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Abstract

Drilling infill wells in HPHT fields can represent a severe challenge. Narrow drilling windows are prevailing in HPHT reservoirs, and pressure depletion will decrease this window even more. It may be critical to drill planned wells as soon as possible after production from the field is initiated because depletion is known to be rapid in HPHT reservoirs.

More complex wells and narrow drilling windows may result in more non-productive time (NPT). This is not a wanted situation, especially since the operational costs has increased dramatically during the recent years. Wellbore stability issues are known to be a large contributor to NPT in the oil industry. Conventional drilling methods may not be the best solution in situations with a limited drilling window. In this study was the following technologies found to have potential advantages with respect to depleted reservoir drilling:

- Conventional drilling
- Lost circulation materials
- Managed pressure drilling
- Underbalanced drilling
- Casing drilling
- Liner drilling
- Expandable liners
- Combination of drilling liner and expandable liner
- Lining while drilling method patented by BP

Gudrun is a HPHT light oil/condensate field located in block 15/3 in the North Sea. Pressures up to 815 bars and temperatures up to 170 °C are expected. Gudrun Øst is a relatively small discovery located approximately 4 km south east of the Gudrun field. The discovery has been implemented in the Gudrun project, and a 6988 meter long horizontal well is planned to be drilled to Gudrun Øst. Production is planned to be initiated from the target reservoir, Draupne 3, before the well is drilled. Initiating production may lead to severe depletion of the reservoir and make the drilling operation to Gudrun Øst difficult to perform.

Conventional drilling of the well to Gudrun Øst was simulated in the Presmod module of Drillbench, with different depletion scenarios. Presmod includes a dynamic temperature model, which makes it more accurate in HPHT environments. The goal was to simulate representative ECDs, and use the results to determine when conventional drilling is no longer applicable for drilling A-14. Simulations were first carried out on a well that was already drilled on Gudrun to verify the accuracy of the model. A good match was achieved between simulated and measured ECDs. The simulated values were less than 0.01 sg from the measured values.

Conventional drilling was found to be applicable for drilling A-14 in situations with 60 bars depletion or less based on theory, experiences and simulation results. Lost circulation materials should be considered to be included in the mudsystem if the depletion exceeds 40 bars depletion. It is recommended to use managed pressure drilling technology if the expected depletion is between 60 and 120 bars. More extensive studies have to be carried out to determine the drillability of the well if the depletion exceeds 120 bars. Underbalanced drilling may be the only applicable solution in this situation.

Preface

The work presented in this Master thesis was conducted during the 10th semester of the Petroleum Engineering studies at the University of Stavanger (UiS). The thesis was done in cooperation with Statoil ASA, and performed at their Stavanger office.

I would like to thank my supervisors Børre Tingstveit at Statoil and Professor Olav Gerhard Haukenes Nygaard at UiS for support and for giving me an interesting and educational Master thesis.

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Morten Dommersnes

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1 Introduction

Drilling in high pressure/high temperature (HPHT) reservoirs can represent a severe challenge. The elevated temperatures and pressures will affect drilling fluids and put an extra demand on the equipment used. The conditions require that special attention is paid to downhole pressure fluctuations and kick detection. Narrow margins between pore pressures and fracture pressures are often prevailing in HPHT reservoirs. This can result in severe wellbore stability challenges. The drilling window will decrease even more when production from the reservoir is initiated, making drilling of infill wells a challenge. Pressure depletion is generally very rapid in HPHT fields, especially in depletion drive reservoirs.

While the drilling targets get harder to reach, the costs are increasing. Drilling costs on the Norwegian continental shelf has increased dramatically in the recent years. At the same time the complexity of the wells is increasing. More complex wells may lead to more frequent wellbore stability problems and less effective drilling operations. Increased cost means that the economic impact of non-productive time (NPT) will increase. Extensive planning and suitable drilling technologies are required to perform a cost efficient drilling operation.

It is not always sufficient to apply conventional drilling measures. One of the main objectives of this thesis is to give an overview of different technologies that can be favorable to apply when drilling in depleted HPHT reservoirs. The idea is to present basic principles, advantages and weaknesses for the different technologies. An additional objective is to present some of Statoil's experiences with these technologies.

Another objective of this study is to build a representative hydraulic simulation model for a planned well in the Gudrun project, and to simulate conventional drilling of the well with different depletion scenarios. Gudrun is a light oil and condensate HPHT field located in block 15/3 in the North Sea. The field is operated by Statoil, with GDF Suez as a partner. Temperatures of 170°C and initial reservoir pressure up to 815 bars are expected. The field consists of 3 hydrocarbon-bearing reservoirs. Drilling of 7 production wells have started, and production is planned to start early in 2014. Adjacent to Gudrun a discovery named Gudrun Øst has been made. This discovery has now been implemented with the Gudrun project. A 6988 meter long horizontal well is planned to be drilled to the Gudrun Øst location. The well is planned to be drilled after pressure depletion has been initiated in the target reservoir, which may make it difficult to drill the well with conventional drilling measures.

Simulations will be carried out in the Presmod module of the Drillbench software. Presmod is an advanced hydraulic simulator, and it includes a dynamic temperature model, which makes the simulations more accurate in HPHT conditions.

The final objective of this study is to use the simulation results, and the information gathered about the different technologies, to evaluate which technologies that would be favorable to apply when drilling the planned the well to Gudrun Øst.

2 Theory

2.1 Rock Mechanics

The general source for this chapter is [1] unless otherwise is stated in the text.

Subsurface formations are always under stress due to overburden pressure and tectonic forces. The in-situ stresses can be identified by three principal stresses, σ_1, σ_2 and σ_3, where $\sigma_1>\sigma_2>\sigma_3$. If one of these is vertical, the stresses can be identified with σ_z as the vertical total stress, σ_H as the maximum horizontal stress and σ_h as the minimum horizontal stress. The type of faulting in an area is related to the local stress regime, as illustrated in Figure 1.

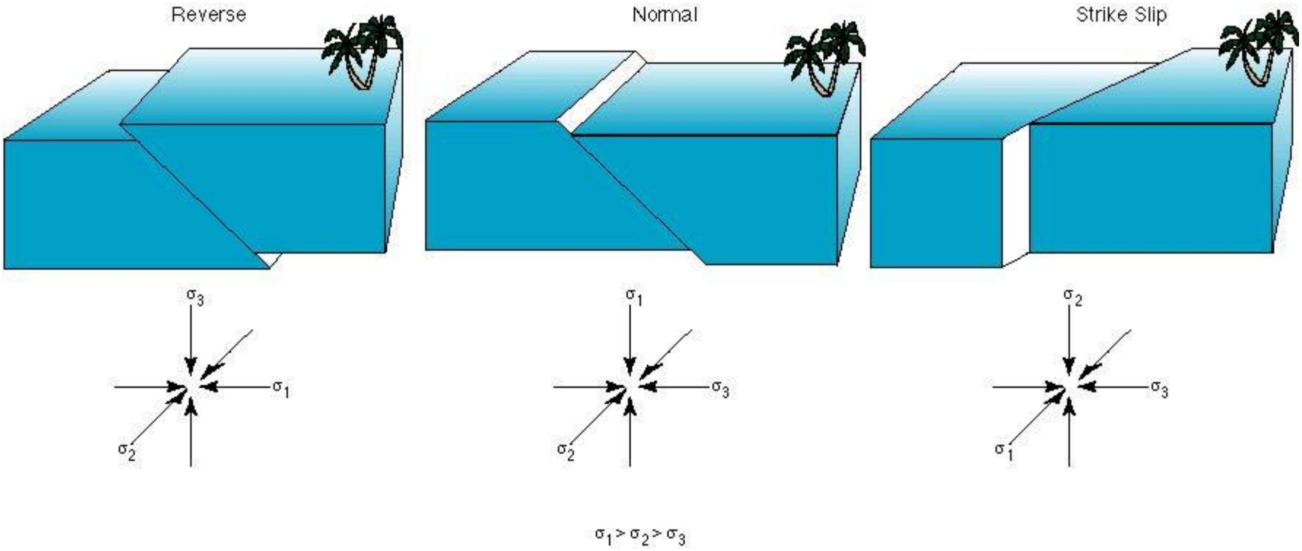


Figure 1: Stress and faulting when assuming that σ_z is one of the three principal stresses [2].

When drilling a borehole in underground formations stressed solids are removed and replaced by fluid. This will usually lead to an alteration in the stress state of the formation around the borehole, because the fluid pressure normally doesn't match exactly the stress which was exerted by the removed solids. Large stress deviations may lead to failure in the formation, which can cause severe operational problems. A good prediction of the in-situ stresses is therefore essential for a successful drilling operation.

It is important to understand both the relative and absolute magnitudes of the principal stresses when determining the stresses on a wellbore wall. The deviation and azimuth of the wellbore relative to the in-situ stresses is also an important factor in wellbore stability. The most stable trajectory is found when the magnitude of the stress difference is minimized between the two principal stresses acting on the wellbore wall. For a normal-faulting stress regime, where it is assumed that the two horizontal stresses are more or less equal, a vertical well will experience least differential stress of any trajectory. However, if assuming that the maximum horizontal stress is slightly lower than the vertical stress, but significantly greater than the minimum horizontal stress, the most stable well is drilled at a deviation of 60°. This illustrates that it is not only important to know the relative magnitudes of the principal stresses, but also the absolute magnitudes. The least stable trajectory when only considering differential stress is found in the direction of the intermediate principle stress [3].

Rocks are porous, so not all the stress is carried by the rock matrix. The term effective stress was introduced by Terzaghi in 1923, and is defined as [4]:

$$\sigma' = \sigma - P_p \tag{2-1}$$

where σ is the total stress and P_p is the pore pressure.

The stress carried out by the fluid is not always exactly equal to the pore pressure. To correct for this Biot added a coefficient, α, which is defined as [5]:

$$\alpha = 1 - \frac{K_{fr}}{K_s} \tag{2-2}$$

where K_{fr} is the bulk modulus of the rock framework and K_s is the bulk modulus of solids.

The effective stress was then defined as:

$$\sigma' = \sigma - \propto P_p \tag{2-3}$$

The Biot coefficient can often be neglected because it is very close to 1. This is generally the case for unconsolidated or weak rocks.

2.1.1 Stresses around a borehole

It is convenient to use cylindrical coordinates when describing stresses around a borehole. Stresses at a point on the borehole wall can be identified as radial stress, tangential stress (also known as hoop stress) and vertical stress.

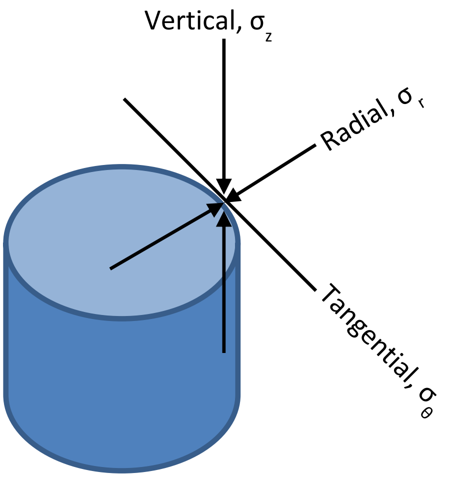


Figure 2: Stresses acting on a borehole wall.

Equations which describe elastic stresses around a hole in an infinite plate in one directional tension were published by Ernst Gustav Kirsch in 1898 [6]. The equations used today to calculate borehole stresses are based on Kirsch's equations. The general linear elastic solution for a deviated borehole with anisotropic stresses is not given in this thesis, but can for instance be found in Bradley (1979) [7]. Anisotropic stress state means that the horizontal stresses vary with direction, and that there are two different horizontal stresses. This stress state can be caused by plate tectonics, local effects like salt domes, topography or faults. The most simplified equations are derived when assuming a vertical borehole, isotropic horizontal stresses and an impermeable borehole wall. The principal stresses at the borehole wall then become:

$$\sigma_r = P_w \tag{2-4}$$

$$\sigma_\theta = 2\sigma_h - P_w \tag{2-5}$$

$$\sigma_z = \sigma_v \tag{2-6}$$

where σ_r is the radial stress, P_w is the well pressure, σ_θ is the tangential stress, σ_h is the minimum horizontal stress, σ_z is the vertical stress and σ_v is the overburden load.

2.1.2 Borehole failure

As previously mentioned there may be large stress deviations in the near wellbore area as a consequence of drilling in the formation. If these stress deviations exceed the borehole failure criteria, the rock will fail. The borehole failure criteria can therefore simply be defined as the boundary conditions for which the borehole fails. A borehole failure means that there is some kind of deformation of the borehole. The consequences of a borehole failure can be from fairly small to severe (for instance a lost well or a blowout).

Assume a vertical borehole with isotropic stresses, so that equations (2-4) to (2-6) are valid. There are several conditions for which the borehole may fail depending on the relative magnitude between the three principal stresses. If the pressure in the well is lower than the horizontal stress at the borehole wall (e.g. $\sigma_\theta>\sigma_z>\sigma_r$) a borehole collapse may occur. This is a shear failure caused by high tangential stress around the hole, exceeding the strength of the rock. According to the Mohr-Coulomb criterion a shear failure will occur when:

$$\sigma_\theta' = C_0 + \sigma_r' \tan^2\beta \tag{2-7}$$

where σ'_θ is the effective tangential stress, σ'_r is the effective radial stress and β is the failure angle.

The failure angle is related to the internal friction angle, φ, of the material:

$$\beta = 45° + \frac{\emptyset}{2} \tag{2-8}$$

The opposite case is when the radial stress that is higher than the tangential stress. This means that the wellbore pressure is higher than the tangential stress, which could lead to fracturing of the formation. This is referred to as a tensile failure. The failure criterion for a tensile failure can be written as:

$$p_{wf} = 2\sigma_h + T_0 - p_p \tag{2-9}$$

where p_{wf} is the well fracture pressure, σ_h is the minimum horizontal stress, T_0 is the tensile strength for the material and p_p is the pore pressure.

Equation (2-9) is based on the Kirsch equations, and is often referred to as the Kirsch model. It states that a fracture will initiate if the pressure in the well exceeds p_{wf}. A more advanced fracture model is presented by Aadnøy in the SPE-paper "*A New Fracture Model That includes Load History, temperature, and Posson's Effects*" [8].

The fracture gradient prognosis for a well is usually based on tests done in offset wells. Examples of tests that can provide information relevant for the fracture pressure prognosis are minifrac, formation integrity test (FIT) and leak off test (LOT). Leak-off tests are conducted right after a casing is set. This means that the operator has a good understanding of which formation that is tested along with the casing shoe. Approximately three meters of the formation is drilled below the casing shoe, and pressure is applied to measure the response of the formation. The typical pressure profile is illustrated in Figure 3.

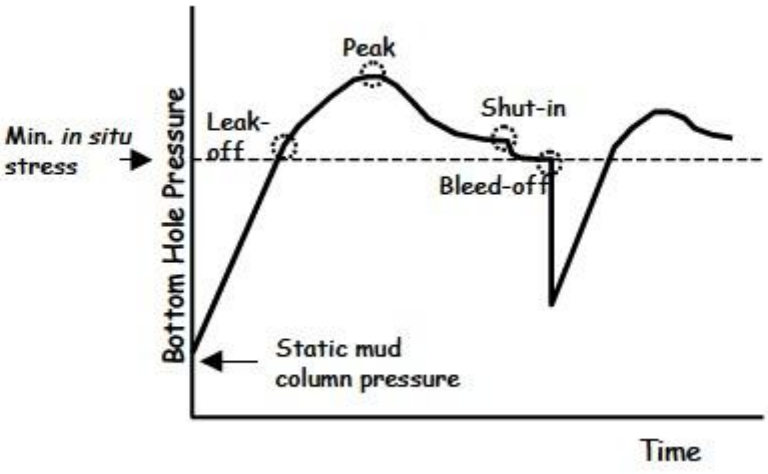


Figure 3: Leak-off test pressure profile [9].

The linear pressure build up in the beginning is determined by the pump rate and the compressibility of the system. The slope of the pressure build-up curve decreases once a fracture is induced in the wellbore wall. This is due to the increased volume associated with the fracture. This point is known as the leak-off point. The pressure continues to build up as the fracture extends through the disturbed near wellbore zone. The pressure will peak and then decline rapidly. A propagation pressure that is lower than the peak pressure can then be settled. When the fracture has been extended beyond the disturbed region, the pressure only needs to exceed the minimum horizontal stress to propagate further. If the test is immediately repeated, the peak pressure will be decreased, while the propagation pressure will be practically identical. The process of taking a leak-off test beyond the initial departure from linearity and then reopening it is called an extended leak-off test. It is important to acknowledge the uncertainties related to the determination of fracture gradients. For instance, during LOTs a leaking cement channel or elastic opening of a micro-annulus between the casing cement and the borehole wall may be a source of error [10]. The fracture pressure is not a true rock mechanical parameter. It depends very much on several other factors, where the mud properties/particle content plays a major role. This means that there always will be an uncertainty in the fracture gradient prognosis [11].

FIT's are testing the strength of the formation and shoe by increasing the bottomhole pressure to a pre-determined pressure. There is no intention of creating fracture in this test. The intension of a minifrac test is to break down the formation to create a short fracture during a period of injection, and to observe the closure of the fracture during the falloff period. These tests are normally performed before fracture stimulation treatments [12].

2.1.3 Depletion effects

A reservoir which is produced will gradually experience a drop in pore pressure due to the removal of fluids, unless there is some pressure-support mechanism (e.g. large connected aquifer or strong compaction drive). The pressure depletion will result in a changed stress state inside the reservoir. The two major effects are a drop in the total horizontal stress, σ_h, and a rise in the effective stresses, σ'_h and σ'_v. The total vertical stress remains constant because the weight of the overburden remains unchanged. Consequences of the changed stress state can be slower drilling (Because the rock is stronger and tougher to drill), higher risks of lost circulation, higher risk of blowout, more casing strings required and a need for lost circulation material (LCM).

Based on Terzaghi's effective stress concept and by assuming linear elastic isotropic behavior the horizontal stress can be derived from the gravitational load and the materials Poisson's ratio [13]:

$$\sigma_h = \left[\frac{v}{1-v}\right]\sigma'_v + P_p \tag{2-10}$$

where v is the material's Poisson's ratio, σ'_v is the effective vertical stress and P_p is the pore pressure.

The Poisson's ratio measures a materials tendency to dilate laterally in response to vertical loading. Naturally occurring materials have Poisson's ratios between 0 and 0.5. Some typical ranges of observed Poisson's ratios are listed in Table 1.

Material	Poisson's ratio
Sands	0.10-0.22
Silts	0.15-0.30
Carbonates	0.20-0.35
Shale	0.22-0.48
Salt	0.45-0.50

Table 1: Typical Poisson's ratios [9].

The total overburden will be constant during the depletion. Assuming that the Biot's constant is 1, the change in the effective vertical stress is equal to the change in pore pressure:

$$\Delta\sigma'_v = \Delta P_p \tag{2-11}$$

By combining equation (2-10) and (2-11) the change in horizontal stress as a function of change in pressure can be obtained:

$$\Delta\sigma_h = \left[\frac{v}{1-v}\right]\Delta P_p + \Delta P_p \tag{2-12}$$

or:

$$\Delta\sigma_h = \left[\frac{1-2v}{1-v}\right]\Delta P_p \tag{2-13}$$

which can be written as,

$$\Delta\sigma_h = A_{SDR} \times \Delta P_p \tag{2-14}$$

where A_{SDR} is the stress-depletion ratio, which in this case is given by:

$$A_{SDR} = \left[\frac{1-2v}{1-v}\right] \tag{2-15}$$

The stress-depletion ratio will always stay positive as long as the materials Poisson's ratio is between 0 and 0.5.

If we assume that T_0 is zero the tensile failure model (Equation 2-9) can be written as:

$$\Delta p_{wf} = 2\Delta\sigma_h - \Delta P_p \tag{2-16}$$

Combing equation (2-13) and (2-16) results in a relationship between change in fracture pressure as a function of change in pore pressure:

$$\Delta p_{wf} = \left[\frac{1-3v}{1-v}\right]\Delta P_p \tag{2-17}$$

A sand formation with a Poisson's ratio of 0.2 will result in a fracture-depletion ratio of 0.5 according to Equation 2-17. This means that a 100 bar drop in pore pressure will result in a 50 bar decrease in fracture pressure. An interesting observation is that a formation with a Poisson's ratio larger than 1/3 will experience an increase in the fracture pressure if the pore pressure drops based on this model.

The above equations are based on simplifying assumptions such as linear isotropic behavior and uniaxial strain. These assumptions may in many cases be appropriate because sand reservoirs tend to be relative isotropic and strains are fairly small during moderate depletion. In some cases the reservoir has been found to be near the frictional-equilibrium limit. For a normal-faulting regime the stress-depletion ratio then can be expressed as [3]:

$$A_{SDR} = \propto \frac{2\sin\phi}{1+\sin\phi} \tag{2-18}$$

where α is the Biot's constant and ϕ the internal friction angle of the faulting material.

Experienced stress-depletion ratios from different fields are given in Table 2. Most of the values lie between 0.5 and 0.7. Assuming that the Biot's constant is 1 this gives Poisson's ratios between 0.2 and 0.3 using equation (2-17), or internal friction factors from 20 to 30° if equation (2-18) is used. This is regarded to be reasonable values.

Field/Location	Stress-depletion ratio (A_{SDR})
Wicksburg formation south Texas	0.53
Waskom east Texas	0.46
Magnus field North Sea	0.68
Ekofisk Chalk North Sea	0.8
Wytch Farm southern UK	0.65
Gulf of Mexico shelf	0.63
Gulf of Mexico deep water	0.65

Table 2: Stress-depletion ratios [3].

2.2 Stability during drilling

The general source for this chapter is [1] unless otherwise is stated in the text.

Borehole stability is an important area in drilling. Wellbore instability is by different sources estimated to cost the industry between 2 and 5 billion USD per year [3]. The costs are especially high in offshore fields where the operational costs are much higher than onshore. The demand for more advanced wells in the later years has contributed to a larger focus on borehole stability. The cost of having problems in horizontal and multilateral wells can be very large, and it is also more difficult to achieve stable drilling in these wells. Stable drilling in depleted reservoirs can obviously be a challenge because of the small drilling window that often exists in these situations. Drilling in deepwater or in tectonically active areas are other situations where borehole stability is especially important to focus on.

Stability problems are often referred to as “tight hole” or “stuck pipe” incidents. The most common formation types to get stuck in are shale or mudstone. Traditionally the focus in the industry has been on preventing clay swelling problems. Drilling in shales which are rich in swelling clay minerals can result in a tight well. Clay swelling is a consequence of chemical reactions between the drilling fluid and the clay. This can be treated by including chemical additives in the drilling fluid. Salt is an example of an additive that can prevent swelling issues.

There are two main types of stability problems; the mentioned “tight hole” or “stuck pipe” incidents and another type called “lost circulation” or “mud loss”. The main problem with a tight hole is that it is time-consuming and expensive, while the mud loss situations also represent a safety issue. Mud losses are often a result of fracturing the formation (tensile failure). Tight hole can be a result of wellbore collapse (shear/compressive failure). Figure 4 illustrates different stability problems.

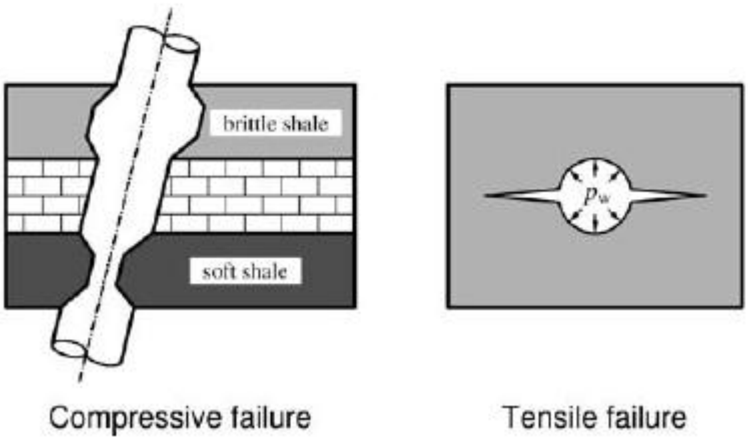


Figure 4: Stability problems during drilling [1].

2.2.1 Tight hole/stuck pipe

There are four main causes for having this kind of stability challenge:

1. Hole collapse
2. Inappropriate hole cleaning
3. Differential sticking
4. Deviation from ideal trajectory

Hole collapse means that the formation around the wellbore fails mechanically. This is normally caused by a shear failure. There can be different consequences of a hole collapse (See Figure 4, leftmost illustration):

- The borehole size is increased due to brittle failure and caving of the borehole wall. If the cavings are not transported away, the pipe could get stuck. In weak rock, the borehole size may also be increased by erosion. An eroded wellbore is in the industry normally referred to as a “washout”. This is caused by high mudflow near the bit, or related to softening of the formation by mechanical failure.
- The borehole size is reduced. This may be the case in plastic shales, sandstones, salt and in some chalk formations. The case of soft shale is sometimes referred to as “gumbo shale”. This shale consists of swelling minerals and can cause problems like bit balling and solids accumulations. Large hole deformation is normally a result of plastic shale deformations because swelling of shale in downhole stress conditions is limited.

Inappropriate hole cleaning may also result in a tight hole. The hole cleaning is not satisfying if the drill cuttings are not removed by the drilling fluid. This problem is larger in shale than sand formations, since the sand particles are easier to transport. Accumulations of cuttings can create a tight hole and the pipe may get stuck. It is important to focus on the drilling fluid’s particle suspension properties to avoid problems with hole cleaning.

Differential sticking is a phenomena caused by differential pressure between the well and the formation. The wellbore needs to be in overbalance, and the pressure maintained by the mud-cake. The pipe may then be forced into the wellbore wall due to the pressure difference between the formation and the drilling fluid. As time goes, the contact area may increase, which will make it more difficult to free the drillstring. The situation is illustrated in Figure 5. This is not a problem in shales because it requires a permeable formation with a mud-cake present. Dupriest et al. (2011) presented several recommended practices to avoid differential sticking [14]:

- Minimize the contact area, especially the drill collar’s contact area.
- Do not use slick assemblies.
- Minimize overbalance, but only if the risk of borehole instability is reduced by doing so.
- Use heavy-weight drillpipe in compression for bit weight in vertical and low-angle wells within the limits specified by manufacturer.
- Use conventional drillpipe in compression in intermediate and high-angle wells within its helical-buckling limits.
- Use standoff subs on drilling jars run above the stabilized BHA.
- Conduct progressive pipe-sticking tests before making connections in wells with high sticking potential.

- Conduct API particle plugging tests and use appropriate blocking solids to improve quality.
- Conduct drill and seal treatments to enhance cake quality in intervals of high differential pressure and chronic cake growth.
- Model the differential sticking risk quantitatively when planning operations that lie outside of previous experience.
- When planning mitigations, consider the sticking risk associated with wear groove in high-angle wells. Additional mitigations may be required, even when non-aqueous fluid is used and all drill collars are supported.

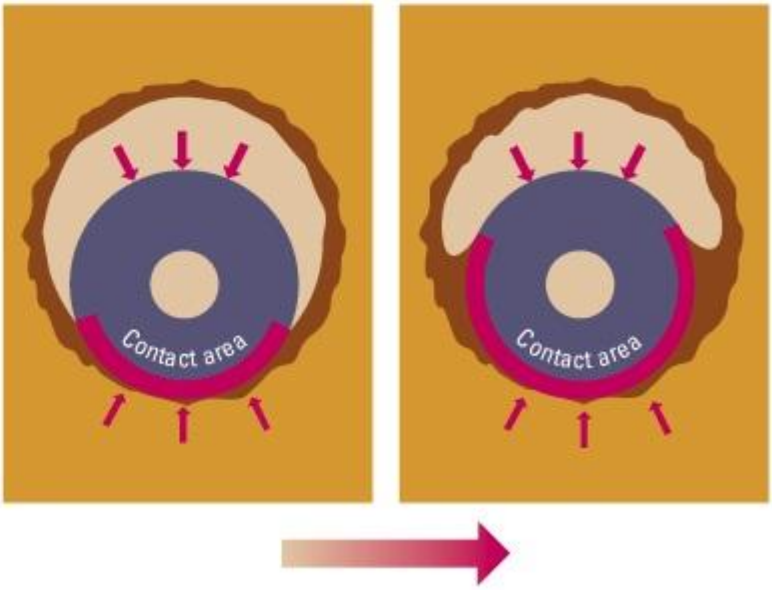


Figure 5: Differential sticking, showing contact area being increased by time [15].

A fourth possible cause for a stuck pipe is deviations in the wellbore trajectory. "Key seating" is a well-known phenomenon in deviated wells. This happens when the lower side of the drilling tool digs into the bottom of the hole and creates a key-shaped pattern in the formation. The pipe can also be stuck if the bend in the wellbore trajectory is too sharp.

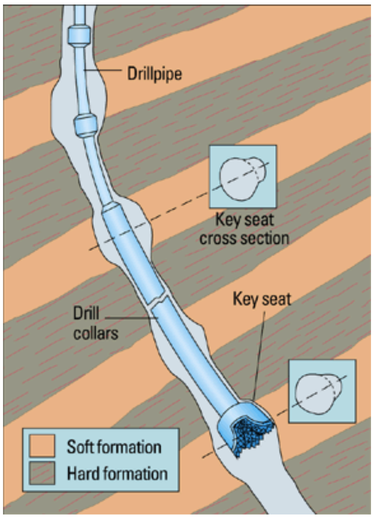


Figure 6: Key seating [16].

The main consequences of a tight hole/stuck pipe situation are loss of time and money. The remedial action is normally to perform reaming or sidetracking. Instabilities may also be an issue in later operations in the borehole. It can make logging operations difficult because of the tight hole itself, and also because interpreting the logs is difficult if the gauge is unknown. Cementing is another job that can be difficult when the hole is tight. It may be difficult to know how much cement that is required, and a tight hole may result in a poor cement job quality. A good well design is critical to be able to achieve stable drilling. The well design includes factor such as mud weight and composition, casing setting depths and well trajectory.

2.2.2 Lost circulation

When a fracture exist or is created in the wellbore wall a significant part of the drilling fluid can be lost to the formation. This situation is called “lost circulation”. Loss of circulation may be dangerous because a reduced fluid-level in the well can result in a reduced wellbore pressure. If the wellbore pressure is reduced below the pore pressure a kick may be induced. A kick can be defined as an uncontrolled flow of formation fluids into the wellbore. The kick may eventually lead to a blowout if it is not stopped. A blowout means that the uncontrolled flow of formation fluid reaches the surface. This can be an extremely dangerous situation where severe environmental damages and loss of equipment and lives can be experienced.

The main solution to prevent loss of circulation is to keep the wellbore pressure below the fracture initiation pressure in non-fractured formations and below the fracture reopening pressure for naturally fractured formations. The pressure must be above the collapse pressure to avoid a wellbore collapse. However, the wellbore pressure is normally designed to be higher than the pore pressure to avoid influxes from the formation. The exception is during underbalanced drilling operations (Discussed in chapter 2.8). The wellbore pressure is conventionally controlled by adjusting the mud weight.

The risk of having significant mud losses can be high in depleted reservoirs. A reduction in pore pressure will weaken the hydrocarbon-bearing rocks, but neighboring or inter-bedded low permeability rock may maintain their pore pressure. This can make the drilling operations very difficult since the mud weight required to support the low permeable zones will, in some cases, fracture the depleted formations. A way to deal with small drilling margins is to increase the margin. Numerous experiments and field cases indicate that this can be done by adding lost circulation materials (LCMs) to the drilling fluid. LCMs will be more broadly discussed in chapter 2.3.3. Other solutions to stop losses may be to cement or to seal of the loss-zone with a casing string or liner.

2.3 Drilling fluids (mud)

Drilling fluids are used during drilling operations for several different reasons [17]:

1. Clean the rock fragments from below the bit and carry them to the surface.
2. Exert sufficient hydrostatic pressure against subsurface formations to prevent fluids from flowing into the well.
3. Keep the newly drilled borehole open until steel casing can be cemented in the hole.
4. Cool and lubricate the rotating drillstring and bit.

It may also be noted that the drilling fluid should not [17]:

1. Have properties detrimental to the use of planned formation evaluation techniques.
2. Cause any adverse effects upon the formation penetrated.
3. Cause any corrosion of the drilling equipment and subsurface tubulars.

The properties of the drilling fluid are chosen based on type of formation to be drilled, temperatures, permeability, pore pressures, HSE considerations and much more. There are two main types of drilling fluids; water based mud (WBM) and oil based mud (OBM). Water based mud is traditionally the commonly used drilling fluid. Oil based mud are generally more expensive and require more strict pollution control procedures. OBM are typically used in high temperature formations or formations that are affected negatively by water based mud. Both mud types consist of oil and water together. The mud is said to be water based if water is the continuous phase and vice versa.

2.3.1 Density

As previously mentioned, the mud density is a key factor in drilling operations. To achieve stable drilling and prevent influx of formation fluids it is important to have a mud density that gives a wellbore pressure that is higher than the pore pressure and lower than the fracture pressure. The margin between these pressures is called the drilling window. Barite is an example of additive used to control the mud weight. The hydrostatic pressure in the well can be expressed as:

$$P_w = \rho_w g D \tag{2-19}$$

where ρ_w is the mud density, g is the acceleration due to gravity and D is the vertical depth.

The magnitudes of the mud weight, fracture pressure and pore pressure are usually given in specific gravity (SG) in the Norwegian oil industry. The wellbore pressure is usually given as equivalent circulating density (ECD) during circulation. The ECD is equal to the static mud weight plus a term proportional to the pressure drop in the annulus. It is important to make sure that the ECD do not exceed the fracture pressure to avoid mud losses. The ECD can be defined as:

$$ECD\ [SG] = \frac{\Delta p_{annulus}\ [bar]}{TVD\ [m] \times 0{,}0981} + \rho_w\ [SG] \tag{2-20}$$

where $\Delta p_{annulus}$ is the pressure loss in the annulus and TVD is the total vertical depth.

It is beneficial to have a wide drilling window for several reasons. One reason is that it may be possible to reach target depth (TD) with fewer casing strings. This makes it possible to drill the upper section with smaller bits and still maintain the required production tubing diameter. A consequence of this will be that cutting volumes and disposal costs can be reduced. Another benefit with a wide drilling window is that the mud density can be adjusted to reduce fluid costs and optimize drilling performance. In general a wide drilling windows mean that the total well operation including drilling, casing installation and cementing can be done more quickly and cost efficient.

In Figure 7 is an example of a stability chart for a well on the Norwegian continental shelf given. The full lines indicate from left to right; pore pressure (p), minimum horizontal stress gradient (h) and overburden stress gradient (v). The dotted lines indicate from left to right; estimated collapse gradient (c) and fracture gradient (f). The dashed line represents the planned mud weight gradient (m).

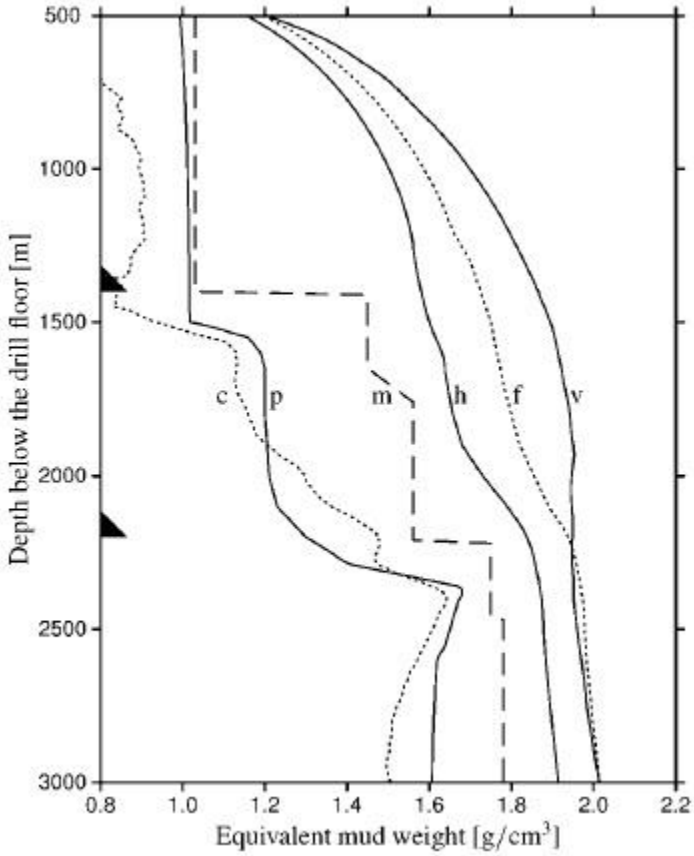


Figure 7: Example of a stability chart for a well from the Norwegian Continental Shelf [1].

2.3.2 Other important mud properties

The rheological characteristics of the mud are important because they influence the frictional pressure drop in in the annulus and the mud's cuttings transport ability. A rotational viscometer can be used to determine the mud's viscosity, yield point and gel strength. Another important parameter is the ability to produce an appropriate mud filter cake. The object of the filter cake is to prevent the mud from entering permeable formations. The filter cake properties can be tested by using a filter press. A third subject that is important is the mud's interaction with the formation. Shales can be very reactive with WBM. Swelling of clay may occur, which can result in a tight hole. Salt is an additive that can inhibit clay swelling.

2.3.3 Lost Circulation Materials

Lost circulation material (LCM) can be added to the mud to control losses to highly permeable formations, fractures and cavernous formations. The LCM additives' objective is to bridge across the openings before a mud filter cake can be built. Several different additives have been used for this purpose. Some examples are nut shell, plastic, limestone, sawdust, bark, cotton seed hulls and prairie hay [3]. Particles can be used in a proactive or reactive manner. A specific concentration of particles (e.g. graphite and calcium carbonate) can be included in the drilling fluid to bridge fractures before losses occur. The use of LCM material can increase the fracture pressure in the wellbore relative to drilling without LCM materials in the mud. This is sometimes referred to as wellbore strengthening. This effect could extend drilling in depleted reservoirs since the drilling window will increase. High concentrations of LCM additives can affect the rheology and increase the ECD. This increase is normally justified by experiencing an even larger increase in the fracture pressure.

Drilling fluids with LCM additives are sometimes called "designer mud". Proper design of particle concentration and particle size distribution is important for creating a well-functioning designer mud [18]. Some of the benefits by using a designer mud can be [19]:

- Access to additional reserves (depleted zones).
- Reduced mud losses in deepwater drilling.
- Loss avoidance when running casing or cementing.
- Improved well control.
- Elimination of casing strings.
- An alternative option to expandable casing.

A popular approach for wellbore strengthening in the later years has been the "stress cage" approach. The idea is to allow small fractures to form in the wellbore wall, and to hold them open by using bridging particles near the fracture openings. This is achieved by drilling with a wellbore pressure above the fracture initiation pressure, and at the same time use a designer mud with appropriate additives. The bridge must have low permeability and provide pressure isolation. The stress cage theory suggest that doing this will create an increased hoop (tangential) stress around the wellbore, which will result in a higher fracture gradient in the wellbore (See Figure 8) [19].

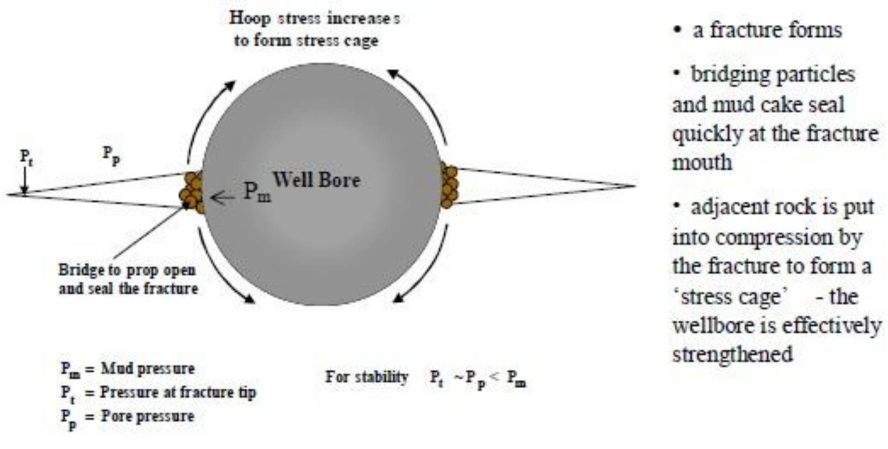


Figure 8: Stress cage concept to enhance wellbore strength [19].

2.3.4 LCM advantages and disadvantages

Some possible advantages and weaknesses with LCMs are listed in Table 3.

Advantages	Disadvantages
May increase drilling window	Particle accumulations if the hole cleaning is insufficient
Mud losses can be reduced or prevented	Rheology and ECD may be increased
Improved well control	Possibility of plugging of downhole tools
Possible elimination of casing strings	

Table 3: LCM advantages and disadvantages.

2.4 Surge and swab effects

Running pipe into the hole and pulling it out will cause cyclic loading of the rock near the borehole. The well pressure will change because the pipe will act as a piston in the hole. Running pipe in the hole will cause a surge effect, while pulling it out will cause a swab effect. The surge effect is related to a pressure increase in the wellbore, which can potentially lead to fracturing of the formation and a mud-loss situation. The swab effect is related to a pressure drop in the annulus, and this can potentially lead to an inflow of formation fluid. This situation may result in more reduction of the bottomhole pressure since the formation fluid that is entering the well normally is much lighter than the drilling fluid.

Several models have been developed to calculate these effects [20] [21]. The majority of these models assume a concentric annulus. This assumption is almost never valid in horizontal and inclined wells which have some degree of eccentricity. Srivastav et al. (2012) presents a new model for horizontal and inclined wells [22]. They found that fluid properties, annular clearance and tripping speed all have significant effect on the surge and swab pressures. The study also showed that surge and swab pressure can be reduced to 40% due to eccentricity effects.

2.5 High pressure/high temperature wells

A high pressure/high temperature (HPHT) well is in NORSOK defined as a well with expected shut-in pressure exceeding 690 bar, or a static bottomhole temperature higher than 150 °C [23]. The high temperatures and pressures in these wells make the design, drilling an operation challenging. HPHT fields are mostly gas fields because of the high temperatures. The majority of the HPHT fields in the North Sea are located in the Central Graben. The Central Graben consists of a series of upthrown and downthrown rocks with several Jurassic gas condensate prospects. The prospects are located at 12000-20000 feet depth, with pressures and temperatures up to 1200 bar and 200 °C respectively. The largest developed HPHT fields in the world are considered to be the Elgin and Franklin fields, which is located in this area. These fields are operated by Total. The first HPHT field to be developed subsea was the Statoil operated Kristin field on the Norwegian continental self [3].

2.5.1 Implications of HPHT conditions

The elevated pressure place an extra demand on the construction materials used in the well. Heavier and larger well control equipment may be required to withstand the pressures. Examples of this are high-pressure valves and manifolds. The high temperatures affect the properties of steel, cement and fluids. Material properties such as strength and elastic modulus normally decrease as temperature increase. Presence of corrosive compounds such as H_2O and CO_2 will require that the effects on the materials are considered. The corrosion rate is a function of temperature. Fluid rheology and PVT behavior can be very different compared to standard well design. This affects both drilling and operability. The casing strings and the fluids in the wellbore annulus respond to temperature changes. The tubing and casing strings will experience thermal expansion when production is started. Depending on the packer, weight and internal and external fluids, the tubing may buckle when this happens. The fluid in the tubing annulus will also expand, resulting in an annulus pressure buildup. The temperature changes can cause wellhead movement which leads to surface facilities and wellbore concerns. Logging, testing and completion operations are also affected by temperature changes. The temperature changes have a serious impact on the loads imposed on the casing string and the integrity of the wellbore [3].

In average there are more than one well-control incident per HPHT well. There are several special challenges when drilling HPHT wells compared to drilling conventional wells [24]:

- High pressures and temperatures have dynamic effects on the mud properties and may have effects on well control.
- Narrow margin between pore and fracture pressure is prevailing in HPHT wells. Pressure depletion is generally also very rapid in HPHT fields, especially in depletion drive reservoirs. Initiating production in these fields can cause severe challenges for drilling of new wells.
- Conditions above the critical point for hydrocarbon influx resulting in hydrocarbon influx that is infinitely soluble in the base oil of the mud.
- In OBM will hydrocarbon influx mix totally with the mud and infinite amounts of gas can dissolve in the mud.
- Barite sag, with particularly serious consequences in inclined and horizontal sections of the well.

Rommetveit et al. (2003) recommend using an advanced modeling tool that includes thermohydraulic modeling, kick modeling and a transient well-control simulator to evaluate well control in HPHT wells [24].

The mud density and rheology depends on the temperature in the well. Temperature variations lead to expansion and contraction of the mud, and thereby a change in the effective volume of mud in the hole. High temperatures in HPHT wells cause thermal expansion of the fluid and a reduction in the effective density. This will affect the hydrostatic pressure. Changes in rheology will affect the frictional pressure drop in the well and the hole cleaning ability. The temperature effect is therefore important to acknowledge when considering the hydrostatic pressures and ECDs in the well.

Significant swab effects may be experienced also while tripping in [25]. This secondary swab effect combined with high temperature conditions may create an underbalance while tripping in. This could lead to a kick, and it is therefore important to adjust the mud weight to account for temperature and swab effects. The secondary swab effect may be caused by high tripping speeds [26]. Mud weight and tripping speed are important design parameters in the planning of HPHT wells.

HPHT wells require special attention to kick detection. Changes in the temperature and pressure conditions lead to expansion or compression of the mud. The volume changes that are related to expansion are called temperature kicks [3]. “Wellbore breathing” (Also known as well ballooning) is another phenomenon that is particularly evident in HPHT wells. Wellbore breathing means flow of fluid from the formation into the wellbore during periods without circulation, and flow into the formation during circulations. The ECD effect may be significant in deep wells with small annular clearance, causing a considerable overbalance. This may cause small fractures which lead to invasion of drilling fluids into the formation and near wellbore pressure charging of the formation. Stopping the circulation could then result in a situation where the wellbore is in underbalance with respect to the near wellbore formation, and influx may occur. It may be difficult to separate this influx from a true kick.

HPHT wells often require additional and more advanced equipment compared to conventional wells. The equipment must be tested and approved for the conditions it will operate under. The production tubing usually is made of corrosion resistant alloy because most HPHT wells contain H_2S. Premium connections are used to ensure leak resistance, and the packer material must also be corrosion resistant. It may be necessary to install mud coolers on the surface to reduce the temperature of the mud. HPHT wells also require a high capacity gas-handling system on the surface [3].

2.6 Drilling in depleted reservoirs

Drilling in depleted reservoirs can represent a severe challenge because of the depletion effects discussed in chapter 2.1.3. An illustration of pressure and stress gradients in a depleted sand layer is shown in Figure 9. The effects of depletion are shown with a reduced pore pressure of Δp and a reduced minimum horizontal stress of $\Delta\sigma_h$. The mudweight may have to be reduced significantly when drilling into the depleted sand formation to avoid fracturing of the formation. A casing or liner has to be set in the interval right above the depleted zone to be able to reduce the mudweight without having influx. In theory this should be a good solution, but there are some troublesome uncertainties. The depleted formation may still contain zones that have not been depleted caused by lack of pressure communication. Drilling into these zones with a low mudweight could lead to a kick, which can have severe consequences. This means that the operator usually must have the initial pore pressure in mind when determining the mudweight. A consequence of this is that situations with negative drilling windows may exist, because the fracture pressure is lower than the initial pore pressure. These situations require designer muds that can strengthen the wellbore, and/or unconventional drilling technologies.

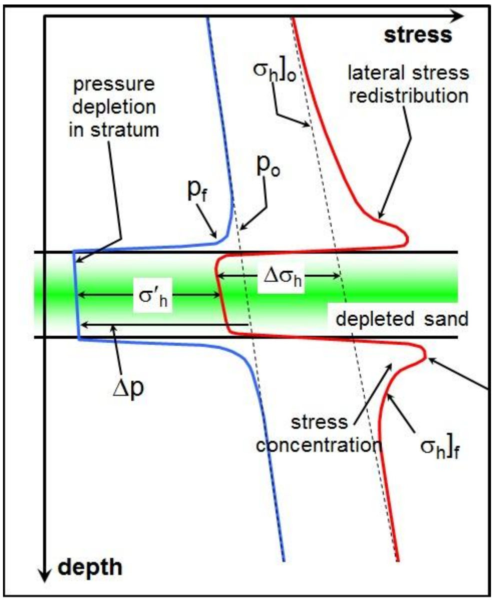


Figure 9: Effect of pressure depletion in a sand layer [27].

Another challenge is when there is several stacked reservoir layers. Drilling through several depleted layers would require that multiple casings or liners are set to isolate the depleted intervals. This could make the hole diameter small and eventually create a situation where it would be impossible to drill further. A solution may be to use expandable liners (Discussed in chapter 2.12), but LCMs may also solve the challenge. Another solution has been to avoid drilling in depleted zones by drilling the deepest reservoirs before starting production from shallower targets. However, this may have large economic consequences because of increased capital expenditure and delay of hydrocarbon production. In many cases, this means that the shallower targets have to be developed first even though the operator is aware of the depletion challenges related to this [3].

2.7 Conventional drilling

Conventional drilling is believed to have its origin from Spindletop, near Beaumount Texas around year 1900. The key technologies were the rotary drive, roller cone bits and drilling mud. Since then, these technologies have been developed further and new technologies have been introduced. In conventional drilling the circulation flow path begins in the mud pit. Drilling fluid is pumped from the mud pit into and down the drillstring through the drillbit. The mud then flows up the annulus and out of the wellbore via a bell nipple. From the bell nipple it goes through a pipeline to mud-gas separation and solids control equipment, before it re-enters the mud pit. The pit tank and the wellbore via the bell nipple are open to the atmosphere. This is called an open vessel approach [28].

Most conventional wells are drilled hydrostatically overbalanced. This means the pressure exerted by the static fluid density in the wellbore annulus is higher than the pore pressure in the formation. The annular pressure is generally controlled by drill fluid density and the pump rate. The bottomhole pressure in static conditions can be expressed as:

$$P_{BH} = P_{Hyd} \tag{2-21}$$

where P_{BH} is the bottomhole pressure, and P_{Hyd} is the hydrostatic pressure.

The pressure conditions in the annulus are dynamic when there is circulation. The bottomhole pressure is then a function of both hydrostatic pressure and annular friction pressure:

$$P_{BH} = P_{Hyd} + P_{AF} \tag{2-22}$$

where P_{AF} is the annular friction pressure.

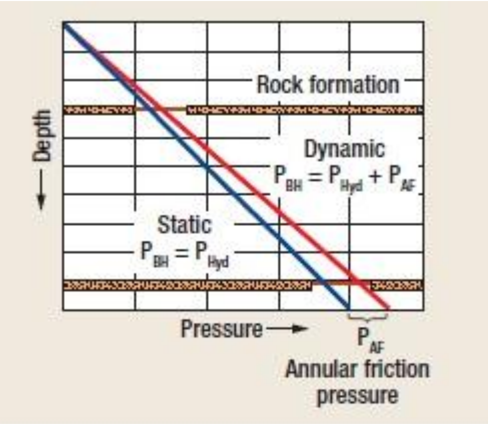


Figure 10: Static and dynamic pressures located within the drilling window [28].

Figure 11 illustrates the drilling windows for conventional drilling, managed pressure drilling (MPD) and underbalanced drilling in relation to collapse, pore and fracture pressure. Underbalanced drilling (UBD) and managed pressure drilling will be discussed in the two following chapters.

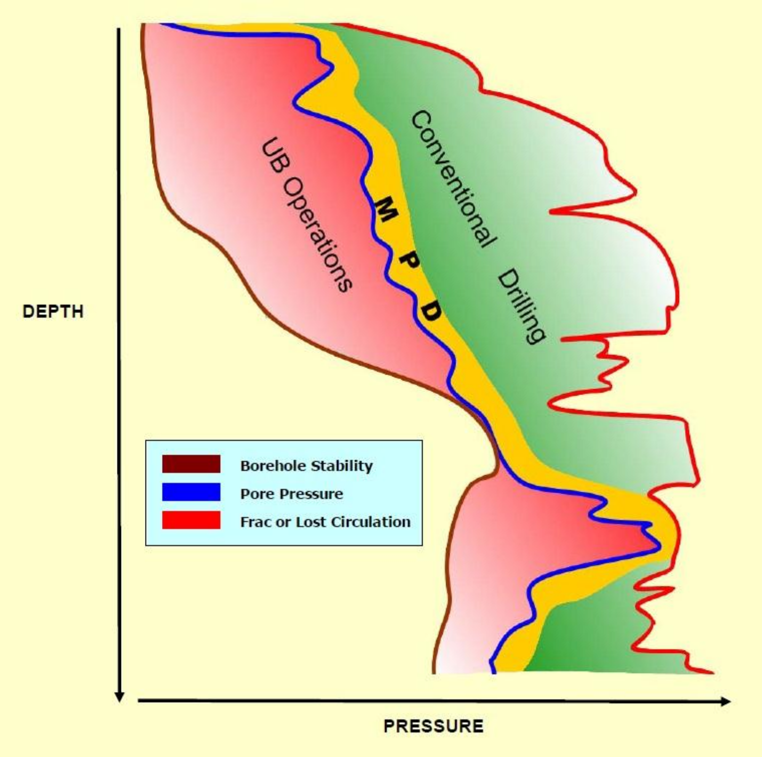


Figure 11: Drilling windows for conventional drilling, MPD and UBD [29].

2.7.1 Advantages and disadvantages

Some potensial advanatages and disadvantages with conventional drilling is given in Table 4.

Advantages	Disadvantages
Well proven technology	Open to atmosphere
No modifications needed	Limited control of BHP
Cheapest option	Surge and swab effects
	Requires a relatively large drilling window

Table 4: Conventional drilling advantages and disadvantages.

2.8 Underbalanced drilling

Underbalanced drilling (UBD) is a drilling method where the hydrostatic pressure exerted by the drilling fluid is intentionally lower than the formation pore pressure. A consequence of this is that formation fluid will enter the well in permeable zones of the wellbore. It is still important to have a certain pressure in the wellbore annulus to avoid a wellbore collapse. Drilling wells underbalanced is not a new method. Initially all wells were drilled underbalanced, and the technique was patented in 1866 in the United States. The International Association of Drilling Contractors (IADC) Underbalanced Operations (UBO) committee defines underbalanced drilling as [3]:

> *Drilling with the hydrostatic head of the drilling fluid intentionally designed to be lower than the pressure of the formations being drilled. The hydrostatic head of the fluid may naturally be less than the formation pressure, or it can be induced. The induced state may be created by adding natural gas, nitrogen, or air to the liquid phase of the drilling fluid. Whether the underbalanced status is induced or natural, the result may be an influx of formation fluids which must be circulated from the well and controlled at surface.*

When drilling underbalanced the bottomhole pressure can be described as:

$$P_{BH} > P_{Hyd} \tag{2-23}$$

where P_{BH} is the bottomhole pressure, and P_{Hyd} is the hydrostatic pressure.

Since the well fluid no longer can be considered as a barrier, underbalanced drilling requires additional equipment for well control. The main additional equipment compared to conventional drilling are a rotating control device (RCD) and a drilling choke manifold for well control and a multiphase separator for separation of produced fluids.

2.8.1 Advantages and disadvantages

Some potential advantages and disadvantages with UBD is listed in Table 5.

Advantages	Disadvantages
Reduction in formation damage	Wellbore stability and consolidation problems
Reduced risk of lost circulation	Increased drilling costs
Improved bit life	Not compatible with conventional MWD systems
Allows drilling of depleted reservoirs	More complex drilling system than in conventional drilling
Quick identification of productive zones	Increased torque and drag
Reservoir characterization and well testing during drilling	Requires more people on location
Eliminated risk of differential sticking	Well control and safety concerns

Table 5: UBO advantages and disadvantages.

2.9 Managed pressure drilling

The development of managed pressure drilling (MPD) was, and still is, driven by small margins between pore pressure and formation fracture pressure. Small margins are often is experienced in offshore developments and is especially a challenge in deepwater drilling and drilling of depleted reservoirs.

Managed pressure drilling is a drilling method that origins from the technologies used in underbalanced drilling. However, the goals of these two drilling methods are not the same. One of the main goals in underbalanced drilling is to reduce formation damage by allowing influx, while managed pressure drilling focus on avoiding influx from the formation. In this sense MPD is similar to conventional drilling, but there are big differences in required equipment. In contrast to conventional drilling operations, MPD usually employs a closed and pressurizable circulating drilling fluid system that facilitates drilling with precise management of the wellbore pressure profile. The MPD equipment provides much better control of influx than a conventional drilling system does.

The IDAC UBO committee defines managed pressure drilling as the following [3]:

> *Managed Pressure Drilling is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. MPD is intended to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.*
>
> *Technical notes:*
>
> 1. *MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.*
> 2. *MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations of thereof.*
> 3. *MPD may allow faster corrective action to deal with observed pressure variations. The ability to control annular pressures dynamically facilitates drilling of what might otherwise be economically unattainable prospects.*

MPD aims on decreasing nonproductive time (NPT) and mitigating drilling hazards. Examples of drilling hazards that are mitigated are loss of circulation, stuck pipe, wellbore instability and well control incidents. Most managed pressure drilling operations is carried out with a closed vessel approach utilizing a RCD, minimum one non-return valve (NRV) and a drilling choke manifold. The chokes can be either manual or automatically controlled. The closed system with controlled pressure provides for rapid detection of pressure changes caused by for instance influx or losses.

In conventional drilling the botthomhole pressure is controlled by hydrostatic pressure and annulus friction pressure. When the mud pumps are shut down to make connections, the annulus friction pressure is zero, resulting in a bottomhole pressure controlled only by the hydrostatic column. If the bottomhole pressure is greater than the hydrostatic pressure, an influx of hydrocarbons may occur. In managed pressure drilling, when the wellbore is closed and able to tolerate pressure, a way to mitigate these pressure variations can be to control the bottomhole pressure with a backpressure provided by a choke and an incompressible fluid. The bottomhole pressure can then be expressed as:

$$P_{BH} = P_{Hyd} + P_{AF} + P_{Back} \tag{2-24}$$

where P_{BH} is the bottomhole pressure, P_{Hyd} is the hydrostatic pressure and P_{Back} is the backpressure.

Adjusting the backpressure makes it possible to avoid the large pressure deviations that are common during conventional drilling operations.

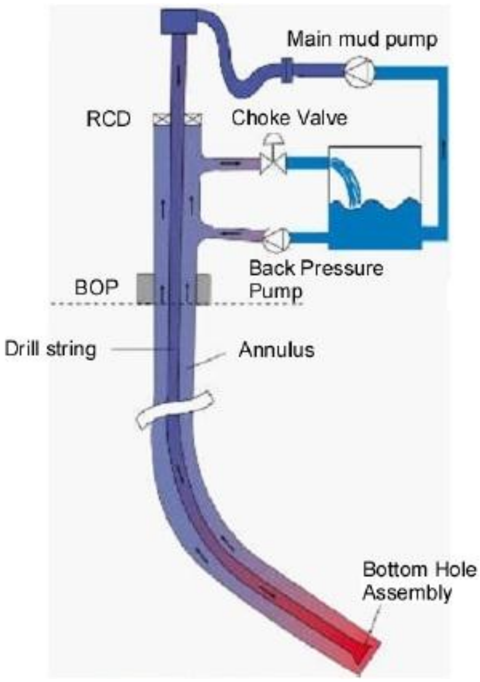


Figure 12: Example of a MPD schematic [30].

2.9.1 Reactive vs Proactive

There are two main approaches to managed pressure drilling; reactive and proactive. Using MPD methods and equipment as a contingency to mitigate drilling problems is called reactive MPD. Normally this means that the well is planned to be drilled with conventional methods and MPD procedures are only activated if unplanned events occur. Proactive MPD means that the managed pressure drilling equipment and methods are used actively to control the annular pressure profile. This approach is used to drill wells that are operationally and/or economically challenging, and often impossible to drill conventionally.

The proactive approach utilizes MPD tools to [28]:

- Better control casing placement with fewer casings
- Easier control mud density requirements and costs
- Provide better pressure control and advanced warning of potential well control incidents.

2.9.2 Variations of MPD

There are large variations in which and how much MPD tools that is employed in different MPD operations. As more equipment is added the operation becomes more and more proactive. Some variations of MPD are [3] [28]:

Returns Flow Control

The objective of this method is to drill with a closed annulus return system instead of an open to atmosphere system. This is done for health, safety and environment (HSE) reasons, and the method is also called the HSE method in the literature. Returns flow control can be accomplished by adding an RCD to the drilling operation. This method can for example be used in situations where there is a significant risk of harmful vapors or shallow gas.

Constant Bottomhole Pressure (CBHP)

The CBHP method focuses on maintaining a constant bottomhole pressure. This is useful when drilling in formations which have a narrow or relative unknown margin between the pore and fracture gradients. The pressure is controlled by adjusting a backpressure with a choke. During connections, when the friction pressure is zero, the choke is closed and the backpressure thereby increased. The goal is to increase the backpressure by the magnitude of the lost friction pressure to maintain a constant bottomhole pressure, as shown in Figure 13. The drilling fluid used is typically lighter than in conventional operations, and may even be hydrostatically underbalanced. Minimum one NRV are installed in the drillstring to avoid fluid from flowing up the drillpipe to the surface.

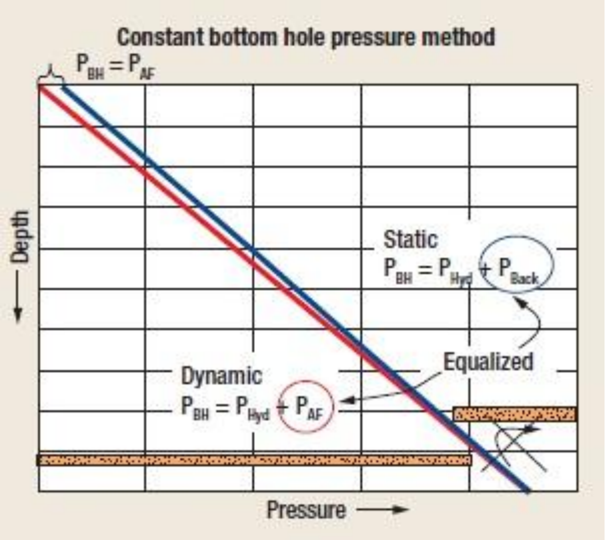


Figure 13: Constant bottomhole pressure principle [28].

Pressurized Mud-cap Drilling (PMCD)

This method mitigates lost circulation issues by applying two drilling fluids. A predetermined column height of heavy, viscous mud is pumped down the backside via the RCDs fill up line connection. This mud cap serves as an annular barrier, while the weak zone is drilled with a less damaging and less expensive drilling fluid (e.g. sea water). The drilling fluid and cuttings are injected into the weak zone during drilling, while the heavy, viscous mud remains in the annulus above the problem zone. The principle is illustrated in Figure 14. The backpressure can be adjusted to assure the ability of the mud cap to prevent returns to surface and to avoid changes in the mud cap drilling height. Some applications of PMCD incorporate the use of a casing isolation or downhole deployment valve because there may be difficulties with receiving the amount of heavy fluid required to trip out the drillstring when the section of interest is drilled.

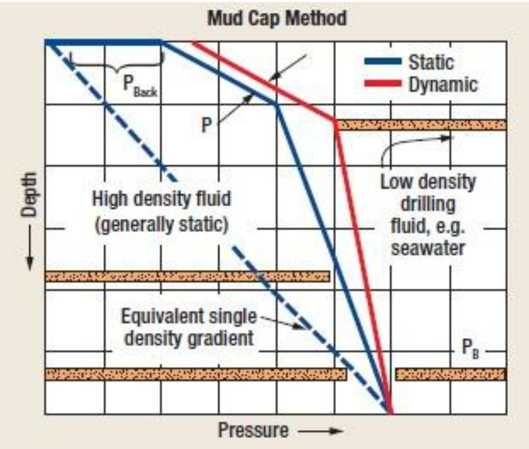


Figure 14: Pressurized Mud-cap drilling principle [28].

Dual Gradient (DG)

In dual gradient drilling two different fluid gradients is used in the annulus wellbore return path. This can be accomplished by injecting a light fluid (e.g. gas) into the annulus of the marine riser at a predetermined depth. Another method is to fill the riser with seawater and artificially lift returns from the seabed back to surface with subsea pumps. The returns are then pumped through dedicated return lines external to the riser. This technique is called *Dual Gradient Riserless Drilling*. DG techniques are often used in offshore drilling where the drilling window is relative small because a significant part of the overburden is water.

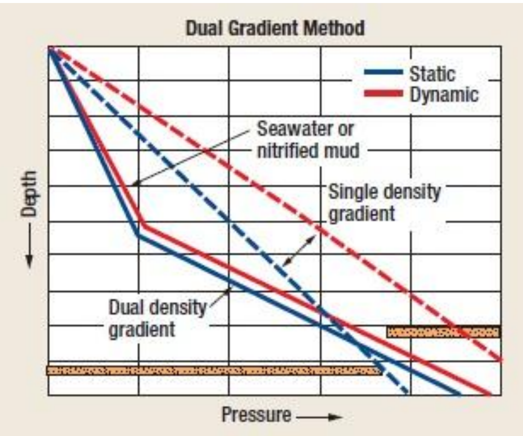


Figure 15: Dual Gradient principle [28].

2.9.3 Additional concepts and equipment

ECD reduction method

A way to reduce the ECD is to modify the annulus pressure profile directly by installing a downhole pump inside the casing. The pump produces a pressure differential at the point of the pump, which can eliminate the ECD effect on the BHP [28]. This is illustrated in Figure 16.

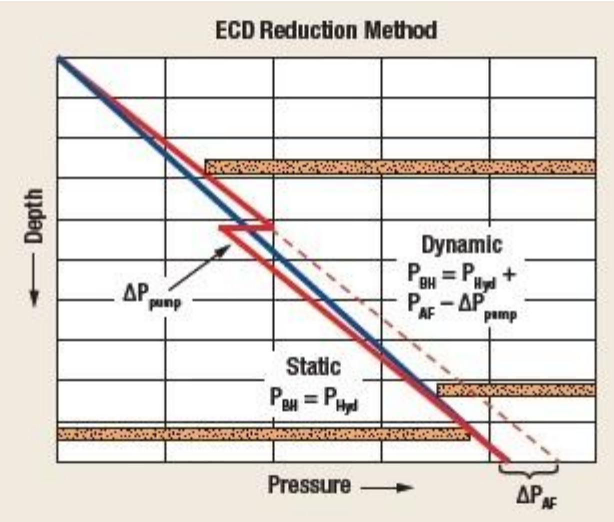


Figure 16: ECD reduction method [28].

Continuous circulating system

A continuous circulating system (CCS) provides the opportunity to make connections without having to stop the circulation. This goal is to maintain the ECD and keep the BHP constant during connections. The CCS breaks the drillstring connection and diverts the fluid flow across the open connection, then the system makes up a new connection to the appropriate torque and drilling may resume [28].

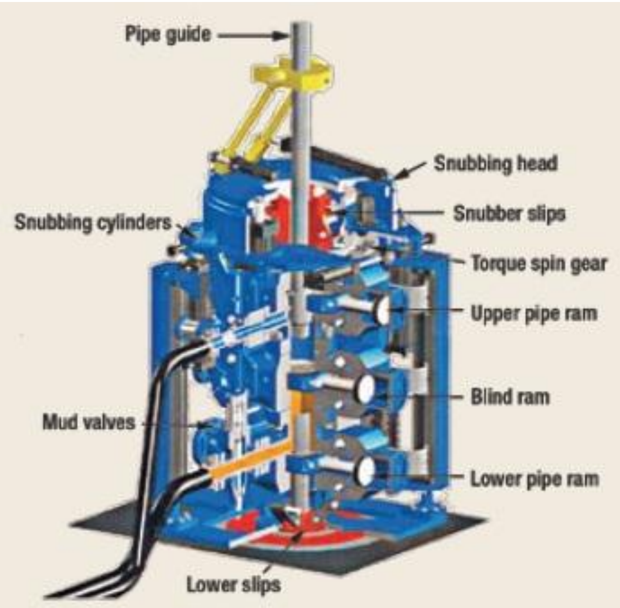


Figure 17: Continuous circulation system [28]

Riserless MPD
In riserless MPD the well control equipment is located on the seafloor. A subsea RCD is used to be able to drill without a riser. The drilling fluid is seawater or other fluids that can be discharged on the seafloor. A ROV or automatic choke is used to adjust back pressure. The purpose of riseless drilling can be to establish deepwater locations by batch drilling. Smaller and less expensive rigs can be used since there is no marine riser and subsea BOP [3].

Dual gradient riserless drilling
This technique is also referred to as riserless mud recovery. Mud and cuttings are transported to the rig from the seafloor by using a subsea pump. The bottomhole pressure can be adjusted via subsea annulus back pressure and speed of both subsea and rig pumps [3].

Continuous Circulating Concentric Casing MPD
This method is based on controlling the bottomhole pressure by using hydraulic friction control. This is achieved by continuously pumping volumes of drilling fluids through a concentric casing or drillstring. The annular fluid rate down the concentric casing is increased by a volume equal to the normal standpipe rate during connections to achieve a constant bottomhole pressure [3].

2.9.4 Advantages and disadvantages

Some potential advantages and disadvantages with MPD is listed in Table 6.

Advantages	Disadvantages
Reduce NPT	Requires extra personnel and deck space
Possibility to control BHP accurately	Requires special equipment and procedures
Possible to drill with narrow drilling windows	More expensive equipment than conventional
Good well control	More complex drilling operation in general
Fewer casing strings may be required	
Possible to drill in formations with different pore pressure regimes	

Table 6: MPD advantages and disadvantages.

2.10 Casing drilling

Casing drilling (Also referred to as casing while drilling (CWD)) uses standard casing as drillstring so that the well is simultaneously drilled and cased. Casing was used as drillstring when rotary drilling was introduced because drillpipe was not invented at the time, so this is not a new technology. Casing drilling has traditionally not been commonly used after the drillpipe evolved because of the limitations in material and cutting tools that were available to use with it. However, during the late 1990s it has become a commercial service. This is due to the development of top drives, polycrystalline diamond compact bits (PDC), better pipe metallurgy and stronger connections together with the need for drilling through depleted formations [3].

The original motivation for commercializing casing drilling was to eliminate non-productive time associated with tripping drillpipe and running casing. However, when the technology was implemented, other benefits were observed.

One of these advantages is that casing drilling can reduce lost circulation problems. The combination of high annular velocity, pipe rotation and the casing's proximity to the borehole wall leads to drill cuttings being crushed and smeared against the formation together with drilling mud. This results in a much less permeable wall cake, and this is referred to as the plastering effect. The process is illustrated in Figure 18. The leftmost illustration is showing casing being forced against the wellbore wall as it advances into the borehole. Then mud is smeared into the formation, and a filter cake builds up. This leads to plastering of filter cake and cuttings against the borehole wall [31].

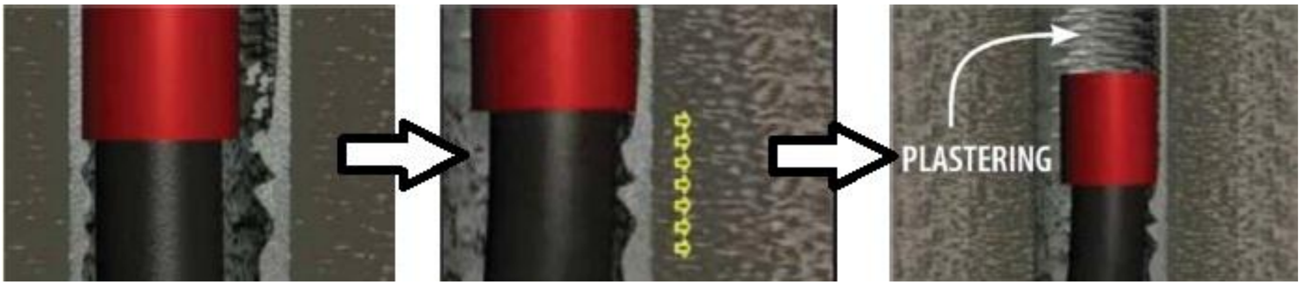


Figure 18: The plastering effect. Modified from [31].

The plastering effect also provides wellbore strengthening. The fracture gradient can be significantly increased, resulting in a wider drilling window. Another positive consequence of the plastering effect is that it can reduce solid and filtrate invasion, leading to less formation damage and higher productivity. The mud cake in casing drilling is normally thinner, less permeable and less porous than the mud cake associated with drilling with drillpipe. This prevents fluid loss to formation and therefore mitigates the drilling induced formation damage. Casing drilling has also proven to be able to mitigate problems with wellbore breathing.

Casing drilling provides several benefits that help maintaining wellbore stability. There is no tripping in casing drilling, which means that swab and surge issues are eliminated. No tripping also reduces problems with cuttings settlement, since the well always can be circulated from bottom. There is also no need for cleaning the well and reaming after reaching TD.

The large casing diameter also creates more gauged wellbores, which are known to be more stable. The drilling time is reduced, since there is no need for tripping and running of casing. This is beneficial because less drilling time reduce the probability for wellbore instability.

The wellbore annulus is also smaller in casing drilling compared to drilling with drillpipe. This provides higher annular velocities, which is beneficial for cuttings transport. This may reduce problems related to insufficient borehole cleaning, such as pack off, barite sag and stuck pipe.

The ECDs will normally be higher when drilling with casing compared to drilling with drillpipe. This is due to an increased annular pressure loss. This can be considered as a disadvantage, and it is normal to use relatively low flow rates to control the ECD. However, the relatively high ECD is an important element in the plastering effect, and it is also preventing borehole collapse issues [31].

A disadvantage with casing drilling is that you may have to set the casing before reaching the planned setting depth if you get stuck. Another disadvantage is that large and heavy casings provide higher torque and drag forces compared to a conventional drillstring. It is crucial to be aware of the casings torque rating, and define the wellpath in a way that failure of the string can be avoided [3]. Casing drilling is also limited by the fact that is does not fit the requirements for drilling subsea wells from a floating rig. The rigs load handling capacity may also be an issue, since the casing string can be very heavy [32].

2.10.1 Equipment

There are different types of casing drilling, and the main types are called Level 2 and level 3. Level 2 is a non-retrievable system that normally is used to drill straight holes where the casing string and drillable bit are cemented in place. Level 3 includes a retrievable casing drilling bottomhole assembly (BHA), and is used to drill directional holes where the BHA is retrieved after target depth is reached. It is common to use a level 3 type in HPHT wells because great depths require directional drilling [33].

The main surface equipment required for casing drilling is the surface lifting and circulation system. This includes a casing drive system and a powered catwalk. The casing drive system can hold and seal the casing. This allows torque to be transmitted and mud to be pumped through the casing. The catwalk can automatically move casing from a pipe rack to the drill floor, and then position it for the next connection.

The downhole equipment consists of either a retrievable or non-retrievable BHA, depending on the type of casing drilling used. The non-retrievable BHA system can include a drillable or non-drillable bit. The drillable bit is made of soft steel and hard cutting materials, and is often used in soft to medium hard formations. The bit is opened by increasing the pressure inside the casing. The pressure can be increased by dropping a ball into a ball catcher, which will close the circulation inside the casing. The pressure will then build up, resulting in an expansion of the bit. This will create an open cylinder inside, which allows drilling to continue with a smaller bit. The non-drillable bit is used to drill through hard formations. This bit has to be disconnected and dropped in a rat-hole for disposal.

A retrievable system consists of a wireline retrievable BHA and a retrievable bit. The bit can be made of hard steel and hard cutting materials, which makes it suitable for drilling in hard formations. The bit can be disconnected and retrieved with a wireline tool when TD is reached. The bit then leaves an open hole in the bottom that allows drilling to continue with a smaller bit and casing size. This BHA type also consists of underreamers that can enlarge the hole [34].

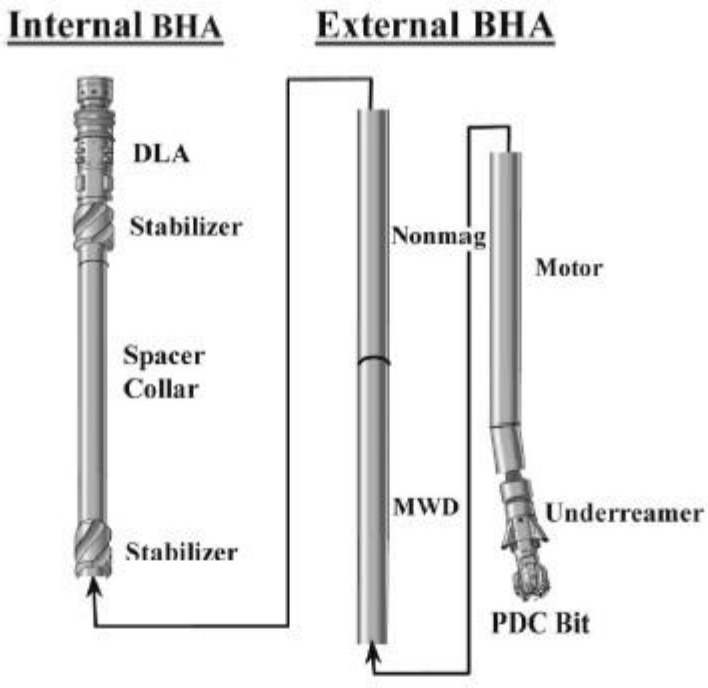


Figure 19: Retrievable directional-drilling assembly [35].

2.10.2 Advantages and disadvantages

Some potential advantages and disadvantages with casing drilling is listed in Table 7.

Advantages	Disadvantages
Reduction of NPT	Casing wear
Lost circulation reduction	Needs special surface equipment
Wellbore strengthening	Potentially high ECDs
Improved wellbore stability	Possibility to get stuck with casing before planned setting depth
Drilling induced formation damage mitigation	Higher torque and drag compared to drillpipe
Mitigate problems with wellbore breathing	Do not fit requirements for drilling from floating rigs
	Possible issue with rig load handling capacity
	Need special bit and BHA

Table 7: Casing drilling advantages and disadvantages.

2.11 Liner drilling

Liner drilling has many of the same advantages as casing drilling; reducing lost circulation, achieve wellbore stability during drilling and prevent well ballooning effects. By having these advantages, liner drilling can be a useful technology for drilling in depleted reservoirs. The main difference between casing drilling and liner drilling is the length of casing used. In liner drilling, the casing is suspended and rotated by using drillpipe. Considering that a majority of the reservoirs nowadays are completed with a liner and not a casing, and also that casing drilling does not fit the requirements for drilling subsea wells from floating rigs, liner drilling may often be the only applicable solution amongst the two [32]. Another big advantage with liner drilling compared to casing drilling is that there is no need for rig modifications. Liner drilling is using the same surface equipment as used in conventional liner running operations [33]. By having the liner in hole, the drillstring can be pulled in cased hole if needed (Tool failure etc.). This protects the formation from hydraulic effects related to tripping. The cement job quality can also be increased by drilling with liner, since there is shorter time between drilling and cementing, and often better hole conditions [36].

The drilling liner technology has improved in the latter years, resulting in steerable drilling liners (SDL). The steerable drilling liners are designed to drill longer and more complex wells than the older "drill-in-liners". SDLs have the same directional and logging capabilities as conventional drilling [32].

2.11.1 SDL system and components

Figure 20 illustrates the main differences between a conventional drillstring and SDL. The numbers on the illustration represents:

1. Drillpipe to surface.
2. Standard drilling assembly.
3. Drill bit.
4. Liner attached to drillpipe.
5. Hole opener.

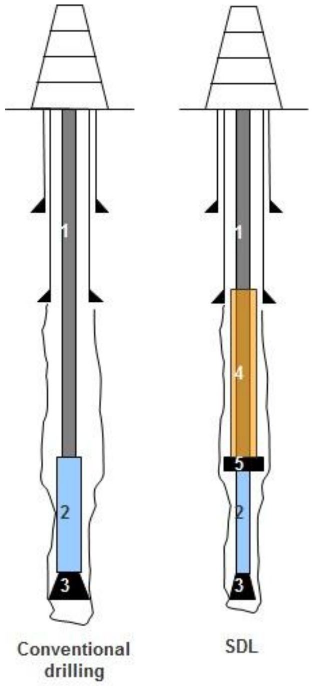


Figure 20: Conventional drilling vs SDL [32].

The first steerable drilling liner system was developed by Statoil together with Baker Hughes. An overview of this system is presented in Figure 21. A running tool (1) provides mechanical connection between the liner (7) and drillpipe (8). A thruster (2) is placed on top of the BHA for length compensation. The force created by the thruster pushes the landing splines (3) into a mechanical seat inside the liner shoe, and the axial position of the pilot BHA (6) relative to the liner is defined. A reamer drive sub (RDS) (4) carries extendable steering pad elements. The pads provide a connection between the reamer bit (5) and the inner string.

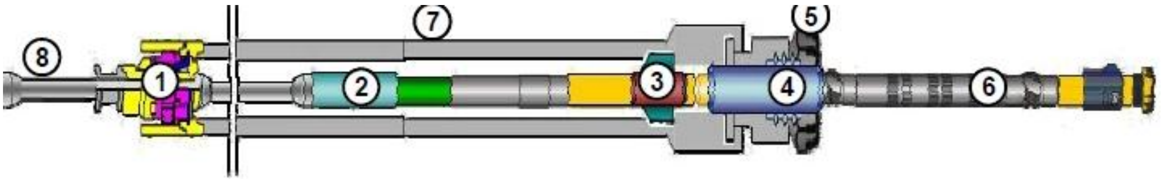


Figure 21: Steerable Drilling Liner System [32].

The operational procedures are illustrated in Figure 22. The steps are [32]:

1. Make up and run in hole with the liner
2. Rig up false rotary table
3. Make up pilot BHA
4. Make up and run in hole with inner string
5. Run in hole with complete SDL system on drillpipe
6. Drill to TD
7. Release and pull out of hole inner string

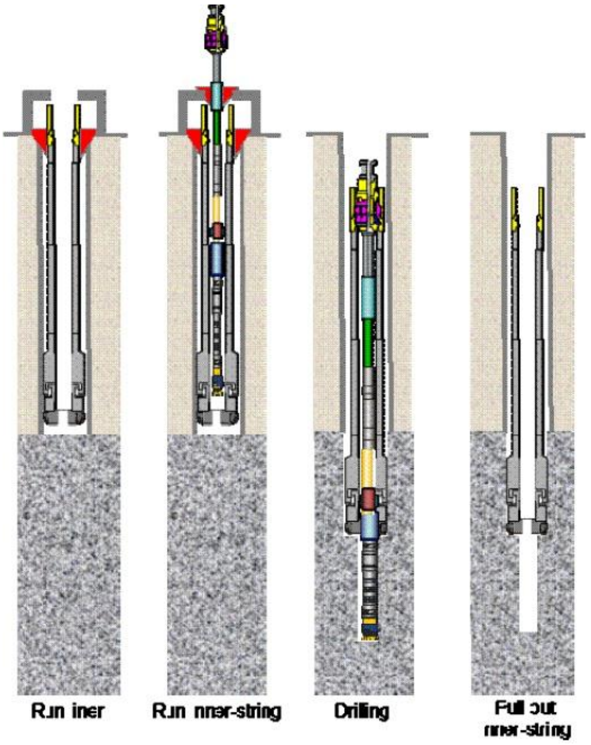


Figure 22:SDL operational procedures [32].

2.11.2 Advantages and disadvantages

Some potensial advantages and disadvantages with the SDL system is listed in Table 8.

Advantages	Disadvantages
Reduction of NPT	Liner wear
Lost circulation reduction	Possibility to get stuck with liner before planned setting depth
Wellbore strengthening	Potentially high ECDs
Improved wellbore stability	Higher torque and drag compared to drillpipe
Drilling induced formation damage mitigation	
Mitigate problems with wellbore breathing	
Steering ability	
Liner in hole	
Increased cement job quality	

Table 8: SDL advantages and disadvantages.

2.12 Expandable liner

Solid expandable tubular systems have been installed in several different types of wells since November 1999. The expandable tubulars are run in hole as a normal casing/liner and then expanded downhole to a pre-determined outside diameter (OD) and inside diameter (ID). The expansion process is based on pushing a cone up or down the liner after it has reached TD. The cone is moved by a differential pressure across the cone area, by a direct mechanical pull or push force, or by a combination of both [37]. There exist several different types of expandable liners. The main differences are related to the grade of expansion, and the purpose of the liner. Some different types are illustrated in Figure 23.

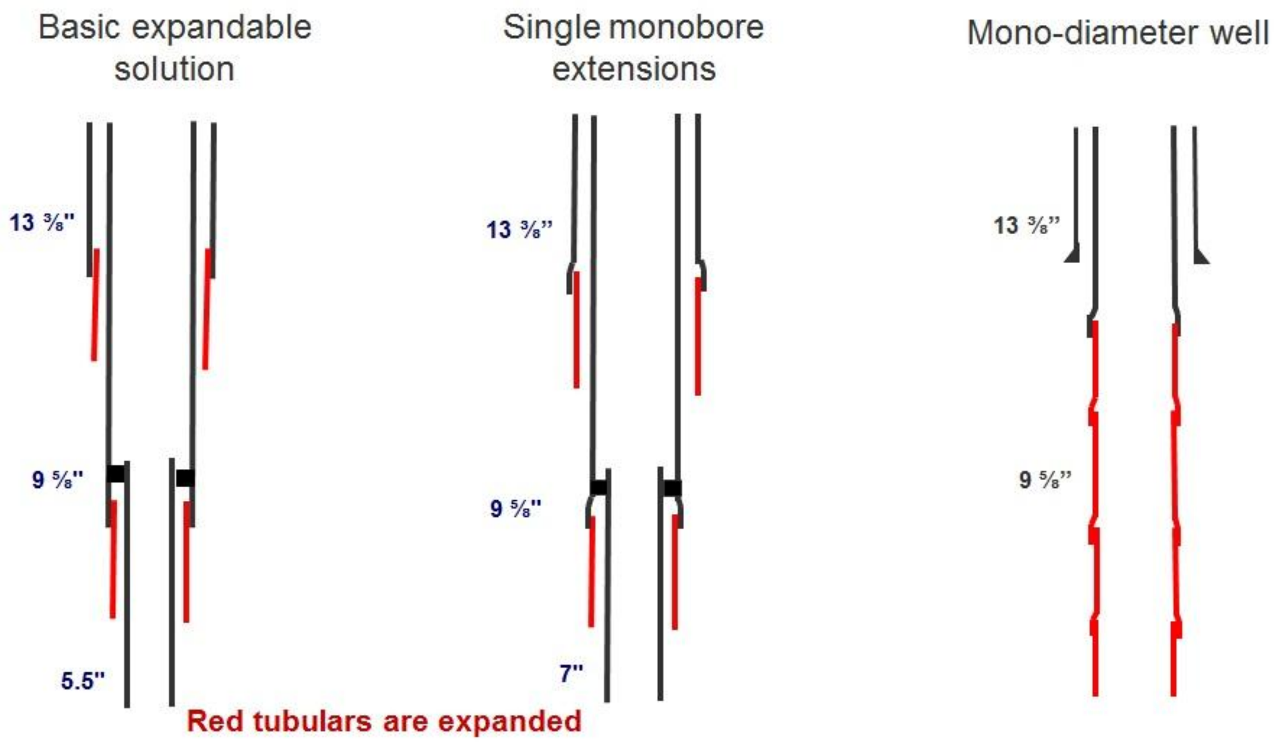


Figure 23: Expandable liner solutions [38].

The monobore solution will provide the same inner diameter as the previously set casing, while the basic expandable solution will result in a loss of ID. Several monobore extensions in a series can provide a mono-diameter well. There exist different expandable liners for cased-hole and openhole applications. The expandable liners used in cased-holes can be used for repairing damaged casing. There are open hole cladding systems for isolating problems zones, and other solutions for attaching the liner on the previous casing. The liner systems illustrated in Figure 23 are attached to the previous casing, and this is the type that is considered in this study.

Use of expandable liners can be either as a basis of the casing design or as a planned contingency. Expandable open hole systems can be ran when unforeseen problems are encountered. These problems may be related to unstable formation, over- or under-pressured formation, loss of circulation and pore pressure/fracture gradient. However, there is always a risk of getting stuck when running in with the liner. This could result in a costly sidetracking operation.

The most recent development is related to monobore expandable liners. If this liner is set successfully, drilling can presume with the same inner wellbore casing size as before. An oversized shoe needs to be incorporated in the previously set casing shoe to have this possibility. This shoe provides a recess for the expandable liner to be expanded into, so that no hole size is lost [39]. The primary concern for usage of expandable liners is the limited collapse strength. The expansion process will reduce the collapse strength. A study by Aguiar showed that 10% expansion yielded an average of 50% reduction of the tubing's collapse strength [40]. The rate of expansion can typically be 30 meters per hour [41].

2.12.1 9 5/8" LinEXX system

The first commercial monobore expandable liner extension system was the 9 5/8" LinEXX system developed by Baker Oil Tools. BP was the first operator to use this system in a commercial well when it was installed in BP's Arkoma asset in September 2006 [41].

Some LinEXX features and benefits are [41]:

- A recess casing shoe that is run on the parent casing.
- An expandable liner hanger that is set into the recess shoe and ties the expandable liner to the parent casing string.
- A top-down hydraulic expansion system that prevents losing the hole if the expansion cone should be blocked.
- A retrievable guide shoe that guides the expandable liner into the open hole.
- Only one trip required to set the hanger, expand the pipe and retrieve the guide shoe.
- Cementing is performed after expanding.

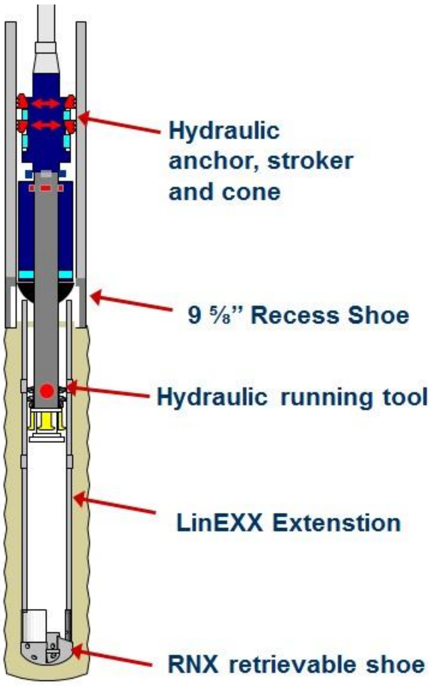


Figure 24: LinEXX system [38].

2.12.2 Advantages and disadvantages

Some potential advantages and disadvantages with expandable liners are listed in Table 9.

Advantages	Disadvantages
Can isolate trouble zones	Relatively low collapse rating
Extended reach drilling with monobore	Requires an oversized shoe in parent casing
Fewer casing strings may be required	Under-reaming of the section where the liner is run may be required
Possibility for larger production tubing may enhance productivity	Takes longer time to run than conventional liner
Can be used in horizontal wells	Risk of getting stuck with the liner.
Can be used as a contingency	More expensive than conventional liner
Less steel consumption	

Table 9: Expandable liner advantages and disadvantages.

2.13 New technologies

The technologies presented in this chapter have not been commercialized.

2.13.1 Combination of expandable liner and drilling liner

The concept of drilling with an expandable liner can both save time and provide a larger diameter of the production casing compared to conventional drilling. In addition to this the liner may mitigate problems with lost circulation and wellbore instability. Because drilling liner and expandable liner operation procedures are quite similar, it may be possible to combine the two technologies into one operation. It should be possible to run this operation in one or two trips. One trip if a drilling-expandable BHA is developed or two trips if the BHA has to be changed with the expansion assembly [34].

There are several possible applications for this combined technology. It can be used to drill through trouble zones, and reduce the risk of having problems with lost circulation and kicks. The technology may be used in wells where higher production rates are needed, since there is a possibility to maintain the casing ID after casings are set. A feasibility study presented in the paper "Feasibility Study of Combining Drilling with Casing and Expandable Casing" presented by Shen and Aadnøy (2008) concluded that it should be possible to combine these technologies. There is however challenges on tools and strength of post expansion materials that needs to be solved before this is accomplished [34].

Some possible advantages and disadvantages with combining expandable liner and drilling liner is listed in Table 10.

Advantages	Disadvantages
Can isolate problem intervals	Low collapse rating after expansion
Liner is in hole when entering problem zones	Rating may be too low for handling experienced drilling torque
Can reduce NPT	Technology not available at the time
Mitigate problems with lost circulation and wellbore stability	
Possibility too maintain ID after setting casing	

Table 10: Possible benefits and disadvantages with combining drilling liner and expandable liner.

2.13.2 Lining while drilling method

This is a suggested method for sealing the wellbore wall while drilling that is patented by BP. The main components in the concept are illustrated in Figure 25. The main goal is to isolate trouble zones and thereby prevent loss of circulation. The sealing material is a cylindrical gathered pack of flexible tubing (6) located in a receptacle (5). A radially expandable locking means (8) is used to lock the tubing to the wall. Further drilling will withdraw flexible tubing from the gathered pack and form a liner in the wellbore.

The locking means is radially expanded at the wellbore when a loss zone is entered, to start the lining process. The flexible tubing is suggested to have a thickness of 0.1 to 2 mm, and a diameter that corresponds to the inner diameter of the wellbore. The patent description suggests that it may be feasible to have a flexible tubing length of 9 to ~1500 meters.

Some possible advantages and disadvantages with the patented lining while drilling method is listed in Table 11.

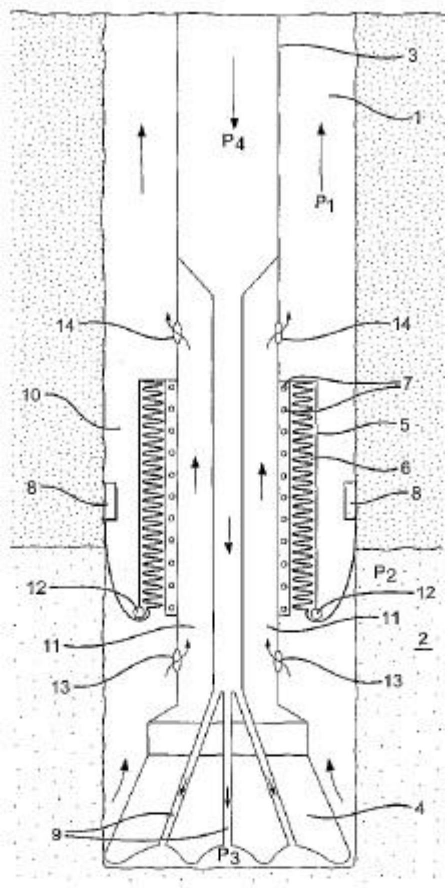


Figure 25: Lining while drilling

Advantages	Disadvantages
Islolate problem zones	Technology not available at the moment
Flexible tubing in place before problems develop	Complex technology
Reduce NPT	

Table 11: Advantages and disadvantages with new proposed lining while drilling method

3 Statoil field experiences

3.1 Depleted HPHT reservoir drilling: Kvitebjørn

Kvitebjørn is a HPHT gas/condensate field located in block 34/11 in the northern North Sea. Water depth is approximately 190 meters. The reservoir consists of sandstones in the Mid-Jurassic Brent group with the top reservoir, Tarbert, located at 4070 m TVD. The reservoir temperature is 155 °C while the initial pore pressure was 775 bar, and the initial fracture pressure 875 bar. Drilling operations started in September 2003, and the production was initiated in October 2004 after drilling and completing the two first wells. Originally, eleven development wells was planned to be drilled. The ninth well, 34/11-A2, was to be the last conventionally drilled well. During drilling of this well zones with 170 bar of depletion was encountered, which resulted in massive losses. The drilling had to be suspended, and the well was eventually abandoned. It was decided to reduce the production to reduce the rate of depletion. The production on the Kvitebjørn platform was reduced by 50% in Desember 2006, and then shut completely down in May 2007 when the depletion approached 200 bar [42].

Planning with respect to drilling in a depleted reservoir had been initiated already in 2002, and a “basis of design” was completed in December 2006. A toolbox with several different techniques was developed to mitigate the small drilling window caused by the depletion. The strategy and “basis of design” stated that the bottom hole pressure (BHP) always should exceed the pore pressure with an ambition to control the BHP with an accuracy of at least +/- 5 bar. Well control incidents should be managed with the rig’s 15 k BOP, and that the wells should be in hydrostatic overbalance before handling of BHA while tripping. It was decided to use managed pressure drilling with a rotating control device combined with a continuous circulation system to control the applied bottom hole pressure. A Balanced Mud Pill was going to be used to bring the well in overbalance before handling the BHA. This reduces the ECD effect compared to displacing the entire well at TD. In addition to this was designer-mud selected to increase the drilling window. The usage of several technologies reduces the dependency on each of the individual technologies [43].

There was not much experience with MPD in HPHT environment from previous operations. Feasibility studies concluded that an accurate automated choke control in addition to a continuous circulation system should be used to compensate for BHP variations. The study also showed the benefits of using a continuous circulation system [44]. An advanced dynamic flow model running in real time was required to be able compensate for BHP variations with the automated choke. The choke is manipulated and the back pressure adjusted to keep a constant BHP. The continuous circulation system permits full circulation during connections. This makes it possible to control the downhole temperature profile and achieve good hydraulic stability. The CCS also makes it possible to do connections without losing the pressure contribution from the circulation in the well. A test of total blackout on the rig showed that the system did not manage to trap pressure. The choke controller was changed to PID (Proportional Integral Derivative), the measurement on pumps where changed from SPM to RPM-measurement and a logic that closed the choke when the pumps stopped were installed. The result of these changes was that all existing backpressure and most of the ECD were kept.

It was decided to use a Cesium/Potassium Formate mud with a controlled particle size distribution and blend of calcium carbonate, graphite and nut plug. This combination showed fracture gradient enhancement properties in laboratory tests done with reservoir sandstones from Kvitebjørn. Initially particle dropouts were a big problem during periods without circulation. This has been resolved by adjusting the particle concentration and focusing more on fluid suspension properties. Suspension properties were initially sacrificed for low ECD properties. The wellbore strengthening properties were found to be important due to the reduced fracture pressure in the reservoir [42].

The Balanced Mud Pill (BMP) was pumped in to make the well hydrostatically overbalanced before handling the BHA. It was decided that a BMP is required because it is not satisfying to trip out of a live HPHT well with only mechanical sealing elements for pressure control. The alternative to make the well hydrostatically overbalanced at TD was not considered to be satisfactory. Two reasons for this are that it would have produced much higher over-pressures on the reservoir and that the surge effects would be larger without the MPD compensation. By using the BMP the trip can be completed conventionally. It is time-consuming to do this, but it is considered to be the most satisfactory practice. The BMP is also used when running in liner. A cross-linked isolation mud pill in Caesium/Potassium Formate base is used to support the heavier mud placed above the lighter drilling mud. This is done to avoid heavy mud of “sinking downhole” during the tripping operation. Extensive laboratory and rig tests were done to confirm the properties of the BMP and cross-linked isolation mud. The isolation pill was proven to be stable, even when non-optimal placement was required after a twist-off under drilling of well A-13. The BMP on A-13 consisted of 2.08 sg heavy mud, 2.08 sg Hi-viscosity pill and a 1.84 sg cross-linked pill [42].

3.1.1 Well A-13

A-13 was the first well that was drilled with MPD on Kvitebjørn. The schematic for the surface equipment used is shown in Figure 26. The High Pressure Blowout Preventer (HPBOP) used on Kvitebjørn needs to meet the requirements for HPHT wells. In this case an 18 ¾” 15-K BOP with four rams and one 10K annular was used. The MPD control stack consisted of an 11” 5-K rotating control device, a 13 5/8” stripper ram and a 13 5/8” 5-K stripping annular. Dual redundant chokes were selected to mitigate choke erosion problems. Pressure relief valves were installed in the return flowline. The primary relief valve upstream of the choke manifold is automatically controlled by the choke control software. It is automatically adjusted to be 5-10 bars higher than the choke set-point pressure. The experience with this valve is that is it has been proven useful and performed as it should. A mass flowmeter was installed with a bypass to make it easier to clean or unplug it. The massmeter showed high quality data, but has only used for monitoring during the drilling of wells on Kvitebjørn. An auxiliary pump was installed to provide a continuous mud flow and the desired back-pressure. This allows full pressure control over the annulus regardless of the main pump. The auxiliary pump has proven itself useful and important, but there were some issues. Pump reliability, pump pressure fluctuations and pump rate optimization were some issues that needed more attention. The issues have been solved on later operations by installing a soft-started on the pump, and controlling the choke manually in some situations.

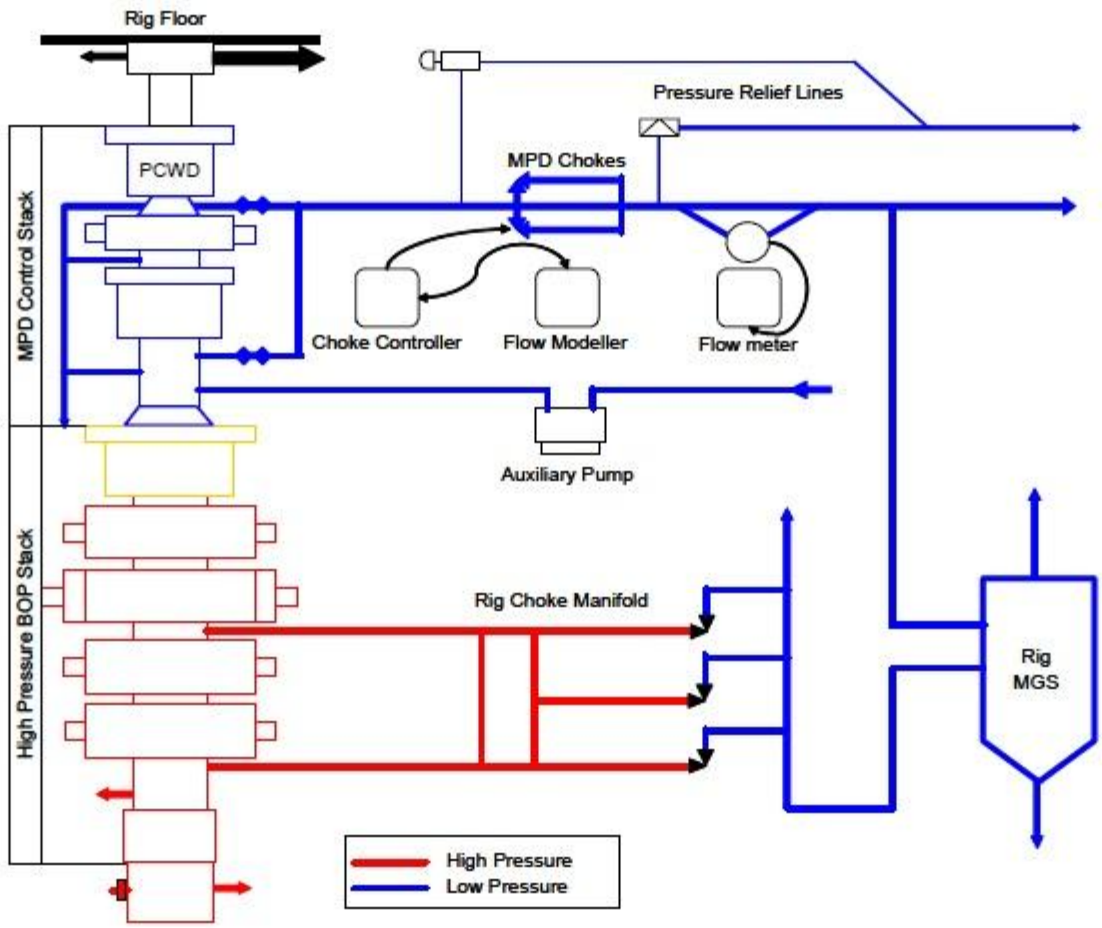


Figure 26: Surface equipment schematic on Kvitebjørn [42].

The initial pressures were known from drilling of previous Kvitebjørn wells. The risk of drilling into undepleted zones in the reservoir was considered to be high and there was also a significant uncertainty in the depleted fracture gradient. The pressure strategy was to always remain 0.02 sg above the expected maximum pressure for reservoir still to be drilled and always stay 0.02 sg above the pore pressure of the reservoir drilled. A key tool to be able to do this is the formation pressure while drilling (FPWD) tool. By including this in the BHA it is possible to take formation pressure tests at any time without tripping or stopping circulation. The measured formation pressures and pressure strategy when drilling well A-13 can be seen in Figure 27. The BHA also consisted of an annulus pressure and temperature sensor. Three tested float valves, a multi-function circulation sub and a tapered drillstring consisting of 4 ½" and 5" drillpipe (for handlig the expected 55 KNm of drilling torque) were also used.

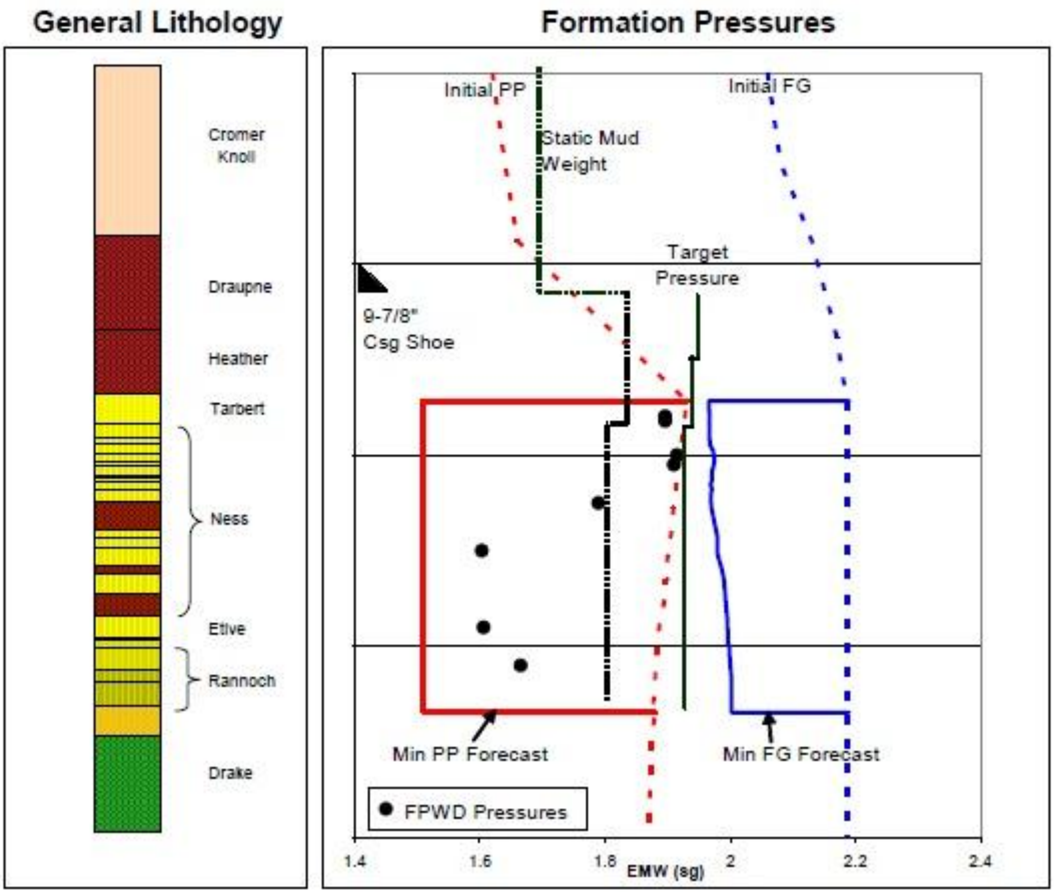


Figure 27: Formation pressure illustration (A-13) [42].

Well A-13 was drilled conventionally down to 6101 m MD (4093 m TVD) where the 9 5/8" casing was set. The well was then displaced to 1.84 sg (50°C reference temperature) Caesium/Potassium Formate drilling fluid. This gave a static underbalance of 31 bar. The MPD system was then installed and activated. A FIT was performed to 2.05 sg after drilling out the casing shoe and 23 m of the new formation.

The mud-weight was reduced from 1.84 sg to 1.81 sg at 6197 m MD because the ECD was 8-10 bar higher than the forecast. A washout of the drillstring was detected, and the drillstring parted at 1900 m during the trip out. The well was then shut in on the HPBOP with an apllied shut in casing pressure (SICP) at 42 bar to compensate for the loss of ECD and back-pressure. There was not registered any net influx volume during this operation. A BMP with 2.12 sg heavy mud was used to make the well hydrostatically overbalanced. An illustration of this situation is shown in Figure 28.The CCS and chokes were used to maintain control of the well when pulling back during fluid placement. The fish was recovered after several fishing trips. During the fishing operations a problem with particle dropouts caused some circulation problems. The well had to be cleaned before the drilling could presume. More attention to particle suspension properties and the mud system's capacity has solved this challenge.

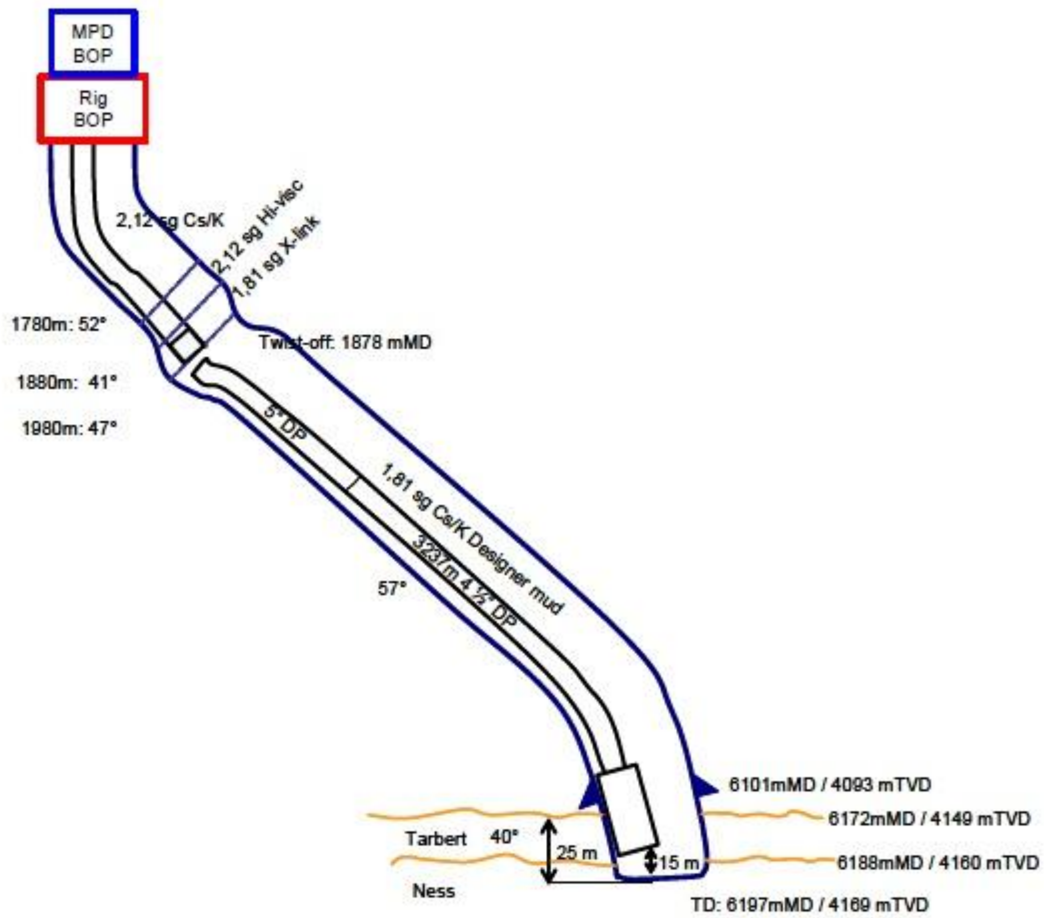


Figure 28: Schematic of drillstring failure (A-13) [42].

The well was then drilled in MPD mode to target depth (TD) at 6351 m MD. The average drilling parameters is given in the table below. The largest depletion seen was 124 bar. The downhole pressure was maintained at 1.92 sg with a choke pressure contribution of 14-16 bar.

ROP	10 m/hr
Mud pump	1000 L/min
Auxiliary pump	580 L/min
RPM	100
Torque	45-58 KNm

Figure 29: Average drilling parameters during drilling of reservoir section in MPD mode (A-13)

The MPD system was able to adjust the downhole pressure with increments within 0.4 bar during periods of stable drilling and circulation. The CCS system made it possible to make connections with no significant change in circulation rate and less than 2 bar pressure fluctuations downhole. Connections were also made without any downhole circulation by increasing the choke back pressure as the ECD is reduced to zero. Fingerprinting was found to be the best method for identifying drilled gas which produced a 400 to 500 liter pit gain beginning 1 hour before the gas reached surface.

3.1.2 General experience

The same MPD technology as used for drilling well A-13 has also been successfully applied to the drilling of A-12. During this operation pressures encountered varied from initial pore pressure to 130 bar of depletion. The rig up, commissioning and testing time were greatly reduced on A-12 from A-13. There were no serious incidents or mud loss during drilling of the reservoir section. The conclusions from drilling these two wells were:

- Extensive testing was necessary to satisfy the required demands.
- Experienced one of the “worst case scenarios” (twist off) and was able to deal with it.
- Able to drill with a bottomhole pressure within +/- 4 bar.
- Drilled two wells that could not have been drilled without MPD.
- The MPD software, equipment, personnel, procedures and overall concept performed according to expectations and proved satisfactory.
- The technology is recommended for drilling wells where excessive depletion is expected.

4 more wells have successfully been drilled with the same MPD system after the drilling of A-12. One well has also been drilled without the CCS installed.

3.2 Lost circulation materials

Lost circulation is a major contributor to NPT during drilling operations. 270 lost circulation incidents were reported in Statoil from 2005-2011. About 100 of these occurred during drilling. In total was around 40 000 m^3 drilling fluid lost, and over 3100 hours was spent on remedial activity [11].

A solution to prevent/stop lost circulation may be to pump particles into the well. There are several applications of using particles in Statoil [11]:

1. As a prevention, when there is a risk of lost circulation.
2. As a particle pill in order to increase/repair low FIT/LOT/XLOT.
3. As a particle pill before POOH.
4. As LCM pill when lost circulation is experienced.

The risk of lost circulation is considered to be high when drilling in HPHT reservoirs and depleted reservoirs, since the operational window usually is small.

The general experience from use of lost circulation materials in Statoil is that the concentration should be as high as possible and the particle-size range wide, with large particles included. Small and subsequent treatments have shown less effect. The best way is to cure the problem area the first time. By using high concentrations and relatively large particles, the goal is to bridge across all unknown fractures and openings, not only the expected ones. There can be a large uncertainty related to the presence of fractures, faults, weak layers etc. The strategy is to deal with this uncertainty by having a high concentration and including large particles. In many cases this strategy may be unnecessary, but the downside of doing it is considered to be small. This also creates standard recipes and procedures, which is beneficial with respect to administration and logistics. On the other hand, if the area is well known, the concentration and size range can be adjusted based on the previous experiences.

There are different types of graphite and calcium carbonate available. The most expensive type of graphite can withstand very high pressures without breaking. The standardized recipe is based on the following principles [11]:

- 30/70 to 70/30 distribution of $CaCO_3$ and graphite.
- Concentration for prevention is normally between 30 kg/m3 to 140 kg/m3.
- Concentration for pills is minimum 350 kg/m3.
- Particle distribution, fine to coarse: Standard: d90 ~1000 microns.
- High risk particle distribution: d90 ~1600 microns and more

Statoil does not apply the stress cage approach actively. The general rule in Statoil is to always have a well pressure that is lower than the fracture pressure. Simulations have shown that an increase in hoop stress demands that 2-3 parallel fractures are created and evenly distributed around the borehole wall. Achieving this is not considered to be very likely, and to drill with this strategy is not recommended in Statoil.

The costs of LCMs are considered to be low with respect to the benefits that are achieved from using them. Statoil have a ‘best practice’ where it is recommended to use graphite and $CaCO_3$ as lost circulation materials. However, they are constantly looking for new technology and methods.

Table 12 shows some experiences with drilling with high overbalance in depleted reservoirs [45]. An interesting observation is that the highest theoretical overbalance with respect to the fracture pressure amongst these five examples is achieved without using any LCM additives. This is considered to be a good illustration of the uncertainties related to determination of fracture gradients rather than the effect of LCMs. The uncertainties make it difficult to quantify the effect of the LCMs.

Rig	**Statfjord B**	**Sleipner A**	**Kristin (HPHT)**	**Tune (Oseberg sat.)**	**Gullfaks B**
Well	33/12-B-13 A	15/9-A-14 T4	6506/11-N-2 H	30/8-A-21 AH	34/10-B-37
Reservoir	Brent	Draupne	Upper Jurassic	Brent	Brent
Formation	Rannoch	Draupne sst.	Garn sst.	Tarbert	Ness 2C
Section	6”	8 ½”	8 ½”	8 ½”	8 ½”
Date logged	27.04.2005	01.04.2008	22.03.2008	05.04.2009	30 - 31.01.1997
Rererance depth [mTVD RKB]	2683	2777.1	4699.3	3402	1854
Reservoir press. [bar]	95	89.4	698	176.4	145.1
Initial res. press. [bar]	393.5	298.4	898	516	304.2
MW [sg]	1.565	1.32	1.96	1.57	1.50
Hydrostatic overbalance [bar]	318	269.6	206	347.6	127.9
ECD [sg]	1.625	1.438	2.05	1.63	0.8/1.0
Dynamic overbalance [bar]	333	302.6	247	367.6	152.9
Mudsystem	OBM-XP07	OBM-Warp	OBM-XP07	OBM-Interdrill + WBM-NaBr	WBM-Formpro
LCM additives	-15 kg/m^3 G-seal (graphite) -15 kg/m^3 $CaCO_3$ medium Total 30 kg/m^3	-15 kg/m^3 graphite -15 kg/m^3 $CaCo_3$ Total 30 kg/m^3	-20 kg/m^3 Steelseal Fine (graphite) -20 kg/m^3 Baracarb 25 ($CaCO_3$) -60 kg/m^3 Baracarb 50 $CaCo_3$ Total 100 kg/m^3 Maintained with unknown amounts of: -Baracarb 150 -Steelseal Regular	There are no reports indicating use of LCM	No LCM additives reported as loss prevention. The basic NaBr contains CaCO3 as filterloss material. Idlube was added to the NaBr, resulting in a reduction of mudweight. This was compensated for by adding huge amounts of CaCO3. How much is not reported.
ECD overbalance wrt theo.frac. press. [bar]	44	0.2	60	127	90
ECD overbalance wrt theo. min hor. stress [bar]	83	27.5	83	Not included in the prognosis	Not included in the prognosis
Comments	No experienced lost circulation problems	No experienced lost circulation problems	The mud system was built with 100 kg/m3 of graphite and CaCO3. During drilling the mudsystem was maintained with unknown concentrations of Baracarb 150 and Steelseal Regular. No lost circulation problems were experienced.	No lost circulation was experienced	No lost circulation problems were experienced

Table 12: Statoil experiences from drilling with high overbalance.

3.3 Underbalanced drilling

Statoil has only applied underbalanced drilling once, in well C-5A at Gullfaks. The Gullfaks field is located in the northern part of the North Sea. The operation took place in July 2004 and was the first underbalanced operation on the Norwegian continental shelf. Underbalanced drilling was chosen as an option due to a small drilling window. Variable pressure regimes were expected, resulting in a large uncertainty in pore pressure. Seawater injection was the main driver for production from at the field. The injection of water resulted in a high pore pressure in the Shetland cap rock, making it impossible to drill trough conventionally. Severe pressure depletion was experienced in the reservoirs below [46]. The situation is illustrated in Figure 30.

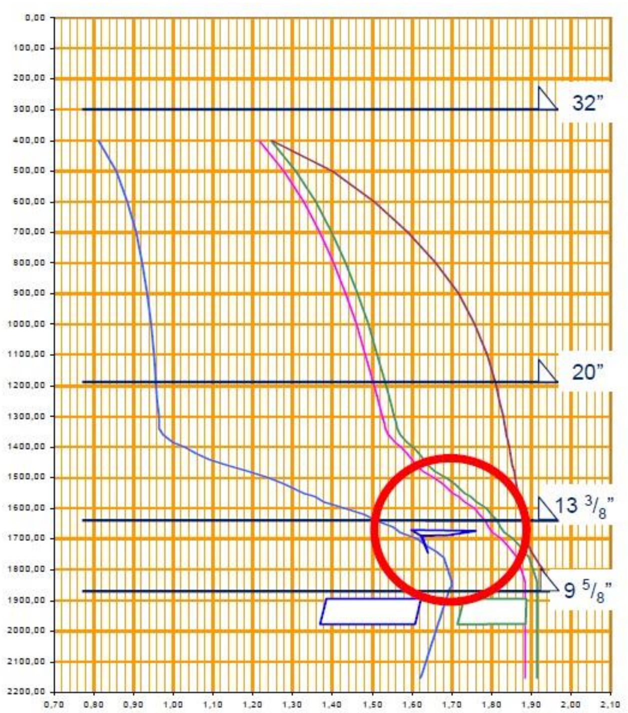


Figure 30: Increased pore pressure in the cap rock due to water injection [46].

Underbalanced drilling methods were successfully implemented on Gullfaks. There were challenges with implementing the technology, since rules and regulations specified for underbalanced drilling did not exist in Norway. Statoil had no previous experience with the technology. Another challenge was to get the partners to approve the project because it was expensive to implement the technology. The investment cost of the whole project had to be written off on one single well, because the field was in tail production and future wells were not certain to generate enough income to support the cost of introducing the technology. The project was approved after a detailed study [47].

The operation was successful. 50 meters of the well was drilled underbalanced and the well was cemented with underbalanced fluid, as the first well in the world. It was also the first underbalanced operation on an offshore platform without burning hydrocarbon gas. Advanced dynamic models were found to be very useful, and it was noted that calibration of the models is important during operations.

3.4 Managed pressure drilling

Statoil has experience with managed pressure drilling from several fields and rigs. An overview of experiences with different MPD variations from 2003 to 2011 is given in Table 13 [48].

Technology	Field	# Wells/section	Year
CCS	Kristin	2	2006-2008
	Kvitebjørn	5	2007-2011
MPD (Manual)	Gullfaks	4	2004-2006
	Grane	6	2007-2008
MPD (Automatic)	Kvitebjørn	5	2007-2011
	Gullfaks	2	2009-2010
	Oseberg C	3	2010-2011
Dual gradient	Mobile drilling units	~30	2004-2011

Table 13: Statoil MPD experiences, 2003-2011

The technology has proven itself useful for drilling in formations with small drilling windows. The experience from Kvitebjørn show that it is possible to maintain the bottomhole pressure within ±4 bars with MPD technology installed.

Statoil has very good experiences overall with the MPD technology. Two serious well incidents have taken place during the MPD operations. The mentioned drillpipe twist-off at Kvitebjørn, and a kick in well C-6 at Gullfaks. A leaking casing resulted in a kick while the well was drilled in MPD mode. Drilling in MPD mode may have had a positive or negative effect on the incident, but the incident was not directly related to MPD.

The cost of implementing the MPD technology is considered to be relatively high. A rough estimation for a standard well is 23 million NOK, including personnel and equipment. The rig cost comes in addition to this.

3.5 Casing/Liner drilling

3.5.1 Casing drilling

Statoil has not much experience with casing drilling. They are looking at it in a simplified design project, but this is only a development project at the moment.

3.5.2 Liner drilling

Statoil is currently not using drilling liners without steering ability. It has been looked into a couple of times, but not used.

The steerable drilling liner (SDL) systems were first tested at the Baker Hughes Experimental Test Area in Oklahoma. These tests concluded that both the 9 5/8" and 7" systems were stable and robust systems, with good steering ability. Statoil has then drilled two times with SDLs, once with a 9 5/8", and once with a 7". Two new wells are planned to be drilled with SDL during the summer of 2012, one on Statfjord and one on Grane. There are also two other possible SDL jobs coming up during the year, but these have not been confirmed yet [36].

9 5/8" SDL pilot

The 9 5/8" SDL was used in well A-13 A on Brage in July/August 2009. The first 3873 meters of the well was drilled conventionally, including the first 979 meters of the 12 ¼" hole section. Then the 12 ¼" drilling assembly was pulled and a 1229 m long liner made up and used to drill the remaining 180 meters of this section (See Figure 31). It was decided to do this as a risk reducing measure since this was the first commercial operation in the world with the SDL system. The SDL system had to be reamed down the last 220 meters to 3873 m MD due to tight hole. The average drilling parameters for the conventional drilled part just before 3873 m MD, and the part drilled with SDL are given in Table 14 [32].

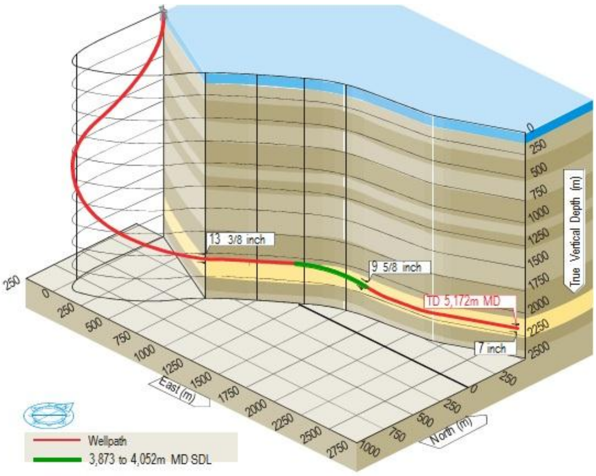


Figure 31: Well trajectory - liner drilling section showing as the green part [32]

Parameters	12 ¼" Autotrack	9 5/8" SDL
Suface RPM	130-180	20-30
Flow [lpm]	4000	2300
SPP [bar]	231	220
ECD [sg]	1.448-1.453	1.52-1.535
MW [sg]	1.42	1.42
Surface torque [kNm]	33-38	40-50
WOB [ton]	8-14	5-15
ROP [m/hr]	12	4-12

Table 14: Drilling parameters conventional drilling vs SDL [32].

The system proved to have a good directional control. A 3 degree dogleg with 50% buildforce was achieved. The experienced ECD's was approximately as simulated, and this was also the case for the surface torque. The additional weigh of the liner compared to drilling conventional can provide a difference of up to 20 kNm in torque for a 1200 meter long liner. Using stronger drillpipe must therefore be considered when planning a well with long liner lengths. There was also an expected increase in ECD because of the reduced annulus in the liner part of the string. The magnitude of

ECD and torque effects depends on the length of the liner. Some whirl was experienced before the stabilizers entered new formation. In this case the BHA had to be reamed to bottom. The pilot BHA was 6 ¾", and not stabilized in the 12 1/4" openhole. This led to lateral vibrations, ranging from the lowest to the highest vibration level (0-7). Reducing the flow rate and thereby the bit RPM helped slightly, but lateral vibrations must be expected during reaming operations [32].

The average ROP was 5.7 m/hr, but it was controlled to mitigate operational risk. The maximum ROP was the same as the average ROP when drilling conventional. Overall the 9 5/8" pilot was considered to be a great success based on excellent drilling dynamics and directional control. However, the pilot revealed some weak points with the SDL system. The running tool unintentionally parted during drilling, leaving the inner string and liner downhole. Two fishing trips were executed before drilling could proceed. The liner had now been stationary for almost five days, making the operational time very high. It took some effort to free the liner, but after rotation and mud circulation was established, the well was successfully drilled to TD at 4053 m MD and cemented in place. All other system components worked as planned. The running tool has now been redesigned for use in future applications to prevent similar events. There was no documentation of any smearing effect.

7" SDL pilot

The 7" was successfully used to drill the entire 8 ½ section in well B-25 A on Statfjord. The 9 5/8" casing shoe was set at 3004 m MD, and the 7" liner was used to drill to 3182 m MD. Some operational parameters from this job are summed up in Table 15. There were no problems with the SDL system itself, but some survey problems were experienced.

Operational; plan vs actual		
	Plan	Actual
ECD	1,55-1,58	1,56-1,60
Torque	26,7 kNm	24 kNm
Other paramters		
WOB	3-5 tonne	
ROP	10-15 m/hr (20 max)	
DLS	3.5 deg/30m (3.9 max)	
Run review		
Circ hrs	Approx 30 (4 bit runs)	
Bit hrs	15	

Table 15: Operational data from drilling of 7" SDL pilot [36].

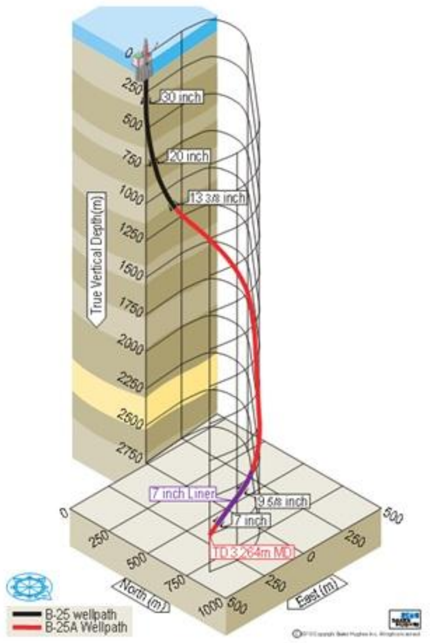


Figure 32: Well trajectory – liner drilling section showing as the purple part [36].

3.6 Expandable liners

Expandable liners are considered to provide a tool that can help face traditionally time consuming drilling challenges. Examples are high pressure gradients, losses and unstable formation. Expandable technology has been used on several fields in Statoil; Glitne, Gullfaks, Heidrun, Krakatoa, Oseberg, Snøhvit, Statfjord, Åsgard. The performed expandable liner jobs have showed good results. However, the experience with expandable tubing's is still considered to be limited. The largest challenges are considered to be the burst and collapse ratings.

The most commonly used expandable liner in general is the openhole liner from Enventure, which is a liner extension with some loss of ID. Statoil have installed 7 of these, while approximately 1200 have been installed worldwide. Cementing is optional, since it is possible to use expandable swell packers instead. It is normal to underream the hole. The liner is expanded bottom up by hydraulically drive a fixed cone upwards. The longest installed liner is 971 meters, and was installed on Statfjord in 2006 to isolate a loss zone in the 12 ¼" hole section. The liner was expanded from 11 ¾" OD to 12.140" OD. The Eventure liners come in several different dimensions. The largest liner has an OD of 16" pre-expansion, while the smallest has an OD of 7.625" pre-expansion. The yield and collapse strengths vary with the dimensions. In general, the smaller liners have a higher rating. The rating is also dependent on the expansion ratio. The 7.625" can have a yield strength of 6130 psi and a collapse strength of 2740 psi, after it is expanded to 8.427". Further expansion will reduce these numbers [38].

The 9 5/8" linEXX liner from Baker Oil Tools has not been installed for Statoil to date. However, it has been planned for as a contingency several times, and recess shoes have been installed on 7 occasions. 3 times on Kvitebjørn due to expected depletion effects, 1 time on Kristin due to unstable shale caused by depletion and 1 time on Antares due to a possibility of depleted reservoir. In addition have recess shoes been installed once on Huldra Exploration and once on Tyrihans for other reasons. It was not necessary to run the liner on any of these occasions. The mains reason for choosing the linEXX solutions in these cases was the possibility to continue drilling a 8 ½" hole after expanding the casing, and thereby maintain ID [38].

The burst rating for the linEXX is given to be 5000 psi, collapse rating 1880 psi and tensile rating 400 000 lbs. All of these numbers are pre-expansion numbers.

The cost of installing a lineEXX recess shoe is approximately USD 150.000, while installing 155 meters linEXX pipe (14 joints) costs approximately USD 700.000.

4 Gudrun and Gudrun Øst

Gudrun is a light oil/condensate field located in block 15/3 approximately 55 km north of the Sleipner fields, 10 km from the British sector. Elf became the first operator on the license (PL025) in 1969, and the field was discovered in 1975. Statoil took over operatorship in 1997, and the Plan for Development and Operation (PDO) for Gudrun was approved in June 2010. Two other discoveries have been made in relation to PL025 and the adjacent PL187 license. Both these licenses are owned by Statoil (75%) and GDF Suez (25%). The discoveries are called Gudrun Øst (Previously called Brynhild) and Sigrun. In the PDO Sigrun was mentioned as a possible subsea tie in to Gudrun, but the decision gate for this developing this is not yet passsed. In addition to these discoveries there is a prospect called Gudrun Sør Øst in the same area, where hydrocarbons are expected to accumulate (See Figure 33) [49].

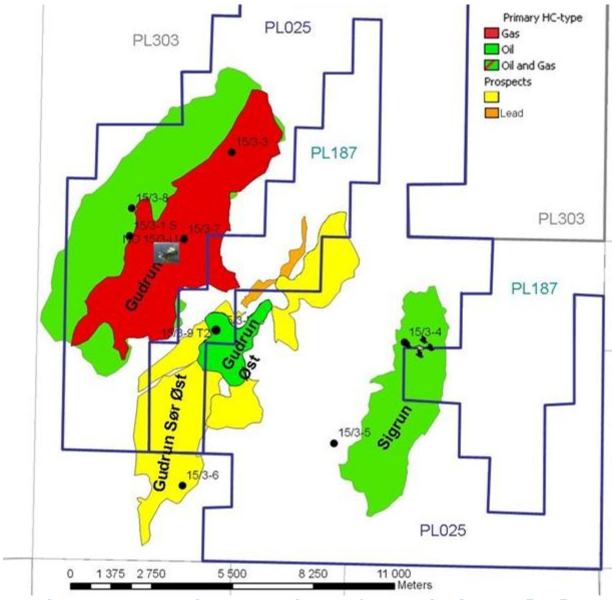


Figure 33: Gudrun, Gudrun Øst and Sigrun [53]

4.1 Gudrun

The Gudrun field consists of four sandstone reservoirs. These are called Draupne 3, Draupne 2, Draupne 1 and Hugin, from the shallowest to deepest reservoir. Draupne 2 is assumed to not contain hydrocarbons. The geology is described as complex, and the pressure and temperature as high (HPHT). The maximum temperature in the lowermost reservoir, Hugin, is about 170 °C with a reservoir pressure of 781 bars at 4440 m TVD MSL. The highest initial reservoir pressure is assumed to be about 814 bars in Draupne 1. See Table 16 for more details about the hydrocarbon-bearing reservoirs [50].

Formation	Draupne 3	Draupne 1	Hugin
Hydrocarbon type	Near critical light oil	Near critical gas condensate	Light gas condensate
Initial Reservoir Pressure [bar]	778	814	781
Max SIWHP (Wellcat) [bar]	558	607	648
Top Reservoir Depth [m TVD MSL]	4033	4332	4440
Saturation Pressure [bar]	355	380	725
Asphaltenes	Likely	Unlikely	Unlikely
Reservoir Temperature [^{o}C]	137	145	170
CO_2 [mole%]	10,6	8,1	3,9
GOR [Sm^3 / Sm^3]	500	795	7760
H_2S (ppm)	20	20	20
Wax Content [wt%]	4,6	4,3	14,9
Water production (m^3/D)	140	1600	700
Design Life (years)	15	15	15

Table 16: Gudrun reservoir properties

The recoverable reserves in Gudrun were estimated to be around 127 million barrels of oil equivalents in the PDO [51]. The reservoirs are planned to be produced with 7 production wells from a steel jacket platform. The water depth is about 109 meters, and the air gap 53.2 meters. The jacket has 16 well slots, and two spare sets of J-tubes for future satellites. The wells are drilled from a jack-up rig called West Epsilon. The conductor sections and the 20” casing sections of the wells were drilled before any further drilling was done. The topside is planned to be installed on the steel jacket platform at the location during the summer of 2013. The first well, A-5, has recently been drilled. 4 of the 7 wells are planned to be drilled in Draupne 3, 2 wells in Draupne 1 and 1 well in the Hugin formation. A part of the drilling strategy is to drill the deepest reservoirs first, so that these can start production early. The production was in the PDO not planned to start before all wells in that reservoir or deeper reservoirs have been drilled and completed. This is done to avoid the problems related to drilling in depleted HPHT reservoirs. Production is planned to start in the first quarter of 2014. To increase the recovery and the lifetime of the field, the strategy is challenged and the possibility to drill in depleted reservoirs is explored. An example of this is the planned well to Gudrun Øst [51].

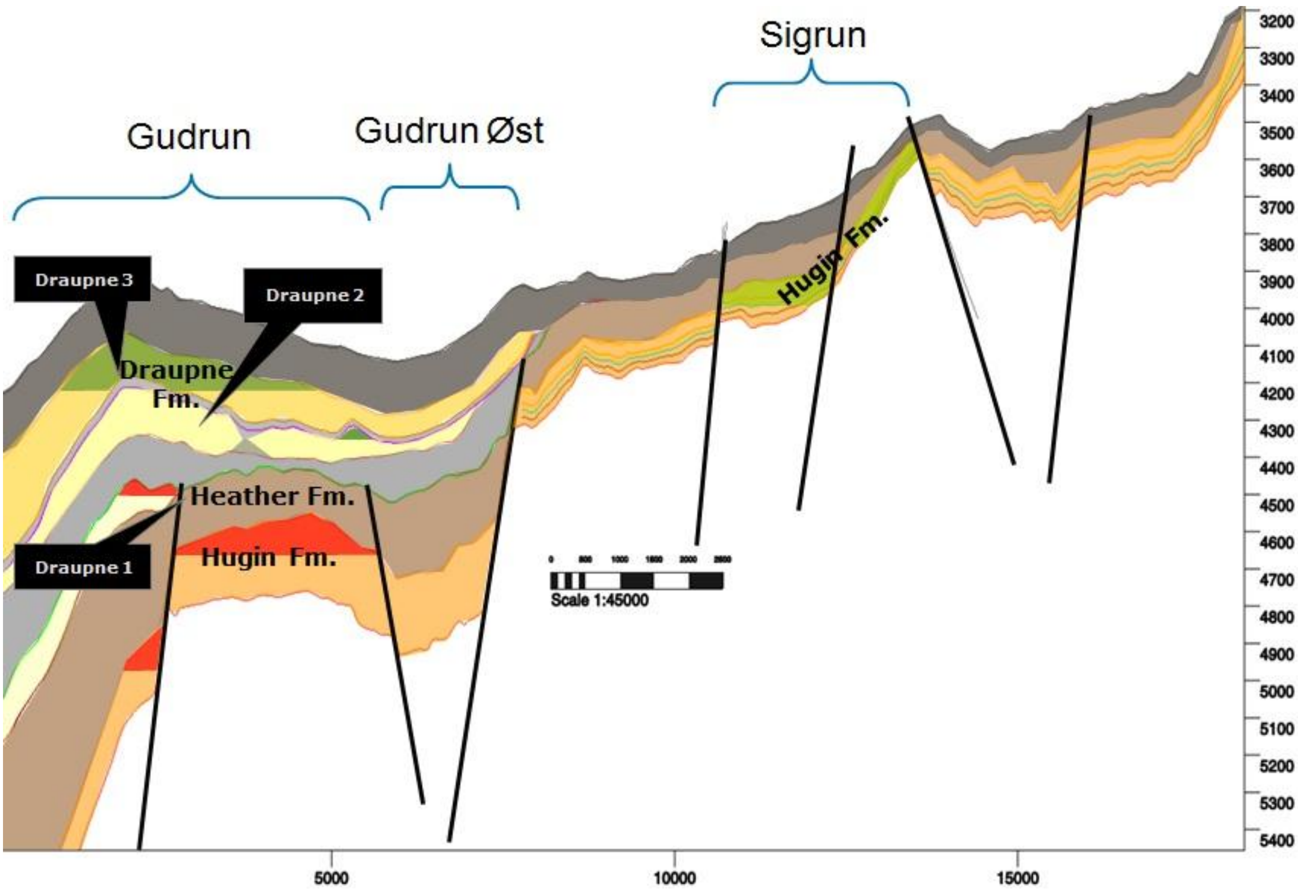


Figure 34: Gudrun reservoirs modified from [49].

4.2 Gudrun Øst

The strategy of drilling before producing from the reservoir does not include drilling of well A-14 to the Gudrun Øst target. Gudrun Øst is relatively a small discovery located approximately 4 km south east of Gudrun. The discovery has been integrated with the Gudrun project, and straddles PL025 and PL187 (See Figure 33). The mean recoverable volumes are estimated to be approximately 8.5 million barrels of oil equivalents. The target is located in Draupne 3. A 6988 meter long well, with a horizontal section in the end, is planned. The well trajectory is expected to cross several faults.

Drilling of well A-14 is planned to start immediately after completing the 7 first wells in the Gudrun-field. Due to the geological uncertainties, the uncertainty in the drilling schedule and progress of same, the severity of depletion is unknown. The seven first wells are planned to be drilled and completed by the end of 2014, and drilling of A-14 is therefore planned to start early in 2015. It is expected that there will be available production capacity on the Gudrun platform from 2016, because Gudrun is expected to have a short plateau production.

The main goal for well A-14 is to maximize the value of the Gudrun development by integrating the well with the Gudrun project. The main objectives are to drill the well before depletion effects make it impossible to drill, and to add value to the Gudrun project by utilizing spare production capacity. The original drilling strategy for A-14 is to have a simple, robust and cost efficient concept, using standard drilling concept based on the Gudrun-wells. However, depending on the grade of pressure depletion, it may be necessary to introduce additional technologies to be able to drill the well. There is a potential extra benefit from drilling well A-14 because a side-track may be drilled to the Gudrun Sør Øst prospect.

An illustration of the planned well trajectories for the Gudrun Øst well and the other Gudrun-wells is given in Figure 35.

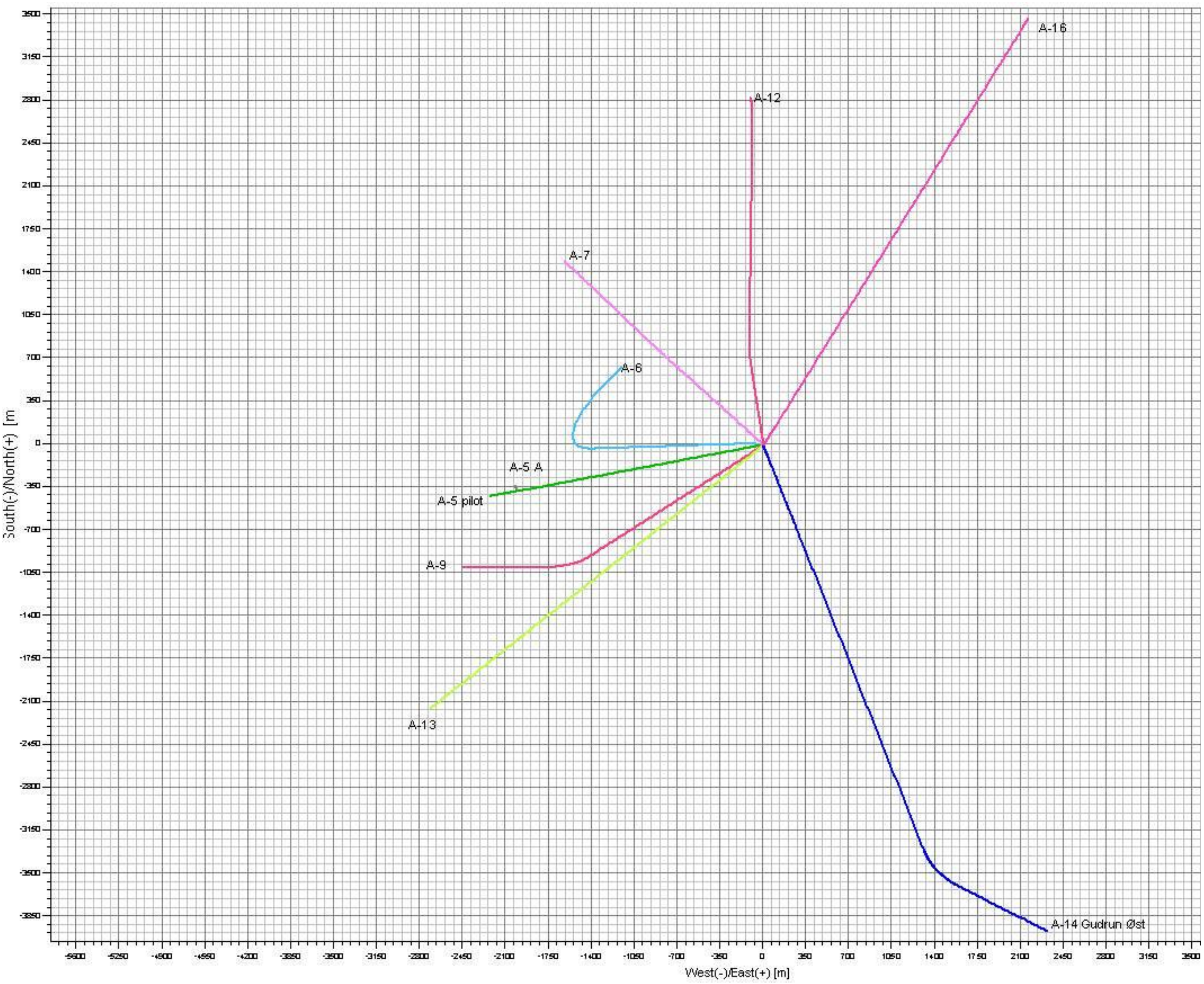


Figure 35: Well trajectories planned to be drilled in the Gudrun field development [52].

The main differences between A-14 and most of the other planned wells is that it is longer, has a higher inclination (up to horizontal), is drilled through several faults and is planned to be drilled into the reservoir after depletion has started.

The planned 17 ½" section on A-14 builds from an inclination of 30° to 60°, the 12 ½" section maintains the 60° inclination throughout the section, while the 8 ½" section is building from 60° to horizontal (89°). A-9 is the only other well in the Gudrun-development that is planned to be horizontal.

The borehole stability prognosis with initial reservoir conditions (prior to start of production) is illustrated in Figure 36. With these conditions the well can be drilled with a mudweight of 2.0 sg, and still be 12 points below the minimum horizontal stress, and 23 points from the fracture gradient with static conditions. 1 point is the same as 0.01 sg, when discussing pressure gradients.

Brynhild A-14 Draupne 3

Well: Brynhild A-14 Draupne 3   Airgap: 54 m Water depth: 109 m

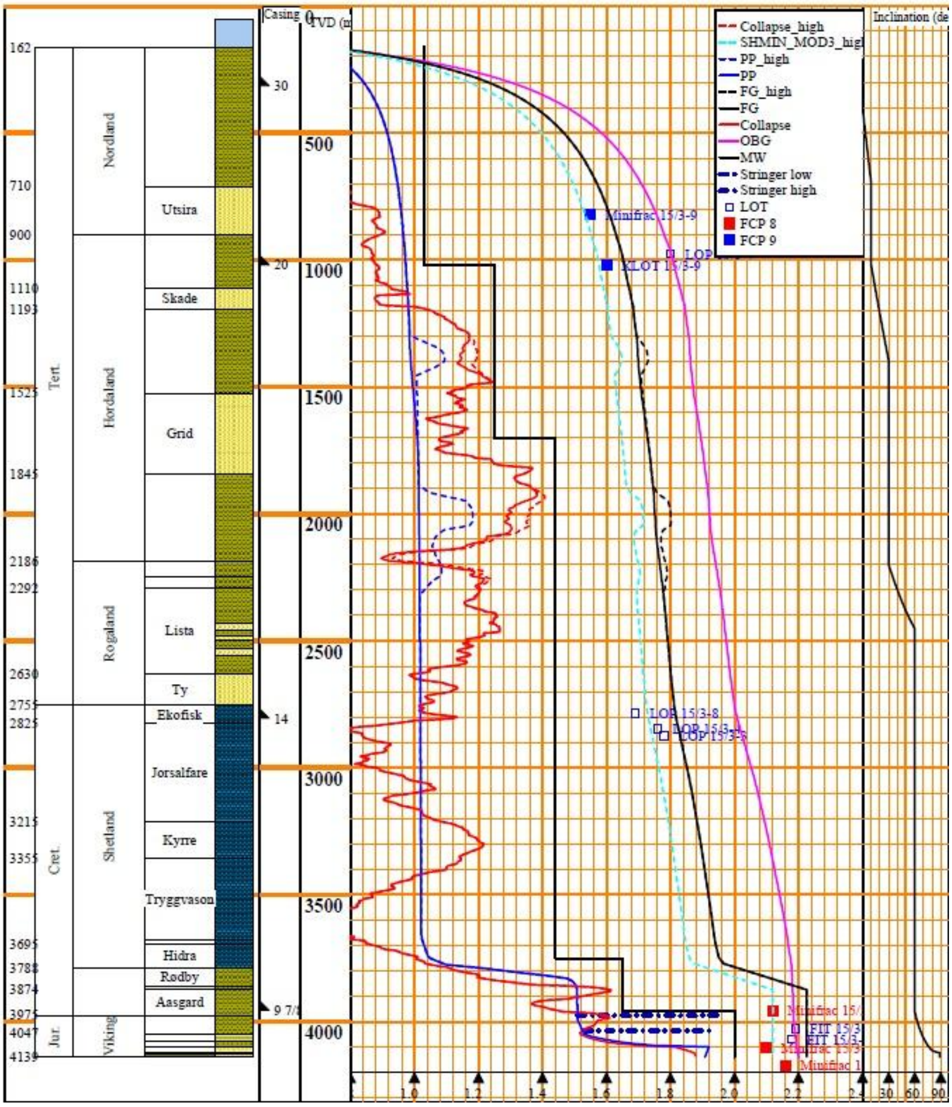


Figure 36: A-14 borehole stability prognosis prior to production start-up [52].

After production start-up in early 2014, Draupne 3 will experience pressure depletion. The magnitude of the effect depends on some uncertain factors. One of these is the reservoir’s channel directions. The channel directions control the pressure communication in the reservoir. A prognosis of two different cases is given in Figure 37. The base case is a depletion of 40 to 140 with 1 to 2 years production respectively [52].

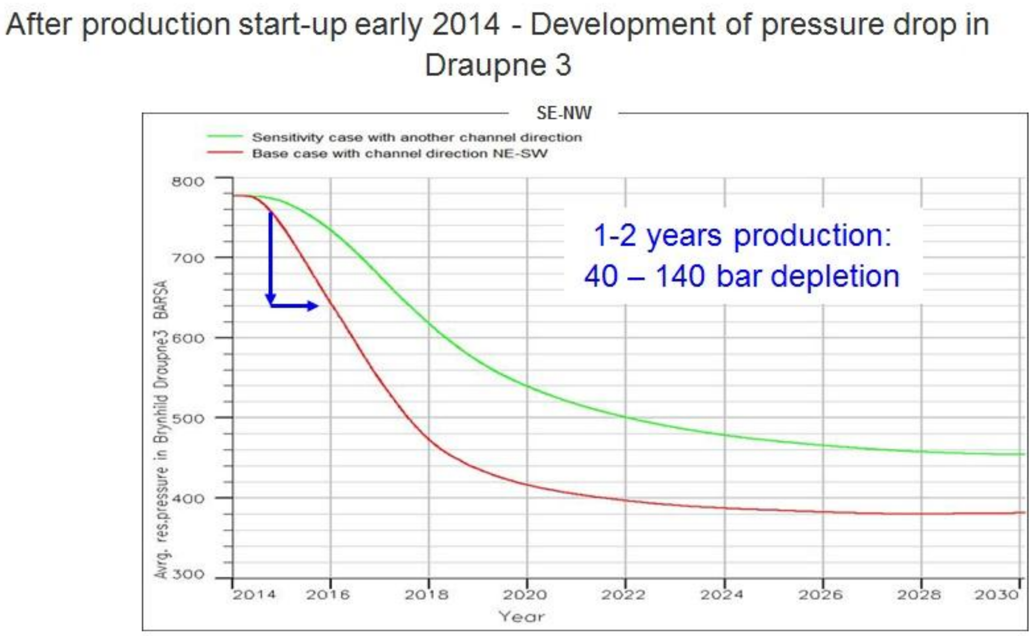


Figure 37: 2 cases of pressure depletion in Draupne 3. Base case is the red line [52].

The expected depletion effects are shown on the pore pressure plot in Figure 38. The fracture-depletion ratio is assumed to be 0.6 for Draupne 3. After one year with production is the minimum horizontal stress 6 points above the minimum required mudweight, and the fracture pressure 17 points above the required mudweight. After 2 years with production is the fracture pressure expected to be 5 points below the minimum required mudweight.

The mudweight was originally selected based on potential stringers in an overlaying formation named Draupne 4 (About 1.97 sg). However, recent experience from drilling well A-5 showed that the pressure of such stringers may be false and the mudweight may be selected based on the initial pore pressure in Draupne 3 (About 1.93 sg). The requirement states that the mudweight should be 2 points above the initial pore pressure gradient, which means that a mudweight of 1.95 sg can be used. This will increase the margins mentioned above by 5 points.

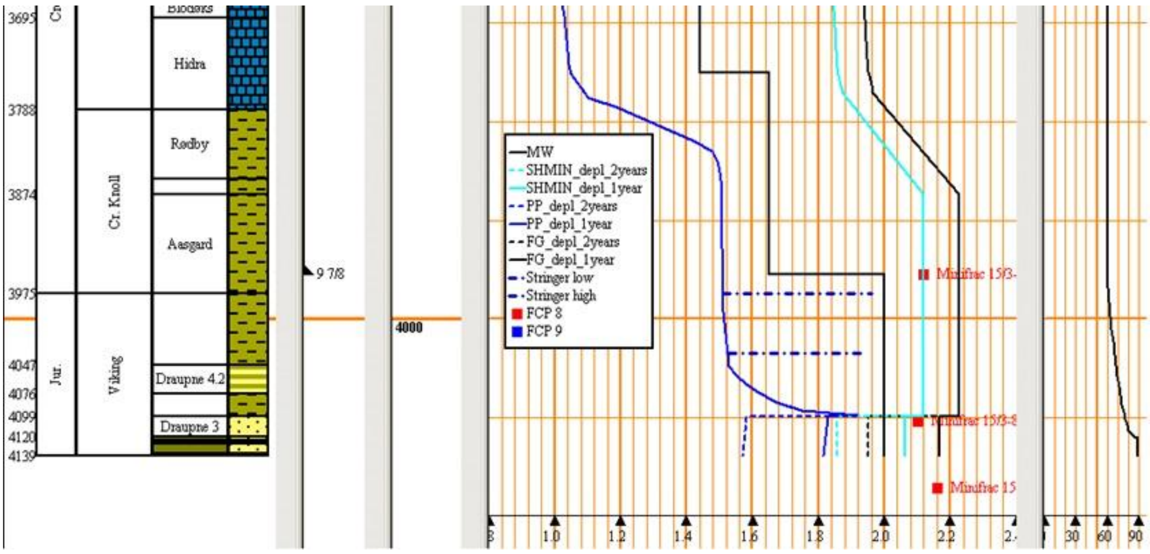


Figure 38: Pore pressure plot including depletion effects [52].

5 Simulations

5.1 Software

Simulations have been carried out in the Presmod module of the Drillbench software from SPT group. The software is a result of more than 15 years of research carried out by Rogaland Reasearch. Presmod is an application in Drillbench that focus on drilling hydraulics and modeling of wellbore pressures and temperatures during the entire drilling operation. It combines dynamic modeling of wellbore temperatures with dynamic flow modeling, and it also includes a surge and swab model. This makes it very useful for simulations of HPHT wells, where it is crucial to include temperature effects. The software has been proven valuable for all drilling operations with narrow margins between pore and fracture pressures. This makes it suitable for simulations of drilling operations in depleted HPHT reservoirs.

5.2 Objectives

The main objectives of the work done in Presmod were to:

1. Build a simulation model of well A-5 where simulation results have a good match with measured data from the actual drilling operation.
2. Build a model for well A-14 based on the A-5 model.
3. Simulate conventional drilling the reservoir section in A-14.
4. Utilize the simulation results in the discussion of how well A-14 should be drilled.

5.3 Matching simulations with measured data from a real operation

It was decided to run simulations for a well that was already drilled to see if a good match could be achieved, and how different parameters affected the model. It was also decided to focus on the ECD values when comparing the model with real data. The last drilled well on Gudrun at the time was A-5, so this well was selected for comparison. Simulations were carried out for drilling an interval in the 8 ½" section of the well.

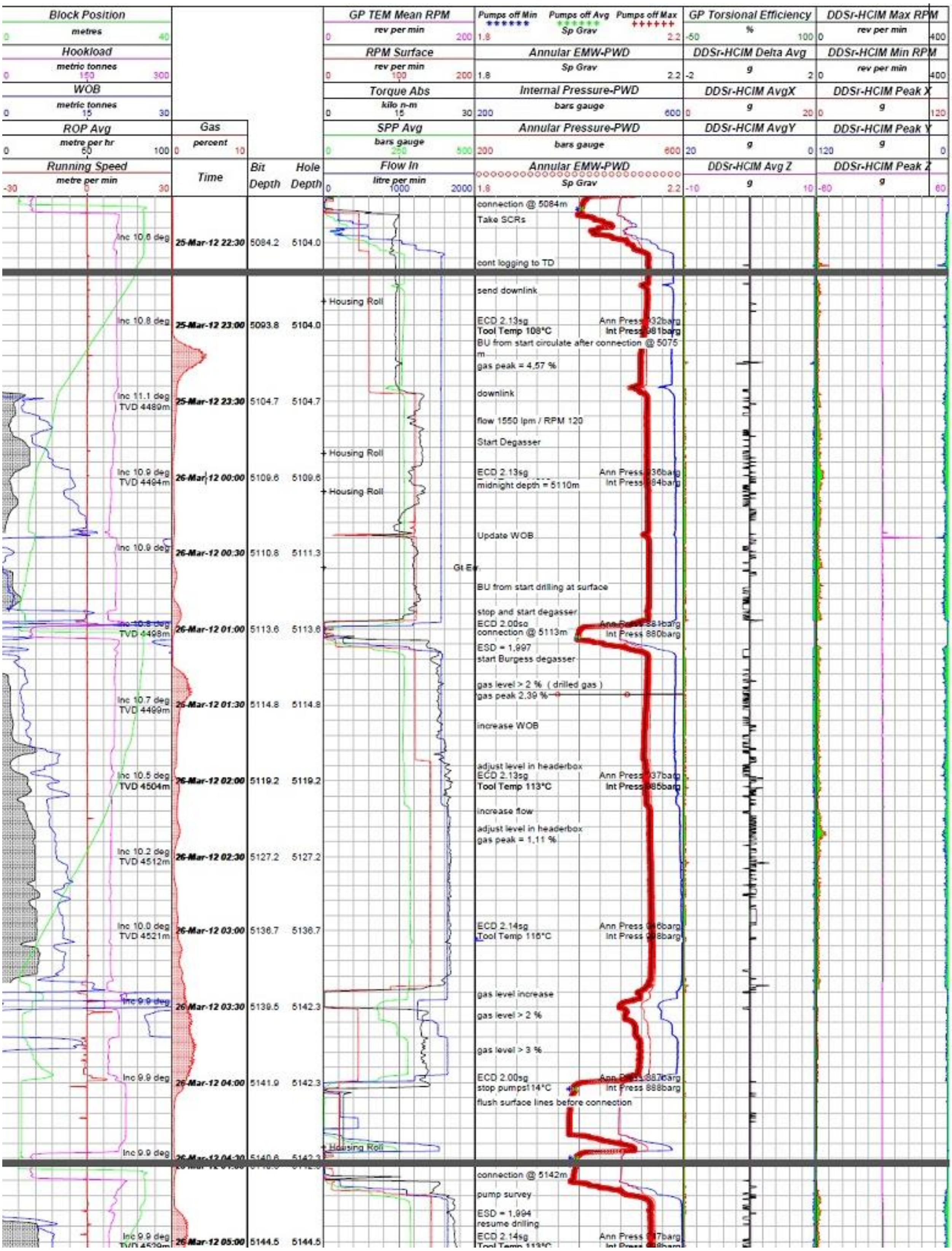
5.3.1 Simulation input data

Most input data for the simulations on well A-5 can be found in Appendix A. This includes formation input data, well trajectory, pore gradients, fracture gradients, wellbore geometry data, drillstring data, mud properties and temperature input. Mud properties where chosen based on specifications from the service provider and information from the daily drilling and well operations reporting system (also known as DBR). The drilling fluid's density correlations were based on PVT properties for the base oil and Dodson-Standing as water density submodel. The values for mud density, base oil density, solids density, reference temperatures and oil/water ratio was taken from DBR. The rheological properties were first based on Fann tables from the service provider, and then later on tests results reported in DBR. An oil based mud which was designed to yield low ECDs was used during drilling of the well.

The objective of the comparison was to compare simulated ECDs with measured ECDs from the actual drilling operation of well A-5. A batch simulation was set up for drilling from 5104 m MD to 5225 m MD. The batch simulation consists of a sequence of time periods where the set of operational conditions are kept constant, before being changed in the next time period. The batch set-up includes pump rate, fluid properties, rotation velocity, torque, rate of penetration (ROP) and the mud's inlet temperature (See Figure 39). Approximated values for all parameters except the inlet temperature where taken from the MWD plot shown in Figure 40. The inlet temperature was found in DBR.

	Duration (hr)	Accumulated time (hr)	Pump rate (l/min)	Choke opening (%)	Fluid	Fluid density (sg)	Inlet temperature (Celsius)	Rotation velocity (rpm)	Torque (Nm)	Rate of penetration (m/hr)	Riser booster pump rate (l/min)	Bit depth (m)
1	0,200	0,200	0		OBM 8 1/2" xp07 spe		38,00	0,0	0,00	0,0	0	5104,0
2	1,000	1,200	1550					60,0	14500,00	0,0		5104,0
3	0,250	1,450	1550					120,0	18000,00	9,0		5106,2
4	0,250	1,700	1550					120,0	19500,00	16,0		5110,2
5	0,250	1,950	1550					120,0	18000,00	8,0		5112,2
6	0,250	2,200	1550					120,0	15000,00	5,0		5113,5
7	0,200	2,400	0					0,0	0,00	0,0		5113,5
8	0,400	2,800	1550					120,0	23000,00	6,0		5115,9
9	0,200	3,000	1550					140,0	24000,00	12,0		5118,3
10	1,200	4,200	1600					140,0	24000,00	20,0		5142,3
11	0,200	4,400	1250					0,0	0,00	0,0		5142,3
12	0,500	4,900	1600					45,0	20000,00	0,0		5142,3
13	0,200	5,100	0					0,0	0,00	0,0		5142,3
14	0,100	5,200	400					20,0	4000,00	0,0		5142,3
15	0,100	5,300	1550					20,0	4000,00	0,0		5142,3
16	0,200	5,500	0					0,0	0,00	0,0		5142,3
17	0,200	5,700	1600				48,00	140,0	27000,00	0,0		5142,3
18	1,400	7,100	1600					140,0	27000,00	19,0		5168,9
19	0,200	7,300	0					0,0	0,00	0,0		5168,9
20	0,900	8,200	1600					140,0	27000,00	20,0		5186,9
21	0,500	8,700	1600					140,0	24000,00	10,0		5191,9
22	0,500	9,200	1600				35,00	160,0	27000,00	13,0		5198,4
23	0,200	9,400	0					0,0	0,00	0,0		5198,4
24	0,300	9,700	1600					160,0	27000,00	11,0		5201,7
25	0,400	10,100	1250					120,0	24000,00	0,0		5201,7
26	3,400	13,500	1100					120,0	26000,00	7,0		5225,5

Figure 39: Batch simulation for drilling from 5104 m MD to 5225 m MD in well A-5.



Block Position
Hookload
WOB
ROP Avg
Running Speed
Gas
Time
Bit Depth
Hole Depth
GP TEM Mean RPM
RPM Surface
Torque Abs
SPP Avg
Flow In
Annular EMW-PWD
Internal Pressure-PWD
Annular Pressure-PWD
GP Torsional Efficiency
DDSr-HCIM Delta Avg
DDSr-HCIM AvgX
DDSr-HCIM AvgY
DDSr-HCIM Avg Z
DDSr-HCIM Max RPM
DDSr-HCIM Min RPM
DDSr-HCIM Peak X
DDSr-HCIM Peak Y
DDSr-HCIM Peak Z
25-Mar-12 22:30 5084.2 5104.0
25-Mar-12 23:00 5093.8 5104.0
25-Mar-12 23:30 5104.7 5104.7
26-Mar-12 00:00 5109.6 5109.6
26-Mar-12 00:30 5110.8 5111.3
26-Mar-12 01:00 5113.6 5113.6
26-Mar-12 01:30 5114.8 5114.8
26-Mar-12 02:00 5119.2 5119.2
26-Mar-12 02:30 5127.2 5127.2
26-Mar-12 03:00 5136.7 5136.7
26-Mar-12 03:30 5139.5 5142.3
26-Mar-12 04:00 5141.9 5142.3
26-Mar-12 05:00 5144.5 5144.5
connection @ 5084m
Take SCRs
cont logging to TD
send downlink
ECD 2.13sg
Tool Temp 108°C
BU from start circulate after connection @ 5075 m
gas peak = 4,57 %
downlink
flow 1550 lpm / RPM 120
Start Degasser
midnight depth = 5110m
Update WOB
BU from start drilling at surface
stop and start degasser
ECD 2.00sg
connection @ 5113m
ESD = 1,997
start Burgess degasser
gas level > 2 % (drilled gas)
gas peak 2,39 %
increase WOB
adjust level in headerbox
ECD 2.13sg
Tool Temp 113°C
increase flow
adjust level in headerbox
gas peak = 1,11 %
ECD 2.14sg
Tool Temp 116°C
gas level increase
gas level > 2 %
gas level > 3 %
ECD 2.00sg
stop pumps114°C
flush surface lines before connection
connection @ 5142m
pump survey
ESD = 1,994
resume drilling
ECD 2.14sg
Housing Roll

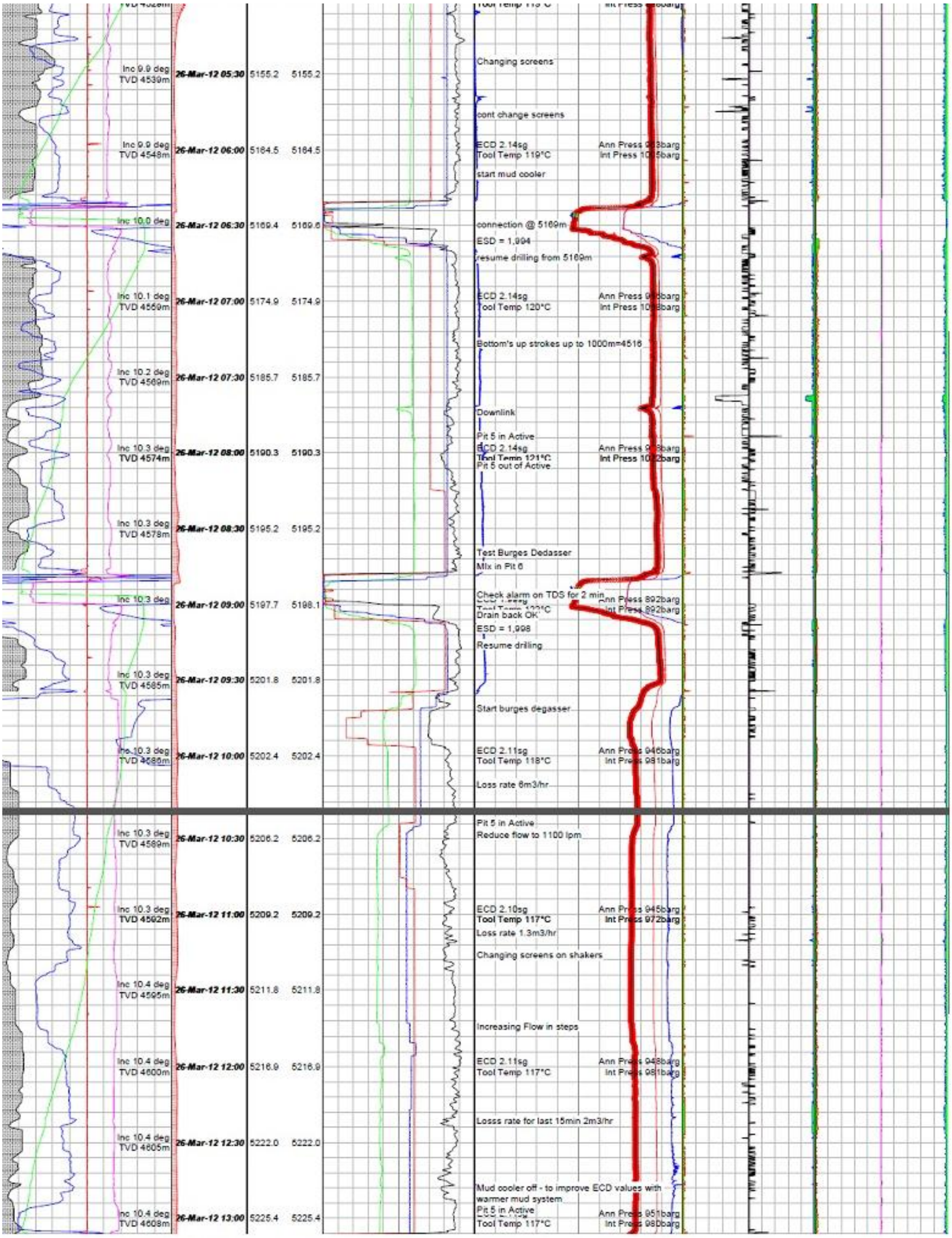


Figure 40: A-5 MWD from 5104 m MD to 5225 m MD.

5.3.2 Simulation results

When comparing the first simulation results (Figure 41, red line) and the measured data from the drilling operation (Figure 40) it was found that the simulated ECDs were more than 2 points below the measured values. The goal was to match the ECD within 1 point. Fann tables specified by the service provider were used to describe the drilling fluid's rheology in this simulation. After checking the daily drilling and well operations reporting system it turned out that the mud properties used on the rig differed somewhat from the optimal values from the service provider. Complete Fann tables were not given in DBR, but a test at 50° Celsius was reported. The values from this test showed that the rheology given in the Fann tables was not valid for the mud that was used in the operation. The drilling fluid's rheology may have been changed because barite sagging was experienced in the well, meaning that the particles were not kept in suspension during periods without circulation. It was suspected that the invalid rheology input was a source of error for the simulation results.

It is recommended to have tests for more than one pressure and temperature state if Fann tables are to be used to describe the fluid's rheology in Presmodm, but this was not available in DBR. An option is to use values for plastic viscosity (PV), yield point (YP) and a low Fann reading at 3 rpm, instead of Fann tables. This is a simpler model, and to use this is not the preferable option in general. Values for PV, YP and a 3 rpm Fann reading were reported in the daily drilling and well operations reporting system. It was decided to run a new simulation, where these numbers were used to describe the drilling fluid's rheology.

The ECD results from the two simulations are illustrated in Figure 41. The red line indicates the first simulation, while the green line represents the last simulation. During circulation, the ECD was increased by more than 2 points when using the mud-properties reported in DBR. The values during connections were about the same.

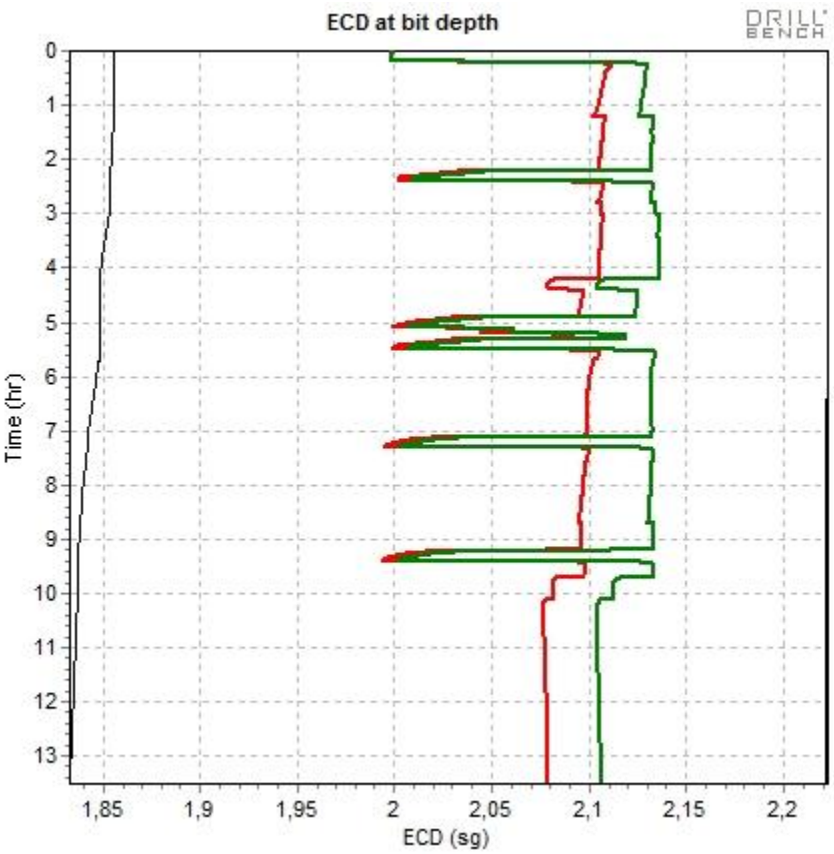


Figure 41: A-5 Batch simulation ECD results. Red line represents simulation with Fann tables, and green line represents simulation with PV, YP and low Fann reading.

When comparing ECDs from the MWD plot in Figure 40 with the simulation results, it is obvious that the results improved drastically when the rheology data from DBR were used. The ECDs are indicated as "Annular EMW – PWD" in the MWD plot, and is illustrated by a thick red line. The ECD values during drilling was measured to be between 2.13 and 2.14 sg for the first 4 stand sections drilled, and this matches very good with the second simulation. The ECD's while drilling the last 30 meters of the selected interval were measured to be between 2.10 and 2.11 sg, and this also matches well with the simulation results from the second simulation. The well pressure was measured to be approximately 2.00 sg during connections. This matches well with both simulations.

The simulated ECDs in the second simulation are within a range of 0.01 sg from the measured values during the simulated 13.5 hours of operation. The predetermined goal was to match the measured data within this range, so the results were satisfactory. It was noted that changing fluid rheology had a severe effect on the simulated ECD. The preferable option in general, is to use Fann tables for the drilling fluid's rheological properties. However, when changes are made to the original mud specifications, the model must be updated with new Fann readings. This was not available in this case, and a simpler rheological model based on values for PV, YP and a low Fann reading proved to be satisfactory.

5.4 Simulations on well A-14

Simulations of drilling the 8 ½” section of well A-14 were carried out with the purpose of using the results when discussing which technologies that could be used for drilling the well in different scenarios. The main focus was to look on simulated ECDs in relation to expected fracture gradients.

5.4.1 A-14 input data

The basis for the simulations was the Presmod file created for A-5. Survey data, pore pressure gradients, fracture gradients and casing setting depths had to be updated. Input data for A-14 can be found in Appendix B. The casing and drill string properties are the same as for well A-5. The mud density was changed from 1.98 sg to 1.95 sg, based on the information given in chapter 4.2. Pore pressure gradients in the formation layers between top of Draupne 4 and top of Draupne 3 were therefore adjusted to 1.93 sg, based on experience from drilling well A-12.

5.4.2 Simulation results

Simulations where carried out for four different scenarios:

1. Initial pore pressure gradients and initial fracture gradients
2. Initial pore pressure gradients and fracture gradients after 40 bars depletion (1 year)
3. Initial pore pressure gradients and fracture gradients with 60 bars depletion
4. Initial pore pressure gradients and fracture gradients after 140 bars depletion (2 years)

Initial pore pressure gradients are used in all scenarios because non-depleted zones may be drilled into after depletion has started. The mud must therefore normally be designed based on the initial pore pressure gradients.

Scenario 1 – Initial reservoir conditions

A batch simulation was set up using pump rates of 1400 l/min, rotation velocity of 120 rpm, torque of 12 kNm and a ROP of 10 m/hr. Connections were set to last for 12 minutes. Drilling was simulated until the target depth at 6988 meters MD was reached. The simulated ECDs are shown in Figure 42. The fracture gradient is indicated by the uppermost black line (~2.23 sg), while the pore pressure is represented by the lowermost black line.

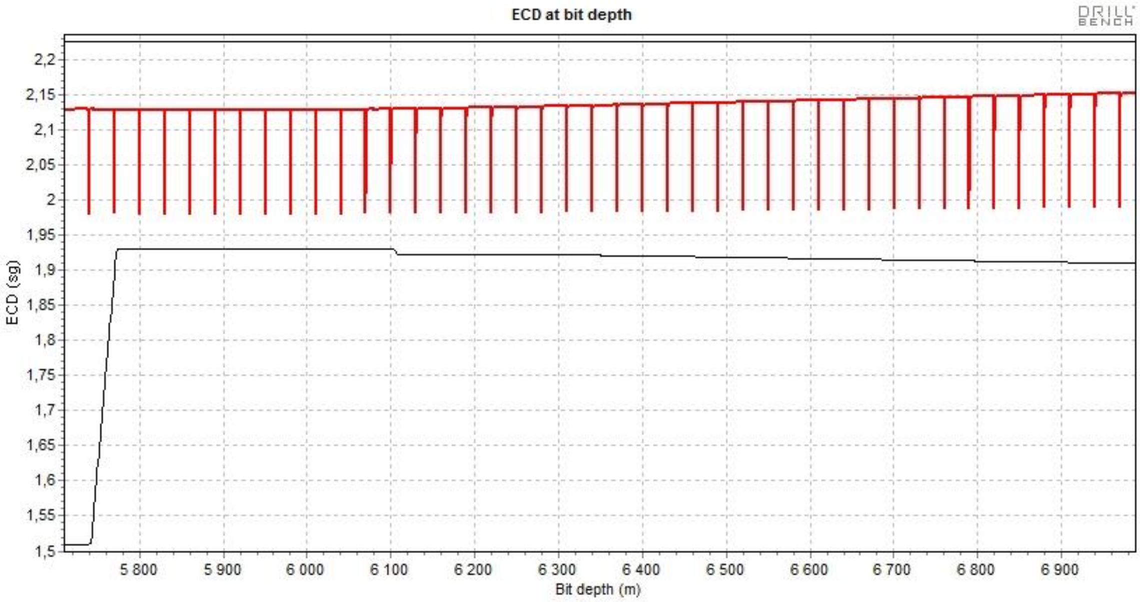


Figure 42: A-14 batch simulation, initial conditions.

The simulations resulted in a margin of approximately 7 points from the highest simulated ECD to the expected fracture pressure. The highest simulated ECD is approximately 2.15 sg, found in the end of the horizontal section. The minimum horizontal stress is expected to be 10 points below the fracture pressure with this scenario, at 2.12 sg. This means that ECD reducing measures need to be initiated if the strategy should be to have an ECD below the minimum horizontal stress. There are several options to do this. One could reduce the rotation velocity and/or the pump rate, which will reduce the frictional pressure drop in the well. A reduction in the rate of penetration can reduce the effective mudweight, since the volume of drillcuttings in the annulus will decrease. Another option is to change the drilling fluid's rheology, which can have a large effect on the ECD. It is critical that the fluid's hole cleaning and particle suspension abilities still are sufficient after these changes are made. Good results have been experienced with cesium formate muds previously.

A new batch simulation was done, where the pumping rate was reduced to 1100 l/min, the rotation velocity to 100 rpm and the ROP to 7 m/hr, for drilling of the last 200 meters. The effect is shown in Figure 43. The ECD was reduced by approximately 2 points. Simulations showed that changing only one of these parameters at a time resulted in a decrease in ECD in all cases.

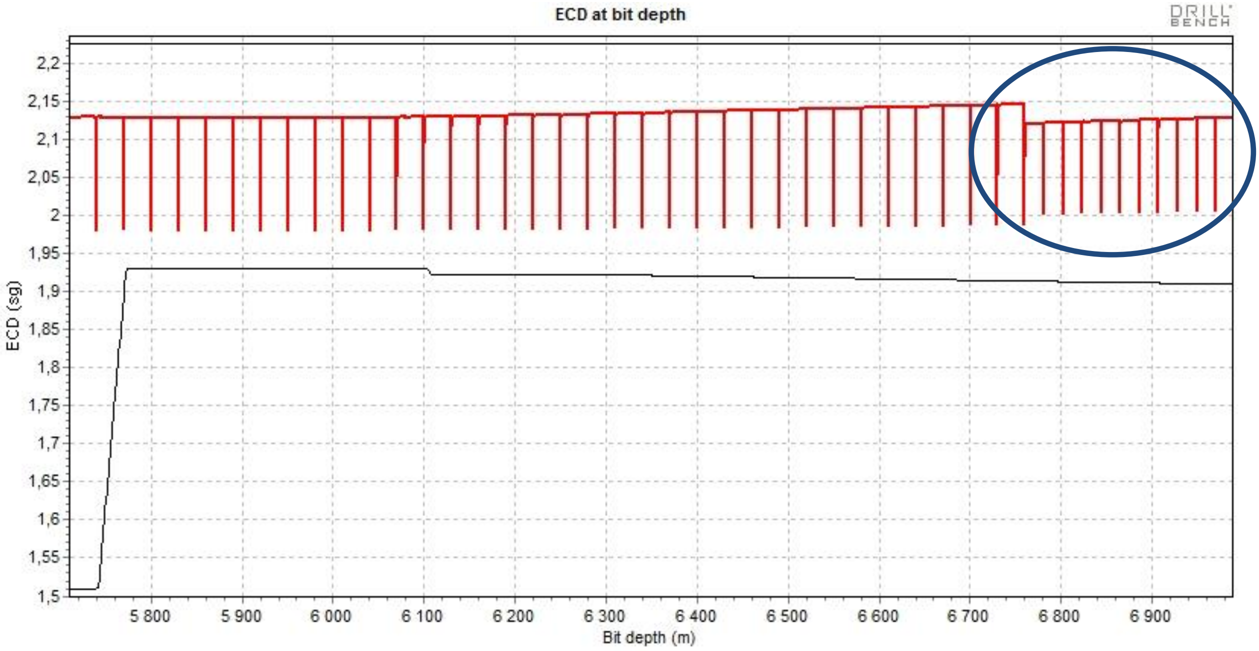


Figure 43: ECD effect on reducing pump rate, ROP and rotation velocity.

Another simulation was carried out, where the Fann tables that were specified by the service provider were used to describe the drilling fluid’s rheology. The original simulation is represented by the red line, while the new simulation is represented by the green line. The ECD is reduced by more than 5 point at the most. The results are shown in Figure 44.

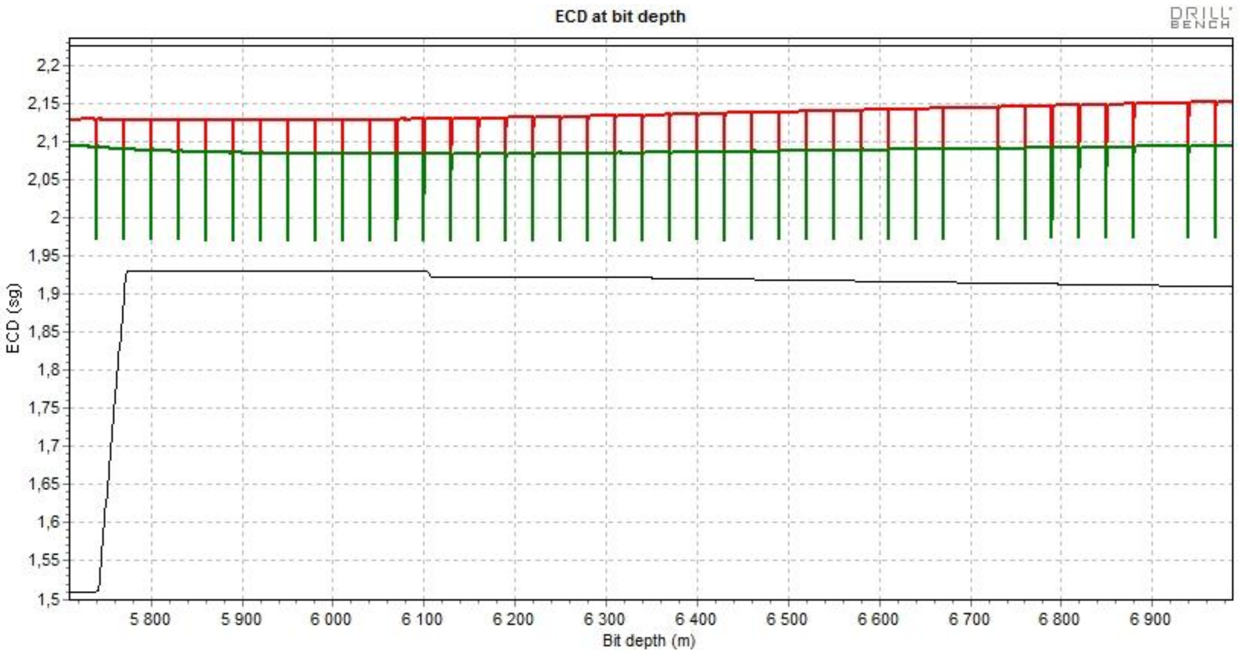


Figure 44: Effect of changing the drilling fluid's rheology.

Scenario 2 – Drilling with 40 bars depletion

A simulation was carried out by using the same input data as in the first simulation with initial conditions. Only the fracture pressure gradient was changed. The results are shown in Figure 45.

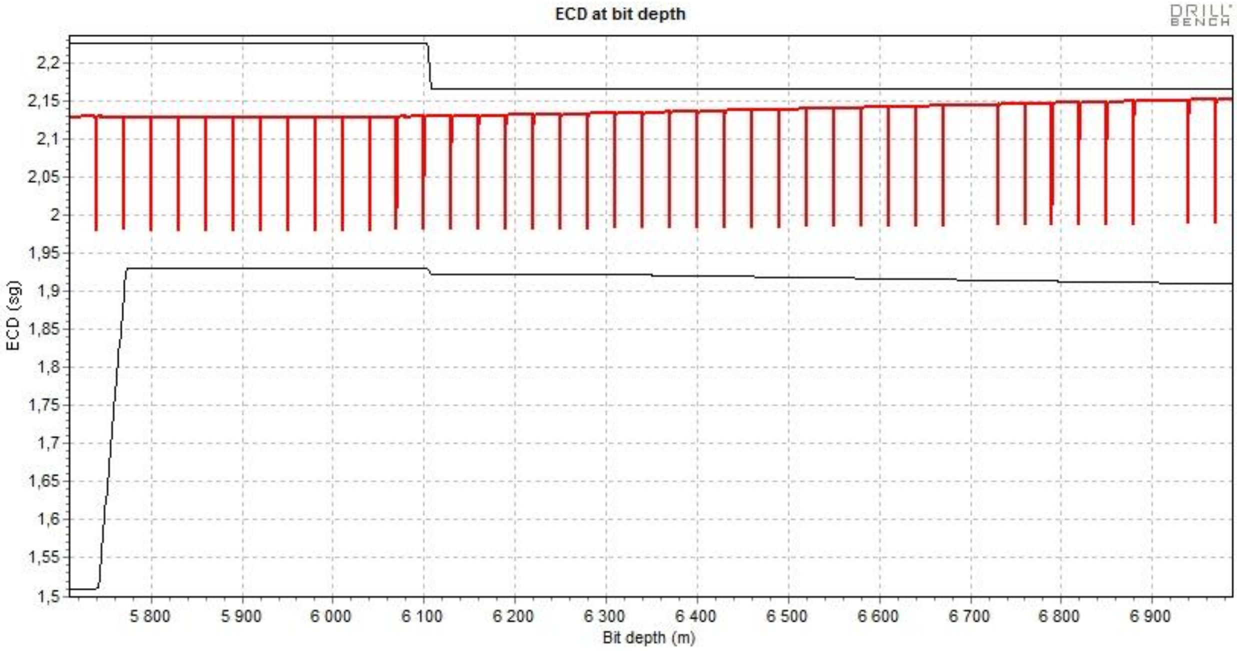


Figure 45: A-14 Batch simulation, 60 bars depletion (1 year).

The simulated ECDs are still within the drilling window after 40 bars depletion. The expected fracture pressure is based on a depletion-fracture rate of 0.6. The expected minimum horizontal stress is about 2.06 sg, so it could be very difficult to lower the ECD below this value.

Scenario 3 – Drilling with 60 bars depletion

It was decided to run simulations with a fracture gradient based on 60 bars depletion to see if it still was possible to keep the ECD below the fracture gradient. The results are shown in Figure 46. The first simulation was carried out with the rheology that gave the best match for well A-5. This simulation is indicated by the red line. The ECDs eventually exceeded the fracture pressure. A new simulation was then done by using the Fann tables specified by the manufacturer to describe the rheology. The ECDs was now kept slightly more than 0.03 sg below the expected fracture pressure.

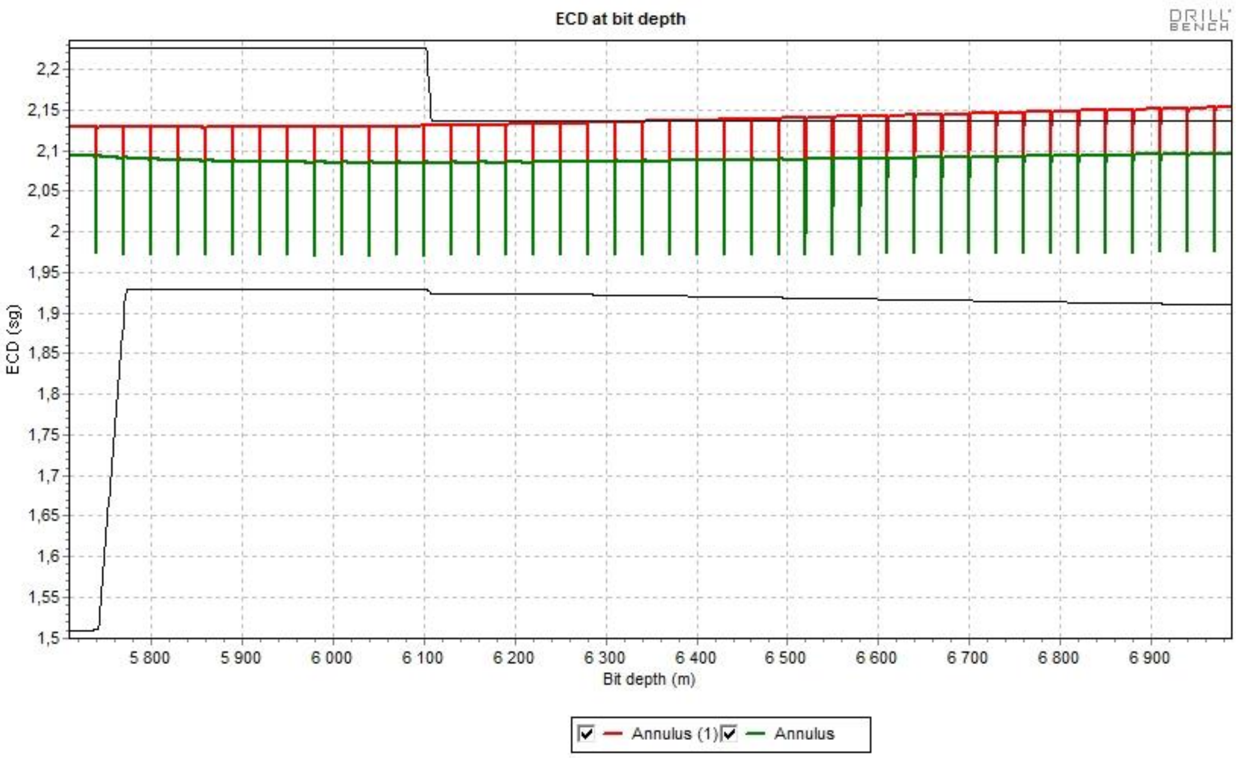


Figure 46: A-14 Batch simulation, 60 bars depletion. Green line with low-ECD mud, red-line with A-5 mud.

Scenario 4 – Drilling with 140 bars depletion

A simulation was carried out using the same input data as in the first simulation with initial conditions. Only the fracture pressure gradient was changed. The results are shown in Figure 47.

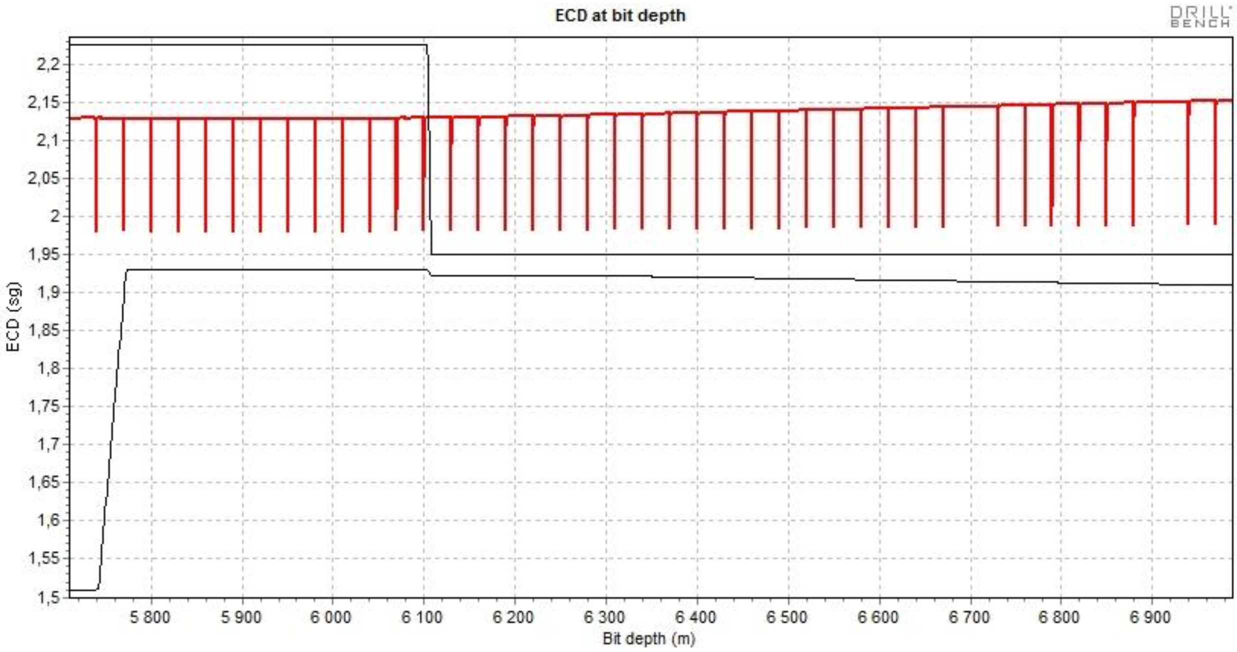


Figure 47: A-14 batch simulation, 140 bars depletion (2 years)

The simulated ECD is about 15 points above the expected fracture pressure and approximately 24 points above the expected minimum horizontal stress (1.86 sg) in the reservoir section, after 140 bars depletion. The drilling window is only 2 points with this scenario.

6 Discussion

6.1 Simulations

A good match was achieved between measured ECD from the drilling operation of well A-5 and results from the simulations. The simulations showed that the drilling fluid's rheology has a large effect on the ECD. It is important use rheology data that is representative for the drilling fluid. Simulations also showed that pump rate, rotation velocity, torque and ROP affected the ECD.

The simulation results for A-14 are believed to be representative for the actual drilling operation of the well, based on the good match for well A-5. The three different scenarios simulated for well A-14 shows that the grade of depletion influences the drillability and technology demand for the well.

6.1.1 Drilling with initial reservoir conditions

According to the simulations, it should not be a problem to drill A-14 with conventional methods if the initial reservoir conditions are valid. There is a relatively large margin from simulated ECDs to the expected fracture pressure. Simulations also indicate that it should be possible to keep the ECD below the expected minimum horizontal stress by optimizing the drilling parameters and the properties of the drilling fluid.

6.1.2 Drilling after 40 bars depletion

It is considered to be possible to drill the well with conventional drilling methods after 1 year's depletion. The margin between ECDs and expected fracture pressure was only around 0.01 sg at the end of the well, but it is possible to reduce the ECD significantly by optimizing drilling parameters and mud properties. LCMs could also be added to the mudsystem to reduce the risk of lost circulation.

6.1.3 Drilling after 60 bars depletion

It was shown that it may be possible to drill A-14 conventionally also after 60 bars depletion. The ECD was kept within the drilling window by selecting a mud that yielded low ECDs. The simulations showed a safety margin of 0.03 sg to the expected fracture pressure. These results imply that the limits for conventional drilling of well A-14 may be around 60 bars depletion. If conventional drilling is to be used for drilling A-14 after more than 60 bars depletion, a minimum requirement should be to use LCMs to bridge across potential fractures. One should also optimize the drilling parameters and drilling fluid to lower the ECD as much as possible. The drilling fluid's hole cleaning and particle suspension ability must still be sufficient after this optimization. This is especially important to point out since A-14 is a horizontal well.

6.1.4 Drilling after 140 bars depletion

With this scenario, it is clear that the well cannot be drilled with conventional methods. The margin between the expected fracture pressure gradient and the initial pore pressure gradient is only 0.02 sg, and the well may be very difficult to drill under these circumstances.

6.2 Evaluation of technologies

The different technologies and techniques that are evaluated for potential use in well A-14 are:

1. Conventional drilling
2. Lost circulation material
3. Managed pressure drilling
4. Underbalanced drilling
5. Casing drilling
6. Steerable drilling liner
7. Expandable liner

Combined drilling liner and expandable liner, and the patented lining while drilling method, are not evaluated for use in well A-14. This is because these technologies at the time only are proposed methods, and are not likely to be commercialized in the near future.

The goal of this evaluation is to find out; which technologies are most favorable to apply in well A-14, and when are they favorable to use. The different technologies are evaluated based on the following parameters:

- Utility
- Feasibility
- Cost
- Complexity and risk
- Experience
- Contingency possibility

6.2.1 Conventional drilling

Conventional drilling requires that a relatively large drilling window exists. The methods used are considered to be simple, cheap and well proven. The required equipment is already in place on West Epsilon, so there is no additional cost to implement it for well A-14. The total cost of drilling the well conventional is roughly estimated to be somewhere around 950 million NOK [52]. Conventional drilling of A-14 can be applied within 60 bars depletion based on the simulation results. It is recommended to optimize the drilling fluid with respect to ECD, and to include LCMs, if the well is to be drilled with around 60 bars depletion.

Experiences show that several wells have been drilled with a relatively large overbalance with respect to the theoretical fracture pressure, even without including LCMs. This means that it could be possible to drill the well conventionally if more than 60 bars of depletion has taken place, but the risk of mud losses and kicks is then considered to be high. Conventional drilling is not considered to be a very useful contingency solution, since it does not provide any extra pressure control compared to the other drilling techniques.

Conventional drilling methods are found applicable for drilling well A-14 in a situation where up to 60 bars depletion is expected. It may also be possible to drill the well conventional in situations with more than 60 bars depletion if the drilling fluid properties can be optimized with respect to ECD, and an effective LCM design is made. However, the risk of well control incidents will increase with the magnitude of depletion.

6.2.2 Lost circulation materials

It is considered to be favorable to use lost circulation materials in depleted reservoirs based on theory and experiences. The materials may increase the drilling window by strengthening the wellbore formation, and prevent lost circulation by bridging across fractures. The cost of implementing LCMs in well A-14 is regarded to be low. The possible downsides of using LCMs in A-14 are the possibility for plugging downhole tools, experience particle dropout and increase ECD. However, there is broad experience with LCMs within the company, so the risk of operational problems caused by using LCMs is considered too be relatively low.

The technology is simple to apply. Some suggested materials for use in well A-14 are graphite and $CaCO_3$. These materials have a long track record in the company, with good results. LCMs can be planned as a contingency, but the general recommendation from the company experts is that a preventive approach is best to use if there is a significant risk of mud losses. It is easier to avoid severe losses if the LCMs are used before the first losses occur.

Based on this, it is considered to be favorable to apply lost circulation materials when drilling A-14 in situations where significant depletion is expected. Based on the simulations and expected pore pressure gradients and fracture gradients, significant depletion is found to be at approximately 40 bars.

6.2.3 Managed pressure drilling

Managed pressure drilling may be very useful in situations where the drilling window is small. Experiences from Kvitebjørn have shown that the technology can be utilized to control the bottomhole pressure within a range of ±4 bars. Based on the expected initial pore pressure gradients, fracture gradients and depletion-fracture ratio, it is calculated that MPD may be used to drill the well with up to approximately 120 bars depletion in the reservoir, if the pressure is controlled by ±4 bars. Managed pressure drilling requires that additional well control equipment is installed on Gudrun. The cost is considered to be relatively high, and feasibility studies have to be carried out before the technology can be implemented on West Epsilon. A rough estimate on the extra cost of implementing and using the technology for drilling A-14 is 150 million NOK, which means that the total cost of drilling the well is estimated to be around 1100 million NOK [52].

The technology is complex, but the company has relatively large experience with it. These experiences are also very positive. The risk of well control incidents depends much on the grade of depletion. In theory, MPD could be used to drill A-14 with up to 120 bars depletion. However, the risk of losses and kicks after this amount of depletion is considered to be relatively high. A-9 on Kvitebjørn was drilled about 6900 meters in MPD mode, so the length of the well is not found to be an issue. The planned 8 ½" section of A-14 is almost 1300 meters. The pressure cannot be kept constant in the entire section, so simulations should be done to verify that it is possible to maintain the ECD within the drilling window both at the casing shoe and at the bottomhole. MPD could be applied as a contingency option if the equipment is installed and operative on the rig.

Based on the elements discussed above, MPD is found to be an applicable technology for drilling A-14 if the expected depletion is somewhere between 60-120 bars. The risk of having mud losses and kicks is considered to be relatively high with an expected depletion of 120 bars, and it desirable to have a larger margin between the initial pore pressure gradients and the expected fracture gradients. A risk reducing measure in this situation will be to use LCMs in combination with MPD.

6.2.4 Underbalanced drilling

Underbalanced drilling can be utilized to drill wells in situations where the drilling window is very small or even negative. So-called "undrillable" wells can be drilled by using the underbalanced drilling technology, because it does not require a positive drilling window. A benefit with drilling underbalanced may be reduced formation damage. Additional equipment is required on West Epsilon if underbalanced drilling is to be used. This includes both well control equipment (RCD and choke) and extra processing equipment (multiphase separator for separating drilling fluids and produced fluids). The cost of implementing this equipment is considered to be high, and feasibility studies have to be done to see if it is possible to install the equipment on the rig.

The technology is regarded to be complex, and the company experience is very limited. Conventional MWD tools cannot be applied when drilling underbalanced. The risk of unwanted incidents when producing fluids from a HPHT reservoir while drilling is considered to be very high. The technology could potentially be used as a contingency method if managed pressure drilling is not sufficient as the basic solution.

Based on the limited experience, complexity and risk of serious incidents, underbalanced drilling is not recommended for drilling A-14 in situations with less than 120 bars depletion. However, it may be the only applicable method if the reservoir has been depleted more heavily. In this case, extensive feasibility, cost and risk studies have to be carried out before it could be considered as a possible solution for drilling A-14.

6.2.5 Casing drilling

Casing drilling can be a good option for drilling in troublesome formations. The method can provide a smearing effect which will strengthen the wellbore. However, it is uncertain how much the wellbore can be strengthened, so the method still requires a drilling window. The technology can reduce NPT, by eliminating the need for drillstring trips. Some downsides are that the torque and drag forces are higher than in conventional drilling, and the ECDs will increase. A-14 is planned to be a long and highly inclined well, so these effects will be significant in this well. Casing drilling also requires that large modifications are made on West Epsilon. Feasibility studies would have to be done to see if this is possible to achieve the required lifting capacity and implement the new equipment. The cost of implementing this is considered to be high.

There is not any field experience with casing drilling within the company, and the technology is regarded to be relatively complex. There is always a risk of getting stuck with the casing in the hole, meaning that it has to be set before TD is reached. The technology is not very applicable as a contingency method, since modifications are required on the rig.

Casing drilling is not regarded as the best method for drilling A-14 in situations where a significant drilling window still exists, and it is not found to be applicable for drilling A-14 in situations where severe depletion is expected.

6.2.6 Steerable drilling liner

The steerable drilling liner can be favorable to use in formations where wellbore stability issues are expected. The technology could yield a similar wellbore strengthening effect as casing drilling. It also provides the same possibility as casing drilling when it comes to reducing NPT. Drilling with liner requires that a drilling window exist, and there is a possibility of getting stuck with the liner before reaching TD. This situation would require that a smaller liner is installed for further drilling.

Only two pilot wells have been drilled with the SDL, so there is not very much experience with this equipment. The cost is not considered to be high, but the technology is more complex than a conventional liner. It does not require any additional equipment on the rig other than the SDL system itself. The method may be planned as a contingency. It may be used to isolate problem zones in the well. SDL could be used to isolate Draupne 4, so that the risk of taking a kick from this formation is reduced. It is also beneficial to isolate Draupne 4 if the geologists should find out that the pore pressure gradient in Draupne 3 is lower than 1.93 sg, since the mudweight then only need to be designed based on the pressure in Draupne 3. However, it should be possible to isolate these zones by drilling conventionally and setting a conventional liner.

Steerable drilling liner is rated above casing drilling for drilling A-14. However, conventional drilling is considered to be a better solution for drilling well A-14 in a situation where a significant drilling window exists. SDL is not found applicable for drilling well A-14 if severe depletion is expected.

6.2.7 Expandable liner

Expandable liners may be a good solution for isolating problem zones. The casing diameter can be maintained if the monobore solution is used. However, the collapse and burst ratings pre expansion are low. The monobore technology requires that a recess shoe is installed at the previous set casing. The cost is not considered to be high, while the complexity of the monobore solution is considered to be medium high. Statoil has quite a lot experience with expandable liners in general, but not with the monobore solution. It is possible to use the expandable liner as a contingency method; the linEXX monobore solution has been planned as a contingency 7 times.

Load scenario studies have to be carried out to see if the expandable liner can be used to isolate problem zones in the well. The limited ratings are expected to be an issue in the elevated conditions in the Gudrun reservoirs. However, recess shoes have been installed on Kvitebjørn for contingency reasons, so it may be a solution that could be used for Gudrun as well.

7 Conclusions

- Presmod seems to be a suitable tool for simulating drilling of well A-14. This is concluded based on the good match that was achieved between simulated ECDs and measured ECDs for well A-5.

- Drilling of well A-14 should take place as soon as possible after initiating production from Draupne 3. This would limit the challenges related to the drilling operation, and most likely reduce the cost of drilling the well.

- As much information as possible must be gathered about the reservoir conditions when drilling wells in Gudrun. Offset data may reduce the uncertainty in pore pressure and fracture gradient prognosis for A-14. This will make it simpler to plan and execute a cost efficient and safe drilling operation.

- Conventional drilling is regarded to be the preferable way to drill well A-14 if the expected depletion is approximately 60 bars or less.

- It is recommended to use LCMs in the mudsystem when the expected depletion exceeds 40 bars. This should be done as a proactive measure to avoid problems with lost circulation.

- It is not recommended to apply conventional drilling if the reservoir has been depleted more than approximately 60 bars. The risk of lost circulation is then considered be high. LCMs must be added to the mudsystem if conventional drilling should be applied with more than 60 bars depletion.

- Managed pressure drilling is considered to be the best method to drill well A-14 if the expected depletion is between 60 and 120 bars. It is recommended to use LCMs in combination with MPD.

- Underbalanced drilling technology may be the only applicable solution if the expected depletion is more than 120 bars. More extensive studies have to be carried out before this can be considered as the best solution in a situation where the reservoir is depleted by more than 120 bars.

8 Abbreviations

BHA	Bottomhole assembly
BHP	Bottomhole pressure
BMP	Balanced mud pill
BOP	Blowout preventer
CBHP	Constant bottomhole pressure
CCS	Continuous circulating system
CWD	Casing while drilling
DBR	Daglig borerapport
DG	Dual gradient
ECD	Equivalent circulating density
EMW	Equivalent mudweight
FIT	Formation integrity test
FPWD	Formation pressure while drilling
HPBOP	High pressure blowout preventer
HPHT	High pressure/High temperature
HSE	Health, safety and environment
IADC	International association of drilling contractors
ID	Inside diameter
LCM	Lost circulation material
LOT	Leak of test
MPD	Managed pressure drilling
MSL	Mean sea level
NORSOK	Norsk sokkels konkurranseposisjon
NPT	Non-productive time
NRV	Non return valve
OBM	Oil based mud
OD	Outside diameter
PDC	Polycrystalline diamond compact
PDO	Plan for development and operation
PID	Proportional integral derivative
PMCD	Pressurized mud-cap drilling
POOH	Pull out of hole
RCD	Rotary control device
RDS	Reamer drive sub
ROV	Remotely operated vehicle
RPM	Revolutions per minute
SDL	Steerable drilling liner
SG	Specific gravity
SICP	Shut in casing pressure
SPE	Society of Petroleum Engineers
SPM	Strokes per minute
TD	Target depth
TVD	Total vertical depth
UBD	Underbalanced drilling
UBO	Underbalanced operations
WBM	Water based mud
XLOT	Extended leak of test

9 Nomenclature

9.1 English symbols

A_{SDR}	Stress-depletion ratio
C_0	Uniaxial compressive strength
D	Vertical depth
g	Acceleration due to gravity
K_{fr}	Bulk modulus of the rock framework
K_s	Bulk modulus of solids
P_{AF}	Annular friction pressure
P_{Back}	backpressure
P_{BH}	Bottomhole pressure
P_{Hyd}	Hydrostatic pressure
P_p	Pore pressure
P_w	Well pressure
P_{wf}	Well fracture pressure
v	Poisson's ratio
$\Delta p_{annulus}$	Pressure loss in the annulus

9.2 Greek symbols

ρ_w	Mud density
α	Biot coefficient
β	Failure angle
σ	Total stress
σ'	Effective stress
σ'_r	Effective radial stress
σ'_v	Effective vertical stress
σ'_θ	Effective tangential stress
σ_1	Largest principal stress
σ_2	Intermediate principal stress
σ_3	Smallest principal stress
σ_H	Maximum horizontal stress
σ_h	Minimum horizontal stress
σ_r	Radial stress
σ_z	Overburden load
σ_θ	Tangential stress
φ	Internal friction angle

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Appendices

Appendix A – A-5 simulation model input data

Surface temperature

10,00 Celsius

Depth are true vertical depth with reference to RKB

Lithology name	Top TVD (m)	Bottom TVD (m)	Geothermal gradient (C/m)	Thermophysical properties
Air gap	0,00	53,00	0	
Sea water	53,00	162,00	-0,055	
Formation to lower Shetland	162,00	4290,00	0,027	
Formation to Cromer Knoll	4290,00	4490,00	0,115	
Formation to TD	4490,00	6005,00	0,022	

Figure 48: Formation input data.

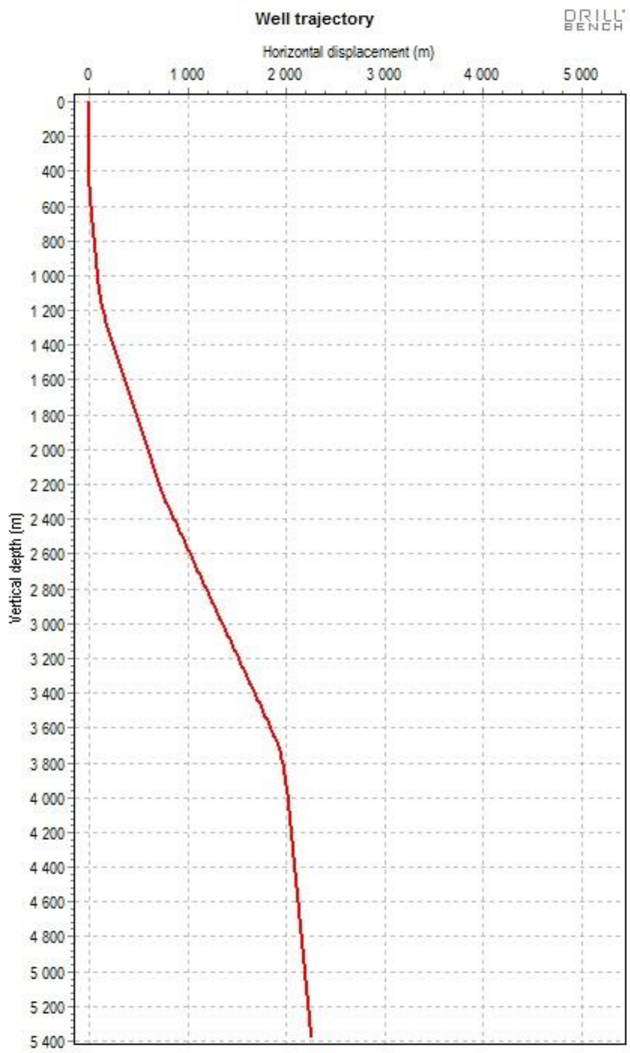

Figure 49: A-5 well trajectory.

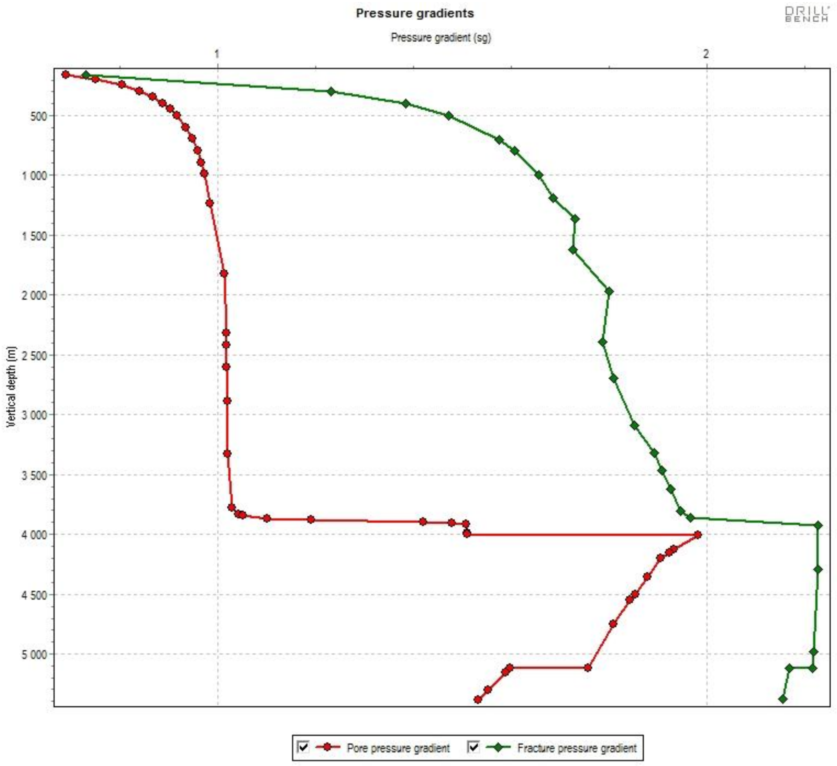

Figure 50: A-5 pore pressure gradient and fracture gradient.

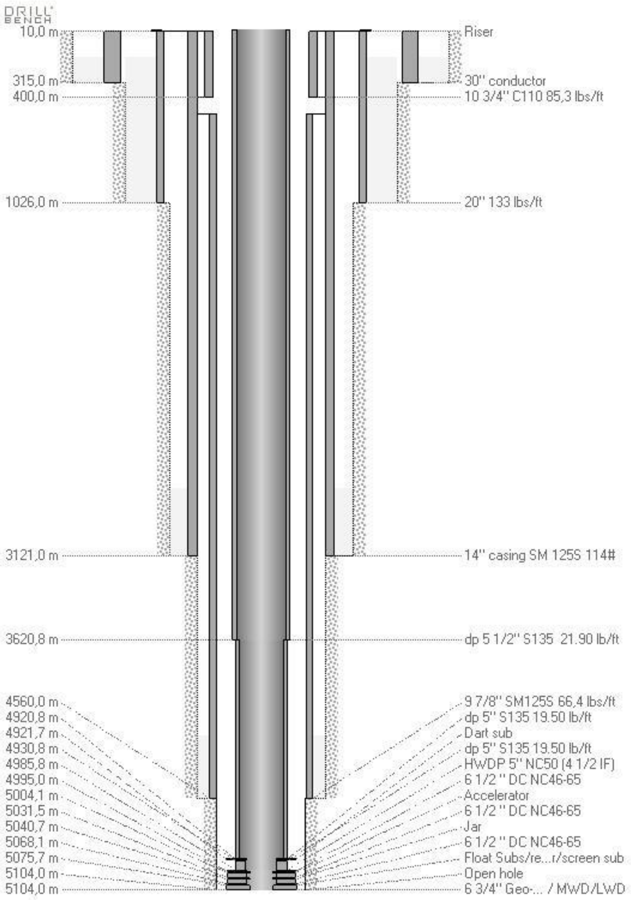

Figure 51: A-5 wellbore geometry.

Riser

Name	Length (m)	Inner diameter (in)	Outer diameter (in)	Thermophysical properties
Riser	10,0	19,000	21,000	

Casing / Liner

Depths are measured depth with reference to RKB

Name	Hanger depth (m)	Setting depth (m)	Inner diameter (in)	Outer diameter (in)	Hole diameter (in)	Top of cement (m)	Material above cement	Thermophysical properties
30" conductor	10,0	315,0	26,875	30,000	36,000	164,00	Default	
20" 133 lbs/ft	10,0	1026,0	18,728	20,000	26,000	164,00	Default	
14" casing SM 125S 114#	10,0	3121,0	12,250	14,000	17,500	2721,00	Default	
10 3/4" C110 85,3 lbs/ft	10,0	400,0	9,158	10,750	12,250	4190,00	Default	
9 7/8" SM125S 66,4 lbs/ft	500,0	4560,0	8,535	9,874	12,250	4190,00	Default	

Figure 52: A-5 Casing data.

Average stand length
30,00 m

Use tool joints

Components are specified from bottom to top

Component	Type	Section length (m)	Inner diameter (in)	Outer diameter (in)	Distance from bottom (m)	Thermophysical properties	Properties
6 3/4" Geo-Pilot / MWD/LWD	Motor	28,3	2,250	6,750	28,3		
Float Subs/reamer/screen su	Custom	7,6	2,813	6,750	35,9		
6 1/2 " DC NC46-65	DrillCollar	27,4	2,813	6,500	63,3		
Jar	Custom	9,1	2,250	6,500	72,4		
6 1/2 " DC NC46-65	DrillCollar	27,4	2,813	6,500	99,9		
Accelerator	Custom	9,1	2,250	6,500	109,0		
6 1/2 " DC NC46-65	DrillCollar	9,1	2,813	6,500	118,1		
HWDP 5" NC50 (4 1/2 IF)	Drillpipe	55,0	3,000	5,000	173,1		
dp 5" S135 19.50 lb/ft	Drillpipe	9,1	4,276	5,000	182,3		
Dart sub	Custom	0,9	2,813	6,750	183,2		
dp 5" S135 19.50 lb/ft	Drillpipe	1300,0	4,276	5,000	1483,2		
dp 5 1/2" S135 21.90 lb/ft	Drillpipe	3620,8	4,778	5,500	5104,0		

Bit data

Bit
8 1/2" PDC

Bit / Open hole diameter
8,500 in

Area definition method
Total flow area

Total nozzle area
0,70 in2

	Nozzle diameter (1/32 in)
1	10
2	10
3	10
4	10
5	10
6	9
7	9

Figure 53: A-5 pipeline and BHA data.

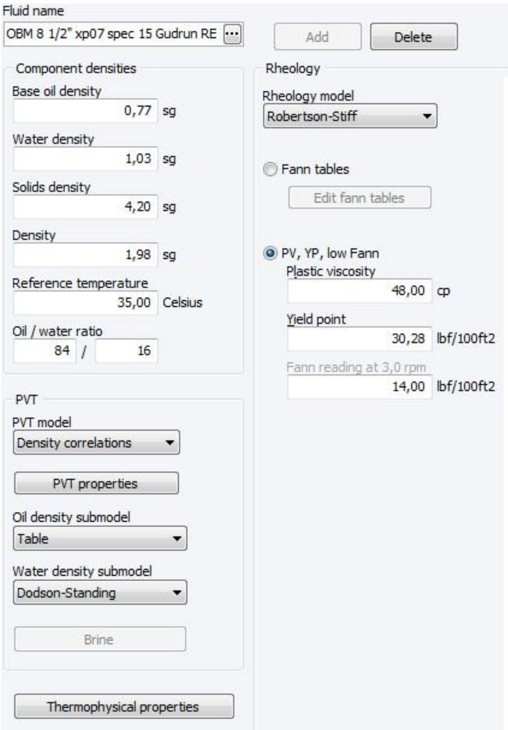

Figure 54: A-5 mud properties.

Appendix B – A-14 Simulation input data

Formation input data casing properties and drillstring properties are the same as in the A-5 simulations (See Appendix A). Casing setting depths are changed. The new depths are shown in Figure 59. The only change in the mud properties are the density change from 1.98 sg to 1.95 sg.

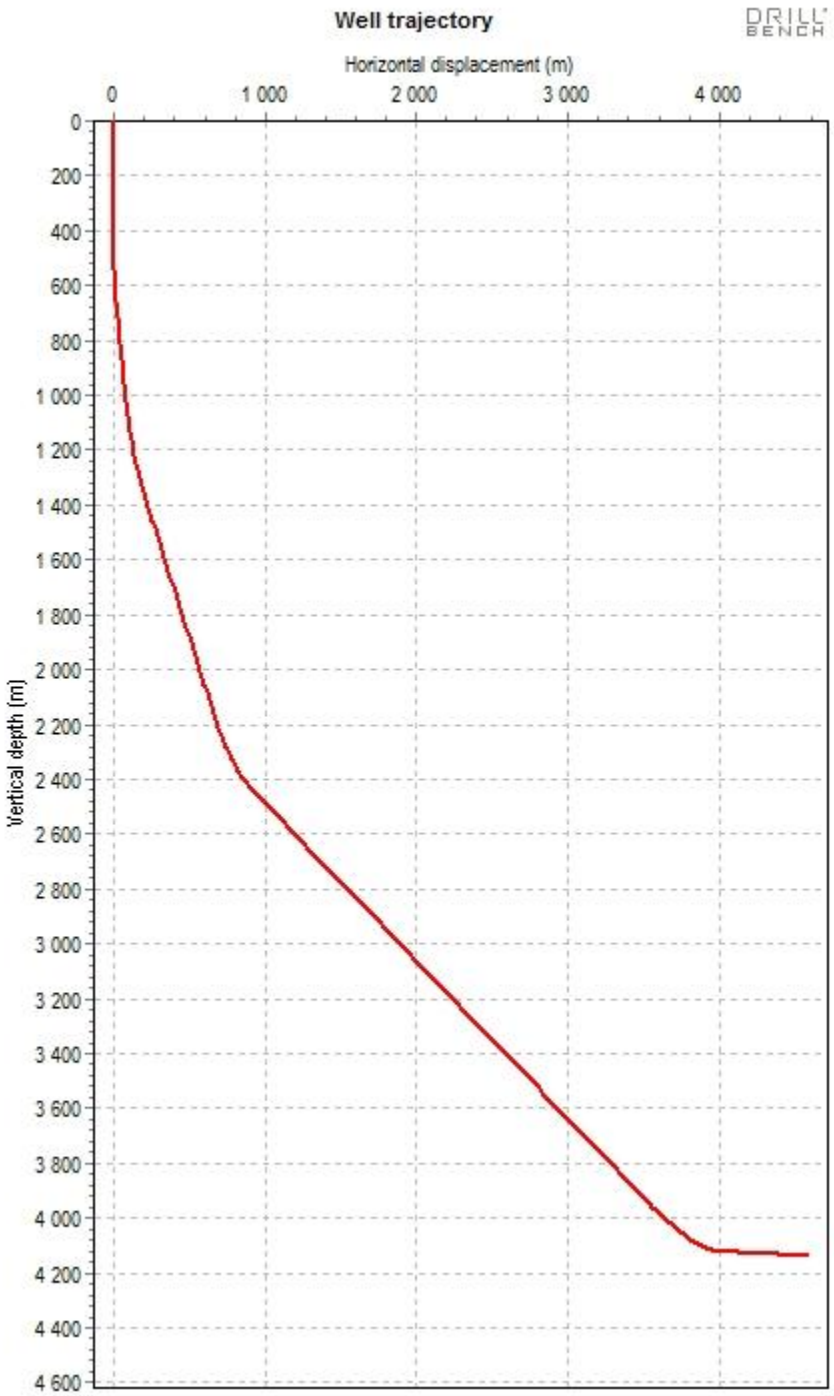

Figure 55: A-14 well trajectory.

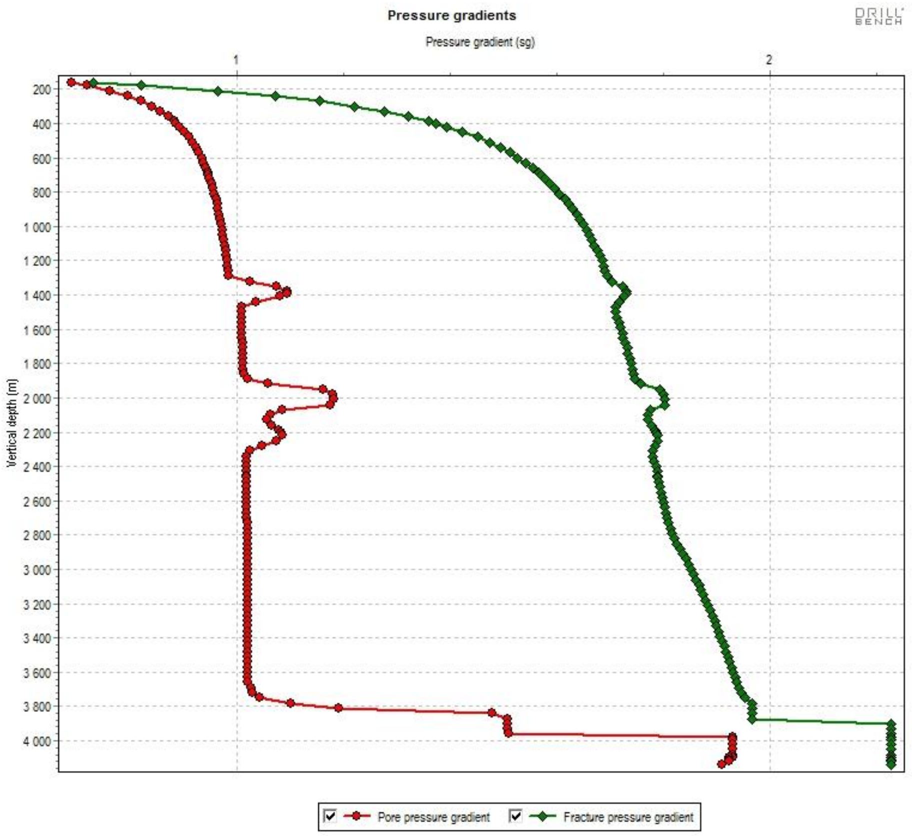

Figure 56: A-14 initial pore pressure gradient and initial fracture pressure gradient.

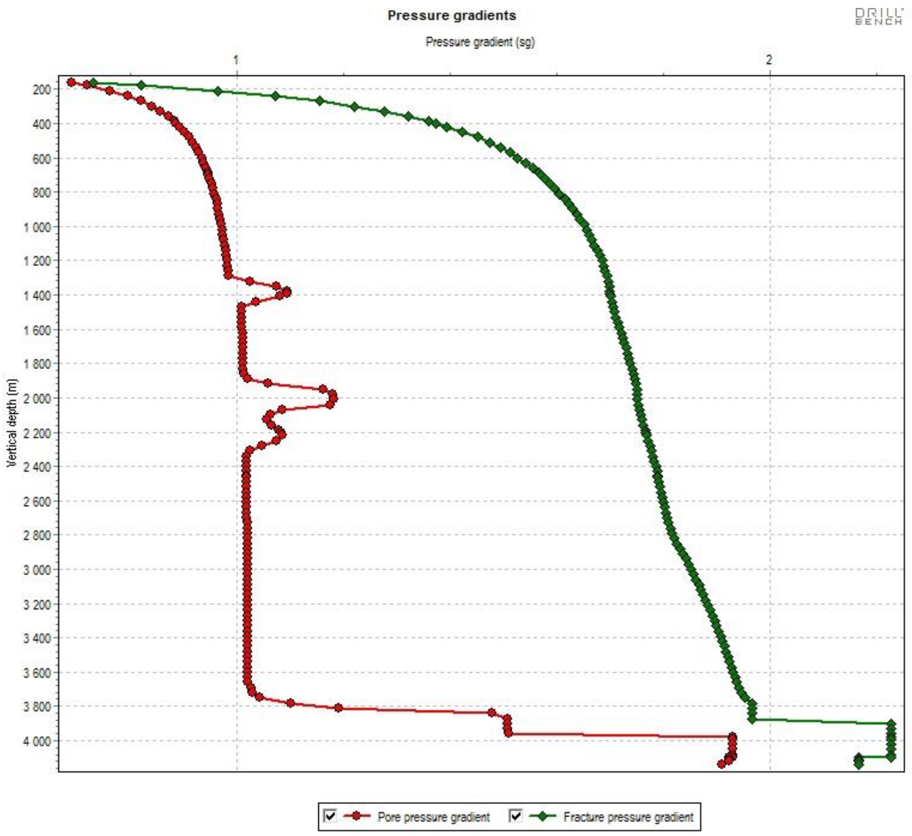

Figure 57: A-14 initial pore and fracture gradient with 1 year depletion (~40 bar).

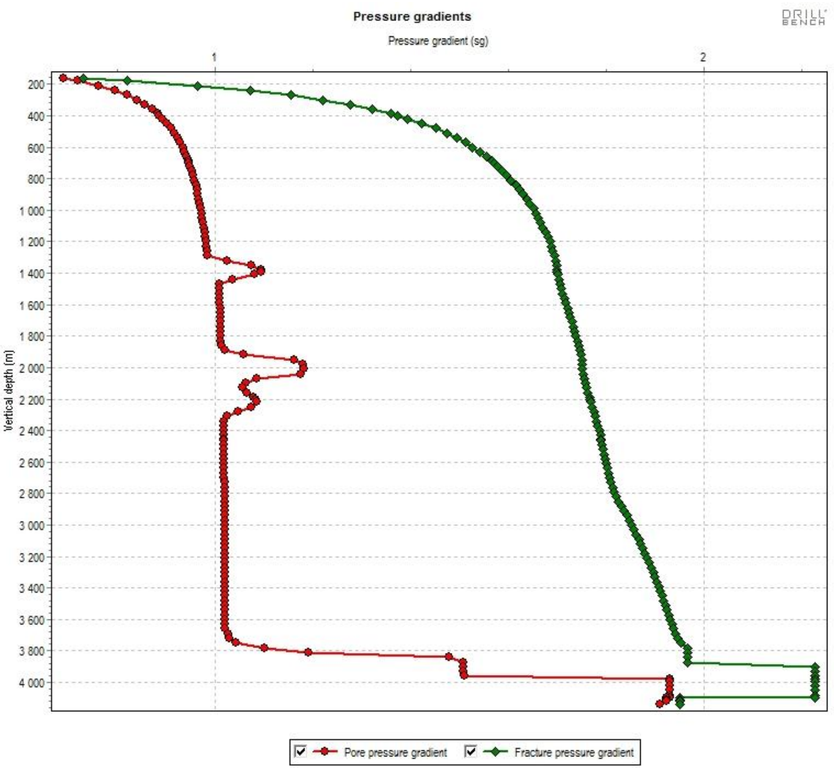

Figure 58: A-14 initial pore and fracture gradient after 2 years depletion (~140 bar).

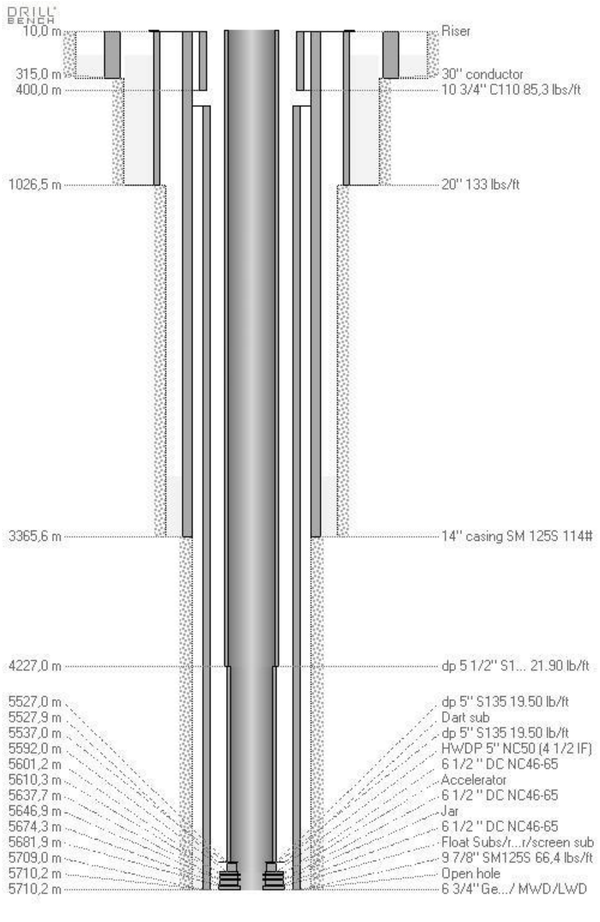

Figure 59: A-14 wellbore geometry.