New Measurement Practices for Cold Climates

Most measurement ‘best practices’ taught in instrumentation colleges and published in standards are intended to be broadly applicable – every industry, every geography, indoor or outdoor applications. In the real world, if a measurement must be located outdoors in a climate where ambient temperatures can fall to -50ºC, the best practice may be very different if the user hopes to achieve reasonable performance, reliability and life cycle cost. In this article, the user will be presented with new best practices for **steam flow** and **liquid level** that have been developed from thousands of installations in northern Canada.

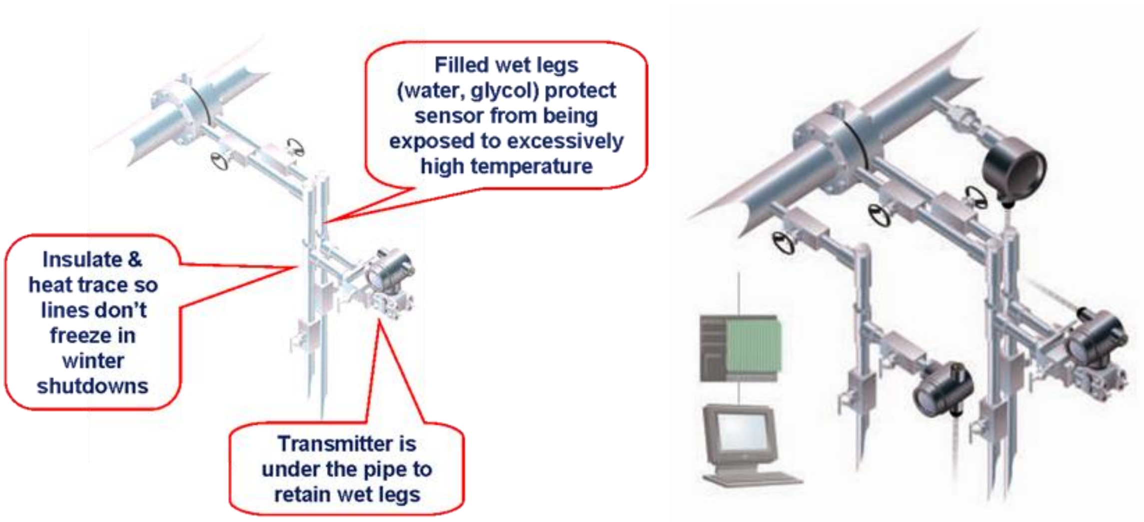
Steam Flow Measurement

Rising energy costs and new environmental regulations are motivating operators to better measure and manage their utility flows, steam in particular. Steam is commonly used for process fluid heat exchange, space heating, and for steam injection in the hydrocarbon industries. Accurate flow measurements are needed to maintain process efficiency, detect leaks and account for consumption. Cost-effectively ensuring high accuracy, repeatability and reliability is a challenge in outdoor applications in cold climates. Although vortex is a newer technology which has enjoyed great success, the most widely used technology for steam flow remains the “dp-flowmeter”, which uses a differential producer – for example, an orifice plate – and a pressure transmitter. This paper introduces ‘new best practices’ for the dp-flowmeter. These new practices have demonstrated improvements in reliability and turndown, at significantly lower initial capital and life cycle cost.

Traditional Practices

The traditional steam dp-flowmeter is illustrated in Figure 1. The transmitter is installed under the pipe, and columns of condensate form in each of the impulse lines leading to the transmitter. These “wet legs” of condensate are hot where they contact the steam, cooling by the time they reach the transmitter. This prevents the oil in the transmitter from over-heating to past its vapor pressure, which would cause the oil to flash and rupture the thin metal diaphragm in the pressure transmitter. Users manually fill the wet legs with condensate prior to startup, and refill the wet legs after any shutdown.

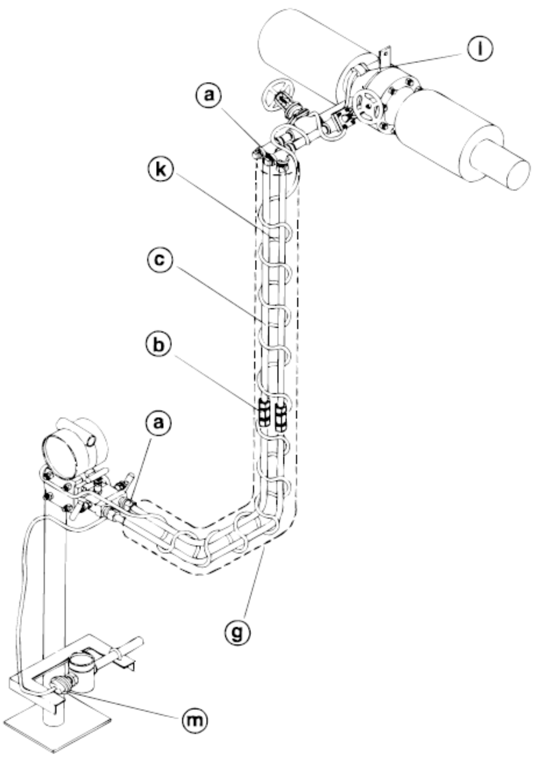
Figure 1 – Traditional Steam Flowmeter Installation



The Figure on the left shows only a single dp transmitter and primary element. Since steam is compressible most real installations utilize density compensation as shown on the right, via a second line pressure measurement, temperature measurement and a flow computer. These can be additional devices, or combined together into a single Multivariable™ transmitter[1].

In outdoor installations in cold climates, the fluid in the impulse lines farthest from the process - nearest the transmitter – can freeze, particularly during planned or unplanned process shutdowns. To prevent this, steam or electrical heat tracing is used to heat the impulse lines above freezing. These systems typically consist of electrical heating cable, a thermostat or controller, and a power distribution panel. Heat tracing is costly to install, as shown in Figure 2, and costly to operate in cold climates. Heat tracing systems require frequent maintenance and inspections, and failure of the heat tracing system – either on or off – can result in freezing or over-heating of the sensing lines, causing errors and possibly transmitter failure, as the expanding ice ruptures the diaphragm.

Figure 2 – Cost of Heat Tracing
(courtesy O'Brien Corp)



MATERIAL COST

1/2" MNPT x 1/2" tube SS compression fittings 4 @ 11.80 ea. **(a)**	$47.20
1/2" SS tube unions 2 @ 17.15 ea. **(b)**	34.30
1/2" O.D. SS x .049 seamless impulse line tubing 60ft @ 4.95/ft **(c)**	297.00
40 feet of high temperature heater cable @ 8.30/ft **(k)**	332.00
E100 end seal 1 @ 18.00 ea. **(l)**	18.00
C75-100-A power connection kit 1 @ 45.00 ea. **(m)**	45.00
Foamglass with jacket for 2" pipe- 1" insulation 28 feet @ 3.01/ft **(g)**	84.28
Foamglass elbows with jacket for 2" pipe- 1" insulation 2 @ 7.41 ea. **(g)**	14.82
TOTAL MATERIAL COST	**$872.60**

LABOR COST
(Labor cost $38.00/hr)

Install impulse lines with fittings 60 feet @ 0.40 mh/ft	24.00 hr
Install electric tracer 40 feet @ 0.18 mh/ft	7.20 hr
Insulate 30 feet of impulse lines with tracer 28 feet @ 0.28 mh/ft = 7.84 hr 2 elbows @ 0.42 mh/ea = 0.84 hr	8.68 hr
Total labor hours	39.88 hr
TOTAL LABOR COST	**$1515.44**

The requirement for a wet leg also limits flow performance and turndown. Variation in the steam flowrate causes variable flashing at the interface between the steam and the wet leg, similar to the "shrink/swell" observed in a boiler drum. In a typical installation, this variable flashing causes noise of 0.1-0.2 inH2O (0.5 mbar), resulting in flow variations of up to 1% of full scale[2]. Even though newer, smart transmitters – especially those that have been "flow characterized" by the manufacturer – are capable of 15:1 or better flow turndown, wet leg instability limits real-world turndown in most steam applications to 4:1 or worse. To minimize the impact of this wet leg instability users will often size their primary elements to produce a higher average pressure drop. This requires a lower beta ratio, causing higher permanent pressure loss.

New Best Practice – Background and Enabling Technology

For nearly two decades, smart pressure transmitters from most manufacturers have been supplied with integral temperature sensors. As distinct from the sensor used to measure fluid temperature – for density compensation – these sensors measure the temperature of the pressure sensor. As the sensor heats and cools due to changing process and ambient temperatures, its oil and mechanical components expand and contract. The transmitter microprocessor uses the sensor temperature input to compensate for these effects, and minimize their impact on measurement accuracy.

Users with HART® or FOUNDATION® fieldbus transmitters connected to an asset management system can conveniently log and trend secondary variables such as sensor temperature.[4] Suppliers can also review logs from transmitters returned to the factory for post-mortem failure analysis. Analysis of operating and failure analysis data from hundreds of steam flow installations has revealed that:

- sensor temperature is difficult to predict in a "traditional" installation, in which the user installs whatever length and diameter of sensing lines best fit the installation.

- sensor temperature is predictable, and consistently lower than expected, when using a pre-engineered "integrated" dp-flowmeter (see Figure 3). These devices include the primary element, the transmitter(s), and any isolation valving. They arrive pre-assembled from the supplier, which minimizes cost and risk of field assembly. In these consistent installations, sensor temperature can be reliably predicted from process and ambient temperatures.

These results have encouraged suppliers to conduct more rigorous heat dissipation testing.

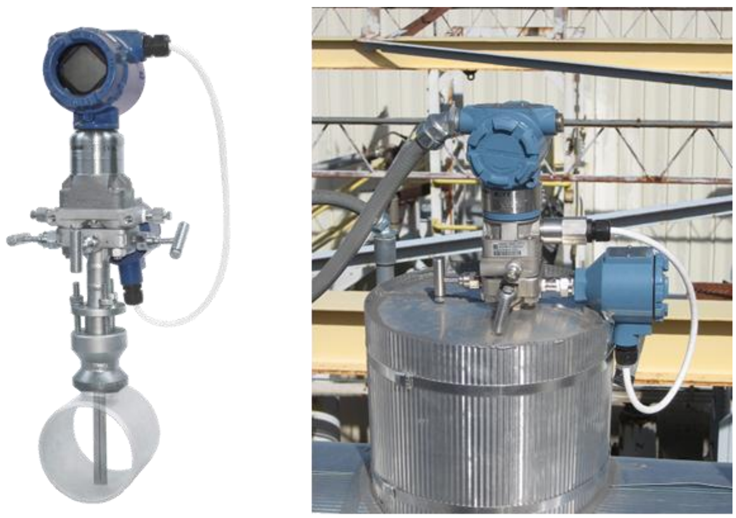
Figure 3 – Integrated dp-Flowmeters and Temperature Test Apparatus

Figure 3 shows dp-flowmeters, with the MultiVariable™ transmitter connected to either wafer-style ("Compact") orifice plate, or averaging pitot tube ("Annubar®") with integral manifold and temperature measurement. The flowmeter is also shown installed in a test pipe for temperature logging. Note that the external RTD measures process temperature, while the sensor inside the transmitter measures oil temperature. These tests revealed that enough heat is dissipated by the short neck of the integrated manifold and the manifold block itself that the transmitter can be directly installed without risk in a process temperature of up to 230ºC (450ºF) without neck insulation. Using normal insulation for personnel protection, the limit was found to be 205ºC.

New Best Practice – Transmitter on Top

Installing the transmitter above the pipe eliminates wet legs. This results in a simpler, lower cost installation. No wet legs means no instability, significantly improving potential turndown. No risk of wet leg freezing during shutdown means no need for heat tracing, and its associated capital and operating costs. Figure 4 shows field installations of an Annubar®-type steam flowmeter. This type of installation is suitable for applications up to 205ºC, with higher temperatures possible with other connection systems.

Figure 4 – Annubar® installation, Transmitter on Top



Annubars are typically used to minimize installed cost in larger lines, and when the user aims to reduce permanent pressure losses[5]. In smaller lines, the orifice plate is more common. Figure 5 shows a compact wafer-style primary element, with the orifice plate integrated with the manifold. This type of installation is also suitable for temperatures up to 205ºC, with higher temperatures possible with other connection systems.

Figure 5 Compact Orifice, Transmitter on Top

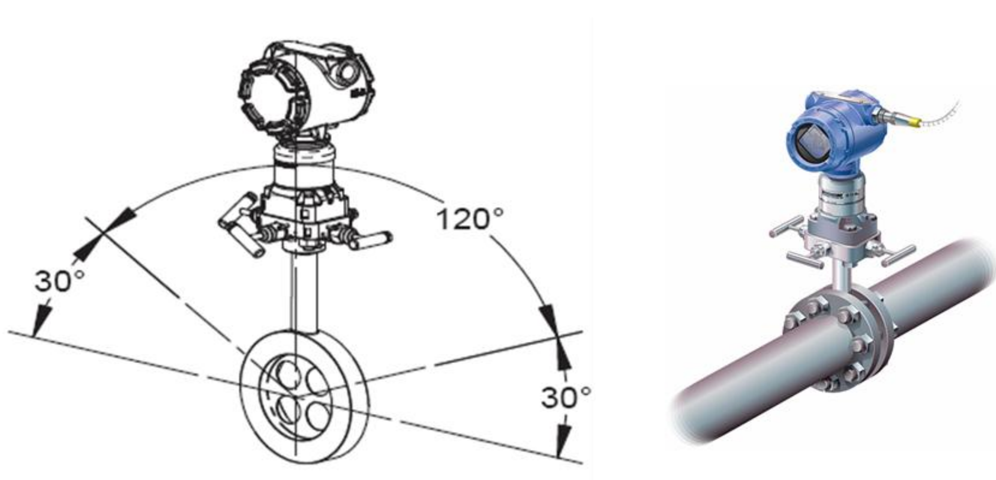
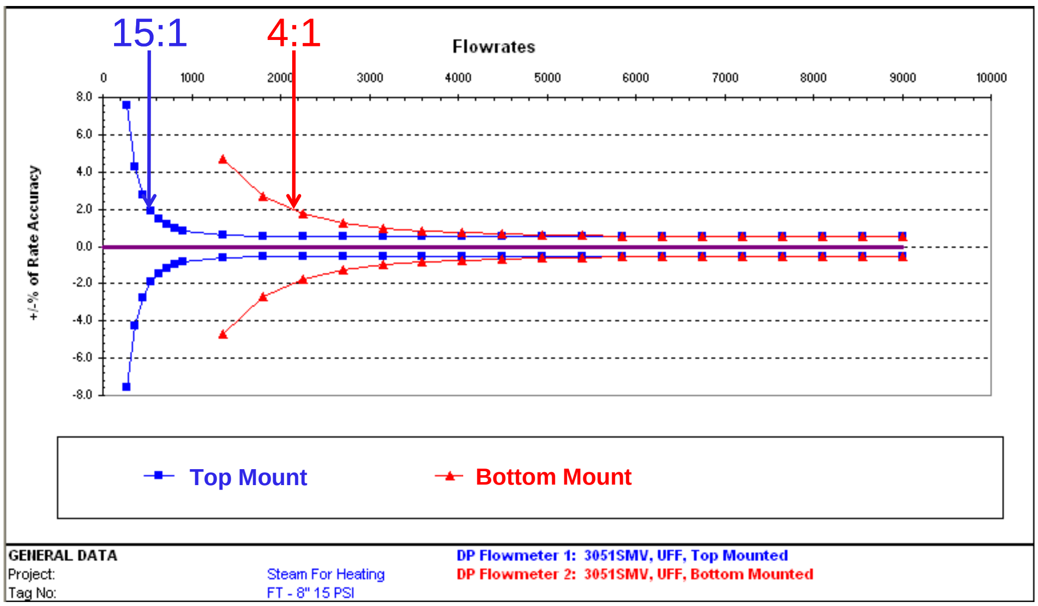


Figure 6 demonstrates the improvement in turndown possible by changing the orientation of the flowmeter from the traditional "transmitter underneath" to the recommended new best practice. With identical transmitter, turndown is dramatically improved. High turndown is especially useful in the heating application shown, which exhibits wide seasonal swings in steam demand.

Figure 6 – Turndown of Transmitter on Bottom (Traditional) vs Transmitter on Top (New Best Practice), Heating Application



Summary and Recommendations

Within the limits described, per supplier recommendations[6], users can install steam flowmeters with the transmitters above the pipe, without wet legs. This new best practice is much less expensive to install and operate – particularly in a cold climate. It also provides higher reliability with less maintenance, and higher accuracy and turndown.

REFERENCES

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4. Miller, R.W., Flow Measurement Engineering Handbook, McGraw-Hill, Toronto, 1996.
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BIO

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