Monitoring Asset Integrity
Using Installed Ultrasonic Sensors

James N. Barshinger, Ph.D.
Bruce A. Pellegrino

Sensor Networks, Inc.
171-500 Technology Drive
Boalsburg, PA 16827
(814) 466-7207
www.installedsensors.com

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Executive Summary:

Corrosion costs the US economy >$276 billion per year according to a federal study commissioned by the US Congress in 2002. [http://www.nace.org/Publications/Cost-of-Corrosion-Study/](http://www.nace.org/Publications/Cost-of-Corrosion-Study/) Globally, the number must be 3X that. Installed ultrasonic sensors are emerging as a viable technology for remote monitoring of assets whose health is affected by corrosion/erosion, particularly in the O&G and power generation industries. This technology, has the potential to compete with the current model of sending technicians into plants to perform manual inspections, particularly for high value/consequence thickness monitoring locations (TMLs) as well as the ability to accurately measure corrosion rate for process-control applications.

Traditionally, hand-held portable Non-Destructive Testing (NDT) inspection devices such as ultrasonic thickness gauges and flaw detectors, eddy current equipment, and x-ray systems are deployed into plant facilities during routine outages and turn-arounds or during normal operations. These techniques take a snap-shot of the localized condition of plant infrastructure such as piping and pressure vessels for issues including wall-thickness reduction due to corrosion/erosion, cracking and other material degradation. While this is a common and industry-accepted practice, asset owners are experiencing rising costs for these inspections due to increasing labor rates, lack of qualified personnel and stricter health and safety requirements, particularly for hard-to-access assets such as buried pipelines or assets in hazardous or remote locations such as offshore platforms. Regulatory requirements are often requiring more frequent or extensive inspections, further driving costs. Also, it is increasingly evident that the probability-of-detection (POD) and overall quality of these “manual” inspections can be relatively low.

Sensor Networks Corporation (SNI) has developed a new solution for monitoring the integrity of these assets for wall-thickness degradation and cracking utilizing permanently-installed ultrasonic transducers and electronics which addresses some of the aforementioned issues with current manual inspections. SNI ultrasonic sensor systems have been developed utilizing a modern and novel, patent-pending architecture that will allow sensors to be network distributed on the asset to provide continuous or periodic monitoring of O&G assets. For hard-to-access assets, this will reduce inspection costs, eliminating the need for inspectors to be deployed and redeployed to the asset, repeated excavation, stripping of insulation, scaffolding, etc. Due to the permanent installation of these devices, data quality will be enhanced due to the secure placement of inspection points and the increased volume of data will allow more sophisticated statistical analysis of asset condition. Developments include ultrasonic transducers suitable for permanent installation in harsh environments, analog and digital electronics to operate the sensors and measure with high precision and data-collection devices with local software and/or a cloud-based data management solutions.

1.0 Background:

Metal loss due to corrosion and erosion is a widespread issue in the O&G and Power Generation industries for tanks, high-energy piping and pressure vessels. Metal loss can result in loss of pressure containment with resulting consequences that can include: loss of life, damage to assets, disruption of service, environmental harm, loss of public image, fines and others. As such, asset inspections are required by operators and are mandated in regulations and codes such as 29CFR–1910; API 570, ASME Sections V & XI, and ASTM E797.

While there are many methods for measuring wall thickness, a predominant method is the use of portable ultrasonic equipment. Ultrasound is non-intrusive as it is applied to the outside of the pipe or
vessel, is accurate and relatively low cost to deploy in most situations. However, it does have several shortcomings including that the ultrasonic transducer or probe needs to be applied in direct contact to the external surface of the pipe requiring scaffolding, excavation, stripping of coatings or insulation, etc. Thus, the cost of access to the structure often far exceeds the basic cost of inspection. Furthermore, a trained and certified inspector is required to operate the ultrasonic instrumentation, requiring personnel to sometimes be exposed to potentially hazardous environments. The accuracy and repeatability of ultrasonic measurements are operator-dependent and recent studies have shown that the probability-of-detection (POD) can be poor. There is a shortage of qualified inspection personnel, thus inspection costs are increasing due to higher labor rates. Finally, the measurements are only performed periodically, taking a snap-shot of plant condition. Thus, while portable ultrasound is certainly an accepted paradigm for asset-health monitoring, there is room for improvement to address these shortcomings.

A recent survey of O&G plant operators yielded the following responses when asked about monitoring asset health:

1. They desire new technology which will provide them with more current data regarding the condition of their assets.
2. They do not want to wait for annual inspections or shutdowns to get this data.
3. They want on-line monitoring versus periodic data collection.
4. They say “we want more and quicker data” and it must be of higher quality.

Furthermore, in plant environments, some equipment cannot be accessed even during shutdowns. Data still must be obtained for these assets, which can be even more critical to overall plant integrity. Every plant manager interviewed is interested in knowing the condition of his / her plant every day, regardless of service status or location of these assets.

Most end users are interested in investing in new technology to overcome these concerns. In the process industries, such as in petrochemical or refineries, all critical process parameters are measured in real time. Obtaining information on flow, temperature, pressure, PH, equipment upsets or unusual conditions are monitored and reported on a continuing basis via Key Performance Indicators or KPI’s. The Plant Manager then feels he / she is in control. Manually-taken thickness data does not result in the same level of visibility to plant health.

From an asset-management perspective, corrosion-rate measurements are also of interest. Plant operators currently use technologies such as Electrical-Resistive (ER) probes or corrosion coupons as a proxy for measuring the corrosion rate due to the process stream. The result is a feedback loop where process variables and corrosion inhibitors are adjusted to minimize the corrosion rate with a typical target being <10 mils (0.010”; 0.25 mm) per year (MPY)

While technologies such as ER probes and coupons are widely used, they have the following limitations:

- The technology relies on a coupon or probe being installed within the pipe, requiring the pipe’s pressure boundary to be penetrated.
- This technology does not produce a direct measure of asset integrity as the actual pipe wall is not being measured.
- Often, the element is a different material than the piping it represents.
- Installation and retrieval of the probes and coupons can be hazardous and deployment of inspection locations are expensive.
- Installations are fixed and cannot be easily re-deployed to problem areas.

Thus, new solutions are desired for corrosion-rate monitoring as well.

### 2.0 A New Solution: Installed UT Sensors

Installed ultrasonic sensors are emerging as a new technology to compete with manual UT inspections and existing corrosion-rate monitoring solutions due to the potential for high data quality, non-invasive installation, ability to operate remotely without operator interaction and the reduction of access costs over time.

Like UT thickness gauging, the solution is based on the ultrasonic principle as shown in Figure 1. A transducer is used to convert electrical energy to high-frequency acoustic or ultrasonic energy and vice-versa and is semi-permanently attached to the surface of the object or asset under test. The transducer is electrically pulsed to generate a stress wave in the object and subsequently converts returning echoes to voltage. The resulting waveform (A-scan) is then recorded and measured by the ultrasonic instrumentation. The transit time between the initial pulse and return echoes (or between echoes) is used to calculate wall thickness. Features such as the distance to the back-wall or the distance to a pit or crack can be very accurately measured with this technique.

![Figure 1. UT principle](image)

Operationally, the installed sensor solution is similar to manual thickness gauging however it is fundamentally different in that the transducers and instrumentation are deployed permanently. This addresses several of the shortcomings of existing solutions.

Some of the major advantages are as follows:

1. Instrumentation and probes are deployed on the asset in a permanent or semi-permanent fashion and can be accessed remotely, thus the cost of access is reduced over time and operators are not deployed to the point of the inspection. Once the instrumentation is deployed, data can be accessed from a convenient access point for the manual data collection option or can be accessed remotely, via the Internet, for integrated systems.
2. Due to the fixed transducer position and instrumentation, operator-to-operator, probe-to-probe, and instrument-to-instrument variability is eliminated. This removes significant sources of error and allows for improved measurement resolution, precision and accuracy which is particularly important for accurate corrosion-rate trending.
3. Data can be collected on a more frequent basis (>1X per day) for automated systems. This allows for more accurate corrosion-rate trending through statistical data analysis, such as linear least squares regression.
4. The system can be deployed with an integrated temperature measurement device so that changes in material acoustic velocity due to temperature variation can be automatically
removed from the measurement, thus eliminating another significant source of measurement error.

5. The data is accessible. Wired and/or wireless installed sensor systems can make use of various forms of data backhaul including the plant wired or wireless intranet, industrial wireless networks such as 802.15.4, (wireless HART, ISA100 or ZigBee), and satellite or cellular networks for remote collection points, allowing practically real-time data/asset health availability.

2.1 System Concept:

SNI has developed a flexible and cost-effective system for deploying hundreds to thousands of installed ultrasonic sensors. The system is modular, scalable and will be offered in both wired and wireless versions, using industry-standard communication protocols to allow integration with existing plant equipment and control systems or backhaul to a cloud-based database using cellular or wireless connectivity.

Figure 2 shows the SNI’s product concept as applied to manual data collection on a buried asset – such as a natural-gas distribution line. Figure 3 is a schematic view, showing the basic components of the system:

![Figure 2. Corrosion monitoring architecture and application for buried pipelines](image-url)
**System controller:** The system controller is a tablet PC, industrial computer, or remote terminal unit (RTU) depending on whether the data collection will be manual, automated (Figure 4a), or integrated with a plant control system (Figure 4b). The system controller communicates with the network of digital sensor interfaces or “DSIs” via Modbus over RS-485 which is a standard industrial instrumentation protocol. The system controller processes the digital ultrasonic data into thickness values and then transmits the data for viewing, analysis and/or archiving. For wireless systems, the system controller is replaced by a wireless gateway (Figure 5).

**Digital Sensor Interface (DSI):** The digital sensor interface is an ultrasonic data collection instrument that is connected with up to 16 transducers and serves the purpose of pulsing and receiving data from the transducers, digitizing the collected data and transmitting the data to the system controller. The DSIs are arranged on a multi-drop network such that a single cable drop can be used to connect up to 32 DSIs representing a maximum 512 individual transducers. For any given DSI, transducers may be arranged randomly, or in a linear or area array, giving the customer the versatility to monitor specialized infrastructure such as a pipe-elbow extrados.

**Transducers:** The ultrasonic transducers transmit and receive ultrasound and are available in several models and types based on the application to be solved. For example, dual-element transducers are particularly well suited for thin measurements (< 0.100” or 2.5 mm) and highly-pitted back-wall surfaces. The transducers can be dry coupled to the pipe using a proprietary elastomeric material (for standard temperatures), adhesively bonded, or clamped with metal foil for high-temperature models.
<table>
<thead>
<tr>
<th>Type</th>
<th>Temperature</th>
<th>Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single-element Contact</td>
<td>Standard / Ambient</td>
<td>General purpose</td>
</tr>
<tr>
<td>Delay-line Contact</td>
<td>Medium to High</td>
<td>High precision, High temperature</td>
</tr>
<tr>
<td>Dual-element</td>
<td>Medium</td>
<td>General corrosion, pitted surfaces</td>
</tr>
<tr>
<td>Angle-beam or shear-wave</td>
<td>Standard to Medium</td>
<td>Crack detection</td>
</tr>
</tbody>
</table>

SNI’s Transducers can be arranged in different configurations such as random, linear or area arrays to suit the needs of the application.

**Temperature measurement device**: To achieve the most accurate and precise readings using ultrasound, it is necessary to correct for the ultrasonic velocity change that occurs due to changes in asset temperature. SNI’s system incorporates a RTD (resistance temperature detector) that can be placed on the asset adjacent to the ultrasonic transducers.

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**Figure 4a. Automated monitoring system**

**Figure 4b. Integrated system**
Data Reporting: SNI incorporates a cloud-based solution for data management that allows for real-time access to thickness and corrosion-rate data from any connected device with an internet browser. This allows for accurate and real-time data reporting from the sensor locations as well as the ability for reporting alert conditions via email or text. The solution can be hosted by SNI or on a company’s internal computing resources. For portable data collection with SNI’s tablet solution, data and report files can also be emailed from the device.

2.2 Wired vs. Wireless solutions:

SNI is developing a flexible solution for corrosion/erosion monitoring with both wired and wireless data backhaul options. The wired solution uses Modbus over RS-485, as previously mentioned, which allows sensors to be deployed in a multi-drop fashion that minimize wiring complexity and cost.

The wireless version implements a mesh network solution using wireless HART (wiHART). Wireless HART is the most widely used plant wireless solution, versus alternative solutions such as ISA100 and ZigBee. The use of a non-proprietary solution is advantageous as devices can interoperate on the mesh network with other wireless devices such as temperature controllers, flow meters and others as offered by companies such as Emerson-Rosemount.

While wireless solutions may be viewed automatically as superior to wired solutions due to the lack of cabling costs, there are many factors to consider when choosing the optimum system for a given application. Some of the factors are listed as follows:
When wired solutions are optimum:

- Buried installations
- Integration with plant control systems
- Lowest hardware cost per TML
- Manual, automated, and integrated data collection options
- Best solution for high data-collection frequency (>2X per day)
- No battery replacement required
- Resistant to RF interference

Applications: Buried pipelines, offshore / integrated erosion monitoring, manual data collection solutions.

When wireless solutions are optimum:

- Wiring cost is prohibitive or impractical
- Fully-automated and integrated data-collection solution
- Typically <2X per day measurement frequency
- DSI and transducers need to be periodically repositioned

Applications: Refinery, power and process plant corrosion monitoring.

Ultimately, it is advantageous to have both wired and wireless options available to optimize the cost and performance of a corrosion-monitoring system for an application. Hybrid solutions can also be advantageous, for example using a wired system for a buried pipe application with wireless data backhaul at the system controller with cellular or satellite communications.

3.0 Accuracy, Precision and Resolution:

Ultrasound has the capability of making very accurate and precise measurements of object wall thickness. Typical corrosion thickness gauges usually have a display resolution of 0.001” (0.025mm) and precision gauges usually display resolution to 0.0001” (0.0025mm). While accuracy and precision can approach this gauge resolution in the lab or on calibration standards, the field accuracy and precision has been shown to be orders-of-magnitude worse, primarily due to operator and equipment variability.

There are many factors that affect the accuracy and precision of ultrasonic thickness measurements taken in the field as shown in Table 1.
Table 1. Some factors effecting gauge accuracy and precision in the field

<table>
<thead>
<tr>
<th>Accuracy</th>
<th>Precision</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operator variability</td>
<td>Operator variability</td>
</tr>
<tr>
<td>Sound velocity and acoustic zero calibration</td>
<td>Velocity and acoustic zero cal (msmt to msmt)</td>
</tr>
<tr>
<td>Echo quality</td>
<td>Echo quality</td>
</tr>
<tr>
<td>Sound velocity uniformity</td>
<td>Electronic or ultrasonic noise</td>
</tr>
<tr>
<td>Surface roughness</td>
<td>Transducer placement variability</td>
</tr>
<tr>
<td>Transducer coupling variability</td>
<td>Transducer coupling variability</td>
</tr>
<tr>
<td>Temperature variation</td>
<td>Temperature Variation</td>
</tr>
</tbody>
</table>

*Parameters in italics are eliminated or reduced with installed sensors

Many of the factors that contribute to variability in the accuracy and precision of UT readings can be removed with installed sensors, primarily due to the removal of operator-to-operator and transducer placement variability. Other factors can be controlled through optimization of the application, such as choosing transducers that are suitable for the thickness range to be measured and the expected surface condition based upon corrosion type; for example, using dual-element transducers when measuring highly-corroded or pitted surfaces. An optimized SNI wall-thickness monitoring system can achieve 0.0001” or 0.0025 mm resolution.

Temperature variation can also introduce significant errors in accuracy and precision, particularly for assets that operate at elevated temperatures or swing through wide temperature ranges especially when taken off-line. Thickness monitoring systems that have integrated temperature measurement devices such as thermocouples allow the potential to compensate for temperature changes and remove the deleterious effects on accuracy and precision.

3.1 Temperature Compensation:

The direct measurement made in an ultrasonic thickness gauge is time, not material thickness. Rather, material thickness is a measurement derived from the measured round-trip travel time of the ultrasonic wave in the object and the ultrasonic velocity of the material as shown in Figure 1. As temperature is increased or decreased in a solid, the ultrasonic velocity also changes due to corresponding changes of the mechanical properties of the material; the relationship between longitudinal velocity and the material properties being shown in Equation 1.

\[ C_L = \frac{E(1-v)}{\sqrt{\rho(1+v)(1-2v)}} \]  

The relationship between the material constants and temperature is usually not precisely characterized or available so it is impractical to use equation 1 to obtain the relationship between ultrasonic velocity and temperature. Furthermore, while extensive material velocity data exists in public literature, there are relatively few references characterizing acoustic velocity as a function of temperature. Some reference values that are available are shown in Table 2.
As seen in the table, the ultrasonic velocity decreases with an increase in temperature at a rate of approximately -1% per 100°F (55°C). Consequently, as temperature rises, a thickness gauge will measure an increase in time-of-flight and a corresponding increase in thickness if the ultrasonic velocity is not temperature corrected. For example, if a calibration is performed on a room-temperature calibration block at 70°F (21°C) and then subsequently a measurement is performed on the same block at 970°F (521°C) without adjusting the velocity, the thickness will be overestimated by approximately 9% due to the shift in material velocity.

### Table 2. Correction factors for ultrasonic velocity in steels

<table>
<thead>
<tr>
<th>Material</th>
<th>Correction Factor</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steel (Typical)</td>
<td>-0.0001 per °F (-0.00018 per °C)</td>
<td>Olympus¹,²</td>
</tr>
<tr>
<td></td>
<td>(-1.0% per 100°F (55°C))</td>
<td></td>
</tr>
<tr>
<td>Steel (Typical)</td>
<td>-1.0 m/s per °C (0.95% per 100°F (55°C))</td>
<td>SNI rule of thumb</td>
</tr>
<tr>
<td>Carbon Steel (Typical)</td>
<td>No Correction T&lt;200°F (93°C)</td>
<td>ASTM E797</td>
</tr>
<tr>
<td>Carbon Steel (Typical)</td>
<td>-1.0% per 100°F (55°C)</td>
<td>ASTM E797</td>
</tr>
<tr>
<td></td>
<td>200°F (93°C) &lt; T &lt; 1000°F (540°C)</td>
<td></td>
</tr>
<tr>
<td>Plain Carbon Steel, AISI 1345</td>
<td>-0.7% per 100°F (55°C)</td>
<td>Marathon Oil Company³</td>
</tr>
<tr>
<td>Low-Alloy Steels AISI 4130 &amp; 4340</td>
<td>-0.6% per 100°F (55°C)</td>
<td>Marathon Oil Company³</td>
</tr>
<tr>
<td>316 Stainless Steel</td>
<td>-0.9% per 100°F (55°C)</td>
<td>Marathon Oil Company³</td>
</tr>
</tbody>
</table>

¹ Source: Olympus 38DL+ manual
² Value is stated as change per degree F, multiply by 1000 to convert to percent per 100°F

The need to correct for this effect depends on the ambient conditions of the test, the calibration procedure (whether the calibration block is of similar temperature as the object under test) and the desired accuracy and precision required for the test. For most inspections occurring at ambient temperature or slightly elevated temperatures, correction for temperature is usually not considered, but may still be necessary if the desire is to measure thickness very precisely and calculate accurate corrosion rates.

Certain codes and standards, such as ASTM E790 and API 570 recognize the effect of temperature on ultrasonic readings and require or recommend a correction of the reading for temperature. ASTM E797 recommend temperature correction of readings by -1% per 100°F (55°C) above 200°F (93°C) and below 1000 °F (540°C). API 530 recommends that corrective procedures should be applied above 150°F (65°C), including the use of heated calibration blocks or applying an appropriate temperature correction factor, but does not give a specific value.
Application of a correction factor can be achieved through Equations 2 and 3, where the correction factor, \( k \), can be determined from a value stated as \% per 100°F (55°C) by dividing by 100 if working in degrees Fahrenheit or 55 if working in degrees Celsius.

\[
d_1 = \frac{1}{2} C_1 \Delta t
\]  
\[
C_1 = C_0 \left( 1 + k (T_1 - T_0) / 100 \right)
\]

\( d_1 \) – temperature corrected thickness  
\( C_1 \) – temperature corrected velocity  
\( C_0 \) – reference or calibration velocity  
\( \Delta t \) – measured, round-trip time of flight  
\( T_1 \) – measurement temperature  
\( T_0 \) – reference or calibration temperature  
\( k \) – correction factor in \% per °F or °C

For large temperature variations, thermal expansion must be also considered in order to achieve maximum accuracy and precision. For carbon steel the coefficient of thermal expansion is approximately \( 11 \times 10^{-6}/°C \) or 0.06\% per 100°F (55°C) which is over an order of magnitude smaller effect than the potential errors induced due to the velocity change over temperature. For example, by applying Equation 4, a 0.500” (12.7 mm) thick steel specimen increases by only 0.0012” (0.03 mm) or 0.24\% from room temperature of 70°F (21°C) to 470°F (243°C).

\[
\frac{\Delta l}{l} = \alpha \Delta T
\]  

The relevance of this effect depends on the goal of the measurement. For code-compliant inspections, it is usually not necessary to include or characterize this effect though the various measurement factors that have been published likely include some amount of compensation for linear expansion if the factors were experimentally determined without removing the linear-expansion effect. For high-precision corrosion-rate measurements, it will be important to capture and remove the effect of linear expansion as well as velocity change. This can be done using statistical techniques such as regression analysis.

In light of the potential reduction to accuracy and precision due to temperature variation, it is critical that a corrosion/erosion monitoring system also has the capability to measure test-part temperature by having a temperature monitoring device as part of the system, such as an integrated RTD or thermocouple. Automated implementation of Equation 3 can be then be used to correct the ultrasonic velocity for temperature effects and thus maximize the accuracy and precision of the measurement system.
4.0 The Power of High-Frequency & High-Quality Data

A major advantage of installed ultrasonic sensors is the ability to collect a larger quantity of high-quality thickness data than would be otherwise available from manually collected measurements. The large amount of data allows first of all visibility to the dynamics of wall thickness reduction. Corrosion rates are often not constant and can vary between periods of virtually zero corrosion to episodic events causing corrosion rates of hundreds or thousands of MPY. The use of data of marginal quality and spaced over long time periods can either overestimate or underestimate corrosion rate and does not allow insight into the actual corrosion history of an asset.

Figure 6 a-d shows a data set including eight distinct corrosion rates with noise having a standard deviation of 0.01mm (0.0004”). Progressing from Figure 6a to Figure 6d is the same data, displaying discrete measurements from the data set on intervals of 1X per year, 1X per month, 1X per week and 1X per day.

When considering a measurement of once per year as might be had from manual UT measurements, only a coarse corrosion-rate calculation is available. Over several years, an operator might get a general feeling for the long-term corrosion rate, but statistically it is impossible to place an uncertainty on this measurement so the ability to use the corrosion rate as a predictive tool (for scheduling maintenance for instance) is poor.

Moving to even a relatively infrequent measurement cycle of 1X per month allows a much better picture of the process of wall-thickness reduction. Separate corrosion rates are evident in the data, including evidence of an episodic event of very high wall-thickness reduction. While a large improvement over a once-per-year measurement cycle, the relatively small amount of data still limits the ability to calculate corrosion rates accurately. Thus, the ability to distinguish two different corrosion rates is impaired which limits the efficacy of using the measurement as a process-control tool.

More frequent measurements, for instance once-per-week, once-per-day or even more often, allows statistical tools to be used to characterize and remove measurement noise, achieving corrosion-rate measurement precision in the range of 1 MPY. As such, installed ultrasonic thickness measurements become a tool for monitoring process conditions as they impact the corrosion/erosion rate within a piping circuit, vessel, heat exchanger shell, or other asset. Numerical tools such as data filtering and linear regression are easily deployed in software.
Figure 6. Wall thickness monitoring data with collection intervals of: (a) 1x/year, (b) 1x/month, (c) 1x/week and (d) 1x/day
5.0 Corrosion Rate Measurements:

Linear regression is a powerful tool for converting measured wall thickness values to corrosion/erosion rate measurements and is the main tool used to calculate corrosion rates with installed sensor data. The term linear regression refers to the process of modeling the relationship between a dependent variable ($Y$) to one or more explanatory variables ($X$). The situation where only a single explanatory variable is considered is called simple linear regression.

As we are considering “linear” regression, the explanatory function is that of a straight line where $m$ is the slope and $b$ is the intercept (the $Y$ value when $X=0$), Equation 5.

$$Y = mX + b$$ \hspace{1cm} (5)

The parameters $m$ and $b$ are chosen to provide a “best” fit of the line to the experimental data. The scheme used to fit the parameters can vary, though a common method is to minimize the sum of squared errors (the error between the predicted values and the experimental data). This is referred to as least squares regression and is an appropriate method for curve fitting to corrosion/erosion data.

For corrosion/erosion monitoring, the thickness value is assigned to the dependent variable and time is assigned to the independent variable $X$, thus, the value of slope, $m$, yields the corrosion rate. Optionally, temperature can be assigned to a second independent variable if a temperature measurement is available for each measured thickness value. In this way, one can statistically explain the effect of temperature on the thickness measurement and thus remove its effect. In order to calculate accurate corrosion rates, it is important to remove the temperature effect by either removing it from the data prior to regression (for instance by using equations 2 and 3) or by removing it by using a second regression variable.

![Linear Regression of Thickness Data](image)

Figure 7. Linear regression of 1X/day thickness measurements
An example of using linear regression to model corrosion rate is shown in Figure 7. In this example, a 0.0005 mm/day (7 MPY) corrosion rate is evident and is accurately predicted using linear regression. The regression process has the ability to predict a corrosion rate very precisely as the process tends to “average” out the measurement noise. In this manner, the precision of the corrosion rate measurement can far exceed that of the base measurement system.

As mentioned, the corrosion rate is often not uniform over an observed timescale so the use of a linear fit can be questionable if the time frame captured is too long. Linear regression can only accurately model a single corrosion rate, thus if the period of data used in the calculation contains more than one corrosion rate, the accuracy and validity of regression is degraded. The use of a goodness-of-fit estimator such as the R-squared value can be used as an indicator that the underlying physical situation is not resulting in a linear change of thickness over time.

It is usually most convenient to think of corrosion rate as two parameters, one “Short” term and one “Long” term. The time frame short and long can only be defined by observing the physical situation presented by the combination of materials and process variables but as a rule of thumb, short term might be defined by measurements collected over several weeks while long term might be defined as measurements taken over a year. The long term rate must be used with care as a linear fit is likely only a poor approximation to the actual corrosion/erosion process such as the presence of multiple corrosion/erosion rates and episodic events with very high corrosion rates such as shown in figure 6. In that example, a long-term rate would overestimate the “typical” corrosion/erosion rate, yet using this value to predict long-term maintenance could be disastrous if an episodic event were to recur and reduce the wall thickness below a critical threshold.

5.1 Precision of Corrosion-Rate Measurements

With certain assumptions, the uncertainty of the slope and intercept coefficients can also be calculated. Figure 8a shows an example calculation for a measurement system with 1 mil standard deviation and measurement intervals from 4X per day to 1X per week. This result makes it clear that the accuracy of corrosion rates calculated from linear regression can be improved by making more frequent measurements over a long time interval, even for a measurement system with modest precision (1 mil (0.001” or 0.025 mm) standard deviation).

While even infrequent measurements such as 1X per week can result in accurate corrosion rate calculations, it is necessary to perform the calculation over a much longer time frame. This is undesirable from a process-feedback perspective and also opens the possibility that the corrosion rate is not uniform over the time period and thus invalidates the use of linear regression to accurately calculate corrosion rate.
Figure 8b shows the same calculation of corrosion rate measurement precision, but for a 10X more precise measurement system: 0.1 mil (0.0001” or 0.0025 mm) standard deviation. Clearly, this results in a drastic improvement in the ability to monitor corrosion rate accurately and quickly. Thus, even though linear regression has the ability to measure accurate corrosion rates by removing measurement noise, the development and use of higher precision corrosion/erosion monitoring systems is very important as well.

Figure 8. Uncertainty of corrosion rate from linear regression for a measurement system with (a) 1.0 mil (0.025 mm) standard deviation, and (b) 0.1 mil (0.0025 mm) standard deviation.
6.0 Some Applications of Installed UT Sensors/ Distributed Ultrasound:

The potential applications of installed UT sensors are virtually unlimited; any asset or TML currently being monitored for corrosion/erosion being a candidate. As such, the choice of converting a point from conventional monitoring can involve many factors including:

- The criticality of the asset or TML and potential loss of assets, loss of life, lost production, environmental damage / fines, damage to company image; the cost of cost of access – scaffolding cost, lagging / delagging, offshore access, personnel costs.
- The desire for improved corrosion management including trending, verification of corrosion mitigation strategies (<5 MPY), feedback for chemical inhibitors, planned maintenance, etc.
  - The need for high-integrity data to enhance RBI and mechanical integrity programs.
  - A desire to eliminate the human factor present in manual UT.
  - A desire to remove inspection personnel from hazardous areas.
  - Regulatory and Code compliance.

Locations currently monitored using ER probes: Figure 9 shows traditional points in a refinery’s crude unit where process corrosion rate is measured using electrical-resistance probes. While this technology is currently status quo, it suffers from several shortcomings including measurement noise due to temperature changes, susceptibility to conductive deposit causing “negative” corrosion readings and relatively short life. ER probes only give a proxy to asset health as the actual asset is not being measured. Furthermore, the probes are invasive and need to be replaced periodically. The replacement operation usually must be done on an energized circuit and failures during that process have had catastrophic consequences including loss of life.

Figure 9. Schematic view of refining crude unit showing corrosion monitoring locations.
Installed ultrasonic sensors including instrumentation that is designed to have high measurement precision can approach the corrosion rate precision of ER probes using regression analysis as shown in Figure 8b. The technology is installed directly on the asset, so in addition to measuring corrosion rate, the wall thickness is measured, giving a direct indication of asset health. UT probes are non-invasive and can be deployed on live piping circuits without the risk associated with penetrating the vessel or pipe’s pressure boundary.

**Injection / Mix-point Corrosion:** Injection/Mix-point corrosion has been responsible for many serious refinery incidents and is episodic in nature, only happening for certain process conditions or during process upsets. API 570 specifies inspection guidelines and NACE IP 34101 provides specific process guidelines to minimize injection point damage. While manual UT and RT provide static monitoring of potential damage areas their use may not coincide with the timeframe where episodic damage occurs and therefore will require repeat inspections of potential damage areas. Installed UT sensors can provide dynamic monitoring of suspected injection point damage locations without repeated access mobilizations.

![Figure 10. Pipe failures due to Injection/Mix-point corrosion.](image)

**Crude Overhead:** Crude Unit Overhead with Chemical Injection and/or Water Washes are subject to periodic inspections per API 570. Many overhead lines have no platform access making these inspections difficult and costly. UT and RT can provide useful inspection data, but it is costly to obtain if crane access / scaffolding is required. Installed UT sensors can be installed and accessed on a continuous basis to reduce cost of access and to improve plant operational knowledge.
Reactor Effluent Air Cooler
Reactor Effluent Air Coolers have suffered numerous Erosion - Corrosion incidents due to ammonium Bisulfide and Ammonium Chloride Erosion. Rigorous monitoring of operating conditions must be followed by extensive UT and RT surveys. The repeated, rigorous monitoring required justifies on-line installed sensors to allow continuous or intermittent monitoring of suspect areas.

Buried Pipelines: Smart-pigging is the often-used solution for monitoring pipelines, and most large-diameter, long-distance transmission lines are fitted with the proper valves, pig launchers, to allow inspection with smart pigs. Most secondary lines however are too small in diameter and not appropriately configured to allow pigging, thus requiring excavation and visual inspection. Federal regulations such as 49 CFR requires repeated excavation of problem areas. Installed UT sensors can be buried in problem areas and then can be periodically measured without further excavation costs.
**Figure 13. Buried pipelines and road crossing**

**Riser Monitoring:** Sand Erosion can occur at change-in-direction or diameter in offshore production risers due to solids production. This erosion is typified by a smooth surface with a sand dune pattern. Riser locations where sand erosion may occur can be difficult to access and inspect with conventional UT or RT in addition to the high mobilization costs of personnel to offshore facilities. Helicopter access to an offshore facility can cost in the range of $50,000 USD per trip. While acoustic technologies can be used to detect the impingement of sand particles on the internal bore of the riser, these techniques only determine the presence or absence of sand and do not measure the remaining wall thickness of the asset. UT installed sensors can be applied to suspect areas for accurate monitoring without the need for manual access and can be integrated with platform or FPSO control systems for a “control panel” view of asset health.

**Figure 14. Eroded surfaces due to sand impingement**
7.0 Summary:

Corrosion/Erosion is a widespread and costly problem for US and Global infrastructure causing degradation of assets due to reduced wall thickness and the corresponding reduction in load-bearing capacity with potential for adverse and catastrophic consequences. Currently, manual ultrasonics and radiography are widely deployed to measure asset integrity for wall-thickness degradation, such as in high-energy piping circuits and pressure vessels in the O&G and Power Generation industries. While these techniques are common and accepted, there are drawbacks in the accuracy and precision of these measurements and they only take a periodic snapshot view of asset health. Asset managers desire a more real-time view of the health of their facilities and equipment similar to the KPI view that they get when monitoring process variables. Additionally, the difficulty and cost of access, safety concerns and regulatory environment are further driving interest in installed monitoring systems.

Installed and network-distributed ultrasonic sensors have the potential for improved asset-health monitoring as compared to current manual inspection techniques. Ultrasonic sensors are non-intrusive and being permanently installed with automated or semi-automated data-collection schemes reduce key variables such as operator interaction, resulting in improved measurement accuracy and precision. Other key noise variables such as temperature change can be removed automatically with temperature sensors and software. Thus, installed ultrasonic monitoring systems can provide more and better data, allowing the use of statistical tools such as linear regression to provide corrosion-rate measurements on par with other technologies such as ER probes and further allowing enhanced trending and feedback to process variables.

Opportunities for corrosion/erosion monitoring systems are widespread, including applications such as ER probe or coupon replacement, mix-point corrosion, crude overhead lines, effluent air coolers, buried pipelines and offshore risers as well as an almost unlimited variety of applications where conventional UT and RT inspections are deployed. Thus, corrosion/erosion monitoring is not one thing. The need exists for a flexible solution to meet the application and customer requirements including wired and wireless solutions depending on the unique situation or requirements.

Sensor Networks, Inc. has developed a flexible solution for corrosion/erosion monitoring. The solution uses a novel, patent-pending approach for deploying network-distributed ultrasonic sensors along a multi-drop system using industry standard, Modbus over RS-485 wired approach or alternatively a wireless HART mesh network. This solution allows the deployment of hundreds to thousands of measurement points in a cost-effective manner. High accuracy and precision is obtained using features such as temperature compensation and linear regression that are built into SNI’s software platform. A cloud software platform is offers unparalleled access to asset health data.
About the authors:

Dr. James N. Barshinger
Jim is co-founder, President & Chief Technology Officer of Sensor Networks, Inc. Jim received his Bachelors, Masters and Ph.D. from Pennsylvania State University School of Engineering Science & Mechanics. His doctoral thesis was in Guided Wave Propagation working under Dr. Joseph Rose as his advisor. Jim has been working in the NDT / Ultrasound industry with Krautkramer-Branson, AGFA NDT, GE’s Global Research Center and with GE Inspection Technologies over the past 15 years. At GE Inspection Technologies, Jim held roles of principal engineer and product manager for their installed sensor product line. Jim has extensive experience in ultrasonic transducer design, guided wave ultrasound, nonlinear acoustics and phased array ultrasound.
barshinger@installedsensors.com

Bruce A. Pellegrino
Bruce is co-founder and Vice President of Marketing for Sensor Networks, Inc. Bruce is a 35+ year veteran of the NDT product & service business having founded EMCO as a NDT sales company in 1978 and Visual Inspection Technologies in 1983. Bruce oversaw the merger of VIT with Everest Imaging and subsequently ran Everest VIT, Inc. as President & CEO from 1999 until 2005 when it was acquired by GE. Bruce held various management positions – Product, Marketing, Government Relations and Business Development – at GE Inspection Technologies from 2005 until 2014.
pellegrino@installedsensors.com