A simple mathematical predictive tool for estimation of a hydrate inhibitor injection rate

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REVIEW

The formation of hydrates in production, processing facilities and pipelines has been a problem to the natural gas industry, that cost several millions of dollars.. Therefore, an understanding of the inception of hydrate formation is necessary to overcoming hydrate problems. The aim of the first step of this study is to develop a simple-to-use correlation for predicting hydrate-forming conditions of sweet natural gases. This simple correlation estimates hydrate formation pressure of sweet natural gases for pressures up to 40 000 kPa and temperatures between 260 K and 298 K as well as molecular weights in the range of 16 to 29. In the next step, novel empirical correlations are developed to predict the required MEG weight percent in the rich solution and the flow-rate for desired depression of the gas hydrate formation temperature. These correlations are generated for a natural gas with relative density of 0.6 at pressures of 3, 5, 7, and 9 MPa, which are applicable to wet gas temperatures of 20, 30, 40, and 50 °C. In order to extend the application of these correlations to wide ranges of natural gas mixtures with specific gravities of up to 0.8, two generalized correction factors are also provided. The accuracy of this simple method is compared with the simulation results obtained by commercial software which showed excellent agreement. In all cases the error percent was approximately 2% and 5% for predicting hydrate formation temperature depression and MEG injection rate, respectively. The fitted equations developed in this study can be of immense practical value for the engineers and scientists to have a quick check on hydrate formation condition of natural gases with or without presence of inhibitor without opting for any experimental measurements. In particular, chemical and process engineers would find the simple equations to be user-friendly with transparent calculations involving no complex expressions.

Key words: gas, production, processing, pipelines, hydrates

1.Introduction

The combination of water molecules and guest gas molecules under favorable conditions, usually at low temperatures and elevated pressures, can lead to the formation of hydrates. The most common guest molecules are methane, ethane, propane, isobutane, normal butane, nitrogen, carbon dioxide and hydrogen sulfide, of which methane occurs most abundantly in natural hydrates. It should be noted that *normal*-butane does form a hydrate, but is very unstable. However, it will form a stabilized hydrate in the presence of small "help" gases such as methane or nitrogen. It has been assumed that normal paraffin molecules larger than normal-butane are nonhydrate formers.[29,17]

Although gas hydrates may be of potential benefit both as an important source of hydrocarbon energy and as a means of storing and transmitting natural gas, they represent a severe operational problem as the hydrate crystals deposit on pipe walls and accumulate as large plugs, resulting in blocked pipelines and over pressuring and eventually leading to shut down of production facilities. Acceleration of these plugs when driven by a pressure gradient (e.g., single-sided depressurization after hydrate formation) can also cause considerable damage to production facilities, and therefore create a severe safety and environmental hazard.[18]

The removal of hydrate plugs in hydrocarbon production/transmission systems poses safety concerns and can be time consuming and expensive.[8] For this reason, the hydrate formation in gas transmission pipelines should be prevented effectively and economically to guarantee the pipelines operate normally. Clearly, it is in the interests of the industry to be able to predict and prevent the formation of hydrates. Recent processing practice, with emphasis on extreme conditions of temperature, pressure, and sour gas composition, has caused a renewed interest in determining hydrate formation conditions. In another view point, a great number of process engineering calculations require knowledge of natural gas hydrate formation conditions.

There are numerous methods available for predicting hydrate formation conditions in natural gas systems. The best method for determining conditions of hydrate formation is to experimentally measure the formation at the temperature, pressure and composition of interest. Because it is impossible to satisfy the infinite number of conditions for which measurements are needed, hydrate formation prediction methods are needed to interpolate between measurements. However, such experimental endeavors are both time consuming and expensive relative to industrial needs for a number of hydrate formation conditions. Therefore some means of interpolation between the experimental results are needed, and ideally one would be able to extrapolate beyond the condition of the data.[4]

The most reliable method for predicting hydrate formation conditions in natural gas systems requires a gas analysis. However, if the gas composition is not known, even the previously mentioned methods cannot be used to predict the hydrate formation conditions, and the Katz gravity chart[10] can be used to predict the approximate pressure and temperature for hydrate formation. Therefore, as a first step to predict hydrate formation temperature, one can develop an appropriate equation representing Katz[25] gas-gravity chart, which is a popular method for rapid estimation of hydrate forming conditions of natural gases. The Katz gravity chart was generated from experimental data and a more substantial amount of calculations based on the K-value method developed originally by Carson and Katz.[15] The components used for the construction of this chart are methane, ethane, propane, butane, and normal pentene; therefore, using this chart for compositions other than those used to derive these curves will produce erroneous results.[15]

In order to avoid tedious calculations based on the Katz gravity chart, an accurate regression analysis will be used to fit the relevant curve to predict the hydrate forming conditions of natural gases. Towler and Mokhatab3 developed a simple-to-use correlation to predict hydrate formation conditions of sweet natural gas mixtures. While their correlation is based on the Katz gravity chart10, it is only accurate up to 291.48 K. Beyond that, it overestimates the temperature slightly. Recently, Bahadori et al[9] developed another simple-to-use correlation for predicting hydrate forming conditions of light alkanes and the sweet natural gases. However, their method is recommended for pressures less than 7 500 kPa and specific density more than 0.6. Therefore, there is an essential need to develop a simple-to-use method, representing the Katz gravity chart, for appropriate prediction of hydrate formation conditions of sweet natural gases.

In the second stage of the current work, novel empirical correlations are developed to predict the required MEG weight percent in the rich solution and the flow-rate for desired depression of the gas hydrate formation temperature. For several decades mono-ethylene glycol (MEG) has been the primary chemical to inhibit the formation of hydrates in natural gas production pipelines and related facilities. When operating within a set of parameters where hydrates could be formed, there are still ways to avoid their formation. Altering the gas composition by adding chemicals can lower the hydrate formation temperature and/or delay their formation. The most commonly used chemicals for this purpose are thermodynamic inhibitors such as methanol, monoethylene glycol (MEG) and diethylene glycol (DEG) commonly referred to as glycol. Today's cost of replacing hydrate inhibitor chemical that is lost to the gas and hydrocarbon liquid product streams is a determining factor in inhibitor selection.[29,17] On projects where inhibition is only required temporarily or sporadically, methanol is well suited because it is a highly effective hydrate inhibitor. However, this is not the case on fields that require persistent inhibition. More methanol is lost in the gas phase when compared to glycols. Furthermore, methanol is an unwanted contaminant in hydrocarbon sales products, especially gases and liquids that are destined for high value processing.[20] MEG is preferred over DEG for applications where the temperature is expected to be -10 °C or lower due to high viscosity at low temperatures. Triethylene glycol (TEG) has too low vapor pressure to be suited as an inhibitor injected into a gas stream. This creates a strong economic drive to use MEG despite the greater quantity of MEG needed per degree of hydrate temperature suppression.[22,29]

2. Formulation of a simple correlation for sweet gas hydrate formation pressure

The primary purpose of the present study is to develop simple to use correlations to predicting hydrate-forming conditions of sweet natural gases as well as estimating the required MEG weight percent in the rich solution and the flow-rate for desired depression of the gas hydrate formation temperature. This is done by a simple predictive tool using an Arrhenius-type asymptotic exponential function with a small modification of the Vogel-Tammann-Fulcher (VTF) equation (14-16).

This is important, because such an accurate and mathematically simple correlation hydrate-forming conditions of natural gases with or without the presence of inhibitor is required frequently for the quick engineering calculations to avoid the additional computational burden of complicated calculations. The Vogel-Tammann-Fulcher (VTF) equation (14-16) is an asymptotic exponential function that is given in the following general form:

$$\ln f = \ln(f_c) - \frac{E}{R(T - T_c)} \qquad (1)$$

In equation (1), f is a properly defined temperature-dependent parameter, the units for which are determined individually for a certain property; f_c is a pre-exponential coefficient, having the same unit of the property of interest; T and T_c are the actual temperature and the characteristic-limit temperature, respectively (both given in degrees Kelvin); E is referenced as the activation energy of the process causing parameter variation (given in units of J/kmol); and R is the universal gas constant 8.314 J/(kmol K)). A special case of the Vogel-Tammann-Fulcher (VTF) equation for $T_c = 0$ is the well-known Arrhenius[4] equation.

For the purpose of the present application which involves the correlation of methanol solubility in gas condensate as a function of temperature, the Vogel-Tammann-Fulcher (VTF) equation has been modified in the following form by adding second-order and third order terms[10,11]:

$$\ln f = \ln f_c + \frac{b}{T - T_c} + \frac{c}{(T - T_c)^2} + \frac{d}{(T - T_c)^3} \qquad (2)$$

In equation (2), T_c has been considered zero to convert equation (2) to the well-known Arrhenius[4] equation type. (See equation 3)

$$\ln f = \ln f_c + \frac{b}{T} + \frac{c}{T^2} + \frac{d}{T^3} \tag{3}$$

In view of the above, equation (1) is a new hydrate formation pressure correlation in which four coefficients are used to correlate hydrate formation pressure of natural gas.

$$\ln(P) = a + \frac{b}{T} + \frac{c}{T^2} + \frac{d}{T^3} \tag{4}$$

Where:

$$a = A_a + B_a M + C_a M^2 + D_a M^3 \tag{5}$$

$$b = A_b + B_b M + C_b M^2 + D_b M^3 \tag{6}$$

$$c = A_c + B_c M + C_c M^2 + D_c M^3 \tag{7}$$

$$d = A_d + B_d M + C_d M^2 + D_d M^3 \tag{8}$$

In Equations (4) to (8), P is the hydrate formation pressure in kPa, T is temperature in K, and the coefficients for these polynomials are correlated as a function of molecular weight (M) in Equations (5) to (8). The tuned coefficients used into Equations (5) to (8) are given in Table 1. These tuned coefficients help to cover experimental data in temperature variation of 260 K to 298 K as well as the gas molecular weight within the range of 16 to 29.

3. Novel correlations to predict the rate of injection of MEG

The current trend for the gas industry is to use primary ethylene glycol (MEG) over methanol for new developments. MEG has also the advantage that it can be effectively recovered, regenerated and recycled. Accurate knowledge of gas hydrate dissociation conditions and phase behaviour of aqueous solutions of ethylene glycol is therefore crucial to avoid gas hydrate formation and for safe and economical design/operation of pipelines and production/processing facilities.[31]

Proper design of an inhibitor injection system is a complex task that involves optimum inhibitor selection, and determination of the necessary injection rates. Therefore, at this stage, an appropriate multiphase flow simulation package must be used to calculate some of the unknown necessary variables, which are required for injection systems design. Several thermodynamic models are available to calculate the required inhibitor concentration and injection rate to depress the hydrate formation to a desired temperature. However, these conventional approaches require rigorous computer solutions.[1] Therefore, there is an essential need to develop a simple-to-use method for accurate determination of hydrate inhibitor injection rate.

4. Base Correlation for Gas Relative Density of 0.6

Feeds with various temperatures, pressure and gas densities were all modeled by HYSYS software.[12] These cover pressures from 3 to 9 MPa, temperatures from 20 to 50 °C and relative densities between 0.6 and 0.8. The HYSYS simulator was used to extract the required data and developing the correlations. The base correlations were developed using a natural gas feed having a relative density of 0.6 with respective pressure and temperature variations as mentioned above. The simulation results of MEG concentration in aqueous phase (i.e. rich solution), depression of the hydrate formation temperature, and MEG solution mass flow rate are correlated by Equations (6) and (7) and tuned coefficients reported in Tables 2 and 3 for pressures of 3, 5, 7, and 9 MPa, respectively.

Table 1. Tuned coefficients used in equations (5) to (8) for natural gas hydrate formation pressure prediction

Coefficient	Sweet natural gas mixtures with molecular weight less than 23	Sweet natural gas mixtures with molecular weight more than 23
A_a	-2.837 555 5 x 10^{4}	9.648 514 82 x 10^{5}
B_a	4.188 723 72 x 10^{4}	-1.298 725 52 x 10^{4}
C_a	-2.042 678 56 x 10^{2}	5.694 312 31 x 10^{3}
D_a	3.299 942 786	-8.029 173 65 x 10^{1}
Ab	2.351 857 71 x 10^{7}	-8.385 194 23 x 10^{8}
B_b	-3.470 311 0 x 10^{7}	1.129 244 3 x 10^{7}
C_b	1.692 130 76 x 10^{5}	-4.948 120 32 x 10^{6}
D_b	-2.733 152 65 x 10^{3}	6.974 372 94 x 10^{4}
A_c	-6.489 903 55 x 10^{10}	2.428 395 04 x 10^{10}
B_c	9.572 892 15 x 10^{9}	-3.271 332 58 x 10^{9}
C_c	-4.667 233 x 10^{8}	1.432 596 98 x 10^{8}
D_c	7.537 325 70 x 10^{6}	-2.018 536 1 x 10^{6}
A_d	5.965 347 74 x 10^{12}	-2.343 053 80 x 10^{12}
B_d	-8.796 372 8 x 10^{11}	3.157 018 11 x 10^{11}
C_d	4.288 197 2 x 10^{10}	-1.381 805 09 x 10^{10}
D_d	-6.924 141 40 x 10^{8}	1.946 350 67 x 10^{8}

Table 2. Tuned coefficients used in Equations (10) to (13) for including into Equation (6) to predict hydrate temperature depression (in °C)

Factors	$p = 3$ MPa	$p = 5$ MPa	$p = 7$ MPa	$p = 9$ MPa
A_a	9.928 378 3 x 10^{2}	2.788 830 07 x 10^{3}	1.129 822 764 x 10^{3}	1.555 027 17 x 10^{3}
B_a	-9.059 231 x 10^{5}	-2.563 591 07 x 10^{6}	-1.036 737 161 x 10^{6}	-1.444 243 941 x 10^{6}
C_a	2.748 370 9 2 x 10^{8}	7.842 628 8 x 10^{8}	3.164 176 68 x 10^{8}	4.465 332 3 x 10^{8}
D_a	-2.772 569 27 x 10^{10}	-7.985 656 64 x 10^{10}	-3.212 187 66 x 10^{10}	-4.594 7401 99 x 10^{10}
A_b	-7.252 081 14 x 10^{1}	-1.935 259 7 x 10^{2}	-7.598 350 761 x 10^{1}	-9.193 414 08 x 10^{1}
B_b	6.713 150 0 1 x 10^{4}	1.7851 477 5 x 10^{5}	6.996 043 289 x 10^{4}	8.587 012 75 x 10^{4}
C_b	-2.065 149 1 4 x 10^{7}	-5.479 373 81 x 10^{7}	-2.141 597 97 x 10^{7}	-2.668 677 462 x 10^{7}
D_b	2.115 040 18 x 10^{9}	5.600 815 26 x 10^{9}	2.183 386 72 x 10^{9}	2.7624 641 37 x 10^{9}
A_c	1.580 325 5	4.243 025 1	1.792 856 545	1.717 730 59
B_c	-1.469 095 28 x 10^{3}	-3.917 582 56 x 10^{3}	-1.649 738 9 x 10^{3}	-1.607 557 904 x 10^{3}
C_c	4.542 212 9 x 10^{5}	1.204 055 85 x 10^{6}	5.052 136 64 x 10^{5}	5.009 019 525 x 10^{5}
D_c	-4.677 018 15 x 10^{7}	-1.232 622 5 x 10^{8}	-5.155 272 41 x 10^{7}	-5.200 591 49 x 10^{7}
A_d	-1.068 446 4 x 10^{-2}	-2.906 263 05 x 10^{-2}	-1.337 552 68 x 10^{-2}	-1.022 953 6 x 10^{-2}
B_d	9.950 148 29	2.684 444 67 x 10^{1}	1.230 128 75 x 10^{1}	9.586 971 67
C_d	-3.082 330 6 x 10^{3}	-8.254 687 38 x 10^{3}	-3.766 054 105 x 10^{3}	-2.991 822 37 x 10^{3}
D_d	3.180 243 97 x 10^{5}	8.455 494 36 x 10^{5}	3.842 346 93 x 10^{5}	3.111 636 593 x 10^{5}

Table 3. Tuned coefficients used in Equations (15) to (18) for including into Equation (7) to predict MEG solution mass flow rate (in kg/MMSCM)

Factors	$p = 3$ MPa	$p = 5$ MPa	$p = 7$ MPa	$p = 9$ MPa
A_α	-3.750 648 638 x 10^{4}	-1.696 413 064 x 10^{4}	7.407 812 042 x 10^{4}	1.643 688 342 x 10^{3}
B_α	3.484 616 589 x 10^{7}	1.574 955 2 x 10^{7}	-6.891 971 572 x 10^{7}	2.340 313 256 x 10^{5}
C_α	-1.077 697 499 x 10^{10}	-4.867 913 62 x 10^{9}	2.135 918 635 x 10^{10}	-5.993 494 052 x 10^{8}
D_α	1.109 581 495 x 10^{12}	5.009 509 858 x 10^{11}	-2.205 064 587 5 x 10^{12}	1.138 060 984 5 x 10^{11}
A_β	2.079 833 879 x 10^{3}	1.064 413 21 x 10^{3}	-4.164 000 725 x 10^{3}	-5.132 676 55 x 10^{2}
B_β	-1.931 833 284 x 10^{6}	-9.879 965 726 x 10^{5}	3.876 826 898 x 10^{6}	3.850 534 941 x 10^{5}
C_β	5.974 672 803 x 10^{8}	3.055 270 43 x 10^{8}	-1.202 163 504 x 10^{9}	-9.151 708 789 x 10^{7}
D_β	-6.151 836 867 x 10^{10}	-3.146 807 570 x 10^{10}	1.241 708 644 4 x 10^{11}	6.696 596 353 x 10^{9}
A_γ	-3.635 357 476 x 10^{1}	-2.012 196 153 x 10^{1}	7.569 813 48 x 10^{1}	1.435 423 398 x 10^{1}
B_γ	3.377 328 114 x 10^{4}	1.868 905 535 x 10^{4}	-7.049 411 66 x 10^{4}	-1.176 931 706 x 10^{4}
C_γ	-1.044 633 119 x 10^{7}	-5.783 120 423 x 10^{6}	2.186 460 75 x 10^{7}	3.170 160 282 x 10^{6}
D_γ	1.075 614 118 x 10^{9}	5.960 319 672 x 10^{8}	-2.258 923 162 x 10^{9}	-2.800 413 259 x 10^{8}
A_θ	2.0289 909 61 x 10^{-1}	1.184 092 123 x 10^{-1}	-4.468 598 029 x 10^{-1}	-1.035 218 853 x 10^{-1}
B_θ	-1.885 378 225 x 10^{2}	-1.100 228 341 x 10^{2}	4.161 809 973 x 10^{2}	8.747 730 605 x 10^{1}
C_θ	5.832 499 563 x 10^{4}	3.406 270 292 x 10^{4}	-1.290 937 11 x 10^{5}	-2.444 536 38 x 10^{4}
D_θ	-6.005 719 427 x 10^{6}	-3.512 493 954 x 10^{6}	1.333 824 099 x 10^{7}	2.259 760 72 x 10^{6}

In brief, Equation (9) presents new correlations to predict the required MEG wt% (weight percent) in order to depress the hydrate formation temperature with respect to gas pressure.

$$\ln(\Delta T) = a + bW + cW^2 + dW^3 \tag{9}$$

In the above equations, ΔT refers to the hydrate formation temperature depression in °C, W refers to the MEG wt% in rich solution needed for a specific hydrate depression, and F refers to the MEG solution mass flow rate in kg/16^{6}m^3

The factors a, b, c and d take into account, the feed gas temperature (K)

$$a = A_1 + \frac{B_1}{T} + \frac{C_1}{T^2} + \frac{D_1}{T^3} \tag{10}$$

Table 4. Factors corresponding to Equation (19)

Symbol	Value
e	6.457 468 343 x 10^{-2}
f	1.786 823 773 x 10^{-1}
g	-1.994 803 764 x 10^{-2}
h	9.071 394 01 x 10^{-4}
i	-1.824 124 716 x 10^{-5}
j	1.362 250 141 x 10^{-7}

$$b = A_2 + \frac{B_2}{T} + \frac{C_2}{T^2} + \frac{D_2}{T^3} \quad (11)$$

$$c = A_3 + \frac{B_3}{T} + \frac{C_3}{T^2} + \frac{D_3}{T^3} \quad (12)$$

$$d = A_4 + \frac{B_4}{T} + \frac{C_4}{T^2} + \frac{D_4}{T^3} \quad (13)$$

In brief, Equations (6) and (7) present new correlations to predict the required MEG wt% in order to depress the hydrate formation temperature with respect to gas pressure.

$$\ln\left(F_m\right) = \alpha + \beta W + \gamma W^2 + \theta W^3 \quad (14)$$

$$\alpha = A_\alpha + \frac{B_\alpha}{T} + \frac{C_\alpha}{T^2} + \frac{D_\alpha}{T^3} \quad (15)$$

Table 5. Constants in Equation (20)

k	7.363 402 945 x 10^{-3}
l	7.476 202 644 x 10^{-1}
m	-1.829 754 67 x 10^{-1}
n	2.955 532 266 x 10^{-2}

$$\beta = A_\beta + \frac{B_\beta}{T} + \frac{C_\beta}{T^2} + \frac{D_\beta}{T^3} \quad (16)$$

$$\gamma = A_\gamma + \frac{B_\gamma}{T} + \frac{C_\gamma}{T^2} + \frac{D_\gamma}{T^3} \quad (17)$$

$$\theta = A_\theta + \frac{B_\theta}{T} + \frac{C_\theta}{T^2} + \frac{D_\theta}{T^3} \quad (18)$$

The factors A_1 through to D_4 and A_α through to D_θ correspond with feed stream pressures and they are reported in Tables 2 and 3 respectively. These correlations can be used to determine the required MEG concentration and flow-rate for a desired hydrate depression temperature for a gas with a relative density of 0.6 at water saturation temperatures between 10 and 50 °C and for pressures ranging from 3 to 9 MPa. For many natural gas streams the gas relative density may vary from 0.6 to 0.8. Therefore, in the following section, methods will be presented to extend the use of these correlations for gases with relative densities up to 0.8.

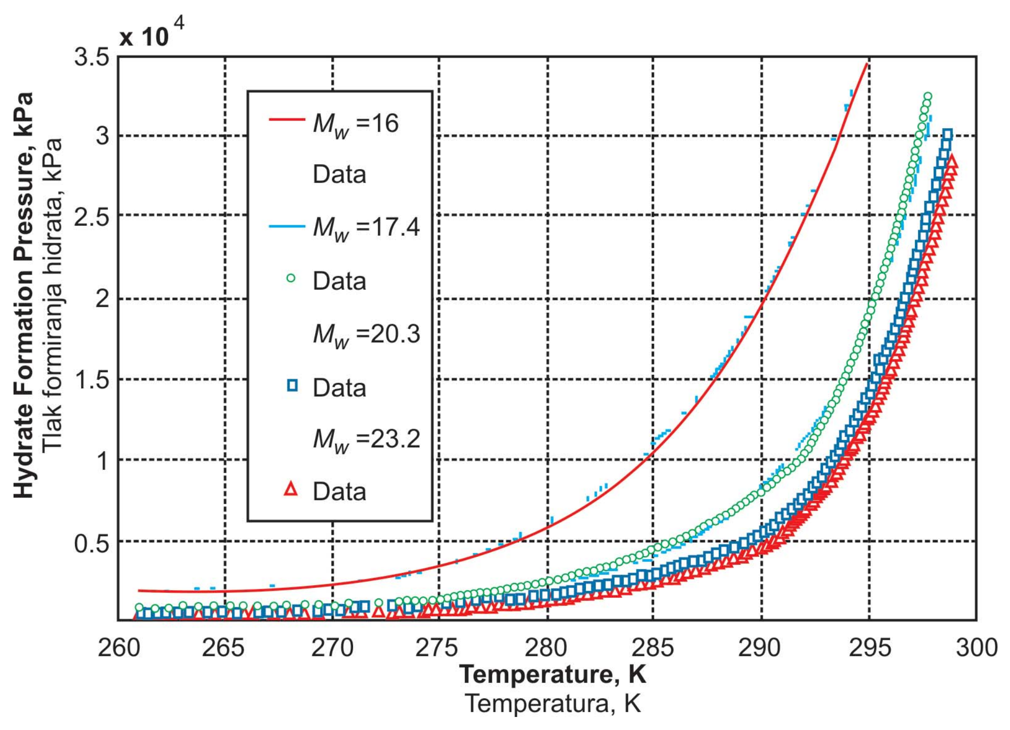

Fig. 1. **Hydrate formation pressure prediction in comparison with the data derived from Katz[18] gravity chart for natural gases with molecular weight less than 23.**

Sl. 1. Predviđanje tlaka formiranja hidrata u usporedbi s podacima dobivenim iz Katzovog dijagrama[18] relativne gustoće za prirodne plinove molne mase manje od 23.

5. Generalized Correlations

In order to extend the proposed correlations (9) and (14) to other natural gases with relative density of up to 0.8, two correction factors are introduced. The first one, ÄW1, is the correction factor for the MEG concentration in the aqueous phase. This factor takes into account different hydrate formation temperature depressions between the base relative density of 0.6 and the other gas relative densities of 0.65 up to 0.8. This correction factor can be obtained from Equation (7).

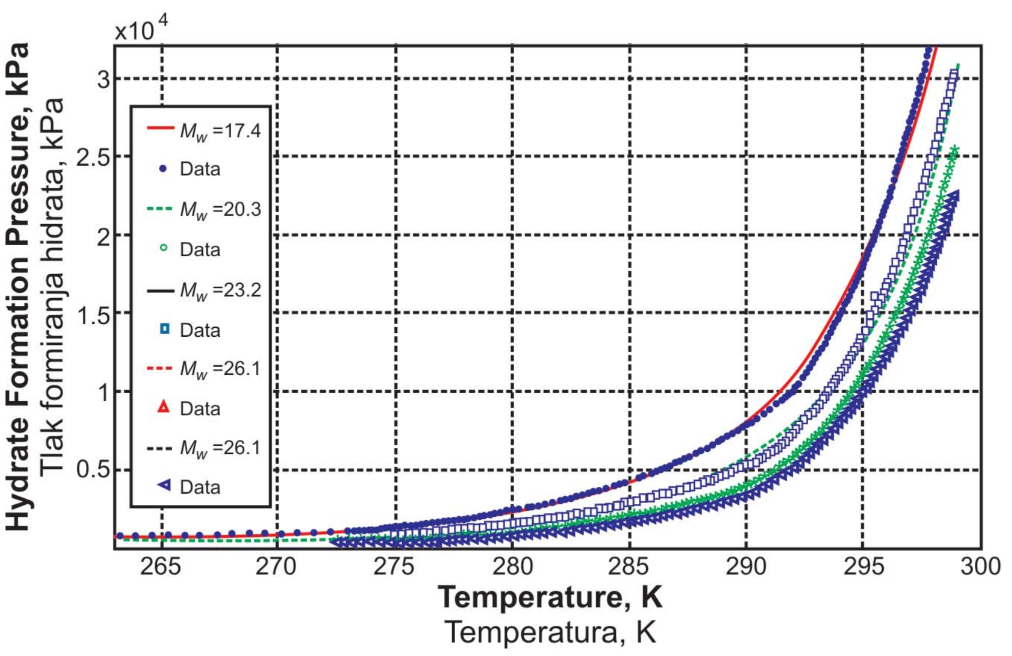

Fig. 2. **Hydrate formation pressure prediction in comparison with the data derived from Katz[18] gravity chart for natural gases with molecular weight more than 23**

Sl. 2. Predviđanje tlaka formiranja hidrata u usporedbi s podacima dobivenim iz Katzovog dijagrama**18** relativne gustoće za prirodne plinove molne mase veće od 23

$$\Delta W_1 = e + f(\Delta T)^2 + h(\Delta T)^3 + i(\Delta T)^4 + j(\Delta T)^5 \quad (19)$$

In Equation (19), ΔW_1 is the weight percent correction factor; ΔT is the hydrate formation depression temperature, °C. The factors e, f, g, h, i and j corresponding to the feed pressures are given in Table 3. Equation (19) is used to calculate the MEG weight percent correction factor (ΔW_1), when the hydrate formation depression temperature, °C and the feed stream pressure are known.

The second correction factor, ΔW_2, corrects the MEG concentration resulting from the difference of MEG concentrations in the aqueous phase at different gas specific gravities. This factor was developed using the five gas compositions having relative densities ranging from 0.6 up to 0.8. To obtain ΔW_2, the factor S is first calculated using equation (21).

$$\Delta W_2 = k + lS + mS^2 + nS^3 \quad (20)$$

where:

$$S = \frac{(\gamma - 0.65)}{0.05} \quad (21)$$

Table 6. Accuracy of correlation for 3MPa, 20 °C depression, γ = 0.7

Factor	Feed T=20 °C	Feed T=30 °C	Feed T=40 °C	Feed T=50 °C
a	0.102 744	-0.109 965 29	-0.306 192 218	-0.310 074 868
b	0.125 407	0.126 573 111	0.134 671 126	0.134 875 055
c	-0.002 090	-0.00199876	-0.002 124 314	-0.002 128 104
d	$1.420\,84 \times 10^{-5}$	1.32865×10^{-5}	$1.400\,36 \times 10^{-5}$	$1.402\,76 \times 10^{-5}$
MEG Wt%	53.114 3	54.259 0	54.636 4	54.691 4
HYSYS results[16]	52.42	53.22	53.62	53.83
error, %	1.324 5	1.952 3	1.895 6	1.600 3

Table 7. Accuracy of correlation for 5MPa, 10 °C depression, γ = 0.65

Factor	Feed T=20°C	Feed T=30°C	Feed T=40°C	Feed T=50 °C
a	0.011 179 643	-0.201 940 7	-0.561 739 3	-0.528484048
b	0.145 491 606	0.145 428 4	0.161 469 992	0.154784208
c	-0.002 640 095	-0.002 503 9	-0.002 772 993	-0.002584326
d	$1.831\,1 \times 10^{-5}$	1.70×10^{-5}	1.86131×10^{-5}	1.7194×10^{-5}
MEG Wt%	25.3815	28.501 6	30.296 8	31.0922
HYSYS results[16]	26.72	30.23	31.97	32.86
%error	5.009 3	5.717 2	5.233 5	5.379 5

Table 8. Accuracy of correlation for 7 MPa, 40 °C depression, γ = 0.8

Factor	Feed T=20 °C	Feed T=30 °C	Feed T=40 °C	Feed T=50 °C
a	0.196 3	0.015 38	-0.196 6	-0.2270
b	0.129 8	0.130 25	0.135 5	0.131 007 564
c	-0.002 2	-0.002 1	-0.0021	-0.002 022 743
d	1.547 78 x 10^{-5}	1.463 45 x 10^{-5}	1.478 83 x 10^{-5}	1.329 96 x 10^{-5}
MEG Wt%	72.070 7	72.113 5	72.063 4	72.112 6
HYSYS results[16]	73.01	73.05	73.07	73.08
% error	1.286 4	1.281 9	1.377 5	1.323 6

Table 9. Accuracy of correlation for 9MPa, 30 °C depression, γ = 0.75

Factor	Feed T=20 °C	Feed T=30 °C	Feed T=40 °C	Feed T=50 °C
a	0.584 88	0.5578	0.3319	0.2381
b	0.103 94	0.0929	0.098 43	0.099 6 8
c	-0.001 64	-0.0013	-0.0013	-0.0013
d	1.114 6 x 10^{-5}	8.815 x 10^{-6}	8.731 74 x 10^{-6}	8.5038 x 10^{-6}
MEG Wt%	63.999 5167 5	64.296 124	64.494 510 72	64.517 268 85
HYSYS results[16]	63.49	63.91	64.13	64.23
% error	0.802 5	0.604 1	0.568 3	0.447 2

The factors k, l, m and n into Equation (20) are constants, which will be displayed in Table 5.

For natural gases with relative density ranging from 0.65 up to 0.8 the revised MEG concentration can be obtained as follows: First, obtain the base MEG concentration from Equations (9) and (14). Then, determine the correction factors (ΔW_1) and (ΔW_2) from Equations (19) and (20). The revised MEG concentration (W_{tr}) is then calculated using Equations (22) and (23).

$$\Delta W = \Delta W_1 + \Delta W_2 \qquad (22)$$

$$W_{tr} = W_t - \Delta W \qquad (23)$$

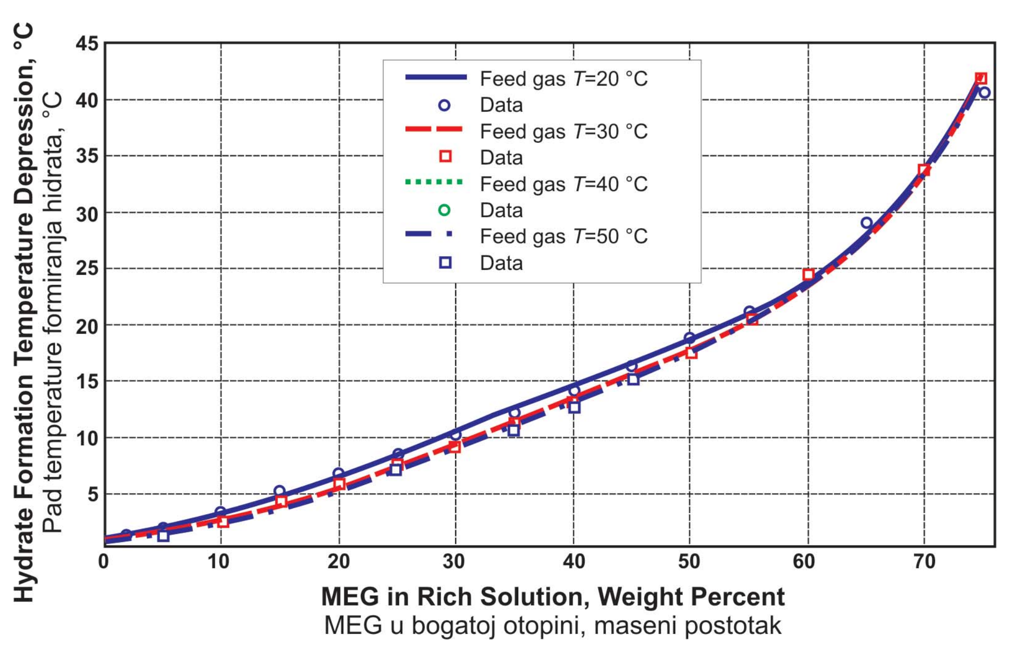

Fig. 3. Hydrate formation temperature depression vs. MEG wt% in Rich Solution at 3 MPa using 80 Wt% MEG lean solution (γ=0.6).

Sl. 3. Pad temperature formiranja hidrata u odnosu na maseni postotak MEGa u obogaćenoj otopini kod 3 MPa, korištenjem masenog postotka 80% siromašne otopine MEGa. (γ = 0,6)

6. Results

Figures 1 and 2 illustrate the obtained results of new developed correlation for predicting hydrate formation pressures of natural gases (at different specific gravities) comparing with the data extracted from Katz gravity chart.[18] As can be seen, there is good agreement between the observed values and the reported data, where the new correlation is applicable to accurately predict hydrate formation pressure of sweet natural gases for pressures up to 40 000 kPa and temperatures between 260 K and 298 K, as well as molecular weight within the range 16 to 29.

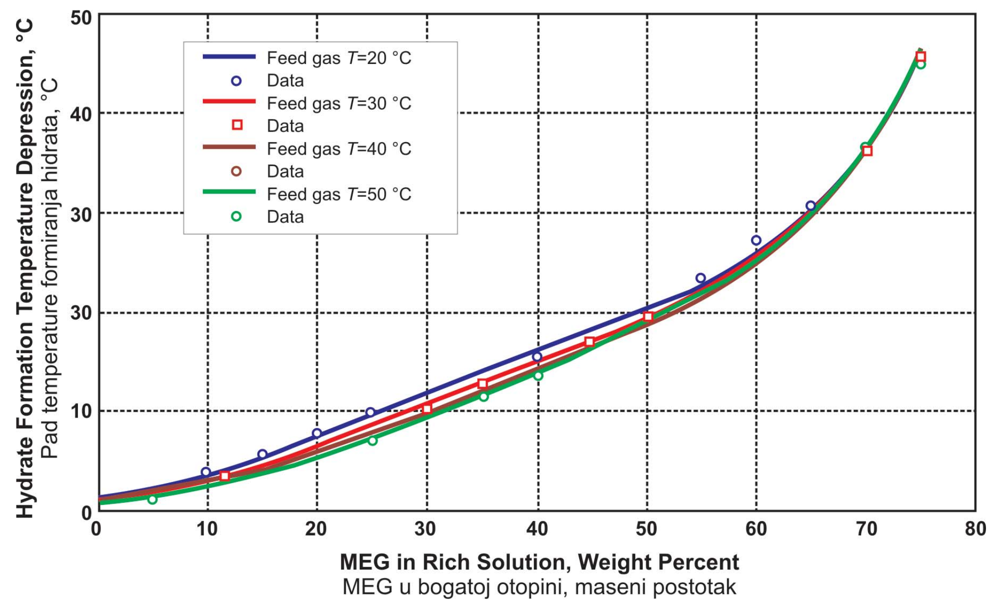

Fig. 4. **Hydrate formation temperature depression vs. MEG wt% in Rich Solution at 7 MPa using 80 Wt% MEG lean solution (γ=0.6)**

Sl. 4. Pad temperature formiranja hidrata u odnosu na maseni postotak MEGa u obogaćenoj otopini kod 7 MPa, korištenjem masenog postotka 80%, siromašne otopine MEGa. (γ = 0,6)

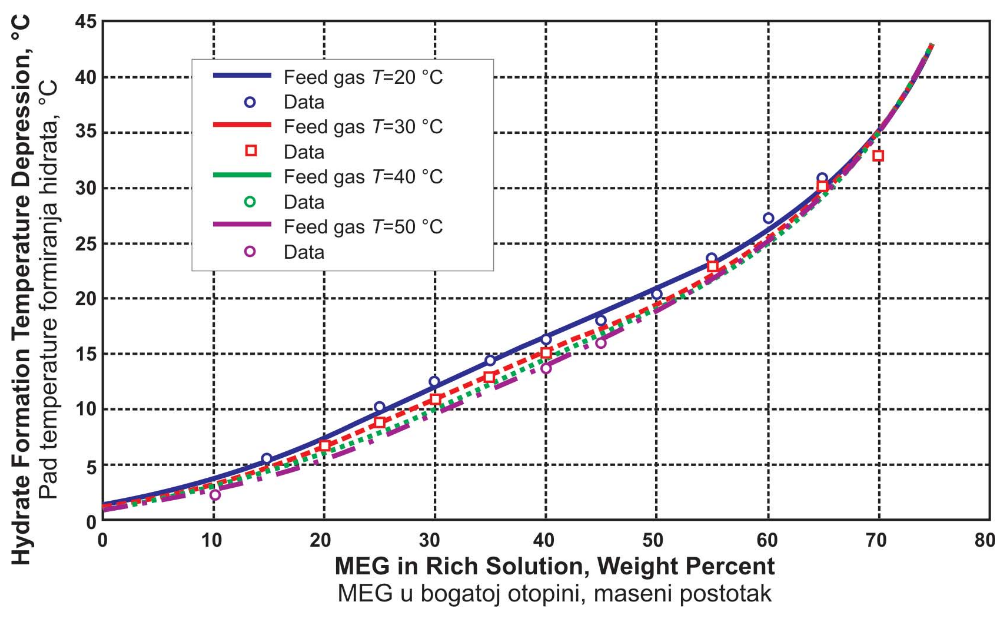

Fig. 5. **Hydrate formation temperature depression vs. MEG wt% in Rich Solution at 9 MPa using 80 Wt% MEG lean solution (γ=0.6)**

Sl. 5. Pad temperature formiranja hidrata u odnosu na maseni postotak MEGa u obogaćenoj otopini kod 9 MPa, korištenjem masenog postotka 80%, siromašne otopine MEGa. (γ = 0,6)

The results of proposed correlations are compared with the obtained data of HYSYS software, based on the HYSYS simulator[16] results which are reported in Tables 6 to 9. Tables display the MEG wt% results from proposed correlation for pressures 3, 5, 7 and 9 MPa. The MEG wt% of each pressure is calculated for a variety of specific gravities and hydrate formation depressions. In this way all variables in the equation are tested. The results are compared with the obtained results from HYSYS. Tables 10 and 11 illustrate the accuracy of proposed method comparing with HYSYS results. Figures 3 to 5 show the hydrate formation temperature depression vs. MEG wt% in Rich Solution at 3 – 9 MPa using 80 Wt% MEG lean solution. There is a good agreement between HYSYS results and proposed correlation.. Both equations (6) and (7) are as a function of MEG weight percent in solution liquid phase and for a given MEG weight percent, hydrate formation temperature depression and the rate of injected MEG are calculated quickly. In addition the correlations verification against actual experimental data have been done in this study. Figure 6 shows typical comparison between proposed method and actual experimental data in the literature[13,4] for typical natural gas composition reported in Tables 12. Figure 6 shows excellent agreement between experimental data1 and a SRK equation of state[28] with the proposed correlations.

7. Conclusion

A novel correlation was developed for rapid estimating hydrate forming conditions of sweet natural gases based on the Katz gas-gravity chart. The new correlation accurately predicts hydrate formation pressure of natural gases for pressures up to 40 000 kPa and temperatures between 260 K and 298 K, as well as molecular weight within the range 16 to 29. Then a simple-to-use method for good estimation of required MEG injection rate to

Table 10. Accuracy of correlation for Prediction of MEG weight percent in water phase at various conditions in compare with HYSYS software[16]

Pressure, MPa	Specific Gravity	Hydrate Formation Depression Temperature (°C)	Feed Gas Temperature (°C)	ΔW_1 (from Equation 7)	ΔW_2 (from Equation 8)	(ΔW_1+ ΔW_2)	MEG Weight% for gas with γ=0.6 (Equation (1) MEGW Wt %)	Revised MEG Weight% (W_{tr} = Equation 2 Wt % + ΔW)	Hysys results	Error %
3	0.7	20	20	0.434	0.602	1.04	53.114 35	52.1	51.4	1.320
3	0.7	20	30	0.434	0.602	1.04	54.259 04	53.2	52.2	1.960
3	0.7	20	40	0.434	0.602	1.04	54.636 44	53.6	52.6	1.902
3	0.7	20	50	0.434	0.602	1.04	54.691 44	53.7	52.8	1.620
5	0.65	10	20	0.595	0.007 36	0.602	25.381 51	24.8	26.1	5.060
5	0.65	10	30	0.595	0.007 36	0.602	28.501 68	27.9	29.7	6.062
5	0.65	10	40	0.595	0.007 36	0.602	30.296 85	29.7	31.4	5.431
5	0.65	10	50	0.595	0.007 36	0.602	31.092 28	30.5	32.3	5.603
7	0.8	40	20	0.460	1.4	1.86	72.070 76	70.2	71.2	1.391
7	0.8	40	30	0.460	1.4	1.86	72.113 5	70.3	71.2	1.331
7	0.8	40	40	0.460	1.4	1.86	72.063 44	70.2	71.2	1.402
7	0.8	40	50	0.460	1.4	1.86	72.112 66	70.3	71.2	1.333
9	0.75	30	20	0.293	1.01	1.3	63.99952	62.7	62.2	0.803
9	0.75	30	30	0.293	1.01	1.3	64.296 12	63.2	62.6	0.633
9	0.75	30	40	0.293	1.01	1.3	64.494 51	63.2	62.9	0.468
9	0.75	30	50	0.293	1.01	1.3	64.517 27	63.2	63.0	0.345
									Error summation	36.67
									AADP*	2.29%

* *AADP* = Average absolute deviation percent

Table 11. Accuracy of correlation for Prediction of MEG Solution mass flow in various conditions in comparison with HYSYS software[16]

Pressure, MPa	Gas Sp.γ.	Temp. Depression °C	Gas T °C	This work	HYSYS [16]	Absolute Deviation Percent	Average Absolute Deviation Percent
3	0.73	20	20	1 067.334 08	1 137.7	6.184 928	
3	0.73	20	30	2 198.657 5	2 184.5	0.648 089	
3	0.73	20	40	3 748.313 73	3 903.7	3.980 487	
3	0.73	20	50	6 417.502 2	6 618.9	3.042 768	3.46
5	0.68	10	20	177.336 81	197.5	10.209 21	
5	0.68	10	30	463.799 401	450.4	2.975	
5	0.68	10	40	912.422 803	862.8	5.751 368	
5	0.68	10	50	1 582.507 36	1 512	4.663 185	5.89
7	0.77	40	20	2 939.525 15	2 780.8	5.707 895	
7	0.77	40	30	5 430.413 31	5 193.6	4.559 714	
7	0.77	40	40	9 538.5469 3	8 940.8	6.685 609	
7	0.77	40	50	15 807.781	14 790	6.881 549	5.95

Table 12. Gas composition to compare proposed method with actual data[1]

Component	Mole fraction
Methane	0.766 2
Ethane	0.119 9
Propane	0.069 1
i-Butane	0.018 2
n-Butane	0.026 6

avoid gas hydrate formation in natural gas transmission/production systems was presented. The accuracy of the method was tested and it was found that in all cases the error percent was approximately 2 to 5% for predicting hydrate formation temperature depression and MEG injection rate, respectively. Unlike existing approaches the fitted equations developed in this study are easy-to-use which can be easily and quickly solved by spreadsheet and these can be of immense practical value for the engineers and scientists to have a quick check on

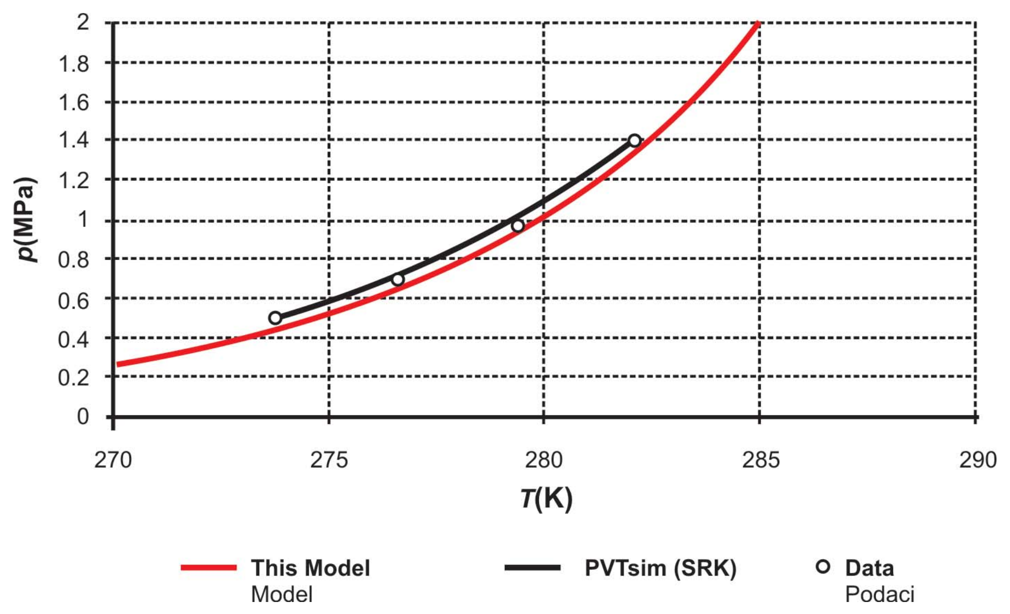

Fig. 6. Comparison between proposed method and actual experimental data in the literature[1] for typical natural gas composition reported in Table 12[1]

Sl. 6. Prikazana je usporedba između predložene metode i stvarnih eksperimentalnih podataka iz literature[1] za tipični sastav prirodnog plina naveden u tablici 12[1]

hydrate formation condition of natural gases with or without presence of inhibitor without opting for any experimental measurements. In particular, chemical and process engineers would find the simple equations to be user-friendly with transparent calculations involving no complex expressions.

Nomenclature

A	Tuned Coefficient
B	Tuned Coefficient
C	Tuned Coefficient
D	Tuned Coefficient
a	Coefficient
b	Coefficient
c	Coefficient
d	Coefficient
ΔT	Hydrate formation temperature depression (°C)
W_t	MEG wt% in rich solution needed for a specific hydrate depression
W	revised MEG concentration
F	MEG solution mass flow rate
M	Molecular weight
T	Temperature (K)
ΔW_1	Correction factor for the MEG concentration in the aqueous phase
ΔW_2	Correction factor for the MEG concentration resulting from the difference of MEG concentrations in the aqueous phase at different gas relative densities
α	Coefficient
β	Coefficient
γ	Coefficient, relative density
θ	Coefficient

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