AES/PR/11-24  EOR Screening for the Rijn Oil Field by Numerical Simulation

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Title : EOR Screening for the Rijn Oil Field by Numerical Simulation

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Abstract

A screening study and subsequent dynamic simulation of selected Enhanced Oil Recovery (EOR) methods for the Rijn oil field are presented. The objective of the study was to obtain insight in the EOR potential of the Rijn field.

The Rijn oil field, located in block P15 in the Dutch sector of the North Sea Continental Shelf, produced 24MMSTB oil cumulative ($R_f = 12-18\%$) by water flooding and gas lift from 1986 until 1998 and was re-developed in 2010, using electrical submersible pumps (ESP's), expecting another 3.5MMSTB (expected $R_f = 21\%$).

In general an EOR method has to address certain reservoir characteristics such as heterogeneity, remaining oil saturation and residual oil saturation. For the Rijn oil field the presence of a thief zone, extensive water cycling, the offshore location and a relatively short remaining field life were also important factors taken into account when making a selection.

From the screening study polymer flooding, surfactant flooding and in-depth conformance control (by BrightWater™) were selected for investigation by numerical simulations. Other techniques such as solvent, microbial and thermally enhanced recovery methods were discarded based on the field characteristics.

Numerical modelling was done on a detailed sector model of the Rijn field with a refined grid, instead of using a conceptual simulation model. This was done to incorporate realistic reservoir and geological conditions.

Polymer flooding showed disappointing production responses mainly caused by injectivity issues due to increased viscosity of the injected fluid.

In-depth conformance control using BrightWater™ did not increase recovery because the poor reservoir quality in the modelled reservoir sector. A simulation run, where the high permeable thief zone was blocked, displayed a decrease in water cut but also a decrease in oil production. It is expected that better results could be obtained when the method is applied to better quality parts of the reservoir.

The EOR method with the best response was surfactant flooding. Adding surfactant to the injection water showed 12% increase in oil recovery. The results presented form a basis for further investigation of surfactant systems for applications in the Rijn oil field.
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Nomenclature

$C^*$ = Effective saturation

$C_i$ = Concentration of fluid $i$

$E_{\text{Surf}}$ = Technical surfactant flood efficiency

$II$ = Injectivity index

$k$ = Permeability

$M$ = Mobility ratio

$MD$ = Rock mass density

$N_c$ = Capillary number

$P_c$ = Capillary pressure

$\text{PORV}$ = Pore volume of a cell

$P_i$ = Internal pressure of fluid $i$

$Q$ = Flow rate

$r$ = Pore throat radius

$R_F$ = Recovery factor

$R_k$ = Permeability reduction factor

$R_{RF}$ = Residual resistance factor

$S_{or}$ = Residual oil saturation

$S_i$ = Saturation of fluid $i$

$\theta_x$ = Angle between interfaces and rock surface

$\lambda_i$ = Mobility of fluid $i$

$\mu_i$ = Viscosity of fluid $i$

$\nu_i$ = Velocity of fluid $i$

$\sigma_{ij}$ = Interfacial tension between fluid $i$ and $j$

$\omega$ = Todd-Longstaff mixing parameter
1 Introduction

The Rijn oil field, located in block P15 in the Dutch sector of the North Sea Continental Shelf, has a developed STOIIP of 137 MMSTB. The field was produced from 1985 to 1998 using water flooding and gas lift. Production was stopped in 1998 due to low oil price and operational issues [1, 2, 4, 5]. Recovery at that time was 24MMSTB (Re =18%). TAQA Energy restarted production in 2010 after re-completing 5 production wells with ESP’s and 5 injection wells for produced water re-injection. TAQA is currently investigating methods to maximise production and to unlock the remaining reserves of the Rijn oil field.

Enhanced oil recovery (EOR) methods have been applied in the oil industry for decades, particularly in the 1980’s during a period of relatively high oil prices [7,8,9]. In the North Sea area, several field applications have been recorded in the last 35 years [20, 21, 24], some more successful than others. The three main categories of EOR are thermal, chemical and solvent [7].

EOR techniques are designed to improve the microscopic and/or macroscopic sweep efficiency. Microscopic sweep efficiency can be improved by lowering the interfacial tension between oil and the driving fluid by several orders of magnitude, thereby increasing the capillary number leading to a substantial decrease in residual oil saturation [8]. This can be achieved by adding surface active agents (surfactants) to the driving fluid or by injecting miscible gas. Macroscopic sweep efficiency is improved by reducing the mobility ratio, which is most effectively done by increasing the viscosity of the driving fluid by adding polymers. Some polymers can also improve conformance of water floods in reservoirs having large permeability contrasts, such as layered and channelled systems [23].

This research aimed to investigate the EOR potential of the Rijn oil field. Screening studies were done based on the geological and reservoir properties and on the recovery issues the field was dealing with. The main recovery issues for the Rijn oilfield were established to be vertical heterogeneity, the presence of a thief zone, extensive water cycling and residual oil saturation.

Polymer flooding, surfactant flooding and in-depth conformance control, using the BrightWater™ technology, were the three best candidates that followed from the screening studies. They were further analysed using a numerical simulator on a sector model of the reservoir which had been conditioned to approximate the saturated state of the reservoir after 24 years of production and shut-in.

Other EOR techniques have been screened but they were left out due to the specific characteristics of the Rijn oil field.

First a brief introduction will be given about the field, and then a screening will be done based on the factors limiting the oil recovery for the Rijn oil field. The EOR methods resulting from the screening will subsequently be modelled in order to assess their applicability. The results of the modelling will be discussed after which conclusions and recommendations for further work will be given.
2 The Rijn Oil Field

2.1 General description

The Rijn oil field is located in block P15 in the Dutch sector of the North Sea Continental Shelf and is situated 40 km off the coast west from The Hague (Figure 1). The field was discovered in 1982 by Amoco Netherlands B.V. and production started in 1985. It was initially developed with 19 production wells placed near the crest and 17 water injection wells placed near the oil water contact (Figure 2) [1].

![Figure 1 Location of the Rijn Oilfield](image-url)
The Rijn field is a NE/SE trending anticline and has 12 km length and 2.75 km width (Figure 2). It was initially developed with two platforms; the Rijn Alpha platform mainly contained producers while the Rijn Bravo platform located mostly injectors. The Bravo platform was dismantled in 2001 and currently Rijn Alpha is used for both production and injection.

![Figure 2 Rijn Field structure map with previous and current well locations and the oil water contact (blue line)](image)

### 2.2 Geology of the Rijn Oil Field and zonation

The name of the field originates from its producing unit, the Rijn Member of the Lower Cretaceous Vlieland Sandstone Formation. The Rijn Member is widely present in the western offshore part of the West Netherlands basin. The reservoir is made of a coarsening upward sequence of sand and shale and locally unconformable overlies the Posedonia Shale Formation, the most likely source rock of the hydrocarbons present in the reservoir. In other regions the Rijnland sandstone overlies the Delfland Formation [2].

The Rijn oil field can be divided into a number of reservoir and non-reservoir units (see Table 1). A vertical sequence analysis derived from the Schlumberger Rijn Oil Field Review [2] is given below. Figure 3 depicts the typical Gamma Ray log responses of the Rijn field.
Table 1 Facies description after Corrigan & Associates [2]

<table>
<thead>
<tr>
<th>Facies/Zone</th>
<th>Description</th>
<th>Environment</th>
<th>Reservoir Quality</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Sandstone Zone A</td>
<td>Clean, fine to coarse, well sorted, massive, bioturbated, occasional shelly debris</td>
<td>Major storm events</td>
<td>Good-excellent $\phi_{\text{average}} = 23%$, $k_{\text{average}} = 570mD$</td>
</tr>
<tr>
<td>2. Sandstone Zone B/C</td>
<td>Carbonaceous, fine to medium, poor- to moderately sorted, bioturbated, abundant detrital clay</td>
<td>Migrating shallow shelf sand bars</td>
<td>Moderate-good $\phi_{\text{average}} = 16%$, $k_{\text{average}} = 77mD$</td>
</tr>
<tr>
<td>3. Sandstone Zone B/C</td>
<td>Clean, very fine, well sorted, massive or thin micaceous laminae, locally bioturbated</td>
<td>Episodic high energy shelf deposition</td>
<td>Poor-moderate $\phi_{\text{average}} = 14%$, $k_{\text{average}} = 3mD$</td>
</tr>
<tr>
<td>4. Sandstone Zone B/C</td>
<td>Argillaceous, silty, very fine-fine, moderately sorted, shelf bioturbated</td>
<td>Low energy shelf</td>
<td>Poor-moderate $\phi_{\text{average}} = 18%$, $k_{\text{average}} = 4mD$</td>
</tr>
<tr>
<td>5. Silty sandstone Zone D</td>
<td>Argillaceous, carbonaceous, glauconitic, very fine-medium, poorly sorted, bioturbated, shelly</td>
<td>Transgressive sands</td>
<td>Non-reservoir? $\phi_{\text{average}} = 13%$, $k_{\text{average}} = 0.6mD$</td>
</tr>
<tr>
<td>6. Sandy shale Zone D</td>
<td>Silt-coarse grained, poorly sorted, occasional pebbles, pyritic, phosphatic</td>
<td>Transgressive lag</td>
<td>Non-reservoir</td>
</tr>
<tr>
<td>7. Shale</td>
<td>Silty, carbonaceous, micaceous, fissile, rare shelly debris</td>
<td>Marine</td>
<td>Non-reservoir</td>
</tr>
<tr>
<td>8. Sandy ironstone</td>
<td>Fine-medium, oolitic, chamositic grains float in black ferruginous clay matrix</td>
<td>Marine (Possible Maximum Flooding Surface)</td>
<td>Non-reservoir</td>
</tr>
</tbody>
</table>

2.2.1 Delfland Formation

The Delfland Formation is encountered by six wells in the east part of the field underneath the main reservoir body. It is deposited as part of a large fluvio-deltaic system. The formation consists of 2-6m thick channel sands and thinner 1-2m thick crevasse sands, in combination with 5-10m thick overbank shales. Average porosity is 15% and some studies assume the Delfland formation has reservoir potential (see Table 2).

2.2.2 Zone D

Zone D consists of three different facies; a transgressive sand, shallow shelf argillaceous deposits and marine shales/ironstone. Possibly the transgressive sands contribute to flow but the marine deposits do not. The marine shale/ironstone at the top of zone D is laterally extensive and is interpreted as a maximum flooding surface.
2.2.3 Zones B and C

The combined thickness of zones B and C does not vary much throughout the field and is about 20-25m of which 1/3 is represented by zone B. Average porosity is about 18% and 19% for zones B and C respectively. Permeability ranges from 1-100 mD.

The zones are two sequences of upward coarsening and cleaning sandstone, typical of a shallow marine shelf deposition. They were deposited in a low to moderate energy environment. Bioturbation is extensive and thorough reworking of the sediments has taken place. Coarser and cleaner sands might have been deposited in the past but it is likely that those deposits have been eroded and re-worked by subsequent depositional events.

Heavily cemented carbonate doggers are encountered at the top of the B and C zones. They most likely originate from shelly material deposited during single storm events which can induce carbonate cement diagenesis. The doggers are likely to be laterally extensive but will not form totally sealing barriers everywhere due to natural fractures that can be present.

2.2.4 Zone A

Zone A is between 2 and 7m thick where present and net sand ranges from 0-4m. Average porosity ranges from 18-20% and permeability varies from 100-1200mD in the best sands.

The zone is a result of a sudden influx of relatively coarse grained sediment that scoured and eroded the underlying finer grained sequences. The mechanism for this deposition is likely a high energy storm event that brought more proximal sediment from the shoreline out on to the shelf. Within the A zone, three different layers can be recognized: a lower, cemented, horizon; a middle, high permeability, coarser sand and an upper clean horizon with good permeability.

Figure 3 Typical GR response of the Rijn field, the zones are also presented [6]
2.3 Production history

Oil is produced from the Lower Cretaceous Rijnland sands and the Upper Jurassic Delfland Sands. Estimates of oil initially in place range from 132 to 187 MMSTB (see Table 2). The current expected developed STOIIP is 137 MMSTB. Ultimate recovery after water flooding was estimated at about 49 MMSTB through the year 2009 ($R_f = 26-37\%$, depending on the uncertainty of the STOIIP) [2]. In 1998 the field was shut down due to well integrity problems, safety issues, high water cut and high operating costs combined with a low oil price. During the 12 years of production the recovery was a little over 24 MMSTB ($R_f = 16-18\%$) [1].

Table 2 Different STOIIP values from various reports (MMSTB) [2]

<table>
<thead>
<tr>
<th>Source</th>
<th>Zone A</th>
<th>Zone B</th>
<th>Zone C</th>
<th>Zone D</th>
<th>Delfland</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>License App (1983)</td>
<td>36.4</td>
<td>48.2</td>
<td>74.9</td>
<td>-</td>
<td>-</td>
<td>159.5</td>
</tr>
<tr>
<td>Bateman (1985)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>186.4</td>
</tr>
<tr>
<td>Powley (1988)</td>
<td>23.9</td>
<td>38.3</td>
<td>56.1</td>
<td>4.7</td>
<td>8.0</td>
<td>131.5</td>
</tr>
<tr>
<td>D’Goyler &amp; McNaughton</td>
<td>26.7</td>
<td>5.1</td>
<td>51.4</td>
<td>9.1</td>
<td>24.1</td>
<td>146.4</td>
</tr>
</tbody>
</table>

Production peaked in 1986 with 22,000 bbl/d and water flooding operations started very shortly after production was initiated (January 1986) [2]. Since the last quarter of 1987 all production wells were artificially lifted by gas-lift, this was necessary to maximize the drawdown as the produced water-cut increased.

During a two year fracture campaign, started in 1987, all producer and injector wells were fractured in an attempt to increase oil production. All wells are generally inclined and sidetrack B10Z is a horizontal well which was initially completed in the lower quality C zone but later recompleted in the high permeability A zone due to disappointing production rates [2].

First water breakthrough occurred very soon after the initiation of the water flooding. Water breakthrough was reported in some wells after only 2 months of injection [5]. At the tail end of production the overall field water-cut was over 90% (see Figure 4).

![Figure 4 Rijn field production history [2]](image-url)
After several redevelopment studies and decline curve analysis [3, 4] the field was again taken into production in November 2010 by TAQA Energy. 10 wells were selected for a work-over and measures were taken to limit the damage that is caused by H₂S production. With the aid of electric submersible pumps (ESP) in 5 producers and pressure support by 5 water injectors it is estimated that an additional amount of 3.5 MMSTB oil can be recovered.
3 EOR Screening for the Rijn Oil Field

In this work a screening study was carried out in order to identify which EOR method could be applicable to the Rijn oil field. First the factors that limited recovery in the Rijn field were identified. Next, suitable EOR methods to counter the limiting factors were selected and then the selected EOR methods were matched to the reservoir properties to assess if they were compatible.

3.1 Enhanced oil recovery

A majority of the North Sea reservoirs are being produced by water injection as a secondary recovery method. Water injection has two main purposes; 1) pressure maintenance, 2) to drive reservoir fluids towards production wells by creating a pressure difference. Recovery factors for water injection in favourable conditions can be in the range of 30-50% of OOIP [9]. The recovery factor rendered from water injection is largely limited by reservoir heterogeneity, well spacing and unfavourable mobility ratio between the displacing fluid and displaced fluid (water and oil respectively) [7].

A definition for Enhanced Oil Recovery was given by Lake: “Enhanced oil recovery is oil recovery by the injection of materials not normally present in the reservoir.” According to this definition this does not place EOR methods in a particular phase in the production life of a reservoir (i.e. primary, secondary or tertiary). Primary recovery is oil recovery by natural drive mechanisms such as solution gas, water influx, gas cap drive or gravity drainage. Secondary recovery is done using techniques such as gas or water injection with the purpose of pressure maintenance. Tertiary recovery is any technique applied after secondary recovery. Although EOR is mostly used as a tertiary recovery mechanism again the definition does not place this restriction [7].

After 12 years of water injection any EOR technique used on the Rijn Oilfield will be considered a tertiary recovery method. Water injection in the Rijn field has only been partly successful, mainly hindered by the vertical heterogeneity of the reservoir.

Recovery from the A sand was relatively high (estimated 50%). The recovery of the entire reservoir was low due to the permeability contrast between the A sand and the underlying sands which contain the largest part of the STOIIP but have a recovery of 3-4%. The research was therefore split up into two different studies. 1) Enhanced oil recovery from the A zone and 2) creating recovery from the B and C zone.

Both options are a research on their own and it was decided to direct the research toward assessing EOR methods that could be beneficial for recovering incremental oil from A zone.
3.2 Factors that limit oil recovery for the Rijn Oil Field

To evaluate which EOR methods would be best for the Rijn oil field it is important to understand the factors that control the recovery efficiency of the field.

Recovery efficiency can be divided into microscopic sweep efficiency and macroscopic sweep efficiency. On a microscopic scale oil is left behind caused by capillary entrapment. On macroscopic scale the sweep efficiency can be affected in a vertical way but also in an areal way, caused by unstable displacement or heterogeneity.

3.2.1 Residual oil saturation

It is important to distinguish residual oil saturation from remaining oil saturation. The residual oil saturation is the oil remaining behind in a thoroughly water swept region of the permeable medium where the relative permeability of oil reaches zero (see Figure 5), the remaining oil saturation is the oil left after a water flood, well-swept or not [7].

![Schematic representation of residual oil saturation](image)

Figure 5 Schematic representation of residual oil saturation [8]

Because of the mature state of the water flood in the Rijn oil field, residual oil saturation is an important target in the Rijn A sand where extensive water cycling has occurred.

Table 3 shows the results of a core flood test on cores taken from the Rijn field reservoir rock. The A sand has an average residual oil saturation (S_{or}) of 27% whilst the other parts of the reservoir show a S_{or} in the range of 32% – 42%.

<table>
<thead>
<tr>
<th>Test</th>
<th>Sample</th>
<th>TVDSS (m)</th>
<th>Permeability to air (mD)</th>
<th>Porosity (%)</th>
<th>Water saturation (%)</th>
<th>Permeability to oil (mD)</th>
<th>Oil Saturation (%)</th>
<th>Permeability to water (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>24</td>
<td>1929.8</td>
<td>51</td>
<td>18.9</td>
<td>45.8</td>
<td>13</td>
<td>26.2</td>
<td>6.9</td>
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<tr>
<td>1</td>
<td>28</td>
<td>1930.3</td>
<td>749</td>
<td>24.7</td>
<td>20.4</td>
<td>580</td>
<td>28.2</td>
<td>370</td>
</tr>
<tr>
<td>1</td>
<td>39</td>
<td>1933.6</td>
<td>11</td>
<td>19.4</td>
<td>30.7</td>
<td>4.9</td>
<td>31.0</td>
<td>2.2</td>
</tr>
<tr>
<td>1</td>
<td>51</td>
<td>1936.6</td>
<td>1.5</td>
<td>17.3</td>
<td>30.4</td>
<td>0.48</td>
<td>36.7</td>
<td>0.22</td>
</tr>
<tr>
<td>1</td>
<td>57</td>
<td>1938.1</td>
<td>68</td>
<td>21.0</td>
<td>24.5</td>
<td>19</td>
<td>42.1</td>
<td>8.1</td>
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<tr>
<td>1</td>
<td>72</td>
<td>1941.8</td>
<td>1.1</td>
<td>18.1</td>
<td>31.5</td>
<td>0.28</td>
<td>41.4</td>
<td>0.15</td>
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<tr>
<td>1</td>
<td>80</td>
<td>1944.1</td>
<td>11</td>
<td>20.5</td>
<td>25.4</td>
<td>5.3</td>
<td>38.4</td>
<td>2.9</td>
</tr>
<tr>
<td>1</td>
<td>85</td>
<td>1945.3</td>
<td>12</td>
<td>22.1</td>
<td>26.9</td>
<td>3.2</td>
<td>32.0</td>
<td>1.3</td>
</tr>
<tr>
<td>1</td>
<td>87</td>
<td>1945.8</td>
<td>4.1</td>
<td>19.5</td>
<td>25.5</td>
<td>1.7</td>
<td>26.5</td>
<td>0.58</td>
</tr>
<tr>
<td>2</td>
<td>28</td>
<td>1936.5</td>
<td>5.9</td>
<td>17.6</td>
<td>35.9</td>
<td>2.8</td>
<td>18.0</td>
<td>0.18</td>
</tr>
<tr>
<td>2</td>
<td>3</td>
<td>1943.9</td>
<td>5.7</td>
<td>19.3</td>
<td>25.2</td>
<td>2.3</td>
<td>24.5</td>
<td>0.27</td>
</tr>
</tbody>
</table>
To reduce residual oil saturation it is important to understand the forces that are keeping the oil from being produced.

Interfacial tension (IFT) is one of the main forces. In an oil field such as the Rijn field there are three different types of interfaces with interfacial tension: oil-water interface \( \sigma_{ow} \), oil-rock surface interface \( \sigma_{os} \), and the water-rock surface interface \( \sigma_{ws} \). These different IFT’s correlate with each other by the following relation:

\[
\sigma_{os} - \sigma_{ws} = \sigma_{ow} \cdot \cos(\theta)
\]  

(3.2.1-1)

where \( \theta \) denotes the contact angle between the interfacial tension of the liquid/liquid interface and the rock’s surface (Figure 6).

![Figure 6 Interfacial forces at the interface between water, oil and the rock [9]](image)

Interfacial tension has a large effect on the capillary pressure. Because interfaces are in tension in a system such as Figure 6, a pressure difference exists across the interface; this pressure difference is called the capillary pressure \( P_c \):

\[
P_c = P_o - P_w
\]  

(3.2.1-2)

where

- \( P_o \): Internal pressure oil (Pa)
- \( P_w \): Internal pressure water (Pa)

Figure 7 shows how the capillary pressure is related to water saturation in a water wet system. It shows drainage by the non-wetting fluid and imbibition by the wetting fluid, in this case water. The threshold pressure is related to the size of the larger pores in the rock. When saturation approaches connate water saturation \( P_c \) is very large [9].
Capillary pressure depends on interfacial tension, the contact angle or wettability of the fluids and the pore size. On small scale, pore size-level the following relationship holds:

\[
P_c = \frac{2 \sigma_{\text{os}} \cos(\theta)}{r}
\]

where \(r\) is the radius of the pore-throat.

From this it is established that a very low interfacial tension or a contact angle close to 90° will result in a lower capillary pressure, reduced capillary entrapment and hence increased recovery.

A measurement of the ratio viscous to capillary forces is the capillary number \(N_c\), given by:

\[
N_c = \frac{\mu \cdot v}{\sigma}
\]

where \(\mu \cdot v\) stands for the dynamic drag and

- \(N_c\) : Capillary Number
- \(\mu\) : Viscosity (Pa.s)
- \(v\) : Velocity of displacing fluid (m/s)
- \(\sigma\) : Interfacial tension (N/m)

The relation between residual oil saturation and capillary forces is visible in the capillary desaturation curve shown in Figure 8.

In case of a low capillary number, \(N_c < 10^{-5}\), the flow in porous media is dominated by capillary forces. Typical conditions for water flooding light oil is an \(N_c\) of about \(10^{-7} - 10^{-6}\); this means an increase in \(N_c\) of 3 orders of magnitude is required to lower the residual oil saturation.
Increasing the capillary number by increasing the dynamic drag is not realistic because of the high velocity or high viscosities required. The most efficient method consists in substantially reducing the interfacial tension using surfactants in which surface active agents are added to the water injected into the reservoir.

3.2.2 Unstable displacement

Unstable displacement is caused by the difference in mobility ratio between the reservoir fluid (i.e. oil) and the driving fluid (water). Mobility ratio is defined as:

$$M = \frac{\lambda_D}{\lambda_d}$$  \hspace{1cm} (3.2.2-1)

where $\lambda_D$ is the mobility of the driving fluid and $\lambda_d$ is the mobility of the displaced fluid.

Mobility of phase $i$ is defined as:

$$\lambda_i = \frac{k_i}{\mu_i}$$  \hspace{1cm} (3.2.2-2)

where $k_i$ is the permeability to fluid $i$ and $\mu_i$ is the viscosity of fluid $i$.

The influence of different mobility ratios sketched in Figure 9 where a quarter of a five-spot pattern is shown. It shows how the liquid front propagates in case of a mobility ratio of 1 and a mobility ratio larger than 1. As expected the sweep efficiency with a mobility ratio of 1 is much better, when $M>1$ fingering occurs leaving large areas of the reservoir unswept.
Figure 9 Displacement fronts for M=1 and M>1 at break trough (BT) for a quarter of a five-spot pattern

The influence of viscosity ratio can also be seen with the help of fractional flow curves as shown in Figure 10. The curves depicted represent three different cases with mobility ratios decreasing to the right.

In Case 1 the displacement is unstable due to the very high oil-water viscosity ratio. This results in the bypassing of oil and premature breakthrough of water. The oil recovery is very small at breakthrough and even after injecting large volumes of water there can still be moveable oil left. Under these circumstances water injection is not effective and efforts such as thermally stimulating the oil or increasing water viscosity should be considered.

For Case 2 the mobility is an order of magnitude lower than Case 1. The displacement is stable and much more favourable, but oil production can still be accelerated by increasing the viscosity of the drive fluid.

Case 3 is in the case of a very low oil viscosity ($\mu_o=0.4$ cp), mobility ratio is smaller than 1. The total recovery at breakthrough is the total movable oil volume [11].
Figure 10 Fractional flow curves for different mobility ratios, after [11]

In the Rijn oil field the mobility ratio of the reservoir fluids is expected to be in the range of 2-3. Since the mobility difference between the water and the oil in the Rijn field is not that large, extensive fingering is unlikely to be an issue. But to accelerate oil production in the Rijn field the mobility ratio can be reduced. This can be achieved by reducing the mobility of the injection water or by increasing the mobility of the oil.
3.2.3 Vertical heterogeneity

As discussed in paragraph 2.2 the reservoir consists of four layers of which the top three layers (A, B and C) are considered to be the main reservoir rock. From these three layers the A layer, consisting of coarse grained sediment is the best quality and has the highest permeability, averaging between 100 and 1200mD. The lower layers have permeabilities ranging from 1 to 80mD.

The high average permeability of the A sand is mainly caused by a high permeable storm sand that is encountered in the middle of the zone. The storm sand is present throughout the field and acts as a thief zone, causing early water breakthrough and high water cuts [5]. This results in poor vertical sweep efficiency, which is also an important cause for the low recovery in the Rijn field.

Figure 11 High permeability thief zones are common causes of early water break trough and high water cut [8]
3.3 Possible IOR & EOR methods

Extensive literature has been written on EOR [7, 8, 9] where sweep efficiency issues and methods to solve those issues are presented. From this literature a simple but comprehensive flowchart was constructed aimed to combine the limiting factors of oil recovery in a reservoir with the EOR methods that could increase recovery. The flowchart is shown in Figure 12 and provides a quick insight in possible EOR solutions for the issues that are present in the Rijn field. The flowchart can also be applied to other reservoirs.

Taking into account the sweep efficiency issues discussed in the above sections, Figure 12 indicates that there are many options for increasing recovery in the Rijn oil field. Several options will not be investigated further in this study for different reasons that will be explained below.

Infill drilling with a vertical or horizontal well appears to be an obvious solution. The drilling of new wells can indeed improve the macroscopic sweep efficiency and maximize the contact between the drive fluid and oil. However, since this study is aimed at both improving macroscopic and microscopic sweep efficiency, drilling new wells will be discarded.

A water shutoff treatment such as a squeeze job to shutoff water production from the high permeable zone would be impractical since all the wells have been fractured in the past which makes it hard to selectively shut off zones.

DPR or relative permeability modification water control treatment will also not be studied in further detail. According to Sydansk et al. [22] DPR will only work if there is an almost 100% oil producing zone and a 100% water producing zone. This is not the case with the Rijn oil field, and reducing permeability to water will not only result in reduced water production but also in a reduction of the total liquid flow.

Solvent and foam flooding will not be investigated either. The field is currently producing with ESP’s that have the tendency to break down when producing too much gas. Therefore it would be too risky to inject solvents. In principle solvent flooding could potentially result in ‘free’ gas lift, which would make the use of ESP’s unnecessary but the Rijn field produces at such a high water cut that the use of ESP’s is more efficient.
3.4 Reservoir compatibility

Earlier studies have done systematic research in field experiences, core flooding experiments and pilot tests [20, 21, 23, 24]. These researches indicated reservoir parameters that were important for EOR projects to succeed. The parameters were summarized and compared to the Rijn field reservoir parameters. Table 4 depicts the parameters and the values for the A zone of the Rijn oil field.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Rijn Field</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Gravity (API)</td>
<td>35.42</td>
</tr>
<tr>
<td>Oil Viscosity (cP)</td>
<td>1.14</td>
</tr>
<tr>
<td>Average Porosity (%)</td>
<td>18</td>
</tr>
<tr>
<td>Average Assumed Remaining Oil Saturation (%)</td>
<td>50</td>
</tr>
<tr>
<td>Formation type</td>
<td>Sandstone</td>
</tr>
<tr>
<td>Average Permeability (mD)</td>
<td>200</td>
</tr>
<tr>
<td>Net reservoir thickness (m)</td>
<td>6</td>
</tr>
<tr>
<td>Reservoir Temperature (C)</td>
<td>96</td>
</tr>
<tr>
<td>Reservoir Depth (m)</td>
<td>2000</td>
</tr>
</tbody>
</table>

Based on these parameters a detailed screening application was specially developed in Microsoft Excel to get a better and quicker overview of the compatibility of the different methods with the reservoir. The results of this application, used on the A zone, can be seen in Appendix I.

From the results it is established that several solvent injection methods are compatible (such as CO₂, hydrocarbon and nitrogen), as well as polymer flooding, (alkaline-) surfactant flooding (according to Taber et al.) and BrightWater™ injection.

Some controversy does exist in the ranges of certain parameters given by the different authors, the selected methods should therefore be elaborately tested in the laboratory to assess possible compatibility issues.

For the reasons discussed in Sec. 3.3 the only EOR methods that are taken into account for further research are water based chemical enhanced oil recovery methods. This includes polymer flooding, surfactant flooding and in-depth water flood conformance control, using the BrightWater™ technology. In the following paragraph the selected methods will be discussed in more detail.
4 Selected EOR methods

In the literature EOR methods are usually divided into four different types; chemical, solvent, thermal and microbial EOR [7, 8, 9].

Each type has its own applications and effects on the volumetric sweep efficiency, displacement efficiency or both. In the next paragraphs only the EOR methods selected by the screening study will be further explained, more information on other investigated methods will be given in Appendix II.

4.1 Polymer flooding

Polymers are large molecules, also referred to as macromolecules. They are formed when a large number of relatively small identical molecules, called monomers, are linked to each other by a covalent chemical bond. The chemical process of joining the monomers together is called polymerization. Polymers can come in solid and liquid forms and sometimes can be dissolved in liquids; these liquid soluble polymers can be used for polymer flooding purposes [10].

Adding polymers increases the viscosity of the drive water. In addition adsorption takes place during flow in porous media, leading to permeability reduction; hereby reducing water relative permeability more than oil relative permeability. This in return will lower the mobility ratio and increase the efficiency of the water flood (Figure 13). Polymer flooding is normally applied when the water flood mobility ratio is high or the heterogeneity of the reservoir is high. Residual oil saturation does not decrease but remaining oil saturation will approach $S_{or}$ in the swept regions [7].

![Figure 13 A more stable displacement front can be obtained by using polymers](image)

There are two types of polymers soluble in water used for polymer flooding, biopolymers such as Xanthan gum and synthetic polymers such as acrylamide-based polymers (HPAM). HPAM is the most frequently used polymer in the field [9], and will therefore be discussed.
The reason that HPAM is most commonly used is that it is relatively inexpensive and less vulnerable to biological degradation by bacteria. The drawback is that it is very sensitive to salinity.

Figure 14 shows the chemical structure of polyacrylamide. The viscosity increasing feature of acrylamide-based polymers lies in their large molecular weight. This feature is emphasized by anionic repulsion between polymer molecules and between segments on the same molecule. The repulsion causes the polymer molecules in solution to interlace, which increases viscosity and decreases mobility at higher concentrations.

\[
\begin{align*}
\text{CH}_2 & \quad - \quad \text{CH} \\
\quad & \quad \quad \text{C=O} \\
\quad & \quad \quad \text{NH}_2
\end{align*}
\]

**Figure 14** A polyacrylamide molecule [7]

The viscosity of the solution is a function of the polymer concentration which can be modelled by the Flory-Huggins equation [7]:

\[
\mu_s = \mu_b [1 + a_1 C_p + a_2 C_p^2 + a_3 C_p^3 + \ldots + a_n C_p^n] \tag{4.1-1}
\]

where \( \mu_s \) is the viscosity of the phase, \( C_p \) is the concentration of the polymer in the solution and \( a_k \) is a constant. An example of the effect of polymer concentration on the viscosity is shown in Figure 15.
When the polymer flows through a porous media polymer retention occurs. Retention is mainly caused by adsorption or trapping of polymer molecules within small pores.

Polymer adsorption can be represented by a Langmuir-type isotherm [7]:

$$C_{Ads} = \frac{aC_p}{1 + bC_p}$$

(4.1-2)

where a and b are constants and a/b determines the plateau value for adsorption. $C_{Ads}$ is determined as the mass polymer adsorbed per mass rock and are expressed in mg/g.

A typical Langmuir-type isotherm for high molecular weight polymers is shown in Figure 16. The rate of adsorption decreases which is caused by the rock’s surface at high polymer concentration being completely covered by polymer molecules which makes it impossible for any more polymer to be adsorbed.

![Figure 16 Typical adsorption isotherm for high molecular weight polymers [19]](image)

The retention process causes a reduction of the permeability of the rock to the flow of the polymer solution itself and any displacing fluid. This permeability reduction is directly correlated to the adsorbed polymer concentration [28].

To describe the permeability reduction effect during flooding a permeability reduction factor, $R_k$, is defined as the ratio of permeability before flooding and after flooding:

$$R_k = \frac{k_{before}}{k_{after}}$$

(4.1-3)

When the polymer flood has passed the adsorbed polymer permanently reduces the permeability, this is defined as the residual resistance factor, $R_{RF}$, which is the mobility of the injection fluid before and after polymer injection [7]:

$$R_{RF} = \frac{\lambda_{w-before}}{\lambda_{w-after}}$$

(4.1-4)
Polymer molecules are relatively large and they can not enter the smaller range of pore sizes. This effect is called inaccessible pore volume (IPV) and causes an acceleration of the movement of the polymer front with respect to water. This means that a polymer slug can be detected at a producer earlier than expected. IPV has been observed in all types of porous media, and for all types of polymers. Depending on rock characteristics IPV can be up to 30% of the total pore space [19].

When polymer is injected in a reservoir it is subjected to shearing. Most polymers are shear thinning; when the shear rate rises, viscosity decreases. Figure 17 shows how viscosity develops when the polymer is subject to shearing. At very high shear rates the viscosity is approximated by the viscosity of the water. It can be an important parameter because shear rate can be very high near the wellbore where the polymer enters the reservoir. However, in the reservoir the flow rate is usually not high enough to cause excessive shearing.

![Figure 17 Effect of mechanical degradation in a carbonate core on solution viscosity [19]](image)

If the salinity of the brine is high, the anionic repulsive effect largely decreases by ionic shielding. The freely rotating carbon-carbon bonds cause the molecule to coil up which decreases the ability of interlocking and therefore decreases the effectiveness of the polymer. The effect of salinity on the polymer molecules is shown in Figure 18.

![Figure 18 Schematic of the effect of salinity on polyacrylamide molecules [10]](image)
The viscosity reduction caused by high salinity can be quite substantial. How the relative viscosity (apparent solution viscosity/solvent viscosity) is influenced by salt concentration is shown in Figure 19 [19].

![Figure 19 Solution relative viscosity as function of salinity](image)

**4.2 Surfactant flooding**

As described earlier in Sec 3.2.1, capillary forces are the result of interfacial tension between water and oil (and gas) in the reservoir. These capillary forces cause large amounts of oil to be left behind in swept zones. To reduce the capillary forces interfacial tension (IFT) has to be lowered considerably, this can be done with the aid of surface active agents (surfactants).

Although alkaline flooding is also based on the use of surface active chemicals it is not defined as surfactant flooding, since with alkaline flooding the surfactant is generated in-situ and not injected at the surface. The enhanced recovery process in the reservoir is identical but the injected chemical is different, therefore alkaline flooding will be discussed in Appendix II.

Figure 20 shows the typical surfactant monomer. It is composed of a hydrophilic (water loving) head and a lyphilic (oil loving) or hydrophobic (water fearing) tail.

![Figure 20 A typical surfactant monomer structure](image)

The tail consists of hydrocarbons or fluorcarbons and can be either a linear or a branched chain. The head group is the polar ionic portion of the molecule. The most common head group used in flooding are petroleum sulfonates [7]. Figure 21 shows two types of surfactant that are commonly used in the field. It also shows the shorthand notation of the surfactant, the tadpole symbol.
Surfactants are normally classified according to the ionic nature of their head group; anionic surfactants have a negatively charged head group, cationic surfactants have a positively charged head group. The head group of a non-ionic surfactant is neutral whereas zwitterionic surfactants have two head groups of opposite charge. The most frequently used surfactants are anionic surfactants; they are relatively resistant to adsorption because the negative charge of their head group repels them from the negatively charged rock surface. They are also good surfactants, stable, and relatively cheap to manufacture [7, 9].

For any class there are numerous varieties of surfactants. In Table 5 the different classes are depicted and some examples are given.

Table 5 The 4 different classes of surfactants and some examples after [7]

<table>
<thead>
<tr>
<th></th>
<th>Anionics</th>
<th>Cationics</th>
<th>Nonionics</th>
<th>Amphoterics/Zwitterionics</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sulfonates</strong></td>
<td>Sulfates</td>
<td>Quaternary ammonium</td>
<td>Sulfates</td>
<td>Sulfates/SESA, Amides</td>
</tr>
<tr>
<td><strong>Carboxylic</strong></td>
<td>Carboxylic</td>
<td>Quaternary ammonium</td>
<td>Carboxylic</td>
<td>Sulfates/SESA, Amides</td>
</tr>
<tr>
<td><strong>Phosphates</strong></td>
<td>Phosphates</td>
<td>Quaternary ammonium</td>
<td>Phosphates</td>
<td>Sulfates/SESA, Amides</td>
</tr>
</tbody>
</table>

When surfactant is added to a solvent the dissolved molecules are dispersed in the fluid as monomers. This is however only true for low surfactant concentrations; when the surfactant concentration increases the molecules tend to group together and form aggregates or micelles. These micelles start to appear when the surfactant concentration reaches a certain level called the critical micelle concentration (C.M.C) and contain several surfactant molecules each. Figure 22 shows a plot of the micelle concentration as a function of the surfactant concentration. The micelles shapes shown in the plot are not static and can take on several different shapes [7].
Figure 22 Surfactant monomer concentration as function of surfactant concentration, after [7]

C.M.C is normally in the range of $10^{-5}$ to $10^{-4}$ kg-moles/m$^3$. Concentration of surfactant as used in EOR applications is usually much higher than the C.M.C to compensate for adsorption [9].

Surfactant molecules tend to accumulate on the oil-water interface because of their dual nature. The hydrophilic head tends to stay in the aqueous phase while the lyophilic phase remains in the oleic phase (Figure 23). This accumulation of surfactant results in a reduction of the IFT between the liquids.

Figure 23 Schematic of surfactant distribution at ideal conditions
IFT is a function of surfactant concentration. Figure 24 illustrates that IFT reduces fast until the C.M.C is reached, after this the IFT will only have a minor decrease. The reduction of the IFT increases the capillary number as shown in equation 3.2.1-4 and when large enough can reduce the residual oil saturation.

![IFT as a function of concentration](image)

**Figure 24 IFT as a function of concentration [9]**

### 4.3 BrightWater™

BrightWater™ is an in-depth water flood conformance improvement chemical. It is designed to seal off high permeable zones, such as a thief zone or a river channel, deep in the reservoir and thereby diverting the water flood flow to lower permeable, less swept zones. The polymer will be injected in granular form at almost water viscosity, but due to temperature rise in the reservoir it will expand and block the pores (Figure 25). A BrightWater™ slug is usually followed by a chase fluid in the form of normal injection water.

![Representation of 5 microns particles in a pore throat](image)

**Figure 25 Representation of 5 microns particles in a pore throat [23]**

When BrightWater™ (BW) is dispersed in the injection water with the help of an added surfactant the particles can move through the rock matrix until the temperature reaches a certain value or certain time has passed. At this time or temperature a BW particle diameter will expand (Figure 26). They will then start to interact with each other much like a conventional polymer but will also block pore throats because of their size.
This “popping” mechanism brings about two different flow diversion mechanisms:

1. The viscosity of the driving fluid rises after temperature rise, the viscous polymer now diverts the water flood to other areas.
   A problem can be that the viscosity is diminished again by dispersion of the BW during injection. This decrease will be less severe in case of a thin thief zone or a small channel.

2. Swollen particles will adsorb and reduce water flow.
   This mechanism is described as having the most positive influence on water conformance. It is more effective than the viscosity effect and it is longer lasting.
   The mechanism is similar to polymer retention and resulting residual resistance factor that is encountered in conventional polymer floods. For good blockage of high permeability zones the adsorption is deep in the reservoir where it will divert chase water to unswept zones. Figure 27 shows a sketch of this mechanism; the BW slugs will be injected and flow through the higher permeable layers, at the temperature front (which differs per layer) they will expand and block the flow. The chase water is then diverted and will be diverted to the unswept parts of the reservoir.
   Because the adsorption is irreversible, BW will contribute to a longer lasting diversion, another advantage is that BW particles will not be produced back again, this reduces separation treatment costs.
Figure 27 Schematic impression of BrightWater™ slugs diverting flow to unswept areas.
5 Reservoir model

To assess the selected EOR methods numerical simulations have been done on a sector model derived from the full reservoir model. The sector model was chosen in such a way that the trend in the historical behaviour of the field could be matched.

A full field structural model of the reservoir was supplied by TAQA. For several reasons it was decided to reduce the size of the model by selecting a section of the field. 1) A small grid size was desired to reduce numerical dispersion and to be able to accurately model the thin thief zone, to reduce the number of grid blocks and computational time the size of the model was therefore reduced. 2) The results of an EOR method would be better understood using only a few wells and cancelling out big structural effects such as (sealing) faults. 3) Modelling the properties and facies of a full field model and to make a full field history match would simply take too much time.

5.1 Sector model location

The selected sector is located in the south east part of the field and is 1800m wide and 2775m long (Figure 28). Figure 29 shows the sector with 4 injection wells (IA-10, IA-12, IA-14 and IA-15) and 3 production wells (PA-01, PA-04 and PA-07z).

![Figure 28 The Rijn field reservoir model, the dashed red square is the sector location](image)
At the start of production in 1986 all the wells in the sector were in use until the shut down in 1998. In November 2010 the field was restarted using wells: PA-01, PA-04, PA-07z, IA-10 and IA-12 of this sector. Wells IA-14 and IA-15 were abandoned.

It is very likely that wells PA-12, PA-7z and PA-04 are communicating on a production time scale [31]. Although this has not been confirmed by tracer test results yet, early production data before 1998 and present pressure measurements support the idea of communication. The production and injection history of the well pair before 1998 is shown in Figure 30, clearly the amount of liquid produced overlaps the amount of water injected. Since this section is assumed to be isolated the well pair could also potentially be used for a pilot test.
5.2 Geological modelling

The reservoir parameters for the sector model were interpolated using initial well logs and logs interpreted by TNO [1] for a full field reservoir model. It would have been convenient to use this complete TNO model but the model is 10 years old and based on a very large grid size and no distinction was made of the high permeable streak within the A zone. Therefore the model was discarded for this research.

The zonation as used in the current model is shown in Figure 31. From Gamma Ray logs eight zones were subdivided, the high permeable zone was picked in every well and classified as one zone (A2_storm) to make sure it would be a continuous layer in the grid system. Shale layers, that were identified between the A,B and B,C zones, were also modelled as continuous layers. This allowed changing their vertical permeability in the reservoir model conditioning procedure, to better match the production profiles. This was done because previous studies were inconclusive about the vertical communication between the A, B and C layers.

Figure 31 Example of zonation as used in the model for well PA-04
A porosity-permeability (poroperm) relation was made from core flood experiments reported by Schlumberger [2]. Figure 32 shows the porosity versus permeability plot as constructed by Schlumberger. Four correlations can be clearly distinguished; they correspond to the general depositional environments already discussed before (see Sec. 2.2).

Figure 32 Porosity vs. Permeability Cross plot [2]

The correlations shown in Table 6 and are slightly different from those reported by Schlumberger because it is thought that they were underestimated. The type 3 sub-correlation was discarded for any correlation since the permeability change would be extremely large in only a few porosity units making it impractical and unrealistic to use.

<table>
<thead>
<tr>
<th>Type</th>
<th>Zone</th>
<th>Porosity (φ) cut-off</th>
<th>Permeability (k) (mD)</th>
<th>Correlation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Mainly Lower Layers B&amp;C</td>
<td>&lt; 15</td>
<td>0.5-0.03</td>
<td>$k = 0.1\times\exp(0.11\times\phi)$</td>
</tr>
<tr>
<td>2</td>
<td>All Layers</td>
<td>15-18</td>
<td>0.2-40</td>
<td>$k = 0.000365\times\exp(0.5\times\phi)$</td>
</tr>
<tr>
<td>3</td>
<td>Top Layers A, B &amp; C</td>
<td>13-17</td>
<td>1-80</td>
<td>--</td>
</tr>
<tr>
<td>4</td>
<td>Layer A, Storm Sand</td>
<td>&gt; 18</td>
<td>250-1200</td>
<td>$k = 100\times\exp(0.11\times\phi)$</td>
</tr>
</tbody>
</table>
The correlations were then applied to the porosity logs to derive a permeability log. An example of the logs is presented in (Figure 33) which shows the porosity and permeability distribution of well PA-04 where also the high permeable layer is clearly visible.

![Figure 33 Porosity and Permeability distribution with zonation of well PA-04](image-url)
Figure 34 shows the permeability distributions of all the reservoir zones as obtained by ordinary Kriging. No facies modelling was done, which would be recommended for a full field analysis. For the spatial dimensions of this sector model Kriging was considered sufficient.

![Figure 34 Permeability distributions obtained by ordinary Kriging between wells](image)

Table 7 shows the average permeability and porosity values of the 5 zones resulting from the poroperm and Kriging procedure. It can be seen that the permeability of all the zones except for the storm layer is lower than expected and reported in the Schlumberger report [2].

<table>
<thead>
<tr>
<th>Zone</th>
<th>Average Permeability (mD)</th>
<th>Average Porosity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>5.68</td>
<td>13.3</td>
</tr>
<tr>
<td>A2_Storm</td>
<td>1126.11</td>
<td>21.7</td>
</tr>
<tr>
<td>A3</td>
<td>1.63</td>
<td>14.2</td>
</tr>
<tr>
<td>B</td>
<td>2.51</td>
<td>16.7</td>
</tr>
<tr>
<td>C</td>
<td>1.82</td>
<td>14.4</td>
</tr>
</tbody>
</table>
An explanation for this is that the poroperm correlations in Figure 32 were measured in cleaner parts of the reservoir whereas this part of the reservoir is of less quality. If clay is present in the reservoir a porosity log derived from a resistivity log can become inconsistent because of the fact that Archie’s equation only works well in clean, clay free sands [25]. Furthermore, excessive bioturbations has been reported (Table 1), this can also improve permeability.

Therefore the decision was made to change the porosity cut-offs for the poroperm correlations and to increase the permeability of the zones in the model. For the A1 and A3 sand permeability was increased with 30mD whereas the B and C zones were increased with 5 and 3mD respectively. This later proved to be a good decision because with the lower permeability values the injection rates as reported in the production history could not be matched in the simulation model. The result of this permeability modification is shown in Table 8.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Average Permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>348.21</td>
</tr>
<tr>
<td>A2_Storm</td>
<td>1126.11</td>
</tr>
<tr>
<td>A3</td>
<td>36.9</td>
</tr>
<tr>
<td>B</td>
<td>5.42</td>
</tr>
<tr>
<td>C</td>
<td>3.23</td>
</tr>
</tbody>
</table>

A special core analysis test done in 1986 on well A10 [26] indicated that the vertical permeability in the zones is equal to the horizontal permeability. This can be explained by bioturbation sometimes in combination with the reworking of the sediments by waves.

### 5.3 Other simulation model parameters

#### 5.3.1 Grid size

Since the grid size of the simulation model had to be small, the grid size from the geological model was adopted. This resulted in a areal grid size of 18mX18m, the vertical grid size varied per zone. Table 9 shows how the grids were vertically distributed per zone. Because zone A has fluctuating permeability in vertical direction (e.g. storm sand) the vertical grid size is very small. For zones B and C a larger vertical grid size was used.

<table>
<thead>
<tr>
<th>Zone</th>
<th># internal layers</th>
<th>Average Vertical grid size (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>12</td>
<td>0.25</td>
</tr>
<tr>
<td>B</td>
<td>10</td>
<td>0.75</td>
</tr>
<tr>
<td>C</td>
<td>5</td>
<td>3.40</td>
</tr>
<tr>
<td>D</td>
<td>Non reservoir</td>
<td></td>
</tr>
</tbody>
</table>
5.3.2 Saturation functions

Two core flood tests were available with relative permeability data but the results of these tests were inconsistent. Therefore a relative permeability curve and capillary pressure curve constructed by TNO for their reservoir simulation was adopted [1]. The functions are shown in Appendix IV.

No gas-oil saturation functions were used since the TNO report indicated that no time during production the reservoir pressure has been below the bubble point pressure of 130 bar. This assumption was therefore adopted to reduce computing time.

5.3.3 PVT Properties

The oil PVT properties were, after a consistency check with the latest laboratory results, also adopted from the TNO research and are shown Appendix IV.
6 Simulations

No saturation data was acquired when the Rijn field was re-developed. Therefore the saturated state of the reservoir after twelve years of production and twelve years of shut-in had to be modelled. This reservoir model conditioning was done using a technique based on history matching. Subsequently four main cases were considered: 1) no further action (NFA) forecast of water injection, 2) BrightWater™ injection, 3) polymer flooding and 4) surfactant flooding.

Dynamic simulations were done using the Schlumberger Reservoir Simulator Eclipse 2010.2.

6.1 Input parameters

6.1.1 Reservoir model conditioning and NFA scenario

The field data (Figure 4) shows large fluctuations in the monthly injection rates, probably for technical reasons. To prevent large pressure unbalances in the reservoir and long simulation times, the injection rates were therefore averaged per year.

The conditioning process involved imposing minimal bottom hole pressure (BHP) constraints (50 bar) on the production wells, no rate constraints were used. The injection wells became rate constraint in a later stage of the process because it was not possible to achieve the historical rates with the initially imposed BHP constraint of 300 bar. It was considered important that at least the injection rate history was matched to a reservoir engineering acceptable level.

The no further action forecast was done using the three currently used wells, PA-04, PA-07z and IA-12. Both production wells were put on a minimum BHP constraint of 50 bar and the injector had a maximum BHP constraint of 300 bar.
6.1.2 Polymer flooding

In polymer flooding several parameters are important to incorporate in the simulation model.

**Viscosity:**

For the model Eq. 4.1-1 was truncated at the cubic term which resulted in the following curve of the viscosity as a function of concentration (Figure 35).

![Viscosity vs Concentration](image)

**Figure 35 Viscosity as a function of polymer concentration used for input**

with $a_1=1.98$ and $a_2=9.22$

This curve is an assumption and is derived from literature on EOR [7], the actual shape of the curve depends on many factors such as salt concentration, temperature and shear rate (Sec. 4.1). Many different polymer brands exist which each have their own characteristics and can be optimised for a certain reservoir.

**Adsorption:**

A linear Henry isotherm was used instead of the Langmuir type isotherm discussed in Sec. 4.1 to simplify the effect of adsorption. Figure 36 shows an example of the Langmuir isotherm and the Henry isotherm actually used in the model. Since there was no reservoir data available on adsorption the assumed maximum amount of adsorbed polymer was set at 0.0005 kg/kg. Of course the rate and amount of adsorption is a reservoir rock property and a better estimation of this should be determined with the help of core flood experiments.
Figure 36 Polymer adsorption modelled with a Langmuir-isotherm and a Henry-isotherm

The mass of adsorbed polymer is calculated in the model as follows:

\[
\text{Mass of adsorbed polymer} = \text{PORV} \times \frac{1 - \frac{\varphi}{\Phi} \times \text{MD} \times \text{CA}(C_p)}{\varphi} \tag{6.1.2-1}
\]

where:

- \(\text{PORV}\) is the pore volume of the cell (m³)
- \(\varphi\) is the porosity
- \(\text{MD}\) is the mass density of the rock (kg/m³)
- \(\text{CA}(C_p)\) is the adsorption isotherm as a function of the local polymer concentration in solution.

**Permeability Reduction**

In the Eclipse \(R_k\) relates to \(R_{RF}\) as follows:

\[
R_k = 1.0 + (R_{RF} - 1.0) \frac{C_{\text{ads}}}{C_{\text{max}}^{\text{ads}}} \tag{6.1.2-2}
\]

This means that a higher \(R_{RF}\) results in a higher \(R_k\) as is also shown in Figure 37.
Mixing:
To incorporate the effects of physical dispersion at the front of the polymer flood and fingerling effects, caused by mobility ration between polymer and driving fluid, at the rear of the flood an effective viscosity $\mu_{p,\text{eff}}$ is introduced. This effective viscosity is calculated using the Todd-Longstaff technique [28] and is given in the equation below:

$$\mu_{p,\text{eff}} = \mu_m (C_p)^\omega \cdot \mu_p^{1-\omega} \quad (6.1.2-3)$$

where $\mu_m(C_p)$ is the polymer concentration in solution (given by Figure 35) and $\omega$ the Todd-Longstaff mixing parameter.

If $\omega=1$ then the polymer solution and the water are fully mixed in each grid block, if $\omega=0$ then no mixing occurs.

The same can be done to calculate the partially mixed water viscosity $\mu_{w,e}$ given by:

$$\mu_{w,e} = \mu_m (C_p)^\omega \cdot \mu_w^{1-\omega} \quad (6.1.2-4)$$
Finally the effective water viscosity can be calculated using:

\[
\frac{1}{\mu_{w,\text{eff}}} = 1 - \frac{C^*}{\mu_{w,\text{e}}} + \frac{C^*}{\mu_{p,\text{eff}}}
\]  

(6.1.2-5)

\[C^* = \frac{C_p}{C_{p,\text{max}}}
\]  

(6.1.2-6)

where \(C^*\) is the effective saturation for the injected polymer solution within the total aqueous phase in the cell.

Figure 38 shows the effect of the Todd-Longstaff parameter on the effective water viscosity. When full mixing occurs (\(\omega=1\)) a small amount of polymer concentration has a significant influence on the effective viscosity, if no mixing is assumed (\(\omega=0\)) only higher concentrations influence the viscosity. When \(\omega=0\) the dispersion or smearing effect of polymer viscosity at the polymer front is reduced and the polymer displacement will be more shock front like.

![Figure 38 Effective water viscosity as function of the Todd-Longstaff parameter](image)

**Non-Newtonian Effects**

Non-Newtonian effects influence the viscosity of the polymer (see Sec. 4.1). Especially near the wellbore, however since the simulations did not incorporate well inflow data the non-Newtonian effects were not taken into account.

**Salinity Effects**

To model the effects of salinity much additional information was required which would make the model too complicated for its purpose. It was decided to incorporate these effects in a later stage, should the polymer flooding simulations show positive results.
6.1.3 BrightWater™ injection
This study only aimed at assessing the effects of setting a non-permeable plug deep in the reservoir in the high-permeable zone. The dependency of BrightWater™ of a temperature front was therefore not included in the model.

To model the shape and penetration depth of the plug, the result of a surfactant flood simulation was used where a surfactant slug was followed by water injection. With the help of a static reservoir modelling program it was possible to create an alternative permeability distribution of the reservoir. At a given time whenever the surfactant concentration \( C_S \) in a grid block would be above a certain value the permeability was manually reduced to zero with the help of an if-statement.

\[
\text{If } C_s > C_{\text{cut-off}} \text{ then } k=0 \tag{6.1.3-1}
\]

where \( C_{\text{cut-off}} \) is the desired concentration value for which permeability will reduce to zero. So a lower value for \( C_{\text{cut-off}} \) will result in a bigger area of zero permeability.

The result of the modification of the permeability distribution by a small BrightWater™ slug injected in the high permeable zone is visible in Figure 51 (with \( C_{\text{cut-off}} = 0.8 \)).

Of course this approach is very rough, but it is sufficient to get a first feeling of what the effect of shutting off the high permeable zone will be.

6.1.4 Surfactant flooding
Input parameters that are important for modelling the EOR potential of a surfactant flood are:

*Adsorption*

The injection concentration of surfactant (1 – 3 volume %) as proposed in the literature [29] is higher than the injected polymer concentration. Therefore an approximation to a Langmuir type adsorption isotherm was made (see Sec. 4.1). Figure 39 represents this isotherm and shows that for low concentrations the adsorption increases with concentration the same way as assumed in the polymer model, but when concentrations are above 1 kg/m\(^3\) the adsorption isotherm is constant, this is a valid assumption since the injection concentration used in the model is 10 kg/m\(^3\).

The mass of adsorbed surfactant is calculated in the similar way as polymer adsorption [28]:

\[
\text{Mass of adsorbed surfactant} = POAV \cdot \frac{1-\varphi}{\varphi} \cdot MD \cdot CA(C_i) \tag{6.1.4-1}
\]

where:

\( CA(C_i) \) is the adsorption isotherm as a function of the local surfactant concentration in solution.
**Interfacial tension**

The isotherm used to model interfacial tension is shown in Figure 40, where it is assumed that the interfacial tension is constant above a concentration of 1 kg/m$^3$, which is a valid assumption looking at the typical behaviour shown in Figure 24. The exact behaviour is depending on multiple parameters including surfactant type, temperature and salinity. To get a better understanding of the behaviour of the surface tension, lab research will be necessary. This lab research will also be necessary to find the optimal surfactant type for the Rijn oil field reservoir.

**Figure 40 The interfacial tension isotherm used in the model**

**Endpoint Residual Oil Saturation**

As described in Sec. 4.2 the goal of surfactant flooding is to reduce the endpoint residual oil saturation $S_{or}$. The rate of $S_{or}$ reduction is dependent on capillary pressure and thus surface tension. The minimum value for the endpoint $S_{or}$ is a parameter that has to be entered in the model and which is also dependent on the capillary number ($N_c$).

The water oil capillary pressure $P_{cow}$ will reduce as the surface tension (ST) is reduced; the way this is modelled is represented by the following equation:
\[ P_{cow} = P_{cow}(S_w) \frac{ST(C_s)}{ST(C_s = 0)} \]  

where

- \( ST(C_s) \) is the surface tension at the present surfactant concentration
- \( ST(C_s = 0) \) is the surface tension at zero concentration
- \( P_{cow}(S_w) \) is the capillary pressure as function of water saturation

(see Figure 77)

For the reduction of the endpoint \( S_{or} \) a new relative permeability curve has to be constructed where the endpoint \( S_{or} \) has a lower value than the original relative permeability curve. The curves used for the base case surfactant scenario and for the non-EOR scenario are depicted in Figure 41 and have an endpoint \( S_{or} \) of respectively 0.15 and 0.25.

![Relative permeability curve](Image)

**Figure 41** Base simulation case surfactant relative permeability curve
However, only when the surface tension is low enough Eclipse will apply the secondary relative permeability curve. This depends on the capillary number as explained in Sec. 3.2.1.

\[ N_c = \frac{H \cdot v}{\sigma} \]  

(3.2.1-4)

The value of \( N_c \) that is necessary to apply the surfactant relative permeability function is also an input, which is shown in Table 10. From where it follows that when \( N_c \) rises above \( 10^{-4} \) the surfactant relative permeability curve is used.

<table>
<thead>
<tr>
<th>( N_c )</th>
<th>Relative Permeability Function Used</th>
</tr>
</thead>
<tbody>
<tr>
<td>( 10^{-10} )</td>
<td>Water</td>
</tr>
<tr>
<td>( 10^{-5} )</td>
<td>Water</td>
</tr>
<tr>
<td>( 10^{-4} )</td>
<td>Surfactant</td>
</tr>
<tr>
<td>( 10^{10} )</td>
<td>Surfactant</td>
</tr>
</tbody>
</table>

This is considered a very simplified solution for a very complex chemical mechanism and is one of the limitations of using Eclipse 100 to model a surfactant flood.

**Viscosity**

The viscosity of the aqueous phase is a function of surfactant concentration and is seen in Figure 42. It is assumed that viscosity will increase linear and not rise above 1 cP at reservoir conditions, although this is of course dependent on the type of surfactant.

![Figure 42 Water viscosity as function of surfactant concentration at reservoir temperature](image)

**Table 10 Capillary de-saturation function as used in Eclipse**
6.2 Results and discussion

6.2.1 Reservoir model conditioning

An attempt to roughly match the production history of the sector is made in order to condition the reservoir model to a realistic post-water-flooding saturation state. The results of this exercise were based on multiple assumptions. However, the result is a good initiation point for EOR modelling because the model approaches the reality of an oil field and is not a theoretical model.

The results of the conditioning process and the inaccuracy with the historic production are summarized in Table 11. The match is fairly good and the maximum error is 29% at well PA-01.

Table 11: The results of the reservoir model conditioning

<table>
<thead>
<tr>
<th>Well</th>
<th>Cumulative Oil Production</th>
<th>Cumulative Water Production</th>
<th>Water Breakthrough Time</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>sim</td>
<td>history</td>
<td>difference</td>
</tr>
<tr>
<td>Producers</td>
<td>Mibi</td>
<td>Mibi</td>
<td>%diff</td>
</tr>
<tr>
<td>PA-1</td>
<td>1.78</td>
<td>1.5</td>
<td>0.28</td>
</tr>
<tr>
<td>PA-4</td>
<td>1.81</td>
<td>2.3</td>
<td>-0.49</td>
</tr>
<tr>
<td>PA-7z</td>
<td>1.07</td>
<td>0.97</td>
<td>0.1</td>
</tr>
<tr>
<td>Sector</td>
<td>4.67</td>
<td>4.77</td>
<td>-0.1</td>
</tr>
<tr>
<td>Injectors</td>
<td>Mibi</td>
<td>Mibi</td>
<td>%diff</td>
</tr>
<tr>
<td>IA-10</td>
<td>FAULT CLOSED</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IA-12</td>
<td>11.21</td>
<td>10.7</td>
<td>0.51</td>
</tr>
<tr>
<td>IA-14</td>
<td>4.38</td>
<td>4.18</td>
<td>0.2</td>
</tr>
<tr>
<td>IA-15</td>
<td>7.19</td>
<td>6.6</td>
<td>0.59</td>
</tr>
</tbody>
</table>

Figure 43 shows a schematic of the sector model with all the producers and injectors that were in production in the simulated period together with the faults present in the sector.

Early in the process it was deemed necessary to close the fault between the injector IA-10 and producer PA-04 since PA-04 was producing too much water coming from IA-10. This assumption can also be supported by the current pressure data which implies that the reservoir pressure derived from IA-10 differs with the pressure derived from wells PA-04, PA-07z and IA-12 [31]. Therefore IA-10 was not used in the conditioning process.
In addition some vertical permeability had to be attributed to the shale layers in order to reach the historic oil production rates. The thought that there is in some level vertical communication between the A, B and C is hereby increased. This could be caused by small fractures that are not visible on seismic but are large enough to provide communication.

The well PA-01 is north of a major fault. The transmissibility of that fault and the production rate of the well were therefore varied to optimise the match in the other 3 wells without matching the well itself.

Furthermore because well IA-14 is located in the bottom left corner on the edge of the sector, the historical injection rates were halved since the injected water is also believed to have supported other wells outside the sector.

The water injection rates of wells IA-12, IA-14 and IA-15 are shown in Figure 44. The imposed rates do not really match closely to the historical rates because of the averaging. However, the cumulative production is only slightly higher than the historical value.
Figure 44 Historic and simulated water injection rates
Figure 45 shows the historical production and simulated production rates of well PA-07z. Well PA-07z was drilled and taken into production 2 years after the majority of the wells were taken into production. Initial production from this well shows a peak of high oil rate and negligible water cut. This is likely caused by well IA-15 pushing oil towards the fault south of well PA-01 which acted as a boundary and pressure started to build up. By the time PA-7z was taken into production, the pressure, built up in the previous years, caused the peak in production. Additionally, the water production rates show a similar trend and so do the cumulative oil and water production.

![Figure 45 Historical and simulated production rates well PA-07z](image)

The oil production rates of well PA-04 presented in Figure 46 show a similar trend as the historical rates although at the start there is not a good match. Water production rates also show a similar trend but again at the start the simulated production is much higher. After the BHP constraint of 300 bars on the injection wells was lifted, the injected water reached the well quicker and with a greater volume.

![Figure 46 Historical and simulated production rates well PA-04](image)
Figure 47 finally shows the production rates of the sector model, although the individual wells are not perfectly matching the history, the overall sector total performance shows a fairly good match. The overall mismatch on water and oil production at the start of the simulation is probably caused by the low modelled permeability of the reservoir. This could indicate that the poro-perm relations in Sec. 5.2 still underestimate the permeability.

![Graph showing historical and simulated production rates](image)

**Figure 47** Historical and simulated production rates of the sector model

In Table 12 the initial STOIP of the sector model is shown together with the volumes produced out of each zone. These values are in good agreement with PLT data which indicates most of the production is coming out of the A zone (Table 13).

<table>
<thead>
<tr>
<th>Zone</th>
<th>STOIP (MMSTB)</th>
<th>OIP (1998) (MMSTB)</th>
<th>Oil Produced (MMSTB)</th>
<th>Recovery Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sector</td>
<td>37.17</td>
<td>32.08</td>
<td>5.10</td>
<td>14</td>
</tr>
<tr>
<td>A</td>
<td>8.49</td>
<td>4.32</td>
<td>4.17</td>
<td>49</td>
</tr>
<tr>
<td>B</td>
<td>8.20</td>
<td>7.89</td>
<td>0.32</td>
<td>4</td>
</tr>
<tr>
<td>C</td>
<td>20.48</td>
<td>19.87</td>
<td>0.61</td>
<td>3</td>
</tr>
</tbody>
</table>

**Table 12** Oil recovery for the three main zones and for the total sector

<table>
<thead>
<tr>
<th>Zone</th>
<th>Recovery Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>62</td>
</tr>
<tr>
<td>B</td>
<td>5</td>
</tr>
<tr>
<td>C</td>
<td>4</td>
</tr>
</tbody>
</table>

**Table 13** Total Rijn field recovery factors based on PLT measurements [31]
The reservoir model conditioning resulted in the following saturation state of the sector model shown in Figure 48.

![Figure 48 Simulated water saturation state at shut-in in 1998](image)

The average saturation values are depicted in Table 14. The average saturation is calculated from both residual oil saturation and remaining oil saturation.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Average $S_o$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0.31</td>
</tr>
<tr>
<td>B</td>
<td>0.48</td>
</tr>
<tr>
<td>C</td>
<td>0.49</td>
</tr>
</tbody>
</table>
**Re-saturation**

During shut-in of the field between 1998 and 2010 the reservoir pressure was restored to 205 bar which is close to the initial value of 207 bar. This could indicate some aquifer influence. Also initial oil production rates at the start-up in 2010 were higher than expected in the production forecast study [3]. This is expected to be the result of gravity segregation and cross flow between less depleted B, C and D zones into the A zone. This was modelled by injecting water at well IA-14 during the time the field was shut-in, hereby acting as a surrogate aquifer. Since there is a big fault south of well IA-12 (see Figure 2) this was justified because aquifer water could only have entered through the area where IA-14 is located.

The expected effect of gravity segregation is that the oil saturation increases at some topographic highs whereas water saturation increased in the lower levels of the field. This effect is also visible in Figure 49. The red zones indicate an increase in oil saturation whereas the blue zones show a decrease in oil saturation.

![Figure 49 Re-saturation in the topographic highs. Red is an increase in oil saturation, blue is a decrease](image-url)
6.2.2 No further action scenario

The rates and cumulative production are shown in Figure 50. The peak in oil production at the start-up is explained by oil accumulation around the wells, which were located at the crest of the reservoir, by gravity segregation. This effect was emphasized by repressurization during the shut-in time which increased total liquid production. Production starts of in the first two years with 400 STB/day and starts declining at a constant rate from July 2013.

Figure 50 Production results of the NFA scenario

With a BHP constraint of 300 bar the injection well was able to constantly inject around 6000 STB/day.

The production data is summarized in Table 15 below. After 10 years cumulative oil production is 1.17 MMSTB and cumulative water production is 21.87 MMSTB, this indicates that the oil is being produced at a high water cut. Results of the EOR scenarios will be compared to the 2011-2021 values to determine their effectiveness.

Table 15 Production data of the No further action scenario

<table>
<thead>
<tr>
<th></th>
<th>From 1986-2021</th>
<th>From 2011-2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Oil Production (MMSTB)</td>
<td>6.91</td>
<td>1.17</td>
</tr>
<tr>
<td>Cumulative Water Production (MMSTB)</td>
<td>38.78</td>
<td>21.87</td>
</tr>
<tr>
<td>Cumulative Water Injection (MMSTB)</td>
<td>45.98</td>
<td>23.19</td>
</tr>
</tbody>
</table>
6.2.3 BrightWater™ injection

Injecting BrightWater™ will shut off the high permeable zone. The water flooding should be diverted to unswept regions where \( S_o > S_{or} \), hereby increasing oil production.

Three different scenarios were done to assess the consequences of injecting a thermally activated polymer to plug the high permeable layer (Table 16).

Figure 51 through Figure 53 show the three different scenarios. In Figure 53 it can be seen that permeability is important to how the slug will propagate through the reservoir. BrightWater™ will not penetrate as deep in the low permeable layers as it will in the high permeable layer.

The results of the three cases are shown in Table 17.

### Table 16 BrightWater™ simulation scenarios

<table>
<thead>
<tr>
<th>Case</th>
<th>Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>BW001</td>
<td>Small slug injected solely in the high-permeable zone</td>
</tr>
<tr>
<td>BW002</td>
<td>Small slug injected in all reservoir zones</td>
</tr>
<tr>
<td>BW003</td>
<td>Big slug injected solely in the high-permeable zone</td>
</tr>
</tbody>
</table>

### Table 17 Results of the BrightWater™ simulation case

<table>
<thead>
<tr>
<th>Case</th>
<th>Cumulative Oil Production (MMSTB)</th>
<th>Cumulative Water Production (MMSTB)</th>
<th>Cumulative Water Injected (MMSTB)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NFA</td>
<td>1.17</td>
<td>21.87</td>
<td>23.19</td>
</tr>
<tr>
<td>BW001</td>
<td>1.16</td>
<td>21.66</td>
<td>22.96</td>
</tr>
<tr>
<td>BW002</td>
<td>1.12</td>
<td>19.53</td>
<td>19.41</td>
</tr>
<tr>
<td>BW003</td>
<td>1.16</td>
<td>18.65</td>
<td>20.03</td>
</tr>
</tbody>
</table>

Neither of the cases show incremental oil recovery, however all cases show reduced water production. This could indicate that because of plugging the high permeable layer, water cycling has diminished. But judging the amount of water injection, this decrease in water production can simply be explained by a reduction of water injection. This also indicated that a decrease in water injection will result in a decrease in oil production.
Figure 51 Shutting off the high-permeable zone with a small BrightWater™ slug (Case BW001)

Figure 52 Shutting off the high-permeable zone with a large BrightWater™ slug (Case BW003)

Figure 53 Cross section of the reservoir between IA-12 and PA-04 showing the BrightWater™ slugs in all 3 reservoir zones (case BW002)
Another reason for low incremental oil recovery could be that the high permeable layer is acting as a channel through which the oil from the rest of the A sand is produced. If this channel is plugged by BrightWater™, liquid production will reduce and oil production as well.

This effect is described in Figure 54 and can also be seen in Figure 55 where the top of the A3 sand is visualized at the end of production. Exactly where the BrightWater™ plug is set in the A2_storm zone, overlying zone A3, no decrease in oil saturation can be seen.

Figure 54 Proposed mechanism resulting in reduced oil production from the A zone

Figure 55 A view of the oil saturation at the top side of the A3 zone for BW001 and Non-EOR case. The shape of the BrightWater™ slug in the overlaying thief zone is clearly visible on the left
There is however some sweep improvement as can be seen at the bottom of the A1 zone. This sand has a slightly higher permeability as the sand in the A3 zone (Sec. 2.2.4), and some signs of flow diversion are visible in Figure 56 where the bottom of A1 is represented and the darker blue area in the left circles indicate sweep improvement.

Figure 56 A view of the oil saturation at the bottom side of the A1 zone, showing indication of sweep improvement in the areas where BrightWater™ was injected in the underlying thief zone

This suggests that if the permeability surrounding the storm layer is higher sweep improvement can occur. However, in this case the volume of residual oil at the bottom of zone A1 is too low to enhance the recovery.

The simulations indicate that the screening parameters for BrightWater™ used in Sec. 3.4 are incomplete. It should be added that the permeability ratio between the thief zone and the surrounding reservoir should not be too large in order to divert the flow effectively while retaining sufficient injectivity.

Summary

The way BrightWater™ is modelled here is a simple but nevertheless effective method to investigate the first effects of shutting off the high permeable zone.

No enhanced oil recovery was seen; however water production was slightly reduced and some sweep improvement was seen in the higher permeable areas. Injecting a larger slug of BrightWater™ resulted in a bigger decrease of water production with comparatively less decrease in oil production, but again overall oil production decreased.

BrightWater™ should only enter the high permeable layer, shutting off other regions will result in an even larger decrease of oil production.

An indication was given that in the Rijn field the high permeable zone is acting as a channel through which oil from surrounding layers is produced. Plugging it will result in decreased oil production.
6.2.4 Polymer flooding

By increasing the viscosity of the injection water the mobility ratio is expected to improve, hereby creating a more stable front and increasing oil recovery.

**Base case:**

For the base case the following input parameters were used:

<table>
<thead>
<tr>
<th>Table 18 Input parameters of the polymer flood base case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection concentration (kg/m³)</td>
</tr>
<tr>
<td>Injection viscosity (cP)</td>
</tr>
<tr>
<td>Inaccessible pore volume</td>
</tr>
<tr>
<td>Residual Resistance Factor</td>
</tr>
<tr>
<td>Desorption Occurs</td>
</tr>
<tr>
<td>Mixing parameter ω</td>
</tr>
<tr>
<td>Max. Polymer Adsorption (kg/kg)</td>
</tr>
<tr>
<td>Polymer injection time (yr)</td>
</tr>
</tbody>
</table>

The production results of the base case are shown in Table 19.

<table>
<thead>
<tr>
<th>Table 19 Base case production results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>NFA</td>
</tr>
<tr>
<td>PLY041(base)</td>
</tr>
</tbody>
</table>

The way the polymer is propagating through the reservoir is shown in Figure 57. Here the polymer concentration in zone A2-storm is visible. The influence of the faults near the injection well is clearly visible. The polymer front changes shape and penetrates the fault where the offset is the smallest, from there on it propagates stable towards PA-04.

The influence of the faults is also visible in Figure 58 where a concentration profile at different time steps is shown. The polymer front is not sharp and at the fault location an immediate decrease in polymer concentration is visible. Furthermore the influence of dispersion is seen here. The polymer is assumed to be fully mixing with the reservoir water, which makes the front smooth. Numerical dispersion is also of influence here. In Appendix VI the effects of dispersion will be further investigated.
Figure 57 Polymer concentration in the reservoir at different time steps

Figure 58 Polymer concentration profile as a function of distance from well
The water saturation profile of zone A_1 is shown in Figure 59. The polymer front is visible followed by a region of polymer mixed with reservoir water and in the end the initial water saturation. Minor influence by the polymer is seen at the front, however the influence is lower than expected. The dotted line represents the expected oil bank in front of a polymer slug. The absence of the oil bank in the saturation profile could suggest that the residual oil saturation at the start of the polymer flooding was too low to gain improved recovery. This could be part of the reason why production is lower than in NFA scenario (Table 19).

![Figure 59 water saturation profile between PA-04 and IA-12](image)

**Figure 59** water saturation profile between PA-04 and IA-12

**Slug size analysis**
In order to determine the effect of polymer treatment size on oil recovery, different injection durations were modelled. The results are shown in Table 20.

<table>
<thead>
<tr>
<th>Case</th>
<th>Polymer injection time</th>
<th>Cumulative Oil Production (MMSTB)</th>
<th>Cumulative Water Production (MMSTB)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NFA</td>
<td>-</td>
<td>1.17</td>
<td>21.87</td>
</tr>
<tr>
<td>PLY044</td>
<td>1 yr</td>
<td>1.16</td>
<td>20.39</td>
</tr>
<tr>
<td>PLY045</td>
<td>3 yr</td>
<td>1.15</td>
<td>17.62</td>
</tr>
<tr>
<td>PLY046</td>
<td>5 yr</td>
<td>1.13</td>
<td>15.17</td>
</tr>
<tr>
<td>PLY047</td>
<td>7 yr</td>
<td>1.08</td>
<td>13.00</td>
</tr>
<tr>
<td>PLY041</td>
<td>10 yr</td>
<td>1.01</td>
<td>10.53</td>
</tr>
</tbody>
</table>

As can be seen no cases show signs of enhanced recovery. This can be assigned to decrease in the injectivity index (II) as a result of the higher viscosity of the injection fluid [7]:

\[
II = \frac{Q}{\Delta P}
\]  

(8.4.2-1)

where Q is the injection rate and a function of \(\mu_w\) and \(k_w\) (Darcy) and \(\Delta P\) is the pressure difference between the BHP and a reference pressure in the reservoir.
How the injectivity of well IA-12 and oil production depends on the viscosity of the injected polymer solution is seen in Figure 60. Injectivity decreases very rapidly in the beginning and even with a low injection viscosity of 1cP there is no incremental oil recovery. The reason for this is that very high injection rates are used.

![Figure 60 Injectivity of well IA-12 and cumulative oil production as a function of viscosity](image)

Figure 60 Injectivity of well IA-12 and cumulative oil production as a function of viscosity

This puts forward the concept that the current oil production of the Rijn field is purely based on massive volumes of water circulation, hereby transporting oil that flows from less permeable zones through the high permeable A zone towards the producers. And every loss in injectivity means a decrease in oil production.

**Summary**

The polymer propagates in a stable front-like manner, providing good sweep efficiency. Indications were given that the oil saturation is very close to residual oil saturation in the swept parts of the reservoir. This prevented polymer flooding to have a positive effect. Injectivity loss resulted in a decrease of overall liquid production. Injectivity and oil production decreased with increasing solution viscosity. It is therefore not recommended to further investigate in polymer flooding as an EOR method for the Rijn oil field.
6.2.5 Surfactant flooding

Surfactant is mixed with the injection water in order to reduce the oil-water interfacial tension. This should reduce residual oil saturation and increase oil recovery.

**Base case analysis**

The modelling of surfactant flooding started with a base case scenario, of which the parameters are shown Table 21. The case started with 10 months surfactant injection and was followed by water flooding until the end of the field life. All following surfactant flooding scenarios assumed the displacement of surfactant by water and results were compared to the base case in which general parameters were used.

<table>
<thead>
<tr>
<th>Table 21 Base case surfactant parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Viscosity (cP)</strong></td>
</tr>
<tr>
<td><strong>Adsorption (kg/kg)</strong></td>
</tr>
<tr>
<td><strong>Minimum IFT (N/m)</strong></td>
</tr>
<tr>
<td><strong>Critical Capillary Number</strong></td>
</tr>
<tr>
<td><strong>Injection Concentration (kg/m3)</strong></td>
</tr>
<tr>
<td><strong>Endpoint S_or</strong></td>
</tr>
<tr>
<td><strong>Injection time (months)</strong></td>
</tr>
</tbody>
</table>

In Figure 61 an oil saturation profile between IA-12 and PA-04 (red line in Figure 62) is presented. This shows how an oil bank, resulting of mobilization of the residual oil due to the lowering of the IFT, propagates through the reservoir in time. At $t=12$ months the bank has reduced in saturation and seems to be spread out. This is probably caused by the fact that surfactant injection was stopped after 10 months and the injection rate increased. The higher flow rate causes dispersion of the oil bank. After 24 months the oil bank was almost fully produced.

![Figure 61 Oil saturation profiles between IA-12 and PA-04 at different time steps](image-url)
The oil bank caused by the surfactant is also clearly visible in Figure 62 where the oil saturation in the A_2 storm zone is shown. The front of high oil saturation (red colour) is followed by a deep blue colour, indicating a very low oil saturation ($<S_{or}$) and a very good sweep.

![Image of oil bank and surfactant fronts]

**Figure 62 Oil bank created by the surfactant flood at t=10 months, red line represents the location of the saturation profile**

Figure 63 shows the oil production and surfactant production of the base case and the NFA case. An increase of the production rate is distinctly visible around May 2013, when the oil bank reaches the producer PA-04.

The peak in oil production is followed by surfactant break-through shortly after. This also indicates an oil bank being created in front of the surfactant flood which is consistent with the theory and behaviour of other fields where surfactant flooding has been applied [7].

65
Figure 63 Top: Oil production rates of the base surfactant case and the NFA case.
Bottom: surfactant production rate

Figure 61 also explains why the cumulative oil production slowly decreases with increased amount of injected surfactant, as seen later in Figure 64. Behind the oil bank there is no more moveable oil because \( S_o = S_{or} \) and as lower permeable layers and remote part of the reservoir are swept by surfactant, a considerable amount of the injected surfactant is produced through the already swept zones. This is a very important surfactant flood design factor because at a certain time the costs of injected surfactant will be too high compared to the incremental profit from the extra oil. Good practice would be to inject just enough surfactant so that the oil bank is produced; this is the maximum technical efficiency. In order to understand the optimum slug size, several volumes of surfactant followed by water injection were modelled. This will be discussed in the next section.
Effect of slug size:
Different cases were run to assess the influence of the volume of injected surfactant with respect to the total oil recovery. Therefore different sizes of surfactant slugs were injected. The cases are listed in Table 22:

Table 22 Surfactant simulation cases

<table>
<thead>
<tr>
<th>Case</th>
<th>Injection time (month)</th>
<th>Mass Surfactant Injected (10^3 kg)</th>
<th>Cumulative Oil Production (MMSTB)</th>
<th>Incremental Oil (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NFA</td>
<td>-</td>
<td>-</td>
<td>1.17</td>
<td>-</td>
</tr>
<tr>
<td>SURF038</td>
<td>1</td>
<td>167</td>
<td>1.17</td>
<td>0.2</td>
</tr>
<tr>
<td>SURF056</td>
<td>4</td>
<td>658</td>
<td>1.18</td>
<td>1.1</td>
</tr>
<tr>
<td>SURF039</td>
<td>7</td>
<td>1180</td>
<td>1.20</td>
<td>3.2</td>
</tr>
<tr>
<td>SURF042</td>
<td>10</td>
<td>1704</td>
<td>1.23</td>
<td>5.8</td>
</tr>
<tr>
<td>SURF040</td>
<td>16</td>
<td>2745</td>
<td>1.30</td>
<td>11.4</td>
</tr>
<tr>
<td>SURF058</td>
<td>17</td>
<td>2922</td>
<td>1.31</td>
<td>12.2</td>
</tr>
<tr>
<td>SURF041</td>
<td>20</td>
<td>3442</td>
<td>1.33</td>
<td>14.2</td>
</tr>
<tr>
<td>SURF059</td>
<td>28</td>
<td>4768</td>
<td>1.37</td>
<td>17.8</td>
</tr>
</tbody>
</table>

The results are also plotted in Figure 64. It is observed that the cumulative incremental production increases smoothly with increasing amount of surfactant injected. However, the rate of increase declines with increasing amounts of surfactant injected.

![Figure 64 Cumulative incremental oil with respect to the amount of surfactant injected](image_url)

This suggests that there is a certain amount of surfactant that can be injected for which the surfactant flood would be most efficient. This can be expressed as technical surfactant flood efficiency, $E_{surf}$ being the number of incremental barrels of oil that can be produced by injecting 1000 kg of surfactant.

$E_{surf}$ can be expressed as follows [29]:

$$E_{surf} = \frac{\text{amount of cumulative incremental oil}}{\text{amount of surfactant injected}} = \frac{\text{stb}}{10^3 \text{kg}}$$

(8.5.2-1)

Comparing $E_{surf}$ with the cumulative incremental oil recovered results in the curve shown in Figure 66. This suggests that, for the single concentration used here and the current model assumptions, with the highest technical efficiency an incremental oil recovery of 0.14 MMSTB can be reached. In this case the highest technical efficiency was obtained with case SURF058. However, the highest economical efficiency can be a different scenario and is depending on oil price and surfactant price. This will be discussed later in this section.


Figure 65 Surfactant efficiency factor as a function of increased oil production

**Sensitivity analysis**

The efficiency of surfactant flooding depends on several variables. To investigate the sensitivity of these variables an analysis was done on the base case, with the parameters described earlier. The input of the sensitivity analysis is depicted in Table 23 and the results are shown in the spider plot in Figure 66.

<table>
<thead>
<tr>
<th>Table 23 Sensitivity analysis input parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viscosity (cP)</td>
</tr>
<tr>
<td>Adsorption (kg/kg)</td>
</tr>
<tr>
<td>Critical Capillary nr.</td>
</tr>
<tr>
<td>Surfactant concentration (kg/m3)</td>
</tr>
<tr>
<td>IFT (N/m)</td>
</tr>
</tbody>
</table>
As expected adsorption plays an important role in the effectiveness of a surfactant flood. The graph in Figure 66 shows that in the case the adsorption is 25% of the base case, incremental recovery will increase by about 7%. But if adsorption is 300% of the base case, incremental recovery drops with just 1.5%. These results indicate that if a surfactant can be designed with very low adsorption it could double the incremental recovery. The same is true for interfacial tension. And because adsorption and IFT are such critical parameters it can be recommended to carry out core flooding experiments on a wide range of applicable surfactants to determine the most effective system.

Viscosity is however different. The simulations show that the incremental recovery rises when viscosity decreases. This behaviour is probably caused by loss of injectivity for the same reason as reported in Sec. 6.2.4. It is however not likely that surfactant solution viscosity increases, only when very high concentrations are used so that complex micellar structures will form. Furthermore in some surfactant floods polymer is added to the solution to improve the mobility, therefore viscosity increase could even be beneficial to oil recovery.

Incremental recovery appears to grow almost linear with surfactant concentration, there is however a minimum at zero incremental oil (-5.5% in the plot) and there will be a maximum amount of incremental recovery produced by when using a higher surfactant concentration. Theoretically there can be a certain concentration or amount of surfactant which will sweep all the oil it contacts but after that no more oil is produced.

---

**Figure 66 Sensitivity spider plot, base case incremental recovery = 5.5%**
The critical capillary number (CCN) seems to be the less sensitive for the oil recovery. This could be caused by the way Eclipse models the effect of desaturation (Sec. 6.1.4). Also the ranges might have been too small to cause any relevant changes. If the number had approached 7 (water flooding CCN) no change in relative permeability would occur and the endpoint $S_{or}$ would be the water flood endpoint $S_{or}$ value of 0.25.

**Economic analysis**

To gain insight in the economical parameters of the surfactant flood a simple economical analysis was done. The results are indicative for the feasibility of an actual surfactant flood. An oil price of 85 $/STB was assumed and the surfactant prices varied, they are shown in Table 24, no discount factor was applied.

**Table 24 assumed surfactant prices for economical analysis**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Low cost</td>
<td>2 $/kg</td>
</tr>
<tr>
<td>Base cost</td>
<td>4 $/kg</td>
</tr>
<tr>
<td>High cost</td>
<td>6 $/kg</td>
</tr>
</tbody>
</table>

The profitability of the project is strongly dependent on surfactant price, which is shown in Figure 67. The undiscouted incremental profit is shown as a function of the amount of surfactant injected. With an oil price of 85 $/STB only the low cost surfactant case is profitable. To break even in this case a maximum surfactant price of 4.15 $/kg would be needed. This can be seen in Figure 68 where the undiscounted Internal Rate of Return (IRR) is plotted against the amount of surfactant injected. A considerable amount of surfactant has to be injected to break-even and if too much is injected the break-even point will not be reached. So the amount of surfactant injected is also here a very sensitive parameter which should be carefully designed before a surfactant flood is started.

**Figure 67 Undiscounted cumulative incremental profit as function of amount of surfactant injected**
Figure 68 Internal Rate of Return as function of amount of surfactant injected
Another important parameter is of course the oil price. This parameter is also the reason why the best technical efficiency case is not always the most profitable. Once the oil price - surfactant price ratio reaches a certain level a less technical efficient case which will recover more oil becomes more economical. This effect is shown in Figure 69 where for three different oil prices the profit has been plotted against technical efficiency. At the oil price of 105 $/STB it is observed that a case, less technical efficient, will create more profit. However over-injecting surfactant will immediately reduce profit again at a fast rate.

Figure 69 Undiscounted profit with relation to the technical efficiency for different oil prices

Remark that ultra-low interfacial tension surfactants exist these days which will reach a very low IFT with low concentrations (0.1 weight %) [30]. This would reduce the amount of surfactant injected for the same amount of incremental oil. A hypothetical case is shown in Figure 70 where it is assumed that the same amount of production can be reached with one tenth of the surfactant injected; not taking into account other factors that will change when using ultra-low IFT surfactants.

Figure 70 Hypothetical case of ultra-low IFT surfactant at 0.1 weight % injection concentration
Summary
Surfactant flooding proved to be a viable EOR method to improve oil recovery in the Rijn oil field. In the performed simulations, surfactant increased oil recovery by as much as 12.2% compared to the scenario with no further action.

The balance between the quantity of surfactant injected and increased oil production is very important, even a small amount of over-injection can make the project uneconomical.

The most sensitive parameters to surfactant flooding were the adsorption rate and the interfacial tension.

Both surfactant price and oil price play a significant role in the economic feasibility of surfactant flooding.
7 Conclusions and Recommendations

7.1 Conclusions
In this work an EOR screening study was done followed by numerical modelling to assess the IOR/EOR potential of the Rijn oil field.

- Detailed literature study and screening procedure of EOR methods showed that polymer flooding, surfactant flooding and BrightWater™ injection were the best candidates for the Rijn oil field.
- Subsequent numerical modelling presented in this work showed that surfactant flooding is the best suitable EOR method for the Rijn oil field. According to the modelling work presented in this report the expected incremental oil gained from surfactant flooding the A zone is 6-18% above the expected oil recovery by water flooding.
- Parameters that proved to have a significant impact on oil recovery are interfacial tension and adsorption.
- Surfactant price is one of the key economic parameters and the simulated cases show a break even price of 4.15 $/kg at an oil price of 85 $/STB.
- Polymer flooding improved mobility control but resulted in a decrease in oil production, compared to water flooding, caused by a decrease of injectivity due to higher injection viscosity.
- BrightWater™ improved conformance but was ineffective because permeability in the A zone (outside the thief zone) was not good enough.
- EOR selection criteria alone are not sufficient to assess the suitability of EOR methods and detailed understanding of the geology and production behaviour of a reservoir is vital for evaluation of EOR potential.
7.2 Recommendations

Future work in how to unlock the remaining reserves of the Rijn oil field is suggested:

- Further investigation into surfactant flooding is recommended with the emphasis on ultra-low interfacial tension surfactant.
- Core flooding experiments should be performed on cores from the Rijn reservoir in order to assess adsorption rates and the effect of interfacial tension on $S_{ir}$. There should be synergy with reservoir simulations to get a more accurate forecast and to optimise the economic efficiency.
- The results of the tracer test that is, at this date, still in progress could be useful to estimate the amount of surfactant that is needed to get a good recovery.
- Implementation of a surfactant flood should be directly applied to the best producer-injector pairs or even the full field. This way the expected profit to investment ratio could become more favourable.
- A more detailed economic evaluation of surfactant flooding is recommended.
- Polymer flooding is not recommended to be further investigated due to the injectivity issues brought by the viscosity increase.
- The screening parameters of in-depth water flood conformance such as BrightWater™ should be updated with a maximum ratio for the thief zone permeability to the remaining permeability in order to assess if the injectivity will not drop below an acceptable rate.
8 References


17. Internet:  http://www.cipr.uni.no/default.aspx


20. A. Aladasani, B. Bai, “Recent Developments and Updated Screening Criteria of Enhanced Oil Recovery Techniques” CPS/SPE International Oil & Gas Conference and Exhibition, Beijing, China, June 8-10, 2010. SPE130726


27. Internet:  http://www.wikipedia.org


**Reservoir Parameters input**

(N.B. If parameter not available use N/A)

<table>
<thead>
<tr>
<th>Name</th>
<th>Bijn Oil Field</th>
<th>Form. type</th>
<th>Sandstone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity (°API)</td>
<td>35.42</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Viscosity (Cp)</td>
<td>1.34</td>
<td></td>
<td></td>
</tr>
<tr>
<td>porosity (%)</td>
<td>20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>oil saturation (%)</td>
<td>50</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depth (m)</td>
<td>2000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Thickness</td>
<td>16-16.8</td>
<td></td>
<td>Avg.</td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°C)</td>
<td>76.1</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Sources used to create this screening application:**

A. Aladasani, B. Bai, 'Recent Developments and Updated Screening Criteria of Enhanced Oil Recovery Techniques' June 2010, China, SPE


Taber et al. 'EOR screening criteria revisited part 1&2' 1997, SPE

Pritchett et al. 'Field application of a new in-depth waterflood conformance improvement tool', 2003, Kuala Lumpur, Malaysia, SPE

N.B.: these screening criteria are only guidelines. Discarded EOR methods might still be possible, but need further investigation.
Appendix II: Other EOR methods

Alkaline flooding

Alkaline flooding, also known as high-pH flooding, has the same recovery mechanisms as surfactant flooding. However, while for surfactant flooding a surfactant is injected in the reservoir, for alkaline flooding instead of a surfactant an alkaline is injected to generate a soap in-situ, following the mechanism discussed below.

The pH in an aqueous solution is defined as

\[ \text{pH} = -\log [H^+] \]  

(1)

pH can be raised by introducing OH\(^-\) to the solution or by removing H\(^+\) ions from it. This can be achieved by adding chemicals to the solution. There are several different chemicals that can be used, but most common are sodium hydroxide (NaOH), sodium orthosilicate (Na\(_2\)SiO\(_3\)) and sodium carbonate (Na\(_2\)CO\(_3\)).

NaOH generates OH\(^-\) by dissociation,

\[ \text{NaOH} \rightarrow \text{Na}^+ + \text{OH}^- \]  

(2)

The other chemicals work by binding H\(^+\) ions with weak acids that are dissociated when they are dissolved in water according to the following reaction:

\[ \text{Na}_2\text{CO}_3 \rightarrow 2\text{Na}^+ + \text{CO}_3^{2-} \]
\[ 2\text{H}_2\text{O} + \text{CO}_3^{2-} \rightarrow \text{H}_2\text{CO}_3 + 2\text{OH}^- \]  

(3)

With both mechanisms it is apparent that free hydroxide anions are being added to the solution by the chemical reaction. Nevertheless OH\(^-\) by itself is not a surfactant, because it does not contain a lyophilic tail which makes it only soluble to water. To create a surfactant the hydroxide has to react with petroleum acid that can be present in the crude oil.

If crude oil contains petroleum acid, some of this partitions into the aqueous phase. This can be expressed by:

\[ \text{HA}_o \rightleftharpoons \text{HA}_w \text{ (partitioning)} \]  

(4)

The water soluble petroleum acid then dissociates in the water according to:

\[ \text{HA}_w \rightleftharpoons \text{H}^+ + \text{A}^- \text{ (reaction)} \]  

(5)

The OH\(^-\) from the high-pH aqueous phase uses up the free H\(^+\) ions by:

\[ \text{HA}_w + \text{OH}^- \rightleftharpoons \text{A}^- + \text{H}_2\text{O} \]  

(6)

This reaction will result in an increase of [A\(^-\)], which is the surface active agent.

The ability of a crude oil to form soaps can be determined based on its acid number. By definition, the acid number is defined as the amount of KOH that is required to neutralize (i.e. pH=7) 1 gram of the fatty acid in the crude and is usually measured in milligrams.
A good value for acid number is 0.5 mg/g or higher, however acid numbers as low as 0.2 mg/g can be considered since only a small amount of surfactant is needed to saturate the oil-water interface (see paragraph 4.2).

The reason for using alkaline flooding instead of surfactant flooding is the difference in costs. High-pH chemicals are substantially cheaper than surfactants, though the efficiency of alkaline flooding is usually less than surfactant flooding. The oil recovery methods for alkaline flooding are the same as in surfactant flooding, namely; IFT lowering, wettability reversal and emulsion formation. Although the latter two were not mentioned in paragraph 4.2, they are also of influence in surfactant flooding but the influence of IFT lowering is by far the most important [7]. Because the IFT lowering effect by alkaline flooding is less than surfactant flooding, wettability reversal becomes more significant.

**IFT lowering**

The generated surfactant $A_w$ accumulates at the oil-water interfaces and can lower IFT. Normally this decrease is not as big as in surfactant flooding, but with the right conditions it can be sufficient to get a good incremental oil recovery. The level of IFT reduction increases with high NaOH concentration and low salinity. As can be seen in Figure 72 the IFT rises with increasing salinity. The figure also shows that there is an optimal alkaline concentration for a given salinity.

![Figure 72 IFT comparison vs. sodium hydroxide and sodium orthosilicate concentration in low saline water and high saline brine [9]]
**Wettability Reversal**

When the alkaline flood comes into contact with the reservoir rock a change in wettability can take place. This can change from water to oil wet and also the other way around. Several researches have shown that both these changes can have a positive effect on oil recovery. The increased oil recovery is the result of two mechanisms: 1) A change in relative permeability which can cause the mobility ratio to decrease. 2) When a reversal of wettability takes place the distribution of fluids within the pores is altered. Discontinuous residual oil can be reconnected and caused to flow. Especially when this wettability reversal is combined with IFT reduction Sor can be decreased considerably [9].

**Emulsion Formation**

When alkaline chemicals are introduced in the reservoir an emulsion can be formed by the decreasing IFT. This emulsion can get trapped in the pore throats and this can cause a reduction of the flow in high-permeability zones. This reduction of flow can mean an improvement of the effective mobility ratio between displacing and displaced fluids [9].

**Low salinity flooding**

Low salinity flooding is a fairly unexplained recovery method. Incremental oil recoveries of 5-10% of OOIP have been reported [12, 13, 14]. Low salinity flooding is an enhanced recovery method where the water used for water flooding is fresh or desalinized. Several theories have been proposed for why injecting low salinity water into a reservoir results in a higher oil recovery [12].

A theory that is becoming more generally accepted proposes a chemical mechanism; at reservoir temperature, pressure and pH an equilibrium is created between adsorbed polar components of the crude oil and inorganic cations of the formation brine. At first both basic and acidic organic materials are adsorbed onto the clay together with inorganic cations, such as Ca$^{2+}$. The pH of reservoir formation water can be around 5 or 6 due to dissolved acidic components such as CO$_2$ and H$_2$S. This low pH value will enhance the adsorption of acidic and basic components onto the clay surface. Now when low saline water is introduced in the reservoir with a concentration of ions much lower than the formation brine the equilibrium is disturbed and results in the desorption of cations. To counteract this H$^+$ protons from the water close to the surface of the clays adsorb on the negatively charged parts of the clay. So effectively a substitution of Ca$^{2+}$ by H$^+$ takes place. And as described before a decrease of H$^+$ in an aqueous solution results in an increase in pH. This local increase in pH close to the clay surface causes reactions between adsorbed basic and acidic material. Figure 73 shows a schematic illustration of the above described mechanism.

<table>
<thead>
<tr>
<th>Initial Situation</th>
<th>Low Salinity Flooding</th>
<th>Final Situation</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image1" alt="Initial Situation" /></td>
<td><img src="image2" alt="Low Salinity Flooding" /></td>
<td><img src="image3" alt="Final Situation" /></td>
</tr>
</tbody>
</table>

Figure 73 Schematic illustration of the low salinity flooding mechanism, after [12]

Still, to make a solid estimation of the potential incremental oil in the Rijn field multiple core flooding experiments have to be done to see how much residual oil can be produced. And there are up to this date no commercially available simulation programs to make a good reservoir simulation.
Also the treatment of injection water needs large installations at the well site which can cause practical problems, especially offshore where space is limited. The low salinity flooding seems less promising but this could change if core floods are done showing an incremental recovery of over 10%. Based on these arguments it was decided not to study the method in this research.

**Solvent EOR**
Solvent enhanced oil recovery is done by injecting a gas into the reservoir. Injecting gas into the formation has several effects which can be beneficial for the recovery of additional oil. With the injection of gas several targets can be reached.

**Bypassed oil**
One way bypassed oil can be described is as attic oil. It can be formed in a reservoir with faults between the producer and water injector, if the reservoir is dipping, oil can get trapped at the top of each fault. Also fining upwards sequences can cause permeability to reduce upwards. This will leave unswept attic areas because of gravitational effects in case of water injection. In case of a down dip water injector and an up dip producer generally pockets of oil in the attic are created because of water tonguing. When a reservoir consists of a poor permeability lower zone and a better quality higher permeability upper zone, injected water tends to move upward and flow through the higher quality zone. This will leave large amounts of cellar oil behind. Bypassed oil may also appear in other situations where reservoir heterogeneities at the level of architectural elements are important, as in fluvial depositional environments. Some channels in these depositional environments may be more accessible to gas than to water. So because of the higher mobility of gas lesser quality parts of reservoir can be swept. But the higher mobility also brings a problem since it can quickly reach producers and cause high gas-oil ratios [16].

**Residual oil**
Residual oil saturation is lowered by injecting gas based on the two principles depending on miscibility. 1) For miscible circumstances the main mechanism is swelling of oil, hereby reducing viscosity making the oil more mobile. 2) The lowering of interfacial tension. 3) When immiscible, gas is the least wetting phase and therefore squeezes the oil out of pores where gas is preferred.

Typical $S_{or}$ after water flooding in a North Sea reservoir is 10-25% while $S_{or}$ after gas flooding is typically less than 10%. [16]

**Thermal EOR**
Thermal EOR is a method that has been around for more than half a century. One of the first field tests was performed in Woodson, TX in the 1930’s [8]. Since then a lot of development has taken place and it is a widely used method for recovering heavy oil. The principle of thermal EOR is producing heavy oil by lowering the viscosity by heat.

Heat can be introduced to the reservoir in different ways; by injecting steam, by injecting air to create in-situ combustion or by electric heating.

Figure 74 shows the effect of temperature on crude oil viscosity. From this it is apparent that the lighter oils do not benefit as much from temperature rise as heavier oils.
Figure 74 Effect of temperature on crude oil viscosity [7]

This observation together with the fact that thermal stimulation is not very practical on an offshore field is the reason that thermal EOR is not seen as an option for the Rijn field. Oil viscosity in the reservoir is low enough to flow easily and to be flooded by water.

**Microbial EOR**

Microbial enhanced oil recovery (MEOR) methods use bacteria to mobilize residual and trapped oil in the pore space. These bacteria can either be injected with the injection water or are already present in the reservoir. When these microbes already exist in the reservoir, nutrients can be added to the injection water to make them grow. Enhanced oil recovery induced by microbes is directed at two recovery methods; reducing residual oil and restriction of flow through higher permeable channels.

When bacteria growth is induced at the interface of the injected water and the oil the bacteria generate surfactant and a bio film which reduces interfacial tension. Depending on how efficient the bacteria are growing interfacial tension will drop to a point where immobile oil is mobilized again.

Figure 75 shows how the IFT reduces with time, i.e. how the IFT reduces with bacteria growth.
Figure 75 Reduction of IFT with growth of bacteria in time. OW IFT, measurements prior to adding bacteria; OWB IFT, measurements after adding bacteria. Flow rates of the water phase during the incubation are indicated in the bottom of the plot [17]

Figure 76 Mechanism of diversion of driving fluid from high permeable zones to less permeable zones by microbe growth [18]

Figure 76 shows the mechanisms of diversion of flow by microbes. In time when they grow they will attach to the rock surface and to each other hereby blocking the pores. Injection water is then diverted to the less permeable zones.

One of the big advantages of MEOR is the relatively low cost. Especially when the microbes are already present in the reservoir they only have to be fed with nutrients to grow enough to have effect. A disadvantage here is that the method is still premature and no good estimates can be made about the incremental oil. This is the reason why MEOR is not considered an option for the Rijn oilfield.
Appendix III: Other simulation properties

![Saturation curves used in the reservoir simulations](image1)

*Figure 77 Saturation curves used in the reservoir simulations*

![Oil viscosity and formation volume factor used in the reservoir simulations](image2)

*Figure 78 Oil viscosity and formation volume factor used in the reservoir simulations*
Appendix IV: Numerical details

Here the numerical details of the polymer flood model and the surfactant flood model in Eclipse 100 will be discussed.

A. Polymer flood model

Eclipse 100 is a fully implicit, three phase, three dimensional black oil numerical simulator. To describe the flow of polymer the standard aqueous (water) conservation equation has to be modified and additional equations are needed. The water and polymer equations used in the model are as follows:

\[
\frac{d}{dt} \left( \frac{VS_w}{B_r B_w} \right) = \sum \left[ \frac{T_{k_{rw}}}{B_r \mu_{w,eff} R_k} (\partial P_w g D_z) \right] + Q_w \tag{A-1}
\]

\[
\frac{d}{dt} \left( \frac{V^* S_w C_p}{B_r B_w} \right) + \frac{d}{dt} \left( V \rho_p C_p \frac{1-\phi}{\phi} \right) = \sum \left[ \frac{T_{k_{rw}}}{B_r \mu_{p,eff} R_k} (\partial P_w - \rho_w g D_z) \right] C_p + Q_w C_p \tag{A-2}
\]

\[
V^* = V \left( 1 - \frac{S_{dmp}}{S_w} \right) \tag{A-3}
\]
where:

\[ S_{dw} \] Dead pore space within each grid cell  
\[ C_p \] Polymer adsorption concentration  
\[ \rho_r \] Mass density of the rock formation  
\[ \phi \] Porosity  
\[ \rho_w \] Water density  
\[ R_k \] Relative permeability reduction factor for the water phase due to polymer retention  
\[ C_p \] Polymer concentration in the water phase  
\[ \mu_{a, eff} \] Effective viscosity of the water (a=w) and polymer (a=p)  
\[ D_z \] Cell centre depth  
\[ B_r, B_w \] Rock and water formation volume  
\[ T \] Transmissibility  
\[ k_{rw} \] Water relative permeability  
\[ S_w \] Water saturation  
\[ V \] Block pore volume  
\[ Q_w \] Water production rate  
\[ P_w \] Water pressure  
\[ g \] Gravity acceleration

The model assumes that the density and formation volume factor of the water phase are independent of the polymer concentrations. The polymer solution 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.

The principle effects of polymer on the flow of the water phase are represented by equations Eq. 1 till Eq. 3, and consist of:
- effective viscosity  
- adsorption  
- permeability reduction  
- dead pore volume
**Effective viscosity:**

The viscosity terms used in the fluid flow equations describe the effects of change in viscosity of the water phase due to the presence of a polymer concentration. However, physical dispersion is calculated by using effective viscosities that are calculated using the Todd-Longstaff technique.

The effective porosity is:

\[
\mu_{p_{-\text{eff}}} = \mu_m(C_p) ^\omega \cdot \mu_p ^{1-\omega}
\]

where:

- \(\mu_m(C_p) ^\omega\): viscosity of fully mixed polymer solution as function of \(C_p\)
- \(\mu_p\): injected polymer concentration
- \(\omega\): Todd-Longstaff mixing parameter

The partially mixed water viscosity is retrieved in a similar way.

\[
\mu_{w_{-\text{eff}}} = \mu_m(C_p) ^\omega \cdot \mu_w ^{1-\omega}
\]

The effective water viscosity is then calculated as follows:

\[
\frac{1}{\mu_{w_{-\text{eff}}}} = \frac{1-\overline{C}}{\mu_w} + \frac{\overline{C}}{\mu_{p_{-\text{eff}}}}
\]

\[
\overline{C} = \frac{C_p}{C_{p_{-\text{max}}}}
\]

where

\(\overline{C}\) is the effective saturation for the injected polymer solution within the total water phase in the cell.

**Adsorption:**

Adsorption is modelled by an adsorption isotherm and is specified as a look-up table of adsorbed polymer as a function of polymer concentration.

**Permeability reduction:**

Adsorption causes permeability reduction of the rock. To compute this permeability reduction a residual resistance factor (RRF) has to be specified for each rock type. The actual resistance factor \(R_k\) can then be calculated:

\[
R_k = 1.0 + (\text{RRF} - 1.0) \frac{C_p^{a}}{C_{p_{-\text{max}}}}
\]

\(C_p^{a,\text{max}}\) depends on rock type and needs to be specified as well.
**Dead pore volume:**

The dead pore volume also has to be specified for each rock type. This is used to model the chromatographic effect of polymer which causes the polymer solution to travel at a greater velocity than the water.

**B. Surfactant flood model**

The Eclipse surfactant model does not aim to model the detailed chemistry of a surfactant process, but more to model the important features of a surfactant flood on a full field basis. Therefore some important chemical phenomena such as the formation of a micro-emulsion with different fluid properties are not modelled. If that is desired a three phase, multi-component fluid simulator such as CMG-STARS is recommended.

The surfactant concentration at a given time at a given position is modelled by solving a conservation equation for surfactant within the water phase. At the end of each time step after the oil and water flows have been computed the surfactant concentrations are updated fully-implicitly. After this the effect of the surfactant concentration on the capillary number ($N_c$), capillary pressure ($P_c$) and the relative permeability in the cell is calculated.

**Calculation of capillary number:**

The capillary number is given by:

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

where:

<table>
<thead>
<tr>
<th>K</th>
<th>permeability</th>
</tr>
</thead>
<tbody>
<tr>
<td>P</td>
<td>potential</td>
</tr>
<tr>
<td>ST</td>
<td>interfacial tension</td>
</tr>
<tr>
<td>$C_{\text{unit}}$</td>
<td>conversion factor depending on the units used</td>
</tr>
</tbody>
</table>

$$|K \cdot \text{grad}P| = \sqrt{(K_x \cdot \text{grad}P_x)^2 + (K_y \cdot \text{grad}P_y)^2 + (K_z \cdot \text{grad}P_z)^2}$$

The surface tension of interfacial tension is a tabulated function of the surfactant concentration.

**Relative permeability model:**

The relative permeability model is a transition from immiscible relative permeability curves at a low capillary number to a miscible relative permeability curve at high capillary number. The terms miscible and immiscible are a bit misleading here but are actually used to be able to model a lowering in $S_{or}$. A relative permeability curve for surfactant solved in water has to be provided and a table that describes the transition between miscible and immiscible as a function of the capillary number (Table 10). This combination is used to approximate the effect of the capillary desaturation curve (see Figure 8).

The relative permeability values are looked up on both curves and the final relative permeability is then interpolated between the miscible and immiscible values.
Capillary pressure:

The oil water capillary pressure is computed as follows:

\[
P_{\text{cow}} = P_{\text{cow}}(S_w) \frac{ST(C_{\text{surf}})}{ST(C_{\text{surf}} = 0)}
\]  

B-(3)

where

\[
\begin{align*}
 ST(C_{\text{surf}}) & \quad \text{surface tension at the present surfactant concentration} \\
 ST(C_{\text{surf}} = 0) & \quad \text{surface tension at zero concentration} \\
 P_{\text{cow}}(S_w) & \quad \text{capillary pressure from the immiscible curves initially scaled to the interpolated end-points calculated in the relative permeability model}
\end{align*}
\]

Solution viscosity:

Surfactant modifies the viscosity of the water. The surfactant viscosity input as a function of surfactant concentration is used to calculate the water-surfactant solution viscosity as follows:

\[
\mu_{\text{surw}}(C_{\text{surf}}, P) = \mu_w(P) \frac{\mu_s(C_{\text{surf}})}{\mu_w(P_{\text{ref}})}
\]  

B-(4)

where

\[
\begin{align*}
 \mu_s & \quad \text{viscosity from the surfactant viscosity table} \\
 \mu_w & \quad \text{water viscosity} \\
 \mu_{\text{ws}} & \quad \text{viscosity of the water-surfactant mixture} \\
 P_{\text{ref}} & \quad \text{reference pressure}
\end{align*}
\]

Adsorption:

The quantity of surfactant adsorbed on to the rock is a function of the pore volume (PORV), porosity (\(\phi\)), mass density of the rock (MD) and the adsorption isotherm as a function of the local surfactant concentration in the solution (CA(C_{surf})), and is given by:

\[
C_{\text{surf, adsorbed}} = \text{PORV} \cdot \frac{1-\phi}{\phi} \cdot MD \cdot CA(C_{\text{surf}})
\]  

B-(5)
Appendix V: Grid size sensitivity

A grid size sensitivity analysis was performed to establish that the grid size used was well-founded. Although, for grid_3 used in the EOR simulations no upscaling was applied but the geological model grid size was adopted. Therefore a smaller grid size would not have been possible. The sensitivity analyses were performed with a reservoir model conditioning case.

Three different grid sizes were used:

**Table 25 Grid size sensitivity parameters**

<table>
<thead>
<tr>
<th>Case</th>
<th>Grid block size (L x W x H) (m)</th>
<th>Dimensions</th>
<th>Number of cells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid_1</td>
<td>91x91x6</td>
<td>30x14x5</td>
<td>2,100</td>
</tr>
<tr>
<td>Grid_2</td>
<td>36x18x6</td>
<td>154x35x5</td>
<td>26,950</td>
</tr>
<tr>
<td>Grid_3</td>
<td>18x18x0.5</td>
<td>154x71x32</td>
<td>349,888</td>
</tr>
</tbody>
</table>

The areal and vertical grid sizes are shown in Figure 79.

*Figure 79 An areal and vertical view of the 3 different grid sizes used for sensitivity analysis*
Figure 80 shows the total oil production for the three different cases. It can be observed that cumulative production decreases with a smaller grid cell size and will stay constant at a certain grid size. The red dotted line is the behaviour expected when increasing the grid cell size, at the start the differences are quite large, but when decreasing grid size the error will minimize. It can be seen that Grid_3 is very close to that minimum and it proves that Grid_3 is has a good quality grid size.
Appendix VI: Numerical versus physical dispersion

In order to determine the influence of numerical dispersion in the model and to verify that the influence is of low enough order two simulation cases were compared:

Table 26 Cases used for dispersion analysis

<table>
<thead>
<tr>
<th>Case</th>
<th>Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>PLY041</td>
<td>Constant polymer injection and fully mixing (Todd Longstaff parameter = 1)</td>
</tr>
<tr>
<td>PLY055</td>
<td>Constant polymer injection and no mixing (Todd Longstaff parameter = 0)</td>
</tr>
</tbody>
</table>

Surfactant flood modelled by Eclipse does not account for any physical dispersion. In polymer flooding the Todd-Longstaff parameter accounts for this. In order to determine the numerical dispersion the Todd-Longstaff parameter was set to 0 so no mixing was modelled, this way the only dispersion that occurred would be a numerical phenomenon.

The results are shown in Figure 81 where it can be seen that the mixing case exhibits about twice as much dispersion as the no mixing case. The red dashed line shows a hypothetical zero dispersion case where the polymer front will move like a shock front. This demonstrates that numerical and physical dispersion are of equal size since the physical dispersion shown in the graph also contains numerical dispersion.

Figure 81 Polymer concentration, after 24 months, as a function of distance from injection well, for mixing and non mixing circumstances