

CO₂ EOR and Storage in Oil Reservoirs

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Résumé — Récupération assistée du pétrole (EOR) et stockage du CO₂ dans des réservoirs pétroliers—L'injection de CO₂ dans des réservoirs pétroliers est une méthode efficace de récupération assistée du pétrole (EOR) et est utilisée par l'industrie pétrolière depuis une quarantaine d'années. La prise en compte des émissions de gaz à effet de serre dans l'atmosphère a mené à étudier ces dernières années le potentiel de cette méthode pour stocker durablement le CO₂. Si les conditions de réservoirs sont adéquates, elle peut permettre à la fois d'augmenter notablement la récupération d'huile et de stocker définitivement du CO₂ dans les formations géologiques.

La plupart des projets passés et actuels d'EOR utilisent du CO₂ peu coûteux et ont un résultat économique appréciable (167-227 sm³ CO₂/STB pétrole). Le potentiel de stockage du CO₂ associé à l'EOR est important, à peu près 60 % du CO₂ injecté est retenu dans le réservoir, en ne prenant pas en compte la réinjection. Il est admis qu'il y a peu de défis technologiques majeurs à relever, cependant les contraintes économiques doivent être prises en compte pour les cas de CO₂ cher (comme par exemple celui provenant de la production d'électricité).

Dans cet article, un panorama des potentiels de stockage de CO₂ associés à l'EOR est donné. Une étude de cas en mer du Nord est présentée.

Abstract—CO₂ EOR and Storage in Oil Reservoirs—CO₂ injection into tertiary oil reservoirs has been widely accepted as an effective technique for enhanced oil recovery (EOR), and has been used by the oil industry for over 40 years. Concerns over greenhouse gas emissions are leading to the investigation and realisation of its potential as a carbon storage method in recent years. With the right reservoir conditions, injection of CO₂ into oil reservoirs can result in incremental oil recovery and permanent storage of CO₂ in geological formation.

The majority of previous and current CO₂ EOR projects use low cost CO₂ sources and have good economic returns in terms of high gas utilisation efficiencies (167-227 sm³ CO₂/STB oil). The potential of CO₂ storage combining EOR is high; approximately 60% injected CO₂ can be retained in the reservoir at the CO₂ breakthrough if reinjection is not considered. It has been accepted that there is little major technical challenges for CO₂ EOR projects, but there are economic constrictions if high cost anthropogenic CO₂ (such as from power plant) is used for EOR and storage operations.

In this chapter, a general review is given on the CO₂ EOR and storage potentials, field screening and economic analysis. A case study for CO₂ EOR application in a North Sea field is also presented.

INTRODUCTION

Oil reservoirs are appealing as good storage sites since they are known to have geologic seal that retained liquid and gas hydrocarbons for millions of years. CO₂ injection into oil reservoirs, leading to enhanced oil recovery (CO₂ EOR), thus gaining a financial return to offset the CO₂ capture and storage cost, has been considered as a favourable option for near-term action (Orr Jr, 2004). CO₂ EOR has been extensively investigated and is commercially pursued. There have been over 80 CO₂ EOR projects in the world (<http://www.ieagreen.org.uk/sept32.htm>); all of them are in onshore operations. Most CO₂ used for EOR is coming from naturally occurring sources. More recently, a large demonstration project using anthropogenic CO₂ has been conducted, namely the Weyburn CO₂ EOR project in Canada. Given appropriate circumstances, captured CO₂ from sources produced by human activities can be competitive for EOR as is demonstrated by the current field project. CO₂ has been considered as an effective injectant for EOR due to its high miscibility with oil. Field projects showed that CO₂ injection into water flooded oil reservoirs could yield an extra of 4-12% OOIP oil production (ECL Report 2, 2001). Over 8% OOIP has been achieved in the Permian Basin of West Texas by CO₂ miscible floods (Nelms *et al.*, 2004). It has been accepted that there is little major technical challenges for CO₂ EOR projects for onshore operations, but there are economic constrictions if high cost anthropogenic CO₂ is used for EOR and storage operations. It has also been acknowledged that commercial EOR projects were more unlikely offshore, where costs are higher and well density lower (Ali, 2003).

In this chapter, a general review of CO₂ EOR is given, considering the current field experience, CO₂ EOR and storage potentials, technical and economic barriers, field screening and economic analysis of CO₂ EOR and storage projects. A case study for CO₂ EOR application in a North Sea field is presented. The recent increase in the price of crude oil and gas coupled with a stable demand and declining production, has made CO₂ EOR and storage a favourable option.

1 EOR MECHANISM AND POTENTIAL

The displacement of oil by gas can be classified as immiscible and miscible or multicontact miscible processes, depending on the properties of the gas injected and the reservoir fluids at reservoir conditions. Immiscible displacement occurs at pressures below a minimum miscible pressure (MMP) of the oil, in which there is less interchange of components or mixing zones between the gas injected and the reservoir fluid. The injected gas can be used for pressure maintenance and gravity stabilised drainage. At miscible conditions, the injected gas and the hydrocarbons are completely miscible and form a single-phase fluid. One of the main advantages of miscible displacement is lack of

capillary effect retaining oil in place. Miscibility also promotes oil swelling, reduces fluid viscosity and increases its mobility. Both vertical and horizontal flooding can be applied through a miscible process.

CO₂ has an advantage of low MMP over other gases, therefore, most field projects are being operated through a miscible flooding mode. The pressure required for miscible or multicontact miscible displacement depends on the reservoir temperature and oil composition. Many MMP correlations that take into account oil and injection gas composition have been proposed (Orr Jr, 2004; Yuan *et al.*, 2004). Holm and Josendal (1974) presented a useful correlation to predict MMP in terms of reservoir temperature and molecular weight of C₅₊ of oil. Miscible displacement in limestone reservoir has also been demonstrated as in sandstones (Mungan, 1991; Langston *et al.*, 1988). The CO₂ MMP is an important parameter for screening, selecting reservoirs and designing miscible CO₂ EOR projects. Experimental techniques, such as the slim tube, are required to determine the CO₂ MMP for the oil investigated (Yellig *et al.*, 1980). The effect of impure CO₂ on MMP, such as the content of N₂, is significant. Simulation results indicates that, when N₂ is the only contaminant, the CO₂ MMP increases by approximately 0.7 bar/mol% N₂, for the range of 0-10 mol% N₂ (ECL Report 14, 2002).

The expected EOR potential from a vertical miscible flooding (gravity stabilised gas injection-GSGI) is in the range of 15-40% OOIP compared to upward water flood (Asgarpour, 1994). In horizontal miscible flooding process, where normally water alternative gas (WAG) injection is applied, the expected EOR factor is 5-15%, affected by gravity override, viscous fingering and inability to control injection profiles.

Industry experience of past and current CO₂ EOR onshore field projects has indicated that tertiary CO₂ injection in onshore North America can achieve incremental oil recoveries in the range of 4-12% OOIP over water flooding (ECL Report 2, 2001). The reported net gas utilisation of most fields was less than 8000 scf/STB (227 sm³/STB), and some had utilisation of less than 6000 scf/STB (170 sm³/STB). In other words, approximately one tonne of CO₂ injected can produce 2.5-3.3 STB of oil. There have been no offshore CO₂ EOR field projects, though there have been several proposed and implemented hydrocarbon gas injection (WAG) projects in the North Sea (Christensen *et al.*, 2001, ECL Report 2, 2001). For instance, the predicted EOR for one of the ongoing WAG injection projects in the North Sea field (the Gullfaks field project) was 5% OOIP, while for the Brage field, it was 9-12% OOIP.

2 CO₂ SOURCES

In the last 40 years, most CO₂ EOR projects used naturally occurring CO₂. Among the earliest projects were SACROC

and North Cross projects, in which CO₂ was separated from natural gas in southwest Texas and then injected (Hawkins *et al.*, 1996; Mizenko, 1992). Commercial CO₂ EOR operations in the Permian Basin of west Texas began in the 1970s and 1980s, using CO₂ transported by pipelines from Colorado and New Mexico, where large natural CO₂ sources exist (Tanner, 1992; Weeter, 1982). The economics of these projects using low cost CO₂ was generally good in terms of incremental oil production by the injection of CO₂. Another very large gas injection project is under way at Prudhoe Bay, in which the injection gas contains a significant fraction of CO₂ (McGuire *et al.*, 2001), which was made by separating CO₂ and intermediate hydrocarbons from the produced gas to create a solvent like gas mixture that allows multicontact miscible displacement. The motivation of these projects was enhanced oil recovery, not the avoidance of CO₂ emission, because the injected CO₂ would not have emitted to the atmosphere (Orr Jr, 2004).

There are a few field projects currently being operated to investigate and materialise the potential of CO₂ EOR combining CO₂ storage. ChevronTexacos Rangely Weber field in Colorado is one of the largest geologic storage sites for anthropogenic CO₂ (Hild *et al.*, 1999), which is purchased from the ExxonMobil LaBarge natural gas processing facility in Wyoming and transported via pipeline to the field. It is estimated that a total of 25 Mt of CO₂ will have been stored in the oil reservoir by the time the project is completed.

In October 2000, EnCana began injecting CO₂ into a Williston Basin oilfield (Weyburn) in order to boost oil production. The CO₂ gas is being supplied via a 330 km pipeline stretched from the lignite-fuelled Great Plains Synfuels plant operated by the Dakota Gasification Company. It is anticipated that some 20 Mt of CO₂ will be permanently stored in the reservoir over the lifespan of the project and contribute to the production of at least 122 Mbbl of incremental oil (Malik *et al.*, 2000). Sales of CO₂ add about \$30 millions of gross revenues to the gasification company each year if carbon trading scheme is not considered.

A summary of main CO₂ EOR projects using anthropogenic sources in North America is listed in Table 1.

The cost of CO₂ from various sources is very different (Lako, 2002). The presumed cost of CO₂ supply (to field for injection) was \$14/t from naturally occurring CO₂. The cost of supply from a pure anthropogenic CO₂ source (chemical plant) was \$18/t. The cost of capture and processing CO₂ from a pulverised coal fired plant can be \$18-54/t.

3 CO₂ STORAGE CAPACITY

The CO₂ storage capacity of a reservoir include the CO₂ remained in the reservoir at the end of EOR operation and any extra CO₂ that can be injected after the EOR project. The US experience indicated that approximately 40% of the originally injected CO₂ is being produced in the producer wells and can be reinjected (Shaw *et al.*, 2002; Hadlow, 1992). This suggests a “gross” CO₂-retention efficiency of approximately 60% at CO₂ breakthrough if separation and reinjection is not considered after the breakthrough.

Shaw *et al.* (2002) presented a method to calculate the mass CO₂ storage capacity (M_{CO_2}) in the reservoir during EOR operations, which is a function of the recovery factor, OOIP, and oil shrinkage:

At breakthrough (BT):

$$M_{CO_2} = \rho_{CO_2, res} \cdot RF_{BT} \cdot OOIP / S_h \quad (1)$$

At any HCPV injection:

$$M_{CO_2} = \rho_{CO_2, res} \cdot [RF_{BT} + 0.6 \cdot (RF_{\%HCPV} - RF_{BT})] \cdot OOIP / S_h \quad (2)$$

where, $\rho_{CO_2, res}$ is CO₂ density at reservoir conditions; RF_{BT} and $RF_{\%HCPV}$ are, respectively, the recovery factor at CO₂ breakthrough and at the assumed percentage of hydrocarbon pore volume (HCPV) of injected CO₂; $OOIP$ is the volume of original oil in place; S_h is the oil shrinkage factor ($= 1/B_o$, B_o is the oil formation volume factor).

TABLE 1

Summary of main CO₂ EOR projects using anthropogenic CO₂ in North America

Location	Plant type	CO ₂ supply (Mt/y)	EOR field	Operator
Oklahoma	Fertiliser	0.7	NE Purdy, Sho-Vel-Tum	Anadarko, Chaparrel Energy
Colorado	Gas processing	1.2	Rangely	ChevronTexaco
Wyoming	Gas Processing	0.6	Lost Solider, Wertz	Merit Energy
Texas	Gas Processing	1.3	Sharon Ridge	ExxonMobil
Saskatchewan	Coal Gasification	1.8	Weyburn	EnCana Energy
Alberta	Ethylene Plant	0.1	Joffre Viking	PanWest Petroleum

Source: V.A. Kuuskraa, Advanced Resources International, www.adv-res.com, presented at the Fourth Annual SECA Meeting, Seattle, WA, April 2003.

Similar volumetric methods were used by *ECL Technology* (UK) to calculate the net CO₂ retained in the reservoir for different EOR operations (ECL Report 5, 2001).

For water alternative gas injection (WAG):

$$\text{Net CO}_{2\text{retained}} = \text{WAG}_{\text{IOR efficiency}} * \text{WAG}_{\text{score efficiency}} * \text{OOIP} * \text{WAG}_{\text{CO}_2\text{factor alpha}} * B_o / B_g \quad (3)$$

Where, $\text{WAG}_{\text{IOR efficiency}}$ is the targeted incremental oil recovery factor (% OOIP) produced by a CO₂ WAG operation, $\text{WAG}_{\text{score efficiency}}$ is a factor between 0 and 1 (it is 1 for an efficiently and fully implemented WAG project). The $\text{WAG}_{\text{CO}_2\text{factor alpha}}$ varies between 1 and 2 and is related to the net CO₂ utilisation efficiency when expressed in reservoir volumes, indicating more gas may be stored in the reservoir than required for WAG operation.

For gravity stable gas injection (GSGI):

$$\text{Net CO}_{2\text{retained}} = (\text{GSGI}_{\text{CO}_2\text{factor}}) * (\text{GSGI}_{\text{score CO}_2\text{factor}}) * \text{OOIP} * 0.7 * B_o / B_g \quad (4)$$

$\text{GSGI}_{\text{CO}_2\text{factor}}$ is the targeted incremental oil recovery by GSGI operations. The $\text{GSGI}_{\text{score CO}_2\text{factor}}$ allows the user to reduce the injected CO₂ volume compared to the potential target volume. For a fully implemented project $\text{GSGI}_{\text{score CO}_2\text{factor}}$ is equal to 1. The factor 0.7 accounts for the fraction of OOIP left in the formation at the end of gas flood and a small amount of mobile water also left in the gas swept region. The GSGI differs from the WAG operation. For GSGI, the amount of CO₂ retained is proportional to the reservoir pore volume, rather than the process IOR. More CO₂ is needed in a GSGI process, which is favourable for CO₂ storage.

These expressions can be used for estimating the CO₂ storage potential in a CO₂ EOR project associated with the targeted incremental oil recovery. The basic assumption is that the theoretical capacity for CO₂ storage in oil reservoirs

equal to the volume previously occupied by the produced oil and water. For more accurate predictions, appropriate numerical reservoir simulations can be used, which may consider the effect of water invasion, gravity segregation, reservoir heterogeneity and CO₂ dissolution in formation water (Bachu *et al.*, 2004). In practice, other considerations need to be taken into account for CO₂ storage, such as reservoir type, depth and size and the safety of the CO₂ storage. The low capacity of shallow reservoirs, where CO₂ would be in the gas phase, makes them uneconomical for storage. On the other hand, CO₂ storage in very deep reservoir may also be not economical due to the high cost of compression. The reservoir depth window of 900-3500 m has been recommended for CO₂ EOR and storage (Winter *et al.*, 1993; Bachu *et al.*, 2004). Large reservoirs with high CO₂ storage capacity are favourable considering the unit cost for building infrastructure for CO₂ capture, transportation and injection, and the lifespan of the project for long time operations. Thus, most likely, only reservoirs with large CO₂ storage capacity (*e.g.* > 1 Mt) will be considered in the short and medium term. The roughly estimated global potential of CO₂ storage using oil reservoirs is in the range of 41-191 Gt (Lako, 2002).

4 RESERVOIR SCREENING

Not all oil reservoirs are suitable for CO₂ EOR and storage for various technical and economic reasons. The following preliminary technical evaluations were suggested for selecting oil reservoir for CO₂ EOR and storage before considering other economic criteria (Shaw *et al.*, 2002):

- screening for EOR and storage suitability;
- technical ranking of suitable reservoir;
- IOR and CO₂ storage capacity predictions.

Table 2 lists a series of criteria recommended by various authors for the technical screening of CO₂ EOR by miscible

TABLE 2
Screening criteria for application of CO₂ miscible flood suggested by various authors

Reservoir parameter	Carcoana (1982)	Taber & Martin (1983)	Klins (1984)	Taber <i>et al.</i> (1997)
Depth (m)	< 3000	> 700	> 914	i) > 1219; ii) > 1006 iii) > 853; iv) > 762
Temperature (°C)	< 90			
Pressure (MPa)	> 83		> 103	
Permeability (mD)	> 1			
Oil gravity (°API)	> 40	> 26	> 30	i) 22-27.9; ii) 28-31.9 iii) 32-39.9; iv) > 40
Viscosity	< 2	< 15	< 12	< 10
Fraction of oil remaining	> 0.30	> 0.30	> 0.25	> 0.20

flood. These criteria are based on the optimising reservoir performance for better IOR. However, some criteria can be ignored since they are affected by other parameters, such as reservoir depth and oil viscosity, which can be ignored because they are related to other parameters, *i.e.* oil gravity and reservoir temperature. Application of these criteria allows for a rapid screening and evaluation of oil reservoirs suitable for CO₂ EOR based on general reservoir and oil properties.

A parametric optimisation method was used for technical ranking of oil reservoir for CO₂ EOR on the basis of intrinsic reservoir and oil characteristics (Rivas *et al.*, 1994; Diaz *et al.*, 1996; Shaw *et al.*, 2002). Using reservoir simulators, Rivas *et al.* (1994) investigated the effect of many reservoir parameters on CO₂ EOR performance. They found a set of optimum values of reservoir and oil properties best suitable for CO₂ EOR operation, which are given in Table 3. Their relative importance, or the weighting factor, is also given in the Table. For any set of reservoir parameters being analysed, the parameter value farthest from the optimum is the worst value. It is possible to have two worst values, one lower and the other higher than the optimum.

Finally, a performance ranking will be taken into account by considering three “performance parameters”: OOIP, CO₂ EOR recovery factor and CO₂ storage capacity. Application of these procedures described above would identify the top oil reservoirs that are technically suited for CO₂ EOR and storage. A final selection of reservoirs would depend also on other extrinsic conditions, such as surface facilities, source and cost of CO₂ and other economic considerations, which are described in other sections of this paper.

TABLE 3

Optimum reservoir parameters and weighting factors for ranking oil reservoirs suitable for CO₂ EOR

Reservoir parameters	Optimum values	Parametric weight
API Gravity (°API)	37	0.24
Remaining oil saturation	60%	0.20
Pressure over MMP (MPa)	1.4	0.19
Temperature (°C)	71	0.14
Net oil thickness (m)	15	0.11
Permeability (mD)	300	0.07
Reservoir dip	20	0.03
Porosity	20%	0.02

5 TECHNICAL CHALLENGES

Although many operators considered CO₂ injection is a technically proven EOR technique, which can be conducted in their fields if this is offered by a satisfactory financial return, there are still some technical concerns over the

projects, especially in offshore operations, such as in the North Sea (Puckett, 2003). The following issues may pose technical challenges to the combination of CO₂ EOR and storage projects, which should be investigated and considered in project design.

1. The main challenge, in terms of oil recovery, can be unfavourable reservoir characteristics causing poor sweep efficiency due to early CO₂ breakthrough as a result of mobility contrast, gas override, and reservoir heterogeneity. Some of the causes of CO₂ flood failure in previous projects in Permian Basin and North Dakota included reservoir heterogeneity, low permeability, high water cuts and early CO₂ segregation and channelling through natural fractures (Nelms *et al.*, 2004). Vertical reservoir containment is one of the key factors associated with failure. Reservoirs with high concentrations of vertical fractures should be avoided due to CO₂ injection losses out of zone and, or early CO₂ breakthrough reducing sweep efficiency. Reservoirs with either very high, or very low, permeability can also be poor candidates for CO₂ flooding. Low permeability can reduce both water and CO₂ injectivity and reduce sweep efficiency. Very thick and high permeability can cause gravity segregation of injected CO₂.

2. Well spacing is another factor that can cause CO₂ EOR less effective. It is suggested that fields or units in North Dakota region with well spacing greater than 80 acres (323 746 m²) would be less likely CO₂ flooding candidates due to sweep efficiency reduction and the increased cost of infill drilling (Nelms *et al.*, 2004). For offshore CO₂ EOR operations, present large well spacing should be considered in terms of sweep efficiency, the timing of incremental oil production, the cost of drilling more wells and their effect on project cash flow.

3. CO₂ related problems on facilities and in reservoirs have always been a noticeable challenge to oil industry and its great impact on project economics is well known. CO₂ can cause severe corrosion on pipelines, well tubing and pumping equipment (Lopez *et al.*, 2003; Crolet *et al.*, 1991). Impact of CO₂ injection on the reservoir formation and reservoir fluid should also be considered. This includes solid deposition caused by CO₂ mixing with reservoir fluids, such as scale formation (Yuan *et al.*, 2001) and asphaltene precipitation (Novosad *et al.*, 1990; Sarma, 2003). For offshore projects, concerns are due to platforms, well completion and pipelines to handle CO₂, such as extra weight on injection and production platforms, and hydrate formation.

4. For offshore operations, such as in the North Sea, the risks of EOR and safe CO₂ storage due to possible insufficient reservoir characterisation need to be assessed. The window of opportunity in terms of the offshore infrastructures is also of major concerns. The question to be answered is when and how long the CO₂ EOR project in the offshore fields can be operated, and can extra CO₂ be injected for storage after EOR operation being ceased?

6 ECONOMIC BARRIERS

The previous and current onshore experience, mainly in the Permian Basin region, has shown that the performance of CO₂ EOR projects in terms of IOR and overall economics is good if low cost CO₂ source can be used. The anticipated final IOR is in the range of 8-11% OOIP. Typical recovery factors are 40-50% of OOIP. Miscible CO₂ flooding implemented as conventional WAG projects typically have gas cycles sizes of 1-4% HCPV. The majority of projects have net CO₂ utilisation efficiency of less than 8 Mscf/STB (227 sm³/STB) incremental oil. In average, CO₂ volumes injected were in the range of 20-40% HCPV (ECL Report 2, 2001, Nelms *et al.*, 2004). There are no economic barriers in these onshore projects. The anticipated performance of the Weyburn demonstration project for CO₂ EOR and Storage is also favourable even the CO₂ is available for injection at a cost of \$35/t.

For offshore CO₂ EOR and storage projects, the economic challenge is the added cost of CO₂ separation, transportation and extra cost on CAPEX and OPEX, such as the cost of adapting platforms and well completions to handle CO₂.

Recently, UK DTI (Department of Trade and Industry) published a report “Implementing a Demonstration of Enhanced Oil recovery (EOR) Using Carbon Dioxide” (UK DTI Report, 2004). The report stressed that CO₂ based EOR remains a potential option demonstrating carbon dioxide capture and storage that was central to the development of near to zero emissions fossil fuel combustion plant. However, under the current market conditions, there is little interest in CO₂ based EOR amongst North Sea oil producers, consequently, a full implementation plan has not been developed. It should be noticed that the DTI’s analysis was based on the following assumptions: oil price: \$20/STB, average recovery of 2.7 STB/t CO₂ injected, exchange rate £1 = \$1.6, and discount rate of 10%. The estimated credit required for CO₂ abatement was \$10-20/t CO₂ for a large-scale EOR project in the North Sea. The CO₂ was assumed from IGCC (Integrated Gasification Combined Cycle) power plants, which can use most cost-effective capture technologies. It should be noted that these studies were conducted with an assumption of average oil price of \$20/STB. Apparently, the current high oil price and the European carbon trading scheme would have a significant impact on the economic revaluation, as it did on the project of CO₂ disposal into an aquifer in the Sleipner fields (Celius *et al.*, 1996; Torp, 1998). At a low oil price environment, oil industry must be provided with some kind of compensation to ensure a positive economic return on carrying out CO₂ injection and storage project.

7 NORTH SEA STUDIES

In late 70’s and early 80’s, the UK Department of Trade and Industry (Department of Energy at that time) was keen to initiate CO₂ injection in the North Sea. Clearly CO₂ was not

seen as a gas to be stored (for CO₂ mitigation) but as an effective gas injection fluid for EOR based on the current US experience (Stewart, 1976; Varotsis *et al.*, 1981; Ross *et al.*, 1981). Since then, there have been many studies for CO₂ EOR in the North Sea based on individual field cases, including Fulmar, Forties, Gullfaks, and Ekofisk fields, using advanced reservoir simulation techniques (Ren *et al.*, 2004; Turan *et al.*, 2002; Agustssen *et al.*, 2004; Jensen *et al.*, 2000; Lindeberg *et al.*, 1994). These fields are good representatives of the North Sea oil fields, with medium to large oil reserves, various geological features and different secondary recovery factors from 38% to 60% after water flooding. The basic field data (in comparison with the EOR screening criteria listed in Table 2) are shown in Table 4. All these studies suggest that CO₂ EOR is technically feasible in these fields in terms of additional oil recovery of 5-10% OOIP. However, as mentioned above, there are economic constraints considering high costs on supplying CO₂ to the fields and high capital and operation cost at offshore conditions.

TABLE 4
Reservoir properties of some North Sea fields

Reservoir parameter	Fulmar	Gullfaks	Ekofisk
Depth (m)	3000	1800	3170
Temperature (°C)	121	74	131
Original pressure (MPa)	37	31	49
Permeability (mD)	100-300	800	1 (matrix)
Oil gravity (°API)	41	32-36	
Viscosity	0.49		
Fraction of oil remaining	>0.4	>0.4	0.62
Remarks			Fractured chalk reservoir

7.1 EOR and Storage Potentials

In December 2001, DTI/ECL (ECL Report 5, 2001) published a report entitled “Potential UKCS CO₂ Retention Capacity from IOR Projects”. Their study was based on a simple model populated with data for each UKCS field to estimate the overall UKCS potential for CO₂ injection EOR/Storage. The reservoirs with over 100 M STB OOIP were selected and screened. Several important conclusions were drawn from the study:

- The UKCS EOR potential is in the region of 350-850 M STB for WAG schemes and 800-1400 M STB for GSGI schemes. The net CO₂ retention capacity from WAG is around 150 Mt, whereas that for the GSGI schemes is around 550 Mt. There are around 60 potential WAG projects, but far fewer GSGI opportunities. The CO₂ retention potential from GSGI projects is approximately 3 times larger than that of WAG injection.

TABLE 5
Incremental Oil Recovery for CO₂ Injection after 20 years

Case	Reservoir P (bar)	Oil density kg/m ³ (RC)	CO ₂ density kg/m ³ (RC)	Injector locations	Incremental oil (% OOIP)
1	193	696	336	Top	10.7
2	400	701	646	Top	8.1
3	193	696	336	Bottom	6.7
4	400	701	646	Bottom	6.7

- The CO₂ EOR projects need to be implemented in the North Sea within a few years of COP (Cease of Production) date. There is more “window of opportunity” for WAG projects to be implemented at any time between now up to the pre-COP deadline, while GSGI is limited to start around the COP date.
- Various technical measures can be suggested to improve the EOR and CO₂ storage efficiency and potentials, such as depressurisation before CO₂ injection to increase gas utilisation and reducing a post water push after gas injection to increase CO₂ retention in the reservoir.

It is expected that similar CO₂ EOR potential and storage capacity exist in the Norwegian sector. Therefore, the CO₂ storage potential in the North Sea can be in the order of 1400 Mt.

7.2 Economic Analysis: Case Study

A case study was conducted by Ren *et al.* (2004) for a North Sea Field (Fulmar) to demonstrate a CO₂ EOR and storage scenario. The reservoir data used is listed in Table 4. The OOIP of the field is 113 million sm³.

Four cases of CO₂ injection were simulated with various combinations of pressure and injector locations, namely injector at the top and bottom of the oil formation. The incremental oil recovery (after water injection) at the end of 20 years gas injection (total 35 years including water and gas injections) is shown in Table 5, the oil production profiles are shown in Figure 1. The best scenario simulated is to inject CO₂ at the top of the reservoir and at a relatively low pressure near MMP (193 bar), where gravity stabilisation prevails for this relatively thick reservoir. The incremental oil recovery was 10.7% OOIP after 20 year gas injection, while 6.5% OOIP can be achieved after 10 years injection. The extra oil appears after two years of gas injection. In Case 4 of Table 5, the densities of CO₂ and oil are very close. However, the injected gas still migrates to the top of the reservoir, resulting in a long delay of oil production. At the end of 20 years CO₂ injection, 55% of CO₂ injected was stored in the reservoir excluding gas reinjection. The produced gas with high CO₂ content needs to be recycled or reinjected into another reservoir.

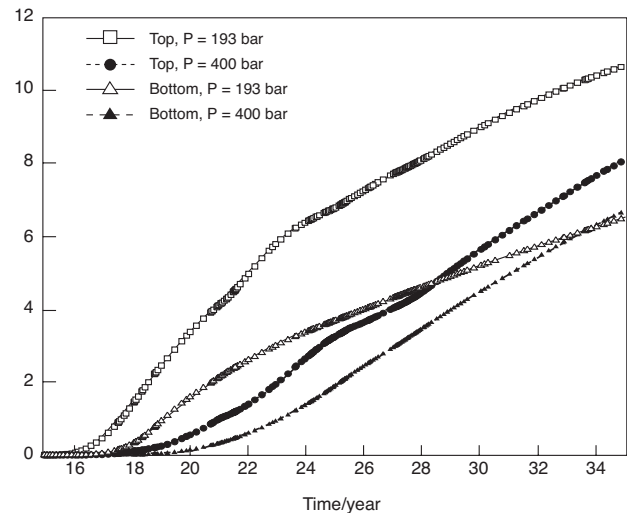


Figure 1

Reservoir simulation results for incremental oil recovery (IOR, %OOIP) at different CO₂ injection scenarios.

A scoping economic analysis is conducted according to published and unpublished data (IEA Report a, b, c, 1993–1999). The IOR data are given based on the field simulated above. The data used for economic calculation are listed in Table 6.

The cost for separation and transportation of CO₂ is much higher than the cost of offshore injection. A separated oil production cost, including or excluding the cost on separation/transportation is given in Table 7. A pie figure for the cost separation, namely capture, transportation and field operation (compression and injection) is shown in Figure 2. Approximately 76% of the total cost is due to CO₂ capture and transportation. The reservoir chosen in the simulation study is not the best for gas injection EOR, and the CO₂ utilisation efficiency can be improved through better reservoir management and well control. This will further reduce the oil production cost. Novel and more advanced technologies are needed to bring down the cost of CO₂ capture from power plant flue gases. The cost of transportation can be reduced when large diameter pipelines or existing pipeline facilities are used.

TABLE 6

Basic economic data used for a North Sea CO₂ EOR case study

Processes	Cost estimation
CO ₂ injection rate	200 MMscf/day
Injection pressure	350 bar
Projection duration	20 years
Compressor + installation	\$20 + \$6 millions
Total compression and injection cost	\$0.5/Mscf
Pipeline (400 km onshore, 100 km offshore)	\$900 millions, CAPEX only
CO ₂ capture cost (from a coal fired power plant of 500 MW)	\$1.5/Mscf, CAPEX and OPEX
Total CO ₂ transportation cost	\$1.0/Mscf
Produced gas processing cost	60% of compression and injection cost

(1 Mscf = 1000 scf = 28.32 sm³).

TABLE 7

Cost estimation for 20 years CO₂ EOR operation

CO ₂ /oil required (GOR) (Mscf/STB)	13.1
Total CO ₂ capture cost (\$/Mscf)	1.5
Total CO ₂ transportation cost (\$/Mscf)	1.0
Compression and injection cost (\$/Mscf)	0.5
Produced gas processing (recycle) (\$/Mscf)	0.3
Total oil production cost (\$/STB)	43.2
	10.5, excluding separation & transportation

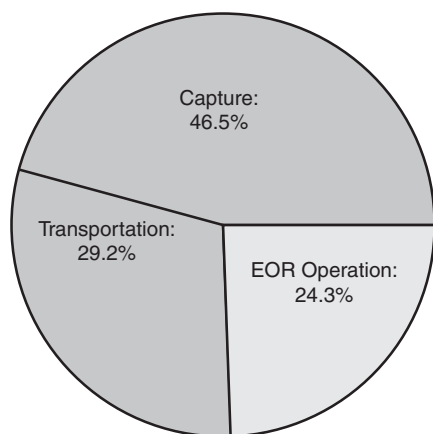
(1 STB = 0.11563 sm³).

Figure 2

Cost of separation for a CO₂ EOR and storage project in the North Sea; the CO₂ is captured from an onshore coal fired power plant and transported to the North Sea by pipelines. The total unit oil production cost is estimated as \$43.2/STB.

7.3 North Sea Uncertainties

Recent assessment studies for the Forties field in the North Sea have shown that the economics of CO₂ EOR were difficult to justify a project to be sanctioned. The problems arise from the differences between onshore and offshore operations (Puckett, 2003), which add to the North Sea challenges and uncertainties:

- First, operating costs in particular are much higher on offshore platforms, especially in a challenging environment like the North Sea.
- Secondly, because the field has naturally low levels of CO₂, the facilities are not designed for high levels of corrosion resistance. Whilst it may be possible to protect some parts of the system with inhibitors, some would have to be replaced. The cost of doing this on old platforms is very high.
- Finally, offshore fields tend to be developed with much lower well densities than is the case onshore. This has two effects. It reduces the effectiveness of the sweep so less oil is recovered. It also means that it takes longer for injected fluids and incremental oil to reach the producers, which has a very detrimental impact on net present value calculations.

8 EFFECT OF OIL PRICE AND CARBON TAXATION

The majority of previous studies on CO₂ EOR and storage were referred to a low oil price of approximate \$16-\$20/STB for project approval. It is obvious that the high cost of CO₂ capture and low oil price would be the main barrier for oil producers to apply the technology, especially offshore where the risk is high. However, the current high and volatile oil price has opened a window of opportunity for CO₂ EOR operations. The influence of volatile oil pricing on the project development and risk needs to be reinvestigated. On the other hand, the forthcoming European Union Emissions Trading Scheme that will be introduced in January 2005 will also have a positive effect on promoting the CO₂ EOR and storage project, although many people thought the carbon emission credits would unlikely be sufficient (DTI Report, 2004).

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions can be drawn from the previous field projects and recent studies:

- CO₂ injection produces the best performance in terms of oil production because of its miscibility effect over other gaseous injectants. Most CO₂ injection projects have produced an incremental recovery of over 8% OOIP with a gas utilisation efficiency of 6000-800 Mscf/STB (167-227 sm³/STB), or approximately one tonne of CO₂ injected can produce 2.5-3.3 STB of oil. A gross of approximate 60% CO₂ injected can be stored in the reservoir at CO₂

breakthrough while gas reinjection can be used to increase the storage capacity.

- There have been no major technical challenges in gas injection EOR projects. The economics of CO₂ EOR and storage projects can be improved through better reservoir screening and management. In terms of greenhouse gas storage, extra values can be produced via CO₂ injection for EOR projects, while more advanced capture and transportation technologies are needed to bring down the cost of bringing CO₂ to the oil fields.
- There have been no offshore CO₂ EOR projects. Apart from economic concerns, technically, there are some challenges that need to be addressed, these include insufficient reservoir characterisation, large well spacing, the lifespan of the offshore infrastructures and extra cost for adapting platform and equipment to handle CO₂.
- A North Sea case study for CO₂ EOR and storage has indicated that the cost to bring CO₂ or flue gas from power plants to oil fields is high may exceed the values produced in the EOR project if oil price is less than \$43. The current high oil price and the introduction of the carbon emission credits may have a positive effect on promoting CO₂ storage projects. The estimated CO₂ storage capacity in the North Sea oil reservoirs can be as high as over 1700 Mt.

In order to further assess the feasibility CO₂ EOR and storage projects and to promote a demonstration project in the North Sea, it is recommended that:

- A ranking of the North Sea oil reservoirs is needed to identify the most suitable fields in terms of incremental oil recovery and CO₂ storage capacity with low technical risks.
- A ranking of the CO₂ sources (power and chemical plants) in the Europe and the UK in terms of CO₂ capture and transportation technologies is needed to find the best sources for the supply of CO₂ to the North Sea with lowest cost.
- A demonstration project should be conducted by choosing the best of oil reservoirs in association with the best CO₂ sources.
- A reassessment of the CO₂ EOR and storage project in terms of high oil price and the CO₂ credit scheme is needed.
- It can be assumed that CO₂ storage in subsea geostructures would be safer than onshore structures due to the possibility of hydrate formation in the seabed, which may block any possible CO₂ leakage due to unidentified seepages. This needs to be confirmed in future research.

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