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Evaluation of Surfactant Flooding for EOR on the Norne Field, C-segment

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Abstract

The world's energy demand is constantly increasing. It offers a problem when hydrocarbons both are the most energy efficient source known in combination with being a limited resource. This motivates to increase the recovery from existing oil fields by means of EOR methods. Surfactant flooding is such a method for enhancing the oil production from an oil field.

The Norne field is located in the North Sea. It is divided into four segments where the C-segment is the focus area of this report. The production of oil started in 1997 and the production is now declining. Water is being injected, however, to extract more oil tertiary recovery is necessary. Surfactants aim to enhance the oil recovery by lowering the interfacial tension between oil and water and hence lower the capillary pressure. This will mobilize the residual oil and make it possible to produce.

Surfactant flooding can be an effective technique to boost the recovery, but there are several challenges to overcome. These challenges include loss of surfactants to the formations, facility and costs. The Norne C-segment being an offshore field represents an extra challenge.

Eclipse 100 is used as simulation tool to model the surfactant flooding. Prior to implementing the surfactant model, history matching was performed. This was to calibrate the model in order to ensure a better prediction of the activity in the reservoir. After implementing the surfactant model, four different cases was evaluated to find the optimum injection strategy. The cases include the injection into different formations, the use of different wells, and alteration of concentration and injection period. An economical evaluation was performed based on the results.

The results from the simulations were somewhat surprising and unexpected. Despite being a suitable candidate through screening, surfactant flooding is not a feasible method to use at the Norne C-segment.

Sammendrag

Verdens energibehov er stadig økende. Når man tar i betraktning at hydrokarboner både er den mest energieffektive kilden til energi i tillegg til å være ikke-fornybar representerer det en utfordring. Dette motiverer til å øke utvinningen fra eksisterende oljefelt ved hjelp av EOR metoder. Injeksjon av surfektanter i reservoaret er en slik metode for å øke utvinningen.

Norne-feltet ligger i Nordsjøen. Det er inndelt i fire segmenter der C-segmentet er fokusområdet i denne rapporten. Produksjonen av olje startet i 1997 og er nå avtagende. Selv om vann injiseres opprettholdes ikke trykket i reservoaret på det nødvendige nivået for å sikre produksjon. Ved å injisere surfektanter i reservoaret vil grenseflatespenningen mellom vann og olje senkes. Det kapillære trykket i porerommet vil som følge av dette bli lavere, dette vil føre til mobilisering av residual olje.

Injeksjon av surfektanter kan være en svært effektiv metode for å øke utvinningen, men det er flere utfordringer som må tas hensyn til. Blant slike utfordringer nevnes tap av surfektanter til formasjonen, logistikk og gjennomføring samt økonomi. At C-segmentet på Norne er lokalisert offshore byr på en ekstra utfordring.

Simuleringsprogrammet Eclipse 100 blir brukt som verktøy for å modellere effekten av surfektanter i reservoaret. Før gjennomføring ble det utført historietilpasning for å kalibrere modellen bedre. Dette ble utført for å bedre predikere aktiviteten i reservoaret. Etter å ha implementert surfektantene i reservoaret ble fire forskjellige caser evaluert for å finne den beste strategien for injeksjon. Casene inkluderte evaluering av formasjon til injisering, valg av brønn, og endring i både konsentrasjon og lengde på injeksjonsintervallet. En enkel økonomisk analyse ble utført på grunnlag av resultatene.

Resultatene var noe avvikende og overraskende i forhold til forventingene. Til tross for å bli karakterisert som en passende kandidat for surfektantinjeksjon, er det ikke lønnsomt å bruke denne metoden på C-segmentet til Norne.

Preface

This report is the result of my master thesis, which all graduates at Norwegian University of Science and Technology execute prior to their graduation. It is an extension of my in-depth project “Introduction to Surfactant Flooding for EOR on the Norne Field, C-segment”, and some of the chapters regarding theory are from this previous work. The process of history matching, presented in chapter 4, was executed in close collaboration with Anders Abrahamsen.

Firstly I would like to address appreciation and gratitude to my supervisor Professor Jon Kleppe at NTNU for his help and support during my work. I would also like to thank Richard Rwechungura, Jan Ivar Jensen and Mehran Namani at NTNU for their support and advice. Further I would like to thank Sindre Lillehaug and Bjørn Tore Samuelsen from Statoil’s Norne team in Harstad for their assistance. I am grateful to Espen Kowalewski, Vegard Kippe and Kristian Sandengen from Statoil who kindly answered questions via email. Finally, I would like to thank the Center for Integrated Operations at NTNU, Statoil ASA as operator on Norne, Petoro and ENI as partners for releasing data regarding the Norne field.

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1. Introduction

Hydrocarbons are still the largest and most effective source of energy known today (IEA, 2011). As the need for energy worldwide constantly is growing there is a rising demand for oil and gas. At the same time the world's production of hydrocarbons is declining. This represents a challenge when knowing that the resources are limited and new discoveries are rare. To be able to address the demand for energy, new technology for enhancing the oil recovery of existing fields is a necessity.

The average recovery factor from oil fields after abandonment is around 30-40% (TOTAL, 2008). For the Norwegian continental shelf it is a bit higher, around 46% (Olje- og energidepartementet, utvinningsutvalget, 2010). These numbers indicate that the residual amount of oil is around 50%. To extract this oil, methods for enhanced oil recovery (EOR) are used.

There is a big portfolio of different EOR methods aiming differently to extract oil from the reservoir. Surfactant flooding is such a method. It can be compared to soap in in the way it targets the extraction of residual oil. No methods for EOR are commercially used on the Norwegian continental shelf today. This is partly due to the high recovery factor, the high cost of EOR-methods and to the new findings on the shelf. The only experiment of surfactant flooding outside laboratory in Norway is two single well studies on Gullfaks and Oseberg (Olje- og energidepartementet, utvinningsutvalget, 2010). Both projects gave increased recovery, however they were not economically feasible. As EOR methods tend to be costly to implement it requires a high and stable oil price in order to provide a positive return.

This study is an extension of the project "Introduction to Surfactant Flooding for EOR on the Norne Field, C-segment", and it aims to explain the method of injecting surfactants into the C-segment of the Norne field in order to recover the residual oil. Prior to the simulation of this, the reservoir model will be history matched to achieve the most accurate results. The simulation program Eclipse 100 will be used as a tool for modeling surfactant flooding of the reservoir. An economic analysis will also be performed to determine the feasibility of such a project.

2. Enhanced Oil Recovery – EOR

This chapter is originally from the pre-study; “Introduction to Surfactant Flooding for EOR on the Norne Field, C-segment” by Kristine Nielsen.

The production of hydrocarbons from a reservoir is typically divided into three stages; primary, secondary and tertiary recovery.

- Primary recovery is also called natural depletion. This denotes the production derived by the natural pressure difference in the reservoir and the bore hole. During production, the pressure in the reservoir will decline. This results in lower production. To maintain the production it is necessary to maintain the pressure. The recovery rate after natural depletion is on average 46% on the Norwegian shelf (Kristensen, 2011).

- Secondary recovery aims to maintain pressure by injecting non-alien fluids or gasses into the reservoir. The fluids and gases are typically water and natural gas.

- Tertiary recovery denotes the production that is done after secondary recovery no longer is successful. This is done by injecting alien fluids or gases into the reservoir. This is in literature also referred to Incremental/Improved Oil Recovery (IGR) and Enhanced Oil Recovery (EOR) (UNSW, 2011).

There are many techniques for EOR, which all aim to improve on the recovery. The term recovery can be divided into microscopic and macroscopic recovery. Some of the methods seek to improve on the recovery by increasing microscopic displacement and others by increasing macroscopic displacement. Some techniques aim to increase both.

The EOR methods are typically divided into solvent-, thermal- and chemical methods;

- Solvent methods denote different strategies of injecting gas into the reservoir. This is typically CO_2, nitrogen or flue gas (UNSW, 2011).

- Thermal methods are techniques where either hot water or steam is injected to increase the reservoir temperature. This aims to increase the oil viscosity which makes the oil more mobile and in turns provide an increase in the production.

- Chemical methods refer to techniques were chemicals are injected. The chemicals can, depending on the particular chemical, both aim to increase the microscopic and macroscopic displacement. Surfactants, polymers and alkalines are examples of such chemicals. These may be used separately or combined in order to boost the production.

Techniques for EOR have been studied at a broad scale. However, no methods are commercially used in the North Sea (Awan, et al., 2006).

2.1 Objective and principle of EOR

As stated the objective of EOR is to increase the microscopic or macroscopic displacement efficiency, or both, and hence the production of hydrocarbons.

The microscopic displacement efficiency (E_D) denotes the displacement on a pore-scale level and is closely related to the residual oil saturation, S_{or} (Green & G Paul, 1998). The amount of oil trapped in the reservoir, after primary and secondary recovery, is on a microscopic level controlled by the capillary pressure and thus the interfacial tension (IFT). These two parameters are correlated and proportional. By decreasing the IFT the capillary pressure will decrease, this makes the residual oil mobile and hence possible to produce. The capillary pressure and the IFT are linked together in Laplace's Equation which is further explained in Chapter 5.4, where the effects of surfactants are described.

The macroscopic displacement is called the volumetric sweep efficiency and is strongly dependent on the mobility between the phases in the reservoir (Johannesen & Graue, 2007). The mobility is controlled by the viscosity of the specific phase. When the residual amount of oil is trapped in the reservoir due to low mobility of the displacing phase, the viscous forces are the dominating forces (Dr.Tran, 2006). The volumetric sweep (E_V) is defined as the product between the areal (E_A) and the vertical (E_I) sweep efficiency. Areal sweep denotes the area swept by the injecting phase divided by the whole area. Vertical sweep refers to the fraction of the vertical area swept by the injecting phase (Dr.Tran, 2006), (Sehbi, et al., 2001).

$$E_V = E_A * E_I \tag{2.1}$$

An important value called the capillary number (N_C) designate whether the capillary forces or the viscous forces dominate in the reservoir. The value is defined as (Johannesen & Graue, 2007):

$$N_C = \frac{v\mu}{\sigma} \tag{2.3}$$

Where v is the Darcy velocity, μ is the viscosity of the displacing fluid which is water containing surfactant in this case and σ is the interfacial tension between the displacing and displaced phase. The value of this number gives an indication of which displacement efficiency important to target in order to improve on the recovery. The reservoir is dominated by the capillary forces if $N_C < 10^{-5}$, the amount of trapping is normally high at this value (Dr.Tran, 2006). To improve on the recovery it will be necessary to lower the IFT to increase N_C and then increase E_V by improving the mobility ratio (M). If the value of $N_C > 10^{-5}$ the viscous forces dominate in the reservoir and thus the residual oil is trapped due to mobility issues. It will then be adequate to improve the mobility ratio to improve on the recovery.

The mobility ratio is defined as (Johannesen & Graue, 2007):

$$M = \frac{\lambda_{displacing\ phase}}{\lambda_{displaced\ phase}} = \frac{\left(k_r/\mu\right)_{displacing\ phase}}{\left(k_r/\mu\right)_{displaced\ phase}} \tag{2.4}$$

Where λ denotes the mobility, k_r denotes the relative permeability and μ denotes the viscosity. The mobility ratio characterizes how the displacing and displaced phase flows in relation to each other. It is desirable to keep $M \geq 1$ (Lien, 2008). This indicates that the displaced phase moves more rapidly than the displacing fluid and thus the front is stable. If $M < 1$ undesirable results like viscous fingering may occur (Lien, 2008). Viscous fingering denotes when the displacing phase moves more quickly and penetrates the displaced phase. This results in an early breakthrough of the displacing phase, which in turns decreases the overall recovery. In order to keep the mobility ratio at a low level the viscosity of the phases must be monitored and altered if necessary. Lowering the IFT or mobility ratio is by means of EOR methods.

3. Norne field

This chapter is based on the pre-study; “Introduction to Surfactant Flooding for EOR on the Norne Field, C-segment” by Kristine Nielsen.

3.1 General

The Norne Field is located on the Norwegian continental shelf about 200 km from the main land between Sandnessjøen and Brønnøysund. Its position is indicated with a red mark in Figure 3.1. The specific location is at block 6608/10 and 6608/11. The operator of the field is Statoil ASA. It is controlled from Harstad in Northern Norway by Statoil with Petoro, with a share of 54%, and Eni Norway, with a share of 6.9%, as partners (Norwegian Petroleum Directorate, 2011).

Figure 3.1 - The location of the Norne Field (Statoil, 2010).

The field was discovered in 1991, drilling started in 1996 and production a year after that in 1997. It is developed using a floating production and storage vessel which is connected to seven subsea templates, as illustrated in Figure 3.2 (Lind, et al., 2001). This vessel has a processing plant aboard and storage tanks for stabilized oil (Statoil, 2010). Norne is divided into two divisions, the Main Structure containing the C-, D- and E-segment and the Northeast segment containing the G- segment. Faulting of the whole reservoir determines the demarcation of the different segments. Faulting is discussed in chapter 0.

The original oil in place (OOIP) and original gas in place (OGIP) was calculated to be 156.0 x 10^6 Sm^3 and 28.90 x 10^9 Sm^3 respectively (Lind, et al., 2001), whilst the recoverable oil and gas in place was calculated to be 93.40 x 10^6 Sm^3 and 11.70 x 10^9 Sm^3. Recoverable oil gas is the oil the volumes possible to produce. Table 3.1 summarizes this.

Table 3.1 - Shows the oil and gas properties in the reservoir. (Norwegian Petroleum Directorate, 2011).

Oil [mill. Sm^3]			**Gas** [bill. Sm^3]		
Orig. in place	Recoverable	Remaining	Orig. in place	Recoverable	Remaining
156	93,4	8,8	28,9	11,7	0,9

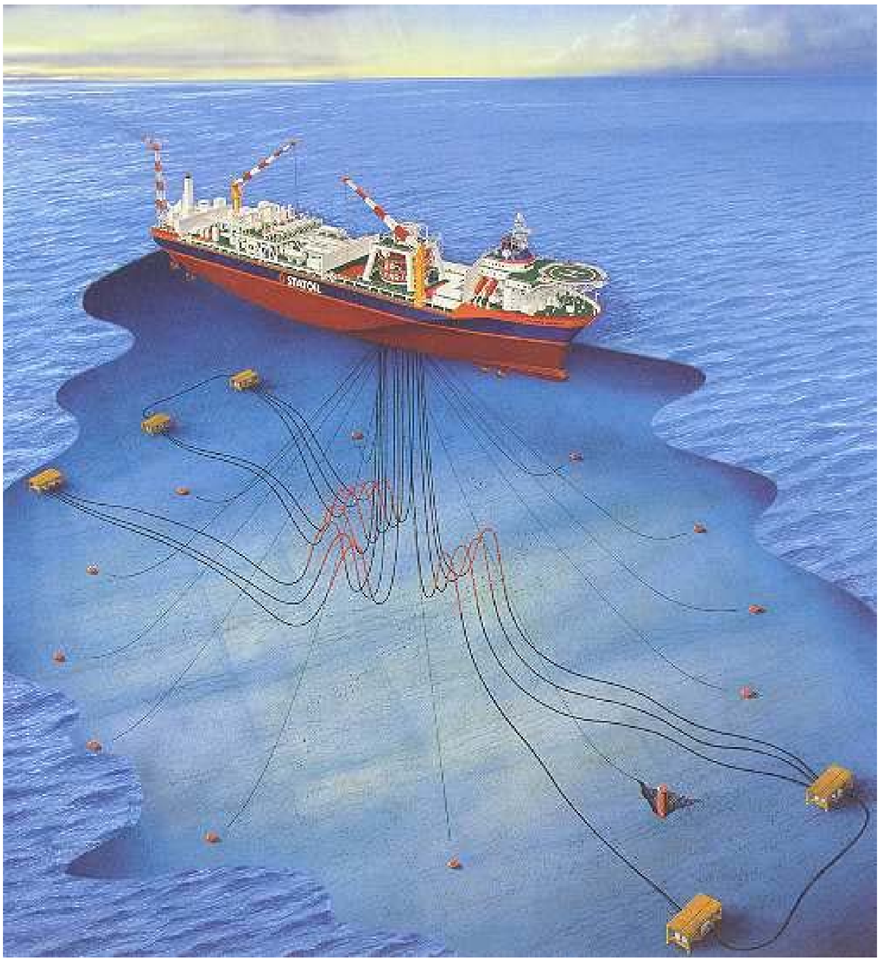

Figure 3.2 - The floating production and storage vessel at Norne (Offshore Technology, 2011).

3.2 Geology

The reservoir is structured as depicted in Figure 3.3. The formations are mainly sandstone from the Middle to Upper Jurassic era. The whole reservoir is measured to be approximately 224 meters thick, and is situated at a depth of 2500-2700 meters. This exposes the reservoir to digenetic processes e.g. mechanical compaction which in turn will reduce the quality of the reservoir. The average porosity is in the range of 25-30%. The permeability differs from 20-2500mD. The initial pressure was determined to be 273bars (Verlo, 2008). Table 3.2 summarizes the key data.

There are four major formations in the Norne reservoir called; Garn, Ile, Tofte and Tilje. Between Ile and Garn there is also a thin layer called the Not formation. About 80% of the oil is assumed to be situated in the Ile and Tofte formations, and the majority of the gas in the Garn layers.

3.2.1 Ile formation

The Ile formation is 32-40m thick and is defined between layer 5 and 11 in the reservoir model. The formation is sandstone deposited in a semi-marine environment during the late Toarcian to Aalenian age in Mesozoic era (Directorate, 2012). There are representations of tidal-influenced deltas and coastline settings (Directorate, 2012). The formation is divided into three zones according to characteristic features particular layers. Zone 1 is the lower layer of the three, both this and layer two consist of fine to very fine grained sandstone. The upper zone is coarser than the underlying zones and has slightly poorer reservoir quality (Verlo, 2008).

3.2.2 Tofte formation

The Tofte formation is also sandstone deposited in a semi-marine environment, but during the late Troarcian to Pliensbachian geologic age period (Directorate, 2012). In the reservoir model Tofte is defined from layer 12 through layer 18. As with Ile it is divided in three zones. The zones are coarsening upwards with medium to coarsed sandstone in zone 1, fine grained in zone 2 and very fine to fine grained sandstone in zone 3.

3.3 Reservoir communication

The Not formation is a sealing layer limiting the vertical communication between Ile and Garn. On top of the Garn formation there is another sealing layer, called the Melke formation, which serves as a cap rock, preventing the oil and gas to migrate from the reservoir. In addition to this obstruction of the vertical flow, there are other barriers in the reservoir.

The barriers include (Verlo, 2008):

- Garn 3/Garn 2 – Carbonate cemented layer at top Garn 2
- Ile 3/Ile 2 – Carbonate cementations and increased clay content at base Ile 3
- Ile 2/Ile 1 – Carbonate cemented layers at base Ile 2
- Ile 1/Tofte 4 – Carbonate cemented layers at top Tofte 4
- Tofte 2/Tofte 1 – Significant grain size contrast
- Tilje 3/Tilje 2 – Claystone formation

In addition to these horizontal barriers Norne has a network of faults in both x and y direction. The flow through the reservoir is to some extent affected by this faulting. The transmissibility of each fault is differs, and some are limiting the flow more than others. A map of this faulting is enclosed in Appendix A, in figure Figure A.1 and Figure A.2.

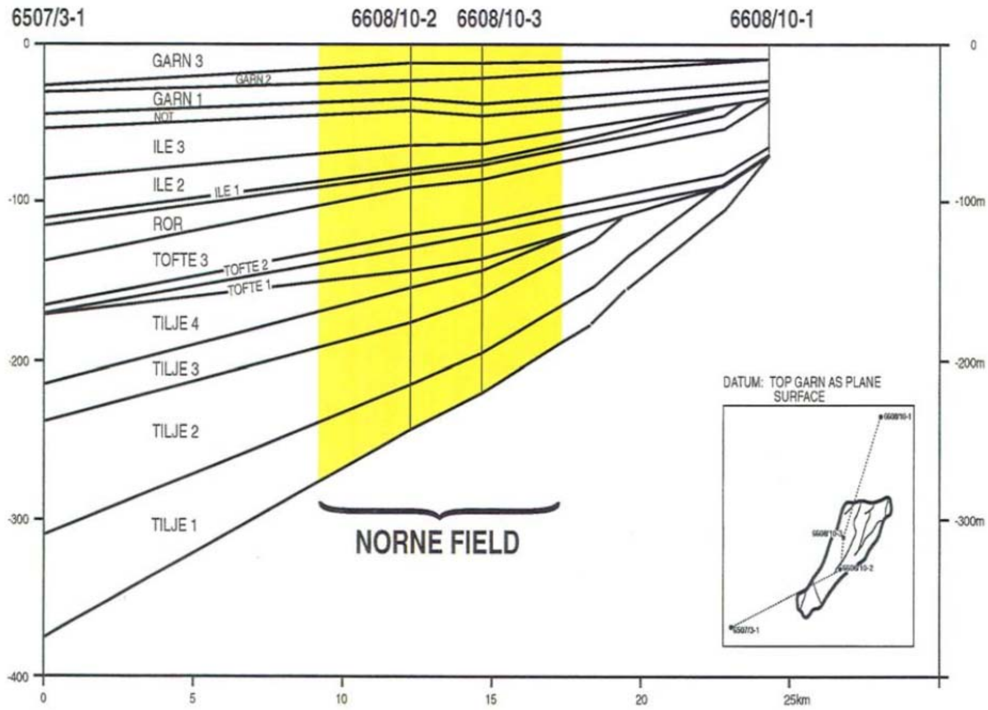

Figure 3.3 - The tilting structure and the layering of Norne (Verlo, 2008).

Table 3.2 - Summarizes the important key parameters in Norne (Maheshwari, 2011), (Lind, et al., 2001).

Properties	Units	Norne Main Structure (C-, D- and E-segment)	Norne G-segment
Fluid			
Initial pressure(P_i)	bar	273.2	273.2
Bubble point pressure(P_{BO})	bar	251	216
Gas oil ratio(GOR)	Sm^3/Sm^3	111	96
Oil formation factor at bubble point($B_{o,BO}$)	Rm^3/Rm^3	1.347	1.30
Oil viscosity at bubble point($\mu_{o, BO}$)	cp	0.58	0.695
Oil density at bubble point($\rho_{o, BO}$)	g/cm^3	0.712	0.729
API gravity	^{0}	32.7	
Gas formation factor(B_g)	Rm^3/Rm^3	4.74E-3	
Reservoir			
Formation type		Sandstone	
Initial temperature(T)	^0C	98.3	98.3
Porosity(ϕ)	%	25-30	
Permeability(K)	mD	20-2500	
Depth(D)	m	2500-2700	
Thickness	m	224	
Oil saturation(S_o)	%	35-92	

3.4 Drainage strategy

In 2006 13 wells were situated in the C-segment at Norne, 9 producers and 4 injectors (Kheradmand, 2011).

There are mainly horizontal producers at Norne. The first production wells drilled were vertical; these have later been sidetracked to horizontal wells (Verlo, 2008). The original drainage strategy was to inject gas into the gas cap and water into the water zone in order to maintain the reservoir pressure. The discovery of the sealing Not formation led to the abandonment of this strategy. It was instead decided to inject the gas into the water zone and lower part of the oil zone (Lind, et al., 2001). In 2005 the injection of gas was stopped as exportation of gas began. Oil was produced with water injection as the only driving mechanism. Figure 3.4 illustrates the drainage strategy. The red color illustrates gas, green color indicates oil, blue color for water. The yellow arrow illustrates injection of water, red arrow illustrates injection of gas and the green arrow depicts production of gas.

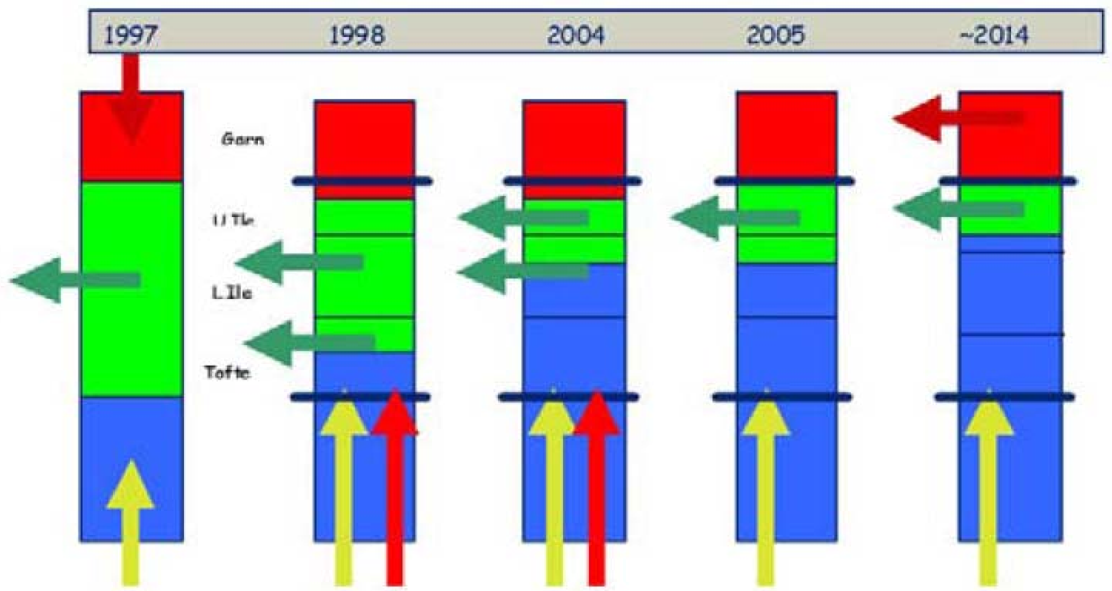

Figure 3.4 - Draining pattern of the Norne field (Verlo, 2008).

3.5 EOR potential

As mentioned in chapter 3.1 the overall oil production from Norne was measured to be 93.40 x 10^6 Sm^3 at the end of 2010. The remaining volume was estimated to be 8.80 x 10^6 Sm^3 (Norwegian Petroleum Directorate, 2011). This gives a volume of recovered oil to be 84.60 x 10^6 Sm^3, which is roughly 90% of the recoverable oil.

The current plan is to produce from the field until 2021 and if possible prolong the production to 2030 (Statoil, 2012). To succeed with this plan various measures are being considered to improve on the recovery. This includes using new well technology (Norwegian Petroleum Directorate, 2011). If all of the recoverable oil is produced, the total recovery will be 60%. This is considered to be very high, as the average recovery on the Norwegian Continental Shelf is approximately 46% (Kristensen, 2011). Despite the high recovery there is a long way to go to extract 100% of the oil in place. The 40% left in the reservoir after production of the so called “easy oil” is a challenge to extract. To extract this, EOR methods needs to be investigated and tested for. Figure 3.5 illustrates the percentages mentioned. The factors to decide if this is profitable are among several the costs involved and the risks involved. There is no doubt that the EOR potential is there. The main issue is the profitability of starting enhanced oil recovery.

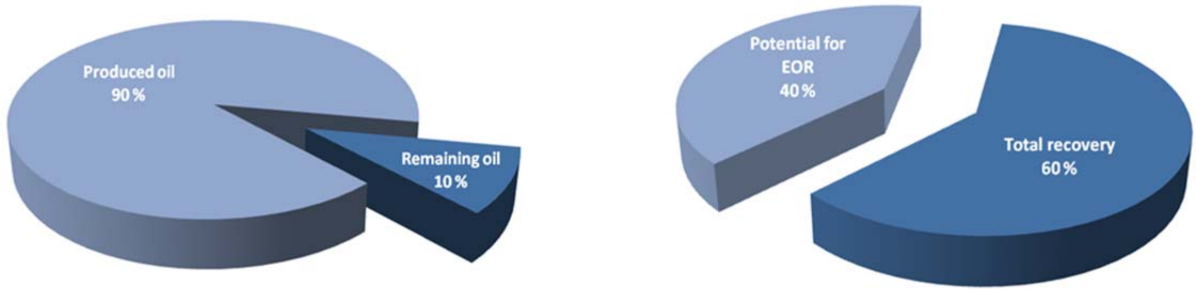

Figure 3.5 - a) The remaining amount of easy oil b) The EOR potential.

3.6 Screening

After having determined whether the potential for improving the oil recovery is of the right scale, it is necessary to screen the field against the different EOR methods. As mentioned in chapter 2 there are several different EOR methods. The process of finding the method best suited for a particular reservoir is often based on a set of screening criteria developed by J. Taber. These criteria are based on data from successful field projects and on the general understanding of conditions that favors recovery from a reservoir. The properties often considered most important are; API-Gravity, viscosity, composition, oil saturation, formation type, net thickness, average permeability, depth and temperature (Taber, et al., 1997). In the procedure of evaluating the field, the properties mentioned have a range of values for each EOR method. The screening is not all black and white and there can be more than one suitable method for a particular field, if so the cost aspect can determine a method. As new technology continuously is being developed, some of the methods may prove to be successful even if it does not agree with the screening model.

The key data from the Norne field in Table 3.2 was compared to the criteria in the screening method developed by J. Taber. An overview of the screening criteria is found in **Error! Reference source not found.** in Appendix 0. The evaluation immediately excluded the majority of the methods. The methods micellar/polymer, ASP and alkaline and polymer flooding, defined as 4 and 5 in Taber's screening model, stood out as the best candidates. Overall, these chemical EOR methods corresponded well with the defined values.

A sandstone reservoir is preferred in order to minimize the adsorption and loss of chemicals (Michaels, et al., 1996). As Norne generally is a sandstone reservoir, it is a good match. The API-gravity at Norne is 32,7° and above the desired 20° for chemical flooding. As for the composition of hydrocarbons it is desirable to have light to intermediate hydrocarbons. An overview of the hydrocarbon composition, shown in Figure A.5 in Appendix A, depicts that this is the case for Norne. The viscosity of the oil distinguish the use of surfactants and polymers in the reservoir. The oil viscosity for a surfactant flood should be less than 10cP and preferably less than 3cP (Michaels, et al., 1996). This is to avoid the need for polymer drive. In Norne the viscosity is 0,58cP and well below the desired value.

3.7 The Norne reservoir model

The model of the Norne field is originally developed by Statoil ASA, the version used in this report was last edited in 2004 (Statoil, 2010). Prior to the simulation of surfactant flooding the model needed to be history matched; this process is discussed in the next chapter.

The full field model of Norne, showed in Figure 3.6, consists of 46x112x22 grids with 49080 active grid cells. The C-segment is indicated with the circle in Figure 3.6 and in its entirety in Figure 3.7. The C-segment consists of 19911 active grid cells (Kheradmand, 2011). The model is coarsed meaning that cells have been merged together to make a more simplistic model. Figure A.3 and Figure A.4 in Appendix A depict the cross-section of the full field model and the C-segment. The procedure of coarsening the full field model it is done in a matter which maintains the quality of the result. The actual procedure of how it is done is not a subject in this report. The model has as previously mentioned 13 wells where 4 are injectors and 9 are producers (Kheradmand, 2011).

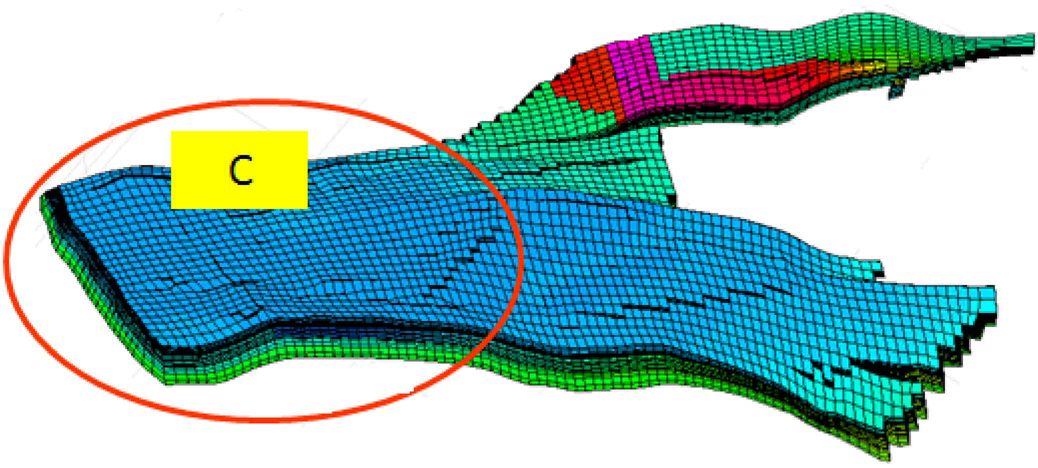

Figure 3.6 - The full field Norne Model.

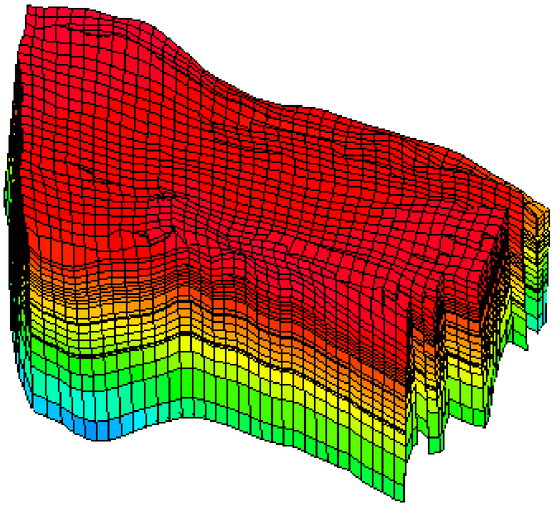

Figure 3.7 - The ECLIPSE model of the C-Segment.

4. History matching

History matching is a challenging task which aims to calibrate a reservoir model against historical data for the particular field. Simulated values are compared to observed well and reservoir performance. The difference between the two sets of results is evaluated. If the difference is characterized to be significant, alterations are done to the reservoir model. Such alterations involve changing reservoir parameters with the highest level of uncertainty. Once the model is history matched the future behavior can be more accurately predicted.

History matching is normally done manually, meaning that the reservoir engineer is evaluating the flow and changing parameters. To speed up this process, one may want to use a computer assisted approach, where the computer simulates for different values within a set of values defined beforehand. The history matching can also be performed solely by a computer, however, this approach is commonly considered to be too inaccurate. In this work manual history matching is performed.

In literature several outlines/sketches on how to best perform history matching are suggested. These advised methods will possibly differ from each other (Carlson, 2003). Performing history matching is complex, and the procedure is dependent on the characteristics of the reservoir in question. Regardless of this, some general aspects can be emphasized as important when performing history matching. Pressure and the translation of geological data to the reservoir model are considered uncertain (Carlson, 2003), (Satter, et al., 2008).

4.1 Preparation of the model

Prior to history matching of the C-segment the model had to be adjusted to get the correct flow curves. The model of the C-segment is a coarsened model of the whole Norne field. Some wells, not located in the C-segment, are producing from and injecting into the C-segment. This is a correct depiction of the situation considering pressure support, however when working solely with the C-segment, these must be left out. The model in this project is therefore a grouping of the wells only situated in the C-segment. The following figures depicts the oil production rate prior to and after the grouping of the wells. The input file to Eclipse showing the grouping of the wells is enclosed in Appendix H.

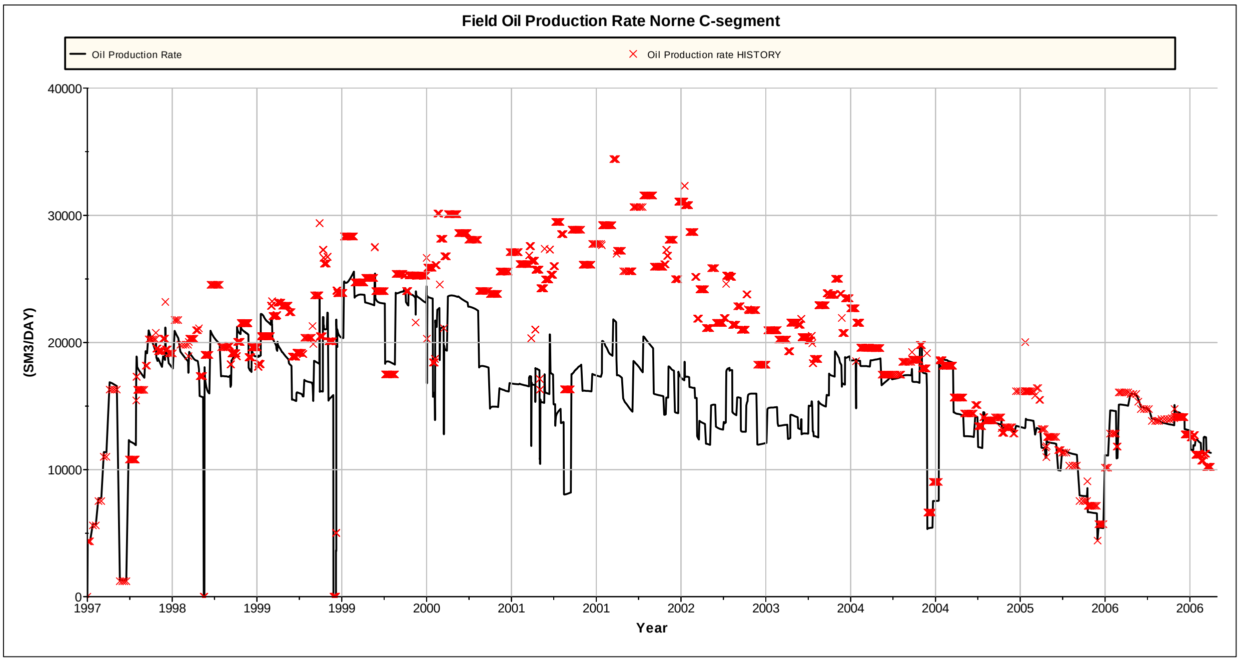

Figure 4.1 - Field production rate vs. historical production data.

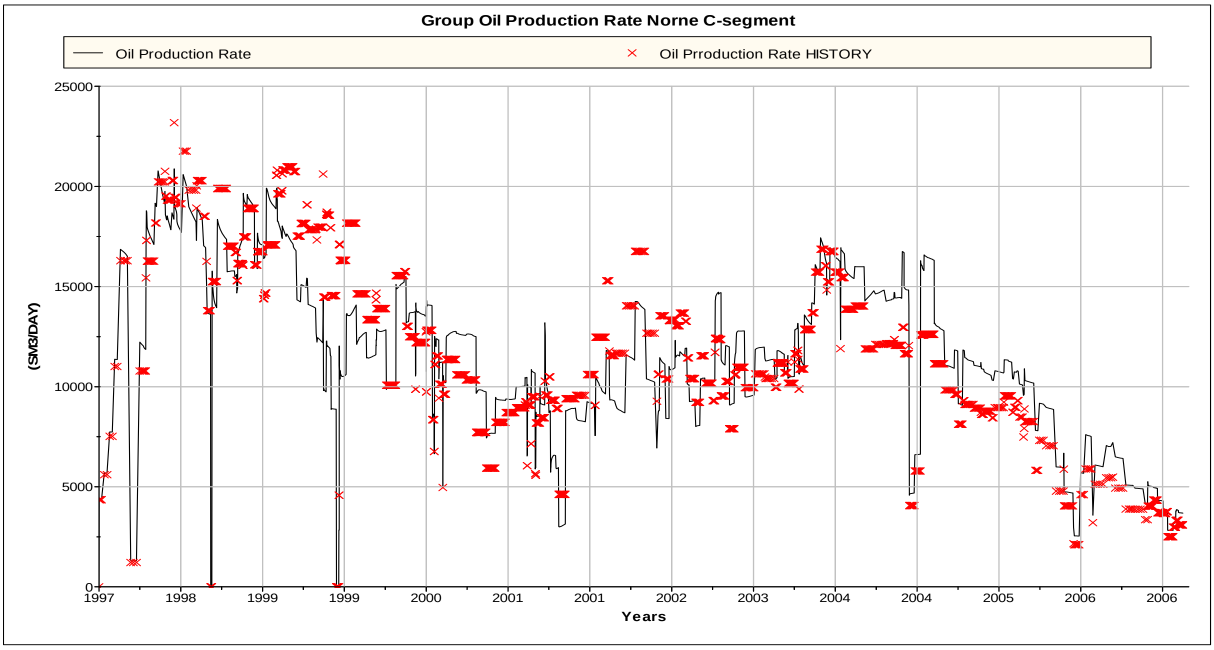

Figure 4.2 - Group production rate vs. historical production rate for the group.

In Figure 4.1 the oil production is too low, especially from 2000 and until 2004, when compared to the measured data. When the wells situated in the C-segment are compared to the history, the match is improved, Figure 4.2 depicts this.

4.2 Workflow

As previously mentioned, pressure is considered a parameter to be matched in an early stage of the process (Satter, et al., 2008). The permeability is altered in order to change the pressure (Gruenwalder, et al., 2007). However, no history data for the pressure in the C-segment of the Norne field were available. In order to improve the reservoir model another aspect considered highly uncertain were investigated, namely the integration between geology and the reservoir model. This is an area likely to cause distance between real and calculated values (Carlson, 2003). Considering the amount of data available, the Norne team in Harstad advised to alter the vertical barriers to match the model. For the C-segment of Norne there are as previously mentioned four major formations (Garn, Ile, Tofte and Tilje) which further is divided into subdivisions. A number of field-wide barriers is said to obstruct flow in the vertical direction (Verlo, 2008). These were presented in Chapter 0, Table 4.1 depicts a recap.

Table 4.1 - Formations and corresponding layers and barriers.

Layer	Formation	
1	Garn 3	carbonate cemented layer @top of Garn2
2	Garn 2	
3	Garn 1	
4	NOT	
5	Ile 2.2	
6	Ile 2.1.3	
7	Ile 2.1.2	
8	Ile 2.1.1	carbonate cemented layer @base Ile 2.1.1
9	Ile 1.3	
10	Ile 1.2	
11	Ile 1.1	carbonate cemented layer @top Tofte 2.2
12	Tofte 2.2	
13	Tofte 2.1.3	
14	Tofte 2.1.2	
15	Tofte 2.1.1	grain size contrast
16	Tofte 1.2.2	
17	Tofte 1.2.1	
18	Tofte 1.1	
19	Tilje 4	
20	Tilje 3	clay stone
21	Tilje 2	
22	Tilje 1	

The barriers between layer 1/2, 15/16, 18/19 and 20/21 were implemented in the original reservoir model. The barrier between layers 8/9 and 11/12 were implemented in the process of history matching.

These existing barriers are implemented in the reservoir model by using the keyword MULTZ with a designated value in the GRID section. When the MULTZ keyword is used in the GRID section in Eclipse the transmissibility values are set to the specified value. The alterations and the implementation of the new barriers are done using the same keyword, but in the EDIT-section. In the EDIT-section the MULTZ value is multiplied with the transmissibility designated earlier. The transmissibility describes the ability of fluids to flow through the grid blocks of the reservoir model.

History matching was performed in the following manner in this report:

1) The transmissibility of field wide barriers was given a low and a high case MULTZ value. The cases were simulated.

2) After simulating these cases, the water cut and gas-oil ratio for each well were studied and they were compared to the original reservoir values. The target was to define the best case for each well. For some wells the performance were improved by the modification to high case. Some showed improvement when using the low case value of transmissibility, and some changed for the worse with either of the adjustments. Layer 18 and 20 were eliminated for further analysis at this stage. This was due to unchanged well performance with the alterations introduced.

3) As mentioned, the geology of the field is challenging to predict and translate into a reservoir model. In accordance with this it is difficult to state whether the barriers are field wide, or have local zones with different transmissibility. After step 2 each of the layers were altered to have a local area of high case transmissibility over the wells that favored this value, and the same approach for the wells that showed a better match for the lower case. When the high or low value of the transmissibility between the layers failed to show any improvement in the well performance the original values was kept. Figure 4.3, Figure 4.4 and Figure 4.5, depicts these local changes.

4) The altered and improved barriers (layers) were then implemented in the original file to make up the new model. When the new edition of layers 8, 11 and 15 were implemented in the model the majority of wells showed a poorer performance than in the base case. The individual well performance was again evaluated in order to determine the problem.

5) Layers and local zones were then removed until the best match was determined. Several alterations were tested for and the best result was achieved when layer 15 was reset to original values together with removing the high case area in layer 11. The high case areas in layer 11 was removed because the wells in this area showed good performance by the changes made in layer 8 and a poorer performance with the changes in layer 11. When these layers were combined the good effects achieved from the alterations of layer 8 became insignificant, thus indicating that including both the low case in layer 8 and the high case in layer 11 cancel the effect.

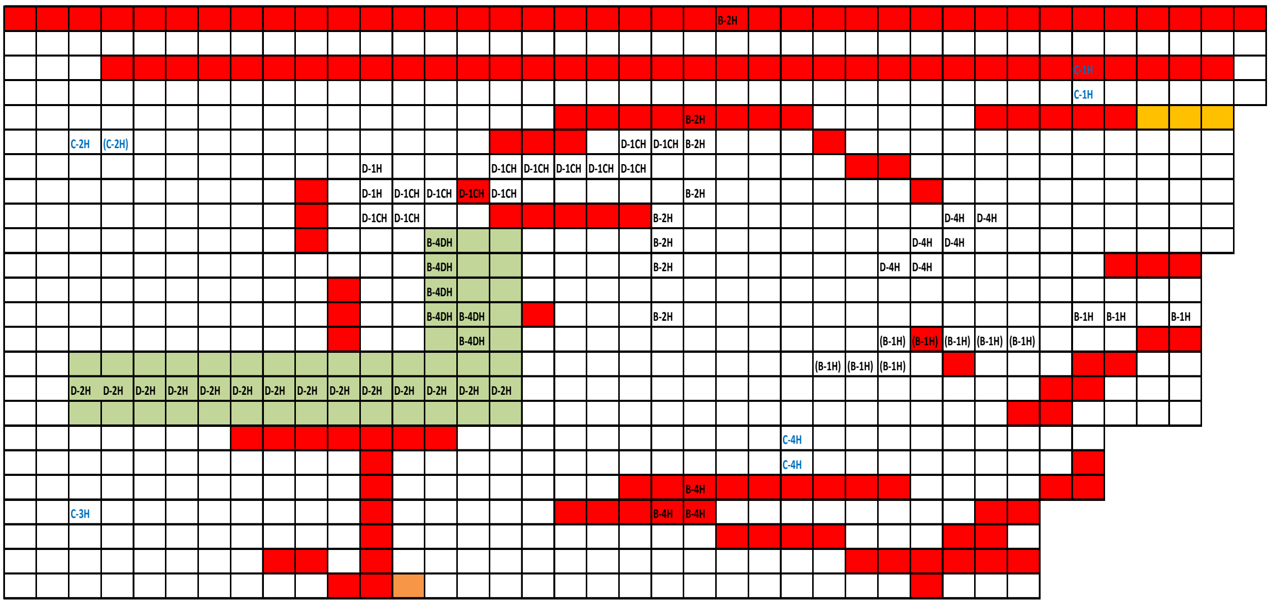

Figure 4.3 - Local changes in layer 8; light green indicates low case area.

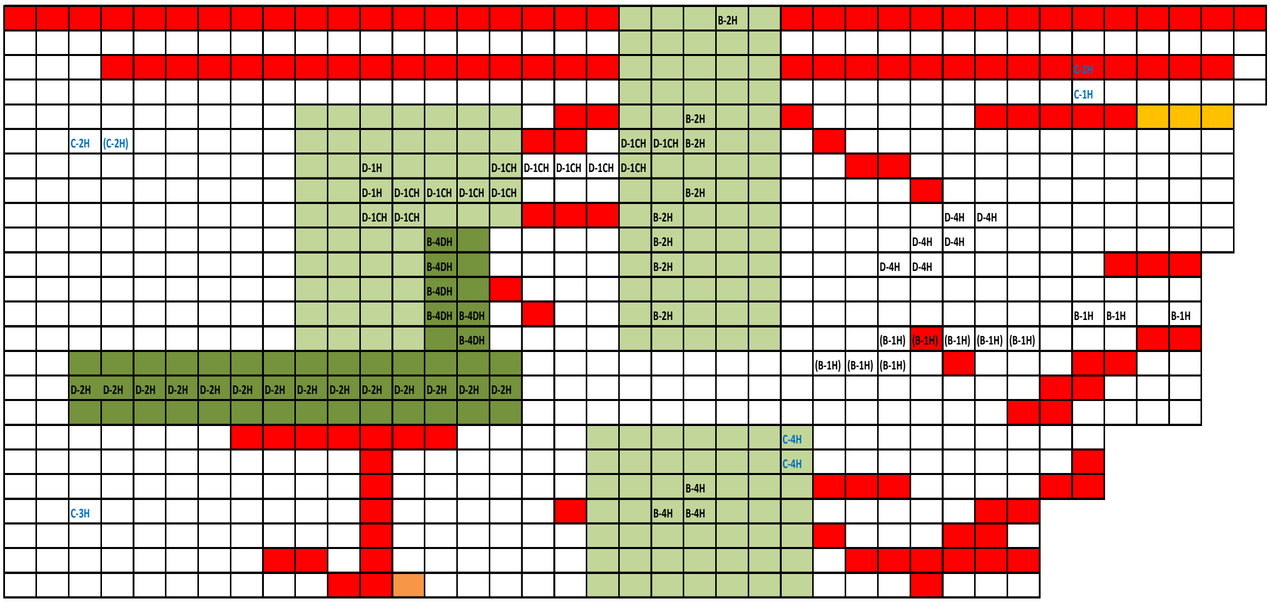

Figure 4.4 - Local changes in layer 11; light green indicates low case area and dark green indicates high case area.

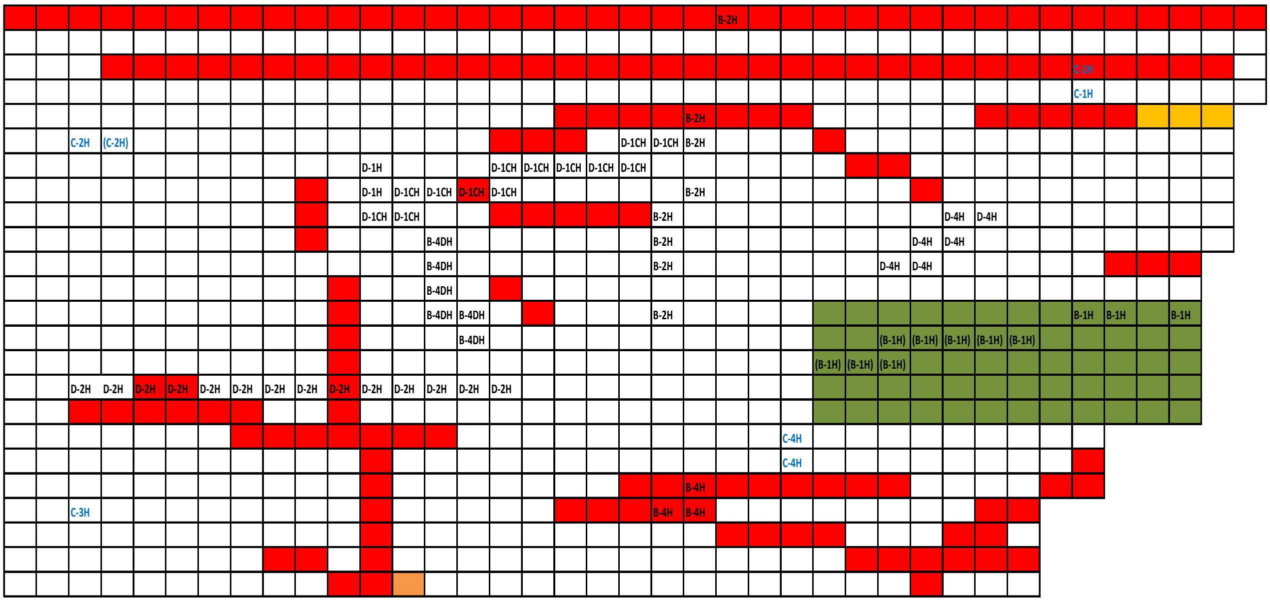

Figure 4.5 - Local changes in layer 15; dark green indicates high case area.

4.3 Results and discussion

Figure 4.6 and Figure 4.7 presents the results from the initial model compared to the renewed model. When looking at the combined oil production or water cut from the group of wells it is difficult to see a significant improvement. The gas-oil ratio has also been evaluated, but it was not weighted as important due to low quality of the history data for the gas (Statoil, 2011). This is due to sparse recordings of the gas prior to 2005, when the gas from Norne C-segment first was being exported and sold. For the water cut the initial breakthrough of water is not matched better with the new model. Until approximately 2004, whether the initial or the new model shows a very accurate match. The trend of the historical data seems to differ from the ones calculated by Eclipse and one may question the data implemented in the model. From 2004, when the water production is rising again the new model is depicting the breakthrough and general trend better than the initial model. As the accuracy of the oil production rate significantly improved after the grouping of the wells, the matching of the new model is not extensively reformed.

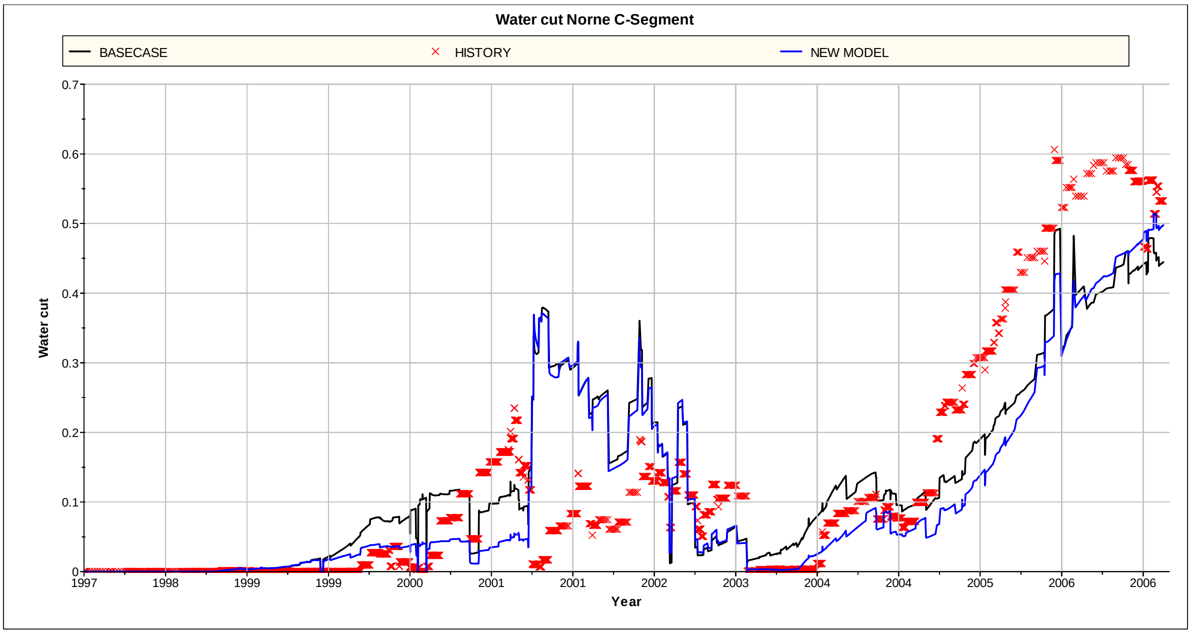

Figure 4.6 - Water Cut, Initial model vs. new model vs. history.

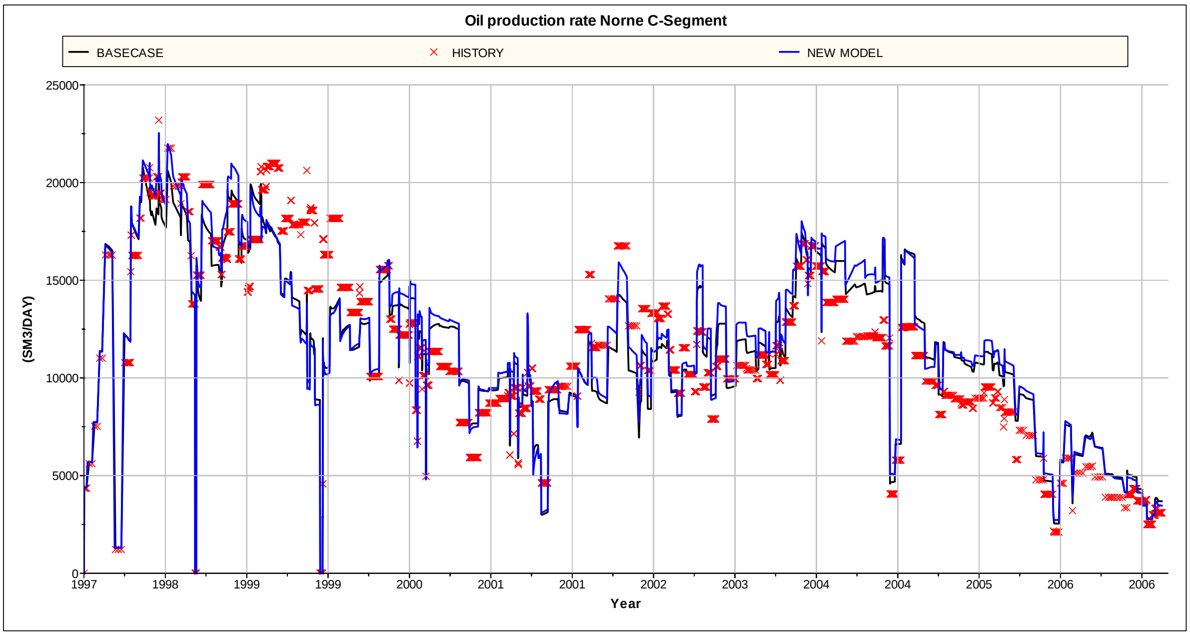

Figure 4.7 - Oil Production Rate. Initial model vs. new model vs. history.

The effect of the changes in the new model is more visible when studying the performance of each well. To illustrate this, Figure 4.8 and Figure 4.9 shows the water cut curve for well B-2H and the gas-oil ratio for well B-4H.

B-2H is a horizontal well situated in the middle of the reservoir and is perforated both in layers 9 and 10. The water is delayed by the changes in transmissibility in the new model, which is in accordance with the history. It may be questioned that the water is too obstructed by the low case transmissibility in layer 11, however the improved match in the beginning makes the new model the better choice. Figure 4.8 on the next panged depicts this.

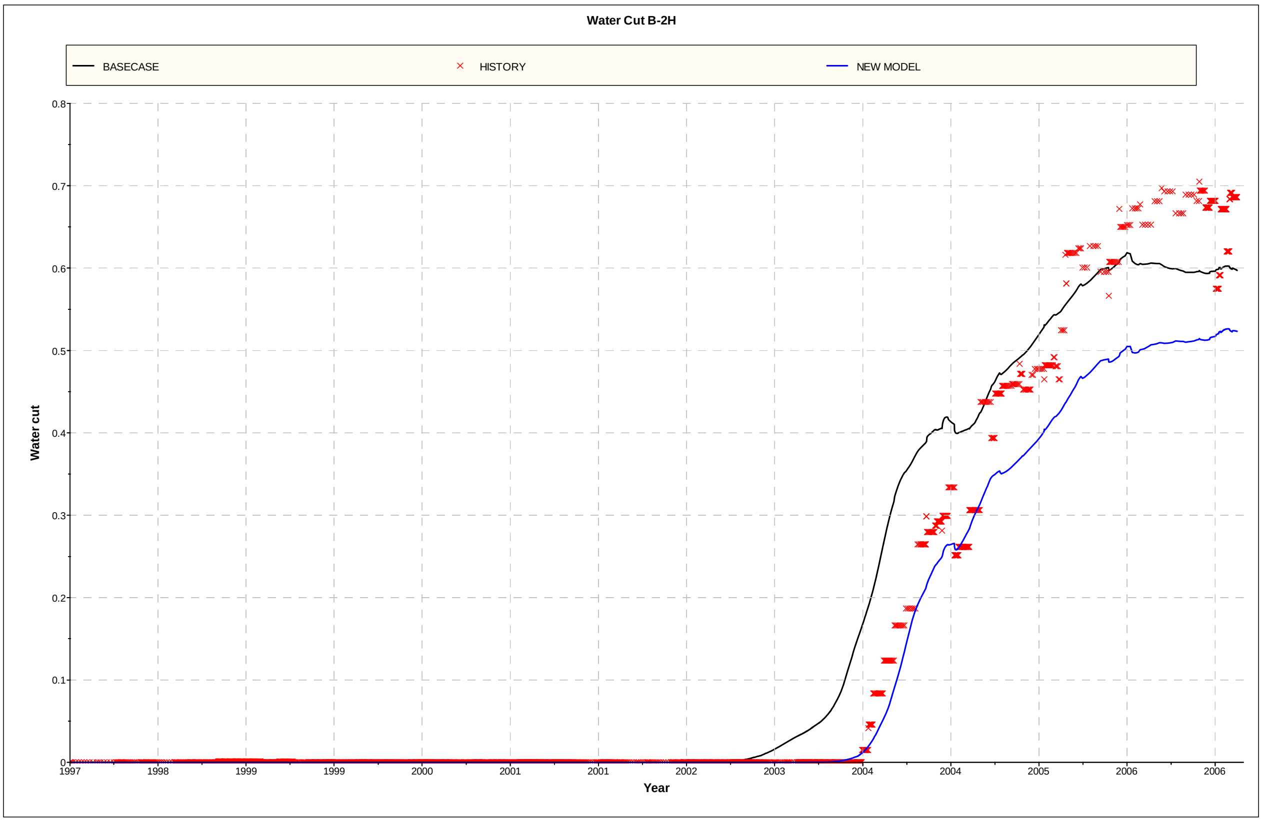

Figure 4.8 - Water Cut well B-2H

Well B-4H is also situated in the middle of the reservoir, south of B-2H and is perforated in layer 13 through 15. This well does not have any water production. The new model gave a considerably better match of the gas-oil ratio between 1997 until 1999. In this case the historical data shows a different trend during 1999, this can be due to the mentioned inaccuracy in the measured gas data. Figure 4.9 on the next page depicts this.

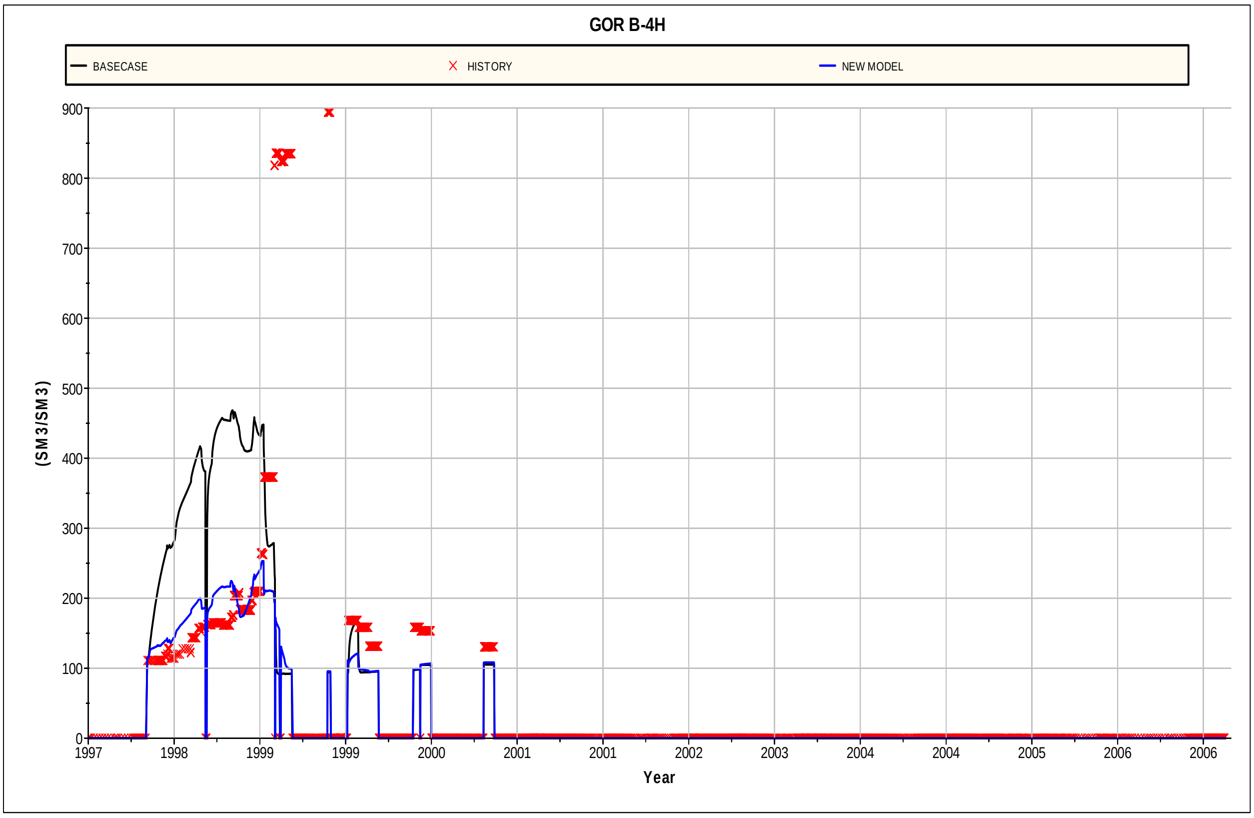

Figure 4.9 - GOR well B-4H.

The workflow presented in this report is one of the many procedures tested in order to better the match. As mentioned the pressure data was lacking. Due to this the main priority was to alter the flow of fluids. Prior to consulting with Statoil in Harstad the focus was more on the faults in the reservoir. Figure A.2 in Appendix A and the red lines in Figure 4.3 shows that there are excessive faulting in the C-segment. These have different transmissibility values which affects the horizontal flow. However, altering these values lacked to show any positive results on the matching. This indicates that the process of history matching is a complex procedure, particularly in a complex reservoir such as the C-segment. It was challenging to make alterations that solely gave good results. The majority of the changes provided both positive and negative results throughout the reservoir.

5 Surfactant flooding

This chapter is based on the pre-study; “Introduction to Surfactant Flooding for EOR on the Norne Field, C-segment” by Kristine Nielsen.

A surfactant can be defined as a surface active agent. It is also referred to as “soap” because it aims to wash out the residual oil. The surfactants seek to mobilize the oil by lowering the interfacial tension between the water and the oil and hence lower the capillary pressure trapping the oil (Olje- og energidepartementet, utvinningsutvalget, 2010).

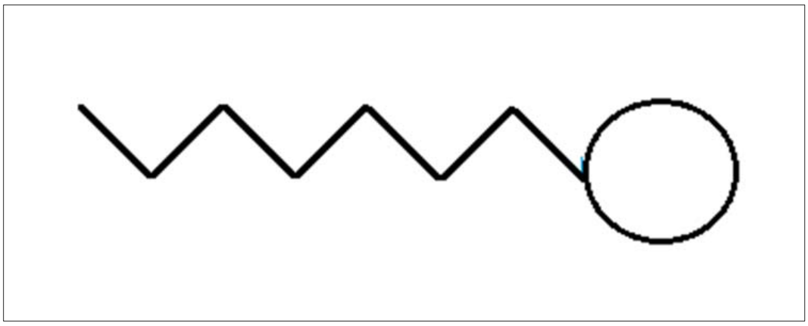

Figure 5.1 - The molecule structure of a surfactant

Figure 5.1 illustrates the molecular structure of a simple surfactant. Surfactants are organic compounds and consist of a hydrocarbon chain, and a polar head. The chain is called the hydrophobic group and the head is referred to as the hydrophilic group. This particular structure makes the surfactants soluble in organic solvents (oil) and in water. Their structure and composition may vary and they are normally divided into subgroups depending on the characteristics of their head group. The subgroups are: anionic, nonionic, cationic and zwitterionic surfactants (Sheng, 2011), (Green & G Paul, 1998).

- Anionic surfactants are chemically stable and have a low tendency of adsorption on to sandstone rocks. This is the most common surfactant to use as it also can be manufactured economically.
- Nonionic surfactants are generally and most often used as cosurfactants to improve on the performance of the surfactant systems. It is more tolerant of high-salinity brine, however its surface active agents is not as good as for anionic surfactants. As it is these agents that lower the IFT, it is normally not preferred as a main surfactant.

- Cationic surfactants have the ability to change the wettability of carbonate reservoirs which may be very beneficial for oil recovery. However they have the tendency to easily absorb into sandstone, and are not used in such a reservoir. As Norne primarily consist of sandstone, this surfactant will not be a candidate.
- Zwittericonic surfactants are temperature- and salinity tolerant, but are hard to manufacture economically as they are expensive.

Every subgroup contains several surfactants.

5.1 Characterization of surfactants

As there are a large number of different surfactants, there are many ways of characterizing them, other than based on their head group. The most frequently used surfactants are sulfonated hydrocarbons. These can be produced by sulfonating a relatively pure organic structure to form an organic acid, followed by neutralization (Green & G Paul, 1998).

5.1.1 Hydrophile-Lipophile Balance (HLB)

This balance is an empirical number that determines if the surfactant is hydrophilic or lipophilic. A surfactant is hydrophilic if it is soluble with water and lipophilic if it dissolves in oil (Sheng, 2011), (Green & G Paul, 1998). The HLB can be calculated in different ways where the goal is to determine if the surfactant will form water-in-oil or oil-in-water emulsions. A low HLB indicates liphophilic surfactant, this type is preferred if the salinity level in the formations is low. When the HLB is high the surfactant is hydrophilic, this is favorable if the salinity level is high. Salinity is further discussed in chapter 5.2.2.

5.1.2 Critical Micelle Concentration (CMC)

This characterization verifies if the surfactants form micelles or not. A micelle is where the molecules form a round structure where the tails or the heads bind them together. If the solvent is water, the micelles form with the tail portion pointed inwards and the head portion outwards (Green & G Paul, 1998). They look like spheres where the heads form the external surface. The head group of the molecule is polar, thus under the right conditions significant amount of oil can be solubilized into the micelles. If the solvent is of hydrocarbons, the micelle will have the surfactant tail pointing outwards and head inwards. When mixed with water the water can be solubilized into the interior of the micelle. Thus, while oil and water each have very limited solubility for the other phase, the addition of a surfactant at concentration above the CMC significantly increases the apparent solubility (Green & G Paul, 1998). The interfacial tension decreases until the CMC is reached. From this point micelles will be formed and adding more surfactants will only increase the number of micelles. The IFT will not decrease further after the CMC is reached (Sheng, 2011).

5.1.3 Solubilization Ratio

The solubilization ratio is defined as the volume of solublized oil to the volume of surfactant present. Where the volume of solublized oil is the difference between the originally volume of oil in place and the excess oil after the surfactant was introduced (Liu, et al., 2008). This ratio needs to be at the right level in order for the surfactant to lower the IFT. The right level was indicated by literature to be higher than 10 (Sheng, 2011). An increasing tail-length in the molecular structure has led to an increase in the solubilization ratio, which in turns decrease the optimum salinity level.

5.2 Phase behavior

Phase behavior is the relationship and interaction between the liquid phases in the reservoir. There are a number of parameters affecting the phase behavior including salinity, types of surfactants, the concentration of surfactants, cosurfactants, type of oil and brine, temperature in the reservoir, and to a lesser extent pressure. The interfacial tension between oil and water without any surfactant added is typically around 30dynes/cm (Green & G Paul, 1998). When adding surfactants the target is to lower the tension several orders of magnitude to about 10^{-3}dynes/cm, to so-called ultralow levels (Sheng, 2011). Eclipse does not depict the chemical composition, or the phase behavior of surfactants described in the following chapters.

5.2.1 Phase behavior test

Prior to injection of the phase containing surfactants into the reservoir, the specific and optimal chemical formula needs to be determined. This is the main objective of the phase behavior tests. A flow chart is depicted in Figure 5.2.

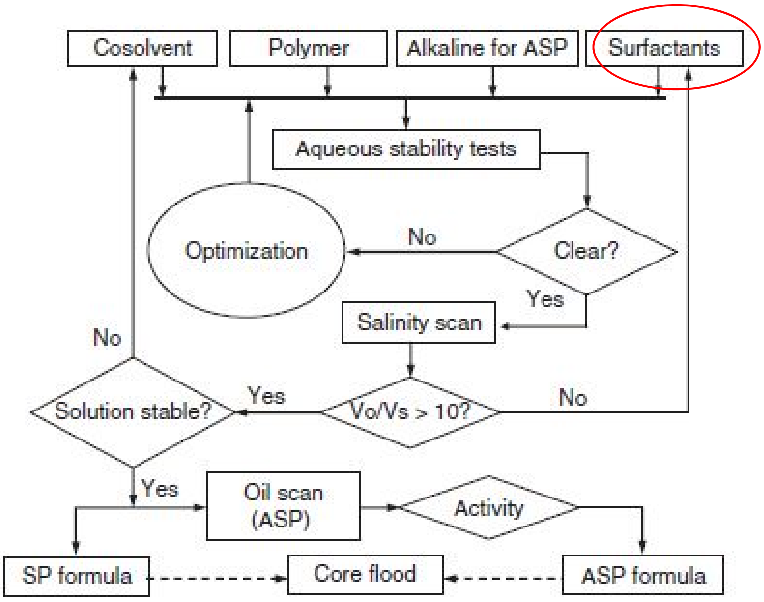

Figure 5.2 - Flow chart of how the phase behavior tests are performed.

The phase tests are; aqueous stability test, salinity scan and oil scan.

- Aqueous stability test

  To prevent a non-uniform distribution of the injected fluid which may lead to phase-trapping or different mobilities of coexisting phases it is important that the fluid is a single-phase solution (Sheng, 2011). The aqueous stability test aims to check whether the solution to be injected is homogenous, and hereby eliminate surfactant precipitation and phase trapping (discussed in chapter 0 and 5.5.2). If this is not the case, the solution needs to be optimized.

- Salinity scan

  This scan is performed if the solution is proved stabile in the aqueous stability test. This step is to decide if the solution to be injected is of the correct chemical composition to reach a low enough IFT in order to mobilize trapped oil. The scan evaluates the salinity and determines if the solubilization ratio discussed in 5.1.3 is correct. The salinity level cannot be too far from the salinity of the intended injection water. If this is the case, the salinity can be altered. However as this is an expensive approach the solution is to change the surfactant and start the behavior test from the start.

- Oil scan

  The oil scan is used if alkali, in addition to the surfactants, is added to the injection phase. Alkalis have the same purpose as surfactants and may be added to make the solution more economically feasible, as alkalis normally cost less.

5.2.2 Salinity

The salinity of the brine in the reservoir is an important factor. The salinity affects the chemical composition of the surfactant, and may prevent it from influencing the IFT in a beneficial way.

Before explaining how the salinity affects the system the term microemulsion needs to be defined. A microemulsion is most easily described as a mixture of either surfactant and oil, or surfactant and water or surfactant and both oil and water. It is a homogenoius phase which is thermodynamicly stable (Sheng, 2011). Microemulsion is also described as micelle-solution if the concentration of the surfactant is above the CMC. A micelle and the CMC were defined in chapter 5.1.2.

When the level of salinity is low the surfactants will mix with the water and together they form a microemulsion phase. At such a low salinity level the oil phase will be free of surfactants. This is contrary to a high salinity level when the surfactants will mix with the oil phase and form into a so called oil-external microemulsion. At this condition the water does not contain any surfactants. At an intermediate salinity level the surfactants will form a microemulsion with both the water and the oil. In addition there will be excess water and oil, not containing any surfactants.

When the salinity level is low the microemulsion is called Type II(-), when the salinity level is high Type II(+) and at an intermediate salinity level Type III (Sheng, 2011). Several studies have been done on what characteristics the different types bring to a reservoir model, Table 5.1 sums up the advantages and disadvantages of the different types (Sheng, 2011). It can here be noted that a modeled reservoir will be an ideal system and a real reservoir will to a larger extent be far more complicated and not ideal.

The salinity level classified as the most desirable and advantageous is called the optimum salinity level. Optimum salinity level is the average salinity in the salinity range covered by Type III (Salanger, et al., 1979). At optimal salinity level the mixture of surfactant oil and water or brine is near the so-called tricritical point where the phases become indistinguishable, at this point the IFT will exhibit ultralow values as it approaches zero. Hence, Type III is described as the preferred type of microemulsion (Green & G Paul, 1998). The tension between the liquid phases can be difficult to measure at the desired ultralow values. It has been shown that the IFT correlates with the solubilization ratio (defined in chapter 5.1.3). The solubilization ratio is easier to measure than the IFT. When the solubilization ratio is measured to be 10 or greater it is believed to be within the optimal salinity range (Green & G Paul, 1998). As this is reached, the IFT can be measured and can be expected to show ultralow values.

Eclipse only support and simulate for surfactants being in the water phase, thus phase II(-). This is also somewhat desirable because by it limits microemulsions. The presence of microemulsions indicates that the IFT is low enough for the capillary trapped oil to be mobilized (Michaels, et al., 1996). Yet, it is not solely favorable because these microemulsions contain a rather high concentration of surfactants. This concentration will be delayed in the process of propagation. When it is desirable to keep the concentrations at a low level the delay will be even more considerate. The presence of microemulsions may also increase the viscosity of the oil which in turns may cause displacement instabilities. This again will possibly require polymers to be added in the reservoir to stabilize the displacement (Michaels, et al., 1996). This addition is expensive and desirable to avoid.

Table 5.1 - Shows the advantages and the disadvantages for the different types of microemulsions (Sheng, 2011).

Type	Advantages	Disadvantages
II(-)	Low phase trapping/adsorption	Bypassing excess oil due to its high velocity
III	Lowest IFT	Phase trapping due to three-phase k_r issues
II(+)	Favorable k_{ro}	Phase trapping due to its high viscosity

5.2.3 Temperature

In general the reservoirs in the North Sea are, including Norne, waterflooded and injection of cold water will give temperature gradients (Skjæveland & Kleppe, 1992). A change in the temperature will affect the solibilization ratio in the system, which in turns will shift the optimum salinity level. It is therefore desirable to keep the system stable and avoid unfavorable phase behavior due to temperature gradients. To obtain ultralow IFT if the temperature increases the targeted salinity level will be expected to be higher as the solubilization ratio decreases (Green & G Paul, 1998).

5.2.4 Oil composition

The type of oil in the reservoir will affect the relationship between oil and water and hence how the surfactants will interact with the liquids. When the carbon number increase, the optimal salinity will increase as well. Basically as the oil gets heavier the width of the salinity region for Type III will expand and the solubility will decrease (Sheng, 2011). The oil in the C-segment is light to intermediate and the width of the salinity region is not expected to expand, which in turns leave the solubility unchanged.

5.3 Flooding of the reservoir

Through flooding of the reservoir the IFT will be lowered which in turns lowers the capillary pressure and thus mobilizes the residual oil. This will increase the oil saturation and the oil bank will be able to flow. Behind the oil bank the surfactant will prevent the oil from being retrapped (Skjæveland & Kleppe, 1992). In order to achieve this in a successful way a detailed plan where the correct strategy is denoted should be made. It may be necessary to add a cosurfactant to the surfactant and it may also be necessary to add polymer to the chase water. The reason for using a cosurfactant can be several. The surfactant chemicals are expensive and may be thinned out, without losing their characteristics, by using a cosurfactant. It can also be desirable to add a surfactant to avoid adsorption where that is predicted. When adding polymers to the chase water the aim is to increase the viscosity of the water phase to avoid fingering which leads to earlier breakthrough of the water, will be mentioned in the next chapter. When the composition of the phase to be injected is decided upon the strategy for flooding must be developed. This will be further discussed in chapter 6.6.

5.4 The effects of surfactants

As mentioned the main task for surfactants is to lower the interfacial tension in order to lower the capillary pressure. This is the desired effect after flooding of the reservoir. By lowering IFT and thus P_c the trapped residual oil will become mobile. The Laplace equation referred to in chapter 2.1 shows the relationship between IFT and P_c:

$$P_c = p_o - p_w = \frac{2\sigma cos\theta}{r} = \Delta\rho g H \qquad (5.1)$$

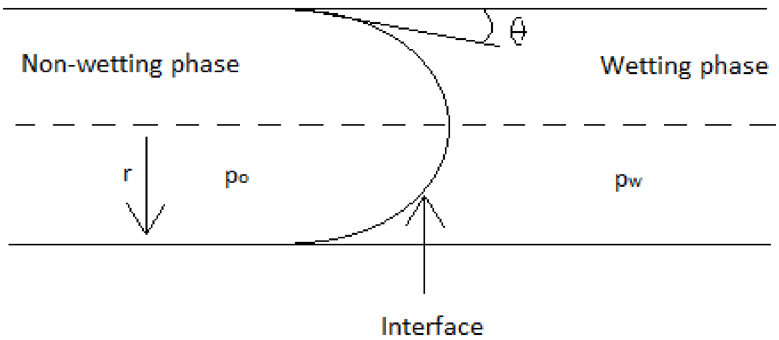

Figure 5.3 - Illustrating the Pc equation (Skjæveland & Kleppe, 1992).

p_o in formula 5.1 and Figure 5.3 denotes pressure in the oil phase, p_w denotes pressure in the water phase, σ is the interfacial tension, θ the contact angle between the non-wetting (oil) and wetting (water) phase, Δρ is the difference in density for the phases, r is the radius and H is the height. Equation 5.1 is developed from the equation of static equilibrium on the interface between oil and water in a cup containing a capillary tube (Lien, 2008). The capillary pressure is the difference between the pressure of the non-wetting phase and the wetting phase (Lien, 2008). Figure 5.4 illustrates two pores/capillaries with different widths. Water is here the wetting phase. As water is flowing through the pore space it will reach highest in the smaller pore due to the smaller radius. The water will break through to production before the largest pore is swept for all its oil. This is called snap-off and it is oil in this form that is called residual oil saturation, S_{or} when the reservoir is water wet(Dr.Tran, 2006).

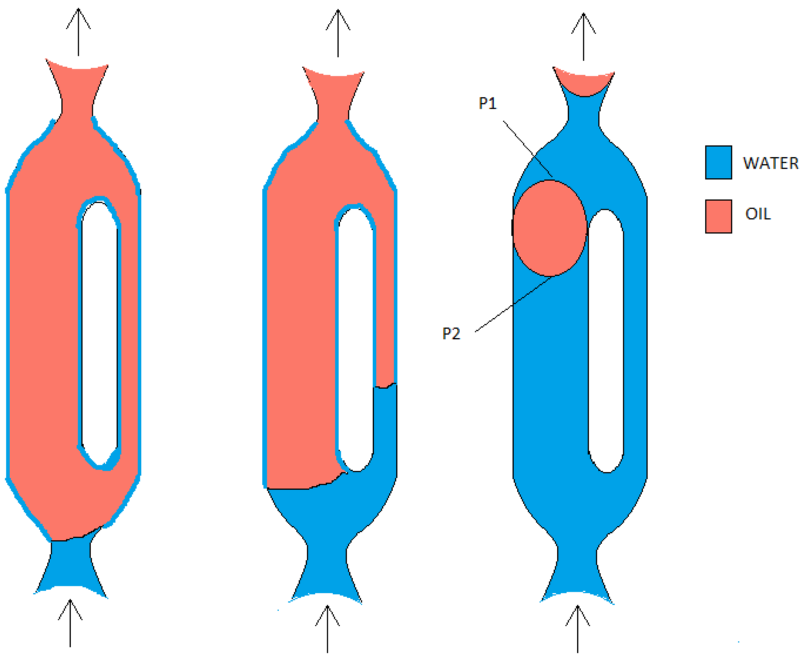

Figure 5.4 - Three phases in the imbibition of oil in a system of two pores in three stages; a, b and c.

The differential pressure across the two pores in Figure 5.4c is equal after the imbibition (production). This implies that the shape of the remaining oil droplet have to satisfy Δp_w=P1-P2. The drop will be trapped and for it to become mobile the capillary pressure and the interfacial tension must approach zero (Lien, 2008).

5.4.1 Capillary Number

The capillary number was defined in chapter 2.1. A high value of this number is desirable as this indicates mobile oil. This relationship between the capillary number and the mobility of oil is shown by the capillary desaturation curve (CDC). This curve plots the residual oil saturation against the capillary number and shows a decline when the capillary number increases. Figure 5.5 shows different CDCs. The different curves represent the wetting and non-wetting phase. The vertical dotted lines indicate the critical value of the capillary number for the two phases. This critical value indicates when the residual saturation starts to decrease. The figure depicts that this critical value is higher for the wetting phase, and hence a higher capillary number is required to displace the wetting phase. Because the rock surface tends to repel the non-wetting phase and attract the wetting phase, the non-wetting phase is easier to mobilize (Sheng, 2011). Thus the reduction in the residual saturation of this more mobile phase will thus occur at a lower capillary number. This indicates that it is desirable to have the reservoir water wet. The wettability is further discussed in the next chapter. The normal range for the value of the capillary number is in the range of 10^{-7} to 10^{-5}, and needs a considerable increase to reduce the residual saturation.

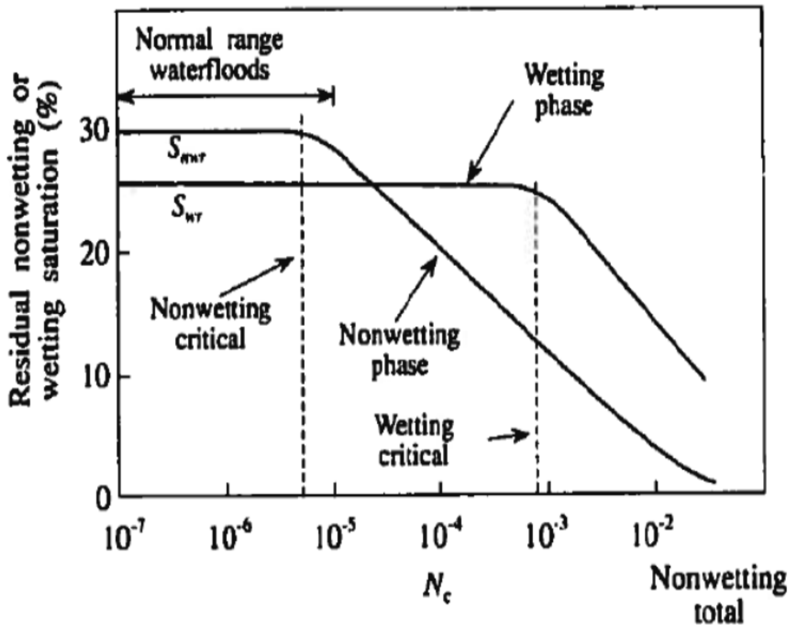

Figure 5.5 - Capillary Desaturation Curve (CDC) (Skjæveland & Kleppe, 1992).

5.4.2 Wettability

The wettability is defined as the preference of a solid to be in contact with one fluid rather than another (Dr.Tran, 2006). The wettability of Norne C-segment is mixed-wet (Verlo, 2008). This indicates an inhomogeneous and thus not strongly water-wet nor strongly oil-wet. Figure 5.6 depicts this.

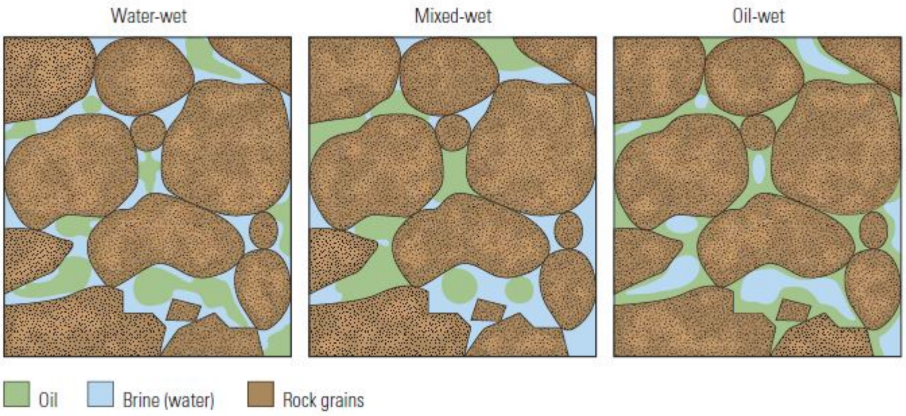

Figure 5.6 - Wettability (Abdallah, et al., 2007).

The wettability affects the amount of residual oil that can be produced. The residual oil previously introduced as capillary trapped, is the oil droplets inside the pores of a water-wet reservoir. In an oil-wet reservoir the residual oil is positioned along the "walls" in the pores. The amount of residual oil a reservoir of this wetting will, due to no capillary trapping, be less than for a water-wet reservoir. The oil migrates out from the pores and, and the recovery can in theory be 100%. In Norne, where the wetting is mixed-wet, both of the conditions above are found. The use of surfactants are foremost a technique tested for water-wet reservoirs (Abdallah, et al., 2007). The distribution and flow of fluids in pores is therefore to a large extent affected by the wettability of the porous medium (Awan, et al., 2006). It has been suggested (mentioned in chapter 2.1) to instead of adding surfactants to lower the IFT and hence the capillary pressure, the surfactants should aim to change the wettability in the reservoir (Rao, et al., 2006). This requires less surfactant and can then prove to be less expensive. Thus mentioned, this is not a subject in this report.

5.4.3 Relative permeability

When flooding the reservoir with water containing surfactants, the relative permeability will be affected. The relative permeability is defined as one fluids ability to flow in the presence of another fluid (Dr.Tran, 2006). When the oil saturation is decreasing the relative permeability to water will increase. When looking at the water mobility and the mobility ratio (formula 2.4) defined in chapter 2.1 these values will increase when the water relative permeability increases. It is not desirable for the mobility ratio to increase too much as this may lead to an earlier breakthrough of the water phase. To reduce the mobility of the injected water that is chasing the surfactant solution it might be necessary to add a cosolvent (polymer) to it.

5.5 Challenges

The theory of how the surfactants target to extract more oil is simple. The implementation however, is not as easy. There are challenges that need to be taken into consideration in order to successfully implement surfactant flooding of a reservoir. Firstly the measurement of the effective IFT in a porous media is difficult. This difficulty limits the laboratory modeling and prediction of surfactant flood performance (Zhang, et al., 2007). When measuring the IFT in the laboratory the conditions will be ideal. The conditions in-situ in the reservoir is far from ideal.

When the surfactant phase is injected into the reservoir occurrences like precipitation, adsorption and phase trapping of the surfactant will happen. All these processes lead to retention of surfactants which in turns potentially raise the effective IFT in the reservoir from the value measured beforehand in laboratory, and thus contribute to oil trapping (Zhang, et al., 2007), (Green & G Paul, 1998). It has also been suggested that nearly 90% of the injected surfactants are retarded by the formation when passing through the reservoir (Skjæveland & Kleppe, 1992). If this suggestion is correct, only a small portion of the surfactant actually contributes in lowering the IFT. Due to this it is very important to calculate the amount of surfactants actually needed in order to successfully implement the flooding. There are also major challenges when it comes to economic feasibility of projects regarding surfactant flooding. As for the Norne field the offshore location will also represent a challenge. The stated challenges are discussed next.

5.5.1 Adsorption

Adsorption is when the surfactant adheres or sticks to the surface of the reservoir. As Figure 5.7 depicts it is the charged head group that will attach to the surface which is oppositely charged. This is the major cause for surfactant retention and thus loss of surfactant. Adsorption can be lowered by adding alkaline as a cosurfactant (Dang, et al., 2011). The adsorption of the surfactants is a complicated matter, but can be generalized into four different stages or regions depending on the concentration of surfactants. When the concentration is low, the adsorption will be increasing linearly as the amount of chemicals increase. This is the first region shown in Figure 5.8. In the second region the increase in surfactant concentration will lead to a rapid increase in the adsorption. In the third region the adsorption subsides as the concentration is reaching the critical micelle concentration (CMC). When this concentration is reached, in region four, the adsorption will stay at a constant level (Skjæveland & Kleppe, 1992).

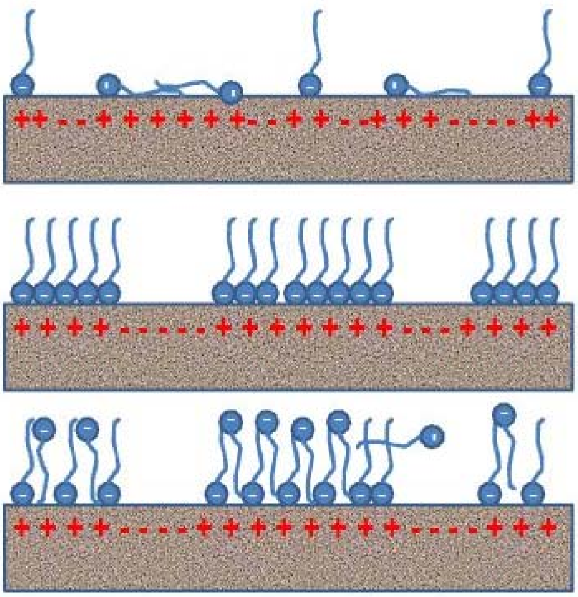

Figure 5.7 - Illustrating how the head groups cling to the surface in the phenomena of adsorption (Dang, et al., 2011).

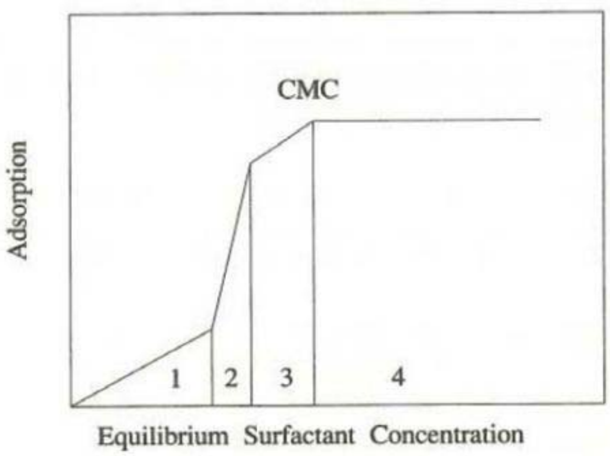

Figure 5.8 - Adsorption curve (Skjæveland & Kleppe, 1992).

5.5.2 Precipitation

A precipitate is a by-product followed by a chemical reaction (Schlumberger, 2011). These by-products can be a result of phase separation of surfactants and a potential cosurfactant or separation of the different kinds of surfactants in solution (Green & G Paul, 1998). This may be a result of a failed aqueous stability test. A preflush of the reservoir, which is injecting water into the reservoir prior to the surfactant phase, can reduce or prevent precipitation (Schlumberger, 2011). Using Alcohol as a cosurfactant has also proved to be beneficial for reducing precipitation (Dang, et al., 2011). It has also been proposed to increase the concentration of surfactants above the CMC because precipitates will not form once micelles have started to form (Sheng, 2011).

5.5.3 Economy

A surfactant flooding project does require a large and spacious economy. The high front-end investments combined with delayed production also require that the oil price is above some threshold price (Tomich, et al., 1987). The front-end investments are the chemicals and the equipment to be used. In some projects it may be of interest to add a cosurfactant or cosolvent as previously mentioned to reduce the cost. For the projects where the chase water following the surfactant slug contains polymers, expenses for this are added. This will not be explained further here, however it can be noted that it is costly. As for the Norne field extra economic constrains will apply because of the offshore location. This is explained next. Prices and costs are further explained in chapter 0.

5.5.4 Field location

To plan and execute a surfactant flooding project for a reservoir located offshore, such as the Norne field is challenging. Firstly the space to store the chemicals to be injected is limited. This is problematic when large quantities are to be injected daily injection. As an example injecting 3000m^3/day of a 2% surfactant solution will require the handling of 60tons of chemicals a day (Skjæveland & Kleppe, 1992). The plan for using chemical flooding must be developed early in order to handle the need for such a storage demand. This will put constrains on the financial planning and economic feasibility. In addition to the issues regarding storage, the surfactants need to be transported offshore. This makes offshore projects extra challenging compared to onshore ones regarding economy and logistics.

5.6 Selection of surfactant

The selection of surfactants is a challenging task. Chapter 5.2 presented the term phase behavior which is important to be aware of. The chemical reactions the surfactant slug undergoes in the reservoir can to some extent be predicted and needs to be fully understood in order to select the best alternative. In general the reservoir engineer is not involved in deciding the chemical composition of the surfactant used, as this is the work of a chemist. The chemical is as previously mentioned commonly an anionic surfactant.

6 Reservoir simulation

The simulations presented in this report aim to boost the recovery from the Norne C-segment by injecting surfactants. The desired outcome is to achieve as high and satisfactory value of incremental oil recovery possible. An economical evaluation to decide on the feasibility of such a project is performed by calculating the Net Present Value (NPV).

6.1 Eclipse 100

Eclipse 100 is a black oil simulator. The data file to be simulated by Eclipse is constructed in a special way. This particular structure is explained in Appendix C. Among several features Eclipse provides modeling options to handle surfactant flooding.

6.2 The surfactant model

The surfactant model does not aim to model the detailed chemistry of a surfactant process, but rather to model the important features of a surfactant flood on a full field basis. The surfactant is assumed to exist only in the water phase and the distribution of injected surfactant is modeled by solving a conservation equation for surfactants within this phase. At the end of each time-step, after the oil-, water- and gas- flows have been calculated, the concentration of the remaining surfactants are updated using fully-implicit calculations (Schlumberger, 2011). This implies that Eclipse does not model the phase behavior of the surfactants. It only models the effect surfactants have on relative permeability assuming that it is in the water phase. This is done by introducing interfacial tension as a function of the surfactant concentration to the model. The capillary number will be calculated as a function of the interfacial tension and further an interpolation constant is given as a function of the capillary number. Eclipse then interpolates between the relative permeability values for the solution not containing surfactants and the solution which does contain surfactants. Together with the capillary desaturation curves and the low tension relative permeability curves, the chemical adsorption is given as input. The keywords required to initiate and use the surfactant model are explained in Appendix E, and how Eclipse calculates is explained in Appendix D.

6.3 Input values used in the surfactant model

The values used in the surfactant input file are collected from Yugal Kishore Maheshwari's master thesis and are originally provided by Statoil ASA. As previously mentioned the type of surfactant used is generally not an issue to the reservoir engineer. A reduced version showing key data is enclosed in Appendix F. In order to successfully implement the surfactant model some of the keyword needs to be defined for each of the PVT regions or for each of the saturation tables in the model. These numbers are 2 and 107 respectively.

There are five different tables in the surfactant input file. Among these the surfactant viscosity table, the capillary desaturation curve and the adsorption table are the most influential. By changing these impact will be notable.

The critical capillary number in the surfactant dataset is 10^{-5}, this is the highest value for immiscible conditions. Exceeding this value indicates miscible conditions and thus higher surfactant concentrations. The residual oil saturation is as mentioned in chapter 5.4.1 reduced when the critical capillary number is reached.

Prior to adding the surfactants the IFT is $3*10^{-2}$N/m. The presence of surfactants lowers the value with a factor of 10^{-4} to 10^{-6}N/m. This is in accordance with the ultralow values for IFT described in literature (Sheng, 2011).

The value of adsorption given in the input file is kept constant. The value is 0,17mg surfactant/g of rock. The average adsorption value for reservoir rocks in the North Sea is reported by literature to be around 0,4mg/g (Jakobsen & Hovland, 1994).

The viscosity of the surfactant solution is given as a function of the surfactant concentration. When the surfactant concentration is zero, the input viscosity is equal to water. As the surfactant concentration increases the solution viscosity increase. A high viscosity of the surfactant solution, or the displacing phase, will seek to lower the mobility ratio between the displacing and displaced phase. This will lead to a more stable displacement.

6.4 Economic model

The economical evaluation performed in this report is of a very simple nature. The revenue for each year is discounted back to a present value. The total revenue of the whole surfactant flooding project from 2007 to its end in 2022 is the sum of the present values for each year. The revenue for each year is simply the injected surfactant times the surfactant price subtracted from the oil production times the oil price. Despite the fact that important factors regarding CAPEX and OPEX are left out, it provides a good indication of a projects potential. It is a simple NPV calculation which gives an indication whether a project is feasible or not, and is given by the formula (Drake & Fabozzi, 2009):

$$NPV = \sum_{t=0}^{N} \frac{C_t}{(1+i)^t} \tag{6.1}$$

N is the total number of discounting periods or time intervals, t is the current time, C_t is the revenue at the given time t and i is the discount rate.

A discount rate of 8% is used. The oil price has varied from US$100 to US$88 per barrel the last five years (Bloomberg, 2012). A value of US$110/bbl is used in the calculations. The costs associated with the injections of surfactants both include the cost of the chemical itself, and logistics such as transport. The price could typically be 7US$/kg, where the isolated cost for the surfactant is between US$1 and US$2 per kg (Sandengen, 2012). The cost of surfactants in this report excludes logistic additives. 100US$/bbl oil and 1US$/kg surfactant was used in the calculations

6.5 Procedure for simulation

Different cases were tested in order to develop an optimum injection strategy. A large variety of different scenarios can be tested and investigated in order to maximize the recovery. This report is as previously mentioned an extension of the report "Introduction to surfactant flooding for EOR on the Norne Field, C-segment", the cases tested in this report is therefore based on scenarios presented in that project. Purely water injection will be used as base case and as a comparative case to the surfactant cases.

The historical data for the Norne C-segment is available through year 2006. Accordingly, the reservoir performance from 2007 until 2022 is purely a prediction. Water is injected in the beginning of 2007, and constantly through the expected life time. With water as the only drive mechanism a recovery of approximately 49%, on a field basis, is calculated by Eclipse. As additional wells, from other segments than the C-segment, are included in this estimate due to the pressure support it is probably a bit lower. Nevertheless 49% is a fairly good estimate which the injection of surfactants aims to raise.

In 2007 there are 5 production wells operating. These are B-2H, D-2H, D-1CH, B-4DH and K-3H. They are all perforated between layers 5 through 10, which is in the Ile formation. The four water injectors; C-1H, C-2H and C-4H are in 2007 perforated between layers 14 through 20, which is in the Tofte formation.

6.6 Simulation Cases

Base case

The base case is the case of water flooding for maintaining a pressure high enough to recover oil. This is used as a comparative case to the cases where surfactants are injected. All the three injection wells are used in the base case and they are perforated in the target layers which for most of the cases are layer 5 through 12.

Case 1 – Formation selection

80% of the oil is said to be situated in the Ile and Tofte formation. These areas are therefore characterized as target areas for the surfactant flooding. However, it is of interest to decrease the area of interest to decrease the amount of chemicals needed and in the simulation aspect, to better see the effect. To do so, injection into Ile and Tofte is compared with respect to oil recovery. Injection well C-2H is used and is in the first scenario perforated in layer 5-11, which is in Ile, and in 12-18 in the second scenario, which is in Tofte. The cumulative oil production is compared to water injection in the same layers.

Case 2 – Well selection

The C-segment is a relatively large reservoir. The injectors are situated in each corner (Figure 4.5 depicts this). Adsorption and loss of chemicals can, as previously described, be an issue in surfactant flooding. The evaluation and decision of what well to use is therefore important. Case 2 is an extreme case testing continuous injection of surfactants in each of the wells separately, and combined using all wells. The wells are perforated in the Ile formation.

Case 3 – Surfactant concentration

In accordance with literature the adsorption of surfactants will stagnate as the surfactant concentration increases (Skjæveland & Kleppe, 1992). When the critical micelle concentration is reached, the adsorption becomes constant and the reservoir rock is fully saturated with surfactant. Figure 5.8 in chapter 5.5.1 depicts this relationship. In this case the concentration of surfactants in the injected phase will be altered to see the impact on oil recovery. As a comparison to the value of 10 kg/Sm^3 used in case 1, values of 5 kg/Sm^3 and 30 kg/Sm^3 are simulated for.

Case 4 – Slug size

This case evaluates the use of a surfactant slug, rather than continuous injection. Scenarios using a slug size of 2, 5 and 8 years will be simulated. Well C-2H is used as injection well, it is perforated in the Ile formation and the surfactant concentration is 10 kg/Sm^3 in case 4a and 5kg/Sm^3 in case 4b.

7 Results from the simulation

Appendix J and Appendix K shows the production, NPV and adsorption values in their entirety. The plots in the next chapters are based on this.

7.1 Case 1 – Formation selection

Figure 7.1 depicts the incremental cumulative oil production when injecting into the Ile formation versus the Tofte formation. The injection of surfactants was using one well, using a two year slug and injecting from 2007 until 2009.

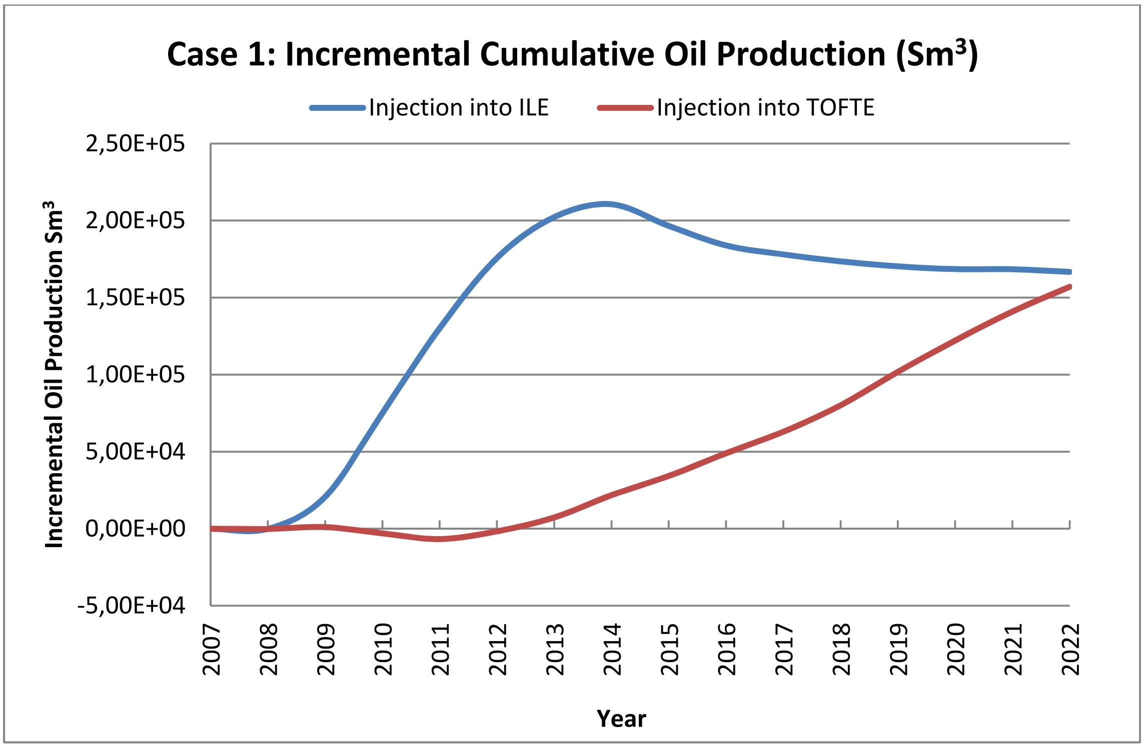

Figure 7.1 - Incremental Cumulative Oil production for Case 1.

The case of injecting surfactants in Ile results in a recovery approximately 1% higher than injecting the same amount of surfactants in Tofte. When both the producers and injectors are perforated in Ile the oil production rapidly increases as the surfactants are added. Around 2013 it reaches its top production and experience a slight decline towards year 2022.

When injecting surfactants into Tofte the production is not increased until after 2012. The production is even lower than basecase before increasing to the same level as the previous scenario. The gap between the two curves is relatively large until the end of the evaluated period. This implies that injecting in Ile will result in money earned at an earlier stage than if injection in Tofte. As mentioned economy is important and can make or break such a project.

Figure 7.2 depicts the adsorption in the two scenarios. It shows that the adsorption is highest when injection in Tofte. For injecting a two year slug, the adsorption is 31% for Ile and 34% for Tofte. In the following cases the surfactants is injected in Ile.

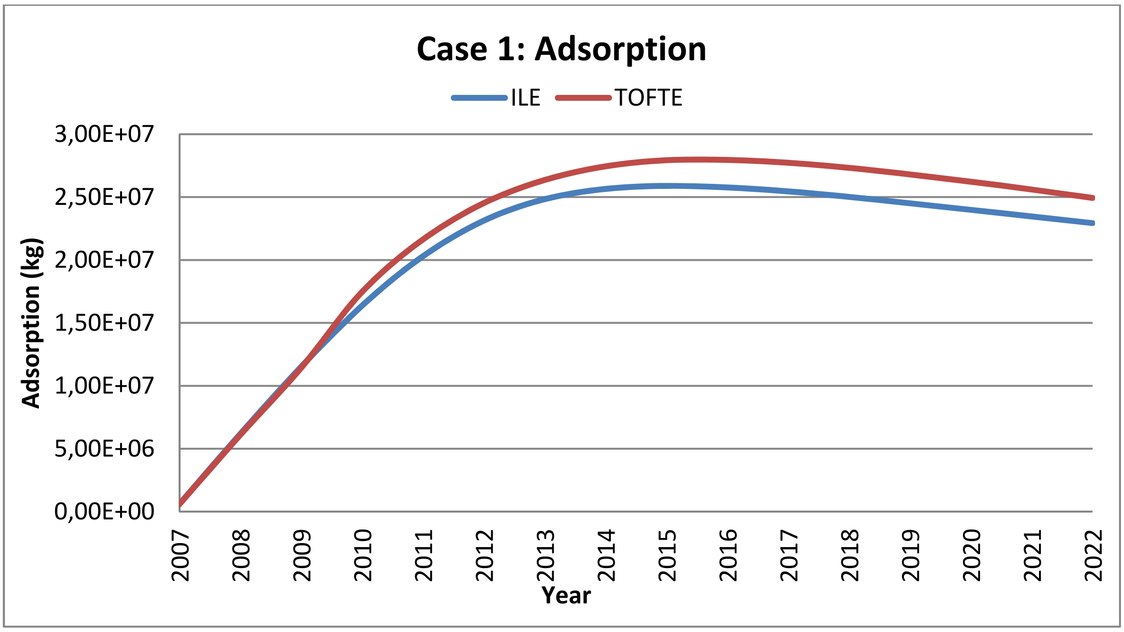

Figure 7.2 - Total adsorption of surfactants in Case 1.

7.2 Case 2 – Well selection

Figure 7.3 shows the incremental oil recovery from each of the wells. The concentration of surfactants used in this case is 10 kg/Sm^3 and the injection is continuous.

Injecting surfactants through all of the three injectors seek to the highest recovery of oil with an 1,23% increase in oil production. When evaluating each well separately using well C-2H gave the best result with an increase in production of 0,94%. The injector C-3H showed the poorest result with an 0,08% incremental recovery. Table 7.1 provides an overview of the key values. Figure 7.4 depicts how the chemicals spread after injection. Blue color represents high concentration and pink color represents zero concentration. The white arrow indicates the position of the injector. The pictures to the left depict the situation in 2009, two years after injection, whilst the pictures to the right depicts the situation in year 2017, 10 years after injection start. The white spots in the figures to the right illustrate the position of the producers.

In general the adsorption is low for all the cases, with values below 40%. As for production of surfactants, well C-3H has the highest value when evaluating the single well scenarios.

Table 7.1 - Total oil production, increase in total production, NPV and adsorption for Case 2.

Case 2					
Surf price (US$/Sm^3)	1	OPT	Increase	NPV	Adsorption
Oil price (US$/bbl)	100	Sm^3	%	Mill US$	%
Basecase		4,81E+07	-	-	-
C-1H		4,85E+07	0,82	-219,81	20,2
C-2H		4,86E+07	0,94	-150,83	12,3
C-3H		4,81E+07	0,08	-320,28	12,2
All Wells		4,87E+07	1,23	-750,58	12,5

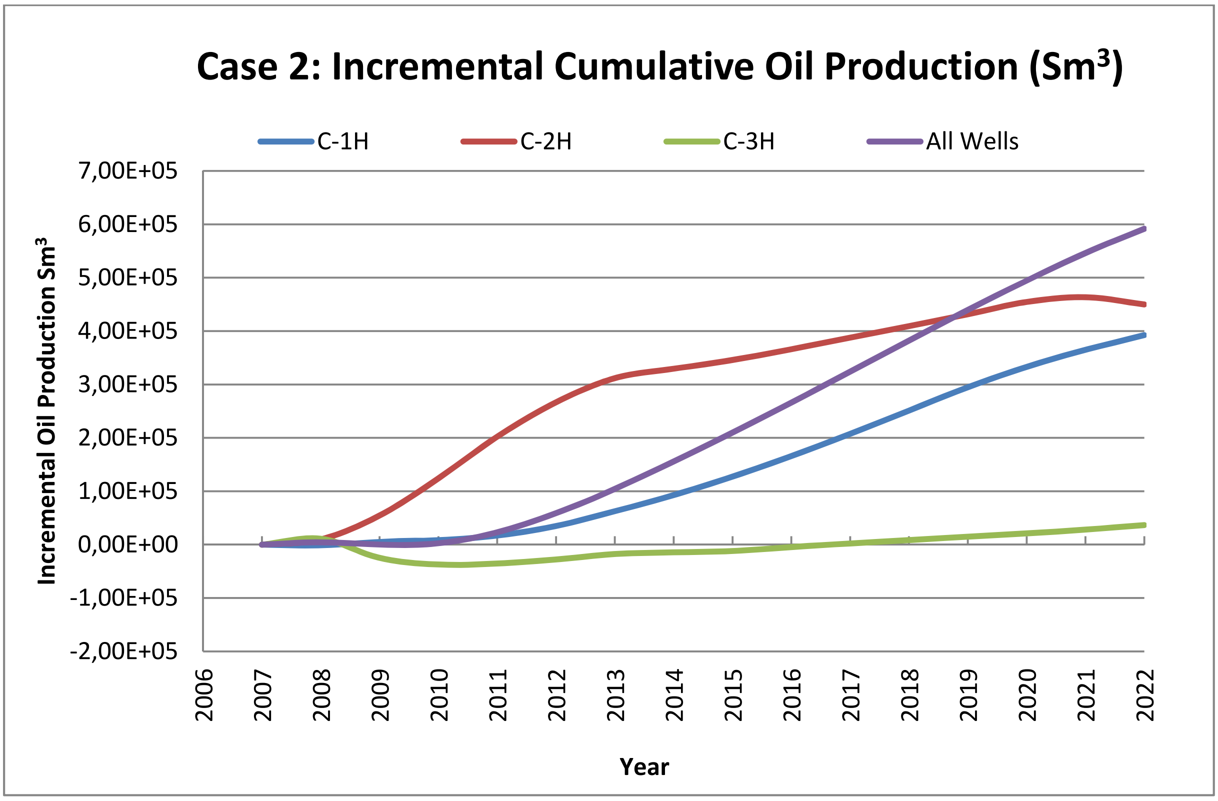

Figure 7.3 - Incremental Cumulative Oil production for Case 2.

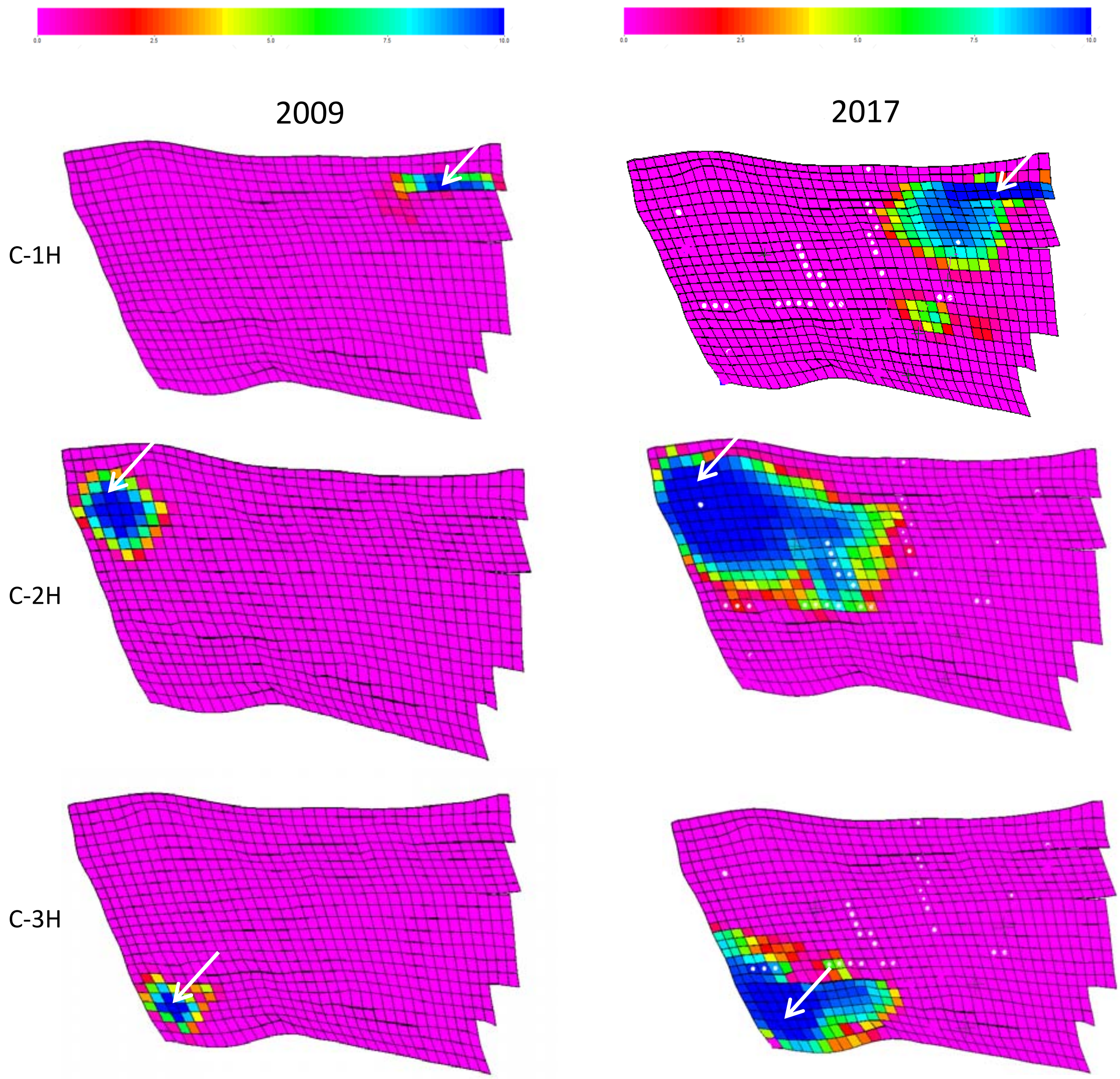

Figure 7.4 - Propagation of surfactants.

7.3 Case 3 – Surfactant concentration

A surfactant concentration of 10 kg/Sm^3 has previously been used. In this case both a lower and a higher concentration, of 5 kg/Sm^3 and 30 kg/Sm^3, are compared to the previously used concentration. The injection is continuous and the surfactants are injected through well C-2H.

The total increase in oil production is 0,60%, using a low concentrated surfactant solution in the reservoir model. Figure 7.5 shows that the increase is highest and most rapid from 2009 through 2014, after this it stagnates and has a slower increase.

A surfactant concentration of 10kg/Sm^3 follow the trend of the low concentrated injection phase, thus it increases to a higher level before it slows down in the last half of the production period. The increase in oil production is 0,94%.

Using 30 kg/Sm^3 provides a higher oil production than the two previous scenarios, which results in a steeper slope in Figure 7.5. The trend is more or less the same as for low and intermediate concentrations as the rate of increase stagnate to a more linear level around 2014. The total increase in oil production is 1,49%. Using a highly concentrated injection also had the lowest value of adsorption.

The NPV values for the three scenarios are negative even with an oil price considered relatively high. Table 7.2 depicts the incremental cumulative oil production at the end of production ant the total NPV. (An extended version of this table is found in Appendix J.)

Table 7.2 - Total oil production, increase in total production, NPV and adsorption for Case 3.

Case 3					
Surf price (US$/Sm^3)	1	**OPT**	**Increase**	**NPV**	**Adsorption**
Oil price (US$/bbl)	100	Sm^3	%	Mill US$	%
Basecase		4,81E+07	-	-	-
Surf. concentration = 5 kg/Sm^3		4,84E+07	0,60	-33,18	24,7
Surf. concentration = 10 kg/Sm^3		4,86E+07	0,94	-150,83	14,7
Surf.concentration = 30 kg/Sm^3		4,88E+07	1,49	-724,22	6,1

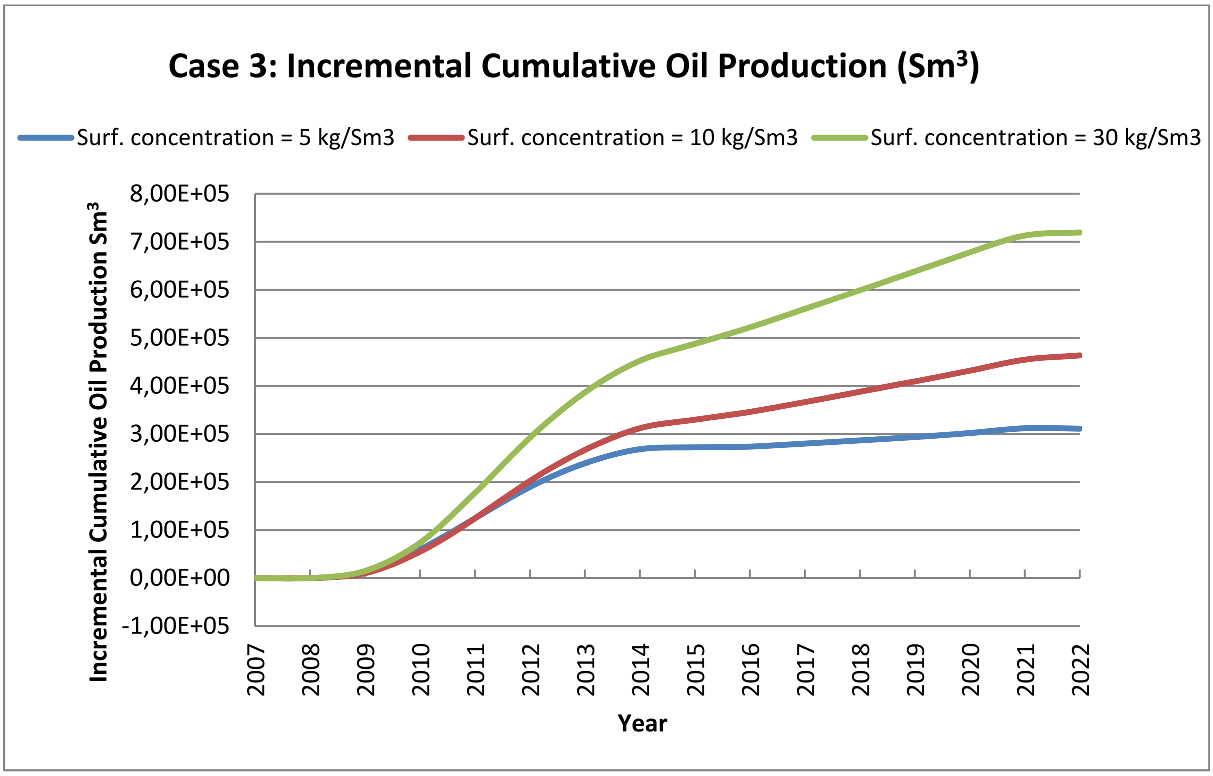

Figure 7.5 - Incremental Cumulative Oil production for Case3.

7.4 Case 4 – Slug size

The injection has been continuous in the previous cases. The duration of the injection is altered in this case. Concentrations of 5 kg/Sm^3 and 10 kg/Sm^3 are used in case 4a and 4b, respectively.

The incremental oil is highest for injecting an 8 year slug, this gives an increase in recovery of 0,51%. However it is followed closely by the 5 year slug with a recovery of 0,49%. Injecting with a two year slug increase the production by 0,44%. All the tree scenarios have the same trend the first five years. In 2012 the oil production in the scenario with the shortest slug declines moderately towards the end in 2022. The two other scenarios continue to increase until 2022. The incremental production for the longest slug has lower slope than when using the intermediate slug. The adsorption is highest at approximately 55% when injecting for 8 years. Figure 7.6 depicts the behavior. Table 7.3 sums up the key data recovered and show that none of the scenarios lead to a positive net present value.

Table 7.3 - Total oil production, increase in total production, NPV and adsorption for Case 4a.

Case 4a, 10 kg/Sm^3					
Surf price (US$/Sm^3)	1	OPT	Increase	NPV	Adsorption
Oil price (US$/bbl)	100	Sm^3	%	Mill US$	%
Basecase		4,81E+07	-	-	-
Slug size = 2 years		4,83E+07	0,22	-17,89	31,4
Slug size = 5 years		4,83E+07	0,49	-57,43	35,1
Slug size = 8 years		4,84E+07	0,51	-120,15	54,8

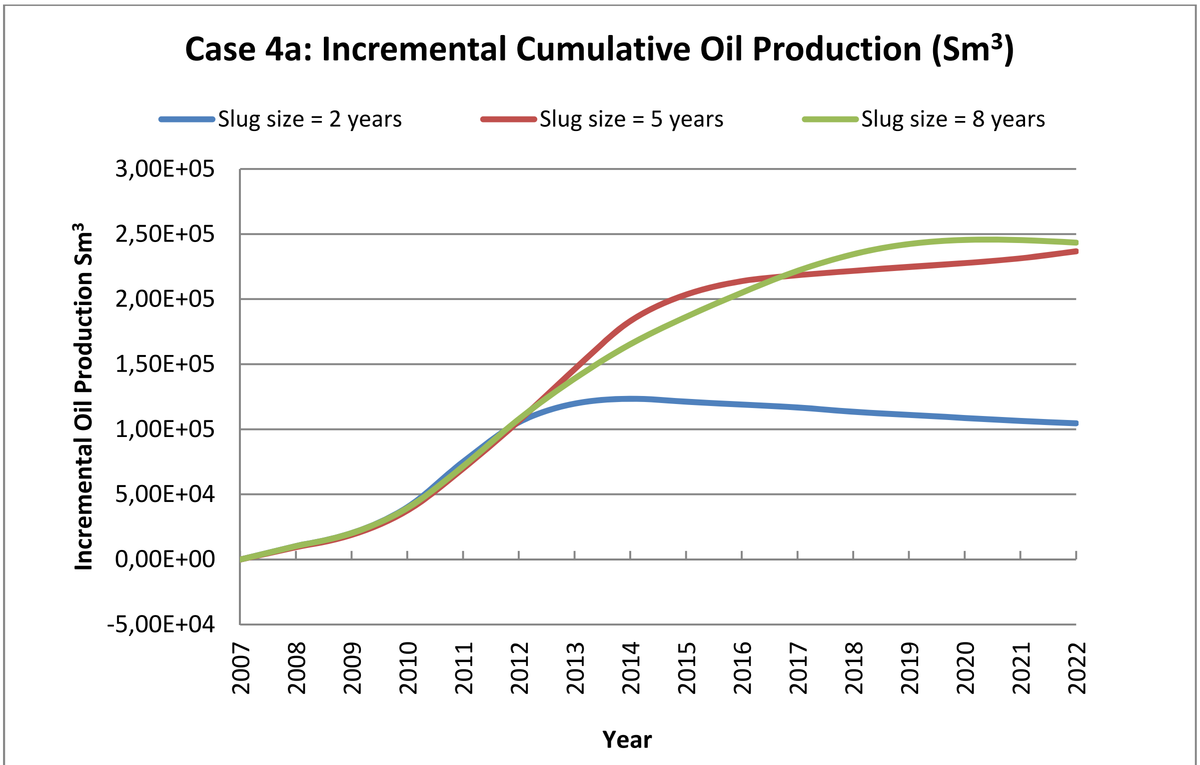

Figure 7.6 - Incremental Cumulative Oil production for Case 4a.

Case 4b is, besides halving the surfactant concentration to 5 kg/Sm^3, identical with 4a. The results are shown in Figure 7.7 and follow the same trend to some extent. Only the incremental production from the 8 year slug deviates from the two other scenarios. It returns a production on a continuously higher level than the shorter slugs. Despite this, the scenario using the shortest slug is the only one leading to a positive net present value. The adsorption is quite similar for all of the three scenarios in the case. Table 7.4 below summarizes this.

Table 7.4 - Total oil production, increase in total production, NPV and adsorption for Case 4b.

Case 4b, 5 kg/Sm^3					
Surf price (US$/Sm^3)	1	**OPT**	**Increase**	**NPV**	**Adsorption**
Oil price (US$/bbl)	100	Sm^3	%	Mill US$	%
Basecase		4,81E+07	-	-	-
Slug size = 2 years		4,83E+07	0,33	5,02	33,3
Slug size = 5 years		4,83E+07	0,37	-21,36	34,2
Slug size = 8 years		4,83E+07	0,40	-43,43	30,2

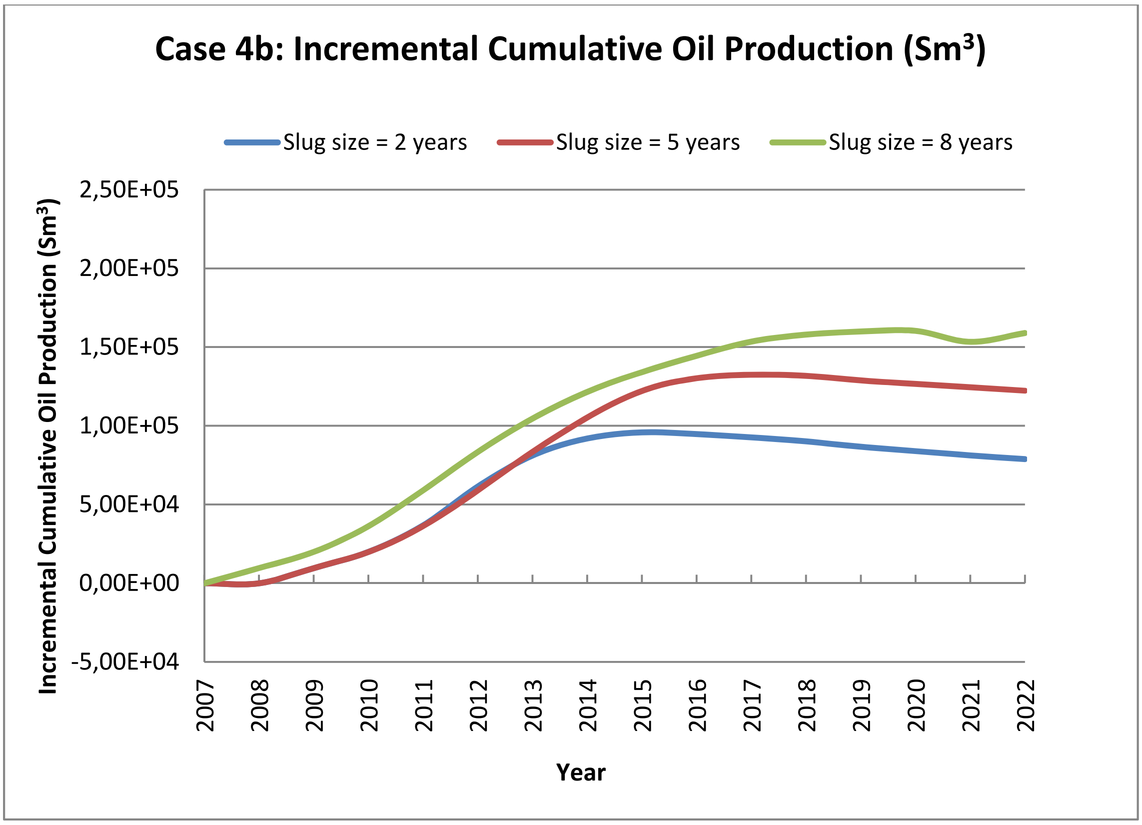

Figure 7.7 - Incremental Cumulative Oil production for Case 4b.

8 Analyses and Discussion

Case 1 – Formation selection

As previously mentioned the water injectors were perforated in the Tofte formation in the original version of the reservoir model. When evaluating the oil in place in Ile and Tofte in 2007 the values are 31% and 21% respectively.

When using water injection it is beneficial to keep the injection below the producer to sweep the reservoir updip. This is to benefit from gravitation as the water is heavier then oil and will sink below the oil phase. When adding surfactants to the displacing phase other factors must be taken account for. With large spacing between injector and producer there will be an increasing likelihood and risk for adsorption. And if the surfactants have to travel long distances to reach the target area, the amount of chemicals needed is increased.

When reviewing the results, the difference in recovery between injecting into Ile and into Tofte is very little. This is somewhat surprising. Due to large spacing between injector and producers, in the case of injection in Tofte, the amount of adsorption was expected to be higher. However the adsorption is only 34% when injecting into Tofte and 31% when injecting into Ile. This is a relative low value as the adsorption can be expected to reach levels of 90% (Skjæveland & Kleppe, 1992). Even though the cumulative results of the two scenarios are of the same order in 2022, the trend differs from each other. As mentioned in the results is the incremental oil production for injection in Ile increasing rapidly at the beginning before decreasing after its peak in 2014. When injecting surfactants in Tofte the incremental production decreases slightly in the beginning before rising constantly. One may question if a longer production period would benefit the scenario of injection into Tofte because of its rising trend.

Because higher incremental production is the ultimate aim of this report, injecting into Ile was chosen as the main strategy for the further analysis. As the difference between the two scenarios was sparse it would have been interesting to use both formations, however only one was chosen.

Case 2 – Well selection

The expectations for case 2 were to some extent met. Using all the wells for injection of surfactants returned an oil production consistently higher than basecase and thus the highest incremental oil recovery.

The injector C-1H is situated in between three faults. These faults obstruct propagation of surfactants to a certain degree (depicted in Figure 7.4). In addition to this the producers situated closest to C-1H are shut in after 2007. This results in a longer way for the surfactants to travel. Due to this the amount of adsorbed surfactant is highest when using C-1H. Yet, as mentioned in the results, the volumes of adsorbed chemicals were uncritical for all scenarios in the case.

Injecting through well C-2H leads to a good distribution of surfactants. This provides a good sweep, and the effect is immediate. Oil production is rapidly increased at an early stage compared to the scenarios using the other wells. This is a clear advantage when evaluating the economical aspect. The investments associated with a surfactant flooding project are major especially at the beginning; a lot due to facilitation. Income to cover these expenses will be crucial for a project.

The scenario using well C-3H showed a somewhat unexpected result when the continuous injection of surfactants resulted in poorer recovery than the basecase for majority of the time. This was unexpected because C-3H is the injection well situated closest to the producers, which should limit the exposure to retention of surfactants. Yet, it results in too early production of surfactant solution which obstructs oil from being produced.

The collective review of case 2 showed a far poorer result than anticipated. The injection was continuous, which should secure a good sweep. Despite this, breakthrough and production of the injected solution will start before the low permeable layers are reached. This is because the injected fluid will spread through high permeability zones first and the low permeable layer may remain untouched due to this (Green & G Paul, 1998). In addition to this, the wells have water breakthrough. This will make it easier for the injected fluid to follow the developed path instead of penetrating new areas.

Due to the cost of chemicals and facilitation of such a project injection on a continuous basis is not feasible (Dang, et al., 2011). All the scenarios in case 2 resulted in negative NPV’s.

Case 3 – Surfactant concentration

To make the project feasible, using a low concentration of surfactants is suggested in literature (Skjæveland & Kleppe, 1992). This is among other things to make the supply and handling of chemicals easier, which especially applies for offshore projects. Yet, the concentration should be kept high enough to not obstruct the solubility between the oil and the injected water solution. It is desirable to have the concentration of surfactants at a level so that the CMC, explained in chapter 5.1.2, is reached. At this level more oil can be solubilized.

The simulation results with varying concentration showed that the highest concentration recovered the most oil. This was expected as high concentration both decrease the IFT to the lowest level and increase the solution viscosity to the highest level. Lower IFT lead to lower capillary force and thus higher amount of residual oil mobilized. The increased solution viscosity will benefit the mobility ratio (M) explained in chapter 2.1. A higher viscosity of the displacing phase will lower M, which in turns stabilizes the displacement. In addition to this the adsorption was as low as 6%. It is suggested that a highly concentrated slug is more stable and may be less exposed for adsorption (Skjæveland & Kleppe, 1992). The combination of these factors increase the production by 1,49%.

When decreasing the concentration to a third, using 10kg/Sm^3 the oil production is increased by 0,94%. This implies that cutting the amount of surfactants needed to a third only decrease the enhanced oil production by 0,55% compared to the highly concentrated injection. As for the even lower concentration of 5kg/Sm^3, the total oil production is increased to 0,60% which is 0,90% lower than the highly concentrated injection. In spite of the highest recovery, the difference between in incremental oil recovered in the scenarios is low and fairly insignificant. The additional increment is not enough to justify the higher surfactant requirement.

Case 4 – Slug size

A continuous injection of surfactants can, as previously mentioned, never be feasible. The injection of surfactants as a slug returns only around half the amount of incremental oil as continuous injection. The most likely reason for this is adsorption and loss of chemicals. Injecting a large slug with low concentration is described as attractive (Skjæveland & Kleppe, 1992). However, the only scenario providing a positive NPV value was injecting a low concentrated slug in the shortest period tested (2 years). The revenue was low, but the only valuable project. According to Harwell, Schetner and Wade at University of Texas an optimal injection strategy for minimizing surfactant losses does exist. Yet it depends on the nature of surfactant mixture used in the flood, and can be difficult to detect. This report only use a single surfactant when injecting and hence finding the optimum injection strategy should be possible. In order to know if the optimum injection strategy of the three scenarios tested here is ideal, it must be compared to several scenarios.

Validation of data and the reservoir model

Reservoir simulation on a full field model requires a lot of input data to estimate desired properties. When working with such a large model as Norne, which has been modified by numerous of involved parties, the validation of data may be questioned. The surfactant input file used is as previously mentioned, collected from another master thesis regarding the Norne field and its E-segment. It is originally provided by Nan Cheng and Statoil ASA (Maheshwari, 2011). The way the IFT was defined in the original dataset was questionable. The IFT increased for the two highest values of the concentration. This provided a decrease of the IFT by a factor of 10^{-4} before an increase which designated the IFT at the highest concentration to only be lowered by a factor of 10^{-2}. This does not correspond with literature where a reduction of IFT by a factor of 10^{-4} is indicated as desirable for the North Sea (Hovland and Jakobsen). As this was detected in time, the input datafile was altered to make the IFT decrease with increasing concentration. However, this may indicate that other undetected errors exist.

One may also discuss if this set of data is compatible with the reservoir and fluid properties defined for the Norne C-segment. When simulating, the output file contained on an average 200 problems and 70 warnings. These were in most cases related to convergence failure, and did not abort the simulations. Due to this they were overlooked.

In addition to this, the history matching performed prior to the simulations may possible have been imprecise. This may have led to an uncertain prediction of the reservoir performance from 2007 to 2022.

General

If the volume of incremental oil solely is the focal point of discussion, the optimal case after evaluation is to continuously inject using a surfactant concentration of 30 kg/Sm^3 via C-2H. However, as previously enlightened continuously injecting is not realistic as both the costs and handling will prevent it. When designating the NPV value as the determining factor the case with injecting a low concentrated slug for two years was the optimum scenario. This case increased the recovery by 0,16%. In comparison the case with continuous injection raised the oil production by 1,49%.

These recoveries are surprisingly low. The incremental oil recovery will vary from field to field. However, using just surfactants as the active chemical can be expected to return a recovery efficiency of about 5-7% (Lakatos, et al., 2007). These percentages are from realistic cases, and not continuous injection. When assessing these results to the results obtained from the C-segment the success of using surfactants here is questioned. As surfactant flooding was elected as the best EOR method to be used at the C-segment one would seemingly expect a higher increase in oil production.

The surfactants target to lower the IFT which in turn lowers the capillary pressure and the residual oil will be mobilized. The low recovery may indicate that one or more of these steps not are fulfilled. A possible reason to this can be that the oil being produced from the reservoir not is capillary trapped. As water injection nearly is as successful, a displacement based on mobility difference between the phases seems to be enough. The reason for this can potentially be that the injection of surfactants is too early, or that the capillary trapping is too low.

A factor which may have an impact on the situation is the wettability. The amount of capillary trapped S_{or} is, as previously mentioned, by far largest in a strongly water-wet reservoir. The wettability in Norne was in chapter 0 described as inhomogeneous and thus mixed-wet. If the larger portions of the reservoir are oil-wet, thus not strongly, the residual oil is not capillary trapped. This will imply that the injected solution will bypass the oil without significantly increasing the oil production. Considering that there are large areas where the oil is the wetting phase, this might obstruct the oil production. This is due to that the rock tends to attract the wetting phase (Sheng, 2011).

Another factor interesting to discuss is the fact that Eclipse overlooks the importance of phase behavior. The simulation will be a simplification of the real and complex situation. This is always the case with reservoir modeling and simulation. However phase behavior is quite important and might affect the result. A simulation program developed by the University of Texas called UTCHEM, take phase behavior into account when simulating. Before deciding upon if a surfactant flooding project should be implemented an analysis using such a simulation program tool should perhaps have been executed. For the C-segment at Norne the recovery was probably too low to expect a result making it feasible to plan surfactant flooding as a method for enhancing the recovery.

9 Conclusion

The demand for hydrocarbons are constantly growing, however the resources are limited. This implies that EOR will be important to maintain oil production. Surfactant flooding is one such method. By lowering the IFT between oil and water the surfactants mobilize the residual oil.

Through the process of screening, surfactant flooding was designated as an EOR method suitable for the C-segment at Norne.

The reservoir model was prepared for simulation in Eclipse through history matching. Due to the lack of history data regarding the pressure, the alterations were made adjusting vertical barriers. However, to group the correct wells in the C-segment provided a better match.

The surfactant flooding of the reservoir returned a surprisingly low result. The following sums up the important factors:

- Using injection well C-2H recovers the most incremental oil.
- The recovery was lower than anticipated. The largest increase in oil recovery is 1,49%. This result was obtained with continuous injection through well C-2H using a high concentration (30kg/Sm^3) of surfactants.
- Adsorption of surfactants was relative low, suggesting that the low recovery not is due to loss of chemicals to the formations.
- High costs of surfactants make the profitability of such a project difficult.
- Only one of the 10 scenarios returned a positive NPV. This was using a low surfactant concentration for a period of two years. However the income was low and the incremental oil recovery was only 0,16%..
- The NPV strongly depends on oil price and surfactant price.
- As the aim of increasing the oil recovery through surfactant flooding is not satisfied and thus it is not a recommended EOR method for Norne C-segment.

10 Uncertainties

In a reservoir simulation project there are a large amount of uncertainties. These spans from the data the reservoir model is based on, the different input data and human errors as a result of the complexity of the problem. When being aware of these uncertainties they can more easily be minimized. The following sums up the main uncertainties:

- The coarsened reservoir model.
- The history matching.
- The Surfactant data used as input to the surfactant model.
- The oil and surfactant price.

11 Recommended further work

This report presents the results from four different cases simulated in order to develop an injection strategy which improves on the recovery. As a large number of different solutions may be tested, the following list represents interesting aspects and features for further work.

- Gather historical data for the pressure and improve on the history matching.
- Analyze whether a later injection time benefits the recovery of oil.
- Analyze whether water alternated surfactants benefits the recovery of oil.
- Vary the rate of injected water.
- Add a cosurfactant to improve on the surfactant performance and possibly lower the costs.
- Add a polymer to improve on the recovery through mobility control.
- Include operational costs and cost related to the facility of a surfactant flooding project.
- Compare results from Eclipse 100 with results from UTCHEM.

12 Nomenclature

$CA(C_{surf})$		Adsorption isotherm as a function of local surfactant concentration solution
CDC	=	Capillary desaturation curve
CMC	=	Critical Micelle Concentration
C_{surf}	=	Concentration of surfactant
C_{unit}	=	Conversion factor
E_A	=	Areal displacement
E_D	=	Displacement efficiency
E_I	=	Vertical displacement
EOR	=	Enhanced Oil Recovery
E_V	=	Volumetric displacement
g	=	Gravity constant
H	=	Height in capillary
HLB	=	Hydrophile-Lipophile Balance
IFT	=	Interfacial Tension
K	=	Permeability
k_r	=	Relative permeability
MD	=	Mass density of rock
M_s	=	Mass of surfactant absorbed
N_c	=	Capillary number
OGIP	=	Original gas in place
OOIP	=	Original oil in place
P_c	=	Capillary Pressure
p_o	=	Pressure in the oil phase
P_{ref}	=	Reference pressure
PV_{cell}	=	Pore volume of a particular cell

p_w	=	Pressure in the water phase
r	=	The radius in the tube/ of the pore throat
S_{or}	=	Residual oil saturation
ST	=	Interfacial tension, same as σ
$ST(S_w)$	=	Interfacial tension at a specific water saturation
S_w	=	Saturation of water
v	=	Darcy velocity
$\Delta\rho$	=	$\rho_o - \rho_w$ = the density difference between oil and water
θ	=	The contact angle between the displacing and displaced phase
λ	=	Mobility
μ	=	Viscosity of displacing fluid
μ_s	=	Viscosity of surfactant
μ_{sw}	=	Viscosity of surfactant-water solution
μ_w	=	Viscosity of water
σ	=	Interfacial tension (IFT) between displacing and displaced fluid
ϕ	=	Porosity

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Appendices

A. Figures related to the reservoir model

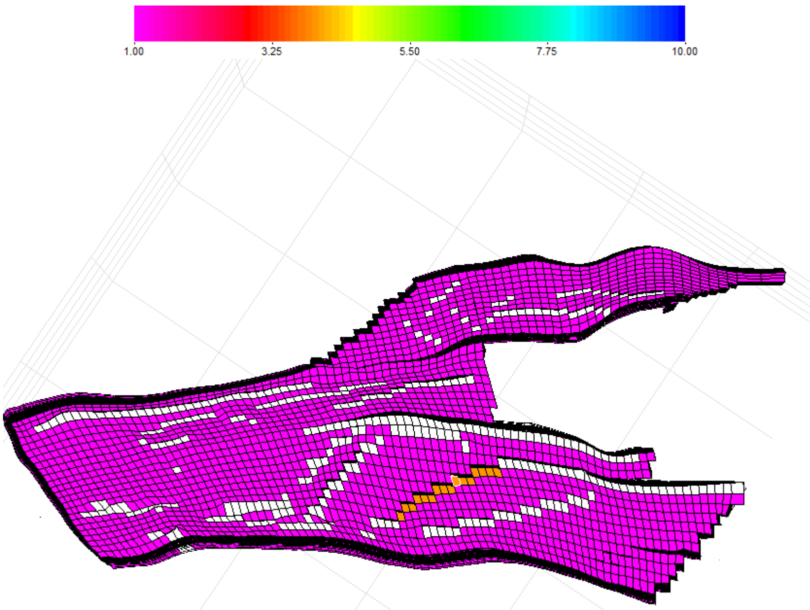

Figure A.1 - Illustration of the Norne field, white lined are indicating faults

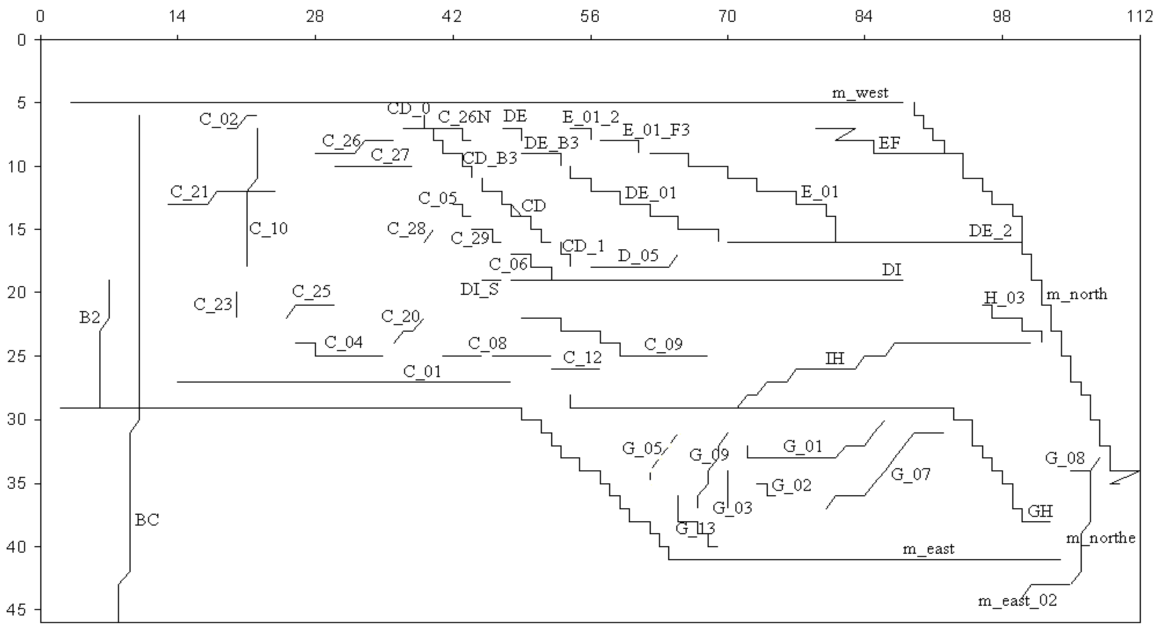

Figure A.2 - Depicts the reservoir faulting. Numbers starting with C is located in the C- segment

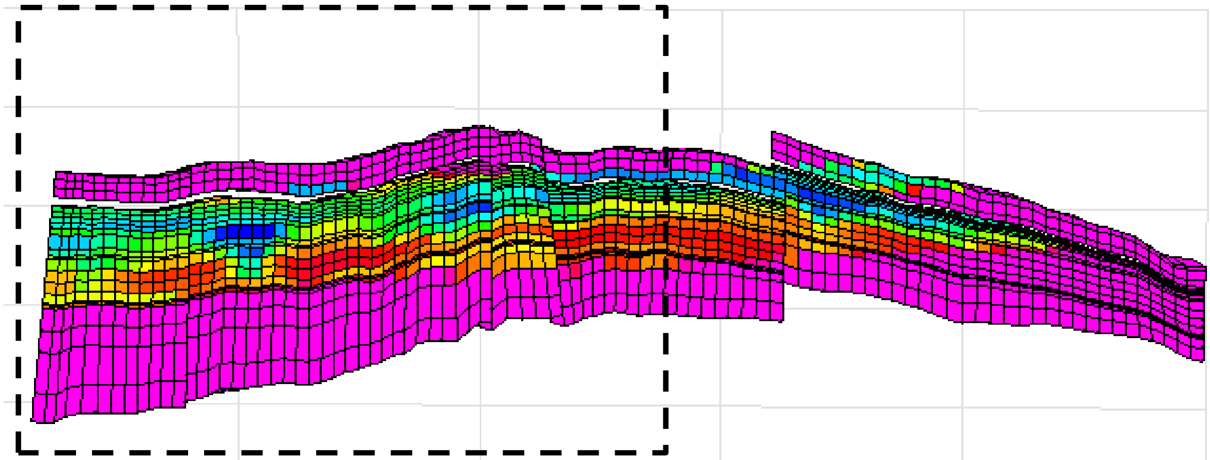

Figure A.3 - Cross-section of the full field model, C-segment indicated with dotted line

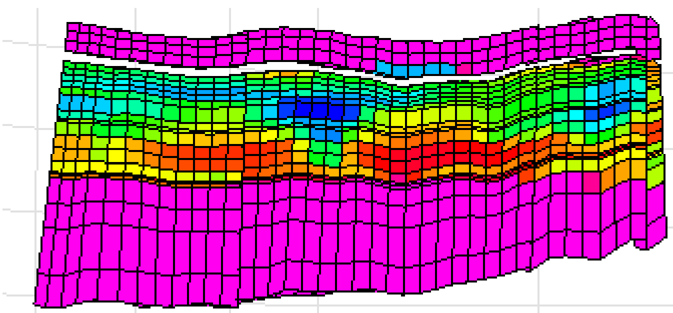

Figure A.4 - Coarsed model of the C-segment

Component	Norne Main Structure		Norne G-Segment
	Reservoir oil (mol%)	Reservoir gas (mol%)	Reservoir oil (mol%)
N2	0,272	0,027	0,32
CO2	0,874	1,306	0,69
C1	47,749	91,174	43,90
C2	3,921	3,869	3,96
C3	2,085	1,371	2,19
iC4	0,445	0,219	0,47
nC4	0,878	0,369	0,93
iC5	0,429	0,131	0,44
nC5	0,467	0,128	0,48
C6	0,871	0,161	0,88
C7	2,505	0,282	2,55
C8	4,071	0,319	4,16
C9	2,992	0,185	3,08
C10+	32,441	0,459	35,96
Molvekt C10+	282 g/mol	171 g/mol	281 g/mol
Tetthet C10+	876 kg/m3	816 kg/m3	877 kg/m3
Fluidprøve	TS-61-06	TS-03-07, A-16745	814700
Prøvetype	bunnhull	separator	bunnhull

Figure A.5 - Hydrocarbon composition at the Norne Field (Kalsnæs, 2010).

B. Screening table

SUMMARY OF SCREENING CRITERIA FOR EOR METHODS

Detail Table in Ref. 16	EOR Method	Oil Properties: Gravity (°API)	Oil Properties: Viscosity (cp)	Oil Properties: Composition	Reservoir Characteristics: Oil Saturation (% PV)	Reservoir Characteristics: Formation Type	Reservoir Characteristics: Net Thickness (ft)	Reservoir Characteristics: Average Permeability (md)	Reservoir Characteristics: Depth (ft)	Reservoir Characteristics: Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	> 35 ↗ 48 ↗	< 0.4 ↘ 0.2 ↘	High percent of C_1 to C_7	> 40 ↗ 75 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 6,000	NC
2	Hydrocarbon	> 23 ↗ 41 ↗	< 3 ↘ 0.5 ↘	High percent of C_2 to C_7	> 30 ↗ 80 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 4,000	NC
3	CO_2	> 22 ↗ 36 ↗ [a]	< 10 ↘ 1.5 ↘	High percent of C_5 to C_{12}	> 20 ↗ 55 ↗	Sandstone or carbonate	Wide range	NC	> 2,500[a]	NC
1–3	Immiscible gases	> 12	< 600	NC	> 35 ↗ 70 ↗	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	> 20 ↗ 35 ↗	< 35 ↘ 13 ↘	Light, intermediate, some organic acids for alkaline floods	> 35 ↗ 53 ↗	Sandstone preferred	NC	> 10 ↗ 450 ↗	> 9,000 ↘ 3,250	> 200 ↘ 80
5	Polymer Flooding	> 15	< 150, > 10	NC	> 50 ↗ 80 ↗	Sandstone preferred	NC	> 10 ↗ 800 ↗ [b]	< 9,000	> 200 ↘ 140
Thermal/Mechanical										
6	Combustion	> 10 ↗ 16 → ?	< 5,000 ↓ 1,200	Some asphaltic components	> 50 ↗ 72 ↗	High-porosity sand/ sandstone	> 10	> 50[c]	< 11,500 ↘ 3,500	> 100 ↗ 135
7	Steam	> 8 to 13.5 → ?	< 200,000 ↓ 4,700	NC	> 40 ↗ 66 ↗	High-porosity sand/ sandstone	> 20	> 200 ↗ 2,540 ↗ [d]	< 4,500 ↘ 1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	> 8 wt% sand	Mineable tar sand	> 10[e]	NC	> 3:1 overburden to sand ratio	NC

NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a]See Table 3 of Ref. 16.
[b]> 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
[c]Transmissibility > 20 md-ft/cp
[d]Transmissibility > 50 md-ft/cp
[e]See depth.

Figure B.1 - Depicts the screening table (Taber, et al., 1997).

C. ECLIPSE 100

The datafile to be simulated by ECLIPSE is constructed in a special way. It is divided into eight sections. These are RUNSPEC, GRID, EDIT, PROPS, REGIONS, SOLUTIONS, SUMMARY and SCHEDULE and they need to be defined in that order (NTNU, 2011).

- RUNSPEC is a required section. This section states the title, problem dimensions, the phases and components present in the model defined.
- GRID is the second section and is also required to be included in the datafile. The geometry of the grid, used to model the reservoir, is defined at this stage. The various rock properties, e.g. porosity and permeabilities, are specified for each grid block. From this information ECLIPSE calculates the pore volumes, the mid-point depths of all the grid blocks and the inter-block transmissibilities.
- EDIT is an optional section. Modifications to the calculated values in the grid section can be modified in this segment.
- PROPS is a required section. This section includes tables of reservoir rock and fluids as functions of fluid pressures, saturations and compositions i.e. density, viscosity, relative permeability and capillary pressure.
- To include REGIONS in the datafile is optional. This is done if it is desirable for the grid blocks to have different PVT properties, saturation properties, initial conditions and amount of fluids in place.
- SOLUTION is a required section. It should contain specification of the initial conditions in the reservoir model. The data includes pressure, saturations and compositions of all the defined grid blocks.
- SUMMARY is optional to include. All of the data that is desirable to have written to the output summary file should be defined in this section.
- SCHEDULE is the last section and needs to be defined. It specifies the operations to be simulated and the times at which output reports are required.

D. Surfactant model

The next chapters contain information about these important features included by the surfactant model.

The Capillary Number

The capillary number is previously defined in this project as the ratio of viscous to capillary forces. It has also been discussed that it is desirable to have a high capillary number. ELIPSE 100 calculates the capillary number in the following way:

$$N_C = \frac{|K \cdot gradP|}{ST} C_{unit} \tag{D.1}$$

Where K is the permeability, P is the potential, ST denotes the interfacial tension and C_{unit} is a conversion factor depending on which units that are used. |K·gradP| is calculated in the following way:

$$|K \cdot gradP| = \sqrt{(K_x \cdot gradP_x)^2 + \left(K_y \cdot gradP_y\right)^2 + (K_z \cdot gradP_z)^2} \tag{D.2}$$

$$K_x \cdot gradP_x = 0.5\left[\left(\frac{K_x}{D_x}\right)_{i-1,i} \cdot (P_i - P_{i-1}) + \left(\frac{K_x}{D_x}\right)_{i,i+1} \cdot (P_{i+1} - P_i)\right] \tag{D.3}$$

The similar approach as for the x-direction is applied for the y- and z- direction (Schlumberger, 2011).

Relative Permeability Model

The relative permeability data is given as input data for immiscible (no mixing) interaction between oil and water. When surfactants are added to the system mixing will occur between the water and the chemicals. Relative permeability data for this miscible phase will be calculated from the given immiscible relative permeability data. These calculated data will only be applied and used by the grid blocks that contain surfactants and thus miscibility will be an option (Schlumberger, 2011).

Capillary Pressure

As mentioned previously the aim of a surfactant flooding is to lower the capillary pressure in order to reduce the amount of trapped oil. The capillary pressure will decrease as the concentration of surfactants increase during flooding. ECLIPSE calculates the pressure in the following way (Schlumberger, 2011):

$$P_c = P_c(S_w)\frac{ST(C_{surf})}{ST(C_{surf}=0)} \quad \text{(D.4)}$$

Where C_{surf} is the concentration of surfactant, $ST(C_{surf})$ is the surface tension at the present surfactant concentration and $ST(C_{surf} = 0)$ is the surface tension when the concentration is zero. $P_c(S_w)$ is the capillary pressure from the immiscible curves scaled and calculated from the miscible relative permeability model.

Water PVT Properties

When the surfactants mix with the water the viscosity of the water (pure or salted, depending on the conditions in the reservoir) will be modified. To calculate the viscosity of the water-surfactant phase ECLIPSE uses the following formula:

$$\mu_{ws}(C_{surf}, P) = \mu_w(P)\frac{\mu_s(C_{surf})}{\mu_w(P_{ref})} \quad \text{(D.5)}$$

Where μ denotes viscosity and the subscript ws indicate water-surfactant solution, s indicate surfactant and w indicate water. P_{ref} is the reference pressure in the water. C_{surf} is the reference salt concentration in the water if this is saline (Schlumberger, 2011).

Adsorption

Adsorption was in chapter 4.5.2 defined as one of the major factors contributing to surfactant loss in a reservoir. ECLIPSE defines the quantity of absorbed surfactant as a function of surrounding surfactant concentration. The absorbed mass is defined as follows:

$$M_s = PV_{cell} \cdot \frac{1-\varphi}{\varphi} \cdot MD \cdot CA(C_{surf}) \quad \text{(D.6)}$$

Where PV_{cell} is the pore volume of the cell, ϕ is the porosity, MD is the mass density of the rock and $CA(C_{surf})$ is the adsorption isotherm as a function of local surfactant concentration solution (Schlumberger, 2011).

E. Keywords in the Surfactant Model

Within the eight sections explained in Appendix C there are some keywords that need to be included in order to implement a surfactant flooding project in Eclipse.

SURFACT

This keyword is mentioned earlier as the word that activates the surfactant model. It should be included in the RUNSPEC section (Schlumberger, 2011).

SURFST

This keyword must be included in order to successfully implement surfactant flooding. It should be in the PROPS section. SURFST defines the interfacial tension between oil and water as a function of the surfactant concentration (Schlumberger, 2011).

SURFVISC

This keyword is also required to be included in the model and should be defined in the PROPS section. It is an abbreviation for surfactant solution viscosity function and is declared by a table where values for the surfactant concentration are in the first column and the associated water viscosities are defined in the second column (Schlumberger, 2011).

SURFCAPD

SURFCAPD defines the capillary desaturation function. It describes the transition between immiscibility, which indicates low surfactant concentration, and miscibility, which indicate high surfactant concentration, as a function of the capillary number. It is required to include this in the PROPS section in a successful implementation of the surfactant model (Schlumberger, 2011).

SURFADS

It is optional to include SURFADS in the PROPS section. This keyword defines the adsorption and is highly recommended to include in the model to make it realistic. The function is defined by a table where the first column states the concentration of surfactants in solution and the second column states the concentration of surfactants absorbed by the rock (Schlumberger, 2011).

SURFROCK

When the adsorption is included in the model it is required to include this keyword. It defines the rock properties used by the surfactant model. The first column contains the so called adsorption index. This is given the value 1 or 2 depending on whether desorbtion is allowed. Desorption is the opposite of adsorption and indicated by defining 1 to be the index. The second column contains the rock density at reservoir condition (Schlumberger, 2011). The keyword should be included in the PROPS section.

WSURFACT

This keyword defines the concentration of surfactant to be injected into the reservoir. It is included in the SCHEDULE section and only applies for the wells declared as water injectors. The first column depicts the name of the water injector whilst the second column defines the concentration as mass of surfactant per mass of water.

F. Surfactant input file

```
SURFST
-- Need as many tables as PVT tables, defined in the second keyword in
TABDIMS = 2
-- Surfactant Water/oil Surface
--conc., kg/m3 Tension, N/m
      0     30.0E-03
      0.1   10.0E-03
      0.25  1.60E-03
      0.5   0.40E-03
      1.0   0.07E-03
      3.0   0.006E-03
      5.0   0.004E-03
      10.0  0.003E-03
      20.0  0.001E-03 /

SURFVISC
-- Need as many tables as PVT tables, defined in the second keyword in
TABDIMS = 2
--Surf conc Water Viscosity
--Kg/m3 Centipoise
      0.0   0.318
      5.0   0.449
      10.0  0.503
      15.0  0.540
      20.0  0.630 /

SURFADS
-- Need as many tables as saturation tables, defined in the first keyword
in TABDIMS = 107
--Surfactant Adsorption by rock
--Surf conc Adsorbed mass
--Kg/m3 (kg/kg) = kg surf /kg rock
      0.0   0.00000
      1.0   0.00017
      5.0   0.00017
      10.0  0.00017 /

SURFCAPD
-- Need as many tables as saturation tables, defined in the first keyword
in TABDIMS = 107
--Capillary De-saturation curve
--Log10 (capillary Miscibility
--number) function 0 = immiscible, 1= miscible
      -8    0.0
      -7    0.0
      -6    0.0
      -5.0  0.0
      -2.5  1.0
      0     1.0
      5     1.0
      10    1.0/

SURFROCK
-- Need as many tables as saturation tables, defined in the first keyword
in TABDIMS = 107
-- No desorption
      1     2650/
```

G. Prediction input file

```
--USER EVENT
ZIPP2OFF
GCONINJE
    'FIELD'     'WATER'      'RATE'  47000.000  9* /
/

GCONPROD
'FIELD' 'ORAT' 36100.000 28500.000 7030000.000  36100.00 'RATE' 'NO'  8* /
'MANI-B2''LRAT' 9000.000  9000.000 3000000.000   9000.00 'RATE' 'YES' 8* /
'MANI-B1''LRAT' 9000.000  9000.000 2000000.000   9000.00 'RATE' 'YES' 8* /
'MANI-D1''LRAT' 9000.000  9000.000 2000000.000   9000.00 'RATE' 'YES' 8* /
'MANI-D2''LRAT' 9000.000  9000.000 2000000.000   9000.00 'RATE' 'YES' 8* /
'MANI-E1''LRAT' 9000.000  9000.000 2000000.000   9000.00 'RATE' 'YES' 8* /
'MANI-E2''LRAT' 9000.000  9000.000 2000000.000   9000.00 'RATE' 'YES' 8* /
/

GCONSALE
    'FIELD' 2949000.000 2950000.000 2948000.000      'NONE' /
/

GUIDERAT
30.000  'OIL'  1.000 10.000 15.000  2.000  0.002  1.500   'YES'  1* /


GCONSUMP
    'FIELD' 441800.000  2* /
/


-- 3343.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2007 /
/

WCONINJE
     'C-1H' 'WATER'  'OPEN'  'RATE'  12000.000  3*  12  1* /
     'C-2H' 'WATER'  'OPEN'  'RATE'  12000.000  3*  13  1* /
     'C-3H' 'WATER'  'OPEN'  'RATE'   8000.000  3*  14  1* /

/

COMPDAT
-- WELL        I    J    K1   K2        Sat.    CF       DIAM    KH SKIN ND
DIR     Ro
'C-1H'  26   44    5    5  'OPEN'  1*  4.787 0.216  446.775 2*  'Z' 16.040/
'C-1H'  26   44    6    6  'OPEN'  1*  4.77  0.21   445.25  2*  'Z' 15.954/
'C-1H'  26   44    7    7  'OPEN'  1*  6.53  0.21   609.083 2*  'Z' 15.888/
'C-1H'  26   44    8    8  'OPEN'  1*  6.508 0.216  604.654 2*  'Z' 15.677/
'C-1H'  26   44    9    9  'OPEN'  1* 52.636 0.216  4889.728 2* 'Z' 15.666/
'C-1H'  26   44   10   10  'OPEN'  1*172.673 0.216  16014.438 2*'Z' 15.538/
'C-1H'  26   44   11   11  'OPEN'  1* 13.370 0.216  1235.506  2*'Z' 15.263/
/

COMPDAT
-- WELL        I    J    K1   K2         Sat.  CF       DIAM   KH SKIN ND
DIR   Ro
'C-2H'  24  14      5   5  'OPEN'  1* 22.116 0.216  1988.961 2*  'Y' 13.365/
'C-2H'  24  14      6   6  'OPEN'  1* 25.523 0.216  2296.808 2*  'Y' 13.419/
```

```
'C-2H'  24   14   7   7  'OPEN' 1*  91.014 0.216  8165.169  2*  'Y' 13.209/
'C-2H'  24   14   8   8  'OPEN  1*   0.357 0.216    31.636  2*  'Y' 12.402/
'C-2H'  24   14   9   9  'OPEN' 1*  76.827 0.216  7207.936  2*  'Y' 16.461/
'C-2H'  24   14   10  10 'OPEN' 1*  76.827 0.216  7207.936  2*  'Y' 16.461/
'C-2H'  24   14   11  11 'OPEN' 1*  76.827 0.216  7207.936  2*  'Y' 16.461/
'C-2H'  24   14   12  12 'OPEN' 1*  22.116 0.216  1988.961  2*  'Y' 13.365/
/


COMPDAT
-- WELL        I    J    K1  K2         Sat.  CF       DIAM    KH SKIN ND
DIR   Ro
'C-3H'  9  13    5   5  'OPEN'  1*  15.871  0.216  1474.759  2* 'Z' 15.685/
'C-3H'  9  13    6   6  'OPEN'  1*  15.768  0.216  1467.264  2* 'Z' 15.796/
'C-3H'  9  13    7   7  'OPEN'  1*   7.937  0.216   736.293  2* 'Z' 15.554/
'C-3H'  9  13    8   8  'OPEN'  1*   7.861  0.216   731.239  2* 'Z' 15.769/
'C-3H'  9  13    9   9  'OPEN'  1*  21.934  0.216  2045.254  2* 'Z' 15.963/
'C-3H'  9  13   10   10 'OPEN'  1*  115.228 0.216  10771.005 2* 'Z' 16.159/
'C-3H'  9  13   11   11 'OPEN'  1*  32.211  0.216  3007.082  2* 'Z' 16.056/
/

WSURFACT
      'C-1H'  0   /
      'C-2H'  10.0 /
      'C-3H'  0    /

 /
WCONINJE

     'C-2H'     'WATER'      'OPEN'     'RATE'   10000.000   1*    1*  3* /

/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /
--------------------------------------------------------------------

-- 3524.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2007 /
/



RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /
--------------------------------------------------------------------

-- 3708.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2008 /
/


RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
```

```
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /
--------------------------------------------------------------------

-- 3890.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2008 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /
--------------------------------------------------------------------

-- 4074.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2009 /
/

WSURFACT
      'C-1H'  0.0 /
      'C-2H'  0.0 /
      'C-3H'  0.0 /
 /

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /
--------------------------------------------------------------------

-- 4255.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2009 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 4439.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2010 /
/


RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 4620.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2010 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /

--------------------------------------------------------------------

-- 4804.000000 days from start of simulation ( 6 'NOV' 1997 )
```

```
DATES
 1 'JAN' 2011 /
/
RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 4985.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2011 /
/
RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 5169.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2012 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 5351.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2012 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 5535.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2013 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 5716.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2013 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 5900.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2014 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 6081.000000 days from start of simulation ( 6 'NOV' 1997 )
```

```
DATES
 1 'JUL' 2014 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 6265.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2015 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 6446.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2015 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /

--------------------------------------------------------------------

-- 6630.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2016 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 6812.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2016 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 6996.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2017 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

-- 7177.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2017 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
```

```
-------------------------------------------------------------------

-- 7361.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2018 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
-------------------------------------------------------------------

-- 7542.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2018 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
-------------------------------------------------------------------

-- 7726.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2019 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
-------------------------------------------------------------------

-- 7907.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2019 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
-------------------------------------------------------------------

-- 8091.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2020 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
-------------------------------------------------------------------

-- 8273.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2020 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
-------------------------------------------------------------------
-- 8457.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JAN' 2021 /
/

RPTSCHED
```

```
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
```

```
-- 8638.000000 days from start of simulation ( 6 'NOV' 1997 )
DATES
 1 'JUL' 2021 /
/

RPTSCHED
 0 0 0 0 0 0 2 2 2 0 1 1 0 1 1 0 0 /
--------------------------------------------------------------------

DATES
 1 'JAN' 2022 /
/
-- END OF SIMULATION
```

H. Group input file

```
WELSPECS
'C-4H'    'MANI-C'           11   35  1*    'OIL'  7* /
'B-2H'    'B1-DUMMY_CSEG'    15   31  1*    'OIL'  2*   'STOP'  4* /
'D-2H'    'D2-DUMMY_CSEG'    14   28  1*    'OIL'  2*   'STOP'  4* /
'B-4H'    'B1-DUMMY_CSEG'    10   32  1*    'OIL'  2*   'STOP'  4* /
'D-4H'    'D2-DUMMY_CSEG'    19   38  1*    'OIL'  2*   'STOP'  4* /
'B-1H'    'MANI-B2_CSEG'     14   34  1*    'OIL'  2*   'STOP'  4* /
'D-1CH'   'MANI-D1_CSEG'     25   37  1*    'OIL'  2*   'STOP'  4* /
'B-4DH'   'B1-DUMMY_CSEG'    10   29  1*    'OIL'  2*   'STOP'  4* /
'K-3H'    'MANI-K2_CSEG'     11   28  1*    'OIL'  2*   'STOP'  4* /

GRUPTREE
   'INJE'         'FIELD'  /
   'PROD'         'FIELD'  /
   'MANI-B2'      'PROD'  /
   'MANI-B1'      'PROD'  /
   'MANI-D1'      'PROD'  /
   'MANI-D2'      'PROD'  /
   'MANI-E1'      'PROD'  /
   'MANI-E2'      'PROD'  /
   'MANI-K1'      'MANI-B1'  /
   'MANI-K2'      'MANI-D2'  /
   'MANI-C'       'INJE'  /
   'MANI-F'       'INJE'  /
   'WI-GSEG'      'INJE'  /
   'B1-DUMMY'     'MANI-B1'  /
   'D2-DUMMY'     'MANI-D2'  /
   'CSEG'         'PROD' /
   'B1-DUMMY_CSEG'        'CSEG'/
   'MANI-D1_CSEG'         'CSEG'/
   'D2-DUMMY_CSEG'        'CSEG'/
   'MANI-B2_CSEG'         'CSEG'/
   'MANI-K2_CSEG'         'CSEG'/

GRUPNET
  'FIELD'     20.000   5* /
  'PROD'      20.000   5* /
  'CSEG'      1* 9999  5* /
  'MANI-B2'   1*    8  1*        'NO'  2* /
  'MANI-B1'   1*    8  1*        'NO'  2* /
  'MANI-K1'   1* 9999  4* /
  'B1-DUMMY'  1* 9999  4* /
  'MANI-D1'   1*    8  1*        'NO'  2* /
  'MANI-D2'   1*    8  1*        'NO'  2* /
  'MANI-K2'   1* 9999  4* /
  'D2-DUMMY'  1* 9999  4* /
  'MANI-E1'   1*    9  1*        'NO'  2* /
  'MANI-E2'   1*    9  4* /

  'B1-DUMMY_CSEG'  1* 9999  4* /
  'MANI-D1_CSEG'   1*    8  1*        'NO'  2* /
  'D2-DUMMY_CSEG'  1* 9999  4* /
  'MANI-B2_CSEG'   1*    8  1*        'NO'  2* /
  'MANI-K2_CSEG'   1* 9999  4* /
```

I. Region input file

```
EQUALS

--Defined by Kristine Nielsen
FIPILE     5    6 29       11 35      5 11 /
FIPILE     5    7 29       36 37      5 11 /
FIPILE     5    8 29       38 38      5 11 /
FIPILE     5    9 29       39 41      5 11 /
FIPILE     5    10 29      42 42      5 11 /
FIPILE     5    11 29      43 44      5 11 /
FIPILE     5    13 29      45 47      5 11 /
FIPILE     5    20 29      48 48      5 11 /
FIPILE     5    25 29      49 49      5 11 /
FIPILE     6    6 6        36 42      5 11 /
FIPILE     6    7 7        38 42      5 11 /
FIPILE     6    8 8        39 42      5 11 /
FIPILE     6    9 9        42 42      5 11 /
FIPILE     6    10 10      43 44      5 11 /

--Defined by Kristine Nielsen
FIPTOFTE  9     6 29       11 35      12 18 /
FIPTOFTE  9     7 29       36 37      12 18 /
FIPTOFTE  9     8 29       38 38      12 18 /
FIPTOFTE  9     9 29       39 41      12 18 /
FIPTOFTE  9     10 29      42 42      12 18 /
FIPTOFTE  9     11 29      43 44      12 18 /
FIPTOFTE  9     13 29      45 47      12 18 /
FIPTOFTE  9     20 29      48 48      12 18 /
FIPTOFTE  9     25 29      49 49      12 18 /
FIPTOFTE  10    6 6        36 42      12 18 /
FIPTOFTE  10    7 7        38 42      12 18 /
FIPTOFTE  10    8 8        39 42      12 18 /
FIPTOFTE  10    9 9        42 42      12 18 /
FIPTOFTE  10    10 10      43 44      12 18 /
```

J. Production rates and NPV

Case 1, Injection into Ile

Year	Date	BaseCase		Injection into ILE										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,525	-0,05	-36,58	-36,58
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,60E+06	2,07E+04	2,08E+04	1,31E+05	36525000	36525000	36,525	11,75	-24,78	-22,94
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,92E+06	7,51E+04	5,44E+04	3,42E+05	73050000	0	0	30,82	30,82	26,42
4	01.01.2010	4,07E+07	1,45E+06	4,08E+07	1,51E+06	1,30E+05	5,50E+04	3,46E+05	73050000	0	0	31,16	31,16	24,73
5	01.01.2011	4,19E+07	1,18E+06	4,21E+07	1,22E+06	1,76E+05	4,55E+04	2,86E+05	73050000	0	0	25,78	25,78	18,95
6	01.01.2012	4,29E+07	9,87E+05	4,31E+07	1,01E+06	2,02E+05	2,66E+04	1,67E+05	73050000	0	0	15,04	15,04	10,23
7	01.01.2013	4,37E+07	8,50E+05	4,39E+07	8,58E+05	2,11E+05	8,31E+03	5,23E+04	73050000	0	0	4,70	4,70	2,96
8	01.01.2014	4,45E+07	7,39E+05	4,47E+07	7,25E+05	1,97E+05	-1,40E+04	-8,81E+04	73050000	0	0	-7,93	-7,93	-4,63
9	01.01.2015	4,51E+07	6,43E+05	4,53E+07	6,30E+05	1,84E+05	-1,27E+04	-7,97E+04	73050000	0	0	-7,17	-7,17	-3,88
10	01.01.2016	4,57E+07	5,65E+05	4,58E+07	5,59E+05	1,78E+05	-5,83E+03	-3,67E+04	73050000	0	0	-3,30	-3,30	-1,65
11	01.01.2017	4,62E+07	5,07E+05	4,63E+07	5,03E+05	1,74E+05	-4,51E+03	-2,84E+04	73050000	0	0	-2,55	-2,55	-1,18
12	01.01.2018	4,66E+07	4,57E+05	4,68E+07	4,54E+05	1,70E+05	-3,22E+03	-2,03E+04	73050000	0	0	-1,82	-1,82	-0,78
13	01.01.2019	4,70E+07	4,16E+05	4,72E+07	4,14E+05	1,69E+05	-1,81E+03	-1,14E+04	73050000	0	0	-1,02	-1,02	-0,41
14	01.01.2020	4,74E+07	3,82E+05	4,76E+07	3,82E+05	1,68E+05	-1,00E+02	-6,29E+02	73050000	0	0	-0,06	-0,06	-0,02
15	01.01.2021	4,78E+07	3,53E+05	4,79E+07	3,51E+05	1,67E+05	-1,70E+03	-1,07E+04	73050000	0	0	-0,96	-0,96	-0,33
16	01.01.2022	4,81E+07	3,26E+05	4,83E+07	3,07E+05	1,48E+05	-1,89E+04	-1,19E+05	73050000	0	0	-10,72	-10,72	-3,38
				Increase in total oil production in %			0,31				SUM NPV Mill US$			7,53

Case 1, Injection into Tofte

Year	Date	BaseCase		Injection into TOFTE										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,525	-0,05	-36,58	-36,58
2	01.01.2008	3,74E+07	2,55E+06	3,74E+07	2,55E+06	1,07E+03	1,16E+03	7,30E+03	36525000	36525000	36,525	0,66	-35,87	-33,21
3	01.01.2009	3,92E+07	1,81E+06	3,92E+07	1,81E+06	-2,98E+03	-4,05E+03	-2,55E+04	73050000	0	0	-2,29	-2,29	-1,97
4	01.01.2010	4,06E+07	1,40E+06	4,06E+07	1,39E+06	-6,69E+03	-3,71E+03	-2,33E+04	73050000	0	0	-2,10	-2,10	-1,67
5	01.01.2011	4,17E+07	1,12E+06	4,17E+07	1,13E+06	-1,67E+03	5,02E+03	3,16E+04	73050000	0	0	2,84	2,84	2,09
6	01.01.2012	4,26E+07	9,32E+05	4,26E+07	9,41E+05	7,33E+03	9,00E+03	5,66E+04	73050000	0	0	5,09	5,09	3,47
7	01.01.2013	4,34E+07	8,00E+05	4,34E+07	8,15E+05	2,18E+04	1,45E+04	9,09E+04	73050000	0	0	8,18	8,18	5,15
8	01.01.2014	4,41E+07	7,01E+05	4,42E+07	7,14E+05	3,43E+04	1,25E+04	7,86E+04	73050000	0	0	7,08	7,08	4,13
9	01.01.2015	4,47E+07	6,19E+05	4,48E+07	6,33E+05	4,90E+04	1,47E+04	9,25E+04	73050000	0	0	8,32	8,32	4,50
10	01.01.2016	4,53E+07	5,51E+05	4,54E+07	5,65E+05	6,30E+04	1,40E+04	8,81E+04	73050000	0	0	7,93	7,93	3,97
11	01.01.2017	4,58E+07	4,93E+05	4,59E+07	5,11E+05	8,01E+04	1,71E+04	1,08E+05	73050000	0	0	9,69	9,69	4,49
12	01.01.2018	4,62E+07	4,44E+05	4,63E+07	4,66E+05	1,02E+05	2,17E+04	1,36E+05	73050000	0	0	12,28	12,28	5,27
13	01.01.2019	4,66E+07	4,07E+05	4,68E+07	4,27E+05	1,22E+05	2,03E+04	1,28E+05	73050000	0	0	11,51	11,51	4,57
14	01.01.2020	4,70E+07	3,75E+05	4,72E+07	3,94E+05	1,41E+05	1,88E+04	1,18E+05	73050000	0	0	10,64	10,64	3,91
15	01.01.2021	4,74E+07	3,48E+05	4,75E+07	3,64E+05	1,57E+05	1,61E+04	1,01E+05	73050000	0	0	9,12	9,12	3,10
16	01.01.2022	4,77E+07	3,24E+05	4,79E+07	3,36E+05	1,69E+05	1,24E+04	7,82E+04	73050000	0	0	7,04	7,04	2,22
				Increase in total oil production in %			0,36				SUM NPV Mill US$			-26,55

Case 2, Injecting through C-1H

Year	Date	BaseCase		C-1H										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,525	-0,06	-36,58	-36,58
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,58E+06	-1,17E+03	-1,08E+03	-6,79E+03	36525000	36525000	36,525	-0,68	-37,20	-34,45
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,87E+06	5,14E+03	6,31E+03	3,97E+04	73050000	36525000	36,525	3,97	-32,56	-27,91
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,45E+06	8,36E+03	3,22E+03	2,03E+04	109575000	36525000	36,525	2,03	-34,50	-27,39
5	01.01.2011	4,19E+07	1,18E+06	4,19E+07	1,19E+06	1,70E+04	8,66E+03	5,45E+04	146100000	36525000	36,525	5,45	-31,08	-22,84
6	01.01.2012	4,29E+07	9,87E+05	4,29E+07	1,00E+06	3,49E+04	1,79E+04	1,13E+05	182625000	36525000	36,525	11,25	-25,27	-17,20
7	01.01.2013	4,37E+07	8,50E+05	4,38E+07	8,78E+05	6,27E+04	2,78E+04	1,75E+05	219150000	36525000	36,525	17,45	-19,07	-12,02
8	01.01.2014	4,45E+07	7,39E+05	4,45E+07	7,69E+05	9,28E+04	3,01E+04	1,89E+05	255675000	36525000	36,525	18,95	-17,58	-10,26
9	01.01.2015	4,51E+07	6,43E+05	4,52E+07	6,77E+05	1,27E+05	3,46E+04	2,18E+05	292200000	36525000	36,525	21,78	-14,74	-7,97
10	01.01.2016	4,57E+07	5,65E+05	4,58E+07	6,03E+05	1,66E+05	3,84E+04	2,41E+05	328725000	36525000	36,525	24,12	-12,40	-6,20
11	01.01.2017	4,62E+07	5,07E+05	4,64E+07	5,49E+05	2,08E+05	4,19E+04	2,64E+05	365250000	36525000	36,525	26,37	-10,15	-4,70
12	01.01.2018	4,66E+07	4,57E+05	4,69E+07	5,01E+05	2,51E+05	4,33E+04	2,73E+05	401775000	36525000	36,525	27,26	-9,26	-3,97
13	01.01.2019	4,70E+07	4,16E+05	4,73E+07	4,60E+05	2,95E+05	4,38E+04	2,75E+05	438300000	36525000	36,525	27,54	-8,99	-3,57
14	01.01.2020	4,74E+07	3,82E+05	4,78E+07	4,20E+05	3,33E+05	3,83E+04	2,41E+05	474825000	36525000	36,525	24,06	-12,47	-4,58
15	01.01.2021	4,78E+07	3,53E+05	4,81E+07	3,85E+05	3,65E+05	3,17E+04	1,99E+05	511350000	36525000	36,525	19,94	-16,59	-5,65
16	01.01.2022	4,81E+07	3,26E+05	4,85E+07	3,54E+05	3,92E+05	2,76E+04	1,74E+05	547875000	0	0	17,38	17,38	5,48
				Increase in total oil production in %			0,82				SUM NPV Mill US$			-219,81

Case 2, Injecting through C-2H

Year	Date	BaseCase		C-2H										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,525	-0,06	-36,58	-36,58
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	9,93E+03	1,00E+04	6,30E+04	36525000	36525000	36,525	6,30	-30,22	-27,98
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,91E+06	5,45E+04	4,46E+04	2,81E+05	73050000	36525000	36,525	28,06	-8,47	-7,26
4	01.01.2010	4,07E+07	1,45E+06	4,08E+07	1,52E+06	1,24E+05	6,96E+04	4,38E+05	109575000	36525000	36,525	43,75	7,23	5,74
5	01.01.2011	4,19E+07	1,18E+06	4,21E+07	1,26E+06	2,02E+05	7,81E+04	4,92E+05	146100000	36525000	36,525	49,15	12,63	9,28
6	01.01.2012	4,29E+07	9,87E+05	4,31E+07	1,05E+06	2,67E+05	6,44E+04	4,05E+05	182625000	36525000	36,525	40,52	4,00	2,72
7	01.01.2013	4,37E+07	8,50E+05	4,40E+07	8,95E+05	3,12E+05	4,52E+04	2,84E+05	219150000	36525000	36,525	28,41	-8,12	-5,12
8	01.01.2014	4,45E+07	7,39E+05	4,48E+07	7,57E+05	3,30E+05	1,77E+04	1,12E+05	255675000	36525000	36,525	11,16	-25,37	-14,80
9	01.01.2015	4,51E+07	6,43E+05	4,54E+07	6,59E+05	3,46E+05	1,61E+04	1,02E+05	292200000	36525000	36,525	10,15	-26,37	-14,25
10	01.01.2016	4,57E+07	5,65E+05	4,60E+07	5,85E+05	3,66E+05	2,05E+04	1,29E+05	328725000	36525000	36,525	12,88	-23,65	-11,83
11	01.01.2017	4,62E+07	5,07E+05	4,66E+07	5,29E+05	3,88E+05	2,16E+04	1,36E+05	365250000	36525000	36,525	13,57	-22,95	-10,63
12	01.01.2018	4,66E+07	4,57E+05	4,70E+07	4,79E+05	4,09E+05	2,15E+04	1,35E+05	401775000	36525000	36,525	13,54	-22,99	-9,86
13	01.01.2019	4,70E+07	4,16E+05	4,75E+07	4,38E+05	4,32E+05	2,22E+04	1,40E+05	438300000	36525000	36,525	13,99	-22,54	-8,95
14	01.01.2020	4,74E+07	3,82E+05	4,79E+07	4,05E+05	4,55E+05	2,31E+04	1,45E+05	474825000	36525000	36,525	14,50	-22,03	-8,10
15	01.01.2021	4,78E+07	3,53E+05	4,82E+07	3,62E+05	4,63E+05	8,88E+03	5,59E+04	511350000	36525000	36,525	5,59	-30,94	-10,53
16	01.01.2022	4,81E+07	3,26E+05	4,86E+07	3,13E+05	4,50E+05	-1,35E+04	-8,49E+04	547875000	0	0	-8,49	-8,49	-2,67
				Increase in total oil production in %			0,94				SUM NPV Mill US$			-150,83

Case 2, Injecting through C-3H

Year	Date	BaseCase		C-3H										
		Total oil prod.	Prod. pr. year	Total oil prod.	Prod. per year	Total increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07		3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,525	-0,06	-36,58	-33,87
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	1,12E+04	1,12E+04	7,07E+04	36525000	36525000	36,525	7,07	-29,46	-25,25
3	01.01.2009	3,92E+07	1,86E+06	3,92E+07	1,83E+06	-2,49E+04	-3,60E+04	-2,27E+05	73050000	36525000	36,525	-22,65	-59,18	-46,98
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,44E+06	-3,74E+04	-1,25E+04	-7,87E+04	109575000	36525000	36,525	-7,87	-44,39	-32,63
5	01.01.2011	4,19E+07	1,18E+06	4,18E+07	1,18E+06	-3,53E+04	2,11E+03	1,33E+04	146100000	36525000	36,525	1,33	-35,20	-23,96
6	01.01.2012	4,29E+07	9,87E+05	4,28E+07	9,95E+05	-2,77E+04	7,54E+03	4,74E+04	182625000	36525000	36,525	4,74	-31,78	-20,03
7	01.01.2013	4,37E+07	8,50E+05	4,37E+07	8,60E+05	-1,76E+04	1,02E+04	6,39E+04	219150000	36525000	36,525	6,39	-30,13	-17,58
8	01.01.2014	4,45E+07	7,39E+05	4,44E+07	7,42E+05	-1,45E+04	3,08E+03	1,94E+04	255675000	36525000	36,525	1,94	-34,59	-18,69
9	01.01.2015	4,51E+07	6,43E+05	4,51E+07	6,45E+05	-1,20E+04	2,53E+03	1,59E+04	292200000	36525000	36,525	1,59	-34,93	-17,48
10	01.01.2016	4,57E+07	5,65E+05	4,57E+07	5,72E+05	-4,51E+03	7,44E+03	4,68E+04	328725000	36525000	36,525	4,68	-31,85	-14,75
11	01.01.2017	4,62E+07	5,07E+05	4,62E+07	5,14E+05	2,14E+03	6,65E+03	4,18E+04	365250000	36525000	36,525	4,18	-32,34	-13,87
12	01.01.2018	4,66E+07	4,57E+05	4,66E+07	4,64E+05	8,53E+03	6,39E+03	4,02E+04	401775000	36525000	36,525	4,02	-32,51	-12,91
13	01.01.2019	4,70E+07	4,16E+05	4,71E+07	4,23E+05	1,50E+04	6,51E+03	4,09E+04	438300000	36525000	36,525	4,09	-32,43	-11,92
14	01.01.2020	4,74E+07	3,82E+05	4,74E+07	3,88E+05	2,11E+04	6,01E+03	3,78E+04	474825000	36525000	36,525	3,78	-32,74	-11,15
15	01.01.2021	4,78E+07	3,53E+05	4,78E+07	3,60E+05	2,81E+04	7,08E+03	4,45E+04	511350000	36525000	36,525	4,45	-32,07	-10,11
16	01.01.2022	4,81E+07	3,26E+05	4,81E+07	3,34E+05	3,66E+04	8,48E+03	5,33E+04	547875000	36525000	36,525	5,33	-31,19	-9,10
				Increase in total oil production in %			0,08				SUM NPV Mill US$			-320,28

Case 2, Injecting through all wells

Year	Date	BaseCase		All Wells										
		Total oil prod.	Prod. pr. year	Total oil prod.	Prod. per year	Total increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2559390	3,48E+07	2559300	-9,00E+01	-90	29751,7	0	109575000	109,575	2,98	-106,60	-98,70
2	01.01.2008	3,74E+07	2583310	3,74E+07	2588040	4,64E+03	4730	-29122,7	109575000	109575000	109,575	-2,91	-112,49	-96,44
3	01.01.2009	3,92E+07	1861310	3,92E+07	1856680	1,00E+01	-4630	16228,2	219150000	109575000	109,575	1,62	-107,95	-85,70
4	01.01.2010	4,07E+07	1451320	4,07E+07	1453900	2,59E+03	2580	128756,3	328725000	109575000	109,575	12,88	-96,70	-71,08
5	01.01.2011	4,19E+07	1177820	4,19E+07	1198290	2,31E+04	20470	226691,6	438300000	109575000	109,575	22,67	-86,91	-59,15
6	01.01.2012	4,29E+07	986970	4,29E+07	1023010	5,91E+04	36040	283112,9	547875000	109575000	109,575	28,31	-81,26	-51,21
7	01.01.2013	4,37E+07	849830	4,38E+07	894840	1,04E+05	45010	327709	657450000	109575000	109,575	32,77	-76,80	-44,81
8	01.01.2014	4,45E+07	738910	4,46E+07	791010	1,56E+05	52100	336640,8	767025000	109575000	109,575	33,66	-75,91	-41,01
9	01.01.2015	4,51E+07	642800	4,53E+07	696320	2,10E+05	53520	353938,3	876600000	109575000	109,575	35,39	-74,18	-37,11
10	01.01.2016	4,57E+07	565010	4,59E+07	621280	2,66E+05	56270	365197,4	986175000	109575000	109,575	36,52	-73,06	-33,84
11	01.01.2017	4,62E+07	507050	4,65E+07	565110	3,24E+05	58060	365700,6	1095750000	109575000	109,575	36,57	-73,00	-31,31
12	01.01.2018	4,66E+07	457180	4,70E+07	515320	3,82E+05	58140	362115,3	1205325000	109575000	109,575	36,21	-73,36	-29,13
13	01.01.2019	4,70E+07	416180	4,75E+07	473750	4,40E+05	57570	343245,3	1314900000	109575000	109,575	34,32	-75,25	-27,67
14	01.01.2020	4,74E+07	381980	4,79E+07	436550	4,94E+05	54570	327080	1424475000	109575000	109,575	32,71	-76,87	-26,17
15	01.01.2021	4,78E+07	353020	4,83E+07	405020	5,46E+05	52000	284874,1	1534050000	109575000	109,575	28,49	-81,09	-25,56
16	01.01.2022	4,81E+07	326000	4,87E+07	371290	5,92E+05	45290	284874,1	1643625000	0	0	28,49	28,49	8,32
				Increase in total oil production in %			1,23				SUM NPV Mill US$			-750,58

Case 3, Using a surfactant concentration of 5 kg/Sm^3

Year	Date	BaseCase		Surf. concentration = 5 kg/Sm^3										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-90	-90	-566,1	0	18262500	18,26	-0,06	-18,32	-18,32
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,60E+06	12240	12330	77555,7	18262500	18262500	18,26	7,76	-10,51	-9,73
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,91E+06	59310	47070	296070,3	36525000	18262500	18,26	29,61	11,34	9,73
4	01.01.2010	4,07E+07	1,45E+06	4,08E+07	1,52E+06	124300	64990	408787,1	54787500	18262500	18,26	40,88	22,62	17,95
5	01.01.2011	4,19E+07	1,18E+06	4,21E+07	1,24E+06	1,89E+05	65120	409604,8	73050000	18262500	18,26	40,96	22,70	16,68
6	01.01.2012	4,29E+07	9,87E+05	4,31E+07	1,04E+06	2,39E+05	49450	311040,5	91312500	18262500	18,26	31,10	12,84	8,74
7	01.01.2013	4,37E+07	8,50E+05	4,40E+07	8,79E+05	268200	29330	184485,7	109575000	18262500	18,26	18,45	0,19	0,12
8	01.01.2014	4,45E+07	7,39E+05	4,47E+07	7,43E+05	271910	3710	23335,9	127837500	18262500	18,26	2,33	-15,93	-9,29
9	01.01.2015	4,51E+07	6,43E+05	4,54E+07	6,44E+05	273590	1680	10567,2	146100000	18262500	18,26	1,06	-17,21	-9,30
10	01.01.2016	4,57E+07	5,65E+05	4,59E+07	5,71E+05	279920	6330	39815,7	164362500	18262500	18,26	3,98	-14,28	-7,14
11	01.01.2017	4,62E+07	5,07E+05	4,65E+07	5,14E+05	286440	6520	41010,8	182625000	18262500	18,26	4,10	-14,16	-6,56
12	01.01.2018	4,66E+07	4,57E+05	4,69E+07	4,64E+05	293390	6950	43715,5	200887500	18262500	18,26	4,37	-13,89	-5,96
13	01.01.2019	4,70E+07	4,16E+05	4,73E+07	4,24E+05	301640	8250	51892,5	219150000	18262500	18,26	5,19	-13,07	-5,19
14	01.01.2020	4,74E+07	3,82E+05	4,77E+07	3,92E+05	311850	10210	64220,9	237412500	18262500	18,26	6,42	-11,84	-4,35
15	01.01.2021	4,78E+07	3,53E+05	4,81E+07	3,52E+05	310890	-960	-6038,4	255675000	18262500	18,26	-0,60	-18,87	-6,42
16	01.01.2022	4,81E+07	3,26E+05	4,84E+07	3,05E+05	290070	-20820	-130957,8	273937500	0	0,00	-13,10	-13,10	-4,13
				Increase in total oil production in %			0,60				SUM NPV Mill US$			-33,18

Case 3, Using a surfactant concentration of 10 kg/Sm^3

Year	Date	BaseCase		Surf. concentration = 10 kg/Sm^3										
		Tot. oil prod.	Prod pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-90	-9,00E+01	-5,66E+02	0	36525000	36,53	-0,06	-36,58	-36,58
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	9930	1,00E+04	6,30E+04	36525000	36525000	36,53	6,30	-30,22	-27,98
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,91E+06	54540	4,46E+04	2,81E+05	73050000	36525000	36,53	28,06	-8,47	-7,26
4	01.01.2010	4,07E+07	1,45E+06	4,08E+07	1,52E+06	124100	6,96E+04	4,38E+05	109575000	36525000	36,53	43,75	7,23	5,74
5	01.01.2011	4,19E+07	1,18E+06	4,21E+07	1,26E+06	202240	7,81E+04	4,92E+05	146100000	36525000	36,53	49,15	12,63	9,28
6	01.01.2012	4,29E+07	9,87E+05	4,31E+07	1,05E+06	266660	6,44E+04	4,05E+05	182625000	36525000	36,53	40,52	4,00	2,72
7	01.01.2013	4,37E+07	8,50E+05	4,40E+07	8,95E+05	311820	4,52E+04	2,84E+05	219150000	36525000	36,53	28,41	-8,12	-5,12
8	01.01.2014	4,45E+07	7,39E+05	4,48E+07	7,57E+05	329560	1,77E+04	1,12E+05	255675000	36525000	36,53	11,16	-25,37	-14,80
9	01.01.2015	4,51E+07	6,43E+05	4,54E+07	6,59E+05	345700	1,61E+04	1,02E+05	292200000	36525000	36,53	10,15	-26,37	-14,25
10	01.01.2016	4,57E+07	5,65E+05	4,60E+07	5,85E+05	366170	2,05E+04	1,29E+05	328725000	36525000	36,53	12,88	-23,65	-11,83
11	01.01.2017	4,62E+07	5,07E+05	4,66E+07	5,29E+05	387750	2,16E+04	1,36E+05	365250000	36525000	36,53	13,57	-22,95	-10,63
12	01.01.2018	4,66E+07	4,57E+05	4,70E+07	4,79E+05	409270	2,15E+04	1,35E+05	401775000	36525000	36,53	13,54	-22,99	-9,86
13	01.01.2019	4,70E+07	4,16E+05	4,75E+07	4,38E+05	431510	2,22E+04	1,40E+05	438300000	36525000	36,53	13,99	-22,54	-8,95
14	01.01.2020	4,74E+07	3,82E+05	4,79E+07	4,05E+05	454560	2,31E+04	1,45E+05	474825000	36525000	36,53	14,50	-22,03	-8,10
15	01.01.2021	4,78E+07	3,53E+05	4,82E+07	3,62E+05	463440	8,88E+03	5,59E+04	511350000	36525000	36,53	5,59	-30,94	-10,53
16	01.01.2022	4,81E+07	3,26E+05	4,86E+07	3,13E+05	449950	-1,35E+04	-8,49E+04	547875000	0	0,00	-8,49	-8,49	-2,67
				Increase in total oil production in %			0,94				SUM NPV Mill US$			-150,83

Case 3, Using a surfactant concentration of 30 kg/Sm^3

Year	Date	BaseCase		Surf. concentration = 30 kg/Sm^3										
		Tot. oil prod.	Prod pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	109575000	109,58	-0,06	-109,63	-109,63
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,60E+06	14620	1,47E+04	9,25E+04	109575000	109575000	109,58	9,25	-100,32	-92,89
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,92E+06	73290	5,87E+04	3,69E+05	219150000	109575000	109,58	36,90	-72,67	-62,30
4	01.01.2010	4,07E+07	1,45E+06	4,09E+07	1,56E+06	177100	1,04E+05	6,53E+05	328725000	109575000	109,58	65,30	-44,28	-35,15
5	01.01.2011	4,19E+07	1,18E+06	4,22E+07	1,29E+06	292080	1,15E+05	7,23E+05	438300000	109575000	109,58	72,32	-37,25	-27,38
6	01.01.2012	4,29E+07	9,87E+05	4,33E+07	1,08E+06	386450	9,44E+04	5,94E+05	547875000	109575000	109,58	59,36	-50,22	-34,18
7	01.01.2013	4,37E+07	8,50E+05	4,42E+07	9,16E+05	452320	6,59E+04	4,14E+05	657450000	109575000	109,58	41,43	-68,14	-42,94
8	01.01.2014	4,45E+07	7,39E+05	4,49E+07	7,74E+05	487290	3,50E+04	2,20E+05	767025000	109575000	109,58	22,00	-87,58	-51,10
9	01.01.2015	4,51E+07	6,43E+05	4,56E+07	6,77E+05	521810	3,45E+04	2,17E+05	876600000	109575000	109,58	21,71	-87,86	-47,47
10	01.01.2016	4,57E+07	5,65E+05	4,62E+07	6,03E+05	560270	3,85E+04	2,42E+05	986175000	109575000	109,58	24,19	-85,38	-42,71
11	01.01.2017	4,62E+07	5,07E+05	4,68E+07	5,46E+05	599030	3,88E+04	2,44E+05	1095750000	109575000	109,58	24,38	-85,19	-39,46
12	01.01.2018	4,66E+07	4,57E+05	4,73E+07	4,96E+05	637930	3,89E+04	2,45E+05	1205325000	109575000	109,58	24,47	-85,11	-36,50
13	01.01.2019	4,70E+07	4,16E+05	4,77E+07	4,56E+05	678030	4,01E+04	2,52E+05	1314900000	109575000	109,58	25,22	-84,35	-33,50
14	01.01.2020	4,74E+07	3,82E+05	4,81E+07	4,17E+05	712890	3,49E+04	2,19E+05	1424475000	109575000	109,58	21,93	-87,65	-32,23
15	01.01.2021	4,78E+07	3,53E+05	4,85E+07	3,59E+05	719340	6,45E+03	4,06E+04	1534050000	109575000	109,58	4,06	-105,52	-35,92
16	01.01.2022	4,81E+07	3,26E+05	4,88E+07	3,22E+05	715070	-4,27E+03	-2,69E+04	1643625000	0	0,00	-2,69	-2,69	-0,85
				Increase in total oil production in %			1,49				SUM NPV Mill US$			-724,22

Case 4a, Using a surfactant concentration of 10 kg/Sm^3 and 2 year slug size.

Year	Date	BaseCase		Slug size = 2 years										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,53	-0,06	-36,58	-36,58
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	1,02E+04	1,03E+04	6,46E+04	36525000	36525000	36,53	6,46	-30,07	-27,84
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,87E+06	2,02E+04	9,97E+03	6,27E+04	73050000	0	0,00	6,27	6,27	5,38
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,47E+06	4,01E+04	1,99E+04	1,25E+05	73050000	0	0,00	12,53	12,53	9,95
5	01.01.2011	4,19E+07	1,18E+06	4,20E+07	1,21E+06	7,50E+04	3,49E+04	2,20E+05	73050000	0	0,00	21,96	21,96	16,14
6	01.01.2012	4,29E+07	9,87E+05	4,30E+07	1,02E+06	1,05E+05	3,04E+04	1,91E+05	73050000	0	0,00	19,09	19,09	12,99
7	01.01.2013	4,37E+07	8,50E+05	4,38E+07	8,64E+05	1,20E+05	1,43E+04	9,01E+04	73050000	0	0,00	9,01	9,01	5,68
8	01.01.2014	4,45E+07	7,39E+05	4,46E+07	7,43E+05	1,23E+05	3,68E+03	2,31E+04	73050000	0	0,00	2,31	2,31	1,35
9	01.01.2015	4,51E+07	6,43E+05	4,52E+07	6,41E+05	1,21E+05	-2,13E+03	-1,34E+04	73050000	0	0,00	-1,34	-1,34	-0,72
10	01.01.2016	4,57E+07	5,65E+05	4,58E+07	5,63E+05	1,19E+05	-2,23E+03	-1,40E+04	73050000	0	0,00	-1,40	-1,40	-0,70
11	01.01.2017	4,62E+07	5,07E+05	4,63E+07	5,05E+05	1,17E+05	-2,21E+03	-1,39E+04	73050000	0	0,00	-1,39	-1,39	-0,64
12	01.01.2018	4,66E+07	4,57E+05	4,67E+07	4,54E+05	1,13E+05	-3,33E+03	-2,09E+04	73050000	0	0,00	-2,09	-2,09	-0,90
13	01.01.2019	4,70E+07	4,16E+05	4,72E+07	4,14E+05	1,11E+05	-2,39E+03	-1,50E+04	73050000	0	0,00	-1,50	-1,50	-0,60
14	01.01.2020	4,74E+07	3,82E+05	4,75E+07	3,80E+05	1,09E+05	-2,39E+03	-1,50E+04	73050000	0	0,00	-1,50	-1,50	-0,55
15	01.01.2021	4,78E+07	3,53E+05	4,79E+07	3,51E+05	1,06E+05	-2,22E+03	-1,40E+04	73050000	0	0,00	-1,40	-1,40	-0,48
16	01.01.2022	4,81E+07	3,26E+05	4,82E+07	3,24E+05	1,05E+05	-1,85E+03	-1,16E+04	73050000	0	0,00	-1,16	-1,16	-0,37
				Increase in total oil production in %			0,22				SUM NPV Mill US$			-17,89

Case 4a, Using a surfactant concentration of 10 kg/Sm^3 and 5 year slug size.

Year	Date	BaseCase		Slug size = 5 years										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,53	-0,06	-36,58	-33,87
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	9,32E+03	9,41E+03	5,92E+04	36525000	36525000	36,53	5,92	-30,61	-26,24
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,87E+06	1,88E+04	9,48E+03	5,96E+04	73050000	36525000	36,53	5,96	-30,56	-24,26
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,47E+06	3,75E+04	1,87E+04	1,18E+05	109575000	36525000	36,53	11,76	-24,77	-18,21
5	01.01.2011	4,19E+07	1,18E+06	4,19E+07	1,21E+06	6,97E+04	3,23E+04	2,03E+05	146100000	36525000	36,53	20,29	-16,24	-11,05
6	01.01.2012	4,29E+07	9,87E+05	4,30E+07	1,02E+06	1,06E+05	3,67E+04	2,31E+05	182625000	0	0,00	23,05	23,05	14,53
7	01.01.2013	4,37E+07	8,50E+05	4,39E+07	8,90E+05	1,46E+05	3,97E+04	2,50E+05	182625000	0	0,00	24,97	24,97	14,57
8	01.01.2014	4,45E+07	7,39E+05	4,46E+07	7,76E+05	1,83E+05	3,71E+04	2,33E+05	182625000	0	0,00	23,32	23,32	12,60
9	01.01.2015	4,51E+07	6,43E+05	4,53E+07	6,63E+05	2,03E+05	2,03E+04	1,27E+05	182625000	0	0,00	12,74	12,74	6,37
10	01.01.2016	4,57E+07	5,65E+05	4,59E+07	5,75E+05	2,14E+05	1,04E+04	6,55E+04	182625000	0	0,00	6,55	6,55	3,03
11	01.01.2017	4,62E+07	5,07E+05	4,64E+07	5,12E+05	2,18E+05	4,51E+03	2,84E+04	182625000	0	0,00	2,84	2,84	1,22
12	01.01.2018	4,66E+07	4,57E+05	4,68E+07	4,61E+05	2,22E+05	3,34E+03	2,10E+04	182625000	0	0,00	2,10	2,10	0,83
13	01.01.2019	4,70E+07	4,16E+05	4,73E+07	4,19E+05	2,25E+05	3,19E+03	2,01E+04	182625000	0	0,00	2,01	2,01	0,74
14	01.01.2020	4,74E+07	3,82E+05	4,77E+07	3,85E+05	2,28E+05	2,75E+03	1,73E+04	182625000	0	0,00	1,73	1,73	0,59
15	01.01.2021	4,78E+07	3,53E+05	4,80E+07	3,57E+05	2,31E+05	3,70E+03	2,33E+04	182625000	0	0,00	2,33	2,33	0,73
16	01.01.2022	4,81E+07	3,26E+05	4,83E+07	3,31E+05	2,37E+05	5,40E+03	3,40E+04	182625000	0	0,00	3,40	3,40	0,99
				Increase in total oil production in %			0,49				SUM NPV Mill US$			-57,43

Case 4a, Using a surfactant concentration of 10 kg/Sm^3 and 8 year slug size.

Year	Date	BaseCase		Slug size = 8 years										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	36525000	36,53	-0,06	-36,58	-33,87
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	1,02E+04	1,03E+04	6,46E+04	36525000	36525000	36,53	6,46	-30,07	-25,78
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,87E+06	2,02E+04	9,97E+03	6,27E+04	73050000	36525000	36,53	6,27	-30,25	-24,02
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,47E+06	3,94E+04	1,93E+04	1,21E+05	109575000	36525000	36,53	12,11	-24,41	-17,94
5	01.01.2011	4,19E+07	1,18E+06	4,20E+07	1,21E+06	7,16E+04	3,22E+04	2,02E+05	146100000	36525000	36,53	20,22	-16,30	-11,10
6	01.01.2012	4,29E+07	9,87E+05	4,30E+07	1,02E+06	1,08E+05	3,63E+04	2,28E+05	182625000	36525000	36,53	22,81	-13,71	-8,64
7	01.01.2013	4,37E+07	8,50E+05	4,39E+07	8,81E+05	1,39E+05	3,11E+04	1,95E+05	219150000	36525000	36,53	19,53	-16,99	-9,92
8	01.01.2014	4,45E+07	7,39E+05	4,46E+07	7,65E+05	1,65E+05	2,65E+04	1,66E+05	255675000	36525000	36,53	16,64	-19,88	-10,74
9	01.01.2015	4,51E+07	6,43E+05	4,53E+07	6,64E+05	1,86E+05	2,10E+04	1,32E+05	292200000	0	0,00	13,20	13,20	6,60
10	01.01.2016	4,57E+07	5,65E+05	4,59E+07	5,84E+05	2,05E+05	1,86E+04	1,17E+05	292200000	0	0,00	11,68	11,68	5,41
11	01.01.2017	4,62E+07	5,07E+05	4,64E+07	5,24E+05	2,22E+05	1,68E+04	1,06E+05	292200000	0	0,00	10,59	10,59	4,54
12	01.01.2018	4,66E+07	4,57E+05	4,69E+07	4,70E+05	2,34E+05	1,27E+04	7,99E+04	292200000	0	0,00	7,99	7,99	3,17
13	01.01.2019	4,70E+07	4,16E+05	4,73E+07	4,24E+05	2,42E+05	7,93E+03	4,99E+04	292200000	0	0,00	4,99	4,99	1,83
14	01.01.2020	4,74E+07	3,82E+05	4,77E+07	3,85E+05	2,45E+05	3,11E+03	1,96E+04	292200000	0	0,00	1,96	1,96	0,67
15	01.01.2021	4,78E+07	3,53E+05	4,80E+07	3,53E+05	2,45E+05	-1,10E+02	-6,92E+02	292200000	0	0,00	-0,07	-0,07	-0,02
16	01.01.2022	4,81E+07	3,26E+05	4,83E+07	3,24E+05	2,43E+05	-1,95E+03	-1,23E+04	292200000	0	0,00	-1,23	-1,23	-0,36
				Increase in total oil production in %			0,51				SUM NPV Mill US$			-120,15

Case 4b, Using a surfactant concentration of 5 kg/Sm^3 and 2 year slug size.

Year	Date	BaseCase		Slug size = 2 years										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	18262500	18,26	-0,06	-18,32	-18,32
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	9,60E+03	9,69E+03	6,10E+04	18262500	18262500	18,26	6,10	-12,17	-11,27
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,87E+06	1,99E+04	1,03E+04	6,45E+04	36525000	0	0,00	6,45	6,45	5,53
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,47E+06	3,67E+04	1,69E+04	1,06E+05	36525000	0	0,00	10,62	10,62	8,43
5	01.01.2011	4,19E+07	1,18E+06	4,19E+07	1,20E+06	6,14E+04	2,47E+04	1,55E+05	36525000	0	0,00	15,50	15,50	11,40
6	01.01.2012	4,29E+07	9,87E+05	4,29E+07	1,01E+06	8,12E+04	1,98E+04	1,24E+05	36525000	0	0,00	12,43	12,43	8,46
7	01.01.2013	4,37E+07	8,50E+05	4,38E+07	8,61E+05	9,19E+04	1,08E+04	6,78E+04	36525000	0	0,00	6,78	6,78	4,27
8	01.01.2014	4,45E+07	7,39E+05	4,46E+07	7,43E+05	9,58E+04	3,90E+03	2,45E+04	36525000	0	0,00	2,45	2,45	1,43
9	01.01.2015	4,51E+07	6,43E+05	4,52E+07	6,42E+05	9,47E+04	-1,14E+03	-7,17E+03	36525000	0	0,00	-0,72	-0,72	-0,39
10	01.01.2016	4,57E+07	5,65E+05	4,58E+07	5,63E+05	9,26E+04	-2,07E+03	-1,30E+04	36525000	0	0,00	-1,30	-1,30	-0,65
11	01.01.2017	4,62E+07	5,07E+05	4,63E+07	5,05E+05	9,01E+04	-2,49E+03	-1,57E+04	36525000	0	0,00	-1,57	-1,57	-0,73
12	01.01.2018	4,66E+07	4,57E+05	4,67E+07	4,54E+05	8,66E+04	-3,50E+03	-2,20E+04	36525000	0	0,00	-2,20	-2,20	-0,94
13	01.01.2019	4,70E+07	4,16E+05	4,71E+07	4,13E+05	8,39E+04	-2,70E+03	-1,70E+04	36525000	0	0,00	-1,70	-1,70	-0,67
14	01.01.2020	4,74E+07	3,82E+05	4,75E+07	3,79E+05	8,12E+04	-2,72E+03	-1,71E+04	36525000	0	0,00	-1,71	-1,71	-0,63
15	01.01.2021	4,78E+07	3,53E+05	4,79E+07	3,51E+05	7,88E+04	-2,39E+03	-1,50E+04	36525000	0	0,00	-1,50	-1,50	-0,51
16	01.01.2022	4,81E+07	3,26E+05	4,82E+07	3,24E+05	7,68E+04	-1,99E+03	-1,25E+04	36525000	0	0,00	-1,25	-1,25	-0,39
				Increase in total oil production in %			0,16				SUM NPV Mill US$			5,02

Case 4b, Using a surfactant concentration of 5 kg/Sm^3 and 5 year slug size.

Year	Date	BaseCase		Slug size = 5 years										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	18262500	18,26	-0,06	-18,32	-16,96
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	9,60E+03	9,69E+03	6,10E+04	18262500	18262500	18,26	6,10	-12,17	-10,43
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,87E+06	1,99E+04	1,03E+04	6,45E+04	36525000	18262500	18,26	6,45	-11,82	-9,38
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,47E+06	3,62E+04	1,64E+04	1,03E+05	54787500	18262500	18,26	10,28	-7,98	-5,86
5	01.01.2011	4,19E+07	1,18E+06	4,19E+07	1,20E+06	5,90E+04	2,28E+04	1,43E+05	73050000	18262500	18,26	14,33	-3,93	-2,68
6	01.01.2012	4,29E+07	9,87E+05	4,29E+07	1,01E+06	8,34E+04	2,44E+04	1,54E+05	91312500	0	0,00	15,37	15,37	9,69
7	01.01.2013	4,37E+07	8,50E+05	4,38E+07	8,72E+05	1,05E+05	2,18E+04	1,37E+05	91312500	0	0,00	13,71	13,71	8,00
8	01.01.2014	4,45E+07	7,39E+05	4,46E+07	7,56E+05	1,22E+05	1,70E+04	1,07E+05	91312500	0	0,00	10,67	10,67	5,77
9	01.01.2015	4,51E+07	6,43E+05	4,52E+07	6,51E+05	1,30E+05	8,04E+03	5,06E+04	91312500	0	0,00	5,06	5,06	2,53
10	01.01.2016	4,57E+07	5,65E+05	4,58E+07	5,67E+05	1,32E+05	2,18E+03	1,37E+04	91312500	0	0,00	1,37	1,37	0,64
11	01.01.2017	4,62E+07	5,07E+05	4,63E+07	5,06E+05	1,32E+05	-6,80E+02	-4,28E+03	91312500	0	0,00	-0,43	-0,43	-0,18
12	01.01.2018	4,66E+07	4,57E+05	4,68E+07	4,54E+05	1,29E+05	-2,89E+03	-1,82E+04	91312500	0	0,00	-1,82	-1,82	-0,72
13	01.01.2019	4,70E+07	4,16E+05	4,72E+07	4,14E+05	1,27E+05	-2,20E+03	-1,38E+04	91312500	0	0,00	-1,38	-1,38	-0,51
14	01.01.2020	4,74E+07	3,82E+05	4,75E+07	3,80E+05	1,24E+05	-2,18E+03	-1,37E+04	91312500	0	0,00	-1,37	-1,37	-0,47
15	01.01.2021	4,78E+07	3,53E+05	4,79E+07	3,51E+05	1,22E+05	-2,16E+03	-1,36E+04	91312500	0	0,00	-1,36	-1,36	-0,43
16	01.01.2022	4,81E+07	3,26E+05	4,82E+07	3,24E+05	1,20E+05	-1,92E+03	-1,21E+04	91312500	0	0,00	-1,21	-1,21	-0,35
				Increase in total oil production in %			0,25				SUM NPV Mill US$			-21,36

Case 4b, Using a surfactant concentration of 5 kg/Sm^3 and 8 year slug size.

Year	Date	BaseCase		Slug size = 8 years										
		Tot. oil prod.	Prod. pr. year	Tot. oil prod.	Prod. per year	Tot. increase	Increase pr. year		Injected surf	Surf bought	OUT	IN	REVENUE	NPV
		Sm^3		Sm^3		Sm^3		bbl	kg		Mill US$			
0	01.01.2006	3,22E+07	-	3,22E+07	-	-	-	-	-	-	-	-	-	-
1	01.01.2007	3,48E+07	2,56E+06	3,48E+07	2,56E+06	-9,00E+01	-9,00E+01	-5,66E+02	0	18262500	18,26	-0,06	-18,32	-16,96
2	01.01.2008	3,74E+07	2,58E+06	3,74E+07	2,59E+06	9,60E+03	9,69E+03	6,10E+04	18262500	18262500	18,26	6,10	-12,17	-10,43
3	01.01.2009	3,92E+07	1,86E+06	3,93E+07	1,87E+06	1,99E+04	1,03E+04	6,45E+04	36525000	18262500	18,26	6,45	-11,82	-9,38
4	01.01.2010	4,07E+07	1,45E+06	4,07E+07	1,47E+06	3,62E+04	1,64E+04	1,03E+05	54787500	18262500	18,26	10,28	-7,98	-5,86
5	01.01.2011	4,19E+07	1,18E+06	4,19E+07	1,20E+06	5,90E+04	2,28E+04	1,43E+05	73050000	18262500	18,26	14,33	-3,93	-2,68
6	01.01.2012	4,29E+07	9,87E+05	4,29E+07	1,01E+06	8,34E+04	2,44E+04	1,54E+05	91312500	18262500	18,26	15,37	-2,89	-1,82
7	01.01.2013	4,37E+07	8,50E+05	4,38E+07	8,71E+05	1,05E+05	2,11E+04	1,33E+05	109575000	18262500	18,26	13,30	-4,97	-2,90
8	01.01.2014	4,45E+07	7,39E+05	4,46E+07	7,56E+05	1,22E+05	1,70E+04	1,07E+05	127837500	18262500	18,26	10,70	-7,56	-4,09
9	01.01.2015	4,51E+07	6,43E+05	4,52E+07	6,55E+05	1,34E+05	1,25E+04	7,86E+04	146100000	0	0,00	7,86	7,86	3,93
10	01.01.2016	4,57E+07	5,65E+05	4,58E+07	5,75E+05	1,44E+05	1,04E+04	6,55E+04	146100000	0	0,00	6,55	6,55	3,03
11	01.01.2017	4,62E+07	5,07E+05	4,63E+07	5,16E+05	1,54E+05	9,04E+03	5,69E+04	146100000	0	0,00	5,69	5,69	2,44
12	01.01.2018	4,66E+07	4,57E+05	4,68E+07	4,62E+05	1,58E+05	4,40E+03	2,77E+04	146100000	0	0,00	2,77	2,77	1,10
13	01.01.2019	4,70E+07	4,16E+05	4,72E+07	4,18E+05	1,60E+05	2,02E+03	1,27E+04	146100000	0	0,00	1,27	1,27	0,47
14	01.01.2020	4,74E+07	3,82E+05	4,76E+07	3,82E+05	1,60E+05	3,80E+02	2,39E+03	146100000	0	0,00	0,24	0,24	0,08
15	01.01.2021	4,78E+07	3,53E+05	4,79E+07	3,46E+05	1,53E+05	-7,00E+03	-4,40E+04	146100000	0	0,00	-4,40	-4,40	-1,39
16	01.01.2022	4,81E+07	3,26E+05	4,83E+07	3,32E+05	1,59E+05	5,61E+03	3,53E+04	146100000	0	0,00	3,53	3,53	1,03
				Increase in total oil production in %			0,33				SUM NPV Mill US$			-43,43

K. Adsorption

Case1	Incected surfactants	Adsorbtion	
	kg	kg	%
Ile	7,31E+07	2,29E+07	31,4
Tofte	7,31E+07	2,49E+07	34,1

Case2	Incected surfactants	Adsorbtion	
	kg	kg	%
C-1H	5,48E+08	1,11E+08	20,2
C-2H	5,48E+08	6,76E+07	12,3
C-3H	5,48E+08	6,69E+07	12,2
All wells	1,64E+09	2,05E+08	12,5

Case3	Incected surfactants	Adsorbtion	
	kg	kg	%
5 kg/Sm^3	2,74E+08	6,76E+07	24,7
10 kg/Sm^3	5,48E+08	8,08E+07	14,7
30 kg/Sm^3	1,64E+09	1,01E+08	6,1

Case4a	Incected surfactants	Adsorbtion	
	kg	kg	%
2 years	7,31E+07	2,29E+07	31,4
5 years	9,60E+07	3,37E+07	35,1
8 years	1,30E+08	7,10E+07	54,8

Case4b	Incected surfactants	Adsorbtion	
	kg	kg	%
2 yeras	3,65E+07	1,22E+07	33,3
5 years	9,13E+07	3,13E+07	34,2
8 years	1,46E+08	4,42E+07	30,2