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Introduction

GPA Standard 2172-09 / API Manual of Petroleum Measurement Standards Chapter 14, Section 5, *Calculating Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer*, Third Edition, January 2009 finds wide application in the natural gas gathering and processing business as well as related natural gas handling activities because it provides methods to calculate these often-used parameters from a gas analysis. Several important changes occurred in the recent revision of this standard that became effective January 1, 2009. The main changes comprised in this revision provide methods for incorporating water vapor into the analysis calculations, include theoretical hydrocarbon liquid content (GPM) calculations on a real gas basis in this standard, discuss characterizing heavy ends in the gas analysis as well as other analysis cautions and present a number of detailed example calculations. Refer to the standard itself for requirements, procedures, details and further explanation.

Affected Audience

The audience includes those involved with gas measurement, analysis and accounting and others who calculate Btu content from composition. As the method often used by those who produce analysis results or reports from composition, the changes affect natural gas laboratories, individuals running chromatographs, people involved in determining gas volume and energy quantities, accountants who rely on the volume and energy amounts as well as the component theoretical hydrocarbon liquid content and the people involved in the commercial agreements.

This revision of GPA 2172 may affect commercial agreements because the standard is often referenced in contracts. Implementing this new standard may require programming changes for flow computers, measurement system software, accounting systems, allocation systems and laboratory reports. It is important for users to assess the impact of the changes in this standard with respect to their agreements and processes. Implementation issues are discussed later in this paper.

Publishing and Similar Standards

This standard is jointly published by GPA[1] and API[2] as Standard 2172-09 and MPMS 14.5. It is similar to AGA[3] Report No. 5, *Natural Gas Energy Measurement*, and to ISO[4] 6976, *Natural gas – Calculation of calorific values, density, relative density and Wobbe index from composition*.

Water Vapor

Water vapor is often one of the components in a natural gas stream. When present, water vapor occupies space in a particular volume of gas. Water, like the other hydrocarbon and inert components, contributes its portion of an individual property to the total for that property in the sample. Its concentration varies depending on the presence of liquid water and on the level of compression, addition or extraction of heat and on the extent of dehydration in the process. If the natural gas is saturated with water vapor, such as when natural gas coexists with liquid water in a separator, the concentration of water vapor varies in a predictable fashion as a function of pressure and temperature.

The cost of a quantity of gas is often valued by its energy content, and its energy content can be determined from the heating value per unit volume of the gas multiplied by the volume of gas delivered. This total energy resulting from the multiplication of the volume of gas by its heating value per unit volume requires both the volume and the heating value to be at the same conditions of pressure, temperature and water content. Since the volume of gas

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[1] Gas Processors Association, 6526 E. 60th Street, Tulsa, Oklahoma 74145, www.gpaglobal.org
[2] American Petroleum Institute, 1220 L Street, NW, Washington, D.C. 20005, www.api.org
[3] American Gas Association, 400 N. Capitol St., NW, Suite 450, Washington, D.C. 20001, www.aga.org
[4] International Organization for Standardization, Geneva, Switzerland,www.iso.org

changes with base pressure and base temperature, the base temperature and the base pressure must be the same for both the gas volume and its heating value.

When the flowing stream is water saturated, the total energy delivered can be determined by compensating for water vapor in the analysis and its subsequent heating value or by volumetrically quantifying and removing the water vapor present in the flowing stream, but not both. For example, the total energy for a gas volume containing water vapor (wet volume) requires the wet volume be multiplied by its wet heating value. If the gas volume is instead compensated by mathematically removing the water vapor, then the dry heating value must be used to calculate total energy delivered. While it is technically consistent to apply one or the other, GPA 2172-09 only addresses water in the analysis calculations.

A method is included in Annex C of this standard to predict the water vapor content of a natural gas stream when it is water saturated at conditions other than base conditions using the relationship described in the Institute of Gas Technology Research Bulletin 8 (IGT RB 8), *Equilibrium Moisture Content of Natural Gases*. The algorithm in this Annex can be used to determine the A and B values from IGT RB 8 for gas at flowing pressure and temperature where the flowing temperature is the water dew point of the gas. GPA 2172 allows for the use of another appropriate industry standard instead of IGT RB 8. When the gas is partially water saturated, the concentration of water vapor would be determined by a physical measurement unless otherwise specified by an agreement or statute.

Heating Value

The gross heating value is calculated from the summation of individual component contributions of heating value per unit volume of ideal gas, as in the previous version of this standard, at the water content condition of the gas. Calculate the dry heating value from the relationship

$$Hv^{id}(dry) = x_1 Hv_1^{id} + x_2 Hv_2^{id} + \cdots + x_N Hv_N^{id} = \sum_{i=1}^{N} x_i Hv_i^{id}$$

The heating value for gas containing water vapor flows from the dry ideal heating value equation through multiplying by the non-water vapor portion of the composition as follows

$$Hv^{id}(wet) = (1 - x_w)Hv^{id}(dry)$$

The water content is on a basis of dry, saturated at base conditions, or "as delivered." Dry gas is often defined to contain a small amount of water such as using a limit of 7 pounds per million cubic feet. Water saturated gas has the maximum amount of water vapor that can be held in the gas. Adding any water to the gas would cause an equal amount to condense. As delivered gas may have an actual condition that is saturated at flowing conditions or partially water saturated. Partial water saturation means a gas with water content between dry and saturated conditions.

Heating value reported on a unit volume basis is the energy transferred in an ideal gas reaction per volume of ideal gas fuel. When divided by compressibility (Z), the heating value provides the energy transferred in an ideal gas reaction per volume of real gas fuel. GPA 2172-09 introduces the term *adjusted heating value*, Hv^{id} / Z, which is the ideal energy content per unit of real gas volume. This heating value, when multiplied by the real volumetric flow rate produces the ideal energy flow rate.

Refer to GPA 2172-09 for additional details and for the definition of terms related to heating value, relative density, compressibility and theoretical hydrocarbon liquid content.

Relative Density

Relative density is the ratio of the mass density of the gas at pressure and temperature conditions to the mass density of air at the same pressure and temperature conditions and is the preferred term to its specific gravity synonym. Ideal relative density is independent of base pressure. Real relative density however is dependent on base pressure because the compressibility ratio multiplier in the equation is a function of pressure.

Calculating ideal relative density G^{id} from composition follows the relationship

$$G^{id} = x_1 G_1^{id} + x_2 G_2^{id} + \cdots + x_N G_N^{id} = \sum_{i=1}^{N} x_i G_i^{id}$$

Since all real gases deviate from the ideal gas law, it is typical for the real relative density to be used in flow calculations and other calculations. Evaluate the relative density parameter needed in downstream calculations when selecting the appropriate relative density condition. Real relative density G is calculated from ideal relative density G^{id} through multiplying by the ratio of the compressibility of air to the compressibility of the gas mixture as follows

$$G = G^{id} \left(Z_a / Z \right)$$

Compressibility

The compressibility factor, given the symbol Z, is the ratio of the actual volume of a mass of gas to its volume calculated from the ideal gas laws at the same pressure and temperature conditions. Compressibility is the term describing the behavior of a real gas as compared to ideal gas at the same conditions.

At pressures near the atmospheric pressure, such as those base pressures used in gas analysis calculations, GPA 2172-09 provides two methods to calculate compressibility from composition, a simple expression and an alternative rigorous method. The simple method takes the following form and uses summation factors (b_i) from GPA 2145, *Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry.*

$$Z = 1 - P_b \left[\sum_{i=1}^{N} x_i b_i \right]^2$$

The alternative rigorous procedure, also referred to as the double summation method or the second virial coefficient method has the following form and uses second virial coefficients given in Table 3 of the standard.

$$Z = 1 + BP_b \text{ where } B = \sum_{i=1}^{N} \sum_{j=1}^{N} x_i x_j B_{ij}$$

Note that volume calculation standards, such as those for orifice, turbine and ultrasonic meters, require the use of AGA Report No. 8, *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases* to determine the compressibility factor. A user may choose to implement the AGA Report No. 8 compressibility method in the analysis calculation or select from the two methods in GPA 2172. Differences in results for the three methods are within the experimental error of the underlying physical data, and for the composition used in the example calculations, vary by 0.00003 from the least to the greatest compressibility factor.

Theoretical Hydrocarbon Liquid Content

Plant settlement, allocation and accounting calculations often utilize the theoretical hydrocarbon liquid content of an unprocessed natural gas stream. In the U.S., theoretical hydrocarbon liquid content is thought of in its units, gallons per thousand cubic feet (MCF), abbreviated as GPM. A GPM value represents the gallons of a hydrocarbon component theoretically condensable from the gas stream per thousand standard cubic feet of gas. In the context of GPA 2172, the gas analysis represents the flowing stream and the GPM values for each component provide the quantity of liquid theoretically condensable from an MCF of this gas.

GPA 2145 provides the fundamental physical property, the ratio of ideal gas to liquid, for each component in this calculation. It is seen in FPS units as cubic feet of ideal gas per gallon of liquid. The inverse of this property would have FPS units of gallons of liquid per cubic feet of ideal gas. The ideal gas portion of this property is at standard conditions of 14.696 psia in GPA 2145 FPS units and must be adjusted to match the base pressure of the gas. The form of this equation in FPS units is

$$LC_i^{id} = x_i \times 1000 \times \frac{1}{(ft_{gas,id}^3 / gal_{liquid})_i} \times \frac{P_b}{14.696}$$

Since the gas portion of this ratio of gas to liquid has ideal gas conditions, it must be adjusted by the compressibility factor Z to arrive at cubic feet of real gas per gallon of liquid. Dividing GPM by Z results in gallons of a component per thousand cubic feet of real gas, which can then be applied consistently to a real volume of natural gas. If the flowing stream is not dry, the water content affects the theoretical hydrocarbon liquid content.

$$LC_i = \frac{LC_i^{id}}{Z} \text{ so, } GPM_i = \frac{GPM_i^{id}}{Z}$$

Analysis Issues, Cautions and Decisions

Chromatographs normally do not detect or quantify the concentration of water vapor in a gas sample, so the amount of water vapor would typically be calculated from pressure and temperature conditions if the gas is water saturated or it would be measured through a physical test. Sampling and analysis must conform to applicable GPA and API standards or their equivalents.

It is important to include all components in the sample analysis and to use them in the resulting calculation, especially for those components with concentrations greater than or equal to 0.01 mole percent. The actual precision of the analysis results, of course, are governed by the detectability limits of the chromatograph and the analysis standard. Excluding one or more components, such as helium, oxygen, water vapor or hydrogen sulfide, from the analysis may adversely affect the calculated results including the heating value, relative density, compressibility and theoretical hydrocarbon liquid content. Usually, the analysis calculation assigns no heating value to the hydrogen sulfide component when present in the stream because it is a contaminant and is removed during processing and thus does not contribute to the energy content of the processed stream. Water vapor when present in the gas stream also does not contribute to the heating value and thus is assigned no heating value.

Physical properties for the components in the analysis calculations are found in the latest publication of GPA 2145. If the analysis includes a component not listed in GPA 2145, then refer to GPA TP-17, *Table of Physical Properties of Hydrocarbons for Extended Analysis of Natural Gases*, for the properties.

GPA 2172 provides a set of methodologies to characterize the heaviest hydrocarbon component in the analysis when that grouping includes the concentration of a component of that carbon number as well as the higher carbon numbers. A typical gas analysis rolls up the hexanes and heavier components, termed C_6+, into a single pseudo component. Characterizing this last or heavy end component should use the most representative data available and, according to GPA 2172, result from an extended analysis or be generalized through an engineering evaluation or as agreed upon between the parties involved. While many gas analysis reports use C_6+ as the heaviest reported component, others may use heptanes and heavier, C_7+, nonanes and heavier, C_9+, or another grouping.

It is technically consistent to apply the heating value and the theoretical hydrocarbon liquid content results from a wet analysis to a wet volume or from a dry analysis to a dry volume, but the same conditions of pressure base, temperature base and water content are required for both the analysis results and the volume.

Example Calculations

This revision of the standard includes several informative annexes containing numerous detailed calculation examples starting from a gas composition in mole percent that includes common inert compounds and hydrocarbons through hexanes plus. Users can check and validate programmed and user-calculated results against the intermediate and final results in these examples.

The examples include calculations for dry gas, for water saturated gas at base conditions, for water saturated gas flowing conditions, and for partially water saturated gas using measured water content. In U.S. customary FPS units, the calculations provided are at base conditions of 60 °F for temperature and both 14.696 psia and 14.65 psia for base pressure. Since the physical property values are published at the 14.696 psia pressure base, the examples at this condition should be helpful to users in building a spreadsheet calculation method and in developing a computer program. The commonly used 14.65 psia base pressure in the examples give check points for adjusting to a different pressure base. There is an example for a calculation using SI units at the base conditions of 15 °C and 101.325 kPa. Two examples of hexanes plus property calculations are given, one for a

60%–30%–10% normal hexane, normal heptane and normal octane composition and one for a 47%–36%–17% split. An example of calculating compressibility via the rigorous or double-summation method is also given.

An annex is included in this version of GPA 2172 that provides water content example calculations such as conversions from dry to water saturated heating value and from water saturated to dry at various base pressures for a base temperature of 60 °F. The calculation uses the vapor pressure of water at this temperature to determine the fraction of water vapor in the gas at base pressure. This results in the commonly used 0.9825 conversion multiplier to determine the water saturated heating value at 14.65 psia from the dry heating value. The non-rigorous conversion of a dry heating value to partially water saturated and from partially water saturated to dry is explained with equations and examples and provides a table of the molar volume of water vapor at 60 °F at four common base pressures.

Additional calculation examples display results for calculating energy content given composition and starting from liquid mass, from liquid volume and from gas volume. Lastly, there is a detailed example for determining gas energy content per unit mass from composition.

Implementation

GPA 2172-09 was published with a two-year implementation period to provide time for users to implement the changes. The inclusion of water vapor mole percentages in the analysis calculations likely will involve changes at laboratories and for the users of analysis reports.

An approach to the implementation decision is to consider the amount of water in the measured streams. If the streams are at relatively high pressure or are dehydrated, it may be easier to implement through determining the amount of water vapor in the volume because the affect of water vapor on the gas relative density and theoretical hydrocarbon liquid content could be minimal.

If the amount of water vapor in the streams under consideration is significant to the analysis such as could be the case with un-dehydrated gas at low pressure, the gas relative density and theoretical hydrocarbon liquid content would be affected and the compressibility at base conditions may be impacted by ignoring water vapor in the gas analysis. In this case, the gas relative density that includes the relative density contribution of water vapor would apply to the volume calculation, so it is likely that a wet analysis calculation will be required in any event. The wet volume could be adjusted to compensate for the amount of water vapor in the stream and the resulting dry volume paired with the dry heating value. Consider the impact of the water content on the theoretical hydrocarbon liquid content in the scenario of dry volume and dry analysis as compared to wet volume and wet analysis in making the implementation decision.

When implementing the wet analysis approach, a decision will be required regarding the pressure and temperature conditions at which the water content will be determined, such as those at sampling time or using an average over the measurement period. The measurement period could include monthly, daily or hourly determinations. If the stream is wet but not water saturated, the amount of water vapor could be measured using available industry techniques such as determining the water dew point via a chilled mirror method or by using a length of stain tube. Alternately, if it is possible to predict the percentage of saturation, the water content could be determined by calculation from pressure, temperature and the degree of saturation. Increased water vapor measurement activities may be required.

There are several ways to calculate the compressibility at base conditions that is used in an analysis report including the two methods described in this standard and the AGA Report No. 8 method required in volume calculations. The GPA 2172 methods are simpler to implement in a spreadsheet calculation or a computer program than AGA Report No. 8, but the AGA method is required in the volume calculation that is often paired with the analysis results later in the accounting process.

This revision supersedes previous editions of GPA Standard 2172 / API MPMS Chapter 14.5, "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis" and it incorporates and supersedes GPA Reference Bulletin 181, "Tentative Reference Bulletin Heating Value as a Basis for Custody Transfer of Natural Gas." It also supersedes the GPM calculations in GPA Standard 2261, "Analysis for Natural Gas & Similar Gaseous Mixtures by Gas Chromatography" and GPA Standard 2286, "Tentative Method of Extended Analysis for Natural Gas & Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography" as well as Table IV of GPA Standard 2261. Expect revisions to GPA 2261 and 2286 to address these changes.

In the Future

AGA and ISO publish standards similar to GPA 2172. As standards undergo periodic review and are updated to address changes in technology and practices, an opportunity arises to combine efforts with these standards developing organizations to provide a single overarching standard. This has the advantage of focusing the diminishing availability of technical experts on a consensus document that meets the needs of all interested in heating value and the other properties determined in this and the related standards. On the other hand, properties like theoretical hydrocarbon liquid content and Wobbe index apply to subsets of the user community for an overarching standard and may overly complicate the work of developing a combined standard. Work is underway to evaluate the differences in the standards and the harmonization opportunities available.