Ultrasonic Meter Diagnostics - Advanced

Overview of advanced diagnostic features of wetted-sensor ultrasonic flow meters

Dan Hackett
Daniel Measurement and Control, Inc.
11100 Brittmoore Park Drive
Houston, Texas 77041

ABSTRACT

This paper discusses advanced diagnostic features of ultrasonic gas flow meters used for measurement of natural gas which are generally used to assess dynamic meter operation and performance. The basic diagnostic features of most gas ultrasonic flow meters were covered in the companion paper "Ultrasonic Meter Diagnostics – Basics" which covered diagnostics that relate to meter "health" or validation that the meter is operating properly. Advanced diagnostics are typically those that provide operators information regarding flowing conditions that may affect optimum meter performance. These can include determination of installation effects, upstream blockages, dirt or other similar operating conditions that can adversely affect the uncertainty or repeatability of the volumetric flow rate information determined by the flow meter. 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 advanced diagnostic features, are based on the Daniel SeniorSonic ultrasonic flow meter.

INTRODUCTION

We will assume the reader has knowledge of how transit time gas ultrasonic flow meters work and the equations used to determine gas velocity and actual volumetric flow rate through the meter. Multipath gas ultrasonic flow meters used for custody transfer of natural gas provide a wealth of additional diagnostic information beyond the basics of gain, signal to noise ratios or performance (signal quality). These generally fall into two categories:

- comparative
- proportional

COMPARATIVE DIAGNOSTICS

Speed of Sound

A fundamental performance aspect of transit time gas ultrasonic flow meters is the determination of speed of sound, which is basically the sum of the transit times divided by their product, all then multiplied by the path length. 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.

It is important to periodically verify that the meter's reported speed of sound is within some reasonable agreement to an independently computed value. AGA 9 recommends just such a procedure in Section 8, Field Verification Tests.

This comparative procedure is generally considered an external or dynamic diagnostic technique, though some meters are capable of doing the comparison internally if provided pressure, temperature and gas compositional data.

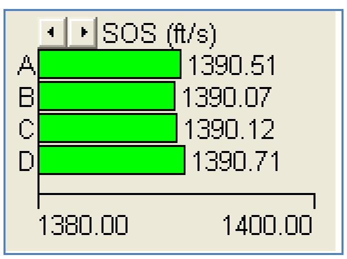
The speed of sound in gas can be easily computed in the field using the equation of state provided in AGA Report No. 10 S*peed of sound in Natural Gas and Other Related Hydrocarbon Gases* which itself is derived from AGA Report No. 8, *Compressibility and Supercompressibility for Natural Gas and Other 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.

It is also important to do these speeds of sound comparison checks under flowing conditions. Attempting to use temperature readings during low or no flow conditions can introduce errors due to sensitivities magnified by incorrect or inadequate insertion depth of the thermowell and/or temperature stratification in the pipe.

Knowing the temperature contributes error in computing SOS is important. However, if the measured/calculated speed of sound check is not in agreement, check that all paths of the ultrasonic meter are in agreement on speed of sound. These are all independent measurements and if they are in close agreement, then the error in the compared speed of sounds lies elsewhere, typically in the temperature measurement.



It is worth chasing the error down as mis-measurement of temperature has a significant effect on the standard volume measurement (the ultrasonic meter is measuring actual volumetric flow and is unaffected by gas pressure, temperature or gas composition). Temperature in error by1º F in the previous example will cause the corrected volumetric calculation to be incorrect by 0.28%. Using a calculated speed of sound vs. measured is a great check of a stations' temperature measurement.

Gas Composition Effects

With the introduction of vast quantities of shale gas and offshore deep water gas into the natural gas production and transmission system, sensitivity to gas composition when calculating speed of sound is a significant issue. Using two examples of traditional AGA 8 gas compositions illustrates the significance of using the right gas composition in the calculation.

Assume a typical Amarillo gas composition with 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.

Assume another example of a Gulf Coast gas with approximately 95% methane. If the methane reading is low by the same 0.5%, and this time the propane reading was high by that amount, the error in computed speed of sound would be 0.67% (or 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.

One may question how the gas composition measurement can be in error by these amounts. Generally this is a function not of the gas chromatograph rather the calibration gas (the known) for which the comparison is made by the gas chromatograph to the sample (the unknown). A calibration gas with a typical 3% ethane component cannot be used by most gas chromatographs to accurately determine ethane composition for an unknown gas containing 5% or more ethane (currently the typically produced rich gas).

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 difficult to dynamically quantify, only because an unsuitable calibration gas is often used by the gas chromatograph. However, similar to temperature, if the meter's path speeds of sounds are in close agreement, then the error in the compared speed of sounds lies elsewhere, typically with the calibration gas used by the gas chromatograph. With the riches gases currently being produced this is proving the most significant contribution to standard volume and energy measurement error.

An error in the gas composition used in natural gas custody transfer measurement compounds twice. The gas composition is first used in the determination of AGA 8 gas compressibility in order to correct the ultrasonic flow meters actual volume flow measurement to standard conditions (SCFH or equivalent units). The same gas composition is also used in the determination of energy (btu/scf or equivalent units) to ultimately arrive at btu/hr (the real unit of trade in the natural gas industry).

Having the ability to check performance of both temperature and gas composition measurement with a single dissimilar device such as the speed of sound measurement from a gas ultrasonic flow meter is the most advanced diagnostic feature currently employed by ultrasonic users.

BASELINING FOR PROPORTIONAL DIAGNOSTICS

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 2014 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.

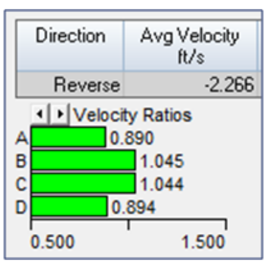
Once cleaned most meters repeat their initial calibration.

PROPORTIONAL 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, hence the term comparative diagnostics. 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

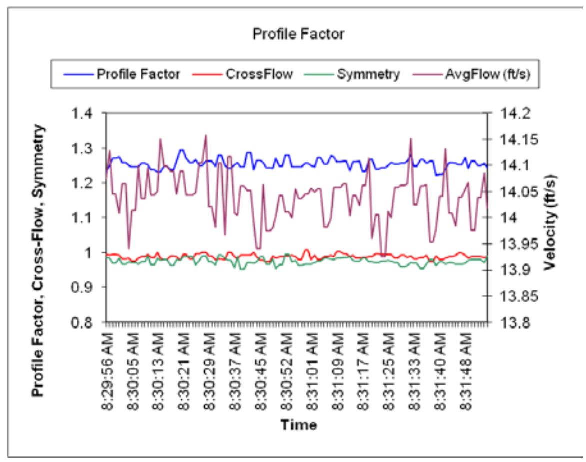
- Cross Flow – a relationship between the paths crossing at different angles through the meter body (indicates roughly horizontal symmetry compared to Symmetry which indicates vertical symmetry)

- Turbulence – an indication of flow stability determined by the deviation of individual velocity measurements over time (also referred to as standard deviation)

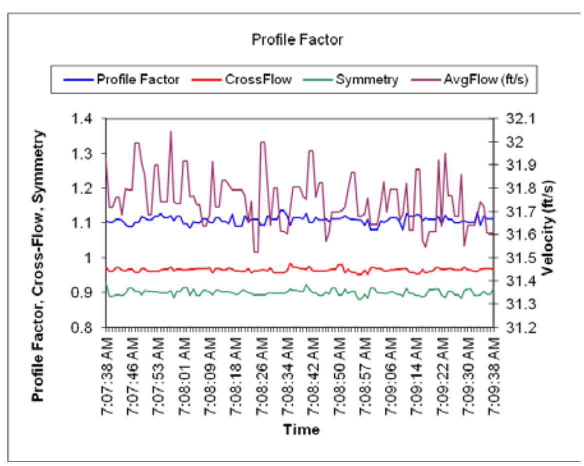
- Swirl Angle – a comparison of individual path velocities to determine rotational stability of the flow

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



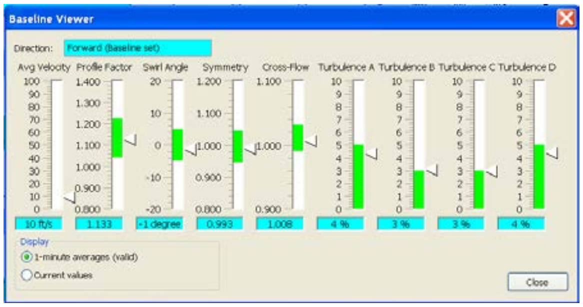
Abnormal Flow
Profile Factor Stable = 1.1
Symmetry biased to bottom of the meter = 0.9
Cross Flow below baseline = 0.98



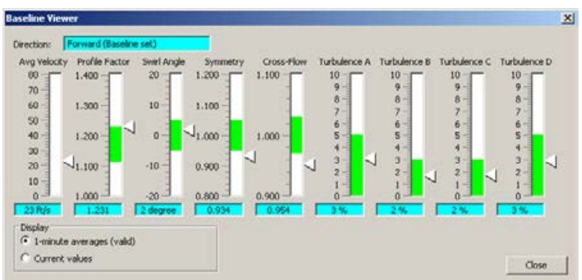
This could indicate a blockage upstream of the meter.

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.

Archive Logging

While not technically an advanced diagnostic feature, an ultrasonic meter which has internal archiving capability provides extensive additional information from which to determine sources of measurement imbalances.

Having large amounts of hourly and daily data stored in the meters memory provides an extremely useful tool for auditing and dispute resolution.

A typical example is reverse flow. Pipelines are generally unidirectional, often with check valves installed to prevent reverse flow. Using the advanced diagnostics of the ultrasonic flow meter will not indicate any problem even when the user is suddenly experiencing a 3% to 4% error in their system balance traced to a specific measurement point. After checking all the basic and advanced diagnostics of the ultrasonic flow, pulling an hourly and daily archive log from the meter often points immediately to the problem.

The archive log files contain forward and reverse flow totals of the uncorrected and, if so equipped, corrected (standard) volumes. The ultrasonic meter is inherently bi-directional. If flow is in the reverse direction, the meter immediately knows it and starts incrementing the reverse flow totalizer. If the user has not been monitoring the flow direction flag from the ultrasonic meter (via contact closure or Modbus status bit), reviewing the logs can immediately tell the user to start walking the pipeline to find the leaking check valve and also reassure them that part of the imbalance is due to the ultrasonic meter measuring some flow of gas twice. This situation is more common than the reader might think.

Also useful information from the logs, if the meter is so equipped, are hourly logs of the average temperature, pressure and gas composition in use. These are extensively used by customers in recalculations or audits. While typically this information resides in the flow computer or rtu employed by the user, having the equivalent of a redundant flow computer built into the ultrasonic flow meter is a feature used by several “advanced” users of ultrasonic metering technology.

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." Additional diagnostics can be performed by using external devices (pressure and temperature) and gas composition information (for example, computing speed of sound). This diagnostic data is available on a real-time basis within the meters themselves or using an external flow computer. These diagnostics 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.

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. Proper installation also provides the important baseline values from which advanced diagnostics will determine blockages, dirty meters, liquid hydrocarbon detection or abnormal flow profiles.

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 the impossible or the implausible may actually become possible.

References:

1. AGA Report No. 9, *Measurement of Gas by Multipath Ultrasonic Meters*, Second Edition, April 2007.

2. AGA Report No. 8, *Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gase*s, Second Edition November 1992, 3rd Printing November 2003

3. Letton, W., Pettigrew, D.J., Renwick, B., and Watson, J., *An Ultrasonic Gas Flow Measurement System with Integral Self Checking*, North Sea Flow Measurement Workshop, 1998.

4. T. A. Grimley, *Ultrasonic Meter Installation Configuration Testing*, AGA Operations Conference, 2000.

5. John Lansing, *Basics of Ultrasonic flow meters*, AGMSC 2003, Coraopolis, PA.

6. John Lansing, *Smart Monitoring and Diagnostics for Ultrasonic Meters*, NSFMW 2000, Gleneagles, Scotland.

7. Larry Garner & Joel Clancy, *Ultrasonic Meter Performance / Flow Calibration Results / CEESI Iowa / Inspection Tees vs. Elbows, CEESI Ultrasonic Conference*, June 2004, Estes Park, CO

8. John Lansing, *Ultrasonic Meter Station Design Considerations*, Western Gas Measurement Short Course, 2003, Victoria, BC, Canada

9. Klaus Zanker, *Diagnostic Ability of the Daniel Four-Path Ultrasonic flow meter*, Southeast Asia Flow Measurement Workshop, 2003, Kuala Lumpur, Malaysia

10. James N. Witte, *Ultrasonic Gas Meters from Flow Lab to Field: A Case Study*, AGA Operations Conference, 2002, Chicago, IL.

11. Dr. Jim Hall, William Freund, Klaus Zanker & Dale Goodson, *Operation of Ultrasonic Flow Meters at Conditions Different Than Their Calibration*, NSFMW 2002, St. Andrews, Scotland.

12. Jim Micklos, *Ultrasonic Gas Flow Meters for Custody Transfer Measurement*, ASGMT 2008, Houston, TX

13. Dr. Jim Hall, Klaus Zanker, Eric Kelner, *When Should a Gas Ultrasonic flow meter be Recalibrated?* North Sea Flow Measurement Workshop 2010

14. Charles Derr, Tina Newsome. *Contaminant Accumulation Effects On Gas Ultrasonic Flow Meters* 2010 International School of Hydrocarbon Measurement