

Research Article

Predicting Compressibility Factor for Gas Condensate under High Temperature High Pressure Conditions by Using a New Combinational Method

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Abstract: Gas condensate is commonly located in the deep strata under High Temperature High Pressure (HTHP) conditions, which is mainly composed of methane and derived its high molecular weight from the quantity of plus fractions (C_{n+}). Thus, in order to accurately predict the volumetric behavior for gas condensate, the selection of suitable characterization methods for the C_{n+} is of key importance. The compressibility factor as an essential volumetric parameter is often used to analyze the PVT behavior in gas condensate engineering. In this study, four empirical correlations for plus fraction characterization are evaluated and then a new combination method is presented to determine the compressibility factor for gas condensate under HTHP conditions.

Keywords: Compressibility factor, characterization method, gas condensate, HTHP condition, plus fraction

INTRODUCTION

With the improvement of the exploration and exploitation technology, several unconventional natural gas resources have been discovered in the world. It includes gas condensate reservoirs under High Temperature High Pressure (HTHP) conditions. For instance, some gas condensate reservoirs at pressure above 110 MPa have been found in the North Sea according to the research by Ungerer *et al.* (1995); In the Tarim region of China, more than 70 condensate gas reservoirs have been discovered with high reservoir pressures and temperatures reported by Yi Cun and Bao Xin (2001). Ultra-high-pressure gas reservoirs have also been found in the South China Sea. As a result, knowledge of the phase behavior of condensate gas system is important for predicting reservoir performance and future processing needs. As one of the basic thermodynamic parameters of gas mixture, the compressibility factor is an essential volumetric parameter and often used to analyze the PVT behavior in gas condensate engineering.

The compressibility factor values are determined by means of experimental measurements, Equations of State (EOS), empirical correlations based on compressibility chart and other intelligent approaches. Experimental measurements can provide direct and repeatable results, but they are costly and time consuming. Several models built by advanced

algorithms have the shortcomings that complicated steps are required. Therefore, the scholars prefer to study this issue with empirical correlations and equations of state. Canas Marin *et al.* (2007) calculated gas condensate compressibility under 110 MPa with SRK EOS. Bang and Pope (2010) did a research on phase behavior of hydrocarbon/water/methanol mixtures at reservoir conditions with PR EOS. Xu Qiang *et al.* (2000) measured the compressibility factors of 10 natural gas samples at the temperature and pressure ranges of 322.5-413.4 K and 20.1-95.9 MPa, respectively. Besides, only a small number of researches were conducted for gas reservoirs, whose experimental conditions can reach at 110 MPa as reported in the literature (Neuhaus *et al.*, 1999; Fort, 2000).

Gas condensate as an important part of natural gas resources is considered as a very complex reservoir fluid due to its heavy hydrocarbon fractions. Therefore, for the sake of evaluating the gas volumetric behavior accurately, the selection of suitable characterization methods for the C_{n+} is of key importance according to the research by Elsharkawy and Elkamel (2000). In this study, four empirical correlations including two mixing rules and two empirical methods for critical properties for plus fraction characterization are evaluated and then a new combination method is presented to determine the compressibility factor for gas condensate under HTHP conditions.

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METHODOLOGY

DPR correlation, which is proposed by Dranchk *et al.* (1974), is one of the most widely used empirical correlations for predicting compressibility factor. It is a function of reduced pressure (P_r) and reduced temperature (T_r), which connect to the gas mixture critical pressure (P_c) and temperature (T_c). For pure components, such as C1-C6, CO₂, H₂S and N₂, the P_c and T_c can be obtained in the hand book. But high molecular components are hard to be separated, so they are always regarded as the heptane plus fraction (C₇₊) whose pseudo critical pressure and temperature should be properly determined. When the composition of a gas condensate sample is available, pseudo critical properties can be calculated by using the characterization methods.

Characterization methods: Sutton (1985) studying with 275 PVT data of high molecular weight gas mixtures rich in C₇₊, developed the following empirical correlations which is a function of specific gravity:

$$P_c = 756.8 - 131.0\gamma_g - 3.6\gamma_g^2 \tag{1}$$

$$T_c = 169.2 + 349.5\gamma_g - 74.0\gamma_g^2 \tag{2}$$

The other empirical correlations proposed by Kesler and Lee (1976) are written as following:

$$P_c = \exp\left[8.3634 - 0.0556/\gamma_g - (0.24244 + 2.2898/\gamma_g + 0.11857/\gamma_g^2) \times 10^{-3} \times T_b + (1.4685 + 3.648/\gamma_g + 0.47227/\gamma_g^2) \times 10^{-7} \times T_b^2 - (0.42019 + 1.6977/\gamma_g^2) \times 10^{-10} \times T_b^3\right] \tag{3}$$

$$T_c = 341.7 + 811 \times \gamma_g + (0.4244 + 0.1174 \times \gamma_g) \times T_b + (0.4669 - 3.2623 \times \gamma_g) \times 10^5 / T_b \tag{4}$$

The Kesler-Lee method (KL method, Kesler and Lee, 1976) correlates critical properties as a function of the boiling point (T_b) and specific gravity. Whitson and Torp (1983) presented an equation for estimating T_b from molecular weight (M) and specific gravity of the C₇₊:

$$T_b = (4.5579 \times M^{0.15178} \gamma_g^{0.15427})^3 \tag{5}$$

Mix rules: Sutton (1985) modified Stewart *et al.* (1959) mixing rules and then proposed the SSBV mixing rules, which is adopted in this study. SSBV mixing rules are given as follows:

$$J = \frac{1}{3} \left[\sum y_i \left(\frac{T_c}{P_c} \right)_i \right] + \frac{2}{3} \left[\sum y_i \left(\frac{T_c}{P_c} \right)_i^{0.5} \right]^2 \tag{6}$$

$$K = \left[\sum y_i \left(\frac{T_c}{P_c^{0.5}} \right)_i \right] \tag{7}$$

$$F_j = \frac{1}{3} \left[y \left(\frac{T_c}{P_c} \right) \right]_{C_{7+}} + \frac{2}{3} \left[y \left(\frac{T_c}{P_c} \right)^{0.5} \right]_{C_{7+}}^2 \tag{8}$$

$$\varepsilon_j = 0.608F_j + 1.1325F_j^2 - 14.004F_j y_{C_{7+}} + 64.43F_j y_{C_{7+}}^2 \tag{9}$$

$$\varepsilon_K = \left(\frac{T_c}{P_c} \right)_{C_{7+}} \left[0.3129y_{C_{7+}} - 4.8156y_{C_{7+}}^2 + 27.3751y_{C_{7+}}^3 \right] \tag{10}$$

$$J' = J - \varepsilon_j \tag{11}$$

$$K' = K - \varepsilon_K \tag{12}$$

$$T_{pc} = \frac{(K')^2}{J'} \tag{13}$$

$$P_{pc} = \frac{T_{pc}}{J} \tag{14}$$

Eq. (6) to (14) suitable for sweet gas (natural gas contains no CO₂, H₂S and H₂O). For sour gas, Wichert and Aziz (1972) method is used to correct the pseudo critical properties. The correction factor is presented as following:

$$\varepsilon = 120(M^{0.9} - M^{1.6}) + 1.5(N^{0.5} - N^4) \tag{15}$$

The coefficient M presents the sum of the mole fraction of CO₂ and H₂S, N is the mole fraction of H₂S in the gas mixture. The correct pseudo critical properties are calculated as follows:

$$T'_{pc} = T_{pc} - \varepsilon \tag{16}$$

$$P'_{pc} = \frac{P_{pc} T'_{pc}}{T_{pc}} \tag{17}$$

Elsharkawy (2004) has developed new mixing rules similar to SSBV. It divided gas condensate into five parts as following:

$$J_{inf} = a_0 + \left[a_1 \left(\frac{y_i T_c}{P_c} \right) \right]_{H_2S} + \left[a_2 \left(\frac{y_i T_c}{P_c} \right) \right]_{CO_2} + \left[a_3 \left(\frac{y_i T_c}{P_c} \right) \right]_{N_2} + \left[a_4 \sum y_i \left(\frac{T_c}{P_c} \right) \right]_{C_1-C_6} + \left[a_5 (y_i MW) \right]_{C_{7+}} \tag{18}$$

Table 1: The values of constants *a* and *b*

<i>i</i>	<i>a</i>	<i>b</i>
0	0.036983	-0.7765003
1	1.043902	1.0695317
2	0.894942	0.9850308
3	0.792231	0.8617653
4	0.018637	1.0127054
5	0.018637	0.4014645

Table 2: Combination of the four characterization methods

Method No.	Characterization methods	Mixing rules
1	Sutton	SSBV+Wichert -Aziz
2	Kesler-Lee	SSBV+Wichert -Aziz
3	Sutton	Elsharkawy
4	Kesler-Lee	Elsharkawy

$$K_{inf} = b_0 + \left[b_1 \left(\frac{y_i T_c}{P_c} \right) \right]_{H_2S} + \left[b_2 \left(\frac{y_i T_c}{P_c} \right) \right]_{CO_2} + \left[b_3 \left(\frac{y_i T_c}{P_c} \right) \right]_{N_2} + \left[b_4 \sum y_i \left(\frac{T_c}{P_c} \right) \right]_{C_1-C_6} + [b_5 (y_i MW)]_{C_7+} \quad (19)$$

$$T'_{pc} = \frac{K_{inf}^2}{J} \quad (20)$$

$$P'_{pc} = \frac{T_{pc}}{J_{inf}} \quad (21)$$

The values of constants *a* and *b* are listed in Table 1.

In this study, four methods: two pseudo-component characterization methods combined with two mix rules, respectively are shown in Table 2.

Reduced pressure and reduced temperature of natural gas are determined by the following correlations:

$$P_r = \frac{P}{P'_{pc}} \quad (22)$$

$$T_r = \frac{T}{T'_{pc}} \quad (23)$$

In this study, the DPR correlation is adopted to calculate the compressibility factor for gas condensate samples as given below:

$$Z = 1 + \left(A_1 + \frac{A_2}{T_r} + \frac{A_3}{T_r^2} \right) \rho_r + \left(A_4 + \frac{A_5}{T_r} \right) \rho_r^2 + \frac{A_6 A_7 \rho_r^5}{T_r} + \frac{A_7 \rho_r^5}{T_r^3} (1 + A_8 \rho_r^2) \exp(-A_8 \rho_r^2) \quad (24)$$

where,

$$\rho_r = \frac{0.27 P_r}{Z T_r} \quad (25)$$

Table 3: The components and mole fraction of the three gas condensate samples

Component	Sample 1	Sample 2	Sample 3
H ₂ S	0.0000	0.000	0.0000
CO ₂	0.3400	1.430	1.5300
N ₂	0.8500	0.100	0.0700
C1	87.500	91.88	77.760
C2	7.5300	2.640	3.3900
C3	2.4900	0.950	4.5300
i-C4	0.3000	0.950	1.3900
n-C4	0.3100	0.260	0.6900
i-C5	0.1200	0.110	0.6000
n-C5	0.0900	0.090	0.4400
C6	0.1400	0.130	1.4200
C ₇₊	1.3100	2.870	10.820
Σ	100.00	100.00	100.00

The values of constant *A1* to *A8* in Eq. (24) are as follows: *A1* = 0.31506273, *A2* = -1.0467099, *A3* = -0.57832729, *A4* = 0.53530771, *A5* = -0.61232032, *A6* = -0.10488813, *A7* = 0.68157001, *A8* = 0.68446549.

Since the unknown parameter *Z* appears on the both sides of Eq. (24), the Newton-Raphson iterative approach is applied and iterative will be end until the error is less than 0.0001.

Working plan: As a result, the working steps are as following:

- Determine the critical pressure and temperature for every component (including C₇₊).
- Mixing all the critical properties of components by mixing rules.
- Calculating the reduced pressure and reduced temperature.
- Computing the compressibility factor by DPR correlation with Newton-Raphson iterative method.

Data base: One condensate gas fluid from China gas condensate reservoirs was sampled and carefully analyzed with a HP6890 gas chromatograph by Chang Yu *et al.* (2012). Two samples were collected from open literature (Yarborough and Hall, 1974). The pressure range of these gas condensate samples was 37-110 Mpa and temperature range was 313.2-408.7 K. Notably, all the samples were above the dew point pressure.

RESULTS AND DISCUSSION

The three gas condensate samples employed in this study are listed in Table 3. Compared charts are shown in Fig. 1 to 6, which clearly demonstrate the beneficial effect of introducing the transition function for describing the compressibility factor.

Figure 1 to 6 show the conclusion in a direct way that Method 1, Method 2 and Method 3 have a stronger adaptability than Method 4 according to the samples listed in the Table 3. The average absolute relative deviation (AAD %) is expressed as following:

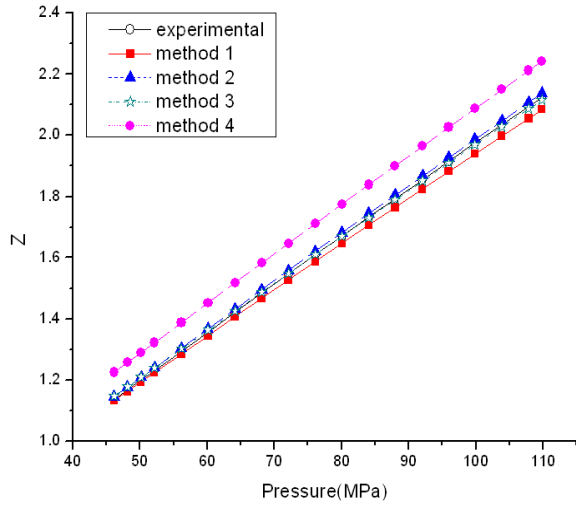


Fig. 1: Measured and predicted compressibility of sample 1 at 313.2 K

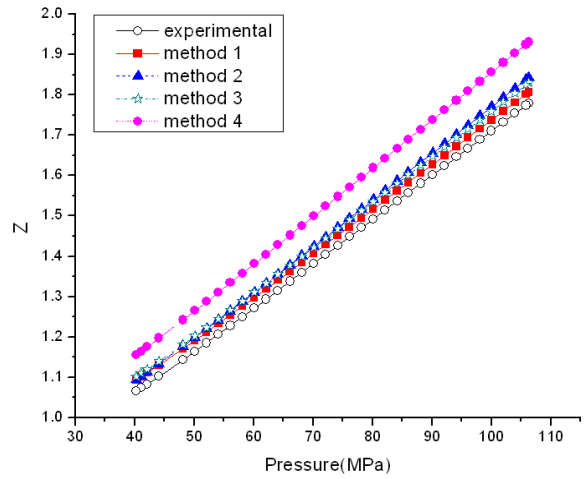


Fig. 4: Measured and predicted compressibility of sample 1 at 407.2 K

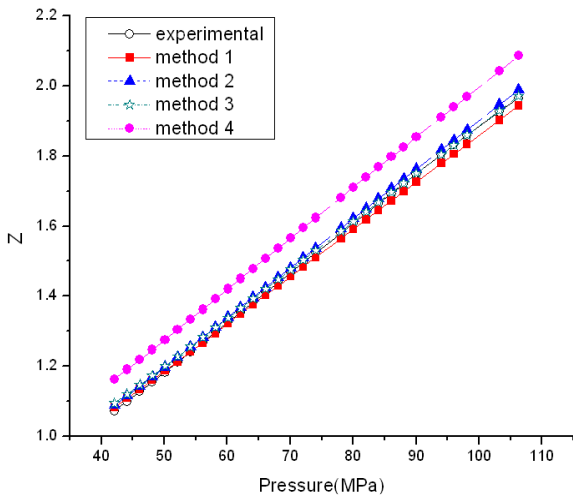


Fig. 2: Measured and predicted compressibility of sample 1 at 343.2 K

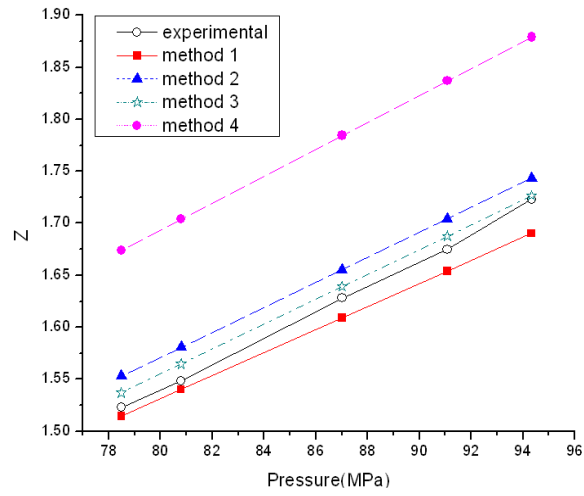


Fig. 5: Measured and predicted compressibility of sample 2 at 408.7 K

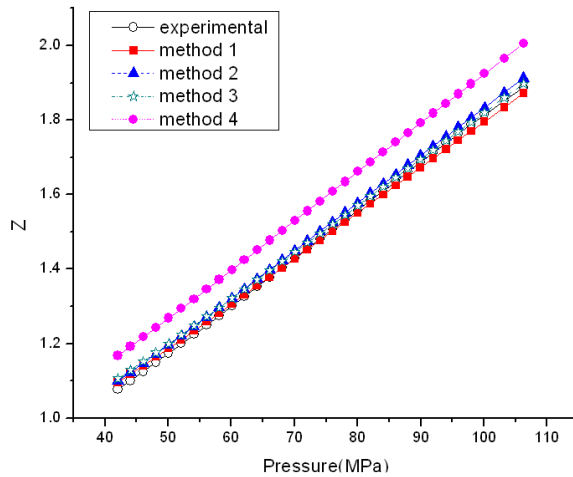


Fig. 3: Measured and predicted compressibility of sample 1 at 373.2 K

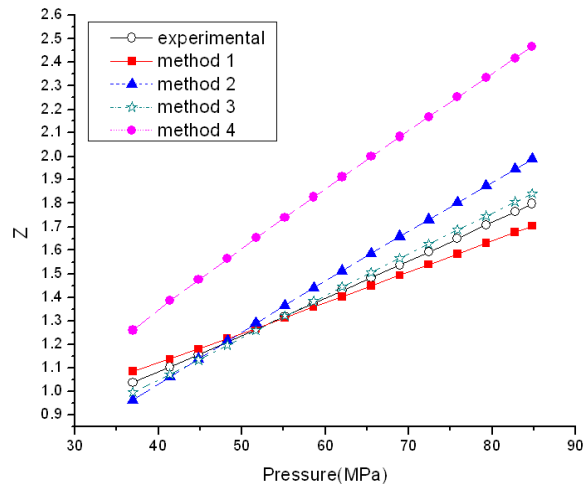


Fig. 6: Measured and predicted compressibility of sample 3 at 406.5 K

Table 4: Comparison of the experimental and calculated compressibility factor for the gas condensate samples

Samples	Temperature (K)	Pressure (MPa)	N _p	AAD%				
				Method 1	Method 2	Method 3	Method 4	SRK
Sample 1	313.2	46-110	19	1.22	0.73	0.24	6.54	2.07
	343.2	42-107	29	0.80	1.05	0.71	6.86	1.59
	373.2	42-107	32	0.71	1.44	1.18	7.01	1.06
	407.2	40-107	35	1.89	3.19	3.00	8.54	0.69
Sample 2	408.7	78-95	5	1.07	1.74	0.82	9.65	1.32
Sample 3	406.5	36-85	15	2.78	6.18	1.80	32.53	2.99

$$AAD = \frac{1}{N} \left| \frac{Z_{cal} - Z_{exp}}{Z_{exp}} \right| \times 100\% \quad (26)$$

In this study, four methods were compared with the SRK EoS and the measurement consequences were presented in Table 4.

In Table 4, Method 1, Method 2 and Method 3 present a strong flexibility. Method 1 and Method 2 used Sutton (1985) method and Kesler and Lee (1976) method for pseudo-component characterization, respectively, with mix rule SSBV (1985) and Wichert and Aziz (1972) for sour gas correction. Method 3 simulated C₇₊ with Sutton (1985) method and Elsharkawy (2004) mixing rules. The satisfactory results revealed its great adaptability. However, Elsharkawy (2004) mixing rules were not fit for Kesler and Lee (1976).

For sample 1 listed in the first column of Table 3 group 1, when temperature was below 343.2 K, Method 1, Method 2 and Method 3 were all better than SRK EOS. With the increasing of temperature, the absolute average deviation of Method 1 decreased to 0.71% when temperature was up to 373.2 K. However, the absolute average deviation of SRK EOS was down to 0.69% at the temperature of 407.2 K.

CONCLUSION

In this study, four empirical correlations including two mixing rules and two empirical methods for critical properties for plus fraction characterization are evaluated and then a new combination method, Sutton (1985) method for pseudo component characterization with El-Sharkawy *et al.* (2009) mixing rules, is presented to determine the compressibility factor for gas condensate under HTHP conditions. With a variety of content of high molecular component, critical properties of pseudo component differ from each other and they will have an enormous effect on the final results. For gas condensate under HTHP conditions, chose the appropriate approach to the situation is the most efficient way. This study proved that the proper correlation and suitable characterization of the plus fraction for gas condensate samples is an efficient way to predict the volumetric behavior.

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