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CO2 for EOR combined with storage in the Norwegian North Sea

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Abstract

The Norwegian Petroleum Directorate (NPD) presented a CO_2 Storage Atlas for the Norwegian Continental Shelf (NCS) in 2014 (Fig.1 [1]). The main objective with this Atlas was to identify safe and effective areas for long-term storage of CO_2. There are more than 20 years of experience with storage of CO_2 in geological formations offshore Norway and a lot of work has been done to map, characterize and evaluate potential storage sites. To get an overview of the possibility of using captured CO_2 for enhanced recovery (EOR), several screening studies were conducted. The technology for CO_2 used for EOR is well documented for onshore fields. Implementing CO_2 for EOR offshore will be more challenging and can carry operational, commercial and financial risks.

In this paper, we present the results from three different screening studies on storage of CO_2 combined with EOR in oil fields in the Norwegian part of the North Sea (Fig.2) and one residual oil study (ROZ) from an oil discovery in the Barents Sea. The input to these studies are production history and characteristics from the different oil fields and the results are based on reservoir simulation from screening studies on these fields. The results from these studies are purely technical, no detailed economic evaluation has been done. The aim was to study the possibility and potential of using CO_2 for EOR on some of the mature offshore oil fields in combination with storing CO_2 in the underground. All these studies showed very interesting results.

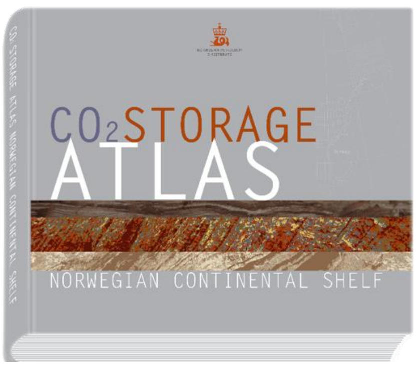


Figure 1 CO_2 Storage Atlas for the NCS

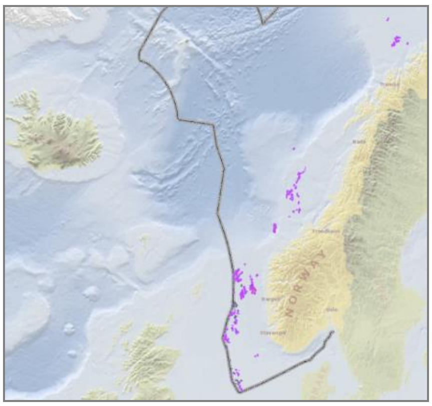


Figure.2 Oilfields (pink) on The Norwegian Continental Shelf

Keywords: CO_2 storage; EO; screening; Residual oil saturation

1. Introduction

Injecting CO_2 into oil fields to enhance the oil recovery (EOR) has been commercially used for several decades by the oil companies. The experience from the projects in North America and from the Weyburn project in Saskatchewan, Canada, has given important information and results to build on [2,3]. Several offshore CO_2 -EOR pilots are on the plan as the CO_2 -WAG projects in the Lula oil field offshore Brazil. All these projects can be of great value for increasing offshore CO_2 -EOR projects [4]. The International Energy Agency (IEA) published a report in 2015 on "Storing CO_2 through Enhanced Oil Recovery" [5]. This report describes benefits of combining EOR and storage of CO_2.

The Norwegian Petroleum Directorate do several screening studies to evaluate the technical potential for EOR on the oil fields offshore Norway. The Norwegian part of the North Sea is a mature petroleum province with several producing oil and gas fields, some new, some facing decline and some close to abandonment. The average oil recovery rate for the oil fields offshore Norway is currently about 47%, and there is a constant ongoing work to find ways to increase the recovery (Fig.3). However, recovery rates differ from field to field.

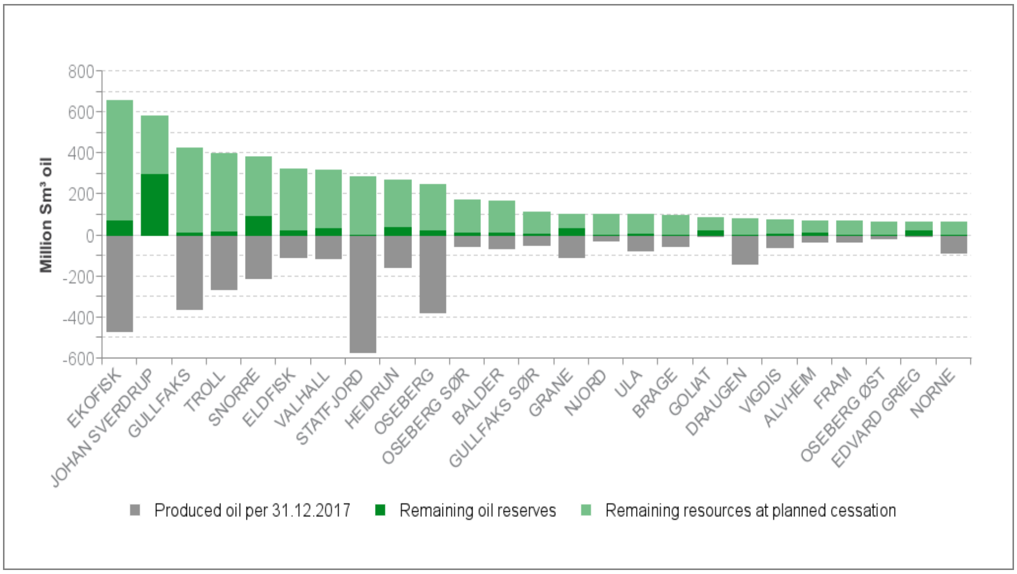


Figure.3 Produced and remaining oil in the 25 largest oil fields offshore Norway. Light green is oil resources with no production plan. About 50% of this oil is categorized as immobile oil.

The volume of oil that can be produced from a field is a function of several factors like reservoir conditions, development solutions, the production strategy, available technology and the economy. Several studies have been conducted, both by the industry, authorities and researchers to identify the EOR potential and try to fine more efficient ways to use and store the CO_2 offshore Norway. No projects for CO_2 -EOR have been tested on these oil fields and one of the reasons might certainly be the lack of large amounts of reliable and affordable CO_2.

The main primary drainage strategy for the Norwegian oilfields are water injection, and some fields have primary gas injection or WAG (water alternating gas).

The oil in the reservoirs represent two categories, mobile and immobile oil.

Mobile oil can in principle be recovered using conventional methods like wells and pressure support. Immobile oil adheres to the pore walls in the reservoir and cannot be forced out of the pores and produced by more wells, water or gas injection. More advanced recovery methods are needed to mobilize the immobile oil. Several different EOR methods have been studied to find a way to be able to produce the immobile oil, but so far, none has been implemented on a full field scale.

CO_2 flooding has proven to be an effective method to mobilize the immobile oil in some reservoirs with right conditions for pressure and temperature. Many of the oil reservoirs in the studied area have the right conditions to be suitable candidates to achieve a good effect from injecting CO_2.
The best effect of injected CO_2 is obtained when CO_2 and oil are miscible in the reservoir. CO_2 have many properties that enables to increase oil production. It swells the oil, reduces oil viscosity and increases oil density. It is soluble in water, can evaporate and extract oil, and it reduces surface tension between oil and water providing a more efficient displacement. Several studies have been done to find more effective ways of injecting CO_2. Some show that in most cases the sweep efficiency of CO_2 flooding will be improved by applying WAG, alternating injection of CO_2 and water. Another way to increase the flooding efficiency can be to add foam to the injection process [6].

In NPD´s studies CO_2 -EOR with permanent storage of CO_2 in the oilfields and in nearby saline aquifers were evaluated. However, insufficient supplies of this gas present a challenge. So, does lack of experience from offshore fields.
Four different studies using CO_2 for EOR and storage is presented:

1. An unrisked screening study of the technical EOR potential across 23 North Sea oil fields, were conducted with unlimited volumes of CO_2.
2. One assessment with available 1-3Mt CO_2 annually were injected in three different oil fields
3. Detailed study of a mature oil field in the North Sea with an annual CO_2 injection of 0.7 Mt.
4. Evaluation of residual oil recovery by injection of CO_2 (ROZ).

The model used for study 1 and study 2 is a techno-economic model for CO_2 for EOR and aquifer storage developed by SINTEF [7,8]. The technical module calculates oil production and water injection followed by miscible CO_2 injection. The CO_2 is injected in supercritical state and in WAG cycles with injection startup in 2020. Saline aquifers located close to the fields are used as buffer storage capacity to maintain a stable CO_2 delivery.

The studies conducted here is an attempt to illustrate the technical potential in the oil reservoirs. An economic evaluation is not presented her. CO_2 is corrosive, and we see that many technical and development studies are ongoing with the aim to get as little as possible of the CO_2 into the processing systems on the platforms. This is of cause of economic importance for offshore developments [9].

2.1 A technical screening study of large scale CO_2 injection for EOR and storage in the Norwegian part of the North Sea

A regional screening study of the technical EOR potential in oil fields on the Norwegian North Sea was conducted. Included here are water flooded oil fields with relevant size, pressure and temperature. 23 oil fields were selected for further studies. No limits were set on available CO_2 for injection at each field. Supply of CO_2 volumes is only limited by the pipeline capacity. Injection of CO_2 in each field is only limited to what is optimal for the reservoirs. CO_2 injection in these 23 oil fields over 40 years gave more than 300 mill. Sm^3 of additional oil with a total injection of about 70 Mt CO_2 and showed a potential for improving recovery with 4% to 12%, with an average of about seven per cent and a storage effect for CO_2 of 70-100 % (Fig.4).
This evaluation showed that the amount of EOR-oil is highly dependent on the size of the field, remaining oil in the reservoir at startup of CO_2 injection and well spacing. The increased recovery corresponds well with studies done by oil companies and research teams in Norway, as well as with international experience (Table 1).

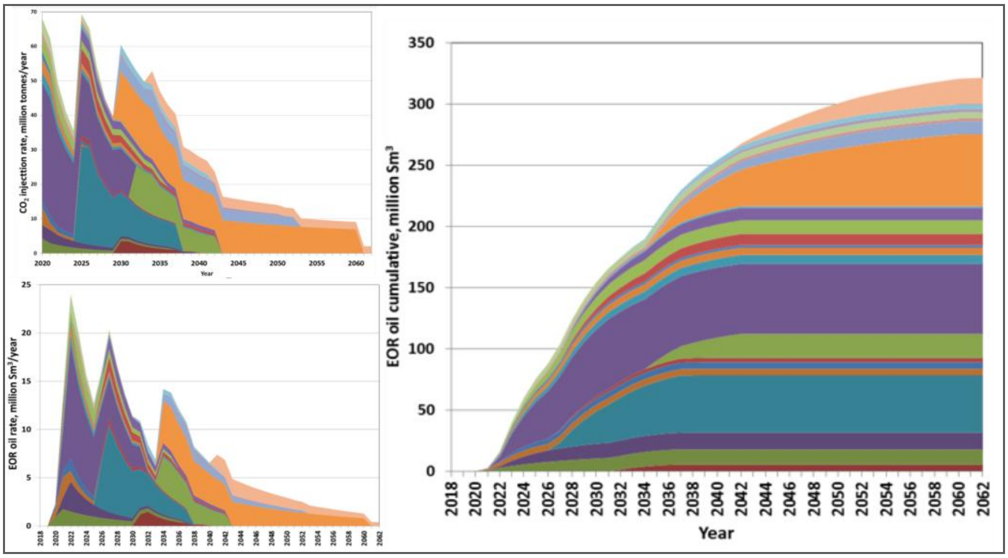


Figure 4 EOR production and CO_2 injected and stored in the study of 23 oil fields

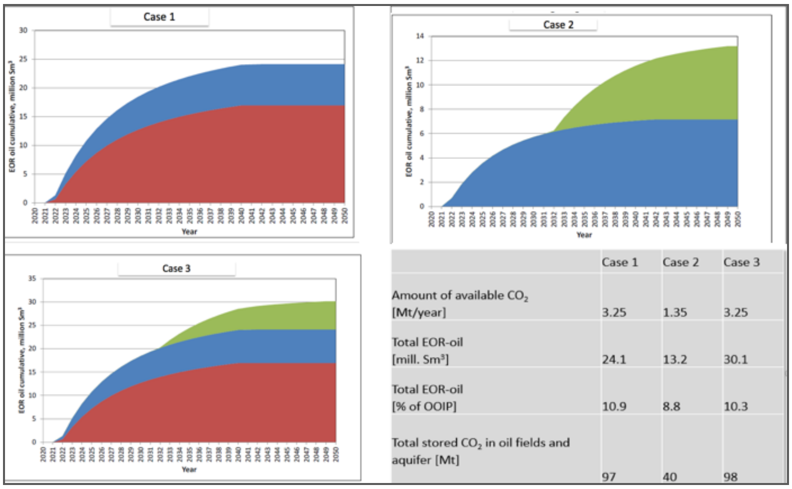
Table 1. Result of large scale CO_2 injection for EOR and storage

Total oljeutvinning, % OOIP	60
Total EOR olje, mill. Sm3	320
Total EOR, % av OOIP	7
Totalt lagret CO2 i oljefelt, mrd. tonn	1,3
Totalt lagret CO2 i akviferer , mrd. tonn	1,7

2.2. Small scale CO_2 injection for EOR and storage

In this study 1-3Mt of CO_2 were available annually for injection in oilfields for EOR. 3 oilfields were selected. These 3 fields. The three fields selected for this study have different geological characteristics, two sandstone fields and one chalk field. With current plans at cease of production, the fields have 160 mill. Sm3, 100 mill. Sm3 and 120 mill. Sm3 oil originally in place, and have a planned recovery factor of 40 %, 30 % and 20 %, respectively.
The CO_2 is transported to the oil fields either by a pipeline or by a ship. CO_2 is injected in the field and circulated until the reservoir is self-sufficient and the CO_2 volume are available over 30 years.

Case 1: Available CO_2 was 3.25 Mt per year injected, into the reservoir of two sandstone fields. The CO_2 is delivered to the fields by ship and pipeline, with a small pipeline between them. The result was 24.1 mill. Sm^3 of additional oil produced and 97 Mt CO_2 stored in oil fields and in nearby aquifer.
Case 2: Available CO_2 was 1.35 Mt per year, injected into the reservoir of one sandstone field and one chalk field. Both fields received CO_2 by ship. The injection starts in one field and when the first field is self-sufficient, the ship transports CO_2 to the next field with start-up in 2030. This resulted was 13.2 mill. Sm^3 of additional oil produced and 40 Mt CO_2 stored in oil fields and in nearby aquifer.



	Case 1	Case 2	Case 3
Amount of available CO_2 [Mt/year]	3.25	1.35	3.25
Total EOR-oil [mill. Sm^3]	24.1	13.2	30.1
Total EOR-oil [% of OOIP]	10.9	8.8	10.3
Total stored CO_2 in oil fields and aquifer [Mt]	97	40	98

Figure.5 The EOR effect from three oil fields with injection of 1-3 Mt CO_2 annually for EOR and storage, over 30 years.

Case 3: Available CO_2 was 3.25 Mt CO_2 per year injected into the reservoirs in all the 3 fields in combination. The CO_2 is delivered to the fields in a combination of ship and pipeline, with a small pipeline between two of the fields. The injection started in the two sandstone fields and in 2030 a sufficient amount is re-routed to the third field. This resulted in 30.1 mill. Sm^3 of additional oil produced and 98 Mt CO_2 stored in oil fields and in selected aquifer.

Large amounts of CO_2 are stored in these three cases, both in the fields with CO_2 injection and in the buffer aquifers close to the fields. The storage efficiency of CO_2 as an average of all the sensitivities is 85 %, with a range of 70 – 100 %. (Fig.5).

2.3 Injection of CO_2 for EOR in a mature oil field in the North Sea.

The objective of this study was to quantify and optimize the potential of CO_2 for EOR and achieving maximum CO_2 storage in a mature oil field. The base case recovery factor for this oil field at the end of field lifetime in year 2040 is estimated to be approximately 30 % without CO_2 injection. This oil field is highly segmented which cause a complex reservoir communication and continuity. One of the fault segments were selected for this study. Production started in 1999 and the estimated remaining oil in the selected segment is approximately 35 mill. Sm^3 at the startup of CO_2 injection in year 2020.

This field is normally produced by partial pressure support from both water and gas injection. Existing wells are used, and one new vertical CO_2 injection well is drilled.

The starting point for this study was a black oil reservoir simulation model including a history match up to 1.1.2015 and prediction thereafter. The model was converted to compositional mode with eight components with CO_2 as a separate component. The model in compositional mode is then re-run with history up to 1.1.2015 and prediction thereafter. The base case in this study is the model in compositional mode without CO_2 injection. The various CO_2 injection runs restarts from the base case in 2020. In the runs with CO_2 injection, the existing wells are kept unchanged while CO_2 at the rate of 1 mill. Sm^3/day or 0.7 Mt/year is injected at supercritical state in one new well.

Table 2 shows cumulative oil production for all the simulation runs with different sensitivities over 20 years of production. The green line is the base case without CO_2 injection.

Several runs were performed to test the sensitivity of the following parameters in the model:

- Lateral location of the CO_2 injector; in the aquifer or in the oil zone (Figure 7)
- Water injection capacity; zero, half of base case capacity or 100 % of the base case capacity
- Perforation intervals of the CO_2 injector; shallow, deep or all layers
- CO_2 injection period; 5 or 20 years, both starting from 1.1.2020

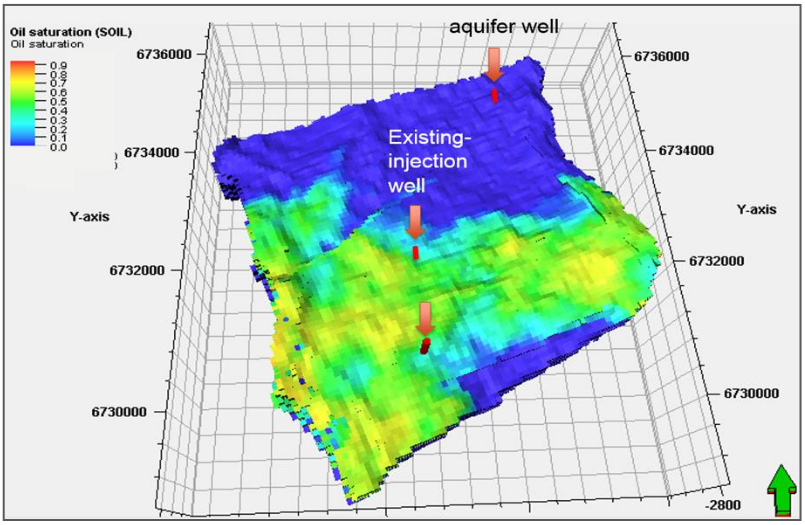


Figure 7 Reservoir model with different location of CO_2 well injection

Results from the simulations are shown in Table 2. The results show that CO_2 injection in the oil zone gives better oil recovery than CO_2 injection in the aquifer in most of the runs. The results are linked to the complex architecture of this reservoir regarding communication and continuity. The simulation results show that the recovery factor with CO_2 injection increased relative to the base case with a range of 0.4 % to 8.4 %. The lowest recovery increase is the result of injection in the aquifer with a deep perforation interval in the reservoir with very limited communication with the main reservoir. Simulations show that water injection in combination with CO_2 injection is beneficial. The results also show that it is better to inject
CO_2 in a concentrated perforation interval rather than injecting in the whole reservoir interval.

Table 2 Results from sensitivity runs

	Lateral location	Water injection capacity	Perforation interval	CO_2 storage	Delta recovery factor
Run 1	Aquifer	0	All	85 %	2.8 %
Run 2	Oil zone	0	All	84 %	4.2 %
Run 3	Aquifer	0.5	All	89 %	5.2 %
Run 4	Oil zone	0.5	All	85 %	4.4 %
Run 5	Aquifer	1	All	95 %	0.9 %
Run 6	Oil zone	1	All	87 %	2.9 %
Run 7	Aquifer	0.5	Deep	100 %	0.4 %
Run 8	Oil zone	0.5	Deep	88 %	8.4 %
Run 9	Aquifer	0.5	Shallow	89 %	5.3 %
Run 10	Oil zone	0.5	Shallow	86 %	7.7 %

In the simulation run where the CO_2 injection period in the oil zone is reduced from 20 to 5 years, the following is observed:
Recovery factor is reduced from +7.5 % to +5.7 % for deep injection
Recovery factor is reduced from +7.7 % to +6.3 % for shallow injection
The storage efficiency is reduced from 87 % to 71 %

2.4 Residual Oil Zone (ROZ)

In the Norwegian Continental Shelf, residual oil is common in the Jurassic aquifer of the Hammerfest Basin in the Barents Sea. Significant residual oil zones are also associated with some of the giant oil fields in the North Sea. These zones were formed when oil was redistributed in the trap and water replaced the oil by natural processes. Two common processes which can result in formation of residual oil appear to be tilting of traps and seepage from traps (Fig.8).
Under miscible conditions, CO_2 can be used to mobilize residual oil and make it possible to produce oil from both natural ROZ and ROZs from oil production (Fig.9).

Some fields have residual oil below the main oil zone originally in the field, so called paleo oil. In the Barents Sea residual oil or paleo oil have a wide distribution. Some fields have residual oil below the main oil zone originally in the field, so called paleo oil. In the Barents Sea residual oil or paleo oil have a wide distribution. A simulation study was performed on a structure with residual oil in the southernmost Bjarmeland Platform in the Barents Sea to investigate if some of the residual oil could be produced. Data was obtained from the wells 7125/1-1 and 7125/4-1. The main oil zone was 1-1,5 m thick in well 7125/1-1 with a 32,5 m residual oil zone below (Fig.10).
The study indicated that the main oil zone could be up to 30 m thick in average. Simulation cases were run both on a thin and a thick oil zone.
The oil was produced (well OP in figure below) from the main oil zone while CO_2 was injected down flank (well GI on figure 11) in the residual oil zone with an injection period of 30 years. Results from the simulation with a 30 m thick main oil zone showed a reduction in oil production when water coned into the producer. However, the oil production increased again when CO_2 together with swept oil from the residual oil zone reached the well.

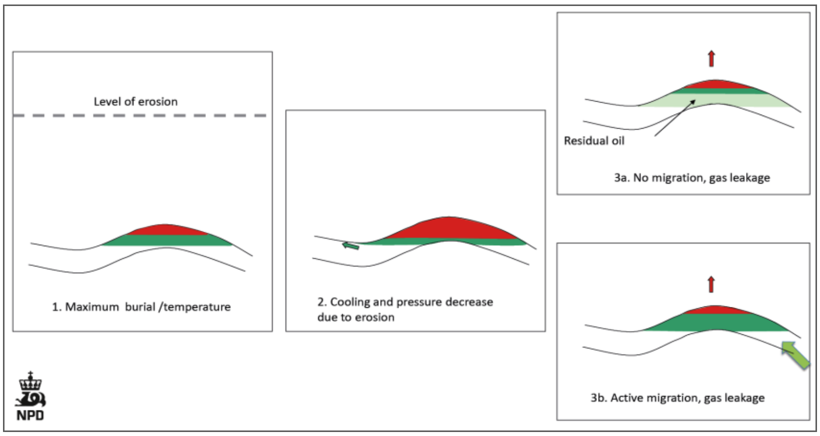


Figure 8 Hypothesis for formation of residual oil zone by natural gas seepage. After maximum burial the rate of seepage of gas is greater than the rate of migration of hydrocarbons into the accumulation. Consequently, fluid contacts move upwards. Residual oil (light green) is formed where water replaces oil in the initial oil zone (green).

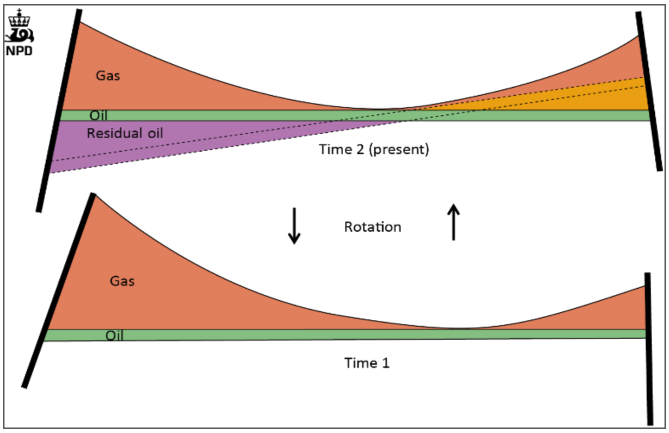


Figure 9 Formation of residual oil zone by rotation of a structural trap with oil and gas. Fluid contacts are controlled by pore pressure and will equilibrate to horizontal surfaces. The pore space where oil is replaced by water will remain with a residual oil saturation (purple zone). There will also be a residual oil saturation in the gas zone (orange zone), but this saturation is much lower than in the water zone. Time 1 – initial trap, Time 2 - rotated trap, dotted lines show the present location of the initial contacts.

With a thin oil zone (3m thick) the water coned very rapidly into the well and the well died before the CO_2 and the residual oil reached the well. To optimize recovery from a thin oil zone overlying a residual zone, CO_2 injection should start some years ahead of the production to keep a continuous production and thereby optimize the economics. The input data and the results for both cases are shown in the figures.
The sector model with a thick oil zone gave a recovery of 6.3 mill Sm^3 including the residual zone. That means a total recovery of 18 %. For the thin oil case the recovery was 4.5 % including the residual zone. It was not easy to distinguish between the main zone and the residual zone recovery in the model. The stored CO_2 in the two cases was 40 and 30 Mt respectively. The recovery of oil is to a large degree dependent on the amount of CO_2 injected.

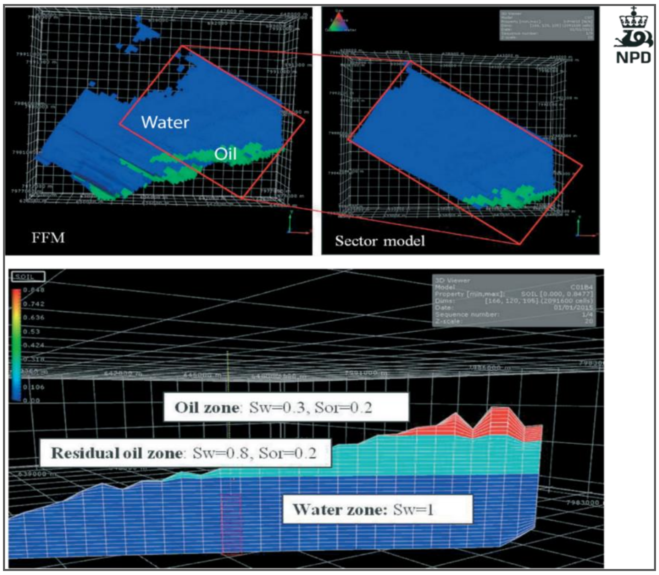


Figure 10 Setup of simulation model, showing the location of the sector model and the distribution of oil and residual oil.

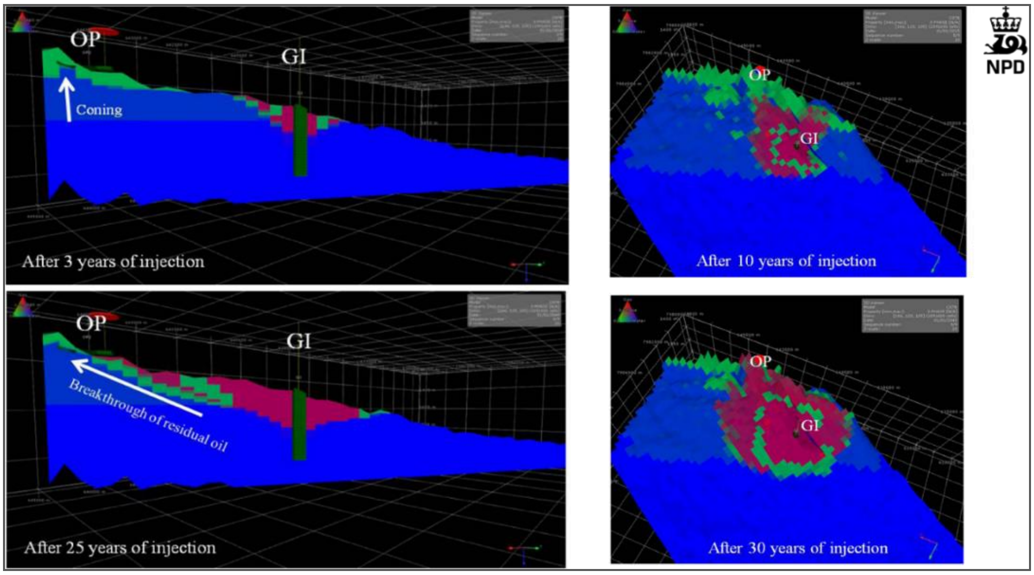


Figure.11 Profiles through the CO_2 injector (GI) and the oil producer (OP), showing distribution of CO_2 (red), oil (green) and water (blue) 3 and 25 years after the injection start. The maps to the right show the distribution of the CO_2 plume. North is down to the left.

Table 3 Input data and results

Porosity:	22 %
Horizontal Permeability:	900 mD
Kv/Kh :	0.5
N/G:	0.94
So oil zone:	75 %
Sor residual zone:	20 %
Oil density:	0.80
GOR:	66 Sm^3/Sm^3
Max injection pressure:	225 bar
CO_2 injection rate:	1.5 MSm^3/d
OP and CO_2 inj. Start:	01.01.2015
Oil in-place, main structure:	23 MSm^3
Res. oil in-place, main structure:	49 MSm^3
Oil in-place, sector model:	9.7 MSm^3
Res.oil in-place, sector model:	25.3 MSm^3
Results thick oil zone(30 m)	
Oil produced in main and residual zone in sector model:	6.3 MSm3.
Recovery factor, sector model (main + residual zone):	18 %
CO_2 stored in sector model:	17 mill tonn

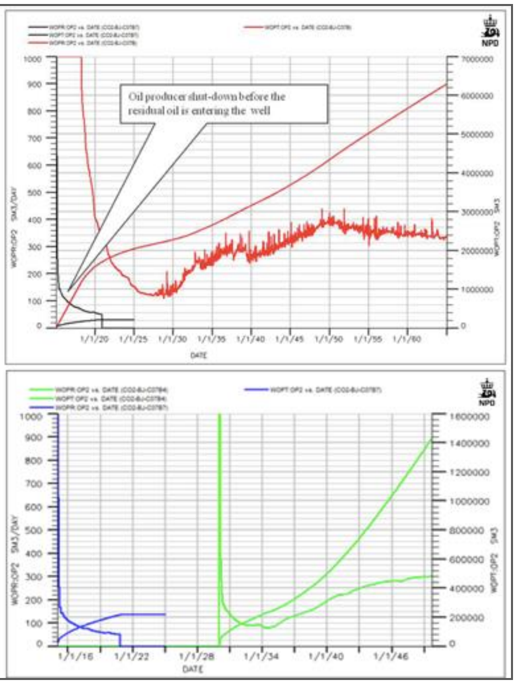


Figure 12a Oil production profiles with sensitivities (Red: base case model with 30 m oil zone. Black: sensitivity with 3 m oil zone.
b. Oil production starts 15 years after CO_2 injection (Blue: CO_2 injection and oil production start-up simultaneously. Green: Delay of production 15 years after CO_2 injection start up.)

3. SUMMARY

Oil production on the Norwegian Continental Shelf is mature and several fields will be decommissioned over the next years. By implementing EOR technology to enhance the oil recovery, recovery of the remaining oil reserves could be improved. A well-known commercial practice in United States and Canada is injecting CO_2 into oil reservoirs to enhance oil recovery. Injection of CO_2 has the additional advantage of storing CO_2 in the underground and thus reduce the CO_2 emissions.

NPD has performed several CO_2 for EOR studies from regional screening to more detailed studies on individual oil fields. The results indicate that the potential to increase oil recovery and store CO_2 in oil fields in the North Sea by CO_2 injection is significant. Oil production, and thus the life of the field, can be extended by implementing EOR projects. By implementing CO_2 for EOR on depleted oil fields which are already well known, a suitable storage location could be provided earlier than deep saline aquifer storage sites.

Research studies and laboratory investigations indicate that CO_2 for EOR is promising, but there are challenges related to realize CO_2 for EOR offshore in a full field scale. There is still work that needs to be done, but if this technology shall move forward, real data from an offshore pilot is needed. An offshore pilot on CO_2 for EOR will contribute to de-risk the technology and to generate learning.

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