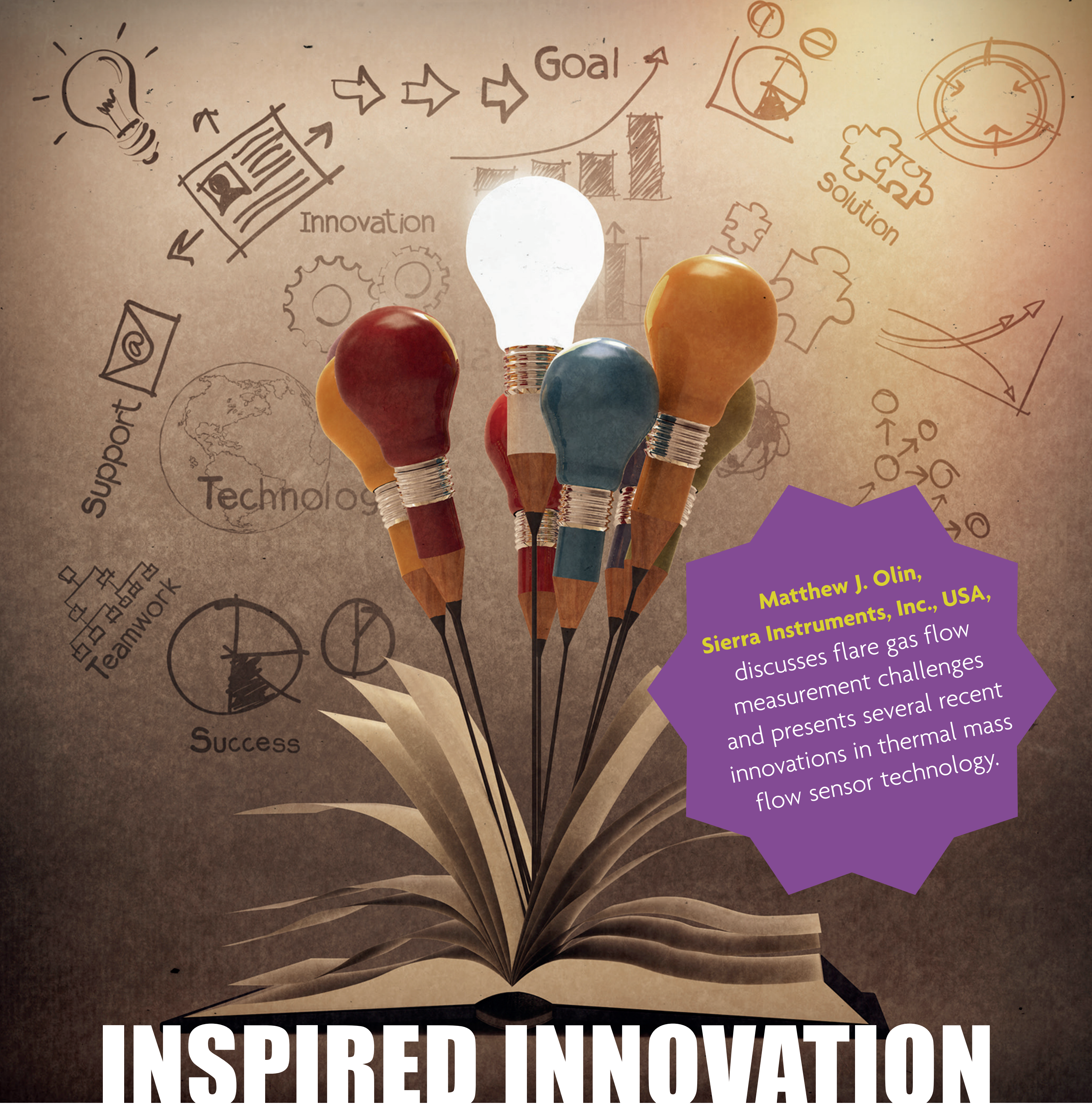

INSPIRED INNOVATION

Matthew J. Olin, Sierra Instruments, Inc., USA, discusses flare gas flow measurement challenges and presents several recent innovations in thermal mass flow sensor technology.

As the drive towards energy independence in the US continues at full speed, oil and gas companies are turning to hydraulic fracturing to increase production. Increasingly stringent state and national regulations for flare gas in particular now require the installation of mass flow measurement instruments to measure waste and excess gases burned off as a result of the hydraulic fracturing process. For gas wells alone, the EPA estimates that the cost of compliance will rise to US$754 million/y by 2015.[1]

Given the immense number of flares that are to be regulated, there is a need for more cost effective mass flow measurement technologies. Multi path ultrasonic flow meters have been widely used for flare gas measurement, but they are extremely expensive and have marked limitations. To comply with regulations, oil and gas companies need new flow meter alternatives that are accurate, durable, reliable and economical.

This article reviews flare gas flow measurement challenges and describes how several recent innovations in thermal mass flow sensor technology give end users an alternative metering choice to consider. Of particular interest is four sensor thermal technology, coupled with an advanced math model algorithm that works in tandem with the American Gas Association's (AGA) compliant gas property database. In combination, these technologies allow the user to adjust the instrument and retain accuracy as flare gas compositions change in the field over time. The ability of this new breed of four sensor thermal meter to adjust for changing gas

Table 1. Examples of flare waste gas compositions: Constituents of interest and variability over 1 year[4]

Flare gas composition variability: Flare 1		
Component	**Mole %**	**Mole %**
Hydrogen	86.18	48.77
Methane	5.93	3.52
Ethane	0.81	0.26
Ethylene	0.02	0.01
Propane	0.34	0.14
Propylene	0.00	0.01
N-butane	0.11	0.05
I-butane	0.11	0.06
Cis, 2-butylene	0.16	0.06
Trans, 2-butylene	0.17	0.06
Isobutylene	0.12	ND
1,3-butadiene	ND	ND
N-pentane	0.03	0.08
I-pentane	0.05	0.05
Pentenes	ND	ND
C_{6+}	0.01	0.01
CO	0.02	0.04
N_2	4.99	45.80
O_2	ND	ND
CO_2	0.06	0.04
Hydrogen sulfide	0.24	0.35
Water vapour	0.68	0.70
Totals	100.00	100.00

compositions gives end users a significantly lower cost alternative to four path ultrasonic meters.

Hydraulic fracturing

Hydraulic fracturing is used to release oil and natural gas from wells drilled into reservoir shale rock formations called 'shale plays'. While fracturing itself is not new (first carried out in 1947), it is the perfecting of horizontal drilling techniques that have made it economical to exploit these shale plays. The oil produced using these techniques and other new exploration technologies is poised to make the USA the world's largest producer of oil by 2020.[2]

The process of hydraulic fracturing releases large amounts of natural gas. While this is the objective in fracturing a natural gas well, some natural gas is inevitably released during the well completion (flow back). Oil wells almost always produce natural gas (associated gas) along with the petroleum. In many cases, it is uneconomical to process due to heavy contamination. Many of the newer fracturing discoveries do not have the pipelines, compressors and gas plant infrastructure to collect this gas. As a consequence, this gas is combusted, flared off or simply vented as is. When all sources are considered, over 150 billion m^3 are flared or vented globally every year. This is equal to 25% of the US' natural gas consumption in 2012.[3] Methane itself is a very potent greenhouse gas, while the carbon dioxide, soot and other contaminants in flared gas are also significant pollutants.

Flare gas measurement challenges

In order to comply with state and federal regulations, oil and gas companies need to invest in mass flow measurement equipment to measure flare gas flowing to: the combustor, vented gas from storage tanks, gas used as fuel, and/or gas sent to the grid for sale. Each well has its unique and constantly changing characteristics that include depth, temperature, pressure, flow rate, soot content and changing gas composition. This makes accurate flare gas measurement very challenging. To comply with stringent state and federal regulations, engineers at oil and gas companies must assess which flow measurement technology yields the highest accuracy with the lowest installation and cost of ownership over the lifetime of the well.

The choice of flow measurement technology for flare gas measurement needs to perform under the following application challenges:

- Wide flow rate variations: Turndowns of up to 1000:1 may be required.
- Non-uniform flow profile: Flare stacks generally have asymmetric and swirling flow.
- Very low pressure with variable temperatures: Most flare headers operate at near atmospheric conditions. Gas temperature varies with well depth and reservoir characteristics.
- Dirty flares versus clean flares: Many flares have significant amounts of dirt, hydrogen sulfide, wax, tar, and other paraffins that make for a dirty, sooty flame.
- Maintenance is difficult and costly: Roaring flames, difficult access and regulatory requirements make flares difficult to service.
- Wide gas density variations: Flare gas composition, and thus the density of flare gas varies over the lifetime of the flare. Traditional flow meters cannot successfully manage the changes in flare gas composition.

As seen in Table 1 (Flare 1), the molecular percentage of hydrogen changes from 86.18% to 48.77%, and methane changes from 5.93% to 3.52% over a year of operation. Faced with such changing flare gas composition, a typical total flow measurement error can be in the 5% to 10% range and could be as high as 20% in applications with widely varying compositions. Correcting measured linear velocities to actual mass flow rates can be problematic if the molecular weight of the waste gas varies by more than 20% from the molecular weight of the meter's calibration gas.

Many meter choices; few good solutions

Over the last five years, multi path transit time ultrasonic meters (typically four path) have been used for flare gas measurement. Given the flare gas measurement challenges they face, multi path ultrasonic flow meters perform reasonably well. With multi path ultrasonic flow meters, speed of sound through the flare gas is directly related to its density. This makes flare gas measurement independent of changing gas composition and facilitates mass flow measurement.

As the sensors are non-intrusive (not exposed directly to the flare gas), they have been used in some installations to measure dirty, wet gas without gumming up mechanical parts,

Table 2. Comparison of flow technologies considered for flare gas metering based on performance factors

	High and low flow (turndown)	Low pressure	Dirty flares	Varying composition	Flow profiles	Cost
Averaging pitot tubes	Poor 10 to 1	Poor Δ device	Poor Prone to clog	Poor Volumetric	Good Averages across pipe	US$2000
Insertion turbines	Poor 10 to 1	Fair Minimum velocity	Poor Prone to clog	Poor Volumetric	Fair Point velocity	US$1000
Insertion vortex	Poor Minimum velocity	Good Multivariable	Fair Sensor head can plug, but is fairly large	Poor Must know gas composition	Fair Point velocity	US$3000
Insertion thermal	Good 1000 to 1	Fair Must be calibrated at operating pressure	Fair Sensor head can get dirty, but is fairly open	Poor Must know gas composition	Fair Point velocity	US$2500
Ultrasonic	Fair 1000 to 1	Excellent Not affected	Excellent External to pipe	Good Infers density from speed of sound	Good Signal across pipe	US$15 000
QuadraTherm Insertion Thermal	Excellent 2000 to 1	Excellent Multivariable	Fair Sensor head can get dirty, but is fairly open	Good Four compositions on board, any other can be uploaded in field	Good Point velocity, Reynolds number and flow profile correction built in	US$3000

resulting in lower maintenance costs. However, in some applications, dirt, wax, tar, and paraffin in the flow causes internal erosion or buildup of material on the inner wall of the pipe. Since multi path ultrasonic meters are built into inline pipe sections, called spool pieces, the entire meter must be removed to clean them. This degrades the flow measurement accuracy without obvious indicators. Susceptibility to the effects of flow profile, especially swirl, will also cause degraded accuracy.

Multi path ultrasonic meters are distinguished by the number of paths they use to compute the flow rate. Multiple paths enable more precise calculation of the gas velocity and the speed of sound (and thus density), but each set of paths substantially increases the cost. Cost also increases with the size of the spool piece. This can cost oil and gas companies over US$15 000[5] for a four path ultrasonic flow meter. This cost is several times more than the traditional flow meters (depending on the technology) listed in Table 2.

Other technologies listed in Table 2, such as averaging pitot tubes and insertion turbine meters, have poor performance for measuring flare gas. These devices measure volumetric flow, not mass flow, which is the desired measurement. They require a clean flare gas with constant gas composition. Additionally, multivariable mass vortex meters successfully measure low pressures of flare gas, but they need to know the gas composition for accurate measurement.

Four sensor thermal mass flow meters

Traditional thermal flow meters have limitations in flare gas measurement as they cannot accurately measure changing gas composition without factory recalibration. Recent innovations in thermal mass flow sensor technology have removed this barrier to market entry. Four sensor thermal mass flow meters now have the ability to adjust for changing flare gas

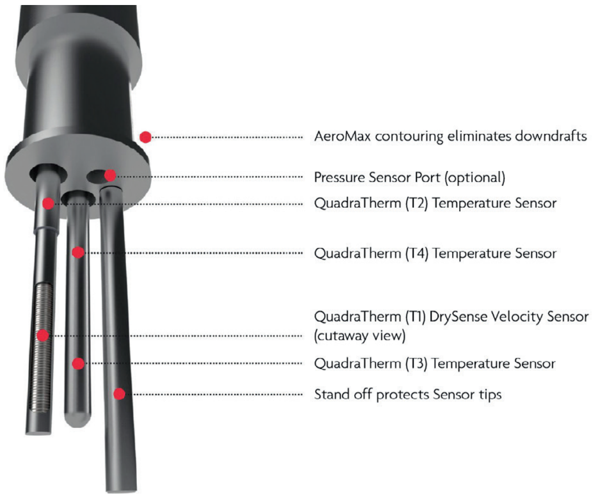

Figure 1. QuadraTherm® four sensor design by Sierra.

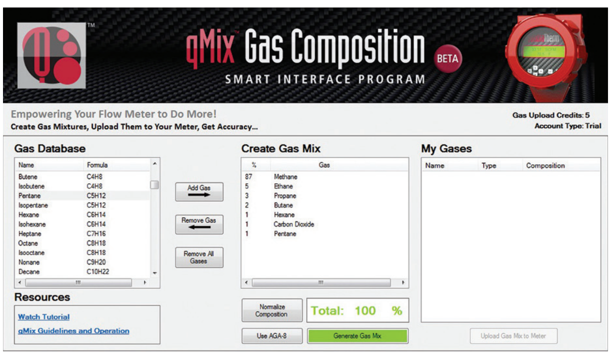

Figure 2. Smart interface portal: QuadraTherm embedded gas composition management tool.

Table 3. Example of five year cost of ownership comparison between traditional and four sensor thermal mass flow meters versus multi path ultrasonic flow meters

	6 in. (150 mm) traditional two sensor thermal insertion probe mass low meter	4 in. (100 mm) inline four path ultrasonic flow meter	6 in. (150 mm) four sensor thermal insertion probe mass flow meter
Instrument initial cost	US$2500.00	US$15 000.00	US$3000.00
Installation	US$500.00	US$1500.00[2]	US$500.00[3]
Calibration 1	US$850.00[1]	US$00.00[4]	US$50.00[5]
Calibration 2	US$850.00	US$00.00	US$50.00
Calibration 3	US$850.00	US$00.00	US$50.00
Calibration 4	US$850.00	US$00.00	US$50.00
Calibration 5	US$850.00	US$00.00	US$50.00
Total	**US$7250.00**	**US$16 500.00**	**US$3750.00**

Figure 3. Four sensor insertion probe QuadraTherm mass flow meter by Sierra.

compositions in the field over time. This new four sensor thermal meter gives end users a lower cost alternative to four path ultrasonic meters in flare applications.

Improved accuracy specification

With four sensor thermal sensor technology, as seen in Figure 1, accuracy specifications are comparable to four path ultrasonic meters at a much more economical price. Pioneered by Sierra Instruments, Inc., in Monterey, California, four sensor thermal has +/- 0.75% of reading accuracy for insertion probe versions (far better than the 2.0% of reading previously possible with traditional thermal). The inline version of the instrument improves on that with +/- 0.5% of reading accuracy.

Field composition changes, now possible

For the first time, four sensor technology can compete with multi path ultrasonic meters due to its ability to compute the mass flow rate of any gas composition. Hyper fast microprocessors run flow measurement algorithms to compute the mass flow of any gas composition. The microprocessor takes the inputs from the four sensors and solves the first law of thermodynamics (heat energy in = heat energy out) for each data point.

In thermal mass flow meters, the composition of the gas is required. Flare gas composition sampling depends on the wellhead and typically carried out once every three months. Once the flare gas composition is known, operators can create, name, store and upload new gas compositions to the four sensor meter (Figure 2). Accuracy is maintained without sending the meter back to the factory for costly recalibration.

The meter itself stores four gas compositions. Operators can access the software's gas library, which is password protected to keep proprietary gas mixtures secure. This gas library contains all AGA compliant gas properties needed to make the algorithmic gas mass flow rate calculations.

Cost savings

It was clear from the comparison of flow technologies for flare gas metering in Table 2 that both thermal and ultrasonic are the preferred choices. At this point, it is a good time to review costs and overall cost of ownership. Table 3 gives a five year cost of ownership example comparing a traditional 6.0 in. (150 mm) long two sensor insertion probe thermal mass meter inserted into a 4.0 in. (100 mm) flare header, with an inline 4 in. (100 mm) four path inline ultrasonic meter, and a 6 in. (150 mm) long four sensor insertion probe thermal mass meter inserted into a 4 in. (100 mm) flare header. The four path ultrasonic meter averages US$15 000 (Flow Research, Inc. 2008 study), while the four sensor thermal insertion probe meter averages US$3000. Insertion probe thermal meters also accommodate larger pipe applications up to 72 in. (2 m) with a single 0.75 in. (19 mm) insertion point.

Ultrasonic meters only have inline flow body configurations, and the cost increases exponentially with pipe size and number of paths.

Using the Table 3 data, assume that a typical customer has 150 flare gas measurement points. When the composition changes five times over the life of the wellhead, costs add up. Using four path ultrasonic metering would cost US$2.475 million, but the instrument would be unaffected by gas composition changes. In contrast, the four sensor thermal meter would be much less expensive at US$562 500, even though periodic field adjustments of the four sensor thermal meter would be required.

If one takes a more macroeconomic view on the industry and makes the reasonable estimate of 30 000 new flares per year that need measurement, annual ultrasonic metering costs are pushed to US$495 million. Under these same assumptions, four sensor thermal would cost much less at US$112 million. These cost estimates support the need for alternative, lower cost metering choices for this tough application. In the absence of lower cost options, energy costs will increase over the long term as high metering costs are pushed to the consumer in the form of higher prices.

Conclusion

Oil and gas companies may potentially lose thousands of dollars a day if they are not in compliance with local, state and federal regulations, and flow metering costs will drive energy prices up as they are passed to the consumer at the gas pump. In addition, as infrastructure is developed, gas that is now flared will eventually be sold to the national distribution network, turning a current liability into a future asset.

While multi path ultrasonic flow meters are widely used today, end users now have an alternative. Primarily due to the significantly lower cost of ownership, four sensor thermal mass flow technology is poised to become a highly attractive alternative. The ability to adjust the instrument in the field in response to changing flare gas compositions over time and the extremely high accuracy of these devices offer oil and gas companies a compelling alternative to multi path ultrasonic meters.

Acknowledgements

The author would like to thank Scott Rouse and Erica Giannini.

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Table 3 notes

Assume a 4 in. (100 mm) flare header and gas composition that has changed five times over five years where it was dramatic enough to warrant instrument adjustment.

1. *Cost to remove instrument, ship back to factory, recalibrate to new gas composition, return and reinstall. Cost of process measurement downtime not calculated.*
2. *Must shut process, cut pipe to install inline ultrasonic flow meters. Cost of process measurement downtime not calculated.*
3. *Single 6 in. (19.1 mm) insertion point, can be hot tapped.*
4. *No need for removal from pipe or adjustment.*
5. *Assume cost of 30 minutes at US$50 labour cost each time the instrument is adjusted for new gas composition via field software interface.*