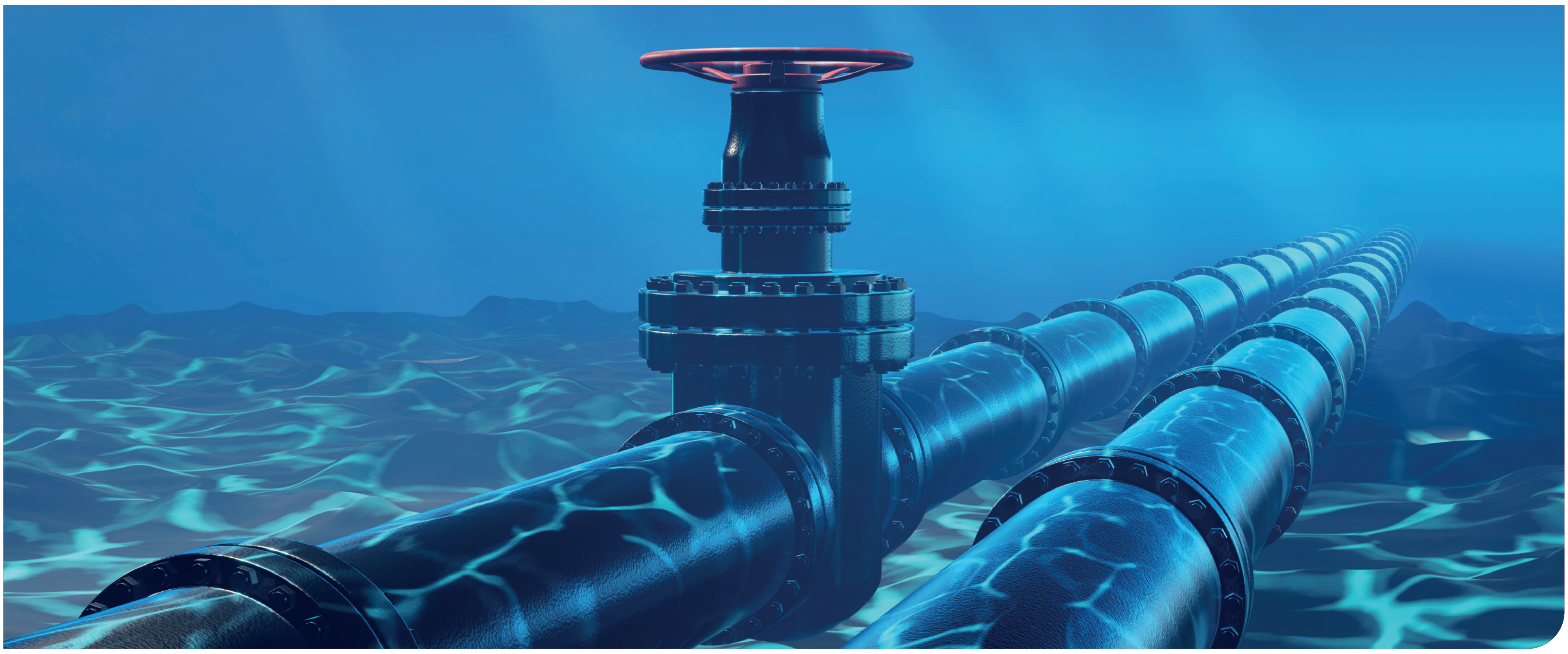
MEETING THE CHALLENGES OF NATURAL GAS STREAM ANALYSIS



Natural gas contains contaminants that need to be carefully monitored to avoid risks to health and safety, and to the very structure of the pipes that carry them. Constant monitoring of natural gas streams demands highly accurate, dependable, and low-maintenance analysers, yet conventional techniques have so far proved less than adequate. Gary Egerton of ABB Measurement and Analytics looks at the challenges and the analyser options.

The global energy industry is increasingly finding itself at a crossroads, as the twin pressures of energy security and the growing evidence of climate change force energy providers and users alike to take a fresh look at the way they provide and consume energy. While the ultimate answer to making the transition to zero carbon emissions lies in renewable power sources, the infrastructural and other challenges associated with immediately switching to sources such as wind, solar, hydrogen and other sources of green energy generation mean that ways need to be found in the meantime to minimize emissions from fossil fuel sources.

Despite the increasing move to more renewable energy technologies, natural gas will continue to play a major role as we transition to non-hydrocarbon sources. The existing infrastructure, mature technology and the high energy density of natural gas will see it remain viable and economic for some time to come.

Although natural gas has clear advantages, it also poses significant challenges. Natural gas has a number of naturally occurring contaminants that are present in the gas stream from the well head, including hydrogen sulphide (H_2S), moisture (H_2O) and carbon dioxide (CO_2). These constitute a significant hazard to an operator's business as they present risks to both safety and pipeline integrity.

H_2S is a dangerous, toxic gas that can cause safety concerns, while excessive CO_2 levels reduce the gases' heating value. Water can also cause problems, with variations in temperature and pressure potentially accelerating internal pipe corrosion.

H_2S is also of particular concern because of the risk it poses to pipeline integrity. Excessive concentrations of H_2S of 5 ppm and above increase the risk of internal corrosion within the natural gas infrastructure, including gas pipelines, storage facilities, and other mission-critical assets.

This corrosion occurs through hydrogen-induced cracking, or hydrogen embrittlement, a chemical phenomenon that causes metal alloys to fracture due to a build-up of hydrogen molecules within the crystal lattice structure. This can occur during forming or finishing processes, but the most common mode is the gradual diffusion of hydrogen atoms into a component's structure throughout its service life.

Hydrogen concentration increases the internal pressure on the component, reducing key properties of the metals such as ductility and tensile strength. These localized flaws can propagate through the surface of the metal, eventually leading to fractures.

This is such a problem that according to the US Environmental Protection Agency, pipelines designed for a service life of 100 years are failing within 20 years due to hydrogen sulphide corrosion. [1]

Constant monitoring essential

These risks mean that measuring H_2S, H_2O and CO_2 concentration is required at processing plants and natural gas custody transfer points to ensure the levels are low enough to meet the required quality specifications.

Parts of the natural gas value chain that can benefit from accurate monitoring include pipeline operators, gas processing plants, natural gas storage facilities and local gas distribution stations.

Pipeline companies collect gas from various sources and make profits by transporting and selling it. Increasingly, CO_2 is also being captured and traded as a valuable commodity for industrial uses such as refrigerants, inflation gas for life preservers, food preservation and carbonated drinks manufacture, and promoting the growth of plants in greenhouses. To make this business viable, trustworthy custody transfer from producer to buyer is essential, demanding a highly accurate gas analyser.

Companies also need to preserve the integrity of their infrastructure and operate a safe and reliable natural gas transmission network.

This means that continuous measurements of natural gas contaminants are required for several reasons, including custody transfer, tariff compliance, and process monitoring.

As well as being continuous, contaminant monitoring should also be performed in real-time. This enables the triggering of threshold alarms, allowing the plant to redirect contaminated streams that would otherwise compromise safety and operational yield.

This demands an accurate fleet of gas analysers, and requires pipeline companies to manage them for reliability, integrity and safety and ensure they have effective process control of gas treatment. They also need to develop plans to manage analyser service, training, and lifecycles, investigate shutdowns and address measurement conflicts in custody transfer agreements.

Essentially, pipeline companies want to increase reliability of their operations and improve the safety of their pipelines. They want monitoring solutions that allow them to respond quickly to process upsets and gas monitors that are easy to install, use and maintain. They want to reduce instrument downtime and the need for site visits, cut the OPEX & CAPEX associated with analysers and protect the environment by ensuring they minimize gas emissions.

Things that frustrate these goals include lack of measurement precision and reliability, instrument unreliability in remote locations, lack of product support or updates for legacy technology, and complex instruments that are difficult both to operate and maintain.

Current measuring approaches

Mitigating the risk of natural gas contaminants can often be frustrating for pipeline operators, as companies are typically required to manage numerous different technologies and analysers. With each of the different contaminants requiring its own gas analyser, maintenance schedule, and specific skill set to operate and validate, this approach is complex, prone to failure and expensive.

Today's analysers often provide inadequate measurement and instrument reliability, false readings – especially during process upsets – and require tedious, time-consuming maintenance. This is particularly problematic for analysers located in remote sites.

For example, one of the common methods is lead acetate tape gas detectors. Typically used to monitor scrubber efficiency and for H_2S monitoring at fixed points, these detectors indicate the presence of hydrogen sulphide with a change in colour of the lead acetate tape. The specially calibrated optics inside the instrument can determine the H_2S concentration by detecting slight variations in the depth of the colour change.

While also available in portable form, this type of analyser is mostly stationary. Disadvantages of this method include its susceptibility to interference from sulphur dioxide (SO_2) as well as low and high humidity. Dry conditions can cause the instrument to underreport results, while high humidity can cause the tape to become moist and the glass components to fog, causing the colour detected by the optic system to become distorted and increasing the risk of an inaccurate final test result.

The lead acetate tapes are also a consumable item, adding to operating expenses. The tapes require replacement every one to four weeks or longer depending on the amount of tape on the roll, the frequency of sampling and the environment in which sampling is conducted. They also have a specific set shelf life and must be protected from humidity in the environment as well as other factors.

Other methods include electrochemical gas sensors. These consist of a sensor, counter, and reference electrode, which are contained in a housing with a gas-permeable membrane. An electrochemical reaction occurs when the gas reaches the working electrode. Although designed to identify a specific gas, most will also respond to gases other than the target gas, which can lead to the non-target gas masking the presence of the target gas.

A more modern approach is Tunable Diode Laser (TDL)-based methods, which operate by measuring the absorption of laser light as it travels through the gas being measured. Although capable of measuring several infrared absorbing gases in difficult process applications, they often rely on chemical scrubbing methods and an existing knowledge of the stream being measured to operate effectively.

Higher accuracy and lower costs

The drawbacks of conventional approaches have been largely overcome by newer solutions that combine high accuracy with ease of use and reliability. An example here is the ABB Sensi+ multi-contaminant analyzer for natural gas. Using a single analyzer element to detect H_2S, H_2O and CO_2, the Sensi+ saves space, removes the need for multiple analyzers and simplifies deployment, operation, and service.

The device uses off-axis integrated cavity output spectroscopy (OA-ICOS). This is a laser technique that increases the effective length of the laser beam to several kilometers compared to only a few meters for most TDL analyzers, allowing for a very low detection limit for target gases. For example, the device can achieve a minimal detectable change in H_2S of 0.2 ppm.

A response time of less than ten seconds ensures minimum product wastage and maximum uptime.

Summary

Accuracy, dependability, and easy serviceability are the watch words of pipeline operators seeking to analyse gas streams. The ABB Sensi+ is an example of a new breed of modern solutions that can be installed at almost any site to provide operators with a cost-effective answer to a major challenge.

References

[1] Hydrogen Sulfide Corrosion: Its Consequences, Detection and Control

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