Peaks and Valleys:
Solving Gas Wellhead Flow Measurement Problems Induced by Plunger Lift Systems
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Executive summary

Accurately measuring flow on a gas wellhead that utilizes a plunger lift system can be a formidable challenge, and one with significant financial consequences if not done properly. While a plunger lift system solves the problem of resuming the flow of gas in mature wells, it creates another set of challenges of its own. With every plunger cycle, the system subjects flow meters to large pressure spikes with wide flow rate variations. As the plunger cycle repeats itself, it makes it impossible for conventional transmitters to accurately measure the flow of gas.

The operator of these aging wells is typically faced with the decision how to best measure the peaks and valleys of varying gas flow induced by the plunger lift system. Using a conventional flow meter designed to only cover the normal working pressure of the well will result in a loss of income for the operator. To further exacerbate the situation, the spike of high-pressure gas produced by a plunger lift cycle may not even be documented until it is farther down the delivery chain, having an even greater economic impact on the operator.

This paper introduces a measurement solution optimized to increase accuracy in measuring varying gas flow rates while offering a universal solution that can be easily implemented.

Plunger automated systems

Wellhead production sites present many challenges to gas flow measurement, especially as they age. Operators want existing wells to produce as much as possible for as long as possible, but as wells mature, pressure declines leading to a decline in production.

In the beginning of the life of a gas well, production rates and velocities are usually high. This keeps the well bore clear of liquid accumulation. The high turbulence and velocity of the gas easily lifts the liquids to the surface and the well produces at steady flow rates. As the gas well ages, the reservoir pressures decline, decreasing flow rates and velocities. This alters the gas lifting characteristics, causing liquids to begin to collect on the walls of the production tubing. When enough liquid accumulates, slugs form which reduce gas flow. As a consequence of not having enough gas pressure to carry the liquid out, the flow rate will eventually fall below a critical value, halting the flow of gas (Figure 1-1 on page 2). More direct measures are then required to clear the well bore and maintain production.
Incorrect flow measurement has severe financial consequences. Using a conventional multivariable flow meter designed to cover only the normal working pressure of the well will result in a loss of income for the operator. The burst of high pressure gas produced by a plunger lift cycle may not even be documented at the wellhead, going unnoticed until it is farther down the delivery chain, generating an even greater economic impact on the operator. The operator is effectively giving away a portion of the gas production to the pipeline operator, understating what is paid to the royalty owner and gas producer.

For example, if gas is selling for $3.00 per 1,000 cubic feet, and 2 percent of the overall volume is missed during pressure spikes, even a depleting well producing only 200,000 cubic feet per day could miss more than $4,000 of revenue per year. A more typical well producing 4 million cubic feet per day will miss more than $85,000 per year.

So how do users cope with this situation? The obvious choice is to use a multivariable transmitter able to read 0-1,000-in. wc, but for conventional transmitters, this will cause a loss of accuracy when the reading is in its normal range at or below 100-in. wc (Figure 1-2 on page 3). Running in the lowest 10 percent of the range is not where most transmitters perform best.
The solution: high performance multivariable transmitters

While solving this problem may be a challenge, it is not an impossible one. The answer lies within the use of a high performance multivariable transmitter. Using such a transmitter not only makes readings more accurate across a wider operating range, it extends measurement capabilities through its ability to gather additional information.

So how does it work?

Multivariable transmitters can gather sophisticated flow measurement points, such as those that are needed at a gas wellhead, by either measuring them directly or calculating them. The data collected by the line pressure, differential pressure and temperature sensors can be combined with the properties of the process fluid to measure a long list of variables:

- Line pressure (direct)
- Differential pressure (direct)
- Volumetric flow (calculated)
- Fluid temperature (direct)
- Product density (calculated if not known)
- Mass flow (calculated using known density)

As stated earlier, a conventional multivariable transmitter may be able to measure the flow on a gas wellhead with a plunger lift system at either normal flow or at peak flow, but it is unable to measure both accurately. Therefore, it is important to use a high performance multivariable transmitter that has the capability of doing so.
To solve this challenge, the Extended Range technology available on the Rosemount™ 4088 MultiVariable™ Transmitter was developed (Figure 1-3 on page 4).

Figure 1-3. Rosemount MultiVariable Transmitter

Extended Range technology is unique because it has the accuracy of a standard 250 inch wc unit, but also has the ability to measure over range up to 800 inch wc. This ensures the entire gas flow cycle is accurately captured. Thus, profits previously lost due to unmeasured or inaccurately measured gas flow can then be recovered.

Using a high performance multivariable transmitter, such as the Rosemount 4088, can also simplify mounting practices encountered at wellhead sites. Its unique design can be incorporated into a variety of configurations utilizing a variety of manifolds, including ones specifically developed for natural gas applications. In addition, using such a manifold as a connection between the process and transmitter makes plugging less likely.

Lastly, studies show that closely coupling the multivariable transmitter to the flow meter’s orifice taps helps minimize gauge-line error. Stabilizing connectors (see Figure 1-4 on page 4) are also often used to achieve a direct-mount installation.

Figure 1-4. Coupling MultiVariable Transmitter to Flow Meter
Conclusion

Pressure and flow instrumentation optimized for wellhead operations can help users solve some of their toughest gas flow measurement problems. Flow meter measurement ranges can and should be wide enough to capture the entire plunger lift cycle, while still maintaining accuracy at nominal flow rates. Using the right multivariable transmitter helps producers capture full production flow data with a high degree of accuracy, avoiding inaccurate measurement that leads to profit lost.
For more information on the Rosemount 4088 MultiVariable transmitter, see Emerson.com/Rosemount-4088/.