Ivan Ruiz Stubelj, Emerson Automation Solutions, Norway, addresses corrosion monitoring and integrity management of pipelines in remote areas.

The integrity of pipelines and the ability to operate such infrastructure in a safe and reliable manner is integral to the safe transportation of gases and other fluids.

The number of pipelines in remote areas is adding to the challenge. The West-East Gas Pipeline Project, for example, that links the gas fields of Turkmenistan in Central Asia with the Chinese cities of Shanghai and Hong Kong, is among the world’s longest onshore pipelines at 2485 miles (4000 km).

One of the biggest threats to the effective utilisation of pipelines today, however, is that of corrosion. In a recent 2016 National Association of Corrosion Engineers (NACE) IMPACT study, the global cost of corrosion was estimated at US$2.5 trillion.

Figure 1. Continuous and online area corrosion monitoring solution deployed on remote pipelines.
Exacerbating the danger of corrosion is the number of ageing pipelines. As of 2015, 67% of oil and gas pipelines across the globe were over 20 years old. This article will look at the challenges of internal corrosion and its impact; the pros and cons of the technologies used to address it; and new innovations – in particular, non-intrusive area corrosion monitoring based on the field signature method (FSM™).

Internal corrosion – causes and tracking challenges

Internal corrosion – corrosion occurring on the inside of a pipeline – is a leading cause of incidents in pipelines. There are a wide variety of causes for internal corrosion that include fluid corrosivity, flow velocity, deposit of water accumulation, H₂S or CO₂, or other pipeline impurities.

There are also challenges in addressing internal corrosion. Firstly, there are difficulties in sourcing cost-effective pipeline monitoring tools for large and remote areas. This might include issues relating to communications, power, transportation and logistics, as well as the inability of commonly used technologies to perform continuous and online area corrosion monitoring on these pipeline assets.

Secondly, there is the need to identify between localised corrosion – corrosion in small areas or zones on the metal surface – and generalised corrosion where corrosion is uniformly distributed over a much larger area. Inorganic acids, salts, CO₂, H₂S and other components that generate localised corrosion and possible leaks are also often difficult to track.

So, what are the potential options for tracking corrosion in remote and targeted area pipelines?

Inline inspection

Inline inspection (ILI) includes a wide variety of tools and techniques, such as ultrasonic inspection, magnetic flux inspection, metal loss tools and pigging.

Smart pigs, for example, have continued to grow in popularity and are playing a key role in detecting stress cracking, and general and pitting corrosion. This is possible through the smart pigs’ highly-tuned sensors that gauge the thickness of pipes and identify integrity issues, such as cracks, fissures, erosion and other problems. The growing automation of pigging systems has also brought with it economic and health, safety and environmental benefits – when compared to traditional manual pigging systems – with fewer personnel required in the field.

However, ILI techniques come with their own challenges as well, such as the need to have pipelines configured to accommodate tools and a wide range of specifications. There are also access issues, particularly in remote areas and in the lower parts of underground pipelines. In the case of smart pigs, there is the issue of pigs travelling through bends in the pipeline and the danger of them getting stuck.

Finally, there are the issues of cost and logistics – especially when large and remote areas have to be monitored. There can be significant cost and transportation implications, with smart pigs being expensive and labour intensive to deploy. Each pig can also only handle a few miles on average, they require multiple launches (some pipelines require pigging a few times daily and others just a few times a week), and a total smart pigging operation can cost as much as US$35 000/mile.

Direct assessment

Another option designed to complement detailed ILI-based inspections is direct assessment, consisting of external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA) and stress corrosion cracking direct assessment (SCCDA).

The goal of ICDA is to prioritise the likelihood of corrosion along a pipeline, identify locations most susceptible to such damage (where water accumulates, for example), excavate and examine them, and then use the results as the basis for assessing the integrity of the complete pipeline. Such assessments can include collecting historical data, field data during the inspection phase, and operational data to help perform pipeline modelling.

Direct assessment is popular today, particularly in pipelines that are ‘unpiggable’ due to their small diameters, bends, connections and low flow, that can cause the pig to get stuck, as mentioned previously. In the case of internal corrosion, NACE has ICDA methods for dry gas, wet gas and liquid product pipelines to meet the need for pipeline integrity.

Limitations of direct assessment, however, include extremely high operating expenditure, very short pipeline sub-segments coverage, the subjective operator selection of the excavation location, and the discrete nature of the data points.

The limitation of lack of data points means that inspection data from a few selected locations along the pipeline is used to characterise the integrity of the entire pipeline, and relies heavily on the ability to model flow and accurately quantify or predict corrosion. In the case of large area pipelines, this can pose significant risks.

The emergence of non-intrusive, online corrosion monitoring

It is against this context, and when evaluating the relative merits of ILI and direct assessment, that we turn to an alternative form of integrity assessment: non-intrusive, online corrosion monitoring and FSM.

FSM is based on feeding an electric current through a target section of a pipe, pipeline or vessel where the applied current sets up an electric field that is monitored as voltage drop values between a set of sensing pins installed on the external pipe wall.

FSM measures the voltage drop between all pairs of sensing pins, and this is called the field signature. Follow-up measurements are compared to the field signature. With general corrosion, a uniform increase in voltage drops between all pin pairs. Localised corrosion causes a local increase in the values.

With FSM, corrosion is measured between the sensing pins, ensuring that the full monitored area is covered; not only under each sensing pin. This is particularly important when monitoring localised corrosion.

The FSM data can then be plotted as metal loss over time for the efficient tracking of changes in metal loss or in 3D plots that show the distribution of corrosion over the monitored area.

Utilising this technology, Emerson has developed the Roxar FSM Log 48 Area Corrosion Monitor™, which delivers permanent, cost-effective and online area corrosion and erosion monitoring.
for remote and targeted area pipelines with minimal personnel requirements.

The new FSM monitor can trend not only general but localised corrosion through its tomographic technology, and avoid unnecessary pipe replacements and excess chemical inhibitors injections. With pipeline construction as much as US$4.5 million/mile, this brings with it significant cost savings. Typical sensitivity for the Roxar FSM Log 48 is 0.1% of wall thickness for general corrosion, corresponding to 10 - 20 µm in most cases.

Armed with comprehensive, real-time pipeline health information, operators can then make better decisions about when and where to conduct pig runs, integrity digs and hydrostatic pressure tests – thereby increasing pipeline availability and transportation capacity. This data-driven proactive maintenance strategy also reduces both unplanned and planned downtime and associated inspection costs.

In addition, the monitor has a total cost of ownership of less than one typical smart pig run of up to 10 km, although this can vary according to the pig technology. In addition, it significantly reduces direct assessment and aerial surveillance costs. When operating alongside pigging, the monitor can optimise pig runs – when pipe bends, valve restrictions and contaminant build-up are restricting pigs from moving through pipelines, for example.

The monitor can be easily retrofitted to any uncovered or buried onshore pipeline segment and, because of its cellular communication and solar power capabilities, can autonomously function in the most remote locations, enabling more data points across several pipeline segments. The fact that a number of monitors can be located over a pipeline minimises the need for assessing pipeline integrity through pigging, which in turn increases transportation capacity.

With 70% of pipeline leaks identified only by visual inspection, the Roxar FSM Log 48 Area Corrosion Monitor can form an important part of future digitalisation strategies and become a key element of an Industrial Internet of Things (IoT) network of intelligent devices that continuously transmit actionable information.1

Conclusions
Meeting increased pipeline integrity management requirements can be best achieved through the deployment of non-intrusive, online corrosion monitoring across large pipeline areas. As well as providing effective corrosion monitoring in their own right, the Roxar FSM Log 48 Area Corrosion Monitor can also aid the deployment of other corrosion monitoring methods, such as pigging and direct assessment.

This helps pipeline operators achieve accurate corrosion and erosion monitoring in the most remote areas; increase pipeline capacity and flow efficiency; reduce risks and OPEX significantly; and gain confidence through cost-effective, data-driven pipeline integrity management.

References
2. RESEARCH AND MARKETS, ‘Global Oil and Gas Pipelines Industry Outlook to 2021: Capacity and Capital Expenditure Forecasts with Details of All Operating and Planned Pipelines,’ May 2017.