The Prospect of Deepwater Heavy Oil Production Using CO_2-EOR

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The prospect of unconventional oil development has long been coming to offset the rapid decline of conventional crude. And looking ahead, the worry is already turning away from the onshore exploitation to the challenging offshore environment, with the question being whether the emerging technology can overcome the challenges of deep-water heavy oil production. In economics terms, the immiscible process shows a negative return, a longer payback time, and a low net present value. With an increased revenue through increased production, there is a degree of strong, dynamic, and appealing prospect to any future heavy oil development using miscible process.

Keywords: CO_2-enhanced oil recovery, CO_2 sequestration, CO_2 utilization, cold heavy oil

1. INTRODUCTION

Formation of heavy oil and bitumen is reported to be identical to that of conventional oil, which is composed of hydrocarbons formed years ago under extreme pressure and high temperatures. This must, to some extent, justify why most scientists believe that crude oil is not heavy at the origin, and that almost all crude oils originate with API gravity between 30° and 40°. Oil becomes heavy only after substantial degradation during migration and after entrapment (Curtis et al., 2002). Conventional oil production goes through three distinct recovery stages, namely, primary, secondary, and tertiary recovery also known as enhanced oil recovery (EOR), where various techniques are employed to maintain production of crude oil at maximum levels. However, heavy oil recovery generally uses different techniques than those of conventional oil and one of the most exploratory techniques to date is CO_2-EOR. The U.S. remains the pioneer and leader of CO_2-EOR technique for conventional oil recovery, accounting for 94% of the worldwide CO_2-EOR oil production (Tzimas et al., 2005). Moreover, 79 CO_2-EOR operations were active in 2004 worldwide (Drilling Production, Special Report, 2005), among which 70 miscible CO_2-EOR projects and 1 immiscible were implemented in the U.S., 2 active miscible displacement CO_2-EOR projects in Canada, 5 immiscible displacement pilot fields in Trinidad, and 1 commercial immiscible displacement operation in Turkey. There has been a number of CO_2-EOR projects in operation in Hungary between the 1980s and the mid-1990s (IEA Greenhouse Gas Programme, 2000). CO_2-EOR technique has also been applied for heavy oil recovery. In the Bati Raman oilfield (southeast Turkey) close to the Turkish-Iraqi border containing heavy oil with very low gravity, 9° to 15° API, CO_2-EOR has been used since 1986 to boost up production to 6,000 bbl/D (IEA Greenhouse Gas Programme, 2000). The addition of CO_2 in poor quality heavy oil may reduce its viscosity by a factor of 10 (ECL Technology, 2001).

There are two types of CO_2-EOR processes known as miscible and immiscible displacements, which are predominantly dependent on the reservoir conditions. The immiscible displacement process has seen very limited applications to date due to efficiency issues and thus unattractive economics. The miscibility of CO_2 in crude oil or heavy crude oil is strongly influenced by pressure, and a minimum miscibility pressure (MMP), which is typically above the critical pressure of the CO_2, is required for CO_2 to become fully miscible with oil. At that pressure, CO_2 exists in a supercritical state with its density varying between that of light crude to that of raw water.

Most CO_2 transportation (pipelines) for EOR has been predominantly onshore, with limited experience reported offshore. Most of these pipelines operate in the 'dense phase' regime, and the flow is driven by compressors at the pipeline inlet, although some pipelines have intermediate compressor stations where necessary to boost the flow as required. Similarly, the difficulty in implementing CO_2-EOR offshore, where space and weight are major limitations, is reflected in the higher costs of implementation, compared with onshore deployment. Higher costs will incur for offshore pipelines and for the provision of new topside processing structures (Tzimas et al., 2005).

While taking into account the economics and the CO_2 sequestration, this article discusses the prospect of CO_2-EOR application for deepwater heavy oil exploitation.

2. MODELING APPROACH

Investigation was focused on the following points: (1) CO_2 sequestration during miscible and immiscible conditions; (2) CO_2 sequestration using integrated surface and sub-surface modeling; and (3) economics of a typical project.

CO_2 sequestration was investigated during miscible and immiscible displacements. Using REVEAL, the reservoir was modeled in 3D with a grid block of 500 ft × 500 ft × 200 ft, with horizontal injection and production wells both placed within grids 5, 5, and 15, 15, respectively. The CO_2 injection pressure used in this analysis was 5,000 psig. The reservoir temperature was 200°F. CO_2 was injected into the reservoir through a horizontal well, 8 km long and completed over a length of approximately 150 m. Six different reservoir pressures were investigated: 800, 1,000, 2,500, 3,000, 4,000, and 5,000 psig.

The surface facilities were modeled using GAP, the subsurface facilities including reservoir using REVEAL, and the surface and sub-surface facilities were integrated together using RESOLVE. The total pipeline length was 250 km covering both onshore (10 km) and offshore sections (240 km). The 2-km water depth was taken into account during steady state simulation to establish the process requirements at the onshore and the behavior of CO_2 along the long distance pipeline. As far as the economics assessment was concerned, two main cases were considered. A difficult production start-up due to low reservoir pressure (kept constant at 1,000 psig) with GOR 100 scf/STB was considered with CO_2 injection pressure varying between 1,000 and 7,000 psig, and a high pressure reservoir (4,000 psig) with constant injection pressure (5,000 psig). Using cost data from various sources, such as McCoy and Rubin (2008), Damen et al. (2005), Gozalpour et al. (2005), Hernandez et al. (2006), Reeves et al. (2004), and US EPA (http://www.epa.gov/cmop/docs/cmm_recovery.pdf) as indicated in Table 1, which summarize the cost parameters used in this analysis. The economics of a typical heavy oil development using CO_2-EOR was evaluated taking into account the cost of CO_2, the transportation, equipment, construction, and operation costs. The profitability of such development

TABLE 1
Key Economics Parameters

Process/Operation	*Units*	*Cost*	*Source*
CAPEX			
CO_2 purchase price[a]	$/Mscf	1.05	McCoy and Rubin (2008)
CO_2 pipeline cost	$/ton	1,600	
Produced gas processing (recycle)[b]	$	84,613	Damen et al. (2005)
Injection well cost (new)[c]	$/ft	100	Reeves et al. (2004)
Production well (new)[c]	$/ft	100	Reeves et al. (2004)
Compressor cost	$ million	20	Gozalpour et al. (2005)
Compressor installation	$ million	6	Gozalpour et al. (2005)
Pipeline construction cost (onshore)	$/m	500	Assumed
Pipeline offshore—vessel day rate	$/day	87,500	Assumed
OPEX			
Injection well	$/month	1,500	Hernandez et al. (2006)
Production well	$/month	1,500	Hernandez et al. (2006)
CO_2 compression	$/Mscf	0.3	Joshi (2003)
Safety and monitoring	$/injector/year	10,000	
Discount rates[d]	%	12	
Heavy oil price	$/STB	50	Assumed
Other			
Duration[e]	Year	20–30	

[a]Refer to Holt et al. (2004) for detailed discussions on the economics of CO_2 capture.
[b]This is the CAPEX of the recycle CO_2 including treatment and compression facilities.
[c]Cost is for a vertical well and includes drilling, completion, production equipment, and pipes. The cost of a horizontal well is estimated to be 1.5 to 2.5 that of vertical wells (Norwegian Petroleum Directorate, 2005; http://www.npd.no/).
[d]The NPV of the projects is calculated at a discount rate of 12%, despite that the rates used in similar studies range from 7 to 11% (Tzimas and Peteves, 2005).
[e]The duration varies between 20 to 30 years, depending on simulation case.

was measured by the net present value (NPV) and return on investment (ROI). The NPV and ROI were estimated by performing a discounted cash flow analysis using the oil production and CO_2 consumption rates from the performance model. The capital expenditures (CAPEX) was estimated considering typical requirements for field production equipment, CO_2 compression and transportation facilities, and new injection and production wells, including drilling and completion costs.

3. RESULTS AND DISCUSSION

3.1. Reservoir Modeling–CO_2 Sequestration (Miscible Process versus Immiscible Process)

Emphasis was placed on the influence of reservoir pressure, i.e., miscible and immiscible conditions, with regards to the CO_2 retention and utilization per barrel of heavy oil produced. It is reported in Tzimas et al. (2005) that immiscible displacement projects can store larger volumes of CO_2 than miscible displacement projects. This was attributed to the CO_2 breakthrough, which is unavoidable in miscible displacement operations and avoidable in immiscible displacement, as the immiscible projects may be designed to eliminate the breakthrough to enable permanent retention of CO_2.

In subplot format, the modeling results (heavy oil production, percentage of CO_2 sequestration, CO_2 requirements, and retention per barrel of heavy oil produced) shown in Figure 1 indicate that a

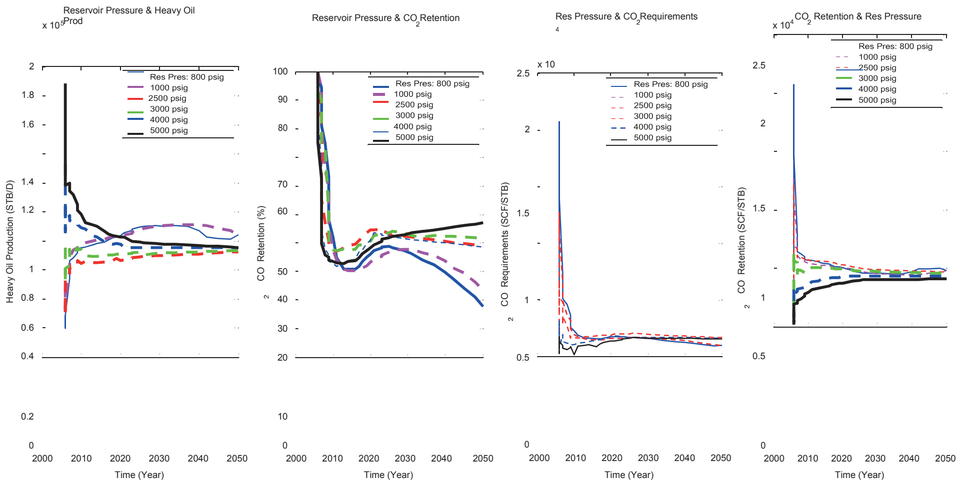

FIGURE 1 CO_2 sequestration–influence of reservoir pressure–injection pressure 5000 psig.

considerable amount of heavy oil was achieved at high reservoir pressure, i.e., miscible conditions. Equally, as the reservoir pressure increased, the influence on the production profile was clearly noticeable.

The recovery factor varied between 8 to 12% of the original heavy oil in place, which was within the range reported by Clarke et al. (2007) who suggested a recovery factor using cold production to be between 6 to 15% of original oil in place (OOIP). Despite the constant injection pressure, the volumetric flowrate of CO_2 reaching the reservoir increased as the reservoir pressure was reduced. High reservoir pressure enabled a high recovery factor. However, in all cases, the production traces of mass flow rate of CO_2 produced showed a significant delay (period of zero flow) before initial CO_2 production at continuous CO_2 injection. On the other hand, all simulation results were based on 20–30 year production forecast and illustrate that during CO_2-EOR applica- tion, the CO_2 requirements varied with time throughout the lifetime of the forecast, which corroborate with the claim reported in Balbinski et al. (2003) and Holt et al. (2004).

While the percentage of CO_2 sequestration was found to be high at high reservoir pressure, in this case the CO_2 utilization and CO_2 retention per barrel of heavy oil produced was found to be significantly higher during immiscible conditions compared to miscible conditions. These findings are in agreement with the theory reported in Tzimas et al. (2005), that immiscible displacement projects would generally require a higher amount of injected CO_2 per incremental barrel of oil produced, typically two to three times more. However, values may vary significantly from field to field. Considering that the "pressure" limit switch between miscible and immiscible process is known to be 1,073 psig, the simulation results indicate that at low reservoir pressure (800–1,000 psig) the CO_2 retention and CO_2 requirements per barrel of heavy oil produced was about two times higher than that required at high reservoir pressure (2,500 psig). This factor varies consider- ably as the reservoir pressure increases.

The percentage of CO_2 retention within the reservoir was influenced by the reservoir pressure, and in this case high sequestration occurred at high reservoir pressure. At the production start-up, the CO_2 retention within the reservoir was maximal for all the reservoir pressures investigated, and for low reservoir pressure (800 and 1,000 psig), the sequestration remained high until production reached a quasi-steady state condition, at which stage the decline in CO_2 retention began progres- sively as the production continued. At high reservoir pressure (above 1,000 psig), the CO_2 retention dropped from 100 to 35%, rose again approximately to 42% during transition from start-up and quasi-steady state production; and at quasi-steady state condition the CO_2 retention within the reservoir continued to rise progressively as the production continued. Results based on peak production show that the minimum percentage of CO_2 retention within the reservoir increased with increasing reservoir pressure, starting with 17.7% retention at 800 psig to 32.8% at 5,000 psig. The maximum CO_2 retention of 100% simply reflects that production or release of CO_2 started approximately one year after CO_2 injection commenced. At high reservoir pressure (above 4,000 psig), the CO_2 retention and CO_2 requirements/utilization per barrel remained within the range reported by many authors, such as Clarke et al. (2007), as being between 6 to 8 Mscf/STB, but at reservoir pressure below 4,000 psig the value was in agreement with that presented by Gozalpour et al. (2005), which is 13 Mscf/STB.

3.2. Integrated Surface and Sub-surface Facilities (Injection-production System)

The process conditions along the pipeline were established based on the CO_2 phase diagram and steady state simulation (where outlet pressure (reservoir) and maximum velocity was used as criteria). The transported CO_2 was predominantly in the dense phase, with possible liquid drop depending on temperature variation.

Remote CO_2 injection required a significant amount of CO_2 capacity, as shown in Figure 2. And in such cases, the higher the reservoir pressure, the lower the volume of CO_2 required to make a significant impact on the production trend. Heavy oil production and the CO_2 requirements were significantly influenced by the reservoir pressure. With the reservoir pressure at 800 and 1,000 psig, the heavy oil production was less than 8,000 bbl/d, and the production was increased beyond 10,000 bbl/d when the reservoir pressure was above 1,000 psig. The total gas production was significantly below the amounts of CO_2 injection for all the reservoir pressures investigated, and particularly when the reservoir pressure was 800 psig, the total gas produced was almost half the volume of CO_2 injected. Despite continuous CO_2 injection, in all cases, the gas production started about a couple of years post start-up and the lower the reservoir pressure, the longer the period of no production. An estimate of percentage of CO_2 retention, CO_2 retention and CO_2 utilization/ requirements per barrel of heavy oil is shown in Figure 3 (subplot format). Remarkably, the high percentage of CO_2 retention in the reservoir was found to occur during immiscible displacement (reservoir pressure lower than critical pressure of CO_2, 1,073 psig) as reported in Tzimas et al. (2005). The minimum percentage of CO_2 sequestration varied from 55% at low reservoir pressure (800 psig) to 47% at high reservoir pressure (5,000 psig). The CO_2 retention and CO_2 requirements per barrel of heavy oil produced were significantly high at low reservoir pressure and progressively reduced as the reservoir pressure increased.

High volume of CO_2 injection was required for immiscible displacement, and was almost double the amount that was injected in the previous cases where only the reservoir

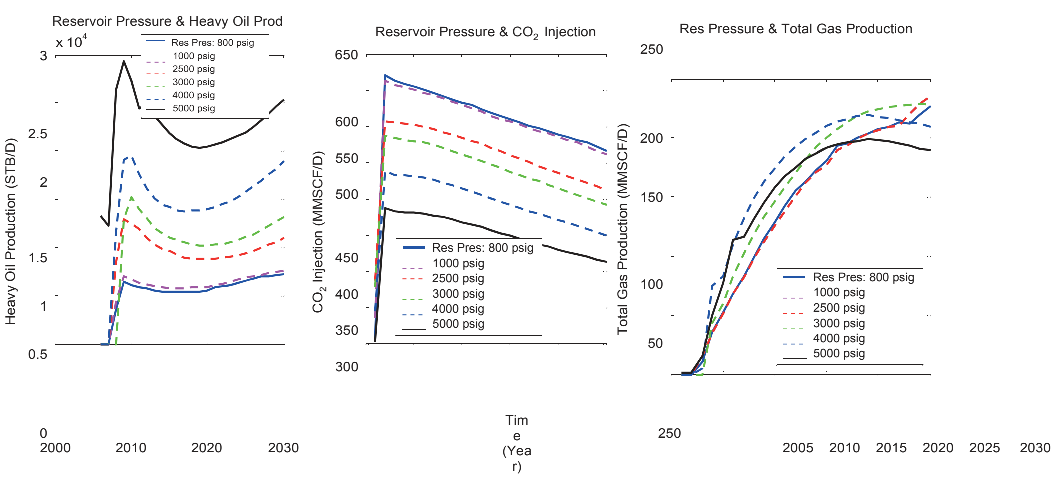

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FIGURE 2 Production profiles based on GAP/RESOLVE/REVEAL modeling.

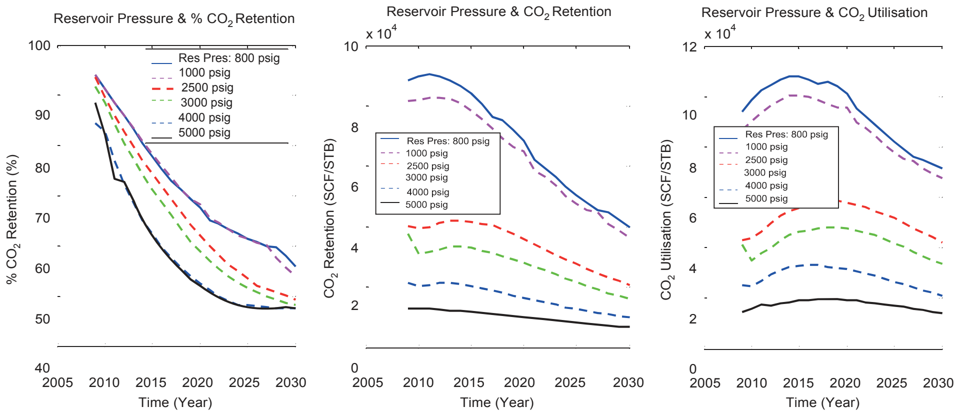

FIGURE 3 CO_2 sequestration based on GAP/RESOLVE/REVEAL modeling.

3D model was considered (no integration with GAP). With the remote injection (integrated modeling), the amount of CO_2 injection rate reaching the reservoir was much smaller at high reservoir pressure (5,000 psig) compared to that when the reservoir pressure was 800 or 1,000 psig. A slim tube displacement experiment test conducted by Chung et al. (1988) has indicated that at pressure as high as 3,800 psig, CO_2 might reach miscibility with viscous oil, and the findings discussed in this article have shown that the amount of CO_2 sequestration increased with increasing CO_2 injection flow rate (i.e., high pressure), particularly during immiscible displacement since the amounts of CO_2 released with the produced heavy oil was minimal.

3.3. Economics of the Project

This economic evaluation is purely illustrative and was carried out using simplified cost assumptions to reflect typical heavy oil development using CO_2-EOR technology. The economics do not take into account detailed pre-tax cash flows (e.g., royalty and severance taxes, etc.) or other costs (e.g., "upgrade" of heavy oil), but assumed a 12% discount rate.

In the estimated CAPEX shown in Table 2, the purchase price of CO_2 makes the dominant portion of the amount. At low reservoir pressure, it appears as shown in Table 2 that the operation was highly profitable, when the injection pressure was above 2,000 psig, due to the additional recovery that yielded significant revenue with smaller payback time, high NPV, and ROI. Table 2 equally shows the "beneficial" effect of individual displacement process based on the CO_2 demands and the production profile. Miscible displacement was effectively the most profitable option, identifiable from revenue generated in the form of NPV, while providing a high ROI and an expected smaller project payback time, and substantial percentage of CO_2 sequestration. The analysis assumed that the project owner/operator will dictate a limiting internal rate of return (IRR) that would decide the feasibility of the project. Similarly, the results also confirmed as generally speculated that the immiscible displacement process has very limited economics values due to significant amounts of CO_2 injection required, the low additional production of heavy oil and consequently the long payback time, which in this case can extend up to 19 years. The results in Table 2 may look very optimistic, but even considering the production cost to be \$13 to \$16 per barrel of heavy oil (Yergin, 2006), miscible displacement will still provide an appreciable benefit as well as reasonable payback time.

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TABLE 2
Economics of CHOP Using CO_2-EOR

	217,250,000			
CAPEX ($)[a]	156,000			
OPEX ($)[b]	*PV, $*	*NPV, $*	*ROI, %*	*Payback Time, Year*
Injection Pressure, Psig[c]				
7,000	536,873,287.7	319,649,419	247.2	7.2
6,000	415,473,950.1	106,821,227	191.3	8.0
5,000	324,045,095.3	106,821,227	164.9	8.9
4,000	358,261,159.5	141,037,291	165	8.9
3,000	289,964,448.6	72,740,580	133.5	9.8
2,000	201,928,146.2	−15,295,722	93.0	11.7
1,000	20,647,780.7	−196,576,088	9.5	22.1[d]
Reservoir Pressure, Psig				
4,000	1,354,180,605	1,136,956,736	623.4	3

[a]Cost includes single pipeline (6-in.) and associated equipment costs, CO_2 purchase, and other costs as shown in Table 1.
[b]Does not include the supply cost of CO_2, which was accounted for separately considering the CO_2 requirements for an individual case.
[c]Variation of injection pressure at constant reservoir pressure (1000 psig) and GOR (100 scf/STB).
[d]Takes into account period of no production beginning at the start-up.

With the breakeven cost of CO_2 being the CO_2 purchase price at which the project net present value (NPV) equals zero, using the economics model as in Table 2, the analysis show that breakeven cost of CO_2 will vary approximately between \$9.5 to \$38.5 per Mscf when the heavy oil price varies between \$40 to \$150 per bbl.

As it costs much less to recycle CO_2 than to buy it at market value (Todd and Grand, 1993), re-injection of the produced CO_2 with production maximization will somehow help towards reducing the high investment costs.

4. CONCLUSIONS

Carrying out this techno-economic evaluation has made it known that CO_2 sequestration was very likely during heavy oil recovery using the CO_2-EOR technique. Nevertheless, the percentage of CO_2 sequestration, the CO_2 retention, and CO_2 utilization per barrel of heavy oil produced were very dependent on process conditions at the pipeline inlet and at the reservoir, as well as the injection-production systems configuration. Consequently, in a real project the results may vary from one field to another. Moreover, there were substantial grounds on which immiscible displacement during CO_2-EOR may be considered as a highly risky investment, particularly at low injection pressure. Immiscible displacement may be very desirable in some context mainly for CO_2 sequestration or as a mean to maintain reservoir pressure. Although not cost-effective, immiscible displacement at high CO_2 injection pressure may be as operational as miscible displacement, but less imperative. Miscible displacement is very pragmatic from an operation point of view and has a higher cash flow stream that extends throughout the lifetime of the asset due to continuous production, while immiscible displacement has the longer payback period due to the time lag between the CO_2 injection and the incremental heavy oil production.

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