MAKING THE RIGHT CHOICE

Dr. William Vickers, Ionix Advanced Technologies, explores how the latest developments in non-invasive ultrasonic integrity and corrosion monitoring systems can help to maximise productivity and minimise downtime.

Online, non-intrusive corrosion and erosion monitoring systems that utilise ultrasonic transducers are becoming an increasingly popular tool to enable operations and maintenance teams to enhance process unit productivity and efficiency whilst not compromising on safety.[1] Traditionally, internal corrosion of assets would be monitored by a combination of invasive probe methods, such as coupons or electrical resistance (ER) probes, and non-invasive non-destructive testing (NDT) techniques such as using ultrasound transducers or other devices. ER probes can be used to provide real time feedback on the corrosivity of process fluids whilst corrosion coupons provide an indication of the potential wall loss, corrosion mechanism, and identification of biological induced issues that may have occurred over the previous window of exposure, usually 3 – 12 months. However, both techniques are invasive and installation requires either hot tapping of a line, installation during shutdown, or operation in separate non-representative loops that can be isolated. On the other hand, NDT inspection techniques, such as ultrasonic testing (UT), provide a direct measurement of the asset wall and, over time, the wall loss rate.[2] Until recently, ultrasonic NDT measurements have all been made manually using UT operators/technicians. This limits the frequency of data collection to times when a technician is at the asset, generally on a 3 – 5 year cycle, reducing its operational value. This manual approach leads to issues with access and exposure to hazardous environments, costs of working at height and safety challenges. Now, a range of automated ultrasonic monitoring solutions have come to the market, which address many of these issues.[3,4] However, choosing which system to use is not a simple task and there are a number of variables which must be weighed up. This article will explore some of the key factors which must be considered when selecting a monitoring system and some of the solutions available on the market now. While the focus of this article is on refining and downstream oil and gas production, the principles apply across the oil, gas and petrochemical industries, as well as energy (including nuclear and fossil fuel) and process control.

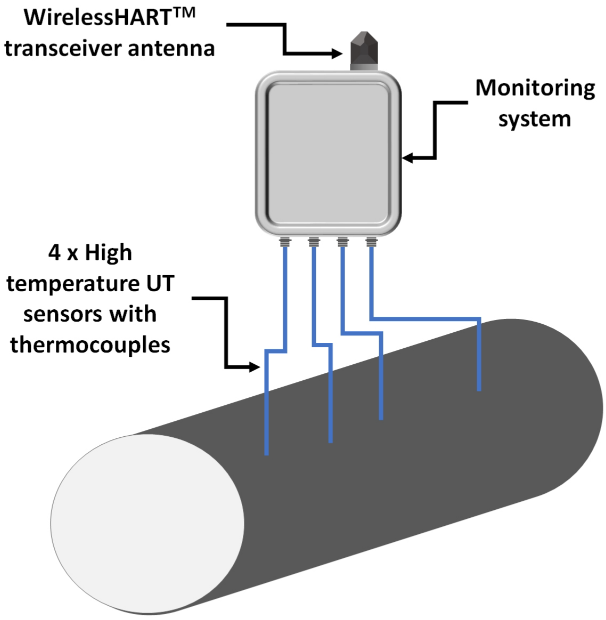

Figure 1. An idealised non-invasive UT monitoring system consisting of multiple high temperature capable UT sensors/transducers with integrated thermocouples connected to a separate WirelessHART™ enabled monitoring system. The monitoring system may be located in a convenient location for access.

Data – what, who, and where?

The first step in choosing a UT monitoring system is identifying the data to generate, who will use and benefit from it, and where and how it will be stored and accessed.

UT monitoring systems provide data on wall thickness and wall loss rates, which is valuable to both operations and maintenance teams. Maintenance engineers use information from these sources to optimise plant availability and minimise downtime, whilst operations engineers look to adjust their processes to maximise productivity and efficiency. Manually collected UT wall thickness measurements generally occur during shutdown intervals of 3 – 7 years and focus on absolute measurements of wall thickness. This is used to determine asset integrity and plan replacement and maintenance using techniques such as fitness for service (FFS) (API 579/BS 7910).[5] The low frequency of data collection, inconsistency and conservative tolerances of UT manual measurements[1] mean decisions on when to repair or replace equipment are made with wide safety margins and rely more on a time-in-service calculation than on actual performance. This leads to unnecessary replacements and plant shutdowns with increased potential for costly unplanned downtime. Many maintenance teams now focus their monitoring of assets according to a risk based inspection (RBI) (API RP 580/EEMUA publication 206) programme.[6] Where an increased frequency of inspection is required or where access is limited by location or hazards, permanently installed/autonomous monitoring systems offer a viable and cost-effective solution to extending asset lifetime. Monitoring data should also be combined with FFS to extend asset life; this is only possible with accurate and reliable data. When selecting a monitoring system, it is important to ensure that it can be calibrated, in line with current UT standards[7,8] to take reliable measurements which can be codified, such as systems using the HotSense™ transducers that have an integrated reference block. It is also preferred to have a temperature measurement device integrated into the system which should be combined with automated software to generate stable data.

Minimising maintenance downtime through monitoring allows for operations teams to maximise productivity. Monitoring systems also allow operations teams to optimise processes due to their ability to detect changes in wall loss rates many times faster than manual inspection, and in real time, unlike corrosion coupons. This feedback can be used to better plan future operations. Non-invasive UT monitoring systems now have the measurement resolution and accuracy required to quickly determine corrosion rates – a resolution of 25 µm is a minimum whilst some systems achieve stable and reliable 10 µm resolutions.

Collecting data from multiple locations can be simplified greatly by using wireless communications, such as WirelessHART™ (IEC 62591).[9] This wireless communication system enables monitoring systems to form self-healing mesh networks using low-power, intrinsically safe transceivers, and communicate using secure encryption. They are ideal for downstream operations where monitoring is undertaken on a 'site' rather than across long pipelines. Wired solutions may suit some deployments but routed cables often limit install locations and prevent systems from being easily relocated.

Once configured, monitoring systems automate measurements, simply transmitting a value for wall thickness and calculating loss rates. By deskilling the process of data collection, which would typically require a trained UT specialist, monitoring systems provide operations teams with access to data that would typically be isolated in maintenance silos.

Where this data is stored should be a key consideration for any monitoring system. Security should be considered in relation to cloud storage unless the facility has already accepted this as a secure and viable method. Alternatively, solutions that offer local server or database storage should be sought. The key is flexibility: ensure that data can be easily exported to the operations distributed control system (DCS) or plant integrity management systems (PIMS) to prevent data silos and ensure that it can be used by all teams that require it. Systems that use the HART-IP enabled wireless gateways can be connected to local IP networks to enable direct submission of measurements to the unit DCS.

As well as transmitting measurement information, some systems can also transmit valuable maintenance and diagnostic information, such as remaining battery life. These features will allow for remote diagnostics as well as planning for routine maintenance, such as battery replacement. With regards to battery life, a monitoring system should last between maintenance intervals or more, usually around routine inspection periods of 3 – 5 years, whilst delivering the required frequency of data collection, usually one measurement per day. Systems which separate the monitoring electronics from the transducer should allow the batteries to be located in accessible locations in case they need replacing earlier where higher data collection rates, or flexibility in collection frequency is required. Some systems

Figure 2. Low profile, high-temperature ultrasonic transducer for wall thickness and corrosion monitoring.

allow for multiple sensors to be plugged into a single monitoring system – reducing the number of batteries per UT channel, and reducing total system costs (Figure 1).

Install location and local environment

One of the first considerations to make regarding installation locations is what environment will the system be required to operate in? The decision on where to monitor should be guided by the integrity and operational requirement, not system limitations.

Possibly the most important environmental consideration is that of explosive hazards. As most UT systems utilise a piezoelectric material, it is important that both the transducer and monitoring system are certified for continuous use in the required environment. The locations that are frequently monitored in downstream operations generally require a minimum of either ATEX (EU) and IECEx (International) Zone 1 or FM/UL/CSA (North America) Class 1 Div 2, where ignitable mixtures of gases and vapours are likely to be present in normal operation, fault or repair. Intrinsically safe systems offer the most flexible protection concept for global deployment, allowing installation and configuration in hazardous environments without requiring hot work permits. When choosing a monitoring system, the level of protection should not be compromised as it may severely limit global deployment options.

Often the most critical locations of a refinery requiring wall thickness monitoring are those which are running at high temperatures – for example, furnace outlets and transfer lines to columns on fluid catalytic cracker and crude distillation units, which contain vapours, residues and slurries, are all highly susceptible to a combination of sulfidation and naphthenic acid corrosion, and failure can be both dangerous and costly. These lines generally run at temperatures over 300°C. Standard ultrasonic sensors/transducers will not operate at these temperatures and so often thermal buffers must be used to isolate installed transducers from the heat source. Although this approach appears a simple solution, it also introduces new problems:

- The units must breach insulation and weatherproofing, opening the pipes to water ingress and corrosion under insulation.
- The exposed unit is prone to damage from moving objects and site personnel.
- Limited space between pipes may limit the install locations.

Recent advances in UT transducers, and the piezoceramic elements at their cores,[10] now allow sensors to be installed directly onto the surface of hot pipes and vessels. For example, low profile, high temperature transducers are now available which can survive continuous operating temperatures from -40˚C up to 550˚C without thermal buffers and are less than 50 mm in height, allowing for installation under standard insulation and weatherproofing (Figure 2).

Conclusions

The correct monitoring system can enhance downstream productivity and efficiency by providing operations and maintenance teams with the up-to-date and reliable data that they need to optimise the operation of a plant. Choosing the correct solution is critical and this article has highlighted key considerations when choosing a system, including:

- Ensure the system can generate robust and reliable measurements by choosing a solution that can be calibrated, has integrated temperature compensation, and provides a minimum resolution of 25 μm.
- The data should be easy to interpret and made available for all teams that require access – look for flexibility in the data management and export options.
- Ensure the data transmission method matches the facility.
- The monitoring system and ultrasonic transducers must be able to survive continuous deployment in the most challenging environments – consider high and low temperatures, potentially explosive environments and space and access restrictions.
- Look for a system with the option to connect multiple transducers and position the electronics separately, this will minimise cost, maximise antenna efficiency and ensure convenient maintenance.

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