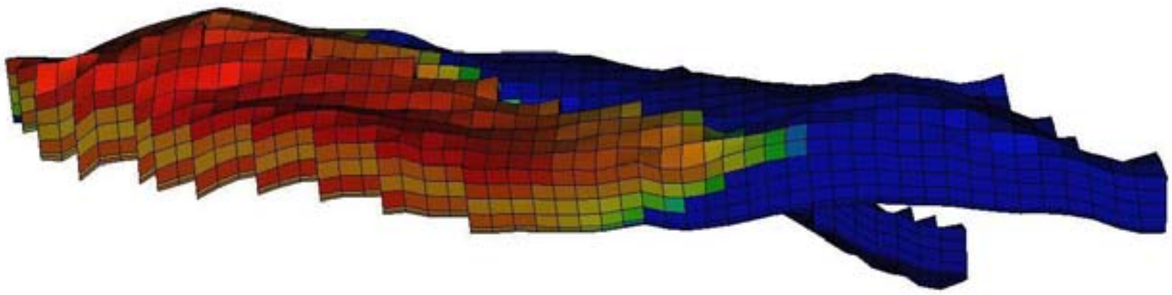
Production potential in the Tofte formation



TPG4852 - Experts in Teamwork - Norne Village

Group 5:

Yasir Baig

Rayhan Habibie

Lars Tingelstad

Joel Ben-Awuah

Kristian Nauste Bunkholt

Li Shidong

Preface

This report is developed as a part of the course TPG 4852 Experts in teamwork – Norne Village in the spring of 2010. The main focus of the course is interdisciplinary teamwork to solve reservoir engineering problems in the Norne reservoir. Two reports to be delivered are one technical and one process report that discusses the team's development during the semester. This is the technical report which is the evaluation of a new production well in the Tofte formation in the Norne E-segment.

The team consists of students from different study programs, nationalities and cultures. Lars Tingelstad is from Norway and has a background in manufacturing engineering at the Department of Production and Quality Engineering. Kristian Nauste Bunkholt is also from Norway and studies analytical chemistry at the Department of Chemistry. Rayhan Habibie is from Indonesia and studies marine and coastal civil engineering at the Department of Civil and Transport Engineering. Joel Ben-Awuah is from Ghana and studies petroleum geosciences at the Department of Petroleum Engineering and Applied Geophysics. Yasir Baig is from Pakistan and studies natural gas technology at the Department of Energy and Process Engineering. Li Shidong is from China and studies reservoir engineering at the Department of Petroleum Engineering and Applied Geophysics.

We would like to thank the village sponsor Statoil, especially Lars Høier and Nan Cheng, for all the information, help and guidance during the semester. We would also like to thank the village leader Tom Åge Jelmert and all the staff at the department of petroleum engineering and applied geophysics for facilitating the course. Last, but no least we would like to thank the student assistants Per Einar Kalnæs, Jorunn Kristiane Plambeck Evandt and Nadine Grace Mosteiro Halvorsen for valuable input and help on both the technical and the process report.

Group 5 – Team Verdande

May 5, 2010

Summary

The Tofte formation is together with the Ile formation the main oil bearing reservoirs in the Norne reservoir. Quantification of remaining oil using the reservoir simulator Eclipse shows that there was 3895896 Sm^3 oil left in the Tofte E-segment at the end of 2004.

Multiple simulations were run in Eclipse to find the best possible solution for a new producer in the Tofte formation. The main parameters evaluated in each case are the installation year, location, well type, well completion as well as the production rates. Horizontal and vertical wells were installed in 2005, 2007, 2009 and 2011 with different well completions. The whole horizontal length is perforated in the horizontal wells but different perforation intervals are evaluated in the vertical wells. All solutions were evaluated at different production rates with a minimum bottom hole pressure of 200 bar.

The best result from the simulations is to install a horizontal well in 2005 between two areas in layer 13 and 14 in the model, as these are the main pay zones. This would have given an increase in oil production of 1041317 Sm^3 opposed to the base case. The best results for the years 2007, 2009 and 2011 are to install two vertical wells in the main pay zones with an upper layer perforation well completion. This would have given an increase in oil production of respectively 868078 Sm^3, 795682 Sm^3 and 735759 Sm^3.

The four best solutions were evaluated using a net present value analysis. The NPV calculations were performed in a simplified model provided by Statoil for use on the Norne field. The economic evaluation shows that all solutions have a positive NPV with an increase in income before tax of respectively 1755 MNOK, 1462 MNOK, 1065 MNOK and 1042 MNOK.

The best solution of drilling a horizontal well in 2005 would have given an increase in income after tax of 451 MNOK. The only real or possible solution is to install two vertical wells in 2011, which would give an increase in income of 268 MNOK after tax.

Contents

List of figures

List of tables

1 Introduction

1.1 General information

1.1.1 Field location

The Norne Field is in the southern part of the Nordland II area in the Norwegian Sea. It is located in blocks 6608/ 10 and 6508/ 1. It is approximately 100 km north of Aasgard Field, 200 km west of the Norwegian shore and 85 km of northeast of the Heidrun Field(Statoil).

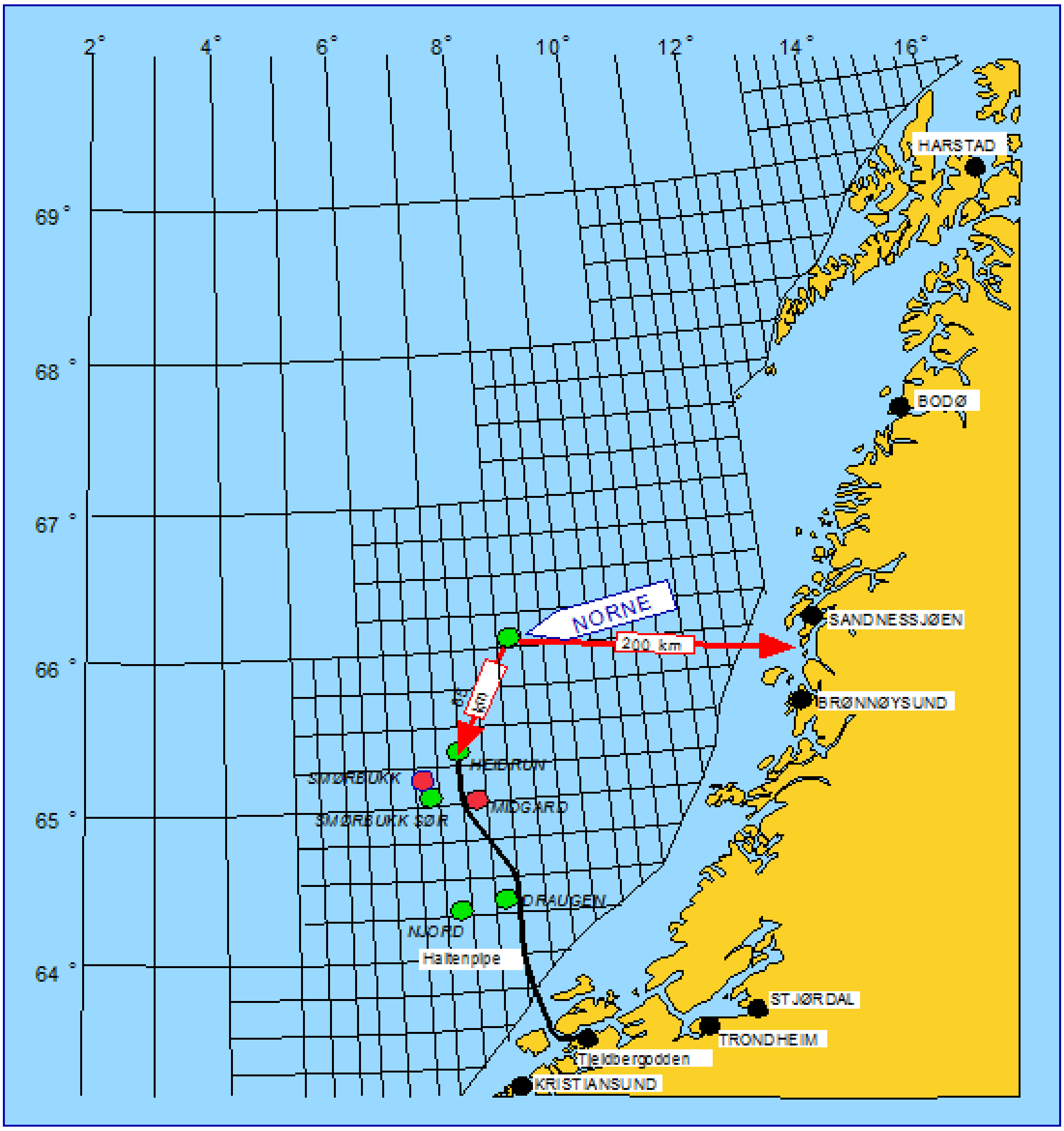


Figure 1: Map of the location of the Norne field redrawn from the Norne Field database (Statoil)

1.1.2 Exploration history

The Norne Field was discovered in December 1991 by well 6608/ 10-2. The well proved a total hydrocarbon column of 135m in rocks of Lower and Middle Jurassic age. The column consists of a 110m thick oil column with an overlying gas cap.

An appraisal well which confirmed the results from the discovery well was drilled in the northern part of the Norne structure in 1993. The appraisal well, 6608/ 10-3 also proved the extension of the field to the north. In 1994, another well, 6608/ 10-4, drilled on a structure approximately 3km east of the Norne Structure discovered a small oil accumulation in the same reservoir rocks as on the Norne structure. (Statoil)

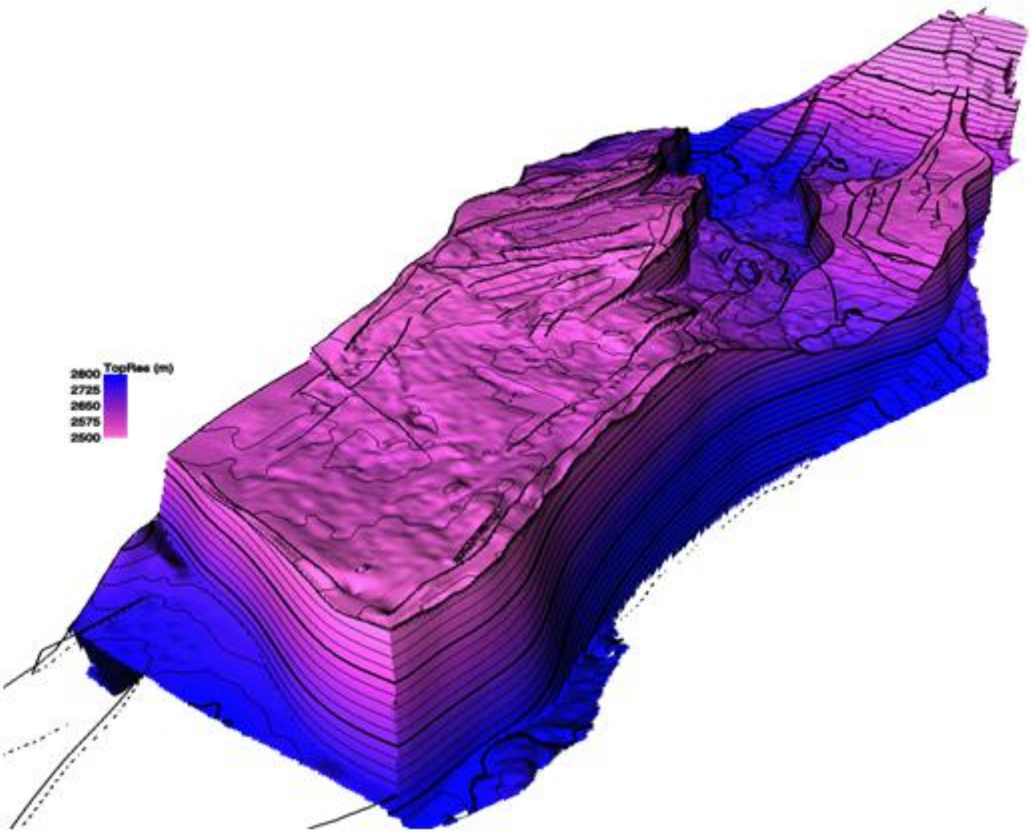


Figure 2: Reservoir model of the Norne field (Nan Cheng, 2010)

1.1.3 Current situation in the Norne E-segment

Production started in the Norne field in November 1997. In total 8 wells have been drilled in the Norne E-segment. These comprise of 2 water injector wells, 5 oil producer wells and 1 observation well.

Some properties of the oil and gas in the Norne field are:

- Initial Pres = 273 bar @ 2639 m TVD, Tres= 98 °C
- Pb = 250 bara, GOR= 111 Sm3/Sm3
- Oil SG = 0.7, Oil viscocity = 0.5 cp
- Boi=1.32 Rm3/Sm3
- Bgi=0.0047 Rm3/Sm3
- Rock wettabiliy: mixed

(Nan Cheng, 2010, Statoil)

1.1.4 Objectives of the project report

- The objectives of this project report are as follows
- Understand basics of well completion and well solutions (vertical, slanted or horizontal wells)
- Study geology of Tofte formation and quantify remaining oil with current drainage strategy
- Evaluate a possible new producer in Tofte formation
- Location, well type, completion, production rates
- Economic evaluation

2 Literature review:

2.1 Well solutions

2.1.1 Vertical wells

A well which is drilled perpendicular to the reservoir bedding plane is known as vertical well. In vertical wells the objective is to keep the drift angle to a minimum in order to minimize the horizontal displacement. The main reasons for avoiding deviation in straight holes is to keep the well within the particular pay zone as well as to comply with government regulations(Joshi, 1991).

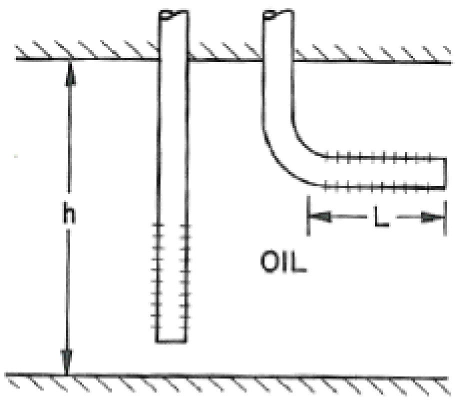


Figure 3: Schematic comparison of conventional vertical well and horizontal well (Joshi, 1991)

2.1.2 Horizontal wells

A well which is drilled parallel to the reservoir bedding plane is known as horizontal well. Horizontal wells are new technology compared to conventional wells. They are used because of an enhancement in the contact area of the well as well as an increase in the well productivity. But there are some limitations with horizontal wells. They are typically 1.4 to 3 times more expensive than vertical wells and also only one pay zone can be drained per horizontal well - recently however these wells have been used to drain multiple layers.

Horizontal wells are applied in naturally fractured reservoirs where they have been used to intersect fractures and drain them. They have also been applied in reservoirs with water and gas coning problems to minimize the coning problems and enhance oil production. Another application of horizontal wells is in enhanced oil recovery (EOR), especially in thermal EOR. Horizontal wells provide a larger reservoir area, which is especially beneficial in EOR applications where injectivity is a problem(Joshi, 1991).

2.1.3 Slanted wells

Slanted wells are wells in which deviation is deliberately initiated in order to intersect a particular zone.

There are certain situations in which a slanted well is the only way to reach a particular producing zone e.g. offshore development, fault drilling, inaccessible and restricted areas, sidetracking, salt dome drilling, relief wells and wildcatting (Rabia, 1985)

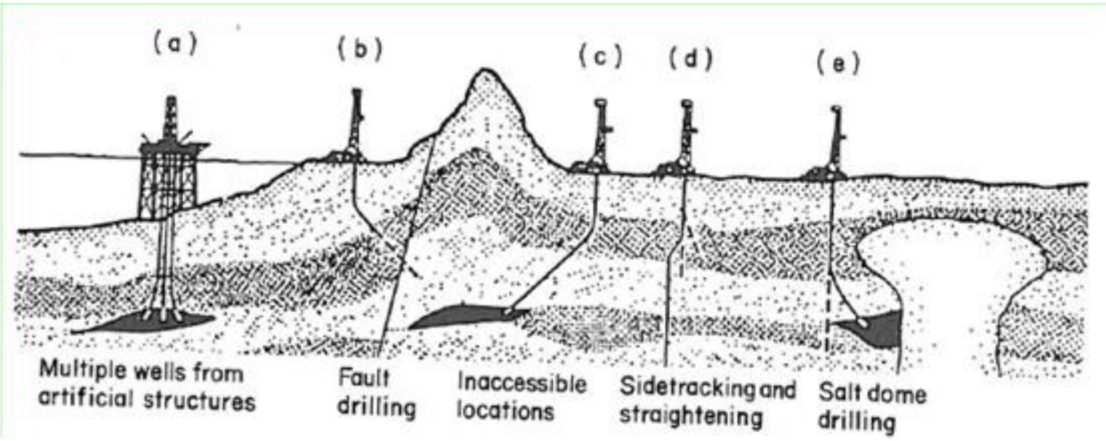


Figure 4: Schematics of different applications of slanted wells(Rabia, 1985)

2.1.3.1 Types of slanted wells:

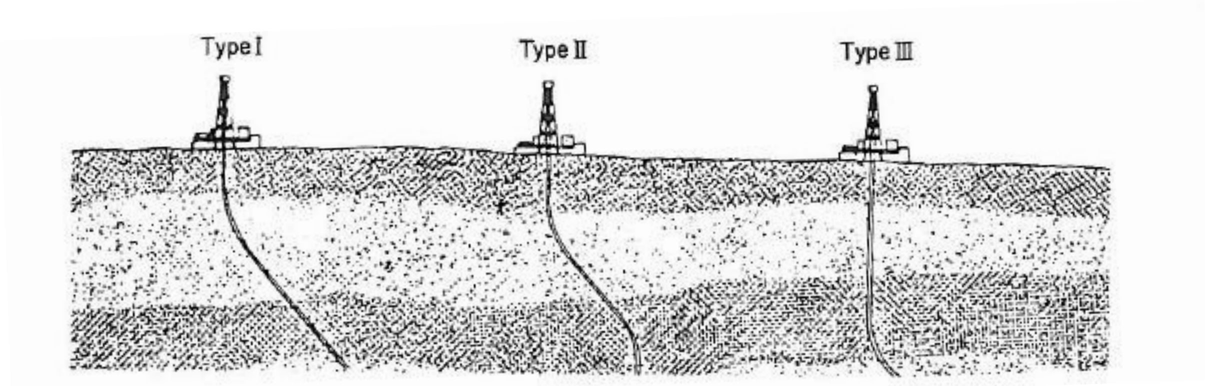


Figure 5: Schematics comparison of three types of slanted wells(Rabia, 1985)

In general there are three basic patterns of directional wells.

Type I is a well which is deflected at a shallow depth and the inclinations is locked until the target zone is penetrated. The main applications of this kind of well is in moderate depth drilling, single zone production, wells that don't require any intermediate casing as well as deep wells that require large lateral displacement(Rabia, 1985)

Type II wells are also called S shaped well as its shape resembles the letter S. This well is deflected at a shallow depth until the maximum required inclination is achieved. The well is then locked in and finally the inclination is reduced to a lower valve or in some cases the well is returned to vertical by gradually dropping of the angle. These kind of wells are mainly used in multi-zone production (Rabia, 1985).

Type III wells are similar to Type I wells, except that the well is deflected at a much deeper position in order to avoid, for example a salt domain. Other applications are sidetracking and wildcat drilling (Rabia, 1985).

2.1.4 Comparison of Slanted well and horizontal well productivities

Horizontal wells are effective in thin reservoirs while slanted wells are highly effective in thick reservoirs therefore one would like to find the optimum completion for a given reservoir thickness. One of the ways to do this is to assume a drilled well having fixed length. This fixed length could either be vertical, horizontal or slant. Then one can compare productivities of horizontal, vertical and slant wells with each other to determine the optimum completion method (Joshi, 1991).

2.2 Well completion

Well completion is the stage in the process of drilling the well until the well starts producing. Well completion has stages like connecting the well into the reservoir, sand control and well simulation, equipping the well and assessing the well performance (Perrin et al., 1999).

2.2.1 Main parameters for completion design

There are multiple parameters that are important for the selection of well completion design. Among these are the type of well, the environment, drilling parameters, reservoir characteristics as well as production parameters and completion configurations.(Perrin et al., 1999)

2.2.1.1 Type of well

The type of well can be distinguished by the well purpose. Exploration wells are wells that are drilled to take samples from the reservoir in order to measure pressure changes in the bottom hole which results in fluid flow. This data is combined with other available data from other sources including geology and geophysics, then based on this information it can be decided either to develop or not to develop the reservoir. A confirmation well can also be drilled to complete or refine the data from the exploration wells(Perrin et al., 1999).

Another type of well is development wells, which can be split into productions wells, injection wells and observation wells. The purpose of production wells is to optimize the productivity to price ratio. Injection wells are drilled to maintain the bottom hole pressure and to push out unwanted fluid. Observation wells are built to monitor the reservoir; it is possible to convert this well into an injection or production well if that is suitable(Perrin et al., 1999).

2.2.1.2 The environment.

There may be limitations on operations due to the country or site where the well is located whether on land or offshore. These restrictions involve: difficulties in obtaining supplies, available space, available utilities delivering supplies, drilling, the reservoir, production rate, completion techniques(Perrin et al., 1999).

2.2.1.3 Parameters related to drilling

Important parameters related to the drilling of the reservoir includes the drilling and casing program, the drilling in itself as well as cementing of the production casing.

Drilling and casing program relates to the size of the borehole. The borehole diameter has to be sufficiently big for the equipment to be installed in it. The smallest diameter which is connecting the borehole into the reservoir is very effective to use in the well when the drilling and casing operation have been concluded. On the other hand optimization for drilling and production must be considered(Perrin et al., 1999).

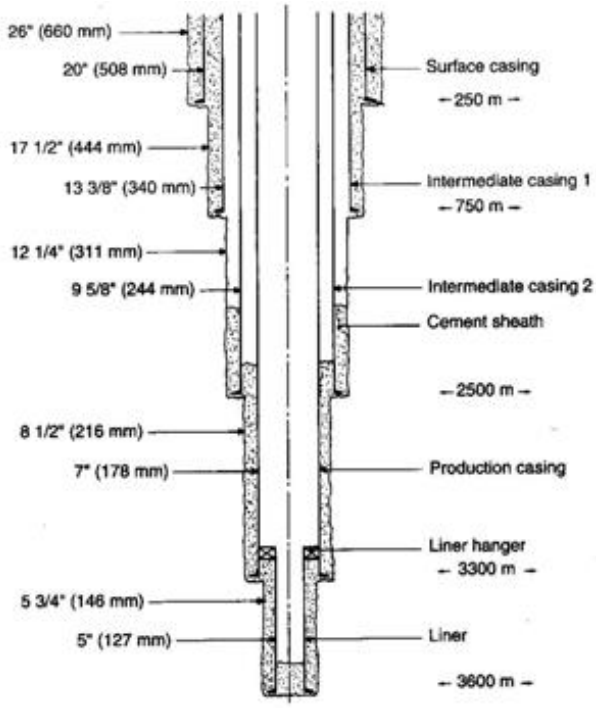


Figure 6: Diameters available according to the drilling and casing program (Source: ENSPM Formation Industrie)

2.2.1.4 Parameter related to the reservoir

A reservoir is influenced by parameters like: reservoir pressure and its changes, interfaces between fluids and their changes, rock characteristics and types, production profile and number of wells required (Perrin et al., 1999).

2.2.1.5 Parameter related to production

Production is dependent on the operating condition, artificial lift and on the maintenance or work-over operations(Perrin et al., 1999).

2.2.1.6 Major types of completion configuration

First type is open hole completion. This type is usually suited for gas well where there is much consolidated well with gravel packing for sand control. The liquid flow through the uncased hole and it has advantages because the reservoir will not be disturbed by cement-perforating in the well.

Second type is cased hole completion mainly used in case of several layers in the reservoir but it has interface related problems. After pay zone has been drilled a casing is run in and cemented opposite the layer. Then it is perforated opposite the zone that is to be produced in order to restore a connection between the reservoir and well. This completion has good control of fluids flow because the connection between borehole and the formation made by perforation that can be positioned very accurately for each level and interfaces between the fluid(Perrin et al., 1999).

2.2.2 Completion phases

- Drilling and checking the borehole: In this phase the condition of the bore hole is checked. The mud used for drilling has to be replaced by appropriate fluid for further operations.
- Perforation: In cased hole completion the cement bond has to be strong enough.
- Well testing: The well testing operation is usually for short times in order to recognize the well productivity index or surfactant effect on the well and any possible damage.
- Treating the pay zone: Reservoir treatment operations consisting of sand control operations and well simulation.
- Equipment installation.
- Activate and monitor the well performance.
- Measurement, maintenance, moving the rig and abandonment.

(Perrin et al., 1999, U.S_Department_of_the_interior, Schlumberger)

2.3 Geology

2.3.1 The geology of the North Sea

The basement of the North Sea was formed in an intraplate setting during the Pre Cambrian era. Rigid blocks were overlaid with various depositions, sands and salts. These rigid blocks were transformed to a metamorphic base due to tectonic processes such as continental collisions which cause horizontal pressure, friction and distortion in the Caledonian plate cycle as well as the Variscan plate cycle. The blocks were also subjected to metamorphic evolution during the Triassic and Jurassic periods when the rock was heated up by the intrusion of hot molten rock called magma from the Earth's interior.

Triassic and Jurassic volcanic rifting and graben fault systems created highs and lows in the North Sea area. This was followed by late Mesozoic and Cenozoic subsidence creating the intracratonic sedimentary basin of the North Sea. This era experienced higher sea levels because of sea floor spreading, cooler lithosphere temperatures. Plate tectonics and continental orogenies combined to create the continents and the North Sea as we know them today. The final events affecting the North Sea coastline features and submarine topography occurred in the Cenozoic era.

The Mesozoic structures underneath the North Sea can be seen as a failed rift system. After initial crustal extension and the formation of rift basins during the Triassic and Jurassic periods, the extension concentrated on the other side of the British Isles, which would create the northern Atlantic Ocean. The rift basins even saw some inversion during the late Cretaceous and Eocene epochs. From the Oligocene onward, tensions in the European crust caused by the Alpine orogeny to the south caused a new, more modest phase of extension. Some grabens in the area are still active.

The subsurface of the North Sea area is dominated by grabens: the north-west south-east oriented Lower Rhine Graben under the southern North Sea and the Netherlands, the north-south oriented North Sea Central Graben that begins north of the Dutch coast and ends in the region east of Scotland, and the Viking Graben along the south-east Norwegian coast. The Horn Graben is a smaller graben east of the Central Graben and in front of the Danish coast. A larger graben is found in the subsurface below the Skagerrak, this north-south structure is called the Bamble-Oslo Graben. The Viking Graben is separated from the Faeroe Shetland Basin below the Atlantic by the Shetland Platform, the two structures join in the area north-east of the Shetland Islands(Wikipedia_Geology_of_the_north_sea).

2.3.2 The Norne field E-segment

2.3.2.1 Source rock

The source rock is Upper Jurassic Shale (Spekk formation) and Upper Triassic to Lower Jurassic Coal beds (Are formation) (Oljedirektoratet).

The overwhelming source of hydrocarbons is the very rich Upper Jurassic Kimmeridgian oil-prone shales that are matured to overmatured over most of the graben areas. Several shales and coals of the Lower and Middle Jurassic are, in addition believed to contribute as hydrocarbon sources locally. Where the shales are overmatured, such as in the deep central graben and in the Northernmost Viking graben, large volumes of gas have been generated(Evans, 2003).

2.3.2.2 Reservoir rock

Norne Field is located in the southern part of the Nordland II area in the Norwegian Sea. The main reservoir rocks are sandstones of Lower to Middle Jurassic age deposited in coastal, deltaic and shallow marine environment. The sandstones are very high quality with porosities between 25-30% and permeabilities between 50-3000mD. The sandstones have a net to gross ratio close to 1 of most of the reservoir zones and a recovery factor around 62%. The hydrocarbon reserves consist mainly of a gas cap situated in Garn formation and oil in Ile and Tofte formations(Osdal et al., 2006).

Present day distribution of Lower and Middle Jurassic rocks is complex due to 3 factors namely the pre-existing Triassic rift topography, mid Jurassic doming and erosion, and Late Triassic rifting and erosion. There are regional differences in facies development and in the ages of the stratigraphic units. A regional unconformity is widely developed within the Lower and Middle Jurassic succession. In most of the central province and large parts of the East province, Lower Jurassic strata and the Middle Jurassic strata rest unconformably on Triassic or older rocks.

The Lower and Middle Jurassic succession in the North Province forms the main petroleum province. The Central Province has the least complete Lower and Middle Jurassic succession. It is rich in volcanic rocks, contains few reservoir rocks and has only minor hydrocarbon accumulations(Evans, 2003).

2.3.2.3 Trap

The Trap consists mainly of rotated fault blocks. The main field is a horst block. There has been some amount of uplift and erosion in the Norne field. The geometry of the rotated fault-block traps was created initially during active rifting. The traps are mainly structural and are located in the crests of the footwall of rotated fault blocks. The Norne field has faults and stratigraphic barrier layers such as carbonate cemented layer and the Not claystone formation which act as restrictions to vertical and lateral flow. The seal in the Norne field is mainly Upper Jurassic Shales (Evans, 2003).

2.3.3 Tofte formation-oil bearing sandstone in the Norne field

The Tofte formation in the Norne field is Pliensbachian to Toarcian in age.

The Tofte Formation is the main oil bearing reservoir in the Norne field and consists of moderately to poorly sorted coarse-grained sandstones which often show large-scale cross bedding. In the type section the quartz content is generally higher than 90%, although the sediment is texturally immature. Bioturbation occurs throughout the cored intervals, especially in zones of very poor sorting and high clay content.

In a type well drilled in the formation, it was observed that the lower boundary of the Tofte Formation occurs at the base of an upwards coarsening sequence. Fine-grained heavily bioturbated sandstones rest on medium-grained sandstones of the Tilje Formation and the gamma ray log shows a marked increase in its response. In wells further to the south and east the Tofte Formation overlies mudstones and shales of the Ror Formation. The transition is there associated with a marked decrease in gamma ray response.

The Tofte formation sandstones were deposited by eastwards prograding fan deltas which reflect tectonic uplift to the west. No known time-equivalent lithostratigraphic units in surrounding areas are similar to the Tofte Formation (Oljedirektoratet, 2010).

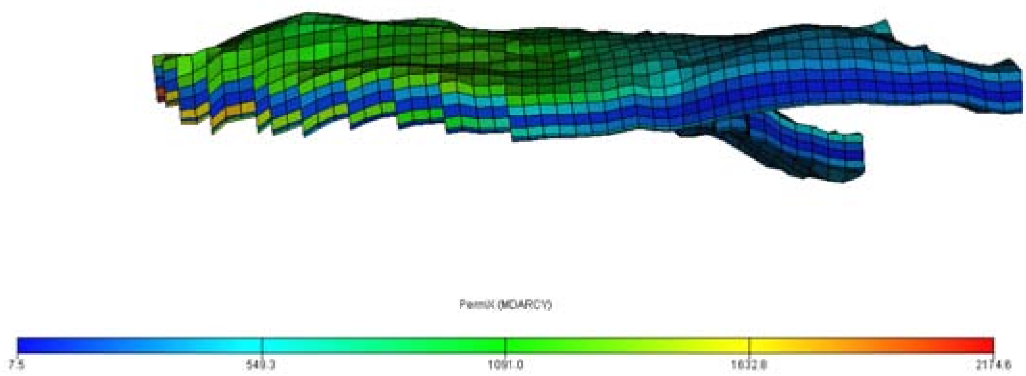


Figure 7: Permeability of the Tofte formation

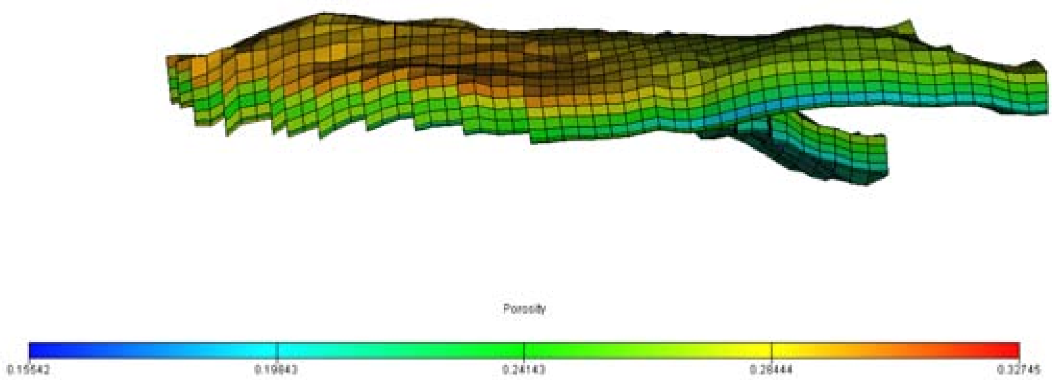


Figure 8: Porosity of the Tofte formation

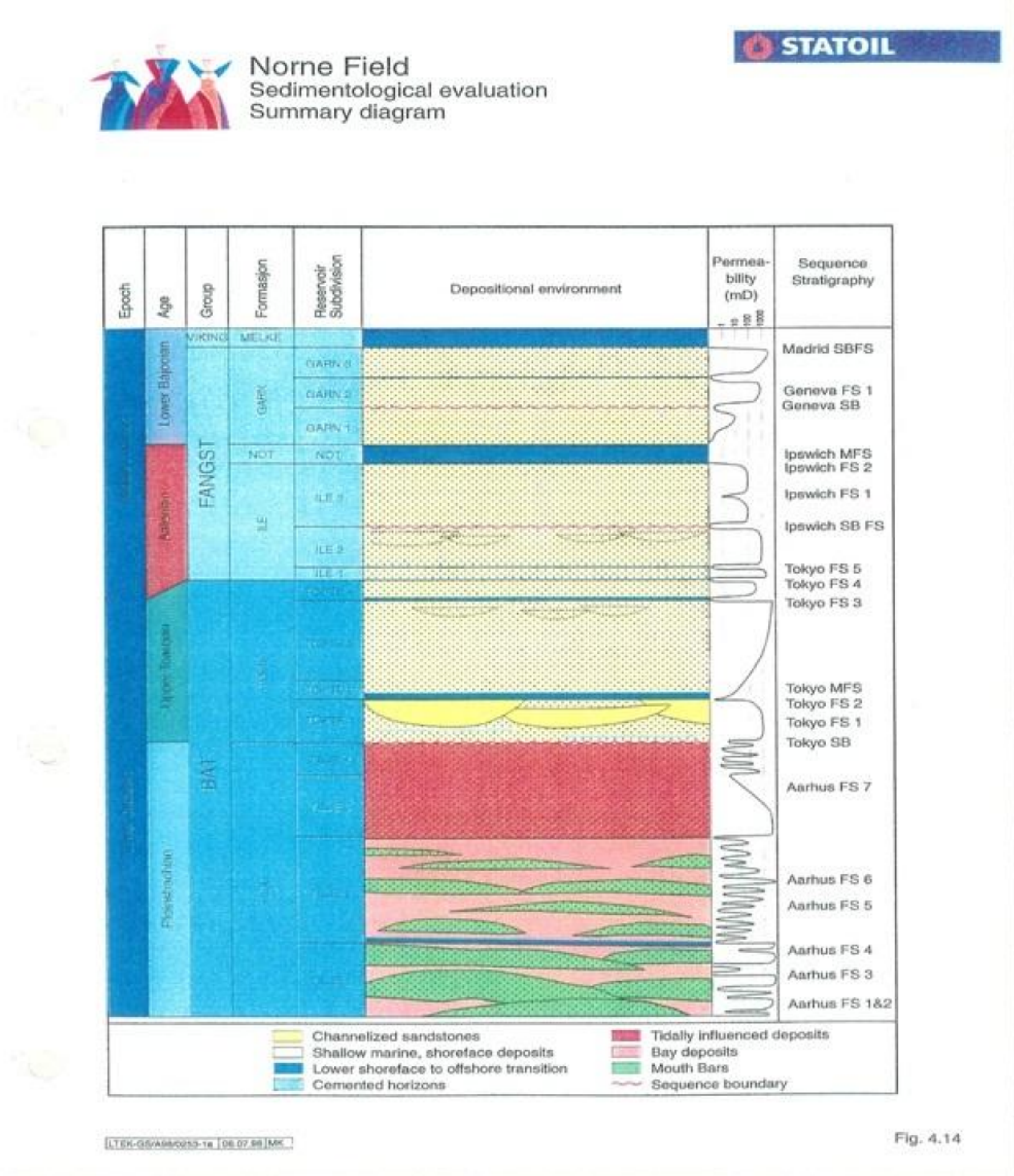


Figure 9:Stratigraphy of the Norne field redrawn from the Norne Field database (Statoil, 1998)

2.4 Reservoir engineering

2.4.1 Reservoir modeling

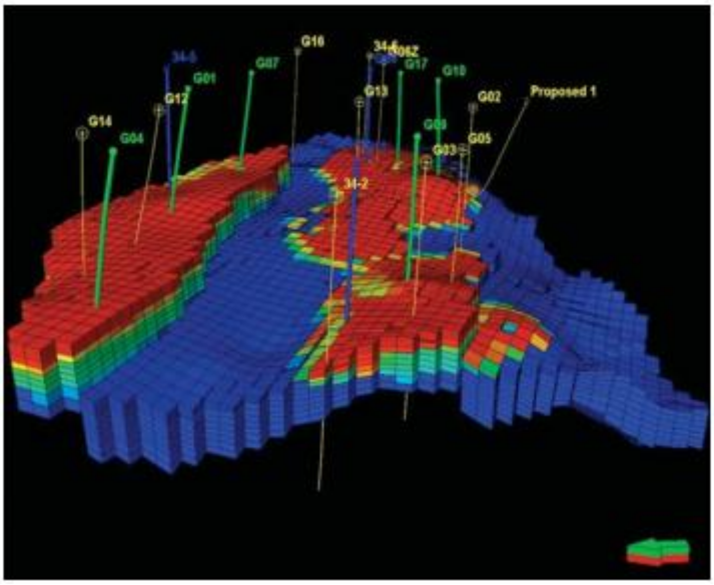


Figure 10: Resevoir model using Schlumberger Eclipse

Reservoir modeling and simulation are used to model the fluid flow in oil and gas reservoirs. Reservoir modeling is the 3D numerical representation of the hydrocarbon reservoir. The models are created using thousands of grid blocks representing the dynamic and static properties of the reservoir. Each cell is assumed to be homogenous in both rock nature and fluid flow. Reservoir modeling is an interdisciplinary collaboration between disciplines, e.g. seismic interpretation, petro-physics, geologists etc. This is described in the figure below.

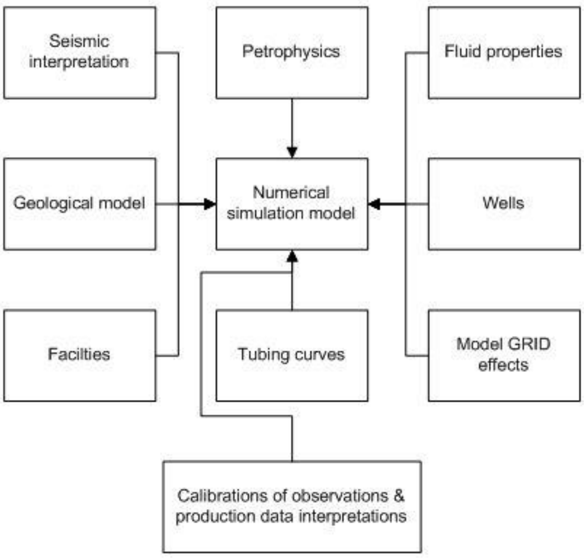


Figure 11: Disciplinary contributions to reservoir flow modeling (after H.H. Haldorsen and E. Damsleth, 1993) (Fanchi, 2006)

The different disciplines contributes with important data for the models, e.g. information about the reservoir structure; stratigraphic horizons and faults, internal architecture; depositional facies, petro-physical properties; porosity and permeability as well as fluid properties like water saturation (Principles of Applied Reservoir Simulation (3rd Edition),Fanchi, John R, 2006) (Fanchi, 2006)

2.4.2 Reservoir simulation

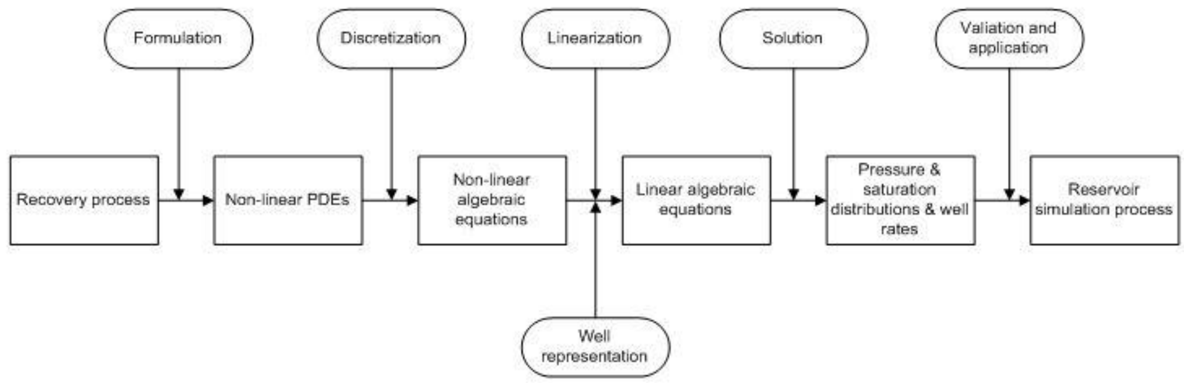


Figure 12: Steps to develop reservoir simulator, redrawn from Odeh (1982)

Reservoir simulation has become the standard for solving reservoir engineering problems. The major steps in reservoir simulation are depicted in the figure above. The formulation box outlines the basic assumptions inherent to the simulator. These assumptions are then applied to a control volume in the reservoir model, which results in a set of coupled nonlinear partial differential equations (PDEs) that describes the fluid flow through the porous media. These PDEs cannot be solved analytically and must therefore be solved using numerical methods. Discretization is used to convert the PDEs into non-linear algebraic equations. These equations can typically not be solved analytically, and this problem is solved by linearization of the PDEs. Well representation is used to incorporate fluid production and injection into the non-linear algebraic equations. Linearization is to approximate non-linear terms e.g. transmissibilities, production and injection, and coefficients of unknowns in the accumulation terms. The linearization results in set of linear algebraic equations which easily can be solved using any standard linear numerical solver. Validation or history matching are necessary to make sure that no errors were introduced during the development(Fanchi, 2006).

One of the leading reservoir simulators are Eclipse from Schlumberger Information Solutions. The Eclipse simulator is based in general on the steps described above and it uses a finite difference approach including multiple numerical solution techniques to solve difficult and advanced reservoir simulation problems.

The reservoir models serve as input to the reservoir simulation in efforts to quantify the remaining hydrocarbon volumes, as well as flow simulation for quantification of recoverable hydrocarbons and well positioning as well as many other factors described below(Fanchi, 2006).

- Coordinate reservoir management activities
- Evaluate project performance
    - Interpret/Understand reservoir behavior
- Model sensitivity to estimated data
    - Determine need for additional data
- Estimate project life
- Predict recovery versus time
- Compare different recovery processes
- Plan development or operational changes
- Select and optimize project design
- Maximize economic recovery

3 Results and discussion:

3.1 Quantification of remaining oil in the Tofte formation

The total estimated remaining oil in the reservoir can be divided into two parts, producible and non-producible oil, and is called oil in place. The non-producible oil is the oil that is left in the reservoir, when it is not economically feasible to produce more oil. The limitations can come from different characteristics in the reservoir, as well as limitations in reservoir extraction technologies.

Before investing in new producers it is important to know how much producible oil that is available with the current drainage strategy. We don't have any explicit specifications about the current drainage strategy at the Norne field, but generally in E-segment it is water flooding. We assume that it is integrated into the eclipse model.

We can quantify the remaining oil by using ECLIPSE. We take the Tofte formation as one region and then export Regional Oil In Place (ROIP) to find out how much oil remained at the end of the simulation.

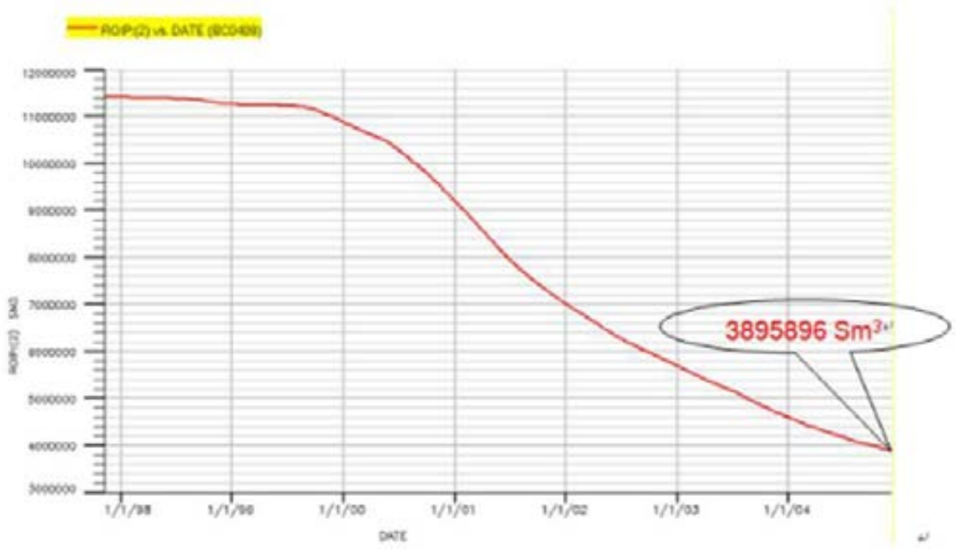


Figure 13: Remaining oil in Tofte formation

We can see from the Figure 11 above that there are 3895896 Sm^3 remaining oil in Tofte formation at the end of basic case simulation.

3.2 New well's parameters optimization

In order to produce the remaining oil in Tofte formation, we plan to place one or two new production well(s) and optimize the new producer(s) with different parameters, which consist of the location of well(s), the perforation interval (only for vertical well), drilling date, well type and oil production rates. Finally, we will base on the additional accumulative oil production of E segment to find out the best solution to produce remaining oil in Tofte formation.

3.2.1 Assumptions

1. The older wells in E segment are still controlled by control mode set before drilling new wells.

2. Although E segment has good communication with other segments we just consider the oil produced from E segment when we conduct new well's optimization.

3.2.2 Selecting location for new producer

3.2.2.1 Main pay zones

There are 7 layers in the Tofte formation; each layer has different oil saturation and thickness, so we need to find the main pay zones to select location for new well(s).

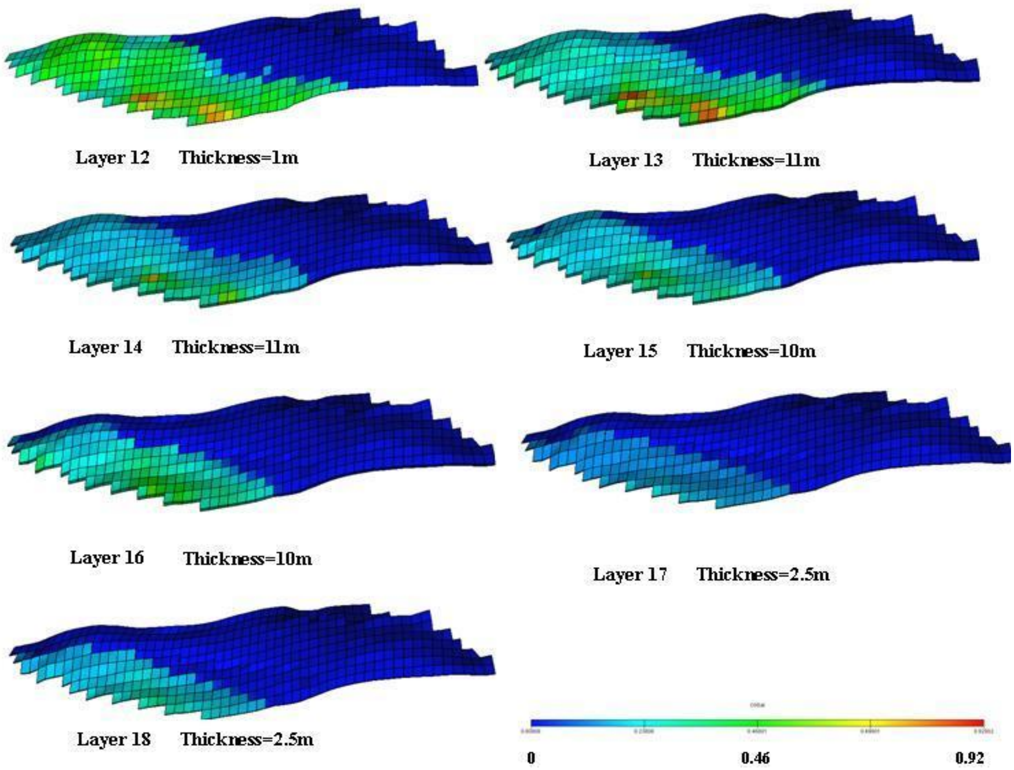


Figure 14: Oil saturation distribution in each layer (1 DEC 2004)

We can see from Figure 12, layers 13&14 have much bigger thickness and higher oil saturation than other layers.

We can also find out the main pay layers based on the value of remaining oil of each layer.

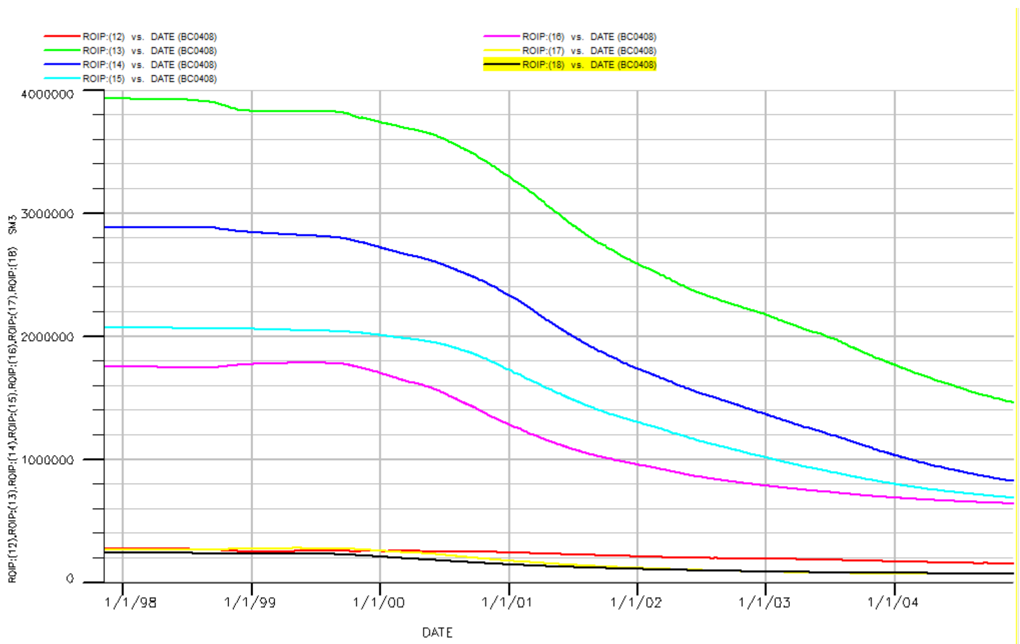


Figure 15: Remaining oil in each layer of Tofte formation

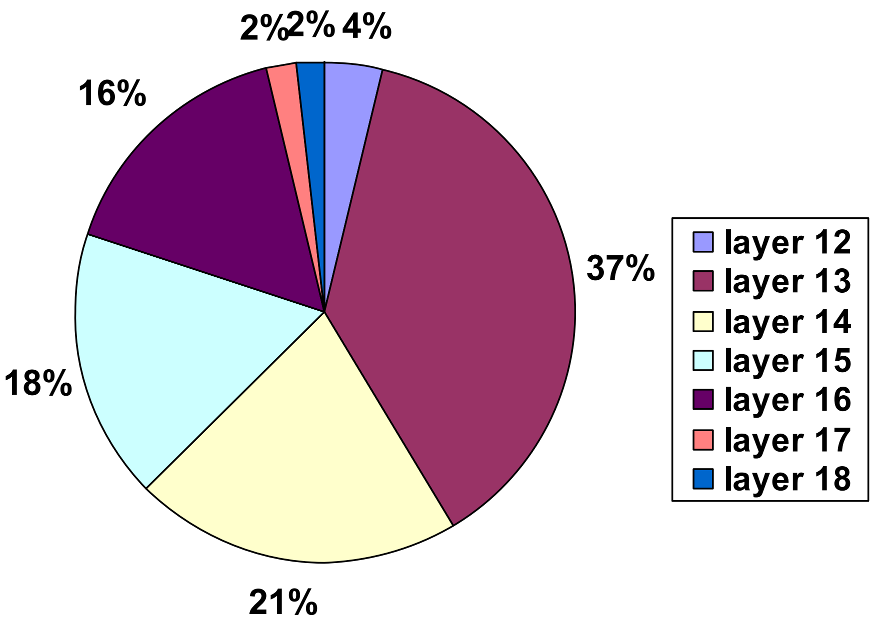


Figure 16: Remaining oil pie chart

We can find from Figure 14 that layer 13 and layer 14 account for about 58% of remaining oil in the Tofte formation, so we can take layer 13&14 as main pay zones.

3.2.2.2 Vertical well

The control area of a vertical well is smaller than a horizontal well; due to this we will place two vertical production wells (P-1 and P-2) in the Tofte formation. This combined with the the information about the main pay zones we can select the best location for the two vertical wells.

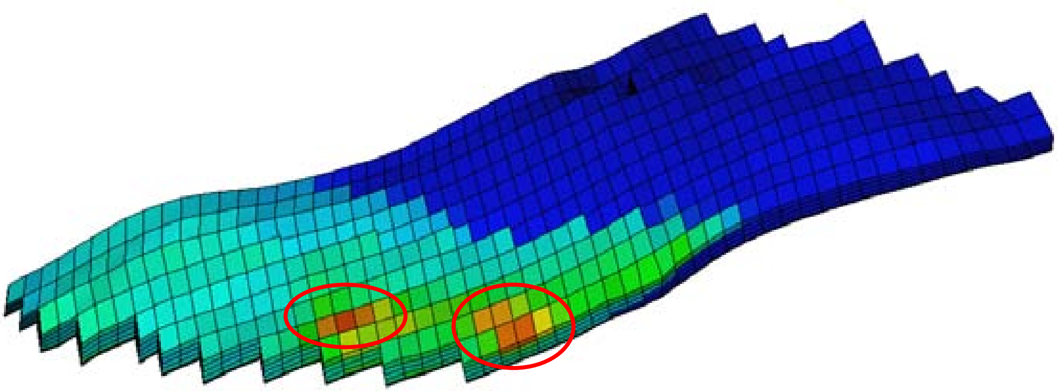


Figure 17: Remaining oil distributions in Tofte formation

In Figure 15 we can see that there are two areas with higher oil saturation (red circle); we place one vertical well in each area (see Figure 16)

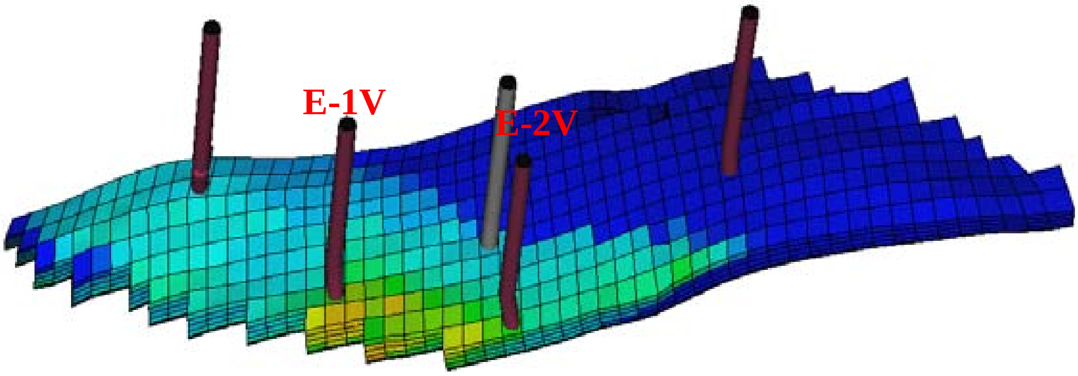


Figure 18: Location of vertical wells

3.2.2.3 Horizontal well

Horizontal wells have larger control area. Due to this we only need one horizontal well (E-5H) to produce the remaining oil in Tofte formation. These days the horizontal part of horizontal well is more than 1000m, so we can place the horizontal well in layer 13 as follows.

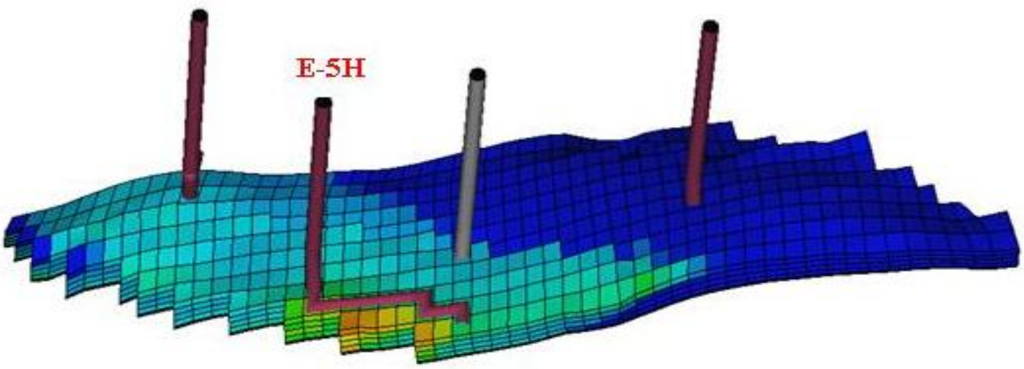


Figure 19: Location of horizontal well

The reason for placing horizontal well in this way (Figure 17) is that firstly horizontal well can connect the two higher oil saturation areas (Figure15), secondly oil density is less than water, so the oil below layer 13 can flow into layer 13 by density difference.

3.2.3 Perforation interval optimization

We perforate the whole horizontal part in the horizontal well, so we only optimize the perforation interval for the vertical wells.

There are 7 layers in Tofte formation; we can see from Figure 12 that the oil saturation of layer 17 and 18 is very close to the residual oil saturation, which means in these two layers there is no recoverable oil. So we take two types of well perforation design for the vertical wells. The first is to perforate the whole formation - the other is to only perforate the upper layers (layers 12-16). Other parameters for the vertical wells are the drilling date: DEC 1st 2005; control mode is an oil production rate of 2000 Sm^3/day and the minimum bottle hole pressure is 200 bar. Then run the simulation to DEC 1st 2021 to find out the difference between these two cases.

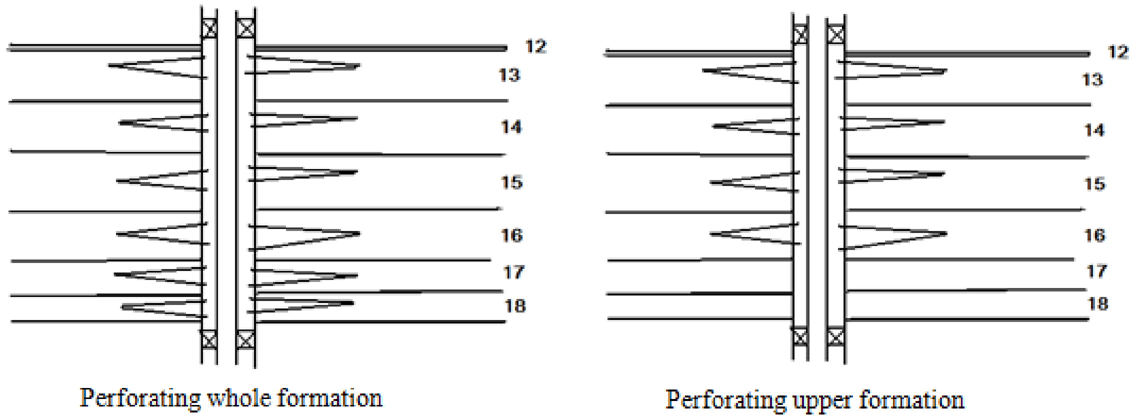


Figure 20: Two types of perforation design

We can get the better one by comparing the accumulative oil production and field pressure.

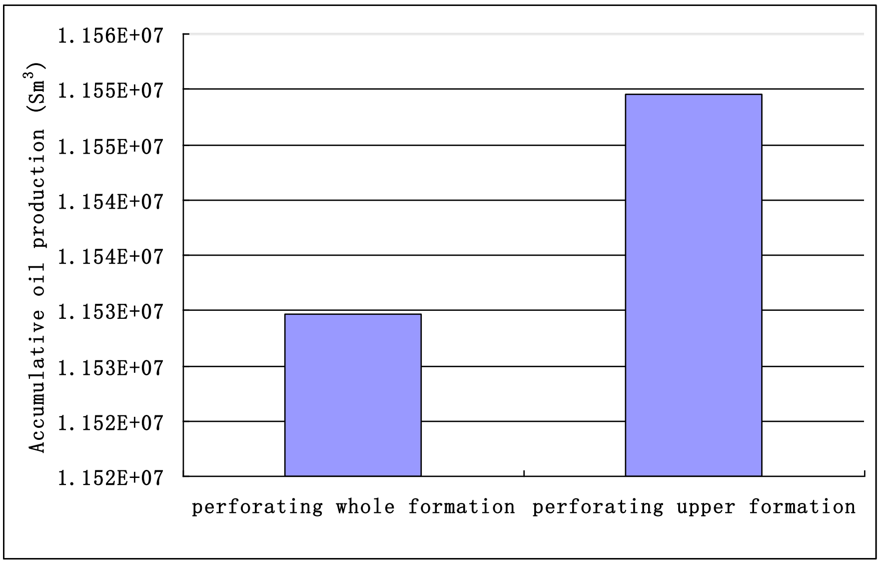


Figure 21: Cumulative oil production for different perforating design

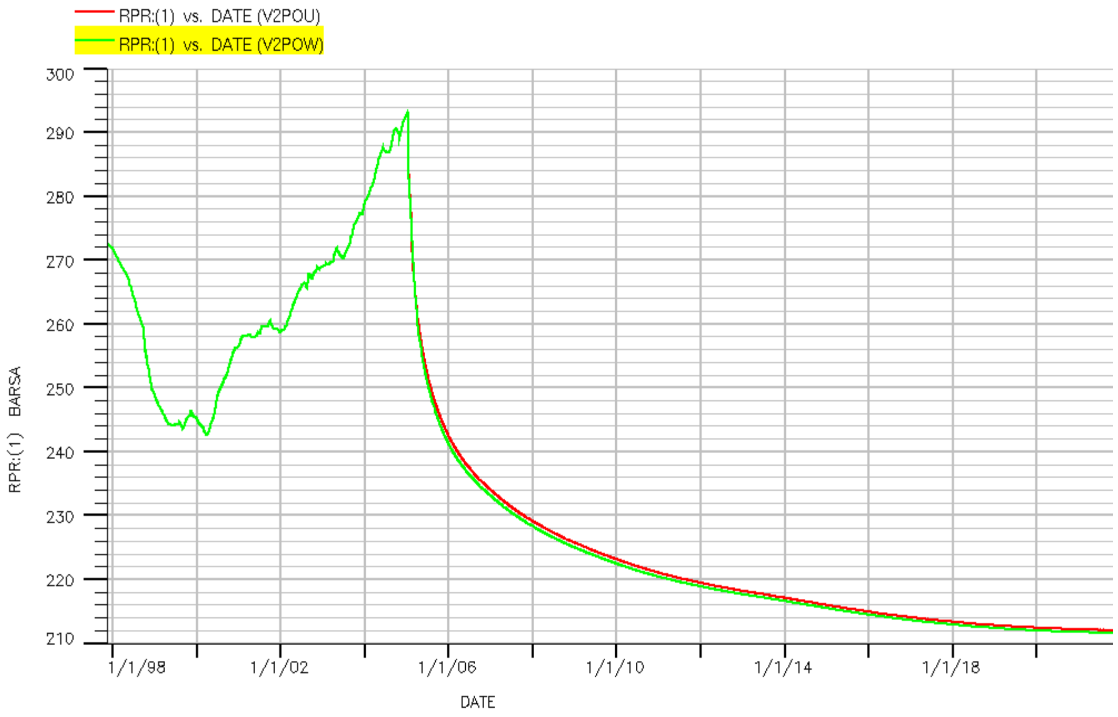


Figure 22: Field pressure for different perforating design

In Figure 20, we find that the upper perforating design has higher cumulative oil production and field pressure than perforating the whole formation case. Based on this we select the upper formation perforation for vertical wells.

3.2.4 Drilling date, well type and oil production rate optimization

We plan to drill new well(s) on Jan 1st 2005, Jan 1st 2007, Jan 1st 2009 and Jan 1st 2011; four different dates to find out the best solution to produce the remaining oil in the Tofte formation. We place both vertical and horizontal well(s) with different oil production rate for each drilling date.

3.2.4.1 Drilling date Jan 1st 2005

We place the horizontal and vertical well(s) as indicated earlier in Jan 1st 2005, taking 8 different oil production rates (1000Sm^3/day, 2000Sm^3/day, 3000Sm^3/day, 4000Sm^3/day, 5000Sm^3/day, 6000Sm^3/day, 7000Sm^3/day, 8000Sm^3/day) for horizontal well and 7 different oil production rates (500Sm^3/day, 1000Sm^3/day, 2000Sm^3/day, 3000Sm^3/day, 4000Sm^3/day, 5000Sm^3/day, 6000Sm^3/day) for vertical wells, see figure 21, at the same time we also control the producer(s) by 200 bar bottom hole pressure, and then run the model to Dec 1st 2021.

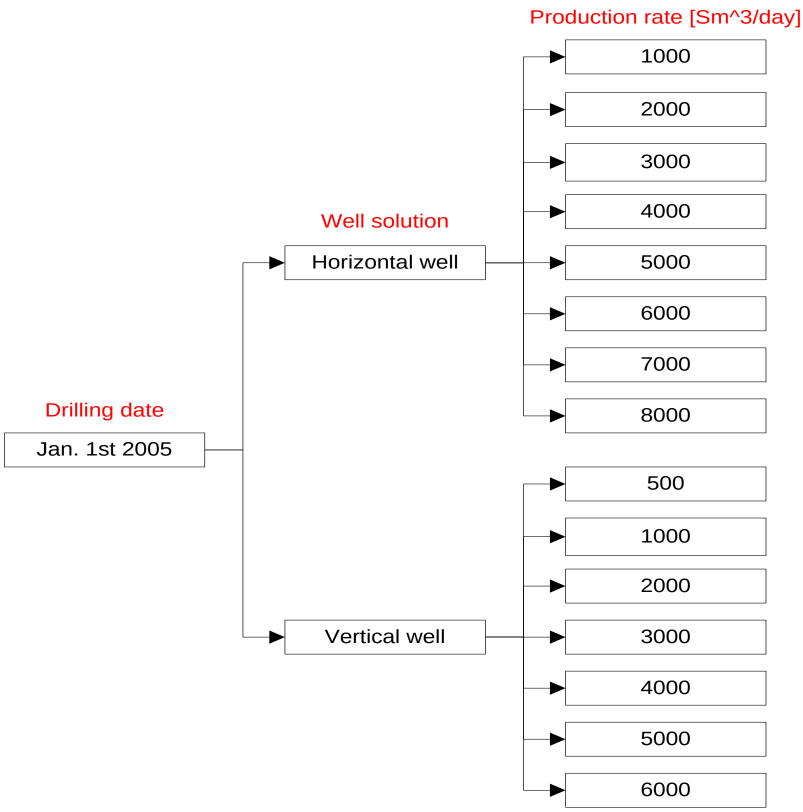


Figure 23: Solution tree (Jan 1st 2005)

We take the whole E-segment as one region to export the regional accumulative oil production by using ECLIPSE.

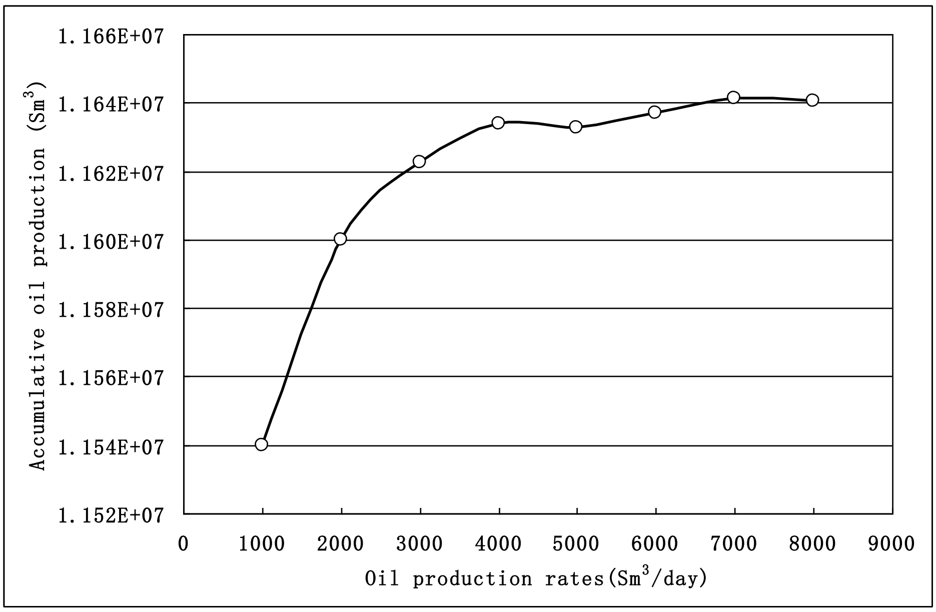


Figure 24: ROPT V.S. oil production rate for horizontal well case in 2005

In Figure 22 we see that the best oil production rate for the horizontal well is 7000 Sm^3/day.

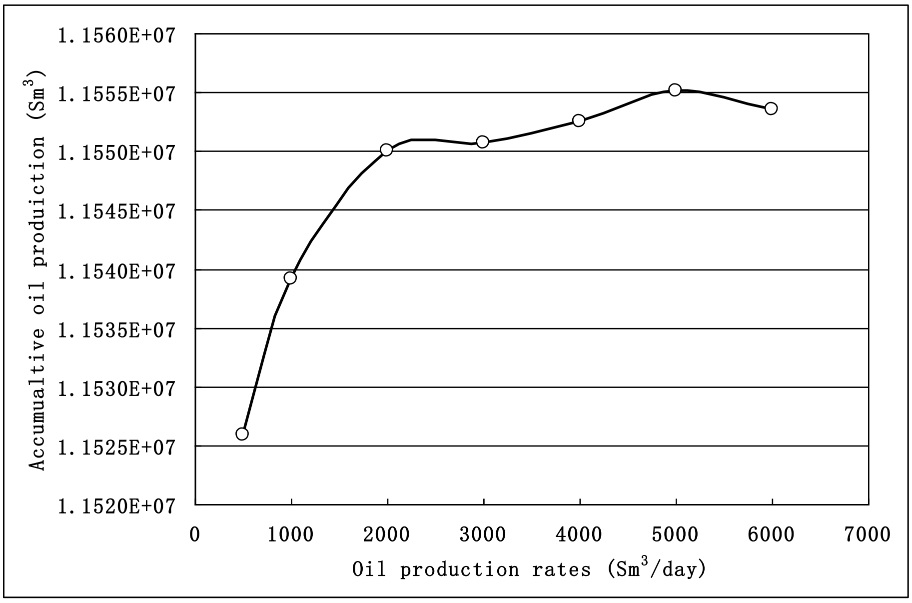


Figure 25: ROPT V.S. oil production rate for vertical wells case in 2005

In Figure 23 we see that the best oil production rate for vertical wells is 5000 Sm^3/day.

Finally we compare the accumulative oil production between vertical wells case and horizontal well case to find the best solution.

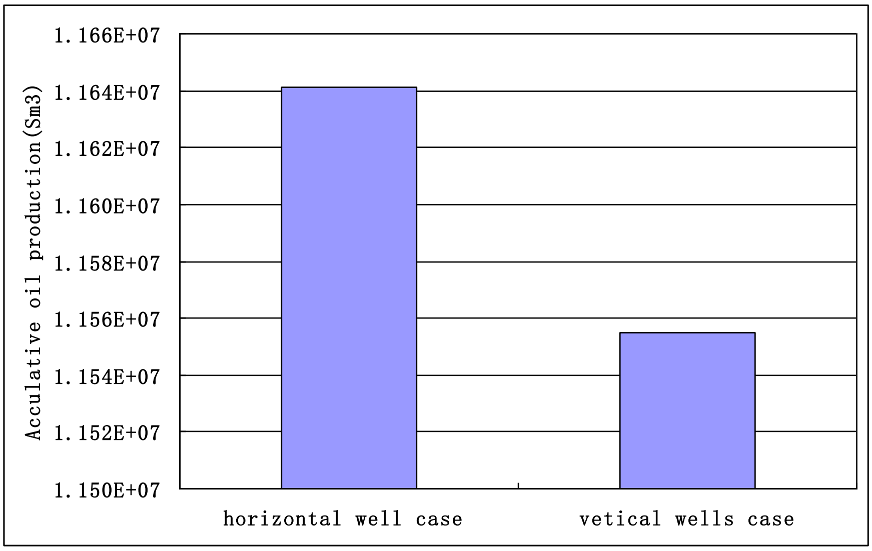


Figure 26: Accumulative oil production for horizontal and vertical well in 2005

From Figure 24 we see that the horizontal well case is much better than the vertical wells case. So the horizontal well case with 7000 Sm^3/day oil production rate is the best solution among all solutions when drilled on Jan 1st 2005; the accumulated oil production for this case is 11641428 Sm^3.

3.2.4.2 Drilling date Jan 1st 2007

We add a new horizontal and two new vertical wells as indicated earlier in Jan 1st 2007, taking 7 different oil production rates (1000Sm3/day, 2000Sm3/day, 3000Sm3/day, 4000Sm3/day, 5000Sm3/day, 6000Sm3/day, 7000Sm3/day) for horizontal well and 6 different oil production rates (500Sm3/day, 1000Sm3/day, 2000Sm3/day, 3000Sm3/day, 4000Sm3/day, 5000Sm3/day) for vertical wells(Figure 25), at the same time we also control the producer(s) by 200 bar bottom hole pressure ,and then run the model to Dec 1st 2021.

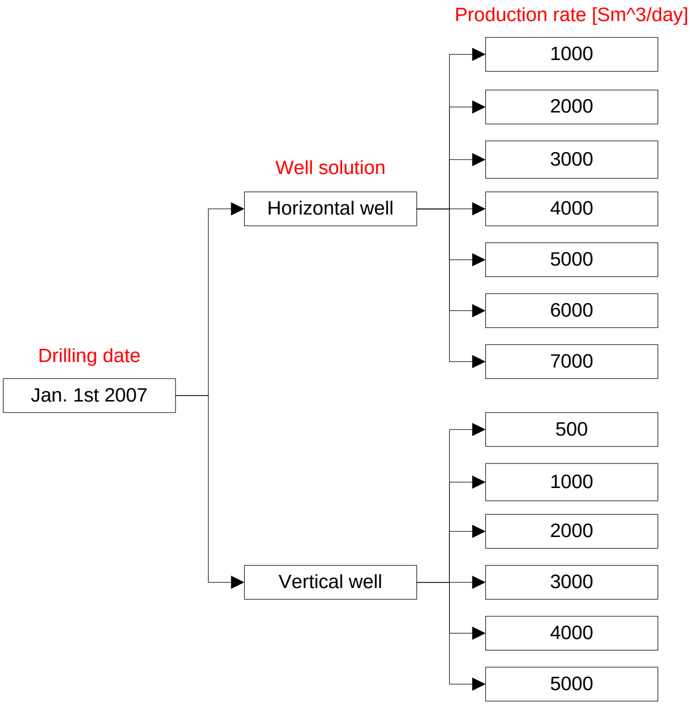


Figure 27: Solution tree (Jan 1st 2007)

We take the whole E segment as one region and export the regional accumulative oil production by using ECLIPSE.

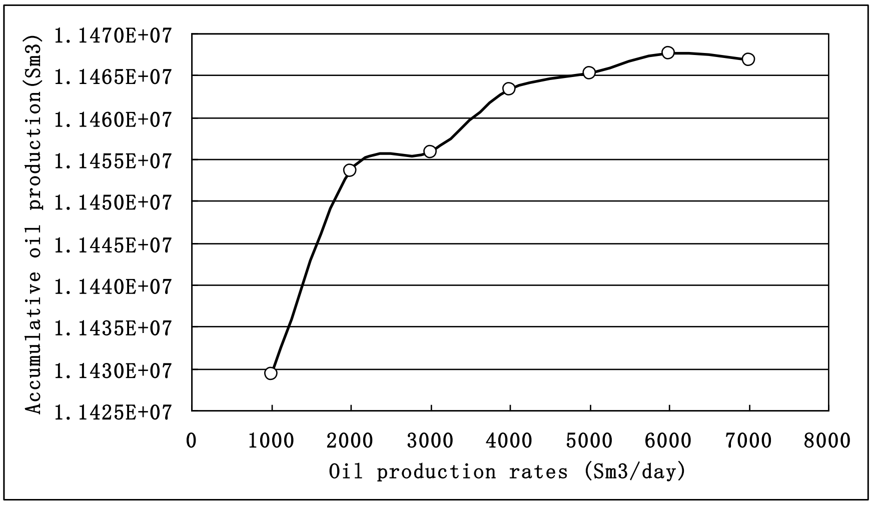


Figure 28: ROPT V.S. oil production rate for horizontal well case in 2007

In Figure 26 we see that the best horizontal well oil production rate is 7000 Sm^3/day.

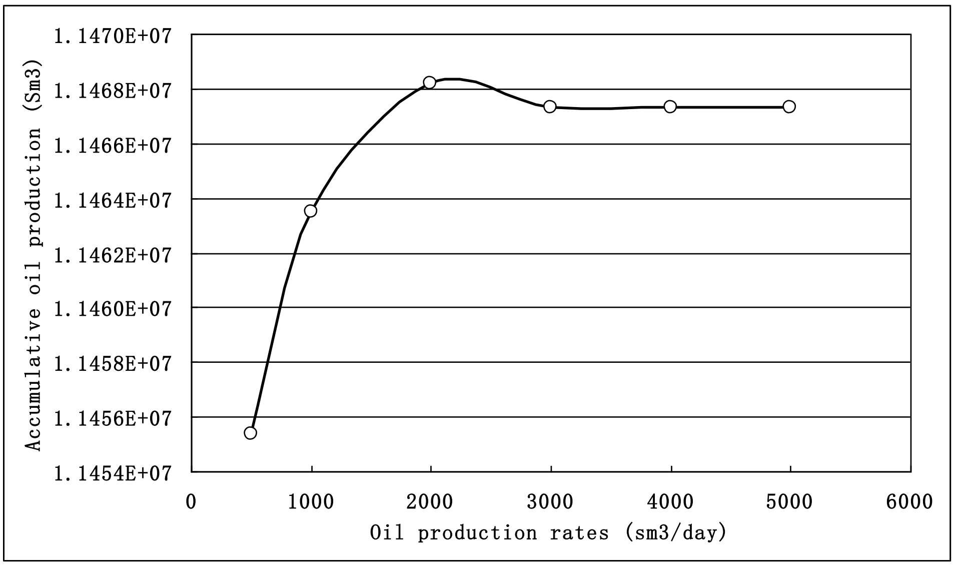


Figure 29: ROPT V.S. oil production rate for vertical wells case in 2007

In Figure 27 we see that the best vertical well production rate is 2000 Sm^3/daye.

And then we can get the best solution by comparing the accumulated oil production in the E-segment between the horizontal well case and the vertical wells case.

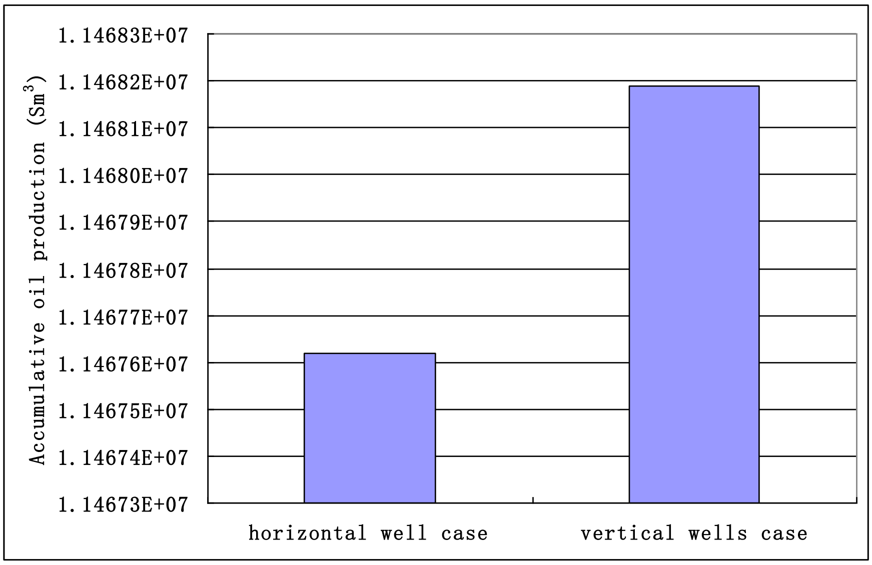


Figure 30: Accumulative oil production for horizontal and vertical well in 2007

From Figure 28 we see that the vertical wells case is better than the horizontal well case, but that the difference is very small. We will explain the reason why the vertical wells case is better than the horizontal well case in the next case.

So the vertical wells case with 2000 Sm^3/day oil production rate is the best solution among all solutions drilled on Jan 1st 2007, and the accumulation oil production for this case is 11468189 Sm^3.

3.2.4.3 Drilling date 1 Jan 2009

We place a new horizontal well and two vertical wells as indicated earlier in Jan 1st 2009, taking 7 different oil production rates (1000Sm^3/day, 2000Sm^3/day, 3000Sm^3/day, 4000Sm^3/day, 5000Sm^3/day, 6000Sm^3/day, 7000Sm^3/day) for horizontal well and 6 different oil production rates (500Sm^3/day, 1000Sm^3/day, 2000Sm^3/day, 3000Sm^3/day, 4000Sm^3/day, 5000Sm^3/day) for vertical wells(Figure 29), at the same time we also control the producer(s) by 200 bar bottom hole pressure, then run the model to Dec 1st 2021.

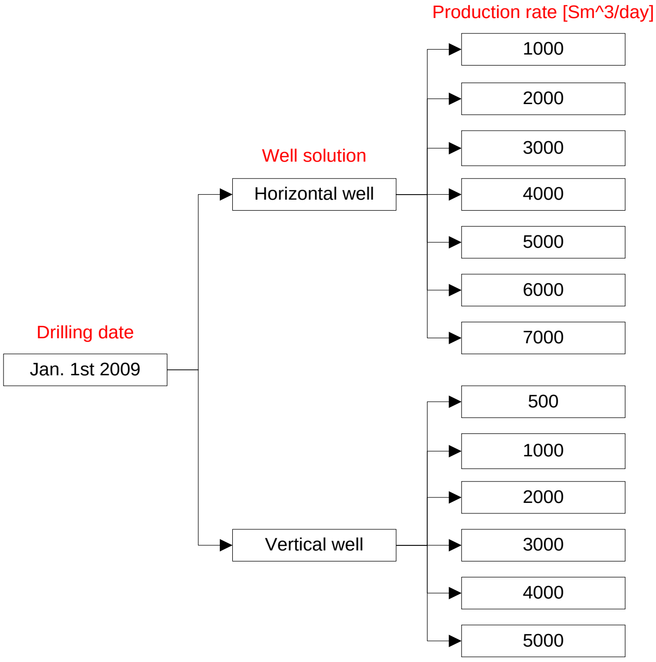


Figure 31: solution tree (Jan 1st 2009)

We take the whole E segment as one region and then export the regional accumulative oil production by using ECLIPSE.

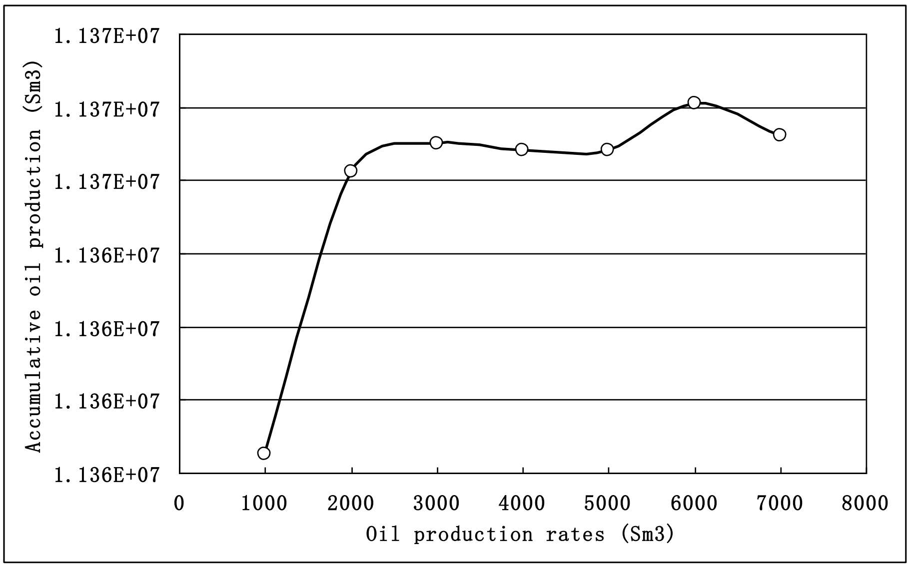


Figure 32: ROPT V.S. oil production rate for horizontal well case in 2009

In Figure 30 we see that the best horizontal well oil production rate is 6000 Sm^3/day.

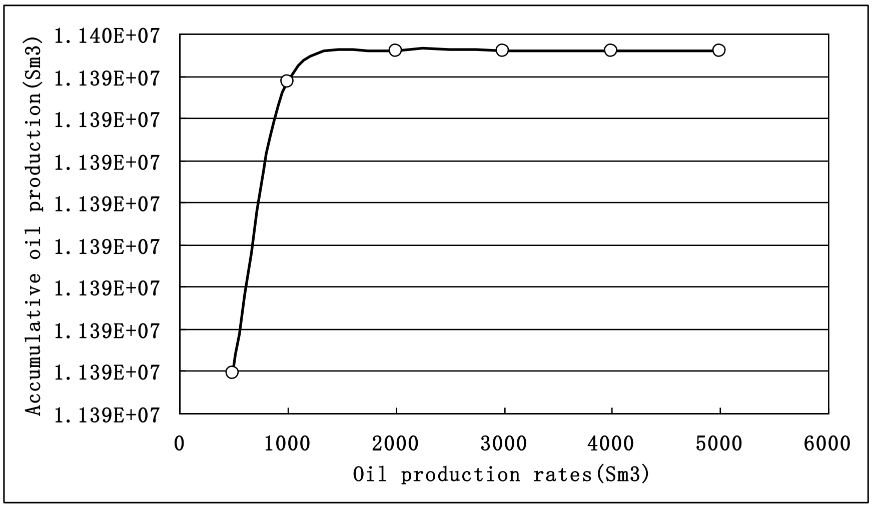


Figure 33: ROPT V.S. oil production rate for vertical wells case in 2009

In Figure 31 we see that the best vertical well production rate is 2000 Sm^3/day.

And then we compare the accumulative oil production between vertical wells case and horizontal well case to find the best one.

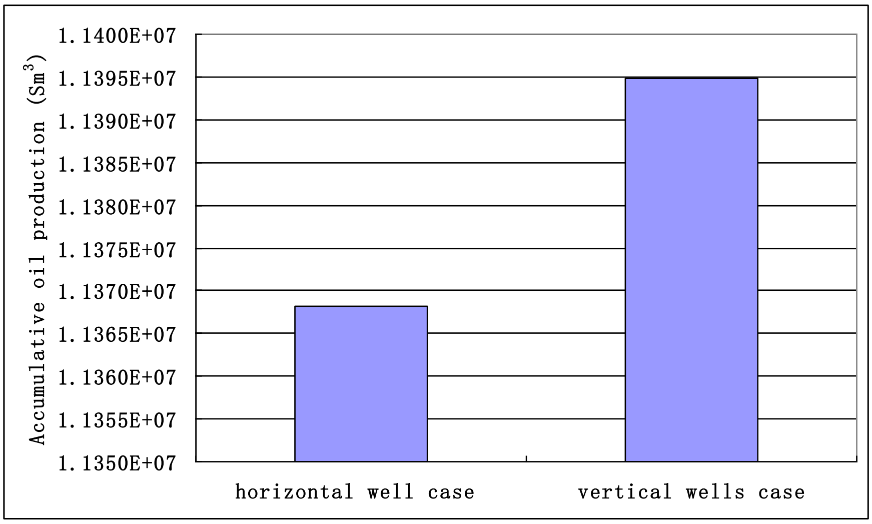


Figure 34: Accumulative oil production for horizontal and vertical well in 2009

In figure 32 we see that the vertical wells case is better than the horizontal well case. Normally we think horizontal wells is better than vertical wells, but now we take the whole E segment as one region, so adding new well will have effect on the older wells, in the vertical wells case the field pressure is higher than horizontal well case (Figure 33), and we can see from Figure 34 accumulative oil production for older wells in vertical wells case is higher than horizontal well case, we produce 88758.87 Sm^3 more oil from older wells in vertical wells case. From Figure 35 we can find horizontal well produce more 62069.5 Sm^3 than vertical wells. Taking one with another we produce more 26689.37 Sm^3 oil in vertical case.

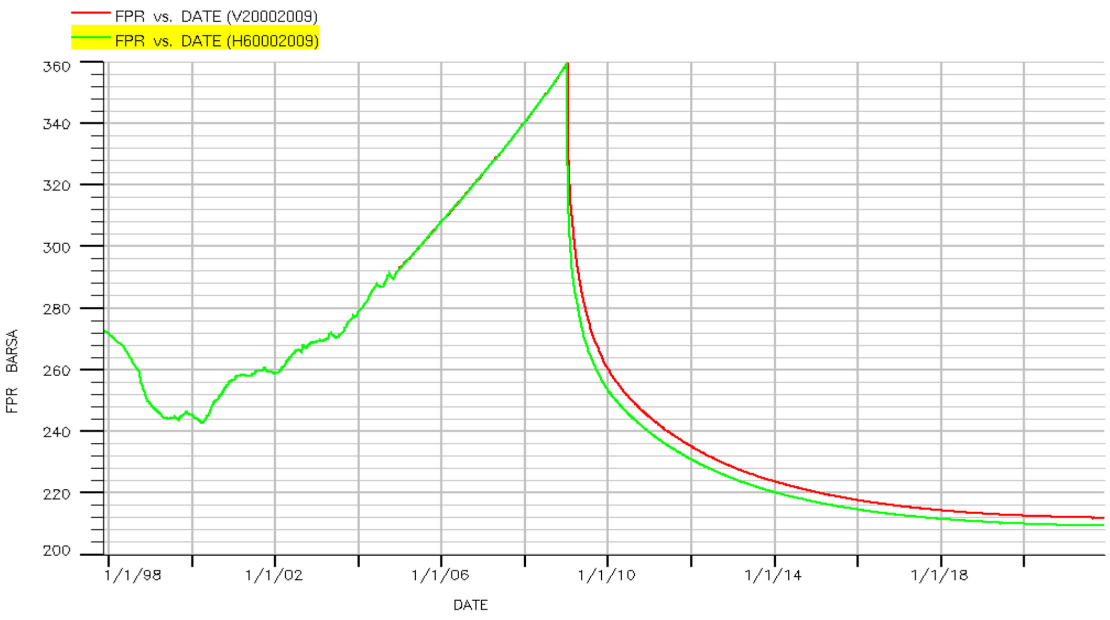


Figure 35: Field pressure for case with new wells in 2007

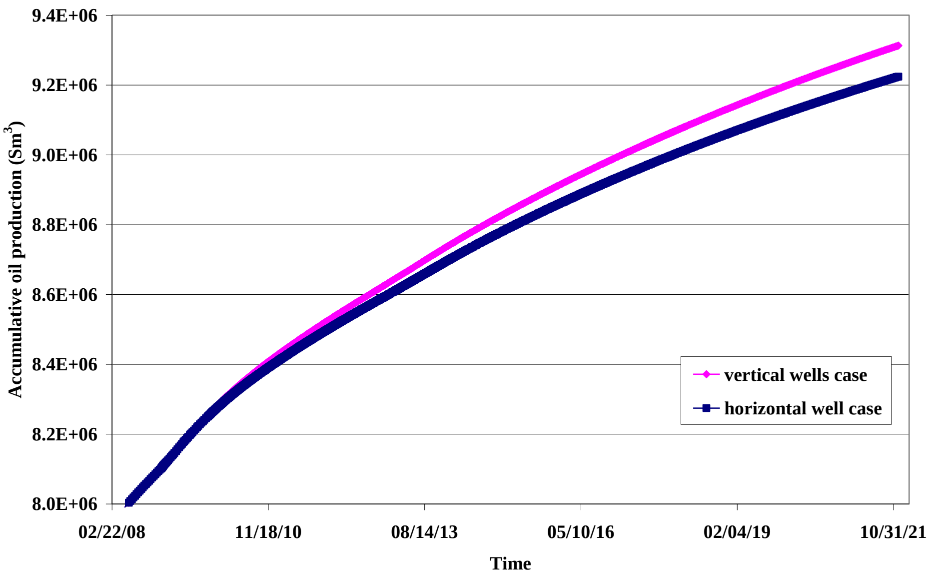


Figure 36: Accumulative oil production for older wells

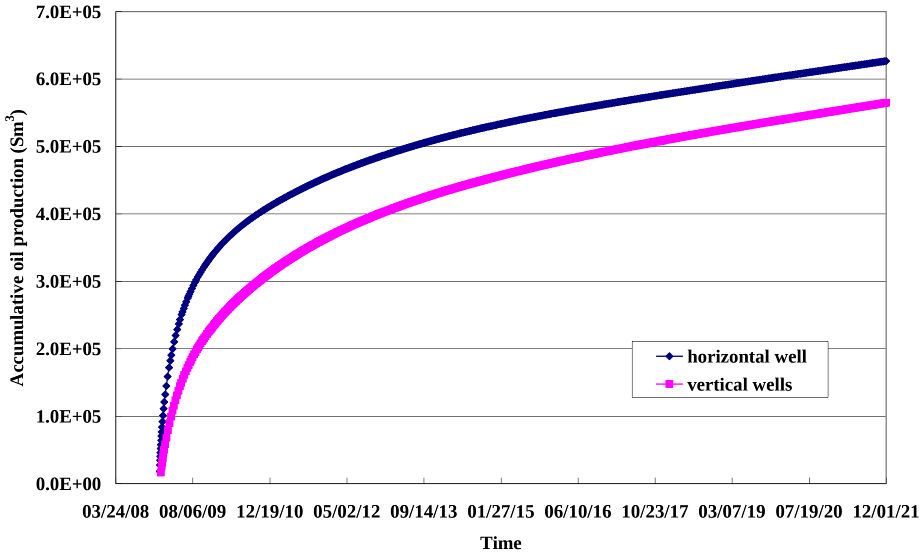


Figure 37: Accumulative oil production for new wells drilled in 2009

So the vertical wells case with 2000 Sm^3/day oil production rate is the best solution among all solutions for new well(s) in Jan 1st 2009, and the accumulation oil production for this case is 11394793 Sm^3.

3.2.4.4 Drilling date 1 Jan 2011

We add a new horizontal and two new vertical wells as indicated earlier in Jan 1st 2011, taking 5 different oil production rates (1000Sm^3/day, 2000Sm^3/day, 3000Sm^3/day, 4000Sm^3/day, 5000Sm^3/day) for horizontal well and 6 different oil production rates (500Sm^3/day, 1000Sm^3/day, 2000Sm^3/day, 3000Sm^3/day, 4000Sm^3/day, 5000Sm^3/day) for vertical wells(Figure 36), at the same time we also control the producer(s) by 200 bar bottom hole pressure ,and run the model to Dec 1st 2021.

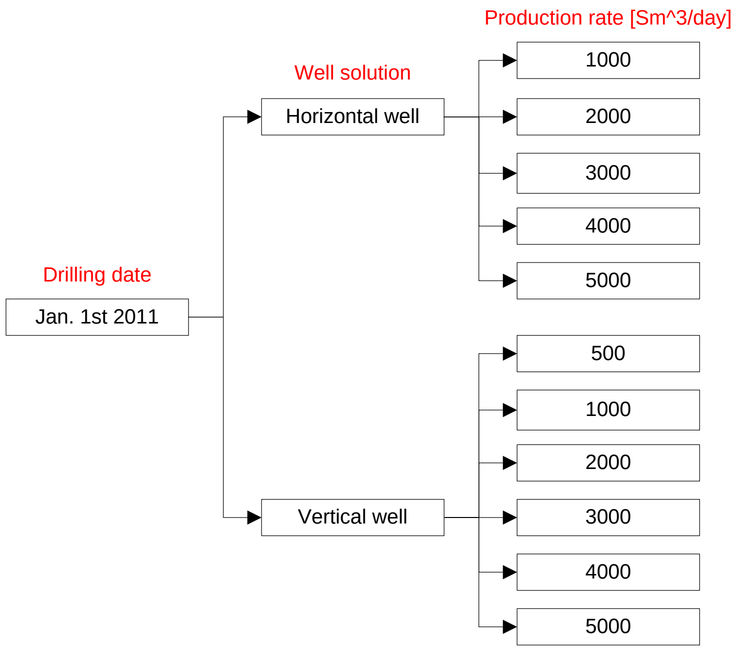


Figure 38: Solution tree (Jan 1st 2011)

We take the whole E segment as one region and then export the regional accumulative oil production by using ECLIPSE.

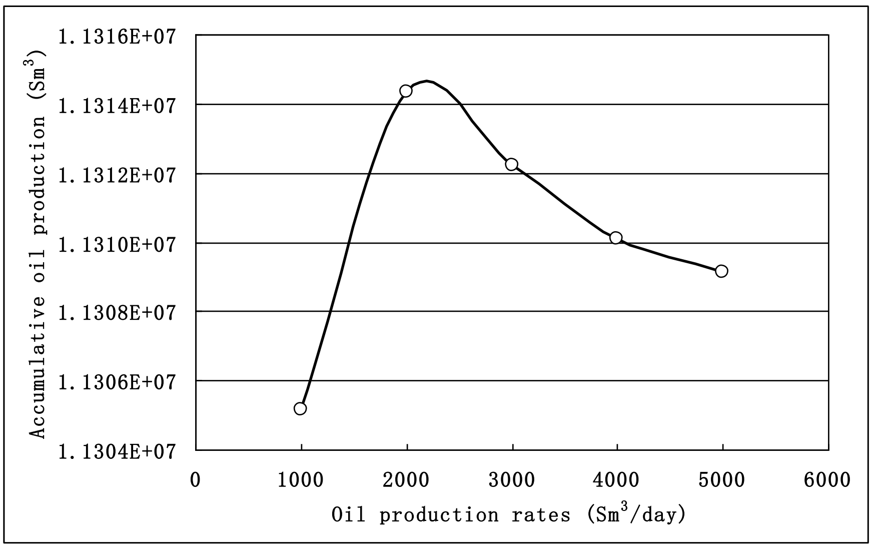


Figure 39: ROPT V.S oil production rate for horizontal well case in 2009

In Figure 37 we see that the best horizontal well oil production rate is 2000 Sm^3/day.

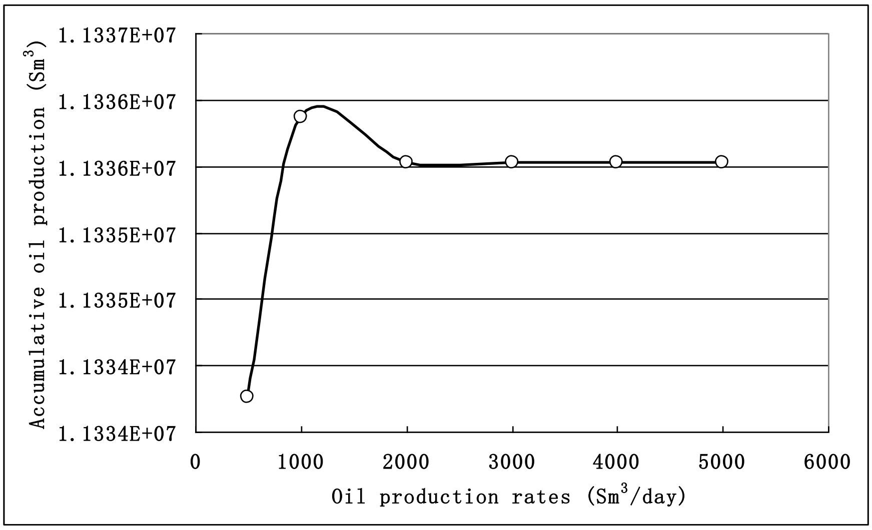


Figure 40: ROPT V.S. oil production rate for vertical wells case in 2011

In Figure 38 we see that the best vertical well oil production rate is 1000 Sm^3/day.

And then we compare the accumulative oil production between vertical wells case and horizontal well case to find out the best one.

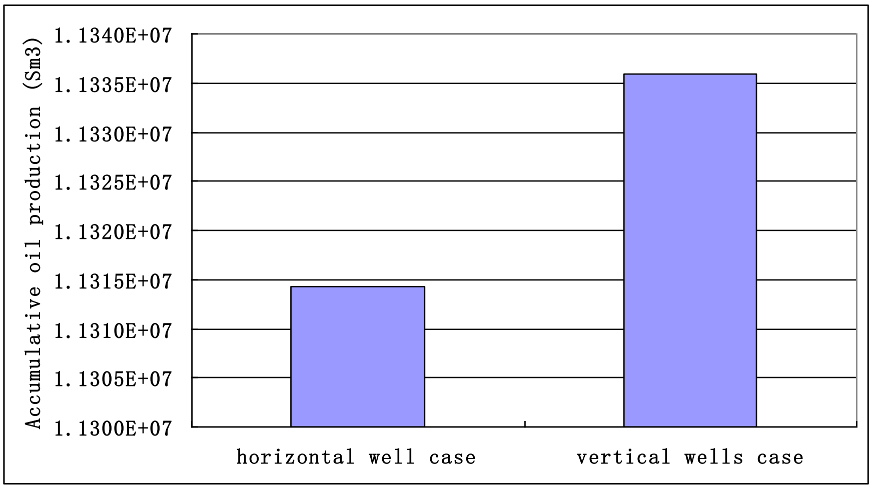


Figure 41: Accumulative oil production for horizontal and vertical well in 2009

From Figure 39 we find that the vertical wells case is much better than the horizontal well case. So the vertical wells case with 1000 Sm^3/day oil production rate is the best solution among all solutions drilled on Jan 1st 2011, and the accumulation oil production for this case is 11335870 Sm^3.

3.2.5 Results

Finally we can get four best cases from each year and list some parameters and additional oil production for each best case.

Addition oil production=accumulative production of new case - accumulative production of the base case

Table 1: Parameters for each best case

Date	Well type	Oil production rate (Sm^3/day)	Additional oil production (Sm^3)
2005	Horizontal well	7000	1041317
2007	Vertical well	2000	868078
2009	Vertical well	2000	794682
2011	Vertical well	1000	735759

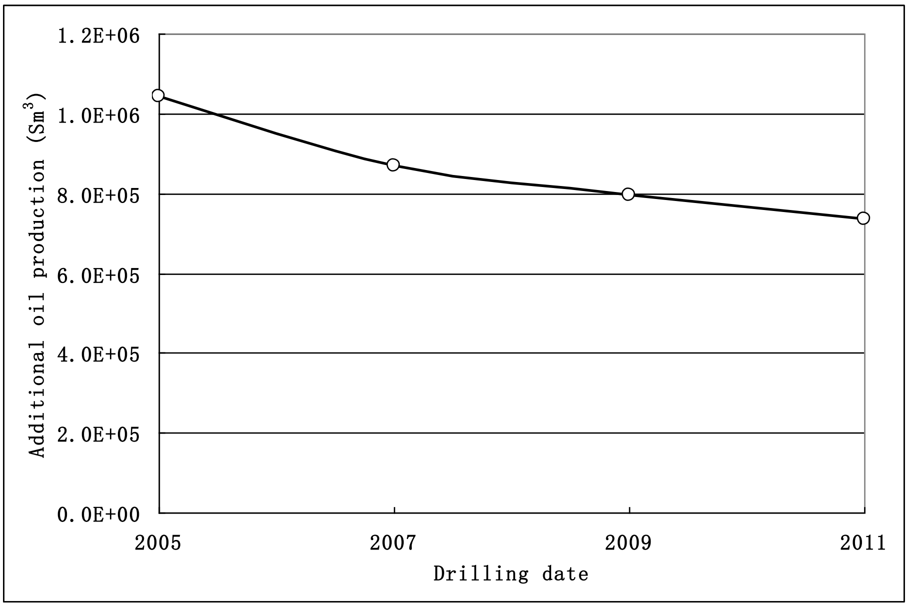


Figure 42: Additional oil production for each drilling date

We can see from Figure 40 that the later we drill new well(s) the less oil we can produce, because E segment has good communication with other segments so some oil may flow into other segments, and another reason is at the later time of oil field development field pressure will become lower and lower.

3.3 Economic evaluation

3.3.1 Procedure

The economic evaluation was performed using a simple net present value (NPV) model used by Statoil for economic calculations on the Norne field. NPV or discounted cash flow is a measure of the value created by an investment. The model calculates the NPV by taking input data from the yearly oil production, capital and operating expenditure as well as expenditure related to the use of rigs during the installation of the new wells.

In the economic evaluation we have firstly evaluated the base case for the Norne E-segment. The base case consists of five wells; three producers and two injectors. This is to establish a framework for comparison of the possible new producers in the Tofte formation. The simulation of new producers has resulted in four possible solutions. One horizontal well installed in 2005 or two vertical producers installed in 2007, 2009 or 2011.

3.3.2 Assumptions and simplifications

In order to predict the NPV for the different solutions we had to make certain assumptions and simplifications for the input to the model.

All simulations and calculations assumes that the present year is 2005, this is due to the NPV model supplied by Statoil, as well as the Eclipse model is only history matched until 2004.

We have only evaluated the P50 scenario or mean of the estimated production rate. This means that there is a 50 % probability that the production rate exceeds or is less than the predicted results. The P10 and P90 scenario production rates can be obtained by Monte Carlo simulations, but this has not been implemented due to time constraints. This means that our result from the NPV calculations only give a probable estimate of the income from the reservoir and not proven and possible values.

The oil price is history matched up until 2009; from the year 2010 until 2021 we assume that the oil price is at a level of 75 USD per barrel. In order to simplify the calculations we assume that the oil price is constant during the year.

The capital expenditure is the expenditure related to investment in fixed assets or when adding value to existing fixed assets. We assume that the capital expenditure only relates to the installation cost of the new producers. From the lack of economic data we assume the cost of one horizontal well is 420MNOK and the cost of one vertical well is 210 MNOK. This makes it easy to compare the different solutions.

We do not have any economic data for the rig rates or operating expenditure. We neglect this term in the economic evaluation in all solutions.

The dollar rate is set to 6.4 NOK in 2005, 6.75 NOK from 2006 until 2021.

Other inputs to the model are a tax rate on taxable income at 78 %, a tax deduction rate at 72,825 % on capital investments, inflation rate at 2.5 % and a discount rate at 7 %.

3.3.3 Base case evaluation

The regional oil production rate and the net present value of the base case are presented below.

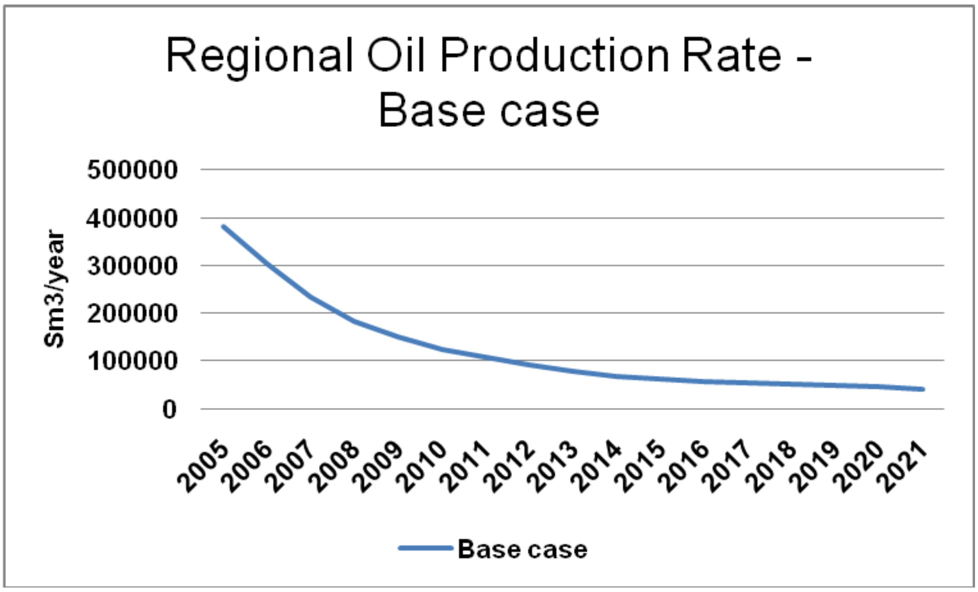


Figure 43: Regional Oil Production Rate - Base case

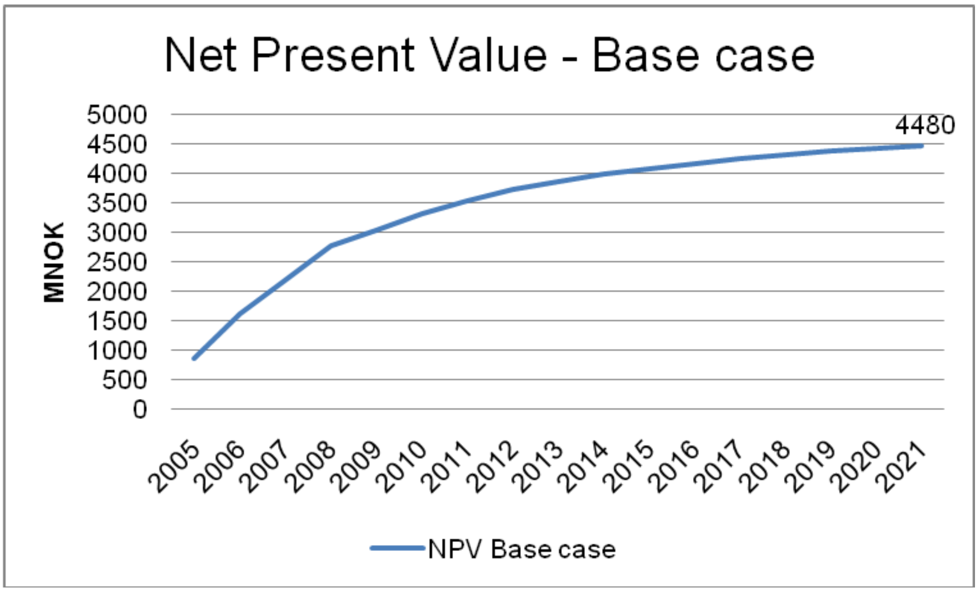


Figure 44: Cumulative NPV - Base case

The NPV of the base case is 4480 MNOK before tax has been deducted. This results in an NPV after tax at 1165 MNOK.

3.3.4 Economic evaluation of new producers

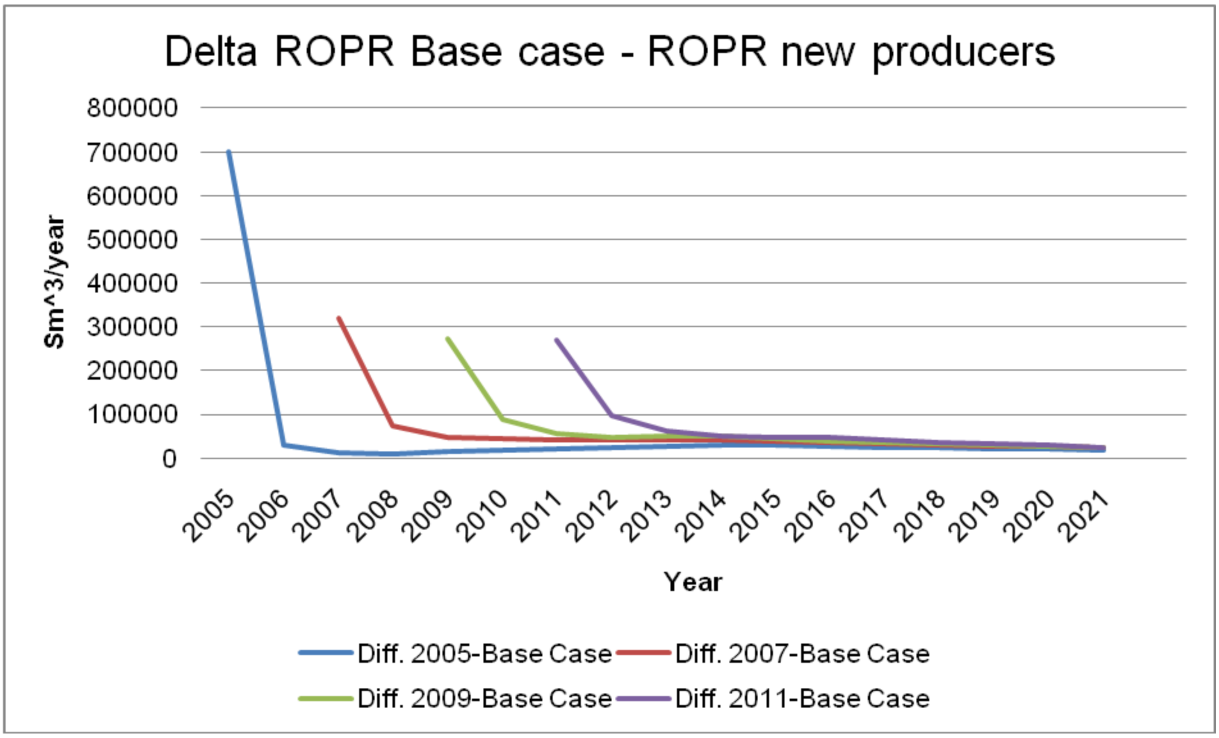


Figure 45: Delta ROPR - Base case - new Producers

Table 2: NPV results

	Base case		H2005		V2007		V2009		V2011	
	Before tax	**After tax**	**Before tax**	**After tax**	**Before tax**	**After tax**	**Before tax**	**After tax**	**Before tax**	**After tax**
Income [MNOK]	4480	1165	6654	1730	6309	1640	5865	1525	5802	1508
Investments [MNOK]	0	0	-420	-114	-367	-100	-320	-87	-280	-76
Sum [MNOK]	**4480**	**1165**	**6234**	**1616**	**5942**	**1541**	**5545**	**1438**	**5522**	**1432**
Extra income [MNOK]			***1755***	***451***	***1462***	***376***	***1065***	***273***	***1042***	***268***

As seen on the graph above, the best solution for a new producer in Tofte formation would have been to install one horizontal well in 2005 with an increase in production rate of nearly 700000 Sm^3 in 2005 and positive figures until 2021. This would have led to an increase in income of 1755 MNOK before tax and 451 MNOK after tax. The other solutions for a new producer in Tofte with installation of two vertical wells in 2007, 2009 or 2011 would all give positive NPV values respectively 1462, 1065 and 1042 MNOK before tax.

As seen from the results the worst solution, installation of two vertical wells in 2011, would give an extra income after tax of 268 MNOK.

In order to fully evaluate the solutions we should consider the day to day operating costs as well as the installation cost. This would maybe have given another situation for the solutions, but at this time the worst solution is still satisfactory.

4 Conclusions

Quantification of remaining oil using Eclipse estimates the remaining oil to be 3895896 Sm^3 at the end of 2004.

The best new producer evaluated is a horizontal well installed in the beginning of 2005. This would give an increase in oil production of 1041317 Sm^3. The production parameters for this are a total perforated well completion in the horizontal section with a production rate of 7000 Sm^3 per day. The well connects the two main pay zones in the E-segment. This increase in oil production increases the NPV of the E-segment with 1755 MNOK before tax, 451 MNOK after tax.

The best "possible" solution is to place two vertical wells in the main pay zones in the beginning of 2011. The estimated extra oil production from these wells is a total of 735759 Sm^3. This gives an increase on income of 1042 MNOK before tax, 268 MNOK after tax.

The results show that there is a large production potential in the Tofte formation in the Norne E-segment.

4.1 Further work

There are some limitations to our result which have to be addressed before installing a new producer in the E-segment.

The reservoir model in itself has to be history-matched until the present day, as the model we have used is only history matched until 2004. This could give significantly different results.

We have only evaluated the P50 case; the P90 case could possibly show negative numbers in the NPV analysis. This has to be checked before using the numbers in any real life application.

Vertical wells are not presently being drilled at the Norne field. A further study of a new producer in the Tofte formation should only consider horizontal well solutions, as this is the only well that will be installed in real life.

The current study has only evaluated the production parameters on the new producer(s). Further work should be to optimize the production parameters of the existing wells in the E-segment as well. An example of this would be to increase the water injection rate in the segment in order to increase the pressure. The reason for this is that the pressure in the reservoir often sinks when new wells are installed in the reservoir; this could result in a decrease in oil production in the total segment even though oil production from the new well is very high.

The NPV model in itself has to be revised. The model should be updated to the present year, the assumptions and simplifications have to be revised to fit today's situation.

5 References

EVANS, D. 2003. *The Millennium atlas: petroleum geology of the central and northern North Sea,* London, Geological Society of London.

FANCHI, J. R. 2006. *Principles of applied reservoir simulation,* Amsterdam, Gulf Professional Pub.

JOSHI, S. D. 1991. *Horizontal well technology,* Tulsa, Okla., PennWell Books.

NAN CHENG, S. 2010. Introduction of Norne Field.

OLJEDIREKTORATET. *Lower and Middle Jurassic Plays - Norwegian Sea* [Online]. Available: http://www.npd.no/en/topics/geology/temaartikler/geological-plays/norwegian-sea/lower-middle-jurassic/ [Accessed].

OLJEDIREKTORATET. 2010. *Tofte formation* [Online]. Available: http://www.npd.no/engelsk/cwi/pbl/en/su/all/170.htm [Accessed].

OSDAL, B., HUSBY, O., ARONSEN, H. A., CHEN, N. & ALSOS, T. 2006. Mapping the fluid front and pressure buildup using 4D data on Norne Field. *The Leading Edge,* 25**,** 1134-1141.

PERRIN, D., CARON, M. & GAILLOT, G. 1999. *Well completion and servicing,* Paris, Éditions technip.

RABIA, H. 1985. *Oilwell drilling engineering: principles and practice,* London, Graham & Trotman.

SCHLUMBERGER. *The Oilfield Glossary: Where the Oil Field Meets the Dictionary* [Online]. Available: http://www.glossary.oilfield.slb.com/ [Accessed January 24. 2004].

STATOIL Reservoir geological update after 660810-4.

STATOIL 1998. Sedimentological Evaluation 1998.

U.S_DEPARTMENT_OF_THE_INTERIOR. *SQ-SY* [Online]. Available: http://www.mms.gov/glossary/sq-sy.htm [Accessed January 24. 2004].

WIKIPEDIA_GEOLOGY_OF_THE_NORTH_SEA. *Geology of the north sea* [Online]. Available: http://en.wikipedia.org/wiki/Geology_of_the_North_Sea [Accessed].