Performance of the injection of different gases for enhanced oil recovery in a compositionally grading oil reservoir

Sajad Pourhadi1 · Aref Hashemi Fath1,2

Received: 20 October 2018 / Accepted: 25 June 2019 / Published online: 1 July 2019
© The Author(s) 2019

Abstract
Reservoir fluid characterization is one of the most important steps in hydrocarbon reservoir engineering calculations and studies. The reservoir fluid composition is not constant along the entire hydrocarbon column and varies along the vertical and horizontal directions. In most cases, such variations have been observed along the vertical direction. This is known as compositional grading phenomenon and has a strong impact on the calculation of original hydrocarbon in place, reservoir development, and oil recovery factor. In this paper, a simulation study was carried out to investigate the effects of compositional grading on reservoir fluid properties and the injection of various gases such as carbon dioxide (CO2), nitrogen (N2), associated petroleum gas (APG), N2–CO2 mixture, and water-alternating-CO2 injection into different depths of a conventional black oil reservoir in the southwest of Iran in order to detect the best injection depth and achieve the highest oil recovery factor. Due to increase in minimum miscibility pressure (MMP) with depth in compositionally grading reservoirs, MMP variations with depth is one of the main challenges in determining the optimal gas injection depth in such reservoirs. The results showed that N2, APG and N2–CO2 mixture were immiscibly injected into all depths of the reservoir due to their high miscibility pressures. The occurrence of gas override and channelling phenomena during the course of immiscible gas injection significantly reduced oil displacement efficiency. On the other hand, CO2 was miscibly injected to all reservoir layers and revealed a higher efficiency in comparison with the injection of N2, APG and N2–CO2 mixture. In fact, better miscibility development was observed in upper reservoir parts, as compared to the lower parts. Through completing injection wells at upper reservoir parts and then injecting gas into these parts, one can thus further enhance oil recovery and extend production plateau. Moreover, the results confirmed that water-alternating-CO2 injection into all reservoir depths, compared to other gas injection scenarios, was associated with increased macroscopic sweep efficiency as well as enhanced oil recovery factor.

Keywords Compositional grading · STOOIP · Gas injection · MMP · Oil recovery factor

Abbreviations

| Acronym | Abbreviation |
|---------|--------------|
| APG     | Associated petroleum gas |
| CCE     | Constant composition expansion |
| CGR     | Condensate gas ratio |
| CO2     | Carbon dioxide |
| DL      | Differential liberation |
| EOR     | Enhanced oil recovery |
| EOS     | Equation of state |
| GOC     | Gas oil contact |
| H2S     | Hydrogen sulphide |
| IFT     | Interfacial tension |
| MMP     | Minimum miscibility pressure |
| MMSCFD  | 10^6 standard cubic feet per day |
| MMMSCF  | 10^9 standard cubic feet |
| N2      | Nitrogen |
| OFVF    | Oil formation volume factor |
| OGIP    | Original gas in-place |
| OOIP    | Original oil in-place |
| PVT     | Pressure volume temperature |
| SCF     | Standard cubic feet |
| STB     | Stock tank barrel |
| STBD    | Stock tank barrel per day |
| STOOIP  | Stock tank original oil in-place |
| VGD     | Vaporizing gas drive |
| WAG     | Water alternating gas |
| WOC     | Water oil contact |

1 Mapna Operation and Maintenance (O&M) Co, Tehran, Iran
2 Young Researchers and Elite Club, Gachsaran Branch, Islamic Azad University, Gachsaran, Iran

* Aref Hashemi Fath
aref.hashemifath@yahoo.com
Introduction

In hydrocarbon reservoirs, compositional grading phenomenon leads to variations in reservoir fluid composition. It causes alterations in reservoir oil and gas composition along the vertical and, in some cases, horizontal directions. Due to their non-equilibrium thermodynamic conditions, a majority of the hydrocarbon reservoirs around the world, particularly reservoirs of large thickness and high dip, are engaged in compositional grading (Hussein and Mahgoub 2005).

Compositional grading largely contributes to the determination of the gas–oil contact (GOC), original oil in-place (OOIP) and original gas in-place (OGIP), gas and oil production forecast, surface production facilities design, and miscible and immiscible water and gas injection process for enhanced oil recovery (Høier 1997; Barrufet and Jaramillo 2004; Kord and Zobeidi 2007; Wheaton 1991). In immiscible gas and water injection processes, such a phenomenon leads to mobility variations with depth; however, when it comes to miscible gas injection, it causes miscibility variations at different depths (Høier 1997).

Many factors (namely gravitational force, thermal diffusion, natural and thermal convection, molecular diffusion, migration or incomplete mixing of hydrocarbons within a reservoir, and asphaltene precipitation) contribute to compositional grading in hydrocarbon reservoirs (Ghorayeb and Firoozabadi 2001, Nikpoor et al. 2011). Among these factors, gravitational force and thermal diffusion have the greatest impacts on compositional grading in reservoir (Dougherty Jr and Drickamer 1955).

In the thick reservoirs, with increasing depth and due to gravitational force, the light and heavy components of reservoir fluid tend to be separated from one another and move towards the top and bottom of the reservoir, respectively (Sage and Lacey 1939; Whitson and Belery 1994). The presence of thermal diffusion in the reservoir, however, makes the light components of reservoir fluid move towards the lower parts and the heavy fluid components move towards the upper parts of the reservoir (Bedrikovetsky 1993).

In fact, lighter components existing in the fluid in higher parts of the reservoir tend to move towards lower regions (where the temperature is higher), while heavier components in deeper reservoir regions tend to move upward (where the temperature is lower), giving rise to phase inversion phenomenon (Whitson and Belery 1994).

The temperature gradient reduces the effect of the gravitational force on compositional grading; however, it is less effective than the gravitational force (Høier and Firoozabadi 1999; Luo and Barrufet 2004). In general, temperature variations might reduce, increase, balance or eliminate the effects of gravity on the compositional grading phenomenon in a reservoir (Whitson and Belery 1994).

Compositional grading can also develop in gas reservoirs. Temeng et al. (1998) investigated the compositional grading in a carbonate gas reservoir (Ghawar Khuff) and observed that all hydrocarbon components of the reservoir gas, dew point pressure, and condensate-to-gas ratio (CGR) decreased with increasing depth; however, non-hydrocarbon gas components such as carbon dioxide (CO2), nitrogen (N2), and hydrogen sulphide (H2S) increased with depth.

In general, near-critical oil, volatile oil, and gas condensate exhibit the largest composition variations with depth, and dry gas and black oil has the lowest variations. Furthermore, fluid composition variations with depth are minimized in fully undersaturated oil reservoirs (Whitson and Belery 1994; Firoozabadi 1999; Luo and Barrufet 2004).

Barrufet and Jaramillo (2004) investigated the effects of compositional grading on OOIP and OGIP estimations for a near-critical reservoir in Cusiana Oilfield. They indicated that the failure to account for compositional grading leads to significant errors in OOIP and OGIP calculations, as their failure in accounting for compositional grading in a volatile oil system resulted in 12% underestimated OOIP and 9.4% overestimated OGIP in the concerned reservoir. Moreover, the failure to account for compositional grading in a gas condensate system led to 54% overestimation of OOIP and 15.6% underestimation of OGIP. They further studied the effects of production well completion on oil recovery in the field, suggesting the maximum oil recovery from the field to be realized when production wells are completed in deeper parts of the reservoir.

Syahrial (1999) studied the natural depletion and miscible gas injection scenarios in a volatile oil reservoir in order to evaluate the compositional grading phenomenon. He found that natural depletion reduced light components of reservoir fluid; however, such components in miscible gas injection tend to be evaporated and move upward, while the intermediate oil components exhibiting some reductions. He further showed that variations of the reservoir pressure and saturation pressure caused by the volatility of reservoir fluid followed nonlinear trends.

Wang et al. (2015) investigated the compositional grading phenomenon in a number of hydrocarbon systems and found that depth-induced variations in black oil and light oil characteristics were much lower than those in volatile oil and near-critical oil types. In the next step, they studied the impact of this phenomenon on oil recovery of a volatile oil reservoir under different scenarios, namely natural depletion, water injection, and gas injection. They concluded that the effect of compositional grading on oil recovery was much greater in the gas injection scenario rather than the other scenarios.

In this paper, a simulation study was conducted to investigate the effects of compositional grading on reservoir fluid properties and the injection of different gases into an Iranian oil reservoir in order to enhance oil recovery and determine...
the optimum depth of gas injection. For this purpose, three-parameter Soave–Redlich–Kwong (Soave 1972) equation of state was used to match the experimental data using PVTi package. In addition, FloGrid package was used to make the reservoir static model. Then reservoir simulation model was matched with the history data using history matching methods in order to achieve a greater reliability. A one-dimensional slim-tube model was defined using ECLIPSE 300 software to determine the minimum miscibility pressure (MMP) for different injection gases. Finally, different injection scenarios were investigated and optimal injection depth was identified.

**Theoretical concept of compositional grading**

Gibbs free energy under a gravitational field can be expressed by Firoozabadi (1999) equation, as follows:

\[
dG = -SdT + VdP + mgdZ + \sum_{i=1}^{c} \left( \mu_i + M_i g Z \right)dn_i
\]  

(1)

where \( G \) is Gibbs free energy, \( S \) is entropy energy, \( T \) is temperature, \( V \) is volume, \( P \) is pressure, \( m \) is mass, \( g \) is gravitational constant, \( Z \) denotes vertical depth, \( c \) is total number of components, \( \mu_i \) refers to chemical potential of the \( i \)th component, \( M_i \) is molecular weight of the \( i \)th component, \( n_i \) denotes the number of moles of the \( i \)th component, with \( i \) denoting the component number.

Pressure and depth are related to one another via hydrostatic head equation:

\[
VdP + mgdZ = 0
\]  

(2)

\[
VdP = -mgdZ
\]  

(3)

\[
dP = -pgdZ
\]  

(4)

At equilibrium, \( dG \) must vanish, since \( Z \) and \( P \) are dependent, then:

\[
dT = 0
\]

\[
\mu_i + M_i g Z = 0 \quad i = 1, 2, 3, \ldots, c
\]

\[
VdP + mgdZ = 0
\]  

(5)

Gibbs sedimentation equation can be derived from the second expression of Eq. (5):

\[
(d\mu_i = -M_i g dZ)_T \quad i = 1, 2, 3, \ldots, c
\]  

(6)

Chemical potential of the \( i \)th component can be expressed in terms of fugacity, as follows:

\[
(d\mu_i = RTd \ln f_i)_T \quad i = 1, 2, 3, \ldots, c
\]  

(7)

Substituting Eqs. (6) and (7) gives:

\[
(RTd \ln f_i = -M_i g dZ)_T = 0 \quad i = 1, 2, 3, \ldots, c
\]  

(8)

By integrating Eq. (8) from zero datum depth to depth \( Z \),

\[
f_i = f_i^0 \exp \left( -\frac{M_i g}{RT} Z \right) \quad i = 1, 2, 3, \ldots, c
\]  

(9)

where \( f_i \) is the fugacity of the \( i \)th component in a given phase at the depth \( Z \) and \( f_i^0 \) denotes the fugacity of the \( i \)th component in a given phase at the datum depth.

Therefore, having both the pressure and fluid composition at datum depth, Eq. (9) can be utilized to obtain the fluid pressure and composition at the desired depth.

**Reservoir fluid properties**

Accurate and correct determination of reservoir fluid properties is one of the most important factors in the study and dynamic modelling of hydrocarbon reservoirs (Sadeghi et al. 2016). In order to model reservoir fluid properties, the available experimental PVT data at datum depth including constant composition expansion (CCE), differential liberation (DL), and separator flash tests were fed into PV Ti package. The reservoir fluid composition at datum depth is reported in Table 1. In order to obtain a proper equation of state (EOS) to predict the PVT properties of the reservoir fluid, sensitivity analysis was performed using several equations of state. According to the obtained results, three-parameter Soave–Redlich–Kwong EOS (Soave 1972) was selected for the present study. Furthermore, the fluid viscosity was calculated using Lohrenz et al. (1964) equation. Afterwards,

| Component | Mole% |
|-----------|------|
| N₂        | 0.12 |
| CO₂       | 0.79 |
| C₁        | 36.74|
| C₂        | 6.35 |
| C₃        | 5.29 |
| iC₄       | 1.36 |
| nC₄       | 3.89 |
| iC₅       | 1.58 |
| nC₅       | 1.7  |
| C₆        | 5.22 |
| C₇        | 4.17 |
| C₈        | 2.97 |
| C₉        | 2.55 |
| C₁₀       | 2.45 |
| C₁₁       | 2.34 |
| C₁₂+      | 22.48|
selecting proper parameters of the EOS for regressing, a good match was obtained between the experimental data at datum depth and calculated results using the EOS. Reservoir fluid simulation results are shown in Fig. 1.

**Reservoir model**

The oil reservoir understudy falls within an extended anticline along a north-west—south-east trend as do other structures in south-western Iran. The present research was conducted on a segment of the south-eastern part of the reservoir into which four active wells had been already drilled. The reservoir is a sandstone reservoir with a little amount of lime, and it consists of six layers. The reservoir fluid composition within each layer is reported in Table 2. This is an undersaturated oil reservoir of no gas cap which contains high quality oil of 33° API gravity. Geological observations indicate an aquifer of limited activity surrounding the reservoir. In order to build the static model of the reservoir, FloGrid Package was used (Fath and Pouranfard 2014; Fath et al. 2016). General properties of the reservoir under investigation are reported in Table 3. Furthermore, the three-dimensional static model of reservoir is illustrated in Fig. 2.

**Results and discussion**

**Compositional grading in the reservoir understudy**

In order to check for the existence of compositional grading phenomenon in the reservoir understudy, variations in reservoir pressure and saturation pressure and also in molar percentages of reservoir fluid components with depth were investigated.

In this reservoir, the temperature gradient was very low and according to the obtained samples from the fluid at
different depths, almost no variation in the composition and physical properties of the fluid in the horizontal direction are observed. Figure 3 shows the changes in reservoir pressure and saturation pressure with depth. As shown in this figure, these two parameters change with depth. As depth increases, reservoir fluid becomes heavier leading to increased reservoir pressure and reduced saturation pressure. According to the figure, the reservoir pressure gradient and saturation pressure gradient are about 0.33 psi/ft and 0.11 psi/ft, respectively.

Whitson and Belery (1994) stated that saturation pressure gradient ranges from 0.112 psi/ft for black oil up to a maximum of 4.48 psi/ft for near-critical oils and near a GOC.

Figure 4 demonstrates variations in molar percentage of different components of the reservoir fluid versus depth. According to the figure, the largest variations are those of methane and plus fraction (C_{12+}) which tend to increase and decrease, respectively, with depth. Other reservoir fluid components are almost constant at all depths, confirming the existence of compositional grading phenomenon.

### The Effect of compositional grading on the estimation of stock tank original oil in place (STOOIP)

In this section, the importance of compositional grading in the calculation of STOOIP is considered. For this purpose, STOOIP was calculated with and without considering compositional grading. The estimated value for the case with compositional grading is considered as the real value of STOOIP.

In order to investigate the effect of reservoir fluid sampling depth on STOOIP calculation, six depths were considered in six reservoir layers. The corresponding results to each depth are demonstrated in Fig. 5.

According to the figure, when reservoir fluid sampling depth falls within either the layer 1 or layer 2, the obtained STOOIP value tends to be underestimated, while it is to be overestimated in cases where fluid sampling depth falls within each of the layers 4, 5, or 6. However, the estimated STOOIP was found to be very close to the real value when reservoir fluid sampling depth fell within the layer 3. The reduction in heavy components and the increase in oil formation volume factor (OFVF) in the upper parts of the reservoir resulted in an underestimated STOOIP. This is while, in lower parts of the reservoir, increased heavy components along with reduced OFVF resulted in an overestimated STOOIP value.

Therefore, taking reservoir fluid samples from either the upper or lower parts of the reservoir may end up in significant errors with the estimated STOOIP value, while selecting the middle of the reservoir (i.e. layer 3) as the sampling depth of the fluid brings satisfying result for the calculation of the STOOIP value which is well-close to the corresponding real value.

### Table 2 Reservoir fluid composition in different layers of the reservoir

| Component | Layer#1 | Layer#2 | Layer#3 | Layer#4 | Layer#5 |
|-----------|---------|---------|---------|---------|---------|
| N_2       | 0.1201  | 0.1199  | 0.1196  | 0.1196  | 0.1192  |
| CO_2      | 0.7899  | 0.7901  | 0.7903  | 0.7903  | 0.7907  |
| C_1       | 36.7909 | 36.664  | 36.5379 | 36.5379 | 36.2883 |
| C_2       | 6.3566  | 6.3401  | 6.3237  | 6.3237  | 6.2909  |
| C_3       | 5.2949  | 5.2826  | 5.2703  | 5.2703  | 5.2457  |
| iC_4      | 1.3612  | 1.3584  | 1.3554  | 1.3554  | 1.3498  |
| nC_4      | 3.893   | 3.8855  | 3.878   | 3.878   | 3.8629  |
| iC_5      | 1.581   | 1.5784  | 1.5758  | 1.5758  | 1.5705  |
| nC_5      | 1.7012  | 1.6982  | 1.6953  | 1.6953  | 1.6894  |
| C_6       | 5.2234  | 5.2149  | 5.2063  | 5.2063  | 5.1889  |
| C_7       | 4.1708  | 4.1687  | 4.1665  | 4.1665  | 4.1619  |
| C_8       | 2.9702  | 2.9697  | 2.9693  | 2.9693  | 2.9681  |
| C_9       | 2.5498  | 2.5503  | 2.5508  | 2.5508  | 2.5516  |
| C_{10}    | 2.4495  | 2.4508  | 2.452   | 2.452   | 2.4542  |
| C_{11}    | 2.3392  | 2.3411  | 2.3429  | 2.3429  | 2.3463  |
| C_{12+}   | 22.4083 | 22.5873 | 22.7659 | 22.7659 | 23.1216 |

### Table 3 General properties of the reservoir

| Parameter                          | Value  |
|------------------------------------|--------|
| Number of grids in X direction     | 24     |
| Number of grids in Y direction     | 17     |
| Number of grids in Z direction     | 6      |
| Dimensions (ft) X                  | 500    |
| Dimensions (ft) Y                  | 500    |
| Dimensions (ft) Z                  | 100    |
| Porosity (%)                       | 14.6   |
| Permeability (md)                  | 10.3   |
| Net to gross (NTG) (%)             | 0.74   |
| Reservoir datum depth (ft)         | 9980   |
| Reservoir reference pressure (psi) | 5650   |
| Reservoir temperature (°F)         | 220    |
Reservoir performance forecast

In this part of the study, the aim was to investigate the effect of compositional grading phenomenon on gas injection process into the reservoir to enhance oil recovery. For this purpose, the injection of various gases including CO₂, N₂, APG, N₂–CO₂ mixture and water-alternating-CO₂ injection into different reservoir layers was studied.

In order to have a proper comparison, different scenarios need to be evaluated under similar operational conditions in terms of layers in which production and injection wells are completed, and well location as well as injection and production rates. To this end, an injection well was created among the production wells and all the injection scenarios were run for 39 years (2015–2054). In all simulations, gas injection rate was set to 18 MMSCFD, bottom-hole injection pressure was set to 5500 psi, and oil production rate was set to 2000 STBD for each producing well. Furthermore, the following economic limitations were considered for shutting the production wells:

- Maximum GOR: 1800 SCF/STB
- Maximum water cut: 40%
- Minimum oil production rate: 150 STBD
Before running different injection scenarios, history matching process should be done in order to ensure the reliability and validity of the simulated model. In this process, the common approach to match the model is to change the parameters with the highest effects, including permeability, porosity, block height, and aquifer parameters (Fath and Pouranfard 2014; Fath and Dashtaki 2016). In this study, the history matching was performed on production rate and reservoir pressure data within a 14-year period (2000–2014). Figures 6 and 7 show the oil production rate of production wells and field pressure, respectively. The figures indicate a good match between the calculated results and historical data. Average reservoir pressure was 4400 psi in the late 2014.

Fig. 4 Variations in molar percentages of reservoir fluid components with depth

Fig. 5 Calculation of STOIP considering the composition of fluids in different layers of the reservoir

Moreover, natural depletion scenario was investigated at the datum depth with and without considering compositional grading in order to have a base for comparison. As shown in Fig. 8, higher oil recovery percentage was obtained when compositional grading was taken into consideration.

The effect of compositional grading on minimum miscibility pressure (MMP)

In a compositionally grading oil reservoir, due to variations in reservoir fluid properties with depth, one would observe the respective variations in MMP.

MMP refers to the minimum pressure at which the displacement process is performed miscibly. In other words,
**Fig. 6** History matching results of oil production rate of different wells

**Fig. 7** History matching results of field pressure
MMP defines the pressure at which displacement efficiency approaches 100%.

At lower parts of the reservoir, due to heavier reservoir fluid and increased reservoir pressure, MMP value is increased and miscibility development is carried out very slow. In many cases, the gas immiscibly displaces oil in this part of the reservoir; however, the existence of light components in reservoir fluid at upper parts of the oil column reduces the value of MMP, resulting in better miscibility and increased sweep efficiency.

Establishing miscibility conditions in the reservoir can improve the reservoir oil displacement through reducing interfacial tension (IFT) between gas and oil, capillary forces, and gas override.

In the present study, a one-dimensional slim-tube model was simulated to determine MMP of different injected gases with reservoir fluid in different reservoir layers. Table 4 reports MMP variations with reservoir depth for injection of different gases into the reservoir.

The effect of compositional grading on different injection gases

The performance of the different injection gases with and without compositional grading are reported in “Appendix”. As can be seen in Table 6, when the reservoir oil composition was supposed to be constant through the entire hydrocarbon column, 2.303%, 2.074%, 3.489%, 3.198%, and 1.66% decrease was noticed in the ultimate oil recovery factor of CO₂, N₂, APG, 50% N₂–50% CO₂, and water-alternating-CO₂ injection scenarios, respectively. This confirms that the ignorance of compositional grading phenomenon results in a decrease in the estimated ultimate oil recovery.

CO₂ injection

CO₂ is one of the most important greenhouse gases whose emission into the atmosphere contributing to environmental pollution and global warming. Nowadays, one of the best and most effective approaches to inhibit CO₂ emission into the environment is to have it gathered and stored into
hydrocarbon reservoirs in order to maintain reservoir pressure and hence increasing oil recovery.

Major sources of CO₂ emission are power plants, oil and gas refineries, and other industries which end up producing this gas as a by-product of their processes. Among these sources, the power plants which use fossil fuels to generate electrical power are deemed to be the most significant CO₂ emitters.

Being close to a power plant, the reservoir was in a suitable condition for collecting the produced CO₂ from the power plant and having the collected gas injected into the reservoir not only to prevent the CO₂ from being emitted, but also to enhance oil recovery factor.

As is specified in Table 4, all MMP values calculated in the course of CO₂ injection were lower than reservoir pressure (i.e. 4400 psi when injecting different gases into the reservoir); therefore, CO₂ injection will be miscible at all layers of this reservoir. In the miscible gas injection process, the gravity segregation of the gas is not possible; hence, the gas override is minimized and sweep efficiency is improved. As a result, oil recovery factor is increased.

Figure 9 demonstrates oil recovery factor for CO₂ injection into the reservoir under different scenarios. As it can be seen in this figure, almost similar oil recovery factor is obtained for all CO₂ injection scenarios, and little differences are noticed among different scenarios.

Increased oil recovery factor in upper parts of reservoir layers, compared to the lower layers, is because of the later achievement of injection bottom-hole pressure and the possibility of allowing more gas to be injected into these layers. According to Table 6 in "Appendix", the difference between cumulative injected gas after 39 years of CO₂ injection under scenarios 21 and 26 was 6.5 MMMSCF which gives rise to an approximately 2 months extended production plateau under scenario 21 (Fig. 10). This increase in the production plateau resulted in the corresponding oil recovery factor to improve by 1.004% under scenario 21. Due to more CO₂ injection, the reservoir pressure drop in upper layers of reservoir was lower, contributing to the maintained reservoir pressure.

N₂ injection

N₂ is one of the most abundant, the least expensive and the most available non-hydrocarbon gases to be injected into a reservoir. N₂ is an inert gas virtually with no reaction to oil and may introduce no impurity into the reservoir oil (Christensen et al. 1998). The required N₂ for enhanced oil recovery (EOR) can be either taken from air, flue gas or gas reservoirs of high N₂ content.

MMP calculation results for N₂ injection indicates that this gas is an immiscible gas in all reservoir layers (Table 4). In general, MMP of N₂ with the reservoir oil is usually too high, so that, it is not possible to achieve such a high pressure and establish miscibility conditions within the reservoir. Therefore, N₂ injection into oil reservoirs often follows an immiscible process. In fact, the immiscible process causes the gas override and faster movement of the gas than the reservoir oil which leads to a large volume of oil reservoir, especially in lower parts of the reservoir is not swept, and ultimately reduced oil recovery.

Figure 11 shows oil recovery factor for N₂ injection into different reservoir layers. As it is shown, the difference between the plots of oil recovery in N₂ injection is greater when compared to CO₂ injection. Furthermore, the completion of the injection well in layer 1 exhibits different
performance and higher recovery factor compared to other N\textsubscript{2} injection scenarios due to the injection of larger volumes of gas into this layer. Injecting larger volumes of N\textsubscript{2} in the first layer extends the production plateau for 9 months as compared to its injection into the lowest layer (Fig. 12).

The difference between corresponding ultimate oil recovery factors to N\textsubscript{2} injection when the injection well is completed in the highest and lowest reservoir layers was found to be 2.022%, which is a higher difference than that in CO\textsubscript{2} injection scenarios.

Injecting N\textsubscript{2} into upper layers of reservoir contributes to better reservoir pressure maintenance, so that the difference between scenarios 27 and 32 is 125 psi (“Appendix”). The simulation results of N\textsubscript{2} injection indicate that N\textsubscript{2} injection is associated with better performance in terms of maintaining reservoir pressure in comparison with the miscible injection of CO\textsubscript{2}, although it has lower oil recovery.

Associated petroleum gas (APG) injection

APG is obtained during the produced crude oil processing at surface. (It can be seen as either oil-dissolved or a separated associate phase with oil.) APG is mainly composed of light hydrocarbons compounds, particularly methane. In addition
to its hydrocarbon components, it sometimes contains such impurities as N₂, CO₂, and H₂S. The most significant advantage of APG injection into oil reservoirs is due to its availability at the site of injection and its reduced transfer costs. In addition to crude oil processing, outflows from gas condensate and wet gas wells can also be processed to obtain similar compounds of APG. The composition of the injected APG into the reservoir is reported in Table 5.

As can be seen in Table 4, the MMPs corresponding to APG injection in all layers are larger than reservoir pressure, indicating immiscible nature of all APG injection scenarios. The high MMP of APG is caused by the high molar percentage of methane in its composition.

Even though miscibility conditions can be developed by injecting excessive APG and evaporating light oil components before being introduced into the injected gas composition (vaporizing gas drive), it is a time-intensive process and a major fraction of the injected APG into the reservoir would form a separated phase from the reservoir oil; therefore, the process can be regarded as immiscible.

According to Fig. 13, the difference between corresponding ultimate oil recovery factors of the injection wells completed in the highest and lowest reservoir layers was found to be 1.992%, resulting in more oil production under scenario 33 in comparison with scenario 38.

Due to immiscible nature of APG injection process and the happening of gas override, microscopic efficiency decreases in the course of the injection process and hence increasing residual oil saturation, particularly in the lower parts of the reservoir and finally reducing oil recovery factor.

According to Fig. 14, production plateau is relatively increased in APG injection, as compared to that in the case of N₂ injection. It is, however, still much lower compared

---

**Table 5** Composition of the injected APG into the reservoir

| Component | Mole% |
|-----------|-------|
| N₂        | 0.19  |
| CO₂       | 1.4   |
| C₁        | 66.18 |
| C₂        | 11.15 |
| C₃        | 8.61  |
| iC₄       | 1.76  |
| nC₄       | 4.52  |
| iC₅       | 1.54  |
| nC₅       | 1.65  |
| C₆        | 1.61  |
| C₇        | 0.98  |
| C₈        | 0.39  |
| C₉        | 0.02  |
| C₁₀       | 0     |
| C₁₁       | 0     |
| C₁₂+      | 0     |

---

**Fig. 12** Reservoir oil production rate for N₂ injection into different reservoir layers

---

**Fig. 13** Ultimate oil recovery factors for N₂ injection into different reservoir layers

---

**Fig. 14** Production plateau for N₂ and APG injection into different reservoir layers
Moreover, APG injection reveals a weaker performance in comparison with N₂ injection in terms of reservoir pressure maintenance. N₂ diluted by CO₂ injection

As previously mentioned, the MMP of N₂ gas is very high, and in most cases, it is immiscibly injected into reservoir. Because of the low density of N₂ relative to the reservoir oil and the immiscible conditions of N₂ injection, the gas override and channelling phenomena would occur, leading to the early production of N₂ from the production wells (breakthrough). Consequently, a large volume of oil within the lower parts of the reservoir would not be swept, and the sweep efficiency would be reduced. To sum up, oil recovery in N₂ injection scenario is lower than the other scenarios.

Fig. 13 Oil recovery factor for APG injection into different reservoir layers

Fig. 14 Reservoir oil production rate for APG injection into different reservoir layers
In order to enhance oil recovery and reduce MMP of N₂ injection, the gas was diluted by CO₂ and N₂–CO₂ mixture (50% N₂–50% CO₂) was provided to be injected into different reservoir layers. Adding CO₂ to pure N₂ reduced its MMP and hence provided better conditions in terms of oil recovery (Shahrabadi et al. 2012; Belhaj et al. 2013).

According to Table 4, the addition of CO₂ to N₂ significantly reduces MMP in comparison with the scenarios in which pure N₂ was injected into different reservoir layers, so that the difference between MMP values of pure N₂ and 50% N₂–50% CO₂ mixture was found to be 835 psi when the injection well was completed in layer 1. Although MMP was reduced by adding CO₂ to pure N₂, the calculated MMP

---

**Fig. 15** Oil recovery factor for 50% N₂–50% CO₂ mixture into different reservoir layers

**Fig. 16** Reservoir oil production rate for 50% N₂–50% CO₂ mixture into different reservoir layers
values for 50% $N_2$–50% CO$_2$ mixture and oil in different reservoir layers are still high and miscibility conditions may not be established within the reservoir.

According to Fig. 15, it can be observed that, the corresponding recovery factors for 50% $N_2$–50% CO$_2$ mixture injection scenarios were higher than those for pure $N_2$ and APG injection, but still lower than those for CO$_2$ miscible injection.

The presence of CO$_2$ in 50% $N_2$–50% CO$_2$ mixture allows more gas to be injected into the reservoir compared to the pure $N_2$ injection (Table 6 in “Appendix”), resulting in greater oil recovery.

Compared to similar case with pure $N_2$ injection, 50% $N_2$–50% CO$_2$ mixture injection into layer 1 was associated
with 10 months extended production plateau, leading to increased cumulative produced oil by 2.4 MMSTB (Fig. 16); however, pure N₂ injection exhibited better performance in terms of reservoir pressure maintenance.

**Water-alternating-CO₂ injection**

Density differences between the injected fluid and reservoir oil gives rise to the gravity segregation of these fluids in the reservoir and reduces sweep efficiency. Gravity segregation consequently leads to the migration of the injected gas into upper parts of the reservoir and develops gas override phenomenon. In water injection, it forces the injected water to move into the lower parts of the reservoir and results in the occurrence of water underride phenomenon. In override and underride phenomena, the oil in the lower parts and the upper parts of the reservoir would not be swept.

Both override and underride phenomena are associated with the reduced vertical sweep efficiency and ultimately reduce the total sweep efficiency. Therefore, in order to enhance total sweep efficiency and eventually enhance oil recovery in different EOR processes, the mobility ratio between injected fluid and reservoir oil should always be controlled.

For instance, in water injection process, one of the methods to control the mobility between the injected water and the reservoir oil as well as piston-like movement of the injected water is the use of the polymer (Sorbie 1991; Hodaie and Bagci 1993). In gas injection process, one of the most effective techniques to enhance sweep efficiency and inhibit gas override is water alternating gas (WAG) injection (Caudle and Dyes 1958).

The WAG can enhance sweep efficiency of the injected gas and eventually enhance oil recovery through extending the contact area of the injected gas with the reservoir, controlling the mobility ratio between the injected gas and the reservoir oil, providing effective access to no swept areas for the gas and establishing a stable movement front (Sanchez 1999). In this section of the present research, water-alternating-CO₂ injection was employed to improve macroscopic sweep efficiency and recovery factor in the course of CO₂ miscible injection.

In most of WAG injection processes, the optimum amount of water-to-gas injection ratio is set to one. In this scenario, water-to-CO₂ injection ratio was set to 1 for injecting into all reservoir layers, and water and CO₂ were alternatively injected into different depths. Figure 17 shows the recovery factor under water-alternating-CO₂ injection process into different reservoir layers. As can be seen from this figure, water-alternating-CO₂ injection scenarios provide higher recovery factors compared to the other scenarios. This enhanced recovery can be explained by improved microscopic and macroscopic sweep efficiencies caused by injecting CO₂ and water, respectively. This resulted in enhancing total sweep efficiency and displacing large volumes of reservoir oil.

According to Fig. 17, there are still differences between recovery factors in different injection scenarios, according to which the difference between the recovery factors when water-alternating-CO₂ was injected into the first and the last reservoir layers was found to be 3.332%, confirming the significance of compositional grading in designing the process of water-alternating-CO₂ injection into the reservoir. Furthermore, higher recovery factor due to
water-alternating-CO₂ injection into upper layers of reservoir results in reduced residual oil saturation within these layers (Fig. 18).

Further water-alternating-CO₂ injection into upper layers of reservoir may also extend production plateau, so that the production plateau of water-alternating-CO₂ injection into the first layer was 21 months longer than the case where it was injected into the lowest reservoir layer (Fig. 19).

With comparing recovery factors under two scenarios, namely water-alternating-CO₂ injection process and CO₂ miscible injection, when the injection well is completed within the first layer, a difference of 4.136% can be noticed which can be attributed to the poor performance of CO₂ injection in terms of enhancing macroscopic sweep efficiency.

Conclusions

The main conclusions of the present study are as follows:

1. Variations in the reservoir fluid properties under the study such as the molar percentage of its components, reservoir, and saturation pressures with depth not only confirms the existence of compositional grading phenomenon but also indicates that the ignorance of this phenomenon leads to an error in the reservoir and production engineering calculations.

2. Compositional grading plays an important role in STOOIP estimation for reservoirs with variations in fluid composition caused by depth. Thus the failure to account for compositional grading may result in underestimated or overestimated STOOIP value. In such reservoirs, selecting the middle reservoir depth as the fluid sampling depth, one can calculate the STOOIP with a greater accuracy.

3. Failure to account for compositional grading in gas injection processes into reservoir gives rise to differences in oil recovery, underestimating the obtained oil recovery.

4. Due to their high MMP values, N₂ and APG were immiscibly injected into all layers of the reservoir. Although in upper layers of reservoir obtained oil recovery was slightly greater due to the possibility of injecting larger volumes of these gases, the gas override and channeling phenomena led to faster introduction of N₂ and APG gases into the production wells, leading to a significant reduction in oil displacement efficiency. Injecting N₂-CO₂ mixture reduced MMP and increased the volume of injected gas into all reservoir layers, subsequently leading to enhanced oil recovery, compared to pure N₂ injection scenario.

5. CO₂ injection was miscible in all reservoir layers; however, due to the reduced MMP, the miscibility was better and developed faster in upper layers of reservoir. It can be thus concluded that, by completing the injection wells in the upper parts of the reservoir, higher oil recovery is achieved. Compared to N₂, APG, and CO₂–N₂ mixture injections, the miscible CO₂ injection results in enhanced reservoir oil displacement through reducing oil viscosity, IFT, and gravity segregation of injected gas.

6. In order to extend the contact area of CO₂, control its mobility, and enhance macroscopic sweep efficiency, water-alternating-FCO₂ injection was used for all reservoir layers. The results indicated that, water-alternating-CO₂ injection was associated with increased oil recovery, extended production plateau, decreased residual oil saturation, and improved reservoir pressure maintenance in all reservoir layers. This can be explained by simultaneous improvements in macroscopic and microscopic sweep efficiencies which together enhance the total sweep efficiency and thus allow for the production of larger volumes of reservoir oil. Compared to the other injection scenarios, water-alternating-CO₂ injection exhibited higher recovery factor in all reservoir layers; however, more satisfying results were achieved in higher reservoir layers because of the compositional grading phenomenon.

Open Access This article is distributed under the terms of the Creative Commons Attribution 4.0 International License (http://creativecommons.org/licenses/by/4.0/), which permits unrestricted use, distribution, and reproduction in any medium, provided you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons license, and indicate if changes were made.

Appendix

See Table 6.
| Scenario | Oil composition | Injected fluid | Completion location of injection well | Completion location of production wells | Average reservoir pressure, Psi | Ultimate oil recovery factor, % | Cumulative gas injected, MMSCF |
|----------|----------------|---------------|--------------------------------------|---------------------------------------|-----------------------------|-------------------------------|-------------------------------|
| 1        | Natural depletion—without compositional grading—using reference composition | – | – | Layers 1–6 | 1612 | 15.911 | – |
| 2        | Natural depletion—with compositional grading | – | – | Layers 1–6 | 1697 | 16.811 | – |
| 3        | Without compositional grading—using reference composition | – | – | – | – | – | – |
| 4        | With compositional grading | – | – | – | – | – | – |
| 5        | Without compositional grading—using first-layer composition | – | – | – | – | – | – |
| 6        | Without compositional grading—using second-layer composition | – | – | – | – | – | – |
| 7        | Without compositional grading—using third-layer composition | – | – | – | – | – | – |
| 8        | Without compositional grading—using fourth-layer composition | – | – | – | – | – | – |
| 9        | Without compositional grading—using fifth-layer composition | – | – | – | – | – | – |
| 10       | Without compositional grading—using sixth-layer composition | – | – | – | – | – | – |
| 11       | Without compositional grading—using reference composition | CO₂ | Layer 4 | Layers 1–6 | 1910 | 27.341 | 258.8 |
| 12       | With compositional grading | CO₂ | Layer 4 | Layers 1–6 | 2016 | 29.644 | 260.4 |
| 13       | Without compositional grading—using reference composition | N₂ | Layer 4 | Layers 1–6 | 2256 | 17.865 | 247.6 |
| 14       | With compositional grading | N₂ | Layer 4 | Layers 1–6 | 2625 | 19.939 | 250.8 |
Table 6 (continued)

| Scenario | Oil composition | Injected fluid | Completion location of injection well | Completion location of production wells | Average reservoir pressure, Psi | Ultimate oil recovery factor, % | Cumulative gas injected, MMMSCF |
|----------|-----------------|----------------|--------------------------------------|----------------------------------------|--------------------------------|--------------------------------|----------------------------------|
| 15       | Without compositional grading—using reference composition | APG | Layer 4 | Layers 1–6 | 2018 | 18.125 | 251.9 |
| 16       | With compositional grading | APG | Layer 4 | Layers 1–6 | 2383 | 21.614 | 253.1 |
| 17       | Without compositional grading—using reference composition | 50% N₂–50% CO₂ | Layer 4 | Layers 1–6 | 2211 | 20.785 | 255.8 |
| 18       | With compositional grading | 50% N₂–50% CO₂ | Layer 4 | Layers 1–6 | 2302 | 23.983 | 257.3 |
| 19       | Without compositional grading—using reference composition | Water-alternating-CO₂ | Layer 4 | Layers 1–6 | 2887 | 30.763 | 133.1 |
| 20       | With compositional grading | Water-alternating-CO₂ | Layer 4 | Layers 1–6 | 3131 | 32.423 | 135.1 |
| 21       | With compositional grading | CO₂ | Layer 1 | Layers 1–6 | 2035 | 30.241 | 264.6 |
| 22       | With compositional grading | CO₂ | Layer 2 | Layers 1–6 | 2029 | 30.045 | 263.2 |
| 23       | With compositional grading | CO₂ | Layer 3 | Layers 1–6 | 2021 | 29.845 | 262.5 |
| 24       | With compositional grading | CO₂ | Layer 4 | Layers 1–6 | 2016 | 29.644 | 260.4 |
| 25       | With compositional grading | CO₂ | Layer 5 | Layers 1–6 | 2009 | 29.441 | 259.7 |
| 26       | With compositional grading | CO₂ | Layer 6 | Layers 1–6 | 2002 | 29.237 | 258.1 |
| 27       | With compositional grading | N₂ | Layer 1 | Layers 1–6 | 2685 | 21.432 | 255.4 |
| 28       | With compositional grading | N₂ | Layer 2 | Layers 1–6 | 2644 | 20.588 | 254.7 |
| 29       | With compositional grading | N₂ | Layer 3 | Layers 1–6 | 2637 | 20.300 | 252.3 |
| 30       | With compositional grading | N₂ | Layer 4 | Layers 1–6 | 2625 | 19.939 | 250.8 |
| 31       | With compositional grading | N₂ | Layer 5 | Layers 1–6 | 2612 | 19.675 | 248.6 |
| 32       | With compositional grading | N₂ | Layer 6 | Layers 1–6 | 2560 | 19.410 | 247.9 |
| 33       | With compositional grading | APG | Layer 1 | Layers 1–6 | 2421 | 22.932 | 257.2 |
| 34       | With compositional grading | APG | Layer 2 | Layers 1–6 | 2412 | 22.498 | 256.7 |
| 35       | With compositional grading | APG | Layer 3 | Layers 1–6 | 2391 | 22.058 | 255.6 |
| 36       | With compositional grading | APG | Layer 4 | Layers 1–6 | 2383 | 21.614 | 253.1 |
| 37       | With compositional grading | APG | Layer 5 | Layers 1–6 | 2370 | 21.390 | 252.3 |
| 38       | With compositional grading | APG | Layer 6 | Layers 1–6 | 2361 | 20.940 | 251.5 |
References

Barrufet MA, Jaramillo JM (2004) Effects in the determination of oil reserves due to gravitational compositional gradients in near-critical reservoirs. J Can Pet 43:31–37

Bedrikovetsky P (1993) Mathematical theory of oil and gas recovery: with applications to ex-USSR oil and gas fields. Springer, New York

Belhaj H, Abukhalifeh H, Javid K (2013) Miscible oil recovery utilizing N2 and/or HC gases in CO2 injection. J Pet Sci Eng 111:144–152. https://doi.org/10.1016/j.petle.2013.08.030

Caudle BH, Dyes AB (1958) Improving miscible displacement by gas-water injection. Society of Petroleum Engineers, Texas

Christensen JR, Stenby EH, Skauge A (1998) Review of WAG field experience. In: SPE international petroleum conference and exhibition of Mexico, Villa hermosa, Mexico, 3–5 March, Society of Petroleum Engineers. https://doi.org/10.2118/39883-MS

Dougherty EL Jr, Drickamer HG (1955) Thermal diffusion and molecular motion in liquids. J Phys Chem 59:443–449. https://doi.org/10.1021/j150527a016

Fath AH, Dashtaki NB (2016) Evaluation of effective parameters on CO2 injection process in a gas condensate reservoir: a case study. Energ Source Part A Recovery Util Environ Eff 38:3680–3686. https://doi.org/10.1080/15567036.2016.1177623

Fath AH, Pouranfard AR (2014) Evaluation of miscible and immiscible CO2 injection in one of the Iranian oil fields. Egypt J Pet 23:255–270. https://doi.org/10.1016/j.ejpe.2014.08.002

Fath AH, Pouranfard AR, Parandvar R, Pourhadi S (2016) An investigation of different gas injection scenarios as enhanced condensate recovery method in a naturally fractured gas-condensate reservoir. Petrol Sci Technol 34:295–301. https://doi.org/10.1080/10914662015.1098663

Firoozabadi A (1999) Thermodynamics of hydrocarbon reservoirs. McGraw-Hill, New York

Ghorayeb K, Firoozabadi A (2001) Features of convection and diffusion in porous media for binary systems. J Can Pet Technol 40:21–28. https://doi.org/10.2118/01-02-01

Hodaie H, Bagci AS (1993) Polymer-augmented waterflooding in a reservoir with a bottomwater zone. In: Middle east oil show, 3–6 April, Bahrain, Society of Petroleum Engineers. https://doi.org/10.2118/25633-MS

Høier L (1997) Miscibility variations in compositionally grading petroleum reservoirs, PhD thesis, Norwegian University of Science and Technology, Trondheim, Norway

Høier L, Whitson CH (2000) Compositional grading—theory and practice. In: SPE annual technical conference and exhibition, Dallas, Texas, 1–4 October, Society of Petroleum Engineers. https://doi. org/10.2118/25633-MS

Hussein H, Mahgoub IS (2005) Methodology of investigating the compositional gradient within the hydrocarbon column. In: SPE annual technical conference and exhibition, Dallas, Texas, 9–12 October, Society of Petroleum Engineers. https://doi.org/10.2118/63085-MS

Kord S, Zobeidi K (2007) Effect of compositional grading on reservoir fluid characterization in a giant Iranian oil reservoir. In: Canadian international petroleum conference, Calgary, Alberta, 12–14 June, Petroleum Society of Canada. https://doi.org/10.2118/2007-126

Lohrenz J, Bray BG, Clark CR (1964) Calculating viscosities of reservoir fluids from their compositions. J Pet Technol 16:1171–1176. https://doi.org/10.2118/915-PA

Table 6 (continued)

| Scenario | Oil composition | Injected fluid | Completion location of injection well | Completion location of production wells | Average reservoir pressure, Psi | Ultimate oil recovery factor, % | Cumulative gas injected, MMMMSCF |
|----------|-----------------|----------------|--------------------------------------|----------------------------------------|-------------------------------|-------------------------------|----------------------------------|
| 39       | With compositional grading | 50% N2–50% CO2 | Layer 1                               | Layers 1–6                             | 2347                          | 25.918                        | 260.8                            |
| 40       | With compositional grading | 50% N2–50% CO2 | Layer 2                               | Layers 1–6                             | 2328                          | 25.279                        | 260.1                            |
| 41       | With compositional grading | 50% N2–50% CO2 | Layer 3                               | Layers 1–6                             | 2313                          | 24.890                        | 259.2                            |
| 42       | With compositional grading | 50% N2–50% CO2 | Layer 4                               | Layers 1–6                             | 2302                          | 23.983                        | 257.3                            |
| 43       | With compositional grading | 50% N2–50% CO2 | Layer 5                               | Layers 1–6                             | 2296                          | 23.332                        | 256.2                            |
| 44       | With compositional grading | 50% N2–50% CO2 | Layer 6                               | Layers 1–6                             | 2385                          | 22.641                        | 255.7                            |
| 45       | With compositional grading | Water-alternating-CO2 | Layer 1                             | Layers 1–6                             | 3185                          | 34.377                        | 138.4                            |
| 46       | With compositional grading | Water-alternating-CO2 | Layer 2                             | Layers 1–6                             | 3174                          | 33.738                        | 137.6                            |
| 47       | With compositional grading | Water-alternating-CO2 | Layer 3                             | Layers 1–6                             | 3152                          | 33.089                        | 136.3                            |
| 48       | With compositional grading | Water-alternating-CO2 | Layer 4                             | Layers 1–6                             | 3131                          | 32.423                        | 135.1                            |
| 49       | With compositional grading | Water-alternating-CO2 | Layer 5                             | Layers 1–6                             | 3095                          | 31.742                        | 133.1                            |
| 50       | With compositional grading | Water-alternating-CO2 | Layer 6                             | Layers 1–6                             | 3079                          | 31.045                        | 131.5                            |
Luo, S., & Barrufet, M. A. (2004). Compositional gradient: its role in near-critical reservoir development. *J Pet Sci Eng*, 45(3-4), 193–201. doi:10.1016/j.petrol.2004.07.005

Nikpoor, M. H., Kharrat, R., & Chen, Z. (2011). Modeling of compositional grading and plus fraction properties changes with depth in petroleum reservoirs. *J Pet Sci Technol*, 29(7), 914–923. doi:10.1080/10916460903485884

Sadeghi, M., Movahedinia, A., & Fath, A. H. (2016). Investigation of immiscible CO2 and C1 injection and comparison with water injection for enhanced oil recovery in naturally fractured reservoirs. *Petrol Sci Technol*, 34(5-6), 232–239. doi:10.1080/10916466.2015.1122629

Sage, B. H., & Lacey, W. N. (1939). Gravitational concentration gradients in static columns of hydrocarbon fluids. *Trans AIME*, 132, 120–131.

Sanchez, N. L. (1999). Management of water alternating gas (WAG) injection projects. In: Latin American and Caribbean petroleum engineering conference, Caracas, Venezuela, 21–23 April, Society of Petroleum Engineers. doi:10.2118/53714-MS

Shahrabadi, A., Dabir, B., Sadi, M., & Fasih, M. (2012). Effect of CO2 Concentration in injecting gas on minimum miscibility pressure: compositional model and experimental study. *Iran J Chem Chem Eng*, 31(1), 113–118.

Soave, G. (1972). Equilibrium constants from a modified Redlich–Kwong equation of state. *Chem Eng Sci*, 27(5-6), 1197–1203. doi:10.1016/0009-2509(72)80096-4

Sorbie, K. S. (1991). Polymer improved oil recovery. Blackie, Glasgow.

Syahrial, E. (1999). Impact of composition variation with depth on volatile oil. In: SPE Asia Pacific oil and gas conference and exhibition, Jakarta, Indonesia, 20–22 April, Society of Petroleum Engineers. doi:10.2118/54382-MS

Temeng, K. O., Al-Sadeg, M. J., & Al-Mulhim, W. A. (1998). Compositional grading in the Ghawar Khuff reservoirs. In: SPE annual technical conference and exhibition, New Orleans, Louisiana, 27–30 September, Society of Petroleum Engineers. doi:10.2118/49270-MS

Wang, W., Ding, S., Xinfei, H., Lu, Y., & Jin, X. (2015). Study on impact of compositional gradient on volatile oil reservoir development. *Adv Petrol Explor Dev*, 9(2), 27–32. doi:10.3968/5772

Wheaton, R. J. (1991). Treatment of variations of composition with depth in gas-condensate reservoirs (includes associated papers 23549 and 24109). In: SPE reservoir engineering, Society of Petroleum Engineers. doi:10.2118/18267-PA

Whitson, C. H., & Belery, P. (1994). Compositional gradients in petroleum reservoirs. In: University of Tulsa centennial petroleum engineering symposium, Tulsa, Oklahoma, 29–31 August, Society of Petroleum Engineers. doi:10.2118/28000-MS

**Publisher’s Note** Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.