IN-SITU (ON-SITE) GAS METER PROVING
Class 4070

Edgar B. Bowles, Jr.
Director – Fluids Engineering Department
Southwest Research Institute
6220 Culebra Road
San Antonio, TX 78238 USA

Introduction

Natural gas flow rate measurement errors at field meter stations can result from the installation configuration, the calibration of the meter at conditions other than the actual operating conditions, or the degradation of meter performance over time. The best method for eliminating these or other sources of error is with in-situ (on-site) calibration of the meter. That is, the measurement accuracy of the field meter station should be verified under actual operating conditions by comparing to a master meter or prover. Field provers have been developed for operation at high line pressures and flow rates. [For purposes of this discussion, a high gas flow rate is any flow greater than 3,000 actual cubic feet per hour or (85 m^3/h) at pressures to 1,440 psig (10 MPa).]

A field meter prover may be either a 'primary' flow standard or a 'secondary' flow standard. A primary flow standard is any measurement device that determines the gas flow rate from the fundamental physical measurements of mass (M), length (L), temperature (T), and time (t). Measurement devices based on other techniques or methods are categorized as secondary flow standards. For highest accuracy, a secondary flow standard (sometimes also called a 'transfer' standard) must be calibrated using a primary flow standard at operating conditions.

Two comprehensive reports on the subject have been produced by Park, et al.,[1] and Gallagher.[2] Much of the following information is referred to in detail in these reports.

The Basics

Figure 1 shows an idealized version of a field meter proving setup in which one flow meter (i.e., the field meter being tested) is compared to another (i.e., the "proof" meter).

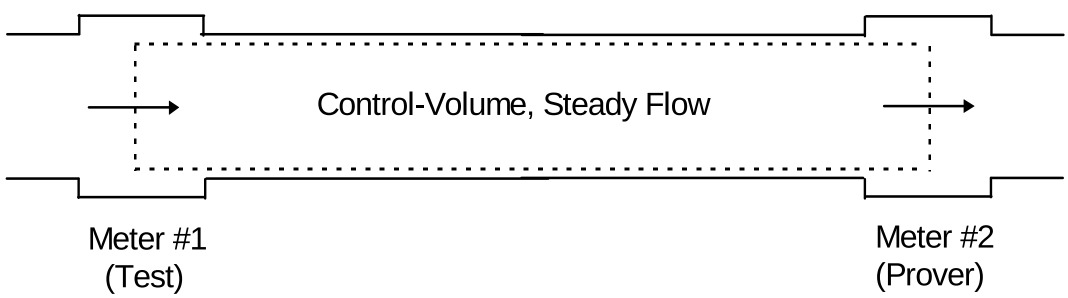

Figure 1. Example Field Meter Prover Setup

In the example shown in Figure 1, it is assumed that the operating conditions are steady; that is, the flow rate; flow stream temperature, pressure, and fluid composition; and ambient conditions are unchanging while the meter proof is taking place. This also assumes that there is no storage of fluid between the two meters while the test is underway. In this case, mass is conserved in the control volume shown in the figure and the governing continuity equation is as follows:

$$Q_m = (\rho \times A \times V)_{Meter1} = (\rho \times A \times V)_{Meter2} \quad \text{Equation 1}$$

where:

Q_m = mass flow rate through the meter

ρ = fluid density

A = cross sectional area of the flow meter

V = velocity of the fluid through the meter

The more fundamental statement of mass conservation for the steady control volume is as follows:

$$-\iint_{CS_1}(\rho V_n)dA=\iint_{CS_2}(\rho V_n)dA \text{ at time } t \qquad \text{Equation 2}$$

where:

ρ = fluid density

V_n = the component of gas velocity normal to the control surface

A = cross sectional area of prover

t = time

CS = a surface of the control volume where fluid crosses

The “simplified” version, shown in Equation 1, assumes that ρ and V are average values (also, assumes that the measured V is the normal component of velocity) across the pipe cross section at locations 1 and 2. Also, note that, strictly speaking, standard volumetric flow rate (e.g., standard cubic feet per hour) is neither mass nor “actual” volumetric flow rate. Standard volumetric flow rate is mass flow rate that has been referenced to arbitrary temperature and pressure conditions for the flowing gas composition. However, standard volumetric flow rate is proportional to mass flow rate through the application of standard gas density and is, therefore, conserved from location 1 to location 2.

It is important to note that not all flow meters are mass-based devices, so meter proof comparisons need to consider this fact. For instance, mass-to-mass meter calibrations can be accomplished by direct comparison of the respective meter outputs. A comparison of a volume-based meter to a mass-based meter requires that a fluid density measurement be made at the volume-based meter so that the meter output can be converted to a mass flow rate for comparison to the mass-based meter. Comparison of two volume-based meters requires that fluid density measurements be made at both meters.

Piston Provers

Figure 2[3] shows one configuration of a (gas) piston prover. A piston prover consists of a section of pipe of known inside diameter and a movable piston that travels inside the pipe. The piston is accelerated from rest by the flowing gas until it achieves a constant speed. While the piston travels through the pipe at a constant velocity, proximity sensors and electronic timing circuits measure the interval of time it takes the piston to move a predetermined distance. By knowing the amount of time it takes for the piston to travel a fixed distance and by knowing the inside dimensions of the pipe, it is possible to calculate the volumetric flow rate of the fluid at the operating conditions.

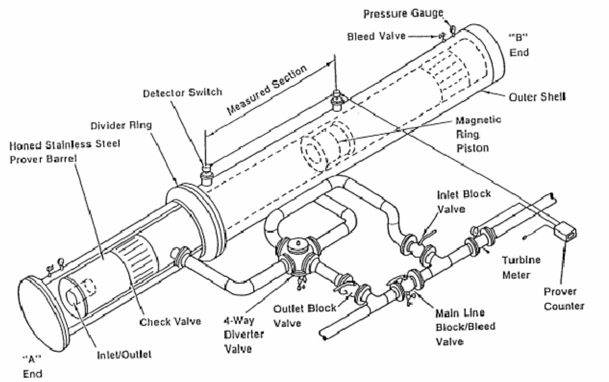

Figure 2. Three-Dimensional Drawing of Double-Wall Bi-Directional Gas Piston Prover[1]

At present, there are no industry standards for piston-type gas provers. However, several variations of field piston provers have been devised. Park, et al.,[1] has summarized the performance limits of several gas piston provers (see Table 1). Figure 2 shows one prover configuration developed by Amoco. It includes a four-way diverter valve that makes it possible for the piston to travel in either direction through the prover. A unique feature of this prover is that a turbine meter has been plumbed in series with the piston prover. The piston prover is used to calibrate the turbine meter that, in turn, can be used to flow test a field meter.

Advantages of gas piston provers include (1) their compactness as portable *primary* flow measurement standards and (2) their ability to function at high pressure with any gas composition (thus, allowing meter calibrations to be performed under actual operating conditions).

Location	**Volume ft^3 (m^3)**	**Pressure psig (MPa)**	**Flow Rate acfh (m^3/h)**	**Uncertainty %**	**Reference**
Amoco Houston, TX USA	2.8073 (0.0795)	1440 (9.9)	18,000 (510)	--	Beaty (1991)[3]
Brooks Instrument	--	870 (6 .0)	14,000 (396)	±0.20	Reid & Pursley (1986)[4]
Gasunie Groningen, NL	5.2036 (0.14735)	870 (6.0)	8,800 (250)	±0.13	Bellinga, et al. (1985)[5]
Gasunie Groningen, NL	49.3982 (1.3988)	960 (6.6)	71,000 (2,000)	±0.15	Bellinga & Delhez (1993)[6]
OGASCO Houston, TX USA	4.811 (0.1362)	1440 (9.9)	18,000 (510)	±0.35	Ting & Halpine (1991)[7]
PTB Braunschweig, FRG	5.2337 (0.14820)	1300 (9.0)	16,000 (450)	±0.13	Schmitz & Aschenbrenner (1990)[8]

Table 1. Performance Summary of Gas Piston Provers[1]

The primary disadvantages of gas piston provers are (1) that they must be manufactured to high precision and, thus, are relatively expensive and (2) they must be large to calibrate at high flow rates. Currently, the largest turbine meter that can be calibrated with a portable piston prover is an 8-inch (203 mm) diameter meter.

Sonic Nozzles or Critical Flow Venturis

Sonic nozzles or critical flow Venturis are flow restrictions that accelerate flow to the speed of sound in the narrowest portion or throat of the nozzle, at which time the maximum flow rate is attained. If the thermodynamic state of the gas at the sonic nozzle throat is known, then the speed of gas at the throat may be calculated from state equations, since the throat speed is equal to the speed of sound at those conditions. For a given nozzle geometry, under sonic or 'choked' flow conditions, the flow rate through the nozzle is a function only of the upstream temperature, pressure, and gas composition.

A sonic nozzle has no moving parts. The contour geometry may vary. At one extreme is the critical flow orifice. Cunningham[9] showed that a standard, thin, square-edged orifice would not achieve choked flow. Ward-Smith[10] showed, however, that an orifice would choke if the plate were made thicker than a standard, thin, square-edged orifice. For plate thickness to bore diameters between 1 and 6, the Ward-Smith data suggest that the sharp-edged orifice discharge coefficient is 0.839, with an estimated accuracy of ±1.6% of reading. Higher discharge coefficients may be achieved by contouring the upstream edge of the bore. Higher pressure recovery may be achieved by contouring the downstream edge of the bore.

The American Society of Mechanical Engineers (ASME) has published a standard for toroidal throat Venturi nozzles.[11] The International Standards Organization (ISO) has also published a standard for critical flow Venturi nozzles.[12] The ASME standard states that the discharge coefficient for toroidal throat Venturi nozzles approaches 0.9935 at high throat Reynolds numbers (which is a ratio of inertial forces to viscous forces). The ASME nozzle construction and installation specifications are provided on Figure 3. The ASME discharge coefficient correlation is estimated to have a bias limit of ±0.5% (95% confidence) for the range of conditions shown on Figure 3.[13] Better nozzle discharge coefficient data may be obtained by flow calibration.

Sonic nozzles are currently being applied as a measurement transfer standard in many flow laboratories, and they have been successful in field prover applications. Chevron has operated several sonic nozzle banks as field provers at custody transfer sites.[14] Their largest facility has eight sonic nozzles with a flow capacity of 302,000 acfh (8,500 m^3/h) at 1,000 psig (6.9 MPa). The system also includes a turbine meter as a ‘master’ meter.

One unique sonic nozzle prover developed as a portable field prover for calibration of turbine meters is shown in Figure 4 and described in detail by Beeson.[15] The device, called a Digicell®, contains 11 binary-weighted sonic nozzles with a resolution of 58.7 acfh (1.66 m^3/h) and a maximum flow rate of 138,000 acfh (3,900 m^3/h) at a maximum operating pressure of 1,440 psig (9.9 MPa). The maximum flow capacity of this prover is equivalent to a 12-inch (300 mm) turbine meter. The prover is mounted on a truck and its accuracy is quoted to be within ±0.5% of reading. A system such as the one shown in Figure 4 must be calibrated as a complete system.

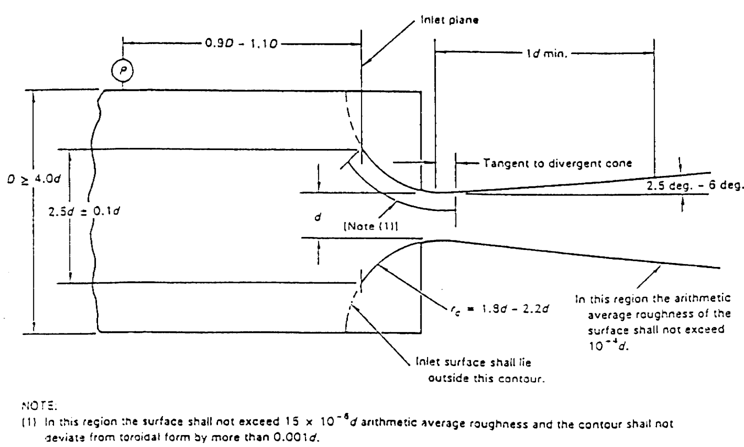

Figure 3. Toroidal Throat Nozzle Construction and Installation Specifications from ASME/ANSI MFC-7M[11]

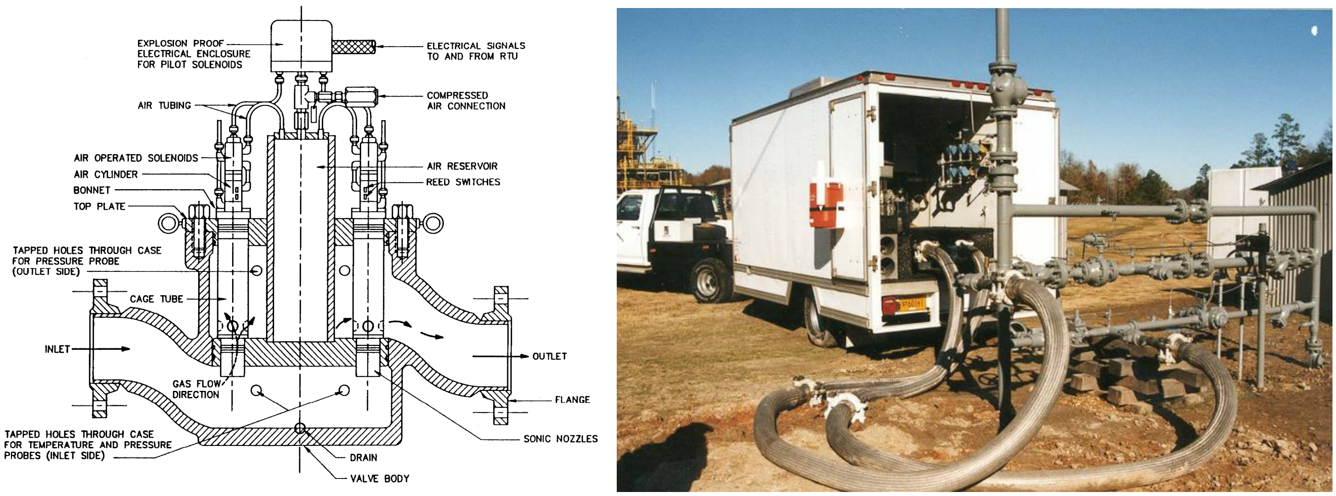

Figure 4. Digicell® Sonic Nozzle Prover[15]
(currently owned and operated by Reliant Energy Corporation)

Since a sonic nozzle has no moving parts, the accuracy of the meter is a function of: (1) the biases associated with the predictive thermodynamic model and discharge coefficient correlation, (2) the degree of thermodynamic equilibrium at the nozzle plenum and throat, and (3) the accuracy of the temperature, pressure, and gas composition measurements. A sonic nozzle requires only two sensors to measure the stagnation (often approximated by the static) temperature and pressure in the low velocity (relative to the nozzle throat) plenum region upstream.

There are no mechanical contact surfaces requiring lubrication in a sonic nozzle. No inertia occurs to delay transient response. At the choked condition, sonic nozzle flow rate is a function only of the upstream thermodynamic state. The thermodynamic conditions downstream do not affect flow rate through the nozzle unless the nozzle unchokes (due to the backpressure rising above the choking value, for example). The thermodynamic state in the upstream nozzle plenum may be determined by measuring the temperature, pressure, and composition of the flowing gas. Although the one-dimensional isentropic process models and state equations required to calculate sonic nozzle flow rate are well defined, the calculations can be computationally intense under non-ideal conditions, depending on the level of reality employed by the model.

No pressure drop measurement across the nozzle is required to determine flow rate, as is the case with subsonic flow resistive meters, but one may be taken to ensure that the nozzle is choked. Sonic nozzles are often installed with an upstream stagnation plenum. Therefore, they are relatively insensitive to upstream piping configurations and may be installed in relatively short meter runs.

Due to the severe flow contraction and acceleration within a sonic nozzle, severe pressure and temperature drops may occur from the plenum to the throat. The resulting thermodynamic changes in the gas may affect composition in the nozzle throat region. For some natural gas mixtures, especially rich grades near production sites, retrograde condensation of heavy hydrocarbons may occur. In addition, natural gases that contain hydrogen sulfide (sour gas) can, under some conditions, undergo an oxidation-reduction process to produce elemental sulfur in the gas phase. There have been reports of solid sulfur deposition in sonic nozzles, usually resulting from a retro-sublimation process (plating out the elemental gas-phase sulfur) in the throat of sonic nozzles.[16] The sulfur deposits can affect measurement accuracy by changing the nozzle throat geometry, reducing the throat diameter.

Turbine Flow Meters

A turbine meter measures fluid flow by the rotation of helical blades located around a circular hub. Essentially, a turbine meter is a volumetric meter, and its calibration constant is in pulses per unit volume. In the United States and ISO turbine meter standards, the maximum permissible measurement error is ±1% of reading over the operating range of the meter. Better accuracy can be achieved through calibration of the meter at the actual operating conditions (i.e., the same pressure, temperature, and gas composition).

The primary guidelines for turbine meters used in the United States are contained in American Gas Association (AGA) Report No. 7[17] and ANSI/ASME MFC-4M-1986,[18] while the relevant international standard is ISO 9951.[19] Additional supporting information is contained in the AGA Gas Measurement Manual.[20] These documents contain information on the following: construction, installation, operation, performance, flow measurement, calibration, and field checks. Information in the standards on turbine meters as field provers is minimal.

Schematics of a single-rotor turbine meter and a dual-rotor 'self-correcting' or 'self-checking' turbine meter (first called the Auto-Adjust® Turbine Meter described by Lee, et al.[21]) are shown on Figure 5. The dual-rotor design was conceived to overcome many of the operational shortcomings of the single-rotor design. Principal drawbacks of the turbine meter include (1) moving parts that are subject to wear and degradation in performance and (2) susceptibility of the meter to the effects of flow pulsation, swirl, and velocity profile distortion.

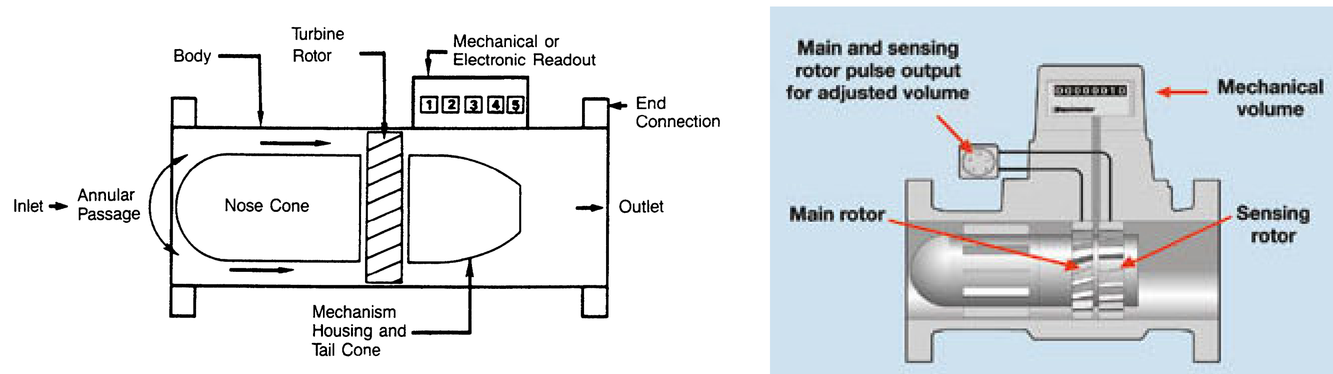

Figure 5. Schematics of a Turbine Meter[17]
(Images courtesy of American Meter and Sensus Metering Systems)

Integral straightening vanes (also called a flow conditioner) are usually installed in gas turbine meters to eliminate the influence of flow swirl on the rotor. AGA Report No. 7 also recommends installation of a straightening vane upstream of the meter. Usually, the straightening vane or flow conditioner consists of 19 tubes arranged in a concentric pattern. A typical turbine meter installation per the AGA Gas Measurement Manual is shown on Figure 6. Note that this particular configuration provides for a proving meter to be installed and operated in series with the field meter.

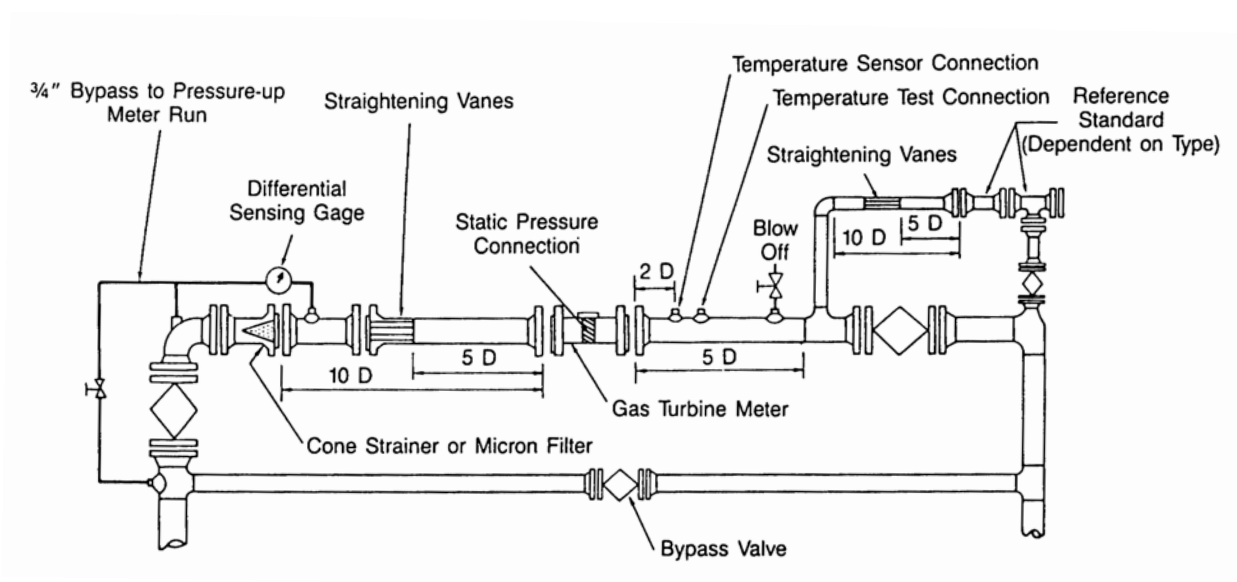

Figure 6. Typical Turbine Meter Installation from AGA Gas Measurement Manual[20]

Chevron has had success using 12-inch (305 mm) diameter turbine meters for custody transfer, and a 12-inch turbine meter as the master meter used in conjunction with sonic nozzles as their field proving method.[14]

Ultrasonic Flow Meters

Although there are no reported cases in which an ultrasonic meter has been used as a field meter prover, the operating characteristics of an ultrasonic meter make it a potential candidate. Ultrasonic meters that measure high-pressure natural gas flows typically use a time-of-flight (or transit time) measurement technique. Figure 7 shows a typical design configuration. A high-frequency (i.e., >100,000 Hz) acoustic pulse (or pressure wave) is broadcast through the flow field from a sending transducer (shown as ‘A’ on Figure 7). The pulse travels at an acute angle across the pipe to a receiving transducer (shown as ‘B’ on Figure 7). The receiver may be located on either the opposite side or the same side of the pipe as the sending transducer. If the sending and receiving transducers are on the same side of the pipe, the acoustic beam is reflected off the opposite pipe wall before being received.

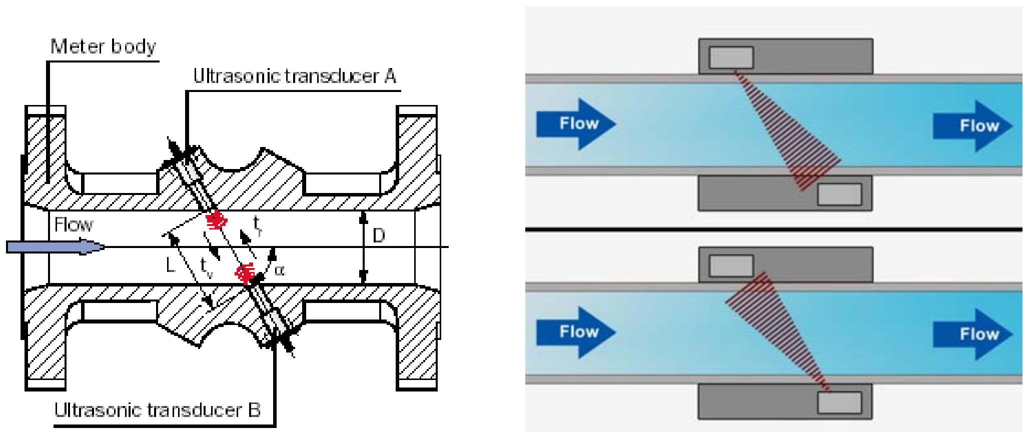

Figure 7. Schematic of an Ultrasonic Flow Meter[22]
(Images courtesy of Bureau of Analytical Complexities & Systems and Alicat Scientific)

The time, t, required for the acoustic pulse to travel from the sending to the receiving transducer (denoted as acoustic path length ‘L’ on Figure 7) is dependent upon the speed of sound of the flowing gas and the direction (and speed) of the flow relative to that of the pulse. The dependency on the speed of sound can be eliminated by using a pair of sending and receiving transducers that transmit along the same acoustic path, but in opposite directions. The axial separation distance between the transducer pair can be divided by the difference in the transit time (typically denoted as Δt) for acoustic pulses broadcast in the direction of the gas flow stream and opposite to the direction of the flow stream to calculate the mean velocity of the gas stream.

Ultrasonic meters may have several transducer pairs with multiple flight paths. The measurement accuracy of a single path meter is highly dependent on the shape of the velocity profile of the gas entering the meter. The multi-path meter was conceived as a means for reducing measurement bias errors by characterizing and accounting for velocity profile asymmetry or swirl. As many as six transducer pairs are utilized in current meter configurations. Mechanical flow conditioning devices can also be installed upstream of the meter to help eliminate velocity profile distortions or swirl.

Currently, the only reference document covering the use of ultrasonic flow meters for gas applications is AGA Report No. 9.[23] Although this document is only a recommended practice and is limited in scope, it includes information on terminology, operating principles, error sources, application guidelines, and meter calibration. It does not address the use of ultrasonic meters as field meter provers.

Present ultrasonic meter designs for gas applications have measurement performance comparable to turbine meters.[22] For the highest accuracy, an ultrasonic meter should be calibrated in its prover installation configuration using another flow standard.

Ultrasonic flow meters are relatively non-intrusive, with no appreciable pressure drop (unless installed in conjunction with a mechanical flow-conditioning device). The maintenance costs are relatively low and reliability appears to be high, since the meter has no moving parts. The meter has a size and weight advantage over most other measurement technologies as pipe size increases. Ultrasonic meters are also able to measure bi-directional flow.

Instrumentation

Although the various provers described in this report have different operating principles, they do have some common instrumentation. In particular, static pressure and temperature must be measured so that density and other physical properties of the gas can be computed from a gas model. Significant improvements in all provers can be achieved with the selection of state-of-the-art instruments for the measurement of temperature and pressure. The precise effect on uncertainty of the prover measurement will be dependent upon the model equation that computes the mass flow rate of the prover in relation to the meter being tested.

The uncertainty in prover measurements from the measurements associated with temperature and pressure is typically within ±0.05% of reading. Consequently, the largest uncertainty in a mass flow rate measurement for a field prover would be in the meter coefficient for a secondary standard, such as a turbine meter, or in the gas model for the density calculation. The uncertainties associated with the gas model and gas composition are discussed in the next section.

Gas Composition Effects on Calibration Accuracy

A complicating factor in field meter proving is the unavoidable reality that field meters are installed on natural gas pipelines and operate on natural gas. The uncertainty in the component concentrations of the gas mixture may significantly increase the composite uncertainty in the field meter calibration. A gas chromatograph (GC) is typically used to separate the gas mixture into its components and then measure the concentrations of the individual components. Guidance on the proper use of a GC is provided in Gas Processors Association (GPA) standards 2261[24] and 2286.[25] Uncertainties in gas composition affect calibration accuracy through the gas properties that are needed to compute flow rate.

Gas density is, arguably, the most important composition dependent property in flow rate measurements. Under nearly all field meter proving scenarios, the gas density at both the field meter and the proving meter must be known, and each will add uncertainty to the calibration. Some meters are sensitive to other thermodynamic properties, such as sound speed, and may require complex thermodynamic calculations involving more properties to model the fluid dynamic behavior. Further, calibration constants of flow restricting meters, such as a sonic nozzle, are often correlated to Reynolds number, and become more sensitive to Reynolds number in the low range. Reynolds number effects also become more important at low flow in turbine meters. The introduction of Reynolds number requires that viscosity be known. Many meters are dependent on both thermodynamic and transport/diffusion properties for accurate flow rate measurements.

Natural gas mixture density calculations may be performed very accurately using the Detail Characterization Method of AGA Report No. 8.[26] This method combines features of a virial equation of state at low density, and exponential functions at high density. A nominal bias of ±0.1% on compressibility factor is specified for most pipeline flow meters. Important derived thermodynamic properties such as heat capacity, enthalpy, entropy, and sonic velocity may be obtained by extending the compressibility results of AGA Report No. 8[26] using thermodynamic principles.

Grouping C_{6+} components in the compositional analysis is very common in process natural gas chromatography. This can lead to gas property calculation errors of the same magnitude as the accuracy of a meter prover. For example, consider a 'light' gas with a molecular weight of 17 that actually contains 0.05% by volume of C_7, and 0.025% by volume of C_8. A mixture density calculation error of about 0.1% may be realized by assigning n-hexane properties to the C_{6+} grouping.

Conclusions

Currently, the most viable technologies as large volume field provers are the sonic nozzle, turbine meter, and gas piston prover. These devices have an established history of high accuracy measurements with high resolution. The ultrasonic meter appears to have significant potential as a field prover, but its performance is not as established.

Since many flow meters are volumetric, the best accuracy is attained when the meter is calibrated against a primary volumetric standard with the same gas at approximately the same temperature and pressure. In this case, the bias uncertainty from gas composition is reduced, and pressure, temperature, and the volumetric flow rate of the flow standard determine the accuracy. An example would be the calibration of a turbine meter by a piston prover. A comparison of a gravimetric (mass) prover and piston (volume) prover in the calibration of a turbine (volume) meter has been shown to be somewhat better for the piston prover calibration on natural gas (assuming no mass storage between the meters), because density (hence, gas composition) must be used to relate mass flow rate to volume flow rate. However, density (hence, gas composition) must still be used to apply the calibration coefficient of a volumetric meter to determine mass flow rate in service.

Gas piston provers should be used in a manner that eliminates or reduces mass storage in the interconnecting pipe. The test gas should be passed through the interconnecting pipe and prover barrel for sufficient time to reach thermal equilibrium prior to initiation of the proving run(s). The temperature in the interconnecting pipe should be monitored during the calibration run to ensure that no mass storage occurs between the field meter and prover.

For repeatable results, rotational or cyclical flow meters, such as turbine meters, should be calibrated using a large number of cycles (~10,000) or an integral number of mechanical cycles. An example of a mechanical cycle would be a single rotation of the rotor in a turbine meter. Usually, a turbine meter will generate a large number of rotor revolutions in a short period of time. However, when a turbine meter is calibrated by a piston prover, the number of rotor revolutions is greatly reduced, and an integral number of revolutions should be counted for a pulse interpolation scheme.[5],[6]

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