Reservoir Management on Norne
An introduction to Time-lapse Seismic and EnKF

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Abstract

Efficient tools and high quality data in reservoir management are essential to make the optimum decisions. New methods of data assimilation create more certain reservoir predictions available. To make decisions based on the most certain models, increases the likelihood to improve the oil recovery. This project specialization report gives an introduction to the Norne field in the Norwegian Sea, and the use of time-lapse seismic in the management of the field. Quantitative interpretation of seismic can determine reservoir properties and fluid front development during production. Methods for such interpretation are described, and by utilize time-lapse seismic in reservoir simulation models, it decreases some of the uncertainty in the reservoir models. Different approaches for automatic history matching, using an objective function, are mentioned. Gradient and non-gradient based methods to solve the optimization problem are reviewed. The methodology behind the ensemble Kalman filter and previous studies are described in particular. Previous studies demonstrate the values using the EnKF filter to characterize reservoir properties, on both synthetic and real field cases. Opportunities to implement algorithms and workflows into mainstream reservoir management software are also mentioned.
Preface

This specialization project was carried out autumn 2009, in the 9th semester of the Master of Science studies at Norwegian University of Science and Technology (NTNU), Department of Petroleum Engineering and Applied Geophysics.

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Part I

Norne field

1 Introduction

Norne is an oil and gas field on the Norwegian continental shelf operated by Statoil Petroleum AS with Eni Norge AS and Petoro AS as partners. The field is located 200km west of Brønnøysund and 80km north of the Heidrun field, in blocks 6608/10 and 6508/10, the southern part of the Nordland II area, see Figure 1.1. It was first discovered in December 1991 and started oil production November 6th 1997. Gas production started in 2001. The field is subsea developed with six subsea templates, connected to a production and storage vessel. In April 2008 an updated plan for development and operation (PDO) for Norne and Urd was approved. This plan also includes 6608/10-11 S Trost and other prospects around Norne and Urd. 24,25,41

Figure 1.1: Fields and discoveries in the Norwegian Sea, Norne field circled in red 24
The Norne data provided by Statoil ASA are made available through the Center for Integrated Operations in the Petroleum Industry (IOCenter), which includes several research program with its center located at NTNU/SINTEF in Trondheim. They collaborate with major national oil companies and Stanford, Carnegie-Mellon, Delft and Kyoto universities. The purpose of releasing the data is to establish a benchmark case, with real data, that can be used to compare different methods in closed-loop reservoir management.

2 Reserves

Most likely in-place volumes reported in the Revised National Budget (RNB) 2006 were 157.0 MSm$^3$ oil in place (OIIP) and 29.8 GSm$^3$ gas in place (GIIP). By August 2009 they had produced 82.1 MSm$^3$ oil and 6.0 GSm$^3$ gas, or recovery of 52.3% and 20.1% for oil and gas respectively. The Norwegian Petroleum Directorate (NPD) estimated the recoverable reserves to be 94.9 MSm$^3$ oil and 11.0 GSm$^3$ gas. This indicates that they expect a recovery of 60.4% for oil and 36.9% for gas.

3 Structure

The field consist of four segments, divided into two compartments. Norne C-, D- and E-segment which are the Norne Main Structure, and Norne G-segment which is the Northeast Segment, see Figure 3.1. The hydrocarbons are proven in the rocks of Lower and Middle Jurassic age. An oil column of 110m, and a gas cap of 25m were proven in exploration well 6608/10-2 and confirmed in well 6608/10-3, the two exploration wells in the Main Structure. A third exploration well, 6608/10-4, were drilled in the Northeast Segment. As much as 98% of the total hydrocarbons were proven in the Main Structure.

The Norne field is a raised fault block, a flat horst structure, bounded by normal faults. In the Main Structure the Garn Formation is gas filled, the structure dips towards north-northwest and has an oil leg. The gas oil contact is in the proximity of the Not Formation. Reservoir pressure data from the wells shows that there is no reservoir communication across the Not Formation. Oil is mostly found in Ile and Tofte Formations.
4 Geology

The reservoir is situated in a fault complex in the Norwegian Sea. Rifting of the area occurred in Permian and Late Jurassic - Early Cretaceous. Normal faults with north-northeast to south-southwest trends are common from the first rifting period. Footwall uplift and erosion of the higher structures appeared in the second rifting. In between the rifting periods there was limited tectonic activity, subsidence and transgression was dominating. As time goes the reservoir has been buried deeper, increasing the diagenetic processes. Norne reservoir rocks are of, as already mentioned, from Late Triassic to Middle Jurassic age.\footnote{41}

4.1 Stratigraphy and sedimentology

The reservoir sandstones in the formations Garn, Ile, Tofte and top Tilje, has a near shore marine depositional environment with source area to the north-east and east. They are fine-grained, well to very well sorted sub-arkosic arenites. Tilje Formation has origin from a marginal marine, tidally influenced environment, and the Not Formation clay stone was deposited in quiet marine environment. Being buried at a deep between 2500m and 2700m, mechanical compaction is an important process which reduces the quality of the reservoir. The reservoir rocks have still good quality with porosity in range of 25-30\% and permeability varies from 20 to 2500mD.\footnote{38} Figure 4.1 shows the formations and their properties of the reservoir.
Figure 4.1: *Stratigraphical sub-division of the Norne reservoir*[^38]
The source rocks are believed to be in the Spekk Formation shale and Åre Formation coal beds. They were deposited in Upper and Lower Jurassic, respectively. Åre has alluvial to delta plain setting and contain mainly channel sandstones interbedded with mudstones, shales and coal.

Due to increased erosion to the North reservoir thickness varies over the entire field. From Top Åre to Top Garn it goes from 260m in the southern parts to 120m in the northern part. From seismic mapping it has been found that particularly the Ile and Tilje Formations decrease.

4.2 Reservoir communication

Both structural and stratigraphic barriers influence the vertical and lateral flow within a reservoir. Structural barriers such as faults, at least major faults, can be seen on seismic. If the faults are sealing and extend over the whole reservoir height it is considered as a trap. This is beneficial in order to trap the hydrocarbons. If it is an intra-reservoir fault this is not wanted as its limiting the reservoir communication. No faults have been cored out from Norne so it is impossible to measure the permeability in these. The Heidrun field located 80km south of Norne is the best analog and three main types are found here. Results from two different fault analysis indicates both that the intra-reservoir faults at Norne most likely are non sealing.

In the formations Tofte, Ile and Garn there are interpreted three continuous calcareous cemented layers. These are believed to act as stratigraphic barriers to vertical flow. They are have a thickness in the range of 0.5-3m. However, there are many intra-reservoir faults which offset the sealing layers and enable vertical reservoir communication. In addition the Not Formation with a thickness of 7-10m is sealing. From well data and RFT (Repeat Formation Tester) pressures such lateral barriers can be shown. These are of variable extension but generally thin, below seismic resolution, and partially sealing.

5 Field development

As of November 2009 the field are developed using six subsea templates connected to a production vessel. There are 8 wells injecting water and 16 wells producing oil. In total there are 4 exploration wellbores and 48 production and injection
wellbores. The drainage strategy was originally pressure support by water injection in the water zone and re-injection of gas into the gas cap. Experience from the first year of production showed that the Not Formation was sealing over the Norne Main Structure and gas injection discontinued in 2005.\textsuperscript{25,40}

The Norne field is developed using only near horizontal producers. In Figure 5.1 the general drainage pattern are shown. Water injectors at the bottom and the water-oil contact (WOC) will gradually move upwards with production.

![General drainage pattern](image)

Figure 5.1: *General drainage pattern*\textsuperscript{3}

Since the Norne field now are considered to be a mature field and in tail production, see Figure 5.2, increased oil recovery (IOR) techniques are needed to achieve their high recovery goal. Uncertainties regarding infill drilling and reservoir performance are major. Infill drilling are being performed using through tubing rotary drilling (TTRD). TTRD meaning drilling through the existing production tubing and conveniently creating multilateral wells, effectively optimize the reservoir drainage. Also to effectively update the reservoir models, time laps seismic are used. Using seismic to interpret the changes in a reservoir over time are beneficial as the production and fluid movements influence the seismic reflection properties. Techniques are developed to estimate reservoir properties and optimize the simulation models giving more accurate predictions. From such updated models, reservoir performance, water-cut (WC) and gas-oil ratio (GOR) development can be predicted more accurate. As a result wells can be plugged and sidetracked in overlaying formations to optimize reservoir drainage, see Figure 5.1.
Figure 5.2: Net production of Sm³ o.e. on Norne, last 24 month, September 09

6 Seismic

Seismic data is an important tool in exploration and production. During exploration, the seismic data is our most important source of information. Interpretation of the area and layers are obtained in this phase. 3D seismic are studied to get an impression of the structure, horizons and faults. The base survey on Norne was acquired in 1992.

4D seismic, or time-lapse seismic, are seismic surveys repeated subsequently. One of the applications for time-lapse seismic are monitoring changes, and identify remaining oil pockets, when producing a hydrocarbon reservoir. Changes during production could be fluid saturation changes, pore pressure changes, temperature changes and changes in layer thickness due to compaction or stretching. Linking these changes and properties to seismic parameters are desired. Targeting remaining oil (TRO) pockets in complex reservoir are important to increase the recovery. In 2005 there was at least six successful placements of infill wells from time-lapse seismic interpretations.

After production start in 1997 there has been five surveys for time-lapse seismic. Surveys shot in 2001, 2003, 2004, 2006 and 2008. Calculated water saturation changes from a presentation given by Cheng and Osdal in 2008 can be seen in Figure 6.1.
Figure 6.1: Change in water saturation from base to 2001, 2003, 2004 and 2006.
WesternGeco have used their Q-marine system on the Norne field for the time-lapse seismic surveys. Acquisition repeatability is very important regarding the quality of the time-lapse seismic data. By using their Q-marine system it is possible to steer the streamers in the horizontal direction, allowing accurate positioning which is crucial. To cover the area below the Norne production vessel undershoot lines have been acquired. During these surveys the same vessel and source were used in 2001 and 2003. The seismic data on Norne have a good repeatability and high quality. Time-lapse seismic and its utilization in reservoir characterization are evaluated further in Part II of this thesis.

7 Reservoir simulation model

Reservoir simulators are used to predict the fluid saturations and pressures throughout the reservoir. The simulation model on Norne is an ECLIPSE 100 model. ECLIPSE 100 is a black oil simulator, fully implicit, three phase and three dimensional. The present reservoir simulation model, see Figure 7.1, available at NTNU is based on the geological model built in 2004. An updated reservoir model based on geological models from 2006 have been developed. This updated geological model was interpreted with focus on improving fault descriptions.

Figure 7.1: Norne initial saturation 1997
The simulation grid was generated using the Reservoir Modeling System (RMS) software. Porosities, permeability and net-to-gross (NTG) properties are upscaled from the geological and petrophysical models. The vertical resolution have although been refined to contain 22 layers instead of 20 layers to improve the gas flow monitoring of top Ile Formation. Vertical permeability is set to a ratio of the horizontal permeability and the stratigraphical barriers described in Section 4.2 are implemented using the ECLIPSE feature and keyword \texttt{MULTZ}-maps.\textsuperscript{39} Faults transmissibilities are considered sealing in the base case and individually adjusted when history matching using the ECLIPSE keyword \texttt{MULTFLT}. The \texttt{MULTZ} and \texttt{MULTFLT} keywords are transmissibility multipliers in the z-direction and across a fault, respectively.\textsuperscript{29}

At Norne they uses WAG (water alternating gas) injectors. By exploiting the hysteresis option in Eclipse they are able to model the relative permeability dependency of the different saturations and the saturation history. The keyword \texttt{WAGHYSTR} enables this option. Different relative permeability curves are defined for absolute permeability above and below 250mD in the model.\textsuperscript{39}

The grid have dimensions of 46x112x22 with blocks of approximately 80-100m in x- and y-direction. 44,431 of the blocks are active in the numerical simulation. Initial saturation (blue, green and red for water, oil and gas, respectively) are shown in Figure 7.1. The porosities, permeability and NTG can be seen in Figure 7.2(a), 7.2(b) and 7.2(c). Grid blocks containing more than 50% oil are filtered and visualized Figure 7.2(d)

### 7.1 History matching

The reservoir model was history matched upon creation in 2005. Then the model was matched until August 2004. As a quality control the remaining period were compared against prediction from the model.\textsuperscript{39} The present model have however been updated and are matched until December 1\textsuperscript{st} 2006.\textsuperscript{41} Production data are now included until 2007.

Both production data and time-lapse seismic data are used for history matching together with FMT pressures (Formation Multi-Tester). By only matching production profiles and FMT pressures several matches are possible. From the time-lapse seismic, the change in water oil contact have been interpreted. This is valuable information and the numerous matches are decreased. The uncertainty are reduced and more precise predictions can be given. This interpretations are
done either by comparison of synthetic seismic from the simulation model, or comparison of interpreted WOC from seismic and saturation changes in the simulation model.\cite{39}

During history matching the transmissibility over faults and stratigraphical barriers have been modified with same keywords as described above. The relative permeability curves are also modified slightly to give a better match against WC and GOR.\cite{39} WC and GOR from history and simulation prediction can be seen in Figure 7.4 and Figure 7.3. The field oil and gas production rate from startup until 2007 are shown in Figure 7.5 and Figure 7.6 respectively.

Figure 7.2: Norne initial conditions 1997
Figure 7.3: *Gas oil ratio*

Figure 7.4: *Water-cut*
Figure 7.5: Norne field oil production rate

Figure 7.6: Norne field gas production rate
Part II

Reservoir management

8 Introduction

In an interdisciplinary reservoir management team, incorporation of geoscience and engineering, as well as sophisticated computer software plays a key role. Throughout the lifetime of a field, different development plans are assessed to optimize oil production or net present value (NPV). There are great dependence on reservoir simulation models as decisions of tremendous size are determined upon them. History matching and updating models to mimic and represent the true behavior, geology and petrophysics. From these models the dynamic behavior of the field are strived to understand. Placement of new wells, drainage strategy and enhanced oil recovery techniques are evaluated to reach the most favorable hydrocarbon recovery.

Traditionally parameters such as porosity, permeability and fault transmissibilities in reservoir simulation models are altered to match the simulated change in saturation and pressures against measured production data. Production data such as flow rates, water cuts, gas oil ratios and well pressures have traditionally been matched on a discrete basis. As technology evolving, more data are captured from wells continuously from digital oilfields, especially data measurements from downhole gauges and multiphase flow meters. Smart wells with zone isolation and sleeve valves are becoming more common. Continuously pressure measurements from such smart wells can be utilized in production optimization and history matching. This are however local measurements in the wells and does not necessarily represent the total field.

Lately time-lapse seismic have been more included in monitoring the reservoir behavior. From time-lapse seismic parameters such as saturations and pressure changes are obtainable. Reservoir management that combines model-based optimization and computer-assisted history matching continuously are often referred to as “real-time reservoir management”, “smart reservoir management” or “closed-loop reservoir management”. Throughout this Part II especially the utilization of time-lapse seismic data and history matching by both computer-assisted and autonomous methods, and the use of ensemble Kalman filter (EnKF), in reservoir management will be discussed.
9 Reservoir simulation

Reservoir simulation is a major part of a reservoir engineers assignments. Models of thousands and maybe hundreds of thousands grid blocks, each with properties such as pressures, porosities, permeabilities in each direction, fault descriptions and transmissibilities and so on, are created and numerical simulations are run. Running simulations itself are a time consuming procedure. The initial models have often considerable uncertainties and modifications of the model properties are made to reflect the actual behavior of the field.

Different types of reservoir simulators exists. Often the reservoir fluid are represented in a simplified manner, by the black-oil model. Fluid phases are described in three phases, oil, water and gas. Fluid functions, depending on pressure and/or saturations, characterize these fluid properties. Properties like viscosities, formation volume factors, solution gas in oil ratio and vaporized oil in gas ratio. Initial conditions, reservoir properties before production, are properties like datum depth, pressure datum, fluid contacts, capillary pressure at contacts and properties that varies with depth (reservoir temperature, vaporized oil-gas ratio and solution gas-oil ratio). Another fluid representation is compositional, where every component have its own set of properties.

A set of analytical flow equations and definitions of the fluids are by discretization and approximations defined numerically. These equations could either be implicit or explicit defined. Solution of these numerical equations can be done either by direct or iterative calculations.

Popular numerical simulators are from Schlumberger’s ECLIPSE family. ECLIPSE 100 is a fully implicit, three phase, three dimensional, general purpose black oil simulator and ECLIPSE 300 is a compositional simulator. FrontSim is a simulator based on a streamline concept. By generating velocity distributions over the model and trace and calculating time of flight along the streamlines, the transportation equation of “saturations” are solved along the streamlines. Thermal simulators are useful when temperatures changes in the reservoir, as in heavy oil reservoirs. In heavy oil reservoirs steam are often injected to heat up the oil and decrease the viscosity to drain the reservoir, using steam assisted gravity drainage (SAGD) technology.

Different oil companies may also have their own “in-house” simulators, non commercial simulators.

The reservoir models are by evaluating production data and data such as time-
lapse seismic updated to less uncertain models, history matched. History matched models are used to predict future performance and production forecast of a field.

10 Time-lapse seismic

Time-lapse seismic are seismic reflecting the change over time. 4D seismic are used as a term for several 3D seismic surveys done at different times. The term for 2D time-lapse are still not referred to as 3D seismic but 4D seismic as well. Time-lapse seismic have several major uses, monitoring changes in a reservoir when producing, monitoring of CO₂-storage and geophysical monitoring of geohazards. Time-shift and amplitude changes are assessed to determine pressure and fluid saturations changes. Monitoring changes within a producing reservoir will be discussed further here.

Time-lapse seismic’s ability to capture fluid flows and identify remaining oil pockets for infill drilling are valuable information which the wells not are able to sample. Such oil pockets could add major reserves to the production and extend the lifetime of a field. Time-lapse seismic can also monitor the progress of costly injected fluid for enhanced oil recovery, and optimize the investments in such programs.

10.1 Seismic

Seismic waves are elastic waves that travels through mediums. There are two types of seismic waves, body waves and surface waves. Surface waves are waves that propagates along an interface. Surfaces waves are normally considered as noise in seismic surveys. From body waves there is P-waves, where p stands for pressure or primary and S-waves for shear or secondary. Pressure waves travels fastest and consequently called primary waves. As liquids don’t have shear modulus shear waves cannot be recorded from marine seismic surveys unless there is recorders placed on the sea bottom.

When a seismic wave face a change in impedance, some of the energy in the wave will be reflected back some will be transmitted through. The impedance $Z$ is the product of wave velocity and density. Both of these will change in different materials and depending on their conditions. Seismic reflection coefficient is, for a wave that hits the boundary perpendicularly, defined as
\[ R = \frac{Z_2 - Z_1}{Z_2 + Z_1} = \frac{V_2\rho_2 - V_1\rho_1}{V_2\rho_2 + V_1\rho_1} \tag{10.1} \]

\( \rho = \text{density} \)
\( Z = \text{acoustic impedance} \)
\( V = \text{wave velocity} \)

Equations for wave velocity can be derived and depends on density and modulus of the medium. P-wave velocity in equation 10.2 and S-wave velocity in equation 10.3.

\[ V_p = \sqrt{\frac{\lambda + 2\mu}{\rho}} = \sqrt{\frac{K + \frac{4}{3}\mu}{\rho}} \tag{10.2} \]

\( \lambda = \text{linear elasticity or Lamé’s first parameter} \)
\( \mu = \text{shear modulus or Lamé’s second parameter} \)
\( K = \text{bulk modulus} \)

\[ V_s = \sqrt{\frac{\mu}{\rho}} \tag{10.3} \]

### 10.2 The rock physics link

Conventional qualitative seismic interpretation maps geologic elements and stratigraphic patterns from seismic reflection data. Quantitative seismic interpretation have become more common in reservoir characterization. Such techniques derive more information about the rocks and their pore fluids. To convert reservoir properties into seismic parameters rock physics models are used.\(^\text{6,16,28}\) Rock physics models are a key element to understand the behavior when looking at porous, saturated rocks. There are many theories and models proposed\(^\text{28}\) but the Biot-Gassmann\(^\text{6,16,28}\) is the most used relationship from \(V_p\) to fluid saturation. The Hertz-Mindlin model are a contact theory model that can be used to estimate pore pressure changes.\(^\text{6}\) Other models that can be used to estimate the parameters in Biot-Gassmann are the Rauss average, which gives the lower bound, and the Voigt average, which gives the upper bound.\(^\text{10}\)
The density used in equation 10.2 and equation 10.3 are the bulk density, meaning average density of fluids and solid phase.

\[ \rho = \phi \rho_f + (1 - \phi) \rho_s \]  
\( s \) = solid  
\( f \) = fluid  
\( \phi \) = porosity

In a hydrocarbon system the bulk density would be

\[ \rho = \phi (\rho_w S_w + \rho_{hc} (1 - S_w)) + (1 - \phi) \rho_s \]  
\( S \) = saturation  
\( hc \) = hydrocarbon  
\( w \) = water

### 10.2.1 Amplitude versus offset

One method of quantitative perception of the reservoir characteristics are amplitude versus offset (AVO) analysis. Main idea behind amplitude versus offset, or amplitude variation with offset analysis, are the changes in reflection coefficient when the wave hits the boundary with an angle. An approximation of the highly nonlinear Zoeppritz equations are developed by Smith and Gidlow.\(^{15}\) This simplification are valid for small \( \theta \) (near offset).

\[ R(\theta) = \frac{1}{2} \left( \frac{\Delta V_p}{V_p} + \frac{\Delta V_s}{V_s} \right) - 2 \frac{V_s^2}{V_p^2} \left( \frac{\Delta \rho}{\rho} \right) \sin^2 \theta + \frac{\Delta V_p}{2 V_p} \tan^2 \theta \]  
\( \theta \) = angle of incidence

here,  
\( V_p \) = average primary velocity  
\( V_s \) = average secondary velocity
Since the reflection coefficient depends on secondary velocity as well, valuable information can be derived. By looking at how $R$ changes with the angle of incidence it is possible to determine the lithology and fluids.

### 10.2.2 Biot-Gassmann

In 1941 Biot\textsuperscript{28} addressed the problem to relating $V_p$ and $V_s$ of porous rocks in terms of elastic constants. Later in 1951 Gassmann\textsuperscript{6,28} did the same by a different approach, but the result where the same.\textsuperscript{28} The terminology in this model are shown in Figure 10.1. The Biot-Gassmann equation (see equation 10.7) calculates the bulk modulus of a saturated rock based on the bulk modulus of the solid matrix, framework and pore-filling fluids.

![Figure 10.1: In Biot-Gassmann theory, a cube of rock is characterized by four components: the rock matrix, the pore/fluid system, the dry rock frame, and the saturated frame\textsuperscript{28}](image)

\[
K = K_{fr} + \frac{K_f}{\phi} \left( 1 + \frac{K_f}{\phi K_s} (1 - \phi - \frac{K_{fr}}{K_s}) \right)
\]

(10.7)

$k_r = \text{framework}$

As we can see from equation 10.5 and 10.7 combined with equation 10.2 and 10.3, the velocities are controlled by several properties. Amongst other, the composition
and texture of the solids, the pore space and pore fluid, stresses and pressure as well as temperature.  

### 10.3 Repeatability

In order to get high quality time-lapse seismic, repeatability of the original base survey is an important factor. Repeatability depends on several factors such as the positioning of the source and receivers at the different surveys and other variations in the surroundings. Weather conditions, sea water temperature, tidal effects, varying source signal, new equipment and noise from vessels or other activity at the scenery are all factors that make a difference.  

As a way to quantify the repeatability the normalized RMS (root-mean-square)-level is used

\[
NRMS = 2 \frac{RMS\text{(monitor} - \text{base)}}{RMS\text{(monitor} + RMS\text{(base)}}
\]  

A result of improved seismic processing and more accurate positioning of sources and receivers, using tools such as WesternGeco’s Q-marine system which allows steering of the streamers into position, the repeatability have improved significant the last years, see Figure 10.2.  

![Figure 10.2: Improvement in seismic repeatability (NRMS)](image)
As seen in Figure 10.2 there will be more difficult to improve repeatability further and more sophisticated technology are needed. Fixed receivers at the sea bottom is one solution to positioning problems and have been proven successful at some fields, such as at BP’s project (LOFS) on Valhall Field. Another suggestion is to tow a super dense grid of receivers to ensure high precision in positioning.

11 History matching

In history matching, uncertainty analysis of factors that influence production and recoverable reserves are assessed. When history matching tuning of the reservoir parameters such as upscaled geological structure and rock and fluid properties are done to mimic the true geological structure and reservoir behavior.

The history matching problem is non-unique, and by evaluating the production data several totally different reservoir models could be established, all matching the data. Manually changing parameters on a trial and error basis, to see the consequence, are both tedious and time consuming. The results and developed models are depending upon the reservoir engineer. Since the problem are non-unique the reservoir engineer have to interpret and “guess” different cases. This is typical a process which depends on the reservoir engineers subjective meaning.

12 Automatic history matching

Introducing assisted or maybe automatic and autonomic history matching can be advantageous. By utilize more data in history matching and make automatic or autonomous workflows, the outcome would at a higher level respect the data integrity. The time savings are also favorable, and history matching can be done on a continuous basis.

12.1 Objective function

The main purpose in history matching is to minimize the difference between the results from simulation and observed data. To minimize the difference in calculated and observed data, an objective function is often introduced. As the parameters
involved in the objective function are increasing, composing could be an intricacy procedure.

There are three different well-known calculation methods for the objective function, least-square, weighted least-square, and generalized least-square method.\textsuperscript{4,17}

**Least-square**

\[
O(m) = [g(m) - d_{obs}]^T [g(m) - d_{obs}] \tag{12.1}
\]

\(m\) = model  
\(g(m)\) = predicted data  
\(d_{obs}\) = observed data

**Weighted least-square**

\[
O(m) = [g(m) - d_{obs}]^T W_d [g(m) - d_{obs}] \tag{12.2}
\]

\(W_d\) = diagonal data weighting matrix

**Generalized least-square**

\[
O(m) = \frac{1}{2} (1 - \beta) [g(m) - d_{obs}]^T C_D^{-1} [g(m) - d_{obs}] + \frac{1}{2} \beta [m - m_{prior}]^T C_M^{-1} [m - m_{prior}] \tag{12.3}
\]

\(m_{prior}\) = prior model  
\(\beta\) = weighting factor (belief in initial model)  
\(C_D\) = covariance matrix of the data  
\(C_M\) = covariance matrix of the parameters in the model
12.2 Gradient based methods

Gradient based methods could use deterministic algorithms and traditional optimization approaches to obtain a local minimum of the objective function. By calculating the gradient of the objective function and determine direction for optimization search. Converging towards the local minimum until desired difference in two iteration are reached. All deterministic algorithms need to calculate sensitivity coefficients to the simulation output, usually the first (gradient or Jacobin) and second (Hessian) derivative of the objective function.4

Methods for gradient calculation have been used widely and studies are dominated by deterministic methods.17

Different used methods are:4

- Steepest descent method
- Gauss-Newton method
- Levenberg-Marquardt algorithm
- Conjugate gradient method
- Sequential quadratic programming

12.3 Non-gradient based methods

In contrast to gradient based methods, non-gradient based methods, or stochastic algorithms, theoretically reach the global optimum.17 These are computationally more expensive algorithms, and earlier less accessible considering computing speed and memory.

Different famous methods are:

- Evolutionary algorithms
  Genetic algorithms
- Simulated annealing
- Scatter and tabu searches
Virtual-intelligence techniques feature the ability to learn and deal with new situations. Evolutionary algorithms are based on nature. In nature, evolution is an optimization process, by following the principle “survival of the fittest”, each new generation inherits characteristics as progress, growth, and development. By continuously searching around good parameter matches and rejecting bad ones, genetic algorithms search for the global optimum. Artificial neural networks are also models that find complex patterns between input and output data. Training of such neural networks applied in the oil- and gas industry are supervised, learning on a feedback basis. Such algorithms could have great potential and seem promising but the technology are still in its infancy.

In order to describe the full posterior probability density function in a Bayesian approach, different realizations of the model have to be run. Since this is time-consuming tasks, algorithms such as neural network and response surface could be used as proxies (approximations).

Simulated annealing is a probabilistic algorithm for the global optimization problem in a large search space. By replacing the current solution by a nearby solution, chosen with a probability depending on the difference between the corresponding function values. This technique have been used in reservoir history matching.

The original Kalman filter, now called simple Kalman filter, is a recursive estimator for solving the linear problem. The filter only uses the previous estimated state and the current measurements to estimate the current state. Meaning no history of observations is needed. Since this simple Kalman filter only solves the linear problem, and more complex systems often are nonlinear, other methods have been developed. Extended Kalman filter (EKF) tries to solve the nonlinear problem. By evaluating the Jacobin matrix, the nonlinear function around the current estimated state is being linearized. Another extension is the ensemble Kalman filter.

13 Ensemble Kalman filter

The EnKF was initially proposed by Evensen in 1994 as a stochastic or Monte Carlo alternative to the deterministic EKF. EnKF method are associated to so-called particle methods, which use a Monte Carlo or ensemble representation of the probability density functions (pdf).
13.1 Methodology

Modeling the evolution of the pdfs by an ensemble integration, and different strategies for conditioning the predicted pdf given the observations. By a large ensemble of realization of the prior pdfs the joint pdf for the model state $\psi(x, t) \in \mathbb{R}^{n_\psi}$, function of space and time, and the poorly known parameters $\alpha(x) \in \mathbb{R}^{n_\alpha}$, where $n_\psi$ and $n_\alpha$ is the number of variables in the state vector and parameters in $\alpha$, respectively, can be evaluated. Starting from Bayes’ theorem, the combined parameter and state estimation formulation are established. Definition of the posterior pdf of the poorly known parameters and model solution conditioned on a set of measurements, $d$. The time interval is discretized, see Figure 13.1, into $k + 1$ nodes, at the times $t_0$ to $t_k$, where the model state vector $\psi_i = \psi(t_i)$ is defined. The measurement vectors $d_j$ are available at the discrete subset of times $t_{i(j)}$, where $j = 1, \ldots, J$.

\[
\begin{array}{cccccccc}
| & & & & & & & \\
| & d_1 & d_2 & d_3 & \cdots & d_j & \cdots & d_J \\
| & t_{i(1)} & t_{i(2)} & t_{i(3)} & \cdots & t_{i(j)} & \cdots & t_{i(J)} \\
| & t_0 & t_1 & t_2 & t_3 & t_4 & t_5 & t_6 & \cdots & t_i & \cdots & t_k \\
| & \psi_0 & \psi_1 & \psi_2 & \psi_3 & \psi_4 & \psi_5 & \psi_6 & \psi_7 & \cdots & \psi_i & \cdots & \psi_k \\
\end{array}
\]

Figure 13.1: Discretization in time. Figure from Evensen (2007)

Evensen defined the matrix, $A(x, t_i) \in \mathbb{R}^{n \times N}$ where $n = n_\psi + n_\alpha$, holding the $N$ ensemble members as

\[
A_i = A(x, t_i) = \begin{pmatrix}
\psi^1(x, t_i) & \psi^2(x, t_i) & \cdots & \psi^N(x, t_i) \\
\alpha^1(x, t_i) & \alpha^1(x, t_i) & \cdots & \alpha^N(x, t_i)
\end{pmatrix}
\] (13.1)

The analysis step of the EnKF can then be written as

\[
A^a_{i(j)} = A^f_{i(j)} X_j
\] (13.2)

$A^a =$ ensemble analysis matrix

$A^f =$ ensemble forecast matrix

$X =$ ensemble updating matrix
where the ensemble updating matrix is defined as

\[ X_j = I + S_j^T C_j^{-1} D_j \]  

\[ I = \text{identity matrix} \]
\[ S = \text{measurements of the ensemble perturbations} \]
\[ D = \text{matrix of perturbed measurement} \]

and the matrix \( C \) as

\[ C = SS^T + (N - 1) C_{\text{ee}} \]  

\[ C_{\text{ee}} = \text{measurement error covariance matrix} \]

\( X_j \) is only dependent on the ensemble at time \( t_{i(j)} \), and therefore only at the measurements locations. The update can therefore be characterized as a weakly nonlinear combination of the prior ensemble and no propagation of information backwards in time.\(^7\)

The method introduce an approximation of the posterior ensemble by only using the mean and covariance of the prior joint pdf, which is assumed to be Gaussian when computing the updates. EnKF will therefore only give the correct answer if the prior joint pdf only have Gaussian contributions.

### 13.2 Previous studies

The EnKF is a sophisticated sequential data assimilation method and have recently been taken into use in simulation of the oil- and gas industry.\(^7\) Estimating reservoir parameters and improving the predictability of the models would be beneficial in the increased oil recovery process.

A review of EnKF, within the petroleum engineering and reservoir models in particular, was carried out in 2009 by Aanonsen et al.\(^1\) According to them the first paper appeared in 2001 following a growing popularity and exceeded 40 publications at the end of 2007. They assessed the EnKF’s main challenge when updating reservoir models, which are related to the low rank representation of the model covariance matrix, non-Gaussian prior models, strong nonlinearities and the large scale of field models.
In 2007 Evensen et al. used the EnKF for assisted history matching of a North Sea reservoir model. As a result there were improvements of the model parameters and of the associated model saturations and pressure at every update. Evensen et al. also noted that the analyzed realizations not just were a sampling of the realizations in the best prior ensemble, but a new set of realizations which are conditioned on production data and hence lower uncertainty.

Haugen et al. also used the EnKF on a North Sea field case in 2007. This were one of the first published studies applying real cases and production data. By using a reservoir simulation model, with around 45000 active grid blocks and 5 years of production data, they estimated permeability and porosity. Comparison with an established model created by manual history matching found improved match using the EnKF, as previously publications did using synthetic data.

Seiler et al. presented in 2009 a method for updating relative permeability curves and an approved method for updating fault transmissibilities. They found significant improvements in history matching by updating the relative permeabilities as well as porosities, permeabilities and initial fluid contacts when using EnKF in their approach.

In 2009 history matching using coupled EnKF and evolutionary algorithms (EA) were assessed by Schulze-Riegert et al. The hybrid optimization scheme, which coupled EnKF and a genetic algorithm, did however not meet their expectations but concluded that more research in this field, to see the full advantages, were required.

14 History matching using time-lapse seismic

The possibility to monitor changes when using time-lapse seismic have direct connection to the reservoir engineer and reservoir management. Seismic have traditionally been seen as a static measurement and used for exploration and development. Nowadays time-lapse seismic are a dynamic measurement and increasingly incorporated in history matching of reservoir simulation models.

Especially the utilize of time-lapse seismic ability to map reservoirs compartmentalization and determine if a fault are sealing or leaking, are helpful when history matching a field.

As examples both Norne Field in the Norwegian Sea and Snorre Field in the Norwe-
gian North Sea are fields that uses time-lapse seismic in history-matching. In 2009 Seldal et al. published a paper on time-lapse seismic on Snorre. By using quantitatively seismic interpretation they improved their understanding of the reservoir. From the seismic they found for instance that their initial fault communication where to restricted. Time-lapse seismic gave them a better overall understanding of the reservoir than they could achieve by traditional history matching. From the Norne field, Cheng and Osdal presented in 2008 their methodology for updating of the Norne reservoir model using time-lapse seismic data. Interpreting flow pattern and saturation changes in the reservoir. Comparison with simulated water saturation and saturation from time-lapse seismic, and change the simulation model thereafter.

In 2007 Dadashpour et al. presented a nonlinear Gauss-Newton optimization technique to automatically estimate reservoir parameters, water saturation and pore pressure changes, from time-lapse seismic data. Later they tested this approach including the reservoir simulation step on a synthetic reservoir, based on field data from Norne.

Skjervheim et al. applied the EnKF combined with an ensemble Kalman smoother in 2005 to time-lapse seismic on both a synthetic and a field case from the North Sea. They found a much better estimate of permeability in the synthetic case. For the real case they found a different permeability field using time-lapse seismic than using traditional history matching. The production data was however still matched in the real case.

15 Software

There are several computer programs within petroleum engineering and reservoir management. Reservoir simulators, seismic interpretation software and model creation, as well as 3D visualization software. All for the purpose of a better reservoir understanding and multidisciplinary cooperation. A better reservoir understanding would give more accurate predictions, higher possibilities for increased oil recovery and longer lifetime of a field.

One particular software which incorporate many of the disciplines from seismic to reservoir engineering is Schlumberger’s Petrel.
15.1 Petrel

Schlumberger’s Petrel seismic-to-simulation software is an integrated workflow tool for the exploration and production companies. Integration of processes and workflows related to reservoir simulation and management in one software package eases the work activities and omit time-consuming procedures of exporting and importing data.

Geophysicist, geologist, drillers and reservoir engineers work in the same environment, thus changes within their respective area of responsibility can reflect easily in the others field of work.

Petrel includes areas such as:  

- 3D visualization
- 3D mapping
- 3D and 2D seismic interpretation
- well correlation
- 3D grid design for geology and reservoir simulation
- depth conversion
- 3D reservoir modeling
- 3D well design
- upscaling
- volume calculation
- plotting
- post preprocessing
- streamline simulation
- ECLIPSE
15.2 Ocean for Petrel

Ocean for Petrel is an open development environment for developing plugins to Petrel.\textsuperscript{31} By providing API's (Application Programming Interface) for interaction with the data in Petrel it alleviates a developer's obligation for building a framework each time, and can focus on the intellectual property (algorithm, workflow etc.) to be implemented.

Ocean are built upon Microsoft’s .NET framework and uses C# programming language. As displayed in Figure 15.1, handling core services and infrastructure, services regarding domains and data types, as well as an interface to the specific application, are Ocean’s essential mission.

![Ocean architecture](image)

The developed application module can use all of the three public Ocean API’s.

**Ocean Core** which implement the essential features and interfaces and is used at the higher levels, both the Ocean Service and Product family in addition to the application itself.

**Ocean Services** which in version 2009.2 consist of six services.\textsuperscript{33}

- **Basics** types such as extents, indices, index ranges, and basic numerical algorithms.
Geometry, fundamental definitions, for example points, lines, planes and boxes.

Unit Service, values associated to units and unit systems. Unit conversions.

Domain Object Hosting provides access to data entities regardless of data sources.

Coordinate Service, transform data between coordinate systems.

Catalogs Service

Ocean for Petrel, a member of the product family, are the API providing access to Petrel data types, user interface (UI) and workflow management. Methods to adjust the UI in a convenient and efficient way. Services to manage the Petrel data, such as PillarGrids, Shapes, Well, Seismic and Simulation data.

When handling a reservoir model there are several uncertainties. From Petrel it is possible to do several simulation runs with a sampler, the Monte Carlo sampler is already implemented, and do optimization analysis on the sampled models. Training proxies are also possible. Provided through the Ocean API it is possible to engage custom algorithms and advanced workflows. From Ocean other simulators than ECLIPSE can be also be integrated in Petrel by using the ECLIPSE deck, input and output formats.
Part III

Discussion

In the first part of this project specialization report, the Norne field is introduced. The general life cycle of the field, from exploration to field development, since discovery in 1991 and production start in 1997, are reviewed. The second part introduce reservoir management and present the essential methodology of time-lapse seismic and automatic history matching by EnKF.

The Norne field is a mature field and 86.5% of the recoverable oil have been produced so far. In order to extend the field lifetime and recover more hydrocarbons, enhanced techniques and new technology are needed. At Norne they already utilize time-lapse seismic in their reservoir management to gain a better reservoir understanding. Interpretation of such data have been proven valuable at Norne and lead to successful drilling of several infill wells.

Quantitative interpretation of seismic data and time-lapse seismic data can give information about saturations and pressures in the rocks, as well as development over time. By using rock physics models, such as Biot-Gassmann, the seismic data can be converted into reservoir properties. Combining such interpretation technique and automatic history matching to characterize the reservoir and predict the future more precise. There are however large amounts of data that needs to be processed for the real case fields, which have been counteracting large-scale use of these kinds of workflows.

For automatic history matching there are several different techniques and procedures. Some methods need to calculate sensitivities (gradients) to an objective function, while others search for optimum using other approaches.

Ensemble Kalman filter have been studied widely the last years within petroleum engineering. Several successful applications to automatic history matching, as well as use within time-lapse seismic, have been reported. One of the EnKF’s powerful feature is when its analyzing the realizations, it not just sample the best one but create a new set of realizations which have a lower uncertainty than the best prior sample. It could also have a great opportunity in combination with genetic algorithms that are being investigated.

As both computer hardware and software becomes more powerful and capable to handle large amounts of data, the potential to solve more computationally demand-
ing problems emerge. Processing of such large amounts of data was inconceivable just few years ago. Computer science and development of methods and software utilizing artificial intelligence, and data assimilation techniques are evolving. Such approaches can be utilized in reservoir management to enhance the understanding of reservoir behavior.\textsuperscript{7,20}

Mainstream computer software for the exploration and production companies are incorporating tools for several disciplines into one software package. Petrel is one such example. Schlumberger also provides APIs for extending and tailor this software for each company needs and preference. This can initiate development of plugins for research purposes and still hit mainstream users easily. Incorporation of the different disciplines into the same software can also be advantageous. Increased understanding and participation in each other disciplines could be a positive outcome for the companies.
Part IV

Conclusion

The main conclusions from this reservoir management literature study can be summarized, and function as suggestions for further work in a master thesis, as follows:

**Time-lapse seismic** have a great opportunity in reservoir management for understanding the reservoir behavior, and use within history matching of reservoir simulation models. The Norne field have high quality time-lapse seismic that can, and have been proven to, increase the reservoir understanding.

**Ensemble Kalman filter** have been successful tested on both synthetic and real field cases in automatic history matching and reservoir characterization. Combination of EnKF (and ensemble Kalman smoother) and time-lapse seismic have a big opportunity, and studies are showing good results.

**Ocean for Petrel** can be used to implement algorithms and workflow from research easily into Petrel as plugins. In-house simulators can be implemented as well as samplers and optimization algorithms, such as EnKF.
## List of abbreviations and definitions

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<tr>
<th>Abbreviation</th>
<th>Definition</th>
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<tbody>
<tr>
<td>API</td>
<td>Application Programming Interface</td>
</tr>
<tr>
<td>AVO</td>
<td>Amplitude Versus Offset</td>
</tr>
<tr>
<td>EKF</td>
<td>Extended Kalman Filter</td>
</tr>
<tr>
<td>EnKF</td>
<td>Ensemble Kalman Filter</td>
</tr>
<tr>
<td>FMT</td>
<td>Formation Multi-Tester</td>
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<tr>
<td>GIIP</td>
<td>Gas Initially In Place</td>
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<tr>
<td>GOR</td>
<td>Gas-Oil Ratio</td>
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<tr>
<td>IOCenter</td>
<td>Center for Integrated Operations in the Petroleum Industry</td>
</tr>
<tr>
<td>IOR</td>
<td>Increased Oil Recovery</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>NRMS</td>
<td>Normalized Root-Mean-Square</td>
</tr>
<tr>
<td>NTG</td>
<td>Net To Gross</td>
</tr>
<tr>
<td>o.e.</td>
<td>Oil Equivalents</td>
</tr>
<tr>
<td>OIIP</td>
<td>Oil Initially In Place</td>
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<tr>
<td>pdf</td>
<td>Probability Density Function</td>
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<tr>
<td>PDO</td>
<td>Plan for Development and Operation</td>
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<tr>
<td>RFT</td>
<td>Repeat Formation Tester</td>
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<tr>
<td>RMS</td>
<td>Reservoir Modeling System</td>
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<td>TRO</td>
<td>Targeting Remaining Oil</td>
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<td>TTRD</td>
<td>Through Tubing Rotary Drilling</td>
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<td>WAG</td>
<td>Water Alternating Gas</td>
</tr>
<tr>
<td>WC</td>
<td>Water-Cut</td>
</tr>
<tr>
<td>WOC</td>
<td>Water-Oil Contact</td>
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References


