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STATE OF TECHNOLOGY REPORT

Flow & Level Instrumentation

The Latest Technology Trends, Back-to-Basics Tutorials, and Application Stories—All Together in One Convenient eBook

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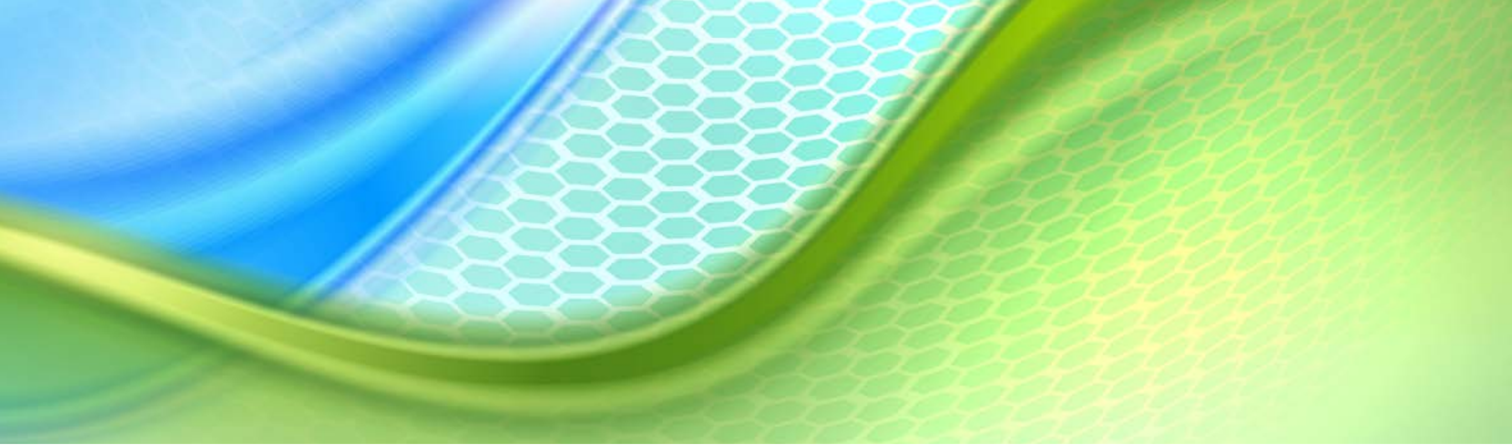


Flow and Level Measurement Still a Subtle Engineering Task

All other things equal, familiarity and trouble-free operation often trump technical specifications when specifying flowmeters and level gauges.

Despite ongoing advances in instrumentation technology, specifying a flowmeter or level gauge that will reliably perform over the anticipated range of process conditions often remains a complex and subtle engineering task.

Dozens of niche instrumentation technologies have been developed over the past several decades to exploit nearly every conceivable physical phenomenon that might be correlated with level or flow.

Our reader surveys indicate that where possible and practical, users continue to move away from mechanical and electromechanical instruments towar electronic transmitters with few or no moving parts to stick or wear. Hence the growing popularity of Coriolis, electromagnetic, vortex and ultrasonic flowmeters in recent years. Dramatic advances in ultrasonic technology in particular have spiked their broader use even in gas custody transfer applications. Thermal dispersion mass flowmeters, too, remain an imporant option for a specialized range of gas measurement applications.

On the level measurement side, this non-mechanical trend is indicated by the increased use of radar, ultrasonic and even sonic profiling gauges that offer a three-dimensional view of solids level in tanks and bins. Fiber optic probes developed for undersea oil and gas applications are measuring flowrate and composition with temperature and pressure to boot. Guided-wave radar, too, is an increasingly popular technology that falls into that category of minimal moving parts: only the float is free to move along a waveguide probe.

But the number one flow and level measurement technology actually measures neither. Indeed, the differential pressure transmitter remains the most commonly applied flow and level measurement device—in no small part because engineers are so familiar with it.

Sure, a differential pressure cell paired with an orifice plate or other primary element can make for a relatively complicated installation (although pre-integrated assemblies are making this less troublesome) as well as incur an energy-consuming pressure drop penalty, but for many users the dependability and familiarity of a differential pressure cell still wins out over other considerations.

Accuracy and other desirable performance specifications are of overriding importance in some applications, but play second fiddle to technology familiarity and trouble-free operation in others. And while more of today's users pay at least lip service to lifecycle costs, initial purchase price remains a key consideration.

The continued preference for differential pressure flowmeters and level gauges, and well as the ongoing viability of numerous niche technologies, demonstrate the complex interplay of criteria that go into a instrumentation purchase decision.

For example, despite the overall trend toward non-mechanical instruments for process measurements, there exists a countervailing trend *in favor* of mechnical devices for safety applications such as pump protection or tank overfill prevention. Here, differentiated technology plays a role in establishing the independence of safety protection layers. A mechanical switch or magnetic level indicator provides assurance against common cause failures when used in conjunction with an electronic gauge.

The balance of this State of Technology Report is a compendium of the latest trends articles, back-to-basics tutorials, and application stories recently published in the pages of *Control*. And while it doesn't cover every corner of the application space, we hope you find it useful. ■

—The Editors

Prevent Tank Farm Overfill Hazards

Catastrophic incidents have led to useful rules for systems that help avoid them.

by William L. Mostia, PE

Driving around petrochemical plants, oil fields or fuel distribution terminals or facilities, it's common to see large tank farms with vessels of various forms and shapes—cylinders, spheres, bullets and spheroids. These tanks can store feedstocks, intermediates and final products. For refineries, many of these tanks are used for what are called oil movements, which blend various products together to provide the many grades of gasoline, diesel and other refinery products required by the market and government regulations.

Process unit tank farms are typically a bit separate from the process units, located in bunds or diked areas, and spread over a large acreage. Fuel distribution terminals, which commonly straddle pipelines, are physically similar and may butt up against residential and light industrial areas, as can some plant tank farms. Many of these tank farms started out as remote sites, but plant expansions have sometimes met external industrial and residential sprawl to increase the potential consequences of a disastrous event.

It's safe to say that thousands of filing, emptying and transferring operations go on each month in these tank farms—maybe even every day. The overwhelming majority are done safely, but some result in overfills, which have led in a few cases to major incidents. Data compiled by a reputable operator in the United States estimated that an overfill occurred once in every 3,300 filling operations ("Atmospheric Storage Tanks," Risk Engineering Position Paper 01, Marsh Ltd.).

Looking over the past couple of decades, we have had some notable tank overfill incidents: Laem Chabang, Thailand, in 1999 (seven dead); Buncefield, UK, in 2005 (43 injured), and the Cataño oil refinery in Bayamón, Puerto Rico, (three injured). All these involved spectacular explosions and fires with extensive damage to the facility.

As it turns out, tank farm overfills that lead to a fire and explosion may not be considered common, but they're certainly not rare. A study of storage tank accidents for the period of 1960-2003 covered 242 tank farm accidents. Fifteen overfill incidents were reported, of which 13 resulted in a fire and explosion ("A Study of Storage Tank Accidents," James Changa and Cheng-Chung Lin, *Journal of Loss Prevention in the Process Industries*, 19 [2006], p.51–59). The numbers of tank farm overfill incidents were probably under reported in this study, but still, tank farm overfill incidents in the study occurred on average every three years. One interesting fact that arose while looking at overfill incidents is that they mostly occurred off day shift, which is very advantageous in regard to people occupancy/exposure, but where supervision is typically more relaxed, and there is less general oversight.

What really brought tank farm overfills to the forefront was an industry-changing incident that occurred on Dec. 11, 2005, at the Buncefield oil storage and transfer depot, Hemel Hempstead, UK. A gasoline tank overflowed, leading to an unconfined vapor cloud explosion that was deemed to be unprecedented—the largest ever explosion in peacetime Europe. It was fortunate that the explosion occurred in the early morning hours on the weekend, for while the damage was extensive, no fatalities occurred. However, 43 people were injured. Had the 6:01 a.m. blast happened during working hours on a weekday, it could have been far, far worse.

On Oct. 23, 2009, another large overfill event led to a fire and explosion at the Cataño oil refinery in Bayamón, Puerto Rico, injuring three and resulting in the Caribbean Petroleum Corp. having to file for bankruptcy. Another tank farm overfill also occurred in Kuwait, resulting in a fire and explosion ("Overfill + Ignition = Tank Farm Fire," Presentation for HSE Moments/Alerts, bit.ly/1rHCPrB).

While not due to an overfill event, but showing the potential consequences, a 2009 tank farm fire and explosion in Jaipur, India, killed 12 people, injured more than 200 and completely destroyed the tank farm.

Poor Instrumentation, Bad Practices

The Buncefield tank that overflowed had both a level gauge and an independent high-level shutdown, neither of which worked. Kuwait also had a level gauge and independent high-level alarm—neither functioned. In Puerto Rico, the liquid level in the tank could not be determined because the facility's computerized level monitoring system was not fully operational. It seems there is a potential pattern: poor instrument maintenance, poor testing practices, lack of operational discipline—take your pick. Since tank farms do not "make money," many times they can suffer when maintenance budgets are constrained.

Another interesting thing to come out of the Buncefield U.K. Control of Major Accident Hazards (COMAH) report, "Buncefield: Why Did It Happen?" (COMAH, 02/11), was the practice of Buncefield operators "working to alarms." Both API 2350-January 1996 and 2005 state that, "High-level detectors and/or automatic shutdown/diversion systems on tanks containing Class I and Class II liquids (2005 only) shall not be used for control of routine tank fining operations." The 2012 version specifically prohibits this practice, but poor operational discipline always seems to trump standards and procedures.

The practice is not new in the process industries, but may deserve more looking into, as it may be more common than one might think, particularly where there are automatic shutdowns protecting transfers into a tank or other process operations. Trust in the protection systems is a form of faith-based risk-taking founded on prior experience, and generally represents normalization of non-conformance to procedures resulting from poor or slack operating discipline. How do your operators really operate your tank farm transfers?

The U.K. issued a number of comprehensive reports and recommendations regarding Buncefield that are worthwhile reading (www.buncefieldinvestigation.gov.uk/reports/index.htm under Reports). From a standards perspective, after Buncefield, the U.K. Health and Safety Executive (HSE) required the competent authority and operators of Buncefield-type sites to develop and agree on a common methodology to determine safety integrity level (SIL) requirements for overfill prevention systems in line with the risk assessment principles in BS EN 61511, Part 3. They should then apply the BS EN 61511, Part 1 for SIL-related systems that come out of the risk assessment. In 2009, the HSE issued the reports, "A Review of Layers of Protection Analysis (LOPA) Analyses of Overfill of Fuel Storage Tanks" and "Safety and Environmental Standards for Fuel Storage Sites."

UK Government

PRECIPITATING EVENT

Figure 1: In December 2005 a gasoline tank at the Buncefield oil storage and transfer depot, Hemel Hempstead, U.K., overflowed. The resulting unconfined vapor cloud explosion was the largest ever in peacetime Europe.

Meanwhile, on the west side of the Atlantic, API RP 2350 3rd Edition, "Overfill Protection for Storage Tanks in Petroleum Facilities," which covers atmospheric tanks storing Class I (flammable) and Class II (combustible) petroleum liquids, was issued in January 2005, the same year as

Buncefield. The third edition of API 2350 was prescriptive in nature and a compilation of best practices that had over the years expanded its reach to these categories.

From an instrumentation perspective, API 2350 had minimal requirements for safety instrumentation and no requirement for evaluation of the safety risk, even though ANSI/ISA S84 (1996, 2003) and IEC 61511 (2004) were in place at that time. This standard divided facilities into attended and unattended operations. For attended facilities, there were no requirements for level detectors on the tanks, while unattended facilities required continuous monitoring, alarms and an automatic shutdown if the operator response time was not adequate, or the operation was fully automatic. This highlights a cautionary note that one should always remember: All standards provide minimum requirements, not maximum. Following good engineering practice and in most cases common sense (an old friend who some say has passed on, bit.ly/1oRKeQZ) should not be hijacked by "minimum" safety requirements in a standard, particularly for cost reasons.

Because of the Buncefield explosion, the API 2350, 4th Ed., (2012) committee took the lessons learned to heart and introduced a number of new risk- and performance-based requirements, which brought it closer conformance to the SIS standards. (See sidebar, "Buncefield's Legacy: API 2350's New Requirements.")

BUNCEFIELD'S LEGACY: NEW API 2350 REQUIREMENTS

Because of Buncefield, the API 2350 4th Edition (2012) committee took the lessons learned to heart and introduced a number of new risk- and performance-based requirements, which brought it closer conformance to the SIS standards. Some of API 2350's new requirements are:

1. A overfill management system is required;
2. A risk assessment shall be used by the owner and operator to categorize risks associated with potential tank overfills;
3. The definition of a set of operating parameters, including critical high level (CH), high-high level (HH), maximum working level (MW) and automated overfill prevention system (AOPS) activation level;
4. More emphasis on operator response time for level alarms;
5. Operators are required to categorize each tank under consideration for overfill prevention based on tank level instrumentation and operator surveillance procedures;
6. Emphasis on proof-testing of independent alarms and AOPS;

When an AOPS is required, the standard provides two options for implementation, depending on whether the installation is existing or new. For existing installations, Appendix A of the standard provides an acceptable, essentially prescriptive approach that contains aspects of ANSI/ISA 84.00.01-2004 (IEC 61511 modified). For new installations, ANSI/ISA 84.00.01-2004 (IEC 61511 modified) must be followed.

Technology Can Help

Placing instrumentation on widely geographically distributed tanks, particularly on existing tanks, can be a challenge both technically and in cost, but technology has advanced significantly in the past 10 years. We can easily digitally transmit multiple sensor inputs across a pair of wires, reducing wiring costs, using any one of the more than 50 fieldbuses available, a number which are third party-approved safety protocols (for example, Profisafe, Foundation fieldbus, ASIsafe).

Tank farm remoteness and geographical distribution often make them suitable for wireless monitoring applications, which can be easily added to existing tanks. These can also be solar-powered. There are wireless applications for tank monitoring systems available using IEEE 802.15.4 (ISA 100.11a and WirelessHART), wireless cellular networks and global satellite networks. Another developing technology is mobile wireless applications, which allow tank farm field operators, in addition to the control room operator, to monitor tank levels.

Available automated safety shutdown systems geared to the tank farm environment range from local, high-reliability shutdown systems connected by Modbus to centralized systems to using safety PLCs. Tank level and inventory management system technologies also have advanced.

Improvements have been made in guided-wave radar (GWR), through-the-air radar and traditional level measurement technologies. One of the main issues remains, which is how to proof-test these to meet API 2350 and ANSI/ISA 84.00.01 (IEC 61511 modified).

On June 10, the FAA authorized BP to use a commercial drone, supplied by Aerovironment Inc. (www.avinc.com), at its Prudhoe Bay, Alaska, site to fly aerial surveys over Alaska's North Slope. The same type of drone has been used in test flights by ConocoPhillips. It seems like a reasonable prediction that in the not-too-distant future, drones could be used to fly continuous circuits above a refinery or chemical plant, use visual and IR sensors, pattern recognition and analytical technology to detect abnormal conditions in the facility, and report them to the control room and field operators. This technology could easily be applied to tank farms.

Heed API 2350

API 2350 has been updated to be better in line with the industry standard ANSI/ISA 84.00.01-2004 (IEC 61511 modified), which is virtually identical to IEC 61511. To make our tank farms safe, we should apply the same safety rigor of assessment that we apply to our process units to our tank farms to ensure that a significant safety, environmental and/or financial incident does not occur in the future.

This API 2350 standard is listed as a "recommended practice," but do not be fooled. In the United States and in other countries that recognize API standards as recommended and generally accepted good engineering practice (RAGAGEP), if you have an incident in your refinery or fuel distribution tank farm, you will be held to this standard or the burden of proof otherwise. Chemical plants should meet NFPA 30, but may also be held to API 2350 overfill requirements as RAGAGEP.

One area that API 2350 does not address in tank farms is the use of combustible gas detectors and fire detectors. Open-path gas detectors could be particularly effective, as they can have a path length up to 200 meters, and point-source gas detectors can be effective inside bunds, since many of the gases involved are heavier than air.

BP

SPILL SPOTTER

Figure 2. On June 10, the FAA authorized BP to use a commercial drone, supplied by Aerovironment Inc. (www.avinc.com), at its Prudhoe Bay, Alaska, site to fly aerial surveys over Alaska's North Slope.

Fire detectors are not as effective for overfill situations, but can help prevent pool fires from spreading to other tanks by detecting rim fires and jet fires. While this seems to be a case of reaction rather than prevention, the sooner you can act to bring an developing incident to heel, even if you can't prevent it, the less the consequences will be.

It would seem important to minimize the potential of an electrical ignition source by properly, electrically classifying tank farm areas and ensuring that electrical equipment and instrumentation meet (and maintain) the classification.

This discussion only covered atmospheric tanks in tank farms, which obviously can create a hazard. One of the biggest hazards in a refinery tank farm typically comes from butane or other compressed gas spheres, which by some estimation can range up there with a hydrofluoric acid leak hazard in a refinery. But that is a discussion for another day. ■

William L. Mostia, PE, Fellow, SIS-TECH Solutions, is a frequent contributor to Control.

Advances in Flow Instrumentation

by Béla Lipták

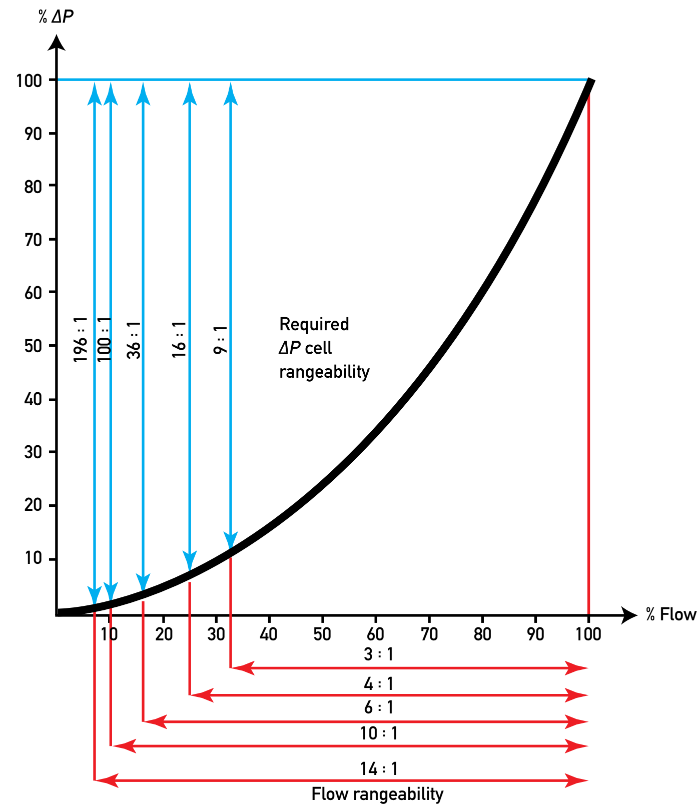
In my May column, I described some new fiber-optic flowmeters used for subsea measurement of multiphase flows (oil, water, methane). Now I will describe some other, more recent advances in the field of flow instrumentation that have occurred partly because of the need for transporting and accurately metering large quantities of oil and natural gas.

Head-Type Flowmeters

When measuring flow by any differential pressure generating element, the measurement error is the sum of the sensor error, which is usually about one percent of actual flow (%AR), and the error of the d/p cell, which used to be around 0.25% to 0.5% of full scale (%FS). Therefore, in the past, if we wanted to keep the total error at minimum flow under 3%AR, the flow turndown (rangeability) had to be limited to about 4:1. Figure 1 shows the relationship between the turndowns in terms of flow and the corresponding turndown requirement of the ΔP transmitter.

Today, the maximum turndown capability of a smart, digital ΔP transmitter is nearly 200:1. Because of the square root relationship, this means that the flow rangeability is 14:1 (142 = 196). With a ΔP measurement error of 0.065%FS, the d/p cell error is 12.74% AR at the minimum ΔP (196x 0.065 = 12.74%). Because of the square root relationship, this minimum ΔP error corresponds to a minimum flow error of √ 12.74% = 3.6%AR. Adding to this ΔP error, the 1%AR error of the sensor (the precision of its discharge coefficient CD), gives us a total error of only 4.6%AR at minimum flow. Naturally, the full 14:1 turndown can only be realized if at minimum flow (100/14 = 7% of full scale), the flow is still turbulent (RE > 8,000).

In addition to the tremendous increase in the accuracy of the state-of-the-art d/p cells, these smart units are provided with local displays, self diagnostics, alarms, memory boards for data acquisition and storage for hundreds of thousands of data points for displaying of trends, total flows, and to provide cell phone connectivity. They can be mounted to the sensor or connected wirelessly (IEEE802.11), allowing the sensor to be located in hard-to-access areas, while the d/p cell is in an easy-to-access location.



DIGITAL ACCURACY GIVES HIGHER TURNDOWN

Figure 1: At a ΔP turndown of 196:1, the flow turndown is 14:1, and at the minimum flow (100/14 = 7%), the total error is kept under 5%of actual flow (AR).

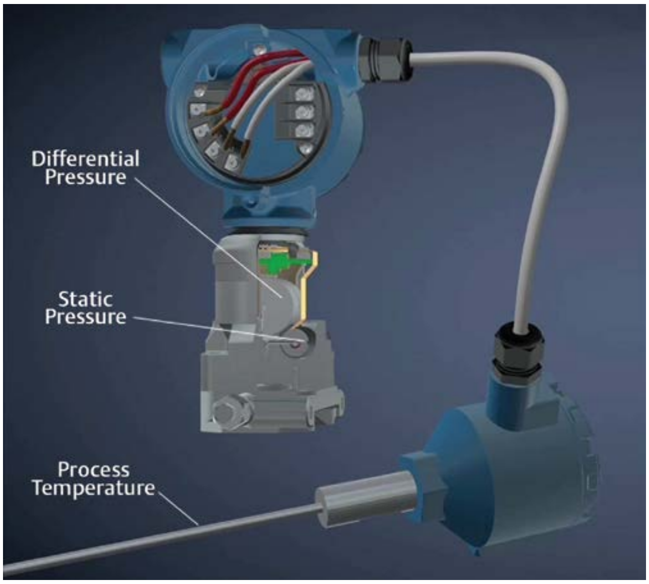
Emerson Rosemount

PLAYING IN THE HYDROCARBON SPACE

Figure 2: Wireless orifice flowmeters are appropriate for some hard-to-reach applications in oil-and-gas markets.

While the Venturi flowmeter is still the favorite when it comes to pressure recovery and accuracy, some of the other head-type flowmeter features also are competing on the hydrocarbon and other markets. For example:

- Conditioning orifice meters with wireless transmission (Figure 2);
- Regular and Venturi wedge meters for fluids containing sand or slurries;
- Averaging Pitot tube inside a flow nozzle combined with pressure/temperature sensors to calculate mass flow of natural gas;
- V-shaped cones. These cones require individual calibration, but their conditioning effect reduces the straight-run requirement; and
- Flow transmitters with pressure and temperature sensors can calculate mass flow of known molecular weight gases (Figure 3).



Emerson Rosemount

THE TEMPERATURE OF FLOW

Figure 3: Flow transmitter with pressure and temperature sensors calculates mass flow of known molecular weight gases.

Emerson/Daniel

TWO-WAY ULTRASONICS

Figure 4: Bi-directional, multi-path, ultrasonic mass flowmeter for gas service.

One should note that, in case of large flows, the unrecovered (permanent) pressure loss caused by the meter is an important consideration. This permanent loss is the worst in case of sharp restrictions (orifice ~ 70%) and the best with smooth transitions (Venturi ~ 15%), while something like the V-shaped cone causes an intermediate amount of permanent loss (~ 40%).

Other Flowmeter Types

In addition to head-type flowmeters, intense activity in the hydrocarbon industry has catalyzed advances in other flowmeter families. In custody transfer applications, for example, the accurate and reliable Coriolis flowmeter is still the favorite, but other technologies are also competing for that market, for example, this bi-directional, multi-path, ultrasonic mass flowmeter for gas service (Figure 4). Similarly, at the drilling end of the hydrocarbon production process, a number of multiphase (oil, water, methane) flowmeters have been introduced, for example, the water cut meter, which uses five NIR wavelengths to distinguish water, oil and gas and the undersea multiphase flowmeter, which calculates the total flow and its oil, water and gas content by simultaneous measurements of variables. These units are designed for operation at some miles of depth under the ocean. ■

Béla Lipták, PE, control consultant, is also editor of the Instrument Engineers' Handbook and is seeking new co-authors for the coming new edition of that multi-volume work. He can be reached at liptakbela@aol.com.

Adaptive Level Control

Exploring the Complexities of Tuning Level Controllers and How an Adaptive Controller Can Be Used in Level Applications

By Greg McMillan, Sridhar Dasani and Dr. Prakash Jagadeesan

The tuning of level controllers can be challenging because of the extreme variation in the process dynamics and tuning settings. Control systems studies have shown that the most frequent root cause of unacceptable variability in the process is a poorly tuned level controller. The most common tuning mistake is a reset time (integral time) and gain setting that are more than an order of magnitude too small.

In this article we first provide a fundamental understanding of how the speed and type of level responses varies with volume geometry, fluid density, level measurement span and flow measurement span for the general case of a vessel and the more specific case of a conical tank. Next we clarify how tuning settings change with level dynamics and loop objectives. Finally, we investigate the use of an adaptive controller for the conical tank in a university lab and discuss the opportunities for all types of level applications.

General Dynamics for Vessel Level

There have been a lot of good articles on level control dynamics and tuning requirements. However, there often are details missing on the effect of equipment design, process conditions, transmitter calibration and valve sizing that are important in the analysis and understanding. Here we offer a more complete view with derivations in Appendix A, available on the ControlGlobal website (www.controlglobal.com/1002_LevelAppA.html).

Frequently, the flows are pumped out of a vessel. If we consider the changes in the static head at the pump suction to have a negligible effect on pump flow, the discharge flows are independent of level. A higher level does not force out more flow, and a lower level does not force out less flow. There is no process self-regulation, and the process has an integrating response. There is no steady state. Any unbalance in flows in and out causes the level to ramp. When the totals of the flows in and out are equal, the ramp stops. For a setpoint change, the manipulated flow must drive past the balance point for the level to reach the new setpoint. If we are manipulating the feed flow to the volume, the feed flow must be driven lower than the exit flow for a decrease in setpoint. The ramp rate can vary by six orders of magnitude from extremely slow rates (0.000001%/sec) to exceptionally fast rates (1%/sec). The ramp rate of level in percent per second for a 1% change in flow is the integrating process gain (%/sec/% = 1/sec). The integrating process gain (K_i) for this general case of level control, as derived in Appendix A, is:

$$K_i = F_{\max} / [(\rho * A) L_{\max}] \qquad \text{Eq. 1}$$

Since the PID algorithm in nearly all industrial control systems works on input and output signals in percent, the tuning settings depend upon maximums. The flow maximum (F_{max}) and level maximum (L_{max}) in Equation 1 must be in consistent engineering units (e.g. meters for level and kg/sec for flow). The maximums are the measurement spans for level and flow ranges that start at zero. Most of the published information on process gains does not take into account the effect of measurement scales and valve capacities. The equation for the integrating process gain assumes that there is a linear relationship between the controller output and feed flow that can be achieved by a cascade of level to flow control or a linear installed flow characteristic. If the controller output goes directly to position a nonlinear valve, the equation should be multiplied by the slope at the operating point on the installed characteristic plotted as percent maximum capacity (F_{max}) versus percent stroke.

Normally, the denominator of the integrating process gain that is the product of the density (ρ), cross-sectional area (A) and level span (mass holdup in the control range) is so large compared to the flow rate that the rate of change of level is extremely slow. For horizontal tanks or drums and spheres, the cross-sectional area varies with level. In these vessels, the integrating process gain is lowest at the midpoint (e.g. 50% level) and highest at the operating constraints (e.g. low- and high-level alarm and trip points).

Most people in process automation realize that a controller gain increased beyond the point at which oscillations start can cause less decay (less damping) of the oscillation amplitude. If the controller gain is further increased, the oscillations will grow in amplitude (the loop becomes unstable). Consequently, an oscillatory response is addressed by decreasing the controller gain. What most don't realize is that the opposite correction is more likely needed for integrating processes. Most level loops are tuned with a gain below a lower gain limit. We are familiar with the upper gain limit that causes relatively fast oscillations growing in amplitude. We are not so cognizant of the oscillations with a slow period and slow decay caused by too low of a controller gain. The period and decay gets slower as the controller gain is decreased. In other words, if the user sees these oscillations and thinks they are due to too high a controller gain, he or she may decrease the controller gain, making the oscillations worse (more persistent). In the section on controller tuning, we will see that the product of the controller gain and reset time must be greater than a limit determined by the process gain to prevent these slow oscillations.

In some applications, exceptionally tight level control, through enforcement of a residence time or a material balance for a unit operation, is needed for best product quality. The quantity and quality of product for continuous reactors and crystallizers depend on residence times. For fed-batch operations, there may be an optimum batch level. The variability in column temperature that is an inference of product concentration in a direct material balance control scheme depends on the tightness of the overhead receiver level control. Since these overhead receivers are often horizontal tanks, a small change in level can represent a huge change in inventory and manipulated reflux flow.

Figure 1. Conical Tank in MIT Anna University Lab with an industrial DCS.

In other applications, level control can be challenging due to shrink and swell (e.g. boiler drums and column sumps) or because of the need for the level to float to avoid upsetting the feed to downstream units (e.g. surge tanks). If the level controller gain is decreased to reduce the reaction to inverse response from shrink and swell or to allow the level to float within alarm limits, the reset time must be increased to prevent slow oscillations.

Adaptive level controllers can not only account for the effect of vessel geometry, but also deal with the changes in process gain from changes in fluid density and nonlinear valves. Even if these nonlinearities are not significant, the adaptive level control with proper tuning rules removes the confusion of the allowable gain window, and prevents the situation of level loops being tuned with not enough gain and too much reset action.

Specific Dynamics for Conical Tank Level

Conical tanks with gravity discharge flow are used as an inexpensive way to feed slurries and solids such as lime, bark and coal to unit operations. The conical shape prevents the accumulation of solids on the bottom of the tank. The Madras Institute of Technology (MIT) at Anna University in Chennai, India, has a liquid conical tank controlled by a distributed control system (DCS) per the latest international standards for the process industry as shown in Figure 1. The use of a DCS in a university lab offers the opportunity for students to become proficient in industrial terminology, standards, interfaces and tools. The DCS allows graduate students and professors to explore the use of industry's state-of-the-art advanced control tools. Less recognized is the opportunity to use the DCS for rapid prototyping and deployment of leading edge advances developed from university research.

The conical tank with gravity flow introduces a severe nonlinearity from the extreme changes in area. The dependence of discharge flow on the square root of the static head creates another nonlinearity and negative feedback. The process no longer has a true integrating response. In Appendix A online (www.controlglobal.com/1002_LevelAppA.html), the equations for the process time constant (τ_p) and process gain (K_p) are developed from a material balance applicable to liquids or solids. The equations are approximations because the head term (h) was not isolated. Since the radius (r) of the cross-sectional area at the surface is proportional to the height of the level as depicted in Figure 2, it is expected that the decrease in process time constant is much larger than the decrease in process gain with a decrease in level.

$$\tau_p = \frac{\pi * r^2}{3 * C} * h^{1/2} \qquad \text{Eq. 2}$$

$$K_p = \frac{h^{1/2} * F_{\max}}{C * L_{\max}} \qquad \text{Eq. 3}$$

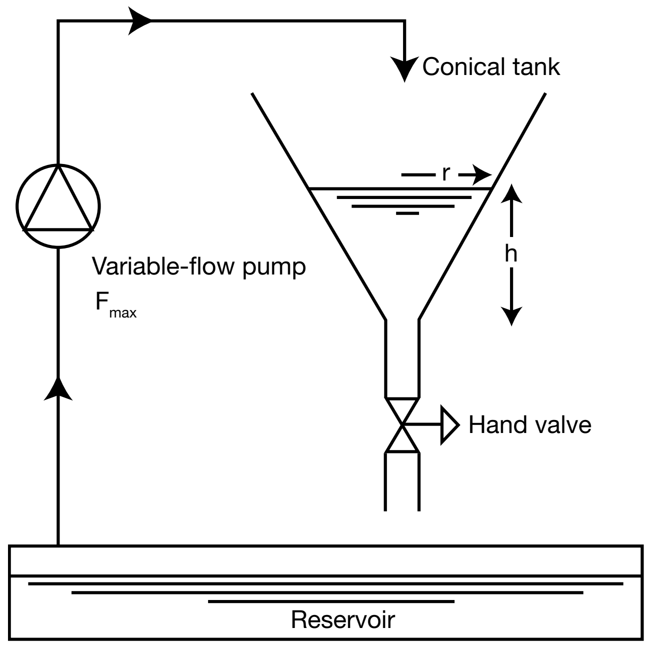


Figure 2. Conical tank detail.

Controller Tuning Rules

The lambda controller tuning rules allow the user to provide a closed-loop time constant or arrest time from a lambda factor (λ_f) for self-regulating and integrating processes, respectively. The upper and lower controller gain limits are a simple fall out of the equations and can be readily enforced as part of the tuning rules in an adaptive controller.

For a **self-regulating process** the controller gain (K_c) and reset time (T_i) are computed as follows from the process gain (K_p), process time constant and process dead time (θ_p):

$$K_c = \frac{T_i}{K_p * (\lambda_f * \tau_p + \theta_p)} \qquad \text{Eq. 4}$$

$$T_i = \tau_p \qquad \text{Eq. 5}$$

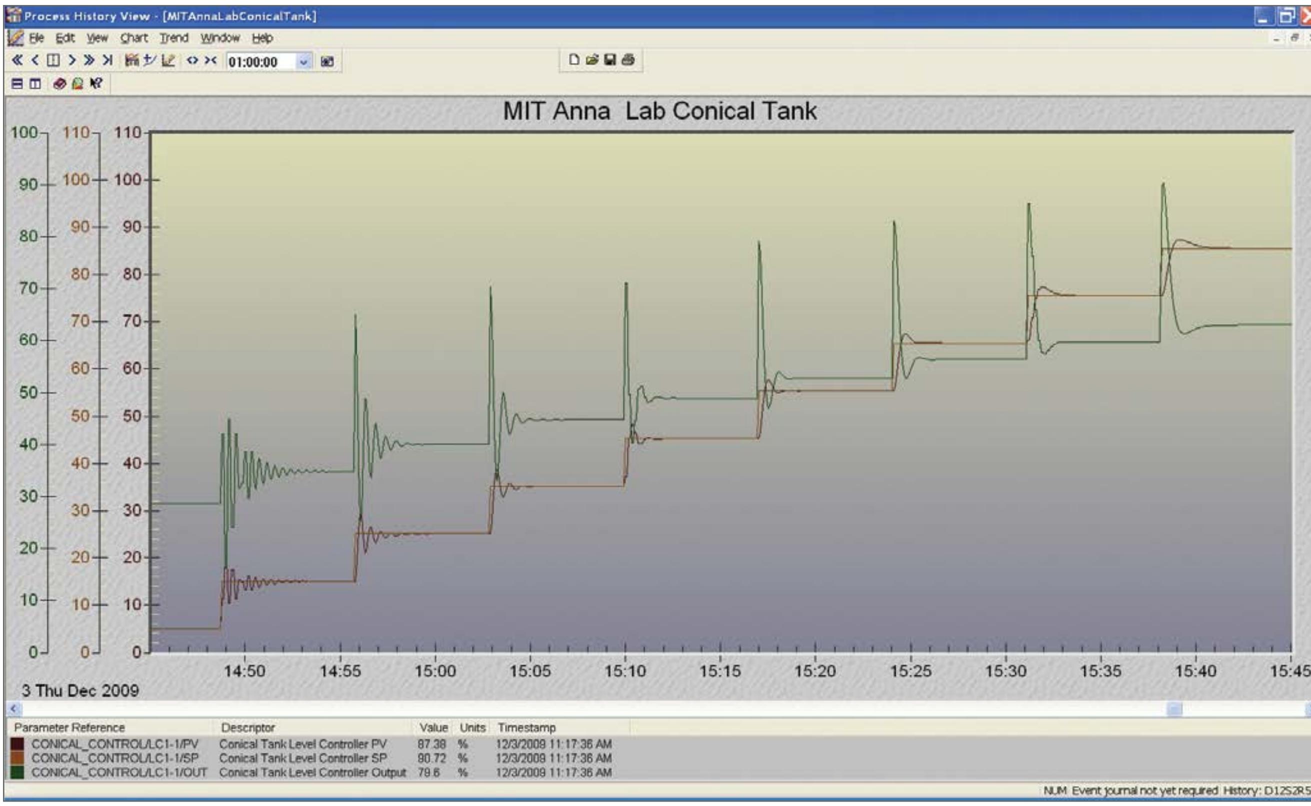


Figure 3. Performance of linear PID level controller for a conical tank.

The upper gain limit to prevent fast oscillations occurs when the closed loop time constant equals to the dead time.

$$K_c < \frac{\tau_p}{K_p * 2 * \theta_p} \qquad \text{Eq. 6}$$

For an **integrating process** the controller gain (K_c) and reset time (T_i) are computed as follows from the integrating process gain (K_i) and process deadtime (θ_p):

$$K_c = \frac{T_i}{K_i * [(\lambda_f / K_i) + \theta_p]^2} \qquad \text{Eq. 7}$$

$$T_i = 2 * (\lambda_f / K_i) + \theta_p \qquad \text{Eq. 8}$$

The upper gain limit to prevent fast oscillations occurs when the closed loop arrest time equals the dead time:

$$K_c < \frac{3}{K_i * 4 * \theta_p} \qquad \text{Eq. 9}$$

The lower gain limit to prevent slow oscillations occurs when the product of the controller gain and reset time is too small.

$$K_c * T_i > \frac{4}{K_i}$$

Eq. 10

Opportunities for Adaptive Control of Conical Tank Level

A linear PID controller with the ISA standard structure was tuned for tight level control at 50% level for a detailed dynamic simulation of the conical tank. Figure 3 shows that for setpoints ranging from 10% to 90%, a decrease in process time constant greater than the decrease in process gain at low levels causes excessive oscillations.

An adaptive controller integrated into the DCS was used to automatically identify the process dynamics (process model) for the setpoint changes seen in Figure 3. The adaptive controller employs an optimal search method with re-centering that finds the process dead time, process time constant, and process gain that best fits the observed response. The trigger for process identification can be a setpoint change or periodic perturbation automatically introduced into the controller output or any manual change in the controller output made by the operator.

The process models are categorized into five regions as indicated in Figure 4. The controller gain and reset settings computed from the lambda tuning rules are then automatically used as the level moves from one region to another. This scheduling of the identified dynamics and calculated tuning settings eliminates the need for the adaptive controller to re-identify the process nonlinearity and tuning for different level setpoints. It was found that the use of lambda time, rather than lambda factors, with protection against going outside the controller gain limits helps provide a more consistent tuning criterion. As seen in Figure 5, the adaptive level controller eliminates the oscillations at low levels, and provides a more consistent level response across the whole level range.

Adaptive level controllers can eliminate tuning problems from the extreme changes in level control dynamics associated with different equipment designs and operating conditions. The integrated tuning rules prevent the user from getting into the confusing situations of upper and lower gain limits and the associated fast and slow oscillations. The smoother and more consistent response allows the user to optimize the speed of the level loop from fast manipulation of column reflux and reactor or crystallizer feed to slow manipulation of surge tank discharge flow control. ■

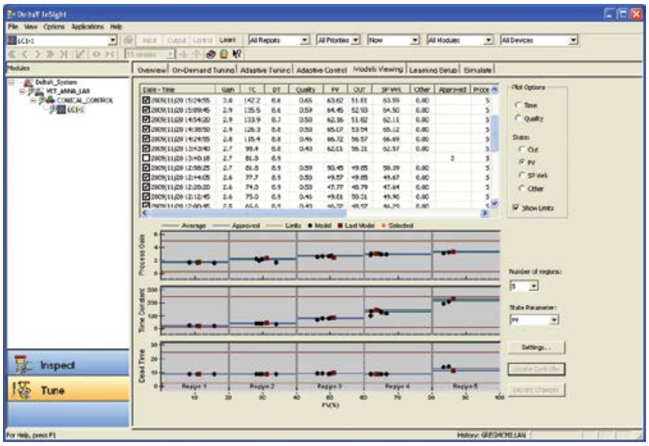


Figure 4. Process models automatically identified for operating regions.

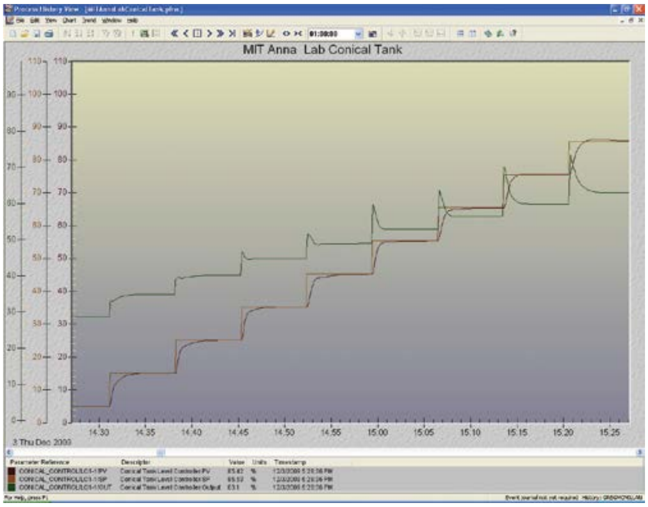


Figure 5. Performance of adaptive PID level controller for conical tank.

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The Incredible Fiber-Optic Flowmeter

by Béla Lipták

Last year, when I was asked about the publication date of the 5th edition of my handbook, I answered 2014. Today, my answer is late 2015, and if you ask me next year, my answer might also shift. Why? Because of the explosion of inventions and international competition during the past decade to meet the needs of the new processes from deep-sea drilling to solar hydrogen, or in automating new nuclear power plants that will operate underwater.

Here I will discuss flow measurement, about which a decade ago I would have said everything that can be discovered already had been. I will describe only one new flow detector, but there are others.

We Have Entered a New Age

The stone age ended, not because we ran out of stone, but because we discovered that bronze tools were better than stone ones. Similarly, the hydrocarbon/nuclear age will end, not because we run out of these materials, but because we will slowly discover that inexhaustible, safe and clean energy is better. Yet, it will take another generation or two to make this transformation.

I call this transition time the "scraping the bottom of the barrel" period. During this period, some nations will be waging wars over what oil and gas is left, while one will use some of its budget to develop green energy technology.

So what's the challenge for our profession? It is to help both. Here I will concentrate on the first group and focus only on the oil and gas flow measurement advances that are occurring in fracking and undersea production processes.

Offshore Drilling and Fiber-Optic Flowmeters

Oil or natural gas production is a multiphase stream consisting of oil, water, gas and sand. When drilling a couple of miles deep under the ocean or fracking a couple miles below the groundwater layer in North Dakota, it's good to know if the total flow rate or the composition of the product changes. This is very important for safety reasons.

Measurement of the multiphase fluid rate and fluid composition is also important for production efficiency reasons and for zonal allocation of gas production in multi-zone well completions. It also supports identification and localization of injection or production anomalies in real time, determination of well productivity index, reduction of the need for surface well tests and surface facilities, etc.

That Was Then, This is Now

In the past, the flow rate and composition of the product was determined by above-ground separators and, after separation, the oil, water and gas flows were separately measured. These separators were not only slow (often intermittent), but they also usually separated only a small bypass stream, which was not necessarily representative. This technique was also expensive and took up a lot of space. Thus, replacing the separators with in-line, subsea, multiphase flowmeters was a major advance both in terms of safety and efficiency.

Most of today's multiphase flow rate measurements use Venturi tubes and nuclear densitometers. They have no moving parts, don't require much maintenance, and use sophisticated flow models to interpret multiple measurements (flow, density, pressure and temperature) into dynamic, multiphase flow and composition determinations. The subsea multiphase flowmeters are "marinized," packaged and deployed by specialist subsea companies to replace topside well test separators, and serve not only the management of individual wells, but also reservoir management and allocation metering.

Fiber-Optic Flowmeters

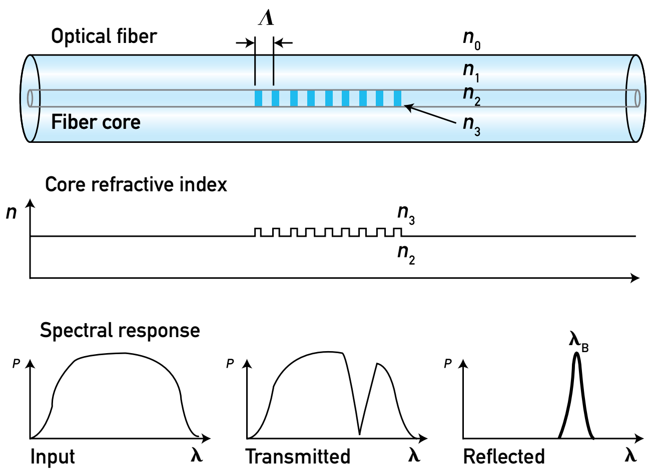
The latest technology in subsea flow metering uses downhole fiber-optic (FO) cables mounted on the surface of the production pipe. On the right of Figure 1, the FO cable connecting the distributed optical temperature sensors (DTS) is shown in red, and the cable connecting the distributed optical pressure sensors (DPS) is shown in blue. They interrogate multiple pressure and temperature sensors mounted on the outside surface of the production pipe.

These optical sensors take advantage of the fact that light in vacuum travels at velocity (C), and when it reaches the surface of a substance, it slows to velocity (V). The refractive index n of a particular substance equals the ratio of these two speeds ($n = C/V$). Therefore, the refractive index determines how much of the light is refracted when it hits the interface of a particular substance.

The refractive index (n) also determines the critical angle of reflection, the angle at which total reflection occurs, and the material behaves like a mirror. Therefore, if one is able to prepare an optical filter grating element that transmits all wavelengths except one, a wavelength-specific mirror is obtained.

The method, allowing a number of sensors to be interrogated by a single FO cable, uses a fiber Bragg grating (FBG). FBGs are constructed from segments of optical fibers. Each of these fiber segments reflects one particular wavelength of light and transmits all others. The FGB can therefore be used to provide in-line optical filters, each of which blocks or reflects a different specific wavelength.

This system is usually referred to as a distributed Bragg reflector. Figure 2 shows the structure of an FBG system. The refractive index profile of the fiber core shows the change of the refractive indexes (n_0, n_1, n_2 ...) along the core, and the spectral response at the bottom shows how the incident broadband signal is split into the transmitted and reflected components at the Bragg wavelength (λ_B).



ALL THE WAVELENGTHS BUT ONE

Figure 2: Fiber-optic cable with a core containing gratings (n_0 to n_3) that transmit all wavelengths except one (λ_B), which is specific to them and which it reflects. Thereby, the receiver algorithm "knows" which wavelengh is coming from which optical sensor, and can read many sensors at the same time.

Optical Pressure and Temperature Sensors

The fluid (a mix of gas, water and oil) passing through the production pipe travels at some average temperature and pressure. Both of these variables oscillate around some average value. These fluctuations (the noise superimposed over the average values of the pressure and temperature of the fluid) carry valuable information because they are caused by eddy currents, gas bubbles, specific gravity changes composition variations, etc. that occur very quickly.

The differential pressure between two detectors, for example, is related to the volumetric flow passing through the pipe, while the time it takes for a particular fluctuation to travel from one detector to another relates to the velocity of the fluid. The extremely fast optical pressure and temperature detectors pick up these oscillations and forward them to the sophisticated algorithms at the receiving end of the FO cable, which interpret them into flow rate and composition. ■

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Level Reaches New Heights

Ever-improving instruments and relaxed regulations are allowing workhorse technologies to excel in dynamic, sticky, multiphase and politically sensitive applications.

by Jim Montague

Windows, floats, displacers, magnets, sonics, radar, lasers and nuclear devices have met or at least partly satisfied each new level measurement challenge over the years, and most continue to be refined even now. However, new problems are always arriving, prompting new ways to look into tanks without opening them.

Tank Vessel Meets Ship Vessel

For example, BP Exploration (www.bp.com) in Houston, Texas, recently replaced unreliable level transmitters on a floating, production, storage and off-loading (FPSO) ship with guided-wave radar (GWR) transmitters from Emerson Process Management (www.emersonprocess.com). Operating about 100 miles off Africa's west coast, BP's FPSO processes and stores oil for export. The ship is 310 meters long, can store 1.77 million barrels of oil, and can process up to 240,000 barrels per day.

Changing process conditions, foam and vapor, and dirty, sticky fluids had made it difficult to measure level on the FPSO. Its original GWR transmitters weren't compatible with the FPSO's Foundation fieldbus (FF) network, and their limited ability to detect low-dielectric hydrocarbons required coaxial probes to increase surface signal strength. However, these probes were prone to sticky build-up, leading to unplanned downtime.

As a result, BP Exploration replaced the existing GWRs with Rosemount 5300 GWRs with signal-processing that ensures detection of low-dielectric fluids, and can send and receive cleaner, stronger signals (Figure 1). This allows use of single-lead probes that increase tolerance to solids build-up and coating, and eliminate trips due to false readings. Also, the Rosemount 5300's FF interface made installation and configuration quicker and easier. After the Rosemount 5300 GWRs were installed, the FPSO's process data confirmed the accuracy and reliability

Emerson Process Management

LEVEL ON THE HIGH SEAS

Figure 1. BP Exploration is using guided wave radar (GWR) transmitters from Emerson Process Management on its floating, production, storage and off-loading (FPSO) vessel to secure accurate and reliable level measurements in challenging process conditions about 100 miles off the coast of Africa.

Trends in Technology

FCC ALLOWS UNLICENSED "LEVEL PROBING RADAR" IN OPEN AIR

In a long-awaited and helpful regulatory update, the U.S. Federal Communications Commission (FCC) reported Jan. 15 that it's adopted rules allowing "level probing radars" (LPRs) to operate anywhere in the country without a license.

The Measurement, Control & Automation (MCAA, www.measure.org) reports it worked closely with the FCC throughout the regulatory process, and the FCC's technical office drafted a Notice of Proposed Rulemaking in 2012 to revise its former rules to allow unlicensed LPRs in "any type of tank or open-air installation."

The report and order are located at http://hraunfoss.fcc.gov/edocs_public/attachmatch/FCC-14-2A1.pdf. They will be published shortly in the Federal Register, and will become effective 30 days after that.

Specifically, the order modifies Part 15 of the FCC's rules for LPRs to operate on an unlicensed basis in the 5.925 to 7.250 GHz, 24.05 to 29.00 GHz and 75 to 85 GHz bands, and revises the measurement procedures to provide more accurate and repeatable measurement protocols for these devices. The rules now require measuring emissions in the main beam of the LPR antenna, and adjusting emission limits to account for attenuation that occurs upon reflection of those emissions. The new limits will still protect any nearby receivers from encountering interfering signal levels. The FCC's order also granted MCAA's request to continue an option for certifying LPRs under Section 15.209's more flexible emission limits because some LPRs need wider bandwidths than the new rules allow.

In addition, by changing these technical testing requirements, the new FCC rules partially harmonize U.S. rules for LPRs with the similar European Telecommunications Standards Institute's (ETSI) Technical Standard for LPR devices, which also bases its measurements on main-beam emission limits. MCAA also sought this because it will improve the global competitiveness of U.S. level instrumentation manufacturers.

of the instruments and their suitability for its widely varying process conditions.

Reining in Reactivity

While its tank isn't out on the ocean, U.K.-based Robinson Brothers (www.robinsonbrothers.co.uk) probably has an even more difficult level measurement challenge—securing level indications for highly reactive carbon disulfide (CS_2). The company uses CS_2 at its Midlands specialty chemicals plant, but it must store the CS_2 under a layer of water to prevent it from igniting. This means the level of the interface between the water and CS_2 needs constant monitoring, so any related instruments are safety-critical.

Robinson previously used a simple, magnetic, float-based device to measure the CS_2 and water level, but it didn't link to any wider control system, So, Robinson sought help from ICA Services (www.icaservices.co.uk), an instrumentation specialist in Manchester, U.K. ICA recommended using ABB's (www.abb.com) AT100 magnetostrictive level transmitter, which provides continuous level indication, transmits analog and/or digital signals

ABB

CAREFUL WITH CHEMICALS

Figure 2. U.K.-based Robinson Brothers is using a magnetorestrictive level transmitter from ABB to meet strict safety standards for handling highly reactive carbon disulfide (CS_2).

for monitoring or control, and can boost its resolution to more than 100 times greater than a conventional reed switch-type device (Figure 2). Most importantly, AT100 also meets the most-extreme ATEX Exd IIC T6 protection standard and toughest SIL1 performance standards. “Our new system provides process signals that output to both our local and site monitoring systems, and it meets our internal requirement for SIL1-capable instrumentation,” says Tom Rutter, Robinson’s E&I manager.

Low-Power, FDT and FCC Aid Level

While ongoing technical advances get the main spotlight in level measurement, organizational efforts have helped, too. Boyce Carsella, consultant at Magnetrol (www.magnetrol.com), reports level measurement’s migration to lower-power sources has enabled it to serve in new and hazardous applications, while electronic device descriptions (EDDs) standardized by the FDT Group (www.fdtgroup.org) are bringing level instruments closer to plug and play.

“Radar and guided-wave radar are the most successful level measurement technologies today because they’re non-contact, unaffected by atmosphere, and can handle the widest range of applications,” says Carsella. “However, radar’s popularity will be helped even more by the FCC’s adding to its Part 15 rules on ‘level probing radar,’ which will allow it to be applied outside or on open tanks [see sidebar]. This will open up many applications, such as water/wastewater or other plants with outdoor or open vessels.” ■

Jim Montague is Control’s executive editor

Flow Charts New Waters

Flowmeters, controllers and their supporting components and software are adding new functions that are allowing them to take on some new and unusual tasks and applications.

By Jim Montague

It shouldn't be surprising, but adding innovations and new capabilities to familiar technologies can make them show up in some unexpected places. For instance, most of the basic parameters of flow sensing and control are well known, but continual advances in flow conditioning and management are enabling them to be implemented in some unusual applications and settings, and be applied by users that hadn't considering using them before or couldn't afford them.

For example, while it might be surprising to see a bunch of Coriolis flowmeters sprouting on top of a filling machine, that's exactly what GF S.p.A. (www.gf-industries.it) in Parma, Italy, did recently to reduce filling times, improve accuracy and repeatability, and enable tighter filling tolerances on its advanced filling equipment (Figure 1). GF's filling machines are used in pharmaceutical, food and medical applications to precisely measure compounds for injections, infusions, ophthalmic preparations, syrups and detergent solutions.

GF previously used filling methods based on time-pressure instruments, as well as piston-syringe and peristaltic (roller type) pumps, on machines for its pharmaceutical customers. Besides seeking to improve filling speed and accuracy, GF also wanted to enable users to change media without replacing the measuring instrument, and enable in-line sterilization without disassembling the machine, according to Marco Serventi, GF's sales manager. GF met its goals by using Micro Motion Elite and H-Series flowmeters and Model FMT filling mass transmitters from Emerson Process Management (www.emerson-process.com). Also, the rangeability of these Coriolis flowmeters allows different media in the range of 0.5 g to 5 kg to be dispensed without changing mechanical components.

"We were able to improve system response time and reduce batch cycle times by taking advantage of integrated valve control from the transmitter, rather than the traditional pulse output set up through a PLC," explains Serventi. "The reliability and accurate results provided by the Micro Motion instruments have now been validated by GF customers over a number of successful applications."

Nuclear and Underwater

Likewise, NRG Laboratory's (www.nrg-labs.com) facility in the Netherlands makes nuclear medical isotopes and tests materials for nuclear power plants. It uses flow metering to measure its nuclear laboratory and reactor's basin cooling system, which uses a medium called "demiwater."

When its old vortex flowmeter wore out and a replacement wasn't available, NRG Lab began searching for a substitute with long-life electronics, low maintenance costs, small footprint, good underwater performance and the ability to withstand radiation. Eventually, NRG Lab settled on McCrometer's (www.mccrometer.com) differential pressure V-Cone flowmeter with built-in flow conditioning for accuracy to +0.5% of the flow rate with +0.1 repeatability. It suits tight retrofit installations because it only requires a minimal 0-3 pipe diameters upstream and 0-1 diameters downstream.

NRG Lab reports its V-Cone flowmeter performs better than its former vortex flowmeter, requires no maintenance such as changing cables, and enhances safety by avoiding having any electronics near the reactor vessel.

Aiding Lubrication Applications

To help give its new lubricant bottom-loading bay more efficient and safer driver-initiated loading, Shell Lubricant Center (www.shell.co.uk) at Stanlow refinery in Ellesmere Port, Cheshire, U.K., recently deployed 10 Promass 83F Coriolis mass flowmeters from Endress+Hauser (www.endress.com). The flowmeters use Profibus DP communications,

Photo courtesy of Emerson Process Management

CORIOLIS COLLECTION

Figure 1: Italy-based filling machine builder GF S.p.A. is using Micro Motion Coriolis flowmeters to reduce filling times, improve accuracy and repeatability, and enable tighter filling tolerances on its filling machines.

and this provides added density and temperature data, reduces cabling and I/O requirements, and links seamlessly with Shell's inventory control system. Because Shell's tankers load according to volume, knowing product density is crucial due to changes cause by temperature fluctuations.

Also, the driver-initiated loading functions are more efficient because drivers no longer have to wait for manual link-ups to pumps; load qualities and grades are validated automatically; and this streamlines and cuts the required steps by 50%. "Driver-initiated loading has proven to be a real benefit all round," says Chris Turner, Shell Lubricant's E&I engineer. "All the data provided by Profibus, such as diagnostic information, helps us maintain smooth operation and system integrity, and the Promass flowmeters are low-maintenance, accurate, secure and user-friendly."

Likewise, Novelis' (www.novelis.com) aluminum flat-rolling mill in Lüdenscheid, Germany, needs to constantly lubricate the 13,000 tons of aluminum rolls it makes each year with high-quality oil. However, this oil often thins during production, which can reduce lubrication, damage the rolls, and stop production. Oil thinning is accompanied by a minimum density change of around 0.8 grams per liter (g/l).

To prevent these problems, Novelis recently installed CoriolisMaster FCB300 mass flowmeters from ABB (www.abb.com), which can perform density measurements at up to 0.5 g/l in field adjustments. This means fluctuations in density can be detected much earlier, and Novelis can take countermeasures to prevent damage to the rolls. Besides high-precision density measurement, FCB350 also gives the rolling mill a smooth density signal, so unique trends can be observed.

Optimized Oxygen = Stronger Steel

While a steel plant might not seem like the most logical place for a flowmeter, a closer look at More s.p.l (www.more-oxy.com) in Gemona del Friuli, Italy, reveals the electric arc furnaces it supplies to mini-mills are using vortex flowmeters to minimize fuel and oxygen consumption, optimize steel quality, prevent rework and reduce costs (Figure 2). More also supplies auxiliary steelmaking equipment, including sidewall injector systems used with chemical energy packages such as oxygen, carbonaceous fuels, lime and other fine compounds. These chemicals are injected into the furnace during the manufacturing process to improve steel quality, and provide additional energy from exothermic reactions, helping to reduce overall energy consumption.

More had been using differential pressure flowmeters to measure critical oxygen flows in its furnaces, but they made it difficult to handle changing process requirements and meet user demands for more accurate control. The company needed more accurate instruments with a broader measurement range, so it evaluated vortex flowmeters, and implemented Emerson's Rosemount 8800 vortex flowmeters, which are designed to addresses the limits of traditional vortex flowmeters. For example, its Adaptive Digital Signal Processing (ADSP) signal filtering and a mass-balanced sensor design maximize measurement reliability, and eliminate the impact of vibrations on measurement accuracy. Also, to meet demands for greater flexibility in furnace installations, Rosemount 8800's 25:1 rangeability helps optimize gas heaters, providing greater opportunities to vary steel characteristics for different applications.

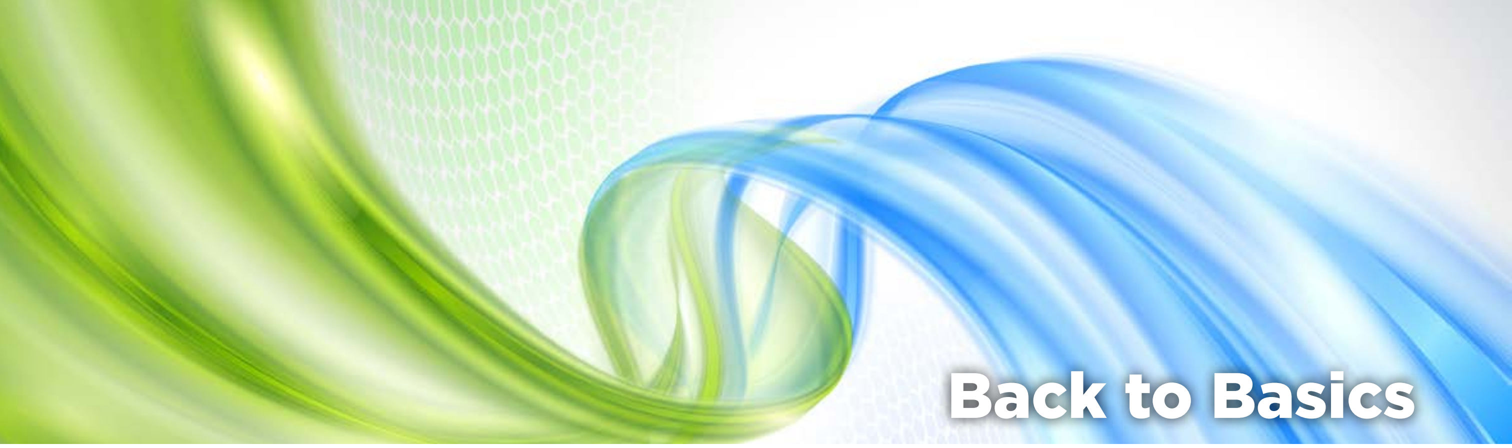
"By implementing Emerson's vortex technology, we've been able to build electric arc furnace solutions that guarantee optimum furnace efficiency for users," says Roberto Urbani, More's purchasing manager. "We've been able to optimize furnace efficiency in terms of productivity and steel quality. Over-oxidation is no longer an immediate concern, which extends furnace lifecycles. Energy consumption and ambient pollution were also reduced." ■

Photo courtesy of Emerson Process Management

OPTIMIZED ARC FURNACE

Figure 2: More s.r.l. has deployed Rosemount 8800 vortex flowmeters to help reduce energy consumption and optimize fuel provided to its arc furnaces.

Jim Montague is Control's executive editor.



Beginner's Guide to Differential Pressure Level Transmitters

The Not-So-Straightforward Basics of This Measurement Technique

By David W. Spitzer

GIGO means "garbage in, garbage out." This phrase applies in industrial automation because using faulty measurements can fool even the best control system. One remedy that can help avoid a GIGO scenario is to understand the measurement technique and its limitations to the extent that its application can be reasonably evaluated. Differential pressure level measurement is one of those key measurements you need to understand to avoid the dreaded GIGO.

The importance of level measurement cannot be overstated. Incorrect or inappropriate measurements can cause levels in vessels to be excessively higher or lower than their measured values. Low levels can cause pumping problems and damage the pump, while high levels can cause vessels to overflow and potentially create safety and environmental problems. Vessels operating at incorrect intermediate levels can result in poor operating conditions and affect the accounting of material.

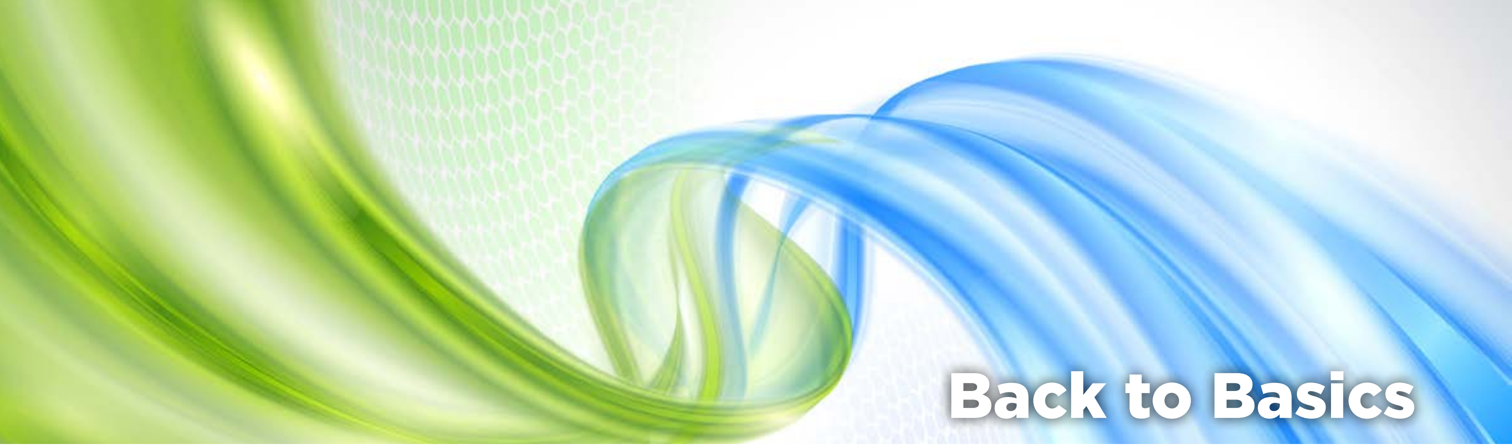
The level of a liquid in a vessel can be measured directly or inferentially. Examples of direct level measurement include float, magnetostrictive, retracting, capacitance, radar, ultrasonic and laser level measurement technologies. Weight and differential pressure technology measure level inferentially. All have problems that can potentially affect the level measurement.

Differential pressure level measurement technology infers liquid level by measuring the pressure generated by the liquid in the vessel. For example, a water level that is 1000 millimeters above the centerline of a differential pressure transmitter diaphragm will generate a pressure of 1000 millimeters of water column (1000 mmWC) at the diaphragm. Similarly, a level of 500 millimeters will generate 500 mmWC. Calibrating this differential pressure transmitter for 0 to 1000 mmWC will allow it to measure water levels of 0 to 1000 millimeters.

Note that this example presumes that the liquid is water. Liquids with other specific gravities will generate other differential pressures and cause inaccurate measurements. Continuing with the previous example, the same 500-millimeter level of another liquid with a specific gravity of 1.10 at operating conditions in the above vessel will generate 550 mmWC of pressure at the transmitter. As such, the differential pressure transmitter calibrated for water would measure 50 millimeters higher than the actual 500 millimeter liquid level. Conversely, if the liquid has a specific gravity that is lower than that of water, this transmitter will measure lower than the actual level. This example illustrates that differential pressure technology does not measure level, but rather infers level.

Three Calculations

All is not lost because the calibration of the differential pressure transmitter can be modified to compensate for a different specific gravity. This technique used to calculate the



new calibration is useful for both straightforward and more complex installations.

Figure 1 shows the vessel both at 0% and 100% level. The pressure generated by the liquid at the level transmitter diaphragm is the liquid height times the specific gravity. The pressure is 1.10*(0 mm) when the vessel at 0% and 1.10*(1000 mm) when the vessel at 100%. Therefore, the transmitter should be calibrated 0 to 1100 mmWC to measure liquid levels of 0 mm to 1000 mm.

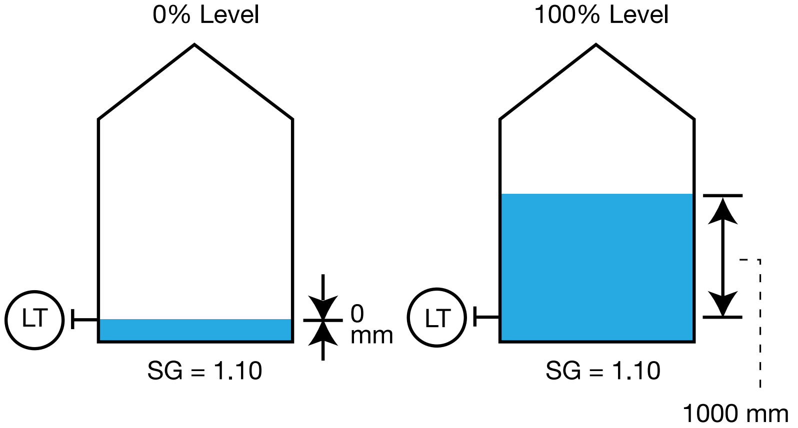


Figure 1. The level transmitter for these vessels should be calibrated 0 to 1100 mmWC to measure liquid levels of 0 to 1000 millimeters.

A somewhat more complex application is illustrated in Figure 2. In this application, for process reasons, we need to take the measurement from 200 mm to 1000 mm above the nozzle. In addition, the transmitter is located 500 mm below the nozzle. Note that the technique of sketching conditions at both 0% and 100% level is the same as performed in Figure 1. At 0% level, the pressure at the transmitter is 1.10*(500 +200 mm), or 770 mmWC. At 100% level, the pressure at the transmitter is 1.10*(500+1000 mm) or 1650 mmWC. Therefore, the transmitter should be calibrated 770 to 1650 mmWC to measure liquid levels of 200 mm to 1000 mm above the nozzle.

Figure 3 illustrates the use of a differential pressure transmitter with diaphragm seals to sense the pressures at the nozzles in a pressurized vessel. In this application, the low-pressure diaphragm is located above the liquid to compensate for the static pressure in the vessel. Other complications include the densities of liquid and capillary fill fluid and 0% and 100% levels that do not correspond to the nozzle positions.

Using similar techniques as in the previous examples, at 0% level, the pressures at the high and low sides of the transmitter are {1.10*(200 mm) + (3 bar)} and {1.05*(1300 mm) + (3 bar)} respectively. Therefore, the differential pressure transmitter will subtract the high side from the low side and measure {1.10*(200 mm) + (3 bar)} minus {1.05*(1300 mm) + (3 bar)}, or -1145 mmWC.

At 100% level, the pressures at the high and low sides of the transmitter are {1.10*(1000 mm) + (3 bar)} and {1.05*(1300 mm) + (3 bar)} respectively. Similarly, the differential pressure transmitter subtracts the high side from the low side to measure {1.10*(1000 mm) + (3 bar)} minus {1.05*(1300 mm) + (3 bar)}, or -265 mmWC. Therefore, the transmitter should be calibrated -1145 mmWC to -265 mmWC to measure liquid levels of 200 to 1000 millimeters above the lower nozzle.

Note that the static pressure in the vessel does not affect the calibration because it appears on both sides of the differential pressure transmitter where it effectively cancels out. Further analysis also will reveal that locating the differential pressure transmitter at different elevations does not affect the calibration.

These same techniques can be used to determine the calibrations for interface level measurements. Note that these techniques involve applying hydraulics to the installation and application. Nowhere do we use terms such as elevation, suppression and span. The use of these terms can easily confuse and mislead the practitioner.

What Ifs

What if the liquid density changes during operation? What if the change is due to changes in the composition of the liquid? What if the change is due to temperature changes? What if the vessel is filled with a different liquid that has a different specific gravity? These are important questions that should be asked (and answered) when considering the use of differential pressure level measurement instruments. Repeating, differential pressure measurement does not measure liquid level—it infers liquid level—so specific gravity changes can affect the performance of the level measurement. In practice, the specific gravity of many liquids is known and relatively stable, so that differential pressure techniques are commonly applied to many liquid level measurement applications.

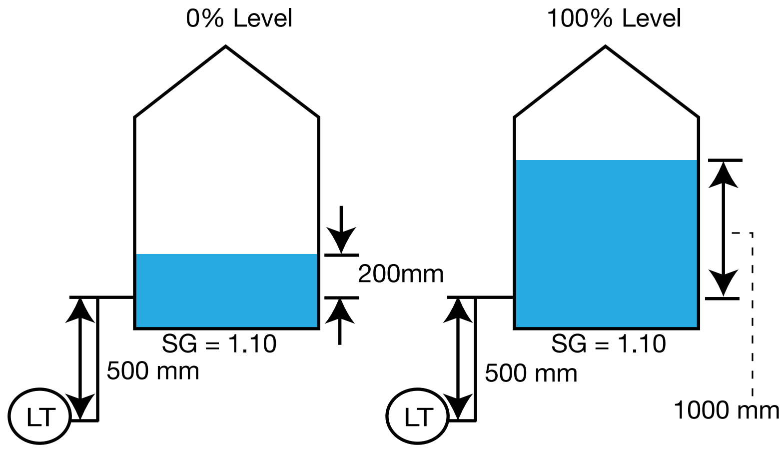
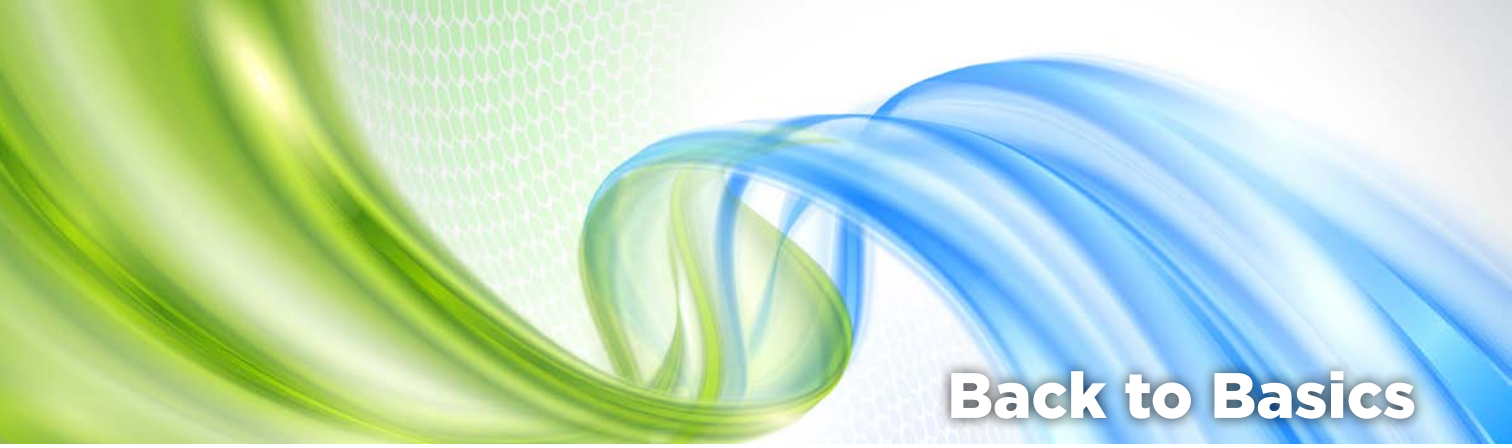


Figure 2. This transmitter should be calibrated 770 to 1650 mmWC to measure liquid levels of 200 mm to 1000 mm above the nozzle.

Spanning Specifications

The differential pressure transmitter should be operated within its published specifications to maintain accuracy. The span of a transmitter is the difference between the 100% and 0% calibration values. Differential pressure transmitters have specified minimum and maximum spans. For example, a given differential pressure transmitter may be calibrated with spans between (say) 400 mmWC and 4000 mmWC. In addition, the transmitter zero may also be raised or lowered by up to, for example, 4000 mmWC. Calibrations that do not meet the transmitter specifications are potentially subject to significant error. The calibrations in the examples were 0 to 1100, 770 to 1650, and -1145 to -265 mmWC, respectively. Each has a span greater than 400 mmWC and less than 4000 mmWC. In addition, their zeros are not raised or lowered by more than 4000 mmWC. Therefore, all of these calibrations are within the transmitter specifications.

However, the calibrated span specified for another transmitter model of the same manufacture may be between 100 mmWC and 1000 mmWC, and allow the zero to be changed by 1000 mmWC. This transmitter would not be applicable to the first and third examples where the span is 1100 mmWC, and the zero is lowered by 1145 mmWC, respectively. However, it could be used in the second example where the span is 880 mmWC, and the zero is raised by 770 mmWC. Using this lower range



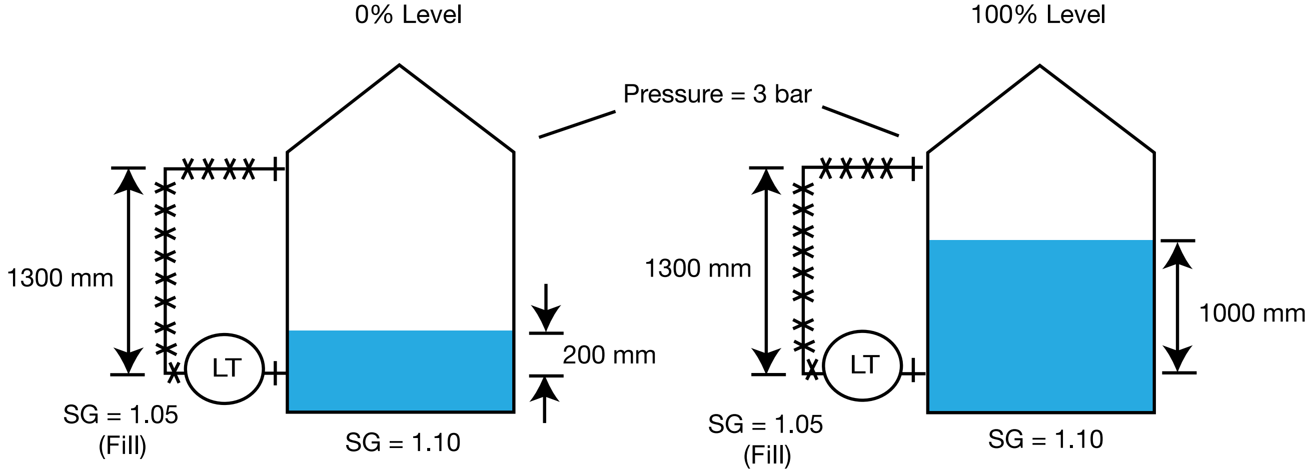


Figure 3. In this case, the differential pressure transmitter subtracts the high side from the low side, so it should be calibrated -1145 to -265 mmWC to measure liquid levels of 200 to 1000 millimeters above the lower nozzle.

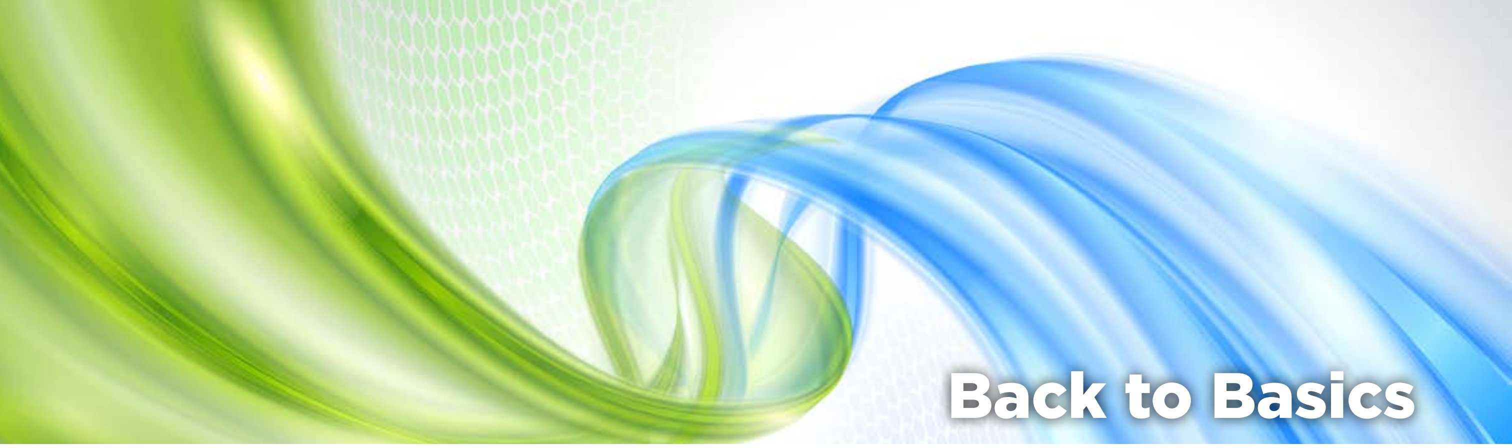
transmitter (1000 mmWC) will usually be more accurate because of the smaller absolute errors associated with other specifications such as temperature, pressure and ambient temperature affects. Therefore, all being equal, it's generally desirable to use the lower range transmitter to reduce measurement error.

The maximum flow rate of flowmeters is often specified to be significantly higher than the design flow rate to allow for transients and increased plant throughput over time. In level measurement, the vessel size is fixed, so using a higher range differential pressure transmitter provides no similar benefit and typically results in additional measurement error that can be avoided by using a lower range transmitter.

Using the available information properly is another potential problem. Some years ago, distributed control system inputs were incorrectly configured to correspond to the maximum transmitter spans. Aside from using incorrect values, the levels should have been expressed in percent. Using absolute level measurement units such as inches, feet, millimeters or meters increases the potential for error because operators must remember the height of each vessel to put the level measurement in context with the vessel. This can easily become overwhelming and cause operator errors because plants often have hundreds of vessels. For example, a vessel operating at 2.8 meters does not readily indicate a problem to the operator even though the vessel overflows at 3.0 meters. On the other hand, the operator can easily determine that a vessel operating at 93% level might warrant attention and that a vessel operating at 97% may need immediate attention.

Differential pressure measurement is a workhorse of industrial level measurement that's been used for decades and will continue to be used for decades to come. ■

David W. Spitzer is a principal in Spitzer and Boyes and a regular Control contributor.



Back to the Basics: Magnetic Flowmeters

Close to being "Prince Flowmeter Charming," magmeters do it (nearly) all.

by Walt Boyes

Ever since the invention in the 1790s of the Woltman-style mechanical turbine flowmeter, we've been looking for the one flowmeter that will work in every application. Unfortunately, there are 12 flow measurement technologies in common use for a very good reason. No single flow technology works well, or even acceptably, in all applications.

Of the more broadly based flow technologies, the one that works in the most applications, across most industries and with higher accuracy than even differential pressure is the electromagnetic flowmeter, or magmeter. According to Jesse Yoder at Flow Research (www.flowresearch.com), the total global market for flowmeters is roughly $4.7 billion, and magnetic flowmeters account for a little less than 20% of that total. Magmeters are used in every process industry vertical. They are designed for handling almost all water-based chemicals and slurries and are furnished with corrosion- and abrasion-resistant linings and even clean-in-place (CIP) designs.

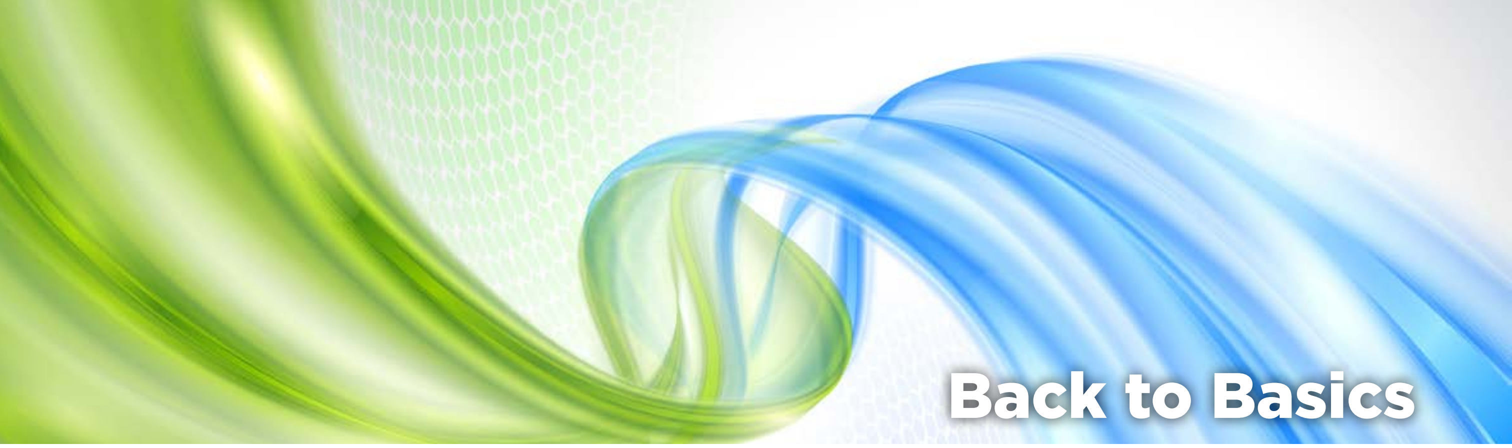
Magmeters also are made in the widest size range of any flowmeter technology because they can be scaled up almost infinitely. The first use of the technology was in the huge sluices that drained the Zuider Zee in the Netherlands in the 1950s, and typically vendors supply a size range from ½ in. (12 mm) to 36 in. (914 mm), with several vendors supplying extended sizes up to 120 ins. (3048 mm). Several vendors sell sizes below ½ in. as well. How it is possible to scale up and down this broadly is directly related to the technology.

How a Magmeter Works

In 1831, Michael Faraday formulated the law of electromagnetic induction that bears his name. As used in an electromagnetic flowmeter, coils are placed parallel to flow and at right angles to a set of electrodes in the sides of the pipe, generating a standing magnetic field (see Figure 1). The pipe must be non-magnetic and lined with a non-magnetic material, such as plastic, rubber or Teflon. When the fluid (which must be conductive and free of voids) passes through the coils, a small voltage is induced on the electrodes, proportional to the deflection of the magnetic field. This deflection is the sum of all of the velocity vectors impinging on the magnetic field.

Modern magmeters operate on a switched DC field principle to zero out ambient electrical noise and noise actually in the process fluid. They turn the field off, measure the voltage that's still induced on the electrodes, then turn the field back on and subtract the off-state voltage from the on-state voltage. They do this several times a second, which reduces zero drift to almost nothing.

What this means is that the voltage induced on the electrodes is directly proportional to the average velocity in the pipe and is, therefore, significantly more accurate than any other velocity-based measurement principle that only looks at a point or line velocity. In fact, the magnetic flowmeter is generally considered the most accurate wide-application flowmeter in current use, approaching the accuracy of positive displacement flowmeters. They're often used for custody transfer when the



flow is of relatively long duration. Typical accuracy of a magnetic flowmeter is 0.5% of measured value from 0.3 ft per sec to 33 ft. per sec (0.1 to 10 m/sec) velocity. Some vendors indicate even higher accuracies over portions of the flow range, up to 0.1% of indicated flow rate.

Where Magmeters Won't Work

Magmeters have such a wide application that it's easier to say where they will not work than to list all the applications in which they will.

They will not work when the pipe is not full (with the exception of several versions designed specifically for this application). If the pipe is not full, there will be significant error. One of the most common application failures of magnetic flowmeters is on a gravity-fed line discharging to atmosphere in a tank. Very often, at very low flows, the pipe is actually not full, and the flowmeter will read in error. If the pipe fill drops below the line of the electrodes, it will not read at all. Applications like this are designed with a u-tube in the line, which is supposed to keep the pipe full at all times. They will not work when the pipe is full of entrained gas or air. This changes the computed volume of the pipe and changes the volumetric flow through the meter in an uncontrolled fashion that's proportional to the amount of bubbles (or void fraction) in the pipe.

They will not work well where the flow starts and stops repeatedly because there's a lag between the time the flow starts and the correct velocity is read by the meter. This means that (again with the exception of some units that are specifically designed to be very fast) magnetic flowmeters don't work well in short-duration batching operations.

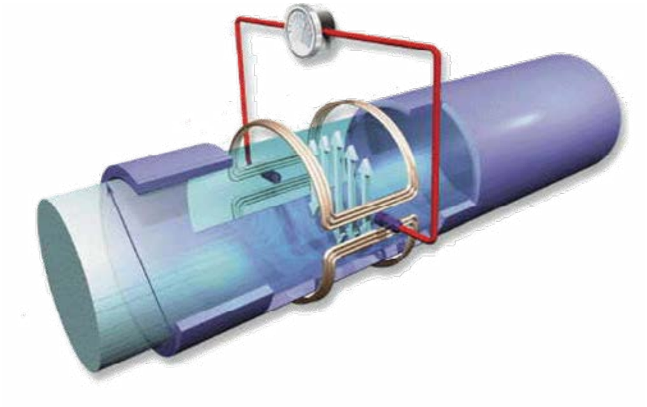


Figure 1. The velocity deflects the standing magnetic field and induces a voltage on the electrodes that is proportional to velocity.

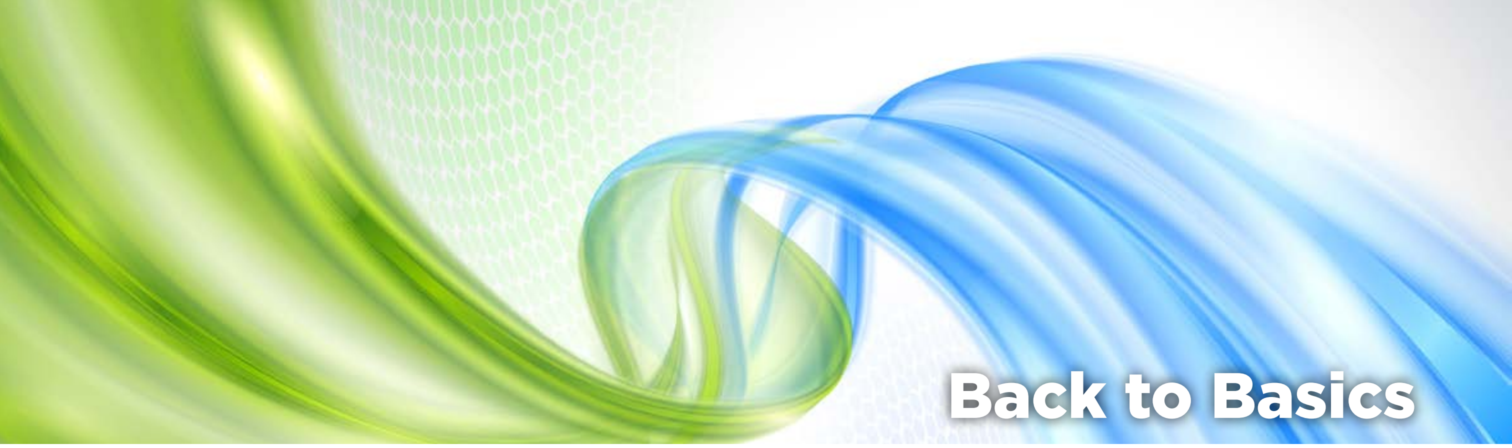
They don't read out in mass flow units, but when combined with an ancillary density measurement device, they can produce a high-precision mass flow measurement. This combination of devices is used to measure mass flow where the pipe size is larger than 12 in. (nominally 300 mm).

Most important, they will not work on non-conductive fluids or on gases at all. The minimum conductivity of a fluid is 5 µS (microSiemens) before a magnetic flowmeter will measure its velocity. In practice, it's not wise to use a magmeter on a fluid whose conductivity is this low.

Finally, except for specially-designed units. magmeters have trouble working on fluids with extremely high or highly variable conductivity, for example, saline brine or seawater.

Using Magmeters

Following these simple rules for using magmeters will produce a satisfactory application.



Straight Run. Magnetic flowmeters need less straight run than most flowmeters, often as little as three diameters upstream of the electrode plane (the centerline of the meter body, usually), and no diameters of straight run downstream. But sometimes, a better choice is to go with as much straight run as you can get. For example, spiraling flow (swirl in the pipe) can propagate for hundreds of diameters after a three-dimensional turn in piping. Spiraling flow causes severe inaccuracy in a magmeter, sometimes as much as 40% of measured value.

Vertical Mounting. One way to make sure you have a fully developed flow profile moving through the meter is to mount your magmeter so that the flow is through the meter in the vertical direction. This helps in cases of spiraling flow and also helps reduce air entrainment.

Right Sizing. Although a magmeter will operate over the entire range from 0.3 fps to 33 fps (0.09 to 10 meters per second) velocity, it isn't wise to install a magmeter that's going to operate permanently at the lower end of that range. This can cause buildup of solids inside the flow tube and sometimes on the electrodes themselves. If buildup occurs inside the flow tube, the calculated volume is now in error, and if buildup occurs on the electrodes, the insulating properties of the buildup can either reduce the voltage or break the circuit entirely. Either will cause inaccurate readings. It's better to size the flowmeter for a normal flow that's about 60% of maximum for that pipe size, and if necessary, install a properly designed meter run.

Proper Grounding. The pipe section of the magmeter needs to be non-conductive for the circuit to work. The electronics are susceptible to interference if they're floating above ground. Magmeter vendors all have grounding procedures, which you ignore at your peril.

Temperature and Pressure. Magnetic flowmeters are designed to work at moderate temperatures and pressures and should not be stressed. Magnetic flowmeters should not be operated where a vacuum can be pulled inside the flow tube when there is a pressed-in polyurethane or Teflon lining, because the vacuum can pull the lining right out of the meter, causing potential hazard. Both Teflon and polyurethaneare de-rated for pressure at the upper end of their temperature range and will deform if overheated.

Magnetic flowmeters have become one of the most widely used flow technologies in the 50 years since their first introduction. They're simple, easy to maintain, and because they have no moving parts, they can operate for years without maintenance. ■

Walt Boyes is a principal with Spitzer & Boyes.

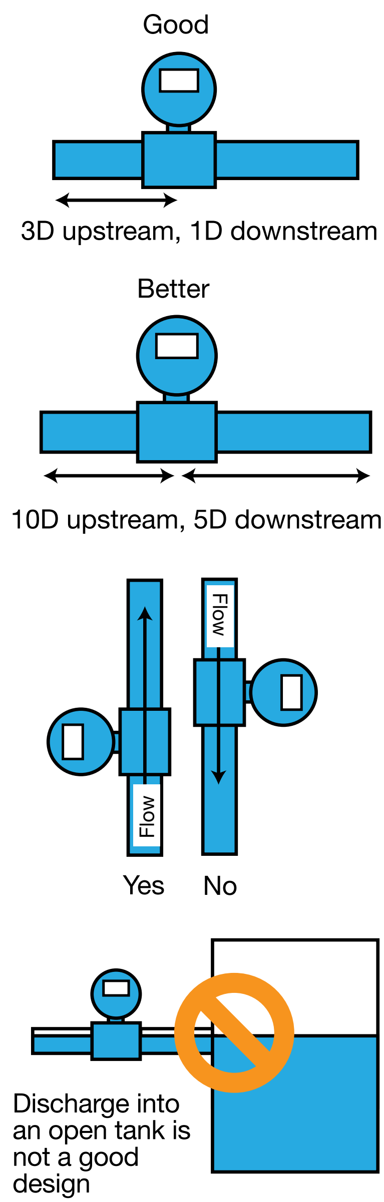
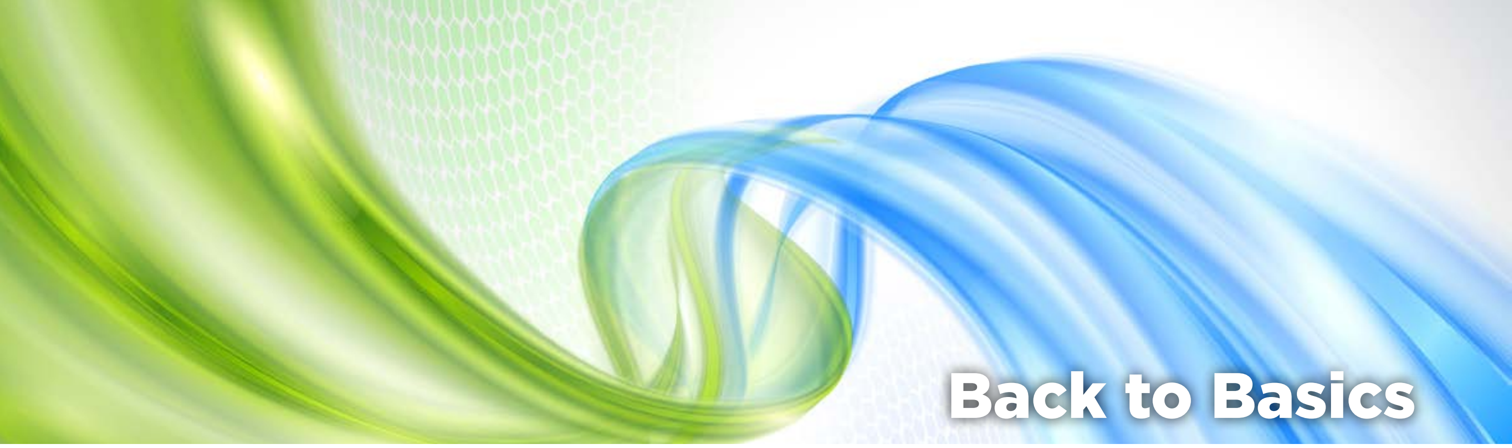


Figure 2. Some basic rules of thumb for using magmeters



The Right Tool for Tricky Measurement Jobs

Gamma nuclear level gauges handle the toughest applications.

by Walt Boyes

Let's say you have a reactor vessel. It is 6 ft. (1.8 m) in diameter, glass-lined, has a big agitator in it, and has both a jacket made of 1-in. (25-mm) copper cooling coils and a 4-in. (100-mm) layer of insulation covered with thin steel lagging. Worse yet, there are no accessible entrances into the top of the vessel that aren't already being used for something. For the process to work, you must measure the level in the vessel with significant precision. You've even tried weigh cells, but there isn't enough precision to just weigh the contents of the reactor, with all that tare weight. Oh yeah, and you can't stop the reactor to modify it, and since it is a glass-lined and code-stamped vessel, you can't drill any holes in it either. What do you do?

Or, suppose you're making glass for a variety of products. The glass is produced by melting silica sand, glass frit from recycled bottles and some trace minerals in a very hot furnace with firebrick walls that are over 1 ft (300 mm) thick. The glass is too hot to pump, so it must flow by gravity down a firebrick-lined channel to where it is cast or molded or extruded. Your requirement is that you have to measure the level of the molten glass and control it to ±0.0005 in. (±0.013 mm), or the process doesn't work. Glass castings have holes called holidays in them, and extruded glass, whether tube or sheet, has flaws and holes. What do you do?

You are responsible for the air pollution control system for a very large coal-fired power plant. You have electrostatic precipitators that remove the fly ash from the stack gas before it gets released into the atmosphere, causing international pollution incidents and costing your utility millions in air-pollution-control violation fines. But the hoppers that hold the precipitated fly ash keep plugging up, and fly ash is very hot and also acts like concrete and sticks to everything. You need some way to tell when the hoppers are full, so you can empty and clean them, but anything you stick into the hopper just gums up and fails so fast that you have given up. What do you do?

Sound familiar? Nearly every plant, from mining to wastewater and every process vertical in between, has a level application that is both critical and difficult, if not impossible, to measure.

Enter the Gamma Level Gauge

Since the 1950s, the answer to all of these applications has been the proper application of a gamma level gauge. Gamma gauges work based on both the inverse-square law—radiated energy decreases with the square of distance—and the fact that dense materials absorb gamma energy—1 in. (25 mm) of steel, for example, cuts the energy from a gamma beam by 50%.

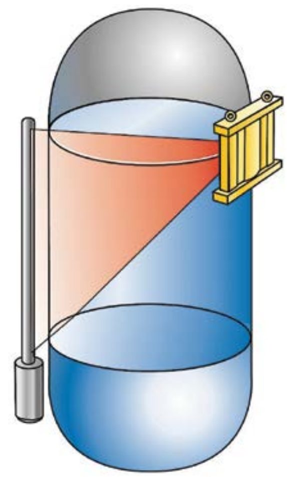
Very early on, engineers came up with the idea that rising material or liquid would change the amount of energy reaching a detector on the other side of the vessel from an emitting source. In the case of a point level switch measurement (Figure 1), rising material would simply trigger a relay if the energy beam were interrupted. In the case of a continuous level measurement (Figure 2), the rising material would cause a decrease in the intensity of the energy beam reaching the detector that could be calibrated to be proportional to the rise in level, and when the level fell, then the energy would likewise increase.

Designing to Fit

In order to figure out how much energy will reach the detector, essentially all you have to do is to add up the densities and thicknesses of all the materials between the energy source and the detector, and make the energy beam intense

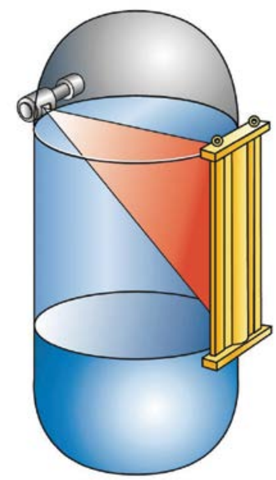
GAMMA POINT LEVEL SWITCH

Figure 1. Rising material triggers a relay if the energy beam is interrupted.



CONTINUOUS LEVEL MEASUREMENT

Figure 2. Rising material decreases the intensity of the energy beam.



STRIP SOURCE AND POINT DETECTOR

Figure 3. Here the apex of the triangle is aimed at the point detector.

enough to pass through all that material and reach the detector. Safety requires that the intensity of the energy beam be designed to be as small as possible and still make the measurement.

"Modern detector designs have made it possible to use significantly lower activity sources than in previous years," says Mick Schwartz, business unit manager of Berthold Technologies USA LLC (www.berthold.com), a manufacturer of gamma level gauging products. "This means that the risk of exposure to gamma energy for personnel is minimized and amenable to proper safety precautions. Gamma energy does not cause any of the measured product or the vessel to become radioactive."

All manufacturers of gamma level gauges have software that makes the calculation of energy source size straightforward. You or the vendor plug in the numbers for the thicknesses and densities of the material, not forgetting the air gap between the walls of the vessels—air has density, and energy decreases with the square of distance—and the software spits out an optimized energy source size and, in most cases, the appropriate housing design and detector selection.

Gauging in the Real World

So let's look at how to do the level application in the jacketed vessel we talked about earlier. This is not quite as easy as putting a source and a detector across from each other because there are vessel internals, including an agitator, that have to be missed. The way to do this application is to "shoot a chord" of the vessel's diameter—that is, put the source and detector off to one side of the diameter. Because the thicknesses that the energy beam will shoot through will be greater, the source activity that will be required will be greater by some amount than shooting the diameter would be. The blades of the agitator need to be considered, and, if possible, eliminated by shooting the chord between the blades and the vessel wall. If that isn't possible, many gamma level gauges can be programmed to ignore the repetitive density fluctuation caused by blades swinging into and out of the beam. It just makes the signal noisy.

Now let's look at the glass level gauge. There's a lot of firebrick on either side of the glass channel, so it may be necessary to drill holes in the firebrick to reduce its thickness. This will cause the temperature on the outside to rise, so the

POINT LEVEL SWITCH IN A HOPPER

Figure 4. A narrowly collimated conical beam is aimed across the vessel at the point detector.

detector must be water-cooled to bring the internal temperature of the electronics down to the normal range.

There are three geometries that can be used in continuous gamma level measurement. The most common is a point source that is collimated to produce a right-triangle-shaped beam with the 90º angle at the top of the detector. Next is a strip source that is characterized to produce a similar shaped beam, but with the apex of the triangle at the point detector (Figure 3). Third, there is the geometry of a strip source and a strip detector. This geometry is often used for highly precise level measurement on small diameter vessels or pieces of pipe, such as vertical risers.

In point level applications (Figure 4), the source produces a narrowly collimated conical beam that is aimed across the vessel at the point detector. In most point level applications, the reason a gamma gauge is being used is because the inner walls of the vessel are subject to vibration, corrosion, abrasion, or fouling or coating with material. Fly ash hoppers are classic examples of this kind of application. The energy activity of the source must be sized, so that the point level gauge continues to work correctly through a reasonable thickness of fouling or coating, perhaps as much as a couple of inches.

How to Measure a Tank of Tomato Paste

Larry Fontes, maintenance and production supervisor at Ingomar Packing Co. (www.ingomarpacking.com) in Los Banos, Calif., uses a gamma level gauge on a very difficult food industry application. "We were using a dual remote diaphragm seal system with chemical T diaphragm seals and a 4-20 mA DC HART transmitter to control a valve, which would control the level in a holding tank," Fontes says. "The holding tank is 38 in. (nominal 1 m) in diameter and about 30 ft (9.1 m) tall. The product inside the tank is tomato paste with a specific gravity of about 1.134 at 210 °F to 215 °F (a little over 100 °C) at a flow rate of approximately 250 gallons per minute."

"After a 100-day processing season," Fontes continues, "the diaphragm seals would become coated due to the temperature of the product, and the level indication would begin to drift as the diaphragm was unable to pick up the change in pressure as the level changed."

Fontes reports that the problem became so severe that product spilled out the vent on top of the tank, while the transmitter reported little or no change in percent level.

Fontes looked into other level technologies, including radar. "I was looking for a level system that wouldn't be affected by the properties of the product due to the thermal processing," he says. "We had used a [gamma] device to measure soluble solids from Berthold Technologies, so I was somewhat familiar with the technology. Berthold worked with the consulting engineer we had contracted for the expansion of our aseptic processing system. [Process Resource Inc.. www.processresource.com]

"Berthold provided onsite start-up and training for myself and several of our operators," Fontes goes on. "The installation was made much easier with the help of all the individuals from Berthold. We operate the gauge under the general license in the Code of Federal Regulations."

And how has it worked out? "Since the installation of the Berthold level gauge (Figure 5) in 2007," Fontes reports, "we have had instances during a couple of processing seasons that would have resulted in the same issues as before. The dual diaphragm system level indication began to drift, while the gamma level gauge remained constant."

CONTINUOUS LEVEL GAUGE ON TOMATO-FILLED COLUMN

Figure 5. During a 100-day processing season, the gamma level gauge remained constant.

Fontes concludes, "The Berthold level gauge installation was part of a $1.3 million expansion to the flash cooler, which is part of our aseptic processing.

The Business of Using Gamma Level Gauges

Similar to every other device that uses nuclear byproduct material, even the smoke detectors in your house, gamma level gauges are required to be licensed. This means that applications, paperwork and rules have to be known, understood, followed and kept current. However, once you are set up to do this, licensing can be relatively simple and not too onerous.

"Many gamma level gauges can be distributed under the general license in most states in the United States," says Berthold Technologies' radiation safety officer (RSO), Mark Morgan, "but the general license does not exist in other countries, and the U.S. NRC plans to do away with it in one to three years anyway, in favor of specific licensing. The NRC plans to make the specific license procedure simpler and more streamlined."

The general license has less paperwork, but has restrictions on gauge geometry, exposure levels, shielding, and other environmental health and safety issues. The other kind of license, used globally as well as in the United States is called a "specific license." This means that you, as the gauge owner, are licensed to do several specific things with the gamma level gauge you own.

So what does this mean for operations and maintenance? Maintenance on the electronics, including the detector, can be done by any plant-qualified instrument tech or maintenance tech. No license is required by persons doing that level of maintenance. Since a gamma energy source is basically a steel-jacketed lead box with a capsule the size of a horse-pill inside of it, maintenance on source housings is minimal. A trained, licensed person is required to change the geometry of the gauge or to move it.

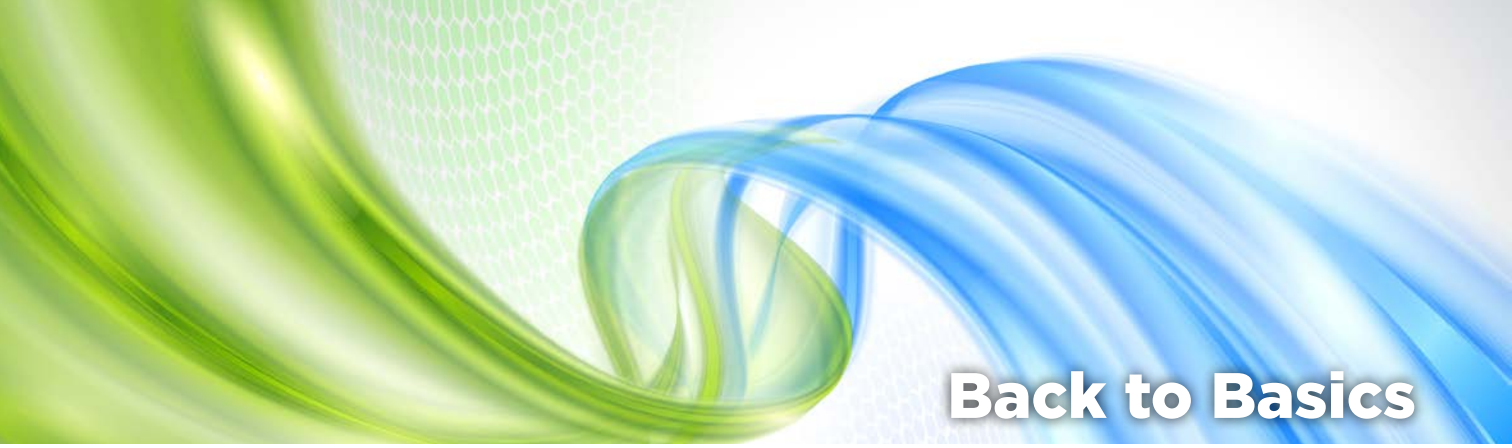
And when you aren't using it anymore, you are required to dispose of it properly—not just send it to a junkyard. Most manufacturers of gamma gauging instruments will accept a returned source, take title to it (so you and your management don't have to keep track of it forever), and send you a document saying that you are no longer responsible for it.

Knowing these simple rules in advance can mitigate management's reluctance to undertake a new regulatory duty.

So There You Have It

Gamma level gauges are a good long-term solution to many of the most difficult level applications you will run into. They will operate with fewer maintenance headaches and, in some cases, operate where nothing else will. ■

Walt Boyes is a principal with process measurement consultancy Spitzer & Boyes.



Bidirectional Flow Measurement

The right flowmeter Is a balance between technical needs and cost-efficiency.

by Ruchika Kalyani

Flow measurement plays a critical role in chemical, petrochemical, oil and gas plants. Criticality of flow measurement in the plants has become a major component in the overall economic success or failure of given processes. Accurate flow measurements ensure the safety of the process and profits in plants. Better measurement can only be achieved by selecting the best/most suitable flow technology for each flow application. Sometimes the accuracy required by the end users is the most significant factor for the specific application. The challenge is to find out the value of the product stream being measured, thus providing the most reliable and cost-effective solution to the end users. Instrument engineers should convince the end user to not install a flowmeter that is more expensive than the yearly value of the stream and the potential loss of money caused by inaccuracies.

A diverse range of flowmeters, along with the turndown factors, is available for various flow applications, such as regular flow control (steam, gas, utilities, etc), process flow rates, fiscal or custody-transfer metering, and others. Most of these applications will be unidirectional, but some will be bidirectional.

The measurement of unidirectional flow rate is possible with all types of flow technologies, but the bidirectional flow measurement capability is required to measure the flow rates within the same flow loop in opposite directions. This sometimes creates difficult situations, challenges, process interruptions and/or measurement inaccuracies that can significantly affect the production and profitability of the plant.

We will further discuss the selection of the appropriate metering for bidirectional situations and applications, limitations, advantages and disadvantages, maintenance and installation costs.

Bidirectional Flow Measurement

Bidirectional flow lines are not very common in refineries and petrochemical plants, but if they are needed, they are always difficult. For bidirectional flow, the piping scheme uses the same line to accomplish delivery and/or control functions for flows moving in opposite directions (forward or reverse flow), depending upon the process conditions and objectives.

Examples of bidirectional flow are

- Raw water feed to two or more water treatment plants,
- Bidirectional steam lines supplying steam from one unit to another unit in the plant,
- Utility and circulating pumping of dielectric fluid into underground electrical cables in order to dissipate heat generated by high-voltage power lines,
- Gas injected or withdrawn from the gas storage field or reservoir,
- Purging and blanketing of nitrogen in plants, and
- Chilled water plant decoupling headers.

Bidirectional Flow Measurement Using Volumetric Flowmeter Options

The selection process of bidirectional flow metering depends on application requirements, process demand, end-user accuracy requirements and physical design constraints of the flowmeter itself. Various flowmeters are available with bidirectional flow capabilities, such as DP transmitters with an orifice, the Venturi or wedge element, Coriolis, ultrasonic, vortex, pitot, turbine and magnetic flowmeters.

Instances where a bidirectional flow measurement is required include

- Possibility of having two different flow rates in either

direction, due to the process and design conditions, and both flows need to be measured,
- Reverse-flow accuracy is required by end user or by the process,
- The need to measure reverse flow in the process,
- Bidirectional flow measurement using dual DP transmitter options.

For bidirectional flow measurement between two process units in a process plant, for example, when two steam units are linked to each other, at the time of deficiency of steam in one unit, the other unit will supply the required steam to the deficient unit and vice versa. If reverse and forward flow rates are identical in both directions, and precise accuracy is not required, then dual transmitters, one for each flow direction, are the best solution for measuring the steam flows in/out of the plant. Two DP transmitters with an orifice plate, along with temperature compensation, can be used for the bidirectional flow. In this case, a non-beveled, square-edge type orifice plate should be used, and the two edges of the orifice should comply with specifications for the upstream edge mentioned in the ISO 5167 standard. It's also necessary to make sure of the full "upstream" straight lengths on both sides of the flow instrument. This must be clearly communicated to the piping design team during design reviews and before construction begins.

With this combination, do not expect high accuracy and turndown. This combination will provide the lowest installed cost with acceptable accuracy, as it is easy to maintain and replace. Also, this dual transmitter combination option will be ideal in cases where the transmitter will experience reverse flow once every four or five years for a four- or five-day period.

Bidirectional Flow Measurement with a Single DP Transmitter

A single DP flow transmitter coupled to a primary element option, such as the special orifice plate mentioned above, can also be adopted for cheap reverse-flow measurement. This arrangement will cut down the expense of installing another (second) DP transmitter, orifice plate, additional hardware, meter installation requirements and the complexity of signal switching.

The square root function is complicated by the one-transmitter option because reconfiguration of the transmitter signal (4-12 mA and 12-20 mA) requires added function blocks and, subsequently, corresponding function blocks or logic at the distributed control system (DCS) side.

In cases where it's only a matter of knowing the reverse flow direction, and accuracy is not important, then the existing DP set without configuration can be used. At zero flow, 4mA is shown, and an output less than 4 mA can be used to alarm for reverse flow even when the square root function is on.

With newer, smarter flowmeter techniques, transmitters are equipped with a feature that allows reconfiguration of the DP transmitter range, such as split-range output signal (4-20 mA) to the system side (DCS, PLC). The bidirectional function, such as square root functions, can be directly applied to the transmitter by either installing special bidirectionality software at the control system side, or by using the built-in capability of the flowmeter to be used in both forward and reverse flow directions.

With equal or unequal flow rates, flow direction will be indicated as the output value (4-12mA = Reverse and 12-20 mA = Forward). With equal flows, zero flow point is established based on the DP range of forward and reverse flow, and for unequal flow rates, zero flow point will be a calculated value.

Bidirectional Flow Measurement with Vortex Flowmeters

The other option of two vortex flowmeters can also be used for steam bidirectional flow if higher accuracy is required than can be achieved using the orifice solution.

However, this application is limited to smaller line sizes because vortex meters are more economical up to 4-in. (100-mm) pipe size. Beyond this size, orifice plates are more economical. In addition, the selection of a vortex-shedding flowmeter may increase the maintenance and installation cost.

Wherever higher accuracy is required, vortex flowmeters are not a good option, as vortices shed by both bluff bodies propagate really far beyond the pipe and may affect the other meters' readings. Another drawback is that the straight pipe run distance required between two vortex meters is unpredictable. For example, in the case of no obstructions, the meter required the run of 10 D (diameters) to 15 D, and if there is a control valve in either direction, the meter may require a higher run of 25 D to 30 D or even more. In comparison to the options of dual transmitters for bidirectional flow measurement between the two process units, DP flow measurement may be the most cost-effective solution.

Bidirectional Flow Measurement with Turbine and Magnetic Flowmeters

Bidirectional flow measurement is always a challenge when there are changes in process parameters, such as viscosity, conductivity, etc. It is always worth keeping these specific situations in mind while selecting any flowmeter technology, but with bidirectional flowmeter applications, it is especially important. DP type meters are usually not really well-suited to handle these process parameter variations.

Again, an example is utility pumping and circulating plants pumping dielectric fluid into underground electrical cables in order to dissipate heat generated by high-voltage power lines. This application requires flow rate monitoring upstream and downstream because it involves dielectric fluid; therefore, it requires viscosity compensation as the temperature of the dielectric fluid changes. In this application, turbine flowmeters can provide the solution for bidirectional flow measurement with moderate accuracy. However, drawbacks associated with this technology include a poor response of the flowmeter at low flows due to bearing friction; lack of suitability for high-viscosity fluids because the high friction of the fluid causes excessive losses; as well as the requirement for regular maintenance and calibration to maintain its accuracy.

The magnetic flowmeter can also be used for bidirectional flow measurement. It has the advantages of no pressure drop, linear output, short inlet/outlet pipe runs (five diameters upstream of the electrode plane and two diameters downstream), and good turndown. Magnetic flowmeters are relatively expensive and are mainly limited to conductive fluid applications, such as acids, bases and slurries, as well as water. A pre-requisite for this type of flowmeter is that the fluid is electrically conductive with an absolute minimum conductivity of 2-5 µSiemens.

Bidirectional Gas Flow Measurement with Ultrasonic Flowmeters

At gas storage fields or natural gas reservoirs, accurate gas flow measurements are required for tasks such as injection and withdrawal of gas from these reservoirs. Reservoirs are used as buffers between suppliers and consumers. In order to maintain the balance for the entire reservoir, it's necessary to monitor bidirectional flow at the wellhead.

For this purpose, conventional DP flowmeters with an orifice are far from a suitable solution, as they lack accuracy and reliability. Orifice plates are subject to wear and tear. Secondly, regular inspections and maintenance are required. While measuring the dirty gas, the pressure taps of the orifice plates are particularly exposed to clogging due to the solid particles which may be present in the dirty gas. These will definitely distort the accuracy of measurement.

In these cases, an ultrasonic flowmeter may be a far better solution because this type of flowmeter has no pressure drop, no flow blockage, no moving parts, and is suitable for high-volume bidirectional flow and also for low-flow measurements where other types of flowmeters do not provide the required results.

The advantage of using the clamp-on gas flowmeter transducer on the outside of the pipe is that it doesn't require any pipe work or any kind of process interruption. With this type of flowmeter even a little moisture content present in the gas can't significantly affect the measurement.

The reliability, negligible maintenance with highest accuracy and long-term cost of ownership are the major benefits of this technology.

Bidirectional Flow Measurement with Coriolis Mass Flowmeters

In the process industries, Coriolis technology has set the standard for flow and density measurements. This technology is used for various applications, such as mass balance, monitoring of fluid density and custody transfer, but also to reduce maintenance, and for bidirectional flow measurements.

In refineries, there are bidirectional applications, such as import and export of product, product transfer to storage and to petrochemical plants, and where the accurate measurement is more important than cost.

Coriolis mass flowmeters can be used for accurate and reliable measurements of all streams in and out of the plant. This is critical for accounting and profitability. End users should take into account that inaccurate measurements sometimes may cause them to give away more product than they are being paid for. This can result in a significant loss of profit.

Conpared to the traditional use of volumetric flow technology for bidirectional measurements, the use of Coriolis mass flowmeters eliminates various well-known drawbacks of volumetric technologies, such as the requirement for significant upstream and downstream straight piping length and the reduction of potential errors that occur in compensation for temperature, pressure, viscosity or specific gravity. The Coriolis mass flowmeter technology does not require that compensation.

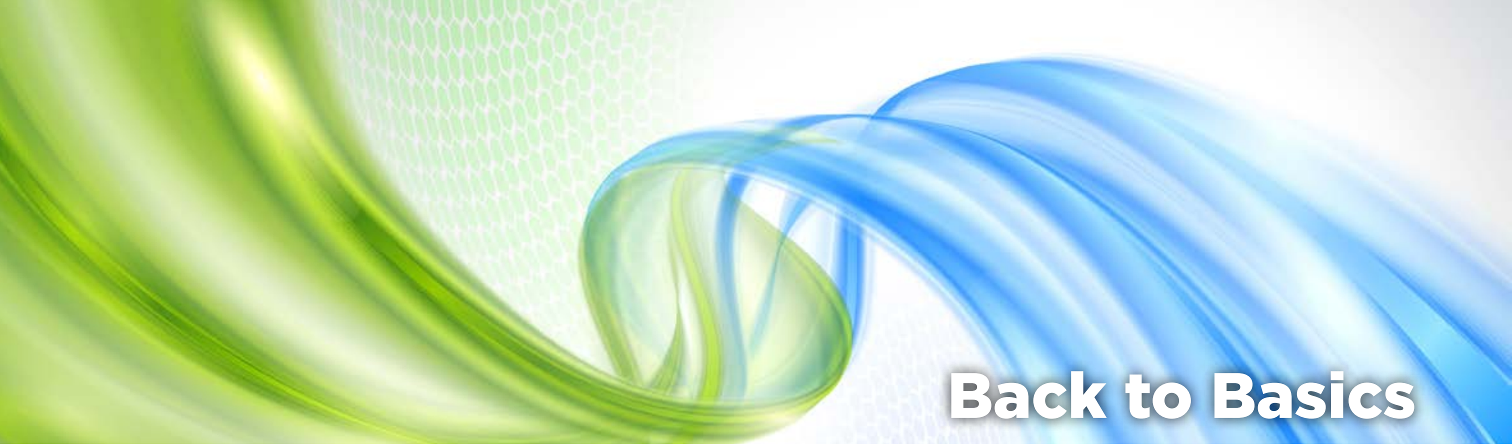
Coriolis meters measure mass flow. They do have their own inaccuracies, but these tend to be low relative to other types of flowmeters. The turndown of Coriolis meters is high compared to other types of flowmeters. Another advantage is that no recalibration is required when switching fluids or for changing process conditions.

Purchase Price vs. Cost of Ownership

It's important for control system engineers to evaluate accuracy required for applications before selecting any bidirectional flowmeter technology, as more accurate and precise flow measurement often results in higher cost of the flowmeter.

The control system engineer must understand that price is always the consideration. However, there are some important distinctions to be made in terms of price. A flowmeter can have a low purchase price, but can be very expensive to maintain. Alternatively, a flowmeter can have a high purchase price, but will require very little maintenance. In these cases, the lower purchase price may not be the best bargain. Other components of price include the cost of installation, the cost of associated software, the cost of training people to use the flowmeter, the cost of maintaining the meter, and the cost of maintaining an inventory of any needed replacement parts. All these costs should be taken into account when deciding what flowmeter to buy. This should be the one reason for many users to look beyond purchase price when considering flowmeter costs. ■

Ruchika Kalyani is a control system engineer at Fluor Daniel India Pvt Ltd.



Back to Basics: Ultrasonic Continuous Level Measurement

Ultrasonic level is one of the five non-contacting continuous level measurement technologies, and the one that is most often misused or misapplied. Here's how to do it right.

by Walt Boyes

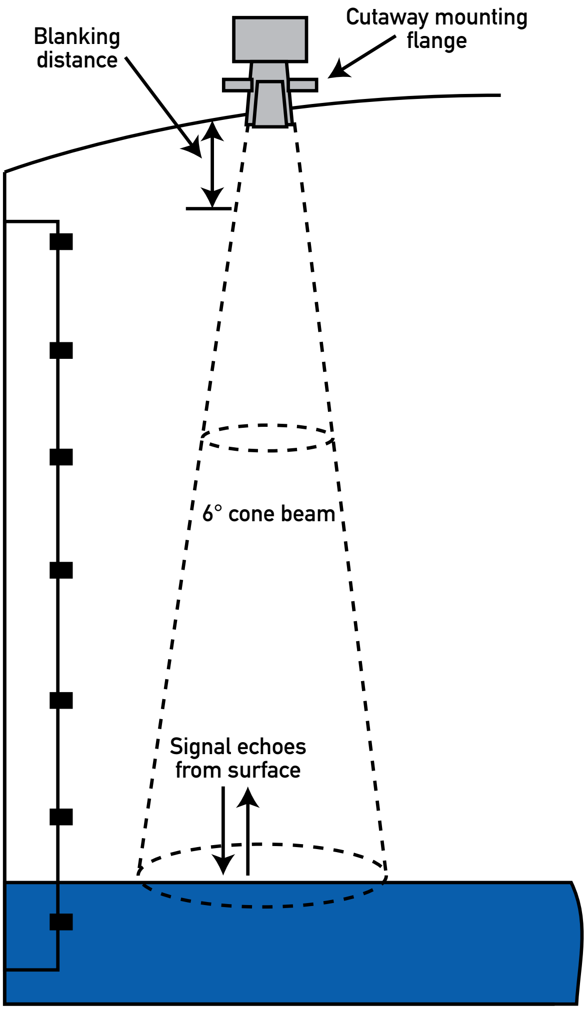
The five non-contacting level measurement technologies are radar, nuclear, laser, weight and ultrasonic. Each of them has both good points and bad. Radar, for example, is relatively expensive in the more accurate versions (frequency-modulated, continuous-wave, FMCW), while nuclear level is limited to relatively small vessels, and there are licensing and safety considerations. Lasers appear to have developed an application niche, especially in the measurement of bulk solids and powders. Weighing systems can be used in some vessels, but it is, again, a relatively niched application solution. Of all of these, ultrasonic level measurement is the most widely used non-contact technology. Ultrasonic level transmitters are used in most industries and are very widely used in open-channel flow measurement systems, sited atop a flume or weir.

How Does It Work?

Ultrasonic level sensors work by the "time of flight" principle using the speed of sound. The sensor emits a high-frequency pulse, generally in the 20 kHz to 200 kHz range, and then listens for the echo. The pulse is transmitted in a cone, usually about 6° at the apex. The pulse impacts the level surface and is reflected back to the sensor, now acting as a receiver (Figure 1), and then to the transmitter for signal processing.

Basically, the transmitter divides the time between the pulse and its echo by two, and that is the distance to the surface of the material. The transmitter is designed to listen to the highest amplitude return pulse (the echo) and mask out all the other ultrasonic signals in the vessel.

Because of the high amplitude of the pulse, the sensor physically vibrates or "rings." Visualize a motionless bell struck by a hammer. A distance of roughly 12 in. to 18 in.



ULTRASONIC SENSOR

Figure 1. The sensor sends pulses toward the surface and receives echoes pulses back.

(300 mm to 450 mm), called the "blanking distance" is designed to prevent spurious readings from sensor ringing. This is important for installation in areas where the distance above the level surface is minimal.

Physical Installation Issues

There are some important physical installation considerations with ultrasonic level sensors.

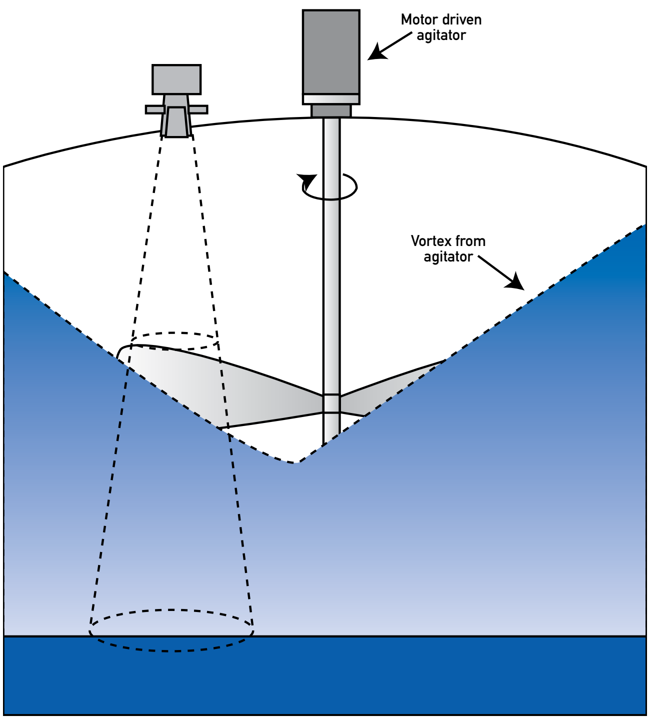
1. Make sure the materials of construction of the sensor housing and the face of the sensor are compatible with the material inside the vessel. Most ultrasonic sensor vendors provide a wide selection of sensor materials of construction in case the standard sensor housing isn't compatible. Most sensors come with a PVC or CPVC housing. PVDF, PTFE (Teflon) and PFA (Tefzel) are usually available. In some cases, a housing of aluminum or stainless steel with a polymer face can be provided.

2. Make sure that the operating temperature range of the sensor is not exceeded on either the high or low temperature end. The materials of construction may deform or the piezoelectric crystal may change its frequency if the temperature range is exceeded. The change in ambient temperature is usually compensated, either by an embedded temperature sensor, a remotely mounted temperature sensor or a target of known distance that can be used to measure the ambient temperature.

3. Locate the sensor so that the face of the sensor is exactly 90° to the surface of the material. This is especially important in liquid and slurry level measurement. In some bulk solids measurements, this can be modified (and this will be discussed in a later section of this article). If you do not do this, your echo will either be missed entirely by the sensor, or it will use an echo that is bouncing off the vessel wall or a vessel internal structure instead of the real level.

4. Make sure that the vessel internals do not impinge on the pulse signal cone from the sensor. If they do, you may get a spurious high amplitude echo that will swamp the real return echo from the surface of the material.

5. Make sure you avoid agitators and other rotating devices in the vessel. Sometimes you can do this with an additional waveguide. If you can't, make sure you purchase a transmitter that can compensate for the effects on the echo of the agitator blade moving in and out of the signal cone.



INSTALLATION ISSUES

Figure 2. Sometimes the measured value is "what the level would be if the agitator were turned off."

6. Mount your sensor where it can't be coated by material or condensation inside the vessel. Coatings attenuate the signal, sometimes so much that there is no longer enough power to get through the coating to the surface and back. If it isn't possible to avoid coatings, try to provide some means of cleaning the sensor face. Some transmitters provide a signal "figure of merit" that can be used to detect coatings or other signal failures and activate an alarm function.

7. Always use the vendor-supplied mounting hardware for the sensor. Hard-conduit-wiring an ultrasonic sensor can increase the acoustic ringing and make the signal unusable.

Application Considerations

Because ultrasonic level sensors and transmitters are inexpensive and usually easy to install, they're often used at the outer edge of the application envelope, and erratic or erroneous signal and signal failure often result.

1. Try to avoid agitated tanks even when the agitator is below the surface of the material. Agitation can produce whirlpools or cavitation, which may attenuate the signal or cause it to bounce off a vessel wall. In some cases, the agitation may be so extreme that the measurement you are trying to make is "what the vessel level would be if the agitator was turned off" (Figure 2). This is not a real measurement, and it may not be possible to make it with any degree of confidence or accuracy.

2. Sparged tanks, where air or another gas is introduced into the vessel by means of diffusers or spargers, can cause bubbles or foam to form on the surface of the material. It is good to avoid this application. A layer of bubbles or foam can attenuate the signal either entirely or partly. If it attenuates the signal entirely, there will be no echo return. It is more insidious if it only attenuates the signal partly. A false echo can occur from somewhere in the foam layer, rather than either the surface of the foam or the surface of the liquid below the foam (Figure 3).

3. Avoid foam. Foam can do three things to the accuracy of the level measurement, and all of them are bad. First, it can attenuate the signal so that there is no echo or only an intermittent echo. Intermittent echo can sometimes be dealt with using a sample-and-hold circuit or algorithm in the transmitter so that the level doesn't change until the next good echo. Sometimes, however, that can be dangerous, as in the case of a vessel where the level is quite near the maximum fill point.

Second, foam can provide a false reading of the true level. You can get a reading from inside the foam layer, instead of the actual level.

Third, foam clumps can cause the echo to be deflected away from the vertical, and the sensor may receive an echo that has made one or two hops against the side of the vessel, yet still be a high enough signal to fool the transmitter.

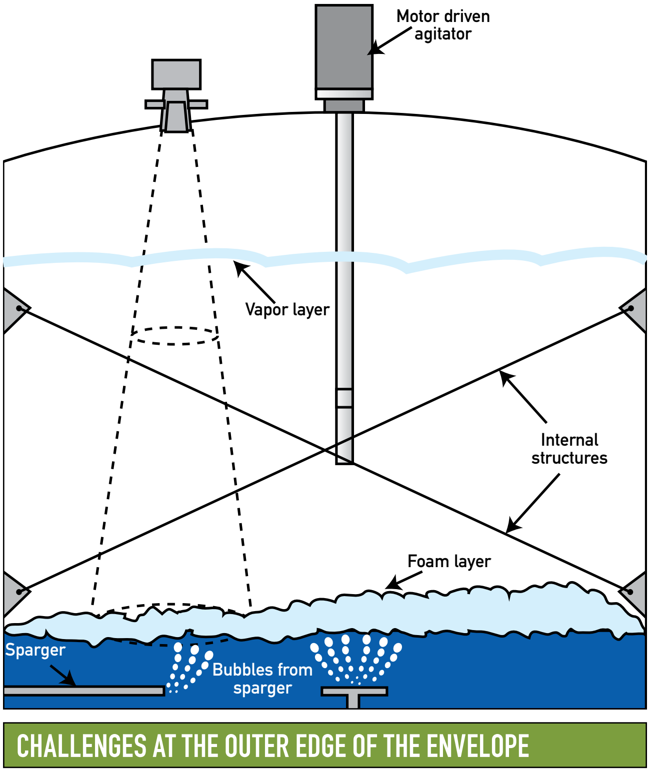


Figure 3. Bubbles, foam, vapor and internal structures make ultrasonic measurement very difficult.

4. Avoid volatile liquids. Back when I was in sales, I sold an ultrasonic transmitter to a major northeastern United States utility for the measurement of level in huge bunker oil tanks. The sensor was installed in early November, and it worked acceptably well until mid-May of the following year, when the customer reported that the sensor was insisting that the level in the tank was several feet higher than it actually was.

This "ghost level" phenomenon is a function of the volatile liquid in the tank. As the ambient temperature rose, the vapor blanket on top of the bunker oil began to become more dense and increased in height. The ultrasonic sensor picked up the top of the vapor layer, instead of the actual oil level in the tank.

By late June, the sensor was regularly reading 80% to 100% because the early summer heat had caused the vapor blanket to fill the tank. We replaced the ultrasonic sensor with a FMCW radar sensor, which worked correctly, and I learned something.

5. In solids and powders, you may have to aim the sensor at a point that is not 90 degrees to the level surface (perpendicular to the vertical axis of the vessel). You may want to aim the sensor because of rat-holing and angle-of-repose issues at the top, midpoint or bottom of the angle of repose. Try to have the transmitter calculate what the actual level might be. At least one vendor has developed a multiple sensor array that can scan the angle of repose and determine what the actual filled volume of the vessel is.

6. Avoid pressurized tanks. The speed of sound changes with temperature and density, and pressurizing the vapor space above the level can affect the density of the vapor space and, therefore, the speed of sound.

Ultrasonic Open-Channel Flowmeters

One of the most important applications for ultrasonic level sensors and transmitters is measuring open-channel flow (Figure 4).

Most of the same caveats apply to ultrasonic level sensors used as flowmeters as apply to ultrasonic level sensors used as tank level measurement devices. There are a few more:

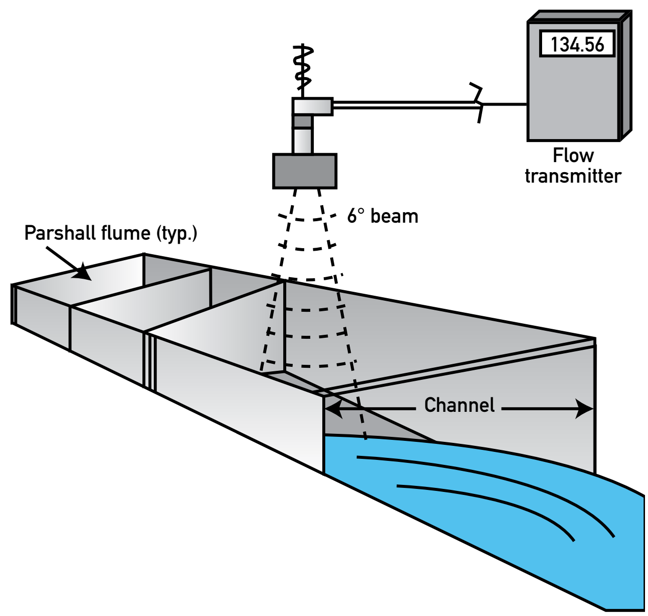
1. Avoid wind and sun. Wind can blow through the vapor space and attenuate the signal or blow it off course. Sun can raise the temperature of the sensor housing itself beyond the operating temperature range of the device—and higher than the ambient temperature.

2. Make sure that there isn't foam on the surface. This can happen often in nitrifying wastewater discharges.

3. Make sure that there is not too much turbulence or ripples (or if the flume or weir is large enough, wave action) on the surface.

4. Above all, make sure that the flume or weir is installed correctly. Many problems blamed on the ultrasonic transmitter are actually problems that are caused by the flume not being installed level both horizontally and vertically, as well as front to back through the measurement zone.

5. Make provisions to keep ice from forming on the sensor in the winter or dripping condensation in the summer.



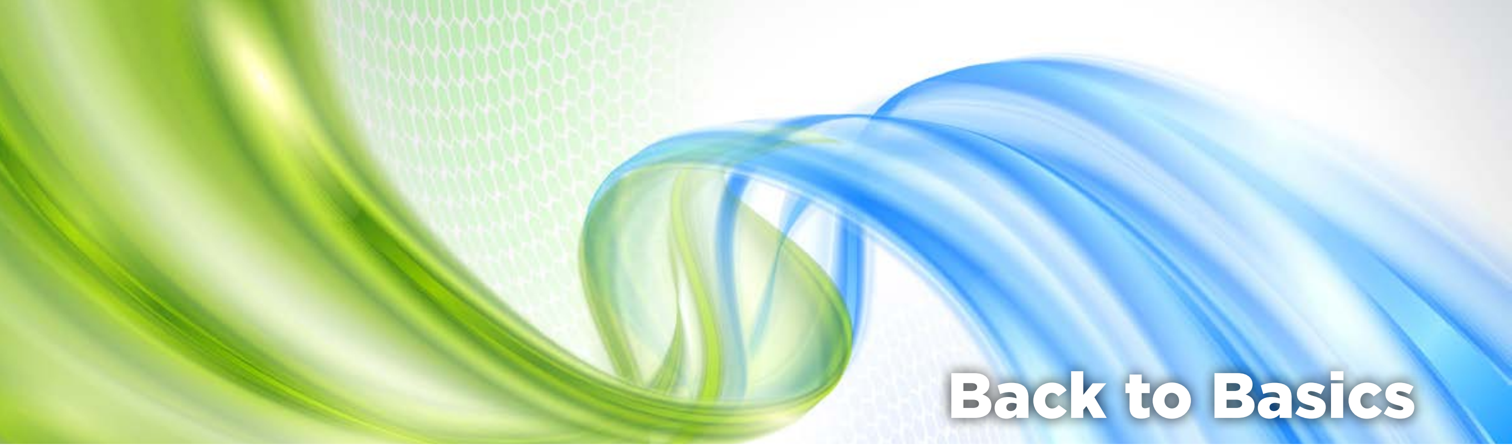
OPEN-CHANNEL FLOW

Figure 4. The level sensor works exactly the same way—measures level. The primary device (flume or weir) measures flow. The flow transmitter takes the level signal and produces a flow value based on the primary device.

The One-Trick Pony—Not!

Ultrasonic sensors are simple to understand, easy to install and inexpensive. It's easy to go to them as the unthinking sensor of choice for level applications, just as many people go to differential pressure level sensors. Yet, as many users have found, ultrasonic sensors and transmitters are tricky beasts. As with any other field instrument, applying an ultrasonic level sensor too far outside the manufacturer's recommended application envelope is destined to fail, and sometimes fail spectacularly. But, if you follow these basic guidelines, you will have successful ultrasonic level installations. ■

Walt Boyes is a principal with process measurement consultancy Spitzer & Boyes.



Stick It!

Insertion flowmeters come in many varieties, but they all share similar characteristics and problems.

by Walt Boyes

You can get flowmeters in insertion versions that are paddlewheel, propeller, turbine, magnetic, vortex and differential pressure sensors. Insertion flowmeters are popular in many industries, because they appear to be easy to install, inexpensive, and come in technology variations that mimic full-pipe meters.

But with no exceptions, insertion flowmeters are not the same as their full-pipe counterparts. In fact, there is some evidence for David W. Spitzer's claim in his book *Industrial Flow Measurement* that insertion flowmeters are a type all their own.

How Does This Work?

In Figure 1, you see turbulent flow and laminar flow. These are based on the concept of the Reynolds number, which is a dimensionless number relating to the ratio of viscous to inertial forces in the pipe. Laminar flow, where the flow profile is straight and smooth, occurs at Reynolds numbers of less than about 2500. Turbulent flow, where there are eddies, vortices and swirls in the pipe, occurs above 4500 Reynolds numbers. Transitional flow, which is neither fully laminar nor fully turbulent, occurs between about 2500 and 4500 Reynolds numbers. Laminar flow profiles are usually visualized as being bullet-nosed, while turbulent flow profiles are seen as plug flows.

Without getting too far into the math, flow studies have shown that in a pipe with a fully developed flow regime, either fully turbulent or fully laminar, the average velocity in the line can be found at a point somewhere between 1/8 and 1/10 of the way in from the side wall, depending on the flow study you read.

Insertion Paddlewheels, Propellers and Turbines

There are three very similar types of insertion flowmeters that use a rotor that spins with the velocity of the fluid.

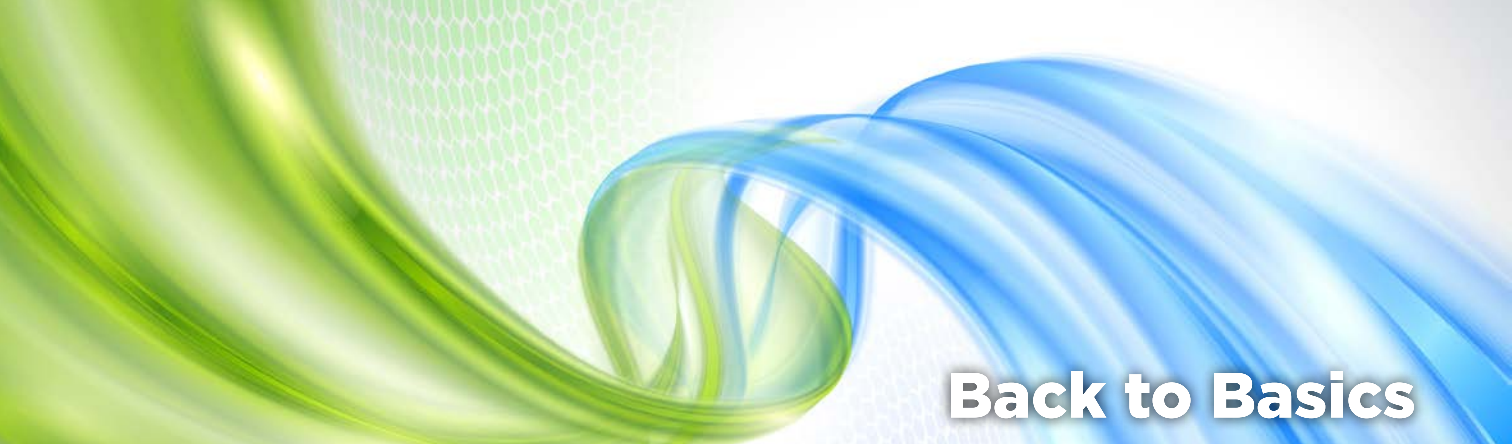
The first is a paddlewheel because the rotor is parallel to the centerline of the pipe, just like a paddlewheel steamboat. Paddlewheels range from very inexpensive to inexpensive, and are designed to be disposable. The least expensive use polymer bearings, which go out of round, and cause the rotor to wobble before the rotor shaft cuts through a bearing and goes downstream. The best use jeweled bearings and ceramic shafts, so they have much more longevity and less drag.

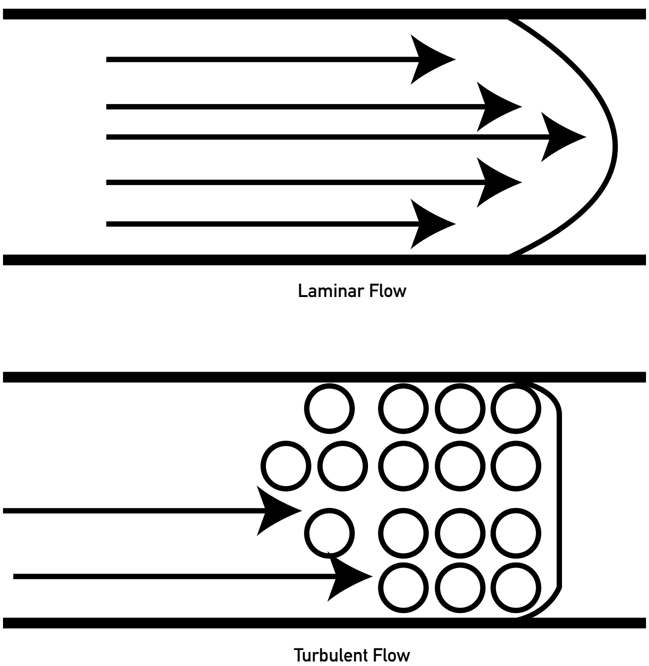
The spinning of the rotor is sensed by either a magnetic pickup that generates a sine wave the frequency of which is proportional to velocity, or a Hall-effect sensor that generates a proportional square wave.

The advantage of the magnetic pickup is that it generates the sine wave without additional power. The advantage of the Hall- effect sensor is that it does not cause "stiction" (the momentary friction stop when the rotor sees the magnetic pickup's magnet). Hall-effect sensors generally are able to read lower flow rates, and are more accurate at lower flow rates as well.

Paddlewheel flow sensors are designed to be easily inserted into a small hole cut into the pipe using a custom fitting. Some paddlewheel sensors can be inserted into the pipe using a hot tap assembly, which allows the sensor to be inserted and retracted without shutting down the flow or relieving the pressure in the pipe.

Propeller meters use a prop shaped very much like an outboard motor's propeller and are generally connected





FULLY DEVELOPED FLOW

Figure 1. Turbulent flow from 4500+ Rn. Laminar flow from 0 to 2500 Rn.

to a mechanical or electromechanical totalizer with a cable very much like a speedometer cable. Some more modern propeller meters use embedded magnets and either magnetic pickups or Hall-effect sensors.

Like paddlewheels, propeller meters have a pulse output that is proportional to the average velocity in the pipe. Because propeller meter rotors are large and located at the centerline of the pipe, they're likely to be quite accurate, and even insertion propeller meters have been certified for billing purposes for decades.

Propeller meters, because their prop is significantly larger than a paddlewheel, are inserted using a flange that mounts into the upright member of a tee fitting.

Turbine meters come in both electronic and electromechanical styles, but the only insertion turbine flowmeters are electronic. They, like paddlewheels, use either a mag pickup or a Hall-effect sensor to produce an output pulse that's proportional to the velocity of the fluid. Like paddlewheels, they must be inserted to the "average velocity point, which exists somewhere between 1/8 and 1/10 of the inside diameter away from the pipe wall.

Most insertion turbine meters have very small rotors, so they can be inserted through a small-diameter fitting or through a small diameter, hot tap assembly. Sometimes, especially in the municipal water industry, this is called a "corporation cock assembly," but it is essentially the same thing—a way of inserting a probe through a valve and still maintaining the pressure in the pipe without leaks.

Propeller meters are almost always used for water service, either in potable water systems or in irrigation systems.

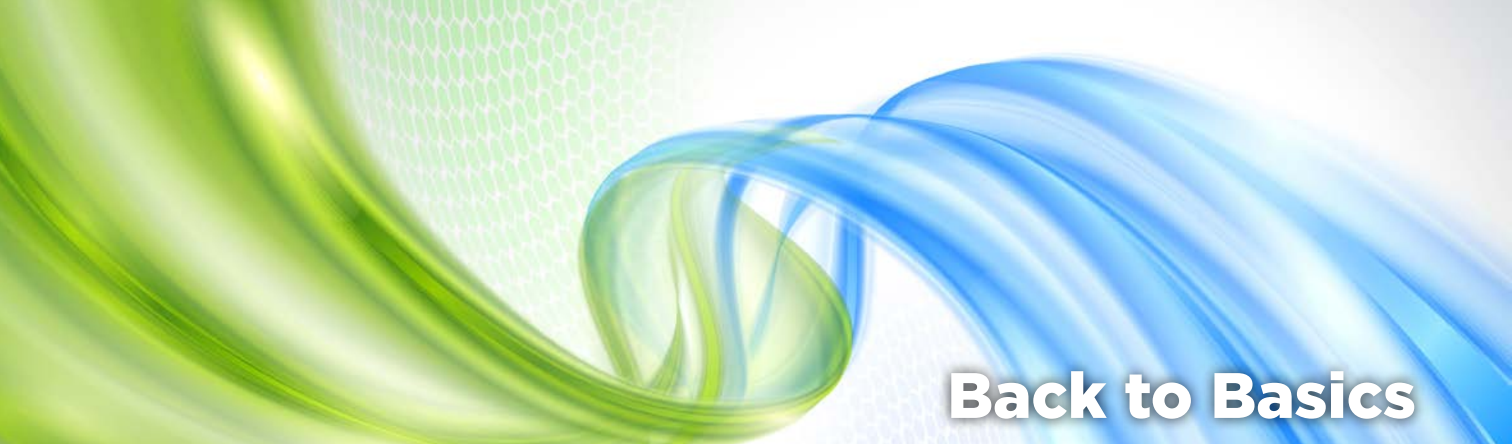
Paddlewheels and insertion turbines can be used in a variety of applications, with materials of construction varying based on the requirements of the applications, such as acids, bases, and hot or cold fluids.

Electronic paddlewheels and turbines can be set up to be bidirectional, using quadrature detectors, which enable the signal to indicate either forward or reverse flow, as well as flow rate. These are often used in HVAC applications where chill water and hot water flow through the same lines depending on the season.

The signal from the paddlewheel or turbine or electronic propeller meter is sent to a transmitter, which uses the pulse (or frequency) output to display flow rate and to increment a totalizer (usually electronic). These transmitters generally have a pulse output, an analog output (usually 4-20 mADC), and often have one or two programmable relay contact closure outputs. These can be used as flow alarms, as diagnostic alarms or as a rudimentary, dead-band controller.

Insertion dP Flowmeters

The most commonly used flow sensor in the world is the differential pressure transmitter connected to a primary device, such as an orifice plate or Venturi tube. In its insertion incarnation, the differential pressure sensor is connected to a pitot tube inserted in the flow stream,



and just as a pitot tube measures velocity on the outside hull of an aircraft, it measures the velocity in the fluid flowing in the pipe.

These devices must also be inserted to the "average velocity point," which is assumed to be somewhere between 1/8 and 1/10 of the diameter of the pipe inbound from the pipe wall. If the average velocity point is not calculated correctly, the single point pitot tube meter will not be accurate.

Several companies now manufacture multiple-point pitot sensors. These sensors are mounted perpendicular to the diameter of the pipe, from one side wall to the other, and have several pitot ports located along their length.

The way these multi-point sensors work is that the differential pressure sensed is the average of all the differentials across the pipe—producing an output signal that very closely corresponds to the average velocity in the pipe. This way, the sensor is connected to a standard differential pressure transmitter, not several of them.

Multiple-port pitot tube flowmeters can be calibrated to take very disturbed flow profiles, such as that in a 90° elbow, into account, and can, therefore, be used in locations where no other flowmeter can be used.

Insertion Mag Meters

Insertion magnetic flowmeters are not the same as spool-piece magnetic flowmeters, even though they share the operation of Faraday's law. In a spool-piece magnetic flowmeter, the design geometry of the coils and the electrodes cause the signal output on the electrodes to be directly proportional to the average velocity in the pipe. Insertion mag meters use the same concept of "average velocity point" as the insertion paddlewheel does, and are about as accurate. Where a spool-piece magnetic flowmeter can reliably be assumed to be close to 0.5% of rate accuracy, an insertion mag meter can often be 10% or 15% of rate, or worse.

Insertion mag meters have a great advantage over other insertion types: They have no moving parts, and are usually highly resistant to acids, bases and abrasives.

Insertion Vortex and Target Meters

Insertion vortex-shedding flowmeters have their proponents. These devices have accuracies similar to insertion turbine sensors, but have fewer moving parts and no rotor. This makes them the clear favorite from a maintenance point of view.

Design and Specifcation

If you can use a spool-piece flowmeter for your application, do it. They are inherently more accurate and have volumetric calibrations instead of just velocity calibrations. Generally, you will use insertion flowmeters where you can't use a spool-piece, either for safety or expense reasons. Insertion paddlewheel flowmeters are often used in industrial water treatment applications and for driving chemical feed systems. Even the multiple-port pitot tube flowmeters are less inherently accurate or repeatable than a spool-piece flowmeter, regardless of technology.

Accuracy and Calibration

The accuracy problem with insertion flowmeters is that they're inserted into an uncalibrated spool section of pipe or even an elbow. The "average velocity point" theory is dependent on a fully developed flow profile with no swirling or distortion.

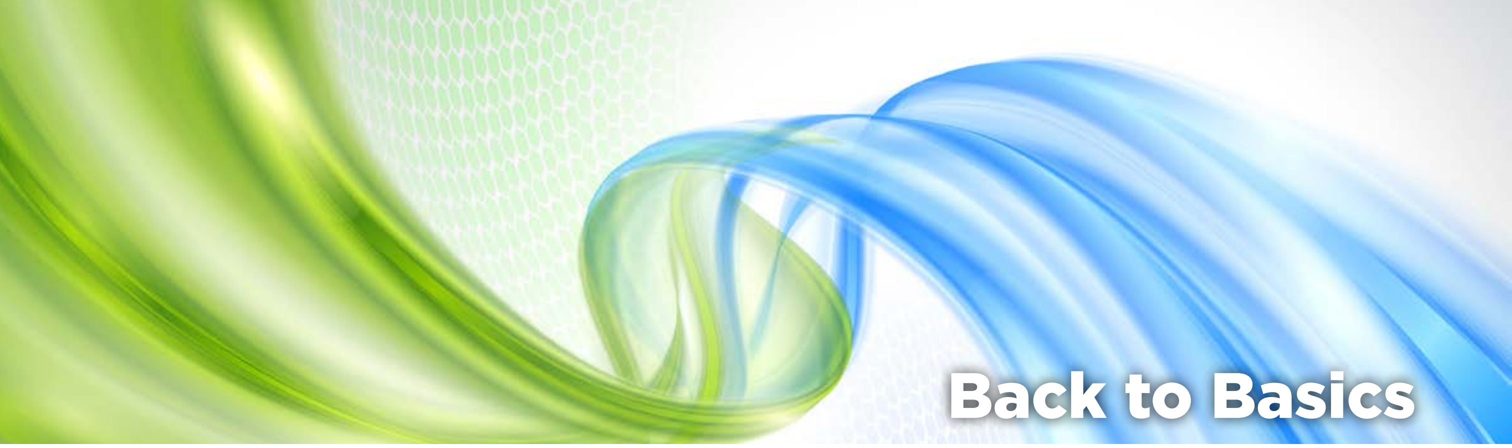
It's almost certain that insertion meters will not be "accurate," but they can be quite repeatable, which, in a flow control loop application may be all you really need.

When you design an application for an insertion meter, you need to be much more careful of piping issues than if you were using a calibrated spool-piece meter. Be aware that the accuracy is going to be substantially less than you can get otherwise. The reason to use an insertion meter is nearly always that it was not designed into the piping originally, or it is being used as a low-cost sensor or a low-cost replacement for an original meter.

For these applications, the insertion flowmeter can be a useful tool in the design engineer's tool bag. ■

Walt Boyes is a principal with process measurement consultancy Spitzer & Boyes..

[Extended version at www.controlglobal.com/1310_flow]



The Lowdown on Radar Level Measurement

Free-air or guided-wave — which do you use when?

by Walt Boyes

We have talked in this magazine about what I call the level measurement continuum before. Basically, there are level measurement applications that are very easy to do, and any level measurement device will work. There are also level measurement applications which are simply too hard to do with current technologies.

Between easy and too hard to do, lay all the level measurement applications that require increasingly complex and costly measurement devices (Figure 1). *[Editor's note: the chart detailing these level measurement concepts can be downloaded at www.controlglobal.com/wp_downloads/pdf/LevelContinuumChart_Ronan100709.pdf.]*

One of the "Okay to Use" bars in the chart that goes furthest toward "Too Hard to Do" is radar level measurement. It is one of the three measurement principles that can do the "really difficult" applications: radar, laser and nuclear level gauges. It is the one of the three with the widest applicability, and one of the most affordable measurement principles.

Radar level measurement is basically divided into two groups, free-air and guided-wave. In free-air radar measurement (Figure 2), a signal is sent from a non-contacting device and received back at the device. Using either transit time or frequency modulation techniques, the distance from the device to the level is derived, and used to calculate the level of the liquid or solid being measured.

Free-air radar works much better than ultrasonic level gauges and is significantly less costly than nuclear level gauges or laser level devices. It's substantially immune to vapor blanket variation in the vessel, to steam, dust and foam in the vessel, and can be easily removed for cleaning and calibration.

Free-air radar solves many of the problems of difficult level measurement applications. You're able to mount the device in many existing vessels using an existing connection, which is normally 4 in. to 12 in. Vessel nozzles on many vessels are unused and available.

However, what happens if you have a vessel where there's extreme agitation, vessel internals, granular materials or extreme coating of the vessel side walls? These all reduce the ability of the radar level gauge to receive the return signal.

In the case of transit-time, free-air radar, signal loss can be total. The dielectric constant of the material being measured matters too. If the dielectric is low and there are other issues, free-air radar may not work well, or it may not work at all.

For decades, we've been installing capacitance or RF admittance devices in tanks to measure level. These devices work very well—if they can be installed to miss internal structures, have appropriate materials of construction and the tank isn't agitated much, if at all.

The physical design is well-suited for tank level measurement, and these devices can often be inserted through a tank nozzle much smaller than the ones necessary for free-air radar level measurement. The problem is that radar works on applications where capacitance or RF admittance devices do not.

Enter a technology called time domain reflectometry (TDR). A probe, somewhat similar to an RF admittance probe in physical shape, is introduced into the vessel

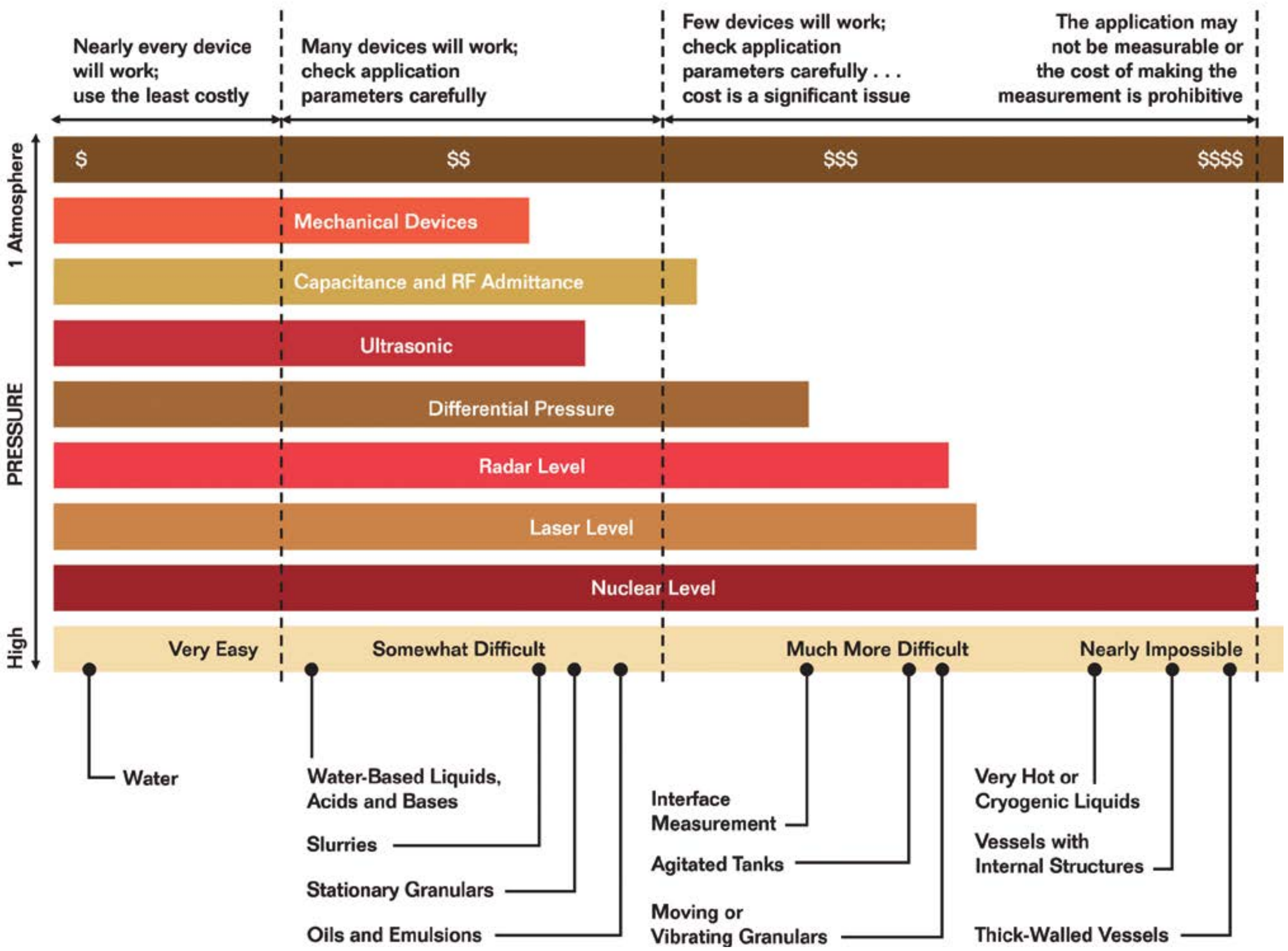
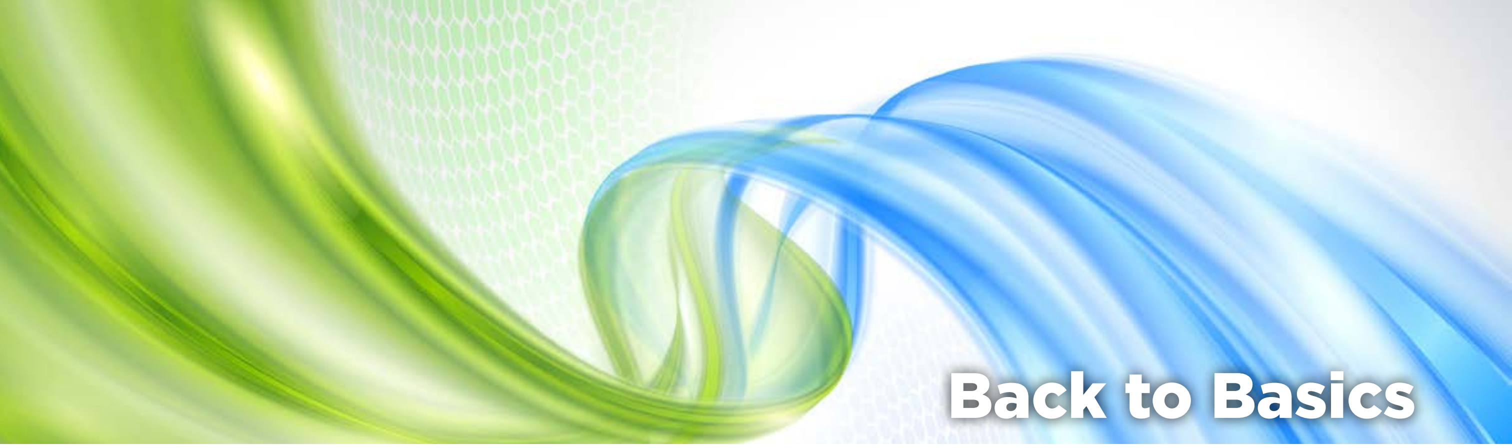
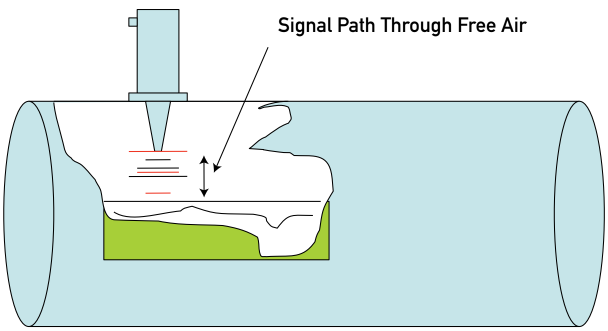


FIGURE 1: THE LEVEL MEASUREMENT CONTINUUM

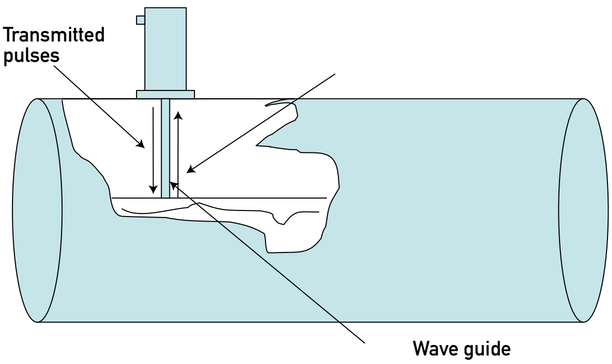
through a tank nozzle. Nozzles can be as small as 2 in. for this purpose. Generated pulses of microwave energy are transmitted down the probe. As soon as the energy pulse encounters a material, liquid or solid, that has a different dielectric constant from that of the vapor space in the vessel, a reflection is generated, and a return pulse travels back up the probe. The transmitter's circuitry creates the transmitted pulses, receives the reflected pulses, and uses the time differential between them to calculate the distance from the probe to the surface of the level to be measured. The difference between that measured distance and the bottom of the vessel is the actual level in the vessel. (Figure 3 shows a typical TDR setup.) Because the probe is used as a waveguide, the technology is





FREE-AIR RADAR LEVEL

Figure 2. Using the distance between the device and the top level gives the level in the vessel.



TIME DOMAIN REFLECTOMETRY — GUIDED-WAVE RADAR

Figure 3. Using a wave guide, the signal is sent down the probe and reflected back to the transmitter.

usually called guided-wave radar.

Guided-wave radar works very well in confined areas where the beam spread of an ultrasonic or a free-air radar level gauge does not. It also works with materials that are of a lower dielectric constant than a typical pulse radar unit, and its precision is comparable to many FMCW radar gauges.

A typical range of dielectric constants for a guided-wave radar gauge is from about 1.5 to around 100. For many years, one of the vendors of guided-wave radar gauges, Magnetrol International, (www.magnetrol.com) has published a *Technical Handbook* that we host at ControlGlobal.com (http://www.controlglobal.com/whitepapers/2005/52.html).

One of the most useful sets of data in that handbook is the tables of dielectric constants for selected materials. That typical range of dielectrics covers a very large spectrum of materials from hydrocarbons to water-based liquids such as acids, bases and other industrial products. Because the wave guide probe can be cleaned in place, it is usually acceptable for service in tanks with food-grade liquids such as orange, apple or grape juice, as well as other water-based liquids.

Guided-wave radar gauges can also be used for interface measurements, such as oil and water, where the dielectric of the top level material is lower than the dielectric at the interface. Both levels send back reflections, and the gauge can be programmed to see the interface as well as the top level. Interface measurements between thick emulsions are not always good applications for guided-wave systems, and the introduction of steam into the vapor space can cause errors of on the order of 20% because of the high dielectric constant of the steam.

Guided-wave radar gauges can be installed in stilling wells to replace existing mechanical float or displacer gauges, and can generally retrofit existing capacitance probe applications quickly and easily.

Most guided-wave radar gauges have HART, Profibus or Foundation fieldbus outputs as well as the standard analog 4-20 mA DC output.

Guided-wave radar helps extend the performance line of radar level gauges in our Level Measurement Continuum chart. ■

Walt Boyes is a principal with process measurement consultancy Spitzer & Boyes.

Saving Steam Saves Money

Matt Brewing Co. reduced energy cost to brew beer by $230,000 per year using mass flow instrumentation.

by Rich Michaels

The Matt Brewing Company is a family-owned business founded in 1888. We make the Saranac brand of specialty products. Nick Matt and his nephew, Fred Matt, currently head the management team at the brewery. Under the leadership of these third and fourth generations of the Matt family, the brewery continues to craft beer to the exacting standards set forth more than a century ago. The brewery currently makes up to 30 varieties of Saranac beer during the course of the year, with distribution to about 20 states.

The heart of a brewing operation is boiling the wort. Brewing starts with the addition of malted barley grain and water to the mash cooker. Mashing allows the enzymes in the malt to break down the starch in the grain into sugars, typically maltose, to create a malty, sugary solution. After mashing, the resulting solution flows to a filter press that separates out the grain. Matt Brewing Company sells the filtered grain byproduct to local farmers as animal feed.

From the filter press, the solution, now called wort, goes into one of two steam-heated, 500-bbl (15,000 gallon) kettles for boiling (Figure 1). One of the kettles boils the wort while the other is cleaned and prepared for the next cycle. A manually operated coil for steam at the bottom of the kettle preheats the wort.

The boiling operation continues for 90 minutes, evaporating about 5% to 10% of the solution. This operation, which includes the addition of the hops, sterilizes the wort and affects flavor, stability and consistency. The hops provide bitterness and flavor. Following wort boiling, the solution goes through a period in fermentation tanks and finally packaging in bottles and kegs.

Steam pressure management is crucial. Depending on the atmospheric pressure, we need to control the steam pressure to get more or less BTUs of heat into the kettle. A pound of steam represents a certain value of BTUs. Steam cost is one of the most important energy variables Matt Brewing deals with. We were looking for a way to improve steam quality and reduce steam use. We consulted with R.L. Stone Co. (www.rl-stone.com), Syracuse, N.Y., on instrumentation to optimize the wort boiling operation.

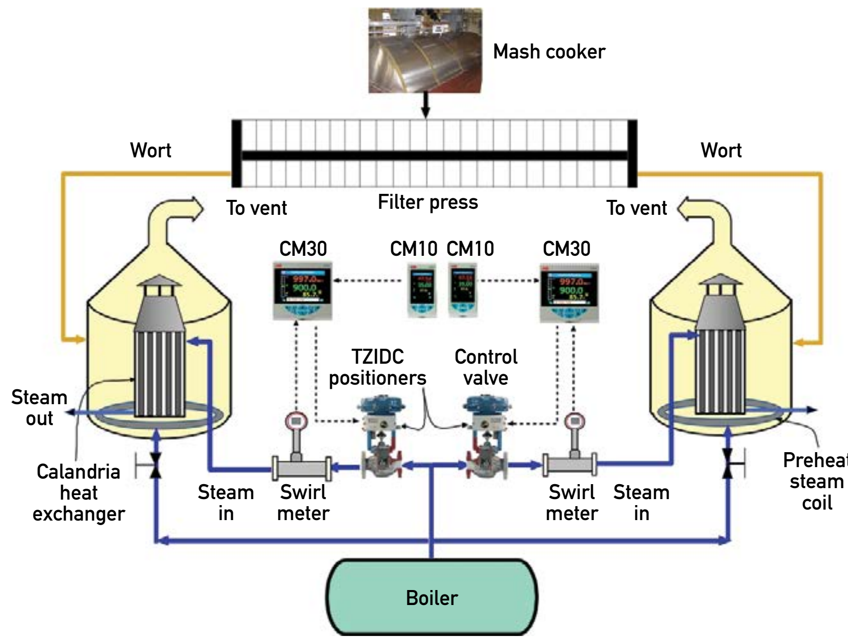
Boiling wort—malt, grain and water—and steam are at the heart of every batch of good beer.

The new instrument system measures and computes mass flow rates of steam to control heat for boiling the wort. As the wort temperature reaches the boiling point, the steam in the bottom preheat coil shuts off, and the recently installed automatic steam heating system takes over. From the steam header, the saturated steam flows through a control valve and an ABB Swirl flowmeter before reaching the kettle. (Figure 2)

The Swirl meter is a "vortex precessing" meter, somewhat akin to a vortex-shedding flowmeter, except that the Swirl meter has far better turndown at low flows and requires minimal upstream and downstream straight pipe, compared to other flowmeter types. We selected this type of meter because our piping geometry was tight, leaving very little

COPPER KETTLES

Figure 1. Wort, the basic beer solution, goes into one of two steam-heated, 500-bbl kettles for boiling.



THE ENGINEER'S GUIDE TO BREWING

Figure 2. This schematic shows the flow of saturated steam through a control valve and a Swirl flowmeter.

space for straight pipe to condition the steam flow (Figure 3). The Swirl meter contains a built-in inlet flow conditioner and outlet straightening vanes, which saved the expense of re-piping the brewhouse.

From the flowmeter, the saturated steam flows to the top of an internal boiler in the kettle called a calandria (Figure 4, p. 48). The calandria is a shell- and-tube heat exchanger. Wort rises through the tube bundle in the calandria while heated by the down-flowing steam, which begins to condense. A deflector at the top of the calandria distributes the wort and prevents foam formation. The internal caldaria efficiently provides both heating and mixing of the wort.

When starting a batch, the operator dials data representing the volume of wort in the kettle into an ABB ControlMaster CM10 flow computer. (Figure 5, p. 48) This unit calculates the optimum mass flow rate of steam based on wort volume and feeds that rate to the ControlMaster CM30 single-loop controller as a setpoint. The CM30 provides indication, recording, math functions and proportional/integral control of the steam mass flow.

The CM30s receive the steam mass flow rates from the Swirl meters and convert them to engineering units used in the brewing process. The CM30s compare the actual versus desired flow rate, and develop a control signal to maintain the predetermined setpoint. The 4-20 mA DC control signal goes to a set of ABB TZIDC intelligent electro-pneumatic positioners we installed on our existing Fisher control valves. An I/P (current to pneumatic) module within the TZIDC positioner precisely regulates air flow to pressurize and depressurize the valve while minimizing air consumption.

The displays for the CM30s indicate the desired steam mass flow rate (the control setpoint) based on the kettle volume, the measured steam mass flow rate in lbs/hr, and the percent control valve opening. The CM30 controller can also display

A TIGHT SQUEEZE

Figure 3. Matt chose the Swirl meter because its piping geometry left little room for straight-run piping to condition the steam flow.

DOUBLE DUTY

Figure 4. The calandria, a type of heat exchanger, both heats and mixes the wort.

DIALING UP THE VOLUME

Figure 5. An operator sets the wort kettle volume on a flow computer prior to batch start.

steam flow rate trends. The CM10 displays wort volume in the kettle dialed in by the operator.

Prior to the installation of the new instruments, we collected three months of data for the wort boiling operation. Measured and calculated variables included kettle volume, steam pressure and temperature, percent evaporation, and necessary water additions. We compared the data we collected to what we believed to be optimum operating conditions and estimated possible savings.

Our savings have resulted from reduced natural gas costs and water usage. The new system for controlling steam pressure has generally reduced required steam pressures from 24 psi to 12 psi. The new system reduces steam use by approximately a third, depending on the brew volume and the operator. It also saves about 1200 gallons of water per brew cycle. We estimate the savings at approximately $630 per day (about $230,000 per year), and the payback time for the instrumentation project is about three to four months.

The results of the new control system are better quality and shelf life for our products with the added benefits of reduced energy and water use. We're considering adding a system to automatically send a signal value for wort kettle volume to the CM10 controller. This would eliminate manual entry errors. We're also planning to add a system for reclaiming energy from plant wastewater to generate electricity for the plant. ■

Rich Michaels is brewing supervisor at
Matt Brewing Company.

Radar Technology for Level Measurement

Precise knowledge of the grain level in UCML's storage silos is essential to production. Radar measurement is the key.

by Monte Smith

United Canadian Malt Ltd. (UCML) is Canada's largest manufacturer of a wide variety of liquid and dry, diastatic and non-diastatic extracts of malted barley, wheat, oats and rice. Our company was founded in Peterborough, Ontario in 1929, and since then has been a major international supplier of premier malt extracts and sweeteners for the food, pharmaceutical and brewing industries. Our customer base is extremely diverse, as customers use our ingredients in everything from cereal, bread, biscuits and pastries to chocolate, pet food, vinegar, chewing gum, ice cream, and, of course, beer.

Malt extract is a vacuum-concentrated sweetener made from high-quality malted barley. United Canadian Malt manufactures approximately 300 different liquid extracts using a variety of grains and process parameters to produce these natural, viscous sweeteners. In the food industry, extracts are used in a variety of baked goods, as the fermentation process assistance improves structure, color and crust appearance. The additional advantage is malt extract's ability to enhance these foods naturally with a unique, subtle and desirable flavor.

UCML is a certified organic production facility offering liquid extracts and syrups made from a range of organically certified grains. In the pharmaceutical industry, the distinct flavor of both liquid and dried malt extracts is an effective vehicle for active substance administration. With its broad nourishment characteristics, malt offers an improvement over plain sugar syrups.

At our facility, the main ingredient, malted barley, is stored in two outdoor silos. From them, it is drawn, crushed and then blended with water to yield a slurry called "mash." Precise quality control on temperature, time and specific water quantity allows the release of nutritional components from the grain. During this process, the natural enzymes inherent in the malted barley convert the grain starches and proteins to soluble and digestible sweeteners and protein components. The resultant fluid, called "sweet wort," is separated by filtration from the spent grains. The wort is then concentrated by evaporation to produce a viscous malt extract consisting of 80% solids material.

Challenge

Brewing production scheduling requires an accurate assessment of our primary ingredient—the malted barley, which is stored in UCML's two 15-m (49.2-ft) steel silos. To do so, we need a very reliable, accurate and robust system to provide constant grain level information from our silos.

WHERE IT HAPPENS

Figure 1. United Canadian Malt Ltd. manufactures extracts of malted barley for the food industry.

Our previous weight and cable level measurement system and rotary paddle switches resulted in ongoing maintenance and reliability issues. Imagine removing caked-on grain dust from an inoperative spindle wheel atop a 15-m (49.2-ft) silo during a June rainstorm. Or better yet, reseating the control rope and winding motor in January's frigid and icy weather.

When the electronics of the weight and cable system failed, we temporarily used a manual level control system. Time and safety issues were substantial cost and efficiency factors, however, as workers had to climb the silo, open the hatch and check levels with a flashlight. And, really, just how accurate is that flashlight level check? Truthfully, the only benefit from all of this climbing to the top of the silos was the positive effect on the manager's heart rate and his fresh air exposure!

All of this took place at UCML with malted barley grain arriving by rail car or truck every few days. Grain delivery was always a control headache, as the silo's capacity is much less than the more than 70 metric tons (MT) on a rail car. With the variable delivery schedules and the expense of rail car unloading demurrage time, it is crucial to have constantly accurate inventory level measurement. Precise inventory monitoring ensures that unloading from rail cars or trucks takes place within the allotted days, and without exceeding the silos' capacity, since cleanup of spilled grain on surrounding streets is not easy. We also wanted the ability to coordinate the brewing usage of the grain discharged from the silos without shutting down production, as this would save both time and money.

UCML investigated several options for reporting silo grain levels. Load cells, a very accurate method, were too expensive to retrofit onto our existing silos. Repairing our weight and cable system's electronics was also quite costly, considering its mechanical problems. An ideal system would have mechanically and electronically reliable construction, and would be accurate over the full length of the silo—especially the bottom cone discharge section. Such a solution would also have a remote readout capability at some distance from the silo and capability for a high- and low-level alarm shut-off option. Finally, it must be able to handle the grain silo's intense dust level during the filling cycle.

SMALL, BUT ACCURATE

Figure 2. Sitrans LR460 (in background) and Sitrans LR560 (in foreground) are measuring the level of malted barley at UCML. The compact size of Sitrans LR560 makes it easy to carry to the top of the silo.

Solution

United Canadian Malt was already familiar with Siemens Industry's level measurement transmitters in its manufacturing process. UCML had previously installed a Sitrans

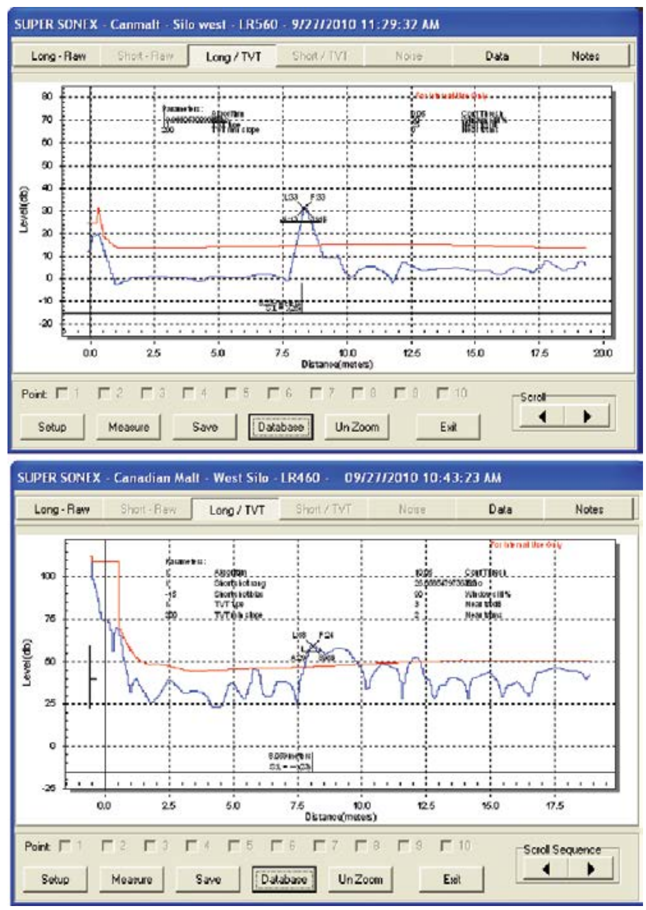
LG200 guided wave radar transmitter on a wort tank. Wort is a challenging substance to measure because of high temperatures and excessive steam and foam that are generated during the wort transfer process. The tank also requires a weekly chemical sanitation bath and a high-pressure water washdown, and there is little headroom, complicating the installation of any instrumentation.

The installed Sitrans LG200 operates with a flexible, single cable probe with a sanitary tri-clamp fitting. The transmitter is connected to a remote display at the operator's station to enable convenient remote monitoring. The LG200 performs consistently and accurately, despite at times working through a meter of foam and its accompanying sticky residue. This unit has done so for several years, which imparts a great deal of confidence in the reliability of Siemens' instruments, both from our production and maintenance operators' standpoints.

UCML's first silo level control monitoring device was a Sitrans LR460 installed on the first of our two outdoor silos. It is connected to a remote display inside the building. Sitrans LR460 is a non-contacting, 25-GHz frequency-modulated continuous wave (FMCW) radar level transmitter, and it uses a four-wire connection (two for 115 VAC power supply and two for the mA output). After some fine-tuning of the signal, Sitrans LR460 provided reliable operation.

The Sitrans LR460 uses a 4-in. horn antenna with an 8° beam angle. Due to the center location of the Sitrans LR460, the transmitter was detecting the seams of the silo, which were tuned out via the process intelligence feature called "Auto-False-Echo-Suppression." This process required the silo to be near empty. Once configured, Sitrans LR460 provided acceptable readings, except for the lower cone area.

With the success of the both the Sitrans LG200 and the Sitrans LR460 in mind, United Canadian Malt selected the new Sitrans LR560 for a solution for level measurement of the second silo. The stainless-steel housing was readily adaptable to UCML's preferred way of installation on our silo inspection hatch, and its compact size made it easy to carry the transmitter to the top of the silo for the installation. From our electrician's point of view, the unit's two-wire configuration was also instrumental in saving installation work and wiring costs.



TWO DEGREES OF ACCURACY

Figure 3. Sitrans LR560 has plug-and-play performance because of the 4° narrow beam and 78 GHz. Alternatively, the 8° wider beam of the Sitrans LR460, requires fine-tuning to find the correct echo profile.

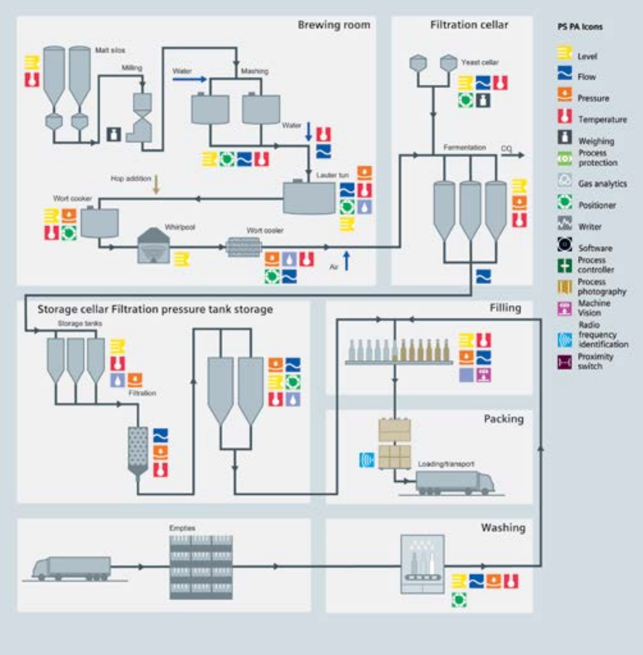
Sitrans LR560 uses a high frequency of 78 GHz and a unique lens antenna to provide a narrow 4° beam. The local display interface has an easy-to-use, graphical Quick Start Wizard that allowed operators to set up the Sitrans LR560 in a couple of minutes using the display pushbuttons. The extreme narrow beam of Sitrans LR560 provides plug-and-play performance, and no additional fine-tuning was required. The seams of the inside of the silo did not interfere with the level readings, and reliable readings are provided all the way to the bottom of the cone area.

Sitrans LR560 is available with HART, Profibus PA or Foundation fieldbus protocols. Programming can be performed remotely with Simatic PDM (process device manager), AMS or PACTware with Siemens' DTM. The local display interface features a backlit display, and can be rotated in four positions. An integrated purge connection is readily available for self-cleaning of the antenna lens if the solids material is exceptionally sticky.The 78-GHz frequency creates a very short wavelength that provides exceptional reflection from sloped surfaces and aiming is rarely necessary. An optional aiming flange is available to aim the antenna away from obstructions or towards the center of the discharge cone for reliable readings in the cone area.

Benefits

Since the Sitrans LR560 was installed, UCML's operators have noticed very stable readings from the transmitter, from completely empty to full. During filling, our operators simply keep an eye on the remote display, monitor the filling cycle and then shut the transfer system off if the level approaches the top of the silo. There has been zero maintenance on the Sitrans LR560 since its installation, and no maintenance is expected.

UCML's silo cleaning schedules have also benefitted from the Sitrans LR560's compact design. Its low profile and lack of extended horn have meant a significantly easier—and safer—cleaning process for the two workers who are on top of the silo performing the required operation.



HOW TO MAKE BEER

Figure 4. The brewing process at United Canadian Malt Ltd.

The yearly maintenance cost associated with the previous mechanical level system has been eliminated. In fact, the cost of the new equipment was paid back well within the first year of its operation.

Overall, as the general manager at United Canadian Malt, I am very happy with all of the instruments we're using from Siemens Industry. We have acceptable performance from the Sitrans LR460, and we were very surprised with the small size of the Sitrans LR560 and how much easier it was to install, set up and operate. Our operators know what is going on throughout our process, and we no longer have any overfilled silos or inaccurate readings from old technology. ■

Monte Smith is general manager at United Canadian Malt Ltd.

Ultrasonic Flowmeters Make Chiller Control Easier

Clamp-on flowmeters are reliable and easily replaceable for maximum uptime

by Kevin H. Evans

For the Federal Aviation Administration (FAA), our most important product is the safety of the traveling public. Every single thing we do is focused on this one goal. We operate facilities that allow modern levels of air transport to occur. One of our Air Route Traffic Control Center (ARTCC) in the southwestern United States handles approximately 5000+ commercial flights a day. Locally, our part of the team effort is to provide the environment that allows the rest of the team to not worry about anything outside of their responsibilities. Power, water, computer support, communications and air temperature are things that need to be present, but invisible to the personnel working the screens.

More specifically to my facility, thousands of different items from mainframe computers to multi-hundred-ton chill water refrigeration units must work in coordination with each other. Providing support to the rest of our team makes the facility's task easier.

This coordinated effort is made possible by control automation. For the control automation to work well, it needs to have information, and, in part, this information is provided by flowmeters.

We have flowmeters on the water coming into facility, flowmeters on the natural gas that fires our boilers, flowmeters on our electricity, flowmeters on the air delivered throughout the ducts of the buildings, and flowmeters on the hot and cold water loops that move throughout the facility. We even have flowmeters on the air vented from the buildings.

The heart of the ARTCC facility is the high-powered computers that manage the flight control data. These aren't desktop PCs, but mainframes that generate considerable heat and must be kept cool. The HVAC air handling system is an essential part of the facilities I maintain.

Our main building depends on four chillers, each with a capacity of 350 tons of cooling. For the hot loop, we have three boilers which can transfer 3.5 million BTUs of heat into the water flowing through the hot-side piping. Another system is our humidifiers. Flowmeters are essential to avoid damage from a system running dry or water overflowing into other equipment.

The system design called for many Controlotron ultrasonic transit-time clamp-on flowmeters, now maufactured by Siemens (www.industry.usa.siemens.com) that report directly to a distributed control system. These meters work especially well for us because they do not change the flow in the pipe where they are making their measurements.

The whole system depends on its flowmeters. The chiller and boiler control system must know how much hot and cold water is being used to create the discharge temperature supplied to the chill loop and the condenser. Without this data, the machinery could have a sudden and catastrophic failure.

In all of these situations, the flowmeters provide the information needed to control the system. Even if we are forced into manual operation, the flowmeters are responsible for giving the human operators the information they need to make the system work.

Our facility runs 24 hours a day, seven days a week, all year long. For heating and cooling purposes, this means two chillers

MEASURING HOT & COLD

Figure 1. These meters are able to handle hot and cold water and indicate bidirectional flows.

HOW TRANSIT-TIME METERS WORK

Siemens Controlotron's founder, Joseph Baumel, designed the first transit-time ultrasonic flowmeter. The basic principle is simple. Transit-time ultrasonic flowmeters, sometimes called time-of-flight ultrasonic flowmeters, transmit ultrasonic energy into the fluid in the direction and against the direction of flow. At no-flow conditions, it takes the same amount of time to travel upstream and downstream between the sensors. Under flowing conditions, the upstream ultrasonic energy will travel slower and take more time than energy traveling downstream. When the fluid moves faster, there is an increase in the difference between the times required for the ultrasonic energy to travel upstream and downstream between the sensors. The electronic transmitter measures the upstream and downstream times to determine the flow rate. Sensors can be wetted, flush with the pipe wall or clamped on the outside of the pipe (Figure 1).

From The *Consumer Guide to Ultrasonic and Correlation Flowmeters,* 2004, by David W. Spitzer and Walt Boyes.

HOW TRANSIT-TIME METERS WORK

Figure 1. By measuring the difference in the speed of sound transmitted and received (transit time), these ultrasonic meters measure velocity and compute flow.

and two boilers in operation.

Following the operation cycle from the point where new chillers and boilers are rotated into the system, the process looks something like this. The first operation is to bring online a new chiller. When the start command is given, the chiller repeatedly checks the output of the flowmeters in the condenser and chilled water loops in order to make certain that proper operating conditions, water flow and valve positions exist.

The transit-time flowmeters provide the fail-safe information to the control processor in the chiller, allowing each step in the starting routine to proceed by verifying that the valves are in the correct position, and that water really is moving through the piping loops for the condenser and chill water sides of the refrigeration unit. Additionally, reports from the flowmeters are sent to the control automation network and regulate the pumps to move the water through the system.

When the oncoming chiller is fully operational and is providing chilled water to the system, a previously operating chiller is turned off and placed into reserve status. Again the flowmeters verify that the chiller is indeed off and the valves are closed. Proper optimization and careful programming can make the system a pushbutton operation, and significantly reduces the number of people needed to rotate fresh chillers into and out of operation. As the cycle continues, the second chiller is rotated into service, and the previously operating chiller is placed in reserve.

As all of the chiller rotations are happening, more transit-time flowmeters inside the chill water loop provide the information and feedback to ensure that the amount of water flowing to the air handlers' coils is the right amount for the building's heat load. Inside the air handlers, other flowmeters confirm that air really is moving to the vents located within the various rooms of the facility. Finally, the exhaust fans from the rooms have flowmeters that verify the air is being removed from the room, ensuring sufficient number of air changes per hour in the facility.

Similar to the chill water system, the heating system cycles boilers in and out of service and maintains proper temperature inside the hot water loop. Boilers can be tricky systems. Improper start-up and improper shutdown can severely damage such systems. Again the flowmeters are integral to the process, providing information for the boiler start-up and shutdown processes, and also verifying that water flow to the air handlers is correct.

Often heat and cooling are required at the same time in an air handler. In such situations flowmeters can balance the demands on the system and reduce overall energy requirements. One of the reasons the Siemens Controlotron flowmeters were selected was their ability to handle both hot and chill water in the air handlers.

In our operation, we have multiple redundant flowmeters so that we can depend on having them when we need them. With good control automation, when the power goes down, and you're on batteries, flowmeters can tell you when things have stopped. Sometimes they provide the critical bit of warning in order to ensure that things like electronic devices do not overheat from cooling loss, or that pipes do not freeze from lack of heat in the building. ■

Kevin H. Evans is an Airway Transportation Systems Specialist, DOT FAA.

Water Is Money. Accuracy Matters

Sustainability Includes Making the Water Distribution System More Efficient

By Walt Boyes

As we progress into the 21st century, water usage for domestic and industrial uses will increase, while new supplies are becoming less available. All you have to do is Google "Colorado River water rights" to get a good picture of how critical water and water use can be.

Many of the same drivers pushing industrial plants to implement plans for sustainable manufacturing are also pushing water utilities the same way. Moving water requires energy. Monitoring a far-flung water distribution system requires substantial manpower—manpower that is getting more expensive and hard to find. Energy is becoming more expensive, and water itself is becoming scarce and must be conserved.

All over the Southwest U.S. and California, water destined for potable service or for irrigation has traditionally been moved through a huge series of canals. Montezuma Valley Irrigation Company, Cortez, Colo., (www.mvic.us) uses such a system This irrigation district provides 1400 shareholders with water for their farms and crops. But MVIC realized that as much as 60% of the water that enters an open canal is wasted by evaporation, seepage and losses at the end of the canal.

So, MVIC decided on an ambitious project to conserve water, and save energy and manpower costs. "A decision was made to replace five miles of open-ditch irrigation canals with a poly pipe water distribution system," said Gerald Knudsen, PE, of AgriTech Consulting, the district's consulting engineer. "The projected savings were on the order of 1000 acre-feet of water per year."

Using high-density polyethylene (HDPE) pipe made it possible to lay the pipe down existing canals in most cases, because it is flexible and easy to work with. The main supply ranges from 12-in. to 36-in. in diameter and is pressurized to 30-50 psi. Each shareholder is served by a "turnout," also made of HDPE with a transition to the PVC pipe commonly used in farming for distribution and irrigation.

Each branch turnout is supplied with a flowmeter and two butterfly valves. The first valve is controlled remotely by MVIC and is used to set flow rates according to the number of shares of water allocated to that shareholder. The second butterfly valve is the throttle or shutoff valve for the owner.

In open-channel water distribution systems, such as MVIC's old one, flow measurement is made via Parshall flumes or wier boxes. Their accuracy ranges from a best of 5% of flow to a typical 20% of flow, and MVIC needed better if it was going to measure and control the entire water distribution system.

Traditionally, closed-pipe water distribution systems have used mechanical flowmeters. The first water turbine meter was

In this pilot project, open ditch irrigation canals were replaced with a closed water distribution system. It reduces evaporation, cuts seepage and eliminates end-of-channel water losses.

produced in the 18th century, and its descendants are similar in design, with a mechanical register for totalizing water usage. They are very accurate and designed for water billing service. But, turbine and propeller meters are maintenance problems, and they are difficult to use as a flow transmitters.

MVIC decided to use transit-time flowmeters clamped to the outside of the HDPE pipe. Two transducers infer the velocity of the water by measuring the difference in the time it takes for an ultrasonic signal to move upstream and downstream through the fluid.

"After extensive review of many types of meters from various manufacturers, a decision was made to purchase ultrasonic flowmeters from Dynasonics (www.dynasonics.com)," said Jim Siscoe, general manager of MVIC.

One of the reasons, Siscoe reported, is that the flowmeters can be solar- or battery-powered. The large turnouts are supplied with continuous power, either by line voltage or by solar power, which is highly advantageous in Colorado. Smaller turnouts are powered by the district's "ditch riders," who carry portable 12-VDC batteries with them. "While the flowmeter is under battery power," Siscoe explained, "the measured flow rate is used to manually adjust flow via the butterfly valve immediately downstream from the meter. Most turnouts require only one setting per season."

Another reason for using ultrasonic flowmeters was the drastically reduced maintenance requirement.

"The Dynasonics flowmeters are now our standard for both new and retrofit applications, particularly replacement of our impeller flowmeters," Siscoe said. "We especially like their non-intrusive aspect, which results in no maintenance, low cost, flexibility and ease of installation." The district now has to keep only one type of flowmeter in inventory.

"The MVIC's long term goal is to fully automate the system by installing wireless flowmeters and automatic control valves downstream of the meters," Knudsen said.

As a pilot, the district received a $75,000 Conservation Innovation Grant from the USDA's National Resources Conservation Service. Scope items for the CIG grant include a solar-powered gate to control water level in the feeder canal and a wireless flow control and measurement system.

"Using solar power saved $25,000 to install an electrical service line to this remote location," Knudsen said. "Based on this success, MVIC has ordered another solar powered flow control gate for another canal next winter."

The transit-time flowmeters use strap-on transducers, which function as ultrasonic transmitters and receivers.

A wireless SCADA system will be implemented at two turnouts. "This portion of the project will demonstrate flow control and measurement at a remote location where flow needs to be changed regularly throughout the season," Knudsen said. "Wireless automation at these two turnouts will demonstrate to the MVIC and its shareholders the benefit of remote flow measurement and control."

"All the turnouts on the closed pipe network have ultrasonic flowmeters with electronics capable of sending flow measurement data to the SCADA master control center at the MVIC office." Knudsen said.

The project has been so successful that the U.S. Bureau of Reclamation (USBR) is providing $2.1 million in stimulus grants to MVIC for construction of a second, seven-mile project.

Knudsen reported that the final project costs were $2.9 million, with annual savings projected to be $2 million. These numbers would yield a payback in about 18 months. ■

Walt Boyes is a principal with process measurement consultancy Spitzer & Boyes.