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REGULAR ARTICLE OPEN ACCESS

Co-optimization of oil recovery and CO_2 storage for cyclic CO_2 flooding in ultralow permeability reservoirs

Lili Sun[1,2], Xining Hao[3], Hongen Dou[4,*], Caspar Daniel Adenutsi[2], Zhiping Li[2], and Yunjun Zhang[4]

[1] CNPC Technology and Economics Research Institute, Beijing 100724, China
[2] School of Energy Resources, China University of Geosciences, Beijing 100083, China
[3] Research Institute of China National Offshore Oil Corporation, Beijing 100027, China
[4] Research Institute of Petroleum Exploration and Development, Beijing 100083, China

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Abstract. Cyclic CO_2 flooding is an efficient method to enhance oil recovery in ultralow permeability reservoirs. As the demand for low carbon economy development, co-optimization of CO_2 storage and utilization should be considered. In this research, initially a comprehensive optimization method was proposed, which co-optimize oil recovery and CO_2 storage by different weighting factors. Then, a series of core flooding experiments were performed using the core samples collected from Changqing oilfield, which is a ultralow permeability reservoir with heterogeneity and micro-cracks, CO_2 injection parameters of slug size and Injection-Soaking Time Ratio (ISR) were optimized. The results revealed that the optimal injection parameters changed for different optimization objectives. In the case where equal important to oil recovery and CO_2 storage were considered, the optimum CO_2 injection parameters in the ultralow permeability reservoirs were 0.03PV for slug size and 1:1 for ISR. Comparing the method of oil recovery optimization ($\omega_1 = 1$) to co-optimization of oil recovery and CO_2 storage ($\omega_1 = \omega_2 = 0.5$), oil recovery was reduced by 8.93%, CO_2 storage was significantly increased by 25.85%. The results provide an insight into parameter optimization of CO_2 enhanced oil recovery design.

1 Introduction

With advancement in the world petroleum industry, the development of low permeability oil fields has attracted more attention. However, conventional recovery methods are not effective in ultralow permeability reservoirs. Due to the nature of ultralow permeability reservoirs (poor physical properties, heavy heterogeneity and natural micro-fracture), water flooding recovery remains low even though long horizontal wells have been drilled and massively fractured (Christensen *et al.*, 2001; Song and Yang, 2017). As an enhanced oil recovery technology, CO_2-EOR (e.g. continuous CO_2 injection, carbonated water injection, water-alternating CO_2 injection, and cyclic CO_2 injection) have shown favorable recovery potential while offsetting the greenhouse gas emissions by CO_2 storage underground (Ma *et al.*, 2015). However, each CO_2 injection method has its merits and demerits (Murray *et al.*, 2001; Xu and Saeedi, 2017). Compared with other CO_2 injection methods, cyclic CO_2 injection is benefited from longer soaking period which enlarges the contact area between oil and CO_2, reduces oil viscosity and interfacial tension, vaporized lighter components of oil, additional it could alleviate CO_2 fingering, gravity override and channeling effectively. It also has good field application in low permeability oil reservoir (Torabi and Asghari, 2010; Abedini and Torabi, 2014). Although the mechanisms of CO_2 flow and interaction with oil, water and rock are well understood by the scientific community, application and the distinction of these mechanisms in ultralow permeability reservoirs could be difficult (Yu *et al.*, 2015). In addition, the optimal operational parameters of cyclic CO_2 injection have not been recommended. It is therefore of practical significance to evaluate the performance of cyclic CO_2 injection process and optimize the injection parameters in ultralow permeability reservoirs.

In the process of cyclic CO_2 injection, slug size as well as Injection and Soaking time Ratio (ISR) are two major parameters which affect the results (Wolcott *et al.*, 1995). Unfavorable CO_2 injection parameters do not only lower the CO_2 microscopic displacement efficiency, but also aggravate CO_2 viscous fingering and breakthrough due to the large difference in density and viscosity between CO_2 and oil. The traditional approach for parameters optimization is pursuing maximum oil recovery by minimum CO_2 injection (Lv *et al.*, 2015; Liu *et al.*, 2016). However, CO_2 emission reduction has increasingly gained attention while CO_2 storage efficiency is very important in the current

* Corresponding author: 149658753@qq.com

situation of climate change. It is therefore necessary to co-optimize both of oil production and CO_2 storage.

In order to investigate the viability of cyclic CO_2 injection processes in ultralow permeability reservoirs and to optimize the injection parameters based on the combination of oil recovery and CO_2 storage, a new objective function was proposed which includes two parts of oil recovery factor and CO_2 storage factor, every part has distinct weighting factors (ω_1, ω_2), and the weighting factors are changed for different optimization objectives. In this paper, the cyclic CO_2 injection parameters were optimized with equal weighting factors. The result provides guidance for field design and operation of cyclic CO_2 flooding in ultralow permeability reservoirs.

2 Methodology

Some researchers have studied optimization of CO_2 storage and oil recovery and the objective functions for parameter optimization were provided (Kovscek and Cakici, 2005; Jahangiri and Zhang, 2010; Kamali and Cinar, 2014). These functions, contain oil recovery factor and CO_2 storage factor, however each function has its method of computing CO_2 storage factor.

Initially, CO_2 storage factor was considered as the ratio of the volume of CO_2 stored to the total pore volume in a reservoir (Kovscek and Cakici, 2005). This ignored the geological limitations and this method assumed that the volume of CO_2 is constant without changing phase with changes in pressure and temperature.

In order to solve this problem, another storage factor was introduced as the ratio of CO_2 stored in reservoir to the total CO_2 storage capacity of the reservoir (Jahangiri and Zhang, 2010). However, the total capacity of CO_2 in reservoir is an uncertain parameter and CO_2 storage capacity in geological formations includes four levels: theoretical, effective, practical and matched storage capacities (Bachu and Shaw, 2003; Shen *et al.*, 2009; DOE, 2010). The calculated results will be different for different level of storage capacities.

To fill this gap, a modified storage factor was proposed which is the ratio of CO_2 stored to the CO_2 injected in reservoir (Kamali and Cinar, 2014). The modified storage factor in this function only represents the injected CO_2 utilization factor rather than reservoir storage. In addition, CO_2 loss was not taken into account from the injector/producer system during EOR project.

In order to estimate the fraction of the CO_2 stored in reservoir accurately, a new CO_2 storage factor is proposed considering the operation loss of CO_2. The new storage factor is defined as the ratio of the cumulative injected CO_2 minus cumulative produced and loss of CO_2 to theoretical CO_2 storage capacity of the reservoir. The modified objective function is as follows:

$$f = w_1 \frac{N_{\mathrm{P}}}{\mathrm{OIP}} + w_2 \frac{M^{\mathrm{I}}_{\mathrm{CO_2}} - (M^{\mathrm{P}}_{\mathrm{CO_2}} + M^{\mathrm{L}}_{\mathrm{CO_2}})}{M^{\mathrm{T}}_{\mathrm{CO_2}}} \quad (1)$$

$$\begin{aligned} M^{\mathrm{T}}_{\mathrm{CO_2}} &= M_{\mathrm{CO_2 str}_i} + M_{CO_2 so_i} + M_{\mathrm{CO_2 sw}_i} \\ &= \rho_{\mathrm{CO_2}} \times [E_{\mathrm{R}} Ah\phi(1 - S_{\mathrm{w}i}) + C_{\mathrm{ws}} Ah\phi S_{\mathrm{w}i} \\ &+ C_{\mathrm{os}}\ (1 - E_{\mathrm{R}})Ah\phi(1 - S_{\mathrm{w}i})], \end{aligned} \quad (2)$$

where, N_{P} is the net oil production, m^3; and OIP is oil in place at the start of CO_2 injection, m^3; $M^{\mathrm{P}}_{\mathrm{CO_2}}$ is the cumulative produced CO_2, t; $M^{\mathrm{I}}_{\mathrm{CO_2}}$ is the cumulative injected CO_2, t; $M^{\mathrm{L}}_{\mathrm{CO_2}}$ is the cumulative loss CO_2, t; $M^{\mathrm{T}}_{\mathrm{CO_2}}$ is the theoretical CO_2 storage capacity in reservoir which is calculated by Shen Pingping's method, t; the formula as shown in equation (2) (Shen *et al.*, 2009; Sun *et al.*, 2017); ω_1 and ω_2 are the weighting factors for oil recovery and CO_2 storage reflecting the extent of subjective intentions; $\omega_1 + \omega_2 = 1$. Selecting the appropriate weighting factor is very important and it is related to the revenue and policy of the producing country. If the goal is maximum oil recovery factor, then $\omega_1 = 1$. However, if the goal is maximum CO_2 storage factor, then $\omega_2 = 1$. In this paper, an equal weighting factor ($\omega_1 = \omega_2 = 0.5$) is assigned, indicating the equal importance of oil production and CO_2 storage.

There is no exact data on CO_2 loss in the Industry Data Set. CO_2 loss mainly includes surface loss and subsurface loss. Surface CO_2 loss is that part of CO_2 in pipe that is released to the atmosphere during the process of power outages or equipment repair. Subsurface CO_2 loss is that part of CO_2 that laterally migrates outside of the production wells or which is not captured by the recycling loop but remains in the subsurface. In this paper, according to industry experience, 5% of cumulative injected CO_2 is assumed to be the cumulative CO_2 loss (DOE, 2010; Azzolina *et al.*, 2015).

3 Experimental section

3.1 Experimental material and apparatus

In this study, coreflooding experiments were conducted with a 2.50 cm diameter, 85.03 cm long natural composite core from Changqing oilfields located in Ordos sedimentary basin, northwest China. The reservoirs in this basin generally feature ultralow porosity, ultralow permeability, microfracture and strong heterogeneity. The average porosity is 9.6%, and average permeability is 0.27 mD. The experimental oil and brine were obtained from the same area as the core. The viscosity of crude oil is 0.95 mPa s, the salinity of brine is 78 g/L. and the purity of CO_2 is 99.99%. CO_2 flooding can be classified as immiscible and miscible based on the reservoir pressure. In an earlier tubule experiment, the Minimum Miscible Pressure (MMP) was measured as 20.78 MPa, which is lower than the initial reservoir pressure of 21.9 MPa.Therefore under the current reservoir condition, the flooding is miscible flooding.

In cyclic CO_2 injection tests, the experimental apparatus consists of three parts: injection part, displacement part and metering part. Injection part includes three intermediate containers connected with a displacement pump to inject fluids. The displacement part includes a high pressure stainless steel core holder with a corrosion resistance of

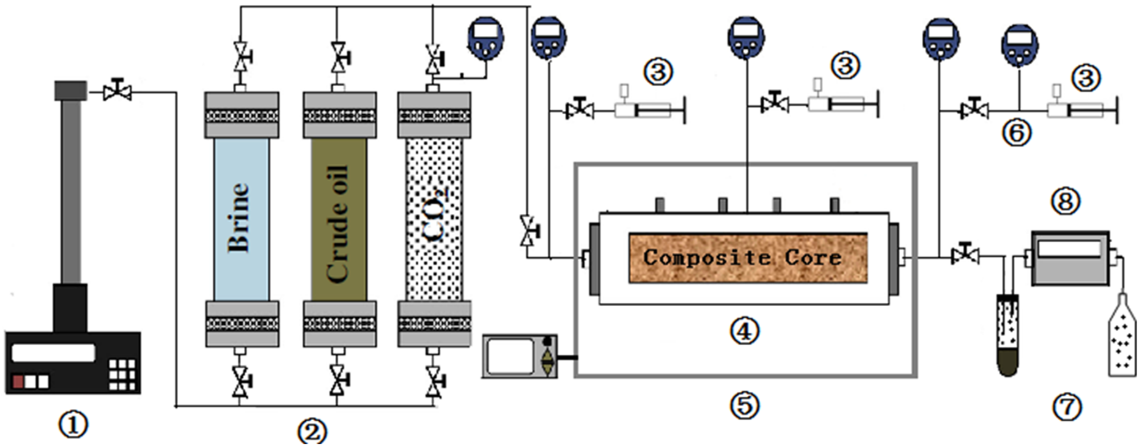

Fig. 1. Schematic diagram of the experimental apparatus used for cyclic CO_2 injection tests. Displacement pumps; intermediate container; manual pump; core holder; isothermal case; back pressure regulator sample collector; gas flow meter.

synthetic rubber sleeve, a back pressure regulator connected to the end of the core holder maintaining the core pressure of 21.9 MPa, and two pressure gauges monitoring the core and the annulus pressure respectively. The annulus pressure was maintained at a value of around 2 MPa higher than the core pressure to avoid the core being ruptured. The metering part includes a three phase separator at ambient conditions used for metering the production of gas and oil. The entire apparatus excluding the displacement pump is housed in an isothermal case to maintain the experiment temperature at 84 °C. The schematic diagram of the experimental set up is shown in Figure 1.

3.2 Experimental procedure

Prior to the coreflooding experiments, the core samples were cleaned, vacuumed, and saturated with brine to obtain the pore volume and permeability at reservoir conditions. The pore volume obtained is 40.1 cm^3. Thereafter, the core sample was saturated with live oil to establish the initial oil saturation and connate water saturation. The initial oil saturation is 54.4% while the irreducible water saturation is 45.6%. After the core sample was saturated with oil and kept in oil to re-establish its wettability. In addition, based the Shen Pingping's method, according to the condition of reservoirs, the value of basic parameters, such as initial water saturation E_R is 20%, CO_2 density in formation ρ_{CO_2} is 0.751 t/m^3, CO_2 solubility in brine C_{ws} is 0.049, CO_2 solubility in oil is 0.35, the theoretical CO_2 storage capacity was calculated as 12.66×10^{-6} t (Shen *et al.*, 2009; Sun *et al.*, 2017).

When the preparation was completed, the cyclic CO_2 flooding experiment was started by injecting supercritical CO_2 with a constant flow rate of 0.05 mL/min. In each cycle, supercritical CO_2 was injected into the core with injection slug of 0.03–0.1 PV and injection time of 2–6.5 h after which the injection end closes for a soaking period of 1–13 h. During the entire process, the production end opens. The injection-soaking process described above is one cycle. The cycle process continues until there is no considerable oil production. In each cycle, cumulative produced oil, injected and produced CO_2 were measured, oil recovery factor, CO_2 storage factor and the objective function were calculated and complex drive and storage mechanisms were analyzed. Finally the optimal injection parameters were determined by co-optimizing oil recovery and CO_2 storage. Detailed experimental design is shown in Table 1. All these operations were carried out at reservoir conditions (21.9 MPa and 84 °C).

4 Experimental results and discussion

4.1 The objective function

In this section, a total of nine cyclic CO_2 injection tests were carried out at different injection scenarios under miscible conditions. Figure 2 depicts objective function *versus* cumulative injected CO_2 at different injection scenarios. It was observed that the objective function increases with cumulative CO_2 injection, and the value increased rapidly during the initial stage. It was mainly attributed to a faster and strong CO_2 drive and storage mechanism (Cao and Gu, 2013; Vahid *et al.*, 2017). Some of the injected CO_2 dissolved in oil and improved the oil mobility by oil volume expansion and viscosity reduction. Some of the injected CO_2 displaced and occupied the pore space of produced oil to store CO_2. However, with increase of cumulative injected CO_2, the curve became gradually flatter. This is because CO_2 viscous fingering and gravity segregation reduced the CO_2 sweep volume and resulted in CO_2 breakthrough which drastically declined oil production and CO_2 storage.

Table 2 shows cyclic CO_2 injection test results conducted at different injection scenarios. As can be seen from the table, with increase in CO_2 slug size, objective function decreased from 54.18% for 0.03 PV (run 2) to 27.85% for 0.1 PV (run 9). In addition, the injection process of each run before gas breakthrough contributed the majority of the ultimate value. The objective function only increased by 6%–10% after gas breakthrough. The same trend could

Table 1. Experiment scenarios of cyclic CO_2 injection.

Run	CO_2 slug size (PV)	ISR	Injection rate (mL/min)
1	0.03	2:1	0.05
2	0.03	1:1	0.05
3	0.03	1:2	0.05
4	0.06	2:1	0.05
5	0.06	1:1	0.05
6	0.06	1:2	0.05
7	0.1	2:1	0.05
8	0.1	1:1	0.05
9	0.1	1:2	0.05

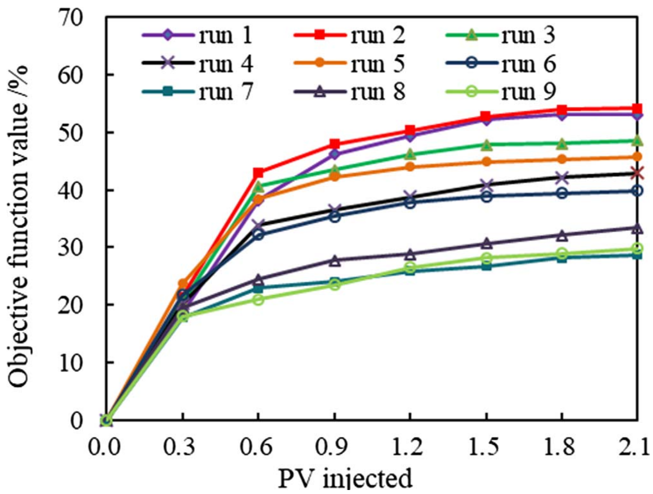

Fig. 2. Objective function value *vs.* PV CO_2 injected for $\omega_1 = \omega_2 = 0.5$.

also be observed for oil recovery factor and CO_2 storage factor. Gas breakthrough is a key factor which affects oil recovery and CO_2 storage. The later CO_2 breakthrough occurred, the more oil produced and CO_2 stored. Therefore, in order to achieve more oil production and CO_2 storage, the injection parameters should be optimized to delay gas breakthrough (Bachu *et al.*, 2007).

4.2 Effects of slug size

CO_2 slug size is an important factor affecting the effect of cyclic CO_2 injection (Wang *et al.*, 2013). In order to study the effects of CO_2 slug on oil recovery factor and CO_2 storage factor, three groups of cyclic CO_2 injection experiments were carried out with different CO_2 slug sizes (0.03, 0.06 and 0.1 PV). The ultimate oil recovery factor of all cyclic CO_2 injection tests *versus* CO_2 slug size are illustrated in Figure 3. As can be seen from this figure, the ultimate oil recovery increases firstly and then decreases with the increase in CO_2 slug size. The main reason is that a large CO_2 slug (0.1 PV) might have larger contact areas between the oil and CO_2 phases than a small CO_2 slug (0.03 PV), resulting in a greater reduced oil viscosity. However, a large slug size is easy to induce CO_2 breakthrough, decreasing oil recovery drastically after breakthrough. In this paper, the peak of ultimate oil recovery is 57.86% when CO_2 slug is 0.06 PV.

Figure 4 shows CO_2 storage factor *versus* CO_2 slug size in different injection tests. Comparison of CO_2 storage factor among 0.03 PV, 0.06 PV, and 0.1 PV suggests that when injected CO_2 slugs increase, CO_2 storage factor decreases from 61.35% for 0.03 PV to 29.46% for 0.1 PV. A small CO_2 slug seems to be more favorable for CO_2 storage, because it is helpful for controlling and delaying gas breakthrough.

4.3 Effect of injection-soaking time ratio

Injection-soaking time ratio, defined as the ratio of injection time to soaking time, is another major operating parameter in cyclic CO_2 injection. For a long period of time, the determination of soaking time relies on field experiences without theoretic basis. In this paper, three group of ISR (2:1, 1:1 and 1:2) were implemented to investigate its effect on cyclic CO_2 injection. Figure 5 shows the ultimate oil recovery factor *versus* ISR in different injection tests. The results indicated that the maximum oil recovery factor of 57.86% is obtained at ISR of 1:1.This is higher than the oil recovery obtained from ISR 2:1 and 1:2, because the soaking time mainly affects the amount of CO_2 dissolved in the oil phase. If the ISR is too high, CO_2 cannot spread into the deep formation and a large amount of CO_2 will gather around the wellbore, which increases injection-production pressure difference. This results in the reduction of CO_2 sweep areas and the ultimate oil recovery factor. If the ISR is too low, CO_2 can be fully dissolved in crude oil but the longer soaking time has little contribution to improve oil recovery and the amount of CO_2 injection is small in each cycle. This weakens the ability of CO_2 to expand the crude oil and reduce viscosity, thus reducing the oil recovery factor.

Figure 6 shows CO_2 storage factor *versus* ISR in different injection tests. The results revealed that ultimate CO_2 storage factor increases with ISR and the maximum CO_2 storage factor is 61.35% for ISR of 2:1. The higher the ISR, the more CO_2 injected and although CO_2 production and loss may be increased, CO_2 storage will also be increased. Under the action of buoyancy, some injected CO_2 is left behind as disconnected or residual droplets in rock interstices and seals and some migrates and dissolves into formation fluid. Those are the two main storage mechanisms (residual and solubility trapping) which take a significant percentage of total CO_2 stored (Ampomah *et al.*, 2016; Liang *et al.*, 2016).

Because oil recovery and CO_2 storage factor exhibit different trends with CO_2 injection parameters, for low permeability reservoirs, injection parameter optimization is a complicated process, which depends on specific field conditions with balances between oil recovery factor and CO_2 storage factor. The objective function established in

Table 2. summary of cyclic CO_2 injection experiment results.

Runs	PV	Function value/%		Oil recovery factor/%		CO_2 storage factor/%	
	Breakthrough	Breakthrough	Ultimate	Breakthrough	Ultimate	Breakthrough	Ultimate
1	0.84	46.22	53.09	36.73	44.83	55.71	61.35
2	0.66	45.48	54.18	41.98	48.93	48.98	59.43
3	0.57	40.56	48.6	34.38	40.17	46.74	57.03
4	0.78	34.45	42.93	37.29	53.02	31.61	32.84
5	0.54	35.49	45.72	47.20	57.86	23.78	33.58
6	0.42	30.71	39.9	29.71	54.38	31.71	25.42
7	0.6	22.44	28.75	24.23	28.04	20.65	29.46
8	0.4	20.57	33.4	20.57	33.74	20.57	33.06
9	0.3	18.01	27.85	16.98	27.49	19.04	28.21

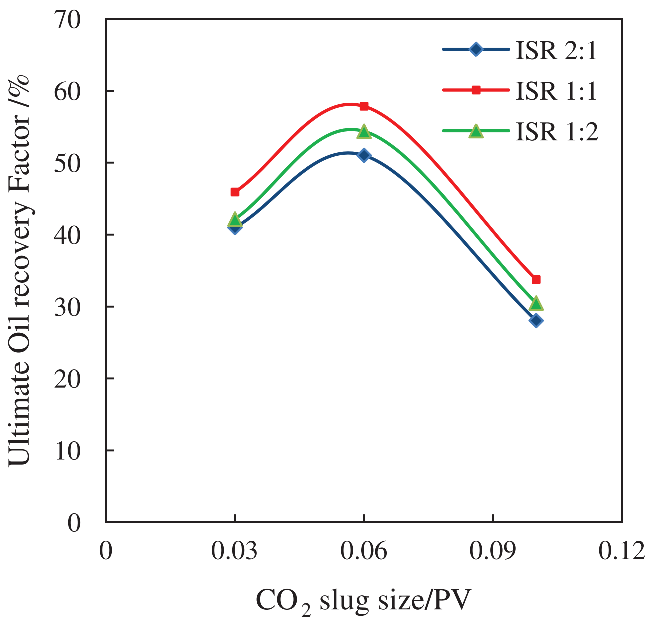

Fig. 3. Oil recovery factor *vs.* CO_2 slug size.

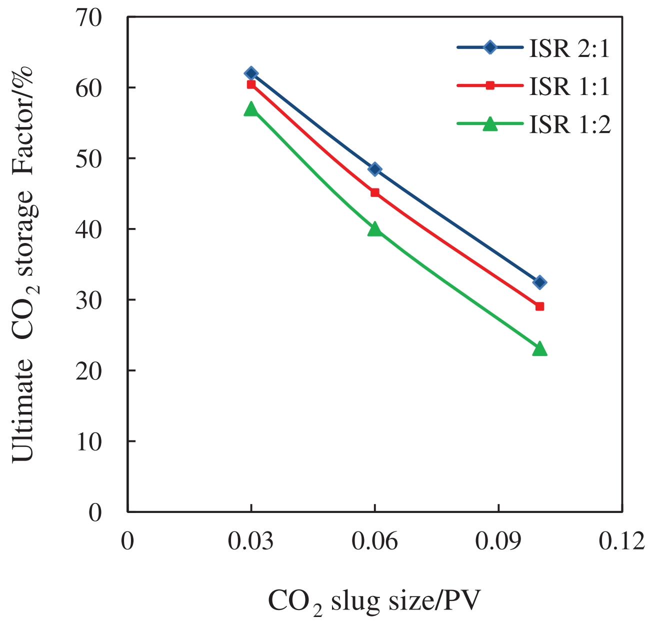

Fig. 4. CO_2 storage factor *vs.* CO2 slug size.

Section 2 can be provided for co-optimization of oil production and CO_2 storage.

4.4 Results comparison and analysis

As mentioned above, due to the different mechanisms of CO_2 drive and storage, CO_2 injection parameters have different influences on oil recovery factor and CO_2 storage factor. In order to investigate the effect of the co-optimization method on different scenarios, three optimization goals were used for comparison and analysis (only for oil recovery factor, $\omega_1 = 1$; only for CO_2 storage factor, $\omega_2 = 1$; co-optimization of oil recovery and CO_2 storage, $\omega_1 = \omega_2 = 0.5$).

The results are illustrated in Figures 2, 7, 8. As can be seen from these figures, the highest oil recovery with $\omega_1 = 1$ is 57.86% and was obtained from run 5 (0.06PV for CO_2 slug, 1:1 for ISR). The highest CO_2 storage efficiency with $\omega_2 = 1$ is 61.35% and was obtained from run 1 (0.03 PV for CO_2 slug, 2:1 for ISR). However, run 2 (0.03 PV for CO_2 slug, 1:1 for ISR) gave the maximum value of the objective function for the co-optimization method (as shown from Fig. 2).

Table 3 shows the maximum value of the objective function for different optimization methods. The results revealed that the oil recovery factor is 48.93% and CO_2 storage factor is 59.43% when the objective function value is maximum for co-optimization method ($\omega_1 = \omega_2 = 0.5$). Although the oil recovery is lower than the maximum oil recovery (57.86% for oil recovery optimization method $\omega_1 = 1$), CO_2 storage factor increases from 33.58% to 59.43%. The co-optimization method which combines the oil recovery with CO_2 storage factor is better, especially in the context of global warming. It provides a win-win solution to achieve economic and social benefits.

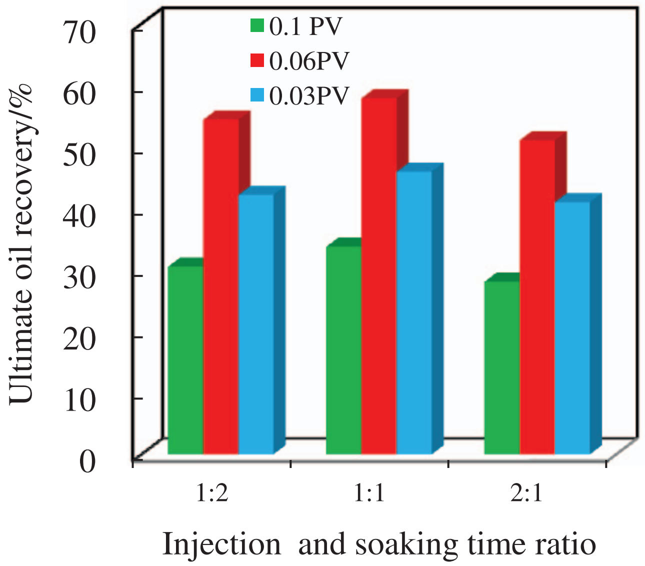

Fig. 5. Oil recovery factor *vs.* ISR.

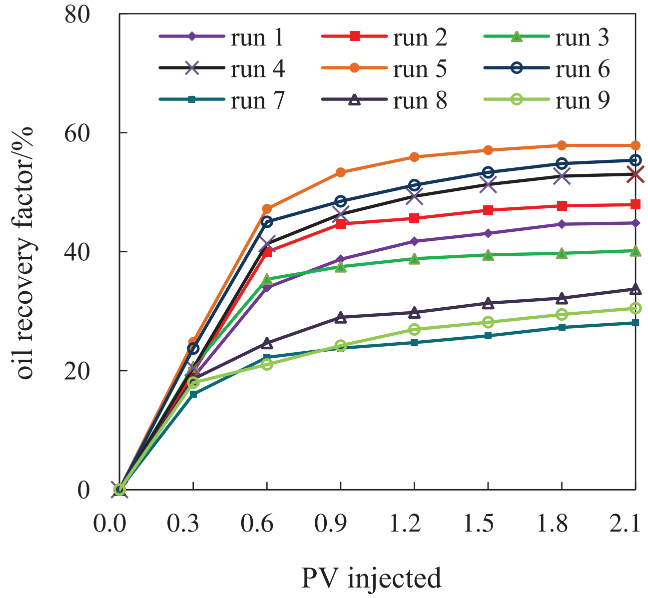

Fig. 7. Oil recovery factor *vs.* CO_2 injected PV for $\omega_1 = 1$.

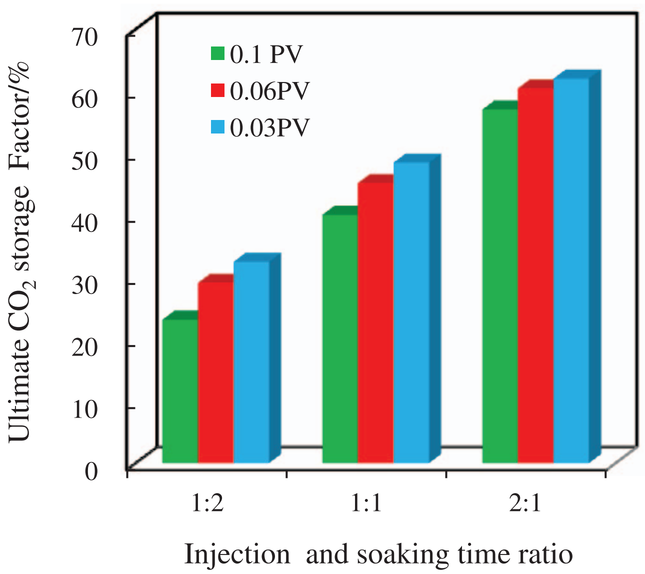

Fig. 6. CO_2 storage factor *vs.* ISR.

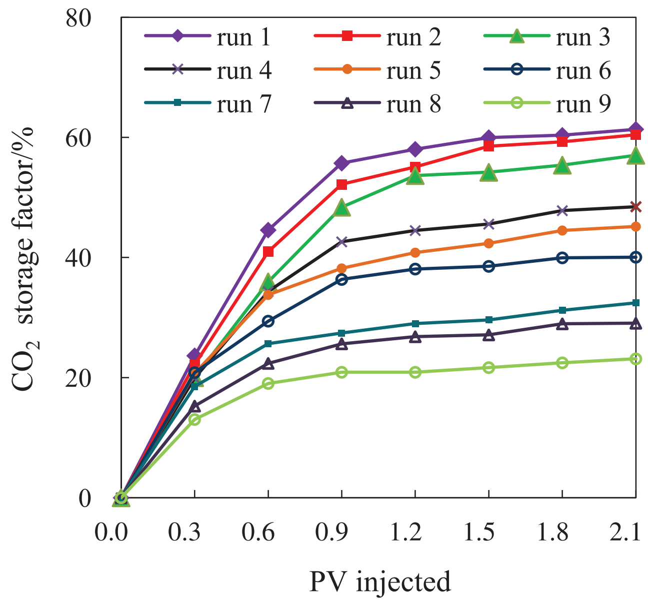

Fig. 8. CO_2 storage factor *vs.* CO_2 injected PV for $\omega_2 = 1$.

Table 3. Maximum objective function values comparison for different optimization methods.

Method	Slug size	ISR	Objective function value	Oil recovery factor	CO_2 storage factor
Oil recovery, $\omega_1 = 1$	0.06	1:1	57.86	57.86	33.58
CO_2 storage, $\omega_2 = 1$	0.03	2:1	61.35	44.83	61.35
Co-optimization, $\omega_1 = \omega_2 = 0.5$	0.03	1:1	54.18	48.93	59.43

5 Conclusion

Cyclic CO_2 injection is an effective method for enhanced oil recovery and CO_2 storage in ultralow permeability oil reservoirs. Through the optimization of injection parameters, a more economically profitable, as well as environmentally friendly enhanced oil recovery/CO_2 storage can be achieved.

1. A co-optimization method was established which coupled the oil recovery and CO_2 storage and considered the loss of CO_2 in actual operation. It gives a guidance on the optimization of CO_2-EOR reservoir engineering design.
2. The injection parameters are important factors which affect oil recovery and CO2 storage. For equal weight factor, the optimal injection slug size was 0.03 PV and ISR was 1:1, while slug size was 0.03 PV and ISR was 2:1 for the highest oil recovery, and slug size was 0.06 PV and ISR was 1:1 for the highest CO_2 storage. The most important thing is to delay gas breakthrough in reservoirs.
3. Comparing the three optimization goals, the co-optimization function which considered equal weight factors ($\omega_1 = \omega_2 = 0.5$) gave the best results with economic and environmental benefits with a reasonable oil recovery factor of 48.93% and CO_2 storage factor of 59.43%.

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