SAMPLING CHALLENGES ASSOCIATED WITH UNCONVENTIONAL GAS SOURCES

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Introduction

Advances in exploration, drilling and production technologies make it feasible to extract natural gas from sources that in the past have been regarded as unconventional and so, such sources are becoming a larger percentage of the gas supply. The feasibility of producing gas from a source is the primary factor in determining whether that source should be categorized as conventional or unconventional. What has been unconventional in the past may be considered conventional in the future.

This paper will discuss gas sampling system design fundamentals and highlight key aspects of current industry standards. It will also explore the challenges associated with sampling gas from unconventional sources such as shale formations, deep-water offshore wells and enhanced recovery systems. Proper sampling of natural gas from unconventional sources usually requires equipment and techniques that are more sophisticated than those that have performed well for conventional gas sources. Methods for the continuous sampling of natural gas that is wet, at high pressure or even supercritical will be presented. The primary focus of this paper is on minimizing the error associated with sampling for compositional analysis. Sampling considerations associated with the measurement of single components will however also be discussed.

Importance of Natural Gas Sample Conditioning Systems

Natural gas is a mixture that varies widely in composition. What consumers call natural gas at the burner tip is very different from what producers call natural gas at the well head. The natural gas that reaches consumers is a finished product that gas processors call residue gas. Residue gas is a very narrow subset of the vast spectrum of raw gas mixture compositions that producers extract from the ground. The monetary value of natural gas is based upon the mixture composition. Gas composition is the primary input for calculating heating value per unit volume, and the primary input for calculating compressibility, a factor in volumetric flow calculations. An accurate compositional analysis is essential to accurately establishing the monetary value associated with custody transfer. Errors in the analysis results translate directly into either one party paying too much for the gas or the other party being paid too little for the gas.

The entire analyzer system impacts the accuracy of the analysis. That includes the sampling system. The purpose of the sampling system is to extract and transport a representative sample that is acceptable to the analyzer. The analyzer itself is only one part of the system. Results can be accurate only to the extent that the sample received by the analyzer represents the source. **The general consensus in the analyzer community is that over 80% of analyzer system problems and errors originate in the sample conditioning system rather than the analyzer**.

Application Driven Design

The benefits of standardization make it tempting to design a sample conditioning system for the worst case scenario that is anticipated and then standardize on that design for all locations. Cost savings can usually be realized from standardization during design, fabrication and installation. Such savings often outweigh the additional cost of components that are unnecessary for installations that are not the worst case. On the other hand added complexity typically increases operation and maintenance costs. Unnecessary complexity usually makes troubleshooting a sample system more expensive. A standardized system may introduce measurement error that a system tailored to the installation would not. The financial impact of such an error over the life of the installation should be taken into consideration before deciding to install a standardized system.

The optimal sample system contains the minimal components that will deliver a representative sample acceptable to the analyzer. Best practice for sample system and component design is to minimize the following: internal volume, internal surface area, operating pressure, and flow rate. Excessive flow rates can be the cause of problems and errors that far outweigh the little or no benefit that might be realized from a shorter response time. The purpose of analyzer is to provide information. The minimum frequency of information update that can be tolerated is what should determine the required

analyzer system response time and the associated flow velocity requirements.
Gas flows are commonly expressed in volumetric units however before increasing the flow rate to an analyzer, or attempting to supply sample to multiple analyzers via a single extraction point, consider the gas velocity rather than the volumetric flow rate. If the sample velocity into the tip of the extraction probe is higher than the flowing source velocity the probe acts like a vacuum cleaner to ingest any contaminant passing anywhere near the tip of the probe. Conversely if the sample velocity into the tip of the probe is lower than the flowing source velocity then the momentum of contaminants will tend to carry them pass the tip of the probe. While using a filter to capture contaminants in the sample system is better than damaging an analyzer, excluding contaminants from the sample system is best.

A well designed natural gas analyzer system should be able to tolerate a limited range of ambient conditions and source conditions; specifically, pressure, temperature and composition. If all ranges, of all conditions, for all of the installations are within system tolerances then it might be possible to standardize on one sample system design. This is rarely the case because of the typical diversity of field locations within an operating company. That does not mean that every sample system must be unique. When application driven natural gas sampling system designs are balanced with the benefits of standardization the result is typically a small number of designs that can perform well if properly applied. Proper definition of source conditions at a specific extraction point is essential to selecting the most appropriate design for that location.

The sample system design should be tailored to characteristics of the analysis. The component(s) of interest, the measurement range, the required accuracy and the detector technology are all factors that should be considered. For instance, condensing even a miniscule amount of heavy hydrocarbons in the sample system introduces significant error to a heating value determination while it would probably have little impact on measuring the H_2S content. Conversely the specialized coatings applied to stainless steel surfaces associated with measuring trace levels of H_2S or moisture would be of little or no benefit in the compositional analysis for the hydrocarbon concentrations used to calculate heating value.

Dry Gas

Natural gas that is generally considered dry is also known by other aliases such as lean gas, or transmission quality gas or residue. Raw natural gas flowing from the well head must typically be processed before it is suitable for transmission pipelines and distribution systems. Transmission quality gas is what gas processors call residue gas. It is what remains after the raw gas from the wellhead has been processed to remove contaminants and to extract natural gas liquids (NGL) such as ethane, propane, butane and heavier hydrocarbon liquids. Transmission quality gas, or residue, is almost entirely methane, perhaps a little ethane and possibly traces of other compounds. In comparison to the wide range of raw gas compositions there is relatively little variation in residue gas composition. Even though the range of residue gas composition variation is relatively narrow, wide variations in operating conditions and ambient environment impact the compliment and configuration of the equipment necessary for analytically correct sampling. Ambient temperature, gas pressure, and gas temperature ranges that dictate the optimal sampling system for one installation could be either woefully inadequate or excessively complex for another installation. For example, a membrane tipped probe regulator alone with no heat tracing may be excellent for sample extraction at a city gate in west Texas whereas at a high pressure storage facility in northern Montana sample extraction may require a membrane tipped probe and a heated four stage regulator mounted inside a heated enclosure with heat traced tubing between the extraction point and the analyzer.

Industry Standards

The American Petroleum Institute, the Gas Processors Association and the International Standards Organization have published the following standards that address natural gas sampling:

API Manual of Petroleum Measurement Standards, Chapter 14 – Natural Gas Fluids Measurement, Section 1 - Collecting & Handling of Natural Gas Samples for Custody Transfer, a.k.a. API 14.1

GPA 2166-05 Obtaining Natural Gas Samples for Analysis by Gas Chromatography

ISO 10715 Natural Gas Sampling Guidelines

It is important to be familiar with the contents of these standards since commercial contracts commonly require adherence to the practices specified in one or more of them.

These standards apply to transmission quality gas. All of them stress the importance of sampling above the hydrocarbon dew point and that obtaining a representative sample from a gas source near the hydrocarbon dew point is difficult. All of them acknowledge the reality that natural gas can contain hydrocarbon liquids at conditions below the hydrocarbon dew point and that natural gas can contain liquids such as oil, water, glycol, amines, or

other contaminants. Clearly indicated in the scope section of each of the three standards is that none of them cover sampling from multiphase natural gas, more commonly known as wet gas.

The standards also recommend that gas sample temperature be maintained above the hydrocarbon dew point. The exact amount varies from 10ºC to 17ºC above the hydrocarbon dew point. Good sample system design practice is to use the more conservative value of 17ºC because of the uncertainty associated with hydrocarbon dew point determination. It follows that if the sample source temperature is within 17ºC of the hydrocarbon dew point then the sample will need to be heated before the sample pressure can be reduced. Any liquids in the sample will of course need to be separated from the gas before it is heated or the gas composition will be altered.

Wet Gas

Wet gas is not new to the oil and gas industry however widespread attempts to sample it are a relatively new development. One reason is that a higher percentage of North American production is coming from unconventional sources such as deep-water offshore wells and shale gas formations; the gas from such sources tends to be richer. Another reason is that analytical technologies that were once also unconventional are now field proven and common in gas distribution, transmission and midstream operations. The natural inclination of the industry is to apply those same technologies farther upstream, where the gas is much wetter. Couple this with the inadequate separation that typically accompanies an accelerated rate of new production and the result is a proliferation of natural gas sampling problems if traditional sampling approaches are employed.

The term **Wet Gas** is widely used in the natural gas industry to describe anything that is not dry gas. It has not been quantitatively defined by any codes or standards body. Compliments to the flow measurement community for identifying the rudiments of a definition by assigning the term **Multiphase** to liquid dominant flow with a gas volume fraction (GVF) <80% and the term **Wet Gas** to a gas dominant flow with a GVF >80%. This definition of wet gas includes everything from a saturated vapor up to gas with up to 20% liquid by volume entrained, with no distinction between liquid contaminants and condensates. Since the range of this definition is too broad for gas sampling purposes it would behoove the analytical community to assign terms to multiple segments of the range and quantitatively define each term.

Membrane tipped probe regulators have become the de facto standard for natural gas sample extraction because of their ability to reject liquid contaminants and obtain a representative sample near the hydrocarbon dew point. Near the hydrocarbon dew point even a small change of temperature or pressure can change the vapor liquid equilibrium and the composition of the gas phase. If the gas composition changes then the BTU value and the monetary value of the gas will change. Membrane tipped probe regulators make it possible to extract a gas sample without changing the composition of the gas. They have performed so well in gas transmission and distribution systems that they are being installed in gathering systems upstream of gas processing, where the gas is wet. If the wet gas is on the saturated vapor end of the spectrum then a membrane tipped probe regulator should work very well. If the wet gas is on the 80% GVF end of the spectrum then such an excessive amount of entrained liquid will very likely overwhelm a membrane tipped probe. In such cases it may still be possible to extract a gas sample by using a preconditioning assembly with a membrane separator at the outlet of the probe rather than at the tip. Although a preconditioning assembly may be able to reliably provide a repeatable sample from a wet gas source it should be noted that it also has the potential to compromise the accuracy of the composition if the sample temperature at the membrane differs from that of the source. Current technology is not able to predict whether or not a membrane tipped probe will function properly in a specific wet gas service prior to installation. GVF is certainly one factor however there are very likely many other variables.

Wet gas is not always wet because it contains natural gas liquids. Sometimes it's wet because it contains liquid water or liquid contaminants such as corrosion inhibitors or treatment chemicals such as amines. Such liquids entrained in sufficient quantity to overwhelm a membrane tipped probe usually indicate excess sample extraction flow rate, poor probe location, an operational problem or some combination of these.

Accurate determination of BTU value requires a compositional analysis of the hydrocarbon concentrations in the gas mixture. Sample accuracy is so critical to compositional analysis that the potential gains from using a membrane tipped probe may be worth expending the resources to replace it should liquids prove to be excessive. If errors in the hydrocarbon concentrations do not significantly impact the accurate measurement of a single component such as moisture, H_2S or CO_2 then the ability of a preconditioning assembly to better tolerate wetter gas may be worth the compromised

accuracy of the hydrocarbon concentrations and the higher initial cost. Whether to install a membrane tipped probe or a preconditioning assembly is a decision that must balance the need for accuracy against the need for higher liquids tolerance. Regardless of the sample extraction apparatus being used, a membrane separator with a liquid block should always be close coupled to the inlet of the analyzer to protect the analyzer from liquids, especially when the sample source is wet gas. Liquids should not be allowed to accumulate within the membrane separator.

High Pressure Gas & Supercritical Fluid

Gas produced from unconventionally deep or unconventionally tight formations is usually at unconventionally high pressures. Temperature and pressure are both required to specify a hydrocarbon dew point. The hydrocarbon dew point with the highest temperature for the associated composition is called the cricondentherm and the dew point with the highest pressure is the cricondenbar. If the source pressure is above the pressure associated with the cricondentherm then heating the sample before reducing the pressure is likely to be necessary unless the source temperature is significantly more than 17ºC above the cricondentherm temperature. If the source pressure is greater than the average of the cricondenbar and the critical pressure associated with the composition then a heated four stage regulator is most likely the appropriate choice for reducing the pressure of the sample. If the sample source pressure and temperature are above the critical temperature and pressure of the gas mixture then elastomers compatible supercritical natural gas will be required.

Natural gas storage facilities inherently sample from sources that are at high pressure and that are sometimes stagnant. Probe regulators rely upon the heat from a flowing gas source to counteract Joule Thomson cooling. If the source is stagnant then the addition of heat or a multistage regulator or both may be required.

Enhanced Recovery

Addressing the most common problem associated with sampling natural gas that has been produced by CO_2 injection is primarily a matter of material selection. Elastomeric sealing materials that have been very successfully used to sample conventional natural gas sources are not suitable at pressures higher than approximately 7 bar-g (100 psig) with gas containing more than about 3% CO_2. An elastomer that will resist CO_2 permeation to prevent explosive decompression is required and CO_2 concentration greater than 90% typically requires a different elastomer.

Wet gas sampling challenges are likely to be encountered when natural gas is produced by either the water flooding or steam injection method of enhanced recovery. Separating liquid water from a lean natural gas sample is however typically less challenging than separating other contaminants or separating heavy hydrocarbon liquids from a rich gas.

Other considerations

Ambient climate conditions, including seasonal changes impact proper sample system design. Consider, for example, a circumstance where the composition of the sampled gas is such that at the pressure in the transport tubing the hydrocarbon dew point temperature is -25ºC (-13ºF). In Corpus Christi, TX the additional expense and complexity of heat traced sample tubing would be unnecessary, whereas in North Dakota heat traced transport tubing would be essential to preventing the errors and operational problems associated with condensed hydrocarbons.

Heating transport tubing and sampling components at locations without access to electrical power lines can be challenging. Without the infrastructure necessary for proper sampling the only alternative may be a compromise in accuracy. Application driven sample system design consciously balances practical considerations against the need for accuracy.

Hydrate formation in process equipment is problematic and likewise in sampling systems. Sample system design should include avoiding combinations of gas composition, temperature and pressure drop that have a high potential to form hydrates.

Conclusion

A one-size-fits all approach to sample conditioning is problematic. Equipment, methods and even industry standards that are utilized to very successfully sample dry gas from conventional sources are seldom able to reliably provide accurate results when applied to unconventional sources of natural gas. Application driven sample system design tailors the system to the requirements of the task. The application of science and good sampling fundamentals to unconventional gas sources usually results in the utilization of unconventional sampling equipment and methods.