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EOR screening and potential applications on the Norwegian continental shelf

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Summary

Enhanced oil recovery (EOR) projects have moved down the industry's priority list given the present oversupply of world crude oil and resulting low oil prices. However, this is the right time for the industry to evaluate options for injecting new life into some of the brown fields on the Norwegian continental shelf (NCS). Inspite of the current market challenges, EOR application in offshore oil fields remains a promising option for increasing the oil production on the NCS. The size of the targeted offshore oil fields is generally large and their proven original oil in place (OOIP) can be sufficiently large to overcome the high cost required for re-development. This means that a large amount of oil remaining on the NCS could potentially be recovered using EOR processes.

In this work, the main objective was to screen some selected oil fields on NCS for possible EOR processes based on present-day reservoir data. The work was carried out in the National IOR Center based on published reservoir data on the selected fields. Thus, available reservoir information for the selected fields were limited. In addition, there were significant differences in the quality of field data supporting the viability of the various EOR processes considered. However, a fast evaluation of various EOR processes based on a simulation screening tool, SWORD proved to be very useful and assisted in providing an assessment of recovery strategies and EOR methods applicable for the selected fields.

The EOR processes screened included hydrocarbon gas, CO_2, surfactant, polymer and a combined surfactant/polymer process. The screening criteria for the EOR processes were based on six quantitative reservoir data namely density and viscosity of reservoir oil, and properties such as depth, temperature, porosity and permeability of the formations. The applicability of the different EOR methods and recovery strategies at different reservoir properties and conditions were evaluated based on existing information published on the selected fields and knowledge collected from a suite of successful EOR projects around the world.

Results based on simulations indicate that the estimates of potential EOR incremental oil recovery compared to water flooding for the screened fields can be quite significant. However, key project development including realistic laboratory experiments and reservoir simulations needs to be performed to evaluate the EOR processes in detail. In addition, implementation and environmental issues, and additional cost elements must be weighed equally with oil recovery forecasts in any EOR

Stavanger, 21. November 2016

John Zuta, Project Manager

1 Introduction

1.1 Background and motivation

The Norwegian continental shelf (NCS) remains one of the most productive hydrocarbon provinces in the world, with some of the largest offshore oil and gas fields that are on production today. Oil and gas fields in the NCS consists mainly of deep sandstone and a few carbonate reservoirs of high pressure and temperature. These fields contain mainly light oil and some heavy oil. Currently, natural water drive does not provide sufficient energy to maintain reservoir pressure, and therefore many fields are supported by water injection. Some of the fields are produced by immiscible/miscible displacement by hydrocarbon gas, thus resulting in higher oil recoveries than would normally be expected from just water flooding.

Recovery factors have been low across mature oil fields with an estimated worldwide average of 22-25%. However, the NCS has an average recovery factor nearing 50% while the US average is 40% (Sandrea and Dharod, 2016; NPD resources report, 2013). Thus, more than half of the oil originally in place (OOIP) in the reservoirs in the NCS will be left in the ground based on current plans. The potential for additional oil recovery by improved oil recovery (IOR) techniques is high.

According to the NPD's resources report (2013), the remaining oil can be classified as immobile or mobile oil depending on its location in the reservoir (*Figure 1*). Immobile oil or "capillary-trapped" oil can be recovered by employing enhanced oil recovery techniques such as miscible gas injection, polymer flooding and surfactant flooding. Mobile oil or "by-passed oil" can be accessed by employing improved oil recovery measures such as drilling new areas based on 4D seismic and improved reservoir characterisation.

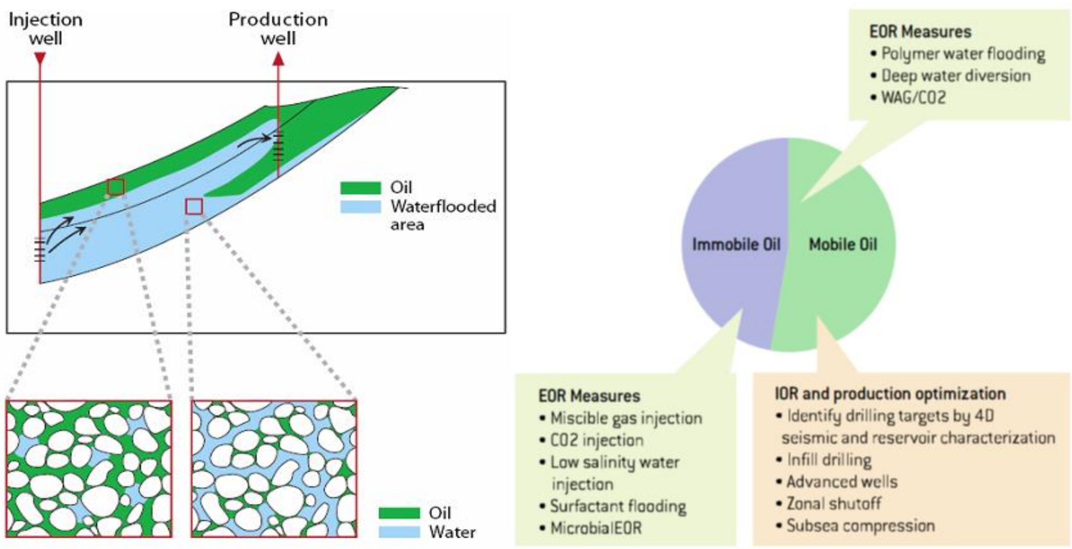


Figure 1: An overview of the location of immobile and mobile oil and the different measures, which can be employed in recovering additional oil (NDP resources report, 2013)

Some secondary and tertiary recovery methods have shown some success on the NCS. Specifically, both improved water flooding through polymer addition and reduction of residual oil saturation behind a water flood by surfactant injection have been recognised as technically feasible methods, however, the methods have not been successfully applied on the NCS. Injecting low-salinity water has also been identified as a potential method. However, most oil fields on the NCS inject seawater with a salinity lower than the formation water. As a result, low-salinity water flooding does not appear to have a big potential in existing fields. Nevertheless, more research needs to be done towards the optimization of the salinity of the injection particularly for new fields.

Inspite of the challenging high costs and looming low price, remaining resources in current producing fields are substantial. Some new discoveries on the NCS have also been made. This represents an important motivation for finding solutions and realising resources. The petroleum industry in Norway creates great value, and its socio-economic profitability is considerable. Recent estimates indicate that every percentage point of increased oil recovery from the fields in operation will result in about 230 billion kroner (based on oil price of 50 USD per bbl.) in increased value creation (Konkraft report, 2015).

1.2 Potential for improved oil recovery on the NCS

The remaining reserves in a field are the quantity of oil/gas included in the approved plans at any given time. *Figure 2* presents an overview of the recovery status for 25 fields with the largest quantity of remaining oil as the end of 2013. When projects that can improved the oil recovery are identified, the reserves will increase and the remaining quantity (light green in *Figure 2*) – target for IOR/EOR can decrease.

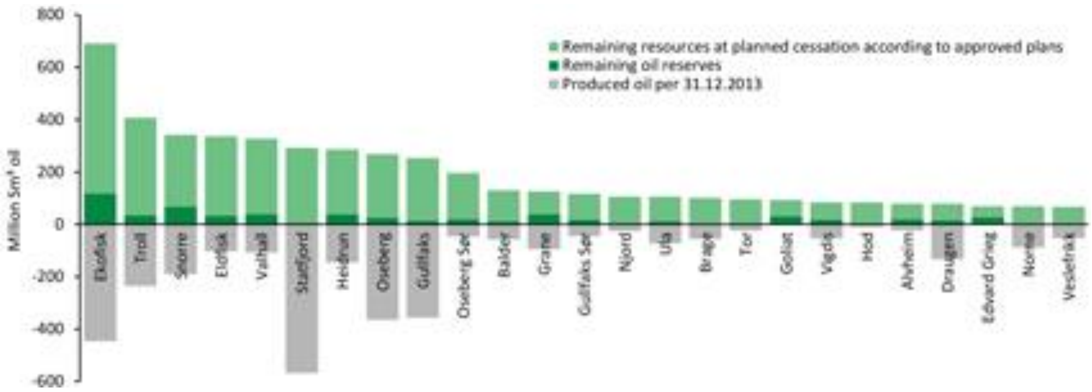


Figure 2: Resources overview for the 25 largest oil fields, quantities sold, reserves and remaining oil without new measures). In the figure, light green show the remaining resources at planned cessation per approved plans, Deep green show remaining oil reserves and gray indicate produced oil as at 3.12.2013 (NPD's resources report, 2013)

1.3 Scope and objectives

The scope of the project is to provide a review of past and current published IOR/EOR field cases studies, drawing out successes, and the reasons for them. Based on the knowledge gained from the review of successful EOR processes, defined possible EOR applications for some selected oil fields on the NCS based on EOR screening using present-day reservoir data. The main objective of the studies is to screen various EOR methods and predict the field performances based on field characteristics. The key reservoir parameters used included reservoir depth, temperature, porosity, permeability, initial oil saturation, oil gravity, and *in-situ* oil viscosity.

1.4 Limitations of project

Due to the inability of the project to get access to present day data for the selected fields on the NCS, EOR potential for the fields based on EOR screening were mostly based on data published in literature. In addition, there are significant differences in the quality and quantity of field data supporting the viability of the various EOR processes considered. Only a limited amount of field-specific data was available for the screening process.

The work does not attempt a full-scale reservoir simulation of the EOR processes. The prediction of the various EOR processes outlined in the report are based a simplified representation of the fields, and therefore the oil recovery factors may be overestimated.

A good screening process will consider several key technical factors outlined in the report in addition to investment and operating costs. However, these aspects are not covered during the EOR screening process.

2 A review of enhanced oil recovery (EOR) field cases

2.1 Introduction

As part of the screening process, a review of the several EOR field cases is required in order to enhance the technology transfer from the reviewed fields to the fields on the NCS. As a first step, a review of water-based EOR processes such as polymer, surfactants, gels and low salinity flooding which are considered to have the greatest potential for application on the NCS was carried out. Several water-based EOR pilots projects have been conducted on the NCS, with varying success, and some methods new to the NCS were adopted (Awan et al. 2006). For example, water-diversion techniques on Gullfaks and Statfjord, surfactant injection at Oseberg and Gullfaks, and MEOR at Gullfaks and Norne are some of the EOR projects which have been tested on the NCS. Field trials with polymer and/or surfactant have been initiated on the NCS, apart from a planned polymer field trial on the Heidrun field (Selle, 2013).

Currently, EOR accounts for about 3.0% of the world's oil production. Most of these EOR projects are based on onshore fields. About 50% of the oil production from EOR related projects are in the USA, China and Canada. CO_2-EOR is the dominant EOR in the USA, China has among other methods, chemical-EOR such as polymer as the dominant EOR technique. Thermal-EOR towards the production of heavy oil is dominant in Canada.

According to Kang et al. (2016), as at the end of 2014, there were 437 onshore and 19 offshore successful EOR projects have been conducted around the world (*Table 1*). These includes only cases were EOR fluid was injected into the reservoir for EOR process.

Table 1: Successful EOR application cases in offshore fields (Kang et al. 2016)

Type	Field	Location	Start Year of EOR Application	Project Scale
		Hydrocarbon (HC) Gas Injection		
miscible gas	Ekofisk	North Sea	1975	field
	Beryl	North Sea	1977	field
	Statfjord	North Sea	1979	field
	Brent	North Sea	1981	field
	South Pass Block 89	Gulf of Mexico	1983	field
	Ula	North Sea	1986	field
	South Pass Block 89	Gulf of Mexico	1989	field
	Alwyn North	North Sea	1999	field
	Smorbukk South	North Sea	1999	field
miscible WAG	Snorre (SnA)	North Sea	1994	field
	South Bae	North Sea	1994	field
	Ula	North Sea	1998	field
	Magnus	North Sea	2002	field
		Polymer Injection		
polymer	SZ36-1	Bohai	2003	pilot
polymer	PF-B	Bohai	2006	pilot
polymer	PF-C	Bohai	2007	pilot
polymer	PF-A	Bohai	2008	pilot
polymer	Captain	North Sea	-	pilot
		Steam Injection		
cyclic steam	-	Bohai	2009	pilot

As shown in the table, miscible gas with hydrocarbon gas is the most successful EOR process on the NCS. Miscible water-alternating with hydrocarbon gas (HC-WAG) has also been implemented with success on the NCS. However, hydrocarbon gas injection would not be considered an EOR process on the NCS, since the method is far advanced on the NCS. Since 1971, close to 2.3 billion bbl. have been injected to increase oil recovery in numerous fields on the NCS (NPD resource report, 2010).

Although polymer flooding has shown some success in the offshore heavy oilfields in Bohai Bay in China (Kang et al. 2011), it is yet to be fully implemented on the NCS. Additionally, successful polymer pilot in the Captain field on UK continental shelf (UKCS) has been reported in 2010 (Poulsen, 2010). *Table 1* does not include Total's polymer flooding Dalia field in Angola which was initialed in 2010. Production response have not been reported due to long well spacing. Other full scale EOR projects not included in the *Table 1* are BP's Clair Ridge low salinity and Chevron's bright water project on the UKCS.

Since EOR mechanisms for improved recovery are the same in onshore and offshore fields, there should be unique governing parameters of offshore applications. Based on *Table 1*, it can be mentioned that the application of EOR techniques in offshore fields is immature but shows high potential, and therefore screening criteria that are more representative of the specific offshore conditions than the conventional onshore screening criteria are needed.

2.2 Review of low-salinity water flooding

2.2.1 Introduction

Several studies conducted mainly on the laboratory and field (pilot) scales indicate that oil displacement can be influenced by the ionic composition of the brine, providing an opportunity to improve recovery by optimizing the brine mixture used in secondary or tertiary recovery. In the industry, this topic has been termed "low salinity flooding (LSF)" while the underlying mechanisms are not very well understood. The increased oil recovery has been attributed to wettability alteration to a more water-wet state. However, in some studies a positive low salinity effect (LSE) has been ascribed to dissolution of rock, which occurs on the laboratory scale but due to equilibration of brine with minerals existing in reservoir rock on larger length scales this is not relevant for the reservoir scale.

2.2.2 Endicott field – North Slope, Alaska

The first comprehensive inter-well field trial of low-salinity water flooding occurred in BP's Endicott's field on the North Slope of Alaska (Seccombe, 2010). The field is the third largest North Slope field with an estimated original oil in-place (OOIP) of around a billion barrels. It was brought on stream in 1987 and has been produced by gas re-injection at the crest and seawater injection around the periphery. As shown in *Table 2*, the salinity and hardness of the reservoir brine and injected seawater are approximately the same.

The original results, which prompted the trial were four single well tests with the saturation change measured using reactive chemical tracer tests (SWCTTs) undertaken in the Prudhoe Bay and Endicott fields (McGuire, 2005) which indicated that the incremental oil recovery from low salinity water injection was in the range 6-12% OIIP. SWITTs indicated that the residual saturation to high salinity water flooding is 41% reducing to 27% if low salinity water is used, this will result to an incremental recovery of 15% OIIP (based on an S_{wi}~5%) which would obviously be lower when areal and vertical sweep effects are taken into consideration

Table 2:Water analysis from the Endicott field (McGuire, 2005)

Species (ppm)	Endicott formation water	Endicott produced water	Endicott seawater	Endicott Well 3-39A low salinity water
Barium	7	0	0	0
Bicarbonate	2,000	1,868	147	6
Calcium	320	194	402	17
Chloride	17,275	14,946	18,964	821
Iron	10	2	0	0
Magnesium	48	360	1,265	55
Potassium	110	177	386	17
Sodium	11,850.	9,190.	10,812.	468
Strontium	24	7	7	0
Sulfate	63	570	2,645	115
pH	6.5	7.0	7.7	
TDS	32,000	28,000	34,644	1,500

Clay content was 12% with kaolinite being the dominant clay followed by illite. Clearly by comparison with North Sea fields the residual saturation of high salinity water flooding at 41% is high and the inter-well spacing at 1040 ft is low.

The trial area was flooded using high salinity water to 95% water cut, followed by 10 months (1.6 pore volumes) of reduced salinity water injection (trucked from a gravel pit nine miles away) with a final high salinity post flush. After about two months an increase in oil rate and a reduction in water cut were observed with the increase in oil rate immediately followed by the arrival of reduced salinity water (*Figure 3*). The oil response was as predicted (from core floods and single well tests) but the drop in water cut (95 to 93%) was less than expected. Analysis of ionic content of the produced water showed that 45% of produced water was coming from outside the pilot area.

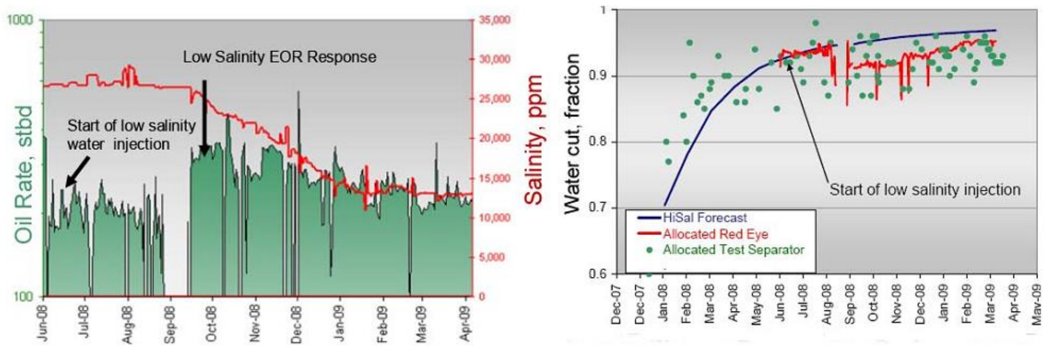


Figure 3: Oil rate and water response from the Endicott field (McGuire, 2005)

Although no iron was present in the formation or injected waters, there was a sharp increase in iron production from non-detectable amounts to 3-4 ppm corresponding to the sharp decrease in water cut (and arrival of the first low salinity tracer injected at start of reduced salinity flood). This confirmed the multi-component ion exchange (MIE) theory of low salinity water flooding. McGuire (2005) postulated that the iron coats the kaolinite binding the polar molecules in the oil to the clay but these bridges are removed by the reduced salinity water releasing polar compounds and free iron.

2.2.3 Omar field, Syria

A detailed analysis of secondary low salinity water flooding in the Omar Field in Syria operated by Al Furat (a subsidiary of Shell) has been undertaken (Vledder, 2010). This is one of the few documented proofs of the concept of low salinity water flooding on a reservoir scale. The field consists of light oil with a viscosity of 0.3 Cp. It came on stream in 1989 but experienced rapid pressure loss indicating absolute lack of aquifer support. Water flooding using a river water source with salinity 500 mg/L (<<100 mg/L divalent ions) began in 1991. The formation water has a salinity of 90000 mg/L with a high content of divalent ions (5000 mg/L) and the clay content is 0.5-4% of which 95-100% is kaolinite (Vledder, 2010).

A detailed special core analysis and low rate core flood measurements performed on reservoir cores showed that the native state wettability in Omar was oil wet (wettability index of 1). Spontaneous imbibition experiments showed additional recovery from low salinity brine subsequent to high salinity brine correlating with kaolinite content (incremental recovery up to 24% PV). Logs in the Omar field show an initial oil saturation of 95% and remaining oil saturation after low salinity water flooding of 15% (but with uncertainty in range the 10-30% as the calculation is very sensitive to the salinity used in determining the saturation from the logs).

The current view at Al Furat (and Shell) is that the measurements and observations at 21 wells in the Omar field present abundant proof of wettability alteration occurring at the reservoir scale. Analysis indicates that the change in wettability is probably from 0.8-1.0 to 0.2 which would give an expected incremental oil recovery of 17% OIIP (compared to high salinity water flooding). However, comparison of high and low salinity water flooding across Al Furat's assets indicates that a more conservative estimate would be an increase in 5-15% STOIIP from low salinity water flooding in Omar.

2.2.4 Powder River Basin

In the Powder River basin of Wyoming numerous fields have been flooded with water from low salinity sources (Robertson, 2007). The waterflood responses in three Minnelusa formation fields, namely; West Semlek, North Semlek and Moran were analysed. Ultimate recoveries from the three fields were plotted as a function of the ratio of the average salinity of the injection water divided by the salinity of the formation water (*Figure 4*) indicating a trend to a higher recovery factor with a lower salinity ratio.

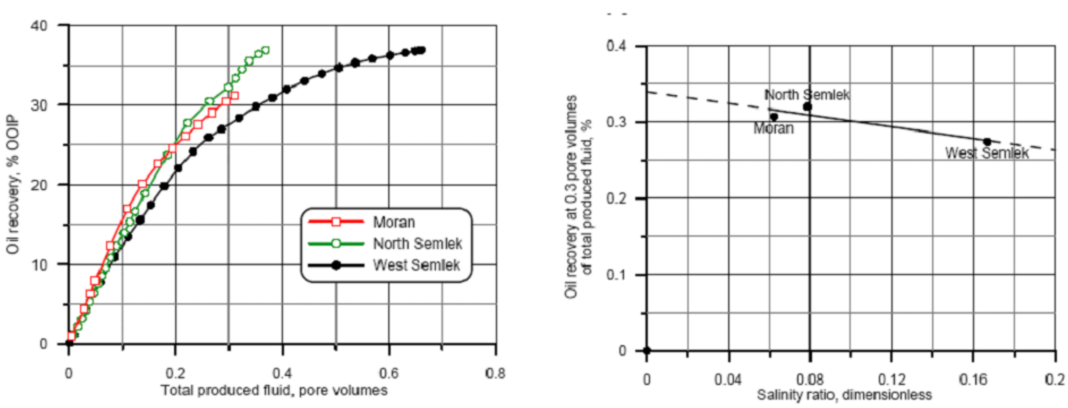


Figure 4: Recovery factor as a function of salinity ratio in the Minnelusa reservoir (Robertson, 2007)

The field results tend to corroborate laboratory core flood results using Minnelusa crude, brine and diluted brine (although the experiments used Berea outcrop material rather than Minnelusa formation) but "should not be considered proof positive".

2.2.5 North Sea applications of Low salinity

The Endicott field case is the only reported tertiary inter-well application of low salinity water flooding so far and no offshore implementation has yet been carried out. However, BP has plans of implementing the first full scale offshore low salinity concept on the Clair Ridge field on the UK continental field. The project has far progressed and first oil is expected in 2017 (). For some Norwegian Continental Shelf fields, laboratory work and chemical tracer tests (SWCTTs) have been carried out over the last few years. Statoil have indicated that Heidrun, Snorre and Gullfaks are all being considered for a possible low salinity pilot (Spangenberg, 2008).

2.2.5.1 Heidrun field

A number of reservoir temperature core floods using various outcrop rock samples and Heidrun stock tank oil have been undertaken (Heigre, 2008). The floods were undertaken using seawater, a mixture of 10% seawater and 90% fresh water, and a mixture of 1% seawater and 99% fresh water. The flooding sequence is not clear, but it is likely there is a combination of secondary and tertiary flooding experiments. *Figure 5* shows the residual saturation to water flooding as a function of seawater percentage for various experiments.

The precise reason for the large ranges is not clear. However, taking the middle of the ranges shown in *Figure 5*, the residual oil saturation reduces from 27% (seawater) to 22% (10% seawater) to 18% (1% seawater); the average reduction is 9 percentage points. There was no information about the individual core floods, and a different number of points are plotted at each salinity (so it is not possible to understand, for instance, if the highest saturation in the black points corresponds to the highest saturation in the red points, etc).

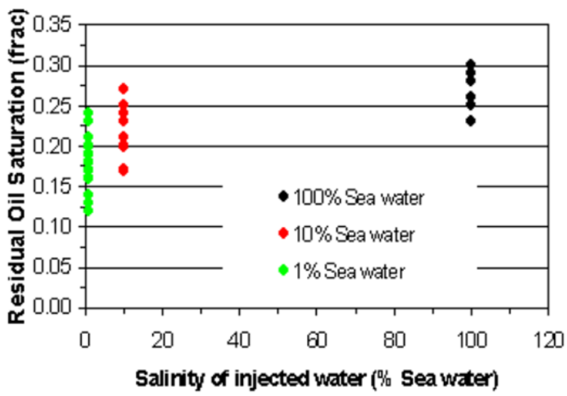


Figure 5: Results of laboratory low salinity experiments (Sprandvery, 2008)

It is likely that some of the variation is caused by the effect of the different outcrop cores used. Although the mechanisms by which low salinity water flooding works are not yet satisfactorily understood, rock surface properties and chemistry play an important role in the process so it is difficult to deduce from these experiments that the process will work in Heidrun. It is understood that a low salinity single well tracer test (SWCTT) was undertaken in Heidrun in late 2009, but no results have been published so far.

2.2.5.2 Snorre field

A comprehensive set of experiments using Snorre core material (Upper Statfjord, Lower Statfjord and Lunde), oil and formation water and flooding with various salinity and divalent cation concentrations showed negligible benefit compared to high salinity water flooding. This, even though the mineralogy was similar to other clastic systems where low salinity water flooding has shown a positive response (Skrettingland, 2010).
Nevertheless, Statoil carried out a single well reactive tracer test (SWCTT) in 2009 after completion of the core experiments. However, this also showed no significant reduction in oil saturation (Skrettingland, 2010). Compared to Endicott the residual oil after water flooding in Snorre is below 25% so the wettability, or other relevant conditions, would appear to be more favorable to seawater injection than in Endicott. This obviously lowers the potential additional benefit from low salinity water flooding. The formation water salinity in Snorre is similar to Endicott, although in Endicott the divalent cations (Ca, Mg) are significantly lower (*cf. Tables 2 and 3*).

Table 3: Composition of Snorre Formation water synthetic seawater and low-salinity water (Skrettingland, 2010)

Constituent	Formation water	Synthetic sea water	Field pilot lowsal
NaCl	30.5	23.74	0.3007
$CaCl_2 \cdot 2H_2O$	4.17	1.500	0.0234
$MgCl_2 \cdot 6H_2O$	1.35	10.70	0.0924
$BaCl_2 \cdot 2H_2O$	0.08	0.000	0.0000
$SrCl_2 \cdot 6H_2O$	0.047	0.024	0.0003
$NaHCO_3$	0.53	0.194	0.0231
KCl	0.23	0.755	0.0211
Na_2SO_4	0.00	3.976	0.0344
Salinity (wt %)	3.43	3.402	0.0440
Ionic strength (mol/l)	0.631	0.691	0.0083

The kaolinite content in the 1 m sand used in the SWCTT would appear to be highly variable with recorded amounts of 14.7% and 1.2% in two cores only 0.5 m apart so it would not be expected that this well would be favorable to low salinity water flooding. Other mineralogy differences are also apparent between the field cores and the SWCTT well (plagioclase content and mica/illite content) making comparison between the laboratory and field results difficult. Skrettingland (2010) also contains a good review of the many conflicting results from experiments in relation to the role of wettability, clays and oil composition. In particular the conflicting evidence in relation to the direction of wettability change with some researchers finding that a successful low salinity water flood requires the wettability to be changed from water-wet to mixed-wet whilst others find the reverse.

2.2.5.3 Gullfaks field

Statoil reported laboratory tests of low salinity water flooding in Gullfaks core as “highly encouraging”, and further studies and a possible pilot test have been under consideration (Talukdar, 2008).

2.2.5.4 Clair Ridge field

BP is implementing secondary low salinity water flooding in the second phase of development at the Clair field, known as Clair Ridge (Mair, 2010; Robbana et al. 2012). 145,000 b/d of injection water will be supplied by a desalination unit fed by treated and filtered seawater. Early in field life the low salinity water would be mixed with produced water for reinjection. In later field life when the produced water rate exceeds requirements it will be disposed by dedicated disposal wells. Mair (2010) presents a very useful timeline of the history of low salinity flooding research and a strategy for appraising the appropriateness of low salinity water flooding for a specific field. Overall BP estimate that implementing low salinity water flooding in Clair Ridge will produce 7% OIIP more than conventional seawater flooding at a development cost of $3 per barrel (Mair, 2010).

2.2.6 Screening criteria and consideration for low-salinity EOR process

Based on the experience on the different field results to low-salinity described above, there seems to be a consensus on some common reservoir features such:

- Clays have to be present and disturbed in the formation,
- Formation water and/or seawater with high salinity from prior flooding has to be present
- The low salinity injection water should have a salinity below some limit (TDS < approximately 5000 ppm)
- The reservoir oil should contain some polar oil components
- The reservoir wettability must be oil-wet or mixed-wet.

None of the above requirements is without some exception but can be applied as first phase screening to identify fields which might benefit from the method. However, because of the complex and often contradicting oil-brine-rock interactions suggested to explain how the process works, there is no theoretical predictive tool to determine the performance in individual reservoirs. Also, the above requirements are actually met by a great number of reservoirs and it is not easy to discount particular fields from consideration. However, it is possible from simple fractional flow theory to demonstrate improved sweep efficiency by altering the wettability from oil-wet to water-wet.

2.3 Review of Polymer flooding

Polymer flooding is the most commonly applied chemical enhanced oil recovery technique (Sheng et al. 2015, Standes and Skjvrak, 2014). The method aims at improving the macroscopic sweep efficiency by reducing the mobility ratio, the viscous fingering and the permeability in high-perm streaks. Although a number of on-shore field trials have been performed, polymer flooding is still rarely used for offshore fields.

The logistics and facility requirements make the operational design and execution more challenging in an offshore environment. The decision of conducting an offshore polymer EOR field trial must be supported by a strong technical evaluation (laboratory and simulation studies) and thorough operational field trial design that aims at targeting the different challenges to reduce risk and uncertainty and increase the likelihood of success.

As shown in *Table 1*, polymer flooding has predominating been applied in Bohai Bay, offshore heavy oil fields in China. Since 2003, there are have been 4 polymer EOR projects on heavy oil sandstone fields with a water cut of between 10-80%. About 20 thousand tons of polymer powder have been injected in 27 wells in the past 5 years. It has been seen that the water cut has declined while the oil production increased (Kang et al. 2011). Additionally, Chevron's successfully tested polymer flooding in the Captain field in the UKCS (Poulsen, 2010). The sandstone field was discovered in 1977, The field consists of a 100 centipoise heavy oil with permeability in the Darcy range. The field has a low temperature with moderate salinity coupled with poor volumetric and microscopy sweep efficiency. The pilot to field testing was initialed in 2014 with the aspiration of improving oil by 50% over water flooding (*Figure 6*).

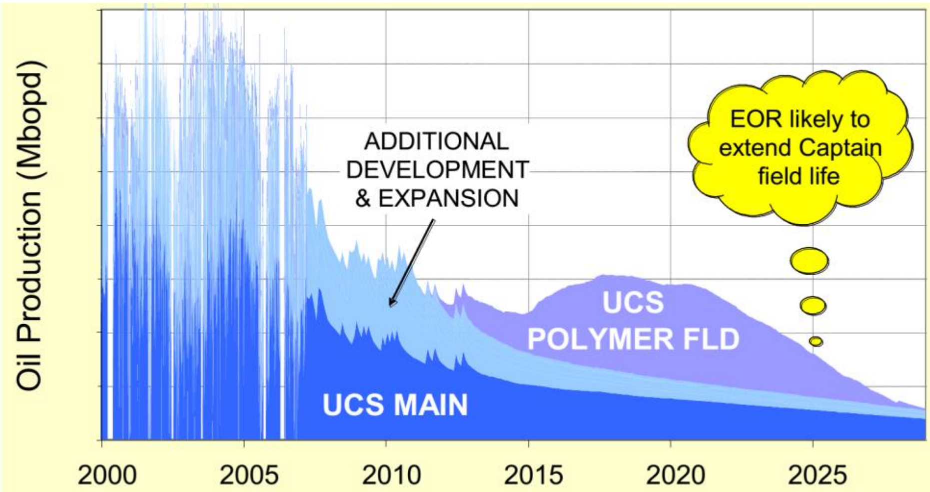


Figure 6: Polymer flood EOR potential for Upper Captain sand (Poulsen, 2010)

In all the cases reviewed, residual oil saturation data is more important for polymer application than average oil saturation at start point of polymer flooding because general targeted oil of polymer flooding is bypassed oil. However, most field data about residual oil saturation was not available and very different depending on reservoir. Although viscoelastic property of EOR polymer can decrease residual oil saturation, there are different opinions about how viscoelastic property of polymer works for decreasing residual oil saturation.

Most polymer cases have been implemented in sandstone (or loosely-consolidated sand) reservoirs. The formation type for all offshore cases is sandstone, owing to concerns over the high retention of polymers in carbonate reservoirs.

On the NCS, full-scale chemical EOR projects are scarce. This may because of the high reservoir temperatures and difficult water chemistries make it challenging to initiate chemical EOR. However, there have been substantial improvements in chemical EOR over recent years. For example, the upper reservoir limit for polymer application has been increased from a total salinity (TDS) of about 20 000 ppm to about 100 000 ppm. Similar improvements have occurred in the maximum reservoir temperature, maximum depth, minimum permeability and upper viscosity limit for chemical applications (McCormack et al. 2014). Considering these cases, screening criteria for the polymer process should be widened as polymer technology develops.

The polymer processes in offshore fields were applied under high oil viscosity conditions compared with onshore cases. Four offshore fields in China, use a newly developed hydrophobically-associating polymer, which has a high salinity tolerance and stability of shear degradation. Water salinity and hardness can critically affect the feasibility of polymer injection because polymer viscosity drastically decreases with increases in salinity and hardness. Above a critical hardness level, polymers can precipitate causing formation damage. Formation salinity and hardness data for the offshore cases reviewed ranged between 3000 – 20,000 ppm. The water hardness varied between 10-800 ppm. The salinity and hardness of these cases in China are low compared with general offshore fields on the NCS. In Dalia Field (Angola), salinity is up to 93,900 ppm and hardness is 21,300 ppm but production responses have not yet been reported due to long well space (Morel et al. 2008, 2012).

2.3.1 Screening criteria and consideration for offshore polymer process

Due to the strong influence on viscosity of partially-hydrolysed polyacrylamide (PHPA), which is the most widely used EOR polymer, injection water with low salinity and low hardness is needed, as too high cation concentrations may increase the possibility of scale deposition. Cation concentrations in seawater and typical formation water in offshore fields are high. Considering the problems of clay swelling, deflocculation, and scale deposition, water management is very important for polymer flooding applications in offshore fields. The membrane-based reverse-osmosis method is compact, lightweight, and requires no heat. However, its major disadvantage is that it provides almost fresh water. Too low a cation concentration may increase the possibility of clay swelling and deflocculation. Xanthan and newly-developed polymers, such as 2-acrylamido-2-methylpropane sulfonic acid (AMPS), poly-vinyl pyrrolidones (PVP), or N-vinyl pyrrolidones, have high tolerance to divalent cations. In the case of these polymer application, high salinity and hardness issues can be mitigated.

For oils with a high acid number, which are found frequently in offshore reservoirs, naphthenic acids in the oil can form very stable emulsions. Polymer addition tends to worsen the emulsion problem, which can be a significant problem owing to the severe constraints on offshore facilities. However, temperatures higher than the cloud point of the polymer can cause polymer precipitation. Chemical additions may be needed to elevate the cloud point of produced polymer fluids. PHPA is not sensitive to biodegradation, which is a good factor for performance in reservoirs. However, environmental restrictions on the NCS may limit the over boarding of poorly biodegradable EOR chemicals.

Commonly, there are two types of polymer: powder and emulsion. Although emulsion polymers are easier to handle, they involve higher costs than powder polymers. Most offshore fields, including SZ36-1, PF-A, PF-B, PF-C (*Table 1*) and Dalia field used powder polymers. For powder polymers, space and time are required for mixing and hydration of the dry polymer. Considering the limited space on the platform, fast hydration of polymer is important. Shear degradation of polymer near the choke is an important issue in offshore fields. According to Rivas and Gathier (2013), between 30% and 70% viscosity loss of the polymer solution can occur depending on the choke dimensions and the polymer concentration and type. In order to compensate for this viscosity loss, polymer over-dosing may be required, but this may increase operation expenses significantly. Long well spacing means a long residence time for the polymer in the reservoir, increasing the time for which the polymer must be stable under reservoir temperature, salinity, and hardness conditions.

2.4 Review of Hydrocarbon (HC) gas flooding

For offshore fields, HC gas injection is the most commonly applied EOR process. This is because of the availability of HC gas is higher than other EOR injectants in the offshore environment. HC gas for injection can be supplied by produced gas from the reservoir or nearby well, or transported from onshore. HC gas is commonly produced from the reservoir, although HC gas production highly depends on the depositional environment and hydrocarbon composition. Considering the transportation cost, produced HC gas is generally the best option for injection, but produced gas needs to be processed in some cases for miscibility achievement or meeting compatibility with injection facilities. In addition to the effectiveness of the HC gas miscible process in improving oil recovery, the limited platform space favors the reinjection of produced gas into the reservoir, unless the economical scale of HC gas is available. Major challenges associated with gas injection include gas fingering and channeling due to the low viscosity and density of gas compared to oil, and reservoir heterogeneity. To mitigate these problems, gas is commonly injected in the form of WAG, which provides better sweep efficiency and reduces gas channeling from injector to producer (Brodie et al. 2012).

Depth relates to reservoir pressure for miscible conditions; however, water depth must be considered in offshore fields. Reservoir pressure and oil composition mainly influence miscibility in the reservoir and they are important parameters in assessing the effectiveness of miscible gas EOR processes. As production progresses, they change and affect miscibility in the reservoir. These parameters need to be monitored in the field. Owing to the lack of data, pressure data was not provided in this research. Considering the high uncertainty in the reservoir characterization of offshore fields, reservoir heterogeneity was not considered for screening criteria. Generally, the presence of a gas cap is unfavorable, although the HC gas miscible application in Brent field, which has a primary gas cap, was successful. As there is some uncertainty as to whether the presence of a gas cap is an appropriate parameter for early EOR screening, it was not included in this study. Considering data availability and the considerations described above, oil viscosity, gravity, and saturation data were analyzed in this study. There is no definite trend in high oil viscosity with time of project implementation, and most HC gas miscible applications in offshore fields have been applied to low viscosity and light oil conditions. HC gas miscible application to high oil viscosity offshore fields is unlikely, but possible (as observed for some of the fields on the NCS), considering that the miscibility mechanism can reduce oil viscosity.

Awan et al. (2006) evaluated a total of 19 IOR projects presented in the open literature and published before 2002, and discussed the introduction of technologies new to the North Sea, such as water-alternating-gas (WAG) injection, simultaneous water-and-gas (SWAG) injection, foam assisted WAG (FAWAG) injection, and microbial EOR (MEOR) on the NCS.
It is interesting to note that hydrocarbon gas injection would not be considered an EOR process on the NCS, since 2 to 2.3 billion bbl. have been injected to increase recovery since 1971 (*Table 4*). Since 2011, about a quarter of the total volume of gas produced (2 000 billion standard cubic metres) has been injected for IOR purposes (NPD facts page, 2011). According to Awan et al. (2006), HC gas injection in the North Sea was initiated because of the limited gas-export capacities.

Table 4: North Sea Gas based IOR/EOR (Awan et al. 2006)

FIELD	OPERATOR	SECTOR	TYPE	START DATE	SUCCESS
Ekofisk	ConocoPhillips	Nor.	HC Miscible[1]	1971	Success
Beryl	Exxon-Mobil	UK	HC Miscible	1976	Success
Statfjord	Statoil	Nor.	HC Miscible	1979	Success
Brent	Shell	UK	HC Miscible[2]	1976	Success
Alwyn North	Total	UK	HC Miscible	1987	Success
Smorbukk South	Statoil	Nor.	HC Miscible	1999	Success
Snorre	Statoil	Nor.	HC WAG Miscible	1992	Success
South Brae	Marathon	UK	HC WAG Miscible	1993	Success
Magnus	BP	UK	HC WAG Miscible	1983	Success
Thistle	Lundin Oil	Nor.	HC WAG Immiscible	1978	Success
Gullfaks	Statoil	Nor.	HC WAG Immiscible[3]	1986	Success
Brage	Norsk Hydro	Nor.	HC WAG Immiscible	1993	Success
Ekofisk	ConocoPhillips	Nor.	HC WAG Immiscible	1971	
Statfjord	Statoil	Nor.	HC WAG Immiscible	1979	Success
Oseberg	Norsk Hydro	Nor.	HC WAG Immiscible	1999	Success
Siri	Statoil	Danish	HC SWAG*	1999	Success
Snorre A (CFB)	Norsk Hydro	Nor.	HC FAWAG	1992	
Snorre A (WFB)	Norsk Hydro	Nor.	HC FAWAG	1992	Success

2.4.1 General screening criteria and consideration for hydrocarbon gas EOR processes

The dipping structure of a reservoir can lead to gravity-stable displacement by the injectant, while gravity override often occurs in thick reservoirs. Although a homogeneous reservoir is a better gas EOR target than a heterogeneous reservoir due to gas channeling, heterogeneous cases in Ekofisk (naturally-fractured reservoir) and Snorre field (high-permeability contrast) were successful. Therefore, previously-suggested screening criteria of reservoir permeability, which is “homogeneous”, needs to be modified to “homogeneous preferred”. Injectant channeling often occurs through high-permeability layers in a heterogeneous reservoir, reducing the volumetric sweep efficiency drastically. Oil composition and reservoir pressure relate to the minimum miscible pressure (MMP) of oil. Even though this aspect could not be analyzed quantitatively, as mentioned above, it is incorporated as “reservoir pressure ≥ MMP” in the screening criteria for HC gas miscible processes. Reservoir pressure at start EOR operation can be more meaningful than initial pressure because injected HC gas contacting with oil in the pressure above MMP is favorable condition for miscibility achievement.

3 The Norwegian continental shelf – An Overview

As at the end of 2015, eighty-two fields were in operation on the Norwegian continental shelf (NCS), compared with 51 ten years ago. This illustrates the enormous development activity that has taken place in recent years on the NCS. More wells were drilled in 2015, than in any other year when exploration wells are included. 11 discoveries were made in the North Sea, and six in the Norwegian Sea (NDP resources report, 2015).
The authorities approved four plans for development and operation (PDOs) in 2015, compared with just one in 2014. These four have led to an increase in the reserves estimate on the Norwegian Shelf – even though around 230 million Sm^3 oil equivalents of the reserves were produced. Four new fields came on stream in 2015. Six new fields are currently being developed in the North Sea, two in the Norwegian Sea and one in the Barents Sea. As at the end of 2015, about 4075.1 millSm^3 of oil and 2076.2 billSm^3 gas or 6610.6 millSm^3 equivalent oil has been produced from the Norwegian shelf. This is equivalent to more than 2 billion barrels of oil. Based on original in-place oil of 11143.20 millSm^3, the current oil recovery factor is 45.8 % with a total water-cut of 64.0%. *Figure 7a* show that original recoverable oil is 29.0% with remaining oil at 6.0% based on current production technology on the NCS. Thus, there is little doubt that the ambitious levels of recovery sought may only be reached through aggressive use of IOR/EOR technologies used to convert some resources to reserves. In this section, water-based and gas-based EOR processes with the aim of improving volumetric, macroscopic sweep efficiency, and displacement and microscopic efficiency on the NCS will discussed. As shown in *Figure 7b*, oil production peaked in 2001 and has since been declining. However, the decline can be stopped through exploration, development of new oil discoveries and a strengthening commitment to IOR/EOR to target the original recoverable oil in place on existing fields.

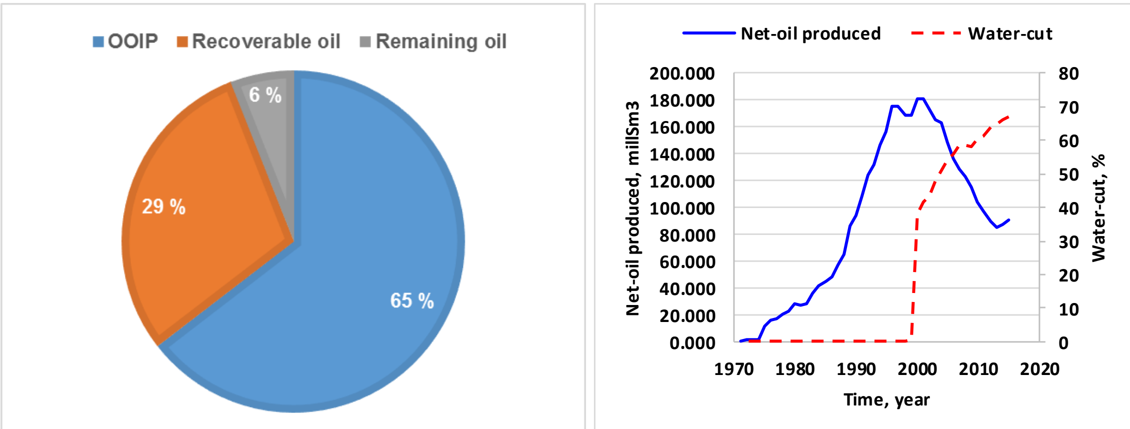


Figure 7: Defined reserves and remaining oil as at the end of 2015, (b) net-oil produced and water produced for producing fields on NCS as a function of time (NPD fact pages, 2015)

3.1 Past and current IOR/EOR activities on the NCS

The average oil recovery factor on the NCS is currently 46 % compared to about 22 % worldwide. Thus, more than half the oil on the NCS will left in the ground. The current prediction for ultimate oil recovery on the NCS is almost two out of every four barrels in place (Søndenå and Henriquez, 2011). The main reason for this is that a national consensus was established at an early stage concerning the need for collaboration between licensees and the government, and a conscious political decision was made to harness the resources properly. One consequence was a ban on gas flaring, this made gas available for injection and pressure maintenance. Another was that technological know-how was developed with the help of the major oil companies and the government. Norway has been at the forefront in applying new technologies such as 3-D and 4-D seismic surveying, modelling of heterogeneities in reservoirs, reservoir simulation techniques, smart and advanced wells, subsea-related developments like light well intervention (LWI).

During the late 1980s and the early 1990s, great efforts were made by research institutes, governmental bodies and field operators to increase ultimate recovery. The efforts lead to the initiation of the following projects: State R&D program for improved oil recovery and reservoir technology (SPOR: 1985-1991), Joint Chalk Research phases I-VII (JCR: 1982- present), PROFIT (1990-1994), Reservoir Utilization through Advanced Technological Help (RUTH: 1992-1995) and SAFARI (1988-1995). The projects have been very successful. For example, the RUTH program focused on gas flooding, combined gas/water injection, polymer gel, surfactants, microbial methods and foam. These resulted in field pilots and the eventual adoption of some technologies new to the North Sea (Søndenå and Henriquez, 2011).

The high oil price was also an incentive to exploit IOR methods which, together with active government support, surmounted the barrier of perceived delays to production and consequent loss of income from the execution of pilots. However, research and technology development in IOR and EOR normally fall worldwide with a decline in oil prices. Initiating offshore EOR pilots is difficult and EOR production remains very small worldwide, since drilling costs and the distances between injectors and production wells are much greater than onshore fields. Environmental aspects are critical issues for certain EOR applications, since some of the chemicals developed are designed to last long enough to be able to fulfil their roles and are therefore not biodegradable within short time frames.

Since production started on the NCS in the 1970s, oil production has been mainly due to natural depletion followed by pressure support through water and/or gas injection. Advanced reservoir monitoring tools have also played a significant role to improve recovery strategies for some of the fields. Systematic data acquisition and use of production and reservoir information have helped increase understanding of reservoir properties throughout the production phase. Improved understanding of the location of oil and gas and their flow properties has been enhanced, thus new drilling targets are constantly being identified.

Much of the remaining mobile oil in the producing fields can in theory be recovered with known and tested technology, injecting water and gas can be used to maintain reservoir pressure and displace oil. The main reasons for improved recovery from the 1970s to the 1990s are advances in IOR such as:

- better understanding of the reservoir owing to the use of 3-D and 4-D seismic surveying, better reservoir simulation, geological modelling based on significantly more data, improved logging tools and modern visualization techniques. These methods answer the question of where the remaining oil is located.
- better well and drilling technology, with advanced wells (long horizontal wells, well branches), better completion techniques yielding higher productivity. All these methods are solutions to the challenge of reaching and producing the oil

mapped, with better sweep efficiency than vertical holes and possibilities for greater production optimization than plain completions.
- water and gas injection probably provided the biggest contribution to this significant increase in ultimate recovery from the 1970s to the 1990s. Pressure maintenance by gas or water injection has now become standard for new fields, making the old definitions of primary, secondary and tertiary recovery processes out of date.

An example on the NCS is the Ekofisk, a fractured chalk field where the initial estimate of ultimate oil recovery in the early 1970s was 17 %. Due to massive water injection, encouraged by the Norwegian Petroleum Directorate (NPD), this figure rose in the late 1990s to 38 % (Jensen et al. 2011; Hermansen et al. 2000). Expected recovery at present is about 50 %, aided by a large redevelopment, aggressive infill drilling, horizontal wells and extensive use of smart field applications. Ekofisk was the first field on the Norwegian shelf to inject gas at the top of the reservoir. This was done from 1975 to 1997. During this period, one-fourth of the gas from Ekofisk and surrounding satellite fields was re-injected, while the rest of the gas was exported. The objective of the gas injection on Ekofisk was that the gas needed to be stored due to operational problems caused by construction of the gas pipeline to Emden in Germany, as well as low demand for gas in the summer months. Initially it was difficult to prove that gas injection improved recovery (Jakobsson and Christian, 1994). However, simulation of reservoir models indicate that gas injection may have improved oil recovery and contributed to maintaining production at a higher level. However, since water injection started in 1987, combination of water flooding and compaction of the reservoir chalk, have contributed most to the increase from 17 % to almost 50 %.

When production started in the Statfjord field in 1979, there were no pipelines to export the gas. It was therefore injected back into the Statfjord formation, which is the next largest formation on the field. Eventually gas was also injected into the largest formation, Brent, as a supplement to water injection. In addition to good reservoir properties and the drilling of many wells, the combination of gas and water injection has ensured that the recovery rate for oil on Statfjord is expected to reach 67 %, according to approved plans

Oseberg was the first field where gas injection was approved as the main method to recover oil, both injection of its own gas and imported gas from the Troll field, where the subsea template Troll Oseberg Gas Injection (TOGI) was put into use. With the current approved plans the oil recovery rate on Oseberg is estimated at 63 % (NPD’s resource report, 2015)

When the gas is injected down into the well and comes in contact with the oil, the gas can behave in two different ways: depending on reservoir pressure and temperature, the gas can mix with the oil under miscible injection, which is what takes place in the Statfjord formation on Statfjord field and in parts of Åsgard field. Alternatively, the gas will not mix with the oil, but forms a separate phase under immiscible injection. This is the case on, among others, the Oseberg and Grane fields on the NCS.

Alternating water and gas injection (WAG) is used as a supplement to water injection, which is the main method on most of the fields on the Norwegian shelf. Thus, alternating water and gas are then injected into the same well. Since WAG does not require large amounts of gas, the method is used by several Norwegian fields such as, Snorre, Gullfaks, Statfjord and Ula. Currently, this accounts for 10-12 % of the total amount of gas injected on the shelf annually (NDP fact page, 2015). Foam-assisted WAG (FAWAG) was tried out in the Snorre field with great success in the 1990s (Blake et al. 2002). The injection of FAWAG resulted in a significant reduction in gas-oil ratio in well P-39 (*Figure 8a*). A significant reduction in gas injectivity was observed in well P-32. Gas breakthrough occurred in 7 months. The cumulative oil produced as a result of FAWAG was estimated as 0.25 millSm^3 (*Figure 8b*).

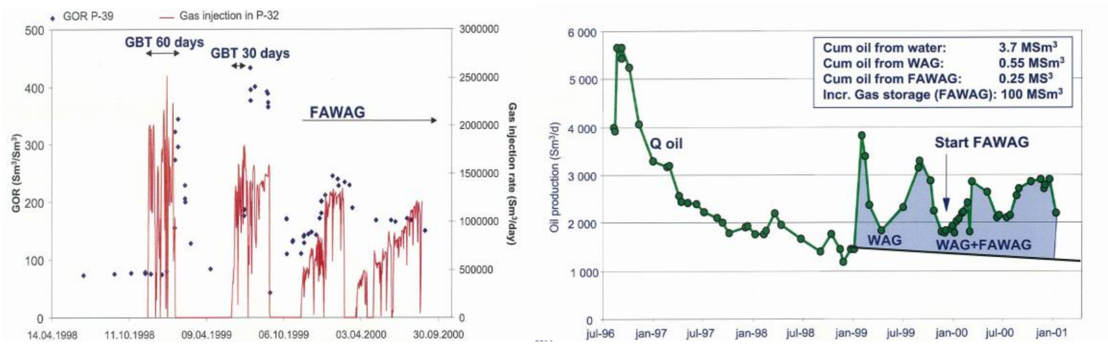


Figure 8:Reduction in GOR (Well P-39) and gas injectivity (well P-32) and (b) cumulative oil recovered during the injection of FAWAG in Snorre field (Blake et al. 2002)

Immobile oil offers a big EOR potential on the NCS. The most promising methods for producing immobile oil are injecting water with chemical additives or miscible gases such as hydrocarbon gas or CO_2. Injecting low-salinity water has also been identified as an interesting method. In general, water production begins when less than half the reservoir volume between wells is flooded and then increases rather quickly, with shorter water circulation time. Reservoir zones with high water circulation have also been found to reach very low residual oil saturation of 15 % to 20 % (as low as 5 % has been reported for the best reservoir units on Gullfaks, (Helland et al. 2008). The higher oil saturations in the neighboring zones are then an interesting target for EOR.

Diversion of water inside the reservoir also reduces water production, and the need to inject water for pressure maintenance therefore decreases. Water flow diversion to unswept zones may be obtained by techniques such as Bright Water, sodium silicate and LPS, which also improves microscopic sweep. Polymers can also be used to avoid water fingering caused by high oil viscosity. Immobile oil is targeted by trying to weaken the bonding of the crude to the reservoir rocks. Polymer assisted surfactants (PASF), microbial enhanced oil recovery (MEOR) and low salinity water injection (LSWI) are some of the methods used for this purpose. PASF also contributes to sweeping mobile oil. Silicate gel and polymer-assisted surfactant flooding (PASF) have been tested on the Gullfaks field. Two pilot tests have been conducted on Gullfaks (Lund and Kristensen, 1993; Rolfsvåg et al. 1996). Both were well production treatments dedicated to reducing the water cut by lowering the permeability in thief zones, and both were successful. Skrettingland et al. (2011) described the single-well field LSWI pilot and core flooding measurements on the Snorre field. The core flooding measurements in the Statfjord and Lunde formation cores yielded practically no incremental recovery response. Since then, low salinity tests have been performed on core material from Heidrun and Gullfaks fields with some promising results. Microbial EOR has formed part of the research programmes and is being used today at the Norne field (NPD fact pages, 2014).

3.2 Possible targets for EOR activities on the NCS

At the end of 2015, the original oil in-place (OOIP) for the 26 largest fields - including Johan Sverdrup (*Figure 9 and Table 5*) was estimated as 8954.1 MillSm^3 (64 %), with a recoverable oil volume of 4203.7 $MillSm^3$ (30 %). The remaining oil is estimated as 798.2 $MillSm^3$ representing 6 % of total volume. Thus, the target for IOR/EOR processes is huge (*Figure 10a*). The 26 fields have an average oil recovery factor of 46.9 %. Among the 26 largest fields, 21 (81 %) are sandstone fields whiles 5 (19 %) are chalk fields (*Figure 10b*).

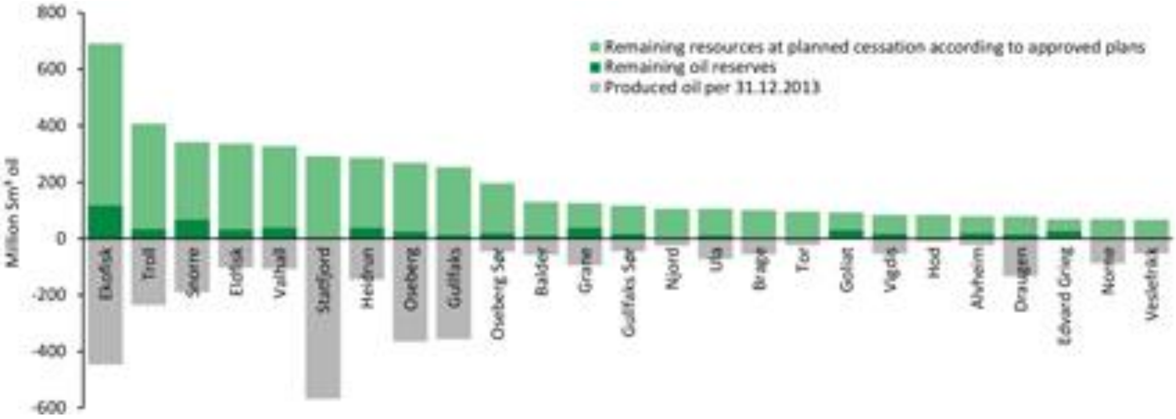


Figure 9: Resources overview for the 25 largest oil fields on the NCS

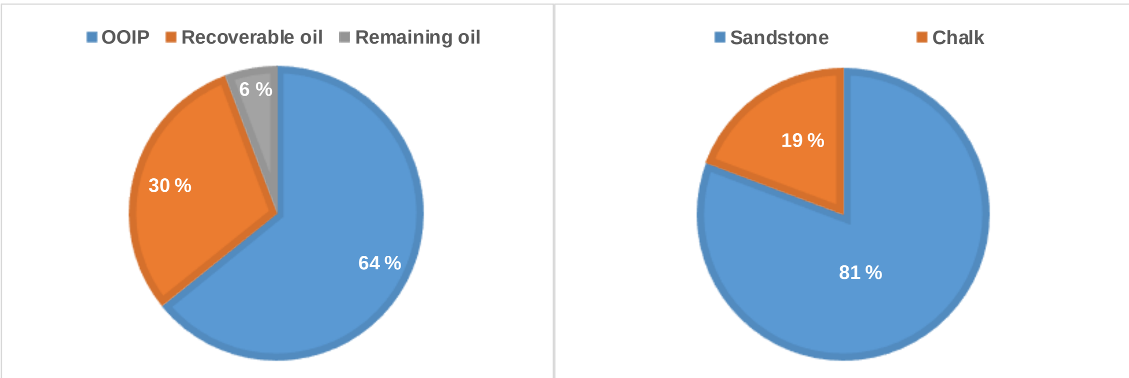


Figure 10: (a) Defined resources and reserves including remaining reserves and (b) distribution of sandstone and chalk fields for the 26 largest fields on the NCS as at the end of 2015

Table 5 presents an overview of 26 largest fields including Johan Sverdrup. The table lists the reservoir type, original oil in-place, original recoverable oil, remaining oil volumes and current oil recovery factors as at the end of 2015. The 5 chalk fields (*see Table 5*) have an average oil recovery factor of 38.6 % whiles the sandstone fields have an average recovery factor of 49.7%. Ekofisk the largest chalk field has an oil recovery factor of 49. 7 %. The Statfjord field is the largest sandstone with an oil recovery factor of 67.0 %. Thus, the largest fields have a higher recovery factor than the smaller ones. This is because large fields have a long producing life, making it possible to implement a number of measures over time during the production phase. This can help improve recovery. The maturity and type of production facility (platform and a combination of platform and subsea) are also presented. As shown in *Table 5*, the maturity for the 26 largest fields averages 0.77.

Table 5: An overview of proven reserves, including remaining oil, recovery factors and maturity for the 26 largest fields on the NCS as the end of 2015 (NPD Fact pages, 2015)

Field name	Reservoir type	Orig. *Oil in place MillSm3*	Orig. Recoverable *Oil MillSm3*	Remaining *Oil Mill Sm3*	*Oil recovery factor %*	Maturity	Facility type
ALVHEIM	SS	105.70	43.5	14.6	**41.15%**	0.66	combined
BLADER	SS	227.90	74.2	11.4	**32.56%**	0.85	combined
BRAGE	SS	157.80	60.9	3.9	**38.59%**	0.94	platform
DRAUGEN	SS	224.40	144.4	7.5	**64.35%**	0.95	platform
EDVARD GREIG	SS	69.40	26.2	26.0	**37.75%**	0.01	platform
EKOFISK	CH	1134.20	545.6	86.5	**48.10%**	0.84	platform
ELDFISK	CH	438.80	131.2	24.4	**29.90%**	0.81	platform
GOLIAT	SS	89.40	28.5	28.5	**31.88%**	0.00	combined
GRANE	SS	220.00	143.7	41.4	**65.32%**	0.71	platform
GULLFAKS	SS	792.60	377.0	16.4	**47.56%**	0.96	platform
GULLFAKS SØR	SS	163.90	62.4	13.8	**38.07%**	0.78	subsea
HEIDRUN	SS	432.00	186.0	34.5	**43.06%**	0.81	combined
HOD	CH	93.20	10.3	0.7	**11.05%**	0.93	platform
JOHAN SVERDRUP	SS	562.00	279.5	279.5	**49.73%**	0.00	platform
NJORD	SS	132.20	29.6	3.0	**22.39%**	0.90	subsea
NORNE	SS	157.00	91.3	2.2	**58.15%**	0.98	combined
OSEBERG	SS	638.00	401.7	31.0	**62.96%**	0.92	platform
OSEBERG SØR	SS	248.40	67.2	16.8	**27.05%**	0.75	platform
SNORRE	SS	558.50	267.5	65.1	**47.90%**	0.76	combined
STATFJORD	SS	859.80	576.1	5.6	**67.00%**	0.99	platform
TOR	CH	119.80	24.5	0.0	**20.45%**	1.00	platform
TROLL	SS	663.50	280.4	31.2	**42.26%**	0.89	platform
ULA	SS	172.30	83.2	9.3	**48.29%**	0.89	platform
VALHALL	CH	435.20	144.8	32.5	**33.27%**	0.78	platform
VESLEFRIKK	SS	120.60	54.8	1.0	**45.44%**	0.98	platform
VIGDIS	SS	137.50	69.2	11.4	**50.33%**	0.84	subsea
TOTAL		*8954.1*	*4203.7*	*798.2*			
AVERAGE					46.9 %	0.77	

SS= Sandstone; CH=Chalk

From *Table 5*, it is possible gather new information, knowledge and address pertinent questions such as;

- What will it take to lift all major sandstone reservoirs to approximately 70% oil recovery factor?
- What will it take to lift recovery factors on chalk fields such as Valhall, Tor and Hod to oil recovery at Ekofisk?
- Why are recovery factors of new fields such as Johan Sverdrup less than those produced on the NCS in the 1980s?
- In terms of remaining oil recovery which fields on the NCS should be EOR candidates?

4 EOR screening for some selected fields on Norwegian Continental Shelf (NCS)

4.1 Introduction

As mentioned in chapter 2, the main objective of the studies is to perform a fast screening of various EOR methods for some selected oil fields on the NCS, and predict the field performances based on present-day field characteristics. The key reservoir parameters used included reservoir depth, temperature, porosity, permeability, initial oil saturation, oil gravity, and *in-situ* oil viscosity.

4.2 Selection of EOR screening tool (s)

A literature review revealed that both qualitative and quantitative EOR evaluation can be performed. Three different EOR screening tools were identified. A brief description of the screening tools are given below:

1. **SWORD**: one dimensional qualitative EOR screening tool at IRIS.
    - Input data: rock and fluid properties (6 parameters as outlined above).
    - A database with EOR data published from Oil and Gas Journal (2008 and 2010).
2. **MAESTRO**: quantitative and qualitative EOR evaluation tool developed by RPS Energy.
    - Performance indicators: preliminary screening based on analytical models
    - Rapid simulation: Evaluate IOR/EOR performance.
    - Input data: SCAL data including rock, fluid data and geology.
3. **EORt**: quantitative and qualitative EOR evaluation tool developed by Schlumberger.
    - Numerical simulation and forward modelling of EOR processes.
    - Input data: current saturation data and rock-type distribution.
    - A database with over 2700 EOR field cases.

4.3 EOR screening with SWORD

In this work, our in-house screening tool SWORD developed at IRIS in the 1990s was selected and used. Some of the advantages in using SWORD are its speed, relatively small amount of data necessary to estimate the recovery of a particular EOR technique and a dispersion free analytical solutions. SWORD uses a simplified representation of the reservoir in the analytical simulation and this helps in understanding the dominating effects and forces, and may be used in verifying numerical results (SWORD manual, 2013)

SWORD consists of five main modules; applicability screening, recovery factor estimation, performance prediction, thermal recovery and economic and risk analysis modules. In this work, the screening for the EOR potential for the selected fields were based on the recovery factor estimation and performance prediction modules. A brief description of the recovery factor estimation and performance prediction modules are given below.

4.3.1 Recovery factor estimation module

The recovery factor estimation module is based on worldwide experience of IOR/EOR applications. The databases used in the estimating recovery factor are generated from oil and gas's companies' in-house databases, governmental databases from the Norwegian petroleum directorate and published databases like the biannual survey of the Oil and gas Journal. These databases typically contain field properties, description of IOR/EOR applications and their efficiency (actual or expected) in terms of additional oil recovery factor. In the recovery factor estimation module, such information can be classified and analysed using statistical methods in order to assess new IOR/EOR potentials. One of the key questions is the selection of the representative reservoir properties to use in the screening study. A large number of such defining properties would require a large database to generate quality predictions (Surguchev et al. 2011). Additionally, these databases are reported for different rock types and contain several hundreds of IOR/EOR field cases. Lee et al. (2011) and Alvarado et al. (2002) have shown that for effective screening, the optimal number of reservoir and fluid properties is six; porosity, permeability, reservoir depth, initial reservoir temperature, oil density and in-situ viscosity.

Screening with the recovery factor estimation module involves a three-step work flow as follows: (a) clusterization of the data from arbitrary number of databases with (b) statistical estimation of recovery factor for different IOR/EOR methods and (c) association of the new field cases with a cluster in order to evaluate statistically possible IOR/EOR methods and corresponding recovery factor for the new field cases. The first step in recovery estimation analysis is the selection of data with rock types representative of the field in question. Using the six reservoir/fluid properties, statistical (cluster) analysis is performed in order to divide similar field cases into clusters. The implementation of the *k-method* (Anderbery, 1973, Kim 1989) in the recovery estimation module allows the division of the all-available field cases into specified number of clusters with similar reservoir characteristics. The resulting clusters can be visualized in 2-dimensions based on dimension reduction (from 6 defining parameter's space to 2D plot) using the principal component analysis (Jolliffe, 2002). The clusterization quality factor is also reported. This makes it possible to choose an optimal number of clusters and configuration of clusters which yields the best visual separation and the highest clustering quality. Finally based on the six reservoir/fluid properties for the field case in question, recovery factors for different IOR/EOR methods and corresponding statistical results are generated by the association rules based on discriminant analysis (Kim, 1989).

4.3.2 Performance prediction module

Performance prediction is a "pre-simulation" tool integrated in SWORD (*SWORD manual, 2013*). It allows for rapid quantitative predictions and fast comparison of IOR methods in simplified stratified reservoirs. The predictions are based on proven analytical solutions: Dykstra-Parson method and gravity-dominated vertical equilibrium approximation. In this work, the Dykstra-Parson method was used. The prediction assumes a continuous injection of a single displacing fluid such as water or gas. Due to lack of relative permeability curves for the selected screened fields (*Table 6*), linear relative permeabilities were assumed. Thus, the predictions are based on changes in fractional flow when screening for EOR processes. Piston-like displacements with cross-flow between the layers were assumed. The injected water may contain additives such as polymer and/or surfactant and the injected gas may have any degree of miscibility. Both miscible and immiscible conditions were simulated. The performance prediction module can be used to evaluate the following EOR processes analytically; Depletion, Waterflooding, Cyclic water flooding, Polymer, Surfactant and combined surfactant/polymer flooding, immiscible and miscible gas (CO_2, N_2 and hydrocarbon) and steam flooding. In this work, the predictions were performed for the following EOR processes: polymer, surfactant, combined surfactant/polymer and miscible and immiscible CO_2 and hydrocarbon gas, and immiscible hydrocarbon gas conditions. The predictions are based on a simplified 2D cross-sectional with 3 layers of the reservoir. The evaluation of the EOR processes were compared to water flooding, assuming water flooding as the base case in the selected fields. The results as shown below are only valid for displacement calculations assuming 2D cross-sectional with an arbitrary layering of the reservoir (*SWORD manual, 2013*). The screening sought to demonstrate and capture the essence of the various EOR processes and did not attempt any detailed reservoir simulations.

4.3.3 Selected fields for EOR screening with SWORD

Based on the availability of present-day data, the following fields (*Table 6*) were selected for the EOR screening. Detailed data for the selected fields were obtained from published data in the literature and SPOR Monograph (1990), and supplemented with oil production data from the NDP's website.

Table 6: An overview of oil fields on the NCS selected for EOR screening

Field name	*Reservoir type*	*Orig. Oil in place MillSm3*	*Orig. Recoverable Oil MillSm3*	*Remaining Oil Mill Sm3*	*Oil recovery factor %*	*Current recovery strategy*
BRAGE	SS	157.80	60.9	3.9	38.59 %	Water, gas and water alternating gas injection
DRAUGEN	SS	224.40	144.4	7.5	64.35 %	Natural water drive and water injection
EKOFISK	CH	1134.20	545.6	86.5	48.10 %	Water injection, earlier pressure depeletion and compaction
GRANE	SS	220.00	143.7	41.4	65.32 %	Gas injection, from 2011 water injection and gas reinjection
GULLFAKS	SS	792.60	377.0	16.4	47.56 %	Water injection, some gas and water alternationg injection
HEIDRUN	SS	432.00	186.0	34.5	43.06 %	Water injection, some gas and water alternationg injection
NORNE	SS	157.00	91.3	2.2	58.15 %	Water, gas and water alternating gas injection
SNORRE	SS	558.50	267.5	65.1	47.90 %	Water, gas and water alternating gas injection
Total		3676.50	1816.4	257.5		
Average					51.63 %	

4.3.4 Selected databases in SWORD

Three different databases namely EOR databases published in the Oil and Gas journal (OGJ 2008 and 2010) and NCS databases exists in SWORD (*Figure 11*). In order to avoid screening the selected fields on the NCS against the NCS database in SWORD database, the NCS database was switched off during the screening process. For the sandstone reservoirs, the recovery factor estimation was performed using only sandstone and unconsolidated in the formation list.

For sandstone fields with stripes of carbonate layers in the formation, the following formations were selected and used: sandstone/tripolite/tripolite/dolomite and unconsolidated formations. Screening for the chalk fields were performed with data from dolomite, limestone and limestone/dolomite formations.

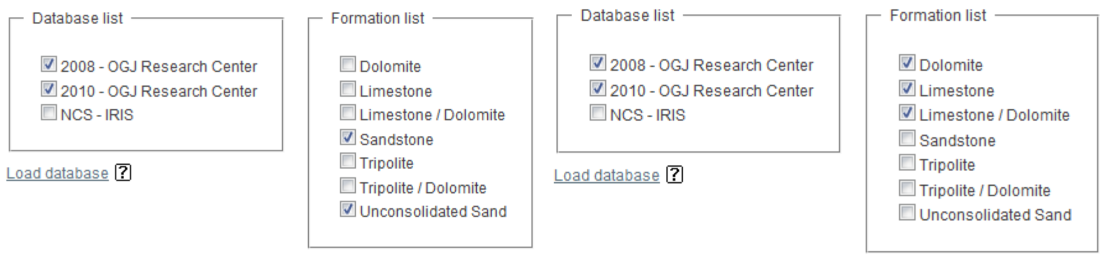
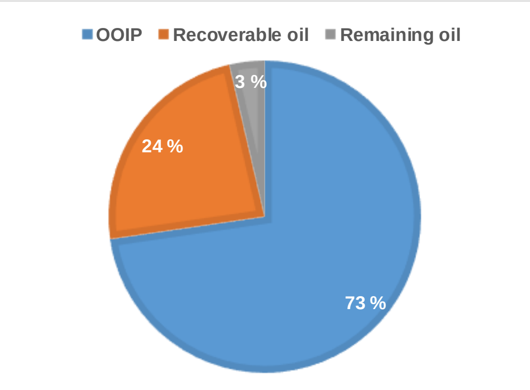


Figure 11: List databases and formations in SWORD

4.3.5 EOR screening for Brage field

Brage is an oil field located east of Oseberg in the northern part of the North Sea. The water depth in the area is 140 metres. The reservoir contains oil in sandstones of the Statfjord Formation of Early Jurassic age, and in the Brent Group and the Fensfjord Formation of Middle Jurassic age. There is also oil and gas in the Sognefjord Formation of Late Jurassic age. The reservoirs lie at a depth of 2 000 – 2 300 metres. The reservoir quality varies from poor to excellent. The recovery strategy in the Statfjord and Fensfjord Formations is water injection. Gas injection started in 2009 in the Sognefjord Formation, but is currently not in use due to limited gas availability. The first oil producers in the Brent Group started production in 2008, supported by a water injector. The water injector was converted to a WAG injector in 2013 (NPD fact pages, 2015). Several enhanced oil recovery methods have been evaluated including an MEOR pilot in 2014.
Figure 12a show the current reserves, an original oil in-place (OOIP) of 157.8 millSm^3 (73 %) with original recoverable oil of 60.9 mill Sm^3 (24%). As shown, the remaining oil reserves is 3.8 millSm^3 (3%). The current oil recovery for the field is 38.6 %. *Figure 12b* show the status of net oil produced, and a water-cut of 96.5% as at the end of 2015. *Table 7* present some of the reservoir and fluid properties collected for the Brage field (SPOR Monograph; Lien et al. 1998).



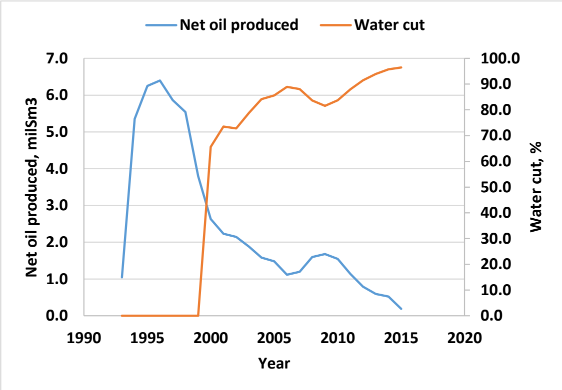


Figure 12: OOIP, recoverable and remaining reserves (b) current net oil produced, millsm^3 and water-cut in percent as at the end of 2015 for the Brage field (NPD's fact pages, 2015)

Table 7: Field case input data for Brage field

Parameter	Unit	Min	Max
Depth	m	2130	2370
Permeability	md	1	5000
Thickness	m	20	88
Temperature	Celsius	40	93
Oil viscosity	cp	0.67	0.91
Pressure	bar	215	244
Oil density	kg/m3	835	843
Anisotropy (kv/kh)	(0-1)	0.01	0.4
Clay content	(0-1)	0	0.05
Salinity	g/l	45	56
Curr/init oil saturation	(0-1)	0.3	0.75
High/low perm. ratio		1	100

4.3.5.1 Recovery factor estimation – Brage field

The six reservoir and fluid properties used in the recovery factor estimation are as listed in *Table 8*. The porosity averages 0.26 and average permeability ranges between 1000 – 5000 mD depending on the lithology in the Brage field. The reservoir oil averages 0.91 cP. The results of the cluster analysis are as shown in *Figure 13 and 14* at 98^{o}C.

Table 8: Field case parameters used in the cluster analysis

Porosity (frac)	Permeability (mD)	Depth (m)	Oil gravity (kg/m3)	Oil viscosity (cP)	Oil temperature (°C)
0.26	1000-5000	2370	843	0.91	98

The figures show that for the majority of cases in the databases the methods mostly used was miscible CO_2 and steam injections with mean recovery factor of 0.41 and 0.33 respectively (*Tables 9 &10*). However, in *Table 9*, the confidence indices of 0.12 and 0.19 are poor and indicate that the reservoirs in the cluster analyses do not have similar properties to the Brage field, and therefore miscible CO_2 and steam injections might not be successful in the Brage field. However, as shown in *Table 10*, CO_2 injection under miscible conditions at 50^{o}C can lead to a recovery factor of 0.33, with a confidence index is 0.67.

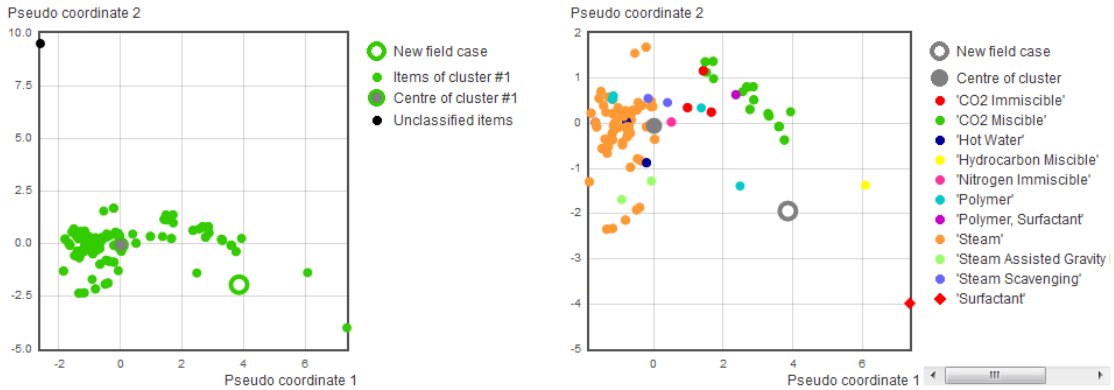


Figure 13: Results of cluster analysis with (a) number of clusters and (b) possible EOR/IOR methods for the Brage field (new field case) at 98^{o}C.

Table 9: Possible IOR/EOR methods with estimated recovery factors and confidence indices for the Brage field at 98^{o}C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Steam	8	0.41	Poor	0.19	0.09
2	CO2 Miscible	8	0.31	Poor	0.12	0.07
3	Hydrocarbon Miscible	1	0.66	Poor	0.47	0.82
4	Hot Water	5	0.48	n/a	0.12	9.41E-3
5	Nitrogen Immiscible	2	0.83	n/a	0.07	6.66E-3
6	Polymer	6	0.19	n/a	0.02	2.06E-3
7	Steam Scavenging	2	0.33	n/a	6.22E-3	9.37E-4
8	CO2 Immiscible	6	0.19	n/a	5.77E-3	2.62E-3
9	Polymer, Surfactant	1	0.04	n/a	6.13E-4	1.57E-4

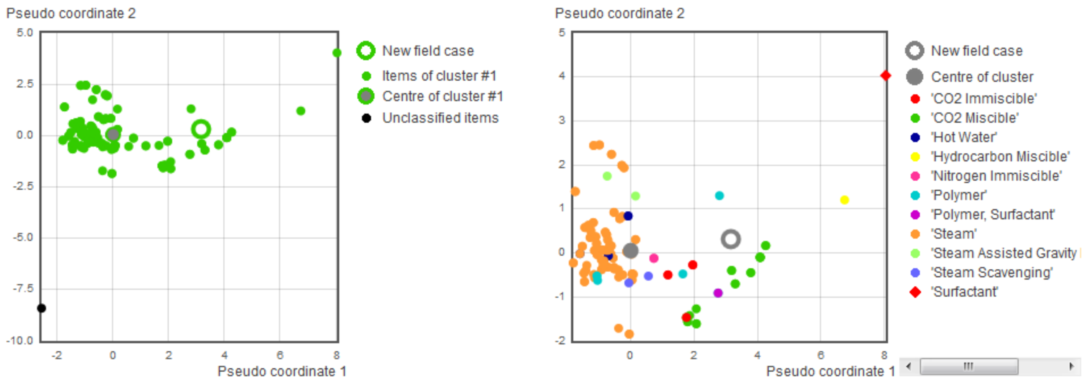


Figure 14: Results of cluster analysis with (a) number of clusters and (b) possible EOR/IOR methods for the Brage field (new field case) at 50°C.

Table 10: Possible IOR/EOR methods with recovery factors and confidence indices estimated for the Brage field at 50 °C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	CO2 Miscible	8	0.33	Good	0.67	0.26
2	Hydrocarbon Miscible	1	0.66	Poor	0.16	0.57
3	Polymer	6	0.26	Poor	0.06	0.07
4	Nitrogen Immiscible	2	0.83	Poor	0.05	0.02
5	Steam	8	0.59	n/a	3.95E-3	0.06
6	Hot Water	5	0.50	n/a	0.03	1.62E-3
7	Steam Scavenging	2	0.33	n/a	0.02	7.58E-3
8	CO2 Immiscible	6	0.20	n/a	3.01E-3	4.01E-3
9	Steam Assisted Gravity Drain	2	0.46	n/a	6.89E-7	3.19E-7

4.3.5.2 Performance prediction – Brage field

Based on the results of the cluster analysis, analytical simulations were performed to predict the effect of gas-based and water-based EOR on oil recovery in the Brage field. The following methods were evaluated; CO_2, hydrocarbon gas, surfactant, polymer, and a combination of surfactant followed by polymer flood. *Tables 11 & 12* show the reservoir and fluid properties used in the screening process.

Table 11: Reservoir and fluid properties defined for the Brage field

Injection to production well distance: 1000.00 m	Oil viscosity: 0.91 cp	Production well bottomhole pressure: 165.00 bar
Reservoir width: 2137.00 m	Oil density: 843.00 kg/m3	Pressure drop from injection to production well: 100.00 bar
Dip: 1.00 deg	Oil formation volume factor: 1.19	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	1000.00	5000.00	0.20	0.26	25.00	0.65
2	10.00	100.00	0.10	0.21	25.00	0.70
3	1000.00	5000.00	0.20	0.26	25.00	0.65

Table 12: Water properties and properties of reservoir layers defined for Brage field

Water viscosity	Water density	Water formation volume factor	Water injection rate
1.00 cp	1020.00 kg/m3	1.00	1.40E04 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.35	0.75	0.35	0.75
2	0.30	0.80	0.30	0.80
3	0.35	0.75	0.35	0.75

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 292 bar
  - CO_2 163 bar
  - Initial reservoir pressure 215 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

Gas-based EOR processes in SWORD are simulated by specifying the miminium miscible pressure between the oil and the gas phase. A detailed description of the gas-models is given in the Appendix of the report. Built-in correlations in SWORD indicate that minimum miscible pressure (MMP) of 292 bar with HC-gas (with 70% methane) and 163 bar with CO_2 at 98°C. Residual oil saturation at miscibility conditions was set to 5%. *Figure 15* show the simulated oil recovery factors for water (base case), polymer, surfactant and a combination of polymer and surfactant floods for the Brage field. Compared to oil recovered with water flooding at 35.2 %, polymer flooding produces slightly more oil at 35.5% after 5000 days. Surfactant flooding will yield 72.0 % whiles a combined surfactant and polymer flood will produce 73.6 %. Results based on gas injection indicate that both CO_2 and hydrocarbon gas under miscible conditions will produce oil than water flooding.

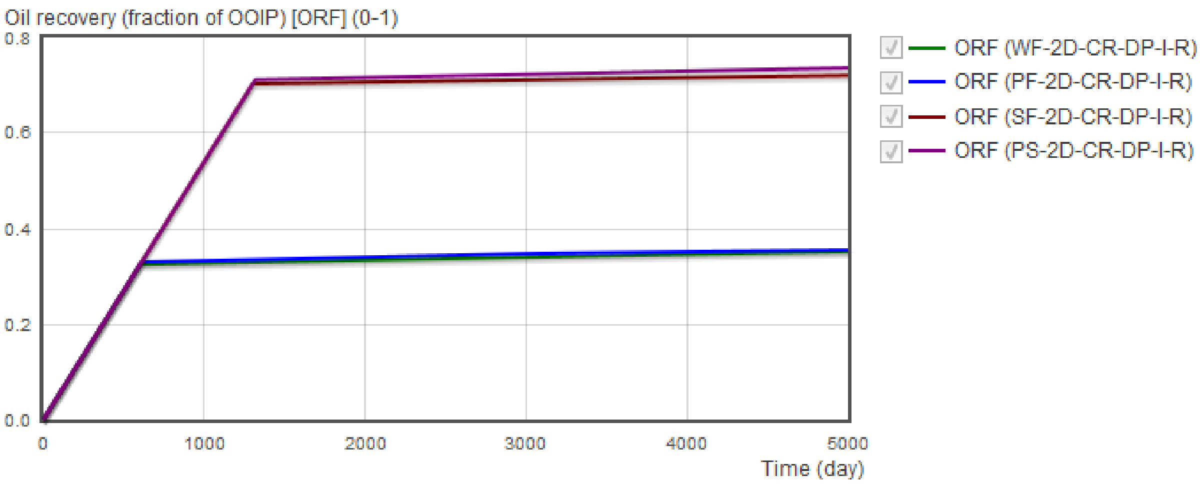


Figure 15: Simulated oil recovery factors (ORF) for WF-water, PF-polymer, SF-surfactant and PS-polymer/surfactant floods. The results are based on simplified 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR) for the Brage field

As shown in *Figure 16*, CO_2 flooding at miscible conditions will produce 47.2 % of oil compared 41.5% with hydrocarbon gas at miscible conditions. Injecting HC-gas at immiscible (*IG in Figure 16*) conditions will produce only 32.6% of OOIP compared to 35.2% with only water flooding. The high oil recovery factor with CO_2 may be due to the low MMP at which miscibility is formed.

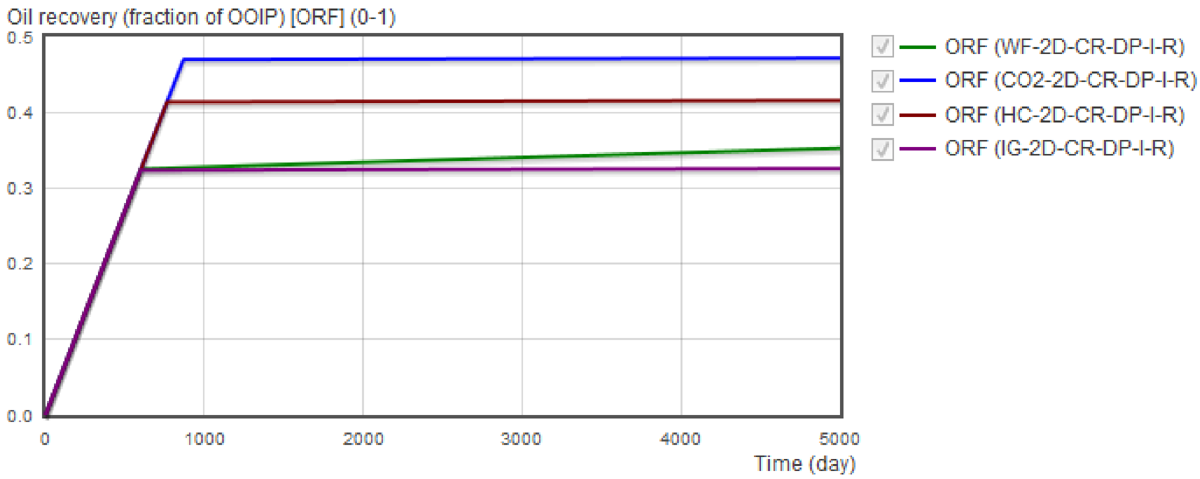


Figure 16: Simulated oil recovery factors (ORF) for CO_2 and HC-gas at miscible and immiscible (IG) conditions compared to WF-water for the Brage reservoir. The results are based on a simplified 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

According to Lien et al. (1998), the fluvial, Lower Jurassic Statfjord formation of the Brage field consists of 1000 to 4000 mD sandstone reservoir, with excellent vertical and lateral communication properties. A recovery of approximately 64 % was expected from water flooding the highly under saturated 36 API oil. The shallow marine Fensfjord formation, of Middle Jurassic Age, is a stratified sandstone reservoir with average zone permeabilities in the range of 1 to 200 mD. Calcite layers and high permeability strikes, with up to 5000 mD permeability, amplify the heterogeneity and complexity of the reservoir. The oil has similar properties as in Statfjord, but a recovery of only about 32 % was expected. The principal recovery mechanism is aquifer support aided by water injection from the flanks. A water-alternating-gas (WAG) injection pilot was established in the Fensfjord reservoir in 1994. Following a successful one-year pilot, emphasize has been placed on performance monitoring through the use of tracers and mapping of high permeability streaks. Since 2013, the WAG process has been gradually expanded to include more injectors. A pilot project for microbial EOR (MEOR) started in the Fensfjord reservoir in 2014. Brage has been producing 1993, and work is still ongoing to find new ways of increasing recovery from the field (NPD fact pages, 2015).

4.3.6 EOR screening for Draugen field

Draugen is an oil field in the Norwegian Sea. It currently has an oil recovery factor of 64.4 % and lies at a water depth of 250 metres. Draugen is developed with both platform and subsea wells, producing in the Garn West and Rogn South reservoirs. The main reservoir is in Rogn Formation sandstones of Late Jurassic age. The field also produces from the Garn Formation of Middle Jurassic age in the western part of the field. The reservoirs lie at a depth of about 1600 metres and are relatively homogeneous, with good reservoir characteristics. The field is produced by pressure maintenance from water injection and aquifer support. *Figure 17a* show the current reserves, an original oil in-place (OOIP) of 224.4 millSm^3 (60 %) with original recoverable oil of 144.4 mill Sm^3 (38%). The remaining oil reserves is 7.5 millSm^3 (2%). The current oil recovery for the field is 64.4 % with a water-cut approaching 80% as at the end of 2015 (*Figure 17b*). *Figure 17b* show the net-oil produced in millSm^3 and water-cut of 79.6 % as at the end of 2015. *Table 13* show input data for the Draugen field used in the screening process.

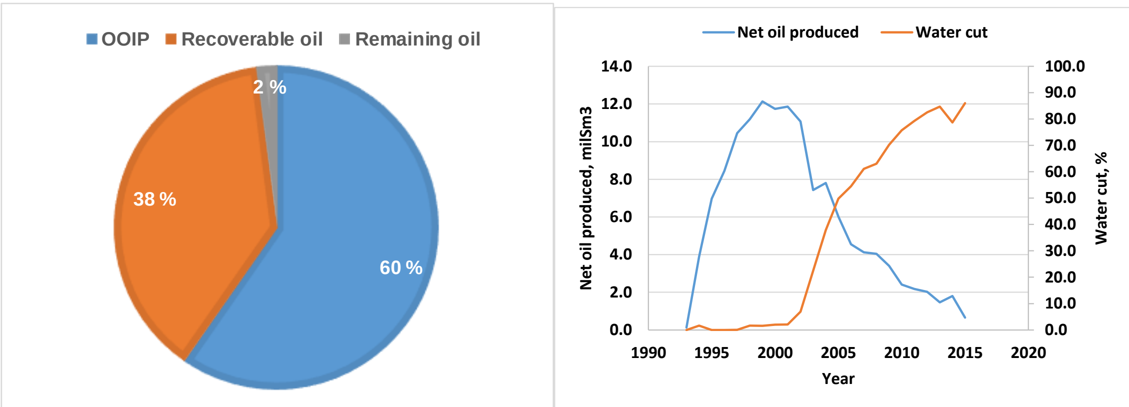


Figure 17: OOIP, recoverable and remaining reserves (b) current net oil produced millSm^3 and water-cut in percent as at the end of 2015 for the Draugen field (NPD fact pages, 2015).

Table 13: Field case input data for Draugen field

Parameter	Unit	Min	Max
Depth	m	1500	1600
Permeability	md	6000	7000
Thickness	m	0	46
Temperature	Celsius	50	71
Oil viscosity	cp	0.5	0.68
Pressure	bar	150	165
Oil density	kg/m3	800	824
Anisotropy (kv/kh)	(0-1)	0.6	0.7
Clay content	(0-1)	0	10
Salinity	g/l	35	37.5
Curr/init oil saturation	(0-1)	0.3	1
High/low perm. ratio		1	100

4.3.6.1 Recovery factor estimation – Draugen field

The Draugen oil is highly under-saturated with an initial hydrostatic pressure of 165 bar (SPOR Monograph, 1992). The reservoir and fluid properties used in the recovery factor estimation are as listed in *Table 14*. The porosity in the field ranges from 28 to 32 %, and permeability ranges up to 30 Darcy with an average of 5 Darcy.
The results of the cluster analysis are as shown in *Figures 18 & 19*. *Tables 15 & 16* show the possible EOR methods which can be applied in the Draugen field. Both tables indicate that gas-based methods have the potential to improve oil recovery in Draugen field. Varying the temperature between 50-71°C can influence the type of EOR method which can be applied (see *Figures 18 & 19*).

Table 14: Field case parameters used in the cluster analysis

Porosity (frac)	Permeability (mD)	Depth (m)	Oil gravity (kg/m³)	Oil viscosity (cP)	Oil temperature (°C)
0.28-0.32	1000-7000	1600	824	0.68	50-71

Figures 18&19 show that for most the cases in the database, the closet EOR methods applicable in the Draugen field are polymer followed by miscible and immisble CO_2 and hydrocarbon gases. The mean interpolated recovery factors with CO_2 and hydrocarbon miscible gas ranged between 0.33–0.66 (*Tables 15&16*). However, the confidence indices are rather poor indicating that number of cases used in the interpolation are low.

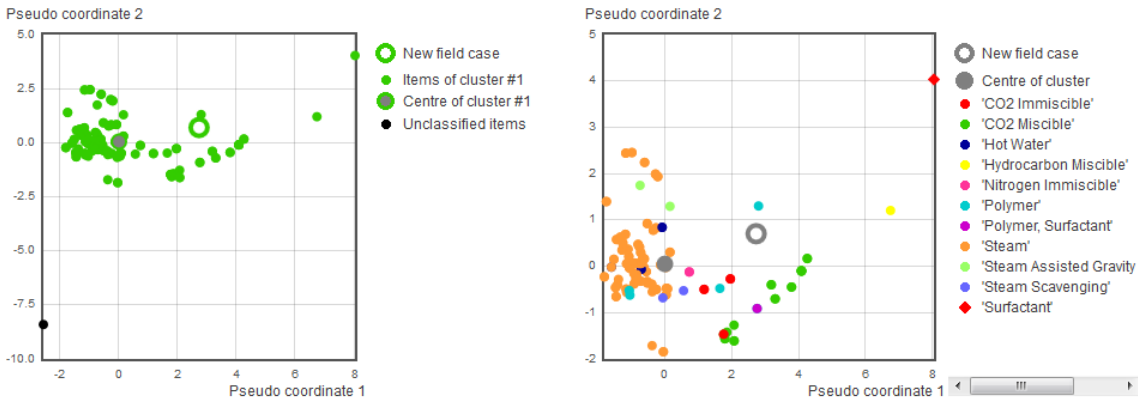


Figure 18: Results of cluster analysis showing possible EOR/IOR methods for the Draugen field at 71°C

Table 15: Possible IOR/EOR methods with interpolated recovery factors and confidence indices estimated for the Draugen field at 71°C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	CO2 Miscible	8	0.35	Poor	0.02	0.02
2	Hydrocarbon Miscible	1	0.66	Poor	0.90	0.94
3	Nitrogen Immiscible	2	0.83	Poor	0.03	0.02
4	Steam	8	0.56	n/a	6.07E-3	0.02
5	Hot Water	5	0.49	n/a	0.04	2.82E-3
6	Steam Scavenging	2	0.33	n/a	3.28E-3	1.39E-3
7	Polymer	6	0.24	n/a	2.11E-3	8.34E-4
8	CO2 Immiscible	6	0.17	n/a	2.64E-4	4.38E-4
9	Polymer, Surfactant	1	0.04	n/a	9.34E-6	3.10E-5

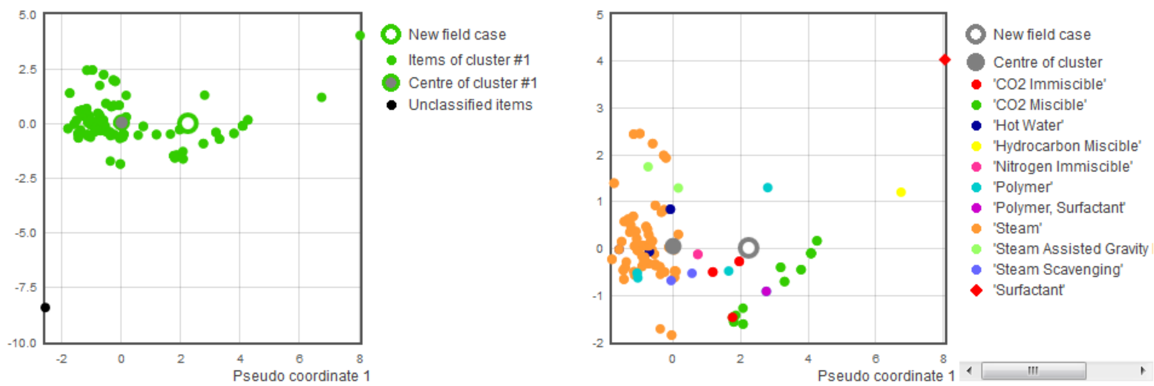


Figure 19: Results of cluster analysis showing (a) number of clusters and (b) possible EOR/IOR methods for the Draugen field (new field case) at 50°C

Table 16: Possible IOR/EOR methods with recovery factors and confidence indices estimated for the Draugen field at 50°C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	CO2 Miscible	8	0.33	Poor	0.17	0.05
2	Hydrocarbon Miscible	1	0.66	Poor	0.63	0.90
3	Nitrogen Immiscible	2	0.83	Poor	0.07	0.03
4	Steam	8	0.64	n/a	3.25E-3	0.02
5	Hot Water	5	0.51	n/a	0.08	1.62E-3
6	Steam Scavenging	2	0.33	n/a	0.02	2.99E-3
7	Polymer	6	0.26	n/a	0.01	4.58E-3
8	CO2 Immiscible	6	0.17	n/a	7.86E-4	7.00E-4
9	Polymer, Surfactant	1	0.04	n/a	8.69E-7	1.33E-6

4.3.6.2 Performance prediction-Draugen field

The main oil-bearing formation is the Upper Jurassic Rogn which is a generally high quality reservoir consisting of an upwards coarsening sand sequence (Langaas et al. 2007). The Garn is oil-bearing to the west of the platform (Garn West) but is water-bearing over the rest of the field forming a regionally active aquifer. Both sands were deposited in a coastal, predominantly shore face setting. The field has been water flooded since coming on production in 1984. Pressure has been maintained by water injection from the north (NWIT) and the south (SWIT) of the Rogn Main area and also from the active aquifer situated in the Garn formation. Reservoir and fluid are shown in *Tables 17 & 18* were used in the evaluating water and gas based EOR process in the Draugen field.

Table 17: Reservoir and fluid properties defined the Draugen field

Injection to production well distance	Oil viscosity	Production well bottomhole pressure
1000.00 m	0.68 cp	165.00 bar
Reservoir width	**Oil density**	**Pressure drop from injection to production well**
1600.00 m	824.00 kg/m3	100.00 bar
Dip	**Oil formation volume factor**	**Injection and production well radius**
10.00 deg	1.19	1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	1000.00	2000.00	0.50	0.32	25.00	0.70
2	100.00	1000.00	0.10	0.32	25.00	0.80
3	1000.00	7000.00	0.14	0.32	25.00	0.70

Table 18: Water properties and properties of reservoir layers defined for Brage field

Water viscosity	Water density	Water formation volume factor	Water injection rate
1.00 cp	1020.00 kg/m3	1.00	1.40E04 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.30	0.90	0.30	0.90
2	0.20	0.90	0.20	0.90
3	0.30	0.90	0.30	0.90

Based on the results from the cluster analysis at reservoir temperature of 71°C (*Figures 18 &19*), water representing the base case, polymer, surfactant and a combined surfactant and polymer floods were simulated based on the field data from the Draugen field. As shown in *Figure 20*, water flooding only will produce 63.6 % compared to 59.1% of OOIP with polymer flooding. Surfactant and a combined surfactant/polymer flood will produce 91.4 % and 88.7 % of OOIP after 5000 days.

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 262 bar
  - CO_2 188 bar
  - Initial reservoir pressure 165 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

Built-in correlations in SWORD indicate that miscible with CO_2 and hydrocarbon gas (70% methane) and oil will occur at 188 bar and 262 bar at a resevoir temperature of 71°C. *Figure 21* show the results for the gas floods. Injecting CO_2 at miscible conditions will recovered close to 50.1 %, while hydrocarbon gas at miscible conditions recoveries 47.3 % and 42.9% at immiscible HC gas condition. Compared to water flooding, the oil recovery from both CO_2 and hydrocarbon gas at miscible conditions are low. The low recovery with gas can be attributed to gravity segregation or early breakthrough through the high permeable streaks of the reservoir. Dedicated laboratory experiments and reservoir simulation will be needed to confirm the EOR processes in the Draugen field.

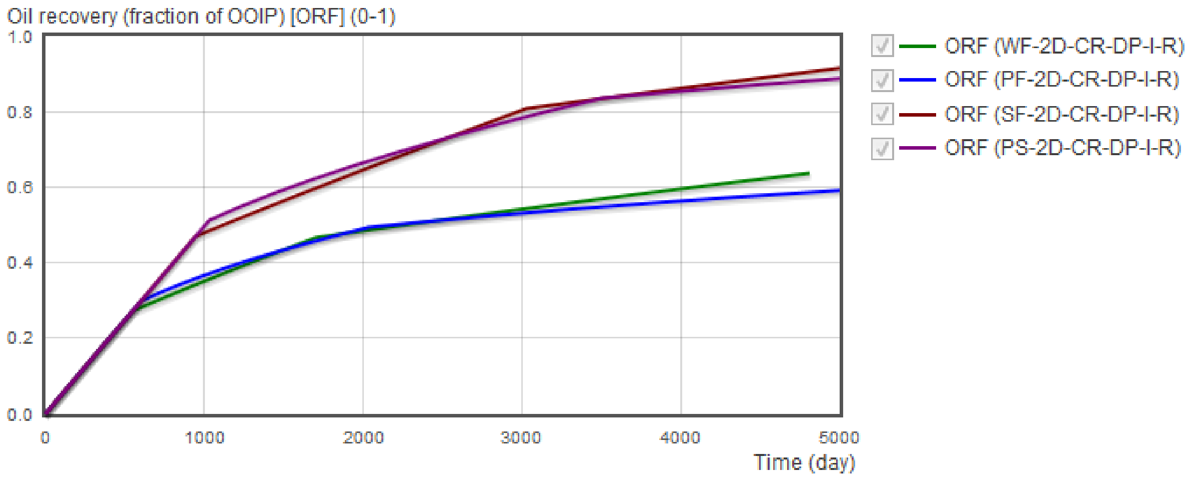


Figure 20: Simulated oil recovery factors (ORF) for WF-water, PF-polymer, SF-surfactant and PS-polymer/surfactant floods. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR) for the Draugen reservoir field.

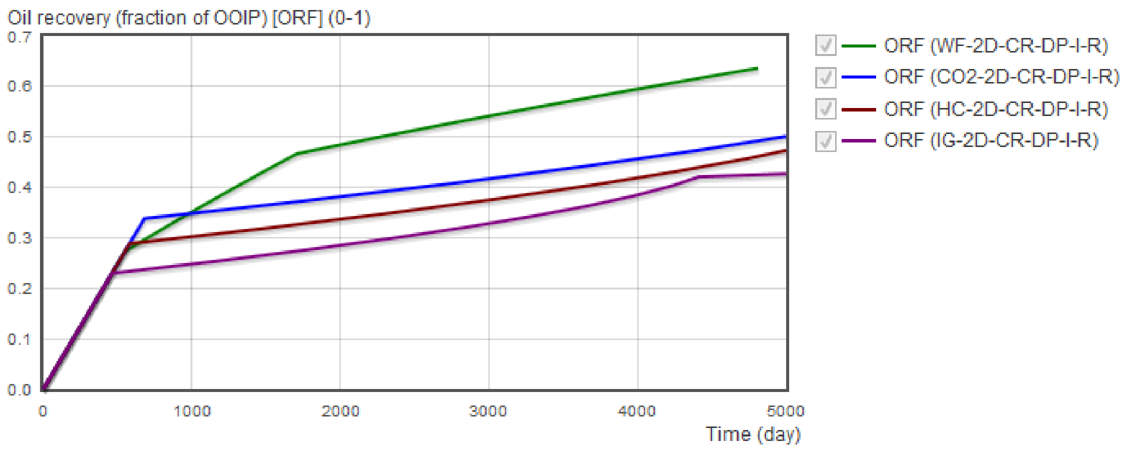


Figure 21: Simulated oil recovery factors (ORF) for WF-water, CO_2 and HC-gas at miscible and immiscible (IG) conditions. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR) for the Draugen reservoir field.

4.3.7 EOR screening for Grane field

Grane is an oil field located east of the Balder field in the central part of the North Sea. It was discovered in 1991 and came on stream in 2003. The water depth is 128 metres. The field consists of one main reservoir structure and some additional segments. The reservoir consists mostly of sandstones in the Heimdal Formation of Paleocene age with very good reservoir characteristics. The reservoir lies at a depth of approximately 1 700 metres, and there is full communication in the reservoir. The oil has high viscosity between 10-12 centipoise. The recovery mechanism is gas injection at the top of the structure, and horizontal production wells at the bottom of the oil zone. The current oil recovery factor is 65.3 %. The field has only limited water injection (*NPD fact pages, 2015*). Oil recovery is maintained by gas injection and drilling of wells, including deep side-tracks from existing producers. *Figure 22a* show the current reserves, an original oil in-place (OOIP) of 220 millSm^3 (54 %) with original recoverable oil of 143.7 mill Sm^3 (36%). The remaining oil reserves is 41.4 millSm^3 (10%). The current oil recovery for the field is 65.3 % with a water-cut approaching 53% as at the end of 2015. *Figure 22b* show the net-oil produced and water-cut as a function of time. *Table 19* show some of the reservoir and fluid properties in the Grane field published in the literature (SPOR Monograph, 1992; Skotner, 2005).

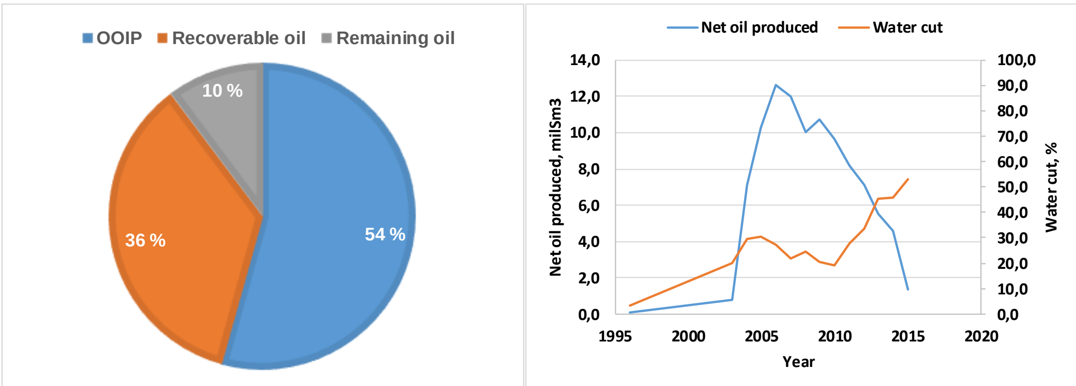


Figure 22: OOIP, recoverable and remaining reserves (b) current net oil and gas produced, water-cut in percent as at the end of 2015 for the Grane field (NPD fact pages, 2015)

Table 19: Field input data for Grane field

Parameter	Unit	Min	Max
Depth	m	1680	1765
Permeability	md	10000	1.20E04
Thickness	m	25	31
Temperature	Celsius	50	76
Oil viscosity	cp	10	12
Pressure	bar	150	176
Oil density	kg/m3	850	890
Anisotropy (kv/kh)	(0-1)	0.01	1
Clay content	(0-1)	0	0.05
Salinity	g/l	30	35
Curr/init oil saturation	(0-1)	0.3	0.7
High/low perm. ratio		1	200

4.3.7.1 Recovery factor estimation–Grane field

As stated above, the sandstones in the Grane field show excellent reservoir properties with permeabilities commonly in the 5 to 10 D range, and an average porosity of 33 %. The oil density of 19 API (0.984 g/cc) and a viscosity of 10-12 cP makes Grane oil among the heaviest oils in the Norwegian Sea (Tipura et al. 2013). Reservoir and fluid properties used in the recovery factor estimation are as listed in *Table 20.*

Table 20: Field data defined for the Grane field

Porosity (frac.)	**Permeability (D)**	**Depth (m)**	**Oil gravity (kg/m³)**	**Oil viscosity (cP)**	**Oil temperature (°C)**
0.33	5-10	1680-1765	984	10-12	50-80

The results of the cluster analyses are as shown in *Figures 23 & 24*. As shown there is no effect of varying temperature on the type of EOR method. Based on the viscosity of the oil, results show that gas based IOR/EOR has the potential to be used at the Grane field. *Tables 21& 22* indicate that for most the cases in the databases, the closest methods are gas-based EOR method. Steam gives an interpolated recovery factor of 0.11. As shown the confidence level is good. Other possible methods are hot water, polymer, immiscible nitrogen and steam assisted gravity drainage with poor confidence levels.

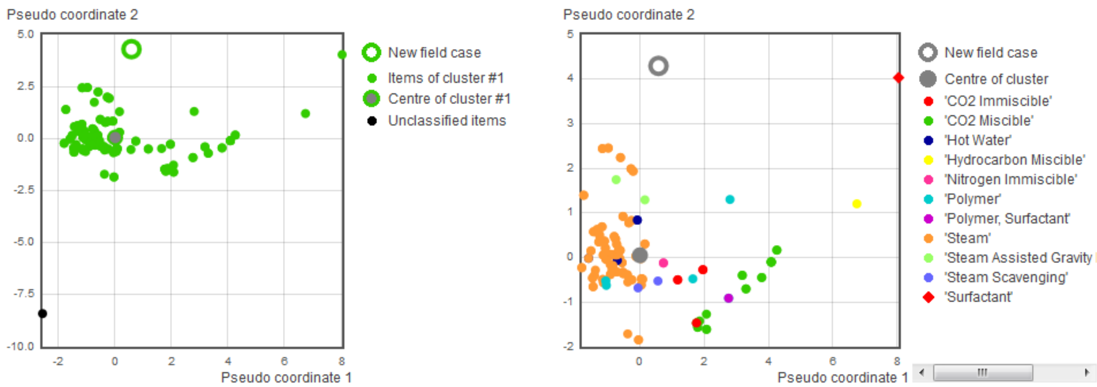


Figure 23: Results of cluster analysis showing (a) number of clusters and (b) possible EOR/IOR methods for the Grane field (new field case) at 80°C

Table 21: Possible EOR methods with interpolated recovery factors and confidence indices estimated at 80°C for the Grane field

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Steam	8	0.11	Good	0.77	0.88
2	Hot Water	5	0.47	Poor	0.09	0.06
3	Polymer	6	0.29	Poor	0.04	0.01
4	Nitrogen Immiscible	2	0.83	Poor	0.04	0.01
5	Steam Assisted Gravity Drain	2	0.45	Poor	0.02	0.04
6	CO2 Miscible	8	0.29	n/a	0.02	6.09E-3
7	CO2 Immiscible	6	0.19	n/a	6.73E-3	1.13E-3
8	Steam Scavenging	2	0.33	n/a	4.95E-3	1.04E-3
9	Hydrocarbon Miscible	1	0.66	n/a	5.57E-4	3.57E-5

At 50°C, steam is still the best EOR method with CO_2 miscible and polymer as possible EOR methods. The mean recovery factors with CO_2 and hydrocarbon gas at miscible conditions are 0.35 and 0.66 respectively (*Table 22*).

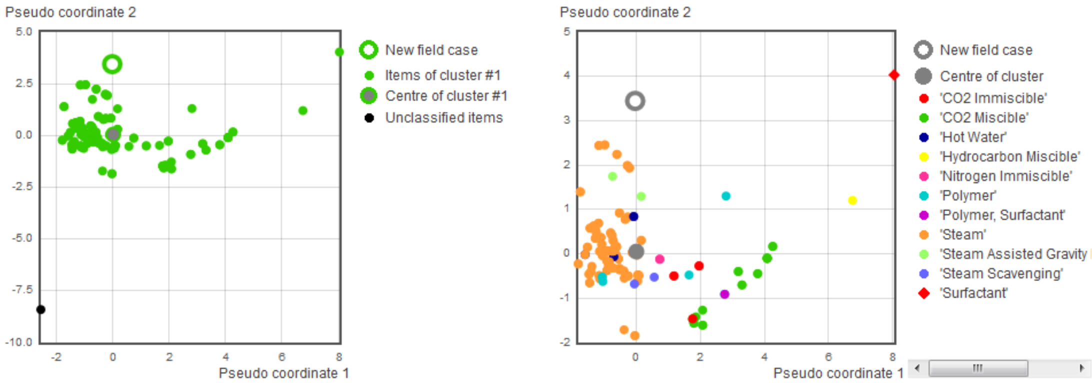


Figure 24: Results of cluster analysis showing (a) number of clusters and (b) possible EOR/IOR methods for the Grane field (new field case) at 50°C

Table 22: Possible IOR/EOR methods with interpolated recovery factors and confidence indices estimated for the Grane field at 50°C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Steam	8	0.11	Good	0.52	0.85
2	CO2 Miscible	8	0.33	Poor	0.25	0.02
3	Polymer	6	0.36	Poor	0.12	0.09
4	Nitrogen Immiscible	2	0.83	Poor	0.05	0.01
5	Hot Water	5	0.49	Poor	0.05	0.02
6	Steam Scavenging	2	0.33	n/a	4.35E-3	2.16E-3
7	CO2 Immiscible	6	0.19	n/a	3.39E-3	1.38E-3
8	Steam Assisted Gravity Drain	2	0.45	n/a	3.21E-3	2.12E-3
9	Hydrocarbon Miscible	1	0.66	n/a	2.83E-3	9.43E-6

4.3.7.1 Performance prediction-Grane field

The original conditions were a relatively low pressure of 176 bar and a temperature of 80°C, with no free gas. The pressure is now depleted to 140 bar. *Table 23* show the reservoir and fluid properties used in the performance prediction modelling.

Table 23: Reservoir and fluid properties defined for Grane field

Injection to production well distance: 1000.00 m	Oil viscosity: 10 cp	Production well bottomhole pressure: 165.00 bar
Reservoir width: 1765.00 m	Oil density: 984.00 kg/m3	Pressure drop from injection to production well: 100.00 bar
Dip: 0.00 deg	Oil formation volume factor: 1.07	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	1000.00	5000.00	0.20	0.33	25.00	0.90
2	1000.00	1000.00	1.00	0.33	25.00	0.85
3	1000.00	5000.00	0.20	0.33	25.00	0.90

Table 24: Reservoir and water properties

Water viscosity	Water density	Water formation volume factor	Water injection rate
1.00 cp	1020.00 kg/m3	1.00	1.40E04 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.10	0.90	0.10	0.90
2	0.15	0.90	0.15	0.90
3	0.10	0.90	0.10	0.90

Based on the results from the cluster analysis (*Figures 23&24*), water flooding representing the base case, polymer, surfactant and a combined surfactant and polymer flood were simulated based for the Grane field. As shown in *Figure 25*, water flooding only will recover 65.3 % compared to 74.5 % with polymer at the end of 5000 days. Surfactant and a combined surfactant/polymer flood produce 73.0 % and 82.3 % of OOIP after 5000 days. The high recovery with polymer flooding could be due an increase in the water viscosity leading to the improvement of mobility control. Thus, due to the far greater water mobility compared to the heavy oil it is important to achieve matrix injection rather than fracture injection to ensure a good sweep. In order words, the polymer is expected to reduce fracture flow and divert the water into the matrix sandstone blocks. The high oil recovery with polymer could also be due to the reduction in water fingering caused by the high oil viscosity of the Grane oil.

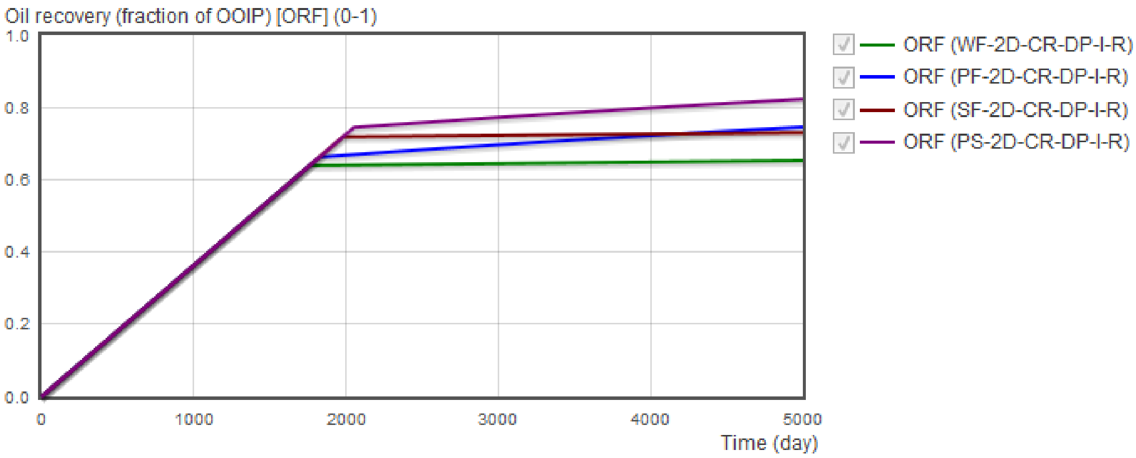


Figure 25: Simulated oil recovery factors (ORF) for WF-water, CO_2 and HC-gas at miscible conditions. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR) for the Grane field.

Tipura et al. (2013) observed that injecting produced water from Well G-32 of the Grane field improved oil recovery. They attributed the improved oil recovery to small amount of oil and particles (in produced water), which can easily be transported through the high permeable zones, but tend to plug the pores in the matrix and thereby reduce the injectivity. However, they observed that it is particularly challenging to do long term matrix injection with produced water, and extensive water cleaning prior to re-injection is often required.

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 288 bar
  - CO_2 208 bar
  - Initial reservoir 165 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

Based on in-built correlations in SWORD, the MMP between CO_2 and hydrocarbon gas (70 % methane) and Grane oil was estimated as 208 bar and 288 bar at a reservoir temperature of 76^{o}C. This is atypical since Grane oil is heavy and is not expected to be miscible with CO_2 at the current Grane reservoir pressure and temperature conditions. Oil recovery with hydrocarbon gas under immiscible (IG) Grane reservoir conditions were also simulated. *Figure 26* show the results for the gas floods compared to present day water flooding with a recovery of 65.3 %. Injecting CO_2 at miscible conditions will recovered close to 65.8 % of OOIP. Hydrocarbon gas at miscible conditions will recovery 63.3 % of OOIP at the end of 5000 days. At immiscible gas conditions, 59.8 % of OOIP can be recovered. Skotner (2005) used reservoir simulations and observed that inspite of the development of immiscibility between CO_2 and the heavy Grane oil, favourable reservoir conditions such as gravity stable displacement and large swelling effect, oil recovery with CO_2 injection can exceed present water flooding and can be similar to the oil recovery with hydrocarbon gas. PVT experiments indicated that CO_2 can dissolve in the oil and increase its volume by 16 %, and decrease the crude oil viscosity from 10 cP to 2 cP, a reduction of 80 % (Skotner, 2005).

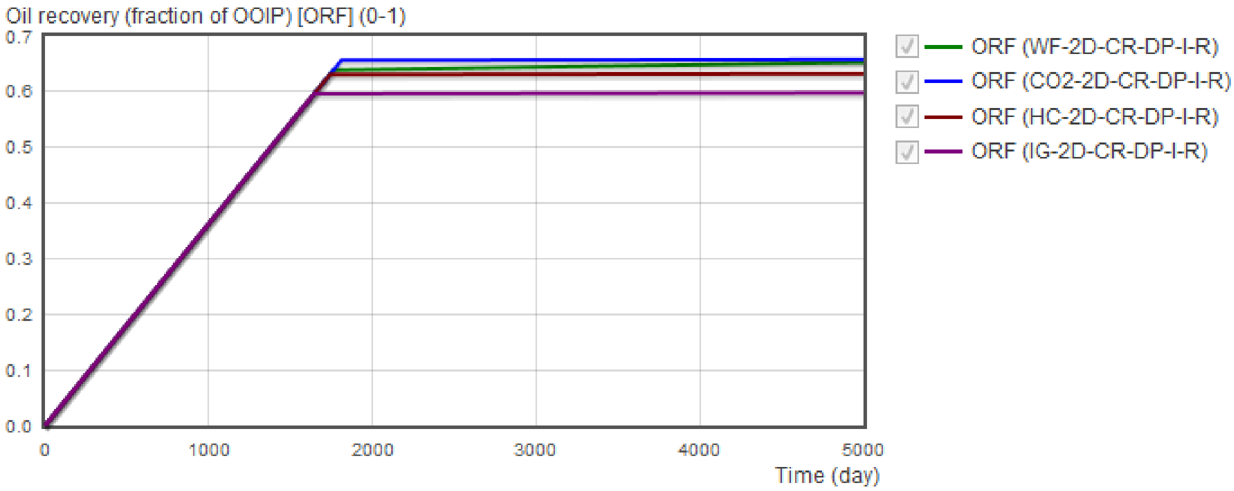
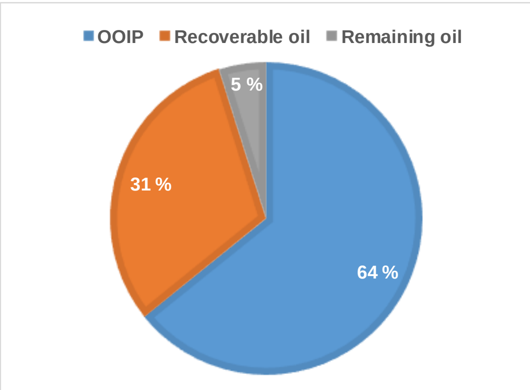


Figure 26: Simulated oil recovery factors (ORF) for WF-water, CO_2, HC-gas at miscible conditions and IG-immisble HC-gas. The results are based on simplified 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR) for the Grane field.

4.3.8 EOR screening for Ekofisk field

Ekofisk is the largest chalk field in the southern part of the North Sea. The water depth in the area is 70-75 metres. The field is naturally fractured chalk and produces from the Ekofisk and Tor Formations of Early Palaeocene and Late Cretaceous ages. The reservoir rocks have high porosity, but low permeability. The reservoir has an oil column of more than 300 metres and lies 2900-3250 metres below sea level. Ekofisk was originally produced by natural pressure depletion and had an expected recovery factor of 17 %. Since then, comprehensive water injection has contributed to a substantial increase in oil recovery. Large-scale water injection started in 1987.

Experience has proven that water injection displaces the oil more effectively than anticipated, and the expected recovery factor for Ekofisk is now approximately 48.1 % at the end of 2015. Water flooding is expected to continue until 2028. In addition to water injection, compaction of the soft chalk provides extra force to drainage of the field. The reservoir compaction has resulted in subsidence of the seabed, which is close to 10 metres in the central part of the field. It is expected that the subsidence will continue, but at a lower rate. As at the end of 2015, OOIP was estimated as 1134.2 millSm3 (64%) with an original recoverable oil of 545.6 millSm^3 (31%). *Figure 27a* show the recent reserves including the remaining oil reserves of 86.5 % (5 %). *Figure 27b* show the net-oil produced with a water-cut of 70.7 %. *Table 25* show some of the reservoir and fluid properties in the Ekofisk field published in the open literature (Knappskog, 2012) and the SPOR Monograph (1992).



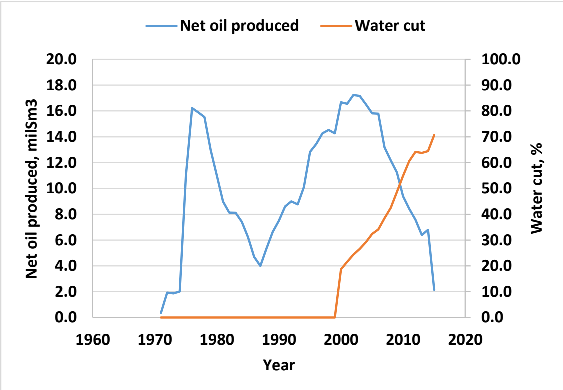


Figure 27: OOIP, recoverable and remaining reserves (b) current net oil produced and water-cut in percent as a function of time for the Ekofisk field (NPD fact pages, 2015)

Table 25: Reservoir and fluid data for Ekofisk field

Parameter	Unit	Min	Max
Depth	m	2900	3250
Permeability	md	1	150
Thickness	m	85	170
Temperature	Celsius	55	70
Oil viscosity	cp	0.68	1
Pressure	bar	340	497
Oil density	kg/m3	800	838
Anisotropy (kv/kh)	(0-1)	0.025	0.1
Clay content	(0-1)	0	0.05
Salinity	g/l	50	75
Curr/init oil saturation	(0-1)	0.25	0.75
High/low perm. ratio		1	10

4.3.8.1 Recovery factor estimation-Ekofisk field

Figures 28 and 29 show the results of the cluster analyses based on the reservoir and fluid properties in *Table 26*. Results show that there are not enough high temperature field cases in the databases (*Figures 28 & 29*). However, in the main field at high temperature of 130°C, combustion seems to the most probable EOR method applicable on the Ekofisk field (*Table 28*). The results (*Tables 27 & 28*) indicate that temperature can affect the type of methods applicable on the Ekofisk field. At low temperatures, near the injector wells where there has been extensive cooling due water injection, results indicate that CO_2-EOR at miscible conditions at 65°C can lead to a recovery factor of 0.65 with a confidence index of 1.0 (*Table 27*).

Table 26: Field input data used in recovery factor estimation

Porosity (frac)	Permeability (mD)	Depth (m)	Oil gravity (kg/m³)	Oil viscosity (cP)	Oil temperature (°C)
0.45	1-150	3250	838	0.68	65-130

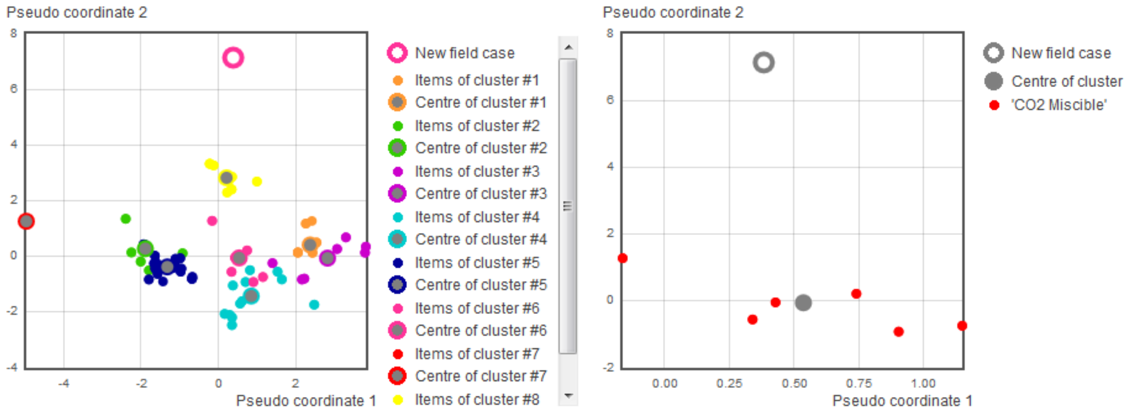


Figure 28: Results of clusters analysis showing (a) number clusters and (b) possible EOR method for the Ekofisk field at 65°C

Table 27: Possible IOR/EOR methods with interpolated recovery factors and confidence indices estimated for the Ekofisk field at 65°C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	CO2 Miscible	8	0.65	Good	1.00	1.00

Table 28: Possible IOR/EOR methods with interpolated recovery factors and confidence indices estimated for the Ekofisk field at 130°C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Combustion	8	0.59	Good	1.00	1.00

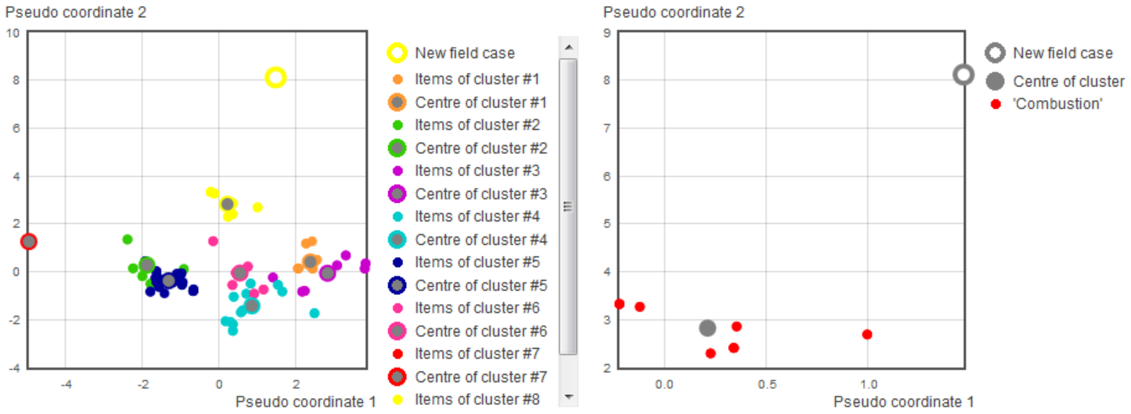


Figure 29: Results of clusters analysis showing (a) number clusters and (b) possible EOR method for the Ekofisk field at 130°C

4.3.8.2 Performance prediction-Ekofisk field

Based on the current oil recovery factor of almost 50 % at Ekofisk field, 3 three reservoir layers with a thickness of 25 m reach were defined as shown in *Tables 29 & 30*. The first and third layers were assigned the similar properties, whiles the third layer simulated a matrix block.

Table 29: Reservoir properties defined for Ekofisk Field

Injection to production well distance: 1000.00 m	Oil viscosity: 0.68 cp	Production well bottomhole pressure: 165.00 bar
Reservoir width: 3290.00 m	Oil density: 838.00 kg/m3	Pressure drop from injection to production well: 100.00 bar
Dip: 0.00 deg	Oil formation volume factor: 1.07	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	1.00	100.00	0.01	0.45	25.00	0.75
2	1.00	10.00	0.10	0.45	20.00	0.80
3	1.00	100.00	0.01	0.45	25.00	0.75

Table 30: Water properties and water-oil data used for the Ekofisk field

Water viscosity	Water density	Water formation volume factor	Water injection rate
1.00 cp	1020.00 kg/m3	1.00	1.40E04 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.25	1.00	0.25	1.00
2	0.20	1.00	0.20	1.00
3	0.25	1.00	0.25	1.00

Numerical simulations show that water flooding (base case) will produce 48.4 % compared to 52.2 % with polymer flooding at end of 5000 days (*Figure 30*). Polymer flooding has been shown to increase water viscosity and reduce fracture flow, and thereby divert water to the less swept zones in fractured reservoirs. Polymer flooding improves on the oil recovery after 2800 days. It is however, important that the polymer solution does not block the pores in the matrix and reduce the recovery of oil.

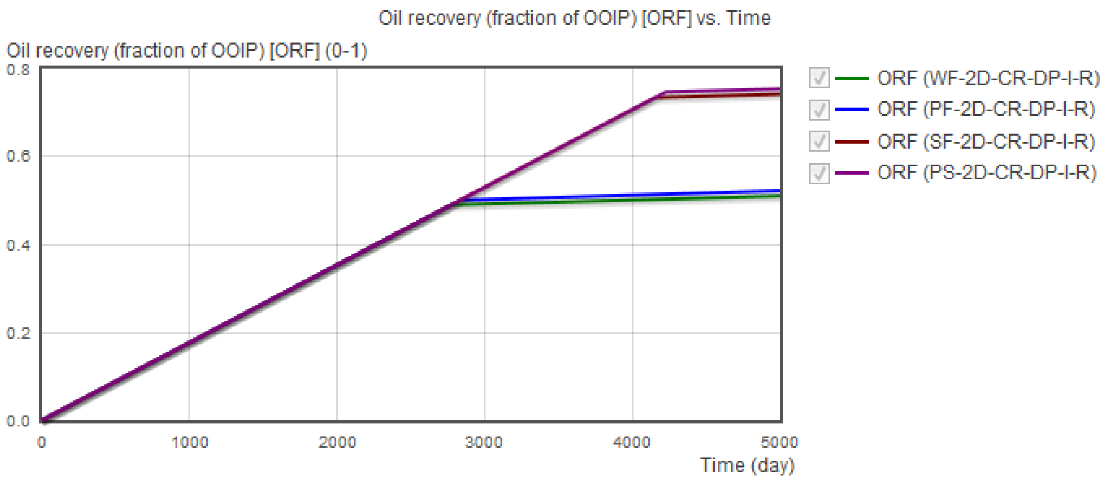


Figure 30:. Simulated oil recovery (ORF) based on water-based EOR methods (WF: water flooding; PF: Polymer flooding; SF: Surfactant flooding and PS; combined polymer/surfactant flooding) for the Ekofisk field at 130^{o}C. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR) for the Ekofisk field.

As shown in *Figure 31*, injecting surfactant solution resulted in an oil production of 74.2 %. A combined surfactant followed by a polymer injection recovered 74.4 % of OOIP.

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 436 bar
  - CO_2 322 bar
  - Initial reservoir pressure 400 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

In-built correlations in SWORD estimated the MMP between CO_2 and Ekofisk oil as 322 bar compared with 436 bar with HC-gas (with 70% methane) at 130^{o}C. Above the MMP, it possible for the gas phases to recover all the oil. The residual saturation at miscibility conditions was set to 5 % and maximum immiscibility pressure set to 100 bar. Injecting gases such as CO_2 and HC-gas at miscible conditions will improve on the oil recovery above water flooding (*Figure 31).* CO_2 recoveries the highest oil recovery after 3300 days at 53.3 %. HC-gas (with 70% methane gas) recovers 50.5 % while immiscible gas recovers 45.1% at the end of 5000 days.
Several improved oil recovery techniques have been screened for application to increase the recovery above present-day water flooding on the Ekofisk field (Jensen et al. 2000). Air injection was evaluated to have a high potential for cost effective recovery of

additional oil (Stokka et. al. 2005) at reservoir conditions. HC-gas has been injected into the Ekofisk field since 1975 (Jakobsson et al. 1994). Laboratory and modelling studies indicate that the presence of natural fractures represents a medium for the injected gas phase to contact the oil in the matrix blocks. In addition to pressure support, some of the recovery mechanisms associated gas injection in the Ekofisk field with improved oil recovery include, viscous displacement, molecular diffusion, gravity drainage and vaporization/stripping of lighter components.

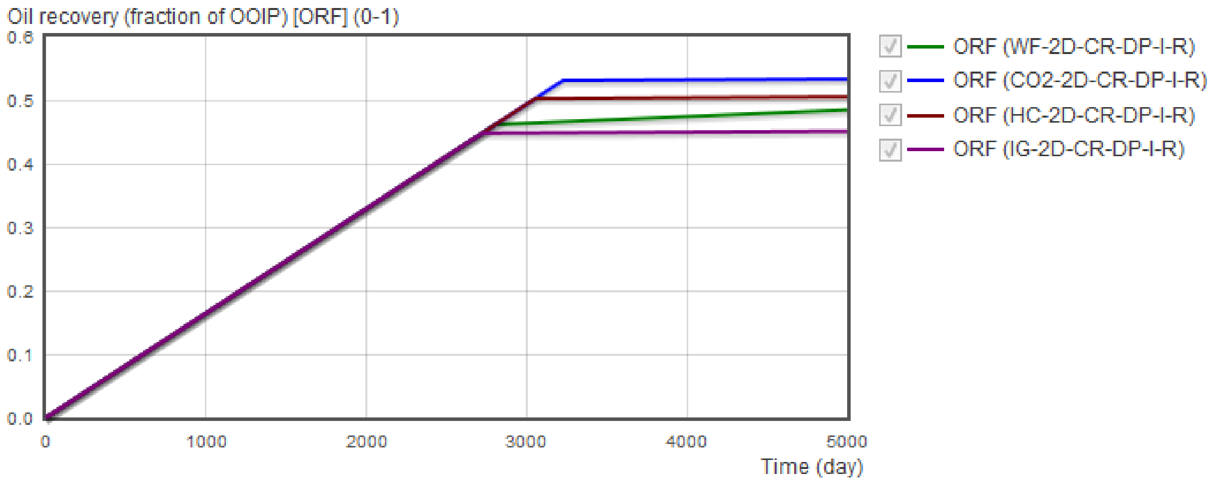


Figure 31. Simulated oil recovery (ORF) based on gas-based EOR methods; CO_2 and HC-hydrocarbon gas at miscible conditions and IG-HC-gas at immiscible conditions compared to water flooding (WF). The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR) for the Ekofisk field.

Due to high miscibility pressure between hydrocarbon gas and Ekofisk reservoir oil, Knappskog (2012) used simulation to investigate the effect of WAG on oil recovery. Mechanistic simulations indicated that trapped gas and residual oil saturation should be included in WAG modeling to avoid over prediction of recoveries for a WAG applications. Sector simulations showed incremental oil potential to the water flood case for all WAG scenarios considered. A WAG ratio of 1 to 2 gave the largest increase with 8.4 million BOE. Increasing WAG ratio showed decreasing oil recovery. A WAG slug size of 0.4 pore volumes was best with 4.4 million BOE incremental to the base case. WAG slug sizes showed decreasing potential with decreasing slug sizes.

4.3.9 EOR screening for Gullfaks field

Gullfaks is an oil field located in the Tampen area in the northern part of the North Sea. The water depth in the area is 130-220 metres. The reservoirs lie at a depth of 1 700-2 000 metres. The field consists of Middle Jurassic sandstones of the Brent Group, and Lower Jurassic and Upper Triassic sandstones of the Statfjord Group and Cook and Lunde Formations. Oil in the overlying Shetland Group and Lista Formation is also being recovered. The drive mechanism is primarily water injection, with gas injection and water/alternating gas injection (WAG) in some areas.

The Shetland/Lista reservoir is produced by controlled pressure depletion above the bubble point. The primary strategy for increased oil recovery on Gullfaks is optimized pressure support in the main reservoirs. Peak production was reached in 1994, followed by an immediate decline (*Figure 32b*). Since then, there has been a growing focus on increased oil recovery (lOR) methods. The effort has resulted in an increased recovery factor from expected 46 % at the time of production start in 1986 to 61 % in 2007. The goal is to end up with a recovery factor close to 70 % (Talukdar and Instedfjord, 2008).

Currently, the oil recovery is 47.6 %. Several different technologies have contributed to the good results, with the most important IOR techniques been time-lapse (4D) seismic, massive water circulation and water-alternating-gas injection. As at the end of 2015, OOIP was estimated as 792.6 millSm3 (67%) with an original recoverable oil of 377.0 millSm3 (32%). The remaining recoverable oil is estimated as 16.4 millSm^3 (1%) (see *Figure 32a)*. *Figure 32b* show the net-oil produced and water-cut as a function of time. The water-cut was estimated as 89.7 % at the end of 2015. *Table 31* show some of the reservoir and fluid properties in the Gullfaks field published in the open literature and the SPOR Monograph (1992).

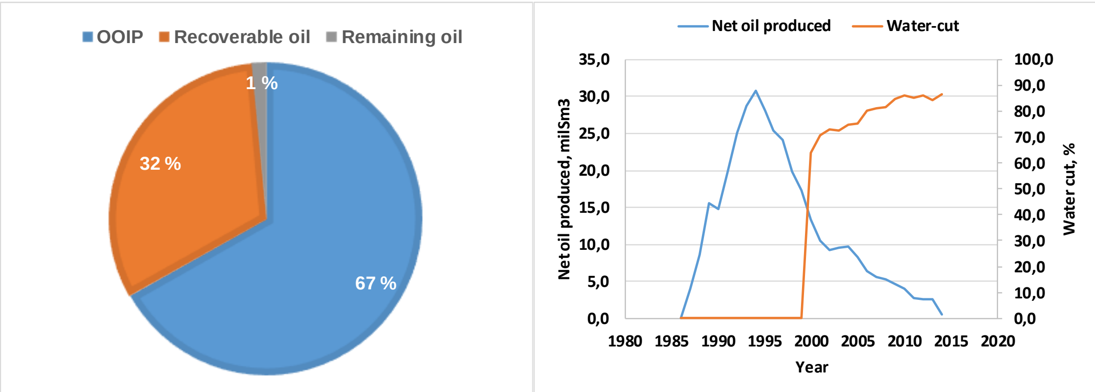


Figure 32: (a) OOIP, recoverable and remaining reserves (b) current net oil produced and water-cut in percent as a function of time for the Gullfaks field

Table 31: Reservoir and fluid data for Gullfaks field

Parameter	Unit	Min	Max
Depth	m	1740	2090
Permeability	md	550	10000
Thickness	m	35	110
Temperature	Celsius	70	80
Oil viscosity	cp	0.4	1.5
Pressure	bar	310	320
Oil density	kg/m3	838	844
Anisotropy (kv/kh)	(0-1)	0.2	0.9
Clay content	(0-1)	0.05	0.1
Salinity	g/l	20	42
Curr/init oil saturation	(0-1)	0.29	0.76
High/low perm. ratio		1	100

4.3.9.1 Recovery factor estimation-Gullfaks field

The Gullfaks field consists of three different formations namely Brent and underlying Cook, Lunde and Statfjord formations. The Brent group represents the major part of the producing formations. These reservoir properties (average porosity and permeability) in the formations varies greatly as show in *Table 32*.

Table 32: Reservoir properties defined for Brent, Cook and Statfjord formations of the Gullfaks field

Porosity (frac)	Permeability (mD)	Depth (m)	Oil gravity (kg/m^3)	Oil viscosity (cP)	Oil temperature (°C)	Formation
0.31	3200	1947	882	1.5	72	Brent
0.28	550	2090	860	0.43	80	Cook
0.27	1000	2028	865	0.40	80	Statfjord

The recovery estimation module in SWORD was used to determine possible EOR methods which could be applied at the Gullfaks field. Cluster analysis (*Figure 33*) were based on reservoir and fluid data in *Table 32*. Results indicate that CO_2 at miscible conditions can yield a recovery factor of 0.31 compared to 0.52 with steam injection for the Cook and Statfjord formations, and similarly for the Brent formation. Close inspection of cluster analyses (*Figures 33 & 34*) show polymer flood as potential EOR-method with interpolated recovery factors of 0.19 and 0.24 respectively. However, the confidence indices are low.

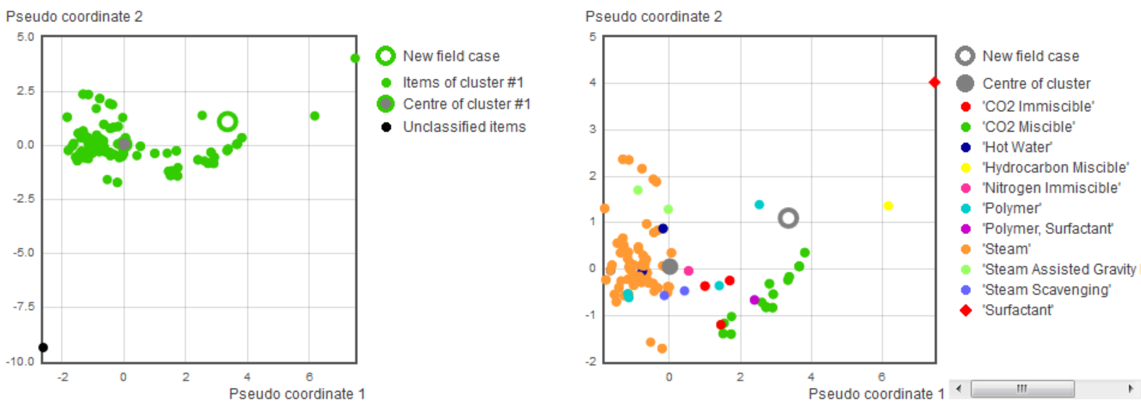


Figure 33: Results of clusters analysis showing (a) number of clusters and (b) possible EOR/IOR methods applicable for the Cook and Statfjord formations at 80°C

Table 33: Possible EOR/IOR methods for the Cook and Statfjord formations at 80°C

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	CO2 Miscible	8	0.31	Fair	0.28	0.43
2	Steam	8	0.52	Fair	0.16	0.42
3	Hot Water	5	0.48	Poor	0.19	0.03
4	Nitrogen Immiscible	2	0.83	Poor	0.14	0.03
5	Hydrocarbon Miscible	1	0.66	Poor	0.12	0.05
6	Polymer	6	0.19	Poor	0.06	0.02
7	CO2 Immiscible	6	0.19	Poor	0.02	0.02
8	Steam Scavenging	2	0.33	n/a	0.03	7.33E-3
9	Polymer, Surfactant	1	0.04	n/a	1.07E-3	2.75E-4

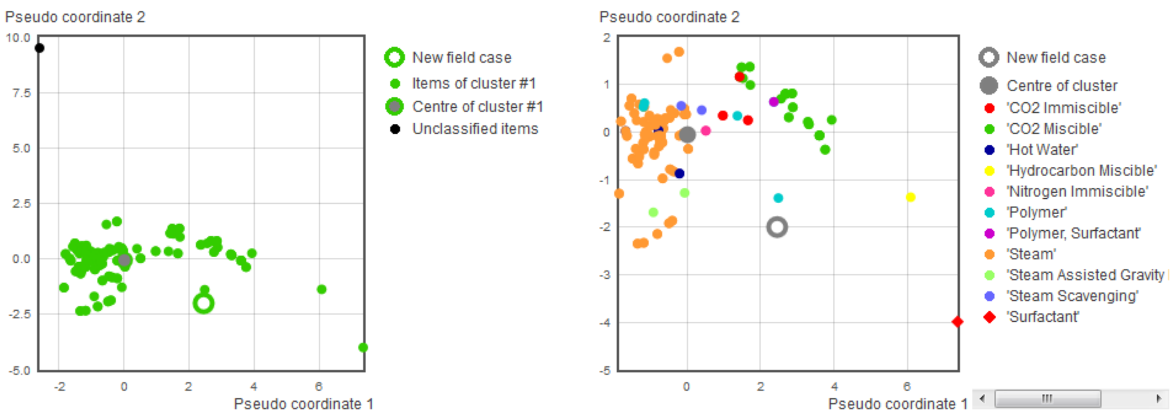


Figure 34: Results of clusters analysis showing (a) number of clusters and (b) possible EOR/IOR methods applicable for the Brent formation (new field case) at 80°C

Table 34: Possible IOR/EOR methods for the Brent formation

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Steam	8	0.20	Poor	0.03	0.15
2	CO2 Miscible	8	0.33	Poor	0.02	0.13
3	Hydrocarbon Miscible	1	0.66	Poor	0.94	0.69
4	Nitrogen Immiscible	2	0.83	n/a	8.65E-3	0.02
5	Hot Water	5	0.48	n/a	5.06E-3	0.01
6	Polymer	6	0.24	n/a	8.84E-4	3.74E-3
7	Steam Scavenging	2	0.33	n/a	1.13E-4	3.46E-4
8	Steam Assisted Gravity Drain	2	0.46	n/a	1.07E-4	1.79E-3
9	CO2 Immiscible	6	0.18	n/a	7.72E-5	6.75E-4

4.3.9.2 Performance prediction-Gullfaks field

The Gullfaks field has a reservoir pressure of 320 bar. The temperature varies between 72-80^{o}C in the three different formations. Reservoir and fluid used in the simulations are as shown in *Tables 35 & 36*. The oil has a viscosity of 0.4 -1.5 cP with an average oil formation factor of 1.37 at current field conditions. The simulations were based on the Brent formation.

Table 35: Reservoir and fluid properties defined for the Brent formation

Injection to production well distance: 1000.00 m	Oil viscosity: 1.5 cp	Production well bottomhole pressure: 165.00 bar
Reservoir width: 2090.00 m	Oil density: 844.00 kg/m3	Pressure drop from injection to production well: 100.00 bar
Dip: 10.00 deg	Oil formation volume factor: 1.37	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	100.00	1000.00	0.10	0.27	25.00	0.65
2	10.00	550.00	0.02	0.28	25.00	0.75
3	100.00	3200.00	0.03	0.31	25.00	0.65

Table 36: Water properties and reservoir layers defined for Gullfaks field

Water viscosity: 1.00 cp	Water density: 1000.00 kg/m3	Water formation volume factor: 1.00	Water injection rate: 1.40E04 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.30	1.00	0.25	1.00
2	0.20	1.00	0.20	1.00
3	0.30	1.00	0.25	1.00

As shown in *Figure 35*, simulated oil recoveries show an oil recovery of 47.7% based only water flooding while polymer flooding yield 47.3% after 5000 days. Surfactant flooding yields a recovery of 70.8% whiles a combined surfactant followed by polymer flooding will yield 69.8%.

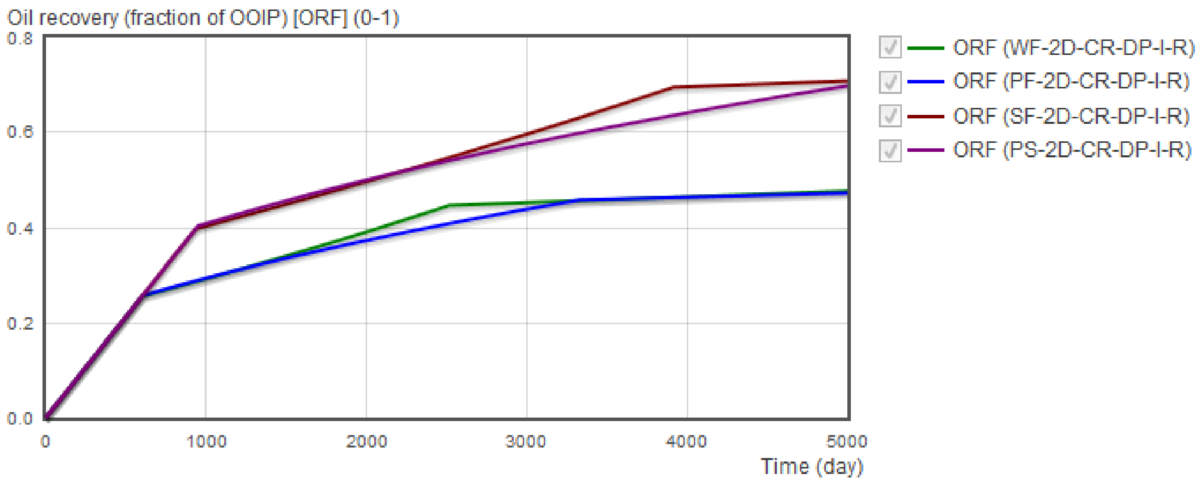


Figure 35: Simulated oil recovery (ORF) based on water-based EOR methods (WF: water flooding; PF: Polymer flooding; SF: Surfactant flooding and PS; combined polymer/surfactant flooding) for the Brent formation at 80°C. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 148-298 bar
  - CO_2 208 bar
  - Initial reservoir pressure 310-320 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

Based on built-in correlations in SWORD, gas-based (CO_2 and HC-gas) EOR methods at miscible conditions were evaluated for Gullfaks field. Immisble HC-gas was also evaluated. The correlations show that miscibility between CO_2 and Gullfaks oil will occur at 208 bar and 298 bar with HC-gas with 70 % methane at 80°C. As shown in *Figure 36*, injecting CO_2 at miscible conditions will recover close to 34 % whiles HC-gas will yield 31.7 %. The recovery factor – estimation module predicted a recovery factor of 0.33 with a confidence index of 0.28 for the Cook and Statfjord formation in the Gullfaks field (*Table 34*). Water flooding seems to perform better that CO_2 and HC-gas at miscible conditions.

Several improved recovery techniques have been studied and some of them implemented. These include infill-drilling, water and WAG injections, polymer assisted surfactant (PASF) flooding, microbial injection and CO_2 injection. Maldal et al. (1998) presented both laboratory and simulation to develop and qualify a polymer-assisted surfactant flooding (PASF) system for economical use in the Gullfaks Brent formation. The PASF system consisted of a branched Sulphonate and Xanthan biopolymer. Laboratory experiments indicated that the PASF system can recover more that 70 % of the residual oil after water flooding. Both outcrop and reservoir cores were used. Reservoir simulation indicated that the PASF system can mobilize about 80% of the by-pass oil if the wells with shortest distances are chosen. The current IOR initiatives are meant to extend the production life of the field to 2030 and thus meet the ambition of recovering 400 MSm^3 of oil (Talukdar and Instedfjord, 2008).

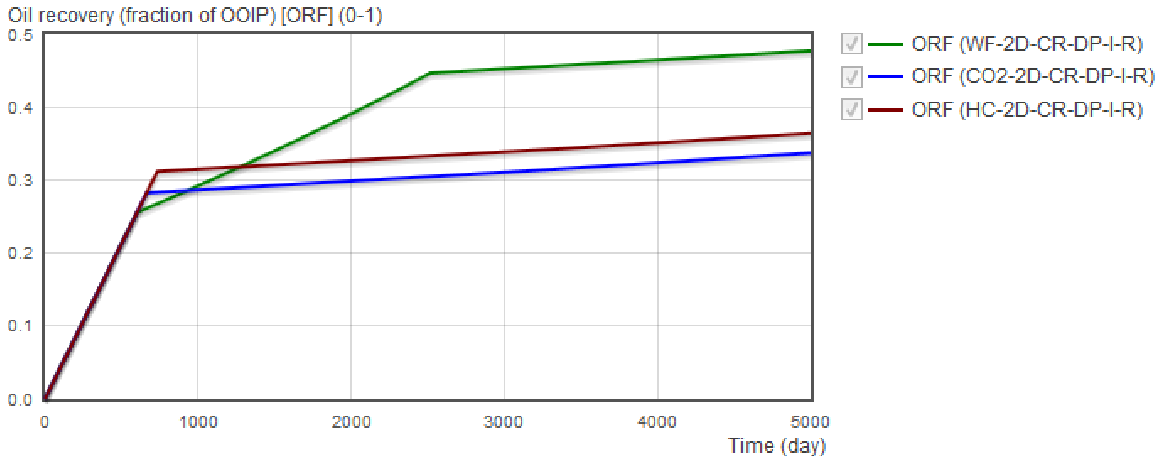


Figure 36: Simulated oil recovery (ORF) based on gas-based EOR methods; CO_2 flooding; HC-hydrocarbon gas flooding compared to water flooding (WF) for the Brent formation. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

Huff and puff gas injection technique (cyclic gas injection and oil production) has been applied on the Gullfaks field (Agustsson et al. 2004). Hydrocarbon gas was injected in a producer in Cook Formation mainly for storage and pressure support. The well was shut-in for a period of time before it was back-produced. The production rate increased during back-production and resulted in a much higher oil recovery from the area than expected. The cause for higher oil production was attributed to gas segregation and better drainage of attic oil. Agustsson et al. (2004) used reservoir simulation to investigate the potential of a large-scale miscible CO_2-WAG (MWAG) injection scheme in the Gullfaks field. Results showed that the MWAG injection strategy will bring a considerable change in reservoir management with a much more rapid circulation of injected fluids due to closer well spacing. The simulation predicted an accelerated oil production, as well as more rapid sweep to lower oil saturations.

4.3.10 EOR screening for Heidrun field

The Heidrun field is located on Haltenbanken in the Norwegian Sea. The water depth is about 350 metres. The reservoir consists of sandstones in the Garn, Ile, Tilje and Åre Formations of Early and Middle Jurassic age. The reservoir is heavily faulted. The Garn and Ile Formations have good reservoir quality, while the Tilje and Åre Formations are more complex. The reservoir depth is about 2 300 metres. The recovery strategy for the field is pressure maintenance using water and gas injection in the Garn and Ile Formations. In the more complex part of the reservoir, the Tilje and Åre Formations, the main recovery strategy is water injection. Some segments are also produced by pressure depletion. Several methods to improve the recovery and prolong the lifetime of the field are evaluated, including increased number of wells, possible implementation of new drilling technology and EOR methods. New well targets are continuously being evaluated in an effort to increase oil recovery. Light Well Interventions have resulted in increased oil recovery. Pilots to improve recovery are being assessed, and some have been implemented (*NPD fact pages, 2015*).

The field came on stream in October 1995, and the production strategy has been waterflooding with re-injection of some of the produced gas in the gas cap for pressure maintenance. Current predictions give an economical oil production till 2030 with a tertiary gas cap production at the end of the field life. To increase the oil recovery, several IOR-methods are currently being evaluated for the Heidrun field, include continuous well optimisation, polymer and surfactant flooding and CO_2-WAG injection (Janssen et al. 2007). *Figure 37a* show the current reserves, an original oil in-place (OOIP) of 432 millSm^3 (66 %) with original recoverable oil of 186 mill Sm^3 (29%). The remaining oil reserves is 34.5 millSm^3 (5 %). The current oil recovery is 43.1 % with a water-cut is 67.1 % as at the end of 2015 (*Figure 37b*). *Figure 37b* show the net-oil produced and water-cut as a function of time. *Table 38* show some of the reservoir and fluid properties in the Heidrun field published in the open literature (Jansen et al. 2007) and the SPOR Monograph (1992).

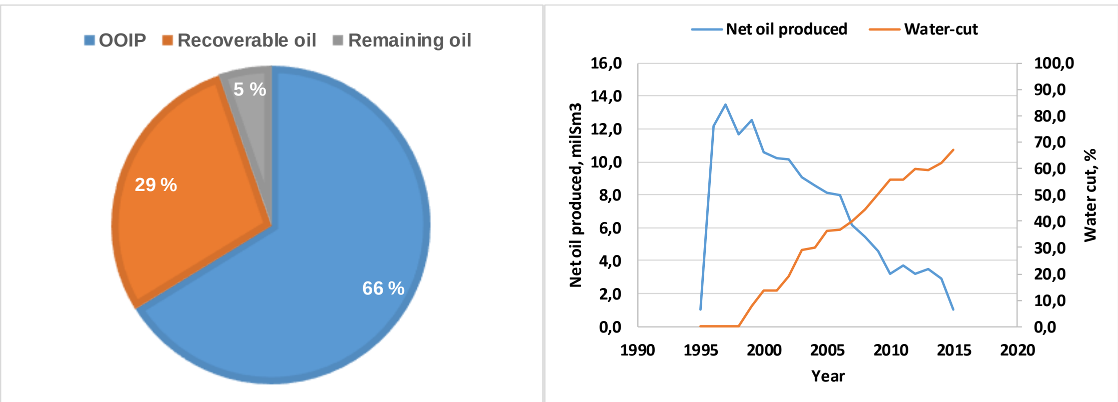


Figure 37: Defined resources and reserves as at the end of 2015 and (b) Net oil produced (millSm^3) and water-cut (%) as a function of time for the Heidrun field (NDP fact pages, 2015)

Table 37: Input field data for the Heidrun field

Parameter	Unit	Min	Max
Depth	m	2080	2240
Permeability	md	10	2200
Thickness	m	70	205
Temperature	Celsius	80	85
Oil viscosity	cp	0.75	2.29
Pressure	bar	250	252
Oil density	kg/m3	882	922
Anisotropy (kv/kh)	(0-1)	0.1	0.9
Clay content	(0-1)	0.08	0.9
Salinity	g/l	27	32
Curr/init oil saturation	(0-1)	0.35	0.75
High/low perm. ratio		1	100

4.3.10.1 Recovery factor estimation-Heidrun field

The reservoir properties used in the recovery factor estimation for the Heidrun field are as shown in *Table 38*. The table includes the properties for the three different formations. As shown, the properties vary with depth, and the Fangst group has very good reservoir characteristics and the more heterogeneous Tilje and Åre formations, which are of substantially lesser reservoir quality and represent the major challenge in the current development planning.

Table 38:Reservoir properties defined for Fangst, Tilje and Åre formations, Heidrun field

Porosity (frac)	Permeability (mD-D)	Depth (m)	Oil gravity (kg/m3)	Oil viscosity (cP)	Oil temperature (°C)	Formation
0.28	0.7-20	2080	882	0.75	85	Fangst
0.25	0.07-2.0	2100	900	1.24	85	Tilje
0.27	0.1-10	2240	922	2.29	85	Åre

Cluster analysis indicate that both water-based and gas-based EOR methods can be applied in the field (*Figures 38-40*). Inspite of the variations in reservoir properties, gas based EOR methods such steam and CO_2 under miscible seem promising in all the formations on the Heidrun field. As shown in *Table 40*, Steam and CO_2 under miscible conditions give an interpolated recovery factor of 0.42 and 0.31 respectively. Although water-based EOR such as polymer appear closet to the new field cases (*Figures 38-40*) with an interpolated recovery factor of 0.17, the method has a rather low confidence index.

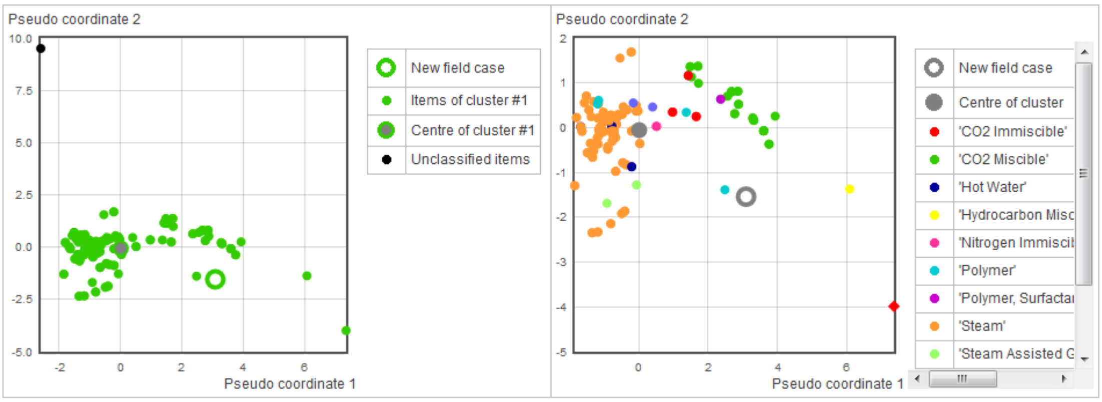


Figure 38: Results of clusters analysis showing (a) number of clusters and (b) possible IOR/EOR methods for Fangst group (new field case) on the Heidrun field

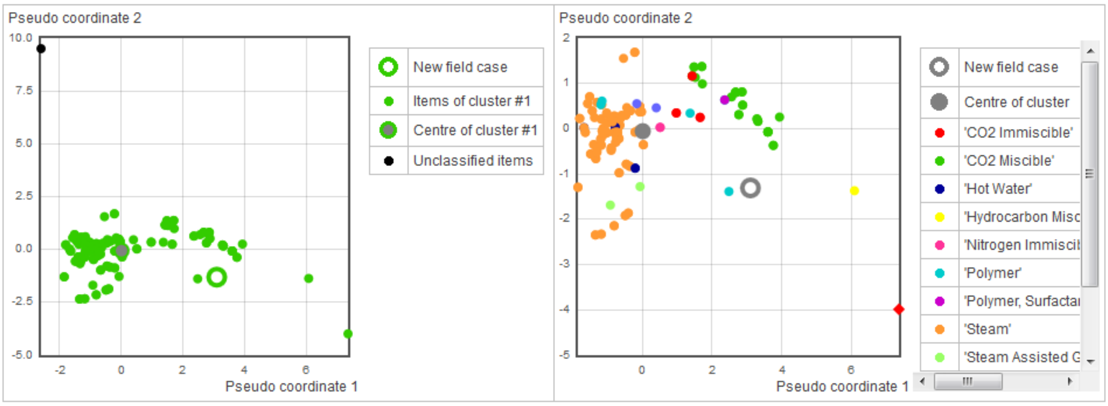


Figure 39: Results of clusters analysis showing (a) number of clusters and (b) possible IOR/EOR methods for the Tilje group (new field case) on the Heidrun field

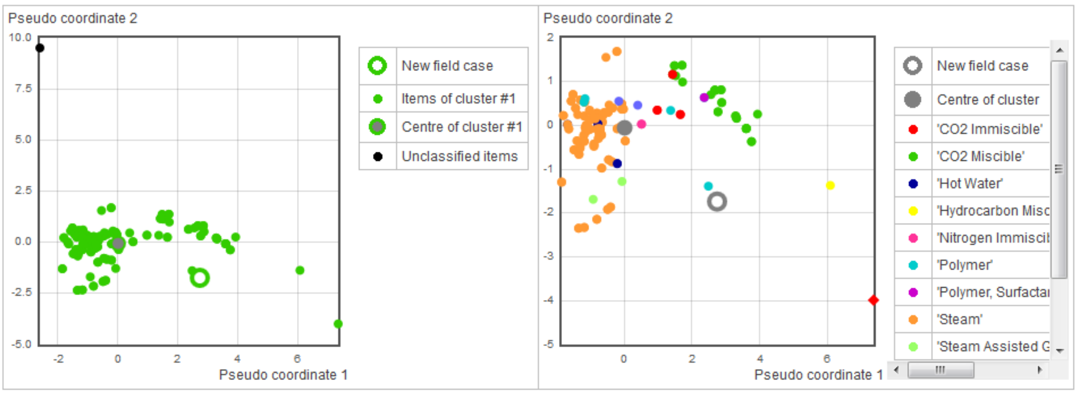


Figure 40: Results of clusters analysis showing (a) number of clusters and (b) possible IOR/EOR methods for Åre group (new field case) on the Heidrun field

Table 39: IOR/EOR methods with interpolated recovery factors for Heidrun field

Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
Steam	8	0.42	Good	0.33	0.67
CO2 Miscible	8	0.31	Fair	0.18	0.21
Hot Water	5	0.48	Poor	0.25	0.04
Nitrogen Immiscible	2	0.83	Poor	0.09	0.01
Polymer	6	0.17	Poor	0.06	0.02
Steam Scavenging	2	0.33	Poor	0.05	0.01
CO2 Immiscible	6	0.19	Poor	0.03	0.01
Hydrocarbon Miscible	1	0.66	Poor	0.02	0.02
Surfactant	1	0.44	n/a	3.32E-4	1.37E-6
Polymer, Surfactant	1	0.04	n/a	2.00E-4	1.58E-5
Steam Assisted Gravity Drainage	2	0.46	n/a	1.86E-4	4.04E-3

4.3.10.2 Performance prediction-Heidrun field

The Heidrun field consists of three formations namely the Fangst group, Tilje and Åre formations. The performance prediction model was used to evaluate to the water-based and gas-based EOR methods in the field. Due to the variation in reservoir properties, the predictions were performed based were reservoir properties for the individual formations. *Table 40* show the reservoir and fluid properties for the Heidrun field. The parameters are based on an average of the reservoir and fluids properties from the different groups.

Table 40: Reservoir and fluid properties defined for Heidrun field

Injection to production well distance: 1000.00 m	Oil viscosity: 1.42 cp	Production well bottomhole pressure: 165.00 bar
Reservoir width: 2240.00 m	Oil density: 901.00 kg/m3	Pressure drop from injection to production well: 100.00 bar
Dip: 5.00 deg	Oil formation volume factor: 1.23	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	1000.00	5000.00	0.20	0.28	25.00	0.75
2	70.00	100.00	0.70	0.25	25.00	0.80
3	1000.00	10000.00	0.10	0.27	25.00	0.75

Figures 41-43 show the simulated oil recovery for water-based EOR methods: water, polymer, surfactant and a combined surfactant/polymer process for the different formations. Compared to water flooding with a recovery of almost 45%, polymer flooding recovers almost 45.6 % at the end of 5000 days. Increasing the viscosity of the water by adding polymer solution increases the rate of oil production with polymer flooding as shown in *Figures 41-43*. The same trend is also observed for surfactant and a combined surfactant and polymer. Surfactant flooding recovers above 68.0 % whiles a combined surfactant and polymer flood recovers above 69.0 % of the OOIP.

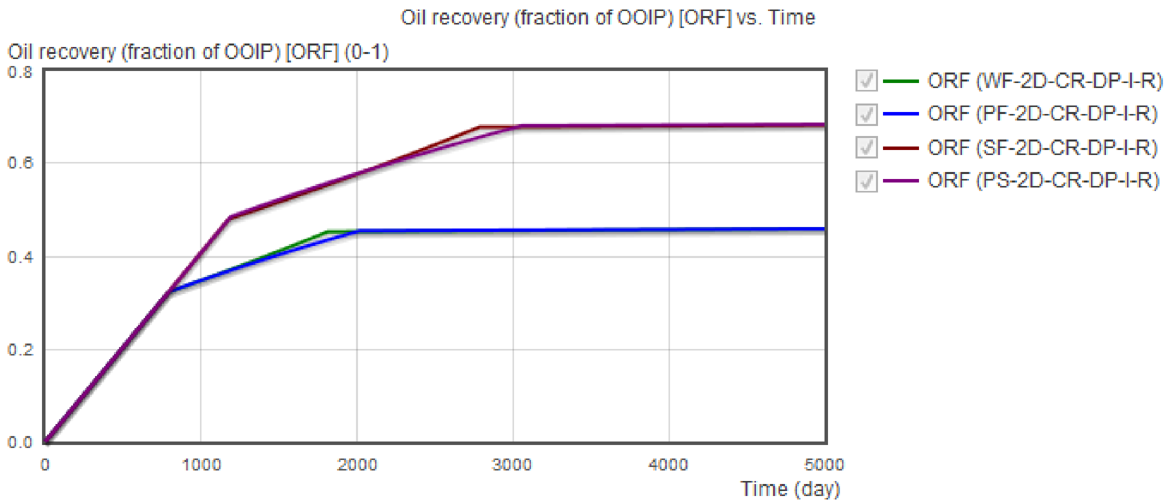


Figure 41: Simulated oil recovery (ORF) based on water-based EOR methods (WF: water flooding; PF: Polymer flooding; SF: Surfactant flooding and PS; combined polymer/surfactant flooding) for the Fangst group. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

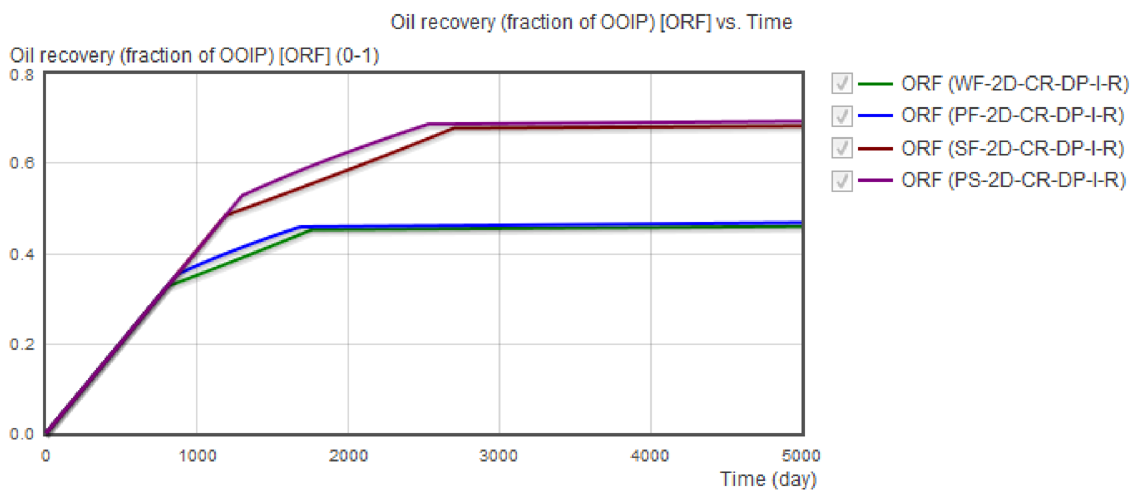


Figure 42: Simulated oil recovery (ORF) based on water-based EOR methods (WF: water flooding; PF: Polymer flooding; SF: Surfactant flooding and PS; combined polymer/surfactant flooding) for the Tilje group. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 436 bar
  - CO_2 219 bar
  - Initial reservoir pressure 250-252 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

Figures 44-46 show the simulated oil recoveries for the gas-based EOR methods; CO_2 and hydrocarbon gas for the three formations. Based on a reservoir pressure of 250-252 bar, miscibility with CO_2 is expected at 219 bar and above 300 bar with HC-gas with 70% methane gas at 85°C. The highest oil recoveries occur in the Fangst formation with good reservoir characteristics (*Figure 44*). CO_2 at miscible conditions recovers 55.2 % compared to 46.7 % with water flooding in the formation. HC-gas with 70.0 % methane will recover 51.0 % while immiscible HC-gas recovers 45.2%. In the heterogeneous formations (Tilje and Fangst formations) CO_2 at miscible conditions recovers between 41.6-50.6% of OOIP, HC-gas at miscible yields 39.2-50.9% of OOIP and HC-gas at 36.1-45.2% at immiscible conditions yields (*Figures 45 & 46*).

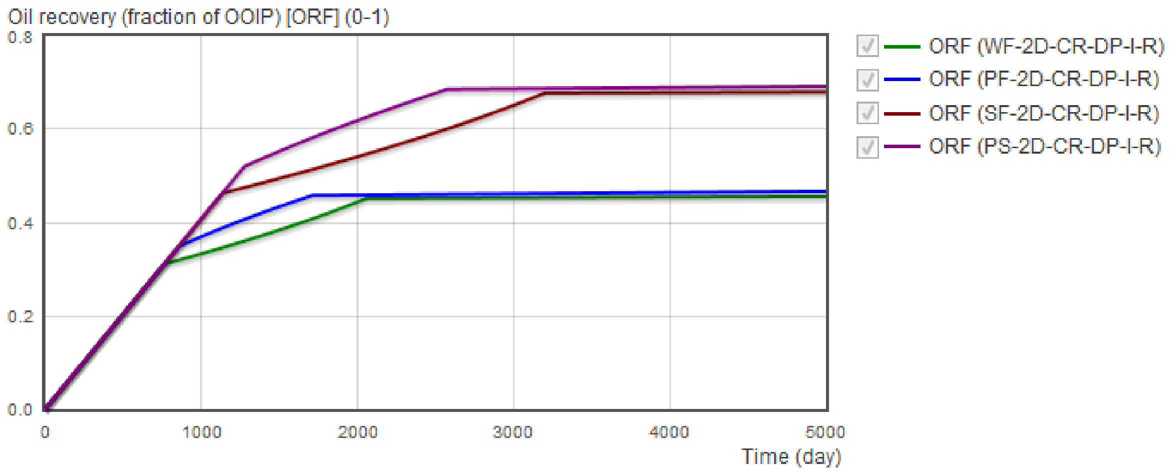


Figure 43: Simulated oil recovery (ORF) based on water-based EOR methods (WF: water flooding; PF: Polymer flooding; SF: Surfactant flooding and PS; combined polymer/surfactant flooding) for the Åre group. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

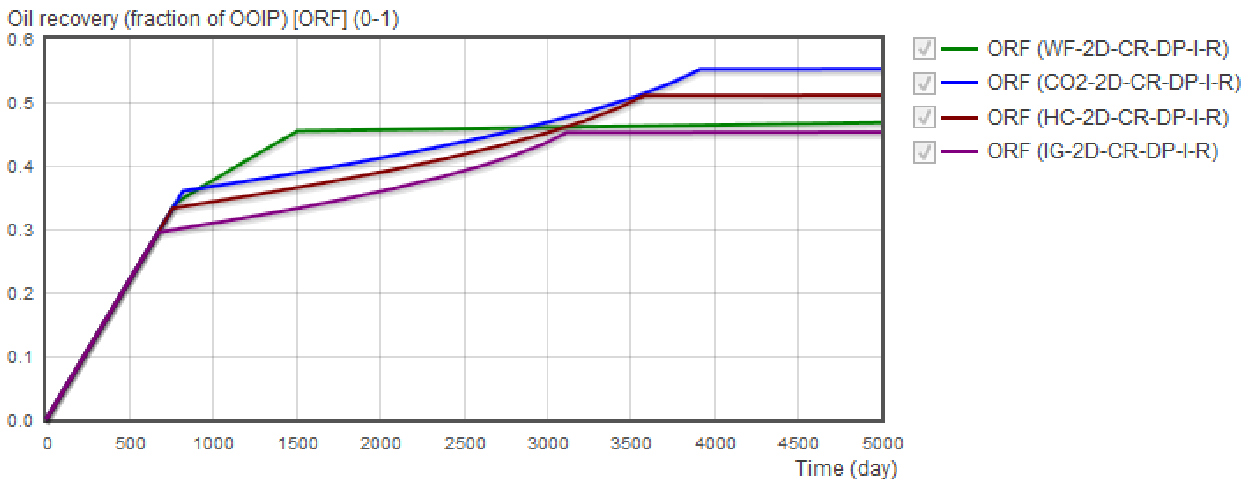


Figure 44: Simulated oil recoveries for CO_2 and HC-gas at miscible conditions and IG-immiscible HC-gas compared to WF: water flooding for the Fangst formation. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

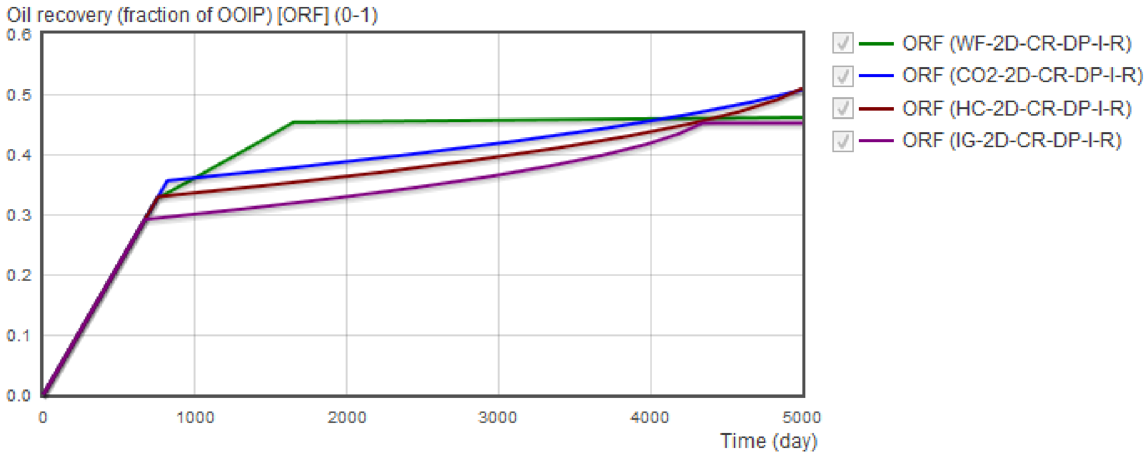


Figure 45: Simulated oil recoveries for CO_2 and HC-gas at miscible conditions and HC-gas at immisble conditions compared to WF: water flooding for the Tilje formation. The results are based on simplified 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR)

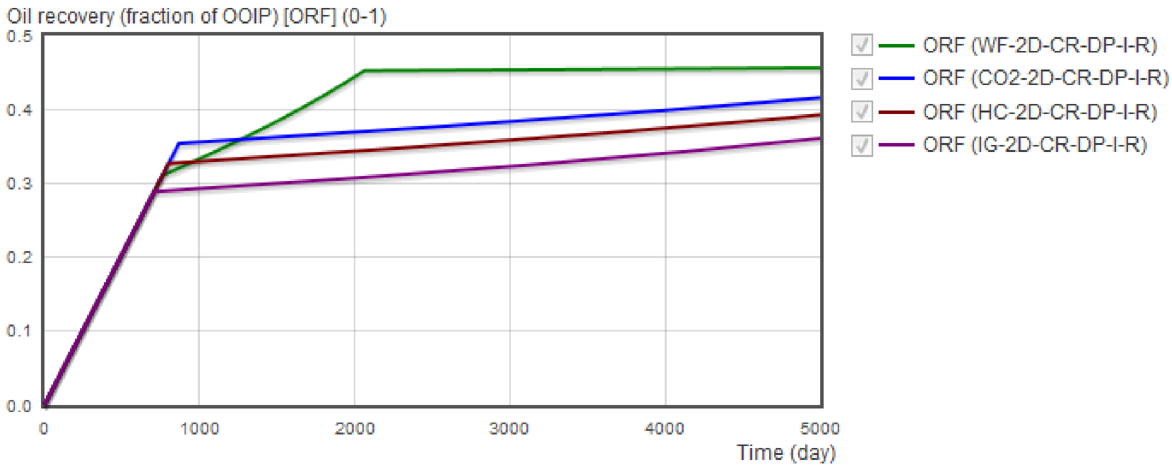


Figure 46: Simulated oil recoveries for CO_2 and HC-gas at miscible conditions and HC-gas at immisble conditions compared to WF: water flooding for the Åre formation. The results are based on simplified 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR)

Janssen et al. (2007) used a compositional reservoir simulator to investigate the effect of gas cap contamination level and mechanisms caused by CO_2-EOR operations in a sector model of the Upper Tilje reservoir. The impact of different EOR and gas cap drawdown operational parameters on the contaminated gas volumes were also determined (Janssen et al. 2007). The results indicated that the contaminated part of the produced gas from the gas cap, with more than 2.5% CO_2, can be correlated to the final position of the CO_2 front during the EOR-period. Massive CO_2-breakthrough on the other hand, which is responsible for the contaminated part of the produced gas with more than 7.5% CO_2, is a nearly linear function of the stored CO_2 mass. This implies that EOR-operations which can both increase oil recovery and CO_2 storage, such as SWAG-injection, short-cycle WAG or oil producer gas shut-off will significantly increase gas cap contamination. They also observed that gas cap contamination could however, can be reduced by well-positioned horizontal gas producers and large gas blowdown flow rates.

4.3.11 EOR screening for Norne field

The Norne Field is located in the southern part of the Norwegian Sea, approximately 85 km north of the Heidrun Field at a water depth of around 380 m. The reservoir formation is sandstone rocks of the Lower and Middle Jurassic age. The field has been developed with a production, storage and offloading vessel, Norne FPSO, connected to seven subsea templates. The main reservoirs are the Ile and Tofte Formations, initially oil bearing. The reservoir drainage strategy in the oil zone has been sea water injection; however, because of lack of gas export, irregular WAG injection has been done during the first ten years of production. (*NPD fact pages, 2015*).

Since 2007 there has been sea water injection only. Since 2012, close to 54 % of the in-place oil has been recovered. Thus, water flooding on the Norne field has been very successful with respect to macroscopic sweep in Tofte Formation (*Atabay et al. 2012*). This has been confirmed by continuous monitoring with 4D seismic and by the production performance of the wells; however, after producing 86MSm^3 of oil and injecting 160 MSm^3 of water in the field, the sweet spots have been efficiently drained *(Atabay et al. 2012*).

As at the end of 2015, the proven original oil-in place was estimated as 157 millSm^3 (63 %) with an original recoverable reserve of 91.3 millSm^3 (36%). The current remaining oil reserves in the field is estimated as 2.2 millSm^3 (1.0 %) (See *Figure 47a*) Currently the oil recovery factor is 58.2% with a water-cut approaching 94 %. *Figure 47b* show the net-oil produced and water-cut as a function of time for the field. Reservoir and fluid properties in the Norne field published in the open literature (Rwechungura et al. 2010).

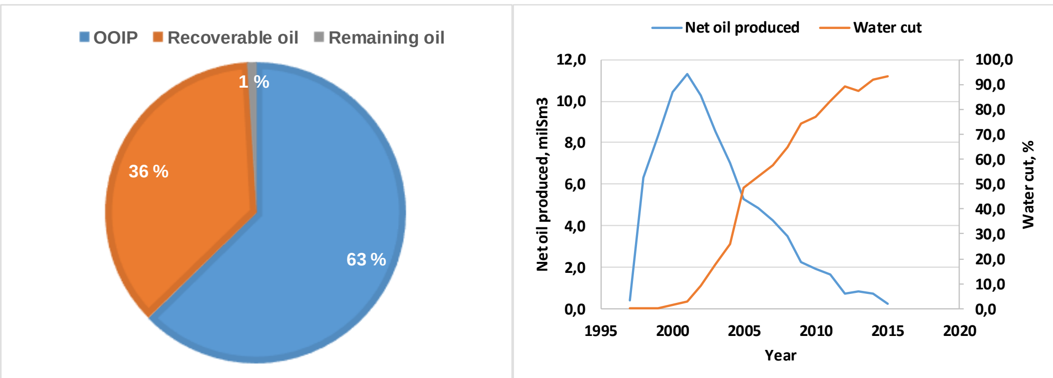


Figure 47: (a) OOIP, recoverable and remaining reserves (b) current net oil produced and water-cut in percent as a function of time for the Norne field (NPD fact pages, 2015)

Table 41: Field case data collected for the Norne field

Parameter	Unit	Min	Max
Depth	m	2500	2700
Permeability	md	20	2500
Thickness	m	80	110
Temperature	Celsius	80	98.3
Oil viscosity	cp	0.58	0.695
Pressure	bar	270	273
Oil density	kg/m3	850	859.5
Anisotropy (kv/kh)	(0-1)	0.1	0.9
Clay content	(0-1)	0	0.05
Salinity	g/l	20	30
Curr/init oil saturation	(0-1)	0.35	1
High/low perm. ratio		1	100

4.3.11.1 Recovery factor estimation-Norne field

The overlaying secondary reservoir, the Not Formation, contains gas with an oil leg. The Norne structure is relatively flat at a depth of about 2525 m below mean sea level. The reservoir properties are generally good with the porosity and permeability values typically in the range 25-32 % and 200-2000 mD. (Atabay et al. 2012). The reservoir and fluid parameters used in the recover factor estimation are shown in *Table 42*.
The cluster analysis results (*Figure 48 & Table 43*) indicate that the closet EOR methods are water-based such as polymer and gas-based methods such as miscible hydrocarbon gas and CO_2, and steam injection. However, the confidence indices are low due to the number of field cases used in the interpolation process.

Table 42: Reservoir properties defined for Norne field

Porosity (frac)	Permeability (D)	Depth (m)	Oil gravity (kg/m³)	Oil viscosity (cP)	Oil temperature (ºC)
0.25-0.30	0.02-2.5	2500-2700	859.5	0.58-0.69	98.3

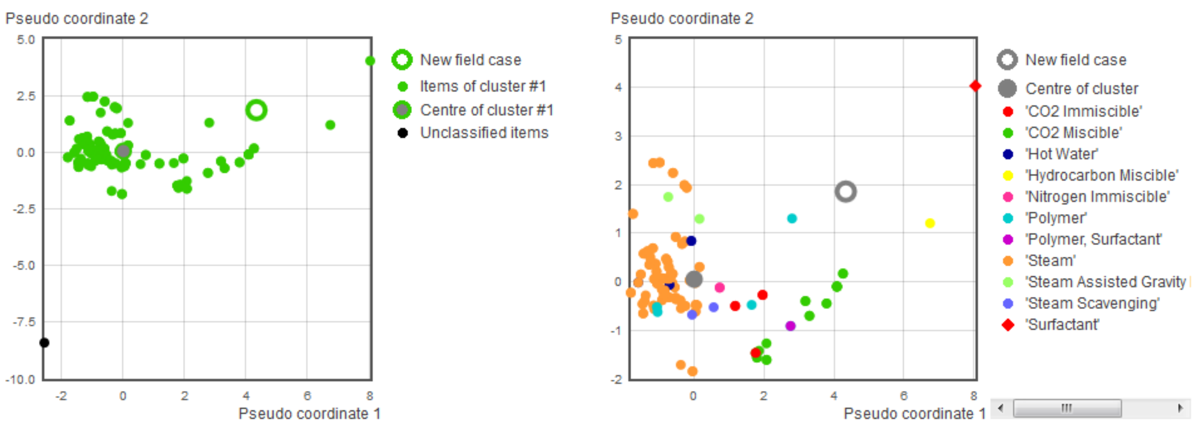


Figure 48: Results of cluster analysis showing (a) number of clusters and (b) possible IOR/EOR methods applicable on Norne field

Table 43: Possible IOR/EOR methods including interpolated oil recoveries for the Norne field

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Hydrocarbon Miscible	1	0.66	Poor	0.75	0.99
2	Steam	8	0.42	n/a	0.08	4.02E-3
3	CO2 Miscible	8	0.30	n/a	0.02	1.48E-3
4	Hot Water	5	0.49	n/a	0.07	4.47E-4
5	Steam Scavenging	2	0.33	n/a	0.04	4.25E-4
6	Nitrogen Immiscible	2	0.83	n/a	0.03	5.77E-4
7	Polymer	6	0.21	n/a	8.13E-3	1.88E-4
8	CO2 Immiscible	6	0.19	n/a	3.23E-3	9.08E-5
9	Surfactant	1	0.44	n/a	9.59E-4	7.36E-6

4.3.11.2 Performance prediction-Norne field

According to Atabay et al. (2012), the remaining oil in the Norne field is located in the upper Ile and Tofte formations with slightly poorer reservoir quality, and therefore, more difficult to produce by present-day water flooding. The remaining oil targets are getting smaller, and it is no longer commercially attractive for conventional infill drilling. Hence, the main challenge in the late phase is to optimize the injection strategy in order to make the waterflood "push" the remaining oil (unswept oil) towards existing producers located in the upper section of the main Norne reservoir. However, water flooding alone cannot recover capillary trapped oil pockets efficiently, thus the need for enhanced oil recovery techniques. Reservoir and fluid properties (*Tables 44&45*) were used in the performance prediction of water and gas based EOR methods in the Norne field.

Table 44: Reservoir and fluid properties used for performance prediction

Injection to production well distance: 1000.00 m	Oil viscosity: 0.7 cp	Production well bottomhole pressure: 165.00 bar
Reservoir width: 2500.00 m	Oil density: 859.50 kg/m3	Pressure drop from injection to production well: 100.00 bar
Dip: 1.00 deg	Oil formation volume factor: 1.35	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	10.00	100.00	0.10	0.32	25.00	0.90
2	1000.00	2000.00	0.50	0.32	25.00	0.85
3	1000.00	1000.00	1.00	0.32	25.00	0.85

Table 45: Reservoir and water properties for the Norne field

Water viscosity: 1.00 cp	Water density: 1020.00 kg/m3	Water formation volume factor: 1.00	Water injection rate: 1.40E04 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.10	1.00	0.10	1.00
2	0.15	1.00	0.15	1.00
3	0.15	1.00	0.15	1.00

Simulations indicated that injecting polymer can recover 57.9% of OOIP compared to 57.1 % with water flooding (*Figure 49*). As shown in *Figure 49*, injecting surfactant alone can recover 63.3% of OOIP whiles a combined surfactant and polymer flood will recovery 64.7 % of OOIP after 3000 days. Maheshwari (2011) used reservoir simulation to evaluate five different EOR scenarios such as surfactant flooding, alkaline-surfactant flooding, polymer flooding, surfactant-polymer flooding, and alkaline-surfactant-polymer flooding in the Norne E-segment. The objective of this study was to evaluate the effectiveness of these chemical methods compared to a conventional water flooding in terms of incremental oil production. Simulation results indicated that ASP flooding is better than other chemical methods in terms of incremental NPV for the Norne E-segment. An incremental recovery factor of 1.40 % by ASP flooding was observed over water flooding.

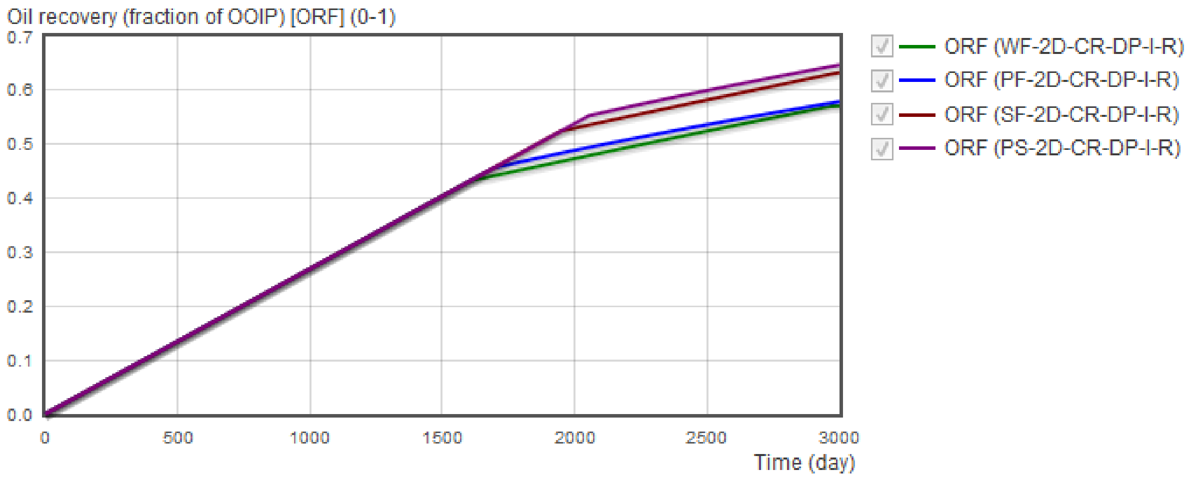


Figure 49: Simulated oil recovery (ORF) based on water-based EOR methods (WF: water flooding; PF: Polymer flooding; SF: Surfactant flooding and PS; combined polymer/surfactant flooding) for the Norne field. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 341 bar
  - CO_2 248 bar
  - Initial reservoir 273 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

Figure 50 show the simulated oil recoveries for the gas-based EOR methods; CO_2 and hydrocarbon gas at miscible conditions. Based on a reservoir pressure of 273 bar, miscibility between Norne crude oil and CO_2 is expected at 248 bar and 341 bar with HC-gas with 70 % methane gas at 98°C. Simulation results indicate the water flooding is the best conventional method when compared to gas flooding in the Norne field. Injecting CO_2 recovers 37.0 % compared to 34.9 % with HC-gas at miscible conditions. Injecting HC-gas at immiscible conditions will only 31.6 % of OOIP at the end of 3000 days.

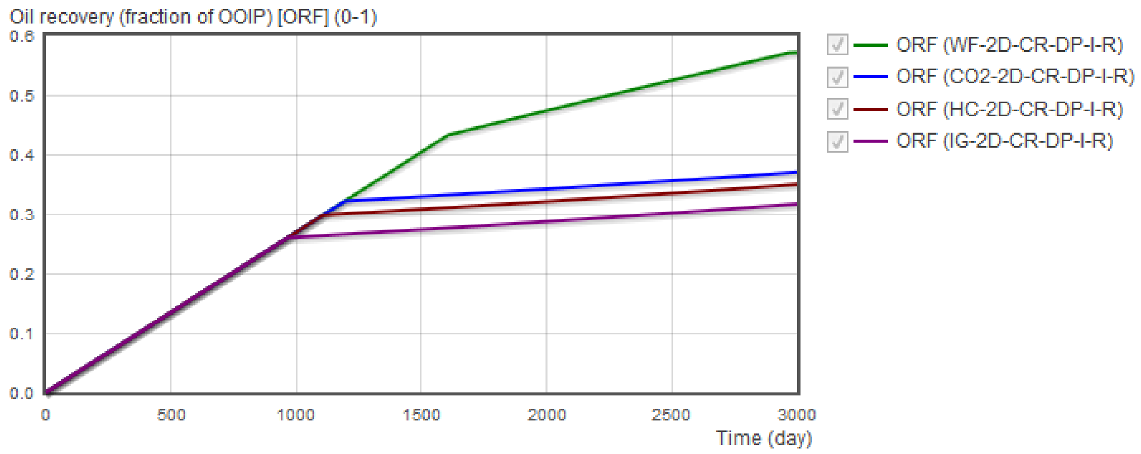


Figure 50:) Simulated oil recoveries for Gas-based EOR methods; CO_2 and HC: hydrocarbon gas at miscible conditions and IG: immiscible gas compared to WF: water flooding in the Norne field. The results are based on simplified 2D model with the Dykstra Parson (DP) approximation method at constant rate (CR).

4.3.12 EOR screening for Snorre field

Snorre is an oil field located in the Tampen area in the northern part of the North Sea. The water depth in the area is 300-350 metres. The Snorre field consists of several large fault blocks. The reservoir contains Lower Jurassic and Triassic sandstones in the Statfjord Group and Lunde Formation. The reservoir depth is 2000-2700 metres. The reservoir has a complex structure with channels and flow barriers. Snorre is produced with pressure support from water injection, gas injection and water alternating gas injection (WAG), where WAG cycles may change as often as every third month. Foam injection (FAWAG) has also been utilized to a small degree on Snorre. The field has been developed in phases, giving both mature and near virgin areas. Currently, the overall recovery is estimated as 47.9 % with a water-cut of 67.5% (*see Figure 51b*), with an ambition to improve oil recovery to 70% through further development. Time-lapse seismic is one key technology with potential to identify remaining oil (Aanvik et al 2008). As shown in *Figure 51a*, the field has a large IOR potential and there is an ambitious vision for improving the recovery factor. As at the end of 2015, the proven original oil-in place was estimated as 558.50 millSm^3 (63%) with an original recoverable reserve of 267.5 millSm^3 (30%). The remaining oil reserves in the field is estimated as 65.1 millSm^3 (7.0%) (See *Figure 51a*). *Figure 51b* show the net-oil produced and water-cut in percent as a function of time. *Table 46* show some of the reservoir and fluid properties in the Snorre field published in the open literature (Skrettingland et al. 2014).

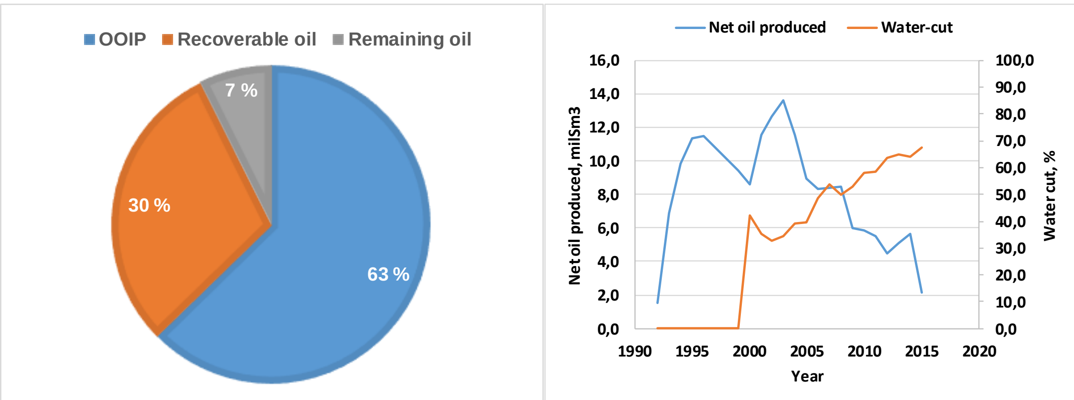


Figure 51: (a) Proven OOIP, recoverable and remaining reserves and (b) net-oil produced and water-cut for the Snorre field (NDP fact pages, 2015).

Table 46: Field case input data for Snorre field

Parameter	Unit	Min	Max
Depth	m	2300	2360
Permeability	md	125	1000
Thickness	m	110	1000
Temperature	Celsius	90	93
Oil viscosity	cp	0.5	0.687
Pressure	bar	380	383
Oil density	kg/m3	690	700
Anisotropy (kv/kh)	(0-1)	0.25	0.3
Clay content	(0-1)	0.05	0.35
Salinity	g/l	30	34
Curr/init oil saturation	(0-1)	0.35	0.85
High/low perm. ratio		1	100

4.3.12.1 Recovery factor estimation-Snorre field

The reservoir porosity is 14 to 32%, and permeability varies from 100 md to 4 Darcy. The heterogeneous nature of the reservoir is characterized by limited vertical and lateral communication, especially in zones with low net/gross. The total clay content is in the range of 5 to 35% (Skrettingland et al. 2014). *Table 47* show the reservoir and fluid properties used in EOR screening.

Table 47: Reservoir properties defined for Snorre field

Porosity (frac)	Permeability (D)	Depth (m)	Oil gravity (kg/m³)	Oil viscosity (cP)	Oil temperature (°C)
0.14-0.32	0.01-4.0	2500-2700	860	0.58-0.70	90-96

Figures 52 and 53 show the results of the recovery factor estimation simulated based on reservoir and fluid properties in *Table 47*. *Figure 52* show the possible EOR methods at low permeability zones of the reservoir. The figure indicates that for the low permeable zones the closest EOR methods are gas-based such as HC-gas at miscible conditions and combustion. In *Table 48*, combustion and CO_2 at miscible conditions can be viable for the Snorre field. Combustion results in an interpolated recovery factor of 0.60 with a good confidence score. In the high permeable zones of the field, mobility control with polymer flooding may result in a recovery factor 0f 0.15 (*Table 49*). The confidence level is however, low probable due to the relatively low number of field cases in the data set.

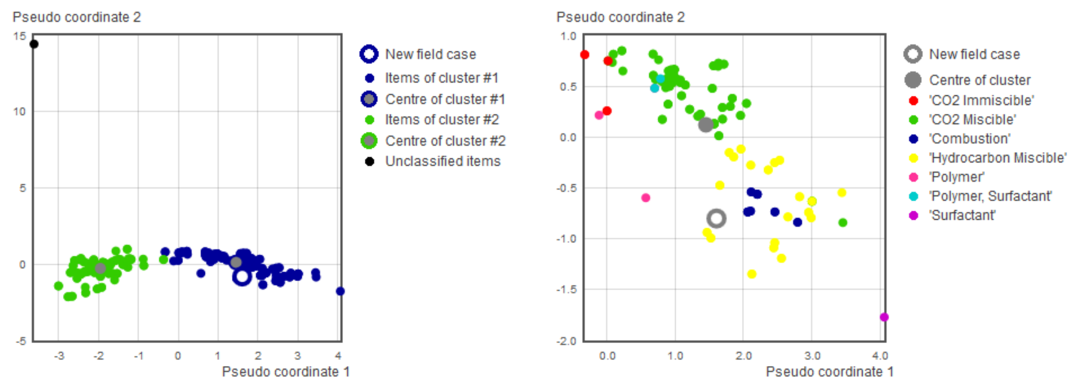


Figure 52: Results of cluster analysis showing (a) number of clusters and (b) possible IOR/EOR methods applicable for low permeable zones of the Snorre field

Table 48: Possible EOR methods for lower permeable zones of Snorre field

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Combustion	8	0.60	Good	0.79	0.93
2	CO2 Miscible	8	0.45	Poor	0.02	0.01
3	Polymer	3	0.14	Poor	0.19	0.05
4	Hydrocarbon Miscible	8	0.70	n/a	8.63E-4	5.15E-4
5	Polymer, Surfactant	2	0.47	n/a	4.99E-5	6.76E-4
6	CO2 Immiscible	6	0.25	n/a	2.39E-5	2.04E-3
7	Surfactant	1	0.44	n/a	5.40E-7	1.13E-6

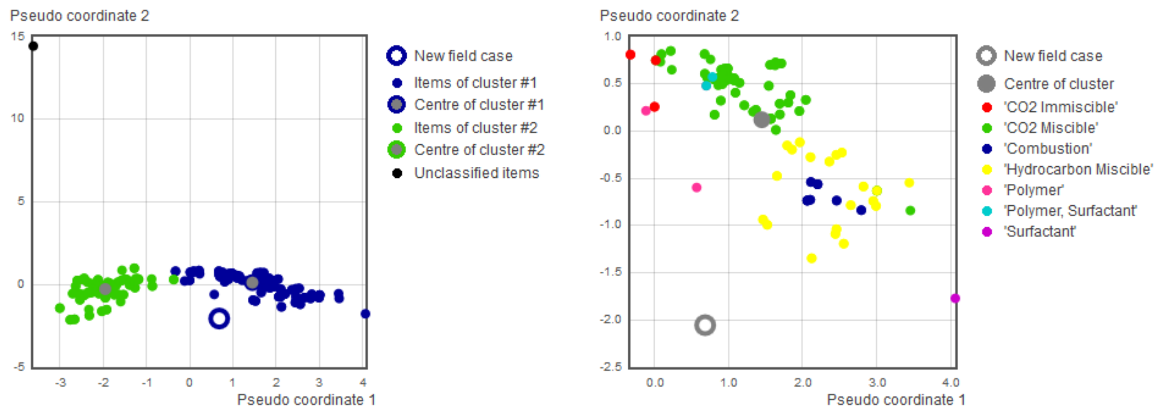


Figure 53: Results of cluster analysis (a) number of clusters and (b) possible EOR methods for high permeable zones of the Snorre field (new field case)

Table 49: Possible EOR methods for high permeable zones of Snorre field

	Method	Number of cases in interpolation	Interpolated recovery factor (0-1)	Confidence	Confidence index - interpolation cases (0-1)	Confidence index - all cases (0-1)
1	Polymer	3	0.15	Poor	0.97	0.97
2	Hydrocarbon Miscible	8	0.94	n/a	0.02	5.23E-3
3	Combustion	8	0.60	n/a	0.01	8.36E-4
4	CO2 Miscible	8	0.45	n/a	3.55E-7	2.16E-4
5	CO2 Immiscible	6	0.26	n/a	2.22E-6	0.02
6	Polymer, Surfactant	2	0.47	n/a	2.46E-8	3.11E-5
7	Surfactant	1	0.44	n/a	4.23E-11	3.24E-11

4.3.12.2 Performance prediction-Snorre field

According to Skrettingland et al. (2014), the formations in the Snorre field are characterized by complex packages of mainly inhomogeneous stratified fluvial sandstones dipping 6 to 8 degrees. The reservoir temperature is 90-96°C with an average initial pressure of 383 bar. The formation oil is highly under-saturated. *Tables 50* & 51 show the reservoir and fluid properties used to predict the performance of the different EOR methods in the Snorre field.

Table 50: Reservoir and fluid properties defined for Snorre field

Injection to production well distance: 1000.00 m	Oil viscosity: 0.7 cp	Production well bottomhole pressure: 165.00 bar
Reservoir width: 2700.00 m	Oil density: 860.00 kg/m3	Pressure drop from injection to production well: 100.00 bar
Dip: 6.00 deg	Oil formation volume factor: 1.35	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	1000.00	4000.00	0.25	0.32	25.00	0.65
2	100.00	1000.00	0.10	0.32	25.00	0.75
3	1000.00	4000.00	0.25	0.32	25.00	0.65

Table 51: Reservoir and water properties defined for Snorre field

Water viscosity	Water density	Water formation volume factor	Water injection rate
1.00 cp	1020.00 kg/m3	1.00	1.40E04 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.35	0.90	0.35	0.90
2	0.25	0.90	0.25	0.90
3	0.35	0.90	0.35	0.90

Figure 54 show the simulated oil recovery (fraction of OOIP) for the water-based EOR methods. Injecting polymer recovers 48.8 % of oil compared to the base case, water flooding. Water flooding alone recovers 49.5% of oil at the end of 5000 days. As shown in the figure, polymer and water flooding only recovers the same amount of oil the first 1000 days, afterwards polymer recovers more oil within the period 1100 – 4250 days. Surfactant only recovers 82.3% whiles a combined surfactant/polymer slug yields 84.8% of oil. Surfactant only and a combined surfactant/polymer flood yield an incremental oil of between 34-36 % above water flooding only.

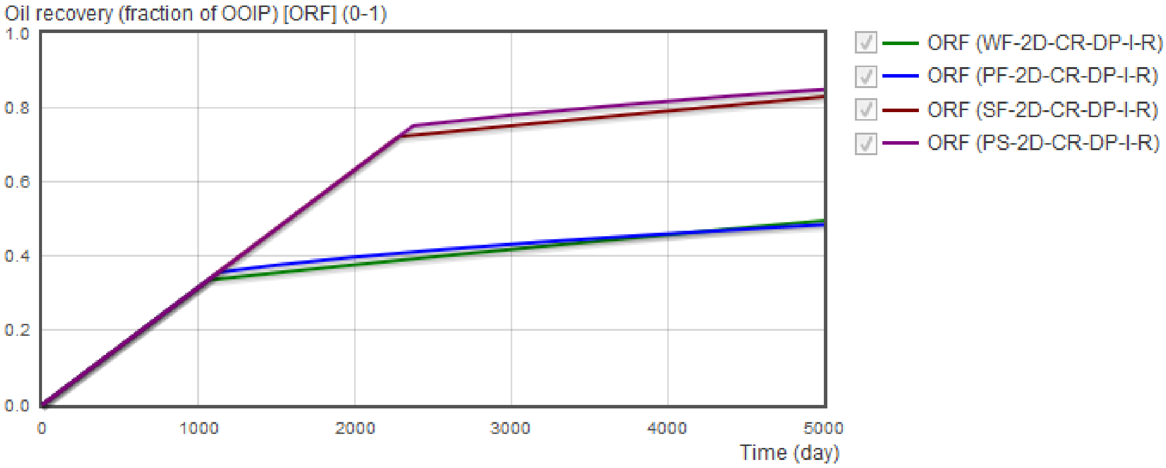


Figure 54: Simulated oil recovery (ORF) based on water-based EOR methods (WF: water flooding; PF: Polymer flooding; SF: Surfactant flooding and PS; combined polymer/surfactant flooding) for the Snorre field. The results are based on 2D model with the Dykstra-Parson (DP) approximation method at constant rate (CR).

Another method which has been evaluated on the Snorre field is the injection of low salinity water (Skrettingland et al 2011). Core flooding experiments and a single-well chemical tracer-test (SWCTT) field pilot have been performed to measure the remaining oil saturation after seawater flooding and after LowSal flooding. The laboratory core flooding experiments conducted at reservoir and low-pressure conditions involved core material from the Upper, Lower Statfjord and Lunde formations. The core material from the Statfjord formations gave incremental recovery in the order of 2% of original oil in place (OOIP) by injection of diluted seawater (Skrettingland et al. 2011). Similar amounts were produced during following NaCl-based LowSal injections. The same trend was observed in the high- and low-pressure laboratory experiments. No significant response to LowSal flooding was observed for Lunde cores. No response was normally observed during alkaline injection. The SWCTT field pilot was carried out in the Upper Statfjord formation. The average oil saturations after seawater injection, after LowSal seawater injection, and after a new seawater injection were determined; no significant change in the remaining oil saturation was shown. The measured in-situ value of remaining oil saturation after seawater flooding was in agreement with previous special core analysis (SCAL) experiments. Skrettingland et al. (2014) reported an interwell in-depth water diversion using sodium silicate improve sweep efficiency and increase oil recovery at the Snorre field. Comprehensive laboratory experiments preceded the pilot project.

Gas injection

- Used built-in correlations to calculate MMP:
  - HC gas (with 70% methane) 335 bar
  - CO_2 244 bar
  - Initial reservoir 383 bar
- Residual oil saturation at miscibility 5 %
- Maximum immiscibility pressure: 100 bar

Figure 55 show the simulated oil recovery for the gas-based methods; CO_2, hydrocarbon gas at miscible conditions and gas at immiscible conditions. Compared to water flooding, the gas-based methods result in lower oil recovery factors. In-built correlations in SWORD indicated that miscibility between the API Snorre oil and CO_2 will occur at 244 bar and 335 bar with hydrocarbon gas at Snorre reservoir temperature of 96°C. Injecting only CO_2 will produce 45.7% of oil compared to 41.2% with hydrocarbon gas. Injecting gas at immiscible conditions will produce 33.9% of oil.

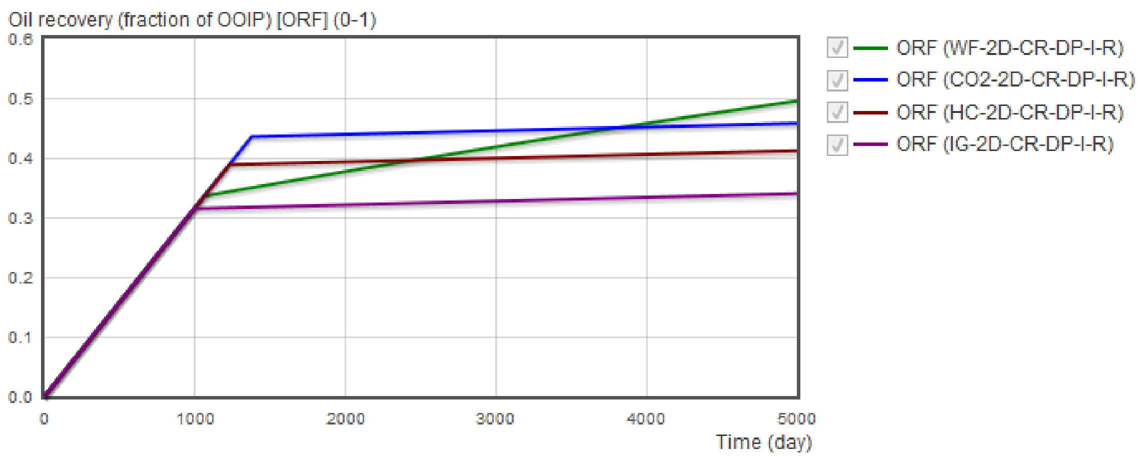


Figure 55: Simulated oil recoveries for Gas-based EOR methods; CO_2 and HC: hydrocarbon gas at miscible conditions and IG: immiscible gas compared to WF: water flooding in the Snorre field. The results are based on simplified 2D model with the Dykstra Parson (DP) approximation method at constant rate (CR)

Stenmark and Andfossen (1994) reported a summary of the Snorre hydrocarbon-WAG pilot initiated in February 1994 in the Snorre field. The injection of gas resulted in a significant increase in oil recovery. A reasonable history-match of the early pilot behaviour was obtained with both miscible and immiscible reservoir modelling assumptions. The miscibility pressure with hydrocarbon gas was estimated as 283 bar based on slim tube displacement experiments. In order to ensure miscible conditions, the reservoir pressure used in the WAG pilot project was kept above 300 bar during the first year of the gas injection (Stenmark and Andfossen, 1994). In-built MMP correlations gave an MMP of 335 bar with HC-gas with 70% methane at 96^{o}C.

5 Discussion

Pre-simulation with SWORD indicates that EOR application in offshore oil fields remains a promising option for increasing oil production on the NCS. The size of the targeted offshore oil fields is generally large, because their proven OOIP are sufficiently large to overcome the high cost of offshore development. For the eight fields screened at a well spacing of 1000 m, the proven oil in place is 3676.5 $millSm^3$, an original recoverable oil in place of 1816.4 $millsm^3$ and the remaining oil at 257 $millSm^3$. The estimates of additional oil recovery based on the studied EOR processes compared to only water flooding are significant. This means that a large amount of oil remaining on the NCS could potentially be recovered using EOR processes such as polymer, surfactant or/and a combination polymer/surfactant injection. However, potential showstoppers such as incomplete subsurface understanding, supply of secure low cost injectants compared to current oil price, challenge of implementing EOR on a brownfield and concerns over project economics can hamper the successful implementation of full scale EOR projects on the NCS.

As outlined in the report, injection of hydrocarbon gas as a supplement to water flooding can recover additional oil compared to only water flooding. On the NCS, huge success has been made with the water-alternating-gas (WAG) technique since the first WAG pilot was conducted on the NCS in 1970s. This has contributed to considerable amount of incremental oil when combined with water flooding. However, the scope of WAG can be limited due to availability of injection gas. Currently most of the WAG injections are performed at immisble conditions. The main mechanisms of incremental oil recovery by WAG are: (1) draining of attic oil, (2) sweeping of other areas not contacted by water, (3) reduction in water-cut and gas lifting of high water-cut wells.

CO_2-EOR has not been implemented on the NCS on the full-scale due to marginal economy and high risk associated with CO_2 injection. Furthermore, the source of CO_2 on the NCS is not readily available. However, Norway has extensive experience with storage of CO_2 in geological structures. Since 1996, approximately 1 Mt of CO_2 have been separated from gas production annually at the Sleipner Vest Field in the North Sea for storage in the Utsira formation, a geological formation more than 800 metres below the seabed. From 2014 a further 0.1-0.2 Mt of CO_2 from the newly developed Gudrun Field will be injected into the same formation every year (NPD CO_2 storage atlas, 2014). Thus, there is a huge potential for improving oil recovery with CO_2 if combined with capture and storage of CO_2 in some of the existing fields on the NCS.

The injection of CO_2 can decrease the viscosity of the oil and provide better or more efficient miscible displacement. As shown in the report, EOR screening show that CO_2 injection would produce more oil when compared to water injection only. Whiles it has been shown to work in the USA, the injection of CO_2 on the NCS will require excessive modifications to the current offshore installations. To implement a full-scale CO_2-EOR project, large amounts of CO_2 will be needed (around 25 million tons per year, which means that Norway must buy CO_2 from other countries). On the other hand, WAG with CO_2 can be beneficial since this will not require much CO_2 compared to a full-scale CO_2-EOR on the NCS.

EOR screening with SWORD indicated that surfactant flooding can recover over 30% of additional oil compared to water flooding in the selected fields at 1000 m well spacing. Surfactant-EOR has not been implemented on a larger scale on the NCS. Several parameters such as high residual oil saturations in the unswept zones of some of the fields on the NCS are favourable for enhancing the oil recovery using surfactants. The validity and effectiveness of this method has been checked through some pilot tests on the NCS.

For example, a single well pilot test was implemented on the Gullfaks field with only surfactant (Nordbotten et al. 1995) This lead to a mobilization of about 40-70% of the water flooded residual oil. The method seems viable for water flooded fields on the NCS, since there should be residual oil left in the reservoir. The technique can reduce the residual oil by improving the microscopic sweep efficiency. Surfactants can easily be added to untreated water injection as seawater is compatible with the reservoir conditions. The method can be costly as surfactants are quite expensive. However, surfactants are chemicals which can be back produced to the environment. This can be an issue if not properly dealt with by monitoring the chemistry of produced water.

The screening results also show that surfactant EOR is most efficient when combined with a polymer flood. Thus, surfactant flooding can improve on the microscopic sweep efficiency while the polymer flooding improves the volumetric sweep efficiency. An increased oil recovery was observed with a combined polymer assisted surfactant system (PASF) simulated on a limited area of Gullfaks field (Maldal et al. 1988). The method added an extra recovery of 3-5%. Moreover, the combined surfactant/polymer technique will depend on the oil price; if the oil price is high then the technique can be tested otherwise it won't be economically attractive.

The potential of microbial EOR on the NCS was not screened, however, a number microbial EOR pilot tests have been reported on the Gullfaks, Heidrun and Brage fields. The method involves giving bacteria the opportunity to change the interfacial tension between oil and water so that more immobile oil can be mobilized. The method is being utilized on the Norne field with some mixed results (NPD resources report, 2014). A pilot test was conducted on segment I1 of the Gullfaks field, and some positive effects of MEOR were expected. Some of the expectations on implementing this method were reduction in injectivity due to change in skin, reduced sea water fraction, less water-cut and increasing circulation time for injection water. Although, the pilot was implemented successfully, the results turned out to be disappointing. There was no response on neither the water-cut nor the production profile from wells in the pilot area. However, laboratory tests prior to the pilot test showed an increase in recovery. This may be because the bacteria used in the laboratory MEOR experiments are not suitable with the real environment of the reservoir. As an example, H_2S present in Gullfaks field due to extensive flooding has been shown to reduce the oil saturation through an anaerobic MEOR process prior to the aerobic MEOR laboratory tests.

Another IOR method which is gaining popularity and has the potential of improving oil recovery on the NCS is water management through gel blocking and water diversion (LPS, bright water, Na-silicate) in well with high water-cuts (Stavland et al. 2010; Stavland et al. 2011). As shown is chapter 2, the water-cut on the NCS averages 70% and is rising. The method has been tested on the Statfjord field (Boreng and Svendsen, 1997) with good results and recently on the Snorre field (Skrettingland, 2014) with some mixed results. These water-soluble chemicals are injected in the reservoir to reduce the permeability of the water channels establishing new water paths and better sweep efficiency at both microscopic and macroscopic levels. Laboratory experiments with linked polymer solution (LPS), Bright water, Na-silicate have been shown to block water production and divert injected water to the less swept zones (Aarra et al. 2005). LPS is an aggregated gel (alloidal dispersion gel) that acts as a blockage gel in zones where the residual oil is low, so that the injected water can go through the zone where the residual oil saturation is high. Bright water is a solution of polymers and surfactants. Laboratory experiments show that for the chemicals to be efficient, there should be a temperature gradient (different) between injector and producer. Na-silicate is quartz dissolved in NaOH which forms a glass like solution.

In the laboratory experiments, the pore space can be sealed by trapping of binary ions and re-crystallization of quartz by neutralizing the solution. The core floods studies have showed very encouraging results. The chemicals shall move into the reservoir and form micro gel particles in zones of high permeability. These gel particles can reduce the permeability and thus force the water to find new paths and invade less water flooded areas. Thus, the technique can increase the macroscopic and microscopic sweep. However, a major problem with this IOR technique is that many of the chemicals used are marked as red, which are environmentally unfriendly on the NCS. The silica based chemicals are marked as yellow (environmentally acceptable).

Finally, experience from other improved oil recovery (IOR) projects (BP's Clair Ridge low salinity and Total's Dalia polymer projects) show it is worth implementing EOR during the initial phase of field development. Statoil has shown some commitment in implementing IOR on the Johan Sverdrup field. Early IOR screening studies such as WAG, low salinity and polymer flooding are being considered (Kulkarni, 2014).

6 Conclusions

Based on the pre-simulation EOR screening study with SWORD, the following conclusions can be drawn:

- Considering the large volume of proven recoverable oil on and the fact that it is it is no longer commercially attractive for conventional infill drilling on some brownfields fields, EOR applications are a highly-promising option for offshore fields on the Norwegian continental shelf (NCS).
- EOR screening show that whatever helps to distribute displacing phases more evenly seems to work:
  - Surfactant
  - Polymer
  - Combined surfactant and polymer
- The efficiency of gas-based processes seems to be hindered by permeability contrast in the different zones.
- The oil and gas companies on the NCS through the Norwegian directorate should be encourage to build a data bank with easy accessibility to research institutions interested in studying EOR processes on the NCS.
- More detailed screening including laboratory experiments and reservoir simulation (for example IORCoreSim) of potential EOR processes would be required to identify potential showstoppers which may hamper the implementation of the process.

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Appendix

Performance prediction – input data

Before simulations can be performed, essential input data from the field are needed. The input parameters have been divided into two main groups; reservoir and fluid data and advanced processes input to ensure a logical presentation of the data. The fluid data describe the fluids in the reservoir (water, oil and gas). It is assumed that the injected water or gas has the same properties as the reservoir water or gas. The water and gas input data thus characterise the injection fluids for the EOR processes, water and gas performed in this work. The input parameters of the reservoir and fluids data (*Figures 56-58*) are grouped into three categories: reservoir, gas and water and water alternating with gas (WAG).

The reservoir input data contains the following parameters;

Injection to production well distance: distance between injection/production wells
Reservoir width: relevant only for cross-sectional geometry
Dip: Dip of the reservoir. Positive value indicates displacing fluid is injected structurally low and vice versa.
Oil viscosity: in-situ oil viscosity at reservoir conditions
Oil density: at reservoir conditions. This strongly depends on composition.
Injection and production rate: at reservoir conditions. This is relevant when a constant rate is specified as the boundary conditions.
Production well bottom hole pressure: relevant only with miscible gas flooding, since microscopic sweep is sensitive to pressure level.
Pressure drop from injection to production well: pressure drop through the reservoir. Only relevant when a constant drop is specified as boundary condition.
Injection and production well radius: Relevant only in 3D, if pressure is an issue.

In addition to the input data describing the reservoir, the table at the lower part of *Figure 56-58* show data describing the layer properties of the reservoir. The input parameters are:

Vertical/horizontal permeability: absolute vertical permeability (k_v) and horizontal permeability (k_h).
Anisotropy: Ratio of vertical (average) to the horizontal (average) permeability.
Porosity: The porosity of the different layers in fraction.
Thickness: reservoir layer thickness
Initial oil saturation: initial (irreducible) oil saturation at the beginning of the calculations.

Figure 56: Reservoir and fluid properties

Reservoir | Water | Gas | WAG

Injection to production well distance: 1000.00 m	Oil viscosity: 0.8 cp	Production well bottomhole pressure: 65.00 bar
Reservoir width: 2000.00 m	Oil density: 800.00 kg/m3	Pressure drop from injection to production well: 10.00 bar
Dip: 10.00 deg	Oil formation volume factor: 1.00	Injection and production well radius: 1.00E-2 m

Reservoir layers

	Vertical permeability, kv (md)	Horizontal permeability, kh (md)	Anisotropy, kv/kh	Porosity (0-1)	Thickness (m)	Initial oil saturation (0-1)
1	1000.00	1000.00	1.00	0.20	5.00	0.90
2	10.00	10.00	1.00	0.20	25.00	0.80
3	100.00	1000.00	0.10	0.20	5.00	0.90

The water/gas input data (*Figures 57-58*) contains the following parameters;

Water/gas viscosity: At reservoir conditions. This strongly dependent on reservoir pressure
Water/gas density: Densities at reservoir conditions (strongly dependent on pressure)
The layer data below includes:
Residual water saturation: residual water saturation.
Residual gas saturation: residual gas saturation – relative permeability phase that corresponds to the minimum gas saturation.
Residual oil or gas saturations: residual oil or gas saturations after water or gas flooding.
End-point relative permeability, oil: relative permeability to oil at initial water or gas saturations.
End-point relative permeability, water: relative permeability to water at residual oil saturation.
End-point relative permeability, gas: relative permeability to gas at residual oil saturation.

Figure 57: Reservoir and fluid data for water-oil system

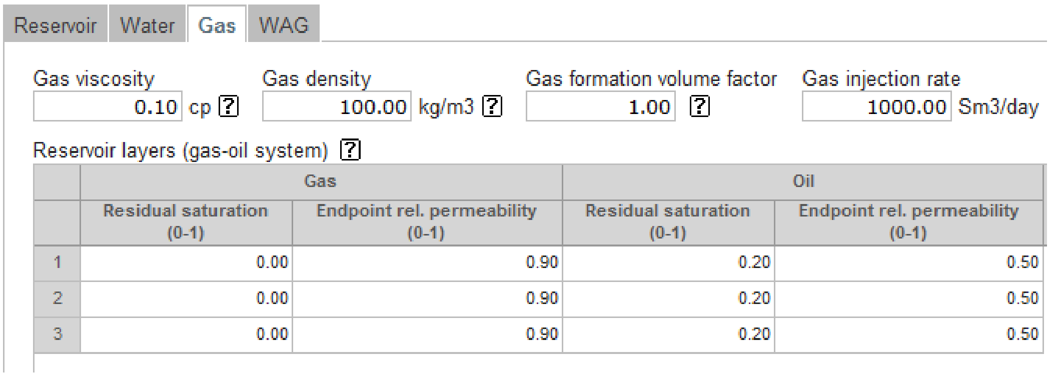
Reservoir | Water | Gas | WAG

Water viscosity: 1.00 cp	Water density: 1000.00 kg/m3	Water formation volume factor: 1.00	Water injection rate: 1000.00 Sm3/day

Reservoir layers (water-oil system)

	Water		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.10	0.90	0.20	0.50
2	0.20	0.90	0.20	0.50
3	0.10	0.90	0.10	0.50

Figure 58: Reservoir and fluid data for gas-oil system



	Gas		Oil	
	Residual saturation (0-1)	Endpoint rel. permeability (0-1)	Residual saturation (0-1)	Endpoint rel. permeability (0-1)
1	0.00	0.90	0.20	0.50
2	0.00	0.90	0.20	0.50
3	0.00	0.90	0.20	0.50

Performance prediction – Advanced processes input

This section describes the properties of the different advanced EOR models used in the performance prediction module. Each EOR model has a unique window for input parameters.

Polymer model in SWORD

The polymer model (*Figure 59*) in SWORD assumes that adding polymer to the water phase increases the water viscosity. This decreases the mobility ratio of the displacing phase (water) to the displaced phase (oil) resulting in an increase in volumetric sweep efficiency. Polymer flooding can be used to improve oil recovery in the unswept zones of the reservoir. Polymer flooding does not influence the microscopic sweep efficiency. The viscosity of the polymer solution depends on the fluid velocity, as it a non-Newtonian fluid. SWORD considers this effect via the Carreau model (Carreau, 1972, Bird et al. 1987). In this work, sensitivity tests were performed to find the optimal parameters, which gives the highest recovery with polymer flooding. Thus, a default of the parameters were used in the all the performance prediction calculations.

The user input parameters (*Figure 59*) are as follows:

Polymer viscosity: Newtonian limit viscosity at reservoir conditions.

Shear thinning index: as defined in the Carreau model.

Relaxation time: as defined in the Carreau model.

Shear rate correction factor: The shear correction factor depends on the porous medium and the type of polymer. A typical number for the shear rate correction factor for North Sea sandstone is 5 (*SWORD manual, 2013*).

Proportionality factor, *C*: This models how the residual resistance factor (RRF) changes with increasing permeability. A large C (in magnitude) produces a large permeability reduction for permeabilities below k_{end}

Limiting permeability, k_{end}: At k_{end}, the permeability is so high that the residual resistance factor (RRF) becomes 1.0, thus no permeability reduction due to polymer contact.

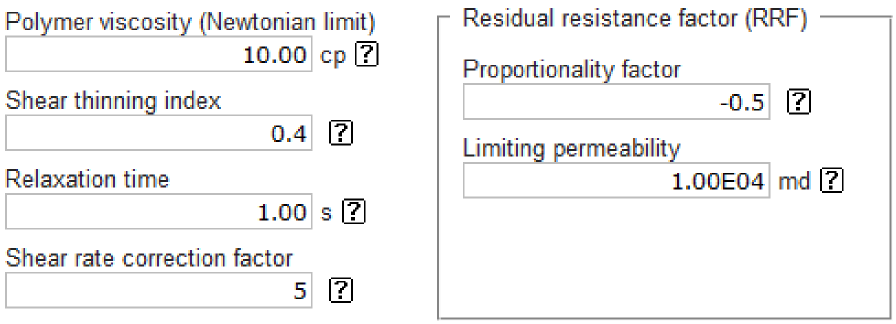


Figure 59: The polymer model in SWORD

Surfactant model in SWORD

The surfactant model (*Figure 60*) in SWORD assumes that adding surfactant to the injected water causes a reduction in the interfacial tension between water and oil. Surfactant flooding can be used mobilise capillary trapped oil in the water swept zones, and thus improve the microscopic sweep efficiency compared to conventional water flooding. A disadvantage is the increased end-point relative permeability to water that turn the mobility ratio even more unfavourable compared to the conventional water flooding. Thus, volumetric sweep efficiency may be reduced.

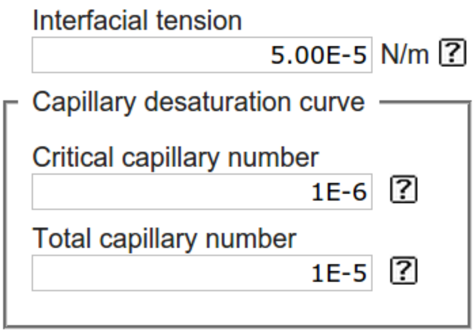


Figure 60: Surfactant model in SWORD

The user input parameters in the surfactant model are:

Interfacial tension: interfacial tension between oil and water phase containing surfactant with a specified concentration.

Critical capillary number: Is the capillary number for which the residual oil saturation after surfactant flooding falls below the residual oil saturation after water flooding on the capillary de-saturation curve (CDC).

Total capillary number: is the capillary number where the residual oil saturation after surfactant flooding becomes zero on the CDC.

Hydrocarbon gas model in SWORD

The hydrocarbon model (*Figure 61*) is as described below. The assumes that the residual oil saturation is a function of the reservoir pressure.

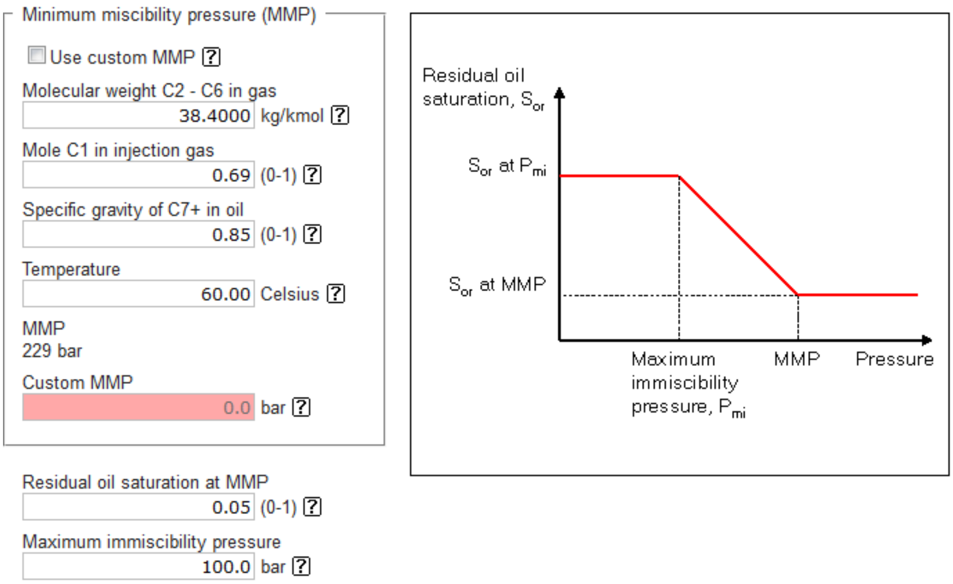


Figure 61: Hydrocarbon model in SWORD

Molecular weight C_2-C_6: Molecular weight of the intermediate fractions C_2-C_6 in the injection gas used in the formula for estimation of Miminium miscibility pressure (MMP)

Mole C1 fraction in injection gas: Mole % of methane (C1) in the injection gas used in the formula for estimation of the MMP.

Specific gravity of C7+ fraction in oil: Specific gravity of the heavy fraction C7+ in the stock tank oil.

Temperature: reservoir temperature

MMP: Calculated miminium miscibility pressure from the above parameters.

Custom MMP: Custom MMP if the data is known from slim-tube tests.

Residual oil saturation at MMP: Residual oil saturation behind the gas front at, and above MMP

Pressure for full immiscibility: This is the maximum pressure at which full immiscibility of gas prevails

CO_2 model in SWORD

The CO_2 model (*Figure 62*) is as described below. The assumes that the residual oil saturation is a function of the reservoir pressure.

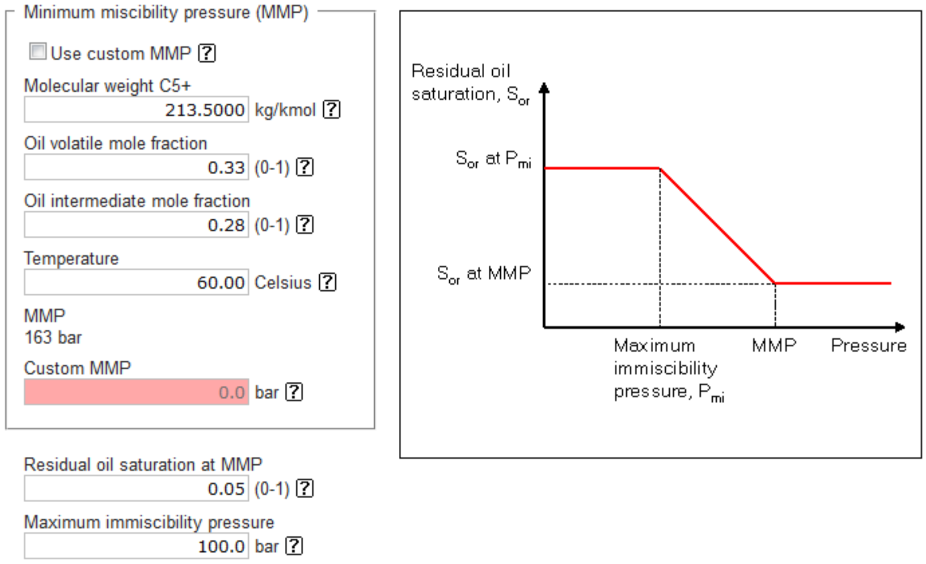


Figure 62: CO_2 model in SWORD

Molecular weight C5+: Molecular weight of pentane and heavier fractions in the stock tank oil used in the formula for estimation of Miminium miscibility pressure (MMP)

Oil volatile mole fraction: The oil volatile mole fraction is considered to consist of methane and nitrogen

Oil intermediate mole fraction: The oil intermediate mole fraction is considered to consist of ethane – butane, CO_2 and hydrogen sulphide.

Temperature: reservoir temperature

MMP: Calculated miminium miscibility pressure from the above parameters.

Custom MMP: Custom MMP if the data is known from slim-tube tests.

Residual oil saturation at MMP: Residual oil saturation behind the gas front at, and above MMP

Pressure for full immiscibility: This is the maximum pressure at which full immiscibility of gas prevails