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Applying Chemical EOR on the Norne Field C-Segment

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Abstract

The world energy demand will grow and oil will continue to be a major part of the energy consumption. Enhanced Oil Recovery will play a key role in meeting the oil demand by increasing the low oil recovery factors in the world today. Half of the oil is still trapped in the reservoir after the production have ceased. The development of new technology has brought a renewed attention for chemical flooding. It has been recognized as a technically feasible method in the Norwegian Continental Shelf and is expected to become attractive.

Norne C-Segment is a good candidate for chemical flooding based on screening, current drainage strategy and high water cut. The objects of this Master Thesis are to find an optimum chemical flooding strategy for the Norne C-Segment to maximise the profit from volume of incremental oil produced. The result of the project is based on Net Present Value calculation. Simulations are run in Eclipse on a simulation model of Norne C-Segment released by Center of Integrated Operations at NTNU and Statoil ASA. The model was not perfect history matched therefore an effort to look at the uncertainties in vertical barriers where done before applying chemicals.

The Ile formation was chosen as the target formation because of the highest OIP and high oil saturation. A synthetic model of the target formation was build to optimize the chemical injection scheme. Based on the evaluation of the injection wells C-2H was best suited for chemical flooding. The chemicals applied are polymer, surfactant, alkaline and combinations of two or all of these chemicals. Surfactant and alkaline are primarily used to reduce oil-water Interfacial Tension and minimize the capillary forces that trap residual oil after waterflooding. Polymers are used as a mobility control to improve reservoir contact and flood efficiency.

Based on the simulation results and economic evaluation polymer flooding is the best chemical flooding method with a net present value of 406 million USD in 2022. Norne C-Segment Ile formation is favourable for mobility control. Surfactant and alkaline cannot mobilize enough residual oil to pay of the cost of chemicals and is not economical attractive.

Sammendrag

Verdens energietterspørsel forventes å vokse sterkt de kommende årene og oljen vil fortsette å være en stor del av energiforbruket. Med dagens produksjonsplaner blir mer enn halvparten av de påviste oljeressursene i norske felt liggende igjen i undergrunnen. 'Enhanced Oil Recovery' vil spille en nøkkelrolle i å møte etterspørselen etter olje. Dette ved å bidra til økt utvinning fra produserende felt, selv noen få prosents økt utvinningsgrad representerer store verdier for samfunnet. Utviklingen av ny teknologi har ført en fornyet oppmerksomhet for stimulert utvinning ved hjelp av kjemisk flømming. Kjemisk flømming har blitt anerkjent som en teknisk mulig metode i den norske kontinentalsokkelen og forventes å bli attraktiv. Norne C-segmentet er en god kandidat for kjemiskflømming basert på screening, dagens dreneringsstrategi og høy vannproduksjon. Objektene i denne masteroppgaven er å finne en optimal kjemisk flømming strategi for Norne C-segmentet. Resultatet av prosjektet er basert på netto nåverdiberegning. Simuleringer kjøres i Eclipse på en simuleringsmodell av Norne i C-segmentet utgitt av sentere for integrerte operasjoner ved NTNU og Statoil ASA.

Modellen var ikke historie tilpasset derfor ble det gjort en usikkerhets analyse av de vertikale barrierene før den kjemiske flømmingen. Ile formasjonen ble valgt på grunn av høyt innhold av olje og høy oljemetning. En syntetisk modell av Ile formasjonen ble bygd for å optimalisere konsentrasjonen til de ulike kjemikaliene. C-2H var best egnet som injeksjonsbrønn basert på høyest bidrag til økt oljeutvinning i Ile formasjonen.

De kjemikaliene som skal brukes er polymerer, surfaktanter, alkalier og kombinasjoner av to eller alle av disse kjemikaliene. Surfaktanter og alkalier blir hovedsakelig brukt til å redusere olje-vann grenseflatespenning, minimere de kapillære kreftene for og dermed redusere restoljen etter vannflømming. Polymers blir brukt som en mobilitets kontroll for å forbedre reservoar kontakt og flom effektiviteten. Basert på simuleringsresultatene og økonomisk evaluering er polymer flømming mest egnet for Norne C-Segment med en netto nåverdi på 410 millioner USD i 2022. Surfaktant og alkaline kan ikke mobilisere nok restolje til å dekke for kostnadene til kjemikaliene. De er derfor ikke økonomisk attraktive for Norne C-Segmentet.

Acknowledgment:

This Master Thesis was carried out at the Norwegian University of science and Technology, Department of petroleum Engineering and Applied Geophysics, and is an extension of my project "Applying Chemical EOR on the Norne Field C-Segment" from autumn 2011. The work on history matching of the Norne C-Segment has been in collaboration with Kristine Nielsen.

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1 Introduction

The world energy demand will grow and oil will continue to be a major part of the energy consumption. Population and income growth are the two most powerful driving forces behind the demand for energy. World population has quadrupled since 1990 and real income has grown by a factor of 25, and primary energy consumption by a factor of 22.5. The future is likely to see continued global integration and rapid growth of low and medium income economies. The population is projected to rise by 1.4 billion over the next 20 years. The world's real income has risen by 87 % over the past 20 years and it is likely to rise by 100 % over the next 20 years. (BP, January 2011) More people with more income mean that the production and consumption of energy will rise as seen in Figure 1.1.

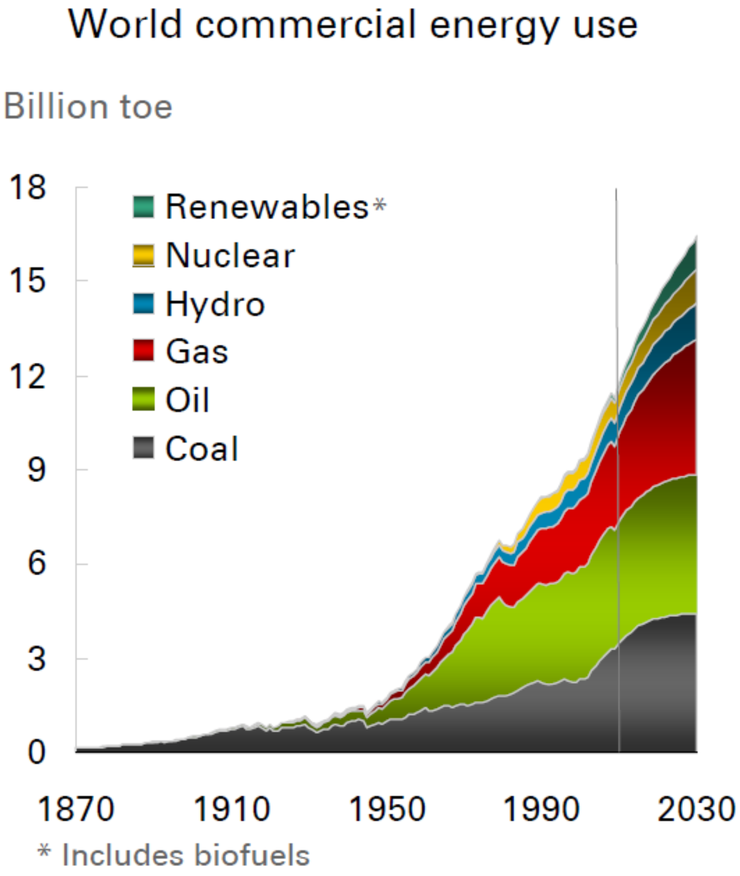
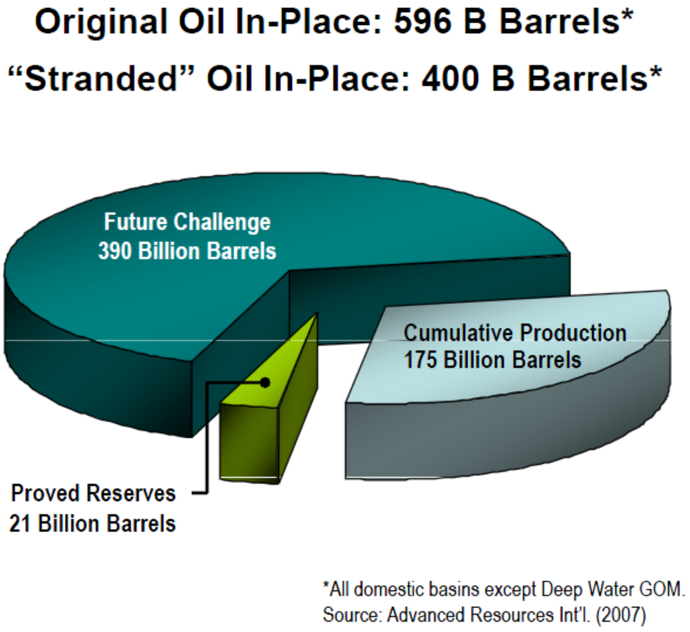


Figure 1.1: World commercial energy use (BP, January 2011)

A considerable portion of current world oil production comes from mature fields and the rate of replacement of the produced reserves by new discoveries has been declining steadily over the last few decades. To meet the growing need for economical energy throughout the world, the recoverable oil resources in known reservoirs that can be produced economically by applying advanced Incremental oil Recovery (IOR) and Enhanced Oil Recovery (EOR) technologies will play a key role in meeting the energy demand in years to come. (Vello A. Kuuskraa, President Advanced Resources International): *"the problem of declining domestic oil production is not due to a lack of resources. We still have nearly 400 billion barrels of oil that is being left behind, "stranded". This is because our primary and secondary recovery methods recover only about one-third of the original oil in-place from our domestic oil fields"* (Kuuskraa & A., 2004), Figure 1.2. This will give an average recovery of 33 % after primary and secondary methods in USA.



*All domestic basins except Deep Water GOM.
Source: Advanced Resources Int'l. (2007)

Figure 1.2: Stranded oil in USA (Cinar, 2011)

The four EOR technologies which have been initiated in the Norwegian Continental Shelf (NCS) from 1975 to 2005 are hydrocarbon (HC) miscible gas injection, Water Alternating Gas (WAG) injection, Foam Assisted Water Alternating Gas (FAWAG) injection and Microbial Enhanced Oil Recovery (MEOR). The average recovery rate from fields on the Norwegian shelf is currently 46 % (Norwegian Petroleum Directorate, 2011). The recovery factor tells us that more than half of the oil remains in the reservoir. Figure 1.3 shows Norwegian fields distribution of produced oil, remaining oil reserves and oil resources which will remain in the ground if the fields are closed down in accordance with currently approved plans. The ministry of Petroleum and Energy of Norway established Oil and Gas in the 21st century (OG21) Task force in 2001 to address the challenge of targeting a 50% average oil recovery factor set by the Norwegian Petroleum Directorate (Awan, Teigland, & Kleppe, 2008).

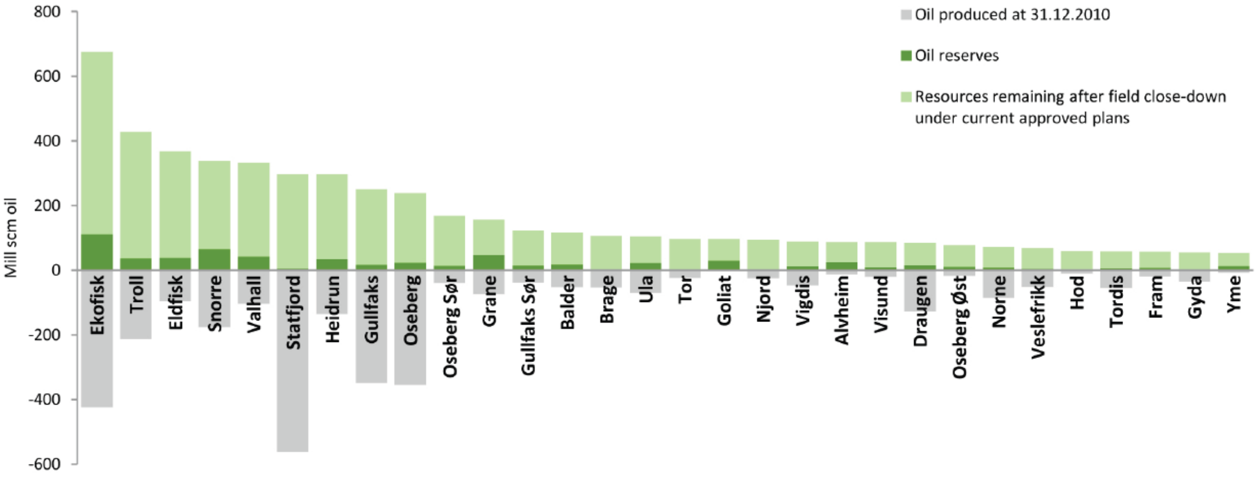


Figure 1.3: Norwegian fields distribution of produced oil, remaining oil reserves and oil resources (Norwegian Petroleum Directorate, 2011)

This Master Thesis is an extension of my project “Applying Chemical EOR on the Norne Field C-Segment” from autumn 2011. In the project I concluded that the Norne C-segment is a good candidate for chemical flooding (Abrahamsen, 2011). The conclusion was based on screening, current drainage strategy, high water cut. The Norne field had an incredible recovery factor of 54% in 2011. Statoil hope to set a world record for the whole Norne field with a recovery factor of 60% before decommissioning (Skagen, 2012). Chemicals could be an important EOR method to achieve this goal.

Chemical flooding has been recognized as technically feasible methods in the North Sea (Skjæveland & Kleppe, 1992), but due to some environmental issues it has not been tested. There is ongoing research regarding the flooding of chemicals in the North Sea and chemical flooding is expected to become attractive in the future (Awan, Teigland, & Kleppe, 2008).

The objects of this Master Thesis are to find an optimum chemical flooding strategy for the Norne C-Segment to maximise the profit from volume of incremental oil produced. The result of the project is based on Net Present Value (NPV) calculation. The chemicals to be used are polymer, surfactant, alkaline and combinations of two or all of these chemicals. Surfactant and alkaline are primarily used to reduce oil-water IFT and minimize the capillary forces that trap residual oil after waterflooding. Polymers are used as a mobility control to improve reservoir contact and flood efficiency. The injection scheme will be decided using a synthetic model of the target formation. The optimum injection strategy and target formation will be investigated.

Chemical flooding is applied on a model of Norne C-Segment released by Center of Integrated Operations at NTNU and Statoil ASA. Simulations are run in Eclipse 100. The model was not perfect history matched and an effort to look at the uncertainties in vertical barriers where done before applying chemicals.

2 Enhanced Oil Recovery[1]

EOR processes involve the injection of a fluid or fluids of some type into a reservoir. The injected fluids and injection processes supplement the natural energy present in the reservoir to displace oil to a producing well. The injected fluids will also interact with the reservoir rock/oil system to create conditions favourable for oil recovery. These interactions might, for example, result in lower Interfacial Tension (IFT), oil swelling, oil viscosity reduction, wettability modification, or favourable phase behaviour. The interactions are attributable to physical and chemical mechanisms and the injection or production of thermal energy (Greeen & Willhite, 1998).

EOR need to target a variety of oil with different physical/chemical characteristics and, American Petroleum Institute, specific gravity (API). The wide spectrum of oil represents the number of different EOR processes. A parallel difficulty is widely varying reservoir characteristics. Oil reservoir types range from very thick carbonate reef formations at significant depths to relatively shallow, thin sandstone bodies. There are several classifications used for EOR methods, Figure 2.1. The classification of Thermal, Chemical and Miscible or Solvent Injection is widely used (Alvarado, 2010). Screening of the Norne C-Segment showed that the Norne field has reservoir characteristics and oil properties that suit chemical flooding (Abrahamsen, 2011). Screening criteria is given in Appendix J.

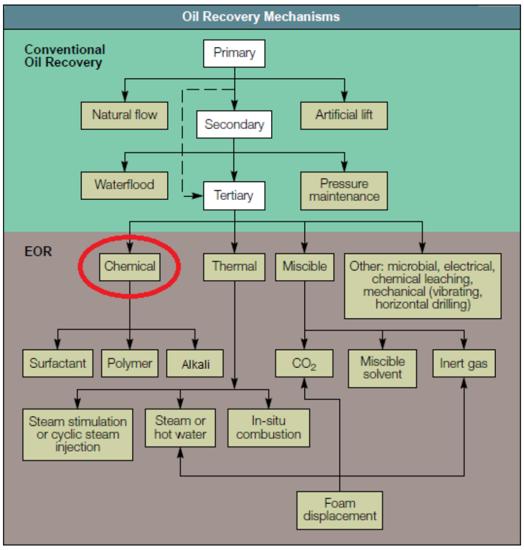


Figure 2.1: Oil recovery mechanisms (W.Lake, Larry, Schmidt, & Venuto, 1992)

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[1] Modified chapter 2 from the project (Abrahamsen, 2011)

2.1 Oil Recovery Controls

After Norne have gone through primary production and waterflood a certain amount of oil remains unrecovered. There is oil in both the unswept and swept zones. The unrecovered oil in the swept zone is called residual oil. The residual oil in the part of the reservoir swept by the waterflood remains largely as isolated, trapped droplets in the pores or films around rock particles, depending on rock wettability. In the swept zones, residual oil is about 20% to 35% (Greeen & Willhite, 1998). An EOR process must be able to mobilize the residual oil or increase the sweep efficiency. The overall displacement efficiency of any EOR process can be evaluated by microscopic and macroscopic displacement efficiencies.

Microscopic displacement relates to the displacement or mobilization of oil at the pore scale. Several physical/chemical interactions occur between the displacing fluid and oil that can lead to efficient microscopic displacement. These include miscibility between the fluids, decreasing the IFT between the fluids, oil volume expansion and reducing oil viscosity. The capillary number is a good representation of the microscopic displacement.

Macroscopic displacement efficiency relates to the effectiveness of volume of oil contacted by the displacing fluid. Macroscopic displacement efficiency is improved by maintenance of favourable mobility ratios between all displacing and displaced fluids throughout a process. Favourable ratios contribute to improvement of both area and vertical sweep efficiencies. Sweep efficiency is strongly affected by the mobility ratio.

2.1.1 Mobility Ratio

Mobility ratio (M) is defined as the mobility of the displacing fluid divided by the mobility of displaced fluid.

Equation 2-1

$$M = \frac{\lambda_{\text{diplacing}}}{\lambda_{\text{diplaced}}} = \frac{k_{r_{\text{displacing}}}}{\mu_{\text{displacing}}} \Bigg/ \frac{k_{r_{\text{displaced}}}}{\mu_{\text{displaced}}}$$

λ Mobility

k_r Effective permeability

μ Fluid viscosity

If M>1 the displacing fluid moves more easily than the displaced fluid. This is not desirable because the displacing fluid will flow past much of the displaced fluid, displacing it inefficiently. This is called viscous fingering, see Figure 2.2 (The blue fluid is water and the red is gas). For favourable displacement efficiency M should be <1.

Favourable mobility can be achieved by:

- Lowering the viscosity of oil
- Increasing the effective permeability to oil
- Decreasing the effective permeability to the displacing fluid

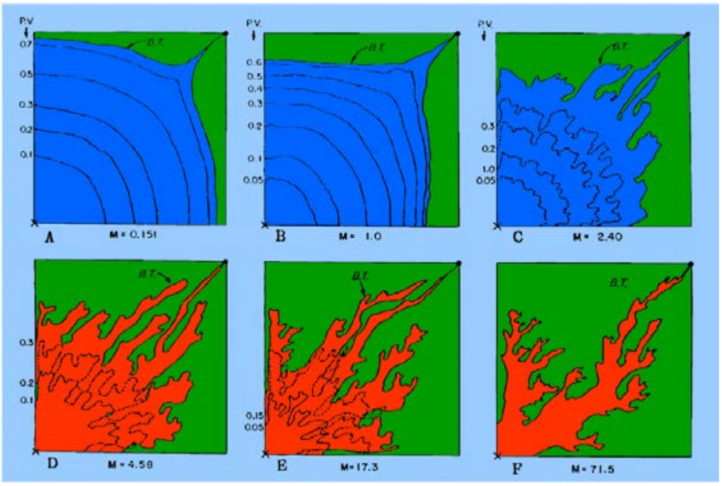

Figure 2.2: Viscous fingering vs. Mobility ratio (Cinar, 2011)

2.1.2 Capillary Number

The residual oil saturation is a function of the Capillary Number (N_c). Increasing the capillary number will decrease the residual oil saturation. The oil droplets will be able to mobilize and an oil bank will be created.

Equation 2-2

$$N_c = \frac{\text{Viscous Forces}}{\text{Capillary Forces}} = \frac{v\mu}{\sigma} = \frac{k_r \Delta p}{\sigma L}$$

N_c	Capillary number
μ	Displaced fluid viscosity
v	Pore velocity
σ	Interfacial tension (IFT)
k_r	Effective permeability to displaced fluid
$\frac{\Delta p}{L}$	Pressure gradient

Favourable Capillary Number can be achieved by:

- Reducing oil viscosity
- Increasing pressure gradient
- Decreasing the IFT

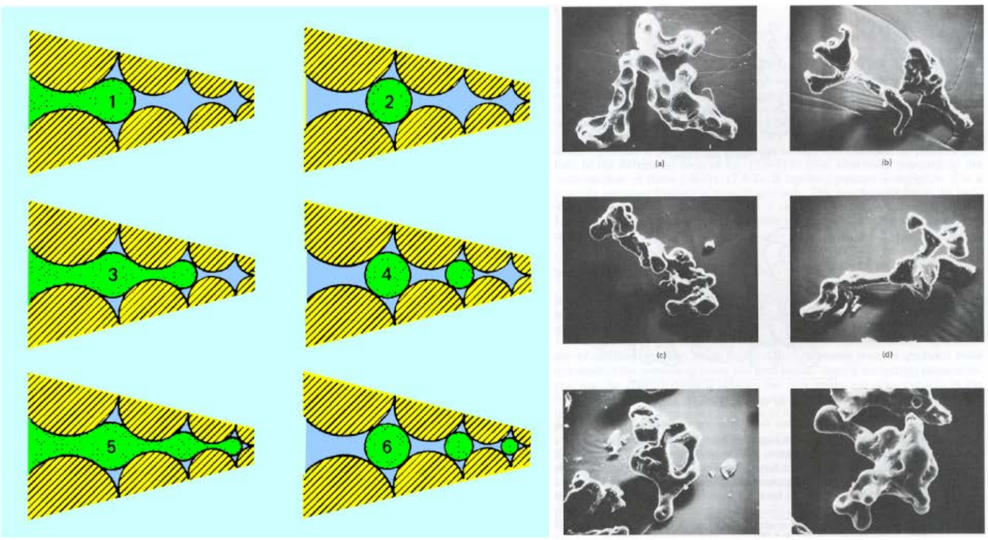

Figure 2.3: Residual oil by Capillary trapping (Tran, 2001)

3 Chemical Methods[2]

Chemical flooding is generally used after secondary recovery (waterflooding) and the methods mainly include polymer, surfactant, alkaline and combinations of two or all of these chemicals. Surfactant and alkaline are primarily used to reduce oil-water IFT and minimize the capillary forces that trap residual oil after waterflooding. Polymers are used as a mobility control to improve reservoir contact and flood efficiency. In both alkaline- and surfactant flooding, polymers can be used in the solution to increase the viscosity. Polymers are also generally used as a second slug to push the alkaline and surfactant slug. The combination of surfactant and polymer (SP) is the most used combination, but the interest in alkaline-surfactant-polymer (ASP) increases. Alkaline chemical is used with the surfactant to promote IFT reduction and to reduce surfactant adsorption. Surfactants are more expensive than alkaline.

A successful chemical flooding mainly depend on the (Zhang, Huang, & Dong, 2003):

- Attainment of ultra-low oil-water IFT
- Attainment of large reservoir contact and flood efficiency
- Optimization of the chemical injection scheme (slug size, chemical concentration, etc.) to maximize the chemical reaction with the oil
- Remaining oil saturation prior applying the chemical injection process

IFT must be reduced from 10 to 30 dynes/cm in a typical waterflood to about 10^{-3} dynes/cm before a large reduction in the waterflood residual oil saturation is achieved. Significant reduction is possible with an IFT of about 10^{-2} dynes/cm (Greeen & Willhite, 1998) (Skjæveland & Kleppe, 1992).

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[2] Expansion of chapter 6 from the project (Abrahamsen, 2011)

3.1 Polymer Flooding

The main objective of polymer injection during water flooding of oil reservoirs is to decrease the mobility of the injected water. Waterflood as secondary recovery results in a poor and incomplete sweep of the reservoir volume. The water-soluble polymers have two effects on the waterflood. Firstly it is to increase the water viscosity. The viscosity of the polymer solution increases as the concentration of the polymer in the water increases. Secondly, the rock permeability to water is reduced after the passage of a polymer solution through the rock material. Both effects will cause a lower mobility ratio. The lower mobility ratio will improve the volumetric sweep efficiency and a higher oil recovery will be achieved at breakthrough. In polymer flooding, usually a slug of 0.3 or higher Pore Volume (PV) of polymer solution is injected into the reservoir (Carcoana, 1992). The slug is followed by a continuous water drive. Injection of freshwater in front and behind the polymer slug is often used to prevent reduction in the polymer solutions viscosity. To achieve maximum efficiency, the polymer solution is often applied in the form of a tapered slug. At the front edge of the slug, the displacement is stable but the interface between the water and the polymer solution smears due to physical dispersion of the polymer. At the rear edge, the mobility ratio is unfavourable and is dominated by viscous fingering (Schlumberger, 2011). Polymer flooding will be favourable in reservoirs where the oil viscosity is high, or in reservoirs that are heterogeneous, with oil-bearing layers at different permeability. For North Sea reservoirs, the heterogeneous reservoirs are the potential candidates for polymer flood (Skjæveland & Kleppe, 1992).

There are two sets of EOR polymers that have been used in reservoirs, synthetic polymers and biopolymers (Carcoana, 1992). The synthetic Hydrolyzed polyacrylamide (HPAM) is the most used polymer in field operations. Due to large molecules the viscosifying effect in water is good, but the polymer structure is sensitive to salinity and temperature. The biopolymers Xanthan and Scheroglucan are more stable, but the disadvantage is the cost. Biodegradation and microbial attack of polymers is common and usually results in a decrease in the solutions viscosity. Formaldehyde is used to prevent both viscosity losses by microbes and biodegradation.

3.1.1 Polymer Process Description

3.1.1.1 Shear Rate

The viscosity of polymer solution changes with shear rate and is therefore classified as a non-Newtonian fluid. Figure 3.2 shows the polymer solution viscosity and the shear rate at fixed salinity. The different curves represent concentration of polymers in the solution. At low share rates viscosity does not change with changing shear rate (Newtonian). At high shear rate the viscosity of the solution decreases with the increasing shear rate (non-Newtonian). High share rates will appear at injections and production wells. High shear rates may be harmful because of the polymers long chains may be broken (Caudle, et al., 1983). The share rate will decline with distance from the well, and the solution will obtain its viscosity, thus favourable mobility ratio.

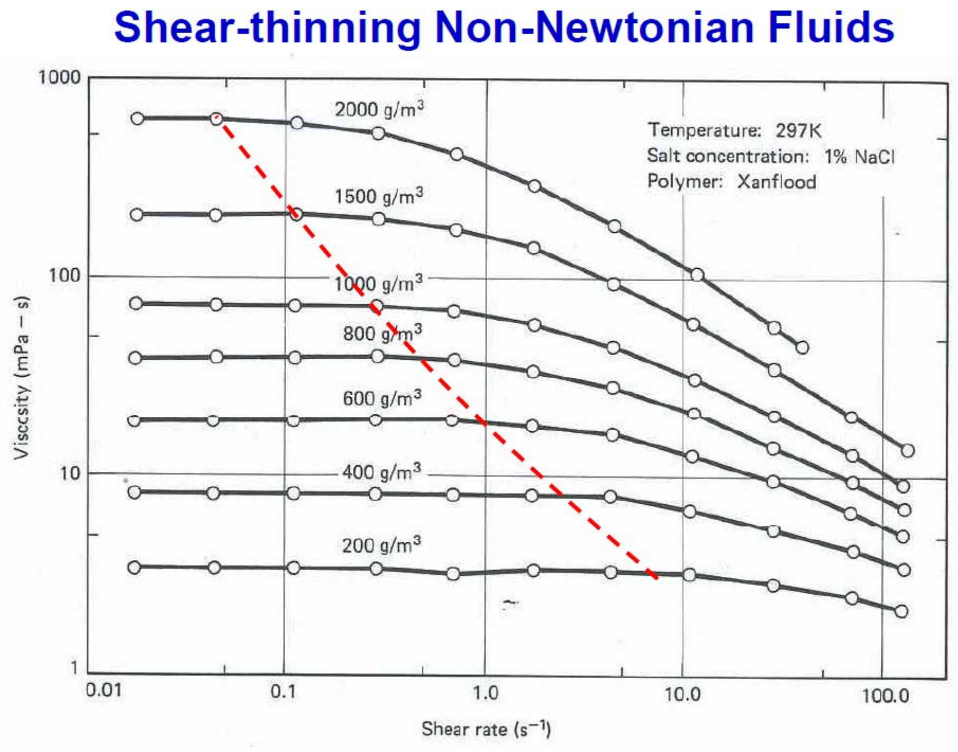

Figure 3.1: Shear rate in polymer solution (Cinar, 2011)

3.1.1.2 Resistance Factor

It is difficult to separate the effect of the permeability reduction and the increase in viscosity under polymer flooding. What is important is that the total effect can be expressed as mobility reduction and this total effect can be measured. The measure of the mobility reduction is known as the resistance factor, R (Carcoana, 1992).

Equation 3-1

$$R = \frac{\lambda_w}{\lambda_p} = \frac{K_{r_w}}{\mu_w} \Big/ \frac{K_{r_p}}{\mu_p}$$

λ_p	water-soluble polymer mobility
K_{r_w}	relative permeability water
K_{r_p}	relative permeability polymer solution
μ_p	viscosity of the polymer solution
μ_w	viscosity of the water

Figure 3.3 shows a plot from (Carcoana, 1992) of R as a function of V_{inj}/V_p (cumulative injected volume per porous volume) with a 300-ppm polymer solution. A rapid increase in R for the first pore volume injected is observed. In this case 0.2 PV of polymer will be enough to generate a max mobility reduction. An R value higher than 10-12 will give a high injection pressure and blockages can occur. It is important to test the polymer slug resistance factor before applying it on a reservoir.

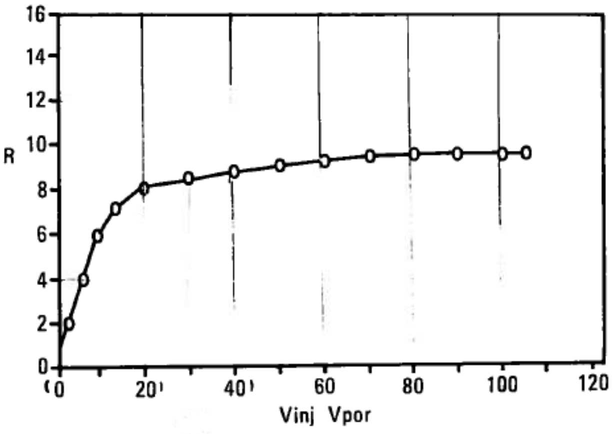

Figure 3.2: The resistance factor R as a function of cumulative volume injected (Carcoana, 1992)

3.1.1.3 Polymer Retention

The existence of retention has an economic importance. Biopolymer polysaccharides are not retained on rock surface, but polyacrylamide is. Molecular weight of the polymer affects the retention. Polymer retention consists of adsorption of polymer on the rock and entrapment of polymer molecules in small pore spaces. The adsorbed polymer layers represent both additional resistance to flow and loss of polymer. The higher the polymer concentration before flowing through the porous space, the higher will be the adsorption on the rock surface. Reservoirs rock offers a variety of opening sizes in the porous space. The long chain of the polymer molecule can easily flow into a large pore opening but cannot leave it if the other end has a smaller opening. The polymer is then trapped because of the size of the opening or flow of brine. The small openings not contacted by flowing polymer molecules form the so called “inaccessible pore volume”. Up to 30 percent of the total pore volume may not be accessible to polymer molecules (Carcoana, 1992). Effective porosity for polymer is less than for brine and therefore oil will be displaced faster. The resistance factor is a measurement of permeability reduction (Caudle, et al., 1983).

Equation 3-2

$$F_{RR} = \frac{\lambda_{wi}}{\lambda_{wa}} = \frac{k_{wi}}{k_{wa}}$$

λ_{wi}	initial mobility
λ_{wa}	mobility after polymer flood
k_{wi}	initial effective permeability
k_{wa}	effective permeability after polymer flood

3.2 Surfactant Flooding

The aim of surfactant flooding is to recover the capillary-trapped residual oil after waterflooding. The residual oil can be mobilized through a strong reduction in the IFT between oil and water. After the surfactants solution has been injected the trapped oil droplets are mobilized. These droplets leads to an increase in oil saturation and an oil bank will form. When the oil bank starts to flow, it will mobilize any residual oil in front. Behind the oil bank surfactants will prevent the mobilized oil from being retrapped. The ultimate residual oil saturation will therefore be determined by the IFT between oil and surfactant solution behind the oil bank (Skjæveland & Kleppe, 1992).

Surfactants are expensive and only a small portion can be injected. Surfactant concentration is usually about 1 wt% (TIORCO, 2009) (Skjæveland & Kleppe, 1992). A low mobility ratio between the surfactant slug and the oil bank and water flowing ahead, would require the use of polymer (SP). The typical solution consists of 0.1 wt% polymer (TIORCO, 2009). When the reservoir water salinity is too high, direct contact with the surfactant solution is avoided by first injecting a low-salinity brine slug which adjusts salinity and hardness. After the surfactant solution, polymer is often injected to improve the mobility. The polymer is driving the surfactant slug and preventing it from being penetrated by the chase water. The chase water is the driving energy to propel the solution through the reservoir and to the producers.

Anionics and nonionics have been used as surfactants in EOR processes. Anionic surfactants have been most widely used because they have god surfactant properties, are relatively stable, exhibit relatively low adsorption on reservoir rock, and can be manufactured economically. Nonionics have been used primarily as cosurfactants to improve the behaviour of surfactants systems. Nonionics are much more tolerant of high-salinity brine, but their reductions in IFT are generally lower than Anionics. The most common surfactant used in surfactant/polymer flooding is sulfonated hydrocarbon. The chemical system for a surfactant flood is complex.

3.2.1 Surfactant Process Description

3.2.1.1 Capillary Desaturation

To reduce the residual oil saturation in the waterflooded zones, the pressure drop across trapped oil has to overcome the capillary force that traps the oil. Surfactants reduce the IFT between oil and water and you will have a higher capillary number and lower residual oil. The Capillary Desaturation Curve (CDC) describes the relationship between N_c and residual fluid saturation and varies with pore size distribution and wettability. As pore size gets narrower, the oil saturation starts to drop at higher N_c, but zero residual saturation is obtained at a lower N_c as seen in Figure 3.5.

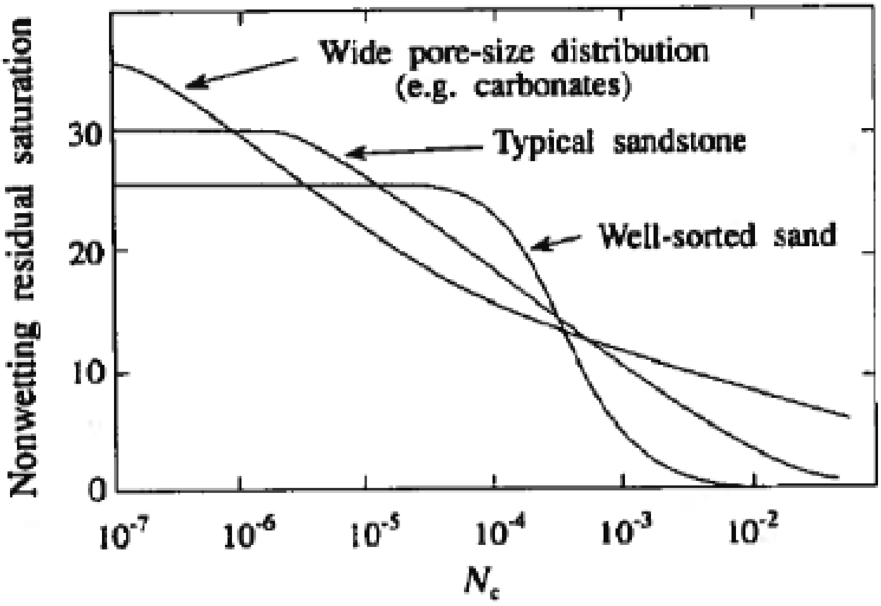

Figure 3.3: Effect of pore size distribution on the CDC (Skjæveland & Kleppe, 1992)

The CDC for the displacement of the wetting phase is shifted to the right of the CDC for the displacement of the nonwetting phase seen in Figure 3.6. A surfactant flood should therefore perform best in a water-wet reservoir with well-sorted sand.

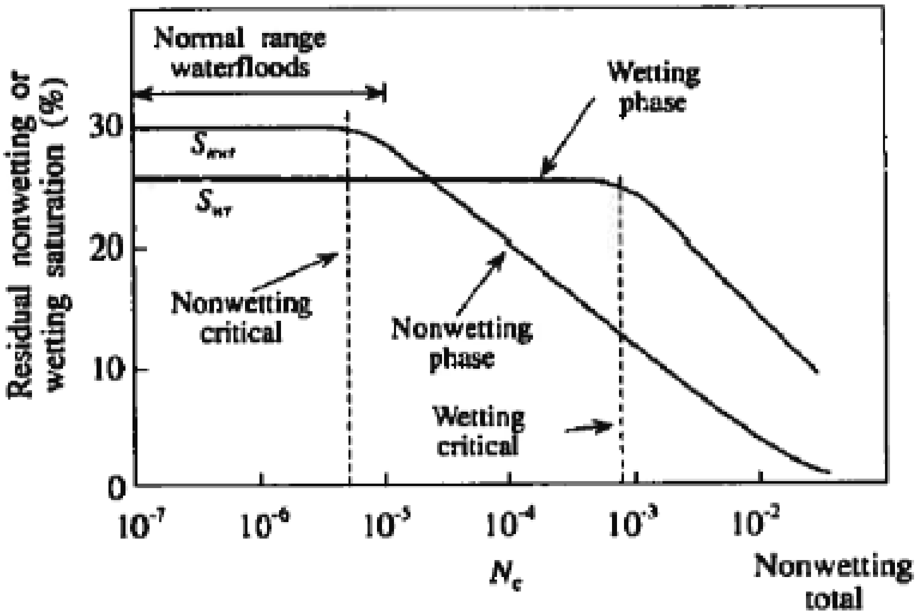

Figure 3.4: Effect of wettability on the residual saturation of wetting and nonwetting phase (Skjæveland & Kleppe, 1992)

3.2.1.2 Relative Permeability and Mobility Ratio

The residual oil saturation will decrease in surfactant flooding. The water is therefore blocked by less oil and we will have an increase in relative permeability to water. In the surfactant flood, the mobility of the injected solution will therefore increase as IFT and residual oil decreases.

In front of the surfactant slug we have oil and water. The total mobility of oil and water is determined by the oil saturation. It is usually less than the total mobility ahead of the initial waterfront. This will give a decrease in mobility ratio.

With an increasing displacing mobility and decreasing displaced mobility the total mobility ratio will increase. In unfavourable cases, it could increase more than ten times (Skjæveland & Kleppe, 1992). To avoid this unfavourable mobility polymer or adjusting viscosity of surfactant is used (Skjæveland & Kleppe, 1992).

3.2.1.3 Adsorption

Surfactants are retained by the reservoir rock by precipitation, phase trapping and adsorption. It is possible to prevent loss of surfactant due to precipitation and phase trapping by using salt tolerant surfactants, and to predict the phase behaviour due to changes in parameters as salt, hardness, pressure, temperature, cosurfactant etc. Adsorption of surfactants will always take place and it is important to acknowledge. In an oil reservoir the surfactant are adsorbed at the oil/water interface and decreases the IFT. The surfactants are also adsorbed at the solid/liquid phase by electrostatic interaction between the solid (adsorbent) and the surfactant (adsorbate). The reservoir minerals show a negative charge at natural pH value of the Brine. To lower the adsorption negatively charged surfactants are usually considered as main surfactant in the slug. Adsorption onto mineral surface is a complex process, but there is a way to reduce the adsorption (Skjæveland & Kleppe, 1992).

Preflush using different chemicals:

- Sodium chloride solution to reduce hardness
- Alkaline additives to decrease hardness and to render the rock more negatively charged
- Sacrificial chemicals that will adsorb and block the active sites of the rock

3.3 Alkaline Flooding

Alkaline flooding improves the oil recovery by one or more of the following mechanisms: emulsification and entrainment, wettability reversal (oil-wet to water-wet), wettability reversal (water-wet to oil-wet) and emulsification and entrapment. These mechanisms result from the formation of surfactants as the alkaline chemicals neutralize petroleum acids in situ. The effect produced in a reservoir appears to be similar to that of surfactant solutions. Alkaline agents are less expensive than surfactants, but the process appears to be highly dependent on minerals on the surface of reservoir rock, the crude oil and injection fluid characteristics. Alkaline is usually more efficient if the acid content of the reservoir oil is relatively high.

Use of cost-efficient alkaline along with surfactant and/or polymer could reduce the amount of high-cost surfactant and cosurfactant required in surfactant flooding (Carcoana, 1992). Alkaline reduces the adsorption of both surfactant and polymer on the rock surface, therefore enhancing the effectiveness of the surfactant and polymer drive.

Emulsification and entrainment result from reduction in IFT and the formation of an emulsion in which oil is entrained. If the emulsion is mobile, the oil saturation will decrease and oil will move through the reservoir. The principal mechanism in alkaline flooding is reduction of the oil-water interfacial tension. The benefit of oil emulsification and entrapment is primarily improved sweep efficiency. In this mechanism, an emulsion formed by decreasing the IFT is subsequently trapped by the pore throats. This, in effect, causes a reduction of flow in high-permeability zones and results in an improvement of the effective mobility ratio between displacing and displaced fluids. Viscous fingering is diminished. Wettability alternation either oil-wet to water-wet or vice versa favourable changes the relative permeability to the oil phase. Discontinuous residual oil can be reconnected and caused to flow. When this wettability reversal is coupled with IFT reduction the residual oil can significantly decrease. With certain types of highly acidic crude oil, improvements in oil recovery can also be achieved by reversing tensions, using the right combination of alkaline chemicals and salt. In a specific alkaline chemical displacement, one or more of the different mechanisms may dominate the recovery efficiency. This depends on the chemical /rock system, but the process is not sufficiently understood to predict this behaviour (Greeen & Willhite, 1998).

The basic alkaline flooding process starts with a softened water preflush injection followed by the injection of an alkaline solution of about 0.1-0.3 PV, and by continuous injection of drive water (Carcoana, 1992). A low mobility ratio between the alkaline slug and the oil bank and water flowing ahead, would require the use of polymer resulting in AP. To control the mobility and to improve sweep efficiency a polymer slug can be injected behind the alkaline. The complexity of mineralogy and lithology of petroleum reservoirs will give many possible reactions, therefore field trials to design the best system for a specific reservoir is important. The alkaline flooding process uses alkaline chemicals, such as sodium hydroxide, sodium orthosilicate, sodium carbonate and ammonium hydroxide in flood water.

3.3.1 Alkaline Process Description

3.3.1.1 Effect of Alkaline Concentration

Several investigations have measured the effect of alkaline chemical type and concentration on IFT between aqueous and oil phases. The minimum IFT value occurs in the narrow concentration range 0.05 to 0.10 wt%, and the minimum value is about 0.01 dyne/cm (Greeen & Willhite, 1998). It is difficult to achieve the weight present in the whole reservoir when there is loss of alkaline chemicals through rock/fluid interactions. IFT's for aqueous solutions of alkaline chemical and oil are functions of oil type, salinity ions, temperature, alkaline chemical concentration and alkaline chemical type (Greeen & Willhite, 1998). Surfactants (AS) can be used to increase the salinity requirement of an alkaline chemical system in a manner analogous to a surfactant system (Greeen & Willhite, 1998). The system with a cosurfactant can be made to have an optimal alkali concentration that is larger than without a cosurfactant present, thus addition of alkaline concentration will result in a decrease in mobility ratio.

3.3.1.2 In-Situ Formation of Surfactants

Alkaline flooding is dependent on alkali reacting with petroleum acids in a crude oil to form surfactants in situ see Figure 3.8. These petroleum acids are many in numbers and varied in composition. Alkaline chemicals results in a high pH because of dissociation in the aqueous phase (Greeen & Willhite, 1998). Sodium hydroxide dissolves as shown in Equation 3-3.

Equation 3-3

$$\mathrm{NaOH} \rightarrow \mathrm{Na}^{+} + \mathrm{OH}^{-}$$

The hydroxide ion must react with a petroleum acid from the crude oil to form a surfactant. The petroleum acids are dissolves as Equation 3-4. HA_w is petroleum acids in water phase.

Equation 3-4

$$\mathrm{HA_w} + \mathrm{OH}^{-} \leftrightarrow \mathrm{A}^{-} + \mathrm{H_2O}$$

This results in an increase surfactant concentration [A$^-$]. The measure of the potential to form surfactants is given by the acid number; unfortunately this number does not always correlate with oil recovery (Greeen & Willhite, 1998).

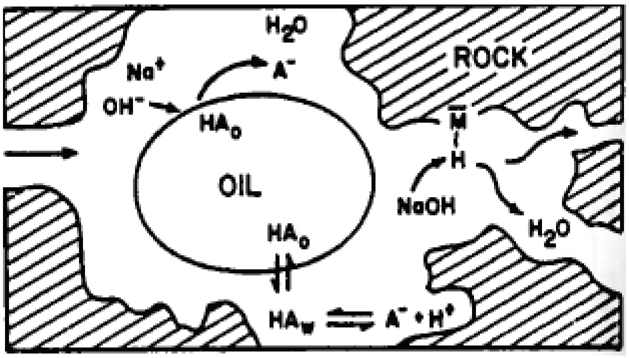

Figure 3.5: Schematic of alkali recovery process (Greeen & Willhite, 1998)

3.3.1.3 Alkaline Loss

Alkaline will be lost through ion exchange with clays in the rock, reaction with ions (in hard water particular) and mineral dissolution by reaction with rock mineral. Ion exchange for a sodium hydroxide alkaline solution is shown in Equation 3-5:

Equation 3-5

$$\bar{\mathrm{M}}\mathrm{H} + \mathrm{Na}^{+} + \mathrm{OH}^{-} \leftrightarrow \bar{\mathrm{M}}\mathrm{Na} + \mathrm{H_2O}$$

$\bar{\mathrm{M}}$ denotes an ion-exchange site on rock

Alkaline reacts with Ca^{++} and Mg^{++} and can precipitate. This reaction can be advantageous and is sometimes used in chemical flooding to soften the brine. This approach results in loss of alkaline chemicals, still preflush with alkaline is common because of low-cost. Precipitates can cause pore plugging (Greeen & Willhite, 1998).

3.4 Alkaline-Surfactant-Polymer

ASP has been found to be one of the major EOR techniques that can be successfully used in producing light and medium oils left in reservoirs after primary and secondary recovery. The state of the art ASP technique uses alkaline, surfactants and polymer simultaneously. The ASP flood benefits from all the three flooding methods (Majidaie, Tan, & Demiral, 2010).

- Polymer increases the viscosity, adsorb onto rock and decreases effective water permeability.
- Surfactants are responsible for reducing the IFT between oil and trapped oil drops. And increase the optimal alkali concentration.
- Alkaline reacts with the acids to generate in situ surfactants to overcome the surfactant depletion in the liquid phase due to retention. It also alters rock wettability and adjusts pH and salinity.

Oil recovery is greatly enhanced by increasing capillary number and improving the mobility ratio. The displacement mechanism of an ASP flood is similar to that of surfactant/polymer flooding except that much of the surfactant is replaced by low-cost alkali (S.Hung & M.Dong, 2004). The overall cost is lower even though the chemical slug can be larger. The ASP slug is injected at about 0.3-0.4 PV for effective performance. The ASP slug consists of about 0.5-1% alkali, 0.1% surfactant and 0.1% polymer (TIORCO, 2009). Typically an ASP flood is followed up with an equivalent pore volume injection of a polymer “push” solution. This helps reduce the slope of oil recovery decline and helps extend the production for a longer period of time.

4 Chemical Models in Eclipse[3]

The chemical EOR methods will be simulated in Eclipse 100. Eclipse provides a model for each chemical method; The Polymer Model, The Surfactant Model and The Alkaline Model. The models are all simplified, however it will give a good prediction if the methods are feasible.

4.1 The Polymer Model

The flow of the polymer solution through the porous medium is assumed to have no influence on the flow of the hydrocarbon phases. The standard black-oil equations are therefore used to describe the hydrocarbon phases in the model. Wells are not allowed to cross flow when the polymer flood model is in use. Further description is in Appendix A.

4.2 The Surfactant Model

The surfactant model does not provide a detailed chemical simulation of surfactant flooding, but models the important features of a surfactant flood on a full field basis. The distribution of injected surfactant is modeled by solving a conservation equation for surfactant within the water phase. The surfactant is assumed to exist only in the water phase. Concentration of surfactant is specified at water injector. After the oil, water and gas flows have been computed at the end of each time-step the surfactant concentration is updated fully-implicitly. Further description is in Appendix B.

4.3 The Alkaline Model

The alkaline model does not take into account the in-situ surfactant creation and the phase behaviour. It is a simplified model to provide some effects of the alkaline on an ASP flooding performance. The chemical flooding methods alkaline or alkaline-polymer (AP) will therefore not be tested. The model provides the effect of the alkaline on the water-oil surface tension and adsorption reduction of surfactant and polymer. Further description is in Appendix C.

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[3] Extension of chapter 7 from the project (Abrahamsen, 2011)

5 Norne[4]

5.1 Introduction to Norne

The Norne Field is situated in the blocks 6608/10 and 6508/1 in the southern part of Nordland II area. Norne is located 200 km from the Norwegian shelf and 80 km north from the Heidrun Field in the Norwegian Sea. The water depth is 380 meters. Figure 5.1 shows the position relative to nearby fields.

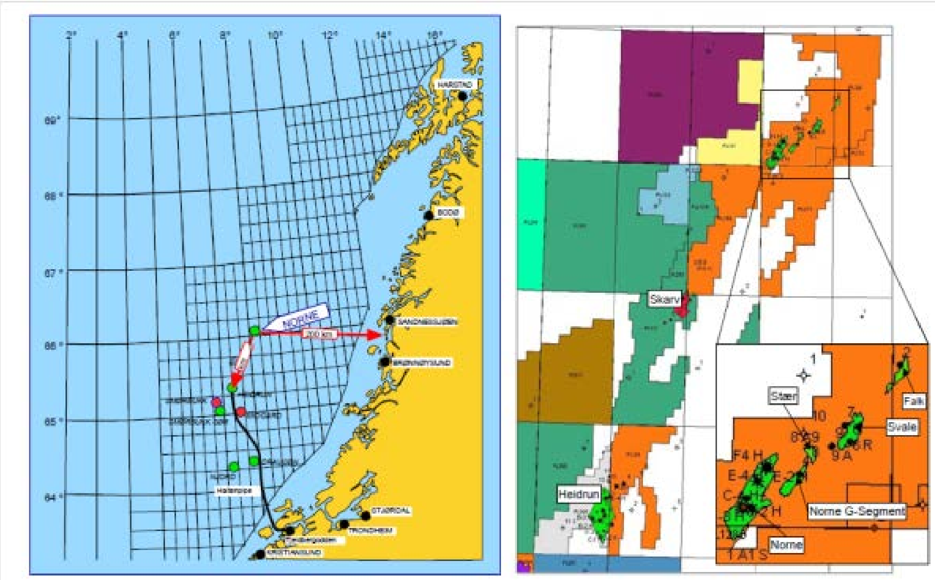

Figure 5.1: Position of Norne (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001)

There are two separate oil compartments in the Norne field. Norne Main structure consists of C-, D- and E segment. The other is the North-East Segment that consists of the G segment. Figure 5.2 shows the location of the segments. The Norne Main structure was discovered in 1991 and contains 97 % of the oil in place (Hetland & Verlo, Geological information, 2008). Well 6608/10-2 was the first well that discovered oil and gas in the Norne Field (Hetland & Verlo, Wells, 2008).

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[4] Modified chapter 3 from the project (Abrahamsen, 2011)

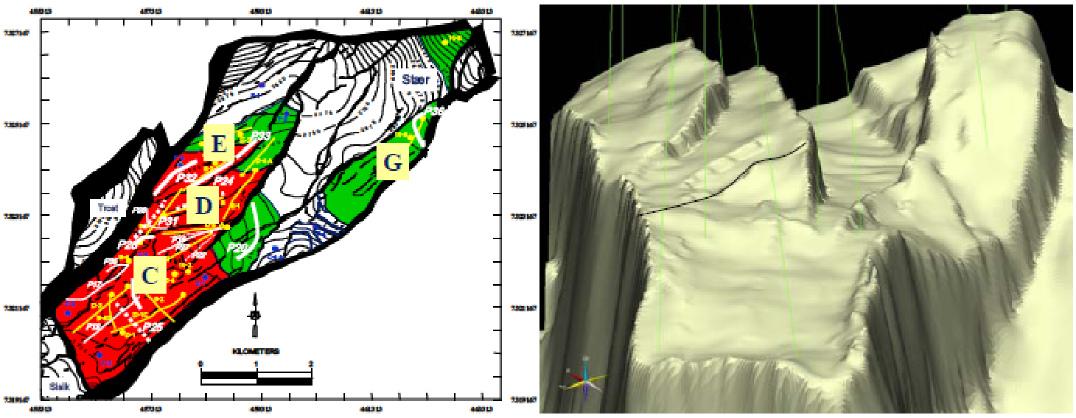

Figure 5.2: Norne field segments (Lind, Annual Reservoir Development Plan, 2004)

The Norne Main structure is relative flat with generally a gas filled Garn Formation and the gas oil contact in the vicinity of the Not formation clay stone. The northern flank dips towards north-north west with an oil leg in the Garn Formation, Figure 5.3. The reservoir depth is about 2 500 meters and the reservoir quality is good.

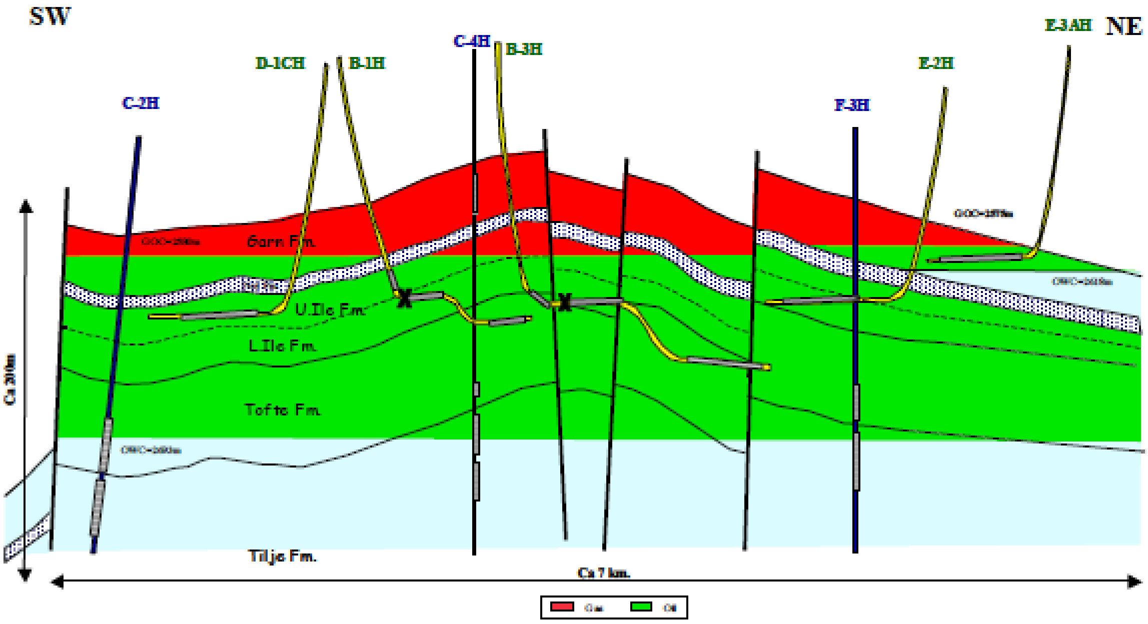

Figure 5.3: Cross section (Lind, Annual Reservoir Development Plan, 2004)

The oil production started in November 1997. The field has been developed with a production and storage vessel “Norne FPSO'” Figure 5.4, connected to seven subsea templates. Flexible risers carry the well stream up to the production vessel. Gas export started in 2001, and the gas is transported through a dedicated pipeline to Åsgard, and on through the Åsgard Transport pipeline to Kårstø.

Figure 5.4: Norne FPSO (Lind, Annual Reservoir Development Plan, 2004)

Water injection is the drive mechanism for the oil production. Gas injection ceased in 2005 and all gas is now being exported. The original- and remaining reserves are listed in Table 5.1 and the gas and oil production in Figure 5.6 and Figure 5.5.

Recoverable reserves:	
Original	Remaining as 31.12.2010
93.4 million scm oil	8.8 million scm oil
11.7 billion scm gas	5.5 billion scm gas
1.7 million tonnes NGL	0.9 million tonnes NGL

Table 5.1: Recoverable reserves (Norwegian Petroleum Direcorate, 2011)

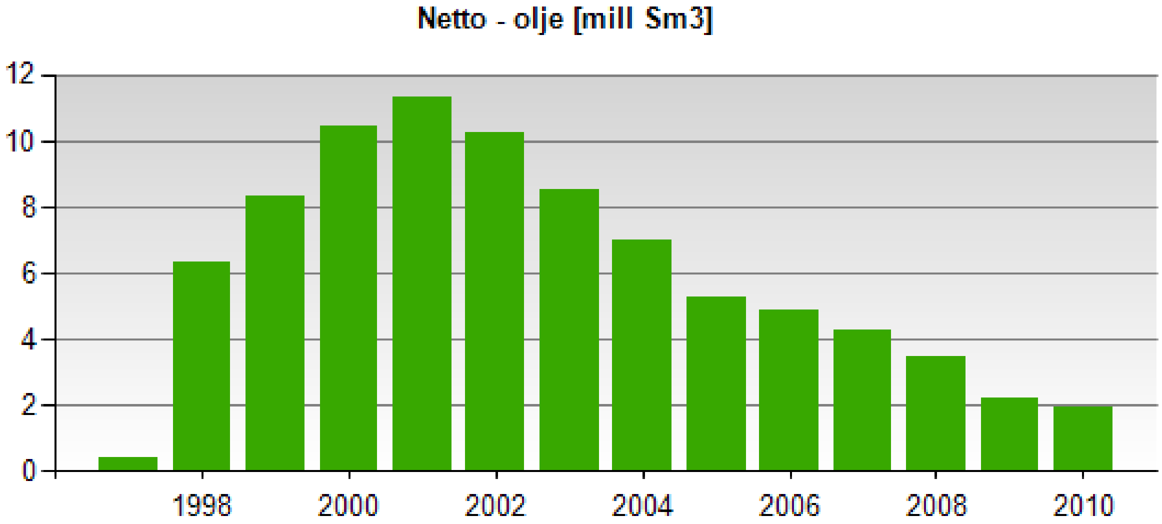

Figure 5.5: Norne oil production (Norwegian Petroleum Direcorate, 2011)

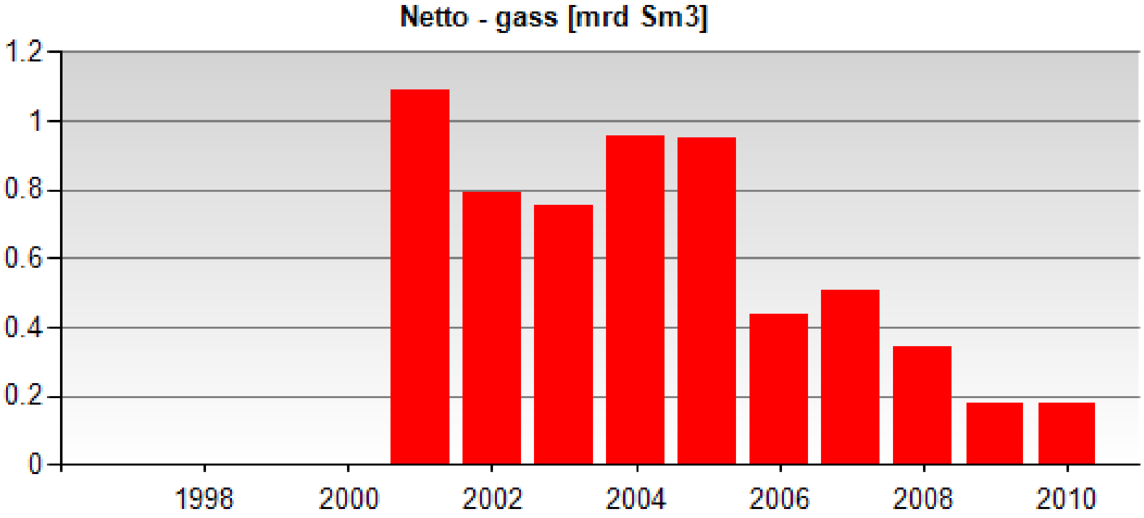

Figure 5.6: Norne gas production (Norwegian Petroleum Direcorate, 2011)

5.2 Geological Information

The reservoir is subdivided into four different formations from top to base: Garn, Ile, Tofte and Tilje. Stratigraphy of the Norne reservoir is shown in Figure 5.7. The Ile and Tilje have gone through erosion in the northern parts of the reservoir, Figure 5.8. The Norne field is 260 m in the southern part and 120 m in the northern (Hetland & Verlo, Geological information, 2008).

Hydrocarbons in this reservoir are located in the Lower to Middle Jurassic sandstones. Most reservoir sandstones within the Norne Field are fine-grained, well to very well sorted sub-arkosic arenites. Being buried between 2500 m and 2700 m these sandstones are affected by diagenetic processes, of which mechanical compaction is the most important process reducing reservoir quality. The reservoir is reported to be good with porosities in the range of 25-30% and permeabilities in the range of 20-2500 mD. The source rocks are believed to be the Spekk Formation, from Late Jurassic, and coal bedded Åre Formation from Early Jurassic. The cap rock is the Melke formation (Hetland & Verlo, Geological information, 2008).

Approximately 80% of the oil reserves on the Norne Main Structure are located in the Ile and Tofte Formations. The free gas is primarily located in the Garn Formation (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001). The Not formation is sealing, therefore Garn and Ile formations cannot communicate.

Ile Formation: The formation is 32-40 m thick sandstone deposited during Aalenian. The Ile formation is divided into three reservoir zones. Ile 1 and Ile 2 are divided by a cemented calcareous layer. This layer is assumed to be continuous throughout the Norne Field. This may be a barrier to vertical fluid. Ile 1 and Ile 2 are fine grained sand which is coarsening to the North. Ile 3 is an extensively bioturbated, upward fining sandstone of fine to very fine grains (Hetland & Verlo, Geological information, 2008).

Tofte Formation: The formation mean height is 50 m and was deposited during the Late Toarcian above an unconformity. Tofte formation is divided into three reservoir zones. Tofte 1 consists of medium to coarse grained sandstone with steep dipping lamina. The lower parts are more bioturbated and have finer grains. Tofte 2 is an extensively bioturbated, muddy and fine grained sandstone unit. Tofte 3 consists of very fine to fine grained sandstone (Hetland & Verlo, Geological information, 2008).

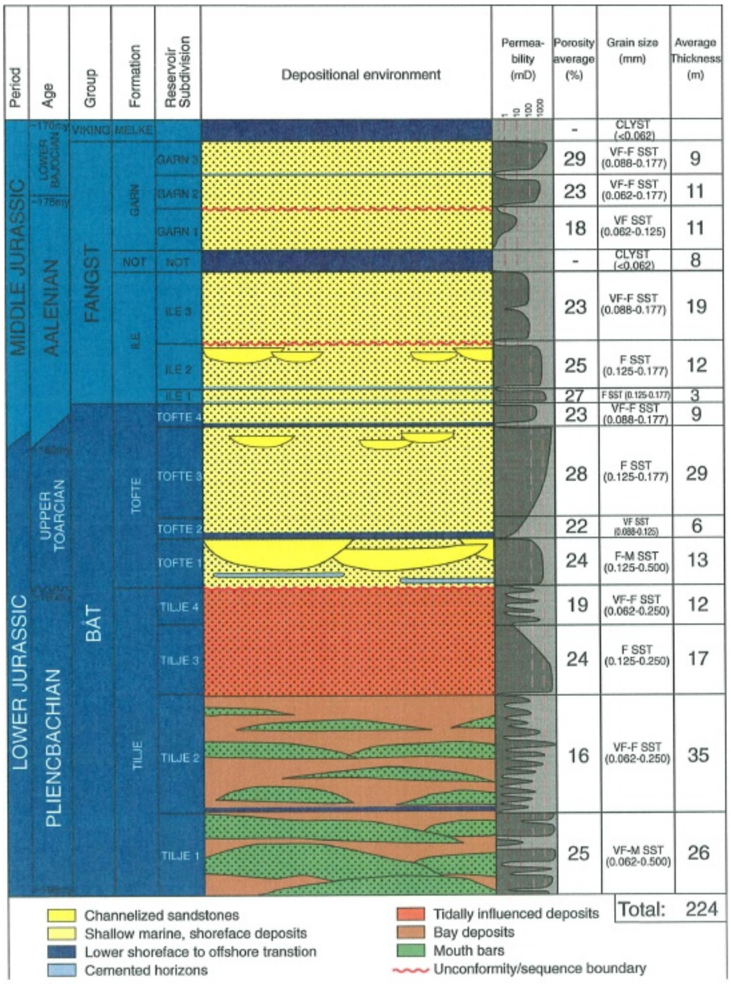

Figure 5.7: Stratigraphy of Norne (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001)

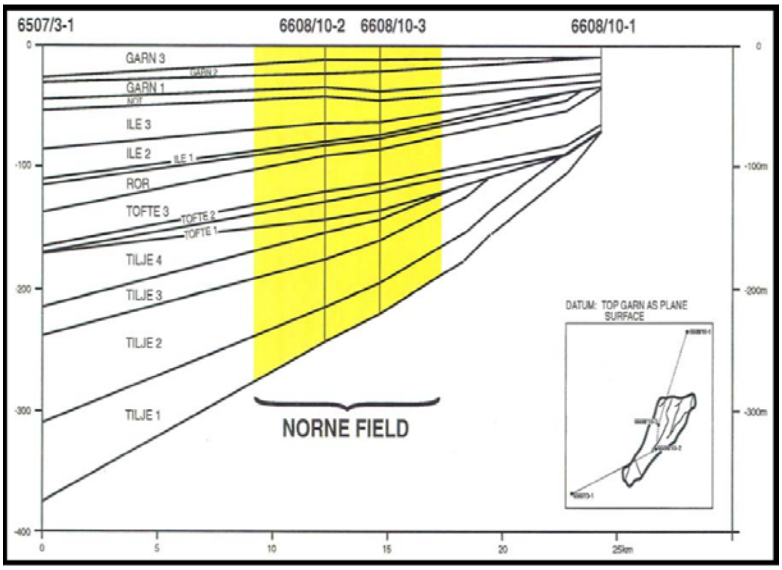

Figure 5.8: Cross section of the Norne reservoir (Hetland & Verlo, Wells, 2008)

5.3 Reservoir Communications

The Norne Field reservoir contains both faults and stratigraphic barriers/layers which will act as restriction for the vertical and horizontal flow. The continuous stratigraphic barriers resulting in less vertical flow is listed below (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001):

- Garn 3/Garn 2, carbonate cemented layer at top Garn 2
- Not Formation, claystone formation
- Ile 2.1.1/Ile 1.3, carbonate cementations and increased clay content at base Ile 3
- Ile 1.2/ Ile 1.1, carbonate cemented layers at base Ile 2
- Ile 1.1/Tofte 2.2, carbonate cemented layers at top Tofte 4
- Tofte 2.1.1/Tofte 1.2.2, significant grain size contrast
- Tilje 3/Tilje 2, claystone formation

The most impediment barriers are the whole Not Formation, Ile 1.1/Tofte 2.2 carbonate cemented layer and Tilje 3/Tilje 2 claystone (Hetland & Verlo, Geological information, 2008).

The capacity for a fault to seal depends on the clay content in the host rock. If the host rock has a high gouge ratio you get clay smear. In the Garn sandstones with fault throw over 15-30 m high gouge values have been found. The interval where clay smear has taken place is along Not and lower Garn and this allows for fault sealing, Figure 5.9. Tofte, Ile and Tilje sandstones have low gouge ratio giving low sealing potential. (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001).

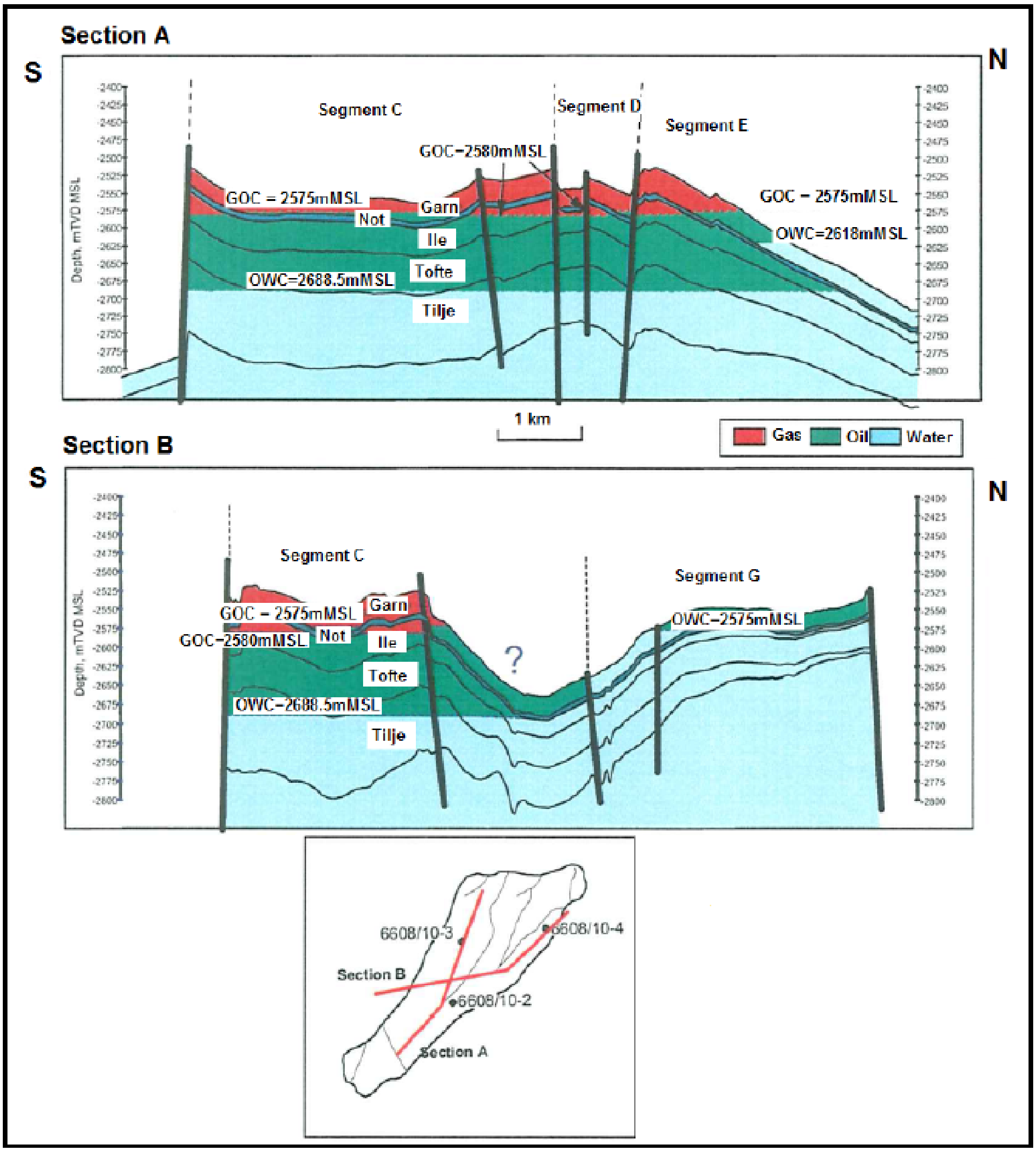

Figure 5.9: Norne cross section with fluid contacts (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001)

5.4 Drainage Strategy

The strategy for production form Norne was to utilize the processing and production potential at their maximum. The pre-start drainage strategy was to maintain the reservoir pressure by re-injection of produced gas into the gas cap and water injection into the water zone (IO center, 2008). During the first year of production it was experienced that the shales in the Not formation was a sealing layer in the Norne Main Structure. The plan for gas injection changed therefore to be injected into the water zone and the lower part of the oil zone. Injection fluids have been both gas and water up to 2004, in 2005 the gas injection was ceased and the oil was produced only by water injection as a drive mechanism (Lind, Annual Reservoir Development Plan, 2004). Figure 5.10 shows the drainage strategy from 1997-2005 and the planed strategy for 2014 (Red illustrates gas, green oil and blue water).

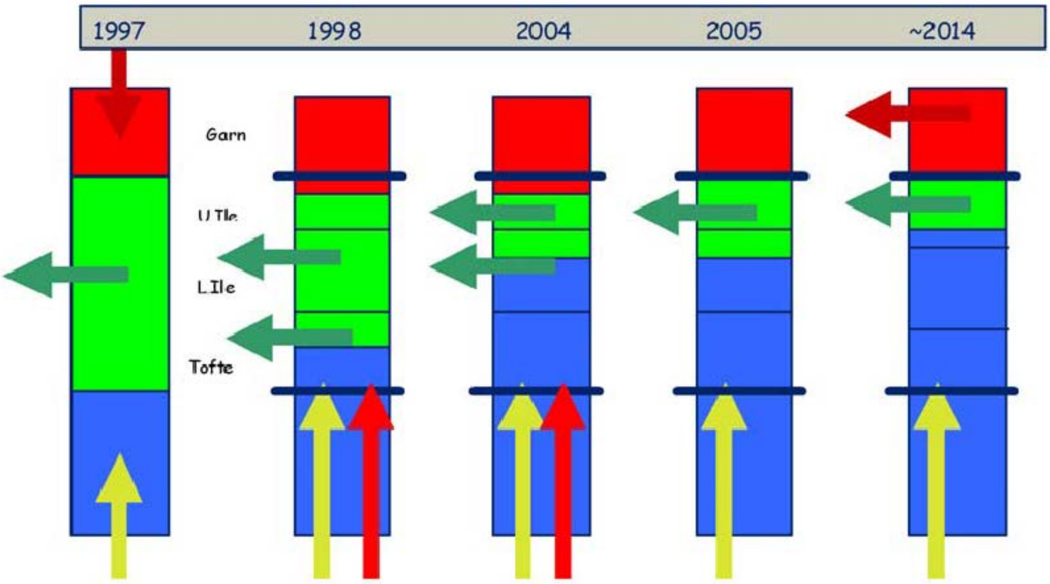

Figure 5.10: Drainage strategy (IO center, 2008)

5.5 Chemical Reactions in the Norne Field

The Norne field has never been tested with chemical EOR. In general chemicals are tested with reservoir properties and fluid characteristics in a laboratory. These data are not available for the Norne field. The chemical properties for this study were gathered from Yugal Kishore Maheshwari Master Thesis written here at NTNU (Maheshwari, August, 2011). Surfactant properties were provided by Nan Cheng (Statoil) and Lars Høier (Statoil) from Norne village, while alkaline properties were provided by Charles A. Kossak (Schlumberger). The Polymer (NBF Xanthan) properties are taken from Eldar Sadikhzadeh master thesis (2007). The input file with chemical properties is given in Appendix D. The number of NTSFUN for Norne is 107 and the number of NTPVT is 2.

6 Reservoir Simulation Model[5]

The original high resolution model was developed based on 2004 geo model. The simulation grid was based on updated fault polygons and new structural and isochore maps, produced in 2004 (Rwechungura, E. Suwartadi, Kleppe, & Foss, 2010). Isochore maps were generated for every individual reservoir zone. They were constructed based on reservoir zonation data, available sedimentological data and overall gross reservoir thickness variations determined by seismic data. The faults were done by dividing the fault planes into sections that followed the reservoir zonation. Then each subarea of the fault planes needed to be assigned transmissibility multipliers. These are a function of rock permeability, fault zone width, matrix permeability (host rock) and dimensions of the grid blocks in the simulation model (Signe Berg Verlo, June 2008). The root mean squares (RMS) has been used for generating the grid and populating the grid with petrophysical properties. The simulation model consists of 46*112*22 grids with 49080 active grid cells (Rwechungura, 2011). The reservoir was divided into 22 reservoir zones for the modelling. Some of the boundaries between zones were selected as sequence boundaries and maximum flooding surface. Other boundaries were based on lithology or defined on porosity/permeability from wells 6608/10-2 and 6608/10-3 (Hetland & Verlo, Wells, 2008). Surrounding wells were used for correlation of boundaries. Table 6.1 shows the reservoir zonation.

Layer Number	Layer Name	Layer Number	Layer Name
1	Garn 3	12	Tofte 2.2
2	Garn 2	13	Tofte 2.1.3
3	Garn 1	14	Tofte 2.1.2
4	Not	15	Tofte 2.1.1
5	Ile 2.2	16	Tofte 1.2.2
6	Ile 2.1.3	17	Tofte 1.2.1
7	Ile 2.1.2	18	Tofte 1.1
8	Ile 2.1.1	19	Tilje 4
9	Ile 1.3	20	Tilje 3
10	Ile 1.2	21	Tilje 2
11	Ile 1.1	22	Tilje 1

Table 6.1: Reservoir zonation

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[5] Modified chapter 8 from the project (Abrahamsen, 2011)

The IRAP (Interactive Reservoir Analysis Package) mapping was used for reservoir modelling. The spatial reservoir model was formed with isochores and seismic depth structure maps. Grid cell sizes of 50x50 meters were used to represent the reservoir. True dips are modelling the major faults in the field, while small faults less than 20 meters are represented by simple addition. Wells in the field are treated as deviated wells by employing true vertical depths and deviation data.

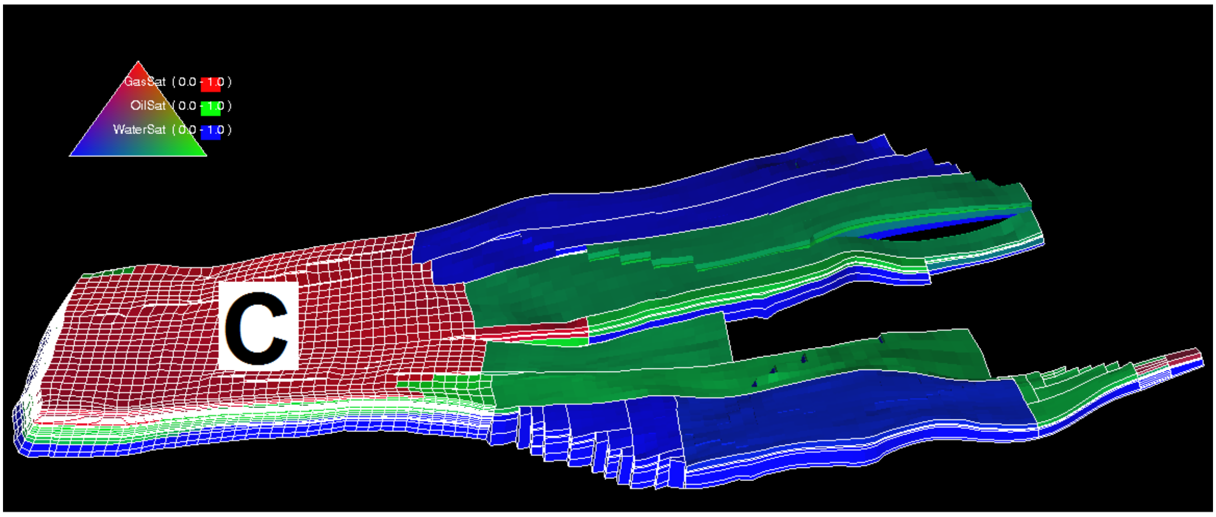


Figure 6.1: Norne model saturations in the end of 2006

6.1 C-Segment

The target for this study is to optimise oil production in the C-segment and therefore a fine gridded model is used for this segment see Figure 6.1. The rest of the reservoir is coarse gridded because of less importance in this study. Due to the modifications of the model some of well B1-H perforations were changed because it was producing outside the C-segment. Well B-3H was removed because only its wellhead is located in the C-segment (Rwechungura, 2011).

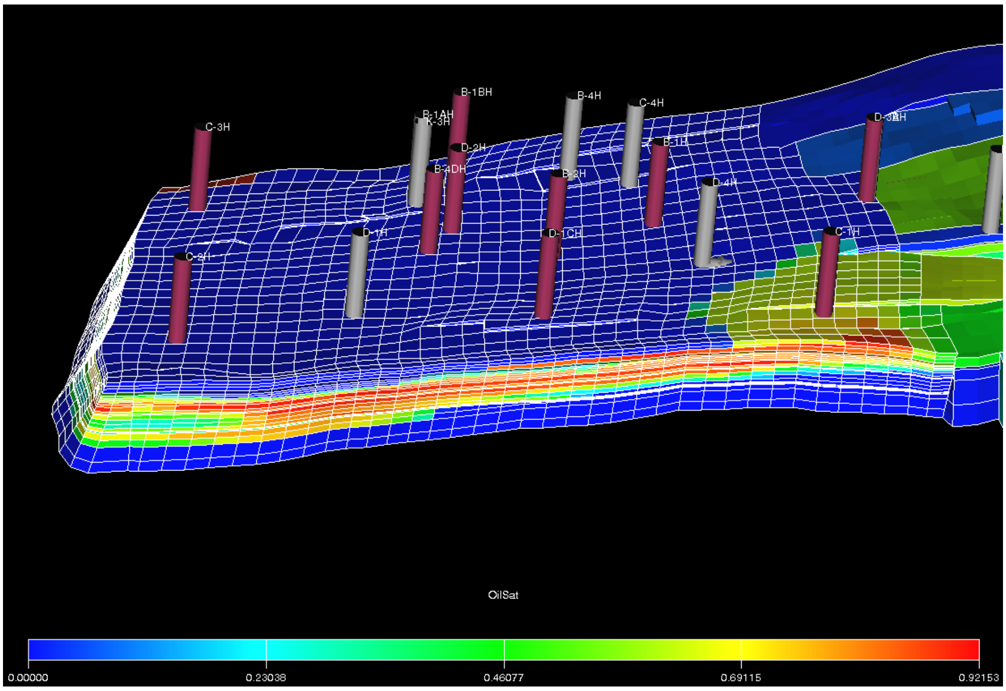
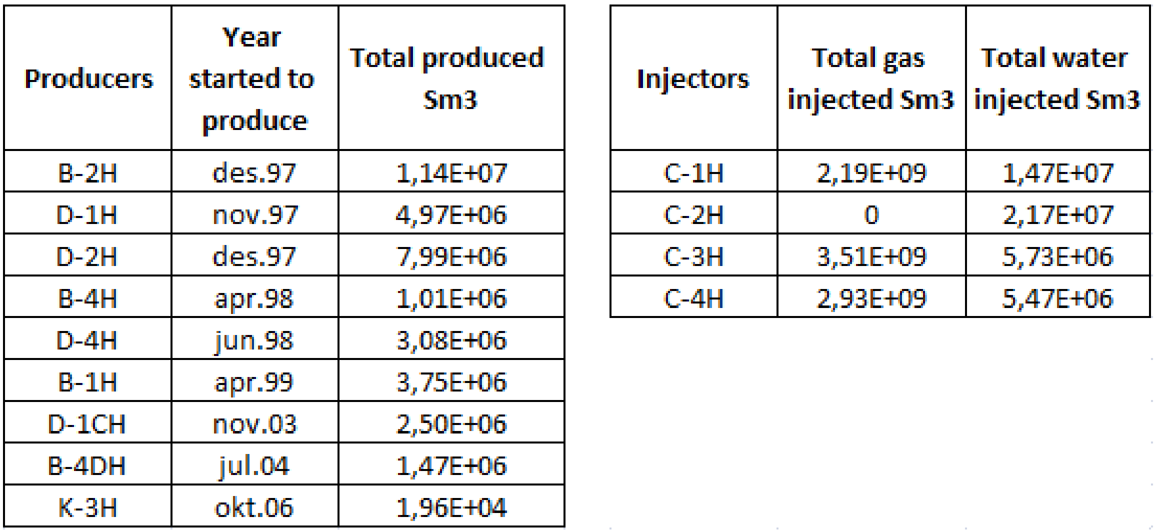


Figure 6.2: Norne wells and oil saturations in the end of 2006

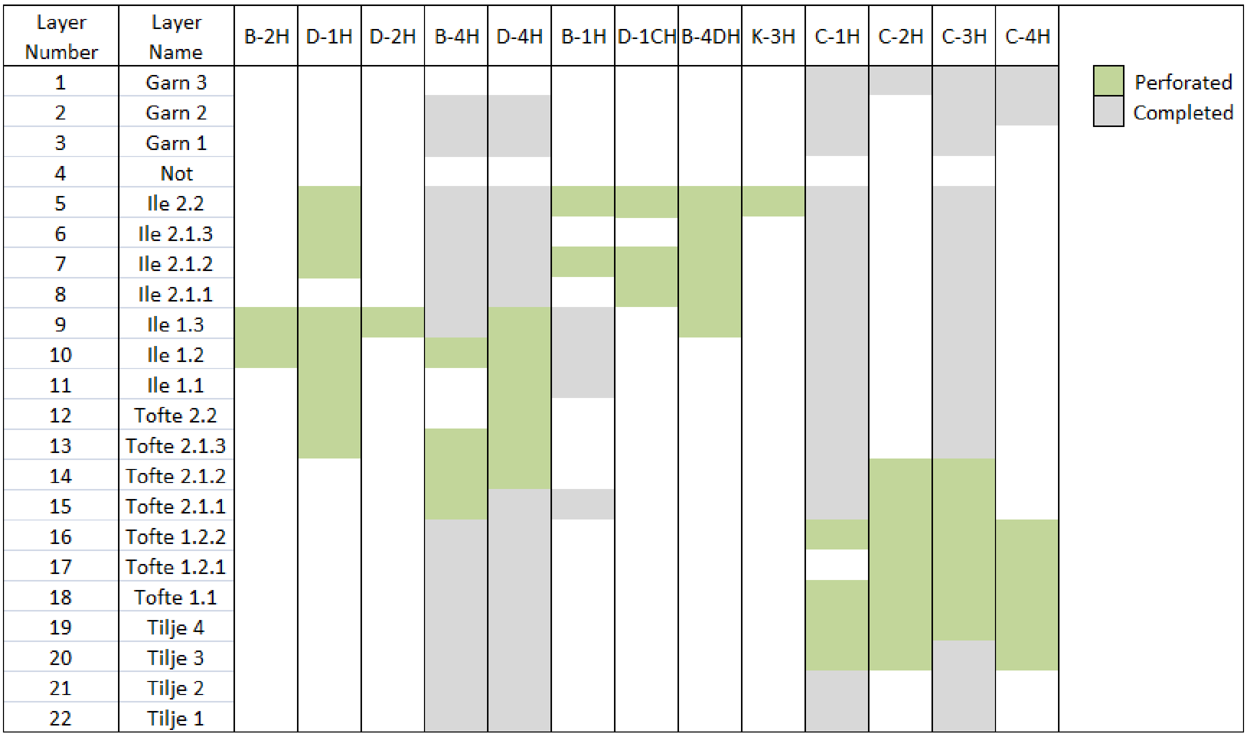
The Norne C-segment model has wells outside the C segment implemented for pressure support. To measure production from only the C-Segment a group was made using GROUP keyword in Eclipse, see Appendix 0. The C-segment has 4 injectors and 9 producers of the end of 2006 (Rwechungura, 2011) listed in Table 6.2 and seen in Figure 6.2. The well completions and perforations are given in Table 6.3 and positions are seen in Table 6.4.



Producers	Year started to produce	Total produced Sm3
B-2H	des.97	1,14E+07
D-1H	nov.97	4,97E+06
D-2H	des.97	7,99E+06
B-4H	apr.98	1,01E+06
D-4H	jun.98	3,08E+06
B-1H	apr.99	3,75E+06
D-1CH	nov.03	2,50E+06
B-4DH	jul.04	1,47E+06
K-3H	okt.06	1,96E+04

Injectors	Total gas injected Sm3	Total water injected Sm3
C-1H	2,19E+09	1,47E+07
C-2H	0	2,17E+07
C-3H	3,51E+09	5,73E+06
C-4H	2,93E+09	5,47E+06

Table 6.2: Producers and Injectors Norne C-Segment (Rwechungura, 2011)



Layer Number	Layer Name	B-2H	D-1H	D-2H	B-4H	D-4H	B-1H	D-1CH	B-4DH	K-3H	C-1H	C-2H	C-3H	C-4H
1	Garn 3										▨	▨	▨	▨
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				▨	▨		🟩	🟩		▨		▨	
9	Ile 1.3	🟩	🟩	🟩	▨	🟩	▨		🟩		▨		▨	
10	Ile 1.2	🟩	🟩		🟩	🟩	▨				▨		▨	
11	Ile 1.1		🟩			🟩	▨				▨		▨	
12	Tofte 2.2		🟩			🟩					▨		▨	
13	Tofte 2.1.3		🟩		🟩	🟩					▨		▨	
14	Tofte 2.1.2				🟩	🟩					▨	🟩	🟩	
15	Tofte 2.1.1				🟩	▨	▨				▨	🟩	🟩	
16	Tofte 1.2.2				▨	▨					🟩	🟩	🟩	🟩
17	Tofte 1.2.1				▨	▨						🟩	🟩	🟩
18	Tofte 1.1				▨	▨					🟩	🟩	🟩	🟩
19	Tilje 4				▨	▨					🟩	🟩	🟩	🟩
20	Tilje 3				▨	▨					🟩	🟩	▨	🟩
21	Tilje 2				▨	▨					▨		▨	
22	Tilje 1				▨	▨					▨		▨	

🟩 Perforated
▨ Completed

Table 6.3: Well completions in Norne C-Segment

X\Y	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
29	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥 B-2H	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥
28																																							
27				🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥 C-1H	🟥	🟥	🟥	🟥	
26																																		C-1H					
25																		🟥	🟥	🟥	🟥	🟥 B-2H	🟥	🟥	🟥						🟥	🟥	🟥	🟥	🟥	🟥	🟥	🟥	
24			C-2H	C-2H												🟥	🟥	🟥		D-1CH	D-1CH	B-2H				🟥													
23												D-1H				D-1CH	D-1CH	D-1CH	D-1CH	D-1CH							🟥	🟥											
22										🟥		D-1H	D-1CH	D-1CH	🟥 D-1CH	D-1CH						B-2H							🟥										
21										🟥		D-1CH	D-1CH			🟥	🟥	🟥	🟥	🟥	B-2H									D-4H	D-4H								
20										🟥				B-4DH							B-2H								D-4H	D-4H									
19														B-4DH							B-2H							D-4H	D-4H						🟥	🟥	🟥		
18											🟥			B-4DH		🟥																							
17											🟥			B-4DH	B-4DH		🟥				B-2H													B-1H	B-1H		B-1H		
16											🟥				B-4DH													B-1H	🟥 B-1H	B-1H	B-1H	B-1H				🟥	🟥		
15											🟥															B-1H	B-1H	B-1H		🟥				🟥	🟥				
14			D-2H	D-2H	🟥 D-2H	🟥 D-2H	D-2H	D-2H	D-2H	D-2H	🟥 D-2H	D-2H	D-2H	D-2H	D-2H	D-2H																	🟥	🟥					
13			🟥	🟥	🟥	🟥	🟥	🟥			🟥																					🟥	🟥						
12								🟥	🟥	🟥	🟥	🟥	🟥	🟥											C-4H														
11						K-3H	K-3H	K-3H	K-3H	K-3H	K-3H	🟥	K-3H	K-3H											C-4H									🟥					
10											K-3H	🟥 K-3H	K-3H							🟥	🟥	🟥 B-4H	🟥	🟥	🟥	🟥	🟥	🟥					🟥	🟥					
9			C-3H									🟥						🟥	🟥	🟥	🟥 B-4H	🟥 B-4H									🟥	🟥							
8												🟥											🟥	🟥	🟥	🟥				🟥	🟥								
7									🟥	🟥		🟥															🟥	🟥	🟥	🟥	🟥	🟥							
6											🟥	🟥																	🟥										

🟥	Faults
Blue	Injectors
Black	Producers

Table 6.4: Well and fault locations on the Norne C-Segment

7 History Matching

History matching is an important phase in a reservoir study. The process tests the reliability of the reservoir model. There is always a difference between the data defining the reservoir in the numerical model and the actual values of the reservoir. Difference will cause errors in the simulation. Adjustments to the reservoir model should be done to minimize the difference. The changes done should be consistent with a comprehensive and rational description of the reservoir.

The way to test accuracy of the model is to simulate past performance of the reservoir and compare the results with actual historical data. Modelling past performance will identify weaknesses in data, suggest modifications that are needed to improve the model, and demonstrate the quality of the reservoir description. If the quality is good, the model is accepted to predict forecasts. Reservoir performance can be complex with numerous interactions. This makes history matching time-consuming and expensive.

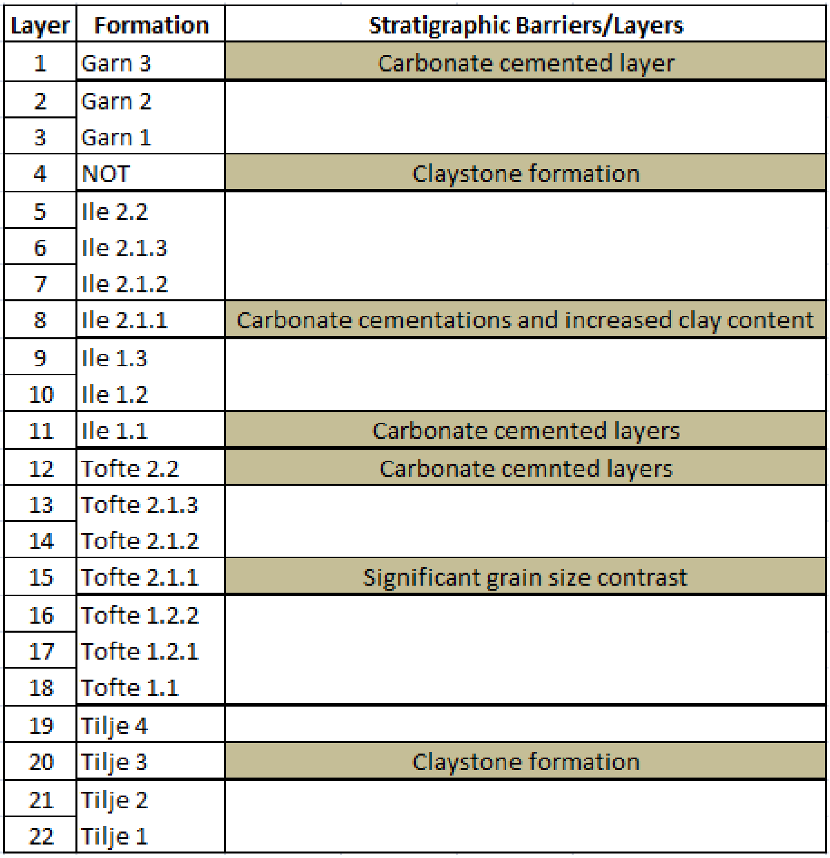
7.1 History Matching of the Norne C-Segment

The Norne model is acceptable for EOR but there are variation between the prediction and the history data. There are uncertainties in the vertical barriers (Lillehaug, 2012) and they will be investigated to minimize the difference. History matching contributed to an understanding of the current status on the reservoir, including fluid distribution and fluid movement and verified the current depletion mechanisms. The given model of Norne produces less oil and gas than the history because of higher water cut. The history and prediction is plotted in Figure 7.5, Figure 7.6 and Figure 7.7 on page 48. Manual history matching will be used as the history matching procedure. This method relies on the reservoir engineering’s intuition.

There is no approach to history matching that is universally applicable, but there are a few techniques that lend some structure to the matching process. In general, the data that are matched are pressure, Water Cut (WC), gas/oil ratios (GOR), water/gas ratios (WGR), water and gas arrival times and fluid saturations (Mattax & Dalton, 1990). Due to the lack of pressure data, production data will be matched. History data used is given from 1997 to 2006. The history matching will be on a detailed level matching individual well behaviour. The wells matched are listed in Table 6.2 on page 38. The well K-3H is not matched due to the fact that production started lack in the end of 2006.

7.2 Barriers

There are several barriers in the Norne field, shown in Chapter 5.3. In the given 2004 model, a new field-wide barrier is introduced in layer 18 and barrier 11 and 12 are not considered field-wide anymore. Due to the changes in the new model, layer 11 will be tested in the sensitivity analysis representing barrier 11 and 12 from the 2000 model. The Norne Model uses MULTZ barriers, FLUX-regions and MULTIREG to control the vertical fluid flow. The difference between these two methods is that the MULTIREG controls the vertical flow in- and between regions, whereas MULTZ acts as single layer barriers. The barriers and which layer they are assigned in the model are shown in Table 7.1 where the thick lines represent barriers. The keyword MULTZ will be used to alter the barriers. This keyword will change the vertical transmissibility's to control the oil-water contact rise.



Layer	Formation	Stratigraphic Barriers/Layers
1	Garn 3	Carbonate cemented layer
2	Garn 2	
3	Garn 1	
4	NOT	Claystone formation
5	Ile 2.2	
6	Ile 2.1.3	
7	Ile 2.1.2	
8	Ile 2.1.1	Carbonate cementations and increased clay content
9	Ile 1.3	
10	Ile 1.2	
11	Ile 1.1	Carbonate cemented layers
12	Tofte 2.2	Carbonate cemnted layers
13	Tofte 2.1.3	
14	Tofte 2.1.2	
15	Tofte 2.1.1	Significant grain size contrast
16	Tofte 1.2.2	
17	Tofte 1.2.1	
18	Tofte 1.1	
19	Tilje 4	
20	Tilje 3	Claystone formation
21	Tilje 2	
22	Tilje 1	

Table 7.1: Stratigraphic barriers/layer Norne

7.3 Procedure

The area of interest is below the Not formation. This is where the production wells are perforated see Table 6.3. High- and low cases where made to analyse the sensitivity of the layers. The high cases were multiplied with a factor of 100, while low cases were divided by 100 to alter the transmissibility. Base case is without alternations. Layers of interest were 8, 11, 15, 18 and 20. Sensitivity analysis is shown in Figure 7.1. From this analysis layer 18 and 20 had the least impact and was eliminated for the future study.

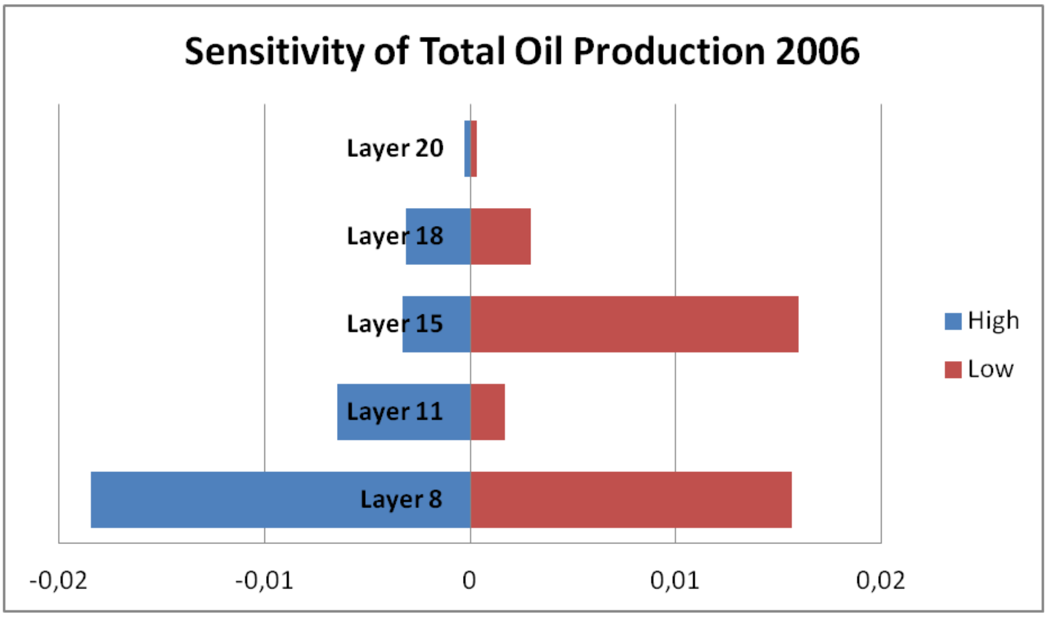


Figure 7.1: Sensitivity of total oil production 2006

The change in field production was minor compared to the change in well production. Therefore in each case all wells were history matched. In Table 7.2 the case with the best match is listed. Overall the analysis shows that field wide barriers should not be altered, but making alternation to local barriers can give a better match. Both high- and low case have some better well matches and will therefore be investigated. The high case increases the transmissibility and opens the layer for faster oil-water rise. The low case reduces the transmissibility and closes the layer for slower oil-water rise. The results in Table 7.2 are used to make a best case for each layer with different local flow regions. WC weighted more than GOR when making a best case.

	Layer		
Well	8	11	15
B-2H	Base	Low	Base
D-1H	Base	Low	Base
D-2H	Low	High	Base
B-4H	Base	Low	Base
D-4H	Base	Base	Base
B-1H	Base	Base	High
D-1CH	Base	Low	Base
B-4DH	Low	High	Base

Table 7.2: Best history match for each Layer

7.3.1 Layer 15

In layer 15 base cases had the best history match for all wells except for the B-1H. B-1H has the best history match with a high case. With this alternation Well B-1H got a better Water Break Through (WBT) and a more matching WC in the start of water production. The GOR also matched overall better with the history. A local high case layer was therefore made near the well. With this alternation the whole field had a better match and a best case for layer 15 was made. Different local high cases were made to make the best case. Figure 7.2 shows the local change that gave the best result.

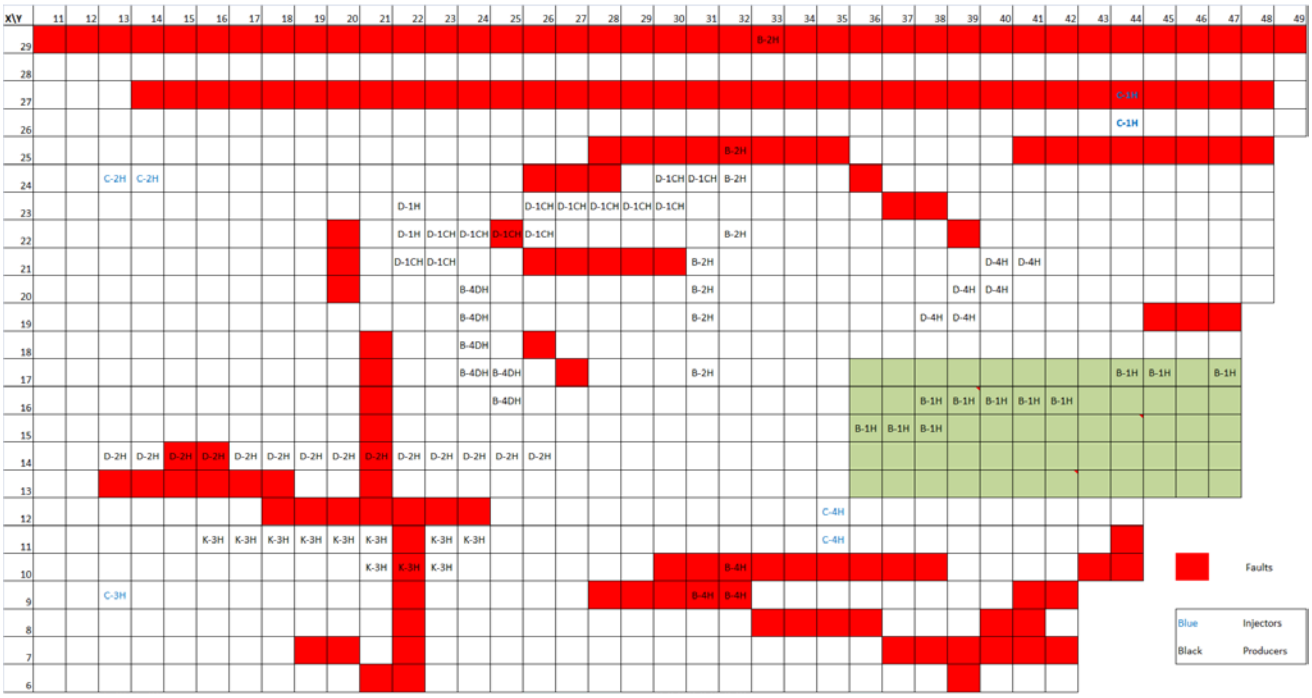


Figure 7.2: Best case layer15

7.3.2 Layer 11

Layer 11 got a better match with both high- and low cases. As seen in Table 7.2 alternation in layer 11 affect almost all the wells. Layer 11 is highly sensitive. The high case gave D-2H and B-4DH a better match. D-2H gets an earlier WBT and higher WC giving a better match. GOR is neither better nor worse. B-4DH gets an earlier WBT, higher WC and GOR. The increased water and gas production gives a better match, but the early WBT makes it worse.

The Lower case gave B-2H, D-1H, B-4H and D-1CH a better match. B-2H WBT is delayed and the total production does not change, making it a better match. GOR is not affected. D-1H WBT is delayed and the total production decreased, making it a better match. GOR is neither better nor worse. B-4H does not produce water, but GOR is lowered and a better match is achieved. D-1CH WBT is delayed and a better match is achieved, but the WC is lowered and making it a poorer match. The GOR is a better match.

Local high cases and low cases were made in the layer near the wells to give a best case for alternations in only layer 11. Different cases were tried out to make the best case. Figure 7.3 shows the local changes that gave the best result.

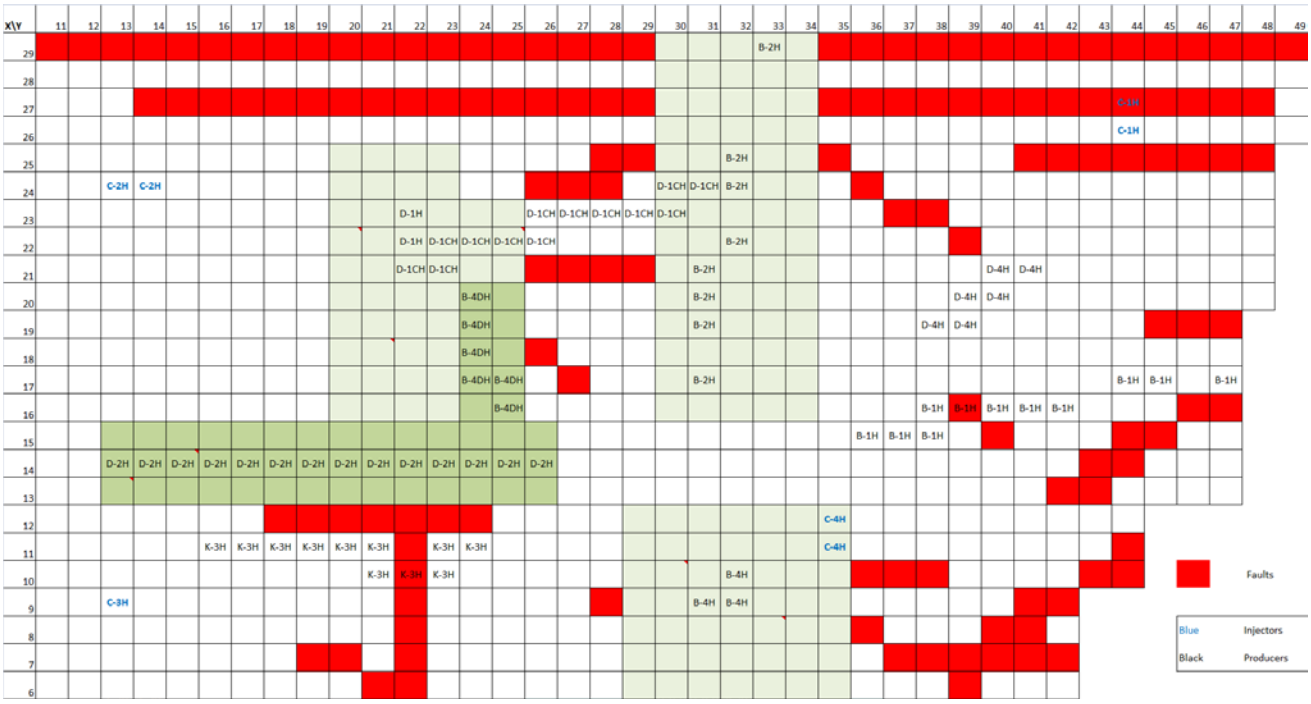


Figure 7.3: Best case layer 11

7.3.3 Layer 8

In Layer 8 well D-2H and B-4DH have a better match using a low case. D-2H gets a faster WBT and the total WC is increased, making it a better match. GOR is neither better nor worse. B-4DH WBT is the same, but total WC increases, making it a better match. GOR is neither better nor worse. Local low cases were made in the layer near the two wells to give a best case for layer 8. Different cases were tried out to make the best case. Figure 7.4 shows the local changes that made the best result.

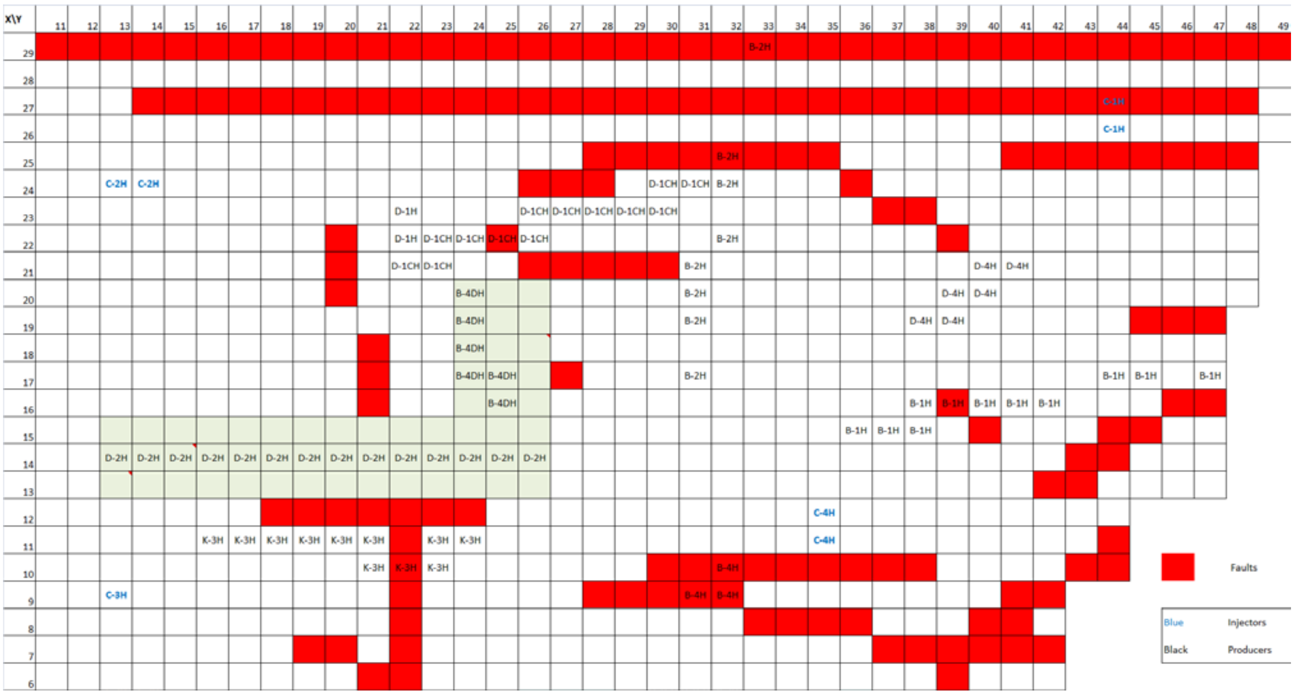


Figure 7.4: Best case layer 8

7.4 New Model

In the previous chapters a best case for each layer was made. To make the new model all the best cases were put together and a new trial and error process started. The process resulted in alternation described in Table 7.3.

Layer	x1	x2	y1	y2	Case
8	13	15	13	26	L
	16	20	24	26	L
11	6	12	29	35	L
	16	29	30	34	L
	16	25	20	23	L
	21	23	24	25	L
	13	15	13	26	H
	16	20	24	25	H

Table 7.3: New Model

The new model with alternation in the barriers where plotted with the old model and history. Below is a plot of Oil production, WC and GOR. The results have a minor change on the global production. In the detailed well behaviour, plotted in Appendix D, changes are more noticeable. The biggest change in the global production data is the WC. The new model has lower water cut through the whole field life except after 2006.

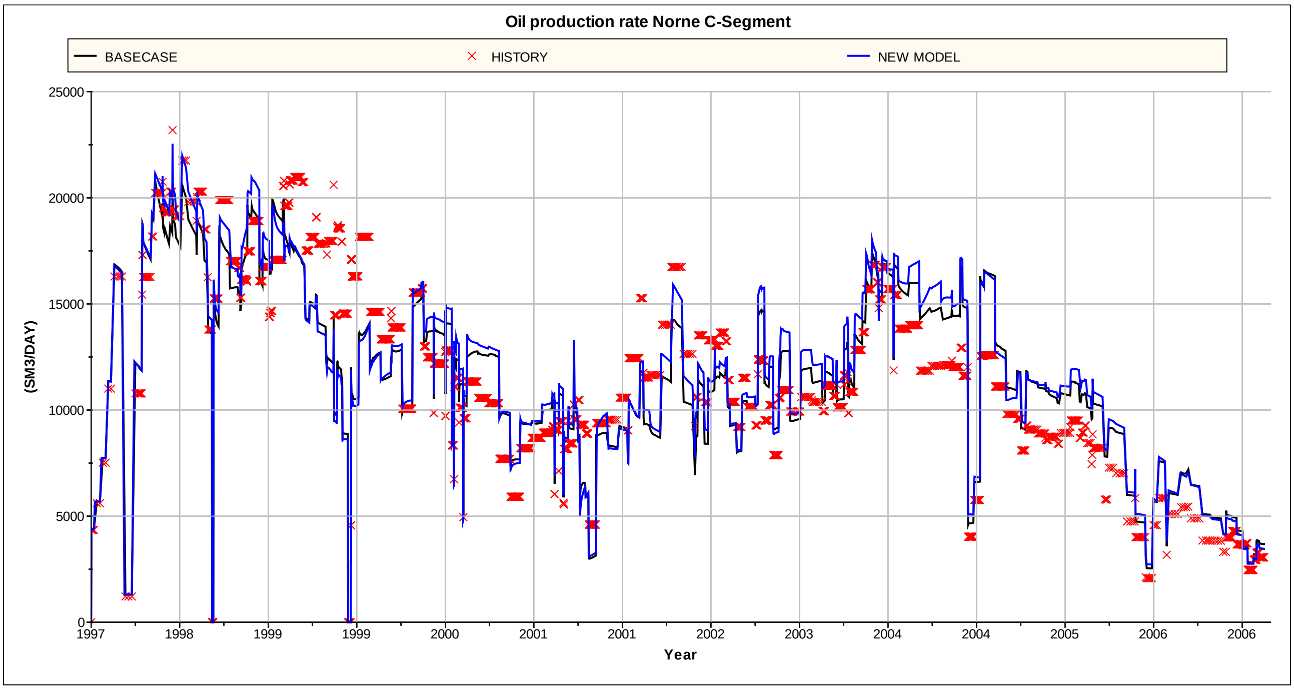


Figure 7.5: Oil production rate Norne C-Segment

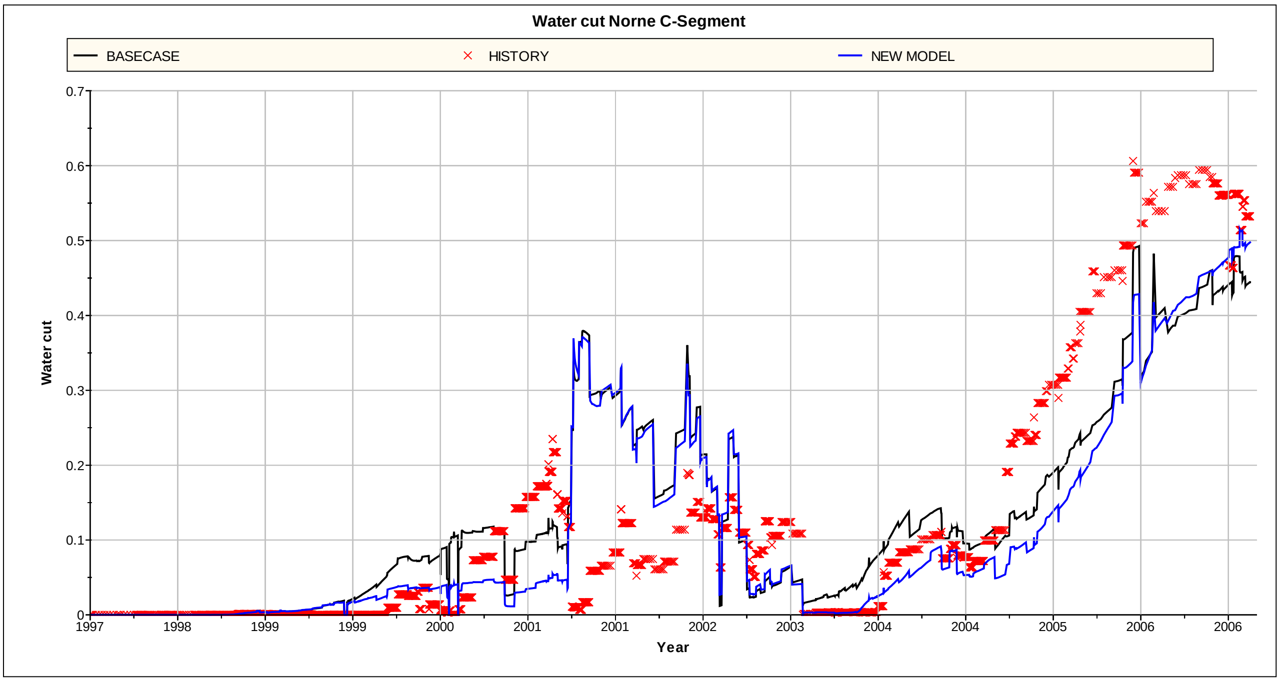


Figure 7.6: Water Cut Norne C-Segment

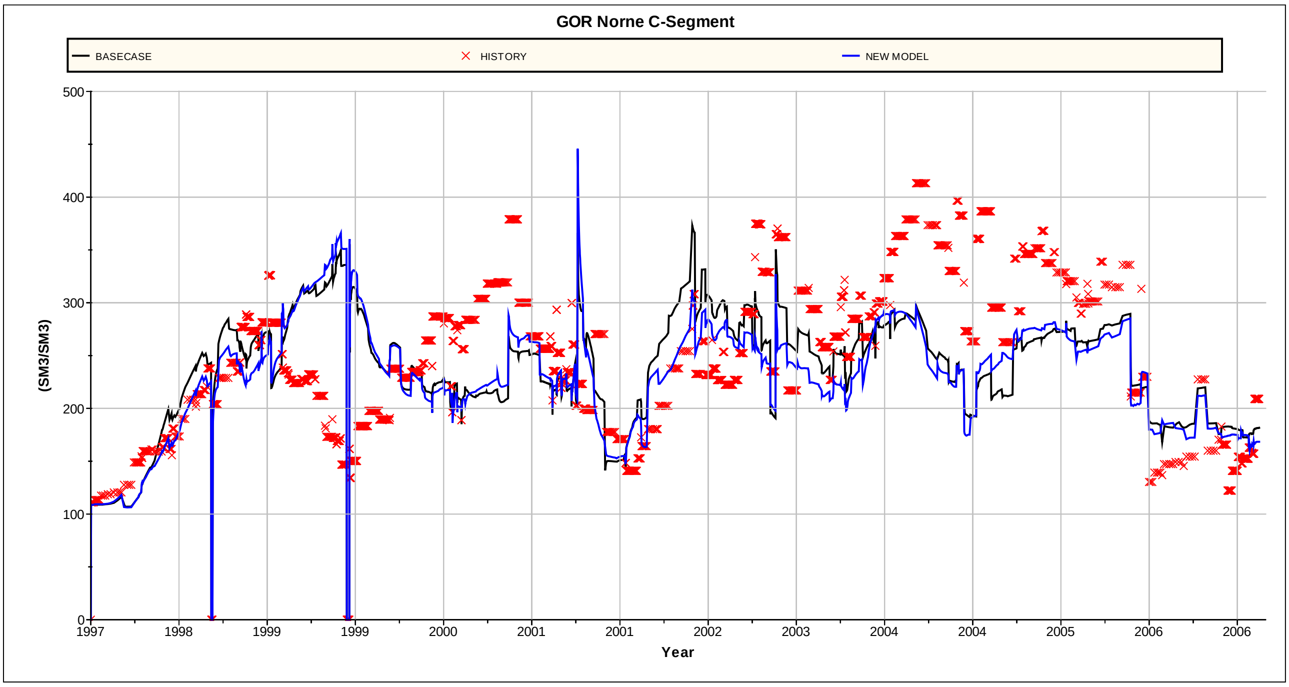
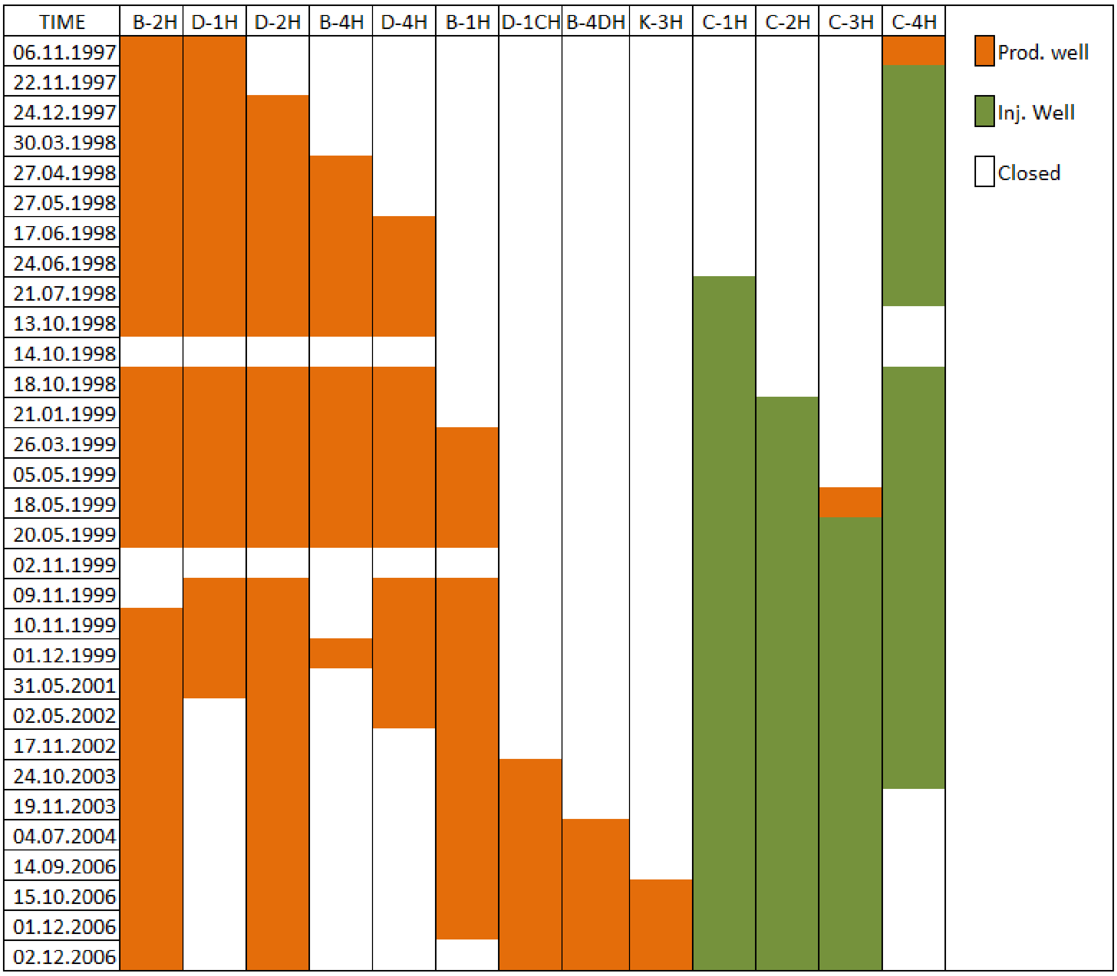


Figure 7.7: GOR Norne C-Segment

8 Forecasting Future Performance

In the foregoing chapter a new model was made based on the history given from 6/11-1997-1/12-2006. Forecast for the chemical flooding study will start in 1/1-2007. The prediction will end in 2021 when the decommissioning of the Norne field is planned by Statoil (Skagen, 29/2- 12). There will not be drilled any new wells, existing wells that have been closed will not be reopened. Figure 8.1 shows the well status for each well in the C-segment from 1997-2006. The wells still open in the end of 2006 are the production wells B-2H, D-2H, D-1CH, B-4DH, K-3H and injection wells C-1H, C-2H, C-3H. The forecast will be made with these wells. The new model made in Chapter 7.4 and the old model has almost the same RF. The difference is 0.007 %. The new model has a better overall history match on the wells to be used in prediction of chemical flooding and will therefore be preferred in the future simulations, see Appendix F.



TIME	B-2H	D-1H	D-2H	B-4H	D-4H	B-1H	D-1CH	B-4DH	K-3H	C-1H	C-2H	C-3H	C-4H
06.11.1997	🟧	🟧											🟧
22.11.1997	🟧	🟧											🟩
24.12.1997	🟧	🟧	🟧										🟩
30.03.1998	🟧	🟧	🟧										🟩
27.04.1998	🟧	🟧	🟧	🟧									🟩
27.05.1998	🟧	🟧	🟧	🟧									🟩
17.06.1998	🟧	🟧	🟧	🟧	🟧								🟩
24.06.1998	🟧	🟧	🟧	🟧	🟧								🟩
21.07.1998	🟧	🟧	🟧	🟧	🟧					🟩			🟩
13.10.1998	🟧	🟧	🟧	🟧	🟧					🟩			
14.10.1998										🟩			
18.10.1998	🟧	🟧	🟧	🟧	🟧					🟩			🟩
21.01.1999	🟧	🟧	🟧	🟧	🟧					🟩	🟩		🟩
26.03.1999	🟧	🟧	🟧	🟧	🟧	🟧				🟩	🟩		🟩
05.05.1999	🟧	🟧	🟧	🟧	🟧	🟧				🟩	🟩		🟩
18.05.1999	🟧	🟧	🟧	🟧	🟧	🟧				🟩	🟩	🟧	🟩
20.05.1999	🟧	🟧	🟧	🟧	🟧	🟧				🟩	🟩	🟩	🟩
02.11.1999										🟩	🟩	🟩	🟩
09.11.1999		🟧	🟧		🟧	🟧				🟩	🟩	🟩	🟩
10.11.1999	🟧	🟧	🟧		🟧	🟧				🟩	🟩	🟩	🟩
01.12.1999	🟧	🟧	🟧	🟧	🟧	🟧				🟩	🟩	🟩	🟩
31.05.2001	🟧	🟧	🟧		🟧	🟧				🟩	🟩	🟩	🟩
02.05.2002	🟧		🟧		🟧	🟧				🟩	🟩	🟩	🟩
17.11.2002	🟧		🟧			🟧				🟩	🟩	🟩	🟩
24.10.2003	🟧		🟧			🟧	🟧			🟩	🟩	🟩	🟩
19.11.2003	🟧		🟧			🟧	🟧			🟩	🟩	🟩	
04.07.2004	🟧		🟧			🟧	🟧	🟧		🟩	🟩	🟩	
14.09.2006	🟧		🟧			🟧	🟧	🟧		🟩	🟩	🟩	
15.10.2006	🟧		🟧			🟧	🟧	🟧	🟧	🟩	🟩	🟩	
01.12.2006	🟧		🟧			🟧	🟧	🟧	🟧	🟩	🟩	🟩	
02.12.2006	🟧		🟧				🟧	🟧	🟧	🟩	🟩	🟩	

🟧 Prod. well

🟩 Inj. Well

☐ Closed

Figure 8.1: Well status

9 Selection of Target Formation

Approximately 80% of the oil reserves on the Norne Main Structure are located in the Ile and Tofte formations, see Chapter 5.2. In Norne C-Segment the Ile formation has the most Oil in Place (OIP) in the end of 2006, see Table 9.1. Ile formation has also a higher oil saturation of 0.58 while Tofte has an oil saturation of 0.28 and was therefore selected as the target formation for chemical flooding. A Region function in Eclipse was made to calculate the OIP and oil saturations, see Appendix I. The region is based on the different FIPNUM regions in the Norne C-Segment. The region function makes it possible to calculate reservoir parameters for the target formation. In the future study RF for the target formation will be compared.

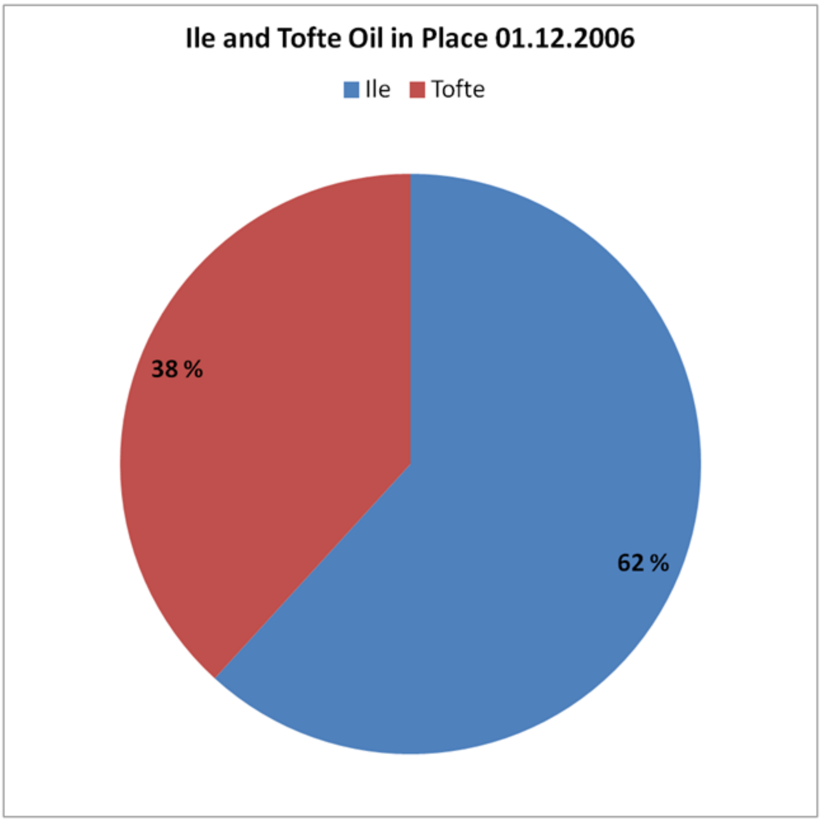


Table 9.1: Ile and Tofte oil in place 01.12.2006

10 Synthetic Model of Ile

Norne C-Segment is complex and simulations are time consuming. Therefore a synthetic model was build to determine if the chemical models in Eclipse can simulate increased oil recovery by reducing IFT and increase sweep efficiency. The model was used for optimization of the chemical injection scheme. More chemical concentrations could be tested and a small model is easier to interrupt. The model was populated with properties from the target formation Ile.

The model consists of 600 blocks, 10 by 10 horizontal and 6 vertical. The model was given one producer and one injector, see Figure 10.1 . Vertical wells are used and both wells perforated in all the 6 layers. The injector was controlled by surface flow rate and the producer was controlled by Bottom Hole Pressure (BHP) of 260 barsa. This will hold the reservoir pressure above bubble point pressure of 251 barsa. The data used for the model was taken from the Norne data file and Norne management plan from 2001 (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001). The data taken from the Norne management plan is listed in Table 10.1.

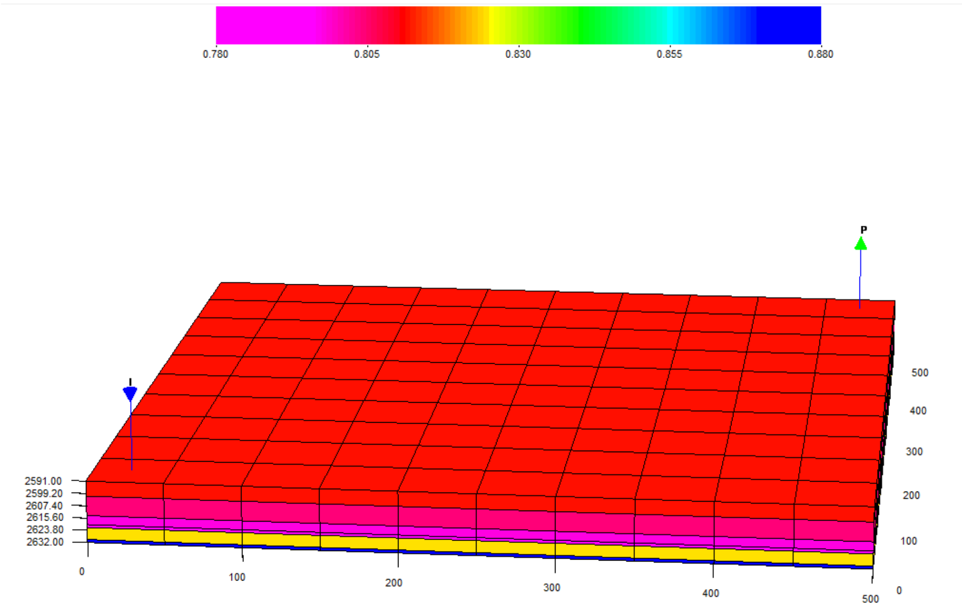


Figure 10.1: Synthetic model of Ile formation, initial oil saturation

Ile Layer:	Top (m)	Thickness (m)	Porosity	PermX (mD)	PermY (mD)
3.2	2591	10	0.23	137.6	13
3.1	2601	13	0.23	87.6	13
2.2.2	2614	6	0.26	723.9	13
2.2.1	2620	2	0.28	1006.4	75
2.1	2622	8	0.22	508.1	75
1	2630	2	0.27	793.5	150

Table 10.1: Ile properties

The most repeated relative permeability curve in each layer of Ile was assigned to the duplicated layer in the synthetic model. Reservoir parameters as PVT, rock properties and rock compressibility where also copied. The model uses the same EQUIL function as the Norne data file to fill the grid data. The model data can be found in Appendix G. The Model uses NTSFUN=4 and NTPVT=1.

The synthetic model is waterflooded for 22 years and ends up with a recovery of 64%. This case will be referred as the base case. Norne C-segment is at tale production in 2006 when chemical flooding will be applied. The synthetic model was waterflooded for 9 years to make the same conditions as Norne C-Segment. At this time it reached its tale production at ¼ of plateau production before chemicals where applied with the oil saturation equal to 0.4 and the producer having a WC of 0.85. The Pore Volume (PV) of the synthetic model is 1/30 of the Ile formation. In the synthetic model a chemical injection rate of 500 Sm^3/day in 4 years represents approximately 0.3 PV. In the Norne C-Segment a chemical injection rate of 10 000 Sm^3/day with 3 producers in 2 years will approximately be 0.3 PV. The scale can be seen in Table 10.2.

	Scale					
Model	PV (Sm3)	# Injectors	PV per injector (Sm3)	Rate (Sm3/day)	Year	PV
Ile formation	7E+07	3	2,3E+07	10000	2	0,31
Synthetic Model	2E+06	1	2,3E+06	500	4	0,31

Table 10.2: Scale synthetic model

11 Optimization of the Chemical Injection Scheme

Modelling the injection of chemicals into an oil reservoir should be a systematic process. Chemicals are expensive, hence it is essential to ensure that you have the right strategy to increase the oil recovery using the least possible amount. Large amount of chemicals will result in excess chemical production at the producer that will be costly to treat. The objective of this chapter is to optimize the chemical flooding efficiency to maximize RF per unit mass of chemicals injected. Several combinations of concentrations and different slug sizes will be tested on the synthetic model to save time. There will be made one optimum case for each chemical flooding method S, P, SP, AS and ASP. The optimum cases will further be tested on the Norne C-Segment.

Assumptions:

- No salinity effect
- No desorption
- All chemicals are injected with pure water
- 1 l water equals 1 kg when calculating wt%

11.1 Concentrations

In total 80 various concentrations of polymer, surfactants and alkaline were combined. RF and adsorption were reported and plotted for each of the simulations. The concentrations will be given in wt%. Appropriate concentrations for the cases were made after consulting with Jan Åge Stensen at SINTEF/ NTNU. (Stensen, 2012). Concentrations are tested with a slug size of 0.3 PV and injection rate of 500 Sm^3/d and are compared with the base case.

In Figure 11.1 and Figure 11.2 the chemical and concentration are given different markers and colours as described below. In Figure 11.3 polymer- and surfactant concentrations are swapped. Tables with results can be found in Appendix H .

- Alkaline concentration has its own colour: Orange 0.0 wt%, Green 0.1 wt%, Blue 0.5 wt%, Red 1 wt%,
- Polymer concentration has its own marker: Square 0.0 wt%, Diamond 0.025 wt%, Triangle 0.05 wt%, Cross 0.1 wt%.
- The Surfactant concentration is noted on the x axis with concentrations: 0.1 wt%, 0.5 wt%, 1.0 wt%, 2.0 wt%.

11.1.1 Recovery Factor

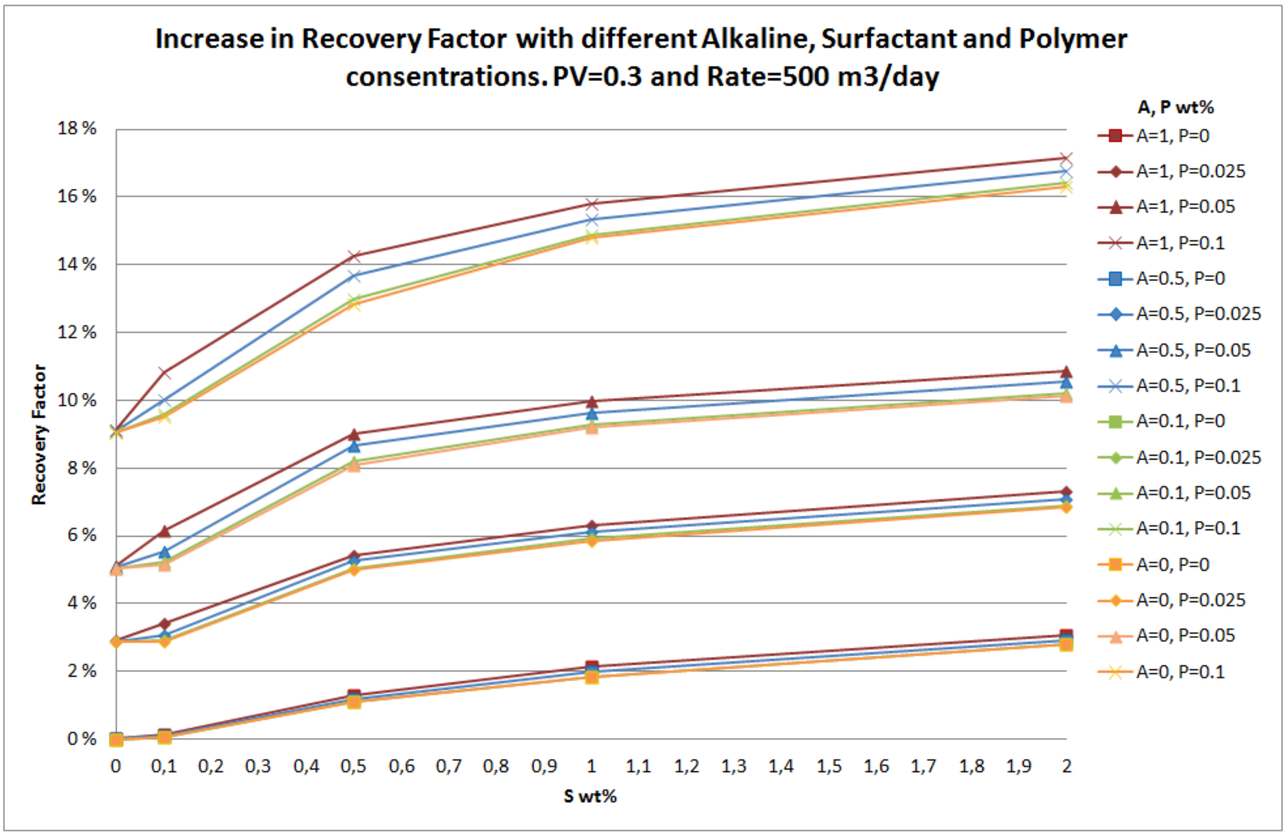


Figure 11.1: Recovery factor with different alkaline, surfactant and polymer concentrations

Change in polymer concentration has the largest impact on the RF. The trend from Figure 11.1 shows that cases with equal polymer concentration are grouped. A higher polymer concentration gives a higher RF despite the surfactant or alkaline concentration. The highest increase in RF by polymer flooding is 9.1% with a concentration of 0.1 wt%. All the polymer concentrations give a good increase in RF.

Surfactant contribution to higher RF is lower than polymer. Concentrations of 0.5 wt% have the highest increase per unit chemical added to the solution. The highest surfactant flooding increase in RF is 2.8% with a concentration of 2.0 wt%. Alkaline contribution to RF in an AS flood is low. The highest increase is at a surfactant concentration of 2.0 wt% and with 1.0 wt% alkaline. The AS flood increases the RF by 3.1 % and alkaline contributes with only 0.3 %.

Combining surfactant and polymer increases the effect of both chemicals (SP). The greatest increase in RF is achieved with 2.0 wt% surfactant and 0.1 wt% polymer with an increase of 16.3 %. The figure shows that surfactants work better at high polymer concentrations.

Combining alkaline with the SP flooding gives us ASP. ASP has the highest RF of all the cases with increase in RF by 17.2 %. This is at a concentration of 1.0 wt% alkaline, 2.0 wt% surfactants and 0.1 wt% polymer. Alkaline in ASP works better at high polymer concentrations. Alkaline effect on RF is still low and is less than surfactants.

11.1.2 Adsorption

Adsorption of the chemicals is an important aspect on the economics of a chemical project. Alkaline prevents surfactant and polymer adsorption. Desorption effect is turned off.

11.1.2.1 Surfactant

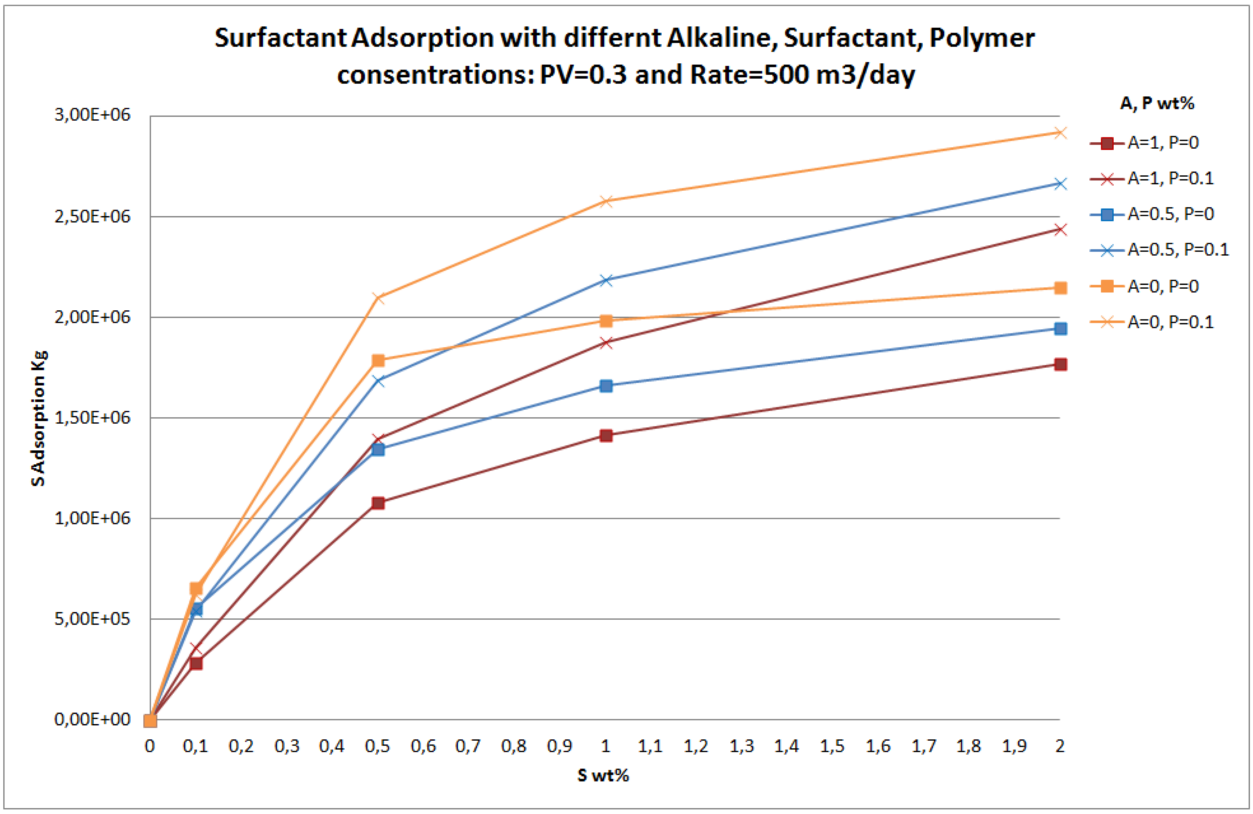


Figure 11.2: Surfactant adsorption

Figure 11.2 shows the surfactant adsorption with three alkaline and two polymer concentrations. The rest of the results can be found in Appendix I. Alkaline with concentration of 0.1 wt% had little effect on adsorption of surfactants. Alkaline effect on reduction of surfactant adsorption is decreasing as more alkaline is introduced. Adsorption increases with higher surfactant concentrations. The adsorption rate is highest between 0.0-0.5 wt% surfactant. At higher concentrations less surfactant are adsorbed per unit surfactant injected. The highest adsorption is 2.9E+06 kg with a concentration of 2.0 wt% surfactant and 0.1 wt% polymer. Higher polymer concentrations contribute to higher surfactant adsorption.

11.1.2.2 Polymer

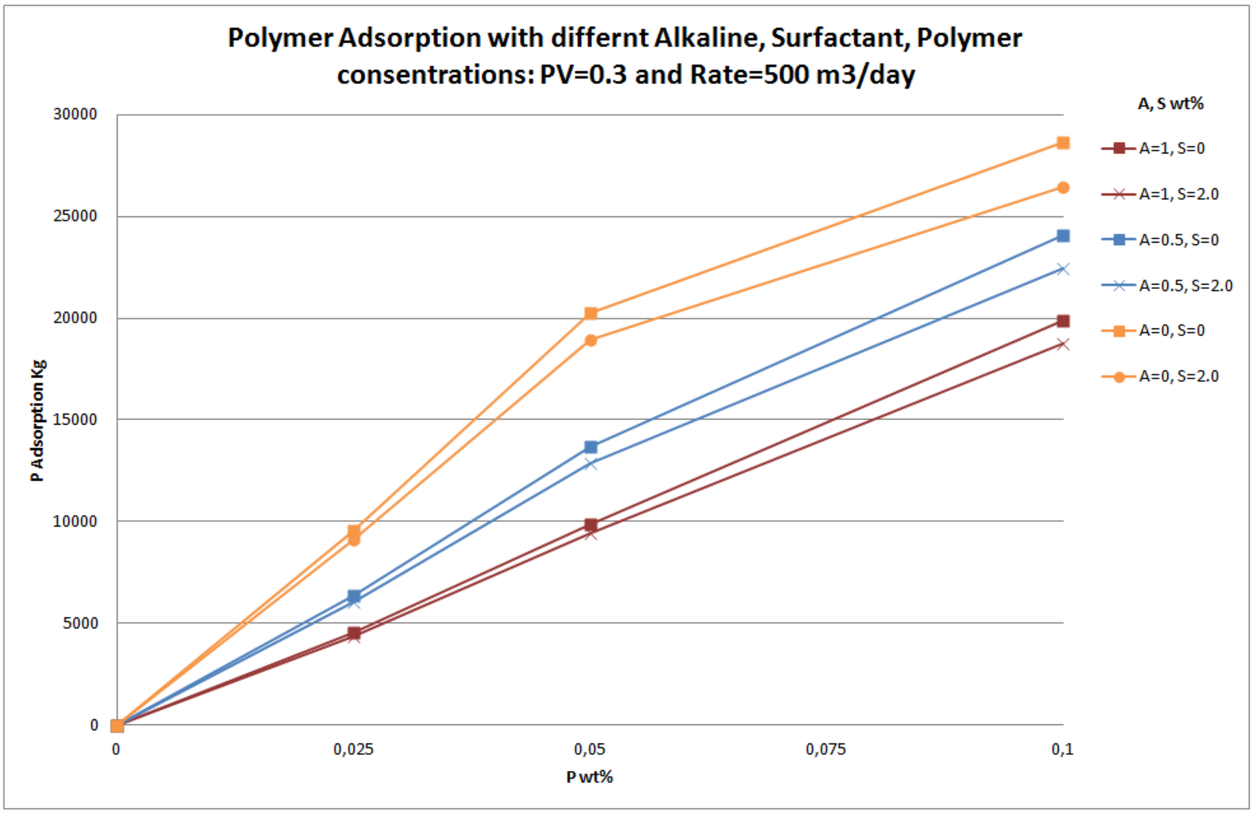


Figure 11.3: Polymer adsorption

Figure 11.3 shows the polymer adsorption with three alkaline and two surfactant concentrations. The rest of the results can be found in Appendix I. It is important to notice that alkaline just prevents polymer to adsorb. Alkaline has no effect on the recovery by reducing IFT. Alkaline of 0.1 wt% had little effect on adsorption of polymer. The polymer adsorption increases almost linear with higher polymer concentrations. The highest adsorption is at 0.1 wt% polymer and 0.0 wt% surfactant with 28651 kg adsorbed. When alkaline is introduced adsorption still increases linearly, but with a lower rate. Surfactant has a minimal effect on decreasing the adsorption of polymer.

11.1.3 Result

The objective of this chapter is to optimize the chemical flooding efficiency to maximize RF per unit mass of chemicals injected. A simple formula was made to find the best cases for each chemical method, see Equation 11-1. The formula does not take into account the cost of the chemical. The results are given in Appendix H. High concentration of polymer and low concentration of surfactant and alkaline is ranked best. One appropriate case for each chemical flooding was based on the results. Polymer concentration of 0.05 wt% is used instead of 0.1 wt% because of high pressures. Each case is tested further for rate and slug size sensitivity. The cases selected are shown in Table 11.1.

Equation 11-1: Rank concentrations

$$\text{Rank} = \frac{\text{RF}}{\text{A} + \text{S} + \text{P}}$$

RF	Increased Recovery Factor over waterflooding
A	Alkaline wt%
S	Surfactant wt%
P	Polymer wt%

		Wt %		
		A	S	P
Case:	#			
Basecase	-			
S	1		0.5	
P	2			0.025
SP	3		0.1	0.05
AS	4	0.1	0.5	
ASP	5	0.1	0.1	0.05

Table 11.1: Chemical concentrations

11.2 Slug Size

The concentrations are tested with slug sizes of 0.1 PV, 0.3 PV, 0.6 PV and continuous injection. With an injection rate of 500 Sm^3/d the injection times will be approximately 16, 48, 96 and 156 months. Table 11.2 shows that a slug size of 0.3 PV and 0.6 PV works best. With Smaller slug sizes the chemicals influence on the reservoir is diminishing. Continuous slug contributes to higher recovery but the cost will be too high.

		Wt %			**PV**			
		A	S	P	0.1	0.3	0.6	Continuous
Case:	#				Increase in RF			
Basecase	-				64 %			
S	1		0.5		0,3 %	1,1 %	1,8 %	2,0 %
P	2			0.025	1,1 %	2,9 %	4,5 %	5,0 %
SP	3		0.1	0.05	1,9 %	5,2 %	8,3 %	9,3 %
AS	4	0.1	0.5		0,3 %	1,1 %	1,9 %	2,0 %
ASP	5	0.1	0.1	0.05	2,0 %	5,2 %	8,4 %	9,4 %

Table 11.2: Increase in RF with changing slug size

11.3 Result

Eclipse can be used to model increased oil recovery by reducing IFT and increase sweep efficiency. Analyse have given good indications on how chemicals can be applied on the Norne C-Segment. It is not certain that chemicals in the Norne C-Segment will perform as in the synthetic model. The different chemicals methods and the effect on the production profile are plotted in Figure 11.4.

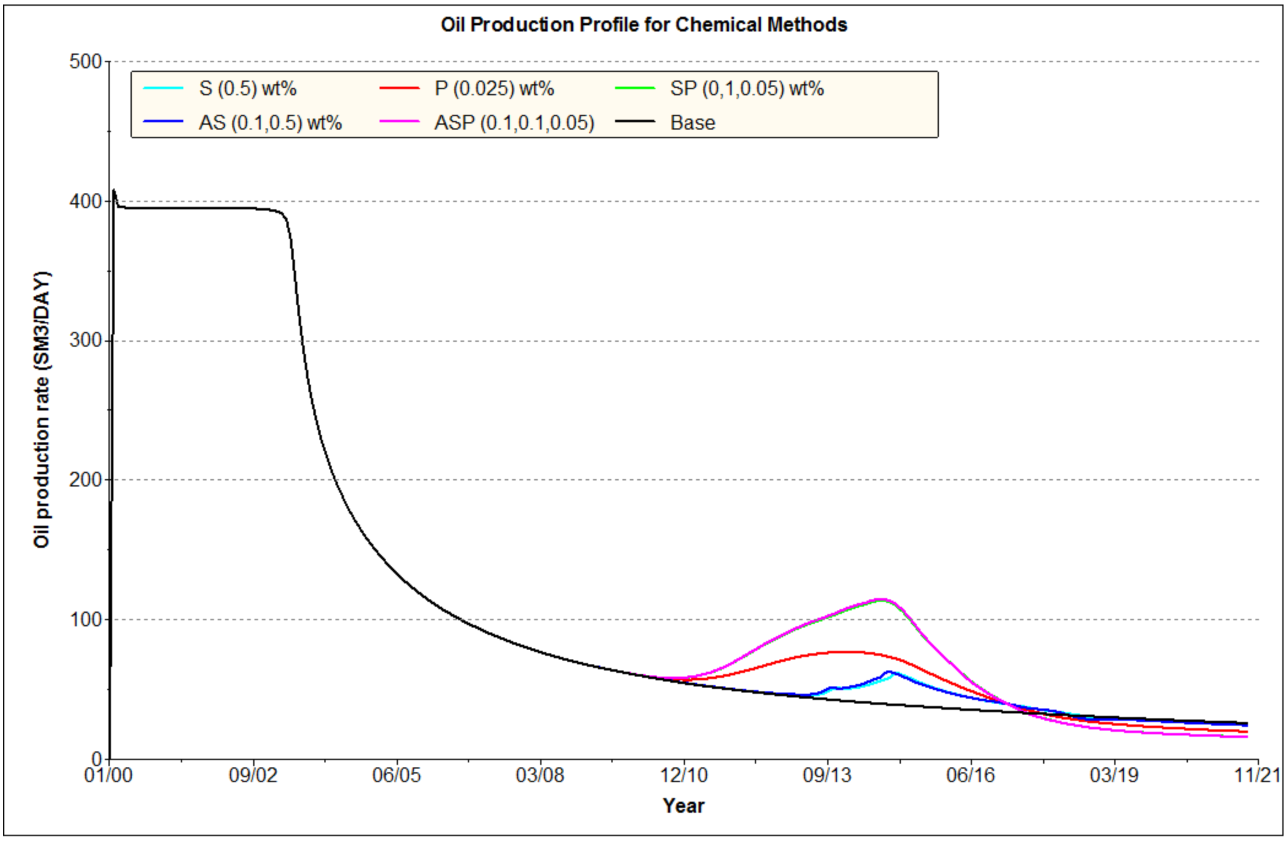


Figure 11.4: Incremental oil chemical Flooding

12 Injection Strategy

The Norne C-segment had 3 injectors and 5 producers still open in the end of 2006, listed in Figure 9.1. The injection wells will be perforated only in the target formation Ile. Injection in the water zone will lower the concentration and chemicals will be lost. C-2H is the only well not completed in the Ile layer and will be completed in layer 5-10, see Table 6.3 . New perforations for C-2H are made based on C-3H perforations in the Ile formation. All the producers are perforated in the target formation Ile and will not be altered. The goal is to find the injection well contributing to the largest increase in incremental oil by chemical injection. The injection rate is 10000 Sm^3/day with a chemical slug of 2 years representing PV 0.1 for each injector. The chemical flooding method is ASP.

Results are shown in Table 12.1. Some of the wells are producing less oil due to higher production from other wells. The injection well will be chosen by total incremental oil. C-2H turns out as the best injector to use with chemical flooding on the Norne C-Segment. Using only C-2H will give an increment of 0.658 MSm^3 oil over waterflooding. The reason is the location and reservoir properties. C-2H is located away from major faults and has a displacement area reaching 4 out of 5 producers still active. The chemicals sweep pattern in the Ile layers are seen in Figure 12.2. The flooding pattern is 1 year and 1 month after injection of the chemicals has stopped. Red lines represent faults reducing the sweep from C-1H and C-3H. Each well is given the same colour as in Figure 12.1. Most of the incremental oil comes from B-2H and D-2H.

Incremental Oil per Producer (m3)					
Slug=2 year	**Injection Wells**				
Production Wells	Basecase	C-1H	C-2H	C-3H	ALL
B-2H	1,42E+07	1,60E+05	3,76E+05	1,70E+04	5,77E+05
D-2H	1,09E+07	-2,05E+03	1,62E+05	6,83E+04	2,32E+05
D-1CH	4,08E+06	-4,53E+03	7,61E+04	-5,97E+04	8,93E+02
B-4DH	1,46E+06	-2,41E+03	5,59E+04	-9,38E+02	4,39E+04
K-3H	8,43E+05	-3,86E+03	-1,28E+04	2,54E+04	1,62E+04
Total Incremental OiL	-	1,47E+05	6,58E+05	5,02E+04	8,70E+05

Table 12.1: Ranking of the injection wells

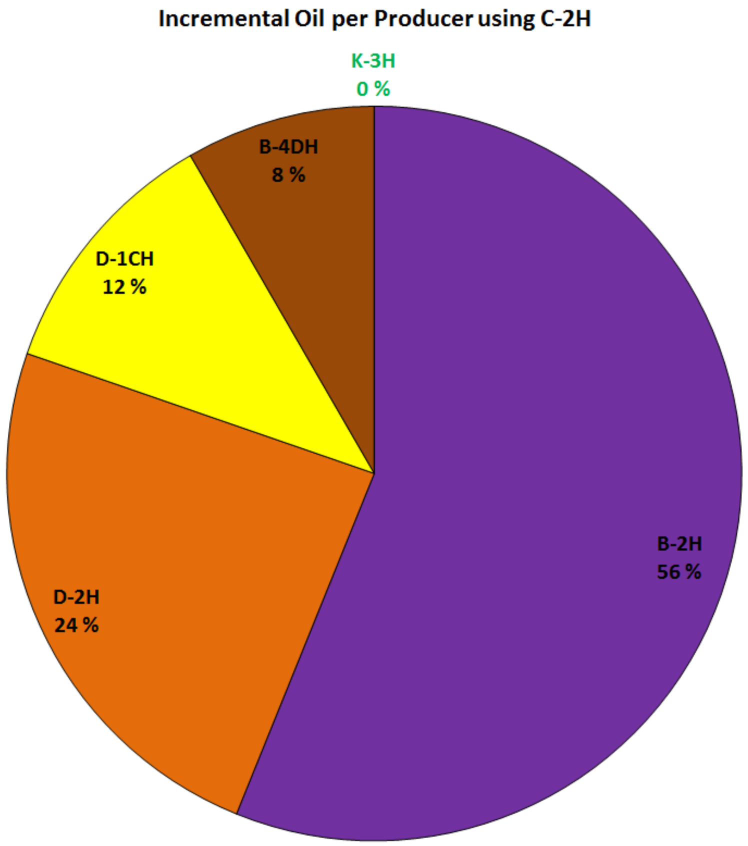


Figure 12.1: Incremental oil per producer using C-2H

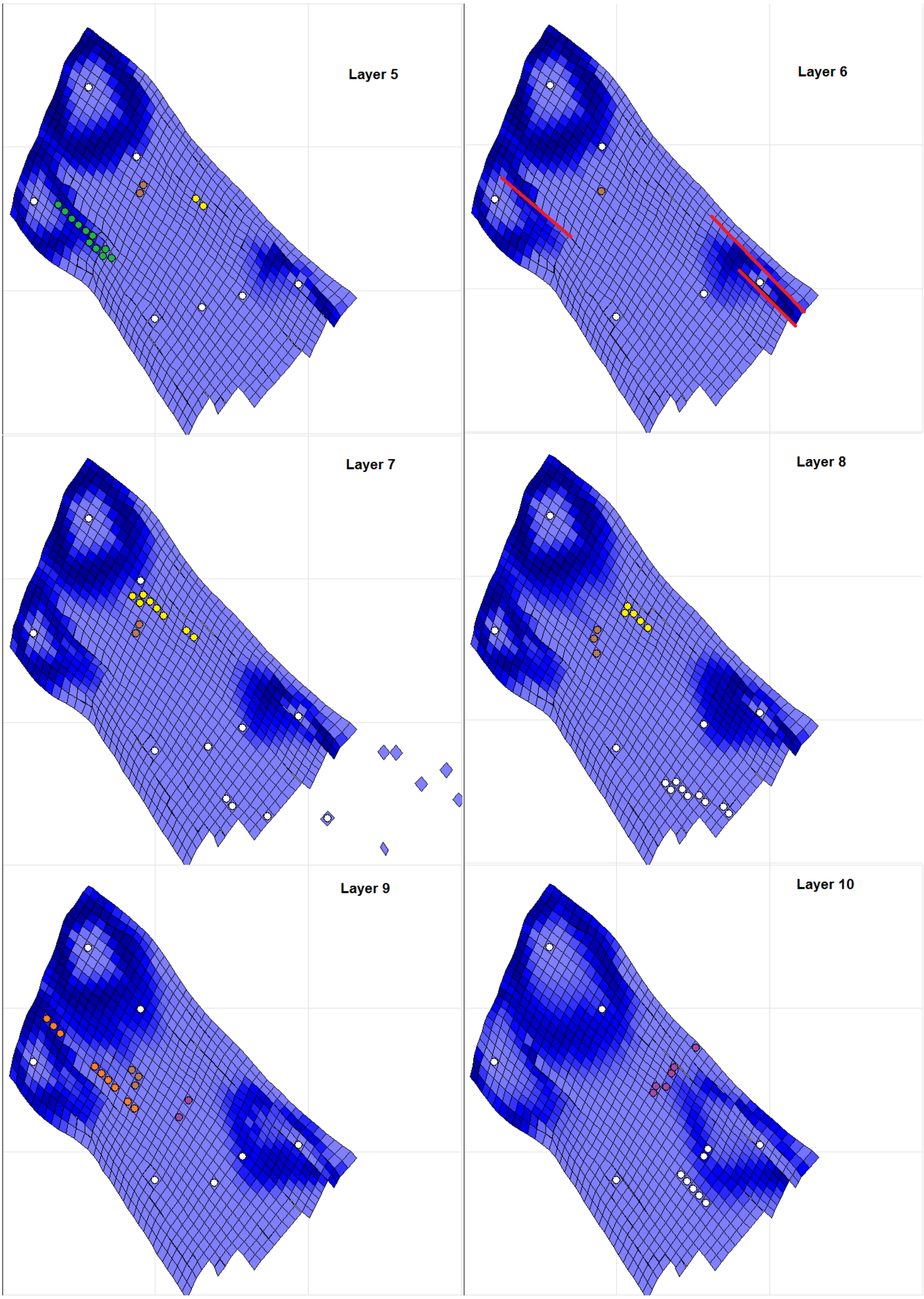


Figure 12.2: Injection pattern 1.02.2010

13 Net Present Value Calculations

NPV will tell us the attractiveness of the EOR method. The technique assists in selecting the best option for chemical flooding on the Norne C-Segment. The model incorporates the timing of cash flows, to account for the effect of the time value of money (Jahn, Cook, & Graham, 2008).

Equation 13-1

$$NPV = \sum_{t=0}^{t-n} \frac{C_t}{(1+r)^t}$$

t Time

r Discount rate

C_t Cash flow in time t

When calculating the value of a chemical flood no capital expenditure, operating expenditure or government take will be taken into account. Additional facility or operating cost for the chemicals will not be considered. The NPV of the project will be calculated from incremental oil over waterflood. A project is successful if the NPV is positive. Table 13.1 provides the discount rate, oil price and chemical prices. The oil price is based on (ycharts.com, 2012) and the chemical prices are given by Kristian Sandengen from Statoil (Sandengen, 2012). The price includes freight offshore. The uncertainties in prices are handled by establishing a base case and then investigating the impact of varying the values of key inputs in a sensitivity analysis as low- and high case.

Case	**Oil Price**	**Alkaline**	**Surfactant**	**Polymer**	**Discount rate**
Low	80	1.3	9.5	7.5	0.09
Base	95	1.0	7	5	0.08
High	110	0.7	5.0	3.0	0.07

Table 13.1: Oil and chemical prices

14 EOR Potential Norne C-segment

The objective is to optimize the chemical flooding efficiency to maximise the volume of incremental oil and NPV. The recovery factor for the Ile formation is 58% in the end of 2022 with only waterflooding. In Chapter 12 two appropriate slug sizes and an optimum concentration for each chemical method were found. Analyses from the synthetic model have given good indications on how chemicals will perform in the Norne C-Segment, but the reservoir is highly complex and therefore other appropriate cases will be tested. All the cases will be compared in order to see which is the most suitable and profitable method in terms of NPV. The case with best NPV will be tested for sensitivity in oil price, chemical price and discount rate. Injection will start 01.01.2007 for each scenario and a rate of 10 000 Sm^3/day is used. Injection interval of 2 and 4 years representing PV=0.1 and PV=0.2 is tested for polymer and surfactant flooding. From the foregoing results in Chapter 13 the injection well is C-2H. The chemical methods are compared to a waterflooding case with same injection rate and perforations.

Polymer:

- **Case 1.1: PV=0.1 Polymer 0.025 wt%**
- Case 1.2: PV=0.1 Polymer 0.05 wt%
- Case 2.1: PV=0.2 Polymer 0.025 wt%
- Case 2.2: PV=0.2 Polymer 0.05 wt%

Surfactant:

- **Case 3.1: PV=0.1 Surfactant 0.5 wt%**
- Case 3.2: PV=0.1 Surfactant 1.0 wt%
- Case 4.1: PV=0.2 Surfactant 0.5 wt%
- Case 4.2: PV=0.2 Surfactant 1.0 wt%

SP:

- **Case 5: PV=0.1 Surfactant 0.1 wt%, Polymer 0.05 wt%**
- Case 6: PV=0.1 Surfactant 0.5 wt%, Polymer 0.05 wt%
- Case 7: PV=0.1 Surfactant 1.0 wt%, Polymer 0.05 wt%

AS:

- **Case 8: PV=0.1 Alkaline 0.1 wt%, Surfactant 0.5 wt%**
- Case 9: PV=0.1 Alkaline 0.5 wt%, Surfactant 0.5 wt%
- Case 10: PV=0.1 Alkaline 1.0 wt%, Surfactant 0.5 wt%

ASP:

- **Case 11: PV=0.1 Alkaline 0.1 wt%, Surfactant 0.1 wt%, Polymer 0.05 wt%**
- Case 12: PV=0.1 Alkaline 0.5 wt%, Surfactant 0.5 wt%, Polymer 0.05 wt%
- Case 13: PV=0.1 Alkaline 0.5 wt%, Surfactant 1.0 wt%, Polymer 0.05 wt%

14.1 Polymer Flooding

Polymers are used as a mobility control to improve reservoir contact and flood efficiency. Waterflood as a secondary recovery results in a poor and incomplete sweep of the reservoir. The water-soluble polymers have two effects on the waterflood. Firstly it increases the water viscosity. Secondly, the rock permeability to water is reduced after passage of a polymer solution through the rock material. Both effects will cause a lower mobility ratio. This scenario involves four cases with combinations of two different concentrations and slug sizes. They will be compared by incremental oil and NPV. Case 1.1 and Case 2.1 have the optimum concentration found in the synthetic model.

- Case 1.1: PV=0.1 Polymer 0.025 wt%
- Case 1.2: PV=0.1 Polymer 0.05 wt%
- Case 2.1: PV=0.2 Polymer 0.025 wt%
- Case 2.2: PV=0.2 Polymer 0.05 wt%

Incremental oil for each case is plotted in Figure 14.1. Incremental oil is produced when injection starts due to lowering the mobility ratio. Case 1.2 and Case 2.2 have a more rapid increase in incremental oil because of higher concentrations. Case 1.2 ends with a total incremental oil of 6.25E+05 Sm^3 while Case 2.2 with larger slug ends with a total incremental oil of 1.09E+06 Sm^3. Case 1.1 and Case 2.1 ends at a incremental oil recovery of 3.33+05 Sm^3 and 5.73E+05 Sm^3. Case 2.2 with a higher incremental oil because of larger slug size. Comparing Case 1.2 and Case 2.1 shows that higher concentration is better than a larger slug size. The same amount of chemicals is used but higher concentration is more effective. Case 2.2 has the highest increase in RF of 2.2 %.

NPV where calculated for the four cases, see Appendix K. Polymer price was 5 USD/kg and oil price 95 USD/bbl. All the cases have positive NPV. Case 2.2, despite high cost due to large amount of polymer used, has the highest NPV of 406 million USD. The lowest NPV is for Case 1.1 with a NPV of 154 million USD.

Measures to improve polymer flooding are adding surfactant and alkaline. Surfactant to reduce the IFT capturing residual oil and alkaline to promote IFT reduction with surfactant and reduce polymer adsorption.

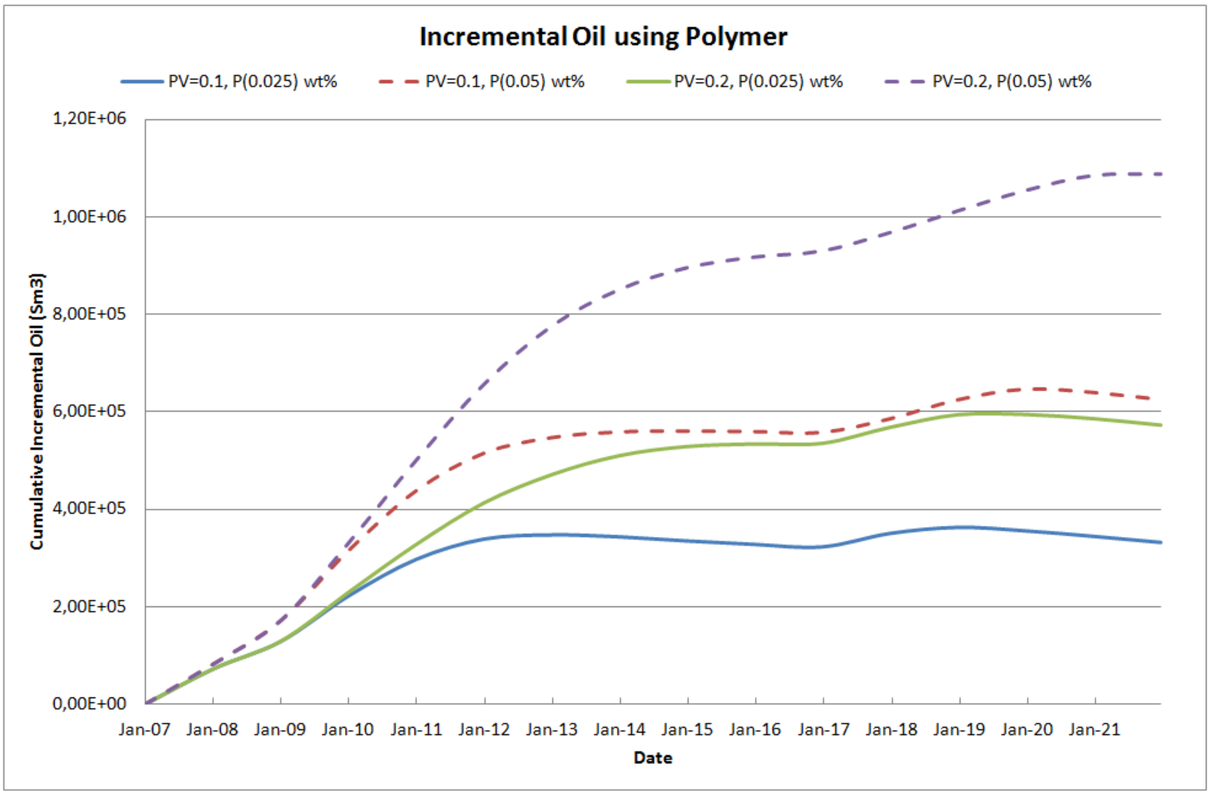


Figure 14.1: Incremental oil using polymer

14.2 Surfactant Flooding

The aim of surfactant flooding is to recover the capillary-trapped residual oil after waterflooding. The residual oil can be mobilized through a strong reduction in the IFT between oil and water. The ultimate residual oil saturation will be determined by the IFT between oil and surfactant solution behind the oil bank. This scenario involves four cases with combinations of two different concentrations and slug sizes. They will be compared by incremental oil and NPV. Case 3.1 and Case 4.1 have the optimum concentration found in the synthetic model.

- Case 3.1: PV=0.1 Surfactant 0.5 wt%
- Case 3.2: PV=0.1 Surfactant 1.0 wt%
- Case 4.1: PV=0.2 Surfactant 0.5 wt%
- Case 4.2: PV=0.2 Surfactant 1.0 wt%

Incremental oil for each case is plotted in Figure 14.2. Incremental oil is produced immediately after the injection starts in 2007 for all cases due to mobilization of residual oil. Case 3.2 and Case 4.2 have a more rapid increase in incremental oil because of higher concentrations. Case 3.2 ends with a total incremental oil of 7.94E+04 Sm^3 while Case 4.2 with larger slug ends with almost a doubling of total incremental oil of 1.58E+05 Sm^3. Case 3.1 and Case 4.1 ends at a incremental oil recovery of 3.52E+04 Sm^3 and 7.35+04 Sm^3. Comparing Case 3.1 and Case 4.1 shows that higher concentration is better than a larger slug size. The same amount of chemicals is used but higher concentration is more effective in the end. Case 4.2 has the highest increase in RF of 0.3 %. Figure 14.3 and Figure 14.4 shows the total adsorption and production rate of surfactants. Higher concentrations and slug sizes contributes to more adsorption and production. Case 4.2 stand out with over a doubling of produced surfactants compared to Case 3.2 and Case 4.1.

NPV where calculated for the four cases, see Appendix K. Surfactant price was 7 USD/kg and oil price 95 USD/bbl. All the cases have a negative NPV value. Surfactants alone cannot produce enough incremental oil to pay of the cost of chemicals. The more chemicals used the lower NPV. The highest NPV is for Case 3.1 with a loss of -210 million USD and the lowest for Case 4.2 with a NPV of -781 million USD.

Measures to improve surfactant flooding are adding polymer and alkaline. A low mobility ratio between the surfactant slug and the oil bank and water flowing ahead, would require the use of polymer (SP). Alkaline chemicals will promote IFT reduction and reduce surfactant adsorption.

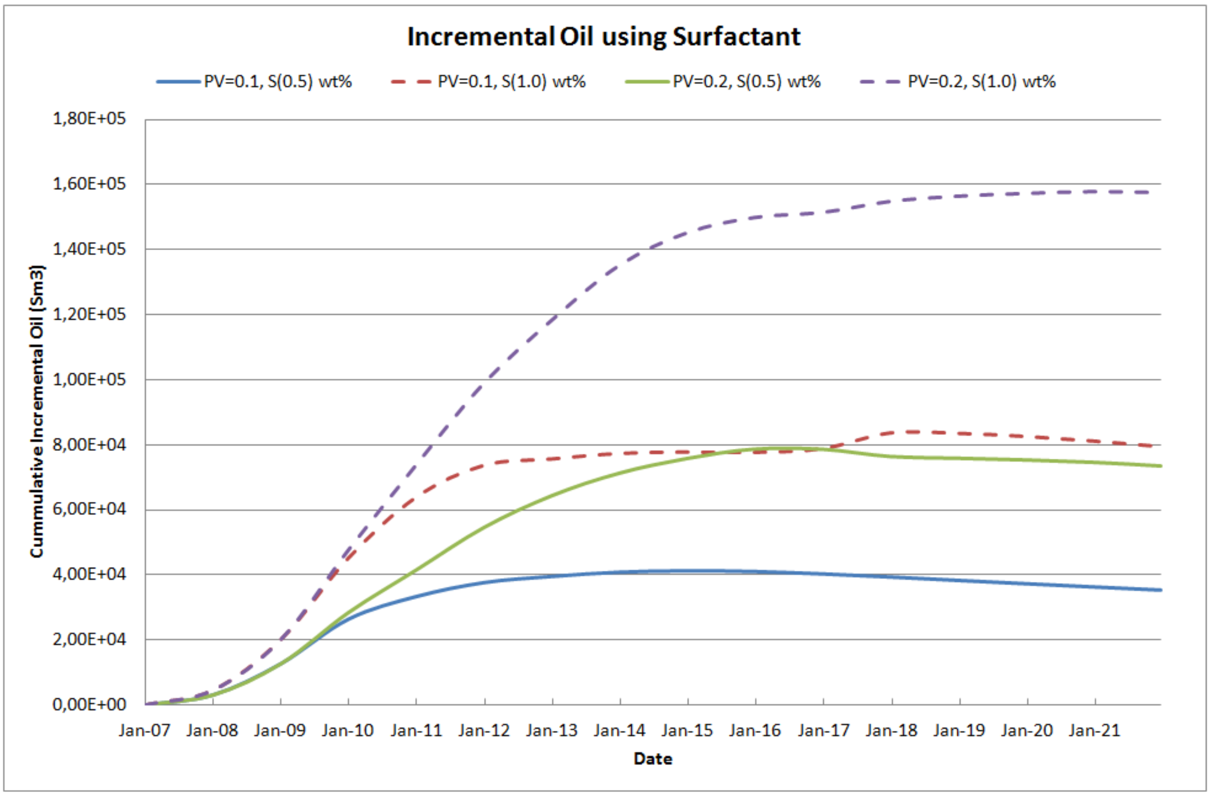


Figure 14.2: Incremental oil using surfactant

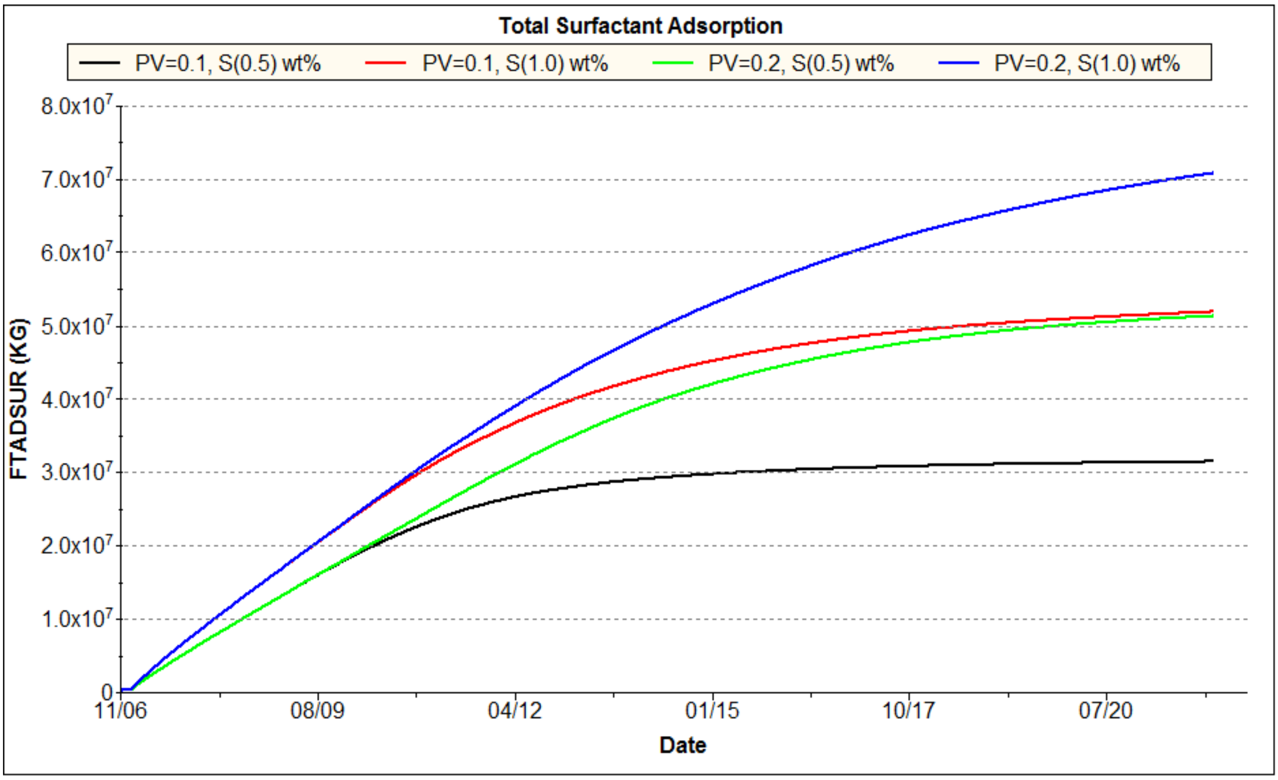


Figure 14.3: Total surfactant adsorption

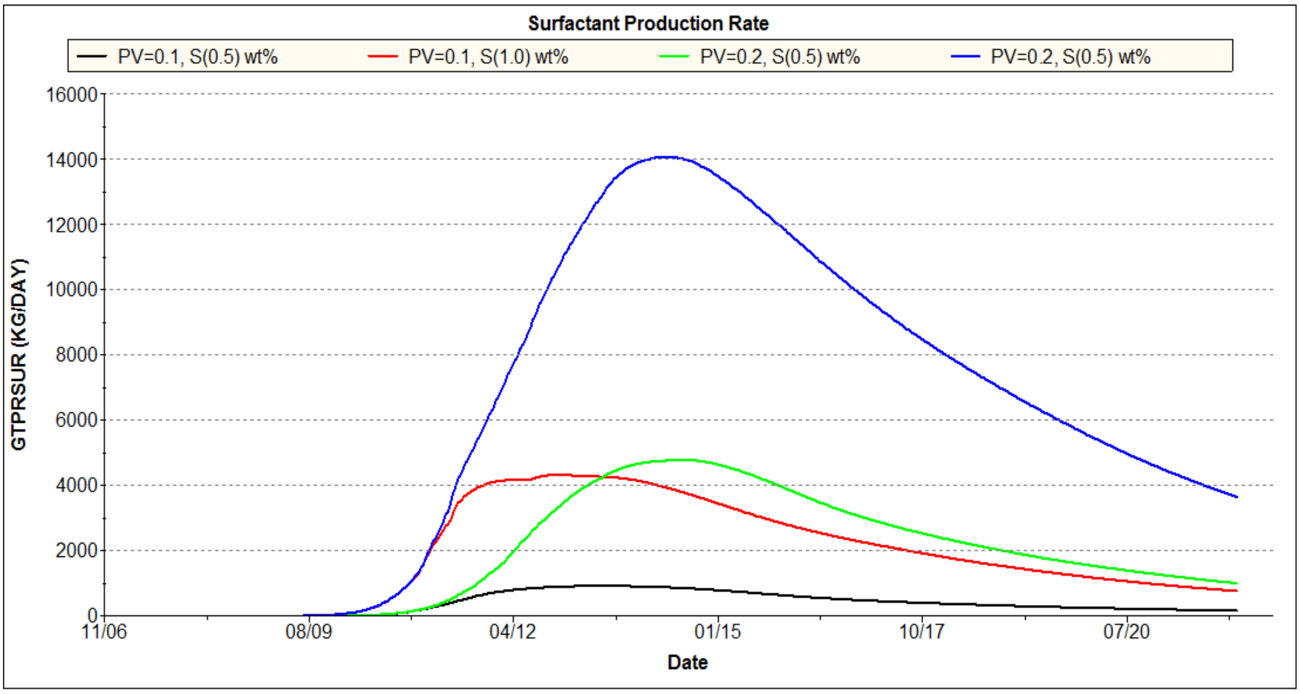


Figure 14.4: Total surfactant production

14.3 Surfactant-Polymer Flooding

The combination of surfactant and polymer is the most used combination of chemicals. Mobility ratio is of great concern using surfactants. Polymers are used as a mobility control to improve reservoir contact and flood efficiency. Surfactants reduce the oil-water IFT and minimize the capillary forces that trap residual oil after waterflooding. The following scenario involves three cases. Case 5 was found to be the best SP scenario from the synthetic model. The two other cases are tested to see the effect of higher concentrations of surfactant in SP flooding. Polymer flooding is plotted to see the improvements. They will be compared by incremental oil and NPV.

- **Case 5: PV=0.1 Surfactant 0.1 wt%, Polymer 0.05 wt%**
- Case 6: PV=0.1 Surfactant 0.5 wt%, Polymer 0.05 wt%
- Case 7: PV=0.1 Surfactant 1.0 wt%, Polymer 0.05 wt%

Incremental oil for each case is plotted in Figure 14.5. All cases in the scenario start immediately to produce incremental oil. All cases follow the polymer flooding until 2010. At this point a large enough amount of residual oil is mobilized to increase incremental oil over polymer flooding. From 2010 towards 2022 more and more residual oil is mobilised and produced. Case 5 have minimal incremental oil over polymer flooding due to low surfactant concentration. Case 6 and Case 7 mobilizes residual oil and higher incremental oil is achieved. The difference between Case 5 and Case 6 are a doubling of the concentration from 0.5 wt% to 1.0 wt%. Case 6 produces 6.50E+05 Sm^3 and has a increase over polymer flooding of 2.53E+04 Sm^3. Case 7 produces 7.03E+05 Sm^3 and has a larger increase over polymer flooding of 7.79E+04 Sm^3. Case 7 achieve the highest RF of 1.4 %.

NPV where calculated for the three cases, see Appendix K. Polymer flooding has a better NPV than all the SP cases. Surfactant cannot mobilize enough oil to make it profitable. This means that Case 5, with lowest surfactant concentration, has the best result of NPV of 217 Million USD. The worst case in NPV is Case 7 with a negative NPV of -172 million USD.

A way to improve SP flooding is by adding alkaline to promote IFT reduction with surfactant and reduce polymer and surfactant adsorption.

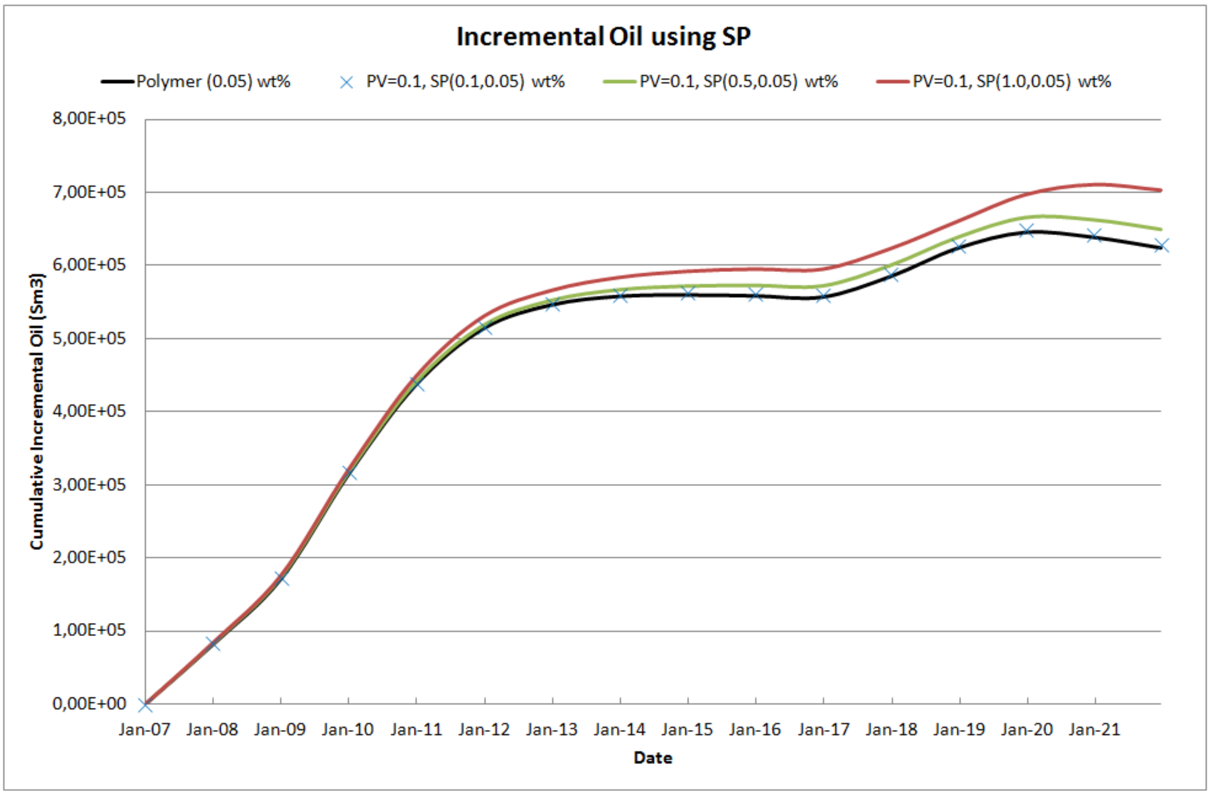


Figure 14.5: Incremental oil using SP

14.4 Alkaline-Surfactant Flooding

Alkaline flooding improves the oil recovery by one or more of the following mechanisms: emulsification and entrainment, wettability reversal (oil-wet to water-wet), wettability reversal (water-wet to oil-wet) and emulsification and entrapment. These mechanisms result from the formation of surfactants as the alkaline chemicals neutralize petroleum acids in situ. The alkaline model in Eclipse does not take into account the in situ surfactant creation and the phase behaviour. The model provides the effect of alkaline on the water-oil surface tension and adsorption reduction of surfactant, see Appendix C. This scenario involves three cases. The first case was found to be the best AS scenario from the synthetic model. The two other cases are tested to see the effect of higher concentrations of alkaline in AS flooding. Surfactant flooding is plotted to see the improvements. They will be compared by incremental oil and NPV.

- **Case 8: PV=0.1 Alkaline 0.1 wt%, Surfactant 0.5 wt%**
- Case 9: PV=0.1 Alkaline 0.5 wt%, Surfactant 0.5 wt%
- Case 10: PV=0.1 Alkaline 1.0 wt%, Surfactant 0.5 wt%

Incremental oil for each case is plotted in Figure 14.6. All cases in the scenario start immediately to produce incremental oil over waterflooding. AS flooding produce less incremental oil than surfactant in the start. Higher concentration of alkaline, results in less incremental oil produced. In 2011 Case 8 and Case 9 starts to produce incremental oil over surfactant while Case 10 starts in 2013. At these points a large enough amount of extra residual oil is mobilized due to lower capillary number and reduction in adsorption due to alkaline. Case 9 and Case 10 have approximately the same incremental oil over surfactant flooding in 2016 but Case 10 decreases towards 2022. The best case is Case 9 with incremental oil over surfactant flooding of 2.05E+03 Sm^3 and 3.72E+04 Sm^3 over waterflooding. Case 8 and Case 10 ends up with an incremental oil over waterflooding of 3.61E+04 Sm^3 and 3.42E+04 Sm^3. Case 9 has an increase in RF of 0.1 %. Figure 14.7 and Figure 14.8 shows the surfactant total adsorption and production rate. The higher the alkaline concentration, the less surfactants are adsorbed, but more is produced.

NPV where calculated for the three cases, see Appendix K. Because of alkaline had little effect the NPV curves are negative. Alkaline cannot contribute with enough reduction in IFT or reduction in adsorption to make it profitable. The best result is Case 8 with the lowest alkaline concentration with a NPV of -216 Million USD. Case 10 is the worst with a NPV of -275 Million USD.

Measure to improve AS flooding is adding polymer. A low mobility ratio between the AS slug and the oil bank and water flowing ahead, would require the use of polymer (ASP).

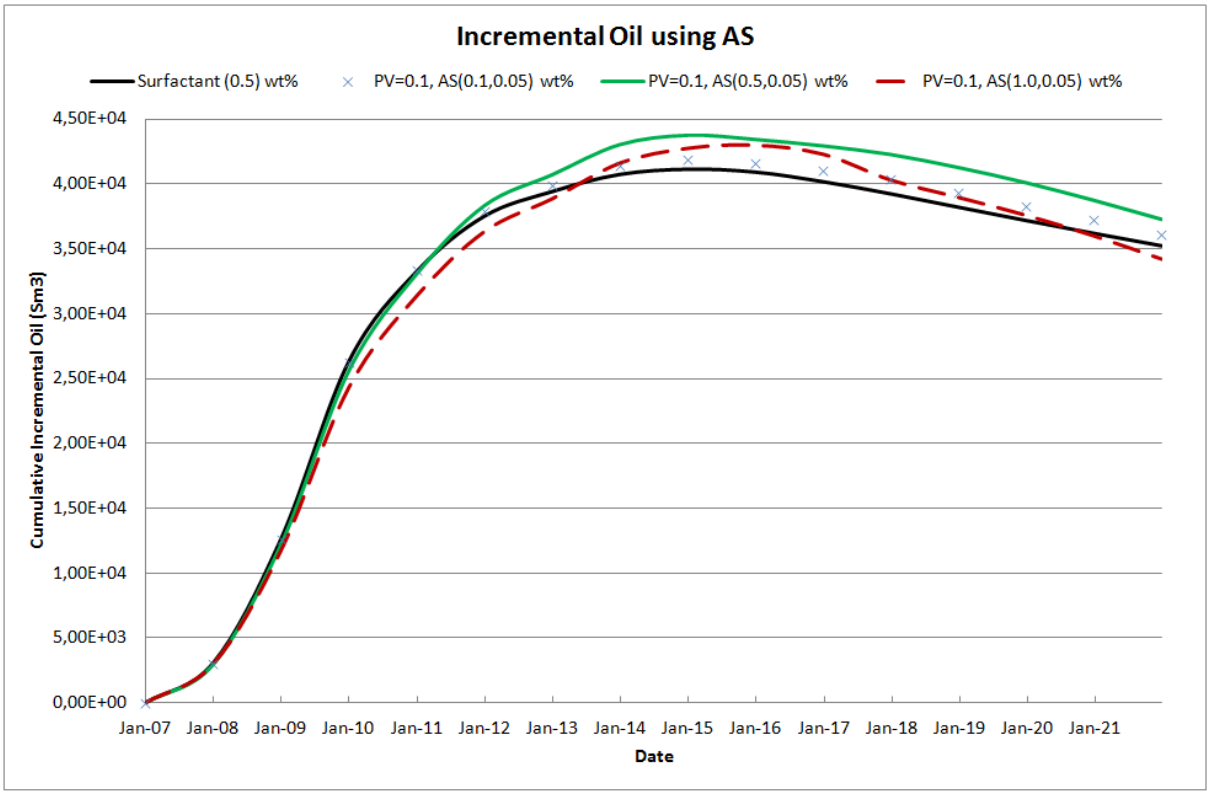


Figure 14.6: Incremental oil using AS

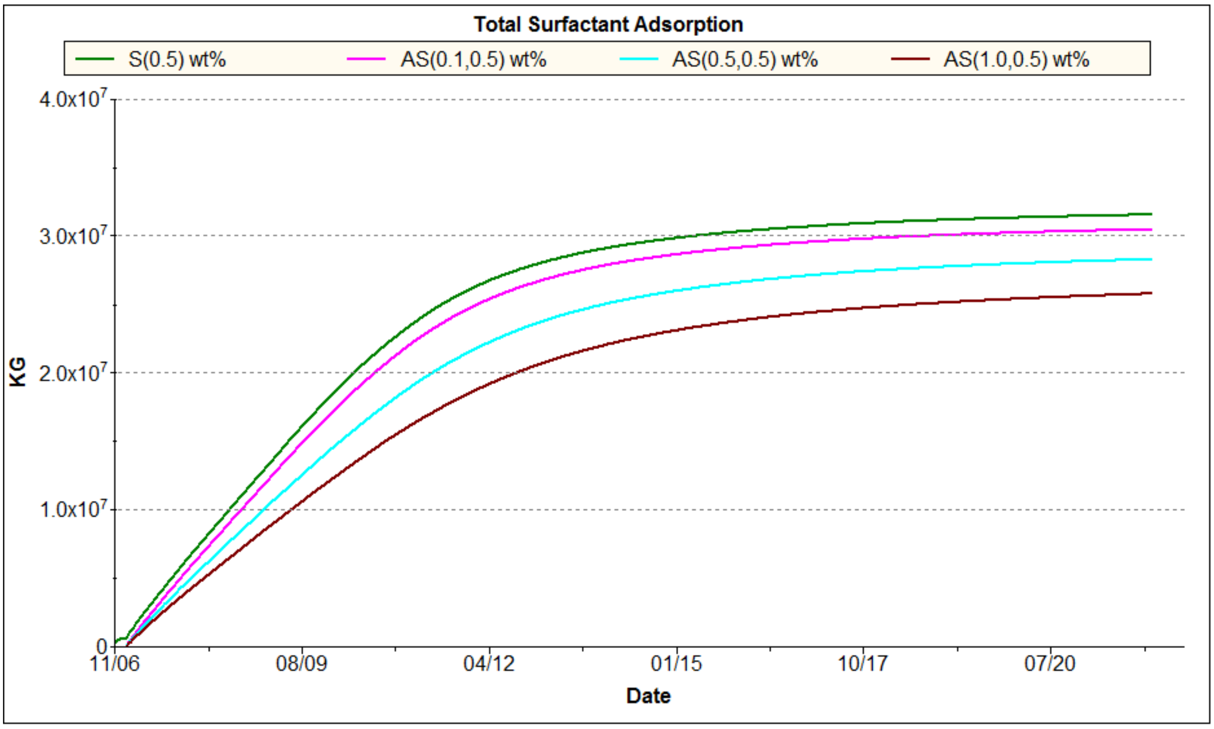


Figure 14.7: Total surfactant adsorption

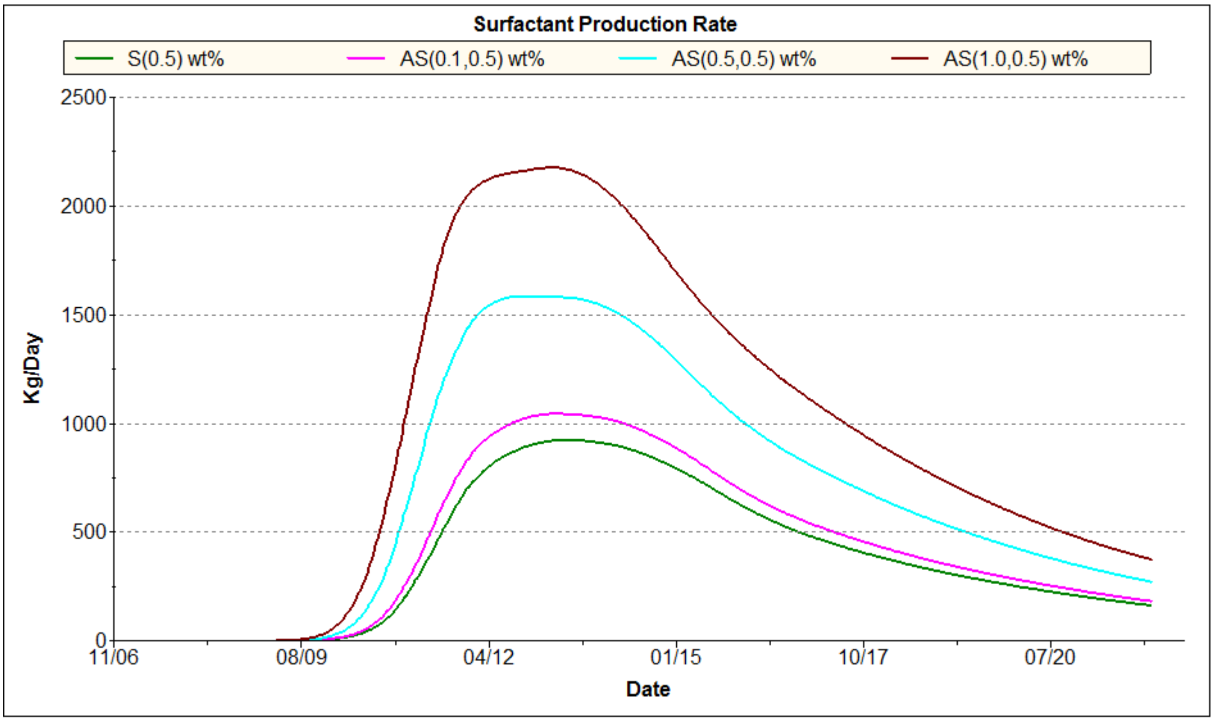


Figure 14.8: Surfactant production rate

14.5 Alkaline-Surfactant-Polymer Flooding

The state of the art technique uses alkaline, surfactants and polymer simultaneously. The ASP flood benefits from all the three flooding methods. Polymer increasing the sweep efficiency, surfactants reducing the IFT and alkaline promotes surfactant IFT reduction and lowers the adsorption of polymer and surfactants. This scenario involves three cases. The first case was found to be the best ASP scenario from the synthetic model. The two other cases are tested to see the effect of higher concentrations of surfactant and alkaline in ASP flooding. Polymer flooding is plotted to see the improvements. They will be compared by incremental oil and NPV.

- **Case 11: PV=0.1 Alkaline 0.1 wt%, Surfactant 0.1 wt%, Polymer 0.05 wt%**
- Case 12: PV=0.1 Alkaline 0.5 wt%, Surfactant 0.5 wt%, Polymer 0.05 wt%
- Case 13: PV=0.1 Alkaline 0.5 wt%, Surfactant 1.0 wt%, Polymer 0.05 wt%

Incremental oil for each case is plotted in Figure 14.9. All cases in the scenario start immediately to produce incremental oil over waterflooding. The effect of alkaline and surfactant is seen in 2010. At this point a large enough amount of extra residual oil is mobilized due to lower capillary number to increase incremental oil. From 2011 towards 2022 more and more residual oil is mobilised and produced. Surfactant is the key chemical for incremental oil over polymer flooding, while alkaline contribution is small. The difference between Case 12 and Case 13 are a doubling of the surfactant concentration from 0.5 wt% to 1.0 wt%. Case 12 produces 6.61E+05 Sm^3 and has an increase over polymer flooding of 3.63E+04 Sm^3 and a increase of 1.09E+04 Sm^3 over SP. Case 13 produces 7.31E+05 Sm^3 and has a larger increase over polymer flooding of 8.84E+04 Sm^3 and an increase over SP with 1.06E+04 Sm^3. Case 13 has an increase in RF by 1.4%.

NPV where calculated for the three cases, see Appendix K. Surfactant and alkaline cannot produce enough incremental oil to pay of the cost using them. The more alkaline or surfactant used the lower NPV. Case 11 has the best NPV of 210 million USD. The worst NPV is for Case 13 with a negative NPV of -202 million USD.

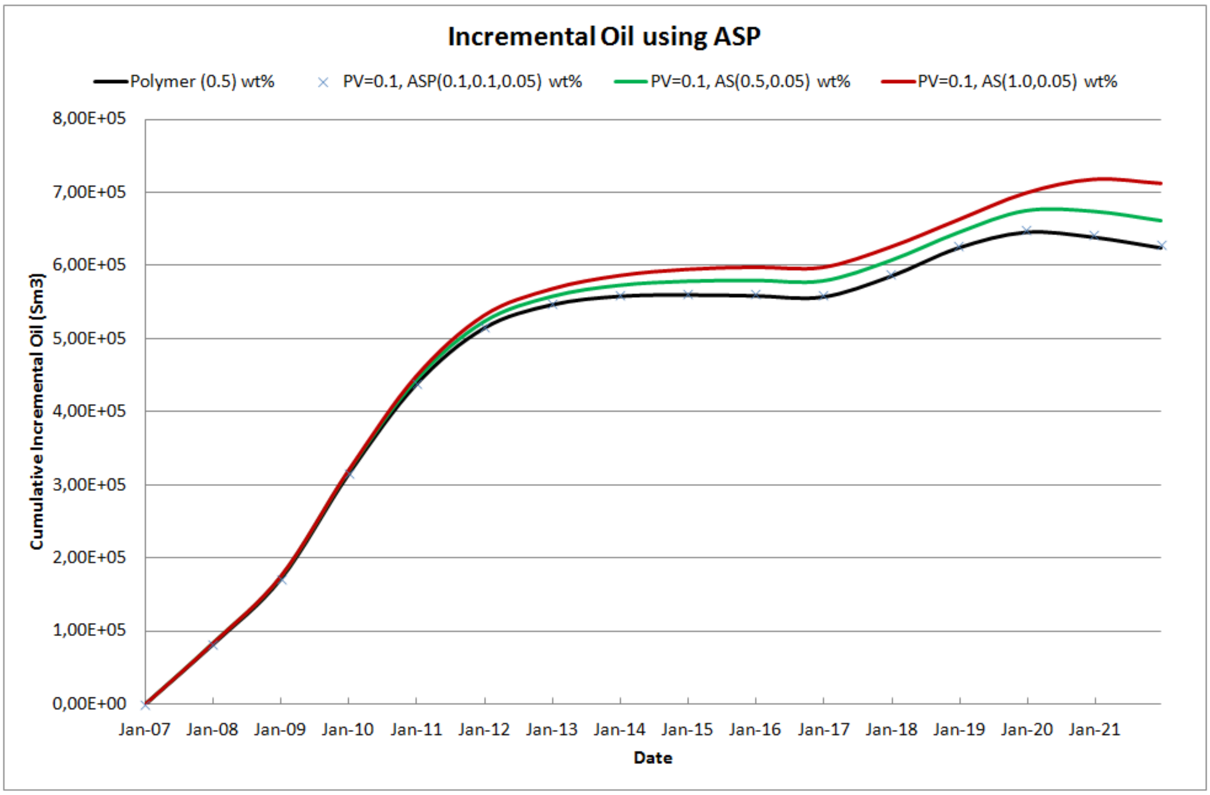


Figure 14.9: Incremental oil using ASP

14.6 Optimum Chemical Method

A comparison of the best NPV for each chemical flooding with a slug size of 0.1 PV are plotted in Figure 14.10. Comparing the results shows that polymer flooding Case 1.2 has the highest NPV of 261 million USD. The concentration is 0.05 wt% polymer. The NPV of SP Case 5 and ASP Case 11 achieve a lower NPV because of additional chemicals. Surfactant Case 3.1 and AS Case 8 have a negative NPV. Surfactant and alkaline cannot produce enough incremental oil to pay of the cost of chemicals.

Polymer has an even higher NPV in Case 2.2 with a PV of 0.2 resulting in a NPV of 406 million USD. This is the optimum case. The production can stop already in 2015 with a result of 360 million USD. Case 2.2 sensitivity to oil- and polymer price and discount rate was tested. The different prices and discount rates are defined in Chapter 14. A low case of Case 2.2 gives a NPV of 308 million USD, while a high case gives 510 million USD. The NPV for all cases are positive.

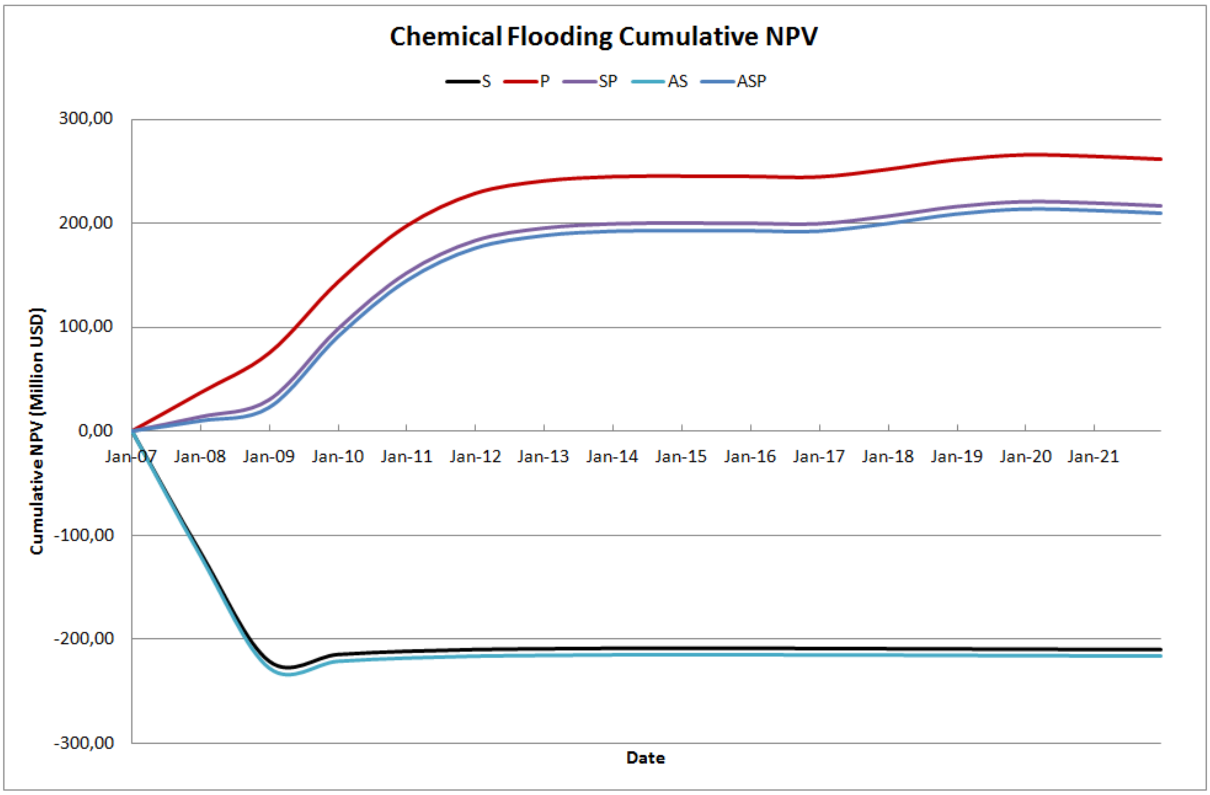


Figure 14.10: Chemical flooding cumulative NPV

15 Discussion and Summary

The Norne field is a good candidate for chemical flooding (Abrahamsen, 2011) with suiting reservoir characteristics and oil properties. The Norne field had an incredible recovery factor of 54% in 2011. Statoil hope to set a world record for the whole Norne field with a recovery factor of 60% before decommissioning (Skagen, 29/2-2012). This goal can be achieved by applying chemicals. Chemical flooding has not been used in the Norwegian Continental Shelf. One of the main reasons is the environmental issues. The NPD, with other companies are now working on impact and risk assessment related to utilization of EOR chemicals in the NCS (FORCE, 2011). The recommended guidelines will answer the issues regarding the environment. It has been recognized as a technically feasible method in the NCS and is expected to become attractive (Awan, Teigland, & Kleppe, 2008). With this in mind chemical flooding has a promising future for the Norwegian continual shelf.

The improvement of an EOR method is evaluated by microscopic and macroscopic displacement efficiency. It should have a favourable mobility ratio and a high capillary number to decrease the oil saturation. Surfactant and alkaline is used to reduce oil-water IFT and minimize the capillary forces that trap residual oil after waterflooding. Polymer is used as a mobility control to improve reservoir contact and flood efficiency. Chemical methods can achieve both a high microscopic and macroscopic displacement and is therefore a good candidate for the Norne field.

15.1 History Matching

A slightly improved model of the Norne C-Segment was made during history match. Due to lack of pressure data and 4D seismic for fluid movements the history matching processes started by guessing. Changes in faults to direct the flooding and field-wide vertical barriers with local openings to control water rises were made with no success. The lack of strategy and use of a complex model made the history matching time-consuming. After consulting with Sindre Lillehaug at Statoil in Harstad, a decision to look only at the vertical barriers was made (Lillehaug, 2012). Sensitive barriers were found in the model and different local vertical barriers were made to find a good match. In the end these barriers were put together making a new model. The alternation in the barriers controlled the water-oil rise and translated the WC curve. To make a better match, other parameters like faults, permeability, relative permeability and critical water saturation should be investigated (Cheng, 2012). The shape of the curves after BT depends on the relative permeability curves, but the BT time depends mainly on the end-points of relative permeability curves. Faults could have been changed to direct the flooding from the injectors and maybe give a better result.

The biggest change in production data between the new- and old model was the WC. The new model had a lower WC than the old model through the whole field life, except after 2006. The new model had slightly better overall match of the wells, that were still open in 2006, and was therefore used for chemical flooding. The changes done are consistent with a comprehensive and rational description of the reservoir. The history matching process contributed to an understanding of the current status on the reservoir, including fluid distribution and fluid movement and verified the current depletion mechanisms.

15.2 Selection of Injection Well

C-2H turns out as the best injector to use with chemical flooding on the Norne C-Segment. The reason is the location and reservoir properties. The C-2H is located away from major faults and has a displacement area reaching 4 out of 5 producers that are still active. The barrier in layer 8 reduces the gravity segregation, while the barrier in Layer 11 contributes to a better sweep in layer 10. C-2H produces incremental oil from B-2H, D-2H, D-1CH and B-4DH. The vertical sweep is affected by gravity segregation due to density differences in the injected fluid and oil. The areal sweep is therefore highest in the lower layers 9-10. Layer 10 is a high permeability layer enhancing the effect of gravity segregation. This is probably why chemical flooding produces most incremental oil from B-2H and D-2H.

C-1H produces only incremental oil with producer B-2H. C-1H areal sweep is broken because of the nearby faults. The chemicals slug follows the faults towards the producers making an unstable front and a poor sweep is achieved at BT. Other wells are to far away to contribute to higher incremental oil. The slug tends to move towards the closed well D-4H and B-1H in the x-direction, making it even more difficult to reach other producers.

C-3H produces incremental oil from B-2H, D-2H and K-3H. The injected chemicals reach only 3 of the perforations of D-2H in layer 9 because of the fault along the x axis. Therefore low incremental oil is produced with D-2H. K-3H and D-2H are too close to the injector to achieve large production of incremental oil. Both wells start to produce chemicals imminently after injection. Other wells are not reached because of the fault blocking areal sweep, exception is well B-2H because of high permeability layer and gravity segregation.

15.3 Applying Chemicals on Norne

Before applying chemicals on the Norne C-Segment a synthetic model was build with properties from the target formation Ile. Firstly it was used to determine if the chemical models in Eclipse can simulate increased oil recovery by reducing IFT and increase sweep efficiency. Secondly, it was used to optimization of the chemical injection scheme. Norne C-Segment is complex and simulations are time consuming. With a synthetic model more chemical concentrations could be tested and a small model is easier to interrupt.

The optimum chemical schemes made in the synthetic model are based on RF per unit mass of chemical. One optimum case was made for each chemical flooding method and is tested on the Norne C-Segment. Additional cases where made to confirm the results.

15.3.1 Polymer

Result from both the synthetic model and Norne C-Segment showed that polymer flooding had a great increase in RF. In the Norne C-Segment polymer improves the sweep efficiency over waterflooding. Firstly it increases the water viscosity. Secondly, the rock permeability to water is reduced after passage of a polymer solution through the rock material. Both effects caused a lower mobility ratio and more incremental oil was produced.

Both higher concentration and larger slug increases the RF. High concentration due to higher viscosity of the slug. Larger slug because viscosity is kept high even though polymer is adsorbed. Higher concentration works better than larger slug in the Norne C-Segment. The synthetic model showed that the amount of polymer adsorbed is low due to low concentration. Reduction in RF by adsorption was lower than 0.03%.

Chemical properties for polymer in Appendix D describe that a concentration of 0.05 wt% will increase the water viscosity with a factor of 5.125. The oil viscosity in the Norne field is less than 1.2 cp which is lower than the average viscosity for chemical flooding in the screening in Appendix J. Still there is large improvement in mobility ratio. Polymer works well in heterogeneous reservoir (Skjæveland & Kleppe, 1992). This is probably why polymer flooding has the highest increase in RF. The most incremental oil is produced by the producer B-2H that are perforated in the lower part of Ile. Waterflooding is affected by the gravity segregation and a high permeability layer. Polymer reduces the WC of B-2H by increasing the volumetric sweep.

The optimum case increases the RF by 2.2% and achieved a NPV of 410 million USD. Despite the high concentration and large slug contributing to high cost. Probably even higher incremental oil can be achieved by increasing both. The constraint will be well constraints and maybe fracturing of the reservoir. With high concentration the BHP and reservoir pressure increases.

15.3.2 Surfactant

The surfactant had considerable less effect on the RF than polymer in the Norne C-Segment. Results from the synthetic model support the results. The aim of surfactant flooding is to recover the capillary-trapped residual oil after waterflooding. The optimum case achieves a low increase in RF of 0.3%. Surfactants alone cannot produce enough incremental oil to pay of the cost of chemicals.

Both higher concentration and larger slug increases the RF. Higher concentration works better than larger slug. Higher concentration is used to make a stronger reduction in IFT between oil and water. In theory a large reduction happens at an IFT of 10^{-6} N/m (Greeen & Willhite, 1998) (Skjæveland & Kleppe, 1992). To achieve this concentration of 2.0 wt% needs to be applied, see Appendix E. Increasing the concentrations to 0.5 wt% to 1.0 wt% achieve higher recovery but a more negative NPV. Therefore it is doubtful that a higher concentration will give any positive NPV. The concentration of 2.0 wt% was tested in the synthetic model with little effect.

The ultimate residual oil saturation will be determined by the IFT between oil and surfactant solution behind the oil bank (Skjæveland & Kleppe, 1992). Higher slug sizes have been tested in the synthetic model with little effect. A slug size of 0.2 gave more incremental oil in the Norne C-Segment and but a more negative NPV.

Surfactant flood perform best in a water-wet reservoir and well sorted sand. Norne C-Segment is a mixed-wet reservoir (Hetland & Verlo, Petrophysical information, 2008).The Norne Field are fine-grained, well to very well sorted sub-arkosic arenites. (Lind, Tevik, & Drønnen, Reservoir Managment Plan Norne Field, 2001). The environment is not optimum for the surfactants and therefore surfactants are less effective.

Polymer is added to increase sweep efficiency letting the surfactants work on a bigger area reducing capillary trapped oil. It also prevents the unfavourable mobility ratio due to the displacement process of surfactant. Still surfactants cannot produce enough incremental oil to pay of the cost. Most of the incremental oil is due to lowering the mobility ratio. A successful SP flooding needs to capture more residual oil. The optimum case achieves an increase in RF of 1.4% but NPV is lower than for polymer flooding

In the synthetic model it is shown that more surfactant is adsorbed when using polymer. This is due surfactants sweeps more of the reservoir and more surfactants is then adsorbed. Surfactant has a minimal effect on decreasing the adsorption of polymer.

The main reason for the poor results is probably that the residual oil saturation in Norne C-Segment is low. In the data file residual oil is 0.12. Since a surfactant will modify the relative permeability and reduce the residual oil saturation towards zero little incremental oil is produced. Typical residual oil in a swept area is about 20% to 35% (Greeen & Willhite, 1998).

15.3.3 Alkaline

The alkaline model in Eclipse does not take into account the in-situ surfactant creation and the phase behaviour. The model provides the effect of alkaline on the water-oil surface tension and adsorption reduction of surfactant, see Appendix C.

AS flooding contribute to higher recovery over surfactant flooding. The optimum case achieves an increase in RF of 0.1% but NPV is lower than for surfactant flooding. The increase in incremental oil due alkaline is minimal. Alkaline cannot contribute with enough reduction in IFT or reduction in adsorption to make it profitable, even though the alkaline is inexpensive.

Increase in RF by reduction of IFT in solution with surfactants is minimal. This is due to the same constraints as surfactant flooding, see Chapter 15.3.2. The synthetic model has confirmed that alkaline has lower effect on RF than surfactant.

It is interesting to see that a lower alkaline concentration ends up with higher incremental oil. This is opposite from the synthetic model. The Norne C-Segment is complex and several parameters can contribute to the inconsistency. In a real case several investigations have measured that the minimum IFT occurs in the narrow range between 0.05 to 0.1 wt% (Greeen & Willhite, 1998). If a lower concentration can achieve this range concentration throughout the reservoir without great loss of alkaline through rock/fluid interactions it is feasible. In Eclipse multiplier is used to reduce IFT in solution with surfactant, see Appendix C.

Therefore higher concentrations should mobilise more oil. The most probably reason is addition of alkaline concentration will result in a decrease in mobility ratio.

Alkaline can reduce the adsorption of both surfactant and polymer on the rock surface, therefore enhancing the effectiveness of surfactant and polymer drive. In the synthetic model alkaline concentration over 0.5 wt% works well with reducing the surfactant and polymer adsorption. The amount of polymer adsorbed is very low compared to surfactant due to lower concentration used. Alkaline can increase the RF by reduction of polymer adsorption, but the effect is minimal. The highest change in RF is 0.03 %. Alkaline cannot reduce the IFT without surfactants.

Measures to improve AS flood are polymer. The optimum case achieves an increase in RF of 1.4% but NPV is lower than for polymer flooding. Surfactant and alkaline cannot produce enough incremental oil to pay of the cost using them. The more alkaline or surfactant used the lower NPV.

15.4 Economic Evaluation

Polymer flooding with the highest concentration and largest slug size gave the best NPV of 410 million USD. The NPV calculation is a simplification of calculating the result. But it gives a good pointer if the project is valuable. Uncertainties in chemical prices and oil price are a big uncertainty. A low case reduces the NPV with 102 millions. It is important to acknowledge that Norne is an offshore field. Offshore fields are constrained by surface facilities and environmental regulations, among other factors. Therefore, EOR applicability in offshore fields is limited compared to onshore fields. The injected polymer must be delivered to the facility, stored, treated possibly diluted and filtered, and injected through dedicate injection wells. Norne has been operated under water injection hence some of the necessary facilities may be already in place. Chemical flooding is expensive onshore and will be even more expensive offshore (Bonder, Hite, & Avasthi, 2005). However, an increase in 410 million USD is a large increase and polymer is attractive for the Norne C-Segment.

16 Uncertainties

The target for this study is to optimise oil production in the C-segment and therefore a fine gridded model is used for this segment. The rest of the reservoir is coarse gridded because of less importance in this study. Due to the modifications of the model some of the perforations of well B1-H were changed because it was producing outside the C-segment. Well B-3H was removed because only its wellhead is located in the C-segment (Rwechungura, 2011). When investigating the model, two production wells D-3BH and D-3AH where found, producing from the C-segment. Their wellheads are located outside the segment, but contribute to reservoir depletion. A coarser grid and alternation of the well configuration contribute to a more uncertain result.

In addition, new perforations where made in the C-2H producer, based on C-3H and will therefore not be entirely accurate. These alternations need to be considered when looking at the results.

There are several uncertainties in the given history data. Injection data tend to be less accurate than production data, either because of measurement errors or because fluids are lost to other intervals as a result of casing leaks or flow behind pipe. Errors in production data may occur for the same reasons, but they are usually discovered and corrected. Oil production rates are usually the most accurate data available. Some errors can occur due to measuring at central sites instead of individual wells. Allocating central data back to the individual wells will be a potential source of error. Also, where production or injection is commingled, allocation to individual zones will be a source of error (Mattax & Dalton, 1990). The gas production in Norne was not measured accurately before they start selling it in 2005 (Cheng, 5/3-12). The new model, based on the history data of 97-06, is not good enough matched making the predictions more uncertain.

Eclipse provides basic models for each chemical method. The surfactant model does not provide a detailed chemical simulation of surfactant flooding. The alkaline model does not take into account the in-situ surfactant creation and the phase behaviour. When using the polymer model, WAGHYST is not compatible. It is not reported in the technical description but was confirmed emailing Huseynov at Statoil (Huseynov, 2012). WAGHYST is therefore not activated resulting in no calculation of WAG hysteresis when finding an optimum scenario for the Norne C-Segment. The chemical methods have some setbacks that need to be accounted for before applying chemicals on the Norne C-Segment.

The Norne field has never been tested for chemical EOR. In general chemicals are tested with reservoir properties and fluid characteristics in a laboratory. These data are not available for the Norne field and gathered properties are used. As a result different chemical reactions in the Norne C-Segment need to be assumed. In the chemical properties gathered from Yugal thesis the surfactants IFT properties had an error. Surface tension should decrease with higher data concentrations. The values given for concentrations 0.5-2 wt% increased. Therefore new appropriate values were selected to represent the higher concentrations of surfactants see Appendix D.

Reservoir pressure increases when injecting polymer. The pressure is highest with the optimum polymer case with the highest concentration and largest slug size. The constraints on how large slug and concentration can be are fracturing and well completion. These constraints need to be evaluated before applying polymer. Solution would be to use a lower injection rate.

Treatment of Non-Newtonian is not taken into account in the polymer properties, see Appendix E. The viscosity of polymer solution changes with shear rate and need to be investigated. At high shear rate the viscosity of the solution decreases and long chained polymers can be broken. High shear rate appear at injection and production wells. This problem needs to be investigated before applying polymer flooding.

17 Conclusion

EOR will play a key role in meeting the oil demand by increasing the low oil recovery. The developments of new technology has brought a renewed attention for chemical flooding. The Norne field had an incredible recovery factor of 54% in 2011. Statoil hope to set a world record for the whole Norne field with a recovery factor of 60% before decommissioning (Skagen, 2012). With Polymer flooding this goal can be achieved in 2022 with a RF of 60.2% in the Ile formation. But it is important to acknowledge that Norne is an offshore field and it will be expensive. However, an increase in NPV of 406 million USD over waterflooding is a large increase, hence polymer flooding is attractive for the Norne C-Segment. This result is with a polymer price of 5 USD/Kg and an oil price of 95 USD/bbl.

The conclusion is based on:

- Better mobility control with low concentration and slug size
- The Norne Field has reservoir characteristics and oil properties that suit a polymer flooding
- Waterflood in the Ile formation cannot recover the oil to reach a RF of 60%
- The Ile formation consist of good reservoir rock
- Injection well C-2H works well because of location in relation to producers and reservoir geology
- Surfactant or alkaline cannot reduce enough residual oil to make it economic
- Adding polymer to alkaline-surfactant or surfactant increase incremental oil by capturing more residual oil

18 Recommendations

- Take environment issues to consideration
- Chemicals need to be costume made and tested in the laboratory before applied on the field.
- Apply the polymers on full field model without well configurations
- Allocate perforation data for injection well C-2H
- The model need to be better matched with the history to be reliable
- Chemicals can be simulated in other simulation programs like CMG for more complex chemical processes
- Chemical properties for Norne need to be gathered
- Pressure and rate sensitivity analysis need to be applied
- Drill new wells and use a different well pattern
- Polymer slug after injection of the different chemicals to stabilize the solution
- Improvements could be achieved with a tapered slug for all chemicals. It will be more cost efficient

Nomenclature

AP	Alkali-Polymer
API	American Petroleum Institute, specific gravity
AS	Alkaline-Surfactant
ASP	Alkali-Surfactant-Polymer
BHP	Bottom Hole Pressure
CDC	Capillary Desaturation Curve
EOR	Enhanced Oil Recovery
FAWAG	Foam Assisted Water Alternating Gas
GOR	Gas Oil Ratio
HC	Hydrocarbon
HPAM	Hydrolyzed Polyacrylamide
IFT	Interfacial Tension
IOR	Incremental Oil Recovery
IOS	Internal Olefin Sulfonates
IRAP	Interactive Reservoir Analysis Package
M	Mobility Ratio
MEOR	Microbial Enhanced Oil Recovery
NCS	Norwegian Continental Shelf
NPV	Net Present Value
OIP	Oil in Place
OG21	Oil and Gas in the 21st century

PV	Pore Volume
R	Resistance Factor
RF	Recover Factor
R&D	Research and Development
RMS	Root Mean Squares
SP	Surfactant-Polymer
V	Volume
v	Pore velocity
WAG	Water Alternating Gas
WBT	Water Breakthrough
WC	Water-Cut
F_{RR}	Resistance Factor
k_r	Effective permeability
N_c	Capillary number
s^{-1}	Shear Rate
ג	Mobility
μ	Fluid viscosity
σ	Interfacial tension (IFT)

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Appendix

A The Polymer Model

A1 Polymer Flood

A modification is required to the standard aqueous (water) equation and additional equations are needed to describe the flow of polymer and brine within the finite difference grid. The water, polymer and brine equations used in the model are as follows (Schlumberger, 2011):

Equation A--1

$$\frac{d}{dt}\left(\frac{VS_w}{B_rB_w}\right) = \sum\left[\frac{Tk_{rw}}{B_w\mu_{w\,eff}R_k}(\delta P_w - \rho_w g D_z)\right] + Q_w$$

Equation A--2

$$\frac{d}{dt}\left(\frac{V^*S_wC_p}{B_rB_w}\right) + \frac{d}{dt}\left(V\rho_rC_p^a\frac{1-\phi}{\phi}\right) = \sum\left[\frac{Tk_{rw}}{B_w\mu_{p\,eff}R_k}(\delta P_w - \rho_w g D_z)\right]C_p + Q_wC_p$$

Equation A--3

$$\frac{d}{dt}\left(\frac{VS_wC_n}{B_rB_w}\right) = \sum\left[\frac{Tk_{rw}C_n}{B_w\mu_{s\,eff}R_k}(\delta P_w - \rho_w g D_z)\right] + Q_wC_n$$

Equation A--4

$$V^* = V(1 - S_{dpv})$$

S_{dpv}	denotes the dead pore space within each grid cell
C_p^a	denotes the polymer adsorption concentration
ρ_r	denotes the mass density of the rock formation
ϕ	denotes the porosity
ρ_w	denotes the water density
Σ	denotes the sum over neighboring cells
R_k	denotes the relative permeability reduction factor for the aqueous phase due to polymer retention
C_p , C_n	denote the polymer and salt concentrations respectively in the aqueous phase
$\mu_{a\,eff}$	denotes the effective viscosity of the water (a=w), polymer (a=p) and salt (a=s)

D_z is the cell center depth

B_r , B_w are the rock and water formation volumes

T is the transmissibility

k_{rw} is the water relative permeability

S_w is the water saturation

V is the block pore volume

Q_w is the water production rate

P_w is the water pressure

Density and formation volume factor of the aqueous phase are independent of the polymer and salt concentrations. The polymer solution, reservoir brine and the injected water are represented in the model as miscible components in the aqueous phase, where the degree of mixing is specified through the viscosity terms in the conservation equations (Schlumberger, 2011).

A2 Treatment of Fluid Viscosities

The effective viscosity values are calculated using Todd-Longstaff technique (Schlumberger, 2011). The effective polymer viscosity is calculated by Equation 9-8 .

Equation A--5

$$\mu_{p,eff} = \mu_m(C_p)^{\omega}\mu_p{}^{1-\omega}$$

ω is the Todd-Longstaff mixing parameter

$\mu_m(C_p)$ The viscosity of a fully mixed polymer solution as an increasing function of the polymer concentration in solution

μ_p The viscosity of the solution at the maximum polymer concentration, denotes the injected polymer concentration in solution

The partially mixed water viscosity is calculated in an analogous manner using the fully mixed polymer viscosity and the pure viscosity (μ_w).

Equation A--6

$$\mu_{w,e} = \mu_m(C_p)^{\omega}\mu_w{}^{1-\omega}$$

The total water equation is written as the sum of contributions from the polymer solution and the pure water. The following expression gives the effective water viscosity.

Equation A--7

$$\frac{1}{\mu_{w,eff}} = \frac{1-\bar{C}}{\mu_{w,e}} + \frac{\bar{C}}{\mu_{p,eff}}$$

$\bar{C}$ is the effective saturation for the injected polymer solution within the total aqueous phase in the cell

Equation A--8

$$\bar{C} = \frac{C_p}{C_{p,max}}$$

A3 Treatment of Polymer Adsorption

Adsorption is treated as an instantaneous effect in the model. The effect of polymer adsorption is to create a stripped water bank at the leading edge of the slug. Desorption effects may occur as the slug passes. The isotherm adsorption can be specified in two models. The first model is to use a table of adsorbed alkaline as a function of alkaline concentration. The second model is a generic analytical adsorption model that enables the adsorption to depend on the salinity and rock permeability.

If desorption is prevented then the adsorbed polymer concentration may not decrease with time. If desorption is allowed then each grid block retraces the adsorption isotherm as the alkaline concentration rises and falls in the cell (Schlumberger, 2011).

A4 Treatment of Permeability Reductions and Dead Pore Volume

The adsorption process causes a reduction in the permeability of the rock to the passage of the aqueous phase and is directly correlated to the adsorbed polymer concentration. The reduction in rock permeability depends on the specific residual resistance factor (RRF) for each rock type (Schlumberger, 2011).

Equation A--9

$$R_k = 1.0 + (\mathrm{RRF} - 1.0)\frac{C_p^a}{C_p^{a\,max}}$$

$C_p^{a\,max}$ denotes the value of the maximum adsorbed concentration

The dead pore volume must be specified for each rock type. The effects is modelled by assuming that dead pore space is constant for each rock type and is independent of the water saturation.

A5 Treatment of the Non-Newtonian Rheology

At higher flow rates shear thinning reduces the polymer viscosity. The model assumes that shear rate is proportional to the flow viscosity. This assumption is not valid in general, as for example, a given flow in a low permeability rock will have to pass through smaller pore throats than the same flow in a high permeability rock, and consequently the shear rate will be higher in the low permeability rock. However for a single reservoir this assumption is probably reasonable (Schlumberger, 2011). The reduction in viscosity of the polymer solution is assumed to be reversible as a function of the water velocity and is calculated as:

Equation A--10

$$\mu_{sh} = \mu_{w,eff}\left[\frac{1 + (P - 1)M}{P}\right]$$

μ_{sh} is the shear viscosity of the polymer solution (water+polymer)

$\mu_{w,eff}$ is the effective water viscosity

P is the viscosity multiplier assuming no shear effect

M is the shear thinning multiplier (M=1: no shear thinning, M=0: maximum shear thinning)

A6 Keywords Polymer Model

Keyword	**Description**	**Notes**
POLYMER	Activates the polymer model	Obligatory
BRINE	If salt-sensitivity	By default the polymer model is not salt-sensitive
TLMIXPAR	The mixing parameter data	Obligatory
PLYADS	The polymer adsorption	Look up table, can also use ADSORP
PLYVISC	Polymer solution viscosity function	BRINE not activated
PLYROCK	Polymer-rock parameters	Dead pore volume and the residual resistance factor
PLYSHEAR	Non-Newtonian rheology	Reduction in viscosity
PLYMAX	Maximum polymer and salt concentrations for mixing	Used in TLMIXPAR
WPOLYMER	Injection concentration	If standard Brine is used

Table A.1: Keywords polymer model

B The Surfactant Model

B1 Calculation of the Capillary Number

Capillary number defines the ratio of viscous forces to capillary forces and is dimensionless (Schlumberger, 2011).

Equation B-1

$$N_c = \frac{|K \cdot \mathrm{grad}P|}{ST} C_{unit}$$

k is permeability

P is potential

ST is the interfacial tension

C_{unit} is the conversion factor depending on the units used

B2 Relative Permeability Model

The model uses an immiscible relative permeability curves at low capillary number and relative permeability curves at high capillary number. A transition between these curves is made, and a table that describes the transition as a function of $\log_{10}$ capillary number is used. This method is only performed for blocks with non-zero surfactant concentration (Schlumberger, 2011).

Figure 24 shows how the relative permeability for oil is calculated. The water permeability is calculated in the same way. Point A is made by interpolation between the endpoints. The miscible and immiscible curves are then scaled between A and B. The relative permeability values are looked up on both curves, and the final relative permeability is taken as an interpolation between these points.

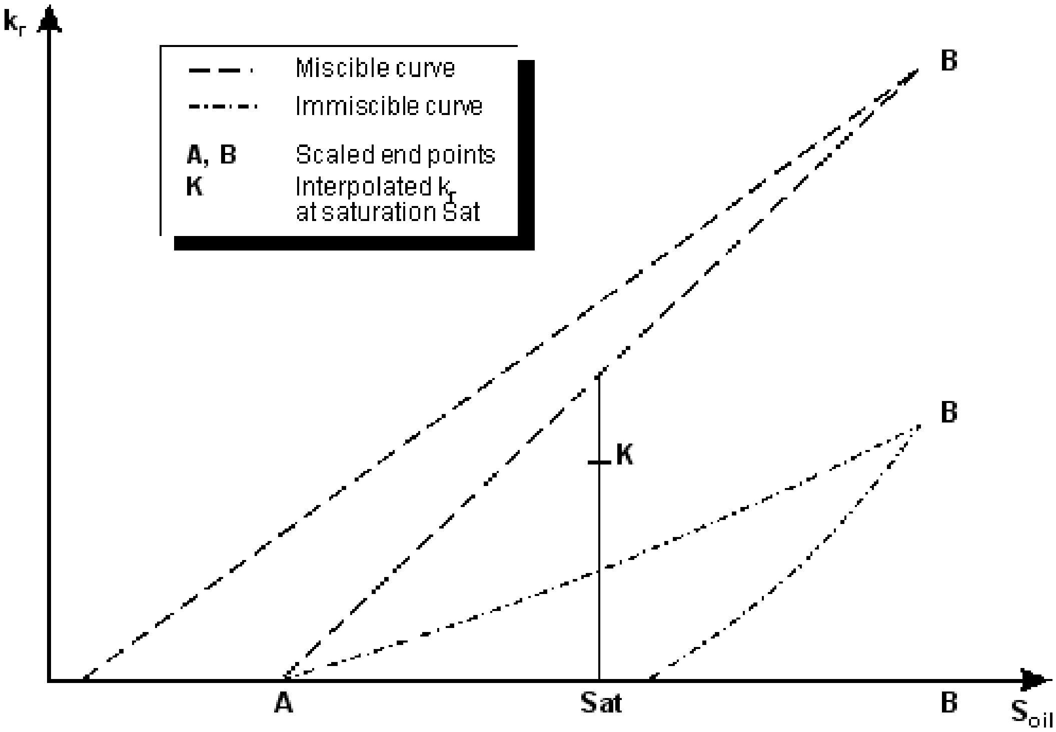


Figure B.1: Calculations of the relative permeability (Schlumberger, 2011)

B3 Capillary Pressure

The reduction in the oil water capillary pressure gives the reduction in the residual oil saturation. This reduction will increase as the surfactant concentration increases (Schlumberger, 2011).

Equation B-2

$$P_{cow} = P_{cow}(S_w)\frac{ST(C_{surf})}{ST(C_{surf}=0)}$$

$ST(C_{surf})$	is the surface tension at the present surfactant concentration
$ST(C_{surf}=0)$	is the surface tension at zero concentration
$P_{cow}(S_w)$	is the capillary pressure from the immiscible curves initially scaled to the interpolated end-points calculated in the relative permeability model

B4 Water PVT Properties

The surfactant modifies the viscosity of the pure or salted water. The surfactant viscosity input as a function of surfactant concentration is used to calculate the water-surfactant solution viscosity as follows (Schlumberger, 2011).

Equation B-3

$$\mu_{ws}(C_{surf}, P) = \mu_w(P)\frac{\mu_S(C_{surf})}{\mu_w(P_{ref})}$$

μ_S	is the surfactant viscosity
μ_w	is the water viscosity
μ_{ws}	is the viscosity of the water-surfactant mixture

B5 Treatment of Adsorption

Surfactants are assumed to adsorb instantaneous, and the amount adsorbed is a function of the surrounding surfactant concentration (Schlumberger, 2011). The quantity of surfactant adsorbed on to the rock is given in Equation 7-14:

Equation B-4

$$\text{Mass of adsorbed surfactant} = \text{PORV} \cdot \frac{1-\phi}{\phi} \cdot \text{MD} \cdot \text{CA}(C_{surf})$$

PORV	is the Pore volume of the cell
ϕ	is the porosity
MD	is the mass density of the rock
$\text{CA}(C_{surf})$	is the adsorption isotherm as a function of local surfactant concentration in solution

B6 Keywords Surfactant Model

Keyword	**Description**	**Notes**
SURFACT	Activates the surfactant model	Obligatory
SURFST	Water-oil surface tension in the presence of surfactant	Obligatory
SURFVISC	Modified water viscosity	Obligatory
SURFCAPD	Capillary de-saturation data	Obligatory
SURFADS	Adsorption isotherm	Optional, can also use ADSORP
SURFROCK	Rock properties and adsorption model indicator	If SURFADS is present
WSURFFACT	The injected surfactant concentration	-

Table B.1: Keywords surfactant model

C The Alkaline Model

C1 Alkaline Conservation Equation

The alkaline is assumed to exist only in the water phase a concentration in a water injector. The distribution of the injected alkaline is modelled by solving conservation Equation C-1. (Schlumberger, 2011).

Equation C-1

$$\frac{d}{dt}\left(\frac{VS_wC_a}{B_rB_w}\right)+\frac{d}{dt}\left(V\rho_rC_a^a\frac{1-\phi}{\phi}\right)=\sum\left[\frac{Tk_{rw}}{B_w\mu_{s\ eff}}(\delta P_w-\rho_w g D_z)\right]C_a+Q_wC_a$$

ρ_w , ρ_r	denotes the water and rock density respectively
Σ	denotes the sum over neighboring cells
C_a	denotes the alkaline concentration
C_a^a	denotes the adsorbed alkaline concentration
$\mu_{s\ eff}$	denotes the effective viscosity of the salt
D_z	is the cell center depth
B_w , B_r	is the water and rock formation volume respectively
T	is the transmissibility
k_{rw}	is the water relative permeability
S_w	is the water saturation
V	is the block pore volume
Q_w	is the water production rate
P_w	is the water pressure
g	is the gravity acceleration

The alkaline concentrations are updated at the end of a time step after the inter-block phase flows have been determined.

C2 Alkaline Effect on Water-Oil Surface Tension

The effect of alkaline on the water-oil surface tension is a combined effect with surfactant by modifying the water-oil surface tension as follows (Schlumberger, 2011).

Equation C-2

$$\sigma_{wo} = \sigma_{wo}(C_{surf})A_{st}(C_{alk})$$

$\sigma_{wo}(C_{surf})$	is the surface tension at surfactant concentration and zero alkaline concentration
$A_{st}(C_{alk})$	is the surface tension multiplier at alkaline concentration

C3 Alkaline Effect on Surfactant/Polymer Adsorption

The alkaline can reduce the adsorption of both surfactant and polymer on the rock surface. This is modelled by modifying the mass of adsorbed surfactant or polymer as follows (Schlumberger, 2011):

Equation C-3

$$V\rho_r C^a_{s,p}\frac{1-\phi}{\phi}A_{dd}(C_{alk})$$

V	is the pore volume of the cell
ϕ	is the porosity
ρ_r	is the mass density of the rock
$C^a_{s,p}$	is the surfactant/polymer adsorbed concentration
$A_{dd}(C_{alk})$	is the adsorption multiplier at alkaline concentration

C4 Keywords Alkaline Model

Keyword	**Description**	**Notes**
ALKALINE	Activates the Alkaline model	The Polymer flood model or the Surfactant Flood model should be active as well
ALSURFST	Table of oil/water surface tension as a function of alkaline concentration	Obligatory if the Surfactant Flood Model is active
ALSURFAD	Table of surfactant adsorption as a function of alkaline concentration	Obligatory if the SURFADS keyword is used
ALPOLADS	Table of polymer adsorption as a function of alkaline concentration	Obligatory if the Polymer Flood Model is active
ALKADS	Tables of adsorption functions	Optional
ALKROCK	Specifies alkaline-rock properties	Obligatory if ALKADS is used
WALKALIN	Concentration of the injected alkaline in a water injector	This concentration can be set as UDA(User Defined Argument)

Table C.1: Alkaline keywords (Schlumberger, 2011)

D Chemical Properties

```
----------------------------------ALKALINE PROPERTIES

ALSURFST
--Appendix C2
--Alkaline concentration (kg/sm3)/Surface tension multiplier
--NTPVT=1

  0.0 1.0
  6.0 0.5
  15.0 0.3
  20.0 0.1
  30.0 0.0 /

ALSURFAD
--Appendix C3
--Alkaline concentration (kg/sm3)/Surfactant adsorption multiplier
--NTSFUN=4

  0.0 1.0
  3.0 0.7
  6.0 0.5
  9.0 0.0 /

ALPOLADS
--Appendix C3
--Alkaline concentration (kg/sm3)/Polymer adsorption multiplier
--NTSFUN=4

  0.0 1.0
  3.0 0.7
  6.0 0.5
  9.0 0.3 /

ALKADS
--Appendix C4
--Alkaline concentration (kg/sm3)/Alkaline adsorbed (kg/kg)
--NTSFUN=4

  0.0 0.000000
  3.0 0.000005
  6.0 0.000007
  9.0 0.000008
  10.0 0.000009 /

ALKROCK
--Appendix C4
-- 2 = No desorption
--NTSFUN=4

  2 /
```

```
-----------------------------------POLYMER PROPERTIES

PLYSHEAR
--Appendix A5
--Water phase flow velocity (m/day)/factor Polymer visc. reduced
--NTPVT=1

 0.0 1.0
 2.0 1.0 /

PLYVISC
--Appendix A6
--Polymer concentration (kg/sm3)/water viscosity multiplier
--NTPVT=1

  0.0   1.0
  0.1   1.55
  0.3   2.55
  0.5   5.125
  0.7   8.125
  1.0   21.2 /

PLYADS
--Appendix A3
--Polymer concentration (kg/sm3)/polymer adsorbed (kg/kg)
--NTSFUN=4

  0.0   0.0
  0.5   0.0000017
  1.0   0.0000017 /

TLMIXPAR
--Appendix A2
-- Todd-Long staff Mixing Parameters –viscosity/-density

  1   1* /

-- Polymer-Salt Concentrations for mixing - maximum polymer and salt
-- concentrations

PLYMAX
--Appendix A6
--Concentration (Kg/sm3) –Polymer/-Salt

   1.0             0.0 /

PLYROCK
--Appendix A4
--Dead pore space/mass density(Kg/rm3)/2=No desorp/max polymer
ads.(kg/kg)
--NTSFUN=4

  0.16  1.0  2650  2  0.000017 /
```

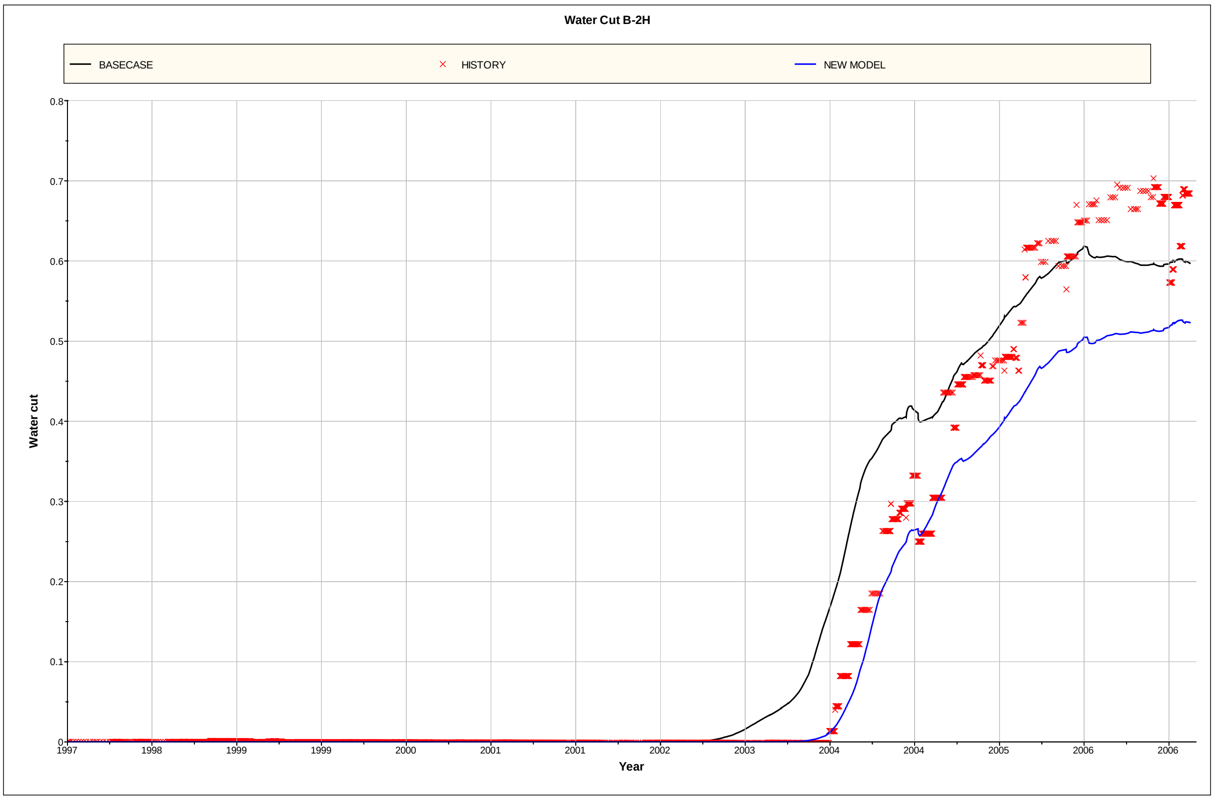
```
-----------------------------------SURFACTANT PROPERTIES
SURFST
--Appendix B1
--Concentration (Kg/sm3)/Surface tension (N/m)
--NTPVT=1

  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
--Appendix B4
--Concentration (Kg/sm3)/ Solution water viscosity (cp)
--NTPVT=1

  0.0   0.318
  5.0   0.449
  10.0  0.503
  15.0  0.540
  20.0  0.630 /

SURFADS
--Appendix B5
--Concentration (Kg/sm3)/Surfactant adsorbed (Kg/Kg)
--NTSFUN=4

  0.0   0.00000
  1.0   0.00017
  5.0   0.00017
  10.0  0.00017 /

SURFCAPD
--Appendix B2
--Log10 (capillary number)/ function 0 = immiscible, 1= miscible
--NTSFUN=4
  -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
--Appendix B6
--2 = No desorption/mass density rock(Kg/rm3)
--NTSFUN=1

  2 2650/
```

E Production Group

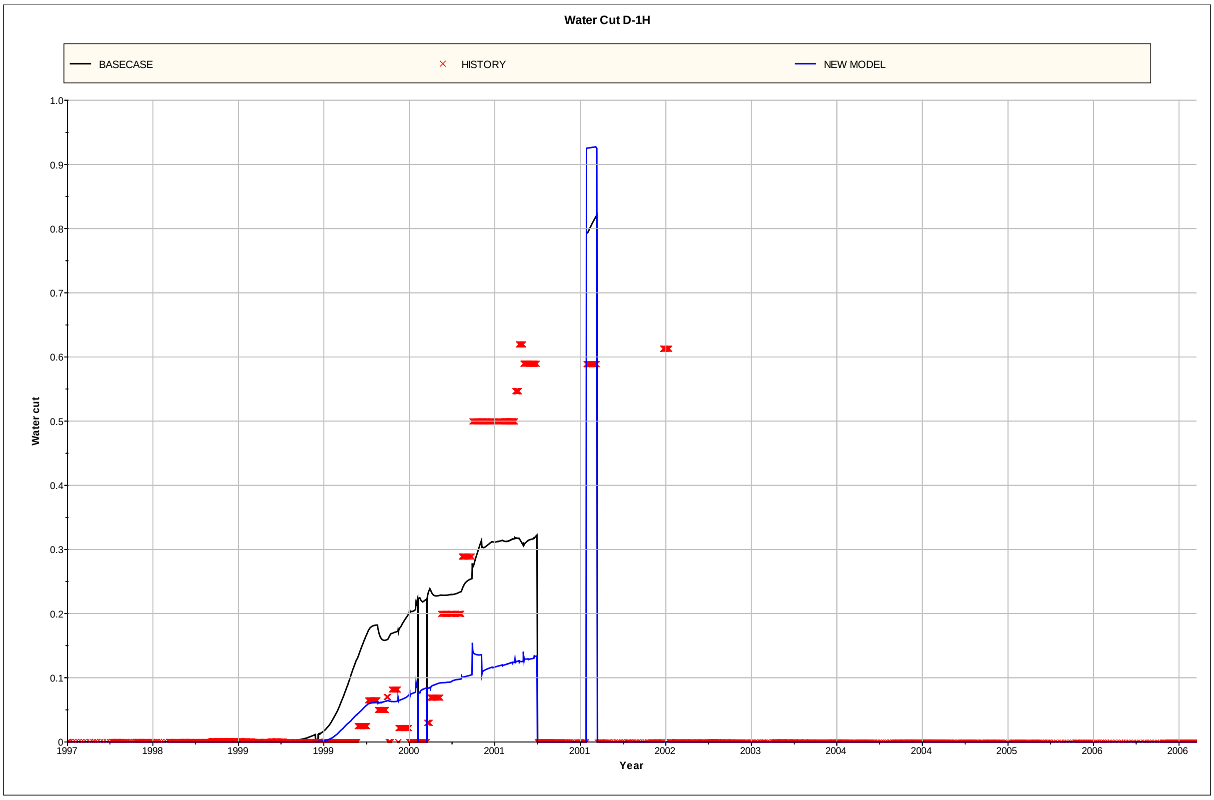
Each well was set in a new subgroup with the copied properties as the old. Then the new main group CSEG inherits the new subgroups.

```
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* /
/
--Example of setting D-2H in Group CSEG:
 WELSPECS
'D-2H'  'D2-DUMMY_CSEG' 14 28  1*  'OIL'  2*      'STOP'  4* /
/
```

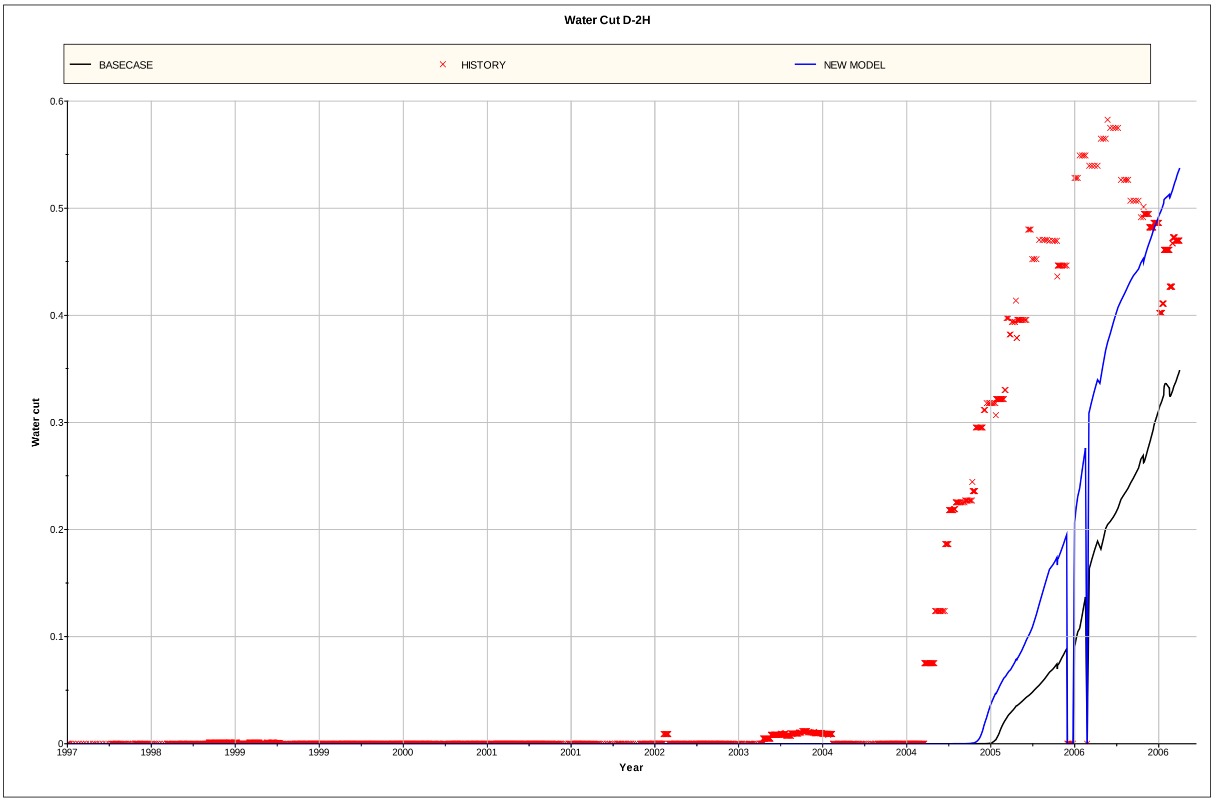
F History Matching



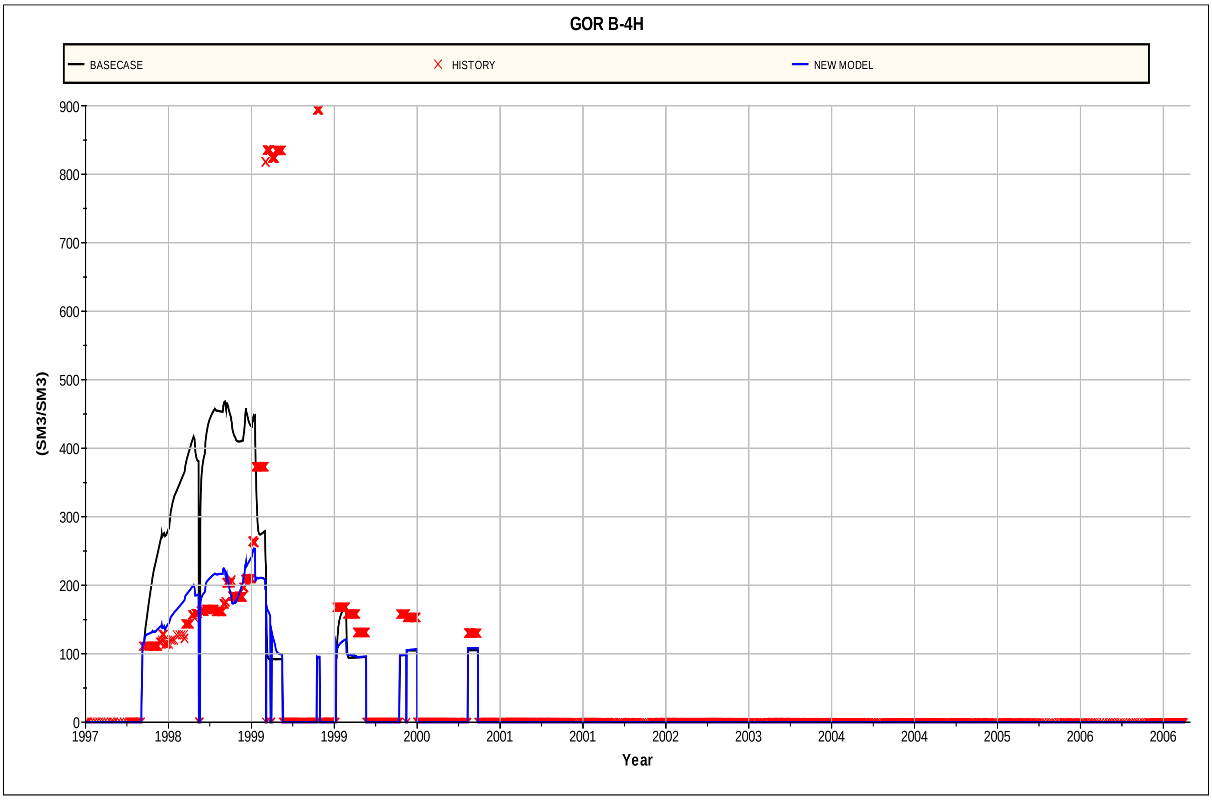
D.1: Water Cut B-2H



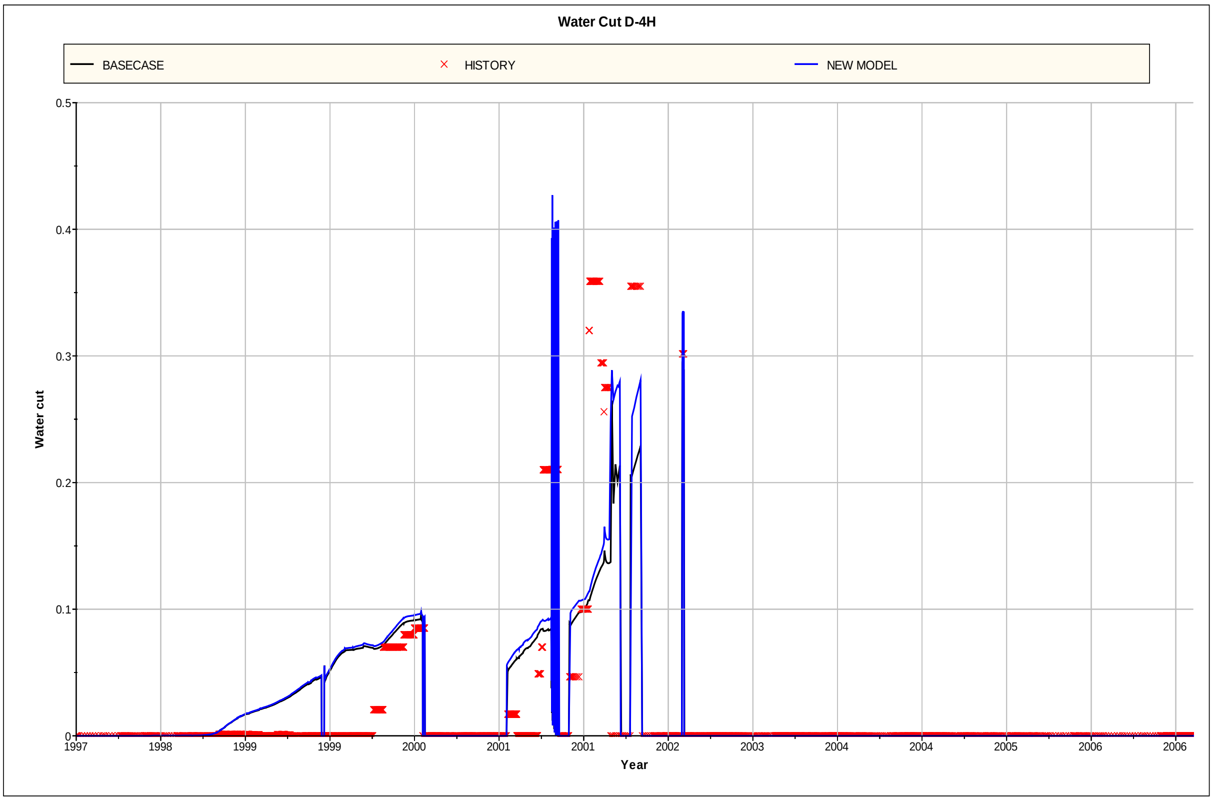
D.2: Water Cut D-1H



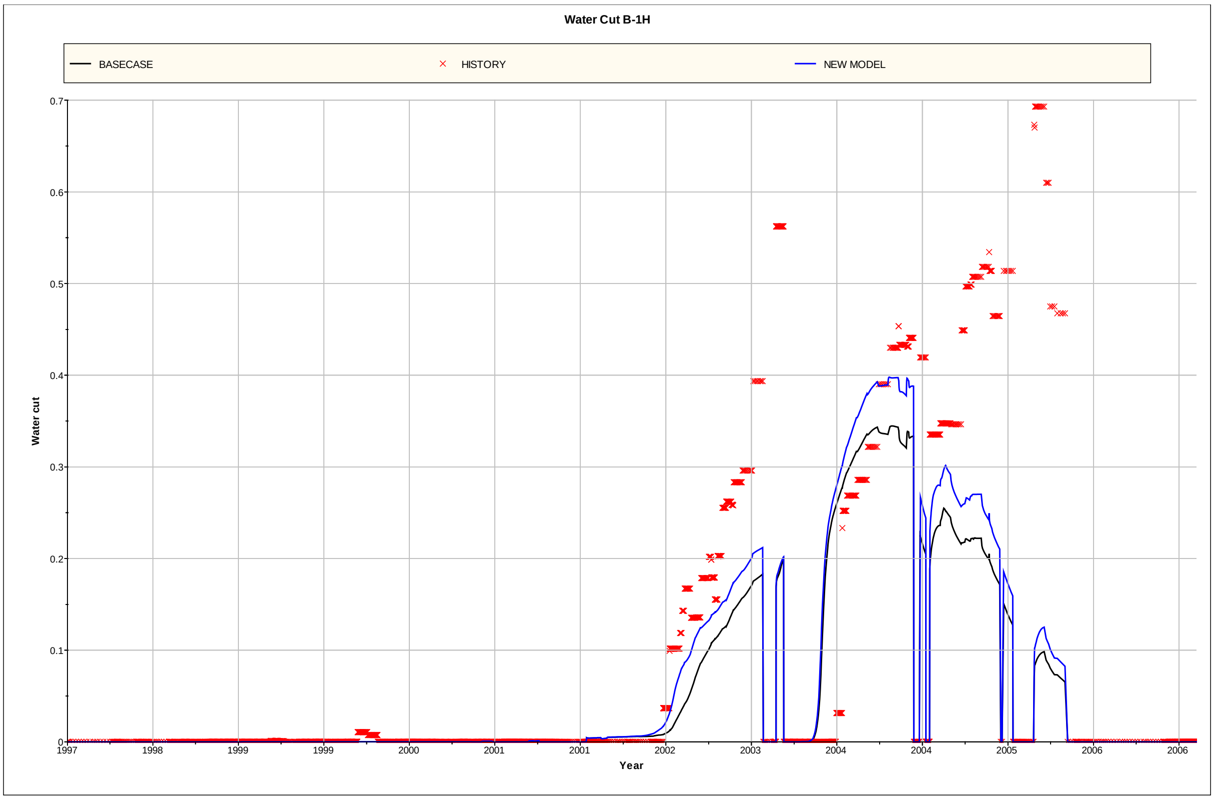
D.3: Water Cut D-2H



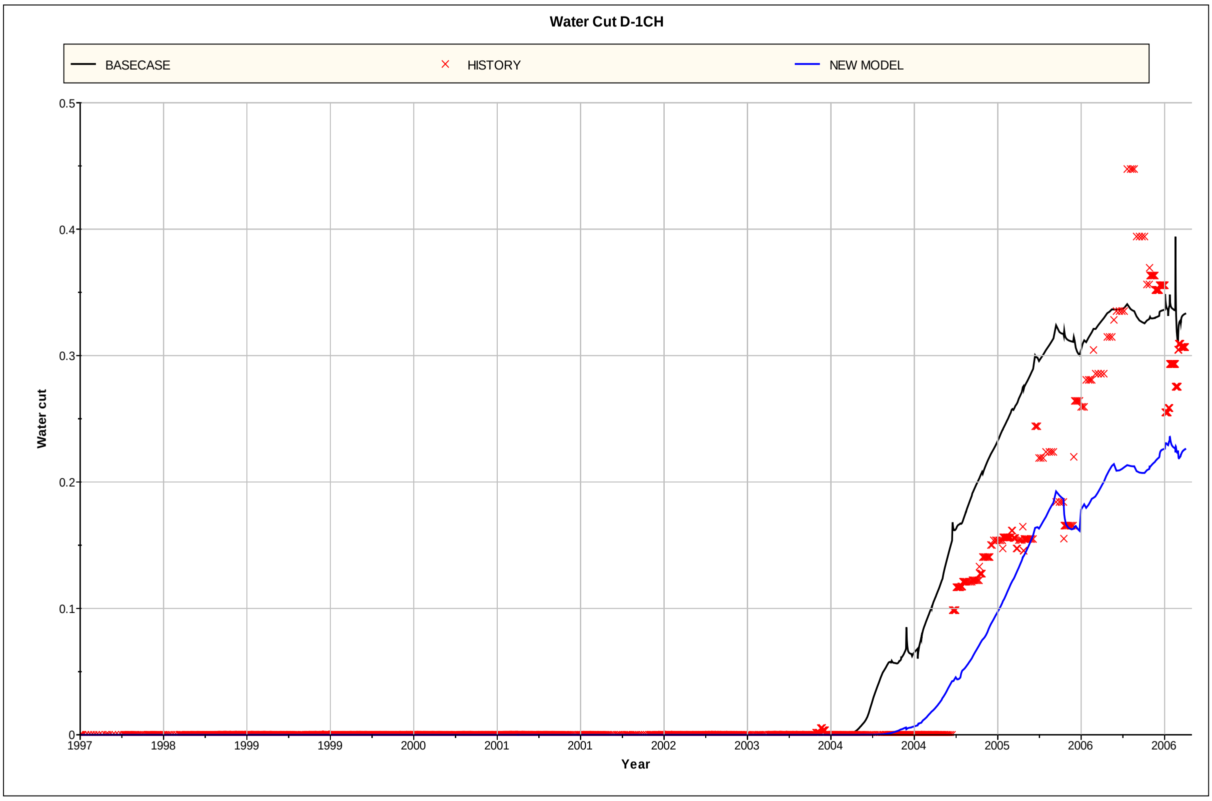
D.4: Gas Oil Ratio B-4H



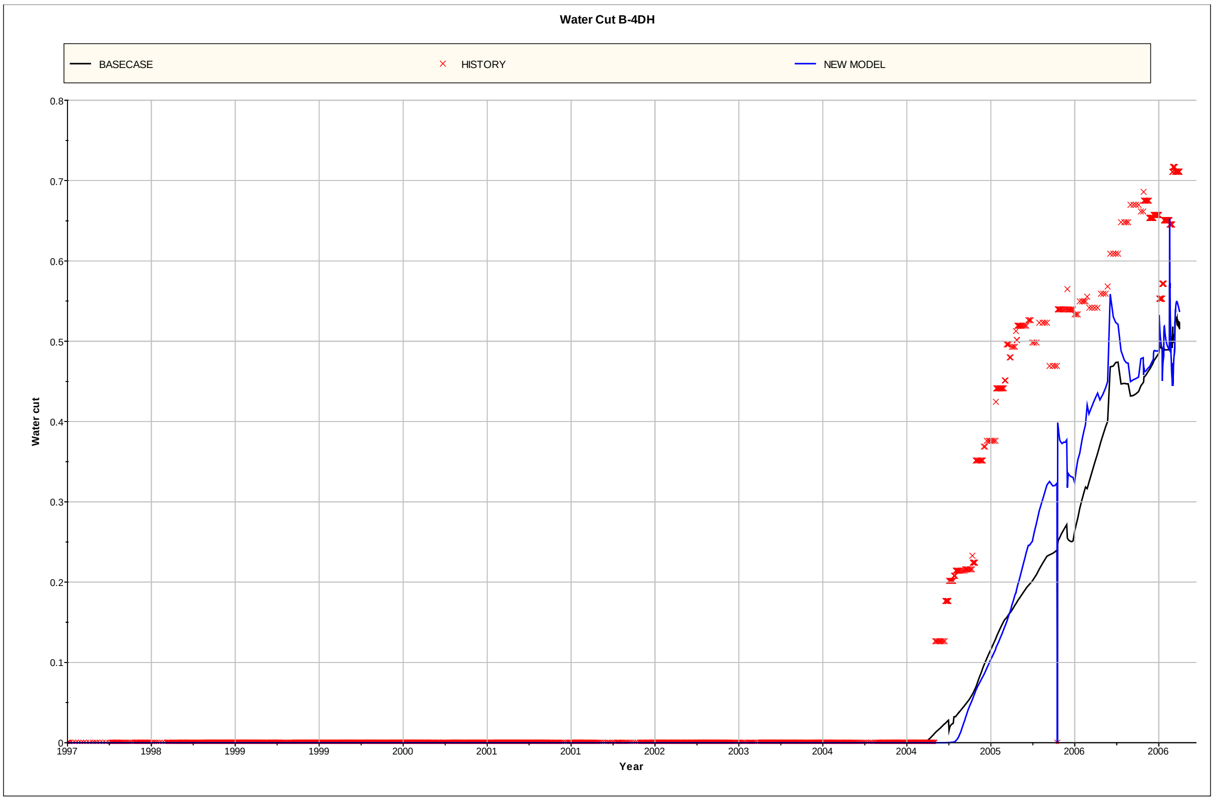
D.5: Water Cut D-4H



D.6: Water Cut B-1H



D.7: Water Cut D-1CH



D.8: Water Cut B-4DH

G Synthetic Model data file

```
RUNSPEC    ============================================================

TITLE
  NORNE MODEL

DIMENS
-- nx   ny    nz
  10   10    6  /

OIL
WATER
GAS
DISGAS
VAPOIL

SURFACT
POLYMER
ALKALINE

METRIC

TABDIMS
-- num num  max  max      max     max
-- sat pvt  sat  press    fip     Rs
-- tab tab nodes nodes   regions nodes
   4   1   30    45            1     45  /

REGDIMS
-- max  sets max  max
-- fip  fip  res  flux
-- reg  reg  reg  reg
   1    1    0    0 /

WELLDIMS
-- max    max max    max
-- wells conn groups wells/gr
   5    6    1     5 /

START
  1 'JAN' 2000  /

NSTACK
   60 /

UNIFOUT
UNIFIN

--NOSIM
```

```
GRID     ===========================================================

PSEUDO

DXV
  10*50   /
DYV
  10*50  /
DZ
  100*10 100*13 100*6 100*2 100*8 100*2 /

PERMX
  100*137.6 100*87.6 100*723.9 100*1006.4 100*508.1 100*793.5 /

COPY
   'PERMX' 'PERMY' 1 10   1 10  1 6 /
/

PERMZ
  100*13 100*13 100*13 100*75 100*75 100*150 /

PORO
  100*0.23 100*0.23 100*0.26 100*0.28 100*0.22 100*0.27 /

TOPS
  100*2591 100*2601 100*2614 100*2620 100*2622 100*2630 /


RPTGRID
/
```

```
PROPS     ===============================================================

SWOF

-- OIL/WATER imbibition curve IMBNUM = 36
--   swl = 0.1700, swcr = 0.0500, sorw = 0.1200, cw = 3.00, co = 2.50
--   sw       krw          kro          pc
  0.1700 0.0000000000 0.9000000000 3.2786792856
  0.2115 0.0000000000 0.7741946514 1.6217649559
  0.2530 0.0001457938 0.6595769798 0.7907460371
  0.2945 0.0011663508 0.5557940410 0.5114473103
  0.3360 0.0039364339 0.4624809909 0.3700572001
  0.3775 0.0093308062 0.3792597923 0.2838061033
  0.4190 0.0182242309 0.3057376697 0.2250977060
  0.4605 0.0314914711 0.2415052358 0.1820990596
  0.5020 0.0500072897 0.1861341829 0.1488879899
  0.5435 0.0746464499 0.1391743844 0.1221687838
  0.5850 0.1062837148 0.1001501669 0.0999583402
  0.6265 0.1457938475 0.0685553807 0.0809888293
  0.6680 0.1940516110 0.0438466371 0.0644088689
  0.7095 0.2519317685 0.0254335859 0.0496224427
  0.7510 0.3203090830 0.0126640003 0.0361966487
  0.7925 0.4000583175 0.0047986245 0.0238061033
  0.8340 0.4920542353 0.0009615928 0.0121979007
  0.8755 0.5971715994 0.0000028782 0.0011685789
  0.8800 0.6093953581 0.0000000000 0.0000000000
  0.9170 0.7162851728 0.0000000000 0.0000000000
  0.9585 0.8502697186 0.0000000000 0.0000000000
  1.0000 1.0000000000 0.0000000000 0.0000000000/

-- OIL/WATER imbibition curve IMBNUM = 10
--   swl = 0.1450, swcr = 0.0500, sorw = 0.1200, cw = 3.00, co = 2.50
--   sw       krw          kro          pc
  0.1450 0.0000000000 0.9000000000 2.7783170692
  0.1877 0.0000000000 0.7749255688 1.3746743200
  0.1878 0.0000000000 0.7746457618 1.3713913989
  0.2305 0.0001457938 0.6606509293 0.6698610892
  0.2732 0.0011643057 0.5573629447 0.4337168838
  0.3160 0.0039364339 0.4642179418 0.3138936117
  0.3588 0.0093389936 0.3810966923 0.2408429317
  0.4015 0.0182242309 0.3077719364 0.1912355782
  0.4442 0.0314730586 0.2436364296 0.1548891261
  0.4870 0.0500072897 0.1881505697 0.1267504339
  0.5298 0.0746791944 0.1410309775 0.1041179207
  0.5725 0.1062837148 0.1018912668 0.0853484226
  0.6152 0.1457426977 0.0701163199 0.0693147747
  0.6580 0.1940516110 0.0451238969 0.0552681007
  0.7007 0.2518581114 0.0264529972 0.0427704091
  0.7435 0.3203090830 0.0133769095 0.0313962221
  0.7863 0.4001585912 0.0052224361 0.0209000767
  0.8290 0.4920542353 0.0011414308 0.0110895892
  0.8718 0.5973025676 0.0000118320 0.0017463994
```

```
 0.8800 0.6190414551 0.0000000000 0.0000000000
 0.9145 0.7162851728 0.0000000000 0.0000000000
 0.9573 0.8504354740 0.0000000000 0.0000000000
 1.0000 1.0000000000 0.0000000000 0.0000000000/

-- OIL/WATER imbibition curve IMBNUM = 6
--   swl = 0.1050, swcr = 0.0500, sorw = 0.1200, cw = 3.00, co = 2.50
--   sw       krw          kro          pc
 0.1050 0.0000000000 0.9000000000 2.2739776679
 0.1497 0.0000000000 0.7757852262 1.1256026664
 0.1945 0.0001457938 0.6622270265 0.5489974559
 0.2393 0.0011683067 0.5592745579 0.3554919283
 0.2840 0.0039364339 0.4667710393 0.2577513379
 0.3287 0.0093229893 0.3841123177 0.1980929815
 0.3735 0.0182242309 0.3107684183 0.1573947650
 0.4183 0.0315090673 0.2465403110 0.1275975461
 0.4630 0.0500072897 0.1911297935 0.1046341924
 0.5078 0.0746777307 0.1438563958 0.0861175575
 0.5525 0.1062837148 0.1044759945 0.0707598195
 0.5973 0.1458427224 0.0723273868 0.0576134233
 0.6420 0.1940516110 0.0470360286 0.0461486471
 0.6867 0.2518614030 0.0279619779 0.0359227548
 0.7315 0.3203090830 0.0144645320 0.0266171100
 0.7762 0.3999625411 0.0059085598 0.0180482934
 0.8210 0.4920542353 0.0014391905 0.0100025922
 0.8658 0.5972967139 0.0000408987 0.0023585550
 0.8800 0.6335410720 0.0000000000 0.0000000000
 0.9105 0.7162851728 0.0000000000 0.0000000000
 0.9552 0.8501113914 0.0000000000 0.0000000000
 1.0000 1.0000000000 0.0000000000 0.0000000000/

 0.0 0.0 1.0 0.0
 1.0 1.0 0.0 0.0/

/

SGOF

-- GAS/OIL drainage curve SATNUM = 35
--   swl = 0.1700. sgoc = 0.0000. sorg = 0.1200. cg = 1.50. co = 3.00
--   sg       krg          kro          pc
 0.0000 0.0000000000 0.9000000000 0.0000000000
 0.0415 0.0100623059 0.7512278813 0.0000000000
 0.0830 0.0284604989 0.6198264225 0.0000000000
 0.1245 0.0522852752 0.5047172656 0.0000000000
 0.1660 0.0804984472 0.4048220524 0.0000000000
 0.2075 0.1125000000 0.3190624249 0.0000000000
 0.2490 0.1478850905 0.2463600250 0.0000000000
 0.2905 0.1863565132 0.1856364945 0.0000000000
 0.3320 0.2276839915 0.1358134754 0.0000000000
 0.3735 0.2716822593 0.0958126096 0.0000000000
 0.4150 0.3181980515 0.0645555389 0.0000000000
```

```
  0.4565 0.3671018251 0.0409639054 0.0000000000
  0.4980 0.4182822014 0.0239593508 0.0000000000
  0.5395 0.4716420783 0.0124635171 0.0000000000
  0.5810 0.5270958167 0.0053980462 0.0000000000
  0.6225 0.5845671476 0.0016845799 0.0000000000
  0.6640 0.6439875775 0.0002447603 0.0000000000
  0.7055 0.7052951510 0.0000002291 0.0000000000
  0.7100 0.7120539402 0.0000000000 0.0000000000
  0.7470 0.7684334714 0.0000000000 0.0000000000
  0.7885 0.8333509165 0.0000000000 0.0000000000
  0.8300 0.9000000000 0.0000000000 0.0000000000/

-- GAS/OIL drainage curve SATNUM = 9
--   swl = 0.1450. sgoc = 0.0000. sorg = 0.0800. cg = 1.50. co = 3.00
--   sg       krg          kro          pc
  0.0000 0.0000000000 0.9000000000 0.0000000000
  0.0427 0.0100446579 0.7592844476 0.0000000000
  0.0855 0.0284604989 0.6337824565 0.0000000000
  0.1283 0.0523158543 0.5229329225 0.0000000000
  0.1710 0.0804984472 0.4260378828 0.0000000000
  0.2138 0.1125394760 0.3417357303 0.0000000000
  0.2565 0.1478850905 0.2695154611 0.0000000000
  0.2992 0.1863098092 0.2082623262 0.0000000000
  0.3420 0.2276839915 0.1569643735 0.0000000000
  0.3848 0.2717352205 0.1148680364 0.0000000000
  0.4275 0.3181980515 0.0811338022 0.0000000000
  0.4702 0.3670432777 0.0547497688 0.0000000000
  0.5130 0.4182822014 0.0347729292 0.0000000000
  0.5557 0.4715784303 0.0203916936 0.0000000000
  0.5985 0.5270958167 0.0106309367 0.0000000000
  0.6412 0.5844987785 0.0046313302 0.0000000000
  0.6840 0.6439875775 0.0014570068 0.0000000000
  0.7268 0.7053679381 0.0002165103 0.0000000000
  0.7695 0.7684334714 0.0000003217 0.0000000000
  0.7750 0.7766867407 0.0000000000 0.0000000000
  0.8123 0.8334278660 0.0000000000 0.0000000000
  0.8550 0.9000000000 0.0000000000 0.0000000000/

-- GAS/OIL drainage curve SATNUM = 5
--   swl = 0.1050. sgoc = 0.0000. sorg = 0.0800. cg = 1.50. co = 3.00
--   sg       krg          kro          pc
  0.0000 0.0000000000 0.9000000000 0.0000000000
  0.0447 0.0100454464 0.7598876335 0.0000000000
  0.0895 0.0284604989 0.6348658017 0.0000000000
  0.1343 0.0523144875 0.5243689109 0.0000000000
  0.1790 0.0804984472 0.4277017529 0.0000000000
  0.2237 0.1124622926 0.3437109120 0.0000000000
  0.2685 0.1478850905 0.2713564707 0.0000000000
  0.3133 0.1864011334 0.2099432840 0.0000000000
  0.3580 0.2276839915 0.1586785720 0.0000000000
  0.4027 0.2716316682 0.1165224715 0.0000000000
  0.4475 0.3181980515 0.0825166738 0.0000000000
```

```
  0.4923 0.3671577588 0.0558684445 0.0000000000
  0.5370 0.4182822014 0.0357193931 0.0000000000
  0.5817 0.4715812748 0.0211112476 0.0000000000
  0.6265 0.5270958167 0.0111353468 0.0000000000
  0.6713 0.5846324635 0.0049333280 0.0000000000
  0.7160 0.6439875775 0.0016131519 0.0000000000
  0.7608 0.7053646850 0.0002647083 0.0000000000
  0.8055 0.7684334714 0.0000014254 0.0000000000
  0.8150 0.7820677360 0.0000000000 0.0000000000
  0.8502 0.8332774082 0.0000000000 0.0000000000
  0.8950 0.9000000000 0.0000000000 0.0000000000/

--NEVER USED
  0.0 0.0 1.0 0.0
  1.0 1.0 0.0 0.0/

/
--41 NODES (PVTO AND PVTG)
-- Input of PVT data for the model
-- Total 2 PVT regions (region 1 C,D,E segment, region 2 Gsegment)
INCLUDE
 './INCLUDE/PVT/PVT-WET-GAS.DATA' /

PVTW
  277.0     1.038     4.67E-5    0.318      0.0 /


ROCK
  277.0    4.84E-5 /

DENSITY
  860.04 1033.0    0.853 /

STONE1

--Chemical Properties see Appendix F
INCLUDE
  ./INCLUDE/CHEMICAL_PROPERTIES.DATA /


RPTPROPS
/
```

```
REGIONS    ============================================================

SATNUM
  100*1 100*1 100*1 100*1 100*2 100*3 /

SURFNUM
  600*4 /

RPTREGS
  20*0 1 /



SOLUTION   ============================================================

EQUIL
-- Datum      P     woc     Pc   goc    Pc  Rsvd  Rvvd
  2585.0  268.77  2693.3   0.0 2585.0  0.0   1   0   0 /   C+D+E:        Ile-Tilje


--2611.5 IS THE MIDDLE OF THE RES
--BUBBLE POINT 251 BAR

RSVD
  2585.9  120.29
  2599.9  110.00
  2663.6  106.77
  2699.9  106.77 /

RPTSOL
  RESTART=1  FIP=3  /

RPTRST
  'BASIC=2' 'VELOCITY' 'RK' 'VISC' /


SUMMARY    ============================================================

RPTONLY
ALL
SEPARATE
RUNSUM
```

```
SCHEDULE   ==============================================================

RPTSCHED
 'FIP=1' 'WELLS'  'SUMMARY=2'  /

TUNING
  .01   10.  .0001 .0001  /
  /
 20 1*  50    /

WELSPECS
-- WELL SPECIFICATION DATA
--
-- WELL   GROUP LOCATION  BHP    PI
-- NAME   NAME    I J    DEPTH  DEFN
   I     G      1  1   2632    WAT   0.0   STD    SHUT    NO   /
   P     G     10 10   2632    OIL   0.0   STD    SHUT    NO   /
/

COMPDAT
-- COMPLETION SPECIFICATION DATA
--
-- WELL   -LOCATION-  OPEN/ SAT CONN WELL EFF   SKIN
-- NAME   I    J    K1 K2  SHUT  TAB FACT  ID    KH
   I    1    1    1  6   OPEN    0  .0   0.15   /
   P    10   10   1  6   OPEN    0  .0   0.15   /
/

-- PRODUCTION WELL CONTROLS
WCONPROD
--
--  WELL    OPEN/  CNTL   OIL  WATER  GAS  LIQ  RESV  BHP
--  NAME    SHUT   MODE   RATE  RATE  RATE RATE RATE
    P      OPEN   BHP          5*                 260 0.0 4* /
/


WCONINJE
-- WELL PHASE  OPEN/  CNTL  SURF    RB/D  BHP
-- NAME        SHUT   MODE  RATE
   I   WAT   OPEN   RATE       500 1*  500 /
/

TSTEP
 108*30 /

WALKALIN
--wt%
--well  alkaline injection
--name  concentration Kg/m3
   I       0.0 /
/
```

```
WSURFACT
--well     surfactant injection
--name      conc Kg/m3
  I       0.0 /
 /
WPOLYMER
-- Polymer-Salt concentrations for injection wells
--Name   Concentration
--      Polymer  Salt
--     Kg/m3   kg/m3
  I    0.0      0.0    /
/


TSTEP
 48*30  /

WALKALIN
--well  alkaline injection
--name  concentration Kg/m3
   I       0.0 /
/
WSURFACT
--well     surfactant injection
--name      conc Kg/m3
  I       0.0 /
 /
WPOLYMER
-- Polymer-Salt concentrations for injection wells
--Name   Concentration
--      Polymer  Salt
--     Kg/m3   kg/m3
  I    0.0      0.0    /
/


TSTEP
 108*30 /

END
```

H Concentrations

RF	Surfactants Concentrations				
	0	0,1	0,5	1	2
A=1, P=0	64,04 %	64,17 %	65,31 %	66,15 %	67,08 %
A=1, P=0.025	66,93 %	67,45 %	69,45 %	70,34 %	71,32 %
A=1, P=0.05	69,13 %	70,19 %	73,04 %	73,99 %	74,88 %
A=1, P=0.1	73,14 %	74,86 %	78,29 %	79,84 %	81,18 %
A=0.5, P=0	64,03 %	64,13 %	65,21 %	66,00 %	66,94 %
A=0.5, P=0.025	66,91 %	67,09 %	69,28 %	70,13 %	71,11 %
A=0.5, P=0.05	69,10 %	69,56 %	72,69 %	73,66 %	74,57 %
A=0.5, P=0.1	73,11 %	74,03 %	77,69 %	79,36 %	80,78 %
A=0.1, P=0	64,02 %	64,09 %	65,13 %	65,87 %	66,82 %
A=0.1, P=0.025	66,89 %	66,94 %	69,07 %	69,93 %	70,90 %
A=0.1, P=0.05	69,06 %	69,24 %	72,23 %	73,32 %	74,23 %
A=0.1, P=0.1	73,09 %	73,62 %	77,00 %	78,91 %	80,42 %
A=0, P=0	64,02 %	64,09 %	65,11 %	65,85 %	66,80 %
A=0, P=0.025	66,88 %	66,91 %	69,02 %	69,89 %	70,86 %
A=0, P=0.05	69,04 %	69,19 %	72,11 %	73,24 %	74,16 %
A=0, P=0.1	73,08 %	73,54 %	76,85 %	78,81 %	80,34 %

Table H.1: Chemical Scheme recovery factors

	Recovery Factor per unit mass Chemical				
RF	Surfactants Concentrations				
	0	0,1	0,5	1	2
A=1, P=0	0,00	0,00	0,01	0,01	0,01
A=1, P=0.025	0,03	0,03	0,04	0,03	0,02
A=1, P=0.05	0,05	0,05	0,06	0,05	0,04
A=1, P=0.1	0,08	0,09	0,09	0,08	0,06
A=0.5, P=0	0,00	0,00	0,01	0,01	0,01
A=0.5, P=0.025	0,06	0,05	0,05	0,04	0,03
A=0.5, P=0.05	0,09	0,09	0,08	0,06	0,04
A=0.5, P=0.1	0,15	0,14	0,12	0,10	0,06
A=0.1, P=0	0,00	0,00	**0,02**	0,02	0,01
A=0.1, P=0.025	0,23	0,13	0,08	0,05	0,03
A=0.1, P=0.05	0,34	**0,21**	0,13	0,08	0,05
A=0.1, P=0.1	0,45	**0,32**	0,19	0,12	0,07
A=0, P=0	0,00	0,01	**0,02**	0,02	0,01
A=0, P=0.025	**1,14**	0,23	0,10	0,06	0,03
A=0, P=0.05	1,00	**0,34**	0,15	0,09	0,05
A=0, P=0.1	0,91	**0,48**	0,21	0,13	0,08

Base
S
P
SP
AS
ASP

Table H.2: Chemical Scheme recovery factor per unit mass chemical

POLY ADS, Kg	Polymer Concentration			
wt%	0	0,025	0,05	0,1
A=1, S=0	3,44E-16	4,56E+03	9,84E+03	1,99E+04
A=1, S=0.1	6,27E-16	4,46E+03	9,68E+03	1,99E+04
A=1, S=0.5	3,39E-16	4,25E+03	9,46E+03	1,94E+04
A=1, S=1.0	3,44E-16	4,27E+03	9,40E+03	1,88E+04
A=1, S=2.0	3,50E-16	4,36E+03	9,40E+03	1,87E+04
A=0.5, S=0	5,36E-16	6,35E+03	1,37E+04	2,40E+04
A=0.5, S=0.1	5,38E-16	6,29E+03	1,35E+04	2,40E+04
A=0.5, S=0.5	4,31E-16	6,02E+03	1,32E+04	2,35E+04
A=0.5, S=1.0	4,47E-16	5,94E+03	1,29E+04	2,27E+04
A=0.5, S=2.0	3,42E-16	6,04E+03	1,29E+04	2,24E+04
A=0.1, S=0	4,73E-16	8,85E+03	1,88E+04	2,77E+04
A=0.1, S=0.1	3,39E-16	8,81E+03	1,86E+04	2,76E+04
A=0.1, S=0.5	4,02E-16	8,47E+03	1,82E+04	2,71E+04
A=0.1, S=1.0	5,47E-16	8,32E+03	1,77E+04	2,61E+04
A=0.1, S=2.0	3,39E-16	8,43E+03	1,76E+04	2,56E+04
A=0, S=0	3,72E-16	9,56E+03	2,03E+04	2,87E+04
A=0, S=0.1	5,37E-16	9,52E+03	2,01E+04	2,85E+04
A=0, S=0.5	3,39E-16	9,18E+03	1,96E+04	2,80E+04
A=0, S=1.0	3,40E-16	9,00E+03	1,91E+04	2,69E+04
A=0, S=2.0	3,40E-16	9,10E+03	1,89E+04	2,64E+04

Table H.3: Chemical scheme polymer adsorption

SURF ADS, Kg	Surfactants Concentration				
wt%	0	0,1	0,5	1	2
A=1, P=0	0	283623	1080134	1410745	1769140
A=1, P=0.025	0	298879	1141426	1529141	2058671
A=1, P=0.05	0	328554	1253574	1707314	2291783
A=1, P=0.1	0	355353	1396786	1877942	2435277
A=0.5, P=0	0	556939	1340930	1658434	1945398
A=0.5, P=0.025	0	562389	1418276	1785661	2251203
A=0.5, P=0.05	0	560317	1555201	1983120	2498091
A=0.5, P=0.1	0	540141	1686978	2182127	2662027
A=0.1, P=0	0	642908	1690447	1913410	2105484
A=0.1, P=0.025	0	641955	1791283	2051650	2415935
A=0.1, P=0.05	0	633170	1934418	2262534	2673466
A=0.1, P=0.1	0	610285	2014467	2493006	2862138
A=0, P=0	0	657428	1788380	1984375	2147693
A=0, P=0.025	0	655546	1895837	2125822	2461629
A=0, P=0.05	0	646311	2036643	2340988	2721576
A=0, P=0.1	0	623786	2096351	2578952	2915918

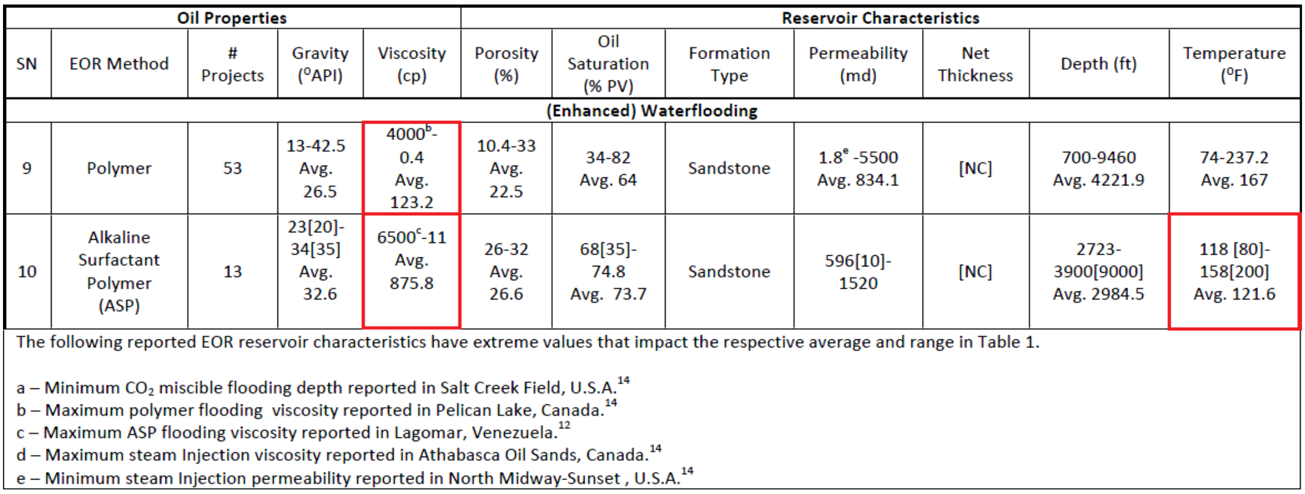
Table H.4: Chemical scheme surfactant adsorption

I New Region

```
EQUALS

--New Region defined for Ile
FIPILE  5   6 6  11 35  5 11 /
FIPILE  5  7 7   11 37  5 11 /
FIPILE  5  8 8   11 38  5 11 /
FIPILE  5  9 9   11 41  5 11 /
FIPILE  5  10 10 11 42  5 11 /
FIPILE  5  11 12 11 44  5 11 /
FIPILE  5  13 19 11 47  5 11 /
FIPILE  5  20 25 11 48  5 11 /
FIPILE  5  26 29 11 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 /

--New Region defined for Tofte
FIPTOFTE  9   6 6       11 35  12 18 /
FIPTOFTE  9       7 7   11 37  12 18 /
FIPTOFTE  9       8 8   11 38  12 18 /
FIPTOFTE  9       9 9   11 41  12 18 /
FIPTOFTE  9       10 10 11 42  12 18 /
FIPTOFTE  9       11 12 11 44  12 18 /
FIPTOFTE  9       13 19 11 47  12 18 /
FIPTOFTE  9       20 25 11 48  12 18 /
FIPTOFTE  9       26 29 11 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 Screening

The screening criterion used is made by Ahmad Aladasani (Ahamad & Bai, 2010). It is an update of the screening made by JJ.Taber (JJ.Taber, Martin, & Serght, 1997). The Norne reservoir and oil characteristics is collected from (Statoil, 2009) and (Hetland & Verlo, Petrophysical information, 2008).



Oil Properties					Reservoir Characteristics						
SN	EOR Method	# Projects	Gravity (°API)	Viscosity (cp)	Porosity (%)	Oil Saturation (% PV)	Formation Type	Permeability (md)	Net Thickness	Depth (ft)	Temperature (°F)
(Enhanced) Waterflooding											
9	Polymer	53	13-42.5 Avg. 26.5	4000^{b}-0.4 Avg. 123.2	10.4-33 Avg. 22.5	34-82 Avg. 64	Sandstone	1.8^{e} -5500 Avg. 834.1	[NC]	700-9460 Avg. 4221.9	74-237.2 Avg. 167
10	Alkaline Surfactant Polymer (ASP)	13	23[20]-34[35] Avg. 32.6	6500^{c}-11 Avg. 875.8	26-32 Avg. 26.6	68[35]-74.8 Avg. 73.7	Sandstone	596[10]-1520	[NC]	2723-3900[9000] Avg. 2984.5	118 [80]-158[200] Avg. 121.6

The following reported EOR reservoir characteristics have extreme values that impact the respective average and range in Table 1.

a – Minimum CO_2 miscible flooding depth reported in Salt Creek Field, U.S.A.^{14}
b – Maximum polymer flooding viscosity reported in Pelican Lake, Canada.^{14}
c – Maximum ASP flooding viscosity reported in Lagomar, Venezuela.^{12}
d – Maximum steam Injection viscosity reported in Athabasca Oil Sands, Canada.^{14}
e – Minimum steam Injection permeability reported in North Midway-Sunset , U.S.A.^{14}

Table J.1: Screening (JJ.Taber, Martin, & Serght, 1997)

Oil Properties:	
Gravity (°API)	32.7
Viscosity (cp)	<1.2
Reservoir Characteristics:	
Porosity (%)	20-30
Oil Saturation (% PV)	0-55
Formation type	Sandstone
Permeability (mD)	20-2500
Net Thickness	361
Depth (ft)	8200
Temperature (°F)	208.4

Table J.2: Screening (Statoil, 2009)

K NPV

Polymer Flooding

Case 1.1: PV=0.1 Polymer 0.025 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,02E+06	7,23E+04	4,55E+05	43,21			9,13E+05	0,00	0,00	4,56	4,56	38,65	35,79	35,79
01.01.2009	2	1,25E+06	1,31E+06	5,69E+04	3,58E+05	34,02			9,13E+05	0,00	0,00	4,56	4,56	29,46	25,26	61,05
01.01.2010	3	1,01E+06	1,10E+06	9,35E+04	5,88E+05	55,87				0,00	0,00	0,00	0,00	55,87	44,35	105,40
01.01.2011	4	8,10E+05	8,85E+05	7,52E+04	4,73E+05	44,90				0,00	0,00	0,00	0,00	44,90	33,01	138,40
01.01.2012	5	6,47E+05	6,89E+05	4,18E+04	2,63E+05	25,00				0,00	0,00	0,00	0,00	25,00	17,02	155,42
01.01.2013	6	5,23E+05	5,32E+05	8,54E+03	5,37E+04	5,10				0,00	0,00	0,00	0,00	5,10	3,22	158,63
01.01.2014	7	4,29E+05	4,25E+05	-4,05E+03	-2,55E+04	-2,42				0,00	0,00	0,00	0,00	-2,42	-1,41	157,22
01.01.2015	8	3,65E+05	3,56E+05	-8,38E+03	-5,27E+04	-5,01				0,00	0,00	0,00	0,00	-5,01	-2,71	154,52
01.01.2016	9	3,16E+05	3,09E+05	-7,02E+03	-4,42E+04	-4,19				0,00	0,00	0,00	0,00	-4,19	-2,10	152,42
01.01.2017	10	2,80E+05	2,75E+05	-5,13E+03	-3,23E+04	-3,07				0,00	0,00	0,00	0,00	-3,07	-1,42	151,00
01.01.2018	11	2,19E+05	2,47E+05	2,77E+04	1,74E+05	16,52				0,00	0,00	0,00	0,00	16,52	7,09	158,08
01.01.2019	12	1,86E+05	1,98E+05	1,24E+04	7,80E+04	7,41				0,00	0,00	0,00	0,00	7,41	2,94	161,03
01.01.2020	13	1,67E+05	1,60E+05	-7,06E+03	-4,44E+04	-4,22				0,00	0,00	0,00	0,00	-4,22	-1,55	159,48
01.01.2021	14	1,54E+05	1,42E+05	-1,12E+04	-7,06E+04	-6,71				0,00	0,00	0,00	0,00	-6,71	-2,28	157,19
01.01.2022	15	1,42E+05	1,29E+05	-1,26E+04	-7,93E+04	-7,53				0,00	0,00	0,00	0,00	-7,53	-2,38	154,82
Sum		8,45E+06	8,78E+06	3,33E+05	2,09E+06	198,89	0,00E+00	0,00E+00	1,83E+06	0,00	0,00	9,13	9,13	189,77	**154,82**	

Polymer Flooding

Case 1.2: PV=0.1 Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,03E+06	8,20E+04	5,16E+05	48,99			1,83E+06	0,00	0,00	9,13	9,13	39,87	36,91	36,91
01.01.2009	2	1,25E+06	1,34E+06	8,96E+04	5,64E+05	53,56			1,83E+06	0,00	0,00	9,13	9,13	44,43	38,09	75,01
01.01.2010	3	1,01E+06	1,15E+06	1,43E+05	9,02E+05	85,66				0,00	0,00	0,00	0,00	85,66	68,00	143,01
01.01.2011	4	8,10E+05	9,33E+05	1,23E+05	7,73E+05	73,39				0,00	0,00	0,00	0,00	73,39	53,95	196,96
01.01.2012	5	6,47E+05	7,24E+05	7,69E+04	4,84E+05	45,97				0,00	0,00	0,00	0,00	45,97	31,29	228,24
01.01.2013	6	5,23E+05	5,55E+05	3,21E+04	2,02E+05	19,16				0,00	0,00	0,00	0,00	19,16	12,07	240,31
01.01.2014	7	4,29E+05	4,41E+05	1,17E+04	7,33E+04	6,96				0,00	0,00	0,00	0,00	6,96	4,06	244,38
01.01.2015	8	3,65E+05	3,66E+05	1,79E+03	1,13E+04	1,07				0,00	0,00	0,00	0,00	1,07	0,58	244,95
01.01.2016	9	3,16E+05	3,15E+05	-1,08E+03	-6,79E+03	-0,65				0,00	0,00	0,00	0,00	-0,65	-0,32	244,63
01.01.2017	10	2,80E+05	2,78E+05	-1,71E+03	-1,08E+04	-1,02				0,00	0,00	0,00	0,00	-1,02	-0,47	244,16
01.01.2018	11	2,19E+05	2,47E+05	2,80E+04	1,76E+05	16,72				0,00	0,00	0,00	0,00	16,72	7,17	251,33
01.01.2019	12	1,86E+05	2,24E+05	3,89E+04	2,45E+05	23,27				0,00	0,00	0,00	0,00	23,27	9,24	260,57
01.01.2020	13	1,67E+05	1,89E+05	2,17E+04	1,36E+05	12,95				0,00	0,00	0,00	0,00	12,95	4,76	265,33
01.01.2021	14	1,54E+05	1,47E+05	-6,61E+03	-4,16E+04	-3,95				0,00	0,00	0,00	0,00	-3,95	-1,34	263,99
01.01.2022	15	1,42E+05	1,27E+05	-1,46E+04	-9,18E+04	-8,72				0,00	0,00	0,00	0,00	-8,72	-2,75	261,24
Sum		8,45E+06	9,08E+06	6,25E+05	3,93E+06	373,37	0,00E+00	0,00E+00	3,65E+06	0,00	0,00	18,25	18,25	355,12	**261,24**	

Polymer Flooding

Case 2.1: PV=0.2 Polymer 0.025 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,02E+06	7,23E+04	4,55E+05	43,21			9,13E+05	0,00	0,00	4,56	4,56	38,65	35,79	35,79
01.01.2009	2	1,25E+06	1,31E+06	5,69E+04	3,58E+05	34,02			9,13E+05	0,00	0,00	4,56	4,56	29,46	25,26	61,05
01.01.2010	3	1,01E+06	1,11E+06	1,00E+05	6,32E+05	60,03			9,13E+05	0,00	0,00	4,56	4,56	55,47	44,04	105,08
01.01.2011	4	8,10E+05	9,08E+05	9,82E+04	6,18E+05	58,70			9,13E+05	0,00	0,00	4,56	4,56	54,14	39,79	144,88
01.01.2012	5	6,47E+05	7,32E+05	8,53E+04	5,36E+05	50,96				0,00	0,00	0,00	0,00	50,96	34,68	179,56
01.01.2013	6	5,23E+05	5,82E+05	5,81E+04	3,65E+05	34,72				0,00	0,00	0,00	0,00	34,72	21,88	201,44
01.01.2014	7	4,29E+05	4,68E+05	3,91E+04	2,46E+05	23,36				0,00	0,00	0,00	0,00	23,36	13,63	215,07
01.01.2015	8	3,65E+05	3,83E+05	1,87E+04	1,17E+05	11,16				0,00	0,00	0,00	0,00	11,16	6,03	221,10
01.01.2016	9	3,16E+05	3,21E+05	5,22E+03	3,28E+04	3,12				0,00	0,00	0,00	0,00	3,12	1,56	222,66
01.01.2017	10	2,80E+05	2,81E+05	1,54E+03	9,69E+03	0,92				0,00	0,00	0,00	0,00	0,92	0,43	223,08
01.01.2018	11	2,19E+05	2,52E+05	3,27E+04	2,06E+05	19,55				0,00	0,00	0,00	0,00	19,55	8,38	231,47
01.01.2019	12	1,86E+05	2,11E+05	2,59E+04	1,63E+05	15,49				0,00	0,00	0,00	0,00	15,49	6,15	237,62
01.01.2020	13	1,67E+05	1,68E+05	5,00E+02	3,14E+03	0,30				0,00	0,00	0,00	0,00	0,30	0,11	237,73
01.01.2021	14	1,54E+05	1,45E+05	-8,46E+03	-5,32E+04	-5,06				0,00	0,00	0,00	0,00	-5,06	-1,72	236,01
01.01.2022	15	1,42E+05	1,29E+05	-1,33E+04	-8,36E+04	-7,94				0,00	0,00	0,00	0,00	-7,94	-2,50	233,50
Sum		8,45E+06	9,02E+06	5,73E+05	3,61E+06	342,55	0,00E+00	0,00E+00	3,65E+06	0,00	0,00	18,25	18,25	324,30	**233,50**	

Polymer Flooding

Case 2.2: PV=0.2 Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,03E+06	8,20E+04	5,16E+05	48,99			1,83E+06	0,00	0,00	9,13	9,13	39,87	36,91	36,91
01.01.2009	2	1,25E+06	1,34E+06	8,96E+04	5,64E+05	53,56			1,83E+06	0,00	0,00	9,13	9,13	44,43	38,09	75,01
01.01.2010	3	1,01E+06	1,17E+06	1,59E+05	1,00E+06	95,09			1,83E+06	0,00	0,00	9,13	9,13	85,96	68,24	143,25
01.01.2011	4	8,10E+05	9,80E+05	1,70E+05	1,07E+06	101,42			1,83E+06	0,00	0,00	9,13	9,13	92,29	67,84	211,08
01.01.2012	5	6,47E+05	8,03E+05	1,56E+05	9,80E+05	93,08				0,00	0,00	0,00	0,00	93,08	63,35	274,43
01.01.2013	6	5,23E+05	6,43E+05	1,19E+05	7,51E+05	71,35				0,00	0,00	0,00	0,00	71,35	44,96	319,39
01.01.2014	7	4,29E+05	5,04E+05	7,51E+04	4,72E+05	44,84				0,00	0,00	0,00	0,00	44,84	26,17	345,56
01.01.2015	8	3,65E+05	4,09E+05	4,48E+04	2,82E+05	26,75				0,00	0,00	0,00	0,00	26,75	14,45	360,01
01.01.2016	9	3,16E+05	3,38E+05	2,20E+04	1,38E+05	13,15				0,00	0,00	0,00	0,00	13,15	6,58	366,59
01.01.2017	10	2,80E+05	2,93E+05	1,26E+04	7,92E+04	7,52				0,00	0,00	0,00	0,00	7,52	3,48	370,08
01.01.2018	11	2,19E+05	2,57E+05	3,77E+04	2,37E+05	22,53				0,00	0,00	0,00	0,00	22,53	9,66	379,74
01.01.2019	12	1,86E+05	2,30E+05	4,45E+04	2,80E+05	26,61				0,00	0,00	0,00	0,00	26,61	10,57	390,31
01.01.2020	13	1,67E+05	2,09E+05	4,15E+04	2,61E+05	24,82				0,00	0,00	0,00	0,00	24,82	9,12	399,44
01.01.2021	14	1,54E+05	1,85E+05	3,10E+04	1,95E+05	18,49				0,00	0,00	0,00	0,00	18,49	6,30	405,73
01.01.2022	15	1,42E+05	1,45E+05	2,86E+03	1,80E+04	1,71				0,00	0,00	0,00	0,00	1,71	0,54	406,27
Sum		8,45E+06	9,54E+06	1,09E+06	6,84E+06	649,92	0,00E+00	0,00E+00	7,30E+06	0,00	0,00	36,50	36,50	613,42	**406,27**	

Surfactant Flooding

Case 3.1: PV=0.1 Surfactant 0.5 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	1,96E+06	3,07E+03	1,93E+04	1,83		1,83E+07		0,00	127,75	0,00	127,75	-125,92	-116,59	-116,59
01.01.2009	2	1,25E+06	1,26E+06	9,59E+03	6,03E+04	5,73		1,83E+07		0,00	127,75	0,00	127,75	-122,02	-104,61	-221,20
01.01.2010	3	1,01E+06	1,02E+06	1,36E+04	8,58E+04	8,15				0,00	0,00	0,00	0,00	8,15	6,47	-214,73
01.01.2011	4	8,10E+05	8,17E+05	6,91E+03	4,35E+04	4,13				0,00	0,00	0,00	0,00	4,13	3,03	-211,70
01.01.2012	5	6,47E+05	6,51E+05	4,26E+03	2,68E+04	2,55				0,00	0,00	0,00	0,00	2,55	1,73	-209,96
01.01.2013	6	5,23E+05	5,25E+05	1,90E+03	1,20E+04	1,14				0,00	0,00	0,00	0,00	1,14	0,72	-209,25
01.01.2014	7	4,29E+05	4,31E+05	1,32E+03	8,30E+03	0,79				0,00	0,00	0,00	0,00	0,79	0,46	-208,79
01.01.2015	8	3,65E+05	3,65E+05	4,00E+02	2,52E+03	0,24				0,00	0,00	0,00	0,00	0,24	0,13	-208,66
01.01.2016	9	3,16E+05	3,16E+05	-2,20E+02	-1,38E+03	-0,13				0,00	0,00	0,00	0,00	-0,13	-0,07	-208,72
01.01.2017	10	2,80E+05	2,79E+05	-7,40E+02	-4,65E+03	-0,44				0,00	0,00	0,00	0,00	-0,44	-0,20	-208,93
01.01.2018	11	2,19E+05	2,19E+05	-9,40E+02	-5,91E+03	-0,56				0,00	0,00	0,00	0,00	-0,56	-0,24	-209,17
01.01.2019	12	1,86E+05	1,84E+05	-1,03E+03	-6,48E+03	-0,62				0,00	0,00	0,00	0,00	-0,62	-0,24	-209,41
01.01.2020	13	1,67E+05	1,66E+05	-1,02E+03	-6,42E+03	-0,61				0,00	0,00	0,00	0,00	-0,61	-0,22	-209,64
01.01.2021	14	1,54E+05	1,53E+05	-9,90E+02	-6,23E+03	-0,59				0,00	0,00	0,00	0,00	-0,59	-0,20	-209,84
01.01.2022	15	1,42E+05	1,41E+05	-9,60E+02	-6,04E+03	-0,57				0,00	0,00	0,00	0,00	-0,57	-0,18	-210,02
Sum		8,45E+06	8,49E+06	3,52E+04	2,21E+05	21,03	0,00E+00	3,65E+07	0,00E+00	0,00	255,50	0,00	255,50	-234,47	**-210,02**	

Surfactant Flooding

Case 3.2: PV=0.1 Surfactant 1.0 wt%

Time		Oil Production	Incremental Oil				Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	1,96E+06	4,55E+03	2,86E+04	2,72		3,65E+07		0,00	255,50	0,00	255,50	-252,78	-234,06	-234,06
01.01.2009	2	1,25E+06	1,27E+06	1,56E+04	9,80E+04	9,31		3,65E+07		0,00	255,50	0,00	255,50	-246,19	-211,07	-445,13
01.01.2010	3	1,01E+06	1,03E+06	2,51E+04	1,58E+05	14,98				0,00	0,00	0,00	0,00	14,98	11,89	-433,23
01.01.2011	4	8,10E+05	8,29E+05	1,86E+04	1,17E+05	11,12				0,00	0,00	0,00	0,00	11,12	8,17	-425,06
01.01.2012	5	6,47E+05	6,57E+05	9,79E+03	6,16E+04	5,85				0,00	0,00	0,00	0,00	5,85	3,98	-421,08
01.01.2013	6	5,23E+05	5,25E+05	1,96E+03	1,23E+04	1,17				0,00	0,00	0,00	0,00	1,17	0,74	-420,34
01.01.2014	7	4,29E+05	4,31E+05	1,72E+03	1,08E+04	1,03				0,00	0,00	0,00	0,00	1,03	0,60	-419,74
01.01.2015	8	3,65E+05	3,65E+05	4,20E+02	2,64E+03	0,25				0,00	0,00	0,00	0,00	0,25	0,14	-419,61
01.01.2016	9	3,16E+05	3,16E+05	-8,00E+01	-5,03E+02	-0,05				0,00	0,00	0,00	0,00	-0,05	-0,02	-419,63
01.01.2017	10	2,80E+05	2,81E+05	1,11E+03	6,98E+03	0,66				0,00	0,00	0,00	0,00	0,66	0,31	-419,32
01.01.2018	11	2,19E+05	2,24E+05	4,84E+03	3,04E+04	2,89				0,00	0,00	0,00	0,00	2,89	1,24	-418,08
01.01.2019	12	1,86E+05	1,85E+05	-1,30E+02	-8,18E+02	-0,08				0,00	0,00	0,00	0,00	-0,08	-0,03	-418,11
01.01.2020	13	1,67E+05	1,66E+05	-9,50E+02	-5,98E+03	-0,57				0,00	0,00	0,00	0,00	-0,57	-0,21	-418,32
01.01.2021	14	1,54E+05	1,52E+05	-1,42E+03	-8,93E+03	-0,85				0,00	0,00	0,00	0,00	-0,85	-0,29	-418,61
01.01.2022	15	1,42E+05	1,40E+05	-1,71E+03	-1,08E+04	-1,02				0,00	0,00	0,00	0,00	-1,02	-0,32	-418,93
Sum		8,45E+06	8,53E+06	7,94E+04	4,99E+05	47,42	0,00E+00	7,30E+07	0,00E+00	0,00	511,00	0,00	511,00	-463,58	**-418,93**	

Surfactant Flooding

Case 4.1: PV=0.2 Polymer 0.5 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	1,96E+06	3,07E+03	1,93E+04	1,83		1,83E+07		0,00	127,75	0,00	127,75	-125,92	-116,59	-116,59
01.01.2009	2	1,25E+06	1,26E+06	9,59E+03	6,03E+04	5,73		1,83E+07		0,00	127,75	0,00	127,75	-122,02	-104,61	-221,20
01.01.2010	3	1,01E+06	1,02E+06	1,58E+04	9,92E+04	9,42		1,83E+07		0,00	127,75	0,00	127,75	-118,33	-93,93	-315,13
01.01.2011	4	8,10E+05	8,23E+05	1,31E+04	8,21E+04	7,80		1,83E+07		0,00	127,75	0,00	127,75	-119,95	-88,16	-403,30
01.01.2012	5	6,47E+05	6,60E+05	1,31E+04	8,22E+04	7,81				0,00	0,00	0,00	0,00	7,81	5,32	-397,98
01.01.2013	6	5,23E+05	5,33E+05	9,77E+03	6,15E+04	5,84				0,00	0,00	0,00	0,00	5,84	3,68	-394,30
01.01.2014	7	4,29E+05	4,36E+05	6,94E+03	4,37E+04	4,15				0,00	0,00	0,00	0,00	4,15	2,42	-391,88
01.01.2015	8	3,65E+05	3,69E+05	4,52E+03	2,84E+04	2,70				0,00	0,00	0,00	0,00	2,70	1,46	-390,42
01.01.2016	9	3,16E+05	3,19E+05	2,87E+03	1,81E+04	1,71				0,00	0,00	0,00	0,00	1,71	0,86	-389,57
01.01.2017	10	2,80E+05	2,80E+05	-5,00E+01	-3,14E+02	-0,03				0,00	0,00	0,00	0,00	-0,03	-0,01	-389,58
01.01.2018	11	2,19E+05	2,17E+05	-2,21E+03	-1,39E+04	-1,32				0,00	0,00	0,00	0,00	-1,32	-0,57	-390,15
01.01.2019	12	1,86E+05	1,85E+05	-5,50E+02	-3,46E+03	-0,33				0,00	0,00	0,00	0,00	-0,33	-0,13	-390,28
01.01.2020	13	1,67E+05	1,67E+05	-5,30E+02	-3,33E+03	-0,32				0,00	0,00	0,00	0,00	-0,32	-0,12	-390,39
01.01.2021	14	1,54E+05	1,53E+05	-7,30E+02	-4,59E+03	-0,44				0,00	0,00	0,00	0,00	-0,44	-0,15	-390,54
01.01.2022	15	1,42E+05	1,41E+05	-1,10E+03	-6,92E+03	-0,66				0,00	0,00	0,00	0,00	-0,66	-0,21	-390,75
Sum		8,45E+06	8,52E+06	7,35E+04	4,62E+05	43,91	0,00E+00	7,30E+07	0,00E+00	0,00	511,00	0,00	511,00	-467,09	**-390,75**	

Surfactant Flooding

Case 4.2: PV=0.2 Surfactant 1.0 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	1,96E+06	4,55E+03	2,86E+04	2,72		3,65E+07		0,00	255,50	0,00	255,50	-252,78	-234,06	-234,06
01.01.2009	2	1,25E+06	1,27E+06	1,56E+04	9,80E+04	9,31		3,65E+07		0,00	255,50	0,00	255,50	-246,19	-211,07	-445,13
01.01.2010	3	1,01E+06	1,04E+06	2,76E+04	1,74E+05	16,49		3,65E+07		0,00	255,50	0,00	255,50	-239,01	-189,73	-634,86
01.01.2011	4	8,10E+05	8,36E+05	2,61E+04	1,64E+05	15,60		3,65E+07		0,00	255,50	0,00	255,50	-239,90	-176,33	-811,19
01.01.2012	5	6,47E+05	6,72E+05	2,51E+04	1,58E+05	15,01				0,00	0,00	0,00	0,00	15,01	10,22	-800,97
01.01.2013	6	5,23E+05	5,43E+05	1,94E+04	1,22E+05	11,57				0,00	0,00	0,00	0,00	11,57	7,29	-793,68
01.01.2014	7	4,29E+05	4,46E+05	1,69E+04	1,06E+05	10,09				0,00	0,00	0,00	0,00	10,09	5,89	-787,79
01.01.2015	8	3,65E+05	3,75E+05	1,00E+04	6,29E+04	5,98				0,00	0,00	0,00	0,00	5,98	3,23	-784,56
01.01.2016	9	3,16E+05	3,21E+05	4,70E+03	2,96E+04	2,81				0,00	0,00	0,00	0,00	2,81	1,40	-783,16
01.01.2017	10	2,80E+05	2,82E+05	1,58E+03	9,94E+03	0,94				0,00	0,00	0,00	0,00	0,94	0,44	-782,72
01.01.2018	11	2,19E+05	2,23E+05	3,37E+03	2,12E+04	2,01				0,00	0,00	0,00	0,00	2,01	0,86	-781,86
01.01.2019	12	1,86E+05	1,87E+05	1,62E+03	1,02E+04	0,97				0,00	0,00	0,00	0,00	0,97	0,38	-781,47
01.01.2020	13	1,67E+05	1,68E+05	8,50E+02	5,35E+03	0,51				0,00	0,00	0,00	0,00	0,51	0,19	-781,29
01.01.2021	14	1,54E+05	1,54E+05	5,60E+02	3,52E+03	0,33				0,00	0,00	0,00	0,00	0,33	0,11	-781,17
01.01.2022	15	1,42E+05	1,42E+05	-3,10E+02	-1,95E+03	-0,19				0,00	0,00	0,00	0,00	-0,19	-0,06	-781,23
Sum		8,45E+06	8,61E+06	1,58E+05	9,91E+05	94,17	0,00E+00	1,46E+08	0,00E+00	0,00	1022,00	0,00	1022,00	-927,83	**-781,23**	

SP Flooding

Case 5: PV=0.1, Surfactant 0.1 wt%, Polymer 0.05 wt%

Time		Oil Production	Incremental Oil				Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,03E+06	8,29E+04	5,21E+05	49,51		3,65E+06	1,83E+06	0,00	25,55	9,13	34,68	14,83	13,73	13,73
01.01.2009	2	1,25E+06	1,34E+06	9,02E+04	5,67E+05	53,88		3,65E+06	1,83E+06	0,00	25,55	9,13	34,68	19,20	16,46	30,20
01.01.2010	3	1,01E+06	1,15E+06	1,43E+05	9,02E+05	85,69				0,00	0,00	0,00	0,00	85,69	68,03	98,22
01.01.2011	4	8,10E+05	9,33E+05	1,23E+05	7,71E+05	73,25				0,00	0,00	0,00	0,00	73,25	53,84	152,06
01.01.2012	5	6,47E+05	7,24E+05	7,68E+04	4,83E+05	45,87				0,00	0,00	0,00	0,00	45,87	31,22	183,28
01.01.2013	6	5,23E+05	5,56E+05	3,22E+04	2,02E+05	19,22				0,00	0,00	0,00	0,00	19,22	12,11	195,39
01.01.2014	7	4,29E+05	4,41E+05	1,20E+04	7,54E+04	7,16				0,00	0,00	0,00	0,00	7,16	4,18	199,57
01.01.2015	8	3,65E+05	3,67E+05	2,20E+03	1,38E+04	1,31				0,00	0,00	0,00	0,00	1,31	0,71	200,28
01.01.2016	9	3,16E+05	3,15E+05	-7,70E+02	-4,84E+03	-0,46				0,00	0,00	0,00	0,00	-0,46	-0,23	200,05
01.01.2017	10	2,80E+05	2,78E+05	-1,53E+03	-9,62E+03	-0,91				0,00	0,00	0,00	0,00	-0,91	-0,42	199,63
01.01.2018	11	2,19E+05	2,47E+05	2,80E+04	1,76E+05	16,75				0,00	0,00	0,00	0,00	16,75	7,19	206,81
01.01.2019	12	1,86E+05	2,24E+05	3,90E+04	2,45E+05	23,28				0,00	0,00	0,00	0,00	23,28	9,24	216,06
01.01.2020	13	1,67E+05	1,89E+05	2,22E+04	1,39E+05	13,24				0,00	0,00	0,00	0,00	13,24	4,87	220,93
01.01.2021	14	1,54E+05	1,47E+05	-6,36E+03	-4,00E+04	-3,80				0,00	0,00	0,00	0,00	-3,80	-1,29	219,63
01.01.2022	15	1,42E+05	1,28E+05	-1,45E+04	-9,11E+04	-8,65				0,00	0,00	0,00	0,00	-8,65	-2,73	216,90
Sum		8,45E+06	9,08E+06	6,28E+05	3,95E+06	375,34	0,00E+00	7,30E+06	3,65E+06	0,00	51,10	18,25	69,35	305,99	**216,90**	

SP Flooding

Case 6: PV=0.1, Surfactant 0.5 wt%, Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,04E+06	8,34E+04	5,24E+05	49,81		1,83E+07	1,83E+06	0,00	127,75	9,13	136,88	-87,06	-80,62	-80,62
01.01.2009	2	1,25E+06	1,34E+06	9,08E+04	5,71E+05	54,23		1,83E+07	1,83E+06	0,00	127,75	9,13	136,88	-82,64	-70,85	-151,47
01.01.2010	3	1,01E+06	1,15E+06	1,43E+05	9,02E+05	85,69				0,00	0,00	0,00	0,00	85,69	68,03	-83,44
01.01.2011	4	8,10E+05	9,34E+05	1,24E+05	7,79E+05	74,00				0,00	0,00	0,00	0,00	74,00	54,40	-29,05
01.01.2012	5	6,47E+05	7,25E+05	7,78E+04	4,89E+05	46,49				0,00	0,00	0,00	0,00	46,49	31,64	2,60
01.01.2013	6	5,23E+05	5,57E+05	3,38E+04	2,13E+05	20,22				0,00	0,00	0,00	0,00	20,22	12,74	15,34
01.01.2014	7	4,29E+05	4,44E+05	1,46E+04	9,16E+04	8,70				0,00	0,00	0,00	0,00	8,70	5,08	20,41
01.01.2015	8	3,65E+05	3,70E+05	4,89E+03	3,08E+04	2,92				0,00	0,00	0,00	0,00	2,92	1,58	21,99
01.01.2016	9	3,16E+05	3,17E+05	1,11E+03	6,98E+03	0,66				0,00	0,00	0,00	0,00	0,66	0,33	22,32
01.01.2017	10	2,80E+05	2,79E+05	-7,60E+02	-4,78E+03	-0,45				0,00	0,00	0,00	0,00	-0,45	-0,21	22,11
01.01.2018	11	2,19E+05	2,47E+05	2,80E+04	1,76E+05	16,72				0,00	0,00	0,00	0,00	16,72	7,17	29,28
01.01.2019	12	1,86E+05	2,24E+05	3,85E+04	2,42E+05	23,02				0,00	0,00	0,00	0,00	23,02	9,14	38,43
01.01.2020	13	1,67E+05	1,94E+05	2,71E+04	1,71E+05	16,22				0,00	0,00	0,00	0,00	16,22	5,96	44,39
01.01.2021	14	1,54E+05	1,51E+05	-3,06E+03	-1,92E+04	-1,83				0,00	0,00	0,00	0,00	-1,83	-0,62	43,77
01.01.2022	15	1,42E+05	1,29E+05	-1,32E+04	-8,32E+04	-7,91				0,00	0,00	0,00	0,00	-7,91	-2,49	41,28
Sum		8,45E+06	9,10E+06	6,50E+05	4,09E+06	388,51	0,00E+00	3,65E+07	3,65E+06	0,00	255,50	18,25	273,75	114,76	**41,28**	

SP Flooding

Case 7: PV=0.1, Surfactant 1.0 wt%, Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,04E+06	8,41E+04	5,29E+05	50,25		3,65E+07	1,83E+06	0,00	255,50	9,13	264,63	-214,37	-198,49	-198,49
01.01.2009	2	1,25E+06	1,34E+06	9,18E+04	5,77E+05	54,86		3,65E+07	1,83E+06	0,00	255,50	9,13	264,63	-209,77	-179,84	-378,33
01.01.2010	3	1,01E+06	1,15E+06	1,45E+05	9,11E+05	86,50				0,00	0,00	0,00	0,00	86,50	68,67	-309,67
01.01.2011	4	8,10E+05	9,38E+05	1,28E+05	8,04E+05	76,38				0,00	0,00	0,00	0,00	76,38	56,14	-253,52
01.01.2012	5	6,47E+05	7,29E+05	8,17E+04	5,14E+05	48,84				0,00	0,00	0,00	0,00	48,84	33,24	-220,28
01.01.2013	6	5,23E+05	5,59E+05	3,54E+04	2,23E+05	21,17				0,00	0,00	0,00	0,00	21,17	13,34	-206,94
01.01.2014	7	4,29E+05	4,47E+05	1,76E+04	1,11E+05	10,53				0,00	0,00	0,00	0,00	10,53	6,14	-200,80
01.01.2015	8	3,65E+05	3,73E+05	8,33E+03	5,24E+04	4,98				0,00	0,00	0,00	0,00	4,98	2,69	-198,11
01.01.2016	9	3,16E+05	3,19E+05	3,07E+03	1,93E+04	1,83				0,00	0,00	0,00	0,00	1,83	0,92	-197,19
01.01.2017	10	2,80E+05	2,80E+05	-1,40E+02	-8,81E+02	-0,08				0,00	0,00	0,00	0,00	-0,08	-0,04	-197,23
01.01.2018	11	2,19E+05	2,47E+05	2,79E+04	1,76E+05	16,68				0,00	0,00	0,00	0,00	16,68	7,16	-190,08
01.01.2019	12	1,86E+05	2,23E+05	3,75E+04	2,36E+05	22,41				0,00	0,00	0,00	0,00	22,41	8,90	-181,17
01.01.2020	13	1,67E+05	2,03E+05	3,64E+04	2,29E+05	21,76				0,00	0,00	0,00	0,00	21,76	8,00	-173,17
01.01.2021	14	1,54E+05	1,67E+05	1,38E+04	8,69E+04	8,25				0,00	0,00	0,00	0,00	8,25	2,81	-170,37
01.01.2022	15	1,42E+05	1,35E+05	-7,47E+03	-4,70E+04	-4,46				0,00	0,00	0,00	0,00	-4,46	-1,41	-171,77
Sum		8,45E+06	9,15E+06	7,03E+05	4,42E+06	419,90	0,00E+00	7,30E+07	3,65E+06	0,00	511,00	18,25	529,25	-109,35	**-171,77**	

AS Flooding

Case 8: PV=0.1, Alkaline 0.1 wt%, Surfactant 0.5 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	1,96E+06	3,05E+03	1,92E+04	1,82	3,65E+06	1,83E+07		3,65	127,75	0,00	131,40	-129,58	-119,98	-119,98
01.01.2009	2	1,25E+06	1,26E+06	9,57E+03	6,02E+04	5,72	3,65E+06	1,83E+07		3,65	127,75	0,00	131,40	-125,68	-107,75	-227,73
01.01.2010	3	1,01E+06	1,02E+06	1,37E+04	8,59E+04	8,16				0,00	0,00	0,00	0,00	8,16	6,48	-221,25
01.01.2011	4	8,10E+05	8,17E+05	7,10E+03	4,47E+04	4,24				0,00	0,00	0,00	0,00	4,24	3,12	-218,13
01.01.2012	5	6,47E+05	6,52E+05	4,55E+03	2,86E+04	2,72				0,00	0,00	0,00	0,00	2,72	1,85	-216,28
01.01.2013	6	5,23E+05	5,25E+05	1,99E+03	1,25E+04	1,19				0,00	0,00	0,00	0,00	1,19	0,75	-215,53
01.01.2014	7	4,29E+05	4,31E+05	1,52E+03	9,56E+03	0,91				0,00	0,00	0,00	0,00	0,91	0,53	-215,00
01.01.2015	8	3,65E+05	3,65E+05	4,60E+02	2,89E+03	0,27				0,00	0,00	0,00	0,00	0,27	0,15	-214,85
01.01.2016	9	3,16E+05	3,16E+05	-2,70E+02	-1,70E+03	-0,16				0,00	0,00	0,00	0,00	-0,16	-0,08	-214,94
01.01.2017	10	2,80E+05	2,79E+05	-6,50E+02	-4,09E+03	-0,39				0,00	0,00	0,00	0,00	-0,39	-0,18	-215,12
01.01.2018	11	2,19E+05	2,19E+05	-6,60E+02	-4,15E+03	-0,39				0,00	0,00	0,00	0,00	-0,39	-0,17	-215,28
01.01.2019	12	1,86E+05	1,85E+05	-1,00E+03	-6,29E+03	-0,60				0,00	0,00	0,00	0,00	-0,60	-0,24	-215,52
01.01.2020	13	1,67E+05	1,66E+05	-1,05E+03	-6,60E+03	-0,63				0,00	0,00	0,00	0,00	-0,63	-0,23	-215,75
01.01.2021	14	1,54E+05	1,53E+05	-1,07E+03	-6,73E+03	-0,64				0,00	0,00	0,00	0,00	-0,64	-0,22	-215,97
01.01.2022	15	1,42E+05	1,41E+05	-1,09E+03	-6,86E+03	-0,65				0,00	0,00	0,00	0,00	-0,65	-0,21	-216,18
Sum		8,45E+06	8,49E+06	3,61E+04	2,27E+05	21,58	7,30E+06	3,65E+07	0,00E+00	7,30	255,50	0,00	262,80	-241,22	**-216,18**	

AS Flooding

Case 9: PV=0.1, Alkaline 0.5 wt%, Surfactant 0.5 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	1,95E+06	2,95E+03	1,86E+04	1,76	1,83E+07	1,83E+07		18,25	127,75	0,00	146,00	-144,24	-133,55	-133,55
01.01.2009	2	1,25E+06	1,26E+06	9,28E+03	5,84E+04	5,55	1,83E+07	1,83E+07		18,25	127,75	0,00	146,00	-140,45	-120,42	-253,97
01.01.2010	3	1,01E+06	1,02E+06	1,34E+04	8,40E+04	7,98				0,00	0,00	0,00	0,00	7,98	6,33	-247,64
01.01.2011	4	8,10E+05	8,18E+05	7,45E+03	4,69E+04	4,45				0,00	0,00	0,00	0,00	4,45	3,27	-244,37
01.01.2012	5	6,47E+05	6,52E+05	5,26E+03	3,31E+04	3,14				0,00	0,00	0,00	0,00	3,14	2,14	-242,23
01.01.2013	6	5,23E+05	5,26E+05	2,39E+03	1,50E+04	1,43				0,00	0,00	0,00	0,00	1,43	0,90	-241,33
01.01.2014	7	4,29E+05	4,32E+05	2,32E+03	1,46E+04	1,39				0,00	0,00	0,00	0,00	1,39	0,81	-240,52
01.01.2015	8	3,65E+05	3,65E+05	7,20E+02	4,53E+03	0,43				0,00	0,00	0,00	0,00	0,43	0,23	-240,29
01.01.2016	9	3,16E+05	3,16E+05	-3,20E+02	-2,01E+03	-0,19				0,00	0,00	0,00	0,00	-0,19	-0,10	-240,38
01.01.2017	10	2,80E+05	2,79E+05	-5,00E+02	-3,14E+03	-0,30				0,00	0,00	0,00	0,00	-0,30	-0,14	-240,52
01.01.2018	11	2,19E+05	2,19E+05	-6,60E+02	-4,15E+03	-0,39				0,00	0,00	0,00	0,00	-0,39	-0,17	-240,69
01.01.2019	12	1,86E+05	1,85E+05	-1,01E+03	-6,35E+03	-0,60				0,00	0,00	0,00	0,00	-0,60	-0,24	-240,93
01.01.2020	13	1,67E+05	1,66E+05	-1,17E+03	-7,36E+03	-0,70				0,00	0,00	0,00	0,00	-0,70	-0,26	-241,19
01.01.2021	14	1,54E+05	1,52E+05	-1,36E+03	-8,55E+03	-0,81				0,00	0,00	0,00	0,00	-0,81	-0,28	-241,46
01.01.2022	15	1,42E+05	1,41E+05	-1,46E+03	-9,18E+03	-0,87				0,00	0,00	0,00	0,00	-0,87	-0,28	-241,74
Sum		8,45E+06	8,49E+06	3,72E+04	2,34E+05	22,25	3,65E+07	3,65E+07	0,00E+00	36,50	255,50	0,00	292,00	-269,75	**-241,74**	

AS Flooding

Case 10: PV=0.1, Alkaline 1.0 wt%, Surfactant 0.5 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	1,95E+06	3,00E+03	1,89E+04	1,79	3,65E+07	1,83E+07		36,50	127,75	0,00	164,25	-162,46	-150,42	-150,42
01.01.2009	2	1,25E+06	1,26E+06	8,79E+03	5,53E+04	5,25	3,65E+07	1,83E+07		36,50	127,75	0,00	164,25	-159,00	-136,31	-286,74
01.01.2010	3	1,01E+06	1,02E+06	1,25E+04	7,89E+04	7,49				0,00	0,00	0,00	0,00	7,49	5,95	-280,79
01.01.2011	4	8,10E+05	8,17E+05	7,05E+03	4,43E+04	4,21				0,00	0,00	0,00	0,00	4,21	3,10	-277,69
01.01.2012	5	6,47E+05	6,52E+05	4,96E+03	3,12E+04	2,96				0,00	0,00	0,00	0,00	2,96	2,02	-275,68
01.01.2013	6	5,23E+05	5,26E+05	2,54E+03	1,60E+04	1,52				0,00	0,00	0,00	0,00	1,52	0,96	-274,72
01.01.2014	7	4,29E+05	4,32E+05	2,75E+03	1,73E+04	1,64				0,00	0,00	0,00	0,00	1,64	0,96	-273,76
01.01.2015	8	3,65E+05	3,66E+05	1,14E+03	7,17E+03	0,68				0,00	0,00	0,00	0,00	0,68	0,37	-273,39
01.01.2016	9	3,16E+05	3,16E+05	2,40E+02	1,51E+03	0,14				0,00	0,00	0,00	0,00	0,14	0,07	-273,32
01.01.2017	10	2,80E+05	2,79E+05	-7,00E+02	-4,40E+03	-0,42				0,00	0,00	0,00	0,00	-0,42	-0,19	-273,52
01.01.2018	11	2,19E+05	2,17E+05	-1,99E+03	-1,25E+04	-1,19				0,00	0,00	0,00	0,00	-1,19	-0,51	-274,03
01.01.2019	12	1,86E+05	1,84E+05	-1,34E+03	-8,43E+03	-0,80				0,00	0,00	0,00	0,00	-0,80	-0,32	-274,34
01.01.2020	13	1,67E+05	1,66E+05	-1,38E+03	-8,68E+03	-0,82				0,00	0,00	0,00	0,00	-0,82	-0,30	-274,65
01.01.2021	14	1,54E+05	1,52E+05	-1,59E+03	-1,00E+04	-0,95				0,00	0,00	0,00	0,00	-0,95	-0,32	-274,97
01.01.2022	15	1,42E+05	1,40E+05	-1,79E+03	-1,13E+04	-1,07				0,00	0,00	0,00	0,00	-1,07	-0,34	-275,31
Sum		8,45E+06	8,49E+06	3,42E+04	2,15E+05	20,45	7,30E+07	3,65E+07	0,00E+00	73,00	255,50	0,00	328,50	-308,05	**-275,31**	

ASP Flooding

Case 11: PV=0.1, Alkaline 0.1 wt%, Surfactant 0.1 wt%, Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,03E+06	8,18E+04	5,15E+05	48,90	3,65E+06	3,65E+06	1,83E+06	3,65	25,55	9,13	38,33	10,58	9,79	9,79
01.01.2009	2	1,25E+06	1,34E+06	8,95E+04	5,63E+05	53,50	3,65E+06	3,65E+06	1,83E+06	3,65	25,55	9,13	38,33	15,18	13,01	22,81
01.01.2010	3	1,01E+06	1,15E+06	1,44E+05	9,03E+05	85,79				0,00	0,00	0,00	0,00	85,79	68,11	90,91
01.01.2011	4	8,10E+05	9,33E+05	1,23E+05	7,74E+05	73,53				0,00	0,00	0,00	0,00	73,53	54,05	144,96
01.01.2012	5	6,47E+05	7,24E+05	7,71E+04	4,85E+05	46,09				0,00	0,00	0,00	0,00	46,09	31,37	176,33
01.01.2013	6	5,23E+05	5,56E+05	3,24E+04	2,04E+05	19,35				0,00	0,00	0,00	0,00	19,35	12,20	188,53
01.01.2014	7	4,29E+05	4,41E+05	1,21E+04	7,62E+04	7,24				0,00	0,00	0,00	0,00	7,24	4,23	192,75
01.01.2015	8	3,65E+05	3,67E+05	2,24E+03	1,41E+04	1,34				0,00	0,00	0,00	0,00	1,34	0,72	193,48
01.01.2016	9	3,16E+05	3,15E+05	-7,70E+02	-4,84E+03	-0,46				0,00	0,00	0,00	0,00	-0,46	-0,23	193,25
01.01.2017	10	2,80E+05	2,78E+05	-1,55E+03	-9,75E+03	-0,93				0,00	0,00	0,00	0,00	-0,93	-0,43	192,82
01.01.2018	11	2,19E+05	2,47E+05	2,80E+04	1,76E+05	16,73				0,00	0,00	0,00	0,00	16,73	7,18	199,99
01.01.2019	12	1,86E+05	2,24E+05	3,89E+04	2,45E+05	23,25				0,00	0,00	0,00	0,00	23,25	9,23	209,23
01.01.2020	13	1,67E+05	1,90E+05	2,25E+04	1,41E+05	13,42				0,00	0,00	0,00	0,00	13,42	4,93	214,16
01.01.2021	14	1,54E+05	1,47E+05	-6,23E+03	-3,92E+04	-3,72				0,00	0,00	0,00	0,00	-3,72	-1,27	212,89
01.01.2022	15	1,42E+05	1,28E+05	-1,45E+04	-9,10E+04	-8,64				0,00	0,00	0,00	0,00	-8,64	-2,72	210,17
Sum		8,45E+06	9,08E+06	6,28E+05	3,95E+06	375,41	7,30E+06	7,30E+06	3,65E+06	7,30	51,10	18,25	76,65	298,76	**210,17**	

ASP Flooding

Case 12: PV=0.1, Alkaline 0.5 wt%, Surfactant 0.5 wt%, Polymer 0.05 wt%

Time		Oil Production	Incremental Oil				Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,04E+06	8,37E+04	5,26E+05	50,01	1,83E+07	1,83E+07	1,83E+06	18,25	127,75	9,13	155,13	-105,12	-97,33	-97,33
01.01.2009	2	1,25E+06	1,34E+06	9,08E+04	5,71E+05	54,26	1,83E+07	1,83E+07	1,83E+06	18,25	127,75	9,13	155,13	-100,87	-86,48	-183,81
01.01.2010	3	1,01E+06	1,15E+06	1,44E+05	9,06E+05	86,08				0,00	0,00	0,00	0,00	86,08	68,33	-115,48
01.01.2011	4	8,10E+05	9,35E+05	1,25E+05	7,87E+05	74,74				0,00	0,00	0,00	0,00	74,74	54,94	-60,54
01.01.2012	5	6,47E+05	7,26E+05	7,92E+04	4,98E+05	47,35				0,00	0,00	0,00	0,00	47,35	32,22	-28,32
01.01.2013	6	5,23E+05	5,58E+05	3,46E+04	2,17E+05	20,65				0,00	0,00	0,00	0,00	20,65	13,01	-15,30
01.01.2014	7	4,29E+05	4,44E+05	1,53E+04	9,59E+04	9,11				0,00	0,00	0,00	0,00	9,11	5,32	-9,99
01.01.2015	8	3,65E+05	3,70E+05	5,55E+03	3,49E+04	3,32				0,00	0,00	0,00	0,00	3,32	1,79	-8,19
01.01.2016	9	3,16E+05	3,17E+05	1,27E+03	7,99E+03	0,76				0,00	0,00	0,00	0,00	0,76	0,38	-7,81
01.01.2017	10	2,80E+05	2,79E+05	-8,60E+02	-5,41E+03	-0,51				0,00	0,00	0,00	0,00	-0,51	-0,24	-8,05
01.01.2018	11	2,19E+05	2,47E+05	2,78E+04	1,75E+05	16,59				0,00	0,00	0,00	0,00	16,59	7,11	-0,94
01.01.2019	12	1,86E+05	2,24E+05	3,82E+04	2,40E+05	22,81				0,00	0,00	0,00	0,00	22,81	9,06	8,12
01.01.2020	13	1,67E+05	1,97E+05	3,00E+04	1,89E+05	17,94				0,00	0,00	0,00	0,00	17,94	6,60	14,72
01.01.2021	14	1,54E+05	1,53E+05	-7,30E+02	-4,59E+03	-0,44				0,00	0,00	0,00	0,00	-0,44	-0,15	14,57
01.01.2022	15	1,42E+05	1,29E+05	-1,28E+04	-8,03E+04	-7,62				0,00	0,00	0,00	0,00	-7,62	-2,40	12,17
Sum		8,45E+06	9,11E+06	6,61E+05	4,16E+06	395,04	3,65E+07	3,65E+07	3,65E+06	36,50	255,50	18,25	310,25	84,79	**12,17**	

ASP Flooding

Case 13: PV=0.1, Alkaline 0.5 wt%, Surfactant 1.0 wt%, Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,04E+06	8,35E+04	5,25E+05	49,91	1,83E+07	3,65E+07	1,83E+06	18,25	255,50	9,13	282,88	-232,97	-215,71	-215,71
01.01.2009	2	1,25E+06	1,34E+06	9,17E+04	5,77E+05	54,81	1,83E+07	3,65E+07	1,83E+06	18,25	255,50	9,13	282,88	-228,07	-195,53	-411,24
01.01.2010	3	1,01E+06	1,15E+06	1,45E+05	9,11E+05	86,53				0,00	0,00	0,00	0,00	86,53	68,69	-342,56
01.01.2011	4	8,10E+05	9,39E+05	1,29E+05	8,11E+05	77,09				0,00	0,00	0,00	0,00	77,09	56,66	-285,89
01.01.2012	5	6,47E+05	7,30E+05	8,31E+04	5,23E+05	49,64				0,00	0,00	0,00	0,00	49,64	33,79	-252,11
01.01.2013	6	5,23E+05	5,60E+05	3,64E+04	2,29E+05	21,76				0,00	0,00	0,00	0,00	21,76	13,71	-238,39
01.01.2014	7	4,29E+05	4,48E+05	1,84E+04	1,16E+05	11,00				0,00	0,00	0,00	0,00	11,00	6,42	-231,97
01.01.2015	8	3,65E+05	3,73E+05	8,54E+03	5,37E+04	5,10				0,00	0,00	0,00	0,00	5,10	2,76	-229,22
01.01.2016	9	3,16E+05	3,19E+05	2,92E+03	1,84E+04	1,74				0,00	0,00	0,00	0,00	1,74	0,87	-228,34
01.01.2017	10	2,80E+05	2,80E+05	-3,00E+02	-1,89E+03	-0,18				0,00	0,00	0,00	0,00	-0,18	-0,08	-228,43
01.01.2018	11	2,19E+05	2,47E+05	2,77E+04	1,74E+05	16,57				0,00	0,00	0,00	0,00	16,57	7,11	-221,32
01.01.2019	12	1,86E+05	2,23E+05	3,72E+04	2,34E+05	22,21				0,00	0,00	0,00	0,00	22,21	8,82	-212,50
01.01.2020	13	1,67E+05	2,04E+05	3,68E+04	2,31E+05	21,99				0,00	0,00	0,00	0,00	21,99	8,09	-204,42
01.01.2021	14	1,54E+05	1,73E+05	1,90E+04	1,19E+05	11,32				0,00	0,00	0,00	0,00	11,32	3,86	-200,56
01.01.2022	15	1,42E+05	1,37E+05	-5,50E+03	-3,46E+04	-3,29				0,00	0,00	0,00	0,00	-3,29	-1,04	-201,60
Sum		8,45E+06	9,16E+06	7,13E+05	4,49E+06	426,21	3,65E+07	7,30E+07	3,65E+06	36,50	511,00	18,25	565,75	-139,54	**-201,60**	

Sensitivity: Low Case

Case 4.2: PV=0.2, Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,03E+06	8,20E+04	5,16E+05	41,26			1,83E+06	0,00	0,00	13,69	13,69	27,57	25,29	25,29
01.01.2009	2	1,25E+06	1,34E+06	8,96E+04	5,64E+05	45,10			1,83E+06	0,00	0,00	13,69	13,69	31,41	26,44	51,73
01.01.2010	3	1,01E+06	1,17E+06	1,59E+05	1,00E+06	80,07			1,83E+06	0,00	0,00	13,69	13,69	66,38	51,26	102,99
01.01.2011	4	8,10E+05	9,80E+05	1,70E+05	1,07E+06	85,41			1,83E+06	0,00	0,00	13,69	13,69	71,72	50,81	153,80
01.01.2012	5	6,47E+05	8,03E+05	1,56E+05	9,80E+05	78,38				0,00	0,00	0,00	0,00	78,38	50,94	204,74
01.01.2013	6	5,23E+05	6,43E+05	1,19E+05	7,51E+05	60,09				0,00	0,00	0,00	0,00	60,09	35,83	240,57
01.01.2014	7	4,29E+05	5,04E+05	7,51E+04	4,72E+05	37,76				0,00	0,00	0,00	0,00	37,76	20,66	261,23
01.01.2015	8	3,65E+05	4,09E+05	4,48E+04	2,82E+05	22,53				0,00	0,00	0,00	0,00	22,53	11,31	272,53
01.01.2016	9	3,16E+05	3,38E+05	2,20E+04	1,38E+05	11,08				0,00	0,00	0,00	0,00	11,08	5,10	277,63
01.01.2017	10	2,80E+05	2,93E+05	1,26E+04	7,92E+04	6,34				0,00	0,00	0,00	0,00	6,34	2,68	280,31
01.01.2018	11	2,19E+05	2,57E+05	3,77E+04	2,37E+05	18,98				0,00	0,00	0,00	0,00	18,98	7,35	287,66
01.01.2019	12	1,86E+05	2,30E+05	4,45E+04	2,80E+05	22,41				0,00	0,00	0,00	0,00	22,41	7,97	295,63
01.01.2020	13	1,67E+05	2,09E+05	4,15E+04	2,61E+05	20,90				0,00	0,00	0,00	0,00	20,90	6,82	302,45
01.01.2021	14	1,54E+05	1,85E+05	3,10E+04	1,95E+05	15,57				0,00	0,00	0,00	0,00	15,57	4,66	307,11
01.01.2022	15	1,42E+05	1,45E+05	2,86E+03	1,80E+04	1,44				0,00	0,00	0,00	0,00	1,44	0,40	307,50
Sum		8,45E+06	9,54E+06	1,09E+06	6,84E+06	547,30	0,00E+00	0,00E+00	7,30E+06	0,00	0,00	54,75	54,75	492,55	**307,50**	

Sensitivity: High Case

Case 4.2: PV=0.2, Polymer 0.05 wt%

Time		Oil Production		Incremental Oil			Chemical Consumption			Chemical Cost			Total Cost	PV	NPV	Cumulative NPV
		Basecase	Case				A	S	P	A	S	P	All			
Date	Year	Sm3	Sm3	Sm3	bbl	Million USD	kg			Million USD						
01.01.2007	0	0,00E+00	0,00E+00	0,00E+00	0,00E+00	0,00				0,00	0,00	0,00	0,00	0,00	0,00	0,00
01.01.2008	1	1,95E+06	2,03E+06	8,20E+04	5,16E+05	56,73			1,83E+06	0,00	0,00	5,48	5,48	51,25	47,90	47,90
01.01.2009	2	1,25E+06	1,34E+06	8,96E+04	5,64E+05	62,01			1,83E+06	0,00	0,00	5,48	5,48	56,54	49,38	97,28
01.01.2010	3	1,01E+06	1,17E+06	1,59E+05	1,00E+06	110,10			1,83E+06	0,00	0,00	5,48	5,48	104,62	85,40	182,69
01.01.2011	4	8,10E+05	9,80E+05	1,70E+05	1,07E+06	117,43			1,83E+06	0,00	0,00	5,48	5,48	111,96	85,41	268,10
01.01.2012	5	6,47E+05	8,03E+05	1,56E+05	9,80E+05	107,77				0,00	0,00	0,00	0,00	107,77	76,84	344,94
01.01.2013	6	5,23E+05	6,43E+05	1,19E+05	7,51E+05	82,62				0,00	0,00	0,00	0,00	82,62	55,05	399,99
01.01.2014	7	4,29E+05	5,04E+05	7,51E+04	4,72E+05	51,93				0,00	0,00	0,00	0,00	51,93	32,34	432,33
01.01.2015	8	3,65E+05	4,09E+05	4,48E+04	2,82E+05	30,98				0,00	0,00	0,00	0,00	30,98	18,03	450,36
01.01.2016	9	3,16E+05	3,38E+05	2,20E+04	1,38E+05	15,23				0,00	0,00	0,00	0,00	15,23	8,28	458,64
01.01.2017	10	2,80E+05	2,93E+05	1,26E+04	7,92E+04	8,71				0,00	0,00	0,00	0,00	8,71	4,43	463,07
01.01.2018	11	2,19E+05	2,57E+05	3,77E+04	2,37E+05	26,09				0,00	0,00	0,00	0,00	26,09	12,40	475,46
01.01.2019	12	1,86E+05	2,30E+05	4,45E+04	2,80E+05	30,82				0,00	0,00	0,00	0,00	30,82	13,68	489,15
01.01.2020	13	1,67E+05	2,09E+05	4,15E+04	2,61E+05	28,73				0,00	0,00	0,00	0,00	28,73	11,92	501,07
01.01.2021	14	1,54E+05	1,85E+05	3,10E+04	1,95E+05	21,41				0,00	0,00	0,00	0,00	21,41	8,30	509,37
01.01.2022	15	1,42E+05	1,45E+05	2,86E+03	1,80E+04	1,98				0,00	0,00	0,00	0,00	1,98	0,72	510,09
Sum		8,45E+06	9,54E+06	1,09E+06	6,84E+06	752,54	0,00E+00	0,00E+00	7,30E+06	0,00	0,00	21,90	21,90	730,64	**510,09**	