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Depleted reservoir drilling: A study of the Ula field in the North Sea



Master Thesis

By

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Abstract

Ula is an oil field operated by BP in the southern part of the Norwegian North Sea. As the field matures depleted intervals are drilled to access remaining reserves. Drilling in highly mature fields is challenging, both with respect to loss of circulation and differential sticking. On the Ula field there is a pressure barrier/baffle isolating parts of the Ula reservoir units. This pressure barrier creates a pressure differential between the units. The units above the barrier (1A1-1A2) have been produced since 1998 without any pressure support, resulting in a pressure decrease in this zone. The units beneath the barrier (Units 2-3) have been produced since 1987 and have been supported by both water- and WAG-injection, giving a much higher formation pressure in these units compared to the units above the barrier. The pressure differential between Units 1 and 2 have produced challenges drilling this interval in terms of losses during drilling and cementing operations.

This thesis describes the challenges in drilling depleted formations with respect to lost returns and differential sticking. The Ula field in the North Sea will be the primary focus throughout the thesis. The study involves reviewing BP's drilling practices on the Ula field and proposing potential recommendations and improvements. Maximum overbalance on the Ula field and different options for drilling depleted reservoirs will be evaluated. Wellbore strengthening techniques and the potential benefits of using such techniques will also be presented.

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1 INTRODUCTION

Drilling costs on the Norwegian continental shelf has increased dramatically since 2004. The daily rental rates for semi-submersible rigs have increased from 147 500 dollars in July 2004 to 500 000 dollars in August 2009. As the costs have gone up, the drilling efficiency in the same time period has gone down, further worsening the situation [53].

As cost goes up and drilling efficiency goes down, the economic impact of non-productive time (NPT) increases as well. Stuck pipe is, for most drilling organizations, the greatest drilling problem worldwide in terms of time and financial cost. It is a situation whereby the drill string cannot be moved along the axis of the wellbore. Lost circulation is another main contributor to NPT and costs operators millions of dollars annually. Other forms of loss, such as matrix seepage and filtrate loss is also of concern, however, fracture propagation is the main contributor to lost returns expenditures. Not only is lost circulation costly, it is also potentially dangerous, thus representing a safety risk that has to be avoided. Induced losses occur when the mud weight, required for well control and to maintain a stable wellbore, exceeds the fracture resistance of the formations.

As producing fields mature, depleted intervals are drilled to access remaining reserves. Today many oil-producing fields in The North Sea are gradually becoming more mature and the Ula field is among these. Drilling into depleted reservoirs is challenging as the fracture gradient of the reservoir is reduced due to pressure depletion from production. Drilling in depleted formations require more advanced drilling techniques and mud designs to mitigate/prevent common problems encountered in depleted reservoirs. In some cases it is virtually impossible to drill through depleted zones as the mud weights required to control adjacent zones creates a very high overbalanced state when drilling through the depleted sands. As mentioned earlier this often leads to severe mud losses and creates the possibility of sticking the bottomhole assembly (BHA), drill pipe, or liner / casing. Operators can choose among different approaches when drilling through depleted formations:

- Under balance drilling
- Casing while drilling
- Additional Casing or liner before and after the depleted formation
- Expandable casing/liner

- Strengthening wellbore by increasing hoop stress with heat
- Strengthening wellbore by increasing hoop stress with particles (“Stress Caging”)

Major lost returns events occur anytime wellbore pressure exceeds wellbore integrity. The integrity consists of the formation minimum stress holding the borehole closed and a small amount of tensile strength in the rock. During the last decades there has been very little progress in how the drilling industry handles lost circulation problems. In the mid-1990’s the oil industry implemented the Fracture Closure Stress (FCS) Operational Practices. This concept was based on the fracture mechanics model used in stimulation design and it showed that integrity was increased by increasing the fracture width. FCS practices are applied as discrete pills after losses have occurred. Recently a new concept of continuous treatment that strengthens the wellbore while drilling has been developed. The concept of continuous borehole strengthening is built on the success of FCS treatments and they share many of the same attributes such as high solids concentration and high fluid loss.

2 THE ULA FIELD

2.1 Introduction

The Ula Field is a mature water-flooded oil-field situated some 270 km south-west of Stavanger in block 7/12 of the Norwegian sector of the North Sea (See fig. 1). The water depth is around 70 metres. BP Norway AS is the current operator with an ownership of 80% and the remaining 20% is owned by Dong E&P Norway AS. The Ula Field was discovered in 1976 when Conoco drilled Well 7/12-2 into the crest of the structure. First oil was produced in 1986 and plateau oil production of 100 to 150 thousand bbl was maintained until late 1993. The field is now off plateau and current oil production is close to 30 thousand bbl.

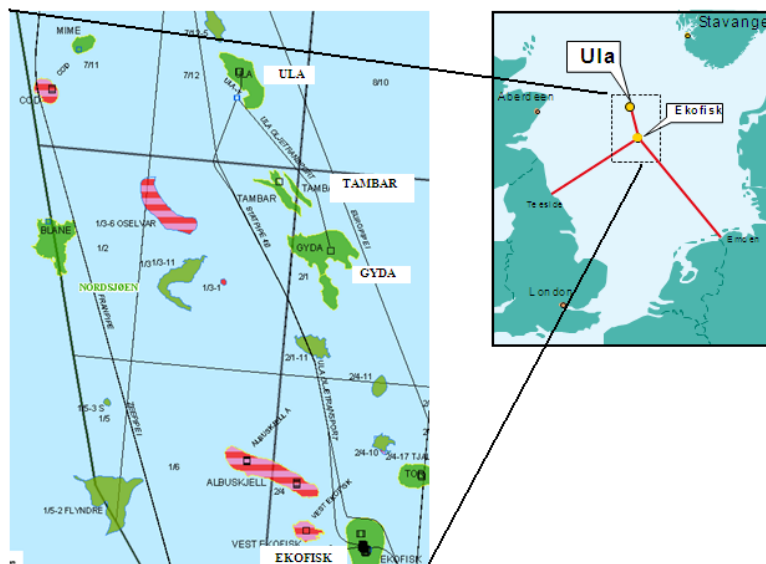


Figure 1 - Ula Field location in the North Sea [2].

The Ula platform consists of three conventional steel facilities, connected by bridges, for production, drilling and accommodation. The oil is transported by pipeline via Ekofisk to Teesside and all gas is re-injected into the reservoir in order to increase the oil recovery [1]. In 2001 the Tambar field, which lies some 16 km SE of Ula was commissioned as a remotely controlled wellhead platform tied back to Ula. The well stream from the Blane field was tied to the Ula field for processing in 2007 [2,3].

Initially, oil was recovered by pressure depletion, but after 2 years water injection was implemented to improve recovery. From 1994 and onward the oil production saw a sharp decline and went from plateau production of more than 100 mbd to around 40 mbd in 1997. To arrest the sharp decline in production rates, two programs were initiated; horizontal infill

drilling targeting the thin, lower permeability Unit 1 reservoir layer, and a Water Alternating Gas scheme (WAG), targeting the very high residual oil saturation after water flood. Due to the initiation of these programs, BP was able to arrest the sharp decline on the field. Today, production from unit 1 contributes 2/3 of the overall production, while the remaining 1/3 is a direct result of the WAG scheme [4].

2.1.1 Lithology at the Ula field

The Ula field is situated on the eastern margin of the Central Graben. The lithology at the Ula field is shown in figure 2. The formation above the Rogaland group (Nordland and Hordaland groups) has historically been drilled successfully in recent drilling campaigns, using oil based muds (OBMs) of 1.65 SG. Some sticking and tight spots were encountered in earlier wells using a lower mud density than the one being applied today.

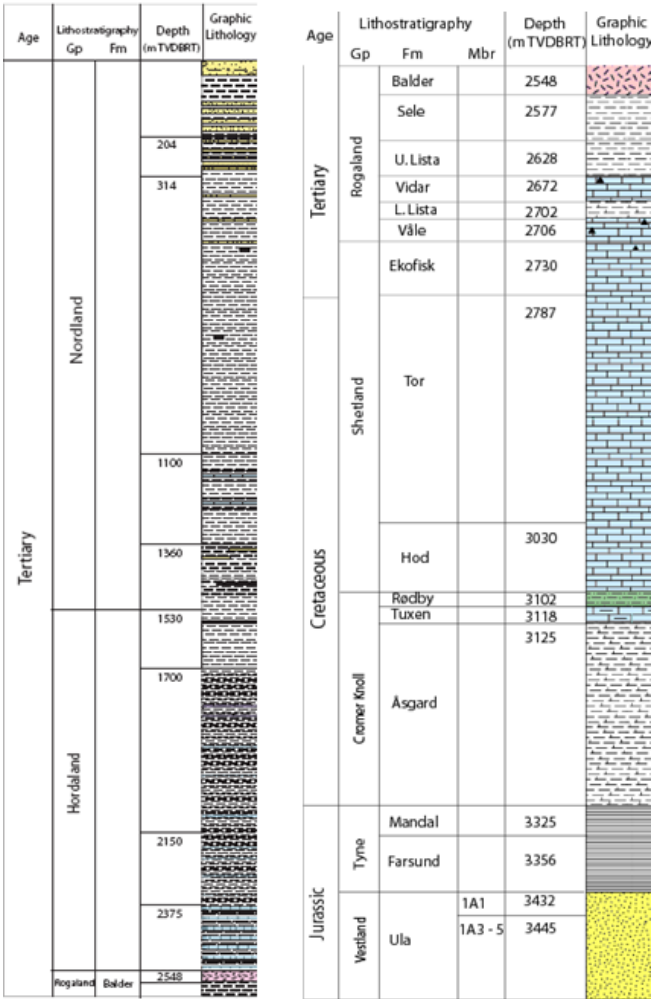


Figure 2 - Generalised lithostratigraphy of the Ula field.

Nordland and Hordaland groups consist mainly of mudstones. The Rogaland group (Balder, Sele, U.Lista, Vidar, L.Lista and Våle formations) consist mainly of tuffaceous mudstone (Balder), dark grey mudstone (Sele, U.Lista and L.Lista) and chalky limestone (Våle and Vidar). The section has historically been drilled successfully with a MW of 1.65 SG. Formation pressures throughout the Rogaland group are considered stable, with a predicted pore pressure of around 1.46 SG. The leak off tests (LOTs) in this section range from 1.80 SG to 1.98 SG.

The Shetland group (Ekofisk, Tor and Hod formations) consist mainly of chalky limestone. It is considered generally stable with respect to formation pressures. An average pore pressure of 1.46 SG has been predicted for this interval. The Shetland group has been drilled successfully using a MW of 1.65 SG. Minimum fracture pressures of between 1.92 and 1.97 SG are expected from this section.

The Cromer Knoll group (Rødby, Tuxen and Åsgard formations) consist mainly of grey mudstone (Rødby and Åsgard) and hard limestone (Tuxen). This group follow the stable trend seen in the overlaying Shetland group, but in the Åsgard formation, the formation pressure ramps up to 1.63 SG in the lower part of the unit. In recent drilling campaigns a MW of 1.65 SG has been applied for this section. A minimum fracture pressure of 1.99 SG is prognosed at the top of the Åsgard formation, increasing slightly to 2.01 SG at the base of the unit.

The Tyne group (Mandal and Farsund formations) consist mainly of dark grey mudstone. The group has a decreasing pore pressure profile, from an average value of 1.54 SG at the top Mandal to 1.46 SG at the base of the Farsund formation. In the lowermost 8 metres of the Farsund formation thin low permeability sandstone stringers are developed and partial communication with the underlying depleted reservoir exists. Well A-14A experienced partial lost returns when drilling with a MW of 1.64 SG 14 metres TVD above the reservoir. Also Well A-7C experienced lost returns in this section when drilling stopped 0.5 metres above the reservoir. Reducing the MW from 1.68 to 1.63 SG ceased the fluid loss and was sufficient to ensure borehole stability. The minimum fracture pressure in the Tyne group is expected to be approximately 2.00 SG.

2.1.2 Ula Reservoir Characterisation

The Ula field is situated on the eastern margin of the Central Graben. The trap is relatively simple: a four-way elongated salt induced dip closure, with a elongated NW-SE fault system bisecting the structure, with ca. 500 metres of vertical closure, dissected into two major and a number of minor blocks by normal faults. The reservoir is located at depths from 3350 to 3800 metres (see fig. 3) and the static temperature in the upper reservoir section is close to 134°C. Several oil-water contacts (OWCs) have been found within the field area, with the shallowest located in the west flank.

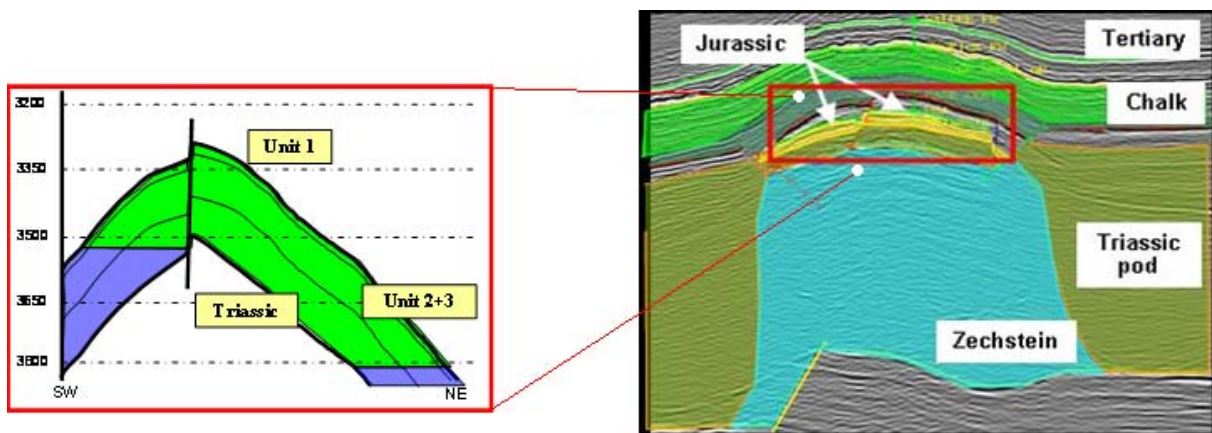


Figure 3 - Ula reservoir depths in a SW-NE profile, showing OWCs in the western and eastern flanks [2].

The main reservoir is moderately deep and located at a depth of 3 350 metres in the upper Jurassic Ula Formation. The source rock for the oil is the overlying Mandal formation, and the main oil accumulation is in sandstones of the late Jurassic Ula formation. The reservoir thickness varies from 80 to 160 metres and a subdivision into three main units has been made, Unit 1-3.

The reservoir consists of three layers and two of them are producing well. The Ula formation includes upper Jurassic shallow marine sandstone and it can be divided into three main units, 1, 2 and 3 (see fig. 4). The divisions into different reservoir units are based upon permeability variations. Unit 1 is very fine grained and is of poorer reservoir quality than Unit 2 - 3, with average porosity of 17% and permeabilities of 20mD. The best reservoir quality is found in Units 2 to 3, which comprise high net to gross sands, where porosity averages 16 to 25% and permeability ranges from 100 to 1500 mD with an average of 200 mD. The Ula formation is generally massive, fine to medium grained, grey sandstone. Sorting and angularity vary between individual units of the formation [3,8].

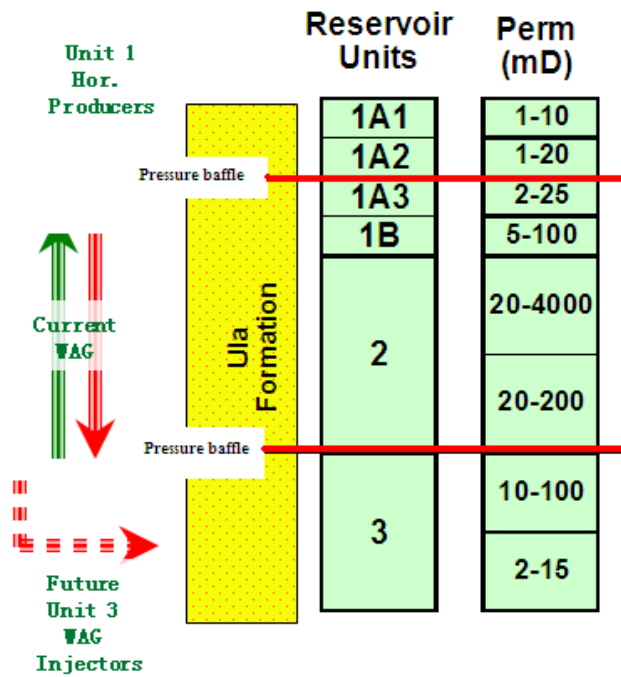


Figure 4 - Ula reservoir units with permeability variations [2].

The reservoir is not homogeneous, due to barriers/baffles isolating reservoir units and causing pressure differential. The pressure barrier located at the base of zone 1A2 consists of one or more mudstone beds. These beds are very thin (1-5 cm) and the pressure baffle/barrier is capable of holding pressures up to 1000 psi (See fig. 4). The presence of these barriers may prevent the pressure change from being transmitted to overlying or lower layers [2,3].

Units 2 to 3 are in pressure communication and were developed during the early years of production, 1986 to 1997. Development of Unit 1 was started in 1997 with the drilling of Well 7/12-A-10A and has continued in staggered drilling campaigns to the present time, with the latest oil producer, 7/12-A-15A being completed in November 2009. Ula field production is now at a mature stage and production is dominated by 4 horizontal Unit 1 oil producers and 2 vertical Unit 2-3 WAG oil producers [17].

3 Theory

3.1 Introduction

Rock failure is an important phenomenon for petroleum related rock mechanics, as it is the origin of severe problems such as borehole instability and solids production. Analyses of the rock mechanical properties and the in-situ stresses of the subsurface formations are therefore essential for a successful drilling operation. Rock failure is a complex process which can be difficult to predict. The models used in rock mechanics are only simplified descriptions of real rock behaviour. This is important to keep in mind when performing rock mechanical analysis and be aware of the possibility that some models may give inaccurate results. The model predictions can be improved by appropriate calibration.

When designing a well trajectory several factors have to be evaluated. To prevent wellbore instability, factors such as rock properties, in-situ stresses, chemical interactions between shale and drilling fluids and thermal effects should be considered, and drilling fluid formulations to mitigate wellbore instability problems. Especially shale formations is regarded as a major challenge in the drilling industry, as these formations have very low permeability and are reactive when exposed to water based mud (WBM). Shale instabilities most often occur in the overburden, but sometimes also within the reservoir. New challenges have appeared in recent years. The industry demand for more advanced well trajectories such as highly deviated, multilateral and horizontal wells have increased the necessity for accurate rock mechanical analyses. Stable drilling is normally more difficult in deviated than in vertical boreholes. The increasing number of infill drilling in depleted reservoirs is also making the stability issue more difficult [6].

3.1.1 Stresses around boreholes

Stresses around a well are essential for discussion of well problems. The stresses around a wellbore are governed by Hooke's law, equilibrium equations and compatibility equations. Underground formations are always in a stressed state, due to the overburden and tectonic stresses. When drilling a well we get stress redistribution around the well. As we drill, stressed solid material is removed and the borehole wall is then only supported by the fluid pressure in the hole. Generally this fluid pressure does not match the in-situ stresses and cannot transfer shear stress. This may lead to deviatoric stresses greater than the formation can support, and failure may result.

Changes in reservoirs arise from changes in the pore pressure. The pore pressure is decreasing due to production, and increasing due to injection. The total stress will have contribution from forces transmitted through the solid skeleton and from the fluid or gas

within the pores. Pore pressure and total stress are connected through the effective stress law [6]:

$$\sigma' = \sigma - \alpha P \quad (3-1)$$

where σ is the total stress, the P is the pore pressure, and α is the Biot's constant.

The biot's constant is given by:

$$\alpha = 1 - \frac{K_{fr}}{K_s} \quad (3-2)$$

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

For high porous weak material we often set $\alpha=1$.

The general solution for a deviated borehole with anisotropic horizontal stress is best described using cylindrical polar coordinates. The stresses at a point P identified by the coordinates r, θ, z , are denoted $\sigma_r, \sigma_\theta, \sigma_z, \tau_{r\theta}, \tau_{rz}$ and $\tau_{\theta z}$, where r represents the distance from the borehole axis, θ the azimuth angle relative to the x-axis, and z is the position along the borehole axis. The stress field in an arbitrarily inclined borehole was considered by *Fairhurst* (1968) and the general elastic stress solutions can be written [6]:

$$\begin{aligned} \sigma_r = & \frac{\sigma_x^o + \sigma_y^o}{2} \left(1 - \frac{R_w^2}{r^2} \right) + \frac{\sigma_x^o - \sigma_y^o}{2} \left(1 + 3 \frac{R_w^4}{r^4} - 4 \frac{R_w^2}{r^2} \right) \cos 2\theta \\ & + \tau_{xy}^o \left(1 + 3 \frac{R_w^4}{r^4} - 4 \frac{R_w^2}{r^2} \right) \sin 2\theta + p_w \frac{R_w^2}{r^2} \end{aligned} \quad (3-3)$$

$$\begin{aligned} \sigma_\theta = & \frac{\sigma_x^o + \sigma_y^o}{2} \left(1 + \frac{R_w^2}{r^2} \right) - \frac{\sigma_x^o - \sigma_y^o}{2} \left(1 + 3 \frac{R_w^4}{r^4} \right) \cos 2\theta \\ & - \tau_{xy}^o \left(1 + 3 \frac{R_w^4}{r^4} \right) \sin 2\theta - p_w \frac{R_w^2}{r^2} \end{aligned} \quad (3-4)$$

$$\sigma_z = \sigma_z^o - \nu \left[2(\sigma_x^o - \sigma_y^o) \frac{R_w^2}{r^2} \cos 2\theta + 4\tau_{xy}^o \frac{R_w^2}{r^2} \sin 2\theta \right] \quad (3-5)$$

$$\tau_{r\theta} = \frac{\sigma_y^o - \sigma_x^o}{2} \left(1 - 3\frac{R_w^4}{r^4} + 2\frac{R_w^2}{r^2} \right) \sin 2\theta + \tau_{xy}^o \left(1 - 3\frac{R_w^4}{r^4} + 2\frac{R_w^2}{r^2} \right) \cos 2\theta \quad (3-6)$$

$$\tau_{\theta z} = \left(-\tau_{xz}^o \sin \theta + \tau_{yz}^o \cos \theta \right) \left(1 - \frac{R_w^2}{r^2} \right) \quad (3-7)$$

$$\tau_{yz} = \left(\tau_{xz}^o \cos \theta + \tau_{yz}^o \sin \theta \right) \left(1 - \frac{R_w^2}{r^2} \right) \quad (3-8)$$

The solutions depend on the angle θ indicating that the stresses vary with position around the wellbore. The superscript o on the stresses denote that these are virgin formation stresses. At the wellbore wall ($r=R$), the equations are simplified to:

$$\sigma_y = p_w \quad (3-9)$$

$$\sigma_\theta = \sigma_x^o + \sigma_y^o - 2(\sigma_x^o - \sigma_y^o) \cos 2\theta + 4\tau_{xy}^o \sin 2\theta - p_w \quad (3-10)$$

$$\sigma_z = \sigma_z^o - \nu \left[2(\sigma_x^o - \sigma_y^o) \cos 2\theta + 4\tau_{xy}^o \sin 2\theta \right] \quad (3-11)$$

$$\tau_{r\theta} = 0 \quad (3-12)$$

$$\tau_{\theta z} = 2(-\tau_{xz}^o \sin \theta + \tau_{yz}^o \cos \theta) \quad (3-13)$$

$$\tau_{yz} = 0 \quad (3-14)$$

where ν is the Poisson's ratio, τ is the shear stress and R_w is the borehole radius.

These equations are used in linear elastic analysis of borehole stability and are valid for nonporous materials or for porous material with constant pore pressure [7].

The Ula Field is situated mainly in an extensional normal faulting stress regime ($\sigma_v > \sigma_H > \sigma_h$) (see fig. 5) with some compression in areas where the fault is transferred laterally. To increase the likelihood of a stable wellbore in an extensional regime the horizontal well should be placed parallel to the minimum horizontal stress (σ_h). In an extensional regime the

wellbore would be least stable in parallel σ_H -orientation. Since the vertical stresses exceed the horizontal stresses on the Ula field, fractures will form in the vertical plane. The importance of these effects depends on the difference between σ_h and σ_H , the horizontal stress anisotropy [2,5].

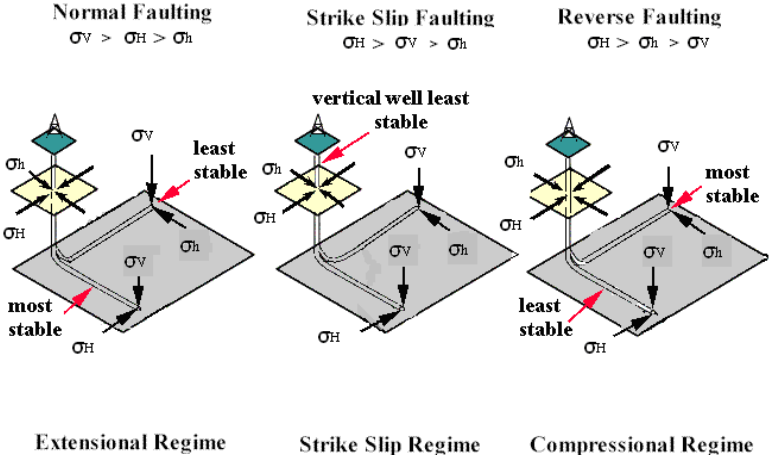


Figure 5 - The figure show the most stable and least stable direction of wellbores in different stress regimes [Modified from ref. 5].

3.1.2 Borehole Failure

Failure in boreholes is governed by the principal stresses. When drilling a circular hole in a homogeneous stress field, stresses will concentrate around the hole since no force can be carried through the interior void. If the stress magnitude somewhere exceeds the failure criterion for the rock, the rock fails. “Borehole failure criterion” simply means the boundary conditions for which borehole failure occurs. Borehole failure according to this definition is normally borehole deformations of some kind (see fig. 6).

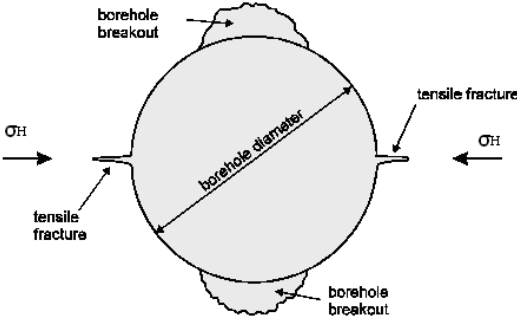


Figure 6 - Stability problems during drilling [Modified from ref. 11].

The largest stress difference (deviatoric stress or shear stress) occur at the borehole wall, hence rock failure is expected to initiate there. For a vertical hole with isotropic (materials whose response is independent of the orientation of the applied stress), isotropic horizontal stresses and impermeable borehole wall (pore pressure is not influenced by the well pressure) principal stresses at the borehole wall are [6]:

$$\sigma_r = p_w \quad (3-15)$$

$$\sigma_\theta = 2\sigma_h - p_w \quad (3-16)$$

$$\sigma_z = \sigma_v \quad (3-17)$$

where $\sigma_r = p_w$ is well pressure, σ_θ is tangential stress, σ_h is min. horizontal stress and $\sigma_z = \sigma_v$ is vertical stress.

The borehole may fail for different conditions, depending on the principal stresses. If the borehole pressure is very low ($\sigma_r = p_w$), we may get a situation where $\sigma_\theta > \sigma_z > \sigma_r$ at the borehole wall. According to the Mohr-Coulomb criterion, failure will then occur when:

$$\sigma'_\theta = C_0 + \sigma'_r \tan^2 \beta \quad (3-18)$$

where σ'_θ is the effective tangential stress, σ'_r is the effective radial stress, C_0 is the uniaxial compressive strength and β is the failure angle, related to the internal friction angle (ϕ) of the material:

$$\beta = 45^\circ + \frac{\phi}{2} \quad (3-19)$$

In addition to shear failure, we must consider situations with high well pressures. These situations can result in a negative effective tangential stress (σ'_θ) according to Eq. (3-16). If $\sigma'_\theta < -T_0$, where T_0 is the tensile strength of the material, tensile failure will occur at the borehole wall. This is an additional criterion for borehole failure:

$$p_{w,\max}^{frac} = 2\sigma_h - p_o + T_0 \quad (3-20)$$

where $p_{w,\max}^{frac}$ is max. well pressure for fracture initiation, σ_h is min. horizontal stress, p_o is pore pressure and T_0 is the tensile strength of the formation.

Eq. (3-20) is often referred to as the Kirsch fracture model and is used in the oil industry for prediction of fracture initiation pressures. This fracture model is very simple and is not useful for analysis of load history. If the well pressure is increased above the value given by Eq. (3-20), tensile failure will occur at the borehole wall. Borehole failure of this kind is called hydraulic fracturing. This fracture criterion applies for perfectly circular holes and linear elastic materials. The model also assumes a non-penetrating mud cake, which means that a mud cake prevents filtrate losses. In practice, these conditions will only be partly fulfilled, and hence the real limit for hydraulic fracturing will occur at a lower value for p_w [10].

It is important to understand that for a hydraulic fracture to create a drilling problem, the fracture needs not only to be initiated, but also to propagate beyond the near well region. A hydraulic fracture will only propagate if the pressure in the fracture exceeds the minimum principal stress, plus an additional term depending on the conditions for fracture growth at the tip. Mud loss into pre-existing fractures is also a likely scenario. This will happen if the well pressure is high enough to reopen such a fracture. During drilling operations the well pressure should therefore not exceed the fracture closure pressure [minimum principal stress], plus an additional contribution which is quantified on the basis of operational experience [6].

In the paper “A New Fracture Model that includes Load History, Temperature and Poisson’s effects” [9], the authors Aadnoy and Belayneh have presented a more precise model which gives a better assessment of the fracture strength, leading to better predictions. They have implemented the effects of Poisson’s ratio and the effect of temperature on the fracturing pressure into the fracture model.

When the borehole pressure is no longer equal to the in-situ stress state a Poisson’s effect arise. This effect can be taken into account by implementing a scaling factor to the model.

$$C = \frac{(1+\nu)(1-\nu^2)}{3\nu(1-2\nu)+(1+\nu)^2} \quad (3-21)$$

where C is the scaling factor and ν is the Poisson's ratio. The lower the Poisson's ratio is, the lower will the fracture gradient be. This relationship implies that sands are most prone to mud losses from fracturing. Below are listed the typical ranges of observed Poisson's ratios for common lithologies [18]:

- Sands: 0.10 to 0.22
- Silts: 0.15 to 0.30
- Carbonates: 0.20 to 0.35
- Shale: 0.22 to 0.48
- Salt: 0.45 to 0.50

The effect of temperature is also identified as having an effect on the fracture pressure. The temperature effect on the fracturing equation can be expressed as:

$$KE\kappa\Delta T \quad (3-22)$$

where E is the modulus of elasticity, κ is the coefficient of linear thermal expansion ($^{\circ}C^{-1}$), ΔT the temperature change from initial condition ($^{\circ}C$) and K is a scaling factor given by the Poisson's effect [9]:

$$K = \frac{(1+\nu)^2}{3\nu(1-2\nu)+(1+\nu)^2} \quad (3-23)$$

The general fracturing equation for arbitrary wellbore orientation now becomes [9]:

$$P_{wf} = \sigma_y + \frac{(1+\nu)(1-\nu^2)}{3\nu(1-2\nu)+(1+\nu)^2} \{\sigma_x - \sigma_y - P_o\} + P_o + \frac{(1+\nu)^2}{3\nu(1-2\nu)+(1+\nu)^2} EK(T - T_{init}) \quad (3-24)$$

where σ_x is the least normal stress acting on the borehole, P_o is the pore pressure, P_{wf} is the fracture initiation pressure, and the in-situ stresses are transformed in space and referred to the x, y - coordinate system.

Compared to the classical Kirsch equation, this model starts with the initial in-situ stress and the virgin in-situ temperature. The mechanical and thermal loading towards fracturing is therefore modelled from this initial state. Examples show that if the Poisson's effect is neglected, the fracture pressure is severely under-predicted. Also temperature effects are important for accurate predictions, especially for WAG-injectors. Typical WAG wells are often injected with cold water over a period of time. When the gas injection starts, temperature rise because gas heats up when it is pressurized through the gas compressors [9].

The traditional method to measure the fracture gradient of a subsurface formation is through the use of leak-off tests. A leak-off test is conducted when casing is set immediately above the interval to be measured and approximately three meters of fresh formation is drilled below the casing shoe in the formation to be tested. It is a test to determine the strength or fracture pressure of the open formation. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure that the formation experiences. At some pressure, fluid will enter the formation, or leak off, either moving through permeable paths in the rock or by creating a space by fracturing the rock. The results of the leak-off test dictate the maximum pressure or mud weight that may be applied to the well during drilling operations. To maintain a small safety factor to permit safe well control operations, the maximum operating pressure is usually slightly below the leak-off test result. [14,18].

Figure 7 shows how the relationship between different pressures as the extended leak-off test (XLOT) is conducted.

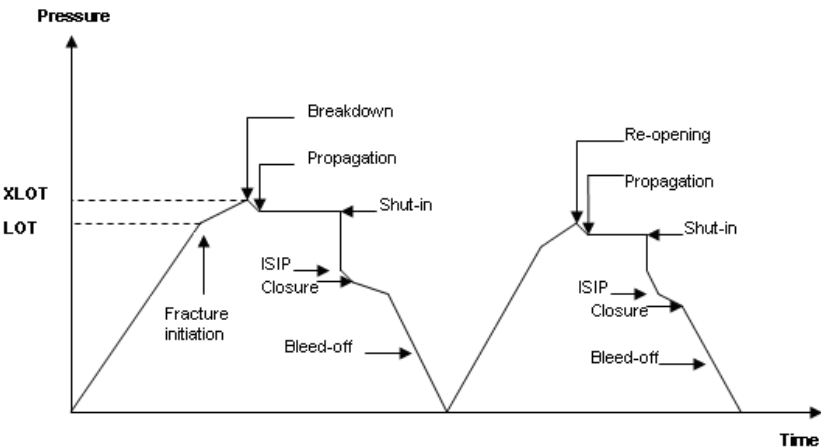


Figure 7 - The Extended leak-off test with two cycles, and show relationship between different pressures that is related to fracture propagation in the rocks.

To get more precise stress data it is often preferable to perform an extended leak-off test. An extended leak-off test takes about an hour to perform, but provides far more precise data

than a normal LOT, and is the recommended test when stress data is required. From an extended leak-off test one can find the ratio between the LOT and the minimum horizontal stress (σ_h), which usually is in the range of 1.02 – 1.10. In figure 7 the minimum horizontal stress can be found at the closure point. By analyzing the plot one can find the ratio between the fracture initiation point (LOT) and the closure point (σ_h). On Ula the common procedure is to perform a standard LOT or a formation integrity test (FIT). Sometime both tests are omitted due to the risk of losses.

The minimum in-situ stress is time - and history - dependent. It changes over the time of the reservoir because of reservoir depletion or injection. The in-situ stresses play a vital role in fracture prediction as they control the orientation, opening and propagation of induced and/or natural fractures. Depletion of a zone has two major effects [26]:

- The lateral total stress drops (S_h)
- The effective stresses rise (σ'_v, σ'_h)

The result of these effects taking place is a decrease in the fracture gradient in the depleted zone and an increase in the confining stress (stronger rock). Typical consequences that arise [26]:

- Slower drilling because the rock is tougher (Different bits may be required)
- LC and blowout risks go up substantially
- More casing strings and possible LCM squeezes

Figure 8 illustrates how the pore pressure decline and the stress are redistributed in a depleted sand zone. The σ_h “lost” in the reservoir zone is redistributed above and below the reservoir.

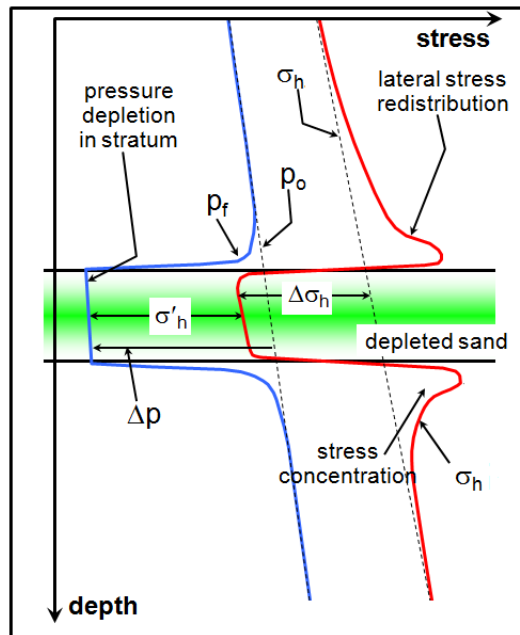


Figure 8 - Reservoir depletion and stress redistribution [26].

The pressure depletion directly affects the fracture gradient, and decreases the fracture resistance of the formation. Predictive methods are required to extrapolate the new fracture gradient in the depleted zone based on previous measured pressure data. The change in the fracture gradient can be found from the following relationship [60]:

$$\Delta P_{fg} = a * \Delta P_p \quad (3-25)$$

where a is given by

$$a = 1 - \frac{\nu}{(1-\nu)} \quad (3-26)$$

where ΔP_{fg} is the change in fracture gradient, ΔP_p is the change in reservoir pressure and ν is the Poisson's ratio. The parameter a is a factor which dictates the trend of the minimum stress with reservoir depletion.

Figure 9 illustrates the prognosed formation pressure detail for the top Ula reservoir. From the figure we can see a step decline in the pore pressure when entering the top reservoir section. This decline in pressure comes from production in the top Ula reservoir, where the pressure barrier is effectively preventing pressure transmission from the lower Ula Units.

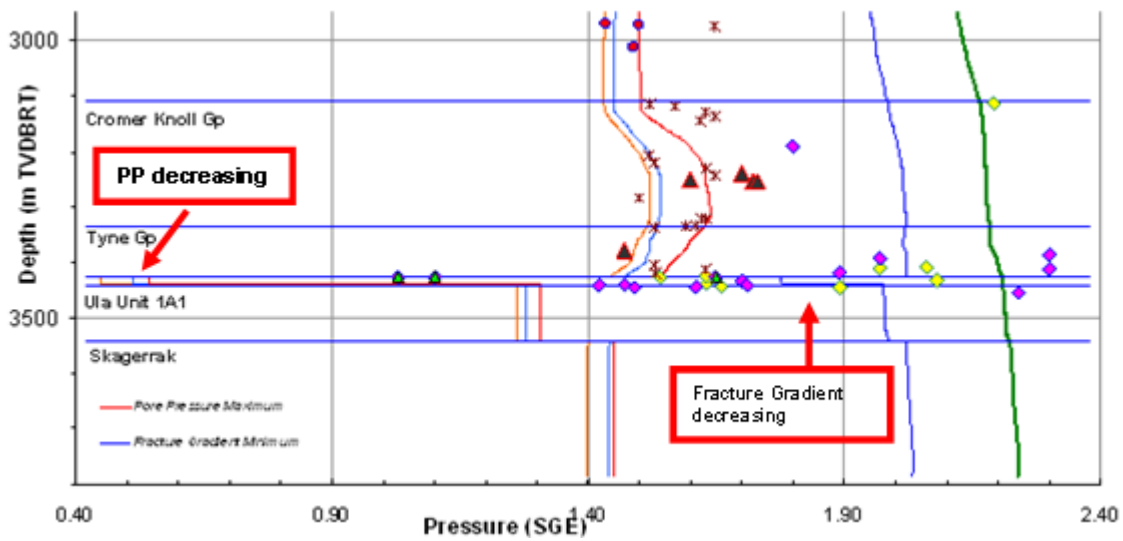


Figure 9 - Shows the prognosed formation pressure detail for the top Ula formation.

Figure 10 shows datapoints taken at the 9 5/8" shoe on Ula. A bit too few datapoints exist to develop a strong correlation between the fracture gradient and the reservoir pressure depletion. The historic data could be used to indicate a trend; however, the large scatter in the data gives a very weak indication of the present stress regime. The trend is showing a decline in potential fracture gradient due to depletion, as expected.

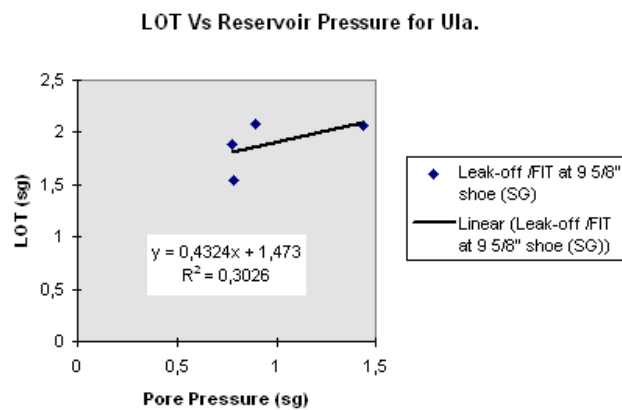


Figure 10 - LOT/FIT data at 9 5/8" shoe (SG) and a linear trend based on these datapoints [41].

3.2 Stability during drilling

Borehole instabilities during drilling is a major challenge for the oil industry. Instabilities most often occur in shale or mudstone, and may result in “tight hole” or “stuck pipe” incidents. As mentioned earlier there have been an increasing number of highly deviated wells over the last decades. This development has made stable drilling more challenging, as it is more difficult to maintain stability in deviated than in normal faulting stress regimes. Figure 11 shows a complete procedure of borehole stability analysis. The input data required are rock properties, earth stresses, pore pressure, and the planned hole trajectory.

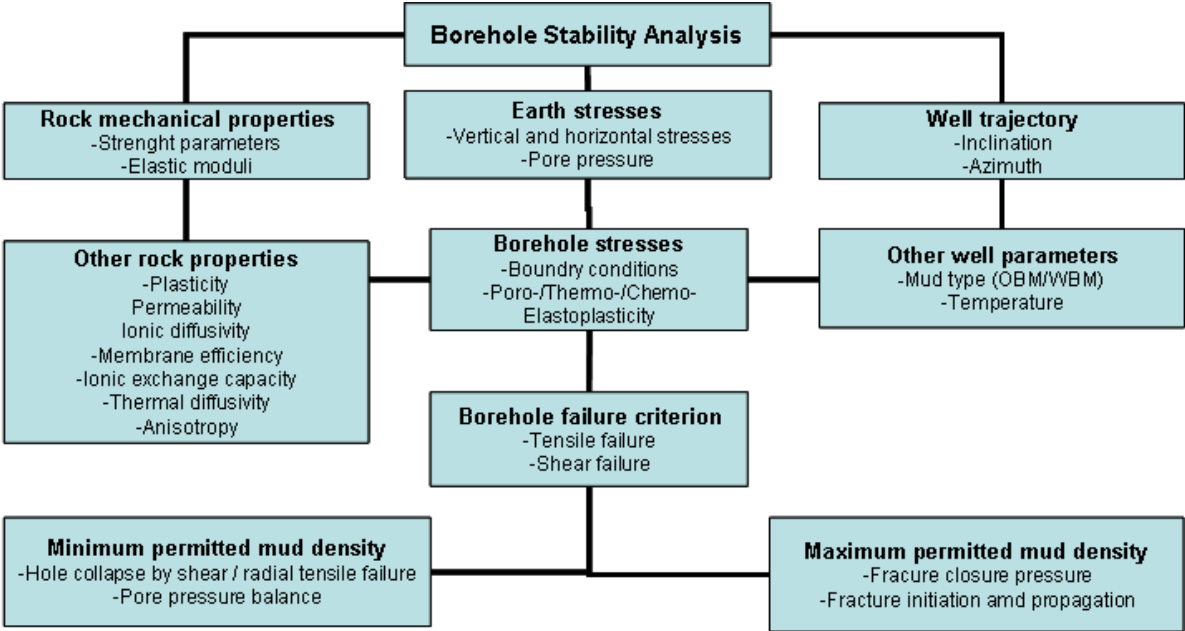


Figure 11 - Schematic borehole stability analysis [Modified from E. Fjær, ref. 6].

One of the key parameters for stable drilling is the mud weight. From the borehole stability analysis the mud weight window can be predicted. The selection of mud weight is governed by the pore pressure gradient and the fracture pressure gradient. In order to prevent influx of fluids it is necessary to keep the mud weight above the pore pressure gradient. To prevent loss of mud into fractures, it is necessary to keep the mud weight below the fracture gradient. A wider mud weight window is preferable compared to a narrow mud window. The mud weight window can be widened by adding LCM material that is proportioned to the specific local conditions. This development has led to an increased chance of successful drilling in

narrow mud weight windows. There are several advantages in operating in a wide mud weight window [6]:

- Total depth (TD) can be reached with fewer casing strings. The upper sections can be spudded with smaller bits, and still maintain the required production pipe diameter.
- Cutting volumes and disposal costs can be substantially reduced.
- Mud density, volume and other properties can be adjusted to help reduce fluid costs and to help optimize drilling performance.
- Cement volume can be reduced and placement quality can be improved.
- The total operation from drilling, casing installation and cementing can be done more quickly.

Figure 12 illustrates how different mud weights are chosen based on the fracture gradient and the pore pressure gradient. The figure also illustrates the two main tools available to drill stable boreholes: the mud weight and the casing program. It is not possible to drill the entire section with one mud weight, hence casings has to be set to seal off the upper part of the section before continuing with an increased mud weight. To reduce costs it is in the operator’s interest to use as few casing strings as possible. Another reason to keep the number of casing strings at a minimum is the reduction in casing diameter for each new string.

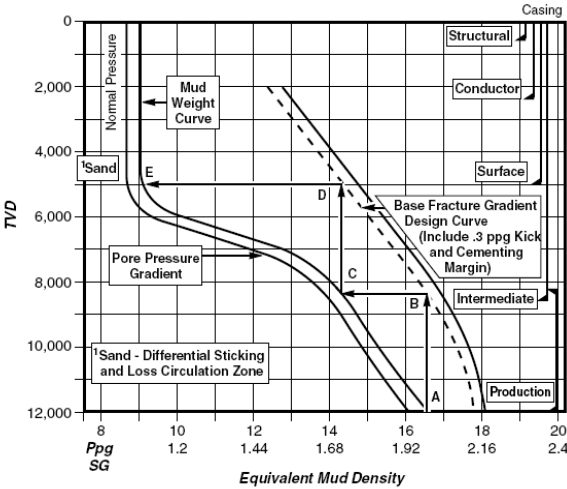


Figure 12 - Illustrates how mud weight and casing setting depths depend on pore pressure gradient and fracture pressure gradient [13].

The mud serves three main purposes: To prevent flow of pore fluid into the well, to prevent hole instabilities and to transport drill cuttings from the hole to the surface. The mud density ρ_w controls the pressure in the well:

$$p_w = \rho_w gD \quad (3-27)$$

where g is the acceleration due to gravity and D is the vertical depth.

Circulation of the mud implies that the effective (dynamic) mud pressure in the well is higher than the static pressure expressed by Eq. (3-27). The dynamic well pressure is often referred to as an equivalent circulating density (ECD). The ECD takes into account the pressure drop in the annulus above the point being considered. The ECD is calculated as:

$$ECD = d[ppg] + \frac{P[psi]}{0,052D[ft]} \quad (3-28)$$

where d is the mud weight, d is the true vertical depth (TVD) and P is the pressure drop in annulus between depth D and surface.

The ECD is an important parameter in avoiding kick and losses, particularly in wells that have a narrow window between the fracture gradient and pore pressure gradient [14]. The most fundamental factors affecting the ECD [15]:

- Hole depth
- Circulation rate
- Mud weight
- Rheology of the mud
- Size of the mud
- Size of the hole
- OD of the drill string

- Quantity of cuttings in the annulus

The drill string OD is one of the factors affecting the ECD. The BHA is usually the drill string part with the highest OD, and hence the most critical part. During drilling in critical sections the OD of the BHA should be as small as possible to avoid increased ECD and decreased ability to pump lost circulation material (LCM) through [15].

3.2.1 Borehole instabilities

This section presents the two main types of borehole instabilities; so called "tight hole" or "stuck pipe" incidents, and "lost circulation" or "mud loss" problems. Both of these instabilities are expensive for the operator. Mud loss may also represent a safety risk. There are four main causes for tight hole/stuck pipe incidents [6]:

1. Hole collapse (rock mechanical failure)
2. Inappropriate hole cleaning
3. Differential sticking
4. Deviation from ideal trajectory

Cause 1 (Hole collapse) means that the formation near the borehole fails mechanically, most often by shear failure. The result of this is often an increased borehole size due to brittle failure and caving of the wellbore wall. The borehole size may also increase by erosion in a weak rock. Excessive hole enlargement is often referred to as a "washout", and it usually occurs as a result of too high mudflow intensity near the drill bit. In weak shales, sandstones and salt a reduced borehole diameter may occur.

Cause 2 (Inappropriate hole cleaning) means that drill cuttings or rock fragments produced by formation failure cannot be fully removed by the drilling fluid. Hole cleaning is less problematic in sand than in shale formations, since the drilling mud can more easily remove sand particles than shale cavings. Mechanism 1 and 2 often act together.

Continuously monitoring of the ECD is important to minimize build-up of cuttings downhole. On the Ula field general BP practice is to maintain a low rate of penetration (ROP) to clean the hole continuously, instead of frequent stops to circulate the hole clean. If the drilling fluid is not properly transporting cuttings, the wellbore around the drill string may get plugged. This is often referred to as "pack off" and is observed by a sudden reduction of the ability to circulate and higher pump pressures.

Cause 3 (Differential sticking) is the most likely reason for stuck pipe in a permeable reservoir rock. When the pipe is differentially stuck it cannot be moved (rotated or reciprocated) along the axis of the wellbore. Differential sticking typically occurs when high-contact forces caused by low reservoir pressures, high wellbore pressures, or both, are exerted over a sufficiently large area of the drill string (see fig. 13). The sticking force is a product of the differential pressure between the wellbore and the reservoir, and the area the differential pressure is acting upon. This means that a relatively low differential pressure (ΔP) applied over a large working area can be just as effective in sticking the pipe as can a high differential pressure applied over a small area. In general a thick mud cake increases the likelihood of differentially stuck pipe. Since shales have extremely low permeabilities, and mud-cakes do not form on shales, this mechanism is not possible in shales [14].

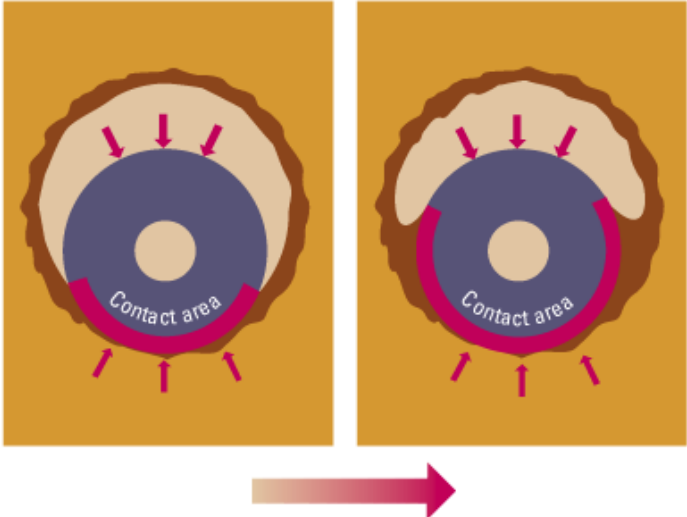


Figure 13 - These cross sectional views show a drill collar embedded in mudcake and pinned to the borehole wall by the pressure differential between the drilling mud and the formation. As time passes, if the drill string remains stationary, the area of contact can increase (right) making it more difficult to free the drill string [14].

Many of the contemporary practices for combating differential sticking were developed in the late 1950s. Examples of the practices include rig crew training, minimizing still-pipe time, stabilization of the BHA, management of filter cake quality, and minimization of overbalance. As the industry started to drill inclined wells and moved into abnormal pressure environments, the incident rate increased as well. The incident rate increased again in the late 1990s as the number of high angle and extended reach trajectories became more common. The high angle wells resulted in a higher contact force on the inclined pipe, higher mud weight (MW) was required for hole stability which increased the overbalance. It is more difficult to free an inclined pipe compared to a vertical pipe. To reduce the number of stuck

pipe incidents the industry has developed recommended practices to lower the risk for differential sticking. The majority of the recommended practices are common in the industry today [16].

Recommended practices to avoid differential sticking [16]:

- Minimize contact area, particularly that of drill collars
- Do not use slick assemblies. The desired objectives can be achieved by other means
- Minimize overbalance, but only in cases where the risk of borehole instability is not increased
- Use heavy weight drill pipe (HWDP) in compression for bit weight in vertical and low angle wells within the limits specified by the manufacturer
- Use conventional drill pipe in compression in intermediate and high angle wells within its helical buckling limits
- Use stand-off subs on drilling jars run above the stabilized BHA
- Conduct progressive pipe sticking tests prior to making connections in wells with high sticking potential
- Conduct API Particle Plugging Tests and use appropriate blocking solids to improve cake quality
- Conduct Drill and Seal treatments to enhance cake quality in intervals of high differential pressure or 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 (NAF) is used and all drill collars are supported

Cause 4 (deviation from ideal trajectory) may result in a stuck pipe situation. Deviations may be caused by non-ideal hole shape. In deviated sections the lower side of the drilling tool may dig into the bottom of the hole and create what is known as a “key seat” (see fig. 14). Larger diameter drilling tools such as tool joints, drill collars, stabilizers and bits are pulled

into the channel, their large diameters will not pass and the large diameter tools may become stuck in the key seat. The tool may also be guided by washouts and breakouts. To prevent incidents like this it is always recommended to keep any turns in the wellbore gradual and smooth. Hole cleaning is more difficult in deviated holes, in particular at angles in the range 40°-60° due to unstable cutting beds. The main reason for this is that hole collapse occurs more easily as deviation increases, as deviated holes are mechanically weaker compared to vertical ones.

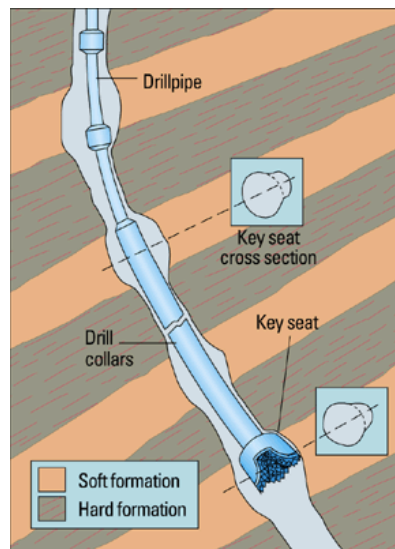


Figure 14 - Key seat. Key seats are often associated with hole deviation and variations in formation hardness [14].

The main consequence of tight hole/stuck pipe situations are loss of time during drilling. Instabilities may also result in difficulties when running wireline logs or other operations such as casing running. The cementing operation is affected by the borehole irregularity as it is difficult to predict the cement volume to be used. A poor cementing of the casing can lead to many different problems such as annular gas migration, problems for perforation, production and stimulation.

An optimal well design is the key to stable drilling. Some of the most important objectives in conjunction with a well design are the well trajectory, mud weight and composition and casing setting depths. One of the main purposes of the well design is to find the well placement that assures optimum drainage during production. The well design must also take into account the drilling speed which will vary depending on the weight on the bit, rotary speed, bit type and size, hydraulics, drilling fluid properties and formation characteristics. One of the most important objectives of the well design is however to assure safe and stable

drilling. If instability occurs during drilling, then the mud is more or less the only adjustable factor. Depending on the borehole stability problem the mud weight will either be lowered or increased. For hole collapse the standard solution is to increase the mud weight. When differential sticking occurs the solution is usually to decrease the mud weight. The diagnosis of the borehole problem is vital, as a wrong diagnosis may lead to even more severe instability problems [6].

3.2.2 Lost circulation

Lost circulation is defined as the reduced or total absence of fluid flow up the annulus when fluid is pumped through the drill string. This implies that a fracture has been created, or that mud is lost into an existing fracture. Operators have different definitions; commonly the following definitions are being used:

- Seepage (Less than 20 bbl/hr)
- Partial lost returns (Greater than 20 bbl/hr)
- Total lost returns (No fluid comes out of the annulus)

When losses occur, the mud level will decrease resulting in a pressure drop in the well. As a consequence, pore fluid may flow into the well from permeable layers higher up. In the presence of gas, this may lead to a rapid increase in well pressure (“kick”) and a high risk of a blowout. To prevent this potential dangerous situation, the main solution is to keep the mud weight below the limit for fracture initiation and growth in non-fractured formations, and below the fracture reopening pressure in naturally fractured formations. There are three conditions that must be met before lost circulation through propagation of a fracture or fault occurs:

- One or more fractures must be in direct communication with the wellbore
- One or more of the fractures must be open enough to allow fluid to enter the fracture
- Fluid pressures must be sufficient to propagate one or more of the fractures

When the margins are small enough, then the ECD may be sufficient to exceed the fracturing pressure. In critical formations such as depleted reservoirs, ECD-control will be critical. This

is why the mud weight is kept well below the critical limit and as close as possible to the pore pressure gradient (see fig. 12). As mentioned earlier, in unfractured formation, fracture growth is necessary in order to lose significant amounts of drilling fluid. However, proper diagnosis must be conducted in order to point out the main cause, as fractured formations are not the only cause for lost circulation. Hole collapse and backreaming may also lead to lost circulation because of the filter cake being removed.

To combat lost circulation different additives are used in the mud system. One type of additive is referred to as lost circulation material (LCM) and is commonly used to heal fractures created during loss situations. Typical particles used in the drilling fluid are graphite and calcium carbonate. The LCM can be used in a preventive manner by adding it to the drilling fluid while drilling. When LCM is added before fracture initiation it functions as a continuous treatment that arrest fracture growth while drilling. This concept will have better effect in permeable formations compared to low-permeable formations, because of the low filtrate leak-off in low permeability formations.

Baker Hughes is the main supplier of drilling fluids on the Ula field. They have prepared a lost circulation decision tree to be used on the Ula field (see fig. 15).

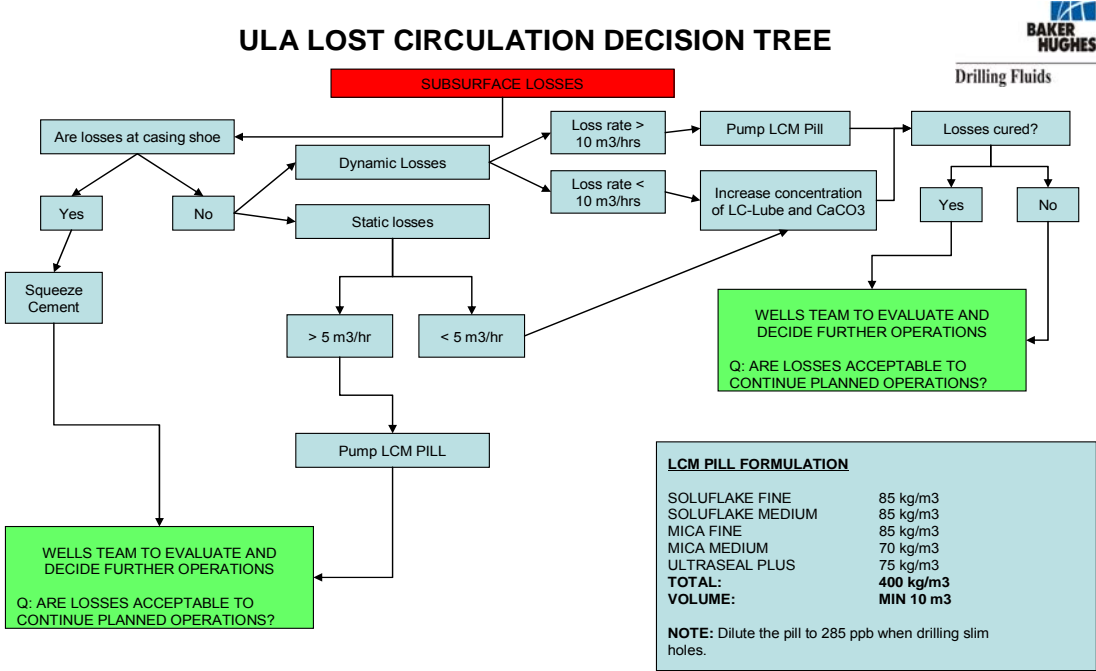


Figure 15 - Lost circulation decision tree for Ula.

Using LCM to plug fractures during drilling is lately referred to as “stress cage theory” and the concept has become increasingly popular in the petroleum industry over the last decade. Some of the advantages with this concept are the possibility to extend drilling in depleting reservoirs, by maintaining a positive mud weight window. Other potential applications include deep water drilling, where the window between the pore pressure and the fracture gradient is often initially low [6].

3.2.3 Swab and surge effects

Swab and surge pressures are caused by the movement of pipe in and out of the wellbore. The movement cause cyclic loading of the rock near the borehole. The string acts as a piston in the hole because the mud cannot flow without restriction, causing the well pressure to fluctuate. If the pressure is reduced sufficiently, reservoir fluids may flow into the wellbore and towards the surface. Swab/Surge is generally considered harmful in drilling operations, because it can lead to kicks and wellbore stability problems. The extent of the pressure fluctuation depends on the tripping speed and the mud viscosity. Common practice have been to calculate surge and swab pressures using a steady-state model, that is based on the assumption that surge and swab pressures are caused by three effects:

- Viscous drag of the mud as the pipe is moved
- Inertial forces of the mud when the speed of the pipe is changed
- Breaking the mud gel

Based on the three main effects, the factors that determine the magnitude of swab and surge pressures are assumed to be [15]:

- The annular clearance
- The viscosity of the mud
- The gel strength of the mud
- The speed of the pipe
- The length of low clearance pipe in the hole
- The position of the low clearance pipe in the hole in relation to the point of interest
- The acceleration or deceleration of the pipe

On the basis of these assumptions, theoretical variations of surge and swab pressures whilst tripping are shown in figure 16. Recent studies have shown that the steady-state models are not adequate to model the behaviour of the mud while tripping. It has been shown that swab and surge pressures are best modelled as a transient, rather than a steady-state phenomenon.

The transient model assumes that a pressure wave is propagated at the instant when the pipe begins to move; the wave then travels down the well at the speed of sound and is reflected back up the hole. As a result of this effect, the pressure at a point in the well oscillates. The oscillations will continue until either the pipe reaches a steady speed, or the pipe has stopped and the reflected pressure waves have diminished [15].

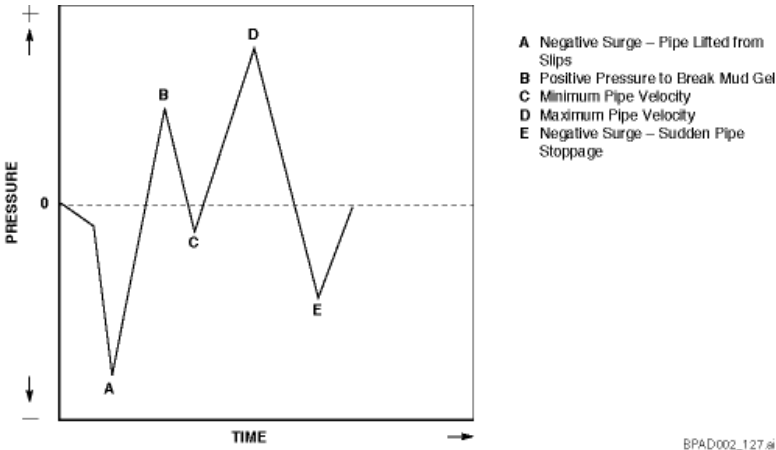


Figure 16 - Theoretical variation in Swab/Surge pressures – when tripping pipe at constant speed [15].

3.2.4 The Fracturing Process

As mentioned earlier a fracture is opened when the wellbore pressure is sufficient to overcome the sum of the stress holding the rock closed and the tensile strength of the rock.

Figure 17 shows the various steps in the fracturing process. The first phase of the fracturing process is the filtrate loss which ensures formation of a filter cake. The build-up of the filter cake stops when there is equilibrium between the filtrate attraction and the erosion due to the flow.

Event	Fig	Main controlling parameters
Filter cake formation	Initially Soft filter cake forming	Filtrate loss
Fracture initiation	Dense filter cake Increase filtrate loss Fracture initiation	Filtrate loss, Stress
Fracture growth	Stress bridge Dense filter Stress field across fracture σ_h	Bridge stress Rock stress
Further fracture growth	Stress zone expands Stress, bridge expands	Bridge/rock stress Particle strength
Filter cake collapse	Yield strength exceeded	Particle strength

Figure 17 - Qualitative description of the fracturing process [Modified from Aadnoy, ref. 10].

When the borehole pressure is increased, the hoop stress in the rock goes from compression towards tension. The filter cake is still in place due to the filtrate loss and the in-situ stresses which control the borehole hoop stress resist the pressure. At a critical pressure the borehole starts to fracture.

In the event of fracture growth a further increase in borehole pressure results in an increase in fracture width. The in-situ stress is opposing this fracture growth and seeks to close the fracture. The filter cake will remain in place because a stress bridge is formed across the fracture. The bridge acts as a natural rock road bridge, the higher top load, the more compressive forces inside the curvature. The mechanical strength of the particles of the filter cake prevents the bridge from collapsing. In this phase both rock stress and the filter cake strength resist failure. Further pressure increase leads to further fracture opening. The stress bridge expands and become thinner with a small thickness, hence the bridge becomes weaker.

In the event of filter cake collapse, too high pressure and a weaker filter cake cause the “rock bridge” to collapse. This occurs when the yield strength of the particles is exceeded. At this point communication is established and we have mud losses towards the formation [10].

The fracture width/length can be estimated for different rock types and pressure regimes. By utilising rock mechanics modeling the fracture widths can be calculated. The model implements the change in stress state around the wellbore and relates the fracture width to the rock elastic properties for a given set of conditions.

Input data required by the model [20]:

- Young's modulus
- Poisson's ratio
- Minimum in situ stress
- Well pressure (ECD)
- Hole diameter
- Length of fracture

Utilizing the input data we can find the excess pressure within the fracture from the following equation [20]:

$$\Delta P = \frac{\pi}{8} * \frac{w}{R} * \frac{E}{(1 - \nu^2)} \quad (3-29)$$

where ΔP is the excess pressure within the fracture, w is the fracture width, R is the fracture radius, E is Young's modulus of formation and ν is Poisson's ratio of formation.

The calculation of the fracture width takes into account the in-situ stresses as well as factors such as Young's modulus and mud ECD. By varying near wellbore fracture length (R) the fracture width can be calculated [20].

It is important to predict the fracture width in order to engineer the optimal size of bridging particles. Based on pore size or the estimated fracture width, software models can be utilized to find the proper sizes of materials to plug the pores and/or an initiated fracture. For pore bridging in the reservoir these materials are selected from ground marble products and for borehole stress treatments, materials are usually selected from specialized resilient graphitic carbon and ground marble products [26].

3.3 Stress Cage theory

Lost circulation together with differential sticking are the two most costly incidents in the drilling industry. Controlling lost circulation has always been a focus; however, the progress in developing new techniques to combat lost circulation has been slow over the last decades. Until recently, the drilling industry has applied a lost circulation strategy where lost circulation material (LCM) is used as a pre-treatment and/or remediation when losses has occurred. BP together with Halliburton has formulated a drilling fluid that can effectively strengthen the weak wellbore while drilling. The approach is called “Stress Caging” and is an extension of the lost circulation strategy that has been used for years in the drilling industry [19].

Drilling into depleted zones will normally result in a high overbalance, due to the lower fracture gradient. This increases the risk of borehole tensile failure, with subsequent lost circulation. To minimize these risks, appropriate engineered mud additives should already be present in the drilling fluid as new formations are exposed.

The materials added to the drilling fluid must not adversely affect the rheology or increase the ECD. Adding the wrong amount or size of particles could result in thicker filter cakes and an increased probability of differentially stuck pipe. The size of the material applied is therefore vital and should be of a size comparable to the openings expected in the loss zone. By adding correctly sized particulate material it can both plug of pore throats and aggregate in the pores.

The application strategy has two components: prevention and correction. The following practices are advocated to provide the best available technology [20]:

- **Pre-treatment.** Pre-treat with optimally sized LCM (finer grinds of sized resilient graphitic carbon and sized calcium carbonate e.g.) before drilling high risk lost circulation zones, such as depleted sands.
- **Subsequent Treatment.** Add subsequent treatments as sweeps, rather than adding material directly into the active drilling fluid system via the suction pit. This type of addition will help ensure the well bore sees a higher concentration of particulate materials in general, and the larger particles in particular.
- **Dynamic Stress Cage Treatment.** When logging-while-drilling (LWD) data indicates that the bit is entering the next depleted sand, a treatment containing larger sized resilient graphitic carbon and sized calcium carbonate to enhance “near size” plugging and build a stress cage around the wellbore is applied in a sweep. These sweeps are continued until the bit enters the next shale. Alternatively, the smaller and

larger size materials are applied, depending on whether a sand or shale is being drilled.

- **Corrective Treatment.** Keep remediation materials on site for immediate application if needed, should wellbore breathing and loss of circulation occur. The selection process here will depend on the severity of the losses and the potential risk.

Emphasis on how to strengthen the wellbore has been growing over the past few years, and a direct result of this is the stress cage theory. Stress caging is the name given to a method for effectively increasing the fracture resistance of rock formations by increasing the hoop stress in the near wellbore region (see fig. 18). This is done by deliberately allowing fractures to form in the wellbore wall and sealing them with LCM of sufficient size and concentration, so that they act as wedges to compress the rock within a zone around the wellbore [61].

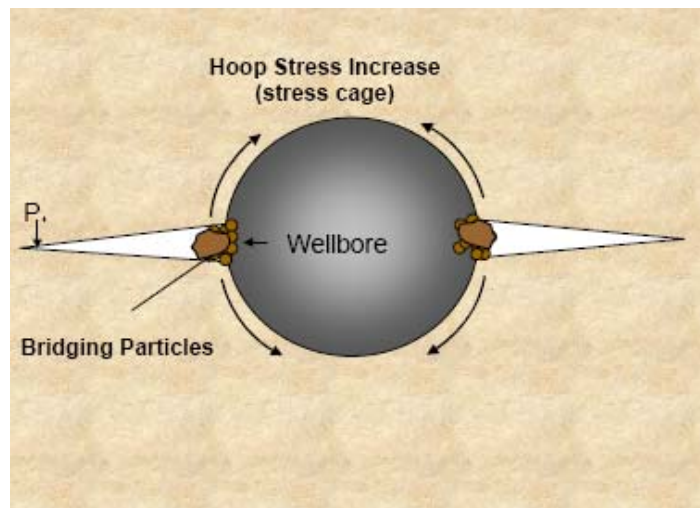


Figure 18 - Principle of stress cage [6].

When the fracture is sealed with bridging material, the adjacent rock is put into compression by the fracture to form a “stress cage”. The increase in closing force between the fracture faces travels around the borehole so that the opening pressure is increased on all sides. It is not one simple equation explaining the increase in hoop stress as the area of rupture mechanics is still not fully understood. To be able to predict the increase in hoop stress, models having input parameters such as Young’s modulus (E) and Poisson’s ratio (ν) are utilized.

Eq. (3-29) is based on a fluid keeping the fracture open. On the other hand, the intention of the designer mud is to use particles bridged at the fracture mouth to hold open the fracture.

The fluid excess pressure is replaced by a mechanical stress caused by the bridging solids. Because fluid and bridging particles behave differently, Eq. (3-29) cannot be used directly to calculate the expected wellbore strengthening effect from stress caging. However, the equation can be useful in understanding the relative importance of the parameters. Some useful observations [62]:

- A short fracture, or at least a short propped length, is best. If the propped length of fracture is long, it will be easier to re-open and would need to be wider to achieve the same strength increase.
- Softer rocks (low Young's modulus) will require larger fracture widths
- The equation is not very sensitive to Poisson's ratio

The increase in hoop stress may result in a potential to drill above the fracture gradient without inducing mud losses, reduce wellbore instabilities and potential loss of the drilled interval. In addition to avoiding these problems, the main economic benefits that wellbore strengthening can provide is the possible elimination of a casing string to reach deeper reservoir targets. There are two basic methods of applying a stress cage treatment [26]:

- **Continuous drilling** whereby bridging solids are maintained in the circulating system. This requires significant planning and engineering with regard to solids control. Proper solids control is important to maintain correct mud weight and rheology.
- **Pill applications** are generally simpler to apply. Often used to strengthen sections that have already been drilled and not already suffered losses.

Wellbore strengthening is preventative rather than remedial. The concept may not be successful if it is applied to seal the fractures after induced losses occur. The fracture is likely to be large and hard to seal, and too easy to re-open. Planning is therefore a vital factor in lost circulation prevention.

Below are listed different applications for the stress cage technology [20]:

Casing shoe set in sand with a low fracture pressure. The casing shoe has been set in a weak formation and the formation integrity test (FIT) or leak-off test (LOT) result is lower than required. To drill to the next casing point will require a mud weight which, when combined with ECD, will exceed the fracture initiation pressure resulting in mud losses at the casing shoe. The interval below the shoe can be drilled and a stress cage pill spotted and squeezed to the appropriate ECD to increase the fracture pressure.

Drilling depleted formations. While drilling depleted reservoirs with higher pore pressure formations above and perhaps below the reservoir, the overbalance required to control these intervals may exceed the depleted reservoir fracture pressure, resulting in massive lost circulation. In Ula reservoir the pressure barriers result in lower pressures above the barrier compared to the sections below which is pressure supported by WAG-injectors. A stress cage can be used in conjunction with appropriate drilling practices to drill the depleted interval without inducing severe lost circulation.

Drilling pore pressure regressions. Drilling from a high pressure interval into a lower pore pressure interval is often caused by crossing into a fault, a fold, or new depositional environment. In this situation a stress cage can be used to increase the fracture pressure of the subnormal pressure interval, and allow the well to reach total depth or to increase the casing setting depth.

Extending casing shoe depth in deep water (narrow fracture window). Since seawater replaces much of the overburden pressure in deep water wells, a lower than normal fracture pressure exist. A common way to solve the drilling problems is so-called dual density drilling. The basic idea is to use only seawater above the seafloor, and the heavier mud from the seafloor and down into the formations. This can be done by using a separate mud lift system to take care of the return mud and cuttings from the borehole. Utilising this concept together with the stress cage technology can be an effective combination. A stress cage can be built and carried for the entire hole section which can strengthen the exposed formations and allow subsequent casing points to be set deeper in the well.

3.3.1 Building Fracture Closure Stress (FCS)

The stress holding the fracture faces closed is often referred to as the Fracture Closure Stress (FCS). The FCS can be thought of as being equal to the fluid pressure required to open the fracture. So if the ECD is less than this stress, the rock closes and losses stop. On

the contrary if the ECD exceed the stress, the fracture will open and losses continue. The fracture is similar to a pressure relief valve and can be reopened repeatedly. There are two main factors contributing to the FCS; the minimum far field stress that is created by the overburden and the smaller hoop stress riser in the near wellbore region.

By dividing the FCS into two separate stress components, the modeling of the fracture behaviour is simplified. The two components will in some situations behave independently. For instance when a fracture is created and starts growing, the hoop stress falls to zero, but the far field stress is still present. This implies that the hoop stress increases the fracture initiation pressure, but not the propagation pressure of the mature fracture. By letting the fracture close, so that the wellbore pressure no longer can act on the fracture face, some of the stress may return. Based on this knowledge the industry has made use of a practice of shutting down after treatments to “let the hole heal”. The waiting period allows time for the fracture to close as filtrate leaks off into the permeable fracture face, and portions of the stress to return.

What was realized in the mid-1990s was that fracture closure stress is increased by increasing fracture width, and not by plugging the tip of the fracture. Today numerous modeling and lab experiments support the basic principle that integrity can only be built by creating width. Figure 19 shows the principle of increasing FCS by increasing fracture width.

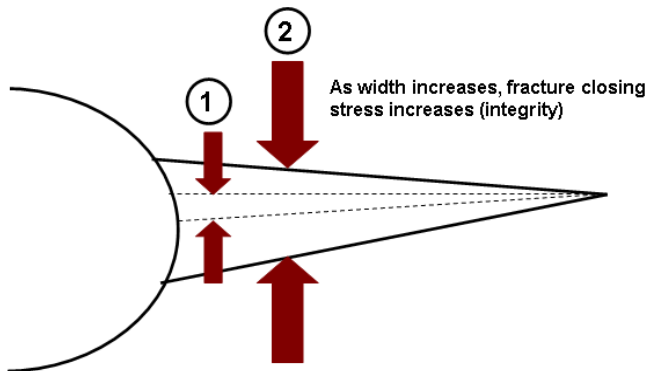


Figure 19 - Fracture closure stress is increased by widening the fracture to compress the adjacent rock. Closing stress determines opening pressure. Losses cannot occur if $FCS > ECD$ [Modified from Dupriest, ref. 24].

If a successful treatment is achieved, the fracture cannot grow in width and it cannot grow in length. The converse is not true. A fracture can be completely filled by an immobile mass, so that it cannot transmit pressure down its length, but it will widen if an ECD is applied that exceed the closing stress. Slurry will then bypass the previous material to continue to

propagate the tip. Another important objective for a successful treatment is the achievement of adequate closing stress between the fracture faces, so the FCS exceed the ECD while drilling ahead (see fig. 20).

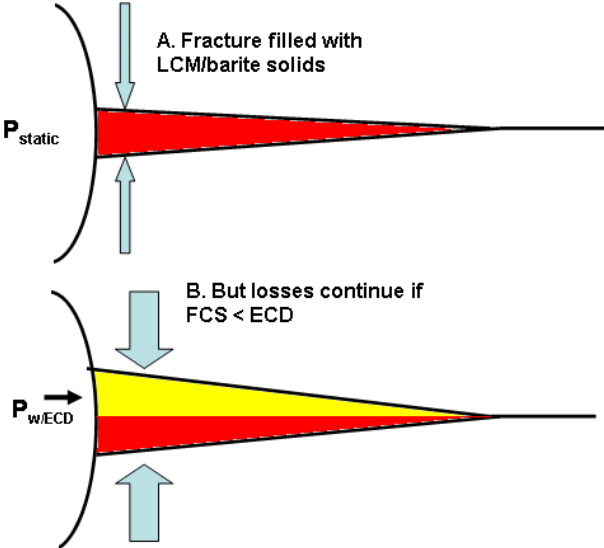


Figure 20 - Losses are not stopped by simple plugging. Effective treatments must simultaneously isolate the tip and achieve adequate width so that $FCS > ECD$ [Modified from Dupriest, ref. 24].

To increase the closing stress (FCS), the fracture growth has to be stopped. As long as mud enters the fracture, the fracture will not grow in width. This is as mentioned earlier because the fracture tip functions as a pressure relief valve. To achieve a successful stress cage an immobile mass has to settle within the fracture (see fig. 21). To sum up there are two main objectives that a successful treatment has to fulfil:

1. The material must achieve and maintain isolation of the tip as the fracture widens, and
2. The final width must be sufficient to create a closing stress greater than the ECD.

Figure 21 illustrates the concept of building integrity by an immobile mass between the fracture faces.

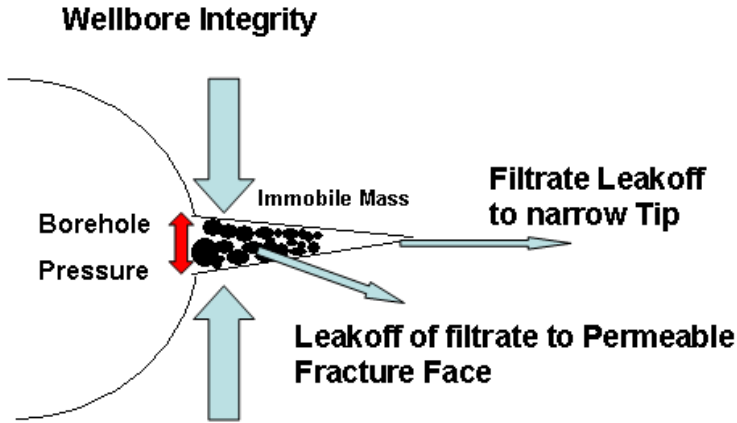


Figure 21 - Shows integrity building by the formation of immobile mass within a fracture.

When LCM loses its carrier fluid and dehydrates it becomes immobile and isolates the fracture tip. Initially there is very little resistance to flow down the fracture. Some resistance may occur due to drag between large particles and the fracture face, however, there will then be created a back-pressure which widens the fracture and hence reduce the resistance. As long as the mud is mobile, it does not isolate the tip. With a non-isolated tip, the width achieved is only that required for the larger particles to travel through the opening [23]. Once the solids become immobile and can no longer transfer pressure, tip growth stops. The main goal is to achieve low permeability across the mouth of the fracture to provide pressure isolation between the fluid in the wellbore and that in the fracture. The hydrostatic head acting against the immobile mass then widens the fracture to compress the elastic rock near the wellbore and increase the closing stress. Most of the carrier fluid is lost to the permeable fracture faces and some filtrate may also escape through the tip [22].

Additional closing stress can also be achieved by closing the preventer and applying positive squeeze pressure. When the permeability of the fracture face is low, there may be very little leak-off as the pill travels down the fracture, resulting in an unsuccessful build-up of the immobile mass. A proposed solution is then to perform hesitation squeezing to allow the LCM to be built up in layers, without the development of an immobile mass (see fig. 22).

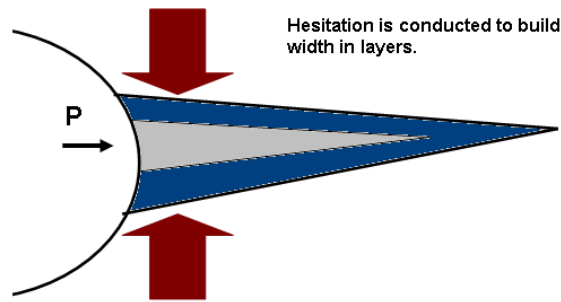


Figure 22 - In low permeability, or if great width is required, hesitation is conducted to build width in layers.

In a typical hesitation operation, 20 bbls of LCM are displaced into the fracture and 60-80 bbls are held back in the wellbore. The steps in a hesitation operation are as follows [24]:

1. When initial squeeze pressure is achieved, this is held to prevent back flow of the pill. The well is kept shut in until the carrier fluid in the fracture has had time to leak-off, leaving the solids behind.
2. The next 20 bbls are squeezed and the original material is held in place by differential pressure.
3. Pressure is again held until leak-off of the carrier fluid has occurred and the process is repeated.

By performing hesitation squeezing the fracture width is built in layers. Compared to normal stress caging operations, the tip is never isolated in these types of operations as the required immobile mass does not develop. The treatment is successful when enough fracture width is created such that the FCS is greater than the ECD.

3.3.2 Low Permeability Formations

The stress cage technique is most effective in high permeability rocks such as sands. A major challenge for the drilling industry has been how to optimize the stress cage technique, to achieve effective wellbore strengthening in low permeability rocks such as shale. In permeable rocks the bridge doesn't have to be perfect, as fluid that passes the bridge will leak away into the formation. Because the fluid can leak away, there will not be a high pressure build-up and the fracture cannot propagate. In shales the stress bridge must have an extremely low permeability to prevent pressure transfer into the fracture. If there is a lack of change in fracture opening pressure at the start of each hesitation this is a clear indication of a low permeability formation. Strengthening impermeable rocks are also of interest for the operators, as these rocks (i.e. shale) often cause drilling problems. It is not as likely to

experience differential sticking in a high permeability zone, compared to a low permeable zone. The reason is that the drilling fluid will form an efficient mud cake faster in high permeable zones, compared to low permeable zones where it will form much slower. Many different solutions as to why it is ineffective to create a sustained stress cage in shale have been proposed. All solutions point at the trapped pressure within the fracture itself and behind the particulate bridge. One of the possible processes taking place is believed to be a leakage through the bridge seal which then allows the fracture to continue to grow, and ultimately resulting in the loss of stress concentration at the wellbore. Another hypothesis is that the trapped fluid exists at the fracture propagation pressure and flow back to the wellbore, thus removing the seal on the bridge and potentially the bridge itself.

The overall understanding is that wellbore strengthening is almost impossible in shale. In sands the trapped pressure will be bled off into the permeable formation as shown in figure 23. This permits the fracture to attempt to close and pinches the bridging particulate into the fracture mouth, and not allowing them to flow back into the wellbore as is believed to happen in shale. The main objective for a successful stress-caging in shale is having a bridging particulate which prop open the fracture and cannot be easily removed [41].

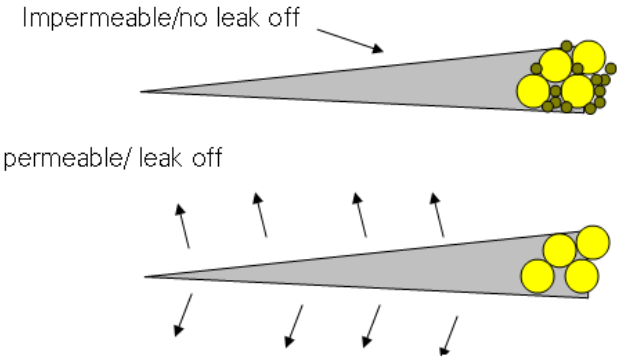


Figure 23 - In shales the bridge must be virtually impermeable to avoid fracture propagation. In permeable formations the bridge can be less perfect as pressure can leak away into the rock.

There are some few cases where it has been observed conventional LCM having an effect in shale formation. On the Trawick field in East Texas the operator had positive results in a formation with less than 0.1 md. By enhancing the fluid loss characteristics and by engineering the particle size distribution they managed to rapidly create an effective immobile mass, and to build integrity above minimum stress. In another extreme case 0.24 SG of integrity was built in 0.1 md permeability, however, the LCM dehydration was aided by

extreme pressure drop into the depleted zone [23,29]. Field tests indicate the possibility of raising the formation fracture resistance in shales utilizing the concept of designer mud, if implemented as a preventative treatment. If the lost circulation has already occurred and a large potentially propped fracture is created, the chance of a successful stress cage is low. This is believed to be because the fracture then has become too large or too deep for the particles to bridge [62].

3.3.3 Mud Design

A proper mud design is a key factor for a successful stress cage. Bridging solids type, size and concentration are some of the main elements to be considered. Depending on the field characteristics and lessons learned, operators use a wide variety of solids type. A blend of marble and graphite is a very popular bridging mix, and has been proven to be more effective than fiber blends. The graphite is resilient, which means it can be compressed when pressure is applied and go back to its original shape when pressure is removed. This ability enables it to maintain seal if the fracture flexes due to pressure variations. The size distribution of the solids is a vital factor. The solids should be large enough to bridge at or near the fracture mouth. They should also be small enough to bridge pores in the rock matrix, to ensure permeable rocks are properly sealed by filter cake. The fracture width will be larger than the pore throat size; hence there should be a size distribution that meets the requirements for both the pore throats and the fractures. The concentration of materials is also important for building an effective seal.

Depending on the selected type of treatment (pill treatment or continuous drilling), the choice of shaker screens is important. If continuous drilling is the preferred treatment method, it will be difficult to maintain the particle size distribution (PSD). If drilling with larger PSDs, most of the bridging solids will be taken out by the shakers. To prevent particles from being taken out by the shaker, coarser shaker screens can be run and a fairly high concentration of solids is recommended. If fine shakers screens are run, coarse bridging material will be ineffective and will blind the screens on the first circulation. In this case continuous addition of bridging materials into the active pit is required.

Operators use several additives in the drilling fluid to prevent lost circulation; however, recent research indicates that too many additives give a poor mud. In a test program carried out at the University of Stavanger they varied the concentration and the number of additives. Some of their key findings are listed below [10]:

- To create a stable bridge to prevent losses, the largest particle diameter should be equal to or exceed the fracture width.
- If carbon fibres are used, the length should exceed the fracture width.
- A minimum particle concentration is required to provide a sufficient bridging material.
- If a high differential pressure is expected in the well, particles with high compressive strength (high Mohs number) should be used.
- There is strong synergy between various additives. Two poor additives may work well in a mixture. The only way to determine this synergy effect is by laboratory testing.
- Many commercial additives do not contribute to loss control. These should be taken out of the mud recipe.
- Particle placement is important. There is very strong effect of particle sag in the lab.
- A stronger fracture healing is seen with water based mud than with oil based mud. It is believed due to water wet rock, allowing filtrate losses.

3.4 Expandable Liner

Expandable liner is a potential technology to be included on the Ula field. It has not been applied in practice on the Ula field, however, it has been a part of the contingency plan. The monobore expandable liner system is an advantageous alternative to conventional, telescoping casing designs. The technology provides a monobore extension, meaning the diameter in the expanded casing/liner is the same as in the parent casing. The main goal of an expandable liner is to optimize the drilling casing programs, by drilling deeper wells with larger hole sizes at the reservoir. When it is applied as part of a contingency as it has been on the Ula field, the goal is to enable the operator to isolate zones that contain reactive shales, subsalt environments, low-fracture-gradient formations or other challenging drilling scenarios. The expandable liner system, LinEXX™, has been developed by Baker Hughes. Figure 24 illustrates how the expandable liner maintains the same ID as the parent casing post expansion.

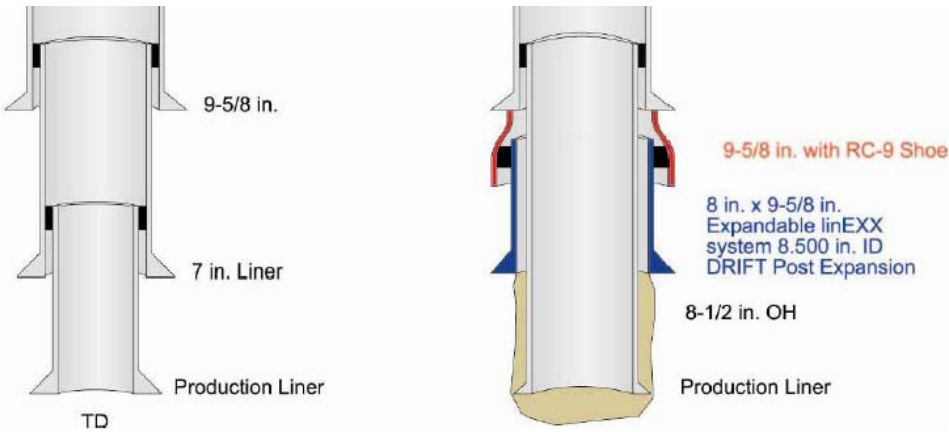


Figure 24 - Show how the expandable liner system can isolate trouble zones with no reduction to critical hole size [Modified from Carl F. Stockmeyer, ref. 31].

3.4.1 General Principle

Expandable liner technology is a relatively new concept that has introduced an alternative to the traditional casing design. When applied as a basis of design, this technology can provide an option for the operator to begin well construction with one smaller casing size. This can again lead to reduced costs and make the project more economically feasible. As a contingency, the product can isolate trouble zones, sub-salt rubble zones, and low fracture

gradient transitions without being forced to reduce casing size and subsequent drilled hole size.

Expandable metal technology is being applied to a wide area today; however, its real value for wellbore construction and HC production is just beginning to be realized. Among others expandable tubular technology can repair corroded or damaged casing and shut of perforations. The traditional way of handling these problems have been through the use of straddle packers, squeeze cement or cementing a liner in place.

Baker Hughes provides two main types of expandable liners. The difference is that one of them facilitates fluid/cement circulation of the expanded liner run below the recess shoe, and the other does not. The system providing circulation, achieve this by utilizing a mechanical sliding sleeve. The other system that provides no flow path between the annulus and the casing ID, relies on the open hole (OH) packers for the zonal isolation, rather than cement. Both versions are rated to 5,000 psi burst and 1,200 psi collapse [31].

On Ula the burst pressure is close to the burst rating and the collapse pressure is above the rating. Today the burst and collapse ratings are too low to be a fully acceptable alternative on Ula. BP is following the development of the LinEXX™ system continuously, and will assess it again when the system is designed with higher burst and collapse ratings. If the low pressure formation seems sticky and it does not seem to heal during drilling of the section, a contingency liner like LinEXX™ could be an alternative in the future. When the design criteria meets BP's requirements, the LinEXX™ could be run in wells that require 8 ½" hole size through the reservoir.

Statoil's conventional way of solving low-fracture-gradient-related problems when drilling into depleted reservoirs has been to run a 7" liner followed by a 4 ½" completion [31]. However, field economics sometimes dictate a 7" production liner through reservoir. To be able to meet economic objectives and to ensure an aggressive drilling program, Statoil decided to install 9 7/8" recess shoes as a contingency in the Kristin and Kvitebjørn fields. The expandable liner was not used by Statoil as the expected pressure differentials were not present, however, the recess shoe is now a part of the basis of design and the liner is part of the contingency. The LinEXX™ system should be considered as either a basis of design or as a contingency in early well planning stages [31].

3.4.2 General Expanding Procedure

To be able to install the LinEXX™ monobore expandable liner system the hole section of interest first has to be drilled and reamed below the last set casing. In the expansion process the outer diameter of the liner is expanded typically 15-20% from its original outer diameter. Expanding the tubular above 20% may lead to surface breaking fractures [34]. As shown in figure 25 the first step in the operation is the installation of the 9 5/8" casing with the recess shoe. When the casing is cemented in place the next step is to run in hole (RIH) with the expandable liner together with the expansion tool. The expansion process can start once the predetermined depth is reached. By applying pressure to the drill pipe, the hydraulic anchors are activated and the expansion piston is hanging of the liner inside the recess shoe (see fig. 25).

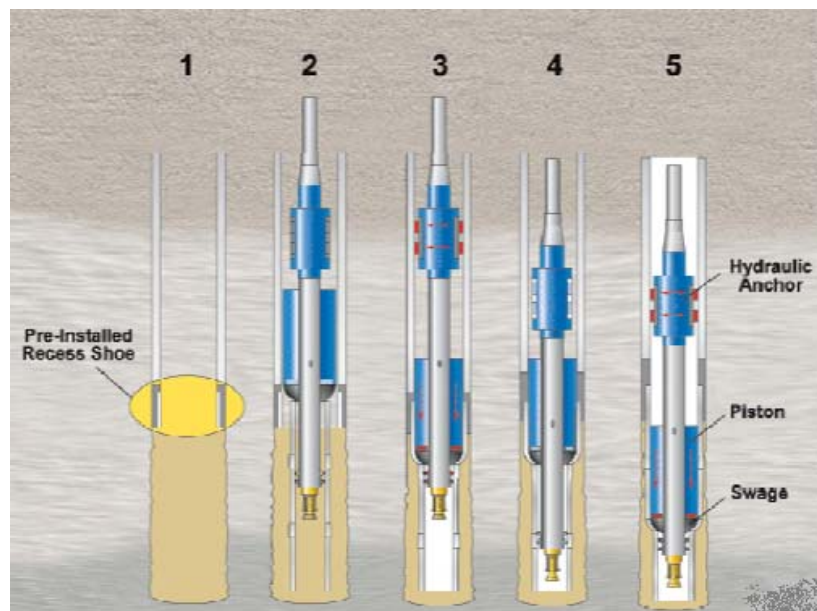


Figure 25 - LinEXX™ monobore expandable liner system installation sequence. [Modified from Carl F. Stockmeyer, ref. 31].

What the LinEXX™ system provides compared to other expandable liner systems is the ability to expand the liner into the recess shoe without introducing ID restriction below the parent casing. The liner is expanded by applying pressure in cycles. Pressure is applied and bled off in cycles until the whole length of the liner is expanded. Typical expansion rates are approximately 100 ft (30m) per hour. The liner mass is conserved during expansion and the liner thickness is reduced only slightly.

This is a one-trip system that relies on the drill pipe pressure to expand the liner. At the end of the operation a retrieval tool retrieves the guide shoe and leaves an unrestricted ID through the entire length of the liner. When the expansion tool has been retrieved from the well, the drilling operation can continue without a reduction in hole size [31].

3.4.3 Stress and Strain

Applying expandable technology requires careful planning and assessment of pipe size and formability. The amount of expansion of the pipe is controlled by the size of the expansion cone. The cone stresses the pipe above the yield limit and into the plastic region, giving a permanent deformation (see fig. 26). A successful expansion of the tubular is achieved when the applied stresses are above the yield point but less than the ultimate strength limit of the material. The region between the ultimate tensile strength and the yield point controls the range of expansion [33].

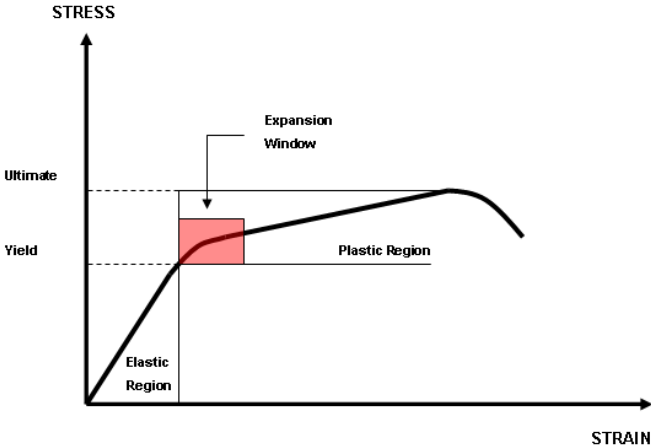


Figure 26 - Shows the expansion window created from the relationship between stress and strain [Modified from Campo, 2003, ref. 33].

The formability of pipe material can usually withstand an expansion ratio of around 30%. The expansion ratio can be found by dividing the difference in ID between the pre-expanded tubular and the expanded tubular, by the pre-expanded ID. Exceeding this ratio will cause the material to fail. The expansion ratio is therefore vital to have in mind when determining realistic expansion sizes [33].

3.4.4 Advantages and Disadvantages

Advantages and disadvantages of applying expandable pipes are presented in table 1 below.

Table 1: Advantages and disadvantages with expandable pipe.

Advantages	Disadvantages
<ul style="list-style-type: none">• Can block off problem drilling zones or unstable formations without a reduction in the casing ID as experienced with a standard liner/intermediate casing string• Eliminates reduction in completion size.• Expansion system can be deployed in vertical and horizontal wells• Extended-reach capabilities of larger-ID cased hole• Provides monobore throughput• Can be used for unexpected problems, as part of initial well design or in contingency situations	<ul style="list-style-type: none">• Low collapse rating• Oversized shoe in parent casing required to maintain drift ID• Under-reaming of the section where the expandable pipe will be run• Takes longer time to run than conventional liner

4 Ula Case Study

The following sections are looking into current drilling practices on Ula and how today's challenges around drilling into the depleted reservoir is solved. Different alternative technologies to drill the Ula reservoir are investigated as well in this section.

4.1 Today's Procedure at Ula

The Ula field is a mature field where depleted reservoir results in more complex and challenging drilling operations. Different solutions exist on how to drill past a troublesome thief zone. Below are listed some of the possible solutions [28]:

- Strengthening wellbore by increasing hoop stress with particles ("Stress Caging")
- Downsize production liner to allow an intermediate string to isolate the problem zone
- Drill and under-ream to allow an extra string of casing/liner to be installed without compromising the production liner size
- Utilize an expandable casing/liner to gain the additional string and maintain the production liner size
- Drill conventionally to just above the problem zone and then isolate the problem zone by casing or liner drilling

Different solutions exist on how to drill past the low pressure Unit 1. One option is to set the 9 5/8" casing just above the Ula reservoir and then drill the reservoir with 8 1/2" hole size. Depending on the choice of design, the procedure is to drill +/- 10 meters past Unit 1 pressure baffle, and then run and cement a 7" liner (see fig. 27). Sealing low pressure Unit 1 from high pressure Unit 2 reduces the overall well control risk. Another reason for running the 7" liner is the reduced risk for differential sticking, especially during logging. Drilling this section requires a high emphasis on the mud properties, since the mud weight will control the highest pressure. The same mud will cover both Unit 1 and 2, hence resulting in a much higher overbalance than what would be chosen for the low pressure zone alone.

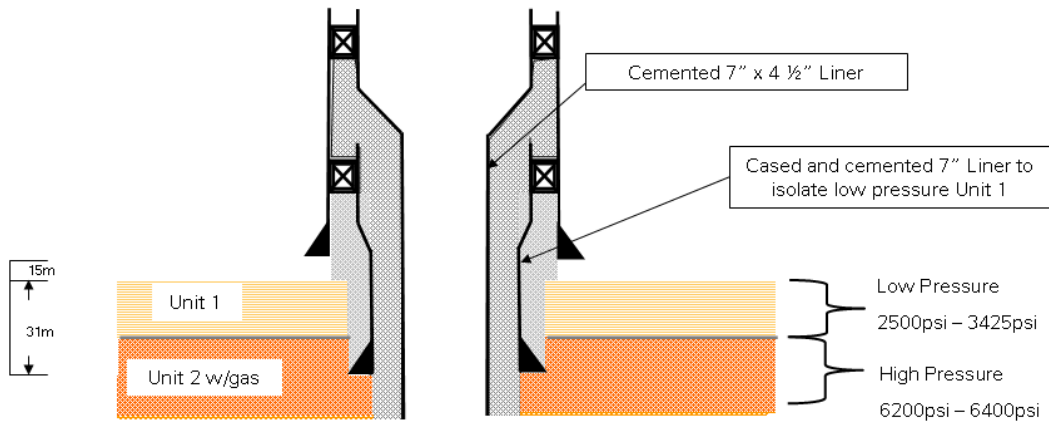


Figure 27 - Show how low pressure Unit 1 is isolated utilizing a cemented 7" liner.

The expandable liner has been evaluated as being a possible alternative for isolating the low pressure Unit 1 on Ula. Figure 28 illustrates how the expandable liner is planned to isolate the low pressure Unit 1. Today the burst and collapse ratings of the expandable system are on border line to be an alternative on Ula. Instead of using an expandable liner to isolate Unit 1, an option is to utilize a cemented 7" (See fig. 27).

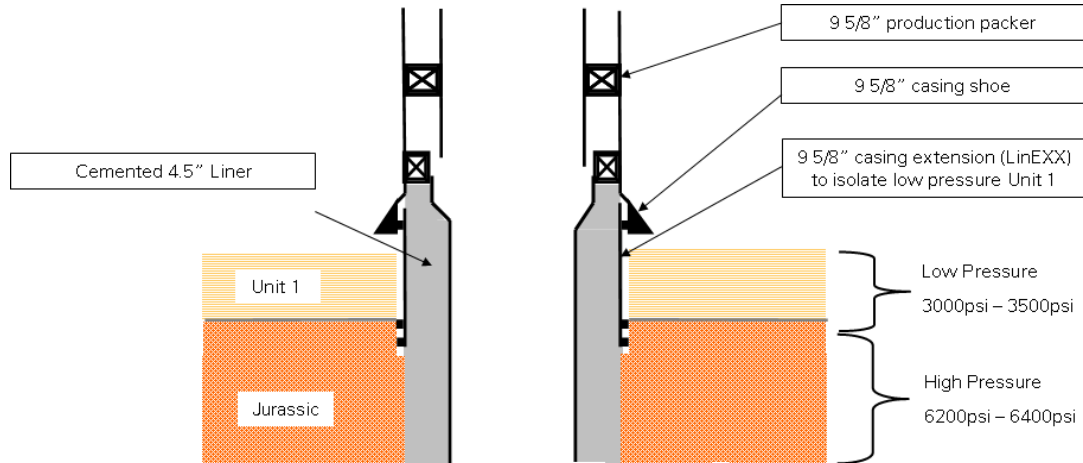


Figure 28 - Show how the extended casing (LinEXX™) isolate the low pressure Unit 1.

Ula Units 1A1-1A2 is estimated to be depleted to 0.51 SG (2500 psi), with an uncertainty range of 0.45 to 0.54 SG (2200 psi to 2650 psi). Below the pressure baffle (below top unit 1A3), expected maximum formation pressure is close to 1.31 SG (6400 psi). Drilling with a MW of 1.33 SG in Unit 1 is anticipated to give an overbalance close to 4000 psi. This is a value with high uncertainty since the pressure tests to confirm the value have not been conducted. The high overbalance can lead to mud losses; hence a heightened LCM

awareness is required during drilling of this section. The concentration of LC-Lube and CaCO₃ should also be maintained to mitigate losses. Another likely risk in this section is differential sticking. To mitigate differential sticking BP focuses on minimizing time the drill-string is kept still, centralizing the BHA and performing sticky tests before making connections.

4.1.1 Mud Design on Ula

The type, concentration and particle size distribution of the LCM is important factors in controlling lost circulation. Of these parameters particle type is believed to be the most important variable for obtaining an effective fracture sealing response. Baker Hughes is the main mud supplier on Ula. In a recent drilling operation (well A-15A) a 1.40 SG OBM was successfully applied drilling into the reservoir. The mud was pre-treated with LC-lube and CaCO₃ before the section was started. Pre-treatment procedures are always recommended (LCM mixed in the whole drilling fluid system). The LC-lube and CaCO₃ is added to strengthen the formation, and to build a sufficient mud cake quickly to prevent differential sticking. LC-lube consists of graphite which is a resilient material highly effective in maintaining a seal in the fracture. Micromax was also added to the mud, which is an inert weighting material that can be used in place of barite. It is a fine red-brown powder with the chemical Manganese Tetroxide (Mn₃O₄) and reduces the potential for sag compared to conventional barite mud [51]. Figure 29 shows the Ula lost circulation tree for the reservoir.

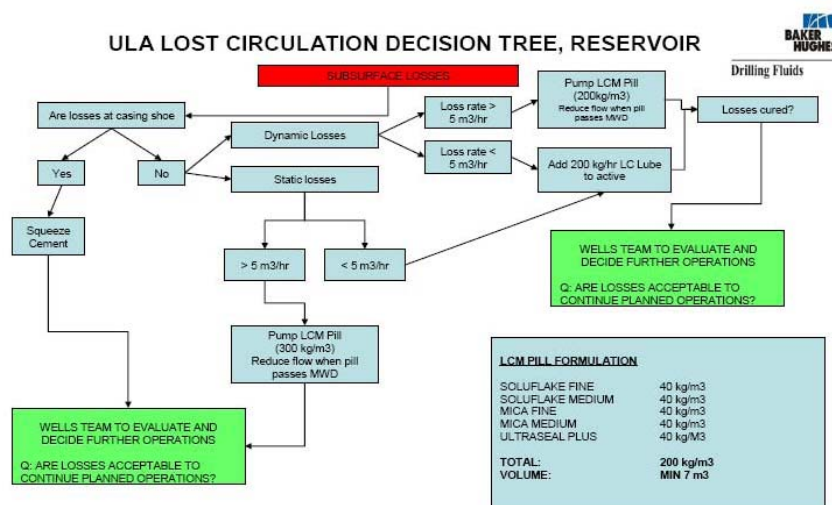


Figure 29 - Ula lost circulation decision tree for the reservoir.

The particle size distribution on U1a is based on U1a permeability and pore sizes. The max permeability of the U1a Unit 1 reservoir is estimated to be close to 30 mD, and the average permeability is 6 mD [1]. Some of the LC-lube and CaCO_3 will be screened out at the shakers when running fine mesh. To compensate for the screened out particles, additional particles must be added to the active system during drilling.

When dynamic losses are encountered and the loss rate is higher than $5 \text{ m}^3/\text{hr}$, the general procedure is to pump a LCM pill (200 kg/m^3). The LCM pill is made up of Soluflake (Calcium Carbonate and Crystalline Silica), Mica and Ultraseal Plus (cellulose). Mica is used as a viscosifier and/or a fluid loss reducer. Soluflake and Ultraseal Plus are used as a fluid loss reducer. When LCM pill treatment fails, the wells team will evaluate other methods for stopping the losses. Specialized LC treatments such as cross-linking technology and oil gallant pills could then become a viable solution.

4.2 Experience and Observations on Ula

Drilling into the reservoir has to be done with a high overbalance, since the top part of the reservoir is depleted and the highest pressure zone has to be penetrated in the same hole section. The main concern when drilling with high overbalance is loss of drilling mud and a subsequent kick in the high pressure zone, due to the decreased hydrostatic column. If losses occur, LCM will be used to cure the losses. Field experience on Ula is that losses can be cured effectively; however losses have occurred later during the cementing operation. Below are listed some relevant field experience from Ula:

- A-1B (2001), successfully drilled 10 metres into the reservoir with 1.66 SG mud. However, Total lost returns was experienced when cementing the 9 5/8". Hesitation cement squeeze was performed, but managed only to place a short column of cement outside the casing. Reservoir pressure was 0.93 SG. Estimated overbalance during drilling is 2487 psi.
- A-14A (2001) was drilled 9 metres below Ula formation with 1.64 SG mud and experienced full loss of returns. The MW was reduced to 1.60 SG and LCM was pumped to cure the losses. Pore pressure was 0.94 SG at entry point. Estimated overbalance during drilling is 3419 psi using 1.64 SG mud. Overbalance when decreasing MW to 1.60 SG is 3178 psi.
- A-7C was drilled 0.5 metres above Ula formation. Experienced losses (350 ltr/min). Cured losses by pumping LCM. Reservoir pressure was 1.24 SG.
- A-2B (2005) was drilled 4 meters below top Ula and experienced losses. MW at 1.73 stabilised the well. Reservoir pressure was 1.27 SG and estimated overbalance was 1902 psi.

4.3 Maximum Overbalance on Ula

Figure 30 shows the prognosed formation pressures in the top Ula formation and the MW chosen for drilling this section in a recent drilling operation. Since the Ula units will be drilled in the same hole section, the low pressure Units 1A1-1A2 will be exposed to the same mud as the high pressure units below. The MW will have to control the zone with highest pressure, resulting in a high overbalance in the depleted top Ula formation. What is important to know is the maximum overbalance Units 1A1-1A2 can withstand before losses occur. Repeat Formation Tester The top Ula formation is still being produced; however, it is uncertain how large the depletion in the low pressure zone will be in the time to come. At one point in time the pressure depletion may result in formation pressures being too low to drill the top Ula units in the same hole section, without applying new technology or improve the mud design.

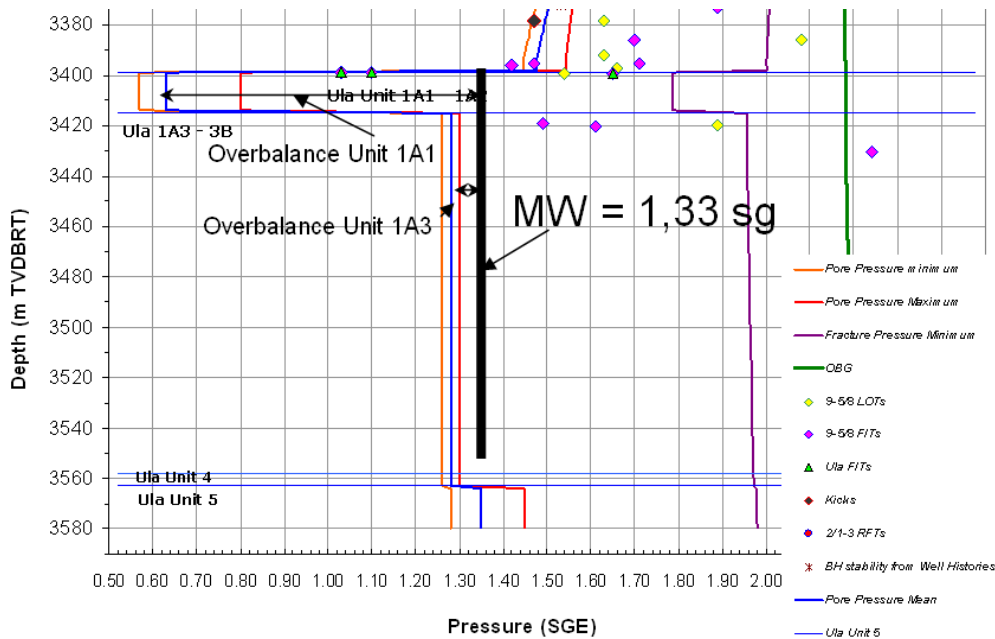


Figure 30 - Prognosed formation pressures in a recent well drilled at Ula. Anticipated overbalance in the low pressure zone and in the high pressure zone is illustrated.

Immediate lost circulation has been experienced when drilling 10 metres MD below the Ula formation (A-14A). This well was drilled without the special additives being added to the mud today. The overbalance in this case was close to 3400 psi, and the losses were cured by lowering the MW and pumping LCM. In well A-1B losses during cementing occurred having an overbalance close to 3200 psi. In the last well drilled (A-03B), the mud overbalance in Unit 1 was predicted to be in the order of 4000 psi; however, this value has not been confirmed by

pressure tests. This well was drilled with mud pre-treated with LC lube and CaCO_3 and did not experience any losses in the low pressure zone.

From the field experience we cannot conclude the exact value for the maximum overbalance in the top Ula reservoir. It is clear that without LCM in the mud, an overbalance of 3400 psi will most likely result in losses. By having an effective designer mud containing correctly sized LCM, there is a good chance that the interval can be drilled successfully with an overbalance close to 4000 psi, as was the predicted overbalance in well A-03B.

The Young's modulus (E) for the top Ula reservoir is 2.07×10^6 psi, found from uniaxial compaction tests [59]. Young's modulus is a measure of the stiffness of the sample. To end up at a precise estimate for the maximum overbalance on Ula, a comparison with other fields having an E-modulus close to Ula's could be a possible procedure. In a list containing stress cage jobs from 41 wells the fracture gradient increase vary from 0.03 – 0.78 SG [19]. One reason for this large scatter is due to the difference in formation stiffness, permeability and mud design for the various fields. The average increase in fracture gradient from the stress cage jobs is 0.17 SG, which clearly indicates the potential of stress caging as a method for improving wellbore strength.

4.4 Evaluation of LOT Data from Ula

LOT at various stages of reservoir depletion are the most reliable approach to provide fracture gradient data. The stress state will normally increase with depth; hence the leak-off pressures typically increase with depth [58]. The model used to find predicted LOT must be evaluated and compared to the actual measured LOT data. If the measured and the predicted data are similar, the model is useful. However, if a large discrepancy exists, this questions the validity of the model. For practical application, the difference should be within 0.05 – 0.10 SG [54].

A large variation is often seen in fracture gradient estimates with pore pressure reduction. As mentioned earlier, Leak-off Tests are the most reliable approach to provide fracture gradient data. However, such data is often not available. Fracture gradient predictions can then be calculated from elastic, isotropic and non-isotropic models, found from laboratory tests and field data. From uniaxial compaction tests the Poisson’s ratio has been determined to be 0.20 for Unit 1A1 [59]. Utilizing the Poisson’s ratio and Eqs (3-25) and (3-26) we can predict the reduction in the fracture gradient. Figure 31 shows the linear trend-line based on Ula LOT data at 9 5/8” shoe, and the predicted LOT.

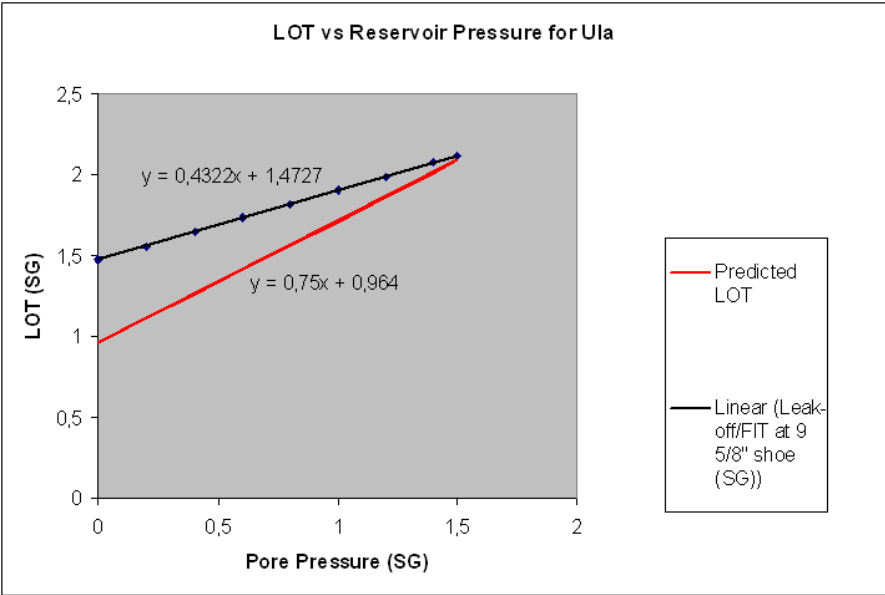


Figure 31 - Predicted LOT (Red line) and a linear fit based on actual LOT (Black line).

Table 2 shows the difference in predicted LOT and measured LOT from the 9 5/8” casing shoe on Ula.

Table 2: Show LOT values based on actual field data from Ula and LOT values based on model.

Pore Pressure (SG)	LOT based on actual data (SG)	LOT based on model (SG)
0.5	1.69	1.34
0.8	1.82	1.56
1.0	1.91	1.71
1.2	1.99	1.86
1.4	2.10	2.01

The LOT/FIT data is important, however, the risk of losses must be taken into consideration. In the last drilling operation on Ula, the 9 5/8” casing was set and cemented with 1.65 SG mud. The ECD during the cementing operation was above what is needed for formation integrity in this section, and FIT/LOT was not conducted. On Ula LOT data is sometimes omitted and FIT test performed instead. FIT is usually conducted to ensure that the formation below casing shoe will not be broken while drilling the next section with higher BHP.

Figure 31 illustrates the importance of actual field data as the difference between predicted and actual data is quite large. Global experience also show a trend where fracture gradients observed in sands tends to be higher than predicted by theoretical models. This is believed to be because of the mud solids and the deposition of mud cake [62]. In a literature search conducted by *Kristiansen et al.*, a large difference between measured and calculated values was found on several fields [60].

Table 3 shows the difference between measured and calculated data found in the literature search.

Table 3: Published data of minimum stress as a function of reservoir pore pressure [60].

Field	$a = \frac{\Delta P_{fg}}{\Delta P_p}$ (measured)	$a = \frac{\Delta P_{fg}}{\Delta P_p}$ (calculated)
Vicksburg, South Texas	0.53	0.67-0.75
Ekofisk, Central North Sea	0.8	0.5-0.75
Valhall, North Sea	0.84	0.7
Venture, Nova Scotia	0.56	0.57
Waskom, South Texas	0.46	0.57-0.75
West Sole, Southern North Sea	1.18	0.33-0.81
Wytch Farm, Southern England	0.65	0.73
U.S. Gulf Coast	0.46	--
Venezuela (region)	0.56	--
Brunei	0.49	--

LOT/FIT is important as they give the most reliable fracture gradient data. The tests are often omitted due to the high cost of the field measurement, because the reservoir is not yet depleted or the operator won't risk losses during testing [60]. XLOT is important and valuable for estimating the magnitude of the minimum horizontal stress. Compared to a standard LOT, the XLOT is more essential for determining the stress magnitude.

4.5 Potential Technologies

Several different options can be applied on Ula, which might offer further mitigation to the challenges met by drilling the depleted reservoir. Risks when drilling into a depleted reservoir are lost circulation and differential sticking. The two general approaches for lost circulation solutions are either proactive or corrective, based on whether lost circulation has occurred or not.

On Ula the common procedure to cure losses is to add LCM until full circulation is obtained. There are a wide variety of treatments for troublesome formations. These treatments vary depending on the severity of the problem, the cause of the problem and the formation characteristics. Treatments can range from a simple LCM recipe to more complex materials designed to create a stress cage around the wellbore. Cement, chemicals and resins can also be squeezed into the formation to treat the lost circulation. In the next sections both conventional and new options for drilling through troublesome formations are evaluated. These options are:

- Underbalanced drilling (UBD)
- Managed pressure Drilling (MPD)
- Drilling liner
- Steerable drilling liner
- Casing drilling
- Drilling liner combined with expandable liner
- Drilling lining

4.6 Underbalanced Drilling

Underbalanced drilling, or UBD, is a procedure used to drill oil and gas wells where the pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled. Since the pressure is lower in the wellbore than in the formation, the pressure gradient will drive fluids from the reservoir to the wellbore. In conventional “overbalanced” drilling operations the fluids flow from the wellbore to the reservoir (see fig. 32).

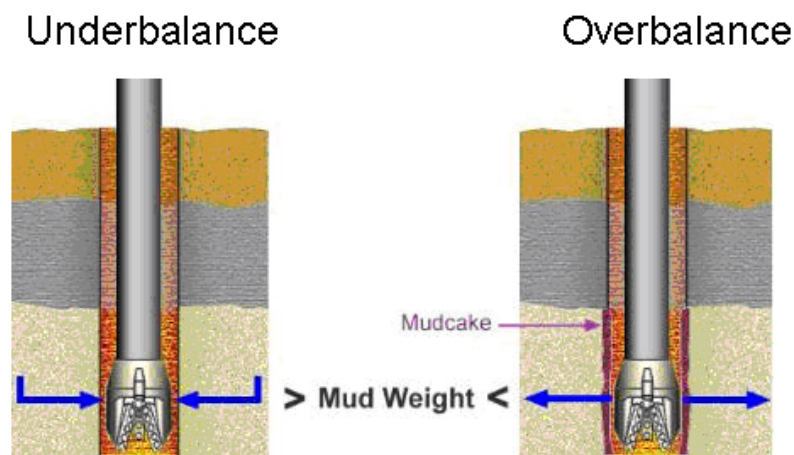


Figure 32 - Underbalanced drilling and conventional overbalanced drilling [Modified from Tianjin Hi-Tech, ref. 42].

Underbalanced drilling is referring to a drilling operation with a circulating pressure less than or equal to the formation pressure. When drilling underbalanced considerable precautions need to be taken, since the underbalanced downhole conditions will result in influx of oil and/or gas into the wellbore. One of the main benefits by utilizing UBD is the reduction or even elimination of formation damage. Normal overbalanced drilling would reduce production due to skin damage. Even if a good filter cake is formed and acts as a protective barrier, some formation damage from drill cuttings will take place. What happens if a good filter cake is not formed, the fine powder from the drill cuttings will enter the formation and reduce the near wellbore permeability.

The skin damage is typically caused by solids invasion, phase trapping, clay swelling and emulsification. UBD stimulates production of formation fluids, therefore preventing severe skin damage. What presents the main challenge for UBD is to keep the well in an underbalanced condition at all times, if formation damage is to be minimized. By applying UBD in the optimal reservoir environment, the drilling project can provide an increased net present value and increase the amount of economically recoverable reserves.

The BOP system must be kept closed while drilling compared to conventional drilling where fluids are returned to an open system with the well open to atmosphere. The influx of formation fluids during UBD requires extra equipment to control the influx and to avoid well control problems. A closed system at surface must be installed to control the well. The surface equipment for UBD can be broken down into four main categories. These are:

- Drilling system
- Gas generation system
- Well control equipment
- Surface separation equipment

Drilling efficiency is largely governed by the efficiency with which hydraulics removes rock chips created by the rotating bit. The rock chips are held in place by overbalance, this phenomenon is often referred to as the “chip hold down effect”. These pressures must be overcome either by hydraulic action, or by mechanical regrinding before the chip may be removed. The degree to which the drilling process is slowed from this effect is a function of the differential pressure. If the differential pressure is positive, drilling is slowed by the overbalance which inhibits dislodgement of the chip. On the other hand, if the differential pressure is negative (UBD), the dislodgement of the chip is encouraged thus increasing the rate of penetration and bit life [43].

A successful UBD operation is often a result of a high-quality planning phase. The candidate reservoir should be evaluated for its suitability for UBD, prior to undertaking an UBD project. Reservoirs that will benefit from underbalanced drilling include [44]:

- Formations that usually suffer major formation damage during drilling or completion operations
- Formations that usually exhibit high trends for differential sticking and lost pipe
- Formations that exhibit regions of high loss circulation or fluid invasion

- Wells with large macroscopic fractures
- Wells with massive heterogeneous or highly laminated formations that exhibit differing permeability's, porosities or pore throats throughout
- High production reservoirs with medium-high permeability
- Formations generally exhibiting very low ROP's with overbalanced drilling

Reservoirs that most likely will not benefit from underbalanced drilling include [44]:

- Wells in an area of very low cost conventional drilling
- Extremely low permeability wells
- Poorly consolidated formations
- Wells with a low borehole stability
- Wells with loosely cemented laminar boundaries
- Wells containing multiple zones of different pressures

Correct selection of drilling fluids is a key to a successful outcome. In UBD fluids are selected to provide a hydrostatic pressure of around 100-200 psi below the initial reservoir pressure. In some chases a drawdown of 200 psi may not be sufficient, depending on the reservoir characteristics.

Figure 33 shows the different fluid systems used in underbalanced drilling.

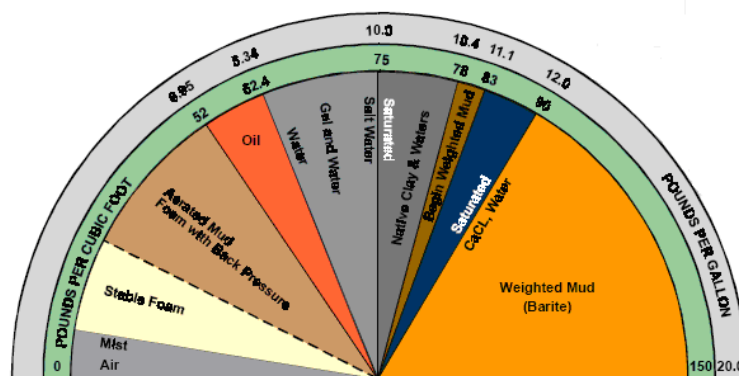


Figure 33 - Drilling fluid systems used in underbalanced drilling [44].

UBD is performed with relatively low borehole pressures compared to conventional drilling. One would therefore assume borehole collapse to be a likely scenario in an underbalanced environment, since borehole collapse is associated with low borehole pressures. However, this doesn't necessarily have to be the case according to Aadnøy (1997). An inward flow into the borehole actually stabilizes the formation because the pore pressure is reduced locally [ref. 54].

4.6.1 Advantages and Disadvantages

Advantages and disadvantages with underbalanced drilling are presented in table 4 below.

Table 4: Advantages and disadvantages with underbalanced drilling

Advantages	Disadvantages
<ul style="list-style-type: none"> • Minimizes lost circulation • Decrease formation damage which gives a higher PI • Increase ROP • Less weight on bit required • Bit life may be extended • Tight hole problems may be reduced • Early detection and dynamic testing of productive intervals while drilling • Can detect potential hydrocarbon zones that would have been bypassed with conventional drilling methods • Chance of differential sticking is reduced as there is no filter cake 	<ul style="list-style-type: none"> • Complicated process that increase the overall production risk • Drill string vibrations are often more pronounced • Possible increased torque and drag • String weight is increased due to reduced buoyancy • Attenuation of the conventional MWD mud pulse signal • Surface cleaning equipment must be made available and may have to accommodate a complex mixture of fluids and cuttings • Need significant extra deck space • Higher drilling cost • In cases of temporary overbalanced periods, deep invasion of the reservoir by the drilling fluid can occur because there is no filter-cake protection

4.7 Managed Pressure Drilling

The purpose of Managed Pressure drilling (MPD) is to manage the annular hydraulic pressure profile to fit within the allowed pressure window. The technology should also be able to handle a well control situation within this window with assistance from advanced model tools and automated control systems. MPD is very similar to UBD and are based on many of the same ideas and tools as UBD. The major difference between the two is that MPD is not designed to allow the well to take an influx of formation fluids, but to drill with the lowest drilling fluid weight possible. On the other hand, the UBD technology is designed to maintain a pressure profile less than the formation pressure during drilling, and thus allowing influx of formation fluids. The main intention of MPD is to stay slightly above or at balance to the pore pressure, or as close to balance as possible during drilling and connections. An advantage with MPD is the ability to stay within the pressure window by accurately controlling downhole pressure, hence eliminating prematurely set casing or running of contingency strings to cover problematic zones [47].

Compared to a conventional drilling system, extra hardware is added to a MPD system. Figure 34 illustrates a MPD system that uses a Rotating Control Device (RCD) to seal in the annulus, a topside choke valve and a pump known as a back-pressure pump. The extra hardware enables the driller to control the pressure profile more precisely, however, it also represent an increase in complexity. This can lead to additional challenges for the driller to maintain downhole conditions. To assist the driller with pressure control, the idea is to implement automatic pressure control using the topside choke valve. Systems utilizing this concept have been successfully implemented offshore, and the technology is expected to increase in popularity [45].

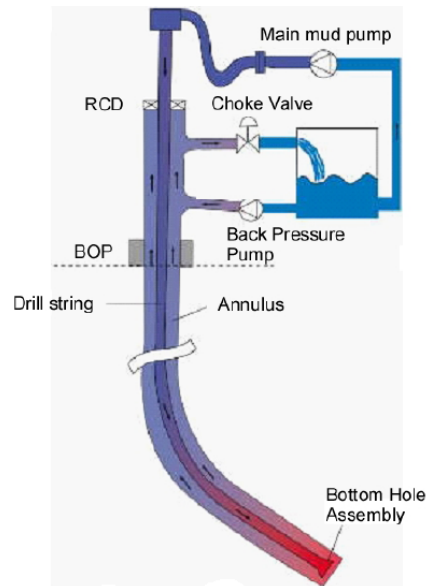


Figure 34 - MPD flow schematic [45].

MPD can be divided into two main categories, Reactive and Proactive MPD. Reactive MPD means drilling with conventional procedures (casing set points and fluid program) and the drilling program is equipped with at least a Rotating Control Device (RCD), a drilling choke manifold and a drill string float. The extra equipment enables the operator to more safely and efficiently drill the prospect, while dealing with any potential unexpected downhole pressure environment. Proactive MPD is a procedure where MPD is a part of the design stages of the operation from the beginning. This enables the operator to more precisely manage the pressure profile, and design of the well's casing and fluid programs.

For a successful MPD operation it is crucial to select the appropriate MPD method. For some scenarios certain MPD tools might be unnecessary. In other situations additional MPD tools might be necessary for added precision. MPD can be divided into four different methods. These are:

- HSE MPD
- Constant Bottom Hole Pressure (CBHP) MPD
- Pressurized Mud Cap Drilling (PMCD) MPD
- Dual Gradient MPD

HSE MPD is a drilling operation performed with a closed annulus returns system, versus a returns system open to the atmosphere. This variant of MPD is used in hazardous zones that

raise health, safety and environmental concerns. Zones expected to contain high concentrations of toxic gases such as H₂S or CO₂ could be drilled with HSE MPD. Drilling into zones with a high risk of well control incidents (e.g. zones with a narrow pore pressure and fracture gradients) could be drilled more safely utilizing HSE MPD. The increase in safety is a result of the wellbore being a closed system. Having a closed system makes it easier to detect pressure variations, and hence to reduce the potential kick magnitude to manageable levels. The closed system is achieved by utilizing a RCD and typically a drilling choke to divert drilling fluid away from the rig floor and personnel.

Constant Bottomhole Pressure (CBHP) MPD is a method that should be considered if offset wells has shown kick-loss scenarios or other well control issues. The objective of CBHP MPD is to maintain the same bottomhole pressure (BHP) whether the fluid column is static or circulating. If the annular flowing pressure is lost, a backpressure is applied at surface to counteract the reduction. A dedicated choke system creates the backpressure and prevents the bottomhole pressure fluctuations that normally occur during conventional drilling operations. The main advantage by applying this method is the ability to accurately control the annular flowing pressure; hence reducing NPT spent fighting well problems. Risk to the well, rig and personnel are reduced, and wells can be drilled deeper. The conventional method to find the effective Bottom Hole Pressure (BHP) is to add the hydrostatic mud weight and the Annulus Friction Pressure (AFP). The only factors that can be changed to effect the bottom hole pressure is the mud density and the pump rates. When utilizing CBHP MPD the BHP can be determined by adding the hydrostatic mud weight, the AFP and the backpressure. [46,47]. Figure 35 illustrates the difference in pressure profile between conventional drilling and CBHP MPD.

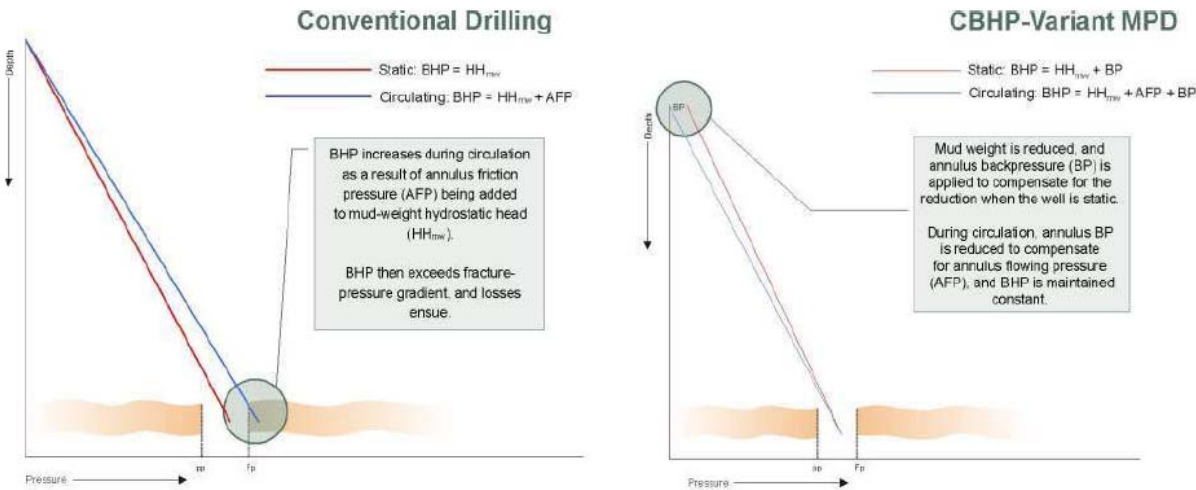


Figure 35 - Constant Bottomhole Pressure MPD Pressure profile compared to conventional drilling pressure profile [47].

Pressurized Mud Cap Drilling (PMCD) MPD is a method which involves a sacrificial fluid. The sacrificial fluid could be seawater with inhibitors. A light viscous fluid is pumped down the annulus with a dedicated mud pump and a dedicated drilling choke. The objective of the light annular fluid is to keep surface backpressure requirements to a minimum. Since the sacrificial fluid is less dense than the annular fluid, the sacrificial fluid is prevented from flowing up the annulus. Instead, the sacrificial fluid and cuttings are forced into the troublesome zone. This MPD variant is beneficial to apply in cases where offset wells have encountered severely depleted zones (As for the top Ula reservoir) and where extreme mud loss has resulted from drilling into fractures or cavernous voids [47]. Figure 36 illustrates the concept of PMCD MPD.

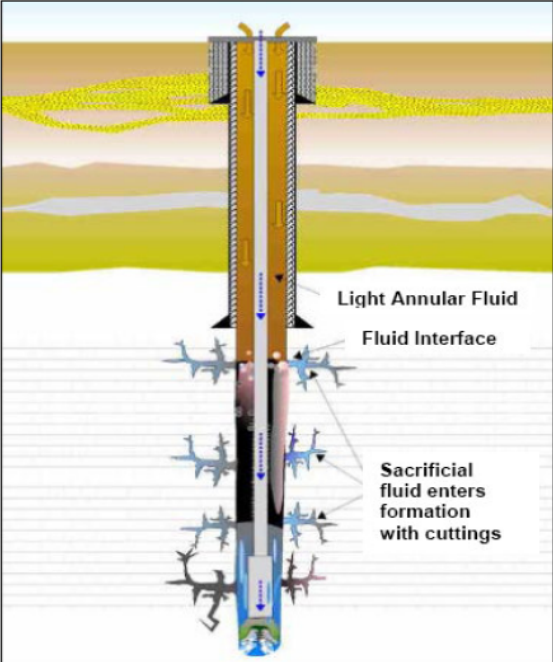


Figure 36 - Illustration of Pressurized Mud Cap Drilling [47].

Dual gradient MPD is a method that is beneficial to apply in formations encountering a rapid pressure gradient increase that cannot be controlled with a single fluid density without fracturing the formation. This is a typical scenario in deep water, where the seawater column dominates the formation pressure in the shallower formations. The dual gradient MPD introduces a lifting mechanism to the wellbore. The lifting mechanism can be a mechanical application or it can be a light fluid. If nitrogen is injected at a predetermined depth into the casing, a different mud pressure-depth gradient will result below the injection point. The main advantage by applying dual gradient MPD is the ability to adjust the effective bottomhole

pressure, without having to change base fluid density. Lost circulation and differential sticking of the drill string can be avoided. Figure 37 show how the dual gradient MPD system can be beneficial in an environment with rapid pressure gradient increase [49].

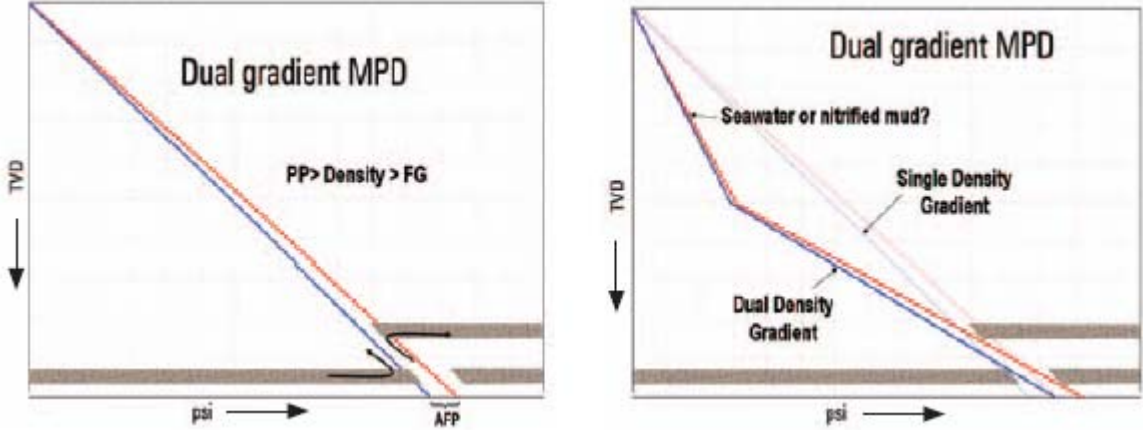


Figure 37 - Situation (above left): Rapid pressure increase. Neither a static nor a dynamic column of single density fluid can be managed. Possible solution (above right): two density gradients in the wellbore, lower on top, higher on bottom [48].

4.7.1 Advantages and Disadvantages

Advantages and disadvantages with managed pressure drilling are presented in table 5 below.

Table 5: Advantages and disadvantages with managed pressure drilling.

Advantages	Disadvantages
<ul style="list-style-type: none"> • Reduce drilling NPT by using various techniques to drill with a more constant bottom hole pressure • Reduces problems in hole sections with tight PP/FG • Provide possibility to set casing deeper and/or eliminate casing string • Drill wells with narrow window margin • Exploit mature fields and drill through depleted reservoirs • Manage high-pressure wells with multiple pressure zones • Manage wells with rapid-change pore pressure regimes • Manage fields with high pore pressure/frac gradient uncertainties 	<ul style="list-style-type: none"> • Operational complexity • For PMCD MPD there are no returns to surface – Geologists don't like this technique – no samples • At TD, or for intermediate trips, there still remains the issue of how to get out of the hole • PMCD MPD uses large volumes of fluid (one week of drilling could require 120 – 150,000 bbls of fluid) • High cost • Surface equipment on Ula must be upgraded • Need significant extra deck space

4.8 Drilling Liner

Drilling liner/casing is a well proven technology that has existed for a long time and is being applied all over the world, including the North Sea. The BP operated field Valhall has used drilling liners since 1993 to combat the heavy losses they experience when drilling into the depleted Tor formation. The technology has not been used on Ula to date, but is included in the thesis as it is a relevant technology which is effective in depleted sands and lost circulation zones. A drilling liner is a non-retrievable system that combines a special polycrystalline diamond compact (PDC) bit in the end of the casing, as shown in figure 38. The PDC bit is constructed such that it is possible to drill through with a smaller bit when drilling the next section.

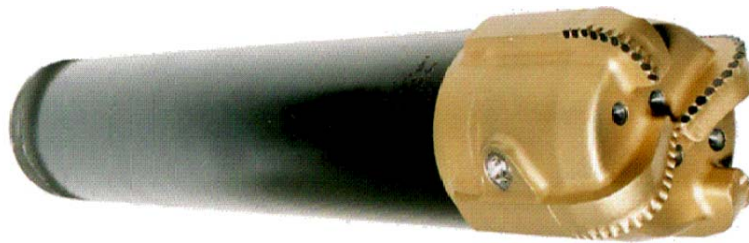


Figure 38 - Show a PDC casing bit [27].

The Drilling Liner System makes use of the liner/casing as a drill string that would normally be set at the casing point. As a drilling tool, it can be set when the string becomes stuck due to formation collapse or severe differential pressure sticking [28]. Every component of the liner system must be capable of handling the large torque and loads created during drilling operations. One of the weakest tools in the drilling liner setup is the running tool which is attached to the liner hanger at the top of the liner, as shown in figure 39.

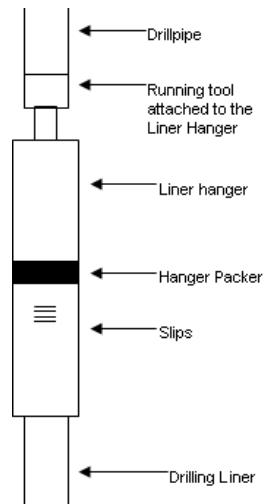


Figure 39 - Illustrates how the drilling liner is attached to the liner hanger, the running tool and the drill pipe.

Once the drilling liner is in place or becomes stuck, a ball is dropped onto the seat, and with minimal pressure, the setting tool is released. In case the primary hydraulic release mechanism fails, a mechanical back-up mechanism is activated by applying left hand torque at the tool. The same type of mechanical release mechanism is applied for conventional liners.

The drilling liner system was first developed for the Arun field offshore Indonesia. At the Arun field they struggled with a total loss of circulation as soon as they drilled through a highly pressured cap rock and into a severely depleted reservoir. By utilizing the drilling liner system, the liner would set simultaneously when drilling into the low pressure formation. Although the mud losses have not been fixed at this stage, the liner is already in place and protects the borehole. Once they had the liner in place, the running tool was released and cementing operations was conducted. After the cementing operation, the mud was changed and the drilling operation could precede using conventional drilling practices. Lessons learned from the Arun field was increased cost savings and a higher success rate drilling into the depleted reservoir.

There are several risks identified with a drilling liner system and some of them are presented below [28]:

- Surface instability
- Break-in Casing bit
- Drilling with incorrect WOB

- Incorrect connection procedures
- Losses
- Bit whirl
- Plugged nozzles
- Drill-out of PDC liner bit
- Axial vibrations

The drilling liner could be an alternative on U1a, but then most likely as part of a contingency plan. Today the problems are minor and not of an art where drilling liner technology would be considered a suitable solution. A drilling liner has been evaluated for the low pressure zone in Unit 1 if incurable losses occur drilling this section. Running a drilling liner into the high pressure zone will lead to an underground blowout, resulting in water production into the low pressure zone. Setting the liner hanger and performing a cement job with an underground blowout may result in a situation where cement is produced away from the high pressure zone to the low pressure zone (Unit 1A1-1A2). This is identified as a likely risk and is the main reason why the drilling liner has not been implemented. Running a drilling liner will also effect the directional drilling, as limitations exist regarding the drilling liners ability to build angle. This could again lead to changes in well design.

If a scenario with incurable losses occurs on U1a, the drilling liner could become part of a contingency plan. The MW would then have to be lowered until losses are stopped and then POOH and RIH with a drilling liner. MW could then be increased and drilling continued with no returns 10 meters into the high pressure zone. Setting the liner hanger and performing the cement job would then have to be performed with an underground blowout ongoing. If the cement can't stop the cross-flow, the cement will be produced away into the low pressure zone.

4.8.1 Advantages and Disadvantages

Advantages and disadvantages of applying drilling liner are presented in table 6 below.

Table 6: Advantages and disadvantages with drilling liner.

Advantages	Disadvantages
<ul style="list-style-type: none">• Liner already in place when problems arise.• A viable and economic technology in troublesome formations• Minimizes the risk of collapse	<ul style="list-style-type: none">• Slower drilling rates (Especially in hard formations)• Conventional drilling liner has limitations in directional drilling• Conventional drilling liner has limitations in the logging capabilities• Liner wear during drilling

Compared to the existing drilling liner technology, the SDL system is able to drill longer, complex 3D well trajectories with the same directional and logging capabilities as conventional drilling. The SDL system combines the advantages of rotary steerable drilling technology with the liner drilling method. The existing drilling liner technology is more applicable for shorter drilling intervals and it cannot provide steering and logging capabilities [35].

Figure 41 shows the operational procedure for the SDL system from the make-up to the release phase. The first step is to run in hole (RIH) with the liner and then RIH with the complete SDL system on drill pipe. When TD is reached, the Reamer Drive Sub is deactivated by mud pulse telemetry and a ball is dropped to hydraulically release the liner running tool, and the inner-string can now be pulled out of hole (POOH) [35].

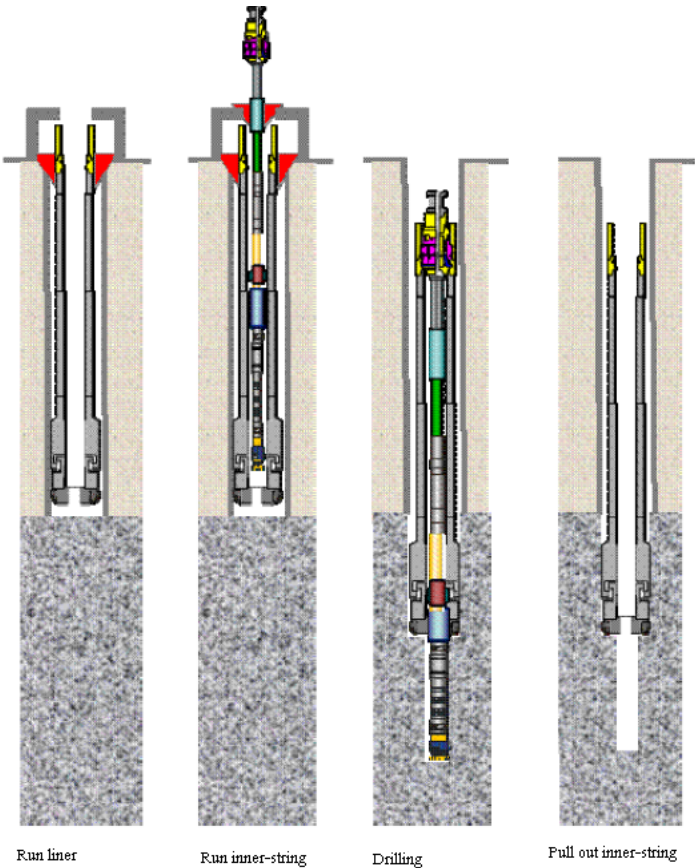


Figure 41 - Operational procedure for SDL system [35].

The steerable liner drilling technology offers several advantages compared to conventional liner drilling. The main advantage is the ability to drill long directional wellbores. In a field test conducted by Statoil they experienced the same penetration rate as for conventional drilling,

and the steerability was good. However, the release of the running tool proved problematic and was redesigned to avoid future problems [55].

On Ula the drilling liner system has only been evaluated for a shorter section in the top Ula reservoir. On Ula the conventional drilling liner would most likely represent a more cost effective alternative compared to the more expensive SDL system. However, if steering and logging capabilities are required to drill the top reservoir section on Ula, the SDL system would represent a highly viable option. Optimal use of the SDL system could potentially open the way to significant time and cost savings.

4.9.1 Advantages and Disadvantages

Advantages and disadvantages of applying steerable drilling liner are presented in table 7 below.

Table 7: Advantages and disadvantages with steerable drilling liner.

Advantages	Disadvantages
<ul style="list-style-type: none"> • Liner already in place when problems arise. Do not have to leave the borehole open and minimizes the risk of collapse. • A viable and economic technology in troublesome formations • SDL system offers directional and logging capabilities • Pilot BHA can be changed while the liner remains on bottom • Extends tool life by protecting tools during running and retrieval 	<ul style="list-style-type: none"> • Liner wear during drilling • Little field experience

4.10 Casing Drilling

Casing drilling is a technology where the wellbore is drilled and cased at the same time. The technology is delivered by Tesco and is a field proven technology. Casing drilling requires few adaptations to a standard drilling rig. The equipment changes required include a top drive and a Casing Drive System (CDS). The CDS is installed just below the top drive and supports the drilling process by its ability to circulate, rotate and reciprocate the casing string simultaneously (see fig. 42).



Figure 42 - Casing drilling has the ability to rotate and reciprocate while circulating fluid [56].

One of the positive effects of applying casing drilling is the cuttings being smeared into the wall of the wellbore, and not scraped off by bit passage or tool joint impacts. This effect is often referred to as the plastering effect. The cuttings are ground up more finely. This results in reduced cuttings at the surface and it also has a strengthening effect on the wellbore. Combining the plastering effect with industry best practices regarding LCM leads to an effective cure for LC incidents and enables continuous drilling.

Wear-resistant accessories are installed to protect the casing against excessive abrasions during drilling. Tungsten carbide coated rings are installed below the coupling to protect the connection. Wear sleeves are also installed to protect the joint from undue wear and to prevent buckling near the bottom of the drill string [56].

ConocoPhillips has actively used Casing while Drilling (CwD) in South Texas since 2001. Downhole problems associated with lost circulation and sloughing shale has been solved utilizing this technology. In 2007 ConocoPhillips applied CwD on the Eldfisk Bravo platform in the North Sea. This is believed to be the first well directionally drilled with casing using wireline retrievable bottom hole assemblies from an offshore installation. The casing sizes used to drill through the overburden were respectively 10 3/4" and 7 3/4" and the well path had inclinations up to 60°. Both casing sections were drilled successfully, however, the overall time required to drill the sections was longer than anticipated [57].

Common practice on Ula is to set the 9 5/8" casing above the reservoir to ensure a good cement job. Borehole challenges in the overburden are today not of an art which requires casing drilling. If casing drilling is applied to set the 9 5/8" casing inside Unit 1, the risk of an unsuccessful cement job is high, and must be taken into consideration if applying the technology. The surface equipment on Ula is also too old and would have to undergo extensive upgrades before casing drilling could be implemented.

4.10.1 Advantages and Disadvantages

Advantages and disadvantages with drilling liner combined with casing drilling are presented in table 8 below.

Table 8: Advantages and disadvantages with casing drilling.

Advantages	Disadvantages
<ul style="list-style-type: none"> • Change BHA without a trip • Ability to pump, rotate and work casing to bottom • Reduces lost circulation • Reduce cuttings at surface • Improved well control (Casing constantly on the bottom reduces well kicks) • Reducing NPT • Directional drilling functionality • Adequate annular velocities for hole cleaning can be achieved at lower mud rates compared with conventional drilling 	<ul style="list-style-type: none"> • Casing wear • Ula surface equipment not designed for casing drilling • Assembly more difficult to trip if problems occur • No cementing float collar, so must balance cement with displacement fluid • Potentially higher ECDs • Risk of casing getting stuck before reaching planned setting depth • Higher torque and drag compared to drillpipe, due to the size and weight of the casing

4.11 Drilling Liner Combined with Expandable Liner

The combination of drilling liner and expandable liner has not been field tested to date; however, non-expandable drilling liners combined with expandable liner hangers have been used. Eventure is a company that have seen the value in drilling liners combined with expandable liners and are looking to develop the system. Several design obstacles must be overcome before the technology is ready to be tested and today Eventure are planning to do a field test at the end of 2011.

Two main phases has to be field proven before Eventure will move over to the true development of the expandable drilling liner. The first phase for application will be to expand against or into the formation. This test has been performed with an 8” open hole clad system, to pass through 9 5/8” base casing, which once expanded will provide an 8.5” pass through diameter (see fig. 43). The next phase would be to provide a shoe extension of the previous casing, without loss of diameter. When these two phases have been field-proven, Eventure will move on to the development phase of the expandable drilling liner.

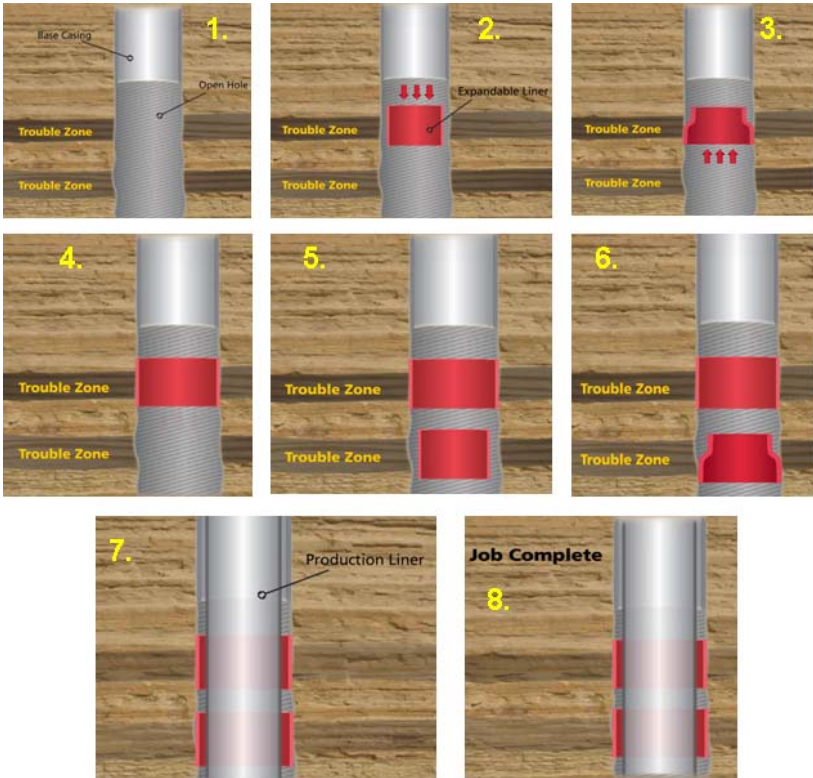


Figure 43 - Test Eventure has done based on an open-hole clad system to isolate trouble zones [50].

Figure 44 illustrates Eventures concept of combining a drilling liner with an expandable liner. The idea is to keep the liner stationary and to have a motor between the cone and the bit. The cone which expands the liner is mounted onto a mandrel, which has a pass-through ID, therefore allowing circulation through the inside of the drill string. The bit is intended to have the same OD as the cone. Alternatively, it could be a bi-centre bit, which can cut a larger diameter hole. If a bit change is required, the expandable liner along with the cone and bit would be POOH.

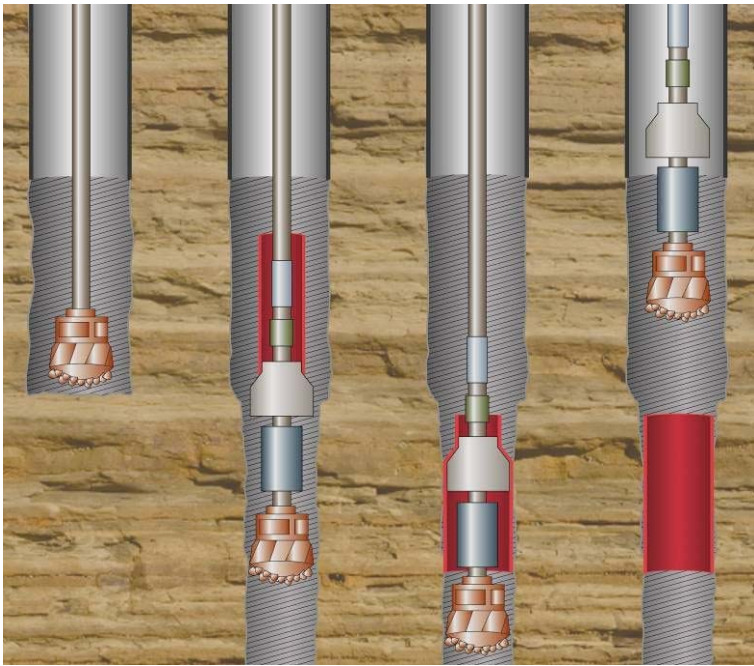


Figure 44 - Drilling liner combined with expandable liner [50].

In practice, this technology is feasible and can become useful for isolating troublesome formations or as a liner. This concept will, if successfully developed, face many of the same challenges as other expandable products. Expanding solid metal will decrease the collapse resistance per the Bauschinger effect. Baker Hughes expandable liner (LinEXX™) design has too low collapse resistance to be an acceptable technology on Ula due to production loads. Low collapse resistance could also become a problem for Eventures' expandable drilling liner. Another major challenge will be how the expanded liner will be hung off inside the parent casing. Some sort of sealing elements must provide a satisfactory seal between the parent casing and the expanded liner.

On Ula the main challenge is the low pressure formation in the top reservoir. This section therefore has to be drilled with a high overbalance, with considerable risk for losses while entering the reservoir. The conventional drilling liner technology has been considered for Ula,

however it has been found not feasible due to the risk of an underground blowout during the cementing operation. In addition to the likely risk of an unsuccessful cement operation, the expandable drilling liner adds extra risk to the operation by added complexity and lower collapse resistance.

4.11.1 Advantages and Disadvantages

Advantages and disadvantages with drilling liner combined with expandable liner are presented in table 9 below.

Table 9: Advantages and disadvantages with drilling liner combined with expandable liner.

Advantages	Disadvantages
<ul style="list-style-type: none"> • Yield and burst ratings increase from expansion • Liner already in place when entering trouble zones • Can be applied as a “open-hole clad system” to isolate trouble zones. 	<ul style="list-style-type: none"> • External damage in the form of scratches or gouges to the outer surface • Collapse rating decrease from expansion • Expandable threaded connections are relatively weak and do not support much drilling torque • Adds extra complexity to the operation

4.12 Drilling Lining

Drilling lining is a new concept which has recently been patented and has not yet been commercialized. To combat lost circulation events and isolate problem zones this could be a viable technology. Figure 45 illustrates the concept with the main components. It is a method of sealing the wall of a wellbore as it is being drilled. The sealing mechanism is a cylindrical gathered pack of flexible tubing (6) which is radially expanded by locking means (8) onto the wellbore wall. The idea is to have the first end of the tubing of the gathered pack connected to the expandable locking means. As drilling proceeds the intension is that the gathered pack will be withdrawn from the receptacle by the movement of the pipe (5), and to be turned inside out, thereby forming a liner for the second section of wellbore.

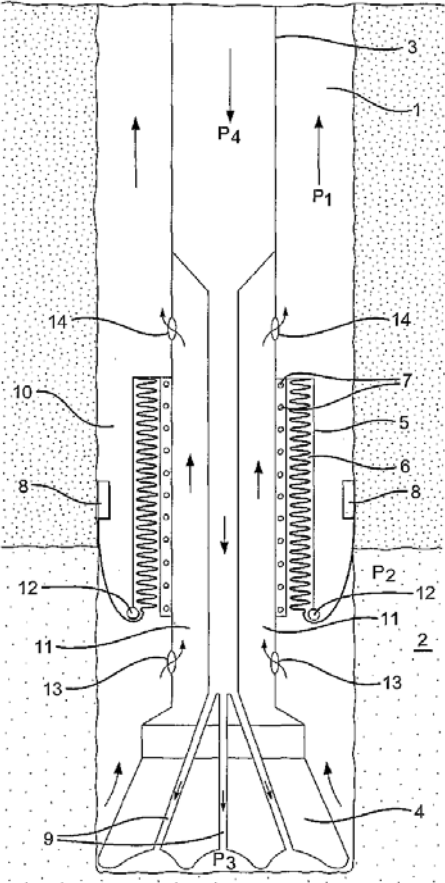


Figure 45 - Drilling lining system and the main components [36].

The primary objective for the drilling lining system is to isolate lost circulation zones. When a lost circulation zone is entered, the locking means is radially expanded against the wellbore

above the lost circulation zone, such that as the drill string moves down through the problem zone, the wellbore is lined [36].

The idea is that the flexible tubing will have a wall thickness of 0.1 to 2 mm, and the diameter of the flexible tubing should correspond to the inner diameter of the wellbore being drilled. The length of the flexible tubing should be as long as the section of wellbore that is to be drilled through the lost circulation zone. If this technology is going to be applied on Ula to seal the low pressure units 1A1 and 1A2, the flexible tubing should at least be 15 metres. In the patent description a length of 9 metres to ~1500 metres is suggested as feasible.

This technology could very well become a solution for combating lost circulation in the future; however, several design obstacles must be overcome. The expansion process and the material properties of the flexible tubing may become a difficult design obstacle. The material should be resistant to the well environment, i.e. temperature, pressure and fluids. Another challenge would be how to rotate the drill string while maintaining the receptacle stationary. If the receptacle is rotated when tubing is being locked to the wellbore wall, this could jeopardise the operation. Figure 46 illustrates the placement of the receptacle and the flow path.

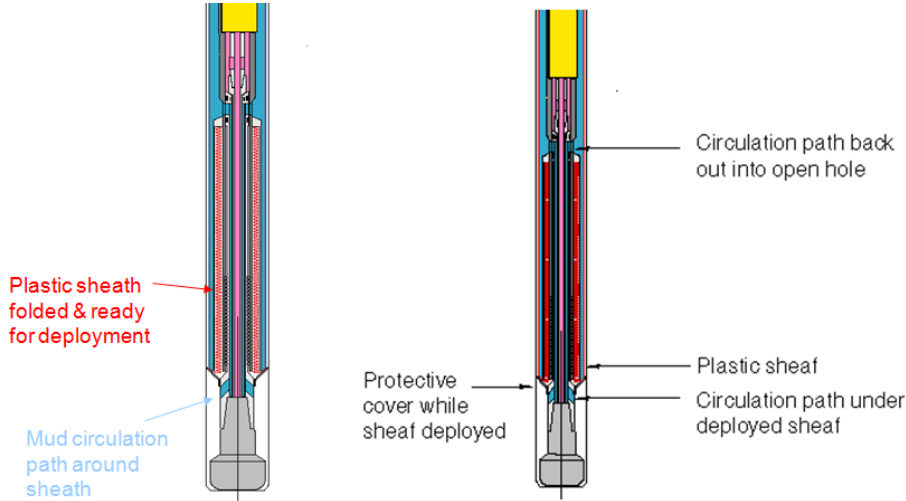


Figure 46 - Illustration of the drilling lining system [ref. 36].

The idea is to have the receptacle of the packed tubing/lining stored in the annular space formed between the inner and outer tubes, and the drill string passing through the interior of the inner tube. The inner tube of the receptacle should have some sort of roller bearing to allow the drill string to rotate whilst the receptacle remains stationary relative to the drill string. The outer tube will have some sort of guides to assist in turning the flexible tubing

inside out as it emerges from the base of the receptacle. The pressure differential across the liner will keep the liner in place. The pressure differential ΔP across the liner must be at least 100 psi, preferably, in the range 100 to 2000 psi.

The first end of the flexible tubing that is withdrawn from the receptacle is connected to the radially expandable locking means such that the tubing is locked in place in the wellbore. The radially expandable locking means can be activated either by diverting the fluid to the radially expandable locking means such that they are hydraulically expanded against the wellbore wall, or a ball may be dropped down the drill string to sit on a ring seal and thereby activating a one-way valve that is in fluid communication with the radially expandable locking means. To allow circulation of fluid and cuttings, there is a conduit having an inlet below the receptacle and an outlet above the receptacle. Alternatively the cylindrical receptacle may itself be provided with a fluid by-pass. The fluid then flows to the surface through the annulus formed about the drill string in the standard manner [36].

4.12.1 Advantages and Disadvantages

Advantages and disadvantages with the drilling lining technology are presented in table 10 below.

Table 10: Advantages and disadvantages with drilling lining.

Advantages	Disadvantages
<ul style="list-style-type: none"> • Isolate trouble zones (e.g. thief zones) • Flexible tubing already in place when problems arise 	<ul style="list-style-type: none"> • Drilling length restriction in conjunction with the flexible tubing • Not field tested • Relatively complex technology

5 Specialized Lost Circulation Treatments

When losses have occurred and conventional LC treatments have failed, good contingency treatments must be available. Specialized treatments include, among other treatments, cross-linking pills and gunk squeezes. The recommended LC treatments should always include conventional LCM pills and treatments. In the next sections some of the specialized treatments are evaluated. These specialized treatments are:

- Thermatek RSP service fluid
- FlexPlug
- InstantSeal

5.1 Thermatek RSP service fluid from Halliburton

Gunk squeeze is an operation where a Gunk plug is squeezed into a lost circulation zone. A Gunk plug normally consists of bentonite, cement or polymers mixed with base oil (bentonite in diesel oil is common). When mixed downhole the material gets stiff and sticky. Halliburton has developed a fluid called Thermatek RSP to tackle the most severe lost circulation problems, where losses are encountered under static conditions. Thermatek RSP is a rigid setting fluid which remains at a low-viscosity during placement and sets by a given formation temperature. The fluid formulation is split into two distinct phases – active and reactive:

1. The active part is pumped through the drilling BHA.
2. The reactive part is water-based and pumped downhole via the drill string/casing annulus.

The two fluids meet below the drilling BHA where they mix. By pumping the two fluids separated from one another there is no possibility of premature set in or around the drilling BHA. Within 30-60 seconds of mixing a “gunking” reaction takes place below the BHA. After the gunk is formed, it is bullheaded to the loss zone where it bridges off in and around the fracture(s). The temperature is the activation mechanism for building compressive strength in the gunk. Temperature activation is achieved through an exothermic reaction from the fluid chemistry and the heat transfer from the downhole formation. Within 30-40 minutes after initial set process normal drilling operation can proceed [37]. Figure 47 illustrates the Thermatek RSP fluid being pumped into a lost circulation zone.

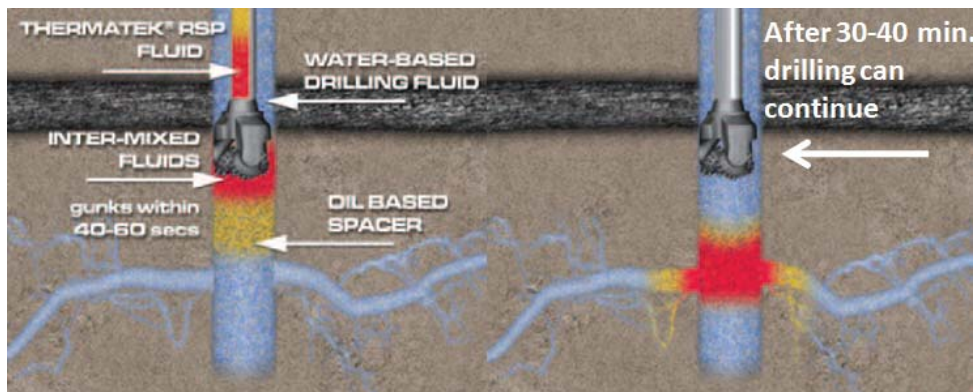


Figure 47 - Illustrate the Thermatek RSP fluid being pumped to a lost circulation zone. After 30-40 minutes normal drilling operation can continue [Modified from Halliburton, ref 37].

Thermatek RSP fluid is intended to help control total loss situations. Today total loss of circulation is not a common scenario on Ula, and the fluid is not part of any contingency plan. Today the reservoir on Ula is drilled utilizing OBM. Thermatek RSP fluid is for use with water-based drilling fluids and is therefore not a suitable lost circulation fluid for the Ula reservoir. Today drilling operations on Ula are successful in drilling with designed LCM in the mud. Thermatek RSP fluid is intended for severe lost circulation incidents; today this is not the case on Ula.

5.1.1 Advantages and Disadvantages

Advantages and disadvantages of applying gunk squeeze are presented in table 11 below.

Table 11: Advantages and disadvantages with gunk squeeze.

Advantages	Disadvantages
<ul style="list-style-type: none"> • Effective in combating severe lost circulation • Treatment does not depend on formation permeability to form the seal • Ideal for very high or very low ambient temperature locations • Premature setting avoided since mixing occurs below the bit • Cost effective. Drilling operations can often recommence within 2 to 3 hr of mixing • Acid soluble 	<ul style="list-style-type: none"> • Can be inaccurately placed and result in poor penetration of the sealing fluid into the fractured formation • If total loss occurs and there is no time to record temperature measurements, the bottomhole temperature must be estimated. Inaccurate estimates may lead to over-retardation, pill contamination, or premature setting. • Material may not reach intended treatment area if limited by another weak formation • Gunk squeezes have been unsuccessful in many instances • Sealing limitations in very large leak-off flow paths into the formation • For use with water-based drilling fluids only

5.2 FlexPlug from Halliburton

FlexPlug is a fluid developed for combating lost circulation. Figure 48 illustrates the FlexPlug being pumped into a lost circulation zone. It is a quick solution for stopping lost circulation in natural or induced fractures, vugs, channels in weak zones, or flowing over-pressured zones.

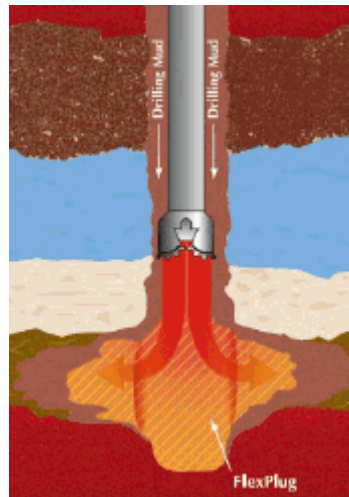


Figure 48 - FlexPlug being pumped into a lost circulation zone [Modified from Halliburton, ref. 38].

The FlexPlug fluid has effectively cured several lost circulation problems and saved the operators from abandoning or sidetracking the well. Different FlexPlug systems exist based on a wide range of downhole conditions. The three main types are [38]:

- FlexPlug W Service is an oil-based system which reacts with water-based drilling/completion fluids or formation waters. Can be formulated with diesel, kerosene, mineral oils, synthetic oils and esters. Cement can be added for additional strength.
- FlexPlug OBM Service is a water-based system that reacts downhole when mixed with oil-based drilling fluids.
- FlexPlug R Service is a water-based system that reacts downhole when mixed with a water-based activator fluid. This system is recommended when a highly flexible sealing material is required or when dry gas cross flows are encountered.

FlexPlug OBM is the most relevant plug for Ula. It is a non-particulate lost circulation material, specifically designed for use with non-aqueous oil-based drilling muds. When mixed with drilling mud it reacts to create a barrier at the face of the lost circulation zone. Temperature working range goes up to 213 °C, making it suitable for Ula. The minimum treatment volume is 10 bbl or the entire volume of the open hole interval losing returns. Because of the reactive nature of the FlexPlug OBM, it is recommended to have 1,500 ft of spacer ahead of the treatment and at least 1,000 feet behind. One of the main benefits by applying FlexPlug OBM is that it only minimally penetrates the formation, hence resulting in less formation damage in productive zones [52].

5.2.1 Advantages and Disadvantages

Advantages and disadvantages of using FlexPlug are presented in table 12 below.

Table 12: Advantages and disadvantages of using FlexPlug.

Advantages	Disadvantages
<ul style="list-style-type: none"> • Effective in a wide range of drilling and formation fluids • Can be pumped through BHAs • Reduces or eliminates trip time • Can control cross-flows and underground blowouts • Can increase integrity in formation, hence allowing a heavier mud weight • Can seal multiple weak zones in a single treatment • When set it remains flexible to withstand surge and swab pressures • Is acid soluble and can be removed from the wellbore when desired 	<ul style="list-style-type: none"> • FlexPlug OBM material should not be used in wellbores that have been severely washed out. Usually such wellbore will not provide adequate surfaces for the FlexPlug OBM material to bridge against

5.3 InstantSeal from Schlumberger

InstantSeal is a pill developed by Schlumberger to cure lost circulation problems. It is a single fluid that generates a high-viscosity gel downhole when it is sheared through the bit nozzles (see fig. 49). InstantSeal is pumped through the BHA in front of the loss zone. When the gel has set it can be stable for several weeks under downhole conditions. This gives the operator enough time to drill the section and complete it [39].

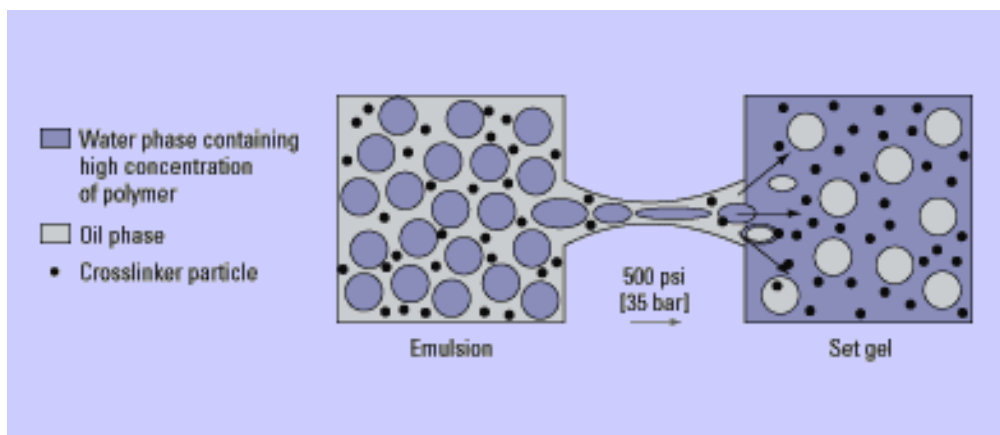


Figure 49 - InstantSeal pill sets when shear causes inversion of an emulsion, wetting a polymer which forms a rigid gel [39].

The fluid can be pumped through the existing BHA and rig time associated with tripping or mixing LCM is eliminated. The high pressure drop across the bit nozzles activates the fluid initiating the gelling process. When the fluid gels it produces a barrier between the thief zone and the wellbore.

Before the fluid is activated it exists as an invert emulsion (water-in-oil). The oil phase encapsulates a cross-linker and the water phase encapsulates a polymer (see fig. 49). This water-in-oil emulsion is maintained by adding a low concentration of surfactant or emulsifier. The surfactant develops a curvature around the water droplets, to prevent the cross-linker from crossing into the water phase. A pressure drop greater than 400 psi will trigger a rupture in the interfacial membrane and cause the emulsion to flip to a more stable oil-in-water state. The cross-linker is now released into the continuous phase of the water, which again initiates the reaction that creates the highly viscous gel structure. The gel setting time can be controlled by adjusting the emulsifier concentration, as shown in figure 50.

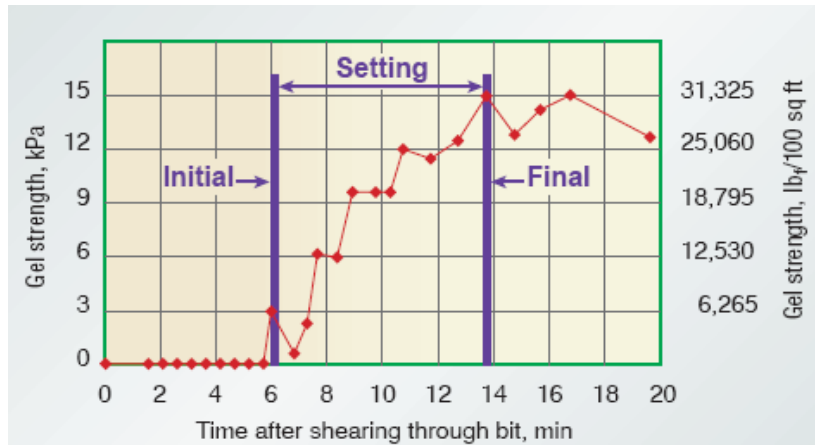


Figure 50 - Showing the shear sensitivity. The gel setting time can be controlled by adjusting the emulsifier concentration [40].

InstantSeal is most effective when it is placed across short intervals of 20-30 ft. For the driller it is important to be aware that for the gel to set, all pumps must be shut down. Dilution of the fluid is a common concern. To avoid dilution weighting agents can be added to the emulsion to make it heavier than the displaced drilling fluid.

The working temperature range is the limiting factor for InstantSeal. The temperature at top Ula reservoir is close to 130 °C, and InstantSeal is not applicable in bottomhole temperatures above 88 °C. InstantSeal will therefore be a more realistic alternative in the overburden, where temperatures are lower. The FlexPlug OBM is a plug that satisfies the reservoir temperature on Ula with a working temperature working range up to 213 °C and is thus a better solution. In the Cranberry field in Canada, wells have been drilled where LCM pills were unsuccessful in curing losses. When applying InstantSeal the circulation was re-established and normal drilling operation could proceed [40]. On Ula the main limiting factor for applying InstantSeal is the temperature.

5.3.1 Advantages and Disadvantages

Advantages and disadvantages of using InstantSeal are presented in table 13 below.

Table 13: Advantages and disadvantages with InstantSeal.

Advantages	Disadvantages
<ul style="list-style-type: none">• Can be pumped through existing BHA• Fluid activated by pressure drop across the drill bit• Well-suited to most worldwide drilling locations• Compatible with all mud types and weighting agents• Can be prepared weeks in advance without deterioration	<ul style="list-style-type: none">• Most effective in short intervals• Not applicable in wells where bottomhole temperature exceed 88 °C (Addition of cement can increase this range)

6 Discussion

The following sections contain the ranking evaluation comparison of the different options.

6.1 Ranking the Different Options

The different options in this thesis represent the main drilling techniques. Some of the options have not been developed to date, and will therefore be evaluated based on the available data. To be able to evaluate which technology would be the most optimum solution for Ula, they are ranked with numerical values. The different options have been ranked based on the following criteria:

- Ability to drill safely through a depleted reservoir section and preventing LC and stuck pipe
- The cost of the implementation
- The ability to provide an acceptable integrity and the feasibility of the technology
- Operational complexity
- Wellbore stability and formation damage
- The ability to be included as a contingency option

The chosen criteria have varying importance in terms of their effect on drilling operations, and will be weighted differently. The following weighting is used in the ranking:

- | | |
|----------------------------|------|
| 1. Drilling depleted zones | = 10 |
| 2. Cost | = 9 |
| 3. Feasibility | = 8 |
| 4. Operational complexity | = 7 |
| 5. Borehole condition | = 6 |
| 6. Contingency | = 3 |

The main topic of this thesis is depleted reservoir drilling, so the ability to drill past a depleted zone is therefore weighted highest with a value of 10. The cost of the implementation is also very important. If the technology is too expensive, other technologies having a higher

price/performance ratio will be chosen. This criterion is therefore weighted with a value of 9. The feasibility of the technology has been ranked based on today's status of the technology and is given a value of 8. Operational complexity is important as well. If the technology is very complex and has no or limited track record, the chance of failures and increase in NPT is higher. This criterion is given the value 7. Technology's ability to provide stable wellbores and as little formation damage as possible is important for a successful operation and subsequent production, and is therefore weighted with a value of 6. The technology's ability to be included as a contingency option is weighted with a value of 3.

Ranking values (RV) of the different options used in table 14 are:

- Not applicable =0 (Red colour)
- Very bad =0 < - < 2 (Red colour)
- Bad =2 ≤ - < 4 (Red colour)
- Average =4 ≤ - < 6 (Yellow colour)
- Good =6 ≤ - < 8 (Green colour)
- Very Good =8 ≤ - ≤ 10 (Green colour)

Table 14: Show the ranking of the different options. Every option has been given a ranking value (RV), which is multiplied with the weighting value. The total is found by summation.

Potential Options	Drilling		Cost		Feasibility		Operational complexity		Wellbore stability and skin damage		Contingency		TOTAL
	[RV]	[RV] x10	[RV]	[RV] x9	[RV]	[RV] x8	[RV]	[RV] x7	[RV]	[RV] x6	[RV]	[RV] x3	
Conventional Drilling system	8	80	6	54	10	80	9	63	6	36	8	24	337
Drilling Liner	7	70	9	81	5	40	7	49	5	30	6	18	288
Steerable Drilling Liner	9	90	5	45	5	40	5	35	5	30	5	15	255

MPD	9	90	3	27	5	40	4	35	6	36	2	6	234
UBD	8	80	3	27	4	32	3	21	8	48	2	6	214
Casing Drilling	8	80	4	36	4	32	4	28	5	30	2	6	212
Drilling Lining	6	60	4	36	4	32	4	28	5	30	4	12	198
Drilling Liner combined with Expandable Liner	6	60	4	36	2	16	3	21	5	30	2	6	169

A detailed argumentation of the specific ranking values has been given in table A1 in Appendix A.

6.2 Results from Evaluating the Ranking Values

Conventional Drilling System

Based on the ranking, the best option would be a conventional drilling system. The rotary steerable drilling system (AutoTrack-G3), combined with specially designed mud maintaining the right concentration of LC-lube and CaCO_3 gives the highest rating as of today. Field experience on Ula confirms that losses can be cured effectively with LCM. This option scores relatively high on each criterion. It is field proven and “safe technology”. However, if the pressure decline continues in the upper Ula reservoir, there is a chance that we might reach an upper limit for the overbalance in this section. If we end up in a situation where the upper reservoir section cannot be drilled in the same hole section, other alternatives will have to be considered.

Drilling Liner

Ranked 2nd. This option represents a well tested drilling option which can effectively drill through severe loss zones. It is not designed to drill long intervals, so if applied on Ula it would be applied to drill past the short low pressure zone. The lack of directional drilling capabilities is one of the main disadvantages with this technology and may lead to changes in proposed well design if implemented on Ula. This technology has low cost and could lower cost even further by eliminating extra tripping time. On Ula this technology is more relevant as a contingency option rather than a primary one. The main concern regarding this technology is the high likelihood of an underground blowout.

Steerable Drilling Liner

Ranked 3rd. Compared to the conventional drilling liner, this technology comes with higher expense. However, it represent the same drilling capabilities as the rotary steerable system (Autotrack-G3) including the ability to have a liner attached. This technology can potentially save costs by eliminating tripping time and reduce borehole problems.

Managed Pressure Drilling

Ranked 4th. The main disadvantage regarding this option is the high cost of the technology and the large deck space required. Several modifications to the Ula platform drilling system will also increase the cost. The technology represents several advantages with respect to downhole pressure control and enhancement of the well integrity during drilling. This technology is more viable in wells with multiple pressure zones.

Underbalanced Drilling

Ranked 5th. This technology represents many of the same advantages as MPD. The main difference being that UBD is performed with a lower borehole pressure, hence stimulating production of formation fluids during drilling. As for MPD this technology represents high costs and would require large deck space. The surface system would have to be upgraded to accommodate the produced fluids during drilling. Drilling underbalanced will also increase the overall risk with respect to well control.

Casing Drilling

Ranked 6th. This technology is very similar to the steerable drilling liner system and has many of the same advantages. Since the drilling process is conducted with heavier pipes, this technology requires surface equipment capable of handling high loads. Casing drilling is still a relatively new offshore technology and more field tests should be conducted before possible implementation on U1a. Since the common procedure on U1a is to set the 9 5/8" casing above the reservoir, the steerable drilling liner system would represent a more realistic option for drilling into the reservoir.

Drilling Lining

Ranked 7th. The main reason for this ranking is the conceptual nature of the drilling lining technology. The technology looks promising and has potential to become an effective solution for isolating the low pressure zone while drilling.

Drilling Liner combined with Expandable Liner

Ranked 8th. The reason for this ranking is the conceptual nature of the technology. The technology would be similar to the conventional drilling liner except for the ability to expand the liner. The expansion represents extra complexity to the drilling operation and would be one of the main risks with this technology.

6.3 Evaluation of the Specialized Lost Circulation Treatments

If LCM treatment is unsuccessful in curing the losses on Ula, specialized lost circulation fluid could be injected to stop the losses. The usage of specialized LC treatments seems to be feasible with all the discussed technologies. The three contingency specialized treatments evaluated in this thesis have been ranked based on their working window with respect to the Ula reservoir. The treatments have been ranked as follows:

1. FlexPlug from Halliburton
2. InstantSeal from Schlumberger
3. Thermatek RSP service fluid from Halliburton

FlexPlug from Halliburton

The FlexPlug OBM fluid has properties which makes it applicable for Ula. The downhole temperature on Ula is not a problem as the working temperature for this fluid is up to 213 °C. It is specifically designed for use with OBM and the fluid can be pumped through the BHA.

InstantSeal from Schlumberger

The main disadvantage with the InstantSeal is the working temperature with an upper limit of 88 °C. This can be increased by adding cement; however, it will still be too low to meet the reservoir pressure on Ula.

Thermatek RSP from Halliburton

The main reason for ranking this fluid last is because Thermatek RSP fluid is designed for use with water-based drilling fluids. The reservoir on Ula is drilled with OBM and Thermatek RSP is therefore not applicable on Ula.

7 Conclusion and Recommendation

Conclusion;

- The best drilling option for the depleted zone in the Ula reservoir is today's well established procedure of having a rotary steerable BHA combined with a pre-treated mud. If losses occur they are treated with LCM. This option offers a high cost-performance ratio and is capable of successfully drilling the depleted section.
- FlexPlug from Halliburton was found to be the best specialized lost circulation fluid for Ula.
- The LOT evaluation showed a large variation between predicted and measured LOT values, thus emphasising the need of real field data.
- The stress cage technique is highly effective in strengthening the formation and increasing the fracture gradient in permeable formations.

Recommendation;

- Maintain today's drilling method of conventional drilling with designed LCM in the drilling mud.
- Keep remediation materials (LCM) on site for immediate application, should wellbore breathing and loss of circulation occur. The LCM material should preferably have a wide particle distribution. Consider having a specialized lost circulation fluid available, should the safe drilling window become smaller in the future.
- Always perform pre-treatment of drilling mud (LCM mixed in the whole drilling fluid system).
- If a higher pressure differential is expected in future wells, materials with a higher compressive strength should be considered (e.g. quartz).
- Conduct more precise pressure tests to verify real pore pressures in permeable reservoir layers and also extended leak-off tests to obtain more reliable fracture gradient data.
- It is also recommended to collect as much LC data as possible for calibration of models.

8 Abbreviations

AFP	Annulus Friction Pressure
Bbls	Barrels
BHP	Bottom Hole Pressure
BP	“British Petroleum”
CBHP	Constant Bottomhole Pressure
CDS	Casing Drive System
CwD	Casing while Drilling
ECD	Equivalent Circulating Density
FCS	Fracture Closure Stress
FG	Fracture Gradient
FIT	Formation Integrity Test
HWDP	Heavy Weight Drill Pipe
ISIP	Instantaneous Shut-in pressure
km	kilometre
LCM	Lost Circulation Material
LOT	Leak Off Test
LWD	Logging While Drilling
mbd	Thousand Barrels per day
MPD	Managed Pressure Drilling
NAF	Non-Aqueous Fluid
NPT	None Productive Time
OD	Outer Diameter

OWC	Oil Water Contact
PDC	Polycrystalline Diamond Compact
PP	Pore Pressure
RSP	Rapid Set Plug
PI	Production Index
POOH	Pulled out of Hole
PMCD	Pressurized Mud Cap Drilling
ppg	pounds per gallon
PSD	Particle Size Distribution
RCD	Rotating Control Device
RIH	Run In Hole
ROP	Rate of Penetration
SE	South East
SG	Specific Gravity
TVD	True Vertical Depth
TOB	Torque on Bit
UBD	Under Balance Drilling
WAG	Water Alternating Gas
WMB	Water Based Mud
WOB	Weight on Bit

9 Nomenclature

9.1 English symbols

S_h	lateral total stress
p_w	well pressure
C_0	uniaxial compressive strength
C	scaling factor
K	scaling factor
a	factor
T_0	tensile strength
E	elastic modulus
$p_{w,max}^{frac}$	maximum well pressure, fracture initiation
p_{wf}	fracture initiation pressure
ΔP_{fg}	change in fracture gradient
p_o	pore pressure
ΔP_p	change in reservoir pressure
ΔT	temperature change from initial condition, °C
T_{init}	virgin in-situ temperature, °C
κ	coefficient of linear thermal expansion (°C ⁻¹)
g	acceleration due to gravity
D	vertical depth
K_{fr}	bulk modulus of rock framework
K_s	bulk modulus of solids
R_w	borehole radius

9.2 Greek Symbols

σ_H, σ_h	maximum and minimum horizontal in-situ stress, N/m ²
σ_r	radial stress
σ_V	vertical stress
σ_θ	tangential stress
σ_z	overburden stress
σ'_θ	effective tangential stress
σ'_r	effective radial stress
σ'_V	effective vertical stress
σ'_h	effective horizontal stress
σ_x, σ_y	normal stress on borehole
τ	shear stress
σ'	effective stress
α	Biot coefficient
ν	Poisson's ratio
β	failure angle

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4. Tor Jan Tjøstheim
5. Irene Brekne

Appendix A

Argumentation of the different ranking values of each option in section 6.1

Table A1: Show the argumentation of ranking the different options.

Options	Argumentation of the ranking
Conventional Drilling System	
Drilling	Very good; the preferred option today. Has the potential of drilling through the depleted section with an overbalance above 4000 psi, provided an effective mud design.
Cost	Good; the Baker Hughes AutoTrack system is cost effective compared to other drilling technologies.
Feasibility	Very Good; reliable and familiar technology.
Operational complexity	Very Good; not complex technology to operate offshore.
Wellbore stability Skin damage	Good; overbalanced drilling will always result in skin damage. Proper mud design will effectively create a mud cake sealing the wellbore fluids from the pay zone. Mud design on U1a is intended to rapidly create an effective mud cake.
Contingency	Very Good; well established contingency plans exist for conventional drilling. If losses occur on U1a, specially designed LCM pills will be pumped to cure losses.
Summary	Combining conventional drilling systems with pre-treated mud is today the preferred way of drilling into the U1a reservoir. The mud and the drilling practice on U1a create an effective mud cake which is capable of withstanding an overbalance above 3000 psi. Today this drilling practice is sufficient to drill through the low pressure zone and then safely isolate the zone with a cemented 7" liner.

Drilling Liner	
Drilling	Good; can effectively drill through a depleted section.
Cost	Very Good; cost effective technology. A conventional liner has no directional drilling tools. Save time spent on tripping since the liner is already in place.

Feasibility	Average; the technology could be implemented. However, high risk of an underground blowout and a subsequent unsuccessful cement job are risks that need to be considered.
Operational complexity	Good; not a complex technology. Have been used for many years on the Valhall field.
Wellbore stability Skin damage	Average; if applied on U1a and drilled into the high pressure zone with no returns considerable skin damage will occur in the pay zone.
Contingency	Average; can be applied if incurable losses occur on U1a, however, the chance of having an underground blowout and subsequent consequences must be taken into consideration.
Summary	Conventional drilling liner could be part of a contingency plan for the future U1a wells. The technology is relatively inexpensive compared to other technologies and can be an alternative if incurable losses occur. The main disadvantage with this technology is the lack of directional steering capabilities and the risk of an underground blowout.

Steerable Drilling Liner	
Drilling	Very Good; has the same directional and logging capabilities as conventional drilling in addition to having the liner attached.
Cost	Average; when commercialized it will most likely be a more expensive technology than the conventional drilling system. Though the initial cost may be higher, the technology has the potential of lowering costs by eliminating time spent on tripping. Surface equipment on U1a would have to be upgraded to handle higher loads.
Feasibility	Average; the technology could be implemented on U1a when commercialized. As for the conventional drilling liner the risk of an underground blowout still exist.
Operational complexity	Average; more complex technology than the conventional drilling liner. Statoil have had some problems with the running tool.
Wellbore stability Skin damage	Average; if applied on U1a and to drill into the high pressure zone with no returns, considerable skin damage will occur in the pay zone. Wellbore is supported by the liner and in case of hole collapse the liner is already in place.

Contingency	Average; can be applied if incurable losses occur on Ula. Most likely the technology would be implemented as part of the main drilling plan and not as a contingency option.
Summary	The technology looks promising based on the field tests conducted by Statoil and Baker Hughes. Drilling from the 9 5/8" casing shoe and into the reservoir with the same drilling capabilities as today and at the same time having the liner attached, can potential cut costs by eliminating tripping time. Combined with special additives in the mud design, this could be a viable alternative on Ula. While the conventional drilling liner is designed only to drill a short interval, the steerable drilling liner can drill with the same functionality as a conventional rotary steerable drilling system.

MPD	
Drilling	Very Good; can drill through depleted zones. The technology is effective in managing wells with a rapidly-changing pore pressure regime. Pressurized Mud Cap Drilling (PMCD) MPD is probably the method which is most relevant for Ula.
Cost	Bad; very expensive technology and requires a large deck space. Upgrades on the surface equipment on the Ula platform is required.
Feasibility	Average; the technology can be included on Ula. Expensive and space consuming modifications must be conducted. Increase the integrity by providing a closed to the atmosphere drilling system and more precise downhole pressure control.
Operational complexity	Average; more complex technology than the conventional drilling technology. Requires highly skilled drillers that know how to operate the system in depth.
Wellbore stability Skin damage	Good; the technology is aiming to drill with the lowest drilling fluid weight possible and hence limiting the skin damage. More precise and adjustable downhole pressures increase the chance of a stable wellbore.
Contingency	Bad; To complex and costly technology to be included in a contingency plan.
Summary	The difference in pore pressure between the low pressure and high pressure zone in the Ula reservoir is today controllable with conventional drilling technology. The MPD systems are tot costly and the pressure regime on Ula is not of an art that requires this advanced drilling technology.

UBD	
Drilling	Very Good; can drill through depleted zones and increase the ROP due to the low mud weight.
Cost	Bad; expensive technology. Surface separation equipment must be made available.
Feasibility	Average; the technology can be included on U1a with necessary surface equipment upgrades. Complicated process that increases the overall production risk. Wells that will benefit from UBD are typically experiencing high loss circulation and major formation damage during drilling or completion.
Operational complexity	Bad; Drilling underbalanced requires highly skilled drillers and a closed system as formation fluids are invading the wellbore during drilling. Considerable precautions need to be.
Wellbore stability Skin damage	Very Good; UBD drilling is believed to have a strengthening effect in the near wellbore area. UBD stimulates production of formation fluids, therefore preventing severe skin damage.
Contingency	Bad; complex and costly technology to be included in a contingency plan.
Summary	At the present situation on U1a, UBD is not a technology which will result in any major benefits. Today losses are effectively cured by LCM and the formation damage is not critical. The technology is expensive and would also require specially trained drilling crews.

Casing Drilling	
Drilling	Very Good; can drill through depleted zones and have many of the same functions as the steerable drilling liner.
Cost	Average; relatively expensive technology compared to the conventional drilling system. Cost can be lowered by a reduction in tripping time.
Feasibility	Average; the technology could be introduced on U1a. The surface equipment on U1a must be upgraded to handle the increase in weight associated with this drilling technology. The top drive system must be able to handle higher torque and drag.
Operational complexity	Average; more complex drilling system than a conventional drilling system.

Wellbore stability Skin damage	Average; the casing will support the wellbore wall and the plastering effect will support in strengthening the wellbore.
Contingency	Bad; too complex and costly technology to be included in a contingency plan.
Summary	Relatively new technology offshore. Still some design obstacles that need to be overcome before it is considered "safe" for implementation. On Ula the technology could be used to drill and set the 9 5/8" casing inside the reservoir and eliminate time spent on tripping. The risk of an underground blowout still exists and must be taken into consideration.

Drilling Lining	
Drilling	Good; the main intention of this technology is to drill past problem zones and isolate the zones with flexible tubing.
Cost	Average; the technology has not yet been developed. It is reasonable to assume that this technology will be relatively costly compared to a conventional drilling system.
Feasibility	Average; the technology, if developed, could become an effective way of isolating the low pressure section on Ula.
Operational complexity	Average; more complex drilling system than a conventional drilling system.
Wellbore stability Skin damage	Average; the flexible tubing can increase wellbore stability by supporting unstable sections. Skin damage will most likely be relatively high as parts of the pay zone are drilled with a high overbalance.
Contingency	Average; could be part of a contingency plan if losses on Ula is incurable.
Summary	The drilling lining system has not been developed yet, however, the idea and intention of the technology looks promising. The low pressure zone on Ula could be drilled and isolated at the same time with the flexible tubing. What could become a challenge is the pressure differential across the depleted zone and if the flexible tubing will be able to withstand the pressure differential. If the flexible tubing collapses, losses will occur in the low pressure zone and further drilling comes to a halt.

Expandable Liner	
Drilling	Average; would provide many of the same capabilities as a conventional drilling liner, except for the expandable option.
Cost	Average; would not cost significantly more than the conventional drilling system used today.
Feasibility	Bad; would not necessarily provide the required integrity due to the expansion and decrease in collapse resistance.
Operational complexity	Bad; the expansion would make the operation more complex and time consuming compared to running a conventional drilling liner.
Wellbore stability Skin damage	Average; drilling liner would seal off troublesome formations and the “plastering effect” seen in casing drilling would strengthen the formation.
Contingency	Bad; risk of underground blowout during cementing operation and more complex than a conventional drilling liner.
Summary	Combining expandable liner with the drilling liner would not be an optimal solution on Ula because of the potential for an underground blowout during cementing, and lack of directional drilling capabilities. Lower collapse resistance than conventional liner could lead to integrity issues. The technology has not been developed yet.