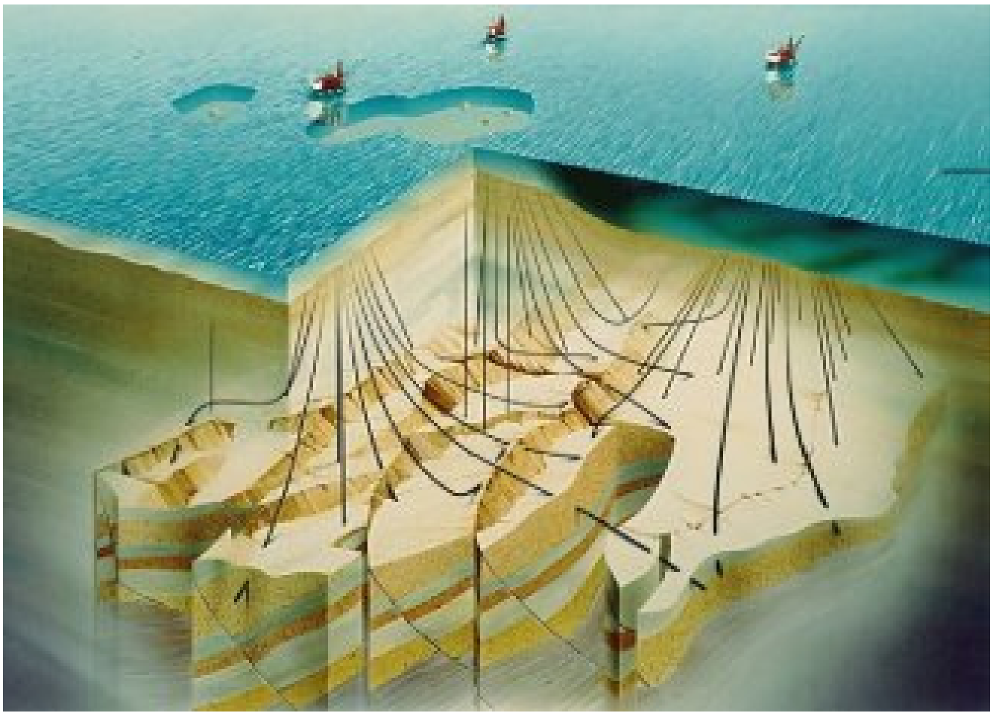
INSTITUTT FOR PETROLEUMSTEKNOLOGI OG ANVENDT GEOFYSIKK

Rimfaks Cook Development



Gullfaks Village 2011

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Acknowledgments

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Abstract
Rimfaks Cook is a part of the Gullfaks Field in the northern part of the Norwegian North Sea. Statoil is the operator of Gullfaks Field and are considering developing Rimfaks Cook. To make a qualitative assessment a business case document was made. This includes a short description of the area strategy and the reservoir in question. The reservoir properties are included in a reservoir model including sensitivity analysis of the parameters. A specific solution was chosen and an economical evaluation was performed.

A base case was made deterministically based on the given data from Statoil. Later the risks and their uncertainties were included in sensitivity analysis and Monte Carlo simulation. All cases showed that the project has good revenue and gives good NPV. This we evaluated as a result of the favorable market with high oil and gas price. Also the factor of utilizing existing infrastructure was looked upon as a major parameter. In addition, the project fits Statoil's strategy of improving the oil recovery on the NCS.

The base case showed that the prospect should be developed due to strong NPV. This was not considering the plugging and abandonment of an existing field to develop our prospect. Rimfaks Cook must then be evaluated against existing field, and compared to alternative development options in combination with other prospects.

Contents

1 Introduction

We were given an undeveloped prospect, Rimfaks Cook, close to the Gullfaks Field. The main delivery for our project is to deliver a business case document. This document should be made to convince the management to either go ahead or walk away from the project. In consultation with our advisor we agreed what should be included in the document.

Initially, we needed an overview of the reservoir and the general area strategy. This was to give us an overview of the reservoir properties and the areas strategy regarding existing infrastructures and capacities. Then we had to make a list of the different stakeholders and their influence on the project. These should also be included in a more thorough analysis of the risks and how we plan to mitigate them.

The risks we evaluated were about the reservoir properties and economical aspects. We started with the reservoir properties to evaluate the uncertainty of the risks in the different parameters. Here we evaluated the effect of different properties such as permeability, porosity and transmissibility. As the uncertainty of these would affect the production and thereby the income, these were very important for estimating the revenue.

After a discussion about the risks and how we mitigated them we made a description of the selected development option and why it was chosen. We then evaluated the options of selling gas and injection of gas. A brief economical assessment were made on which of these models was more favorable. When this showed us that selling gas without injection was the desired option we made further economical analysis on this option. Sensitivity analysis on oil price, production and investment were implemented in our solution. After the sensitivity analysis we performed Monte Carlo simulation with randomization of the different uncertainties. This was to give a better mean than the deterministic base case.

Before we gave our conclusion to the project, we made a description of the different solutions that could be considered as options to the one assessed in the project. Milestones about what were the next steps in the decision phase were evaluated and given before our conclusion to the project. Here we gave our recommendation for the future of the prospect.

2 Area strategy

The Rimfaks Cook reservoir is located within the Gullfaks satellite area, which in addition to the Rimfaks field also includes the Gullfaks South, Gullveig and Skinfaks fields. It is situated within the 34/10 block, and part of production license PL050/050B. The license is owned by Statoil (70%) and Petoro (30%), and is operated by Statoil (Reservoir Management Plan, 2007).

2.1 History

The development of the Gullfaks Satelites was initiated in 1998 (RMP, 2007). This consisted of production of oil and condensate reserves to the Gullfaks A platform. The operation was expanded in 2001 when production and export of gas and associated liquid volumes from Gullfaks South Brent reservoir was started. These were produced to the Gullfaks C platform.

The plan for development and operation of Skinfaks and Rimfaks IOR was approved in 2005 (RMP, 2007). This consisted of a new subsea template and a satellite. The new fields were to be produced to Gullfaks C through the L and M templates already in place.

2.2 Recovery strategy and reserves

2.2.1 Gullfaks main field

The main recovery strategy for Gullfaks is injection of water to replace produced reservoir volumes and maintain pressure. As of 2007 the field is estimated to contain 599 MSm3 for STOOIP and 358.4 MSm3 for reserves. (RMP, 2007)

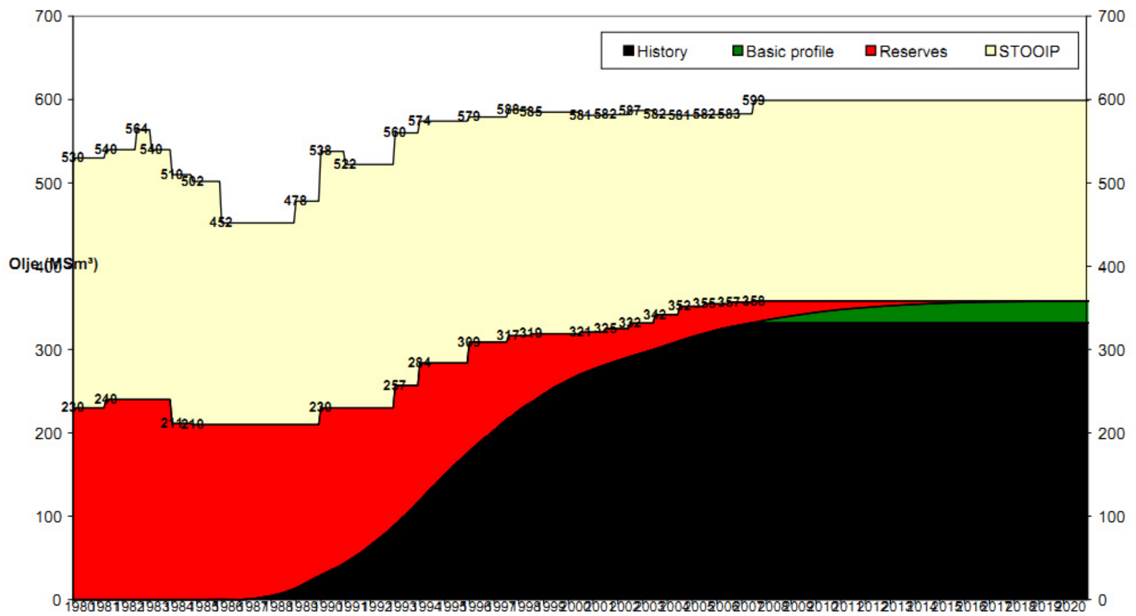


Figure 2.1: Development of resources and reserves, Gullfaks main field (Fig. 2.1.1 RMP-07)

2.2.2 Gullfaks Satellites

The main recovery strategy for Gullfaks Satellites is gas injection. Exceptions from this are the Gullveig and Skinfaks fields that have surrounding water basins providing pressure support. The reserves are estimated to be 48.1 MSm3 as of 2007. (RMP, 2007)

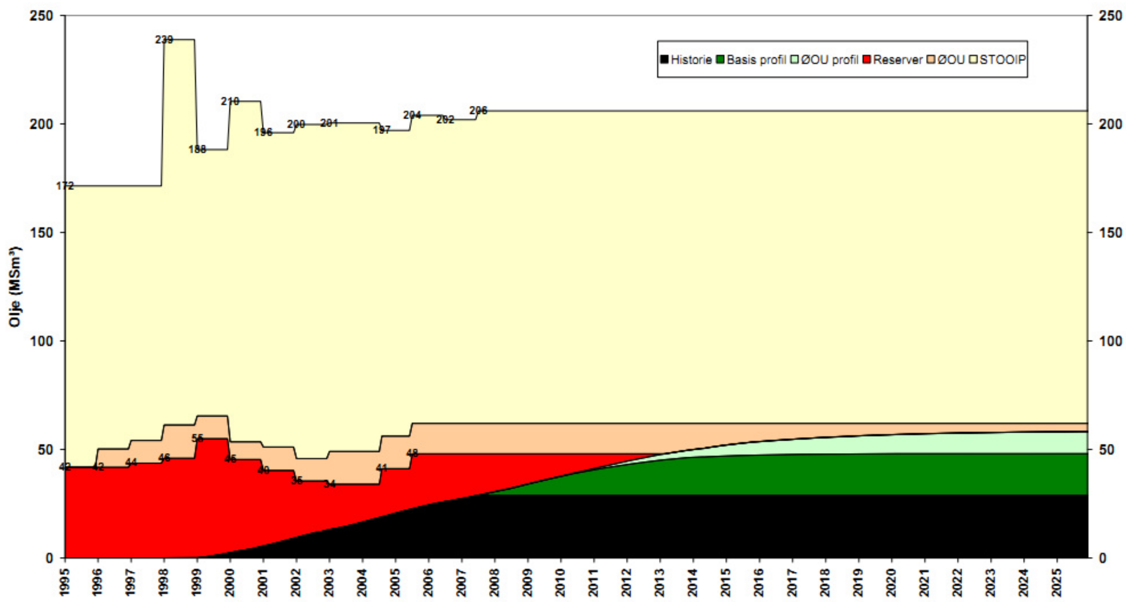


Figure 2.2: Development of resources and reserves, Gullfaks Satelites (Fig. 2.1.2 RMP-07)

2.3 Infrastructure

The satellite fields are produced by subsea templates, connected to the Gullfaks main field through pipelines. Currently the Rimfaks field has three templates located within it, templates I, J and H. There are no imminent plans of expanding this number with another template. Basically this implies that any new production have to be developed in compliance with the capacity of the existing infrastructure.

An overview of the installments in the Gullfaks area is shown in figure 3 below.

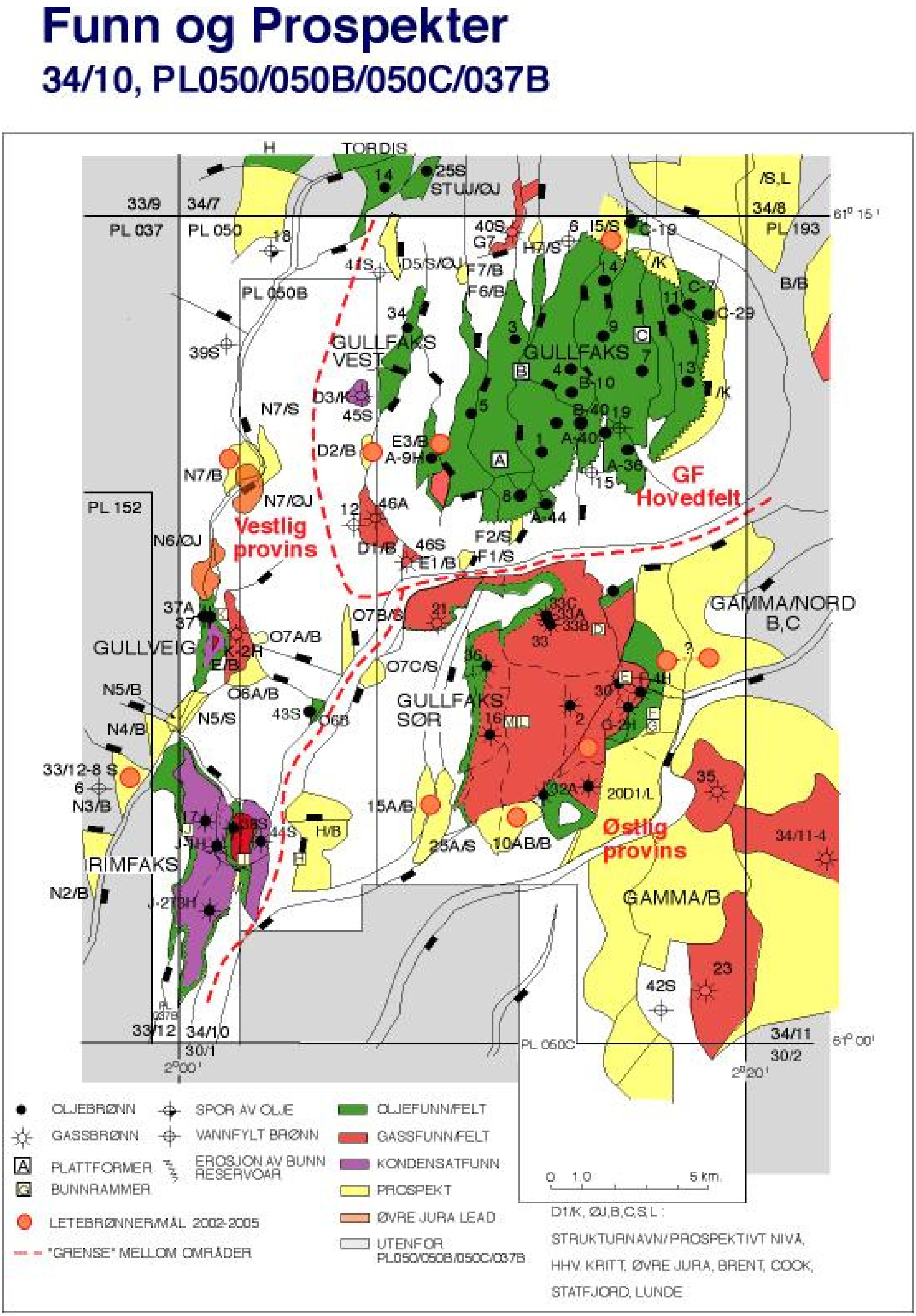


Figure 2.3: Overview of fields and installations in the Gullfaks area.

3 Reservoir description

3.1 Structural geology

The Gullfaks Satellite fields are situated to the west and south of the Gullfaks main field. They all lie in the Tampen area on separate, westwardly rotated fault blocks. These structures are pre-Cretaceous and are a result of different rift phases, one Permian-Triassic and one late Jurassic/early Cretaceous.

The Rimfaks fault block is delineated by three large faults, oriented N-S, NW-SE and E-W. The N-S faults are dominating. The top of the reservoir structure is located approximately 2500 m TVD below sea bottom. (RMP, 2007)

3.2 Rimfaks Cook

The Cook formation is located below the Drake formation, and is divided into three. The Cook-1 is considered a non-reservoir, consisting of mainly marine shale with thin sandstone intervals. Above it lays Cook-2 and Cook-3 which are reservoirs. The upper one, Cook-3, consist of medium to fine grained sandstone beds, alternating with many layers of shale and lamina beds. Cook-2 is more homogeneous, consisting mainly of fine grained sandstones (RMP, 2007). In terms of reservoir properties, Cook-3 considered to have much better properties then Cook-2. This is due to Cook-2 high content of fine grained materials.

Below are two figures illustrating the differences between Cook-2 and Cook-3.

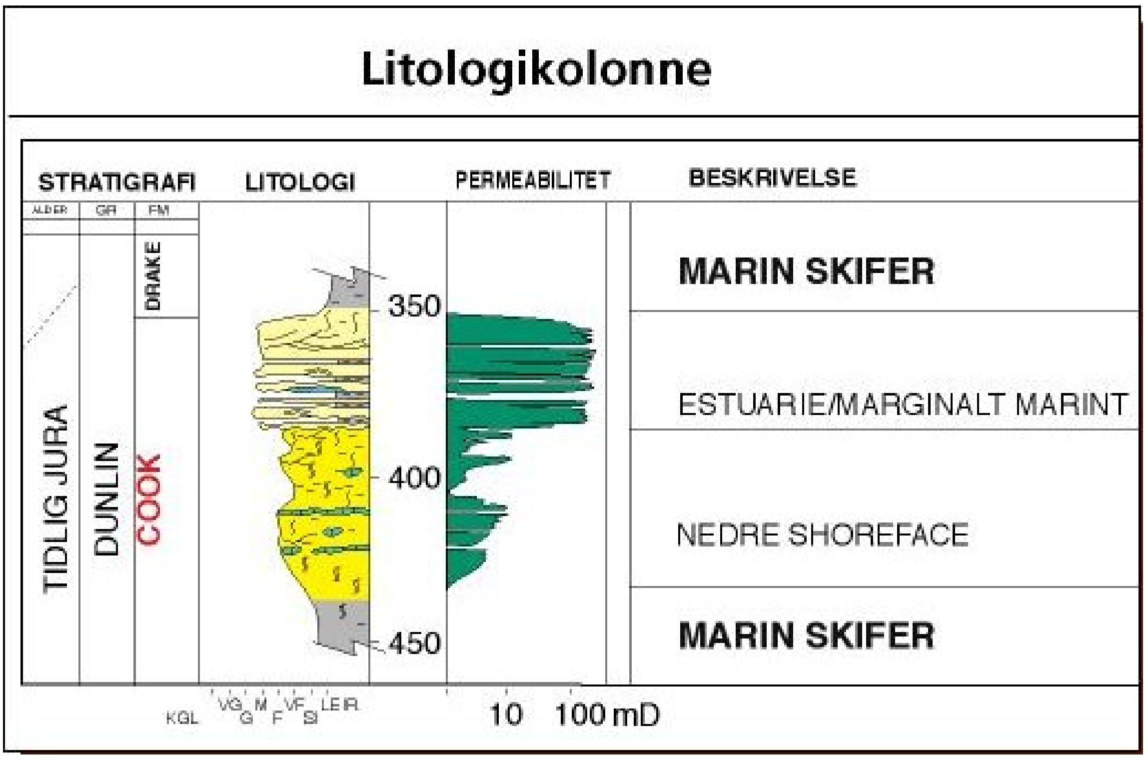


Figure 3.1: Showing the different layers of the Cook formation, with corresponding permeabilities. (Statoil-RCM, appendix 2.2)

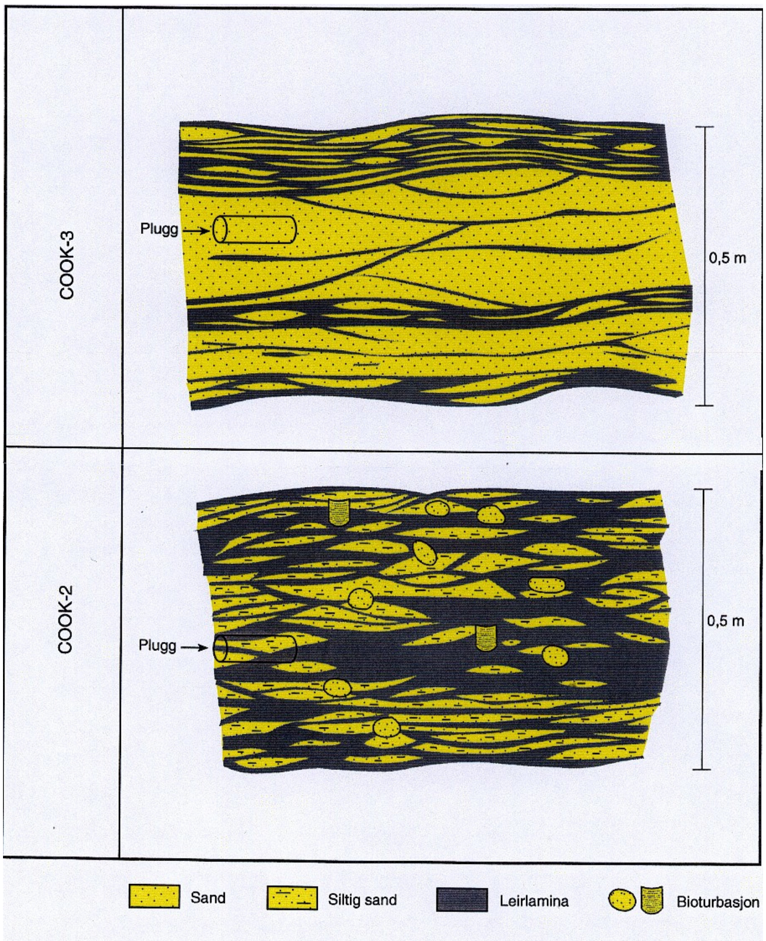


Figure 3.2: Illustrating the differences in sedimentology. (Statoil-RCM, appendix 2.1)

3.2.1 Reservoir properties

The petrophysical data known about the formations is based on well logs from wells drilled into the Rimfaks Brent formation. Some of these wells also penetrate Rimfaks Cook. However, only two wells are considered to yield both precise and sufficient data about the different layers of the reservoirs. These are the 34/10-J-1H and 34/10-J-3H (Statoil-RCM). The simulation model for the reservoir is based on these data. The following tables show the data that is being used for the porosity, permeability and the net to gross ratio. Layers 1-5 are believed to represent the Cook-3 formation, while layer 6 is the top of the Cook-2.

	Porosity	
Layer/well	34/10-J-1H	34/10-J-3H
1	0,155	0,159
2	0,145	0,150
3	0,129	0,133
4	0,103	0,103
5	0,112	0,095
6	0,114	0,114

Table 3.1 Porosity values (Statoil-RCM, table 3.3)

	Permeability (mD)	
Layer/well	34/10-J-1H	34/10-J-3H
1	10,62	12,72
2	12,05	12,70
3	3,94	4,61
4	1,45	1,45
5	2,02	1,07
6	2,24	2,24

Table 3.2 Permeability values (Statoil-RCM, table 3.4)

	Net to gross ratio	
Layer/well	34/10-J-1H	34/10-J-3H
1	0,821	0,585
2	0,911	0,914
3	0,460	0,289
4	0,0	0,0
5	0,303	0,059
6	0,290	0,0

Table 3.3 Net to gross ratios (Statoil-RCM, table 3.5)

3.2.2 Fluids

The formations within the Gullfaks Satellites appear to be filled with hydrocarbons the same way as their corresponding formations in the main field. There are some uncertainties related to the fluids within the Rimfaks Cook due to the lack of information about the reservoir. The probability of a gas cap within the reservoir is deemed very low (Statoil-RCM). The reservoir is estimated to contain fluid volumes of OIIP of 1,9 MSm^3 and GIIP of 0,9 GSm^3.

At surface level the fluid densities is believed to be 810,4 kg/Sm^3 for the oil phase, and 0,912 kg/Sm^3 for the gas phase (Statoil-RCM). The API gravity of the oil is 42,6°, which is above the Brent crude classification.

4 List of Stakeholders and their Influence on the Project

The Gullfaks field is operated by Statoil and the license is shared by Statoil and Petoro, where Statoil own 70% and Petoro 30%. One of Petoros main tasks is monitoring the provision of the petroleum produced from the states ownerships in compliance with the provision instructions given to Statoil. Since the state have the major shareholding in Statoil and Petoro is fully state owned, the state conducts common ownership strategy through the provision instructions (Petoro, 2011).

This means that Statoil at all time has to follow the instructions from the provision instructions. Statoil is in control of the project but are monitored by the state through Petoro. If the state see that the project is not following the instructions given this could lead to closing or new routines. Still, the state shows confidence in the Statoil board and do not intervene with their plans (Salthe, 2011). Statoil has 70% of the license and therefore are dominating the decisions of the fields' future. The only way for the state to proclaim their dissatisfaction in the board is at the general meeting. As Statoil is put on stock there would not be smart for the state to intervene too much in Statoil and make them less attractive on the stock exchange.

One of Statoil's goals is increased oil recovery on the Norwegian Continental shelf, NCS (Statoil, 2011). To accomplish this one has to develop small pockets and marginal field with new and better technology. The Rimfaks Cook prospect fits into this description and should be a part of this strategy either now or in new future. Therefore, it seems likely that if this project gives a good economical analysis to be developed. Long horizontal wells and by using existing infrastructure it fits well in this strategy.

These factors combined we see that Statoil is the main stakeholder and has the main influence on the project. The main purpose of the business case document is then to show that this is a prospect in line with Statoil's strategy if proven economically favorable.

5. Risks involved and how we plan to mitigate them

Starting the development of a new well/field there are a lot of risks which reflects the unknown outcome. These risks represent our inability to predict the outcome of the future of the project. If a certain event takes place uncertainty gives the possible outcomes of the event (Tresselt, 2011). To mitigate the risks in the project one has to recognize them and evaluate their range of possible outcomes. In field development, uncertainty and risks cannot be eliminated, only reduced (Golan, 2011). For risk reduction better information is needed and this costs money.

5.1 Reservoir Model

When starting the development of a new prospect all the information have to be gathered to make a good decision. There were not very much information about Rimfaks Cook and therefore much of the evaluation had to be based on surrounding fields and wells. This increases the uncertainty and so the risks in the prospect. Still, it is the most reliable data availeble and in cooperation with geologists and geophysics one gets the opportunity to make the best possible decisions.

The production data used in the economical evaluation was based on a reservoir simulation model. This means that the geological and petro physical data is put into this model. Some of the data was read directly from logs while other data was estimated due to correlations or surrounding formation.

There exists top Cook interpretation, but this is old and outdated. To make the reservoir model for Rimfaks Cook, data from Rimfaks Brent was used as a base (Rimfaks Cook model). From the Brent formation we then got the isochors map with horizons and modeling of the faults to give the structural model. Further some of the parameters that are included in the models will be discussed, which ones were read directly from the logs and which were estimated due to the surroundings or correlations to the log data.

5.1.1 Petrophysical data

The geological model was made in IRAP RMS which is a powerful reservoir modeling tool to make three-dimensional models of reservoirs. The models were based on all available data; seismic, well data etc. There have been drilled six wells that penetrate Rimfaks Cook, but only four that goes through all six layers of the reservoir (Statoil-RCM).

Sone/Brønn	17	38S	J-3H	J-1H	J-2 HT3	I-3H
3C	X		X	X	X	
3B	X		X	X	X	
3A	X		X	X	X	X
2C	X	X	X	X	X	X
2B	X	X	X	X	X	X
2A	X	X	X	X	X	X

Table: Overview of which wells goes through which layers.

34/10-17 and 34/10-38S are exploration wells, while the others are producers/injectors at Rimfaks Brent and Rimfaks Statfjord. Because of missing data and being far from the hydrocarbon zone 34/10-17 and 34/10-J-2-HT3 were excluded. That meant that J-3H and J-1H was the basis for our petro physical data. Only the porosity and the net to gross were read directly into the model from the logs.

5.1.2 Porosity and Net to Gross

When "blocking"/up scaling porosity for the model geometrical average was used, which means that all the values from the block is averaged geometrically. Here one only used the sand zones for blocking because non-reservoir zones have very low porosity. Blocking the values for the net to gross was done by the same method as the porosity (Statoil-RCM).

5.1.3 Permeability

Cook is a very complex reservoir that makes it difficult to model in the right way. By using the geometrical averaged porosity this would compensate for complexity and a correlation between permeability and porosity was used, $\phi = 0{,}0932 + 0{,}026 \cdot \ln k$. In the base case relative permeability was taken from the Gullfaks main field (Statoil-RCM).

5.1.4 Simulation

These parameters among many made the basis for the model that now should be the basis for the production data and the economical analysis. Where logging data did not exist, correlations in cooperation with geologists were made to optimize the result. Now we could start simulating and then the goal is to get an answer to the following question:"Can the volume justify the development of the field?"

Find the best location for the well depends on a lot of factors and all of them had to be taken into account. Some of the reservoir properties are described but still it is uncertain how the model will react to the well. Here are some points evaluated to get a good base case for the simulation (CCOP, 2003):

- What kind of well? Vertical or horizontal?
- At what depth in the reservoir?
- What is the preferential path?
- Effective length of well
- Perforation

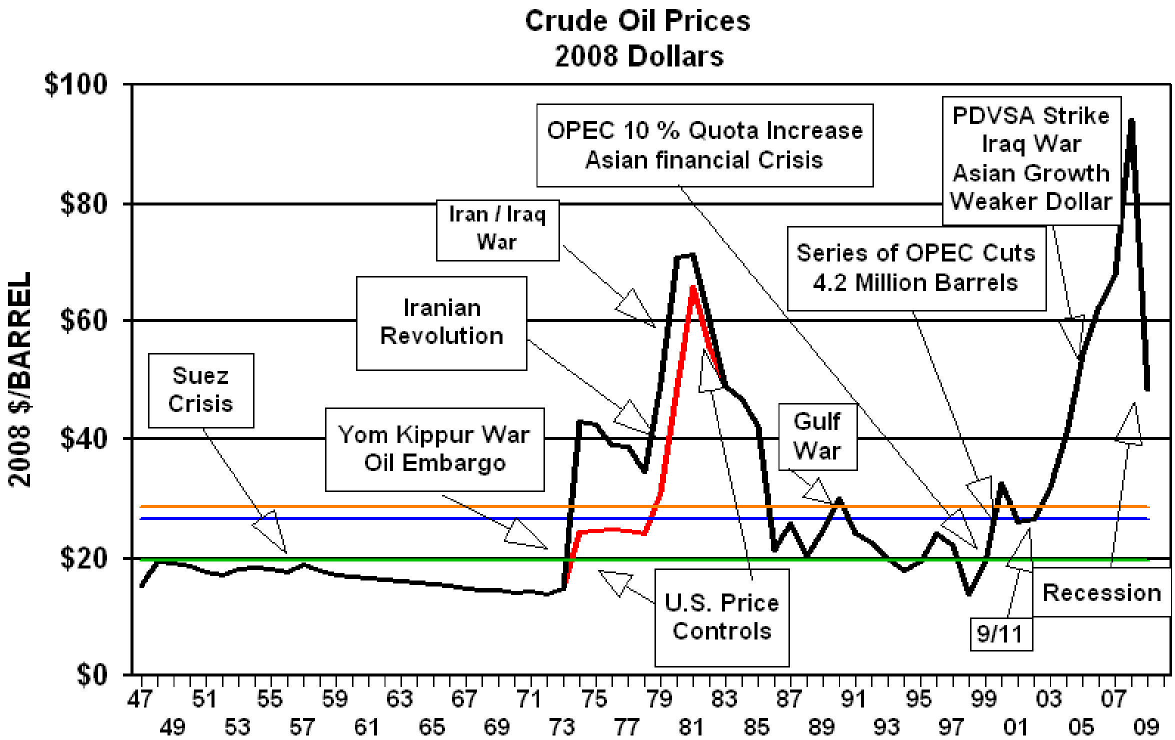
To mitigate these obstacles several simulations with random properties were made. Choosing a reasonable base will make this a good way to optimize on how we will plan the well and get as much oil as possible from the prospect. Changing the properties one by one is called sensitivity analysis. This was used to evaluate the extent of the uncertainties of the reservoir properties.

5.1.5 Analysis

All of these factors are unsystematic risks. This represents the fluctuations in the return from the reservoir with the different reservoir properties. A good way to solve this is Monte Carlo simulation (Golan, 2011). This meant that a high number of simulations were run to get a distribution of possible outcomes. The permeability, relative permeability, porosity, transmissibility and the position of the well were changed. Because we did not have enough computer processing capability to do this for the reservoir model, we had to implement this uncertainty in another way. The solution was then to perform sensitivity analysis on these factors. This gave an interval for the production data which was used in the economical Monte Carlo simulation. The mean of the Monte Carlo simulation was evaluated as the expected mean of the analysis (Tresselt, 2011).

5.2 Economical Risks/Commerciality

The volume acquired together with the oil and gas price will make the income for the prospect and the base for the evaluation for commerciality. This means that the volume acquired is dependent on the market for oil and gas which controls the price. Here it has been a lot of fluctuations the last years. You had a steady increase after the terrorist attack on September 11th until the recession in late 2008 (WTRG, 2009).



After the recession it has been a rapid increase and we have again seen oil prices as high as 120$. This shows us that there is a risk with enormous uncertainty in choosing the oil price. The gas price follows the oil price to a certain degree, but is not fluctuating to the same extent.

The commerciality is then dependent on the market, which controls the oil price and the demand for oil. The oil market and world economics are very turbulent at the time with the war in Libya and the tsunami in Japan. This makes it very difficult to predict the oil price for the lifetime of the field. We had to make an evaluation of the market and how the oil and gas price will develop during the lifetime of the field. The product of the expected oil price with expected volume gives the income from our prospect. To see if it is possible to commercialize we looked at possible solutions and compared it to the costs of our selected option. This was selected due to the use of existing infrastructure, cost of investments etc. in the different solutions.

Investments are also a risk when developing the prospect. In Rimfaks Cook the costs from investments comes from rig rental and services. Here as well the price depends on the market, but the length of rental has the most effect on the costs. This meant that an evaluation of the period of rental had to be made. Here the time of plugging and abandonment and the progress of drilling were considered. This will be evaluated thoroughly later in the part rig costs in the economics chapter.

All of these factors combined with the uncertainty of the risk with the reservoir model were then combined into the Monte Carlo simulation. Then the risks in oil and gas price, investments, production and the reservoir model were accounted for. By executing 5000 simulations with different values for each of the parameters we got a distribution for the expected cash flow of the project.

5.3 Environmental

Offshore drilling is very challenging due to a harsh environment and one has to take precautions. The most notably risk from offshore drilling are oil spills from tankers or pipelines transporting oil from the platform to the facilities onshore and from leaks and accidents on the platform. Rimfaks Cook is planned connecting to an existing subsea template and use existing pipeline. Being a part of an already existing system where monitoring is implemented and with Statoil following several industry specific criteria to minimize the harm on the environment (Statoil, 2007). Based on the information given we do not evaluate the reservoir as a big risk compared to the rest of the Gullfaks area. We do not have the capacity to evaluate the environmental risk to exactly this well.

5.4 Stakeholders

Statoil is the operator of the field owning the licenses together with Petoro. This gives the State a share of about 77% of the licenses. As the State seems to approve of the direction of Statoil's business we assume there being little risk for the prospect to be turned down by stakeholders.

Statoil being a big company also allows them to take risks in developing fields. If a prospect is evaluated as a marginal field or a high risk/high gain it is more likely to be developed by a large company. Simultaneously, it seems as Statoil is expanding out of the NCS and might cause a hold up in marginal prospects on the NCS.

Another risk is the rental of a rig and competing with this one against other licenses. At the time being the license is awarded a rig and is to keep this unless something happens. To mitigate this, a thorough analysis of the uncertainties to prove this as a good prospect was made.

5.5 Portfolio

Rimfaks Cook is a part of a group of prospects, a portfolio of projects. Using portfolio theory reduces the risk of the project evaluated individually. The risk of the project is reduced as the risk is spread over a portfolio of projects (Tresselt, 2011). Therefore, even if the individual prospect is evaluated as risky the portfolio could give a positive mean. If the portfolio is evaluated as positive most projects should be developed. This type of thinking increases the attractiveness of marginal fields and fits into Statoil's strategy of increased oil recovery.

After the economical analysis the prospect should also be evaluated as a part of the portfolio of projects at the Gullfaks Field. This does not reduce the uncertainties or risks in Rimfaks Cook evaluation, but is reduced as part of a total in a portfolio.

6 Description of the selected solution

The Rimfaks Cook reservoir being evaluated in this development plan is a fairly small reservoir zone. It is located more than 10 km away from the large installations of the Gullfaks main, which would make it difficult to reach with a well from any of these. Even if this was possible, this solution would not be considered economically feasible given the reservoir size and expected production rates and lifespan.

Because of this the reservoir would be produced by use of subsea installations like most other fields of the Gullfaks Satellite area. This would require either installation of new equipment on the seabed, or utilizing the infrastructure already in place in the area. Due to its size and expected production the Rimfaks Cook reservoir is not deemed to justify the investments required to add any new infrastructure to the area. The production would have to be executed through the existing installations of the Rimfaks field, as described in the area strategy section.

The subsea template considered to be most fitting for this development is the H-template. It is connected to a well currently in production, and has one available slot that could be used for a well into Rimfaks Cook. However, there is a pressure difference between the existing production well and the Rimfaks Cook reservoir that cannot be handled by the valves of this template. This makes producing these reservoirs simultaneously impossible. Because of this, the existing production well would have to be shut in order to be able to use this template in production of Rimfaks Cook.

If this production well is cancelled it is possible to drill a sidetrack well from the existing one. This would reduce the time needed for drilling and completing a well into the Rimfaks Cook, thus reducing rig time and expenses. In addition this enables the currently available slot of the H-template to be used for an injection well into the reservoir. This could improve the overall production and recovery factor, but would also require additional investments to drill and complete. By use of reservoir simulation and economic models these two solutions for production of the Rimfaks Cook reservoir will be further evaluated within this report.

7 Reservoir simulation

7.1 Introduction

To figure out if there was possible to develop the Rimfaks field with profit, a production optimization in the reservoir was needed to get as much oil out as possible. An ECLIPSE 100 simulator was used to simulate different opportunities and to compare results. The simulation model has been discussed earlier. To optimize the field production it was important to see the effect on field oil efficiency, FOE, by different well placement, type of wells, number of wells, injection wells, type of injection wells and different production/injection rates. We wanted to come up with the most valuable production plan, but because of the limitation of the subsea template as discussed above we had only 2 real cases to compare.

7.2 Results

Initially no wells were placed in the reservoir. To start the production, a vertical production well was introduced as being the easiest case. After some trial and error, it appeared that a horizontal well was clearly the best type of well in this reservoir. This was mainly due to the bad properties in the field. The field has low permeability and many small pockets of oil, as discussed earlier, that is hard to reach and produce with one single well. A horizontal well is also preferable because of the thickness of the layers in the Rimfaks field and it seemed to give a slower gas breakthrough. A vertical well would give lower recovery for thin zones than for thick zones. The model also contains some faults that limit the communication across them. This made the recovery for a horizontal well between the faults lower than for a horizontal well across the faults. It also mitigates the risk of only being able to produce from one single zone in the reservoir. Therefore, the best placement of the well seemed to be a horizontal well that was located across the faults, and reservoir layer 3 appeared to be the best production layer because it had the highest permeability. If an injection well was wanted or needed to maintain the reservoir pressure, a horizontal injector was preferable due to the same reasons for the horizontal producer. It seemed that the distance between the injection and the production well played a big part, and the decided positions are shown on the figures below.

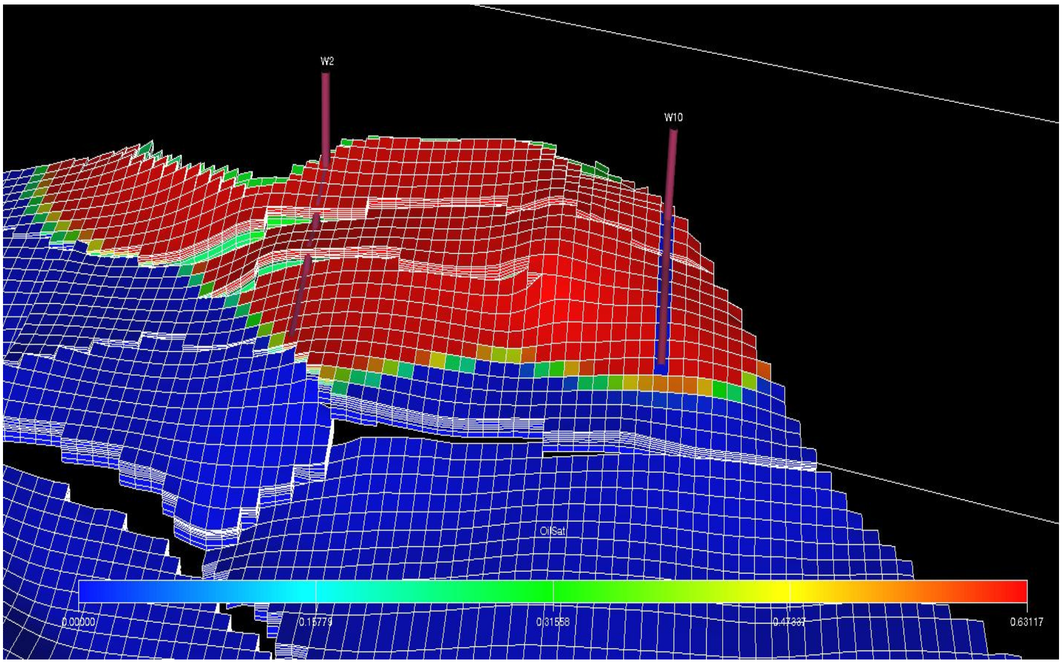


Figure 1: Initial oil saturation in layer 1. Placement of wells; W2 – producer, W10 – injector.

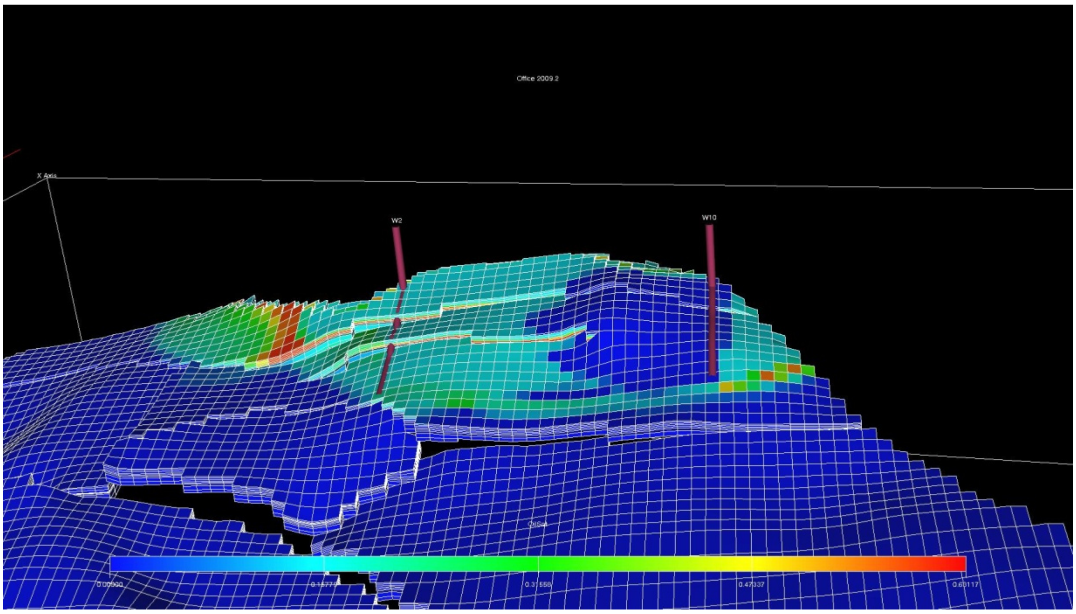


Figure 2: Oil saturation in layer 1 after production. Placement of wells; W2 – producer, W10 – injector.

For the first case with one horizontal production well, the oil recovery was at around 27% as seen from the plotted results below. This was significantly higher than for a single vertical well that did not produce more oil than up to 17% mainly due to a smaller production area. The reason for such low recovery from a single well was because of the bad properties in the reservoir and because of a rapid pressure drop when there was no pressure support. Together this gave a quick gas breakthrough when the reservoir pressure dropped below the bubble point pressure, and a rapid decrease in the production rate.

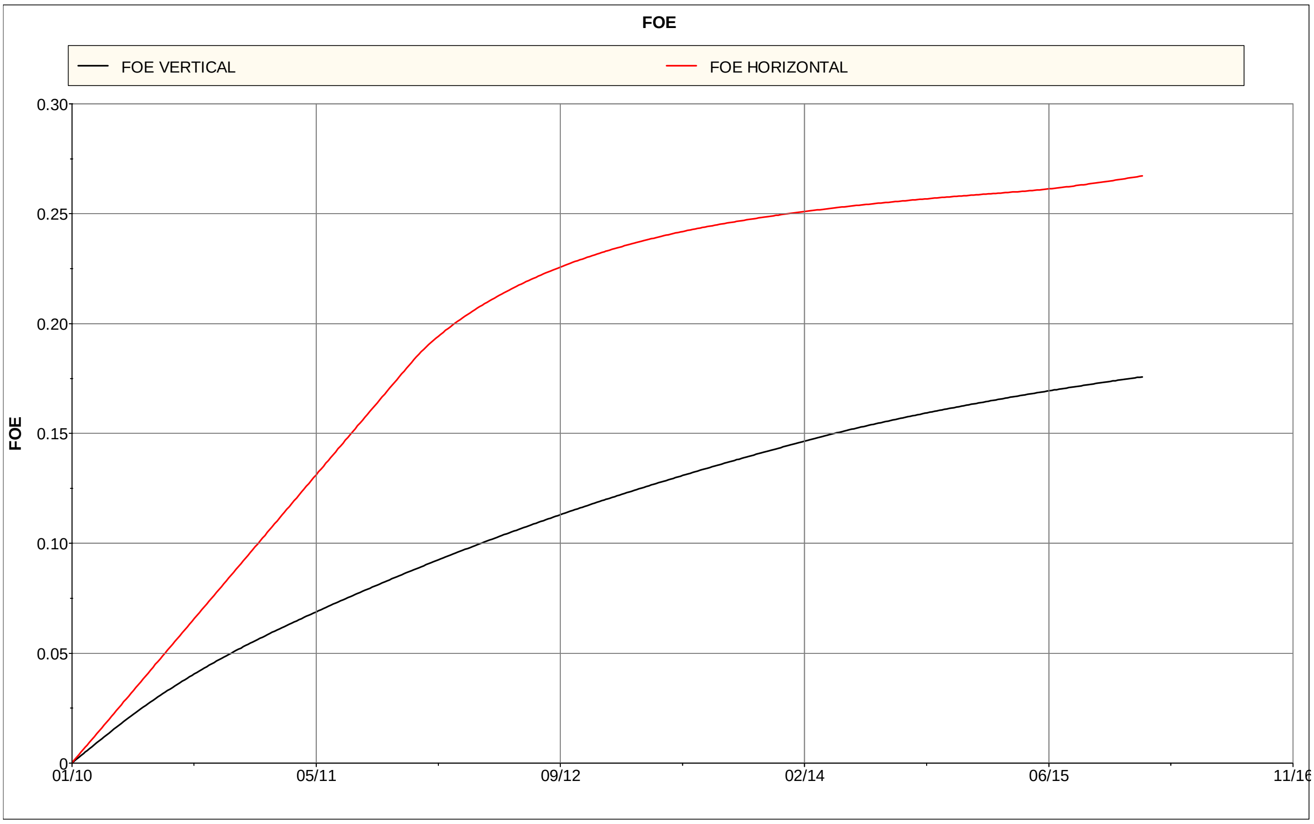


Figure 3: FOE vs time. Red: horizontal producer, Black: Vertical producer

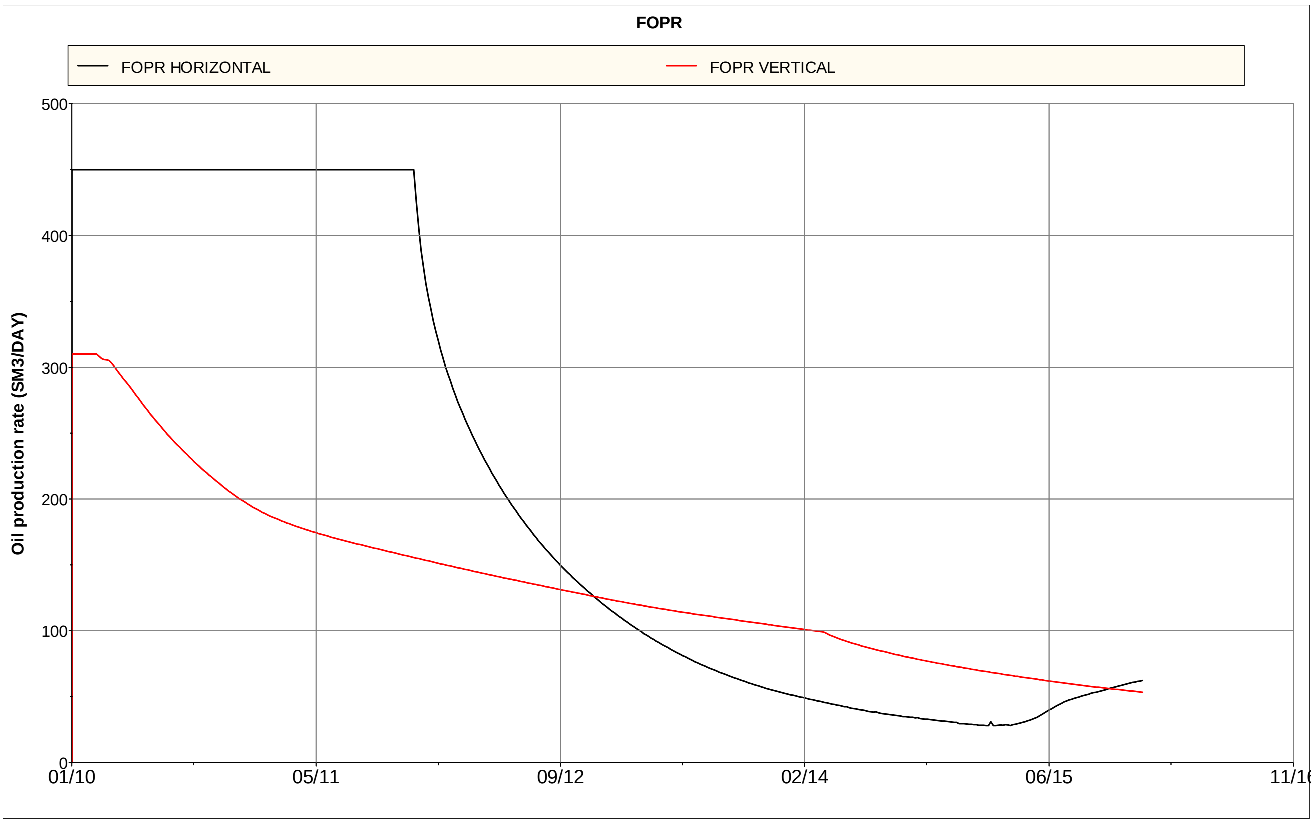


Figure 4: FOPR vs time. Red: vertical producer, Black: horizontal producer.

For the second case an injection well was installed in the last available slot in the template. The effect of this was interesting because it would give the reservoir some pressure support and would increase the production rate and the length of the plateau production. By introducing an injector, the pressure maintained above the bubble point for a longer time, and increased the time before gas breakthrough. The oil recovery increased to around 46% for a gas injection well.

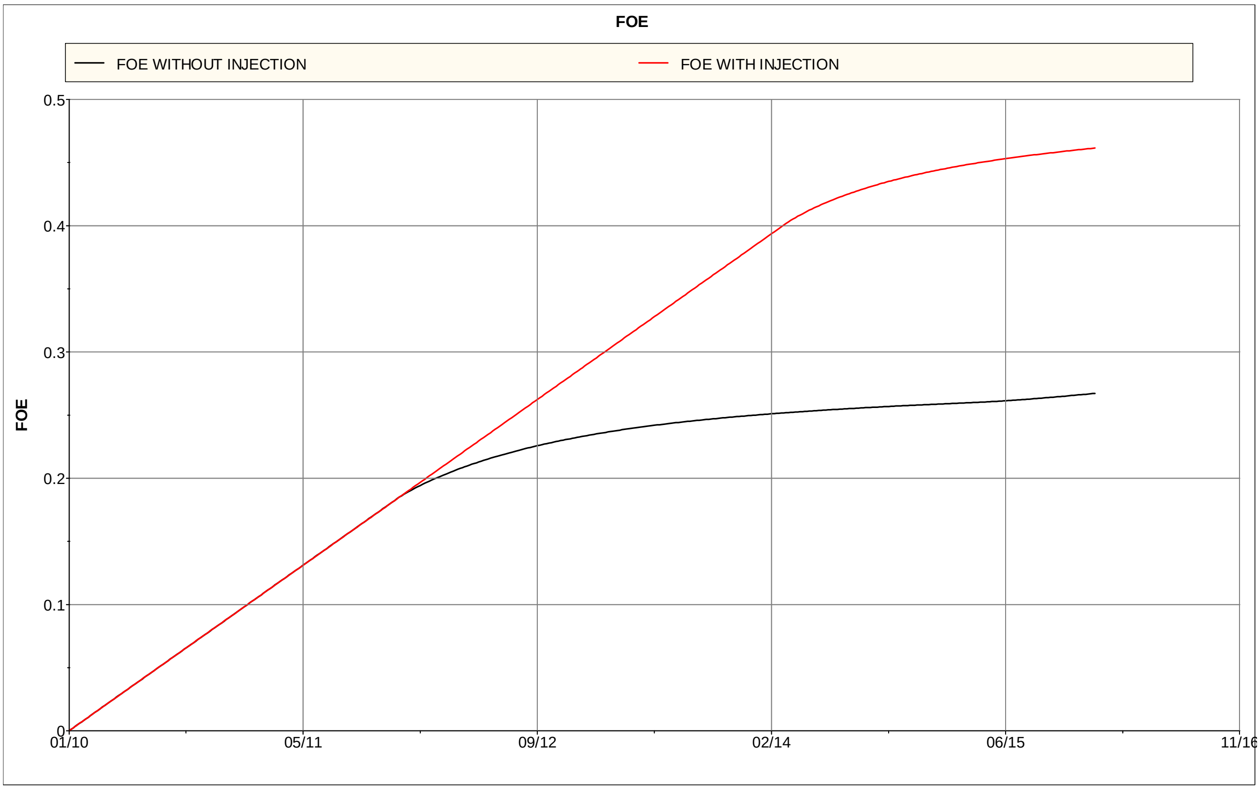


Figure 5: Oil recovery. Green: FOE for gas injection, Black: FOE for one production well only.

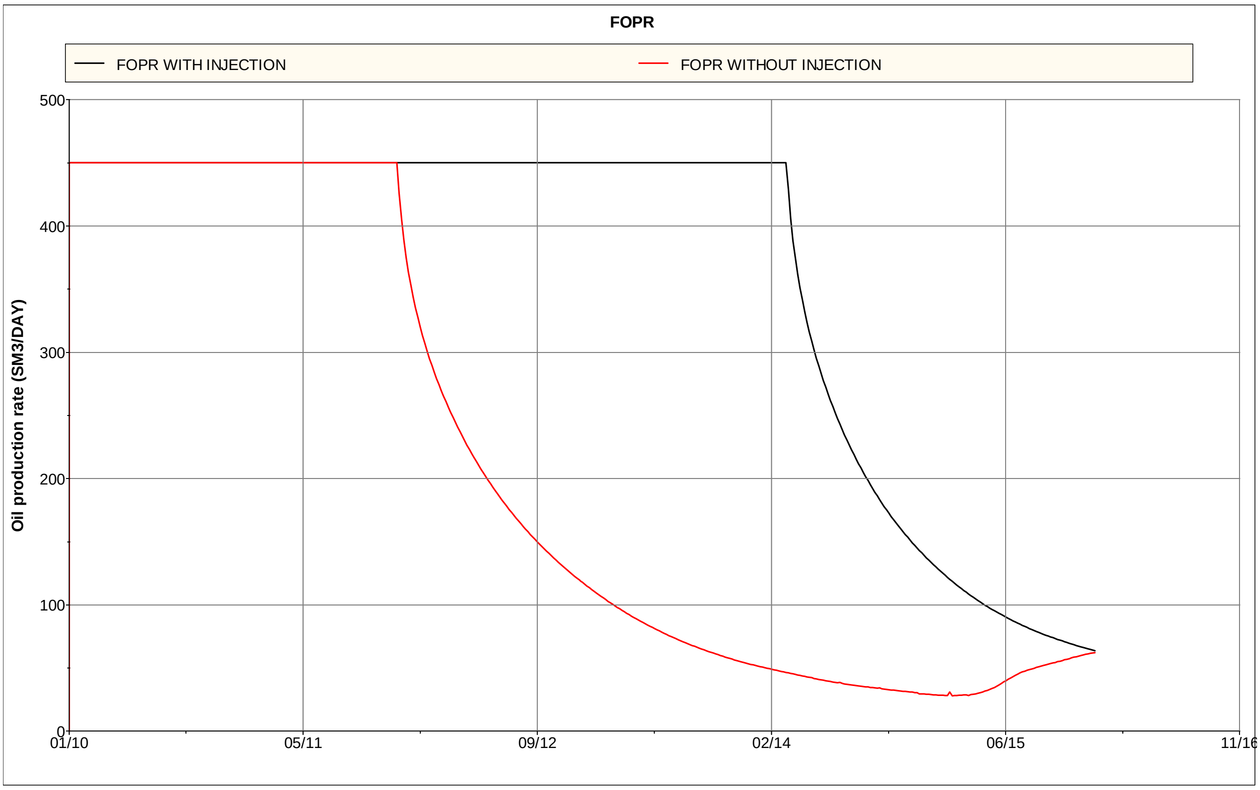


Figure 6: FOPR vs time. Black: FOPR for gas injection, Red: FOPR for one production well only.

Even though the recovery of oil increased with 19% for an injection well, the costs of an injection well had to be checked with respect to the increased income. The result regarding this is discussed later under the economy part.

7.3 Sensitivity analysis

A sensitivity analysis was needed to be done regarding some of the properties in the reservoir to mitigate the uncertainties. This was done by changing parameters in the ECLIPSE model, and observing the effect of the changes on the oil production. Especially the permeability seemed to greatly affect the total oil production because of the complexity and low initial permeability in the Rimfaks Cook.

7.3.1 Permeability

For both available cases the investigation from the sensitivity analysis gave similar results. Increased permeability in the reservoir gave an increasing oil recovery, whilst a decreasing the permeability decreased the recovery. For the case without injection the oil recovery was originally at around 27%. By increasing the permeability with a factor of 3, the oil recovery increased up to around 36%. If the permeability was reduced to half of the original, the production became around 22%. In the original case for both production and injection the oil recovery was approximately 47%. By increasing the permeability with a factor of 10 in this case, the recovery increased with around 10% and ended up with around 57% oil recovery. Similar effect was observed with decreasing permeability. It was a significant decrease in the oil recovery with decreasing permeability. By multiplying the permeability with a factor of 0.7, the oil recovery decreased with around 4% and ended up at around 43% for the lowest simulated case.

The observed results were as expected because the original permeability was very low with 12 mD as a maximum. For the higher permeability the recovery also seemed to increase more in the future, while in the original case the recovery seemed to flatten more out. The effect of the increased permeability seemed to affect the rate of recovery more for the case of only a production well. This is clearly seen on the graphs below. A reason for this might be because of the longer plateau production when pressure maintenance was applied. Also that the effect of changing the permeability was not significant before the production started to decrease could be an explanation. The changes on the permeability was done by adding a multiply factor to the permeability in the x-, y – and z direction

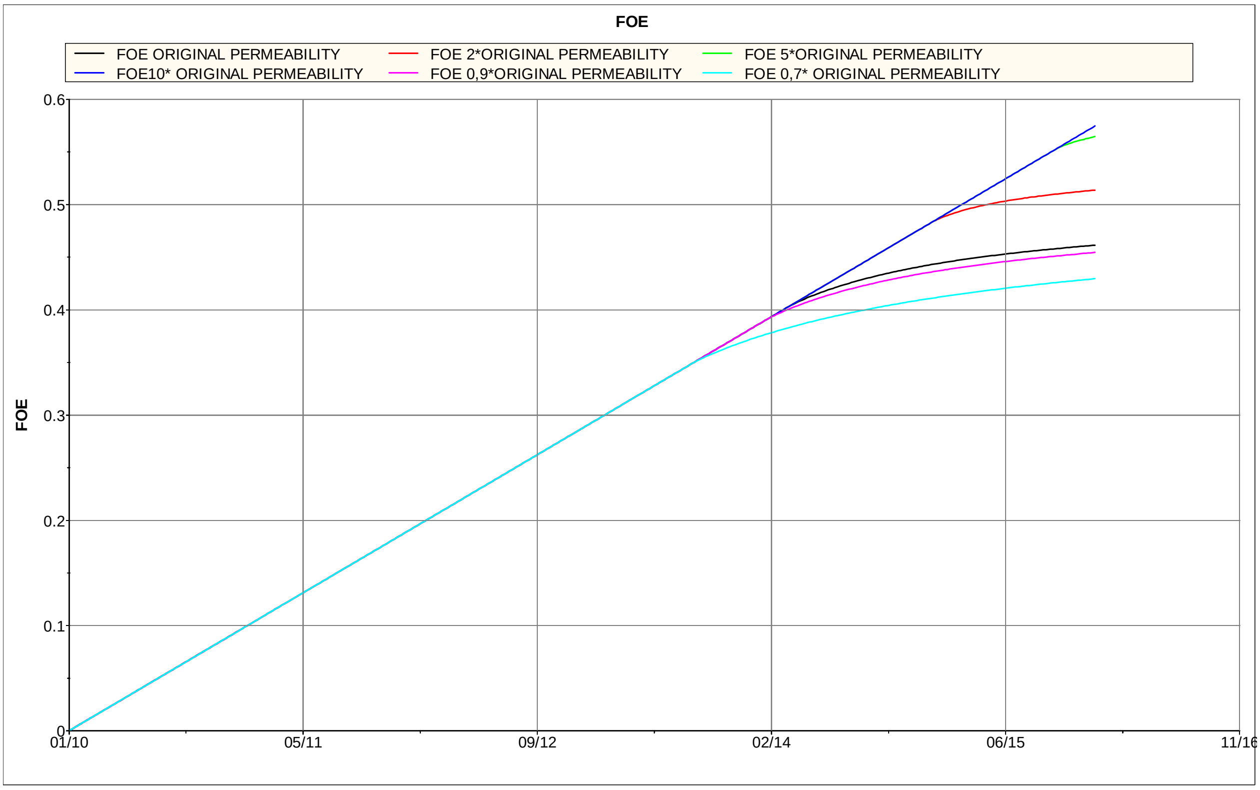


Figure 7: FOE vs time for injection and production. Light blue: 0,7*Original permeability, Pink: 0,9*Original permeability, Black: Original permeability, Red: 2*Original permeability, Green: 5*Original permeability, Blue: 10*Original permeability

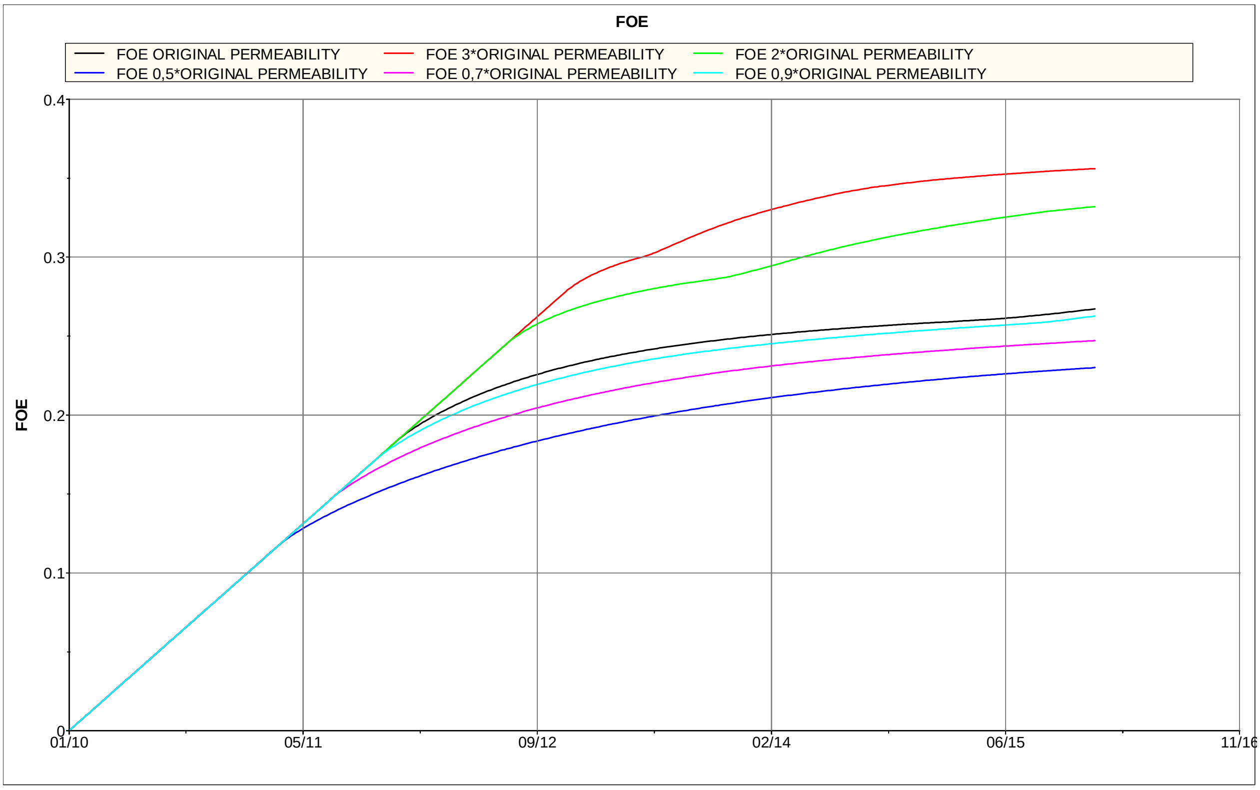


Figure 8: FOE vs time for only a production well. Blue: 0,5*Original permeability, Pink: 0,7*Original permeability, Light blue: 0.9*Original permeability, Black: Original permeability, Green: 2*Original permeability, Red: 3*Original permeability.

7.3.2 Transmissibility across the faults

As discussed earlier the Rimfaks Cook field contains a number of faults that makes the oil production in the field more unpredictable. A sensitivity analysis regarding the transmissibility across these faults was necessary to inspect the possible effects on the oil production.

For both cases small changes for increasing or decreasing transmissibility factor across the faults were observed. Doubling the transmissibility gave an increase in oil recovery around 1-2% for the case with only a production well and around 2-3% for the case that included injection.

The lowest simulated case was transmissibility equal to zero. The observed results are presented graphically below. The changes were done by adding a multiplication factor in the DATA – file.

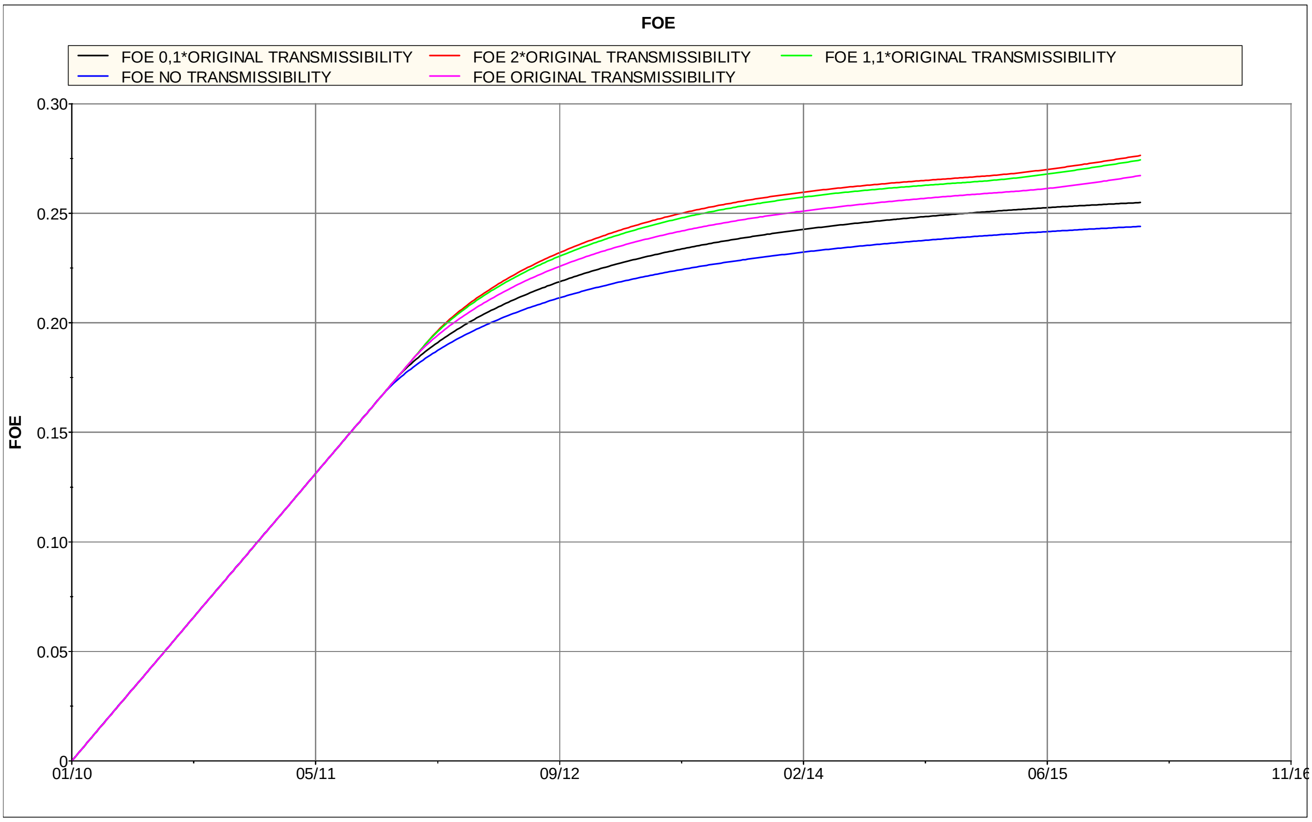


Figure 9: FOE vs time for only a production well. Blue: 0 transmissibility, Black: 0.1* original transmissibility, Pink: original transmissibility, Green: 1.1* original transmissibility, Red: 2* original transmissibility.

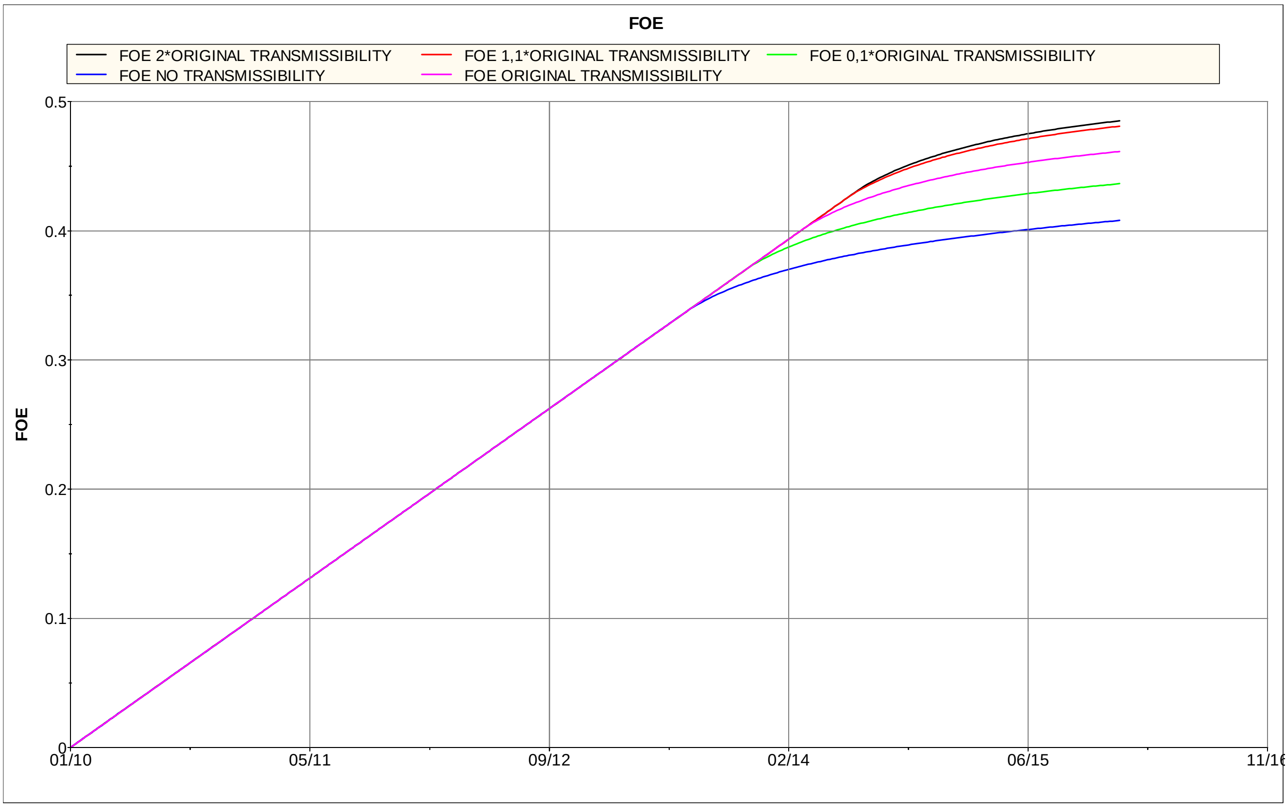


Figure 10: FOE vs time for injection and production. Blue: 0 transmissibility, Green: 0.1* original transmissibility, Pink: original transmissibility, Red: 1.1* original transmissibility, Black: 2* original transmissibility.

7.3.3 Relative permeability

One of the most difficult parameters to measure is the relative permeability. A short sensitivity analysis regarding this parameter was therefore applied for two different relative permeability curves.

The initial permeability curve was included in the model. A new curve was made simply by saying that the relative permeability to oil was equal to the relative permeability to water. This was done just to check the impact of changing relative permeability curves on the oil production. The results showed that the effect of changing the water relative permeability curve was small for cases of only depletion of the reservoir and gas injection. If water was injected into the reservoir as an imbibitions process, the results probably would have been more dependent of the water relative permeability. We did not have enough time to check this. By changing the relative permeability the oil recovery increased about 2% for the case with only a producer and approximately 1% for the case with gas injection. The different relative permeability curves and the observed results are presented below.

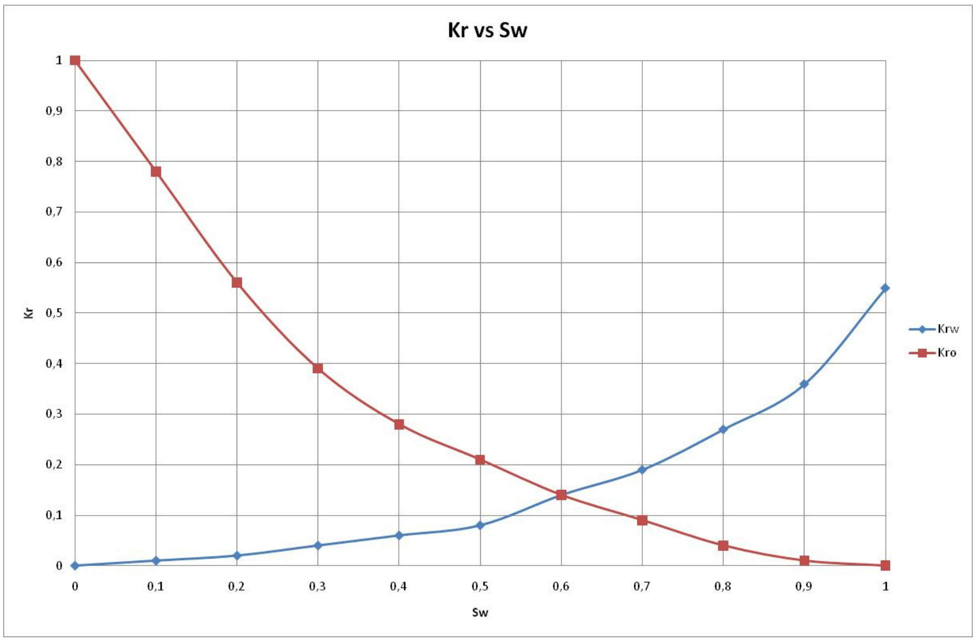


Figure 11: Relative permeability curve initially. Blue: Kro, Red: Krw.

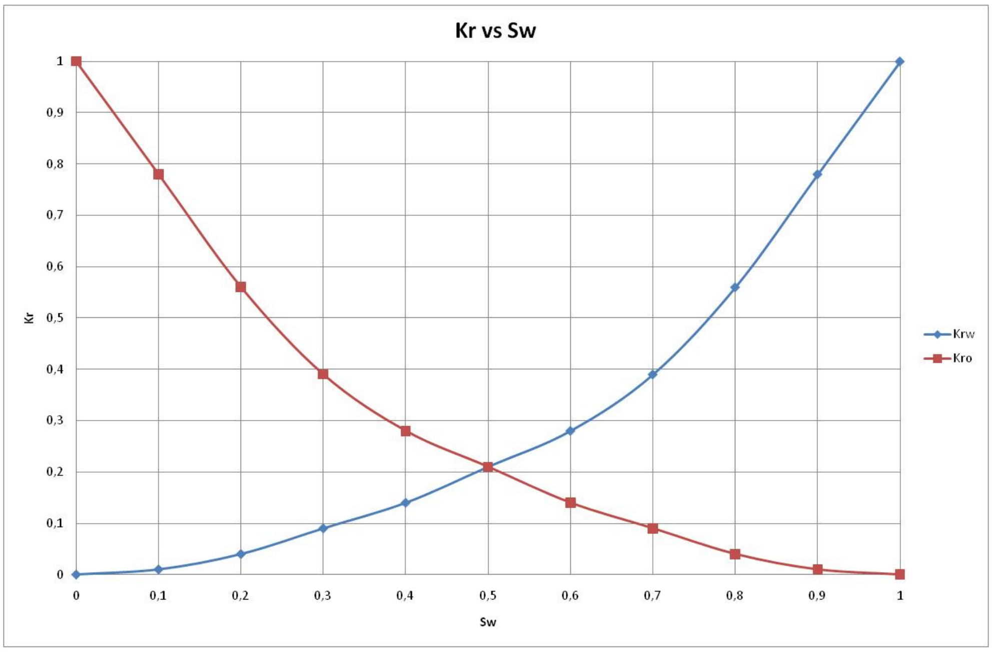


Figure 12: Relative permeability curve 2. Blue: Kro, Red: Krw.

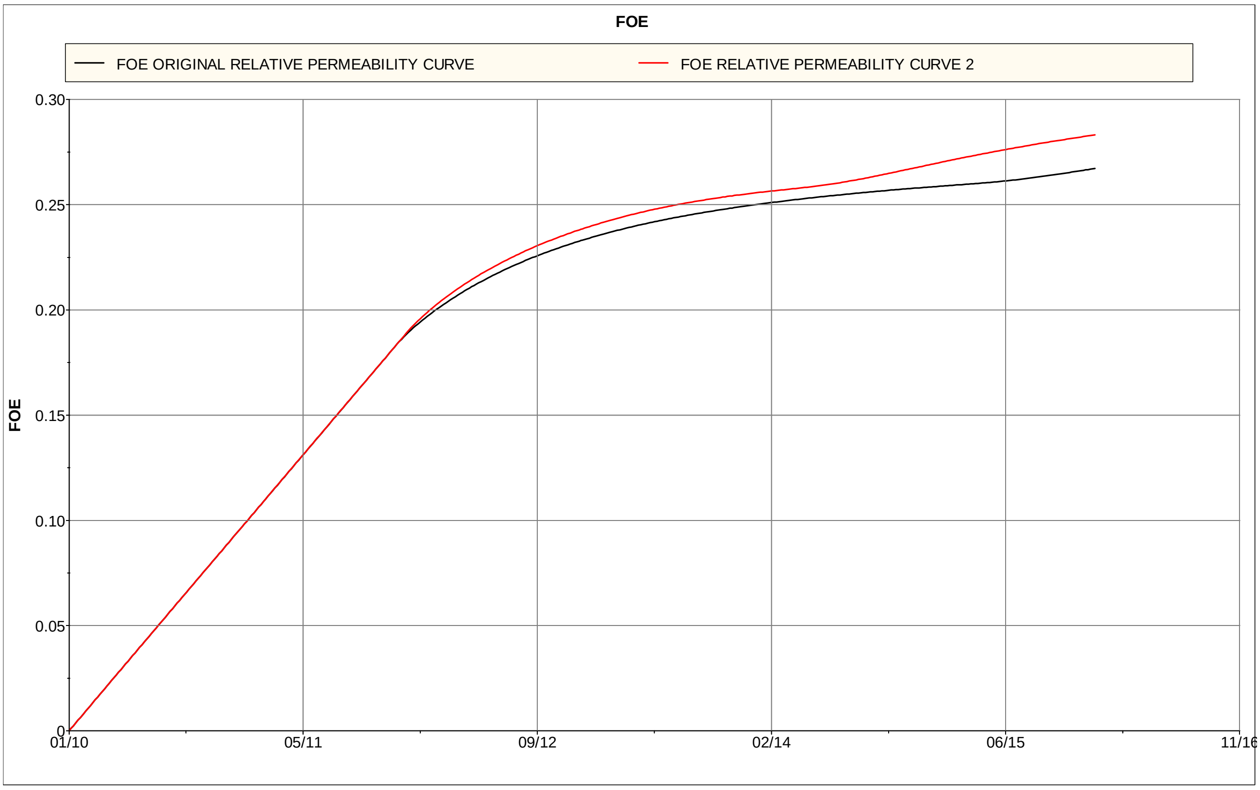


Figure 13: FOE vs time only for a production well. Black: Initial relative permeability curve. Red: Relative permeability curve 2.

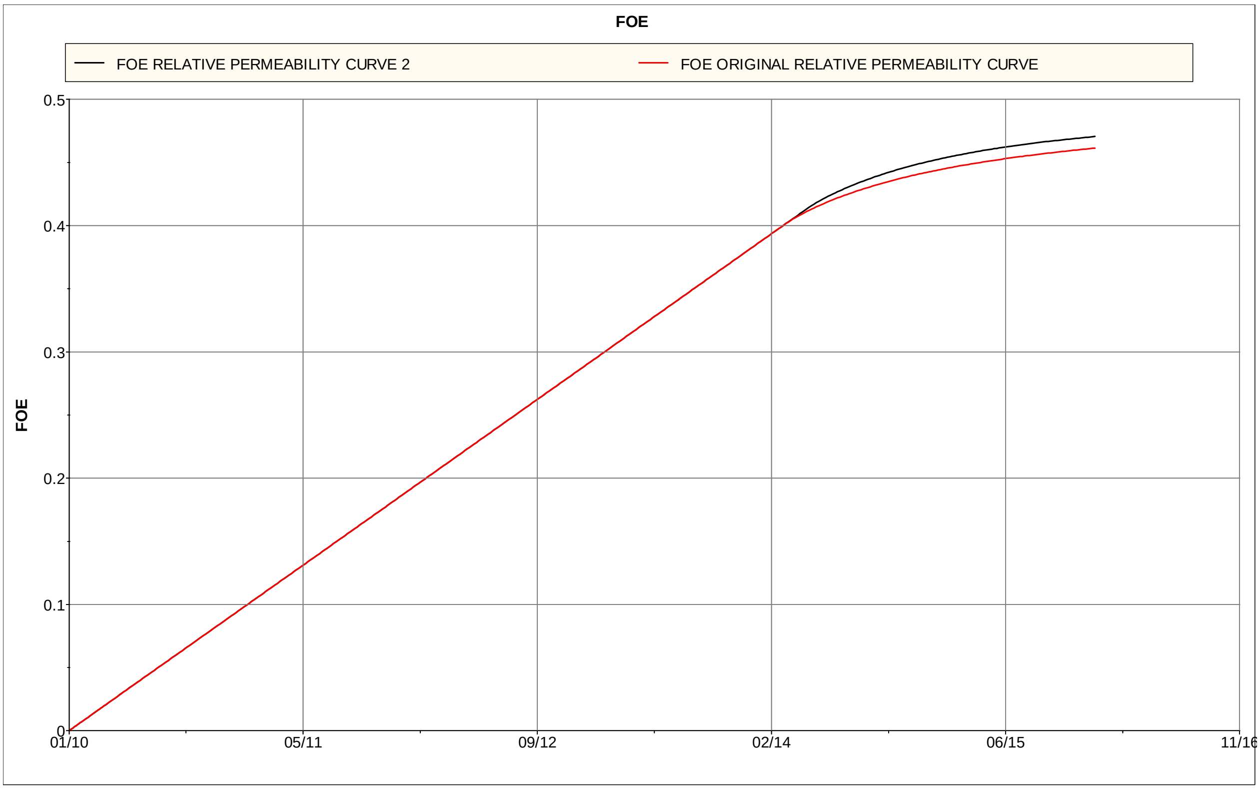


Figure 14: FOE vs time for injection and production. Red: Initial relative permeability curve. Black: Relative permeability curve 2.

7.3.4 Porosity

The effect of changing the porosity in the reservoir was also investigated. In this case, however, it was not convenient to check the effect on oil recovery because the pore volume in the reservoir also depends on the porosity. Comparing oil recovery from the same reservoir but with different HCPV may give misleading results. Therefore the effect of porosity changes was checked with respect to changing oil production. The porosity parameter was changed the same way as the permeability by adding a multiply factor to the porosity for the whole reservoir.

The results observed were as expected. Increasing porosity gave an increase in the total amount of oil produced, whilst a decreasing porosity gave a decreasing oil production. On the other hand, the increase and decrease in the production rate were not linearly dependent on the multiplying factor. This is as discussed earlier because the pore volume also changes with a change in porosity. It is therefore a bit hard to say something certain about the changes due to the different porosity. Increasing the porosity will increase the oil recovered and obviously the revenue of the project due to higher production. Intuitively, the effect is the same for reducing the porosity which reduces the revenue of the project.

Due to some simulation error the effect of decreasing porosity for the case without injection is only included for 0.99*original porosity.

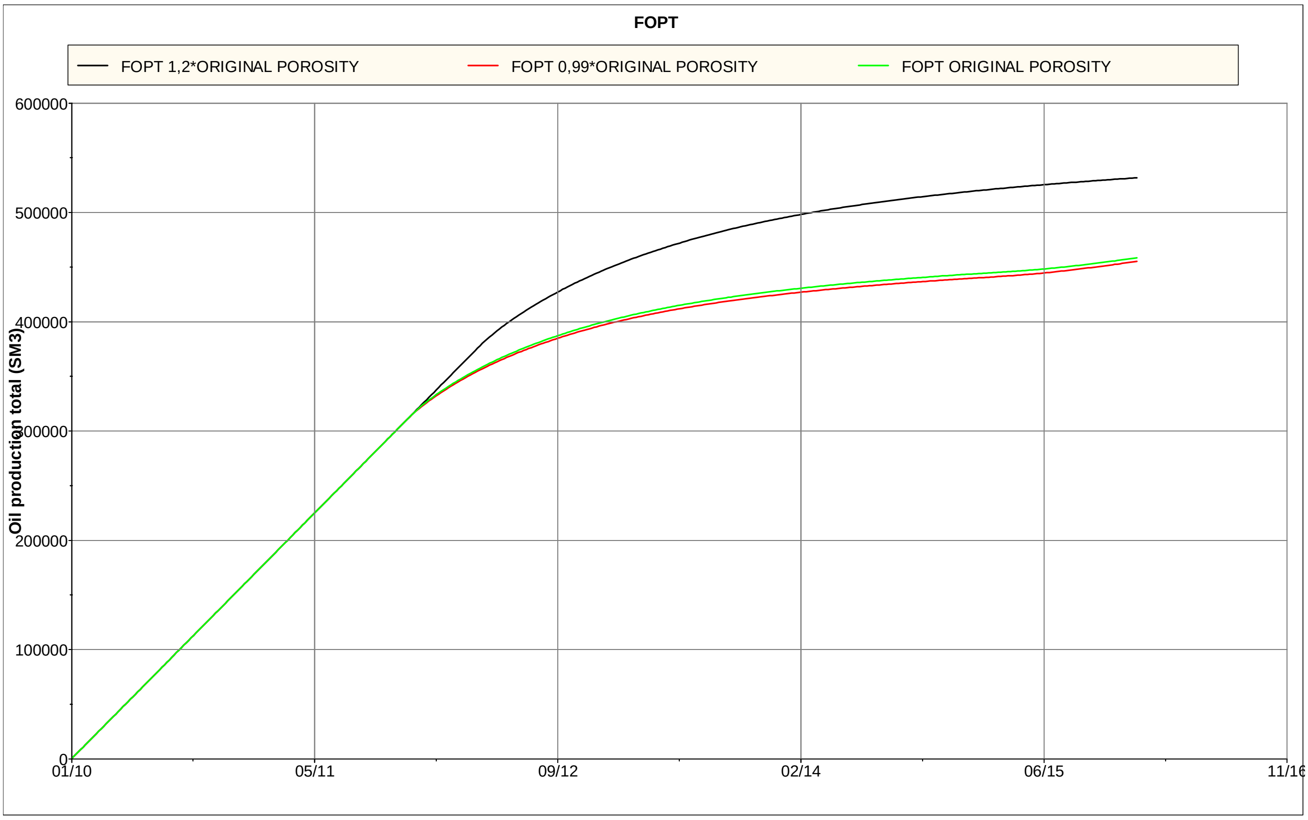


Figure 15: FOPT vs time for only a production well. Red: 0.99*Original porosity, Green: Original porosity, Black: 1.2*Original porosity.

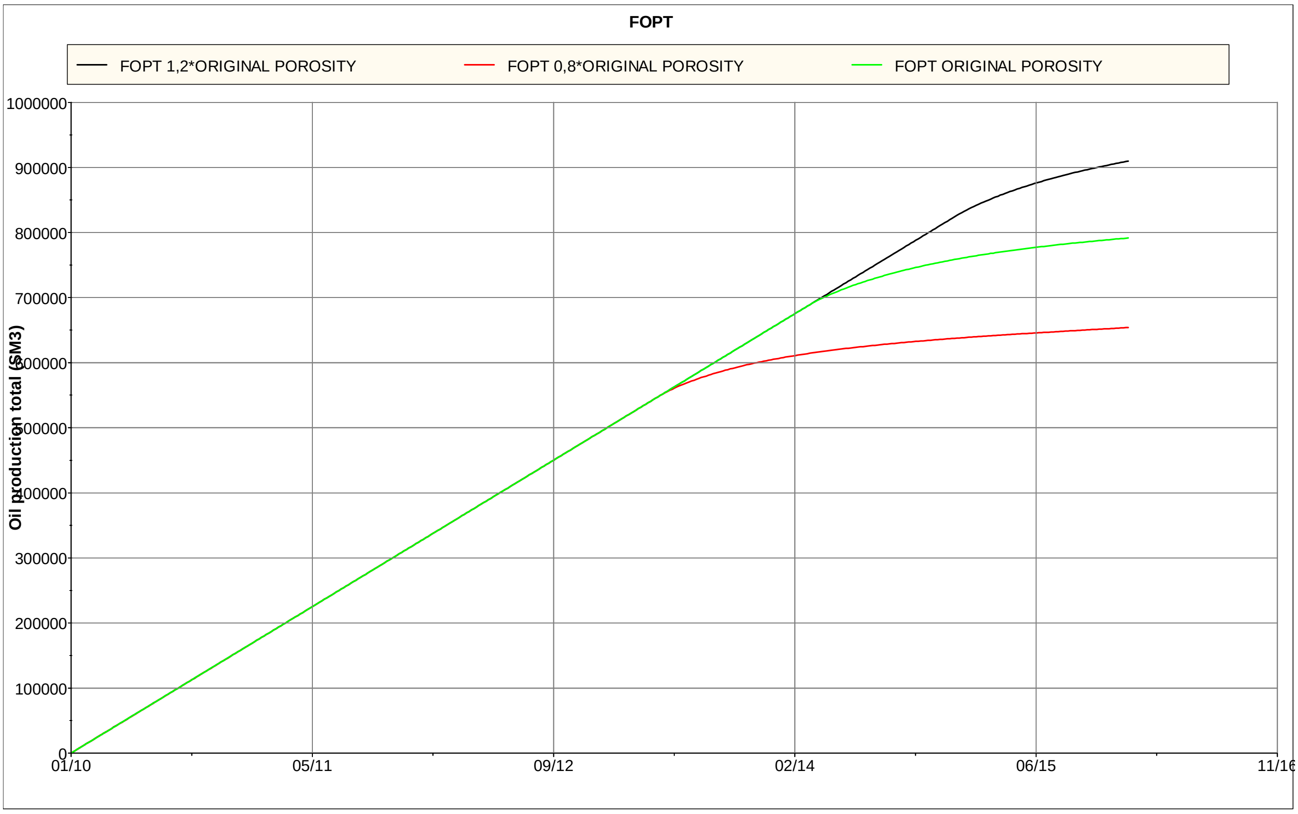


Figure 16: FOPT vs time for injection and production. Red: 0.8*Original porosity, Green: Original porosity, Black: 1.2*Original porosity.

7.4 Observation

The sensitivity analysis showed that there is possible deviation in the oil recovery regarding parameters in the reservoir. Permeability clearly has the biggest impact. It gives an increase in recovery on about 9-10% for the highest simulated case and a decrease on about 4-5% for the lowest simulated case. These extremes are the basis for the chosen sensitivity analysis regarding the economical analysis below. Statoil operates with a standard +/- 30% sensitivity regarding economical analysis. By combining our extremes and Statoil standard, we figured out that a +/- 20% sensitivity in our economical analysis would be an appropriate case. This gives a good safety margin, and regarding the above sensitivity analysis 30% would be too optimistic for our reservoir.

8 Economical Analysis

8.1 Capital expenditure

When all the uncertainties and risks were listed an evaluation if the field is economically favorable was made. First the capital expenditure (CAPEX) and drilling expenditure (DRILLEX) were accounted for. In the calculations the DRILLEX were included in the CAPEX. This includes rig rental with service, drilling, completion, P&A etc. These are expenses that will come before production is started and therefore are very crucial to the project. In the prospect and economical analysis only the DRILLEX had to be taken into consideration. This is because existing infrastructure is used in our chosen solution. There will be some costs of transport but these are included in the operational expenditure later.

8.2 Rig cost

From the summer 2011 Statoil will have two semi-submersible drilling rigs working in the Gullfaks area. These are the Odfjell drilling rig “Deepsea Atlantic” (Rigzone, 2011), and the Songa offshore rig “Songa Dee” (Offshore.no, 2010). The Deepsea Atlantic is the bigger one, being able to handle water depths within 70 – 3000 m, with a drilling reach of 11500 m (Odfjell, 2009). The Songa Dee is able to operate up to 550 m water depth with a reach of 9120 m (Songa Offshore, 2008). Both rigs are able to perform the drilling operations needed to develop the field, if they could be made available for the project.

On average the daily rates for semisubmersible rigs of this size in the North Sea is between 310000 and 395000 USD/day (Rigzone, 2011). This varies with the size of the rig. These figures exclude service costs related to maintaining drilling operations. Service costs can be estimated as equal to the rental cost, thus yielding a daily rate of 620000 – 790000 USD/day. When evaluating the drilling costs for the project the highest value is chosen as these figures have some uncertainties, yielding a daily rate of approximately 4.6 million NOK/day. Due to large contract backlogs the market for semi-submersibles was not highly influenced by the recession of 2008 (Rigzone, 2009). There was however a decline in terms of new contracts awarded, making the daily rates stabilize as more rigs would become available coming off contract. At the moment the market is described as stable, but current oil prices may cause an increase in the activity (ODS-Petrodata, 2011). We do not expect that a change in these rates could have a major impact on the project, especially as it is set to be started up already in 2012.

Two different options were considered for the development of the field, with or without an injection well. If only to drill the production well was chosen, 20 days for P&A, 15 days for completion and 60 days for drilling into the reservoir were assumed. This gave a total of 105 days of rig rental. In addition the possibility to also drill an injection well was evaluated. This alternative then includes 20 days of P&A, 30 days for completion and 120 days of drilling, a total of 170 days. We assumed that the lengths for drilling the wells are approximately the same, 4500m. The assumption of drilling 4500 m in 60 days was based on drilling to the Topas formation. The Topas prospect lies between the Gullfaks and the Visund fields and here they drilled 7400 m in 102 days (Statoil, 2004).

This is however an estimate with uncertainties. Drilling operations is generally exposed to time delays, which could be caused by a number of reasons. Both downtime caused by equipment errors on the rig and problems within the wellbore could arise. This also applies to the P&A procedure and the completion. This must be accounted for when evaluating the economic feasibility, creating different scenarios for the total rig time. In the high expense case, the rig time is extended by 50% to evaluate how a significant delay may influence the result. A case where the drilling is more efficient than expected is also created, reducing rig time by 15%. This assumption is made as the probability of a significantly reduced rig time is assessed to be much lower than the chance of a delay.

When the production is completed there has to be performed a P&A procedure the production well, and the injector well if this alternative is chosen. This operation is assumed to require 20 days for each well, the same as for the initial investments. The daily rates for rig rental assumed to be at current level. This is somewhat uncertain, but it is difficult to make a reasonable assumption for the rig market several years ahead. Also, using a discount factor of 15% means that the impact on the project NPV from these expenditures will be reduced.

8.3 Operational expenditure:

When the CAPEX were accounted for, the operating expenditure (OPEX) had to be evaluated. This includes fixed costs such as field operations and transportation. Production related expenses such as energy consumption, water disposal, injection and export should also be included. There can also be need for maintenance, either planned (preventive) or unplanned. In Rimfaks Cook most of the CAPEX are included earlier as existing infrastructure is used. The costs for transportation and processing of the produced oil and gas had to be considered and accounted for. Some general information about the economics in developing a prospect was given from Statoil. For subsea production of oil 200NOK/bbl and 10 NOK/bbl for transportation should be used (Statoil, 2011). By our advisor we were advised to use 0.50 NOK/Sm^3 for gas transport and processing.

8.4 Oil price:

When both the capital and operational expenditures were accounted for an evaluation of the oil price had to be made. This is a very difficult part of the economical analysis. There are a lot of factors that will influence the price of oil in short, medium or long term. Right now you have the riots and developments in Libya. Only weeks ago you had the same tension in Egypt which drove the Brent Oil over 100$/barrel and later with the situation in Libya it has risen up to 118$/barrel (Lior, 2011). Still, unless these situations do not solve themselves or they spread to other countries these are short-term factors. In the field development process and production one has to look at the whole production period. The price will probably have a steady increase due to long term implications as demand outgrowing the supply. Also, the expansion and development of countries like China are another important factor (LiveOilPrices, 2010).

After writing this the tsunami hits the coast of Japan. This meant that the third largest economy starting dropping and concerns about the demand of oil would drop started rolling. The oil price then dropped immediately to about 112$/barrel. At the same time the news did not cover “the day of rage” in Saudi Arabia (Dagens Næringsliv, 2011). At the time being tension seems to be subsided but it remains to see if the tension erupt into something more. Another factor is that other OPEC members pick up Libya’s oil production and increase theirs’. By doing so it reduces the pressure of further increase in the oil price.

Some are conservative, while other believes there is a bubble emerging in the oil market. What most traders/consultants agree upon is that demand is steadily outgrowing the supply. The EIA latest energy report with outlook for 2011 shows a WTI spot price estimated at 105$ which is an increase from earlier (EIA, 2011). The Brent Oil has some higher spot price and during 2011 there has been a difference of just over 10$/barrel. This means that EIA assume about 115$/barrel for Brent oil in 2011. We believe this is a good approach for the oil price in following years if the market stabilizes.

Since the terrorist action until the peak in oil price in 2008 the world saw a fast increase just as after the recession. Therefore the assumption that the oil price will keep rising during the lifetime of the field was made. With all the tension in Middle East and in the market as a general it could be smart to be conservative in the coming years. An increase of 1% p.a. is a bit conservative, but evaluated as a good choice in an unsecure market.

As the oil price has fluctuated as much as it has historically it would be smart to do the sensitivity for quite a big interval in the low and high case. The lifetime of the field is seven years before P&A for the production well. If we look back at the oil price for the last seven years this has varied from 45$ to 150$ (fig.5.1). Going ten years back it was as low as 30$, which gives a range of about 100$ in a very short period of time.

We assume the optimistic case to be 130$. This choice is based on the assumption that there will be tension in the Middle East, demand from Japan and the debate about nuclear power. If these factors are correct there will be a higher demand to replace other energy supplies and a reduction of oil from the Middle East. On the downside we believe this could be estimated at 70$. This is if there is stabilization in the Middle East, Gaddafi is removed, OPEC maintains or increases their production and the supply is satisfactory. Still, this is a very pessimistic case looking at the market today but as the fluctuations have been immense we chose a large downside.

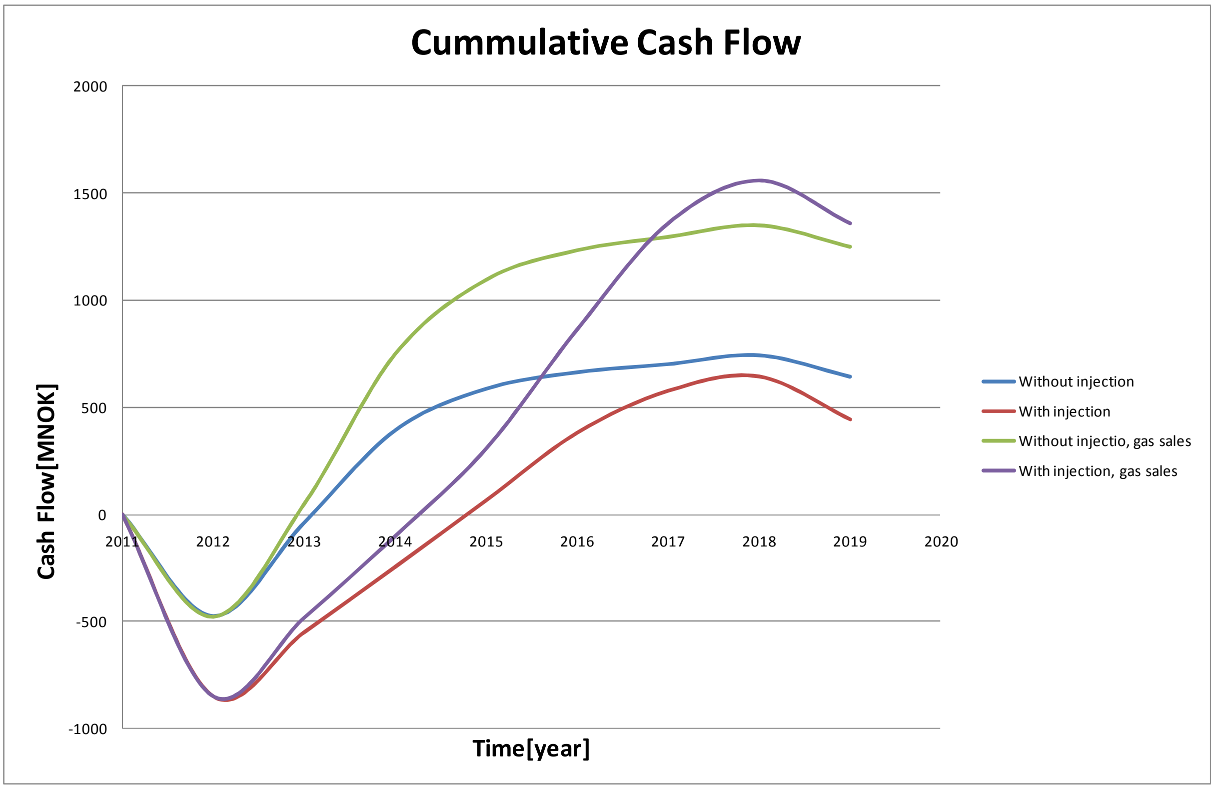
8.5 Other factors

From our advisor in Statoil we were given that the gas was sold to the EU at 2.06 NOK/Sm3 to date. As the market here as well had increased during the last couple of months we chose in consultation with our advisor that 1.79 NOK/Sm3 was a good base case. As the gas market is fluctuating some as well we had to evaluate an interval for this. An optimistic case would be stabile prices at the level we have today and chose 2.10 NOK/Sm3. After the recession the gas price has been low as many has the supplies while the demand has not increased. Taking the large amount of gas in the market together with the demand we chose a pessimistic case at 1.30 NOK/Sm3.

The dollar is used as the currency for trading oil. This means that the price of oil is dependent on the exchange rate of the dollar which depends on the US economy. As the US is in large economical depth we assume a low dollar, at least historically (The Titi Tudorancea Bulletin, 2011). We therefore assume an exchange rate of 5,5NOK/$ in our calculations. There are a lot of factors that affects the economy of a prospect but we do not have the possibility to take all into account.

8.6 The Results

Four different solutions for the base case in the economical analysis were evaluated. The solutions are no injection without gas sales, with gas sales, injection without gas sales and injection with gas sales. All the four cases gave a good cumulative actual cash flow:



This means that all four cases give us a positive internal rate of return, IRR, in the base case. All of the solutions have a negative cumulative cash flow in the beginning of the project as most of the investments are placed here. The turning point comes in the second year, which is logical as production starts here. To check which solution is the best, the IRR and break even oil price are calculated:

Method:	Internal Rate of Return:	Break even oil price:
No injection, no gas sales	65,8%	74,4$/bbl
No injection, with gas sales	104,2%	36,3$/bbl
Injection, no gas sales	42,2%	74,3$/bbl
Injection, with gas sales	58,4%	41,8$/bbl

This shows that injection is not a desired solution and that the gas produced should be sold. As the prospect is a very complex field with low permeability, injection will not improve recovery enough to defend the investments of an injection well. In addition, the extra OPEX of injecting the gas were not considered. As the solution with injection does not improve the recovery to a big enough extent the option will not be evaluated. We choose to sell the gas, but the decision depends on the gas supply at Gullfaks and if the gas is needed for injection. Still, the IRR is high and the project gives positive NPV. For further analysis no injection with gas sales will be used as the base for our analysis. Rimfaks

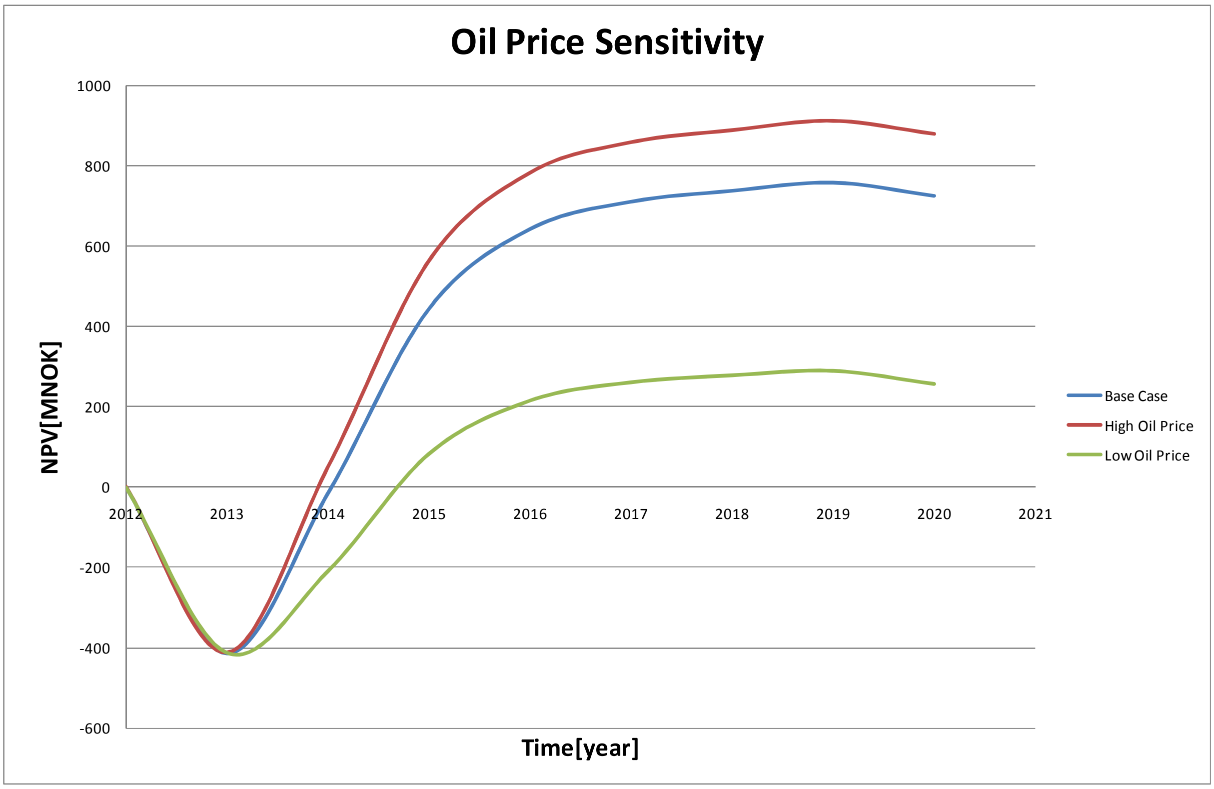
Cook then seems like a good prospect/investment, but the effect of the factors described above have to be evaluated.

8.7 Sensitivity Analysis

Sensitivity analysis means checking the effect of one risk while keeping the uncertainty of the others constant. Here the sensitivity for oil price, investments and production are checked. All of the sensitivities are presented with Net Present Value with a discount factor of 15%.

8.7.1 Oil Price Sensitivity

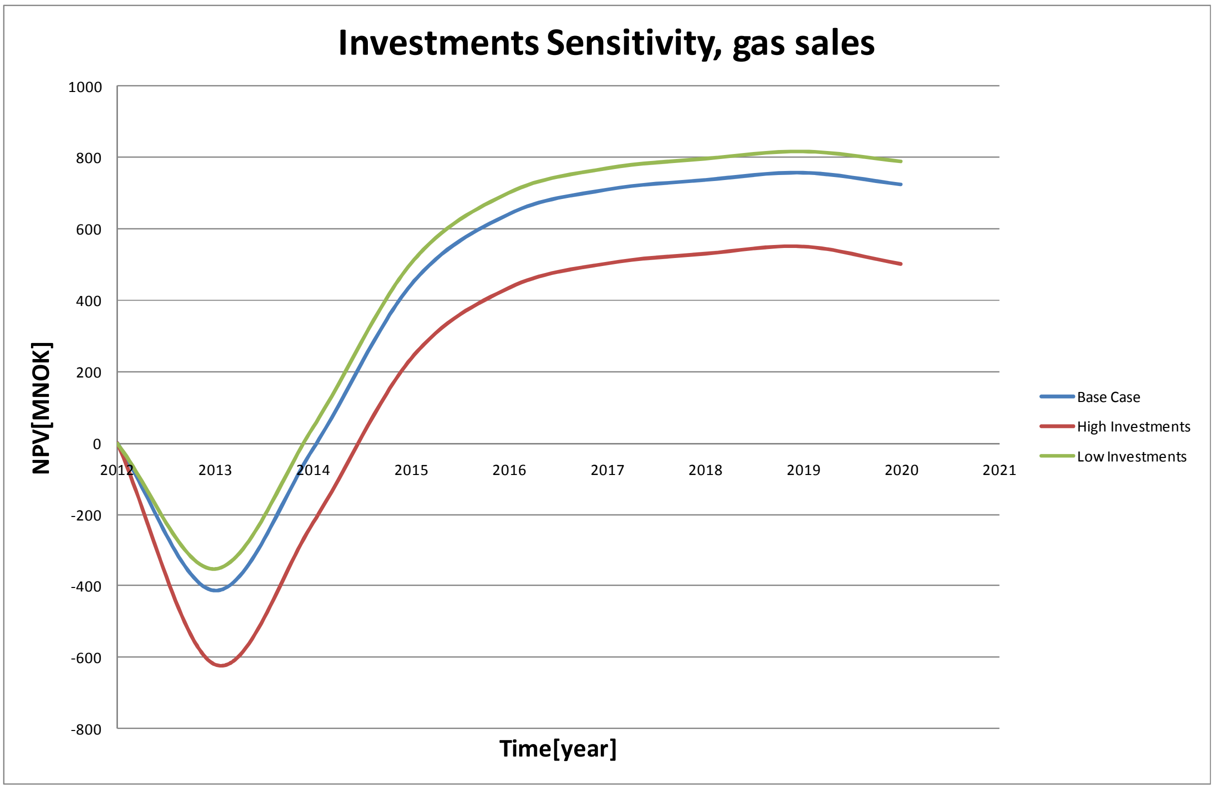
Using Excel gives a break even oil price at 36.3$/bbl for the chosen case. This gave a positive NPV for all three scenarios of the oil price:



There is no difference the first year as the investments are not affected by changing the oil price. When production starts in 2013 the cumulative NPV starts increasing and reaches a positive NPV after about one year for base and optimistic case. The pessimistic case needs about 20 months of stable oil price at 70$ to get a positive cumulative NPV. Still, all of the oil price cases give positive NPV.

8.7.2 Investment Sensitivity

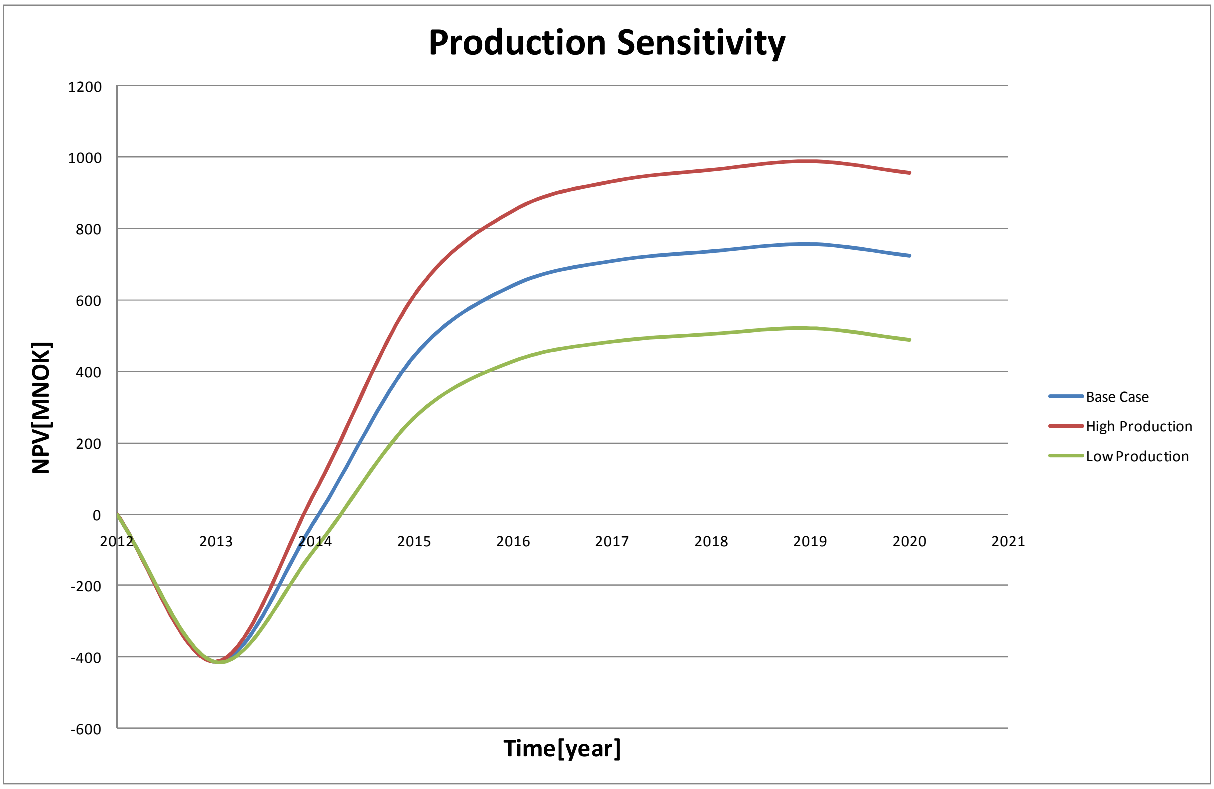
-15% is chosen for best case scenario and +50% for the worst case scenario. These are estimates for how many days of rig rental needed differing from the base case.



In the investments sensitivity all the differences are at very beginning and the very end. The investment costs in the beginning are much larger and the most important. Both because they are larger than at the end and that they come before the project gets any income. Reducing the uncertainty by a good evaluation here is very important to reduce the uncertainty of this risk.

8.7.3 Production Sensitivity

From the reservoir analysis an evaluation of +/- 20% were made as a good interval for the production numbers:

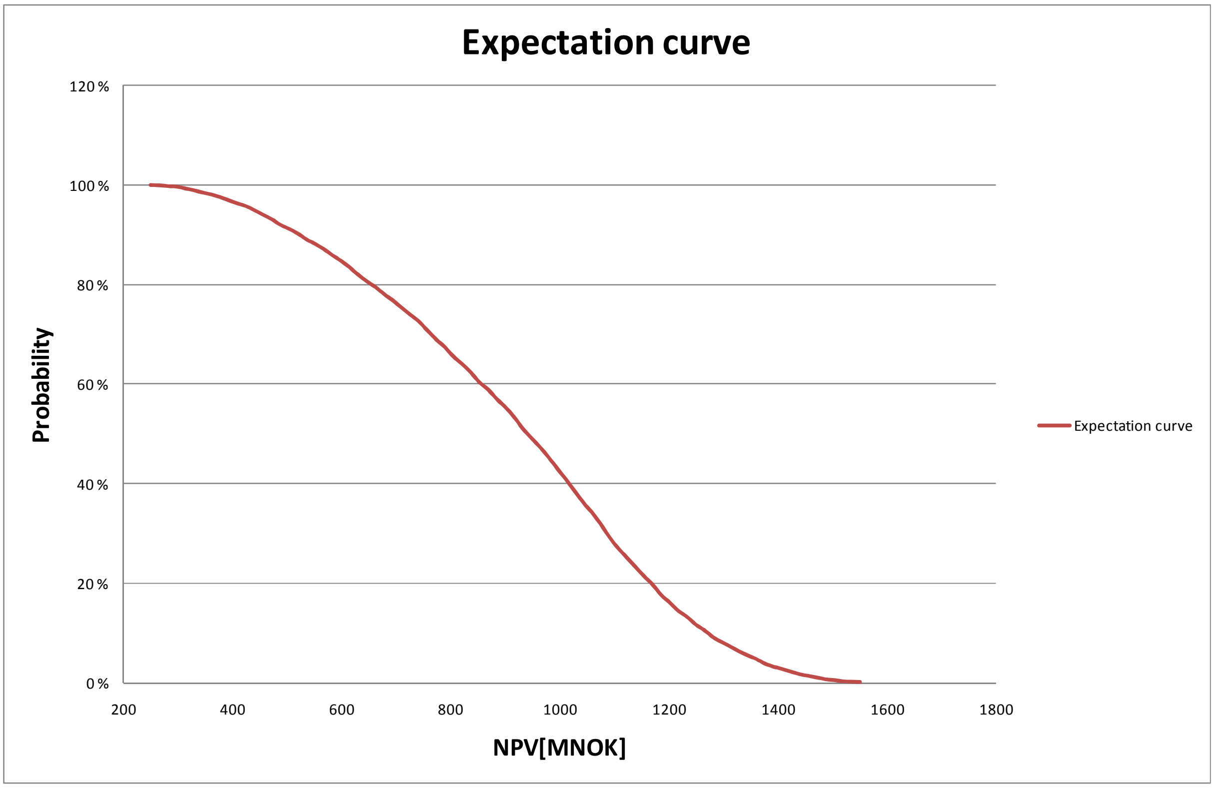


The uncertainty of the risk in the production is based on the sensitivity analysis of the reservoir parameters. This means that permeability, porosity and transmissibility are included where the permeability has the most effect. All of the estimated volumes from the reservoir volume give positive NPV. When selling both oil and gas, one has some margin for profit.

8.7.4 Monte Carlo

In the sensitivity analysis only one factor were changed at a time and checked for the effect of this. Here in the Monte Carlo analysis all the parameters changed at random in the given intervals. The same uncertainty in each risk was the same as in the sensitivity analysis. The gas price is also included as described earlier in the chapter. We have evaluated P-10, P-50, P90, mode and mean as the different possible cases. One random simulation gave these values:

P-90 [MNOK]	P-50 [MNOK]	P-10 [MNOK]	Mean [MNOK]	Mode [MNOK]
539	951	1285	895	959



We chose to use the mean as a base for the evaluation of the prospect. This is because a mean would give the expected outcome when performing a high number of iterations. As we see this gives a good outcome for our prospect and gives 890-900MNOK with NPV 15%.

8.8 Summary

As one can see the project gives good revenue and is economically viable according to our assumptions and sensitivities. The best way to evaluate the project due to the assumptions made we believe is the Monte Carlo simulation. This takes all the uncertainties into account and gives the mean of the uncertainties in the risks. Evaluating the project from the assumption that this gives the most likely outcome we get a very good result. Performing several Monte Carlo simulations we get a mean that is varying from 890-900 MNOK which are very good numbers for this project.

We have evaluated several sensitivities and none of these gives a negative NPV. This means that we believe that this is a good prospect in the market as it is today with a high oil and gas price. Having the possibility to use existing infrastructure is of course crucial to make this profitable. Use of existing infrastructure is also a part of the Statoil strategy on the NCS, another reason for going further with the prospect in near future.

9 Alternative production options

9.1 Current producer

The H-template is currently connected to a producer in a reservoir zone below the Rimfaks Cook. This well is under a production license expiring 2015. Currently the well is shut down while injecting gas to build up pressure. This process is planned ending in 2013, when final pressure depletion is to be conducted before the expiry of the production license. The Rimfaks Cook reservoir is planned to be produced through a sidestep operation from the existing well. In order for this plan to be executed before the existing production is completed in 2015, the well has to be shut in and plugged. It could be possible to resume production from the existing well after production of Rimfaks Cook is completed. However it is not certain that it would be possible to extend the production license beyond 2015. Because of this, initiating the Rimfaks Cook development before the existing production is completed could result in loss of the remainder of this production.

9.2 Extended well into adjacent reservoir

There is a Brent reservoir zone adjacent to the Rimfaks Cook reservoir. This would be possible to reach if the well planned drilled into the Cook formation is extended. This could increase the project value making it more economically feasible. There is no model estimating the volumes of producible hydrocarbons, making this option require additional data collection and simulating. This has to be done in order to assess whether the reservoir contain enough hydrocarbons to have an impact on the Rimfaks Cook project.

9.3 New prospect in the region

An adjacent prospect might prove large enough to finance additional subsea installments, from which the Rimfaks Cook could be produced. This would enable production of the Rimfaks Cook reservoir without having to plug in the existing producer. This could prove to be a better solution economically, and could also be combined with the extended well into the Brent reservoir. There is however too little knowledge regarding the prospect to assess whether this is a realistic development scenario.

10 Milestones

The next step in the decision phase is to evaluate the prospect versus the existing production well. The reservoir simulation and economic analysis show positive results for Rimfaks Cook. Still it must be compared with the existing well in terms of NPV and IRR to decide which has the highest value for the operator. If Rimfaks Cook proves more valuable the risk assessment must be taken into consideration. Assuming that the existing well has low risks and uncertainties, it must be determined whether the increased value is deemed high enough to replace a field already in production with a new development.

Regardless of whether this evaluation shows Rimfaks Cook as the more valuable option or not, it should also be investigated if the value of the development could be increased further. This might be achieved by attaching it to other projects in the area, as described in the section covering alternative production options.

If the current development plans for the Rimfaks Cook is considered the best option the next step is well planning. This process requires some time to complete, making it possible to initiate drilling of the well in the summer 2012. This is based on the assumption that a rig will be available to the project at this time.

11 Conclusion

Based on the results from the simulation model and its following economical evaluation we find that the Rimfaks Cook reservoir should be developed. The chosen production option is producing the hydrocarbons by a single production well. Using the infrastructure that is already in place in the area and selling the produced gas will yield a substantial outcome compared with the required investments. Even if selling the gas is not possible due to infrastructure limitations or it being needed for injection, the project still has a positive NPV and an IRR of 65,8%.

There have been made evaluations of the risks and uncertainties associated with the various expenses and incomes. These have been tested both with a sensitivity analysis, and through a Monte Carlo simulation. The sensitivity analysis shows that the variable with the most influence on the project is the oil price. This is also the factor that is most difficult to predict as it is influenced by the global economy. The chosen production option have a break even oil price of 36,3 USD (74,4 USD without gas being sold), which is far less than the current value. This should give the project an ability to tolerate variations of the oil market. The results of the Monte Carlo analysis contribute to this conclusion. It shows that the project will have a positive economy, even if the various economical factors were to develop in a non favorable direction. The minimum estimate from this simulation shows a NPV of 350 MNOK with a 15% discount rate.

The conclusion that the Rimfaks Cook reservoir should be developed is made viewing the reservoir as a standalone project. This is however not the case, as it must be evaluated in comparison with the remainder of the Gullfaks Satellite area. The production option that is chosen for Rimfaks Cook in this report involves closing an existing production well. It also means allocating resources in terms of available infrastructure and rig time to the project. Because of this the value of the Rimfaks Cook reservoir has to be compared with the value of the existing production well. It should also be compared with the value of any other production options in the area that may require use of the same infrastructure. This evaluation has to be performed in order to make a final decision on whether to initiate the project or not.

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Attachments

Gullfaks Village 2011

Part A – Group 5

Introduction

The main purpose of this part is to demonstrate and get an understanding of the challenges related to production with pressure depletion and aquifer support. The task is to match the measured data with calculated data using the material balance equation, and then calculate the recovery factor in the Beta ridge. To do this the data provided is gathered in Microsoft Excel and the pressure versus time is analyzed.

To do the material balance for the Beta ridge some assumptions have been done. The most significant one is that it is assumed full communication within the whole area and therefore it can be seen as one field. This means that the production and injection for the wells is summarized. In 1986 the initial pressure was given to be approximately 380 bar and the total compressibility was $9 \cdot 10^{-5}$. To avoid a negative pressure we had to assume an immense pore volume, between, 5-10 billion Sm^3, therefore an initial approximation of 7 billion Sm^3 was selected after analyzing the data.

After doing the calculations and the material balance a sensitivity analysis is done by changing the uncertainty factors separately. For example what will be the effects of decreasing the compressibility or by changing the pore volume of the field.

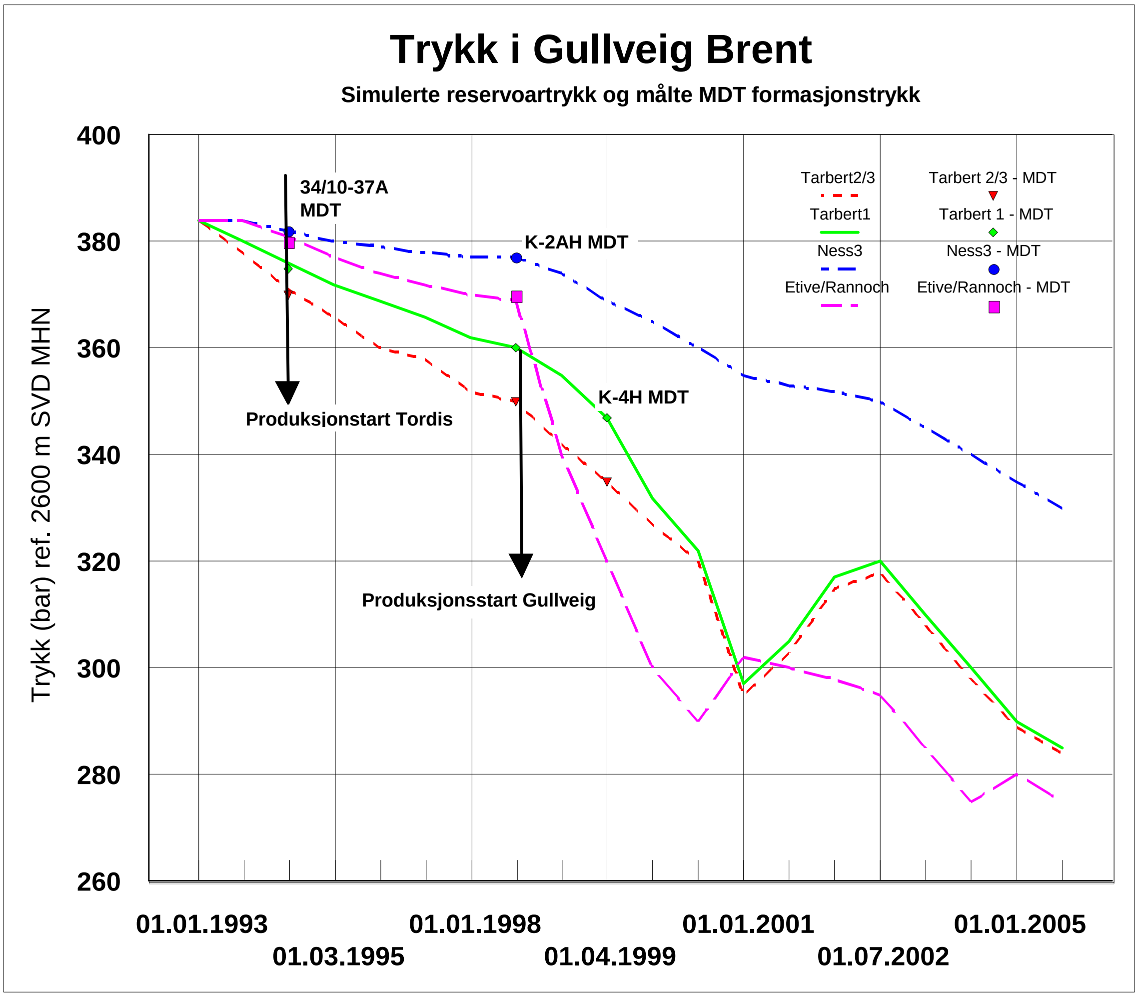

Figure 1: Original given graph

Material balance

The material balance in this case is a very simple calculation. The calculated ΔV, the assumed pore volume and compressibility is used to calculate the pressure drop:

$$\Delta V = V \cdot c \cdot \Delta P \Rightarrow \Delta P = \frac{\Delta V}{V \cdot c}$$

Pressure drop

Plot when the pressure drop is calculated and subtracted from the initial pressure:

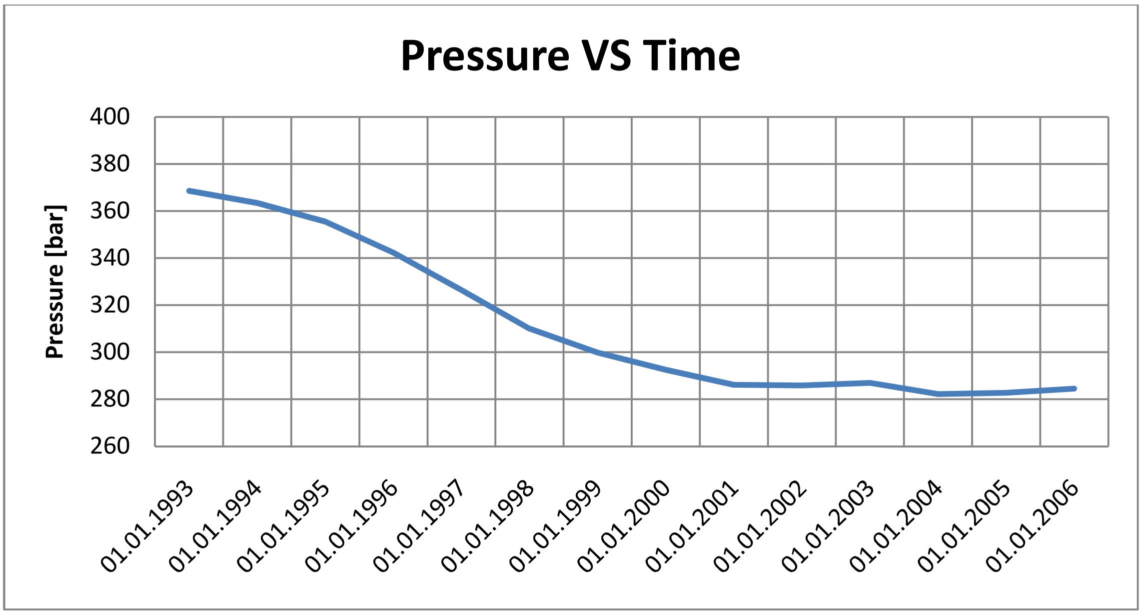

Figure 2: Pressure VS Time

The graph illustrates that there is a small pressure drop in the beginning. This is possibly due to a careful production the first few years. This is further implied when the pressure drop became more considerable in 1994 when the Tordis production well was introduced, and the introduction of Vigdis and Gullveig in 1996 and 1997. After all the production wells were introduced the pressure drop started to stabilize, and around year 2000 an increase in the pressure appeared. This was mainly because that all the injection wells started their injection just before year 2000.

When comparing the new graph to the given, the same tendencies are revealed from 1993-2001. Compared to the given graph the new graph is a bit flatter the first couple of years, but the pressure drop during the first 8 years is equal. The curve lies about 10bar below the simulated. This could imply that there either is a pressure increase before 1993 or that the assumed initial pressure is too low.

From 2001 until July 2003 there is a significant pressure increase due to an increase in injection rate in the simulated graph. The reason for the more dramatic increase in the simulated is possibly due to it is one well that will be more sensitive to an injection in that area compared to the calculated which sees the Beta Ridge as one field. This could imply that there is not full communication in the whole Beta Ridge, as then the tendencies should be the same in the whole area.

Look to the past

Plotting the period before 1993 confirms there is no tendency of a period with pressure increase:

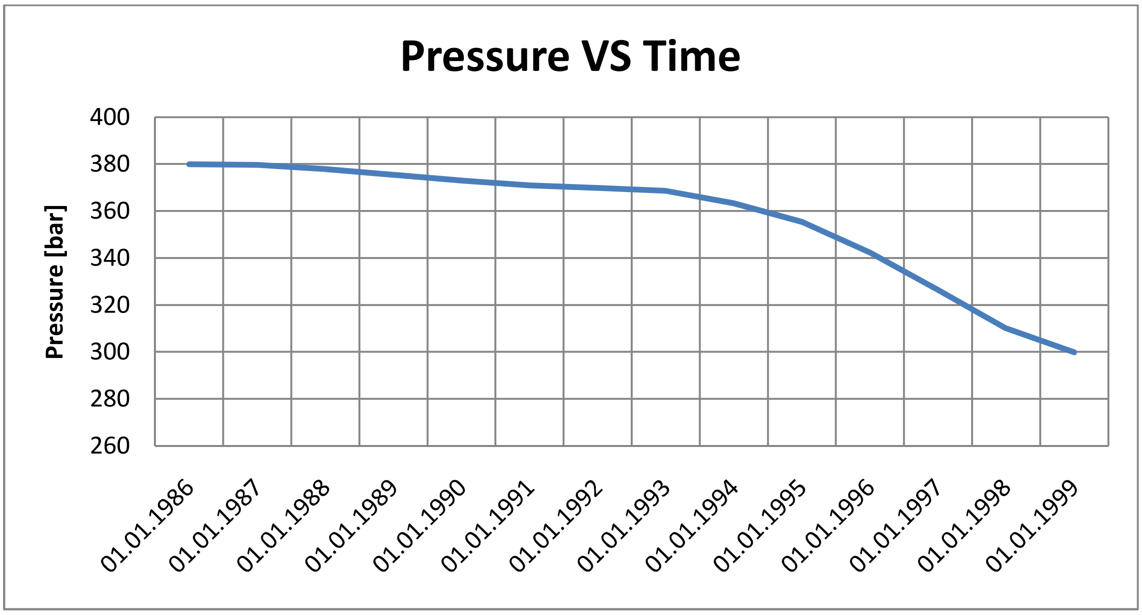

Figure 3: Before 1993

Increase of bar

By increase the initial value to 390 bar the values of the simulated fits better the given plot. This could either indicate that the assumed initial pressure is too low or that the properties in this area deviate some from the general area. As mentioned this indicates that there probably is not full communication in the whole Beta Ridge.

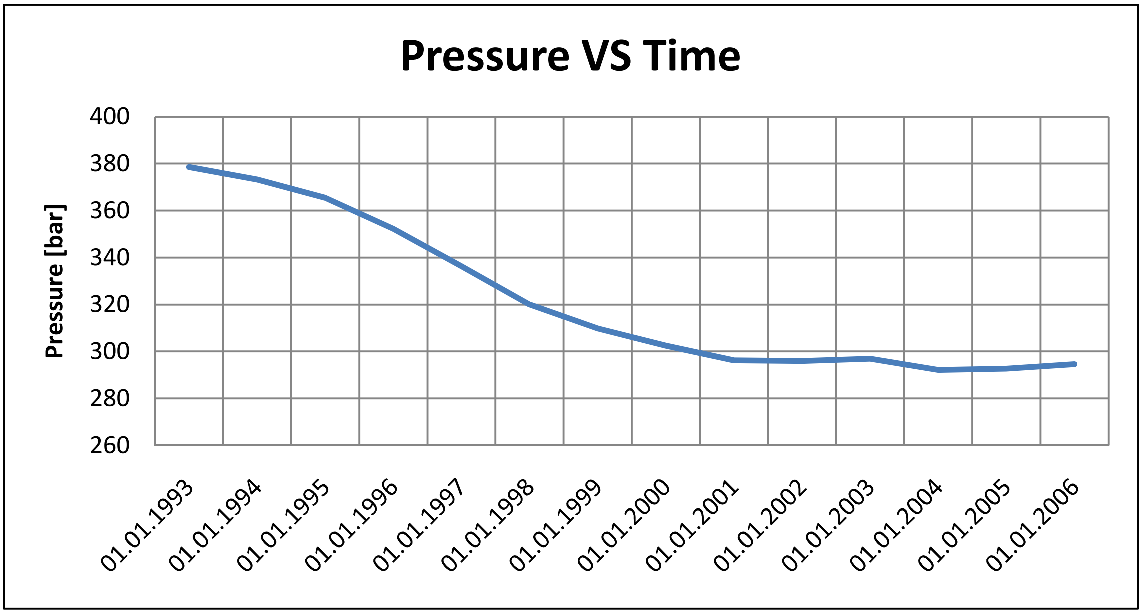

Figure 4: Bar increased to 390

Different pore volumes

The effect of changing the volume:

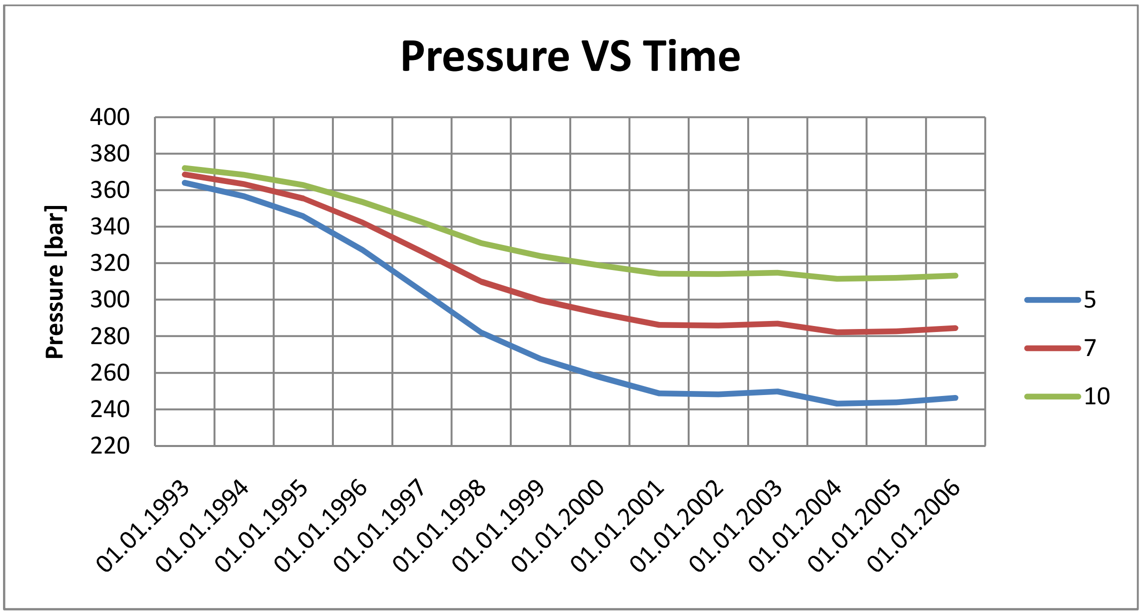

Figure 5: Volume of $5 \cdot 10^9$ Sm^3, $7 \cdot 10^9$ Sm^3 and $10 \cdot 10^9$ Sm^3,

By changing the pore volume the pressure drop is effected which the equation demonstrates as well. It relies linearly on the volume:

$$\Delta V = V \cdot c \cdot \Delta P \Rightarrow \Delta P = \frac{\Delta V}{V \cdot c}$$

Changing the compressibility

Checking for the effects from changing the compressibility we see that we get the same effect as for the volume. As we can see the pressure drop is linearly dependent on the compressibility as it is for the volume.

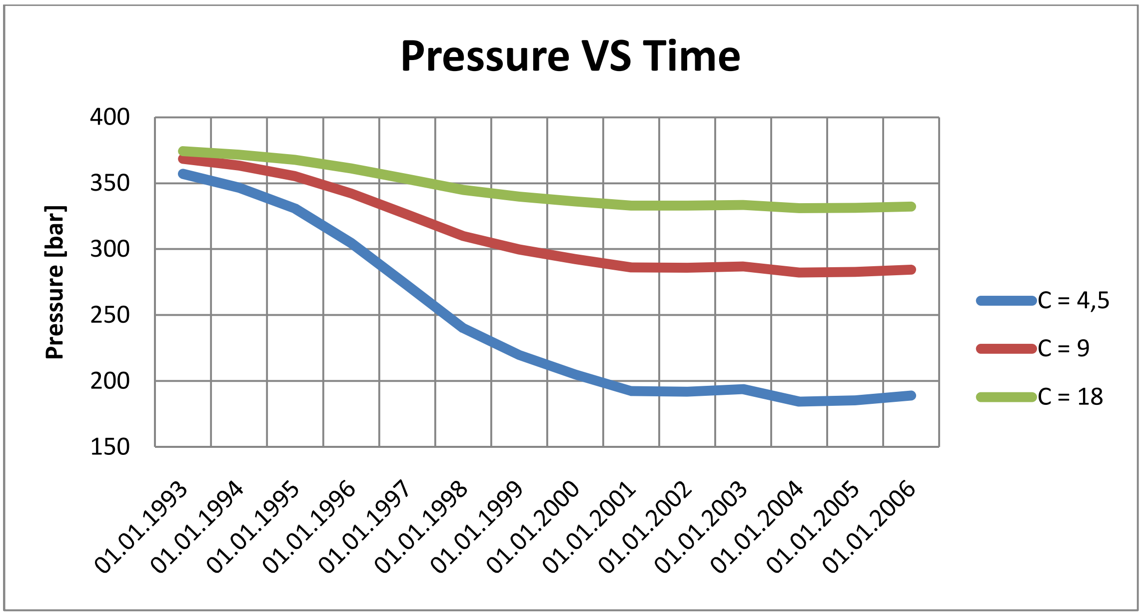

Figure 6: Compressibility of $4{,}5 \cdot 10^{-5}$ bar^{-1}, $9 \cdot 10^{-5}$ bar^{-1} and $18 \cdot 10^{-5}$ bar^{-1}

Conclusion point 2 & 3

Similar pressure drop in the calculated and the simulated, but the calculated lies somewhat lower on the curve. This is possible due to a higher initial pressure in the well A-32 than we were given for the Beta Ridge. The deviation after 2001 might be caused by the lack of communication compared to our assumption of full communication. Full communication should give the same tendency over the whole field and not just in the area close to the injection zone.

Point 4 Possible interference within the fields and estimation of the recovery factors

To find out if the fields interfere with each other, we both plotted the cumulative production/injection rates versus time and the average yearly production/injection rate versus time.

By first looking at graphs of the average yearly production and injection rates, we clearly see some communication between the different fields. Especially the fields that are located close to each other seem to interfere, both during production and injection.

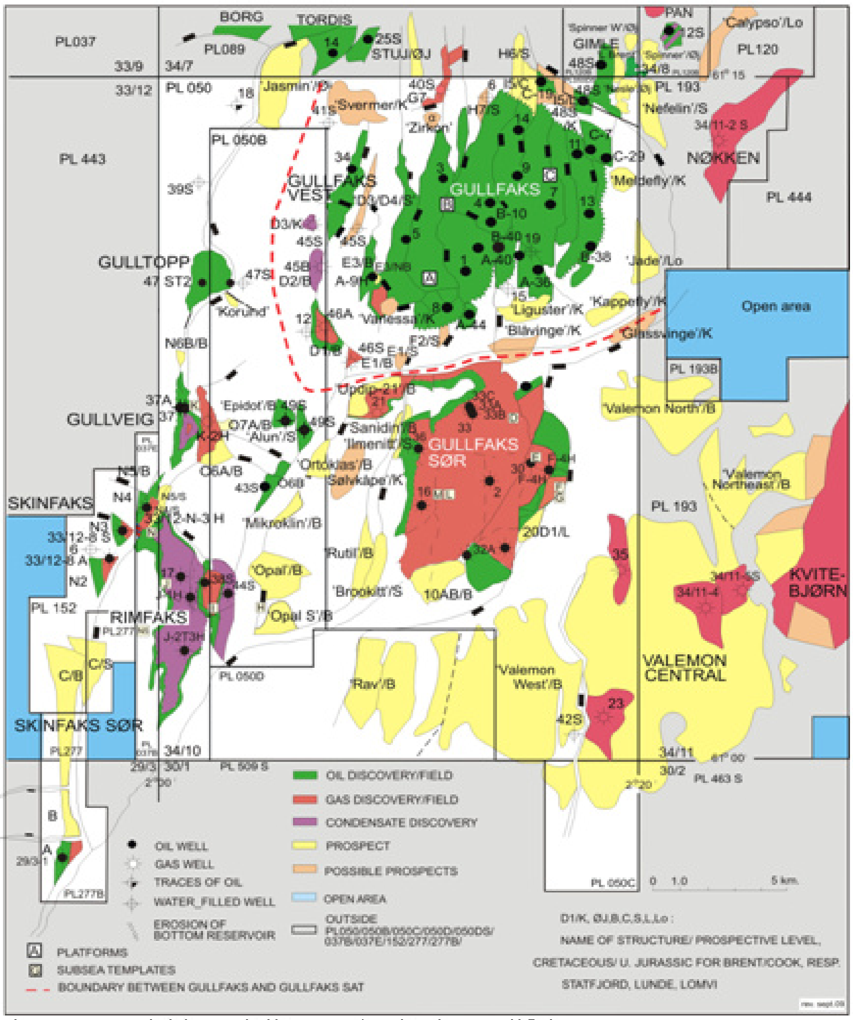

Figure 7: Gullfaks overview. Beta Ridge is located to the west.

Tordis vs Vigdis:

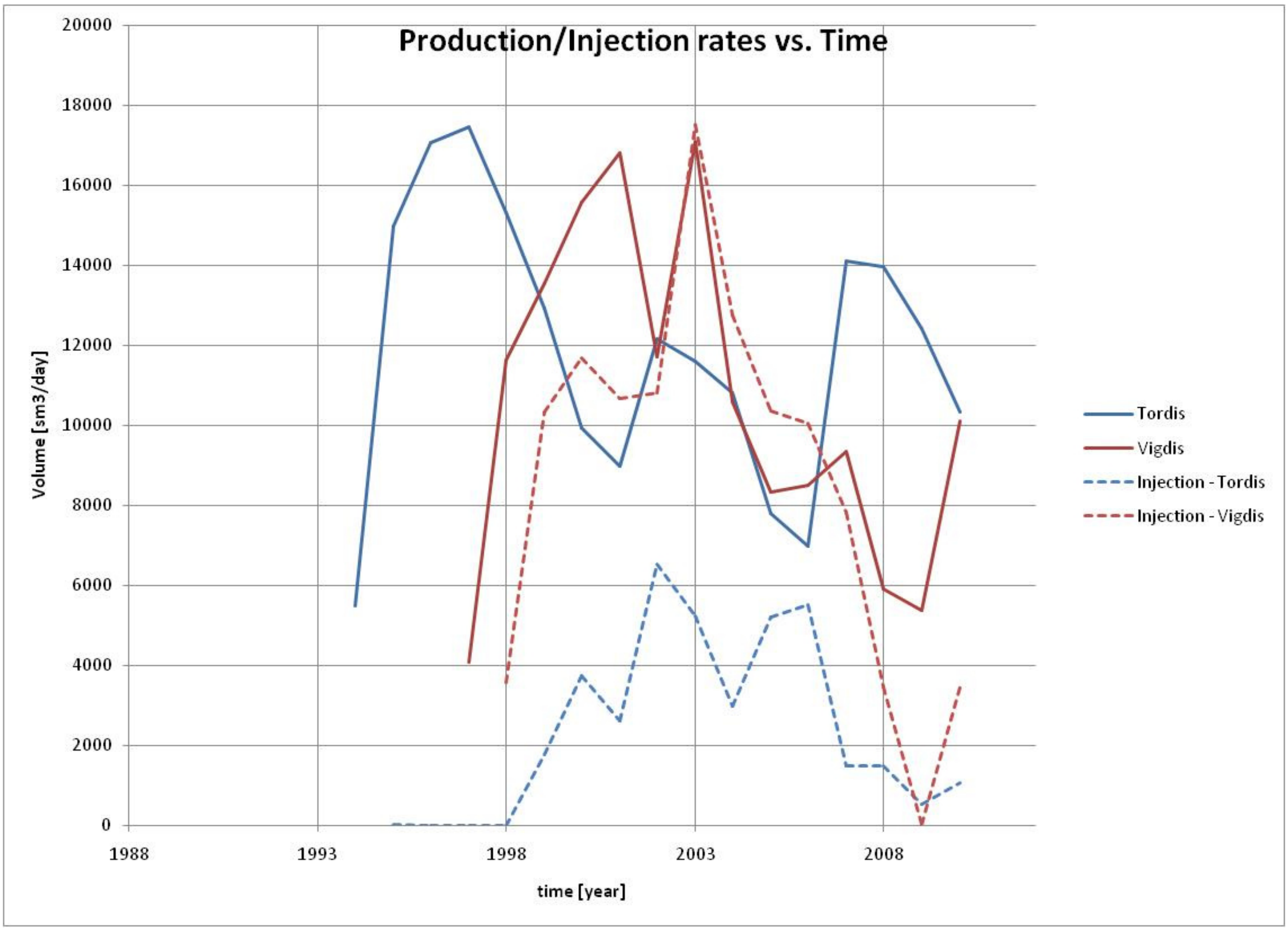

Figure 8: Tordis/Vigdis production and injection rates.

In the northern part of the ridge, Tordis and Vigdis are located. From the graphs we can see that the production rate of the Tordis field decreases once the Vigdis field starts producing in 1997. This happens before any injection has been initiated, and could be an indication that the fields are interfering with each other. Also around year 2006 there is a possible sign of interference between the two fields. The production from the Vigdis field gets a sudden increase while the injection in Vigdis still is decreasing. On the other hand, there is an increase in the injection rate in the Tordis field around the same time period. It might therefore be reasonable to assume that this increase might have lead to the sudden increase in the production in the Vigdis field.

Gullveig vs Gullfaks Vest:

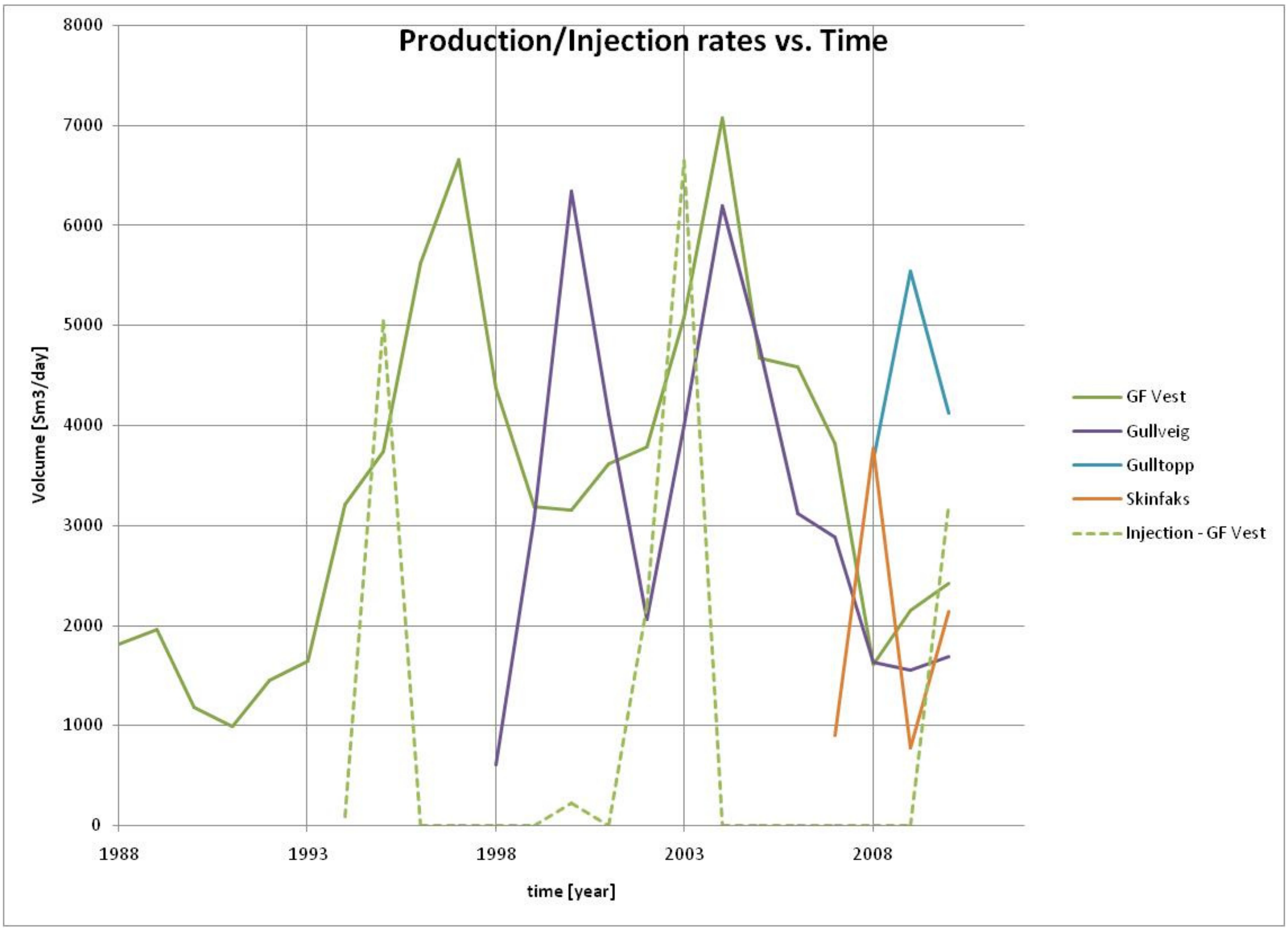

Figure 9: Gullveig/Gullfaks Vest production and injection rates.

We can also see indication of interference between the Gullfaks Vest and Gullveig fields. Around year 2001 injection is initiated in the Gullfaks Vest field, and from the plotted data we can see that the production rates of both the Gullveig and Gullfaks Vest fields are increasing with approximately the same amount.

When we make an estimate for the recovery factor we must state some assumptions because of the lack of information. First of all we have to assume the volume of oil in the reservoir, initial oil in place (IOIP). From the reservoir management plan we find that $80*10^6$ Sm^3 is a reasonable assumption for the volume of oil at production start. Our numbers includes oil, water and gas which mean that we have to assume how much of the production actually is oil. In the beginning for each production well we can assume that all that is produced is oil, but sooner or later we get water break-through due to the water drive which maintains the pressure in the wells. The water cut will also increase. It might only be 10-20 % in the first phase, but in the late life of the well the water-cut could be 80-90 % which would affect our results when calculating the recovery factor.

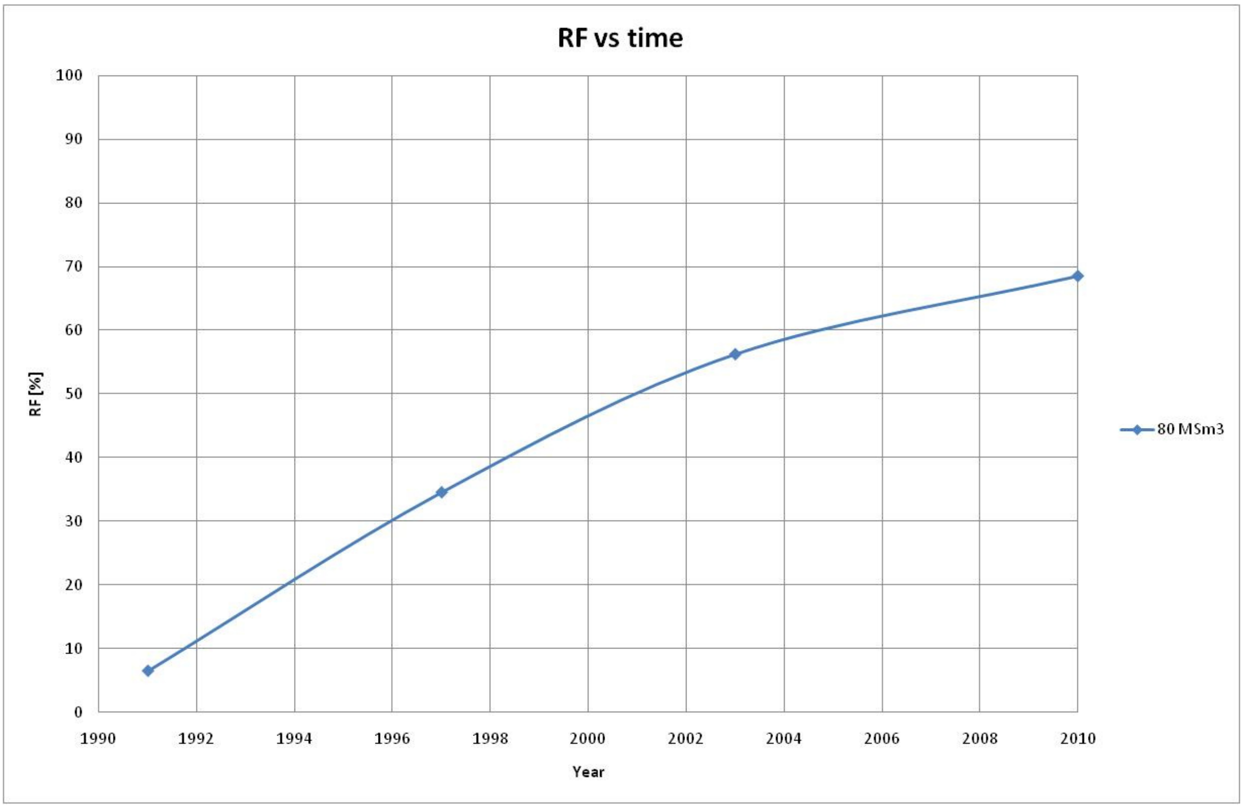

Figure 10: Estimated recovery factor 2010.

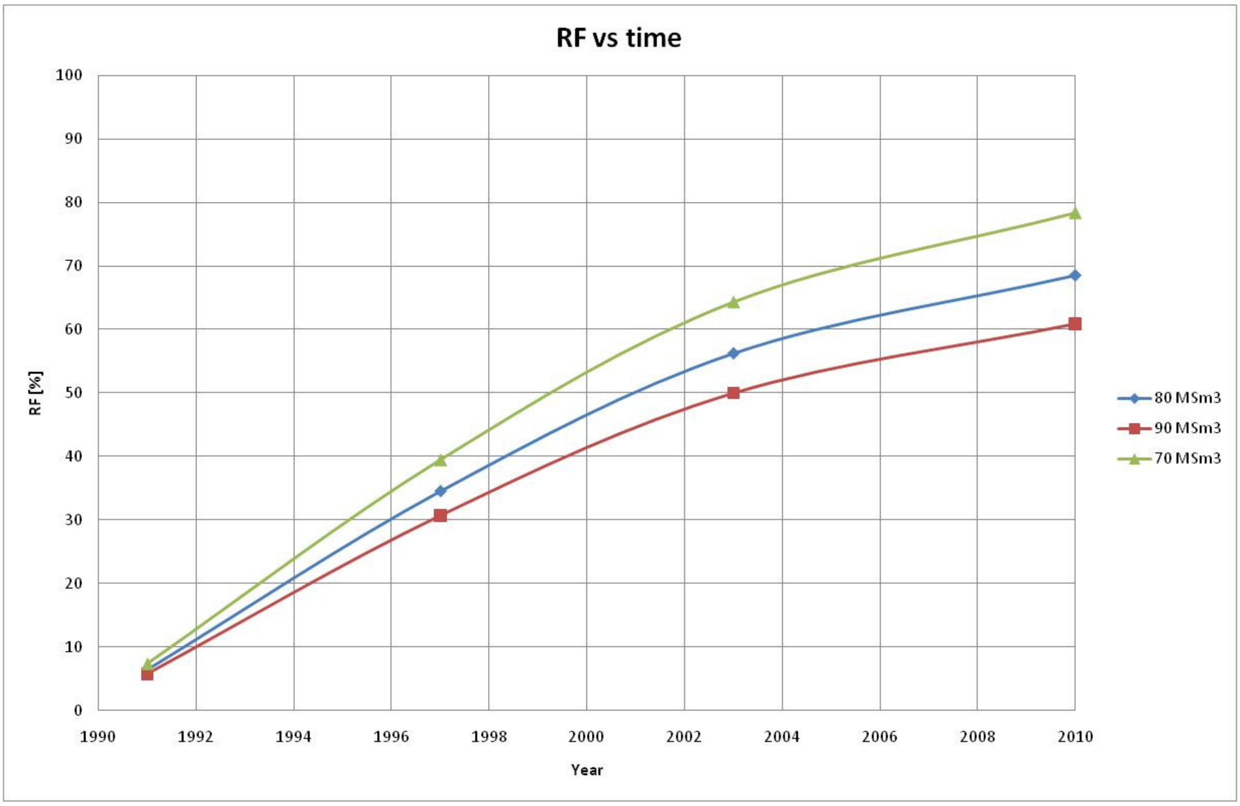

Figure 11: Effect of IOIP on the recovery factor.

We can also analyze the approximated recovery factor based on different assumed IOIP. Increasing or decreasing the assumed initial volume of oil affects the recovery factor quite significantly as recovery factor is defined as cumulative production over IOIP.

Expected recovery factor will be somewhat higher than it is today but it will not increase significantly compared to earlier years. This is because of increasing water-cut and decreasing volume of oil produced in the future. Graphically this means that the inclination of the curve will get close to zero.

Conclusion Point 4

As we saw there probably is communication between the different reservoirs, at least between those that lies close to each other. This was seen as injection in one field may also affect the production in a nearby field which does not have any injection. When it comes to the recovery factor we have to make some assumptions. This is due to the lack of data of IOIP and that our production data is given as a total of water, oil and gas. By assuming an initial volume of oil and a growing water-cut in the production, we get a reasonable estimation for the recovery of the fields. We assume that the recovery factor is identical in the different reservoirs but this is not the case in reality. Because of the complexity of the reservoir, the properties are different in the different regions of the field. This means that the geology varies through the Beta Ridge and our calculation is a major simplification.