

Simulation of Critical Salinity and Heavy Component Concentrations in Natural Gas – Water Systems

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Abstract

Dissolved salt and heavy hydrocarbon components reduce the water content of natural gas. This work investigated the effect of different concentrations of salt and mole fractions of the heavy-hydrocarbon components on the water content of natural gas to determine the critical concentrations for which corrections become necessary. Water content values were simulated using Aspen HYSYS at different temperatures and pressure ranges of 0°C to 50°C, and 5000 KPa to 100 000KPa, respectively. The concentrations of salt (NaCl) in mole fraction ranged from 0 to 0.036, and the concentrations of the heavy-hydrocarbon components (i-C₅H₁₂) in mole% from 0 to 50. The results showed that increasing salt concentrations and heavy hydrocarbon components decrease water content for the temperature and pressure ranges considered. The decrease in water content due to the presence of salt and heavy components starts becoming significant as pressure decreases beyond 20 000 KPa and temperature increases beyond 30°C. The average percentage change for salinity increase up to 120 000 ppm was 1.84 while that for heavy components up to 1.52 specific gravity was 1.75. Therefore, natural gas water content corrections may not be necessary for salinity equal to or less than 120 000 ppm mass and heavy hydrocarbons with specific gravity equal to or less than 1.52 for temperatures not greater than 30°C and pressures not less than 5 MPa. Also, the changes in water content were found to be more pronounced for salinity variation than for heavy component variation.

Keywords: Natural gas, Water content, Correction factors, Salinity, Heavy components

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1. Introduction

Natural gas in the reservoir is always saturated with water so that when the gas is produced, water is also produced with it either directly from the reservoir or condensed out of vapor due to variations in pressure and temperature during production (Bahadori et al., 2009). The solubility of water in natural gas increases with an increase in temperature and decreases as pressure increases (Ikoku, 1984). Water content is usually expressed as pound mass of water per million standard cubic feet of natural gas (lbm/MMscf) (Standard British unit) or mg per m³ (Standard European unit). Other units are ppmV (i.e., parts per million volume) and mole fraction. It is defined as the amount of water vapor in a gas or the water vapor a gas can hold at a particular temperature and pressure.

The primary forms in which dissolved water exists are liquid water, gas hydrates, and ice. The formation of a liquid phase may cause corrosion and/or two-phase flow problems. Additionally, a

decrease in temperature or an increase in pressure will worsen the problems caused by the gas hydrates or ice. The acid gases contained in the natural gas may generate acid liquor, which would combine with free water to cause corrosion of pipelines, instruments, valves, etc. Thus, to prevent corrosion and avoid the formation of ice or gas hydrate, it is necessary to remove saturated water from the acid gas concentration through dehydration facilities before transmitting and processing. For engineers, accurate prediction of water content forms the foundation of calculating the consumption of dehydrating agents and predicting the aqueous dew points.

Natural gas can be divided into two main categories viz: sweet natural gas (acid concentration is less than 5% of the gas mixture) and sour natural gas (acid concentration is more than 5% of the gas mixture) (Zhu et.al. 2003). Also, if the gas contains a significant amount of heavy hydrocarbon components, it is referred to as rich

gas. On the other hand, when the algebraic sum of the mole fractions of methane, ethane, propane, and butane together is up to 90% and above with little or none of the heavier hydrocarbon components, the gas is referred to as lean gas (Aimikhe et al., 2019). Many approaches have been conducted to estimate the water content of natural gas. The methods for sweet natural gas are composed of three main types: charts plotted with limited experimental data, thermodynamic models based on phase equilibrium, and empirical or semi-empirical correlations developed with limited application. The presence of acid gases (i.e., hydrogen sulfide and carbon (IV) oxide) makes the water content of natural gas increase because an increase in the amount of liquefied hydrogen sulfide or carbon (iv) oxide significantly enhances the solubility of water (Carroll, 2002). Various correction factors to account for the effect of acid gases on the water content of natural gases exist in literature. Also, salts dissolved in the liquid water in equilibrium with natural gas reduce the water content of the gas (Ikoku, 1984). Brooks et al. (1951) reported that the solubility of sweet natural gas in water is influenced mainly by the solubility of methane, ethane, propane, and butane components in water, and the solubility of the heavier components is very low and relatively insignificant. Therefore, some corrections should be applied when analyzing the water content of sour natural gas and those containing dissolved salts and heavy hydrocarbon components.

To describe the water content of gas in equilibrium with hydrocarbon, several charts have been presented, some of these being: the McKetta-Wehe Chart (GPSA, 1998), Campbell, (2004), chart, the Katz Chart (Khaled, 2007), etc. The McKetta – Wehe chart is the most popular of the available charts, with surprising accuracy for sweet natural gas containing over 0.7 (mole fraction) of methane (GPSA, 1998). The McKetta – Wehe chart has provisions to correct for dissolved salts and heavy hydrocarbon components in the gas. Furthermore, some correction charts, such as the Wichert and Wichert (2003) and the Campbell (2004), have been developed for estimating the water content of sour natural gas.

By fitting existing data to equations, researchers have also obtained some empirical or semi-empirical correlations that are simple, convenient, and operated with high accuracy. Consequently, these correlations remain popular among engineers. Increasing numbers of correlations such as Sloan et al. (1982), Ning et al. (2000), Bahadori et al., (2009), Ghiasi, and Bahadori (2014), Lin et al.

(2015), and Aimikhe et al. (2020) have been reported. Nonetheless, large amounts of heavy hydrocarbons may give the correlations lower accuracy. Most correlations are generally used for the sweet natural gas containing few or no heavy hydrocarbon at the applicable conditions. Correlations have been developed to account for dissolved salts, such as Katz's correction factor (Katz and Kobayashi, 1959), and heavy hydrocarbons, such as Chapoy's correction factor (Chapoy et al., 2005), to help correct the presence of salts and heavy components, respectively. These correlations have become popular among engineers because of their high accuracy, speed, convenience, and programmable nature.

Most of the correlations and charts were developed to account for the contributions to water content made by salt and heavy hydrocarbon components in the gas. However, studies on the critical concentration of salt and mole fraction of the heavy components at which the water content of natural gas begins to be affected significantly to require correction are scarce in the open literature. As in the use of charts, the exact concentration of salt and mole fraction of the heavy components at which the water content of natural gases are significantly affected to require corrections are lacking in the open literature. Hence the primary focus of this study is to determine the critical concentrations of salinity and heavy component, temperature, and pressure, for which corrections become necessary. This study will be of immense value to gas process engineers and scientists to account for the effect of salt and the heavy hydrocarbon components on the water content of natural gas, the determination of which is paramount for the design of an efficient dehydration unit.

2. Materials and methods

This study used the ASPEN HYSYS software to couple a saturator. The natural gas, both sweet and sour, was separately saturated with water containing varying amounts of salt and mole fractions of the heavy components at conditions of temperature and pressure. The salt content was varied to cover from 0 ppm mass (0.000-mole fraction) to 10^5 ppm mass (0.0299-mole fraction); the mole fractions of i-pentane as a heavy component were varied from 0 mole% to 50 mole%; the mole fractions of CO₂ were 10 mole%, 30 mole%, and 50 mole%. The temperature values ranged from 0°C to 50°C, while pressure values ranged from 5Mpa (5 000 Kpa) to 100 MPa (100

000 Kpa). The saturation process is illustrated in Fig. 1.

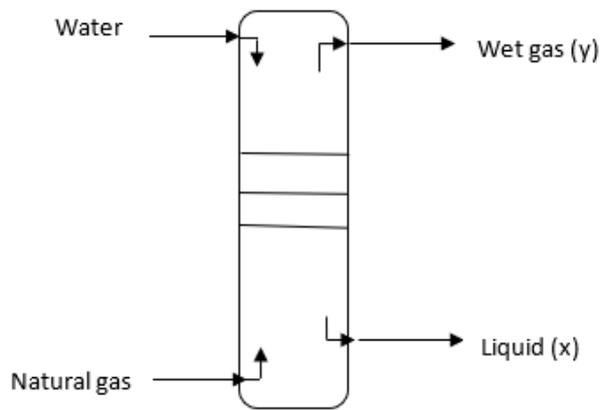


Fig. 1: Saturation process of natural gas with water

The amount of water vapor in the wet gas stream (y) was calculated using the Soave Redlich Kwong (Soave, 1972) equation of state (SRK Eos), which is expressed as:

$$\left[P + \frac{a(T)}{(V+b)V} \right] (V-b) = RT \quad (1)$$

$$\text{where, } a(T) = a_0 \alpha(T_r) \quad (2a)$$

$$\text{where, } \alpha(T_r) = \left[1 + m \left(1 - T_r^{\frac{1}{2}} \right) \right]^2 \quad (2b)$$

$$\text{where, } m = 0.48 + 1.574\omega - 0.175\omega^2 \quad (2c)$$

The parameters, “a” and “b,” are calculated from critical point conditions as follows:

$$a = \Omega_a \frac{R^2 T_c^2}{P_c}$$

$$b = \Omega_b \frac{RT_c}{P_c}$$

$$\text{where, } \Omega_a = 0.4274; \Omega_b = 0.086640; Z_c = \frac{1}{3}$$

2.1 Salinity range

The average salinity of sandstone gas reservoirs is about 30 000 ppm mass or 30 g/l or 0.00916-mole fraction, while the salinity of carbonate gas reservoirs is 90 000 ppm mass or 90 g/l or 0.02697. Hence the salinities chosen for this study ranged from 0.000-mole fraction to 0.036-mole fraction at 0.004 intervals.

2.2 Pressure range

For this study, the pressure range of 5 Mpa to 100 Mpa was chosen to accommodate pressures in all natural gas systems, including gas processing plants (7.5 Mpa), offshore flow lines (16 Mpa), pipeline transport (up to 25 Mpa), gas storage (30 Mpa), and reservoir pressures (up to 50 Mpa) (Aimikhe and Adeyemi, 2019). The simulation result data used for the analysis in this study can be found in the appendix.

3. Results and discussion

Fig. 2 to 5 show the variation in water content with salinity, temperature, and pressure. Similarly, Fig. 6 shows the water content variation with the heavy component, temperature, and pressure. Each data point on the figures corresponding to water content and pressure value represent varying salinity values from 0.000-mole fraction to 0.036-mole fraction (Fig. 2 to 5) and heavy component from 0% to 50% (Fig. 6). For each pressure value, there are six data points representing temperatures of 0 °C, 10 °C, 20°C, 30°C, 40°C, and 50°C.

In Fig. 2 to 5, the water content of sweet gas against pressure gives the expected exponential curve for all the temperatures and salinity studied. Water content decreases as pressure increases and increases as temperature increases, as expected. A continuously decreasing water content with increasing salinity is observed as pressure increases and temperatures drop. A decrease in water content starts becoming significant from 20 000 KPa and less and about 30°C and more, as shown by the stretch at the data points. The most extensive stretch is observed at 5000 KPa and 50°C for all the figures. A similar trend is also observed in figure 6, which shows water content variation with heavy components, temperature, and pressure. As observed in Fig. 2 to 5, water content decrease as pressure increases and increase as temperature increases. A reduction in water content with an increasingly heavy component is observed at high pressures and low temperatures. Likewise, a decrease in water content starts being more noticeable from pressures of 20 000 KPa and below and temperatures of about 30°C and above, as shown by the stretch at the data points. The most significant stretch is observed at 5000 KPa and 50°C.

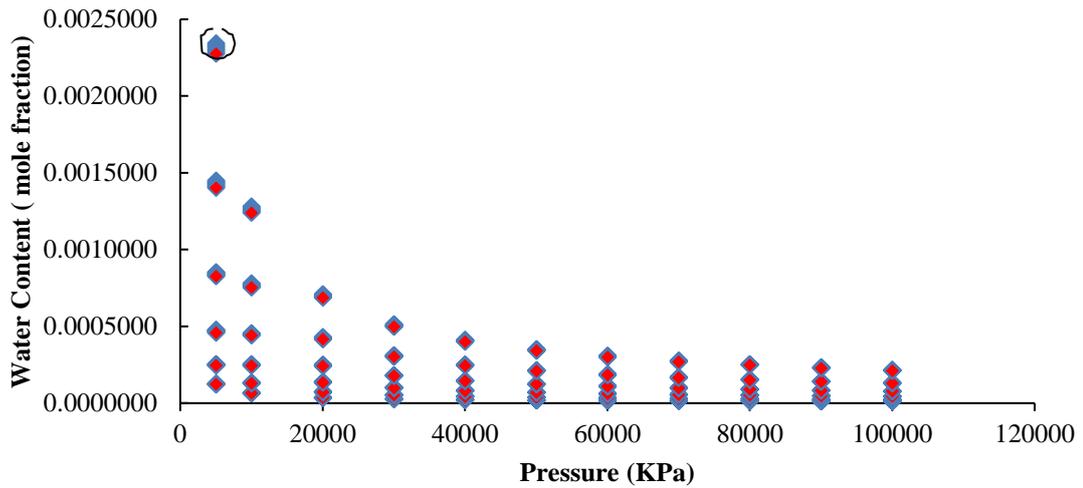


Fig. 2: Variation of water content with salinity, pressure, and temperature – methane gas

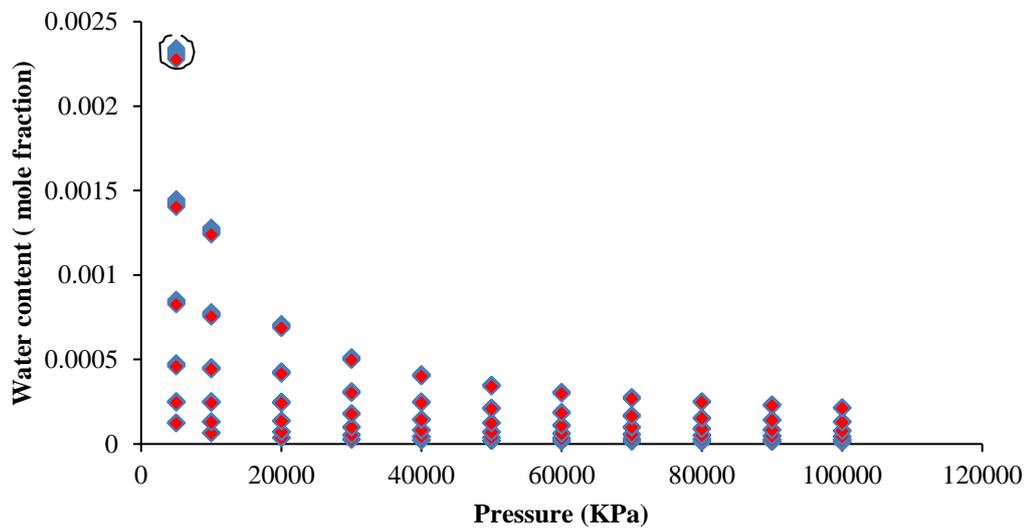


Fig. 3: Variation of water content with salinity, pressure, and temperature for 50 mole% CH₄ + 50 mole% CO₂

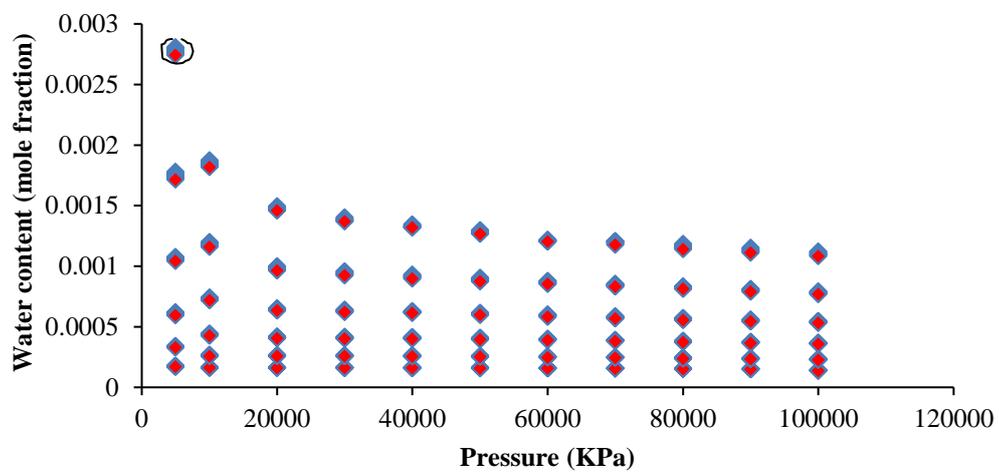


Fig. 4: Variation of water content with salinity, pressure, and temperature for 70 mole% CH₄ + 30 mole% CO₂

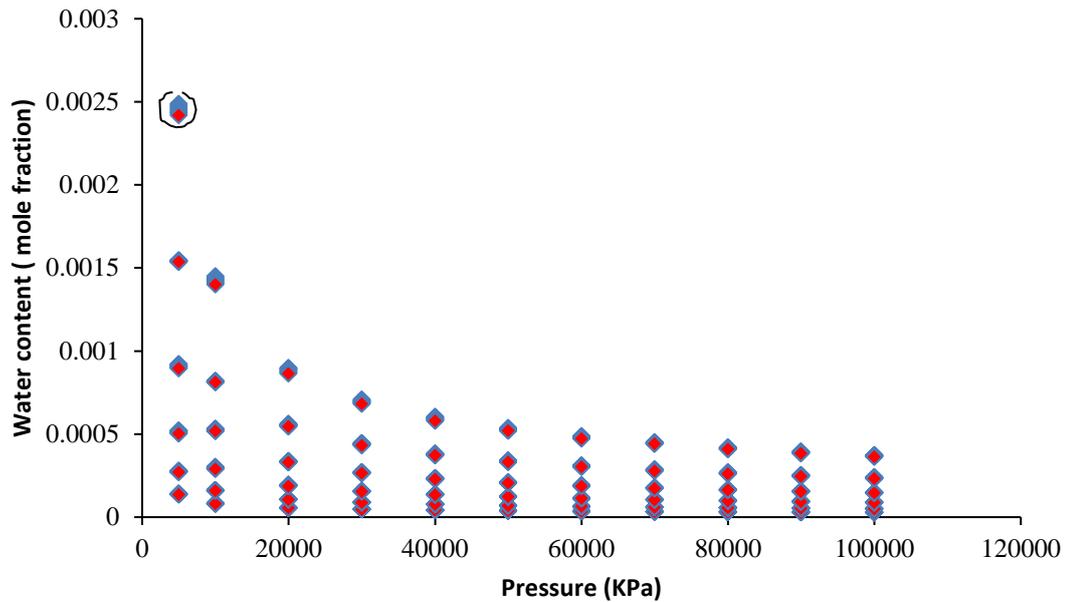


Fig. 5: Variation of water content with salinity, pressure, and temperature for 90 mole% CH₄ + 10 mole% CO₂

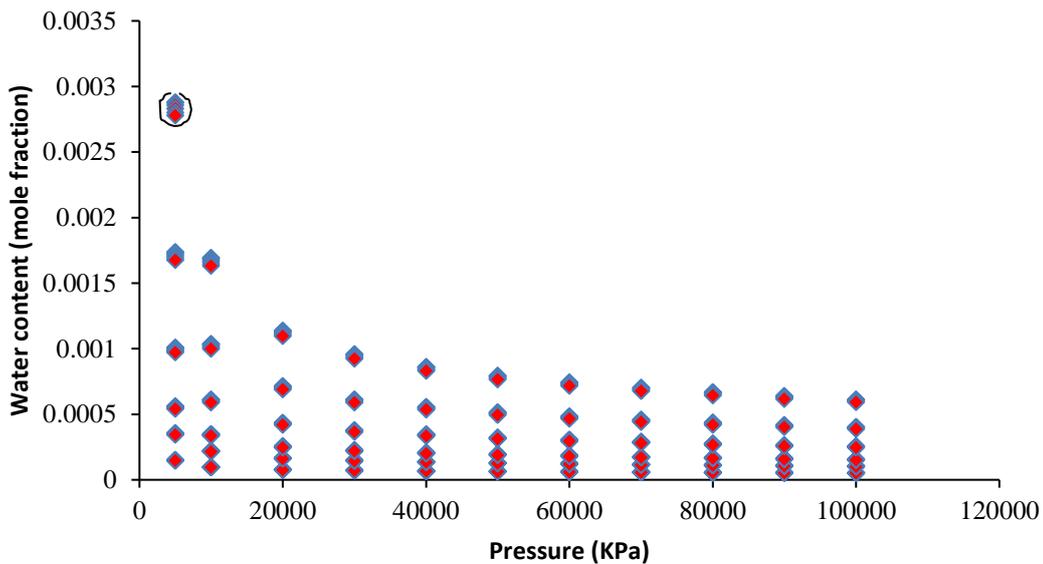


Fig. 6: Variation of water content with heavy hydrocarbon (i-C₅H₁₂), pressure, and temperature

Fig. 2 to 6 show that the water content variation starts becoming significant as temperatures exceed 30 °C. The most changes in water content are noticed at lower pressures. Tables 2 and 3 further show the cumulative changes in water content due to increasing salinity and heavy component at 5000 KPa and temperatures of 30°C, 40°C, and 50°C.

The results show that increasing the salinity from 0 to 0.036-mole fraction decreased the water content by 1.794%, 1.83%, and 1.835%, respectively. Likewise, increasing the heavy component from 0 to 50% reduced the water content by 1.711%, 1.734%, and 1.754%, with the most significant changes occurring at 50°C.

Table 2: Change in water content due to increasing salinity.

Salinity		Water Content @ 5000 KPa and 30°C		Water Content @ 5000KPa and 40°C		Water Content @ 5000KPa and 50°C	
mole fraction	ppm mass	Water Content (mole fraction)	Percentage change (%)	Water Content (mole fraction)	Percentage change (%)	Water Content (mole fraction)	Percentage change (%)
0.000	0.000	0.0008510		0.0014495		0.0023434	
0.004	13052.209	0.0008479	0.351	0.0014442	0.366	0.0023358	0.324
0.008	26209.677	0.0008448	0.714	0.0014389	0.731	0.0023282	0.649
0.012	39473.684	0.0008448	1.077	0.0014336	1.097	0.0023206	0.973
0.016	52845.528	0.0008417	1.440	0.0014283	1.463	0.0023130	2.8036
0.020	66326.524	0.0008387	1.792	0.0014230	1.828	0.0023054	2.8036
0.024	79918.033	0.0008356	2.155	0.0014177	2.194	0.0022978	2.8036
0.028	93621.399	0.0008325	2.518	0.0014124	2.560	0.0022902	1.8306
0.032	107438.030	0.0008295	2.869	0.0014070	2.932	0.0022826	1.405
0.036	121369.295	0.0008264	3.232	0.0014017	3.298	0.0022750	2.919
Average % Change			1.794		1.830		1.835

Table 3: Change in water content due to increasing heavy component.

Gas		Water Content @ 5000 KPa and 30°C		Water Content @ 5000KPa and 40°C		Water Content @ 5000KPa and 50°C	
CH ₄ (mole %)	i-C ₅ H ₁₂ (mole %)	Water Content (mole fraction)	Percentage Error (%)	Water Content (mole fraction)	Percentage Error (%)	Water Content (mole fraction)	Percentage Error (%)
100	0	0.001007		0.001735		0.002878	
90	10	0.001006144	0.085	0.001733351	0.095	0.002874978	0.105
80	20	0.000999897	0.705	0.001722241	0.735	0.002855992	0.765
70	30	0.000990559	1.633	0.001705901	1.677	0.002828517	1.719
60	40	0.000980434	2.638	0.001688568	2.676	0.002800035	2.709
50	50	0.000971825	3.493	0.001674471	3.489	0.00277802	3.474
Average % change			1.7108		1.7344		1.7544

4. Conclusion

From the results obtained, it can be seen that natural gas's water content, whether lean or rich, sweet or sour, increases as temperature increases and decreases as pressure increases. Water content decreases slightly as salinity increases from 0.000 to 0.036-mole fraction and decreases slightly as the heavy components increase from 0 mole% to 50 mole% (i.e., specific gravity up to 1.52). The decrease in water content due to the presence of salt and heavy components starts becoming significant as pressure decreases beyond 20 000 KPa and temperature increases beyond 30°C. The average percentage change for salinity increase up to 120 000 ppm is 1.84 while that for heavy components up to 1.52 specific gravity is 1.75. Therefore, natural gas water content corrections

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