Enhanced oil recovery with infill drilling at Gullfaks

TPG 4851 – EIT GULLFAKS VILLAGE

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In cooperation with
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Abstract

The Gullfaks field started production the 22. December 1986 and is located in block 34-10 in the North Sea. Today, Statoil owns 70% of the field and Petoro owns 30%, with Statoil as the operator. The field is located approximately 175 km northwest from Bergen and based on numbers from 2007 IOIP was 599 MSm3. According to Statoil 96% of the recoverable reserves has been produced with an expected recovery factor of 61%.

To increase the recovery rate actions have to be initiated, research and studies indicate high potential in the different segments of Gullfaks. Analyzing the behavior pattern and communication between formations and segment can plan a good strategy

One of the major improvements that can be done on Gullfaks is to drill new wells. This project focus on the geology, communications factor and simulation results of the benefits of drilling a new well. Lower Brent in H1 was chosen as the area of target due to the properties of the segment. H1 is relatively isolated from the surrounding segments, which makes it easier to see the impact of the modifications. Lower Brent in H1 has also a fairly low recovery factor.

A new injector and a new production well were drilled with a resulting increase in production. The wells were placed with oil saturation and transmissibility analyzes in mind. By applying pressure support from the new injector, the new production well produced a total of 827 440.80 Sm^3, causing a total enhance in production 447 219 Sm3 compared to base case. When adding the new well, the production from the other wells in the segments decreases. If different IOR measures where applied and further studies carried out the increase in production could have been improved. During the simulation time from 1.1.2012 to 31.12.2024 the NPV value from adding the two new wells ended up at 1300MNOK.

Table of Contents

Figure list

List of Tables

1 Introduction

The report contains a description of the geology and the reservoir quality of Gullfaks mainfield, with a focus on the H1 segment. H1 mainly consists of four different reservoirs; Cook, Statfjord, Lunde and Brent. Tarbert, Ness, Etive, Rannoch and Broom, forms the Brent formation and is divided into upper and lower Brent. Tarbert and Ness is regarded as the upper Brent, while Etive, Rannoch and Broom form the lower Brent. The lower Brent will be the focus for this report.

Increasing the recovery factor on a field has a high economical potential. A summary and ranking of different methods to increased oil recovery (IOR) and effective oil recovery (EOR) that were suggested in the Aam-report are given. The methods are active measurements like injection techniques and more general measurements like economical incentives.

A simulation model in Eclipse of H1, containing the historical oil production and the predicted oil production till 2025, was provided by Statoil. The transmissibility across the faults was then set to zero and the oil production was compared to the original model. To increase the oil production back to the original level or higher were new wells added to simulation model.

Net present value (NPV) was calculated for the case where the wells were added. The price for a new well was 200 million Norwegian kroner (MNOK), the barrel price was 100 $ and the discount rate was 8 %.

2 Literature

This chapter starts the average numbers of the reservoirs on Gullfaks explained briefly, before the reservoir parameters of the Brent group are explained. The main focus in the task is on Brent, so the description of Cook, Lunde and Statfjord is located in Appendix A. The chapter continues with explaining why there are differences in recovery in the segments, before H1 is analyzed. Different methods for increase oil recovery (IOR) and enhance oil recovery (EOR) winds up the chapter.

2.1 Recovery evaluation

Gullfaks has and complex and varied geology through the field with spread recovery factor. The field contains of lots of faults which might be sealing or with limited communication. If one just look at the map, and try to define the different segments based on the faults, there will be a large amount of segments. According to Statoil most or almost everyone are communicating in some way or another [1]. This leads to a difficult challenge trying to determine the transmissibility across the faults. Due to the complex structure and some small segments, is it hard to determine the recovery factor from each segments and the end result might end up relatively far away from the truth. This is because the flow of hydrocarbons might occur between the respective segments.

The goal in the Gullfaks village is to look on different ways how to increase the recovery factor 10 % at the Gullfaks field. The formula for recovery factor is:

$$\mathrm{RF} = \frac{\text{Cumulative oil produced}}{\text{Original oil in place}} * 100\%$$

To try to get more out of the field it is important to understand why there are differences between the formations and the subdivided segments.

In Appendix B are the parameters for reservoir quality explained. As explained in greater detail in Appendix B is hydro carbon pore volume (HCPV) the total volume available for hydrocarbon storage, but not all of this amount can be produced. Hence there is immobile oil left in the segment. By multiplying the HCPV with the RF one achieves the total amount of recoverable oil and gas. But it is not possible to economically produce all of the oil, which is in the reservoir, due to fluid and rock properties. This field of study is left outside this report.

In reservoir engineering there are different kinds of recovery factor. The one expressed in the equation above is the current and producing recovery factor, which describes the achieved recovery to date. The second one in this discussion is the estimated recovery factor, which is defined as:

$$\mathrm{RF} = \frac{\text{Total reserves}}{\text{Original oil in place}} * 100\%$$

In this equation the term reserves is new. The reserves are defines as the amount of recoverable hydrocarbons by use of the planned and projected methods and techniques. The Table 3, in Chapter 2.4, exemplifies this where the total amount of reserves increased from the year 2007 to the yearend of 2011, from 358 to 366 MSm^3 (Million Standard cubic meters). This increase was due to enhanced and improved recovery techniques.

2.2 Isolated segments on Gullfaks.

As mentioned earlier Gullfaks have a complex structure with many faults. All the formations in Gullfaks are divided by the area of drainage, each area of drainage consists of one or more segments (e.g.: F, G), which are divided into several sub-segments (e.g.: F2, F3… G1, G2, etc.).

A drainage area is natural drainage unit of the reservoir, which could in practice have communication with adjacent drainage areas [2]. An isolated segment means that there is no pressure communications or cross flow with other segments. According to the task, isolated segments should be located from the Base Ness map in the Reservoir management plan from 2007. When looking at the map, it is hard to know how many isolated segments there are on the field. Referring to Statoil [1] they guessed around 20. In Figure 1 below, the different base maps applied in the task are given for the different formations.

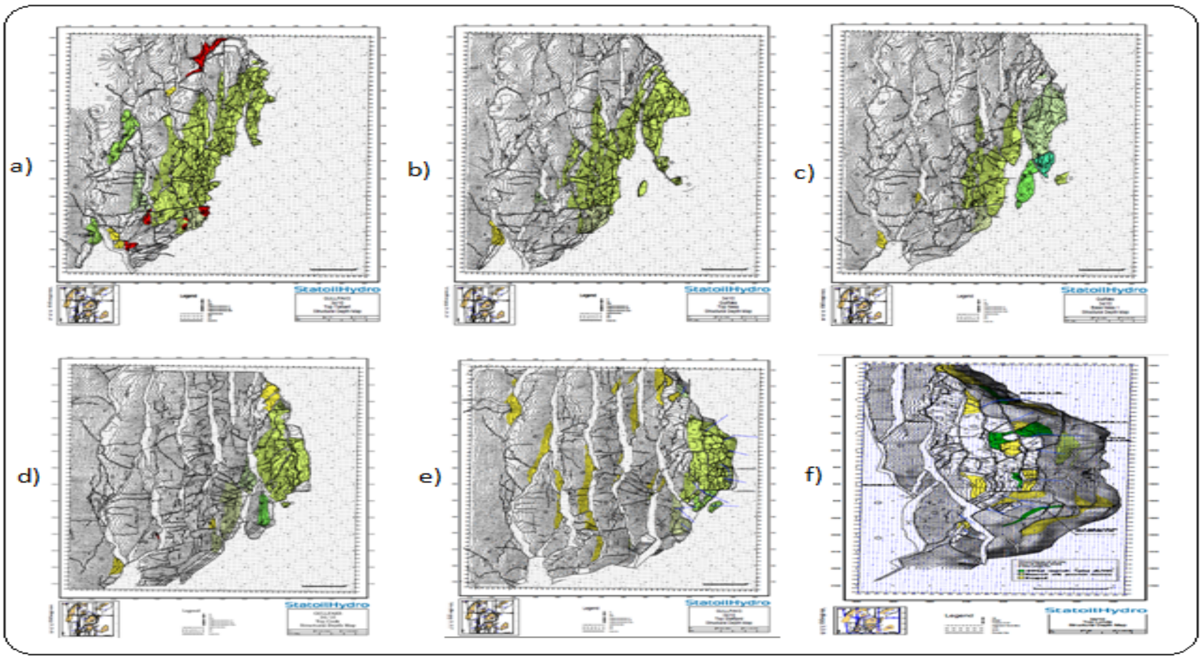

Figure 1 Show the different Base Ness maps a) Tarbert, b) Top Ness, C Base Ness 1, d) Statfjord, E) Cook, F) Lunde

After some time of production it is possible to locate, at some level, which faults that are sealing and which one who are open. To do these analyses, the production, bottom hole pressure (BHP) and other measurements are applied. By only applying the map it is almost impossible to locate isolated segments.

In Figure 2 below an illustration on how the analyzed was carried out is given. When a segment boundary passes through a fault, it was assumed to be isolated in some way in the task.

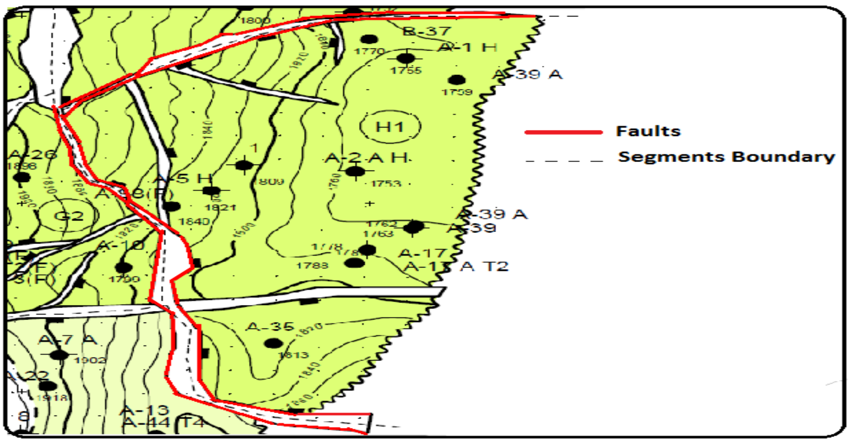

Figure 2 An example of an isolated segment

Some of the sub-segment might be isolated as well, but it is hard to locate from the base Ness map. Table 1 shows the result from the isolated segments from the maps. As the

Table illustrates there are 17 relatively isolated segments in the maps and 83 isolated sub-segments.

Table 1 Different isolated segments on Gullfaks

Formation Gullfaks main field	Isolated Segments	Sub- segments	TOTAL
Tarbert	D, E, I	E1; E2; E3; E4; F1; F2; F3; F4; G1; G2; G3; H1; H2	13
Top Ness	D, G, H, I, U	E2; F1; F3; F4; G1; G2; G3; G7; H1; H2; U1	11
Base Ness 1	D, U	E2; E3; E4; F1; F3; F4; G2; G3; G7; H1; H2;H4; I1; I2A; U1	15
Statfjord	D, E	D1; D2; E1; E2; F1; F2; F7; G1; G2; H1; H2; H3; H7; I1; I3A; K1	16
Cook	D, E, F, G, K	D1; D2; D3; D4; E1; E2; E3; E4; F1; F4; F7; G1; G2; G3; G6; G7; H3; H4; H5; H7; I1; J3; K1	23
Lunde	-	H7; I1; K1; L2	4
Total segments isoltated	17	Total sub-segments	83

2.3 General reservoir description

In this chapter are the different formations that form the Gullfaks main field explained. The formations are illustrated in the stratigraphic column in Figure 3. If one look closely at the figure the different geological and reservoir parameters are described. Impermeable sections have separated the different formations, which reduces the communication between the layers.

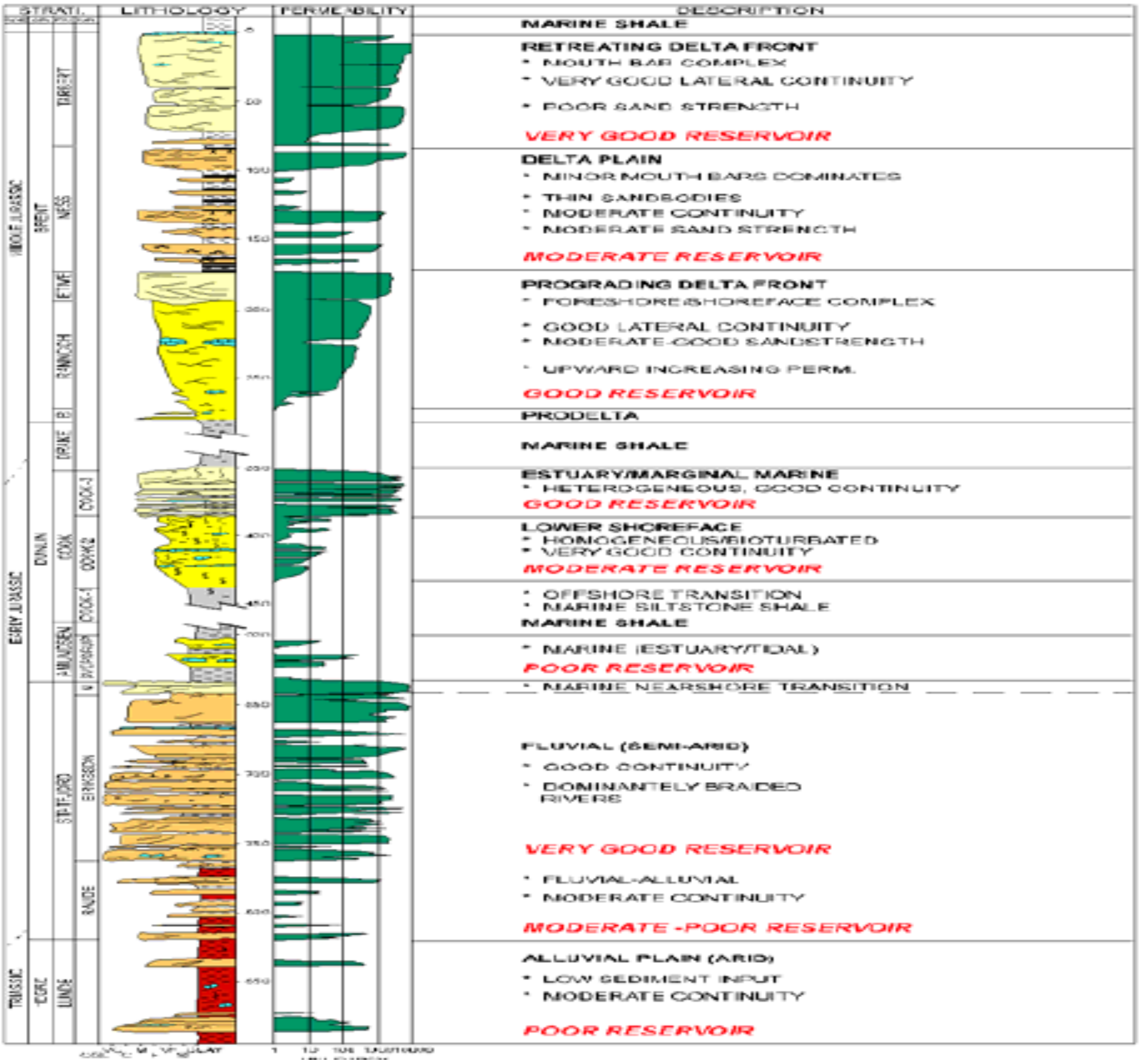

Figure 3 Illustration of the different stratigraphic columns in the Gullfaks field [2]

The different formations and segments on Gullfaks have different properties. Table 2 illustrates Statoil's average numbers on Gullfaks [3].

Table 2 The average reservoir numbers on Gullfaks [3]

Current daily production	14 K Sm^3
Current average water cut	84 %
Initial temperature (1850m TVD MSL)	71 ^0C
Initial pressure (1850m TVD MSL)	310 – 320 bar
Bubble point pressure (1850m TVD MSL)	200 – 250 bar
GOR	100 Sm^3/ Sm^3
Oil Viscosity	0,5 – 1 cp

The geologic understanding of the Gullfaks field is a result of long studies, analyzes and interpretation of several different seismic volumes. Gullfaks is mainly located at the west from the Viking Graben and is a height in the Tampen area. It is a highly complex field due to deformation and changes during the late-Jurassic early cretaceous period. These deformations and changes created an irregular and complex fault pattern. The fault pattern at Gullfaks consists of a domino system with faults block dipping to the west, an accommodation area in the middle and a horst complex to the east, as illustrated in Figure 4 [2][4].

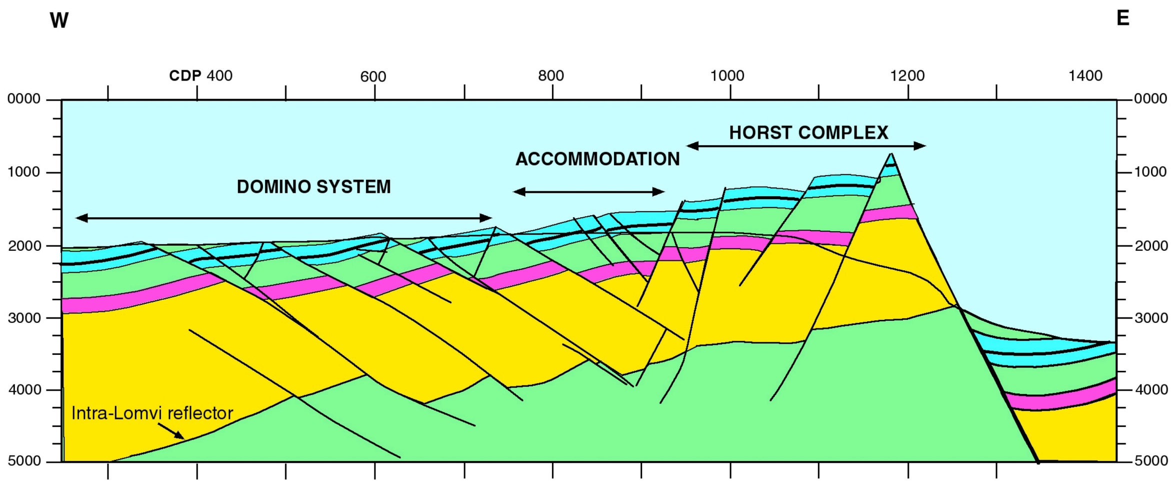

Figure 4 Illustration of the fault pattern at the Gullfaks field [2].

2.4 Brent Group

The Brent group is composed of the five stratigraphic formations; Broom, Rannoch, Etive, Ness and Tarbert, which in order gives the name Brent by the first letter of each formation from below. Figure 5 shows the distribution of the original oil in place volumes (OOIP), 73% of the OOIP volumes are situated in the Brent group, making it an important part of the production on Gullfaks[5].

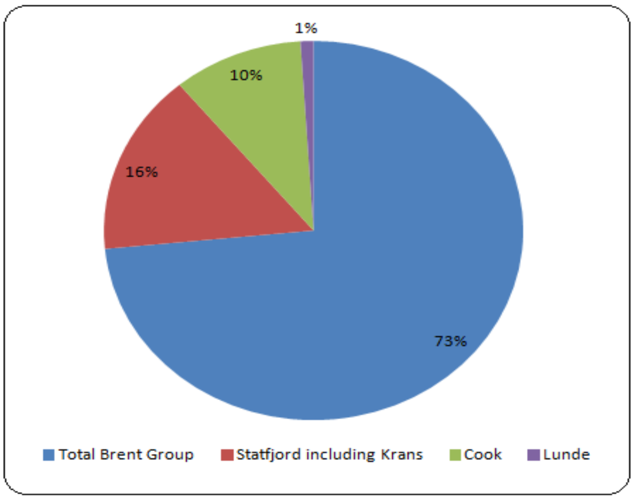

Figure 5 The originally oil in place volumes in the Gullfaks main field

The recovery factor in Brent is 60 %, as seen in Table 3, showing that the quality of the reservoir is good.

Table 3 The status of different reservoir units in terms of in place volume, cumulative production, recovery factor and basic reserves[2]

Formation		In – Place (MSm^3)	Production (MSm^3)31Dec.07	Recovery Factor, current	Total reserves (MSm^3)
Brent Group	Tarbert	198	129	65	135
	Ness	72	41	57	46
	Lower Brent	170	95	56	101
Total Brent Group		440	265	60	282
Statfjord including Krans		93	52	56	55
Cook		60	17	28	20
Lunde		6	0.5	8	1
Total Year 07		599	334.5	56	358
Total Year 11			351,3	59	366

The Brent formations primarily consist of sandstone, shale and siltstone in a sequence order from the middle Jurassic epoch, ageing from about 176 to 161 million years ago. There is overlaying marine shale acting as a cap rock for the Brent. Reservoir pressures and temperatures are in the area of 310 bars and 74 °Celsius and the datum depth is 1850 m in true vertical depth mean sea level (TVD MSL). The first oil discovery was in the Brent formation by the first exploration well 34/10-1, and later wells proved an oil column of 160 m in this group [2].

2.4.1 Tarbert

The Tarbert formation stands for the T in the Brent name, meaning that the Tarbert unit is the youngest formation. Together with Ness, Tarbert form the upper Brent. The lateral continuity in Tarbert is good and the permeability is in the range of several darcys (3-10). The strength of the rock comprising this section is of poor magnitude. Despite the poor rock strength, this gives the Tarbert formation a very good reservoir quality. Some areas of the formation have "Silky Sand", which is an interval of relatively homogeneous and favorable sandstone having the thickness up to 50 meters. This typical sandstone is spread out over the Gullfaks field. The oil reserves and recovery in Tarbert in segment H is 58.2 MSm3 and 70%, respectively, as illustrated in the Table 4 [2].

Table 4 Oil recovery in H in Tarbert [2]

Segment	STOOIP M Sm^3	Recovery				Active Well point	
		As of 1 Aug. 2004		Final		As of 1 Aug. 2005	
		M Sm^3	%	M Sm^3	%	P	I
H	58.2	40.6	70	42.9	74	9	2

2.4.2 Ness

Ness is the other part of the upper Brent. The top structure is in about 1850 meters below MSL, with a thickness of about 90 m. It is a delta plain having minor mouth bars dominating the area, thin sand bodies, moderate continuity and moderate sand strength. This summarizes to a moderate reservoir having thin zones of reservoir height (1-20m) and relatively high permeability up to 1 Darcy in magnitude, but the variation is big. It is a heterogeneous formation with a lot of faults present, leading to a complex communication pattern internally and with other formations. This gives a reduced reservoir quality. Ness has 27.1 MSM3 oil in place and a recovery factor of 61 %, as shown in Table 5 [2].

Table 5 The oil recovery in Ness in segment H1 [2]

Segment	STOOIP	Recovery				Active Well point	
		As of 1 Aug. 2004		Final		As of 1 Aug. 2005	
	M Sm^3	M Sm^3	%	M Sm^3	%	P	I
H	27.1	16.5	61	18.4	68	9	2

2.4.3 Etive

Etive, Rannoch and Broom form the lower Brent. The lower Brent has been proven to be oil filled in the accommodation and domino area of the field. The deposition of lower Brent is often explained as a delta front and beach deposits. The Etive formation consists mainly of huge cross-stratified sandstones. The Etive formation has a relative high grain size. Due to the large grain size of the sand, permeability can vary in the range of 0.02 to 5.0 Darcy. Etive is only about 22 m in lateral extension, but is still acting as a good reservoir. Recovery and resources are not measured in Etive alone, but are included in the lower part of Brent illustrated in Table 6[2].

2.4.4 Rannoch

Rannoch is deposit in the same matter as Etive and consists of sandstones. Rannoch formation is a good reservoir with a large lateral continuity. The grain size is increasing up through the formation and ending in the top with a grain size close to Etive's size. For the permeability in Rannoch is the situation the same, it is increasing up through the formation and ending with almost the same order as Etive. The sand strength in Rannoch is of moderate magnitude. These factors give an increasing reservoir quality upwards. In the lower part there is a more heterogeneous rock, including calcite cementation and high clay content, which reduces the quality of the reservoir.
Oil recovery are, as in Etive not measured alone, but included in Table 6 [2].

2.4.5 Broom

This section is very limited in both vertical extension and its importance for the oil production. The vertical height is just about 6 m and it's a very small part of the Brent group. Table 6 illustrates the reserves and recovery in lower Brent [2].

Table 6 Illustrates the resources and recovery in lower Brent [2]

Segment	**STOOIP M Sm^3**	**Recovery**				**Active Well point**	
		As of 1 Aug. 2004		**Final**		**As of 1 Aug. 2005**	
		M Sm^3	**%**	**M Sm^3**	**%**	**P**	**I**
H1	20.2	11.4	56	12.2	60	1	1
H2	21.1	11.9	56	12.3	58	1	1
H3	0.1	0	0	0	0	0	0
H4/H5/H6	27.4	16.1	59	16.9	62	2*)	2
Total H	**68.8**	**39.4**	**57**	**41.3**	**60**	**5**	**3**

2.5 Difference in recovery

Through the reservoir description, the specific parameters in the respective fluid segments and formations and through the evaluation of the recovery factor it is possible to get a better understanding for the deviation in recovery.

As an example it is possible to look on Table 3 chapter 2.4, it is clear that the recovery factor in Cook and Lunde formation deviates much from the Brent formation. This is consistent with the reservoir parameters telling us that it is hard for the fluid to flow in these formations. In such a situation it demands more effort to make the oil flow in the desired direction and thus giving a lower amount produced. The situation is the opposite in the remaining part including the most of the Brent group and the Statfjord that has much higher reservoir quality.

Speaking of reservoir quality, the reason for the high difference in recovery for the different formations is much due to the difference in permeability. As explained in the reservoir quality section, the permeability is how easy the fluid may flow in the reservoir and is an important factor in production. High permeability makes it easier for water distribution around the reservoir. When the water is distributed evenly the pressure support will be more evenly distributed. Gullfaks have high difference in permeability throughout the field. This makes the water find "highways" where it experiences lowest resistance [6]. In high permeable sands the permeability might be as large as 10 Darcy's (Tarbert), while in other formations as low as a few milli Darcy (lower part of cook). This is illustrated in Figure 6. Because of the high difference in permeability the fluid will move uneven choosing the easiest way. This will lead to pressure differentials and cross flow in different zones.

A fault is a fracture along the formation where two different blocks have moved relative to another. The faulted formation in the Brent Group plays a great part in the recovery at Gullfaks. As mentioned in Chapter 2.4 are the faults a result from the deformation in the late Jurassic/early Cretaceous period. The picture below illustrates how the Brent group is tilted in eastern part of Gullfaks, Figure 6[2].

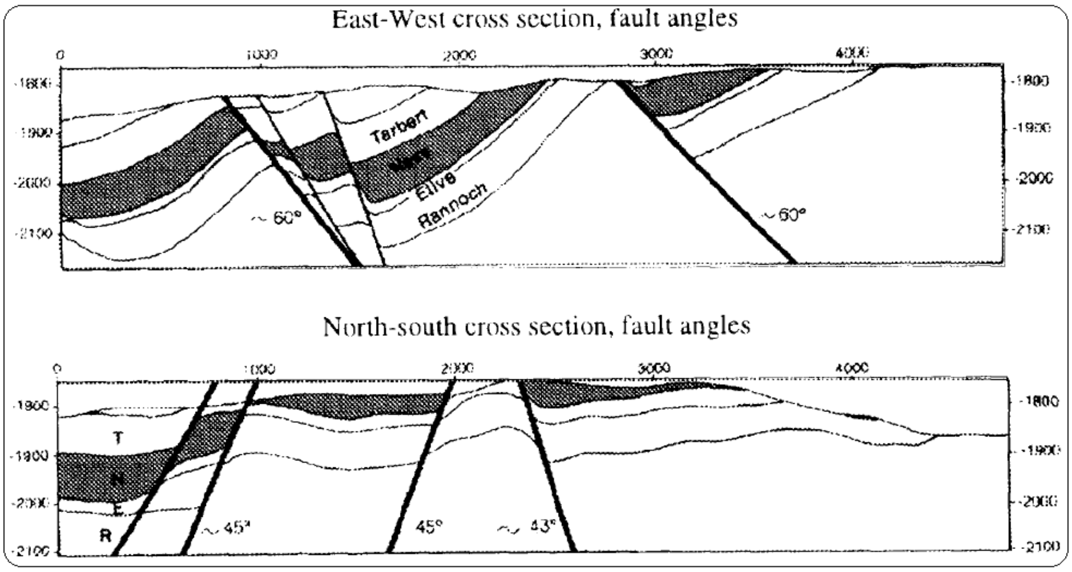

Figure 6 Show the faults in the Brent group in the eastern part of Gullfaks [2]

In general it is possible to suggest that there are two kinds of faults. Some faults may act as barriers, trapping the hydrocarbons, while some faults may increase the communication in the layers. Faults may shift permeable sand layers next to an impermeable shale layer, causing decrease pressure communication and limiting horizontal cross flow. This can also be inverse, giving permeable layers next to other permeable layers, hence the negative effect turns positive. [4] When a sealing fault is present it stops the migration of hydrocarbon and normally creates a structural trap where hydrocarbons can accumulate. This is illustrated in Figure 7 below.

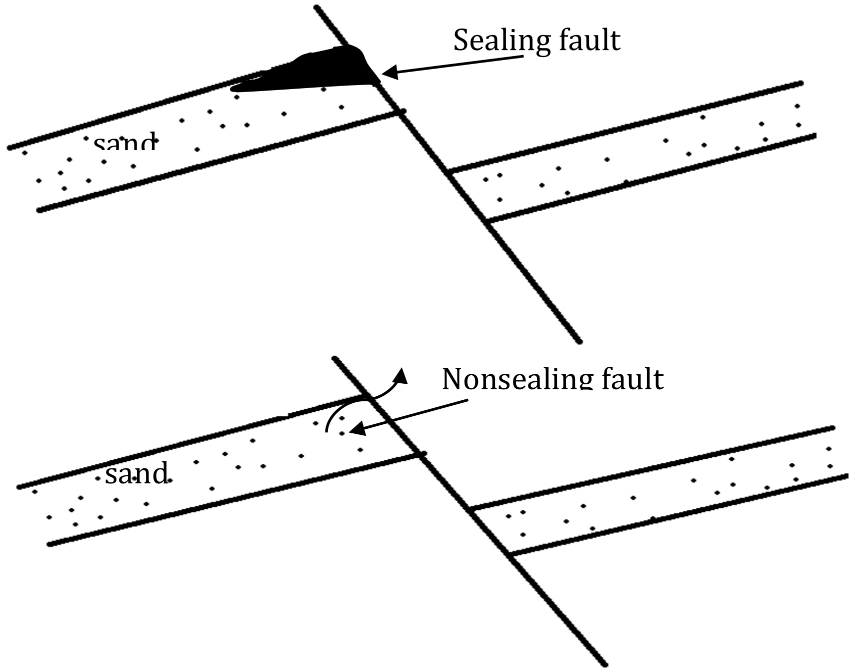

Figure 7 Illustration of sealing and non sealing faults

In the start of the field the Brent group gave an indication of the complexity and faulted formation while drilling new wells. There were high pressure differences internally in the sands. Many of these pressure difference have now even out now, due to the communication across the faults. [4]

These two factors are the ones that have the strongest influence on the variation in recovery, and they make it more difficult for the pore fluid to flow. The parameters describing the formation and the fluid help to predict and understand the flow pattern in the reservoir. They give a lot of information about how the different fluid types will behave in coexistence and thus explain why a difference in recovery is experienced. In addition to the variation in reservoir rock parameters as permeability etc, the geometry of the segments plays an important part. As for any fluid flow, it will be obstructed by irregularities. The ideal condition for lowest pressure loss is a straight line and not having to flow in complex patterns. Meaning that the oil have to travel a longer and more difficult way to get to the lower pressured area close to the producing well. In addition it loses its pressure faster and thus decreasing its lust to flow towards the low pressure zone. The faulting and heterogeneous geological situation in some of the formation described gives this effect.

2.5.1 H1 Segment

The H1 segment was preferred for this project because it is relatively isolated. Since the segment is isolated it is easier to detect the magnitude of the different attempts to increase the recovery. The main mechanism for increased recovery in segment H1 has been water injection, from east towards west. Previously two injectors were used, but now the injection points have been moved from north to south in the segment, giving improved oil recovery, due to the increased sweep effect

The first production on Gullfaks was from H1. Now H1 have three producers (B-37, A-39A and A-38A) and one injector (A-35). A-35 is located in the lower Brent and was in august 2004 converted from a water injector to water and gas (WAG) injector. Due to problems and shut downs, the injection procedures where changed in 2007 to inject gas into the reservoir one month a year. A-39A is the producer in lower Brent. High water circulation in the reservoir causes the well to produce a lot of H_2S. This is a significant problem with the well that sometimes causes a stop in the production. B-37 is partly located in upper and lower Brent, while A-38A is located in the upper Brent [7].

It is proven that there is communication between B-37 and lower Brent, but Statoil are not sure if A-38A communicates with lower Brent. Tracers in the injection from gas injector A-19AT3, located in the G segment, has proven some communication between the G segments and H1 in the Tarbert formation. Measurements have been done in Tarbert which indicates gas flooding. The focus for future recovery has therefore been switched to the Ness formation. [2]

To narrow the project more, the lower Brent is the focus for the project. It was originally 20.3 MSm^3 oil in the lower Brent formation, the reserves is estimated to be around 2-5 MSm^3 and the recovery factor is only 57%. The relative low recovery factor makes the area a good area for pilots [2].

2.6 Drilling new wells

Drilling new wells is the critical factor for the returns on investment when developing an oil or gas field. The cost of a new well represents a significant expense of developing a field, especially the cost of renting a rig. To make the investment more profitable lot of resources have been used and still are used to develop more efficient way to drill. The key is to reduce rig time to save money, making the project more efficient and thereby giving a higher profit. Studies have showed that the Non-Productive-Time (NPT) accounts for 25 % of the rig time [8].

To decrease the NPT there has been some main focus areas [8]:

- Reduce the problem of stuck pipe with better cleaning of the hole.
- Improve the measure while drilling equipment and bottom hole assembly making it easier to detect problems.
- Reduce problems related to lost circulation
- Increase wellbore stability

As mentioned earlier, Gullfaks is a complex field with a lot of faults and pressure differences. This has caused problems both in drilling and recompletion on Gullfaks. The Shetland formation on Gullfaks has been proven to particularly hard to drill. Due to high pressure water injection, bad cementing along water injection wells and re-activation of old faults, the Shetland formation been pressurized to reservoir pressure in some parts of Gullfaks. Statoil have summarized the challenges with drilling at Gullfaks in the following way [9]:

- The window between the pore pressure and fracture pressure are narrow
- There are uncertainty in the pore pressure prediction
- Pressure are varied throughout the regimes
- Borehole stresses due to pressure cycling
- There are operations risks due to depleted reservoir zones

Different solutions have been applied by Statoil to overcome the challenges on Gullfaks e.g. managed pressure drilling and underbalanced drilling [9] [10].

Approximately 70 % of today's worldwide petroleum's production is from mature fields [11]. A pattern, which follows the mature field, is the skepticism to new investment because of the tail production. In other words, to invest large amount of money the plan on the mature fields have to be exact and precise. By using a systematic and thorough plan the mature field would become more effective, hence the net present value of the projects implemented will be enhanced.

Wells on Gullfaks follows typically the same pattern as wells on mature fields in the tail production. The water cuts are high and increasing, while the fields have to gain pressure support from injector wells to be able to produce [12] .

2.7 Methods for increased IOR and EOR

In the Aam-report, which this chapter is based upon, are there suggested different measurements to improve the recovery factor on the Norwegian shelf [13]. The measurements can be divided into two groups, active and general measurements. General measurements are mainly economic incentives that can help to increase the recovery factor on the whole Norwegian shelf, an explanation of them can be seen in Appendix C. The active measurements are different injection techniques and seismic scanning, and their potential for increasing the recovery factor on the Gullfaks field has been ranked, as can be seen in Table 7. How the active measurements works are described in chapter 2.7.1-2.7.7, together with reasoning for their rank.

Table 7 Ranking of potential for active measurements on Gullfaks

Active measurements	Rank
Chemical injection	1
4D mapping	2
Alternativ water and gas injection	3
Huff and puff – injection	4
CO2 – injection	5
Water injection	6
Tailored salinity injection	7

2.7.1 Chemical injection

A general term for injection processes that use special chemical solutions to improve oil recovery. Chemical injection have many advantages, it can remove formation damage, clean blocked perforations or formation layers, reduce or inhibit corrosion, upgrade crude oil and address crude oil flow-assurance issues. Injection can be administered continuously, in batches, in injection wells or at times in production wells. The main disadvantage is that many of the chemicals are listed as environmental damaging.

2.7.2 Reservoir mapping

The Gullfaks field is a complicated field, with many complicated wells. A better picture and understanding of the reservoirs could increase the IOR. 4-D mapping have already been applied to help understanding the reservoirs better, installing seabed cables could be a further improvement. That would make it easier to perform the mapping and leave out the interference caused by the seawater. With better and more frequent seismic pictures would it be easier to understand the behavior of the oil and gas and to understand the geology of Gullfaks.

2.7.3 Gas-and water-alternating-gas injection

Water injection and gas injection (WAG) are alternately injected in an enhanced oil recovery process for periods of time to provide better sweep efficiency. This method could reduce gas channeling from injector to producer, improve hydrocarbon contact time and sweep efficiency of the CO_2. Low gas prices make this method more profitable. The disadvantage is that it is more costly than water injection and requires a more complex operation procedure. A further extension of using foam may be a next step to improve recovery from fields.

2.7.4 Huff and puff gas injection

A cyclic process in which a well is injected with a recovery enhancement fluid and, after a soak period, the well is put back on production [14]. This method could provide cyclic steam injection and cyclic CO_2 -injection. On the other hand is the method costly and has a complex operation procedure.

2.7.5 CO2 Injection

Carbon dioxide (CO_2) is injected into a reservoir to increase production by reducing oil viscosity and providing miscible or partially miscible displacement of the oil. This method belongs to an enhanced oil recovery method, meaning that it can recover the immobile oil to improve the efficiency. The downside is that the method is costly and the cost fluctuates with the price of gas. In addition is there no reliable source in Norway that is big enough, and CO_2 that is not used has to be stored in a safe manner. The lack of a reliable source puts CO_2–injection below WAG and huff-and-puff injection.

2.7.6 Water injection

Water injected into the reservoir to pressurize and displace oil to the producing wells. Injection water can be used in water-storage operations in offshore and remote locations. This method is quite economically, environmental friendly without pollution and is documented to give a good effect. The main IOR mechanism on Gullfaks is water injection, this helps keeping the reservoir pressure above bubble point, though it is not as effective as WAG and other injection methods, thus placed further down on the list.

2.7.7 Injection of water with tailored salinity

Water injection with tailored salinity is supposed to mobilize oil that has not been mobilized by injecting sea water. Injection of water with low salinity could increase production in both laboratory studies and field. The method provides a limited improved recovery compared with other advanced recovery processes, but the costs are relatively low. It is during pilot stage, so it could be risky and some potential issues may exist. The method as tested on the Snorre field in which it had no measurable positive effect in the tested area. Because of it has not given any documented effect is this method placed in last place.

3 Simulation

Statoil provided a simulation model in Eclipse for the oil production at the H1 segment. The model included the historical oil production from 1986 till 2012, and a prediction for the production until 2025. A restart file from 2012 was then made, and the transmissibility across all faults in H1 was then set to zero in the restart file. Setting the transmissibility to zero reduces the fluid flow in the reservoir, and thus reduces the oil production. New wells were then drilled to increase the oil recovery back to the original level or higher.

3.1 Base case

The simulation model from Statoil contained the oil production on H1 from the startup in December 1986 till August 2011. It also included a prediction for how the development of the oil production would be from 2012 till 2025. The simulation with the historical production and the prediction is the base case for this rapport.

As previously mentioned there are now two producers in the lower Brent on H1, A-39A and B-37, and one injector, A-35. B-37 is situated in both upper and lower Brent, while A-39A is in the lower Brent.

3.2 Zero transmissibility across faults

The transmissibility of the faults was then adjusted to zero from 2012 in the base case. It was adjusted in Eclipse by adding the coordinates of the faults and their properties to the data file. The file with the coordinates and properties of the faults can be seen in Appendix E. After the changes were done to the simulation the oil production from 2012 to 2025 was simulated with zero transmissibility. This case is called the closed fault case.

3.3 Adding new wells

To increase the oil production back to the original value or higher was a new producer and injector drilled. The project focuses on lower Brent; hence the well was placed in between layer 24-52 in the grid file. Placement of the new producer was determined by analyzing the oil saturation in layer 24-52 in S3Graf. In Appendix F figures illustrates the oil saturation for a selection of the layers, where the new producer, NW, was placed.

Figure 8 shows the placement off the new production well , NW, and the new injector, INJ, on H1. In Figure 8 they can be seen in the center.

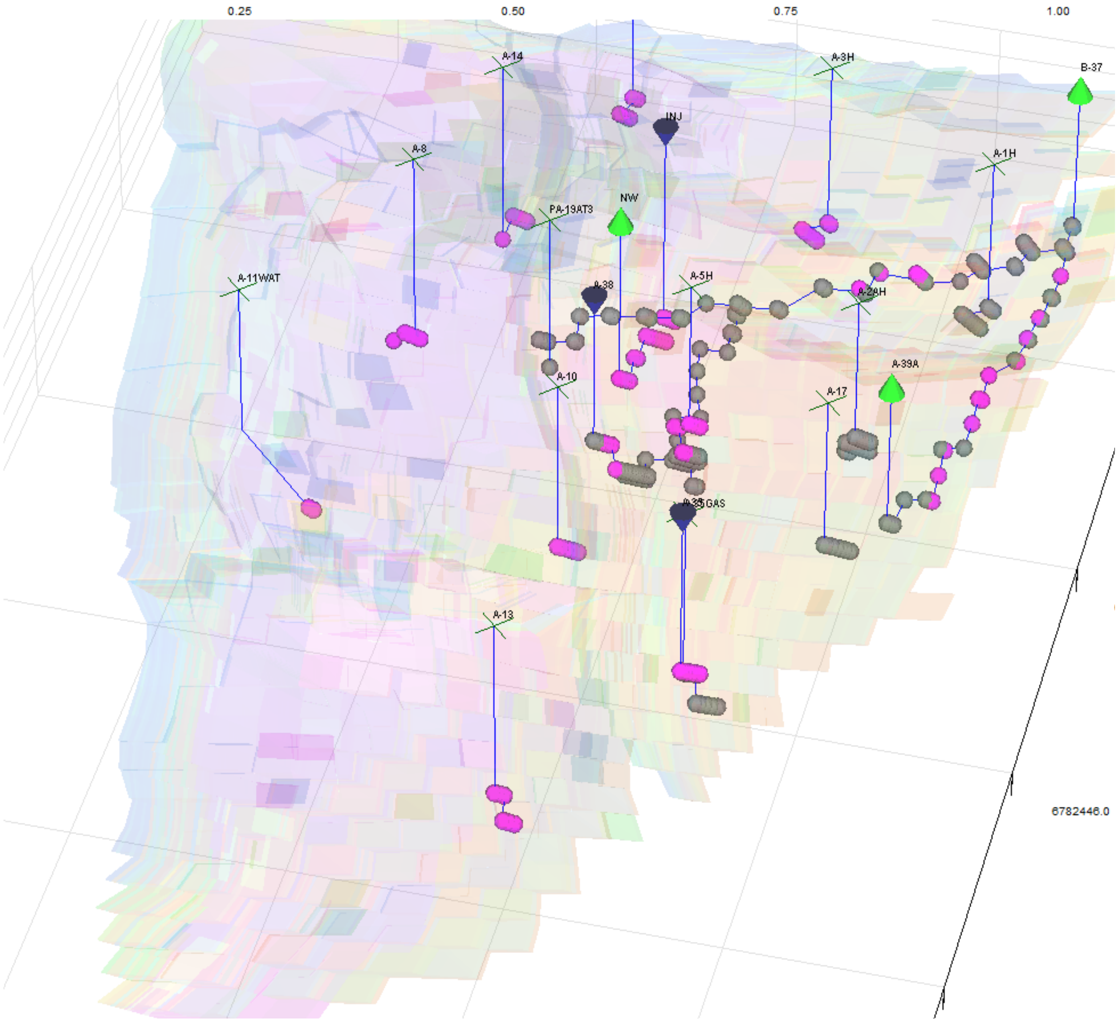

Figure 8 Placement of NW and INJ. In the picture can they be seen in the middle, near well A-38.

The I- and J-coordinates for NW is 37 76. This area is highly impacted by a nearby fault and contained a lot of oil. The pressure in the area where also slightly deviating from the surroundings, due to the fault. This made an impact on the results and will be further discussed in the results. Oil saturation and pressure illustration are given in Appendix F and H.

Analyzing the transmissibility in x-direction around the producer, determine the location of the injector. In Appendix G is the transmissibility in x-direction shown for layer 41 to 45. The addition of new wells to the simulation is called the new well case.

To add a new well and producer in the simulation was a new schedule file, "NEW_INJ.SCH", created. The schedule file contains the keywords for adding new producers and injectors, and setting their properties. 0 contains “NEW_INJ.SCH”. The keywords used in the simulation will now be described.

The new producer, NW, was placed in this area. The keyword “WELSPECS” was used in Eclipse to add NW to the simulation. NW was added to the simulation 01.01.2012. Figure 9 shows how “WELSPECS” was used and the placement of NW.

```
WELSPECS
  'NW'   1*  37  76 1*   'OIL'  7* /
  /
```

Figure 9 The new producer is added to the simulation

NW was placed in January 2012, with the I- and J-coordinates 37 and 76, respectively. The word “ ’OIL’ “ means that it is a producer. NW was then perforated in several layers; the perforation was done in Eclipse as shown in Figure 10

```
COMPDAT
-- WELL    I  J     K1  K2                Diameter pipe
  'NW'   37  76    30  35   'OPEN' 2*   0.178          /
  'NW'   37  75    36  37   'OPEN' 2*   0.178          /
  'NW'   37  74    38  44   'OPEN' 2*   0.178          /
  /
```

Figure 10 Perforations made for the new producer

NW is a vertical well with perforations i layer 30 to 44, and it moves slightly in the J-direction. The diameter of the well pipe is 0.178 m. Production rate and lower BHP limit for NW was given with the keyword “WCONPROD”, Figure 11 shows how the keyword was used.

```
WCONPROD
  'NW'   'OPEN'   'LRAT'   3* 1000   1* 50.000/
/
```

Figure 11 Production rate for the new producer

“ ‘LRAT’ “ means that the production in NW is controlled by liquid rate. The liquid rate production is given as 1000 Sm^3/day and the lower BHP is 50 barg.

To avoid pressure drop in NW an injector was added to the simulation in the first of June 2012. Injectors are added to simulation in almost the same manner as producers. In Figure 12 is an injector, INJ, added to the simulation.

```
WELSPECS
  'INJ'   1*  37  73 1*   'WATER' 7* /
/
```

Figure 12 Adding a new water injector to the simulation

INJ is placed in I- and J-coordinates 37 and 73, respectively, and is a water injector. Perforations, injection rates and BHP are applied to INJ in almost the same way as the producer. Figure 13 and Figure 14 Injection rates in the new injector shows how the parameters are defined in Eclipse.

```
COMPDAT
-- WELL    I   J     K1  K2                Diameter
  'INJ'   37  73    41  41      'OPEN'   2*  0.178 /
  'INJ'   37  73    42  42      'OPEN'   2*  0.178 /
  'INJ'   37  73    43  43      'OPEN'   2*  0.178 /
  'INJ'   37  73    44  44      'OPEN'   2*  0.178 /
  'INJ'   37  73    45  45      'OPEN'   2*  0.178 /
  /
```

Figure 13 Perforations in the new injector

```
WCONINJE
  'INJ' 'WATER'    1*      'RATE'  1000 1* 320 3* /
  /
```

Figure 14 Injection rates in the new injector

INJ is perforated from layer 41 to 45, and has a well pipe diameter of 0.178 m. The keyword “WCONINJE” specifies that INJ injects water at rate of 1000 Sm^3/day with a lower BHP limit of 320 barg.

4 Results

This chapter contains the results from the simulations done in the project. During the project a lot of simulations were done. The most successful simulation is explained in Chapter 3.

4.1 New perforations

Drilling new wells might not be the best way to enhance the oil recovery. It was also decided to look on the impact of optimizing existing perforations in B-37 and A-39A in the lower Brent and adding new perforations. If it is possible to increase the recovery without adding new wells, it would be the preferable option. Two options were simulated and analyzed for increasing the recovery by well re-perforation.

1. In the first simulation re-perforation and opening and shutting of previous perforation was done both in well B-37 and A-39A.
2. In the second simulation re-perforation and opening and shutting was done only in well B-37.

In Eclipse the well trajectory is defined by the perforations. New perforations were therefore not made in the horizontal plane, due to the risk of perforate in a direction that the well was not drilled. It was assumed that the well was vertical from the point that it was created in the data file, even though this might not be the case. Old perforations were shut or closed based on saturation in the zones and some new perforations were made in the vertical plane. In the simulations with re-perforations there were little or no difference from the base case, and if there were some, it was negative. Due to the lack of results it was chosen to not include these cases in the report.

4.2 Base case

Figure 15 below shows the oil saturation in the Base Case in the year 2012. The main focus in the project is H1 located to the right in the grid cell, where the different wells are located.

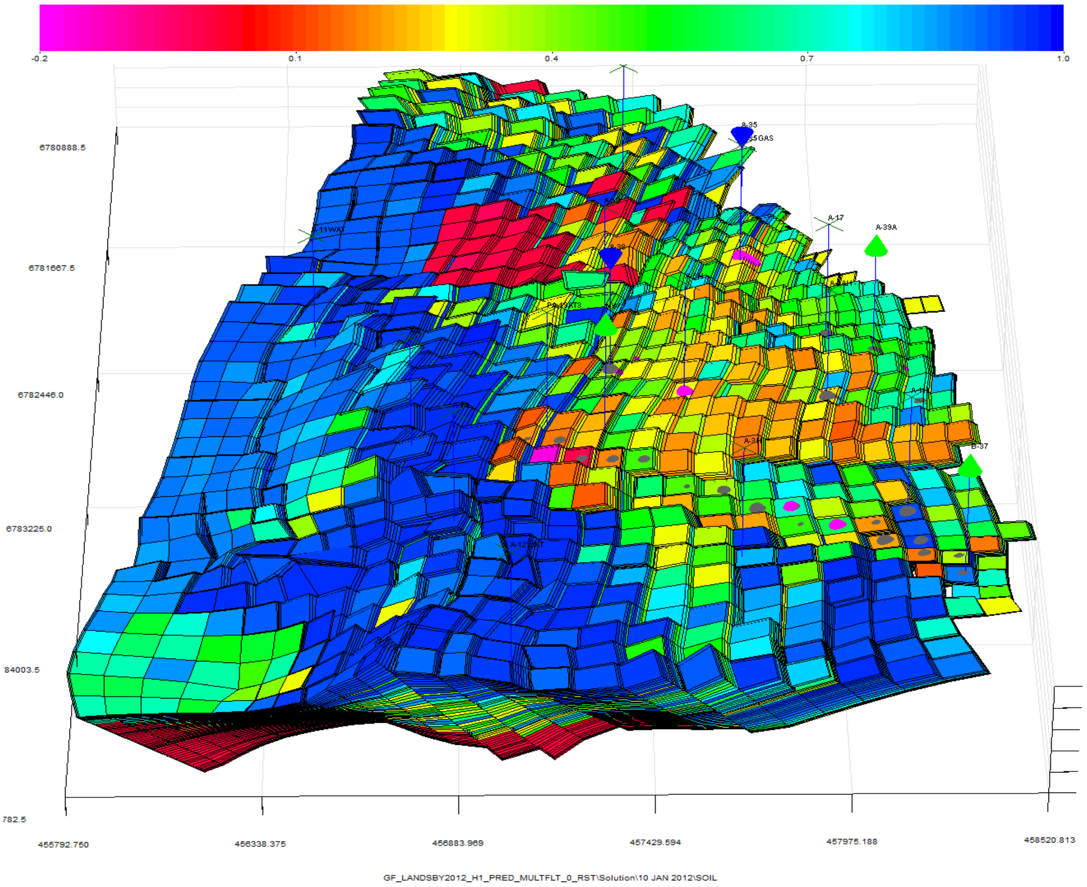

Figure 15 Shows the oil saturation in H1 and some area around it the 1. of January 2012. Strong blue color means that the saturation is 1.

The Figure also illustrates the complexity of the reservoir. The faults and downshift formation, which makes it hard to monitor and analyze how the fluid will flow and behave in the reservoir.

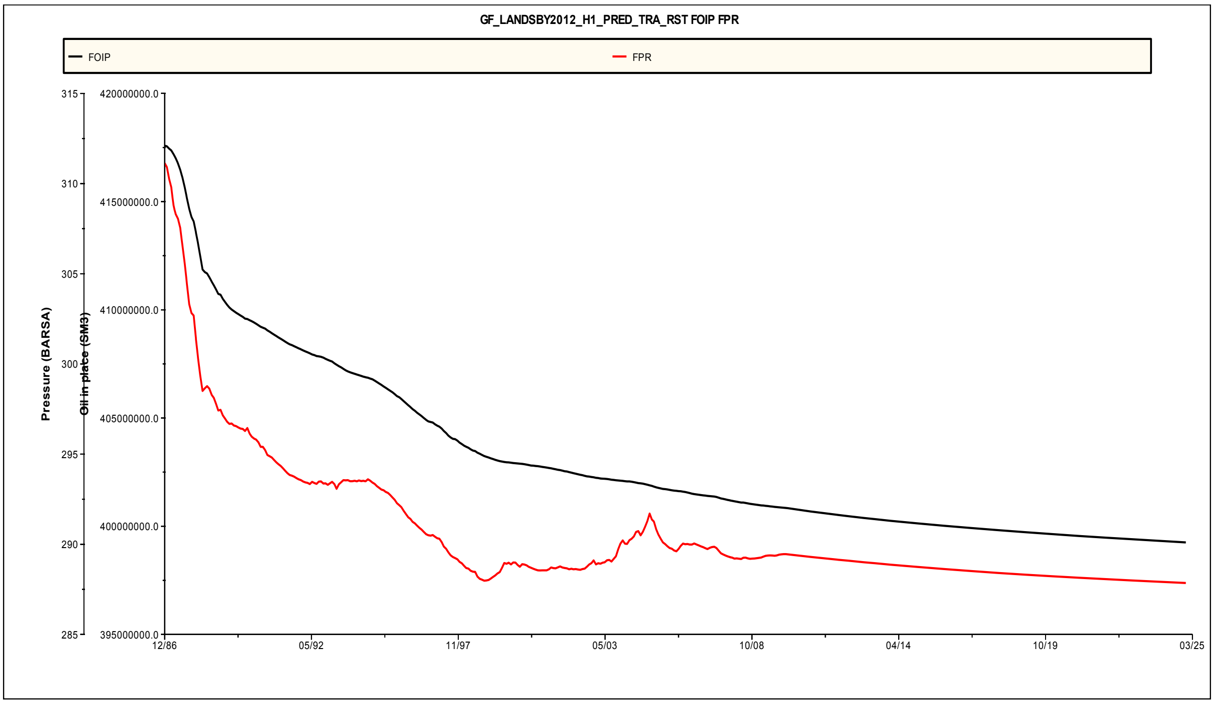

Figure 16 Show the OIP and the pressure in the simulation model in the Base Case. The black line is field oil production while the red is field production rate

According to the simulation model the total amount of oil in place was approximately 4,175 $*10^8$ Sm^3 in place in the reservoir model while the initial pressure was ca. 312 Bar. This is illustrated in Figure 16. It is not easy to define what field is in this simulation, because the amount of initial oil is much lower than the initial oil in the main field, 599 MSm^3, and more than initially volume in H1 [2]. The model is probably made at an early time or some part of the field has not been included.

4.3 Base case versus closed faults case

By closing all faults it's possible to look into how the fluids behave across the different formations, the segments and the impact of the faults. Comparison of pressure profile can give an insight of the path of the injected water. The production of water and oil and the bottom hole pressure (BHP) of the wells were also analyzed. BHP is a measurement of the reservoir pressure near the well.

Assumptions

- Transmissibility across all faults are set to zero
- The effect of closing the faults were checked by comparing well B-37 and A-39A, since they are situated in lower Brent

4.3.1 Oil production

In Figure 17 the differences in production of oil in well B-37 is compared. The total amount of oil produced from 1.1.2012 to 1.1.2025 is 810 000 Sm3 in the base case while the production decrease by almost 25 % to ca. 610 000 Sm3, in the closed fault case.

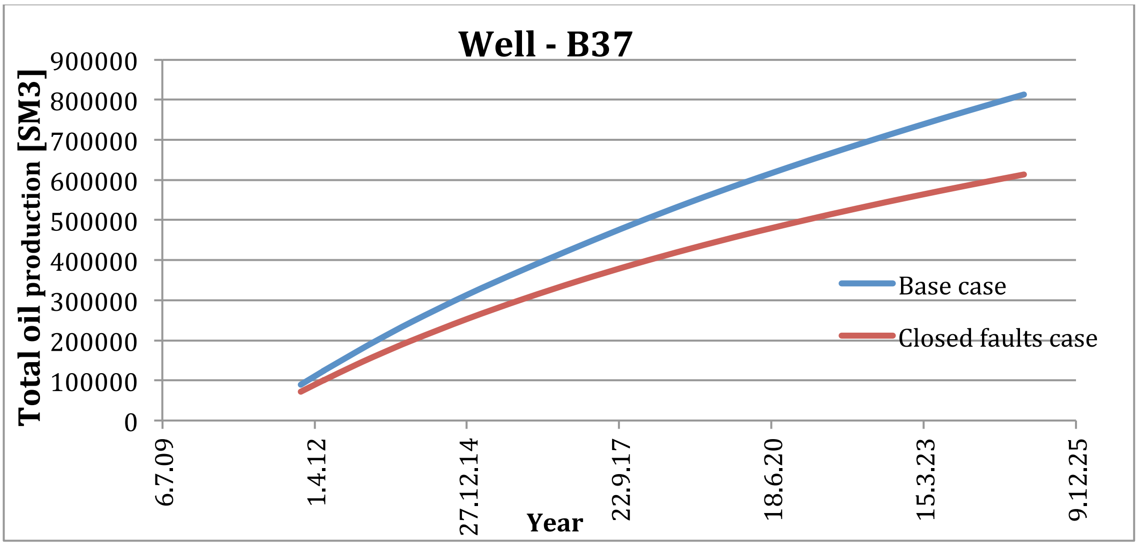

Figure 17 Show the production from Well B 37 in the base case and closed faults case

The oil production in well A-39A when comparing the two cases, as illustrated in Figure 18, follows the same pattern as well B-37. As a consequense of closing the faults, the production of oil decreases from 617 775 Sm3 to 537 096 Sm3, giving a loss in production of around 13 %.

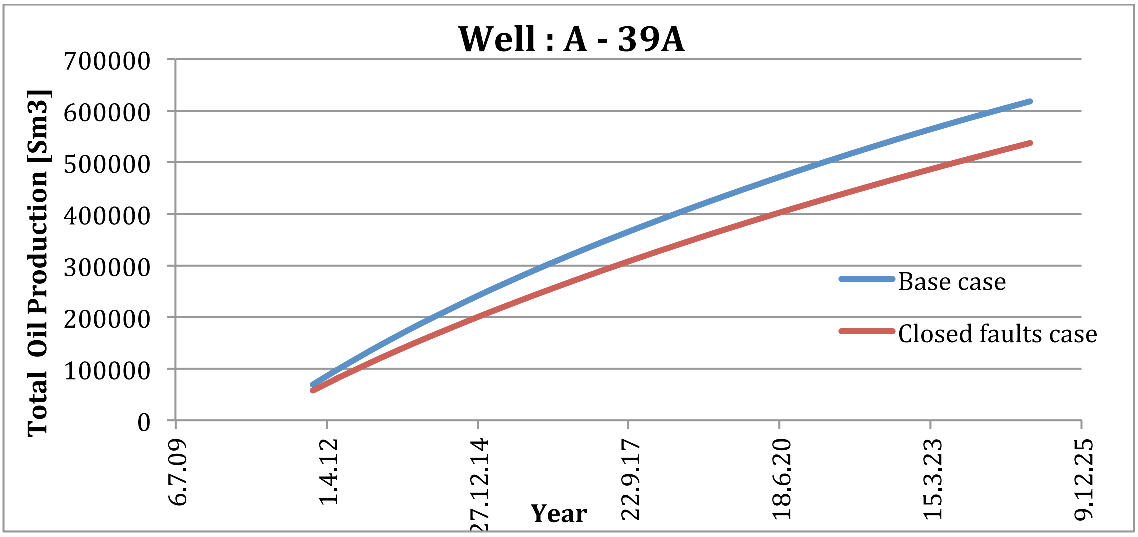

Figure 18 show oil production in A-39A for base case and closed faults case

4.3.2 Water production

Figure 19 show the difference in the water production in the base case vs closed fault case. When closing the faults in the simulation model, water production in well B-37 increases, but not by a significant amount.

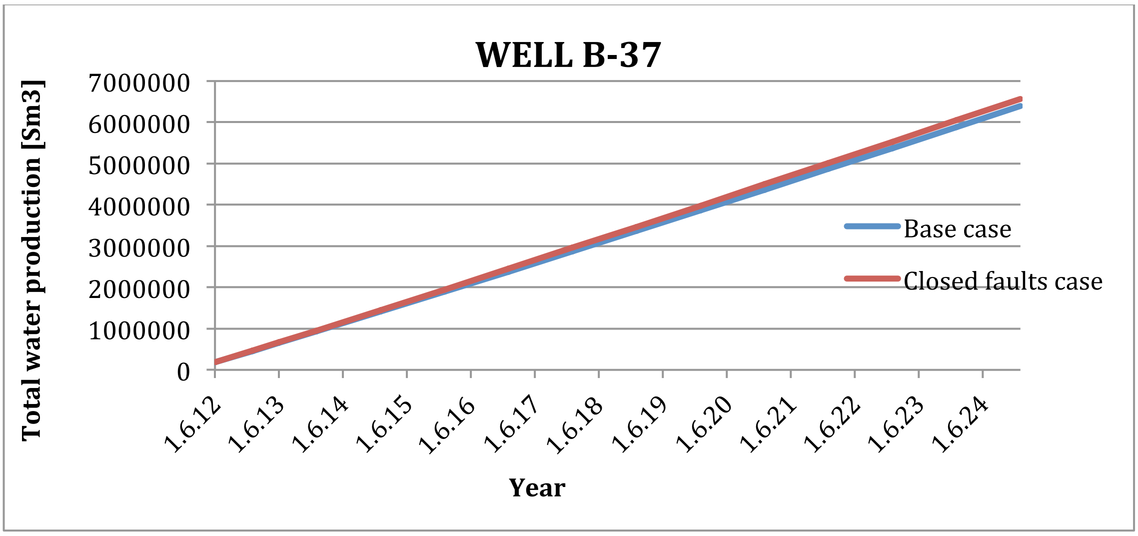

Figure 19 show water production in Well B 37 in base case and closed faults case

Well A-39A follows the same pattern as well B-37. It has the same water production in the start of the simulation, before it starts to increase in the closed fault case by a small amount. Graph 5 shows the development of water production in A-39A.

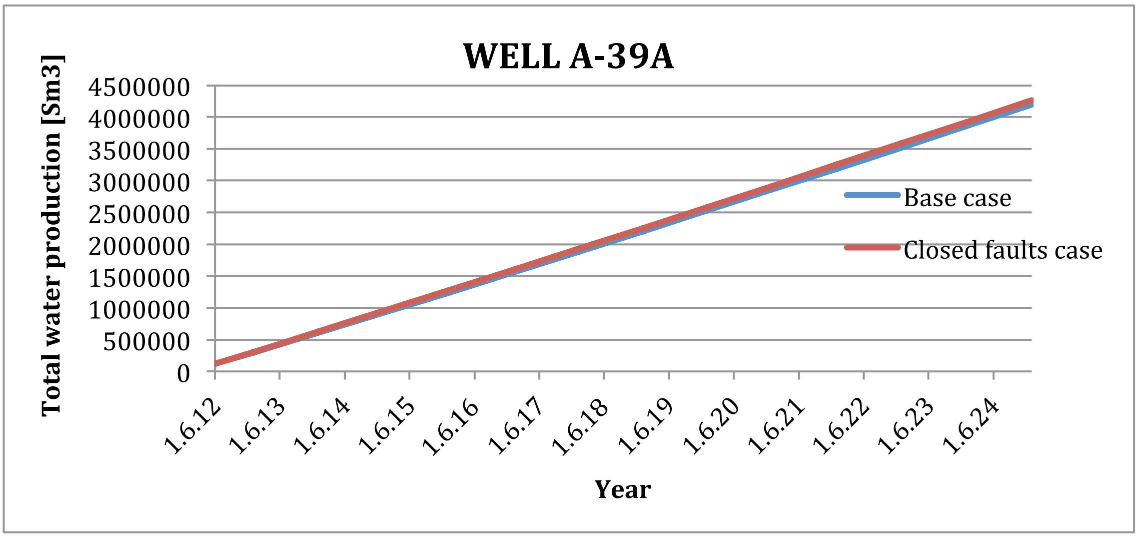

Figure 20 The water production from well A-39A from base case and closed faults case

4.3.3 Reservoir pressure

Figure 21 and Figure 22 shows a comparison of the pressure in layer 29 for the base case and the closed fault case. These figures show how the pressure is lower in the closed fault case due the lack of fluid flow from other segments and decreased pressure communication.. Appendix H contains comparison for more layers.

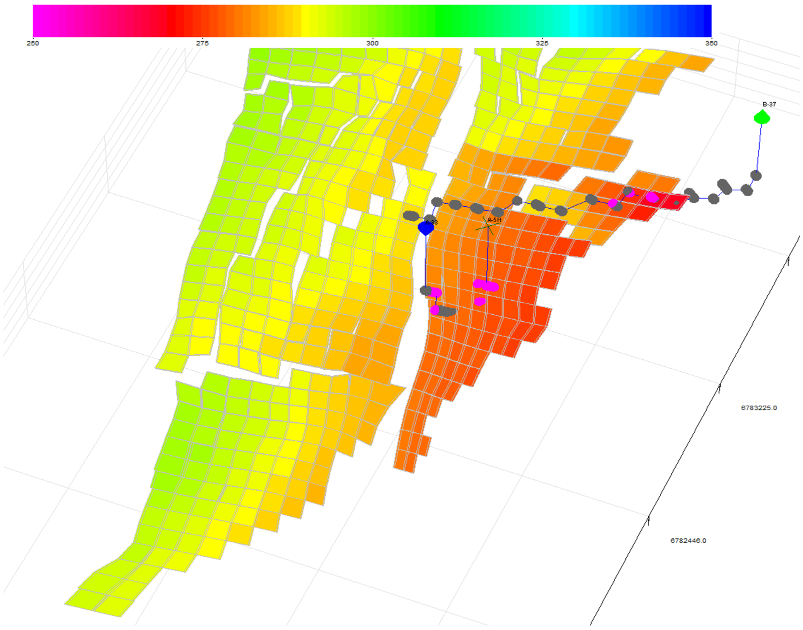

Figure 21 Pressure distribution in layer 29 for base case 1. January 2012. The scale goes from 250 to 350 bar, where strong blue color is 350 bar.

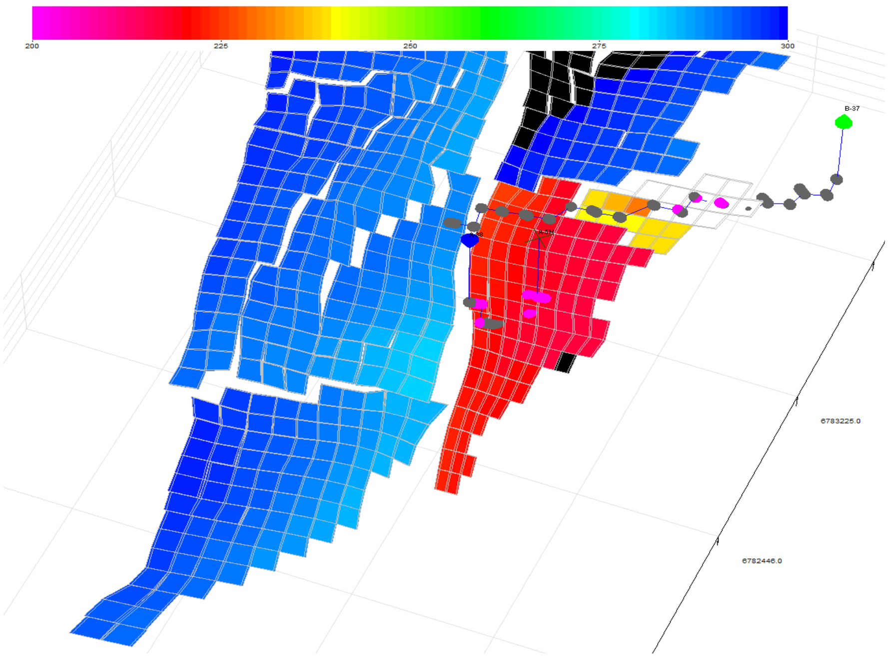

Figure 22 Pressure distribution in layer 29 for closed fault case 1. January 2012. The scale goes from 200 to 300 bar, where strong blue color is 300 bar.

The result from the BHP in well B-37 illustrates how the pressure drops, when closing the faults in H1 and between the surrounding segments. When closing the faults the BHP falls from around 275 bar to around 175 bar, illustrated in Figure 23.

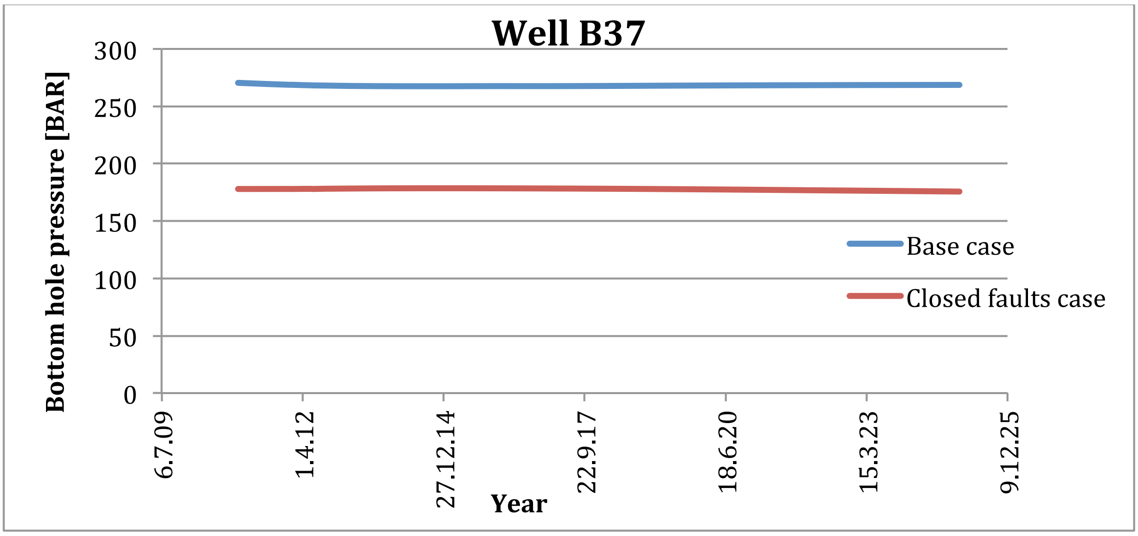

Figure 23 show a comparison of BHP in well B-37 for base case and closed faults case

Well A-39A shows the same pattern as well B-37. The pressure falls from around 250 bar in base case to a little bit more than 200 bar in the closed faults case, shown in Figure 24 below.

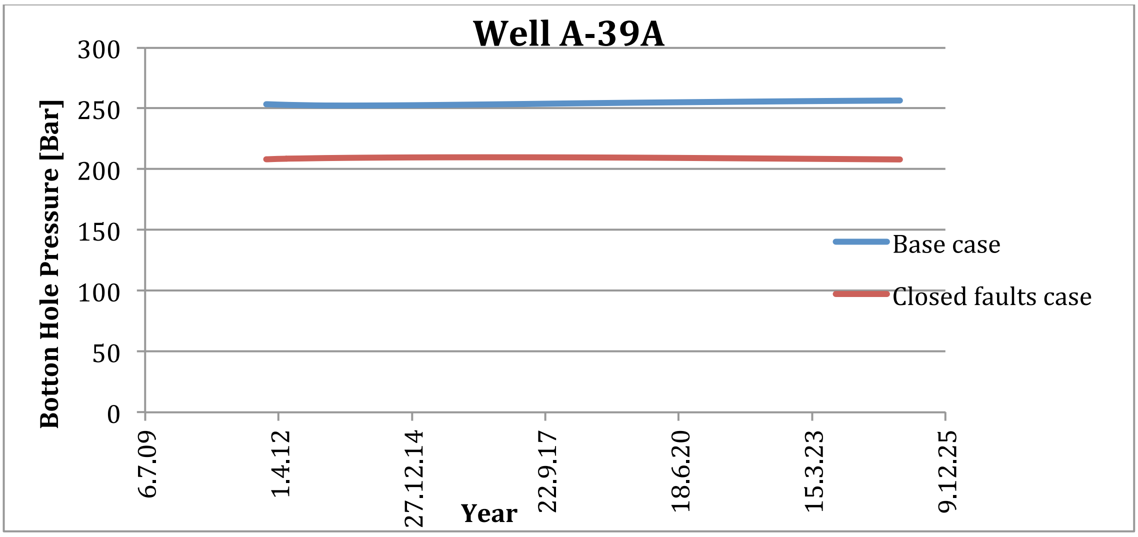

Figure 24 show a comparison of BHP in well A-39A for base case and closed faults case

4.3.4 Summary closed faults

The comparison of the base case and the closed fault case, paints a clear image of the effect from the faults in the Lower Brent, it changes the fluid flow pattern and decreases the pressure in the segment. The pressure decrease is much more in B-37 (ca 36 %) than in A-39A (ca 25 %). Due to extend decrease in pressure in B-37 the amount of produced oil is much more reduced in that well. The decrease in B-37 is almost 25% from the base case, while the production loss in A-39A is 13 % by closing the faults.

The reason for the production loss when closing the faults is that the faults in the segment enhance the fluid flow in the reservoir and that no oil flows in from the surrounding segments. Closing the faults might trap hydrocarbons or at least hinder them from reaching the producers and it reduces the communication in the reservoir, hence the effect from injector well A-35 on especially well B-37 is reduced. Losing some of the effect from the injector reduces the pressure and swipe effect. In other words, the faults have a greater influence on well B-37 than well A-39A in H1.

4.4 Introducing a new well

To increase the oil production in the closed fault case to the level of the base case, a new producer and injector were introduced. The production well was placed according to the oil saturation in the different layers and the injector was added to give pressure support. In the northern part of H1 was there high oil saturation from layer 30-44. The new production well was placed in this area. More information about the I- and J-coordinates can be found in the completion data in Appendix D.

Assumptions:

- Transmissibility across all faults are set to zero
- Comparing well B-37 and A-39A with the previous simulation were done to look on the relative effect of the drilling the new wells.
- The production well should have a production rate of 1000 Sm^3/day and was placed 01.01.2012
- Injector was drilled in 01.06.2012, injecting water at a rate of 1000 sm^3/day.

4.4.1 Results

The new wells are first analyzed by themselves before compared with closed fault case and the base case.

When placing the new well it was expected that it would produce oil until the end of the simulation date. The simulation was carried out, but the well did not deliver enough amount of oil, due to BHP, it needed pressure support from an injector keep the production up. At first the injector was placed in 2015, the producer performance was not good enough, and the injector was therefore placed in 2012, same as the production well. In Figure 25 below, are the performance of the new well described in terms of rate of production of oil and BHP.

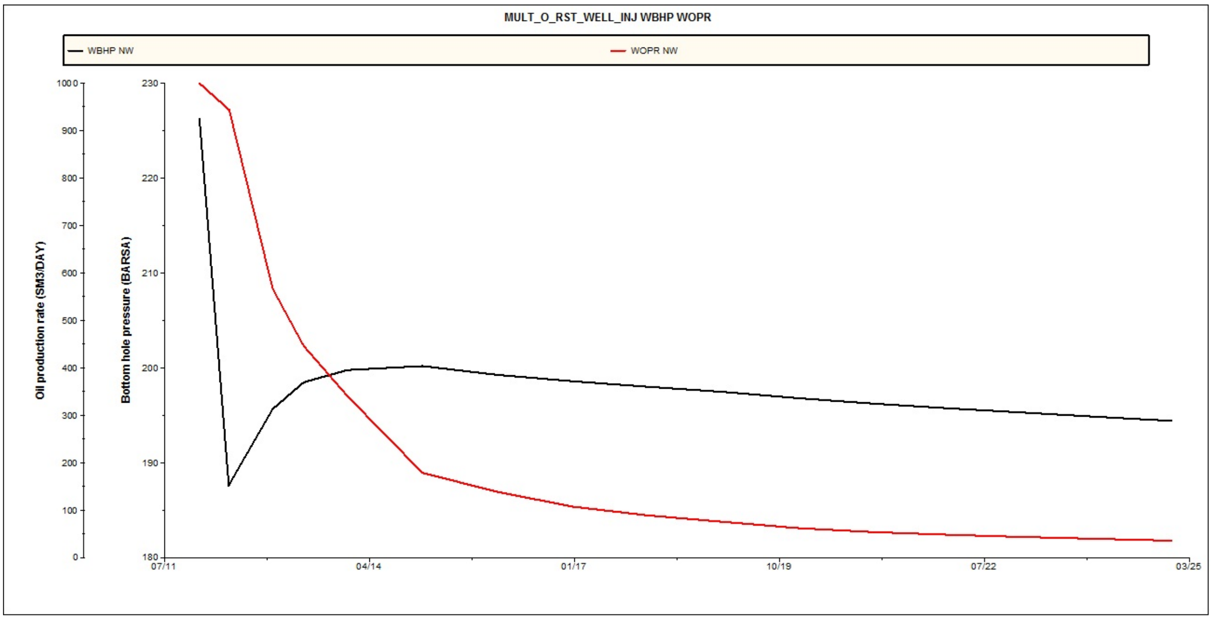

Figure 25 BHP and oil production rate for the new producer. The black line is BHP and the red is oil production rate.

The production in the new producer follows a typical pattern for new producers, with high start production and no water breakthrough. Then the production starts to slowly decrease as the water cut increases. The production limit was set to 1000 Sm^3/day which might have been a little too high. Well performance stimulation and improvement could be carried out to improve the performance of the well furthermore. The BHP also decreases rapidly after startup, before it increases and stabilizes after the injector is placed. The performance of the new well is relatively good. The BHP never falls below 185 bar, while the production rate only decreases to around 50 Sm^3/day in the tail end production. 50 Sm^3/day is a less than both well B-37 and A-39A, but the water cut in the new well is lower than in B-37 and A-39A.

In Figure 26 below, are the performances of the new injector described. As mentioned earlier was the injection volume set to 1000 Sm^3/day, indicated by the red line. The resulting pressure from this rate was approximately 210 bar, which is way below the limiting BHP at 310 bar.

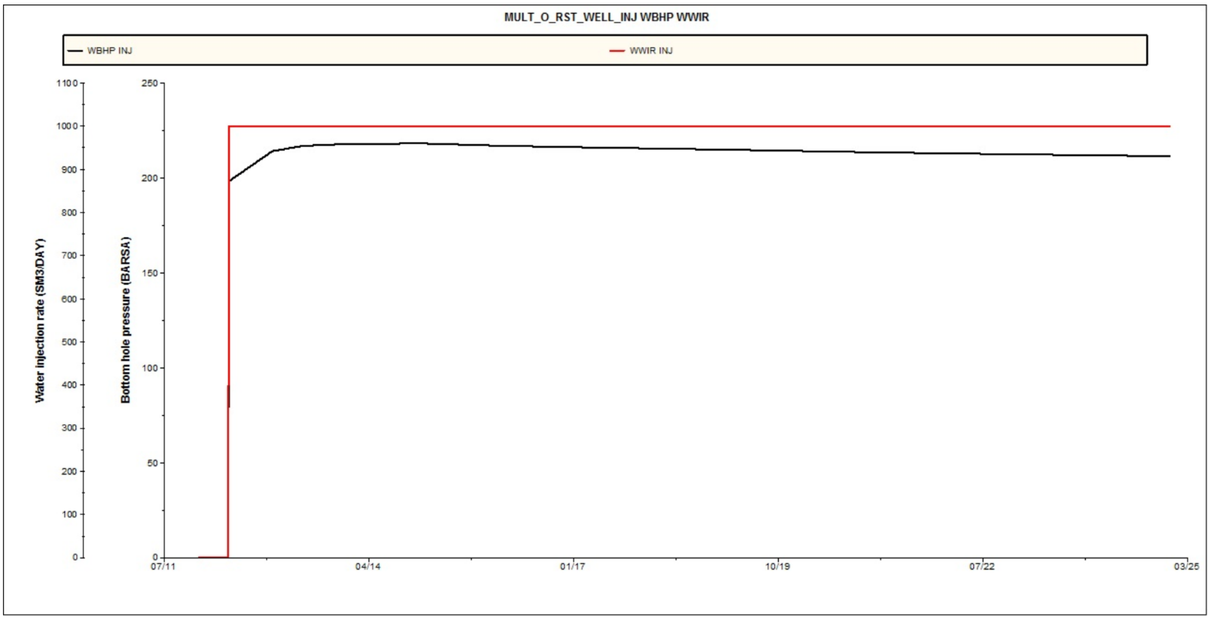

Figure 26 The bottom hole pressure and water injection rate for the injector well

4.5 New well case compared to the closed fault case and base case

A new well in the segment will affect the performance of the existing wells in lower Brent. The total amount of produced oil in the New Well case has to cover the loss of production in the old wells and the drill costs.

4.5.1 Oil production

Figure 27 below shows the difference in production in A-39A in the 3 different simulations.

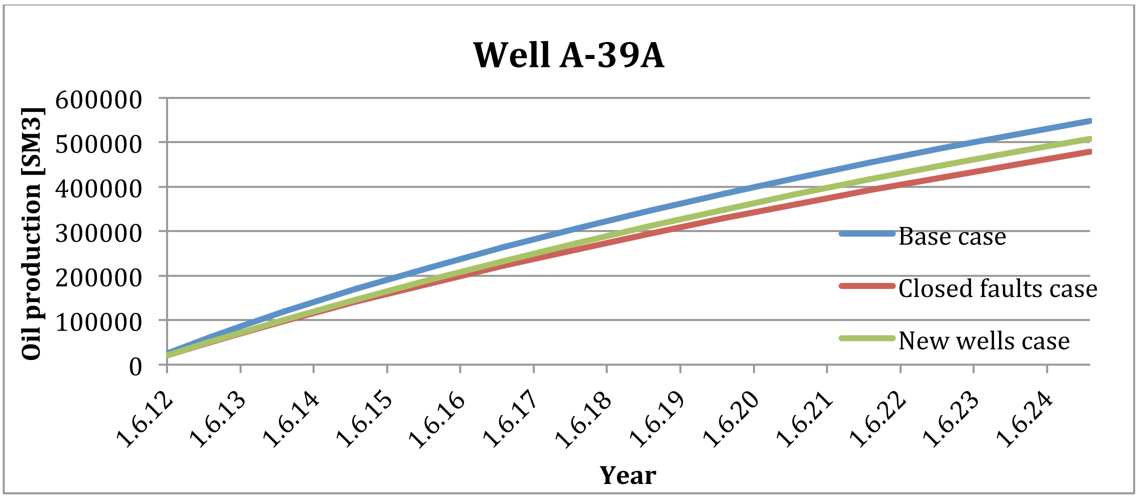

Figure 27 show the total oil production from well A-39A in the 3 different simulations

In the new well case does the production in A-39A increases compared to the production in the closed fault case. The reason for the increased production in well A-39A is that the new injector gives a better pressure support and a better drainage. The increased production in the new well case in A-39A is 40 000 Sm^3.

The production of oil in well B-37 was analyzed in the same way as for well A-39A.

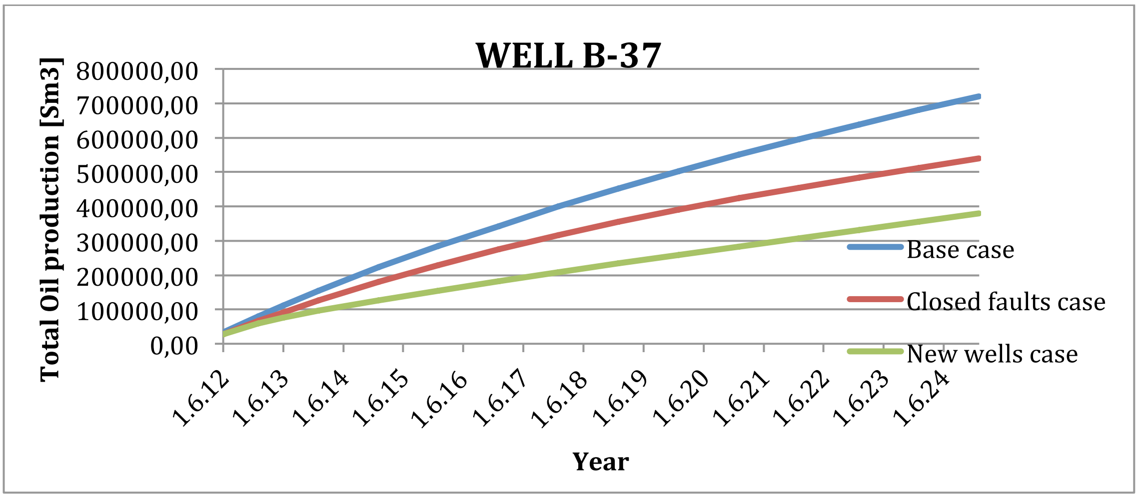

Figure 28 show the total oil production from well B-37 in the 3 different simulations

Well B-37 shows a decrease in production after the introduction of the new producer and injector, as shown in Figure 28. This is most likely caused by the placement of the wells. The reduction in oil production compared to base case is close to 50 %. The new production well are placed relativly close to well B-37 and therefore reduces the drainage area for B-37. The loss in production from the new well case to base case is 340 000 Sm3.

4.5.2 Water production

Making a new injector adds more water to the system. The water production in the new well case were analyzed and compared to the base case and closed fault case. Water production in well A-39A is not change by placing the new injector, as shown in Figure 29.

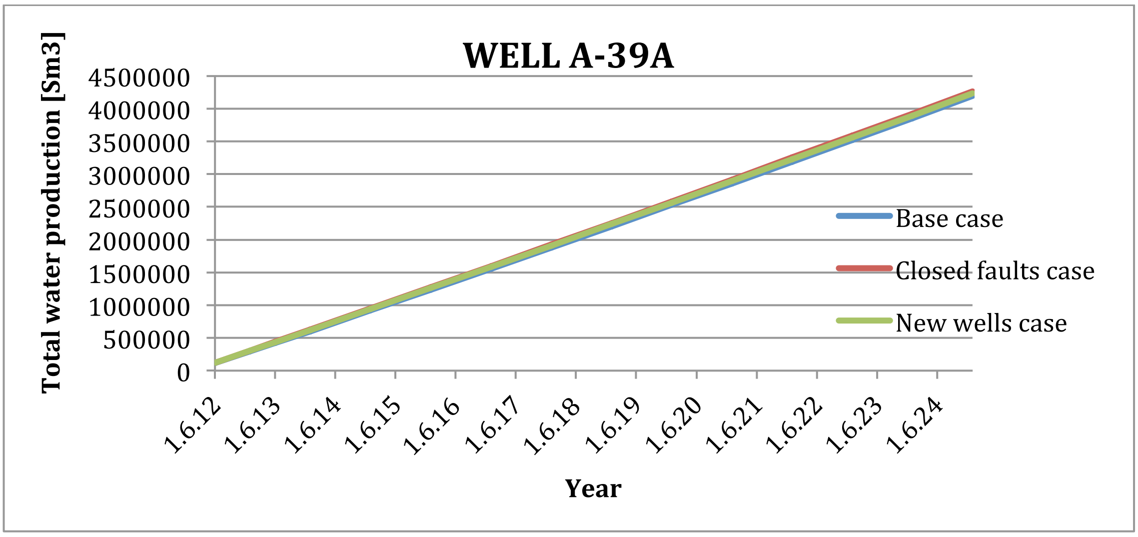

Figure 29 compare the water production in well A-39A in the 3 different simulations

Figure 30, below, illustrates the difference in water production in well B-37. The water production increases by a small amount from the base case to the new wells case. Due to the reduction in oil production in well B-37 the water cut increases in well B-37. Optimization of the production in B-37 could decrease the water cut and perhaps increase the oil production.

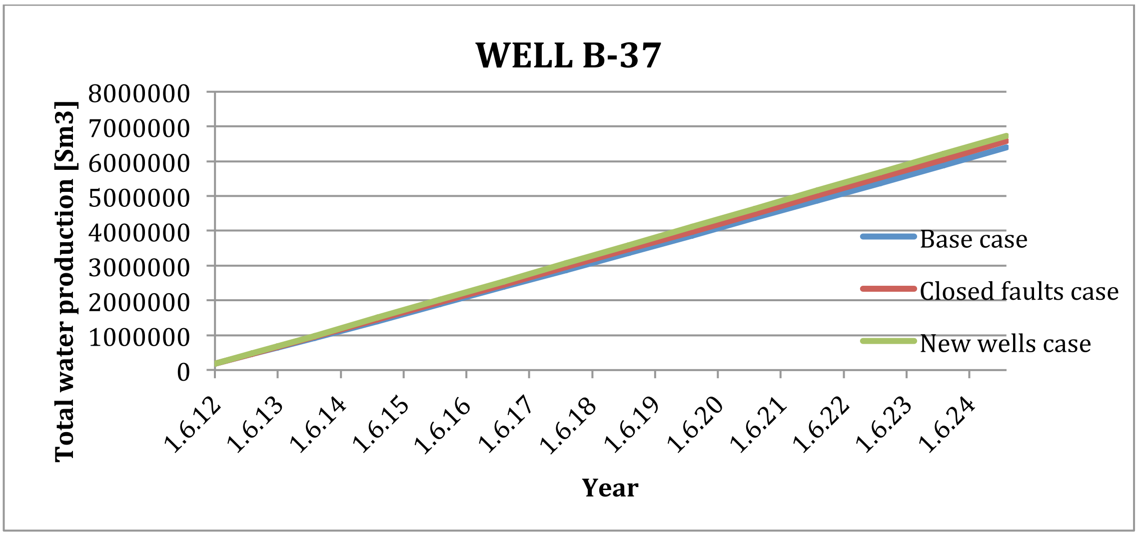

Figure 30 compare water production in well B-37 for the 3 different simulations

4.5.3 Summary of the comparison

The production rate in the new producer falls in the end of production. A constant rate of water injection has been applied in the simulation and the pressure from the injector is significant below the pressure limit, hence it is possible to increase the injection rate after some years.

The new well produce a total of 827 440.80 sm3 by the end of the simulation time, with the given assumptions. Production losses from B-37 and A-39A are approximately 380 000 sm3. The results for the new well simulation are presented in Figure 31 below. The blue column is the total production, while the red color is the difference in total production from the base case.

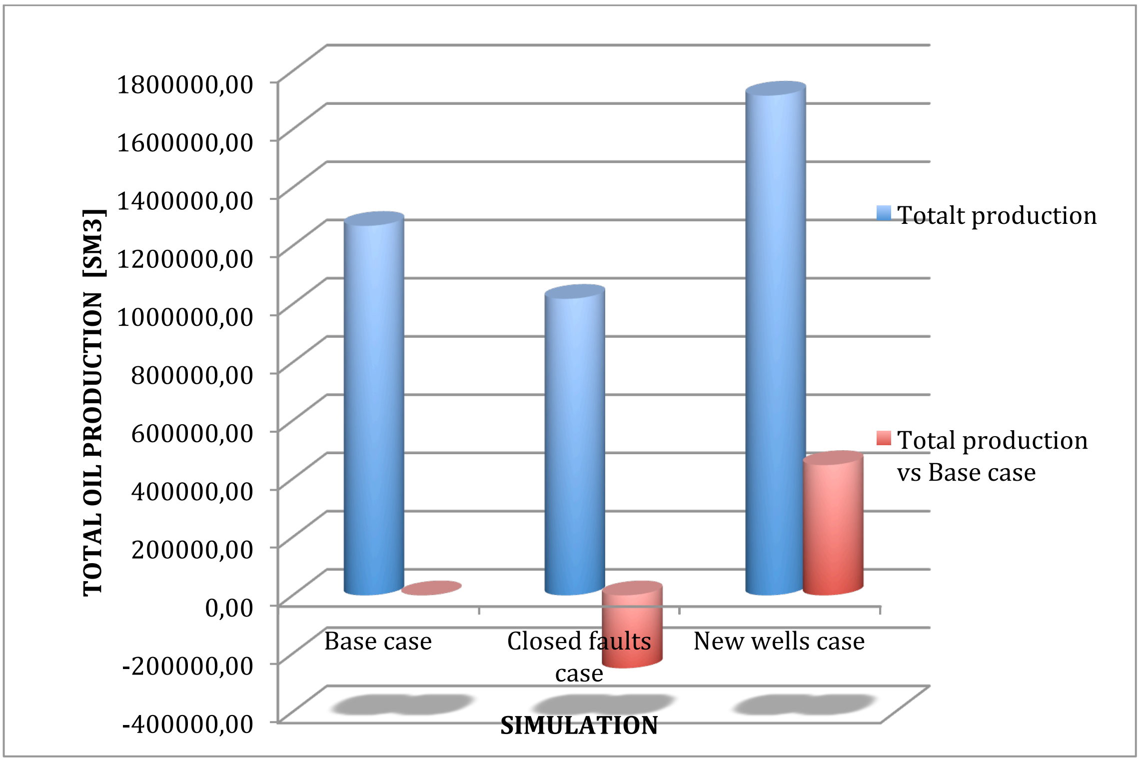

Figure 31 show the total oil production from the different simulations presented in the report

The increase in production by placing the new producer and injector is 447 219 Sm3. The total increase in production is quite significant and the economic potential of adding new wells is done in Chapter 5.

5 Economic evaluation

As discussed in chapter 2.6 and 2.7 there have to be an economic upside for investment on mature fields. IOR on the Norwegian continental shelf is one of the main focus areas from the Norwegian government and Petoro. The 17th April 2012 the minister of Petroleum and Energy, Ola Borten Moe, stated that the Norwegian government is thinking about changing the system for the companies with licenses on mature field. One of the main concerns on the fields is that new production wells are postponed, which might cause a reduced recovery rate. [15]

5.1 Oil price

The oil price is complicated, determined and effective by a lot of factors. After OPEC was established the demand and supply was more regulated, hence the price became more stable and predictable. OPEC is acting as some sort a monopolist in the marked, with the producers outside OPEC as price followers. Even though the price was more stabilized with the establishment of OPEC, it has still varied from 30 USD per barrel to 140 USD per barrel within the last five years [16]

The price of oil is set in London and at NYMEX in New York, for different types of oil, e.g. Brent Crude. Factors that influence the price determination of oil is economic growth, technological development, politic and crises (particularly in the Middle East), consumer behavior and how much oil OPEC and the other producers allows into the marked.

5.2 Evaluation

In this project net present value (NPV) have been applied to calculate the economical aspect of drilling new wells, NPV is the present value of the net cash flows of a project. In other words, by including inflation on returns into the equation you compare the value of the dollar today with the same dollar in the future. If one or more project is on the decision table, the project with highest positive NPV should be carried out. NPV was calculated according to the formula given below

$$\mathrm{NPV} = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t}$$

The constants in the formula are:

- t = the time periode for the cash flow
- i = the discount rate. The discount rate is the opportunity cost of the capital and is set by the financial department in the company.
- R_t = The cash flow for the project. [17]

It is important to note that this economic analyzes is a simplification of the reality. A lot of assumptions have been made during the calculations. Oil price is set fixed at 100 USD while the cost of a new well is 200 MNOK. The well cost is probably way to low, while the oil price is hard to predict. The value of dollar have been set to 5.75 NOK per 1 USD and the discount rate at 8 %. In Norway is the petroleum tax set to 78 %. In the main analyzes are taxes, depreciation and operational cost not included in the calculation, which makes the results just an indication of the real NPV.

Due to the many uncertainties related to both the production and economic aspects it is hard to form a reliable sensitivity analyzes. Factors that have been altered in the two sensitivity analyzes are:

- Oil price set to 90 USD per Barrel
  USD = 5,5 NOK
- Production decrease of 5 %
  USD = 5,5 NOK

Since the production is falling in B-37 and A-39A, the economic analyzed have to been looked on relative to not drilling new wells in H1. The total production from the formula below:

$$Relative\ production = Production\ with\ new\ wells - Production\ Base\ case$$

5.2.1 Results:

As the production indicates, the earnings in the first years are much more than in the last year of the simulation. Looking relatively on the results, the discounted cash flow becomes slightly negative in 2017. The calculated cash flow is shown in Figure 32 below.

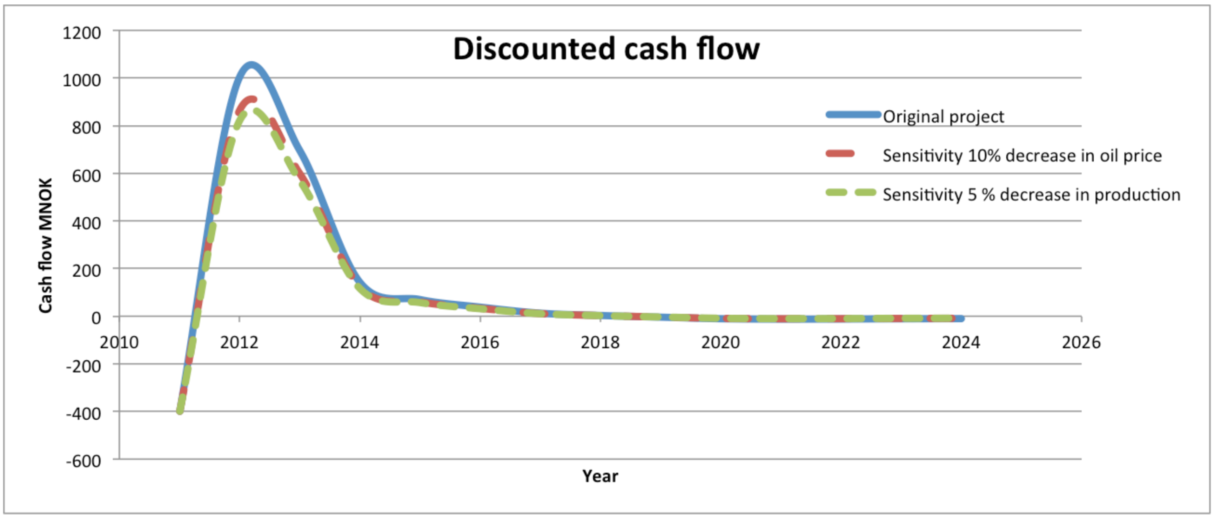

Figure 32 show cash flow and sensitivity analysis for adding the new wells

As Figure 32 illustrates a combination of decreased dollar value compared to the Norwegian krone with 10 % fall in the oil price causes less impact on the cash flow than the decrease in production of 5 % combined with the decreased value of the NOK.

The positive contribution on the NPV is as the cash flow indicates, in the startup. Relatively there is not much increase in production after 2017. The project, with the assumptions applied, has a positive NPV, in total the NPV is 1 300 MNOK, as shown in Figure 33.

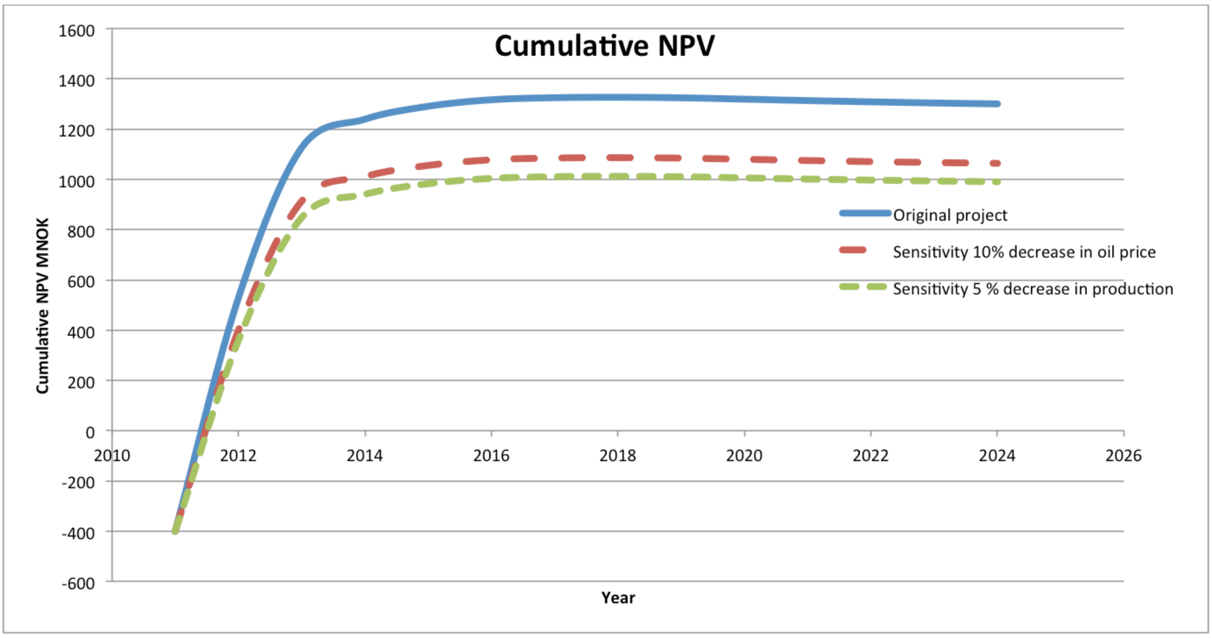

Figure 33 shows NPV and sensitivity for the NPV analysis

As the discounted cash flow indicates, alternative 2 have a higher impact on relating to the sensitivity of the project on. A decrease in oil price of from 100 to 90 compared with a dollar price of 5,5 NOK per USD, results in a NPV of 1063MNOK. By decreasing the production with 5 % and a dollar price of 5,5 NOK per USD the NPV of the project is 990MNOK. The decrease in NPV from the production fall is severe and can become a reality if there are severe problems with one of the wells drilled, and something that have to be in mind in the decision process.

6 Discussion

The underlying attempt in this project was to increase the recovery rate on Gullfaks by 10 %. Hence by producing 450 000 Sm^3 there still a long way to go. The results in this project have to been looked upon as a suggestion and an indication of the potential of extracting more oil from lower Brent in H1.

Optimization of the injector could have improved the simulations results significantly. It could have been placed further away from the producer, in a lower layer and also have increased injection rates. Transmissibility studies indicated that the well should be very close to the producer, but its position could have been optimized further to improve the results. Drilling the injector well deeper could enhance the production rate. If the injection rate had been increased, especially after year 2017, the total value of the project could have been higher. Higher injection rates would increase the pressure in the surrounding wells and most likely improve the sweep effect. The potential for increased rate in the injector is high given the BHP of 210 bar, while the pressure limit is set to 310 bar. Another factor, which could improve the total production, is to increase the injection rate from the other injector, A-35, in lower Brent causing the same positive effect as mentioned for the new injector.

The trajectory for the injector well is strictly vertical. By drilling a horizontal injector well the oil recovery would likely increase. A horizontal injector would be able to provide pressure support a greater area, not just the new producer. Giving increased production in B-37 and A-39A. Drilling a horizontal injector is considerably more expensive and complicated than drilling a vertical injector, but could also provide a greater economic benefit. If the injection technique and/or fluid properties were altered, there might also be positive effects.

In discussion with Statoil it was decided to drill the production well relatively vertical, as the injector, to simplify the task. In the reality a horizontal well would most likely be the preferable choice. Drilling a horizontal well would increase the drainage area due to the extended well length. The well placement will be placed more accurate according to the oil layers causing the well performance to increase. The downside is that a horizontal well is more expensive.

Many of the wells drilled on Gullfaks are Diacs wells. A Diacs well are able to close production from zones, which produce too much water. The WECON commando in Eclipse is the same as placing a Diacs well. The command closes the perforation which produces more than the limited water cut. This could have been used to optimize the production well, but a Diacs well is also more expensive.

The project and simulations contain high uncertainties with regards to the numbers and simulations carried out, which is important to have in mind. The major uncertainties can be listed up as:

- It is hard to calculate the total increase in recovery. The numbers in hand are from 2007 and in the simulation model it is hard to narrow down the area of relevance.
- By closing the faults production, saturation, pressure, etc changes from the base case with faults open. If the wells were placed in simulations with the faults more open it would cause a totally different result.
- The injector well trajectory is drilled vertically, while the production well is drilled almost vertically. This would not be the case in the real life
- Well cost are really low and it is assumed that there will be no complications, with respect to drilling and production, in none of the wells. A-39 can be closed down, due to the H_2S level. Problems like this have been neglected.
- Tax and operational costs have been neglected from the economical analyzes. Petroleum tax is 78 % in Norway and by applying this in the analyzed would cause a significant impact.

7 Conclusion

Oil production in the H1 segment on Gullfaks was simulated in Eclipse. A comparison was then done on what the effect of zero transmissibility across the faults in the segment, would be for the oil production, and where new wells could be placed to make up for the lost production.

When the simulations were carried out, following results were obtained. The production in the base case in A-39A and B-37 was 617 775 Sm^3 and 810 000 Sm^3, from the 1th of January 2012 till the 1th of January 2025. With zero transmissibility did the production in A-39A drop by 13 % till 537 096 Sm^3 and in B-37 it dropped by 25 % till 610 000 Sm3. The total production from the well was 827440.80 Sm3 during the production time. Production in A-39A and B-37 in the simulation with the new producer is 507754 Sm^3 and 380437.90 Sm^3, respectively which the New wells have to account for.

According to Statoil there are 2-5 MSm3 of mobile oil left in reservoir with an initially STOOIP 20.3 M Sm^3 and recovery rate of 57 %, ref chapter 2.4. These numbers are from 2007 and to use the numbers to calculate the recovery would be incorrect. Assuming that there is around 5M Sm^3 of mobile oil left, an increase in production of around 450 000 Sm3 by placing a new well, is around 10 % of the mobile oil left. The enhanced oil recovery causes a positive NPV of 1 300 MNOK for the project.

When analyzing the results it is good, but need improvement to be carried out. The potential in lower Brent in H1 is high. Due to the high uncertainties in this project, it has to be looked upon as an experiment/suggestion on one way to increase the recovery.

Even though the high uncertainties, this project visualize the potential of drilling one, two or even more wells in lower Brent and even other segments on Gullfaks. By applying some of the suggestion in the discussion and complete more analyzes the recovery rate, hence the lifetime of the field can be extended.

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Appendix A: Cook, Lunde and Statfjord

Cook

The Cook formation is divided into three sub parts, the Cook-3, Cook-2 and Cook-1 from the top and downwards. On top of the Cook we have the Drake marine shale formation dividing it from the Broom and Rannoch. The lower one, Cook-1, is a marine siltstone continuing into the lower Amundsen and together they divide the Cook from the lower Statfjord. Having described the outer edges of the Cook, it is time to get to the middle. The upper section of Cook is a good reservoir having a permeability up to a couple of darcys, while the underlying Cook-2 has a permeability in the range of 0,02 - 0,1 making it a moderate to poor reservoir. Even though the permeability in general is high in section 3 of the Cook, it has some heterogeneous zones where it varies a lot. The calcite layers contribute to this heterogeneity and make it harder for the fluid to flow[2].

Statfjord

The Statfjord formation on the Gullfaks field was deposited in late Triassic/early Jurassic. The formation was deposited in many different ways. The lower part is dominated by alluvial deposition, while the upper part was dominated by fluvial depositions. The Sverdrup formation is overlying as a seal stone. Zone 3 - 11 in the Erikson zone have been classified as a really good reservoir with high continuity. The pressure in these zones varies from 313 to 342 bar, while the permeability varies from 0,01 to 3 darcys in the different segments. Zone 1 and 2 are of bad reservoir quality with low permeability. On the Gullfaks field the Statfjord formation contains approx. 15,5 % of the oil in place, with a recovery rate at 56 %.

The Statfjord formation has proven to by oil-bearing in the eastern part of the field, mainly in the horst and accommodation area. Later it has also been proven some oil in slump area east for segment K1 and some oil in the domino area. Well B-7B proved that segment H1 is filled with water. [2]

Lunde

The formation in Lunde contains a 800-1200 meters thick continental deposition. The

Lunde formation has bad characteristic in the Gullfaks area, but good reservoir quality in the rest of the Tampen area. The deposition is changing between sand and shale layers and is hard to survey. Lunde formation was deposited Ladinian to Rhaetian age. The top of the Lunde formation is 1940 m TVD MSL while the lower Lunde formation is ca. 2600 m TVD MSL meter deep. The pressure in the Lunde formation varies from 313 bar at 1850 m to 378,7 at 2450 meter TVD MSL. While the temperature is changing from 75,8 degree at 1850 m Celsius to 97,9 degree Celsius at 2450 meter. The Lunde formation is varying in permeability from 300 to 1900 millidarcy. [2]

Appendix B: Parameters for reservoir quality

The background needed to understand the reservoir quality and how it affects the fluid flow, lies in understanding the parameters that describes the reservoir quality. The hydrocarbons, which may be recovered, are situated in pores inside a porous rock deep down in the earth's crust. This void space is called pore volume, and is given by the formula for porosity;

$$\varphi_a = \frac{pore\ volume}{bulk\ vomule}$$

The bulk volume is the total volume of rock considered. The porosity describes the ratio of void fluid space to the total bulk volume, this porosity is called the absolute pore volume. In petroleum engineering it is more interested to look on the effective porosity. A varying part of the void pore space are not connected to the others pores. The case for some compact shale is that they have almost zero effective porosity, but a very high absolute porosity. In order to recover petroleum from a reservoir rock, we need interconnected pores. The pores have to be connected so that fluid can travel through the rock. This defines the effective porosity:

$$\varphi_e = \frac{interconnected\ pores}{bulk\ vomule}$$

The effective porosity defines the amount of fluid that is connected. The effective porosity is a heavily discussed term. This is due to a lot of complicating factors influencing it. Since this project is not to evaluate in reliability of the in-place volumes and given reserves, this will not go be discussed. The definition will be a amount of interconnected pores, as this is the normal practice in petroleum engineering.

Together with the size of the reservoir, the total bulk volume, we can calculate the PV (pore volume). This is the total possible amount of volume that can contain recoverable fluid.

$$PV = V_{bulk} \times \varphi_e$$

By knowing the PV of a reservoir, it is possible to know the amount of fluid volume that can be stored in it. Thereafter one has to know what kind of fluid it contains. Most of the rocks and formations are filled with water, but a small fraction has accumulated hydrocarbons in the form of oil or gas. Depending on the saturation of water, S_w, it is possible to calculate the HCPV (hydrocarbon pore volume) from this equation:

$$HCPV = PV \times (1 - S_w)$$

An important assumption for this is that the sum of the saturation of water oil and gas is one:

$$S_w + S_O + S_g = 1$$

Knowing the saturation of water gives us the in-place volumes of recoverable hydrocarbons. The Gullfaks field mainly consists of oil and some amount of gas. The gas is calculated into oil equivalents. This calculation is not included in this report.

The main reservoir parameters influencing the in-place volumes have now been explained, and up next are the parameters that affect the fluid flow. Darcy's equation is very important when trying to understand and to explain how fluid flows in porous media. The equation yields:

$$Q = \frac{-k \times A \times \Delta P}{\mu \times L}$$

This equation gives the flow rate, Q, as a function of permeability, k, cross sectional flow area, A, differential pressure, ΔP, viscosity, μ and the distance of flow, L. To understand

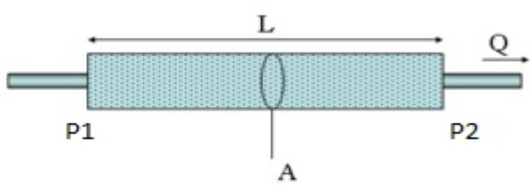

Figure 34 Darcy's law

this essential expression, the different terms making it up needs to be explained.

The pressure difference is the most obvious thing that contributes to fluid flow. The higher the pressure differential is, the higher the fluid flow across the cross sectional areal. This is because the fluid wants to flow to the region of lower pressure. In this case

$P1 > P2$, so the flow is towards the right hand side, seen Figure 34[18]. The cross sectional areal contributes in the same manner. With a higher areal the fluid has more space to flow trough. The permeability is a rock property measuring how easily the fluid flow though the rock itself. This parameter is one of the most important parameters when trying to explain how the fluid flow varies in a reservoir. This rock property is an absolute measure, assuming single fluid flow. When more than one fluid is present, a reduction in the measured permeability is experienced. This effect can be described as a competition of the fluids present, and it is resulting in a reduced total flow, or in other words reduced total permeability. Figure 35 illustrates permeability[19]. The fluids present will have their individual effective permeability and Darcy's law suddenly gets

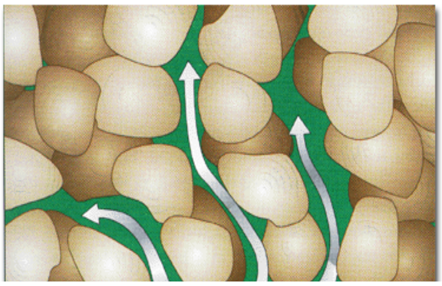

Figure 35 Illustrating Permeability

more complex. This rapport limits its discussion to the basic form of Darcy's equation. The viscosity of a fluid is its resistance to flow. The higher the value, the more resistant the fluid is to flow. This property has the opposite effect compared to the permeability. The oil in Gullfaks has a relative low viscosity and flow easily.

Appendix C: General measurements for increased recovery

Many of the measurements suggested by the Aam-report are applicable to all the oil-fields on the Norwegian shelf. Funds from the government to IOR-research, for an example, can benefit the whole shelf.

Three different economic incentives to stimulate the oil companies to work on increasing the IOR and EOR were suggested in the Aam-report. These incentives mainly include funding from the government, either by refunding of tax or by government funded research. Developing and testing new technology is costly, the technology could fail and while the technology is tested there will be decreased oil production. The Aam-report suggests that companies that are testing out and developing new technology should be able to write off their costs on the tax. This transfers parts of the economic risk from the companies to the government, which can make it easier to invest more in new technology.

The government fund different research foundations and programs, like FoU (Research and Development), PETROMAKS and DEMO2000, through these foundation and programs can the companies apply for financing to their technology development and pilot projects. The Aam-report suggests increasing the money given to these programs in the government budget. They have all proven valuable in increasing the oil production.

New technology has to be developed and tested, but the procedure is not always straight forward. After the development and testing phase comes the implementation phase. Many technologies have been discarded during these three steps, mainly because it is a costly process to develop new technology. The problem is that in order to test a new technology, a pilot, it is necessary to deprioritize the regular oil production. When the effects of the new technology are uncertain, it is easier to continue regular production, so often do pilots get post-poned. Postponing of the pilots can decrease the pilot's effect, since the well can be emptied before they are tested out. After the technology has been tested and proven successful, it has to be implemented at other platforms and oil wells. Unfortunately it takes some time from the technology is proven useful till it is implemented at different location. This dead time can decrease the efficiency and potential of the new technology.

A standardization of the oil business will decrease the production and maintenance cost for the oil companies, this will increase the economic potential of every oil field. So that oil in fields and reservoirs that are just marginally profitable can be extracted. Standardization enables mass production of equipment, thus lowering the production cost and delivering time. Engineering of a project can be done once and consecutive projects only have to do slight modifications, cutting the work time.

Integrated operations (IO) can increase the efficiency on the shelf, by using information technology to change work procedures to achieve better distance control of equipment and processes, and move functions and staff to land. Examples of processes that can be improved are reservoir monitoring, drilling, operation, maintenance and logistics. Difficulties with performing these changes are for an example that the supplier require compensation for their lost income when their services are no longer required, old habits are hard to change, information security and lack of resources.

Appendix D: Schedule file

```
-- Prediction for H1 --------------------------------------------------------------------------

-- METRIC UNITS
-- SIMULATION START DATE 1 'DEC' 1986


DATES
 1 'JAN' 2011 /
/

DATES
 1 'JAN' 2012 /
/

WELSPECS
   'NW'     1*   37   76  1*    'OIL'  7* /
   /

COMPDAT
--  WELL    I   J       K1   K2                     Diameter     Direction
    'NW'    37  76  30  35    'OPEN'  2*    0.178            /
    'NW'    37  75  36  37    'OPEN'  2*    0.178                /
    'NW'    37  74  38  44    'OPEN'  2*    0.178                      /
    /

WCONPROD
    'NW'     'OPEN'     'LRAT'    3* 1000    1* 50.000/
/

DATES
 10 'JAN' 2012 /
/


DATES
 1 'JUN' 2012 /
/

WELSPECS
   'INJ'     1*   37   73  1*    'WATER'  7* /
/

COMPDAT
--  WELL    I   J       K1   K2                     Diameter     Direction
    'INJ'   37    73  41   41      'OPEN'    2*   0.178 /
    'INJ'   37    73  42   42      'OPEN'    2*   0.178 /
    'INJ'   37    73  43   43      'OPEN'    2*   0.178 /
    'INJ'   37    73  44   44      'OPEN'    2*   0.178 /
```

```
   'INJ'   37   73  45   45      'OPEN'    2*   0.178 /
   /


WCONINJE
-- WELL   INj_type    Open/Shut
   'INJ'  'WATER'      1*        'RATE'  1000 1* 320 3* /
   /

DATES
 2 'JUN' 2012 /
/


DATES
 1 'JAN' 2013 /
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DATES
 1 'JUN' 2013 /
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 1 'JAN' 2014 /
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 1 'JAN' 2021 /
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 1 'JAN' 2023 /
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DATES
 1 'JAN' 2024 /
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DATES
 1 'JAN' 2025 /
/

-- END OF SIMULATION
```

Appendix E: Location of faults

'H1_NS_UB' 36 36 78 78 1 26 X /
'H1_NS_UB' 36 36 78 78 1 26 Y /
'H1_NS_UB' 37 37 77 77 1 26 X /
'H1_NS_UB' 37 37 77 77 1 26 Y /
'H1_NS_UB' 38 38 76 76 1 26 X /
'H1_NS_UB' 38 38 76 76 1 26 Y /
'H1_NS_UB' 38 38 72 75 1 26 X /
'H1_NS_LB' 36 36 78 78 27 52 X /
'H1_NS_LB' 36 36 78 78 27 52 Y /
'H1_NS_LB' 37 37 77 77 27 52 X /
'H1_NS_LB' 37 37 77 77 27 52 Y /
'H1_NS_LB' 38 38 76 76 27 52 X /
'H1_NS_LB' 38 38 76 76 27 52 Y /
'H1_NS_LB' 38 38 72 75 27 52 X /

'H1_A-35' 40 40 87 87 43 52 X- /
'H1_A-35' 40 40 87 87 43 52 Y /
'H1_A-35' 39 39 86 86 43 52 X- /
'H1_A-35' 39 39 86 86 43 52 Y /
'H1_A-35' 38 38 85 85 43 52 X- /
'H1_A-35' 38 38 85 85 43 52 Y /
'H1_A-35' 37 37 84 84 43 52 X- /
'H1_A-35' 37 37 84 84 43 52 Y /
'H1_A-35' 36 36 83 83 43 52 Y /
'H1_A-1H' 43 49 72 72 35 52 Y /

'H1_A-17' 36 36 83 83 19 52 X /
'H1_A-17' 37 38 82 82 19 52 Y /
'H1_A-17' 38 38 82 82 19 52 X /
'H1_A-17' 39 41 81 81 19 52 Y /
'H1_A-17' 41 41 81 81 19 52 X /
'H1_A-17' 42 44 80 80 19 52 Y /
'H1_A-17' 44 44 80 80 19 52 X /

Appendix F: Oil saturation

Oil saturation in layer 30, 36, 40 and 44 the 1. January 2012. The scale goes from 0 to 1, where 1 is equal to a strong blue color.

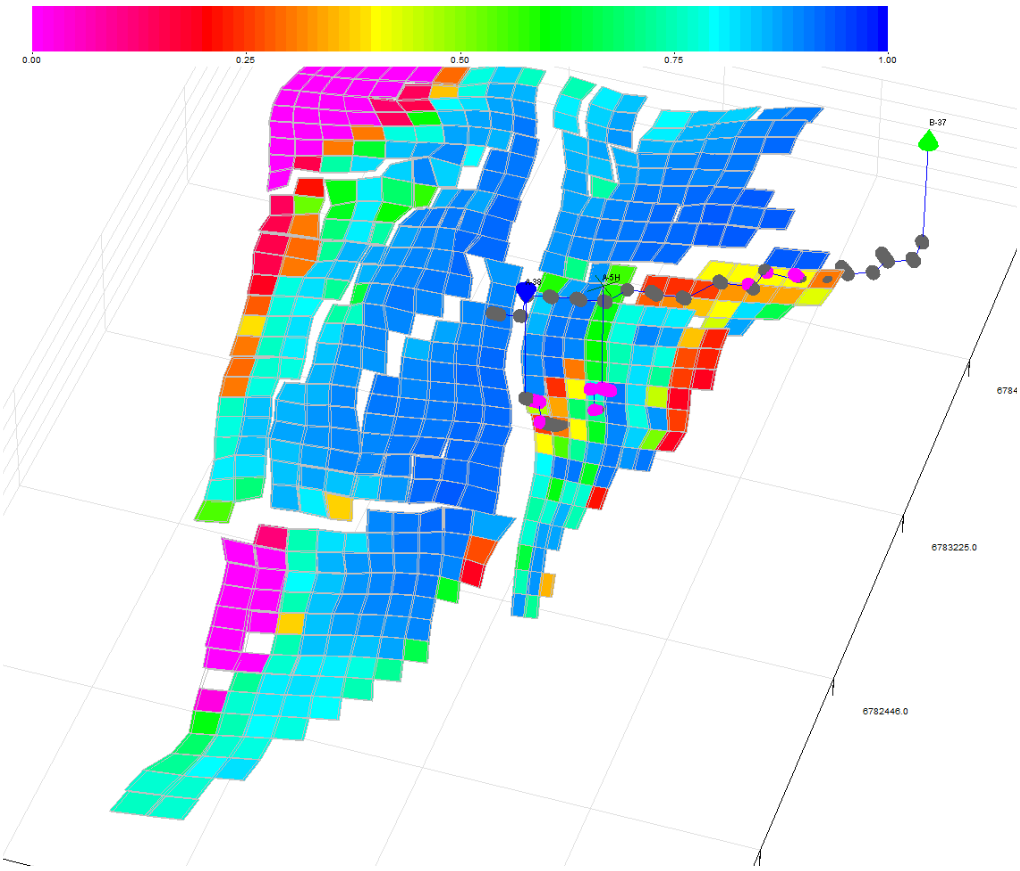

Figure 36 Oil saturation layer 30

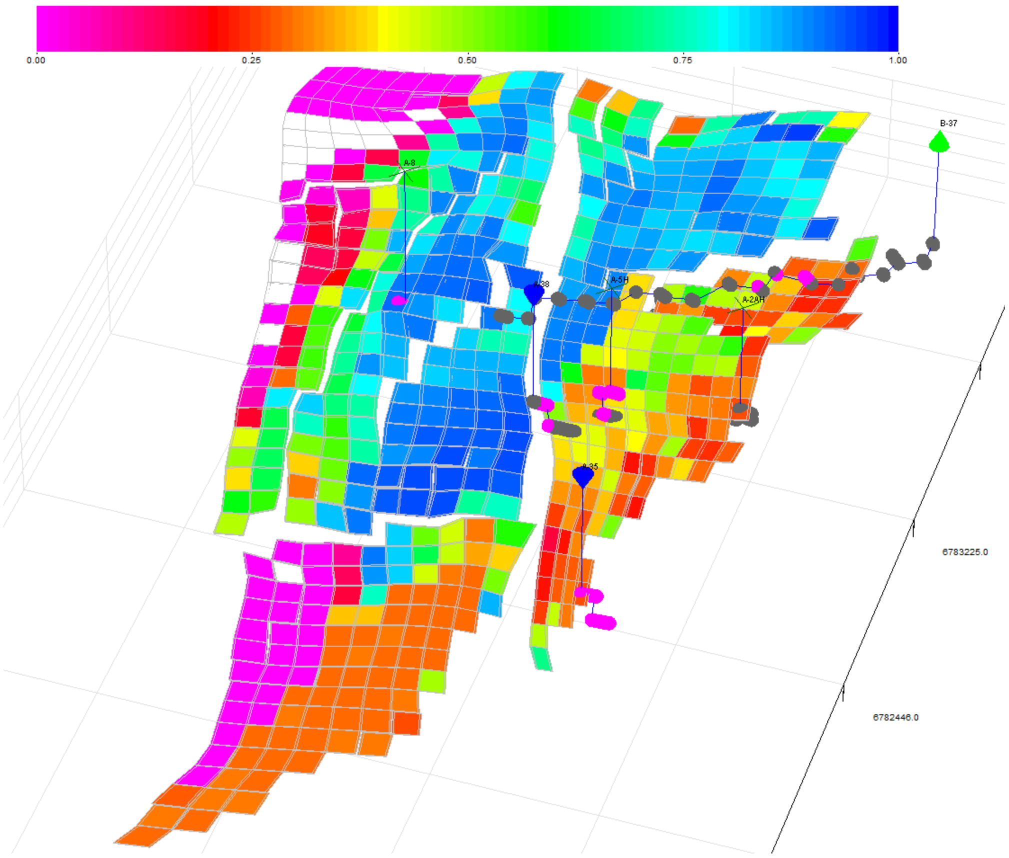

Figure 37 Oil saturation layer 36

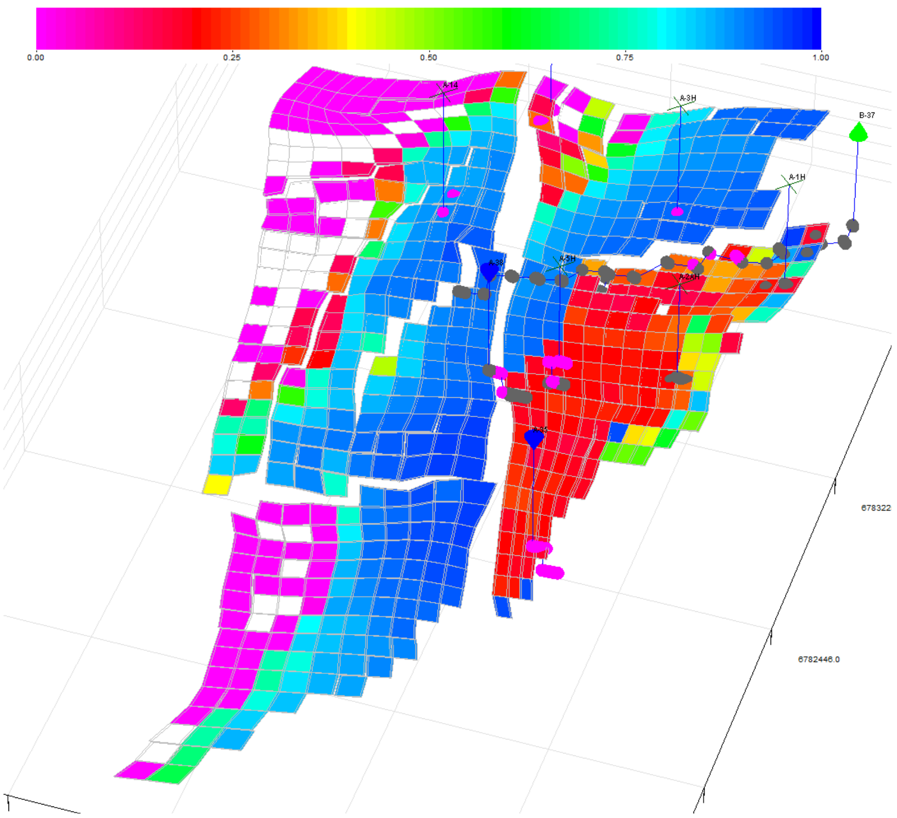

Figure 38 Oil saturation layer 40

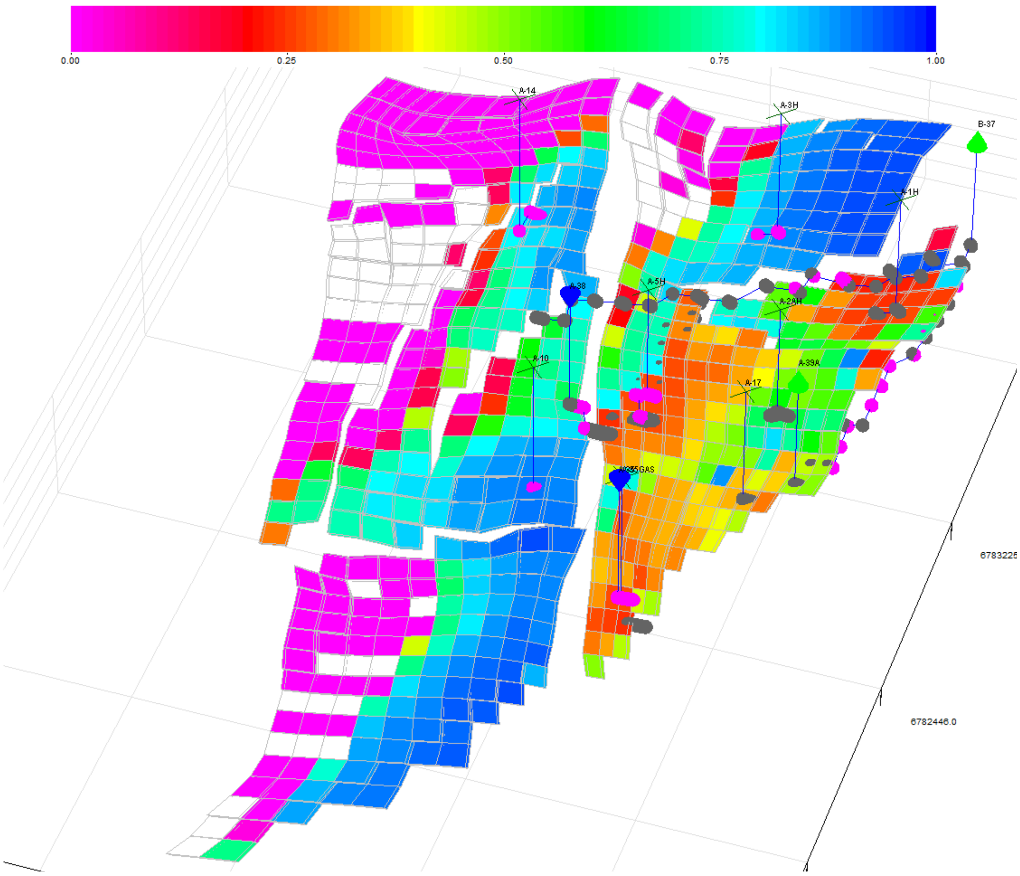

Figure 39 Oil saturation layer 44

Appendix G: Transmissibility x-direction

The figures show the transmissibility in x-direction for layer 41 to 45, the scale goes from 0 to 300, where 300 is a strong blue color. Cells that are colored black have a transmissibility higher than 300. The scale was still kept at 0 to 300 since the area of interest, around the placement of NW and INJ are best shown with this scale.

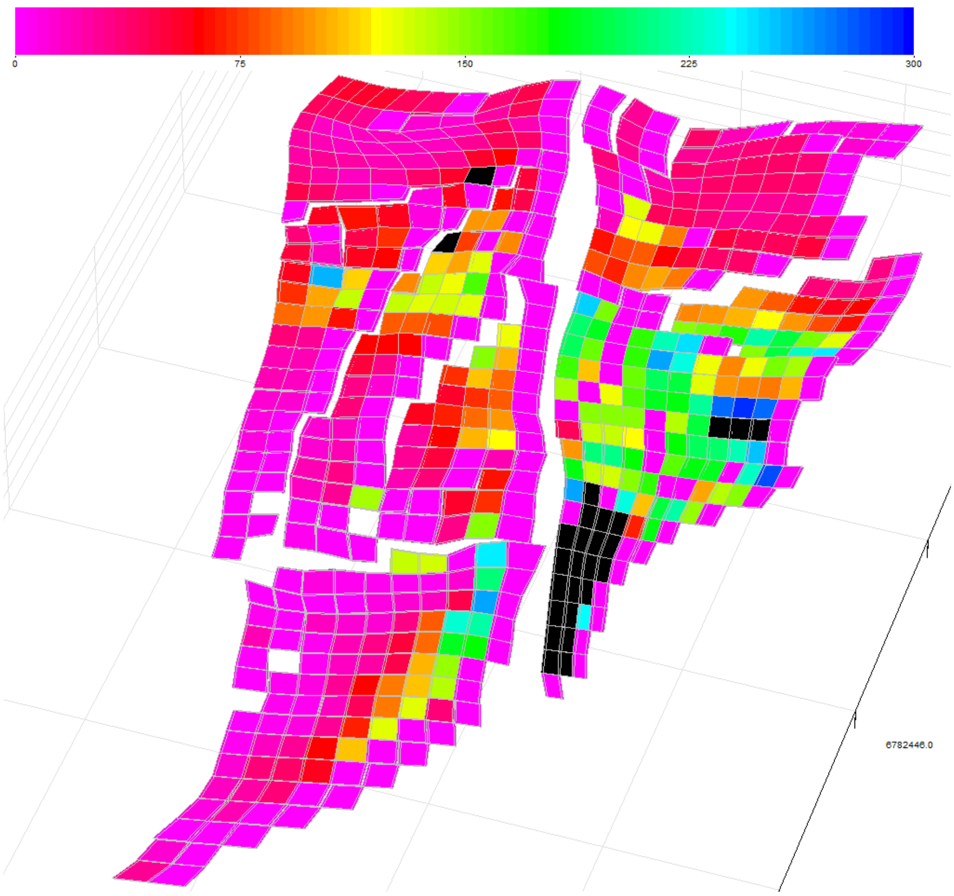

Figure 40 Transmissibility x-direction layer 41

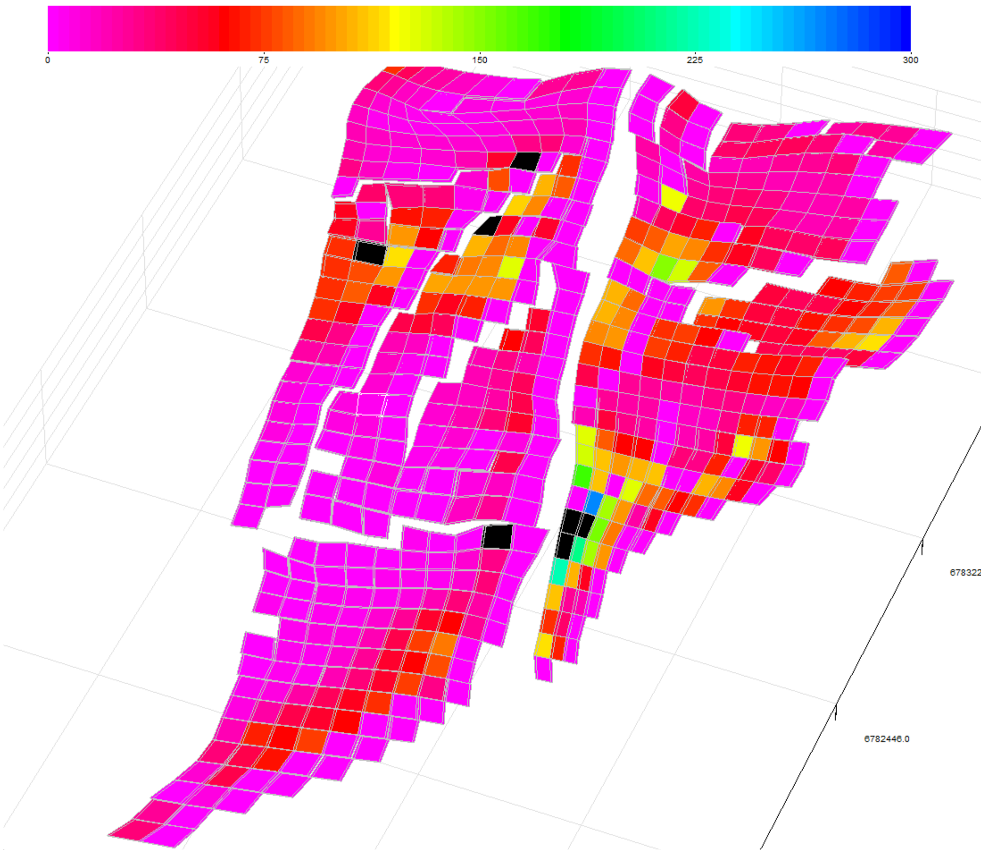

Figure 41 Transmissibility x-direction layer 42

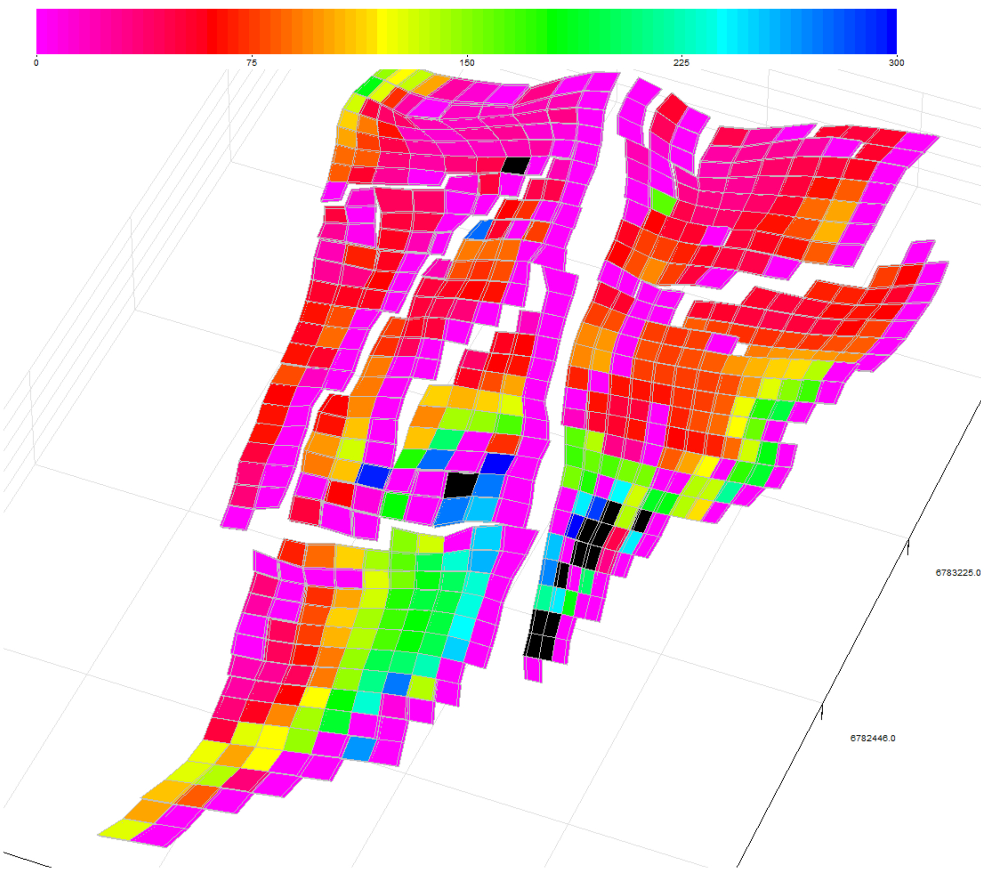

Figure 42 Transmissibility x-direction layer 43

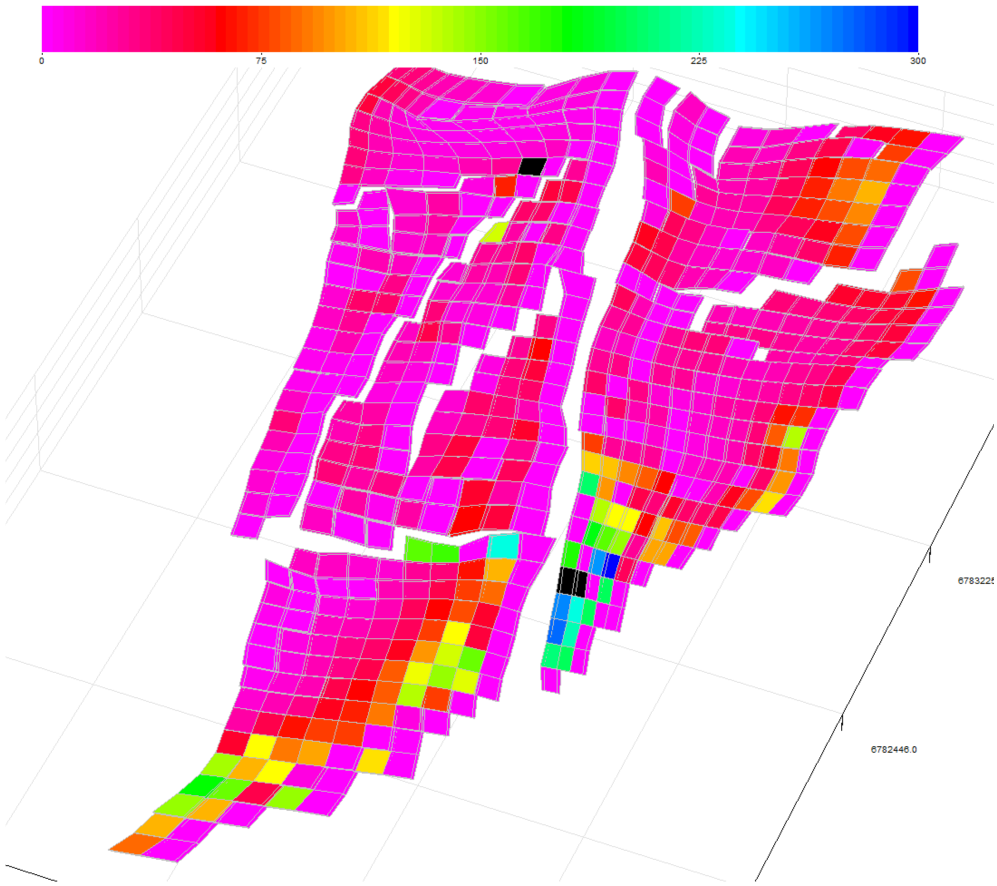

Figure 43 Transmissibility x-direction layer 44

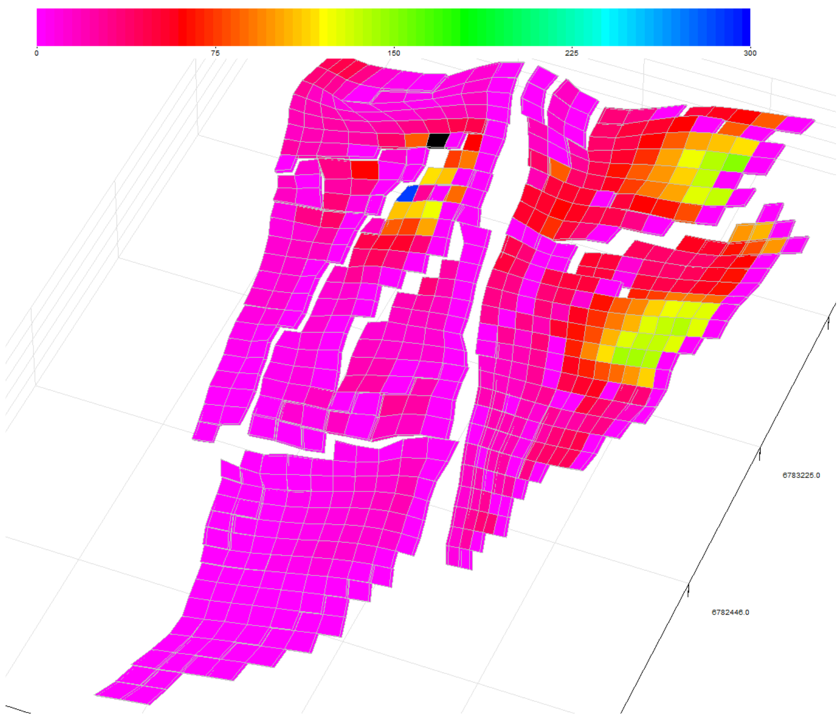

Figure 44 Transmissibility x-direction layer 45

Appendix H: Pressure differences

Figure 45 and Figure 46 show the pressure for the base case in layer 36 and 45 on the 1. January 2012. The scale goes from 250 to 350 bar, where strong blue color is 350 bar. Figure 47 and Figure 48 shows the pressure for the closed fault case in the same layers and at the same timestamp. For these figures is the scale from 200 to 300 bar, where strong blue color is 300 bar.

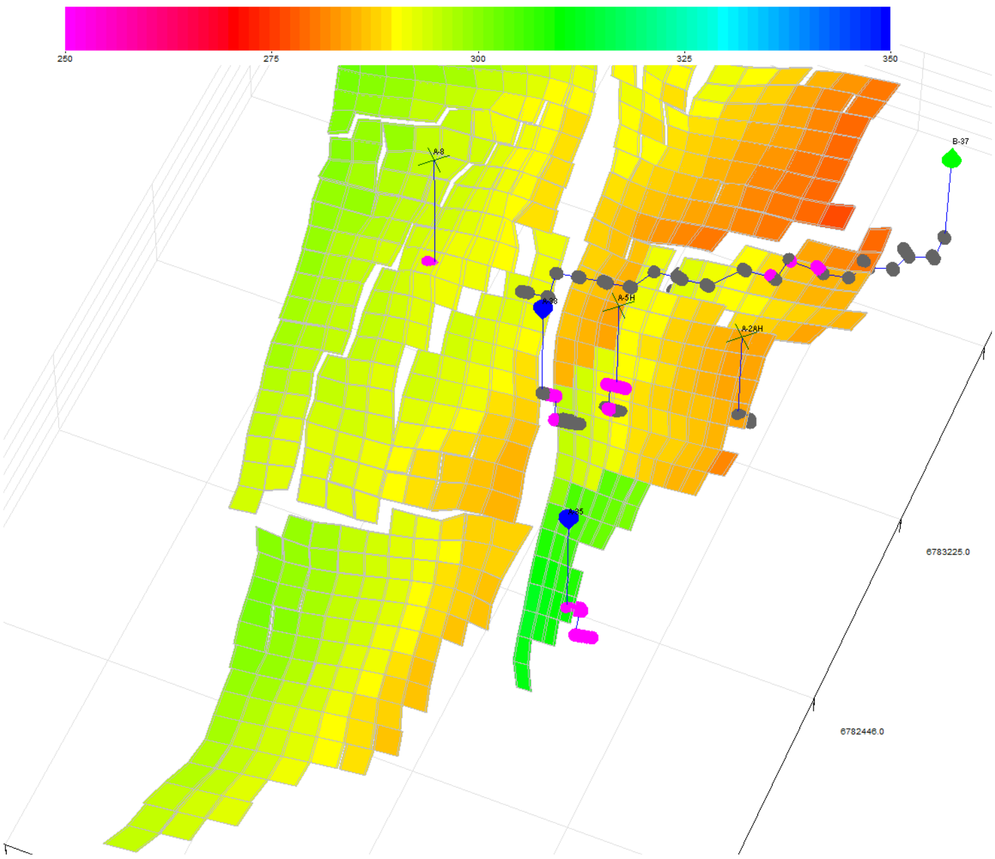

Figure 45 Pressure in base case for layer 36

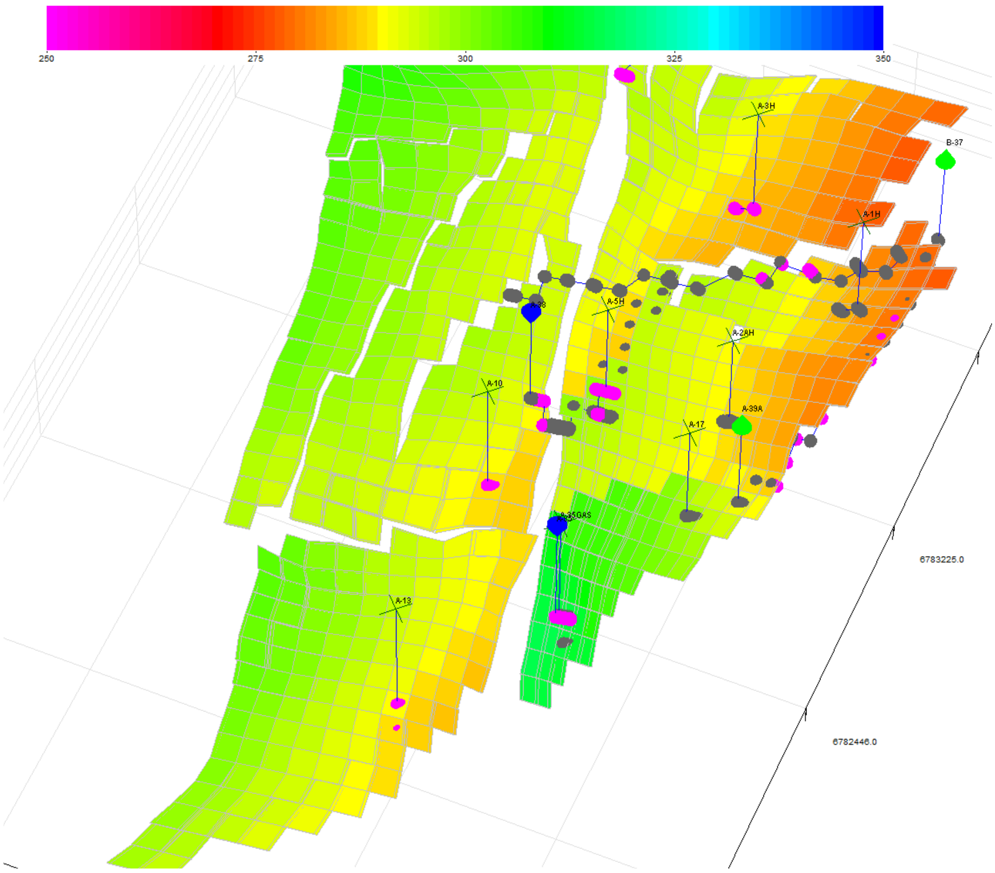

Figure 46 Pressure in base case for layer 45

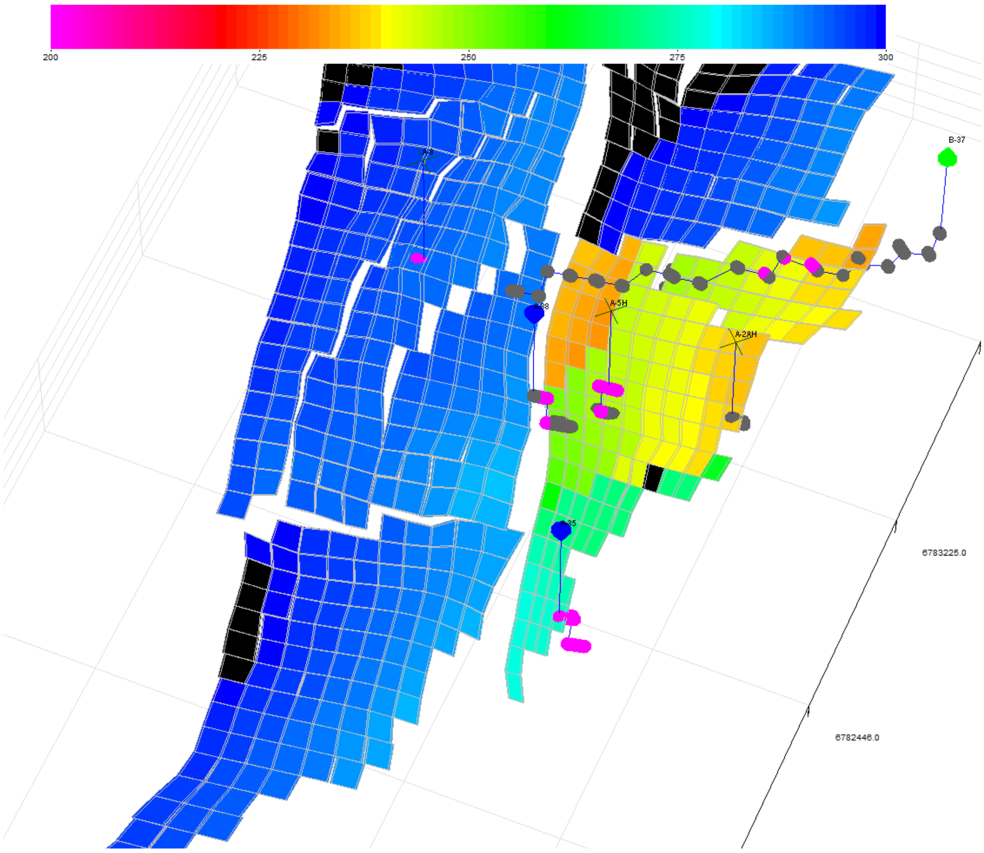

Figure 47 Pressure in closed fault case for layer 36

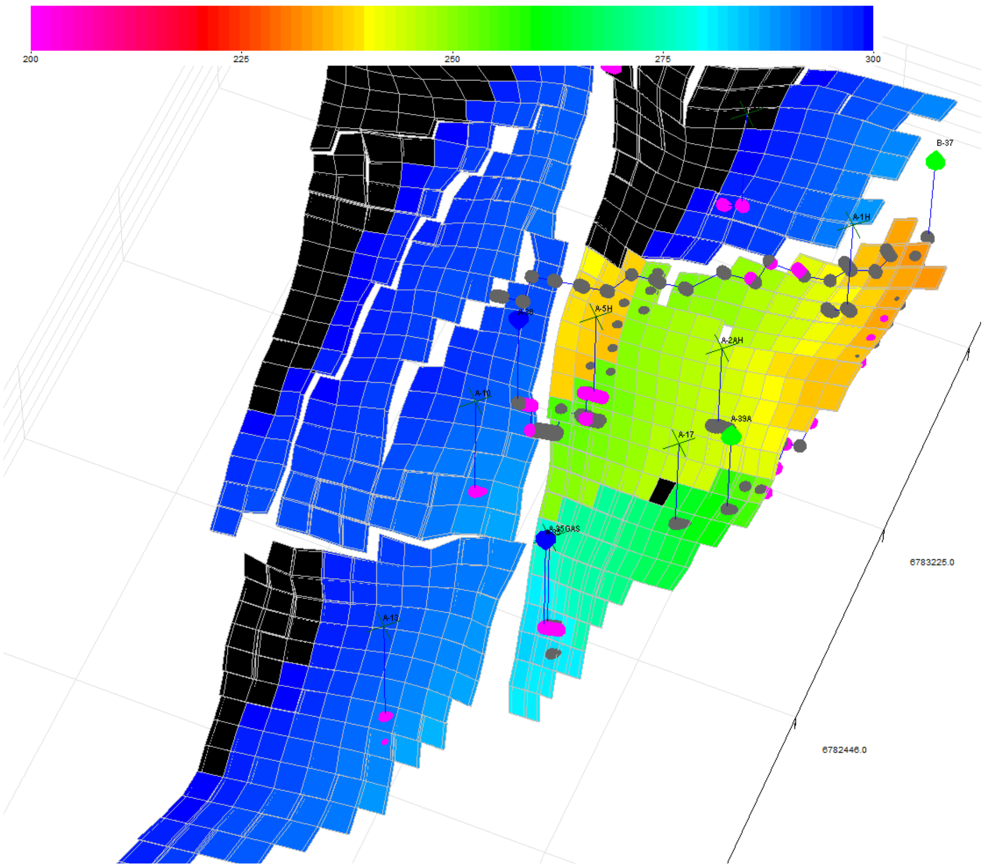

Figure 48 Pressure in closed fault case for layer 45