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Assessing the application of miscible CO_2 flooding in oil reservoirs: a case study from Pakistan

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Abstract

Miscible carbon dioxide (CO_2) flooding has been recognized as a promising approach to enhance the recovery of oil reservoirs. However, depending on the injection strategy and rock/fluid characteristics, efficiency of the miscible CO_2 flooding varies from reservoir to reservoir. Although, many studies have been carried out to evaluate the performance of the miscible CO_2 flooding, a specific strategy which can be strictly followed for a hydrocarbon reservoir has not been established yet. The aim of this study is to assess one of Pakistan's oil reservoirs for miscible CO_2 flooding by applying a modified screening criterion and numerical modeling. As such, the most recent miscible CO_2 screening criteria were modified, and a numerical modeling was applied on the prospective reservoir. Based on the results obtained, South oil reservoir (S3) is chosen for a detailed assessment of miscible CO_2 flooding. It was also found that implementation of CO_2 water-alternating gas (CO_2-WAG) injection at early stages of production can increase the production life of the reservoir.

Keywords Miscible CO_2-EOR · Screening criteria · Injection strategy · Oil reservoirs · Numerical modeling

Introduction

Major oil reservoirs around the globe have an average recovery factor of 20–40% (International 2006; Sandrea 2007). As such, their complete development often requires secondary recovery (injection of gas or water), and tertiary/enhanced oil recovery (EOR) methods (injection of miscible/immiscible fluids, chemical or thermal) (Orr et al. 1982). Unlike the secondary methods, which are known as physical processes, in the tertiary recovery, microscopic displacement and macroscopic sweep efficiency are improved by oil swelling, variation of interfacial tension (IFT), oil viscosity and wettability (Bayat et al. 2016; Brashear and Kuuskraa 1978; Sun et al. 2017). The most common EOR methods were established in the early 1970s (Muggeridge et al. 2014) and are further classified into gas, chemical and thermal technologies. Table 1 summarizes methods, phenomenon and challenges of different EOR technologies (Alvarado and Manrique 2010; Ayatollahi and Zerafat 2012; Kong and Ohadi 2010; Silva et al. 2007; Souza et al. 2005; Thomas 2008).

Among these three, the gas technology using CO_2 is perhaps the best method as it helps to achieve the minimum miscible pressure (MMP)—the lowest pressure for CO_2 phase to reach the multiple contact miscibility (MCM) under dynamic conditions (Bachu 2016; Gao et al. 2013). As such, CO_2 can be applied for miscible EOR or immiscible EOR operation depending on the MMP (Gao et al. 2013).

To optimize recovery of miscible CO_2 flooding, continuous CO_2 injection (CCO_2) and CO_2 water-alternating gas (CO_2-WAG) injection are often used as well-known injection strategies (Caudle and Dyes 1958). There have been many studies indicating the application of CCO_2 or CO_2-WAG. For instance, Caudle and Dyes (1958) carried out an experimental investigation and reported that the CO_2-WAG process is far better than the CCO_2 in terms of cost and performance due to the improvement of displacement. John et al. (1990) carried out numerical modeling for probabilistic cash flow analysis of the miscible CO_2 flooding in West Virginia. The results of statistical analysis showed that the CO_2-WAG is very suitable and cost effective compared to the CCO_2.

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Table 1 Different EOR technologies with different phenomenon and challenges

EOR technology	Different methods	Phenomenon	Challenges
Gas technology	Hydrocarbon gas injection	Pressure maintenance	Gravity override
	CO_2 injection	Viscosity reduction	Fingering and early gas breakthrough
	Nitrogen (N_2) injection	Oil expansion	High minimum miscibility pressure (MMP) in miscible flooding
	Air injection	Miscibility	CO_2 corrosion
	WAG injection		Asphaltene deposition
Chemical technology	Alkaline flooding	IFT reduction	High cost
	Surfactant flooding	Wettability alteration	Low effectiveness on IFT and viscosity changes
	Polymer flooding	Mobility control	Damage due to incompatibility
	Alkaline surfactant polymer (ASP) flooding	Emulsification	Unfavorable mobility ration
	Micellar flooding		Slow diffusion rate in pore structure
Thermal technology	Electrical heating	Gravity drainage	Heat loss from heat generator to the reservoir
	Steam-assisted gravity drainage (SAGD)	Oil expansion	Less significant thermal degradation
	In situ combustion	Steam distillation	Heat leakage to the undesired layers
	Steam flooding	IFT reduction	Low thermal conductivity of rock and fluids
	Cyclic steam stimulation (CSS)	Viscosity reduction	High energy cost

Heidari et al. (2013) carried out comparison experimentally and numerically between CO_2-WAG and CO_2 simultaneous water-and-gas (CO_2-SWAG) injection. They concluded that the CO_2-SWAG enhanced oil production as compared to CO_2-WAG in immiscible, near-miscible, and miscible modes of injection, and miscible CO_2-SWAG produces more than 74% of original oil in place. Inaloo et al. (2014) performed numerical analysis for one of the Iranian oil reservoirs to determine the optimal production strategy through water flooding, gas injection and WAG. The results obtained indicated that water injection gives a better recovery than gas or WAG injections. In a similar study, Song et al. (2014) numerically investigated the reservoir parameters to evaluate the efficiency of CO_2 flooding. It was found that a five-spot injection well pattern is more feasible than inverted nine-spot and seven-spot patterns for CO_2-WAG flooding. They also indicated that CO_2-WAG flooding is much feasible than CCO_2 if cost and tax credit per ton of CO_2 are considered. Ahmadi et al. (2016) numerically studied three different CO_2 injection scenarios including CO_2 injection into an aquifer, CO_2 injection into the pay zone, and simultaneous CO_2 injection into the aquifer and pay zone. Their study showed that simultaneous CO_2 injection into the aquifer and pay zone gives a better oil recovery compared to other scenarios. In a recent study, Jaber and Awang (2017) numerically evaluated the injection strategies during miscible CO_2-SWAG injection in a highly heterogeneous clastic reservoir. The results indicated that the CO_2-SWAG injection with the ratio of 2:1 provides the maximum oil recovery compared to other injection modes. It seems that the efficiency of miscible CO_2 flooding varies from reservoir to reservoir and more studies are required to have a deeper understanding of how miscible CO_2 flooding can be successfully employed to improve the recovery in oil reservoirs.

The aim of this paper is to show how oil fields can be screened for miscible CO_2 flooding and why an optimum injection strategy must be chosen for production enhancement. A case study from Pakistan is also brought to highlight the application of the methodology proposed.

Preliminary screening

To select a particular EOR technology/method for oil reservoirs, a few essential steps must be taken including: (1) preliminary screening for suitability of EOR method, (2) a comprehensive laboratory and simulation study, (3) pilot tests, and (4) field study (Bourdarot and Ghedan 2011). In this paper, attempts are made to show how these steps must be taken and carefully followed for a successful implementation of miscible CO_2 flooding.

Preliminary screening for suitability of EOR

A total number of 15 reservoirs from Pakistan were available for this study with a complete set of data. Preliminary screening of candidate reservoirs was initiated by looking into the technical criteria of EOR methods. Table 2 summarizes different criteria used in this study for the assessment of EOR methods. Looking at this table and analysis of the results indicated that South oil fields, notably the S3, are falling within the range of screening parameters proposed for miscible and immiscible CO_2 flooding, whilst North oil

Table 2 Implementation of screening criteria by Al-Adasani and Bai (2011) on Pakistan oil reservoirs for selection of EOR method

EOR method		Reservoir properties						
		Oil gravity (API)	Viscosity (cP)	Start oil saturation	Permeability (mD)	Porosity (%)	Depth (ft)	Temperature (°F)
EOR criteria proposed by Al-Adasani and Bai (2011)								
Miscible flooding		34–44	0–1	0.33–0.55	0.1–100	7–16	4200–6700	95–160
Immiscible flooding		19–36	0–10.5	0.42–0.62	30–300	22–32	1970–5708	120–194
Steam flooding		10–16	3–2000	0.50–0.70	1000–3000	30-38.8	800–1800	80–130
Combustion		19–27	1.44–2	0.50–0.70	10–85	17–25	1575–5000	185–230
Chemical (mainly polymer)		32-42.5	9–75	0.65–0.82	173–875	21–33	2723–3921	108–158
Conventional screening of Pakistan oil fields in north and south								
North oil field characteristics								
N1	Sandstone	25	2.1	–	24	–	11,555	210
N2	Limestone	13	2	–	145	–	11,227	205
N3	Limestone	30	0.252	–	4200	–	9784	224
N4	Limestone	33.3	0.27	–	0.19	–	9518	245
N5	Dolomite	26	3	–	126	–	8258	171
N6	Limestone	25	3	–	107	–	7530	202
N7	Sandstone	29	3	–	33	–	8209	185
N8	Limestone	19	3	–	14.5	–	8461	208
N9	Limestone	12	2	–	12	–	7162	210
South oil field characteristics								
S1	Sandstone	43	0.22	–	186	–	6500	225
S2	Sandstone	43	0.277	–	35	–	6560	230
S3	Sandstone	42	0.4	0.15–0.30 (22% average)	40	9.5–18 (14% average)	7500	250
S4	Sandstone	43	0.3	–	45	–	7545	250
S5	Sandstone	41	0.327	–	60	–	6560	227
S6	Sandstone	45	0.317	–	70	–	7180	230

fields seem to be suitable for combustion and chemical EOR methods.

Development and implementation of miscible CO_2-EOR criteria

There have been many screening criteria proposed to initially chose a reservoir for suitability of miscible CO_2 flooding (Al Adasani and Bai 2011; Bachu et al. 2004; Bachu 2016; Brashear and Kuuskraa 1978; Carcoana 1982; Diaz et al. 1996; Fulin 2001; Geffen 1973; Goodlett et al. 1986; Haynes et al. 1976; Iyoho 1978; Klins 1984; McRee 1977; OTA 1978; Rivas et al. 1994; Shaw and Bachu 2002; Taber et al. 1997; Taber 1983), most of which are given in Table 3. The common parameters involved in these criteria are: (1) viscosity and API gravity of oil, (2) reservoir's oil saturation, (3) temperature and pressure of reservoirs, (4) net pay thickness, and (5) permeability.

There have also been numerous studies reporting the effect of various parameters on miscible CO_2 flooding. For instance, Sehbi et al. (2001) reported that phase behavior, diffusion and dispersion are key processes to develop and sustain miscible displacement in a CO_2 flood. It was also stated that a uniform pore geometry and pore structure offer a better microscopic displacement efficiency. Shedid (2009) carried out a series of miscible CO_2 flooding by considering various modes of reservoir heterogeneity (i.e., fractured reservoirs with different inclination angles, permeability configurations and the sequence of permeability distributions). The results obtained showed that unfractured reservoirs are better than single-fractured ones to get the good recovery. An oil reservoir with a 30° of inclination angle for a single fracture gives the maximum oil recovery, whilst fractured rocks with a 45° inclination angle offers the lowest recovery. Sahimi (2011) stated that the difference between the viscosity of oil and displacing gas has a strong effect on the efficiency of the miscible displacement. Muggeridge et al. (2014) indicated few limitations for the miscible CO_2 flooding such as sensitivity to heterogeneity, poor vertical sweeping efficiency and pressure management. Bikkina et al. (2016) evaluated the effect of reservoir wettability and permeability heterogeneity on the performance

Table 3 Screening criteria proposed by many researchers for screening of reservoirs suitable for miscible CO_2 flooding

Screening parameters	Geffen (1973)	Lewin et al. (1976)	NPC (Haynes 1976)	McRee (1977)	Lyoho (1978)	OTA (1978)	Carcoana (1982)	Taber & Martin (1983)	Taber et al. (1997)	Brashear et al. (1978)	Klins, (1984)	Goodlett et al. (1986)	Rivas et al. (1994)	Diaz et al. (1996)	Fulin (2001)	Bachu et al. (2004)	(Al Adasani and Bai, 2011)
Depth (ft)	–	> 3000	> 2300	> 2000	> 2500	(a) > 7200 (b) > 5500 (c) > 2500	< 9800	> 2000	(a) > 4000 (b) > 3300 (c) > 2800 (d) > 2500	–	–	–	–	–	762meters	–	1500–13,365 Avg. 6230
Temperature (°F)	–	Not critical	< 250	–	–	–	< 195	Not critical	–	Not critical	Not critical	Not critical	150	160	–	32–121	82–257 Avg. 138.1
Original pressure (psia)	> 1100	> 1500	–	–	–	–	> 1200	–	–	> 1500 BHP	> 1500 BHP	–	–	–	–	> 1102	–
Permeability (mD)	–	Not critical	–	> 5	> 10	–	> 1	Not critical	– Not critical	Not critical	Not critical	Not critical	300	300	–	–	1.5–4500 Avg. 209.7
Oil gravity (°API)	> 30	> 30	> 27	> 35	30–45	(a) < 27 (b) 27–30 (c) > 30	> 40	> 26	(a) 22–27.9 (b) 28–31.9 (c) 32–39.9 (d) > 40	> 28	> 30	> 25	> 36	> 37	> 22	27–48	22–45 Avg. 37
Viscosity (cP)	< 3	12	< 10	< 5	< 10	< 12	< 2	< 15	< 10	< 12	< 12	< 15	–	–	< 10	–	Avg. 2.08
Fraction of oil remaining	> 0.25	> 0.25	–	> 0.25	> 0.25	–	> 0.30	> 0.30	> 0.20 > 30	0.25	> 0.25	> 0.30	0.60	0.60	> 20	> 0.25	15–89 Avg. 46
Net pay thickness (ft)	–	–	–	–	–	–	–	–	Thin unless dipping	Not critical	Not critical	Thin unless dipping	40	50	–	–	Wide range

of miscible CO_2 flooding. They concluded that the oil-wet system is better choice for miscible CO_2 flooding compared to the water-wet system. Homogeneous oil-wet core was also found to be favorable for the miscible CO_2 flooding. Moreover, heterogeneous water-wet core with a fracture could not be beneficial to have improved oil recovery. Ding et al. (2017) experimentally investigated the effects of reservoir heterogeneity, CO_2–oil miscibility, and injection patterns on the oil recovery for the immiscible and miscible flooding. It was found that the recovery of oil is sensitive to heterogeneity and multiple-contact miscible CO_2 injections. They also indicated that CO_2-WAG is the most suitable after the primary continuous CO_2 injection for immiscible CO_2 flooding. Considering the above studies, the most comprehensive criterion proposed by Bachu (2016) was modified to screen the oil reservoirs for miscible CO_2-EOR operations, as given in Table 4.

Table 5 gives the range of parameters required for a reservoir for an effective CO_2-EOR practice. The outcome of the mapping of Pakistani fields' data into the screening table is very encouraging as it shows that most of the South reservoirs possibly meet the initial screening criteria for CO_2-EOR. However, after a thorough discussion with the EOR experts and management of the operating company, S3 was selected based on its larger reservoir size compared to other South oil reservoirs for the full field compositional study for CO_2 flooding.

Numerical modeling

Geological background

The S3 oil reservoir with an aquifer in its bottom has reached the water-flooding stage. At this stage, the production wells are showing a high water cut, natural decline of oil production, and unfavorable recovery. Therefore, improving oil recovery is a matter of concern and CO_2 injection is a potential method that can be considered. This oil field is classified into western, main central, eastern and unproductive southeastern blocks. Central block is enriched with oil, but the whole reservoir does not contribute into production. The reservoir model is composed of 18 layers which are subdivided into four producible layers (i.e., 1–4, 6–9, 11–15, and 17–18). Compared to bottom layers, two sections of 1–4 and 6–9 are enriched by hydrocarbons. There are three injection wells from which one injection well has been used as the water injection well. The oil produced from this field has different quality ranging from 37° API to 44° API in western and central blocks and 49° API in eastern block. Porosity varies from 9.5 to 18% in the main central horst. Irreducible water saturation (S_{wir}) is estimated to be around 26.1% based on the capillary pressure data and close to 17.5% according to the water–oil relative permeability data. Moreover, residual oil saturation in the water–oil system (S_{orw}) is changing from 15 to 30% with an average of 22%.

Table 4 The criteria proposed by Bachu (2016) and modified by adding parameters in Sr. 15–17 to screen oil reservoirs for miscible CO_2-EOR

No.	Reservoir characteristics	Suitable for miscible CO_2-EOR
1	Already undergoing enhanced (tertiary recovery)	No
2	Commingled	No
3	Depth (ft)	≥ 1600
4	Oil gravity (°API)	≥ 22
5	Temperature (°F)	≥ 82
6	Oil viscosity (cP)	0.4≥
7	Pressure (psi)	≥ MMP
8	Initial pore pressure gradient (psi/ft)	<Grad (S_{min})
9	Porosity (%)	≥ 3
10	Initial oil saturation (%)	≥ 26.5
11	Initial pore space oil saturation	≥ 0.05
12	Original oil in place (OOIP) million stock tank barrels (MMSTB)	≥ 12.5
13	Remaining oil fraction in the reservoir (%)	≥ 20
14	Remaining oil fraction in the reservoir (MMSTB)	≥ 5
15	Wettability	Oil-wet system
16	Heterogeneity	Approach to homogeneous
		Unfractured or less fractured
17	Permeability configurations	Medium–low–high (MLH) mode for composite reservoirs and medium–high–low (MHL) distribution mode for layered reservoirs

Table 5 Oil reservoir screening based on the updated screening criteria of miscible CO_2-EOR

EOR method		Already undergoing enhanced (tertiary recovery)	Commingled	Oil gravity (API)	Viscosity (cP)	Reservoir properties										Wettability	Heterogeneity	Permeability configurations
						Initial oil saturation (fraction)	Initial pore space oil saturation	Porosity (%)	Depth (ft)	Temperature (°F)	Pressure (psi)	Initial pore pressure gradient (psi/ft)	Original oil in place (OOIP) (MMSTAB)	Remaining oil fraction in the reservoir (%)	Remaining oil fraction in the reservoir (MMSTB)			
Suitable for miscible CO_2-EOR		No	No	≥ 22	0.4≥	≥ 0.265	≥ 0.05	≥ 3	≥ 1600	≥ 82	≥ MMP	<Grad (S_{min})	≥ 12.5	≥ 20	≥ 5	Oil-wet system	Approach to homogeneous	Medium–low–high (MLH) mode for composite reservoirs and medium–high–low (MHL) distribution mode for layered reservoirs
	North oil field characteristics										Undisclosed info	Undisclosed info	Undisclosed info	Undisclosed info	Undisclosed info			
Conventional screening of Pakistan oil fields in north and south																		
N1	Sandstone	No	No	25	2.1	–	–	–	11,555	210	Yes	Yes	Yes	Yes	Yes	–	–	–
N2	Limestone	No	No	13	2	–	–	–	11,227	205	Yes	Yes	Yes	Yes	Yes	–	–	–
N3	Limestone	No	No	30	0.252	–	–	–	9784	224	Yes	Yes	Yes	Yes	Yes	–	–	–
N4	Limestone	No	No	33.3	0.27	–	–	–	9518	245	Yes	Yes	Yes	Yes	Yes	–	–	–
N5	Dolomite	No	No	26	3	–	–	–	8258	171	Yes	Yes	Yes	Yes	Yes	–	–	–
N6	Limestone	No	No	25	3	–	–	–	7530	202	Yes	Yes	Yes	Yes	Yes	–	–	–
N7	Sandstone	No	No	29	3	–	–	–	8209	185	Yes	Yes	Yes	Yes	Yes	–	–	–
N8	Limestone	No	No	19	3	–	–	–	8461	208	Yes	Yes	Yes	Yes	Yes	–	–	–
N9	Limestone	No	No	12	2	–	–	–	7162	210	Yes	Yes	Yes	Yes	Yes	–	–	–

Table 5 (continued)

		North oil field characteristics									Undis-closed info	Undis-closed info	Undis-closed info	Undis-closed info	Undis-closed info			
South oil field characteristics-																		
S1	Sand-stone	No	No	43	0.22	–	–	–	6500	225	Yes	Yes	Yes	Yes	Yes	–	–	–
S2	Sand-stone	No	No	43	0.277	–	–	–	6560	230	Yes	Yes	Yes	Yes	Yes	–	–	–
S3	Sand-stone	No	No	42	0.4	0.15–0.30	≥ 0.05	9.5–18 Avg 14	7500	250	Yes	Yes	Yes	Yes	Yes	Water-wet	Reason-able hetero-gene-ous	Medium–high–low (MHL) distri-bution mode for layered reser-voirs
S4	Sand-stone	No	No	43	0.3	–	–	–	7545	250	Yes	Yes	Yes	Yes	Yes	–	–	–
S5	Sand-stone	No	No	41	0.327	–	–	–	6560	227	Yes	Yes	Yes	Yes	Yes	–	–	–
S6	Sand-stone	No	No	45	0.317	–	–	–	7180	230	Yes	Yes	Yes	Yes	Yes	–	–	–

MLH medium–low–high mode for composite reservoirs; *MHL* medium–high–low distribution mode for layered reservoirs

Data sources and model setup

A reservoir model was built for the purpose of this study consisting of 43,200 grid cells with 30, 80 and 18 grids in *X*-, *Y*- and *Z*-directions, respectively. The reservoir with a total number of 18 layers with the thickness of 240 m, an initial reservoir pressure of 3238 psia, oil saturation of 80% and connate water saturation of 20% was considered. The bubble point pressure obtained from the pressure–volume–temperature (PVT) analysis was set to be 1722 psia at 246 °F. An aquifer was put at the bottom of the reservoir using the Carter–Tracy analytical model. Characterization of the reservoir fluid was done before simulating the phase behavior. Component characterization including the lumping and splitting theory was modeled to observe the laboratory phase behavior so that a representative PVT fluid model could be developed based on a reliable match between the observed and the calculated data. Widely accepted three-parameter Peng–Robinson (PR) Equation of State (EoS) (O'Reilly 2009) was calibrated/regressed to represent the fluid model in the compositional simulation. Initial bottom-hole sample data are listed in Table 6.

In the very first step, fluid systems (mixtures) represented by pure and pseudocomponents (Whitson and Brulé 2000) were initially assessed for critical volume, critical temperature, critical pressure, acentric factor, volume shift parameter, and binary interaction coefficients. The observed and experimental data were compared by regression for tuning the properties for compositional modeling and to accurately estimate the fluid phase behavior as well as the vapor liquid equilibria (VLE). To decrease the simulation time, C_1–C_3 and multiple isomers were clustered into a single or pseudocomponent, and as such the reservoir fluid was represented by seven components consisting of CO_2 and six pseudocomponents in the PVT analysis. The mole fractions and molecular weights of these components are provided in Table 7.

Table 6 Composition of the reservoir fluid

Component	Mole fraction range (%)
N_2	0.94–1.54
CO_2	1.10–1.42
C_1	20.03–23.91
C_2	4.80–7.13
C_3	6.51–7.16
i C_4	2.06–4.12
n C_4	2.89–5.74
i C_5	1.77–4.17
n C_5	1.79–3.83
C_6	2.68–6.99
C_7	1.77–4.17
C_8	1.73–3.83
C_9	3.84–5.65
C_{10}	1.81–5.60
C_{11+}	12.55–28.95
C_{7+}	39.46–52.62

Table 7 Mole fraction and molecular weights of pseudocomponents

Pseudocomponent	Mole fraction (%)	Molecular weight
CO_2	14.89	16.81
C_{1-3}	24.85	38.91
C_4	4.95	58.12
C_{5-6}	7.96	78.64
C_{7-13}	28.05	129.82
C_{14-24}	14.48	237.58
C_{25+}	4.82	426.81

The observed and experimental data accurately matched for saturation pressure are shown in Fig. 1 while oil relative volume, relative volume, gas gravity and gas *z*-factor are depicted in Fig. 2. Match of *z*-factor is not as good as other matches included. It was possible to have relatively better match of *z*-factor. In that case, other matches such as saturation pressure, oil relative volume could have bad match. Upon successful validation, the fluid model was considered as an input in different phases for history matching, predictive and optimization phases.

In the absence of slim tube apparatus, three options are available to estimate MMP: correlation, PVTi module, and Eclipse compositional to simulate the slim tube experiment. Hence, MMP of the reservoir fluid was estimated by reliable compositional modeling approach. Results of slim tube compositional mdoeling are plotted as shown in Fig. 3. As it can be seen in Fig. 3, the intersection lines for the low and high recovery factors give MMP value of 1325 psia at 246 °F. If MMP is less than bubble point pressure, then the CO_2 MMP is set equal to the bubble point pressure (Goodrich 1980; Klins 1984; Khazam et al. 2016). Furthermore, CO_2 injection pressure for the case under study is even more than the bubble point pressure.

Simulation results and discussion

This section was divided into three connected parts. In the first part, "Do_Nothing" primary recovery forecast is presented that considers no fluid injection. The second part brings the results of the optimum operating conditions for CCO_2 and CO_2-WAG. The last and the third part provides a comparison among the primary recovery, CCO_2 and CO_2-WAG scenarios.

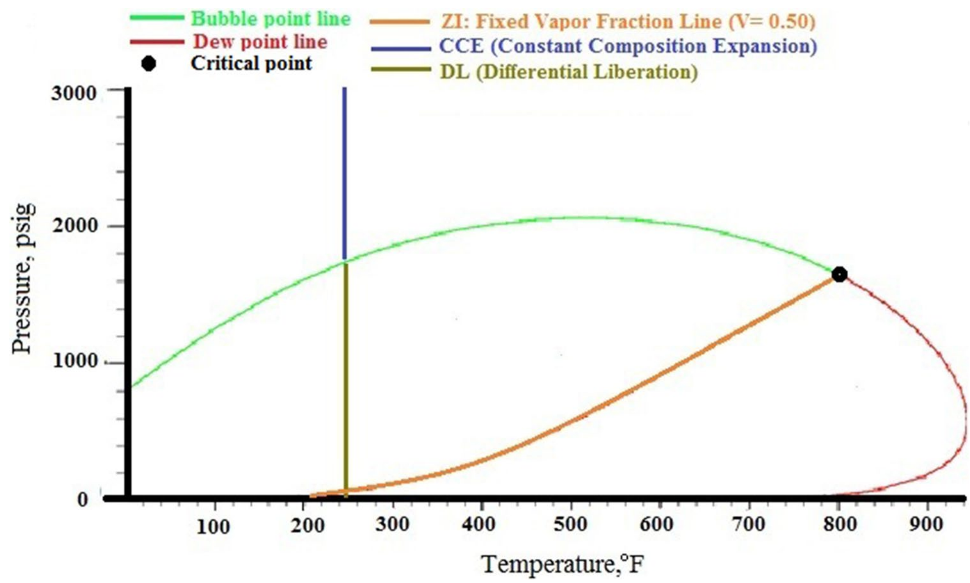

Fig. 1 Phase diagram of S3 reservoir fluid sample using Eclipse PVTi at 246 °F

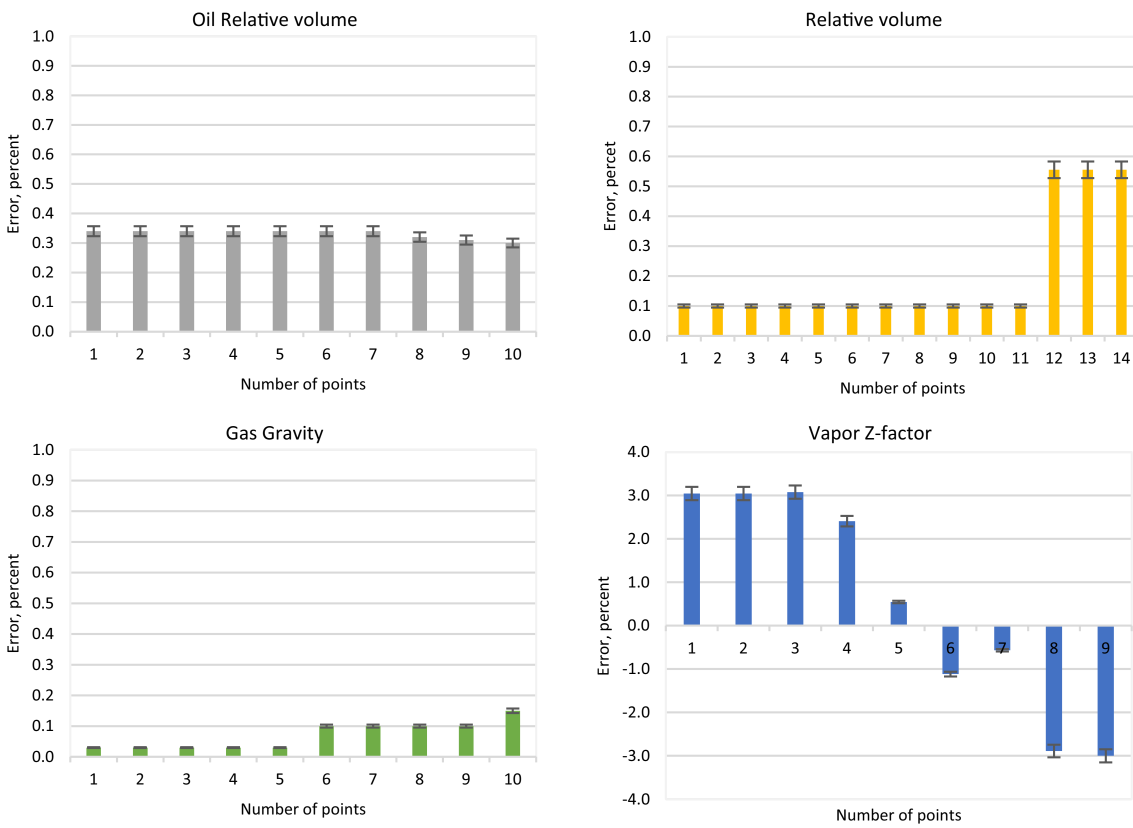

Fig. 2 Comparison between experimental and simulated PVT properties of oil: oil relative volume, relative volume, gas gravity, and gas z-factor

Primary recovery and forecast

After calibration of the PVT model, the model was run for history matching by considering the production strategy followed by the operator. A good history match between the actual field oil production rate history (FOPRH) and observed field oil production rate (FOPR) of more than 23 years was achieved as shown in Fig. 4. The average

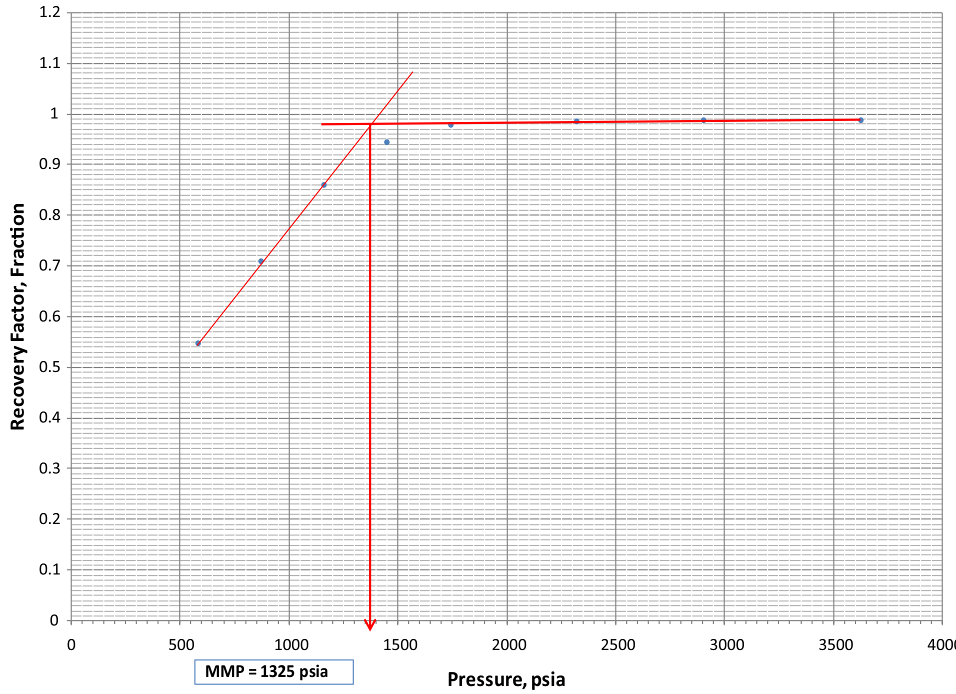

Fig. 3 Estimation of MMP at 246 °F reservoir temperature

reservoir pressure of 1801 psia was then found which was still more than the bubble point pressure at the end of the history match period. Figure 5a, b displays initial fluid saturations and well locations, respectively. In this figure, red colored wells are production wells and white colored wells are showing shut-in wells. Oil rate was set as a constraint to shut the low-productivity wells, and as such half of the producer wells were shut-in during the prediction phase. During the primary recovery phase, water was flooded in the water zone after 14 years of production by converting two down-dip central block producers (one is in Northern part and other in Southern part) into injectors. Water injection with a rate of 860 stock tank barrel per day (STB/D) was performed for 39 months. The injected water pushed the oil–water contact (OWC) away from northern part of the field which can be seen by comparing Fig. 5c and d.

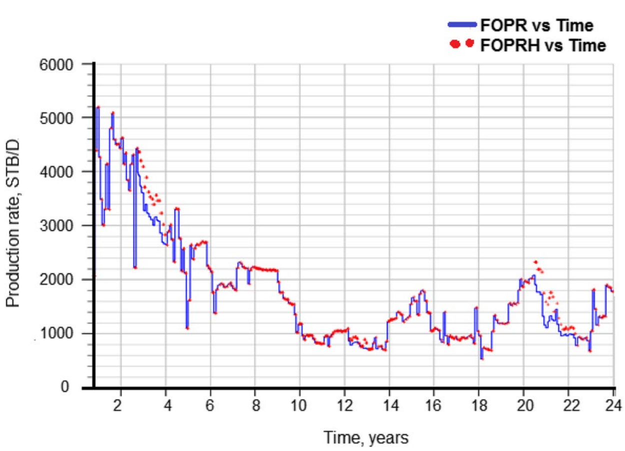

Fig. 4 Production history match of the S3 reservoir

Upon history matching, the recovery was forcasted for the next 20 years by setting only six wells on the production with eight wells closed. As mentioned earlier, history matching was carried out by following the production strategy of the operating company; therefore, totally eight wells were kept close due to a very high pressure drop and low productivity. However, a number of oil companies shut in oil and gas production wells due to low prices and lease issue (http://www.fhoa.ca). However, only three wells were open at the end of 20 years of production forecast. The results obtained from field oil recovery efficiency as $\mathrm{OOIP}_{\mathrm{initial}} - \mathrm{OOIP}_{\mathrm{now}}/\mathrm{OOIP}_{\mathrm{initial}}$ (FOE), cumulative field oil production (FOPT) in stock tank barrel (STB), field oil production rate (FOPR) in STB/D, filed reservoir pressure (FPR) in psia, field gas production rate (FGPR) in 1000 standard cubic feet per day (MSCF/D), and field instantaneous water cut (FWCT) in percentage are shown in Fig. 6a, b.

The results of the primary recovery forecast did not seem favorable which might be due to the low aquifer support at the edge water drive reservoir. Having said that, the oil recovery during the forecasted period was found to be 20% less than the half of the recovery by the end of the history period which confirms the volumetric behavior. Water cut is not, however, significant at the end of the forecasted period. The effect of water injection for 16–19 years was observed on FPR. After 20 years of forecasting, the field oil production rate was 212 STB/D which is not high enough to keep

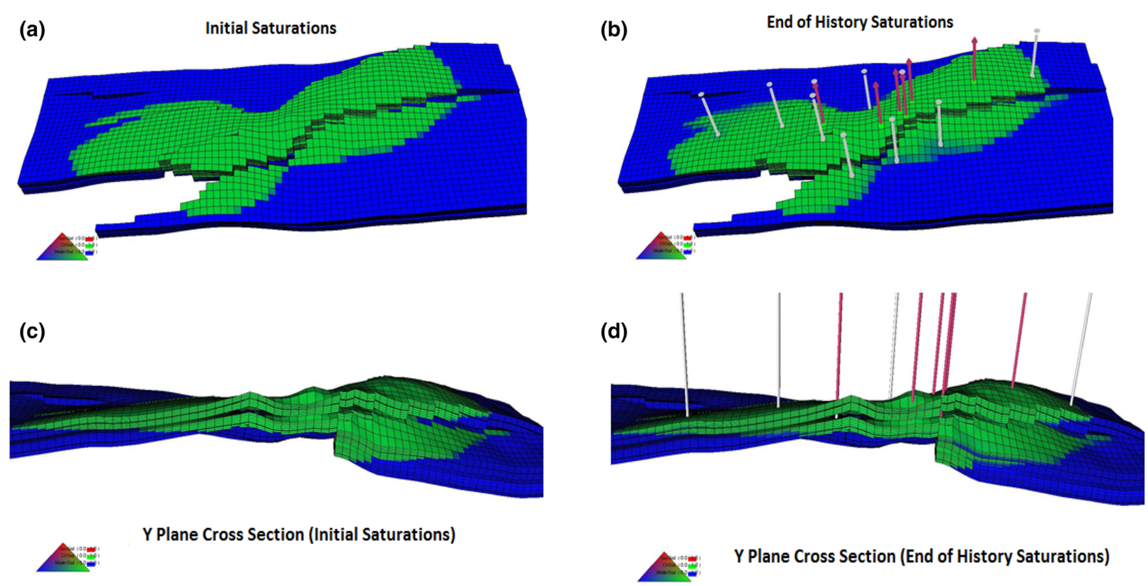

Fig. 5 a Initial fluid saturations, **b** end history fluid saturations, **c** cross section along the *Y*-plane with initial saturations, and **d** cross section along the *Y*-plane with the end of history saturations

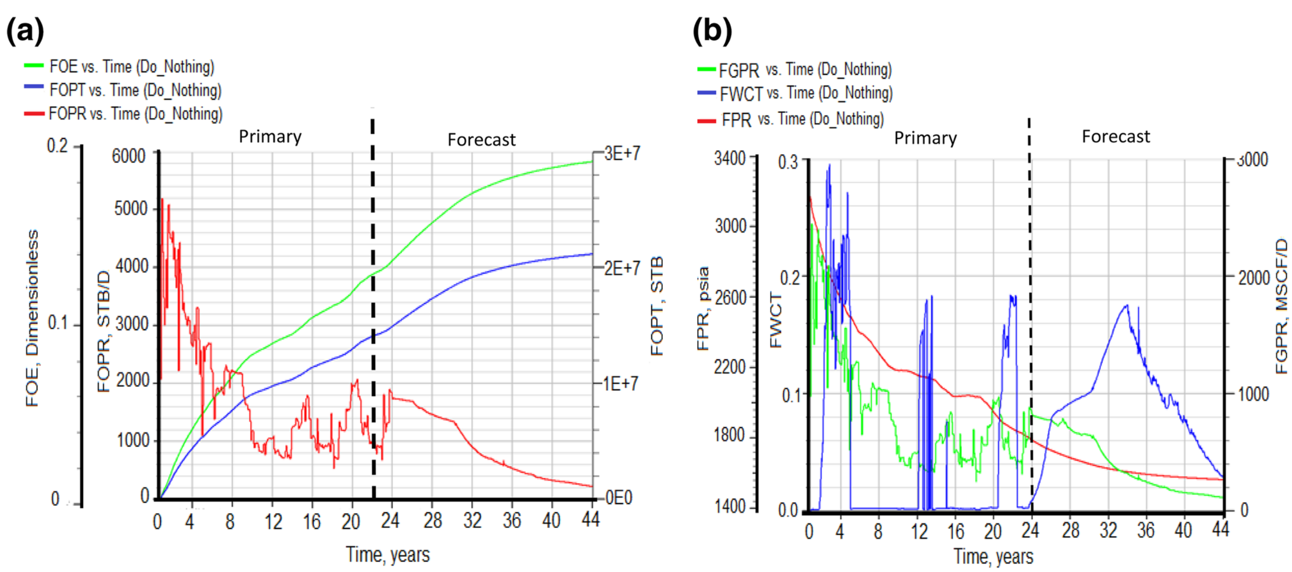

Fig. 6 **a** Primary recovery forecast for FOE, FOPT and FOPR; **b** primary recovery forecast of FPR, FGPR, and FWCT

Table 8 Primary recovery forecast of S3 reservoir

Primary recovery (Do_Nothing case)	End of history	20-year forecast
FOE (%)	13.74	19.45
FOPT, MSTB	14.944	21.159
FOPR, STB/D	1778	213
FPR (psia)	1801	1576
FGPR MSCF/D	829.5	109.4
FWCT (%)	0.0	2.8

the reservoir at the primary recovery stage. Table 8 presents the statistical results at the end of history match and forecast period which strongly point out the essential of implementing oil recovery enhancement.

Optimum constraints for CCO_2 and CO_2-WAG injections

In this section, the importance of well locations in a CCO_2 operation is presented. The WAG ratio and well completion

Table 9 Constraints used to run CCO_2 and CO_2-WAG numerical modeling

Parameter	Value
Total injector well	1
Total production wells	6
CO_2 injection rate	7 MSCF/D
Water injection rate	5000 STB/D (applicable to CO_2-WAG run only)
Maximum bottom-hole pressure	6000 psia
Forecasting period	10 years

Table 10 Performance evaluation during up-dip and down-dip injections

Parameters	Down-dip (location 1)	Up-dip (location 2)
FPR (psia)	1780	1650
FOPT (STB)	2.44×10^7	2.5×10^7

Table 11 Performance forecast of S3 reservoir considering different CO_2-WAG ratios

CO_2-WAG ratio	1:1	1:2	1:3	2:1	3:1
FOE (%)	23.24	23.18	22.86	22.86	22.6
FOPR, STB/D	1330	1405	1094	1348	1299
FPR (psia)	1890	1792	1728	1973	2012
FGPR, MSCF/D	2468	3820	4732	1659	1280
FWCT (%)	49	42	37	52	55

strategy, in different layers for CO_2-WAG, are also discussed by numerical modeling using the data given in Table 9.

To assess the importance of injector well's location on a dipping central block, an injector was considered on two different locations: one up-dip and the other down-dip (see Fig. 7a, b). The injector well (solid red with a red circle around it) was in the center and completed in the top four layers. Red colored wells are production wells and white colored wells are showing shut-in wells. All production wells were set up-dip except the one. Production wells were displayed by solid red with a red circle around them while the white circle with an arrow represented the shut-in wells. The simulation results for the FOPT, FPR, FOPR and FGPR for both locations are given in Table 10.

Obtained results showed that location 2 (up-dip) offers a better oil production as compared to location 1 (down-dip), but the breakthrough occurs before 2 years. It was also found that the reservoir pressure increases during the down-dip CO_2 injection. Comparatively, the CCO_2 injection offers a better result than the primary recovery. Thus, an up-dip CO_2 injector might be the best choice when it comes to selecting the better location.

Caudle and Dyes (1958) recommended to employ SWAG to mitigate the mobility contrast, but the issue of gravity segregation could be raised. Therefore, the CO_2-WAG mode was considered rather than SWAG. However, the CO_2-WAG process is influenced by reservoir heterogeneity, wettability, miscibility condition, fluid properties, and WAG ratio (Kyrylovych 2012). Thus, five CO_2-WAG ratios were considered to pick the optimal one based on the analysis of FOE, FOPR, FPR, FGPR and FWCT. These ratios were 1:1, 1:2, 1:3, 2:1 and 3:1 with water as the first fluid. The well locations for all CO_2-WAG scenarios (see Fig. 7) were the same as that of the CCO_2 up-dip case. The comparison indicated that the CO_2-WAG ratio of 1:2 is an optimal ratio, as presented in Table 11.

To determine a suitable well completion, the CO_2-WAG ratio of 1:2 was considered by considering the top four layers and top nine layers (i.e., excluding the non-reservoir layers) with the results presented in Table 12. Comparatively, both completion schemes had similar recovery, water cut, and rate. On top of that, the FPR was found to be above the

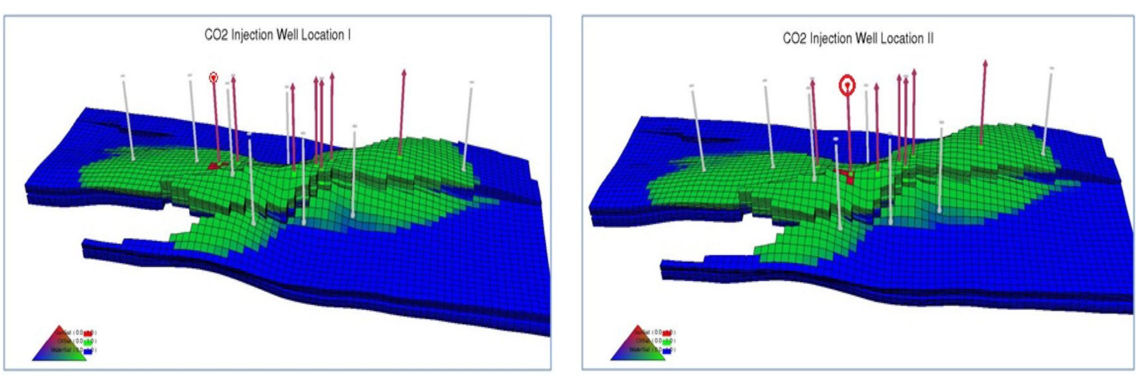

Fig. 7 (Left) CO_2 injector location 1 (down-dip); (right) CO_2 injector location 2 (up-dip)

Table 12 CO_2-WAG performance in case of different completion schemes of the injector well

CO_2-WAG completion layers	Top four layers	Top nine layers
FOE (%)	23	24
FOPR, STB/D	1406	1271
FPR (psia)	1792	1698
FGPR, MSCF/D	3816	4761
FWCT (%)	41.9	42

Table 13 Constraints used to run CCO_2 and CO_2-WAG modeling

Parameter	Value
Total injector well	1
Total production wells	6
CO_2 injection rate	7 MSCF/D
Water injection rate	5000 STB/D (applicable to CO_2-WAG run only)
CO_2-WAG ratio	1:2 (water as first fluid)
Maximum bottom-hole pressure	6000 psia
Forecasting period	20 years

bubble point pressure which indicated that the top four layers must be chosen for recovery optimization.

Optimized field oil recovery

To evaluate the scenario of an optimized recovery in the reservoir understudy, in terms of a suitable recovery phase (i.e., Do_Nothing for primary, while CCO_2, and CO_2-WAG for tertiary), three models were run. The well locations for producers and injector were similar to that of CCO_2 case. The run details of the models are given in Table 13.

The field was put on production for 23 years and forecasting the performance was made for the next 20 years. Figure 8a shows the FOE for all three cases. As it is shown in Fig. 8, it seems that the recovery performance of both CCO_2 and CO_2-WAG cases is more promising than the primary recovery for the first 6 years. The CO_2-WAG model is then resulting in a favorable recovery which is twofold better than Do_Nothing and CCO_2 cases. Figure 8b compares the FOPR of different recovery phases. Likewise, the overall performance of CO_2-WAG is more favorable than CCO_2 and Do_Nothing. FPR versus time by various processes is shown in Fig. 8c.

It is observed that there is a depletion mechanism under the primary recovery phase (Do_Nothing). The pressure drop of 225 psi and a total pressure of 1576 psia were observed at the end of the forecasting period. It seems from the pressure trends that CO_2 injection process slightly contributes to stabilizing the pressure, and as such the reservoir pressure in the forecasting period is following the same trend as that of the Do_Nothing case. A pressure drop of 172 psi and a total pressure of 1629 psia were observed at the end of forecasting period. On the contrary, the CO_2-WAG process was found to be a successful injection strategy to maintain the field pressure at 1830 psi at the end of the forecasting period. These results are aligned with the performance of CO_2-WAG published earlier by Caudle and Dyes (1958) and Mousavifar et al. (2012). The field gas oil ratios (FGOR) in MSCF/STB of all three cases are plotted in Fig. 8d.

It is interesting to see high and elevated gas oil ratios (GOR) in the field by the CO_2 injection compared to other two cases, which could be due to the position of well locations. The CO_2-WAG injection, on the other hand, was offering an acceptable FGOR by enhancing the frontal profile via reducing channeling, gravity override, and relative permeability to gas. In the beginning of the simulation (at 24 years), the water cut was negligible and close to 1% as shown in Fig. 8e.

Form Fig. 8e, it can be concluded that the FWCT by the primary (Do_Nothing) process gradually increases to almost 0.18 and then started to decrease with the same rate until the value of 0.03 is reached at the end of forecasting period. The trend of the FWCT in of the CCO_2 was like Do_Nothing case between 24 and 35 years, but its decline rate was much slower, reaching 0.13 at the end of simulation run. The FWCT in the CO_2-WAG case increased at a higher rate compared to the other two cases. However, it gave a manageable FWCT level during the forecasting period, thereby not affecting the superior recovery performance of the process. Table 14 compares simulated vectors of all three cases at the end of forecasting period (20 years). By taking this comparison into consideration, the CO_2-WAG process was technically found highly suitable to enhance the recovery compared to other two cases.

Conclusion

Oil reservoirs have a naturally low recovery factor. The miscible CO_2 displacement mechanism is one of the methods in this scenario which can assist to improve the recovery significantly. Preliminary screening for CO_2-EOR is an essential step to determine a suitable oil reservoir for a detailed assessment. However, wettability, heterogeneity and permeability configurations are important parameters that should be included in the screening criteria of miscible CO_2 flooding. The S3 reservoir was found to be a potential candidate based on the updated screening criteria. Numerical modeling of injection strategy for miscible CO_2 flooding shows that

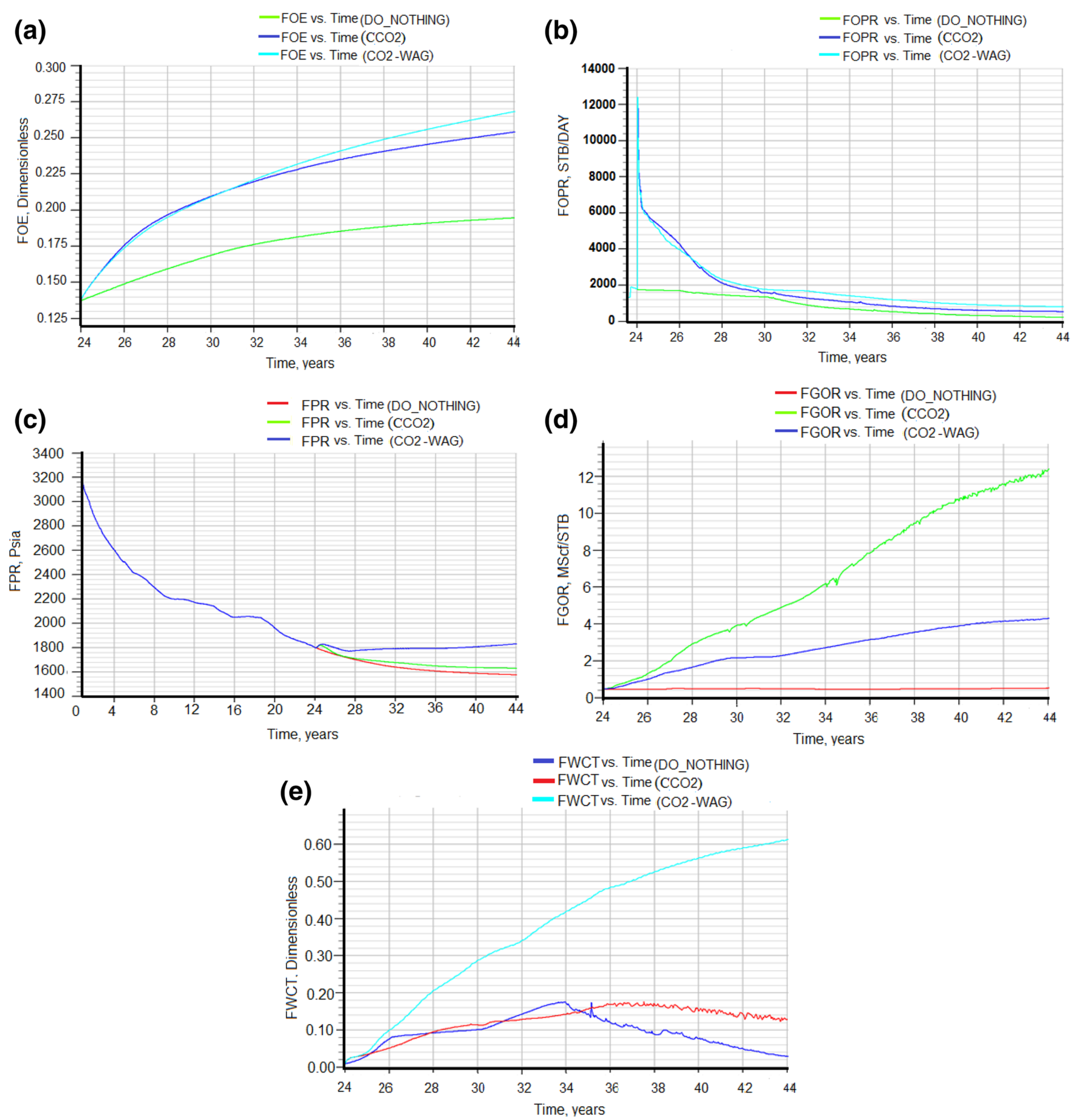

Fig. 8 Comparison among Do_Nothing, CCO_2, and CO_2-WAG injection cases for **a** FOE, **b** FOPR, **c** FPR, **d** FGOR, **e** FWCT

the recovery performance of CCO_2 and CO_2-WAG processes is far better than the primary recovery. Particularly, the CO_2-WAG process with an optimum injection well completion and CO_2-WAG ratio was technically the most successful method to increase the incremental recovery by more than two times compared to the primary recovery and continuous injection scenarios.

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Table 14 Comparison of different production types with respect to various aspects at the end of forecasting period (20 years)

Recovery process	Predicted recovery forecasts		Predicted total cumulative oil production		Field oil production rate (FOPR), STB/D	End of forecast period predicted field pressures		Predicted field gas oil ratio	CO_2 fraction	Forecast field water cut
	Recovery by Jan 2028 (%)	20 years incremental (%)	FOPT	Increment		FPR (psia)	(FPR-1801) (psia)	FGOR, MSCF/STB	CO_2 (%)	FWCT (%)
Do_Nothing	19.45	5.7	21.16 MMSTB	6.21 MMSTB	212	1576	− 225	0.514	31	3
CCO_2	25.4	11.66	26.97 MMSTB	12.03 MMSTB	527	1629	− 172	12.419	96	13
CO_2-WAG	26.8	13.6	28.63 MMSTB	13.69 MMSTB	799	1830	+29	4.312	91	61

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