



A Critical Evaluation of Natural Gas-water Formula Correlations

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Authors' contributions

This work was carried out in collaboration between both authors. Author VJA designed the study, performed the statistical analysis, wrote the protocol, and wrote the first draft of the manuscript. Author VJA and MAA managed the analyses of the study. Author MAA managed the literature searches. Both authors read and approved the final manuscript.

Article Information

DOI: 10.9734/JSRR/2019/v25i630206

Editor(s):

(1) Dr. Suleyman Korkut, Department of Forest Industry Engineering, Duzce University, Division of Wood Mechanic and Technology, 81620 Beciyorukler Campus Duzce, Turkey.

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Complete Peer review History: <http://www.sdiarticle4.com/review-history/54334>

Original Research Article

Received 23 November 2019

Accepted 27 January 2020

Published 01 February 2020

ABSTRACT

The performance evaluation of fourteen (14) formula correlations for predicting the water content of natural gas in equilibrium with water, and the suitability of some of these correlations in predicting the water content of natural gas in equilibrium with hydrates, has been presented. Also presented was an evaluation of acid gas and gravity correction factor correlations. The evaluation was achieved by using the cubic plus association equation of state - CPA EoS, published experimental water content data from a tuneable diode laser adsorption spectrometer, and data from the gas processors supplier's association (GPSA) chart, to validate the results of the correlations. The results of the validation showed that for the prediction of the water content of natural gas in equilibrium with water, the Bukacek correlation was best suited for low pressures of 1 and 2.5 MPa at a temperature range of 9 to 58°C. The modified ideal model (MIM) correlation was the best for pressures of 5 and 10 MPa, at temperature range of 30 to 89.6°C. The Aimikhe correlation was best suited for pressures of 7.5 MPa, at a temperature range of 30 to 86°C, while the Khaled's correlation performed better for high pressures of 25 and 50 MPa, at a temperature range of 30 to 91.5°C. The Maddox correction factor had better accuracy than other acid gas correction factors when accounting for the presence of acid gases. The Mohammadi or Chapoy gravity correction factors were the best correlations for accounting for the presence of heavy components in natural

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gas. For processed methane-rich natural gas in equilibrium with hydrates at a temperature range of -20 to 10°C, the Lin correlation was best suited for pressures of 2.5 and 5 MPa while the MIM correlation performed better at pressures of 7.5, 15 and 20 MPa.

Keywords: *Natural gas water content; heavy hydrocarbon correction factor; salinity correction factor; acid gas.*

NOMENCLATURE

A_i	: Association sites on a molecule;
P	: Pressure, psi / atm/ MPa;
p_c	: Critical pressure, MPa;
p^V	: Vapor pressure, MPa;
T	: Temperature, Celsius /Fahrenheit/Rankine;
T_c	: Critical temperature, Kelvin;
T_o	: Reference Temperature, K;
P_o	: Reference Pressure, MPa;
W_c	: Water content, mole fraction/ ppm mole/mgsm ⁻³ ;
W_{exp}	: Experimental water content, mole fraction/ppm mole/mgsm ⁻³ ;
W_{cal}	: Calculated water content, mole fraction/ppm mole/mgsm ⁻³ ;
S, W_{salt}	: Salt concentration;
R	: Gas constant, psi-ft ³ /lb-mol °R;
Ma	: Apparent molecular weight;
N	: Total number of data points;
x_i	: Mole fraction of component i ;
X^{A_i}	: Hydrogen bond component;
V	: Molar volume, ft ³ /mol;
V_W	: Average molecular volume of water, m ³ /mol;
Z	: Compressibility factor;
Z_{CO_2}	: CO ₂ mole fraction;
Z_{H_2S}	: H ₂ S mole fraction;
$Z_{H_2S}^{equi}$: Equivalent H ₂ S mole fraction;
g	: Radial distribution function;
a, b, \dots, l	: Constants;
a_0, a_1, a_{11}	: Constants;
A, B, C, D	: Constants;
A_1, \dots, A_3	: Constants;
B_1, \dots, B_3	: Constants;
C_1, \dots, C_3	: Constants;
A_B, \dots, E_B	: Constants;
A_A, \dots, E_A	: Constants;
$a_{acid}, \dots, d_{acid}$: Constants;
a_V, \dots, C_V	: Constants;
F_{salt}	: Salinity correction factor;
F_{HC}	: Gravity correction factor;
F_c	: Correction factor;

GREEK SYMBOLS

ρ	: Molecular density, lb/ft ³ ;
γ_g	: Gas specific gravity;
ϕ_w	: Fugacity coefficient of water;

ABBREVIATIONS

% AD	: Percentage Absolute Deviation;
% AAD	: Percentage Average Absolute Deviation;

CPA – EoS : Cubic Plus Association, Equation of State;
 SRK-EoS : Soave Redlich Kwong, Equation of State;

1. INTRODUCTION

Natural gas from the development and production of oil and gas conventional and unconventional reservoirs [1,2] and other sources of hydrocarbon gases like biogas usually contain water as an impurity. Water in natural gas is a critical component of the gas mixture, which must be removed or minimized during processing for the gas to meet pipeline or market specifications. If not removed or reduced, the water in the gas can lead to numerous flow assurance problems. Fig.1 shows most of these flow assurance problems that can occur during production, processing, transportation, and storage of natural gas. These flow assurance problems can result in pipe blockage, incessant plant shut-down, equipment failure, poor gas quality, increased pigging frequency, and increase operating cost. It is, therefore, imperative for natural gas to be adequately dehydrated to avoid these problems. An efficient dehydration process is mostly achieved by accurately estimating the water content of the gas at given temperatures and pressures. The water content of the gas is the amount of water held within a specified volume of the gas at a given temperature and pressure. It is measured

in lb per MMSCF (Standard British unit) or mg per m³ (Standard European unit). Other units are ppm and mole fraction.

Natural gas water content is the basis of natural gas processing and designing [3]. Its accurate estimation and monitoring is key to the mitigation of the flow assurance problems described in Fig. 1, and as such, it is essential for the study of gas hydrate management, corrosion mitigation and control, water disposal programs, enhanced oil recovery, gas well production efficiency, CO₂ capture and storage, natural gas storage, estimating the limits of numerous (old and novel) dehydration techniques [4], troubleshooting of gas processing systems and setting dehydration specifications for hydrocarbon processing. The monitoring and assessment of the water content of natural gas are performed at nearly all the critical facets of the gas value chain. It is done routinely at; the liquefied natural gas (LNG), natural gas liquids (NGLs) and liquefied petroleum gas production facilities; the high-pressure fiscal metering points, low-pressure consumer stations, natural gas storage facilities, CO₂ capture, storage and utilization facilities [5] and other production, processing, custody transfer, and storage facilities.

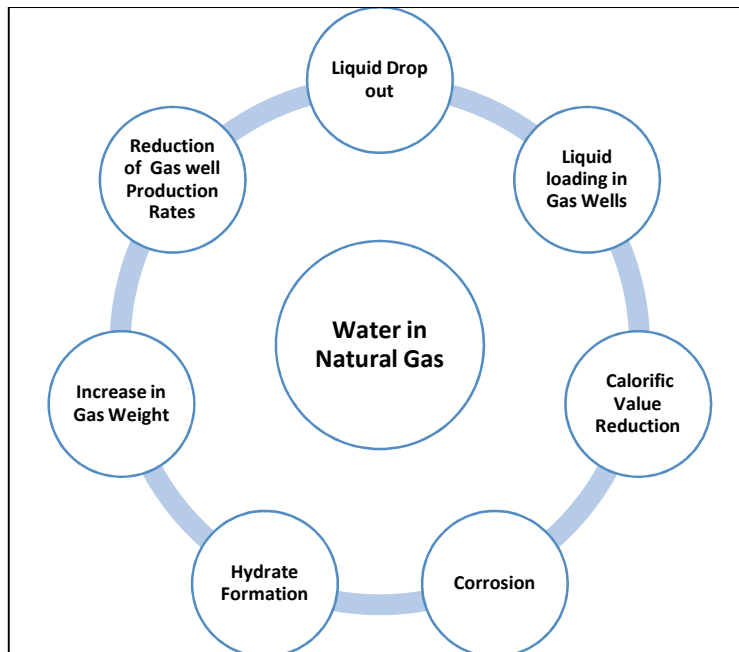


Fig. 1. Flow assurance problems emanating from the presence of water in natural gas

There are various methods of estimating the water content of natural gases. These include the use of moisture measurement devices (Chilled mirror, Tuneable Diode Laser Adsorption Spectrometer), thermodynamic / equations of state (EoS) models, formula correlations, and charts. The advantages and disadvantages of using the water content measurement devices have been extensively highlighted in the literature [6,7]. Thermodynamic / equations of state models [8-14] provide very accurate estimations of natural gas water content for any equilibrium system. They cover a wide range of temperature and pressure and are not limited by gas composition. However, they are very rigorous, with some model input parameters not easy to come by, making them difficult to use. Formula correlations and charts [4,15-19] still play a significant role in the determination of natural gas water content. This is due to their simplicity and the ease of formula correlations to be programmed into spreadsheets. As a result, both charts and formula correlations remain popular among engineers and scientists in the natural gas industry for the estimation of the water content of natural gas.

Numerous formula correlations have been developed over the years for the prediction of the water content of natural gases. These correlations were either developed from charts [20–25], experiments [3,26,27] and data from water -hydrocarbon systems [28-30]. The reliability of these correlations depends on the accuracy of the data used. The majority of the water content data used for the development of these formula calculations were from water – hydrocarbon binary systems [4,31-38], and natural gas mixtures [1,2,4,36,39-42].

In the development and validation of these correlations, some authors have reported their work as the best performing correlation when compared to other selected correlations, using data in which the most stable equilibrium phase (water, hydrates, ice, and aqueous solutions) was relatively unknown. Only a few authors reported water content data in equilibrium with the most stable phase. As a result, it is most likely that any correlation(s) developed (regressed) or validated with such data will only be reliable in the region where the data used was in equilibrium with the most stable phase. Also, published works on the validation of these correlations with a *tailor-made* EoS, e.g., The cubic plus association equation of state- CPA EoS (which can determine the most stable

equilibrium phase), are limited. Most of the published works were for sweet natural gas in equilibrium with the water. Comparative studies on sour natural gas and gravity correction factor correlations in equilibrium with water are scarce. Also, the literature on the evaluation of formula correlations for predicting the water content of sweet natural gas in equilibrium with hydrates has been scarcely reported.

In this study, a comprehensive performance evaluation of published correlations for determining natural gas water content in equilibrium with water and hydrates is presented. This is achieved by comparing the water content results from existing correlations for a given real gas composition, with those obtained using the CPA-EoS. Correction factors [2,21,38,43,44] that account for the presence of acid gases and heavy components were also evaluated. The novelty lies in that this study provides a comprehensive performance evaluation for up to date published water content of natural gas correlations, using water content results from the CPA-EoS, TDLAS and GPSA chart, as the basis for comparison, over a *more extensive pressure range*, that is consistent with gas processing plants (7.5 MPa), offshore flowlines (16 MPa), pipeline transport (up to 25 MPa), gas storage (30 MPa), and reservoir pressures (up to 50 MPa). It highlighted the correlations' ability to adequately predict the water content of natural gas in equilibrium with water and hydrates, and *also evaluated acid gas and gravity correction factors*.

This study, therefore, presents content adequate for a broad audience, from beginners to industry professionals through a detailed performance analysis of the formula correlations for determining natural gas water content. The evaluation will enable scientists and engineers to grasp the essential knowledge and capabilities of existing correlations that help in selecting appropriate models best suited for various natural gas – water systems as well as upgrade existing software models and spreadsheets.

2. LITERATURE REVIEW

This section outlines the various formula correlations for estimating the water content of sweet natural gases. Emphasis is made on sweet natural gases because correction factors have been developed to account for the presence of acid gases, salinity, and heavy components when the water content of the sweet

gas component is known. So, the water content of the sweet gas component is a significant determinant when estimating the overall water content of the gas.

2.1 Lean Sweet Natural Gas Formula Correlations

Formula correlations for estimating the water content of sweet natural gas are available in the open literature. Table A-1 of Appendix A shows the temperature and pressure range for which the correlations are applicable. The correlations coefficients can be found in the original manuscripts. The lean sweet natural gas correlations are presented as follows:

I. Lin's Correlation

Lin et al. [3] developed a correlation for estimating the water content of sweet natural gas. The correlation is given as:

$$W_c = 101.325 \sum_{i=0}^7 \left(\frac{a_i T^i}{P} \right) + \sum_{i=0}^7 b_i T^i \quad (1)$$

II. Sloan's Correlation

Sloan et al. [20] presented a correlation by fitting low-temperature water content data into the developed model. The correlation is of the form:

$$W_c = 16.02 \exp \left[a_1 + a_2 \ln p + \frac{a_3 + a_4 \ln p}{T + 273.15} + \frac{a_5}{(T + 273.15)^2} + a_6 (\ln p)^2 \right] \quad (2)$$

III. Ning's Correlation

Ning et al. [21] presented a correlation by fitting data obtained from the Mcketta and Wehe chart. The correlation is of the form:

$$W_c = (1015.32 + 1.1T - 18.2\gamma_g - 1.42T\gamma_g) \times (1 - 0.02247S) \times \exp(a_0 + a_1 T + a_2 T^2) \quad (3)$$

IV. Khaled's Correlation

Khaled [22] proposed a correlation based on published data extracted from charts. The correlation is given as:

$$W_c = \frac{W_1}{P} + W_2 \quad (4)$$

$$W_1 = \sum_{i=1}^5 b_i \times T^{i-1}$$

$$W_2 = \sum_{i=1}^5 c_i \times T^{i-1}$$

V. Ghiasi and Bahadori's Correlation

Ghiasi and Bahadori [24] proposed a logarithmic function for estimating the water content of sweet natural. The correlation is of the form:

$$\begin{aligned} \log W_c = & [A_1 \log P + A_2 \log P^2 + A_3 \log P^3] \\ & + [B_1 \log T + B_2 \log T^2 + B_3 \log T^3] \\ & + \\ & [C_1 \log P \times \log T + C_2 \log P^2 \times \log T + C_3 \log P \times \\ & \log T^2] + D \end{aligned} \quad (5)$$

VI. Aimikhe's Correlation

Aimikhe et al. [25] presented a correlation for estimating the water content of the sweet gas component of natural gas. The correlation is of the form:

$$W_c = \frac{a}{(P+f)} T^4 + bT^3 + \frac{c}{P^g} T^2 + \frac{d}{P^h} T + \frac{e}{P} + I \quad (6)$$

VII. Behr's Correlation

Behr [26] presented a correlation of the form.

$$\begin{aligned} W_c = & a_0 + \exp \left[a_1 + \frac{a_2 + a_3 \ln P + a_4 (\ln P)^2}{(T + 273.15)^2} + a_5 \ln P + \right. \\ & \left. a_6 \ln^2 P + a_7 \ln^3 P + a_8 + a_9 \ln P + a_{10} \ln^2 P + a_{11} \ln^3 P \right. \\ & \left. T + 273.153 \right] \end{aligned} \quad (7)$$

VIII. Kazim's Correlation

Kazim [27] presented a model based on data obtained from the McKetta and Wehe chart.

$$W_c = A \times B^T \quad (8)$$

$$A = \sum_{i=1}^4 a_i \left(\frac{p - 350}{600} \right)^{i-1}$$

$$B = \sum_{i=1}^4 b_i \left(\frac{P - 350}{600} \right)^{i-1}$$

IX. Modified Ideal Model (MIM)

Carroll [30] presented a water hydrocarbon equilibrium model by modifying the ideal model. The equation is of the form.

$$W_c = 761900.42 \frac{P_{sw}}{P} \exp \left[11.81479 \frac{P^{0.92951}}{T + 273.15} \right] \quad (9)$$

Tohidi [29] presented two models for estimating P_{sw} For gas-liquid equilibrium and a gas-solid equilibrium condition. The models are given respectively as:

$$P_{sw} = 10^{-6} \exp \left[73.96 - \frac{7258.2}{T+273.15} + 2.276 \times 10^{-3} T - 7.3073 \times \ln(T + 273.15) + 4.1653 \times 10^{-6} T^2 \right],$$

$$P_{sw} = 1.33322 \times 10^{\left[\frac{-1032.5576407}{T+273.15} + 51.0557191 \times \log(T+273.15) - 0.05927 \times T + 7.0358 \times 10^{-5} T^2 - 123.968 \right]}$$

X. Modified Wang's Correlation

Li et al. [45] developed a modified version of the Wang [28] water content correlation for natural gas. the modified correlation is as follows:

$$W_C = 804 \times \frac{P_{sw}}{P - P_{sw}} + \frac{B}{1000} \quad (10)$$

$$B = 0.0642 T^2 + 2.0548 T + 13.782$$

P_{sw} was obtained from the Keenan and Keyes [46] vapor pressure model.

XI. Bukacek's Correlation

The Bukacek water content correlation, as presented in the work of Zhao and Burgass [47], was used in this study. The correlation is given as:

$$W_C = 0.016 \times \left[47484 \frac{P_{sw}}{P} + B \right] \quad (11)$$

$$\log B = \frac{-3083.87}{459.6 + 1.8(T + 32)} + 6.69449$$

P_{sw} was obtained from the Keenan and Keyes [46] vapor pressure model.

XII. Gandhidasan's Correlation

Gandhidasan [48] proposed a correlation for calculating the water content of natural gas. The correlation is given as:

$$W_C = 593.335 e^{0.0548 T} \times P^{-0.81462} \quad (12)$$

XIII. Simplified Thermodynamic Model (STM)

Mohammadi et al. [49] presented a simplified thermodynamic model of the form:

$$W_C = 761900.42 \frac{P_{sw}}{\phi_w P} \exp \left[\frac{(p - p_{sw}) V_w}{R(T + 273.15)} \right] \quad (13)$$

Where

$$\phi_w = \exp \left[\left(0.069 - \frac{30.905}{T + 273.15} \right) P + \left(\frac{0.3179}{T + 273.15} - 0.0007654 \right) P^2 \right]$$

For the estimation of V_w ;

$$V_w = -0.5168E - 02 + 3.036E - 04T + 1.784E - 06T^2$$

For a gas-liquid equilibrium system

$$V_w = 19.655 + 0.0022364T$$

For a gas-solid equilibrium system

XIV. Moshfeghian's Correlation

Moshfeghian [50] presented correlations for estimating the water content of sweet lean natural gases. They include:

$$W_C = 47430 \left[\frac{P_{sw}}{p} \right] \quad (14)$$

$$\ln \frac{P_{sw}}{p_c} [a_1 \tau + a_2 \tau^{1.5} + a_3 \tau^3 + a_4 \tau^{3.5} + a_5 \tau^4 + a_6 \tau^{7.5}] \left[\frac{T_c}{T} \right]$$

$$\tau = 1 - \left(\frac{T}{T_c} \right)$$

For pressures below 100 psi, and

$$W_C = \left(\frac{A}{P} + B \right) C \quad (15)$$

$$A = A_A + B_A T + C_A T^2 + D_A T^3 + E_A T^4$$

$$B = A_B + B_B T + C_B T^2 + D_B T^3 + E_B T^4$$

For pressures above 100 psi

2.2 Correction for Acid (Sour) Gas Component

The water content of natural gas with acid gas components like CO₂ and H₂S has been reported to increase as the acid gas composition increases [51]. The effect of these acid gases becomes significant when the gas mixtures contain more than 5% mole fraction of CO₂, or H₂S, or both especially at high-pressures [52]. This additional water in the sour gas, play essential roles in processes like enhanced oil recovery, flow assurance, corrosion monitoring, and gas hydrate management. Hence, accurate predictions of the water content of sour natural gases are imperative.

Various correction factors to account for the effect of acid gases on the water content of

sweet natural gases exist in literature The range of applicability of these correction factors can be found in Table A-2 of Appendix A. They include:

I. Chapoy [38] Correction Factor

$$W_{c(Sour)} = C_{acid} W_{c(Sweet)} \quad (16)$$

$$C_{acid} = 1 - Z_{H_2S}^{equi} \left[a_{acid} \left(\frac{T}{T_o} \right) + b_{acid} \left(\frac{T}{T_o} \right)^2 + c_{acid} \left(\frac{P}{P_o} \right) + d_{acid} \left(\frac{P}{P_o} \right)^2 \right]$$

$$Z_{H_2S}^{equi} = Z_{H_2S} + 0.75 Z_{CO_2}$$

II. Maddox et al. [43] Correction Factor

$$W_c = W_{c(Sweet)} Z_{(Sweet)} + F_c \quad (17)$$

$$F_c = W_{CO_2} Z_{CO_2} + W_{H_2S} Z_{H_2S}$$

III. Wichert and Wichert [44] Correction Factor

$$W_{c(Sour)} = F_{sour} W_{c(Sweet)} \quad (18)$$

$$F_{sour} = Z_{H_2S}^{equi} = Z_{H_2S} + 0.75 Z_{CO_2}$$

IV. Mohammadi et al. [48,53] Correction Factor

$$W_{c(Sour)} = F_{sour} W_{c(Sweet)} \quad (19)$$

$$F_{sour} = 1 + Z_{H_2S}^{equi} \left[C_1 \left(\frac{T}{T_o} \right) + C_2 \left(\frac{T}{T_o} \right) \left(\frac{P}{P_o} \right) + C_3 \left(\frac{P}{P_o} \right) \right]$$

$$Z_{H_2S}^{equi} = Z_{H_2S} + 0.75 Z_{CO_2}$$

From the models presented, it can be inferred that an accurate estimation of the water content of the sour gas depends significantly on the accuracy of the predictive model used for determining the water content of the sweet gas component.

2.3 Correction for Salinity

The presence of significant salt concentrations in natural gases can affect the water content of the gas. This, in turn, can affect the accuracy of existing correlations for predicting its water content [2]. As a result, correction factors have been developed to account for the presence of significant amounts of salt concentrations.

Mohammadi, et al. [2,49,53] and Danesh [54] and recommended the use of the correlation developed from the observed depression in water vapor pressure of brine, for correcting the water content of natural gases due to the presence of dissolved salt (equilibrium with brine). The correlation is of the form:

$$F_{salt} = 1 - 4.920 \times 10^{-3} W_{salt} - 1.7672 \times 10^{-4} W_{salt}^2 \quad (20)$$

2.4 Correction for Heavy Hydrocarbons

The water content of natural gases is mostly dependent on temperature, pressure, and composition. The effect of gas composition is particularly negligible for lean methane-rich sweet natural gases [42,55]. For a rich gas, i.e., natural gas with significant amounts of heavy hydrocarbons, the water content is expected to be lower. As a result, some correction factors have been developed for taking into account the presence of the heavy hydrocarbons in the gas. Notable among the correction factors are:

I. Ning Correction Factor

Ning et al. [21] presented a correction factor for accounting for the presence of heavy hydrocarbons. The correlation was developed from the McKetta and Wehe chart, and is of the form:

$$F_{HC} = 1.01532 + 0.011(T - 273.15) - 0.0182\gamma_g - 0.0142\gamma_g(T - 273.15) \quad (21)$$

II. Chapoy Correction Factor

Chapoy [38] developed a gas gravity correction factor. His model is given as:

$$C_\gamma = 1 - a_\gamma(\gamma_g - 0.554) + b_\gamma(\gamma_g - 0.554)^2 \frac{T}{T_o} + C_\gamma(\gamma_g - 0.554)^3 \frac{T^2}{T_o} \quad (22)$$

III. Mohammadi Correction Factor

Mohammadi et al. [49] developed a correction factor to correct the effect of gas gravity on the water content of natural gas containing heavy hydrocarbons. The correlation emanated from the McKetta and Wehe chart, and is of the form:

$$F_{HC} = 1 + b_1(\gamma_g - 0.554) + b_2(\gamma_g - 0.554) \left(\frac{T}{T_o} \right) + b_3(\gamma_g - 0.554)^2 \left(\frac{T}{T_o} \right)^2 \quad (23)$$

2.5 Water Content of Natural Gas in Equilibrium with Water, Hydrates, Ice and Aqueous Solutions

During the processes of production, transmission, and storage, natural gas can either be in equilibrium with liquid water, ice, hydrates, or aqueous chemical solutions, depending on its temperature and pressure. In any case, the phase behavior of the gas in equilibrium with either liquid water, ice, hydrates, or aqueous chemical solutions cannot be the same. At certain temperatures and pressures, water can precipitate either as liquid water, ice, hydrates, or aqueous (water and glycol) phase [2,4]. At such conditions, the water content of the gas in equilibrium with any of the phases cannot be the same. Hence an adequate knowledge of the water content of natural gas in these equilibrium systems is imperative for the efficient design of natural gas facilities.

The majority of the published water content correlations are for natural gas in equilibrium with liquid water. The models presented in section 2.1 apply in this case. The work of Lin et al. [3] presented a performance and adaptability analysis for various sweet natural gas water content correlations. However, the comparative analysis didn't consider pressures and temperatures higher than 17.6MPa and 74.2°C, respectively. Also, previous work on the performance analysis of the various correction factors that account for the presence of acid gases and heavy hydrocarbons in natural gas water content estimation is limited.

Studies involving the development of correlations that predict the water content of natural gases in equilibrium with hydrates and ice are very limited in the open literature. This limitation of correlations may be attributed to the scarcity of experimental water content data. For this equilibrium system, the water content is very low and highly dependent on the gas composition, and as such, it becomes challenging to develop a general correlation for water content prediction. Fig. 2 illustrates the effect of composition on the water content data for a 0.66 and 0.71 specific gravity (sg) gas, measured at 15 MPa. It can be observed that the minimum and maximum percentage errors in the water content can be as high as 17 and 42, respectively. However, some authors [1,4,31,56,57] have provided water content experimental data for natural gas – hydrate equilibrium systems. For the natural gas – Ice equilibrium system, limited experimental data exist in the open literature [36], and it is based on the assumption that ice is the most stable phase. As a result of the scarce data, thermodynamic models and semi-empirical models [38,49], are mostly used for predicting the water contents of natural gas – hydrate/ ice equilibrium systems, although some formula correlations [3,20,28,50] have also been reported to be valid for measuring the water content of natural gases at low temperatures and high pressures. However, studies on the performance of these formula correlation's ability to accurately predict the water content of natural gas -hydrate equilibrium systems, are limited.

Natural gas can be in equilibrium with certain chemicals used during processing. For instance,

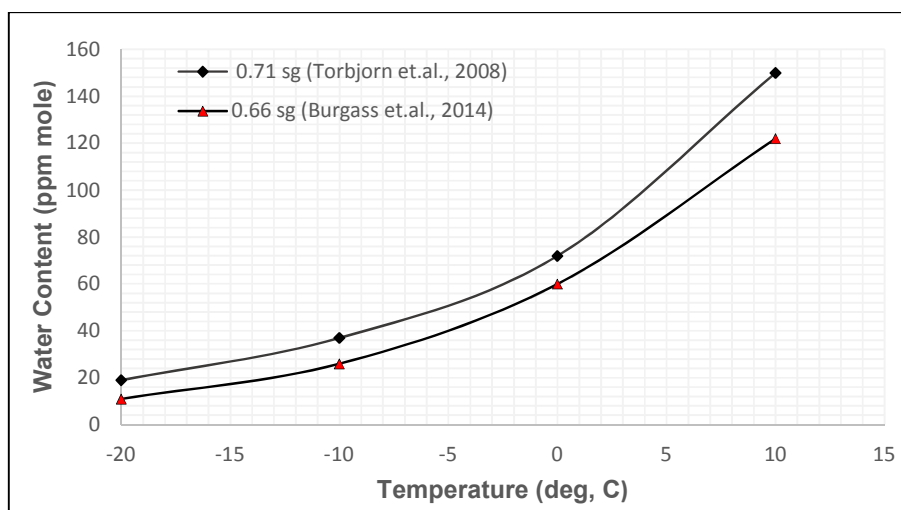


Fig. 2. The effect of composition on the water content data (0.66 and 0.71 specific gravity (sg) gas) measured at 15 MPa

it is most likely that the natural gas leaving the Triethylene glycol (TEG) dehydration column is at its aqueous dew point. It is, therefore, correct to assume that the gas is in equilibrium with lean TEG [4]. Similar assumptions can be made for other systems involving chemicals used in the gas sweetening and dehydration process as well as chemical hydrate and corrosion inhibition processes. For these systems, there is a tendency for a solution of water and any of the chemicals to condense when the system temperature drops. Hence a good knowledge of the system's phase behavior and water content is required for an efficient design of the processing system. Thermodynamic models are often used for modeling the phase behavior of such systems. Experimental data for determining the water content of natural gases in equilibrium with aqueous solutions are scarce. As a result, the correlations for determining the water content of natural gas – glycols equilibrium systems are very limited if not non-existent. This is also the case for other natural gas in equilibrium with chemical solutions.

3. MATERIALS AND METHODS

For this study, the cubic plus association equation of state – CPA EoS [8,58] is used to predict the water content of a real natural gas with gas gravity of 0.71. This EoS is chosen because of its adequacy in modeling water - hydrocarbon systems [58]. The CPA-EoS has been reported [58] to perform as good or better than the GERG water EoS model, which has been accepted as an ISO standard [11] for natural gas water content determination. Another advantage of the CPA- EoS, is its ability to determine the most stable phase (water, ice, hydrates, or aqueous) over a wide range of temperature and pressure. The water content data generated using the CPA-EoS model is then used as a benchmark for evaluating the performance of fourteen (14) formula correlations in the prediction of the water content of sweet natural gas in equilibrium with liquid water. The gas composition and the form of the CPA EoS used for this purpose are given in Appendix B.

The comparative analysis is extended to formula correlations reported to be valid for estimating the water content of natural gas at low temperatures and high pressures (natural gas in equilibrium with hydrates). In this analysis, the published water content data of natural gas in equilibrium with gas hydrates by Burgass et al.

[1], is used as the basis for comparison. The data by Burgass et al. [1] was chosen due to the reliability of the experimental data generated from a state-of-the-art Tuneable diode laser adsorption spectrometer (TDLAS), with high precision. Also, the results from a thermodynamic model developed by Burgass, et al.[1], and reported to be adequate for the water content prediction, is compared with the results of the formula correlations.

For the evaluation of the sour gas correction factors, four (4) correction factors are evaluated using the CO₂ – water content data generated with a TDLAS equipment, published by Chapoy et al. [51]. In practice, the majority of the problems emanating from the presence of acid gases in natural gas are mainly due to the presence of CO₂ [59]. As a result, CO₂ – water content data were used for the evaluation of the sour gas correction factors. Coupling the correction factors with an appropriate sweet gas correlation, the sour gas correction factors are evaluated.

Also, three (3) gravity correction factor correlations are evaluated with the water content data of a 0.897 (Ma = 26) specific gravity gas using the reproduced Mcketta and Wehe chart [52] at pressures of 3 and 6 MPa and a constant temperature of 40°C. For data accuracy, the GetData Graph digitizer is used to extract the data points from the chart. The percentage average absolute deviation (% AAD) is used to evaluate the correlations' performance and ascertain the best-performing ones at specific conditions of temperature, pressure, and composition. The percentage AAD used in this study is given as:

I. Percentage Average Absolute Deviation (% AAD)

$$\% AAD = \frac{1}{n} \left| \frac{W_{exp} - W_{cal}}{W_{exp}} \right| 100 \quad (24)$$

4. RESULTS AND DISCUSSION

Tables 1 to 7 present the results of the comparative analysis performed on the formula correlations developed for predicting the water content of natural gases in equilibrium with liquid water. For this study, three pressure categories were evaluated. They include the low pressure (1 and 2.5 Mpa), intermediate pressure (5, 7.5, and 10 MPa) and high pressure (25 and 50 MPa) categories.

Table 1. Water content of natural gas in equilibrium with water at 1MPa

T(°C)	CPA Value (mg/m ³)	Estimated Value (mg/m ³)							
		Ning	MIM	Bukacek	Gandhidasan	STM	Moshfeghian	Lin	Aimikhe
9.47	913.04	1034.25	991.71	--	997.53	989.92	991.54	1004.80	--
20.81	1923.13	2009.97	2295.98	1940.41	1858.26	2285.97	2020.58	2030.10	1519.31
30.88	3464.53	3529.65	3467.25	3470.61	3228.70	3444.82	3619.43	3617.50	2959.99
41.14	6105.67	6103.33	6082.03	6043.94	5668.61	6030.52	6349.84	6298.50	5547.16
	% AAD	4.93	7.12	0.69	6.65	7.27	5.53	5.80	14.9

Table 2. Water contents of natural gas in equilibrium with water at 2.5MPa

T(°C)	CPA Value (mg/m ³)	Estimated Value (mg/m ³)											
		Sloan	Behr	Kazim	Ning	MIM	Bukacek	Gandhidasan	STM	Khaled	Moshfeghian	Lin	Aimikhe
22.10	838.23	917.05	864.26	948.94	900.83	1062.13	879.05	945.52	1055.22	--	946.52	954.52	935.92
32.17	1506.39	1598.43	1512.30	1832.05	1526.86	1571.61	1534.94	1642.83	1553.08	--	1672.33	1659.30	1529.26
44.16	2920.07	2954.72	2800.60	3006.75	2786.32	2993.92	2871.71	3171.46	2941.25	3139.50	3190.29	3120.80	2863.45
58.18	5972.92	--	5406.96	5803.30	5425.99	5946.15	5655.27	6843.71	5804.59	6111.09	6184.23	6202.20	5748.42
	% AAD	5.57	4.27	10.20	5.64	8.50	3.44	11.30	8.13	4.91	9.18	8.68	4.72

Table 3. Water contents of natural gas in equilibrium with water at 5 MPa

T(°C)	CPA Value (mg/m ³)	Estimated Value (mg/m ³)												
		Sloan	Behr	Kazim	Ning	MIM	Bukacek	Gandhidasan	STM	Khaled	Ghiasi & Bahadori	Moshfeghian	Lin	Aimikhe
30.00	756.51	811.55	798.60	797.41	798.70	754.79	717.90	829.21	742.57	--	762.08	828.56	818.99	732.13
40.28	1320.25	1377.24	1369.92	1408.48	1357.13	1324.42	1215.22	1457.44	1289.83	1445.40	1300.28	1428.50	1397.70	1269.88
50.80	2270.59	--	2288.80	2260.07	2276.10	2257.43	2032.49	2595.58	2177.19	2365.73	2162.98	2382.49	2375.10	2178.12
63.39	4050.71	--	4034.97	3980.21	4085.73	4064.75	3624.00	5178.41	3878.01	4189.87	3803.27	4242.26	4270.40	3937.89
77.89	7569.67	--	7318.37	7637.94	7657.25	7538.46	6705.63	11472.68	7109.77	7647.40	6909.91	7823.78	7788.10	7223.65
	% AAD	5.80	2.77	3.04	2.13	0.38	9.10	22.70	3.72	4.53	4.36	6.15	5.41	3.69

Table 4. Water contents of natural gas in equilibrium with water at 7.5 MPa

T(°C)	CPA Value (mg/m ³)	Estimated Value (mg/m ³)												
		Sloan	Behr	Kazim	Ning	MIM	Bukacek	Gandhidasan	STM	Khaled	Ghiasi & Bahadori	Moshfeghian	Lin	Aimikhe
30.22	568.47	601.46	530.95	614.57	622.33	551.72	507.97	603.20	539.30	--	594.56	617.89	606.92	555.13
44.16	1174.20	1212.43	1092.33	1273.07	1239.30	1165.31	1007.67	1295.95	1116.71	1259.54	1205.74	1271.70	1233.00	1162.78
60.26	2515.88	--	2312.76	2592.78	2606.79	2529.03	2127.05	3134.55	2373.53	2626.87	2521.80	2758.69	2673.20	2545.66
71.24	4021.14	--	3685.49	4211.52	4192.37	4090.99	3420.24	5725.04	3789.47	4178.90	4000.39	4246.15	4268.30	4102.36
86.03	7226.42	--	6553.16	--	7631.69	7415.06	6198.80	12887.13	6756.92	7427.78	7110.39	7586.15	7474.80	7287.39
	% AAD	4.53	7.86	6.08	5.70	1.71	13.90	32.40	5.59	4.60	1.93	7.44	5.52	1.47

Table 5. Water contents of natural gas in equilibrium with water at 10 MPa

T(°C)	CPA Value (mg/m ³)	Estimated Value (mg/m ³)												
		Sloan	Behr	Ning	MIM	Bukacek	Gandhidasan	STM	Khaled	Ghiasi & Bahadori	Moshfeghian	Lin	Aimikhe	
30.06	469.86	481.93	381.34	537.17	443.21	395.83	473.01	429.97	--	492.63	503.24	492.29	441.37	
40.66	790.51	823.55	664.65	899.38	786.50	656.65	846.10	748.13	874.46	845.45	864.11	835.77	779.42	
52.99	1431.07	--	1206.57	1591.44	1452.69	1166.04	1664.13	1352.69	1533.63	1511.38	1538.72	1539.00	1456.30	
67.35	2780.86	--	2272.77	2974.86	2784.33	2195.30	3658.65	2534.06	2854.66	2810.65	2885.39	2920.70	2801.06	
78.41	4348.02	--	3554.56	4680.12	4408.97	3466.65	6711.65	3947.65	4436.44	4371.67	4486.48	4496.60	4393.30	
89.56	6666.83	--	5402.55	7205.78	6783.85	5339.09	12373.21	5980.85	6719.44	6635.45	6834.05	6687.50	6633.08	
	% AAD	3.37	14.50	10.30	1.83	15.40	18.30	7.95	4.65	3.17	5.56	4.47	1.92	

Table 6. Water contents of natural gas in equilibrium with water at 25 MPa

T(°C)	CPA Value (mg/m ³)	Estimated Value (mg/m ³)									
		Ning	MIM	Bukacek	Gandhidasan	Khaled	Ghiasi & Bahadori	Moshfeghian	Lin	Aimikhe	
30.46	337.06	361.17	282.81	204.38	229.21	--	317.14	312.48	299.89	240.25	
41.35	537.42	576.08	500.82	316.34	416.57	532.44	532.01	525.26	498.56	438.11	
57.69	1088.58	1122.12	1088.89	623.78	1020.93	1074.18	1079.46	1070.63	1088.70	988.78	
72.28	2009.57	1966.40	2028.90	1128.84	2273.05	1920.01	1912.25	1917.83	1961.80	1852.51	
89.12	3755.33	3609.10	3874.34	2152.48	5725.71	3537.16	3485.76	3564.93	3418.30	3464.38	
	% AAD	4.69	5.41	41.90	25.30	3.13	3.95	4.17	5.92	14.40	

Table 7. Water contents of natural gas in equilibrium with water at 50 MPa

T(°C)	CPA Value (mg/m ³)	Estimated Value (mg/m ³)							
		MIM	Bukacek	Gandhidasan	Khaled	Ghiasi & Bahadori	Moshfeghian	Lin	Aimikhe
35.77	359.16	374.44	162.00	174.39	324.52	307.71	311.21	290.70	231.15
50.30	677.77	748.53	267.92	386.99	594.70	583.07	588.78	578.92	501.71
65.12	1200.30	1413.73	463.40	872.56	1070.26	1053.52	1062.63	1103.70	986.12
78.21	1946.76	2354.68	753.51	1789.24	1728.61	1700.80	1719.85	1725.70	1651.80
91.47	3043.87	3781.40	1216.07	3703.34	2714.47	2664.84	2715.79	2526.90	2618.60
	% AAD	12.90	59.60	30.30	11.30	13.10	12.10	14.00	21.70

Table 8. Water contents of natural gas in equilibrium with hydrates at 2.5 MPa

T(°C)	Experimental Value Burgass et al. [1] (ppm mole)	Estimated Value (ppm mole)								
		Sloan	Ning	Lin	Behr	MIM	STM	Moshfeghian	Wang	Burgass
-20	38	54.83	79.46	40.76	50.93	33.83	--	52.51	--	37.40
-10	99	116.45	146.13	96.46	108.04	84.66	--	113.27	92.35	98.20
0	233	233.67	263.34	235.57	217.57	198.12	199.41	232.16	196.78	240.40
10	543	445.75	465.07	470.08	417.34	436.97	437.13	452.91	--	542.60
	% AAD	20.00	46.00	6.10	18.20	15.00	17.00	17.40	11.10	1.40

Table 9. Water contents of natural gas in equilibrium with hydrates at 5 MPa

T(°C)	Experimental Value Burgass et al. [1] (ppm mole)	Estimated Value (ppm mole)								
		Sloan	Ning	Lin	Behr	MIM	STM	Moshfeghian	Wang	Burgass
-20	20	32.92	42.71	20.59	30.24	18.67	--	32.94	--	20.60
-10	56	69.09	80.36	51.70	64.14	46.56	--	68.72	46.17	52.40
0	121	137.14	147.75	141.15	129.17	108.57	110.51	136.90	98.39	125.40
10	279	258.97	265.40	280.06	247.78	238.70	240.03	261.57	--	282.70
	% AAD	27.10	46.00	6.90	20.90	12.10	11.30	26.70	18.10	3.60

Table 10. Water contents of natural gas in equilibrium with hydrates at 7.5 MPa

T(°C)	Experimental Value	Estimated Value (ppm mole)								
	Burgass et al. [1] (ppm mole)	Sloan	Ning	Lin	Behr	MIM	STM	Moshfeghian	Wang	Burgass
-20	13	24.85	36.80	13.87	19.87	13.69	--	26.41	--	16.20
-10	46	51.79	67.48	36.78	42.14	34.02	--	53.88	30.78	39.60
0	87	102.15	121.11	109.68	84.86	79.07	81.25	105.14	65.59	91.70
10	198	191.76	212.74	216.72	162.78	173.29	174.96	197.79	--	202.20
	% AAD	31.10	69.10	15.60	20.40	13.20	9.12	35.30	28.80	13.80

From the results, the Bukacek correlation performed better in the lower pressure categories of 1 and 2.5 Mpa, having the least % AAD of 0.69 and 3.44, respectively. All other correlations had a % AAD of 10 and below, except for Aimikhe's correlation with 14.9 at 1MPa and Gandhidasan with 11.3 at 2.5 MPa. This high % AAD shows that the Aimikhe and Gandhidasan correlations are not suitable for use at pressures of 1MPa and 2.5 MPa, respectively. For the intermediate pressure categories, the MIM correlation had the least % AAD of 0.38 and 1.88 at 5 and 10 MPa, respectively, while the Aimikhe's correlation performed better with a % AAD of 1.47 at 7.5 MPa. All other correlations had % AADs of 10 and below, except those of Bukacek (13.9) at 7.5 MPa, Behr (14.5), Bukacek (15.4) at 10 MPa. The Gandhidasan correlation was the least performing correlation with % AADs of 22.7, 32.4, and 18.8 at pressures of 5, 7.5, and 10 MPa, respectively. At 25 MPa, the Khaled correlation had the least % AAD of 3.13. The correlations of Aimikhe, Gandhidasan, and Bukacek had % AADs of 14.4, 25.3, and 41.9,

respectively, making them unsuitable for predicting the water content of natural gases at pressures of about 25 MPa. The other correlations were relatively accurate since their % AADs were 10 or below. The water content results at 50 MPa, showed that all the correlations were less accurate, with % AADs higher than 10. This can be attributed to the reliability and availability of the water content data or the validity of the correlations at this pressure. However, Khaled's correlation had the least % AAD of 11.3 and therefore is the most suitable for estimating the water content of natural gases at 50 MPa.

Tables 8 to 12 presents the evaluation results of some formula correlations reported to be valid in the natural gas – hydrate equilibrium region. The results show that the thermodynamic model by Burgass et al. [1] performed better than all the formula correlations at pressures of 2.5 and 5 MPa, with % AADs of 1.4 and 3.6, respectively. However, the Lin et al. [3] correlation had the least % AAD of 6.1 and 6.9 respectively,

Table 11. Water contents of natural gas in equilibrium with hydrates at 15 MPa

T(°C)	Experimental Value Burgass et al. [1] (ppm mole)	Estimated Value (ppm mole)						
		Ning	Lin	Behr	MIM	Moshfeghian	Wang	Burgass
-20	11	25.04	7.15	9.11	9.01	19.89	--	15.20
-10	26	53.82	21.86	19.32	22.16	39.03	15.39	32.40
0	60	97.81	78.21	38.90	50.99	73.39	32.80	67.40
10	122	150.26	153.38	74.62	110.77	134.01	--	137.00
	% AAD	80.20	26.80	29.20	14.30	40.80	43.10	21.90

Table 12. Water contents of natural gas in equilibrium with hydrates at 20 MPa

T(°C)	Experimental Value Burgass et al. [1] (ppm mole)	Estimated Value (ppm mole)						
		Ning	Lin	Behr	MIM	Moshfeghian	Wang	Burgass
-20	10	25.97	5.47	6.69	8.07	18.26	--	15.10
-10	26	54.70	18.13	14.20	19.71	35.32	11.54	31.40
0	55	97.81	70.34	28.59	45.08	65.45	24.60	63.30
10	166	148.50	137.55	54.84	97.35	118.07	--	124.60
	% AAD	87.00	30.20	48.40	25.70	34.40	55.40	26.10

Table 13. Water content of 70% CH₄ + 30% CO₂ mixture at 40°C

Pressure (MPa)	Experimental Value Chapoy et.al. [51](mole %)	Estimated Value (mole %)			
		Maddox	Wichert & Wichert	Mohammadi	Chapoy
3	0.2873	0.2975	0.2714	0.2713	0.1672
	% AD	3.6	5.5	5.6	41.8
6	0.1693	0.1703	0.1563	0.1664	0.1523
	% AD	0.6	7.7	1.7	10.0
	% AAD	2.1	6.6	3.7	26.0

Table 14. Water content of 90% CH₄ + 10% CO₂ mixture at 40°C

Pressure (MPa)	Experimental Value Chapoy et.al. [51] (mole %)	Estimated Value (mole %)			
		Maddox	Wichert & Wichert	Mohammadi	Chapoy
3	0.2806	0.2698	0.2611	0.2611	0.2264
	% AD	3.9	6.9	6.9	19.3
6	0.1543	0.1551	0.1504	0.1538	0.2215
	% AD	0.5	2.5	0.3	43.6
	% AAD	2.2	4.7	3.6	31.5

Table 15. Water content of a 0.897 specific gravity (Ma = 26) sweet natural gas at 40°C

Pressure (MPa)	GPSA [52] (mg/m ³)	Estimated Value (mole %)		
		Ning	Mohammadi	Chapoy
3	1909.51	1810.18	1930.73	1936.77
	% AD	5.2	1.1	1.4
6	1099.44	1021.93	1089.98	1093.39
	% AD	7.0	0.9	0.6
	% AAD	6.1	1.0	1.0

among the formula correlations. It is important to note that any correlation with a % AAD of less than 10 could be considered to be very reliable and adequate for water content predictions of a natural gas – hydrate equilibrium system, due to the meager amount of water and the difficulty in measurement at this thermodynamic condition. For pressures of 7.5, 15, and 20 MPa, the MIM correlation had the least % AAD of 13.2, 14.3, and 25.7, respectively, while the thermodynamic model had % AADs of 13.8, 21.9, and 26.1, at the same pressures, respectively. This showed that the MIM correlation compared favorably and performed better than the thermodynamic model at 7.5, 15, and 20 MPa.

For the sour gas water content prediction, four (4) correlations were evaluated. The sour gas is in equilibrium with liquid water. Tables 13 and 14 show the results at pressures of 3 and 6 MPa, at a constant temperature of 40°C, for two (2) sour gas compositions. The Maddox correction factor had the least % AAD of 2.1 and 2.2 for the two (2) gas compositions, respectively. The Mohammadi correlation also had % AADs of 3.7 and 3.6, respectively. The Chapoy correction factor correlation, however, had % AADs as high as 26 and 31.5, making it unsuitable for the conditions in this study. The high % AAD of the Chapoy correlation could be due to a different natural gas equilibrium system or temperature and pressure ranges for which it is valid.

This was not indicated in the original manuscript. Although the Maddox correlation performed better, its significant drawback is in the subjective nature of evaluating the equivalent CO₂ and SO₂ from charts, making it difficult to be programmed

in spreadsheets and also quite rigorous, especially when interpolation is required. This subjective and rigorous process of reading and interpolating values from charts also makes the Wichert and Wichert correlation cumbersome, although the results from this method could be accurate when used with care. The simplicity and relative accuracy of the Mohammadi correction factor, which is wholly formula based, makes it suitable for use in spreadsheet calculations.

Table 15 shows the performance evaluation of three (3) gravity correction factor correlations at pressures of 3 and 6 MPa and a constant temperature of 40°C. The results show that the Mohammadi and Chapoy correction factors had the least % AAD of 1. This makes both correlation suitable for use. The Ning correction factor was least accurate, with a % AAD of 6.1. This could be as a result of the correlations' non-dependency on temperature, which is a significant parameter that affects water content predictions in the presence of heavy hydrocarbons.

5. CONCLUSION

The performance evaluation of fourteen (14) formula correlations for predicting the water content of natural gas in equilibrium with water, and the suitability of some of these correlations for predicting the water content in natural gas – hydrates systems, has been presented. Also presented is an evaluation of acid gas and gravity correction factor correlations. The conclusions from the study are highlighted below.

- For the prediction of the water content of natural gas in equilibrium with water, the

Bukacek correlation is best suited for low pressures of 1 and 2.5 MPa at a temperature range of 9 to 58°C. The MIM correlation should be used for pressures of 5 and 10 MPa, at temperature range of 30 to 89.6°C. The Aimikhe correlation is best suited for pressures of 7.5 MPa, at a temperature range of 30 to 86°C while the Khaled's correlation should be used for water content calculation at high pressures of 25 and 50 MPa, at a temperature range of 30 to 91.5°C

- To account for the presence of acid gases in natural gas in equilibrium with water, the Maddox correction factor should be used for better accuracy. However, the Mohammadi correlation is best suited for spreadsheet applications.
- The Mohammadi or Chapoy gravity correction factors should be used to account for the presence of heavy components in natural gas.
- For processed methane-rich natural gas in equilibrium with hydrates at a temperature range of -20 to 10°C, the Lin formula correlation should be used for pressures of 2.5 and 5 MPa. Although the STM correlation had the least % AAD of 9.12 at temperatures of 0 and 10°C, the MIM correlation is best suited for a wider temperature range of -20 to 10°C, for pressures of 7.5, 15 and 20 MPa.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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APPENDIX A

Tables A-1 and A-2, show the range of temperature, pressure, and concentration for which the sweet gas correlations and the acid gas correction factors, are valid.

Table A-1. Temperature and pressure ranges for sweet natural gas correlations

Correlations	Temperature Range (° C)	Pressure Range (MPa)
Moshfeghian	-40 ~ 100	0.1 ~ 68
Lin	- 58 ~ 140	0.1 ~ 100
Behr	-nil-	1.38 ~ 20.7
Sloan	-40 ~ 48.89	1.38 ~ 13.8
Ning	-nil-	0.1 ~ 100
Gandhidasan	-nil-	-nil-
Ghiasi & Bahadori	25 ~ 140	3 ~ 80
Aimikhe	20 ~ 90	2.5 ~ 25
Modified Wang	-2 ~ 100	0.49 ~ 13.79
MIM	-nil-	-nil-
STM	0 ~ 104.44	≤ 13.8
Bukacek	15.6 ~ 237	0.103 ~ 68
Kazim	< 82	2 ~ 8.3
Khaled	37.88 ~ 171.11	1.38 ~ 69

Table A-2. Validity for acid gas correction correlations

Correlations	Temperature Range (°C)	Pressure Range (Mpa)	CO₂ Mole Fraction (%)
Maddox	27 ~ 71	0.7 ~ 20.7	< 40
Wichert & Wichert	10 ~ 177	1.4 ~ 69	< 55
Mohammadi	37 ~ 147	0.5 ~ 40	≤ 50
Chapoy	N/A	N/A	N/A

* N/A = Not Available

APPENDIX B

CPA – EoS Form used in this Study

The CPA-EoS, used in this study is similar to the one used in the work of Torbjorn et al. [4], and is of the form:

$$Z^{CPA} = Z^{SRK-EoS} + Z^{association}$$

$$Z^{SRK-EoS} = \frac{V}{V-b} + \frac{a}{RT(V+b)}$$

$$Z^{association} = \frac{-1}{2} \left[1 + \rho \frac{\partial \ln g}{\partial \rho} \right] \sum_i \sum_{A_i} x_i (1 - x^{A_i})$$

Table B-1. Real gas composition [4]

Component	GC (mole %)
Nitrogen	0.6032
Carbon dioxide	2.6094
Methane	80.1380
Ethane	9.4689
Propane	4.6227
i- Butane	0.6420
n-Butane	1.1427
2,2-dimethyl propane	0.0136
i-pentane	0.2349
n-pentane	0.2272
Cyclopentane	0.0121
2,2-dimethyl butane	0.0031
2,3-dimethyl butane	0.0068
2-methylbutanepentane	0.0416
3-methylpentane	0.0216
n-Hexane	0.0535
C7	0.1056
C8	0.0441
C9	0.0074
C10	0.0016
C11	0.00011
C12	0.00004
C13	0.00004
SUM	100

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