FOCUS DISCUSSION GROUP A

Recent Developments in Flow Measurement as it Relates to the Oil And Gas Industry.

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RECENT DEVELOPMENTS IN FLOW MEASUREMENT AS IT RELATES TO THE OIL AND GAS INDUSTRY

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Abstract

In recent years developments in traditional flowmeter technology have substantially increased their functionality and performance, due in part to the wider acceptability and use of microprocessor based smart electronic transmitters. Similar developments have been taking place in other areas of instrumentation such as temperature measurement. The logical progression of such improvements is the consolidation of multiple process variables in a single transmitter package giving the user real-time compensated flow outputs, and access to the raw data for informational use. The emergence of this technology gives rise to a new generation of "head type Multivariable Flowmeters". Multivariable technology will, in the coming years, appear in other traditional flowmeters such as magnetic, vortex and ultrasonic. The implications to the user are significant cost savings and dramatic changes in the current control architecture. This paper includes an explanation of recent developments in multivariable flowmeters including calculated performance results for both liquid and gas, and recent advances in vortex flowmeters with practical experiences on their applications in the oil and gas industry.

Introduction

Differential pressure, *or head-class* metering is probably the most written about and best understood of all flow technologies, and historically is the most used; approximately half of all flow meters sold in the world today are differential pressure meters. The basic principle for measurement is Bernoulli's streamline energy equation. When the flow is contracted due to the insertion of a primary element such as an orifice plate or pitot tube, Kinetic energy increases resulting in a decrease in potential energy (static pressure). The pressure difference between the upstream (full pipe) section and the constriction at the primary element exhibits a square root relationship to the fluid velocity and can be written as:

$$q = K\sqrt{\frac{h}{d}} \quad (1)$$

Where: q = Flow rate
K= Meter constant
h = Differential pressure
d = density

Due to the square root relationship from equation (1), a transmitter with a 100:1 DP turndown is the same as a 10:1 flow turndown.

Mass Measurement

In measuring gasses, significant changes in actual volume can occur when operating conditions vary, resulting in significant uncertainties in the flow measurement. Pressure and temperature compensation has traditionally been the most commonly applied method of compensating for these uncertainties, this method assumed the compressibility factor was constant at operating conditions and often neglected compressibility effects as shown in the simplified equation: —

$$q_m = K_2 \sqrt{\frac{h\,P}{T}} \quad (2)$$

The use of microprocessor based flow computers significantly improves the accuracy of gas flow measurement; particularly natural gas where dynamic compensation is standard. Compensation is achieved through utilizing the inputs from a Differential Pressure, a Gauge Pressure and a Temperature transmitter. The flow computer can perform complex mathematical functions that relate to flowmeter output such as fluid density, flowmeter gas expansion coefficients and supercompressibility factors.

$$q_m = N\, C_d\ E\ Y_1\ d^2 \sqrt{\rho\ h} \quad (3)$$

where: Q_m = Mass flow rate
N = Units conversion factor
C_d = Discharge coefficient
E = Velocity of approach factor
Y_1 = Gas expansion factor
d = Orifice bore
ρ = Fluid density
h = Differential pressure

This method does, however, have a number of drawbacks including cost, high maintenance, cumulative errors of the transmitters, and programming requirements of the flow computer. Recent developments in ASIC technology has resulted in the emergence of a single Multivariable™ Mass Flow Transmitter which performs the same measurement and computing functions as the system previously described, but with greater accuracy and at a fraction of the total installed cost. Configuration is done through an Engineering Assistant software package containing all process information. With the advent of HART® digital communication users can now have access to a wide range of real-time process data.

Multivariable™ Transmitters

A Limiting factor to DP/orifice meter measurements has historically been the limitations on range (nominally 4:1). Test data from four Multivariable™ transmitters show that differential pressure does not significantly affect the flow data until 8:1 range down is achieved. Uncertainty is due largely to the geometry and installation of the orifice plate itself and properties of the gas or liquid such as viscosity and density. Indeed, the flow discharge coefficient proves to be the largest contributor to the overall uncertainty. To calculate flow uncertainties actual differential pressure data was used. The test results showed the average pressure uncertainty to be 0.04% . The temperature uncertainty was assumed to be 0.2%. The units tested had 62.2KPa of water URL (Upper Range Limit) differential pressure sensors, and 5515KPa URL pressure sensors. The sensors for each unit were trimmed at zero and URL prior to testing. Figure 1 shows the differential pressure range down results at 1378.95KPa static pressure along with the calculated flow uncertainty for the air flow example. The results for the water flow example were essentially the same.

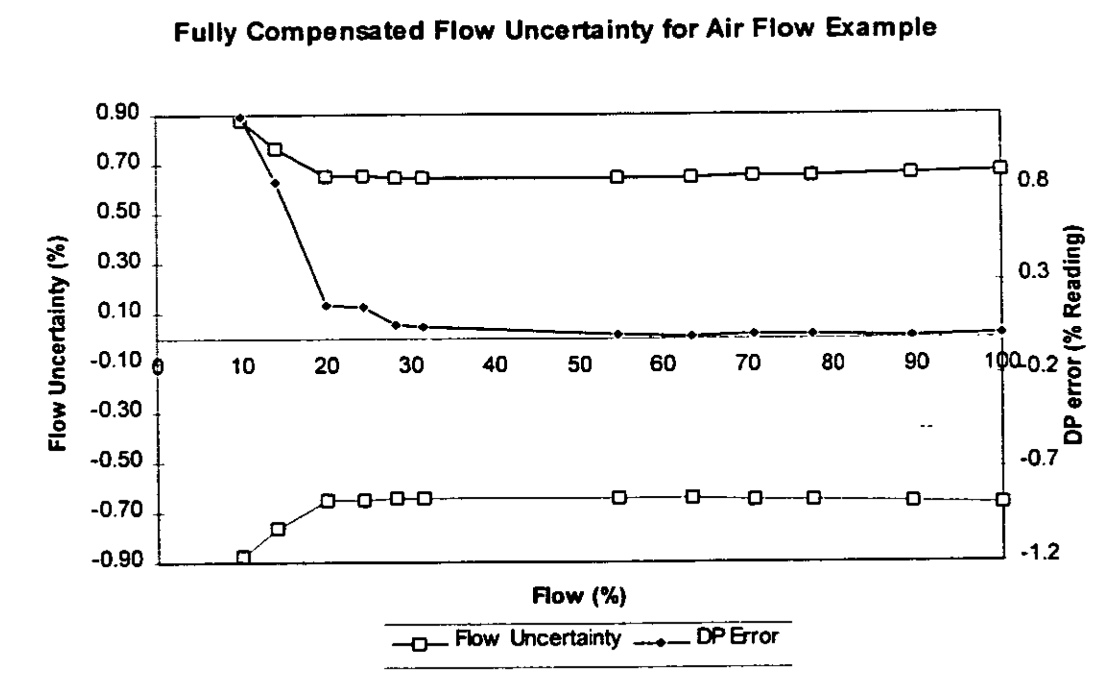

Figure 1. - DP Error and Flow Uncertainty vs. Flow Range

Table 1. shows a breakdown of the maximum flow uncertainty. This point occurred at 100:1 range down in differential pressure or 10:1 in flow.

Term	Uncertainty %	% Cont.
Cd	0.6	46.26
Y1	0.108	1.50
D	0.4	1.82
d	0.07	3.32
h	1.19	45.43
r	0.227	1.66
Total	0.88	100

Table 1.

Where Cd = Discharge coefficient
Y1 = Gas expansion factor
D = Meter tube diameter (inches)
d = Orifice bore
h = Differential pressure
r = Fluid density

Even at high range downs, exceeding 8:1 rangedown in flow, the overall calculated flow uncertainty was less than 1% for all four transmitters.

Applications of Multivariable Transmitters in the Oil & Gas Industry

Heat management is an important area in which cost savings can be realized; one company in California, USA, reduced production costs from \$6.27/bbl in 1990 to \$4.86/bbl in 1994 due in large part to better heat management. Steam, gas and liquid measurement can be achieved through Multivariable pressure transmitters or Vortex meters with accuracy's of 1% or better.

The measurement of natural gas has very specific requirements as to how flow calculations are to be performed. In addition, many government agencies place strict audit trail requirements on the natural gas industry, creating the need for non-volatile logging of such parameters as process variables, flow rate calibration changes, orifice plate changes etc. Multivariable transmitters have undergone testing at the Colorado Engineering Experiment Station (CEESI). The results are summarized below.

The tests at CEESI were totalizing tests conducted with air as the flowing medium. A series of four tests were run on two transmitters using the CEESI gravimetric Primary A system as the reference. A 2 inch orifice meter run with a beta ratio of 0.2 was used across the tests. The two 3095FT transmitters were connected in parallel across the orifice meter to provide redundant data. The test conditions are tabulated in table 2.

Test Number	Static Pressure (KPa)	Differential Pressure (KPa)	Temperature Deg.C	Test Duration
1	2068.427	37.326	21	4 Hours
2	2068.427	37.326+/- 6221	21	4 Hours
3	2068.427	37.326	21	4 Hours

	+/- 344.738			
4	2068.427	37.326 varied to 0	21	4 Hours

Table 2.

During tests 2 &3 the conditions were held at the respective levels for approximately one half hour. Changes in the flow conditions were made over approximately one minute. During test 4 the flow was shut off for several minutes at a time. Both transmitters were configured to calculate the compressibility factor using the Detail Characterization Method of A.G.A. Report No.8. Since the limits for the various constituent gases in this report allows for a gas composition which matches that of air, no correction was required to compare the results with those from CEESI's primary system. The results are tabulated in Table 3.

Test Number	CEESI Total Mass (Kg/m)	3095 FT #1 Total Mass (Kg/m)	3095 FT #2 Total Mass (Kg/m)	Deviation 3095 FT #1 (%)	Deviation 3095 FT #2 (%)	Deviation Between 3095 Fts (%)
1	4308.018	4276.463	4276.884	-0.732	-0.723	0.0098
2	4281.288	4255906	4257.286	-0.593	-0.561	0.0324
3	4284.72	4255.603	4256.562	-0.680	-0.657	0.0255
4	2170.872	2156.550	2156.330	-0.861	-0.871	-0.0102

Table 3.

As can be seen from the above data, this Multivariable meter performs well within the requirements for the natural gas industry as a logging meter.

Vortex

Recent improvements in vortex shedder bar design and signal filtering has increased the acceptability of this technology in the industry. Historical problems such as susceptibility to vibration and process noise which had previously excluded it from many installations have been overcome, allowing the use of an accurate volumetric instrument which provides negligible pressure loss.

Resistance to vibration noise is achieved through mass-balancing of the shedder bar and sensor. An 8800 meter was tested under SAMA PMC 31.1-1980 Section 5.3 condition 3. from 5 to 2,000 Hz. The results are shown in Figure 2.

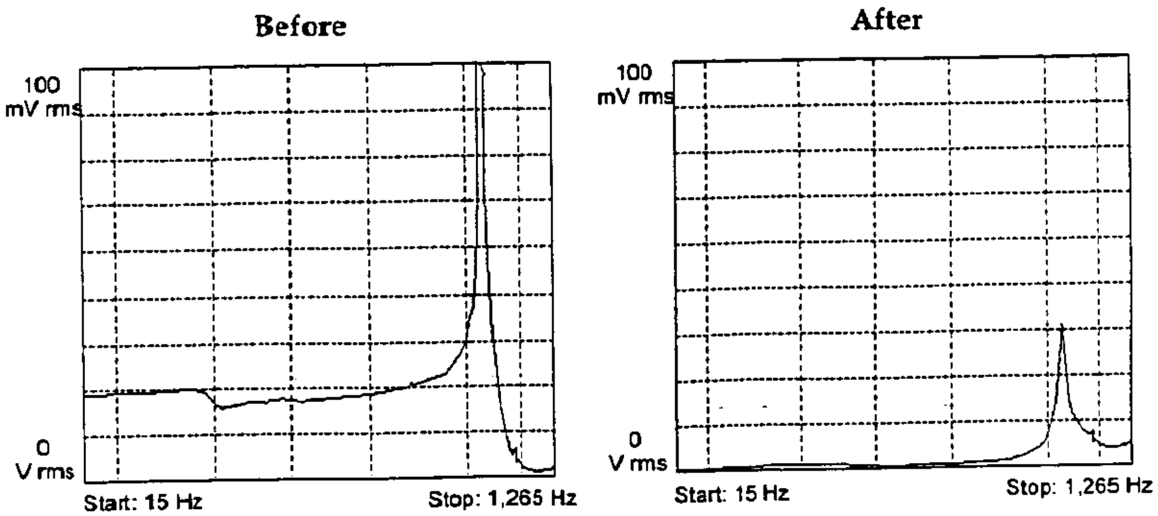

Figure 2.

Effects due to process noise are filtered out by means of Adaptive Digital Signal Processing (ADSP). At low flow rates, vortex signal amplitude is small and the signal to noise ratio can be adversely affected by the presence of both low and high frequency noise components. At higher flow rates the greater velocities result in higher amplitude signals, but those signals can be distorted by low frequency noise components. Signal to noise degradation is compounded by the potential amplitude swings presented by wide flow and density ranges. When density is constant, the flow range is approximately 25:1. This results in a significant amplitude range of 625:1. Density variation from atmospheric pressure air to liquids represents an 800:1 density range. This variation results in an even wider range of signal amplitudes. The wide dynamic range of the vortex signal coupled with the inherent potential for noise make the problem of accurate measurement a challenge.

The filtering scheme now available on the 8800 Vortex Transmitter reduces the effects of low and high noise components while enabling measurement of the vortex frequency throughout the wide dynamic range of the signal.

Conclusion

Companys are facing increasing pressures from competitors and shareholders to decrease costs and maximize profits. Transmitter technology is developing at a fast pace, more process information and control functions are being made available at the transmitter.
Instrumentation which provides greater flexibility and multiple process variables in real-time enables the user to better understand and control the process. Increasing the efficiently of steam injected into the well is one such example.

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