Iranian Journal of Oil & Gas Science and Technology, Vol. 10 (2021), No. 1, pp. 107–126
http://ijogst.put.ac.ir

Determination of Minimum Miscibility Pressure Using PVTi Software, Eclipse 300, and Empirical Correlations

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Highlights

- The MMP of four reservoir oils was determined by using PVTi software, Eclipse 300, and some empirical correlations and compared with the experimental results;
- A comprehensive study of different empirical correlations for pure and impure CO_2 was done to determine the MMP of 24 types of oil;
- Eclipse 300 was more accurate than PVTi software and the empirical correlations in the MMP calculation;
- Using suitable commercial simulation software can be the most accurate and cost-effective tool for the MMP determination.

Received: October 15, 2020; *revised*: January 28, 2021; *accepted*: February 03, 2021

Abstract

One of the most important factors in the miscible gas injection process is to determine the minimum miscibility pressure (MMP). According to the definition, the minimum miscibility pressure is the minimum pressure at which, at a constant temperature, the oil and gas injected can dissolve into each other to form a single phase. Among the available methods for determining the minimum miscibility pressure, laboratory methods, including the slim tube test and the ascending bubble apparatus test are more widely utilized. Although the mentioned tests have high measurement accuracy, they are very time-consuming and expensive. Therefore, the determination of the minimum miscibility pressure is usually done using computational and simulation approaches that also have high accuracy. Conducting PVT tests and determining their MMP using the slim tube method was previously performed. In this study, the minimum miscibility pressure of reservoirs was determined by applying three simulation methods utilizing PVTi software, Eclipse 300 software, and empirical correlations. Comparing the obtained data with the laboratory results revealed that the simulation by Eclipse 300 is the fastest and most accurate approach.

Keywords: Empirical Correlations, First-contact Miscibility (FCM), Gas Injection, Multi-Contact Miscibility (MCM), Simulation

How to cite this article
Karamnia V, Ashoori S, Determination of Minimum Miscibility Pressure Using PVTi Software, Eclipse 300, and Empirical Correlations. Iran. J. Oil Gas Sci. Technol., Vol. 10, No. 1, p. 107–126, 2021.
DOI: 10.22050/IJOGST.2021.252493.1567

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1. Introduction

Regarding the decline in the pressure of the existing reservoirs due to the primary production by the natural energy of the reservoir, the issues related to the secondary and tertiary production are becoming more controversial. Miscible gas injection is one of the effective ways to enhance oil recovery. The displacement efficiency of the crude oil system by gas injection is highly dependent on pressure. It should be mentioned that the miscibility occurs when the injection pressure is higher than the specified minimum pressure. This minimum pressure is called the minimum miscibility pressure and is abbreviated as MMP. By reaching this pressure, the percentage of oil recovery increases significantly. Since the injection pressures higher than MMP have a negligible impact on oil recovery percentage, raising the injection pressure to values higher than the MMP is not economically welcome. Therefore, given the importance of the issue, it is necessary to determine a fast and accurate method for calculating the MMP. Various methods have been proposed to calculate the MMP, and they can be divided into two categories of experimental and nonexperimental techniques. The slim tube test is widely recognized as a standard laboratory approach to estimating the MMP. Despite the high measurement accuracy, this test is assumed to be very time-consuming and expensive. Hence, it is recommended that the minimum miscibility pressure should be determined using computational methods, especially simulation.

Therefore, the purpose of this study is to determine the minimum miscibility pressure using PVTi software and to simulate the slim tube test by means of Eclipse 300 software as well as the existing empirical correlations. Then, the results obtained from the aforementioned methods are compared with the MMP determined in the laboratory. The method that demonstrates the least error is selected as an alternative approach to the laboratory methods to determine the MMP of oil reservoirs through the gas injection process.

The determination of the MMP depends mainly on factors such as pressure, temperature, and the composition of the oil reservoir and the gas injected into it. Among the mentioned factors, the reservoir fluid composition and the injected gas play a significant role. So far, the effect of various parameters on the minimum miscibility pressure has been investigated by many researchers. For example, Zhang et al. (2004) performed laboratory studies on the effect of impurities in the injected CO_2 on the minimum miscibility pressure for two samples of light oil. The results showed that by increasing the concentration of N_2 and/or C_1 in the CO_2 gas flow, the amount of MMP increased unfavorably. Additionally, compared with the presence of ethane, the existence of propane in the carbon dioxide gas flow has a greater effect on the reduction of the MMP. Moreover, Sayegh et al. (2007) studied the impact of H_2S on the MMP of carbon dioxide. Their results revealed that the amount of MMP decreases almost linearly with increasing the amount of H_2S in the injected gas. Vahidy and Zargar (2007) investigated the effect of temperature, the reservoir fluid composition, and the injected gas on the nitrogen gas MMP in a light-oil reservoir. The simulation results revealed that the amount of light (C_1) and medium (C_2–C_6) components in the oil phase is the most important factor in fulfilling the miscibility between nitrogen and reservoir oil. Increasing the medium components and decreasing the amount of methane lead to the reduction of the MMP. Similar to nitrogen, methane is capable of reaching miscibility by gas evaporation mechanism. Studies have shown that the injection of a combination of nitrogen and propane diminishes the MMP of nitrogen gas, but a combination of nitrogen and methane has little effect on the MMP. The results show that when the temperature decreases, a slight increase in the MMP of nitrogen gas is observed.

Through recent years, the simulation of oil–gas MMP using artificial intelligence (AI) has been reported in many studies. For instance, Huang et al. (2003) developed an artificial neural network (ANN) to estimate the MMP. The parameters involved in determining the MMP of pure carbon dioxide for a reservoir are C_{5+} molecular mass, reservoir temperature, and the concentrations of light (methane) and medium (C_2–C_4) components in the oil phase. The impurity coefficient of the MMP of carbon dioxide, denoted by F_{imp}, is estimated by the concentration of the associated impurities (N_2, C_1, H_2S, and SO_2) in the carbon dioxide gas stream and their critical temperatures. F_{imp} is a correction factor used for the MMP of pure carbon dioxide. The results proved that nitrogen gas has the greatest effect on the MMP in a way that a slight change in the amount of N_2 causes a large fluctuation in the MMP of carbon dioxide. The amount of C_1, with a slightly lower effect, is an increasing function of the MMP of carbon dioxide, while the amounts of H_2S and SO_2 are decreasing functions of the MMP. Shakibasefat and Estakhr (2018) were able to estimate the MMP well using the laboratory data of the slim tube model and the Eclipse 300 simulator in one of the oil fields in southern Iran. Based on the experimental results of the slim tube, the MMP approximated 4500 psia, while the MMP computed by the simulation was reported to be 4550 psi.

2. Theorical section

In Sections 2.1 to 2.4, we provide all the laboratory data from the work of Jaubert et al. (2002) needed to simulate the slim tube test by commercial software.

2.1. Experimental data

Laboratory data are one of the most fundamental aspects of scientific researches, so accurate and precise data must be utilized. This section briefly discusses the test fluids, the pressure volume temperature (PVT) test data, the specifications of the slim tube apparatus, the experimental procedure, and the calculation of the MMP.

2.2. Test fluids

In the current study, we selected four reservoirs from the work of Jaubert et al. (2002) which has more complete information, and performed the PVT tests and gas injection on them. The compositions of these oil reservoirs are summarized in Table 1.

Table 1

Experimental components of the oil reservoirs.

Components	Molar percentage (F2)	Molar percentage (F3)	Molar percentage (F4)	Molar percentage (F5)
H_2S	0	0	0	0.383
N_2	0.2	0.45	0.35	0.45
CO_2	1.34	1.64	3.14	2.07
C_1	23.64	45.85	54.26	26.576
C_2	8.56	7.15	8.57	7.894
C_3	6.68	6.74	5.72	6.73
iC_4	1.25	0.84	0.76	1.485
nC_4	4.05	3.11	2.45	3.899
iC_5	1.78	1.03	0.75	1.937
nC_5	2.67	1.65	1.2	2.505
C_6	4.03	2.52	1.53	3.351
C_7	4.57	3.77	2.6	4.311
C_8	4.28	4.28	3.02	4.133

Components	Molar percentage (F2)	Molar percentage (F3)	Molar percentage (F4)	Molar percentage (F5)
C_9	3.88	2.7	1.2	3.051
C_{10}	2.93	1.69	1.74	2.033
C_{11}	3.15	1.81	1.36	2.635
C_{12}	3.19	1.47	1.1	2.285
C_{13}	3.05	1.45	1.11	2.364
C_{14}	1.16	1.28	0.95	2.038
C_{15}	1.98	1.15	0.86	1.752
C_{16}	1.72	0.91	0.68	1.589
C_{17}	1.6	0.82	0.6	1.492
C_{18}	1.16	0.8	0.56	1.263
C_{19}	1.1	0.71	0.51	0.812
C_{20+}	12.03	6.18	4.08	12.962
MW_{C20+} (g/mol)	530	474	418	450
SG_{C20+}	0.9493	0.9253	0.905	0.956

2.3. Specifications of slim tube apparatus

In the laboratory, the MMP is measured using the slim tube apparatus which is filled with glass beads or sands, creating a porous media. It must be highlighted that the slim tubes are different depending on the usage in the industry. The slim tube used in these experiments had a length of 10 m, an inner diameter of 0.635 cm, a porosity of 38%, and a permeability of 2000 millidarcy. Also, the gas was injected into the slim tube at a flow rate of 10 cc per hour.

2.4. Experimental procedures

First, the slim tube was saturated with the reservoir oil at a certain pressure. The gas was then injected into the tube at a constant flow rate of 10 cc⁄h. The outlet fluid from the slim tube was segregated by a separator at an atmospheric pressure, and the volume of the oil and gas phases were measured. The oil recovery factors as the initial oil in place percentage and the gas-to-oil ratio in the output fluid (SCF/STB) were recorded versus the different volumes of the injected gas as the effective pore volume percentage. After injecting the gas in about 1.2 pore volumes, the experiment was stopped and repeated at the other pressures. The test might also be terminated at a preselected high producing gas-to-oil ratio around 40000–50000 SCF/STB, with the ultimate recovery determined under those conditions. To interpret the conducted experiments, the ultimate recovery curve was plotted versus pressure. Since the changes of the increase in the ultimate recovery declines as the pressure increases, the breaking point in the diagram is the first pressure at which the miscibility occurs.

2.5. Modeling of fluid samples using commercial software

By preparing a representative model of the reservoir fluid, which is regarded as one of the key factors in oil reservoir modeling, we can predict the reservoir behavior. In Schlumberger Simulation Luncher software, the fluid modeling module in PVTi (2010) has been used to simulate the experiments.

PVTi is a program-based hybrid PVT state equation used to determine the properties of a set of fluid samples for use in an Eclipse simulator. PVTi is a vital part of simulation because we need a real physical model of the reservoir fluid sample before using it in the reservoir simulation. PVTi can be used to simulate experiments performed on a series of fluid samples in the laboratory, and then theoretical predictions can be made from the observations made during laboratory experiments; hence, the accuracy of the fluid models can be examined. The difference between the measured results and the calculated data is minimized using regression, so the various parameters of the equation are adjusted. We performed the regression operation by selecting the parameters of the equation of state, namely Ω_A, Ω_B, P_C, T_C, Z_C, V_C, and ω. First, we obtained the amount of saturation pressure with a high degree of accuracy because it was a very important parameter; then, we continued the calculations until the difference between the laboratory results and the calculated data is minimized.

2.6. Primary calculations

The PVT properties of the fluids have been calculated using the three-parameter equation of Peng–Robinson. The parameters of the equation of state are adjusted by regression to obtain a good match between the laboratory results and the calculated data. Ω_A, Ω_B, P_C, and T_C for pseudo components have been selected as the regression parameters, and a number of runs were performed until an acceptable match between the laboratory results and the calculated data was achieved.

2.7. Grouping of pseudo components

To better understand the pseudo composition of the reservoir fluid, it is better to use the separation method of the pseudo components. Since a large number of equations must be solved in a hybrid model simultaneously, efforts should be made to reduce the number of the fluid components, which consequently leads to a reduction in the volume of the calculations. At this stage, it is important to know how to select various groups of pure components, each of which is represented by a pseudo component. To this end, in the PVTi software, we must use "Edit/Fluid Model/Splitting/Whitson" option and group the heavy components into three different categories. Table 2 groups the components of the reservoir fluid after the separation. In this table, X_{1+} indicates two components of C_1 and N_2, and X_{2+} represents three components of C_2, CO_2, and H_2S.

Table 2

The reservoir oil components after grouping.

Components	**Molar percentage (F2)**	**Components**	**Molar percentage (F3)**	**Components**	**Molar Percentage (F4)**	**Components**	**Molar Percentage (F5)**
$\mathbf{X_{1+}}$	23.84	X_{1+}	46.3	X_{1+}	54.61	X_{1+}	27.026
$\mathbf{X_{2+}}$	9.9	X_{2+}	8.79	X_{2+}	11.71	X_{2+}	10.347
$\mathbf{C_3}$	6.68	C_3	6.74	C_3	5.72	C_3	6.73
$\mathbf{C_{4+}}$	5.3	C_{4+}	3.95	C_{4+}	3.21	C_{4+}	5.384
$\mathbf{C_{5+}}$	4.45	C_{5+}	2.68	C_{5+}	1.95	C_{5+}	4.442
$\mathbf{C_{6+}}$	12.88	C_{6+}	10.57	C_{6+}	7.15	C_{6+}	11.795
$\mathbf{C_{9+}}$	9.96	C_{9+}	6.2	C_{9+}	5.2	C_{9+}	7.719
$\mathbf{C_{12+}}$	7.4	C_{12+}	4.2	C_{12+}	3.16	C_{12+}	6.687
$\mathbf{C_{15+}}$	5.3	C_{15+}	2.88	C_{15+}	2.14	C_{15+}	4.833
$\mathbf{C_{19+}}$	2.26	C_{19+}	1.51	C_{19+}	1.07	C_{19+}	2.075
$\mathbf{C_{23+}}$	3.3187	C_{23+}	2.0789	C_{23+}	1.7544	C_{23+}	4.8105
$\mathbf{C_{31+}}$	3.044	C_{31+}	1.7265	C_{31+}	1.2267	C_{31+}	3.7588
$\mathbf{C_{55+}}$	5.6672	C_{55+}	2.3746	C_{55+}	1.0989	C_{55+}	4.3927

3. Results and discussion

3.1. Regression results

In the following, the results related to the regression of the experiments and the error value before and after the regression are obtained and graphically illustrated in Figures 1–7. The solid-line and the dash-line represent the results before and after tunning the equation respectively.

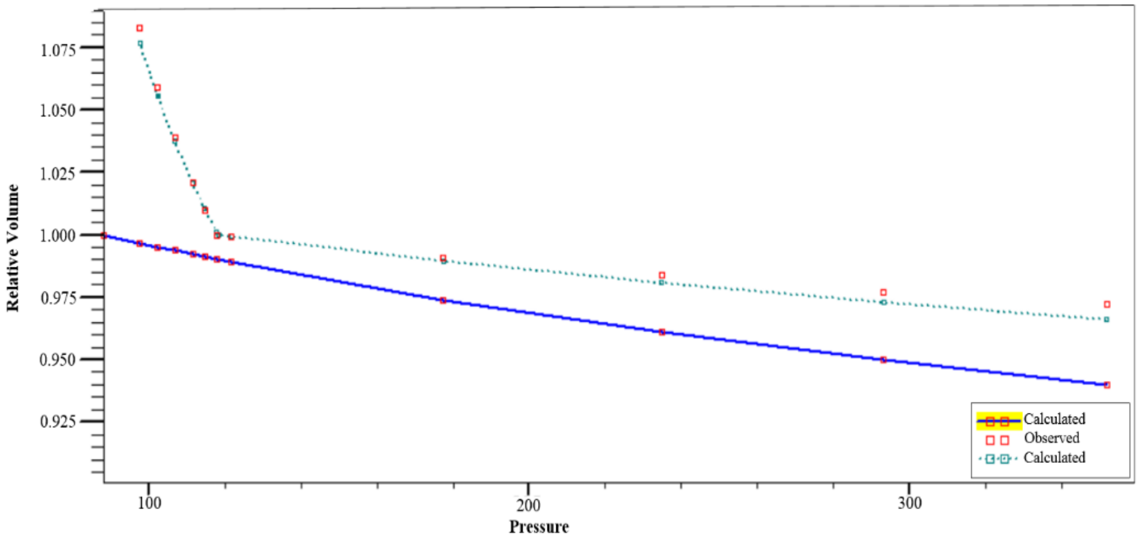

Figure 1

Adjusting the "calculated" and the "experimental" relative volume of reservoir fluid F2.

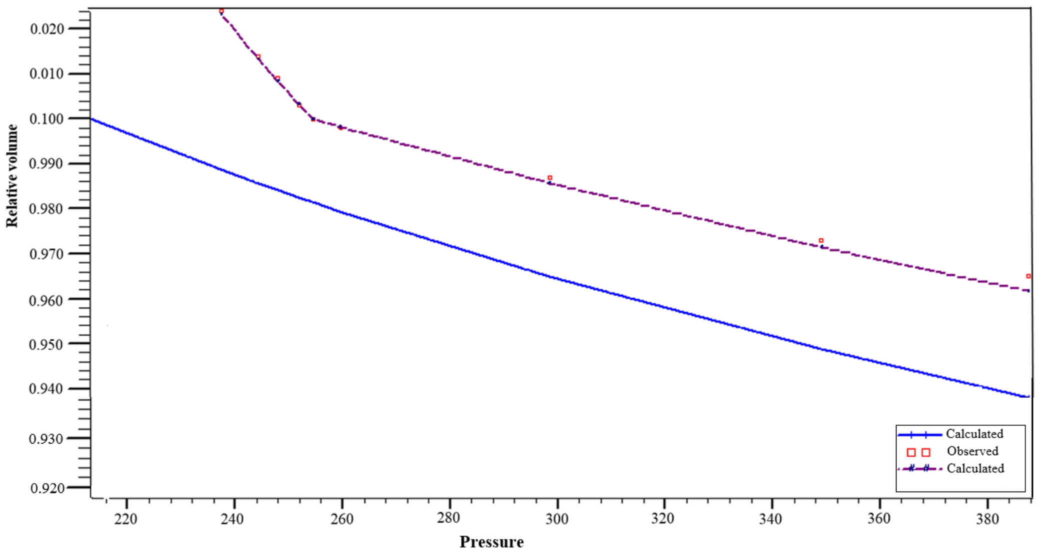

Figure 2

Adjusting the "calculated" and "experimental" relative volume of reservoir fluid F3.

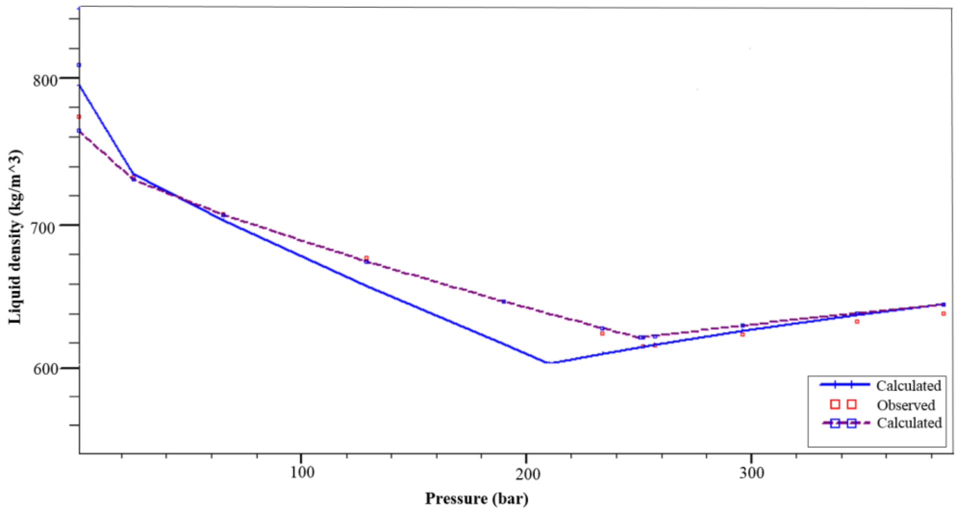

Figure 3

Adjusting the “calculated” and “experimental” oil density of reservoir fluid F4.

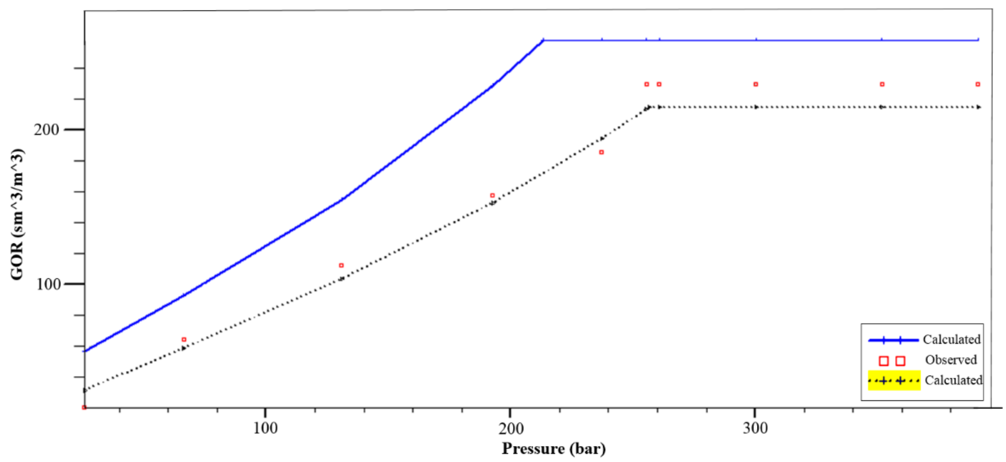

Figure 4

Adjusting the gas-to-oil ratio from the “experimental” and “calculated” data on reservoir fluid F3.

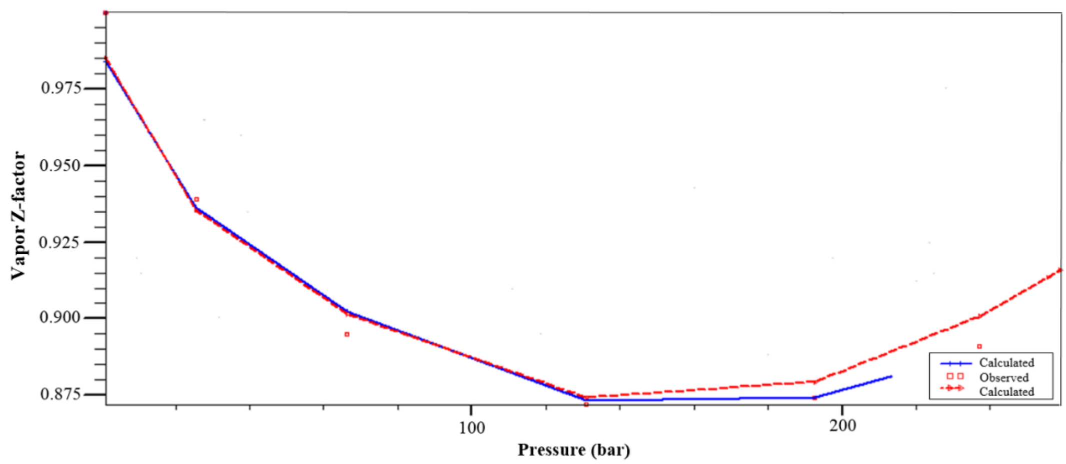

Figure 5

Adjusting the compressibility coefficient from the “experimental” and “calculated” data on reservoir fluid F3.

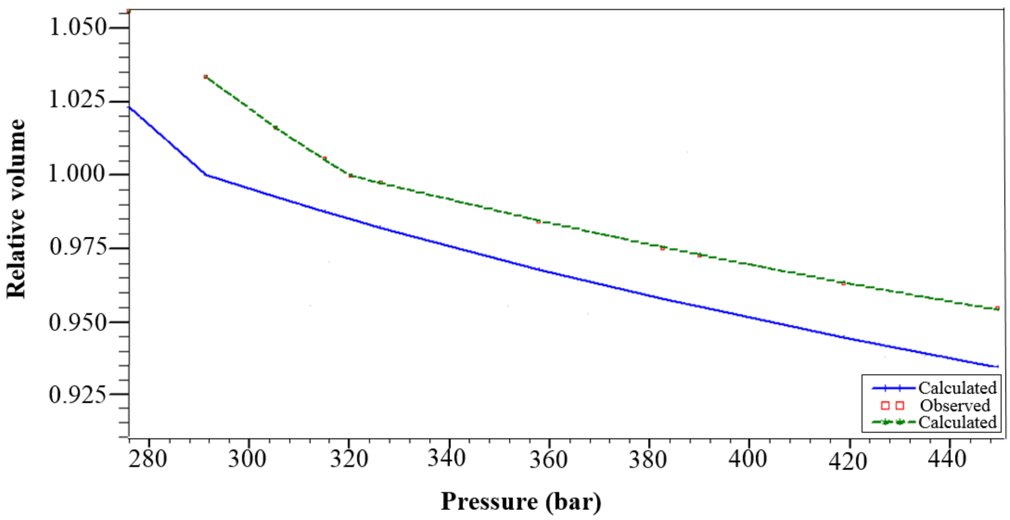

Figure 6

Adjusting the “calculated” and “experimental” relative volume of reservoir fluid F4.

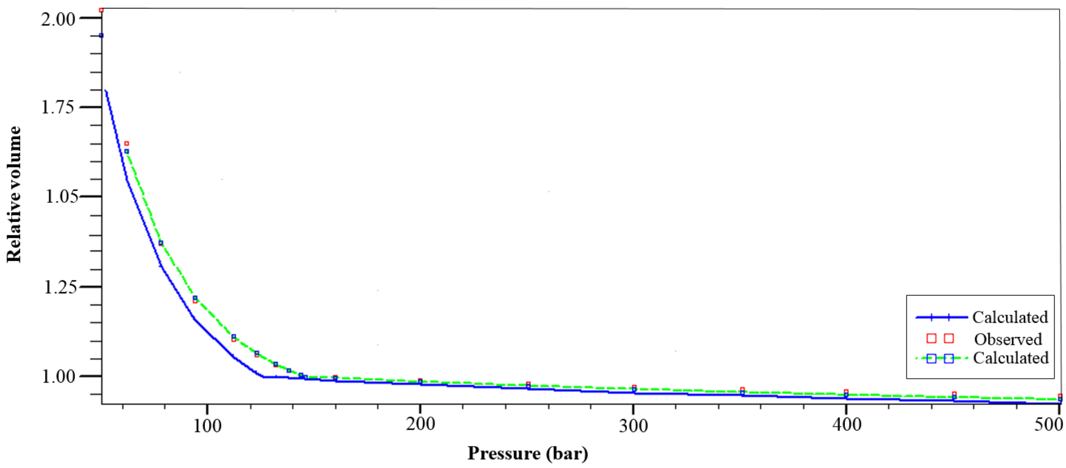

Figure 7

Adjusting the “calculated” and “experimental” relative volume of reservoir fluid F5.

3.2. Determining MMP with software

In a miscible injection, based on the reservoir conditions, the two contacting fluids will not be miscible, but a miscibility intermediary, the pressure of which is one of the most important factors, must be provided. The miscibility pressure is high in most reservoirs, and this is a type of limitation for the miscible injection because it is not cost-effective to implement high pressures. Determining the MMP is therefore necessary as there may be some cases where no miscibility is achieved. As a result, this part attempts to determine the minimum miscibility pressure using commercial software.

Because the injected gas is a lean gas, we select the vaporizing gas drive mechanism and then enter the temperature of the reservoir. In most of the reservoirs, the combined condensing–vaporizing gas drive mechanism is manipulated, but the commercial software is not capable of simulating this mechanism.

On the other hand, since the injected gas is a lean gas, the dominant mechanism is merely the vaporizing one; hence, this mechanism is selected herein.

Table 3

The compositions of the injected gas.

Components	Molar percentage (G2)	Molar percentage (G3)	Molar percentage (G4)	Molar percentage (G5)
H_2S	0	0	0	0.383
N_2	0.2	0.45	0.35	0.45
CO_2	1.34	1.64	3.14	2.07
C_1	23.64	45.85	54.26	26.576
C_2	8.56	7.15	8.57	7.894
C_3	6.68	6.74	5.72	6.73
iC_4	1.25	0.84	0.76	1.485
nC_4	4.05	3.11	2.45	3.899
iC_5	1.78	1.03	0.75	1.937
nC_5	2.67	1.65	1.2	2.505
C_6	4.03	2.52	1.53	3.351
C_7	4.57	3.77	2.6	4.311
C_8	4.28	4.28	3.02	4.133
C_9	3.88	2.7	2.1	3.051
C_{10}	2.93	1.69	1.74	2.033
C_{11+}	3.15	1.81	1.36	2.635

Table 4 lists the results of the first-contact miscibility (FCM) and the multi-contact miscibility (MCM) calculated by PVTi software. In the last section, the difference between this method and the other techniques is calculated and compared.

Table 4

The results of the MMP determination by PVTi software.

Reservoir	First-contact miscibility pressure (bar)	Multi-contact miscibility pressure (bar)
F2	551.1	340.4
F3	665.2	430.9
F4	594.5	380.1
F5	460.0	280.8

3.3. Simulation of slim tube test with Eclipse 300 software

To evaluate the accuracy of the software, a number of laboratory data compilations, including reservoir fluid samples, injected gas, and the MMP of the gas injected into the reservoir fluid at the desired temperature were adopted from the work of Jaubert et al. (2002). The compositions of the four different reservoir fluids, as well as the compositions of the various gases injected into these reservoirs, are presented in Tables 1 and 3 respectively.

A typical approach to numerically predicting the minimum miscibility pressure is to simulate the displacement using a one-dimensional slim tube model with the equation of state and a simulator with a compositional model. The slim tube is simulated at different pressures, and the recovery factor after injecting the gas is recorded at a rate of 1.2 pore volumes for each run (for each pressure). Regarding the immiscible displacement with Buckley–Leverett assumptions without any component exchange between the injected gas and the in situ oil, the recovery after the infinite gas injection is equal to $1–S_{or}$ where S_{or} is the residual oil saturation. Empirically, a thorough miscible process should lead to the entire recovery of the in situ oil. The 100% recovery is independent of the saturation endpoints or the relative permeability curve status. As a result, a one-dimensional slim tube compositional simulator was used to determine the MMP of various gases in contact with the reservoir fluids. A one-dimensional slim tube with a length of 10 m was prepared. Due to the fact that the real slim tube structure has high porosity and permeability, the porosity and permeability of the model were selected to be 0.38 and 2000 millidarcies respectively.

In this model, two wells were defined: the injection well was placed in the first model block, and the production well was situated in the last model block to produce at a constant bottomhole pressure. However, the main challenge in using this type of simulator is the significant impact of the grid size on the results, which causes the calculated MMP to be greater than the actual value. In all the miscible displacement processes, the displacing and displaced fluids are mixed together, indicating that there is a dispersion phenomenon between different miscible fluids. The dispersion phenomenon creates a transient region in which the displacing fluid dilutes the displaced fluid and affects the phase behavior. According to the scientific hypothesis of Johns et al. (1992), under the conditions in which the penetration and capillary pressure are small and under the conditions without dispersion, the length of this transient region should reach zero. As the number of the blocks rises, the length of this area increases, so the dispersion decreases. To solve this problem (the removal of dispersion), the method proposed by Stalkup (1984) is applied as follows:

1. Initially, a 100-block oil-saturated model is made taking into account the laboratory dimensions and the properties of the porous medium. The time steps must be set so that the fluid front remains at least 10 time steps in a block; in this study, 12 time steps are considered.
2. The above model is implemented at different pressures, and the results are plotted as the final oil recovery factor of the gas injection equal to 1.2 pore volumes versus pressure.
3. By changing the number of the blocks from 100 to 200 and finally to 500 blocks, the above model is implemented for different pressures too.
4. By plotting the final recovery factor versus $1/\sqrt{N}$, where N is the number of the blocks, and extrapolating it for N (infinite equivalent), the true value of the final recovery factor (RF_{∞}) per each pressure is determined.
5. The final recovery coefficient obtained from the previous step (RF_{∞}) is plotted versus the pressure. It should be noted that the point at which two direct lines passing through the desired points intersect is considered as the MMP.

As a result, to determine the minimum miscibility pressure, by injecting different gases (Table 3) into various reservoir fluids (Table 1), different simulations at various pressures were performed by the models with 100, 200, and 500 blocks. The recovery factor diagram was then plotted for an infinite number of blocks versus pressure to calculate the MMP for the various injected gases and reservoir fluids.

a. Injecting gas G2 into reservoir fluid F2

According to the laboratory results of the slim tube tests, the MMP of injecting gas G2 into reservoir fluid F2 at a temperature of 372.05 K equals 235 bar. The simulation results are listed in Table 5.

According to Figure 8, the value of the MMP, i.e. the intersection of the two lines, is 240 bar.

Table 5

The recovery factors at different pressures and numbers of blocks of reservoir fluid F2.

***P* (bar)**	**Recovery factor (100 grids)**	**Recovery factor (200 grids)**	**Recovery factor (500 grids)**	**Recovery factor (infinite grids)**
80	58.87	59.25	59.78	60.15
110	65.45	66.25	66.98	67.16
140	72.25	73.68	74.29	75.61
170	79.95	80.89	81.67	82.18
200	86.14	87.74	88.42	89.71
230	91.35	92.75	93.87	95.82
260	94.73	96.65	98.23	99.92
290	96.73	98.41	99.21	100.68
320	98.47	99.21	99.63	100.25

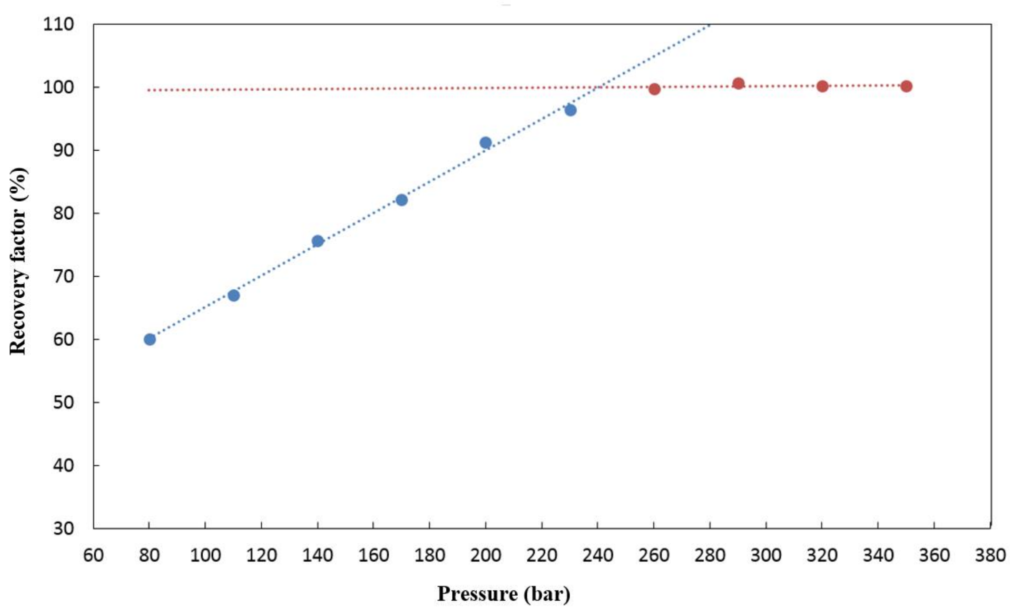

Figure 8

The final oil recovery factor versus pressure for an infinite number of blocks in reservoir F2.

b. Injecting gas G3 into reservoir fluid F3

According to the laboratory results of the slim tube tests, the MMP of injecting gas G3 into reservoir fluid F3 at a temperature of 387.35 K is equal to 376 bar. The simulation results are presented in Table 6. According to Figure 9, the value of the MMP, i.e. the intersection of the two lines, is 385 bar.

Table 6

The recovery factors at different pressures and numbers of blocks of reservoir fluid F3.

***P* (bar)**	**Recovery factor (100 grids)**	**Recovery factor (200 grids)**	**Recovery factor (500 grids)**	**Recovery factor (infinite grids)**
240	69.26	69.87	70.11	70.73
270	75.56	76.06	76.49	77.20
300	80.23	80.97	81.68	82.99
330	87.85	88.87	89.90	91.43
360	90.05	91.09	92.23	93.75
390	93.23	94.47	95.61	97.56
420	96.81	97.95	99.14	99.95
450	98.27	98.89	99.58	100.16
480	98.62	99.05	99.49	100.12

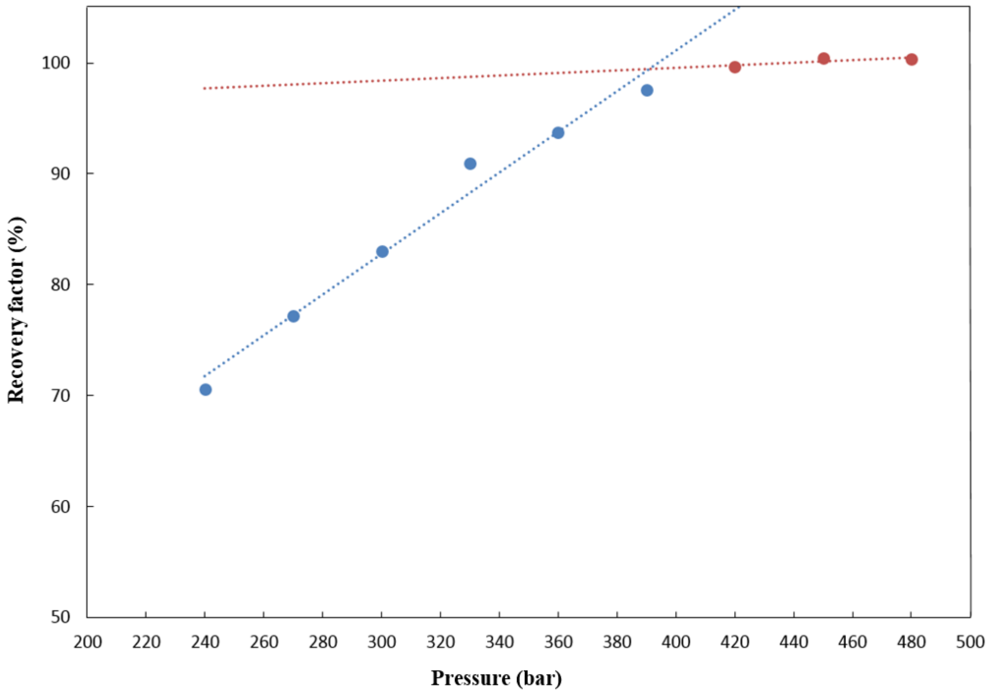

Figure 9

The final oil recovery factor versus pressure for an infinite number of blocks in reservoir F3.

c. Injecting gas G4 into reservoir fluid F4

Based on the laboratory results of the slim tube tests, the MMP of injecting gas G4 into reservoir fluid F4 at a temperature of 388.15 K is equal to 379 bar. The simulation results are tabulated in Table 7. According to Figure 10, the value of the MMP, i.e. the intersection of the two lines, is 386 bar.

Table 7

The recovery factors at different pressures and numbers of blocks of reservoir fluid F4.

P **(bar)**	**Recovery factor (100 grids)**	**Recovery factor (200 grids)**	**Recovery factor (500 grids)**	**Recovery factor (infinite grids)**
240	60.37	60.75	61.15	61.70
270	68.58	69.05	69.45	69.85
300	75.65	76.15	76.57	77.35
330	83.16	83.96	84.53	85.35
360	88.52	89.15	89.75	90.85
390	94.36	95.63	96.54	98.25
420	97.73	98.69	99.41	100.02

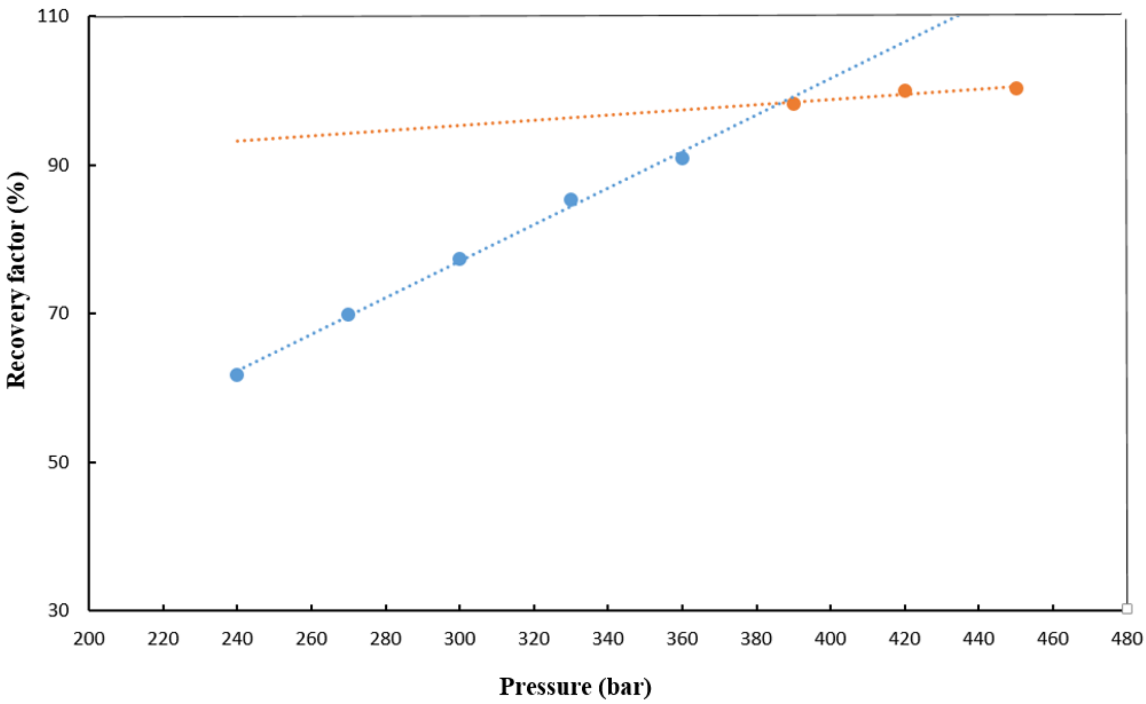

Figure 10

The final oil recovery factor versus pressure for an infinite number of blocks in reservoir F4.

d. Injecting gas G5 into reservoir fluid F5

According to the experimental results of the slim tube tests, the MMP of injecting gas G5 into reservoir fluid F5 at a temperature of 394.25 K is equal to 366 bar. The simulation results are presented in Table 8. According to Figure 11, the value of the MMP, i.e. the intersection of the two lines, is 369 bar.

Table 8

The recovery factors at different pressures and numbers of blocks of reservoir fluid F5.

P **(bar)**	**Recovery factor (100 grids)**	**Recovery factor (200 grids)**	**Recovery factor (500 grids)**	**Recovery factor (infinite grids)**
250	82.49	83.67	84.47	86.19
280	35.41	36.65	88.15	90.31
320	88.45	89.75	91.34	93.85
350	91.16	92.85	94.63	97.41
380	93.95	95.45	97.41	99.97
410	96.16	97.15	98.48	100.45
440	97.15	97.69	98.81	100.24

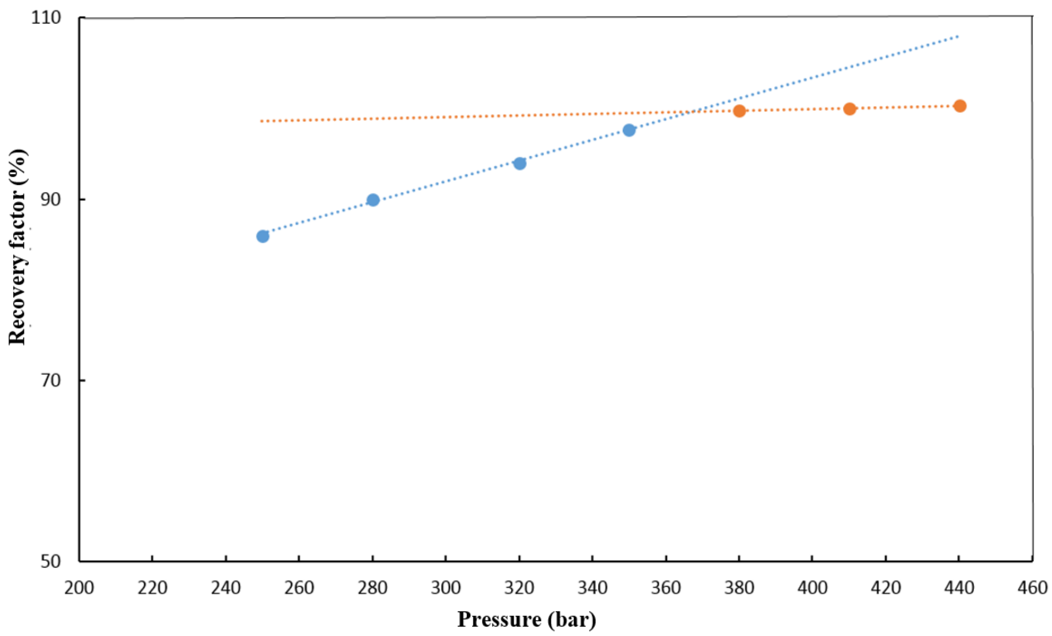

Figure 11

The final oil recovery factor versus pressure for an infinite number of blocks in reservoir F5.

3.4. Estimation of MMP using empirical correlations

Existing empirical correlations estimating the MMP are divided into two categories: 1) the empirical correlations for pure and impure carbon dioxide and 2) the empirical correlations for light gases and nitrogen. Most of the correlations in the literature are related to empirical correlations for pure and impure carbon dioxide, and a limited number of works have investigated the light gases and nitrogen. It should be mentioned that in the reservoirs investigated in this study, a light gas is injected into the reservoir, so the second category of the correlations is employed.

Furthermore, in order to cover the first category of the correlations, 24 types of the oil samples with different compositions were selected from different works; the pure carbon dioxide was then injected into the oil samples, and the values of the MMP of them were determined using a slim tube test. Subsequently, the values of the MMP of the oil samples were calculated using the existing empirical correlations.

a. Comparing empirical correlations for light gas and nitrogen

Table 9 presents the parameters required to estimate the MMP of the fluid using the empirical correlations, and Table 10 lists the pertinent results of this estimation.

Table 9

The parameters required to calculate the MMP of the fluid.

Reservoir	T (K)	X_{vol} (%)	X_{int} (%)	MW_{C7+}	MMP (bar)
F2	372.05	23.64	26.33	254.44	235
F3	387.35	45.85	22.16	216.34	376
F4	388.15	54.26	22.59	194.84	379
F5	384.25	26.576	26.903	245.43	366

Table 10

The results of the MMP calculation for light gas and nitrogen.

Reservoir	Experimental MMP (bar)	MMP (bar) after Firouzabadi and Aziz (1986)	MMP (bar) after Hudgins et al. (1990)
F2	235	370.88	309.57
F3	376	379.31	312.23
F4	379	354.1	303.94
F5	366	367.98	308.61

In Table 9, X_{vol} stands for the molar percentage of the light hydrocarbons (C_1), and X_{int} indicates the molar percentage of the medium-weight hydrocarbons (C_2–C_5, H_2S, and CO_2).

b. Comparison of empirical correlations for pure and impure CO_2

In the following, we compare the empirical correlations using 24 existing laboratory data given in Table 11. The injected gas was pure carbon dioxide. In addition, six empirical correlations were evaluated using MATLAB software, and the results are presented in Table 12.

Table 11

The laboratory data on the MMP for the pure carbon dioxide injection.

Reference	Temperature (°F)	X_{vol} (%)	X_{int} (%)	MW_{C5+}	MW_{C7+}	MMP (psia)
Rathmell et al. (1971)	103	28	30	200	223	2000
Rathmell et al. (1971)	109	17	28.8	204	222	1550
Rathmell et al. (1971)	186	45	13	248	268	5000
Rathmell et al. (1971)	135	2	15	183	193	1900
Holm and Josendal (1980)	105	11	25	188	206	1190
Holm and Josendal (1980)	135	11	25	188	206	1720
Holm and Josendal (1980)	90	11	25	188	206	1100
Alston et al. (1985)	230	33	36	181	185	2930
Alston et al. (1985)	160	41	7	221	227	3400
Alston et al. (1985)	216	51	10	205	210	4085
Alston et al. (1985)	100	4.9	2	236	245	2400

Reference	Temperature (°F)	X_{vol} (%)	X_{int} (%)	MW_{C5+}	MW_{C7+}	MMP (psia)
Alston et al. (1985)	154	31	23	204	210	2450
Alston et al. (1985)	234	33	28	214	220	3502
Alston et al. (1985)	176	53	9	241	245	3880
Sebastion et al. (1985)	88	12	24.2	205	240	1175
Abdassah et al. (2000)	250	0.4	12.3	259	278	3160
Dichary et al. (1973)	130	29	40.4	171	197.4	1550
Cardenas et al. (1984)	164	49	8.84	210	218	3500
Zhou et al. (1999)	180	4.4	24	185	234	3250
Chaback and William (1986)	104	24	30.7	202	221	1316
Chaback and William (1986)	109	17	23.4	221	235	1822
Spence and Watkins (1980)	220	43	30.8	154	273	3190
Spence and Watkins (1980)	130	30	37.3	169	190	1708
Hamoodi (1986)	110	54	43.5	160	284	1572

Table 12

The results of the MMP calculation using the empirical correlations of pure and impure carbon dioxide.

T (°F)	Experimental MMP (psia)	MMP (psia) after Cranquist (1978)	MMP (psia) after Lee (1979)	MMP (psia) after Yelling and Metcalfe (1980)	MMP (psia) after Glaso (1985)	MMP (psia) after Alston et al. (1985)	MMP (psia) after Li et al. (2012)
103	2000	1403	1271	1248	1376	1475	1472
109	1550	1512	1357	1340	1450	1525	1508
186	5000	3680	2824	2317	3471	4838	3546
135	1900	1659	1776	1696	2024	1288	1691
105	1190	1342	874	1279	1368	1217	1375
135	1720	1705	1776	1696	1728	1589	1821
90	1100	1159	1098	1027	1188	1034	1149
230	2930	2720	3989	2853	2770	2887	3205
160	3400	2417	2250	2006	3423	3608	3107
216	4085	2960	3591	2680	3652	4257	4000
100	2400	1635	1230	1200	3303	2189	1658
154	2450	2116	2130	1933	1971	2461	2332
234	3502	3373	4107	2903	3032	4099	3581
176	3880	2980	2594	2198	3542	4661	3536
88	1175	1234	1072	990	1221	641	1196
250	3160	4721	4600	3108	4792	3790	3590
130	1550	1503	1689	1632	1652	1379	1781
164	3500	2330	2333	2054	3199	3357	3109
1880	3250	2202	2684	2246	2452	1860	2493
104	1316	1431	1285	1264	1384	1481	1460

T (°F)	Experimental MMP (psia)	MMP (psia) after Cranquist (1978)	MMP (psia) after Lee (1979)	MMP (psia) after Yelling and Metcalfe (1980)	MMP (psia) after Glaso (1985)	MMP (psia) after Alston et al. (1985)	MMP (psia) after Li et al. (2012)
109	1822	1651	1357	1340	1494	1808	1567
220	3190	2223	3702	2729	3543	2187	3729
130	1708	1487	1689	1632	1645	1371	1771
110	1572	1217	1372	1355	1792	1105	1792

c. Error calculation

Using the obtained results, the mean absolute error of the three methods is calculated by Equation (1):

$$mean\ absolute\ error = \frac{1}{n}\sum_{i=1}^{n}\left|\frac{MMP_i^M - MMP_i^P}{MMP_i^M}\right| \times 100 \quad (1)$$

Table 13 tabulates the results related to the calculation of the MMP by the methods used in this study, namely utilizing PVTi software, using simulation of the slim tube test by Eclipse 300 software, and employing the empirical correlations.

Table 13

The results of calculating the MMP using the different methods.

Reservoir	Experimental MMP (bar)	MMP (bar) after Firouzabadi and Aziz (1986)	MMP (bar) after Hudgins et al. (1990)	MMP (bar) using Eclipse 300	MMP (bar) using PVTi
F2	235	370.88	309.57	240	340.35
F3	376	379.31	312.23	385	430.94
F4	379	354.1	303.94	386	360.19
F5	366	367.98	308.61	369	280.78

The mean absolute errors related to these methods are compiled in Table 14.

Table 14

The mean absolute error of the different methods.

Reservoir	Error (%) Firouzabadi and Aziz (1986)	Error (%) Hudgins et al. (1990)	Error (%) Eclipse 300	Error (%) PVTi
F2	57.82	31.73	2.13	44.82
F3	0.88	16.96	2.39	14.61
F4	0.07	19.8	2.64	4.96
F5	0.54	15.68	0.82	23.28

Table 15 also presents the mean absolute error of the six empirical correlations for the injection of pure and impure carbon dioxide.

Table 15

The mean absolute error of the empirical correlations for pure and impure carbon dioxide.

Correlation	Mean absolute error (%)
Cranquist (1978)	18.06
Lee (1979)	20.62
Yelling and Mercalfe (1980)	20.98
Glaso (1985)	14.23
Alston et al. (1985)	14.79
Li et al. (2012)	11.93

4. Conclusions

From the calculations and the simulations performed to determine the MMP of these four reservoirs and to calculate the pertinent error values, it was concluded that the calculation of the MMP using the slim tube test simulation by Eclipse software 300 is the most accurate, the most cost-effective, and rapidest method compared to the other proposed techniques.

Among the existing empirical correlations related to light gases and nitrogen, the relation proposed by Firoozabadi and Aziz has a high degree of accuracy. It must be highlighted that this correlation is very accurate when the amount of methane in the injected gas is above 80%, which was regarded in this study. Among the empirical correlations related to the pure and impure carbon dioxide, the relationship developed by Li et al. (2012) has an acceptable degree of accuracy.

Nomenclature

F_{imp}	Impurity coefficient
MMP	Minimum miscible pressure
MW	Molecular weight
N	Number of blocks
P	Pressure
RF	Recovery factor
T	Temperature
X_{1+}	Molar percentage of the two components of C_1 and N_2
X_{2+}	Molar percentage of the three components of C_2, CO_2, and H_2S
X_{int}	Molar percentage of medium-weight hydrocarbons
X_{vol}	Molar percentage of light hydrocarbons
Z	Gas compressibility factor
Greeks	
Ω	Centric factor of the substance
Subscripts	
c	Critical

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