INTERNATIONAL JOURNAL OF ADVANCED STUDIES IN COMPUTER SCIENCE AND ENGINEERING
IJASCSE VOLUME 5 ISSUE 11, 2016
11/30/2016

Signal Processing and Applications in Metering System

A. Harrouz and A. Benatiallah
Department of Hydrocarbon and Renewable Energy,
Laboratory LEESI, University of Ahmed Draïa,
Adrar, Algeria
Harrouz.onml@gmail.com Benatiallah.ali@gmail.com

O. Harrouz
Institute of Natural Sciences and Agri-food Bordeaux (ISNAB), Bordeaux
Bordeaux, France
harrouz@isnab.com

***Abstract*—This paper presents a comprehensive study on the performance of measurements and signal processing in metering system. We have present measurement, applications and metrological control of a signal sensor from dynamic metering system. After that, we present instruments of sensor communication with more detailed discussions to the reference standards and the important fundamental parameters to consider when designing a dynamic communication metering system.**

Keywords-Metering; signal; communication.

I. INTRODUCTION

Transducers convert physical phenomena into electrical signals such as voltage and current for signal conditioning and measurement within DAQ systems. While the voltage or current output signal from transducers has some direct relationship with the physical phenomena they are designed to measure, it is not always clear how that information is contained within the output signal.

Often sensors must be remotely located from the computer in which the processing and storage of the data takes place. This is especially true in industrial environments where sensors and actuators can be located in hostile environments over a wide area, possibly hundreds of meters away. In noisy environments, it is very difficult for very small signals received from sensors such as thermocouples and strain gauges (in the order of mV) to survive transmission over such long distances, especially in their raw form, without the quality of the sensor data being compromised.

An alternative to running long and possibly expensive sensor wires is the use of distributed I/O, which is available in the form of signal conditioning modules remotely located near the sensors to which they are interfaced. One module is required for each sensor used, allowing for high levels of modularity (single point to hundreds of points per location). While this can add reasonable expense to systems with large point counts, the benefits in terms of signal quality and accuracy may be worth it. One of the most commonly implemented forms of distributed I/O is the digital transmitter.

These intelligent devices perform all required signal conditioning functions (amplification, filtering, isolation etc); contain a micro-controller and A/D converter, to perform the digital conversion of the signal within the module itself. Converted data is transmitted to the computer via an RS-232 or RS-485 communications interface. The use of RS-485 multi-drop networks, as shown in Figure 1, reduces the amount of cabling required, since each signal-conditioning module shares the same cable pair.

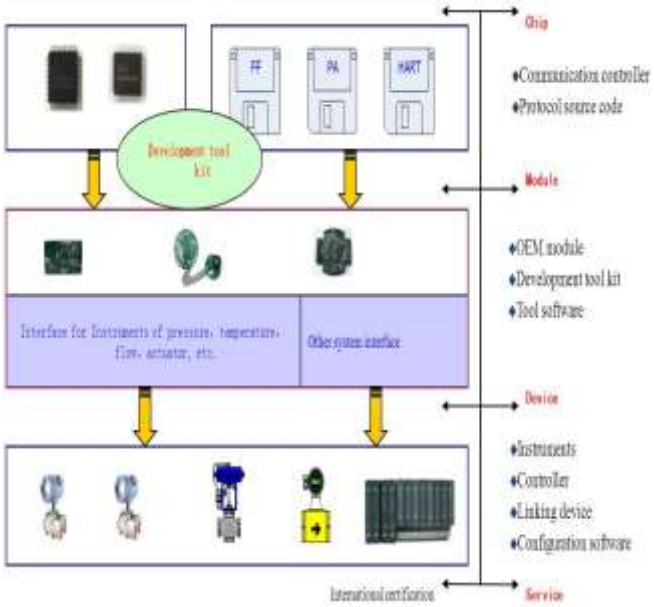

Figure 1. Digital transmitter modules and control in metering systems.

The orifice flow meter (Fig. 1) is used to create a constriction in the flow path. As the fluid flows through the hole in the orifice plate, in accordance with the law of

conservation of mass, the velocity of the fluid that leaves the orifice is more than the velocity of the fluid as it approaches the orifice [1]. By Bernoulli's principle, this means that the pressure on the inlet side is higher than the pressure on the outlet side.

Measuring this differential pressure gives a direct measure of the flow velocity from which the volumetric flow can easily be calculated. The overall accuracy of a flow meter depends to some extent on the circumstances of the application [1]. The effects of pressure, temperature, fluid, and dynamic influences can potentially alter the measurement being taken.

II. Signal Processing From Ramp Metering

Flow measurement is the quantification of bulk fluid movement. Flow can be measured in a variety of ways. Positive-displacement flow meters accumulate a fixed volume of fluid and then count the number of times the volume is filled to measure flow. Other flow measurement methods rely on forces produced by the flowing stream as it overcomes a known constriction, to indirectly calculate flow. Flow may be measured by measuring the velocity of fluid over a known area [2].

Figure 2. Flow Meters used in metering system of fluid

A. *Flow Measurments*

First, flow measurement is used for applications where extreme flowing products and conditions such as liquids mixed into gases, sand, paraffin, and many other foreign items – these are sometimes referred to as the "blood, guts, and feathers" in the producing world [3]. A producing well often brings many bits of the earth up to the primary measurement device. Orifice measurement can generally handle the worse conditions for gas measurement. Turbine meters and PD (Positive Displacement) meters can be used where there is little or no foreign matter hitting the meter [3].

Today the hot meters for large volumes of measurement are the Ultrasonic meters, first meter as show above. These meters generate sound waves along transverse sections of a single spool section of pipe. These signals are monitored, when there is flow in the pipe the sound signals sent through the gas are delayed, and the meter measures the delay of the signal. By measuring this delay precisely, the meter can determine the velocity of the gas and thus the flow rate [3]. Ultrasonic meters are very cost effective when measuring great volumes of gas that vary in flow rate.

Figure 3. Transmitters and sensors

B. *Calculator and Sensors*

The AGA-3 has written recommended practices for measurement of natural Gas when using orifice measurement. Three measuring devices in the form of transmitters or transducers for orifice measurement are the Differential Pressure, which is often integrated with the Static Pressure transducer. These integrated transmitters are called Multi Variable Transmitters (MVT) shown above. For orifice measurement a flowing temperature is necessary. This signal is usually retrieved by using an RTD (Resistive Temperature Device) thus completing the required secondary elements to measure natural gas when using an orifice or differential head measurement. For Turbine meters, Ultrasonic and PD meters only the static pressure and flow temperature is required [3].

Figure 4. Flow computer systems or calculator (*MECI: model*)

Often the quality of the gas is important enough to have a Gas Chromatograph (GC) as part of the secondary devices. A GC will sample the natural gas being measured and feed back an analysis of the gas to the Tertiary Device or flow computer. The flow computer uses this analysis to determine the compressibility of the gas along with flow volume.

The flow computer will take this data and with the use of a calculation from AGA 8 determine the compressibility of the gas under flowing conditions. Today's GC's are highly technical and expensive devices that need constant maintenance and up keep [3].

III. COMUNICATION SYSTEM OF PROCESS AND CONTROL

A. *HART communication signal*

HART (Highway Addressable Remote Transducer) protocol allows simultaneous communication of analog and digital data. This protocol serial communication type is specific to industrial and compatible control loops analog current 4 to 20 mA.

The digital signal used for additional device information including device status, diagnostics, additional measured or calculated values, etc. Therefore, the HART communication including analog and digital information provides a low-cost and very robust complete field communication solution that is easy to use and configure [3]. HART is a master/slave protocol, which provides for up to two masters (primary and secondary) and the secondary master such as handheld can used to monitor/control the information of HART bus. HART can used in various modes such as point-to-point or multi-drop for communicating information to/from smart field instruments and central control or monitoring systems. The following are the description of two main HART operation modes.

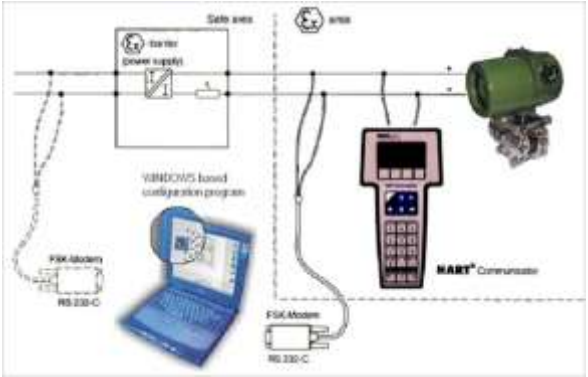

Figure 5. HART signal used to communicate with sensory in metering system.

Finally, communication made in digital form using an alternating current modules traveling web frequency is superimposed on analog current 4 to 20 mA without altering since its average value is zero. The protocol is based on a modulation system 202 and Bell method of FSK (Frequency Shift Key): the digital data are transmitted in series with a frequency of 1200 Hz for the logical state1 and a frequency of 2200 Hz for logic 0.

B. *Fieldbus*

The principle of a field bus is to link all transmitters, actuators and systems for controlling, an industrial sector in a network where all the instruments communicate with each other (Figure 6) each.

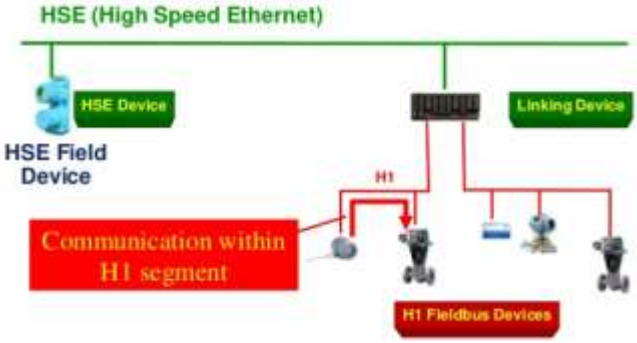

Figure 6. Fieldbus FF-H1 link all transmitters of system [8].

The two fieldbus most prevalent in the industrial process control are the Fieldbus Foundation FF-H1 and Profibus PA. They are recognized by the international standard IEC 61158-2. The only link between all the instruments used to dialog and configuration, as well as alimentation. The network structure enables the connection of instruments by linear bus 32, except in the hazardous area to electrical reasons, from 8 to 9 (Profibus) and 4 to 6 (FF-H1). The advantages of this numerous digital communication: the fieldbus simplifies connections by freeing the analog implementation and thus interchangeability, configuration, and monitors for preventive maintenance, through internal memory of the transmitter or actuator.

C. *SCADA Systems*

Most all gas measurement systems have a way to collect data remotely from metering sites. There is still the practice of manually driving to the sites and collecting the measurement data via a PC or some type of hand held device. Generally, overall the Host Supervisory Control and Data Acquisition (SCADA) system is a PC based program that resides in the corporate office or in the field office [3]. This PC system contains a polling software package that is designed to communicate via radio to the remote location (see Radio Systems above) [3]. Usually these systems communicate once an hour or on a more frequent basis to the well sites to be sure the processes are running at the site and to retrieve timely information.

However, the communications front end of most modern SCADA systems can poll for both real-time operational data and custody transfer data [4]. The drawing below depicts a basic Wireless SCADA with the new integrated wireless end node instrumentation.

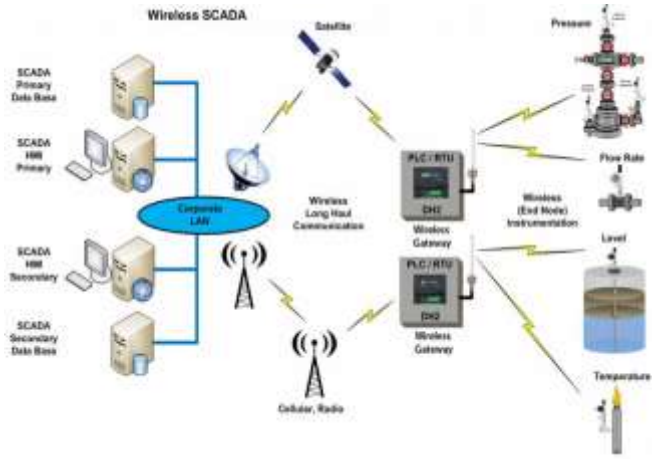

Figure 7. Wireless SCADA [9].

The physical (liquid level, flow, temperature) connection to the pipeline is through the end devices or instrumentation. The collected data is wirelessly communicated via Modbus protocol through a Wireless Gateway to a third-party PLC, RTU, HMI, or DCS that are part of a SCADA system. This instrumentation is connected to Programmable Logic Controllers (PLCs), Remote Terminal Units (RTUs) and/or flow computers, depending on the type of remote station. Data then flows from these remote devices through the communications network to the SCADA host (also referred to as the SCADA Master or Master Station).

IV. EXPERIMENTALY

In order to verify the transmission-line method, which has been proposed to evaluate the temperature the method consists in verifying the value of the temperature reading on the computer with that of a temperature standard at various points in the measuring range, with increasing and decreasing resistance [8]. The instrument used for this operation is a box decades of resistance for six positions (potentiometers: 100, 10, 1, 0.1, 0.01 and 0.001 Ω) [4].

The Pt100 sensor (RTD) are linear than thermocouples and in cases of beaches and limited accuracy, we can consider that they are linear. The transmitter input to consider when selecting transmitters PT100 temperature specifications include reference materials, reference resistor, other input and the measured temperature settings. The transmitter, mounted on the head of the temperature sensor, convert the data into a linear signal loop 4 to 20 mA DC current. We sending the standard values of temperature on the site of metering using box decade, then you look display of calculator these values on the computer panel at the room of supervision.

For our work, we have implemented hardware and means (reference standards) as thermometer, decade of resistance, millimeter and temperature thermostatic bath.

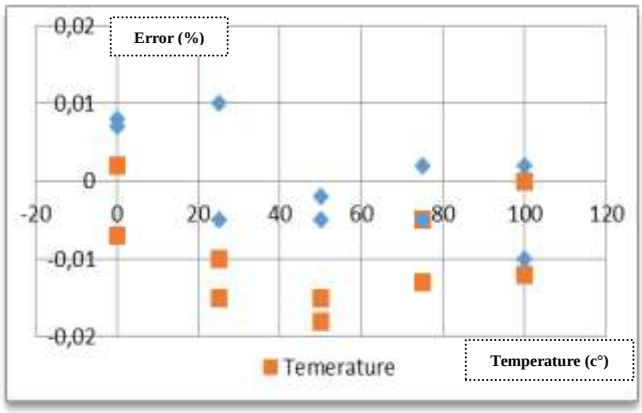

Figure 8. Graphic of accuracy of temperature.

The results of simulated values for the range of the temperature in our case (0-100 ° C) give errors in the margin of error defined by the maximum permissible recommendation International R117. This recommendation is intended for systems for measuring gas, it has the maximum permissible errors on the calculation of each characteristic quantity of the gas, positive or negative, are equal to one fifth of the relevant value specified in Table1. In this approach, the associated measuring instruments and the calculations are verified separately. Each associated measuring instrument is verified globally (Table 1), using the indication available on the conversion device [7]. The verification of the calculation consists in verifying the calculation concerning each characteristic quantity of the gas and the calculation for the conversion.

TABLE I. MPE FOR ASSOCIATED MEASURING INSTRUMENTS OTHER THAN WATER [1]

Maximum Permissible Errors "MPE"	**Classes A (%)**	**Classes B (%)**	**Classes C (%)**
Temperature	± 0.5	± 0.5	± 1
Pressure	± 0.2	± 0.5	± 1
Density	± 0.35	± 0.7	± 1
Compressibility factor	± 0.3	± 0.3	± 0.5

To control the state of turbines used for liquid volume metering, they must calibrated, certified and defined with the new *K-factor* (Kf). This operation is periodically required every (06 months).

Figure 9. The simulations of volume with HART communicator

The K-Factor, expressed in pulses per unit volume, may be used to electronically provide an indication of volumetric throughput directly in engineering units. We look at the display of these values on the calculator at the metering panel in the room supervision.

TABLE II. CONFIGURATION OF VALUES AND CORRECTION FACTORS

Configured	**Values simulates**		**Factors of correction**	
Density (kg/m3)	*Temperature (ºC)*	*Pressure (bar)*	*CTL*	*CPL*
610	25.00	25.00	0.983418	1.005958
630	30.00	30.00	0.976302	1.006334
660	50.00	50.00	0.9481970	1.012110
700	30.00	30.00	0.9798770	1.004591
730	25.00	25.00	0.9874400	1.003114

TABLE III. THE RESULTS OF SIMULATIONS VOLUME

Volume of service conditions			**Volume of reference conditions**		
Volume (m3)	*Calculator (m3)*	*Error (%)*	*Volume (m3)*	*Calculator (m3)*	*PME (%)*
20.000	19.999	-0.005	19.786	19.781	-0.023
20.000	19.999	-0.005	19.650	19.655	0.027
20.000	19.999	-0.005	19.194	19.193	-0.003
20.000	19.999	-0.005	19.688	19.687	-0.003
20.000	19.999	-0.005	19.810	19.810	-0.002

The results of both tests accuracies and repeatability respect well the tolerances defined by standards, as is shown in Tables 2 and 3. The calibration of meter turbine volume is effected in accordance with EN-12261 (turbine flow meter) or ISO 17089-1 (ultrasonic meter).

After installing these meters turbines as either pilot or the line must be setup again (Kf) in the computer room to supervision. Based on the certificate of calibration, apply linearization in the computer.

When liquid is subjected to changes in its temperature and pressure, its density will increase or decrease as the temperature falls or rises. This change is proportional to the thermal coefficient of expansion of the liquid, which varies with base density and the liquid temperature. The correction factor used to adjust the metered volumes:

- For the temperature, effect is called CTL, which are specified in the Physical Properties standards of either the API MPMS Ch 11.1 or the appropriate ASTM standard (D 1250) for Crude Oils or Refined Products. Various other products, such as LPG, NGL, aromatics have different standards which define their thermal expansion and/or contraction amount [5].
- For the pressure effects is called CPL. This CPL factor is a function of the liquid's compressibility (F), base pressure (Pb), equilibrium vapor pressure (Pe) and the weighted average pressure (PWA) [5]. The basic correction factor for the effect of pressure on the liquid is calculated from the following equation:

$$CPL = 1/(1 - [PWA - (P_e - P_b)] \times [F]) \quad (1)$$

Where:

P_b = base pressure
P_e = equilibrium vapor pressure
PWA = weighted average pressure
F = compressibility factor for the liquid

- For the indicated volume of a meter during a transfer called the meter factor (MF). A meter factor is calculated for each run and if within the specified tolerance, the average is the resultant meter factor used for that transfer, the meter factor (MF) can be expressed as the following base equation:

$$MF = NPV \div NMV \quad (2)$$

Where:

MF = Meter Factor
NPV = Net Prover Volume
NMV = Net Meter Volume

When the calibration process is started, it must be done at the conclusion of a continuous process, without interruption or delay. Table 4 shows the results of tests of the turbine metering.

TABLE IV. CONFIGURATION OF VALUES AND CORRECTION FACTORS

	Turbine PROVER	**Turbine CONTROLLED**
Pulses	50974	68498
K-factor base (pulse/m3)	1475.6	2013.9
Meter Factor	1.00137	1.00000
Pressure (Brag)	55.20	55.60
Temperature (°C)	66.41	66.49
CTL med.	0.85000	0.84978
CPL med.	1.04397	1.04435
Net Standard Volume (m3)	30.696	30.185
Meter Factor final		**1.01693**

The tables 4 show that, the standard proving report and calibrations of turbine on LACT metering. We have testing net standard volume with three proving runs to see if they have deviation of turbine and to determine the new Meter factor MF.

V. CONCLUSION

In this paper, we have presents the most important of signal processing and communication on dynamic metering system. We introduce the digital transmitter modules, the basic Wireless SCADA with the new integrated wireless end node instrumentation and data acquisition system.

After that, we have doing real control of this system metering in petroleum industry.

This paper presents a comprehensive study on the performance of measurements and the entire correction factor used to adjust the metered volumes. We have testing net standard volume with three proving runs to see if they have deviation of turbine and to determine the new Meter factor MF.

REFERENCES

[1] Pedhazur, J. Elazar; Schmelkin, L. Pedhazur, "*Measurement, Design, and Analysis: An Integrated Approach* (1st ed.). Hillsdale, NJ: Lawrence Erlbaum Associates. pp. 15–29. ISBN 0-805-81063-3, 1991.

[2] P. Donnelly, 'Fundamentals of gaz mesurement', NiSource Energy Distribution, American Meter,2009, pp.25-27.

[3] J. Griffeth, "Fundamentals of Electronic Flow Meter Design, Application & Implementation", Emerson Process Management Remote Automation Solutions, Houston, Texas, 2013.

[4] E. Smyth, "SCADA and Telemetry in Gas Transmission Systems," Business Development Manager, ABB Total flow, Houston-Texas, website of the American School of Gas Measurement Technology, 2013.

[5] A. Harrouz, A. Benatialah, and O. Harrouz, "Experimental study of control and verification of dynamic metering system," IEEE Xplore, pp. 1–5, Juin 2013 [Eighth International Conference and Exhibition on Ecological Vehicles and Renewable Energy, Monaco, France, March 27-30, 2013

[6] A. Harrouz, A. Benatiallah, O. Harrouz," Practical Control of Dynamic Metering System and Data Acquisition" International Journal of Industrial Engineering & Technology journal with ISSN(P):2277-4769 ; ISSN(E):2278-9456 ;Impact Factor (JCC) - 4.3729, TJPRC global community.sept.2013

[7] P. Kosewicz, "Calculation Of Liquid Petroleum Quantities", The University of Texas -- PETEX , Houston, Texas, 2008, pp.164-173.

[8] http://www2.emersonprocess.com

[9] http://www.oleumtech.com/what-is-scada/