White Paper

Solve 6 Leading Pressure and Temperature Measurement Issues Using Advanced Instrumentation

Older technologies and practices can be obstacles to more effective operation, but advanced instrumentation provides solutions.

EMERSON

Introduction

What is an obstacle? It's a barrier standing in the way of achieving a goal, making advancement more difficult, and requiring a higher degree of effort to accomplish a task. Obstacles can be overcome, but it's better to eliminate them.

Many professionals working in manufacturing plants are confronted with obstacles every day caused by outdated instrumentation technologies and practices. When first installed, these solutions were likely state-of-the-art and improved upon existing installations, but many have now been superseded by even better solutions as new innovations have been introduced and disseminated throughout process industries.

In this white paper, we will examine six areas where these issues create a variety of problems ranging from operational annoyances to outright hazards. The causes and effects of the problems are different, but all can be mitigated or eliminated entirely by using advanced instrumentation, with each instrument consisting of a sensor in contact with the process, connected to an electronic transmitter. Let's look at the following six obstacles one by one and address how to solve them.

1. Measurement degradation due to deteriorating instrument wiring
2. Heat tracing headaches
3. Impulse lines and process connection issues
4. Mechanical Bourdon tube pressure gauge challenges
5. Reducing thermowell safety risks
6. Temperature sensor degradation and failure

1. Measurement degradation due to deteriorating instrument wiring

Production units and plants typically have hundreds of process instruments operating in a variety of roles (Figure 1.1). These instruments are the operators' eyes and ears, providing critical variables used to monitor and control operations. They can also send diagnostic information to warn of a variety of developing problems internal to the instrument, within the actual process, or the larger automation infrastructure. The latest generation of advanced instruments now exhibits a high degree of sophistication in this area.

Diagnostic information can be transmitted as a HART® value superimposed on the normal 4–20 milliamp (mA) wired analog current loop, or via a digital protocol such as FOUNDATION™ Fieldbus, or *Wireless*HART®. When introduced, these diagnostics represented a major advance for reliability and maintenance departments, allowing them to address developing problems before they caused an inaccurate reading or full failure.

Figure 1.1: Process instruments measure many things, but all depend on effective communication infrastructure.

Everything, including the main process variable and any diagnostic functions, depends on reliable communication infrastructure. The most sophisticated transmitter cannot send data without a reliable connection to the distributed control, asset management, or other host system. In most environments, the majority of transmitters are wired using a 4–20 mA current loop, possibly with HART. Normally these are very reliable but can develop problems capable of causing inaccurate readings.

Loop integrity diagnostic

In a typical plant environment, a pressure transmitter's analog current loop may involve a long cable, potentially several hundred feet or more, between the transmitter and the host system I/O connection. A current loop is very robust, so this does not necessarily pose a challenge if all the elements are intact.

However, a long cable could easily have a dozen termination points from one end to the other as it passes through trays and marshalling cabinets. Screw terminals that have worked loose or become corroded can cause a signal to be lost completely. A short circuit can also cut off data. The live zero feature of the loop will usually call attention to a full signal loss. More subtle problems, where the reading is corrupted but not drastically enough to be immediately recognizable, can cause operators to take the wrong action. Here are two examples of how these can happen.

Leakage current – Some situations can create a partial short circuit where a new circuit path is formed. Electrical current "leaks" from one side to the other, often due to moisture or corrosion (Figure 1.2), which might change the signal level. For example, if the actual signal from the transmitter is 12 mA and the leakage allows another 3 mA, the host system will believe the reading is 15 mA and show a corresponding value to the operators. If the transmitter sends a signal greater than 18 mA, the system will incorrectly show a fault because the value will exceed 20 mA. This on-scale failure can cause operators to take improper action, or it can cause a control loop governed by that transmitter to respond incorrectly.

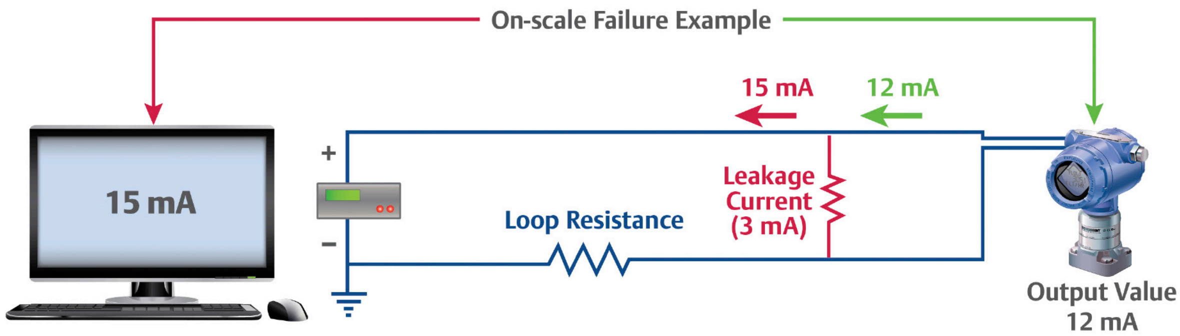

Figure 1.2: Current leakage causes readings from instruments to appear higher than they actually are.

Increased electrical load – Correct functioning of a loop depends on having a known resistance for the wiring and a reliable, consistent power supply. If wires or terminals are corroded or loose, there may still be contact, but those points will add an additional load just as if a resistor had been added to the circuit. Similarly, a failing or overtaxed power supply can create a brownout condition with sagging output. These can reduce the voltage available to the transmitter (Figure 1.3) which can keep it from being able to reach a full 20 mA signal. Under those conditions, the transmitter might only be able to communicate a maximum of 15 mA even though the process calls for something higher. This condition is particularly difficult to recognize since the transmitter can behave correctly through much of its range leaving operators unaware of this critical failure condition.

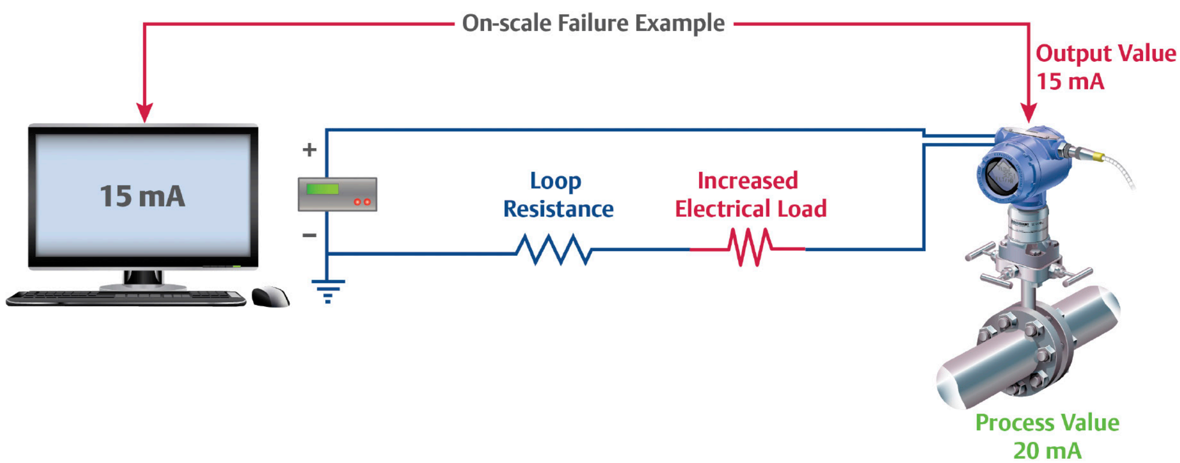

Figure 1.3: Increased electrical load can lead to brownout conditions where readings appear lower than they actually are.

Both these conditions can be detected through manual loop checks by a qualified technician, but few facilities have the resources to perform these with sufficient regularity. Some new advanced transmitters are available with loop integrity diagnostics to perform these tests automatically, monitoring the available voltage on a continuous basis. If voltage deviates from baseline conditions, operators and maintenance technicians can be notified immediately, allowing them to detect and correct the issue, avoiding potential process upsets or even safety incidents. Thresholds can be programmed in the configurations to correspond to the criticality of a given loop.

Failing wiring infrastructure

Some older plants still running ancient automation infrastructure often deal with the loop integrity problems just discussed, combined with outright failures of legacy cabling, but the cost of replacing it is impractical or far too expensive for every instrument. Plants may try workarounds, but eventually the failures are simply too significant, and operators begin to lose critical information

The easiest and most economical solution is abandoning the wiring entirely and replacing it with *Wireless*HART for all monitoring applications and some real-time control applications. Any existing 2-, 3- or 4-wire HART-enabled transmitter (Figure 1.4) can be equipped with a *Wireless*HART adapter, capable of sending multiple process variables and diagnostic data via the network. This allows working legacy transmitters to stay in place where possible, although some may still need external power.

Figure 1.4: Emerson's Wireless 775 THUM™ Adapter can be added to HART enabled instruments with advanced diagnostics to send data and diagnostic information via a *Wireless*HART network.

This eliminates the need to replace long wiring runs, likely improves on existing signal quality and reliability, and can deliver more data to the host system. It may be desirable to replace some of the oldest transmitters with newer units using native *Wireless*HART designs. The variety of these self-powered units is growing, eliminating the need for signal or power wiring.

2. Heat tracing headaches

Installations using differential pressure (DP) and in-line pressure transmitters frequently depend on impulse lines to carry pressure from the process penetration points to the transmitter. (More on this topic in Section 3.) Impulse lines are used in all types of applications, including where DP measures flow and level. The heat tracing headaches discussed here can emerge anywhere but are particularly problematic for level applications so they are the primary example.

Measuring level in a tank or vessel by using DP is an excellent approach, particularly when there are internal structures or other liquid conditions that make other methods impractical. It has been a favorite approach for countless years, and many plants have an example somewhere. It is usually a simple approach to implement, but challenges can develop in situations where the tank is particularly tall, the process media is often at a high temperature, or there are ambient temperature changes. These conditions create obstacles to effective level readings, made worse by maintenance headaches.

While today's pressure transmitters have a wide range of operating temperatures, some hot processes may exceed what is tolerable. In that case, the transmitter has to be far enough away from the process medium to protect it from the heat. Usually this means a remote diaphragm exposed to the high temperature and sending pressure via a sealed, fluid-filled capillary designed to withstand the heat (Figure 2.1). Over the length of the impulse line or capillary, cooling should protect the transmitter.

Figure 2.1: Remote diaphragm seals and temperature tolerant fill fluids can solve some problems but may introduce others in certain situations.

This is fine as far as it goes, but real-world users sometimes encounter implementation problems. If the environment is cold, even only intermittently, the impulse line may cool too much, which causes the high-temperature fill fluid to become excessively viscous at the transmitter end and interferes with accurate pressure transmission. Careful design can mitigate this heat loss and minimize the problem for the high-pressure side connection at the tank bottom, but the low-pressure side impulse line coming down from the top of the tank has the same problem and is far more difficult to control.

Conventional wisdom says a solution for both sides is simple: wrap all the impulse lines in steam- or electrically-heated tape and the problem is solved. This may work, but heat tracing is a costly and maintenance-intensive solution with a poor track record for reliability. Let's look at this challenge more closely and consider approaches for the high- and low-sides individually.

The high side impulse line, which bears the liquid's weight and temperature, is usually relatively short and close to the tank. Nonetheless, if the impulse line is configured to provide adequate heat dissipation under normal operating conditions, a particularly cold snap may create a problem. A better solution than heat tracing is using a Thermal Range Expander, a sealed impulse line arrangement with two sections, each using a different fill fluid.

Building in heat tolerance

The Thermal Range Expander may be used at process temperatures up to 770 °F (410 °C) and ambient temperatures as low as -157 °F (-105 °C). It uses a combination of two fill fluids separated from each other with an internal diaphragm (Figure 2.2). The hot end connects directly to the process using a flange mount which can bolt to a nozzle on the vessel. Behind the hot-side diaphragm is a small diameter tube filled with high temperature fluid which transmits pressure to the intermediate diaphragm, which conveys pressure to a second tube filled with a low temperature fluid. The pressure in the second tube is then measured by the transmitter.

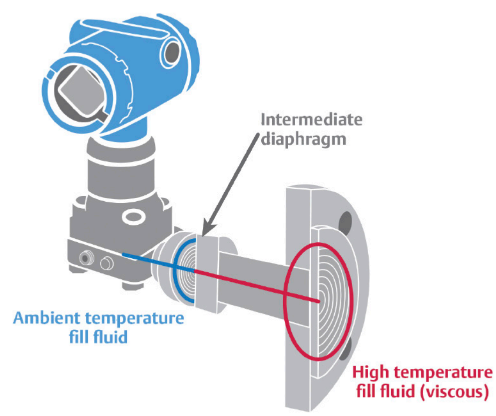

Figure 2.2: The Rosemount™ 3051S Thermal Range Expander uses two fill fluids, separated by an internal diaphragm. Both can be selected for specific conditions.

The fill fluid adjacent to the diaphragm adjoining the process is selected to respond quickly at high temperatures, and its temperature and correct viscosity are maintained by the process itself. The fill fluid in the second tube is selected to respond quickly over the anticipated range of ambient atmospheric temperatures, from cold to hot. In this way, measurement fluctuations due to fill-fluid viscosity issues are eliminated.

Losing long lines

Solving the impulse line to the top of the tank can be more of a problem due to its length. Where temperatures are high enough the Thermal Range Expander may be necessary on the top of the tank as well as the bottom. As with the bottom, there is the temperature stratification concern, but also the pressure created by the fill fluid itself. A better approach eliminates the long impulse line entirely. The Rosemount 3051S Electronic Remote Sensor (ERS)™ System uses a second transmitter at the vessel top (Figure 2.3). This transmitter measures the headspace pressure and sends the measurement electronically to the primary transmitter at the bottom. One or both transmitters can be outfit with the Thermal Range Expander if necessary.

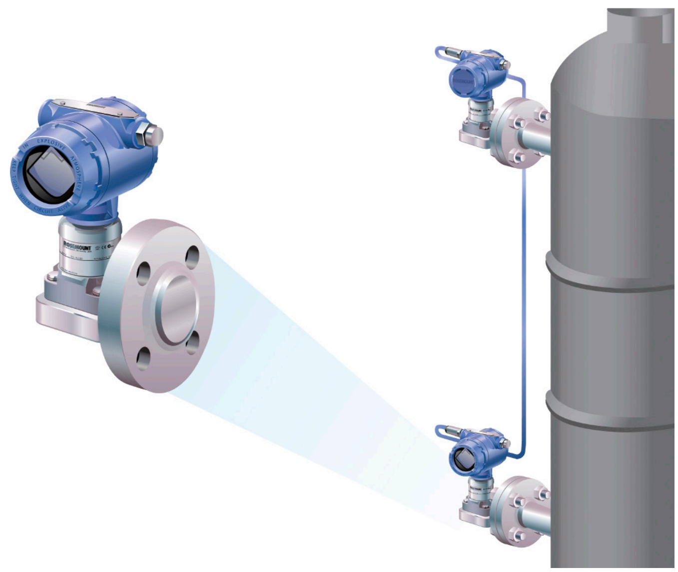

Figure 2.3: ERS technology uses two transmitters connected electronically to eliminate conventional impulse lines.

ERS technology eliminates any need for the long impulse line, along with associated heat tracing or required maintenance, to ensure an accurate reading from the top of the tank. With an electronic connection, there is no reason to doubt the head-space pressure value.

The combination of Thermal Range Expander and ERS System can easily deliver major installation and operational cost-savings as compared to heat-traced exterior units during setup and installation, plus with no electricity or steam needed for heat tracing, ongoing saving of operating and maintenance costs are also possible.

The Thermal Range Expander reliably reports DP level in the unit in less than one second and is unaffected by ambient temperature changes outside the tower. The ERS System can also provide an independent pressure reading from the top of the tank. All data is sent from the transmitter at the bottom of the tank, so only one connection to the host system is required.

This technology upgrade can improve process monitoring and reporting over older methods, improve safety by enabling faster response to the development of upset conditions, and saves money.

3. Impulse lines and process connection issues

Taking a DP, gauge, or absolute pressure reading from a process involves creating process connections so the pressure can reach the sensor. (We'll discuss mechanical gauges in Section 4. Here we'll concentrate on electronic pressure transmitters.) Frequently this is done via impulse lines which carry the pressure to the transmitter (Figure 3.1). In some cases, these can be short and very direct, or they may need to be long to allow mounting the transmitter some distance from the process equipment.

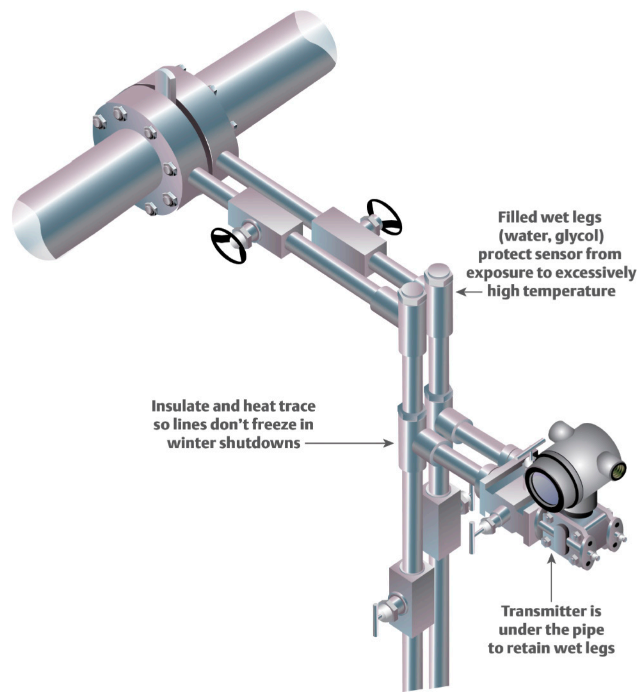

Figure 3.1: Impulse lines may be simple or complex, but they share a similar set of problems.

Conventional impulse lines can create a variety of problems:

- They are part of the process containment
- If they leak, product is lost, with potential safety, economic, and environmental implications
- If process equipment calls for exotic materials, the impulse lines need it too
- They can fill with gas or liquid which compromise their ability to transmit pressure accurately
- They can freeze in cold weather

Impulse lines are typically custom efforts and often built in the plant's maintenance shop, reflecting the skill of local contractors or pipe fitters. A better choice is to use a pre-assembled instrument, such as is available with a DP flow meter like Emerson's Rosemount 3051SFP Integral Orifice Flow Meter (Figure 3.2), a complete unit built in a factory and fully tested. All fasteners are tightened to the optimum torque level and the finished assembly can be leak tested. These meters are ready to install right out of the box and even include a calibration report.

Figure 3.2: A fully assembled flow meter avoids the problems associated with custom impulse line setups.

Avoiding operational obstacles

Whatever the situation, impulse lines must not impede pressure delivery so the transmitter can read the sensor value indicating the actual process condition. As an extreme example, if there is an isolation valve on the impulse line and the valve is closed, nothing can reach the transmitter, and its reading will not reflect the process conditions. Such a situation is not always easy to detect because some pressurized fluid may be trapped in the line and reflected by the transmitter. Similarly, inaccurate readings can result when the line is partially plugged, frozen, or there is some other internal obstruction.

Today's advanced transmitters are able to perform a plugged impulse line diagnostic (Figure 3.3) and detect such situations because they listen to the process noise through the connection. If the noise level decreases or changes character and there is no attributable cause, there is likely an obstruction forming in the lines. Once the change crosses a designated threshold, the transmitter can warn operators and maintenance engineers.

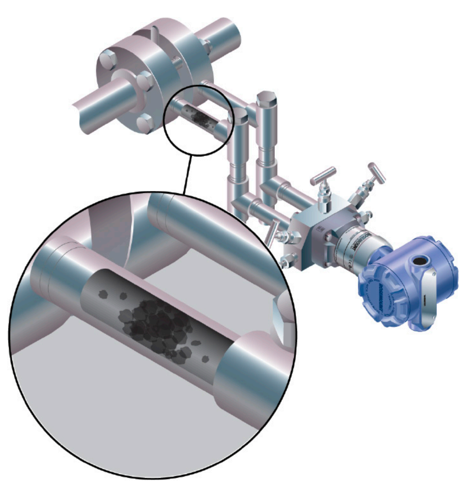

Figure 3.3: Debris and ice accumulating in an impulse line reduces the amount of process data reaching the transmitter from the sensor.

Process intelligence capabilities can also be built into pressure transmitters, allowing them to listen to process noise continuously (Figure 3.4). Once a baseline of normal noise is retained in the transmitter's memory, it can perform statistical analysis on what it hears, listening for patterns deviating from normal. Reasons for such changes can include:

- Pump cavitation
- Distillation column flooding
- Regulator and valve setting changes
- Furnace flame instability

Characterizing and analyzing such noise provides a tool to help operators or engineers identify a likely source. Operators and maintenance engineers can be informed early so the situation can be corrected immediately if necessary or monitored until a scheduled shutdown.

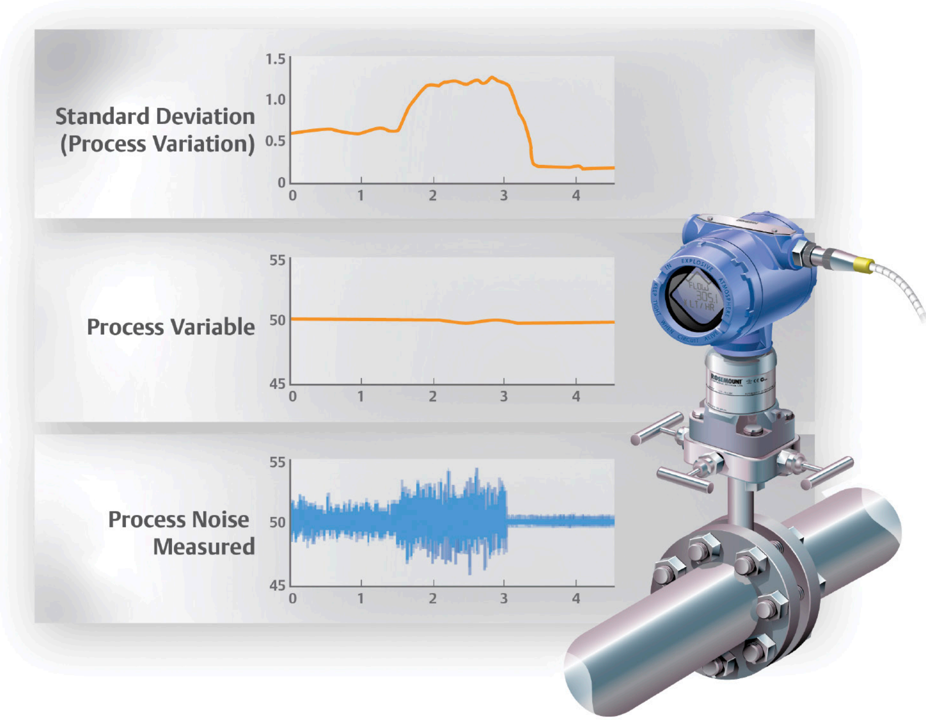

Figure 3.4: Process noise can be quantified and analyzed by the transmitter. It can alert operators to changes which may indicate problems developing.

Process alerts can also indicate upsets and other conditions capable of creating spikes or dips in normal readings. Such alerts can be logged in individual transmitters and accessed during troubleshooting. A status log can look back at the last 10 events, with time stamps to capture extreme readings for later analysis.

4. Mechanical bourdon tube pressure gauge challenges

Long before there were pressure transmitters, there were mechanical pressure gauges. The concept of a curved Bourdon tube dates back to the mid 19th century and there are devices available today little removed from that time. Gauges operate using a delicate mechanism with springs and gears, making them vulnerable to shock and damage (Figure 4.1). Most operators have seen typical failures including broken glass, bent indicator needles, or needles pointing straight down from broken gearing. In many environments, pressure transmitters are considered disposable due to their low cost and frequent failures.

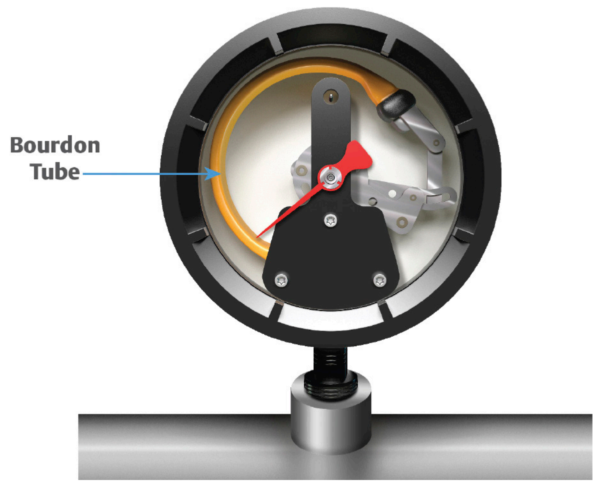

Figure 4.1: Mechanical gauges remain popular due to their low cost but still have many drawbacks.

So, what is the use case for gauges? They are installed where a reading may be useful for occasional checking, troubleshooting, or maintenance. Any critical output likely already has an instrument installed and connected to the host system. Gauges also serve a critical safety function by verifying the local process pressure when servicing equipment. A gauge must be read by an operator, and given the few manual rounds performed these days, it may not be checked regularly. Functionally, it has to provide a visual, local indication of the pressure. If it could also send the reading to a central location, such as the host system or maintenance shop, it could probably be useful there also.

A modern alternative

Electronic gauges, including Emerson's Rosemount Wireless Pressure Gauge and Smart Pressure Gauge (Figure 4.2), combine the benefits of an electronic transmitter with the usefulness of a traditional mechanical design. These gauges use a solid-state sensor rather than a Bourdon tube and process the signal electronically rather than mechanically. The needle is driven by a tiny motor, so there is only one moving part, making the mechanism far more resistant to shocks, vibration, and other extreme operating conditions.

Figure 4.2: The Rosemount Wireless Pressure Gauge and Smart Pressure Gauge are identical except for the wireless capability.

Eliminating the Bourdon tube removes a critical failure point. An electronic gauge has multiple barriers of process isolation vs a single process isolation with a Bourdon tube. The overpressure tolerance of this electronic solution is also much higher. The added layers of isolation and overpressure capabilities mean there is far less potential for process fluid escape with an electronic gauge. Using sophisticated electronics, these new gauges are also able to monitor their own status. There is no way to verify a mechanical gauge is working properly short of removing it from the process and testing, but a glance at an electronic gauge can show its operational status via an LED indicator.

For some applications, the most critical drawback of a traditional gauge is its inability to send information to an automation system. This issue is addressed by the Rosemount Wireless Pressure Gauge because it includes *Wireless*HART communication protocol which is able to send the pressure reading and status indications to the host system. This is an optional function and can be used whenever necessary. This communication capability can be deployed in a sophisticated networking environment as the IIoT moves into more manufacturing applications. Even if the wireless capability might not be needed today, it may be soon, and the Rosemount Wireless Pressure Gauge future proofs any installation.

5. Reducing thermowell safety risks

An instrumentation engineer seeking to measure temperature by installing a sensor and thermowell into a flowing fluid stream must make a number of critical evaluations.

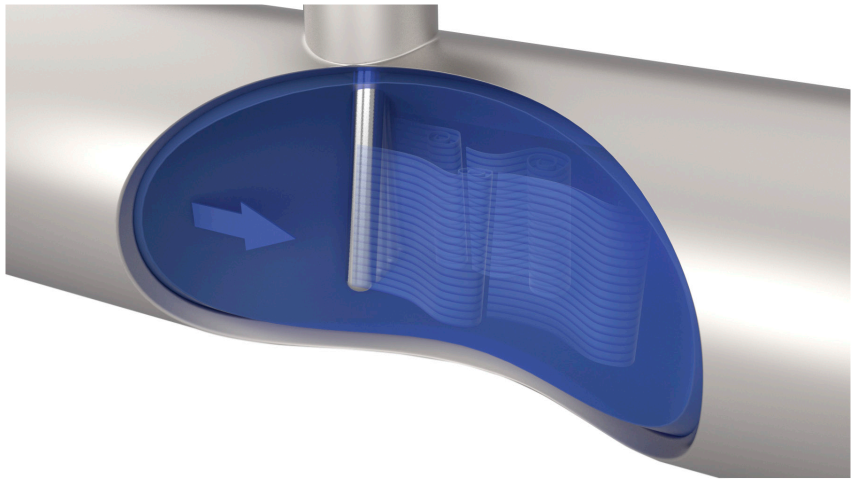

Figure 5.1: Fluid flowing around a conventional round thermowell produces wake shedding effects which can induce vibration.

As fluid flows past a thermowell, high- and low-pressure vortices form at both sides. These vortices detach, first from one side and then from the other, in an alternating pattern. This phenomenon is commonly known as vortex shedding. The differential pressure caused by the alternating vortices produces vortex-induced vibration (VIV) (Figure 5.1), resulting in stresses and causing transverse and axial deflection, which can ultimately lead to fracture of the thermowell (Figure 5.2). Is it possible for the engineer to design the thermowell to avoid the VIV-related conditions that could lead to fatigue and failure? The answer is yes, but only with the right tools.

Figure 5.2: Severe vibration causes metal fatigue which can result in a break.

Evaluating a thermowell

The success or failure of a given thermowell in a given operational context relates to how closely the VIV frequency matches the natural resonant frequency of the thermowell. When those two values match each other (Figure 5.3), the displacement will be its greatest and damage will be most likely to result.

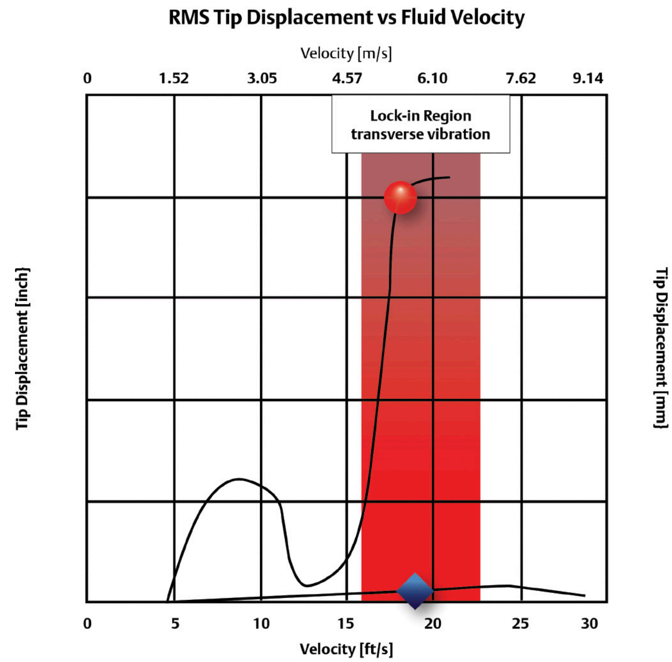

Figure 5.3: The most damaging condition is where the VIV frequency matches the resonant frequency of the thermowell.

Both these frequencies can be calculated using a formula created by the American Society of Mechanical Engineers (ASME). Its present version is ASME PTC 19.3 TW-2016, and it can be used to evaluate the component configuration and operating parameter combinations on four points:

- Frequency limit: the thermowell's resonance frequency must be high enough that it won't be reached in operation, avoiding the potential for a match with the VIV frequency.
- Dynamic stress limit: dynamic stress must not exceed the fatigue stress limit.
- Static stress limit: steady-state stress must not exceed the stress limit.
- Hydrostatic pressure limit: external pressure must not exceed the ratings of the tip, shank, or flange.

All four of those limits must be satisfied for the thermowell design to be deemed safe.

Turning a formula into a tool

With nearly 20 variables related to process conditions and thermowell dimensions in the ASTM formula, doing the calculations by hand isn't practical. Engineers often build the formula in a spreadsheet to facilitate data retention and number crunching. An engineer must follow the same steps for each situation:

- Design the dimensional parameters
- Place it in the operational contexts (which should include a range of conditions such as normal, startup, maximum, grade change, etc.)
- Create the implementation
- Test it iteration by iteration, gradually working toward a solution able to pass all four evaluation points.

This time-consuming, trial-and-error effort often results in thermowells far thicker and larger than necessary since the formula cannot indicate that a workable result is actually overkill nor does it offer an optimal design solution. An oversized thermowell slows temperature measurement response time and requires a larger penetration and obstruction into the pipe.

Less trial, less error

The formula does what it promises: it weighs a given set of parameters and provides a pass or fail grade, but that is all. It does not point the user toward a better solution. Moving to the next level of functionality demands a more sophisticated approach. There can be tens or even hundreds of temperature measurement points in a process unit, all needing evaluation. The right thermowell design software should include capabilities to help an engineer optimize thermowell design.

As an example, consider a set of hypothetical dimensional and operational parameters for “Tag TE-101.” What might we want, beyond a simple pass or fail, for the thermowell design software to tell us about Tag TE-101 now, both individually and in context with all of the other temperature tags involved in a unit, process, plant, or enterprise? Here are some basic functions thermowell design software can provide:

In/Out of scope – The ASME formula includes dimensional standards (wall and tip thickness, etc.) which any thermowell must meet. If any input variables fall outside acceptable ranges, they are flagged and a more appropriate solution is suggested.

Dimensional issues – If a thermowell is not compatible with the installation, e.g., longer than the pipe diameter or too short to extend out of a mounting spud, this will be flagged. A modeling routine can turn the dimensional data into a scale drawing of the thermowell and its mounting to indicate how the assembly fits together and how close the thermowell tip is to the center of the pipe.

Call-Up of similar installations – If a tag calls for a flange mount on a four-inch pipe, the thermowell design software should look for similar installations, including defined dimensions, operational parameters, or other relevant factors and recommend the same design if possible, to reduce inventory complexity.

Company practices – If a company or facility has preferences for a certain thermowell profile, mounting method, or other consideration, the thermowell design software should suggest these first.

Thermowell catalog – Thermowells used previously should have all their dimensions stored in the thermowell design software database so one can be pulled easily from a listing. This look-up function can extend to specific part numbers for the facility, or to an approved supplier’s catalog, to minimize the number of potential inventory items.

Similar tags – When there are similar applications with minor variations, it should be easy to copy all the values for a given tag and then change only those variables required for the new application, without having to reenter duplicated information.Multiple operating ranges – Because thermowell lifespan is dependent on process conditions, testing across a range of conditions (normal, startup, maximum, grade change, etc.) is critical and should therefore be part of the design analysis. Most installations could easily see three or four different conditions, and some could experience many more than that.

Cloud-based collaboration and data management – When the thermowell design software is hosted in the cloud, it eliminates the need for it to reside on individual computers or servers, while providing mechanisms for centralized support and access by any number of authorized users. This will also increase the ease of report generation.

Failure analysis and recommendations – Simply reporting that a given tag has failed the test at one or multiple conditions is not enough. The thermowell design software must go to the next step and provide analysis of why it failed, and then go one step farther still and suggest a remedy. In simple situations this might be an easy change such as shortening the insertion length without sacrificing the desired measurement location, or possibly adding a millimeter or two to the wall thickness. In a more difficult scenario, it may suggest a totally different solution, such as the VIV-resistant Rosemount Twisted Square™ Thermowell profile (Figure 5.4), or a non-contact temperature measurement solution such as Emerson's Rosemount X-well™ Technology.

Figure 5.4: Twisted Square Thermowells are available in a wide range of sizes and mounting configurations.

The Twisted Square Thermowell has a unique profile designed to avoid normal wake shedding problems. Its geometry disrupts formation of the long vortices (Figure 5.5), allowing them to form on both sides, so they tend to balance and cancel each other out. The result is far less vibration, up to a 90% reduction in some cases.

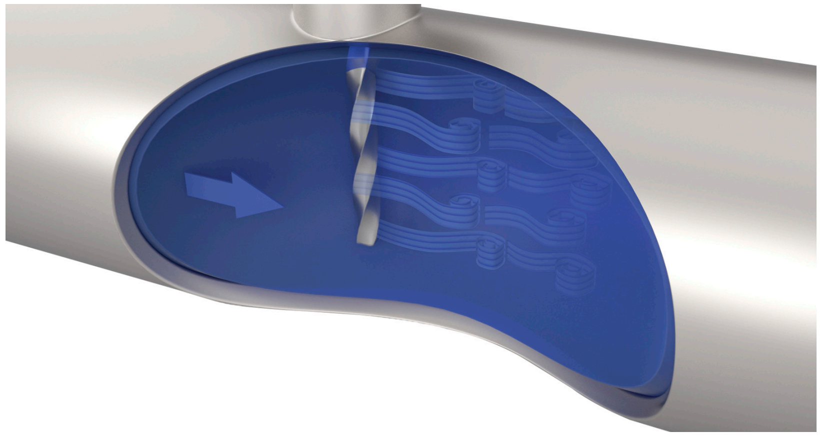

Figure 5.5: The helical geometry of the Twisted Square Thermowell disrupts formation of harmful long vortices.

Helical geometries like this have been used successfully with wind stacks and deep-sea risers to solve similar problems. This type of thermowell does not depend on a specific orientation when inserted, and it reduces the need for excessively thick thermowells and large diameter process penetrations. Moreover, it is effective and suitable across a wide range of operating parameters and negates the need for a thick thermowell with its detrimental effects on response time.

Eliminating thermowells

The complexity and issues inherent to thermowell design can also be alleviated by opting for a solution that eliminates the need for them altogether. Rosemount X-well technology (Figure 5.6) provides an accurate process temperature measurement without a physical intrusion or penetration into the process. Rosemount X-well Technology consists of a surface temperature sensor and a transmitter with a unique algorithm that compensates for heat transfer and ambient condition effects.

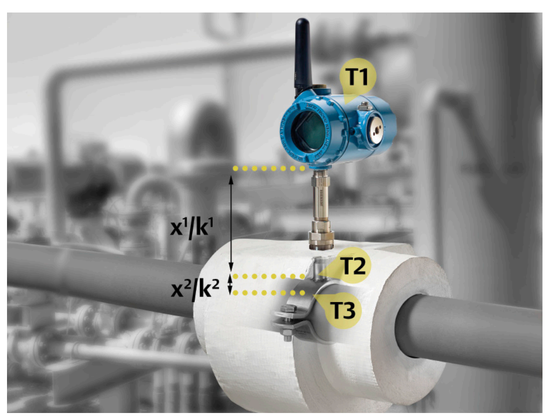

Figure 5.6: Rosemount X-well Technology can provide a process temperature reading without a process penetration.

The instrument can be installed using a simple pipe clamp assembly and then insulated. Pipe material and wall thickness data are entered into the transmitter so it can calculate heat flow and extrapolate the process temperature inside the pipe. The X-well algorithm also uses an ambient temperature reading made by the transmitter to compensate for changing conditions.

6. Temperature sensor degradation and failure

Temperature sensors fall into two general categories: thermocouples (TCs) and resistance temperature detectors (RTDs). There are many resources discussing the selection process, so for this discussion, we will concentrate on how these behave in operation, as well as what can go wrong with each.

Sensor elements are typically enclosed in a stainless-steel sheath, which is then inserted into a thermowell. Some sensor and thermowell combinations are paired as matched sets (Figure 6.1), designed to fit precisely for best heat transfer and high accuracy. Other approaches use piece-part components, and it is up to the installer to match them closely.

Figure 6.1: Packaged systems including a thermowell, sensor, and transmitter simplify installation and ensure accurate performance.

Some users prefer to wire each TC or RTD directly to the host system input, but this complicates the installation and can impair performance. For example:

- The thermocouple cabling from the sensor to the input card must match the sensor. If a different type of sensor needs to be installed, the cabling must be changed.
- Likewise, the input card must match the sensor, although some input cards allow for multiple options.
- The weak signals from a TC or RTD cannot be sent over long distances and are subject to problems caused by electrical interference.

Adding a temperature transmitter (Figure 6.2) close to the sensor eliminates all these problems:

- A 4–20 mA with HART or digital protocol such as FOUNDATION Fieldbus, provides a much more robust signal that can be sent longer distances.
- There is no need for special cabling nor a special input card.
- Most transmitters work with a variety of RTD and thermocouple types, making it easy to change the sensor when required.
- Multiplex transmitters can capture data for multiple sensors and send it back on one cable.
- Smart transmitters can collect and send diagnostic, calibration, and other data.
- *Wireless*HART transmitters are also an option, eliminating wiring and the need for control system inputs, which may be in short supply. These smart transmitters have built-in power modules and can run for years without any required maintenance.

Figure 6.2: Temperature transmitters come in many form factors and have a wide range of capabilities.

While these capabilities are all helpful, the most important advance in many applications is the transmitter's intelligence: the ability to turn the sensor and transmitter combination into a smart instrument able to send diagnostic information to the host system. Temperature sensors exhibit tell-tale signs when they are suffering from mechanical deterioration, or from wiring and termination problems. These can be spotted by the transmitter and used to call attention to incipient problems before they escalate to a failure.

Smarter and safer temperature sensors

Many temperature measurement applications suffer from electrical noise, spiking, and signal dropouts. Noise can come from electromagnetic interference, often caused by radios, motors, and lightning. Other problems can be caused by wiring problems, mechanical shock, or vibration. These can be detected, diagnosed, and possibly even corrected by sophisticated transmitters.

Even with close coupling between sensor and transmitter, noise or dropouts can still be problematic, so most users apply damping to suppress the effects. While damping improves stability, it increases response time during rapid changes in process temperature. A better approach is to use the signal validation capabilities built into the transmitter as part of its signal processing and diagnostic functions.

Thermal inertia of a temperature sensor inside a thermowell makes measuring extremely fast temperature changes (i.e. 200 °C to 400 °C) in half a second, physically impossible. Even if the transmitter sees such an instantaneous shift between successive readings, it can reasonably assume the change is a spike (or dropout if the change is negative), and simply repeat the last good measurement. This approach provides stability without damping or slow response, preventing the overall system from being disrupted unnecessarily, but it should not be applied where the measurement can legitimately see fast full-scale excursions.

Although a sensor can be damaged by an extreme mechanical shock event, most failures are caused by ongoing vibration, loose terminations, corroding connections, or chemical attack. These can weaken the sensor and wiring, causing the number of spikes and dropouts to increase over time. These can also cause the sensor to drift, decreasing accuracy over time. The transmitter can detect and trend this increasing number of problems to predict impending failure, alerting maintenance early enough to prevent total signal loss. Signal validation digs deeper into the condition of the sensor itself, which can improve both the safety and reliability of temperature measurements.

When fast response times or high temperatures (>600 °C) are involved, and when a high degree of precision is not required, TCs are often preferred over RTDs. TCs are typically more physically robust than RTDs, but they can fail in a way not readily apparent. The junction at the tip where the dissimilar wires are joined is the temperature measuring point, but if physical shock or vibration breaks down the insulation and the two wires form a contact somewhere else, this new contact point becomes the temperature measuring point, wherever it might be.

Since this new junction is invariably farther from the hot process, in most hydrocarbon applications a damaged TC will read low, although the opposite is true in cryogenic applications. Most processes are dangerous when they run too hot, so a low reading can create a safety risk.

Modern smart temperature transmitters are configurable to accept either RTD or TC inputs. When configured for a TC, the transmitter uses its voltage circuitry to determine temperature. But the transmitter can also use its resistance measuring circuitry, which would be used with an RTD, to monitor the resistance of the TC. While resistance of the TC cannot be used to determine temperature, it does help detect and predict failures.

Changes in TC circuit resistance can suggest several things. If the resistance goes to infinity, the circuit is open. If the resistance decreases from its normal level, there may be a short. If resistance increases, the wire or termination may be corroding. These changes may be immediate, but more often they are gradual, so measuring and trending resistance changes and analyzing the results can be used to predict failure and improve reliability.

When a temperature measurement is especially critical to a process, redundant sensors can be an option. Temperature sensors are relatively inexpensive, and some transmitters have the ability to accept and process signals from multiple sensors (Figure 6.3). If the measurements from the two sensors differ by an amount programmed into the transmitter, it can alert operators to a problem. Similarly, if one sensor fails, an automated backup switchover allows the transmitter to switch immediately from the primary to a backup sensor, reducing the chance of losing a temperature reading. This Hot Backup™ feature can be used with dual-element sensors or two independent sensors.

Figure 6.3: The Rosemount 644 Temperature Transmitter provides inputs for two sensors to extend redundant and diagnostic functions.

The greatest reduction in risk is achieved with two independent sensors, however this requires additional process intrusions. Two independent sensors, even if they are feeding one transmitter, can reduce the probability of losing the reading by 80%. Both sensors working simultaneously can identify if one is beginning to drift or develop some other type of problem.

Summary

This white paper presents a variety of technologies and practices to improve instrumentation performance, increase reliability, and reduce maintenance. None of the provided suggestions represent major capital projects, nor do they have to be executed on a grand scale. Each improvement can be implemented one-by-one to deliver incremental gains and a quick return on investment, eliminating obstacles to effectiveness and profitability.

For additional information on Emerson's pressure measurement products, visit Emerson.com/PressureMeasurement

For additional information on Emerson's temperature measurement products, visit Emerson.com/TemperatureMeasurement

Emerson Automation Solutions
6021 Innovation Blvd
Shakopee MN 55379
USA
+1 800 999 9307
+1 952 204 8889
RFQ.RMD-RCC@Emerson.com

00870-0500-4801 Rev AB, August 2020

Linkedin.com/company/Emerson-Automation-Solutions
Twitter.com/Rosemount_News
Facebook.com/Rosemount
YouTube.com/user/RosemountMeasurement

ROSEMOUNT™ EMERSON™