EFFECTS AND CONTROL OF PULSATION IN GAS MEASUREMENT

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One of the most common measurement errors and the most difficult to identify in natural gas metering systems is that caused by pulsating flow. It is important to understand the effects that pulsations have on the common types of flow meters used in the gas industry so that potential error-producing mechanisms can be identified and avoided. It is also essential to understand pulsation control techniques for mitigating pulsation effects. This paper describes the effects of pulsation on orifice, turbine, ultrasonic, and other flow meter types. It also presents basic methods for mitigating pulsation effects at meter installations, including a specific procedure for designing acoustic filters that can isolate a flow meter from the source of pulsation.

Pulsation Basics

Pulsation is a periodic fluctuation in local pressure and velocity that occurs throughout a piping system or network. Due to the physics of inviscid fluid flow through a conduit (i.e., the Bernoulli principle), there cannot be a variation in the local pressure (pulsation) without a corresponding variation in the local velocity. Conversely, if velocity perturbations are present, there will be pressure variations, as well, propagating along the pipe. Pulsations travel as acoustic waves, both upstream and downstream from the source. Equation 1 shows the Bernoulli principle (in its simplest form for steady, one-dimensional flow of a compressible fluid (e.g., natural gas) through a conduit), and Figure 1 illustrates the generation of pulsation waves (from a prime mover, such as a reciprocating compressor or pump) and shows how pressure and velocity variations travel in a pipe.

$$\frac{V^2}{2} + \left(\frac{\gamma}{\gamma - 1}\right)\frac{P}{\rho} + gz = constant \quad \text{Equation 1}$$

where

V = nominal fluid velocity
P = static line pressure
ρ = fluid density
g = gravitational acceleration
z = elevation of a point above a reference plane
γ = ratio of the specific heats of the fluid

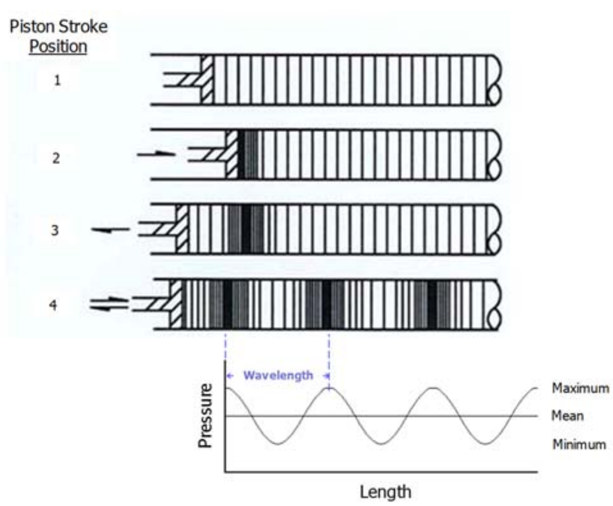

Figure 1. Illustration of an Ideal Generation of a Pulsation Wave

Pulsations typically move through a piping system as ***traveling*** waves. These traveling waves can be reflected from ‘closed’ and ‘open’ ends of a piping network. ‘Closed’ ends, for example, may be the capped or flanged ends of headers, closed branch line valves, or terminations of gauge or drain lines. ‘Open’ ends may not be truly ‘open.’ For instance, significant and sudden diameter changes, such as at scrubbers, large headers, or locations where a small branch line connects to a larger diameter pipe, have acoustic characteristics closely approximating those of a truly ‘open’ pipe end. Through the principle of superposition, traveling waves can be reflected in a piping network and added together in such a way that summations of the amplitudes of the various waves form peaks (maximums) at some locations and nulls (minimums) at other locations along the pipe network. At certain conditions (characterized by the speed of sound of the flowing medium, the pipe length, and pulsation frequency), traveling pulsation waves are reflected to form ***standing*** waves that reinforce pulsation amplitudes. This condition is known as ‘acoustic resonance’ and occurs at the natural resonant frequency of the pipe at the given operating conditions.

The relationship between the speed of sound of the flowing medium, c (a.k.a., the acoustic velocity), the pipe length, L, and pipe end conditions determine the frequency, f, and fundamental wavelength, λ, of the acoustic response. The fundamental wavelength is defined by Equation 2. An acoustic resonance in a piping section is dependent upon the quotient of the speed of sound of the flowing medium, c, divided by the length of the pipe element, L. ‘Half-wave’ acoustic resonances occur between two open pipe ends or two closed pipe ends. ‘Quarter-wave’ resonances (i.e., Figure 2) occur between one open and one closed pipe end. Multiples of the fundamental half-wave or quarter-wave resonant modes occur at higher frequencies in the same length of pipe. Simple acoustic theory can be used to estimate the acoustic response frequencies of meter runs, meter headers, and instrument-sensing lines (a.k.a., gauge lines).

$$\lambda = \frac{c}{f} \quad \text{Equation 2}$$

where

λ = pulsation wavelength

c = speed of sound of the flowing gas

f = pulsation frequency

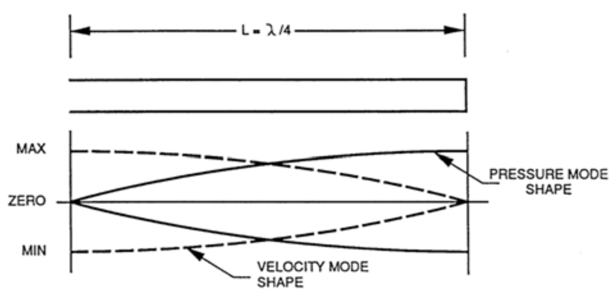

Figure 2. Quarter-wave Pulsation Resonance Between Open and Closed Ends

The amplitude of pulsation in a piping system reaches the largest value during resonant conditions, with pressure maximums in fixed locations and velocity maximums in other, fixed locations. Pulsation problems at flow metering sites frequently involve resonant conditions.

Pulsations in piping systems are created by any flow disturbance or source of periodic pulses or change in the flow rate. Common sources of pulsation in natural gas pipeline systems may include:

- Reciprocating compressors
- Rotary screw or booster compressors
- Centrifugal compressors (away from the optimum design point)
- Pressure regulating or flow control valves
- Rapid load or supply transients
- Vortex shedding and similar flow-induced phenomena
- Fluidic instabilities, such as slug flow

Because compression or pump machinery (and control valves and other unsteady aspects of station operation) are typically in close proximity to flow meter pipe runs, pulsations are common at field sites and can have an adverse effect on flow meter accuracy.

Pulsation Effects On Orifice Flow Meters

Primary Element Error

In the case of orifice flow meters, pulsation affects both the primary flow element (i.e., the orifice plate) and the secondary measurement system (i.e., pressure transducers and the connecting gauge lines). The most basic pulsation-induced error mechanism at an orifice flow meter installation is called ***square root error*** (SRE) because it results from averaging the differential pressure (ΔP) across a square root response device. Flow through an orifice is proportional to the square root of the differential pressure, ΔP, across the orifice plate, as noted in the simplified orifice flow equation shown in Equation 3.

$$\Delta P = K * Q^2 \qquad \text{Equation 3}$$

where

ΔP = differential pressure measured across the orifice plate

K = empirical coefficient

Q = volumetric flow rate

The square root of the *instantaneous* ΔP should be averaged over time for proper flow rate determination. However, typical industrial-grade pressure transducers customarily used to measure the pressure drop across an orifice plate are not capable of accurately tracking the rapid pulsating changes in ΔP. Thus, the resulting measurement process captures an *averaged* ΔP reading before the square root value of the ΔP is taken to determine the flow rate. This means that SRE is inherent in the measurement. Pulsations across the orifice plate must be eliminated to avoid SRE being introduced when *average* ΔPs are recorded by the measurement system. Figure 3 shows the relationship between the ΔP and the flow rate for an orifice flow meter and indicates what happens when pulsating flow exists.

As seen in Figure 3, the average ΔP signal is slightly higher than the ΔP that corresponds to the average flow.

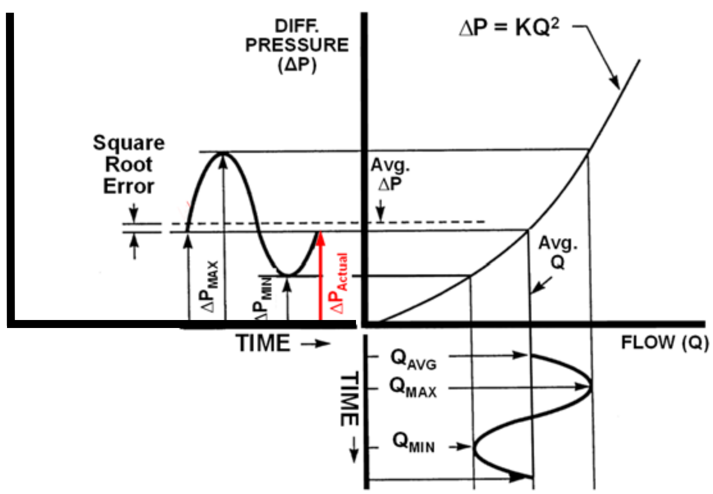

Figure 3. Square Root Error Results from Pulsation Effect on an Orifice's Square Law Curve

The square law relation between flow rate, Q, and the differential pressure across the orifice plate, ΔP, creates this distortion through the square law curve, since a larger portion of the ΔP wave occurs above the average flow line. Therefore, when a measurement-grade ΔP transmitter averages the ΔP signal, the average ΔP is higher than the ΔP that corresponds to the average flow. This real difference in ΔP across the orifice plate is the pulsation effect known as SRE.

SRE is always positive and increases with increasing pulsation amplitude. SRE is a data processing error resulting from averaging the ΔP signal before taking its square root. This usually cannot be avoided when industrial-grade pressure transmitters are used because transmitters of this type have a relatively low operational frequency range, which prevents the transmitters from accurately tracking the rapidly-varying pressure signals produced by flow pulsations; hence, they provide an 'averaged' value instead. Furthermore, digital or 'smart' pressure transmitters take a small, but finite, amount of time to record and transmit the measured pressure values for processing by data logging devices, such as flow computers or supervisory control and data acquisition (SCADA) systems. A consequence of this whole data acquisition process is that the differential pressure across the orifice plate is usually averaged over some finite period before the square root of the resultant value is calculated, thus, creating the SRE.

If one uses a pressure transmitter with a frequency response range high enough to accurately measure the differential pressure across an orifice plate experiencing pulsating flow, the mathematical relationship shown in Equation 4 can be utilized to determine the magnitude of the SRE. This method for determining SRE is a patented process developed at Southwest Research Institute during research sponsored by the Gas Machinery Research Council and is the basis for the commercially-available Square Root Error Indicator that measures the SRE.

$$SRE = \frac{\sqrt{avg\Delta P} - avg\sqrt{\Delta P}}{avg\sqrt{\Delta P}} * 100 \qquad \text{Equation 4}$$

where

SRE	=	the square root error in percent of differential pressure transmitter reading
$\sqrt{avg\Delta P}$	=	the square root of the time averaged value of the differential pressure across the orifice plate
$avg\sqrt{\Delta P}$	=	the time averaged value of the square root of the instantaneous differential pressure across the orifice plate

SRE usually accounts for most, but not necessarily all, of the pulsation-induced error associated with an orifice flow meter. Inertial effects can also contribute to measurement error. Inertial effects typically don't become problematic unless relatively high-amplitude pulsations occur at relatively high frequencies. Because SRE usually develops well before inertial effects become significant, inertial effects are generally ignored when diagnosing the adverse effects of pulsation in the flow stream.

Error due to inertial effects can be derived from the one-dimensional momentum equation for steady flow through an orifice. The momentum equation for unsteady flow may also be used to develop the orifice flow equation, but a time rate of change term must be included also. In Equation 5 that follows, the term to the right represents the fluid inertia term, which includes the derivative of the fluid velocity with respect to time and accounts for the extra differential pressure needed to accelerate or decelerate the gas as it flows through the orifice. One feature of the inertial effect is that when it is averaged over time, the average is *zero*. However, if the square root of the instantaneous differential pressure, ΔP, across the orifice is recorded correctly to eliminate SRE, then the inertia effect is *not* zero.

$$\Delta P = K * V(t)^2 + L\frac{dV(t)}{dt} \quad \text{Equation 5}$$

where

ΔP	=	differential pressure across the orifice plate
V	=	nominal gas velocity
L	=	pulsation wave acoustic length
K	=	proportionality constant
t	=	time

It is important to note that the measured amount of SRE cannot be used to perfectly correct for orifice measurement error associated with flow pulsation, but SRE can be used to indicate if pulsation is causing a significant problem at an orifice flow meter. The maximum allowable pulsation level specified in Section 2.6.4 of Part 2 of American Gas Association (AGA) Report No. 3, i.e., the U.S. orifice flow meter standard, is 10% root mean square (RMS) variation in the ΔP (RMS is a statistical measure of the magnitude of the variation in the ΔP), which corresponds to an SRE value of approximately 0.125% of reading. This applies to single frequency flow pulsations with or without several harmonics and to broadband flow pulsations/noise. Any SRE above this threshold indicates that the pulsation is adversely affecting the orifice meter accuracy. Section 2.6.4 further states that… **"*Currently, no satisfactory theoretical or empirical adjustment for orifice measurement in pulsating flow applications exists that, when applied to custody transfer measurement, will maintain the measurement accuracy predicted by this standard. Arbitrary application of any correcting formula may even increase the flow measurement error under pulsating flow conditions. The user should make every practical effort to eliminate pulsations at the source to avoid increased uncertainty in measurements.*"**

Secondary Element Error

Pulsation may also adversely affect the secondary measurement system (i.e., the gauge lines connecting the pressure transmitters to the meter fitting and the pressure transmitters themselves) of an orifice meter installation. The gauge lines that connect the pressure transmitters to an orifice fitting can *amplify* the pulsation amplitude <u>or</u> *attenuate* the pulsation amplitude and, in the process, change the apparent ΔP value. When gauge line *amplification* occurs, as shown in Figure 4, the actual pulsation amplitude in the pipe and SRE at the orifice meter might be small, and the effect of pulsation on the orifice flow measurement should be negligible. However, pulsation at the differential pressure transmitter appears high and if SRE is occurring at the end of the gauge lines, an apparent (and significant) pulsation error results.

Gauge line amplification is usually a result of a gauge line being excited by pulsation at its fundamental acoustic frequency (i.e., 100 Hz in the example shown in Figure 5) or one of its higher orders. Figure 5 illustrates the frequency response characteristics of an example gauge line (illustrating both pressure signal *amplification* and *attenuation* effects, depending on the frequency). It is desirable for the pressure measured at the transmitter, P_t, to be exactly equal to the pressure at the orifice, P_o (i.e., P_t/P_o=1.0, as shown in Figure 5). It is critically important to note also that the measurement systems used to determine SRE are also subject to pulsation amplification and care should always be taken to ensure that real pulsations across the orifice pressure taps are not amplified in the gauge lines to the pressure transmitter being used to detect or diagnose the presence of SRE at the orifice meter.

Gauge line *attenuation*, which can occur when gauge lines are not responsive to the pulsation frequency, has the opposite effect as amplification. When attenuation occurs, there can be large pulsation amplitudes and a significant SRE at the orifice meter, while there is little or no indication of pulsation at the ends of the gauge lines connected to the differential pressure transmitter. If attenuation is present and SRE is measured at the end of the gauge line, then a pulsation error can be missed.

Experience has shown that the likelihood of gauge line effects becoming a problem can usually be reduced or avoided by minimizing the lengths of all gauge lines (since the acoustic natural frequency of a gauge line is inversely proportional to the line length) or by mismatching the acoustic response of the gauge lines with respect to the meter tube pulsation frequencies. For example, close-coupling the pressure transmitter(s) (and associated valving) to a senior orifice fitting, as shown in Figure 6 (with isolation valves circled in red in the figure), can increase the response frequency of the gauge lines, such that when a low-speed compressor is the pulsation source, the pulsation excitation frequency is mismatched with respect to the acoustic response of the gauge lines. This close-coupled configuration may still be problematic when a high-speed compressor is the pulsation source. In that instance, the lower pulsation harmonic frequencies (e.g., fourth-order of compressor running speed) may coincide with the acoustic response of the gauge lines, thus, producing gauge line error.

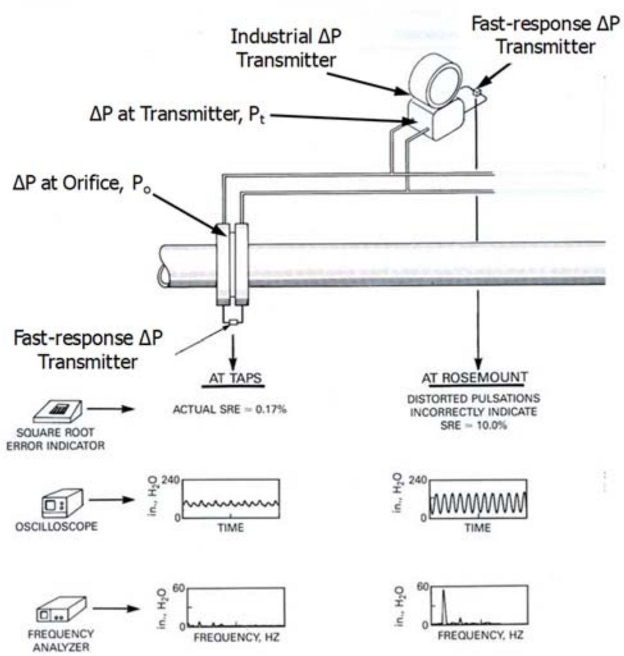

Figure 4. Amplification of Orifice Meter Differential Pressure Signal in the ΔP Transmitter Gauge Lines

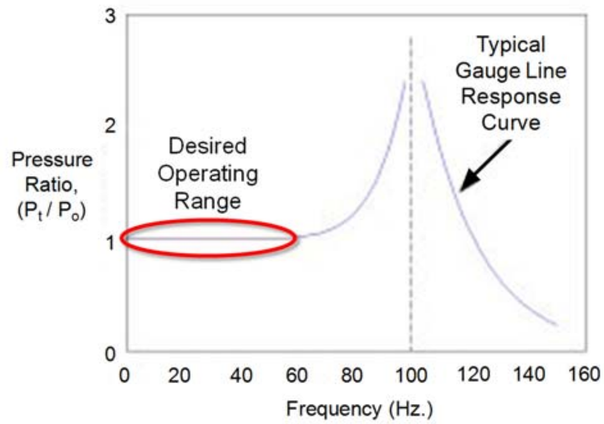

Figure 5. Example Frequency Response Characteristics of a Constant-bore Gauge Line

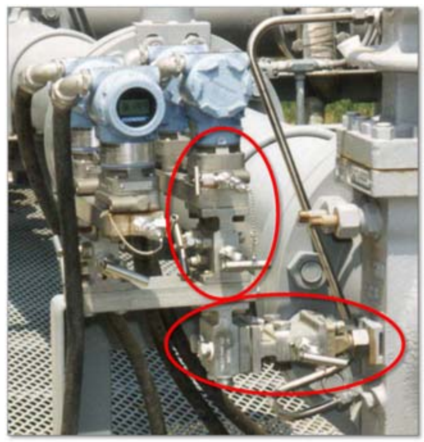

Figure 6. Example Close-coupled Pressure Transmitter Installation
(to help minimize the likelihood of gauge line effects)
(Photograph provided courtesy of PGI Division, Parker Hannifin Corporation)

Gauge line *shift* is a change in ΔP along the length of a gauge line and is a result of phenomena associated with the gas alternately flowing into and out of a gauge line. Example results from laboratory measurements at Southwest Research Institute of pressure along a gauge line with pulsation present are shown in Figure 7. There is a change in the pressure at the entrance to the gauge line (i.e., at the orifice meter pressure taps) and there is a pressure gradient along the gauge line. One reason for these changes in gauge line pressure under dynamic conditions is that the resistance to flow into the gauge line is less than the resistance to flow out of the gauge line. Frequency dependent influences can also contribute to gauge line shifts. Research has shown that the amplitude of a gauge line shift is related to the velocity head and is usually only on the order of a few inches of water column differential pressure. Gauge line shift does not usually make a significant difference in static pipeline pressure measurements. However, a few inches of water column difference out of perhaps 30 to 50 inches of water column total differential pressure across an orifice plate can result in a relatively large flow measurement error.

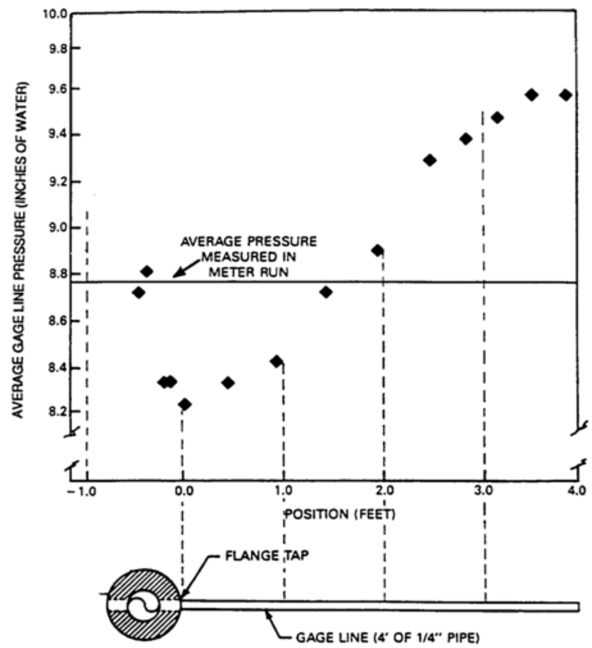

Figure 7. Measured Pressure Along a Gauge Line Indicating a Shift in the Differential Pressure

To correctly sample gas pressure in pulsating flow, a pressure transmitter must be capable of accurately sampling and recording the pressure signal at a frequency of at least twice (and, preferably, 10 times) the highest pulsation frequency present in the flow. Sampling and recording a transmitter output at a frequency slower than at least two times the maximum pulsation frequency will cause data describing actual flow changes to be lost and flow measurement error will result.

It is important to note that industrial-grade analog and digital (i.e., 'smart') pressure transmitters used today by the natural gas pipeline industry, are not capable of sampling at a high enough frequency to follow precisely the typical variation in pressure caused by pulsations.

This point is illustrated in Figure 8, which demonstrates the responsiveness of industrial-grade pressure transmitters, typical of those used at gas meter stations, to a sudden change in pressure. A test was set up in which each pressure transmitter was initially exposed to its maximum rated working pressure (denoted in Figure 8 as a transmitter output of 20 milliamps - the maximum output signal for a transmitter having a 4 to 20 milliamp output range). The test pressure was dropped suddenly to zero gauge pressure (i.e., atmospheric pressure) and the response of each transmitter was recorded. The actual time required for the test pressure to drop to its minimum value (i.e., 4 milliamps transmitter output value) was less than 0.1 second. The outputs of some of the transmitters took well over one second to reach the minimum test pressure. Clearly, pressure transmitters of this type are not able to accurately measure typical pulsation pressure fluctuations occurring at frequencies of one cycle per second and higher.

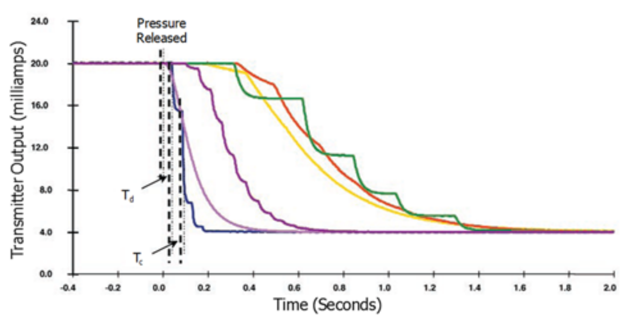

Figure 8. Industrial Pressure Transmitter Response to Test Pressure Step Change
(Source: Rosemount, Inc., *Pipeline and Gas Journal* article, published in 2001)

Square Root Error Indicator

In order to diagnose properly any SRE that may exist at an orifice flow meter, ‘fast-response’ pressure transmitters capable of accurately measuring the pressure variations associated with pulsating flow should be used. The SRE Indicator described previously has been purpose-built for such applications. The latest version of the *SRE* Indicator (distributed by PGI Division, Parker Hannifin Corporation) is pictured in Figure 9. Figure 10 shows an actual installation of an SRE pressure transducer on an orifice fitting. An example SRE data analysis produced by the SRE Indicator is pictured in the computer screen capture shown in Figure 11. The example analysis shows the existence of a high-frequency pulsation (at a frequency of about 163 Hz) superimposed over the differential pressure being measured across an orifice flow meter. As the screen capture notes, the estimated SRE in this example is approximately 0.468% of the measured flow rate.

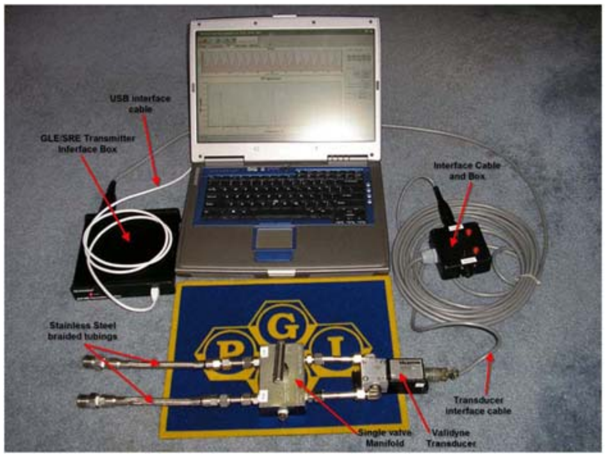

Figure 9. Square Root Error Indicator
(Photograph provided courtesy of PGI Division, Parker Hannifin Corporation)

Figure 10. Example Square Root Error Pressure Transducer Installation
(Photograph provided courtesy of PGI Division, Parker Hannifin Corporation)

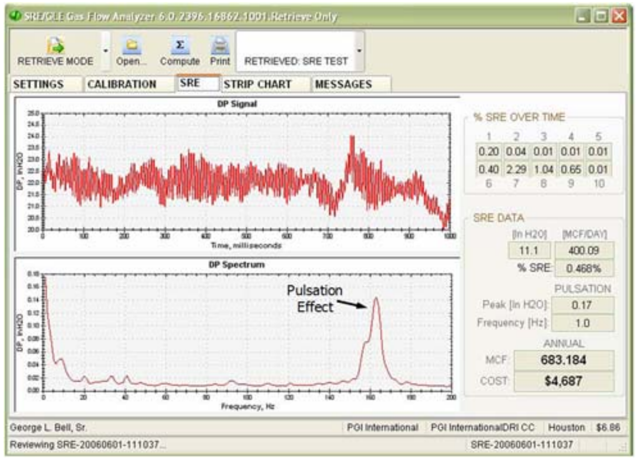

Figure 11. Example Analysis Produced by the Square Root Error Indicator
(Image provided courtesy of PGI Division, Parker Hannifin Corporation)

<u>Pulsation Effects On Turbine Flow Meters</u>

Turbine flow meters can be adversely affected by pulsation, which can cause flow rate measurement errors as large as 50% of the meter reading, depending on many factors, including the pulsation velocity amplitude at the meter, flow rate, gas density, and both meter and pulsation properties. The effects of pulsation on turbine meters are somewhat complex but when an error exists, it usually results in an ***over-registration***, compared to the actual or ‘true’ flow rate. In recognition, AGA Report No. 7 (i.e., the U.S. natural gas industry recommended practice for turbine flow meters) notes that pulsation causes a positive error in turbine meter output that is dependent upon the factors listed above. AGA Report No. 7 also recommends that in order to avoid pulsation-related measurement errors, pulsation should be eliminated by filtering or reduced by taking a pressure drop to dampen the pulsation.

A number of flow tests have been conducted with turbine meters in pulsating flow. Example results produced at the Southwest Research Institute flow laboratory are shown in Figure 12, where the zero error ‘baseline’ or reference flow rate value is for the flow meter output recorded with a steady flow condition, free of any pulsations. The pulsation-induced flow measurement errors in this test varied from zero to over 20% of the meter reading, depending on the flow rate and the pulsation frequency. Pulsation amplitudes were essentially identical for all of the flow tests. The observed frequency dependence was due to the pulsation mode shape and resulting velocity modulation changing at the flow meter location, which was at a fixed point in the flow facility piping network.

Turbine meters are velocity-measuring devices and, as such, are more sensitive to gas velocity variations than to gas pressure variations. At some pulsation frequencies, the velocity modulation at the meter will be large and the flow measurement error will be large, while at other frequencies, the velocity modulation at the meter and corresponding measurement error will be small, despite the overall pulsation level being relatively high. Pulsation effects at a turbine meter can be mitigated by reducing the pulsation amplitude or, in the case of the presence of a standing pulsation wave, by changing the meter location with respect to the pulsation mode shape, such that the velocity modulation at the measurement point is relatively low.

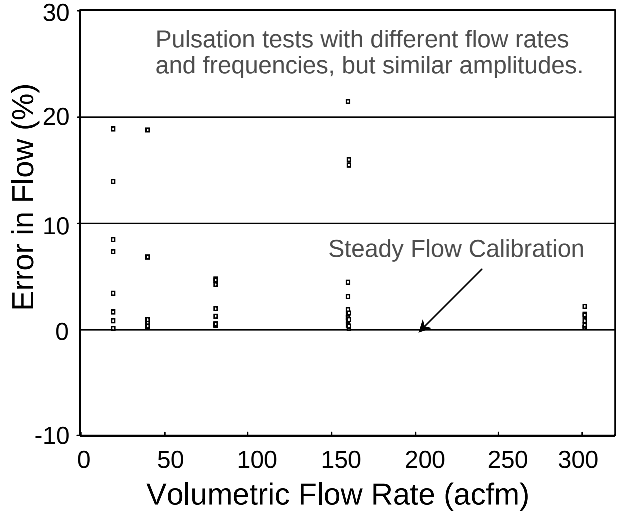

Figure 12. Example Pulsation Test Results for a Turbine Flow Meter

Pulsation Effects On Ultrasonic Flow Meters

As with other metering technologies, ultrasonic flow meters can be adversely affected by pulsation. Ultrasonic meters that measure high-pressure natural gas flows typically use a time-of-flight (or transit time) measurement technique. Figure 13 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 13). The pulse travels at an acute angle across the pipe to a receiving transducer (shown as 'B' on Figure 13). 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. Ultrasonic energy pulses are sent in both the 'upstream' and 'downstream' direction across one or more acoustic paths that traverse the pipe. The differences in these transit times provide an indication of the flow velocity in the pipe, which can be correlated to the volumetric flow rate. The measured times are affected by several factors, including the velocity profile of the gas stream at the measurement point and the acoustic signal characteristics, among others. The ultrasonic pulses are typically sent through the flow stream many times per second. The meter electronics process the measured data and average the results before outputting a flow rate value approximately once to several times per second. Because the method used is inherently sampling the flow periodically, instead of continuously, meters of this type may not perfectly track the rapid changes in the flow field that can occur during pulsating flow. Hence, measurement errors can result.

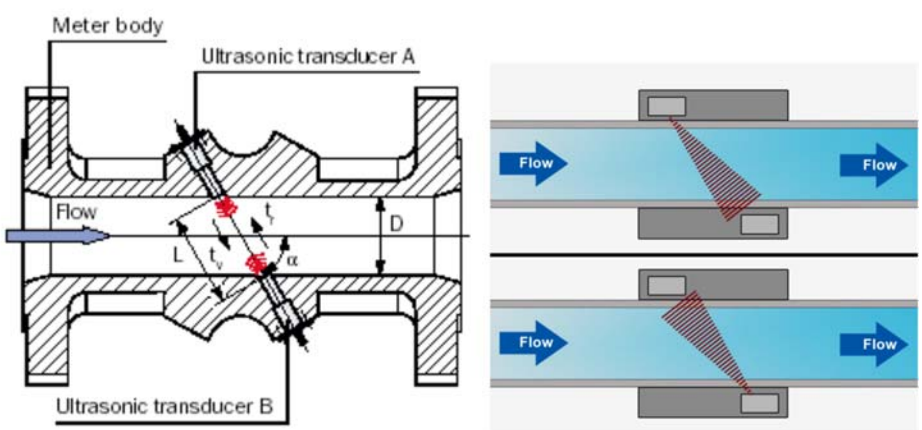

Figure 13. Schematic of an Ultrasonic Flow Meter
(Images courtesy of Bureau of Analytical Complexities & Systems and Alicat Scientific)

Ultrasonic flow meter error does not appear to closely correlate to the amplitude of the pulsation pressure. The flow rate measurement generally depends on the pulsation velocity amplitude, and errors as great as several percent of the meter reading (or even greater, in some instances) have been reported in the open literature (see Figure 14, for example). As shown in Figure 2, for standing waves, velocity amplitudes are highest at points of lowest pressure amplitude. This means that if a standing pulsation wave is present, severe pulsation may be undetectable using pressure transducers. Additionally, this means that meter error is a function of meter location relative to areas of high amplitude velocity pulsation. Errors of over-registration relative to the 'actual' or 'true' flow rate, as well as errors of under-registration, have been reported. Some meter error has been attributed to aliasing of the measured flow values due to inadequate flow data sampling frequency by the meter. However, at least some test results have shown that higher data sampling rates do not necessarily reduce the magnitude of the measurement error.

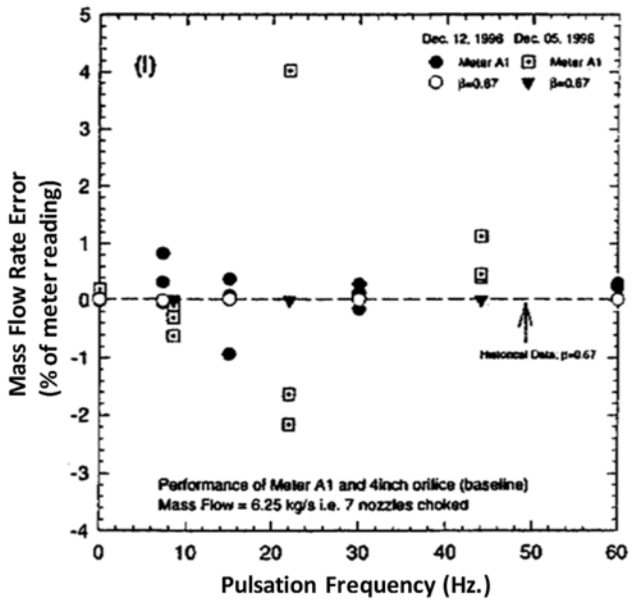

Figure 14. Example of Pulsation Effects on Ultrasonic Flow Meter Accuracy
(Source: NOVA Research and Technology Centre, *International Pipeline Conference* paper, published in 1998)

Although multipath ultrasonic meters can accommodate certain levels of flow distortion, they provide more accurate measurement when presented with a fully developed flow profile. As exemplified in Figure 15, velocity pulsations can directly and significantly distort flow profile. The figure presents data taken during a test in natural gas in an 8-inch diameter line travelling at a nominal flow velocity of 31 ft/sec. The gas was subjected to high amplitude pulsation at 43 Hz. In the figure, the flow profile at a given time is presented in blue. The markers are velocity point measurements taken directly using a hot-wire anemometer. The blue line is a curve fit of those markers showing an estimation of the instantaneous flow profile. The black line is the time average flow profile. All flow velocity has been normalized in these plots such that the average flow velocity is located at the center of the x-axis. Considering this point to be 100% of nominal flow velocity, the left edge of each plot would be 0% of nominal flow velocity, and the right edge of each plot would be 200% of nominal flow velocity. Given this scale, some of the velocity shifts are seen to exceed 30% of nominal flow velocity. The number in the top right corner of each plot signifies the order in which the profiles were observed in the cycle. The time step between profiles is 1.94 milliseconds. The centerline flow velocity was observed to vary as much as 18 ft/sec in approximately 12 milliseconds. These profile shifts were occurring at 43 Hz, the same frequency as the pulsations. The ultrasonic meter measuring the flow in Figure 15 consistently exhibited errors of greater than 1%. Despite the well-developed shape of the time-averaged flow profile, the drastic profile shifts led to significant measurement error.

Ultrasonic meters may also be affected by pulsation from broadband ultrasonic noise sources, such as pressure regulating valves, which may produce background acoustic noise in the flow stream that could potentially interfere with the acoustic pulses produced by the flow meter. In these cases, the usual solutions are to either greatly reduce or eliminate the pulsation and background acoustic noise present at the flow meter or to change the operational frequency range of the meter transducers.

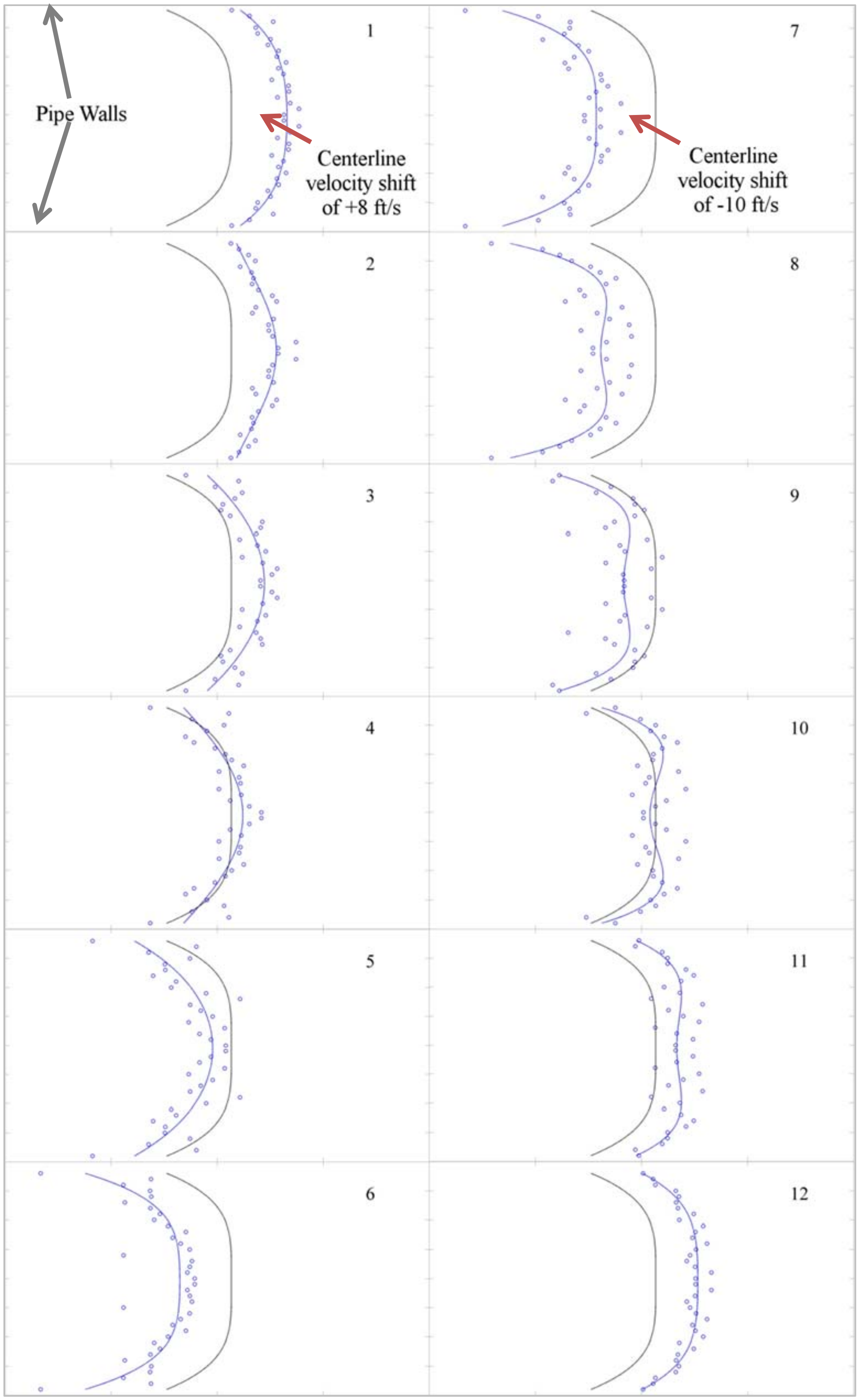

Figure 15. Velocity Profile Shifts When Subjected to High Amplitude 43 Hz Pulsation
Natural gas flow in an 8-inch line at a nominal flow velocity of 31 ft/sec.

Pulsation Effects On Other Flow Meter Types

Most other gas flow meter types, including Coriolis flow meters, Pitot probes, multi-port Pitot probes, V-cone flow meters, Venturi flow meters, and vortex shedding flow meters, can also be adversely affected by the presence of pulsation in the flow stream. The differential producing meters in this group are affected in ways similar to those for the orifice flow meter.

Coriolis meters, which sense the vibratory motion of fluid-containing tubes, are generally affected by vibrations caused by pulsation and can be severely affected at some pulsation frequencies (i.e., those that can synchronize with the mechanical natural frequency (frequencies) of the flow meter) and less affected at other frequencies.

Pitot probes and the multi-port Pitot probes typically have a dynamic response similar to that of pressure transmitter gauge lines and, therefore, can be adversely affected by pulsation. Some frequency specific adjustments can be made to particular meters, such as vortex shedding meters, to correct for some types of pulsating flow conditions, but this is not usually a correction that is effective when a range of pulsation conditions may exist at a particular meter installation.

Several types of positive displacement meters, including diaphragm meters, are generally insensitive to pulsation effects, but these meter types are not very useful for high-volume flows. Rotary-type positive displacement meters, for example, are not normally subject to errors in pulsating flow but they do produce pulsations because of the nature of their design and can, therefore, adversely affect parallel or nearby flow meters of other types. ***In general, the best approach to eliminating metering errors in pulsating flow is to mitigate the pulsation levels.***

Pulsation Control Methods

Several approaches for mitigating pulsation effects in gas flow measurement are available. The most practical method for a particular situation will depend on the meter type and the pulsation characteristics. The most effective method for mitigating pulsation effects is installation of what is commonly referred to as an acoustic filter. Acoustic filters are less dependent on the source of pulsation or the type of meter than other mitigation approaches because acoustic filters isolate a flow meter from pulsation sources. There are multiple configurations to consider when designing acoustic filters, so it is advisable to consult an experienced designer when considering installation of an acoustic filter. Following shortly is an example design of a symmetric, in-line, low-pass acoustic filter that works well in many pulsation isolation situations.

There are other techniques for mitigating pulsation effects for particular pulsation sources, selected meter types, or situations where only a small improvement is needed. For instance, a large pressure drop can be taken when a less costly, although less effective, approach is required. It is noteworthy that separating a flow meter from a pulsation source by a significant distance is ***not*** usually an effective pulsation mitigation strategy because pulsations can travel great distances. For instance, low-frequency pipe flow pulsation (e.g., a 2 Hz pulsation) can have an adverse effect on a flow meter located over 20 miles from the pulsation source. Typical pipeline pulsation frequencies in the 5 to 45 Hz range can propagate several miles from the source and higher frequencies (e.g., over 100 Hz) can exist at significant levels hundreds of yards to a mile from the source. Thus, placing a meter at a location well removed from a pulsation source is not usually effective (or practical) for mitigating pulsation effects. In select cases, relocating a meter a considerable distance from a pressure regulator or a flow control valve that is producing primarily high-frequency noise may prove effective.

If standing wave pulsations exist, then placement of a flow meter relative to the local standing wave pattern can be important. For example, if the acoustic wave characteristics of a particular meter installation are known, it may be possible to place a turbine meter at a point in the pipe network where the pulsation mode shape produces a negligibly small velocity modulation for all of the operating conditions. In that instance, the pulsation effect on the flow meter may be minimal or nonexistent. The center point of a flow meter run between two large-diameter headers (open ends) is a location with negligible velocity modulation for the first-order, half-wave resonance.

Selecting pipe lengths to avoid acoustic resonant frequencies can be an effective mitigation technique when a specific pulsation frequency or acoustic wave mode shape is a problem. For instance, if a nearby compressor is to operate at a fixed running speed, the flow meter run and header lengths should *not* be designed as half-wavelengths or quarter-wavelengths for that particular driving frequency. Meter runs, headers, and pipe segment lengths should *not* be simple fractions of the speed of sound of the flowing medium divided by the compressor running speed (in Hertz). In a case in which the compressor speed varies significantly, there may not be an acceptable pipe length that can avoid all potential pulsation problems.

A change of pipe length can be very effective in the case of a side-branch pipeline that is excited by vortex shedding created by the flow through the pipe. Figure 16 illustrates this phenomenon. This particular example is of water flowing through a pipe, past a closed side-branch pipe. Similar flow structures (called vortices) can also form in natural gas pipe flows and create pressure waves that propagate the length of the closed side branch.

Changing the branch line length can avoid the creation of an acoustic resonance and significantly reduce the pulsation amplitude. For orifice flow meters, the pressure transducer gauge line length should be selected to avoid resonance at the compressor running speed or other known excitation frequencies. A change in the pipe length can be considered for any resonant pipe if the change will eliminate pulsation rather than just change the pulsation frequency.

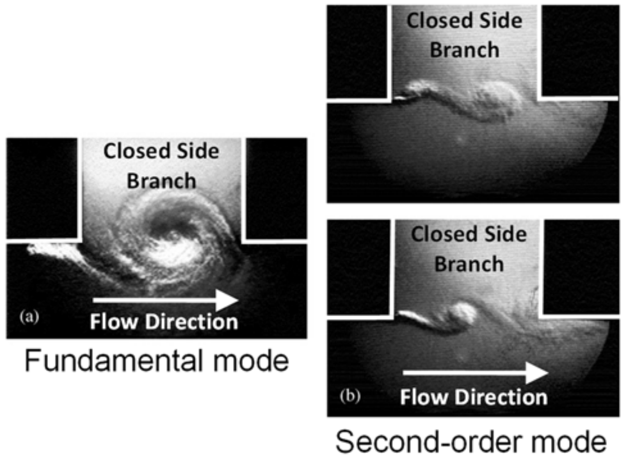

Figure 16. Example Closed Side-Branch Pipe Vortices
(Photographs courtesy of S. Dequand, et al.)

Addition of pressure drop via installation of an orifice (or restricting valve) can produce a reduction in pulsation amplitude, but it will not eliminate a pulsation or change its frequency. However, in most cases, additional pressure drop is not practical. Furthermore, achieving an effective solution by adding an orifice may end up being a trial-and-error approach, unless a detailed acoustic analysis of the installation is part of the process.

One pulsation mitigation technique that applies specifically to orifice flow meters is the reduction of the orifice beta ratio, which, in turn, increases the ΔP. As long as the pulsation amplitude remains constant, the SRE effect on the orifice will be reduced. In many cases, changing the orifice beta ratio will not affect the amplitude of pulsation.

A final comment on pulsation mitigation methods is that large vessels are not acoustic filters and will not necessarily eliminate or completely remove pulsation but, in many cases, may attenuate or absorb some pulsation energy (amplitude). Scrubber vessels and large headers can be placed strategically and may be utilized to help reduce pulsation amplitudes.

Acoustic Filter Design

The most effective method for controlling pulsation in metering applications is to place an acoustic filter between the pulsation source and the flow meter to be protected. There are many approaches to designing acoustic filters. The filter design described below and pictured in Figure 17 is a symmetric, in-line, low-pass acoustic filter that can be used in many situations to eliminate pulsation in selected frequency ranges. As the name implies, this filter passes pulsation below its natural frequency and filters out (or, at least, significantly reduces) pulsation at frequencies above the natural frequency. One important characteristic of this type of filter is that it amplifies pulsation at and near its natural frequency. Therefore, pulsation energy that is to be controlled should never be coincident with the natural frequency of the filter. Filters of this type are placed directly in the mainline pipe and are symmetric, meaning that the acoustic length of each element, i.e., a volume, a choke, and another volume, is the same. Other acoustic filter types can be non-symmetric, take up less space, be used on side branches, and have special characteristics when properly designed.

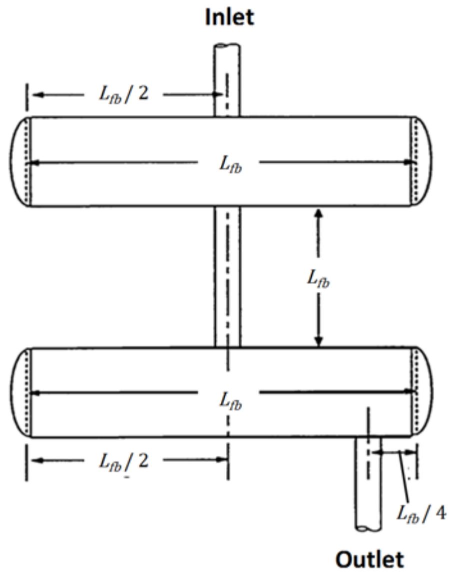

Figure 17. Example Symmetric, In-line Acoustic Filter Design

Conclusions

Pulsating flow, that is, the periodic variation in flow velocity and pressure, can adversely affect flow measurement devices. Flow meter types vary, and the error mechanism(s) for each can differ. Some, such as the orifice flow meter, are sensitive to ΔP pulsation amplitudes, while others, such as the turbine flow meter, are sensitive to velocity modulation amplitude and frequency content. Diagnosing pulsation-induced measurement error requires knowledge of the error-producing mechanism(s) and, often, special diagnostic instrumentation and testing techniques.

The most reliable way to avoid flow measurement errors related to pulsating or unsteady flow is to minimize or, preferably, eliminate pulsations at the flow meter. Unfortunately, pulsations can be generated by a number of pipeline sources ranging from reciprocating compressors and flow past piping branch connections to flow stream blockages, such as valves, pressure regulators, and thermowells. Once created, pulsations can be amplified by acoustic responses throughout the piping system. As demonstrated in this paper, a properly designed low-pass acoustic filter offers a reliable means to attenuate pulsations past the filter.

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