Lost & Unaccounted Natural Gas

The Effect and Control of Pulsation in Natural Gas Measurement

Reducing Lost & Unaccounted Gas

Lost and unaccounted for natural gas, particularly at pipeline custody transfer points, is becoming a focal point for both buyers and sellers. Even somewhat small measurement error can result in very large economic gains or losses at current natural gas prices. One relatively large source of lost and unaccounted for natural gas is due to pulsation at the orifice meter induced by compressors, flow control valves, regulators and some piping configurations. This article discusses some historical research and findings surrounding the topic of pulsation. In addition, we will provide some methods of measuring, monitoring and potentially correcting various types of pulsation supported by relevant examples.

Contact Information:

Parker Hannifin Corporation
PGI Division
16101 Vallen Drive
Houston, TX 77041 USA

phone 713 466 0056
fax 800 568 9228
pgi_sales@parker.com

www.parker.com/pgi
www.pgiint.com

Background

In recent years the Pipeline-and Compressor Research Council (PCRC), now known as (GMRC) Gas Machinery Research Council and a subsidiary of the Southern Gas Association, commissioned and funded various pulsation research projects at Southwest Research Institute (SWRI) in San Antonio, Texas.

That research culminated in the publication of several technical papers, including the April 1987 PCRC report 10.87-3 titled "Pulsation and Transient Induced Errors at Orifice Meter Installations" and a report, "An Assessment of Technology for Correcting Pulsation Induced Orifice Flow Measurement" dated November 1991. The PCRC sponsored research programs concluded that pulsation induced measurement errors fall into two broad categories:

1) **Primary Element Error:** Includes Square Root averaging error (SRE), inertial errors, and shifts in the orifice coefficient.

2) **Secondary Element Error:** consists of gauge line distortion and gauge line shift, together commonly referred to as Gauge Line Error (GLE).

SRE directly relates to flow measurement error and therefore a very important topic to those who buy and sell natural gas. This paper will focus on methods to measure and quantify Square Root Error and subsequent Gauge Line Error, while also recommending several techniques to reduce pulsation effects on natural gas measurement.

Square Root Error

Most natural gas flow measurement in the United States is performed by measuring pressure drop at two points (pressure differential) induced by an orifice plate. The gas flow rate (Q) is calculated using the basic formula $Q = K\sqrt{\Delta PXP}$. The fixed orifice coefficient (K) is derived from a formula found in the latest edition of AGA Report Number 3. Differential pressure ΔP and line pressure P are measured either using mechanical chart recorders or electronic transmitters, remotely or direct mounted to the pressure taps, using a configuration of instrumentation valves, manifolds, and tubing.

Under steady-state flow conditions, gas flow rates can be accurately measured with current state-of-the-art equipment, including highly accurate pressure transmitters

ENGINEERING YOUR SUCCESS.

and flow computers. Despite the high degree of accuracy of current electronic measurement devices, inaccurate measurement still occurs when the ΔP modulates, or changes, at a frequency greater than the frequency that the measurement system extracts the square root of the ΔP.

This type of measurement error is called Square Root Error (SRE) and is the calculation of unsteady flow using the square root of the average ΔP verses the average of the square root values of the instantaneous ΔP.

Pulsation from gas compressors, control valves, pressure regulators, and some piping configurations are one source of frequent ΔP modulation. Figure 1 is an excellent example that illustrates the amplitude and frequency of pulsation generated by a reciprocating compressor and a control valve. Three separate pulsation peaks are occurring in this system.

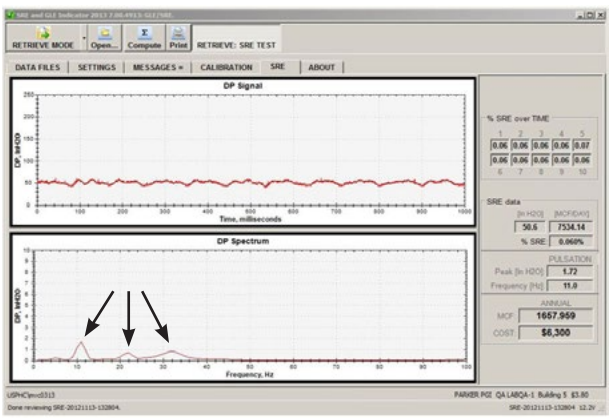

Figure 1: A graph exhibits three separate pulsation peaks. The operator can isolate the pulsation source by using new software filtering capability and modifying conditions in the new field. Minimizing and eliminating the pulsation source can ultimately improve the meter's measurement accuracy.

The field technician operating the SRE Indicator is typically able to isolate the pulsation source(s) by using new filtering software and modifying the field conditions to generate new responses. This enables the operator to make necessary field changes that should improve measurement accuracy.

In a paper presented at the 2002 American School of Gas Measurement Technology Conference entitled "Pulsation Effects on Orifice Metering Considering Primary and Secondary Elements", Mr. Robert J. McKee of SWRI states, "A mathematical definition of SRE can be developed from the fact that the average flow is proportional to the average of the instantaneous square root of ΔP as opposed to the square root of the average ΔP."

The formula developed by SWRI to determine the severity of SRE is illustrated below:

$$\%SRE = \frac{(\sqrt{Avg.\Delta P} - Avg.\sqrt{\Delta P})}{Avg.\sqrt{\Delta P}} \times 100$$

An illustration of a %SRE calculation of a series of six ΔP readings taken from a pulsating flow is shown in Table 1:

Table 1: Pulsating Flow Readings

Reading	ΔP's (in. wc.)	√ΔP's (in. wc.)
1	75.0	8.660
2	30.0	5.477
3	47.5	6.892
4	52.2	7.225
5	26.1	5.109
6	71.6	8.462
Total	**302.4**	**41.825**
Avg. ΔP	**50.4**	
√Avg. ΔP	**7.099**	**6.971**

$$\%SRE = \frac{(7.099 - 6.971)}{6.971} \times 100 = +1.84\%SRE$$

Note that %SRE is a positive number and is mathematically impossible to be negative. In addition, %SRE increases with pulsation amplitude, and is inversely proportional to ΔP (for a given pulsation amplitude, %SRE will be greater at low ΔP than at high ΔP).

Other Primary Element Errors

SRE is the largest component of pulsation induced primary element error. However, inertial error and coefficient shift will both increase in magnitude under extreme pulsation conditions. A brief explanation of each follows:

Inertial error

Pulsating gas flow will tend to remain in motion due to its inertia. As a result, flow velocity changes lag behind ΔP changes. Inertial errors are insignificant unless pulsation amplitude and frequency are both relatively high.

Coefficient Shifts

Though difficult to quantify, test data indicates that pulsation levels above 1.5% SRE contribute to shifts in the orifice co-efficient.

Measuring %SRE

The %SRE is measured at operating conditions and is used to approximate the primary element error induced by pulsation and to determine whether corrective action is necessary.

Percent Square Root Error (%SRE) is measured with a device manufactured and marketed by Parker called the Square Root Error (SRE) Indicator. This analytical instrument utilizes a high frequency response ΔP transducer and software to calculate %SRE according to the formula developed by SWRI, illustrated earlier in this paper.

The SRE Indicator is used by field technicians to measure the severity of pulsation and calculate %SRE. The results can be used to determine if corrective action is necessary. However, because other primary element errors (inertial error and co-efficient shifts) are not directly measured, %SRE should not be used to correct flow measurement readings.

Reducing Pulsation

Measurement error caused by pulsation at custody transfer points can create large economic discrepancies between natural gas buyers and sellers. Therefore, many natural gas purchase contracts contain language that set limits on %SRE (sometimes as low as 0.20% SRE) and typically place the burden of reducing or eliminating pulsation on the seller.

The simplest method of reducing pulsation induced SRE is to raise the ΔP by changing the orifice plate. Unfortunately, this may also limit the operating range of the measurement system.

In some cases, the piping system could be modified or the pulsation source could be moved to reduce SRE. This can be time consuming and costly.

Another popular corrective action for high SRE is to install a device, such as a restricting orifice, between the pulsation source and the measuring station. However, these restricting devices can result in higher compression cost and a limited flow range.

%SRE can also be reduced by installing an acoustic filter to remove most of the pulsation. Although more costly than a restricting device, a properly designed acoustic filter will operate over a much wider flow range with a lower pressure drop.

Gauge Line Error

Gauge Line Error (GLE) exists when the differential pressure (ΔP) at the taps does not equal the differential pressure (ΔP) at the end of the gauge lines. GLE is typically caused by either pulsation or other flow phenomena.

The gauge line starts at the orifice taps and ends at the transmitter, flow computer, or chart recorder connections. It includes any pipe fittings, valves, valve manifolds, tube fittings, instrument tubing, and condensate chambers or bottles that may be installed between the orifice taps and the measurement device.

Research conducted by SWRI determined that gauge line error has two components:

Gauge Line Distortion

Gauge Line Distortion is defined as the amplification (increase) or attenuation (decrease) of the pulsation amplitude in the gauge lines. This is similar to the noise created when playing a flute or blowing across the top of an open bottle.

Gauge Line Shift

Gauge Line Shift is defined as the actual shifting of the average pressure along the length of the gauge line. This may be created by pulsation rectification effects, which occur when the ΔP signal is transmitted through changing inside diameters of gauge line. Diameter changes are created by multiple instrument tubing sizes, bottles or condensate chambers, shut-off valves with a smaller ID than the instrument tubing, or male-to-female NPT connections.

Other causes of gauge line shift include gas oscillation at the mouth of the gauge line, and density changes caused by pressure and temperature fluctuations in the gauge line.

Measuring Gauge Line Errors

Parker developed its initial GLE Indicator in 1990, following it in 1996 and 2005. The current SRE/ GLE Indicator includes the ability to perform both %SRE and GLE tests, thus measuring and quantifying both gauge line error and square root error.

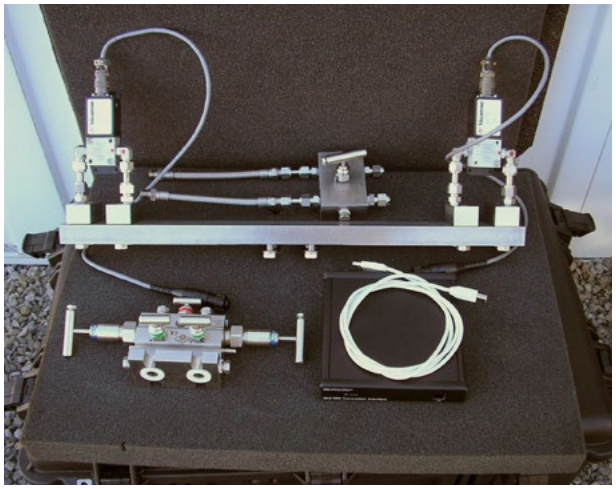

Figure 2: SRE6 and GLE6 test equipment that enables operator to perform an SRE and GLE test simultaneously.

The GLE Indicator compares the differential pressure at the orifice taps with the differential pressure at the end of the gauge lines. Any difference between the two signals would be associated with gauge line error.

The GLE Indicator consists of two Validyne P855D differential pressure transducers and mounting hardware to install one Validyne directly at the orifice taps and the other at the end of the gauge lines.

A USB transducer interface converter changes the voltage output signals from each Validyne transducer into a digital signal. The signal is analyzed by specially developed software supported by a portable, battery operated laptop computer. The SRE/GLE 6 software is Windows® based for ease of operation.

Operation of the SRE or GLE Indicator is fairly straightforward. Station and test data are entered as shown in Figures 3 and 4.

A calibration procedure corrects any output signal deviations as shown input differential pressures, as illustrated in figure 5.

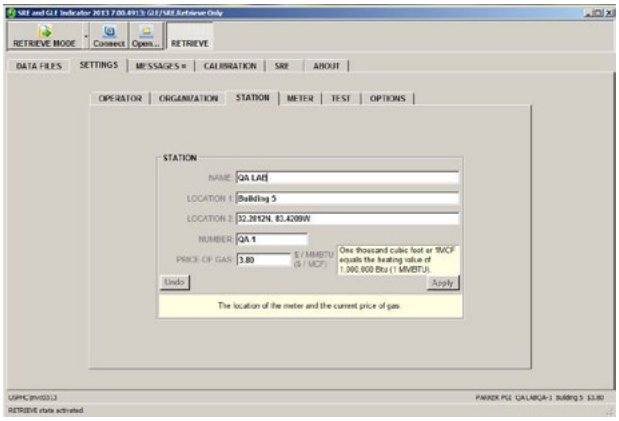

Figure 3: A screen shot showing the "Settings" tab for the SRE/GLE 6 software program. Tabs are used to organize the information needed to perform the field test.

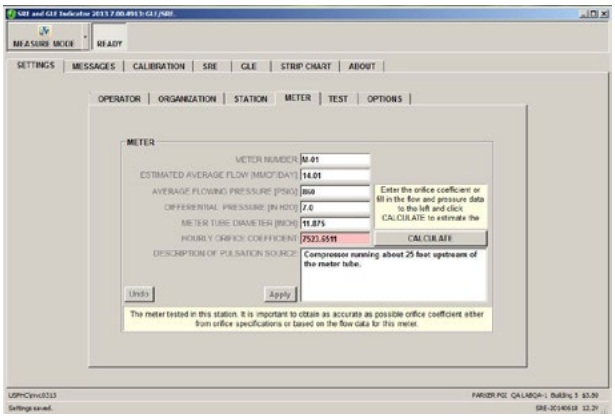

Figure 4: This illustrates the "Meter" setup tab. One feature of the software is to estimate pulsation error's total effect on an annual basis. The operator enters the meter data for calculating total volume error.

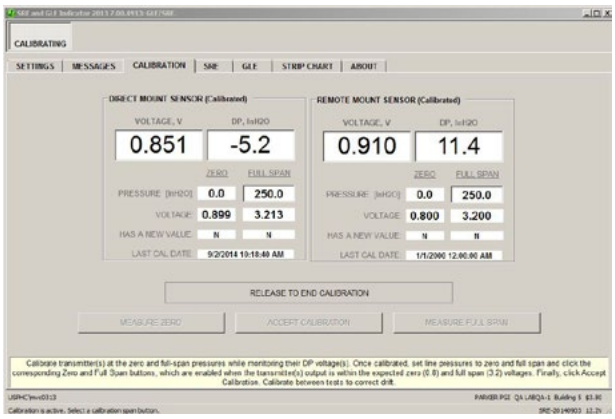

Figure 5: The "Calibration" tab is used to conduct a mandatory calibration of the high-speed transducers before each test. The operator applies a known upper range pressure to ensure test accuracy.

A “noise test” is then performed to determine system error (Figure 6). During the “noise test,” both Validyne transducers measure the same differential pressure, which is manually modulated using a hand pump. The noise test should show that the Validyne transducers are reading the same and that no outside electrical interference is present.

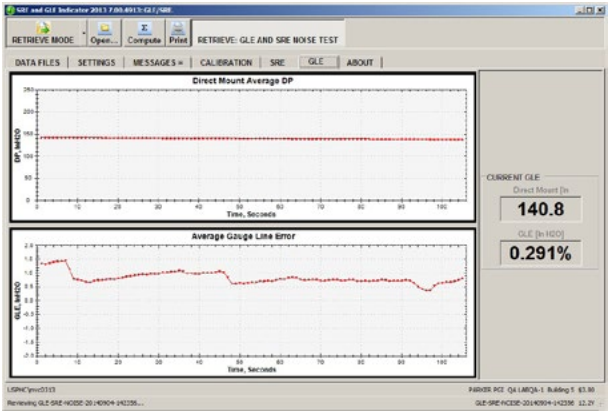

Figure 6: A noise test that would result in ΔP difference of 0.291%

A bias test can also be done.

One of the Validyne transducers is installed at the end of the gauge lines and then is pressurized to line pressure and re-zeroed to correct for transducer position and static pressure, zero shift.

During the timed GLE test, the ΔP of each Validyne is sampled at a frequency of more than 250 samples/second. A flow calculation for each transducer is performed once each second using the average of the ΔP’s.

The GLE Indicator graphically indicates the true ΔP at the orifice, and the actual gauge line error. Average gauge line error in inches of water and %GLE are also displayed. At the conclusion of the test, the flow calculated from each transducer is compared. Any difference in the two volumes is displayed as “Annual Volume” (MMCF) of natural gas and subsequently multiplied by the user’s current natural gas price to obtain “Annual Monetary Gain (or loss).”

Numerous tests can be performed at various flow rates. All gauge line and square root error tests are automatically stored to the hard disk for future analysis or printing.

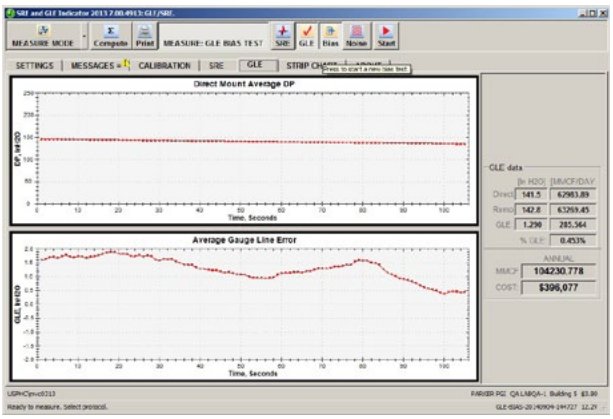

Figure 7: Bias test results

Testing Results

Extensive field-testing with the GLE Indicator confirmed the research conducted at Southwest Research Institute (SWRI) by PCRC. The following lab test examples should provide a better understanding of GLE issues and measurement problems resulting from incorrect transmitter mounting practices. In the following test examples, “DM” represents the ΔP of the reference Validyne that was directly mounted on one side of the orifice fitting.

GLE-Test 1

As illustrated in Figure 8, gauge line error was measured at the outlet of a small bore (0.187"), 5-valve manifold connected to the orifice fitting with 4.5' of 3/8" O.D. tubing. A pair of 3/8" I.D. ball valves were installed at the taps. Gauge line error was positive 0.453% at 141.5" wc. ΔP. The resulting measurement error approximates US $396,077.00 annually based on US $3.80/Mmbtu natural gas prices.

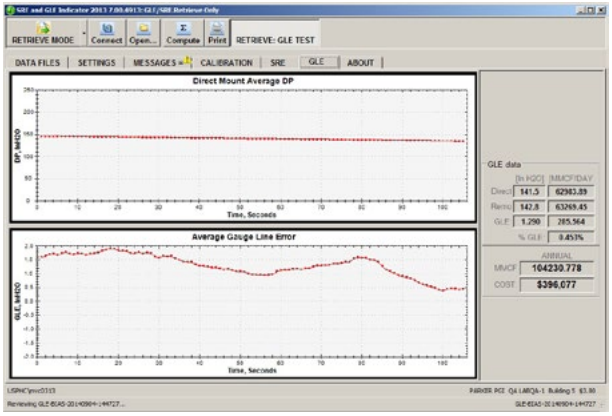

Figure 8: GLE-Test 1 results

GLE-Test 2

As illustrated in Figure 9, gauge line error was measured at the end of the 3/8" O.D. gauge lines 5' from the orifice taps. GLE measured negative 0.019% at 165.7" wc. ΔP at a changing flow rate of about 25.00 MMCFD. The resulting measurement error approximates negative US $17,741.00 annually based on US $3.80/Mmbtu natural gas prices.

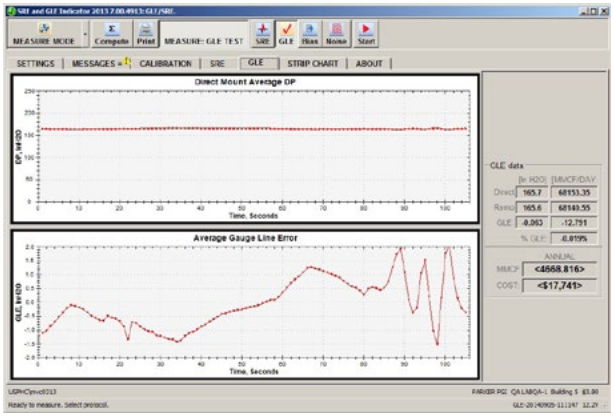

Figure 9: GLE-Test 2 results

Eliminating or Minimizing GLE

As noted previously, numerous gas contracts now include pulsation magnitude clauses and many transmission companies require the installation of acoustic filters to minimize pulsation levels and %SRE. However, GLE tests conclude that gauge line error may continue to be present even after the installation of an acoustic filter and despite %SRE readings as low as 0.1%.

System complexity and numerous dependent variables, including pulsation levels, gauge line lengths, gauge line diameters, operating pressure, gas density, and gas velocity make it extremely difficult to observe a measurement location and predict what gauge line error, if any, will be present. GLE testing is currently the only recognized method to determine the presence of gauge line error.

Proper installation of the transmitter and/or electronic flow meter (EFM) in a manner that minimizes or eliminates gauge line error by removing as many of these dependent variables as possible is the best option.

Best practices include:

- Closely couple the differential measurement device (transmitter or electronic flow meter/ computer) with the orifice fittings
- Remove or minimize system vibration that can effect measurement or the measurement device
- Use equal lengths of large bore (0.375" internal diameter or greater) tubing
- Maintain the same large bore (0.375" I.D.) through all tubing, valves and manifolds between the measurement device and the orifice fitting
- Use of instrument valves rather than quarter turn ball valves. Opening and closing quarter turn ball valves make it is very easy to shock one side of the measurement device with full line pressure. Any pressure shock may create a significant static shift in the calibration of the transmitter not detectable under normal calibration procedures.

Using a short length of 1/2" O.D. instrument tubing and full opening quarter turn ball valve between the orifice fitting and measurement device creates numerous mating of female NPT connections and small “volume chambers,” which could create gauge line shift (pulsation rectification effects). “Best practices” suggest using a system the directly mounts and closely couples the measurement device to the orifice taps as shown in Figure 9. This method continues to gain wide acceptance within the industry illustrated by over 10,000 installations currently in service.

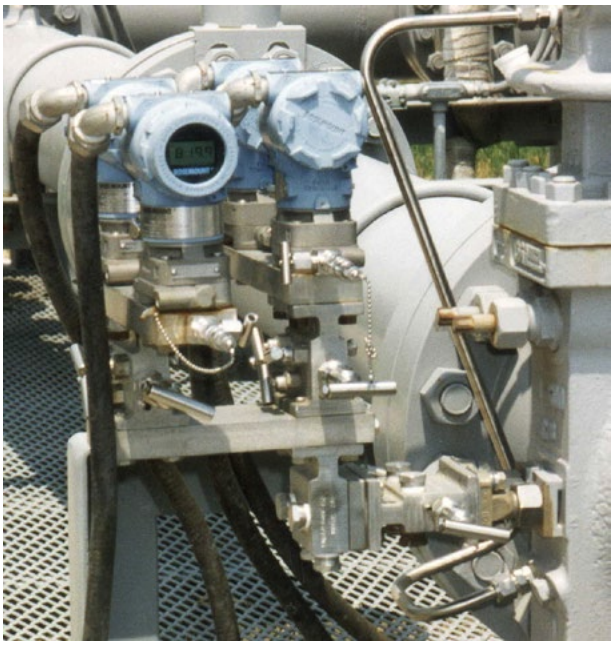

Figure 10: Parker's Direct Mount System. The manifold system reduces effect of Gauge Line Error on the total measurement system. Note the reduced numbe of leak points and sensing line length, and uniform diameter between the orifice ports and the measuring elements.

The Direct-Mount® System includes:

- A pair of stabilized connectors that provide a stable, safe connection and minimize system vibration. The connectors include a roddable large bore (0.375" I.D.)
- Soft seat instrument manifolds that are typically located within 13" of the orifice taps.
- Flanged connections with PTFE seals that eliminate the "volume chambers" found with NPT connections.
- Multiple turn instrumentation valves prevent "shocking" of the measurement device when opened.
- Frequent valve stem packing adjustments are eliminated by a dynamically loaded stem seal that is guaranteed leak-free under fluctuating pressure (vacuum to +10,000 PSI) and temperature (-40°F to +450°F).
- Dielectric isolators rated to 2,500 volts DC should be installed between the stabilized connectors and the manifold to protect the electronic transmitters from cathodic protection currents and possible transients.

Summary

Pulsation created by compressors, flow control valves, regulators, and some piping configurations may create unacceptable levels of Square Root Error (%SRE) and/ or resulting Gauge Line Error (GLE). Pulsation at the orifice meter is a major source of lost and unaccounted for natural gas, which can create large economic gain or loss for both buyers and sellers along a natural gas pipeline system.

%SRE and GLE can be measured and quantified using a SRE/GLE Indicator to verify measurement accuracy at a specific time and place. Pulsation and resulting high % SRE creates a high probability that GLE is present. Volume chambers or numerous measurement devices connected to the same set of orifice taps may compound or create GLE. Transmitters or EFM should be close coupled to the orifice taps with equal length, large bore (0.375" I.D. or greater), constant diameter gauge lines to minimize or eliminate GLE; however, this process will not reduce or eliminate %SRE. The pulsation source must be eliminated, piping systems modified, ΔP increased, a restricting device installed, or a properly sized acoustic filter installed to reduce pulsation and resulting %SRE.

References

1. McKee, Robert S. "Pulsation Effects on Orifice Metering Considering Primary and Secondary Elements," Proceedings of the Twenty-Second Gulf Coast Measurement Short Course, pp. 112-118, 1989.

2. Gegg, Debbie, "Effects and Control of Pulsation's in Gas Measurement," Arkia Energy Resources, Shreveport, La. Proceedings of the Sixty-Fourth International School of Hydrocarbon Measurement, pp. 331-335, 1989.

3. Durke, Ray G. and Sparks, Cecil R., "Pulsation and Transient-Induced Errors at Orifice Meter Installations,' PCRC Technical Report No. 87-3, 1987. Floyd, J.H. and Everett, W.S. "The Effect of High Frequency Pulsation's on Differential Meter Accuracy," Proceedings of the Twenty Third Appalachian Gas Measurement Short Course, pp. 283-294, 1963.

4. Durke, Ray G., Smalley, Anthony J., and McKee, Robert J. "An Assessment of Technology for Correcting Pulsation-Induced Orifice Flow Measurement Errors," PCRC Technical Report No. TA 91-1, 1991.

Sales Offices Worldwide

Parker Hannifin Corporation
PGI Division
16101 Vallen Drive
Houston, TX 77041
USA
phone 713 466 0056
fax 713 744 9897
email pgi_sales@parker.com
www.parker.com/pgi
www.pgiint.com

Parker Hannifin Corporation
PGI Division
18 Huashan Road, New District
Changzhou, Jiangsu
213022
China
phone +86 519 8980 7258
fax +86 519 8980 7212

Parker Hannifin Corporation
PGI Division
11, Fourth Chin Bee Rd
619702
Singapore
phone +65 6887 6300
fax +65 6265 5125

Parker Hannifin Corporation
PGI Division
2620 21st Street NE
Calgary, Alberta
T2E 7L3
Canada
phone 403 291 3154
fax 403 291 3292

Safety Guide – See www.parker.com/safety.

© 2015 Parker Hannifin Corporation. All rights reserved.

Bulletin PGI-LUNG 01/2015-DDP

Parker Hannifin Corporation
PGI Division
16101 Vallen Drive
Houston, Texas 77041
phone 713 466 0056
fax 713 744 9897
www.parker.com/pgi

Your Local Authorized Parker Distributor