Fundamentals of Multipath Ultrasonic flow meters for Gas Measurement

Overview of selection, installation, operation and maintenance of wetted-sensor ultrasonic flow meters

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ABSTRACT

This paper discusses fundamental principles of ultrasonic gas flow meters used for measurement of natural gas. A review of an ultrasonic meter's operation and the equations used to determine actual volumetric flow is presented. The ultrasonic flow meter's diagnostic capability will also be briefly presented. Further, diagnostic data, in conjunction with gas composition, pressure and temperature, will be reviewed to show how this technology provides diagnostic benefits beyond that of other primary measurement devices. The basic requirements for obtaining good meter performance, when installed in the field, will be reviewed. Most of this information can be generalized to other manufacturer's transit time ultrasonic flow meters however, these examples provided, particularly with respect to some diagnostic features, are based on the Daniel SeniorSonic ultrasonic flow meter.

INTRODUCTION

During the past decade the use of ultrasonic flow meters for natural gas custody transfer measurement has grown significantly as end users come to understand and accept the technology. Many end users are also utilizing the technology to validate other measurements within a metering system, particularly gas composition and temperature measurement. The publication of AGA Report No. 9, *Measurement of Gas by Multipath Ultrasonic Meters, 2nd edition* in April 2007 and ISO 17089, *Measurement of fluid flow in closed conduits - Ultrasonic meters for gas*, *Part 1: Meters for custody transfer and allocation measurement* in 2009 has greatly accelerated the installation of ultrasonic flow meters worldwide. Today virtually every gas transmission company is using this technology, either for fiscal, or for operational applications.
There are many reasons why ultrasonic metering is gaining such broad acceptance in a traditionally conservative industry. Some of the benefits of this technology include the following:

- **Accuracy:** Can be calibrated to <0.3%, little or no drift.
- **Large Turndown:** Typically 50:1, or more.
- **Naturally Bi-directional:** Measures volumes in both directions with comparable performance.
- **Tolerant of Wet Gas**: Important for production applications.
- **Non-Intrusive:** No pressure drop.
- **Low Maintenance:** No moving parts mean reduced maintenance.
- **Fault Tolerance:** Meters remain relatively accurate even if sensor(s) should fail.
- **Integral Diagnostics:** Data for determining both a meter's health and dynamic online performance is readily available.

It is clear that there are many benefits to using ultrasonic flow meters. Although the first several benefits are important, the most significant often turns out to be the ability to diagnose the meter's dynamic online performance. The primary purpose of this paper is to discuss basic gas ultrasonic meter operation, present the basics of diagnostic information, and review installation considerations to assure best meter performance.

ULTRASONIC METER BASICS

Before looking at the main topic of integral diagnostics, it is important to review the basics of ultrasonic transit time flow measurement. In order to diagnose any device, a relatively thorough understanding is generally required. In today's world of increasingly complex devices, and productivity demands on everyone, companies rely on a well trained work force and instruments that are increasing capable of self-diagnostics. Without a good grounding in the basics, understanding diagnostic messages can be confusing.

Fortunately for everyone, the basic operation of an ultrasonic meter is relatively simple. Consider the meter design shown in Figure 1. Even though there are several designs of ultrasonic meters on the market today, the principle of operation remains the same.

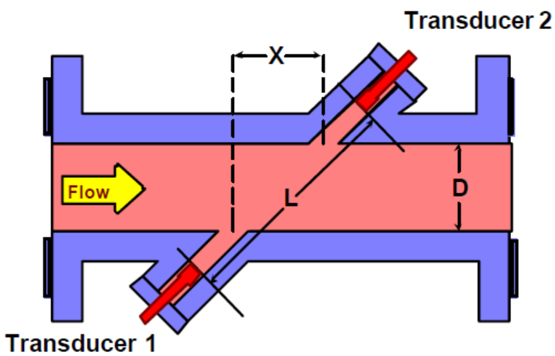


Figure 1 - Ultrasonic flow meter

Ultrasonic meters are velocity meters by nature. That is, they measure the velocity of the gas within the meter body. By knowing the velocity and the cross-sectional area, uncorrected volume can be computed. Let us review the equations needed to compute flow.

The transit time (T_{12}) of an ultrasonic signal traveling with the flow is measured from Transducer 1 to Transducer 2. When this measurement is completed, the transit time (T_{21}) of an ultrasonic signal traveling against the flow is measured (from Transducer 2 to Transducer 1). The transit time of the signal traveling with the flow will be less than that of the signal traveling against the flow due to the velocity of the gas within the meter.

Let's review the basic equations needed to compute volume. Assume L and X are the direct and lateral (along the pipe axis and in the flowing gas), distances between the two transducers, C is the Speed of Sound of the gas, V the gas velocity, and T_{12} and T_{21} are transit times in each direction. The following two equations would then apply for each path:

$$T_{12} = \frac{L}{C + V \cdot \frac{X}{L}} \qquad (1)$$

and

$$T_{21} = \frac{L}{C - V \cdot \frac{X}{L}} \qquad (2)$$

Solving for gas velocity yields the following:

$$V = \frac{L^2}{2X} \left(\frac{T_{21} - T_{12}}{T_{21} \cdot T_{12}} \right) \qquad (3)$$

Solving for the speed of sound (C) in the meter yields the following equation:

$$C = \frac{L}{2} \left(\frac{T_{21} + T_{12}}{T_{21} \cdot T_{12}} \right) \qquad (4)$$

Thus, by measuring dimensions X & L and transit times T_{12} & T_{21}, we can compute the gas velocity and the speed of sound (SOS) along each path. The speed of sound for each path will be discussed later and shown to be a very useful parameter in verifying good overall meter performance.

The average transit time, with no gas flowing, is a function of meter size and the speed of sound through the gas (pressure, temperature and gas composition). Consider a 12-inch meter for this example. Typical transit times, in each direction, are on the order of one millisecond (and equal) when there is no flow. The *difference* in transit time during periods of flow, however, is significantly less, and is on the order of several nanoseconds (at low flow rates). Thus, accurate measurement of the transit times is critical if an ultrasonic meter is to meet performance criteria established in AGA Report No. 9.

It is interesting to note in Equation (3) that gas velocity is independent of speed of sound, and to compute speed of sound (Equation (4)), gas velocity is not required. This is true because the transit time measurements T_{12} and T_{21} are measured within a few milliseconds of each other, and gas composition does not change significantly during this time. Also, note the simplicity of Equations (3) and (4). Observe that only the dimensions X and L, and the transit times T_{12} and T_{21} are required to yield both the gas velocity and speed of sound along a path. These equations look relatively simple, and they are; the primary difference between computing gas velocity and speed of sound is the *difference* in transit times is used for computing velocity, where as the *sum* of the transit times is used for computing speed of sound.

Unfortunately, determining the correct flow rate within the meter is a bit more difficult than it appears. The velocity shown in Equation (3) refers to the velocity of each individual path. The velocity needed for computing volume flow rate, also known as bulk mean velocity, is the average gas velocity across the meter's area. In the pipeline, gas velocity profiles are not always uniform, and often there is some swirl and asymmetrical flow profile within the meter. This makes computing the average velocity a bit more challenging. Meter manufactures have differing methodologies for computing this average velocity. Some derive the answer by using proprietary algorithms. Others rely on a design that does not require "hidden" computations. Regardless of how the meter determines the bulk average velocity, the following equation is used to compute the uncorrected flow rate.

$$Q = V * A \qquad (5)$$

This output (Q) is actually a flow rate based on volume-per-hour, and is used to provide input to the flow computer. A is the cross-sectional area of the meter. In summary, some key points to keep in mind about the operation of an ultrasonic meter are:

• The measurement of transit time, both upstream and downstream, is the primary function of the electronics.

• All path velocities are averaged to provide a "bulk mean" velocity that is used to compute the meter's output (Q).

• Because the electronics can determine which transit time is longer (T_{21} or T_{12}), the meter can determine direction of flow.

• Speed of sound is computed from the same measurements as gas velocity (the "X" dimension is not required).

Transit time is the most significant aspect of the meter's operation, and all other inputs to determine gas velocity and speed of sound are essentially fixed geometric (programmed) constants.

INTEGRAL DIAGNOSTICS

One of the principal attributes of modern ultrasonic meters is their ability to monitor their own health, and to diagnose any problems that may occur. Multipath meters are unique in this regard, as they can compare certain measurements between different paths, as well as checking each path individually. Measures that can be used in this online "health checking" can be classed as internal or external (dynamic) diagnostics. Internal diagnostics are those indicators derived only from internal measurements of the meter. External or dynamic diagnostics are those methods in which individual path measurements from the meter are combined in various ratios or with parameters derived from independent sources to detect and identify fault conditions.

Some of the common internal meter diagnostics used are as follows:

Gain

One of the simplest indicators of a meter's health is the presence of strong signals on all paths. Ultrasonic flow meters have automatic gain control on all receiver channels. Any increase in gain on any channel indicates a weaker signal, perhaps due to transducer deterioration, fouling of the transducer ports, or liquids in the line. However, caution must be exercised to account for other factors that affect signal strength, such as operating pressure and flow velocity.

Gain numbers vary from manufacturer to manufacturer. Thus, recommendations may also differ. However, regardless of design or methodology for reporting gain, it is important to obtain readings on all paths under somewhat similar conditions. The significant conditions to duplicate are metering pressure and gas flow rate.

Gain readings are generally proportional to metering pressure (and to a much lesser extent, temperature). That is, when pressure increases, the amount of gain (amplification) required is reduced. If an initial gain reading were taken at 600 psig, when the meter was placed into service, and subsequent readings taken at 900 psig, one would expect to see a change. Understanding that pressure affects gain readings helps guard against making the false assumption something is wrong.

Fortunately, most applications do not experience a significant variation in metering pressure. If pressure does vary, the observed gain value can be adjusted relatively easily to allow for comparison with baseline values. This method of adjustment varies with manufacturer, so no discussion will be incorporated here.

Gas velocity can also impact the gain level for each path. As the gas velocity increases, the increased turbulence of the gas causes an increase in signal attenuation. This reduction in signal strength will be seen immediately by increased gain readings. These increases are generally small compared to the amount of gain required. Typical increases might be on the order of 10- 50%, depending upon meter size and design.

Thus, it is always better to “baseline” gain readings when gas velocities are below 30 fps. Using velocities in excess may provide good results, but it is safe to say that lower velocities provide more consistent, repeatable results.

So, what else causes reductions in signal strength (increased gain) you ask? There are many sources other than gas velocity and pressure. For instance, contamination of the transducers (buildup of material on the face) will attenuate the transmitted (and received) signals. The reader might assume that this buildup would cause the meter to fail (inability to receive a pulse). However, this is not generally the case. Even with excessive buildup of more than 0.050 of an inch of an oily, greasy, and/or gritty substance, today’s Ultrasonic flow meters will continue to operate.

The reader may wonder what impact on transit time accuracy could be attributed to transducer face contamination. It is true the speed of sound will be different through the contaminated area when compared to the gas. Let us assume a build-up is 0.025 of an inch on each face, and the path length is 16 inches. Also assume the speed of sound through the contamination is twice that of the typical gas application (2,600 fps vs. 1,300 fps).

With no buildup on the transducer, and at zero flow, the average transit time would be 1.025641 milliseconds. With buildup the average transit time would be 1.024038 milliseconds, or a difference of 0.16%. This would be reflected in the meter’s reported speed of sound .

However, it is the difference in transit times that determines gas velocity (thus volume). This is the affect that needs to be quantified. Maybe the easiest way to analyze this is assume the transit time measurements in both directions are reduced by 0.16% (from the previous example).

Remembering in Equation (3) that gas velocity is proportional to a constant (L^2 / 2*X)* multiplied by the difference in transit times, all divided by the product of transit times. The decrease in transit times will occur for both directions and this affect will be negated in the numerator. <u>In other words, the Δt will remain the same.</u>

However, the error in both T_{12} and T_{21} will cause the denominator value to decrease, thus producing an error that is twice the percentage of transit time (0.16%), or 0.32%. Thus, the meter’s output will increase by 0.32%. However, this amount of buildup is abnormal, and not typical of most meter installations.

Transducer placement can further alleviate this concern, with protruding transducers more subject to this effect than those located at the pipe wall or recessed into the transducer prot.

Concluding the discussion on gain readings, ultrasonic flow meters all have more than adequate amplification (gain) to overcome even the most severe reductions in signal strength. The amount of buildup required to fail today’s high-performance transducers and electronics generally exceeds pipeline operational conditions. Periodic monitoring of this parameter, however, will help insure good performance throughout the life of the meter.

Metering accuracy (differences in transit time velocity computation) can be affected, but only when significant buildup of contamination occurs.

Signal Quality

This expression is often referred to as performance (but should not be confused with meter accuracy). All ultrasonic meter designs send multiple pulses across the meter to another transducer before updating the output. Ideally, all the pulses sent would be received and used. However, in the real world, sometimes the signal is distorted, too weak, or otherwise the received pulse does not meet certain criteria established by the manufacturer. When this happens the electronics rejects the pulse rather than use something that might distort the results.

The level of acceptance (or rejection) for each path is generally considered as a measure of performance, and is often referred to as signal quality. Meters provide a value describing how good signal detection is for each ultrasonic path. As mentioned above, there are several reasons why pulses can be rejected. Additional causes may include extraneous ultrasonic noise in the same region the transducer operates, distorted waveforms caused by excessive gas velocity, and to some degree, contamination on the face of the transducer.

Typically, the value of acceptance for each path, under normal operating conditions, will be 100%. As gas velocity increases to near the meter's rating, this percentage will begin to decrease. Depending upon design, this percentage may decrease to below 50%. Generally, this reduction in performance will have little impact on meter accuracy. However, if the percentage of accepted pulses is this low, it is safe to say the meter is not operating at top performance, and investigation may be warranted (assuming the meter isn't operating at 110+% of rated capacity).

Concluding the discussion on performance, this parameter should be monitored periodically as poor performance on a path may be an indication of possible impending failure. Lower than expected performance can be caused by several factors. Besides excessive gas velocity, contamination on the transducer face and excessive extraneous ultrasonic noise can reduce signal quality. However, by monitoring gains, this condition can be easily identified before it becomes a problem.

Signal-to-Noise Ratio

This parameter is another variable that provides information valuable in verifying the meter's health, or alert of possible impending problems. Each transducer is capable of receiving noise information from extraneous sources (rather than its paired transducer). In the interval between receiving pulses, meters monitor this noise to provide an indication of the "background" noise. This noise can be in the same ultrasonic frequency spectrum as that transmitted from the transducer itself.

Noise levels can become excessive if a control valve is placed too close and the pressure differential is too high. In this scenario the meter may have difficulty in differentiating the signal from the noise. By monitoring the level of noise, when no pulse is anticipated, the meter can provide information to the user, warning that meter performance (signal quality) may become reduced. In extreme cases, noise from control valves can "swamp" the signal to the point that the meter becomes inoperative.

All meters can handle some degree of noise created from this condition. Some ultrasonic flow meter designs can handle more than others can. The important thing to remember is the best time to deal with control valve noise is during the design of the metering station. Today's technology has improved significantly in dealing with extraneous noise. Reducing it in piping design is always the best choice.

Other sources can cause reduced signal to noise values. Typically they are poor grounding, bad electrical connections between electronics and transducers, extraneous EMI and RFI, cathodic protection interference, transducer contamination and in some instances, the meter's electronic components. However, the major reason for decreased signal to noise ratios remains pressure drop from flow control or pressure reducing valves.

Concluding this discussion on signal to noise, the most important thing to remember is high-pressure drop (generally in excess of 200 psig) across a control valve can cause interference with the meter's operation. If the noise is isolated to a transducer or pair of transducers, the cause is generally not control valve related. Here probable causes are poor component connections or a potential failing component. Control valve noise usually causes lower signal to noise levels on the transducers that face the noise source (all would be affected).

Velocity Profile

Monitoring the velocity profile is possibly one of the most overlooked features of today's ultrasonic meter. It can provide many clues as to the condition of the metering system, not just as a monitor of the meter. AGA Report No. 9 requires a multipath meter to provide individual path velocities.

As mentioned previously, the output used by the flow computer is an average of these individual readings. Once the ultrasonic flow meter is placed in service, it is important to collect a baseline (log file) of the meter. That is, record the path velocities over some reasonable operating range, if possible. Good meter station designs produce a relatively uniform velocity profile within the meter. The baseline log file may be helpful in the event the meter's performance is questioned later.

Many customers choose to use a high performance flow conditioner (not tube bundles) with their meter. This conditioner is intended to isolate any upstream piping effects on gas profile. In reality, they don't totally isolate the disturbance, but do provide a reasonably repeatable profile. The important issue here is the velocity profile is relatively repeatable. Once a baseline has been established, should something happen to the flow conditioner, it can be identified quickly by comparing path velocities or path velocity ratios with the baseline.

Many things can happen to impact the original velocity profile. Changes can be caused by such things as:

- partial blockage of the flow conditioner,
- damage to the flow conditioner,
- or upstream piping affects, such as a change in a valve position.

Of course, something could have also occurred with the meter to cause a significant profile change. Generally speaking, this is unlikely as all components are securely mounted. However, the velocity of a given path could be affected by other problems. When considering that only *X* and *L* dimensions, and transit times, impact path velocity, it is relatively easy to eliminate these.

If a problem develops within the meter that impacts only one or more paths, other performance indicators, such as gain, path performance, and speed of sound will also be indicating problems.

Concluding this discussion on path velocities, most good installations produce somewhat symmetrical velocities within the meter. Comparing each path's velocity with the average, and sometimes to other paths, depending upon the ultrasonic flow meter design, can give the user confidence the profile has not significantly changed. Today's ultrasonic flow meter can handle some relatively high levels of asymmetry within the meter. It should *not* be assumed that the meter's accuracy is significantly impacted just because the velocity profile has changed. It is usually an indication, however, that something within the meter set, other than the meter itself, is probably causing the effect. Careful review of other diagnostic parameters can determine if the meter is at fault, or not.

Speed of Sound

Probably the most discussed and used diagnostic tool is the meter's speed of sound (SOS). The reader may recall that speed of sound is basically the sum of the transit times divided by their product, all then multiplied by the path length (Equation (4)). As was discussed earlier, the primary measurement an ultrasonic meter performs to determine velocity is transit time. If the transit time measurement is incorrect, the meter's output will be incorrect, and so will the speed of sound.

Thus, it is important to periodically verify that the meter's reported speed of sound is within some reasonable agreement to an independently computed value.

Modern Ultrasonic flow meters use high frequency clocks to accurately perform transit time measurements. In a typical 12-inch meter, the average transit time may be on the order of one millisecond (one thousandth of a second). When there is no flow within the meter, the difference between T_{12} and T_{21} will be zero. As flow rate increases, the difference will be detected, and a resulting flow rate computed. To obtain a perspective on this differential time, values start out in the 10's of nanoseconds (one billionth of a second) and typically increase to maybe 100 microseconds (one millionth of a second) at the highest velocities. Obviously accurate meter performance requires consistent, repeatable transit time measurements.

Comparing the SOS to computed values is one method of verifying this timing. This procedure would be considered an external or dynamic diagnostic technique.

Let's examine the affects (or uncertainties) on computing speed of sound in the field.

Pressure & Temperature Effects

The speed of sound in gas can be easily computed in the field. There are several programs used for this purpose and they are generally based upon the equation of state provided in AGA Report No. 10 S*peed of sound in Natural Gas and Other Related Hydrocarbon Gases* which itself is derived from AGA Report No. 8, *Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases*.

When computing speed of sound, there is always some uncertainty associated with this operation. It is important to realize that the speed of sound is more sensitive to temperature and gas composition than pressure.

For example, a 1º F error in temperature at 750 psig, with typical pipeline gas, can create an error of 0.13%, or about 1.7 fps. An error of five psig at 750 psig and 60º F only contributes 0.01% error. Thus, it is very important to obtain accurate temperature information.

Knowing the temperature contributes error in computing SOS is important. However, if the temperature is in error by the amount in the previous example, a more significant question might be "what error is this causing in the volumetric measurement?"

A quick calculation shows a 1º F error will cause the corrected volumetric calculation to be incorrect by 0.28%. Having a history of calculated SOS vs. measured may actually be a good "health check" on the stations temperature measurement!

Gas Composition Effects

Sensitivity to gas composition is a bit more difficult to quantify as there is an infinite number of sample analyses to draw from. Let's assume a typical Amarillo gas composition with about 90% methane. If the chromatograph were in error on methane by 0.5%, and the remaining components were normalized to account for this error, the resulting effect on speed of sound would be 0.03%. Thus, minor errors in gas composition, for relatively lean samples, may not contribute significantly to the uncertainty.

However, let's look at another example of a Gulf Coast gas with approximately 95% methane. Suppose the methane reading is low by 0.5%, and this time the propane reading was high by that amount, the error in computed speed of sound would be 0.67% (8.7 fps!). Years ago one could argue this may not be a "typical" error. However, with the recent introduction of shale gas and deep water gas into the mix this has become an increasing "typical" application.

There are many scenarios that can be discussed and each one would have a different effect on the result. The uncertainty that gas composition contributes to the speed of sound calculation remains the most elusive to quantify, and, depending upon gas composition, may prove to be the most significant.

A typical question is "what difference can be expected between that determined by the meter, and one computed by independent means?" It has been shown [Ref. 3] that the expected uncertainties (two standard deviations) in speed of sound, for a typical pipeline gas operating below 1,480 psig, are:

- ultrasonic flow meter measurement: $\pm$ 0.17%
- Calculated (AGA 8): $\pm$ 0.12%

Since the ultrasonic flow meter's output is independent of the calculation process, a root-mean-square (RMS) method can be used to determine the system uncertainty.

Thus, when using lean natural gas below 1,480 psig, it is expected that 95% of readings agree within 0.21% (or about 2.7 fps). Therefore, it may be somewhat unrealistic to assume the meter will agree within 1 fps under typical operating conditions.

Concluding this discussion on speed of sound, this “integral diagnostic” feature may be the most powerful tool for the technician. Using the meter’s individual path speed of sound output, and comparing it to not only the computed values, but also comparing within the meter itself, is a very important maintenance tool.

Caution should be taken when collecting the data to help minimize any uncertainty due to gas composition, pressure and temperature. Additionally, it is extremely important to obtain data only during periods of flow as temperature stratification can cause significant comparison errors. By developing a history of meter SOS, and comparing with computed values, it can also be used as a “health check” for the temperature measurement used to determine corrected volumes.

Importance of SOS Verification

As was discussed earlier, SOS verification helps insure the meter is operating correctly. However, what other changes in a meter can affect the reading? From the previous discussion on gain, buildup on the face of a transducer will affect the speed of sound. Thus, if a pair of transducers has a different value, when compared to the average (or to other paths, depending upon meter’s design), this might be an indication of contamination. One thing to remember is that the percent change in speed of sound, given the same buildup, will be greater for a smaller meter than a larger one. As path length increases from say 10 inches to 30 inches (or more), a buildup of 0.025 inches will affect the transit time less.

By utilizing gain information with SOS data for a given path, it can be quickly determined if the change in SOS is due to contamination, or other causes. Another benefit in monitoring path SOS is to verify proper identification of reception pulses. In the section on signal to noise, extraneous noise was noted to potentially interfere with normal meter operation. That is, if ultrasonic noise within the meter (caused by outside sources) becomes too great, meter performance will be impacted.

As the noise level increases, there is the possibility that the circuit detecting the correct pulse will have difficulty. Good meter designs protect against this and reject received pulses that have increased uncertainty regarding their validity. If this scenario occurs, it is unlikely all paths will be affected simultaneously, and by the same amount. Monitoring variations in SOS from path to path will identify this problem and help insure the meter’s health is satisfactory.

Typical Speed of Sound Field Results

This section provides actual data from two different meters. Figures 2 and 3 show trended vs. time. Data is shown for an eight -inch meter in Figure 2. It compares the average speed of sound over the four paths with the AGA 8 calculated value.

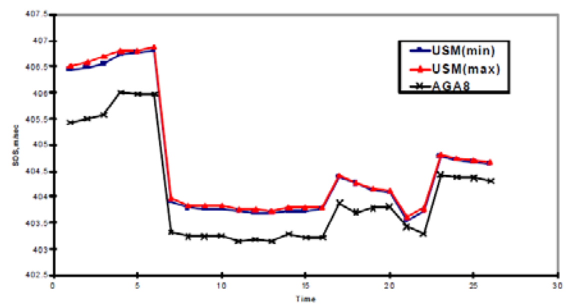


Figure 2 - 8-inch Meter Measured vs. Calculated SOS

At each measurement point, ten successive values of the ultrasonic meter’s SOS were logged. The two curves that show the minimum and maximum values in Figure 2 demonstrate repeatability in SOS measurements of better than 0.03%. The difference in the meter’s speed of sound vs. computed values are also, for most points, less than 0.3%.

Figures 3 shows the AGA 8 calculated speed of sound trended against the individual SOS readings from the four paths. Note that in each case the agreement on all chords is roughly as expected (better than 0.3%). In the area where speed of sound deviations exceeded 0.3%, (Figure 3) low flow temperature stratification was likely the cause. In the event of significant contamination on one or more pairs of transducers, this graph would have shown the impact.

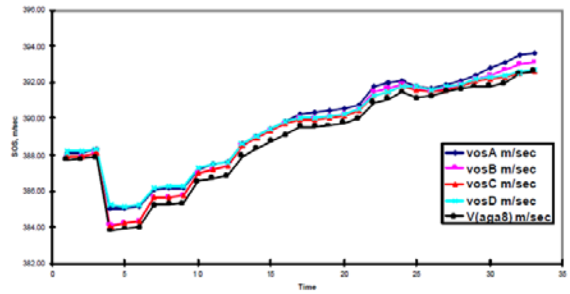


Figure 3 - 10-inch Meter SOS with Four Chords

Concluding this discussion on external calculations, the results demonstrate multi-path ultrasonic meters show good correlation between the computed speed of sound and the meters reported speed of sound. Even though there are differences between computed and reported values, these remain relatively constant though out the test period. This also suggests that when performing an on-line comparison of speed of sound, an alarm limit of about $\pm$ 0.3% between the meter and computed values, as recommended earlier, is reasonable. However, as shown in Figure 3, for a short interval the error exceeded 0.3% (during periods of low (or no) flow and temperature stratification). Since this situation can occur in the field, safeguards should be implemented to insure gas velocity is above some minimum value, and for a specified time, before alarming occurs.

Thus, the use of independent estimates of gas speed of sound, derived from an analysis of the gas composition, can be an effective method of understanding how well an ultrasonic meter is performing.

BASICS OF ULTRASONIC FLOW METER INSTALLATIONS

When installing ultrasonic flow meters, many factors should be taken into consideration to insure accurate and trouble-free performance. Before discussing these issues, let's review the basics of a good installation.

Basic Piping Issues

Ultrasonic meters require adhering to basic installation guidelines just as with any other technology. Primary metering elements, such as orifice and turbine, have adopted recommendations for installation long ago. These are provided through a variety of standards (API, AGA, etc.) to insure accurate performance (within some uncertainty guidelines) when installed. The reason for these guidelines is the meter's accuracy can be affected by profile distortions caused by upstream piping. One of the benefits of today's ultrasonic flow meter is that they can handle a variety of upstream piping designs with less impact on accuracy then other primary devices.

Installation effects have been studied in much more detail than ever before. This is due in part to the available technology needed for evaluation. Reducing uncertainty for pipeline companies has also become a higher priority today due to the volatility in the price of natural gas. Let's look at a typical velocity profile downstream of a single elbow. From this mathematical velocity profile model it is apparent the velocity profile at 10D from the elbow is far from being fully symmetrical. What isn't apparent in this model is the amount of swirl generated by the elbow. According to research work performed at Southwest Research Institute (SwRI) by Terry Grimley, it would take on the order of 100D for the profile to return to a fully symmetrical, fully developed, non-swirling velocity profile [Ref 4]. More complex upstream piping, such as two elbows out of plane, create even more nonsymmetrical and swirl than this model shows. Today's ultrasonic flow meter must handle profile distortion and swirl in order to be accurate and cost-effective. However, just as with orifice and turbine meters, installation guidelines should be followed.

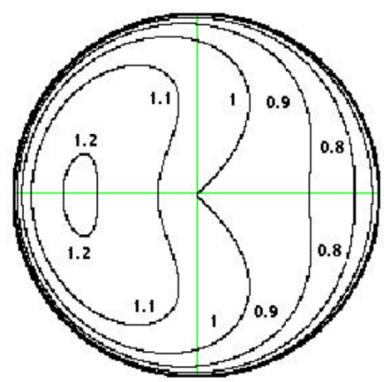
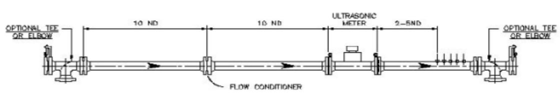


Figure No. 4 – Single-Elbow Flow Profile

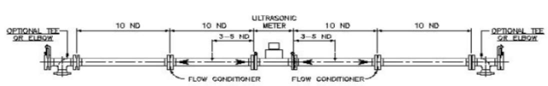
In 2007 AGA released the second edition of the Transmission Measurement Committee Report No. 9 entitled Measurement of Gas by Multipath Ultrasonic Meters. This document discusses many aspects and requirements for installation and use of ultrasonic meters. Section 7.2.2 specifically discusses the Ultrasonic flow meters required performance relative to a flow calibration. It states the manufacturer must "Recommend upstream and downstream piping configuration in minimum length – one without and flow conditioner and one with a flow conditioner - that will not create an additional flow rate measurement error of more than ±0.3% due to the installation configuration."

In other words, assuming the meter were calibrated with ideal flow profile conditions, the manufacturer must then be able to recommend an installation which will not cause the meter's accuracy to deviate more than ±0.3% from the calibration once the meter is installed in the field.

Each manufacturer has their own recommendations, supported by test data, as required by AGA 9. However, the AGA 9 document also provides a default recommendation, a kind of catch-all configuration, generally longer than the individual manufacturers' recommendation:



UNI–DIRECTIONAL



BI–DIRECTIONAL

One major change in the second edition of AGA 9 is section 6.4 regarding flow calibration of the metering package. When used in custody transfer it is a requirement that the metering package be flow calibrated. The metering package is the ultrasonic flow meter and the associated upstream and downstream meter tubes, flow conditioners, thermowells and sample probes.

Other Piping Issues

Noted in the AGA 9 default recommendation are optional inspection tees. Ongoing industry testing is being conducted with various combinations of tees, elbows and separation distances between flow disturbances (the elbows and tees being considered flow disturbances) to provide guidance whether a user should also provide these end treatments to the calibration laboratory along with the metering package as part of the total calibration package.

From AGA 9 "the designer may choose to flow calibrate the UM … in a flow calibration facility in which the test piping configuration is identical to the planned installation or with flow conditioning elements that will effectively isolate the meter from upstream piping conditions. By the law of similarity, it is presumed that the meter performance obtained in the flow lab may be reasonably reproduced in the field installation."

FLOW CALIBRATION BASICS

The primary use for Ultrasonic flow meters today is in custody measurement applications. As was discussed earlier, the introduction of AGA Report No. 9 has helped spur this growth. Section 5 (of AGA 9) discusses performance requirements, including flow calibration. For non-custody transfer use it does not require meters be calibrated before use. However, paraphrasing, it does require "the manufacturer to provide sufficient test data confirming that each meter shall meet these requirements." The basic accuracy requirement is that 12-inch and larger meters be within ±0.7%, and 10-inch and smaller meters to be within ±1.0%. Again, these maximum error values are "prior" to flow calibration. In the change noted above, custody transfer use requires flow calibration, however, most users feel their applications deserve, and require, less uncertainty than the minimum un-calibrated requirements of AGA 9. Thus, for virtually all ultrasonic flow meter applications, users are flow calibrating their meters. The only difference is non-custody transfer applications usually use surrogate meter tubes supplied by the calibration laboratory rather than the entire metering package.

In a majority of applications today customers are using flow conditioners. Ultrasonic flow meters were originally envisioned to be installed without a flow conditioner and without a flow calibration. Part of the benefit of an ultrasonic meter is there is no pressure drop. However, many feel that using a "high performance" flow conditioner (not a 19-tube bundle) further enhances performance. Even though data exists to support some ultrasonic flow meters perform quite well without flow conditioners, the added pressure drop and cost is often justified by the reduction in uncertainty, particularly over time once installed. The real benefit of using a flow conditioner is that it provides a stable, repeatable flow under various installation configurations. Calibrated USM packages remove installation effects and establish baseline diagnostics. Irrespective of the resultant diagnostic values established during flow calibration this allows long term monitoring of meter performance.

Most companies have standard designs for their meters. They typically specify piping upstream and downstream of the flow conditioner(s) and meter. Thus, Ultrasonic flow meters are typically calibrated with either 3 or 4 piping spools. Calibrating as a unit helps insure the accuracy of the meter, once installed in the field, is as close to the results provided by the lab as possible.

There are several flow calibration labs in North America that provide calibration services. Labs usually test meters throughout the range of operation. Once all the “as-found” data points have been determined, an adjustment factor is computed. The adjustment is uploaded to the meter and either one or two verification points are used to verify the “as-left” performance.

Periodic Flow Calibration

AGA 9 does not require an ultrasonic meter be recalibrated. As Ultrasonic flow meters have no moving parts, and provide a variety of diagnostic information, many feel the performance of the meter can be field verified. That is, if the meter is operating correctly, its accuracy should not change, and if it does change, it can be detected. The use of Ultrasonic flow meters for custody began increasing rapidly in 1998 with the initial release of AGA 9. In 2012 ultrasonic flow meters are the meter of choice for natural gas custody transfer measurement.

During the past several years many meters have reached a requirement for mandated recalibration in Canada. Their governmental agency, Measurement Canada, requires ultrasonic flow meters be re-tested every 6 years (this requirement is changing to every 5 or possibly 4 years in 2013-2014). Many meters that have been re-tested have exhibited very minor shifts from their initial calibrations and this is often due to dirt buildup on the meter tubes. Once cleaned most meters repeat their initial calibration.

DYNAMIC DIAGNOSTICS

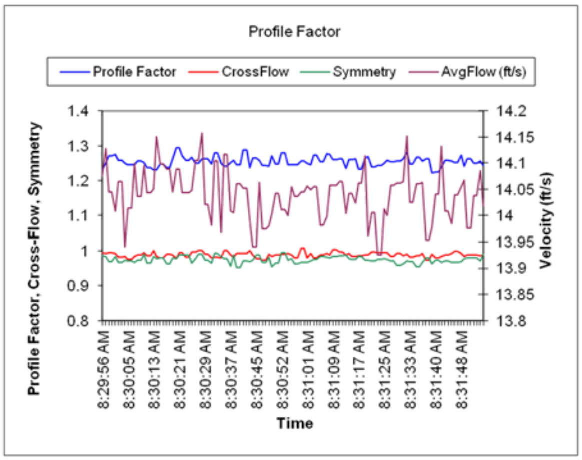
After the initial calibration and installation the meter diagnostics can be baselined against those captured during the flow calibration. If the installed flow diagnostics (separate from the internal or meter health type of diagnostics) closely match those of the calibration, the user has high confidence that the flow calibration has been transferred successfully to the field installation.

These diagnostics are typically related to various ratios or relationship of the meters multiple velocity paths to each other. While they might be referred to by different terms by different manufacturers most have similar diagnostic information:

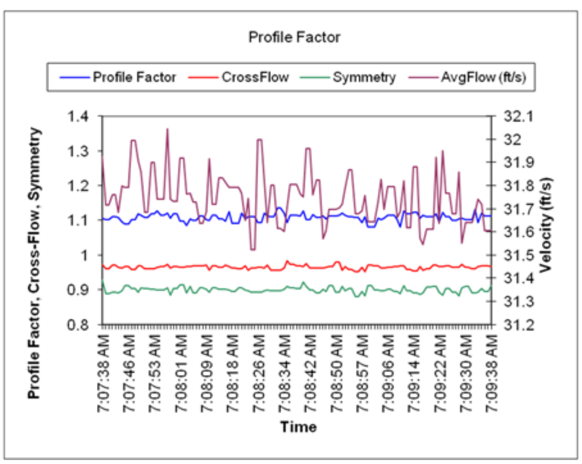
- Profile Factor – a relationship between the inner and outer paths of a meter also referred to as flatness ratio. It is an indication of the shape of the flow profile passing through the meter. Changes can indicate dirt build up, presence of liquids or blockages upstream of the meter
- Symmetry – a relationship between the paths in the top of the meter compared to the paths in the bottom half of the meter. Asymmetry can also indicate blockages or liquids. Installation effects often are identified here as flow out of elbows or tees can present as different velocities in the top compared to the bottom of the meter
- Cross Flow – a relationship between the paths crossing at different angles through the meter body (indicates roughly horizontal symmetry compared to Symmetry which indicates vertical symmetry)
- Turbulence – an indication of flow stability determined by the deviation of individual velocity measurements over time (also referred to as standard deviation)
- Swirl Angle – a comparison of individual path velocities to determine rotational stability of the flow

These diagnostics are presented in different ways by various manufacturers; here are examples of Daniel’s presentation:

Normal Flow
Profile Factor Stable = 1.25
Symmetry and Cross Flow = 1.00



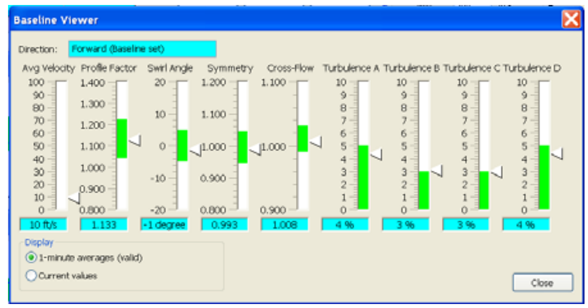
Abnormal Flow
Profile Factor Stable = 1.1
Symmetry biased to bottom of the meter = 0.9
Cross Flow below baseline = 0.98



This could indicate a blockage upstream of the meter.

A quick view offered by Daniel is the Baseline Viewer which gives users a single screen to check the dynamic diagnostic values deviation from baseline values:

Baseline within limits



Baseline outside of limits

As meters get more intelligent they can report out alerts such as abnormal profile, dirty meter, blockage upstream or liquids present. Daniel offers these features now.

CONCLUSIONS

During the past several years ultrasonic meters have become one of the fastest growing new technologies in the natural gas arena. The popularity of these devices has increased because they provide significant value to the customer by reducing the cost of doing business. One of the most significant benefits is the reduction in maintenance over other technologies.

There are several factors that can be attributed to this increased usage. First, as there are no moving parts to wear out, reliability is increased. Since Ultrasonic flow meters create no differential pressure, any sudden over-range will not damage the meter. If the meter encounters excessive liquids, it may cease operation momentarily, but no physical damage will occur, and the meter will return to normal operation once the liquid has cleared.

Most importantly, ultrasonic meters provide a significant amount of diagnostic information within their electronics. Most of an ultrasonic meter's diagnostic data is used to directly interpret its "health." Some additional diagnostics can be performed by using external devices and information (for example, computing speed of sound). This diagnostic data is available on a real-time basis and can be monitored and trended in many of today's remote terminal units (RTUs). Ultrasonic flow meters support remote access and monitoring in the event the RTU can't provide this feature.

There are four commonly used diagnostic features being monitored today. These include speed of sound by path (and the meter's average value), path gain levels, path performance values (percentage of accepted pulses), and signal to noise ratio. By utilizing this information, the user can help insure the proper meter operation.

Probably the most commonly used tools are path speed of sound and gains. Speed of sound is significant since it helps validate transit time measurement, and gains help verify clean transducer surfaces. When computing speed of sound in the field, care should be taken to collect data only during periods of flow in the pipeline as temperature gradients will distort comparison results. Additionally, as shown in one of the graphical examples, low-flow limits should be implemented to insure pipeline temperature is uniform and stable before comparing meter speed of sound with computed values from gas composition, pressure and temperature.

One significant benefit in performing online comparisons between the meter's speed of sound and a computed value is to provide a "health check" for the entire system. If a variation outside acceptable limits develops, the *probable cause* will be temperature, or gas composition measurement error rather than the ultrasonic flow meter. In this regard, the ultrasonic flow meter is actually providing a "health check" on the measurement system!

Installation of an ultrasonic meter is important if proper operation is to be obtained. The two primary issues relating to a good installation are upstream effects and the potential impact of control valve noise. Upstream effects are much better understood today. Testing conducted by Southwest Research Institute, under the guidance of the measurement community, and funded by the Pipeline Research Council (PRCI) provides much the information needed to help understand installation effects.

Control valve applications are much better understood today than a few years ago. All manufacturers have methods to deal with this issue, and it varies depending upon design. The manufacturer should be consulted prior to design to help insure accurate and long-term proper operation.

Today's ultrasonic flow meter is a robust and very reliable device with many fault-tolerant capabilities. It is capable of handling a variety of pipeline conditions including contaminants in the natural gas stream. In the event of transducer failure, the meter will continue to operate, and some ultrasonic flow meter designs maintain excellent accuracy during this situation. When encountering contamination such as oil, valve grease, and other pipeline contaminants, todays ultrasonic flow meter will continue working and, at the same time, provide enough diagnostic data to alert the operator of possible impending problems.

As ultrasonic metering technology advances, so will the diagnostic features. Today ultrasonic flow meter diagnostic data has become even more useful (and user friendly) as more intelligence is placed within the meter. They can not only provide diagnostic data, but can identify what the problem is.

Future incarnations of ultrasonic flow meters may be able self-diagnose and correct settings to automatically deal with valve noise issues, or, a much pursued goal, be able to estimate error. With the advances taking place at the current rate anything may be possible.

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