JOURNAL GEOLOGICAL SOCIETY OF INDIA
Vol.88, September 2016, pp.273-280

Assessing the Feasibility of CO_2-Enhanced Oil Recovery and Storage in Mature Oil Field: A Case Study from Cambay Basin

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Abstract: The utilization of anthropogenic CO_2 for enhanced oil recovery (EOR) can significantly extend the production life of an oil field, and help in the reduction of atmospheric emission of anthropogenic CO_2 if sequestration is considered. This work summarizes the prospect of EOR and sequestration using CO_2 flooding from an Indian mature oil field at Cambay basin through numerical modelling, simulation and pressure study based on limited data provided by the operator. To get an insight into CO_2-EOR and safe storage process in this oil field, a conceptual sector model is developed and screening standard is proposed keeping in mind the major pay zone of the producing reservoir. To construct the geomodel, depth maps, well positions and coordinates, well data and well logs, perforation depths and distribution of petrophysical properties as well as fluid properties provided by the operator, has been considered. Based on the results from the present study, we identified that the reservoir has the potential for safe and economic geological sequestration of 15.04×10^6 metric ton CO_2 in conjunction with a substantial increase in oil recovery of 10.4% of original oil in place. CO_2-EOR and storage in this mature field has a bright application prospect since the findings of the present work could be a better input to manage the reservoir productivity, and the pressure field for significant enhancement of oil recovery followed by safe storage.

Keywords: CO_2-EOR, numerical modeling, reservoir simulation, oil recovery, CO_2 storage, pore pressure.

INTRODUCTION

The majority of oil operators are now focusing on to improve the oil recovery from a mature field since it is becoming extremely difficult to discover new giant fields. In such circumstances, improving the oil recovery from a mature oil field will certainly help to maximize the production life of the field (Orr and Taber, 1984; Akervoll and Bergmo, 2010; Muggeridge et al., 2014). EOR by CO_2 flooding has been extensively investigated, and is widely applied tertiary oil recovery technique around the world (Taber et al., 1997; Kovscek, 2002). Thus, utilizing CO_2 as an EOR agent in mature fields provide a unique opportunity to gain a considerable financial return for storing anthropogenic CO_2 once oil production diminishes prior to field abandonment. This will help to mitigate the impact of the rise of atmospheric CO_2 primarily due to the burning of fossil fuels, which is a key driver of anthropogenic climate change (Schrag, 2007). Sequestrating atmospheric CO_2 that released from industrial sources such as petroleum extractive plants or fossil fuel fired plants involve transporting CO_2 via pipeline to the injection site, compressing CO_2 to achieve the injection pressure, and injecting it into the reservoir. The effectiveness of CO_2 sequestration in reservoirs depends on their storage capacity, reservoir stability, risk of leakage, and the retention time (Hawkins, 2004; Rochelle et al., 2004), with depleted oil and gas reservoirs (Bachu, 2000; Jessen et al., 2005) receiving the greatest research attention. Hydrocarbon bearing reservoirs are appealing as safe storage sites since they are best understood to have geologic seal that trapped buoyant reservoir fluids for millions of years (Bickle, 2009; Dimri, 2014, Ganguli et al., 2014).

Reduction of anthropogenic CO_2 in the atmosphere and growing energy demand are the two significant issues confronting the economic development of India. Moreover, CO_2-EOR and storage is a new research area in India, hence, a systematic approach is desirable prior to CO_2 injection into the hydrocarbon reservoir. The key questions regarding CO_2 storage are cost, storage timescale and storage capacity in suitable reservoir (Bickle, 2009). Deciding the long term fate of CO_2 in the reservoir is not straight forward if CO_2 storage is pursued in conjunction with enhanced oil recovery process, the issue regarding optimum amount of CO_2 stored becomes more vital since it has direct effect on the economy of the project.

Estimation of the oil recovery factor and sequestration capacity of an oil field is the key to assess the economics of the project. The purpose of this present work is to elucidate the findings from a numerical simulation and geomechanical study conducted with an aim of estimating the CO_2-EOR and storage potential in an Indian mature oil field.

The oil field under study has produced about 48.5% of the initial oil in place with a high water-cut (88%), which implies that it can be a potential candidate for CO_2-EOR (Srivastava et al., 2012; Dimri et al., 2012; Ganguli et al., 2014). Therefore, the development of a conceptual model that forecasts the field oil recovery factor and sequestration capacity has been reported. Additionally, pressure study is also conducted in the oil field to ensure better screening of the reservoir for safe CO_2 storage followed by miscible CO_2-EOR. The results indicate that the Ankleshwar oilfield in Cambay basin has great potential for CO_2-EOR and sequestration, and the technique has a bright application prospect.

METHODS

Calculation of Theoretical Sequestration Capacity

In case of high water cut reservoirs, the theoretical CO_2 sequestration capacity includes three parts, theoretical sequestration capacity: (a) in free space of oil reservoir, (b) dissolving in water, and (c) dissolving in oil (Bachu et al., 2007;Zhao et al., 2014), represented by

$$M_{CO_2t} = M_{CO_2\,displace} + M_{CO_2\,in\,oil} + M_{CO_2\,in\,water} \tag{1}$$

$$M_{CO_2\,displace} = \rho_{CO_2r}\,(R_f \times POIP - V_{iw} + V_{pw}) \tag{2}$$

$$M_{CO_2\,in\,water} = E_f \times \rho_{CO_2r}\,(PWIP - V_{iw} + V_{pw}) \times m_{CO_2\,in\,water} \tag{3}$$

$$M_{CO_2\,in\,oil} = E_f \times \rho_{CO_2r} \times POIP \times (1 - R_f) \times m_{CO_2\,in\,oil} \tag{4}$$

where, M_{CO_2t} is the theoretical sequestration capacity; $M_{CO_2\,displace}$ is sequestration capacity in the process of CO_2 flooding; $M_{CO_2\,in\,oil}$ is sequestration capacity of CO_2 dissolved in crude oil; $M_{CO_2\,in\,water}$ is sequestration capacity of CO_2 dissolved in water; ρ_{CO_2r} is the density of CO_2 at Ankleshwar reservoir temperature and pressure conditions; R_f is the recovery factor; POIP is the amount of oil in the reservoir after water flooding; PWIP is the amount of water in the reservoir after water flooding; V_{iw} and V_{pw} are the volumes of injected and produced water; E_f is the sweep efficiency of CO_2 displacement; $m_{CO_2\,in\,water}$ and $m_{CO_2\,in\,oil}$ are the solubility of CO_2 in water and oil, respectively.

Calculation of Pore Pressure and Overpressure

The overburden stress/vertical stress (S_v) can be calculated using the equation given by Plumb et al. (1991), represented by

$$Sv = \int_0^z \rho\,(z)\,gdz\,, \tag{5}$$

where, $\rho(z)$ is the bulk density of the rock, represented as function of depth (z), and g is the acceleration due to gravity. The pore pressure (PP) is calculated using Eaton's sonic equation (Eaton, 1972), given by

$$PP = S_v - (S_v - P_{hyd}) \times (DT_n/DT)^3 \tag{6}$$

where, P_{hyd} is the hydrostatic pressure; DT_n is sonic travel time in low permeable zone which is calculated from normal compaction trend (NCT); DT is observed sonic travel time. The fracture pressure (FP) is determined in terms of minimum horizontal stress (S_h), vertical stress (S_v), and pore pressure (PP), using Matthews-Kelly's equation (Matthews and Kelly, 1967), represented as

$$FP = PP + \left(\frac{S_h}{S_v}\right) \times (S_v - PP) \tag{7}$$

Here, the minimum horizontal stress can be estimated using the equation based on poroelastic theory (Mandl and Harkness, 1987; Engelder and Fisher, 1994):

$$Sh = PP + [\sigma/(1 - \sigma)] \times (S_v - PP) \tag{8}$$

where, σ = Poison's ratio of the rock formation in Cambay Basin, which is reported to be 0.2-0.25 (Kumar et al., 2008).

Case Study: Ankleshwar Oil Field in Cambay Basin, Western India

Ankleshwar oil field is a part of the Cambay basin, one of the main onshore Cenozoic oil basins of western India, runs as an elongated graben into the Gulf of Cambay in an approximately NNW-SSE direction. The oil field under study was discovered in 1960 and put on production since August 15, 1961. The sediments deposited over the Deccan trap, ranges from Paleocene to recent age (Mukherjee, 1981). Later, a deep seated fault system formed horst and graben type of structures that served as traps. Figure 1 depicts the stratigraphy of the study area where the reservoir formation of middle to upper Eocene age was further divided into four main members, Ardol, Hazad, Telwa, and Kanwa, comprised of a thick sequence of sands and shales respectively. The reservoir is multi-layered with 11 producing sand units of

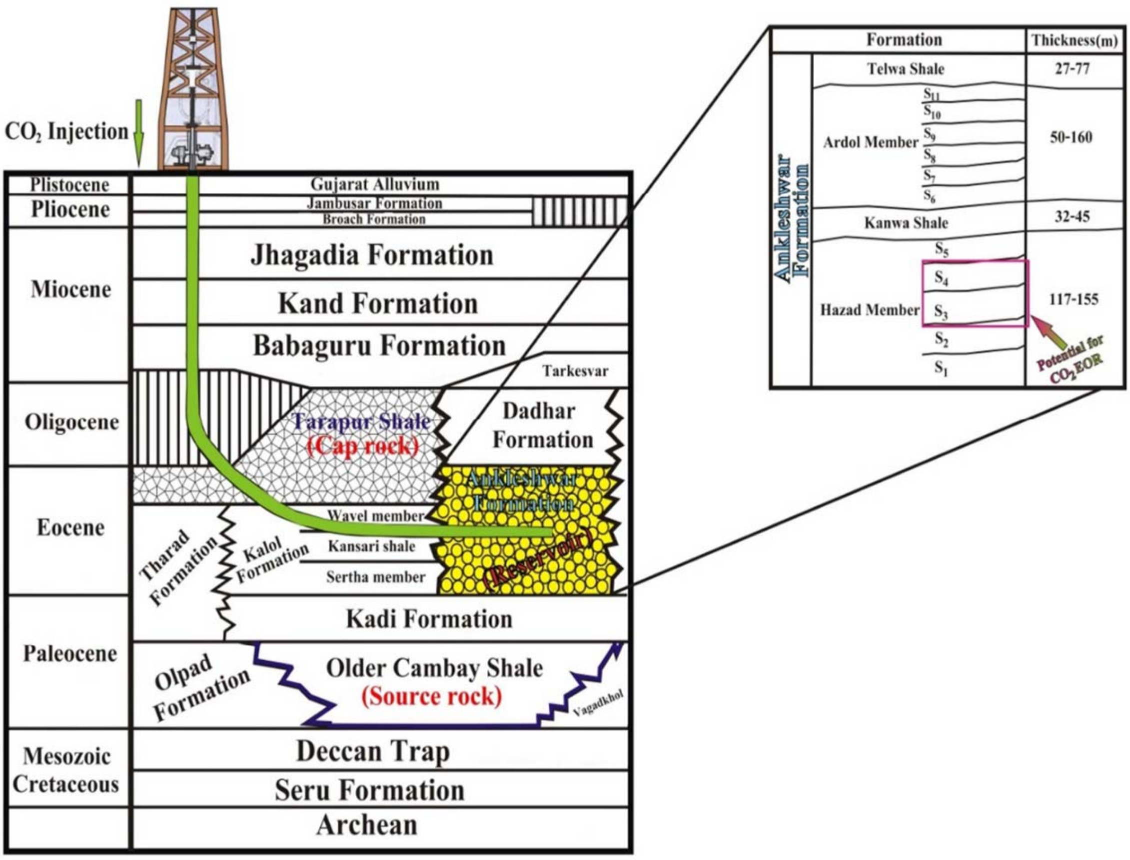

Fig.1. Schematic distribution of the Litho-Stratigraphy of the study area. CO_2 flooding is proposed in the Ankleshwar formation, particularly within S3+4 sand layer, the most productive layer. The trajectory of the possible injection well is shown within the Ankleshwar formation.

Eocene age, where S1 to S5 represents the middle sand group and S6 to S11 represent the upper sand group (Mamgai et al., 1997).

Geomodel Building

We developed a conceptual Geomodel based on the inputs provided by the operator that predicts incremental oil recovery and sequestration capacity due to CO_2 injection after massive water flooding, depending on the state of the reservoir. The model represents the major pay zone of the reservoir from Cambay basin. It is identified that the potential layers for CO_2 injection for EOR and storage are S3 and S4 layers that are clubbed together in the simulation model, and are referred as S3+4 in the following sections . It is noteworthy to mention that S3+4 layers are not continuous throughout the reservoir and some pinching out was observed, leading to production challenges.

Figure 2 shows the geometry, well positions, depth and grid system of the 3D conceptual reservoir model with realistic heterogeneities, inspired by the generic sandstone reservoir and represents mainly the most productive layer S3+4 of the reservoir. This is a 38×34×23 cell model, consists of six sand layers representing Hazad and Ardol formation and five sandwiched shale layers alternatively

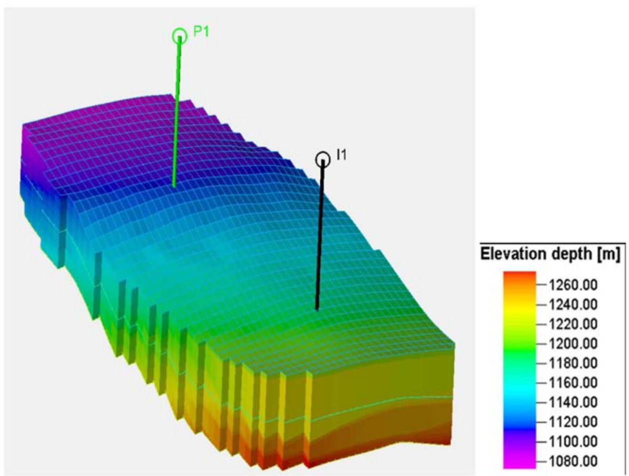

Fig.2. Geometry, grid, depth and well positions of the conceptual model for CO_2-EOR and sequestration in the Cambay Basin. Colour bar indicates depth, the model is exaggerated by a factor 7.5 in the vertical direction.

within the sands representing Telwa and Kanwa formation. The depth of reservoir model extends from 1078 m to 1265 m. The reservoir model is penetrated by two wells, one injector (I1, water and CO_2) and one producer (P1).

Data

This research work is basically dependent on the reservoir data, e.g. production data, petrophysical data (e.g. porosity, permeability, rock compressibility etc.), structural depth maps, wireline log data, well tops, etc., and were provided by the operator. The reservoir properties of the oil field, used in the present study are given in Table 1. The S3+4 layers have average porosity of 23% and permeability 1000 mD (ONGC Pvt. Ltd., personal communication). The porosity and permeability assigned to the individual sub-layers of the conceptual model were summarized in Table 2. The shale layers were assigned 100% water saturation with negligible permeability. The rock compressibility was taken as 2.167e-5 psi^{-1}. Nevertheless, for detailed study, to implement CO_2-EOR on field scale, we are much dependent on more data like seismic, rock physics, etc.

Model Validation

The Geomodel is initialized for reservoir simulation with under-saturated oil (no gas-cap) and enclosed aquifer with the OWC at 1200 m. The model is tuned to match the reported initial oil in place of 552 MMbbls (Srivastava et al., 2012).

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

Table 2. Reservoir rock properties of the sub-layers of S3+4 layer, the major pay zone of Ankleshwar oil field in Cambay Basin

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

Oil Recovery Mechanism in Eclipse 100

Eclipse 100 (E-100), a commercial simulator to conduct the simulations has been used. The oil recovery mechanism in E-100 is based on the principle of material balance equation, originally presented by Schilthuis (1936). This can be expressed in the following (Dimri et al., 2012):

Amount of fluids present in reservoir initially (std vol.)
– Amount of fluids produced (std. vol.) =
Amount of fluids remaining in the reservoir
(std. vol.), (9)

This simulator helps to quantify the proportion of oil produced by each physical process such as rock compaction, water influx, etc. The oil in place within a grid block can be represented by (Schlumberger, 2011):

$$\text{Total oil in place} = PV \,.\, S_0 . \frac{1}{B_0} \tag{10}$$

where PV, S_0, B_0, are pore volume, oil saturation and oil formation volume factor, respectively. The change in oil in place over a time step can be attributed by:

$$\begin{aligned}
&\text{Production due to rock compaction} = -d(PV) \,.\, S_0 . \frac{1}{B_0}\\
&\text{Production due to water influx} = PV.d(S_w). \frac{1}{B_0}\\
&\text{Production due to gas influx} = PV.d(S_g). \frac{1}{B_0}\\
&\text{Production due to oil expansion} = PV.S_0.d\left(\frac{1}{B_0}\right)
\end{aligned} \tag{11}$$

The oil production from each mechanism described above is summed over time steps to calculate the final one.

RESULTS AND DISCUSSION

The above stated methodology was applied to a mature oil field, Ankleshwar in Cambay basin (western India) with the available data provided by the operator. The results are presented and discussed in this section.

Table 3. The results from the feasibility study of CO_2-EOR and storage in Ankleshwar oil field, Cambay Basin

Recovery factor before CO_2 flooding	Recovery factor after continuous water flooding	Recovery factor after CO_2 flooding	Recovery increment (%)	Sequestration Capacity (metric ton)
0.568	0.612	0.716	10.4	15.04×10^6

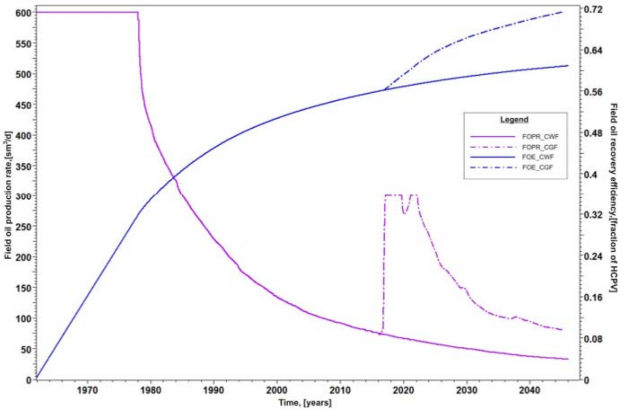

Fig.3. Production scenario based on the simulation results, with the field oil production rate (magenta curve) and oil recovery efficiency (blue curve) as a function of time in years. The solid curve represents the results from continuous CO_2 flooding, while dashed-dotted curve represents continuous water flooding.

Screening standard for CO_2-EOR and storage mentioned by previous workers (e.g. Bachu, 2000; Bachu et al., 2007) was adopted to carry out the appraisal study for the suitability of CO_2 flooding. The model is initialized for reservoir simulation with under-saturated oil (no gas-cap) at all reservoir conditions, and contributes to gas production. Further, we assumed that the injection of supercritical CO_2 into the reservoir would be miscible with the reservoir oil. In this case, the conceptual model was subjected to water flooding for about 50 years followed by continuous gas injection for 30 years, and then the results for incremental oil recovery, and sequestration is summarized in Table 3. Figure 3 illustrates the simulation result from the reservoir under study during both, water and CO_2 flooding. The oil production maintained a plateau for quite long time (~ 16 years) during water injection period, and then started declining with time, e.g. from 600 Sm^3/day to 75 Sm^3/day (magenta solid curve). Whereas, it is interesting to note that there is a significant increase in field oil production after continuous CO_2 flooding, from 75 Sm^3/day to 300 Sm^3/day (magenta dash-dot curve), which would have not been possible if considering continuous water injection alone even for longer period (magenta solid curve), depicted in Fig.3. Increased oil production justified by the significant increase in field oil recovery factor, shows promising results for CO_2-EOR in this oil field. We assessed about 10.4% of additional oil recovery can be accomplished from the field as a result of CO_2-EOR, validated with the difference in recovery from continuous water injection (blue solid curve) and continuous CO_2 injection in the oil reservoir (blue dash-dot curve).

The injected CO_2 was monitored in the reservoir using time lapse CO_2 saturation in each layer. Changes in the lateral spreading of CO_2 with time in the reservoir provide qualitative insights into the plume dynamics. In the upper layers, the plume extension is more rapid laterally and layer edges correspond to extensive layer spreading and thickening (Fig.4). Results from the simulation not only highlighted

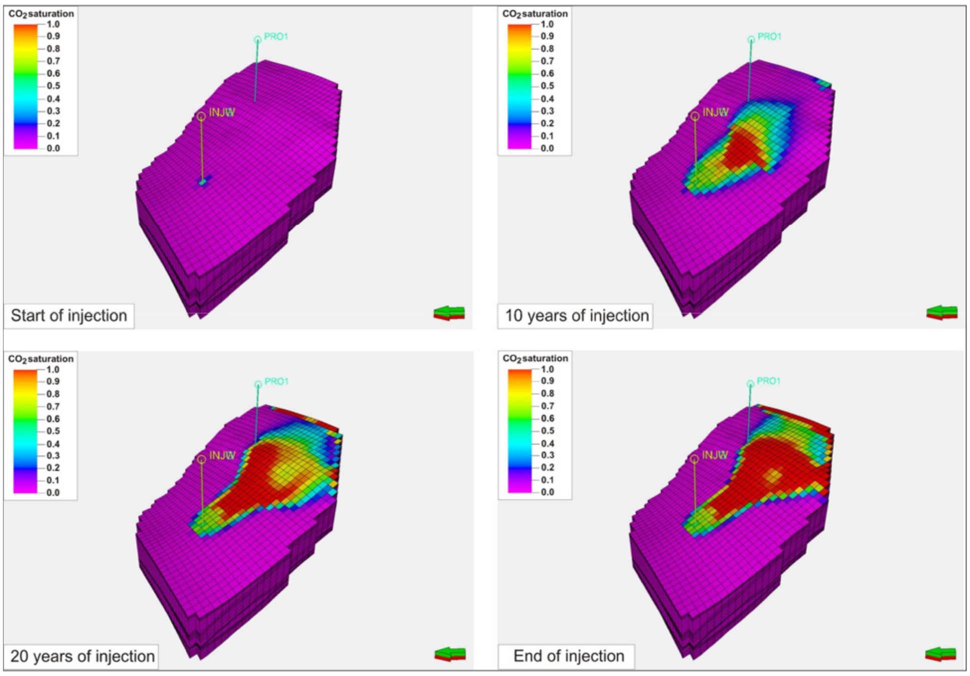

Fig.4. Time lapse CO_2 saturation in the reservoir as a consequence of CO_2 flooding for EOR. The colour bar represents the CO_2 saturation, where in red and pink represents maximum and minimum CO_2 saturation respectively.

reservoir areas with high CO_2 saturation, but also reveal that mobility ratio needs to be improved for effective field oil recovery.

With the available data, and considering eq.(1-4), it is found that the oil field under study has the potential to sequestrate 15.04×10^6 metric ton CO_2 beside the incremental oil recovery of 10.4% of original oil in place, illustrated in Table 3. This is feasible since we considered miscible CO_2 flooding that helps to displace the crude oil more effectively towards the production well, hence creating further more space for CO_2 accumulation.

To investigate the effect of CO_2-EOR and storage on the stress field of the reservoir, a comprehensive geomechanical analysis was conducted that determines the existing state of stress, and forecasts after CO_2 flooding. This was performed in regard of a safe and successful CO_2 storage along with EOR operation. Figure 5 illustrates the

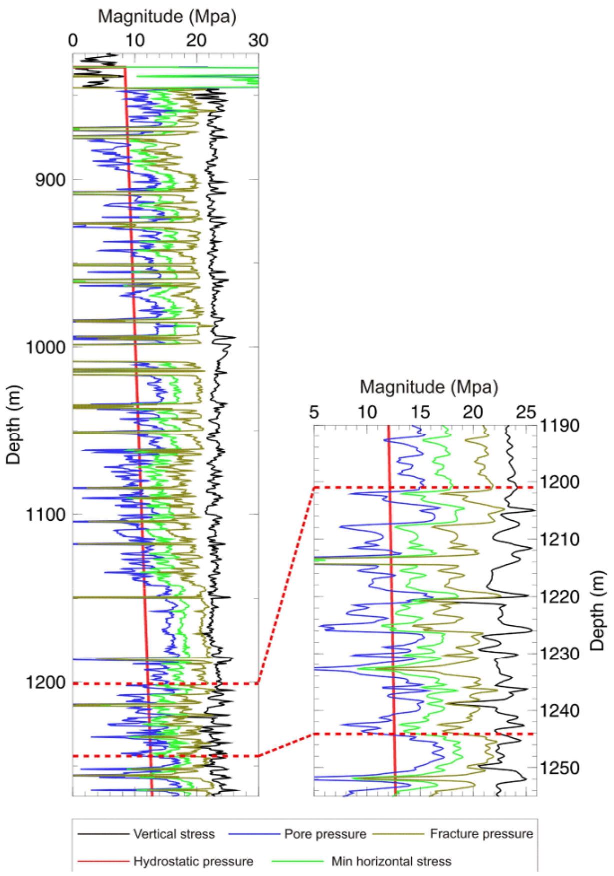

Fig.5. In situ stress profile along depth at Ankleshwar oil field in Cambay Basin, India. The black, blue, dark green, red, and green curve represents overburden/vertical stress, pore pressure, fracture pressure, hydrostatic pressure and minimum horizontal pressure, respectively. The zone demarcated by red dotted line signifies the potential sand layers of S3+4, which can be utilized for CO_2-EOR, and storage.

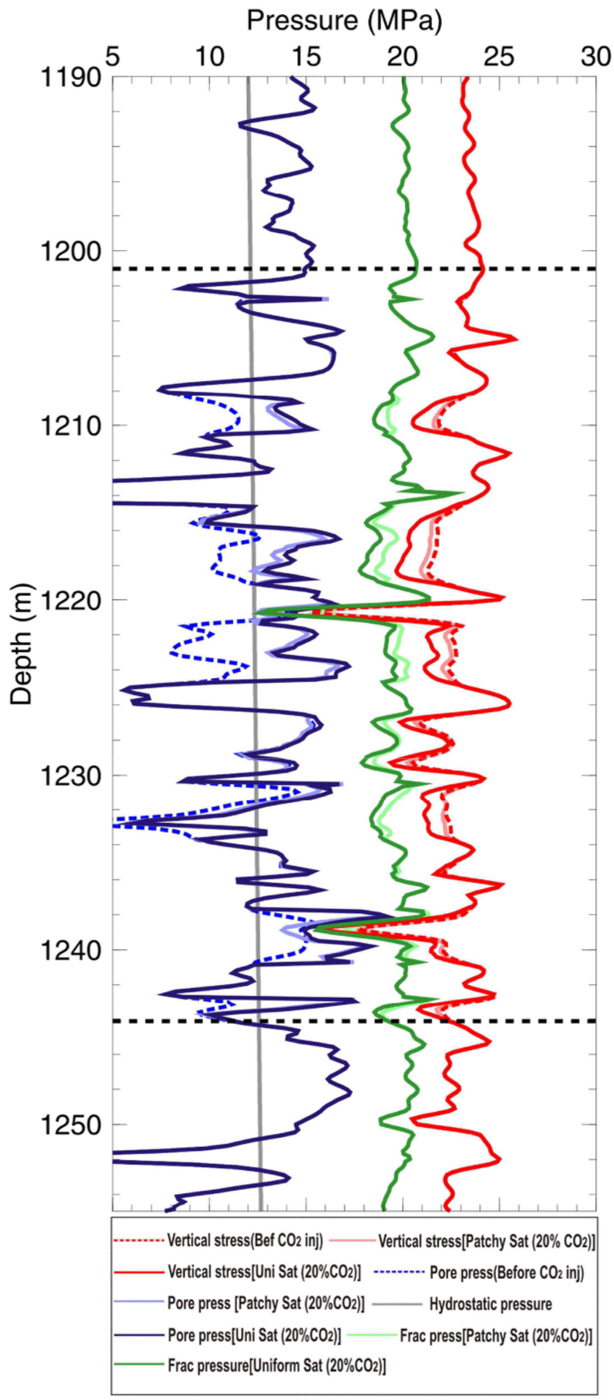

Fig.6. Stress profile obtained from the Ankleshwar oil field in Cambay Basin, India showing the overburden/vertical stress, pore pressure, fracture pressure, hydrostatic pressure respectively during and after the CO_2 injection. The dashed and solid curves illustrate the pressure prior and after CO_2 injection, respectively. The dark colours and light colours represents the uniform- and patchy saturation models at 20% CO_2 saturation. The zone demarcated by black dotted lines indicate the potential sand layers, S3+4, which can be utilized for CO_2-EOR, and storage.

existing state of stress of the reservoir, where various pressures were estimated using eq. (5-8). It was found, as expected, the pore pressure is in good agreement with the hydrostatic pressure within the target zone (i.e. S3+4 zone (1201m-1244.1m)), and comparatively of less magnitude than the fracture pressure and the overburden pressure. We determined the pore pressure and fracture pressure in the target zone after CO_2 flooding, and illustrated in Figure 6. To demonstrate the effect of CO_2 saturation on the various pressure distribution. Two different saturation scenario, *uniform* and *patchy* saturation was considered, since in case of mixed pore fluids, pore pressure induced in each phase by passing wave will be different, leading to saturation heterogeneity. It is interesting to note that there is a significant change in pore pressure, overburden pressure and the fracture pressure after CO_2 flooding, and the average pore pressure is 28% higher than the pore pressure estimated before CO_2 injection. Also, in comparison with uniform saturation, patchy saturation shows a gradual decrease (2-3%) in pore pressure with CO_2 content. However, the predicted pore pressure is not higher than the fracture pressure, which is the upper limit of pressure should be kept below in a well in order to maintain safe and economic drilling.

CONCLUSIONS

We have studied the feasibility of CO_2-EOR followed by CO_2 storage in a mature oil field from Cambay basin and based on the characteristics of the present field, encouraging results were found. The following conclusions are drawn from the present study:

- The study has been carried out on 3D conceptual reservoir model keeping in mind S3+4, the most producing sand layers of Ankleshwar formation, and simulations were performed by considering miscible displacement process. On the basis of good response from the conceptual model, the field has the potential to produce additionally 10.4% of original oil in place, and sequestrate about 15.04×10^6 metric ton of CO_2. Of course, detailed study on field scale is encouraged prior to the deployment of large scale of CO_2 in the field which is beyond the scope of the present work.
- The feasibility study of state of stress of the reservoir as a consequence of anthropogenic CO_2 injection is necessary to control injection pressures, formulating stable deviated well trajectories, planning micro-seismicity treatments (Lucier et al., 2008), and it was found that the oil field has the potential for safe and economic drilling for EOR and storage. No over-pressure zone has been identified in the present analysis. However, a detailed geomechanical study will help to come into any final conclusion, which is beyond the scope of this study.
- The screening level approach taken here helps to interpret the functioning of an Indian oil field with regard to CO_2 flooding based on limited information about the reservoir. Several unresolved questions remain regarding CO_2 sequestration in this oil field, importantly, the long term fate of CO_2 in the reservoir, and/or conservative estimates for CO_2 retention capacity of a reservoir if leakage takes place, has to be addressed properly. For better understanding of the reservoir in terms of CO_2 storage in conjunction with improving oil recovery on field scale, compositional simulations and rock physics modeling has to be performed, which is beyond the scope of this study. Also, in the absence of required information from this mature oil field, we couldn't perform history matching properly, but managed to mimic the production curve based on random choice of producers and injectors.

Acknowledgments: We appreciate the anonymous reviewers for providing fruitful comments to improve the manuscript. We thank Director, CSIR-NGRI for his kind permission to publish these results. SSG would like to appreciate Dr. Prakash Kumar and Per Bergmo for suggestions. The Royal Norwegian Embassy is acknowledged for providing financial support to a part of the research work. SSG would like thank to CSIR for awarding CSIR-SRF fellowship. Our sincere gratitude to ONGC and Ankleshwar asset for sharing the data.

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(Received: 4 March 2015; Revised form accepted: 8 October 2015)