Evaluating tertiary water based EOR methods on the Veslefrikk field, with emphasis on analyzing sodium silicate injection by numerical simulation

by

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Preface

After having been working as a drilling engineer for a number of years I wanted to change my scope of work to include reservoir engineering. Nearly 20 years since I took my Bachelor degree within petroleum engineering at the University of Stavanger I felt a need of both refreshing and increasing my knowledge on this subject. The courses I've been attending at the University of Bergen, prior to doing my master thesis, have been very useful and instructive.

The topic in my master thesis have been chosen in such a way that both my employer and I could benefit from the lessons learned, which especially also can be useful for the Veslefrikk field.

First, I would like to thank my supervisor, professor Arne Graue, both for giving me great freedom in defining the topic for the master thesis and for giving me the necessary help and corrections on the way.
My "external" supervisor, in the Veslefrikk petroleum technology department within StatoilHydro, Brit Gunn Ersland, deserves a great thank for defining a very relevant topic for the master thesis, and for my future job. She has been an enthusiastic supervisor supporting in doing the simulations and drawing the conclusions.
My good colleagues within the Veslefrikk petroleum department should not be forgotten, giving me a lot of help especially with the reservoir simulations.

I am also very grateful for the good collaboration I have had with key personnel in the department of technology and new energy within StatoilHydro. Especially, I thank Herbert Fischer for giving me instructions on how to simulate placement of sodium silicate by using the tracer option and "FloViz" in Eclipse. Thanks to Dag Chun Standnes for giving me extensive help, especially in preparing the conceptual reservoir simulation model.

Last, but not least, I would never have managed this master study without the good support from my husband Kjell and my children Kai and Maja. I bet they look twice as much forward to the completion of this master study as I do!

Bergen, 30.04.09

Beate Hansen

1 Summary

The Veslefrikk field is now in the tail end production phase implying a low oil production rate and a high water cut, but still approximately 60% of the oil originally in place is left in the reservoir. The main oil recovery method utilized has been water injection, but also gas- and water alternating gas (WAG) injection have been made use of. In order to increase the oil recovery within the field economic life time, different methods are looked into.

Since water flooding has been an efficient oil recovery method on Veslefrikk, this master thesis has mainly concentrated on studying water based enhanced oil recovery (EOR) methods. A screening study was performed on the applicability of some water based EOR methods on the Veslefrikk reservoir. Several methods was discarded due to not having a range of application within the specifications for this reservoir.

Diversion of injection water to unflooded or partly flooded areas in the Veslefrikk reservoir was regarded as having an EOR potential. Injection of sodium silicate was found to be particularly applicable as a water diverging method. Sodium silicate may be simply explained as quartz dissolved in caustic soda. When injected into the reservoir, it reduces the permeability in the treated area, and a diversion of the subsequent water injection is obtained.

A parameter study was deemed necessary to evaluate if an EOR potential was present prior to actuate expensive laboratory experiments. With this context injection of sodium silicate was analyzed by numerical simulation, first by utilizing a conceptual model and then by using the full field reservoir model.

From the analysis of different sensitivities in a conceptual simulation model, which investigated EOR from the Etive formation on the Veslefrikk field, it was found that especially the degree of vertical communication within the model, made a big difference with regards to EOR. A much higher EOR value was obtained if the vertical communication was low.

For a high vertical communication model, the EOR was increased if the sodium silicate batch volume was bigger and displaced a longer distance into the reservoir. The EOR result was better if the permeability in the simulator model cells, invaded by sodium silicate, only was slightly reduced. For a high vertical communication reservoir a low EOR may be expected based on the results from the simulations. For the Veslefrikk field, however, a higher heterogeneity is expected in the Etive formation and thus a higher EOR may be expected.

An EOR potential was analyzed for the Ness 2 formation by utilizing the full field simulation model. More specifically, the potential of increased oil production in a horizontal Ness 2 well was simulated by the injection of sodium silicate in a near-by water injection well. A significant EOR potential was identified, both from the field and from the specific production well. The best EOR case was obtained by a strong reduction of the permeability in the Ness 2 formation around this specific water injection well.

Simulation results indicate that a near-wellbore sodium silicate treatment of this water injection well could be advantageous. Successful near-wellbore sodium silicate treatments have previously been performed in production wells at the Gullfaks field. Further reservoir simulations should be conducted refining the grid and simulating the reservoir temperature in the near-wellbore injector area. Also a revised injection and production strategy is needed to improve the EOR potential of the simulated treatment. Finally, laboratory experiments would be needed to adjust the design properties for sodium silicate to the specific purpose and actual reservoir characteristics.

2 Introduction

The Veslefrikk field has been producing oil since December 1989 and is in the tail end phase. The main drainage strategy has been to produce oil while maintaining the reservoir pressure above the initial saturation pressure through water injection. Later on, the recovery methods have been extended to include gas injection, and water alternating gas injection (WAG).

The Veslefrikk reservoir is composed of several reservoir zones. Most of the wells on the field are producing or injecting commingled. A few of the production wells are dedicated to one single reservoir zone. To improve zonal reservoir steering, the completion strategy for the injector wells has lately been changed to include DIACS (Downhole Instrumentation And Control System).

Water saturation logs from wells have proved that water flooding is quite efficient in most parts of the reservoir. On the other hand, drilling of new wells in the neighbourhood of abandoned producers have in some occasions shown higher oil saturation than expected. Expecting that approximately 60% of the stock tank oil volume originally in place, is still left in the reservoir, indicates that the volumetric sweep is not satisfactory.

The average field water cut is 85-90%. Increased water cut creates environmental, technical and economical challenges. Different measures are therefore used to reduce the water production.

Mechanical water shut-off techniques may be used, however in many cases mechanical zonal isolation is found technically challenging and/or expensive or even represents a risk of plugging off a significant oil contribution.

Alternatives to mechanical water shut-off methods may be various chemical water shut-off systems. These may be Relative Permeability Modifiers (RPM) to be used in producer near well bore area reducing the water relative permeability. Two different RPM's have been tested on the Veslefrikk field, in two different production wells. The tests were considered successful, but still improvement is required regarding providing environmentally acceptable and properly designed chemicals. However, these methods only influence the water production in the producer near well bore area and do not make any changes to the water flooding far out in the reservoir.

To improve the volumetric sweep, one need to find methods diverging water flooding in the reservoir, targeting oil in unswept or poorly swept areas. Different water based enhanced oil recovery methods are discussed in the master thesis but the main focus is on diverging injection water in the reservoir by means of injecting sodium silicate.

A conceptual reservoir simulation model is studied for the Etive formation, aiming to close off a "thief zone", hence improving oil production from the upper layers.

A study is further performed on a possible field pilot test. The current full field reservoir simulation model is used to analyze the opportunity of increased oil production from the Ness 2 formation. The analysis focuses on evaluating the potential of increased oil production in a horizontal Ness 2 oil producer, by means of closing off the water short cut from a near by water injection well, through sodium silicate injection.

3 The Veslefrikk field

3.1 Veslefrikk production history

The Veslefrikk field is located in block 30/3 of the Norwegian sector of the North Sea and is situated approximately 145 kilometres west of Bergen.
The field has been on production since December 1989. It was developed by a 24 slot wellhead platform with drilling facilities in combination with a semi-submersible process platform with a living quarter, see Figure 1 and [1].

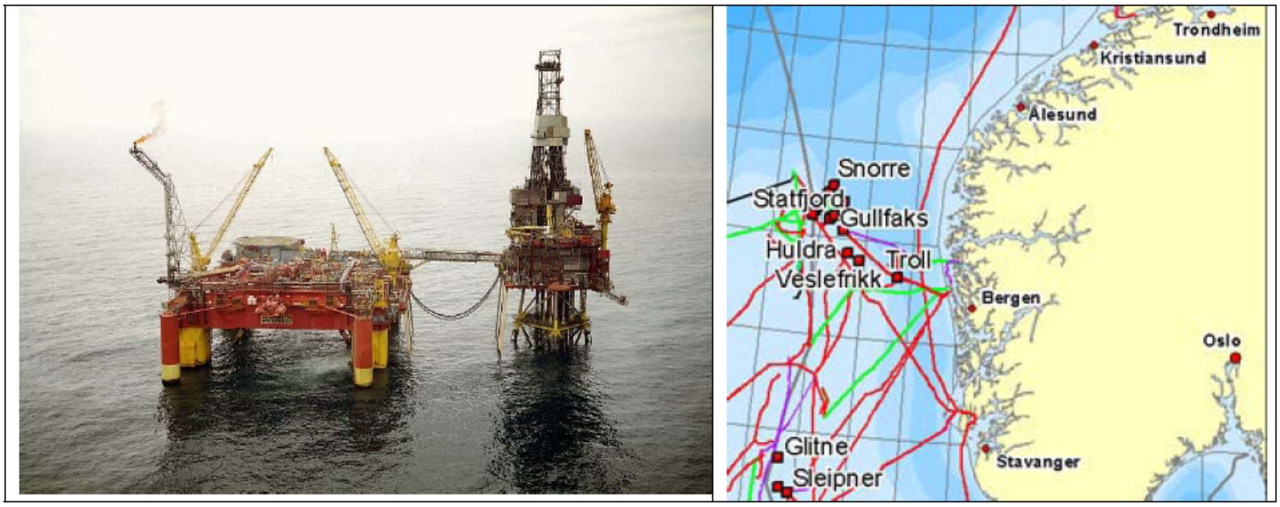


Figure 1 The Veslefrikk field, platforms and location

Initial recoverable reserves were estimated to 36 million Sm³ of oil to be developed during 20 years of production starting from 1989 [2]. Today approximately 49,5 million Sm³ has been produced and the total recoverable reserves have been adjusted to nearly 56 million Sm3 of oil. Approximately 6 more million Sm³ of oil is planned to be produced [3].

The production rate peaked in 1995, and the field is now far into the tail production phase, see Figure 2 (official production data, StatoilHydro).

Seawater injection has been the main method of pressure support, but water alternate gas (WAG) injection has also been performed to further reduce the residual oil saturation in the water-flooded areas of the field [1].

The first water breakthrough was observed during 1992 and the field water cut has in 2009 reached 85-90%. The produced water contains in average 50-60% seawater [1].

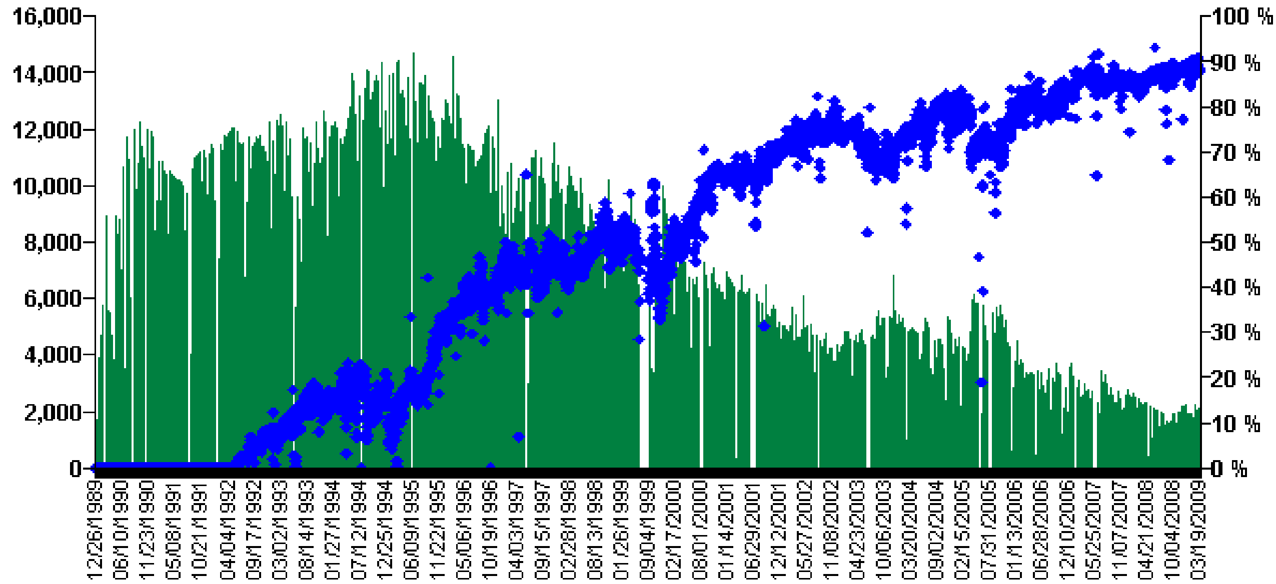


Figure 2 Veslefrikk historical oil production and water cut (Sm3/day on left axis)

The Veslefrikk reservoir is layered, see Figure 4 [2], consisting of several zones with independent pressure regimes and to some degree also different fluid systems. Commingled production is extensively used at the field, due to the limited number of well slots and to optimize the production rate [1].

Due to seawater injection, commingled production and high reservoir temperature, severe tendency towards deposition of sulphate and carbonate scale has been observed. The two most common types of scale in the Veslefrikk field are calcium carbonate ($CaCO_3$) and barium sulphate ($BaSO_4$). Calcium carbonate can precipitate if produced fluid containing formation water is pressure depleted, for instance when flowing into or inside the well. Barium sulphate scale is a sparingly soluble salt which is rapidly precipitated when barium rich formation water is mixed with sulphate rich injected sea water. A significant improvement in downhole scale control has been obtained through a more aggressive use of preventive scale inhibitor squeezes and the implementation of new technology [1].

Recently it was decided to change injection strategy in the Statfjord formation from gas recycling to WAG, and this will make increased WAG-injection into the Brent Group feasible. WAG has been performed successfully in the Intra Dunlin Sand for several years.

The field is now in an infill drilling phase, and one of the main challenges is to find available well slots for the new drilling targets. Drilling of multilateral wells is considered.
Based on experienced problems with injection steering in fractured water injectors, the current strategy has changed to plan for utilizing DIACS (Downhole Instrumentation and Control System) and WAG in all future injectors. The first DIACS WAG injector was completed in 2004, the second in 2008 and one more is being completed early 2009. This will, in addition to reducing the number of slots used for injectors, make the injectors more efficient [2].

3.2 General description of the reservoir

The Veslefrikk structure is a horst block with gently dipping strata (1-2 degrees) away from the crest, which is located on the central part of the field near the eastern margin [4]. The surface area of the main field is approximately 9 km x 3 km, see Figure 3.

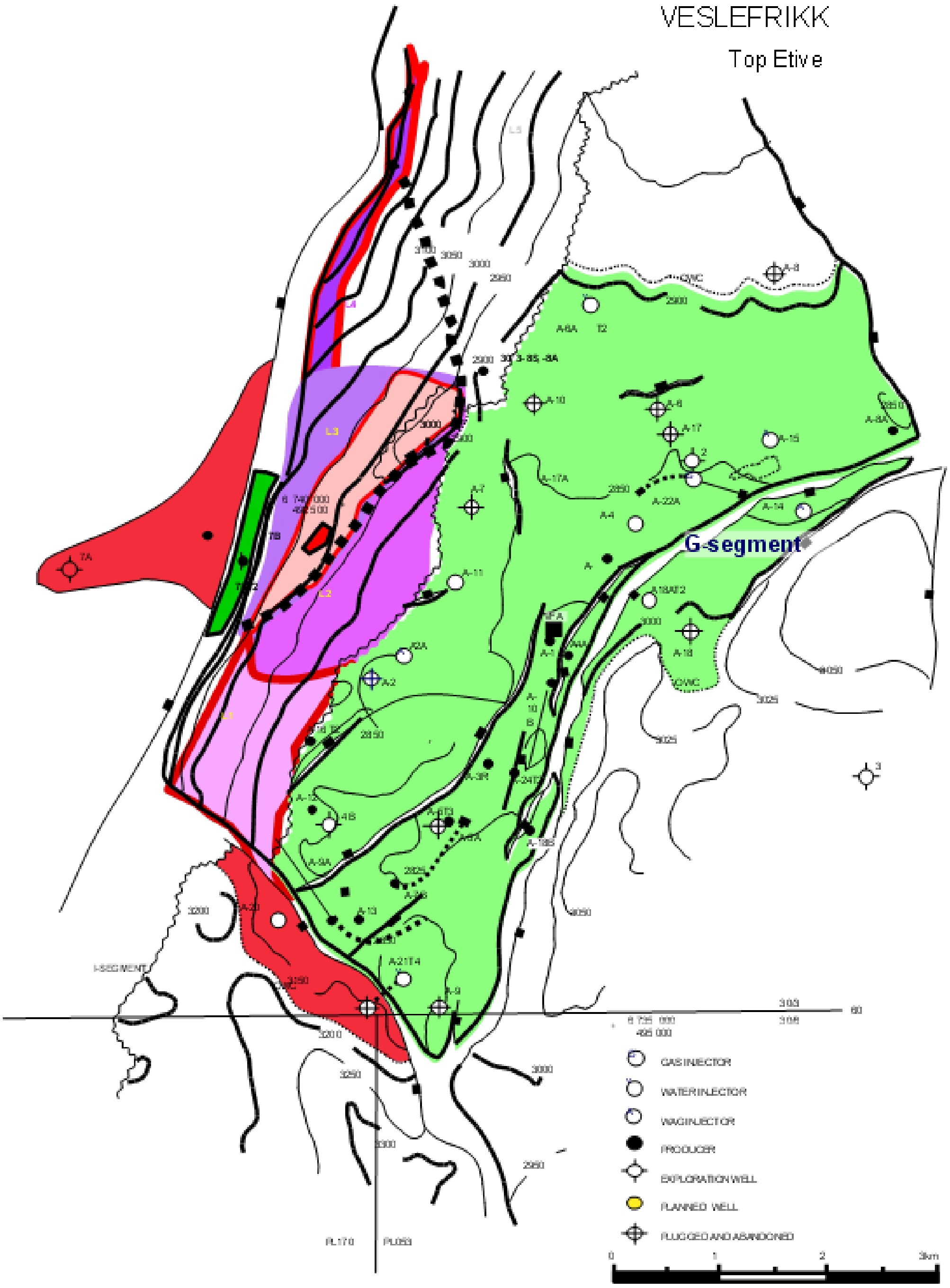


Figure 3 Overview of wells at the Veslefrikk field. Updated per October 2007

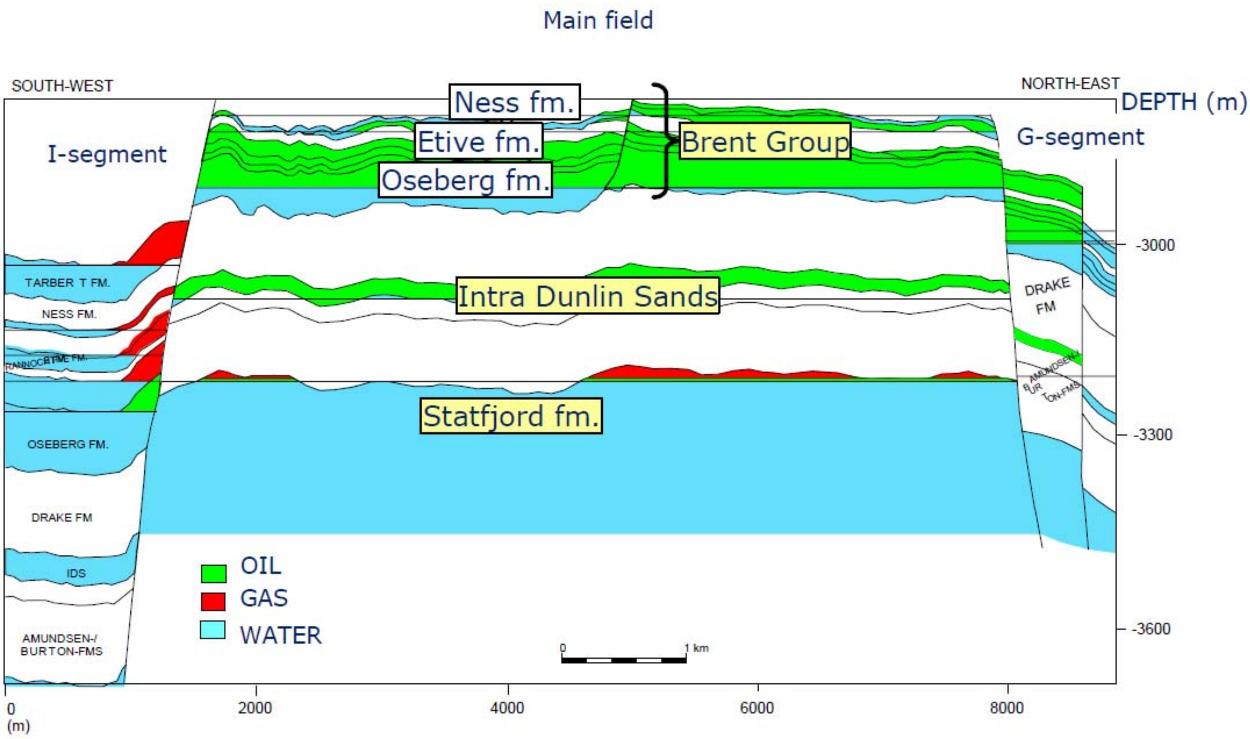


Figure 4 Cross-section of the Veslefrikk field [2]

3.3 Description of the different formations/zones [4]

Generally, an overview of the reservoir formations and their main characteristics are given in Figure 5 and Figure 6.

3.3.1 The Brent Group formations

The Brent Group is the main reservoir with approximately 80% of the reserves. The Brent Group is 125 metres thick with averaged reservoir parameters like sand content of 60%, porosity of 18% and permeabilities in the range of 100-500 mD. The Brent Group includes the Tarbert, Ness, Etive, Rannoch and Oseberg formations.

3.3.2 The Tarbert formation

The Tarbert Formation is composed of poor reservoir quality deposits, deposited within a distal lower shoreface environment. Due to the poor reservoir quality, the formation is defined as a marginal facies.

3.3.3 The Ness formation

The Ness Formation on Veslefrikk consists of fluvial delta plain deposits. The formation is a 35 – 45 m heterolitic interval with bay fill and delta plain mudstones, minor and major channel sandstones and coal layers. The Ness Formation has been subdivided into three zones, the Ness 1, Ness 2 and Ness 3.
The Ness 1 has been classified as marginal facies due to the mix of reservoir properties and the lateral variability of the reservoir properties.

The Ness 2 is the main reservoir zone within the Ness Formation. A channel system covers the south-western part of the field with good connectivity between the channel sand bodies.
In the Ness 3 zone, the channel bodies are mostly found in the north-eastern part of the field.
The Ness 2 and Ness 3 channel systems have different initial oil water contacts and are generally not in pressure communication during production.
The individual channel thickness within the Ness Formation is 1-2 m. In the Ness 2, stacking of the channels has resulted in a sand thickness of ~10 m.
Ness 1 has poor pressure support due to poor connectivity between the producers and the injectors. There are commonly limited vertical communication between Etive and Ness 1, due to the presence of shale and coal in the lower part of the Ness 1 zone, an exemption is the southern part of the B-segment, where Ness 1 channels have removed the fine-grained interval by erosion.
The Ness 2 channel sand stones are mostly found in the A-segment and B-segments. The reservoir communication is good. Ness 3 is composed of isolated channel sand stones with poor reservoir connectivity on the main field.

3.3.4 The Etive formation

The Etive Formation consists of high energy upper shoreface and beach deposits. The palaeo shoreline has moved across the field from southeast to northwest. The stepwise movement of the shoreline is seen as areas of thinning of the Etive Formation, interpreted as rapid movements leaving less room for deposition. The drainage strategy for the Etive formation has been mostly down dip water injection. From 2001 gas have been injected mainly to drain the attic oil in Etive 3, since the injected water tends to drain the high permeable conglomerate layer Etive 2 and gravity forces helps the water to drain Etive 1. The WAG (Water Alternating Gas) injection has resulted in a massive “WAG effect”; increased oil production rate.
The Etive formation is one pressure regime and it is impossible to split the production in Etive 1, 2 and 3. There is restricted communication over an Etive thinning in the North and good communication between faults. There are limited communication between Etive and Ness 1, due to shale and coal between the formations over a major part of the field. Etive communicates with Rannoch. Pressure measurements from Rannoch indicate some pressure drop in the formation. These pressure drop are because of volumes have been produced though the Etive Formation. Basically the remaining oil is left in Etive 3 while Etive 1 and 2 are mostly water flooded. The massive water injection in the Etive formation has drained the high permeable conglomerate layer Etive 2 and gravity forces helped the water to drain Etive 1.

3.3.5 The Rannoch formation

The lower shoreface deposits of the Rannoch Formation has poor reservoir quality (usually less than 10 mD, average 8mD), and is therefore defined as a marginal facies reservoir zone.

3.3.6 The Oseberg formation

The Oseberg Formation on Veslefrikk is a submarine fan delta prograding from the east north-east as a response to tectonic uplift of the eastern margin of the North Sea. Thickness varies from 52 m in the north-east to 66 m in the south-west. The Oseberg Formation is the main reservoir on the Veslefrikk Field. The formation is subdivided into Oseberg 1, 2 & 3. The Oseberg 2 Member is 38 – 58 m thick and is composed of upwards coarsening and upwards fining units, the upward coarsening pattern being the volumetrically dominant.
Clinoforms are characteristic features in fan deltas. In the Oseberg 2 Member, 17 clinoforms have been interpreted based on the sedimentological framework, seismic data and production and injection data.

3.3.7 The IDS (Intra Dunlin Sandstone) formation

The IDS is generally a complex tidal deposit with occasionally excellent reservoir quality, due to chlorite coating of the sand grains. The average sand thickness is approximately 20 metres. The IDS is a tide influenced delta lobe prograding from E-SE towards W-NW during an overall stratigraphic base level fall. The reservoir consists of a delta front, tidal bars, channels and fines. It is divided into three subzonations, IDS 1,2 & 3. It ranges from 46-62 meters in thickness. The properties depend on chlorite coating, and the best reservoir unit lies in the IDS 3. The IDS reserves are located mainly in the IDS sub zones 3.3, 3.4 and 3.5.
The main recovery mechanisms for producing IDS are water injection, WAG and depletion. Laterally the reservoir is divided into three lobes which trend northwest to southeast. The lobes are areas with good reservoir quality separated by areas of poor quality. Other reservoir confinements are the main faults dividing the reservoir into the segments A, B, and D.

3.3.8 The Statfjord formation

The Statfjord formation comprises of stacked braided river channels. It contains a 14-meter thick oil zone overlain by a gas cap that is 30 meters thick at the crest of the field.
The main recovery strategy for the Statfjord formation has been dry gas recycling with one producer south in the A-segment and one injector north in the D-segment. In 2005 the drainage strategy was changed to water alternating gas (WAG). Statfjord gas is currently in use for WAG injection in the Brent Group, the IDS and the Statfjord formation.

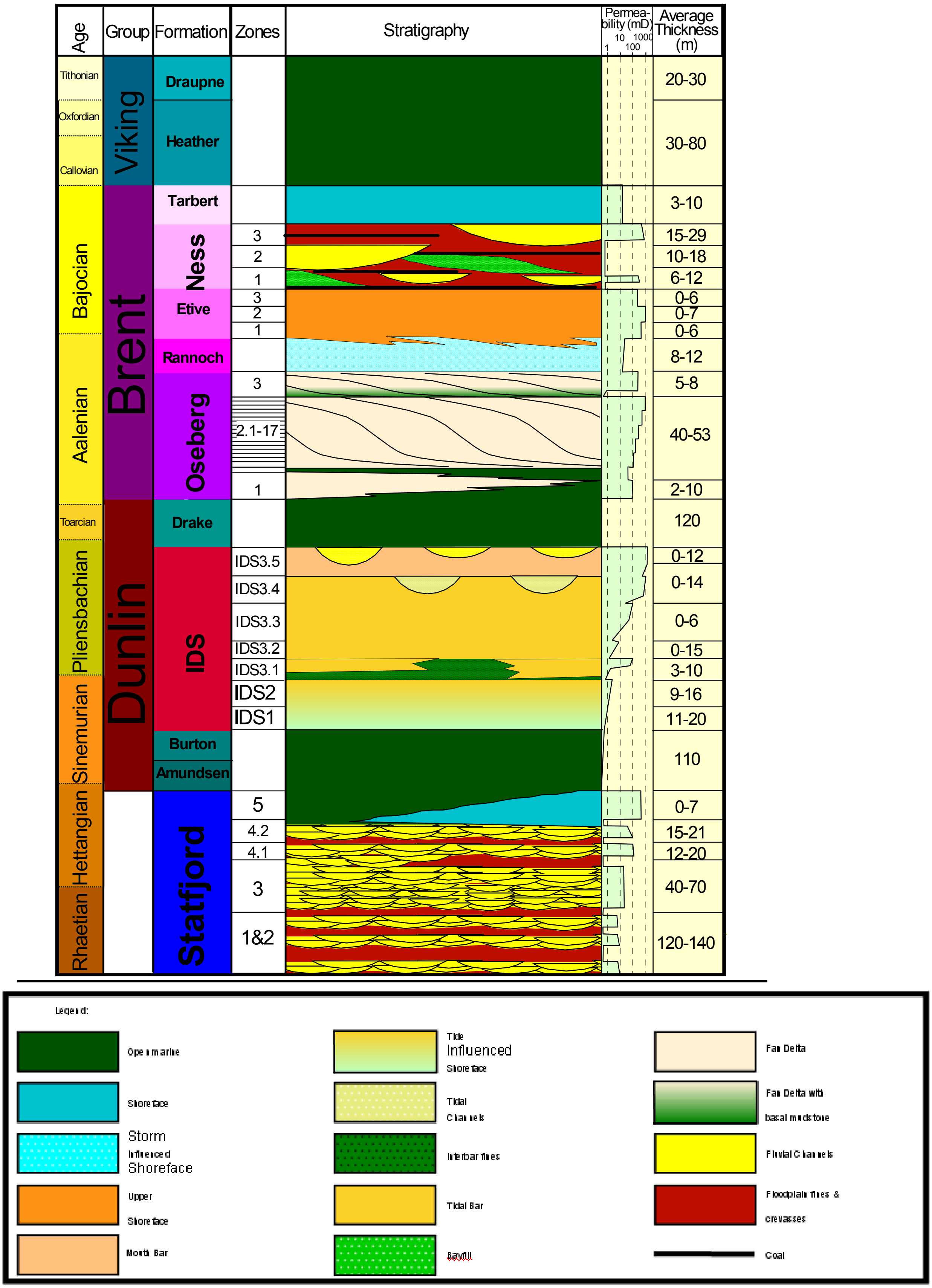


Figure 5 Veslefrikk stratigraphy

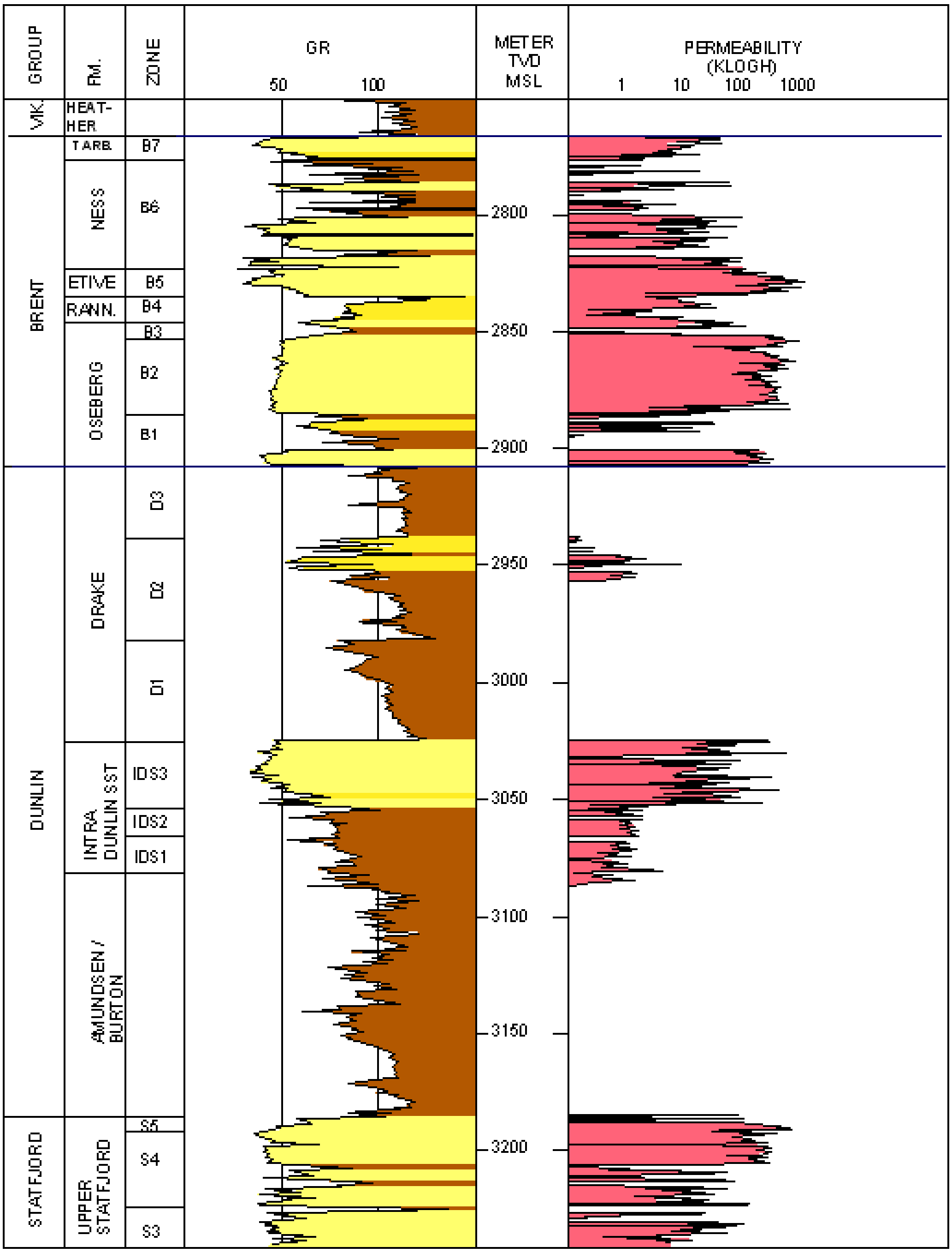


Figure 6 Type log for the Jurassic sequence on the Veslefrikk field

3.3.9 *Veslefrikk reservoir parameters*

Table 1 Veslefrikk Reservoir Parameters

		A-, B-, D-segments			**G-segment**	**I-segment**
		Brent	**IDS**	**Statfjord**	**Brent**	**Brent**
Oil zone						
P_{init}, @datum depth	bar	321.2	346.8	354.9	321.2	329.9
P_{bp}, boiling point pressure	bar	187.5	199.0	354.5	176.5	316.0
Oil density at standard cond.	kg/m³	824	814	830	834	822
Gas density at standard cond.	kg/m³	1.0188	1.0388	1.009	1.15	0.97
Oil gradient	bar/m	0.0663	0.0676	0.051	0.0642	0.06
GOR	Sm³/Sm³	118	134	380	112	290
Volume factor B_o at P_{bp}	Rm³/Sm³	1.463	1.506	2.24	1.454	
Volume factor B_o at P_{init}	Rm³/Sm³	1.417	1.45	2.24	1.406	
Viscosity	cp	0.312	0.305	0.17	0.338	
Oil density at P_{bp}	kg/m³	652	628	508	654	
Oil-water contact	TVD MSL	2906	3064/3079	3208	several	
Gas zone						
Pv, dew point pressure	bar			354.5		315.5
Gas density at standard cond.	kg/m³			1.009		0.94
Gas gradient	bar/m			0.038		0.034
Gas condensate ratio	Sm³/Sm³			985		1150
Volume factor, B_g	Rm³/Sm³			0.0047		0.0046
Max liquid dropout (at 210 bar)				0.3		
Gas-oil contact	TVD MSL			3191		
Water zone						
Volume factor B_w	Rm³/Sm³	1.041	1.047	1.051	1.041	1.051
Viscosity	mPa*s	0.25	0.242	0.26	0.25	0.26
Compressibility C_w	1/bar	$4.5\ 10^{-5}$	$4.6\ 10^{-5}$	$3.4\ 10^{-5}$	$4.5\ 10^{-5}$	$3.4\ 10^{-5}$
NaCl	eq. Ppm	19800	29495	43727	19800	
Density at standard cond.	kg/m³	1001	1001	1000	1001	1027
Gradient	bar/m	0.095	0.101	0.0974	0.095	0.101
Rock						
Compressibility C_f	1/bar	$3.9\ 10^{-5}$	$6.0\ 10^{-5}$	$5.7\ 10^{-5}$	$3.9\ 10^{-5}$	$5.7\ 10^{-5}$
Reservoir temperature						
Initial	^{0}C	118	127	133		

Table 2 Veslefrikk PVT data

Brent				IDS				G-segment (Brent)			
Pres.	Bo	Rs	Visc.	Pres.	Bo	Rs	Visc.	Pres.	Bo	Rs	Visc.
bar		Sm^3/Sm^3	mPa*s	bar		Sm^3/Sm^3	mPa*s	bar		Sm^3/Sm^3	mPa*s
359.5	1.4076		0.390	376.3	1.4406		0.328	352.5	1.3969		0.418
334.3	1.4138		0.376	331.5	1.4544		0.341	303.7	1.4114		0.396
305.8	1.4217		0.361	286.2	1.4701		0.332	276.8	1.4194		0.382
208.1	1.4295		0.349	245.2	1.4865		0.313	250.9	1.4274		0.376
255.5	1.4383		0.340	217.0	1.4990		0.309	226.3	1.4363		0.365
230.3	1.4462		0.330	199.0	1.5064	134.10	0.305	201.3	1.4442		0.345
205.7	1.4558		0.322	181.4	1.4582	117.86	0.336	183.7	1.4513		0.342
187.5	1.4628	118.16	0.312	151.5	1.3846	93.75	0.390	176.5	1.4540	112.40	0.338
167.5	1.4225	103.63	0.335	121.5	1.3203	72.19	0.452	162.4	1.4247	102.64	0.351
141.6	1.3770	86.65	0.368	91.5	1.2611	51.97	0.518	137.0	1.3759	85.70	0.390
111.7	1.3219	66.95	0.419	61.5	1.2028	32.77	0.584	107.0	1.3200	66.80	0.438
81.7	1.2720	48.30	0.479	31.5	1.1385	12.81	0.684	72.1	1.2606	45.95	0.525
56.5	1.2273	32.90	0.542					37.1	1.1950	25.11	0.735
32.4	1.1818	17.58	0.622					12.4	1.1240	6.57	

Table 3 Average endpoints for the formations

Formation	Sw_initial	Sorw	Sorg
Ness 2	0.228	0.208	
Etive 1& 3	0.178	0.161	
Etive 2	0.146	0.162	
Oseberg 2	0.208	0.159	
IDS 3.5 & 3.4	0.201	0.160	
Statfjord	0.200	0.200	0.100

4 Theory of water based tertiary EOR methods

This chapter represents a screening performed on the usefulness of different water based enhanced oil recovery (EOR) methods on the Veslefrikk field. Each EOR method has a range of requirements/specifications to be met to be advantageous on a field. Based on this an evaluation is made whether the method should be investigated further for the Veslefrikk field or not.
A literature study is made for the methods which are considered to have a possible potential.

4.1 General theory on EOR mechanisms and associated reservoir parameters

Waterflooding, using seawater, has been the most frequently applied recovery technique in the North Sea reservoirs. The oil recovery, yielded from waterflooding, is mainly restricted by reservoir heterogeneity, well siting/spacing and unfavourable mobility ratio between displacing (water) and displaced (oil) fluids [5].

Enhanced oil recovery (EOR) is defined as oil recovery by the injection of materials not normally present in the reservoir. Further, EOR is not restricted to a particular phase like primary, secondary or tertiary recovery. Primary oil recovery is based on natural drive mechanisms, solution gas, water influx, gas cap drive or gravity drainage. Secondary recovery is defined as techniques whose main purpose are to maintain reservoir pressure, such as gas or water injection. Tertiary recovery is any technique applied after secondary recovery [6].

As water- and gas injection have been used as the secondary oil recovery techniques on the Veslefrikk field up to this stage, the enhanced oil recovery techniques looked out for are per. definition tertiary recovery techniques. As stated in the introduction chapter, waterflooding has been quite efficient on the Veslefrikk field as a low residual oil saturation, Sorw, is logged in wells with well flooded zones, see Table 3. Still, calculating on remaining oil volumes, it is revealed that more effort should be put into accelerating the oil production and increasing the total oil volume produced within the life time of the field. This is the main background for the choice of topic for this master thesis.

The main objective of all methods of EOR is to increase the volumetric (macroscopic) sweep efficiency and/or to enhance the displacement (microscopic) efficiency, compared to an ordinary (conventional) waterflooding. One way to increase the volumetric sweep is to reduce the mobility ratio between the displacing and displaced fluids and thereby lower the tendency to fingering effects and consequently early break through of displacing fluid in producing wells. The amount of oil trapped due to the capillary forces (microscopic entrapment), can be reduced by reducing the interfacial tension between the displacing and displaced fluids [5].

The waterflooding performance is strongly dependent on the wettability properties of the rock.
In strongly water-wet formations waterflooding is more efficient than in strongly oil-wet porous media [5]. Figure 7 shows that a higher degree of displacement is obtained for the strongly water-wet rock.

Many experts today believe, however, that most oil reservoirs have some mixed-wetting characteristics. The original, water-wet condition is altered to some extent by oil migration [7].

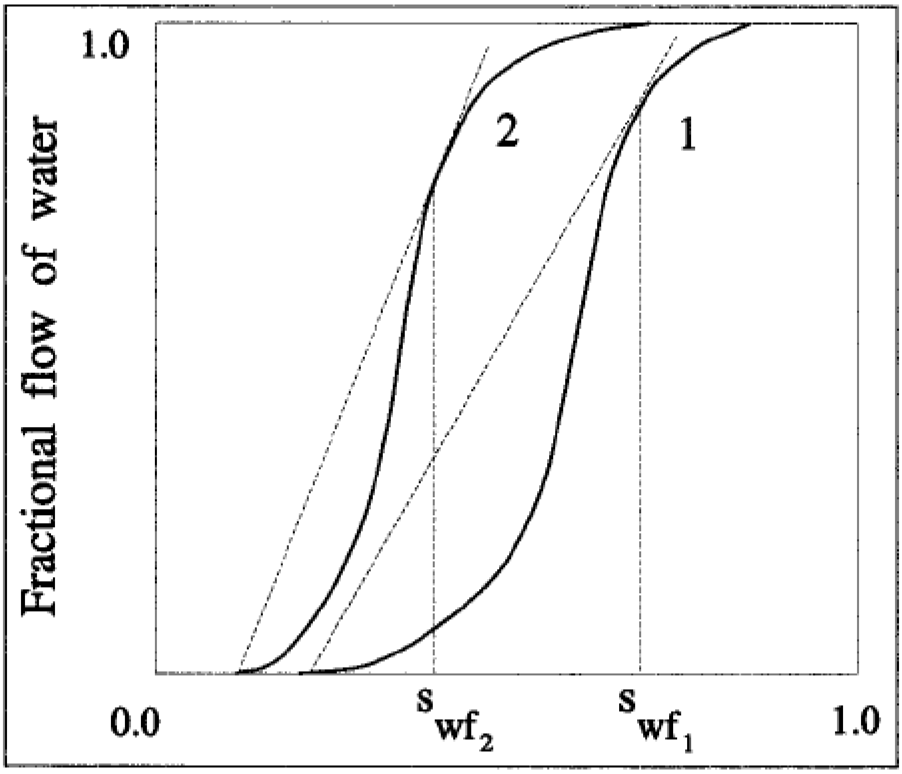


Figure 7 Fractional flow curves for strongly water-wet (1) and strongly oil-wet (2) rock [5]

The wettability of a solid can be defined as the tendency of one fluid to spread on, or adhere to, the solid's surface in the presence of another immiscible fluid. Wettability influences on waterflooding, relative permeability, capillary pressure, irreducible oil saturation (Sor) and initial water saturation (Swi).

The wettability of a reservoir rock can be estimated quantitatively by measuring the contact angle between the interfacial tension of the liquid/liquid interface and the solid's surface. The value of the wetting angle (θ) reflects, to some extent, the "strength" of the solid's wettability by a particular fluid [5].

Contact angle values	Wettability preference
0 – 30	Strongly water wet
30 – 90	Preferentially water wet
90	Neutral wettability
90 – 150	Preferentially oil wet
150 – 180	Strongly oil wet

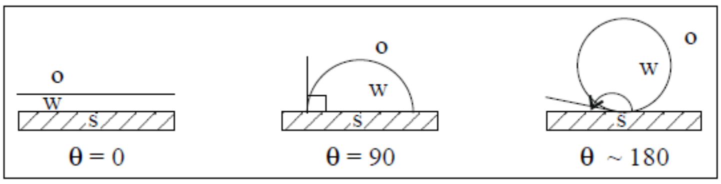


Figure 8 Wettability preference expressed by contact angle [5]

There are three types of interfacial tension/surface tension, between oil and solid σ_{os}, between water and solid σ_{ws} and between oil and water $\sigma_{ow,}$ to be considered in a reservoir system of two immiscible fluids. The relationship between the interfacial tensions and the wetting/contact angle is as follows:

$$\sigma os - \sigma ws = \sigma ow \bullet \cos\theta \qquad (1)$$

The capillary pressure (Pc) is defined as the molecular pressure difference across the interface of the two fluids, or the molecular pressure difference between the non-wetting and the wetting fluid. On a macroscopic level a definition of the capillary pressure is given as follows (Young's Equation):

$$Pc = po - pw \qquad (2)$$

where po and pw are the internal pressures of the two liquids.

Figure 9 shows how the capillary pressure changes as a function of primary drainage by non-wetting fluid, imbibition by wetting fluid and secondary drainage by non-wetting fluid. The Swc (initial water saturation) and Snc are the residual saturations of wetting and non-wetting fluid. Pcb is the threshold capillary pressure [5].

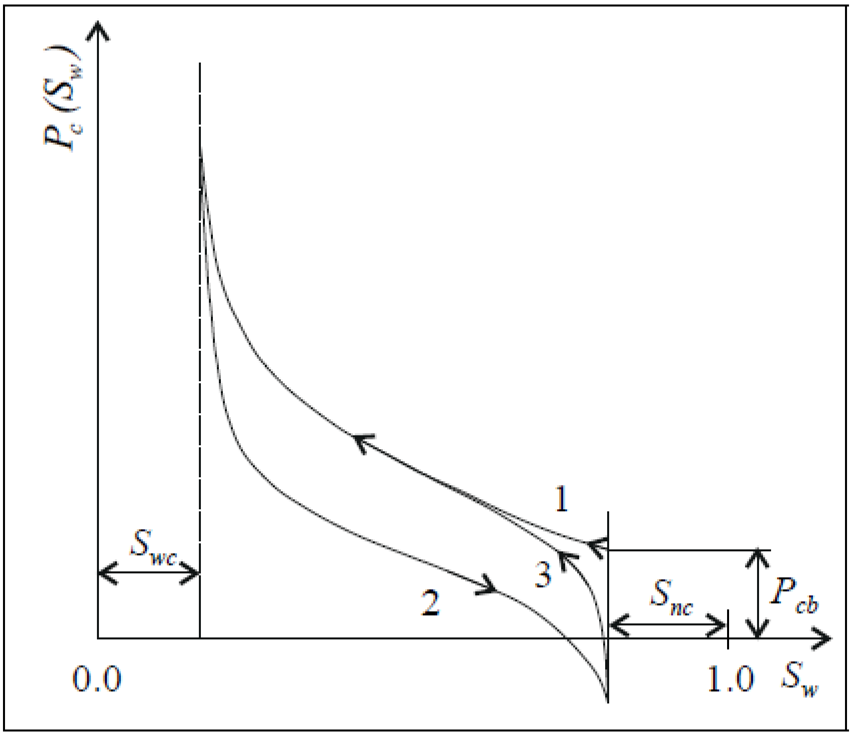


Figure 9 Typically capillary pressure curve for a two-phase flow problem, for the mobile fluid volume: (1) drainage, (2) imbibition and (3) secondary drainage [5]

On a microscopic, pore – level the following relationship is valid:

$$Pc = \frac{2\sigma \bullet \cos\theta}{r} \qquad (3)$$

where r is the radius of the pore throat.

A low σ and/or a θ close to 90^0 gives the lowest capillary pressure. A high capillary pressure result in more oil drops being captured in the pores during waterflooding (for a water-wet system). To make oil flow again, the viscous forces need to be increased to overcome the capillary pressure. For oil-wet systems which are preferentially mixed-wet, capillarity is the mechanism that retains the oil in the matrix and water uptake by capillary forces is limited.

The capillary number Nc is a measure for a ratio between viscous and capillary forces that is acting on the interface between oil and water:

Error! Objects cannot be created from editing field codes. (4)

where μ is the viscosity of - and v is the velocity of the displacing fluid.

A high capillary number reflects that viscous forces are dominating and results in high oil recovery. This may be obtained by either increasing the viscosity of the displacing fluid by e.g. the use of polymers in the injection water or by e.g. lowering the interfacial tension by the use of surfactants in the injection water.

Total permeability, K, is the mediums capability to transmit fluids through its network of interconnected pores [5]. When several fluid phases are present the effective permeability for each fluid phase needs to be defined as the fraction of the total permeability depending on the saturation of that fluid. The relative permeability is then defined as:

$$kr = \frac{keff}{K} \qquad (5)$$

Figure 10 and Figure 11 describe how analysis of relative permeability curves in the laboratory can be used as an indicator of rock wettability.

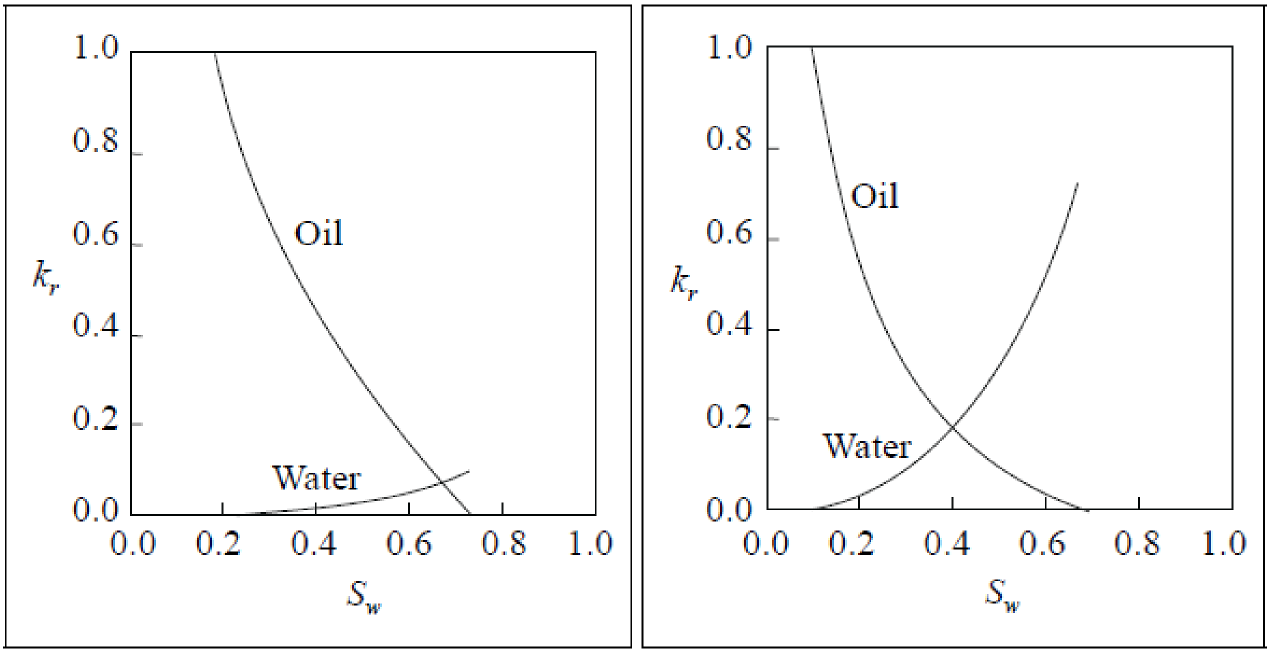


Figure 10 Typical water-oil relative permeabilities for strongly water-wet (left) and oil-wet (right) formations, for a two-phase oil/water system [5].

	Water-wet	Oil-wet
Connate water saturation	Usually greater than 20 to 25 percent PV	Generally less than 15 percent PV, frequently less than 10 percent
Saturation at which oil and water permeabilities are equal (crossover saturation)	Greater than 50 percent water saturation	Less than 50 percent water saturation
Relative permeabilities to water at maximum water saturation; i.e. flood-out	Generally less than 30 percent	Greater than 50 percent and approaching 100 percent

Figure 11 "Rule of thumb" indication of wettability preferences based on observed flow properties [5]

In the literature, wettability is usually characterized by the shape and saturation end-points of the imbibition curves obtained in the laboratory experiments. From Figure 12 the red dashed lines represent the imbibition curve for typical water-wet and mixed wet conditions. For the water wet case, the spontaneous imbibition of water (Pc>0) result in a high water saturation and consequently a low residual oil saturation, while for the mixed wet case spontaneous imbibition of water leads to a much lower water saturation and a higher residual oil saturation. For the forced imbibition (injection/flooding by water and Pc<0) a minor reduction in residual oil saturation is obtained for the water-wet case while for the mixed-wet case a much bigger reduction in residual oil saturation is obtained.

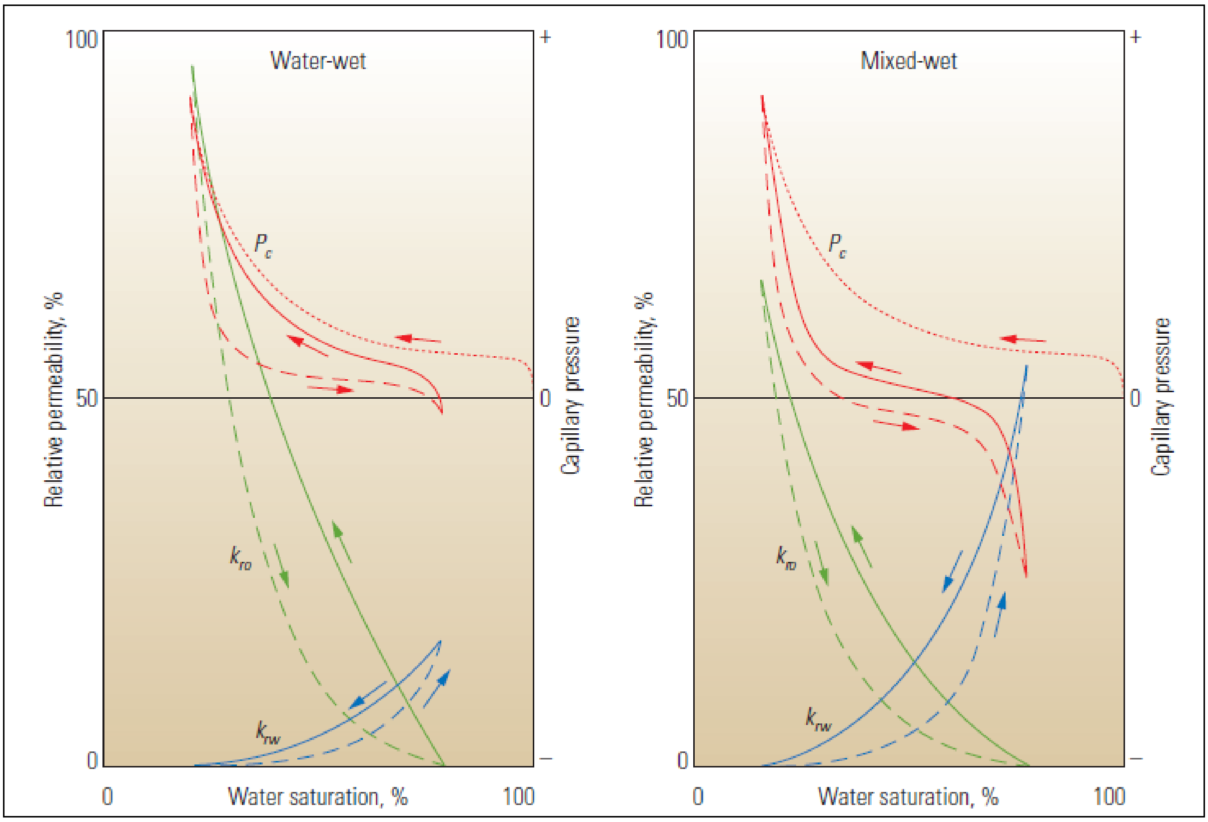


Figure 12 Typically capillary pressure and relative permeability curves for two-phase flow through a uniformly water-wet and mixed-wet medium [7].

Mobility ratio, M, is defined as follows:

$$M = \frac{\frac{krw}{\mu w}}{\frac{kro}{\mu o}} = \frac{krw \bullet \mu o}{kro \bullet \mu w} \qquad (6)$$

the ratio between the displacing fluid rel.perm/viscocity and the displaced fluid rel.perm/viscocity.

The Figure 13 and Figure 14 shows that the frontal water saturation is lower in case of a higher mobility ratio and that the residual oil saturation is usually higher for heavy (high viscosity) oils. An EOR may be obtained if the water viscosity is increased as when adding polymers to the injection water.

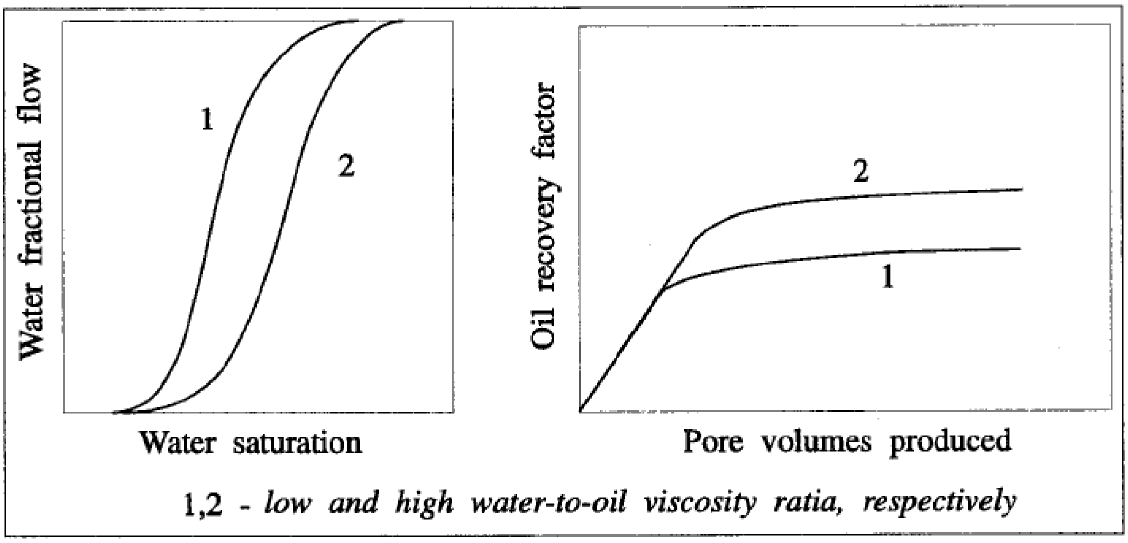


Figure 13 Influence of mobility ratio on waterflooding performance [5]

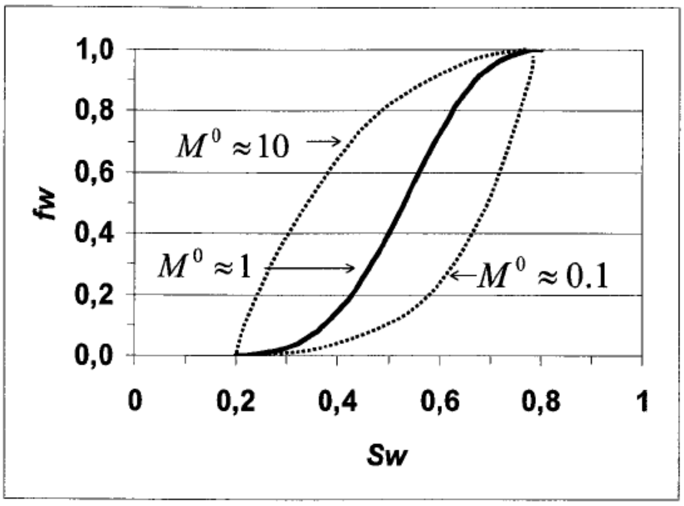


Figure 14 The effect of endpoint mobility ratio, M^0, on the water fractional flow curve, fw [8]

Gravity drainage is an important mechanism in water- or gas- flooding. The water fractional flow curve has lower values for updip water injection (injector located at a lower level than the producer) as compared to downdip displacement, which means that updip displacement of oil by water is more preferable than downdip, see Figure 15 and Figure 16 [5].

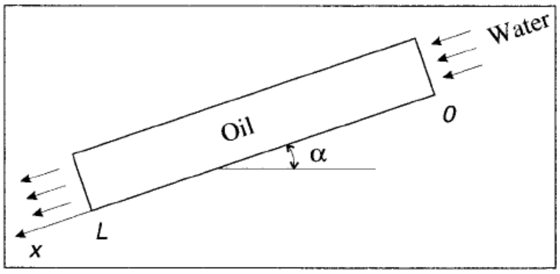


Figure 15 Schematic view of a dipping reservoir, downdip water injection [5]

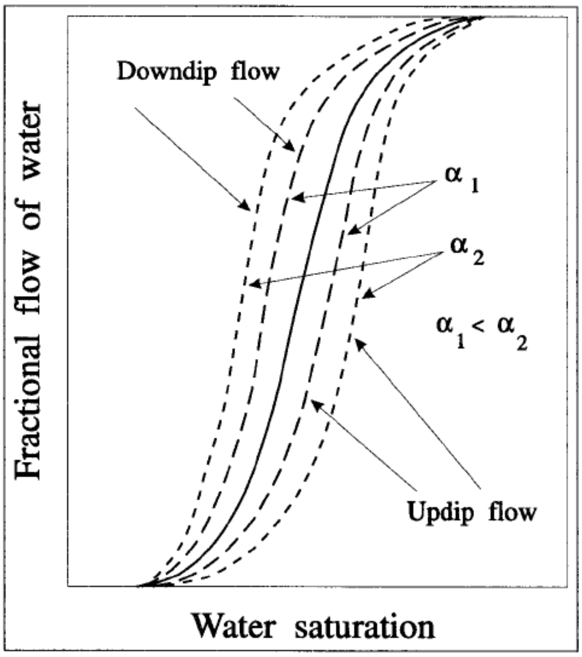


Figure 16 Effect of formation dip on fractional flow curve, α :dip inclination [5]

4.2 Evaluated water based EOR methods

The methods listed below have been evaluated for the Veslefrikk field.

- MEOR (Microbial Enhanced Oil Recovery)
- Bright water
- LPS (Linked Polymer System)
- Polymer/Surfactants
- Low Salinity Water
- Sodium Silicate

Table 4 gives an overview of the method's main EOR mechanism(s).

Table 4 Characterization of the evaluated water-based EOR methods

EOR method	Microscopic sweep; Mobilization of residual/remaining oil in flooded zones	Macroscopic sweep; Target oil in unswept or poorly swept areas
MEOR	**x**	**(x)**
Bright Water™		**x**
LPS		**x**
Polymer-Surfactants	**x**	
Low Salinity water	**x**	**(x)**
Sodium Silicate	**(x)**	**x**

4.3 MEOR (Microbial Enhanced Oil Recovery)

The ability of oil degrading bacteria to mobilise oil may be used to increase oil recovery. In this process, oxygen and/or nutrients (phosphate and nitrate) are injected into the reservoir in order to stimulate growth of aerobic/anaerobic oil degrading bacteria in the reservoir. SRB (Sulphate Reducing Bacteria) will also give enhanced oil recovery.
The method implies bacteria growth at the interface between injected water and oil. The bacteria generate soap as they grow and create their biofilm which reduce the interfacial tension between oil and water. Depending on the efficiency of this process the interfacial tension might be reduced to an extent resulting in immobile oil becoming mobile; the microscopic sweep is increased.
An increase in volumetric sweep is also expected as an accumulation of biomass might result in diversion of flow.
The method should generally be evaluated used on fields where water injection is the main recovery mechanism. The EOR potential could be large on new fields.
Another advantage of MEOR may be a positive effect in reducing reservoir souring. A field pilot test has been conducted on the Gullfaks field in a reservoir segment with low oil saturation. No MEOR effect was obtained. The most probable interpretation of the test result is that the oil volume that could be mobilized as a result of bacteria growth was already mobilized due to the activity of the SRB. It is also possible that the old established biofilm from SRB activity prevented any formation of a new biofilm. On Veslefrikk injection of seawater have been conducted almost for the entire life time of the field. The Veslefrikk field should thus not be the priority area for testing of the MEOR method [9].

4.4 Bright water™

The method is based on flow diversion by swelling and agglomeration of micro-gel particles in the injection water. The injected particles are activated by temperature. The chemicals are regarded as "red" with respect to HSE (Health Safety and Environment) and thus it should not be used on fields where produced water is not re-injected, as is the case on the Veslefrikk field.

The following points should be considered when evaluating a potential candidate for Bright Water™, preferred target properties [10]:

- Available movable reserves
- Early water break through to high water-cut
- Problem with high permeability contrast (thief zone at least 5 times unswept zone)
- Porosity of highest permeability zone >17%
- Permeability of thief zone >100 md
- Minimal reservoir fracturing
- Temperature from 50 to 150 ºC
- Expected injector-producer transit time >30 days
- Injection water salinity under 70000 ppm

In water injection projects excess water production is often linked to poor sweep efficiency, which renders significant amounts of oil irrecoverable during the economic life of a field. Poor sweep efficiency can be the result of zones with unfavourable permeability in heterogeneous reservoirs or unfavourable mobility ratio within homogeneous rock. Specifically water can break through from the water injection wells to the production wells in the most permeable zones("thief zones", see Figure 17) while significant oil is left in the reservoir, or it can pass through low mobility oil by a process of viscous fingering [10].

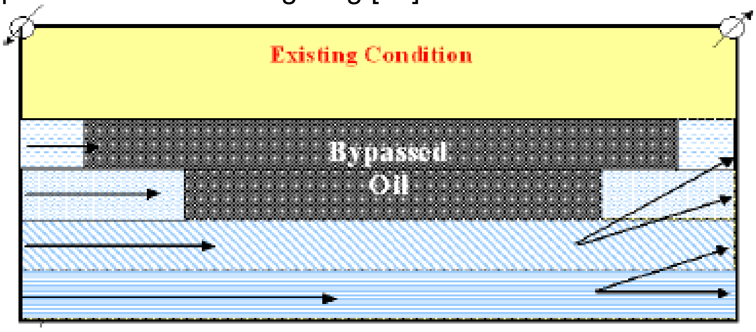


Figure 17 Thief zone in an oil reservoir [10]

The aim of the Bright Water™ method is to reduce the permeability of thief zones deep within the oil reservoir to achieve more efficient displacement of the oil to the producing wells. In the development of the Bright Water™ technology an essential feature was seen as having only one injected component so that no separation could occur. Also the density should be close to that of an injection brine to minimize segregation. Figure 18 illustrates conceptually how incremental oil could result from the Bright Water™ system [10].

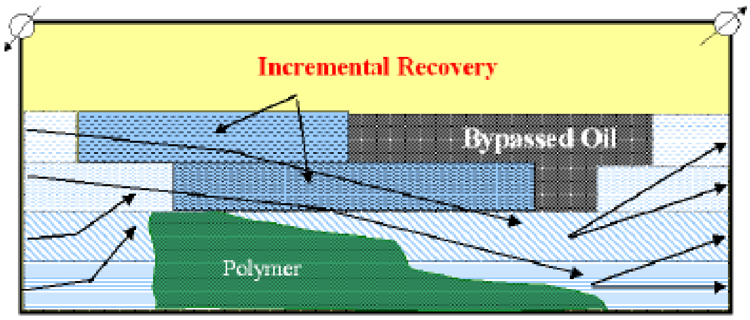


Figure 18 Thief zone plugged with Bright Water treatment [10]

The Bright Water™ concept was that of a particle which could inject and propagate with the water flood through the pores of the rock matrix, then after a temperature change in the thief zone or after a certain time, would increase in volume (popping) to block pore throats, diverting chase water into poorly swept zones. To maintain injectivity it was important that the injected viscosity of the system should be as near as possible to that of water. Once popped, interactions with pore throats were intended to be the means of delivering water resistance factor.

Rock thermal properties together with the water injection and reservoir temperatures determine the conditions under which the particles must propagate and trigger. The diameters and rheological properties of the particles before popping must be compatible with the pore throat size distribution of the target rock. Studies suggested that the mean particle diameter should be less than one tenth of the mean pore throat size and physical properties, such as density, should be likely to ensure that they were carried effectively with the water flow. After “popping”, the “popcorn” particles were predicted to need a mean diameter on the order of, or greater than, one quarter of the mean pore throat diameter. Both these conditions are particle-concentration dependent. At a lower concentration of injected particles, particle sizes closer to the pore throat size would become injectable. An illustration of the “popping” mechanism is given in Figure 19 [10].

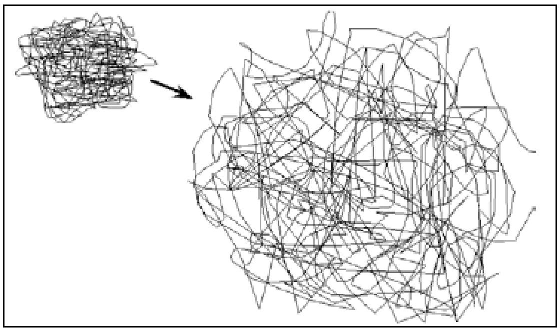


Figure 19 Illustration on particle expansion [10]

4.5 LPS (Linked Polymer System)

The LPS method is based on flow diversion at the pore scale by micro-gels and improved volumetric sweep due to improved mobility ratio.

The method could not be used on the Veslefrikk field due to limited temperature area of application of maximum 80 deg.C. In addition the chemicals are classified as “red” and thus not allowed to be used in the injection water on fields where there is no re-injection of produced water, as on Veslefrikk. An illustrated principle of the LPS method on the pore scale is given in Figure 20.

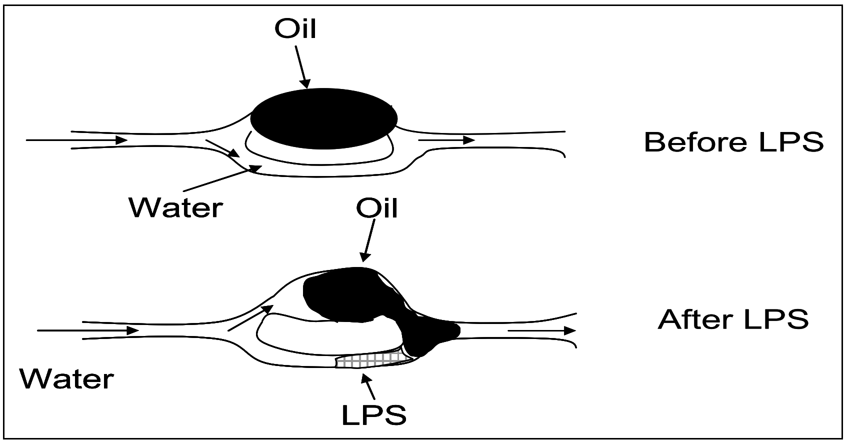


Figure 20 Illustrated principle of LPS method

4.6 Polymer/Surfactants

The polymer/surfactant method is based on improved volumetric sweep efficiency by improved mobility ratio (increased water viscosity), improved microscopic sweep by reduction of the interfacial tension between oil and water and generation of micro-emulsions due to adding surfactant to the polymer/injection water.

The method is not recommended on the Veslefrikk field due to the polymer temperature limitation of maximum 80 deg.C. In addition to this the method is not expected to have any essential potential since a low Sorw is already obtained in well flooded areas in the Veslefrikk reservoir.

4.7 Low salinity oil recovery mechanism

Generally, the mechanisms that lead to increased oil recovery when injecting low salinity water into the reservoir are not completely understood. A lot of work has been done to identify these mechanisms and several hypotheses have been devised.
One simplified explanation on why injection of low salinity water leads to increased oil recovery is that the low salinity water appears to induce chemical changes that break down the bonds that cause oil to adhere to the underground rock. The change to a more water-wet character reduces the residual oil saturation and releases oil captured in the pore system under initial oil-wet conditions.

Also a flow diversion is expected by mobilization of clay particles. Mobilized fine particles can partly or completely block the exit from the small pore, which forces the water into the larger pore. If the viscous pressure drop is sufficient to overcome the capillary forces this oil is mobilized.
The main advantage of low salinity water compared to other water-based recovery methods is the relatively high EOR potential (big uncertainties). Benefits also include less reservoir souring and less environmental restrictions.

EOR depends on complex COBR (Crude Oil Brine Rock) interactions. Basic screening criteria for EOR effect on a field, using low salinity injection brine, have been collected from the literature study. Based on this an evaluation is made for the Veslefrikk field and the result is included in Table 5.

Based on the data evaluated the EOR potential by utilizing low salinity injection water does not seem to be high on the Veslefrikk field. Based on learning from literature study on the topic the EOR potential by using this method increases for a strongly oil wet formation and/or a high salinity formation brine. For the Statfjord formation gas injection is regarded as the best recovery method based on the expected Sorg and Sorw, see Table 3. WAG is however a possibility but a high content of Barium in the formation brine would favour the use of low salinity water to prevent Barium-Sulphate ($BaSO_4$) scale deposition in the reservoir.
The low EOR potential combined with such challenges/cost related to availability/production of low salinity water indicates that the Veslefrikk field should not be the primary field for testing of the method.

Table 5 IOR potential by injecting low salinity water on the Veslefrikk field?

Key factors	Optimum	Veslefrikk reservoir characteristics:
Brine, salinity contrast between formation water and injection water, ppm TDS (Total Dissolved Solids). Ionic type, valence and concentration.	High salinity of formation water 30000-40000 ppm TDS or more, low salinity injection water 500-3000 ppm TDS. Formation water: high content of divalent cations (Ca^{2+}, Mg^{2+}) Low salinity injection water: low content of divalent cations.	Formation brine: Brent: 23200 ppm TDS IDS: 36417 ppm TDS Statfjord: 43727 ppm, equivalent NaCl. (Generally, need formation water analysis)
Rock, clay type and content (%) [10+several], Figure 26. CEC (Cation Exchange Capacity) of clay / Net negative charge of clay, zeta potential	Kaolinite, IOR increases with increasing % of clay. Medium? (too high CEC/net negative charge of clay may result in formation damage, a high pH strengthen this effect) Chlorite has a positive zeta potential and is not optimum in this perspective.	Brent: 4-14 % Kaolinite, 0-2% Chlorite IDS: Chlorite Statfjord: mainly Kaolinite
Crude Oil, content of polar organic compounds	High?	Analysis from 3 wells concerning asphalthenes: A-18: 1,8 wt%, A-10B: 1,5 wt% and A-15: 1,3 wt%
Swi	< 10-15 %	Ness 2: 22,8%, Etive 2: 14,6%, Oseberg: 20,8%, Statfjord:20%
Krw & Kro curves, Sw crossing point	< 50 %	Brent: <50% (mixed wet / oil wet) Statfjord>50% (water wet?)
Sorw after conventional high salinity water flood	High	Ness 2: 20,8%, Etive: 16,2%, Oseberg: 15,9%, IDS: 16%, Statfjord: 20% (Sorg=10%)

BP (British Petroleum) research results show that, by choosing the right brine for the right reservoir, oil recovery by waterflooding can be increased by up to 40% in some cases, see Figure 21. The average benefit represent 14% increase in oil recovery [12].

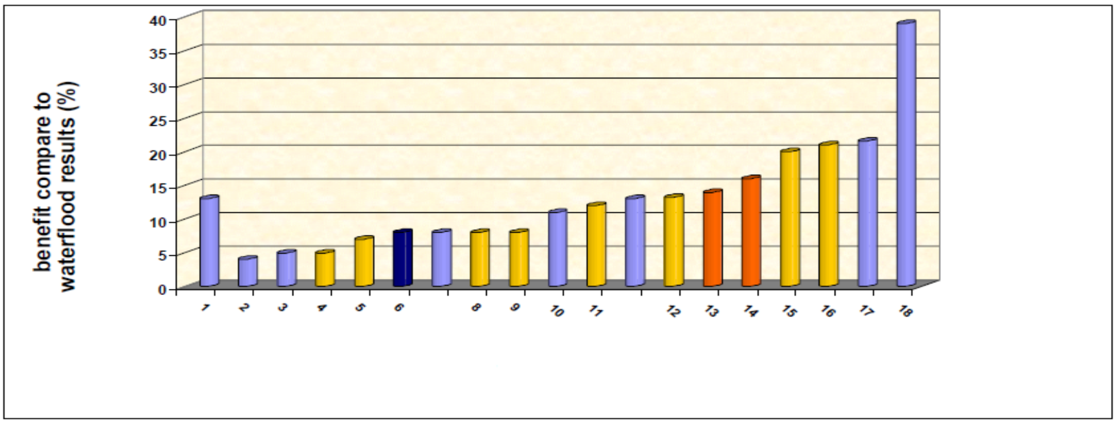


Figure 21 Summary of oil salinity recovery benefits for various fields [12]

Several laboratory experiences exist but only a few field tests (well-log-injection tests[13], single well chemical tracer tests[14] [11], inter-well field data). Single well chemical tracer tests (SWCT) have been used on the Endicott field to measure Sor before and after EOR treatment. The Sor has been measured both after secondary and tertiary LoSal^{TM} EOR flood. The drop in residual oil saturation after LoSal^{TM} injection varies as a function of Kaolinite clay fraction [11], see Figure 26. The results from the tests as given in Figure 22.

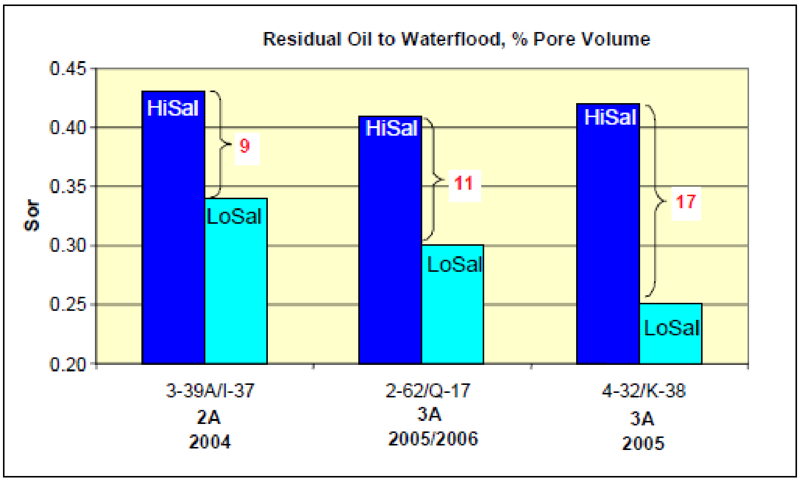


Figure 22 Single Well Tracer Test Results [11]

In early 2008 an expanded field test (inter-well test) of injecting low salinity brine was started on the Endicott field, Alaska [15], where 3 wells would be involved. The Endicott field has a high quality reservoir that is well along in its producing life but still has potential resources in the ground. The main reasons for the operator BP of choosing this field for the test are:

- 45% of the hydrocarbon fluids would be left in the rock under the production technologies now used (aim is to increase oil recovery to 75-80%)
- 20 years of production information available
- the results can be accurately measured and verified

A further description of the test is given in [11] but results are not published yet.

The several hypotheses devised to explain the increase in oil production associated with low salinity water injection can be listed as follows:

-Tang and Morrow: fines migration (mainly Kaolinite); clay particles detach from the pore surface; exposure of underlying surfaces and thereby increased water-wetness of the system. If high-salinity brine is used clays are undisturbed and retain their oil-wet nature leading to poorer displacement efficiency [16], see Figure 23, Figure 24 and Figure 25.
-Lever and Dave: fines migrate with flowing fluid and get captured at pore throats/ pore constrictions causing formation damage [17].
-Tang and Morrow: the detachment of mixed-wet clay particles from pores, mobilized previously retained oil droplets attached to these clays allowing an increase in oil recovery. Also a reduction in permeability when the injection brine salinity was less than 1550 ppm TDS [16].
-Valdya and Fogler: showed that the release process is primed by a combination of extremely low-salinity and high pH.>9. At pH>11 a rapid and drastic decrease in the permeability was observed implying that severe damage was caused on contact with the high-pH fluid and the absence of salts in the solution [17].
-The DLVO theory of colloids: The permeability reduction occurs if the ionic strength of the injected brine is equal to or less than the critical flocculation concentration (CFC) which is strongly dependent on the relative concentration of divalent cations such as Ca^{2+} and Mg^{2+}[17].

-Basin and Labrid: High CEC (Cation Exchange Capacity) sandstone will lead to a high potential for permeability reduction[17].
-Numerous BP Low salinity reduced condition and full reservoir condition core floods have all shown increased oil recovery, no fines migration or significant permeability reductions have been observed. This question the link between fines migration and oil recovery [17].
-Increasing pH leading to in-situ saponification and interfacial tension reduction, emulsion formation, clay migration and wettability alteration [17].
-The rise in pH is expected to be caused by two concomitant reactions; carbonate dissolution (slow process) and cation exchange (faster process). The dissolution of carbonate results in an excess of OH^- and cation exchange occurs between clay minerals and the invading water. The mineral surface will exchange H^+ present in the liquid phase with cations previously adsorbed which again leads to a decrease in H^+ concentration inside the liquid phase resulting in a pH increase [17].
-Jensen and Radke**:** A pH above 9 would be equivalent to an alkaline waterflood which implies;

- reduction of oil/water interfacial tension (due to increasing pH leads to in-situ saponification)
- wetting alteration of the matrix grains
- formation of water drops inside the oil phase (emulsion)
- draining oil from volume between alkaline water drops, an emulsion containing very little oil

Alkaline water flooding requires an acid number>0,2 (to generate enough surfactant to induce wettability reversal and/or emulsion formation(Ehrlich/Wygal). Conflicting evidence on the alkaline mechanism being the cause of the LoSal effect since the best Low Salinity core flood results obtained to date come from a North Sea reservoir (40% increase in oil recovery) where the crude oil has an acid number < 0,05. Experience shows that the benefit of LoSal could be achieved at a pH below 7. At reservoir conditions CO_2 act as a pH buffer and an increase of pH up to 10 is therefore unlikely. Also proton buffering from oxides present in the reservoir rocks will occur. This might prove that high pH is not responsible for the increase in oil recovery due to injection of LoSal™ water[17].

Multicomponent ionic exchange (MIE) [17]:
- geochemical analysis of the low salinity effluents highlighted the predominant role of the Multicomponent ionic exchange
- extended DLVO theory (Derjaguin, Landau, Verwey and Overbeek theory, see Figure 27) ; organic matter adsorption onto clay minerals in seawater, dominant mechanisms; van der Waals interaction, ligand exchange and cation bridging. Figure 28 illustrates how polar molecules from the oil are attracted to the negatively charged clay surface. Some mechanisms involve divalent cations (calcium and magnesium) that act as bridges between the negatively charged molecules in the oil and the negatively charged clay surface. Due to the change in ion exchange equilibria at low salinity, bound oil becomes mobile and oil recovery increases [11].
- core flooding experiments indicated that high salinity connate brine containing Ca^{2+} and Mg^{2+} resulted in poor recovery. Removing the Ca^{2+} and Mg^{2+} from the rock surface before water flooding led to higher recovery irrespective of salinity.
- During the injection of low salinity brine, MIE will take place, removing organic polar compounds and organo-metallic complexes from the surface and replacing them with uncomplexed cations.
- In theory, the desorption of polar compounds from the clay surface should lead to a more water-wet surface, resulting in an increase in recovery.
- Cation exchange between the mineral surface and the invading brine has been demonstrated to be the primary mechanism underlying the improved waterflood recovery observed with LoSal™ water flooding.
- Low Salinity water injection has no effect on mineral oil as no polar compounds are present to strongly interact with the clay minerals.
- MIE also explains why LoSal™ does not seem to work on carbonate reservoirs [17], but later on it was found that sulphate brines (excess of multivalent anions, i.e. SO_4^{2-}) should give similar EOR effect on carbonate reservoirs [12].

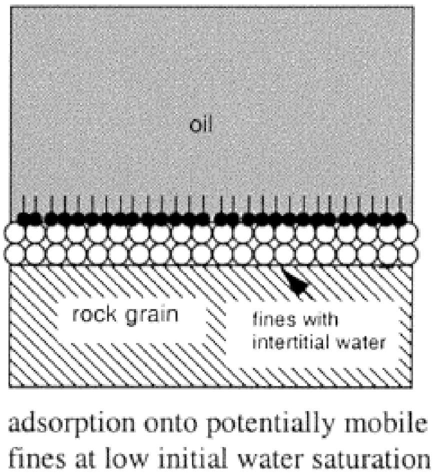


Figure 23 Adsorption of polar components from crude oil to form mixed-wet fines [16]

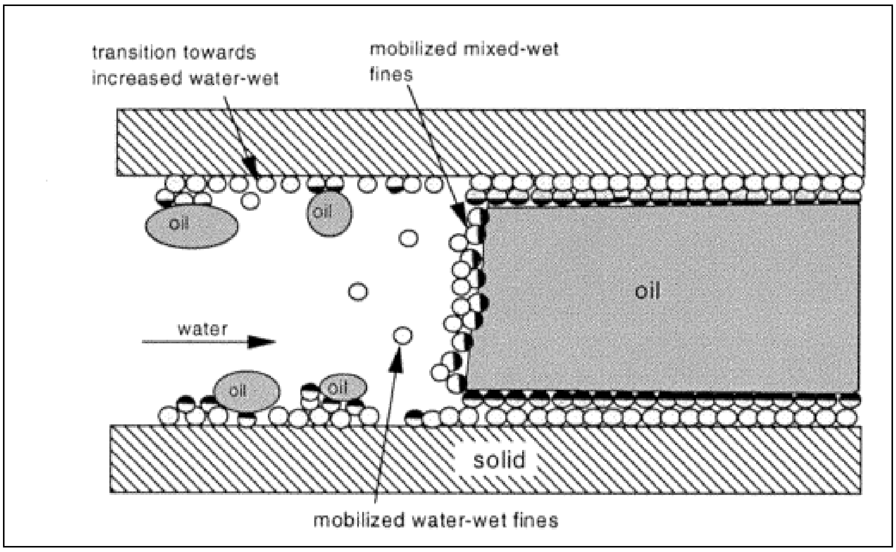


Figure 24 Partial stripping of mixed-wet fines from pore walls during waterflooding [16]

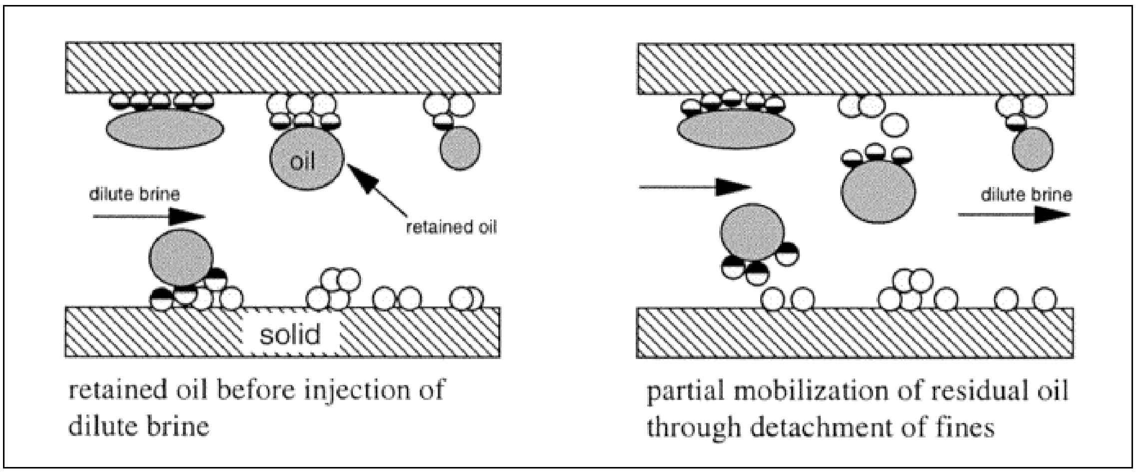


Figure 25 Mobilization of trapped oil [16]

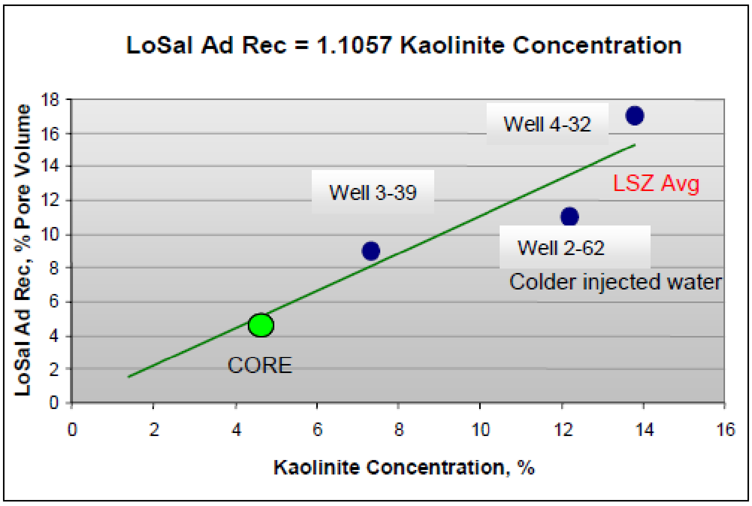


Figure 26 Additional recovery versus % Kaolinite [11]

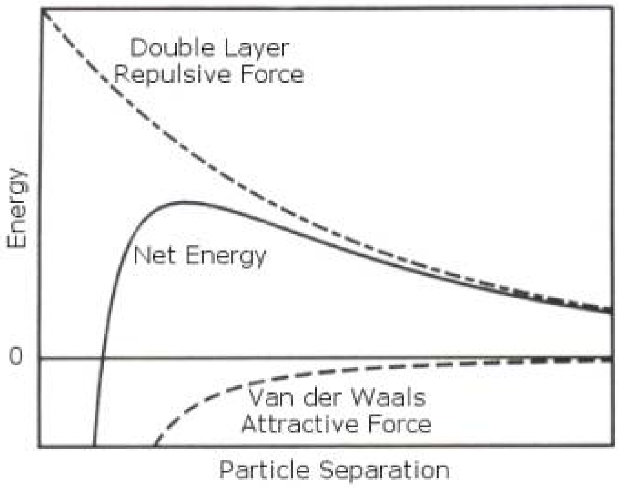


Figure 27: Schematic diagram of the variation of free energy with particle separation according to DLVO theory. The net energy is given by the sum of the double layer repulsion and the van der Waals attractive forces that the particles experience as they approach one another [18].

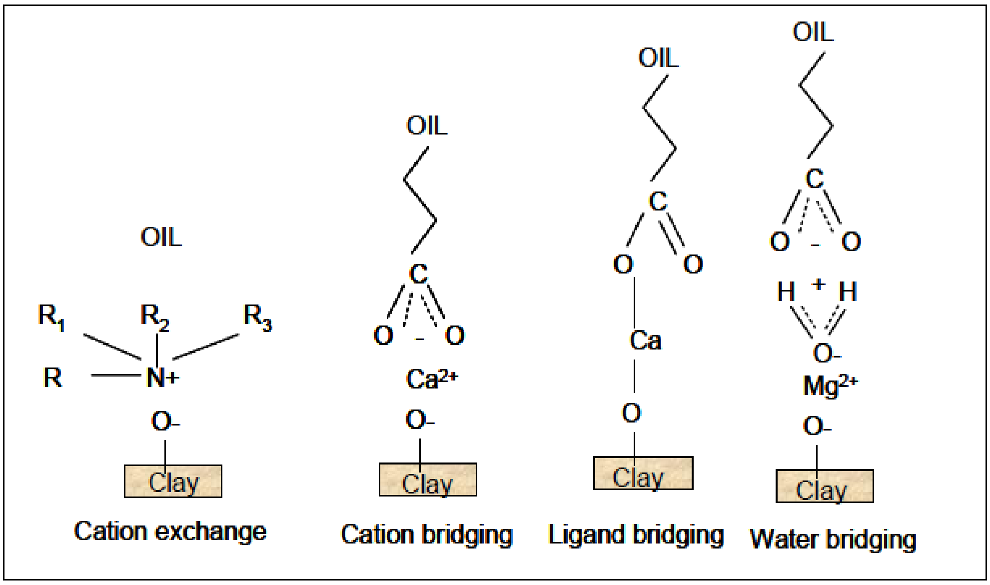


Figure 28 Oil Wettability Mechanism Examples, adhesion mechanisms occurring between clay surface and crude oil [11][12]

4.8 Sodium Silicate

4.8.1 General on mechanism and usefulness on the Veslefrikk field

By injecting water with sodium silicate a reduction of the total permeability is obtained in the water channels. The EOR potential in a heterogeneous reservoir can be realized by plugging off the "waterways", change the sweep pattern of the injection water (improve macroscopic sweep), force the water to flush new areas and thereby reduce the residual oil saturation.
By injection of water, breakthrough usually happens after flooding of less than 50% of the reservoir pore volume. The "primary" flooded area is also a target for diversion of injected water as the residual oil saturation in this area varies between 5-25%.
Until now, sodium silicate has only been used in the near wellbore area to modify injection profile in water injection wells, to shut off water production in oil producers and even to close off leakages in well completions [19][20][21][22][23][24][24]. For the last few years research has been performed on applying sodium silicate as a water diverging method further out in the reservoir.

One illustration on a typical waterflooding pattern and sweep efficiency is given in Figure 29. Improved volumetric sweep depends on the heterogeneity of the reservoir; vertical communication, horizontal permeability, mobility and gravity effects. Figure 30 illustrates how waterflooding may be improved in the upper layer(s) (not same case as in Figure 29) by closing off lower layers with sodium silicate.

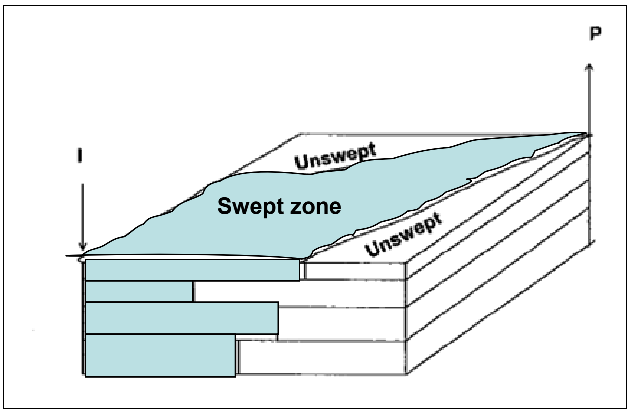


Figure 29 Sweep efficiency schematic [8]

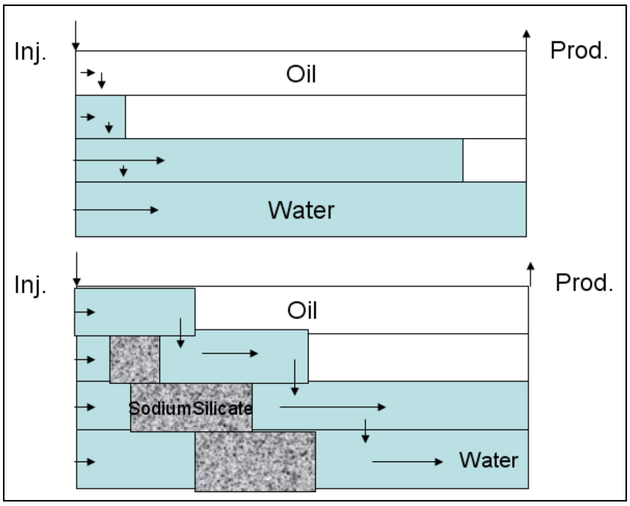


Figure 30 Illustration of possible EOR effect from sodium silicate placement, vertical view.

In addition to EOR due to improved sweep of unflooded areas other advantages are; reduced circulation of water, reduced water production and consequently reduced need of water injection to maintain reservoir pressure, existing wells can be used and the chemicals used are regarded as "green". Also EOR effects like in "alkaline flooding" could occur; formation of emulsion. Interfacial tension may be reduced resulting in reduced residual oil saturation in the flooded area.
The increased pH of the solution may also deactivate sulphate reducing bacteria which can reduce H_2S problems and thereby increase oil production.

Some disadvantages/challenges are; cost of chemicals, logistics and managing the injection of chemicals offshore. Also the EOR potential is dependant on the ability to place the chemicals only in the "thief" zones and establish increased injectivity/injection rate in non-flooded/target zones. Other challenges may be that water is injected above the hydraulic fracture pressure and that this can affect the possibility of altering the sweep direction.

This method is regarded to have a high EOR potential on the Veslefrikk field and is further studied in this master thesis. The background for this is that there exist thief zones where the injection water rapidly flows through and also that saturation logs proves that water flooding is very efficient on the Veslefrikk field. The challenge is the ability to diverge the injection water to un-flooded and/or poorly flooded reservoir areas.

4.8.2 Theory on Silicate method

Colloidal silica refers to stable aqueous dispersions of discrete nonporous particles of amorphous silicon dioxide (SiO_2). Commercially available solutions contain 15 to 40 weight % SiO_2 as spherical particles with diameters ranging from 4 to 200 nm. The stability of the silica concentration increases with increasing particle size. Increasing the number of silica particles in solution decreases gel time. Particle concentration can be increased by either increasing total silica concentration at fixed particle size or by decreasing particle size at fixed silica concentration see Figure 32. The particle surface is composed of silanol (SiOH) groups, which ionize in alkaline solution, see Figure 31. The ionic charge of the particles is the principle mechanism for the stabilization of concentrated commercial solutions [24].

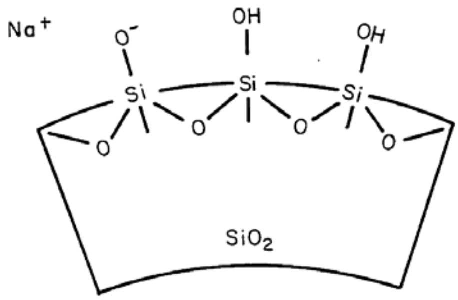


Figure 31 Schematic of Silica Particle Surface [25]

Colloidal silica solutions are stable at moderate pH (9,5 to 10,5) and at silicon dioxide-alkali ratios in excess of 50 (SiO_2:Na_2O).
The gelation of colloidal silica is believed to result from particle collision, bonding and aggregation into long chain networks.
Particle collision is promoted by lowering surface charge (reducing the pH of a stable solution), by charge screening (addition of cations to the solution), by increasing particle concentration or by increasing temperature. Particle bonding is probably a condensation reaction between both neutral and ionized silanol groups to form a siloxane (Si-O-Si) bond. This condensation reaction is

catalyzed by hydroxide ion. Gelation occurs when particle aggregation ultimately forms a uniform, three-dimensional network of long bead-like strings of silica particles [25].
Upon initial gelation, the few siloxane bridges between particles at the points of contact result in weak interparticle bonding and a weak gel. However these bonds are strengthened by dissolution of silica from the particle surfaces and redeposition at the contact points. This curing reaction, which builds gel strength, diminishes asymptotically with time, and the gel finally reaches an ultimate strength [25].

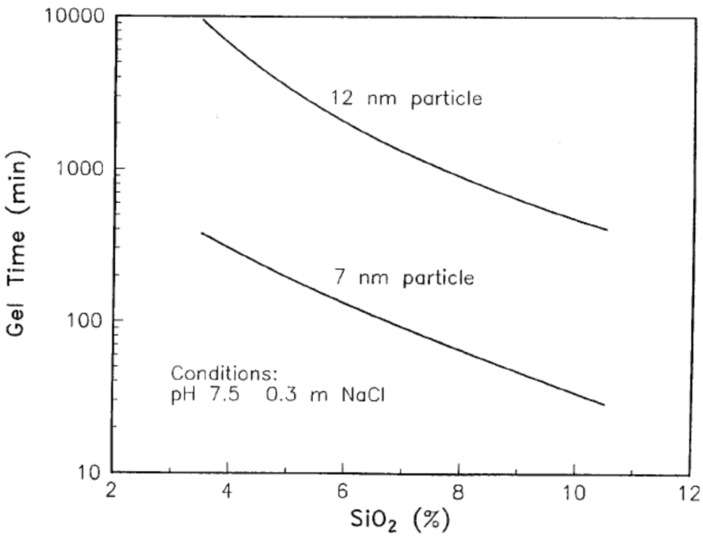


Figure 32 Gel time as a function of particle size and silica concentration [25]

In laboratory, the permeability reduction of colloidal silica gels in both consolidated cores and sandpacks was measured to be greater than 99%. Figure 33 shows gel permeabilities as a function of silica concentration [25].

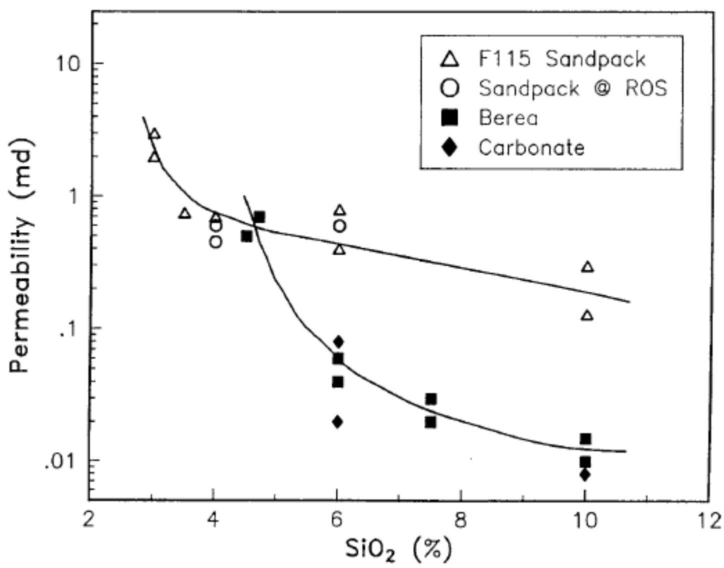


Figure 33 Gel permeability as a function of silica concentration [25]

Gel time for colloidal silica is less sensitive to changes in SiO2 concentration than sodium silicate, but higher SiO_2 concentrations are required for gelation of colloidal silica than for sodium silicate. Also the gel times of colloidal silica solutions are less sensitive to changes in salinity than the sodium silicate system is, see Figure 34.

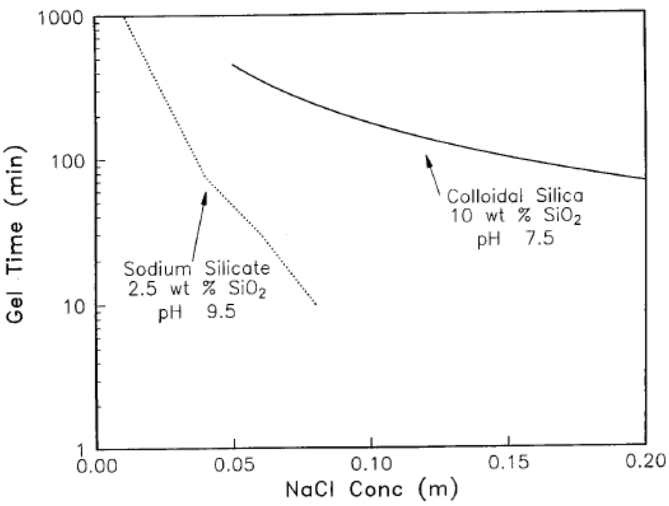


Figure 34 Gel time versus salinity [25]

Sodium and potassium silicate solutions differ from colloidal silica solutions in the form and distribution of silica in solution. Commercial silicate solutions have a maximum silica-alkali ratio of 4, more than an order of magnitude lower than colloidal silica solutions. Sodium silicate solutions require a higher pH (11,3 to 13) than colloidal silica solutions to be stable against gelation. The gelation of silicate solutions is a complex superposition of several processes: particle formation (polymerization of silicic acid), particle growth and particle aggregation. The rates of polymerization and particle growth are strongly influenced by salinity and pH [25].

A sodium silicate system is generally placed as a water-thin, freshwater based solution that consists of a silica source and an activator that is designed to trigger gelation of the silicate at a designed time. The gel times of the sodium silicate system is mainly controlled by the pH and temperature. The target pH is either reached on the surface, by the use of strong or weak acids, or in situ, by adding materials that slowly release acids. Typical set-time curves as a function of temperature, activator type and concentration are given in Figure 35 [26].

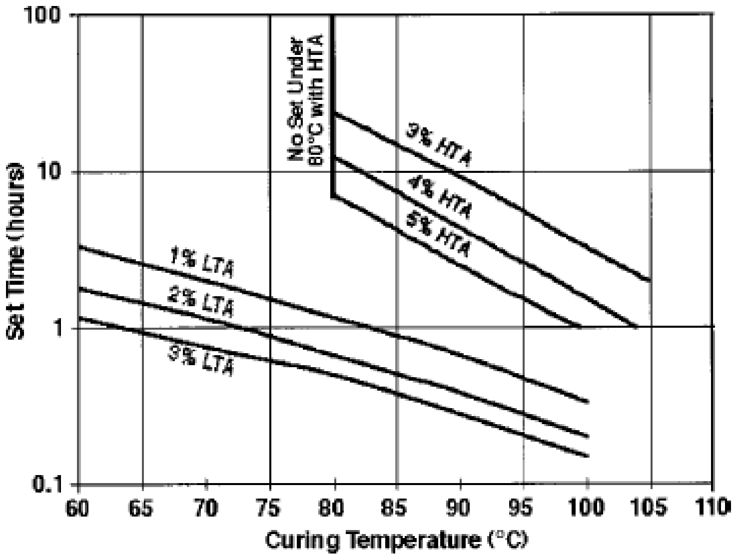


Figure 35 Curing temperature, LTA (Low Temperature Activator) and HTA (High Temperature Activator)[26]

The general chemical formula for sodium silicate from the reaction between sodium carbonate (soda ash) and silicon dioxide (when molten) is as follows:

$Na_2CO_3 + SiO_2 \rightarrow Na_2SiO_3 + CO_2$ [Wikipedia]

The blocking of the water flooded pores occurs as a result of polymerization / crystallisation to quartz and precipitation with binary ions, see Figure 36. The gelation is pH controlled and silicate gel is formed at high pH. One of the problems with silicate is undesired precipitation in contact with divalent ions from the formation water. The system is generally activated by temperature, pH and the gelling time influenced by salinity. A low salinity water pre- and post slug is thus required. Adsorption of silicate is found to be linearly increasing with increasing silicate concentration see Figure 41. The rock buffer capacity is found to be strongly dependent on mineralogy. Kaolinite has a buffer capacity more than ten times higher than other minerals. Both adsorption and buffer capacity will strongly influence the composition and gelation properties of the silicate solution. A field test confirmed the laboratory results concerning silicate adsorption and buffer capacity. The buffer mechanism is described as the direct adsorption of hydroxyl ions (OH^-) on the rock surface [20]. The latter statement is questioned since the clay mineral should have a negative charge. In chapter 4.7 and reference [16] the following statement is conflicting since it is stated that "the mineral surface will exchange H^+ present in the liquid phase with cations previously adsorbed which again leads to a decrease in H^+ concentration inside the liquid phase resulting in a pH increase".

The final composition of the gel is calculated based on the volumes needed, the amount of permeability reduction needed and the necessary gelling time based on the desired radius of displacement.

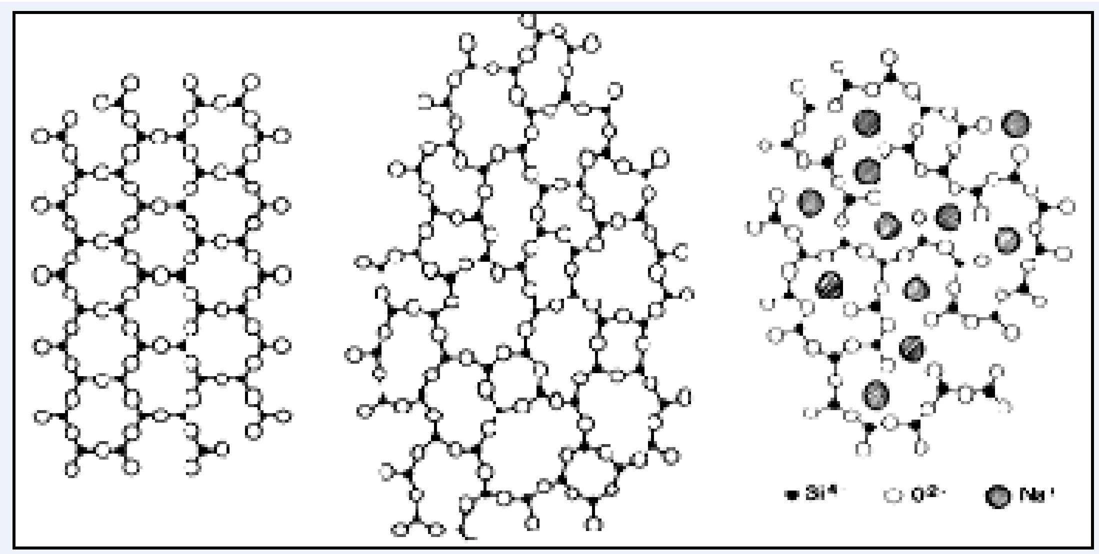


Figure 36 Illustration of polymerization of silicate and sodium silicate on the molecular level, 3-dimensional polymer-grids [27]

The characteristics of the Sodium Silicate system (alkaline solution) may be summarized as follows:

- Low viscosity (nearly as water)
- Long gelation time (stable at high pH)
- Variables; Gelation time decreases at:
  - Decreasing pH
  - Increasing temperature
  - Increasing salinity
  - Increasing concentration of silica
- Precipitation:
  Hardness ions, Ca++ & Mg++ (approx. 2000 ppm in sea water)

- Other significant parameters:
  - Buffering (OH-) capacity of formation
  - Adsorption
- HSE: Environmentally acceptable for use in the North Sea

The mechanism / chemicals is described as follows [23]:
- $(SiO_2)_x (Na_2O)_y$
- Alcaline solution (pH= 10-14)
- Concentration ≥ 4-6 wt%

A low ratio between x and y result in a high pH of the solution which again means that the system needs a significant amount of protons, H+, in order to gel. A x:y ratio of 2,4 has been used at Gullfaks (wells B-5 and A-13).
At the end of the treatment glyoxal is used as a pH reducing agent. Glyoxal gives a slower pH reduction than HCl which ensures that gelation is not initiated before the entire silicate solution is pumped into the formation. At the same time glyoxal allows for a larger amount of proton equivalents to be safely added and therefore a higher conversion of silicate to gel [23].

Laboratory experiments [20]:
Na-Silicate ratio: $SiO_2 : Na_2O$ = 3,3 : 1. Given concentration and pH was obtained by adding the proper amounts of water and HCl.

Silicate bulk studies
- Crystallisation time vs. pH, temperature and silicate concentration. See Figure 37 and Figure 38.
- pH reduction due to adsorption of OH- ions on the core material (strongly dependant on mineralogy). The adsorption mechanism is believed to be dominating since the gelation time was increased for solutions containing sand and Kaolinite, see Figure 39 and Figure 40)
- Silicate adsorption (linearly increasing with increasing silicate concentration and decreasing with increasing temperature, see Figure 41 and Figure 42). Adsorption and desorption values are calculated by mass balance.

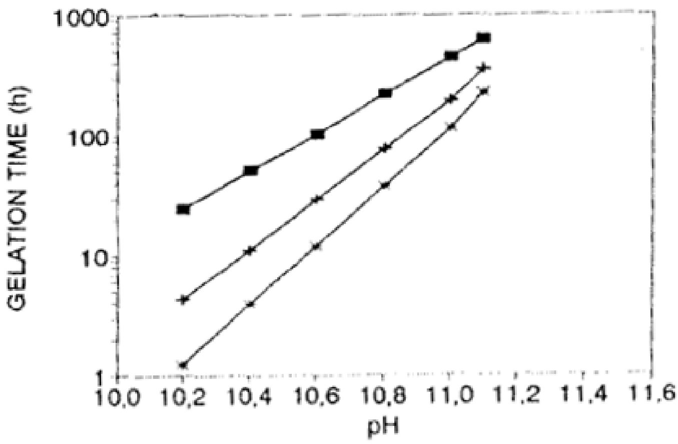


Figure 37 Gelation time vs. pH and concentration (temperature 20˚C), silica concentration of 3%(■), 3,5%(+) and 4%(*) [20]

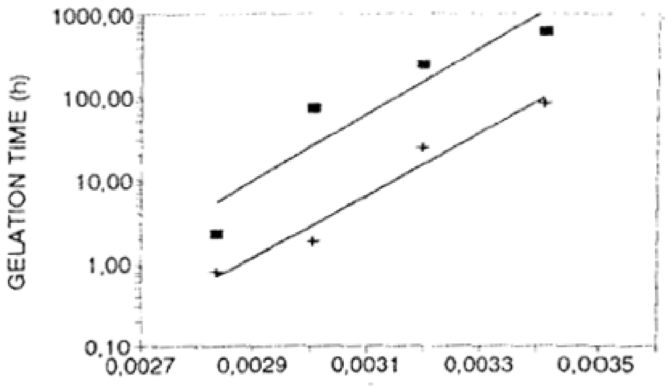


Figure 38 Gelation time as a function of inverse temperature (1/T (ºK)) for 6% silicate solutions in fresh water, pH=11,40 (■) and pH=11,15(+) for temperatures 20, 40, 60 and 80ºC. [20]

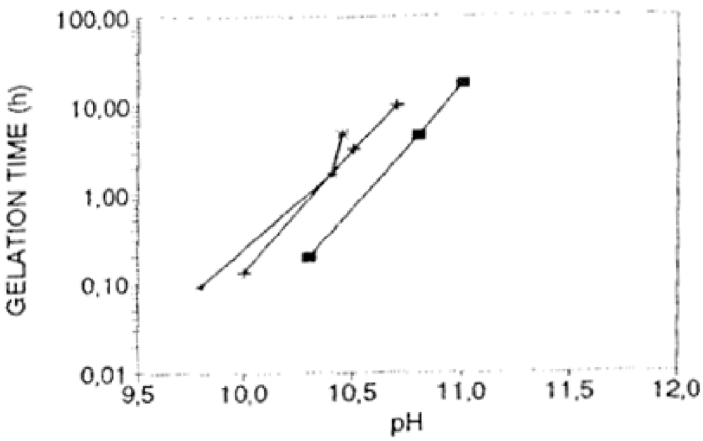


Figure 39 Gelation time as a function of pH solutions without sand (■) and the same solutions with added quartz sand (+) and a mixture of 84% quartz, 11% Kaolinite and 5% carbonate (*). Comparing solutions at the same pH, the gelation time is longer for solutions containing sand [20]

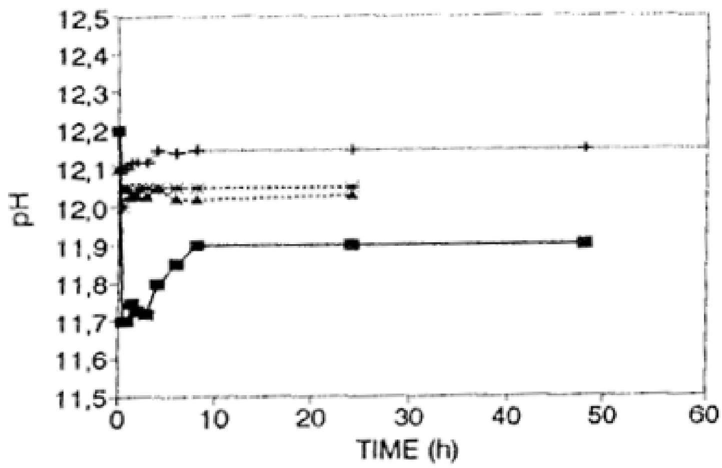


Figure 40 Solution pH as a function of time in contact with different minerals and a mineral mixture. Quartz (+), Kaolinite (■), carbonate (*) and a mixture of 84% quartz, 11% Kaolinite and 5% carbonate (▲) [20]

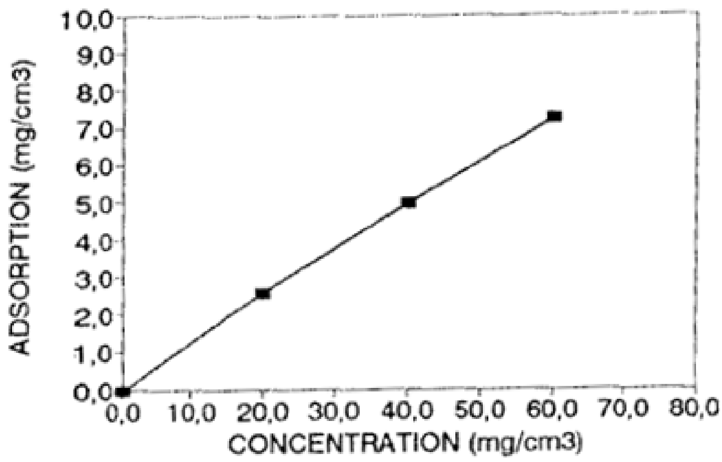


Figure 41 Adsorption of silicate vs. silicate concentration in fresh water at 25 ºC [20].

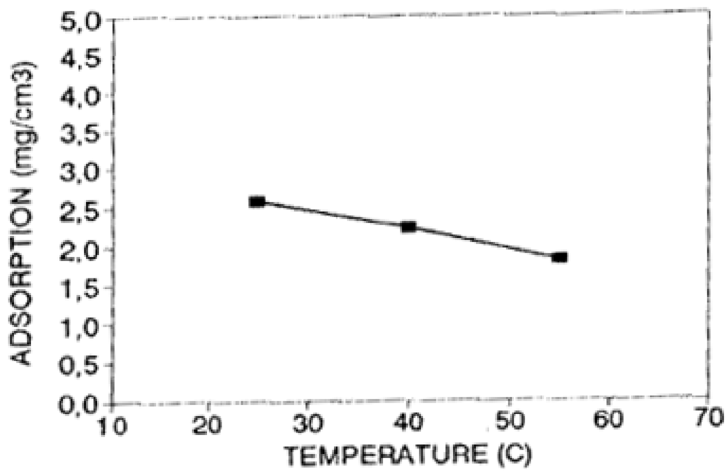


Figure 42 Adsorption of silicate in fresh water vs. temperature. The silicate concentration is 2% [20]

4.8.3 Experience on the use of Sodium Silicate gel

Several papers/publications, [19] [20] [21] [22] [23] [24] [25] [26] [28], speak about experience from the use of silicate gel for optimizing injection- and production well performance. Common for all is that the treatment has been performed only in the near wellbore area. In the following, mainly experience from testing of sodium silicate intended used on the Gullfaks field, North Sea, is summarized since this has the highest relevance for the Veslefrikk field.

1. Martyshi, Kasakhstan (3 wells, 1 test in each) [20] [21]

Field tests of sodium silicate was performed on the Martyshi oilfield to verify and upscale laboratory data and qualify the system for larger-scale North Sea operations (Gullfaks field). The reservoir parameters of the Martyshi oilfield matched the Gullfaks field. In addition to EOR the aim was to obtain learning on scheme for injection of silicate solutions into reservoirs with brines with high salinity and hardness, to decide on methods, logistics and handling of chemicals. A preflush of fresh water was found to condition the critical reservoir parameters and allow for good injectivity of the basic silicate solution.

The first well test was mainly a formation test to analyze adsorption and reservoir buffering capacity. The silica concentration used was 0,82wt% in the non-gelling regime. Tracers were used to measure back produced fluids. Laboratory data was confirmed except that a 50% higher retention of silica was observed.

For the second and third well test the silicate concentration was chosen high enough to gel, 4,6wt% and 5wt%. The potential of water shut-off treatment of high water cut producers was examined. The water cut was reduced in both wells from 96% to 20%, and the oil rate was increased. The second well test showed that the silicate slug size was insufficient since the improvement in water-cut and oil rate only lasted for 14 days. The silicate slug was increased for the third well test resulting in water-cut reduction from 96% to 10-20% and the oil rate was increased from 3 Sm3/d to 80 Sm3/d for the whole observation period of 8 months.

2. Producer treatment (Silicate) in two wells on the Gullfaks field, B-5 and A-13(1993 – 1994)[20], [21], [22] and [23]

Gullfaks, B-5 well sodium silicate treatment:

The technical goal for the project was to develop and qualify a method for large volume gel treatments under North Sea operational conditions. Further, the aim for the sodium silicate operation on the first north sea well, Gullfaks B-5, was to reduce productivity of the high water-cut middle perforation interval and increase oil production from a lower zone in the lower Brent reservoir unit, see Figure 43. Production at a higher draw down would reactivate the production from the lower interval. Prior to gel treatment, the gravel packed interval did not contribute to the oil production due to scale deposits. A PLT run just before the treatment showed that only the middle perforation interval was contributing to production. Prior to the gel treatment the water cut was 80% and the PI was 520 Sm3/d/bar. See Figure 45.

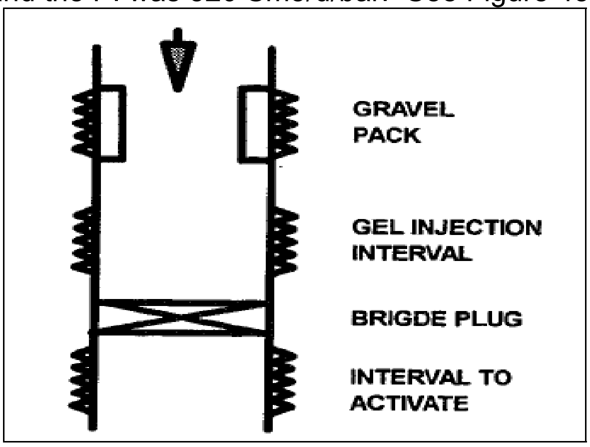


Figure 43 Well B-5 well status related to the gel injection [22]

The gel system used was alkaline 4-6 wt% sodium silicate. A low salinity preflush was used to pretreat the formation to avoid precipitation of silicate with binary ions in the formation water. Displacement of mobile oil will also improve the control of injectivity of the gel. The preflush of 0,5wt% Na-silicate was injected to adjust pH in the wellbore and reduce adsorption of the “main” gel. A total gel volume of 5000 m3 was estimated to penetrate 25-30 m into the water “channels”. The treatment was performed in 5 days with a maximum injection rate of 2000 Sm3/d. Hydrochloric acid was used to reduce pH and thereby gelation time. The shut in period, to allow gel to develop sufficient strength, was 4 weeks.

PREFLUSH:	
0.5 wt% KCl	1978 m^3
0.5 wt% Na-silicate	1976 m^3
GEL:	
4 wt% Na-silicate	805 m^3
4 wt% Na-silicate + Acid	2389 m^3
6 wt% Na-silicate + Acid	2571 m^3
POSTFLUSH:	
Fresh Water	38 m^3
TOTAL INJECTED VOLUME	9757 m^3

Figure 44 Injection sequence well B-5 [22]

Most of the handling of chemicals, dilution and quality control, was done onshore. Chemical tankers were used as storage vessels for the pre-mixed chemicals on the field site and supply boats transferred the chemicals to the platform.
A production log (PLT) was run after the treatment and the results are given in Figure 45. The reduction of PI in the treated interval has resulted in an essential increased oil production from the lowest perforation interval, estimated to about 6 vol.% of the total oil production from the well drainage volume. The oil rate was increased by approximately 90 Sm3/d (see Figure 47)giving an incremental oil recovery of about 47000 Sm3 oil.

	Q oil (%)	PI (Sm3/d/b)
PLT before Treatment		
Upper Interval	97	-
Lower Interval	(3)	-
WC (well)	79-80 %	PI(well)=520
PLT after Treatment		
Upper Interval	94	104
Lower Interval	6	6.4
WC (well)	77.8 %	PI(well)=110

Figure 45 A comparison of results from production logging of the B-5 well before and after gel treatment, well B-5 [22]

The predicted water-cut after gel treatment is confirmed by the observed water-cut. See Figure 46. The well life time was increased by 1,5 years. The main conclusion was that the gel had reduced the permeability in the treated zone obtaining an efficient water diversion and provided for an optimized and increased oil production from the lower perforation interval.

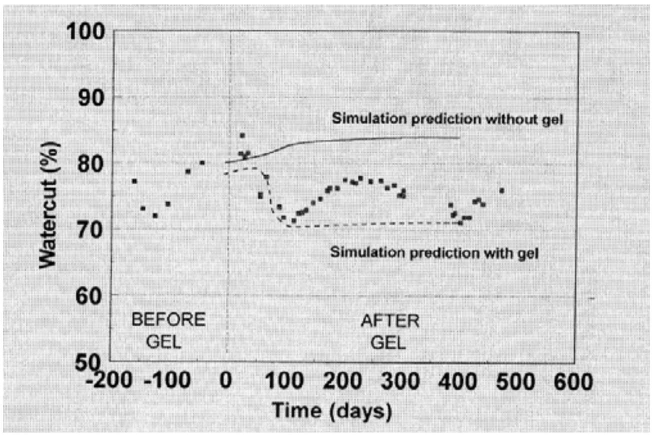


Figure 46 Predicted and actually measured water-cut before and after gel treatment, well B-5 [22]

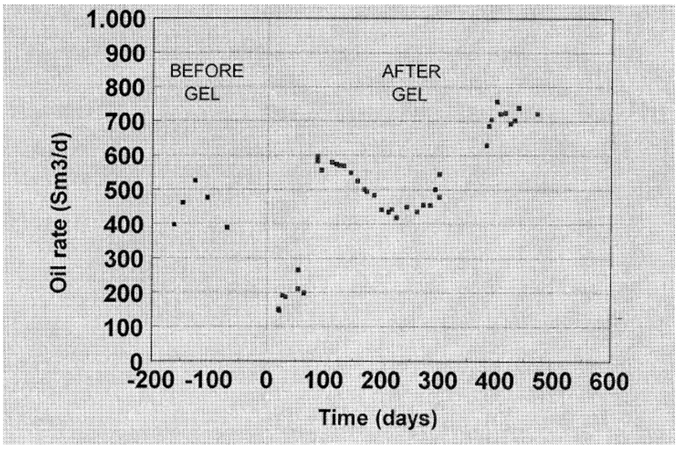


Figure 47 Oil production rate from well tests before and after gel treatment, well B-5 [22]

Gullfaks A-13 sodium silicate gel treatment [23]:

The second sodium silicate well treatment on the Gullfaks field was performed in the well A-13 and optimized based on the experience from the work done in the B-5 well. See Figure 48 for injection sequences. The main improvements on the gel placement operation was:

- In-line mixing, instead of batch mixing, of the pH reducing agent and the sodium silicate.
- Glyoxal used as pH reducing agent instead of HCl at the end of the treatment. Glyoxal gives a slower pH reduction than HCl . This allows a larger amount of proton equivalents to be added leading to a higher conversion of silicate to gel and ensuring that gelation is not initiated before the entire silicate solution has entered the formation.

Sequence	Composition	Volume (m^3)
Preflush	1.0 wt% KCl + 0.5 vol% n-propanol	960
	1.0 wt% KCl + 0.5 vol% Na-silicate	778
Gelant	4.0 wt% Na-silicate + i-propanol	1 178
	4.0 wt% Na-silicate + HCl	1 138
	6.0 wt% Na-silicate + HCl	1 494
	6.0 wt% Na-silicate + Glyoxal	431
Postflush	1 wt% KCl	60
Total injected volume		6 049

Figure 48 Injected compositions and volumes, well A-13 [23]

The time frame for the gel placement was designed as described in Figure 49.

Cumulative time (days)	Na-Silicate (wt%)	pH	Inj.rate (m^3/d)	Simulated gelation time [days]
0.5	0.0	---	2000	---
1.0	0.5	11.9	2000	infinite
1.5	4.0	11.9	2000	14 to 28
2.5	4.0	11.1	2000	7 to 28
3.5	6.0	11.1	2000	1 to 28

Figure 49 Initial injection design for gel treatment of well A-13 [23].

The well A-13 well was completed in the lower Brent reservoir where the flow properties generally are much better in the upper zones compared to the lower zones. The aim of the gel treatment was to partially block the high permeable upper interval while protecting the lower interval, see Figure 50.

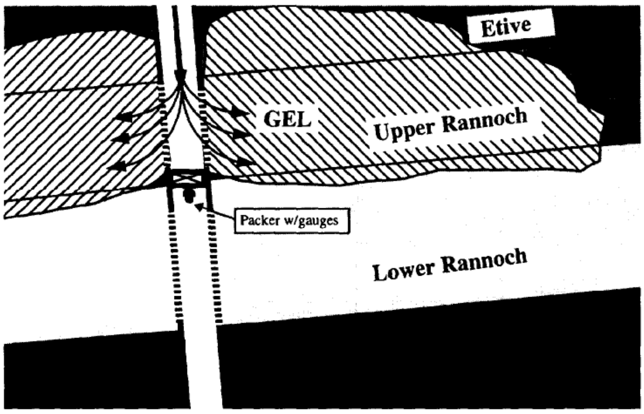


Figure 50 Sodium silicate gel injection in the upper perforated interval in well A-13 [23]

The water-cut was reduced after the gel treatment, but was rate dependant, see Figure 51. The water-cut was reduced by 13%.

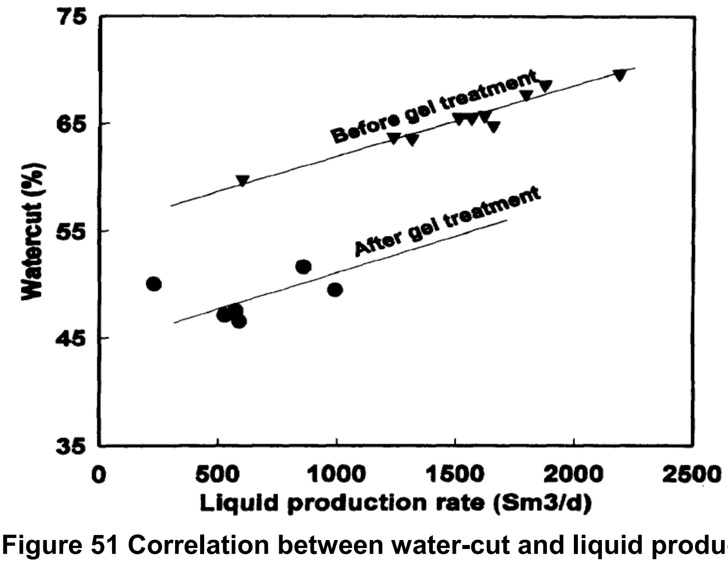


Figure 51 Correlation between water-cut and liquid production rate before and after gel treatment, well A-13 [23]

The gelation of sodium silicate was modelled using the “Scorpio” chemical simulation software. The permeability reduction was modelled with the residual resistivity factor, RRF. The RRF is defined as the initial absolute permeability divided by the final absolute permeability.

The simulated relationship between RRF and amount of gel deposited on the rock is given in Figure 52.

.

Amount of gel (mg gel / g rock)	RRF
0.0	1
1.6	8
3.2	16
4.8	24
6.4	32
8.0	40

Figure 52 RRF as a function of amount of gel [23]

The simulated RRF as a function of time and radial distance from the well is given in Figure 53.

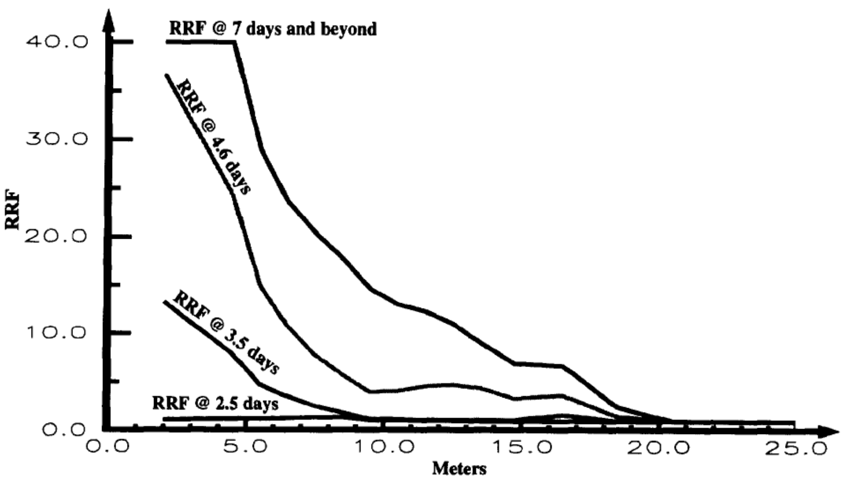


Figure 53 Simulated RRF as a function of time and radial distance from the well [23]

An overview of the reservoir segment where A-13 is located is given in Figure 54. Water is injected in well A-15 and gas is injected in well A-11.

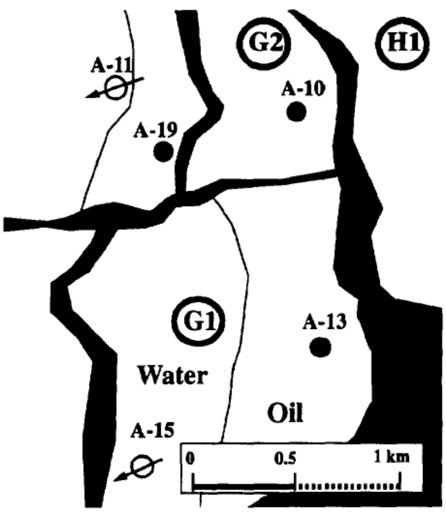


Figure 54 Schematic map with well positions, Lower Brent at Gullfaks [23].

The potential additional oil recovery was predicted to 325000 Sm3, 5 years after gel treatment. The net pay value (NPV) was estimated to 180 mill.NOK based on a cost of the treatment of 11 mill.NOK. Important assumptions in these simulations were:

- constant liquid production rate of 2000 Sm3/d in A-13.
- constant water injection of 3000 m3/d in A-15.
- no gas injection in A-11 after November 1993.
- the gel treatment is technically successful.
- the gel penetrates 20 meters into the reservoir and reduces the permeability of the treated formation by two orders of magnitude (RRF=100).

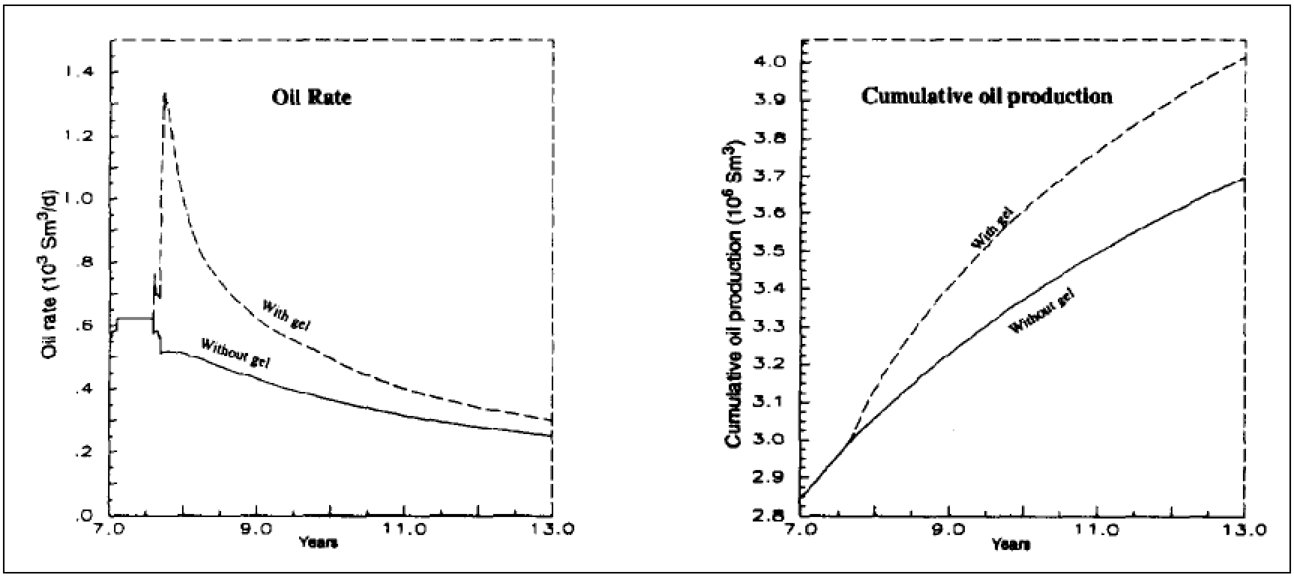


Figure 55 Predicted oil rate and cumulative oil production with and without gel treatment, from potential study, well A-13 [23]

In the process of detailed history matching of the simulation model, after the gel treatment, additional understanding was achieved about the flow properties in the reservoir. The most important change was the improved vertical communication through the upper part of the Rannoch formation. The increased vertical communication reduced the expected benefits of the gel treatment. The updated simulation model predicted an additional oil production of 130000 Sm3 (in 5 years), which was half the volume predicted in the potential study prior to treatment. See Figure 56. This gave an added NPV of 50 mill.NOK.

The assumptions for the updated simulations were:

- Reduced liquid production rates from 2000 to 1000 Sm3/d from may 1995 (well A-13).
- Gas injection in A-11 during 1994 and 1995 is introduced.
- No water injection in A-15.
- The productivity of the upper interval was not reduced as much as planned. This is the combined effect of a lower RRF than expected (40 instead of 100), and the fracturing of the formation at the end of the injection program.

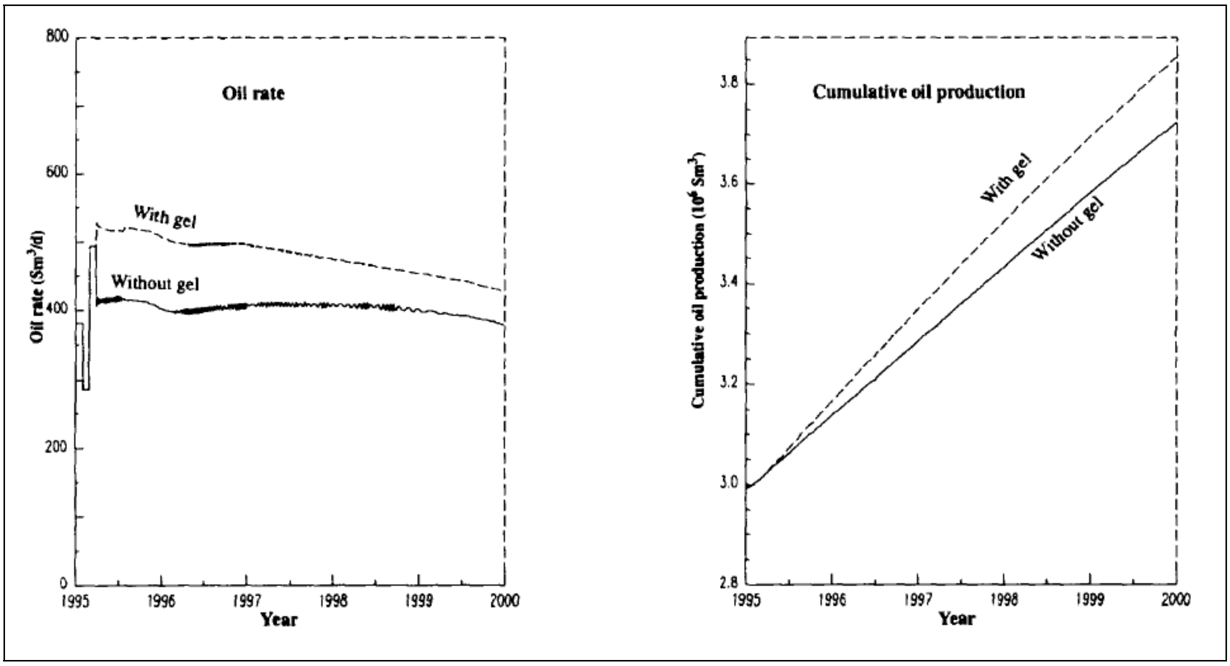


Figure 56 Revised prediction of oil rate and cumulative oil production with and without gel treatment, well A-13 [23]

Main results of the sodium silicate treatment in the Gullfaks well A-13:

- The gel penetrated 20 m into the treated zone
- 14 days shut-in time was sufficient for the gel to culminate
- The liquid productivity index of the of the treated zone was reduced from 300 to 74 Sm3/d/bar
- The residual resistivity factor was estimated to be in the range 30 to 50
- The expected additional oil volume produced after 5 years was 130000 Sm3 and the NPV 50 mill.NOK. After one year the additional oil volume, as an effect of the gel treatment, was interpreted to be 26000 Sm3 from the A-13 well.

5 Evaluation of EOR potential of the sodium silicate method, applied in the Etive formation, utilizing a conceptual simulation model.

5.1 Base case

For qualitative evaluation of the applicability of sodium silicate as an EOR method for the Etive formation, Veslefrikk field, a simple conceptual reservoir simulation model was made. Sensitivity studies and interpretation of results were expected to be easier utilizing a simple model compared to the full field simulation model.

A 1000 m x 1000 m x 11 m grid size is used with grid cells 50 m x 50 m in x and y directions and 6 layers in z direction. The grid is made using the Resview software. A one degree dip is constructed from the production well, in one of the corners, towards the water injection well, in the opposite corner. The thickness and horizontal permeability for the layers are average parameters from the full phase simulation model for the Veslefrikk field, Etive formation. Other reservoir parameters like average porosity, net to gross, relative permeability curves, PVT data etc. are also taken from the full phase field model.
The conceptual simulation model is set up in such a way that the reservoir volume produced is replaced with injected water. A constant production rate of 2000 Rm3/day is used throughout the production period. The production period is 7+ years, from 1/1-2009 to 1/4-2016.

For data file used for simulation, see App B (Base Case, Tracer simulation and simulations for reduced PERMX).

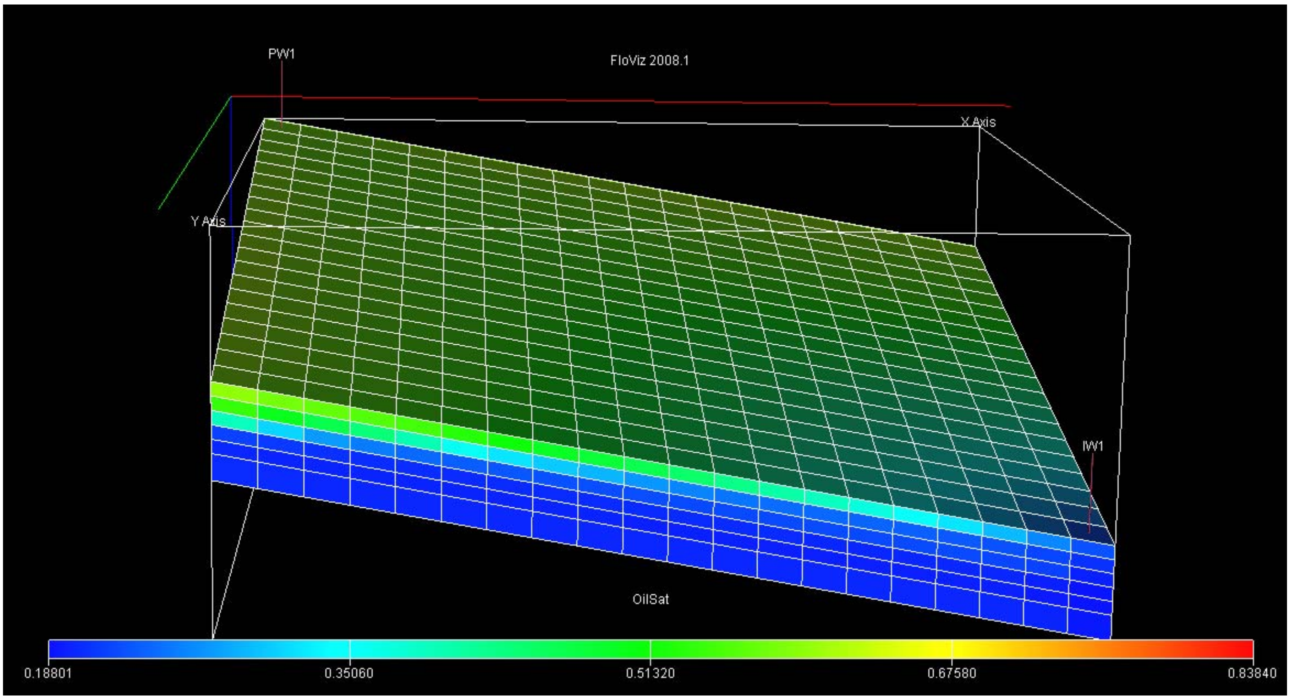


Figure 57: Simple model Etive Formation, Veslefrikk, Oil saturation at end of production period

As can be seen in Figure 57, at the end of the production period, the upper layers still have significant oil saturation while the 3 lower layers are completely flooded. Since the horizontal permeability is much higher in the lower layers than the upper layers the water production dominates after water break through in the lower layers.

The vertical communication between the layers is good. In the full phase simulation model the PERMZ is defined as 0.5 times the PERMX.
The upper two layers of the model represent the Etive 3 formation. Data acquisition, from wells in the Etive 3 formation on the Veslefrikk field, shows that this formation ranges from unflooded to partly flooded. This coincides with the simulation model.

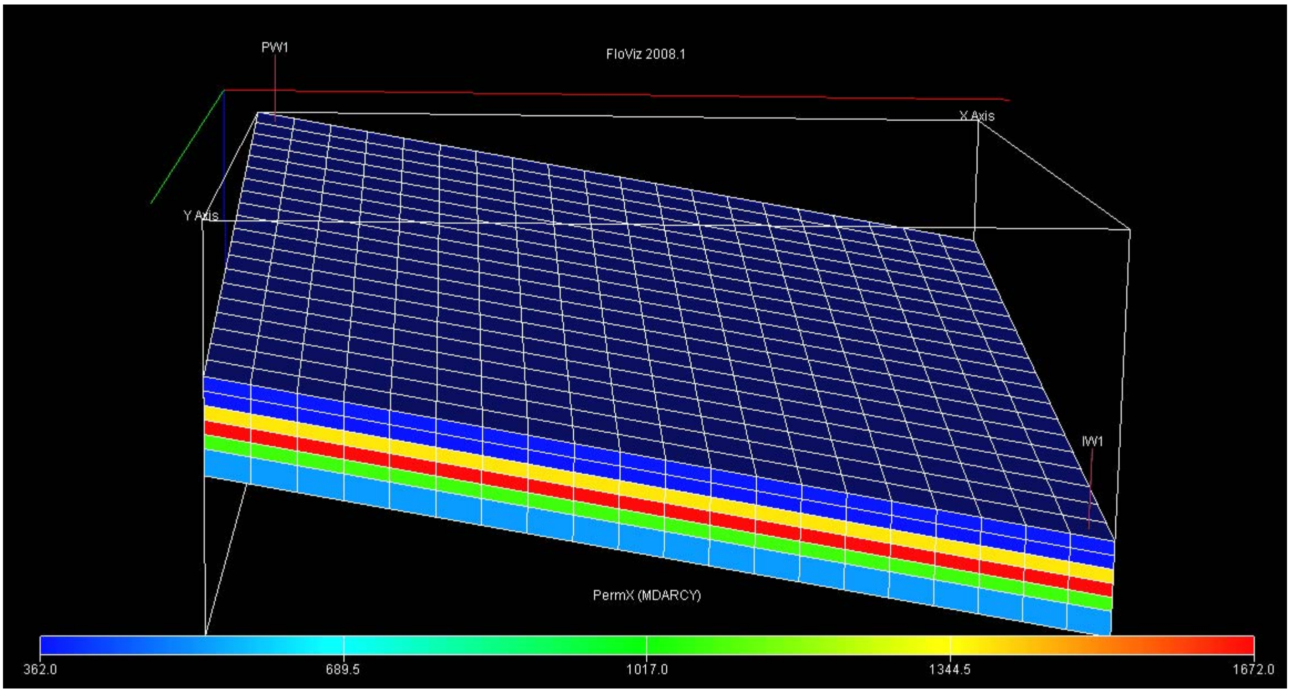


Figure 58: Simple Etive model, horizontal permeability (PERMX) in the layers

Table 6 Thickness and permeability of layers

Layer no.	Thickness (m)	PERMX (mD)	Kh product
1	1,6	368	589
2	1,6	362	579
3	1,6	1383	2213
4	1,6	1672	2675
5	1,6	1084	1734
6	3,0	545	1635

5.1.1 *Choice of time for "water shut off" / production results for base case*

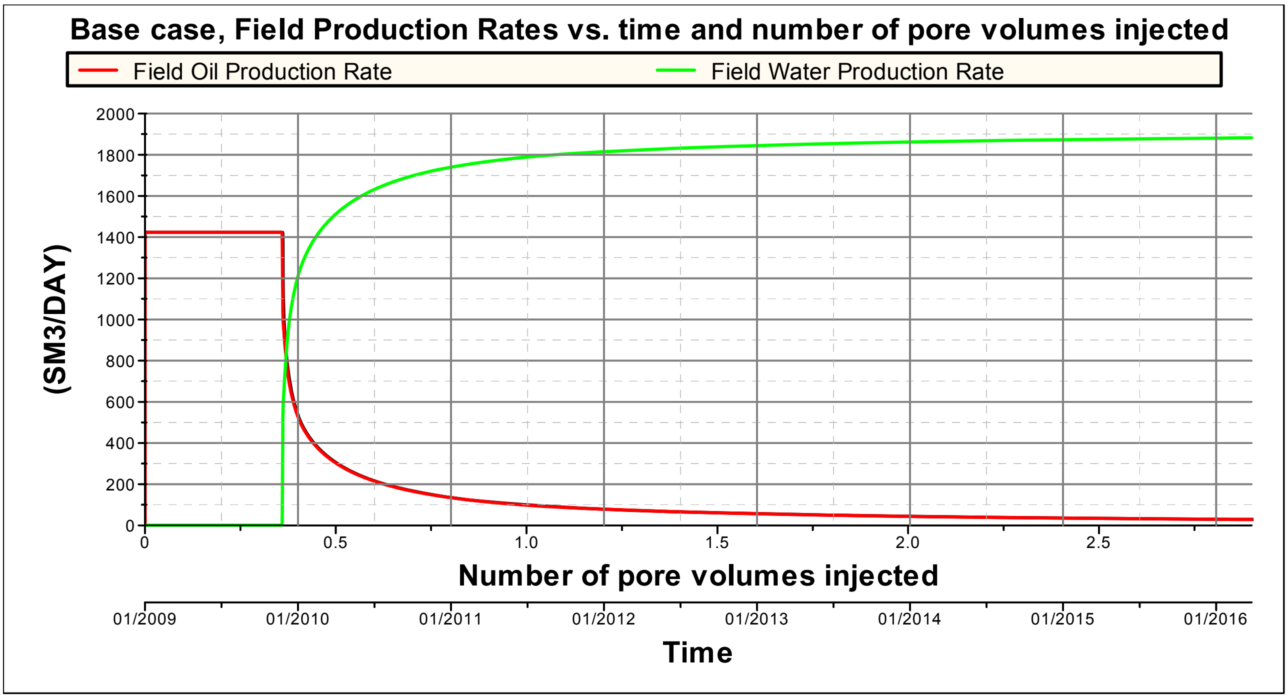


Figure 59: Water break through, Field Production Rates versus time

In less than one year water breaks through in the two lower layers, and after two years (01.01.11) with production and simultaneous water injection the oil production rate is reduced from initially 1425 Sm3/d to 130 Sm3/d. At 01.01.11 a water volume equivalent to 0.8 pore volumes have been injected and the recovery factor is calculated to 55 %, see Figure 59 and Figure 60. The water cut at this time is 93%. This seems to be the right time to shut off the waterways in the lower layers and thereby increase the oil production from the upper layers.

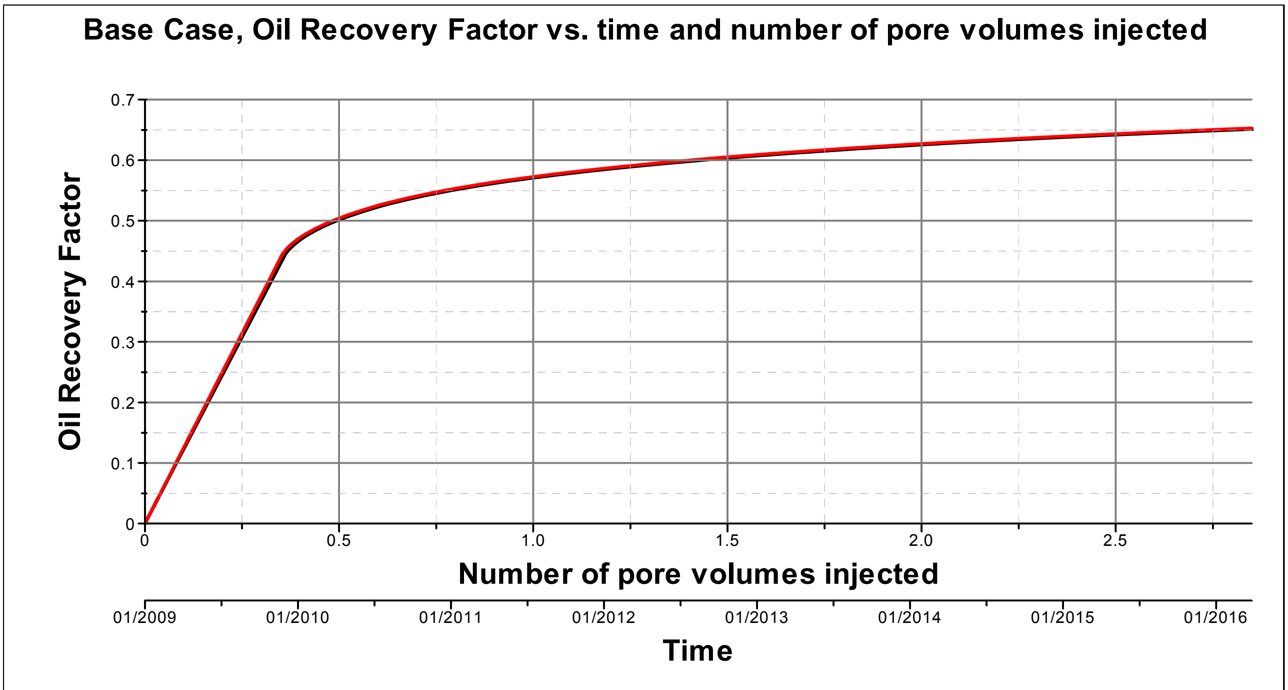


Figure 60: Oil recovery factor, base case

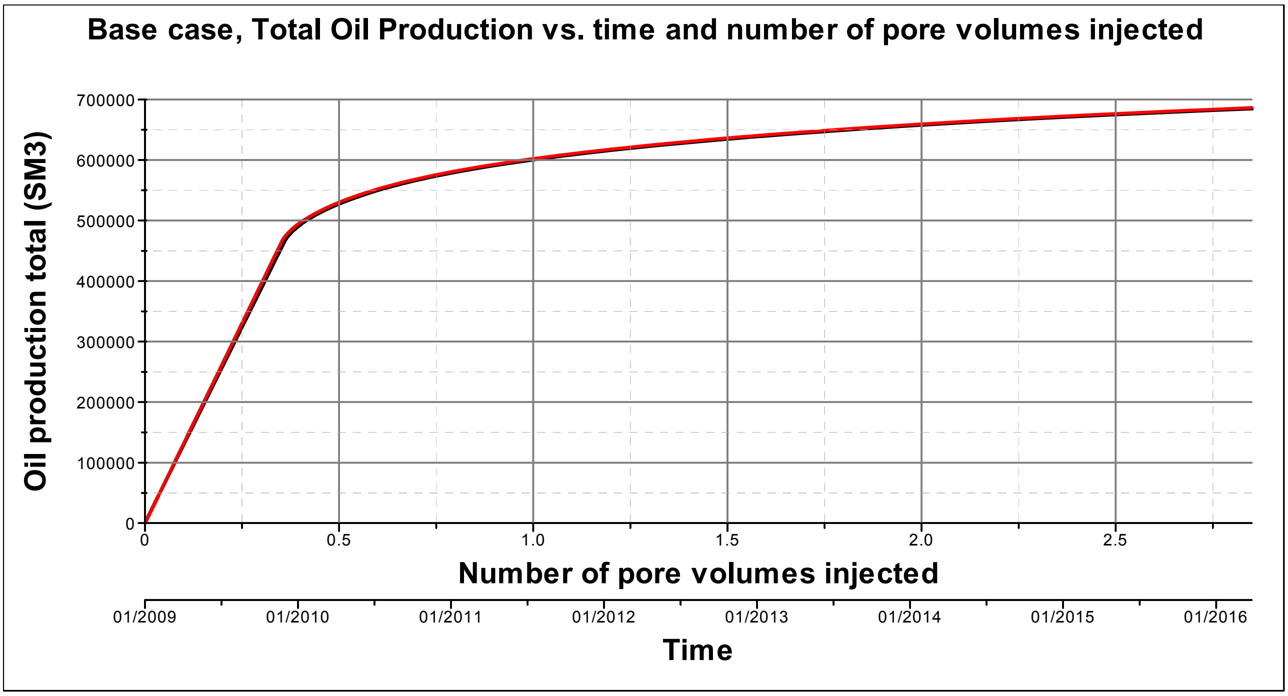


Figure 61: Total oil production, base case

The development of the oil and water production rates in each layer is illustrated in the Figure 62 and Figure 63. When water breaks through in the lower layers an increase in the oil production occurs in the two upper layers for approximately 3 months. From this point and one year forward the highest oil production rate occurs in layer 3, followed by layer 1 and 2. At the end of the production period the oil production rate is very low and most of the oil production comes from layer 1.

There are practically no water production from layers 1 and 2 throughout the complete production period. The water production rate, at water break through point, is initially highest in layer 6. As water breaks through in layers 5 and 4 the water production rate is distributed within the layers according to the size of the Kh product. Figure 65 show that the layer 4 has the highest total water production.

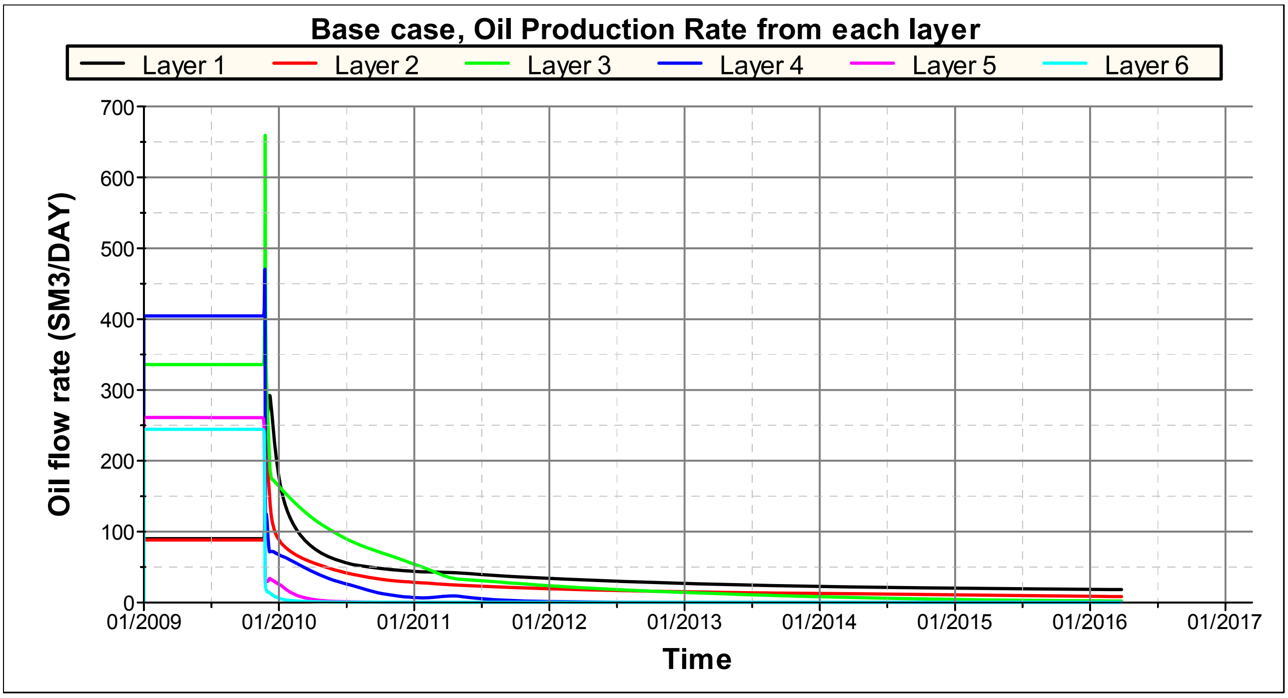


Figure 62: Base case, development of oil production rate in each layer

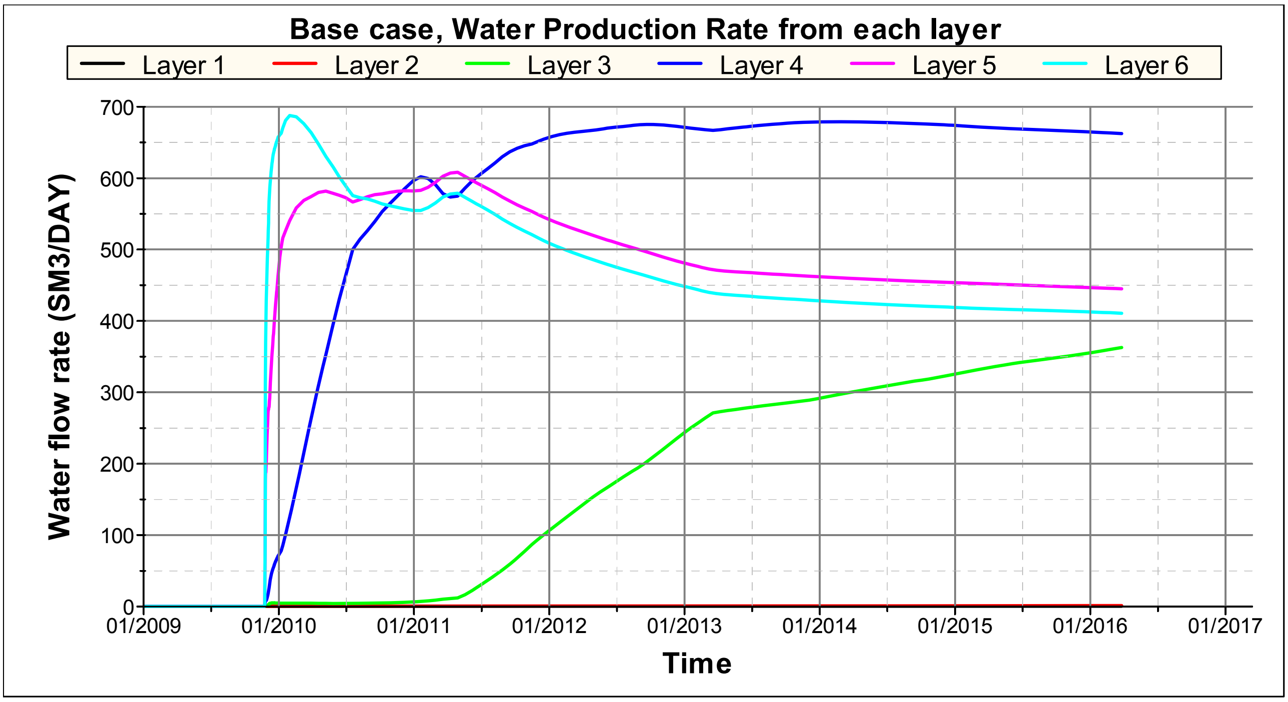


Figure 63: Base case, development of water production rate in each layer

Since the vertical communication in the model is good it is obvious, from Figure 64, that oil is pushed and migrates upwards as a result of water injection. Also, due to gravity, water injected in the upper layers tends to “sink” down to the lower layers. Initially layers 1 and 2 contain the same amount of oil as the thickness, porosity and oil saturation is the same. From Figure 64 it can be seen that the total oil production increases in layer 1 compared to layer 2 from the point of water break through in the lower layers. The layer producing most of the oil volume is layer 3 which in addition to having the "optimum position" with regards to the above mentioned effects also has a high Kh product.

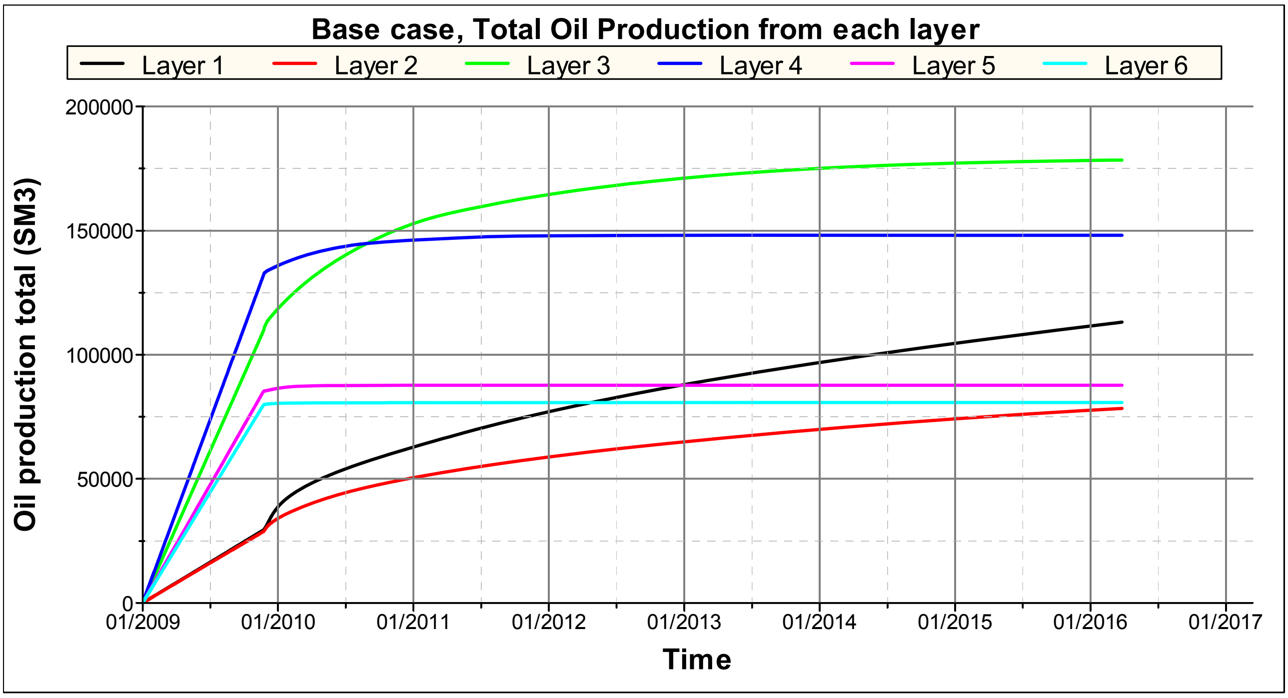


Figure 64: Base case, total oil production from each layer

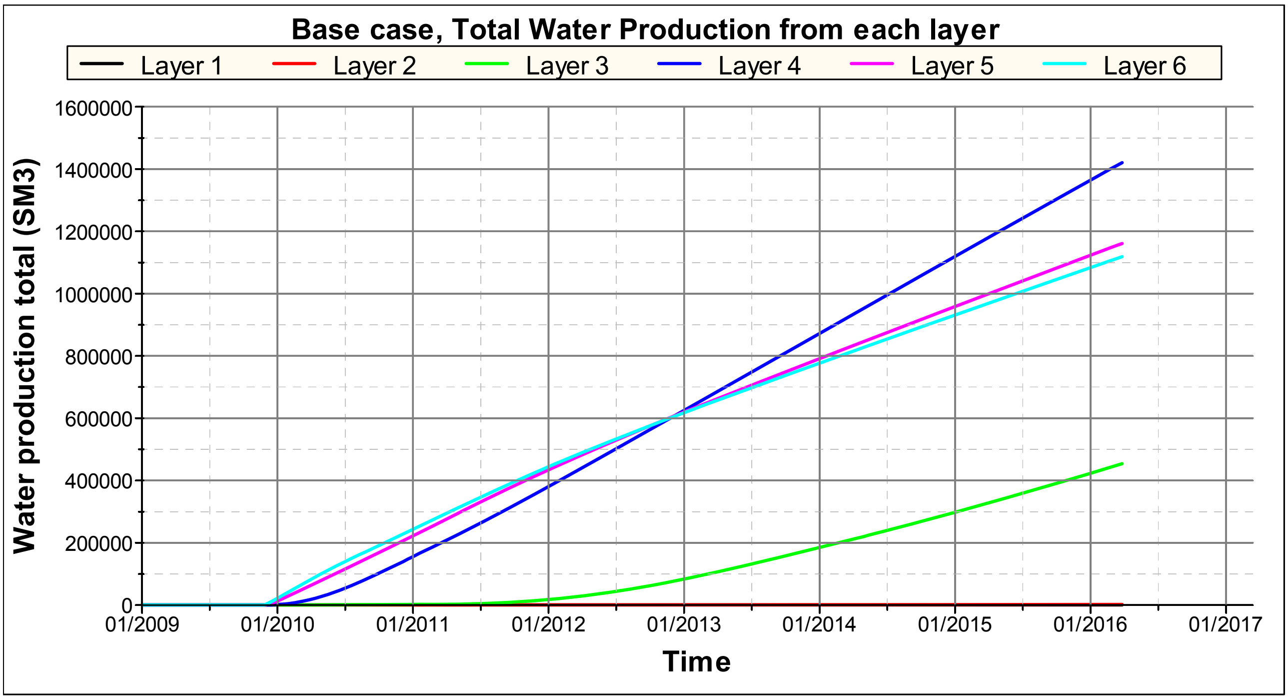


Figure 65: Base case, total water production from each layer

5.2 Injection of Sodium Silicate, tracer simulation

To simulate injection of sodium silicate the WTRACER option in ECLIPSE is used. A certain volume of tracer is pumped and displaced to a given distance from the injector. The displacement distance is calculated based on cylinder volume calculations and "piston-like flow".
Using the FloViz option in ECLIPSE the PERMX is modified (reduced) in cells having a concentration of tracer above a given value (black cells in Figure 66). The concentration limit value is chosen, as far as possible, in such a way that a complete closure is obtained in the lower layer(s), see Figure 66; example from Case 1a, while the upper unflooded layers remain unchanged.

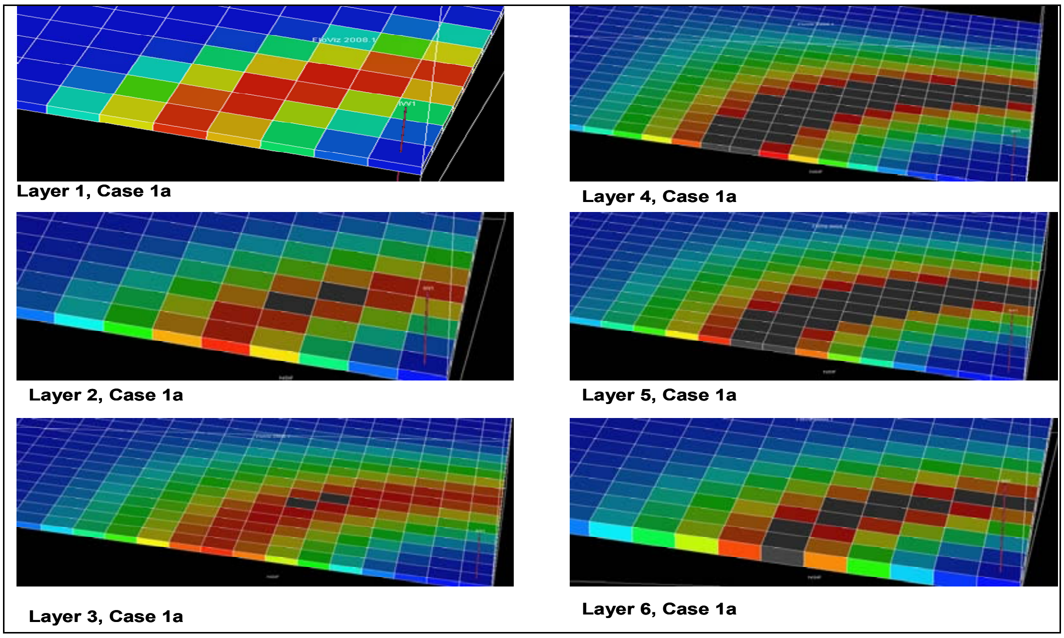


Figure 66: From FloViz; PERMX reduced in "black" cells for concentration of tracer > 0,265

A new simulation is run using a "restart" file and a new PERMX file valid from the decided gelation point of time for the sodium silicate. A new total oil production is simulated and compared with the total oil production simulated in the base case, at the end of the production period, and the difference is the enhanced oil recovery (EOR) resulting from the simulated treatment. A constant injection rate of 2000 Sm3/d is used for all simulations.

This procedure is followed for several sensitivity cases and results are given in the following report sections. The sensitivities studied are effect of batch size (volume of sodium silicate pumped), displacement radius from the injector well, reduction factor for PERMX, reduced vertical communication (PERMZ), and finally the effect of starting the treatment with sodium silicate one year earlier. An overview of the cases studied is given in chapter 5.3 and in Table 8.page 87.

5.3 Sensitivities / cases studied

1. Case 1a (1'st batch), 1b (2'nd batch) and 1c (3'rd batch): Small batch(es) of silica, short displacement radius, PERMX*0,002
2. Case 2a (1'st batch), 2b (2'nd batch) and 2c (3'rd batch): Big (double) batch(es) of silica, short displacement radius, PERMX*0,002
3. New base case, same parameters as for original base case except that the vertical communication is reduced: PERMZ=PERMX*0,05 instead of PERMZ=PERMX*0,5

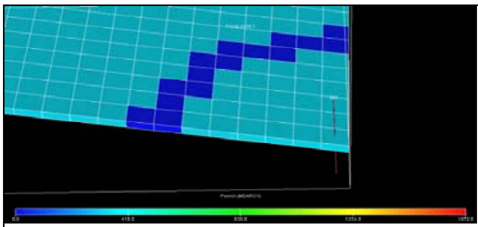
4. Case 3 (one batch): Small batch of silica, short displacement radius, PERMX*0,002, low PERMZ
5. Case 4 (one batch): Big (double)batch of silica, short displacement radius, PERMX*0,002, low PERMZ
6. Case 5a (1'st batch) and 5b (2'nd batch): Big (double)batch(es) of silica, long displacement radius, PERMX*0,002
7. Case 6a (1'st batch) and 6b (2'nd batch): Big (double)batch(es) of silica, long displacement radius, PERMX*0,1
8. Case 7a (1'st batch) and 7b (2'nd batch): Big (double)batch(es) of silica, long displacement radius, PERMX*0,01
9. Case 8a (1'st batch) and 8b (2'nd batch): Big (double)batch(es) of silica, long displacement radius, one year earlier, PERMX*0,002
10. Case 9a (1'st batch) and 9b (2'nd batch): Big (double)batch(es) of silica, long displacement radius, one year earlier, PERMX*0,1

5.4 Case 1, small batch of silica, short displacement radius, PERMX*0,002

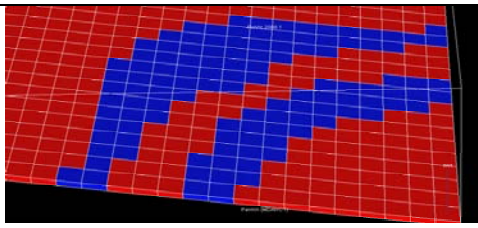
For case 1a, 1'st batch of silica, 60000 Sm3 of sodium silicate is injected with an injection rate of 2000 Sm3/d, 30 days. This is equivalent to a calculated 200 m radius distance from the injector well. The tracer is displaced with 120000 Sm3 water, 2000 Sm3/d, 60 days, 282 m radius. In FloViz PERMX is modified to 0,002 * PERMX in the cells where the tracer concentration is higher than 0,265, see "black" cells in Figure 66.
The EOR resulting from the simulated sodium silicate treatment, at the end of the production period, is calculated to 959 Sm3.

Another batch of sodium silicate is injected, case 1b, the same size as in case 1a. Batch no.2 is pumped and displaced right after batch no.1. This time the displacement time is increased with one month (3 months – 346 m radius) to obtain the best possible effect of the operation. To avoid closing off layer 1 and close off as much as possible of the lower layers, especially layer 6, PERMX in cells with tracer concentration higher than 0,205 is reduced to 0.002 * PERMX. With these criteria only layer 6 gets closed ("curve" no.2 in Figure 67). The reasons for this seems to be that both layer 4 and 5 are closed at approximately the same x/y location as a result of batch no.1, the vertical communication is good and gravity forces promote the flow path into layer 6. As can be seen in Figure 68, the second batch with silica closes off between the layers 5 and 6.
The second batch of sodium silicate only adds additionally 400 Sm3 to the EOR compared to batch no.1. A total of 1362 Sm3 EOR is obtained compared to the base case.

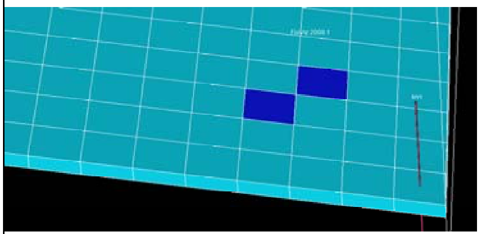
A third batch of sodium silicate is injected, case 1c, the same size as in case 1a and 1b, and following right after batch no.2 has been pumped and displaced. The batch is displaced for 4 months. To be able to close off in layer 6, layer 1 is also unfortunately closed. Also layers 4 and 5 get an extra closure, which is good. A part of layer 3 also gets closed. For cells with tracer concentration above 0.135, PERMX is multiplied with 0.002. Figure 67 and Figure 68 show which parts of the layers that get reduced/nearly zero permeability.
Batch no.3 adds 4363 Sm3 to the oil production volume. A total of 5725 Sm3 EOR is obtained as a result of injecting 3 batches of 60000 m3 each of sodium silicate. This is 0.83 % EOR compared to the base case. The recovery factor is increased by 0.5 %.



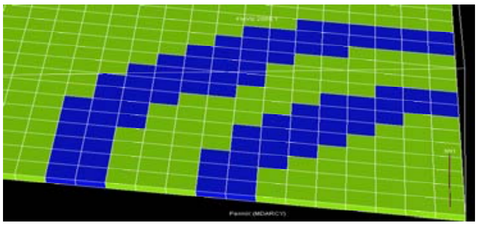
Layer 1: Reduced PERMX after 3'rd batch of silica



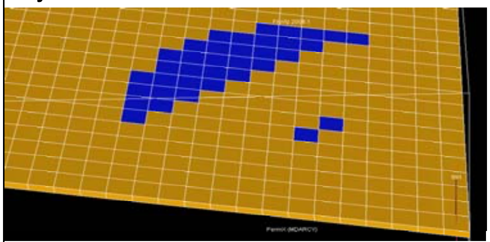
Layer 4: Reduced PERMX after 1'st and 3'rd batch of silica



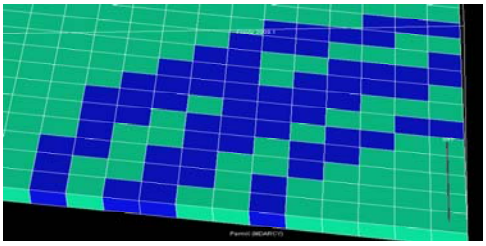
Layer 2: Reduced PERMX after 1'st batch of silica



Layer 5: Reduced PERMX after 1'st and 3'rd batch of silica

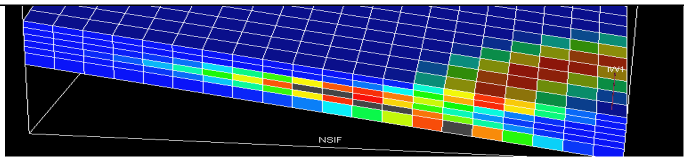


Layer 3: Reduced PERMX after 1'st and 3'rd batch of silica

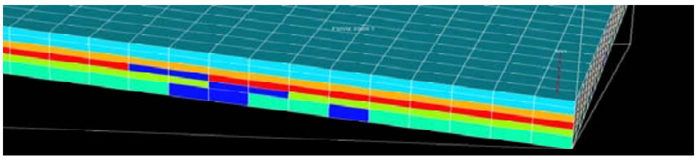


Layer 6: Red. PERMX after 1'st, 2'nd and 3'rd batch of silica

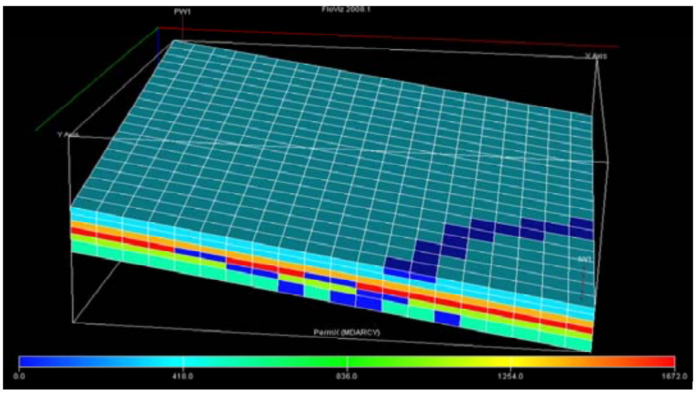
Figure 67: Reduced PERMX in each layer after 3 small batches of silica displaced a short radius



Tracer concentration after 1'st batch of silica, closure between layers 4 and 5



Reduced PERMX after 2 batches of silica, closure between layers 4, 5 and 6



Reduced PERMX after 3 batches of silica, new closure between layers 4, 5 and 6

Figure 68: Case 1, Cross-section view, Closure between layers

Figure 69and Figure 70 show that only the third batch of sodium silicate makes any essential difference as regards oil production. The reason for this is that the biggest closure of the lower layers is obtained with batch no.3 resulting in flooding and mobilizing of more oil in the upper layers.

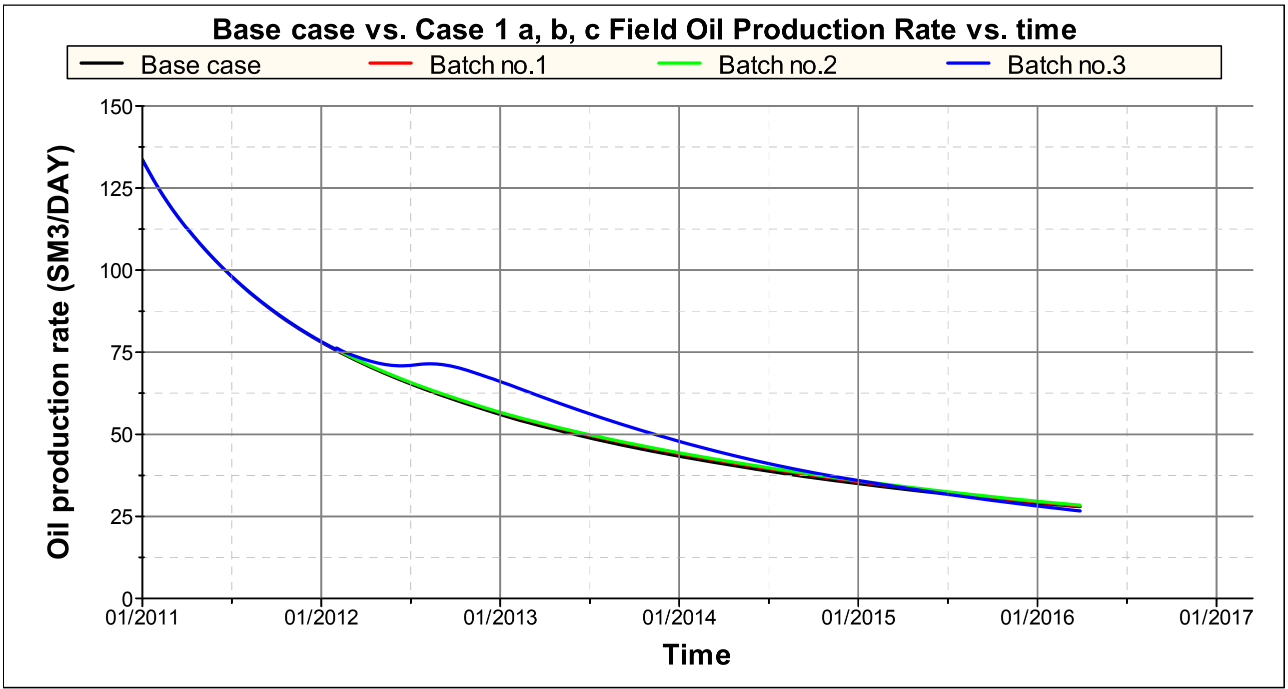


Figure 69: Field oil production rate, the third batch of sodium silicate slightly accelerates production.

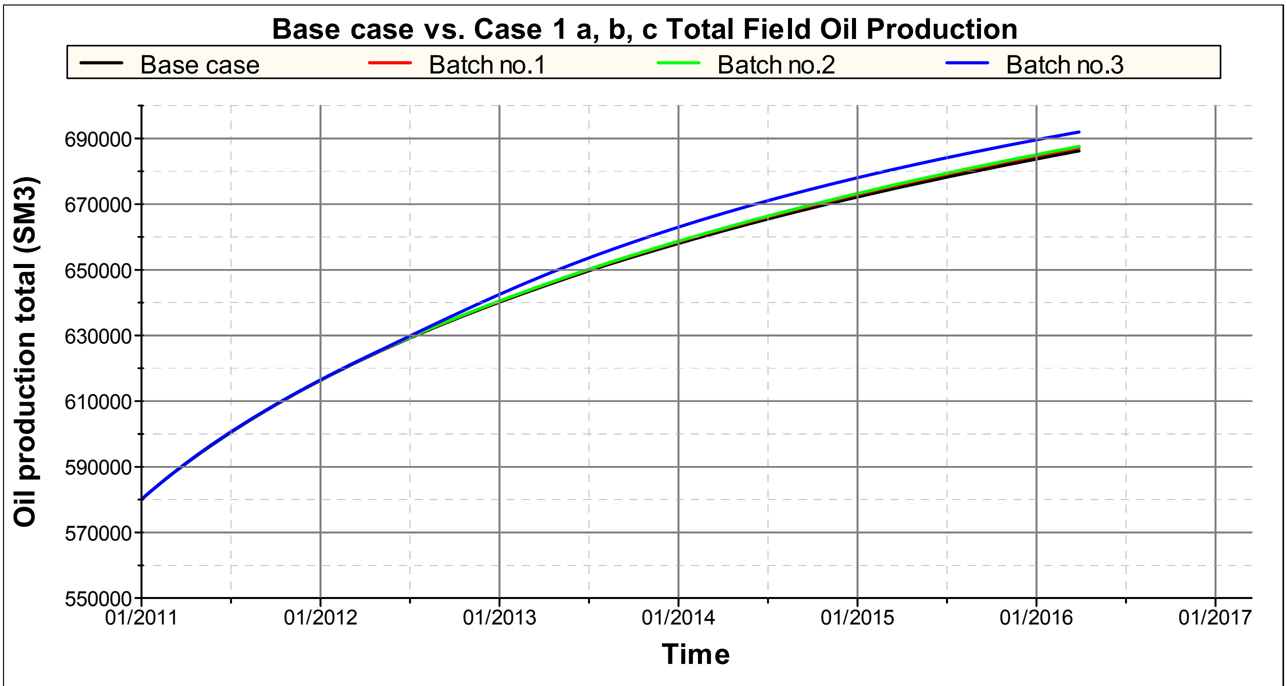


Figure 70: Total oil production, 3 batches of sodium silicate, from start treatment

As a result of the third batch with sodium silicate, the oil production rate increases for a couple of years especially in layer 3 but also in layers 1 and 2. Layers 4, 5 and 6 have already got water

breakthrough before injecting sodium silicate and negligible oil volumes may be produced from these layers.
For the same period of time the water production rate decreases significantly in layer 3 but is slightly increased in layers 4, 5 and 6. An increase in water production was not expected in the layers that were attempted closed off with sodium silicate.
The oil and water production rates for each layer, after the third batch treatment, are plotted against the base case rates in Figure 71, Figure 72, Figure 73, Figure 74, Figure 75 and Figure 76.

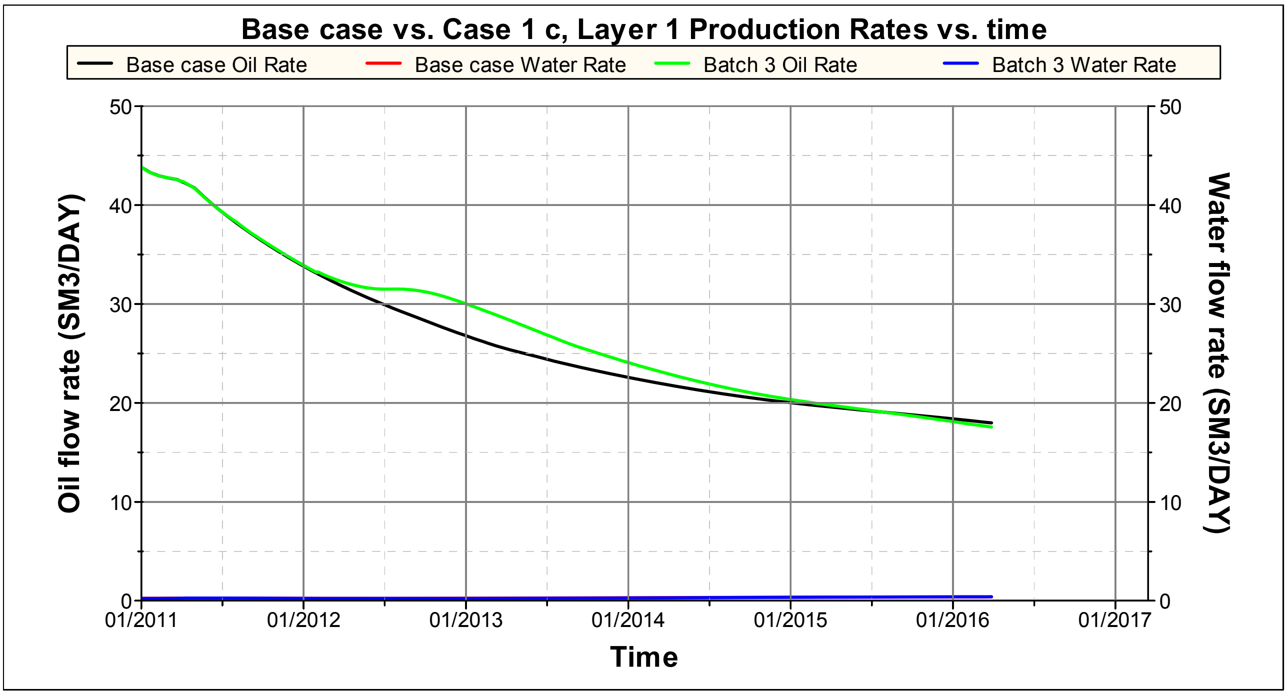


Figure 71: Development of oil production rate, layer 1

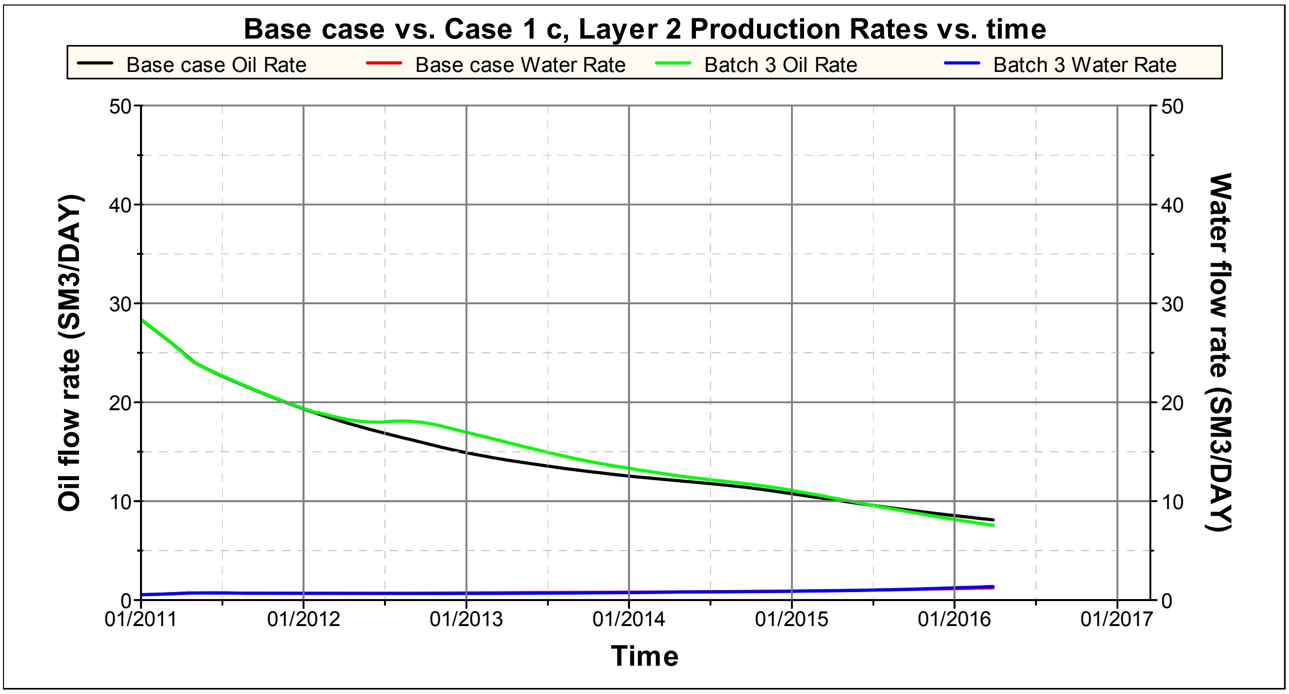


Figure 72: Development of oil production rate, layer 2

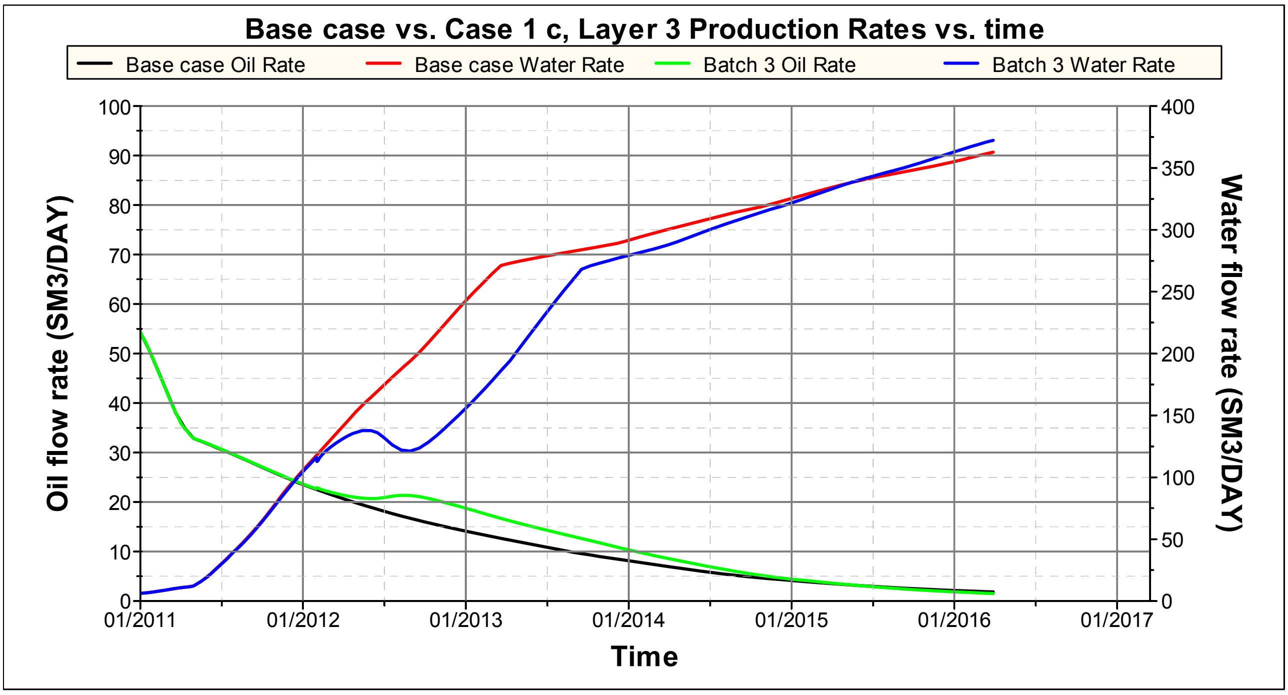


Figure 73: Development of oil production rate, layer 3

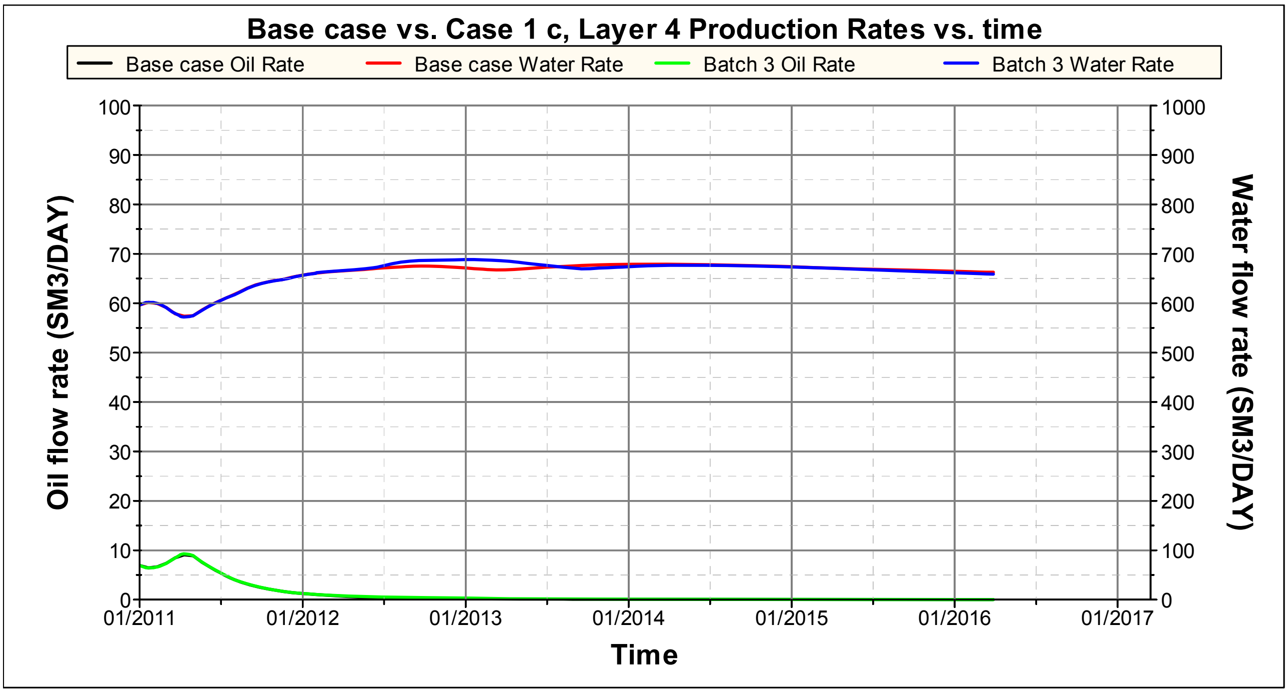


Figure 74: Development of oil production rate, layer 4

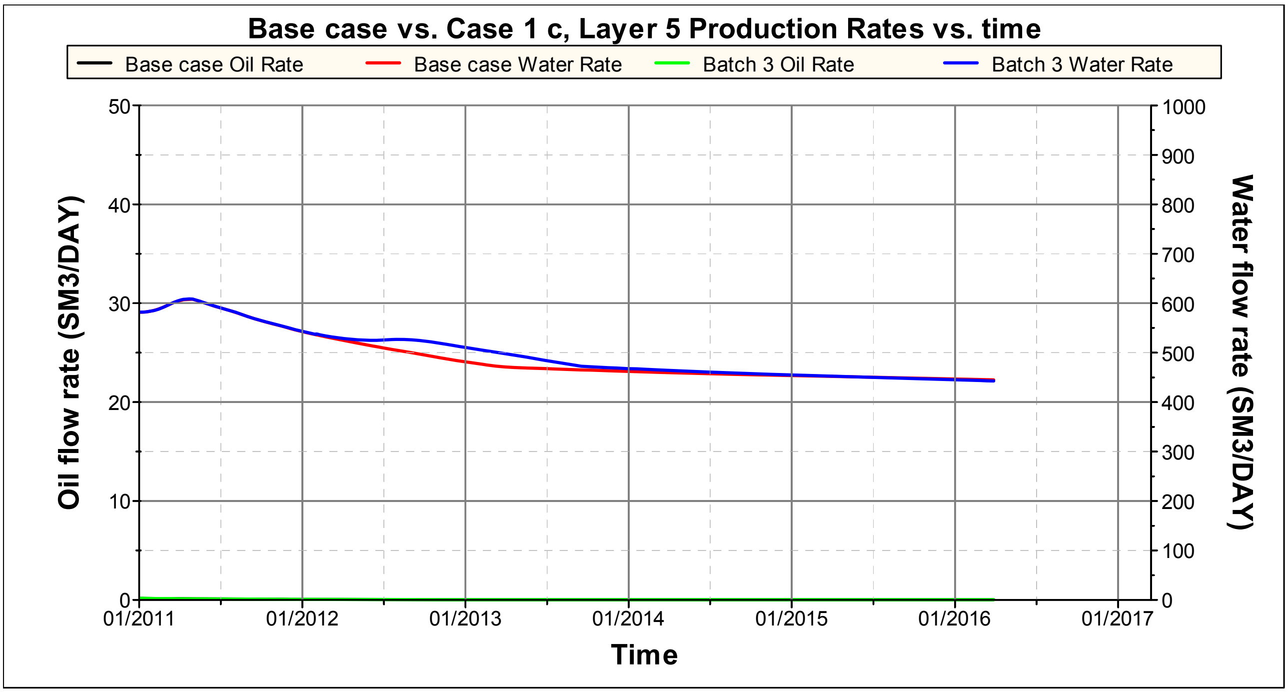


Figure 75: Development of oil production rate, layer 5

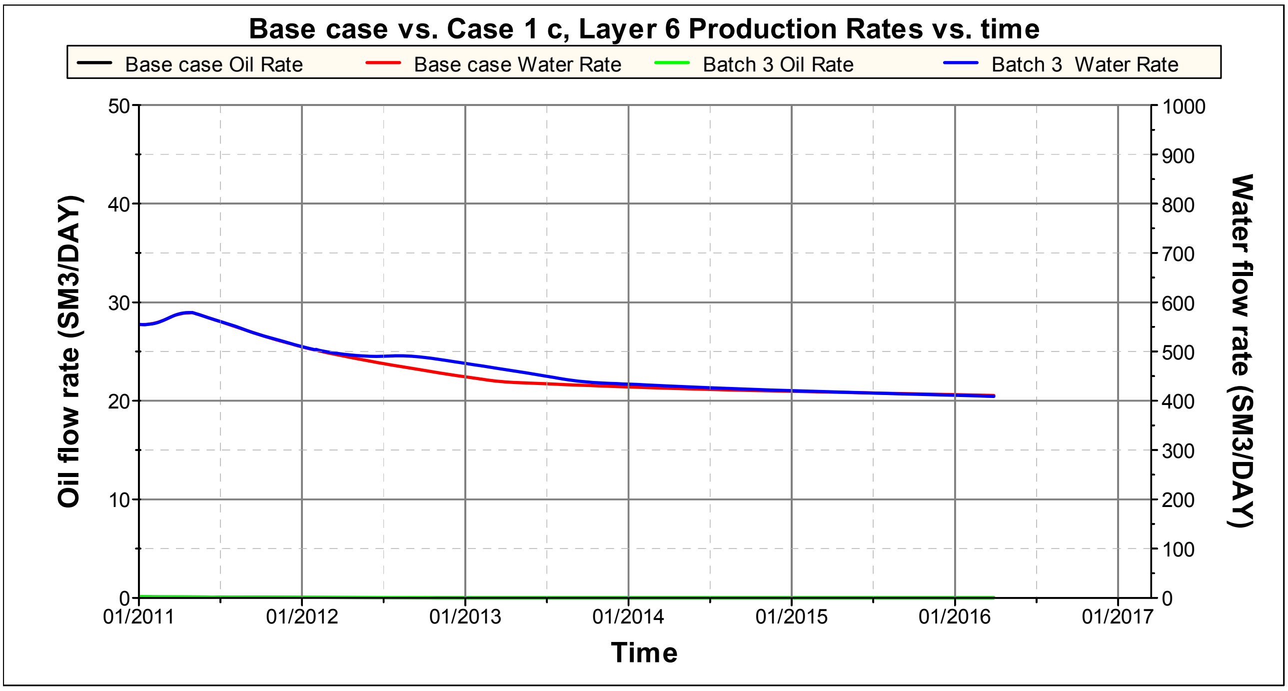


Figure 76: Development of oil production rate, layer 6

Figure 77, Figure 78, Figure 79, Figure 80, Figure 81 and Figure 82 show development of oil in place and total oil production in each layer after pumping the third batch of silica, compared to the base case. The biggest reduction of oil in place can be seen in layers 1 and 2. Layer 3 ends up on approximately the same oil in place for the silica injection case compared to the base case. Layers 4, 5 and 6 get slightly higher oil in place after injection of silica. This is probably due to the heavy reduction of PERMX in the silica treated cells, and that these cells still have some mobile oil left which get captured. Also a less effective water flooding is expected in these layers after silica treatment.

The same figures also show how oil and water cross flow between the layers due to the effects of gravity, good vertical communication and water injection. Figure 78 and Figure 82 show that the oil production from layer 2, at the end of the production period, is similar to the total oil production from layer 6 even though the initial oil in place volume is twice as big in layer 6 as in layer 2. Layer 6 gets rapidly flooded while layer 2 is still not flooded at the end of the production period. The oil in place in layer 6 is reduced by the double of the volume that is produced from the layer, which shows that a large oil volume migrates to the layer(s) above. Also, total oil production from layer 1 is much higher than from the layers 5 and 6.

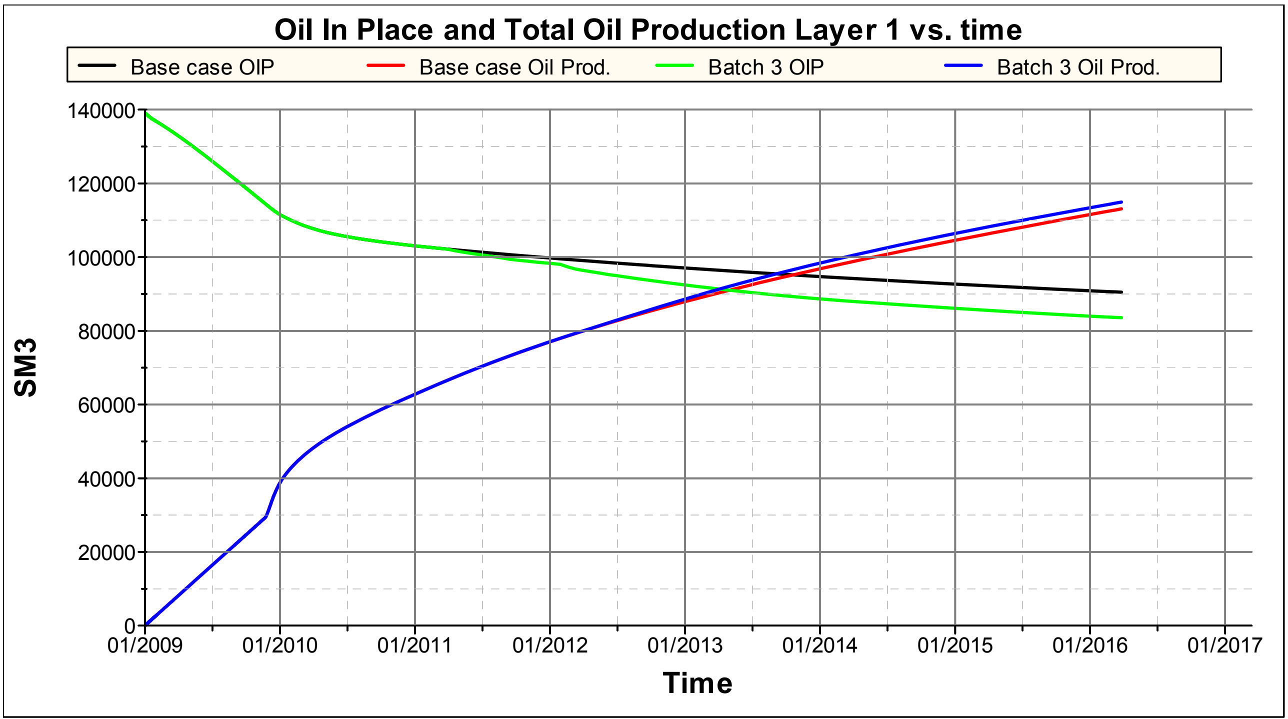


Figure 77: Layer 1; Development of oil in place, 3rd batch silica compared to base case

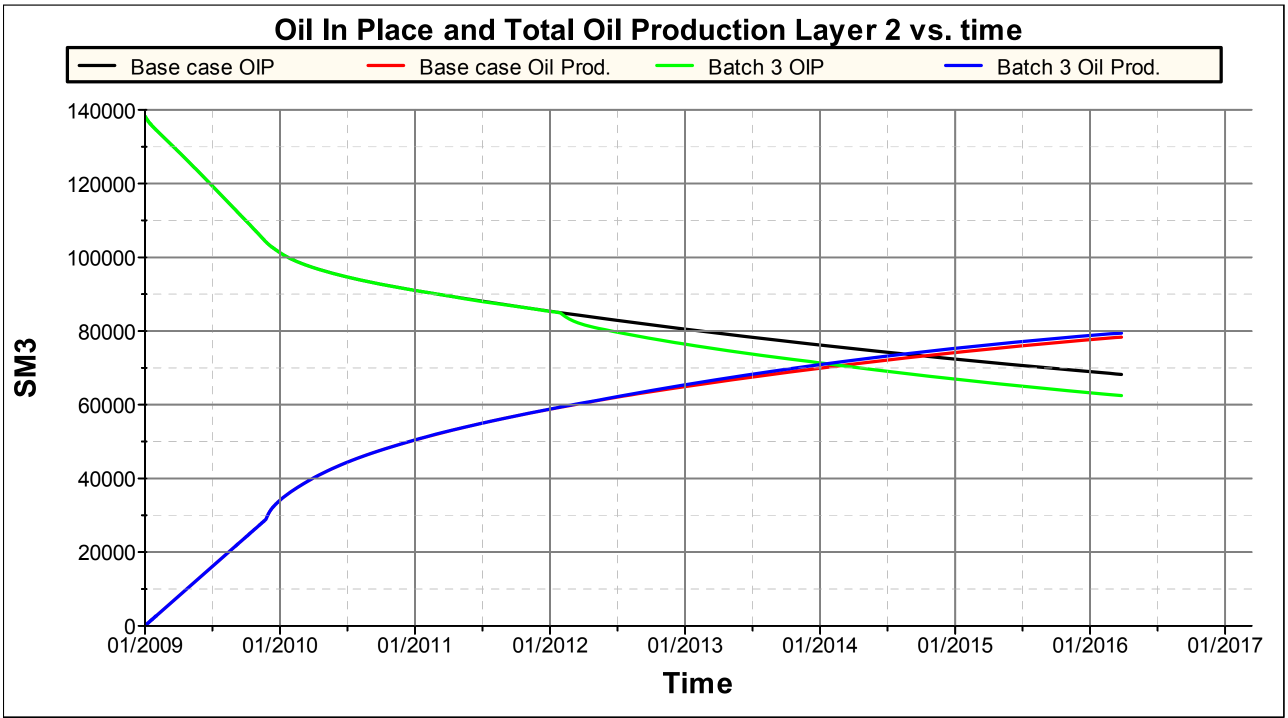


Figure 78: Layer 2; Development of oil in place, 3rd batch silica compared to base case

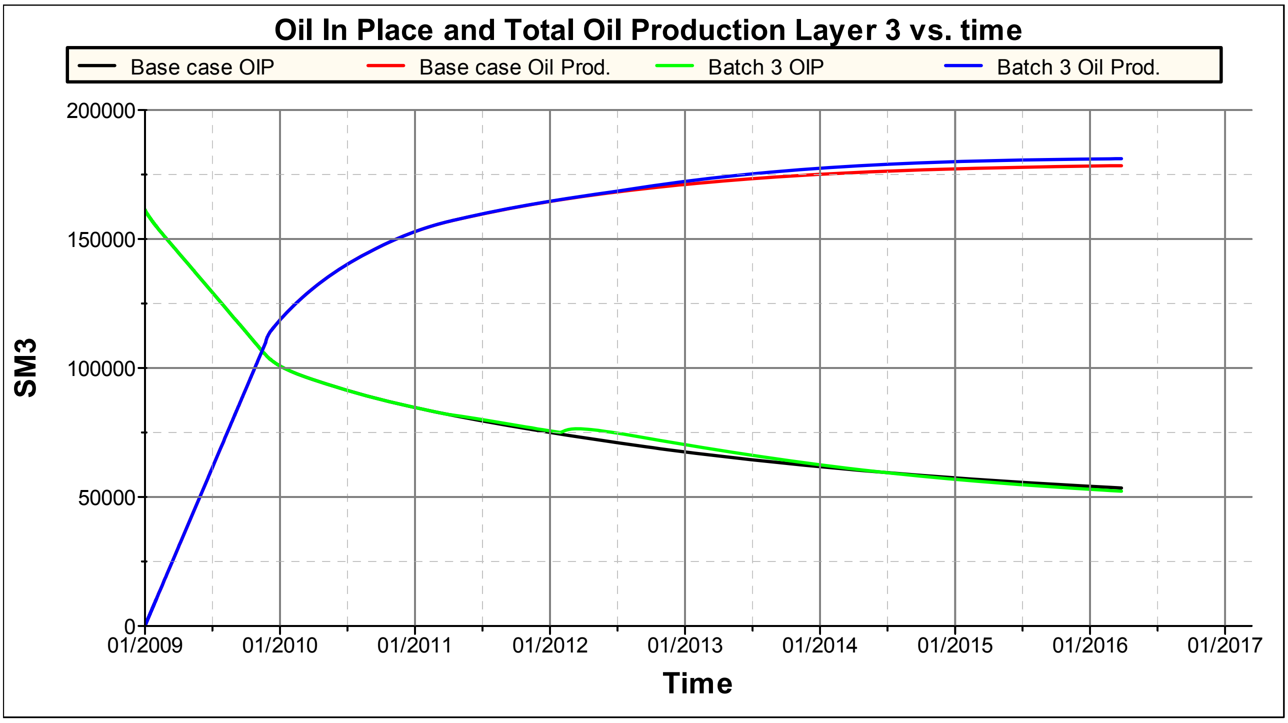


Figure 79: Layer 3; Development of oil in place, 3rd batch silica compared to base case

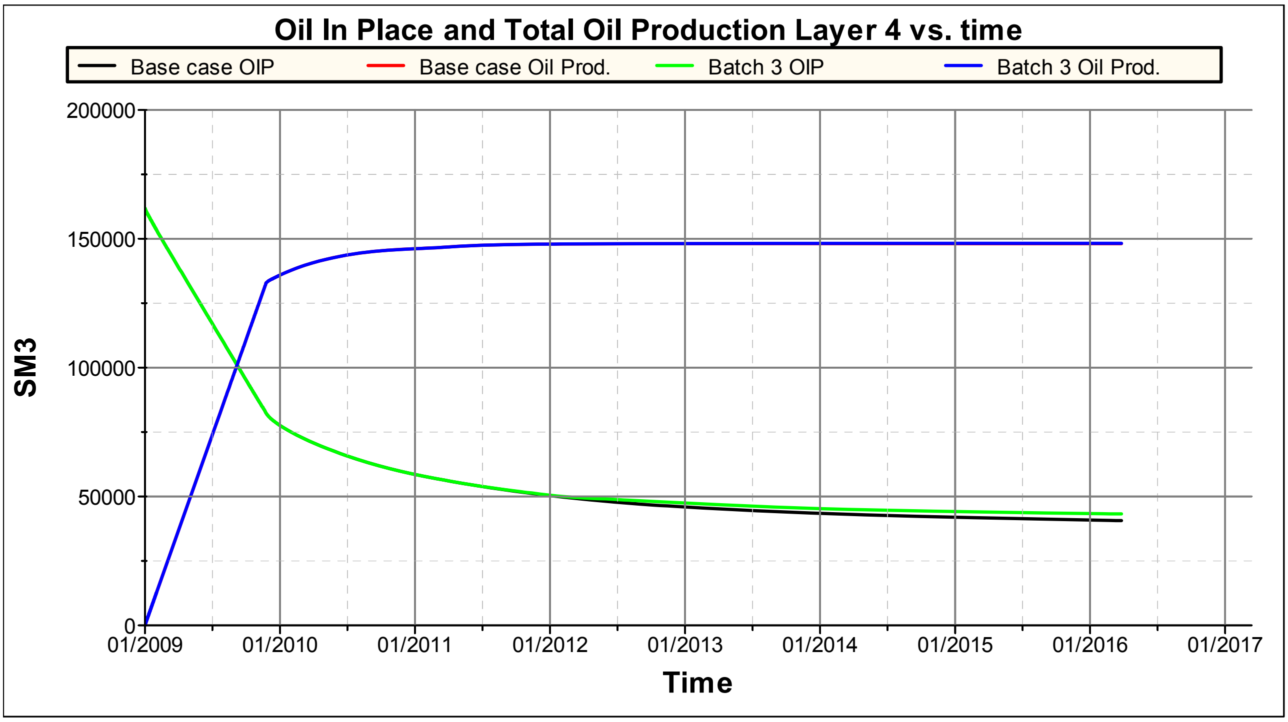


Figure 80: Layer 4; Development of oil in place, 3rd batch silica compared to base case

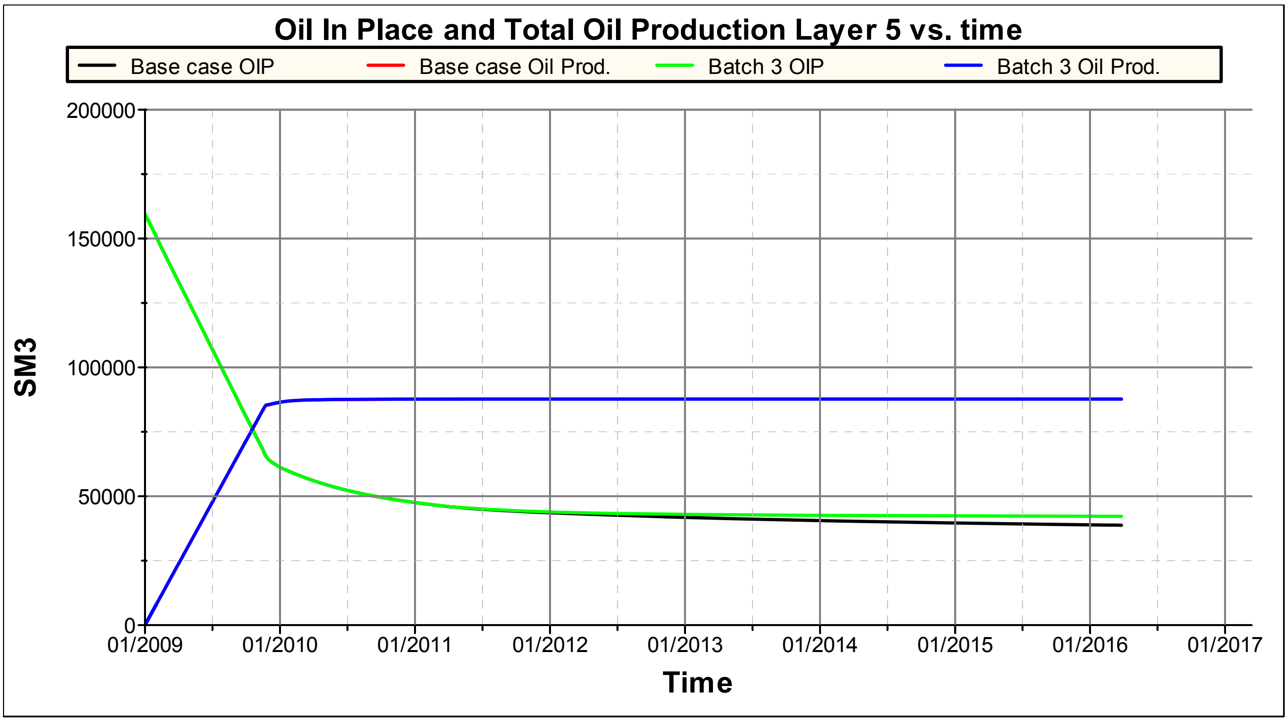


Figure 81: Layer 5; Development of oil in place, 3rd batch silica compared to base case

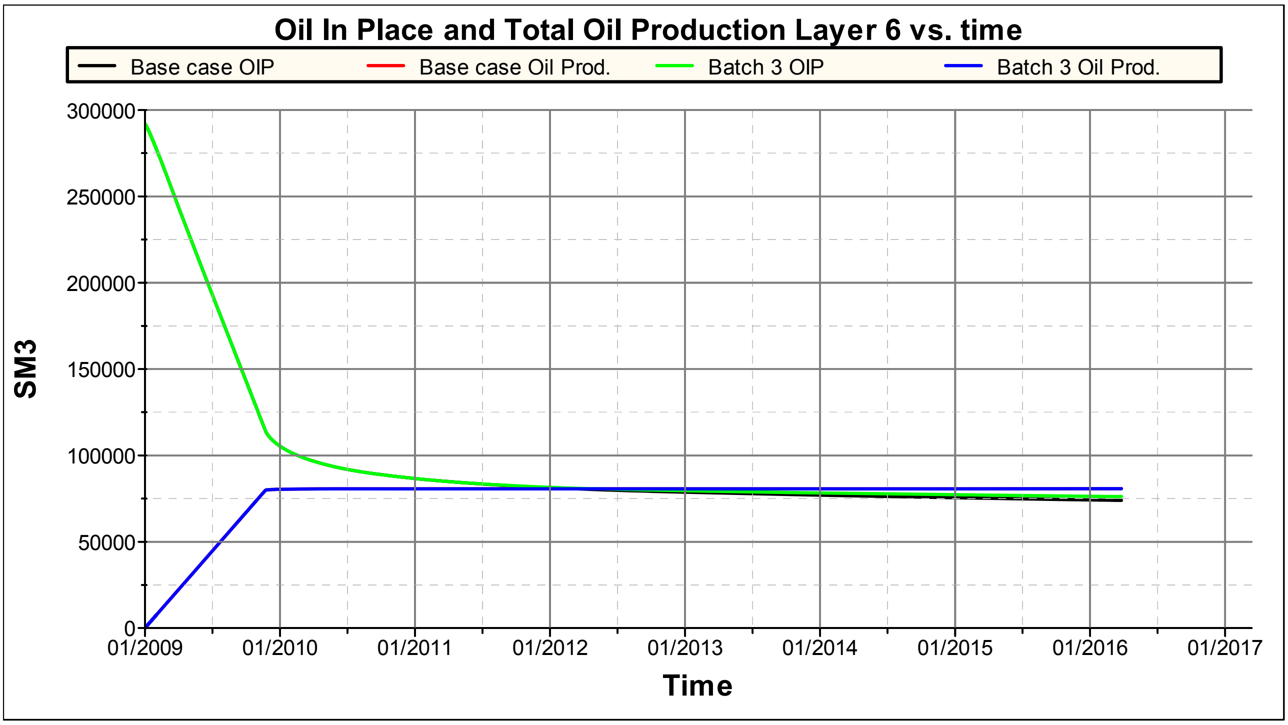


Figure 82: Layer 6; Development of oil in place, 3rd batch silica compared to base case

5.5 Case 2, big batches of silica, short displacement radius, PERMX x 0,002

For case 2 the batch size is increased to the double of the case 1 batches, i.e. 120000 m3 of sodium silicate which corresponds to a calculated 282 m of radius from the injector. Also for this case the PERMZ = 0.5 * PERMX and cells with tracer (sodium silicate) concentration above a specific level get a reduced / nearly zero PERMX * 0.002. The concentration level is also for this case chosen based on the principle that the lower layers should be closed off while the upper layers should remain open. The displacement radius for the batches is approximately the same as for the case 1 (small batches).

For case 2a, first big batch of sodium silicate, the tracer is displaced with the same volume of water as for the first small batch of silica (case 1a); 120000 Sm3 corresponding to a calculated displacement radius of 282 m.
To obtain a completely closed off area ("curve") in layer 6, some cells have to be closed off also in the upper layers. Layer 4 and 5 are also completely closed off, which is good. For a tracer concentration above 0.43, PERMX is multiplied with 0.002. As for the case 1 a (small batch of silica), a closure is obtained vertically between the layers 4 and 5 but not between the layers 5 and 6, see Figure 83. A complete closure is obtained in layers 4, 5 and 6 (see Figure 87, Figure 88 and Figure 89) while a few cells get closed in layers 3, 2 and 1 (see Figure 84, Figure 85 and Figure 86). An EOR volume of 1659 Sm3 is obtained compared to the base case.

A second batch of 120000 m3 sodium silicate, case 2 b, is pumped and displaced for 3 ½ months. For cells with a tracer concentration above 0.33, PERMX is multiplied with 0.002. A closure is obtained vertically between layers 5 and 6, see Figure 83. A new complete closure is obtained in layer 6 (see Figure 89) and 2 more cells get closed in layer 1 (see Figure 84).
An EOR volume of 2421 Sm3 is obtained compared to the base case.

A third batch of 120000 m3 sodium silicate is pumped and displaced for 5 months. For a tracer concentration above 0.225, PERMX is multiplied with 0.002. An extra complete closure is obtained in layers 1, 3, 4, 5 and 6, ref cross-section view in Figure 83 and layers view in Figure 84, Figure 85, Figure 86, Figure 87, Figure 88 and Figure 89.
An EOR volume of 6234 Sm3 is obtained compared to the base case. This is only approximately 500 Sm3 more than the result that was obtained with 3 batches of sodium silicate with half of the size. EOR is increased by 0,91% compared to the base case and the recovery factor is increased by 0,6%.

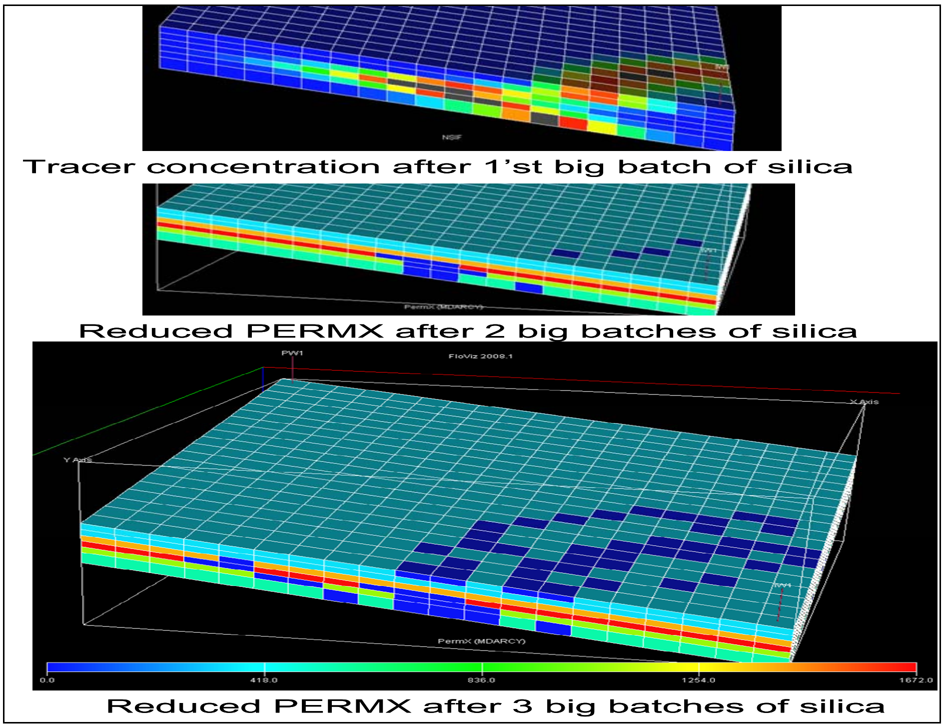


Figure 83: Case 2, Cross-section view, vertical closure between layers

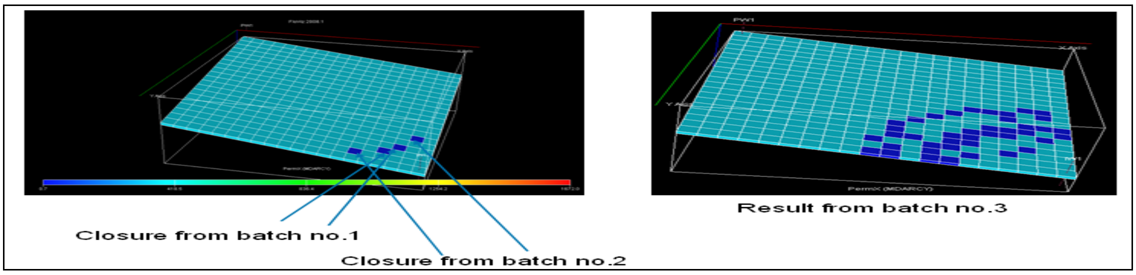


Figure 84: Layer 1: Case 2, closures from big batches 1, 2 and 3

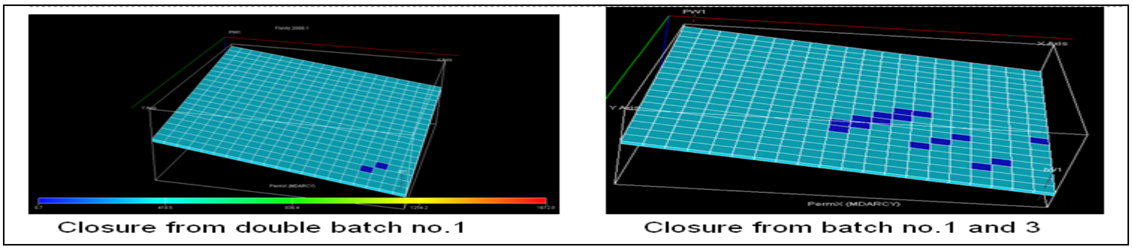


Figure 85: Layer 2: Case 2, closure from big batches 1 and 3

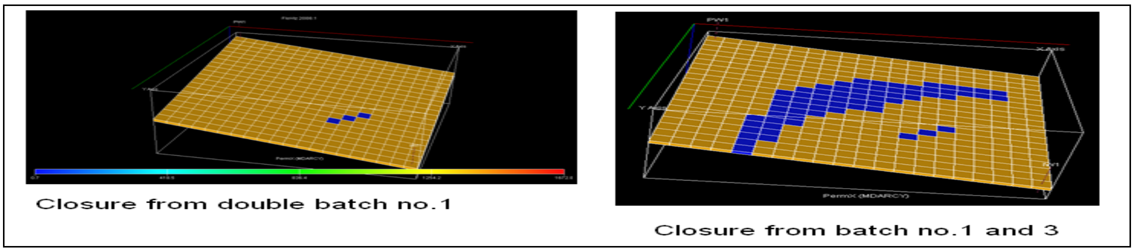


Figure 86: Layer 3: Case 2, closure from big batches 1 and 3

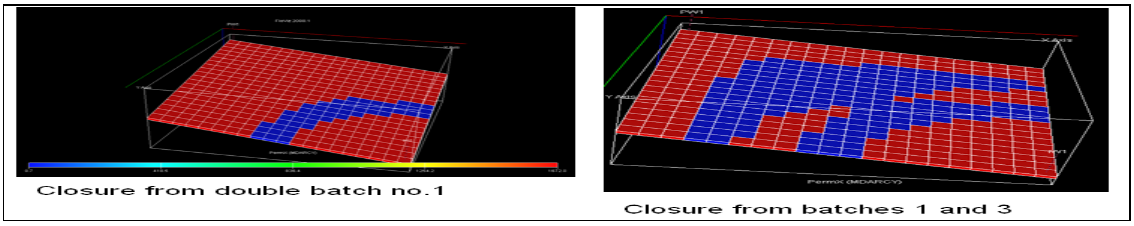


Figure 87: Layer 4: Case 2, closure from double batches 1 and 3

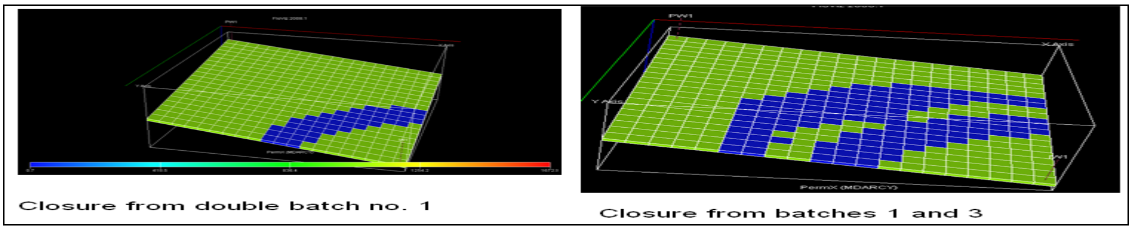


Figure 88: Layer 5: Case 2, closure from double batches 1 and 3

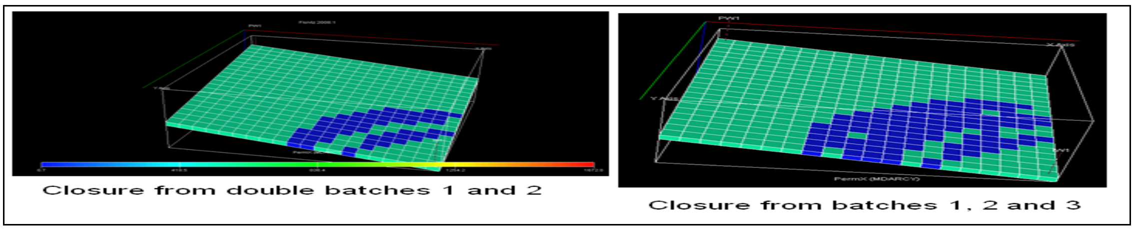


Figure 89: Layer 6: Case 2, closure from double batches 1, 2 and 3

The distribution of sodium silicate for the big batches of silica follows approximately the same pattern as for the cases of small size batches (case 1). Also for case 2 the main contribution to the EOR follows after the third batch of silica is pumped. Both for case 1 and 2, an extra major closure is obtained in layers 4, 5 and 6, also vertically between these layers, by the third batch of silica, see Figure 68 and Figure 83. Concerning which layers that gets the highest EOR effect the same tendency is discovered for case 2 as for case 1. Layers 1 and 2 get reduced oil in place, layer 3 is unchanged while the layers 4, 5 and 6 get increased oil in place when injecting sodium silicate. This effect is bigger for big batches of silica. The figures studied are not included in the report since they look approximately the same as for the case 1, except having a little higher values than for the case 1, see Figure 77, Figure 78, Figure 79, Figure 80, Figure 81 and Figure 82.

A comparison of case 1 and case 2, small and big third batches, is made in Figure 90 and Figure 91. The oil production is accelerated by the case 2c more than by case 1c, but at the end of the production period there is no big difference in total oil production.

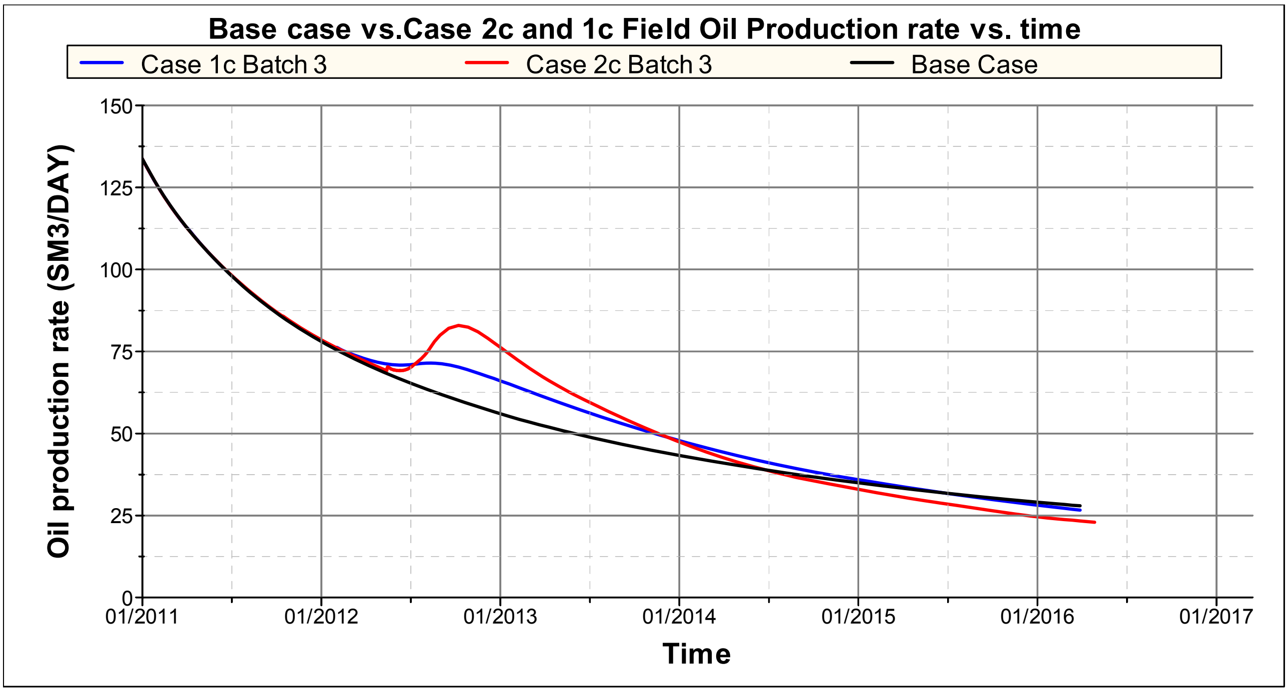


Figure 90: Oil production rate, comparison of third batch of silica in case 2c and 1c vs. base case

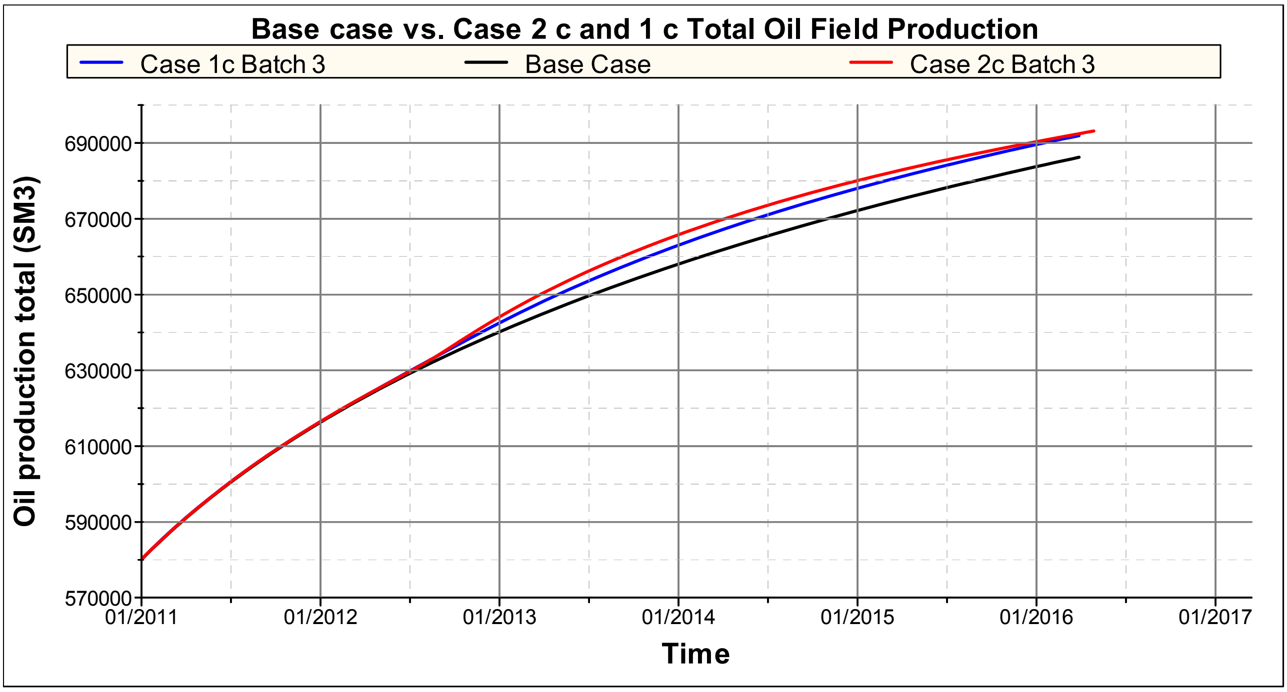


Figure 91: Total oil production, comparison of case 2c and 1c 3'rd batch of silica vs. base case

5.6 Effect of reducing the vertical permeability / communication between the layers

A new base case is simulated where the parameters used in 5.1 (original base case) is valid except the vertical permeability which is reduced. PERMZ used is 0.05 times the horizontal permeability instead of 0.5 * PERMX as used in the main base case.

Reducing the vertical permeability to 0.05 * PERMX result in essential less oil production for the same production period; 46864 Sm3 less oil produced. This means that the recovery factor is reduced by 5%.
Water flooding is far less efficient for this case. The reduced vertical permeability leads to a reduced effect of the segregation mechanism of oil and gas.
Only layer 1 benefits of a reduced vertical permeability in terms of oil production and reduced oil in place. The recovery factor increases with 3% in this layer. The injection water is displacing the oil in layer 1 more efficient, less water flows from layer 1 to layer 2. Layer 6 gets approximately the same result while the other layers get reduced production, see Figure 92 through Figure 97.
Concerning oil flowing from the lower layers and upwards, totally 20000-30000 Sm3 less oil is flowing between the layers for the new base case.
From Figure 97 it can be seen that in layer 6 the oil in place at the end of the production period is approximately 25000 Sm3 higher for the new base case compared to the original base case. This means that less oil migrates from the lower layer and upwards due to the reduced vertical permeability.
The simulated oil saturation in the upper layer, at the end of the production period, is compared with an updated flooding map for top Etive 3 formation (layer 1). As the original base case gives higher oil saturation in layer 1 at the end of the production period, it is believed that this model, with higher vertical permeability, matches the reservoir conditions better. Based on this, only 2 sodium silicate cases are analyzed where PERMZ = 0.05 * PERMX.

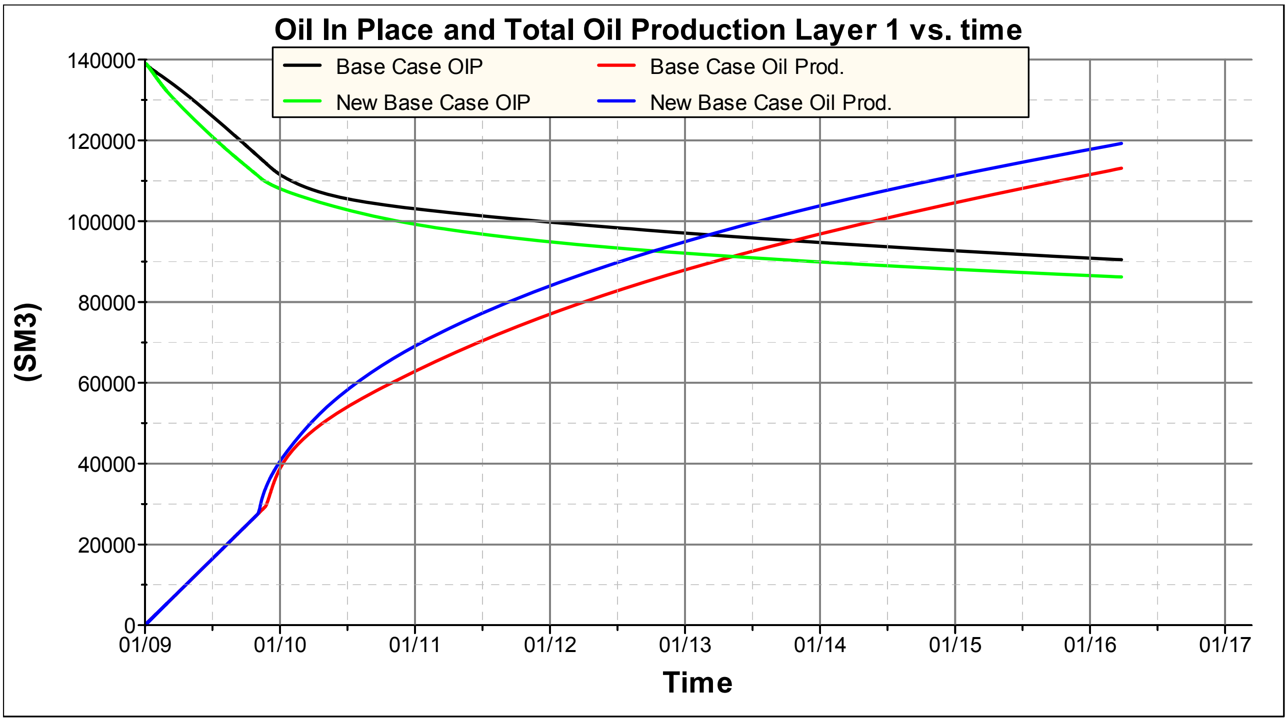


Figure 92: Comparison of original base case and new base case, layer 1

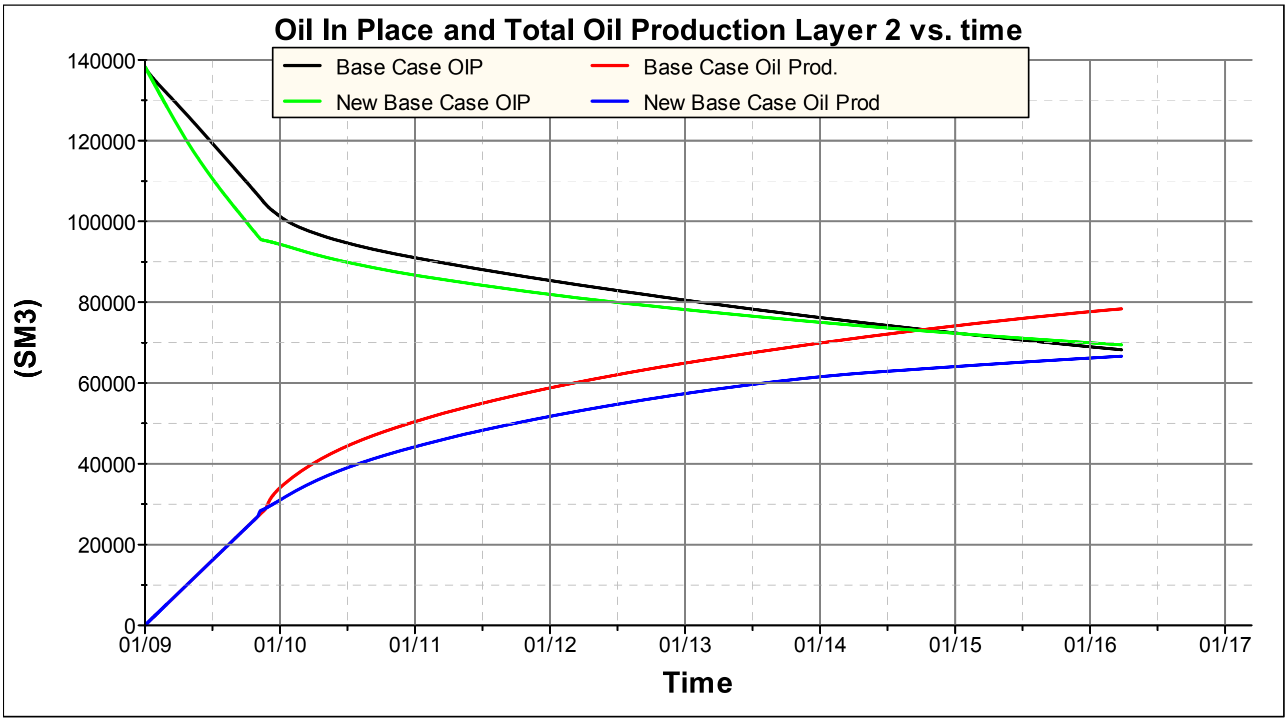


Figure 93: Comparison of original base case and new base case, layer 2

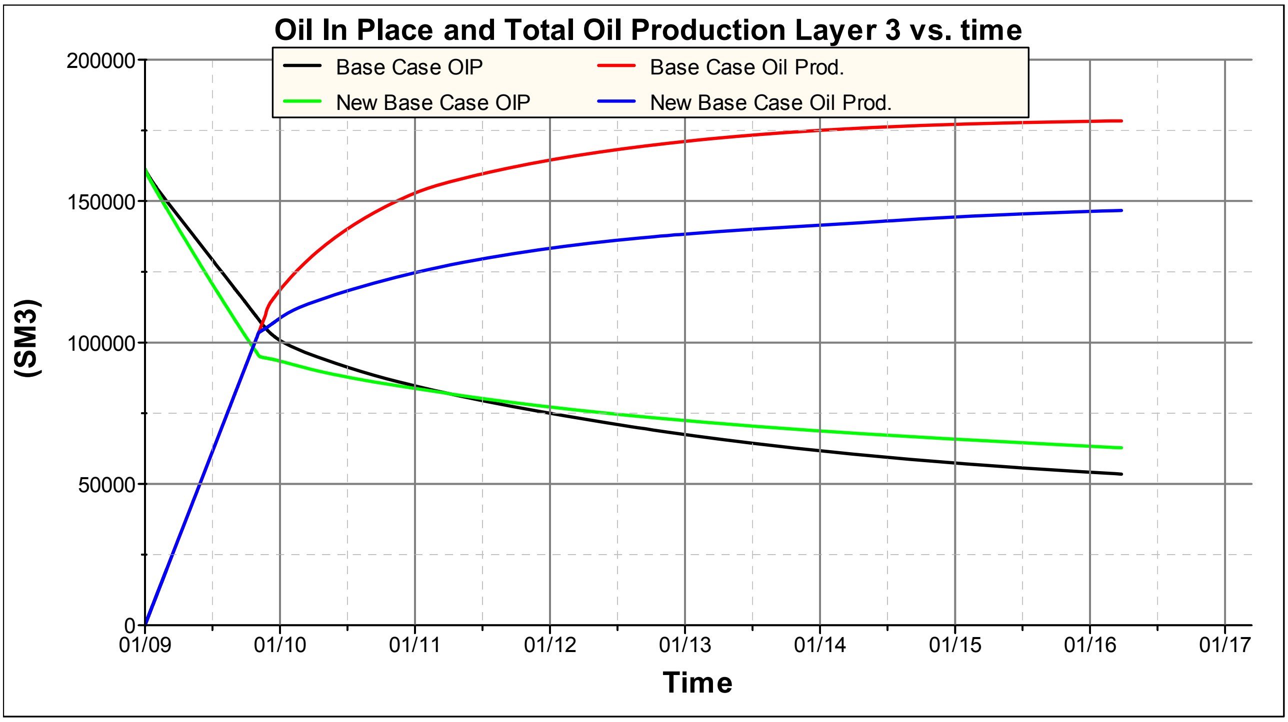


Figure 94: Comparison of original base case and new base case, layer 3

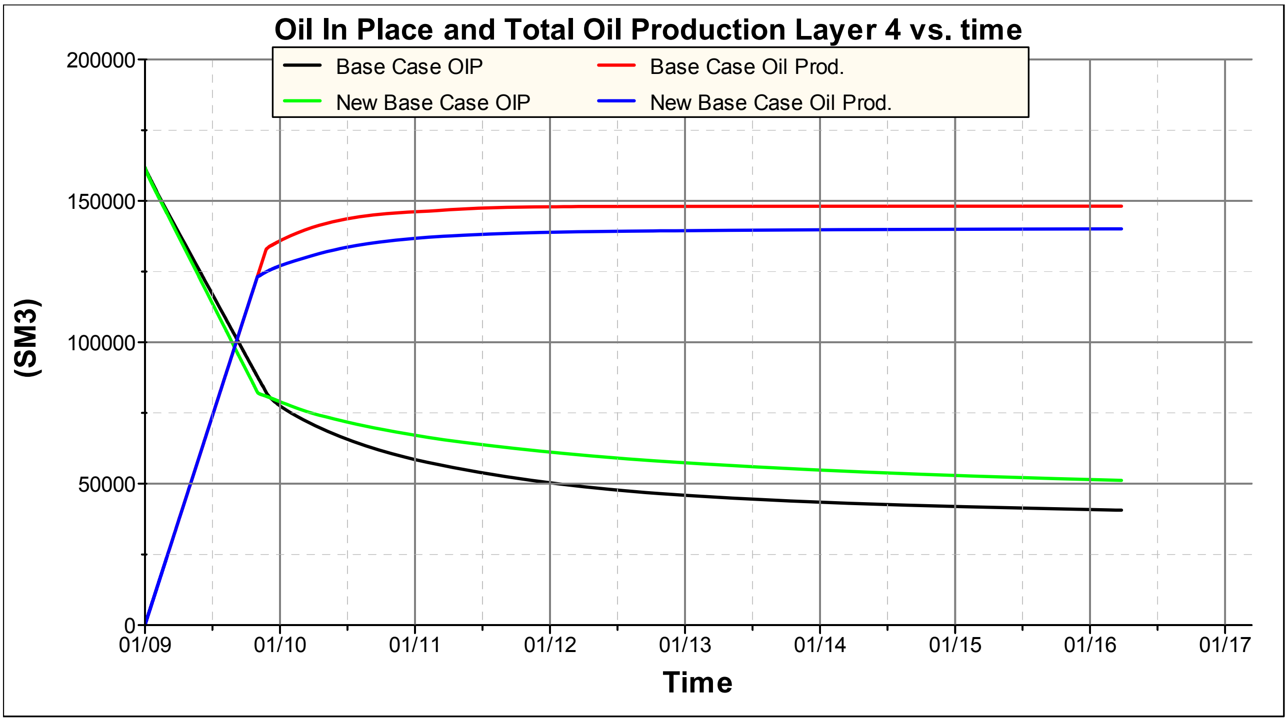


Figure 95: Comparison of original base case and new base case, layer 4

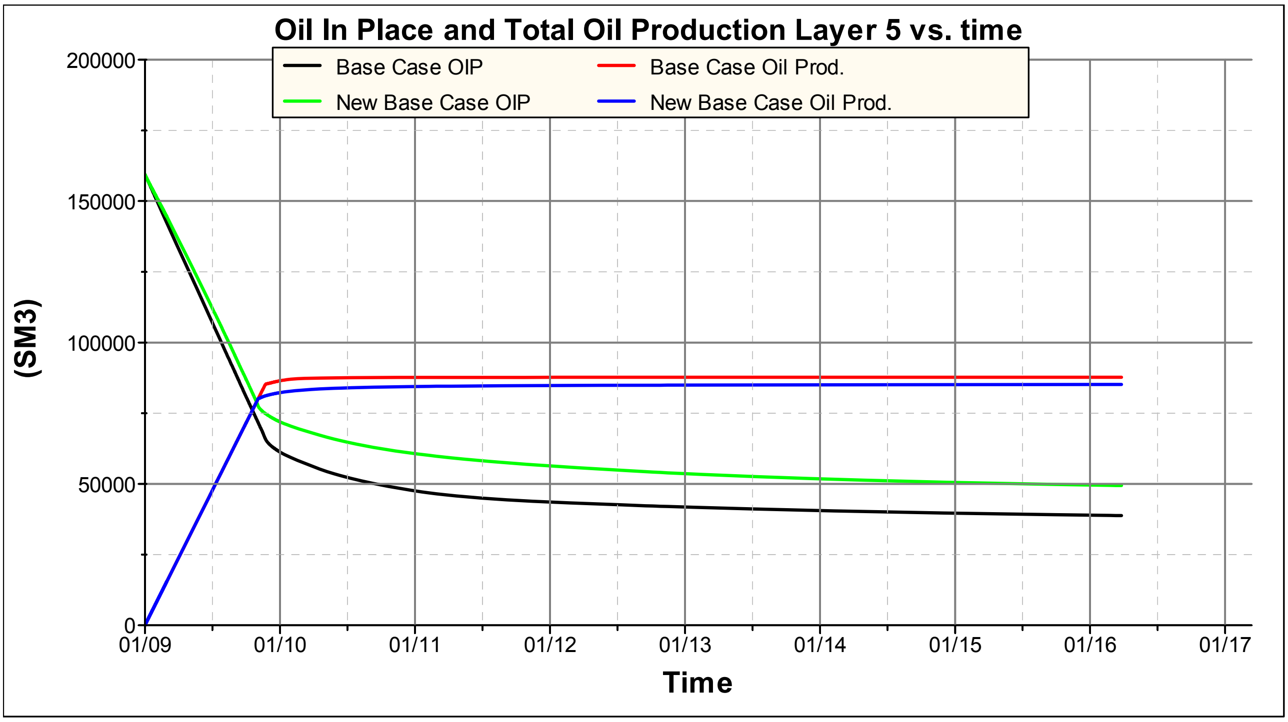


Figure 96: Comparison of original base case and new base case, layer 5

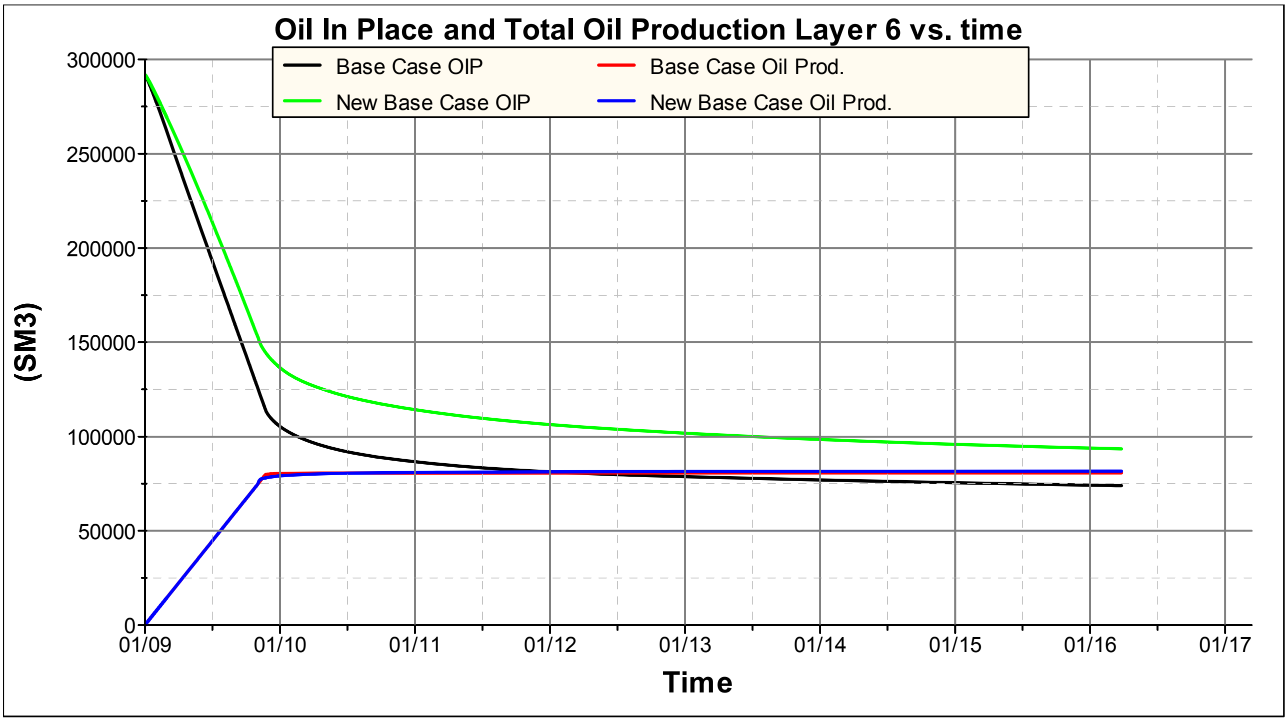


Figure 97: Comparison of original base case and new base case, layer 6

5.7 Case 3, one small batch of silica, short displacement radius, PERMX x 0.002, PERMZ = 0.05 * PERMX

The same simulation procedure is followed as described earlier. 60000 Sm3 of sodium silicate is injected with 2000 Sm3/d, 30 days. This is equivalent to a calculated 200 m radius distance from the injector well. The tracer is displaced with 120000 Sm3 water, 2000 Sm3/d, 60 days, 282 m radius similar to case 1a.
In FloViz PERMX is modified to 0,002 * PERMX in the cells where the tracer concentration is higher than 0.27. The concentration for which the PERMX is reduced is chosen based on the principle that the waterways in the lower layers should be closed while the upper unflooded layers should remain open.
This is visualized by the black colour in Figure 98. The distribution of sodium silicate is quite similar to the 1a case analyzed in 5.4 where the model and parameters are similar except of the PERMZ = 0.5*PERMX. However, slightly higher concentration may be observed in layer 5 for the low vertical permeability case. A complete closure is obtained in layers 6, 5 and 4, but only closed vertically between the layers 4 and 5 as for the case 1a. 2 cells get closed in layers 1 and 2. The case 3, with lower vertical communication than case 1a, seems to “suffer” less when a vertical closure is not obtained between layer 5 and 6.
An EOR volume of 30026 Sm3 is obtained compared to the new base case! The EOR is increased by 4.7 % compared to the new base case and the recovery factor is increased by 2.86%.
Obviously a much higher EOR effect may be expected if the vertical permeability/communication is low, but this seems not to be the case for the Veslefrikk Etive formation.

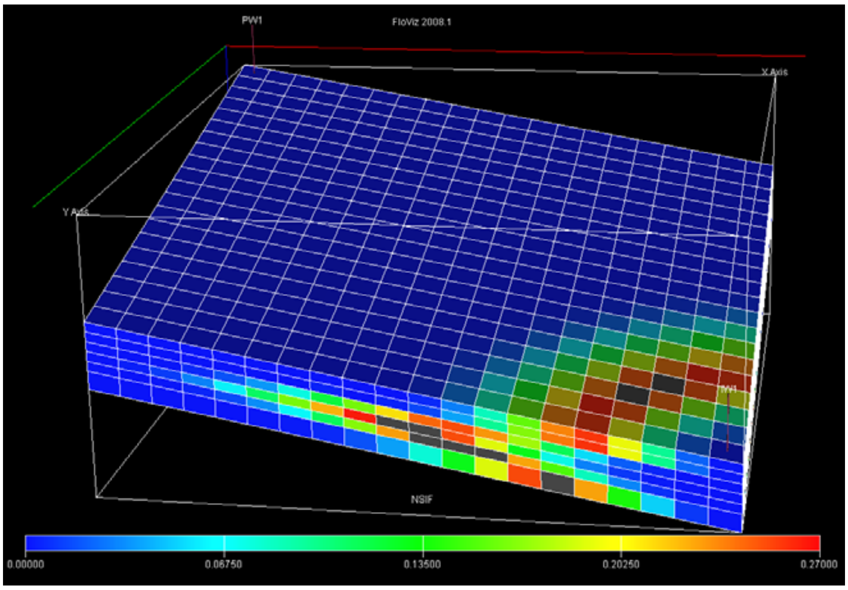


Figure 98: Concentration of tracer after displacement of small silica batch, PERMZ=0.05*PERMX

5.8 Case 4, one big (double) batch of silica, short displacement radius, PERMX*0.002, PERMZ = 0.05 * PERMX

The same procedure is followed as in 5.7 (case 3) except that a double size batch of sodium silicate is pumped (120000 m3 / 282 m radius, and displaced with same volume of water).The sodium silicate is distributed similarly as in 5.7 but a step further out. A complete closure is obtained in layers 6, 5 and 4, but only closed vertically between the layers 4 and 5. 1 cell gets closed in layers 1 and 2, see Figure 99. The EOR obtained from this case is slightly lower than for the case 3; 29448 Sm3. The only reason for this difference seems to be that the EOR effect from the sodium silicate occurs one month earlier in the case 3 than for the case 4, see Figure 100 and Figure 101. Also an extra oil volume is expected to be captured when utilizing a bigger batch of silica and reducing the PERMX with a factor of 0,002.

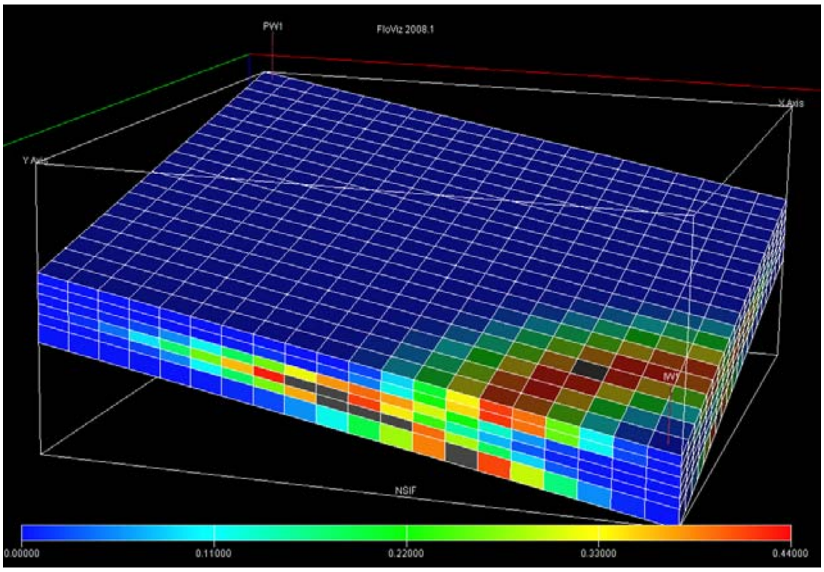


Figure 99: Concentration of tracer after displacement of big (double) silica batch, PERMZ = 0.05 * PERMX

5.9 Comparison of the new base case and the cases with small (case 3) and big (case 4) batch of silica

As can be seen in Figure 100 injection of silica accelerates oil production. The same increase in oil production rate is obtained for both the small batch and the big batch of silica. The small batch of silica gives an earlier increase in oil production rate.

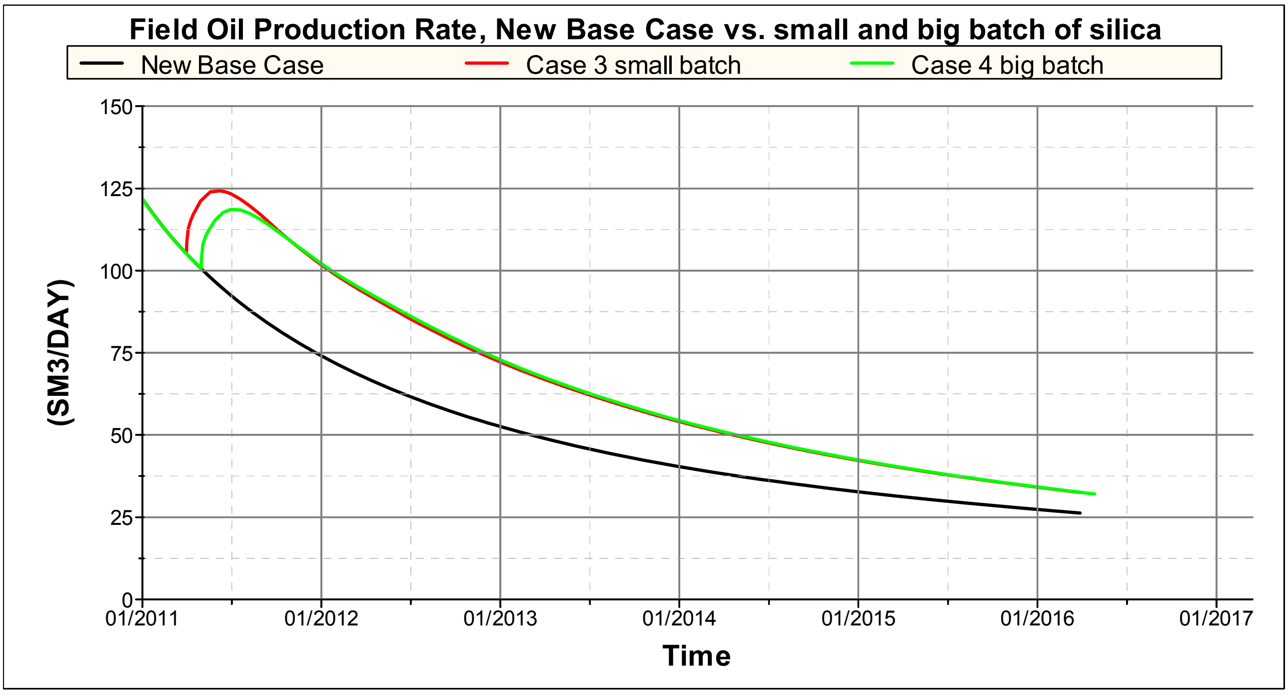


Figure 100: Field Oil Production Rate, new base case compared to silica cases

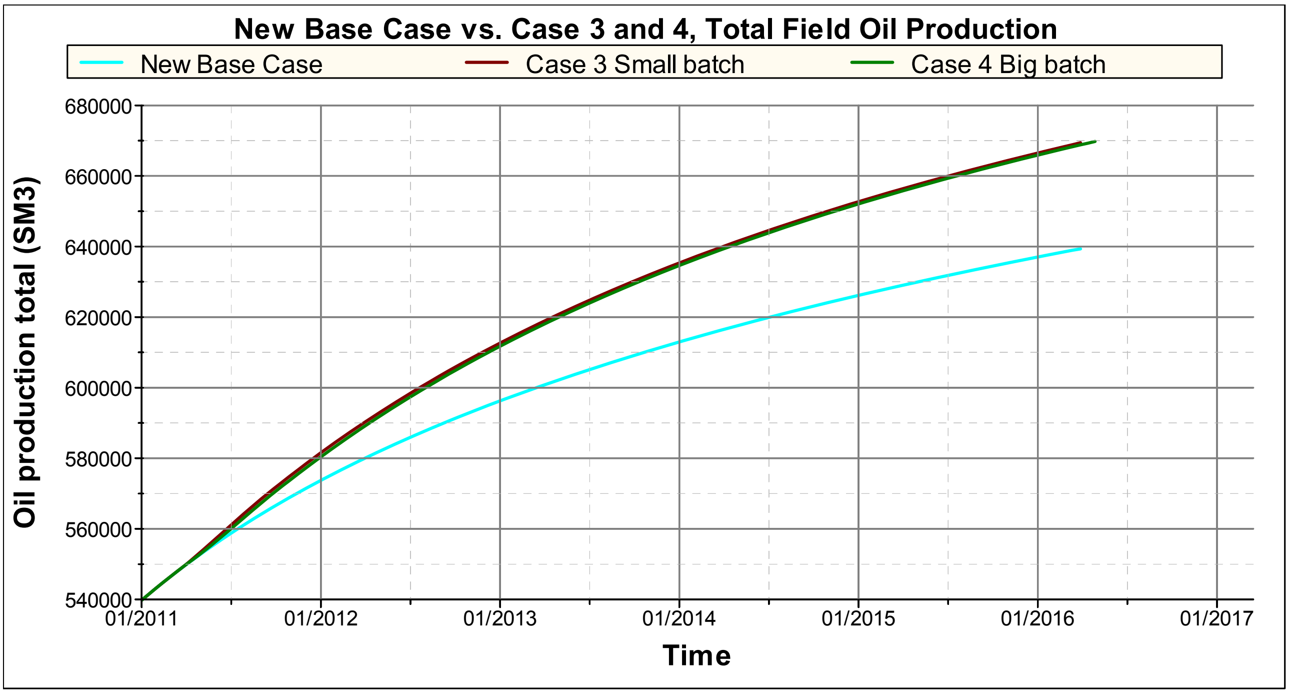


Figure 101: Total oil production after injecting sodium silicate vs. new base case, PERMZ=0.05*PERMX

The following figures, Figure 102, Figure 103, Figure 104, Figure 105, Figure 106 and Figure 107, show the result concerning development of total oil production and remaining oil volume for the different layers, comparing the new base case with the case 3 (small batch of silica). For the case of injecting silica the total oil production increases a lot in layer 1, 2 and 3, while the oil in place increases especially in layer 1 and some in layer 2. In layer 3 the oil in place gets reduced with silica. In layer 4 the total oil production is the same while in layers 5 and 6 the total oil production gets slightly reduced with silica. The oil in place gets reduced also in layers 4 and 5 but most of all in layer 6.
The EOR effect, from injection of silica in a reservoir with low vertical communication, seems to result from a changed production pattern; the vertical flow increases.

The total oil production and the oil in place resulting from injecting silica (small batch case 3) in a low vertical communication reservoir is compared with the results obtained in 5.4 (small batch case 1) for a higher vertical communication reservoir, in Table 7.
The silica cases are compared with their respective base cases and the effects of pumping silica are different.

Table 7 Effects of sodium silicate compared to the base cases

	PERMZ=0.05*PERMX		PERMZ=0.5*PERMX	
Layers	Oil in Place	Total oil Production	Oil in Place	Total oil Production
1	+	+	-	+
2	+	+	-	+
3	-	+	same	+
4	-	same	+	same
5	-	-	+	same
6	-	-	+	same

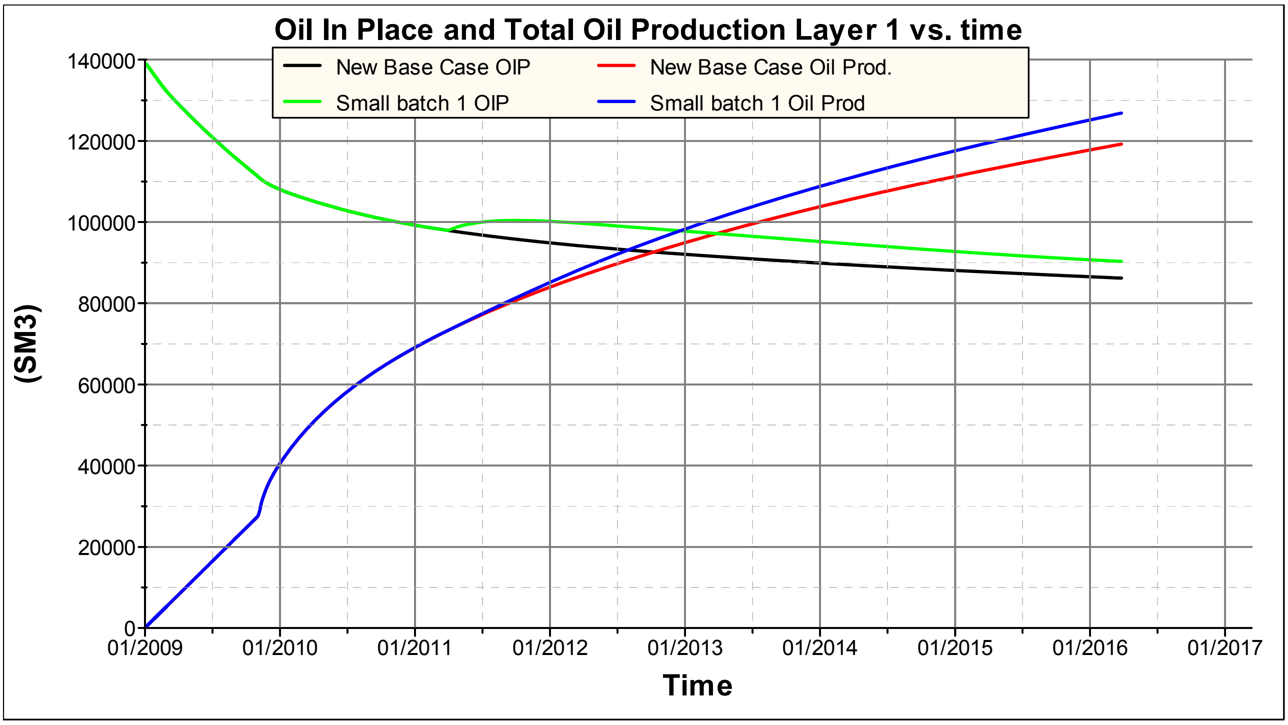


Figure 102: Comparison of new base case vs. case 3 injection of silica, layer 1

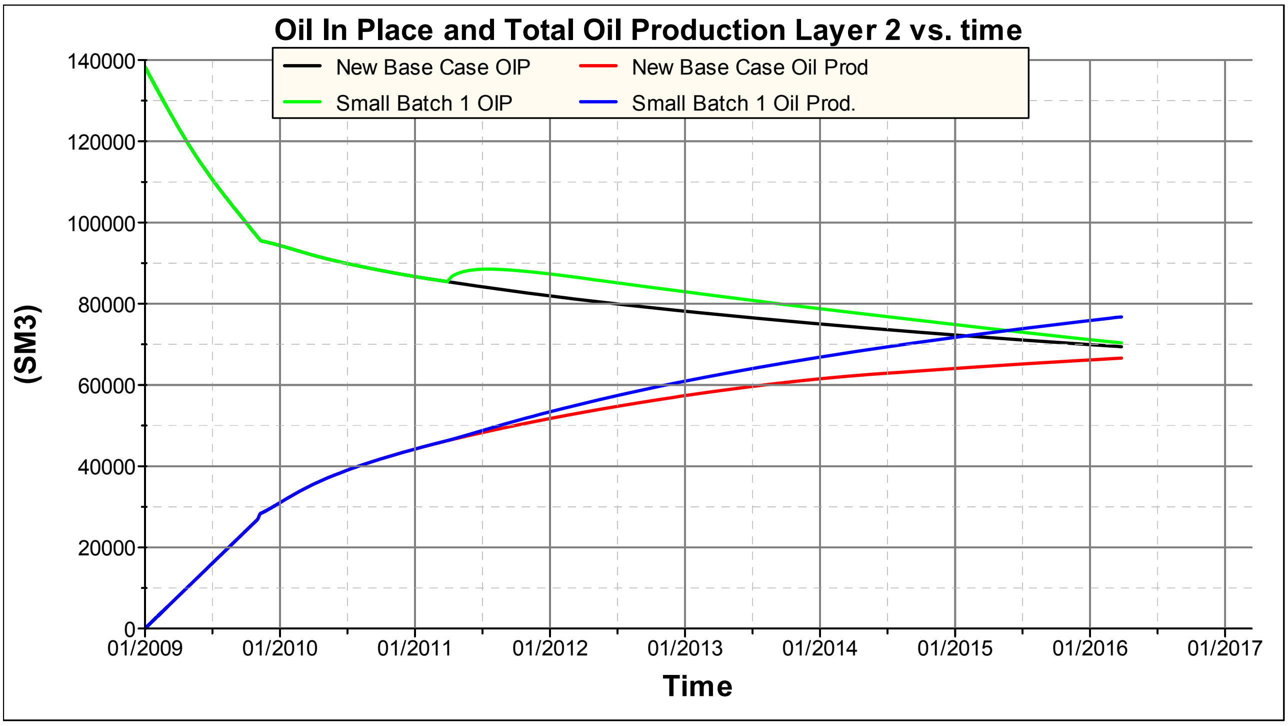


Figure 103: Comparison of new base case vs. case 3 injection of silica, layer 2

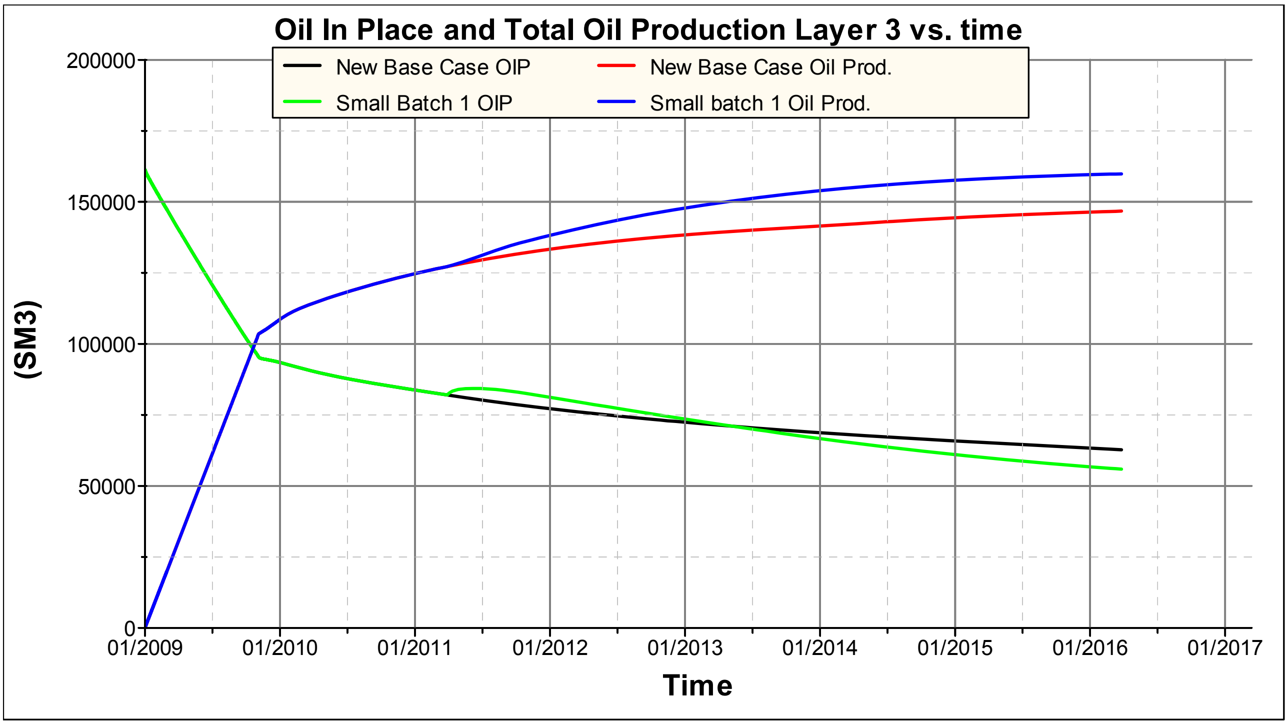


Figure 104: Comparison of new base case vs. case 3 injection of silica, layer 3

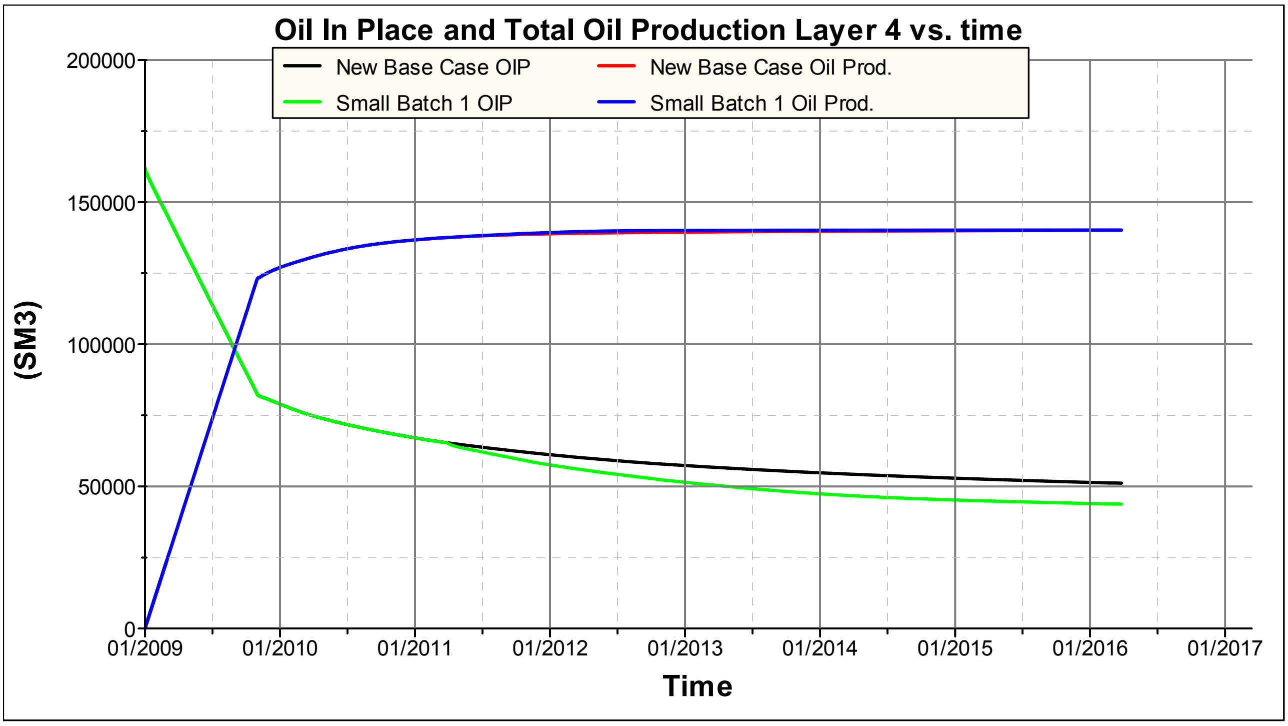


Figure 105: Comparison of new base case vs. case 3 injection of silica, layer 4

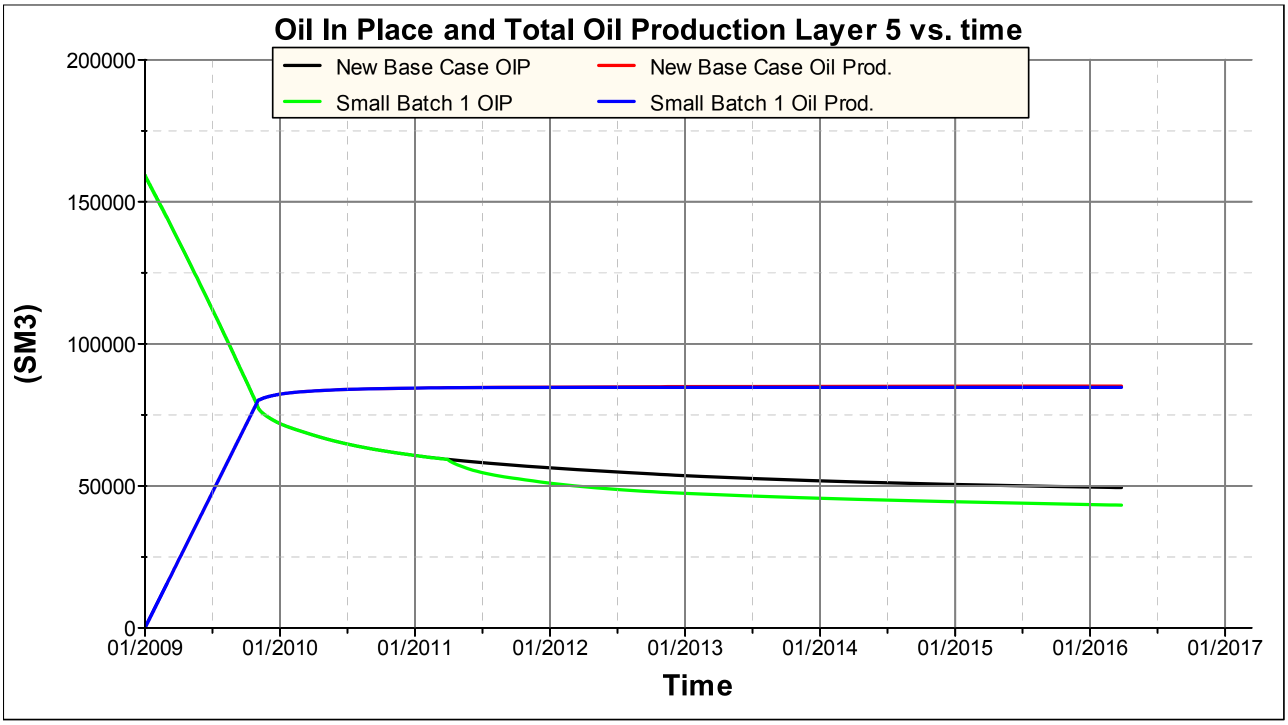


Figure 106: Comparison of new base case vs. case 3 injection of silica, layer 5

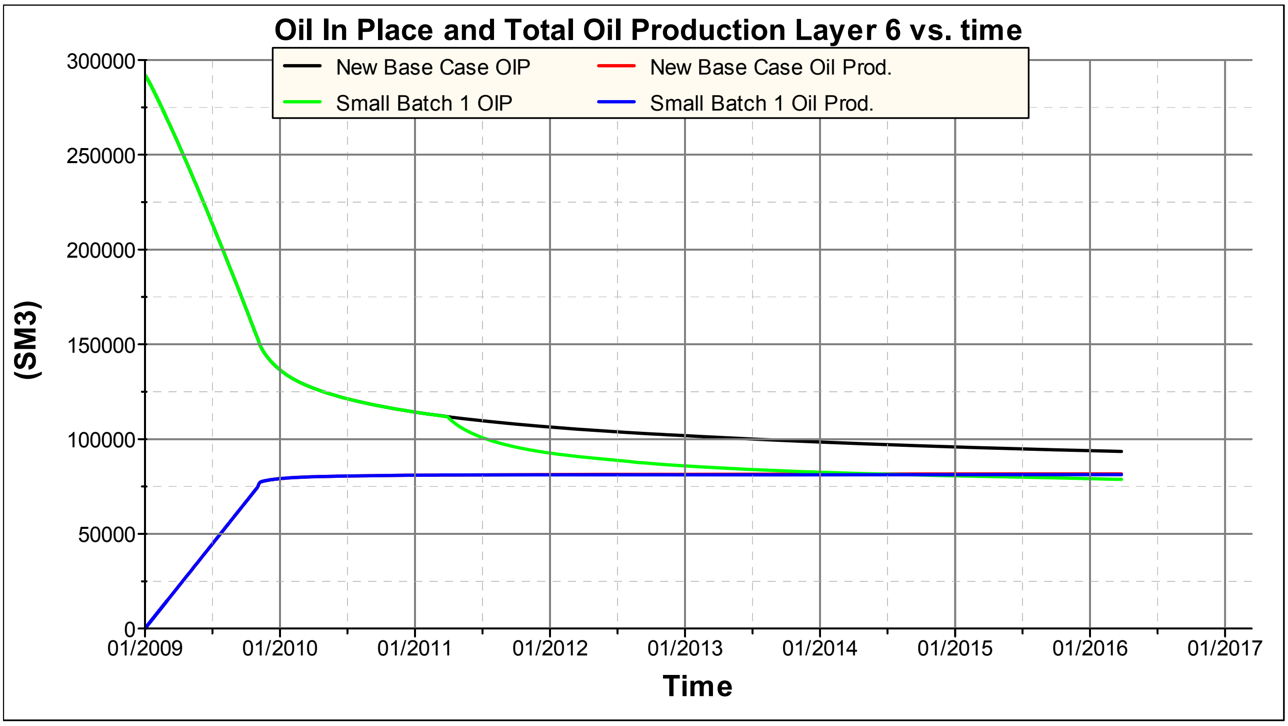


Figure 107: Comparison of new base case vs. case 3 injection of silica, layer 6

5.10 IOR effect of displacing the sodium silicate batches even further into the reservoir

The same simulation procedure as described in chapter 5.5 is used. The main difference is that the sodium silicate is displaced even further into the reservoir. Big (double) size, i.e. 120000 m3 of sodium silicate is pumped in two batches. The first batch is displaced for 5 months, 446 m radius. The second batch is displaced 5 to 6 months (446 – 489 m radius) depending on what leads to the best distribution of sodium silicate. For these cases the PERMZ=0.5*PERMX and cells with tracer (sodium silicate) concentration above a specific level get a reduced PERMX. The concentration level is also for these cases chosen based on the principle that the lower layers should be more closed while the upper layers should remain open. A lower concentration of the tracer needs to be chosen for the “far distance” than the “short distance” displacement.
Generally, the EOR effect of pumping the first batch of sodium silicate far into the reservoir is significantly better than that of three batches as described in case 1, chapter 5.4.

5.11 Case 5: Big (double) batches of silica, long displacement radius, PERMX*0,002

The first batch of sodium silicate is displaced 5 months /446 m radius, and the second batch 6 months / 489 m radius, into the reservoir. For tracer concentration above 0.245 in batch no.1 and 0.24 in batch no.2, the PERMX is multiplied with 0.002.
As a result of batch no.1, an EOR volume of 7410 Sm3 is obtained compared to the main base case, while the second batch of sodium silicate adds an additional oil volume of 1953 Sm3 to a total of 9363 Sm3. The EOR is increased by 1,36% compared with the base case and the recovery factor is increased by 0,89%.
No figures are included for this case since the distribution of tracer is similar as for the case 2 in chapter 5.5 except that it is displaced further out in the reservoir. Also for this case a vertical closure is not obtained between layers 5 and 6 by the first batch of silica. For the first batch of silica the tracer distribution is similar to that shown in the Figure 108. For the second batch of silica only layer 6 gets a big new complete closure. A few cells get closed in the other layers, especially in layer 2.

5.12 Case 6: Big (double) batches of silica, long displacement radius, PERMX*0,1

The first batch of sodium silicate is displaced 5 months / 446 m radius, and the second batch 5 months / 446 m radius, into the reservoir. For tracer concentration above 0.245 in batch no.1 and 0.2 in batch no.2, PERMX is multiplied with 0.1. For a cross-section view of tracer concentration, see Figure 108 and Figure 109. As a result of batch no.1, an EOR volume of 8477 Sm3 is obtained compared to the main base case, while the second batch of sodium silicate adds an additional oil volume of 4022 Sm3 to a total of 12499 Sm3.

To obtain a better distribution of sodium silicate in the lower layers the PERMX is multiplied with 0.1 for a lower sodium silicate concentration; 0.21 instead of 0.245 in batch 1. With this case more cells in the upper layers also get reduced PERMX and an IOR volume of 11083 Sm3 is obtained compared to the main base case. A comparison of the distribution of sodium silicate is done by studying the Figure 109 and Figure 111. The most important difference is that a closure between all the 4 lower layers is obtained already by the first batch. The second batch of sodium silicate is displaced for 6 months / 489 m radius and cells with sodium silicate concentration of 0.2 get reduced PERMX= PERMX x 0.1. This adds an extra EOR of 4790 Sm3 and a total of 15873 Sm3 compared to the main base case. The EOR is increased by 2.31% compared with the base case and the recovery factor is increased by 1.51%.

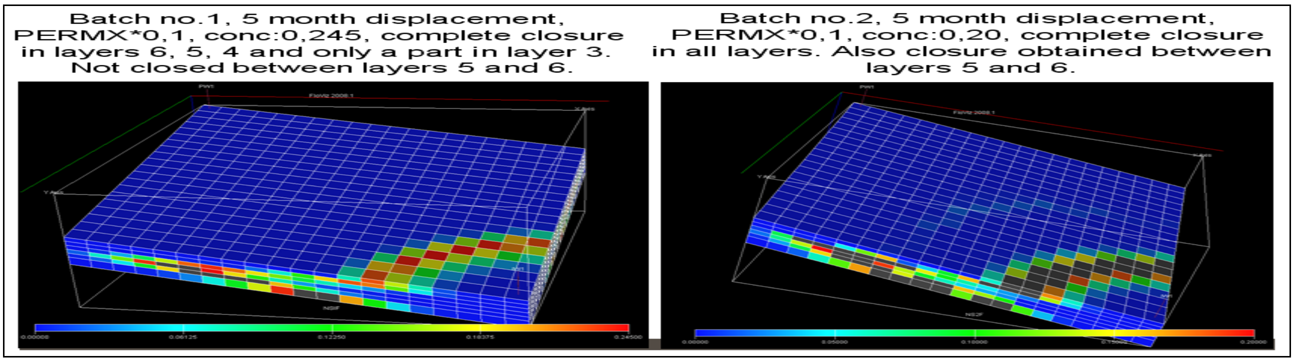


Figure 108 PERMX*0.1 for sodium silicate concentration 0,245 in batch 1 and 0, 2 in batch 2.

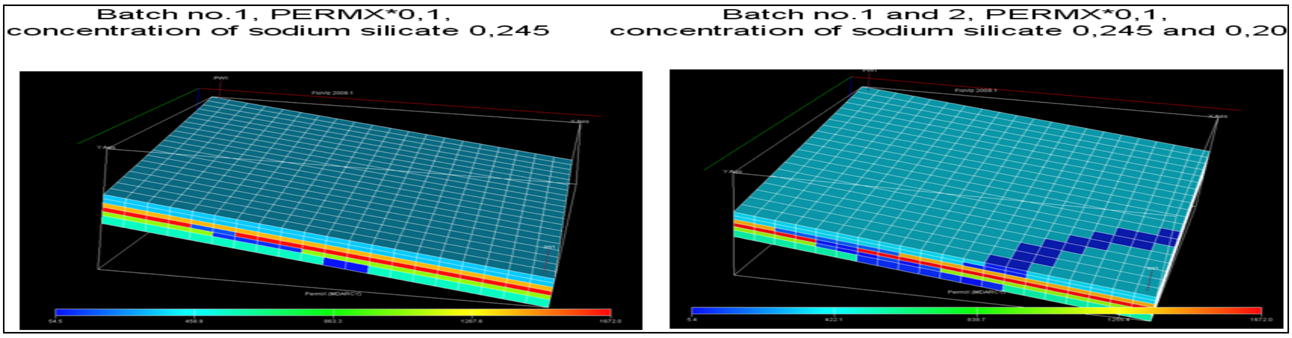


Figure 109 PERMX *0.1 for sodium silicate concentration 0,245 in batch 1 and 0, 2 in batch 2

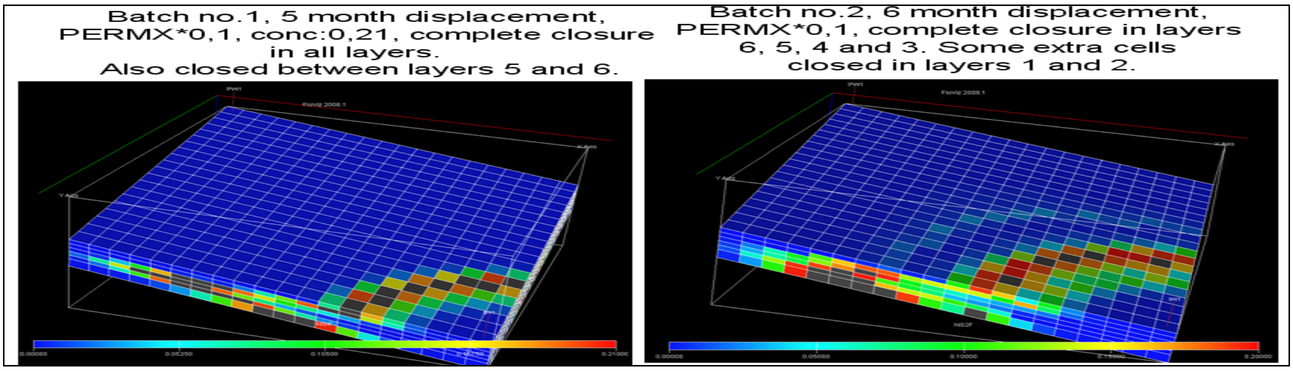


Figure 110 PERMX *0.1 for sodium silicate concentration 0, 21 in batch 1 and 0, 2 in batch 2

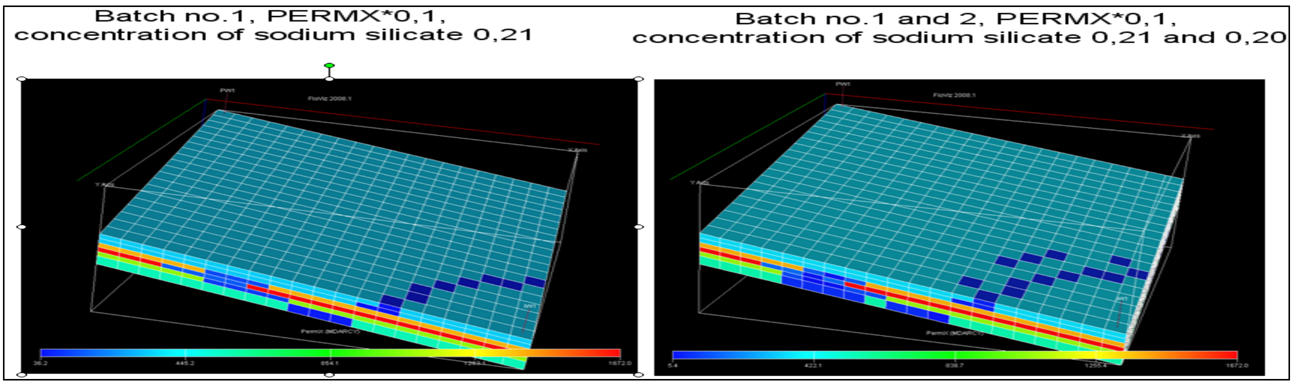


Figure 111 PERMX *0.1 for sodium silicate concentration 0.21 in batch 1 and 0.2 in batch 2

For the best case the reduction of PERMX in each layer is shown in Figure 112, Figure 113 and Figure 114.

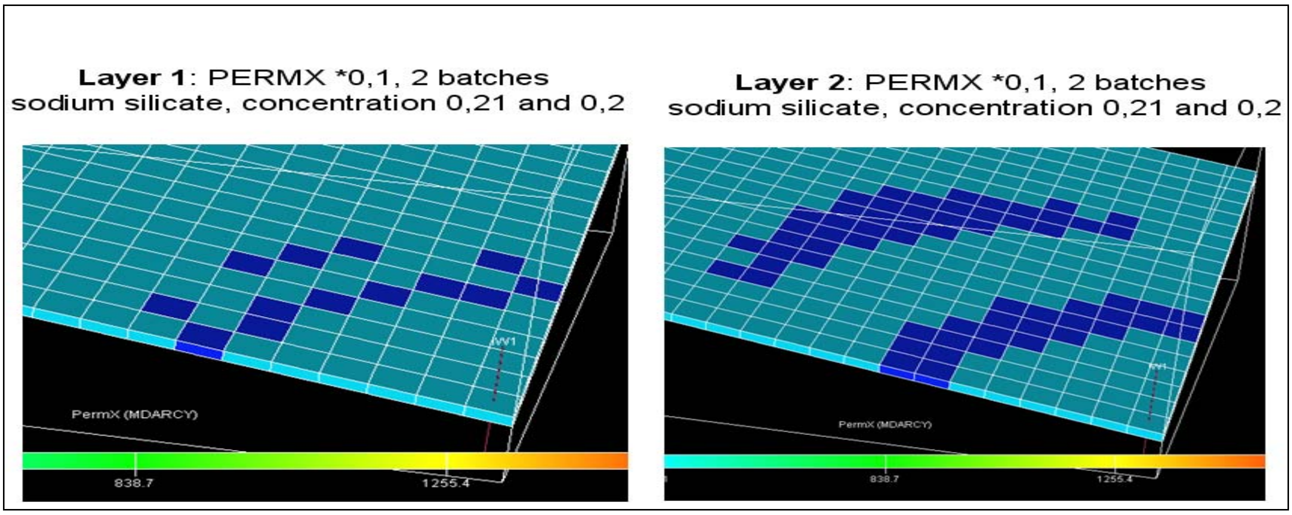


Figure 112 Layers 1 and 2, PERMX*0.1, sodium silicate concentration 0, 21 and 0, 2

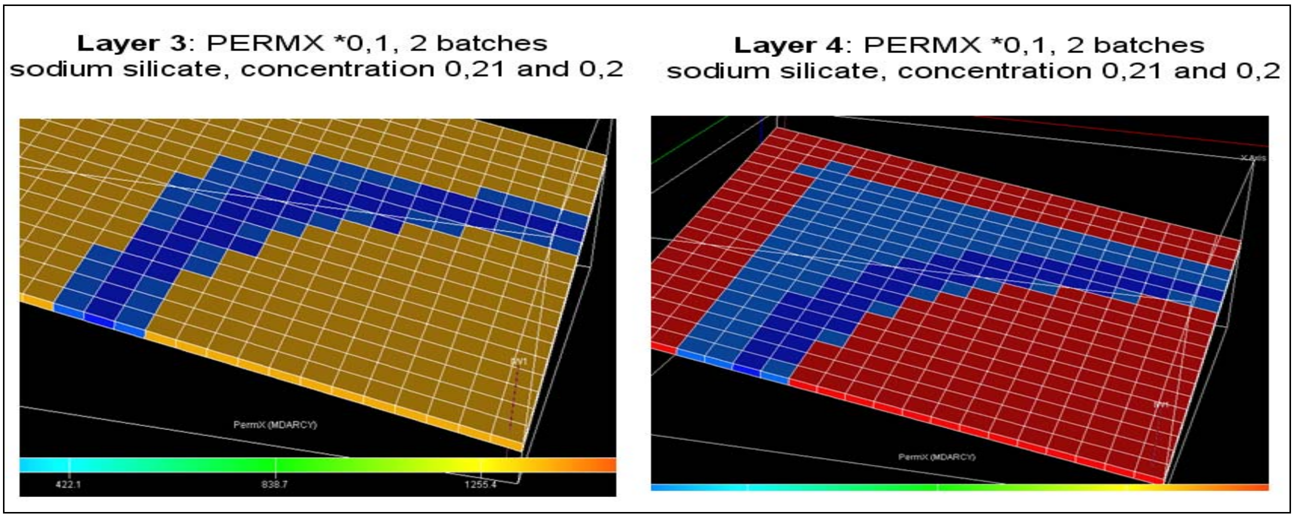


Figure 113 Layers 3 and 4, PERMX*0.1, sodium silicate concentration 0.21 and 0.2

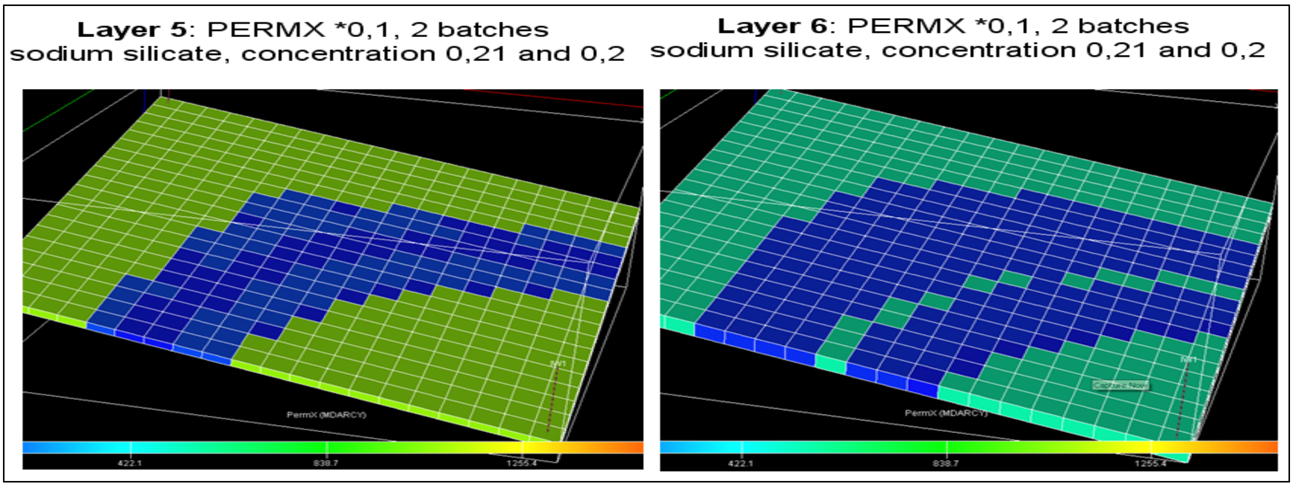


Figure 114 Layers 5 and 6, PERMX*0.1, sodium silicate concentration 0.21 and 0.2

5.13 Case 7: Big (double) batches of silica, long displacement radius, PERMX*0.01

The first batch of sodium silicate is displaced 5 months / 446 m radius, and the second batch 6 months / 489 m radius, into the reservoir. For tracer concentration above 0.21 in both batch no.1 and batch no.2, PERMX is multiplied with 0.01.
As a result of batch no.1, an EOR volume of 8797 Sm3 is obtained compared to the main base case, while the second batch of sodium silicate adds an additional oil volume of 3797 Sm3 to a total EOR of 12594 Sm3 compared to the main base case. EOR is increased by 1.84% compared with the base case and the recovery factor is increased by 1.2%.

5.14 Case 8: Big (double) batches of silica, long displacement radius, PERMX*0.002, start treatment 1 year earlier

This case simulates that the injection of sodium silicate starts one year earlier than the other cases, short time after water break through in the lower layers.
The first batch of sodium silicate is displaced 5 months / 446 m radius, and the second batch 6 months / 489 m radius, into the reservoir. For tracer concentration above 0.25 in batch no.1 and 0.23 in batch no.2, PERMX is multiplied with 0.002.
Batch no.1 leads to a complete closure in layers 6, 5, 4, and 3. Also a vertical closure is obtained between these layers. Layer 2 also gets a nearly complete closure. See Figure 115.
Batch no.2 gives a big extra closure in layer 6 but also a complete closure in layers 5 and 2. A few extra cells get closed in layers 4 and 3. See Figure 116.

As a result of batch no.1, an EOR volume of 2340 Sm3 is obtained compared to the main base case, while the second batch of sodium silicate adds an additional oil volume of 6031 Sm3 to a total EOR of 8371 Sm3 compared to the main base case. EOR is increased by 1.22% compared to the base case and the oil recovery factor is increased by 0.8%.
*For the case of PERMX multiplied with 0.002 it seems like EOR is improved if sodium silicate is injected at the later point of time, when the water saturation and thereby the relative permeability for water has become higher due to water injection. More oil is captured in the cells where the PERMX is reduced to PERMX*0.002 when starting earlier in the field life injecting sodium silicate.*
This is illustrated in Figure 117 and Figure 118.

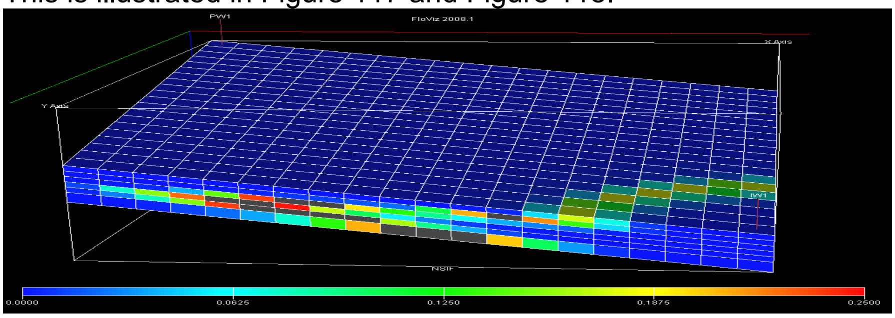


Figure 115 Tracer distribution batch no.1, start one year earlier, and concentration 0.25

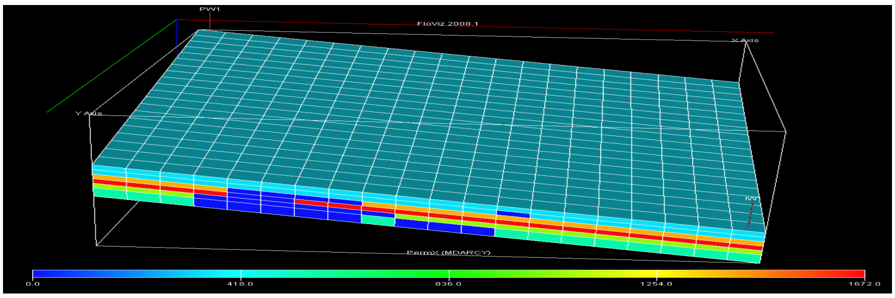


Figure 116 Reduced PERMX*0.002 after injecting 2 batches of sodium silicate, one year earlier

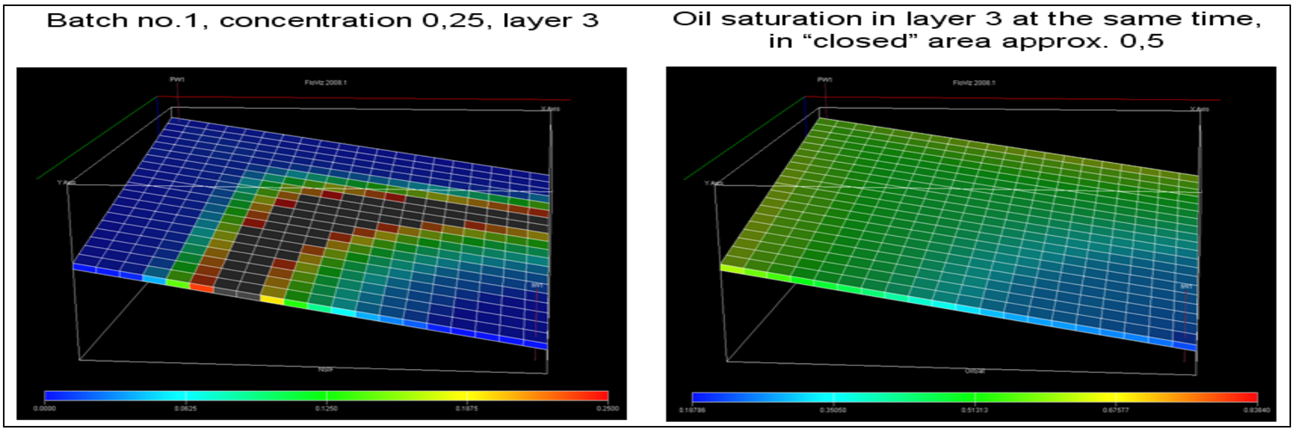


Figure 117 Closed cells in layer 3 and oil saturation, one year earlier injection of sodium silicate.

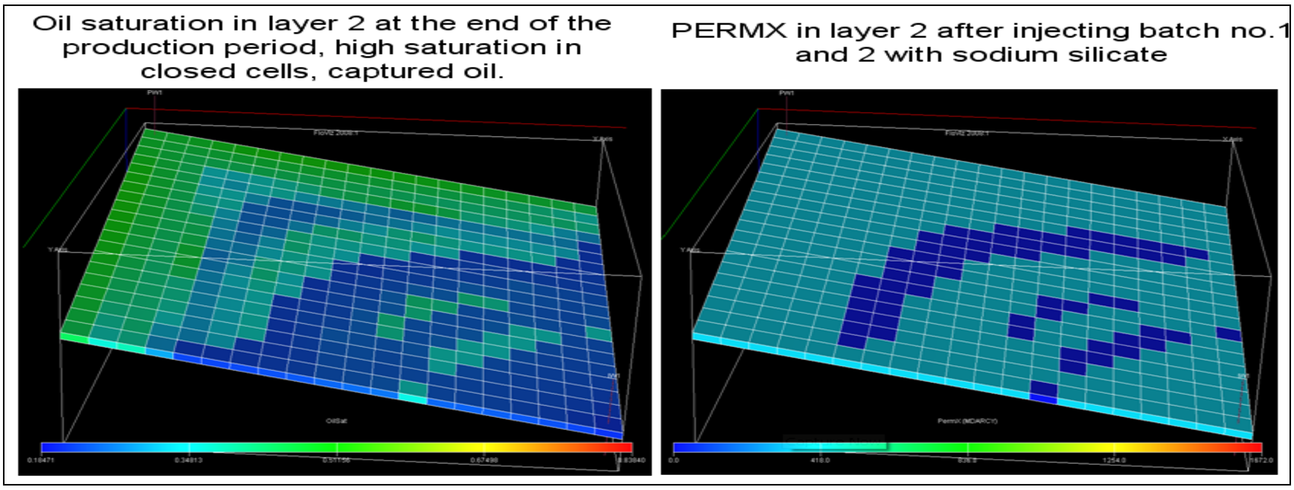


Figure 118 Captured oil in cells with PERMX*0.002, early injection of sodium silicate

5.15 Case 9: Big (double) batches of silica, long displacement radius, PERMX*0.1, start treatment 1 year earlier.

This case is similar to case 7 in chapter 5.14. The only difference is that PERMX is reduced to PERMX*0.1 in cells where the sodium silicate concentration is higher than 0.25 (batch no.1) and 0.23 (batch no.2).

As for the case 7, with PERMX*0.002, batch no.1 leads to a complete closure in layers 6, 5, 4, and 3. Layer 2 also gets a nearly complete closure. Also a complete vertical closure is obtained between the 4 lower layers already by the first batch. See Figure 115.

Batch no.2 gives a big extra closure in layer 6 but also a complete extra closure in layers 5, 4 and 3. A few extra cells get closed in layer 2 while for the PERMX*0.002 case a complete closure was obtained for this layer. Else, the distribution of sodium silicate differs mainly in layers 4 and 3 for the cases PERMX*0.002 and PERMX*0.1. See Figure 119.

As a result of batch no.1, an IOR volume of 8600 Sm3 is obtained compared to the base case, while the second batch of sodium silicate adds an additional oil volume of 4579 Sm3 to a total EOR of 13179 Sm3 compared to the base case. EOR is increased by 1.92% and recovery factor by 1.25% compared to the base case.

These results show that a greater EOR is obtained if the PERMX is reduced by multiplying with 0.1 instead of closing completely off by multiplying with 0.002. This shows that treatment with sodium *silicate may start as soon as water break through has occurred in one or more layers.* Figure 120 shows, compared to Figure 118, that less oil is captured in the cells where PERMX is multiplied with 0.1.

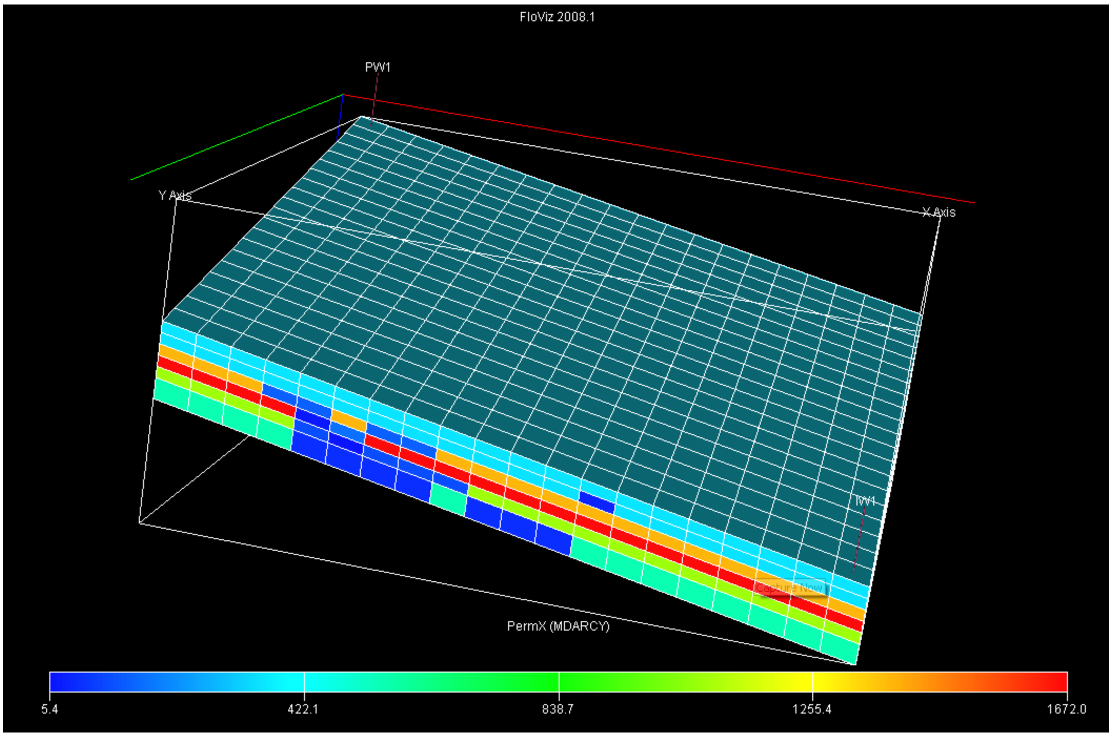


Figure 119 Reduced PERMX*0.1 after injecting 2 batches of sodium silicate, one year earlier

Oil saturation in layer 2 at the end of the production period, slightly higher oil saturation in cells with PERMX*0,1

PERMX in layer 2 after injecting batch no.1 and 2 with sodium silicate (PERMX*0,1)

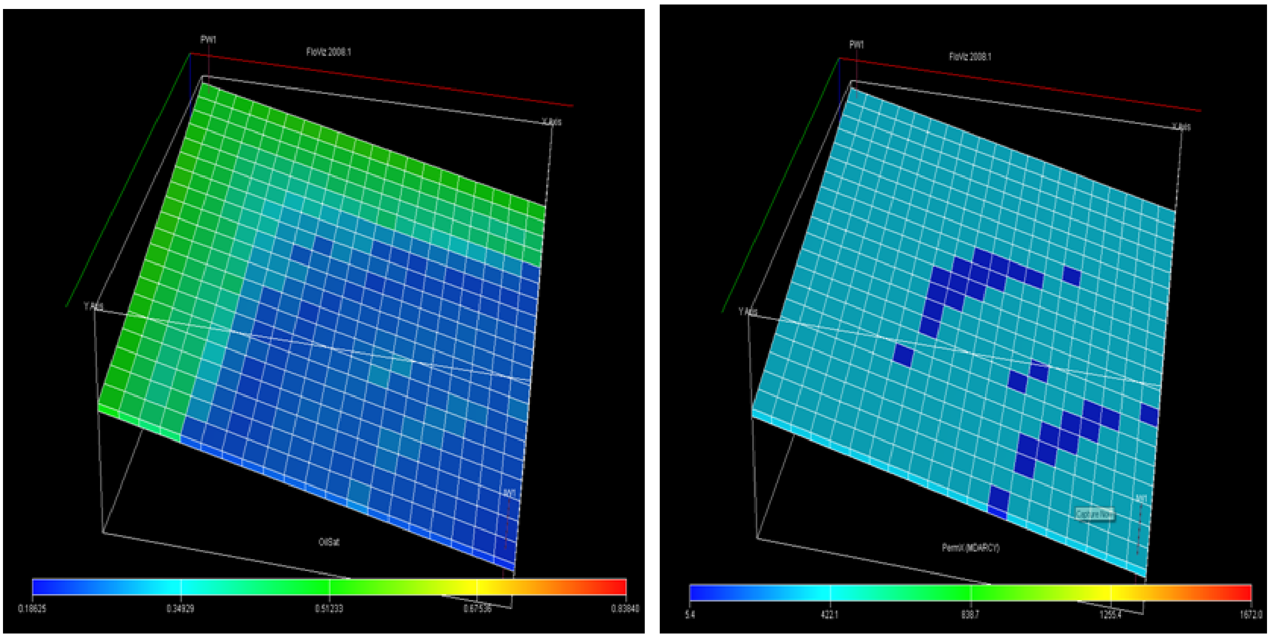


Figure 120 Less captured oil in cells with PERMX*0.1, early injection of sodium silicate

5.16 Comparison and discussion of results from the conceptual model cases

Due to the limited heterogeneity of the conceptual model it is possible to study several interesting effects of different reservoir parameters. The results from water injection and oil production from the “base case” in the model, concerning remaining oil saturation and water flooding, coincides well with the historic data collected from the Etive formation (see chapter 3.3.4).

The main effect detected from simulated production from the base case is the extensive vertical segregation of oil and water within the reservoir model due to the good vertical communication. The low horizontal permeability in the two top layers (Etive 3 formation) combined with the much higher horizontal permeability in the four lower layers amplify the poor flooding effect in the top layers while a rapid water break-through occurs in the three lower layers. The three lower layers are well drained due to effective water flooding and migration of oil to the upper layers. The highest oil production occurs in layer 3 (in top of the Etive 2 formation) which has a high horizontal permeability. At the end of the production period the oil production rate is quite low and most of the oil is produced through the upper layer.

When changing the vertical communication by reducing the vertical permeability, with one magnitude of order, leaving the other reservoir and flow parameters unchanged, the overall oil recovery from the model is strongly reduced. The oil recovery factor at the end of the production period is reduced from 65% to 60%. The main difference from the good vertical communication model is that the segregation effect is reduced and the water flooding effect in the upper layer is improved. For the rest of the layers water flooding is less effective. The result from this is that the remaining oil volume at the end of the production period is reduced in the upper layer, unchanged in layer 2 while all the lower layers get increased remaining oil volume. The oil production is increased in the upper layer while all the other layers get reduced production, especially in layer 3 (top of the Etive 2 formation).

Simulation results from injection of one small batch of sodium silicate a short distance in the poor vertical communication model, and the following reduction of the horizontal permeability in the treated cells, give a significant higher EOR effect compared to the good vertical communication model. For the poor vertical communication model the flow path is changed in such a way that more oil is migrating upwards resulting in a better drainage of the lower layers and a higher oil production from the upper layers. The oil recovery factor is increased by 2.86% and 4.7% EOR is obtained compared to the produced oil volume from the poor vertical communication base case.

Compared with the good vertical communication model, case 1a, injection of a small batch of sodium silicate a similar distance result in approximately the same distribution and closing in the cells and layers in the model, see Figure 127 and Figure 128. Despite of this only 0.09% increase in oil recovery factor and 0.14% EOR is obtained by the first small batch of silica in the good vertical communication model, compared to the base case.

To obtain a higher EOR by the use of sodium silicate in the good vertical communication model it is clearly important to inject big batches and displace these longer distance from the injector. This is illustrated by the plotted simulated production results from the cases in the Figure 121, Figure 122, Figure 123, Figure 124, Figure 125 and Figure 126.

Also it is crucial to obtain a vertical closure between the lower layers preferably by the first batch of silica. This is obtained for the case (6a, b) where a reduction of the PERMX is done for a lower concentration value and the PERMX is less reduced. This is the best EOR case. The closed cells and layers are illustrated in the Figure 110 through Figure 114. The purpose of Figure 130 should also be to show where, along the diagonal between the injector and the producer, closures are obtained and for which concentration value for the tracer. The ability to illustrate this is, however, a bit incomplete since only three layers in the model are represented as Etive 3 (layer 1), Etive 2 (layer 4) and Etive 1 (layer 6). For the case 6a, b the Figure 130 does not show that there is also a vertical closure between the layers 6, 5 and 4 already by the first batch of silica, but the figures from FloViz do (Figure 110 through Figure 114). Also the complete closure in the upper layer already obtained by batch 1, which can be seen in Figure 112, does not show in Figure 130. From the Figure 129 through Figure 132 one can see that batch number 2 is more evenly distributed in the layers and at a lower concentration when PERMX has been reduced by batch number 1 with a factor of 0.1 instead of 0.002. This, and the fact that more oil is captured in the cells when reducing the PERMX more strongly, show that a higher EOR may be obtained by a slight reduction of the permeability in the mostly water flooded zones.

The “best case” also depends on which economic oil “cut-off” rates that is applied.

If producing until the planned end of the production period, 1 April 2016, the case of PERMX*0.1 and “1 year later” (case 6) gives the highest total oil volume produced, see Table 8 and Figure 124. But then the oil production rate is very low, below 50 Sm3/d, for the last 2(+) years of production, see Figure 123.

The case of PERMX*0.1 and “1 year earlier” (case 9) is the best case, regarding acceleration of oil production. If the “oil economic cut-off rate” is higher than 50 Sm3/d, the case of PERMX*0.1 and 1 year later will produce 0.5-1 year longer than the previous mentioned case and will give the highest total oil production, see Figure 123 and Figure 124.

Simulations show that increasing the heterogeneity in the model, by reducing the vertical permeability with an additional magnitude of order, a different flooding pattern is obtained and the EOR effect of injecting sodium silicate increases significantly. Since the reservoir, in reality, is more heterogeneous than the conceptual model, a higher EOR should, thus, be expected.

Based on the previous discussion of the results a summary of the main conclusions from analyzing the reservoir simulation results, utilizing this particular conceptual model, may be listed as follows:

- The grade of vertical communication in the reservoir is crucial for the applicability of sodium silicate as a method to diverge injected water to unflooded zones
- Sodium silicate should be injected as far into the reservoir as possible
- The batch(es) should be as big as possible
- A slight reduction of PERMX gives the best IOR result also since less oil get captured in the treated area, in the cases analyzed in the conceptual model the PERMX*0.1 gave the best result both for “early” and “later” operation
- For the PERMX*0.1 case, or a slightly reduced PERMX, the IOR result improves if the reduction occurs for a lower sodium silicate concentration and thus a wider area in the reservoir is affected
- For this model it is an advantage if a closure is obtained between the layers 5 and 6 already by the first batch of sodium silicate (this is also more easily obtained if the concentration limit for reduction of PERMX is low)
- The best time for starting to inject sodium silicate is as soon as water break through has occurred
- To continue accelerating production by keeping a highest possible oil production rate the sodium silicate injection should be resumed after some time, for this case after approximately 1,5 years of production

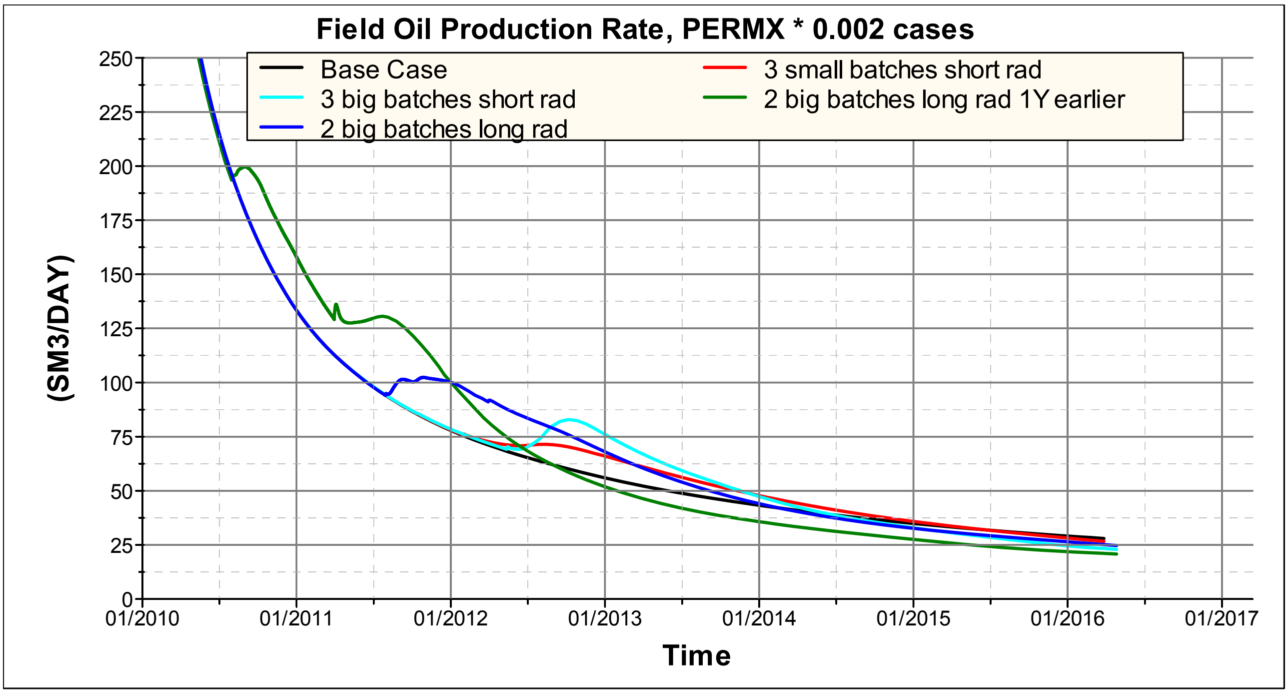


Figure 121: Oil Production Rate, PERMX*0,002 cases

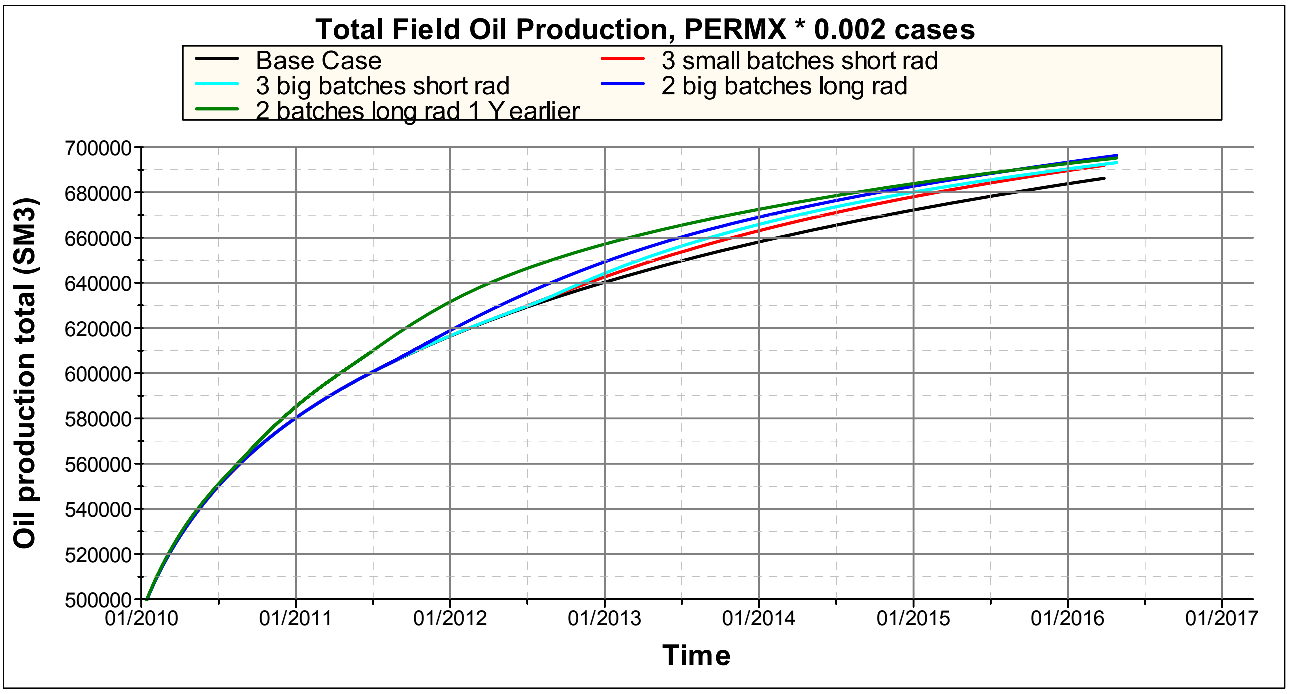


Figure 122: Total oil Production, PERMX*0.002 cases

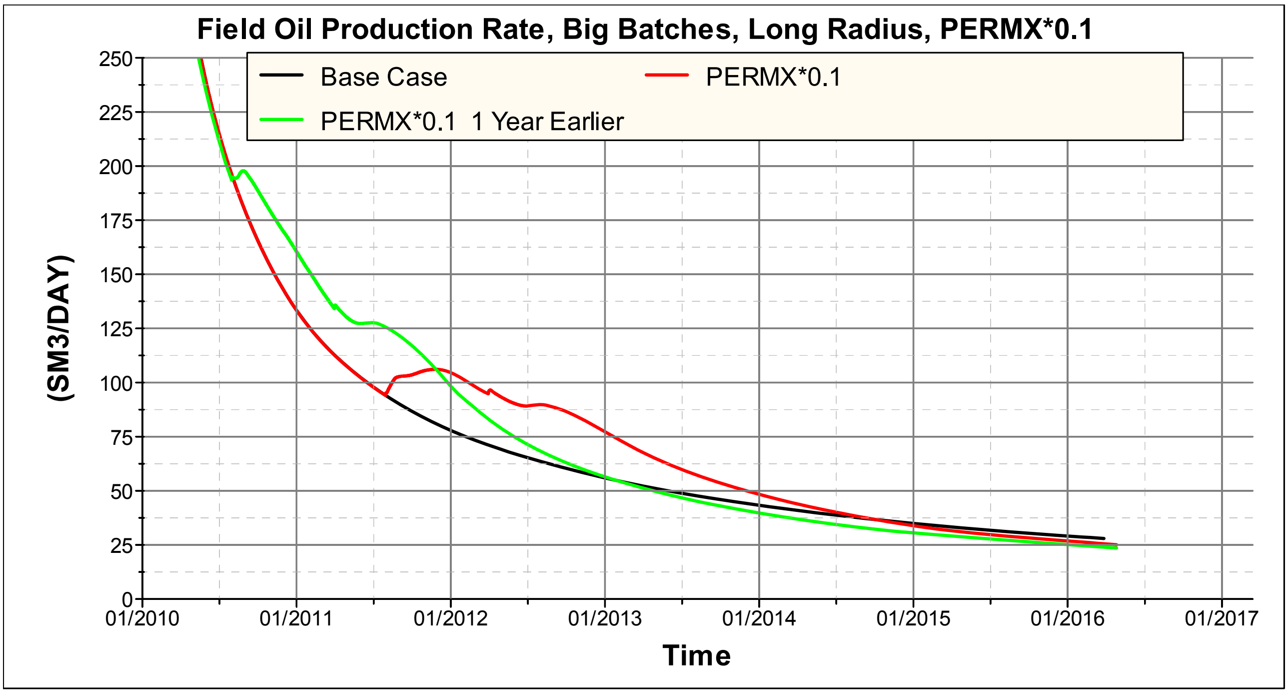


Figure 123: Oil Production Rate, PERMX*0.1 cases

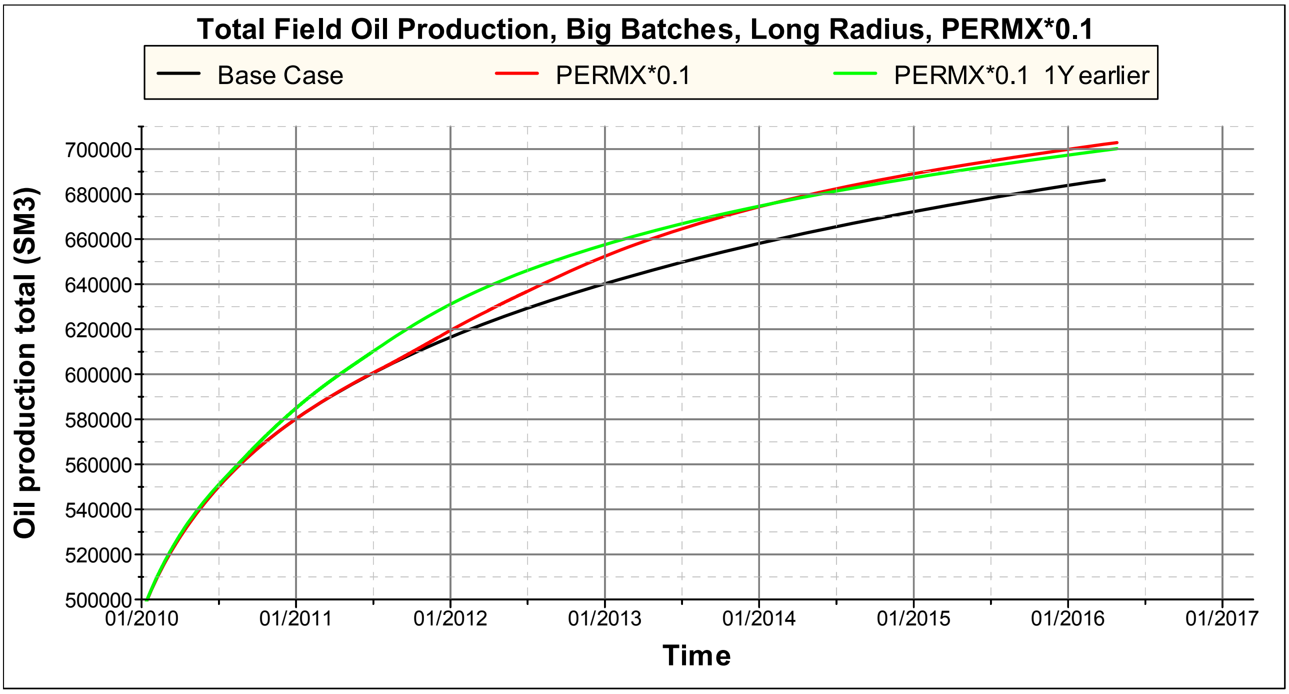


Figure 124: Total Oil Production, PERMX*0.1 cases

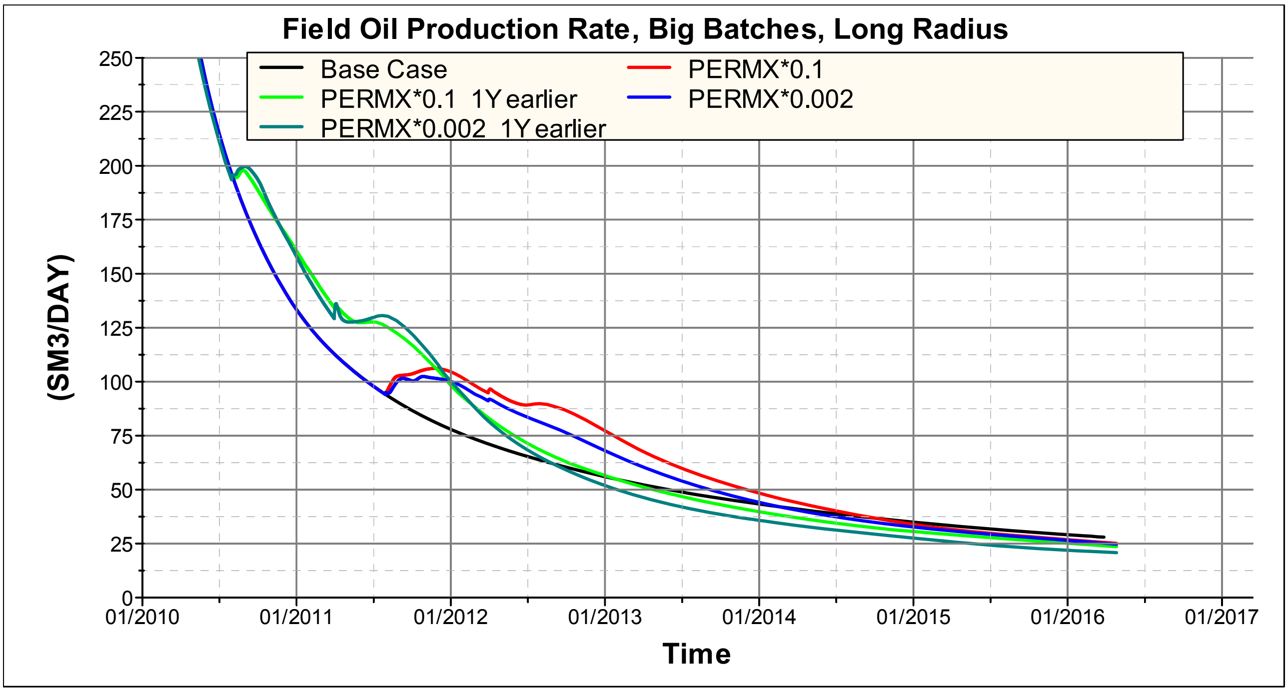


Figure 125: Oil Production Rate, Comparison of best cases

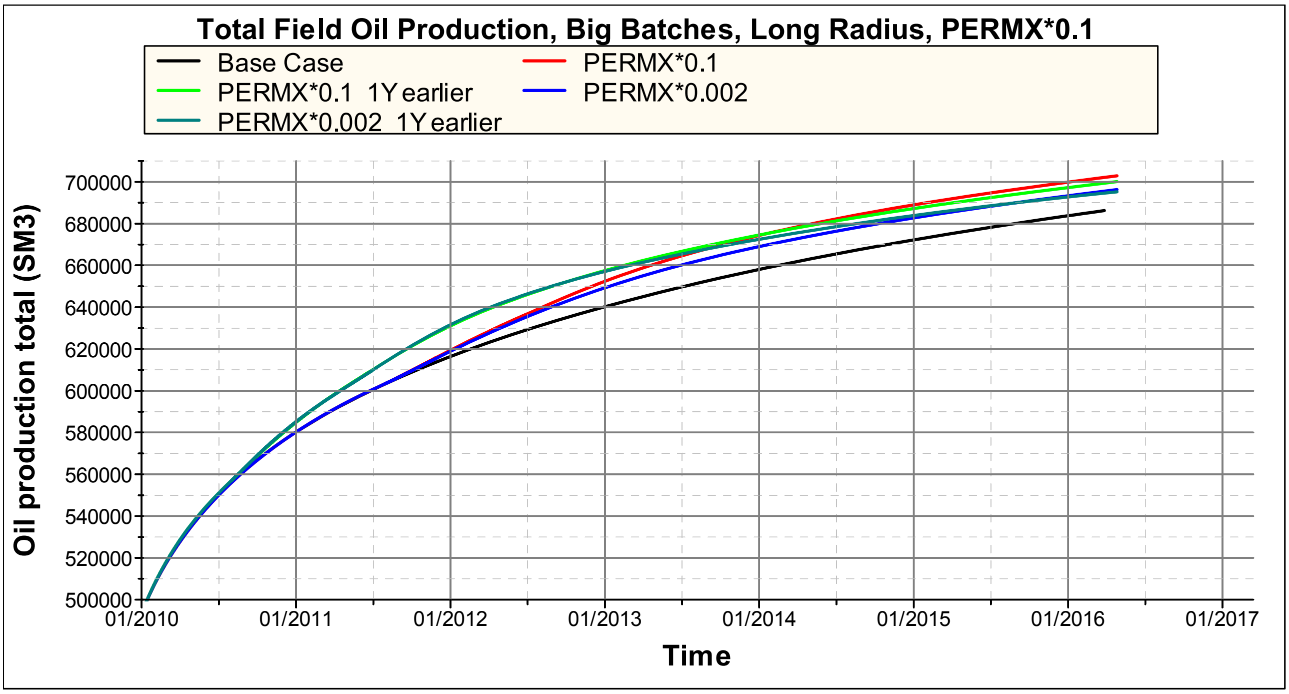


Figure 126: Total Oil Production, Comparison of best cases

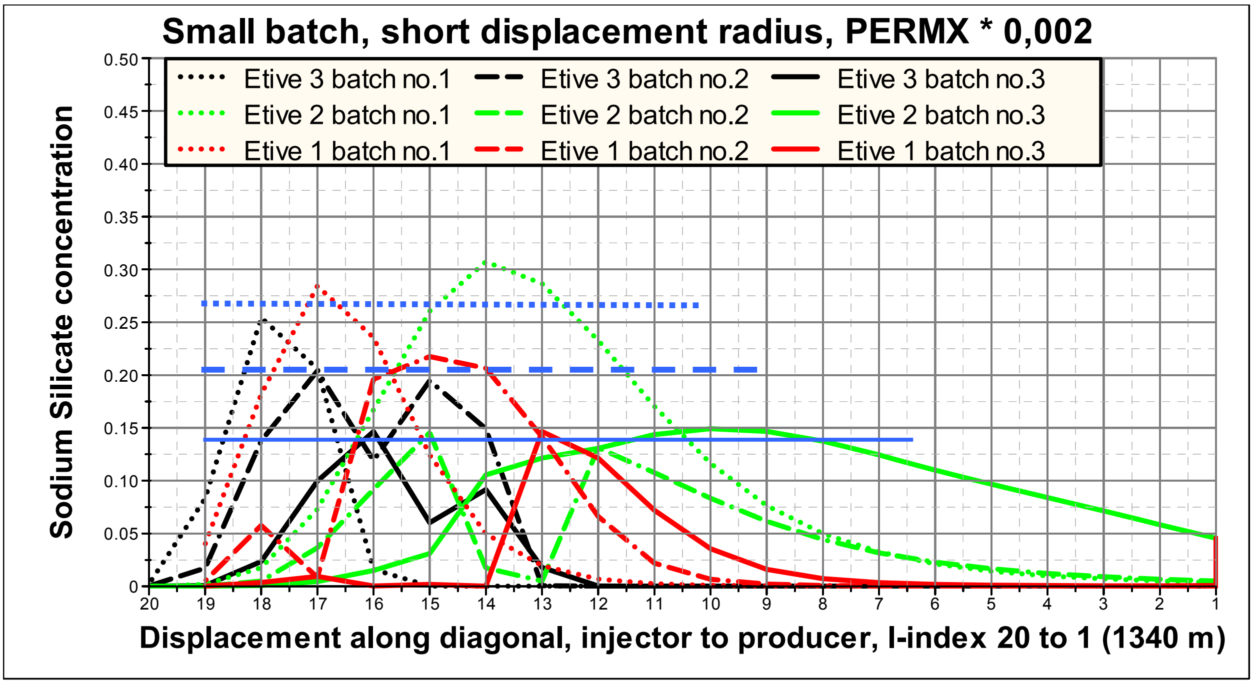


Figure 127: PERMX reduced in batch 1, 2 and 3 at concentration 0.265, 0.205 and 0.135 (case 1 a, b, c)

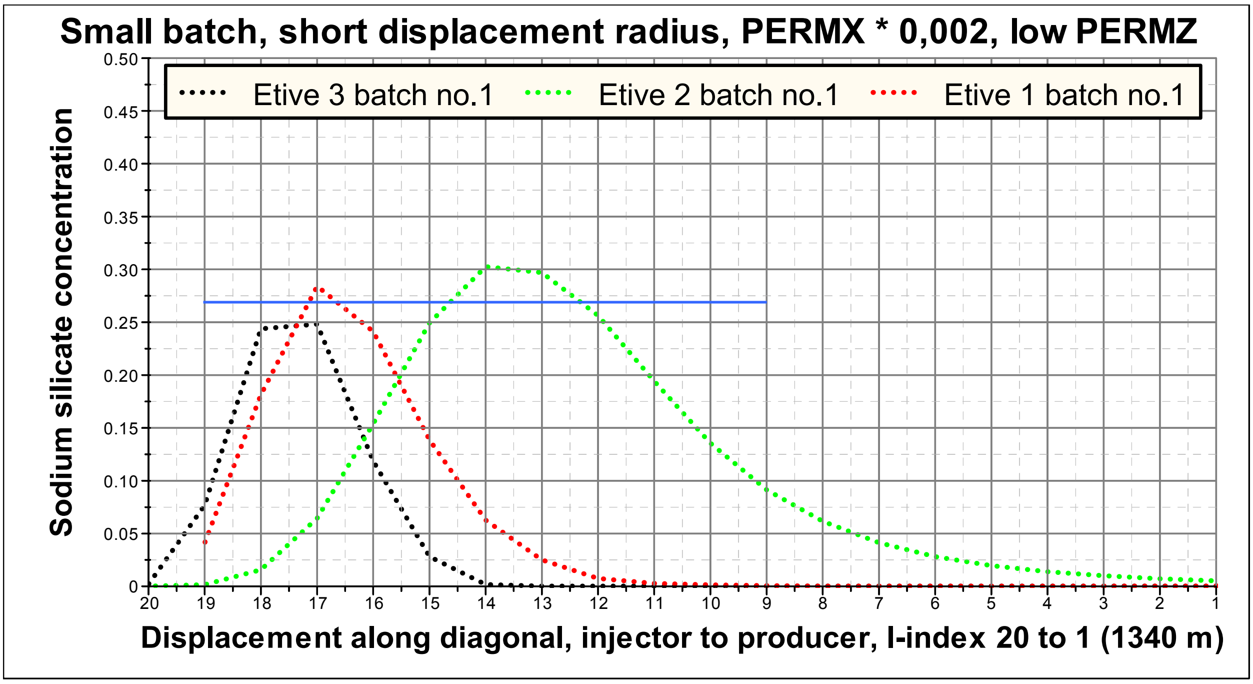


Figure 128: PERMX reduced in batch 1 at concentration 0.27 (case 3)

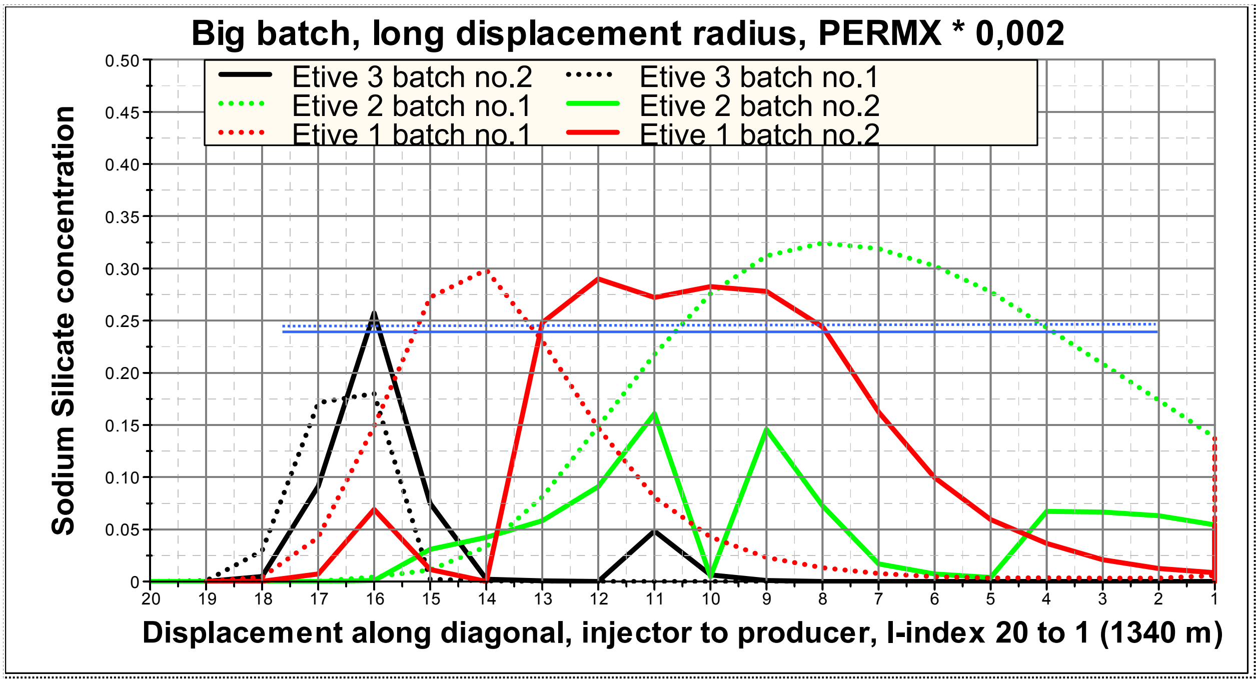


Figure 129: PERMX reduced in batch 1 and 2 at concentration 0.245 and 0.24 (case 5 a, b)

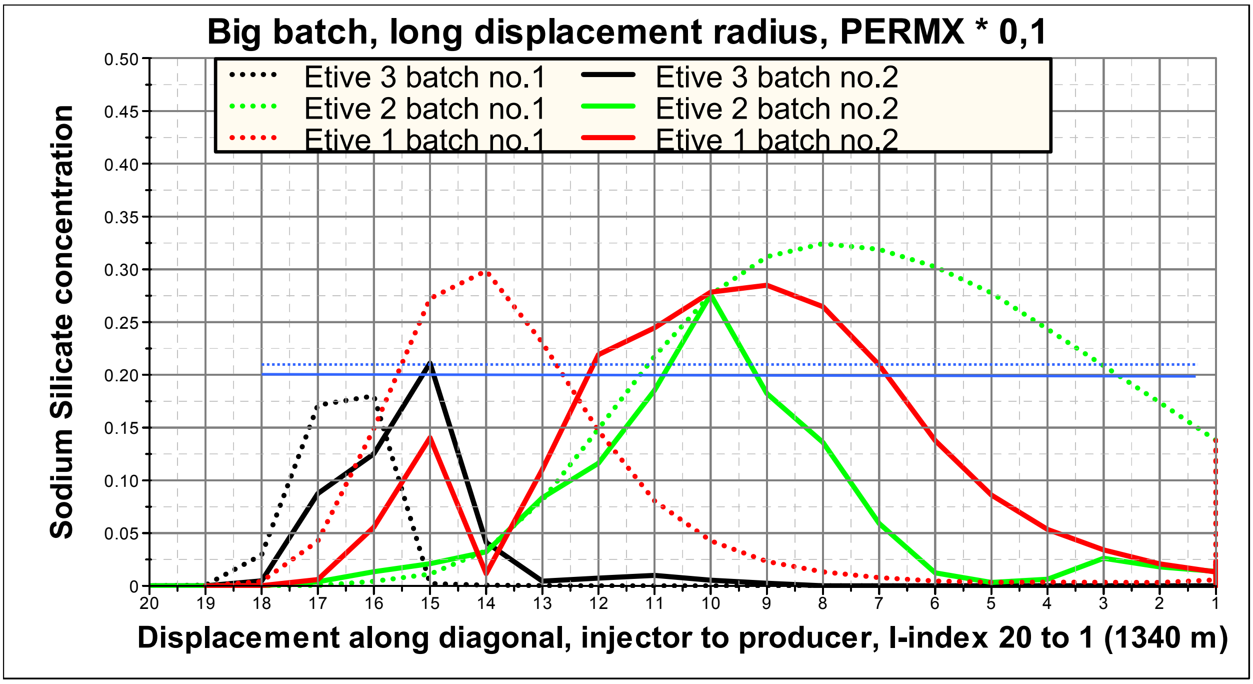


Figure 130: PERMX reduced in batch 1 and 2 at concentration 0.21 and 0.2 (case 6a, b)

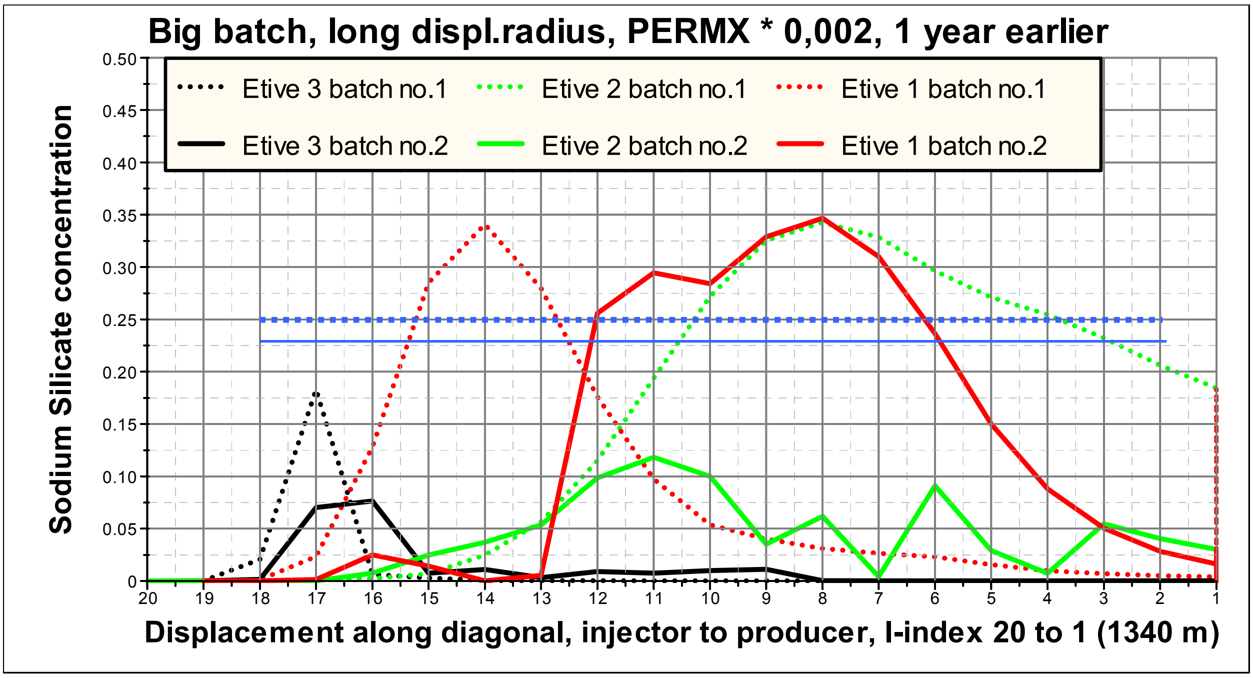


Figure 131: PERMX reduced in batch 1 and 2 at concentration 0.25 and 0.23 (case 8 a, b)

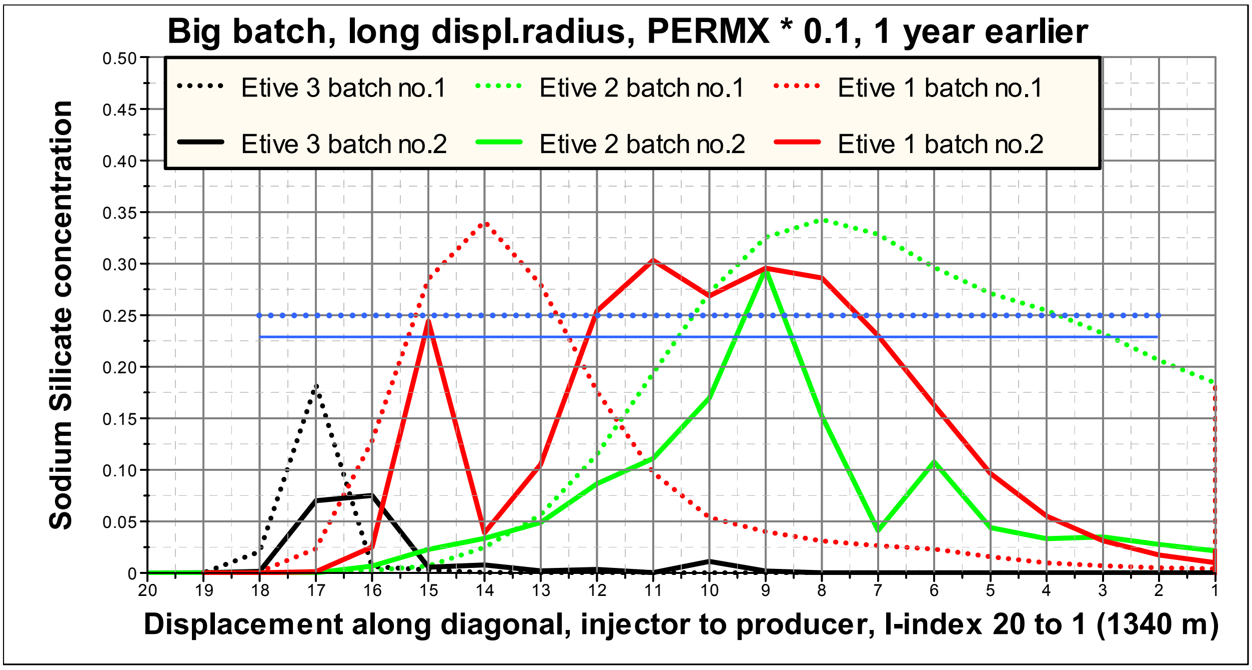


Figure 132: PERMX reduced in batch 1 and 2 at concentration 0.25 and 0.23 (case 9 a, b)

Table 8: Summary of simulation results

Case	Description	Silica volume Sm3	Radius m	Displaced volume Sm3	Radius m	PERMZ= PERMX x ?	Tracer concentr.	PERMX x ?	Total oil prod. by 1/4-2016 (total 7 years) Sm3	Rf. by 1/4 2016	Difference to basecase Sm3 (IOR)	IOR % Rf	IOR % compared to basecase
Base Case	high PERMZ					0,5			686191	0,65257			
1a	Batch 1	60000	200	120000	282	0,5	0,265	0,002	687150	0,65348	959	0,09	0,14
1b	Batch 2	60000	200	180000	346	0,5	0,205	0,002	687553	0,65386	1362	0,13	0,20
1c	Batch 3	60000	200	300000	446	0,5	0,135	0,002	691916	0,65801	5725	0,54	0,83
2a	Batch 1	120000	282	120000	282	0,5	0,43	0,002	687850	0,65415	1659	0,16	0,24
2b	Batch 2	120000	282	210000	374	0,5	0,33	0,002	688612	0,65487	2421	0,23	0,35
2c	Batch 3	120000	282	300000	446	0,5	0,225	0,002	692425	0,6585	6234	0,59	0,91
New Base Case	low PERMZ					0,05			639327	0,608	-46864		
3	Batch 1	60000	200	120000	282	0,05	0,27	0,002	669353	0,63655	30026	2,86	4,70
4	Batch 1	120000	282	120000	282	0,05	0,44	0,002	668775	0,636	29448	2,80	4,61
5a	Batch 1	120000	282	300000	446	0,5	0,245	0,002	693601	0,65962	7410	0,71	1,08
5b	Batch 2	120000	282	360000	489	0,5	0,24	0,002	695554	0,66147	9363	0,89	1,36
6a	Batch 1	120000	282	300000	446	0,5	0,21	0,1	697274	0,65962	11083	0,71	1,62
6b	Batch 2	120000	282	360000	489	0,5	0,2	0,1	702064	0,66766	15873	1,51	2,31
(6a)	Batch 1	120000	282	300000	446	0,5	0,245	0,1	694668	0,66063	8477	0,81	1,24
(6b)	Batch 2	120000	282	300000	446	0,5	0,2	0,1	698690	0,66445	12499	1,19	1,82
7a	Batch 1	120000	282	300000	446	0,5	0,21	0,01	694988	0,66093	8797	0,84	1,28
7b	Batch 2	120000	282	360000	489	0,5	0,21	0,01	698785	0,66454	12594	1,20	1,84
8a	Batch 1	120000	282	300000	446	0,5	0,25	0,002	688531	0,65479	2340	0,22	0,34
8b	Batch 2	120000	282	360000	489	0,5	0,23	0,002	694562	0,66053	8371	0,80	1,22
9a	Batch 1	120000	282	300000	446	0,5	0,25	0,1	694791	0,66075	8600	0,82	1,25
9b	Batch 2	120000	282	360000	489	0,5	0,23	0,1	699370	0,6651	13179	1,25	1,92

6 Reservoir Simulation, full field model, the Ness formation, Veslefrikk field

6.1 Base case

The Full Field Simulation Model for the Veslefrikk field (FFM2001), with DXxDYxDZ 55x83x42 grid cells, is used for simulation. The production history is updated until 01.06.08. The new events included in the simulation are according to the long term well plan for Veslefrikk updated in November 2008. Oil production and EOR are measured at the Veslefrikk field milestones 31.12.2013 (after 5 years production) and 31.12.2020 (after 12 years production).
The background for this analysis is that a high water production is lately observed in the Ness 2 formation in the production well PA-08B. Pressure measurements in the near-by water injection well IA-20A corresponds to the measurements in PA-08B. The high water-cut in the PA-08B well is thus expected mainly to be caused by the high through-put of water from the injection well IA-20A.

The distance between the injector well IA-20A and the toe of the horizontal production well PA-08B is approximately 600 m. An overview of the well locations is given in Figure 133 and in Figure 134.

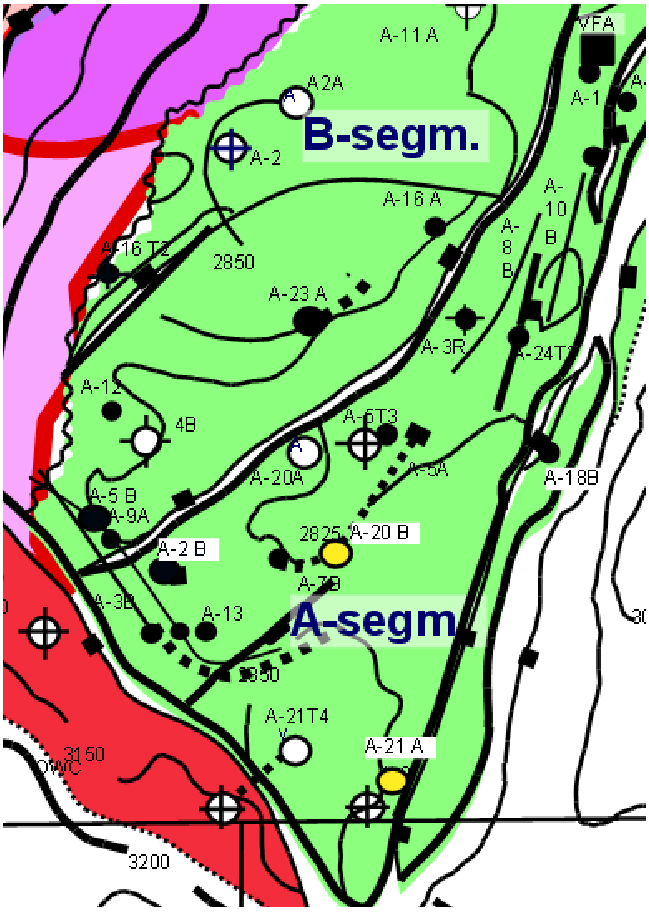


Figure 133: Overview of wells, injector IA-20A and producer PA-8B

In the simulation model the area between the well IA-20A and PA-08B is quite water flooded at the same time of investigation (S_o maximum 40%). The objective for a possible water shut-off using sodium silicate is to close off the water short cut and increase the oil production in the well PA-08B from other parts of the field.

Since the water injection well IA-20A also is injecting in the IDS formation a comparison of the injection rates is made also for this formation before and after the simulated treatment with sodium silicate.
In the simulation model, base case, the percentage distribution of the water injection rate in Ness2/IDS is 70/30. In reality, the last PLT performed in February 2008 shows an injection split of 80/20.

The vertical communication between the layers is quite good both for the Ness and IDS formations. In the full phase simulation model the PERMZ is defined as 0.3 times the PERMX. As shown in Table 9 the PERMX in Ness2 (layers 8-10) is quite low in the injection well IA-20A area. PLT logs show that the injection rate has increased in the Ness formation compared to the IDS formation. This indicates that the Ness2 formation in the IA-20A well is fractured and the simulation model is updated with a skin factor of minus 2. For the IDS formation a skin factor of 20 is used.

Table 9 Thickness and permeability of layers in the injection well area, Ness 2 and IDS formations

Layer no.	Thickness (m)	PERMX (mD)	Kh product
8	5,54	42	233
9	5,54	131	726
10	5,54	153	848
38	8,32	247	2055
39	11,92	226	2694
41	5,98	303	1812

In the simulation model the Ness 2 formation is perforated in layers 9 and 10, while the IDS formation is perforated in layers 38, 39 and 41.

The pore volume in the Ness 2 formation, between the IA-20A injector and the PA-08B producer, is approximately 950000 Sm3. The average porosity in the Ness 2 formation is 18%. With an injection rate of 4000 Sm3/d, and that 70% of the injection water is injected in the Ness 2 formation, the through-put time would be 340 days (11+ months). But that is of course if the Ness2 formation was homogeneous and a piston-like flow occurs, which is not likely.

6.2 Injection of sodium silicate, tracer simulations in Eclipse.

Tracer simulations are performed in ECLIPSE and cells in the Ness 2 and IDS formations get reduced permeability in cells where the concentration of the silica is higher than a specified value. Due to some communication between the Ness and the Etive formation some of the injected water and tracer are also detected in the Etive formation in the model.

When injecting and displacing the sodium silicate an injection rate of 4000 Sm3/d is used. Half a year later the injection rate is reduced to 2000 Sm3/d. For each case only one batch is pumped and displaced.

The following cases are analyzed, see Figure 137:

The cases SILICA1A, 1B, 1C, 2A, 2AR, 2B and 2C are made as follows: 2 months of sodium silicate pumped (240000 Sm3) and displaced according to the indexes A, B and C: A; 2 months (240000 Sm3), B; 1 month (120000 Sm3) and C; 3 months displaced (360000 Sm3). For the 1A,

1B and 1C cases the cells with a specific silica concentration get reduced PERMX=PERMX * 0.1 while the 2A, 2B and 2C cases get reduced PERMX=PERMX * 0.001.
The principle used is that a complete closure should be obtained around the A-20A injection well in the Ness2 formation. This was not completely obtained in the 2A case and consequently the 2AR case was made which provide this.

When defining a “complete closure” this means that cells surrounding the injector well and bordering on to a fault with transmissibility defined by MULTX/MULTY of 0.01 get reduced PERMX. An illustration is made for one of the layers in Figure 134.

The 3B case was made to see the effect of using a smaller batch of sodium silicate (1 month-120000Sm3) and displace this only one month (120000 Sm3) into the reservoir. For this case the PERMX=PERMX * 0.001 in cells with tracer concentration is above 0.28. Also a 4B case was made where the only difference from the 3B case was that PERMX=PERMX*0.000001.

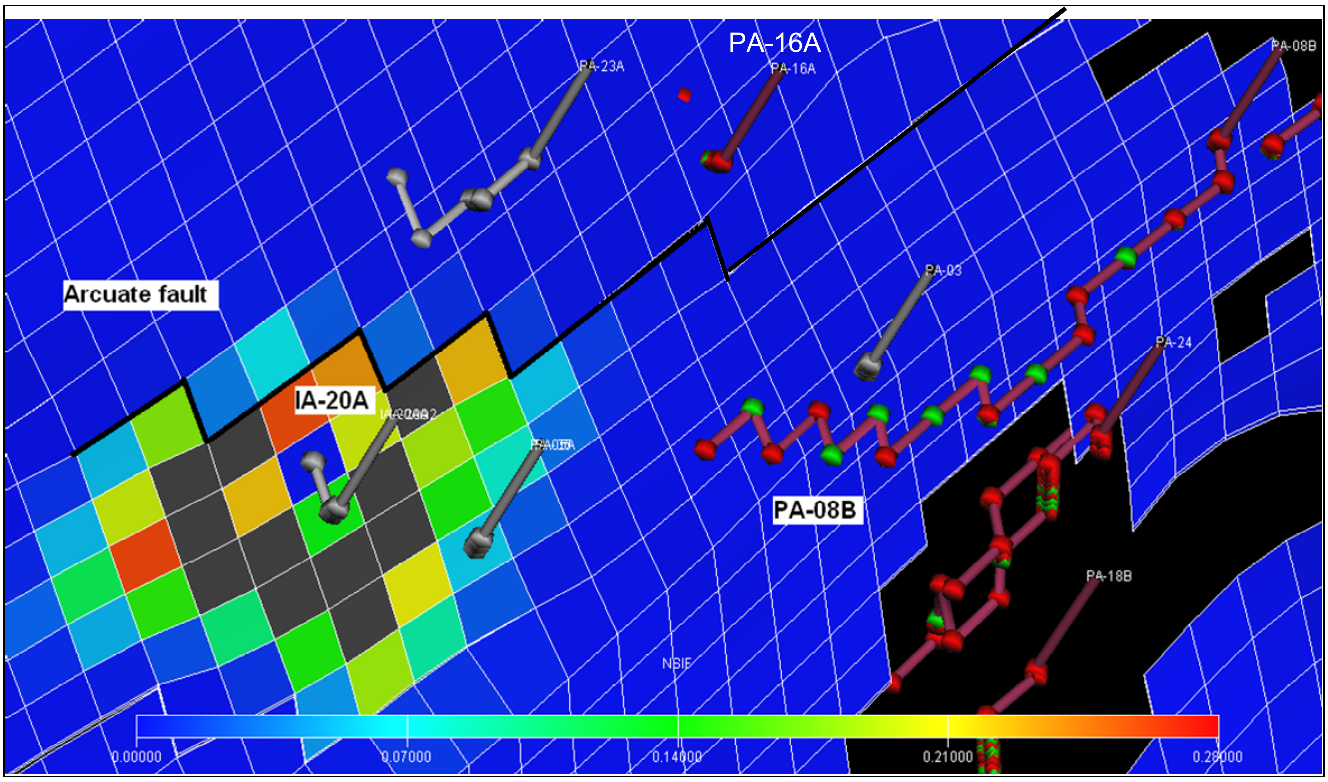


Figure 134: Closed cells in Ness2 layer 10, (SILICA3B) 120000 Sm3 sodium silicate, 120000 Sm3 displacement

As illustrated in Figure 135, the “complete closure” is only obtained in each layer but there is still a possibility for water being injected in layer 9 and 10 to flow upwards to layer 8 and from there being pushed laterally further out in the reservoir. To avoid this problem in the model one need to make a local grid refinement (LGR) in the near wellbore area. This will be a part of the further work to be done in the possible pilot project. For the Silica3B case no closure is obtained in the IDS formation when the limit for closing cells is set to a concentration of tracer/silica to 0.28, ref Figure 136. But especially for the cases where a bigger batch size, of 240000 Sm3 silica, is used some cells get closed also in the IDS formation.

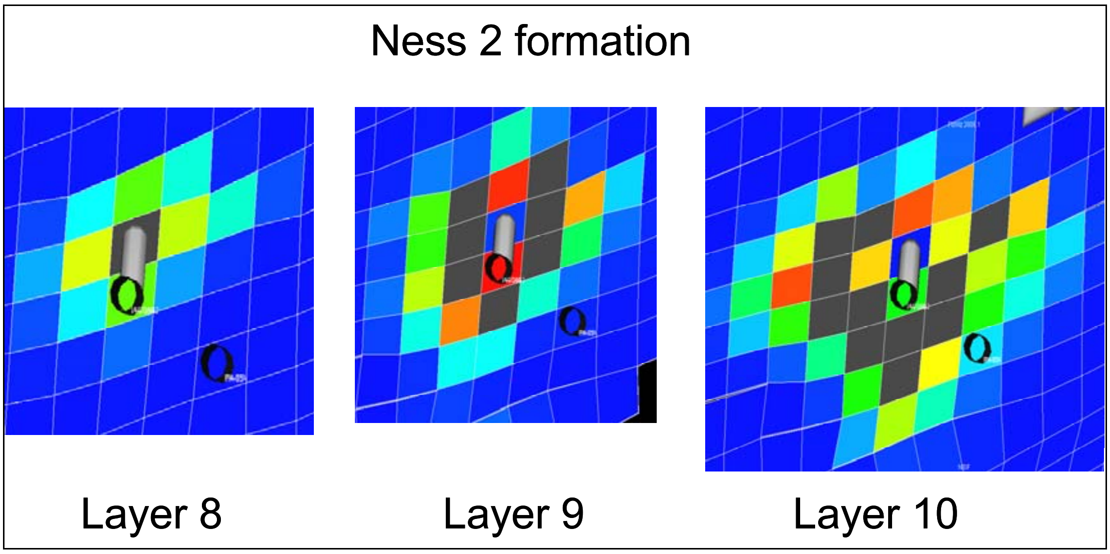


Figure 135: Illustration of silica placement in the Ness 2 formation, from FloViz, case SILICA3B

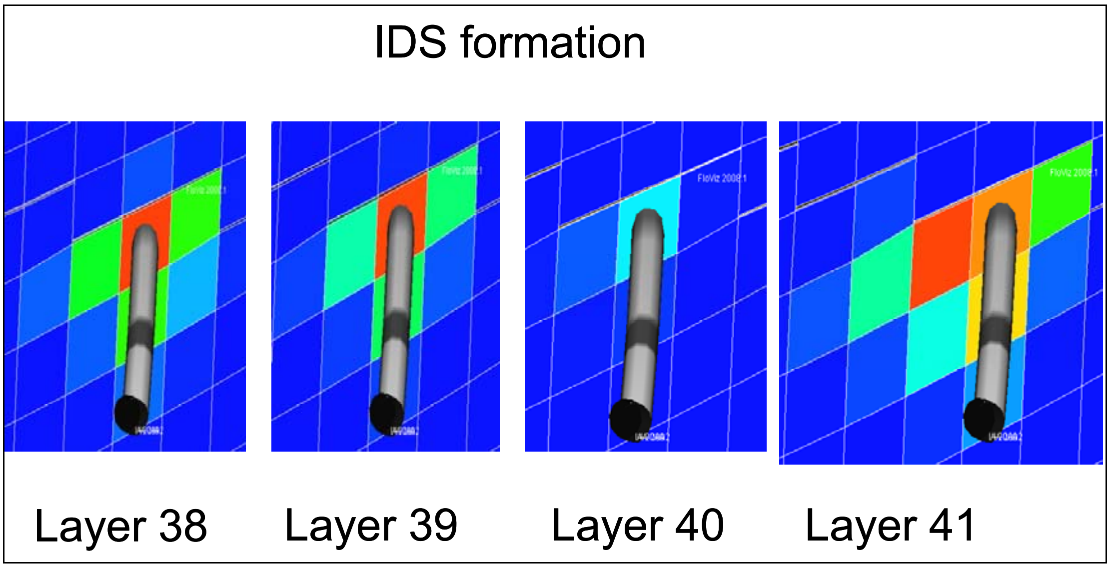


Figure 136: Illustration of silica placement and concentration in the IDS formation, from FloViz, case SILICA3B

To simulate an absolute complete shut-off of the Ness formation in the injection well IA-20A the SQUEEZE option was used in Eclipse. The first case; SQUEEZE_RATE3000 was made in such a way that as from 1/1-2009 the perforations in the Ness formation were completely closed off while the water injection into the IDS formation was kept at 3000 Sm3/d (had to reduce the injection rate from 4000 Sm3/d to 3000 Sm3/d to avoid the simulation to be stopped due to the bottom hole pressure being exceeded beyond the limit). As can be seen in Figure 137 and Figure 138 a negative EOR value is obtained on the field. This may be explained by a reduced pressure support to other Ness 2 producers on the field and consequently a reduced oil production. This is illustrated in the Figure 145 and Figure 147. Another possible reason for a worsen EOR result on the field, could be that the modified water injection strategy leads to a “drowning” of other IDS producers.

An attempt to improve the pressure support on the field in the Ness 2 formation was done by introducing the case; SQUEEZE_RATE2000injA16A. The difference from the previous squeeze case was that the injection rate in the IA-20A well (IDS formation) was reduced by 1000 Sm3/d water to 2000 Sm3/d and the injection rate in another Ness 2 injector, PA-16A, was increased with 1000 Sm3 to a total of 3000 Sm3/d. The injector PA-16A is located on the other side of the arcuate fault, see Figure 133 and Figure 134. Unfortunately, this attempt worsens the situation and a much lower oil production was obtained on the field, see Figure 137 and Figure 138. A further optimization of the injection strategy is put aside and has to be done by a possible pilot project.

6.3 Discussion of results from reservoir simulations

The Figure 137 summarizes the EOR results obtained from the simulations.

Case	Silica volume Sm3	Displaced volume Sm3	Tracer concentr.	PERMX * ?	Difference on field to basecase after 5 years Sm3 (EOR)	Difference on field to basecase after 12 years Sm3 (EOR)	Comments:
Basecase							
SILICA2A	240000	240000	0,32	0,001	18757	23924	No closure in layer 8. Some cells closed in the Etive formation i layer 13 and 14.
SILICA2AR	240000	240000	0,27	0,001	*13881*	*90318*	Closure in the cell penetrated by the well in layer 8. Also closed cells in Etive formation layers 13, 14 and 15. 3 cells closed in IDS layer 41.
SILICA2B	240000	120000	0,37	0,001	176	85019	Big batch and short displacement radius result in a high concentration. No closures in Etive formation. Closed in the cell penetrated by the well in layer 8. 2 cells closed in IDS layer 41.
SILICA2C	240000	360000	0,23	0,001	1317	89085	A low concentration obtained for a long displacement radius. Some cells closed in layer 12 (Ness 1) and in Etive formation in layers 13, 14, 15 and 16. 2 cells get closed in IDS layer 41.
SILICA1A	240000	240000	0,32	0,1	9693	12120	Low reduction of PERMX result in poor EOR.
SILICA1B	240000	120000	0,37	0,1	4786	7946	Low reduction of PERMX result in poor EOR.
SILICA1C	240000	360000	0,23	0,1	4144	9684	Low concentration!
SILICA3B	120000	120000	0,28	0,001	4359	73667	Closed in the cell penetrated by the well in layer 8. No closures in Etive and IDS formations. A test was done to reduce PERMX after only 15 days displacement (60000Sm3) but then the concentration had to be chosen to 0,41 to avoid closing off the IDS formation. At this concentration no closure is obtained in layer 8 and incomplete in layer 10. Conclusion: nedd a fine grid for near well simulations!
SQUEEZE_RATE3000					-23282	-13425	"SQUEEZE" keyword used in Eclipse for the Ness perf. From 1/1-09. Need to reduce the inj.rate from 4000 to 3000 Sm3/d to avoid too high pressure in IDS (BHP in IA-20A within the limit). Complete shut-off in Ness2 result in insufficien preesur support in Ness 2 and decreased oil production from the Ness 2 formation on field basis.
SILICA4B	120000	120000	0,28	0,000001	3359	32705	A big EOR difference from the SILICA3B case!
SQUEEZE_RATE2000injA16A	120000				-63765	-76125	Attepted to improve pressure support in Ness 2 formation by increaseing injection in another injector on the other side of the arcuate fault, PA-16A by 1000Sm3/d to total 3000Sm3/d. Reduce inj.rate in IA-20A to 2000Sm3/d.Not a good solution. Decreased oil production both in PA-08B and on the field.Case is not comparable with the base case due to changed injection strategy.

Figure 137: EOR results from simulation and overview of parameters used in simulation cases

The results indicate that the EOR both on a field basis and from the target well PA-08B is enlarged if a complete closure is obtained in the Ness2 formation around the IA-20A water injection well. A high reduction of the permeability in these cells gives the best result.

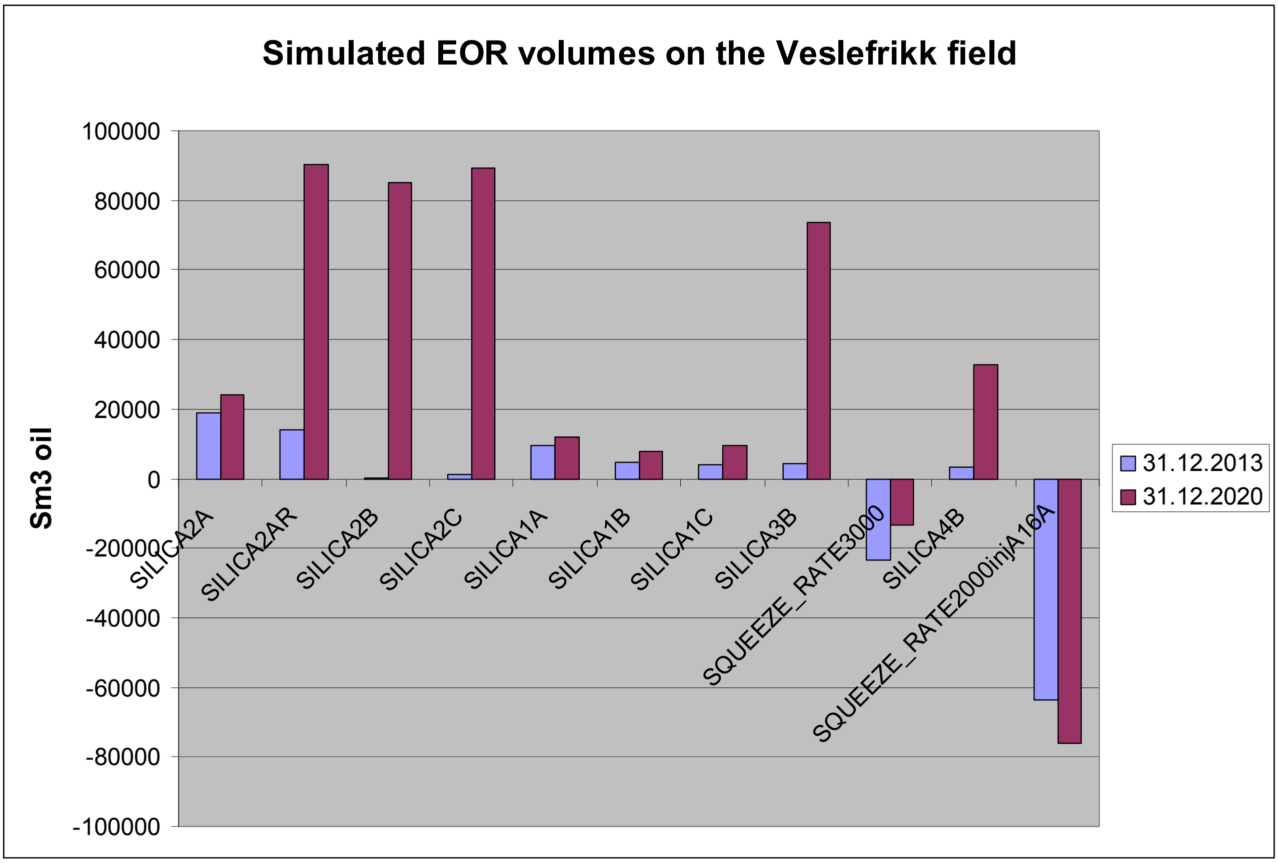


Figure 138: Simulated EOR volumes on the field

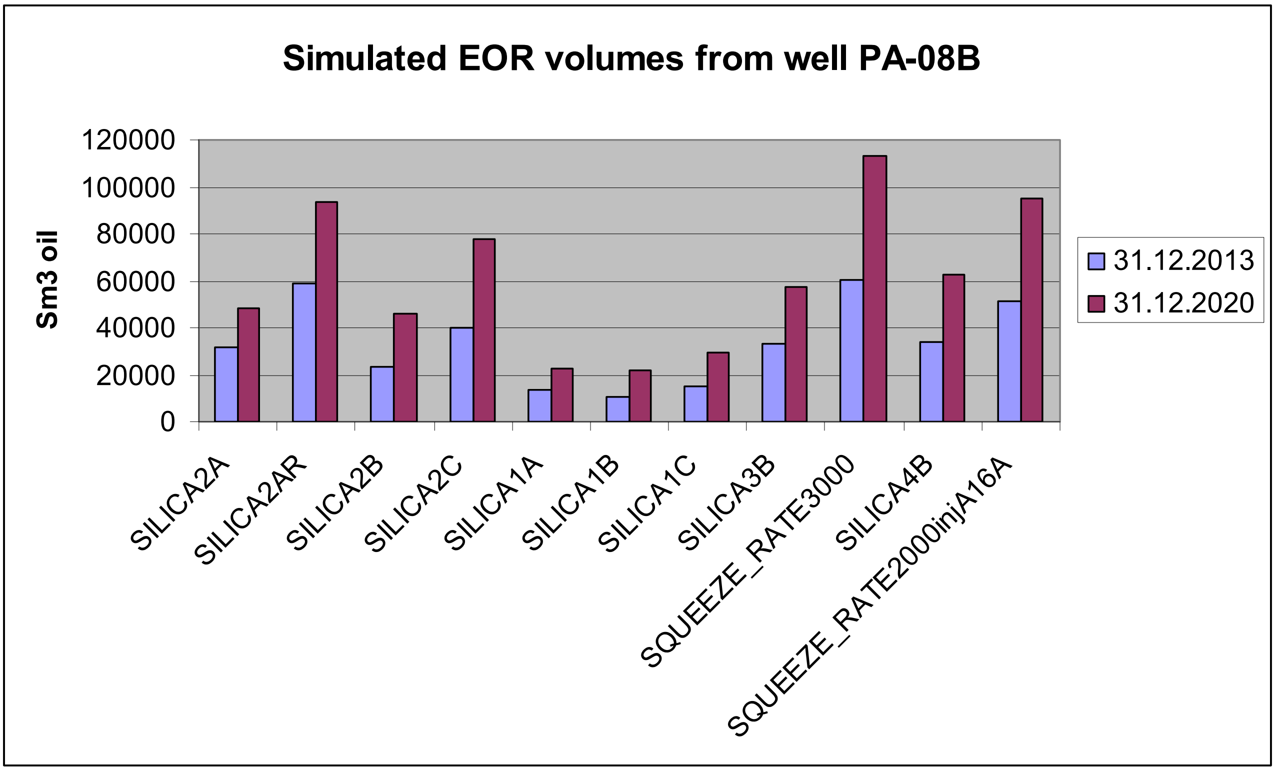


Figure 139 Simulated EOR volumes for well PA-08B

Figure 140 shows that by closing off the Ness 2 formation around the injection well IA-20A the oil production rate increases and the water cut is reduced in the production well PA-08B.

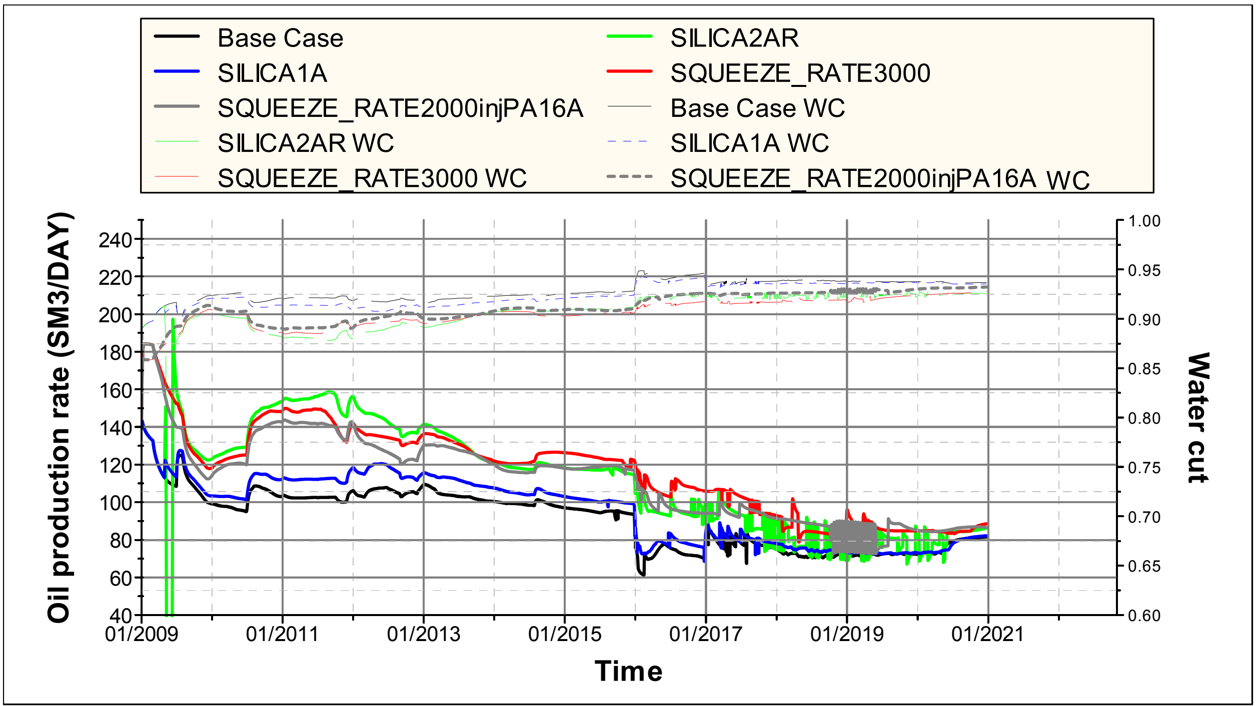


Figure 140: Well PA-08B Oil Production Rate and water cut

The SILICA2AR is the best case concerning acceleration of the oil production in the PA-08B well, where cells having a silica concentration of 0.27 get reduced horizontal permeability with a factor of 0.001. The oil production rate in PA-08B is increased by 50-60 Sm3/d and the water cut reduced by 5% for nearly 2 years, see Figure 140. On the field, the SILICA2AR case is the best EOR case, see Figure 138.
The best case regarding total oil production in well PA-08B, and maintaining a high oil production rate in the same well, is the squeeze case which completely shut off the perforations in the Ness 2 formation, see Figure 139 and Figure 140. The other squeeze case, which also increases the water injection rate in the PA-16A well, is also giving a good EOR result concerning increased oil production and decreased water cut from the PA-08B well. The negative EOR difference in PA-08B compared to the first squeeze case seems to be caused by higher water cut in PA-08B. Both squeeze cases give a negative EOR result on the field basis.

The reason for the SILICA2AR being a better EOR case, on the field, than the squeeze case, should be that a pressure support both to PA-08B and to other Ness 2 producers is retained even though the closed cells get a reduced horizontal permeability by a factor of 0.001. As explained before, a complete closure is not necessarily obtained vertically between the layers and there still exist a certain communication over the arcuate fault. Also, there is some communication to the Etive formation. But for the 2AR case, from studying the figures in FloViz, there seems to be a better closing between the layers (8, 9 and 10) than for the 3B case. This is probably the reason for the 2AR case giving a better EOR result than the 3B case.

The SILICA1 cases where PERMX is only reduced by a factor of 0.1 are not giving any essential EOR result on the field or in the production well PA-08B, see Figure 138, Figure 139 and Figure 140.

The SILICA3B and 4B cases simulate that a smaller batch size (half of the SILICA2AR case) is pumped and displaced only for one month (half displacement volume as in the 2AR case). For the

3B and 4B case PERMX is reduced respectively by a factor of 0.001 and 0.000001 in cells having a silica concentration of 0.28. There are no big differences on the two cases regarding obtained oil production rate in well PA-08B but on the field there is a big difference on the EOR, see Figure 141 and Figure 138. It could be expected that the difference was caused by a worsen pressure support, but this seems not to be the case when studying Figure 143 through Figure 148.

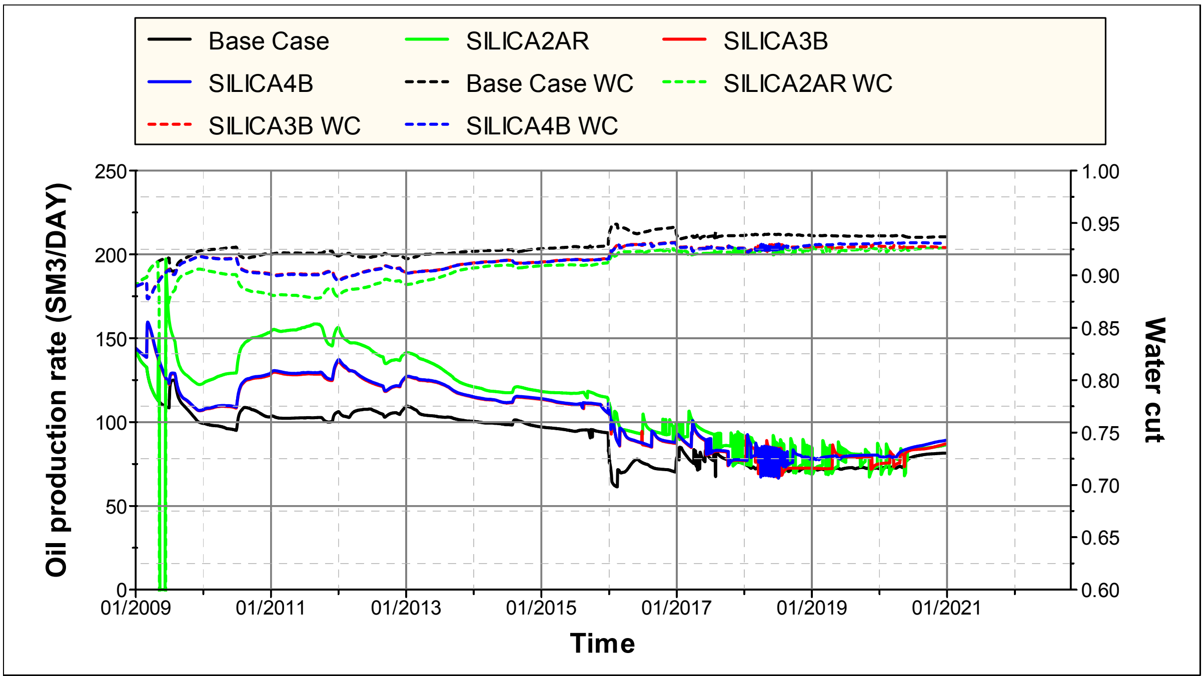


Figure 141: Oil Production rate and water cut in well PA-08B, strong reduction of PERMX

For the same cases as in Figure 141 an illustration of the change in injection rates into the Ness 2 and IDS formations are given in Figure 142. Initial percentage distribution of injection water, tracer base case, is 70/30 Ness2/IDS. The best silica case (2AR) change the distribution to 20/80 Ness2/IDS. Cases 3B/4B are quite similar; 35/65 Ness2/IDS.

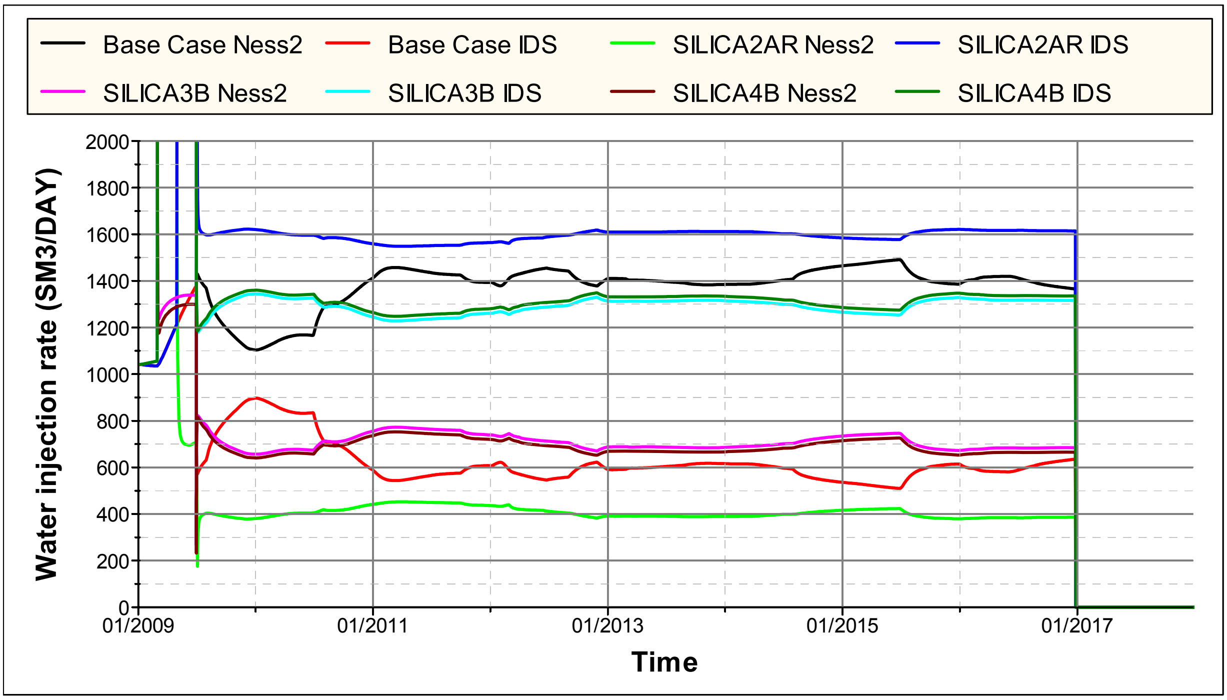


Figure 142: Water injection rates into well IA-20A, Ness2 and IDS formations, before and after treatment

The Figure 143 show that all the "shut-off" cases result in approximately a similar pressure as the initial well pressure. The squeeze case which also increases the injection rate in the other injector well PA-16A gives a good pressure support to the well PA-08B.

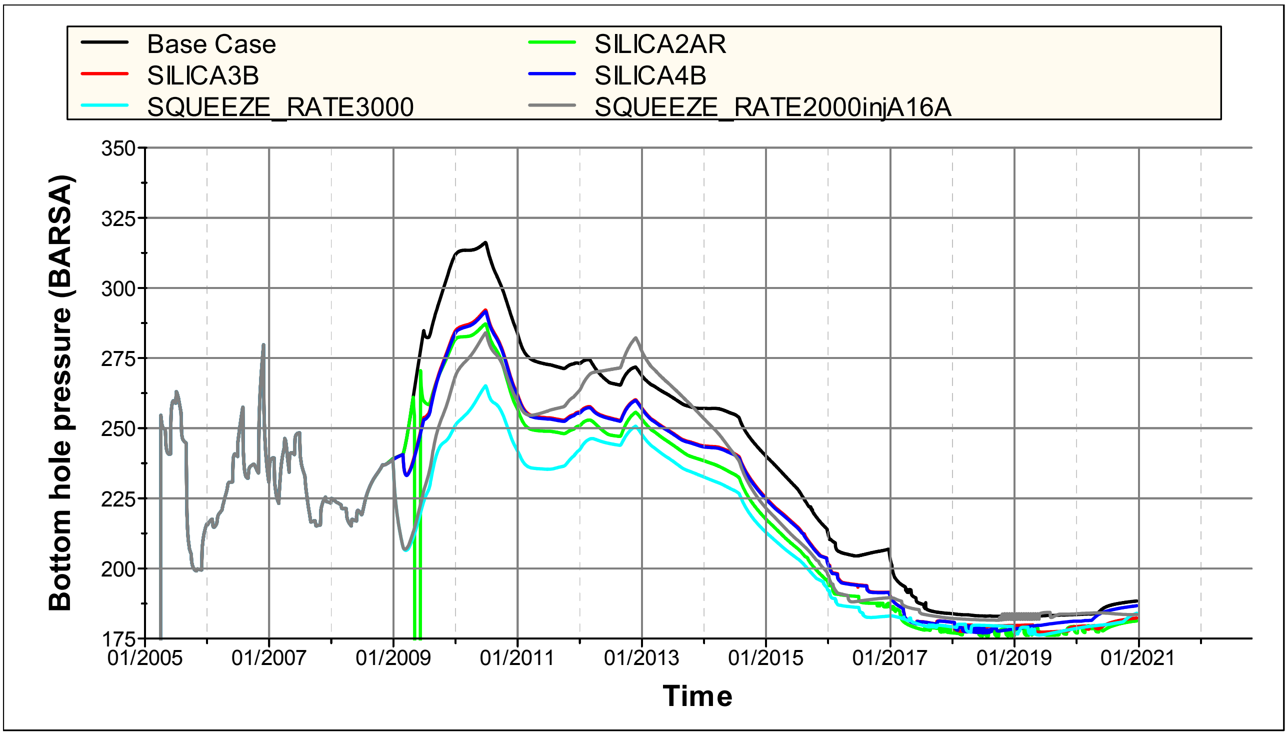


Figure 143: Bottom-hole pressure in well PA-08B, different simulation cases

The average reservoir pressure on the field is best retained at the initial pressure by the squeeze case which increases the injection rate in PA-16A, see Figure 144.

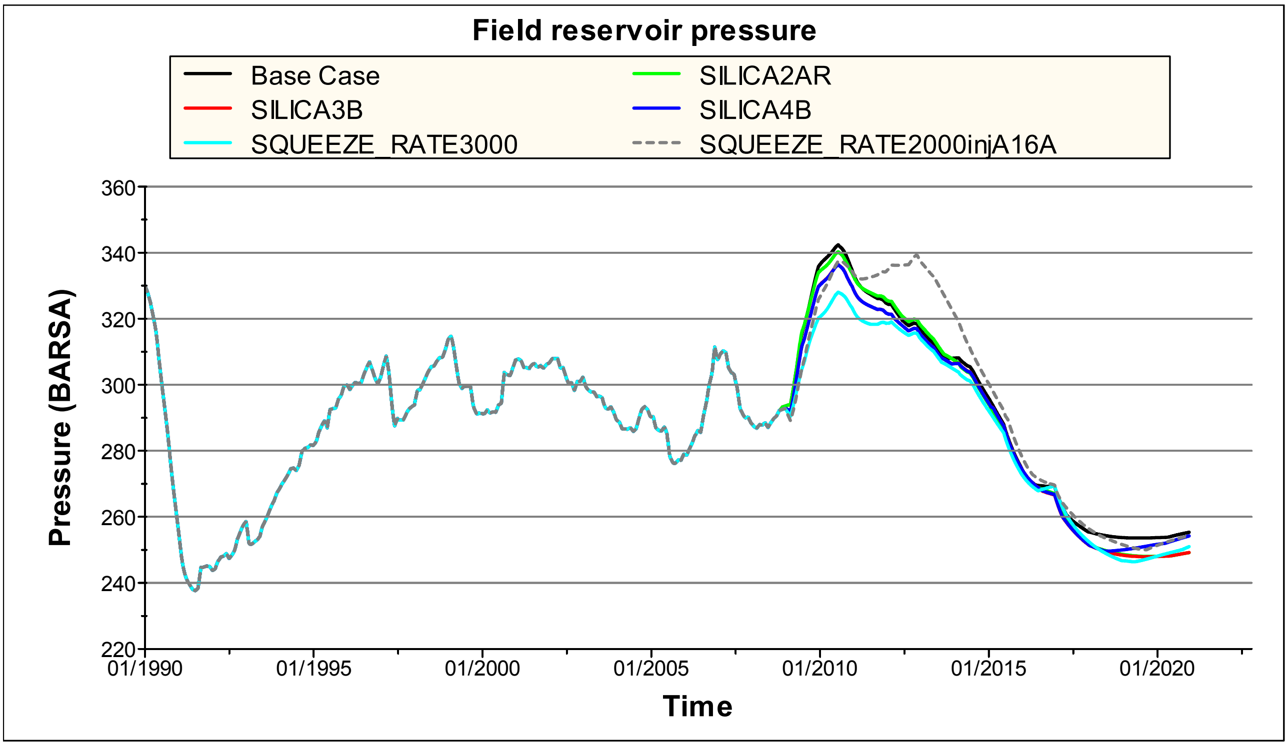


Figure 144 Development of field reservoir pressure for the different simulation cases

The well PA-08B is located in the A-segment, see Figure 133. The average reservoir pressure in the Ness 2 formation is following the same trends as in the PA-08B well (Figure 143), but shifted approximately 30 bars higher.

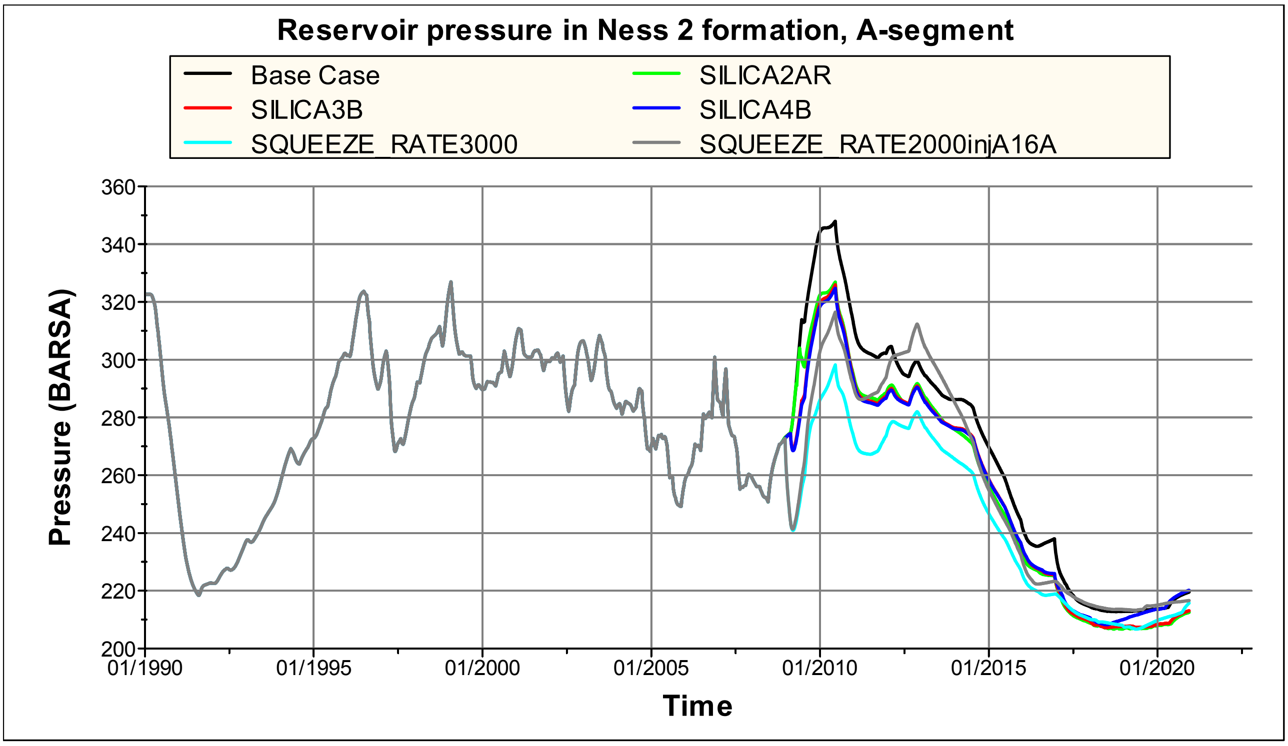


Figure 145 Region reservoir pressure, Ness 2 formation in the A-segment

The IDS formation in the A-segment gets an increased reservoir pressure, above the initial pressure, due to the increased water injection rate into the IDS formation in well IA-20A.

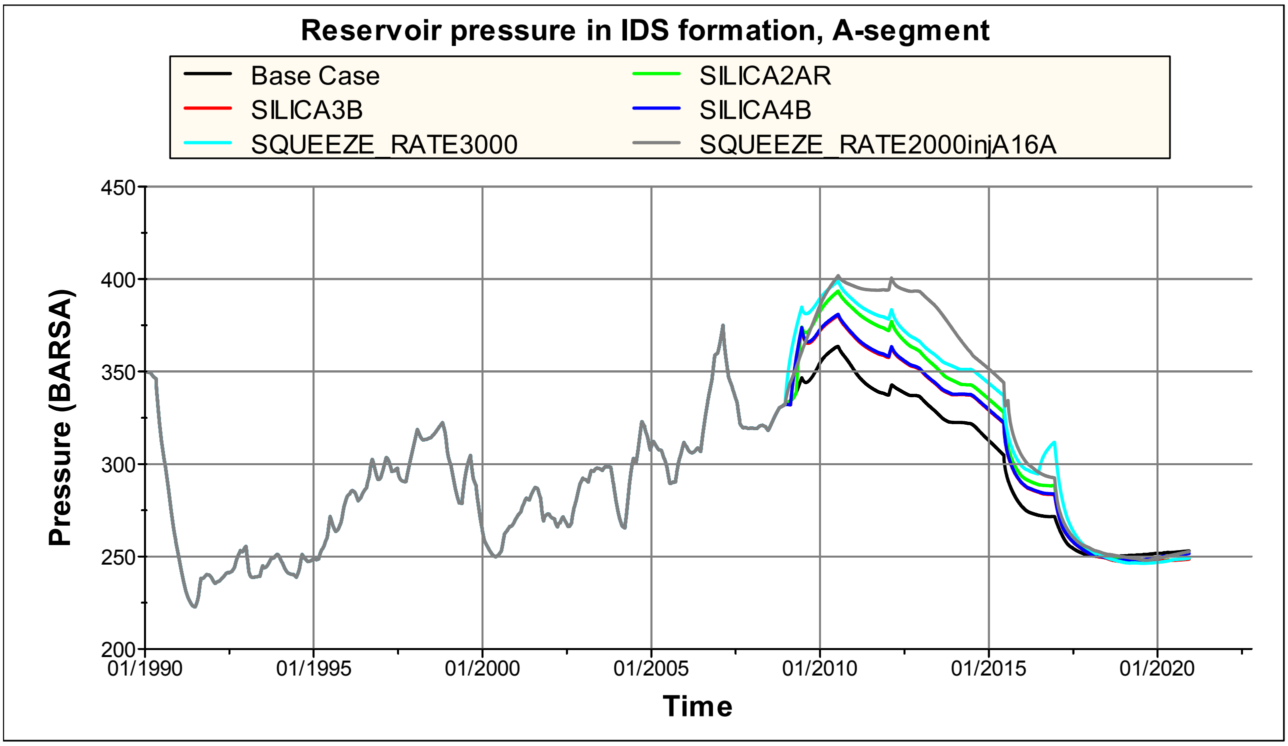


Figure 146 Region pressure, IDS formation in the A-segment

Also on the other side of the arcuate fault, the B-segment (see Figure 133), the average reservoir pressure in the Ness 2 formation get reduced when reducing or stopping the injection rate into the Ness 2 formation in the well IA-20A. But the reduction is not severe compared to the initial pressure, see Figure 147.

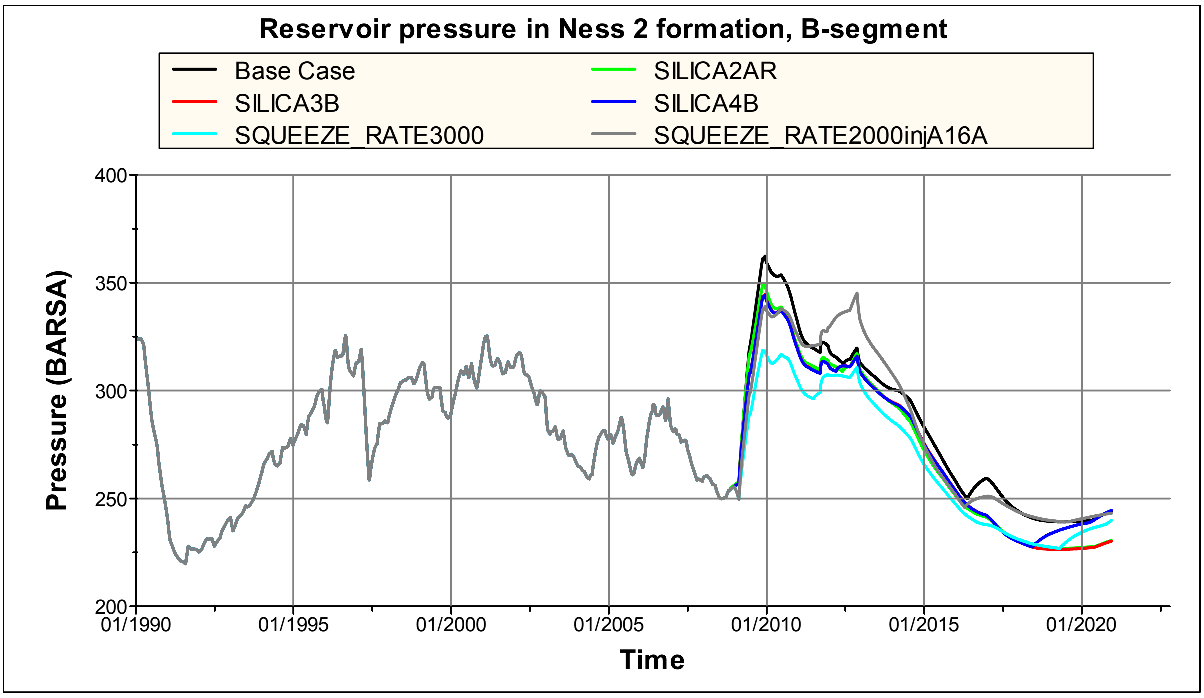


Figure 147 Region pressure, Ness 2 formation, B-segment

Both in the A-segment (Figure 146) and in the B-segment (Figure 148) the average reservoir pressure in the IDS formation increases and exceeds the initial pressure due to the increased water injection rates in the well IA-20A. The pressure maintains a high level especially when increasing the injection rate in the PA-16A well, which also get perforated in the IDS formation in 2012 (grey colour curve).

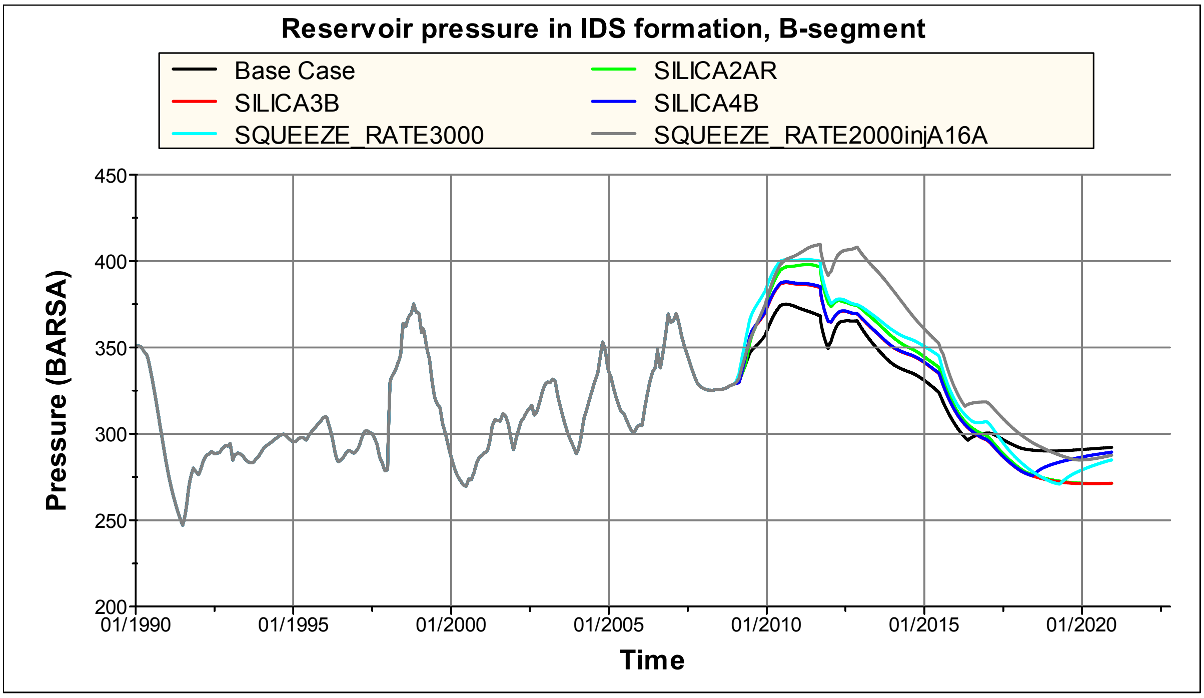


Figure 148 Region pressure, IDS formation, B-segment

6.4 Conclusions from reservoir simulations in the full field simulation model

The increased heterogeneity of the reservoir model, compared to the conceptual model, makes it more challenging to interpret the results from the simulations. It seems, however, as if a strong reduction in the horizontal permeability (PERMX*0.001) in the Ness 2 layers around the water injection well IA-20A could result in a higher oil production both from the horizontal oil producer PA-08B and totally on a field basis. It is also important to obtain a vertical closure between the layers 8, 9 and 10.
The “best” silica case gives an EOR both on the field and in the production well PA-08B, at the end of the field life (31.12.2020), of approximately 90000 Sm3 of oil. By optimizing the injection strategy the earlier EOR volume on the field might be increased. In the production well PA-08B an early EOR is obtained already 31.12.2013 by 60000 Sm3 of oil.

A total shut-off of the Ness 2 perforations in the IA-20A well, while increasing the injection rate in the IDS formation or in another injector well PA-16A, seems not to be a good case on the field basis. The main reason seems to be that the injection strategy is not optimum and that several wells get increased water production. However, for the well PA-08B, this gives the best EOR result.

From studying the simulation cases one could conclude that a near-wellbore silica treatment should be evaluated. To be able to simulate such a case there is a need for a refined grid around the well IA-20A and temperature simulations should be performed using the TEMP option in Eclipse to estimate the reservoir temperature in the planned treatment area. It is further important to study the injection logs (PLT’s) from the well and evaluate if the expected fracture pattern in the Ness2 formation is rate dependant or not and thus decide if the fractures are hydraulically or thermally made. If the fractures are rate dependant this can be utilized by increasing the injection rate and thus increase the injection of silica into the Ness 2 formation relatively to the injection of silica into the IDS formation. It is important to remain the ability of water injection into the IDS formation and thus effort should be made to avoid closing off in the IDS formation.

For a near-wellbore silica treatment a high concentration of silica would be needed to make the gel strong enough to withstand the future differential pressure when resuming water injection in the well. Laboratory studies will have to be done to decide upon the necessary design properties of the gel based on the simulated reservoir temperatures in the planned treatment area, the properties of the formation brine, the injectivity and the necessary gelation times.

Field experience from near-wellbore silica treatment of 2 producers on the Gullfaks field will be looked into for the further work to be done.

Looking at the obtained EOR volumes from the simulations and considering a near-wellbore treatment which implies a small silica volume similar to the Gullfaks cases [23], a positive NPV should be expected.

7 Conclusions and further work

Water flooding is the main oil recovery method on the Veslefrikk field. This method is regarded as efficient since the residual oil saturation, in most of the reservoir zones, is low after water flooding. Despite of this, a considerable oil volume is still left in the reservoir indicating that the volumetric (macroscopic) sweep could have been better. The field is producing in the tail end phase which implies a low oil production rate and a high water cut. To increase the oil production, methods which could reduce the water production should be evaluated.

Concentrating on water based EOR methods, a screening have been performed on the applicability of some of the methods on the Veslefrikk field. Several of the methods have been discarded due to either the application area for the chemicals not being suitable for the Veslefrikk reservoir parameters (e.g. temperature), the chemicals being regarded as “red” and not acceptable with regards to HSE or the recovery mechanisms not being expected to provide any essential EOR potential on the Veslefrikk field.

The diversion of injection water by the utilization of sodium silicate was found to be the most relevant method for a further investigation. Except from being valuable in terms of diverging injection water to unflooded or poorly flooded areas, the chemicals involved and the system can be properly designed for, and adjusted to the Veslefrikk reservoir parameters, like for instance the high initial reservoir temperature. An EOR was expected to be obtained both as a result of injection water diversion and a reduced water production.

Numerical simulations indicate that there exists an EOR potential on the Veslefrikk field by injecting sodium silicate. A conceptual model have been studied for the Etive formation evaluating the potential of closing off “thief” zones in the Etive 2 formation and reduce the residual oil saturation in the Etive 3 formation. The best EOR cases are obtained by displacing a big batch of sodium silicate far into the reservoir, and slightly reduce the horizontal permeability in the sodium silicate treated cells. The timing for injecting sodium silicate should be as soon as water break-through has occurred, and the treatment should be repeated after some time.

Only near-wellbore sodium silicate treatments have been conducted so far. The ability of placing a proper gel far out in the reservoir, and still remain having the properties necessary to obtain the planned reduction of horizontal permeability, is a challenge still to be investigated.

Simulations show that with an increase of the heterogeneity in the conceptual model, through reduction of the vertical permeability with an additional magnitude of order, a different flooding pattern is obtained giving a significant increase of the EOR effect by the injection of sodium silicate. The rather low EOR potential resulting from the simulations done in the low heterogeneity model may, thus, be challenged by the idea that a higher EOR in reality would be obtained due to a higher heterogeneity of the real reservoir.

Further, a study has been performed on a possible field pilot test. The full field reservoir simulation model has been used to analyze the opportunity of increasing the oil production, especially in the horizontal production well PA-08B dedicated to the Ness 2 formation. This is being done by the injection of sodium silicate in the Ness 2 formation in the near by water injection well IA-20A.

Contrary to the studies performed on the conceptual model, the cases which strongly reduce the horizontal permeability in the sodium silicate treated cells, gave the best EOR result both on the field basis and for the production well PA-08B. The application of the sodium silicate method depends on the objectives for the treatment and the characteristics of the reservoir zone it is intended for.

The preliminary results are promising and a possible pilot test implying a near-wellbore sodium silicate treatment of the water injection well IA-20A should be further investigated.

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App A Nomenclature

Abbreviations:

EOR:	enhanced oil recovery
f_w:	fractional water flow
IOR:	improved oil recovery
K:	absolute permeability
$k_{eff.}$:	effective permeability
$k_{r.}$:	relative permeability
$k_{ro.}$:	relative permeability for oil
$k_{rw.}$:	relative permeability for water
M:	mobility ratio
M^o:	end point mobility ratio
N_C:	capillary number
OIP:	oil in place
P_C:	capillary pressure
PERMX:	syntax for horizontal permeability, x-direction in Eclipse simulations
PERMZ:	syntax for vertical permeability, z-direction in Eclipse simulations
p_o:	internal pressure in the oil phase
p_w:	internal pressure in the water phase
PV:	pore volume
PVT:	pressure, volume and temperature
Rm3:	reservoir cubic meter, at reservoir conditions
RRF:	residual resistivity factor
Sm3:	standard cubic meter, at standard conditions (1 atm. pressure and 15°C)
S_{nc}	connate non-wetting fluid saturation
S_o:	oil saturation
S_{or}:	residual oil saturation
S_{org}	residual oil saturation after gas flooding
S_{orw}	residual oil saturation after water flooding
S_w:	water saturation
S_{wc}:	connate water saturation, also connate wetting fluid saturation
S_{wf}:	water saturation at the front (here; in the well area at water break-through)
S_{wi}:	irreducible water saturation
wt%:	weight percent

Greek letters:

Φ:	porosity
μ_w:	viscosity of water
μ_o:	viscosity of oil
σ:	interfacial tension
σ_{ow}:	interfacial tension between oil and water
σ_{os}:	interfacial tension between oil and solid
σ_{ws}:	interfacial tension between water and solid
θ:	contact angle
v:	velocity of displacing fluid
α:	reservoir dip inclination

For oil field terms see Schlumberger Oilfield Glossary: http://www.glossary.oilfield.slb.com/

App B Reservoir simulation data files for the conceptual model

B.1 Base Case Conceptual Model, data simulation file

```
--*****************************************************************************
-- VESLEFRIKK
--*****************************************************************************
--
-- Simple model for qualitative evaluation of IOR as a result of injecting NaSilicate
-- Base case: thickness and petrophysical properties of layers in Etive formation as in
FFM01
-- Tuned to avoid convergence problems, grid from resview.
--
RUNSPEC

--ECLIPSE
TITLE
VESLEFRIKK IOR ETIVE base case ECLIPSE model /

DIMENS
-- NX NY NZ
  20 20 6 /

METRIC

OIL
WATER
GAS
DISGAS

--NOSIM

START
  1 'JAN' 2009 /

TABDIMS
--ntsfun ntpvt nssfun nppvt  ntfip nrpvt  notused  ntendp
    1      1     100    50     6   25  /

WELLDIMS
 5 10  1 5 /

EQLDIMS
-- NTEQUL   NDRRVD  NDRXVD
     1      100     18  /

ROCKCOMP
 HYSTER /

ENDSCALE
/

NSTACK
36 /

UNIFOUT

MESSAGES
--      Message Comment Warning Problem Error   Bug
-- print limit
        5000    5000    10000   100     100     100
--stop limit
        100000  100000  100000  100000  100     10
/
```

```
---------------------------------------------------
--
--      Input of grid geometry
--
---------------------------------------------------
GRID

GRIDFILE
-- control of gridfile output, an extended gridfile is produced
2 /

-- simple grid 1000 x 1000 m (NX=20, NY=20, NZ=6 400 cells ea layer)
-- grid made in resview 21.08.08
INCLUDE
 '../INCLUDE/GRID.GRDECL' /

PERMX
 400*368 400*362 400*1383 400*1672 400*1084 400*545 /

COPY
 PERMX PERMY /
 PERMX PERMZ /
/
MULTIPLY
 PERMZ 0.5 1 20 1 20 1 6 /
/
PORO
 800*0.16 1600*0.18 /

NTG
 2400*0.95 /

INIT

PROPS
-------- THE PROPS SECTION DEFINES THE REL. PERMEABILITIES, CAPILLARY
-------- PRESSURES, AND THE PVT PROPERTIES OF THE RESERVOIR FLUIDS
----------------------------------------------------------------------------

-- Relative permeability

INCLUDE
 '../INCLUDE/RELPERMETIVE_M6.txt' /

INCLUDE
 '../INCLUDE/GASSRELP_1ETIVE.txt' /

EQUALS
 SWCR 0.15771 1 20 1 20 1 1 /
 SWCR 0.16221 1 20 1 20 2 2 /
 SWCR 0.13059 1 20 1 20 3 3 /
 SWCR 0.12713 1 20 1 20 4 4 /
 SWCR 0.13974 1 20 1 20 5 5 /
 SWCR 0.15840 1 20 1 20 6 6 /
 SOWCR 0.16160 1 20 1 20 1 1 /
 SOWCR 0.16142 1 20 1 20 2 2 /
 SOWCR 0.16258 1 20 1 20 3 3 /
 SOWCR 0.16270 1 20 1 20 4 4 /
 SOWCR 0.16229 1 20 1 20 5 5 /
 SOWCR 0.16157 1 20 1 20 6 6 /
 SOGCR 0.13006 1 20 1 20 1 1 /
 SOGCR 0.12898 1 20 1 20 2 2 /
 SOGCR 0.13646 1 20 1 20 3 3 /
 SOGCR 0.13728 1 20 1 20 4 4 /
 SOGCR 0.13455 1 20 1 20 5 5 /
 SOGCR 0.12989 1 20 1 20 6 6 /
 SGCR 0.03154 1 20 1 20 1 1 /
 SGCR 0.03244 1 20 1 20 2 2 /
```

```
 SGCR 0.02612 1 20 1 20 3 3 /
 SGCR 0.02543 1 20 1 20 4 4 /
 SGCR 0.02775 1 20 1 20 5 5 /
 SGCR 0.03168 1 20 1 20 6 6 /
 SGU 0.68610 1 20 1 20 1 1 /
 SGU 0.67808 1 20 1 20 2 2 /
 SGU 0.73882 1 20 1 20 3 3 /
 SGU 0.74574 1 20 1 20 4 4 /
 SGU 0.72254 1 20 1 20 5 5 /
 SGU 0.68433 1 20 1 20 6 6 /
/


COPY
  'SWCR' 'SWL' 1  20   1  20   1  6 /
/

-- PVT PROPERTIES OF WATER
--
--    REF. PRES. REF. FVF  COMPRESSIBILITY  REF VISCOSITY  VISCOSIBILITY
--     Pw (bara)    Bw        Cw (1/bar)     Vwi= .19 (cp)  (dVw/dP)/Vw
PVTW
    320      1.042      4.5D-5       0.25      .0000  /

INCLUDE
 '../INCLUDE/PVTO_STEX_ETIVE.PVT' /

INCLUDE
 '../INCLUDE/DEAD_GAS_ETIVE.PVT' /

-- SURFACE DENSITIES
--        OIL      WATER    GAS
DENSITY
        826.7    1001.  0.997 / Brent

ROCKTABH
-- ROCK region 1 (Brent) - PV reduksjon til 0.9928 @ 150 bar ==> Cr=4e-5
--       PV mult  Trans mult
150      0.9928       1.0
     500 1.0068       1.0 / Ingen hysterese i Brent
330      1.0000       1.0
     500 1.0068       1.0 /
/
-- ROCK region 2 (IDS) - PV reduksjon til 0.9766 @ 170 bar ==> Cr=10e-5
--170      0.982       1.0
--     180 0.9826       1.0
--    520 1.003       1.0 / Hysterese i IDS
--350      1.0000       1.0
--     520 1.0102       1.0 / Tilnærmet elastisk ekspansjon --> Cr=6E-5
--/

-- SWITCH ON OUTPUT OF ALL PROPS DATA
RPTPROPS
0 0 0 0 0 0 0 0 /

--------------------------------------------------------------------------------
REGIONS

FIPNUM
400*1 400*2 400*3 400*4 400*5 400*6 /

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

----------------------------------------------------
SOLUTION
---------------------------------------------------
-------- THE SOLUTION SECTION DEFINES THE INITIAL STATE OF THE SOLUTION
-------- VARIABLES (PHASE PRESSURES, SATURATIONS AND GAS-OIL RATIOS)
```

```
--------------------------------------------------------------------------
--
--
--    DATUM   DATUM   OWC    OWC    GOC    GOC    RSVD   RVVD   SOLN
--    DEPTH   PRESS  DEPTH   PCOW  DEPTH   PCOG  TABLE  TABLE   METH
EQUIL
-- 5  MB/LB Main Field (Ness 2 - Oseberg 1)
      2907.00 328.3  2907.0  0.0    0.0    0.0     5      5     10  /
RSVD
-- Brent
  2000  118
  4000  118/

RPTSOL
 'FIP=3' 'EQUIL' 'RESTART=2' /

----------------------------------------------------------------------------------
SUMMARY

INCLUDE
 '../INCLUDE/SUMMARY.DATA' /

----------------------------------------------------------------------------------
SCHEDULE
----------------------------------------------------------------------------------

SKIPREST

DRSDT
 1.3 /

RPTRST
 BASIC=3 FREQ=1  /


RPTSCHED
 'FIP=3' 'CPU=1' 'NEWTON=1' 'WELLS=5' /

WELSPECS
--wname  grp  iwh jwh Z(bhp) prefPhase rPI/II  sp.Infl AutoShut X-flow Ptab densCalc
FIPnr
  'PW1' 'G'   1    1   1*     'OIL'  /
  'IW1' 'G'   20  20   1*     'WATER'  /
  /

-- Completion data (5,5" liner)
COMPDAT
--wname  ic  jc  k_hi k_lo open/shut satnum tfac   wdiam  Kh skin Dfac penDir r0
  'PW1'  1   1   1    6    'O'        0      -1    0.12   3*            'Z'      /
  'IW1'  20  20  1    6    'O'        0      -1    0.12   3*            'Z'      /
  /

WCONPROD
--wname open/shut  ctrlmode orat wrat grat lrat rvol bhpmin thpmin vfptab artlift ...
  'PW1'   OPEN      RESV    4*                  2000   190     0     0       0 /
/
WCONINJE
--wname injtype open/shut  ctrlmode rate resv bhpmax thpmax vfptab...
  'IW1'  WATER  OPEN        RATE    2000  1*   550      2*           /
/
GCONINJE
--gname injtype ctrlmode  surfrate  resrate reinfract voidfract xxxx  guiderate
def.of.guiderate
  'G'     WATER  VREP         3*                          1      NO     2000
VOID       /
/
TUNING
 0.05  0.1 0.01 /
```

```
 /
 12    1   36 /

DATES
1 'FEB' 2009 /
/

TUNING
 0.1   2 /
 /
 12    1   36 /

DATES
1 'SEP' 2009 /
/

TUNING
 0.05  0.5 0.01 /
 /
 12    1   36 /

DATES
1 'JAN' 2010 /
/

TUNING
 0.1   20 /
 /
 12    1   36 /

DATES
1 'JUL' 2010 /
1 'JAN' 2011 /
1 'JUL' 2011 /
1 'JAN' 2012 /
1 'JUL' 2012 /
1 'JAN' 2013 /
1 'JUL' 2013 /
1 'JAN' 2014 /
1 'JAN' 2015 /
1 'JAN' 2016 /
1 'APR' 2016 /
/

END
```

B.1.1 Include files: Rel.perm. tables, Saturation tables

```
******** START OF INCLUDED FILE ../INCLUDE/RELPERMETIVE_M6.txt

 1: --  Corey  1.9  2.5
 1: --  Rel  perm  for  Olje  Corey    justert  til  2.5
 1: --  Skal  brukes  sammen  med  Sorwc    15  %  og  Krwr  ca  3
 1: SWOF
 1: --  Etive  formation  saturation  functions
 1: --  Corey  exponents
 1: --  Water-Oil  1.9  4.5  Etive
 1: --  Swn  Krw  Krow  Pcd
 1:   0.000  0.000E+00  1.000E+00  5.2802
 1:   0.050  2.955E-08  7.939E-01  1.6261
 1:   0.100  1.536E-06  6.224E-01  0.7591
 1:   0.150  1.550E-05  4.813E-01  0.3996
 1:   0.200  7.987E-05  3.664E-01  0.2481
 1:   0.250  2.849E-04  2.740E-01  0.1487
```

```
1:   0.300  8.055E-04  2.009E-01  0.1130
1:   0.350  1.939E-03  1.439E-01  0.0773
1:   0.400  4.152E-03  1.004E-01  0.0639
1:   0.450  8.125E-03  6.786E-02  0.0504
1:   0.500  2.679E-01  4.419E-02  0.0370
1:   0.550  3.211E-01  2.751E-02  0.0317
1:   0.600  3.789E-01  1.619E-02  0.0263
1:   0.650  4.411E-01  8.878E-03  0.0210
1:   0.700  5.078E-01  4.437E-03  0.0182
1:   0.750  5.789E-01  1.953E-03  0.0154
1:   0.800  6.544E-01  7.155E-04  0.0135
1:   0.850  7.343E-01  1.961E-04  0.0116
1:   0.900  8.186E-01  3.162E-05  0.0104
1:   0.950  9.071E-01  1.398E-06  0.0093
1:   0.980  9.623E-01  2.263E-08  0.0086
1:   1.000  1.000E+00  0.000E+00  0.0081
1: /

******** END OF INCLUDED FILE

0:
0: INCLUDE

******** START OF INCLUDED FILE ../INCLUDE/GASSRELP_1ETIVE.txt

1: SGOF
1: --  Etive fm
1: --  Corey  exponents
1: --  Gas-Oil  2  1.3
1: --  Sgn  Krg  Krog  Pcd
1:   0  0.00E+00  1.00E+00  0
1:   0.005  2.50E-05  9.94E-01  0
1:   0.01  1.00E-04  9.87E-01  0
1:   0.02  4.00E-04  9.74E-01  0
1:   0.04  1.60E-03  9.48E-01  0
1:   0.08  6.40E-03  8.97E-01  0
1:   0.16  2.56E-02  7.97E-01  0
1:   0.25  6.25E-02  6.88E-01  0
1:   0.35  1.23E-01  5.71E-01  0
1:   0.5  2.50E-01  4.06E-01  0
1:   0.65  4.23E-01  2.55E-01  0
1:   0.75  5.63E-01  1.65E-01  0
1:   0.85  7.23E-01  8.49E-02  0
1:   1  1.00E+00  0.00E+00  0
1: /

******** END OF INCLUDED FILE

******** START OF INCLUDED FILE ../INCLUDE/PVTO_STEX_ETIVE.PVT

1: -- PVT dataset 4CORR.ECL (ref J. Milter) - Statfjord/Export (50/50) inj
1: --
1: PVTO
1: --
1: --         ***   O I L   D A T A    BRENT ***
1: --
1: --    RSO    PRESSURE     B-OIL     VISCOSITY
1: --            (BAR)                   (CP)
1: ----------------------------------------------
1:    15.57     30.00      1.144     0.61594
1:             128.00      1.129     0.69326
1:             208.00      1.117     0.77204
1:             263.00      1.107     0.85175
1:             323.00      1.097     0.93180
1:             373.00      1.089     1.01168 /
1:    28.48     50.00      1.181     0.56937
1:             148.00      1.164     0.63673
1:             228.00      1.151     0.70514
```

1:		283.00	1.139	0.77420	
1:		343.00	1.129	0.84347	
1:		393.00	1.121	0.91254	/
1:	47.85	80.00	1.233	0.49455	
1:		178.00	1.215	0.53961	
1:		258.00	1.199	0.59001	
1:		313.00	1.186	0.65209	
1:		373.00	1.175	0.72238	
1:		423.00	1.165	0.79084	/
1:	60.76	100.00	1.268	0.45150	
1:		198.00	1.248	0.48917	
1:		278.00	1.232	0.52612	
1:		333.00	1.218	0.56237	
1:		393.00	1.206	0.59791	
1:		443.00	1.195	0.63272	/
1:	73.68	120.00	1.304	0.41379	
1:		218.00	1.283	0.44678	
1:		298.00	1.266	0.47909	
1:		353.00	1.251	0.51075	
1:		413.00	1.238	0.54175	
1:		463.00	1.227	0.57207	/
1:	86.59	140.00	1.342	0.38011	
1:		238.00	1.320	0.40915	
1:		318.00	1.301	0.43753	
1:		373.00	1.285	0.46533	
1:		433.00	1.272	0.49255	
1:		483.00	1.259	0.51917	/
1:	99.50	160.00	1.382	0.34976	
1:		258.00	1.359	0.37544	
1:		338.00	1.339	0.40049	
1:		393.00	1.322	0.42500	
1:		453.00	1.307	0.44898	
1:		503.00	1.294	0.47245	/
1:	112.48	180.00	1.425	0.32225	
1:		278.00	1.400	0.34503	
1:		358.00	1.379	0.36723	
1:		413.00	1.361	0.38892	
1:		473.00	1.345	0.41014	
1:		523.00	1.331	0.43090	/
1:	118.00	187.50	1.449	0.31257	
1:		285.50	1.416	0.33438	
1:		365.50	1.394	0.35561	
1:		420.50	1.376	0.37635	
1:		480.50	1.360	0.39663	
1:		530.50	1.346	0.41648	/
1:	140.28	211.51	1.505	0.28244	
1:		309.51	1.477	0.30136	
1:		389.51	1.453	0.31975	
1:		444.51	1.433	0.33767	
1:		504.51	1.416	0.35519	
1:		554.51	1.401	0.37233	/
1:	162.08	233.29	1.567	0.25805	
1:		331.29	1.537	0.27478	
1:		411.29	1.512	0.29099	
1:		466.29	1.490	0.30678	
1:		526.29	1.471	0.32219	
1:		576.29	1.455	0.33726	/
1:	183.80	253.23	1.630	0.23799	
1:		351.23	1.597	0.25299	
1:		431.23	1.570	0.26750	
1:		486.23	1.547	0.28162	
1:		546.23	1.527	0.29538	
1:		596.23	1.509	0.30884	/
1:	205.45	271.62	1.691	0.22125	
1:		369.62	1.657	0.23487	
1:		449.62	1.628	0.24802	
1:		504.62	1.603	0.26080	
1:		564.62	1.582	0.27325	

```
 1:              614.62      1.563     0.28540 /
 1:   227.03    288.75      1.753     0.20711
 1:              338.75      1.716     0.21960
 1:              388.75      1.686     0.23165
 1:              438.75      1.659     0.24333
 1:              488.75      1.637     0.25470
 1:              538.75      1.617     0.26580 /
 1: --  227.04    568.00      1.595     0.27906
 1: --            597.00      1.579     0.28963
 1: --            623.00      1.565     0.29999
 1: --            645.00      1.553     0.31013
 1: --            668.00      1.541     0.32008
 1: --           688.00      1.530     0.32983 /
 1: /

 ******** END OF INCLUDED FILE

 0:
 0: INCLUDE

 ******** START OF INCLUDED FILE ../INCLUDE/DEAD_GAS_ETIVE.PVT

 1: -- PVT dataset 4CORR.ECL (ref J. Milter) - Statfjord/Export (50/50) inj
 1: --
 1: PVDG
 1: --
 1: --         ***   G A S   D A T A   BRENT ***
 1: --   PRESSURE        B-GAS     VISCOSITY
 1: --    BAR                                 (CP)
 1: --------------------------------------------------
 1:      30.00       0.043958     0.01419
 1:      50.00       0.026013     0.01495
 1:      80.00       0.016023     0.01596
 1:     100          0.012748     0.01666
 1:     120          0.010596     0.01741
 1:     140          0.009085     0.01821
 1:     160          0.007974     0.01906
 1:     180.         0.007128     0.01995
 1:     187.5        0.006862     0.02030
 1:     211.51       0.006134     0.02150
 1:     233.29       0.005618     0.02264
 1:     253.23       0.005234     0.02373
 1:     271.62       0.004937     0.02477
 1:     288.75       0.004699     0.02575
 1:     300          0.004564     0.02633
 1:     350          0.004086     0.02887
 1:     400.         0.003743     0.03130
 1:     450.         0.003486     0.03362
 1:     500.         0.003285     0.03583
 1:     550.         0.003124     0.03794
 1:     600.         0.002992     0.03995
 1:  /

 ******** END OF INCLUDED FILE
```

B.1.2 Summary include file

```
0: SUMMARY
 0:
 0: INCLUDE

 ******** START OF INCLUDED FILE ../INCLUDE/SUMMARY.DATA

 1: WOPR
 1: /
```

```
1: WOPRH
1: /
1: WOPT
1: /
1: WOPTH
1: /
1: WGOR
1: /
1: WGORH
1: /
1: WGPR
1: /
1: WGPRH
1: /
1: WGLIR
1: /
1: WWCT
1: /
1: WWCTH
1: /
1: WWPR
1: /
1: WWPRH
1: /
1: WBHP
1: /
1: WTHP
1: /
1: WWIR
1: /
1: WWIT
1: /
1: WWITH
1: /
1: WWIRH
1: /
1: WGIR
1: /
1: WGIT
1: /
1: WMCTL
1: /
1: WGLIR
1: /
1: WLPR
1: /
1: WLPRH
1: /
1: WVPR
1: /
1: WVIR
1: /
1: COFR
1:   'PW1' /
1: /
1: COPT
1:   'PW1' /
1: /
1: CWFR
1:   'PW1' /
1: /
1: CWPT
1:   'PW1' /
1: /
1: CWIR
1:   'IW1' /
1: /
1: CWIT
```

```
1:   'IW1' /
1: /
1:
1: FGIR
1: FGIRH
1: FGIT
1: FGITH
1: FGIP
1: FGOR
1: FGORH
1: FGPR
1: FGPRH
1: FGPT
1: FGPTH
1: FLPR
1: FLPT
1: FLPTH
1: FOPR
1: FOPRH
1: FOPT
1: FOPTH
1: FPR
1: FVIR
1: FVIT
1: FVPR
1: FVPT
1: FWCT
1: FWCTH
1: FWIR
1: FWIRH
1: FWIT
1: FWPR
1: FWPRH
1: FWPT
1:
1: FMWPR
1: FOE
1: FOEW
1: FGLIR
1:
1: ROFT
1: /
1: RWFT
1: /
1: RGFT
1: /
1: ROIP
1: /
1: RWIP
1: /
1: RGIP
1: /
1: ROPR
1: /
1: ROPT
1: /
1: RWPR
1: /
1: RWPT
1: /
1: RWIR
1: /
1: RWIT
1: /
```

B.2 Tracer data file

```
--******************************************************************************
-- VESLEFRIKK
--******************************************************************************
--
-- Simple model for qualitative evaluation of IOR as a result of injecting NaSilicate
-- Base case: thickness and petrophysical properties of layers in Etive formation as in
FFM01
-- Inject 60000 m3 NaSilicate, 30 days, 2000 m3/d from 1/1-2011 (after 2 years
production).
-- Displace NaSilicate with 120000 m3 water, 60 days, 2000 m3/d
--
--
--
--
--
--
RUNSPEC

--ECLIPSE
TITLE
VESLEFRIKK IOR ETIVE TRACER case ECLIPSE model /

DIMENS
-- NX NY NZ
  20 20 6 /

METRIC

OIL
WATER
GAS
DISGAS

--NOSIM

START
  1 'JAN' 2009 /

TABDIMS
--ntsfun ntpvt nssfun nppvt  ntfip nrpvt  notused  ntendp
    1      1     100    50     6   25  /

WELLDIMS
 5 10  1 5 /

EQLDIMS
-- NTEQUL   NDRRVD  NDRXVD
     1      100     18  /

TRACERS
-- max.oiltracers  max.wat.tracers  max.gastracers  max.environ.tracers  num.diffusion
max.NL.iter min.NL.iter ..........
   1*                1                  2*                                   'NODIFF'
/

ROCKCOMP
 HYSTER /

ENDSCALE
/

NSTACK
36 /

UNIFOUT
```

```
MESSAGES
--      Message Comment Warning Problem Error   Bug
-- print limit
        5000    5000    10000   100     100     100
--stop limit
        100000  100000  100000  100000  100     10
/
---------------------------------------------------
--
--      Input of grid geometry
--
---------------------------------------------------
GRID

GRIDFILE
-- control of gridfile output, an extended gridfile is produced
2 /

-- simple grid 1000 x 1000 m (NX=20, NY=20, NZ=6 400 cells ea layer)
-- grid made in resview 21.08.08
INCLUDE
 '../INCLUDE/GRID.GRDECL' /

PERMX
 400*368 400*362 400*1383 400*1672 400*1084 400*545 /

COPY
 PERMX PERMY /
 PERMX PERMZ /
/
MULTIPLY
 PERMZ 0.5 1 20 1 20 1 6 /
/
PORO
 800*0.16 1600*0.18 /

NTG
 2400*0.95 /

INIT

PROPS
-------- THE PROPS SECTION DEFINES THE REL. PERMEABILITIES, CAPILLARY
-------- PRESSURES, AND THE PVT PROPERTIES OF THE RESERVOIR FLUIDS
-----------------------------------------------------------------------

-- Relative permeability

INCLUDE
 '../INCLUDE/RELPERMETIVE_M6.txt' /

INCLUDE
 '../INCLUDE/GASSRELP_1ETIVE.txt' /

EQUALS
 SWCR 0.15771 1 20 1 20 1 1 /
 SWCR 0.16221 1 20 1 20 2 2 /
 SWCR 0.13059 1 20 1 20 3 3 /
 SWCR 0.12713 1 20 1 20 4 4 /
 SWCR 0.13974 1 20 1 20 5 5 /
 SWCR 0.15840 1 20 1 20 6 6 /
 SOWCR 0.16160 1 20 1 20 1 1 /
 SOWCR 0.16142 1 20 1 20 2 2 /
 SOWCR 0.16258 1 20 1 20 3 3 /
 SOWCR 0.16270 1 20 1 20 4 4 /
 SOWCR 0.16229 1 20 1 20 5 5 /
 SOWCR 0.16157 1 20 1 20 6 6 /
 SOGCR 0.13006 1 20 1 20 1 1 /
```

```
 SOGCR 0.12898 1 20 1 20 2 2 /
 SOGCR 0.13646 1 20 1 20 3 3 /
 SOGCR 0.13728 1 20 1 20 4 4 /
 SOGCR 0.13455 1 20 1 20 5 5 /
 SOGCR 0.12989 1 20 1 20 6 6 /
 SGCR 0.03154 1 20 1 20 1 1 /
 SGCR 0.03244 1 20 1 20 2 2 /
 SGCR 0.02612 1 20 1 20 3 3 /
 SGCR 0.02543 1 20 1 20 4 4 /
 SGCR 0.02775 1 20 1 20 5 5 /
 SGCR 0.03168 1 20 1 20 6 6 /
 SGU 0.68610 1 20 1 20 1 1 /
 SGU 0.67808 1 20 1 20 2 2 /
 SGU 0.73882 1 20 1 20 3 3 /
 SGU 0.74574 1 20 1 20 4 4 /
 SGU 0.72254 1 20 1 20 5 5 /
 SGU 0.68433 1 20 1 20 6 6 /
/


COPY
  'SWCR' 'SWL' 1  20   1  20   1  6 /
/

-- PVT PROPERTIES OF WATER
--
--    REF. PRES. REF. FVF  COMPRESSIBILITY  REF VISCOSITY  VISCOSIBILITY
--     Pw (bara)    Bw        Cw (1/bar)     Vwi= .19 (cp)  (dVw/dP)/Vw
PVTW
    320      1.042      4.5D-5       0.25       .0000  /

INCLUDE
 '../INCLUDE/PVTO_STEX_ETIVE.PVT' /

INCLUDE
 '../INCLUDE/DEAD_GAS_ETIVE.PVT' /

-- SURFACE DENSITIES
--        OIL      WATER    GAS
DENSITY
        826.7    1001.  0.997 / Brent

ROCKTABH
-- ROCK region 1 (Brent) - PV reduksjon til 0.9928 @ 150 bar ==> Cr=4e-5
--       PV mult  Trans mult
150      0.9928       1.0
     500 1.0068       1.0 / Ingen hysterese i Brent
330      1.0000       1.0
     500 1.0068       1.0 /
/
-- ROCK region 2 (IDS) - PV reduksjon til 0.9766 @ 170 bar ==> Cr=10e-5
--170      0.982       1.0
--     180 0.9826       1.0
--    520 1.003       1.0 / Hysterese i IDS
--350      1.0000       1.0
--     520 1.0102       1.0 / Tilnærmet elastisk ekspansjon --> Cr=6E-5
--/
TRACER
--tracer in the injection water to simulate injection of NaSi
--name fluid  units part.tracers  table.no
  'NSI' 'WAT'   /
/

-- SWITCH ON OUTPUT OF ALL PROPS DATA
RPTPROPS
0 0 0 0 0 0 0 0 /

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

```
REGIONS

FIPNUM
400*1 400*2 400*3 400*4 400*5 400*6 /

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

----------------------------------------------------
SOLUTION
---------------------------------------------------
-------- THE SOLUTION SECTION DEFINES THE INITIAL STATE OF THE SOLUTION
-------- VARIABLES (PHASE PRESSURES, SATURATIONS AND GAS-OIL RATIOS)
------------------------------------------------------------------------
--
--
--    DATUM   DATUM   OWC    OWC    GOC    GOC    RSVD   RVVD   SOLN
--    DEPTH   PRESS  DEPTH   PCOW  DEPTH   PCOG  TABLE  TABLE   METH
EQUIL
-- 5  MB/LB Main Field (Ness 2 - Oseberg 1)
      2907.00 328.3  2907.0  0.0    0.0    0.0     5      5     10  /
RSVD
-- Brent
  2000  118
  4000  118/

RPTSOL
 'FIP=1' 'EQUIL' 'RESTART=2' /

-- Tracer NaSilicate
TVDPFNSI
0     0.0
6000  0.0 /

--------------------------------------------------------------------------------
SUMMARY

INCLUDE
 '../INCLUDE/SUMMARY_TRACER_NSI.DATA' /

--------------------------------------------------------------------------------
SCHEDULE
--------------------------------------------------------------------------------

SKIPREST

DRSDT
 1.3 /

RPTRST
 BASIC=3 FREQ=1  /


RPTSCHED
 'FIP=3' 'CPU=1' 'NEWTON=1' 'WELLS=5' /

WELSPECS
--wname  grp  iwh jwh Z(bhp) prefPhase rPI/II  sp.Infl AutoShut X-flow Ptab densCalc
FIPnr
  'PW1' 'G'   1    1   1*      'OIL'  /
  'IW1' 'G'   20  20   1*      'WATER'  /
  /

-- Completion data (5,5" liner)
COMPDAT
--wname  ic  jc  k_hi k_lo open/shut satnum tfac   wdiam  Kh skin Dfac penDir r0
  'PW1'  1   1   1    6    'O'        0      -1    0.12   3*             'Z'      /
  'IW1'  20  20  1    6    'O'        0      -1    0.12   3*             'Z'      /
  /
```

```
WCONPROD
--wname open/shut  ctrlmode orat wrat grat lrat rvol bhpmin thpmin vfptab artlift ...
  'PW1'   OPEN      RESV    4*                 2000   190     0     0       0 /
/
WCONINJE
--wname injtype open/shut  ctrlmode rate resv bhpmax thpmax vfptab...
  'IW1'  WATER  OPEN        RATE    2000  1*   550      2*           /
/
GCONINJE
--gname injtype ctrlmode  surfrate  resrate reinfract voidfract xxxx  guiderate
def.of.guiderate
  'G'     WATER  VREP         3*                          1      NO     2000
VOID       /
/
TUNING
 0.05  0.1 0.01 /
 /
 12    1   36 /

DATES
1 'FEB' 2009 /
/

TUNING
 0.1   2 /
 /
 12    1   36 /

DATES
1 'SEP' 2009 /
/

TUNING
 0.05  0.5 0.01 /
 /
 12    1   36 /

DATES
1 'JAN' 2010 /
/

TUNING
 0.1   20 /
 /
 12    1   36 /

DATES
1 'JUL' 2010 /
1 'JAN' 2011 /
/

WTRACER
 'IW1'  'NSI'  1 /
/
DATES
15 'JAN' 2011 /
1 'FEB' 2011 /
/

WTRACER
 'IW1' 'NSI' 0 /
/

DATES
15 'FEB' 2011 /
1 'MAR' 2011 /
15 'MAR' 2011 /
```

```
1 'APR' 2011 /
15 'APR' 2011/
1 'JUL' 2011 /
1 'JAN' 2012 /
1 'JUL' 2012 /
1 'JAN' 2013 /
1 'JUL' 2013 /
1 'JAN' 2014 /
1 'JUL' 2014 /
1 'JAN' 2015 /
1 'JUL' 2015 /
1 'JAN' 2016 /
1 'APR' 2016 /
/
END
```

B.3 Silica restart simulation file

```
--*****************************************************************************
-- VESLEFRIKK
--*****************************************************************************
--
-- Simple model for qualitative evaluation of IOR as a result of injecting NaSilicate
-- Base case: thickness and petrophysical properties of layers in Etive formation as in
FFM01
-- Inject 60000 m3 NaSilicate, 30 days, 2000 m3/d from 1/1-2011 (after 2 years
production).
-- Displace NaSilicate with 120000 m3 water, 60 days, 2000 m3/d
-- PERMX changed in Silica treated cells: PERMX * 0,002, restart file 01.04.2011
--
--
--
--
--
RUNSPEC

--ECLIPSE
TITLE
VESLEFRIKK IOR ETIVE TRACER case ECLIPSE model /

DIMENS
-- NX NY NZ
  20 20 6 /

METRIC

OIL
WATER
GAS
DISGAS

--NOSIM

START
  1 'JAN' 2009 /

TABDIMS
--ntsfun ntpvt nssfun nppvt  ntfip nrpvt  notused  ntendp
    1      1     100    50     1   25  /

WELLDIMS
 5 10  1 5 /

EQLDIMS
-- NTEQUL   NDRRVD  NDRXVD
```

```
     1      100     18  /

TRACERS
-- max.oiltracers  max.wat.tracers  max.gastracers  max.environ.tracers  num.diffusion
max.NL.iter min.NL.iter ..........
   1*                1                  2*                                   'NODIFF'
/

ROCKCOMP
 HYSTER /

ENDSCALE
/

NSTACK
36 /

UNIFIN
UNIFOUT

MESSAGES
--      Message Comment Warning Problem Error   Bug
-- print limit
        5000    5000    10000   100     100     100
--stop limit
        100000  100000  100000  100000  100     10
/
---------------------------------------------------
--
--      Input of grid geometry
--
---------------------------------------------------
GRID

GRIDFILE
-- control of gridfile output, an extended gridfile is produced
2 /

-- simple grid 1000 x 1000 m (NX=20, NY=20, NZ=6 400 cells ea layer)
-- grid made in resview 21.08.08
INCLUDE
 '../INCLUDE/GRID.GRDECL' /

-- PERMX
-- 400*368 400*362 400*1383 400*1672 400*1084 400*545 /
-- Reduced PERMX in FLOVIS in areas where tracer concentration is larger than 0.265.
INCLUDE
 '../INCLUDE/PERMX1A.txt' /

COPY
 PERMX PERMY /
 PERMX PERMZ /
/
MULTIPLY
 PERMZ 0.5 1 20 1 20 1 6 /
/
PORO
 800*0.16 1600*0.18 /

NTG
 2400*0.95 /

INIT

PROPS
-------- THE PROPS SECTION DEFINES THE REL. PERMEABILITIES, CAPILLARY
-------- PRESSURES, AND THE PVT PROPERTIES OF THE RESERVOIR FLUIDS
----------------------------------------------------------------------
```

```
-- Relative permeability

INCLUDE
 '../INCLUDE/RELPERMETIVE_M6.txt' /

INCLUDE
 '../INCLUDE/GASSRELP_1ETIVE.txt' /

EQUALS
 SWCR 0.15771 1 20 1 20 1 1 /
 SWCR 0.16221 1 20 1 20 2 2 /
 SWCR 0.13059 1 20 1 20 3 3 /
 SWCR 0.12713 1 20 1 20 4 4 /
 SWCR 0.13974 1 20 1 20 5 5 /
 SWCR 0.15840 1 20 1 20 6 6 /
 SOWCR 0.16160 1 20 1 20 1 1 /
 SOWCR 0.16142 1 20 1 20 2 2 /
 SOWCR 0.16258 1 20 1 20 3 3 /
 SOWCR 0.16270 1 20 1 20 4 4 /
 SOWCR 0.16229 1 20 1 20 5 5 /
 SOWCR 0.16157 1 20 1 20 6 6 /
 SOGCR 0.13006 1 20 1 20 1 1 /
 SOGCR 0.12898 1 20 1 20 2 2 /
 SOGCR 0.13646 1 20 1 20 3 3 /
 SOGCR 0.13728 1 20 1 20 4 4 /
 SOGCR 0.13455 1 20 1 20 5 5 /
 SOGCR 0.12989 1 20 1 20 6 6 /
 SGCR 0.03154 1 20 1 20 1 1 /
 SGCR 0.03244 1 20 1 20 2 2 /
 SGCR 0.02612 1 20 1 20 3 3 /
 SGCR 0.02543 1 20 1 20 4 4 /
 SGCR 0.02775 1 20 1 20 5 5 /
 SGCR 0.03168 1 20 1 20 6 6 /
 SGU 0.68610 1 20 1 20 1 1 /
 SGU 0.67808 1 20 1 20 2 2 /
 SGU 0.73882 1 20 1 20 3 3 /
 SGU 0.74574 1 20 1 20 4 4 /
 SGU 0.72254 1 20 1 20 5 5 /
 SGU 0.68433 1 20 1 20 6 6 /
/


COPY
  'SWCR' 'SWL' 1  20   1  20   1  6 /
/

-- PVT PROPERTIES OF WATER
--
--    REF. PRES. REF. FVF  COMPRESSIBILITY  REF VISCOSITY  VISCOSIBILITY
--      Pw (bara)    Bw        Cw (1/bar)     Vwi= .19 (cp)  (dVw/dP)/Vw
PVTW
    320      1.042      4.5D-5       0.25      .0000  /

INCLUDE
 '../INCLUDE/PVTO_STEX_ETIVE.PVT' /

INCLUDE
 '../INCLUDE/DEAD_GAS_ETIVE.PVT' /

-- SURFACE DENSITIES
--        OIL      WATER    GAS
DENSITY
        826.7    1001.  0.997 / Brent

ROCKTABH
-- ROCK region 1 (Brent) - PV reduksjon til 0.9928 @ 150 bar ==> Cr=4e-5
--       PV mult  Trans mult
```

```
150      0.9928       1.0
     500 1.0068       1.0 / Ingen hysterese i Brent
330      1.0000       1.0
     500 1.0068       1.0 /
/
-- ROCK region 2 (IDS) - PV reduksjon til 0.9766 @ 170 bar ==> Cr=10e-5
--170      0.982       1.0
--     180 0.9826       1.0
--    520 1.003       1.0 / Hysterese i IDS
--350      1.0000       1.0
--     520 1.0102       1.0 / Tilnærmet elastisk ekspansjon --> Cr=6E-5
--/
TRACER
--tracer in the injection water to simulate injection of NaSi
--name fluid  units part.tracers  table.no
  'NSI' 'WAT'   /
/

-- SWITCH ON OUTPUT OF ALL PROPS DATA
RPTPROPS
0 0 0 0 0 0 0 0 /

--------------------------------------------------------------------------------
REGIONS
--------------------------------------------------------------------------------

----------------------------------------------------
SOLUTION
---------------------------------------------------
-------- THE SOLUTION SECTION DEFINES THE INITIAL STATE OF THE SOLUTION
-------- VARIABLES (PHASE PRESSURES, SATURATIONS AND GAS-OIL RATIOS)
------------------------------------------------------------------------
--
--
--    DATUM   DATUM   OWC    OWC    GOC    GOC    RSVD   RVVD   SOLN
--    DEPTH   PRESS  DEPTH   PCOW  DEPTH   PCOG  TABLE  TABLE   METH
-- EQUIL
-- 5  MB/LB Main Field (Ness 2 - Oseberg 1)
--    2907.00 328.3  2907.0  0.0    0.0    0.0     5      5     10  /

RESTART
 '../TRACER/VFR_ETIVE_TRACER3'  11 /

RSVD
-- Brent
  2000  118
  4000  118/

RPTSOL
 'FIP=1' 'EQUIL' 'RESTART=2' /

-- Tracer NaSilicate
--TVDPFNSI
--0     0.0
--6000  0.0 /

--------------------------------------------------------------------------------
SUMMARY

INCLUDE
 '../INCLUDE/SUMMARY_TRACER_NSI.DATA' /

--------------------------------------------------------------------------------
SCHEDULE
--------------------------------------------------------------------------------

SKIPREST
```

```
DRSDT
 1.3 /

RPTRST
 BASIC=3 FREQ=1  /


RPTSCHED
 'FIP=1' 'CPU=1' 'NEWTON=1' 'WELLS=5' /

WELSPECS
--wname  grp  iwh jwh Z(bhp) prefPhase rPI/II  sp.Infl AutoShut X-flow Ptab densCalc
FIPnr
  'PW1' 'G'   1    1   1*     'OIL'  /
  'IW1' 'G'   20  20   1*     'WATER'  /
  /

-- Completion data (5,5" liner)
COMPDAT
--wname  ic  jc  k_hi k_lo open/shut satnum tfac   wdiam  Kh skin Dfac penDir r0
  'PW1'  1   1   1    6    'O'        0      -1    0.12   3*            'Z'      /
  'IW1'  20  20  1    6    'O'        0      -1    0.12   3*            'Z'      /
  /

WCONPROD
--wname open/shut  ctrlmode orat wrat grat lrat rvol bhpmin thpmin vfptab artlift ...
  'PW1'   OPEN      RESV    4*                  2000   190     0     0       0 /
/
WCONINJE
--wname injtype open/shut  ctrlmode rate resv bhpmax thpmax vfptab...
  'IW1'  WATER  OPEN        RATE    2000  1*   550      2*           /
/
GCONINJE
--gname injtype ctrlmode  surfrate  resrate reinfract voidfract xxxx  guiderate
def.of.guiderate
  'G'     WATER  VREP         3*                          1      NO     2000
VOID       /
/
TUNING
 0.05  0.1 0.01 /
 /
 12    1   36 /

DATES
1 'FEB' 2009 /
/

TUNING
 0.1   2 /
 /
 12    1   36 /

DATES
1 'SEP' 2009 /
/

TUNING
 0.05  0.5 0.01 /
 /
 12    1   36 /

DATES
1 'JAN' 2010 /
/

TUNING
 0.1   20 /
 /
```

```
 12    1   36 /

DATES
1 'JUL' 2010 /
1 'JAN' 2011 /
/

WTRACER
 'IW1'  'NSI'  1 /
/
DATES
15 'JAN' 2011 /
1 'FEB' 2011 /
/

WTRACER
 'IW1' 'NSI' 0 /
/

DATES
15 'FEB' 2011 /
1 'MAR' 2011 /
15 'MAR' 2011 /
1 'APR' 2011 /
15 'APR' 2011/
1 'JUL' 2011 /
1 'JAN' 2012 /
1 'JUL' 2012 /
1 'JAN' 2013 /
1 'JUL' 2013 /
1 'JAN' 2014 /
1 'JUL' 2014 /
1 'JAN' 2015 /
1 'JUL' 2015 /
1 'JAN' 2016 /
1 'APR' 2016 /
/
END
```