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Communication and Calibraton of Sensing Meters

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Abstract

The purpose of this paper is to review the essential definitions, roles and characteristics of communication on metering system. We discuss measurement, data acquisition 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. We finished with control and calibration of turbine flow meter and we given resultats expermentaly of this work.

Keywords: *communication, turbine flow meter, panel computer, HART, signal, digital transmitter*

1. Introduction

In the real world, physical phenomena, such as temperature and pressure, vary according to the laws of nature and exhibit properties that vary continuously in time; that is they are all analog time-varying signals. 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. Linking up to 32 modules, communicating over distances up to 10 km, is possible when using the RS-485 multi-drop network. However, since very few computers have built in support for the RS-485 standard, an RS-232 to RS-485 converter is required to allow communications between the computer and the remote modules.

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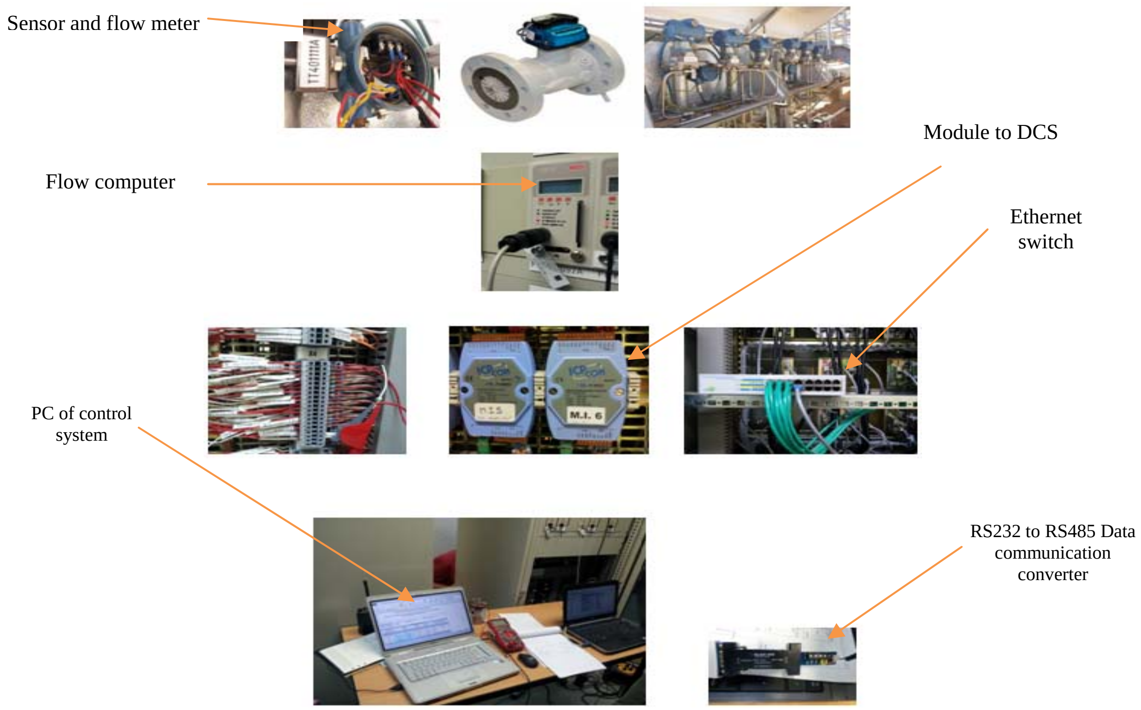

Figure 1. Digital Transmitter Modules and Control

The orifice flow meter (Figure 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 [17]. 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 [17]. The effects of pressure, temperature, fluid, and dynamic influences can potentially alter the measurement being taken.

2. Research Method

2.1. Flowmeter

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 [18]. In the API 21.1 Document "Manual of Petroleum Measurement Standards – Flow Measurement Using Electronic Metering Systems" describes very fundamental principles [6]:

a) Primary device: Orifice, turbine, rotary, or diaphragm measurement devices that are mounted directly on the pipe and have direct contact with the fluids being measured.
b) Secondary device: provides data such as flowing static pressure, temperature flowing, differential pressure, relative density, and other variables that are appropriate for inputs into the tertiary device.
c) Tertiary device: is an electronic computer, programmed to correctly calculate flow within specific limits that receives information from the primary and/or secondary devices.

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 [6].

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 and 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 [6]. Ultrasonic meters are very cost effective when measuring great volumes of gas that vary in flow rate.

Fluid flowing through the meter is channeled through the inlet flow straightened section (upstream rotor support assembly). This reduces the turbulent flow pattern to a more stable, laminar flow, prior to coming in contact with the multi-bladed turbine rotor. Flow through the rotor's angular blades cause the turbine rotor to spin at a speed proportional to the velocity of the flowing media [11].

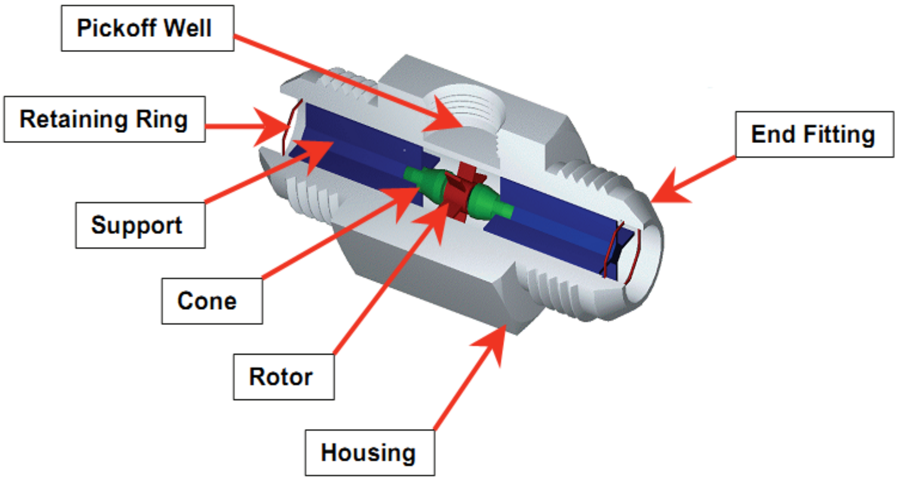

Figure 2. Turbine Flow Meter

Turbine flow meters use a variety of pickup transducers to convert the rotational energy (speed) of the turbine wheel to a measurable electrical signal. These transducers then transmit a proportional output signal to external readout displays or other interfacing electronic data acquisition equipment.

The Mechanical Gear System uses a shaft which is mechanically driven by a gear mounted on the rotor shaft. This shaft, in turn, drives a mechanical readout which may display flow rate, total batch, or both. The Magnetic Inductive sensing method features magnetic pins inserted in the turbine rotor blades. The transducer contains a simple sensor coil and core. An electrical pulse is induced in the coil as each blade passes the base of the transducer coil. This method offers less magnetic drag than the Magnetic Reluctance sensing method.

Turbines flow meters are controlled by the pipe prove standard; there is automatic update of "Meter Factor" after each sequence. The bidirectional prover requires a displacer round trip to complete one prover run. It can be made U-shaped, folded, or straight shaped depending on space requirements [12].

The standard prover (**U-shaped bidirectional**) is the most common and uses an inflated ball displacer. Regardless of construction and operating details, all provers perform the same function. Flow is passed through an operating meter into the prover [12].

When temperature and pressure have been stabilized, the displacer is launched. Since this creates a temporary slowdown in flow until the displacer gets up to speed, some prerun length in the prover must be allowed before displacement of the accurately measured volume begins. At a point after flow rate stabilization, a switch indicates entry of the displacer into the calibrated section, and the meter pulses are sent to the proving counter or circuit (see Figure 3).

2.2. Calibration

To calibrate means = to standardize (as a measuring instrument) by determining the deviation from a standard so as to determine the proper correction factors." There are two key elements to this definition: determining the deviation from a standard, and ascertaining the proper correction factors [22].

Flow meters need periodic calibration. This can be done by using another calibrated meter as a reference or by using a known flow rate. Accuracy can vary over the range of the instrument and with temperature and specific weight changes in the fluid, which may all have to be taken into account. Thus, the meter should be calibrated over temperature as well as range, so that the appropriate corrections can be made to the readings [22]. A turbine meter should be calibrated at the samekinematic viscosity at which it will be operated in service. This is true for fluid states, liquid and gas.

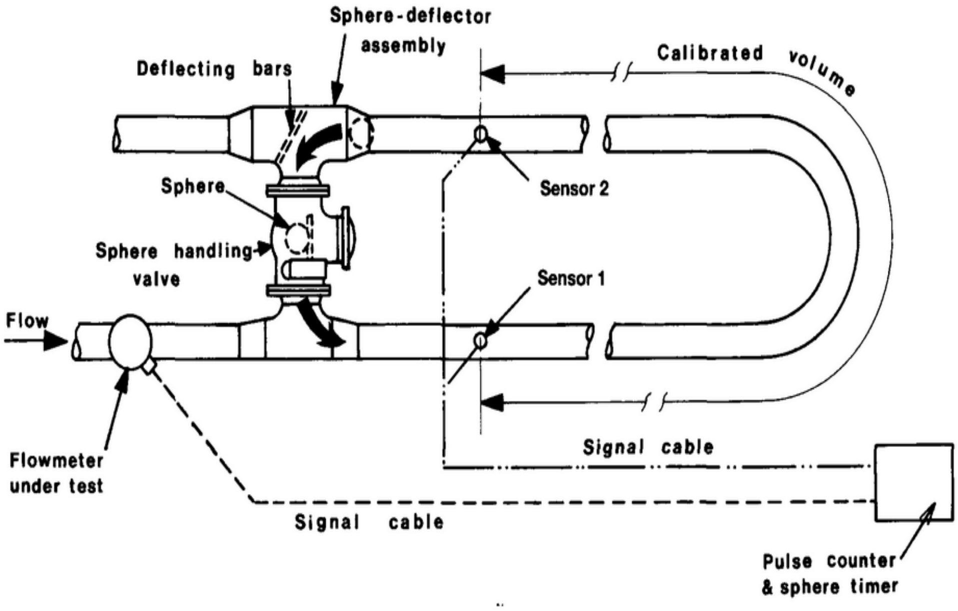

Figure 3. Typical Bidirectional U-type Sphere Prover System [23]

The necessity of proving a meter depends on the value of accurate measurement for the product being handled. Large volumes and/or high-value products are the prime candidates for using provers. Oil industry measurement of crude oil and refined products are examples of where meters typically involve proving systems. The proving systems are considered part of the cost of the meter stations and are permanently installed at larger facilities. When product value is lower, provers are usually portable (used within a limited geographical area); as product value drops further, proving frequency is reduced, and for the lowest value products proving is not done at all [23].

In other industries, proving in place is seldom done; metering is assumed correct until a process goes out of control or a meter breaks down and requires repair or replacement. For meters such as the orifice type, calibration is accepted as correct as long as mechanical requirements of the meter's specifications are met. Some meters are "tested" by calibrating only the readout units, with no test or inspection of the primary device. This does not have the same value as a complete system examination or the use of a prover.

2.3. Repeatability

Is the variation in measurements taken by a single person or instrument on the same item and under the same conditions. A less-than-perfect test–retest reliability causes test–retest variability. A measurement may be said to be repeatable when this variation is smaller than some agreed limit [24]. Or it's the maximum deviation from the corresponding data points taken from repeated tests under identical conditions.

2.4. HART Communication Signal

The HART (**H**ighway **A**ddressable **R**emote **T**ransducer) 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 20mA.

The digital signal can be 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.

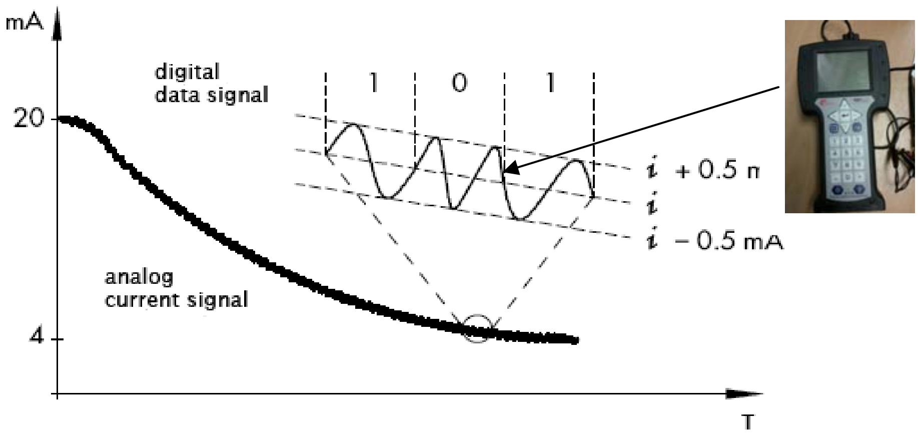

Figure 4. HART Signal

The HART is a master/slave protocol which provides for up to two masters (primary and secondary) and the secondary master such as handheld can be used to monitor/control the information of HART bus. HART can be 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.

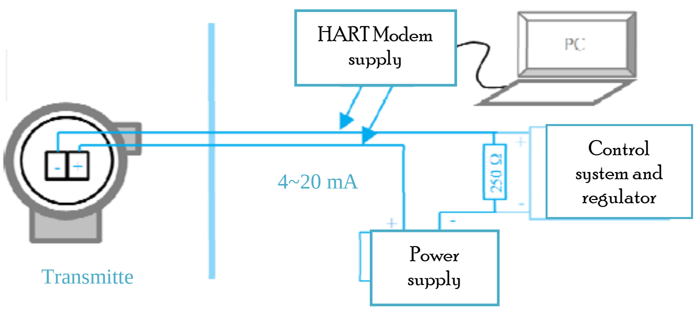

Figure 5. Digital Transmitter

Communication made in digital form using an alternating current modules traveling web frequency is superimposed on analog current 4 to 20mA 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.

2.5. Field Bus

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 4) each.

The two fieldbus most prevalent in the industrial process control are the Fieldbus Foundation FF-H1 and Profibus PA.They is 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.

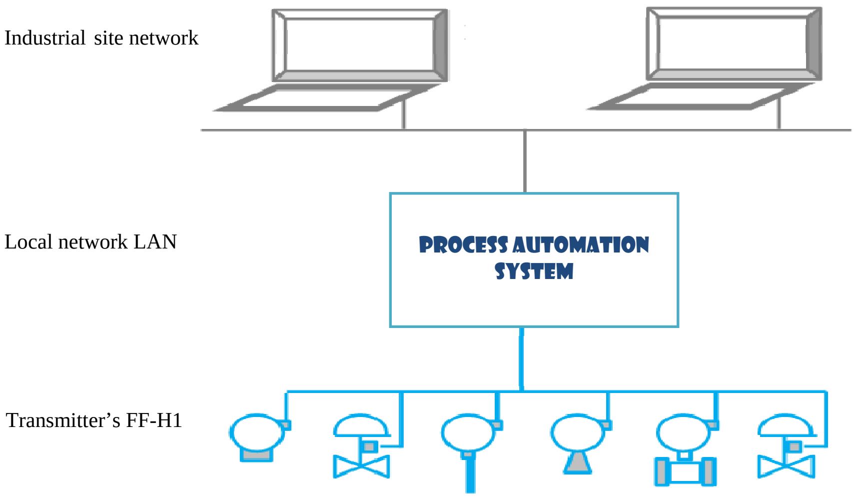

Figure 6. Fieldbus FF-H1

2.6. 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 [6].

This PC system contains a polling software package that is designed to communicate via radio to the remote location [6]. 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.

Measurement systems are used by pipeline companies to manage the custody transfer data from the metering stations. This is often referred to as the “cash register” aspect of operating a pipeline. The flow computers and/or RTUs at the metering stations provide both real-time flows and volumes for operational purposes and historical records for measurement. The host measurement system is almost always separate from the SCADA system. However, the communications front end of most modern SCADA systems can poll for both real-time operational data and custody transfer data [21]. The following drawing shows the five logical levels that make up the SCADA system.

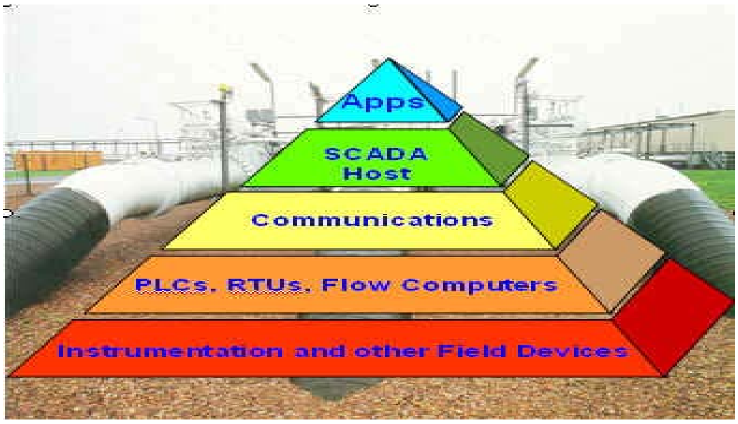

Figure 7. SCADA System [21]

The physical connection to the pipeline is through the end devices or instrumentation. 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). Examples of applications at the top of the pyramid would be advanced control and optimization applications used by the gas controllers as well as business applications used by other departments within the pipeline company's organization [21].

3. Results and Analysis

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

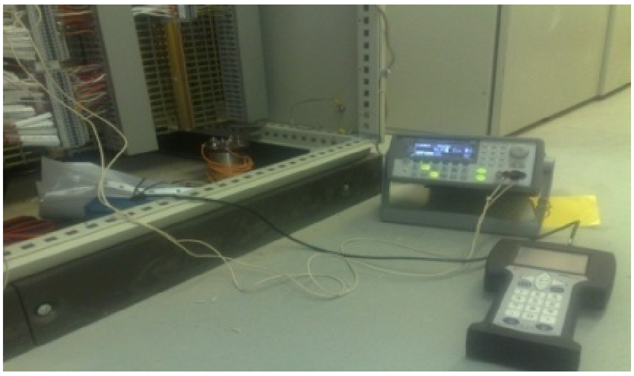

Figure 8. The Simulations of Volume with HART Communicator

We are looking at the display of these values on the calculator at the metering panal in the room supervision. The Table 1 and 2 show the results of this test. The calibration of meter turbine volume is effected in accordance with EN-12261 (turbine flowmeter) or ISO 17089-1 (ultrasonic meter). The calibration is made on high-pressure by a company approved (ISO 17025) for traceability of measurement according to the cubic meter of natural gas harmonized by the manufacturer or approved as an international laboratory (LNE, NMI, PTB, Westerbork TransCanada Calibrations).

Table 1. The Values Configured with the 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 2. The Results of Simulations Volume

Volume of service conditions			Volume of reference conditions		
volume (m3)	Calculator (m3)	Error (%)	volume (m3)	Calculator (m3)	Error (%)
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 Table 1 and 2.

After that, the turbine flow meter is controlled by the pipe prove standard; there is automatic update of "Meter Factor" after each sequence. The bidirectional prover requires a displacer round trip to complete one prover run. The Table 1 shows this control:

Table 3. The Resultats of Turbine Control with Standard Prover (u-shaped bidirectional)

Compteur turbine						
Débit m3/h	Fréquence HZ	Nombre impulsion	Pression bar	temps ºC	CPLM	CTLM
2571	1187	23325	14.22	34.80	1.00208	0.97602
2603	1201	23319	14.17	34.80	1.00208	0.97602
2538	1171	23326	14.26	34.80	1.00209	0.97602
2535	1170	23326	14.27	34.80	1.00209	0.97602
Tube étalon						
Pression bar	temps ºC	CPSP	CTSP	CPLP	CTLP	MF
12.97	35.05	1.00029	1.00067	1.00190	0.97571	1.0051
12.90	35.05	1.00029	1.00067	1.00189	0.97571	1.0054
13.04	35.05	1.00029	1.00067	1.00192	0.97571	1.0051
13.06	35.05	1.00029	1.00067	1.00192	0.97571	1.0051

The medium value of meter factor is 1.0052, with reliability (0.03%). After installing these meters turbines either as 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.

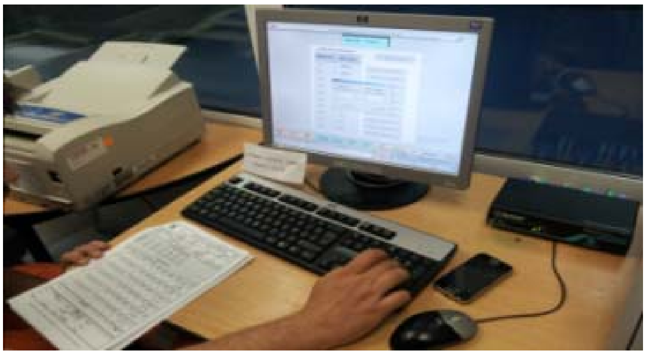

Figure 9. The Setup Again (Kf) in the Computer Room

When the calibration process is started, it must be done at the conclusion of a continuous process, without interruption or delay. Table 3 shows the results of tests of the turbine metering.

Table 4. Proving Report Runs, (day and start time: 14/06/2013, 3:17:34 p.m.)

	Pilot turbine	Controlled turbine
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 Table 4 show 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.

4. Conclusion

This paper present and discuss the important fundamental communication and parameters to consider when controlling a dynamic metering system. We introduce the digital transmitter modules, the basic building blocks of the SCADA system and including field devices.

The HART communication and fieldbus applications are discussed in detail. The paper concludes with an experimental resultats of calibration of turbine flow meter on a petroleum site. The results obtained are considered very satisfactory and correct; errors identified as measuring instruments are within the range of the permissible maximum errors PME by the regulations.

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