Application Note
Moisture in natural gas

Industry:
Natural Gas
Application Note 10101

Key Points

- Virtually maintenance free
- No interference from glycol, methanol or amine
- Accurate, real-time measurements
- No wet-up or dry-down delays
- Reliable in harsh environments
- Short term payback; no consumables
- NIST-traceable calibration
- Analog and serial outputs for remote monitoring
- Analyzer Management Software included

Natural gas dehydration All natural gas contains water (moisture) which is measured in natural gas pipelines at production and gathering sites, custody transfer points, compression stations, storage facilities and in the distribution markets. Several methods are used for dehydration such as pressurizing, chilling, and absorption processes that use liquid and solid desiccants. Commonly, dehydration is achieved in the field with triethylene glycol (TEG) contactors. Glycol carryover to the analyzer is more likely at closer proximities to the outlet.

Measurement of H_2O Moisture measurement is critical for gas companies to meet quality specifications and to protect pipelines from corrosion. False positives are very costly because the gas cannot be delivered if it is “wet”. Natural gas streams may also contain high levels of solid and liquid contaminants as well as corrosive gases in varying concentrations (glycol, methanol, compressor oil, sulfur compounds). This presents a challenge for the measurement of moisture because the contaminants destroy some moisture sensors and cross-interference effects with the moisture readings must be avoided.

Issues with traditional measurements Moisture measurements have traditionally been performed using a chilled mirror. A chilled mirror determined dew point on a carefully cooled mirror, but it is a slow and subjective measurement because many other components in natural gas can condense on the mirror. Additionally, a variety of electronic sensors have been used which rely on the adsorption of water onto a sensitive surface which is placed into the natural gas stream. In practice, sensors that are in contact with natural gas streams are adversely affected by natural gas components, which cause errors, interferences, and failures. Ultimately, they are too costly to operate and the measurement is unreliable.

SpectraSensors’ solution Tunable diode laser absorption spectroscopy (TDLAS) was introduced to the natural gas industry by SpectraSensors more than a decade ago. The rugged nature of these laser-based analyzers has allowed them to be used in natural gas pipelines with very little maintenance, no interference, and with no detrimental effects from glycol, methanol, amine, H_2S, moisture slugs, etc. Since its inception, this technology has demonstrated its reliability in thousands of installations worldwide.

Validation SpectraSensors analyzers require no calibration in the field and the calibration is stable for the life of the analyzer, however, validation of H_2O concentration is simple to perform. The analyzers are equipped with validation gas connections to accept binary gas blends blend of H_2O. A detailed procedure and recommended setup for performing validations is available from SpectraSensors.

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Application Data

Target Components	H_2O in Natural Gas
Typical Measurement Ranges SS2100 (a)(i)(r)[1], J22	0-50, 0-100, 0-200, 0-500 , 0-1000, 0-2500, 0-6000 ppm_v
Typical Measurement Ranges SS1000, SS2000(e), SS3000(e), J22	0-20, 0-50, 0-100, 0-250 lb/MMscf (0-422, 0-1055, 0-2110, 0-5275 ppm_v)
Typical Measurement Ranges SS500(e)	0.25 -20, 0.25 - 50, 0.25-100 lb/MMSCF (5-422, 5-1055, 5-2110 ppm_v)
Typical Repeatability	±1 ppm_v or ±1% of Reading (whichever is greater)
Typical Accuracy SS1000, SS2000(e), SS3000(e), SS2100(a)(i)(r)[1], J22	±2 ppm_v plus 2% of Reading
Typical Accuracy SS500(e)	±10 ppm_v or ±2% of Reading (whichever is greater)
Measurement Update Time	1-4 seconds
Principle of Measurement	Tunable Diode Laser Absorption Spectroscopy
Sample Flow Rate	0.5-1 L/min (1-2 scfh)
Recommended Validation	Chilled Mirror per ASTM D1142, Portable TDL or Binary Cal Gas with Methane Background[2]

1. Various product models with differing features are available for this application. For a comparison of product models, refer to the Analyzer & Application Guide. For complete product specifications, refer to the respective Product Data Sheets.
2. Certain product-measurement combinations are calibrated in a nitrogen background instead of methane. Consult the analyzer calibration certificate or contact SpectraSensors prior to sourcing validation material.

Typical Stream Composition

Component	Minimum (Mol%)	Typical (Mol%)	Maximum (Mol%)
Hydrogen Sulfide (H_2S)	0	2-4 ppm_v	5
Moisture (H_2O)	0	30-80 ppm_v	0.5
Carbon Dioxide (CO_2)	0	2	20
Nitrogen and Oxygen (N_2+O_2)	0	1	20
Methane (C1)	50	90	100
Ethane (C2)	0	7	20
Propane (C3)	0	3	15
Butanes (C4)	0	<2	5
Pentanes Plus (C5+)	0	<1	3

The process stream composition must be specified for proper assessment, calibration and measurement performance. This includes the normal or typical composition, as well as the expected variation (min./max.) for each component (including the measured analyte). Deviations from the typical composition table will be reviewed by SpectraSensors for suitability.

The chart at right depicts the output of a SpectraSensors TDL analyzer to a large "slug" of moisture in a natural gas stream. Note the rapid response at the beginning of the event ("wet-up"), and at the end ("dry-down").