Improved measurement of water content in natural gas

New TDLAS analyzers use updated designs and more connectivity options to provide high accuracy and reliability without traditional problems

By Alan Garza and Sam Miller, Endress+Hauser

Consumers who have some idea of what natural gas is likely imagine it as a stream of pure methane. Those who are closer to the energy industry know that methane is the major component, but there can easily be dozens of other substances making up a sizeable portion of the total volume. Natural gas producers, pipeline operators, and major industrial users—such as various types of petrochemical plants—have reason to be concerned about what's in the mix (Figure 1).

Contaminates in natural gas can cause a variety of problems for pipeline operators and petrochemical plants, especially when combined with water. This makes accurate and reliable measurement of water content in natural gas streams critical, but traditional techniques often fall short. Fortunately, new analyzers offer much improved performance.

Water exacerbates issues

Natural gas composition is controlled to some extent. Wherever natural gas is traded commercially, there are regulations as to its chemical content and attributes such as calorific value. Local specifications and ranges vary, but typically there are limits for total sulfur, hydrogen sulfide, carbon dioxide, oxygen, and water. This list is not exhaustive, as there are many other possible components, such as higher hydrocarbons and other diluent gases. The common element of these specific components is that they are contaminants and considered undesirable:

- Sulfur and its many compounds represent the most widely encountered contaminant in all fossil fuels, including natural gas, known for their toxicity and pollutants produced during combustion.
- Oxygen degrades amine and some mercaptans which are used in natural gas treatment.
- Carbon dioxide dilutes overall heat value.

Figure 1: Since natural gas can come from a variety of sources, fossil and renewable, its composition and attributes vary, for better or worse.

The greater problem results when these contaminants combine with another: water. All of them work together with water to produce acids capable of attacking carbon steel piping, valves, and other equipment to cause internal corrosion and metal loss over time (Figure 2). Natural gas pipelines can corrode from the outside and inside, but internal metal loss is more difficult to recognize and measure.

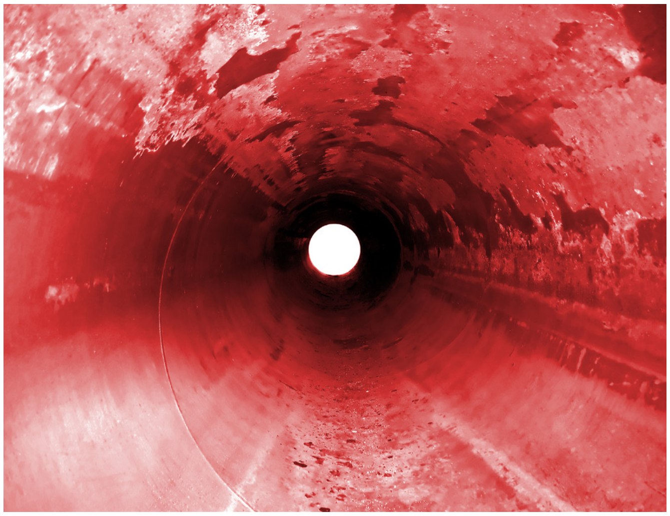


Figure 2: When water mixes with other contaminants in natural gas, corrosive acids can form, able to attack carbon steel piping from the inside.

A Pipeline Corrosion report compiled by PHMSA, part of the U.S. Department of Transportation, summarizes the situation:

"Typically, sales-quality dry gas will not corrode pipeline interior surfaces. However, natural gas, as it comes from the well, may contain small amounts of contaminants such as water, carbon dioxide, and hydrogen sulfide. If the water condenses, it can react with the carbon dioxide or hydrogen sulfide to form an acid that might collect in a low spot and cause internal corrosion."

This leaves natural gas producers, pipeline companies, and users understandably concerned about water content, both liquid and vapor, in the gas flow since a pipeline leak or break caused by unchecked corrosion can cause enormous damage.

As a given volume of gas makes its way from source to ultimate consumption point, it may experience variations in temperature, above and below the immediate dew point, causing water to change phase multiple times. If enough vapor condenses in a cold section of pipe, liquid water can accumulate in a low spot. If the temperature is cold enough, water accumulations can freeze, causing solid clogs. This was a common problem in Texas during the freezing temperatures of February, 2021. Even if the water remains liquid, it may cause enough of a blockage to force the gas velocity to increase, entraining water droplets in the gas stream or pushing liquid slugs that accumulate somewhere else downstream. If a slug reaches the final use point, such as a gas turbine, it can cause serious damage.

Water can be removed by chemical and physical mechanisms, but this adds processing costs. Consequently, there is little incentive to treat gas once it meets the standard for tariff gas. This amount varies between 50 to 200 ppmv depending on the location. Once water is below the limit, it is less of a problem provided it stays there and continues to flow from a reliable source. The supply can and will change from time to time, so there is no reason to assume conditions at one time or location will invariably persist. Given all these considerations, it is clear that knowing the specific moisture content of the gas flow in real time is critical.

Measuring water content

There is a small selection of measurement technologies able to determine the amount of water in a gas pipeline, and as is normally the case with instrumentation, each has its particular combination of practicality, accuracy, and cost trade-offs. All typically involve extracting a sample for individual testing, rather than inserting a sensor for a continuous real-time reading. Here are several common electrochemical and electromechanical approaches:

Aluminum oxide: Water content is determined by measuring the change of capacitance of water molecules captured in microscopic pores across the sensor surface. After an increase in water content, the pores must be dried. Problems occur when molecules are trapped inside as this causes incomplete drying, or when surface contamination clogs pores, keeping molecules out. This technique can also misidentify glycol and methanol content as water. These characteristics make these types of instruments prone to drifting and therefore maintenance intensive.

Phosphorus pentoxide: Gas passes through a cell containing electrodes coated with P_2O_5 able to electrolyze water molecules. Current passing through the electrodes is proportional to the amount of water present. Combining the gas flow rate with the current consumed yields an absolute moisture content measurement. However, the reading can be distorted by changes in flow rate through the analyzer or methanol content in the gas, which is read as water. The sensor is also susceptible to contamination similar to aluminum oxide, and must be replaced on a regular basis, increasing operational costs.

Quartz crystal microbalance: Sample gas is fed into a chamber where water molecules condense on a chilled surface attached to a quartz crystal. The action assesses the change in mass of the microscopic amount of liquid that forms. This approach has high sensitivity, but it cannot differentiate between water and other liquids that condense, such as glycol. If the mechanism does not dry fully between samples, readings will appear higher than actual. Corrosion inside the chamber is common when hydrogen sulfide and carbon dioxide are present in the sample.

Chilled mirror: This approach calculates water content by determining the dew point. A glass surface inside the sample chamber is chilled until the dew point is reached where condensation forms, which can be detected optically or by visual inspection. Again, this technique lacks the ability to identify water specifically apart from other liquids which may be in the stream.

Electrochemical measurement methods

Gas feed contaminant	Aluminum oxide	Phosphorus pentoxide	Crystal quartz	Chilled mirror	TDL sensor
Methanol	◗	◗	◗	◗	✔
Glycol	◗	◗	◗	◗	✔
Amine	◗	◗	◗	◗	✔
Mercury	●	✔	✔	✔	✔
Hydrogen sulphide	●	◗	◗	●	✔
Hydrogen chloride	●	◗	◗	●	✔
Chlorine	●	◗	●	●	✔
Ammonia	●	◗	●	●	✔

Figure 3: Electrochemical measurement methods can be made ineffective or damaged by sufficient exposure to compounds frequently found in natural gas streams. These do not affect a TDLAS analyzer.

✔ Analyzer unaffected
● Can cause permanent damage to sensor
◗ Can cause slow or in accurate readings

A common drawback to all these approaches is the potential for contamination (Figure 3). Some contaminants, such as compressor oil, methanol, and amine, can cause slow or inaccurate readings. Other contaminants can poison the sensor and require its replacement. For example, chlorine and ammonia traces in sufficient quantities can damage all these technologies, with the exception of phosphorus pentoxide.

The problem, ultimately resulting from a poorly performing electrochemical sensor, is a mistrust of the technology. Operators simply assume the reading is incorrect and act on whatever estimate they substitute for reliable data. This leaves two possibilities. First, they assume the gas can't possibly have as much water as the sensors indicate, so they take less action than is truly merited, allowing the corrosive conditions to get worse. Second, they assume the gas must have more water than the sensors indicate and they overtreat it, adding cost. The first situation could contribute to a safety incident, whereas the second hurts profitability. The clear need to solve both of these challenges is a water content measurement that is correct and consistent.

Traditional tunable diode laser analyzers

From a theoretical standpoint, a tunable diode laser absorption spectroscopy (TDLAS) analyzer is arguably the most effective mechanism to measure water content in natural gas. Using an infrared wavelength laser, it is possible to isolate the very distinct peaks in the wavelength absorption spectrum indicating water and other components in the stream. This means the analyzer can provide a water content measurement unaffected by glycol, methanol, amine, or hydrogen sulfide. This underlying capability is a matter of physics but putting it to work in a way that is practical and usable in a typical operating environment is challenging for manufacturers.

TDLAS analyzers are, by nature, very stable and rarely need calibration. The sensor itself is not subject to drift or problems from chemical contamination. However, the supporting mechanisms can challenge effective operation. For example, a TDLAS analyzer is optical in nature, so designs employ mirrors and lenses to direct and focus the beam from the source to the detector (Figure 4).

The sample gas flows through the measurement cell, the space where the beam passes. When the sample contains free liquids, there is an opportunity for flooding the cell. If the mirrors become coated, the beam can be attenuated or blocked. When such problems eventually occur, the cell requires service, however it may take operators some time to realize this type of problem.

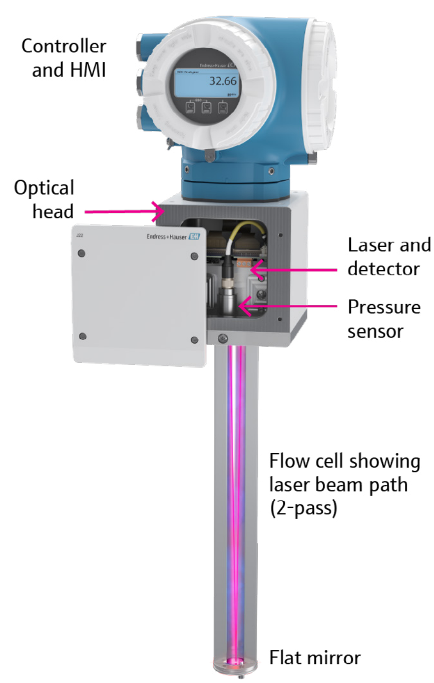


Figure 4: A gas sample must be contained in the space where the beam passes through, so a dirty sample can coat optical surfaces.

These difficulties stem largely from the sample conditioning system. It must capture contaminants and deliver a clean sample to the measurement cell, but it must not affect the water content. The system must also control temperature and pressure of the sample gas to ensure accuracy and repeatability. When servicing is necessary, some analyzer designs can be very complex or impossible to disassemble, with extensive tweaking required as part of reassembly. Some analyzers call for matched sets of components, requiring expensive replacement-part kits, or the end user is forced to send the analyzer back to the factory for repair. This can detrimentally lower measurement uptime availability in critical custody-transfer points.

Fortunately, TDLAS analyzer designs have been evolving to provide operational simplicity while delivering more sophisticated analysis.

Analyzer improvements

TDLAS analyzer improvements have concentrated on three main areas:

- Transmitter electronics, including the HMI, data presentation, system connectivity, and diagnostics.
- Modular construction to simplify serviceability, including sampling system, optical enclosure, sample cell, and electronics.
- Enclosure protection for mounting versatility.

A field-mounted analyzer depends on its transmitter to perform a very wide range of functions. It must support the basic metrology calculations to provide excellent accuracy, linearity, and repeatability. It must also provide internal HMI support for its local display, plus connectivity to send its data to a larger SCADA or other automation host system. The ability to program functions easily and intuitively makes all the difference for ease of use and enables high measurement uptime, so this capability must be provided.

Desired connectivity options have expanded to include web server capabilities, extending the range of remote data access via the internet to any device capable of hosting a web browser, such as a laptop, smartphone, or tablet. This capability is particularly critical when an analyzer is deployed in a location not easily accessible by technicians and operators. When remote access is combined with internal data storage, it is a simple matter for authorized users to upload gas analysis data from extended periods of time.

In many respects, the most important new capability the transmitter supports is internal diagnostics to indicate how the unit is functioning (Figure 5). This determines when problems are developing that are capable of causing poor readings or a complete outage. When severe enough, these situations must trigger alarms to call for immediate maintenance attention.

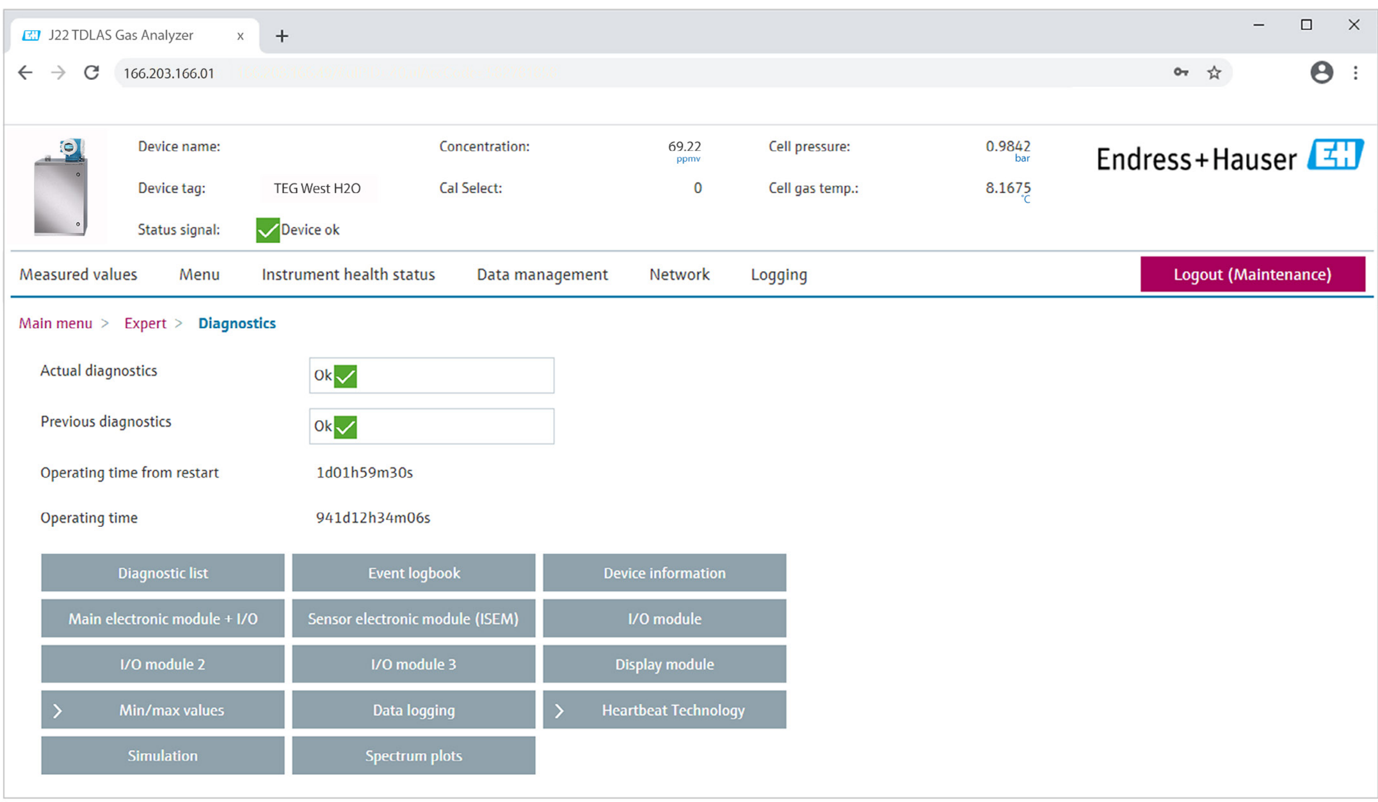


Figure 5: Analyzer diagnostics include a range of functions related to the sensing cell and sampling system.

There should also be continuous evaluation and reporting, which has been simplified for many types of instrumentation through use of NAMUR 107 alarm categories for consistent data presentation.

Since analyzers all need service work eventually, modular construction makes this task much easier and less expensive. Previous designs tended to be difficult to access and reassemble, calling for fussy adjustments before return to full operation. These requirements could cause lengthy outages, leaving users with no analysis data.

But now, major functional components can be extracted as a unit and either serviced quickly, or a substitute assembly, standing by, can be inserted to resume operation with minimal delay. When supported by detailed diagnostic information, a technician knows exactly what needs to happen and can have the necessary parts in hand before the unit is serviced.

Analyzers traditionally have a reputation for requiring specialized enclosures to protect their delicate mechanisms from the harsh surrounding environment. Improvements in construction with more robust internals (Figure 6) allows them to be mounted in more environments with a broader range of environmental temperatures.

Upgraded enclosures, combined with better insulation and enclosure heating, permit outside installation, even in wet and cold climates.

Solution to a clear need

Given the unsettled nature of energy markets caused by the pandemic, the importance of monitoring critical attributes of pipeline gas is very high. With changes in gas fields and the growth of renewables, there is every reason to take nothing for granted. Keeping pipelines and other equipment in reliable and safe operation calls for knowing when corrosion might be happening internally, and this is driven to a large extent by condensation combining with other contaminants.

Pipeline natural gas is routinely monitored for a range of attributes and composition at sources and transfer points, but the reliability of these measurements is no better than the technologies applied and their operators. Where water content is critical, operators have depended on electrochemical techniques, often with hit-or-miss results from poorly performing sensors. In other cases, operators struggle with finicky analyzers, struggling to keep them working properly, and often being forced to return them to the factory for repair.

Both these challenging situations can be solved through today's improved TDLAS analyzers, able to deliver a high degree of accuracy combined with an easy-to-use operator interface and reliable construction. On a continuous basis,

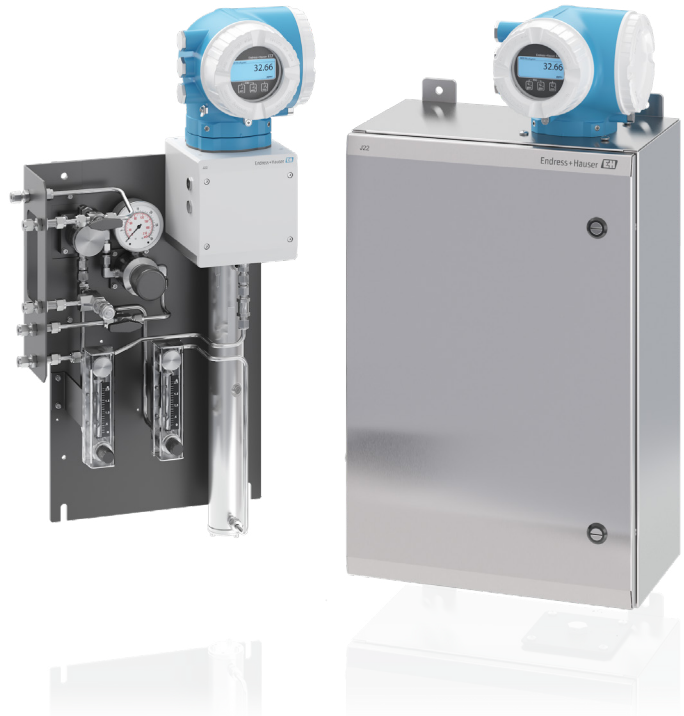


Figure 6: Robust internals protected in solid enclosures avoid the need for analyzer shelters.

with readings only seconds apart, operators can tell if gas quality specifications are met or if remedial actions need to be taken. They can also monitor the analyzer 24/7 by watching diagnostic data.

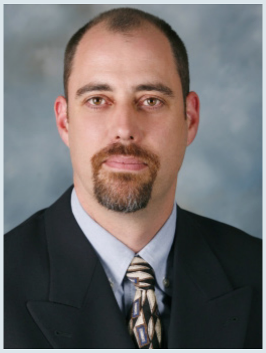
If a problem is developing due to highly contaminated gas, operators will know if the reading data is impaired in any way, and they will understand exactly what actions are necessary to correct the situation. Operators need not be close by, as improved connectivity means they can access the analyzer from virtually anywhere.

While gas supplies are in question, it is important to know that the analysis is reliable.

All figures courtesy of Endress+Hauser

About the Authors

Alan Garza is the product marketing manager for the Advanced Analysis product lines at Endress+Hauser. He began his career at Endress+Hauser as a rotational engineer where he developed in multiple instrumentation technologies. Alan was also part of the Inside sales team where he championed gas analytics and developed as an applications engineer. His background also includes business development and operations management. Alan holds a BS in Mechanical Engineering Technology from the University of Houston.



Sam Miller, PE is responsible for product marketing at Endress+Hauser. He has more than 20 years of experience in oil and gas markets and in the development of laser-based products. Sam is a member of the ASTM D03 standards committee and participates in numerous natural gas conferences including AGA, ISA Analytical Division Symposium, and various international hydrocarbon measurement organizations. Sam holds a BS degree from California Polytechnic University, Pomona and received an MBA with honors from the University of California, Irvine.

www.addresses.endress.com

WP01179C/66/EN/01.22

Endress+Hauser

People for Process Automation