Per Einar Kalnæs
An introduction to applying surfactant simulation on the Norne field
Trondheim, 17. December, 2009
Abstract

Surfactant flooding is a promising EOR method, which is of modest experience on the Norwegian Continental Shelf. By injecting surfactant after water flooding the residual oil saturation can be reduced. The surfactant flooding will mobilize the capillary trapped oil by reducing the interfacial tension between oil and water.

This project is a pre assignment for the Master thesis where the objective is to apply a surfactant flooding simulation on the Norne field. So an introduction to the Norne field is made together with a synthetic reservoir model based on parameters from the Norne field.

The surfactant flooding model was applied to the synthetic reservoir model, and results of the simulation together with the literature indicates that surfactant flooding has a promising effect of the oil recovery.

The performance of the surfactant is dependent on the adsorption level in the reservoir together with the properties of the surfactant. The simulation indicated that a big surfactant slug and high surfactant concentration will perform best, while a high adsorption level will reduce the effect of the surfactant.
Preface

This report is a result of the specialization project for all post graduate students at the Norwegian University of Science and Technology. This project is a pre assignment for the Master thesis where the objective is to apply a surfactant flooding simulation on the Norne field.

I wish to address a great thanks to my supervisor Prof. Jon Kleppe at NTNU, and Dr. Lars Høier at Statoil ASA for putting this project into life, and supervising during this project.

I would also like to thank Vegard Kippe at Statoil ASA, who provided me with the appropriate data and advice according to surfactant flooding, Jan Ivar Jensen, Prof. Ole Torsæter, post doc. Hassan Karimaie and Chinemwe Clara Emegwamu for helpful discussions and advice.

Finally I will acknowledge the Center for Integrated Operations at NTNU, Statoil ASA (operator of the Norne field) and its license partners ENI and Petoro for the release of the Norne data.

Trondheim, December 17, 2009

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1 Introduction

The trends is that the demand of energy will increase in the coming years. The International Energy Agency (IEA) indicates that the consumption will increase with 40% from current consumption until 2030, and fossil fuels will dominate this increase. This indicates a big chance for a record high oil price[8].

At the moment the gas price is high, so gas is being exported by pipelines and sold instead of re-injected into the reservoirs, even though gas injection is more effective than water injection. This opens for more studies on water-based methods for recovering oil[9].

In the North Sea the current recovery are above 40%, however a average of 50% is set as the target for by Norwegian Petroleum Directory (NPD). Enhanced Oil Recovery (EOR) is one of the solutions to meet this goal for Norwegian sector[6] and world wide the EOR projects continues to supply an increasing percentage of the world’s oil production[13].

An EOR method that has a big potential under right circumstances but little experience on the Norwegian Continental Shelf is the surfactant flooding[6]. There are some environmental and economical issues according to applying surfactants, but for this project it is assumed that these issues are solved. So this project will be a pre assignment for the Master thesis where the objective is to do an EOR study of surfactant flooding on the Norne Field, by applying the surfactant flooding to the reservoir simulation.

1.1 Enhanced Oil Recovery - EOR

Oil recovery have traditionally been divided into three, primary, secondary and tertiary stages, mainly due to chronological orders.

- Primary recovery: the first step of production as a result from the natural effects in the reservoir, without introducing any substances into the reservoir.
- Secondary recovery: the second step of production resulted by injecting substances into the reservoir, i.e water flooding and gas injection to maintain the pressure in the reservoir.
- Tertiary recovery: the third step of production obtained after the secondary
recovery and uses miscible gases, chemicals and/or thermal energy to displace additionally oil.

This subdivision often comes in conflicts with the fact that production processes are not always conducted in the specified order, and sometimes the tertiary process might be applied as a secondary process together with water flooding[7]. Due to the difficulties of production classification, classification based on the process description is more useful and is now generally an accepted approach. The naming still incorporates with the earlier chronology. So the recovery processes are now divided into primary, secondary and EOR processes[7], but the tertiary processes should not be a synonym for EOR, because some EOR methods work well as secondary and tertiary projects while others are more effective as enhanced secondary projects[13]. EOR processes involves injection of either gas or liquid into the reservoir, and the injected fluid supply the natural energy presented in the reservoir by interacting with the reservoir rock/oil system. These interactions will create conditions that are favorable for oil recovery(lowering interfacial tension, oil swelling, reduction of oil viscosity, wettability modification or favorable phase behavior)[7].

EOR processes can be further divided into five categories; mobility control, chemical, miscible and other processes(microbial EOR)[7].
2 Surfactant Flooding

2.1 Introduction

Surfactant flooding is a chemical process, and together with polymer flooding have the best potential in terms of ultimate oil recovery in the category of water based EOR[7]. The purpose of surfactant flooding is to recover the capillary trapped oil after water flooding [11]. After the surfactant solution has been injected the trapped oil droplets can be mobilized by a strong reduction in Interfacial Tension (IFT), between oil and water. The most common scenario when surfactant is used in a reservoir is to use a small, but highly concentrated surfactant slug, followed by a large polymer drive[11].

2.2 Process Description

When the surfactant solution is injected, the surfactant will mobilize the trapped oil droplets in the water swept zone, because of the surfactants ability to reduce the IFT between oil an water. Behind the flowing oil bank the surfactant will prevent the mobilized oil to be re-trapped. Because of the high prize of surfactant, only a small surfactant slug is normally injected followed by water[11].

2.3 Capillary Desaturation

To reduce the residual oil saturation in the water flooded zones, the pressure drop over the trapped oil has to overcome the capillary forces that keep the oil trapped. This is done by the surfactant when the IFT between oil and water is reduced. A large number of studies indicates how the residual oil saturation correlates with Capillary Number($N_c$)[11]. The $N_c$ is a dimensionless ratio between the viscous forces and the capillary forces[5].

$$N_c = \frac{u\mu}{\gamma} \quad (2.1)$$

$u$ is the Darcy’s velocity, $\mu$ is the viscosity of the displacing fluid(water with surfactant solution) while $\gamma$ is the interfacial tension between oil and the surfactant solution. The Capillary Desaturation Curve(CDC) describes the relationship between $N_c$ and residual fluid saturation and varies with pore size distribution and...
wettability. When the pore size gets more narrow the oil saturation starts to drop at a higher $N_c$, but the zero oil saturation is achieved at a lower capillary number and vice versa (see figure 2.1). The CDC for a wetting phase is shifted to the right compared for a non-wetting phase (see figure 2.2), this indicates that surfactant should have a better performance in a water wet system. In numerical simulations the efficiency of the surfactant will relay upon the CDC, and should therefore be measured for every distinct rock type [11].

Figure 2.1: Effect of pore-size distribution [11]
Figure 2.2: Effect of wettability on residual saturation of wetting and non-wetting phase[11]
2.4 Relative Permeability and Mobility Ratio

It is expected that the relative permeability to water should increase when the residual oil saturation decreases, simply because there is less oil to restrain the water from flowing. This applies an increase in mobility for the injected solution when the interfacial and residual oil saturation is decreased due to surfactant flooding.

The close relation between the CDC and relative permeability indicates that the relative permeability should be measured several times in the decline part of the CDC, but since the relative permeability measurement is expensive and time consuming, it is only measured at two capillary numbers. One at a capillary number less or equal the critical capillary number and the other at the highest expected capillary number when the residual saturation is at minimum.

From experimental studies it has been observed that the endpoint permeability to water increases from $S_{orw}$ (residual oil saturation after water flooding) to one when the residual saturation goes against zero[11]. A common simplification is to use straight lines as relative permeability curves for water and oil when surfactant is used[10]. In a case of low concentration of surfactant where the viscosity of the surfactant solution and water is assumed to be the same, the mobility of the displacing fluid will increase. When the mobility of the displacing fluid is increasing and the displaced is decreasing by a large amount, it is expected that the mobility ratio is increasing rapidly when going from water flooding to surfactant flooding. In some cases it can increase ten times which is not favorable. To prevent this the mobility is controlled by use of polymer or adjusted surfactant viscosity[11].

2.5 Volumetric Sweep Efficiency

The mobility ratio is preferred to be as low as possible to get an efficient displacement of the oil bank, and prevents fingering of the surfactant slug into the oil bank. It also prevents large scale dispersion due to permeability differences, gravity segregation and well patterns. A lower mobility ratio will force the injected fluid into lower permeability zones and further away from the line between the producer and injector, and this will result in a better sweep efficiency. From simulation studies in layered reservoirs, the mobility ratio was of great importance according to the recovery, while the size of the surfactant slug gave small differences in performance[11].
2.6 Surfactant Retention

The aim of surfactant to improve the recovery is often related to the retention of the surfactant by the reservoir rock. To design and optimize a surfactant flood, it is important to understand the transportation of the surfactant. Different mechanisms of the rock to retain the surfactant has been identified as precipitation, phase trapping and adsorption. In many cases there is designed surfactant systems that prevent loss of chemicals due to precipitation and phase trapping. By using salt tolerant surfactant and changes of parameters only take place within the accepted limits. The problem with absorption of surfactants by the solid liquid interface will always take place, and will be important to understand[11].

2.6.1 Adsorption

The adsorption of surfactant occurs at the interface between the solid and liquid, and is initiated by electrostatic interaction between the solid and surfactant. Adsorption is divided into 4 different regions. Figure 2.3 shows the 4 different regions with the respective adsorption level according to each other.

Figure 2.3: Schematic S-shaped adsorption curve[11]
**Region 1:** The surfactant is mainly absorbed by anion exchange, and the relation between adsorbed material and equilibrium concentration.

**Region 2:** A significant increase in absorption due to the interaction between the hydrophobic chain between the arrival surfactant and the surfactant that already has been adsorbed.

**Region 3:** A decrease in adsorbed surfactant because the adsorption has to overcome the electrostatic repulsion between surfactant and the similar charged solid.

**Region 4:** The plateau adsorption is reached at the Critical Micelle Concentration (CMC), this means that the micelles does not adsorb onto the surface.

The interfacial tension between oil and water decreases until the CMC is reached. The key problem with surfactant flooding is to obtain as low IFT as possible and it is important to keep the surfactant concentration over CMC. The shape of the adsorption isotherm may vary for different systems, and some factors that influence the plateau is salinity, pH-value, temperature and wettability. With increased salinity the plateau adsorption will increase while a decrease in pH will cause an increase in adsorption. It is suggested that surfactant adsorption decrease as the temperature increases. Due to the heterogeneous nature of reservoir rocks it is difficult to decide when the reservoir is water wet or oil wet. There has been conflicting effects of wettability on surfactant adsorption. Later studies has showed that adsorption of surfactant has been greater on oil wet surfaces than water wet under no salt conditions, but in presence of salt the highest adsorption is reported on water wet systems[11].

To prevent adsorption it is suggested to use pre-flushing with different types of chemicals in order to reduce hardness, make the rock more negative charged and block the active sites of the rock. Injection of low concentration surfactant together with biopolymer has showed positive effect of the adsorption but the mechanism has not been understood yet[11].
3 Norne Field

3.1 General field information of Norne

The Norne field is located 200 km from the Norwegian coast line, in the southern part of the Nordland II area. Figure 3.1 shows a map of the location of the Norne field according to other onshore and offshore locations. Approximately 90% of the field is situated in the PL 128 licence block 6608/10 while the rest of the field lies in north western part of block 6508/1(PL 128B)[4][3].

![Figure 3.1: Location of the Norne Field](image)

The Norne Field consist of two separate oil parts, the Norne Main Structure(C-, D- and E-segment) and the Norne G-segment(se figure 3.2). The Norne Main
Structure was discovered in December 1991 and contains 97% of the oil in place[3].

A discovery well(6608/10-2) was started drilled in October 2001. A 135 meters hydrocarbon bearing column was found with a 110 meters thick oil leg, with an overlying gas cap. The rocks were from the Lower and Middle Jurassic age. These findings were later confirmed with the discovery well(6608/10-3)[3][12].

The production started on 6th of November in 1997, and the oil is produced by water injection as a drive mechanism. In the early days gas was injected, but are now being exported. The field is developed by five sub sea templates that are connected to a floating production vessel with flexible risers. The oil is loaded to tankers for export, while the gas is transported by pipelines to Åsgard and further to Karse[3][12].

The NPD has reported the numbers in table 3.1 for the total production per October 2009, and estimation of recoverable and remaining reserves as of 31.12.2008.
Table 3.1: NPD’s estimated reserves as of 31.12.08 and total produced per Sept.09

<table>
<thead>
<tr>
<th>Reserves</th>
<th>Oil[mill Sm$^3$]</th>
<th>Gas[bill Sm$^3$]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recoverable</td>
<td>94.90</td>
<td>11.00</td>
</tr>
<tr>
<td>Produced</td>
<td>82.20</td>
<td>5.97</td>
</tr>
<tr>
<td>Remaining</td>
<td>14.40</td>
<td>14.40</td>
</tr>
</tbody>
</table>

3.2 Geology of the Norne Field

The reservoir rock is Jurassic sandstones and most of the reservoir sandstones within the Norne Filed are fine grained and well to very well sorted. The sandstone is buried at depth of 2500 to 2700 meters and is affected by diagenetic processes, where compaction is the most important factor for reducing the reservoir quality. But the reservoir quality is reported to be good. The porosity is between 25-30% and permeability between 20-2500 mD.

The oil is mainly located in the Ile and Tofte formation while the gas are located in the Garn formation[2][12]. A schematic outline of the zones in the reservoir can be seen in figure 3.3. The Not formation(se figure 3.3) is indicated to be sealing and there is no communication across this formation. These findings are due to the reservoir pressure data from the development wells[2].

3.3 Stratigraphy and Sedimentology

The Norne reservoir consist of eight formations(Åre, Tilje, Tofte, Ror, Ile, Not, Garn and Melke), and these formations are divided into sub formations. Figure 3.4 shows an overview of the formations with further subdivisions. The Ile and Tofte are the most important formations and will therefore be emphasized since respectively 36% and 44% of the proven oil are located in these two formations[1].

3.3.1 Tofte Formation

The Tofte formation was deposited during the late Toarcian, and is approximately a 50 meter thick sandstone. The formation was deposited above an unconformity, with significant changes in sediments. Figure 3.4 shows that the Tofte formation is further divided into three reservoir zones(Tofte 1, 2 and 3). Lowest the Tofte 1 zone with coarse to medium grained sandstone, with variable but generally very good
Figure 3.3: *Cross Section Through the Reservoir*[14]
Figure 3.4: An overview of the formations[1]
reservoir properties. In the middle a very fine grained sandstone (Tofte 2), and on top a fine grained sandstone (Tofte 3). The Tofte 2 and 3 zones reflect a coarsening trend upwards corresponding to an increase in porosity and permeability [1]. In the reservoir model from 2004 the Tofte formation is divided in 7 parts, and is presented by layer 12 to 18.

3.3.2 Ile Formation

The Ile formation is a 32-40 meter thick sandstone, deposited during the Aalenian. From figure 3.4 it is seen that the formation is further divided into three zones (Ile 1, 2 and 3). The Ile 1 and 2 are generally of regressive deposition with a separating cemented layer, that might form a barrier from vertical fluid flow and is therefore important for the reservoir modeling. The reservoir quality for these two formations are very good. Ile 3 is a transgressive unit with good reservoir qualities, but these are gradually decreasing towards the top of the formation [1]. The Ile formation is also divided into 7 parts in the reservoir model from 2004, and is presented by layer 5 to 11.

3.4 Reservoir Communication

The Norne field consists of both stratigraphic barriers and faults that restricts the lateral and vertical flow. To better understand the flow patterns and the communication of the reservoir during production, vertical transmissibility multipliers and fault transmissibility multipliers has been implemented in the reservoir simulation model [2].

3.4.1 Stratigraphic Barriers

The stratigraphic barriers has been identified by the use of cores and logs to decide their lateral extent and thickness. The believed intervals that goes through the Norne Field and restrict the vertical fluid to flow is:

- **Garn 3/Garn 2**: Carbonate cemented layer at the top of Garn 2
- **Not Formation**: Clay-stone formation
- **Ile 3/Ile 2**: Carbonate cementation and increased clay in the base of Ile 3
• Ile 2/Ile 1: Carbonate cemented layers at base Ile 2
• Ile 1/Tofte 4: Carbonate cemented layers at top Tofte 4
• Tofte 2/Tofte 1: Significant grain size contrast
• Tilje3/Tilje 2: Clay-stone formation

The Not formation provide the most predominant barrier, together with the carbonate cemented layers between Ile 1 and Tofte 4, and the interbedded clay stone separating Tile 2 and 3[2].

3.4.2 Faults

Since the Norne field is located on a horst a number of faults is expected. Figure 3.5 shows two different cross sections through the Norne field, where faults and fluid contacts are shown[2].

To describe the faults in the simulation model, the fault planes was divided into sections. The sections follows the reservoir zonations(3.3). Each subarea of the fault planes was given transmissibility multipliers. The transmissibility multipliers is shown in figure 3.6 and is a function of fault rock permeability and the width of the fault zone as well as the matrix permeability and the dimensions of the grid blocks[2].

The places that allows for fault seals is the Not and the lower Garn shales according to Smear Gouge Ratio[2].

3.5 Drainage Strategy

The main goal of the development of the Norne field is to obtain an economic optimum production profile. In the first years the focus was to achieve a maximum in processing and production potential. In 2004 the focus was to optimize the value by[3]:

• Safe and cost effective drainage of the proven reserves
• Prove new reserves and utilize existing infrastructure
Figure 3.5: *Cross Section Through the Reservoir with fluid contacts*[2]
Figure 3.6: Fault Transmissibility Multipliers\cite{2}

- Explore the potential in the license
- Adjust capacities where it can be done cost effectively
- Increase the pressure in the Ile formation and the G-segment

At the beginning the drainage strategy was to maintain the reservoir pressure by re-injecting the produced gas into the gas cap and the produced water into the water zone. But during the first year of production it was experienced that the Not formation was sealing over the Norne main structure, so the gas injection was changed to inject water at the bottom at the lower part of the oil zone\cite{3}(see figure 3.7).
Figure 3.7: The drainage strategy for the Norne field[3]
3.6 EOR potential in the Norne Filed

Figure 3.8 is a result of the reservoir simulation, and shows the recovery factor for the Norne Field. From the simulation the expected recovery factor in year 2022 is approximately 65% which is very good, but it is still 35% left in the reservoir. From figure 3.9 its seen that this 35% will amount approximately 60 mill $Sm^3$ of oil. The figure show also the total oil produced.

Figure 3.10 and 3.11 shows the oil saturation for zone 10 (Ile 2.1 formation) and zone 13 (Tofte 2.1.3 formation) in November 1997 and 2009. Figure 3.12 shows a cross section($j = 29$ in the reservoir model) with additional oil saturation in November 1997 and 2009. All these figures indicates that the sweep in the reservoir is good, and might be promising for surfactant flooding. By looking at figure 3.10 and 3.11 it also indicates that the sweep is best in the lowest layers and might be even more of current interest for surfactant flooding.

![Figure 3.8: The Field Oil Efficiency at the Norne Field](image)

An introduction to applying surfactant simulation on the Norne field
Figure 3.9: Oil in Place and Oil Produced at Norne
Figure 3.10: Oil Saturation in Ile formation (zone 10)
Figure 3.11: Oil Saturation in Tofte formation (zone 13)
Figure 3.12: Cross section with Oil Saturation
3.7 From the Norne Model to the Synthetic Model

The synthetic model consists of 500 grids (10-10-5), with the same porosity and permeability within each layer, but different porosity and permeability in each layer. The parameters were taken from the 5 upper most layers in the Tofte formation (layer 12 to 16 in the Norne model). The motivation for basing the model on this data is because the Tofte formation is where most of the oil is located. The position of the cells (x = 11, y = 65) that give the input to the synthetic model was located in the middle of the E-segment (see figure 3.2). Table 3.2 shows some of the parameters that were taken from these cells. The five relative permeability tables was also taken from these cells. The input for relative permeability that was used for the top layer was:

```
SWOF
-- DIRT/WATER imbibition curve IMBNUM = 56
-- sw  kro  kro  pc
  0.1600  0.9000000000  0.0000000000  3.0268147326
  0.2020  0.7744359463  0.0000000000  1.4973553514
  0.2440  0.6600153826  0.0000000000  0.7302609648
  0.2860  0.5563875210  0.0000000000  0.4724467555
  0.3280  0.4631897739  0.0000334474  0.3419328075
  0.3700  0.3800464749  0.0003784142  0.2623164106
  0.4120  0.3065735090  0.0093488332  0.2081240437
  0.4540  0.2423456709  0.0176966790  0.1684329855
  0.4960  0.1869559663  0.0303532736  0.1377766135
  0.5380  0.1399511700  0.0484370128  0.1131127310
  0.5800  0.1008589413  0.0731494693  0.0926107831
  0.6220  0.0691768103  0.1057699738  0.0751004653
  0.6640  0.0443655272  0.1476511367  0.0597958864
  0.7060  0.0258395169  0.2002150675  0.0461468776
  0.7480  0.0129522762  0.2649501256  0.0337538370
  0.7900  0.0049718446  0.3434080896  0.0223164106
  0.8320  0.0010327956  0.4372016611  0.0116011466
  0.8740  0.0000057054  0.5480022429  0.0014202342
  0.8800  0.0000000000  0.5653192952  0.0000000000
  0.9160  0.0000000000  0.6775379433  0.0000000000
  0.9580  0.0000000000  0.8275917726  0.0000000000
  1.0000  0.0000000000  1.0000000000  0.0000000000
/
```
The rest of the relative permeability tables can be found in the datafile in Appendix A. The size of each grid is 50 meters in both directions and differs from the Norne model. The top of the reservoir was set at the same depth as the top of the Tofte formation.

Table 3.2: **GRID input from the Norne reservoir model**

<table>
<thead>
<tr>
<th>Layer</th>
<th>Dz[m]</th>
<th>Permx[mD]</th>
<th>Permz[mD]</th>
<th>Porosity</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>1.1</td>
<td>253</td>
<td>33</td>
<td>0.30</td>
</tr>
<tr>
<td>13</td>
<td>11.5</td>
<td>1197</td>
<td>766</td>
<td>0.30</td>
</tr>
<tr>
<td>14</td>
<td>11.5</td>
<td>347</td>
<td>222</td>
<td>0.27</td>
</tr>
<tr>
<td>15</td>
<td>11.5</td>
<td>88</td>
<td>57</td>
<td>0.25</td>
</tr>
<tr>
<td>16</td>
<td>11.5</td>
<td>1534</td>
<td>982</td>
<td>0.27</td>
</tr>
</tbody>
</table>

The pressure in the chosen cells is in the range of 272-276 BARSA initially, so the fluid and rock properties were picked according to that pressure range. These properties can be found under Appendix A. The synthetic model was given one producer and one injector, figure 3.13 shows the placement of the wells. The wells was completed in all 5 layers, and the injection rate was kept constant under the whole simulation. Both the injector and producer was controlled by the reservoir volume rate, and the upper rate was set to 7000m$^3$/d. The production and injection rates was picked based on production and injection rates from well F1-H and E3-CH.

By looking at the chosen cells in the Norne reservoir model, the gas saturation was zero during the whole simulation. Based on this observation a two component model was chosen for the synthetic case, with only water and oil presented. The dead oil (no dissolved gas) option was chosen.
Figure 3.13: The synthetic reservoir model with initially oil saturation
4 The Surfactant Model in Eclipse

Eclipse 100 does not provide a detailed chemical simulation of surfactant flooding, but modeling the most important features of surfactant flooding on a full field basis[11].

The surfactant distribution is modeled by solving the conservation equation for surfactant within the water phase. The surfactant concentration is calculated fully implicit at end of each time step, after the calculation of water, oil and gas is done. The input of surfactant to the reservoir is specified by concentration of the surfactant in the injected water and occur only in the water phase[5].

4.1 Calculation of the capillary number

The capillary number($N_c$) is a dimensionless ratio between viscous forces and capillary forces.

$$N_c = \frac{|K \text{grad}P|}{ST} C_{unit}$$ (4.1)

$K$ is the permeability

$P$ is the potential

$ST$ is the interfacial tension

$C_{unit}$ is a constant, depending on the unit

$$|K \text{grad}P| = \sqrt{(K_x \text{grad}P_x)^2 + (K_y \text{grad}P_y)^2 + (K_z \text{grad}P_z)^2}$$ (4.2)

$$K_x \text{grad}P_x = 0.5 \left[ \left( \frac{K_x}{D_x} \right)_{i-1,i} (P_i - P_{i-1}) + \left( \frac{K_x}{D_x} \right)_{i+1,i} (P_{i+1} - P_i) \right]$$ (4.3)

Equation (4.3) is measured in x direction for cell i, but the same procedure is followed for y and z direction[5].
4.2 Relative Permeability

In addition to the existing immiscible relative permeability curves with low capillary number a miscible relative permeability curve with high capillary number is required. A transition between these curves are made, and a table that describes the transition as a function of $\log_{10}$ of the capillary number must be included[5].

Figure 4.1 illustrates the calculation for the relative permeability for oil, the relative permeability for water is calculated in the same way. First an interpolation between the endpoints are made(point A), then the miscible and immiscible curves are scaled between A and B. Then the relative permeability are found for both curves, and the final relative permeability is an interpolation between these two values.

![Figure 4.1: Calculation of the relative permeability[5]](image)
4.3 Capillary Pressure

The capillary pressure will be reduced along with the increase in surfactant concentration, but it is only the reduction in the oil water capillary pressure that will reduce the residual oil saturation\cite{5}. The oil water capillary pressure is given as:

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

(4.4)

\(P_{cow}(S_w)\) is the capillary pressure from the initially immiscible curve scaled according to the end points calculated in the relative permeability model.

\(ST(C_{surf})\) is the surface tension with present surfactant concentration

\(ST(C_{surf} = 0)\) is the surface tension with no surfactant present

4.4 Water PVT properties

When surfactant is injected the water input in \(\text{PVT}_W\) is modified according to:

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

(4.5)

\(\mu_{ws}\) is the water-surfactant solution viscosity for a given concentration of surfactant

\(\mu_w\) is the water viscosity

\(\mu_s\) is the surfactant viscosity

\(P_{ref}\) is the reference pressure found under \(\text{PVT}_W\)

Equation 4.5 shows that the viscosity of the water surfactant solution differ from the pure water\cite{5}, but in low surfactant concentrations it is assumed the same viscosity for water surfactant solution as pure water\cite{11}. 

An introduction to applying surfactant simulation on the Norne field
### 4.5 Adsorption

The adsorption of the surfactant is assumed to happen immediately, and the amount of the adsorbed surfactant is a function of the surfactant concentration and is given as:

\[
\text{Mass of adsorbed surfactant} = \frac{PORV}{\phi} \frac{1 - \phi}{MD} \times CA(C_{\text{surf}}) \tag{4.6}
\]

\(PORV\) is the pore volume in the cell

\(\phi\) is the porosity

\(MD\) is the mass density of the rock

\(CA(C_{\text{surf}})\) is the adsorption as a function of local surfactant concentration. The adsorption concentration is explicitly updated\(^5\).

### 4.6 Keywords to activate the Surfactant Model

To activate the Surfactant flooding in Eclipse 100, three keywords are required in the PROPS section (SURFST, SURFVISC and SURFCAPD) and one in the RUNSPEC section (SURFACT) and Schedule section (WSURFACT). To take adsorption of the surfactant into the account two more keywords are needed in the PROPS section (SURFADS and SURFROCK), these are optional but should be used together\(^5\). Examples of the use of keywords are included under each keyword.

#### 4.6.1 SURFACT

Indicates that the surfactant model is used in the run, and the keyword has no associated data\(^5\).

#### 4.6.2 SURFST

Gives the surface tension between oil and water as a function of surfactant concentration in the water\(^5\). The concentration of surfactant (left column) is given
in $kg/m^3$ while the surface tension (right column) is given in $cP$.

**SURFST**

-- Constant water viscosity

-- Same data for each PVT region (1 table)

-- $C_{surf}$ (kg/m$^3$) $uw$ (cP)

<table>
<thead>
<tr>
<th>$C_{surf}$ (kg/m$^3$)</th>
<th>$uw$ (cP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0.02</td>
</tr>
<tr>
<td>0.001</td>
<td>0.0039</td>
</tr>
<tr>
<td>0.1</td>
<td>0.00002</td>
</tr>
<tr>
<td>1</td>
<td>0.000001</td>
</tr>
<tr>
<td>3</td>
<td>0.000001</td>
</tr>
<tr>
<td>5</td>
<td>0.000001</td>
</tr>
<tr>
<td>7</td>
<td>0.000001</td>
</tr>
<tr>
<td>10</td>
<td>0.000001</td>
</tr>
</tbody>
</table>

**4.6.3 SURFVISC**

A table of surfactant viscosity, that describes the effect on the viscosity when the concentration of surfactant in the water changes[5], but in this simulation the viscosity is not dependent on the surfactant concentration. The concentration of surfactant (left column) is given in $kg/m^3$ while the viscosity (right column) is given in $cP$.

**SURFVISC**

-- Constant water viscosity

-- Same data for each PVT region (1 table)

-- $C_{surf}$ (kg/m$^3$) $uw$ (cP)

<table>
<thead>
<tr>
<th>$C_{surf}$ (kg/m$^3$)</th>
<th>$uw$ (cP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00</td>
<td>0.3</td>
</tr>
<tr>
<td>1.0</td>
<td>0.3</td>
</tr>
<tr>
<td>10.00</td>
<td>0.3</td>
</tr>
</tbody>
</table>
4.6.4 SURFCAPD

The capillary de-saturation function describes the transition between immiscible and miscible conditions as a function of capillary number[5]. The left column is given as a the 10-logarithm of the capillary number, and the right column tells which relative permeability curve will be used. If the $log_{10}(N_c)$ is in the range -8.0 to -5.0 the immiscible condition will be used and this means that the surfactant concentration is low or zero, but if the $log_{10}(N_c)$ is -2.5 or higher the miscible condition is satisfied and the surfactant concentration is high enough to mobilize the capillary trapped oil.

```
SURFCAPD
-- Capillary de-saturation curve
--
-- Equal definition for each saturation table (2 tables)
--
-- Log10 Nc   Misc. func
-8     0
-7     0
-6     0
-5.0   0
-2.5   1.0
 0     1.0
 5     1.0
10    1.0 /
```

4.6.5 SURFADS

The surfactant adsorption functions describes the adsorption of the surfactant by the rock. The left column gives the surfactant concentration while the right column gives the corresponding surfactant adsorption[5].

```
SURFADS
-- Surfactant adsorption isotherm
--
-- Equal definition for all saturation tables
--
-- Csurf (kg/m3)   Adsorp (kg/kg)
```
4.6.6 SURFROCK

Specifies the rock properties, the left value is the adsorption index, and can be either 1 or 2. In this simulation only adsorption index 2 are used and means no desorption occur. The number to the right is the mass density given in kg/m³ and is used to calculate the loss of surfactant due to adsorption[5].

SURFROCK
-- Surfactant related rock properties
--
-- Same data for all saturation tables
--
-- Desorp  Density (kg/Rm3)
--
  2  2650  /

4.6.7 WSURFACT

Sets the concentration of surfactant in the injected water for each well, it is required that the well is defined as a water injection well[5].

WSURFACT
  'INJ' 10.0 /
/
5 Results of the Eclipse simulation

The surfactant model was applied to the synthetic case described in section 3.7. Different scenarios of surfactant flooding was applied and compared. The surfactant was injected when a sudden drop in production rate occurred and before the water cut got to high. All cases was only simulated for 900 days because of the high water production.

5.1 Effect of Surfactant Flooding

Three different scenarios was tested on the model to see the effect of surfactant. One base case and two different cases with surfactant injection. In the two cases with surfactant the adsorption function was included.

1. **BaseCase:** Only water is being injected.

2. **Continuous-Surfactant-Flooding:** A surfactant concentration of $10 \, \text{kg/m}^3$ water is being injected after 210 days of water flooding, and continues to the end of the simulation.

3. **Surfactant-Slug:** A surfactant concentration of $10 \, \text{kg/m}^3$ water is being injected after 210 days of water flooding. The surfactant is injected for 100 days, and then followed by water injection (the datafile for this case is attached in Appendix A).
5.1.1 Field Oil Efficiency

Figure 5.1 shows the field oil efficiency for the three cases section. The two cases with surfactant injection have a higher recovery factor than just water flooding. The base case (green line) has a recovery factor of 61%, while the continuous surfactant flooding (dark blue line) and surfactant slug (light blue line) have a recovery of 79% and 72% respectively.

Figure 5.1: Field Oil Efficiency
5 Results of the Eclipse simulation

5.1.2 Field Oil Production

Figure 5.2 shows the oil production rate while the figure 5.3 shows the cumulative oil production for the field. The oil production rates follow the same trend until day 280, then the two surfactant cases give a higher production rate according to the base case. The same peak production is reached after the surfactant is injected for both surfactant cases, but the production drop is smaller for the continuous surfactant flooding.

![Field Oil Production Rate](image)

Figure 5.2: Field Oil Production Rate
Figure 5.3: *Field Oil Production Total*
5.1.3 Water Production

Figure 5.4 shows the Total Water production of the field, for the two cases with surfactant the total water produced is less than for the base case. The smallest amount of water production is obtained for the continuous surfactant flooding. The water break through occurs at the same time for all three cases, 150 days after the production started.

![Field Water Production Total](image)

**Figure 5.4:** Field Water Production Total
Results of the Eclipse simulation

Figure 5.5 shows the Water Cut that have been achieved during the simulation. The Water Cut is decreasing after 310 days for the two surfactant cases according to the base case where the water cut continuously increasing. The continuous surfactant flooding has a lower water cut at the end of the simulation, while the surfactant slug has a water cut slightly higher than the base case.

Figure 5.5: Water Cut
5.1.4 Reservoir Pressure

Figure 5.6 is showing how the average pressure is differing in the three cases after the surfactant is introduced, before the surfactant is introduced the pressure follows the same line. The pressures for the two surfactant cases is pretty similar until day 680 when the pressure for the continuous surfactant flooding drops according to the surfactant slug.

![Figure 5.6: Average Field Pressure](image)
5.2 Effect of Adsorption

The eclipse 100 are able to handle adsorption, this section looks at the effect of the adsorption function. Four different scenarios was ran on the model.

1. **Continuous-Surfactant-Flooding**: With the adsorption function activated, a surfactant concentration of 10 kg/m$^3$ water is being injected after 210 days of water flooding, and continues to the end of the simulation run.

2. **Continuous-Surfactant-Flooding-No-Adsorption**: Without the adsorption function activated, a surfactant concentration of 10 kg/m$^3$ water is being injected after 210 days of water flooding, and continues to the end of the simulation run.

3. **Surfactant-Slug**: With the adsorption function activated, a surfactant concentration of 10 kg/m$^3$ water is being injected after 210 days of water flooding. The surfactant is injected for 100 days, and then followed by after injection.

4. **Surfactant-Slug-No-Adsorption**: Without the adsorption function activated, a surfactant concentration of 10 kg/m$^3$ water is being injected after 210 days of water flooding. The surfactant is injected for 100 days, and then followed by water injection.

5.2.1 Field Oil Efficiency

Figure 5.7 and 5.8 indicate a higher recovery when the adsorption function is omitted for the continuous surfactant flooding and the surfactant slug.
Figure 5.7: Oil Efficiency for the continuous surfactant flooding with and without adsorption
Figure 5.8: Oil Efficiency for the surfactant slug with and without adsorption
5 Results of the Eclipse simulation

5.2.2 Field Oil Production

Figure 5.9 is showing the Field Oil Production rate for the continuous surfactant flooding. It indicates a higher production rate earlier and an more even production rate when the adsorption function is omitted, but the oil production rate at the end of the simulation is the same for both cases. This gives a higher production total when the adsorption function is omitted and can be seen at figure 5.10

Figure 5.9: Oil Production Rate for the continuous surfactant flooding with and without adsorption

Figure 5.11 is showing the Field Oil Production Rate for the surfactant slug. The production is more even when the adsorption is included, and a higher peak is achieved for when the adsorption is omitted. But the total oil production is highest for the no adsorption case and is shown in figure 5.12.
Figure 5.10: Total Oil Production for the continuous surfactant flooding with and without adsorption.
Results of the Eclipse simulation

Figure 5.11: Oil Production Rate for the surfactant slug with and without adsorption
Figure 5.12: Total Oil Production for the surfactant slug with and without adsorption
5.3 Effect of Surfactant Concentration

Three different surfactant concentration (5, 10 and 25 kg/m$^3$) was injected for 100 days, the surfactant injection started after 210 days of water flooding.

5.3.1 Field Oil Efficiency

Figure 5.13 shows the effect of the surfactant concentration. The highest recovery is attained by the highest surfactant concentration.

Figure 5.13: Oil Efficiency for three different concentrations (5, 10 and 25 kg/m$^3$)
5.3.2 Field Oil Production

Figure 5.14 shows the field oil production rate for the three different concentrations. The two highest concentrations reach the same production peak, but the highest concentration reach the peak earlier. The lowest concentration does not reach the same production peak as the two highest concentrations. The highest surfactant concentration has a higher end production rate, than the two lowest concentrations.

![Figure 5.14: Oil Production Rate for three different concentrations (5, 10 and 25 kg/m³)](image)

An introduction to applying surfactant simulation on the Norne field
5 Results of the Eclipse simulation

5.4 Effect of the Slug Size

A surfactant concentration of 10 kg/m³ was injected after 210 days of water flooding. The slug size was adjusted by changing the injection time of the surfactant while the injection rate was kept constant. The injection time of surfactant was 50, 100, 150 and 200 days. The surfactant slug was followed by water flooding.

5.4.1 Field Oil Efficiency

Figure 5.15 shows the field oil efficiency for different slug sizes. The base-case with no surfactant, and the continuous surfactant flooding was also included in the figure. When the slug size is increasing the recovery will approach the continuous surfactant flooding.

![Figure 5.15: Field Oil Efficiency for different slug sizes](image)

Stud.techn. Per Einar Kalnæs
5.4.2 Field Oil Production

Figure 5.16 shows the Field Oil Production Rate with different slug sizes. When surfactant is injected for 100 days and longer, the same production peak is reached after 380 days. With shorter injection time, the production rate will drop earlier.

![Figure 5.16: Oil Production Rate with different slug sizes](image-url)
5 Results of the Eclipse simulation

5.5 Same Amount Surfactant - Different Slug Size and Concentration

Two cases were tested out, with the same amount of surfactant but different slug size and concentration. One case with a surfactant concentration of $5 \text{ kg/m}^3$ was injected for 200 days, and the other case a surfactant concentration of $20 \text{ kg/m}^3$ was injected for 50 days. Both cases were followed by water injection.

5.5.1 Field Oil Efficiency

Figure 5.17 shows the Field Oil Efficiency with two different ways to inject the same amount of surfactant. The case when a high concentration is injected for a short period has a better recovery early, but ends up a little lower when a low concentration is injected for a longer time.

![Figure 5.17: Same amount surfactant but different slug size and concentration](image-url)
5.6 Effect of a finer grid

A model with finer grids was made to see the difference from the original grids. The original model contained 100 grids in each layer the new model contained 400 grids in each layer. A surfactant slug was applied to both models. A surfactant concentration of $10 \text{ kg/m}^3$ water was injected after 210 days of water flooding. The surfactant was injected for 100 days, and then followed by water injection.

5.6.1 Field Oil Efficiency

Figure 5.18 shows the difference in field oil efficiency for the original grids and finer grids. The finer grids has a higher recovery early but a lower recovery at the end of the simulation. This difference occur after 200 days of production.

![Figure 5.18: Field Oil Production for two different grid sizes](image)
6 Discussion

6.1 Effect of Surfactant Flooding

By looking at the field oil efficiency in figure 5.1 the effect of injected surfactant occurs at day 340, 130 days after the surfactant was introduced in the reservoir. Since a little increase in production rate will not show an effect on the field efficiency immediately, the field oil production rate (figure 5.2) indicates a faster effect of the surfactant. The effect of the surfactant occurs at day 280, 70 days after the injection started. The continuous surfactant flooding is most effective. This is due to the continuous surfactant flooding reach and mobilize more of the capillary trapped oil, while the surfactant slug will be absorbed before it reaches all the capillary trapped oil. The continuous surfactant flooding will also be absorbed, but due to the continuous flow, new surfactant will come and mobilize the capillary trapped oil.

Less water is being produced for both surfactant cases, because oil is being produced instead. So the water cut goes down after the surfactant starting to pay off. But for the surfactant slug the water gets slightly higher than the base case at the end of the simulation. This can be due to the surfactant went into the most permeable layers and reduced the residual oil in those layers. When less oil is present, the oil does not prevent water from flowing and it allows more water to flow in this layers.

6.2 Effect of Adsorption

For the continuous surfactant flooding the recovery is higher without the adsorption (figure 5.7). If the simulation time had been extended for a long enough time, the same end point recovery had been achieved. This is due to a delay in the entrance of surfactant in the grids far from the injector and specially in the low permeable layers when the adsorption function is active. Because the surfactant injection is continuous, the surfactant will also reach the low permeable layers and cells far away from the injector and mobilize the capillary trapped oil. The same end recovery is reached with and without the adsorption function. This will not occur in a real case when a surfactant slug is injected followed by water flooding. If the surfactant slug is not large enough, the surfactant will not reach the grids in low permeable layers and far away from the injector because it will get adsorbed in the high permeable layers closer to the injector. This is why the end recovery
is lower with the adsorption function activated for the surfactant slug case (figure 5.8).

If the two no adsorption cases for continuous surfactant flooding and surfactant slug are compared in figure 5.7 and 5.8, they have end recoveries of 80% and 78%, this is due to the volumetric sweep efficiency. Even no adsorption is taking place the surfactant slug is not big enough to sweep as much of the reservoir reservoir as the continuous surfactant flooding.

6.3 Effect of the Surfactant Concentration

The highest recovery is obtained with the highest concentration (see figure 5.13), this is due to adsorption. Even the adsorption is a function of local surfactant concentration, a higher concentration of surfactant will reach more of the capillary trapped oil and have a better volumetric sweep. A strong surfactant concentration will last longer since the same amount of surfactant will be absorbed if the concentration of surfactant in the solution is higher than 2.0 kg/m$^3$.

6.4 Effect of Slug Size

The field oil efficiency (figure 5.15) is highly dependent on the slug size. A larger surfactant slug will reach a greater area than a smaller surfactant slug mainly because of adsorption. Figure 5.16 shows that all cases that has injected surfactant for longer than 50 days will have the same peak after 380 days. That is probably because the surfactant slug is big enough to mobilize all the capillary trapped oil in the main stream (where most of the fluid are flowing). A later drop in oil production rate occur for the bigger slug sizes because they are mobilizing capillary trapped oil at a wider range and in layers with the lower permeability than the small slugs.

6.5 Effect of different scenarios with same amount of surfactant

How to use the amount of surfactant that are provided might depend on when the pay of is wanted and might have a huge impact in a real case. From figure 5.17 it looks like a smaller and more concentrated surfactant will pay off a little earlier.
compared to a less concentrated and bigger slug. The difference in this case does not look big, but a difference on 2% according to recovery factor will be of great importance to consider how to use the surfactant.

6.6 Effect of a finer grid

The difference in recovery factor was limited when the surfactant was tested on different grid sizes. Both grid sizes followed the same trend under the whole simulation.
7 Conclusion

- The surfactant flooding is a promising EOR-method under right conditions.
- The effect of the surfactant flooding will not pay off immediately.
- A high adsorption level will reduce the effect of the surfactant flooding.
- Higher surfactant concentration will be more effective than a lower surfactant concentration.
- A big surfactant slug will be more effective than a small surfactant slug.
- How to use the amount of provided surfactant will be of great importance in a real case.
- The redefined grid indicated very small differences in performance.

8 Uncertainties

A lot of uncertainties is connected to reservoir simulation because of the simplifications that is made. The uncertainties in this simulation will rely on the surfactant properties and the simplified model used.

Viscosity differences of pure water and water with surfactant was not included in the simulation.

9 Recommendation

When the surfactant simulation is apply to the Norne reservoir model. It will be of great importance to known the flow pattern in the reservoir, so it will be of great help to inject tracers in the reservoir to map the flow pattern.

A economical and environmental evaluation should be taken into account before a surfactant flooding is put into practice.

An evaluation of the surfactant model in Eclipse 100 together with a comparison with other simulation tools should be made.
Other aspect of surfactant flooding that should be considered is; the timing, salinity, temperature, phase behavior and mobility control.
## Nomenclature

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\gamma$</td>
<td>Interfacial tension between oil and the surfactant solution</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Viscosity of the displacing fluid</td>
</tr>
<tr>
<td>$\mu_s$</td>
<td>Surfactant viscosity</td>
</tr>
<tr>
<td>$\mu_{ws}$</td>
<td>Water-surfactant solution viscosity</td>
</tr>
<tr>
<td>$\mu_w$</td>
<td>Water viscosity</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Porosity</td>
</tr>
<tr>
<td>$C_{\text{unit}}$</td>
<td>A unit constant</td>
</tr>
<tr>
<td>$CA(C_{\text{surf}})$</td>
<td>Adsorption as a function of local surfactant concentration</td>
</tr>
<tr>
<td>$EOR$</td>
<td>Enhanced Oil Recovery</td>
</tr>
<tr>
<td>$IEA$</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>$IFT$</td>
<td>Interfacial Tension</td>
</tr>
<tr>
<td>$K$</td>
<td>Permeability</td>
</tr>
<tr>
<td>$MD$</td>
<td>Mass Density</td>
</tr>
<tr>
<td>$N_c$</td>
<td>Capillary Number</td>
</tr>
<tr>
<td>$NPD$</td>
<td>Norwegian Petroleum Directory</td>
</tr>
<tr>
<td>$P$</td>
<td>Potential</td>
</tr>
<tr>
<td>$P_{cow}$</td>
<td>Capillary pressure</td>
</tr>
<tr>
<td>$P_{cow}(S_w)$</td>
<td>Capillary pressure from the initially immiscible curve scaled according to the end points</td>
</tr>
<tr>
<td>$P_{\text{ref}}$</td>
<td>Reference pressure</td>
</tr>
<tr>
<td>$PORV$</td>
<td>Pore volume in a cell</td>
</tr>
<tr>
<td>$S_{orw}$</td>
<td>Residual oil saturation after water flooding</td>
</tr>
<tr>
<td>$ST$</td>
<td>Interfacial tension</td>
</tr>
<tr>
<td>$ST(C_{\text{surf}})$</td>
<td>Surface tension with present surfactant concentration</td>
</tr>
</tbody>
</table>
9  Recommendation

$ST(C_{surf} = 0)$  Surface tension with no surfactant present

$u$  Darcy’s velocity

CDC  Capillary Desaturation Curve

CMC  Critical Micelle Concentration
References


A Appendix

RUNSPEC
TITLE
Surfactant model test case.

DIMENS
10 10 5 /

OIL

WATER

SURFACT

METRIC

TABDIMS
6 1 23 20 1 20 /

WELLDIMS
2 5 1 2 /

START
1 'NOV' 1997 /

NSTACK
8 /

--NOSIM

GRID

PSEUDO
DXV
   10*50 /
DYV
   10*50 /
DZ
   100*1.1 100*11.5 100*11.5 100*11.5 100*11.5 /
PERMX
   100*253 100*1197 100*347 100*88 100*1534 /
COPY
 'PERMX' 'PERMY' 1 10 1 10 1 5 /
/
PERMZ
   100*33 100*766 100*22 100*57 100*982 /
PORO
   100*0.3 100*0.3 100*0.27 100*0.25 100*0.27 /
TOPS
   100*2640 /
RPTGRID
 /
PROPS ================

SWOF
   -- OIL/WATER imbibition curve IMBNUM = 56
   -- sw   krw   kro   pc
 0.1600 0.0000000000 0.9000000000 3.0268147326
 0.2020 0.0000000000 0.7744359463 1.4973553514
 0.2440 0.0000334474 0.6600153826 0.7302609648
 0.2860 0.0003784142 0.5563875210 0.4724467555
 0.3280 0.0015641802 0.4631897739 0.3419328075
 0.3700 0.0042812675 0.3800464749 0.2623164106

64
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<th>sw</th>
<th>krw</th>
<th>kro</th>
<th>pc</th>
</tr>
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<tr>
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<td>0.0000000000</td>
<td>0.9000000000</td>
<td>1.7670728033</td>
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<td>0.1260</td>
<td>0.0000000000</td>
<td>0.7761504375</td>
<td>0.8748881643</td>
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<tr>
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<td>0.0000334474</td>
<td>0.6631330696</td>
<td>0.4274164388</td>
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<tr>
<td>0.2180</td>
<td>0.0003784142</td>
<td>0.5606121625</td>
<td>0.2770248166</td>
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<td>0.015641802</td>
<td>0.4682408747</td>
<td>0.2008916803</td>
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<td>0.0042812675</td>
<td>0.3586600748</td>
<td>0.1544487821</td>
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<td>0.3560</td>
<td>0.0093488332</td>
<td>0.3124969331</td>
<td>0.1228365681</td>
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<tr>
<td>0.4020</td>
<td>0.0176966790</td>
<td>0.2483632210</td>
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<td>0.4940</td>
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<td>0.0674133024</td>
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<td>0.1059777841</td>
<td>0.0554538327</td>
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<td>0.5860</td>
<td>0.1057699738</td>
<td>0.0736861504</td>
<td>0.0452394807</td>
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<td>0.6320</td>
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<td>0.0211206142</td>
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<td>0.0144487821</td>
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<td>0.0016291740</td>
<td>0.0081982115</td>
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<td>0.0022593459</td>
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<tr>
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<td>0.0000000000</td>
<td>0.0000000000</td>
</tr>
<tr>
<td>0.9080</td>
<td>0.6775379433</td>
<td>0.0000000000</td>
<td>0.0000000000</td>
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<td>0.9540</td>
<td>0.8275917726</td>
<td>0.0000000000</td>
<td>0.0000000000</td>
</tr>
</tbody>
</table>

-- OIL/WATER imbibition curve IMBNUM = 48

/
1.0000 1.0000000000 0.0000000000 0.0000000000
/

-- OIL/WATER imbibition curve IMBNUM = 54
-- sw    krw    kro    pc
 0.1450  0.0000000000  0.9000000000  2.7783170692
 0.1877  0.0000000000  0.7749255688  1.3746743200
 0.1878  0.0000000000  0.7746457618  1.3713913989
 0.2305  0.0000334474  0.6606509293  0.6698610892
 0.2732  0.0003776402  0.5573629447  0.4337168838
 0.3160  0.0015641802  0.4642179418  0.3138936117
 0.3588  0.0042856505  0.3810966923  0.2408429317
 0.4015  0.0093488332  0.3077719364  0.1912355782
 0.4442  0.0176846082  0.2436364296  0.1548891261
 0.4870  0.0303532736  0.1881505697  0.1267504339
 0.5298  0.0484618023  0.1410309775  0.1041179207
 0.5725  0.0731494693  0.1018912668  0.0853484226
 0.6152  0.1057266825  0.0701163199  0.0693147747
 0.6580  0.1476511367  0.0451238969  0.0552681007
 0.7007  0.2001467763  0.0264529972  0.0427704091
 0.7435  0.2649501256  0.0133769095  0.0313962221
 0.7863  0.3435085118  0.0052224361  0.0209000767
 0.8290  0.4372016611  0.0011414308  0.0110895892
 0.8718  0.5481424609  0.0000118320  0.0076839944
 0.8800  0.5714869997  0.0000000000  0.0000000000
 0.9145  0.6775379433  0.0000000000  0.0000000000
 0.9573  0.8277799991  0.0000000000  0.0000000000
 1.0000  1.0000000000  0.0000000000  0.0000000000
/

-- OIL/WATER imbibition curve IMBNUM = 80
-- sw    krw    kro    pc
 0.1700  0.0000000000  0.9000000000  3.2786792856
 0.2115  0.0000000000  0.7741946514  1.6217649559
 0.2530  0.0000334474  0.6595769798  0.7907460371
 0.2945  0.0003784142  0.5573629447  0.5114473103
 0.3360  0.0015641802  0.4642179418  0.3138936117
 0.3775  0.0042856505  0.3810966923  0.2408429317
 0.4190  0.0093488332  0.3077719364  0.1912355782
0.4605 0.0176966790 0.2415052358 0.1820990596
0.5020 0.0303523736 0.1861341829 0.1488879899
0.5435 0.0484370128 0.1391743844 0.1221687838
0.5850 0.0731494693 0.1001501669 0.0999583402
0.6265 0.1057699738 0.068553807 0.0809888293
0.6680 0.1476511367 0.0438466371 0.0644088689
0.7095 0.2002150675 0.0254335859 0.0496224427
0.7510 0.2649501256 0.0126640003 0.0361966487
0.7925 0.3434080896 0.0047982645 0.0238061033
0.8340 0.4372016611 0.0006915928 0.0121979007
0.8755 0.5480022429 0.0000028782 0.0011685789
0.8800 0.5611112792 0.0000000000 0.0000000000
0.9170 0.6775379433 0.0000000000 0.0000000000
0.9585 0.8275917726 0.0000000000 0.0000000000
1.0000 1.0000000000 0.0000000000 0.0000000000
/

-- OIL/WATER imbibition curve IMBNUM = 48
-- sw    krw    kro    pc
0.0800 0.0000000000 0.9000000000 1.7670728033
0.1260 0.0000000000 0.7761504375 0.8748881643
0.1720 0.0000334474 0.6631330696 0.4274164388
0.2180 0.0003784142 0.5606121625 0.2770248166
0.2640 0.0015641802 0.4682408747 0.2008916803
0.3100 0.0042812675 0.3856600748 0.154487821
0.3560 0.0093488332 0.3124969331 0.1228365681
0.4020 0.0176966790 0.2483632210 0.0996834508
0.4480 0.0303523736 0.1928532264 0.0818005672
0.4940 0.0484370128 0.1455411505 0.0674133024
0.5400 0.0731494693 0.1059777841 0.0554538327
0.5860 0.1057699738 0.0736861504 0.0452394807
0.6320 0.1476511367 0.0481555940 0.0363118097
0.6780 0.2002150675 0.0288334072 0.0283498879
0.7240 0.2649501256 0.0151122468 0.0211206142
0.7700 0.3434080896 0.0063095626 0.0144487821
0.8160 0.4372016611 0.0016291740 0.0081982115
0.8620 0.5480022429 0.0006834374 0.0022593459
0.8800 0.5963616344 0.0000000000 0.0000000000
0.9080 0.6775379433 0.0000000000 0.0000000000
0.9540 0.8275917726 0.0000000000 0.0000000000
PVTW
277 1.038 4.6E-5 0.318 0.0 /

PVDO
275 1.314 0.628
300 1.308 0.647
325 1.302 0.665 /

ROCK
277 4.85E-5 /

DENSITY
860. 1033. 0.853 /

SURFVISC
-- Constant water viscosity
--
-- Same data for each PVT region (1 table)
--
-- Csurf (kg/m3) uw (cP)
0.00 0.3
1.0 0.3
10.00 0.3 /

SURFADS
-- Surfactant adsorption isotherm
--
-- Equal definition for all saturation tables (2 tables)
--
-- Csurf (kg/m^3)   Adsorp (kg/kg)
    |      |
  0.0  |  0.0   |
  0.5  |  0.00026 |
  1.0  |  0.00034 |
  2.0  |  0.00050 |
 10.0  |  0.00050 /|
  0.0  |  0.0 |
  0.5  |  0.00026 |
  1.0  |  0.00034 |
  2.0  |  0.00050 |
 10.0  |  0.00050 /|
  0.0  |  0.0 |
  0.5  |  0.00026 |
  1.0  |  0.00034 |
  2.0  |  0.00050 |
 10.0  |  0.00050 /|
  0.0  |  0.0 |
  0.5  |  0.00026 |
  1.0  |  0.00034 |
  2.0  |  0.00050 |
 10.0  |  0.00050 /|
  0.0  |  0.0 |
  0.5  |  0.00026 |
  1.0  |  0.00034 |
  2.0  |  0.00050 |
 10.0  |  0.00050 /|

SURFST
-- Constant water viscosity
--
-- Same data for each PVT region (1 table)
--
-- Csurf (kg/m^3)   uw (cP)
SURFCAPD
-- Capillary de-saturation curve
--
-- Equal definition for each saturation table (2 tables)
--
-- Log10 Nc   Misc. func
-8     0
-7     0
-6     0
-5.0   0
-2.5   1.0
  0    1.0
  5    1.0
 10   1.0 /
-8     0
-7     0
-6     0
-5.0   0
-2.5   1.0
  0    1.0
  5    1.0
 10   1.0 /
-8     0
-7     0
-6     0
-5.0   0
-2.5   1.0
  0    1.0
  5    1.0
 10   1.0 /
SURFROCK
-- Surfactant related rock properties
--
-- Same data for all saturation tables (2 tables)
--
-- Desorp  Density (kg/Rm3)
--
2 2650 /
2 2650 /
2 2650 /
2 2650 /
2 2650 /
2 2650 /

RPTPROPS
-- PROPS Reporting Options
'SURFVISC'
/

REGIONS

SATNUM
100*1 100*2 100*3 100*4 100*5/

SURFNUM
500*6 /

RPTREGS
/

SOLUTION

EQUIL
2640 277 2700 /

RPTSOL
--
-- Initialisation Print Output
--
'PRES' 'SOIL' 'SWAT' 'RESTART=1' 'OILAPI' 'FIPTR=2'
'TBLK' 'FIPPLY=2' 'SURFBLK' 'SATNUM'
'FIPSURF=2' /

SUMMARY

WBHP
/
FWPT
FWPR
FWCT
FPR
FWIR
FOPR
FOPT

72
FOE
FTPRSUR
FTPTSUR
FTIRSUR
FTITSUR
FTADSUR

BTCNFSUR
 1 1 1 /
 2 2 1 /
 3 3 1 /
 4 4 1 /
 5 5 1 /
 5 5 2 /
 5 5 3 /
 6 6 1 /
 7 7 1 /
 8 8 1 /
 9 9 1 /
 10 10 1 /
 10 10 2 /
 10 10 3 /
/

BOSAT
 1 1 1 /
 2 2 1 /
 3 3 1 /
 4 4 1 /
 5 5 1 /
 5 5 2 /
 5 5 3 /
 6 6 1 /
 7 7 1 /
 8 8 1 /
 9 9 1 /
 10 10 1 /
 10 10 2 /
 10 10 3 /
/

73
```
WTPRSUR
 'OP' /

BTADSUR
  5 5 1 /
 /

RUNSUM

SCHEDULE

RPTSCHED
 'PRES' 'SOIL' 'SWAT' 'RESTART=2' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2'
 'NEWTON=2' 'OILAPI' 'FIPTR=2' 'TBLK' 'FIPSALT=2' 'TUNING' 'SURFBLK' 'SURFADS' 'IMBNUM' 'FIPSURF=2' /

WELSPecs
 'OP' 'G' 10 10 2640 'OIL' /
 'INJ' 'G' 1 1 2640 'WAT' /
 /
COMPDAT
 'OP ' 10 10 1 5 'OPEN' 0 .0 157E-3 /
 'INJ ' 1 1 1 5 'OPEN' 0 .0 157E-3 /
 /
WCONPROD
 'OP' 'OPEN' 'RESV' 4* 7000 0.0 4* /
 /
WCONINJE
 'INJ' 'WAT' 'OPEN' 'RESV' 1* 7000 /
 /
TSTEP
  3*70 /

--WSURFACT
--'INJ' 10.0 /
-- /

74```
TSTEP
  50 /

--WSURFACT
-- 'INJ' 0.0 /
--/

TSTEP
  20*180
/

END