accurate and cost-effective means for measuring 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. Upstream gas measurement applications which require wet gas measurement solutions can be subdivided into two categories: 1) applications known to contain liquids, or 2) applications may contain liquids, either continuously or sporadically. The first group is the classic wet gas application such as well head production, and the second group contains flows such as separator gas outlet flows.

Currently, differential pressure-based meters are used for the overwhelming majority of gas rate measurements. For accurate measurement, it is assumed that the gas is dry, i.e. contains no entrained liquids. While this assumption may be valid for many applications, most differential pressure-based gas measurements provide no real time indication or quantification of wetness. Since the presence of even small amounts of entrained liquid can result in significant over-reporting gas rates, an unnoticed introduction of wetness to an assumed-dry gas stream can result in significant over-reporting of gas flow rates. As such, the commercial options for measuring gas continuous flows containing entrained liquids are far more limited than those available for dry gas measurement.

The effectiveness of any wet gas metering approach depends in large part on the application and the objective of the measurement. In an effort to classify wet gas applications, the literature (Mehdizadeh, 2002) has classified wet gas metering into three types of applications using the Lockhardt-Martinelli number (LM) as a measure of wetness. The Lockhardt-Martinelli number is can be viewed as square root of the ratio of the dynamic head associated with the liquid component compared to that of the gas component if the gas and liquids were flowing separately.

$$LM \equiv \sqrt{\frac{\rho_l V_{s_l}^2}{\rho_g V_{s_g}^2}} = \sqrt{\frac{\rho_l}{\rho_g}} \sqrt{\frac{A^2 V_{s_l}^2}{A^2 V_{s_g}^2}} = \sqrt{\frac{\rho_l}{\rho_g}} \frac{Q_l}{Q_g} \quad (1)$$

Where ρ is the density, V_s is the superficial velocity, A is the cross sectional area of the pipe, Q is volumetric flow rate, and the subscripts l and g denote the liquid and gas components respectively.

Type I wet gas applications are characterized by low wetness ($X < 0.02$) and typically, the primary interest in this type of wet gas measurement is an accurate measure of the gas rate. The over-report characteristics of differential pressure-based flow meters due to wetness have been well classified in the literature (Stevens, 2005). Thus, if the wetness level of a wet gas mixture is either known or can be estimated, the impact of the wetness on the gas flow measurement can be mitigated by correcting for the over-report. Thus, a common approach for Type 1 gas measurement is to use a standard differential pressure gas flow meter and correct the gas flow measurement based on some estimate of the wetness.

Type II wet gas applications have wetness levels in the range of $0.02<X<0.3$. In these applications, typically both the gas rate and the liquid rate are of interest. Given the objective of measuring both the gas and the liquid rates, Type II wet gas measurements are inherently more difficult than type I. A common approach used for Type II applications is to use multiple differential pressure-based devices that have repeatable, but distinct, wetness over-report characteristics in series. The two independent measurements enable the determination of both gas and liquid flow rates. As noted in the literature (Agar, 2002 and Stewart, 2003), the challenge for these approaches is to ensure that the over-report due to wetness of each device is sufficiently repeatable and sufficiently distinct to enable adequate wet gas measurement.

Type III wet gas meters address flows with Lockhardt-Martinelli number greater than 0.3. In these applications, typically the amount of oil, water and gas are sought, and Type III wet gas applications are often viewed as a subset of the conditions typically addressed with partial separators and/or more general multiphase flow meters.

2.1 Scope

This paper describes a novel approach for Type I and Type II wet gas applications and presents flow loop data validating the concept. The approach combines SONAR-based flow measurement with differential pressure-based measurements to provide a convenient, robust solution for wet gas applications. A data set is presented that characterizes the over-report due to wetness of a SONAR meter and a venturi meter for Type I and Type II wet gas applications. A relatively straight-forward approach is presented to parameterize the wetness sensitivity of the venturi meter and the SONAR meter tested here in this work. While this characterization was used as the basis for evaluating the wet gas metering capability of the combination, it is recognized that specifics of the wet gas sensitivity parameterization is not unique. The work does, however, demonstrate the ability of the DP plus SONAR wet gas system to determine both gas and liquid flow rates of wet gas flows, without requiring any a priori knowledge of the wetness.

The experimental set-up utilized a venturi meter as the differential pressure flow measurement device. While it is recognized that the other types of DP meters have different over report characteristics, the over-report characteristic of other DP devices are sufficiently similar the device utilized in this work that conclusions should serve to validate the DP plus SONAR concept for any combination of DP meter plus SONAR meters in which the over-report characteristic of the DP device is known.

2.2 SONAR Flow Measurement

SONAR-based flow measurement leverages SONAR processing technology to determine the speed at which coherent flow patterns convect past an array of sensors. 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 (Kragas, 2001). Since then, SONAR-based flow measurement has evolved to include clamp-on versions and has been applied to a wide range of long-standing flow measurement challenges, with a focus on under-served multiphase applications within several industries, including Oil and Gas, Oil Sands, Mining, and Pulp and Paper (Gysling, 2003, and Gysling et al, 2005).

2.3 SONAR plus Differential Pressure Meters for Wet Gas Measurement

Unlike differential pressure devices, SONAR meters are comparatively insensitive to wetness. SONAR measurements are derived from a direct measurement of the speed at which flow moves past stationary sensors. Thus, for well mixed flows, liquid particles entrained in the flow have little influence on the measured flow rate. This insensitivity to wetness combines well with the well-documented wetness sensitivity of differential pressure-based devices to form a Type II wet gas meter. The approach is shown schematically in Figure 1. Conceptually, measuring the differential pressure across a DP device and measuring the mixture velocity with a SONAR meter provides a basis to determine flow rate and wetness of wet gas flows.

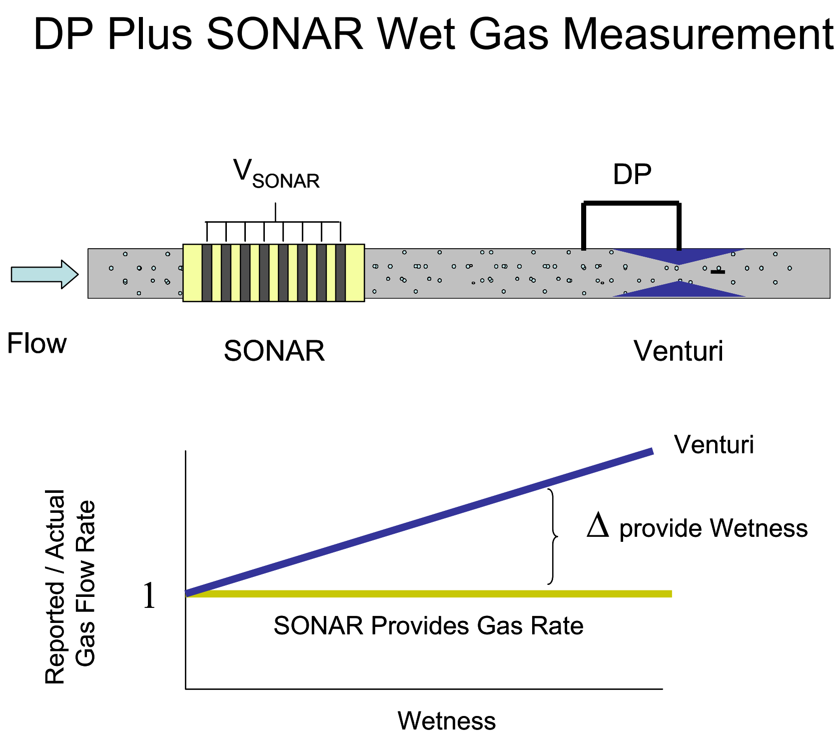

Figure 1: Schematic of Combination of DP plus SONAR Meters for Wet Gas Measurement

Since SONAR meters are available as clamp-on meters, the combination of SONAR and DP meters becomes an attractive clamp-on retrofit to convert existing DP meters operating in wet gas applications to provide accurate Type I and Type II wet gas meters.

3. DISCUSSION

3.1 Differential Pressure-Based Flow Meters Over-Report Measuring Wet Gas

For well mixed flows, it is well known that differential pressure-based flow meters characteristically over-report gas flow rates in the presence of wetness. Differential pressure devices measure the pressure change associated with a known change in flow path geometry. To accurately determine flow rate, the density of the fluid is required. For well mixed wet gases, the effective density of the gas / liquid mixture is strongly influenced by wetness, causing significant increase in differential pressure associated with a given flow path geometry with increasing wetness at constant gas flow. Within the wet gas community, this over-reporting due to wetness is expressed as the ratio between the flow rates reported with liquid present to the flow rate reported without the liquid present.

Assuming well mixed flows of low axial Mach numbers with no phase change between the gas and liquid, the over-report *(OR)* of the DP device can be expressed theoretically as:

$$OR = \sqrt{\frac{\Delta P_{TP}}{\Delta P_g}} = \sqrt{\frac{C_{D_{TP}}\left(\frac{1}{\beta^4}-1\right)\frac{1}{2}\rho_{TP}V_{TP}^2}{C_{D_g}\left(\frac{1}{\beta^4}-1\right)\frac{1}{2}\rho_g V_{s_g}^2}} \qquad (2)$$

Where V_{TP} is the mixture velocity for the two phase (TP) flow and is V_{sg} the superficial gas velocity for the gas only flow. C_D is the discharge coefficient and β is the square root of the throat diameter to the upstream diameter of the DP device.

For mixtures with small liquid phase fractions, the mixture velocity with the liquid present is not significantly different from that of the dry gas velocity (V_{TP}/V_g ~1)). Mixture density can be expressed as a volumetrically weighted average of the component densities:

$$\rho_{TP} \equiv \phi_{gas}\rho_{gas} + \phi_{liq}\rho_{liq} \qquad (3)$$

Applying these assumptions to equation (2), over-report for well mixed wet gas flows through differential pressure devices can be expressed as a simple function of the liquid to gas mass ratio (LGMR):

$$OR = \sqrt{\frac{\Delta P_{wet}}{\Delta P_{dry}}} = \sqrt{1+\frac{\dot{m}_{liq}}{\dot{m}_{gas}}} = \sqrt{1+LGMR} \qquad (4)$$

This theoretical formulation of the over-report, applicable well mixed flows with low liquid void fractions, serves as a simple, but useful, first principles estimate of the impact of entrained liquids on the over-report function of DP meters.

The well mixed formulation derived above differs from the classic idealized analysis of Murdock aimed at flows through orifice plates (Murdock, 1962). Although the physics is similar, in Murdock's idealized formulation it is assumed that the gas and the liquid phases remain separate and do not transfer momentum between each other as they flow through the orifice plate. Applying a constant pressure boundary condition upstream and downstream of the orifice to both the gas and the liquid streams results in the liquid phase flowing significantly slower than the gas phase as the two streams pass through the orifice. In this idealized formulation, the liquid displaces the flow area through the orifice remaining for the gas and resulting in an increase in the differential pressure across the orifice due to the liquid. This stratified flow model results in a theoretical over-report due to wetness being directly proportional to the Lockhardt-Martinelli parameter (LM).

$$OR_{DP} = \sqrt{\frac{\Delta P_{TP}}{\Delta P_{dry}}} = 1 + LM \qquad (5)$$

$$\text{where } LM \equiv \sqrt{\frac{\dot{m}_{liq} Q_{liq}}{\dot{m}_{gas} Q_{gas}}} = \sqrt{\frac{\rho_{gas}}{\rho_{liq}} LGMR}$$

3.2 SONAR Meter Over-Report Measuring Wet Gas

For well mixed flows, the theoretical over-report of SONAR meters due to wetness can be calculated by assuming that the SONAR meter continues to accurately measure the mixture volumetric flow rate. Thus, the well-mixed theoretical over-report for the SONAR meter is given by:

$$OR_{SONAR} = \frac{Q_{liq} + Q_{gas}}{Q_{gas}} = 1 + \frac{Q_{liq}}{Q_{gas}} = 1 + \frac{\rho_{gas}}{\rho_{liq}} LGMR = 1 + \sqrt{\frac{\rho_{gas}}{\rho_{liq}}} LM \quad (6)$$

3.3 Experimental Set-up

Experiments were conducted on the 4 inch multiphase flow loop at the Colorado Engineering Experimental Station, Inc.(CEESI) facility in Nunn, Colorado to evaluate the performance of a DP plus SONAR wet gas meter. A picture of the SONAR meter and venturi meter installed in the loop is shown in Figure 2. The flow facility generated fully-developed wet gas flows of known input liquid rate and input gas rate. The flow was first passed through a SONAR meter, clamped on to a standard 4inch, schedule 80 pipe, and then through a 0.6 beta ratio standard venturi meter. Stoddard Oil and Natural Gas were used as the working fluids.

Figure 2: Picture of DP plus SONAR Configuration installed on 4 inch Multiphase Loop at CEESI (Flow is from right to left)

3.4 Test Matrix

The performance of the combination was characterized at pressures of 200 psi and 1000 psi (gas-to-liquid density ratios of 0.013 and 0.08, respectively), over flow velocities ranging from 20 ft/sec to 80 ft/sec, and for wetness ranging from 0.0 to 0.2 Lockhardt-Martinelli numbers. The densimetric Froude number, defined below, ranged from 1.5 to 7.0. The data is presented in Table 1 for the 200 psi set points and in Table 2 for the 1000 psi set points. For each pressure and nominal flow rate, the first set-point was a dry gas calibration point. For each subsequent wet gas test point, the input liquid rate was adjusted as the gas flow rate was maintained to achieve the desired wetness.

4. RESULTS

The results of the test are tabulated in Tables 1 and 2 for the 200 psi and 1000 psi pressures, respectively. The results can be considered in two parts. The first part evaluates the response of each of the meters to wetness independently. As described above, wet gas measurement systems based on dissimilar wetness sensitivities require each device to have a repeatable and distinct response to wetness. As described above, the response of venturi meters, orifice plates, and V-cones is well-documented in the literature, and therefore, the novelty of this aspect of the data is focused on the over-report characteristics of the SONAR meter.

The second part examines the performance of the combination of the SONAR meter and the venturi meter as a wet gas metering system. For this section, a methodology to parameterize the wetness sensitivity of the two devices was developed. The detailed overall system accuracy will depend, to some extent, on the details regarding the characterization of the wetness sensitivity. Testing two devices in series on the same line simultaneously ensures that both devices are presented practically identical conditions, an important aspect in assessing the performance of the combination of the two devices as a Type II wet gas metering system.

Table 1: Test Matrix Reference Conditions and Over Reports at 200 psi

	Set Point Targets		*Input Reference Flow Rates*				*Flow Parameters*						
Point No.	*VSgas (ft/s)*	*Loop Pressure (psig)*	*Gas density (lb/ft3)*	*Qgas (acfh)*	*Liquid Density @ Meter P and T (lb/ft3)*	*Qliq @ Meter (ft3/hr)*	*LM*	*Liquid to gas Mass Ratio*	*Gas Volume Fraction*	*Gas Oil Ratio (scft/b)*	*Densimetric Froude Number*	*Venturi over-report*	*SONAR OverReport*
1	80	200	0.595	22741	45.98	0.0	0.000	0.000	100.0%		2.91	0.00%	0.00%
2	80	200	0.621	22268	46.09	492.8	0.191	1.586	97.8%	3352	2.95	62.83%	-0.88%
3	80	200	0.614	22542	46.01	398.8	0.153	1.283	98.3%	4185	2.96	53.73%	0.68%
4	80	200	0.609	22694	45.96	328.4	0.126	1.059	98.6%	5103	2.97	46.13%	1.59%
5	80	200	0.606	22724	45.95	266.3	0.102	0.864	98.8%	6290	2.96	40.91%	0.99%
6	80	200	0.602	22894	45.94	194.9	0.074	0.633	99.2%	8635	2.97	33.81%	-0.07%
7	80	200	0.598	22981	45.93	138.6	0.053	0.452	99.4%	12155	2.97	27.12%	0.77%
8	80	200	0.592	22951	45.91	67.5	0.026	0.224	99.7%	24822	2.95	15.49%	1.77%
9	80	200	0.588	23067	45.93	27.6	0.011	0.092	99.9%	60830	2.94	7.15%	2.45%
10	80	200	0.585	22918	45.95	13.4	0.005	0.045	99.9%	124091	2.91	3.97%	2.52%
11	80	200	0.580	22719	45.98	0.0	0.000	0.000	100.0%		2.87	-1.07%	0.20%
12	60	200	0.629	17607	46.00	0.0	0.000	0.000	100.0%		2.31	0.00%	0.00%
13	60	200	0.644	17710	46.07	373.6	0.178	1.475	97.9%	3472	2.37	57.43%	3.61%
14	60	200	0.640	17555	46.08	309.0	0.149	1.242	98.3%	4152	2.34	48.53%	3.72%
15	60	200	0.637	17643	46.09	259.6	0.125	1.045	98.6%	4959	2.34	42.52%	4.17%
16	60	200	0.634	17447	46.11	205.4	0.100	0.842	98.8%	6187	2.31	35.54%	4.78%
17	60	200	0.631	17542	46.12	156.9	0.076	0.643	99.1%	8137	2.32	29.21%	4.19%
18	60	200	0.628	17631	46.12	103.5	0.050	0.425	99.4%	12369	2.32	22.74%	3.58%
19	60	200	0.624	17432	46.12	52.0	0.026	0.218	99.7%	24315	2.28	13.43%	2.67%
20	60	200	0.620	17583	46.12	20.5	0.010	0.086	99.9%	61854	2.29	6.29%	2.65%
21	60	200	0.618	17676	46.11	10.2	0.005	0.043	99.9%	124830	2.30	3.52%	2.39%
22	40	200	0.608	11631	46.08	0.0	0.000	0.000	100.0%		1.50	0.00%	0.00%
23	40	200	0.618	11762	46.19	249.3	0.183	1.570	97.9%	3413	1.53	49.75%	10.68%
24	40	200	0.614	11859	46.15	205.4	0.150	1.291	98.3%	4173	1.54	44.31%	9.23%
25	40	200	0.611	11891	46.13	174.1	0.127	1.096	98.6%	4930	1.54	39.96%	8.43%
26	40	200	0.609	11758	46.11	137.8	0.102	0.880	98.8%	6159	1.52	33.71%	6.76%
27	40	200	0.606	11812	46.09	103.7	0.077	0.663	99.1%	8212	1.52	28.33%	5.70%
28	40	200	0.604	11791	46.07	68.7	0.051	0.442	99.4%	12357	1.52	21.40%	3.05%
29	40	200	0.601	11724	46.05	34.6	0.026	0.225	99.7%	24365	1.50	13.91%	1.19%
30	40	200	0.598	11814	46.03	13.3	0.010	0.087	99.9%	63583	1.51	7.21%	-0.35%
31	40	200	0.596	11884	46.02	6.7	0.005	0.043	99.9%	128160	1.52	4.22%	-0.64%

Table 2: Test Matrix Reference Conditions and Over Reports at 1000 psi

	Set Point Targets		*Input Reference Flow Rates*				*Flow Parameters*					*Over Report due to Wetness*	
Point No.	*VSgas (ft/s)*	*Loop Pressure (psig)*	*Gas density (lb/ft3)*	*Qgas (acfh)*	*Liquid Density @ Meter P and T (lb/ft3)*	*Qliq @ Meter (ft3/hr)*	*LM*	*Liquid to gas Mass Ratio*	*Gas Volume Fraction*	*Gas Oil Ratio (scft/b)*	*Densimetric Froude Number*	*venturi over-report*	*SONAR OverReport*
32	60	1000	3.544	17312	44.34	0.0	0.000	0.000	100.0%		5.50	0.00%	0.00%
33	60	1000	3.567	17238	44.39	366.4	0.075	0.262	97.9%	16058	5.49	16.73%	1.92%
34	60	1000	3.558	17335	44.37	295.1	0.060	0.211	98.3%	20037	5.52	13.84%	1.65%
35	60	1000	3.552	17199	44.36	215.7	0.044	0.156	98.8%	27185	5.47	10.53%	1.73%
36	60	1000	3.550	17235	44.35	180.8	0.037	0.130	99.0%	32489	5.48	9.05%	1.59%
37	60	1000	3.546	17266	44.34	138.7	0.028	0.100	99.2%	42428	5.49	7.21%	1.62%
38	60	1000	3.544	17298	44.34	91.4	0.019	0.066	99.5%	64478	5.49	5.03%	1.40%
39	60	1000	3.539	17339	44.34	46.6	0.010	0.033	99.7%	126722	5.50	3.05%	1.27%
40	60	1000	3.537	17316	44.34	22.9	0.005	0.017	99.9%	257065	5.49	2.10%	1.17%
41	60	1000	3.533	17374	44.34	11.2	0.002	0.008	99.9%	528745	5.51	1.38%	0.86%
42	40	1000	3.537	11605	44.56	0.0	0.000	0.000	100.0%		3.67	0.00%	0.00%
43	40	1000	3.544	11486	44.60	244.0	0.075	0.266	97.9%	16019	3.64	16.44%	1.51%
44	40	1000	3.540	11582	44.60	383.7	0.118	0.415	96.8%	10276	3.67	23.95%	0.74%
45	40	1000	3.533	11446	44.61	195.7	0.061	0.215	98.3%	19897	3.62	13.77%	1.54%
46	40	1000	3.527	11514	44.62	148.4	0.046	0.162	98.7%	26401	3.63	10.98%	1.57%
47	40	1000	3.523	11558	44.63	122.8	0.038	0.134	98.9%	32015	3.65	9.41%	1.41%
48	40	1000	3.515	11421	44.62	90.4	0.028	0.100	99.2%	42961	3.60	7.19%	1.60%
49	40	1000	3.513	11448	44.63	61.0	0.019	0.067	99.5%	63754	3.60	5.24%	1.55%
50	40	1000	3.507	11452	44.63	30.0	0.009	0.033	99.7%	129727	3.60	3.41%	1.79%
51	40	1000	3.503	11508	44.63	14.9	0.005	0.016	99.9%	262034	3.62	2.02%	1.28%
52	40	1000	3.500	11526	44.63	7.7	0.002	0.008	99.9%	511285	3.62	1.46%	1.12%
53	80	1000	3.462	21544	44.37	0.0	0.000	0.000	100.0%		6.77	0.00%	0.00%
54	80	1000	3.490	21764	44.36	473.9	0.078	0.274	97.9%	15723	6.87	18.10%	0.99%
55	80	1000	3.480	21566	44.32	367.4	0.061	0.215	98.3%	20072	6.80	14.21%	0.76%
56	80	1000	3.473	21565	44.29	287.6	0.048	0.168	98.7%	25630	6.80	11.26%	0.54%
57	80	1000	3.470	21570	44.27	230.1	0.038	0.135	98.9%	32029	6.79	9.28%	0.57%
58	80	1000	3.466	21521	44.25	173.0	0.029	0.102	99.2%	42492	6.78	7.09%	0.44%
59	80	1000	3.464	21485	44.24	125.5	0.021	0.074	99.4%	58449	6.76	5.56%	0.64%
60	80	1000	3.462	21537	44.22	104.3	0.017	0.061	99.5%	70506	6.78	4.66%	0.47%
61	80	1000	3.460	21541	44.22	87.1	0.014	0.051	99.6%	84430	6.78	4.06%	0.49%
62	80	1000	3.460	21553	44.20	80.2	0.013	0.047	99.6%	91806	6.78	3.84%	0.52%
63	80	1000	3.460	21590	44.19	69.1	0.011	0.041	99.7%	106617	6.79	3.29%	0.41%
64	80	1000	3.458	21571	44.18	58.7	0.010	0.034	99.7%	125410	6.79	3.04%	0.46%
65	80	1000	3.455	21592	44.17	45.8	0.008	0.027	99.8%	160838	6.79	2.55%	0.45%
66	80	1000	3.453	21616	44.16	34.3	0.006	0.020	99.8%	214994	6.80	2.04%	0.34%
67	80	1000	3.452	21618	44.15	23.2	0.004	0.014	99.9%	317900	6.80	1.65%	0.32%
68	80	1000	3.449	21620	44.15	11.5	0.002	0.007	99.9%	643925	6.80	1.28%	0.34%
69	20	1000	3.491	5764	44.57	0.0	0.000	0.000	100.0%		1.81	0.00%	0.00%
70	20	1000	3.450	5766	44.53	474.9	0.296	1.059	92.4%	4125	1.80	45.58%	-19.92%
71	20	1000	3.449	5789	44.54	308.8	0.192	0.687	94.9%	6366	1.81	31.69%	-29.93%
72	20	1000	3.443	5860	44.55	154.3	0.095	0.340	97.4%	12896	1.83	17.58%	6.39%
73	20	1000	3.439	5710	44.56	78.0	0.049	0.176	98.7%	24854	1.78	9.92%	4.47%
74	20	1000	3.436	5725	44.57	38.4	0.024	0.087	99.3%	50601	1.78	5.34%	2.17%
75	20	1000	3.433	5751	44.58	16.4	0.010	0.037	99.7%	119175	1.79	2.07%	0.37%
76	20	1000	3.429	5760	44.59	7.7	0.005	0.017	99.9%	255078	1.79	0.86%	0.09%

4.1 Over Report Due to Wetness

The over-report as defined in Equation 2 is plotted versus Lockhardt-Martinelli number for the venturi meter and the SONAR meter in Figure 3. A dry gas set point was recorded for each pressure and gas rate tested. The output of the SONAR flow meter and the venturi meter was calibrated to the reference meter, and thus the offset for each dry gas point was, by definition, zero; and the over-report is due solely to the wetness. Data points 70 and 71 at the lower limit of Froude numbers and higher limits of wetness were clearly out-of-family and were excluded from the graphical presentation of the results.

As shown in Figure 3, the over-report of the venturi meter exhibits sensitivity to pressure, with the higher pressure and lower pressure data exhibiting different characteristics. For each pressure, the over-report of the venturi meter was fairly linear with Lockhardt-Martinelli number. However, noting that the idealized Murdock formulation predicts a wetness over-report equal to the Lockhardt-Martinelli number, quantitatively, the wetness sensitivity of the venturi meter tested herein was significantly greater than that anticipated by the idealized Murdock formulation.

The SONAR meter exhibited a repeatable response the wetness which was significantly reduced (~10X less) compared to that of the venturi meter. The SONAR meter exhibited quantitatively similar over-report as a function of liquid to gas mass ratio for the two pressures.

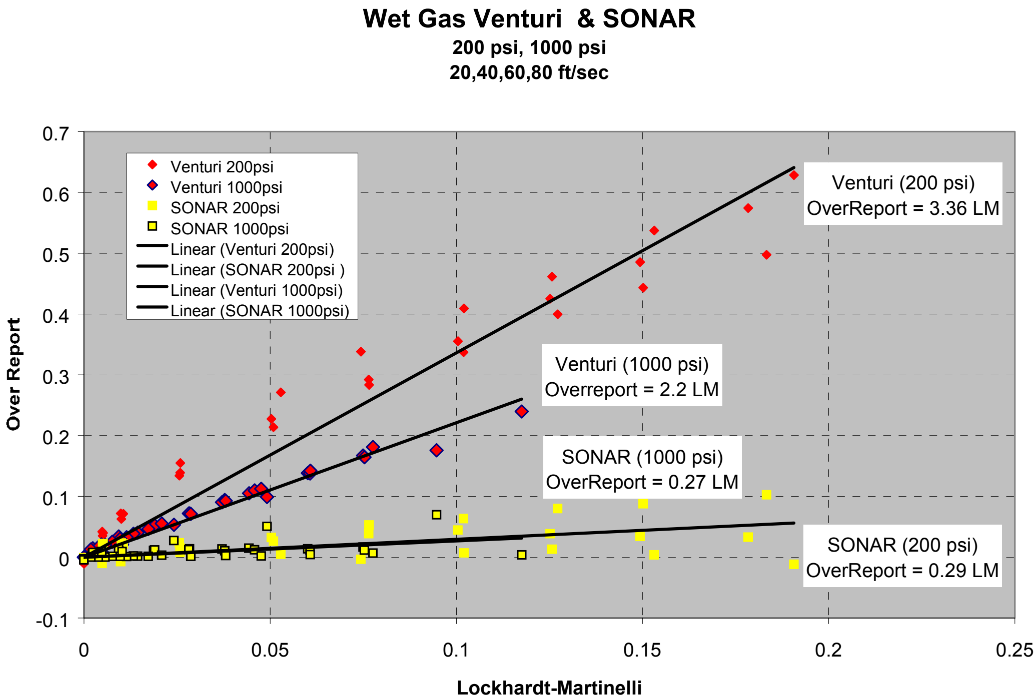

Figure 3: Over Reading of SONAR and Venturi Meters as a Function of Lockhardt-Martinelli Number

The over-report characteristic of the SONAR meter did, however, exhibit sensitivity to densimetric Froude number. The densimetric Froude Number is a non-dimensional measure of the mixedness of a gas / liquid mixture and is defined as the square root of the ratio between the dynamic pressure of the flowing gas phase to the gravimetric pressure head (ρgD where g is the acceleration due to gravity) generated by a column of liquid with a height of the diameter *(D)* of the pipe immersed in the gas phase:

$$Fr = \sqrt{\frac{\rho_{gas} V_{mix}^2}{(\rho_{liq} - \rho_{gas}) g D}} \qquad (7)$$

In flows with high densimetric Froude numbers, the gas and liquid phases tend to be well mixed. In flows with low densimetric Froude numbers, the gas and liquids tends to stratify. Figure 4 shows the over-report of the SONAR meter due to wetness as a function of Froude number with the wetness (LM) of each set point denoted.

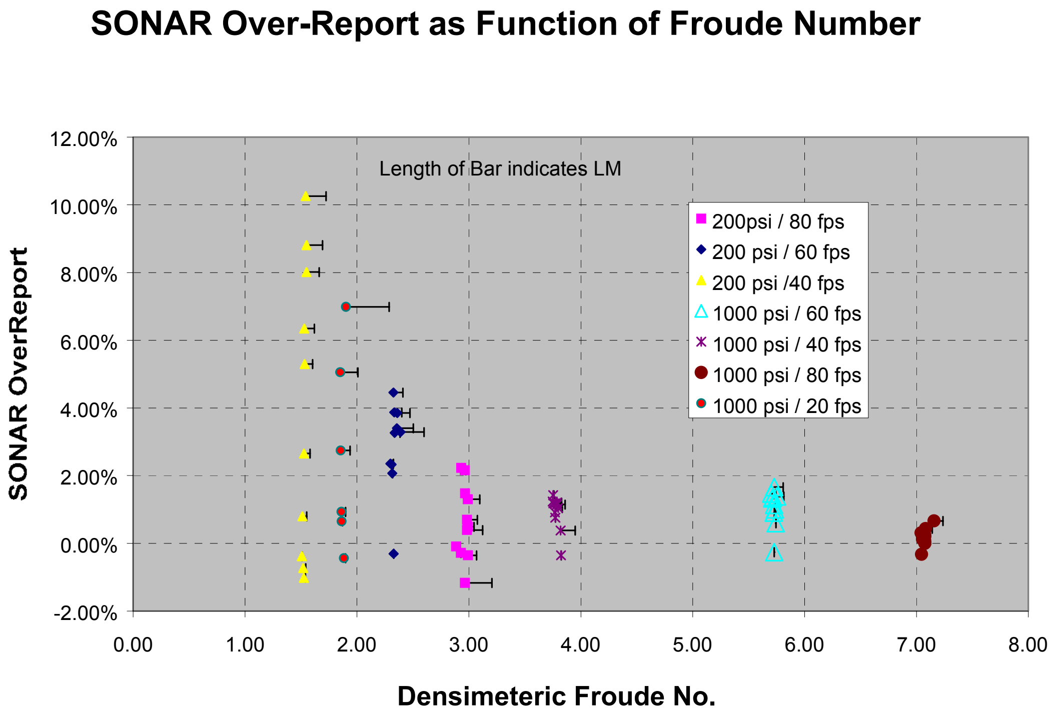

Figure 4: Over Report of SONAR meter plotted as function of Densimetric Froude Number with Wetness Denoted (Lockhardt-Martinelli Number)

For higher Froude Numbers, (FR>3), the over-report was small with little sensitivity to wetness. At low Froude numbers, while the over-report of the SONAR meter remained small compared to that of the venturi meter, the over-report increased and scaled with wetness. This effect at low Froude numbers could be attributed to the stratified liquids holding up and reducing the effective flow area of the gas and thereby increasing the velocity of the gas phase resulting in the over-report.

4.2 Venturi Meter Over Report as Function of Liquid to Gas Mass Ratio

Figure 5 shows the venturi and SONAR meters over-report data as a function of liquid to gas mass ratio. As shown, the over-report of the venturi meter appears to follow a single trend for both pressures as a function of liquid to gas mass ratio.

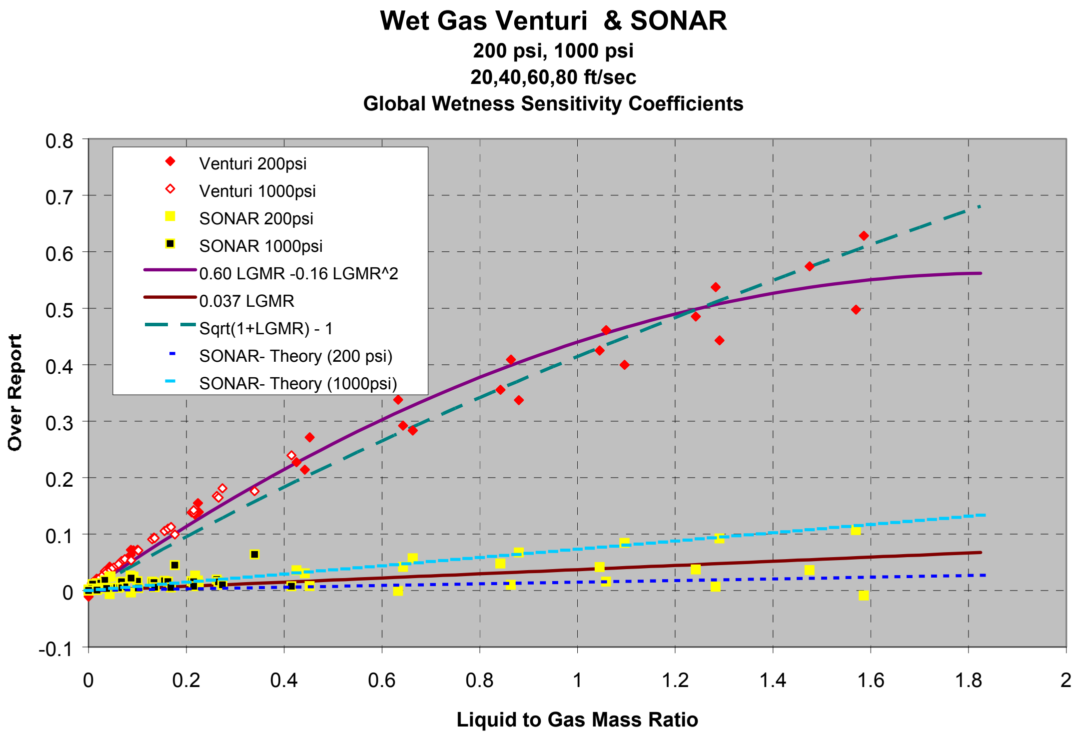

Figure 5: Over-Report of SONAR and Venturi Meters due to Wetness plotted as Function of Liquid to Gas Mass Ratio (curve fit and Theoretical result for Well mixed Model Included)

This behavior is well-predicted by the idealized, well-mixed, model of two phase flow through a venturi meter in which the over-report is a direct function of liquid to gas mass ratio, as depicted in Figure 5. As shown, the well-mixed theory represents a good approximation to the experimental over-report of the venturi over the range of Froude numbers and wetness levels tested.

4.3 Performance of Combination of SONAR and Venturi Meters

The data presented for the over-report of the SONAR and the venturi meters tested shows that the two devices have dissimilar and repeatable over-report characteristics due to wetness. To effectively utilize the combination to determine both gas rate and liquid rate simultaneously, the response of each meter to wetness requires parameterization. A schematic of the DP plus SONAR wet gas meter is shown in the Figure 6.

Although from reviewing the literature, it appears to be more standard to formulate the wetness sensitivity of the DP meter in terms of the Lockhardt-Martinelli parameter, the DP meter tested herein demonstrated a more universal response to liquid to gas mass ratio (LGMR). For this reason, it was decided to characterize the wetness sensitivity as a function of liquid to gas mass ratio in this report.

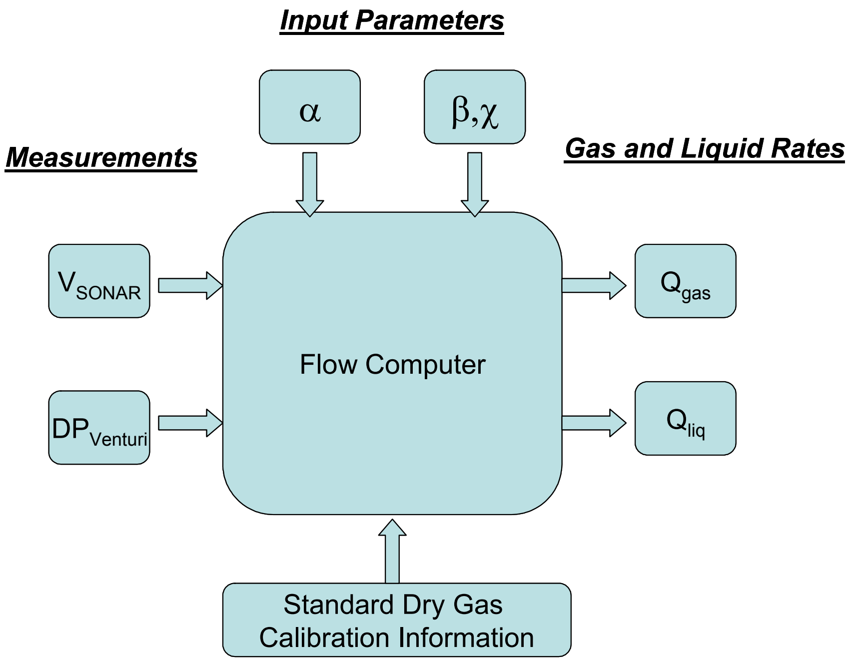

Figure 6: Schematic of the DP plus SONAR Wet Gas Metering System

4.4 Wetness Sensitivity Coefficients

In this analysis, the over-report of the SONAR and the venturi meters is parameterized as a function of a single variable, liquid to gas mass ratio. The wetness sensitivity of the SONAR meter was characterized with a linear wetness sensitivity parameter, (α), and the wetness sensitivity of the venturi was characterized with a two-coefficient (β,χ) quadratic wetness sensitivity parameters.

$$V_{SONAR} = (1+\alpha LGMR)V_{S_{gas}} \qquad (8)$$

$$V_{venturi} = (1+\beta LGMR+\chi LGMR^2)V_{S_{gas}} \qquad (9)$$

Here, V_{SONAR} is the output velocity from the SONAR meter and $V_{venturi}$ is the output velocity from the venturi meter. With the wetness sensitivity coefficients defined, the liquid to gas mass flow ratio can be calculated directly from the outputs of the two meters:

$$LGMR = \frac{-(\beta-\alpha\frac{V_{S\,venturi}}{V_{S_{SONAR}}})+\sqrt{(\beta-\alpha\frac{V_{S\,venturi}}{V_{S_{SONAR}}})^2-4\chi(1-\frac{V_{S\,venturi}}{V_{S_{SONAR}}})}}{2\chi} \qquad (10)$$

The gas flow rate is then determined using the SONAR meter formulation,

$$V_{S_{gas}} = \frac{V_{SONAR}}{(1+\alpha LGMR)} \qquad (11)$$

Knowing LGMR and gas flow rate, additional flow parameters such as liquid rate and gas-to-liquid volume flow rate parameters can be calculated in a straight-forward manner.

Figure 5 shows the over-report from the SONAR meter and the venturi meter fitted with what is termed “global wetness sensitivity parameters” – i.e. the over report data recorded from each set point, spanning a wide range of flow rates, pressures, and liquid loading characterized versus a single flow parameter. While this single global correlation provides an indication of the robustness of this approach, to evaluate the potential of the DP plus SONAR metering system to provide accurate and meaningful wet gas measurements, it was decided to use localized wetness sensitivity parameters to characterize the over-report characteristic for each gas flow rate and pressure tested.

It should be noted that more sophisticated wetness sensitivity correlations, considering, for example, other non-dimensional parameters such as Froude number, could be used and would likely expand the generality of the results. For example, the wetness sensitivity of V-cone meters are parameterized as a function of Lockhardt –Martinelli and Froude numbers by (Stevens, 2005).

Figure 7 shows the over-report data as a function of wetness at a nominal flow rate of 80 ft/sec at 1000 psi corresponding to a densimetric Froude number of 7.1. Similar data is presented for the 40 ft/sec at 200 psi (Froude = 1.5) in Figure 8. As shown, the over-report of the meters is well captured by the local wetness sensitivity parameters.

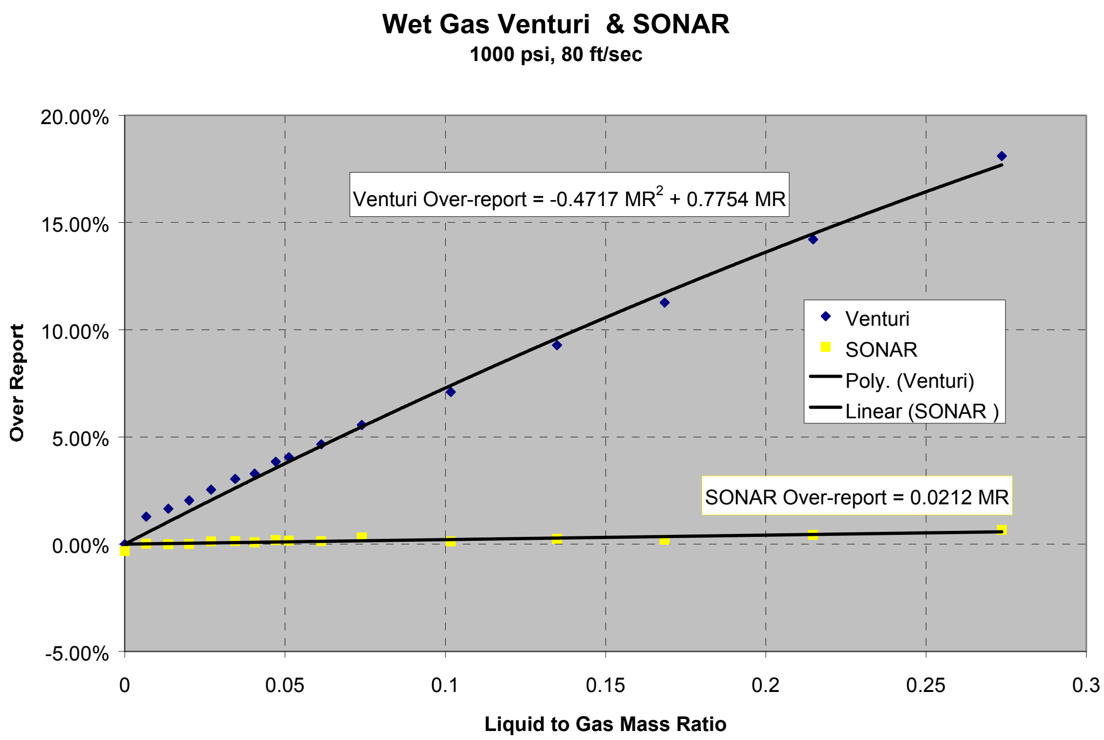

Figure 7: Over-report data as a function of wetness at a nominal flow rate of 80 ft/sec at 1000 psi (Froude number = 7.1)

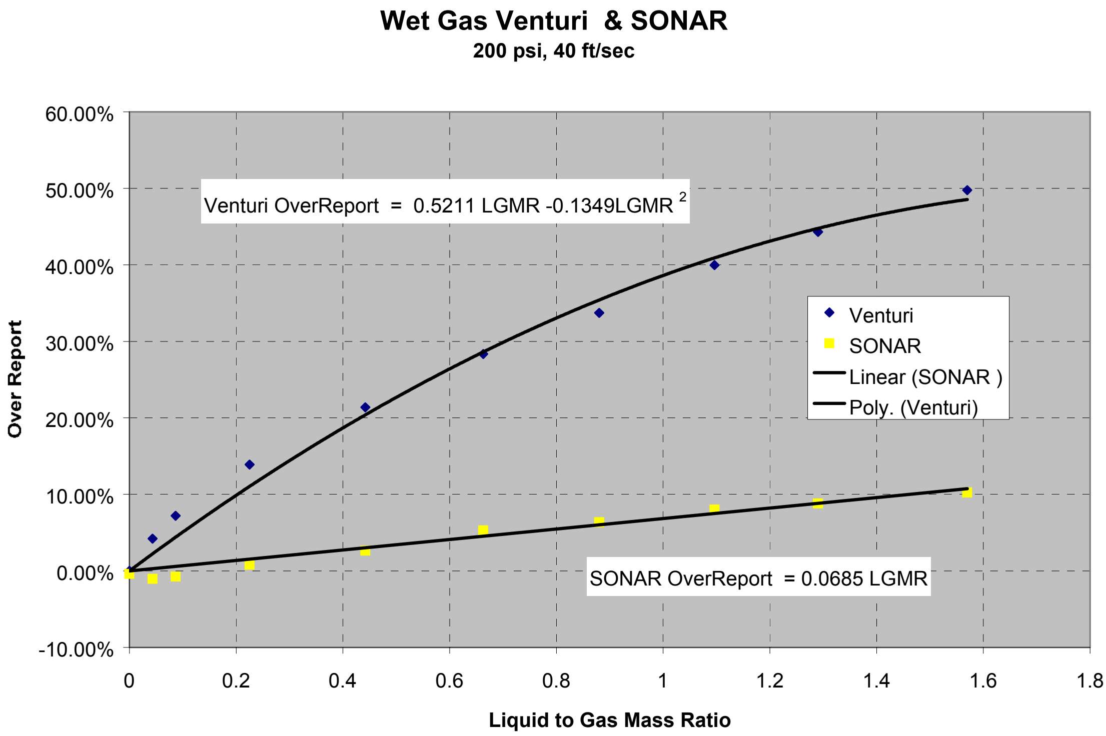

Figure 8: Over-report data as a function of wetness at a nominal flow rate of 40 ft/sec at 200 psi (Froude number = 1.5)

The global and localized wetness sensitivity coefficients determined for the testing are listed in Table 3.

Table 3: SONAR Experimentally Determined Wetness Sensitivity Coefficients

			Venturi		SONAR
			Chi	**Beta**	**Alpha**
Global Coefficients			-0.1593	-0.593	0.037
Localized Coefficients					
Pressure (psi)	Rate (ft/sec)	Fr			
200	80	2.9	-0.1449	0.6138	0.0019
	60	2.3	-0.1001	0.5245	0.0349
	40	1.5	-0.1349	0.5211	0.0685
1000	60	5.7	-0.5772	0.7794	0.0818
	40	3.8	-0.4358	0.7517	0.0379
	80	7.1	-0.4717	0.7754	0.0212
	20	1.9	-0.1178	0.5526	0.228

The gas rates measured with the venturi plus SONAR wet gas system using the localized wetness sensitivity coefficients are plotted versus reference in Figure 9. The relative gas rate error is plotted versus liquid to gas mass ratio in Figure 10. As shown, the system measures the gas rate quite accurately over the range of wetness tested, with errors of less than 2% of reference over a large range of wetness and Froude numbers. For the range of wetness tested, the venturi over-report due to wetness would have resulted in significant errors in dry gas flow rate if interpreted in isolation, exceeding 50% over-report as the liquid to gas mass ratio approached 2.0. The data demonstrates that using a clamp-on SONAR meter to augment an existing DP meter operating in wet gas service could significantly improve the accuracy of existing DP gas measurements operating in wet gas service.

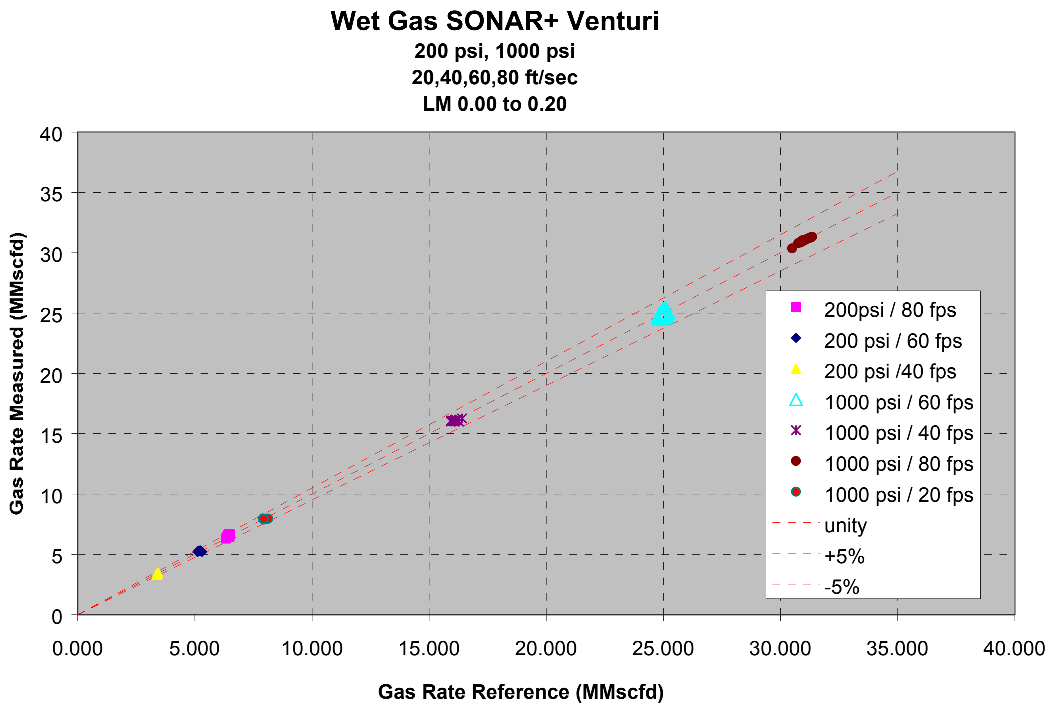

Figure 9: The gas rates measured with the venturi plus SONAR wet gas system using the localized wetness sensitivity coefficients are plotted versus reference

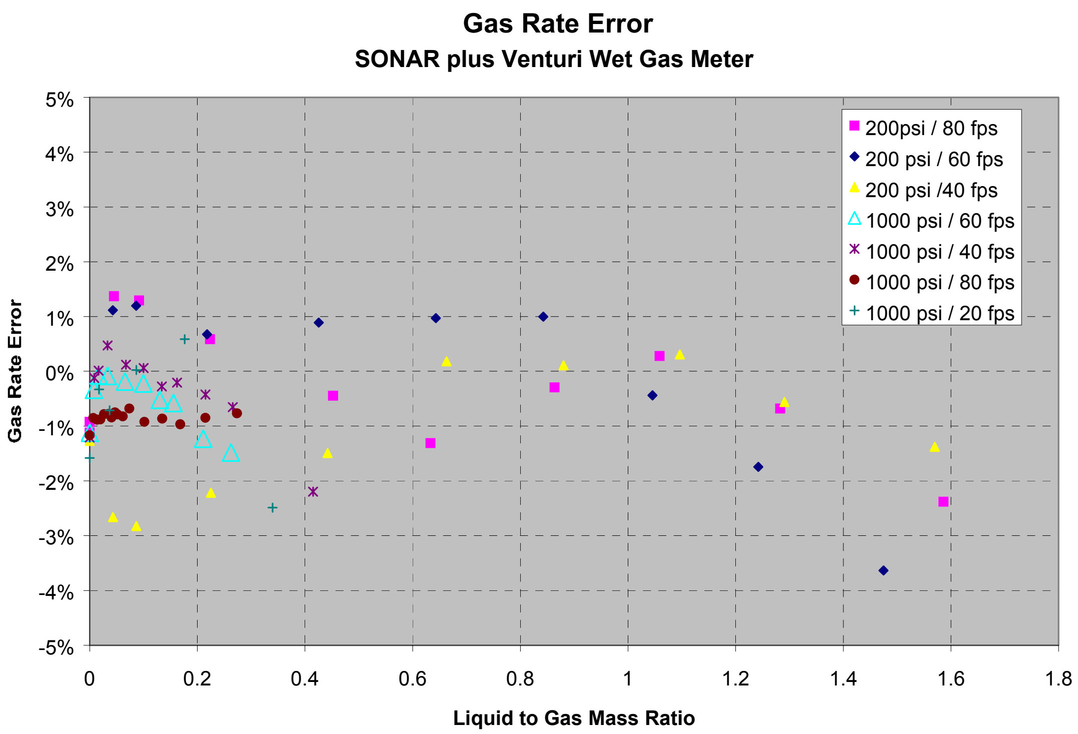

Figure 10: Relative Error in Gas rates Measured with the venturi plus SONAR wet gas system using the localized wetness sensitivity coefficients plotted versus LGMR

Similar data is presented for the measured liquid rates in Figures 11 and 12. As shown, the system provides a meaningful measurement of liquid rates, providing approximately +/-10% measurement of liquid rates for LGMR > ~0.2 (or approximately LM>0.02). The relative error in liquid rate increases significantly as the wetness approaches zero. Thus, to focus on the performance in the Type II wet gas range (LM>0.02), the axis of Figure 12 was limited to +/-50% error, eliminating some of the higher relative error points at the low liquid loading rates.

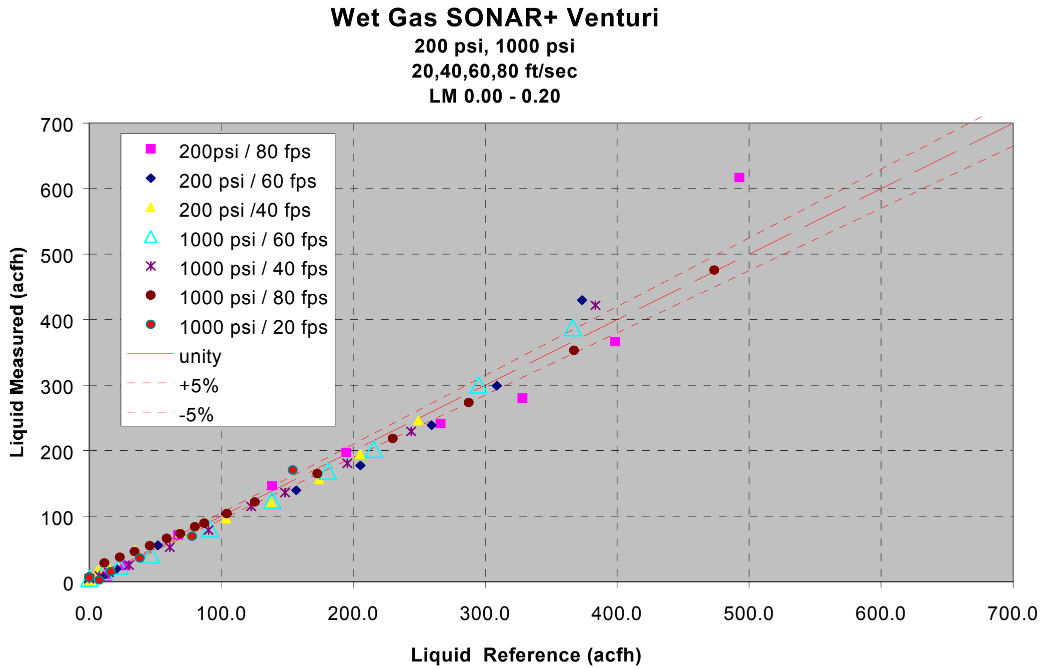

Figure 11: Liquid rates Measured with the venturi plus SONAR wet gas system using the localized wetness sensitivity coefficients are plotted versus reference

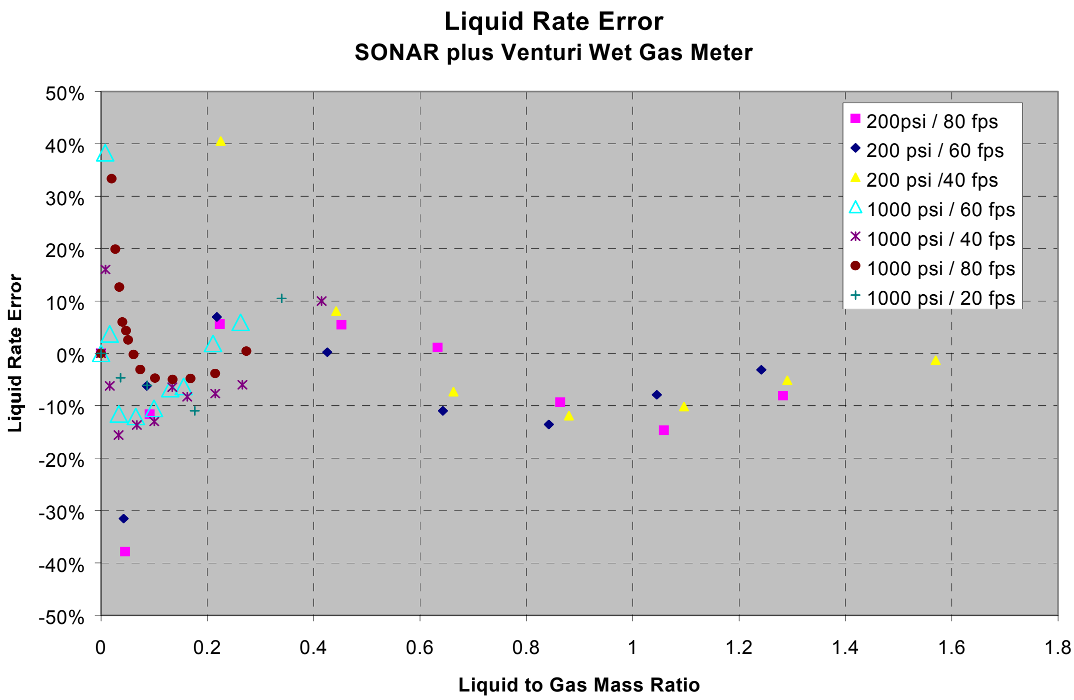

Figure 12: Relative Error in Liquid rates Measured with the venturi plus SONAR wet gas system using the localized wetness sensitivity coefficients plotted Versus LGMR

Figure 13 and 14 illustrate the ability of the DP plus SONAR system to provide a direct measurement of the gas wetness. These figures are derived directly for the gas and liquid rate data presented above. These figures further highlight the ability of the system to monitor gas / liquid ratios, an important operating parameter in many oil and gas production and processing operations. Figure 13 shows the measured versus reference gas / oil ratio calculated from the results presented above. Figure 14 shows the measured versus reference Lockhardt Martinelli number. As shown, the DP plus SONAR system provides a direct measure of wet gas wetness.

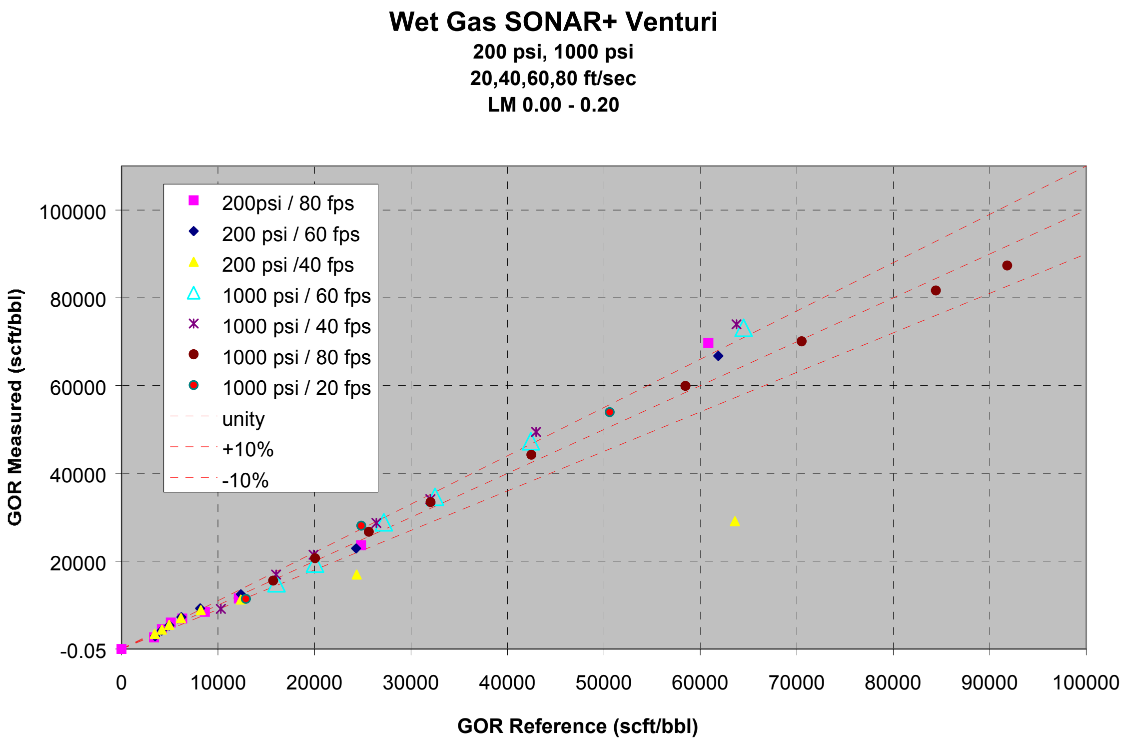

Figure 13: Measured Gas Oil Ratio with the venturi plus SONAR wet gas system using the localized wetness sensitivity coefficients versus Reference GOR

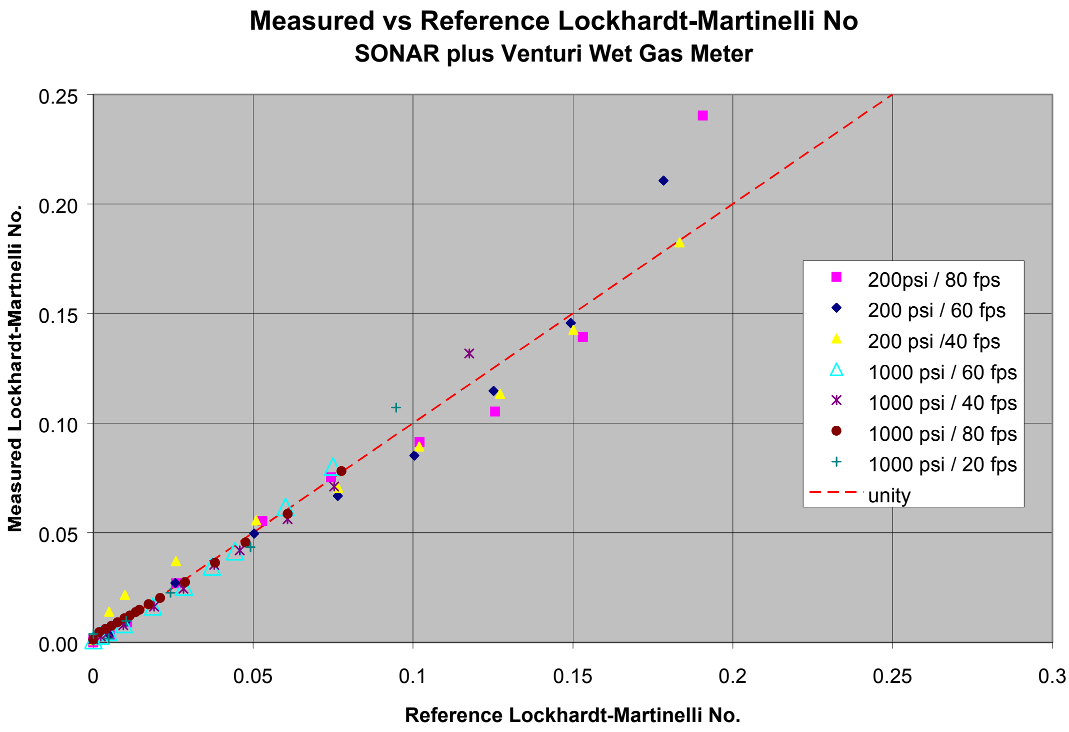

Figure 14: Measured Lockhardt-Martinelli with the venturi plus SONAR wet gas system using the localized wetness sensitivity coefficients versus Reference Lockhardt-Martinelli

5. SUMMARY

A method to measure the gas rates and liquid rates of wet gas flows was presented. The approach combines any differential pressure-based gas flow meter of known wetness sensitivity with a SONAR-based flow measurement. The two independent measurements have repeatable and distinct wetness sensitivity and can be used to accurately determine gas and liquid flow rate.

Experiments were conducted to validate the ability of a DP plus SONAR metering system to measure gas and liquid rates of wet gas flows. The over-report due to wetness of a 0.6 beta ratio venturi meter and a clamp-on SONAR-based flow meter were measured and characterized over a wide set of flow conditions representative of oil and gas production and processing conditions. The experimentally determined over-report due to wetness of each was in good agreement with theoretical models of the over-report associated with well-mixed gas / liquid mixtures. The over-report characteristics of both the venturi meter and the SONAR meter were correlated with the liquid to gas mass ratio of the wet gas flow.

The ability of the combination of the venturi plus SONAR system was evaluated using experimentally determined wetness sensitivity coefficients to solve for the gas and liquid rates based on the outputs of the venturi and SONAR installed in series on the test loop. The combination was shown to accurately measure gas flow rates to within ~+/- 2% and liquid rates to within +/-10% over a wide range of wet gas flows.

The results of these experiments suggest that the addition of a clamp-on SONAR-based flow meter to a differential pressure-based device is a viable means to provide both liquid and gas flow rates of Type I and II wet gas flows.

6. ACKNOWLEDGEMENTS

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Uncertainty Based Allocation
Work in Progress?

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Lupus Consultancy

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1 INTRODUCTION

Recently I was asked by a customer to write a summary of frequently used reconciliation and production allocation methods. One of these methods was "Uncertainty Based Allocation", presented first at the NSFM workshop in 2002 [1] and later as an appendix in API RP 85 "Use of Subsea Wet-Gas flow meters in Allocation Measurement Systems" [2]. In 2004 a an other UBA method was presented [3], which will be considered a variation on [1] and [2].

When studying this method a number of mixed thoughts crossed my mind, the most important being

- A very interesting novelty to include the measurement uncertainty in the allocation method. – a commercial 'return' for accuracy and a penalty for inaccuracy
- What a complicated allocation formula results from the RP85 "optimum" solution.
- The method is presented in a document about subsea wet gas measurement, but nothing in the method restricts its application to that area. If the method is both general and optimum, then it should be considered for more general application.

In general I am of the opinion that there are still quite a number of queries about this method, which would justify a public debate. The objective of this paper is to make an attempt to start that discussion now.

The paper will conclude with a proposal for a different, much simpler formula for uncertainty based allocation. The formula will be based on a different "optimisation" criterion.

2 SUMMARY OF THE METHOD AS PRESENTED IN RP 85

Step a) A bulk metered quantity "Q_B" has to be allocated to the feeding points. The raw quantities of the feeding points are "Q(j)"

An imbalance ("I ") is calculated, which is the difference between the bulk quantity QB and the sum of the feeding streams

$$I = Q_B - \sum Q(i) \qquad (1)$$

For any allocation method, adjusted feeding quantities are calculated as

$$Q_{adj}(j) = Q(j) + \alpha(j) * I \qquad (2)$$

With the condition that $\sum \alpha(i) = 1$

As an example, in the conventional proportional reconciliation (or allocation) formula α(j) is:

$$\alpha(j) = Q(j) / \sum Q(i) \qquad (3)$$

This can simply be verified by substitution.

Step b)
Within the condition that the sum of α(j) equals unity, a whole series of formulas for α(j) is possible. Proportional allocation is given in the example formula (3) above. In RP85 the expression proposed for α(j) is

$$\alpha(j) = \sigma(j)^2 / (\sigma_B^2 + \Sigma\sigma(i)^2) + (1/n)*\sigma_B^2 / (\sigma_B^2 + \Sigma\sigma(i)^2) \qquad (4)$$

Where σ(j) is the standard deviation of the (absolute) uncertainty of each contributing quantity Q(j) , σ_B is the standard deviation of the (absolute) uncertainty of the bulk quantity QB and n is the total number of feeding streams. The formula comprises two terms. The first represents that the allocation factors α(j) increase with increasing uncertainty of the stream that the factor belongs to, the UBA principle. The second term is a refinement. It represents that the uncertainty in the bulk measurement is allocated in a certain way to the contributing streams.

3 DISCUSSION OF VARIOUS ASPECTS OF THE RP85 METHOD

3.1 Uncertainty As Basis For Allocation

In the UBA method allocation of the imbalance “I” is not done simply on the basis of the incoming stream quantities but on the basis of the absolute uncertainty of those quantities. The intention is to allocate more of the imbalance to the less accurately metered quantities than the more accurately metered quantities. This is the great attractiveness of the principle, i.e. there is a tangible benefit for accuracy. Although the correction may still represent either a gain or a loss, better measurements mean "less dependent on measurements by others".

However to achieve a similar result, in principle many formulas and methods could be designed and used. The method presented in RP 85 is only one of these.

3.2 An "Optimum" Solution

In RP 85 the derivation of the allocation formula, is based on a very common "optimisation" method, the least square minimisation method. Many years ago when I first heard about "optimum solutions", I was in particular impressed by the suggestion that apparently mathematics were capable of calculating some kind of absolute optimum solution to a problem. Later I learned that there is nothing absolute about such a solution. The trick is in the selection of the criterion, which has to be minimised. If one chooses a different criterion one gets a different optimum. In other words the optimum is not stronger than the criterion. A good reason to examine the criterion used.

3.3 No Smooth Transition To Conventional Proportional Allocation Methods

One of the characteristics of the RP 85 method is the lack of smooth transition to the conventional proportional allocation method(s). More specifically, if all streams are measured with the same relative uncertainty one would want to see that the UBS method produces results that are not different from the proportional allocation method.
This point can best be explained with an example. Assume the case of just two feeding streams. The metering method of both streams is similar. So one assumes that the relative uncertainty of both measured streams is equal. For simplicity sake we will also neglect the uncertainty in the bulk stream.
The absolute uncertainty of stream Q(j) can be written as $\sigma(j) = \sigma_{rel}(j) * Q(j)$, where $\sigma_{rel}(j)$ is the relative uncertainty of the stream. As it is assumed now that the relative uncertainties of both streams are equal, the uncertainties vanish from the formula and (4) becomes:

$$\alpha(j) = \sigma(j)^2 / \Sigma\sigma(i)^2 = Q(j)^2 / \Sigma Q(i)^2 \qquad (5)$$

Fig.1 gives a graphical comparison of the allocation coefficient according to formula (5) (all relative uncertainties having the same value) and the ones according to the proportional allocation of (3). The difference between the two results is clear. It is the authors opinion that this difference is an unwanted characteristic of the RP 85 method.

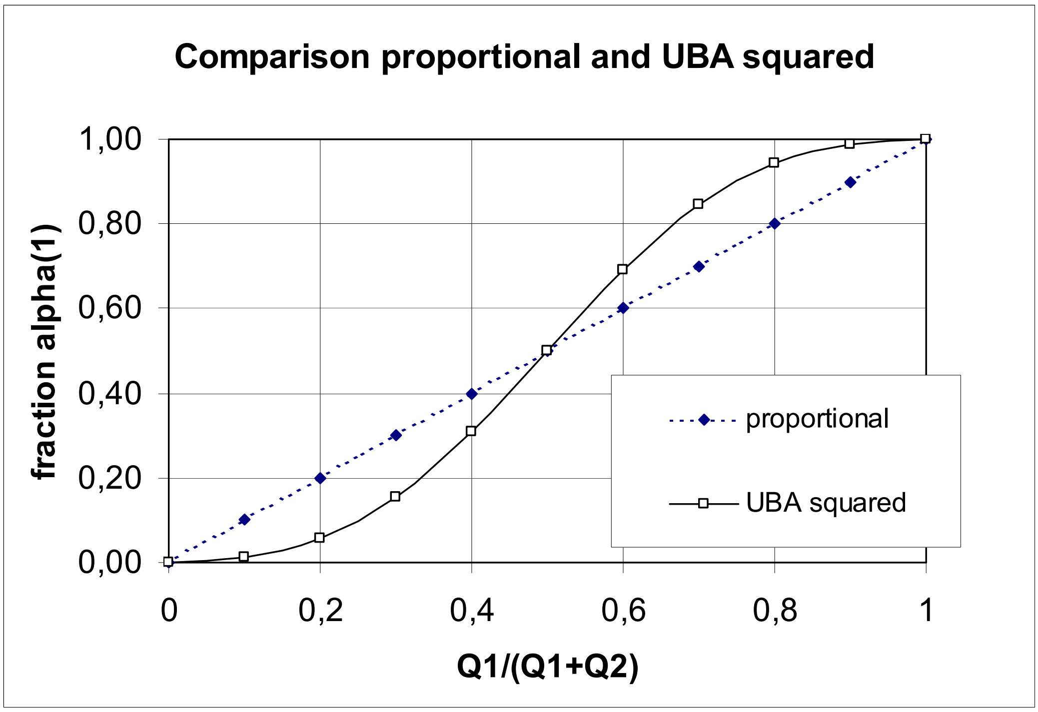

Fig.1 Comparison of proportional allocation and RP85 allocation if relative uncertainties are equal. Only α(1) is shown. α(2) = 1 – α(1)

3.4 The Uncertainty In The Bulk Quantity

Apparently the authors of RP 85 are not happy with the term that represents the uncertainty in the bulk measurement: $(1/n)^*\sigma_B^2 / (\sigma_B^2 + \Sigma\sigma(j)^2)$ as it would "feel" unfair.

They propose to replace the factor 1/n by Q(j)/ ΣQ(i) and accept that the solution is sub-optimum. [2, Appendix E]

However, if one is prepared to accept a deviation from the mathematical optimum solution, then a much simpler and in my view more elegant sub-optimum formula would be obtained by simply deleting the whole term from the formula. The consequence is that ∑ α (i) is no longer unity, but that can be resolved. For example by stating that the uncertainty in the bulk measurement is zero. Which would be consistent with the fact that the bulk quantity is not adjusted anyway. (See also 3.6 below)

3.5 Random Errors

The mathematical derivation of the "optimum" solution uses a number of assumptions. One of these is that are no systematic components in the measurement errors. This assumption is used in the derivation of the expectations of the variances of the resulting individual errors i.e. the errors after the imbalance allocation has been applied.
I am of the opinion that this assumption is not correct as is explained below. As a consequence the mathematical basis under the derivation of the "optimum solution" would be absent. The arguments are the following:

It would be beyond the scope of this extended summary to enter into an argument about the definition of random and systematic errors. For those interested, the author's opinion on that subject is condensed in [4].
Fortunately a definition of random errors is not really required in the context of this discussion. For the derivation of the "optimum" solution in RP 85, it would be sufficient (and easier defined) to require that the measurement errors in the contributing streams are uncorrelated. Thus the expectation of cross-products of errors would indeed vanish.

However, especially in the case of wet gas metering, where RP 85 is primarily targeted at, the measurement errors are most likely strongly correlated. An important error source is in the wetness correction formula. Scientists are still improving this formula, taking into account more properties of the multiphase streams. Errors due to shortcomings of these models are very likely strongly correlated. Therefore the expectation of the cross-products should not be assumed to vanish.

Another assumption made is that by proper calibration the “systematic” errors in measurements can be eliminated. However this is debatable. During calibration also a measurement error will be made, which may be considered random at that moment in time. But for the period until the next calibration this error is a bias and hence systematic. It might be that this error, although systematic, is still uncorrelated with the other errors. But it would require further analysis before it can be assumed that these calibration errors are uncorrelated.

However, as said earlier, the discussion about randomness of errors is believed to be beyond the scope of this summary. In the formulas proposed in the next paragraphs for an alternative uncertainty based allocation method, the subject does not play a role.

3.6 Special Aspects of the UBS Method by Melbø et.al

As the authors of this method point out themselves, the results of the method are very similar to those of the RP85 method. The most striking difference is perhaps that in the Melbø method the consequence of assigning an uncertainty to the bulk measurement is that also the bulk measurement has to be adjusted (reconciled). In normal language it means that if the bulk measurement has a finite uncertainty, then it shall also take its share of the imbalance. From a scientific point of view this is very elegant and it leads to formulas that are very transparent. In RP85 that consequence is not accepted (for good reasons) and the part of the imbalance that should be allocated to the bulk measurement is allocated to the feeding streams. In the modified RP85 method this is done proportional to the flow rates.

Although scientifically elegant, adjusting the bulk metered value is a revolution with respect to conventional practice and will become a contractual and accounting nightmare in financial allocation systems. It is very understandable that RP85 does not accept this consequence.

4 DIFFERENT OPTIMISATION CRITERIA

As mentioned above, an optimum solution is entirely dependent on the criteria applied. Various criteria are possible in principle. The least square minimisation is only one of them.

The criteria that I consider important though, are

4.1 The less accurate a stream, the bigger its share of the imbalance (this is the basis for UBA and common with the previously discussed methods)

4.2 The solution shall have a smooth transition to conventional proportional allocation methods, as explained in section 3.3.

4.3 "Simplicity is the seal of truth" i.e. the solution shall not be more complicated than necessary to achieve the objective.

5 A SOLUTION SATISFYING THE REQUIREMENTS

There is a solution (there might be more) that satisfies all three criteria mentioned above. In that sense that solution is "optimal". This "optimum" solution is

$$\alpha(j) = \sigma(j) / \sum \sigma(i) \qquad (5)$$

Note that σ(j) represents the absolute uncertainty of stream j. If one introduces the notation $\sigma_r(j)$ for the relative uncertainty, then (5) can be rewritten as

$$\alpha(j) = \sigma_r(j)*Q(j) / \sum \sigma_r(i)*Q(i) \qquad (6)$$

From this it can easily be seen that the three criteria 4.1 until 4.3 are satisfied. In the case that the streams (j) are measured with the same relative uncertainty (all $\sigma_r(j)$ have the same value), formula (6) reduces to formula (3), which was the formula for conventional proportional allocation.

6 QUANTIFICATION OF THE UNCERTAINTY

This remains a very difficult task, which is considered outside the scope of this paper. In [3] an interesting method for this is presented. An issue will remain that for an allocation contract more transparency and simplicity may be required.
In my humble opinion it may be a practical solution that in an allocation contract in which uncertainty based allocation is used, there will also be an appendix simply stating what values have been agreed between partners for the (relative) uncertainties of the various stream measurements.

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Traceable Calibration of Liquid Densitometers

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Traceable Calibration of Liquid Densitometers

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1 INTRODUCTION

Density measurement is a key element of both mass and volume flowrate measurement in the oil industry. The most widely implemented approach for mass flow measurement is to use a volumetric flowmeter and a densitometer. In this case, the uncertainty in mass flow measurement is dependent equally on the uncertainty in volumetric flowmeter measurement and in densitometer measurement. The calculation of volume flow rate however also requires a knowledge of the density since it is necessary to reduce the measurements of volume throughput to standard conditions. It can therefore be seen that density measurement, volumetric and mass flow measurement are of equal importance.

The essential requirements of a density measurement system are that:

- calibrations should only be carried out using instruments that form part of a calibration chain traceable to national standards and

- densitometers should be checked and calibrated regularly at actual operational conditions.

All commercial densitometers, for use on gases or liquids, operate on an oscillatory principle and as such are not independent of other fluid properties. However, the theory of such methods is not rigorously established and even with careful design it is not possible to uncouple fully the effects of density from the other physical properties of the calibration fluids. To maximise the accuracy attainable with such densitometers, it is necessary to calibrate them against reference fluids with similar physical characteristics (such as speed of sound and viscosity).

However, the calibration of most industrial densitometers is undertaken using fluids whose physical characteristics are significantly different to the actual working or operational fluids. Additionally, the range of pressures and temperatures at which the instruments are normally calibrated is limited to near ambient conditions but many densitometers, particularly those used in offshore applications, operate under high pressure, high temperature conditions. This can be a significant source of error in density measurement. Ideally, calibration should be undertaken at metering pressures and temperatures using fluids whose volumetric properties are known accurately across the full temperature and pressure range required for the calibration.

Whilst the existence of these effects has been recognised, it was accepted industry practice to quote a calibration at only a single reference temperature (generally 20°C) and apply correction factors to account for the influence of temperature and pressure on both the calculated density and its uncertainty. However, recent work has raised a number of issues with regard to the whole calibration process, in particular when a densitometer is operated at a temperature different from the reference temperature. This has significant implications for fields operating in common transportation systems, where the mass allocations are based on densitometer readings. As a result, the Aberdeen-based Licensing and Consents Unit of DTI's Energy Group identified a need for research into practical methods for the in-situ calibration of densitometers, as well as a greater understanding of the effects on densitometer performance of variations in product density, pressure and temperature. A Joint Industry Project involving oil companies, densitometer suppliers, DTI and NEL was therefore set up to address that requirement [1].

2 BACKGROUND

The aims of this project are:

- to give confidence in high temperature and pressure densitometer measurements by developing well characterized transfer standard fluids and

- to establish a calibration procedure that ensures traceability to National Standards, making use of the existing National Fluid Density Standard Facilities for high temperatures and pressures developed under previous Flow Programmes.

Using the National Density Standard Facilities, two densitometers of a commercial design will be calibrated across a range of temperatures and pressures using transfer-standard fluids characterized in the Primary Liquid Density Facility. Results from each densitometer will be assessed for accuracy and stability across the range chosen. The test programme will investigate the influence of fluid properties (density and viscosity), densitometer temperature and pressure on the calculated densities provided by the densitometers.

The calculated density values produced by the densitometers will be compared with the accurately known values for the transfer fluids and any differences noted. This will provide an assessment of the suitability of the current calculation procedure to convert measured oscillation periods to densities accurately across the full operational temperature and pressure range required for UK Continental Shelf use. In the event that significant differences are found, better calculation procedures will be developed.

As part of previous Flow Programmes, DTI funded the establishment of density standard facilities at NEL [2]. These consist of two primary standard densitometers, one each for liquids and gases. In addition, a transfer standard facility for the calibration of liquid densitometers (insertion and in-line devices) was also developed. The existence of the primary liquid densitometer and the transfer standard facility means that this project does not have to invest in costly and time-consuming facility development.

The National Fluid Density Standard Facilities were maintained in a mothballed state during the 2002-2005 Flow Programme. The task of bringing the facilities back up to full operational standard has been undertaken as a project within the 2005-2008 Flow Programme. The main part of the project, characterization of transfer standard fluids and characterization of reference densitometers, is being cash co-funded through a Joint Industry Project (JIP). To date, 13 operators (Talisman Energy (UK) Ltd, BP Exploration Operating Co Ltd, Paladin Resources Ltd, Kerr-Mcgee North Sea (UK) Ltd, BG International (CNS) Ltd, ChevronTexaco, Marathon Oil UK Ltd, Amerada Hess Ltd, Shell UK, Total E & P UK plc, ConocoPhillips, Exxonmobil and Nexen) and the densitometer manufacturer Solartron have joined the project. Discussions are also ongoing with other operators and densitometer suppliers. DTI Energy Group, Licensing and Consents Unit, Aberdeen, have also joined the project.

3 DENSITOMETER THEORY

All commercial liquid density transducers operate on the same general principle. The manufacturers generally model the instruments as a simple spring mass oscillator system comprising the vibrating test section and the fluid contained in it, totally disregarding hydrodynamic effects. As the liquid density changes it in turn changes the total vibrating mass, which is then detected by a change in the resonant frequency. For a simple system, the resonant frequency is given by:

$$f = \frac{1}{2\pi}\sqrt{\frac{K}{M}} \tag{1}$$

where K is the stiffness and M is the mass of the element (M_1) plus the mass of the fluid (M_2).

If K, M_1 and V (the volume of fluid in the test section) are constant then equation 1 can be written in terms of density ρ as

$$\rho = K_0 + \frac{K_2}{f^2} \tag{2}$$

where $K_0 = -M_1/V$ and $K_2 = K/4\pi^2 V$, or, in terms of oscillation period τ,

$$\rho = K_0 + K_2\tau^2 \quad . \tag{3}$$

In recognition that equation 1 is only a first approximation to the actual behaviour of an oscillating tube filled with liquid [3], equation 3 is normally modified by the inclusion of a linear term K_1, giving an empirical expression of the form

$$\rho = K_0 + K_1\tau + K_2\tau^2 \quad . \tag{4}$$

At any given temperature and pressure the three constants in equation 4 can be determined by calibrating the device with three fluids of known density. To ensure the highest accuracy this should be undertaken across the full operational temperature and pressure range, thus requiring a knowledge of the density of each calibration fluid at the corresponding conditions. Accepted practice however has been to calibrate at one reference temperature (normally 20°C) at atmospheric pressure to determine the coefficients at those conditions and then apply correction terms to account for the effects of operation at other temperatures and elevated pressure. The correction terms are of the form

$$\rho_T = \rho_0\{1 + K_a(T - T_0)\} + K_b(T - T_0) \tag{5}$$

where ρ_0 is the density at the reference calibration temperature T_0 and

$$\rho_{T,P} = \rho_T\left\{1 + K_c(p - p_0) + K_d(p - p_0)^2\right\} + \left\{K_e(p - p_0) + K_f(p - p_0)^2\right\} \quad . \tag{6}$$

Current industrial calibration practice is to calibrate each densitometer in a test rig using three fluids at atmospheric pressure and the reference pressure, the density of each test fluid being measured by two in-line transfer standard densitometers. The transfer standard densitometers are periodically calibrated using fluids of accurately known density. From at least 1986 accepted practice was to check the temperature coefficients (K_a and K_b in equation 5) of the transfer standard densitometers using air and then apply corrections for use with other calibration fluids and assume that no systematic bias was introduced. However, a note issued by the Licensing and Consents Unit of DTI's Energy Group [4] summarising a review carried out by industry, has found that there is a small but systematic 'offset error' when a densitometer is operated at a temperature different from the reference temperature.

Although the magnitude of the particular offset error identified by DTI seems small, 0.014kg m^{-3} K^{-1}, a number of UK Continental Shelf fields operate with measuring stations at temperatures approaching 100°C. For a field producing 50,000 barrels per day the mis-measurement at the platform would be of the order of 25,000 barrels per annum. A similar effect will occur at the on-shore terminal. If the oil from a number of fields has been fed in to a common pipeline the allocation to each field is based on the 'measured' mass fed in by each. Clearly the actual mis-allocations will depend on the temperatures of each off-shore measuring station, the flow rates and the temperature of the on-shore measurements but could easily run to 10s of thousands of barrels per annum for each field. Assuming an average price of £12 per barrel, this amounts to £6 million over the 20 odd years this systematic error has been occurring. The mismeasurement on condensate fields will be greater than that for oilfields, as the relative error in density measurement is greater for lower-density product; in addition, condensate production tends to be at relatively high temperatures. Taken over the whole of the UK production, mis-allocation errors arising from this effect alone could run to several million pounds per annum and possibly hundreds of millions over a 20 year period.

In addition to this specific point, the review has raised a number of issues with regard to the whole calibration process and the calculation methodology. NEL have been aware for many years of the influence of other fluid properties (primarily viscosity and speed of sound) on the operation of oscillatory densitometers and sponsored work to investigate these effects [5-6]. For liquids, this clearly demonstrated the coupling between density and viscosity: it is possible to optimise a vibrating element to respond to either density or viscosity as a first-order effect but the other property is always present as a second-order effect. Accurate characterisation, and calibration, of oscillatory densitometers therefore requires knowledge of the effects of temperature and pressure on a number of fluid properties across the full operational range of the device. Furthermore, a complete characterisation of a vibrating tube densitometer would also require to investigate additional effects including fluid velocity, torque loading, mounting misalignment etc.

4 TECHNICAL APPROACH

The NEL Primary Standard Densitometers are both based on the Archimedes buoyancy principle in which the density of a fluid is determined from measuring the apparent mass of a body immersed in the fluid:

$$\rho = \frac{m_S - m_S^*}{V_S} \tag{7}$$

where m_S is the 'true' mass of the sinker, m_S^* is the apparent mass of the sinker when surrounded by the fluid and V_S is the volume of the sinker. m_S can be determined by vacuum weighing and V_S by calibration with water. Because of the small differences between the true an apparent masses when working with gases the NEL Primary Standard Gas Densitometer uses a dual-sinker system. For the Primary Standard Liquid Densitometer that will be used for this work a single-sinker system is sufficient (Figure 1). A magnetic suspension coupling transmits the apparent mass of the sinker through the pressure vessel and thermostated bath to a precision microbalance.

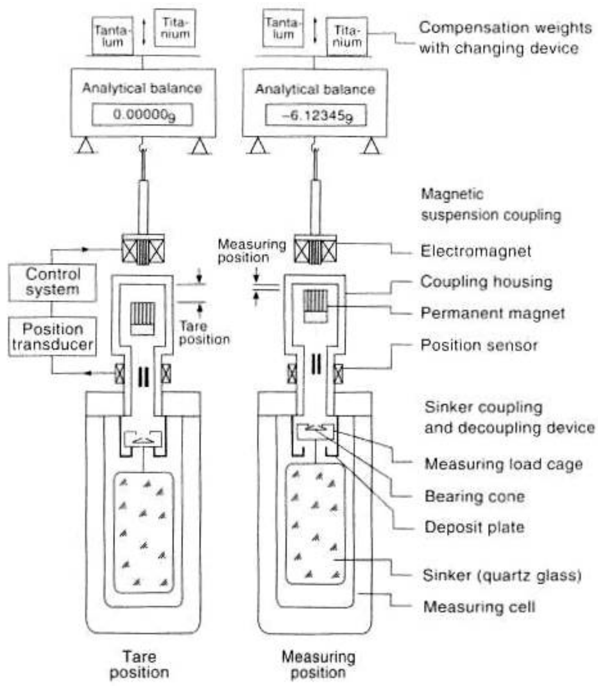

Fig. 1 – NEL Primary Standard Liquid Densitometer

The Primary Standard Liquid Densitometer is capable of determining the density of liquids across the temperature range from -40 to 150°C at pressures from 0.1 to 30 MPa with an expanded uncertainty of 0.015% (at 95% confidence).

The Transfer Standard Facility for the calibration of liquid densitometers consists of a thermostated enclosure with fluid pressurisation (Figure 2). The temperature of the enclosure can be controlled across the range from 10 to 125°C with an expanded uncertainty of 0.005K (at 95% confidence) and the fluid in the densitometer controlled between 0.1 and 20 MPa with an expanded uncertainty of 0.01% (at 95% confidence).

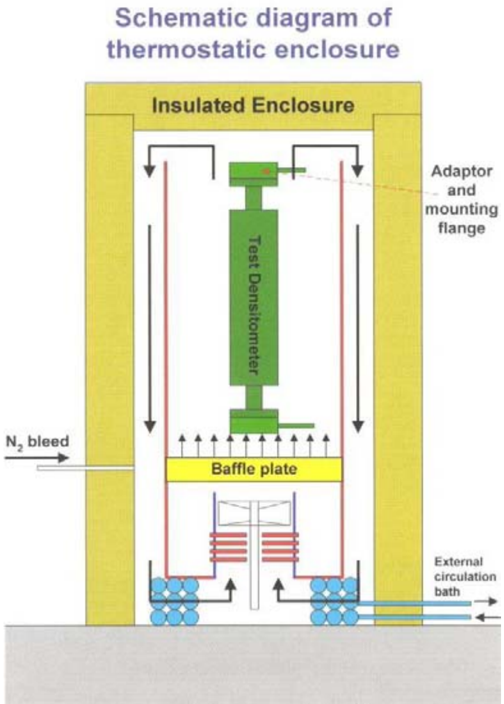

Fig. 2 – NEL densitometer transfer standard facility

The original concept for the Transfer Standard Facility envisaged that the facility would be directly linked to the NEL Primary Standard Liquid Densitometer. Whilst this has the merit that the fluid in the densitometer under calibration is the same as that in the Primary Standard Liquid Densitometer and at identical conditions, thus minimising the uncertainty in the fluid density, it has a number of practical drawbacks. In particular, the time required for the Primary Standard Liquid Densitometer to reach equilibrium and make a measurement is substantially longer than the time required in the Transfer Standard Facility. In addition, the task of cleaning the Primary Standard Liquid Densitometer is time-consuming, particularly if it has been filled with difficult fluids such as heavy oils.

In view of these considerations, a better approach is to use stable, accurately characterised transfer standard fluids. The first task is therefore the selection of a sufficient number of suitable fluids. As noted in Section 3, there is a coupling between fluid density and viscosity in an oscillatory densitometer and it is envisaged that a minimum of four fluids will be required to cover the density and viscosity ranges which are encountered across the full temperature and pressure range of operation of UK offshore oil facilities.

To be considered for use as true transfer standard fluids, the fluids must either be single components or stable mixtures of known composition. Such fluids have the advantage that once their PVT behaviour has been established (using the NEL Primary Standard Liquid Densitometer) they can then be used in any other (transfer) facility without further characterisation, thus providing much closer traceability to primary standards.

The Primary Standard Liquid Densitometer and the Transfer Standard Facility have now been fully re-commissioned. In addition to recalibration of all the instrumentation a number of minor modifications have been made to both facilities to simplify operation, particularly with high viscosity fluids. A survey of the JIP members provided information on current and future densitometer operating conditions. The temperatures, pressures and densities determined from the survey are all within the range of capabilities of both the primary standard densitometer and the transfer standard facility. Potential transfer standard fluids have also been identified and work is in progress on the first fluid.

4 CONCLUSIONS

Completion of the overall project (re-commissioning the facilities and undertaking the measurement programme) will provide the first stage in establishing a calibration procedure to provide traceability to National Standards for densitometers used in the UK sector of the North Sea and Continental Shelf. According to Douglas Griffin, DTI Oil & Gas Regulator,

> "Errors in flow measurements using densitometers could run to several million pounds per annum and possibly amount to hundreds of millions over the last 20 years. This is the single biggest mis-measurement issue in the history of oil production and the Flow Programme has provided the impetus for the whole industry to address the issue".

In addition to providing traceability for calibrations, the project is expected to lead to standards for the calibration of oscillatory densitometers for liquid service.

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Impulse-Line Blockage Diagnostics of Differential Pressure Flowmeters

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Impulse-Line Blockage Diagnostics of Differential Pressure Flowmeters

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1 INTRODUCTION

Differential pressure (DP) flowmeters are widely used throughout industry. Although DP transmitters and orifices are very reliable, impulse-lines are vulnerable to blockages caused by fluid condensation, freezing, or corrosion. Blockage diagnostics technique has been developed by detecting fluctuations of static, differential pressures.

2 DIAGNOSTICS BY SENSING PRESSURE FLUCTUATIONS

In general, fluids in closed conduits flow in turbulent region, which cause fluctuations in static and differential pressures. When blocking in impulse lines occurs, the amplitude of fluctuations decreases. Silicon-based resonant sensors are capable to detect rapidly the fluctuation amplitude for both static, differential pressures. Diagnostics algorithm is based on statistical calculation of these fluctuations and provides prognostic information of impulse-line blocking status in order to reduce maintenance workload.

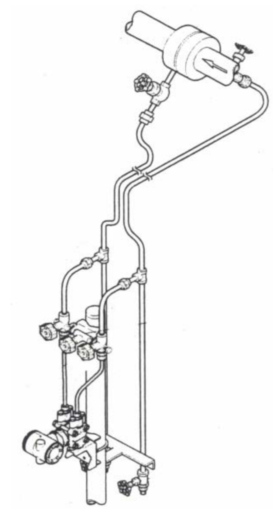


Fig.1 Impulse-line connection for liquids

3 FLUCTUATIONS OF STATIC AND DIFFERENTIAL PRESSURES

Fluctuating components of static, differential pressures generally decrease when an impulse line is blocked. Fluctuating components are calculated as the square summation of the difference of static and, differential pressures that are sampled at very short time intervals.

Table 1. Fluctuating component values in impulse lines

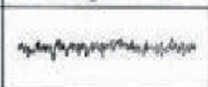
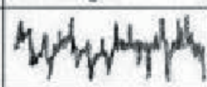
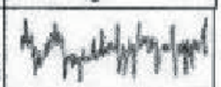
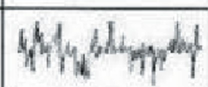
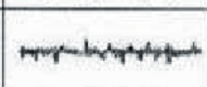
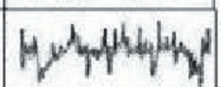
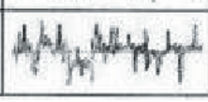
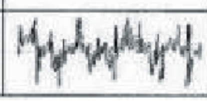
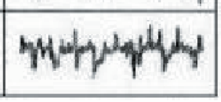
	H/L side both blockage	H side blockage	L side blockage	No blockage
PH (Static Pressure H side)				
PL (Static Pressure L side)				
DP (Differential Pressure)				

Table1 shows the value of the fluctuating components when blocking occurs on the Hi-side, Lo-side, and both sides. The values for when no blocking occurs are also shown. When both sides of impulse lines are blocked, all fluctuating components decrease. When one side of an impulse line is blocked, the corresponding fluctuating component decreases. In this case the fluctuating component of differential pressure is larger than when no blockage occurs.

4 DIAGNOSTICS ALGORITHM

Differential pressure DP is the difference between Hi-static pressure PH and Lo-static pressure PL; DP=PH – PL, then fluctuating components are described as $F_{dp}(i)=F_{PH}(i) - F_{PL}(i)$, where i stands for sequential timing of sampling. For definite interval of total sampling N, the extent of fluctuation is represented by following definition:

$$R.M.S_{dp}=SQRT(Sum(F_{dp}(i)^2)/N)\ ) \qquad (1)$$

$$R.M.S_{PL}=SQRT(Sum(F_{PL}(i)^2)/N) \qquad (2)$$

$$R.M.S_{PH}=SQRT(Sum(F_{PH}(i)^2)/N) \qquad (3)$$

Taking into account that when Hi-side impulse line is blocked, correlation between $F_{PL}(i)$ and $F_{dp}(i)$ becomes dominant, we derive the blocking factor F using correlation functions CorL, CorH as follows:

$$CorL=Sum(F_{dp}(i)\cdot F_{PL}(i))/N/(R.M.S_{dp}\cdot R.M.S_{PL}) \qquad (4)$$

$$CorH=Sum(F_{dp}(i)\cdot F_{PH}(i))/N/(R.M.S_{dp}\cdot R.M.S_{PH}) \qquad (5)$$

Error! Objects cannot be created from editing field codes. (6)

Blocking factor F approaches to +1 for Hi-side blocking and -1 for Lo-side blocking. Generally in most applications, impulse-line blocking would not progress at same rate. Whichever impulse-line is blocked, we can diagnose blocking status of the impulse-lines by means of the blocking factor F.

5 BLOCKING DIAGNOSTICS FOR WATER FLOW

Fig.2 shows blocking diagnostics for water flow using flow test facilities. Needle valves are installed in the middle of the impulse-lines, simulating impulse-line blocking. The figure shows the blocking status of Hi-side and Lo-side in which F approaches +1 and -1 respectively.

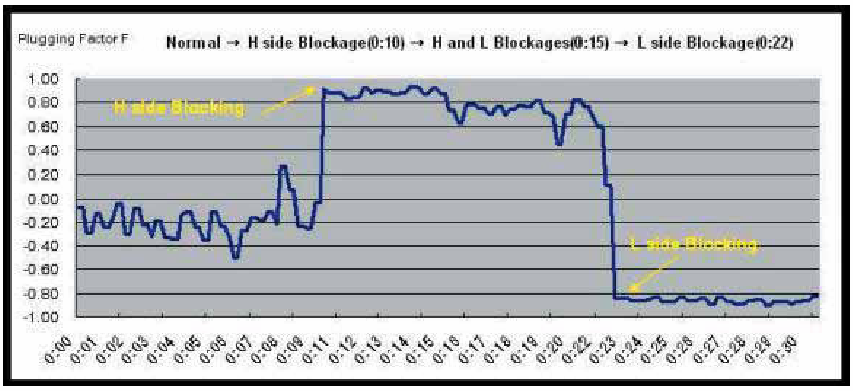


Fig.2 Blocking diagnostics for water flow

The blocking factor can be effectively used for predictive diagnostics of impulse-line blockage.