Norwegian University of Science and Technology

Gullfaks Village 2012

Improved Oil Recovery from Gullfaks

Technical Report

GROUP 6

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TPG4851

Abstract

This work has been a modest attempt to study the effects of injecting Abio gel in the H1-segment at the Gullfaks Main Field, by modifying the transmissibility multiplier between cells. This project report is the product of an interdisciplinary project in ”Experts in Team”(EiT) - Gullfaks Village 2012. The report is subdivided into two main parts; Part A is a literature study, whereas Part B addresses the challenge of simulating Abio gel.

From the data we obtained in this project, it is clear that the best option would be to aim for a plugging higher than 90%, by injecting Abio gel repeatedly, but this value is considered to be highly unlikely to obtain. It is also apparent that plugging should not be less than 40%, as Abio gel does not seem to be effective below this limit. Further, to keep a certain level of plugging, it is advised to secure gelling at a certain time interval.

Through this project we have found that a 70% blockage will be the most feasible case. This conclusion is based on the gelling strength of the Abio gel, and it also accounts for unpredicted uncertainties. From sensitivity analysis, oil production and oil prices have proven to be the most influential parameters. However, despite fluctuation in these parameters obtaining a 70% blockage proves to be a good investment.

Based on our findings we have concluded that injection of Abio gel is a sustainable investment. The simulations show an increase in the oil production as well as a lowered water cut compared to the Base Case. Despite the numerous uncertainties still present in the simulations, our future recommendations are to move forward with the project and to use Abio gel for IOR in the H1-segment at the Gullfaks Main Field. We also recommend further research on this area to ensure the best possible recovery.

Preface

This report is written as part of the subject TPG4851 Experts in Team, Gullfaks Village 2012. The objective is to conduct an interdisciplinary project with students from various study programs and with different nationalities.

We would like to thank our village leader, Professor Jon Kleppe and Scientist Jan Ivar Jensen for their guidance during the semester, and also the learning assistants Ane Hestad, Cornelia Gerarda Dam, and Thor Helge Billington for facilitating us in the process work.

We would also like to thank Petter Eltvik from Statoil for his guidance, and for proving us with useful information about the challenges related to improved oil recovery of the Gullfaks main Field. We are also grateful that we could visit Statoil in Bergen to discuss progress with the advisors in Statoil.

Trondheim, April 18, 2012

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1. Introduction

1.1 Presentation of the Project

The challenge of the Gullfaks Village 2012 is to increase the oil recovery from the Gullfaks field by means of advanced chemicals called Enhanced Oil Recovery (EOR) measures. The project is divided in three parts. The technical part is divided in two, Part A and Part B, which represent 50% of the grade. In addition, there is a process part, which counts for the remaining 50%.

1.1.1 Part A

The main purpose of Part A is to demonstrate an understanding of challenges related to tail-end production at Gullfaks main field [1]:

1. Study the Gullfaks paper and the Åm report.
2. Make an evaluation of the oil recovery factor for Gullfaks main field to date and how it varies across the field in the different fluid segments and formations (Brent, Cook, Statfjord and Lunde). From the Base Ness 1 structural map, locate the H1 segment, which is relatively isolated. By looking at all the maps in RSP07, make an estimate of how many similar isolated segments there are at the Gullfaks main field. With "isolated" we mean that the pressure communication to the rest of the field is limited. Explain why there are differences in oil recovery between the different fluid segments and formations?
3. Based on the EOR measures in Section 5 in the Åm-report, rank measures according to the potential for the Gullfaks main field. List pro and contra for each of the EOR measure at Gullfaks main field.

1.1.2 Part B

In Part B, six different challenges were given by Statoil. These were later changed to three, and our group got IOR-challenge 3 - Existing H1 model with transmissibility multiplier between cells. This challenge had four different tasks [1]:

1. Discuss the use of the Abio gel, and how it can be simulated in the program Eclipse.
2. Make a base case Eclipse simulation with existing wells in H1 without chemical injection. Additional perforations in the wells are possible.
3. Simulate chemical injection with use of transmissibility reduction keywords in Eclipse. Tips: Use tracer option to find out where the waterways are.
4. Estimate EOR and calculate Net Present Value for the measure. Chemical cost is 20 MNOK and oil price fixed is 100 $/bbl. Use discount of 8%.

1.2 Presentation of the Gullfaks Main Field

The Gullfaks main field is currently owned by Statoil, 70%, and Petoro, 30%, where Statoil is the operator. The field is located mostly in block 34/10 in the northern part of the Norwegian North Sea [2]. Block 34/10 was awarded in 1978 to three Norwegian companies: Statoil (operator), Norsk Hydro, and the former Saga Petroleum. This was the first time a purely domestic consortium had been awarded an offshore license. Interest in this acreage was very high, and it was given the nicknamed the Golden Block before being awarded [3].

The Gullfaks area includes nine production licenses and has been developed with three large concrete production platforms respectively Gullfaks A, Gullfaks B, and Gullfaks C. Gullfaks A, see Picture 1, began its production on 22 December 1986, with Gullfaks B following on 29 February 1988 and Gullfaks C on 4 November 1989. Oil is loaded directly into shuttle tankers on the field, while associated gas is piped to the Kårstø gas treatment plant north of Stavanger and then on to continental Europe [3]. Gullfaks A is used for storing and exporting stabilized crude from the Vigdis and Visund fields. Oil and gas from Gullfaks B is transferred to the A and C platforms for processing, storage and export. Since June 1994, Gullfaks C has received and processed oil from the Tordis field. The field set a production record of 605,965 barrels for a single day on 7 October 1994 [3].

The recovery factor on Gullfaks is 59%, but the goal is to increase it to 62%. Measures to improve recovery include horizontal and extended-reach wells, new completion and sand control technology, and water alternating gas injection [3]. Continuous application of improved recovery technologies is a major focus of the reservoir management strategies at Gullfaks today [2].

Picture 1: Gullfaks A [3].

1.3 General Introduction to the Gullfaks Area

In this chapter we will give the reader a brief introduction to the Gullfaks area and the sediment and structural history of the Viking Graben and the North Sea areas.

1.3.1 Geography

The Tampen Spur area is located in the northern part of the Norwegian North Sea, between the north-south trending Viking Graben and the East Shetland Basin. It represents a continuation of the East Shetland Platform, see Figure 1. Several giant oil fields have been discovered in this area, among others the Gullfaks Field on the border between the Norwegian and the UK sector [4].

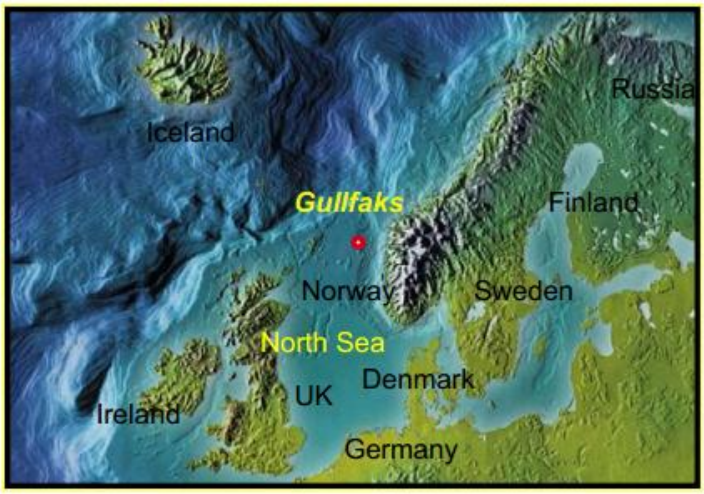


Figure 1: Map of the geographical location of the Gullfaks Field [3].

1.3.2 Geology of the Viking Graben

We have considered the Permian – Triassic and Jurassic, to be the most important geological period regarding the formation of the reservoirs in the Viking Graben.

In the Permian the western and central parts of Europe were a part of Pangea. The Triassic time began with a pronounced phase of multi-dimensional tectonic extension, which resulted in a large number of rifts in the area, and included full-scale formation of the North Sea triple-junction rift system, comprising the Central Graben, the Viking Graben and the Maray-Firth Basin, see figure 3. Pangea was pulled apart and tilted fault blocks limited by N-S trending fault zones were created as a result of the extension. By the end of the Triassic, a 140-150 km wide basin in this area was formed. During middle Jurassic until lower Cretaceous the area went through another phase of rifting. This rifting resulted in new N-S- and NNE-SSW-oriented listric faults and even higher subsidence of the basin floor. The rift margins are characterized by stair-shaped fault systems. Structures within this area are characterized by large rotated fault blocks (rotational "domino" blocks) with sedimentary basins in asymmetric half-grabens associated with lithospheric extension and thinning of the crust.

The tectonic history of Late Jurassic was directly responsible for the structures that have formed the majority of traps in the North Sea. In the Cretaceous and Tertiary the extension rate is falling and there is a subsidence due to thermal cooling and sediment load [5].

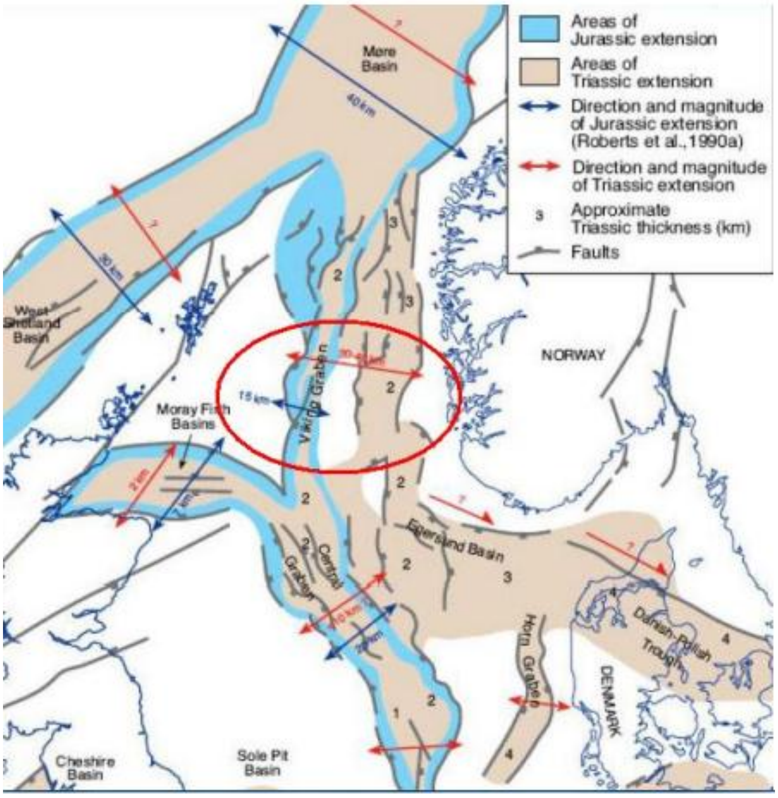


Figure 2: Showing the direction and magnitude of Triassic and Jurassic extension. The North Sea triple-junction rift system is created. The Viking Graben is highlighted in red [5].

1.3.4 Sedimentary History of the Viking Graben

In our assignment we were told to focus on the lower part of the Brent Group, in particular the two formations Etive and Rannoch, see figure 3. The Brent Group was deposited during the Jurassic period. During the early Jurassic there was a global transgression and the climate was changing from dry to a more humid. Delta deposits from the Middle Jurassic period dominate the reservoirs of the Viking Graben. Delta deposits are typically coarsening upwards, as we can see in Figure 3, where the sediments get gradually coarser from the bottom of the Rannoch Formation to the top of Etive. And in the northern North Sea Basin a large river system drained northwards. After the transgression occurred and the thermal dome subsided, the system retreated southwards. Sediments transported by this system produced the Brent Delta, which is of great importance for the Norwegian oil industry. The rifting in Jurassic led to a relative sea level rise and marine deposits became dominant in the northern North Sea, characterized by the organic rich deposits from this period. Subsidence combined with a sea level-rise led to a quick burial of the Triassic and Jurassic sediments, and the relief made by the rotated fault blocks in the Viking Graben was covered by sediments by the end of Cretaceous [6].

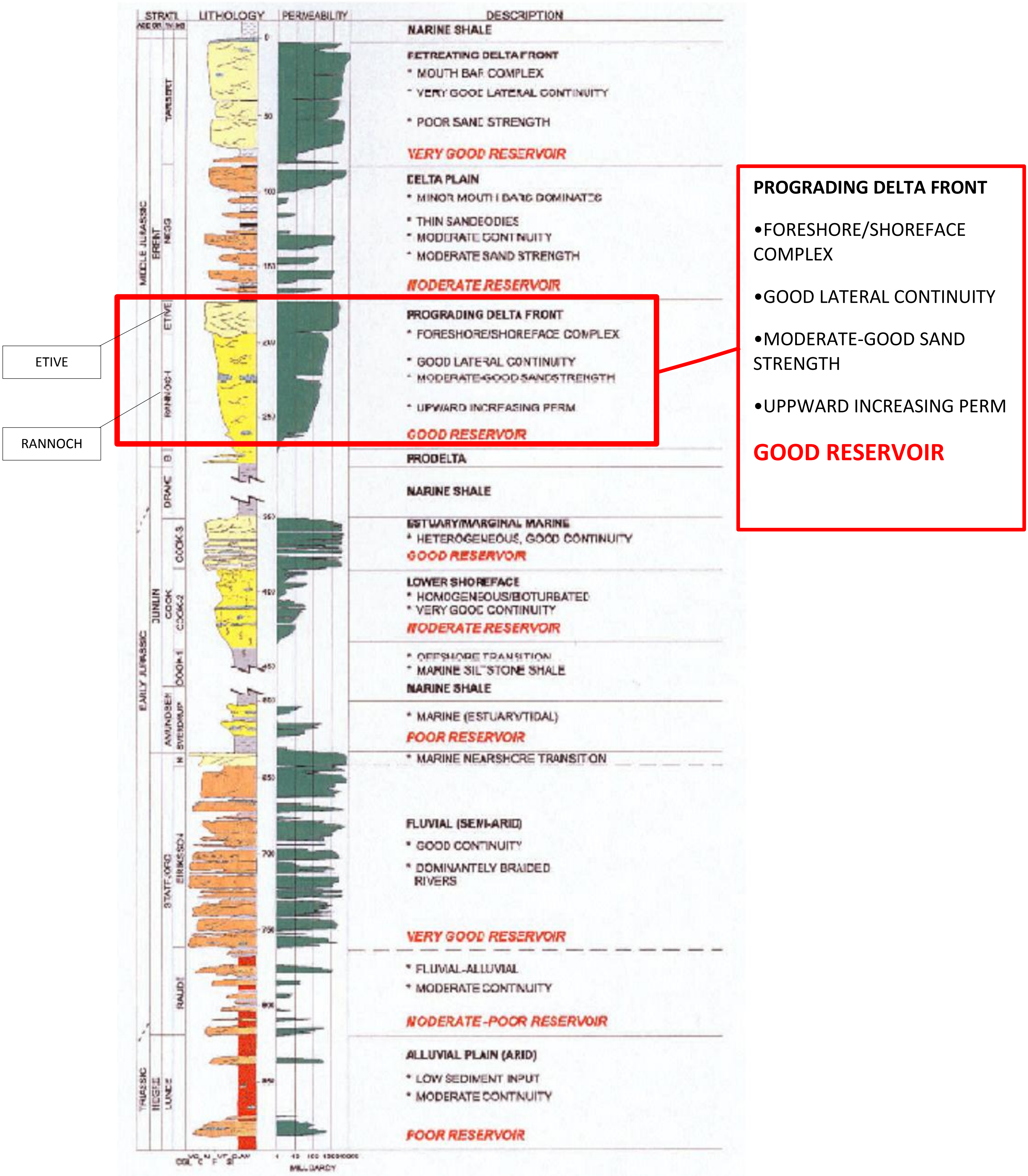


Figure 3: Stratigraphic column of the Gullfaks Field showing the differences in the reservoir quality in the different reservoirs. Rannoch and Etive are marked [7].

2. Part A

2.1 Evaluation of the oil recovery factor for the Gullfaks Main Field

2.1.1 Reservoir quality

Gullfaks is divided in the Brent Group, Cook Formation, Statfjord Formation and Lunde Formation, which all have different reservoir properties. The various properties and the amount of oil in influence the recovery factor in the different formations. The great difference in reservoir quality between the segments is due to different depositional environments as described in the General Introduction to the Viking Graben. A short summary of the specific qualities for each formation follows:

Brent Group

Most of the oil at the Gullfaks Field is found in the Brent Group. The Brent Group is a delta system deposited in the mid-Jurassic period, with mouth bars displaying excellent reservoir properties. Some of the sand bodies are poorly consolidated causing sand production problems. The recovery factor in the Brent Group is 60 % [8].

Cook Formation

Cook-1 is not a reservoir, while Cook-2 mainly contains fine grained bioturbated sandstone and mudstone. Calcite cemented layers affect the fluid flow in the formation, and it has a moderate to poor reservoir quality. Cook-3 mainly consists of medium to fine grained non-bioturbated sandstone interbedded with shales. Cook-3 has good reservoir quality, and a recovery factor of 28 % [8].

Statfjord Formation

In the Statfjord Formation a distinction has been made between “young sands” and “old sands”, this is based on Sm/Nd ratios and refers to the age of the sourcerock. The mica content is lower in the “young sands” which constitutes the upper part of the Statfjord Formation. The sand strength is poor. The recovery factor in Statfjord including the Krans Formation is 56 % [8].

Lunde Formation

The lowermost part of the Gullfaks reservoir is characterized by alternating sand- and mudstone; these are fluvial and lacustrine deposits. There is a lack of good reflectors within the Lunde Formation makes it difficult to map by seismic. The formation has moderate to poor reservoir quality, and contains substantial amounts of water. This makes oil production challenging. The formation is not fully developed, but so far the recovery factor is 8 % [8].

The recovery factor in the different formations are presented in Table 1, this clearly shows the variation in properties in the different parts of Gullfaks:

Table 1: The recovery factor for each formation in Gullfaks [8].

Formation	Oil Recovery Factor
Brent	60%
Cook-3	28%
Statfjord	56%
Lunde	8%

2.1.2 Isolated segments

Gullfaks consists of numerous isolated segments. By isolated we mean that pressure communication to other parts of the field is limited by faults. This means that changing the reservoir properties in one segment will not affect the adjacent areas. By looking at structural maps in the Reservoir Management Plan for the Gullfaks Field and Gullfaks Satelites 2007, we have identified a total of 60 isolated segments. When considering the maps, Top Tarbert, Top Ness, Base Ness and Top Broom are included in the Brent Group. The isolated segments are presented in Table 2:

Table 2: Isolated Segments in the Brent, Cook, Statfjord, and Lunde formations.

Formations	Isolated Segments	Number of segments	Map Number [8]:
Brent	I1 U1 12A H1 H2 G2 G3 G7 F4 E2 E3	11	3.3.2 3.3.3 3.3.4 3.3.5
Cook	I1 K1 H3 H4 H5 G1 G2 G3 G4 G5 G6 G7 F4 F7 E1 E2 E3 D1 D2 D3 D4	21	3.3.6
Statfjord	K1 K2 K3 J3 13A I1 H1 H2 H3 G1 G2 F7 F4 F3 F2 F1 E1 E2 D1 D2	20	3.3.7
Lunde	H3 H7 I1 K1 J1 J2 L2 L1	8	3.3.8

2.1.3 Differences in oil recovery in the different segments

There are several reasons for the variation in the Oil Recovery Factor (ORF) in the different fluid segments in the reservoir. As discussed in the previous sections there can be great variation within the same oil field, and it can be separated into a number of isolated independent segments. At the Gullfaks Main Field, however, there are three main reasons for the great differences in ORF.

Structural Geology

Knowing the intricate structural geology in the Tampen area, the geology was the first reason for differences in ORF we wanted to investigate. Gullfaks Main Field contains three main structure areas: The central and western parts, with domino system and westerly dipping fault blocks, and the eastern part, which consists of a horst complex with non-rotated or slightly easterly dipping blocks. Between these two parts one can find the complex accommodation area with fragmented anticlines [2].

We found that coexistence of westerly and easterly-dipping faults, especially in small areas, probably could cause spatial problems accompanied by local reverse faulting. In this case, the oil recovery would be relatively low compared with other segments in the other two structural areas. Besides, the accommodation area exhibits progressive erosion towards the east. Thus, the differences of erosion could also cause the differences of the oil recovery among segments and formations. There is also some uncertainty due to relatively poor seismic quality, and the communication pattern among the different fault segments [2].

Lithology and Reservoir Properties

Due to permeability, porosity, depositional environment and quality of different reservoir units and formations, the oil recovery from different formations and areas will have apparent differences. The permeability shows the degree of communication of different faults and formations, which influences the oil recovery considerably. There could also be a problem with H_2S content in some of the fluid segments and formations, which may result in a change in the oil recovery. In addition, considering the physical properties of reservoirs such as reservoir pressure, temperature and size, the uncertainty of the oil recovery for each segment tends to be greater [2].

There are also some geometric parameters influencing the oil recovery in the different segments. The thickness of the formation could influence the effectiveness of the drilling technology and other aspects. The size and the dipping degree and -direction can also affect the oil recovery. Those aspects restrain the IOR methods, which may be used [2].

Applied IOR Technology

Different Improved Oil Recovery technologies result in different oil recovery factors. For each IOR-method: cost, applicability, and effectiveness need to be considered as each one will influence in the recovery factor [2]. The IOR technologies are further discussed in the following section.

2.2 Introduction to the challenges related to IOR at Gullfaks

For Statoil the main objectives on the Gullfaks field have been to optimize the production without causing damage to the people, the environment and the installations. Statoil have previously been rewarded for their use of IOR methods in the Gullfaks main field, which tell us that research to improve oil recovery is one of their top priorities. However, there is a lot of uncertainty involved in obtaining these goals, and some of the main challenges of IOR on the Gullfaks Field are summarized below.

The greatest challenge at Gullfaks is that the reservoir contains a large number of faults, and due to relatively poor seismic quality the structural picture is somewhat uncertain. This complex structural geology makes placing the wells particularly challenging. There are also uncertainties related to the communication pattern among the different fault segments.

Another challenging aspect at Gullfaks is the high contrast in permeability, which ranges from just a few milli-Darcies to as high as 10 Darcies. This causes uneven fluid movement, pressure differential and cross flow in different zones. This results in poor recovery in the low permeable reservoirs, and the main challenge is therefore to be able to monitor injection and production from the different reservoirs. In order to achieve an acceptable recovery factor, a large number of wells and well interventions will be required.

The production at Gullfaks has also been challenged by poorly consolidated reservoir rocks, and after the water breakthrough the maximum sand free rate is to be reduced. In order to maintain a high production rate, effective sand control is necessary. Gullfaks has furthermore been struggling with H_2S production in the reservoir. Due to the water circulation around the injectors, favorable conditions for some H_2S generating bacteria have formed. This has resulted in excessive H_2S forming in part of the reservoir. The H_2S is corrosive, it is a health hazard and it pollutes the export gas. The H_2S is therefore unwanted in the installations, and an effective method for its handling needs to be developed.

Our main focus for this part is to look at the IOR methods presented in the Åm-report and in the “Reservoir Management of the Gullfaks Main Field”-report, and make an evaluation of what methods we think are the most important for IOR at the Gullfaks Main Field. An overview of the IOR measures presented in the Åm-report can be seen in figure 4 [9].

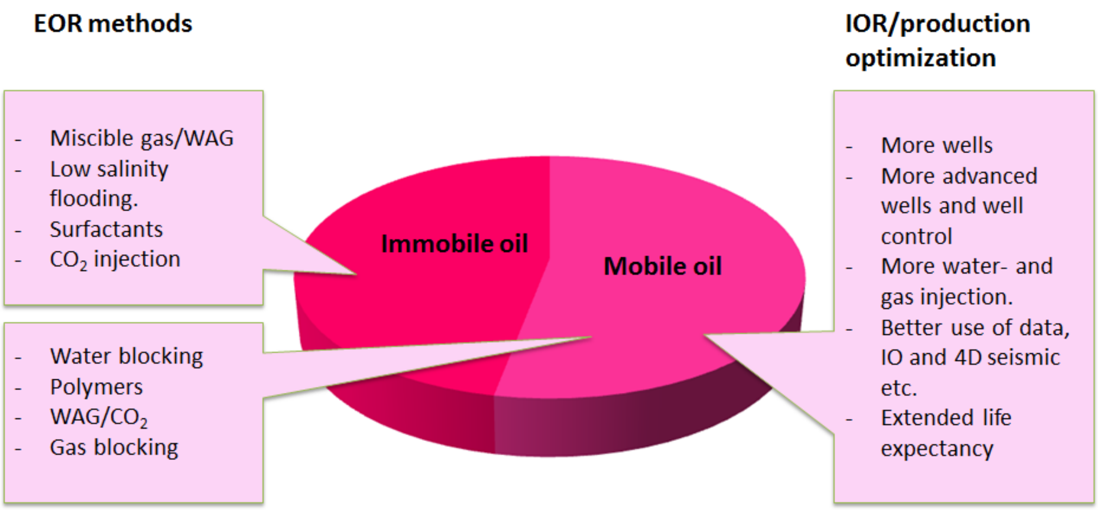


Figure 4: Overview of the IOR methods presented in the Åm-report [9].

2.2.1 Ranking of IOR Measures

The measures presented in figure 4 were evaluated with respect to the potential they have for IOR in the Gullfaks field. The methods are ranked by order of importance in the list presented below.

1. More Wells and more advanced wells
2. 4D Seismic
3. Continued Water injection
4. WAG
5. CO_2 Miscible Injection
6. Water blocking (gel injection)
7. Surfactant injection
8. Polymer injection
9. Integrated Operations (IO)
10. Nano Particles

2.2.2 Pros and Cons for the IOR Measures

1) More Wells and more advanced wells

The Gullfaks field can be shut down before the number of wells required to producing the planned amount of oil and gas, is drilled [2]. This can also affect the possibilities of developing findings and possible prospects in the vicinity. More production and injection wells are therefore needed to improve the oil recovery on the Gullfaks field.

Although it is profitable to drill production wells, the activity can be prevented by a shortage of manpower, rigs and other technical equipment. This can further reduce and delay the production, and also lead to postponements of projects. In recent years the drilling costs has tripled, which is primarily driven by higher rig rates. The number of production and injection wells drilled each year has since 2001 been a downward trend. However, recent years this trend has shifted, and the number of wells drilled is currently at its highest [10].

On Gullfaks, the drilling equipment is now 20-25 years old [2]. This results in a greater need for maintenance, which in turn leads to higher costs and lower drilling rates. More upgrading projects are ongoing and planned, like the project “Gullfaks toward 2030”, but although these projects can better the situation, there will most likely be a rebuilding phase with further delays [2]. Drilling more wells should therefore be prioritized to improve the recovery of the residual oil of the Gullfaks field.

Implementing advanced wells is also something that has helped increase the recovery. Advanced wells are wells completed with valves or chokes down hole in the reservoir and with equipment, which can be operated from the surface [11]. Implementing this technology in the wells has offered several advantages, for example; the option of shutting off unwanted production, control the water injection, eliminate the need for well intervention and to attain an improved reservoir description. But the effect relevant in this paper is the increase in the ultimate recovery factor. Injection of gas and water into the reservoir in order to improve the sweep efficiency offers another effective way to increase the oil recovery factor and is enhanced even more by controlling the injection rate in the individual reservoir layers [11].

2) 4D Seismic

Good understanding of the reservoirs is essential for an optimal drainage strategy and improved oil recovery. The development and use of seismic data over the past 30-40 years from simple 2D lines to 3D and to todays 4D have been very important for better an understanding of the reservoir designs and the fluid flows [9]. This contributes to better reservoir models that can lead to more accurate drilling and optimal production. Statoil estimates that up to 2010, the use of 4D seismic on Gullfaks field has given a value of 6 billion NOK [2].

It has been very useful on Gullfaks to identify areas where significant gas saturation changes have occurred and to locate fluid communication paths [2]. This information is helpful to get a robust history match of the simulation models, and allows for a direct comparison of predicted gas saturation changes with 4D seismic response using visualization tools. 3D visualization of the 4D response is extremely useful to plan new wells avoiding areas where increased gas saturation or pressure depletion is observed [2].

Finding smaller infill drilling targets in a mature field like Gullfaks is extremely important to improve the overall recovery. This is particularly important for a segmented reservoir where 4D seismic can improve the level of confidence significantly. 4D seismic has been widely used on Gullfaks to locate undepleted areas, and so far 14 wells have been drilled based on 4D seismic. All wells have hit their target and most of them produced more than expected. Today seismic data on the Gullfaks field is typically collected every other year by boat, and by placing seismic cables on the seabed one can collect seismic data several times a year. The corresponding geo-and reservoir models can thus be updated on a more continuously basis [2].

3) Continued Water injection

Water injection was implemented from the start of Gullfaks production and due to good results from laboratory experiments, early production experience and simulation results showed very high recovery potential by massive water flooding. Water flooding is the main IOR mechanism on Gullfaks maintaining the reservoir pressure above bubble point. Saturation logs have later confirmed residual oil saturation as low as 5% in heavily flooded areas, and for this reason water injection has been given top priority ever since [2].

4) WAG

Water-alternating-gas (WAG) injections have so far been performed in 7 wells on Gullfaks since the first WAG pilot in 1991 [2]. This has contributed to considerable amount of incremental oil. Gas has a low viscosity, and if it is injected directly into a reservoir it will choose the route with the highest permeability. If water is injected simultaneously this has a positive effect on the viscosity of the gas and you get better macroscopic sweep efficiency. One of the disadvantages with this method at the Gullfaks field is that the scope of WAG is somewhat limited due to availability of injection gas. Gullfaks had a gas sale agreement, but the limited transport capacity and less gas sale in low gas-demand season provided opportunity to inject some gas for increased oil recovery without high economic consequence. An advantage is gravitational segregation of injection gas which gives better sweep in the areas not contacted by water. Therefore WAG might give better oil recovery since you will sweep areas outside of the Etive-Rannoch override. WAG on Gullfaks also helps to maintain oil production during low gas export period and reduces CO_2 tax and storage cost. A thing worth nothing about WAG is the negative effect injecting the wrong bulks of water and gas can give. If the water reaches the immobile oil first it will block the gas from getting in contact with the oil banks. If this happens you will not obtain the desired miscibility and displacement [2].

5) CO_2 miscible injection

CO_2 for enhanced recovery can have a significant potential on the Norwegian continental shelf, but there are still a number of technical, regulatory and economic conditions to be resolved before commercial decisions can be made in the license [9]. The advantage of CO_2 injections is that CO_2 is miscible with crude oil at low pressures compared with other injection gasses. The CO_2 can also cause swelling of crude oil, which can mobilize immobile crude oil, and hence give a higher recovery. In low-pressure cases there is not a density difference between CO_2 and crude oil, therefor making an immiscible segregation displacement more effective. In the Gullfaks field the pressure is not high enough for the CO_2 to become miscible with the hydrocarbons. When implementing CO_2-WAG the CO_2 obtain a higher viscosity, because it is displaced by water similar to the HC-WAG described previously. The MWAG project was not implemented on Gullfaks due to marginal economy and high risk. The cost is definitely the biggest disadvantage of CO_2 injections, which is closely related to the low availability of gas. The source of 5 million tons CO_2 per year was not readily available. This summarizes the biggest disadvantages of CO_2 injections [2].

6) Water blocking (gel injection)

In heterogeneous reservoirs the water will follow the high permeable zones between the injector and production well, but if the high permeable zones are blocked by injection of gel the water is forced to find a new route reaching previously unreached oil, thus increasing the macroscopic sweep efficiency. Some of the disadvantages are that the injected gel will deteriorate, and continuous injections are therefore required. This means that there will be a question of whether the costs of the chemicals are too high for the method to be economically beneficial. There is also a risk that the injected chemicals block unwanted areas. There is also risk involved with the environmental aspects [12]. Two wells have been successfully treated with silicate on Gullfaks. They were both successful and resulted in increased oil production and lowered the water cut, and also increased the lifetime of the well with 1.5 years [2].

7) Surfactant injection

Another great challenge met in every oil field is to extract the immobile oil. Surfactant injection lowers the interphase tension between the injection water and the crude oil leading to less capillary trapped oil. The disadvantage of this method is high retention due to absorption to pore walls; this is caused by an opposite atomic charge between the pore wall and the surfactant. This is one of the main reasons why this method is so expensive. This method is now being considered again due to the high oil prices, and the preliminary results show 3-5% extra oil recovery by this method [2].

8) Polymer injection

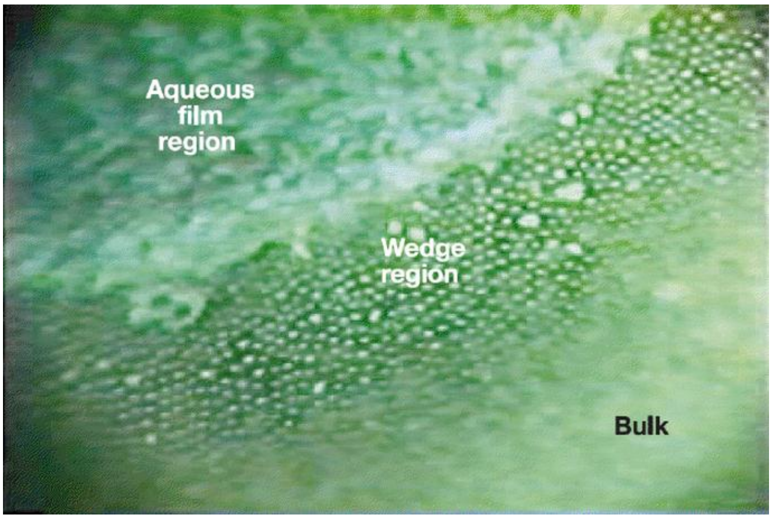
Polymers increase the viscosity of the injection water, and are used to increase recovery from fields with viscous oil. In China, the polymer injection has been used in large scale over a long period on the Daqjing field. Recently, large-scale use of polymer has also been implemented in Oman, West Africa and Canada. It should be considered to implement pilots, which examines the potential of how polymer injection may improve recovery from the Gullfaks Field where water injection is the drive mechanism [2].

9) Integrated Operations (IO)

Integrated Operations (IO) can improve recovery fields through more efficient operations and better decision-making related to reservoir solutions [9]. Most companies have good plans and intentions the use of IO in all stages, from exploration to field operations [9]. The infrastructure is also in place to make use of IO through the fiber network for fast transfer of large amounts of data, well-instrumented systems and collaboration. The focus so far has been to add data to inform, improve coordination between sea and land, and visualization of data. However a number of factors such as contractual, cultural and technological challenges have delayed the implementation of IO [9].

10) Nano particles

There are numerous methods being developed within the area of IOR. An example of an IOR method that is still in the developing phase is the use of Nano particles. The most important research in this area is conducted to gain understanding and control of the desired properties of Nano fluids at high temperature, high pressure and harsh chemistry [13]. Nano particles modify the adhesion between the fluid and the solid, and have been found to enhance the oil separation from the rock. Small-scale experiments can be easily carried out, and have given promising results, see Picture 2. And this method can hopefully improve future production. This is interesting new research and it is clear that in order to keep extracting more immobile oil from the reservoirs in the future it is important to keep investing in research [13].



Picture 2: Nano particles separate the oil and the rock [13].

2.3 Summarizing Part A

The main purpose of Part A was to demonstrate an understanding of challenges related to tail-end production at the Gullfaks Main Field. By getting familiarized with the complex geological history of the Gullfaks area, and realizing the variances in the reservoir properties in the different formations together with identifying a vast number of isolated segments, we have gotten a better understanding in the difficulties associated with oil exploration at the Gullfaks Field.

Since the Gullfaks Field has been produce since 1986, IOR-technology has been of great importance the later years. We have ranked ten different IOR-methods with respect to the potential they have for IOR in the Gullfaks field. Based on the pros and cons for each method, we have considered the following methods as the most important:

1. More Wells and more advanced wells
2. 4D Seismic
3. Continued Water injection
4. WAG
5. CO_2 Miscible Injection
6. Water blocking (gel injection)
7. Surfactant injection
8. Polymer injection
9. Integrated Operations (IO)
10. Nano Particles

In Part B, we will further investigate the effects of water blocking (gel injection) by simulating the outcome of injecting Abio gel.

3. Part B

3.1 Introduction

Gullfaks has numerous isolated segments, which are characterized by different reservoir properties. Our focus in this paper is the lower Brent in segment H1, see figure 5. Lower Brent is characterized as a good reservoir due to its high average permeability and good lateral continuity. This allows for fluid displacement and production with a small pressure drop. The segment has been selected for a water-based chemical method.

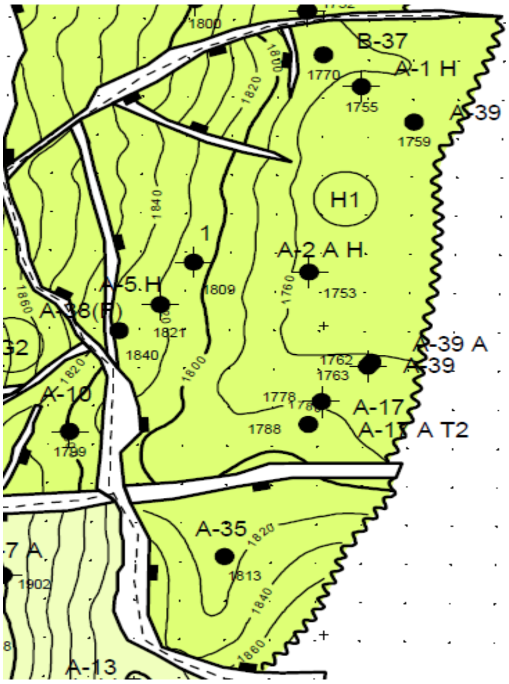


Figure 5: H1 Segment [12].

The Stock Tank Oil Originally In Place (STOOIP) in lower Brent is 20,3 MSm³ oil. So far it “only” has a recovery factor of 57 % in H1. However, it still has a potential of 2-5 MSm³ of mobile oil left. This segment is relatively isolated, and since it was the first production area, there is a lot of good, initial data collected from this segment. There are two active wells in lower Brent, A-35, which is the injector, and A-39A, which is the producer.

The basis for Part B is R&D cooperation between Statoil and China National Petroleum Corporation (CNPC). Statoil bought 1000 tons of chemicals from them, and the silica-based chemicals will be injected into the injector A-35. Due to less than 1% of aluminates, the chemicals are classified as yellow. They are therefore unproblematic to use, as they are environmentally acceptable. The purpose of the chemicals is that after they are injected into the reservoir, they will form micro gel particles. These particles will stick to the surface of the pores and thereby reduce the permeability in invaded zones. In this way the water will invade less water-flooded areas, as it will be forced to find new paths, and we will be able to reach previously bypassed oil, see figure 6, and enhance the oil recovery [12].

There is some recoverable oil left in the lower Brent. Though Statoil is producing oil by injecting water and to keep the reservoir pressure above the bubble point pressure, it was decided to use the enhance oil recovery method to extract the unswept oil from the formations. The chemical injection was decided with the consultation of CNPC, as they have used this technique in some fields of China. The improved recovery results from those fields encouraged Statoil to implement this multi diverging technique for the first time in the North Sea.

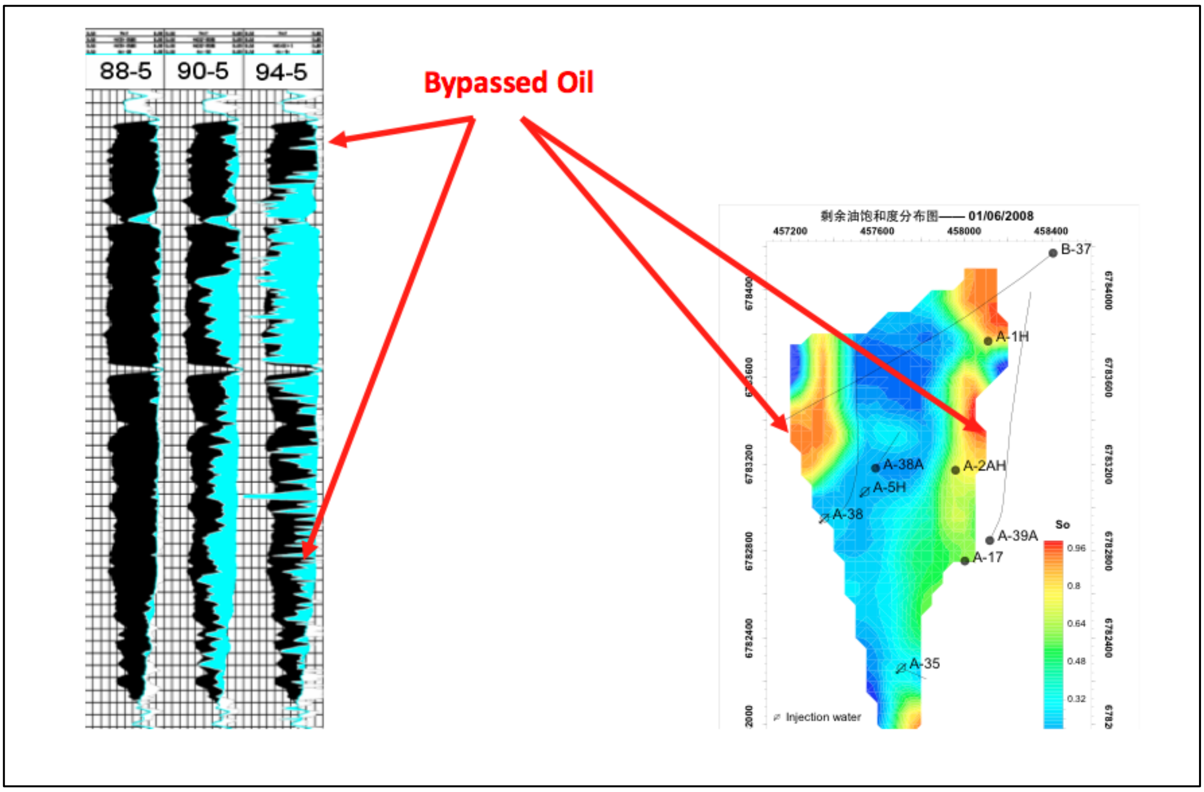


Figure 6: Bypassed Oil in the H1-segment [12].

3.2 Abio Gel

Abio gel is compound, primarily consisting of Sodium Silicate. When brought into contact with bivalent cations, for example Ca2+ and Mg2+, in formation- or seawater, the Abio gel will react to form a microcrystalline suspension [12]. It may become a stiff gel if the concentration of bivalent cations exceeds approximately 1 %. If the concentration of the bivalent cations is less than 1%, the Abio gel will behave as cement, paint-coating the rock matrix. The object of using Abio gel is to narrow the flow channels gradually, but still keep certain permeability [12]. Abio gel will coat the pores in the high permeability water flushed zones and change the water path to the unswept zones. Water will start changing its path near the injection well due to high reduction in permeability. The time taken by the Abio gel to gain its required gelling strength is of great importance. If it takes more time, then the effect of permeability reduction will be observed away from the injection well. As a result, water will change its path far from the injection well.

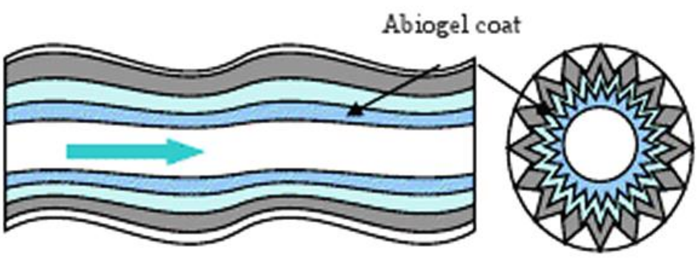


Figure 7: The illustration shows how the Abio gel paints the inside of the pores. The get narrows the pore throats decreasing the permeability in the reservoir [12].

Another reason why Abio gel has been chosen is because Abio gel-A (Abio gel) is HSE-tested, and classified as yellow. It is environmentally green, but as it is not on the PLONOR list, it is classified as yellow [12]. Abio gel-B (Calcium Chloride) is classified as green and is on the PLONOR list, while alternative chemicals from other suppliers are mostly red. Another reason choosing Abio gel for this project is because of its suitable temperature range between 30-200 ^{o}C [12]. It is thermal stable for a long period at 140 ^{o}C, which is well suited for the Gullfaks field. It has also been tested suitable for sandstone reservoirs with high permeability and high heterogeneity [12].

In this particular case, the injected water tends to choose the simplest route. But due to the great difference in the permeability between the Etive- and Rannoch Formation the water tends to move up and through the more permeable Etive Formation, as showed in figure 8 [14]. By using tracer in Eclipse, the effect of injecting Abio gel can be simulated. This can be done by changing the flow parameters between the grid blocks, but this can first be done after applying the tracer option in order to find the waterways.

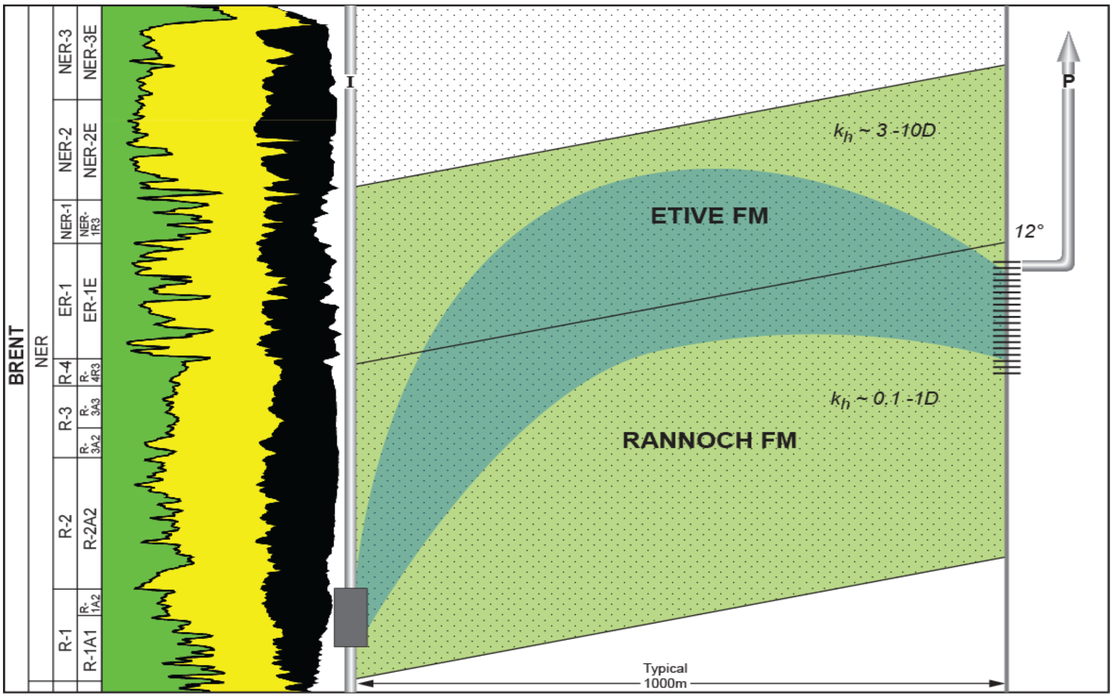


Figure 8: Illustration of how the water is diverted by the pore-coated areas injected with Abio get [14].

Transmissibility is derived from a combination of numerous reservoir properties including relative permeability, fluid viscosity, the formation volume factor, and geometric parameters [15]. As a result of this a reduction in permeability due to the use of Abio gel will also cause a reduction in transmissibility.

3.3 Simulation of Abio gel in Eclipse

3.3.1 Base case

We are considering the H1 segment in Lower Brent. There are two active wells in Lower Brent. A-35 is an injector while A-39A is a producer. A-39A produces from layers 44 to 49 of the Lower Brent section. Figure 9 shows the oil saturation before injection of chemicals. The Base Case simulates how much oil can be produced if well A-35 continues to inject water into segment H1 without chemical injection. The Base Case was simulated without changing any of the parameters. The Base simulation starts at 1st of December 1986, and runs until 1st of January 2025. This case will be an important tool, as it is used for comparison in order to determine the effect of adding chemicals to the injection water.

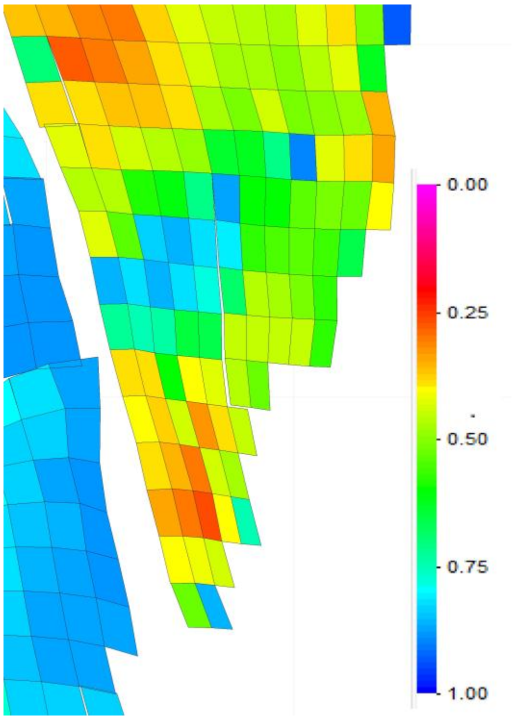


Figure 9: Base Case Model of H1-segment with oil saturation 1st June 2012.

3.3.2 Adding Tracer

In order to detect were the waterways are, the tracer option was activated in the existing model. The water tracer follows the water path in the flooded areas in the reservoir. The keyword EORF is used for the tracer.

In the properties of the data file, the keywords 'EOR' 'WAT' were used to observe the effect. Injection and production rates were also mentioned along with the injection rate of water because the tracer is associated with the flow rate of water. The concentration of the tracer is kept in a range so that we may see the effect of it only in the area of interest. For the tracer to work properly, the name of the injection well and the starting dates are important in order to see the effect.

3.3.3 Simulating Prediction Cases

Generate New Properties

In order to simulate the effect of the Abio gel, we needed to change the transmissibility between the grid blocks. Based on the tracer distribution, we generated new properties by using the keywords TRANX and TRANY for the X-axis and Y-axis respectively. In order to create new cases, we needed to generate new properties in the Classic Property Calculator using FloViz. Here we generated a new property type by using the following script [16]:

*IF (EORF>250) THEN TRAN(X or Y)*0.02*
ELSEIF
*((EORF<250) AND (EORF>50)) THEN TRAN(X or Y)*0.04*
ELSEIF
*(EORF<50) THEN TRAN(X or Y)*1*
ENDIF

In this set of conditions, EORF shows the concentration of tracer. If the EORF is greater than 250, the transmissibility, TRAN(X and Y) will be reduced using a multiplier, in this example 0.02. If the EORF is less than 250, and greater than 50, the TRAN(X and Y) will be reduced by two times the prior multiplier. When the EORF is less than *50*, the multiplier will be 1, hence leaving no changes to the transmissibility.

Export Generated Properties

Once the new properties were generated, they were exported and saved into a single file as we generated them for X and Y directions separately. These newly generated properties were exported into a file with keywords ECLIPSE RESTART.GRDCEL. The time step is worth mentioning here, as it monitors the time after the Abio gel injection. Then these X and Y properties along with the desired time steps were saved in a new file and given the extension ".TRAN".

We use time steps 317, 318, and 319. The time step 317 is the monitoring date 1st of June 2012. We simulated many cases on this date, but we realized that at this time step was too early to observe the behavior of the Abio gel. In order to generate better results, we decided to run cases for later time steps. Time step 318 is the monitoring time 2nd of June 2012, one day after the injection of Abio gel. While time step 319 is the date 1st of January 2013, which is six months after the Abio gel injection. The two time steps gave us more accurate and comprehensive results.

Final steps

As a final step this new ".TRAN" file is included into the DATA file and saved as a new case data file. Finally the new model with the new properties was ready for simulation.

Case Simulations

We ran several cases by changing their properties by adjusting the transmissibility multipliers. A range was selected for the multipliers by observing a trend, using maximum and minimum values. We used 0.1 for EORF > 250, which shows the maximum percentage of the plugging i.e. 90%. The other value used was 0.9 for 250<EORF>50, which is the minimum transmissibility multiplier. We got an interesting result from the simulation of this case. The production from this case was almost equal to the Base Case. This result gave us a better understanding of the behavior of the multipliers and the reservoir. We assumed that the plugging near the injection well was considerably higher, if the gelling time was short, and as a result, water was forced to find new paths quite fast.

As the chemicals move away from the injection well, the Abio gel may lose its concentration and effectiveness. This was simulated by applying the minimum multiplier. As a result the water followed the previously flushed path and thus had lower sweep efficiency. In this case the production was similar to that seen in the Base Case.

We concluded that if we kept the minimum difference between the ranges of the multipliers, we would be able to get better results and sweep efficiency. We applied this idea and we were able to increase the oil recovery. Using this idea we ran four cases from 30-90% plugging. The combination of the multipliers we used were:

Table 3: Transmissibility Multipliers

	TRAN Multipliers in X&Y directions		
	EORF>250	250<EORF<50	EORF<50
CASE A	0.1	0.2	1
CASE B	0.2	0.3	1
CASE C	0.3	0.4	1
CASE D	0.6	0.7	1

From Table 3 we can see that for Case A, when EORF is bigger than 250 the plugging will be 90% and it will decrease to 80% when its concentration values fall between 250 and 50. If the concentration falls below 50 there will be no reduction in the transmissibility.

We believe that the levels below 30% are not worth pursuing, as we would not be able to get a sufficient increase in oil recovery. For the EORF concentration limits we have decided to use a limit greater than 250 for the maximum plugging. This limit is high and it has been used to magnify the effect of the Abio gel and to obtain a visible difference in the results.

3.3.4 Tracer Simulation of Abio gel in Eclipse model

Figure 10 to 13 show how the Abio gel moves within layer 40 of the lower Brent. The tracer simulated the movement and the concentration of the Abio gel in the reservoir. The Abio gel will behave in a similar manner and by using the tracer option we can observe how the concentration of Abio gel is reduced from its maximum in 2012.

The steps for making a .DATA file have been explained previously. Once we had created a new data file, it was simulated to visualize the changes and variations in the properties of the formation. In order to get better EOR results, we ran several cases. All the cases differ from each other by applying different transmissibility multipliers, which can be seen from Table 3. In this paper, we have chosen to include four cases and compare them with the base case. The mechanism for each case is the same. To demonstrate how the tracer will move in the formation with water, we chose the case with 90% plugging. The pictures are taken at time step 318, 2nd of June 2012.

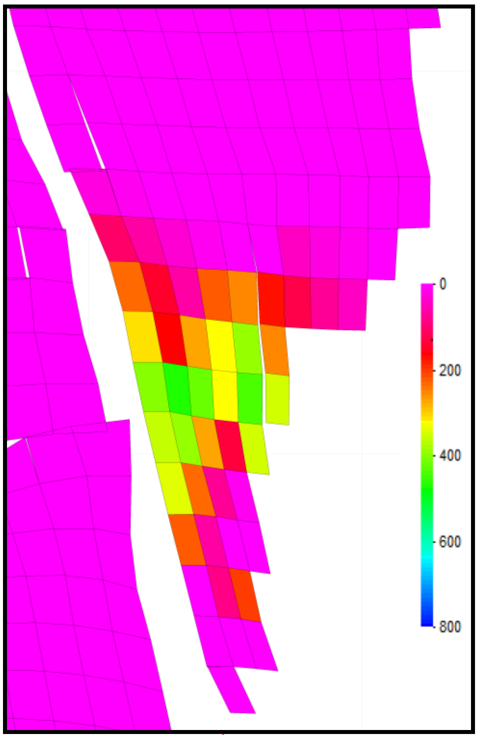


Figure 10: EORF on 2nd June 2012.

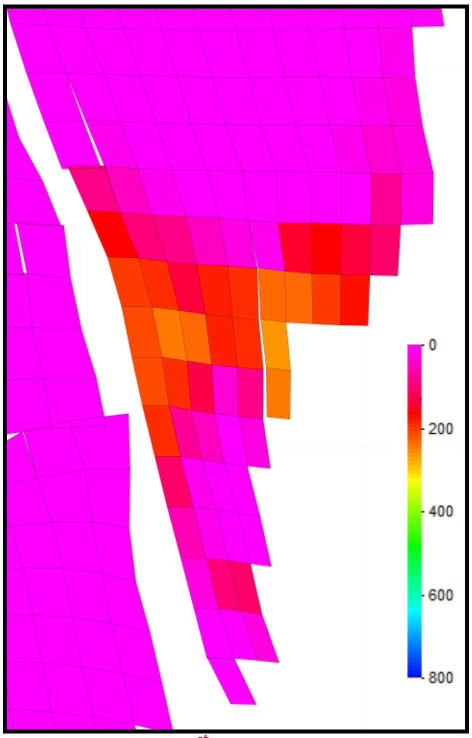


Figure 11: EORF on 1st January 2013.

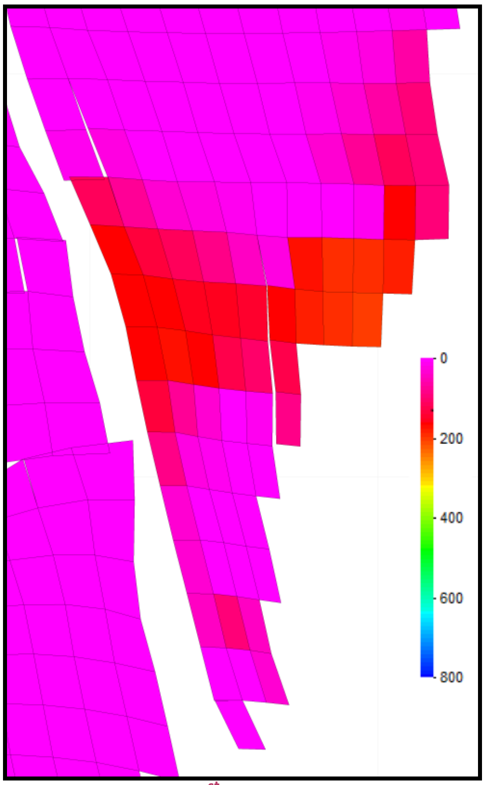


Figure 12: EORF on 1st June 2013.

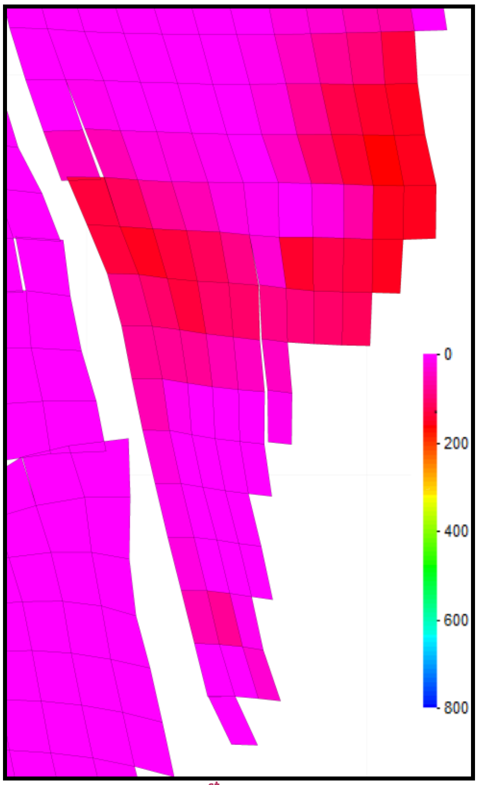


Figure 13: EORF on 1st January 2014.

It is apparent from the figures that the concentration or the effect of the tracer diminishes as it moves away from the injector with the passage of time. Hence, we can say that the Abio gel will lose its effect after a certain period of time. After that, it will not be effective anymore and the water may follow the previous path.

3.4 Abio Gel and oil saturation

The following figures, 14-23, represent a comparison between the Abio gel concentration and the oil saturation during different time steps in layer 37-47. These figures are from Case A, which is our best case with the maximum sweep efficiency. The plugging in this case is 90% and the monitoring time step is 318, June 2nd 2012. The models on the left hand side represent the tracer concentration while the models on the right side show oil saturation in the same layer.

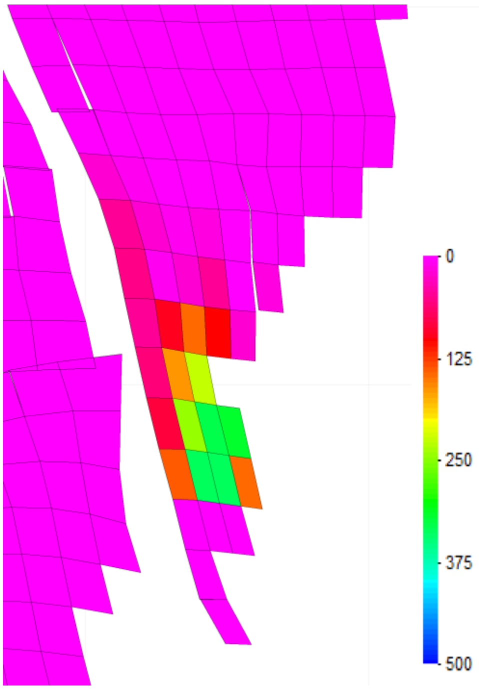


Figure 14a: EORF in Layer 38

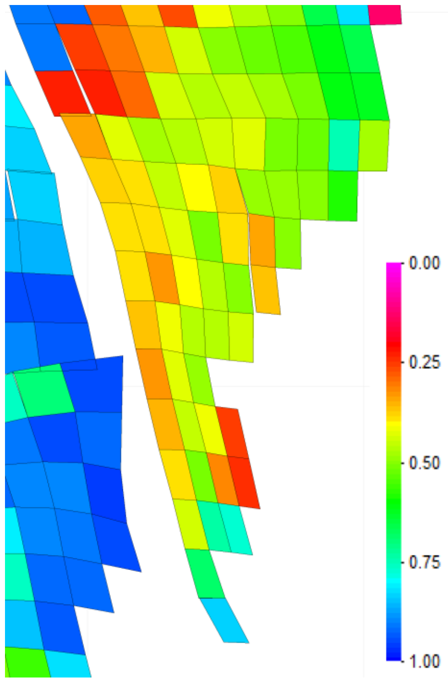


Figure 14b: Saturation of oil in Layer 38

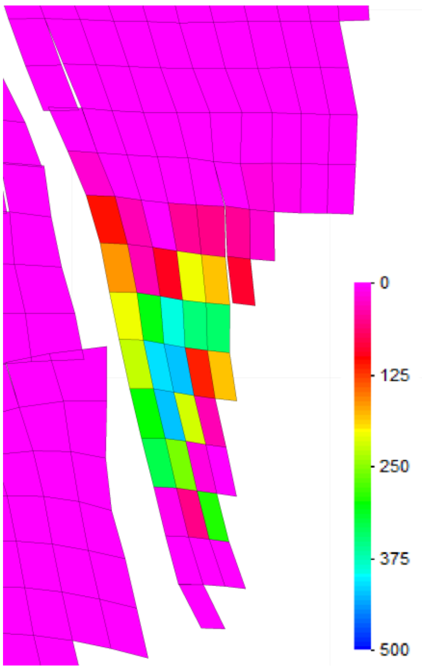


Figure 15a: EORF in Layer 39

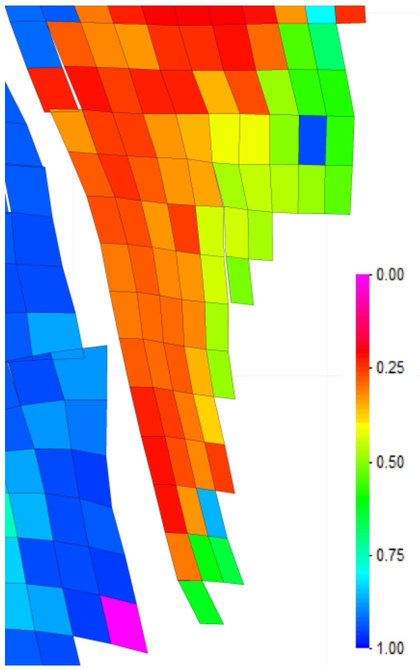
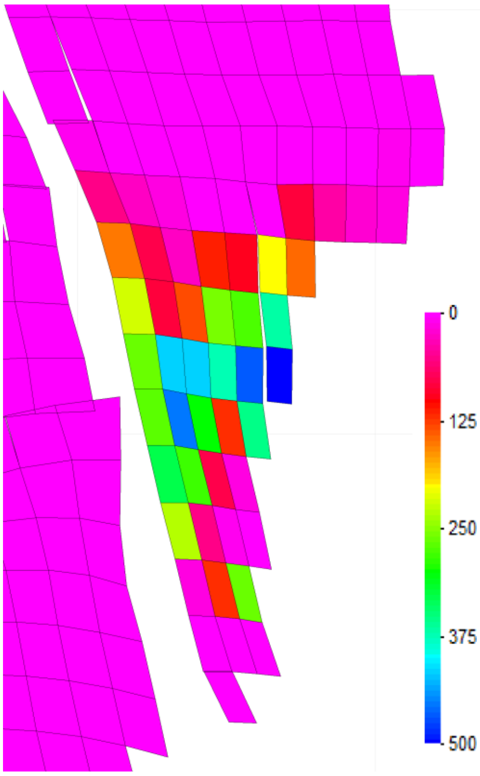


Figure 15b: Saturation of oil in Layer 39



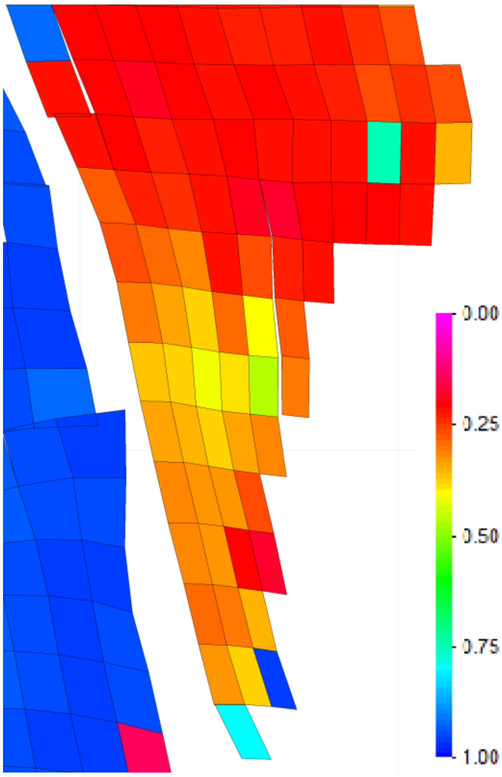
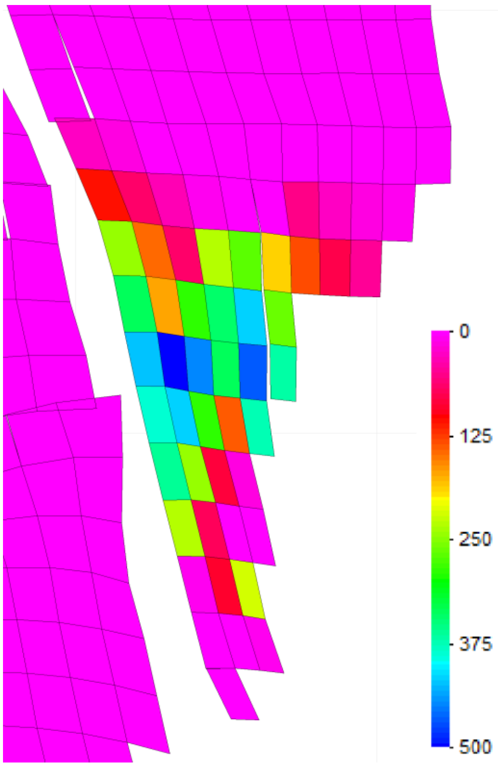


Figure 16a: EORF in Layer 40

Figure 16b: Saturation of oil in Layer 40



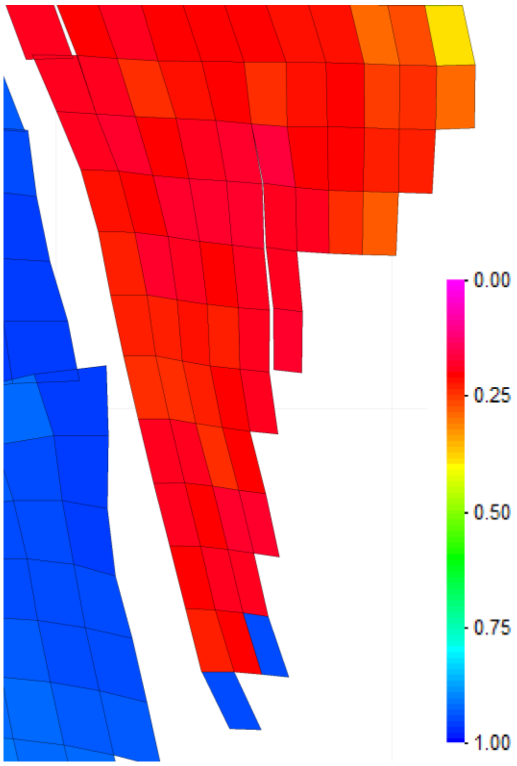


Figure 17a: EORF in Layer 41

Figure 17b: Saturation of oil in Layer 41

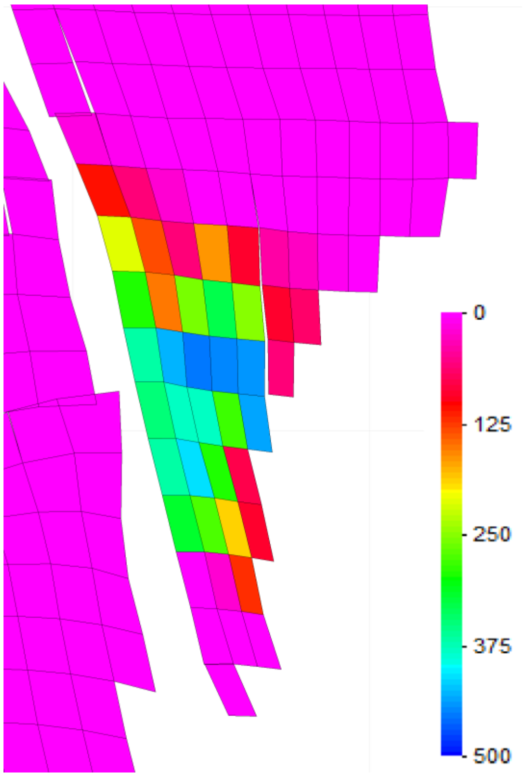


Figure 18a: EORF in Layer 42

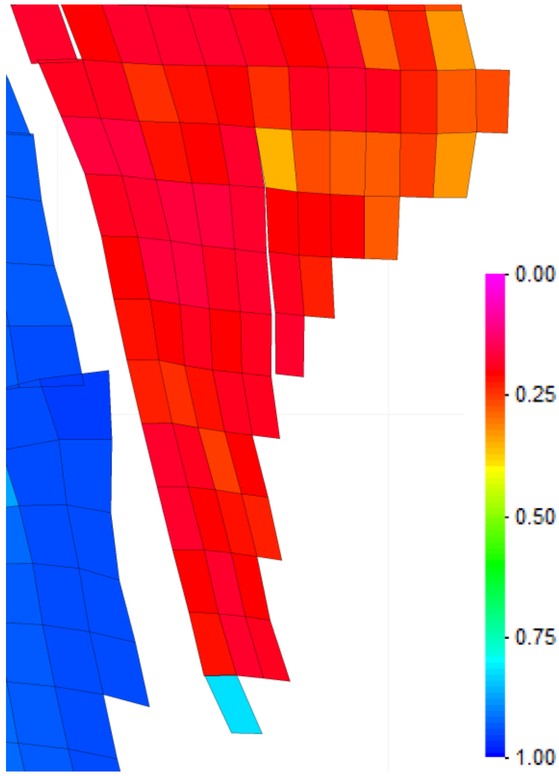


Figure 18b: Saturation of oil in Layer 42

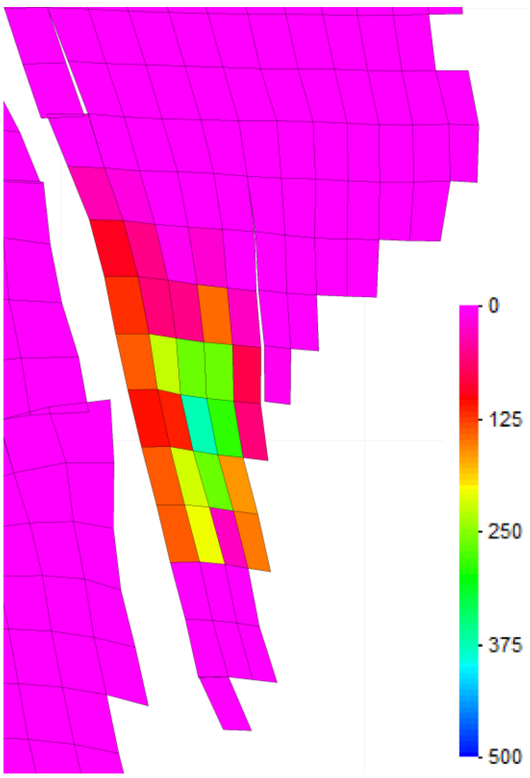


Figure 19a: EORF in Layer 43

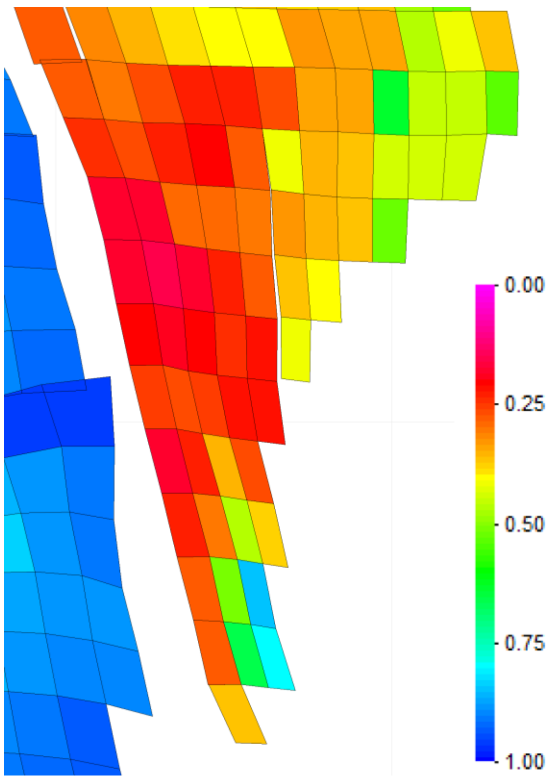


Figure 19b: Saturation of oil in Layer 43

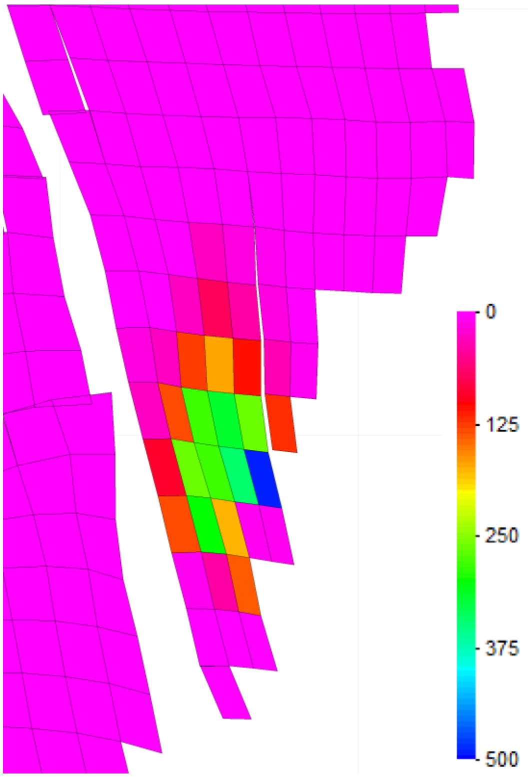


Figure 20a: EORF in Layer 44

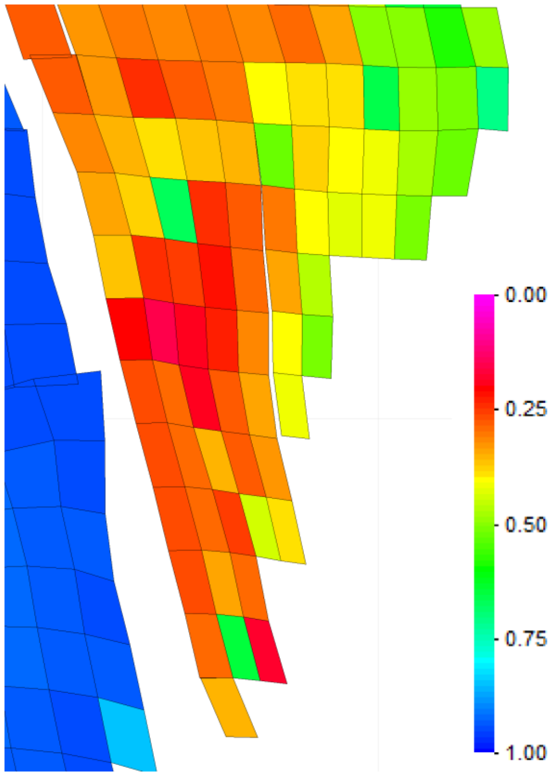


Figure 20b: Saturation of oil in Layer 44

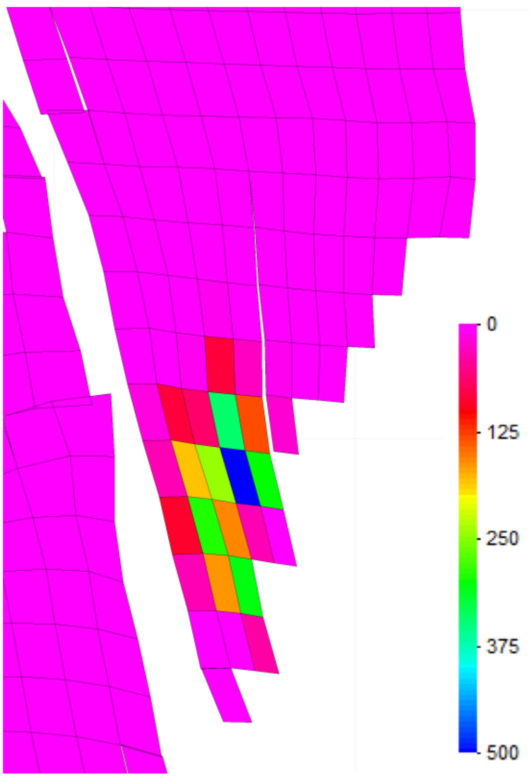


Figure 21a: EORF in Layer 45

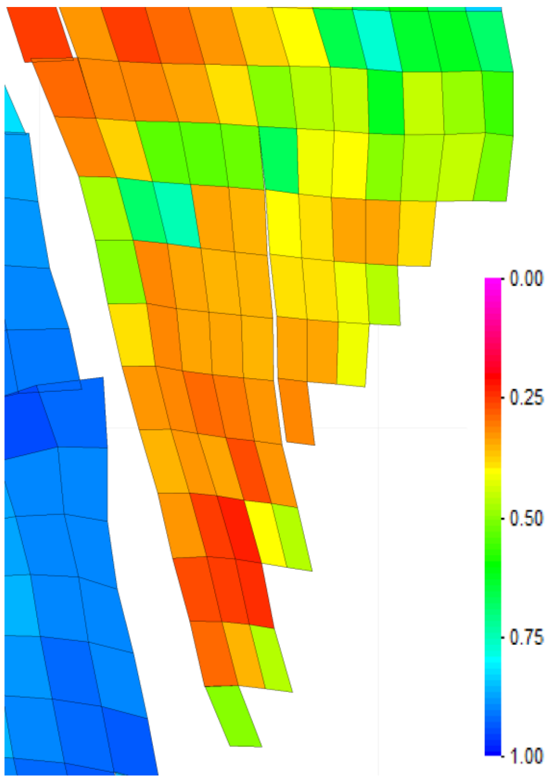


Figure 21b: Saturation of oil in Layer 45

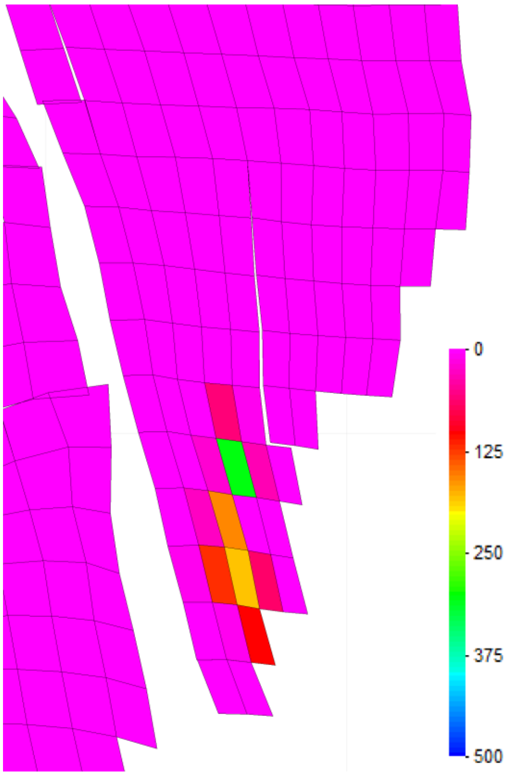


Figure 22a: EORF in Layer 46

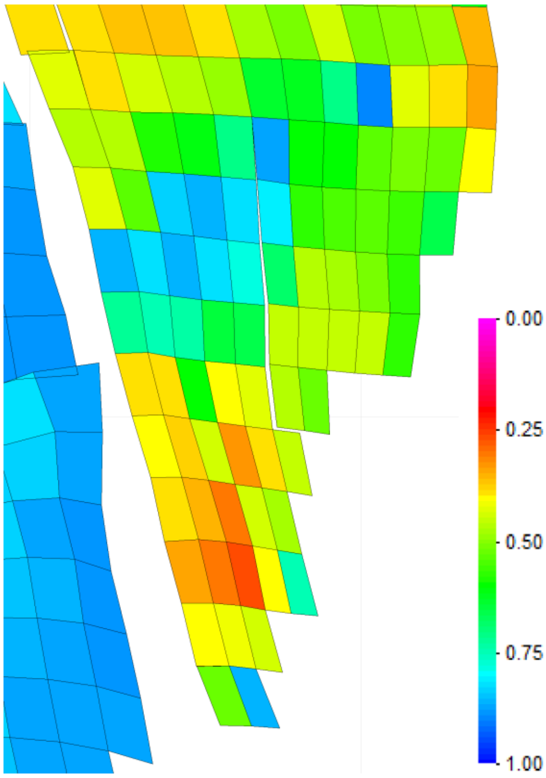


Figure 22b: Saturation of oil in Layer 46

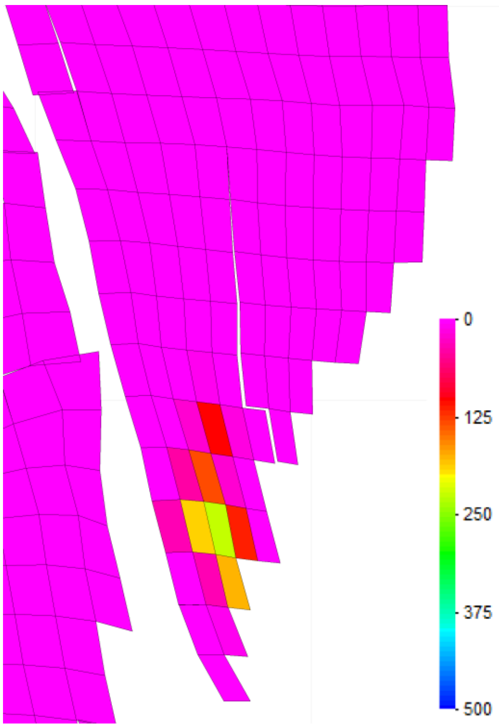


Figure 23a: EORF in Layer 47

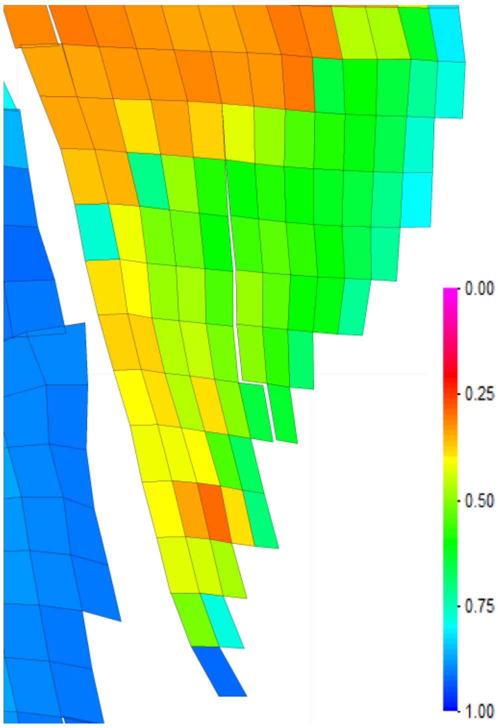


Figure 23b: Saturation of oil in Layer 47

The models show a significant change in oil saturation after the injection of Abio gel. We can observe that the areas with higher Abio gel concentration result in better sweep efficiency.

3.5 Results

In Figure 25 and 26 we can see the oil saturation in the predicted model for Base Case by the end of 2014 in comparison with Case A after the Abio gel was injected. When studying these models in detail, it can be seen that the oil saturation has changed.

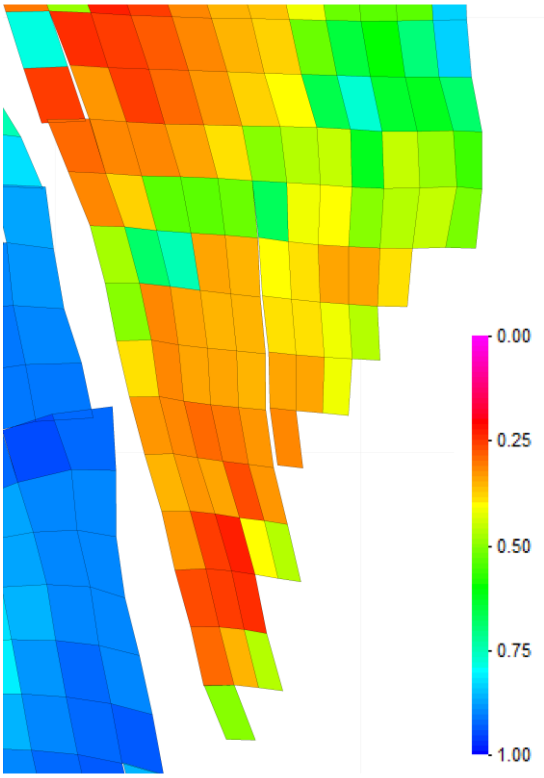


Figure 25: SOIL at 1st June 2012

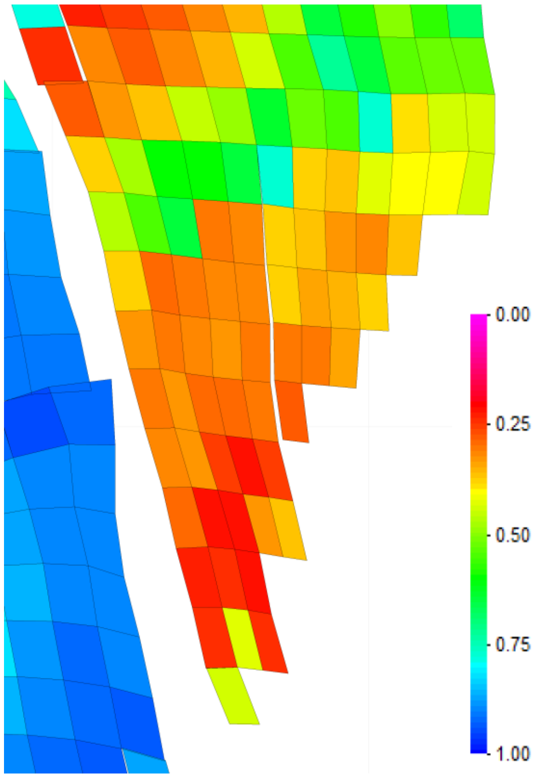
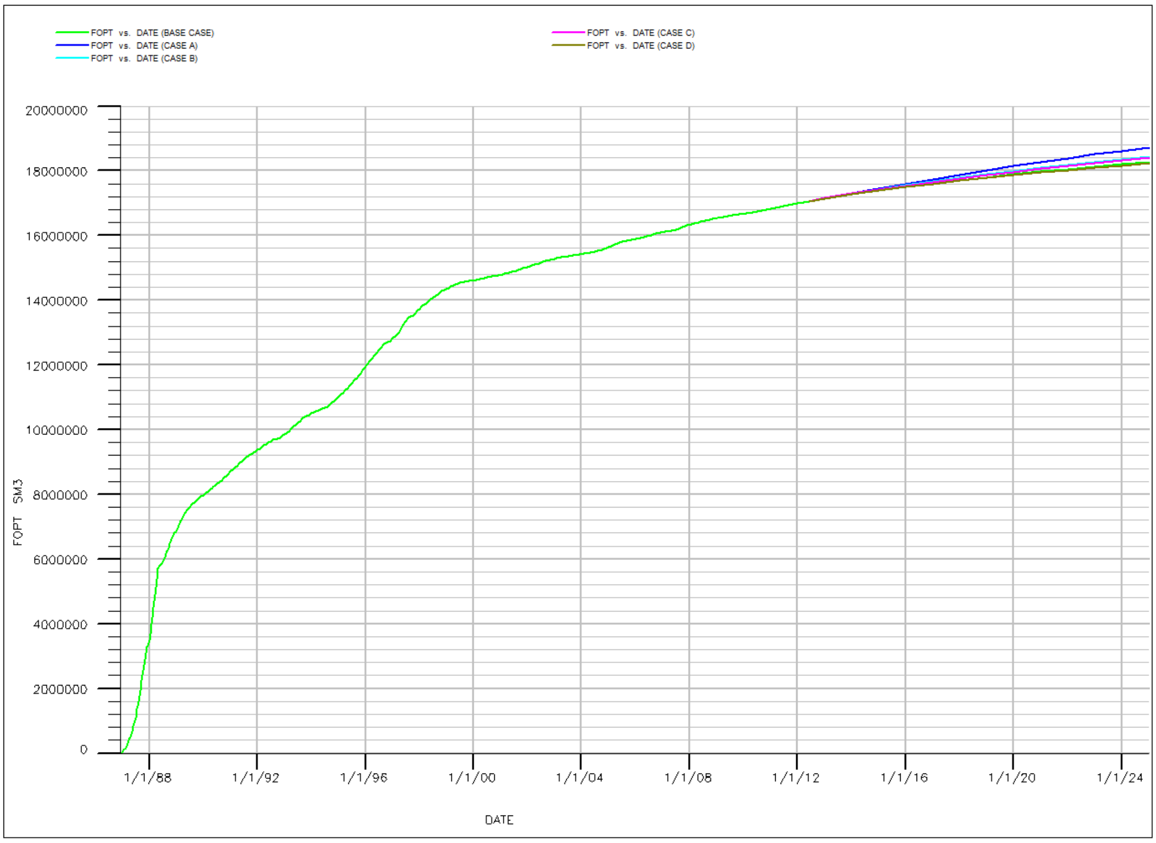


Figure 26: SOIL at 1st January 2025

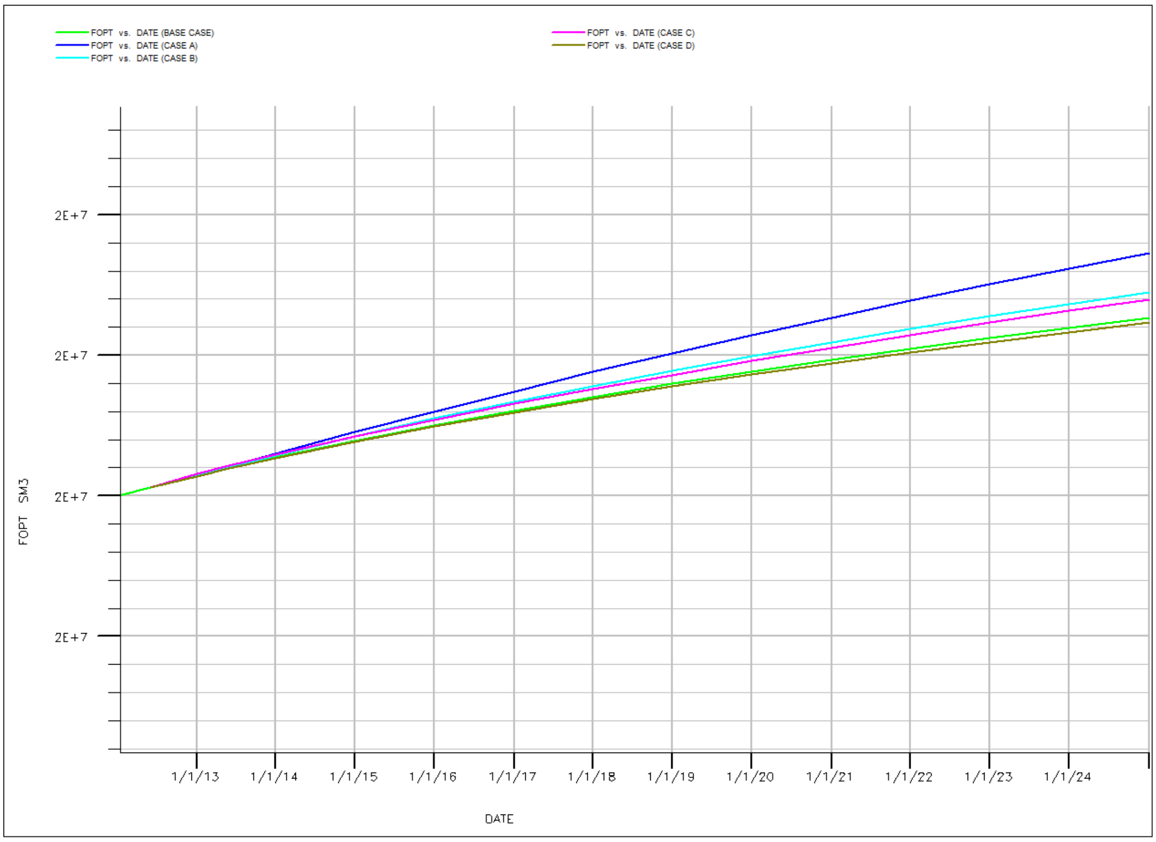
3.5.1 Field Oil Production Total (FOPT)

The injection of Abio gel resulted in a change of the transmissibility in the formation. This transmissibility change ultimately effected the oil production from the wells. The change in the trend of oil production can be observed in Graph 1 and 2. These are graphical representations of Field Oil Production Total (FOPT) in Sm^3.

The base case production up to 2025 is 18.3 Million Sm^3. This is the production without any chemical injection in the formation. There are three cases in which the production is greater than the base case. Case A has the highest value of production 18.72 Million Sm^3, which is 2.45 % more than the Base Case. This is the best case with the maximum oil recovery if we could obtain 90% plugging in the formation. We have 1% more oil recovery if we reach 80% plugging in Case B. If we plug the formation 70%, we can have 0.7% more oil than the Base Case. The zoomed section, Graph 2, makes these amounts of production more clear.



Graph 1: Comparison of FOPT for all cases.

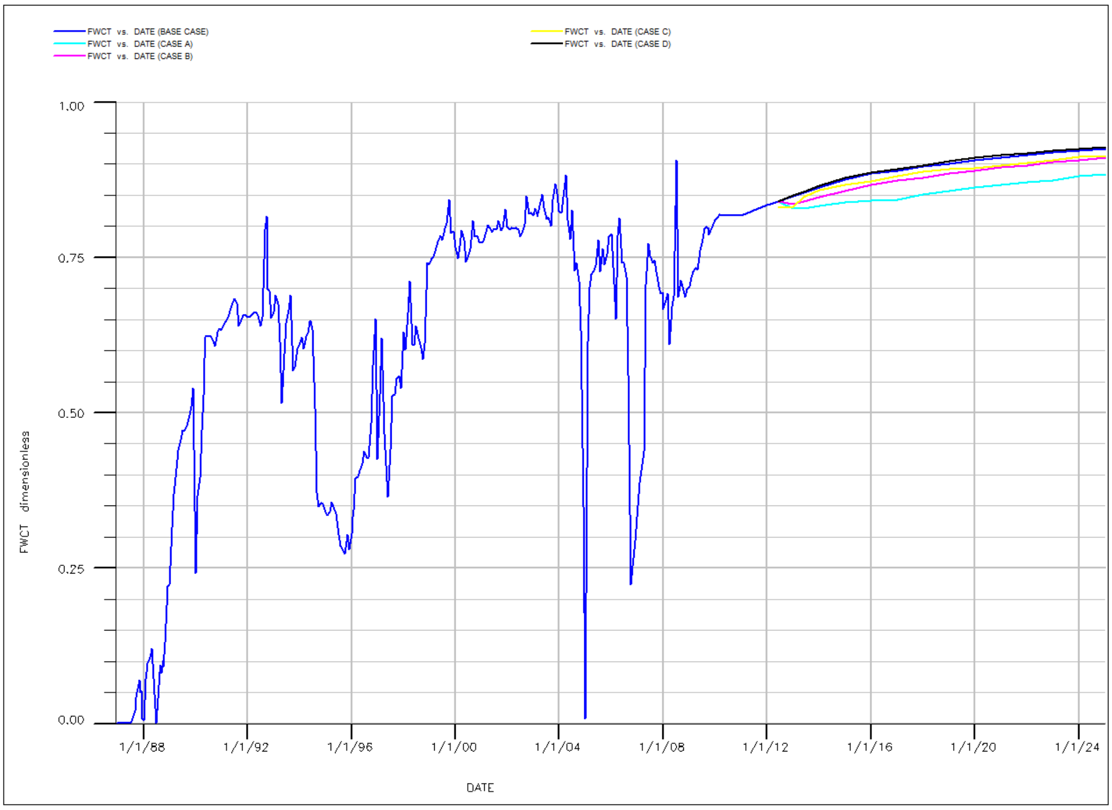


Graph 2: Zoomed section to emphasize the difference between the FOPT in the different cases.

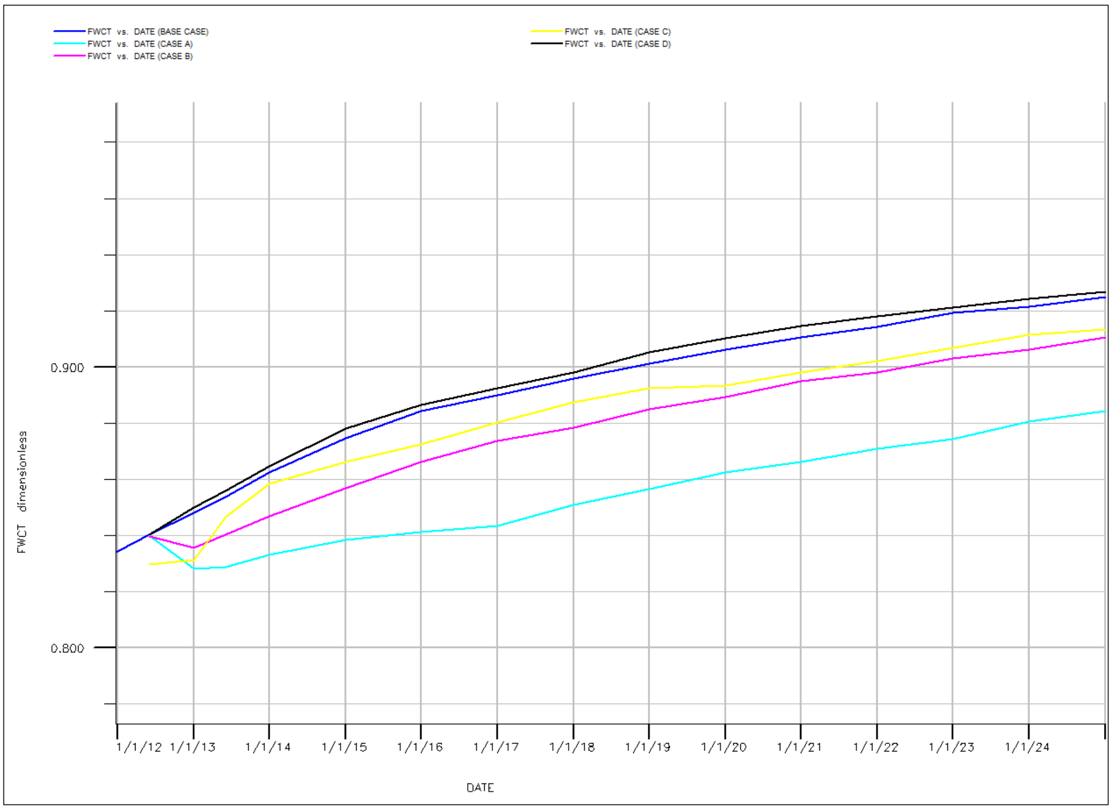
Case D shows production lower than the Base Case, this case represents 40% plugging. As this gives a lower amount of oil, this option is not viable. It also makes it clear that there is no effect on the oil recovery if the plugging is below 40%.

3.5.2 Water Cut

Graph 3 and 4 show a comparison of the total water cut in Sm^3 for all cases including the Base Case. In Case A the water cut is considerably lower than in all the other cases. However, the water cut has also been significantly reduced in Case B and C. This trend makes these cases suitable for further consideration. Case A shows a positive indication but the high value of plugging makes it too optimistic. For this reason we consider Case B and C to be the most probable cases. Concerning the last case, Case D, the water production is much higher than the Base Case, which makes it an inappropriate case to implement.



Graph 3: Water cut comparison for all cases.



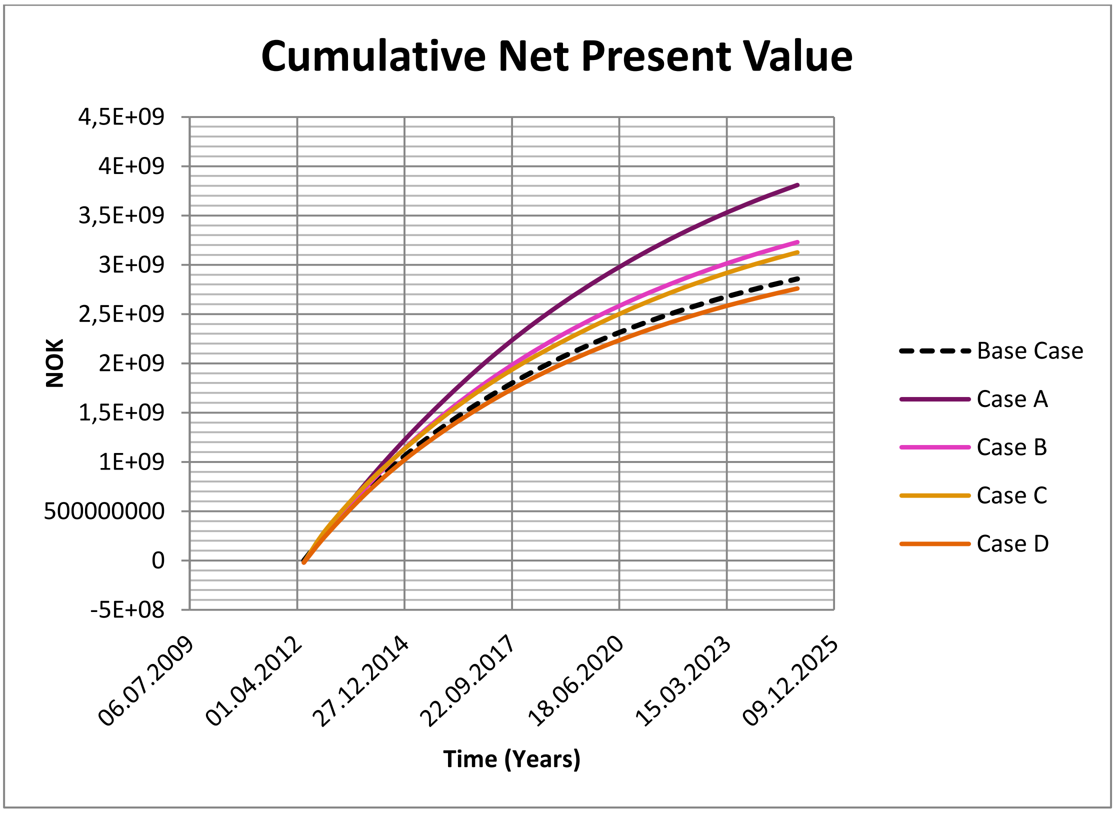
Graph 4: Zoomed section of the graph taken to emphasize the difference in water cut in the different cases.

3.6 Economic Analysis

3.6.1 Net Present Value (NPV)

The Net Present Value (NPV) calculations were made according to the set of economic conditions given by Statoil. We were given a discount rate of 8% and an oil price fixed at 100 US dollars per barrel. We calculated cumulative NPV in Norwegian Kroner (NOK) by conversion. The cumulative oil production is changed to barrels as it was in Sm^3 initially. The cost of chemical injection is estimated to 20 Million NOK, given by Statoil. No operational cost is included in our economic analysis.

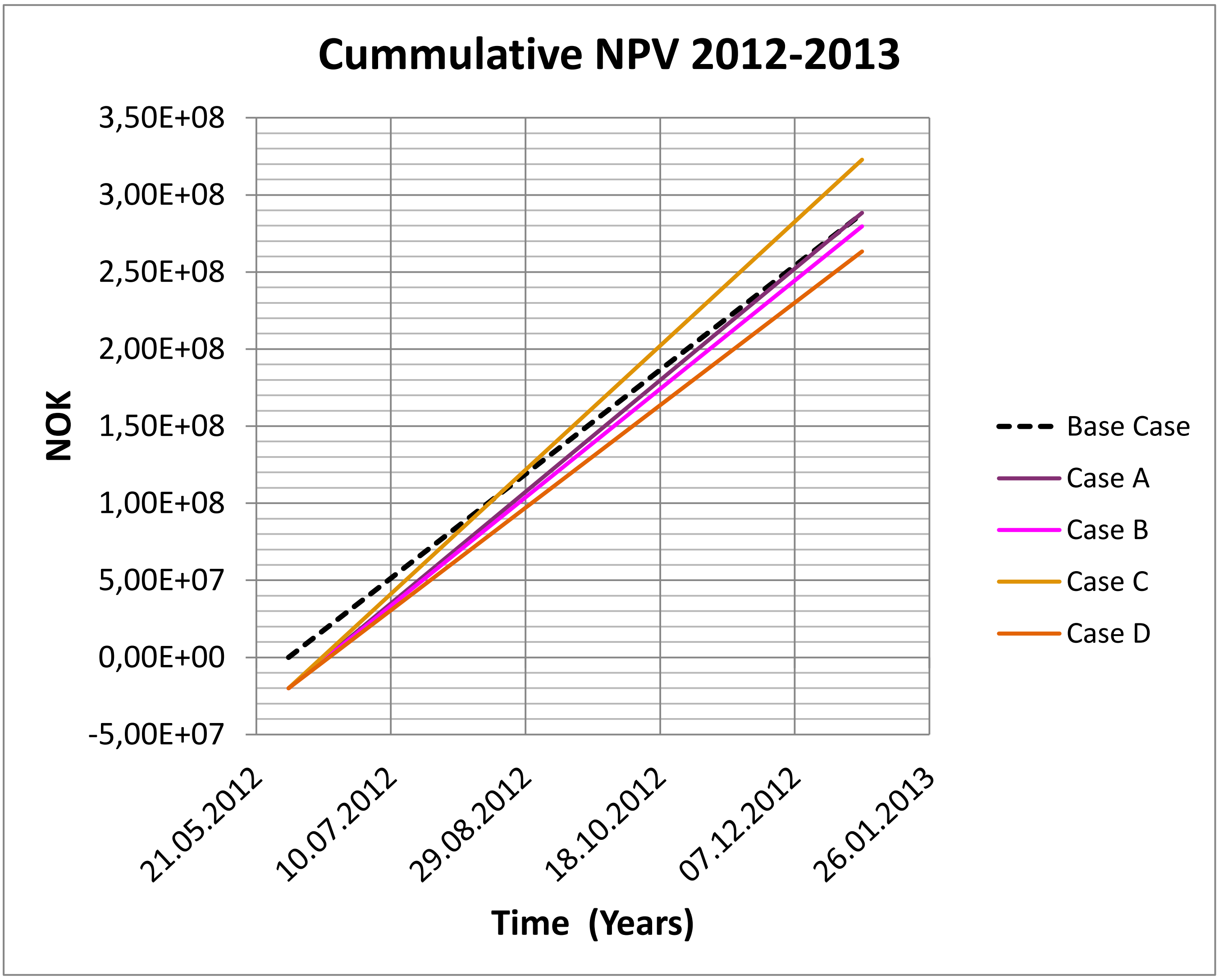
Comparison of all Cases



Graph 5: Cumulative Net Present Value for all cases.

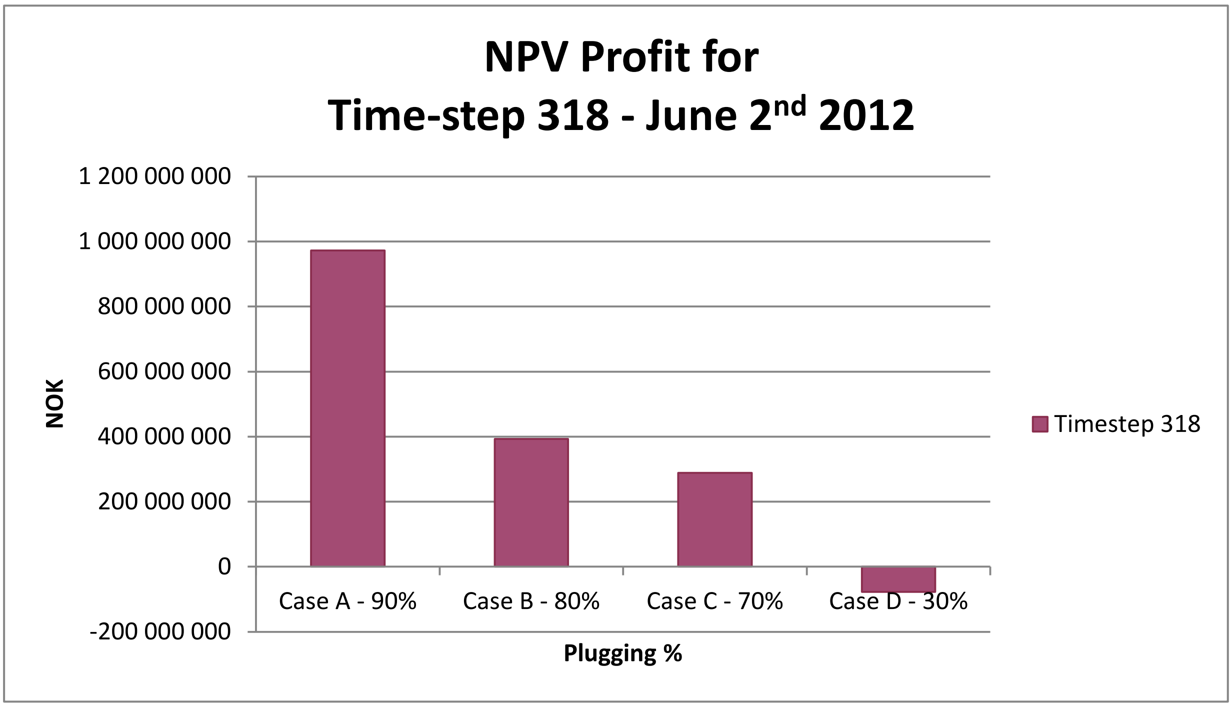
Graph 5 shows an increment in the NPV for all cases when compared to the Base Case except for Case D. For the Base Case we got 2.86 Billion NOK at the end of year 2024. For Case A, we have 3.8 billion NOK. Further, in Case B we earned 3.25 billion NOK, and last for Case C, we got 3.14 billion NOK. Case D with a total of 2.78 Billion NOK, is mentioned just to show that if are not able to achieve a blockage higher than 40% it will be a poor investment.

Graph 6 gives the accumulated NPV in the first 6 months after the Abio gel injection. The initial NPV values are negative due to an initial investment of 20 million NOKs. The investment is, however, covered in the first month for 70-90% blockage, and gives an idea of the feasibility of Abio gel.



Graph 6: Cumulative Net Present Value for 2012-2013.

When we subtract the Base Case earnings from those where Abio gel was used we end up with the net profit of the NPV. In Graph 7 we can see how much profit each case generate when compared to the Base Case for time-step 318, June 2nd 2012. Case A yields 0.97 billion NOK, which is 34% more that the Base Case. Case B yields 0.39 billion NOK, 14% more than the Base Case. Finally, Case C yields 0.28 billion NOK which represents a 10% increment over the Base Case.



Graph 7: Net profit for Case A, B, C, and D.

Table 4 shows the Base Case earnings for each year along with the net profit or loss margins of each case when compared with the Base Case. Numbers are in Million NOK, where red numbers represent negative values. The initial investment of Abio-gel is 20 million NOK for all cases.

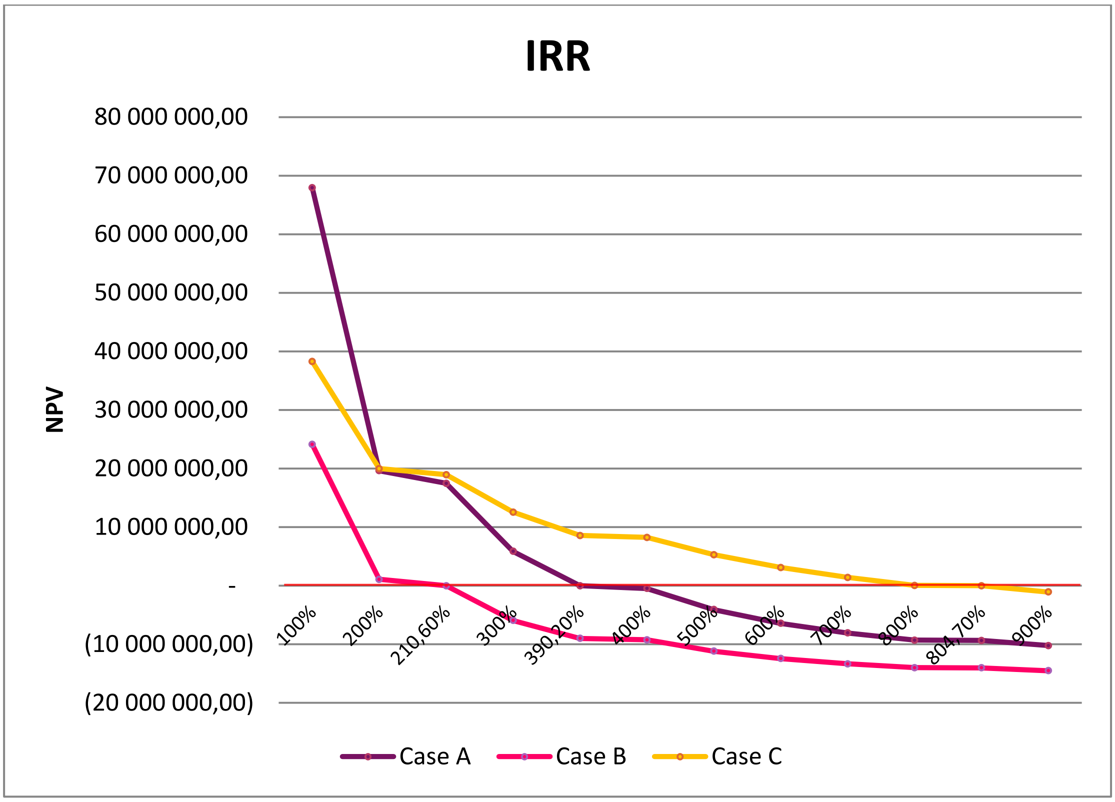
Table 4: Additional NPV obtained in each case.

Additional NPV (Million NOK) obtained in each case					
Year	Base Case	Case A	Case B	Case C	Case D
01.06.12	-	(20,00)	(20,00)	(20,00)	(20,00)
01.01.13	299,09	21,37	12,26	57,19	(4,66)
01.01.14	473,76	83,14	45,28	24,34	(7,49)
01.01.15	429,77	109,10	54,35	18,57	(9,57)
01.01.16	394,06	128,57	57,80	34,88	(10,47)
01.01.17	372,05	145,53	54,10	34,92	(11,40)
01.01.18	353,40	143,45	51,59	26,93	(11,51)
01.01.19	333,61	143,20	54,28	25,60	(11,69)
01.01.20	315,00	144,74	54,03	36,25	(11,54)
01.01.21	300,13	148,43	53,35	43,17	(12,26)
01.01.22	285,17	148,50	52,78	41,95	(11,51)
01.01.23	272,30	144,74	51,77	40,44	(9,43)
01.01.24	260,44	141,12	50,73	39,29	(7,56)
01.01.25	250,58	138,29	49,69	38,65	(6,20)
	Total Profit	1 620,17	622,02	442,18	(145,31)
	% Over Base Case	34 %	14 %	10 %	-3 %

3.6.2 Internal Rate of Return (IRR)

The Internal Rate of Return (IRR) is the discount rate for which a project's cash flows will yield, or sum "zero", and it is used to compare the profitability between projects. Since all the Abio gel cases are not interdependent and have the same project conditions we can apply this economic technique. Graph 8 shows the IRR for each case except for Case D, as it has already proven to be a poor investment.

We found that Case C is the best project in the short term as it has an 804% discount rate before its NPV goes to zero. This can be seen in Table 4 as this project receives a huge positive cash flow in the first 6 months when compared to the others cases. Case A yields 390% and Case B 210%. Nevertheless, we recommend aiming for Case A or B, as we are more interested in a largest NPV.

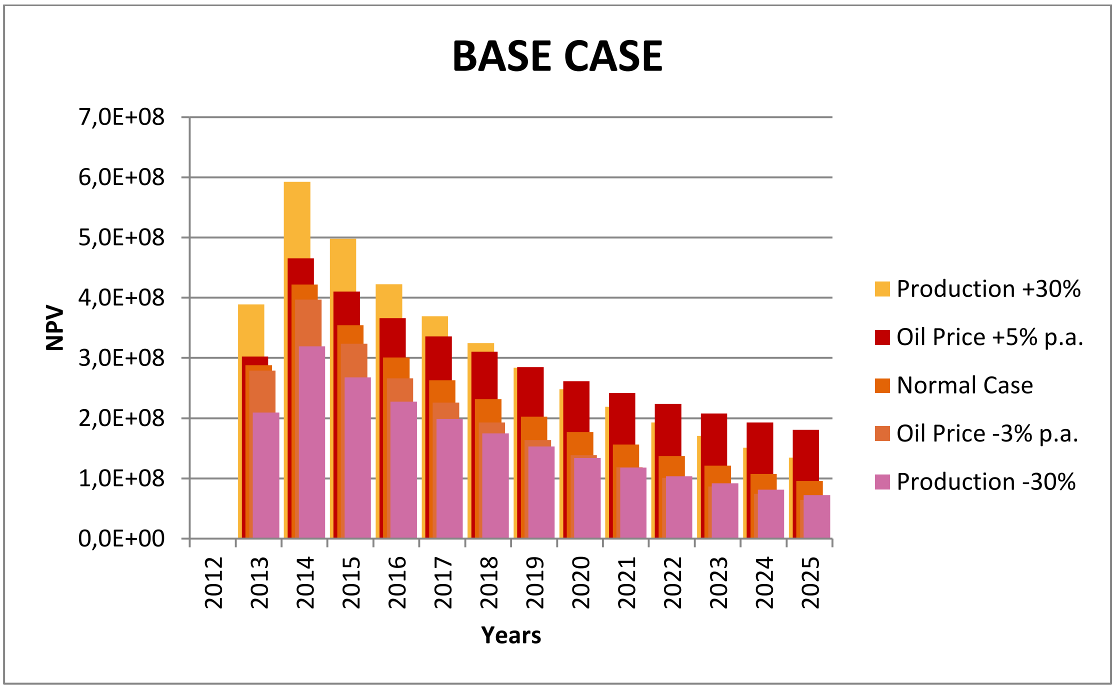


Graph 8: IRR for Case A, B, and C.

3.6.3 Sensitivity Analysis

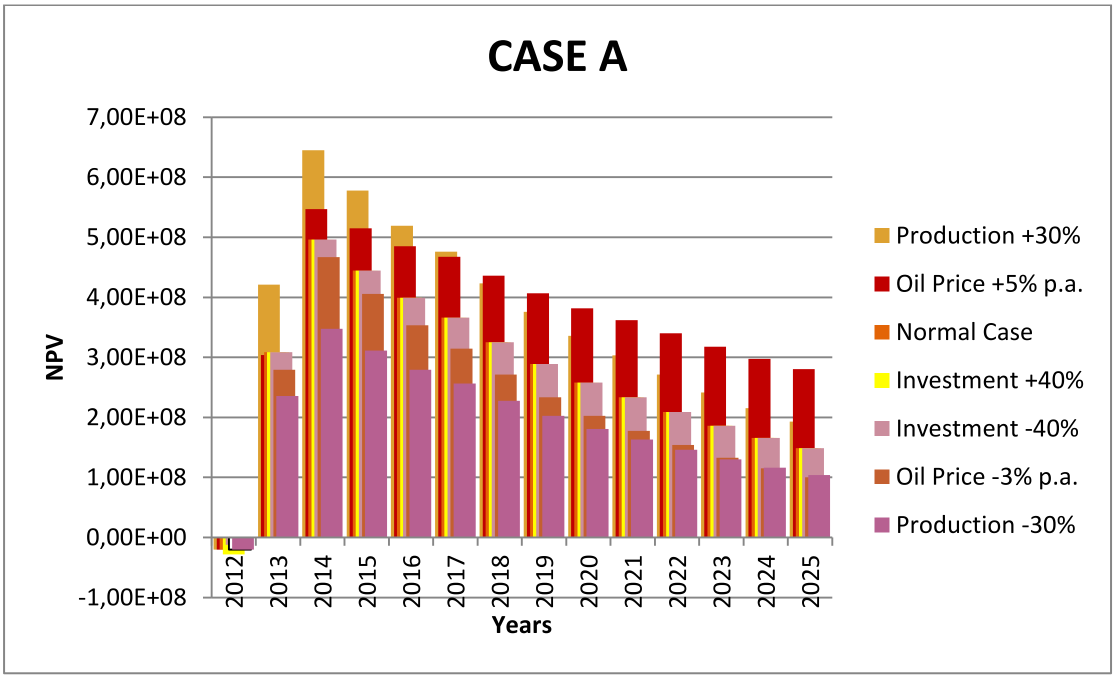
Sensitivity analysis was done with the provided economic data from Statoil: Production +/- 30%, Oil price +/-5% pro anno, and Investment +/-40%. This analysis was carried out in order to find the factor that will have the biggest impact on the project and the effects of the best and worst case scenarios.

Graph 9 shows the sensitivity analysis for the Base Case as the oil production and the oil price variables are moved up and down within their range. The oil production is the most important variable during the first six years. After this, the oil price will dictate the new upper and lower NPV obtainable.



Graph 9: Sensitivity analysis for Base Case.

The same analysis has been carried out for Case A, B and C, however, we will only present Case A as this is the best case among the three, with highest oil production and NPV, therefore displaying the trends more apparently. Graph 10 includes the changes in the variable "Investment", where a change of +/-40% lies within production and oil price, and proves not to be an important variable compared to the others. Similar to Graph 9 we found that oil production is the most important variable during the first years, and then the oil price will control the new upper and lower NPV obtainable. Sensitivity analysis for all the cases are included in Appendix A.



Graph 10: Sensitivity analysis for Case A.

3.7 Discussion

Once the obtained data from the simulations was processed we could see a trend indicating that the growth in Net Present Value was directly related to the transmissibility multiplier: a with a 70% plugging the NPV is 3.14 Billion NOK, with 80% it is 3.24 Billion NOK and finally 90% plugging will give us a NPV of 3.82 Billion NOK by year 2025.

Based on previous research carried out by Xiaofen Tang et al., on the topic of deep fluid diversion agents a 90% blockage has been proven to be obtainable [16]. However, these results are attained in a laboratory after repeated injections, and optimal conditions. It is therefore highly uncertain that this level of blockage would be obtainable with the conditions in an actual reservoir. Based on these uncertainties we have made an evaluation of the four cases presented, grading the probability of the obtained blockage in the various cases. Case A is marked yellow, as it is considered to be too optimistic and the least probable of the cases. Case B and C are both considered green, as we believe these levels of blockage can be obtained. We have considered Case C to be slightly more probable, as this requires a lower percentage of plugging. However, Case D has proven to be a poor investment, and is therefore marked red even if we consider this level of blockage to be within reach.

Case A	Considered to be too optimistic. However, it is still marked yellow as it has been obtained in laboratory research.
Case B	High level of blockage, this level could be obtained by repeated injections of Abio gel
Case C	Most level is considered the most probable case. Repeated injections would still be a requirement.
Case D	This case is not economically viable, however, the blockage is well within reach

Maintaining a high blockage in the reservoir has proven to be a challenging factor, especially subsurface. The concentration of Abio gel is vital in this scenario, and if we succeed to keep the concentration at a high level, it will reach maximum plugging, which has proven to give the best NPV. Repeated injections of Abio gel in batches should also be done to overcome this challenge.

We found that the project is feasible. By investing 20 Million NOK we were able to increase production by 3%, which in turn lead to an increase of the result of the NPV of 34%, which can be considered as a very good investment. However, we believe that there are numerous factors that should be included in order to make the project more feasible. To account for these uncertainties, we have included a short section covering some of the most critical sources of errors.

3.8 Uncertainties

When running simulations it is important to remember that the simulations are only predictions of how the fluids will behave in the reservoir. There are many risks involved, which need to be taken into consideration. However, we were not able nor had the time to implement these risks into our calculations. Some of the main risks are listed below:

- The main uncertainty was human error using the software. Throughout the project we were struggling with getting identical results for plugging ranging from 40-70%. We got the same production from all these cases, but after several attempts with our Professor, Jan Ivar Jensen, we were still not able to identify the problem.

- We only changed transmissibility in X and Y directions. Changing the transmissibility in the Z-direction could have given different results.

- There is another well B-37 in the H1-segment from layer 12 to 49. Well A-39A is from layers 44-49, which means that well B-37 is overlapping. It might be possible that some of injected water may go in that direction of B-37.

- The time it takes for the Abio gel to attain its required gelling strength is important because the water will start changing its path at a distance where the Abio gel settles. Here, there will be a difference from the simulations as it is not possible to control the time of the gelling in a similar fashion in nature.

- Concentration of Abio gel is noteworthy. The greater the concentration, the greater will be the plugging.

- Fluctuation in oil prices may cause an increase or decrease in the NPV.

- Changes in the production rate could be an influential factor in the NPV calculations.

- We were not given any operations costs. Therefore our economic analysis is without these calculations.

3.9 Conclusion and Future Recommendations

This work has been a modest attempt to study the effects of Abio gel. Based on our findings we have concluded that injection of Abio gel is a sustainable investment. From our simulations we have seen an increase in the oil production as well as a lowered water cut compared to the Base Case.

The best option would be to aim for a plugging higher than 90%, by injecting Abio gel repeatedly. This would lead to layered pore coating decreasing the permeability in the reservoir. However, plugging should not be below than 40%, as Abio gel does not seem to be effective below this limit. Further, to keep a certain level of plugging, it is advised to secure gelling at a certain time interval.

Through this project we have found that Case C with 70% blockage, will be the most feasible case. This conclusion is based on the gelling strength of the Abio gel, and to account for unpredicted uncertainties. From sensitivity analysis, oil production and oil prices have proven to be the most influential parameters. However, despite fluctuation in these parameters Case C proves to be a good investment.

There are no doubts that further work needs to be carried out in order to remove some of the uncertainties. A team of experienced reservoir engineers would have been more capable of spotting errors in the software. Another factor that should be considered is that we only changed transmissibility in X and Y directions. Changing the transmissibility in the Z-direction could have given different results.

Our future recommendations are to move forward with the project and to use Abio gel for increased oil production at the Gullfaks Main Field. We also recommend further research on this area to ensure the best possible recovery.

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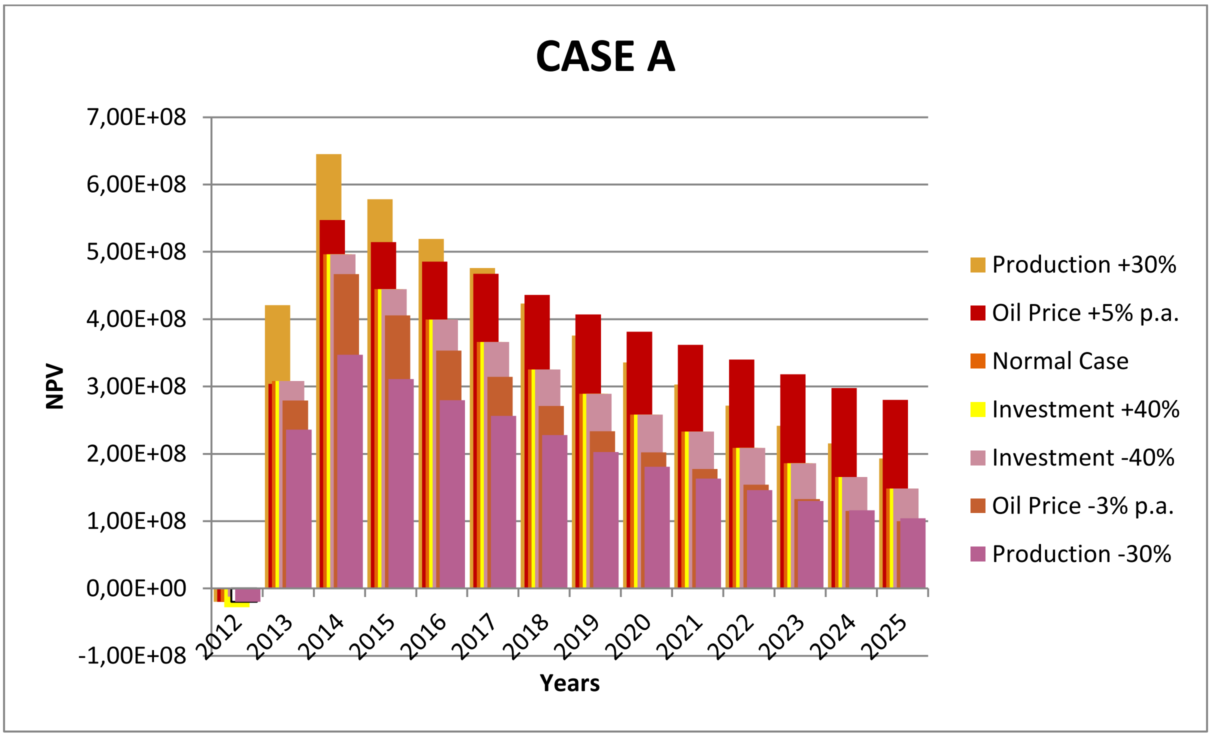
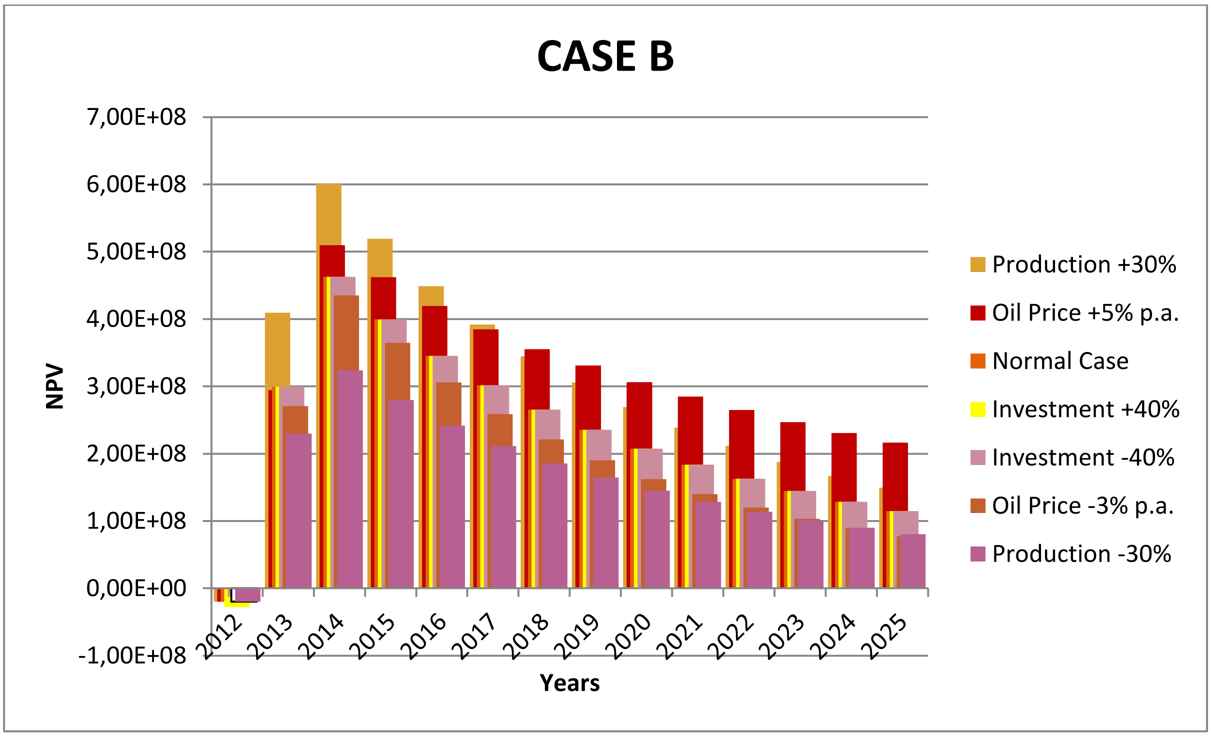
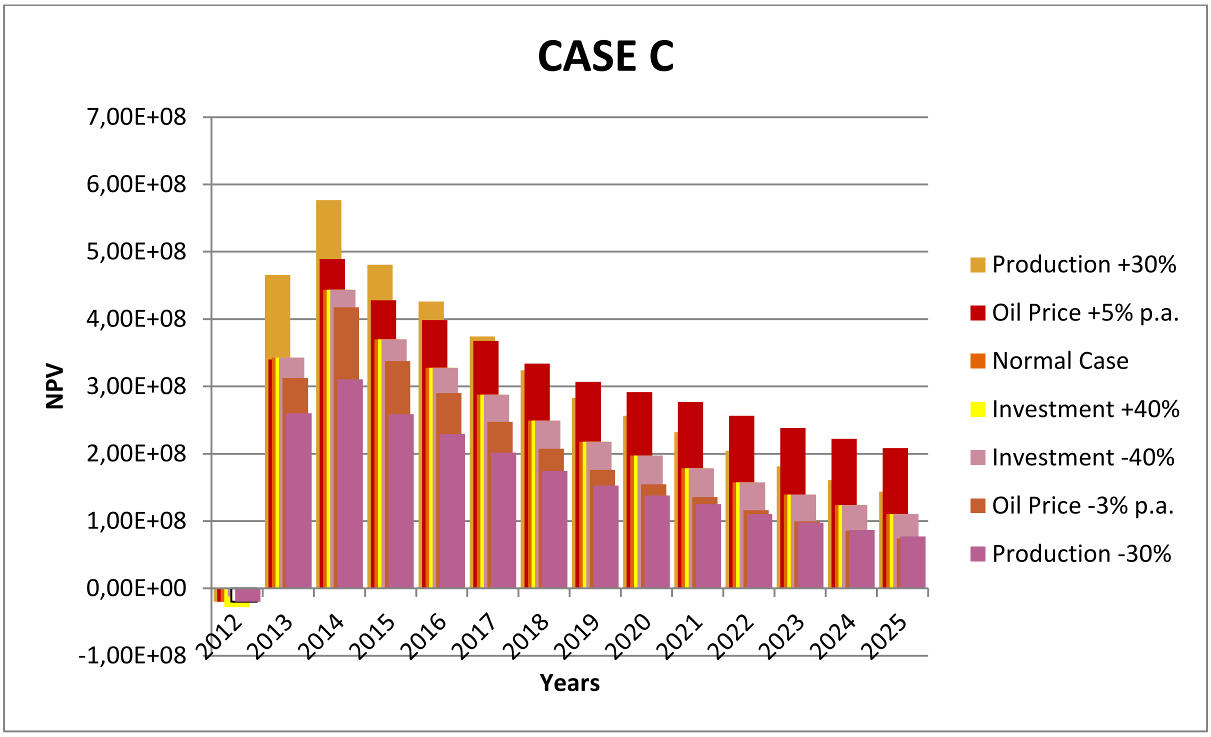
Appendix A

Sensitivity analysis for Case A, B, C and D



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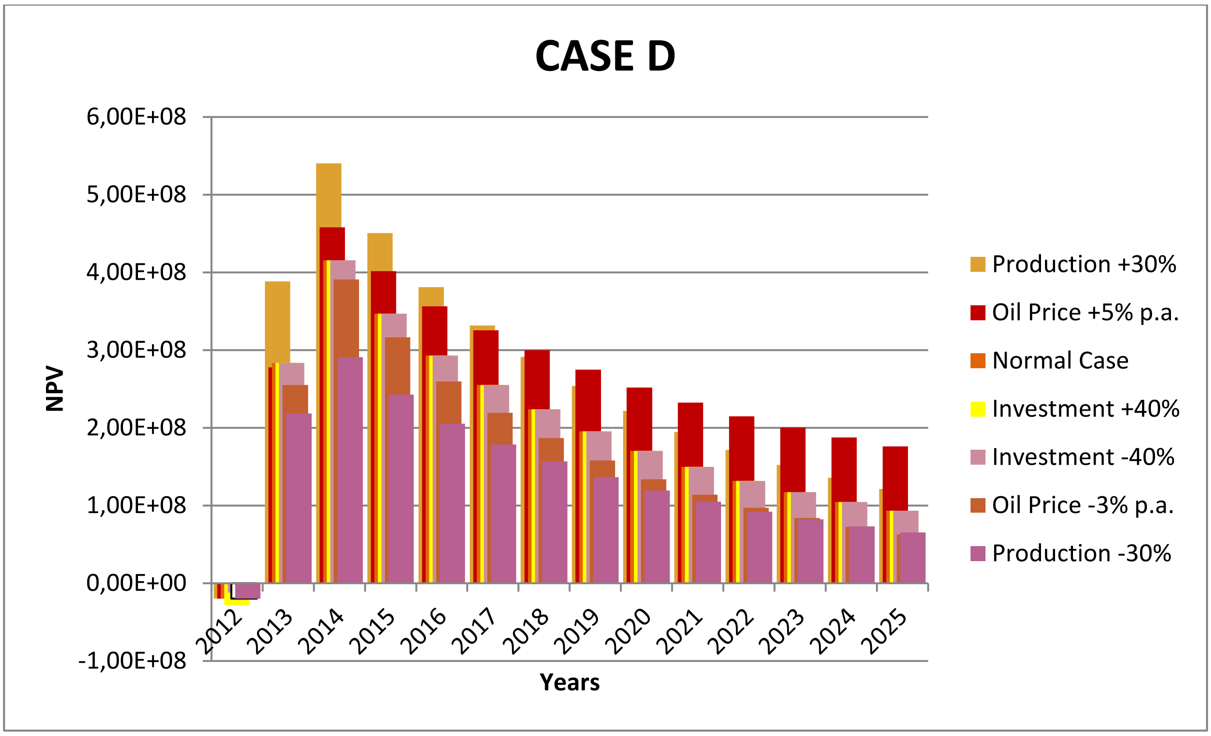
-1,00E+08
NPV
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
Years
Production +30%
Oil Price +5% p.a.
Normal Case
Investment +40%
Investment -40%
Oil Price -3% p.a.
Production -30%


CASE D
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NPV
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
Years
Production +30%
Oil Price +5% p.a.
Normal Case
Investment +40%
Investment -40%
Oil Price -3% p.a.
Production -30%