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Investigation of CO_2 Sequestration during Cold Heavy Oil Production

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CO_2 sequestration during cold heavy oil production using captured carbon dioxide was investigated using REVEAL of Petroleum Experts. The results indicated that the CO_2 release was influenced by the production phases. The prediction showed high CO_2 retention in the first few years post start-up, followed by a gradual decline toward 16.5% post peak production. The recovery rate was strongly influenced by the reservoir characteristics, such as fluid properties, permeability, aquifer, and well completion. Horizontal wells provided better performance than vertical wells. The CO_2 utilization and retention per barrel of heavy oil increased as the CO_2 injection pressure increased.

Keywords: CO_2-EOR, cold heavy oil production, CO_2 sequestration, CO_2 utilization, well completion

1. INTRODUCTION

Carbon dioxide capture for enhanced oil recovery (CO_2-EOR) is one of the preferred enhanced recovery techniques to date and offers potential economic benefit through additional oil recovery as well as CO_2 storage. There are four main techniques used to capture CO_2 from large-scale industrial facilities or power plants: (1) post-combustion capture, (2) pre-combustion capture, (3) oxy-fuel combustion capture, and (4) industrial processes. Description of each process can be found in the Intergovernmental Panel on Climate Change report (IPCC, 2005). There are two main storage options known as ocean storage and geological storage. Due to substantial uncertainties, legal and health, safety, and environmental issues, the ocean storage lack behind and face enormous hurdles to be attractive. As for geological storage, three main types of geological environments are being considered for carbon sequestration: (1) oil and gas reservoirs, (2) deep saline reservoirs/aquifers, and (3) un-mineable coal seams. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO_2 and prevent further upward migration (National Technology Laboratory, 2013). Saline and other types of reservoirs also have two additional trapping mechanisms that help trapping/storage of the CO_2 known as solubility and mineral trapping.

During CO_2-EOR, a small amount of the injected CO_2 dissolves in the oil. Laboratory results have demonstrated that the injection of CO_2 would result in swelling of the oil by over 20%, a significant reduction in oil viscosity, and a 95% reduction in interfacial tension (Hycal, 2004), thus, making the oil flow more easily in response to pressure gradients (Nummedal et al., 2003). CO_2-EOR is known to allow recovery up to 20% of the OOIP (original oil in place) (Meyer, 2008). Approximately 53 to 82% more oil could be produced by the CO_2 flood than is produced by water in the best areas of the waterflood, according to the test conducted by Holm and O'Brien (1971) and Holm (1987).

There is a variety of speculation with respect to CO_2 storage during enhanced oil recovery (EOR). Some believe that CO_2-EOR in a conventional oil reservoir will result in increased carbon emissions from incremental oil production (IEA GHG, 2007); others believe that 40% (Shaw and Bachu, 2002; Hadlow, 1992) or up to two-thirds of the injected CO_2 is being produced and can be re-injected. In the Bati Raman heavy oilfield (9ˡ to 15ˡ API) in southeast Turkey close to the Turkish-Iraqi border, where immiscible displacement using CO_2-EOR is in operation, approximately 1,700 tonnes of CO_2 are injected daily, 16 to 60% of which is recycled (Stevens et al., 2000). Despite most scientists believing that crude oil is not heavy at the origin (Curtis et al., 2002), CO_2 storage during heavy oil recovery or in heavy oil reservoir has not been investigated widely and the question is whether the existing theories for conventional oil are by default applicable for heavy oil reservoir.

CO_2-EOR enables chemical and physical interaction of the injected CO_2 with the reservoir rock and fluids, creating favorable conditions that improve oil recovery. These conditions are discussed in detail by Tzimas et al. (2005).

2. MODELING APPROACH

The reservoir was modeled using REVEAL, the reservoir simulator by Petroleum Experts. The grid block was the dimensions of 25, 25, 15 in I, J, and Z directions, respectively. A block size was 500 ft x 500 ft x 200 ft, grid depth was 10,000 ft, and a single porosity. There are two wells, one producer and an injector, and both are horizontal. The model was homogenous as shown in Figure 1. The simulation was performed over 25 years starting from January 1, 2006. Tables 1 and 2 present the reservoir and fluid properties used in the simulation and the aquifer properties are given in Table 3.

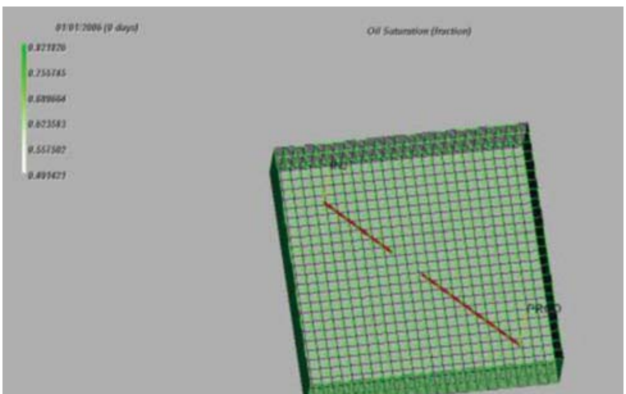

FIGURE 1 Block grid and horizontal wells. (color figure available online)

TABLE 1
Fluids Properties and Rock Properties

	Data	*Units*
Rock compressibility	3×10^{-5}	1/psi
Permeability	100	md
Reservoir porosity	0.2	Fraction
Well control: Constant injection pressure	3,000	psig
Water compressibility	$2{:}9 \times 10^{-6}$	1/psi
Heavy oil specific gravity	15	API
Heavy oil viscosity	523–2,188	cP
Heavy oil FVF	1.19	RB/STB
Water FVF	0.99	RB/STB
Gas FVF	0.0034	RB/STB
Gas oil ratio, GOR	500	scf/STB
Reservoir temperature	122–200	C
Water gravity	1.068	Sp. gravity
Gas gravity	0.7	Sp. gravity

TABLE 2
Residual Saturation Used for the Simulation

	Data	
Critical oil/gas residual saturation, Sogc	0.05	Fraction
Critical oil/water residual saturation, Sowc	0.2	Fraction
Critical water residual saturation, Swc	0.2	Fraction
Critical gas residual saturation, Sgc	0.2	Fraction
End point oil/water relative permeability, Krow	1	Fraction
End point oil/gas relative permeability, Krog	1	Fraction
End point water relative permeability, Krw	1	Fraction
End point gas relative permeability, Krg	1	Fraction
Corey exponent for oil-water	2	
Corey exponent for oil-gas	2	

TABLE 3
Aquifer Properties

	Units	*Values*
Aquifer model		Infinite linear
Aquifer porosity	Fraction	0.2
Aquifer permeability	md	1,000
Aquifer compressibility	1/psi	3×10^{-6}
Thickness	Feet	300
Encroachment angle		90
Width	Feet	300
Region 1		X_West, from (1, 1, 1) to (1, 25, 15)
Region 2		X_West, from (25, 1, 1) to (25, 25, 15)

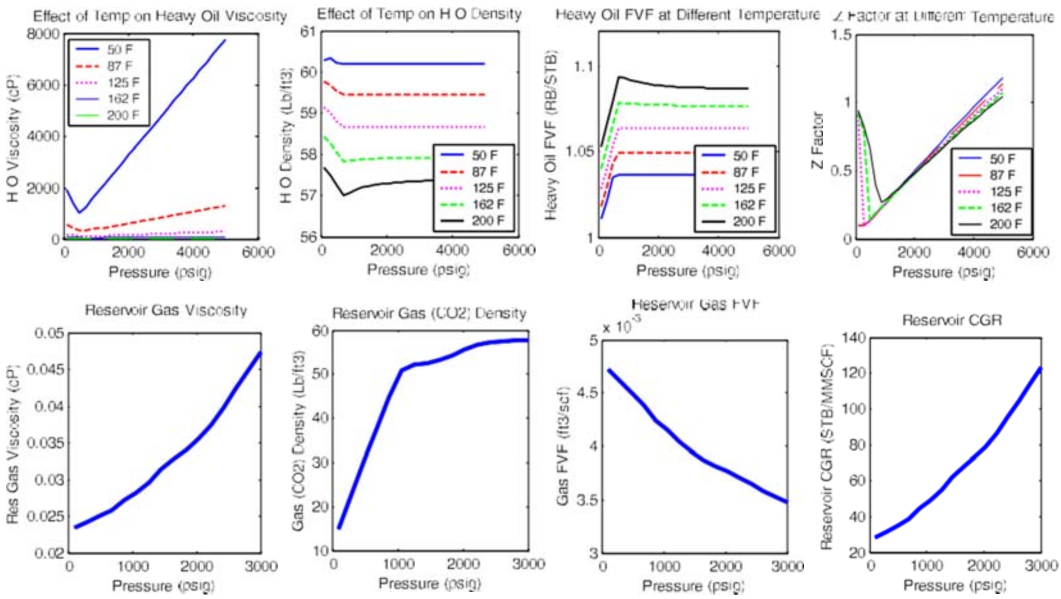

FIGURE 2a (a) Variation of reservoir heavy oil and gas (CO_2) properties with temperature and pressure.

The initial pressure used in this analysis was 2,500 psig, with the temperature of 200°F. The CO_2 was injected into the reservoir through a horizontal well 8 km long and completed over a length of approximately 150 m. The reservoir gas was modeled as CO_2. With a critical pressure of 1,073 psi and critical temperature of 87.8°F, CO_2 will be in a supercritical state at bottom- hole injection and reservoir conditions; hence, CO_2 was defined in the model as gas with the corresponding dense phase density.

In a subplot format, Figure 2a shows the variation at different temperatures and pressure of the reservoir heavy oil and gas viscosity, density, formation volume factor (FVF), and condensate gas ratio (CGR). The temperature ranged between 50 and 200°F, while the pressure varied from 100 to 5,000 psig. Mobility of heavy oil is known to be much easier at high temperatures. At 200°F, the reservoir heavy oil viscosity was approximately 25 cP; as the temperature reduced the heavy oil viscosity increased. During the injection, as the reservoir heavy oil comes in contact with the injected CO_2 at lower temperatures (50–70°F), the heavy oil viscosity will significantly vary as the reservoir temperature will reduce. Hence, the heavy oil viscosity profile purposely illustrated the heavy oil viscosity variation at different temperatures, and indicated that the heavy oil viscosity could rise up to 7,730 cP at 50°F if the reservoir pressure was to reach 5,000 psig. The heavy oil density was very close to that of water and varied between 57.5 and 60.2 lb/ft^3 at the temperatures and pressures investigated. The heavy oil FVF was almost constant.

As shown in Figure 2a, the reservoir gas thermodynamic properties were deliberately modeled to reflect those of CO_2. The reservoir gas was modeled as retrograde condensate to take into account the phase change at various temperatures and pressure. CO_2 is expected to reach the reservoir in a supercritical state due to the high pressure within the transported line as well as the reservoir. This phenomenon is effectively represented in the modeling by the retrograded condensate process, which takes into account the condensate CO_2 being lost in the gas stream. The phase behavior of the reservoir gas is adequately illustrated in the density and CGR profiles at various pressures. With regard to the density profile, the gas density sharply rose from 15 lb/ft^3

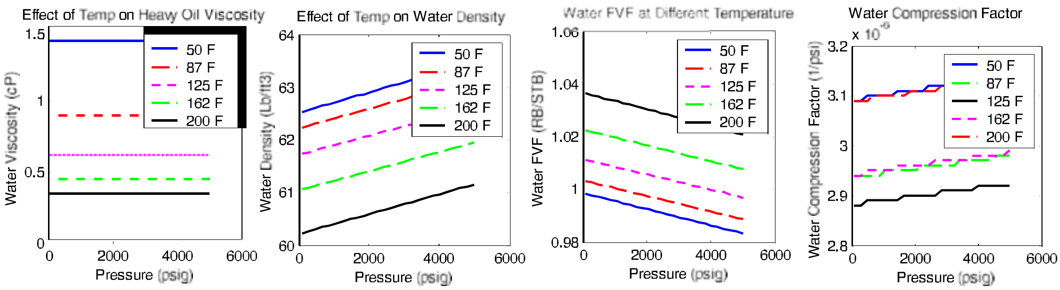

FIGURE 2b (b) Variation of reservoir water properties with temperature and pressure.

(dry gas phase) to 52.5 lb/ft^3 (dense phase) when the pressure reached 1,073 psig. Above 1,073 psig, the variation in density was very slow and only changed from 52.5 to 57.8 lb/ft^3 (3,000 psig). The high reservoir gas density at 1,073 psig was in agreement with conventional knowledge and also ascertained that the properties of the fluid were appropriately modeled. On the other hand, the CGR reflected the phase variation of CO_2 within the reservoir at different pressures as shown in Figure 2a. REVEAL was also used to calculate the reservoir CGR and gas FVF with the dense phase CO_2 density and viscosity for pressure varying from 100 to 3,000 psig. The CGR increased with increasing pressure from 28 STB/MMSCF at 100 psig to 123 STB/MMSCF at 3,000 psig. There was negligible variation in the reservoir gas (CO_2) viscosity and FVF at different pressures and temperatures. The reservoir FVF was about 0.004 ft^3/scf and the viscosity ranged approximately from 0.023 to 0.048 cP.

Figure 2b shows the variation at different temperatures and pressures of the reservoir water viscosity, density, and FVF in a sub-plot format. The temperature ranged between 50 and 200'F and the pressure varied from 100 to 5,000 psig. Once again, the profiles were in accordance with predictions published in the public domain. The viscosity was about 0.34 cP at 200'F and progressively increased with reducing temperatures. The maximum viscosity was 1.4 cP at 50'F. The density varied between 60.5 and 63.5 lb/ft^3, and the variation was very minimal. The formation volume factor was approximately 1 RB/STB and the compressibility factor was extremely low.

The variation of the reservoir fluids' (heavy oil, gas, and water) properties with temperature, when the reservoir gas is modeled as natural gas as opposed to CO_2, is presented in Figure 3. It is also comprehensible that the maximum gas density is 0.0595 lb/ft^3 and the maximum viscosity is 1.3 cP. The heavy oil viscosity increased as the temperature dropped and other fluids' behaviors, with respect to temperature rise/drop, were as previously reported.

3. METHODOLOGY

Both black oil and compositional models were used. The PR EOS was selected to generate the VLP files for the injection and production system using PROSPER. The production system was modeled as a black oil model, while the injection system remained compositional, with the properties of CO_2 clearly inputted. However, although the models take into account the fluid composition through the VLP file created using PROSPER, the output from REVEAL provides no information regarding the reservoir fluid composition.

Two methods, mass conservation of CO_2 around the reservoir loop and the production profiles evaluation, were used to interpret the REVEAL results in order to estimate the CO_2 sequestration during CO_2-EOR.

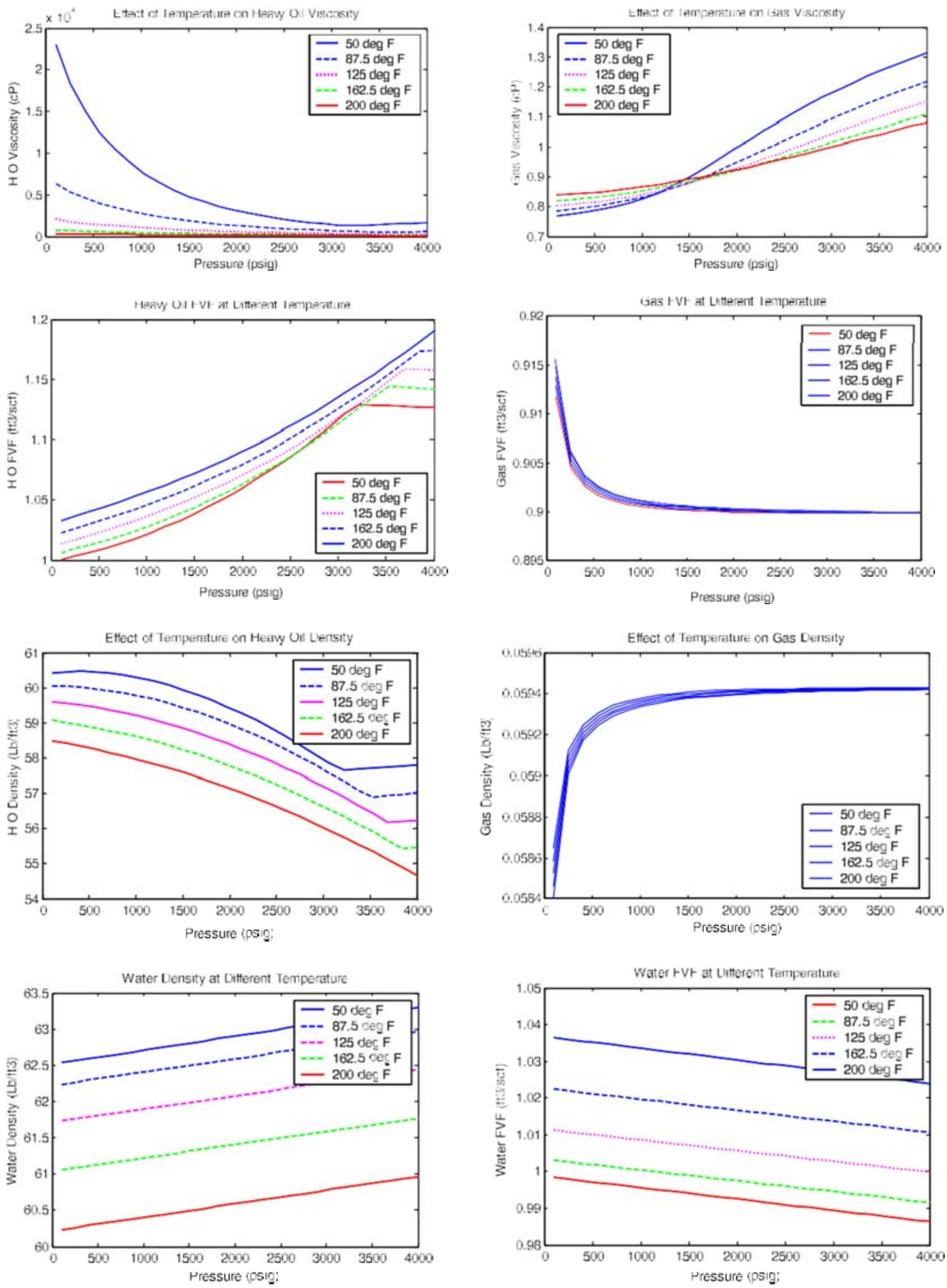

FIGURE 3 Reservoir fluids properties and influence of temperature and pressure.

3.1. Mass Conservation

This approach considered the mass of CO_2 entering $(\dot{m}_{CO2\ inj})$ and leaving $(\dot{m}_{CO2\ out})$ the reservoir and the mass of CO_2 retention $(\dot{m}_{CO2\ Seq})$ within the reservoir, which is conveyed in the following expression:

$$\dot{m}_{CO2\ inj} - \dot{m}_{CO2\ out} = \dot{m}_{CO2\ Seq}. \tag{1}$$

The density of CO_2 changes in a significant way as its pressure (P) changes and using the ideal gas equation of state (EOS), the CO_2 density (ρ_{CO2}) can be calculated at the appropriate pressure, and hence the volumetric flowrate of CO_2 $(Q_{CO2\ Seq})$ can be established using the expression below. "T" stands for temperature and "M_W" for molecular weight of CO_2:

$$Q_{CO2\ Seq} = \frac{\dot{m}_{CO2\ Seq}}{\frac{M_W}{R}\,\frac{P}{T}}. \tag{2}$$

3.2. Production Evaluation

Likewise, the formulation is consistent with the ones described in the mass conservation. The CO_2 sequestration $(Q_{CO2\ Seq})$ is estimated as the difference between the injected and the produced CO_2 $(Q_{CO2\ inj})$, taking into account the rates of CO_2 production during steady or quasi-steady state since the reservoir gas was modeled as CO_2. $Q_{CO2\ out\ WI}$ produced CO_2 when there is no CO_2 injection:

$$Q_{CO2\ Seq} = Q_{CO2\ inj} - (Q_{CO2\ out} - Q_{CO2\ out\ WI}). \tag{3}$$

In the case where the reservoir gas is modeled differently other than CO_2, the $Q_{CO2\ out\ WI}$ term in the equation shall be omitted. $Q_{CO2\ out\ WI}$ was found to be less than 1% of that produced during CO_2 injection, hindering negligibly any influence on the overall results, as far as the simulations are concerned.

The CO_2 retention as function of barrel of heavy oil produced (Seq_{CO2}) was calculated using the volumetric flowrate of heavy oil produced ($Q_{oil\ prod}$) and the CO_2 sequestration by the following expression:

$$Seq_{CO2} = \frac{Q_{CO2\ Seq}}{Q_{oil\ prod}}. \tag{4}$$

The CO_2 requirement/utilization per barrel of heavy oil produced ($CO2_{Req}$) was obtained using the required CO_2 injection as follows:

$$CO2_{Req} = \frac{Q_{CO2\ inj}}{Q_{oil\ prod}}. \tag{5}$$

4. RESULTS AND DISCUSSIONS

The residual in place estimated by the solver based on the information provided is given below:

Water in place: 3.31093e + 009 STB
Heavy oil in place: 1.27529e + 010 STB
Gas in place: 1.27529e + 006 MMSCF

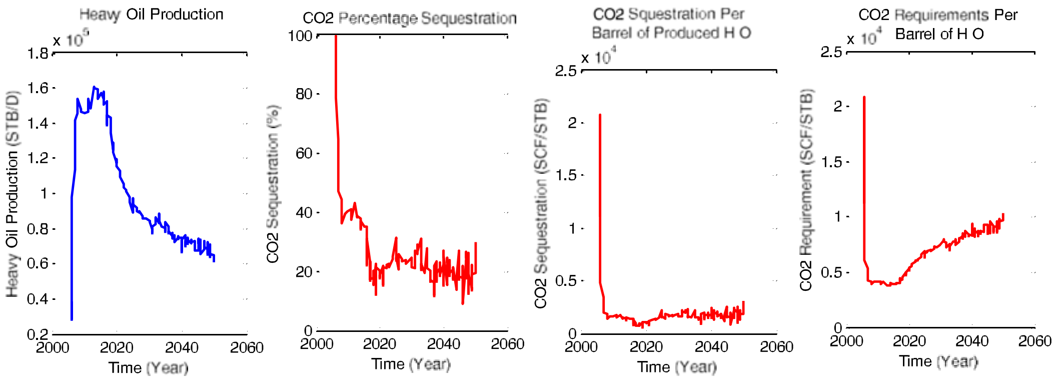

FIGURE 4 CO_2 sequestration–reservoir pressure: 2,500 psig; injection pressure: 5,000 psig.

Figure 4 shows the heavy oil production rates when the injection pressure was 5,000 psig, the calculated CO_2 sequestration per barrel of heavy oil produced, the percentage retention, and the CO_2 requirements per barrel of heavy oil produced. The results reveal that the percentage of CO_2 sequestration was 100% for months post start-up. This may be justified by the theory that the injected CO_2, which is in the dense phase, expands as it reaches the reservoir. As the CO_2 expands, it reduces the reservoir fluid (heavy oil) viscosity by dissolving into the heavy crude. This process facilitates the mobility of heavy oil within the reservoir and toward the production system. Results also show that the CO_2 sequestration reduced sharply from 100 to 47% when the heavy oil production reached the first peak and reduced further to approximately 22% when the second peak of production occurred. A sharp decline in production was also noticed, which was almost reflected by a continuous decline in the percentage of CO_2 retention. In the year 2020, a rather slow reduction in the heavy oil production was noticed, at which stage the CO_2 sequestration remained almost stable around 22%. The CO_2 sequestration per barrel of heavy oil produced remained extremely high at the start up as no CO_2 was released. But as soon as CO_2 production started, the CO_2 retention per barrel varied between approximately 1,500 and 2,000 SCF/STB. On the other hand, the volume of CO_2 utilized per barrel of heavy oil produced was significantly high (11.2 MSCF/STB) at the beginning of the production when there was no CO_2 being produced, sharply reducing to approximately 4 MSCF/STB as the production rose to the peak, stabilized for a couple of years before progressively increasing as the heavy oil production reduced.

4.1. Analysis Based on CO_2 Mass Balance

Figure 5 shows the mass of CO_2 sequestrated, the CO_2 retention per barrel of heavy oil, the CO_2 requirements, and the percentage retention for the 25 years prediction. The CO_2 injection pressure was 5,000 psig.

During the 25 years prediction, the results show that the CO_2 mass balance around the reservoir inlet and outlet was not consistent, as the CO_2 input was by far greater than the amount released (output). At the beginning (year 2006) of the production, no CO_2 was released as indicated by the mass flow rate of produced CO_2. The calculated percentage of CO_2 retention shows 100% of CO_2 being retained in the reservoir in the major part of the first year (2006). In the meantime, the heavy oil recovery was spontaneous following the injection of CO_2. The beginning of heavy oil

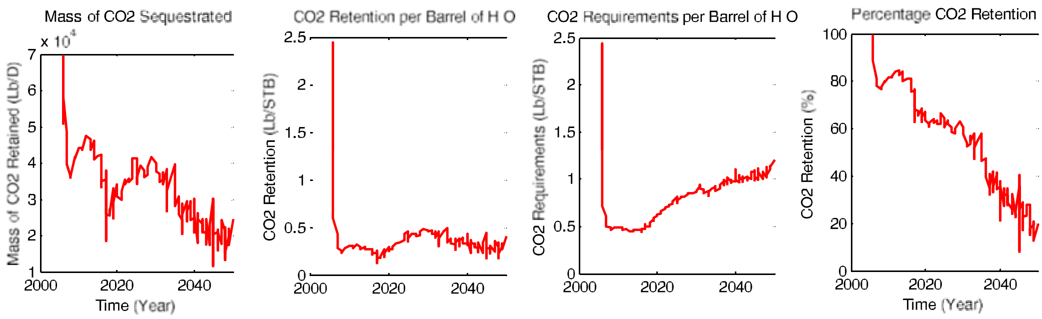

FIGURE 5 CO_2 sequestration at 5,000 psig injection pressure–analysis by mass balance.

recovery also implied a progressive decline in the percentage retention of CO_2 in the reservoir, reaching approximately 17% at the end of the prediction period (2050).

The heavy oil and gas production peaked twice as shown on the production profile, first at the same time in 2008; then the heavy oil peaked again in 2013 and remained almost steady until the peak gas production occurred in 2017. Following that trend, the heavy oil production began to decline while the gas production remained steady till the end of production in 2050. The difference between the mass of injected CO_2 and the mass of produced CO_2 shows that during that period (peak production) the CO_2 retention dropped sharply as the production peaked, perhaps justifying the momentum required to increase the mobility of the heavy crude. Between years 2020 and 2050, the variation in CO_2 retention was much lower than it was between years 2006 to 2020.

From 2006 to 2008, where the production rose to the peak, the CO_2 retention per barrel of produced heavy oil reduced from 2.4 to about 0.4 lb/STB and remained almost constant around that value. The utilized mass of CO_2 for every barrel of heavy oil produced dropped from 2.4 to about 0.5 lb/STB, stabilized till 2018, and began to rise again progressively as the heavy oil production gradually was in decline.

4.2. Analysis Based on Peak Production

In this case, CO_2 sequestration was investigated at various injection pressures. The injection pressure was varied from 1,000 to 7,000 psig, in increments of 1,000 psig.

Figure 6 shows in a sub-plot format the peak heavy oil production, the percentage retention of CO_2, the CO_2 requirements for barrel of heavy oil, and the CO_2 retention per barrel of heavy oil produced at different CO_2 injection pressures. The peak production increases with injection pressure. The recovery was about 1.3% when there was no CO_2 injection, however, showed appreciable growth as the CO_2 injection pressure was increased. From 0 to 1,000 psig injection pressure, there was an increase of 9.7% recovery. The percentage increase in recovery factor for every increment of injection pressure above 1,000 psig was very tiny, although the recovery was significantly high in the first increment (0–1,000 psig). The difference between the injected volume of CO_2 and that produced gives an indication of how much CO_2 was retained in the reservoir daily. Although the daily CO_2 retention increased as the CO_2 injection pressure increased, the percentage of retention remarkably indicated that a high percentage of CO_2 was retained at low CO_2 injection (2,000 psi). Beyond 3,000 psig injection pressure, the percentage CO_2 retention was almost stable.

The analysis shows that when the injection pressure was 7,000 psig, for every barrel of heavy oil produced, about 4,290 SCF of CO_2 was required and approximately 690 SCF of CO_2 was

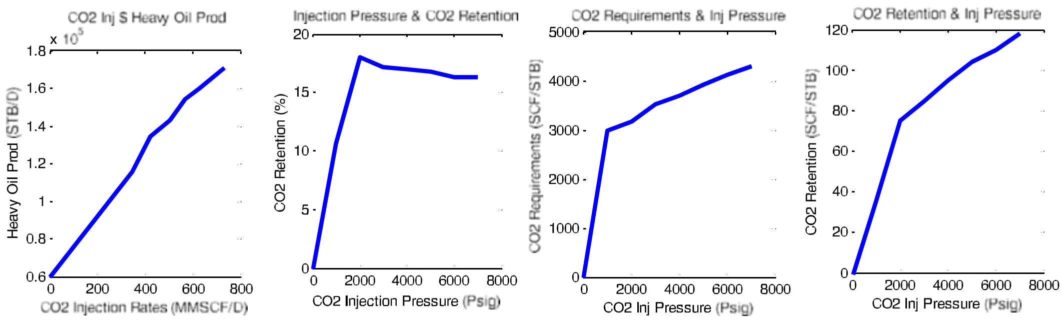

FIGURE 6 CO_2 sequestration and the relationship with injection pressure and recovery rates.

TABLE 4
Results Summary for CO_2 Sequestration Based on Evaluation of Production Profiles

CO_2 Injection Pressure, psig	*CO_2 Injection, MMscf/D*	*Maximum Heavy Oil Production, STB/day*	*Maximum Gas Production, MMscf/D*	*Maximum Recovery Factor, %*	*Difference between Inj and Prod CO_2, MMscf/D*	*CO_2 Retention, SCF/STB*	*CO_2 Requirements, SCF/STB*	*CO_2 Retention, %*
7,000	733	170,900	615	13.5	118.00	690.46	4,289.06	16.32
6,000	685	166,056	575	13.3	110.00	662.43	4,125.11	16.29
5,000	629	160,275	525	13.00	104.00	648.88	3,924.50	16.79
4,000	570	154,480	475	12.70	95.00	614.97	3,689.80	16.95
3,000	505	143,280	420	12.20	85.00	593.24	3,524.57	17.15
2,000	425	134,300	350	11.77	75.00	558.45	3,164.56	18.03
1,000	345	115,463	310	11.00	35.00	303.13	2,987.97	10.61
0	0	60,000	3.9	1.30	−3.90	−65.00	0.00	0.00

trapped in the reservoir by various mechanisms. The CO_2 requirement and retention per barrel of heavy oil reduced as the injection pressure reduced or as the peak heavy oil reduced. Nevertheless, further analysis using different data may well predict a diminutive variation or an improved ratio on the amount of CO_2 stored and that required per barrel. Also, ways to improve CO_2 storage during CO_2-EOR have been discussed in Jessen et al. (2005); one of the methods consisted of re-pressurizing the reservoir after the end of oil production with continuous injection. On the other hand, Kovscek and Cakici (2005) claims that a well controlled process, where wells are shut in according to a gas-to-oil production ratio limit to avoid excess gas circulation, is the best way to obtain both maximum oil recovery and CO_2 storage at the same time. This opinion that was, however, rejected by Jayasekera et al. (2005).

The calculations summary shown in Table 4 is based on maximum production; hence, illustrating the CO_2 sequestration occurring during a quasi steady state condition.

5. CONCLUSIONS

On the basis of this investigation, heavy oil recovery was achievable using the CO_2-EOR technique, and the volume of CO_2 produced together with heavy oil was appreciably lower than the volume of CO_2 injected. The results revealed lower CO_2 release in the first few years of the operation, followed by a gradual decline of CO_2 retention after the production peaked. The CO_2 retention per barrel was almost constant post peak production and the CO_2 utilization per barrel of heavy oil increased as the heavy oil in place reduced.

The injected CO_2 was partly trapped in the heavy oil reservoir by various means and the volume of the trapped CO_2 was very much dependent of the production phase/cycle. Despite the low percentage of CO_2 sequestration at quasi-steady state production, the CO_2 returning with the produced heavy oil will have to be re-injected into the reservoir to minimize the project CAPEX. Moreover, a detailed analysis of the geochemical interaction between the reservoir rock and the injected CO_2, with a close look into the dissolution and mineralization process during CO_2-EOR, may provide an improved prediction of CO_2 sequestration.

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