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# Investigating $CO_2$-enhanced oil recovery potential for a mature oil field: a case study based on Ankleshwar oil field, Cambay Basin, India

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**Abstract** $CO_2$-enhanced oil recovery (EOR) is an upcoming technology in India. At present, no Indian field is under $CO_2$-EOR and implementation of this technique to a mature oil field needs a rigorous study. In the present work, we made an attempt to investigate the $CO_2$-EOR potential of a mature oil field, situated in Cambay Basin, India. The field was put on production in 1961, and it has produced approximately 65.36 MMt oil during massive water flooding, leading to residual oil reserves of 6.49 MMt. The operator of the field is interested in incremental oil recovery from this field by injecting $CO_2$. This requires estimation of incremental oil recovery potential of the field by carrying out systematic study. We, therefore, developed a conceptual model inspired by Ankleshwar oil field of Cambay Basin using available information provided by the field operator and carried out systematic studies to establish an optimized strategy for $CO_2$ injection. To achieve this goal, we investigated the effect of various operational parameters on oil recovery efficiency of our conceptual model and selected optimum parameters for reservoir simulations. Simulation results clearly indicate that the field can be a good candidate for $CO_2$-EOR, and an additional oil recovery of 10.4% of hydrocarbon pore volume is feasible. Major outcome of the study is an optimized black-oil simulation model, which is in good agreement with the fine grid compositional model of high accuracy. The proposed black-oil model can easily be implemented and updated compared with compute intensive finer compositional simulation model.

**Keywords** Cambay basin · Black oil simulation · Todd and Longstaff parameters · $CO_2$-enhanced oil recovery

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## Introduction

In recent years, $CO_2$ injection has emerged as a significant enhanced oil recovery (EOR) technique due to the twin advantages of EOR and mitigating the impact of $CO_2$ on climate. A cost-effective EOR can extend the production life of an oil field for several years (Muggeridge et al. 2014). In response to these reasons, the practice of $CO_2$-EOR has increasingly attracted the policy makers and industries to implement it. Oil industries have been utilizing $CO_2$ flooding successfully worldwide as a tertiary recovery mechanism for several years in which, $CO_2$ is compressed and injected into the reservoir. Studies show that $CO_2$-EOR in oil fields can improve the oil recovery significantly (Orr and Taber 1984; Bondor 1992; Akervoll and Bergmo 2010; Vuillaume et al. 2011; Dimri et al. 2012; Ganguli et al. 2014; Ganguli et al. 2016a). Nevertheless, reduction of injectivity is a serious threat to $CO_2$ flooding and is reported in many fields (Stein et al. 1992; Rogers and Grigg 2000; Goodyear et al. 2003; Barati et al. 2016), which should be avoided by decreasing the water alternating with gas (WAG) ratio, increasing injection pressure, etc. The overall process of $CO_2$-EOR involves efficient displacement of oil towards the production wells by overriding gas and under-riding water fronts. In practice, the $CO_2$ is injected in the reservoir as a supercritical fluid (temp. 31.1 °C, pressure 74 bar), and hence, it can lower the viscosity of the oil and increase its mobility. Injected $CO_2$ can displace oil either by miscible or immiscible displacement, which depends on minimum miscibility pressure (MMP). The MMP is defined as the lowest pressure at which multi-contact miscibility can be achieved. Immiscible displacement takes place at reservoir pressure below MMP, and miscible displacement takes place when reservoir pressure is above MMP. The miscible $CO_2$-EOR works more efficiently than the immiscible one (Clark et al. 1958; Bondor 1992; Muggeridge et al. 2014). If initial reservoir pressure is less than attaining MMP by virtue of injection may affect reservoir health, hence implementation of $CO_2$-EOR in an oil field needs a systematic approach and research.

This paper details the development of a conceptual $CO_2$-EOR model based on Ankleshwar oil field, and a systematic study to estimate the incremental oil recovery efficiency using limited data provided by the operator. Further, we investigate the possibility of miscible displacement in Ankleshwar oil field of Cambay Basin by analysing various operational parameters.

## Geology and reservoir description

The Ankleshwar oil field is situated in Cambay Basin, India, which is one of the main onshore Cenozoic oil basins of India. The field is being operated by Oil and Natural Gas Corporation of India Pvt. Ltd. (ONGC). The field was put on production on August 15, 1961, and subjected to peripheral water injection since 1966. It has produced approximately 49% of original-oil-in-place (OOIP) under natural aquifer drive and peripheral water injection (ONGC personal communication; ONGC report 2010). This is an arenaceous multi-layered reservoir structure, runs into the Gulf of Cambay in an approximately NNW-SSE direction (Fig. 1a). Age of the sediments ranges from Paleocene to recent (Mukherjee 1981; Mehdizadeh et al. 2010). Figure 1b depicts the stratigraphy of the study area, in which, the reservoir formation is of middle to upper Eocene age, comprised of thick sequence of sands (e.g., Ardol and Hazad) and shales (e.g., Telwa and Kanwa). The Telwa and Kanwa shale members are devoid of coarser clastics and act as a cap-rock to the Ardol and Hazad members, respectively. In total, the Eocene sandstones broadly divided into 11 layers (S1–S11), constitute the reservoir, where S1 to S5 layers represent the middle sand group and S6 to S11 represent the upper sand group (Srivastava et al. 2015). The potential layers identified for $CO_2$-EOR are S3 and S4 layers, the most productive sand layers, were clubbed together in the simulation model as S3 + 4 (Ganguli et al. 2016b). It is noteworthy to mention that S3 + 4 layers are not continuous throughout the reservoir and some pinch-outs were observed. These discontinuities cause production challenges. The formation thickness of the target layers (S3 + 4) is around 30 m. The oil-water-contact (OWC) varies between 1190 to 1214 m, and gas oil contact (GOC) is around 1050 m. For conventional hydrostatic equilibrium, the datum was fixed at 1113 m with initial pressure of 115.5 bar.

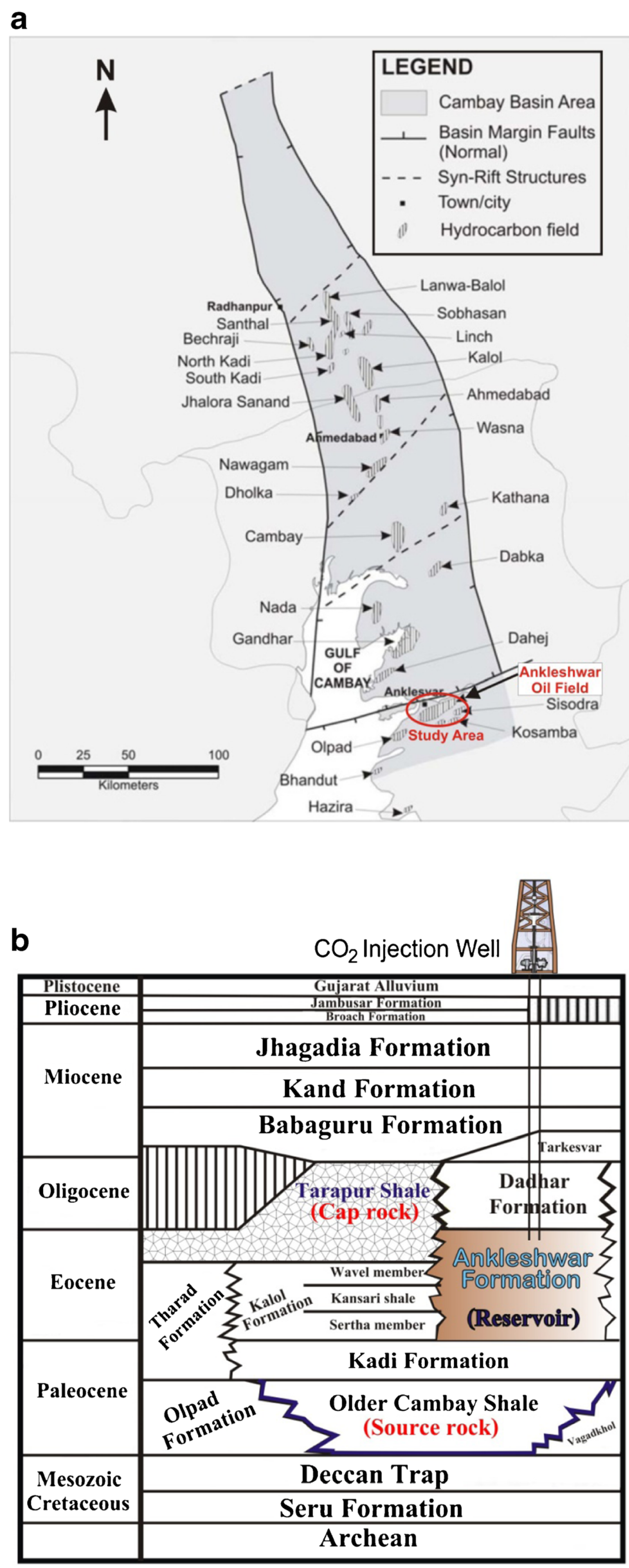


**Fig. 1** **a** Location map of the main oil and gas fields in the Cambay Basin, where the study area is marked by red ellipse. **b** Schematic distribution of the litho-stratigraphy of the study area along with the trajectory of the feasible $CO_2$ injection well within the Ankleshwar formation

## Laboratory studies for $CO_2$-EOR

Before going for a pilot study, the operator carried out laboratory experiments using different injection fluids such as $CO_2$, $N_2$, and hydrocarbon gas (HC) to evaluate the feasibility of tertiary gas injection in sand S3 + 4 for EOR. Berea cylindrical core with oil sample from the Ankleshwar reservoir have been used to evaluate the potential of various fluid (i.e., $CO_2$, $N_2$, HC gas, etc.) injection in mobilizing the residual oil within water flooded sand unit of S3 + 4. The injection rate for all the fluids was set to 1 $cm^3/h$ (ONGC Pvt. Ltd., personal communication). $CO_2$ injection resulted in an incremental oil recovery of approximately 11.8% of hydrocarbon pore volume (HCPV) over water flooding as compared to $N_2$ and HC gas injection, which were contributed to the oil recovery of about 4.8 and 4.0% of HCPV, respectively.

## Estimation of MMP

Slim-tube simulations were performed by using Eclipse-300 software to estimate the MMP between the recombined Ankleshwar oil and pure $CO_2$, and mixtures of $CO_2$ and intermediate hydrocarbon gas components, all at reservoir temperature and pressure. We identified that the MMP is around 134 bar (Fig. 2a), suggesting that Ankleshwar oil is not

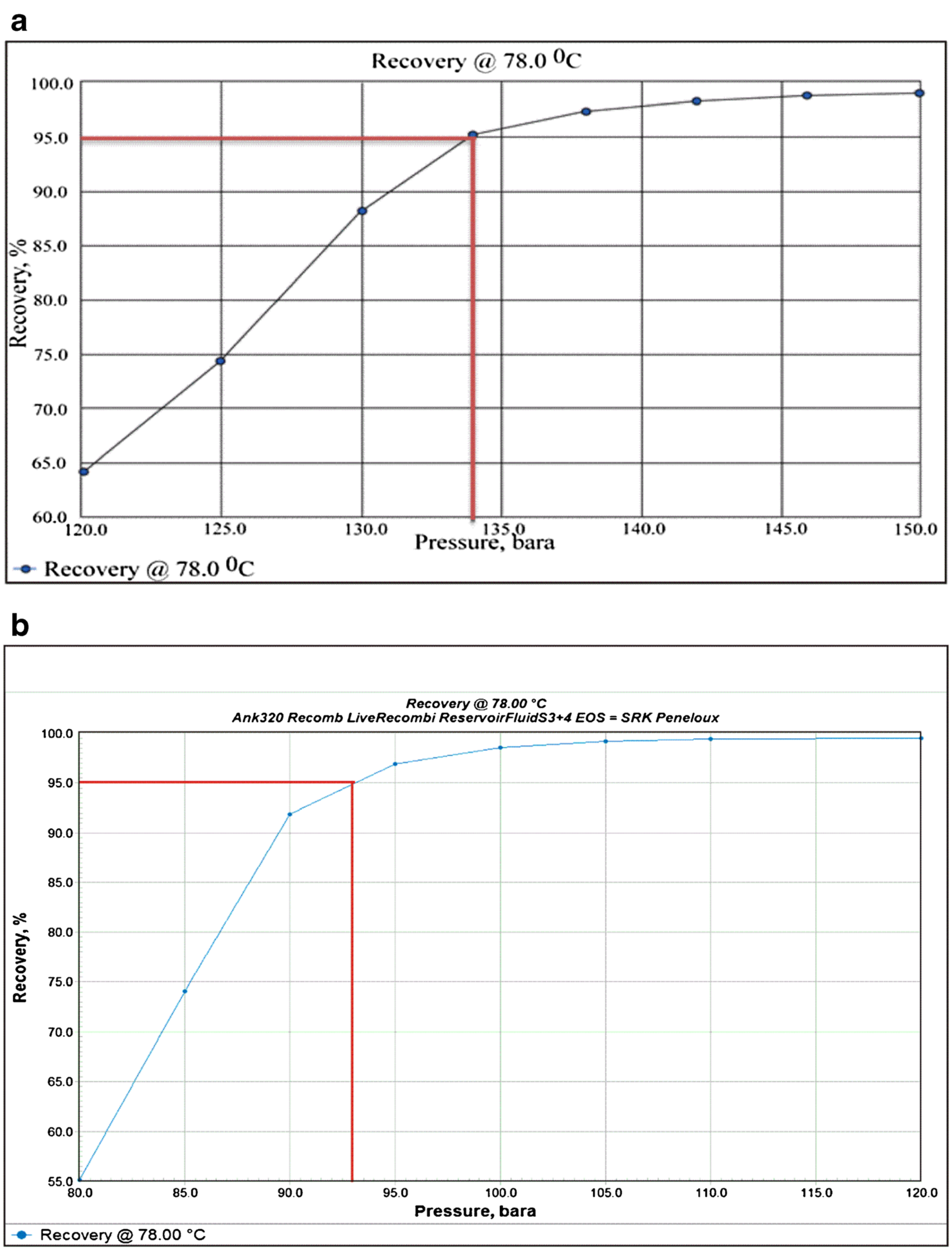


**Fig. 2** The estimated MMP at reservoir conditions **a** before introducing the new injection fluid and **b** after introducing the new injection fluid composition, consisting of 40% mole volume of $CO_2$, 10% methane, 20% ethane, 20% propane, and 10% butane, respectively

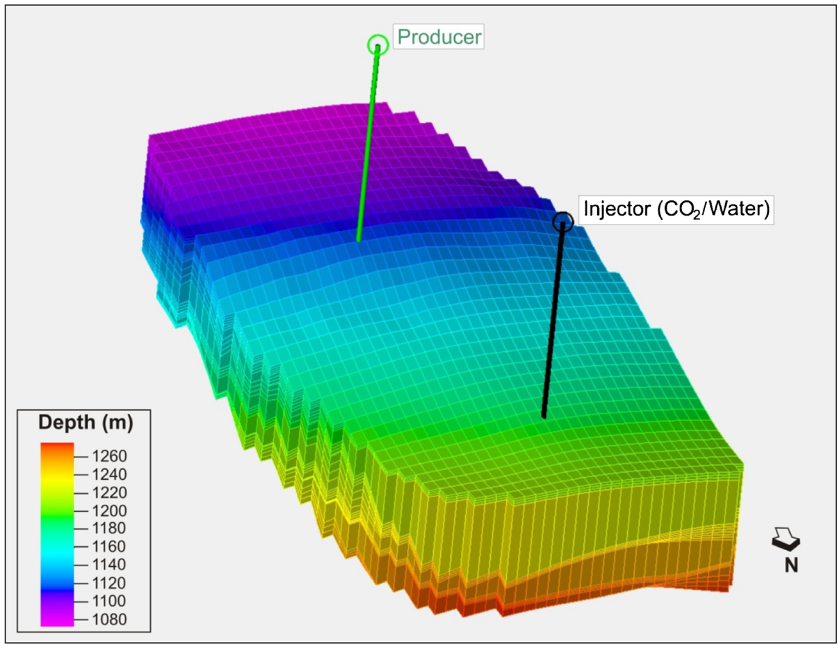


**Fig. 3** Geometry, grid, depth, and well positions of the 3D conceptual model for $CO_2$-EOR in the Cambay Basin. *Color bar* indicates depth; the model is exaggerated by a factor 7.5 in the vertical direction

miscible with pure $CO_2$ at the reservoir temperature and pressure (102 bar, and 78 °C). Thus, to lower the MMP, we developed a new injection fluid composition, consisting of 40% mole volume of $CO_2$, 10% methane, 20% ethane, 20% propane, and 10% butane. The combined condensing and vaporizing drive mechanism was used in MMP calculation at 78 °C. The slim-tube simulation results show that MMP was reduced to 93 bar from 134 bar by using this injection fluid (Fig. 2b).

## Conceptual $CO_2$-EOR model

To study the field in detail, we developed a conceptual $CO_2$-EOR model, inspired by the generic sandstone reservoir (Fig. 3). The model consists of 38 × 34 × 23 cells representing six sand layers of Hazad and Ardol formation and five shale layers alternatively within the sands representing Telwa and Kanwa formations. The reservoir model is penetrated by two wells, one injector (I1) and one producer (P1). The production well is located in the up dip direction or at the crest of the model, while the injector is located in the down-flank. The average distance between the wells is around 920 m. The depth of reservoir model extends from 1075 to 1265 m. The reservoir parameters were used for the simulations as shown in Table 1 (ONGC report 2010). To conduct the simulations, we considered that the reservoir contains under-saturated oil (i.e., no gas-cap condition) with oil API gravity of 47. Aquifer lying below the reservoir has provided a strong pressure support for oil production.

**Table 1** Reservoir properties of the Ankleshwar oil field, Cambay Basin

| Field/input data | Units | Values |
|---|---|---|
| Reservoir temperature | °C | 78 |
| Reservoir pressure | Bar | 113.7 |
| Saturation pressure | Bar | 102.41 |
| Depth | M | 1113 |
| Oil viscosity | Cp | 0.36 |
| Water viscosity | Cp | 0.343 |
| Density of stock tank oil | $kg/Sm^3$ | 820 |
| GOR | $Sm^3/Sm^3$ | 80 |
| $B_o$ | $Rm^3/Sm^3$ | 1.44 |
| Gas density | $kg/Sm^3$ | 0.739 |

## Petrophysical properties

Petrophysical properties such as porosity, permeability, rock compressibility, etc. populated in the conceptual model were provided by the operator. The total thickness of the reservoir is 26 ± 1.5 m. The S3 + 4 layers have average porosity of 23% and permeability of 1000 mD, respectively. The porosity and permeability assigned to the individual sublayers of the

**Table 2** Reservoir rock properties for the sublayers of S3 + 4 sands, the major pay zone of Ankleshwar oil field

| Parameters/layers | S4–1 | S4–2 | S4–3 | S4–4 | S3–1 | S3–2 |
|---|---|---|---|---|---|---|
| Effective thickness (m) | 3.19 | 3.69 | 6.85 | 3.65 | 4 | 3.8 |
| Porosity (%) | 24.7 | 24.9 | 23.5 | 23.5 | 23.9 | 21.7 |
| Permeability (mD) | 540 | 1013 | 938 | 630 | 945 | 1953 |

**Table 3** Live oil properties as a function of pressure, which were used for reservoir simulations (ONGC, personal communication)

| Pressure (bar) | Oil viscosity (cP) | Oil FVF ($B_o$) |
|---|---|---|
| 1.0 | 1.06890 | 0.444 |
| 15.0 | 1.06510 | 0.459 |
| 30.0 | 1.06123 | 0.475 |
| 50.0 | 1.05636 | 0.496 |
| 60.0 | 1.05404 | 0.507 |
| 70.0 | 1.05179 | 0.518 |
| 80.0 | 1.04961 | 0.529 |
| 90.0 | 1.04750 | 0.540 |
| 100.0 | 1.04545 | 0.552 |
| 102.6 | 1.04493 | 0.555 |
| 102.7 | 1.04491 | 0.555 |
| 103.4 | 1.04477 | 0.555 |
| 110.0 | 1.04346 | 0.563 |
| 125.0 | 1.04057 | 0.580 |
| 150.0 | 1.03602 | 0.608 |
| 200.0 | 1.02774 | 0.666 |

conceptual EOR model are summarized in Table 2 (ONGC report 2010). The shale layers were assigned 100% water saturation with negligible permeability. The rock compressibility of 2.167e−5 $psi^{-1}$ was considered for all the simulations.

## Fluid properties and flow parameters

As per the information obtained from the operator of this mature hydrocarbon field, the live oil viscosity and oil-formation-volume factor ($B_o$) as a function of increasing pressure are summarized in Table 3 (ONGC Pvt. Ltd., personal communication). Capillary pressure is assumed to be neglected since no reliable measured data were provided to us. The relative permeability functions were derived by using

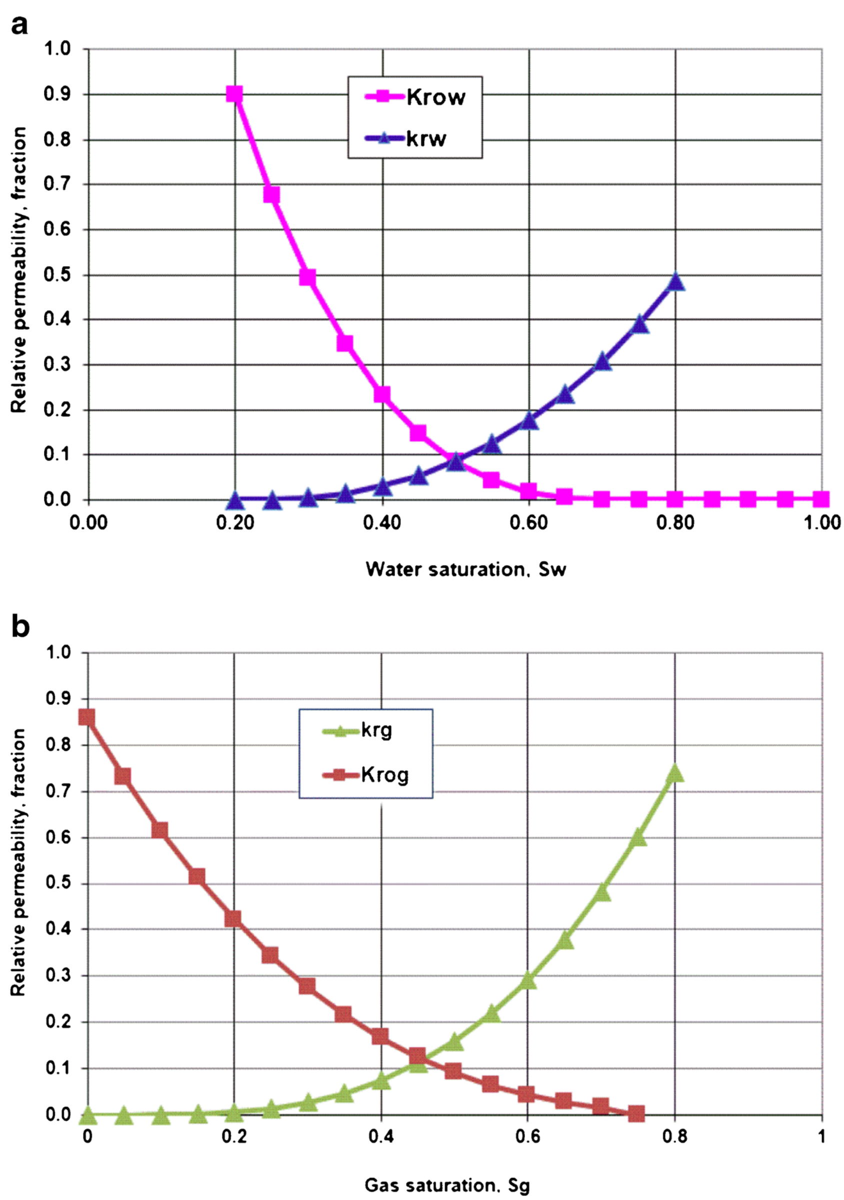


**Fig. 4** **a** Drainage oil/water relative permeability curves as a function of water saturation. **b** Drainage gas/oil relative permeability curves as a function of gas saturation

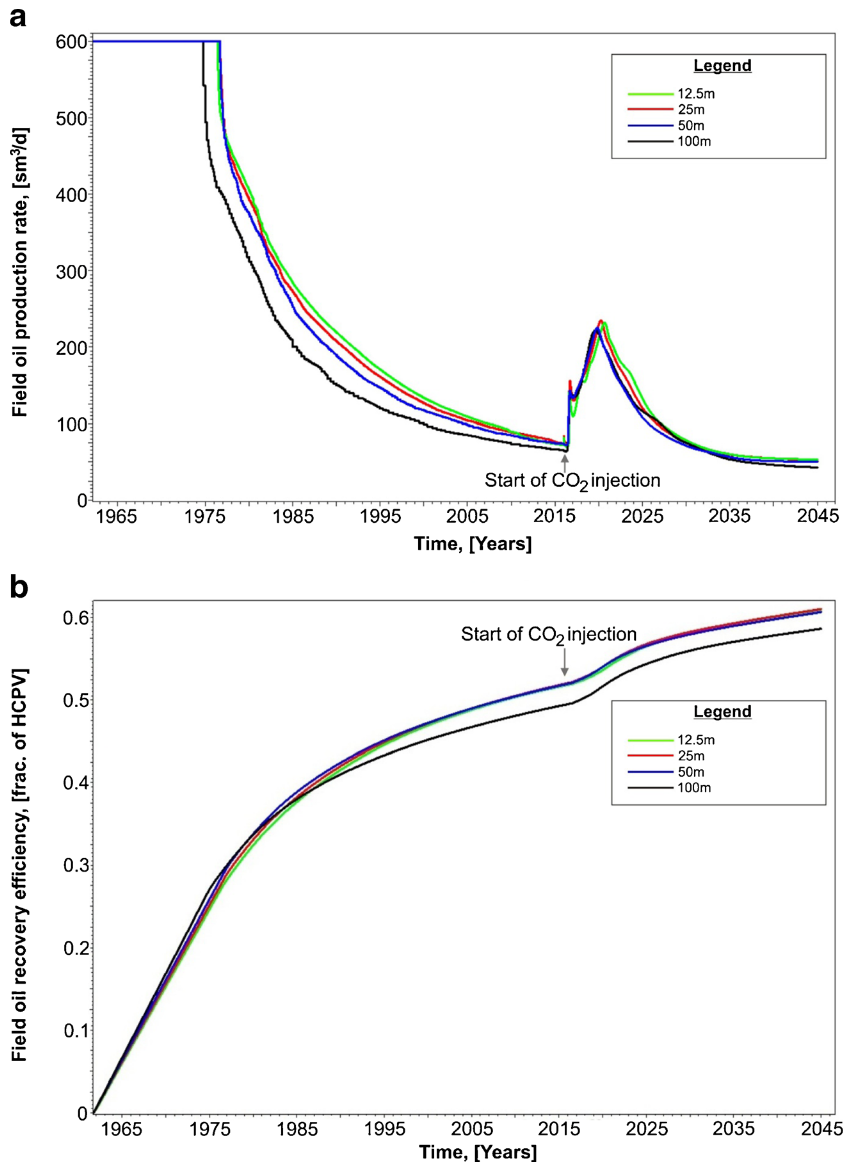


**Fig. 5** The grid resolution sensitivity plots for the conceptual $CO_2$-EOR model of the Cambay Basin: **a** the field oil production rate as a function of time, **b** field oil recovery efficiency. *Legend* represents the different values of grid size in *x* and *y* directions, where the *green curve*, *red curve*, *blue curve*, and *black curve* represent 12.5, 25, 50, and 100 m grid resolution, respectively

Corey relative permeability correlations, and the water-oil and gas-oil relative permeability curves are illustrated in Fig. 4.

## Selection of optimum operational parameters

Before doing reservoir simulations, we carried out sensitivity analysis of various reservoir parameters to understand the reservoir performance under $CO_2$-EOR. The simulations were carried out by using commercial software such as Eclipse 300 (E-300) and E-100. It is well known that E 300 is more reliable as it honors compositional oil, but it takes more computational time. Hence, we also made an attempt to recommend a faster black oil model in E-100, which can be comparable with the compositional model.

Miscible $CO_2$ injection was assumed and $CO_2$ injection rate was controlled by the production rate target. The bottom-hole-pressure (BHP) of the producer was maintained at 102.9 bar, which is above the bubble point pressure. To mimic the reservoir conditions, the conceptual model was subjected to water flooding for about 50 years followed by continuous gas injection for next 30 years.

### Grid sensitivity analysis

We know in simulations that there is a tradeoff between computational time and accuracy. In general, very fine grid simulations are more accurate than coarser ones, but computational time is more for fine grid models. Hence, to select optimum grid size for simulation, we consider four grid sizes, ranging from very fine scale, viz., 12.5 m (155 × 140 × 23) to coarse scale, i.e., 100 m (19 × 17 × 23). The petrophysical properties like permeability and porosity were upscaled accordingly for each grid resolution. Our aim was to recommend an optimum

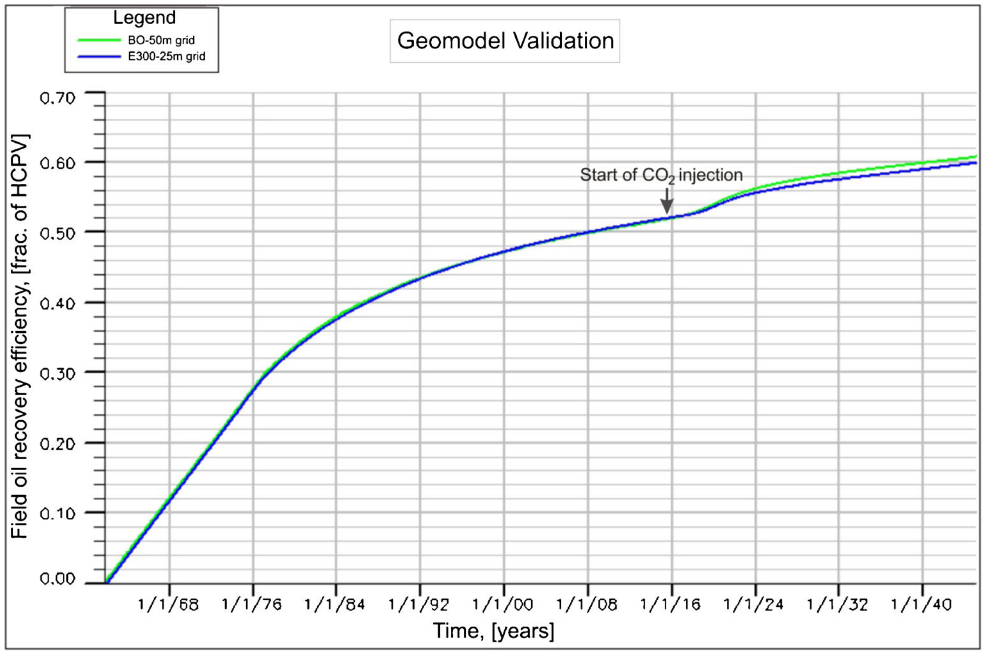


**Fig. 6** Geomodel validation including the field oil recovery efficiency for fine grid compositional (25 m) and medium grid black oil simulation model (50 m)

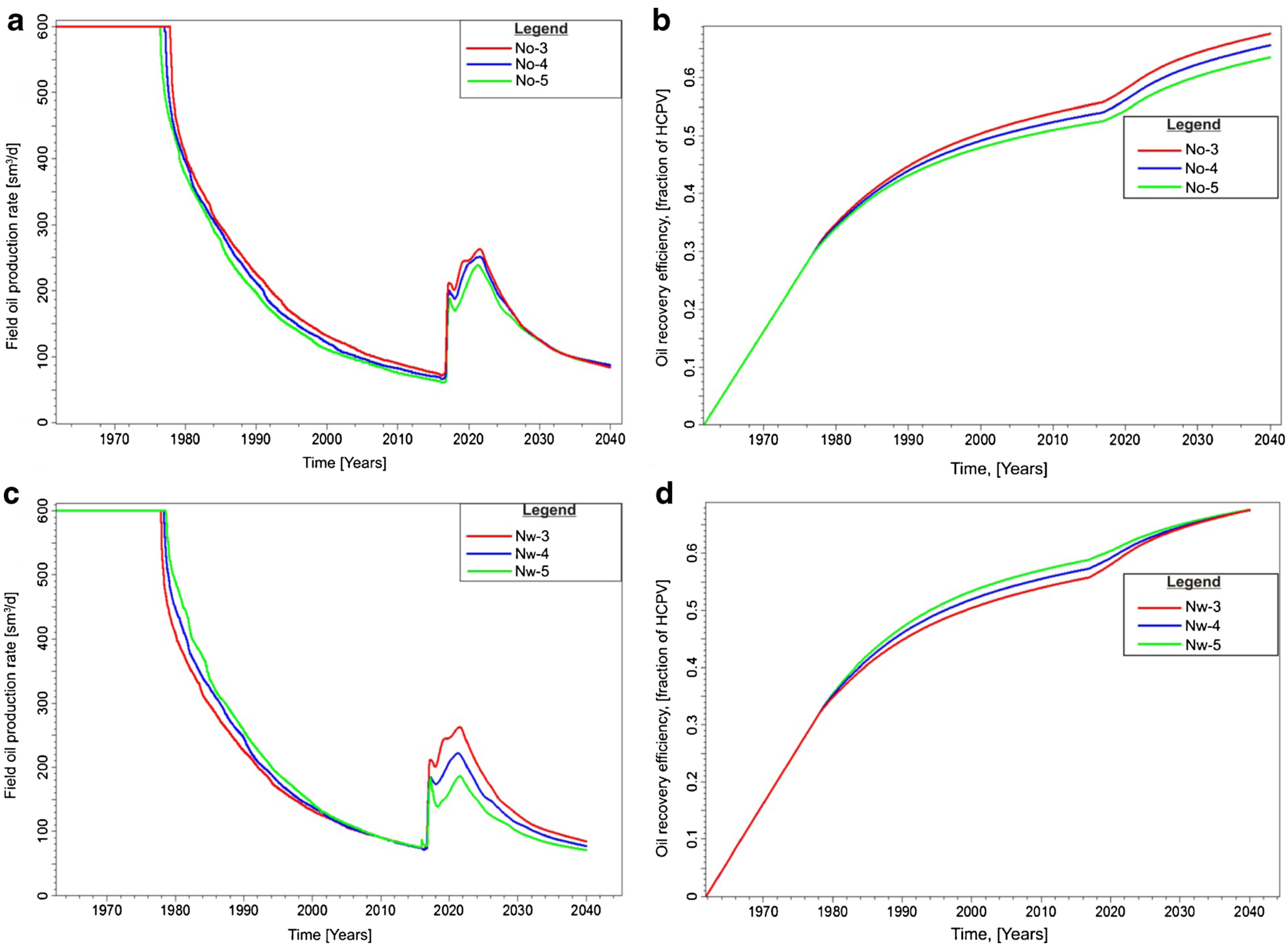


**Fig. 7** The impact of different Corey exponents for oil ($N_o$) and water ($N_w$) on the field oil production rate and the field oil recovery efficiency. *Red curve*, *blue curve*, and *green curve* represent the value of Corey exponents for oil and water as 3, 4, and 5, respectively

**Table 4** Different T&L mixing parameters ($\omega$) used to calculate the viscosity and density for miscible $CO_2$ flooding

| T&L parameter for viscosity | T&L parameter for density |
|---|---|
| 0.33 | 1 |
| 0.67 | 1 |
| 0.33 | 0.67 |
| 1 | 0.33 |
| 0.67 | 0 |
| 0.67 | 0.67 |
| 0.33 | 0.33 |
| 1 | 0.67 |
| 0 | 0.33 |
| 0.33 | 0 |
| 1 | 0 |
| 0 | 0.67 |

grid size for the model, which can adequately represent the reservoir geometry and correctly describe the reservoir behavior with a good agreement with the fine scale compositional oil model.

The field oil production rate (FOPR) for various grid sizes is shown in Fig. 5a. The production curve for 50 m grid black oil model (blue line) is comparable with the production curve for 25 m grid compositional oil model. It is also seen that after the gas-breakthrough (2016), the oil production increases rapidly for 12.5 m grid model (green line) and 25 m grid size grid model (red line), but these models are very expensive in terms of the computational cost. The field oil recovery efficiency (FOE) also follows the trend similar to oil production rate as shown in Fig. 5b. We found that simulations results obtained

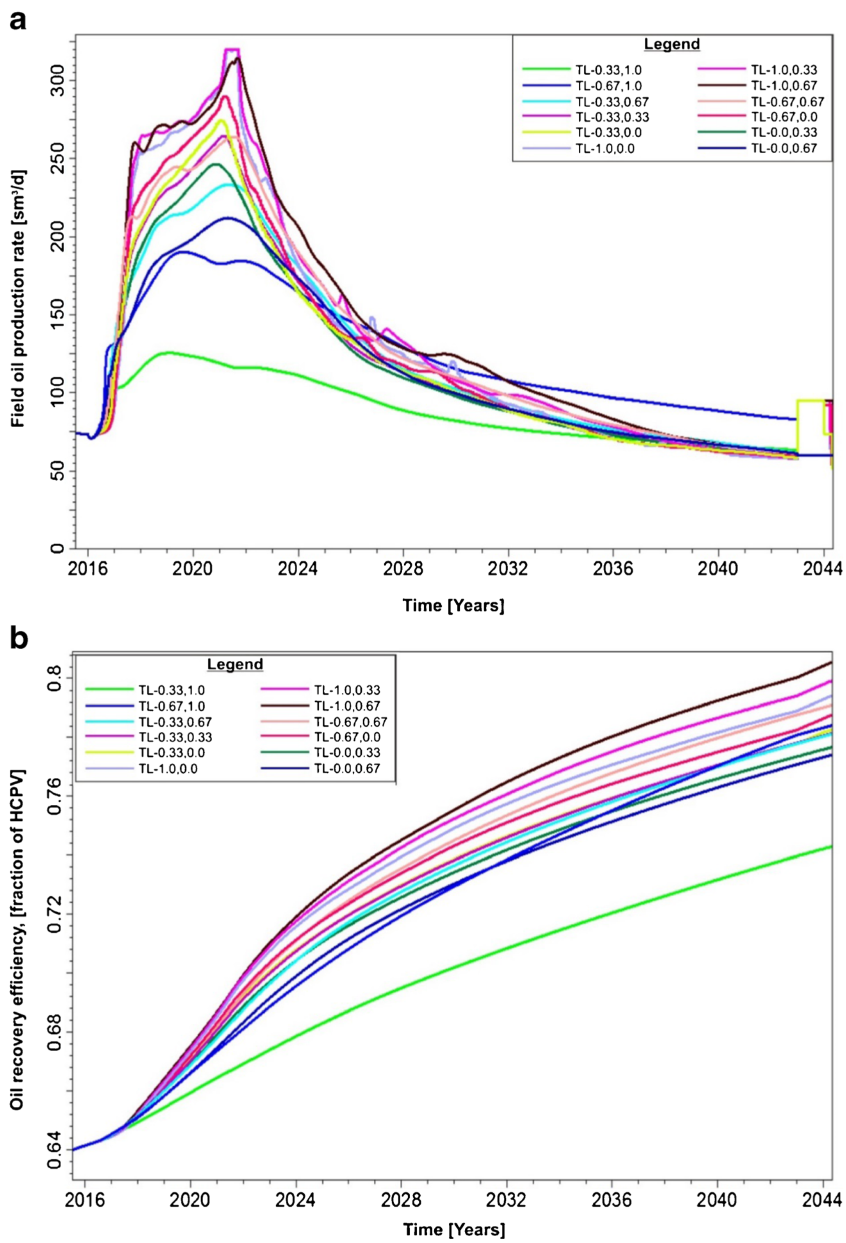


**Fig. 8** Effect of various T&L parameters on **a** the field oil production rate and **b** the field oil recovery efficiency for the conceptual $CO_2$-EOR model. *Color bar* represents the different combination of the T&L mixing parameter for viscosity and density calculations

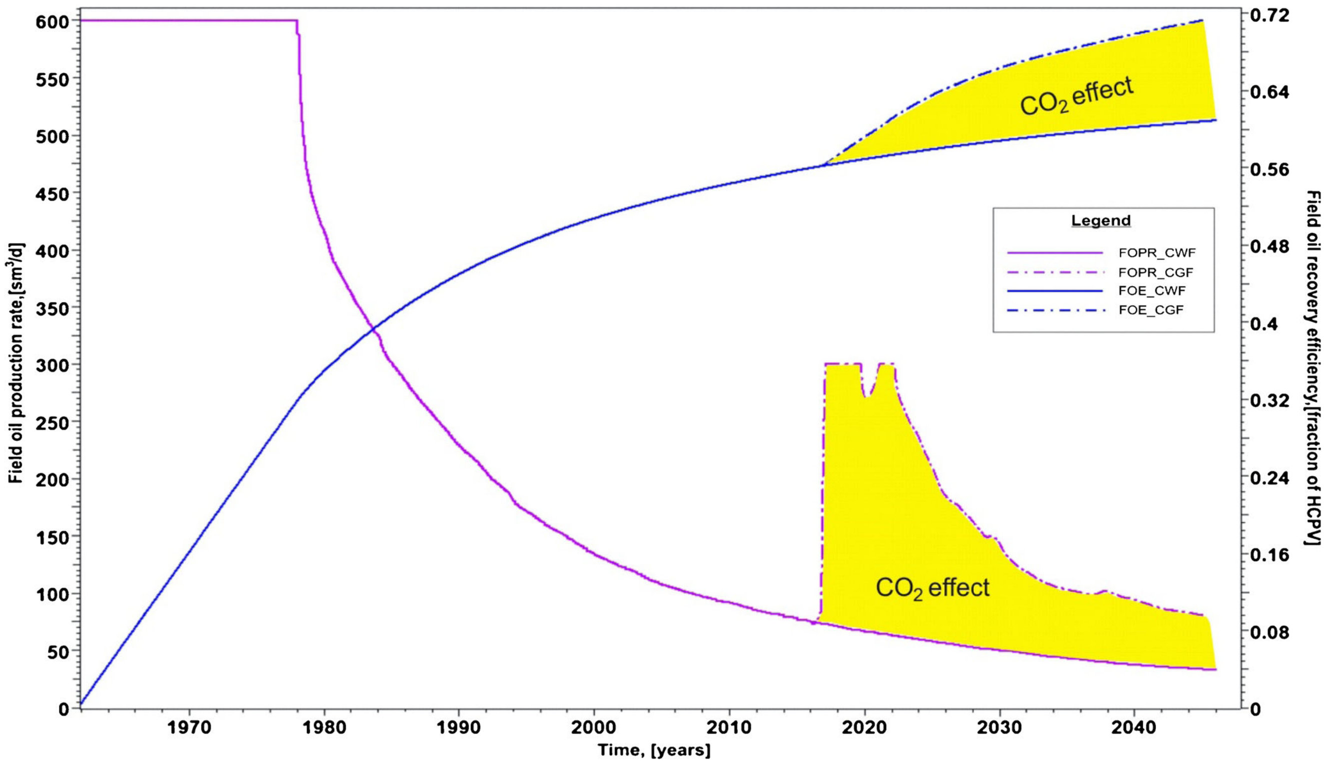


**Fig. 9** Quantitative estimation of $CO_2$-EOR potential for Ankleshwar oil field in Cambay Basin, India. The field oil production rate (*magenta curve*) and oil recovery efficiency (*blue curve*) has been plotted as a function of time. The *solid line* represents the results from continuous $CO_2$ flooding, while *dashed-dotted line* represents continuous water flooding. The difference in results from continuous $CO_2$ flooding and water flooding helps to estimate the incremental oil recovery from this field

by using 50 m grid black oil model are in good agreement with the 25 m compositional model (Fig. 6), which is widely accepted for its accuracy. Therefore, we selected 50 m grid black oil model for further analysis.

## Corey exponent for oil and water

Relative permeability, between constrained endpoints, is controlled by the Corey exponents, $N_w$ (water) and $N_o$ (oil). In general, Corey's exponents are obtained from relative permeability curves generated by using laboratory studies. In case of nonavailability of laboratory data, two-phase relative permeability curves can be generated by using empirical correlations (Corey 1954; Stone 1970; Sigmund and McCaffery 1979). For unconsolidated sands, oil-water Corey exponents of 3.0 and 3.5 have been proposed in literature (Honarpour et al. 19867). It is noteworthy that lower Corey exponent values result in more concave relative permeability curve, thus lower relative permeability, indicating more sand heterogeneity, while higher exponent values result in comparatively a less concave curve, indicating more homogeneous sand (Kevin 2002). Corey's exponents are reservoir specific; hence, its value must be adjusted based on simulation results. To analyze the effect of Corey water exponent ($N_w$) and oil exponent ($N_o$) on reservoir performance, we selected values of $N_w$ and $N_o$ typically as 3, 4, and 5 in a consistent manner by keeping one fixed at a time, which covers wide range of heterogeneity of the sand layers. Hence, we assumed that the wetting phase is water and nonwetting phase is oil.

We observed that the field-oil-production rate (FOPR) and field-oil-recovery-efficiency (FOE) decreases drastically with the increase of value of $N_o$ (Fig. 7a, b). These results are reasonable as previous studies suggest that oil permeability and recovery decrease with an increase in $N_o$ (Corey 1954). However, an opposite scenario is seen for $N_w$ in this case. We observed increase in FOPT and FOE with increase in the exponent (Fig. 7c, d). We selected the values of $N_o = 3$ (red solid line) and $N_w = 5$ (green curve) as for these values reservoir performance was better.

## Todd-Longstaff (T&L) parameters on reservoir response

Todd and Longstaff (1972) have proposed an empirical mixing parameter (ω), known as T&L mixing parameters, particularly for viscosity and density calculations to define the effective properties during miscible displacement. These parameters are generally used for field-scale miscible flood simulations, particularly, for $CO_2$ flooding in the reservoir. Use of these parameters can circumvent intensive computations for the compositional simulation, without compromising the accuracy level. The values of ω lie between 0 and 1 and control the degree of injected fluid mixing within each grid cell. The value ω = 1 suggests that the fluids are miscible in each grid cell and if ω = 0, the fluids are immiscible (Todd and Longstaff 1972). These parameters are also adjusted on the basis of simulation results. Thus, to analyze all possible scenarios, we considered different combinations of values of ω for viscosity and density computations, which are tabulated in Table 4.

Figure 8 depicts the sensitivity of T&L mixing parameters on reservoir performance. We observed promising results for "ω" = 1 and 0.67 for viscosity and density computations, respectively (brown curve). However, for ω = 1 and 0.33, the field oil production peaked during gas injection period (pink curve), but the field-oil-recovery-efficiency curve was not satisfactory. Hence, the optimum value of ω for viscosity and density computation were selected as 1 and 0.67, respectively. Miscible $CO_2$ injection can be possible by considering the optimum T&L parameters suggested by this sensitivity analysis. This allows more injection of gas into the reservoir, and hence results in incremental oil recovery.

## Estimation of $CO_2$-EOR potential

After performing the simulations of the 3D conceptual model, we estimated that about 10.4% of additional oil recovery can be achieved from this field as a result of $CO_2$-EOR. This has been validated from Fig. 9, which illustrates the difference in recovery due to two different injection schemes, continuous water injection (blue solid curve) and continuous $CO_2$ injection (blue dash-dot curve).

## $CO_2$ distribution in the reservoir

Once the operational parameters are adjusted, we carried out simulations using E-100 (black oil simulator). The conceptual model was subjected to water flooding for about 50 years

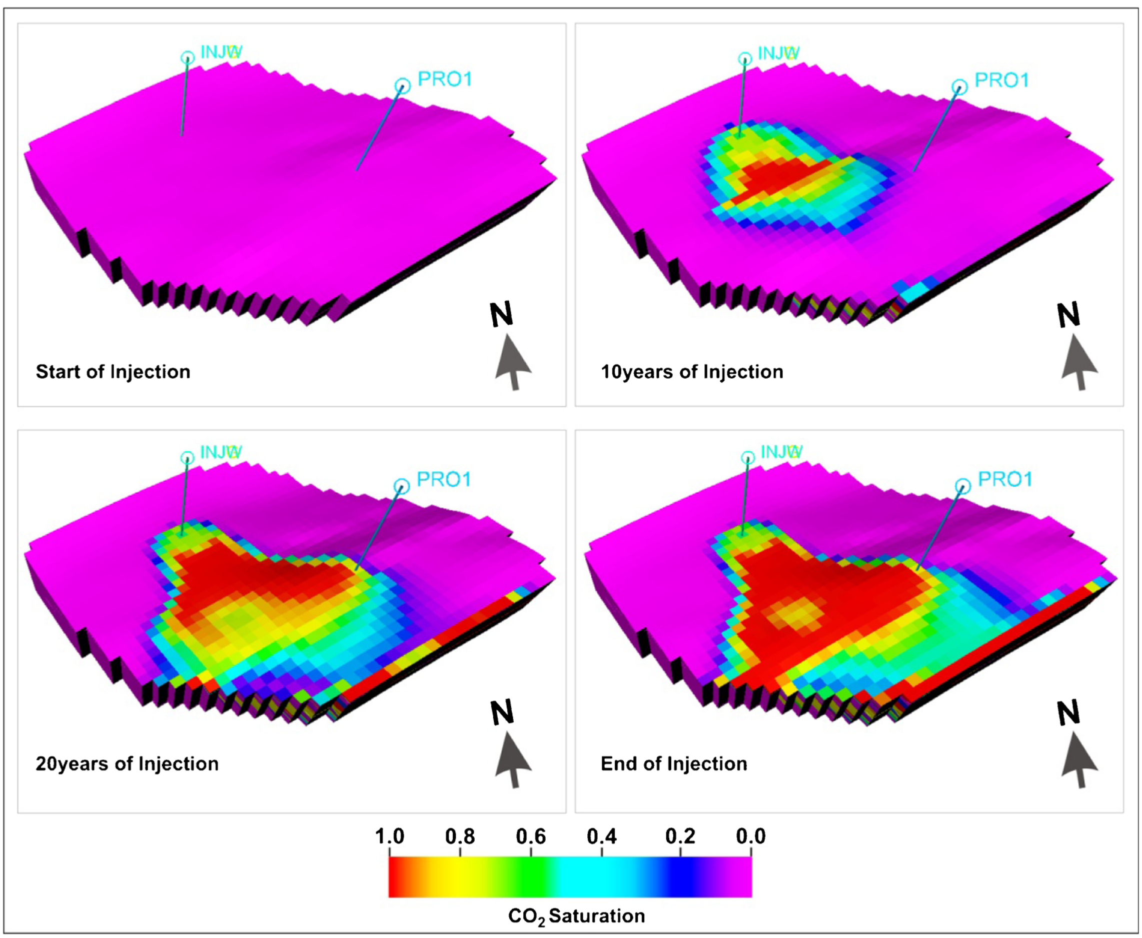


**Fig. 10** Time lapse $CO_2$ saturation in the reservoir as a consequence of $CO_2$ flooding in the reservoir for EOR. The *color bar* represents the $CO_2$ saturation where *red* and *pink* represent maximum and minimum $CO_2$ saturation, respectively

followed by continuous gas injection for next 30 years. Changes in the lateral spreading of $CO_2$ with time in the reservoir can provide qualitative insights into the plume dynamics. Simulation results indicate patchy $CO_2$ distribution, with highest saturation in the top-most layer of reservoir (Fig. 10). The saturation of reservoir fluids at different stages, i.e., from the beginning to till the end of the $CO_2$ injection period is shown in Fig. 11. This study reveals that the oil saturation is comparatively less near the high gas saturated zones, which suggests that $CO_2$ has successfully pushed the residual oil towards the production well and resulted in incremental oil recovery. Results from the simulation not only demarcated reservoir areas with high oil saturation but also revealed that the mobility ratio needs to be improved for better incremental oil recovery. The problem of unfavorable mobility ratio is quite common with $CO_2$ flooding, leading to poor sweep efficiency and low oil recovery due to viscous fingering. This type of issue has been well taken by using polyelectrolytes and polyelectrolyte complex nanoparticles in addition to $CO_2$ foam (Kalyanaraman et al. 2015; Kalyanaraman et al. 2016). This type of information can be useful for the production engineers to plan the drilling strategy for optimum tertiary oil recovery.

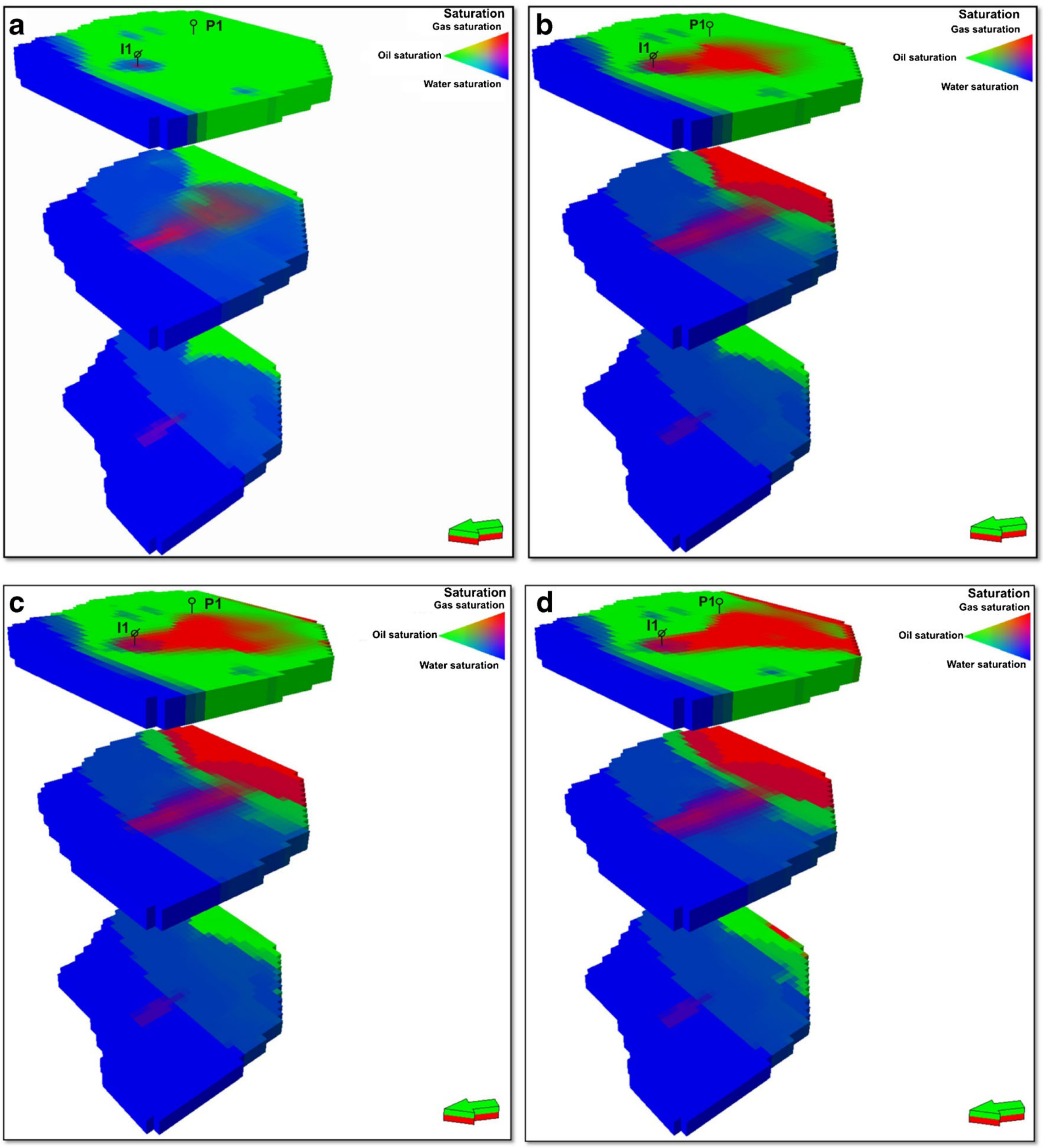


**Fig. 11** Time lapse ternary diagram of saturation of reservoir fluids at different time scales due to $CO_2$ flooding in the reservoir: **a** after gas breakthrough, **b** after 10 years of $CO_2$ injection, **c** after 20 years of $CO_2$ injection, and **d** at the end of $CO_2$ injection. The *color bar* represents the saturation of various reservoir fluids, where *red*, *green*, and *blue* represent $CO_2$ saturation, oil saturation, and water saturation, respectively

## Conclusions

The present study shows interesting and optimistic results for the possible $CO_2$-EOR in Ankleshwar oil field situated in Cambay Basin, India. In this work, a dynamic 3D model is developed to simulate the behavior of the $CO_2$-EOR process over the time. In order to study the influence of various reservoir parameters on reservoir performance, the sensitivity analysis of various reservoir parameters is performed, and optimum reservoir parameters are recommended for improved $CO_2$-EOR for this mature field.

We propose a 50-m grid size (horizontal *x* and *y* directions) black oil model with the optimized parameters for industrial-scale simulations. This model is in good agreement with the fine-scale (25 m grid) compositional simulation model of high accuracy. Sensitivity studies on Corey exponent for oil ($N_o$) and water ($N_w$) were performed, and we found that the reservoir responded very well for $N_o = 3$ and $N_w = 5$, which are recommended for conducting further numerical analysis on improved oil recovery in this mature field. For miscible displacement, we propose the optimum values of T&L mixing parameter for viscosity and density calculations should be 1 and 0.67, respectively. We also synthesized a new injection fluid, which can reduce the MMP for miscible, and more efficient displacement of $CO_2$. Thus, we can conclude that this reservoir has $CO_2$ EOR potential, but keeping in mind the age of platform, the operator should evaluate the proposal very carefully before initializing a pilot study. Moreover, the present estimation of $CO_2$-EOR potential were made possible by considering zero capillary pressure and the quantification of tertiary oil production will differ if capillary pressure from reliable source is considered, which is beyond the scope of the present study.

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