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Use liquid ultrasonic meters for custody transfer

This technology is gaining widespread acceptance in the field

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Using liquid ultrasonic meters for liquid petroleum applications such as custody transfer or allocation measurement is gaining global acceptance by the hydrocarbon processing industry. Ultrasonic technology is well established but using it for custody transfer and allocation measurement is relatively new. End users often try to utilize the same measurement practices that apply to turbine technology.

While the two approaches share some similarities—such as the need for flow conditioning and upstream and downstream piping requirements—there are also differences. Several in-situ proving methods can be used to successfully field calibrate a liquid ultrasonic meter.

Transit time ultrasonic flowmeters. This device uses the transit times of the signal between two transducers to determine the fluid velocity. The transducer transmits ultrasonic pulses with the flow and against the flow to a corresponding receiver (Fig. 1). Each transducer alternates as a transmitter and a receiver.

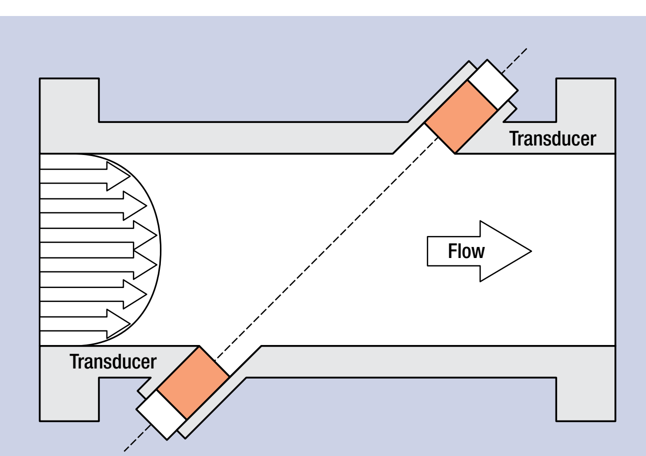

FIG. 1 Transit-time principle for ultrasonic flowmeters.

Consider stationary fluid in a full meter spool. In theory, it will take precisely the same amount of time for a pulse to travel through the fluid in each direction since the speed of sound is constant within the fluid. If fluid is flowing through the pipe, then a pulse traveling with the flow traverses the pipe faster than the pulse traveling against the flow. The resulting time difference is proportional to the fluid velocity passing through the meter spool. Single and multiple acoustic paths can be used to measure fluid velocity. Multipath meters tend to be more accurate since they collect velocity information at several points in the flow profile.

The transit time of the ultrasonic signal is measured and used with other variables to calculate flow. Although the ultrasonic signal is traveling in a straight line, it is traveling at an angle, θ, to the pipe axis (Fig. 2). Eqs. 1 and 2 define the flowrate between two transducers located at positions *u* (upstream) and *d* (downstream):

$$t_{ud} = \frac{L}{C + V_i \cos\theta} \tag{1}$$

$$t_{du} = \frac{L}{C - V_i \cos\theta} \tag{2}$$

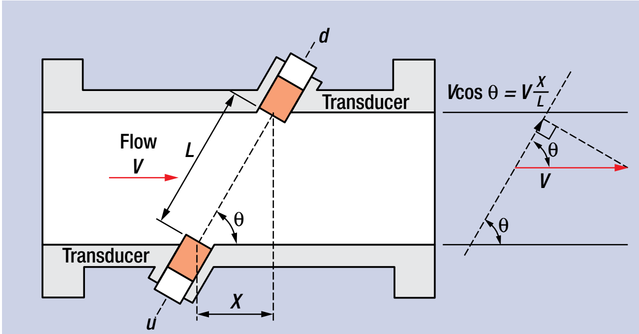

FIG. 2 Variables for calculating transit time.

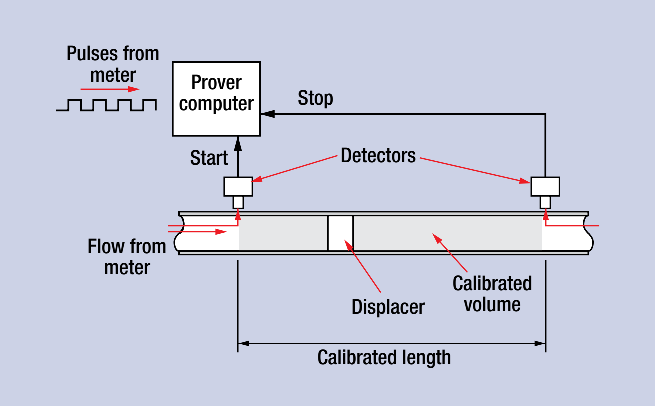

FIG. 3 Proving a meter by displacement.

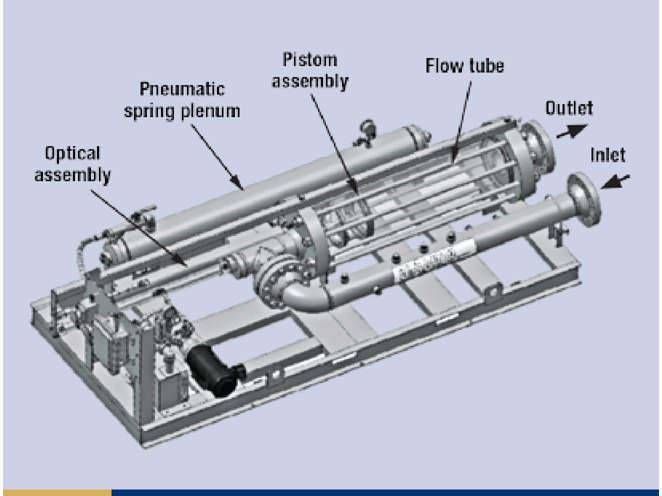

FIG. 5 A small volume prover.

Solving eq. 3 and 4 simultaneously yields the following results for V_i and C (notice that V_x/L can be substituted for "$V\mathrm{Cos}\,\theta$" to simplify eq. 4):

$$V_i = \frac{L}{2\cos\theta}\ \frac{t_{du}-t_{ud}}{(t_{ud})(t_{du})} = \frac{L^2}{2\chi}\ \frac{t_{du}-t_{ud}}{(t_{ud})(t_{du})} \qquad (3)$$

$$C = \frac{L}{2}\ \frac{t_{du}+t_{ud}}{(t_{ud})(t_{du})} \qquad (4)$$

where: t_{ud} = transit time from transducer u to d
t_{du} = transit time from transducer d to u
L = path length between transducer faces u and d
x = axial length between transducer faces
C = velocity of sound in the liquid in still condition
V_i = mean chord velocity of the flowing liquid
θ = acoustic transmission angle.

Since the equations are valid for fluid flowing in either direction, the method is inherently bidirectional. Also, the speed of sound term through the medium drops out of the velocity equation. Consequently, velocity is determined from the transit times through the predetermined distances, and is independent of factors such as temperature, pressure and fluid composition.

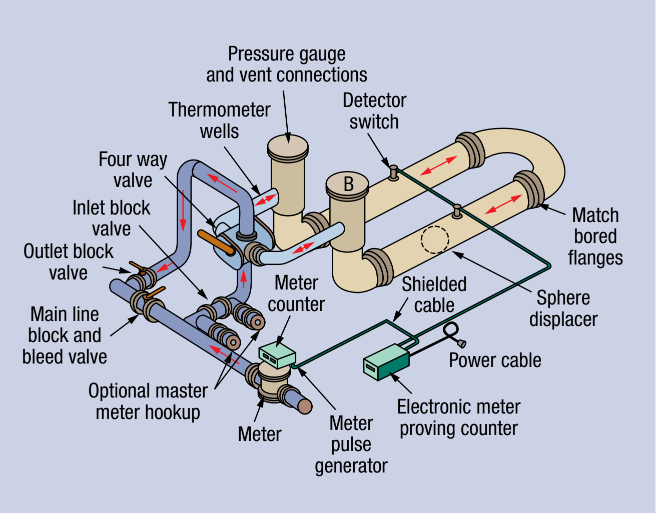

FIG. 4 A bidirectional ball prover.

Field proving. In custody transfer or allocation measurement applications, it is common practice to periodically prove liquid meters in the field. This is done to reduce uncertainty and maintain accuracy for fiscal measurement, establish meter factors at working conditions and determine meter factors for different fluids. The measurement application or the customer contract generally determines the frequency at which it is proved.

Meters in a pipeline that transports several liquids may be proved at every product change. The American Petroleum Institute (API) provides guidelines and requirements. There are four basic requirements for successful proving:

1. The meter should be proved under the normal conditions in which it is expected to operate. Flow variables, including flowrate, pressure and temperature must be stable and unchanging.
2. Adequate prover capacity is required to provide proving runs of sufficient duration. Larger volumes and longer run times will improve repeatability performance. Upstream flow conditions can affect the run time and volume required.
3. A sufficient number of runs are required to establish a valid proving. If the run-to-run variation is small, then an adequate meter factor can be found by averaging a few runs. As the run-to-run variation increases, the average of more runs is required for an adequate meter factor.
4. Results should be traceable to the National Institute of Standards and Technology (NIST). The meter prover calibration must be traceable to NIST-calibrated test measures.

Proving principle. Displacement prover systems operate on the displacement principle. This is the repeatable displacement of a known volume of liquid from a calibrated section of pipe between two detectors (Fig. 3).

Liquid displacement is achieved by a sphere or a piston traveling through the pipe. A corresponding volume of liquid is simultaneously measured by a meter installed in series with the prover. A meter that is being proved on a continuous-flow basis must be connected at the time of proof to a proving counter. The counter is started and stopped when the displacing device actuates the two detectors at either end of the calibrated section of the prover.

A displacement-type prover must be installed so that the flow of the liquid stream through a meter being proved will fully pass

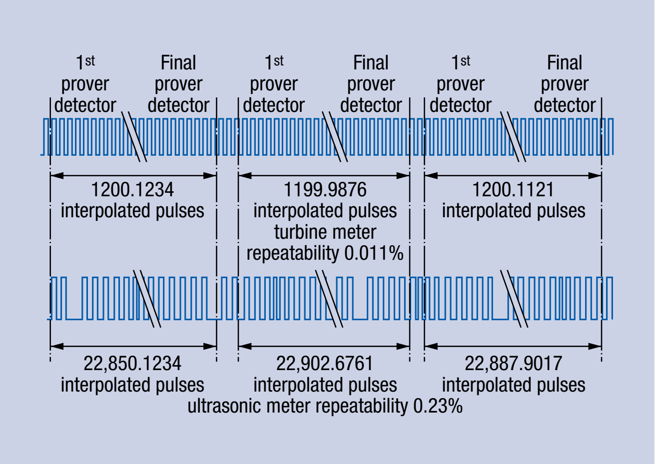

FIG. 6 Typical proving results for turbine and ultrasonic meters using small proving volumes.

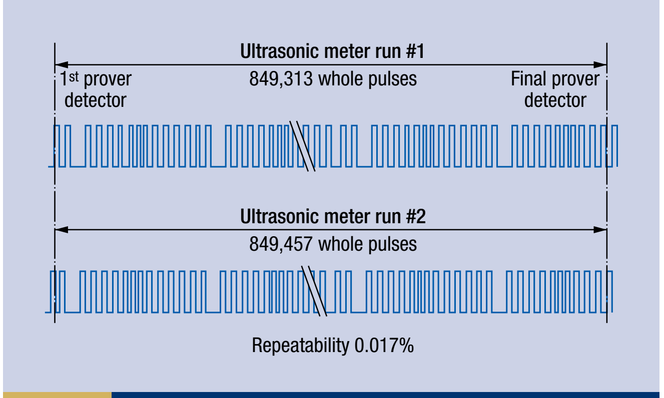

FIG. 7 Typical proving results for ultrasonic meters using a larger proving volume.

through the prover. When flow through the meter and prover has stabilized, the proving sequence is initiated. The displacer then travels through the pipe, while maintaining a seal between it and the pipe wall. Each of the detector switches is individually actuated upon displacer passage.

A high-resolution pulse counter connected to the meter output is gated on and off by the detectors. In the event the meter being proven cannot generate a minimum of 10,000 whole meter pulses between detector switches, some form of pulse interpolation must be used to allow discrimination at a rate higher than 1 part per 10,000.

Types of provers. A displacement prover may utilize either a sphere or a piston as a displacer and may be either unidirectional or bidirectional. Liquid always flows in the same direction through a unidirectional prover which has a mechanism that returns the displacer to its initial position in the prover pipe.

A bidirectional prover utilizes a flow reversal mechanism (such as a four-way valve) that causes the displacer to alternate its direction of passage through the prover pipe. Unidirectional proving runs consist of single trips of the displacer past the detectors in the same direction. Bidirectional proving runs consist of "round trips" of the displacer (a complete cycle past the detectors in both directions). A typical bidirectional prover is depicted in Fig. 4; a typical unidirectional "small-volume" prover is depicted in Fig. 5.

Small-volume displacement provers are defined as those with a calibrated volume that permits a minimum of 10,000 pulses to be collected by the meter under test. Its attributes include smaller size and weight, shorter proving cycles and extremely wide rangeability (in excess of 1,000:1).

Meter characteristics. Flowmeter characteristics are important in developing a proving methodology. For example, both positive displacement and turbine meters have mechanical elements that rotate as fluid passes through the meter. It is convenient to use electrical sensors to detect the passing of gear teeth or rotor blades. These pulses are totaled to determine the flow volume through the meter.

Since these mechanical elements rotate as a result of the flow passing through them, it tends to average out eddies associated with turbulent flow. The frequency output, representing pulses per unit of volume, is quite steady and is considered to be a uniform pulse output. These meters exhibit good proving repeatability with fairly short volumes and run times.

An ultrasonic meter has no moving parts. It determines the average velocity over one or more acoustic paths. The actual measurement made is the transit time of an ultrasonic pulse over the path in both the upstream and downstream directions. From this, an average velocity is calculated for each path. The path averages are then combined to form an average velocity for the whole meter, and the volume flow through the meter can be determined based on the cross-sectional area of the meter.

Since an ultrasonic meter has no moving parts, there is nothing to rotate to provide pulse counts. Pulse generation is done by means of a digital-to-frequency converter. Since the frequency is generated as the result of a measurement, it always lags the flow by the update period.

Also, since the meter is sampling the flow at several locations, turbulence in the flow will be measured. The standard deviation of the path velocity measurements is typically 2% to 5%. This implies a peak-to-peak variance of 12% to 30%. The turbulence is noise in the flow measurement that averages to zero. As a result, these meters have varying frequency output and are said to have a non-uniform pulse output. In proving ultrasonic meters, volumes and run times must be sufficient to average the turbulence to an acceptably low value.

Regardless of the calibration method, repeatability is an important criterion used to determine the acceptability of proving results. Ultrasonic meter performance verification

TABLE 1. Number of runs and repeatability needed to achieve ±0.027% uncertainty in proving an ultrasonic flowmeter

$$Repeatability = \frac{High\ counts - low\ counts}{low\ counts} \times 100$$

Runs	Repeatability	Uncertainty
3	0.02%	±0.027%
4	0.03%	±0.027%
5	0.05%	±0.027%
6	0.06%	±0.027%
7	0.08%	±0.027%
8	0.09%	±0.027%
9	0.10%	±0.027%
10	0.12%	±0.027%
11	0.13%	±0.027%
12	0.14%	±0.027%
13	0.15%	±0.027%
14	0.16%	±0.027%
15	0.17%	±0.027%
16	0.18%	±0.027%
17	0.19%	±0.027%
18	0.20%	±0.027%
19	0.21%	±0.027%
20	0.22%	±0.027%

Per API MPMS Ch. 4.8, Table A-1 to achieve ±0.027% uncertainty of meter factor.

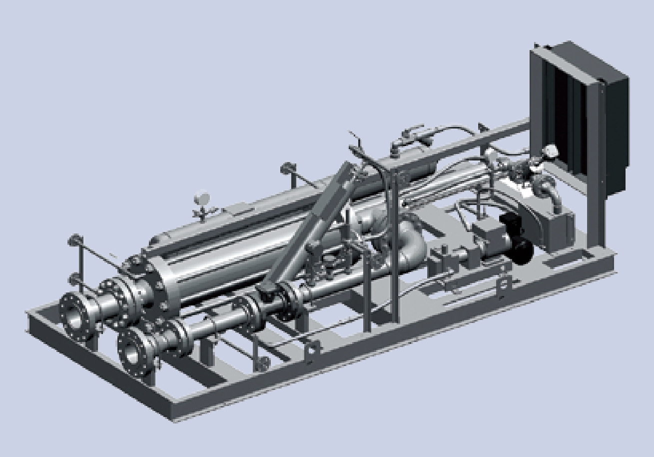

FIG. 8 Small volume prover with turbine master meter.

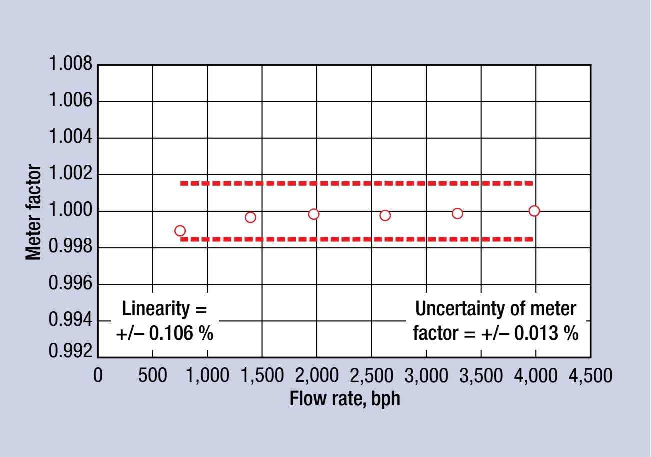

FIG. 9 Liquid ultrasonic meter 6-in. calibration chart—using ball prover with ample volume.

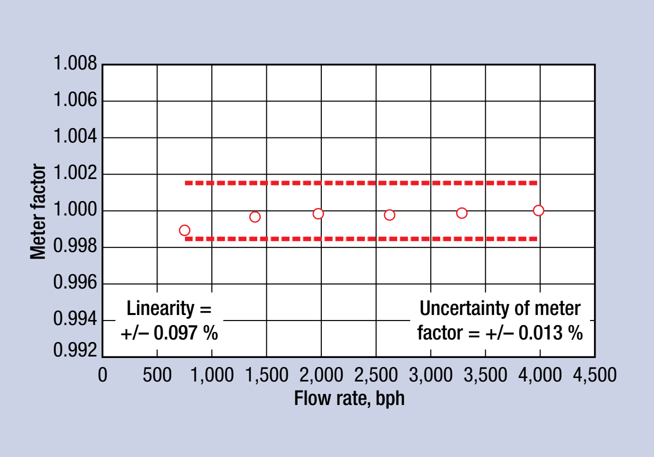

FIG. 10 Liquid ultrasonic meter 6-in. calibration chart—using in-situ master-meter/small volume prover.

can be ascertained by conventional means and to a consistent level. Table 1 provides guidance in determining the consecutive number of proving runs that may be required to obtain a meter uncertainty factor of ±0.027% at a 95% confidence level.

Any of the number of runs chosen from this table will produce results that verify a meter's performance to ±0.027% uncertainty. There is no difference between the traditional 5 consecutive runs that repeat within 0.05% and 10 consecutive runs that repeat within 0.12%, they both demonstrate the exact same uncertainty. The operator in the field will attempt to prove the meter in the smallest number of runs possible.

How proving volume has a direct effect on repeatability is shown in Fig. 6. The example shows a turbine and ultrasonic meter being proven simultaneously with a small-volume displacement prover. Each of the three proving cycles could be as short as 0.5 sec., depending upon flowrate. As a result of the small proving volume, it can be seen that the turbine meter, with its uniform pulse output, displays excellent repeatability (0.011%) over the 3 runs, while the ultrasonic meter does not—it shows a repeatability of 0.23%.

This does not mean that the turbine meter is more accurate or repeatable than the ultrasonic meter since both meters would provide excellent results over a longer time period. An ultrasonic meter proven using a prover with a larger volume, which effectively allows more time for the non-uniform pulse variations to average out, is depicted in Fig. 7. The important point is that increasing proving volumes improves repeatability.

Increasing proving volume. It can be seen that repeatability has improved significantly from 0.23% in Fig. 6 over 3 consecutive runs to 0.017% in Fig. 7 over two consecutive runs. This is a direct result of increasing the proving volume, thus allowing additional time for the meter to average the signal output. Increasing the proving volume can be accomplished by using a larger-volume prover or by using another method that is being adapted by many end users—the prover-master meter method (Fig. 8).

Master meter proving is an accepted and recognized method of proving flowmeters. However, master meters must also be calibrated on a regular basis to minimize errors. Calibrating a master meter in any situation other than the actual operating conditions can introduce uncertainties that must be compensated for. Changes in fluid composition, viscosity, density and pressure can affect a meter's performance as can installation.

Using a prover-master meter combination installed in series with the meter under test eliminates all of these uncertainties. The master meter is first calibrated by the meter prover in-situ under the actual operating conditions and using the actual fluid being measured. Once this is accomplished, then the master meter is used to calibrate the ultrasonic meter using the master meter calibration methodology. The advantage of this method is that it allows for much larger proving volumes since the volume can be as large as necessary thus allowing an acceptable level of repeatability.

Existing provers, whether ball-type or small-volume, can be fitted with master meters in the field if it is determined that the existing prover does not have sufficient volume to provide acceptable repeatability. An actual calibration curve on a 6-in. ultrasonic meter that was calibrated using a bidirectional ball prover, with a volume in accordance with API recommendations, is shown in Fig. 9. The same 6-in. meter calibrated using the prover-master meter method is depicted in Fig.10.

A small-volume prover was used to calibrate an 8-in. turbine meter, which was then used as the master meter to calibrate the 6-in. ultrasonic meter. The results are virtually identical to those above, illustrating the viability of both methods and the reproducibility of the meter itself.

Summary. Liquid ultrasonic meters are a relatively new technology and they continue to gain acceptance in a variety of applications. Proving a meter per API guidelines requires a ±0.027% meter uncertainty factor with a 95% confidence level. A key to meeting this requirement is having sufficient proving volume, which has a direct impact on repeatability. Generally, the longer the proving cycle, the larger the proving volume and the more repeatable the results.

Despite the relatively recent use of ultrasonic technology in this application, oil and gas companies with a good understanding of the issues are successfully proving liquid ultrasonic meters in the field on a regular basis. **HP**

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API Manual of Petroleum Measurement Standards (MPMS), Chapter 4 – Proving systems, Section 5 – Master – Meter Prover

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